

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

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PART 3

RULES REGULATING ELECTRIC UTILITIES

3628. – 3629. [Reserved].

WILDFIRE MITIGATION AND PUBLIC SAFETY POWER SHUTOFF PLANNING AND PROCEDURES

3630. Applicability.

- (a) Rules 3630 through 3644 apply to all investor-owned jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority.
- (b) These rules do not apply to cooperative electric associations or municipally owned electric utilities in the state of Colorado.
 - (I) The Commission encourages cooperative electric associations and municipally owned utilities to develop and publicly post wildfire mitigation plans (WFP) and annual WMP update reports that use the same terminology and meet the same requirements, as those adopted in rules 3632 through 3637, as appropriate.
 - (II) The Commission also encourages all such utilities that deploy proactive de-energization as a wildfire mitigation tool to adopt the public safety power shutoff (PSPS) nomenclature and procedures set forth in rules 3631, 3638, and 3641 to promote the safety and understanding of all Colorado residents. Utilities are also encouraged to engage in outreach and education to ensure understanding of and resilience during PSPS events.

3631. Definitions.

The following definitions apply to rules 3630 through 3644. In the event of a conflict between these definitions and a statutory definition, the statutory definition must apply.

- (a) "Access and functional needs population" or "AFN population" means a population who may require additional assistance to prepare for, respond to, and recover from a PSPS event or wildfire-related emergency, including individuals

with disabilities; older adults; or individuals with limited mobility, medical dependencies, limited English proficiency, or persons with other access or functional needs. AFN populations include medical baseline customers.

- (b) “Area of Concern” means areas considered for a potential PSPS event.
- (c) “Community-based organization” refers to a nonprofit, grassroots organization that operates locally to address specific needs, improve resident well-being, and advocate for community interest.
- (d) “Consequence attribute” means a measurable category of harm or loss resulting from wildfire, including safety, reliability, and financial consequences. Measures of consequence attributes include numbers of deaths or injuries, acres burned, structures damaged or destroyed, customer minutes of interruption, financial losses, and other stated units.
- (e) “Critical facility” or “critical infrastructure” means a facility essential to public health and safety that may require additional planning, notice or assistance to maintain operations during de-energization events. Such facilities and infrastructure include the following industry sectors:
 - (I) Notification Tier 1 Critical Facility (facilities receiving notification 72-48 hours before a PSPS event):
 - (A) interconnected utilities that may be impacted by the PSPS event (e.g., cooperative electric associations or municipally owned electric facilities);
 - (B) water and wastewater (e.g., water treatment facilities and wastewater processing facilities); and
 - (C) communications (e.g., wireless and wireline telecommunications facilities and central offices).
 - (II) Notification Tier 2 Critical Facility (facilities receiving notification 48-24 hours before a PSPS event):
 - (A) emergency services (e.g., police stations, fire stations);
 - (B) government facilities (e.g., schools, jails, and prisons);
 - (C) healthcare and public health (e.g., public health departments and medical facilities such as hospitals);

- (D) chemical industry (e.g., facilities associated with the provision of manufacturing, maintaining, or distribution of hazardous materials or chemicals)
 - (E) public safety answering points for 9-1-1 services;
 - (F) transportation;
 - (G) food and agriculture; and
 - (H) military bases and military facilities.
- (f) “First responder/emergency responder” means those individuals or entities who, in the beginning stages of an incident, are responsible for the protection and preservation of life, property, evidence, and the environment, including emergency response providers.
- (g) “Frequently de-energized circuits” means any circuits that experience three or more de-energizations in a calendar year due to PSPS or Enhanced Performance Protection Settings (EPPS).
- (h) “High Fire Risk Area” or “HFRA” means a geographic area that a utility identifies through its quantitative wildfire risk assessment as having high wildfire risk, independent of whether utility equipment is present.
- (i) “Medical baseline customer” means a customer who is certified and enrolled in a Commission-approved utility program regarding dependency on electricity for medical or mobility needs.
- (j) “PSPS event” means the time period from the first notification to a public safety partner of a PSPS through re-energization of all those affected.
- (k) “Public safety partner” means first responders/emergency responders at the federal, state, and local level, and entities or individuals with community health or safety responsibilities during a PSPS event, including state and local offices of emergency management (OEMs) and local, regional, and tribal governments; interconnecting electric utilities transmission providers, and communications providers.
- (l) “Public Safety Power Shutoff” or “PSPS” means the proactive de-energization of electrical facilities to reduce wildfire ignition during periods of elevated wildfire risk.
- (m) “Quantitative Wildfire Risk Assessment” or “QWRA” means the probabilistic analytical framework used to estimate utility-attributable wildfire risk, including ignition likelihood, fire spread potential, and associated wildfire consequences.

- (n) “Qualitative target” means specific, measurable, achievable, realistic and timely outcome for the overall WMP strategy, or mitigation initiatives that a utility can implement to satisfy the primary goals of the WMP.
- (o) “Quantitative target” means forward-looking, quantifiable measurement of work to which an electrical corporation commits to in its WMP.
- (p) “Re-energization” means the restoration of power through the electrical system to customers affected by a PSPS event.
- (q) “Risk event” means an event with probability of ignition, such as a wire down event, contact with objects, line slap, event with evidence of heat generation, or other event that causes sparking or has the potential to cause ignition. The following all qualify as risk events:
 - (I) ignitions;
 - (II) outages not caused by vegetation;
 - (III) outages caused by vegetation;
 - (IV) wire-down events;
 - (V) faults; and
 - (VI) other events with potential to cause ignition.
- (r) “Risk Spend Efficiency” or “RSE” means the ratio of estimated wildfire risk reduction benefits to the cost of a mitigation measure, used to evaluate the relative cost-effectiveness of mitigation activities.
- (s) “Sensitive line settings” means utility operational settings or practices intended to reduce wildfire ignition risk, including, where applicable, sensitive protection settings, fast-trip settings, or modified reclosing practices.
- (t) “System-wide estimated wildfire risk” means expected wildfire-related loss per year, calculated through a quantitative wildfire risk assessment, expressed in a stated common unit, and aggregated across modeled scenarios and the utility’s service territory.
- (u) “Wildfire event” means a reportable incident as described in rule 3636. A wildfire event is an event where utility facilities are associated with the following conditions:
 - (I) a self-propagating fire of material other than electrical and/or communication facilities,

- (II) the resulting fire traveled greater than one linear meter from the ignition point, and
- (III) the utility had knowledge that the fire occurred.
- (v) “Wildfire risk” means the potential for adverse wildfire outcomes, characterized by the wildfire scenarios that may occur, the frequency or probability of each scenario, and the consequences associated with each scenario.

WILDFIRE MITIGATION PLANNING AND PROCEDURES

3632. Overview and Purpose.

- (a) The purpose of these rules is to establish minimum statewide requirements for filing, updating, implementing, and reporting on Wildfire Mitigation Plans. These rules are intended to promote transparency, comparability, accountability, and continual improvement of utility Wildfire Mitigation Plans. Commission staff may issue guidance to clarify or request specific information to satisfy the requirements of these rules.
- (b) Consistent with §§ 40-3-101(2) and 40-3-102, C.R.S., these rules are intended to provide the Commission with a sufficient record to evaluate whether a utility’s WMP is supported by a transparent and adequately documented assessment of wildfire risk and whether the utility reasonably used that assessment to compare the expected risk reduction, RSE, costs, and reliability impacts of alternative mitigation measures, consistent with rules 3634 and 3635, and to select and prioritize those measures.

3633. Wildfire Mitigation Plan Filing Requirements.

- (a) Each utility must file a WMP as an application every three years and must submit an annual WMP update as described in rule 3637 in each intervening year. WMPs and WMP updates must be filed no later than March 31. Based upon the evidence of record, the Commission must issue a written decision approving, disapproving, or ordering modifications to the WMP, in whole or in part.
- (b) Effect of Commission decision. Commission approval of the WMP creates a presumption that utility actions consistent with the plan are prudent. The Commission must make a separate determination of cost recovery associated with the WMP.
- (c) In developing each triennial WMP, each utility must host at least four stakeholder meetings addressing its proposed quantitative wildfire risk assessment and cost benefit analysis, including wildfire risk mapping and the treatment of reliability consequences. The utility must consider stakeholder input in good faith but

retains ultimate decision-making responsibility. The WMP application must summarize the stakeholder process and any resulting revisions.

- (d) Each WMP application, annual WMP report, supplemental filing, and supporting workpaper must comply with any applicable Commission-approved or staff-issued filing instructions, data templates, workpaper requirements, or technical guidance issued to implement rules 3633 through 3637 and demonstrate compliance with these rules. Commission staff must post any such materials on the Commission's website.
- (e) If a utility makes a material change to a filed or approved WMP outside the annual update cycle, the utility must file a supplement describing:
 - (I) the change or changes;
 - (II) the rationale for the change;
 - (III) the expected impacts on wildfire risk, customers, operations, and costs; and
 - (IV) any implementation timeline.
- (f) Each utility must file a public version of its WMP that is sufficiently detailed to inform the public, stakeholders, and the Commission regarding the utility's wildfire risk, mitigation strategies, and planned activities. The utility may designate information as confidential only to the extent necessary to protect critical energy infrastructure information or other information eligible for protection under Commission rules. Where information is redacted, the utility must provide a non-confidential summary describing the nature of the redacted information and the basis for its confidential treatment. The public version must not be redacted to the extent that it obscures:
 - (I) the utility's wildfire risk assessment methodology;
 - (II) the nature and scope of planned and completed mitigation activities;
 - (III) geographic areas of elevated wildfire risk at an appropriate level of detail; and
 - (IV) performance metrics, program progress, and key outcomes.

3634. Wildfire Mitigation Plan Contents.

- (a) Unless otherwise directed by the Commission, each WMP must include the following sections in substantially the same order and with substantially the same headings.

- (I) Executive summary. This section must describe the utility's service territory, catastrophic wildfire history, and provide a summary of the WMP at a level accessible to the public.
- (II) Responsible persons.
- (III) Plan metrics. This section must include:
 - (A) qualitative and quantitative targets;
 - (B) prioritized list of wildfire risk and risk drivers;
 - (C) performance metrics;
 - (D) projected expenditures;
 - (E) projected risk reduction over the plan period, including how risk reduction is calculated;
 - (F) projected risk reduction on highest-risk circuits over the WMP cycle; and
 - (G) a ranking of circuits or circuit segments from highest to lowest overall utility risk, including the associated risk drivers. The utility must identify the unit of analysis, risk metric, and any normalization used in the ranking. If the ranking uses a normalized risk metric, the utility must also report absolute risk for the same unit of analysis. Risk drivers must be ranked in order of their contribution to risk.
- (IV) Risk methodology. This section must document the utility's quantitative risk assessment approach consistent with the requirements in rule 3635.
- (V) Risk-informed prioritization and mitigation selection process.
 - (A) This section must describe how the utility selects circuit segments at risk for wildfire for potential mitigations including, at a minimum, the following:
 - (i) geographic scale used in prioritization (e.g., regional, circuit, circuit segment, span, asset);
 - (ii) statistical approach used to select prioritized areas (e.g., circuit segments in top 20 percent for risk, circuit segments in top 20 percent for consequences); and

- (iii) feasibility constraints (e.g., limitations on data resolution, jurisdictional considerations, accessibility).

- (B) The utility must then describe how it selects mitigations, including the following:

- (i) identification and evaluation of mitigation activities;
- (ii) selection of mitigation activities, including:
 - (1) mitigation effectiveness assumptions, including the expected risk reduction associated with each mitigation and the basis for each assumption. Expected risk reduction must be calculated as the difference between baseline risk and post-mitigation risk over a common analysis horizon and must account for the timing of implementation and any material change in effectiveness over the mitigation's anticipated lifetime;
 - (2) costs, including the capital and change in ongoing operations and maintenance costs for each mitigation;
 - (3) anticipated mitigation lifetime or duration, such as the expected asset life or planning horizon over which the mitigation's risk reduction benefits accrue;
 - (4) alternatives analysis, including which alternative mitigations are analyzed and considered for a given project;
 - (5) decision framework, including any decision trees or scoring rubrics used to integrate risk model outputs, effectiveness assumptions, costs, and subject matter expertise to prioritize mitigations; and
 - (6) scheduling and feasibility constraints.

- (C) The utility must describe how it considers interim mitigations - the mitigations the utility relies upon on an interim basis while waiting to implement any mitigation that takes one year or more - including how the utility selects the interim mitigation and considers costs of the mitigation as part of overall mitigation selection.

- (b) Mitigation practices in the HFRA. This section must address the following:

- (I) grid design and system hardening, including an overview of each activity, quantitative and qualitative targets, impact of the activity on wildfire risk, and updates or changes to the activity from the previous WMP. This section must also include grid design and system hardening activities to reduce the scale, scope and frequency of PSPS events;
- (II) asset inspections, including quantitative and qualitative targets, impact of the activity on wildfire risk, type of activity (distribution, transmission, or substation), inspection program name, frequency or trigger for the inspection, method of inspection, method for designating priority, percentage of the HFRA covered annually by the inspection, quantitative and qualitative targets, previous find rates, whether inspections are conducted by full-time employees or contractors, and updates or changes since the previous WMP;
- (III) equipment maintenance, repair, work orders, including the utility's strategy for maintenance (proactive replacement versus run to failure), procedures used to manage open work orders resulting from asset inspections, description of procedures for tracking and correcting past due work orders, description of whether and how work orders are prioritized based on risk, a description of whether repairs are conducted by full time employees or contractors ,a tabular reporting of past due asset work orders by HFRA tier categorized by age, and updates or changes since the last WMP submission;
- (IV) vegetation management, including the utility's vegetation management inspection program, pruning and removal program, pole clearing, wood and slash management, defensible space, and integrated vegetation management, if applicable. The utility must include quantitative or qualitative targets. The utility must describe:
 - (A) vegetation management inspections, including the type of inspection (distribution, transmission), level, inspection program name, area inspected (including percentage of both the HFRA and non-HFRA inspected each year), frequency (including whether cycle or risk-based), how the utility prioritizes work orders resulting from vegetation management inspections (including priority assignment, and backlog elimination identification and procedures, tabular reporting of backlog in the HFRA, whether inspections are conducted by full time employees or contractors, and any updates or changes since the previous WMP;
 - (B) pruning and removal, including an overview, specifications, list of internal procedure documents, scheduling (timelines in which clearance and removal work is prescribed by the inspection

program and if the timeline differs by HFRA tier or other risk designation), whether inspections are conducted by fulltime employees or contractors, and updates or changes since the previous WMP;

- (C) pole clearing, including an overview, specifications, list of internal procedure documents, scheduling, and updates or changes since the last WMP;
 - (D) wood and slash management, including an overview, specifications, list of internal procedure documents, and updates or changes since the last WMP;
 - (E) defensible space, including an overview of actions taken to reduce wildfire risk to substations, generation facilities or other electrical facilities, specifications, list of internal procedure documents, scheduling, and updates or changes since the last WMP;
 - (F) integrated vegetation management, including an overview of actions not covered by previous sections and performed in accordance with integrated vegetation management principles (this may include, but is not limited to, use of herbicides, growth regulators, or other chemical controls, tree-replacement activities, promotion of native shrubs, prescribed fire, or other fuel treatment activities); list of internal procedure documents, scheduling, and updates or changes since the last WMP;
 - (G) weather-related vegetation management, including an overview of activities undertaken in response to forecasted wildfire conditions that indicates an elevated fire threat in terms of ignition potential likelihood and wildfire potential, scheduling, list of internal procedure documents, and updates or changes since the last WMP; and
 - (H) post-fire service restoration, including an overview, scheduling, a list of internal procedure documents, and updates or changes since the last WMP.
- (V) Quality assurance and quality control. This section must cover the utility's quality assurance and quality control activities for asset inspections, grid hardening, grid maintenance, and vegetation management programs and must include: quantitative and/or qualitative targets, the initiative being audited, program type, type of audit (desktop or field), population/sample unit, population size, sample size, percentage of sample in HFRA each year, confidence level and margin of error, scheduling of quality assurance

and quality control after inspection/work completed, target pass rate for each audited initiative for each year of the WMP cycle, whether quality assurance and quality control activities are conducted by full time employees or contractors (and whether quality control is conducted by the same or different persons as those conducting the inspections work, and updates or changes since submission of the last WMP.

- (VI) Workforce planning. This section must describe the utility's process for identifying and ensuring an adequately trained workforce to conduct its grid hardening, asset inspections, vegetation management and situational awareness activities.
- (VII) Situational awareness. This section must describe the utility's situational awareness program, including quantitative and/or qualitative targets, environmental monitoring systems, grid monitoring systems, ignition detection systems, weather forecasting capabilities, fire potential index or equivalent, and updates or changes since submission of the last WMP.
- (VIII) Emergency preparedness and recovery. This section must describe the utility's emergency preparedness and response plan, including plan name, version, and effective date, and updates or changes since submission of the last WMP. If not included in the emergency preparedness plan, the utility must describe or reference to how it:
 - (A) communicates, coordinates and prepares with public safety partners for wildfires;
 - (B) prepares and collaborates with Tribal Nations for wildfires;
 - (C) conducts outreach and education around wildfire preparedness; and
 - (D) supports customers during wildfires.
- (IX) Data management and data governance. This section must describe whether the utility has a formalized data management and data governance policy and describe elements of that policy, including updates or changes since submission of the last WMP. In addition, the utility must list and describe whether it has and/or how it manages the following:
 - (A) centralized asset registry/single source of truth on asset type, location, age, maintenance activities, manufacturer, installation date, and any other information the utility may collect, including assumptions made for missing information;

- (B) vegetation management systems of record, including names of each system and information contained in each system and duplication of information across systems; and
- (C) asset inspection and equipment repair/maintenance systems (if not included in a centralized asset registry), including names of each system information contained in each system and duplication of information contained in each system.

3635. Quantitative Wildfire Risk Assessment Standards.

- (a) WMPs must include a quantitative wildfire risk assessment. Qualitative analysis may supplement, but may not substitute for, that assessment. Relative or ordinal risk scores may likewise supplement, but may not substitute for, an assessment meeting all requirements of this rule. Quantitative wildfire risk assessments must meet the following minimum criteria.
 - (I) Includes sufficient documentation and explanation to allow the Commission to understand, review, and reproduce the wildfire risk assessment results. Documentation must include, at a minimum, data sources, data transformations, assumptions, model logic, software or platforms used, model version identifiers, material configuration settings, and external dependencies, including external programs, software libraries, and model dependencies. Documentation must disclose model versions and material changes to the quantitative wildfire risk assessment since the prior WMP filing, including the rationale for such changes. The utility must maintain and document internal quality assurance and quality control processes appropriate to the assessment, including controls for data quality, model performance, reproducibility, and change and version control. Use of a vendor-supplied or proprietary model does not relieve the utility of any requirement of this rule. Subject to applicable confidentiality protections, the utility must obtain and provide documentation, data, model outputs, and access rights sufficient for the Commission, Commission staff, and the independent evaluator to understand, review, reproduce, verify, and validate the model and its results for the stated use.
 - (II) Identifies HFRA that the utility has deemed at high risk from wildfire, independent of the presence or absence of utility equipment. The utility must describe the data it uses to classify areas within its service territory as HFRA or not, including but not limited to wildfire spread potential, topographic features, and population impacts. The utility must provide maps of the HFRA, and the utility must discuss areas outside of the HFRA that it is evaluating for potential future classification as an HFRA.

- (III) Identifies which wildfire risk drivers, such as equipment failure, vegetation contact, or animal contact, are explicitly modeled, which are excluded, and the basis for any exclusion.
- (IV) Identifies and cites the source(s) for all key quantitative parameters, including, but not limited to ignition likelihoods, association rates, and mitigation effectiveness assumptions.
- (V) Includes safety, reliability, and financial consequence attributes. The safety attribute must include estimated deaths and injuries resulting from wildfire. For each consequence attribute, the utility must report each measure of that attribute separately, in the unit in which it was calculated, before combining it with another measure or attribute. The utility must identify the method used to estimate, value, or monetize each measure and document the supporting evidence, uncertainty, and limitations. The utility must also document any fixed weights, equivalencies, or point conversions used to combine consequences and explain whether they are based on data, assumptions, policy judgments, or a combination thereof. For each material input used to monetize a consequence attribute, the utility must identify the value or range used, the source and basis for that value or range, the year in which any dollar value is expressed, and any inflation or escalation method applied. Where uncertainty in the input could materially affect the results, the utility must evaluate a reasonable range of values consistent with subparagraph (IX).
- (VI) Documents the aggregation methods and probabilistic structure used to calculate system-wide estimated wildfire risk from modeled wildfire outcomes. For each modeled scenario or simulation result, the utility must associate its frequency or probability with its consequences before aggregating the results or demonstrate that another method is mathematically equivalent. The utility must explain how the method preserves the relationship between the frequency or probability of each scenario and its consequences, including relationships arising from common weather, fuel, asset, and operating conditions. The utility must also describe how geographic segmentation, correlation among risk drivers, and any truncation or capping of losses are treated. The utility must separately report ignition frequency, RSE, and reliability-impact metrics and state the units of each metric. Where mitigation effects are reflected in the assessment, the utility must identify whether each material effect is credited implicitly in an underlying model or applied as an explicit credit and explain how double counting of mitigation effects is avoided.
- (VII) Calculates tail risk and incorporates tail risk into its quantification of risk. The utility must disclose thresholds or other parameters that are used to define tail risk and explain how the modeled probability distribution

accounts for credible, locally relevant low-frequency, high-consequence conditions.

- (VIII) Provides a risk ranking of highest risk assets and segments as part of its quantitative assessment and documents how that ranking has changed over time across model versions.
- (IX) Provides decision-relevant sensitivity and uncertainty analyses demonstrating how key assumptions affect risk estimates, mitigation rankings, and cost-effectiveness comparisons used to support proposed wildfire mitigation measures. To the extent material over the applicable planning horizon, the analyses must address potential changes in assets and asset conditions, fuels, population and urban development, weather and climate, and emerging technologies, policies, and tactics.
- (X) Segments average values where feasible to reflect material differences by asset type, geography, or operating conditions.
- (XI) For electric-reliability consequences, distinguishes between localized outages and system-wide reliability measures and explains how each is estimated, valued, and applied.
- (XII) Identifies whether cascading or interdependent impacts, including impacts on water systems, fuel supply, telecommunications, evacuation, or critical facilities, are included in the wildfire risk assessment. If not included, utility must explain their exclusion.
- (XIII) Explains how prior Commission or Commission staff feedback, lessons learned from wildfire events, model-performance assessments, validation activities, and independent reviews have been addressed and describes any resulting changes in core risk metrics, mitigation prioritization, or related performance measures. The utility must also identify planned improvements to its quantitative wildfire risk assessment, including the anticipated benefit, implementation timeframe, and key milestones for each improvement.
- (XIV) Is independently verified and validated by an independent evaluator. The utility must summarize and document the results, including any material discrepancies identified through that process. The utility must submit the independent evaluator's report together with a public summary of findings, recommendations, and material discrepancies as part of its WMP filing. For purposes of this subsection, an independent evaluator must be a third party with no direct involvement in developing, selecting, calibrating, or materially modifying the quantitative wildfire risk assessment and must have demonstrated expertise in quantitative risk modeling, verification and

validation of complex models, data and systems review, and utility wildfire risk analysis. The independent evaluator's report must include, at a minimum:

- (A) verification of model implementation, including review of model logic, data inputs, assumptions, calculations, and version control;
 - (B) validation of whether the model adequately represents the real-world system and phenomena it is intended to represent for its stated use, including comparison, where reasonably available, with relevant historical events, field measurements, experiments, or other observations not used to calibrate or train the model. If independent validation data are unavailable, the evaluator must identify that limitation and evaluate the alternative validation evidence and methods used;
 - (C) evaluation of key uncertainties, limitations, sensitivities, and material model changes; and
 - (D) identification and documentation of any material discrepancies, limitations, and recommended corrective actions.
- (b) Commission review. In reviewing a WMP, the Commission must determine whether the quantitative wildfire risk assessment satisfies paragraph (a) and provides a reasonable basis for the utility's proposed selection and prioritization of wildfire mitigation measures. The Commission may require additional analysis necessary to make that determination. Dismissal of a utility's application does not modify the utility's responsibility to comply with §§ 40-3-101(2) and 40-3-102, C.R.S.

3636. Wildfire Event Reporting.

- (a) The utility must report to the Commission and the State Emergency Operations Center, any wildfire event that meets one or more of the following criteria:
- (I) results in damage to utility infrastructure or injury that requires medical attention from a healthcare professional at a hospital or other medical facility, fatality, or evacuation;
 - (II) is identified by the utility as significant to system performance;
 - (III) is the subject of media coverage and is attributable or allegedly attributable to the utility electrical facilities (media as used in this context refers to any of the major news outlets and publications (i.e., a minimum daily circulation of 25,000 or minimum daily followers of 25,000) in the area, city and/or county where the incident occurred); and

- (IV) involves damage (caused by a utility facility) to property estimated to equal or exceed \$200,000. Property in this rule refers to any utility-owned and/or non-utility owned property and facilities. In calculating the amount of damages, the utility must estimate the cost to replace any damaged facilities that belong to the utility or properties of a non-utility entity. The cost does not include the labor involved to replace the damaged facilities and should be broken down to show the cost of damages to the utility's facilities and non-utility properties; or prompted a government entity to investigate whether the infrastructure owned or operated by the utility caused a wildfire.
- (b) The utility must initially notify the Commission and the State Emergency Operations Center of an event as soon as practicable, but no later than two hours during business hours and four hours after hours and weekends, after the utility becomes aware of a reportable wildfire event.
- (c) The utility must file a preliminary report on the Commission website within five business days of the conclusion of a reportable wildfire event, and a final report within 30 days of the conclusion of the event. To the extent practicable at the time of filing, each report must include:
 - (I) a description of the event, including the date, time, duration, and location of the event (including county and geographic area, latitude and longitude); weather and environmental conditions at the time of the event; and any known or suspected causes or contributing factors;
 - (II) any utility assets or equipment involved (including voltage class and type of facility);
 - (III) a detailed summary of impacts including estimated acreage burned, structures damaged or destroyed, the number of customers affected, any resulting injuries or fatality; and the location and duration of any associated outage;
 - (IV) a description of actions taken by the utility in response, including any coordination with emergency responders and local agencies; and
 - (V) a detailed shapefile that identifies the extent of wildfire damage and location of any impacted utility infrastructure.

3637. Annual Wildfire Mitigation Plan Update Reporting and Semi-Annual Data Reporting.

- (a) On or before March 31st of each year covered by a WMP, a utility must file an annual WMP update report of no more than 20 pages with the Commission that

covers the prior calendar year. This update report must be filed in the proceeding of the appropriate Wildfire Mitigation Plan. Data must be submitted electronically, using a template available on the Commission's website. Commission staff may update the template periodically. The update report must include:

- (I) a summary of implementation progress and a list of all reportable events;
 - (II) an explanation of key mitigation activities completed;
 - (III) a discussion of significant wildfire risk trends and wildfire activity during the year;
 - (IV) identification of any material deviations from the approved WMP, organized by program of work, and explanation for the deviations; and
 - (V) a quantitative assessment of wildfire risk reduction resulting from WMP implementation.
- (b) In addition to the annual WMP update report, the utility must also provide semi-annual performance data, by September 1 for quarters one and two and by March 1 for quarters three and four, provided in Excel and Geographic Information System executable files, with both a summary of progress and data to include:
- (I) system overview, including assets, at the most granular level possible, divided by HFRA tier and non-HFRA;
 - (II) WMP quantitative and qualitative targets, organized by initiative category (e.g. grid hardening), initiative name, tracking ID, brief initiative description, unit of measure, target type (yearly versus additive over the three-year period (cumulative)) performance against targets, planned initiative spend, and actual spend;
 - (III) unplanned outages, broken out by transmission and distribution, HFRA tier and non-HFRA, outage cause, and red flag warning/high wind warning;
 - (IV) ignitions, broken out by transmission and distribution, HFRA tier and non-HFRA, and ignition driver (e.g., animal contact) and metric type (e.g., contact from object);
 - (V) performance metrics broken out by HFRA tier and system total, including number of ignitions, number of wire-down events, number of unplanned customer interruptions, number of PSPS events, number of circuits de-energized, total customers impacted by PSPS, duration of PSPS events,

average restoration time after all-clear, PSPS notification success rate (24-48 hours), unplanned outages on circuit segments where sensitivity settings were enabled, and customer minutes of interruption on circuit segments where sensitivity settings are enabled;

(VI) system hardening and continuous monitoring projects completed, including location and designation within the HFRA, presented in Geographic Information System; and

(VII) any additional metrics identified by the Commission.

PUBLIC SAFETY POWER SHUTOFF PLANNING AND PROCEDURES

3638. Overview and Purpose.

- (a) The purpose of these rules is to clarify responsibilities regarding PSPS events and establish minimum statewide requirements for filing of PSPS plans, post-PSPS event reports and PSPS annual reports.
- (b) Public Safety Power Shutoff plans will include comprehensive information about utilities' PSPS programs, including the information required in these rules.
- (c) Pursuant to these rules, a utility may conduct a PSPS only if it determines there is an imminent and significant risk of wildfire. PSPS must not be used as the utility's primary mitigation measure.
- (d) Utilities must use lessons learned from PSPS events to inform future planning for mitigation and reduction in scale, scope, and duration of future PSPS events.
- (e) Electric utilities are responsible for notifications and communications during PSPS events.

3639. Public Safety Power Shutoff Plan Filing Requirements.

- (a) Each electric utility must file a PSPS plan with the Commission as an application every three years, or more frequently as directed by the Commission, that includes the information outlined in rule 3640. Annual reporting must be filed in accordance with rule 3644. Based upon evidence of record, the Commission must issue a written decision approving, disapproving, or ordering modifications, in whole or in part to the PSPS plan.
- (b) Each utility must file a public version of its PSPS plan that is sufficiently detailed to inform the public, stakeholders, and the Commission regarding the utility's PSPS methodologies, decision-making criteria, education and outreach, and communication strategies. Utilities may designate information as confidential

only to the extent necessary to protect critical energy infrastructure information or other information eligible for protection under Commission rules.

- (c) The public version must not be redacted to the extent that it obscures utilities' PSPS methodologies, decision criteria, education, outreach and communication strategies, areas of the service territory that may be subject to PSPS at an appropriate level of detail, customer protections, notification procedures, and restoration procedures, performance metrics, program progress, and key outcomes.
- (d) Where information is redacted, utilities must provide a non-confidential summary describing the nature of the redacted information and the basis for its confidential treatment.

3640. Public Safety Power Shutoff Plan Contents.

- (a) A PSPS plan must describe how utilities will comply with rules 3641 through 3642 and also must include, at a minimum, the information set forth below.
 - (I) Whether the PSPS plan applies to distribution or transmission infrastructure, or both.
 - (II) Governance and decision-making structure.
 - (A) A description of the decision-making structure within the company that identifies the roles and responsibilities of individuals involved in making PSPS implementation decisions, a discussion of whether an incident command structure is used during PSPS events, and a description of how the PSPS plan aligns with recognized emergency management planning processes.
 - (B) An explanation of the decision-making criteria and analytical framework for de-energization, including objective meteorological, fuel-condition, topographic, and operational thresholds and triggers. At a minimum, the explanation must address temperature, wind speed and wind gusts, relative humidity or vapor pressure deficit, live and dead fuel moisture, precipitation or drought conditions, terrain or topographic factors where applicable, fuel type or vegetation conditions, condition of utility assets and open work orders, condition of vegetation and open work orders, and any other inputs used to determine whether a PSPS event may be necessary.
 - (C) Utilities must describe how they aggregate the inputs identified in subparagraph (B) into a fire potential index, fire danger rating, or

equivalent composite metric used to support PSPS decision-making. Utilities must describe the metric's inputs, data sources, weighting or aggregation methodology, spatial and temporal resolution, update frequency, decision thresholds, limitations, treatment of uncertainty, and role in PSPS preparation, notification, de-energization, continuation, cancellation, restoration, and all-clear decisions. If this information is contained in the WMP, utilities may reference the corresponding sections of the WMP.

- (D) An explanation of how utilities develop, calibrate, validate, and update quantitative and qualitative thresholds for calling a PSPS event and the composite metric described in subparagraph (C). The explanation must describe how the thresholds and composite metric account for grid hardening, grid modernization, open work orders, operational mitigations, seasonal conditions, post-event lessons learned, and comparison of forecasted conditions to actual conditions.
 - (E) A decision-tree or flow chart that illustrates the factors considered and decision-points along the way to calling a PSPS event or cancelling a previously noticed PSPS event.
 - (F) A description of the PSPS operational protocols, including the sequence of operational stages, associated readiness actions, and thresholds for moving between stages, and the thresholds or metrics used to formally end a PSPS event (all-clear).
 - (G) How lessons learned are incorporated into future governance and decision-making frameworks.
- (III) Preparation and resilience of the public and stakeholders.
- (A) Public safety partners.
 - (i) A description of the strategy and timing for maintaining up-to-date and accurate public safety partners contact information including 24-hour primary and secondary contacts and preferred methods of communication. Utilities must maintain current contact lists and provide them to Commission staff or the Commission upon request, subject to appropriate confidentiality protections.
 - (ii) A plan for providing a single utility point of contact during PSPS events.

- (iii) A description of the strategy and timing for coordinating with public safety partners in advance of a PSPS event to identify needs and develop strategies for successful communication, integration, and support during a PSPS event, including details of hosting tabletop and functional exercises.
 - (iv) A description of the strategy and timing for coordinating with public safety partners to identify appropriate support services for customers and other individuals affected by a PSPS event. This may include identifying appropriate locations, hours, staffing for, services at, and transportation to community resource centers and any funding sources associated with community resource centers.
- (B) Critical facilities and critical infrastructure.
 - (i) A description of the strategy and timing for maintaining up-to-date and accurate critical facility and critical infrastructure contact information including 24-hour primary and secondary contacts and preferred methods of communication. Utilities must maintain current contact lists and provide them to Commission staff or upon request, subject to appropriate confidentiality protections.
 - (ii) A plan for providing a single utility point of contact during PSPS events.
 - (iii) A description of the strategy and timeline for coordinating with critical facilities and infrastructure to ensure critical facilities and infrastructure have resources or support needed to maintain safe operations during a PSPS event. This may include, but is not limited to, providing backup power.
- (C) Access and functional needs populations.
 - (i) A description of the strategy and timing for identifying and maintaining up-to-date and accurate contact information for all access and functional needs populations within the service territory.
 - (ii) The customer categories used to administer AFN populations protections.

- (iii) An explanation of support services offered to AFN populations to prepare for a PSPS event, such as backup power or energy storage.

(D) Pre-fire season PSPS outreach and education.

- (i) A plan for educating all individuals potentially affected by PSPS events with information about the purpose of PSPS events and how to prepare for them, including specific outreach and education for:
 - (1) critical facilities and infrastructure;
 - (2) AFN populations, including identification of the most prevalent non-English languages spoken across the service territory and within each county; and
 - (3) Tribal communities and governments.
- (ii) Methods for amplifying education and preparedness methods using community-based organizations, local governments, schools, community centers, and other agencies.
- (iii) The educational materials used within each relevant community and a description of the strategy for using those materials to educate relevant communities. All educational materials must use understandable language appropriately targeted to each relevant community, with special provisions for public safety partners, critical facilities and infrastructure, and AFN populations, as specified in the PSPS plan.
- (iv) The methods for disseminating outreach and education, which may include, but are not limited to, social media, paid media, direct messages, and partnerships with community-based organizations.
- (v) A public-facing PSPS website, translated into the most prevalent languages in the service territory, that provides the following information:
 - (1) the purpose of the PSPS program;
 - (2) a description of what happens during a PSPS event;

- (3) preparedness resources for remaining safe during a PSPS event, including information on how to locate community resource centers during a PSPS event;
 - (4) what to do if a PSPS event is called; and
 - (5) utility contact information for further questions.
- (IV) PSPS event notifications.
 - (A) Sample scripts and communications for providing notification at each stage of a PSPS event in compliance with the protocols in rule 3641 for the following populations:
 - (i) public safety partners;
 - (ii) critical facilities (Tier 1 and Tier 2 Notification Critical Facilities);
 - (iii) AFN populations; and
 - (iv) all other populations, including non-customers located within the boundary of a PSPS event (including master metered tenants or other persons who may be affected but are not the utility account holder).
 - (B) A plan for how utilities will coordinate with public safety partners, the media, government agencies, community-based organizations, and other entities to provide timely and accurate notifications and avoid providing conflicting or contradictory information.
 - (C) The communication methods that will be used to provide notification at all stages of a PSPS event for the following populations:
 - (i) public safety partners;
 - (ii) critical facilities (Tier 1 and Tier 2 Notification);
 - (iii) AFN populations; and
 - (iv) all other populations.
 - (D) A list of the languages in which PSPS event notifications will be provided.

- (V) Post-PSPS event evaluation and integration.
 - (A) Strategy for assessing PSPS event impacts on customers, including critical facilities and AFN populations, and process for ensuring lessons learned are integrated into future PSPS events.
 - (B) Plans for capturing all data and documentation needed for reporting and auditability, including maintenance of geospatial data, decision logs, contact records, notification records, and all other materials needed for the Commission to review or audit the event process.
- (VI) Standard operating procedures. A list of all standard operating procedures associated with preparing for and executing a PSPS event, including restoration. The list must include titles, date approved, and version, if applicable.
- (VII) Any other information as requested by the Commission and Commission staff.

3641. Public Safety Power Shutoff Event Notifications and Coordination.

- (a) Utilities must coordinate PSPS notifications with public safety partners and, where practicable, align their communications with existing state and local emergency response protocols to avoid duplicate or conflicting information.
- (b) Utilities must develop and use a common nomenclature that integrates existing state and local emergency response communication messaging and outreach.
- (c) Utilities must provide notice in the languages prevalent in the service territory and also provide methods for accessing notifications in less prevalent languages.
- (d) Utilities must adhere to the following minimum notification timelines:
 - (I) 48-72 hours before the start of de-energization, utilities must issue priority notifications to the Commission, public safety partners, and Notification Tier 1 Critical Facilities;
 - (II) 24-48 hours before the start of de-energization, utilities must notify all other potentially affected populations, including Notification Tier 2 Critical Facilities; and
 - (III) 1-4 hours before the start of de-energization, utilities must notify all potentially affected populations.
- (e) At the time that the PSPS is initiated, utilities must notify all potentially affected populations.

- (f) During the PSPS event, when power is shut off, utilities must provide updates to affected customers regarding changes to conditions that could affect the duration of the outage at the intervals specified in its PSPS plan, but no less frequently than every four hours, and sooner when there is a material change in expected duration or restoration timing.
- (g) After determining that de-energization is no longer required for public safety (all-clear), utilities notify affected populations, including the Commission, public safety partners, critical facilities, and the media, with notice of all-clear status, estimated restoration timing, and any known conditions that may materially affect restoration.
- (h) During restoration, utilities must provide updates regarding material changes to estimated restoration timing or scope.
- (i) For purposes of paragraphs (f), (g), and (h), a material change includes, at minimum: a change that is expected to delay de-energization by two hours or more from the most recently communicated estimate; a change in the geographic area or customer group expected to be de-energized or restored; a change affecting a critical facility, public safety partner, or identified AFN population support measure; or any change expected to extend restoration beyond 24 hours after declaration that the conditions precipitating the PSPS event are no longer present (all-clear).
- (j) When re-energization is complete, utilities must notify affected populations through standard outage communication channels.
- (k) Utilities must notify all populations previously notified of a PSPS event in the following circumstances:
 - (I) in the event of a delay or cancellation of the PSPS event; and
 - (II) in the event of changes in scope to the PSPS event prior to de-energization.
- (l) If utilities are not able to meet the minimum notification timeline requirements in this section, utilities must explain the reasons for not doing so in the post-event report.
- (m) In addition to direct notification of customers, utilities must use multiple channels, including but not limited to paid media, community-based organizations, and local government partners, to provide notification, ensure accurate information, and avoid conflicting messaging, and to reach non-customers who may be affected by the PSPS event.
- (n) Utilities must provide at least the following information in PSPS notifications:

- (I) a 24-hour phone number and/or web chat portal that customers may use to ask questions and/or seek information in all languages spoken within the service territory;
- (II) estimated date and time of the PSPS event;
- (III) estimated length of the PSPS event and estimated time to restoration, where available, which may be communicated as a range;
- (IV) time of the next expected communication about the PSPS event;
- (V) answers to five key recipient questions:
 - (A) Who is the source of the warning?
 - (B) What is the threat?
 - (C) Does this affect my location?
 - (D) What should I do?
 - (E) Where should I go for more information?;
- (VI) a link to webpage or map that includes a search function that allows the public to determine whether a specific address is affected;
- (VII) special provisions for medical baseline and AFN populations;
- (VIII) utilities must ensure that AFN populations receive notification in advance of a PSPS event by making positive contact. Positive contact is defined as ensuring that the notification has been both sent and received;
- (IX) special provisions for public safety partners and critical facilities and infrastructure;
 - (A) utilities must ensure public safety partners and critical facilities and infrastructure receive notification in advance of a PSPS event by making positive contact with a designated representative of the public safety partner or critical facility; and
 - (B) utilities must develop and maintain a public safety portal where public safety partners may access up to date information on PSPS events, including real-time polygons showing the boundaries of the PSPS event, locations of critical facilities, locations of utility lines equipment, and any other information deemed necessary by public safety partners.

3642. Operational Procedures During and Immediately After a Public Safety Power Shutoff Event.

- (a) During PSPS events, utilities must monitor and maintain a safe environment, including:
 - (I) monitoring and maintaining equipment; and
 - (II) monitoring environmental conditions to inform decision making on the length and extent of the PSPS event.
- (b) After the “all-clear,” utilities must safely re-energize equipment according to the standard operating procedures for service restoration, which must include, but may not be limited to, the following:
 - (I) safety inspections,
 - (II) patrol requirements,
 - (III) remediation procedures,
 - (IV) coordination with public safety partners and electric-system operational partners,
 - (V) authorization requirements for restoration,
 - (VI) estimated restoration-time communication, and
 - (VII) procedures for communicating major restoration delays.
- (c) Utilities must re-energize all customers affected by the PSPS as soon as safely practicable after the “all-clear” determination and, unless it is unsafe to do so, within 24 hours.

3643. Public Safety Power Shutoff Post Event Reporting.

- (a) For each PSPS event, and for each anticipated PSPS event where customers were notified but de-energization is ultimately not executed, utilities must file a post event report within ten business days of completion of re-energization within the proceeding of the PSPS Plan. For a noticed event in which de-energization does not occur, the report is due within ten business days after the event is cancelled or the utility determines that de-energization will not occur. Data must be submitted electronically, including through a template available on the Commission’s website. Commission staff may update the form periodically.
- (b) Each post event report must include the following information.

- (I) Decision-making and operational actions:
 - (A) whether the PSPS event impacted the distribution or transmission system, or both;
 - (B) inputs used in making PSPS event decisions;
 - (C) key decision points and timing of key decisions;
 - (D) individuals responsible for making key decisions, including the decision to de-energize;
 - (E) a description of operational actions and resources deployed to prepare for the PSPS event, including but not necessarily limited to staff positioning and advance deployment of resources and equipment;
 - (F) coordination with public safety partners, including first responder/emergency responders, local governments and tribal leaders, and others;
 - (i) a list of public safety partners and critical facilities (if any) embedded in the utility's emergency operations center and utility staff embedded within or directly coordinating with public safety partners and critical facilities leading up to and during the PSPS event;
 - (ii) how public safety partners were included in or kept informed of the decision-making related to the PSPS event;
 - (G) a benefit-risk comparison for PSPS compared to not de-energizing (alternatives considered); and
 - (H) report for each de-energized circuit or circuit segment, forecast and observed conditions, applicable thresholds, and whether and when the thresholds were met.
- (II) Scale and scope of PSPS event:
 - (A) detailed information on the location of the PSPS event and what equipment was affected, including GIS shapefiles of the progression of areas considered for the PSPS event and the area ultimately de-energized, with circuit mapping;
 - (B) any discrepancies between maps used to identify locations of the PSPS event and actual customers de-energized;

- (C) the number of customers de-energized and length of the de-energization; and
 - (D) customer minutes interrupted, including System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) minutes.
- (III) Notifications and communications completed:
- (A) AFN populations (including medical baseline customers):
 - (i) methods used to notify AFN populations;
 - (ii) the number and percentage of AFN populations for whom positive contact was confirmed, compared to the total number of AFN population customers;
 - (iii) number of customers receiving an in-person visit or welfare check to confirm positive contact;
 - (iv) number of AFN population customers de-energized who were not notified of the PSPS event; and
 - (v) number of AFN population customers notified of the PSPS event who were not de-energized;
 - (B) critical facilities:
 - (i) number and percentage of positive notifications achieved;
 - (ii) number and critical facilities de-energized who did not receive notification; and
 - (iii) number and percentage of critical facilities notified of the PSPS event who were not de-energized;
 - (C) public safety partners: when and percentage of public safety partners who were notified of the PSPS event;
 - (D) all others:
 - (i) notification timeline, channels used, and measures of notification success;
 - (ii) number and percentage of customers de-energized who did not receive notification of the PSPS event; and

- (iii) number and percentage of customers who received notification of the PSPS event who were not de-energized;
 - (1) description and examples of all channels used for notification, including community-based organizations, paid media, social media, press release, company website, text messages, and other forms of communication; and
 - (2) an explanation for any missed notification timeline, including why the timelines could not be met.
- (IV) Customer support and community resources support:
 - (A) thresholds and decision-making criteria for opening and citing customer resource centers;
 - (B) locations of customer resource centers;
 - (C) customer resource center hours of operation and services offered;
 - (D) number of customers using customer resource centers; and
 - (E) any other actions taken to support those impacted by the PSPS event, including any specific actions to support AFN populations.
- (V) Restoration:
 - (A) a discussion of the restoration process, including safety inspections, and the timeline for actual restoration;
 - (i) percent of customers restored within 24 hours of the decision to re-energize (all-clear);
 - (ii) a map showing locations for which service was restored prior and up to 24 hours following all-clear and areas where service was restored 24 hours or more after the all-clear, color-coded in 12-hour increments (e.g., 25-36 hours, 37-48 hours, etc.); and
 - (iii) explanation for why re-energization could not occur in the time allowed, including factors affecting restoration timing as well as actual restoration times.
- (VI) Reporting of material patrol, inspection, and restoration finding, including an affirmative statement when none were identified:

- (A) summary and examples of restoration-related communications, including all-clear notices, estimated restoration-time updates, major restoration-delay communications, and completion notices provided to affected populations, public safety partners, and critical facilities.
- (VII) Issues encountered:
 - (A) a description of any operational problems or issues encountered in the de-energization process, or while equipment is de-energized, and how those issues were addressed;
 - (B) any issues or problems encountered in issuing notifications and how those were resolved; and
 - (C) any other issues or problems encountered and how those were resolved.
- (VIII) Lessons learned and corrective actions:
 - (A) lessons learned covering PSPS event education and outreach, PSPS event preparation, PSPS event notifications, PSPS event decision-making, PSPS event operationalization, and PSPS event restoration;
 - (B) corrective actions or programmatic updates resulting from lessons learned; and
 - (C) methods for soliciting feedback from public safety partners, critical facilities and AFN populations and any feedback provided.
- (IX) Any additional information and/or documentation requested by the Commission.

3644. Public Safety Power Shutoff Annual Update Reporting and Semi-Annual Data Reporting.

- (a) On or before March 31st, electric utilities must file an annual PSPS report summarizing all PSPS events, performance metrics, customer impacts, and corrective-action progress for the preceding calendar year. The PSPS report must be filed within the plan proceeding and include the following.
 - (I) PSPS preparation, including:

- (A) types and methods of outreach and education performed during the year to prepare customers for PSPS events, including partnerships with community-based organizations;
 - (B) number of tabletop and/or functional exercises held, broken out by county, and including a description of the participants (number of participants, titles);
 - (C) battery and backup generation programs offered, including statistics around uptake;
 - (D) education and outreach effectiveness including key measures around customers' understanding of the purpose of PSPS events and how to prepare for PSPS events; and
 - (E) utilities must include information on any surveys conducted, including survey questions, methods for selecting survey participants, survey outcomes, and demographics of survey respondents as compared to customers impacted by PSPS events throughout the year.
- (II) Lessons learned and corrective actions, including:
 - (A) a summary of key lessons learned over the previous year covering PSPS event education and outreach, PSPS event preparation, PSPS event notifications, PSPS event decision-making, PSPS event operationalization, and PSPS event restoration;
 - (B) key corrective actions or programmatic updates implemented as a result of lessons learned; and
 - (C) an annual assessment of threshold and forecast performance, material forecast-observation differences, resulting changes, and why changes were or were not warranted.
- (b) In addition to the annual PSPS update report, the utility must also provide semi-annual performance data, by September 1 for quarters one and two and by March 1 for quarters three and four, provided in Excel and Geographic Information System executable files, including basic statistics for all PSPS events that occurred throughout the year including, by filing this within the plan proceeding:
 - (I) the number of PSPS events;
 - (II) the number of PSPS events where notification of any type occurred, but for which the utility ultimately did not de-energize;

- (III) scope of PSPS events (circuits or miles de-energized);
- (IV) types of PSPS events (transmission or distribution or both);
- (V) number of customers impacted by each PSPS event, broken out by customer type;
- (VI) number of customers de-energized more than once, more than twice, etc.;
- (VII) duration of each PSPS event;
- (VIII) customer minutes interrupted for each PSPS event;
- (IX) a map of each PSPS event;
- (X) basic demographic information for customers impacted by each PSPS event, including primary languages spoken;
- (XI) notification timelines for each PSPS event broken out by public safety partners, Notification Tier 1 and Notification Tier 2 critical facilities, AFN population, and all others, including whether notification timelines were met;
 - (A) brief explanations for any timelines not met;
 - (B) number and percent of AFN populations customers for whom positive contact was and was not achieved for each PSPS event;
 - (C) number and percentage of customers impacted by each PSPS event who were not notified; and
 - (D) number and percentage of customers notified who were not ultimately de-energized when a PSPS event occurred;
- (XII) number of customer resource centers opened for each PSPS event, locations, services offered, number of customers that visited customer resource centers, transportation services provided (if any);
- (XIII) number and location of frequently re-energized circuits; and
- (XIV) significant or recurring issues encountered during PSPS events.

3645. – 3649. [Reserved].