SOUTHERN CALIFORNIA
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Carla Peterman
Senior Vice President
Strategy and Regulatory Affairs

February 26, 2021

Caroline Thomas Jacobs
Director, Wildfire Safety Division
California Public Utilities
Commission 505 Van Ness Avenue
San Francisco, CA 94102

SUBJECT: Southern California Edison's 2021 Wildfire Mitigation Plan Update Supplemental Filing - CORRECTED Regarding Action Statements in Wildfire Safety Division's Evaluations of its Remedial Compliance Plan and First Quarterly Report

Dear Director Thomas Jacobs,

Pursuant to Wildfire Safety Division's (WSD) January 8, 2021 Evaluation of Southern California Edison Company's (SCE) First Quarterly Report (QR) and WSD/SCE agreement on certain Action Statements in WSD's Evaluation of SCE's Remedial Compliance Plan (RCP), attached herein is SCE's 2021 Wildfire Mitigation Plan (WMP) Update Supplemental Filing that includes the remaining responses to Class A and Class B Deficiency Action Statements that were not included in our 2021 WMP Update. In Appendix 9.6 of our 2021 WMP Update, SCE responded to many Action Statements. Please also see Table 2-1 in Chapter 2 of SCE's 2021 WMP Update that identifies where the response to each Action Statement can be found.

SCE appreciates the WSD's recognition of the limited time between the issuance of the Evaluations of our RCP and First QR and the February 5, 2021 2021 WMP Update submission and permission to submit a single supplemental filing to address all insufficient elements of its RCP and First QR not previously addressed in the 2021 WMP Update.

We look forward to continuing to work with the California Public Utilities Commission, WSD, local government officials, Community Based Organizations and other stakeholders to build a more resilient California. If you have any questions, or require additional information, please contact me at carla.peterman@sce.com.

Sincerely,

//s//
Carla Peterman
Senior Vice President, Strategy and Regulatory
Affairs Southern California Edison

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(U 338-E)

Southern California Edison 2021 Wildfire Mitigation Plan Update Supplemental Filing - Corrected

February 26, 2021

Contents

Responses to WSD Action Statement on Remedial Compliance Plan
SCE-2, Determining Cause of Near Misses

Action SCE-5*: In its 2021 WMP update, SCE shall provide the specific protocols, including supporting documentation (e.g. reports, analysis, procedures, checklists, etc.), used for determining outages.*

Response:
Field staff, including troublemen and senior patrolmen, as well as substation operators, are SCE's first responders to unplanned outages. As described in SCE's response to SCE-2 condition i.[1], field staff use various tools to assist in their determination of outage causes (e.g., ammeter, fault indicators, smart meter exception data). Distribution Operations Center (DOC) dispatchers and system operators collect outage information from field staff and substation operators and enter information into the relevant system (Outage Management System (OMS) for dispatchers and Interruption Log Sheet for system operators). The OMS contains pre-populated outage cause codes (i.e., drop-downs) while system operators enter outage information manually into ILS. Dispatchers and system operators are required to provide sufficient information into the respective systems so that a reliability event can be validated for accuracy and provide a historical record of the event.

Please find attached the following supporting documentation on protocols and procedures used for determining outages. The **SOB 1100 - General Instructions for Recording Interruptions** provides a comprehensive overview of the process, including specific roles and responsibilities:

- ***General Instructions for Recording Interruptions*****:** System Operating Bulletin describing and outlining SCE's functional requirements for accurate collection and recording of reliability events.
- ***OMS User Guide for Processing Incidents***: User guide/job aid on processing requirements to accurately record outage data using OMS. Also attached is an excel file summarizing OMS Outage Cause Codes (***OMS Cause Code List.xls***)
- ***SCE ILS Training Presentation*****:** Presentation describing system operator/field personnel/DOC Dispatcher/ROC responsibilities in recording/reporting reliability information, information that should be reported including on weather conditions and reported cause.
- ***SCE ODRM User Guide*****:** Document providing an overview of creating and validating incidents in ODRM.
- ***SCE ODRM User Guide – Training Presentation*****:** Presentation on roles/responsibilities and creating ODRM entries, including providing appropriate outage cause details (e.g. see Slide 13) and a description of outage types (e.g., Slide 14).

Action SCE-6*: In its 2021 WMP update, SCE shall provide all supporting documentation (e.g. reports, analysis, procedures, checklists, etc.) relating to its "deeper investigations into ignitions".*

[1] SCE *Remedial Compliance Plans for Class A Conditions*, July 27, 2020.

Response:

In April 2019, SCE launched the Fire Incident Preliminary Analysis (FIPA) process to perform more in-depth investigations into ignitions that occurred in connection with SCE facilities. The FIPA process was established to gain insights and learn lessons to help further SCE wildfire mitigation efforts. The FIPA process has three levels of investigation, depending on the complexity of the ignitions. The three levels vary in complexity, and a brief description of the actions taken for each level are listed below:

- Level 1 - May include a review of pictures, telephone interviews, and Repair Orders.
- Level 2 - In addition to Level 1, may include site visits and fault analysis.
- Level 3 - In addition to Level 2, it will include evaluating the equipment/material by a root cause engineer.

During the FIPA process, the assigned staff enter the data in a database that tracks the information. An extract of 2019, CPUC reportable events titled ***FIPA_extract.xlsx*** contains all the fields housed in the database.

The FIPA process captures more data than the CPUC reportable fields, including Circuit, Substation, Fire Location, Primary Ignition Cause, and Root Cause. Please note that not all fields are required to be filled out in the database, and new fields may have been added since the start of the FIPA process, which may result in blank fields for earlier investigations.

The attached file ***FIPA Process*** provides an overview of the FIPA process. The FIPA process has continued through 2020 and provides additional data through more in-depth investigations into ignition events, which have helped SCE's mitigation strategies.

Action SCE-7*: In its 2021 WMP update, SCE shall provide the number and percentage of crew-initiated interruptions classified as equipment failures.*

Response:

SCE's ODRM system tracks outages, and not faults. SCE codes outages in ODRM using a series of information from the field, in a series of values, based upon this information. SCE took its ODRM data, and then transcribed this data into the WMP tables and attempted to determine which events were faults. During this effort SCE noticed an increase in "faults" as inspections increased. To answer the question as to how many faults were crew caused, SCE cross compared its Repair systems vs ODRM, and if the repair order occurred before the outage, SCE believes that these were crew-caused outages. In 2019, approximately 750 equipment failures and 200 contact from foreign objects, appear to be crew-caused and not "faults," but emergency outages.

Action SCE-8*: In its 2021 WMP update, SCE shall 1) explain how it determines which staff are required to take outage determination training, and 2) describe how SCE tracks that the mandatory outage determination training is properly taken and continued to be taken by such staff.*

Response:

Outage determination training is part of the formal computer-based training (CBT) for SCE's system operators and includes courses on SCE's Interruption Log Sheet (ILS) system and ODRM (outage database reliability metrics). Training is incorporated into SCE's new hire training program and in 2020 all existing system operators were required to take these training courses. In addition, refresher courses are offered on two-year rotating basis. Completion of training courses is tracked via SCE's online training portal "Success Factors" wherein employees are assigned courses with corresponding deadlines and with managers notified upon completion of training.

SCE's Distribution Operations Center includes on-the job training, including job aides. Training is currently in development for all staff.

Action SCE-9*: In its 2021 WMP update, SCE shall 1) explain how it determines which outage-related staff are required to receive the at least 16 hours of continuing education every two years, and 2) describe how SCE tracks that the training is properly taken and continued to be taken by such staff.*

Response:
SCE's system operators can receive up to 16 hours of refresher training on a biannual basis that covers numerous subjects (i.e., not just outage-related) and which can vary year-to-year. Training is not targeted to specific employees, but rather half of the population is targeted in one year, with the remaining half in the subsequent year. Completion of training is tracked via an internal report. Prior to COVID-19, training was conducted in-person. Due to COVID-19-related restrictions, training is now conducted virtually.

There is no formal process for refresher training for DOC dispatchers but as described in SCE's response to SCE condition ii, DOC supervisors occasionally provide refresher on-the-job training to dispatchers on an as-needed basis. SCE is currently working to develop a formal training program for dispatchers which would include regular refresher training.

Action SCE-10*: In its 2021 WMP update, SCE shall describe when it began improving its training programs to reduce "other" and "no cause found" categorizations and provide all supporting training materials and procedures used.*

Response:
Improved training programs and processes began to develop around 2018 to re-train field personnel / system operators to be more vigilant in identifying causes of outages. Training materials, processes and procedures include(d):

- Communication plan for troublemen and patrolmen to encourage them to assign most likely cause of outages (instead of unknown or other)
- Encouraging DOC dispatchers and system operators to reach back out/follow up with field personnel to collect more information and assign a cause code
- Weekly reliability calls to review and close out open incidents
- Formal improved training programs for System Operators commenced in 2020 including ILS and ODRM training (see attached for the following documents). The training program was deployed across existing system operators and also incorporated into SCE's new-hire program:
    - ILS Logging Expectations
    - ODRM
    - ODRM User Guide

- Formalized training is in development for all DOC/Reliability Operations Center (ROC) staff. When the formalized training is developed and implemented, supporting training materials and procedures can be provided.

Action SCE-11*: In its 2021 WMP update, SCE shall provide the percentage and number of outages selected for validation per month and provide the supporting procedures for performing the validation.*

Response:
All unplanned outages are validated in ODRM by system operations and the ROC on a monthly basis. Please see SCE's response to Action SCE-12 below for more details on the supporting procedures for performing these validations.

Action SCE-12*: In its 2021 WMP update, SCE shall describe its current QA/QC process for Outage Database & Reliability Metrics System (ODRM) validation.*

Response:
SCE provided a description of its current QA/QC process for its ODRM validation in its Remedial Compliance Plan response to SCE-2 Condition iv, copied below with some additional details for clarity. In addition, SCE has attached the documentation which provides additional information on SCE's QA/QC process for ODRM validation:

Outage cause determination goes through a multi-step verification process during or immediately following the outage and after the outage, during data checks.

1) The first step occurs in real time. In recent years, SCE has placed an increasing emphasis on improving training programs and tools to reduce the categorization of outages as "Other" or "No Cause Found." DOC dispatchers and system operators have also been instructed to follow up and collect sufficient information from field staff in order to more accurately assign and describe causes in OMS and ILS.

2) Next, the OMS and ILS information is then transcribed into ODRM. All unplanned outages are validated in ODRM by system operations and the ROC.

    a) **Validation of outages when distribution load is impacted**
    If distribution load is impacted by the outage, staff at SCE's ROC**,** consisting of experienced engineers and technical experts, verify that the transcribed information matches with what occurred in the field (i.e., location, start and load-restoration times, customer counts) and that the right cause code was selected. ODRM has built-in nested logic for cause selection to facilitate accurate recording. If an outage cause does not make sense, it will be flagged for further review and correction by staff.

    Attached please find the following document which provide more details on the ROC Outage Validation Process:
    - ***SCE Outage Validation Process Job Aid***

b) **<u>Validation of outages where no distribution load is impacted</u>**

System operators are responsible for validating Transmission, Sub-Transmission lines and Substation equipment ODRM outages when no distribution load is impacted. Details on the process are provided below and in attached documents referenced below.

- It is the responsibility of a System Operator Supervisor to coordinate efforts with the system operators to make sure all Transmission Line and Substation Outage entries in ODRM that do not include distribution load are validated.
- It is a best practice for the ODRM to be validated by a different System Operator or System Operator Supervisor (SOS), other than the individual that created the initial outage when possible.
- When the interruption event occurs, as described above, an ILS is created, and the event is entered into ODRM. Once the ILS is closed out and a cause has been recorded, the ODRM event can be validated.
- Tools available to be used by the SOS to track these efforts are:
  - The ILS & Transmission Control Report that is sent out monthly (the second week of each month via email) and is a back-up to verify that all events have been created and are validated
  - The SAS Pending-Validated Outage Report that is available at all times to be viewed by SOS (available daily for all switching centers to access and provides a full report on ODRM status)
  - The Search Function by Date in ODRM, comparing against the ILS entries
- SOS's have responsibility to check all work is accurate and complete (e.g., a monthly goal to track ODRM validations to verify process implementation).
- As described above in Action SCE-8, ODRM training is offered to all new hires as part of their classification training and refresher training is offered
- SOS's are expected to coach system operators monthly when ILS Reporting is distributed, and training gaps are identified. SOS's can reach out to gain additional training support as needed.

The following attached documents provide more details on ODRM Validation by Substation Operators / Supervisors:

- ***SCE ODRM User Guide*** (referenced above in response to Action SCE-05)
- ***SCE ODRM User Guide – Training Presentation*** (referenced above in response to Action SCE-05)

3) Finally, outage information where distribution load is impacted is reviewed on a monthly basis, typically in the first week or two following the end of the month, whereby a sample of outages are flagged, based on certain criteria (e.g., potential anomalies), and selected for further review. This process seeks to verify that information in SCE's ODRM matches with the description of what occurred in the field and the information is correctly entered into the ILS and OMS. Supervisors work with Senior Specialists to review and correct any anomalies that are found and reapprove the ODRM entry.

Action SCE-13*: In its 2021 WMP update, SCE shall describe its current QA/QC process to ensure that training being taken by staff is effective in determining the proper cause of outages by decreasing the number of falsely entered causes.*

Response:
No formal QA/QC process has been implemented. Rather, supervisors provide on-the-job informal training as needed and/or discuss lessons learned and continuous improvement during weekly meetings.

Action SCE-14*: In its 2021 WMP update, SCE shall provide a list of all new situational awareness tools that were deployed and describe how they are being utilized to inform outage cause determinations.*

Response:
The lighting tool described in SCE's response to condition v. is the key situational tool employed to help inform personnel making outage cause classifications. As described in its 2021 WMP Update, SCE is also currently piloting DFA technology,[2] or continuous monitoring sensors, which will help SCE detect, locate and categorize electrical events such as incipient and traditional faults.

Action SCE-15*: In its 2021 WMP update, regarding the algorithm that assigns a cause to outages classified as "no cause found", SCE shall: 1) provide the percentage and number of outages that are assigned a cause by the algorithm, 2) describe how SCE checks the algorithm for accuracy, 3) provide all QA/QC procedures related to the algorithm, including frequency of QA/QC assessments, and 4) provide an analysis demonstrating the effectiveness and accuracy of the algorithm.*

Response:
1) provide the percentage and number of outages that are assigned a cause by the algorithm

- In 2019, approximately 20% of sub-transmission outages (451) were assigned a cause by the algorithm (using the algorithm, 423 were assigned a specific cause, and 28 were ultimately assigned to "no cause found").
- In 2020, approximately 13% of sub-transmission outages (216) were assigned a cause by the algorithm (where 203 of these outages were assigned a specific cause and 13 were ultimately assigned "no cause found").

2) describe how SCE checks the algorithm for accuracy

- SCE has a 3-step process to determine a cause for all of outages:
    - Field staff patrol interruptions and identify if damage has occurred to equipment or structures. If damage is found, this information is transferred over to SCE's switching centers or dispatch center and is documented into the Interruption logs (ILS) or OMS system
    - SCE also receives customer calls which provides additional information on the location and possible cause of outages.
    - If after a patrol is completed with no cause found, SCE will review other databases to provide information that allows to determine a probable cause for outages. These databases

[2] SCE 2021 Wildfire Mitigation Plan Update, Section 7.3.2.2.

are fault device locators, weather data from Indji Watch which provides historical data of lightning strikes in any cases where there is a strike within ¼ mile of Transmission and Sub transmission lines.

3) provide all QA/QC procedures related to the algorithm, including frequency of QA/QC assessments

- The algorithm was built by analyzing historical data of all cause codes used over a 15-year period.
- As SCE receives information from new interruptions that occur these are placed into the algorithm and re-adjust the probable code from past outages. This update occurs after information on each outage is received and is validated after research is completed.
- The use of database tools is used to validate the probable cause for these outages that occur where SCE found no cause. ILS logs provide the information for distance fault indicators to provide the area in which the fault occurred. This information is updated into the system quarterly.
- Switching center supervisors review the interruptions that occur on the Transmission and Sub-transmission system to validate a cause code was provided.

4) provide an analysis demonstrating the effectiveness and accuracy of the algorithm.

The algorithm utilizes historical outage data and knowledge about weather patterns, seasonal migration and known activities (e.g., tree trimming) to provide insights on probable causes of outages when no cause can be found. In 2017, SCE identified that it had many cause codes which indicated that it did not identify a cause on the bulk power system. As SCE reviewed this data it found that during a period where there were multiple interruptions over a short period of time, SCE was not able to patrol prior to the next interruption that occurred. Therefore, SCE would close the interruption as “no cause” or “not patrolled.” During this time, SCE’s reporting combined these outages together as a “No cause found” code.

After researching many outages and using a weather detection tool, SCE identified that the many outages that occurred were related. As an example, a particular circuit had five momentary interruptions over a period of six days. Patrol crew were informed and completed a patrol on day two and day four. Both occasions indicated no damage was identified. On day six, a patrol crew identified that an insulator flashed over due to a lightning strike. Four of the outages were labeled as no cause found while the fifth outage was labeled as a lightning strike. Using insights from the fifth outage, SCE could then assign likely probable cause to the first four outages (e.g., lightning-related).

Another scenario for providing a probable cause would be during the spring in several areas of SCE territory birds migrate and build nests on SCE structures. While the nests are being built, foreign objects are either dropped onto non-covered conductors or they are built in close proximity to lines. When the interruption occurs, the material is not found to support determining the cause of the interruption. Using the algorithm (e.g., proximity to seasonal nesting areas and month of the year) allows for providing a reasonable cause for what may have occurred.

A third analysis would be in windy areas or where tree trimming is occurring, and a circuit or section of line has an interruption and field crews find debris on the ground in many areas but do not identify any damage to SCE equipment or structures. The historical data provides a reasonable cause for the outages (e.g., wind or tree-trimming related interruptions).

General Instructions for Recording Interruptions

Contents

1. Introduction

1.1 Purpose

This System Operating Bulletin (SOB) describes and outlines Southern California Edison (SCE) functional requirements for accurate collection and recording of reliability events.

1.2 Background

1. As SCE moves toward the ability to capture actual reliability data (instead of using an algorithm) the Distribution/Transmission Inventory Menu (DTIM) system has been deployed.

   A. This database replicates the electrical connectivity of electrical lines and equipment and will be utilized for capturing reliability data.

   B. The captured information will be recorded in the Outage Database and Reliability Metrics (ODRM).

2. SCE has replaced old databases and utilizes capabilities within the Outage Management System (OMS). The captured outage information will be recorded in the ODRM. A properly maintained inventory, along with accurate interruption data, provides the basis for Customer Minutes of Interruption (CMI) calculations, equipment performance data, statistical compilation, and historical analysis.

   A. The *number* of operations, number of customers, and the *length* of interruptions, influence performance measurements.

   B. This data *defines* reliability to our customers and is reported to the California Public Utilities Commission (CPUC).

   C. The accuracy of this data is critical since it reflects our performance and will be audited by outside parties at some point in the future. This data will also be used to plan future network improvements and improve the level of service to our customers.

3. At this point in time, planned outages are tracked but not reported to the CPUC. The log for these outages is created utilizing OMS.

4. There have been multiple changes to the definitions of interruptions both in terms of times and the equipment involved. The intent of these changes is to assure consistency in reporting across utilities both in California and nationally.

5. As a result of a recent agreement with the CPUC, SCE will no longer be tracking interruptions at the circuit level only.

6. SCE will begin tracking interruptions to customers at the level of the distribution transformer and higher. This means that customers interrupted as a result of secondary voltage line problems or individual service problems will not be tracked or reported to the CPUC as part of our annual reliability report.

7. Maintaining accurate inventory data, and thus accurate CMI and reliability data requires cooperation from those individuals who are primarily involved with changes and reporting; Mapping, GMC Analysts, Substation Operations Supervisors, System Operators, Distribution Operation Center Specialists, Engineers, Troublemen, Line crew personnel and any user who has a role in restoring and tracking customer interruptions.

2. Notifications & Changes

2.1 Assistance

For notification, changes, assistance, or any questions which arise regarding Distribution/Transmission Inventory Menu (DTIM) contact the DTIM Administrator or GMC Analyst by Email.

2.2 Making Changes to DTIM

Notify the DTIM Administrator and GMC Analyst via Email whenever changes to Transmission, Subtransmission, and Distribution facilities are made which would affect the status of the equipment in the following ways:

- In or Out of Service
- Source Line/Circuit Changes – including PT, padmount, or Underground Substations
- Jurisdiction Changes
- Number of Customers – e.g. Load rolling
- Pole Top to padmount or U.G. S. conversions

2.3 Making Changes to Historical Interruption Records

Changes to validated Historical Interruption records in completed status in ODRM shall be coordinated through Manager of Reliability Analytics and Reporting and/or send requests by E-mail to the DTIM Administrator.

3. Responsibilities

3.1 Substation Operations Supervisor (SOS)

In regards to Transmission, Subtransmission, and Distribution facilities it is the responsibility of the SOS, *or representative* to ensure that:

- Corresponding Interruption logs for Distribution interruptions are initiated on OMS as interruptions occur and are verified within 24 hours of the incident; under normal conditions (as outlined in SOB-12)
- All interruption records accurately reflect what is recorded in Switching Center Log
- Substation interruptions are validated (this includes Pole Top Substations) within 72 hours of the incident; under normal conditions
- The DTIM Administrator is adequately notified regarding inventory changes (as outlined in SOB-12)

3.2 Substation Construction and Maintenance Supervisor

It is the responsibility of the Substation Construction and Maintenance (SC&M) Supervisor, *or representative* to ensure that Substation outages involving CMI are reported accurately and verified within 72 hours under normal conditions.

3.3 Transmission Supervisor

It is the responsibility of Transmission Supervisor, *or representative* to ensure that Transmission outages involving CMI are reported accurately and verified within 72 hours, under normal conditions.

3.4 System Operator

System Operators shall perform the following:

1. Provide sufficient information on the Interruption Log Sheet (ILS) so that a reliability event can be re-created for the purpose of analysis or calculating reliability. The information provided shall include:

    A. All information which identifies the status of the lines and equipment prior to the start of the event (whether the circuit status was normal or abnormal at the start of the event).

B. Circuits, substations (including split loads with all downstream load affected), lines or equipment affected.

C. All the restoration steps in the exact order performed.

D. Individual All Load Up (ALU) times for the various lines and equipment affected.

E. The status of all lines and equipment upon completion of the reliability event.

2. Maintain Transmission line inventory fields: Miles of Line, Overhead, Underground, Line ampere ratings.

3. Operate graphics on OMS, creating incidents to reflect correct status of switching and circuitry.

3.5 Transmission Patrol / Distribution Troublemen / Distribution Line Crews

1. It is important for the field personnel to provide all required data to System Operators and GMC personnel in a timely manner and maintain communications throughout the restoration process.

2. To ensure accurate completion of interruption records Transmission Patrol, Distribution Troublemen, and Distribution Line Crews shall:

   A. The patrol crews/Troublemen must ascertain the cause, conductor type, pole number, tower type and any other pertinent information regarding an interruption and communicate this information in a timely manner to System Operators and GMC personnel

   B. It is critical to not only know the "what", but also the "why". For example: Wire down, was it a result of fatigue, connector failure, etc. If a tree branch is in the line, did it fall, blow or grow. This will help accurately choose the correct cause code

3.6 Distribution Operations Support Specialist / Clerk

Provide sufficient information on the Incident Manager Crew Repair Remarks / Outage Alert Note (OAN) to reflect what and where (e.g. tree FELL into transformer, wire down at pole XXXX), as well as when power was restored.

3.7 Grid Operations Analyst

The Grid Operations Analyst shall:

- Update and maintain distribution circuit inventory, in terms of number of customers
- Responsible for validating all reportable customer interruptions
- Document the results in ODRM

3.8 Distribution Reliability

Facilitate and document all corrections to the Completed Outage Database file.

3.9 DTIM Administrator

The DTIM shall keep inventory up to date.

1. This requires cooperation from those individuals who are primarily involved with changes, for example:
    - Map supervision
    - GMC Analysts
    - Substation Operations Supervisors
    - System Operators
    - Engineers

4. Reliability Definitions

ACMI — Average Customer Minutes of Interruption. A calculated figure that is related to the system reliability to the entire Edison electrical system. This figure is a measure of how long the average customer was without service over a specified period of time, typically a year.

ACMI = CMI ÷ total number of customers served

Area Out — Refers to when we receive three or more "No Lights" calls on one or more connected, contiguous SCE facilities.

AGMS — Automated Grid Maintenance System. Computerized system used to track inventory and inspections of underground electrical facilities.

ALU All Load Up. Refers to the recorded time when all of the load on a distribution circuit interruption or reportable event may be considered picked up. Exceptions for when ALU may be declared if customers are still without power are when:

- Load not serviceable (Ex.: all remaining services were destroyed or uninhabitable)
- Denied access or road washed out
- Seasonal load not required due to time of year
- Customer on SCE furnished Generator

Note: Any exceptions must be documented on the ILS.

AR Automatic Recloser. A line device used to sectionalize portions of a distribution circuit.

BLF Branch Line Fuse. A fuse located at the source site of a circuit branch. The fuse is intended to isolate the branch in the event of a downstream failure or short circuit.

BLF Interrupt Time A Branch Line Fuse interruption, the time of which is recorded as beginning with a customer call without regard to the time that district personnel may arrive at the outage location.

BURD Buried Underground Residential Distribution.

CARLA Circuit and Automatic Recloser Lockout Alarm. An alarm, triggered by an interruption of the circuit, that goes to a paging system, which directly pages Operators and District personnel with the circuit number. This system has been cut-over from pagers to the OMS, which is quicker than the paging system. The system consists of cellular phone and voltage transformer mounted to the secondary side of pole top transformers and is initiated upon loss of potential.

Cascade An arrangement of electrical component devices (i.e. substations, lines, circuits, ARS, BLFs etc...) which feeds into the next component device in succession where a "parent - child" relationship is established.

Major Event An outage or interruption event is classified as a "Major Event" when the event causes the ACMI for the Edison system to exceed 5 ACMI during a 24-hour period.

Cause Code A number representing a specific causal event that produces an electrical service interruption. It is part of a list of numerical identifiers of events that describe electrical service interruptions.

CCC	Customer Communication Center. Point of contact for customers to report service problems. Customer orders are put on-line to be dispatched by the Distribution Operations Centers.
Circuit	Distribution circuit <= 33 kV.
Circuit Interruption	A distribution breaker and/or automated recloser operation resulting in either a momentary or a sustained interruption.
CLU	Customer Load Up. The actual time a customer's load has been restored.
CMI	Customer Minutes of Interruption. A calculated figure that relates the number of interrupted customers and the amount of time that their service was interrupted, indicating localized electrical system reliability.
DOC	Distribution Operations Center - The DOC provides information and the dispatch of Troublemen in response to circuit interruptions, customer complaints and emergencies. Under normal conditions, DOC personnel assign and dispatch Troublemen, complete orders, and act as a communications center for their zone. There are four DOC zones: • [redacted] (Southern) • [redacted] (Western) • [redacted] (Northern) • [redacted] (Eastern)
DTIM	Distribution/Transmission Inventory Menu. A computerized system used for management of transmission lines, substations, and distribution circuit inventories.
EMS	Energy Management System. This is a real-time SCADA, computerized control system, used for monitoring station loading, alarms, and controlling circuit breakers, and other substation devices.
ETR	Estimated Time of Repair. Refers to the time given to the customers when it is estimated that repairs will be complete.
FI	Fault Indicator. A device located on the primary distribution circuit in a strategic location. FIs are numbered (FI 1, FI 2...) and this facilitates the location of a fault on a circuit. FIs are referenced in the lockout procedure and are marked on circuit maps.

Flickering Lights A condition where customers are experiencing periodic dimming of lights potentially due to a number of possible factors such as energizing a large load (arc welder or motor loads), a failing neutral, or arcing in the customers panel.

Fuse Interruption A fuse operation that results in an interruption.

GCC Grid Control Center. The organization that coordinates and supervises outages within the SCE transmission and subtransmission systems. The GCC System Operating Supervisor has jurisdiction over the entire SCE electric system and has the authority to assume jurisdiction of any Switching Center.

GMC Grid Management Center. A work location that houses both a DOC and a Switching Center in the same facility.

Interruption Loss of service to one or more customers.

Listed below are what Grid Operations enters as an "interruption", which potentially have no impact on customers or CMI:

- Loop Transmission/Subtransmission/Distribution lines that relay at one or both ends
- Any banks at stations where load is not split and each bank has enough capacity to carry the entire station load
- Station capacitor banks

Note: See "Outage", "Momentary Interruption", "Sustained Interruption", "Fuse Interruption", and "Source Interruption".

Line Transmission/subtransmission $\geq$ 33 kV.

Lockout When a circuit or line relays, and then relays on test.

MAIFI Momentary Average Interruption Frequency Index. A calculated figure used to provide information about the average frequency of momentary interruptions.

MAIFI = total # of customer momentary interruptions ÷ total # of customers served **OR** MAIFI = (Sum of ID_i N_i) ÷ N_T

- ID_i = # of interrupting device operations
- N_i = # of interrupted customers during reporting period
- N_T = # of customers served

Momentary Interruption An interruption of duration limited to the period required to restore all services by an interrupting device. Such switching operations must be completed in 5 minutes or less.

No Lights	A situation where a customer notifies SCE that they have no electrical service.
Non-storm Event	A wide range of events that produce electrical service interruptions. For reporting purposes, "non-storm" refers to all events that are neither "storm" nor "catastrophic".
ODRM	Outage Database and Reliability Metrics. A database used for reliability analysis and internal and external reporting.
OMS	Outage Management System. A system whose primary function is to group trouble calls by the parent device to which the customer is attached. This replaces the old CIS system which had no way of relating calls on a list with their associated areas. Another function is that of graphically modeling the electrical system. The old paper-based circuit maps are replaced with on-line graphical version which can be re configured to dynamically represent the current state of the electrical system - globally.
Outage	Refers to the state of a component (such as a circuit, substation, transformer, transmission line, etc.) when it is <u>not</u> available to perform its intended function due to some event associated directly with that component. An outage may or may not cause an interruption of service to customers, depending on system configuration.
Padmount Sub	A weatherproof metal-clad transformer enclosure located on a distribution circuit and used to reduce one primary voltage to another primary voltage on a section of the circuit.
Partial Circuit Interruption	Occurs after a distribution circuit breaker operation when some service has been restored and one or more customers remain off during the repairs and the district has not declared "all load up".
Partial Duration of Interruption	The information entered in this field is the length of the interruption in minutes of a partial circuit interruption.
Part Lights	A situation where a customer only has a portion of their service available. This situation typically manifests itself with residential customers where only half of their electrical outlets are working.

PBR	Performance-Based Ratemaking. An approach to electric utility rate construction that rewards or punishes the utility for performance outcomes in relation to specified standards. The standards of performance are negotiated by the utility with the California Public utilities Commission (CPUC). The utility must record electrical service data and provide the data in reports to the PUC. Failure to meet the agreed upon performance standards, results in reduced rates of return for the shareholders of the utility.
PBR Reporting	An evolving area in which different electric utilities measure performance standards according to historical practices, which may or may not be consistent across utilities. To permit customer evaluation of electric utility performance across utilities and to ensure equitable comparisons, IEEE and participating utilities are moving toward consistent measurement definitions.
PLU	Part Load Up. Refers to the recorded time when the first portion of the interrupted distribution load is restored. If the entire interrupted load is restored at one time, then the PLU is zero.
Pole-Top Sub	A pole-mounted substation located on a distribution circuit and used to reduce from one primary voltage to another primary voltage.
Radial Fuse	A device that is intended to protect a radial distribution line consisting of more than one transformer. Examples are branch line fuses, overhead fuses protecting underground radials, and BURD fuses protecting residential radials.
RCS	Remote Control Switch. A field switch that can be opened and closed remotely.
Reliability Event	An event that interrupts service at the transformer level to our customers.
Repair Time	A measure used to track how quickly line crews repair or replace broken or damaged facilities. The time, measured in minutes, is from when service has been restored to a portion of customers on an interrupted circuit until all customer loads have been restored.
Reportable Outage	An unplanned outage that affects a single transformer or more on the SCE grid.
Response Time	A measure used to track how quickly Troublemen respond to circuit interruptions. The time, measured in minutes, is from the start of the interruption until some portion of the customer load has been restored.

R&R	Relay and Reclose. This term refers to the process by which a circuit breaker relays (opens) as a result of a transitory fault and restores load when the circuit breaker recloses (close) for a test.
SAIDI	Sustained Average Interruption Duration Index. A calculated figure used to provide information about the average time that customers are interrupted. SAIDI is commonly identified as ACMI. SAIDI = Sum of customer interruption durations ÷ total # of customers served **OR** SAIDI = (Sum of r_i N_i) ÷ N_T • r_i = resolution time for each interruption event • N_i = # of interrupted customers during reporting period • N_T = # of customers served
SAIFI	Sustained Average Interruption Frequency Index. A calculated figure that gives information about the frequency of sustained interruptions per customer for a pre-defined area. SAIFI = Total # of customer interruptions ÷ total number of customers served **OR** SAIFI = Sum of N_i ÷ N_T. • N_i = # of interrupted customers during reporting period • N_T = # of customers served
SCADA	Supervisory Control and Data Acquisition. An electronic system that provides switching centers with data and remote control capability.
Scheduled Outage	An outage that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventive maintenance or repair.
SOB	System Operating Bulletin. Standard operating policies and procedures issued and maintained by the GCC.
Source Interruption	An interruption caused by the loss of a source feed. A source interruption may produce one transmission interruption and multiple distribution interruption records.
Storm Event	A wide range of events which are not controllable and that produce electrical service interruptions are grouped into the category "storm". These include, but are not limited to; rain, wind, lightning, fire, earthquake, snow, ice, fog and flood.

Substation Log Written log located at each substation location into which detailed, site-specific record of events and other data is entered, including:

- load readings
- CB counters
- equipment/station normal and current status
- equipment/line clearances
- personnel at work
- switching performed

Sustained Interruption Any interruption with an entire or partial circuit interruption that is greater than 5 minutes.

Switching Center Log Place of entry for all pertinent information regarding switching center activities and all relevant details of any significant event including:

- Switching by Sub Operators, District and Transmission crews
- Clearances
- Personnel at Work (PAW)

Interruption data for outage reporting system (targets, CB counters, cause code, start time/part load up time/all load up time, switching, circuit status).

TLM Transformer Load Management. Database that captures the number of customers per transformer and calculates transformer loading.

5. Special Considerations

5.1 Operating Region

1. The value in this field assigns the ultimate responsibility for the interruption.
2. All of the interruption screens have this field. The field will default to the type of transaction being entered.
    A. For example, a Transmission Line interruption will default to "Trans".
    B. The default is not always correct, if for some reason the cause of the interruption is not the line.

C. There are nine categories, as follows:

- Generation
- Grid Control
- Transmission
- Sub-Operations
- Sub-Test
- Sub-Maintenance
- Distribution
- Telecommunications
- Foreign

5.2 Jurisdiction in OMS

OMS handles jurisdiction as follows:

1. Lines and circuits are individually assigned to a Jurisdictional Switching Center.

2. But there are some discrepancies as follows:

   A. For each distinct pair of voltages there is a substation record in DTIM.

   B. Each substation record is assigned to a Jurisdictional Switching Center NOT each voltage at a substation.

   C. So, at a station where jurisdiction is split between high/low voltages, only ONE switching center is assigned jurisdiction in DTIM.

   Note: Refer to Section 5.8, *Bus Differential/Load Shed Operations/SOB-21* for more information.

5.3 Bank Numbers

In DTIM, this is not *necessarily* the Bank Number. Bank No. 0 is used to indicate all banks of a particular voltage. Bank No. X is used when load is split, and circuits assigned to Bank No. X were de-energized as a result of a Bank/Bus operation. Use the F10 Key to show the relationships established for a Substation in regard to Bank/Circuit assignments.

5.4 Transmission: Nearest Tower or Pole

1. This field is found on the ANTR screen and is very important information for reliability improvement studies.

2. Certain cause codes will require an entry in this field, and it should be entered in the following format: "M2T4" Translated: Mile 2 Tower 4.

5.5 Nearest Structure

1. Distribution Circuit Outages require the nearest structure number, which is very important information for reliability improvement studies.

2. The identifier that should be placed in this field is a valid structure number, as found in OMS, for the nearest structure that the fault occurred at.

5.6 Point of Contact

The point of contact field is required when station equipment is faulted. Once again, this is very important information for reliability improvement studies. The codes will be available on line and describe the closest point in the substation to the faulted equipment.

5.7 Device 143

Currently, Device 143 changeovers must be initiated by the DTIM System. The changeover time should be recorded on the ILS as 6 seconds.

5.8 Bus Differential / Load Shed Operation / SOB-21

1. At an A-Bank station, the jurisdiction of the Station may belong to Switching Center ***A***, and the individual 66 kV lines belong to Switching Center ***B***.

2. In order to get the correct cascade in DTIM, when a 66 kV bus is de-energized by a Load Shed operation or bus differential operation, the interruption must be entered as a Substation Outage (ASIN).

3. DTIM doesn't know the difference between Bank and Bus substations.

   A. The problem lies in the fact that Switching Center ***B*** is responsible for the 66 kV System and cannot initiate a substation outage.

   B. In these instances, you may want to contact the DTIM Administrator to temporarily change the jurisdiction of a station.

   C. In this case, the best solution is to temporarily change the jurisdiction of the substation in DTIM to allow the outage to be entered by the responsible party.

   Note: For Stage 3/SOB-21 interruptions add a "G" (Generation) OPER.Region field.

5.9 Cause Code Usage

5.9.1 Cause Code: 0358 Relayed on District Test (or 0469 storm related)

After Part-Load has been picked up on a distribution circuit from the original interrupting device, all subsequent interruption records which occur as a result of the sectionalizing/testing activities, shall receive the following Primary Cause Code.

5.9.2 Cause Code: 650 Loss of Foreign Source

The obvious exception to the rule; to initiate all interruptions at the source is here, where the source is outside of Edison jurisdiction. There are other Foreign Cause Codes as well, use the *Cause Code Program* Foreign command button, or refer to the appendix.

5.9.3 No Cause Found

These are two distinct sets of causes (unknown & patrolled). Here, again, if the storm code is used as the primary cause code, it will be transferred to all the *cascaded* interruptions.

- 0498 Unknown Not Patrolled (Storm)
- 0499 Patrolled No Cause Found (Storm)
- 0598 Unknown Not Patrolled
- 0599 Patrolled No Cause Found

5.10 Three or More Terminal Transmission Line Interruptions

1. A very common error in entering these line outages occurs when different times are recorded for when the line tests, and then when the loop is restored.

2. The field labeled: *FINAL LINE SECTION*: does not refer to restoring the loop, but rather to a line section that was still de-energized when the *ENTIRE LINE:* time was recorded.

3. If the entire line was energized, on test, then record only the *ENTIRE LINE*, not a *FINAL LINE SECTION*.

5.11 Distribution Circuit Interruptions

1. To provide consistency in reporting, the following policies apply to determining the number of interruptions to report and who shall report them:

   A. Distribution circuits that relay and reclose shall be counted as one (1) interruption.

(1) If the same circuit relays again before five (5) minutes have elapsed, it is considered to be the same single (1) interruption.

Note: This rule applies when reporting the interruption within the Distribution Transmission Outage Data Menu (DTOM) system.

(2) Relay operations to the same circuit occurring after five (5) minutes have elapsed are counted as separate interruptions.

B. If a portion of a circuit is interrupted, it shall be counted as one (1) interruption.

C. If a circuit is de-energized to clear trouble from the line, it shall be counted as one (1) interruption.

D. In cases where more than one Switching Center has jurisdiction of a circuit, and that circuit relays, the Switching Center having jurisdiction of the CB (or other fault interrupting equipment) shall report the interruption.

E. If the distribution circuit is manually de-energized to clear trouble (without a relay operation), the interruption and/or trouble shall be reported by the Switching Center having jurisdiction at the point of trouble.

6. Summary

1. The key to creating and maintaining a reliability database that is accurate and useful is consistent, timely and accurate reporting of reliability events.
2. It is important that System Operators document the status before the event occurred, the restoration steps in the exact order they occurred, and the status of any affected lines and equipment when the event has ended.

7. Next Review Date

1. This SOB shall be reviewed and updated as required.
2. Revisions shall be tracked in the Revisions History section below.

8. Data Retention

1. Once retired or replaced, this document shall be retained for a minimum of four (4) years from the revision date indicated within the header.
2. A signed hard-copy of all current and in-force SOBs are kept in the Grid Control Outage Request area.
3. Electronic copies are kept on the Grid Control Operating Documents SharePoint site.

9. Distribution

- SOB SLD Distribution List

10. Approval

Please cancel and destroy copies of System Operating Bulletin No. 1100 dated July 13, 2020.

11. References

SOB-21, Operating Reserve Deficiency Contingency Plan

12. Revision History

Date	Description of Revision	Contact
10/28/20	Opened SOB 1100 for revision based on the request from S.Aumick (*GCC Dispatcher*) and made the following changes: • Added Section 5.11 "Distribution Circuit Interruptions". This information was removed from SOB 12 and added to SOB 1100. Requirement and statement regarding each jurisdictional Switching Center reporting total number of interruptions within their jurisdiction for the previous day to the GCC Transmission Dispatcher was removed.	
10/28/20	Submitted SOB 1100 for Manager review and approval via the GC Document Tracker.	
11/13/20	Published and distributed revised SOB 1100.	

TABLE OF CONTENTS

1.0 GOAL/PURPOSE

This job aid will provide an overview of the philosophy and the processing requirements to accurately record outage data using the Outage Management System (OMS). It will provide information on what constitutes a Reportable vs. Not Reportable incident as prescribed per Reliability Reporting rules. It will provide a step-by-step guide how to properly identify and process Reportable and/or Not Reportable incidents to ensure data integrity in reporting. It will also provide a step-by-step guide how to make corrections to archived incidents before approving for upload into the Outage Management & Reliability System (ODRM), if deemed necessary.

Objectives

After completion of this module, participants will be able to do the following:

- Identify Reportable vs Not Reportable incidents
- Process Not Reportable incidents
- Process single location Reportable incidents
- Process simple multi location Reportable incidents (not included in this version)
- Correct completed incidents
- Correct archived incidents
- Approve Reportable incidents for ODRM upload

2.0 IDENTIFYING REPORTABLE VS. NOT REPORTABLE INCIDENTS

It is important to realize that when dealing with incidents on OMS there are basically only two type of incidents that are fundamental to our Reliability Reporting: 1) Reportable Incidents and 2) Not Reportable incidents.

Understanding this distinction is key for an efficient data processing and for achieving corporate goals that may have significant impact to the success of our organization and beyond.

2.1 What are Reportable Incidents?

Reportable incidents are all emergency or unplanned interruptions to a transformer load – where either a transformer has failed, or the power feed to a transformer was interrupted, resulting in customer(s) experiencing a total loss of power. We often describe these incidents as interruptions/outages on the primary circuit level.

This would include all circuit Lock Outs, Relay & Reclosers, Area-outs, and/or single transformer outages - These interruptions/outages are subject to PUC reporting and are driving our SAIDI/SAIF metrics.

- **Note:** A field crew might call an Emergency Outage a Planned Outage as they "plan" to de-energize a structure in a controlled manner but unless the customers has received a 3-day notification prior to being de-energized or the structure is a part of an existing planned outage that has increased in scope, the outage is still an emergency outage and subject PUC reporting

It is also important to note that this does not match with the Outage Alert Note criteria for an Area Out, which requires 3 customer calls. <u>Reportable Outages do not require ANY customers to call</u>.

Examples of incidents that result in outages and are Reportable incidents:

- All Transmission Outages interrupting Substations and/or Distribution Circuits
- All Substation Outages interrupting Distribution Circuits
- All Distribution Circuits Interruptions where CBs or RARs operate (open) resulting in customer load interruption
- All outages beyond Branch Line Fuses or Fuse Dips
- All outages beyond Switchable devices or taps (ex: RCS, PMH/PMS, OS, GS, BS) interrupting customer load
- All Transformers loosing or without power
- Primary Wire Downs resulting in No Lights, Part Lights or Low Voltage
  - Please verify if wire down is on Primary and document in Crew Remarks along with location of wire down (nearest OMS structure #)
- Emergency "controlled" Outages (ex: "Manual Opens" to clear or repair trouble location)
- Outages that start at the secondary level and later escalate to de-energized structures/transformers at the primary level to isolate or make repairs

2.2 What are Not Reportable Incidents?

Not Reportable incidents are all incidents/trouble tickets where the customers <u>did not</u> experience a total loss of power, or if they did, this interruption was caused due to a fault below the transformer level – on the secondary circuit level (secondary service wires, weather-heads, hand-holes, etc.). The key component here is that the transformer was never de-energized or lost power.

These incidents are not subject to PUC reporting and are not part of our SAIDI/SAIFI metrics, therefore they must be excluded in order not to adversely impact our Reliability reporting.

Note: Maintenance outage are also classified as Not Reportable outages.

Examples of Outages that are Not Reportable:

- Pre-Scheduled Maintenance Outages with at least 3-day notification to customers
- Maintenance Outages with Customers not notified due to TLM error, or increase in scope of job (these customers will be compensated through the Service Guarantee Std #3)
- Secondary wire down or Secondary Fuses blown
- Service wire down
- Outages at weatherheads, customer panels, or customer main breakers
- Part Lights or Low Voltage incidents – UNLESS there is a PRIMARY Wire down
- Customer requests to de-energize a single transformer (if they are the only customer on the transformer)
- Outage to replace equipment, ex: a cross-arm, when NO CUSTOMER LOAD is affected
- Cut for Non Pay
- Reset Customer Breaker
- Customer Equipment Problem
- Incidents created to generate a CAD ID number
- Single AMI Calls

2.3 How to properly process and status an incidents on OMS as Not Reportable?

- Remove the Total Loss of Power flag (TLP) from all locations on the Device tab
- Set all Couse Code fields and Occurrence fields on the Location tab to one of the appropriate "Not Reportable" codes
- Complete Order and sent to History

2.4 How to identify OMS incident locations as Reportable or Not Reportable?

- All Reportable locations (valid outage restorations steps) of an incident will have the TLP flag checked and the appropriate cause code assigned to them
- All Not Reportable locations (trouble tickets for non–outages, or invalid outage restoration steps) will have the TLP flag unchecked and one of the "Not Reportable" codes assigned to them

2.5 Step-by-Step Examples for how to identify and clear/complete Not Reportable incidents on OMS/CAD

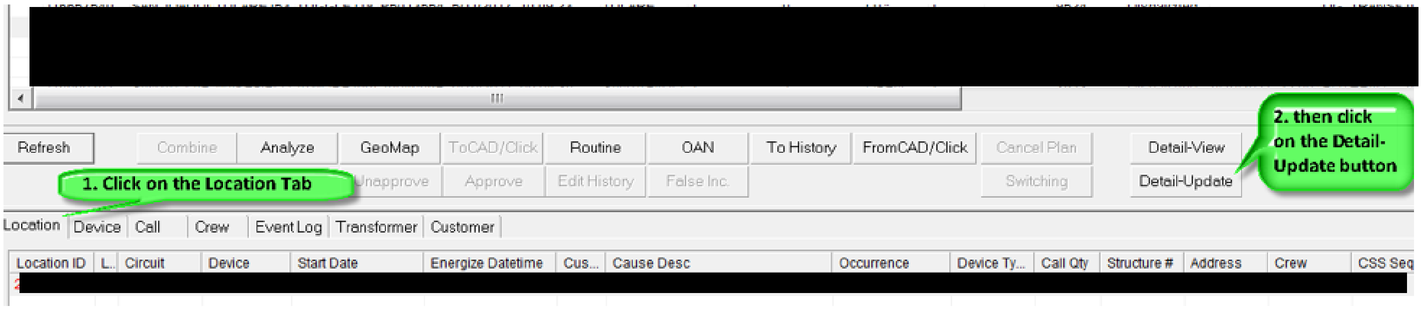
There are four main types of non-reportable incidents, we will present them one-by-one, including how to mark them non-reportable.

- **SINGLE NO LIGHTS CALL, NOT SENT TO CAD - MARKING IT NOT REPORTABLE FOLLOWING QC**
- **A QUICK INCIDENT THAT IS CREATED TO GENERATE A CAD ID**
- **NL CALL SENT TO CAD, NOT SCE PROBLEM**
- **SECONDARY OUTAGES – SENT TO CAD**

a) SINGLE NO LIGHTS CALL, NOT SENT TO CAD - MARKING IT NOT REPORTABLE FOLLOWING QC

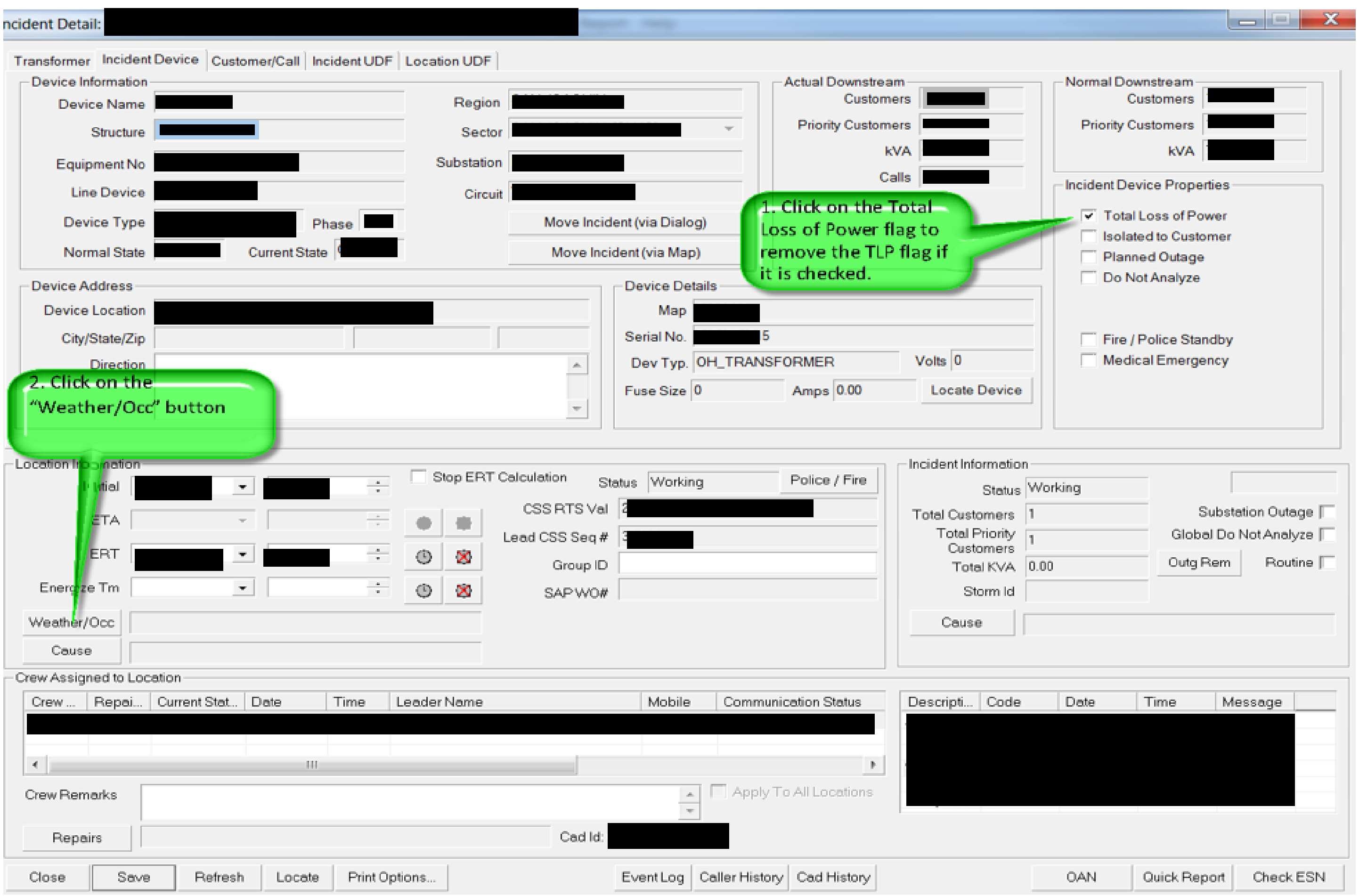
This procedure is for single no light calls that are QC'd and NOT sent to CAD. Examples are; breakers reset, meter pinged voltage okay, ALU following an interruption, etc.

- In the secondary screen of Incident Manager, click on the Location tab on the secondary screen and then click Detail-Update,

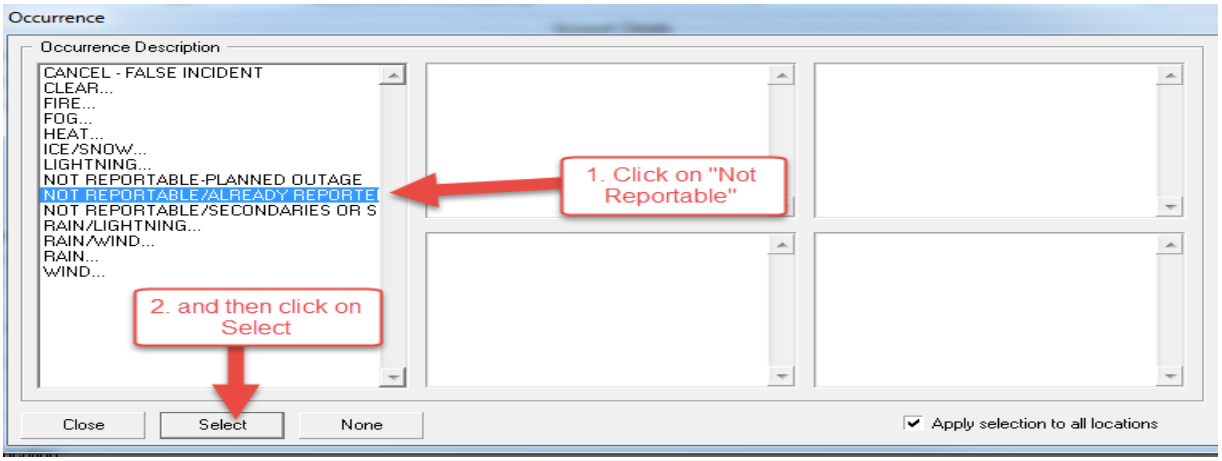


- a new window will open.

- In the new window, 1. Click on the Total Loss of Power flag to remove the TLP flag if it is checked. 2. Click on the "Weather/Occ" button



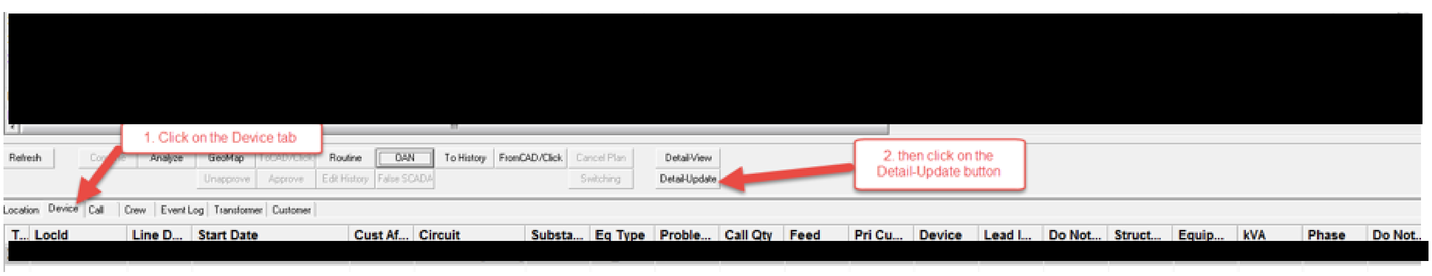
- This will open another new window, in this window, click on “NOT REPORTABLE/ALREADY REPORTED” and then “Select”, this will close the window



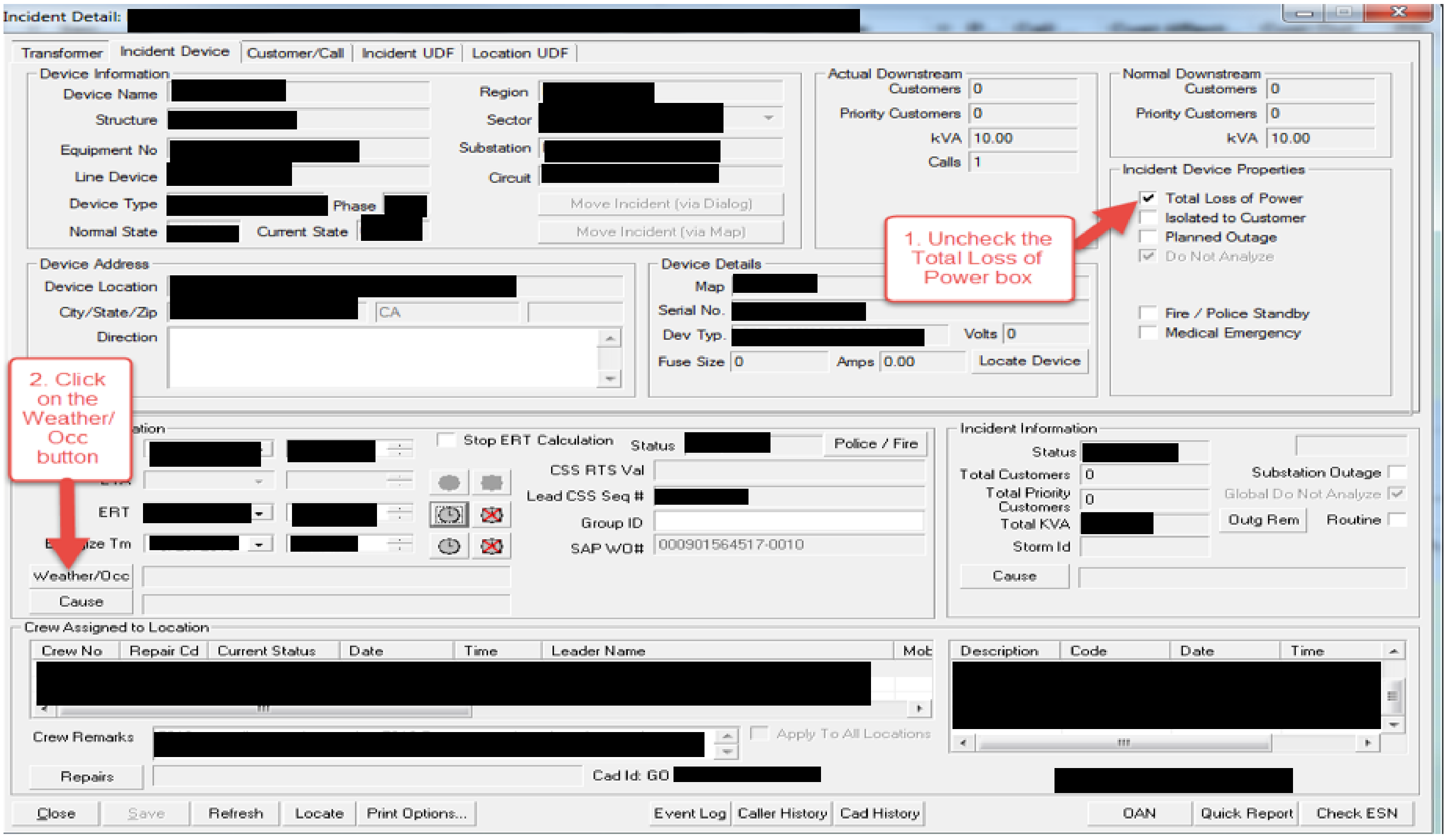
- Then close the remaining open window, **saving** your changes. This is the end of the process.

b) A QUICK INCIDENT THAT IS CREATED TO GENERATE A CAD ID.

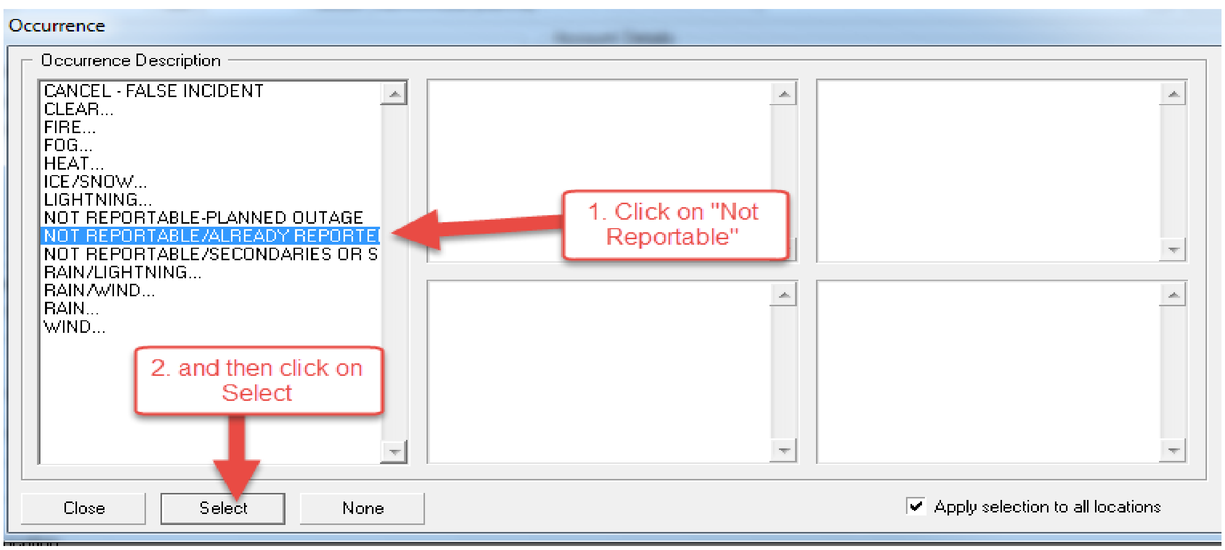
- In Incident Manager, secondary screen, 1. Click on the Device Tab and then 2. Click on Detail/Update



- The Incident Detail window will open, 1. uncheck the “Total Loss of Power” box, and then 2. Click on the “Weather/Occ” button.



- This will open another new window, click on “NOT REPORTABLE/ALREADY REPORTED” and then click on Select

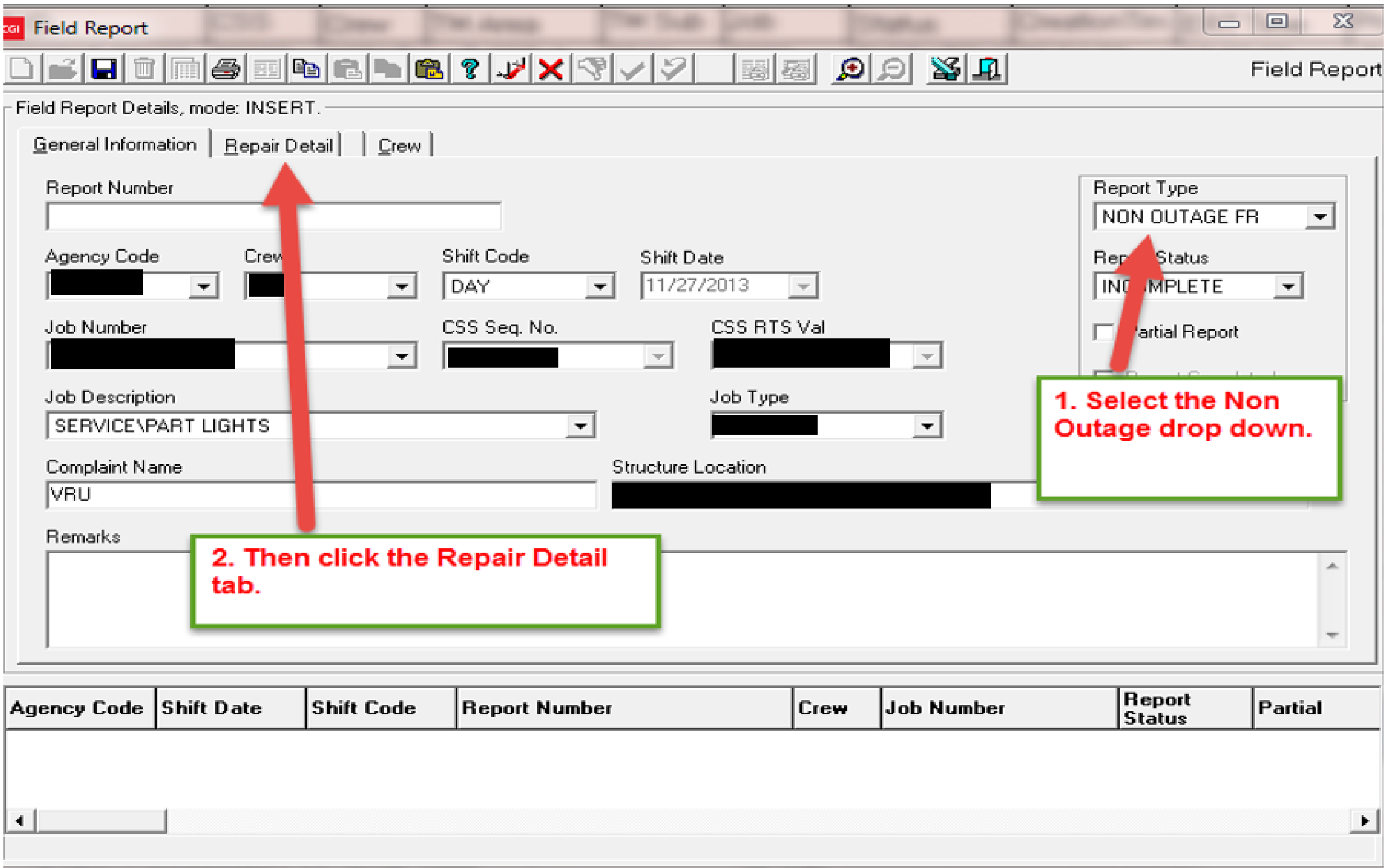


- Then close the remaining open window, saving your changes. This is the end of the process.

c) NL CALL SENT TO CAD, NOT SCE PROBLEM

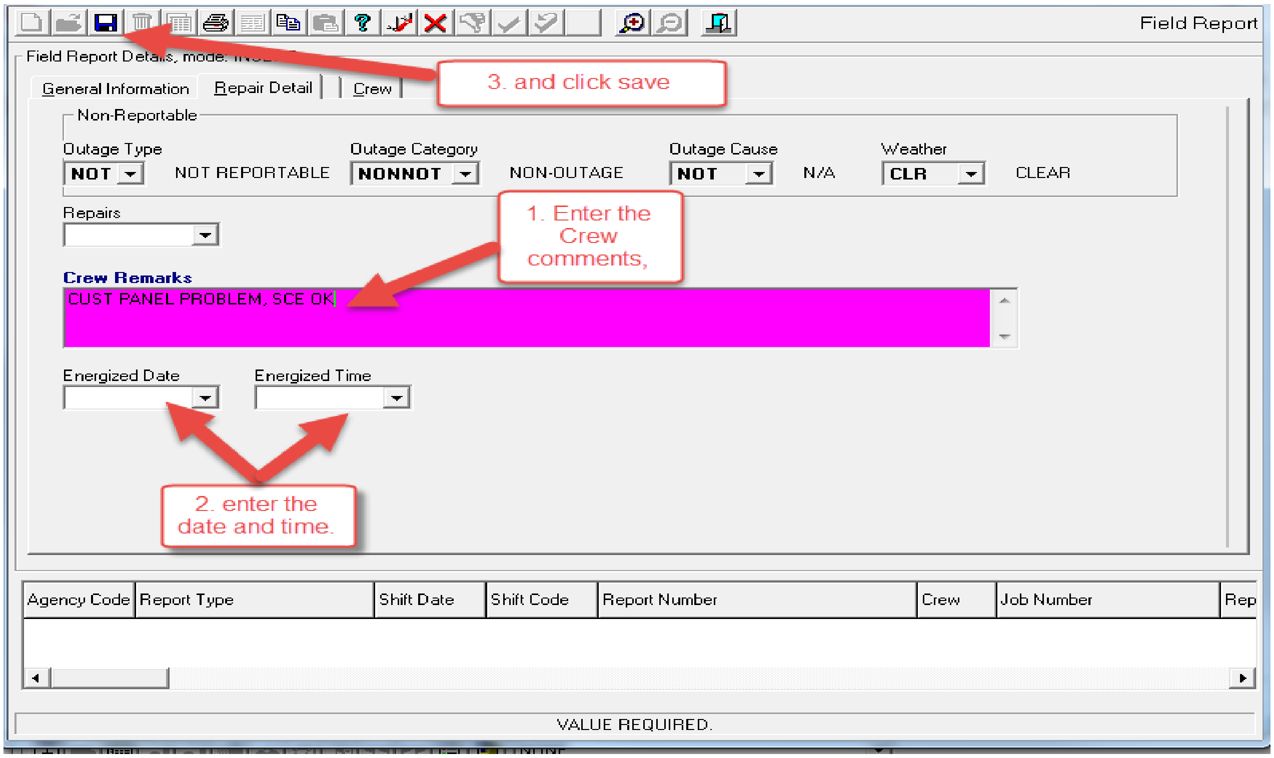
This procedure is for single no light calls that are QC’d AND sent to CAD. TM reports back, not SCE problem. Examples are; breakers reset, customer problem, TM found lights on, etc.

- When clearing the order in CAD using the Field Report, first select the “Non-Outage” drop down, then click the Repair Detail tab.

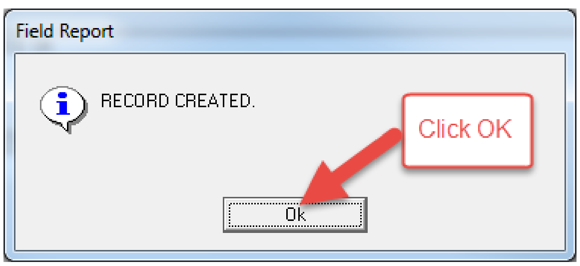


- This will open the Repair Detail window.

- In the Repair Detail window, enter the Crew comments, the date and time and save.



- The Record Created window will pop up, click OK. This completes the CAD process- See note below.

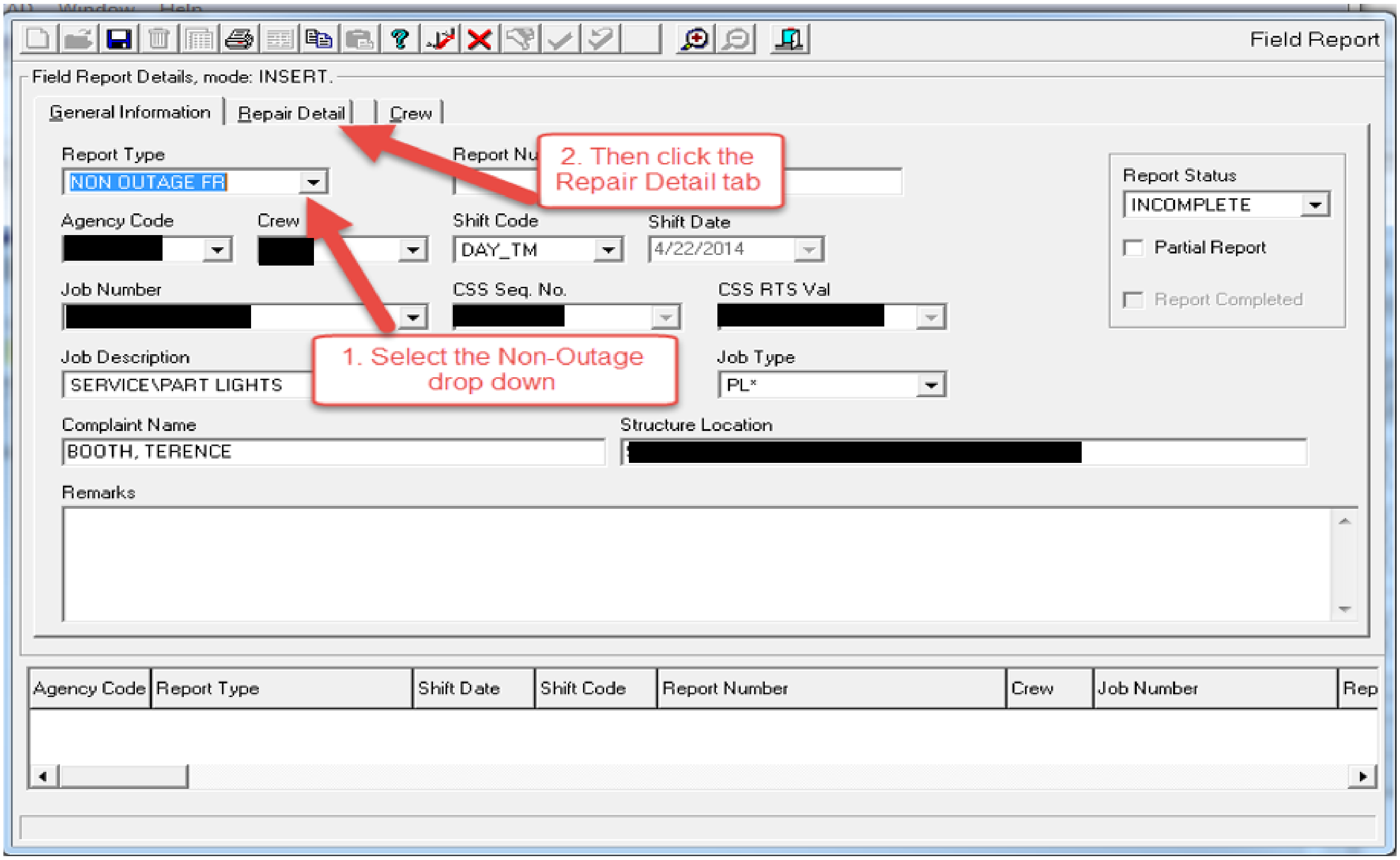


Note: It is vital that you check the incident in Incident manager to confirm that the TLP flag is not checked since no visibility of the TLP flag exists in CAD. The steps in the aforementioned instruction do not guarantee that the incident will not fall into the pending Potential outage report unless the TLP is unchecked.

d) SECONDARY OUTAGES – SENT TO CAD

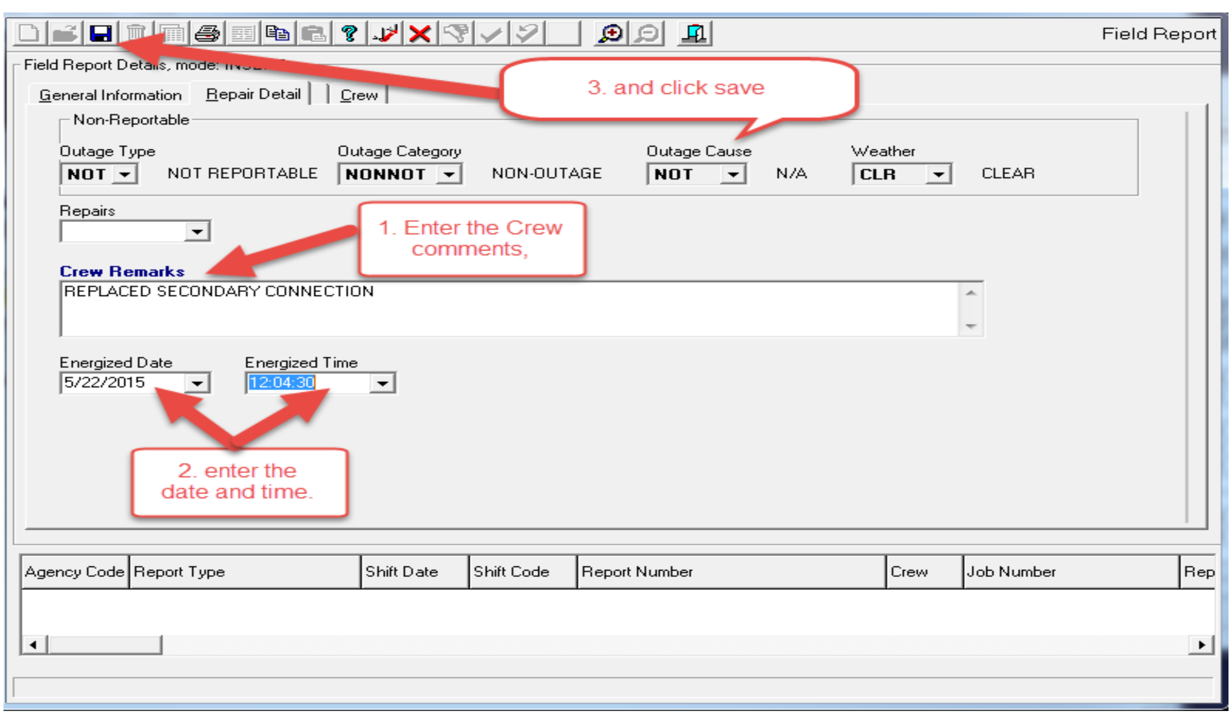
This procedure applies only to secondary outages that are NOT associated with a primary outage. Some examples are; secondary fuse blown, service wire down, bad UG service, etc. The customer calls are commonly part lights. This **DOES NOT apply** to any outage that starts as secondary but progresses to primary (such as bad run of secondaries and then TM or LC opens BURD switch, cuts open taps, de-energizes transformer, etc.), there is no change to clearing that type of outage.

- When clearing the order in CAD using the Field Report, first select the “Non-Outage” drop down, then click the Repair Detail tab.

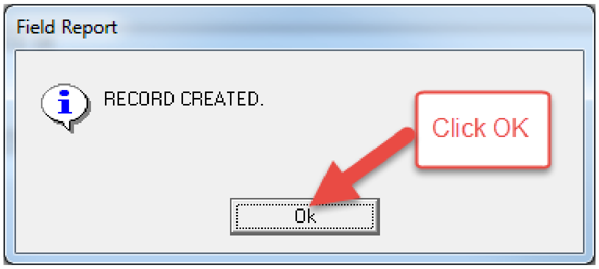


- This will open the Repair Detail window.

- In the Repair Detail window, enter the Crew comments, the date and time and save.



- The Record Created window will pop up, click OK. This completes the CAD process- See note below.



Note: It is vital that you check the incident in Incident manager to confirm that the TLP flag is not checked since no visibility of the TLP flag exists in CAD. The steps in the aforementioned instruction do not guarantee that the incident will not fall into the pending Potential outage report unless the TLP is unchecked.

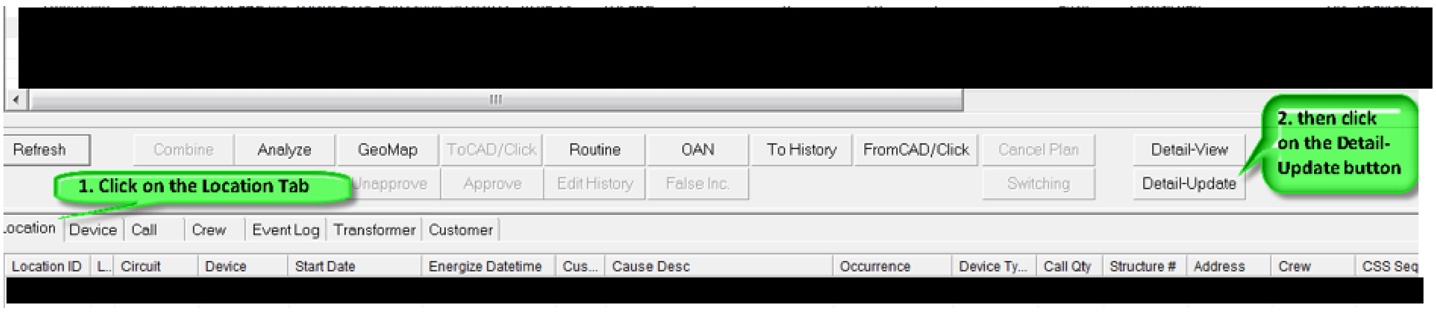
3.0 PROCESSING SINGLE LOCATION INCIDENTS IN ACTIVE STATUS

3.1 Determine if an incident is Reportable or Not Reportable

If an incident is determined to be **Reportable** proceed to section 3.2 for processing steps but if incident is determined to be **Not Reportable** follow the steps below:

- Remove the Total Loss of Power flag (TLP) from <u>all</u> locations on the Device tab
- Set <u>all</u> Couse Code fields and Occurrence fields on the Location tab to one of the appropriate "Not Reportable" codes
- Complete Order and sent to History

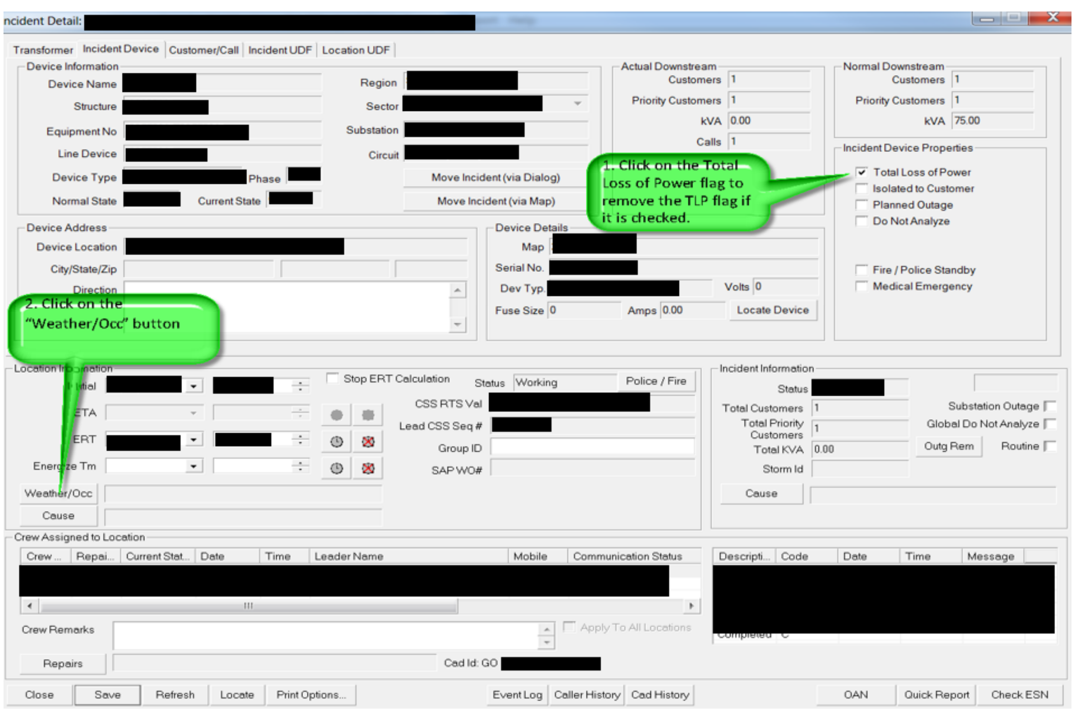
Example: In the secondary screen of Incident Manager, click on the Location tab on the secondary screen and then click Detail-Update

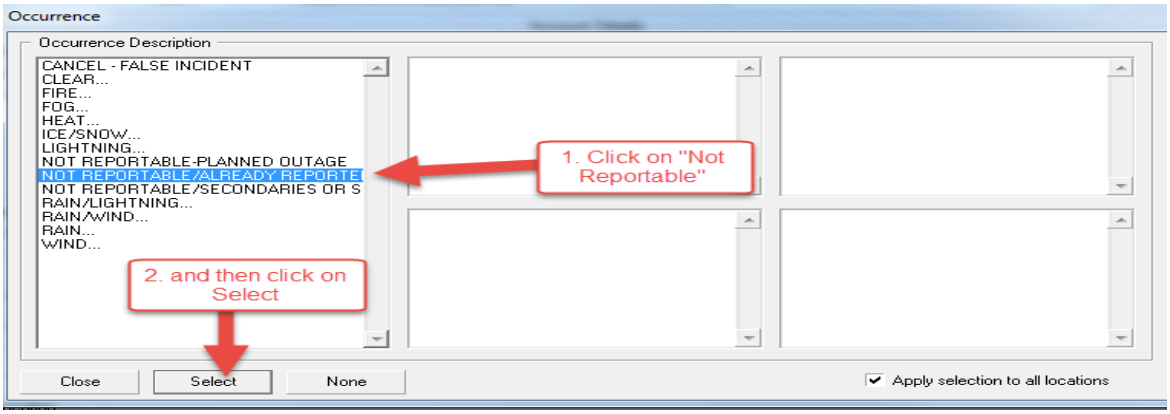


- **In Detail-Update window:**

1. Click on the Total Loss of Power flag to remove the TLP flag if it is checked

2. Click on the "Weather/Occ" button to select the appropriate Not Reportable code option





3. After the occurrence description is selected close the Occurrence window and **save** your changes

Note: When processing Not Reportable incidents you may leave the Cause field unpopulated but if you choose to populate it you must select one of the "Not Reportable" code options.

4. Close Detail-Update window, complete incident and send to history

→ This concludes the processing of a Not Reportable incident

3.2 Processing a Reportable incident in active status

If an incident is determined to be Reportable, there are 6 data points that must be verified for accuracy before the incident can be completed and send to history:

1. Device to be reported

2. Start Date & Time of outage

3. Energize Date & Time of outage

4. Customer Count for the Reportable location

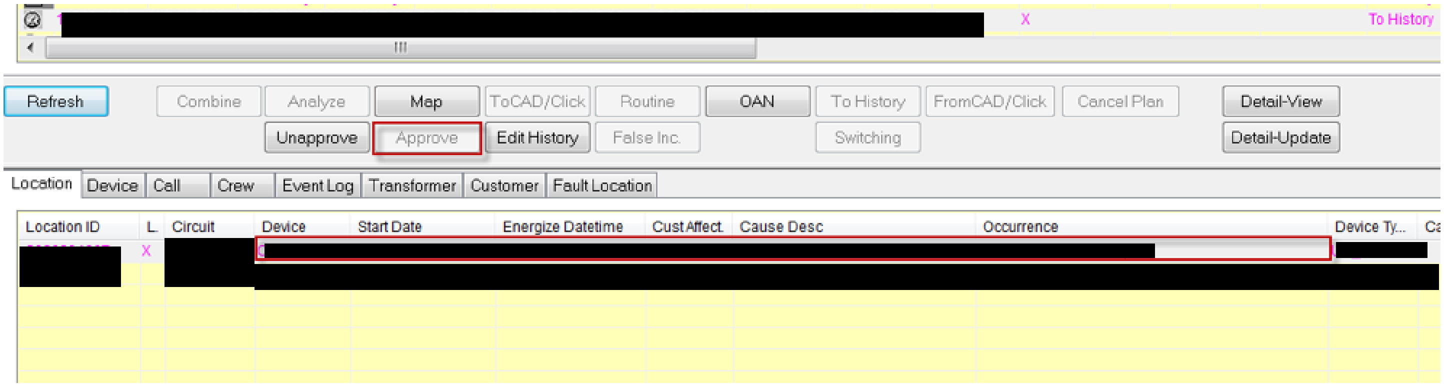
5. Cause and Occurrence Codes must reflect the outage trigger (root cause of fault)

6. The Total Loss of Power (TLP) flag on the Device tab must be checked for the reportable location

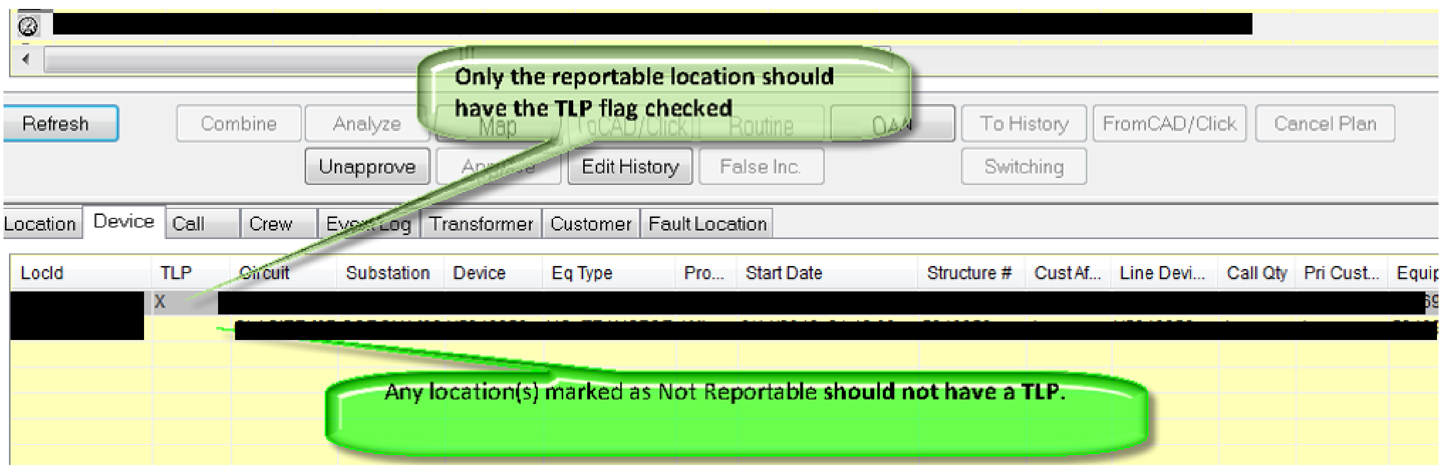
<u>Example of Single Location outage:</u>

In this example below you can see a single location outage beyond device OS4432-3 which needs to be reported and as mentioned above before you can complete this incident you must first confirm the accuracy of the following data points:

1. Device to be reported, 2.Start Date & Time, 3.Energize Date & Time, 4.Customer Count for Reportable location, 5.Cause and Occurrence Codes, 6. TLP flag.



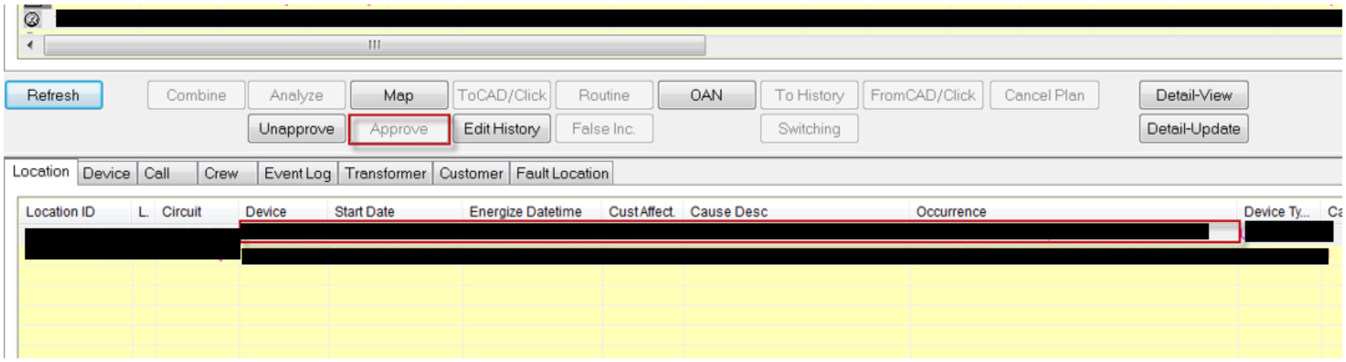
Important: Only the reportable locations should have the TLP flag checked (only one TLP flag per Location can be checked in order for the outage to upload into ODRM). Any location(s) marked as Not Reportable must not have a TLP flag checked.



Note: It is equally important that any location(s) (of an incident) deem Not Reportable must be marked as such, meaning: the Occurrence code field must be populated with a Not Reportable code and the TLP flags must be removed for the not reportable location(s) before the incident is completed and send to history.

Once you are satisfied with all the data captured and confident that the saved information accuratly reflectes the outage as it occurred in the field, the final step on OMS is to approve this incident to allow it to be uploaded into the Outage Database & Reliability Metrics System (ODRM) – an application used by the Reliability Team for SAIDI/SAIFI and other reporting.

To approve an incident for ODRM upload, click on the “Approve” button in the middle section of the screen

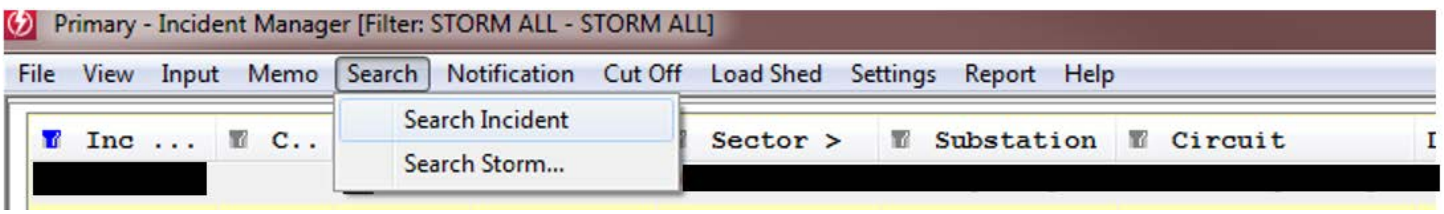


4.0 MAKING UPDATES TO COMPLTED INCIDENTS IN "INCIDENT DETAIL" WINDOW

4.1 How to find a completed incident in Incident Manager?

If the incident to be updated is not on your screen anymore you can search for it and here is how:

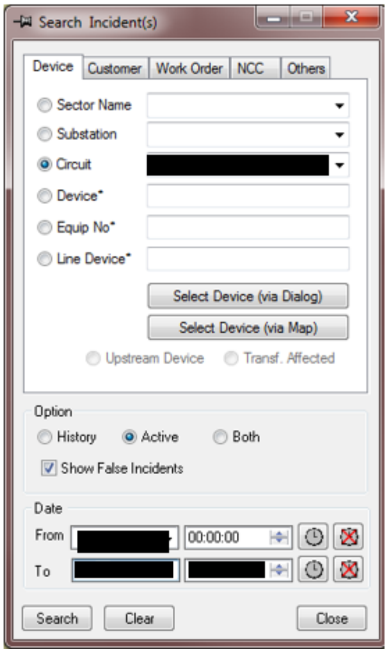
a) Click the Search option on the (top) tool bar of the incident manager and select "Search Incident"



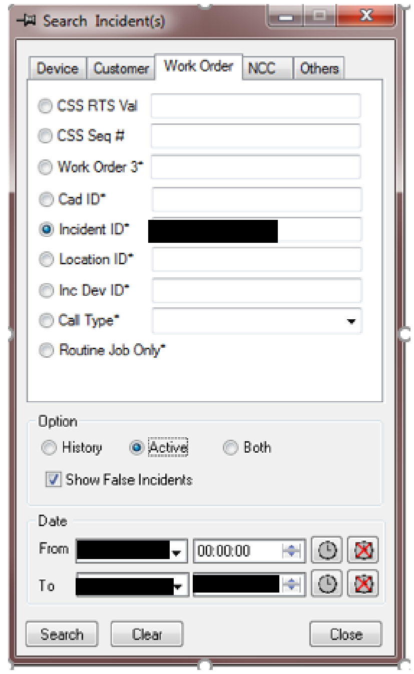
b) Once Search window opens, click on Device tab (top left), then type in circuit name into the Circuit window, check the Active option, and specify date of outage/incident, then click search (Pic 1) – There is also an option to search by incident number (if known), which can be used instead of the circuit name but to do this you must to be in the Work Order tab (Pic 2)

Pic 1

Pic 2



Search Tip: You may type only the first few letters of the circuit name, then hit the "tab" key on your keyboard and the circuit name will auto populate or a list will appear from which you may choose the correct circuit, if there is more than one option.

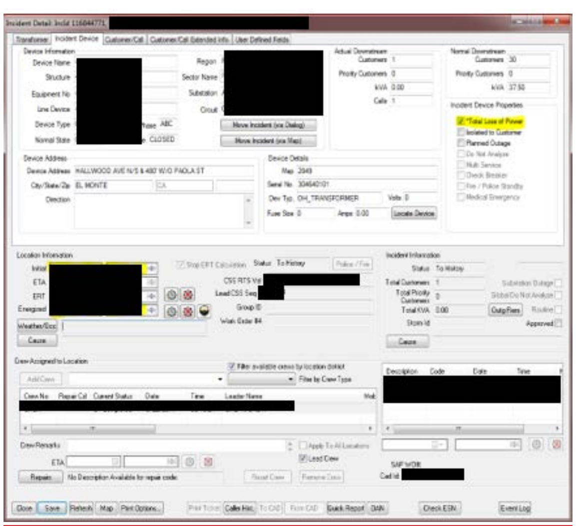


c) Once you find your incident/outage, highlight the incident to be edited by clicking on it in the top section of the Incident Manager screen, then select the location you wish to update in the bottom section of the screen by clicking on the location line and then click on the "Detail-Update" button:

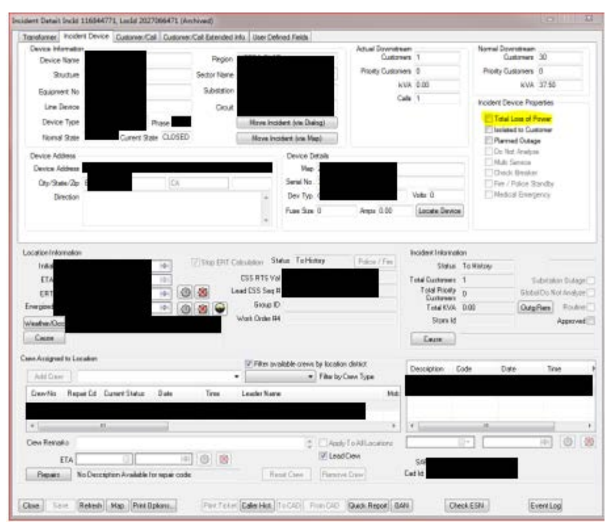
……..Incident Detail window will open

4.2 In Incident Detail window you can correct the date and times as well as assign outage cause codes. It is also important to ensure that the "Total Loss of Power" flag (TLP) is checked to signal that this incident location is a legitimate outage restoration step. If you satisfied with the changes (if changes were needed) click the "Save" button and close window (Pic 1).

Pic 1:



Pic 2:



To increase accuracy of incident energize times, it is strongly recommended to use the PRN times provided by the smart meter technology system.

4.3 If an outage step (location) was created in error or there is a duplication, you can disallow this step (deletion is not possible) by unchecking the “Total Loss of Power” flag and setting the Occurrence code to “Not Reportable/Already Reported”. If you satisfied with the changes click the “Save” button and close window (Pic 2).

Note: Steps lined out in section 3.4 and 3.5 should ideally only be performed by a system operator since they typically require status changes of OMS production maps and may interfere with other live switching!

4.4 If an incident location (switching/restoration step) was energized with the incorrect customer count, you can also correct this in the Incident Detail window, as long the incident was not completed and sent to history:

a. Click on the location to be corrected first and then click on “Detail-Update” button to open the Incident Detail window
b. Remove the energize time in the Incident Detail window under “Location Information”
c. Open the respective circuit map in production and set map to the desired status to recreate the switching step
   Note: After opening the device window, uncheck the “create incident” box, since you do not want to create a duplicate location
d. Energize the device via the map as you would normally do while switching and the customer count should update
e. If you satisfied with the changes click the “Save” button and close window

4.5 If a location needs to be added:

a. De-energize the location prior to the missed step in Incident Detail window under “Location Information”
b. Add the location via circuit map as you would normally do while switching (by creating an incident via the device window)
c. Re-energize the locations via circuit map again following the outage restoration sequence as logged on the interruption log

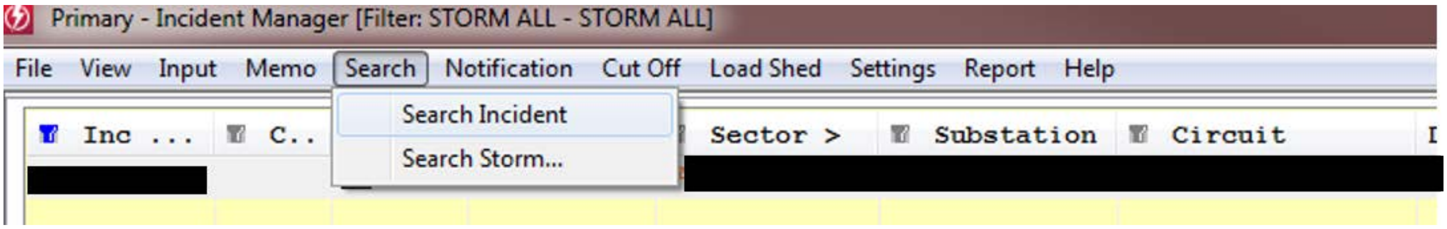
Important: Corrections in “Incident Detail” windows can and should only be done as long the incident is in “active status”, once an incident has been “archived” (Sent to History), all data corrections must be done in “History-Editor” window and should no longer be performed by the dispatchers to avoid potential conflicts of interest and to ensure data integrity. Post outage data adjustments to historical data ideally should be performed by a System Supervisor or a designee – Refer to: Making Updates in “History Editor”.

5.0 MAKING UPDATES IN "HISTORY EDITOR" WINDOW

Once an incident has been "archived" (sent to History), all corrections must be done in "History Editor" window and can no longer be performed on the active screens/windows of Incident Manager. This responsibility will fall to the System Supervisor or a designee.

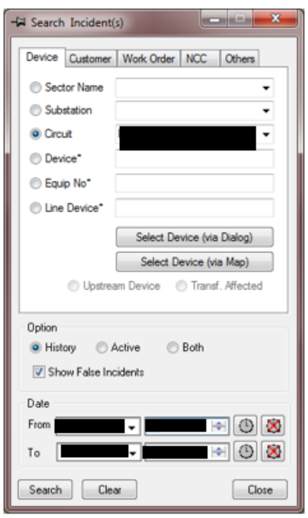
5.1 How to find an incident/outage in History?

d) Click the Search option on the (top) tool bar of the incident manager and select "Search Incident"



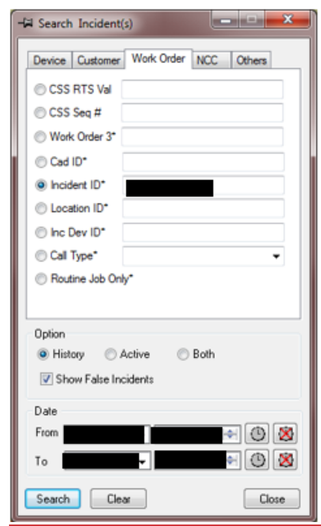
e) Once Search window opens: Type in circuit name into the Circuit window, check the History option, and specify date of outage/incident, then click search (Pic 1) – There is also an option to search by incident number (if known), which can be used instead of the circuit name (Pic 2)

Pic 1

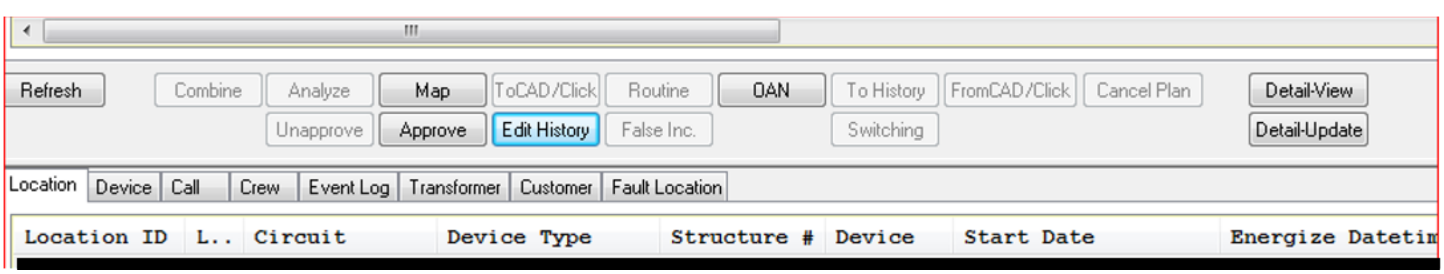


Search Tip: You may type only the first few letters of the circuit name, then hit the "tab" key on your keyboard and the circuit name will auto populate or a list will appear from which you may choose the correct circuit, if there is more than one option.

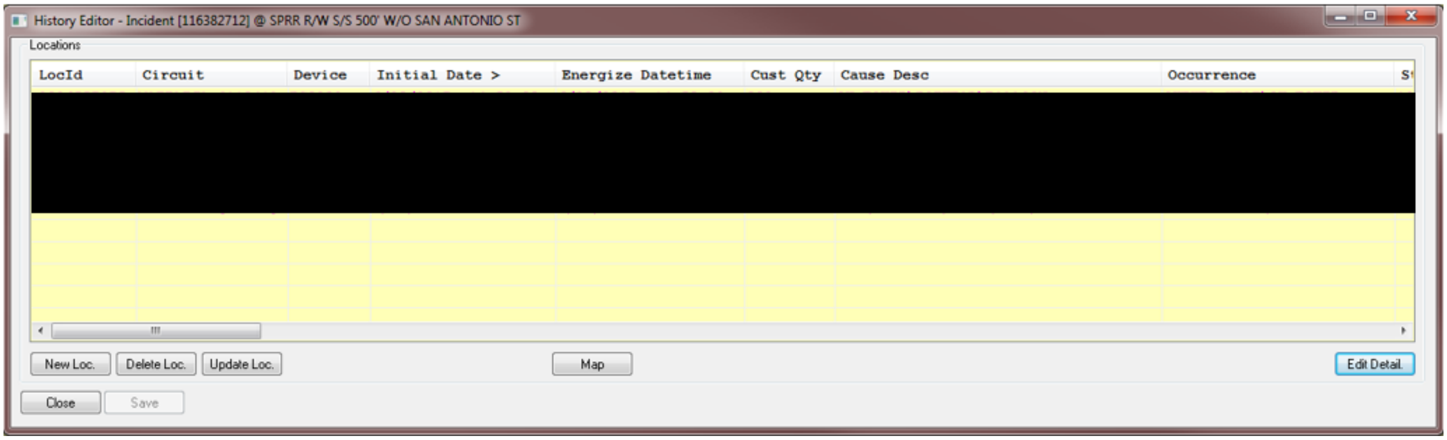
Pic 2

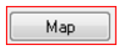


f) Once you find your incident/outage, highlight the incident to be edited by clicking on it in the top section of the Incident Manager screen, and then click the "Edit History" button in the middle section of the screen to open edit window

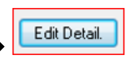


From here you can make updates to customer counts, open maps, locate devices on maps, delete locations, create new locations, as well as make corrections to times and cause codes, and add remarks.

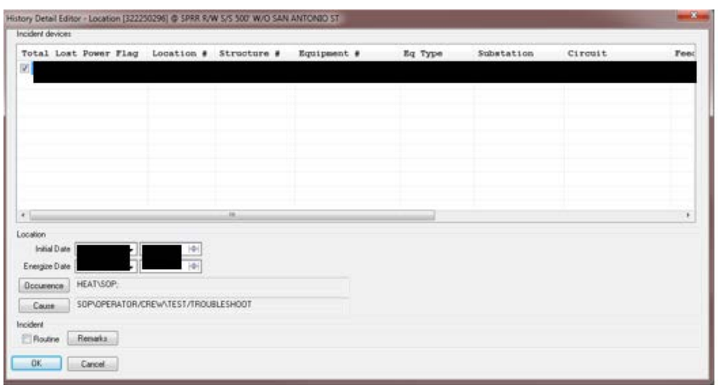


5.2 To open a map or locate a device on map from History Editor click → 

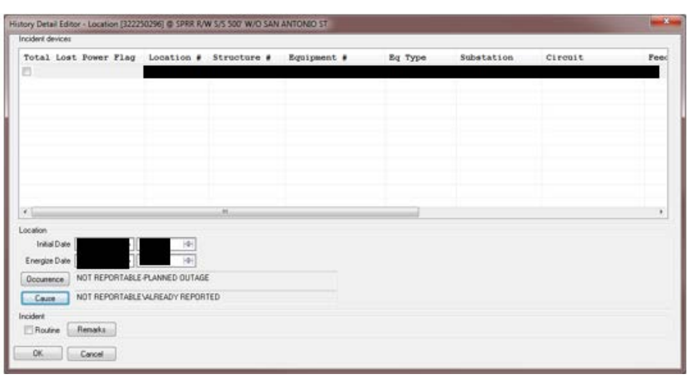
Highlight device in Edit History window (by clicking on it) and click "Map" -- Note: map will open in simulate mode – this is the only way to make edits in history

5.3 To make corrections to date, time, cause, and occurrence, or add remarks click → 

After you made your corrections and/or added remarks, click "OK" to close window (see below):



If an outage step (location) was created in error (during switching) or there is a duplication you can disallow this step (since deletion is not possible) by unchecking the "Total Loss of Power" flag and setting the Cause and Occurrence codes to "Not Reportable/Already Reported". If satisfied with the changes click the "OK" to close window (see below):

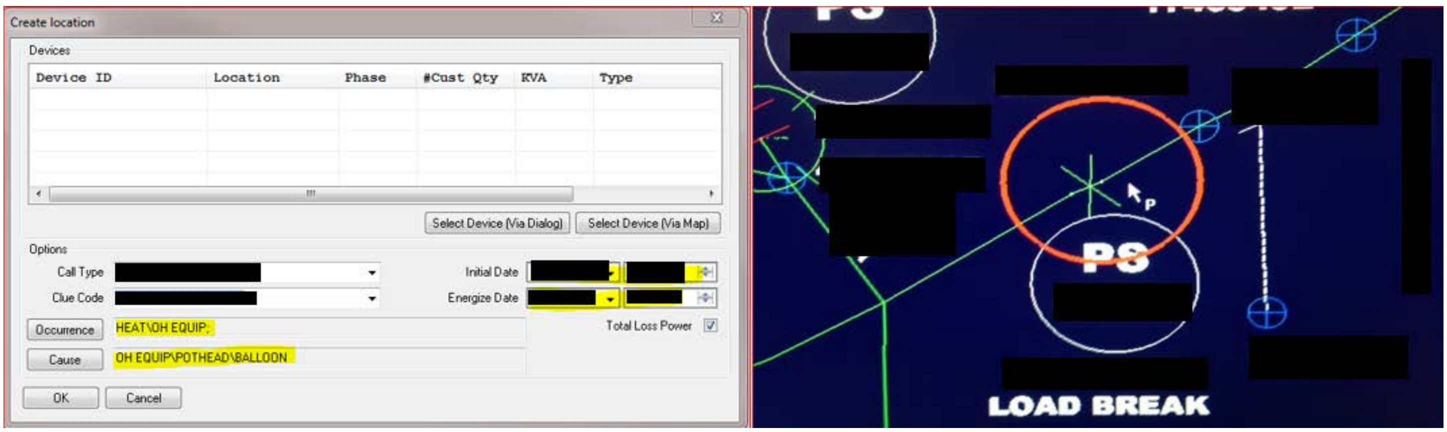


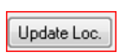
5.4 To add a new location click → 

Adding a new location is very similar to creating a "switching step" when writing a program:

a) Open the respective circuit map in simulation mode thru History Editor window and set devices to desired status
b) Click on "New Location", in Create Location window, adjust date, times, cause, occurrence, then click "Select Device via Map"
c) Use "pick point" to select device on map, which will populate device information and customer count in window
d) Click "OK" if satisfied with the results to close window

Important: If creating locations/steps using "cuts", the newly created location must be saved before the cut is removed from map



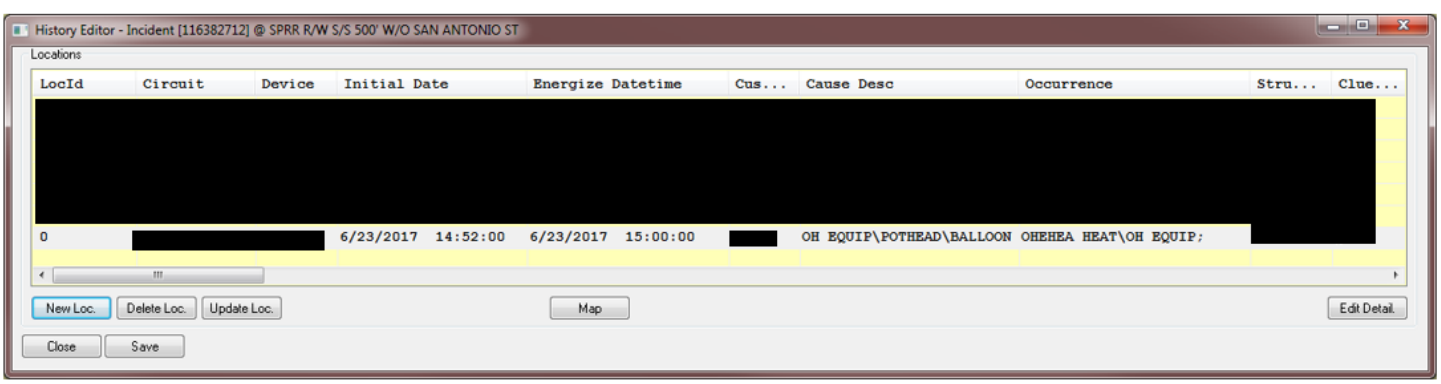
5.5 To update a customer count click "Update Location" → 

but before doing that:

a) The location to be updated must be selected in the History Editor window by clicking on it
b) The respective circuit map must be opened in simulation mode
c) The section of line must reflect (or be set to) the status for which the customer count needs to be updated to

5.6 To delete a location click → 

Highlight the location to be deleted (by clicking on it) and then click delete --- Note: Locations can only be deleted if they were not created during "live" switching or were not previously saved in History Editor.

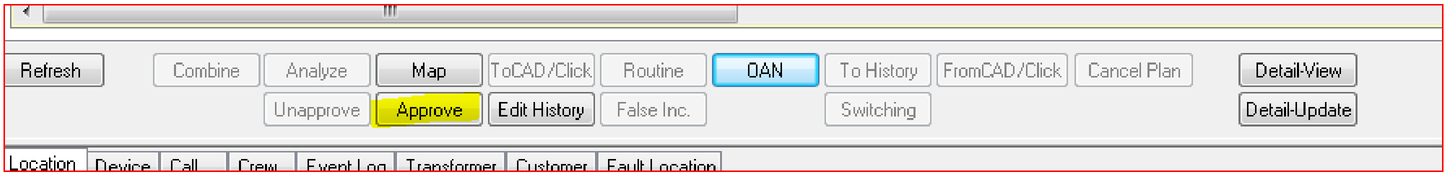


Important: Make sure to "SAVE" all your changes before closing the History Editor window

6.0 APPROVING VALIDATED INCIDENTS FOR ODRM UPLOAD

Once you are satisfied with all the data captured and confident that the saved information accuratly reflectes the outage as it occurred in the field, the final step on OMS is to approve this incident to allow it to be uploaded into the Outage Database & Reliability Metrics System (ODRM) – an application used by the Reliability Team for SAIDI/SAIFI and other reporting.

To approve an incident for ODRM, click on the Approve" button in the middle section of the screen



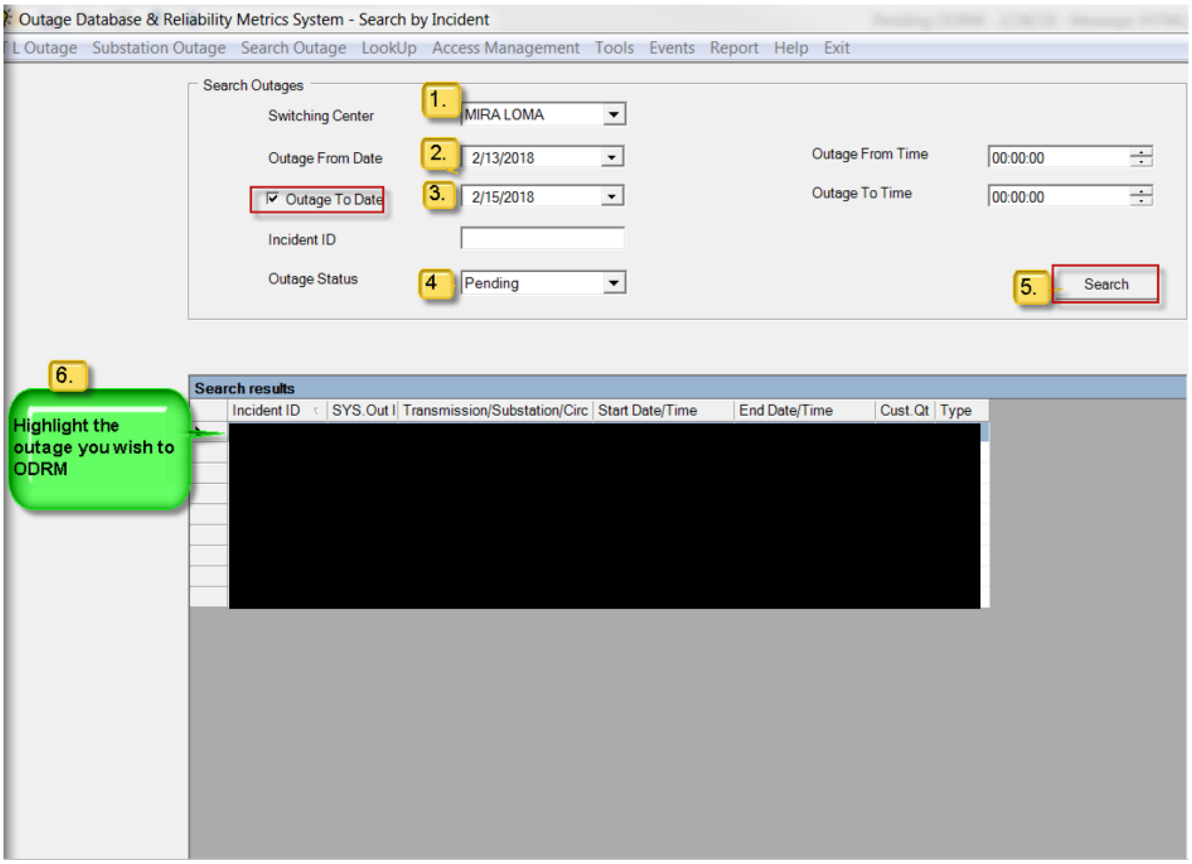
Once approved on OMS the incident will upload automatically into ODRM as scheduled batch jobs. The batch uploads are scheduled to be performed 4 times a day (0500, 1100, 1400, 1700), seven days a week.

This will conclude the OMS portion of the outage validation process, for the ODRM portion of the outage validation process please refer to the next chapter – 7.0 Basic steps for validating single location incidents on ODRM.

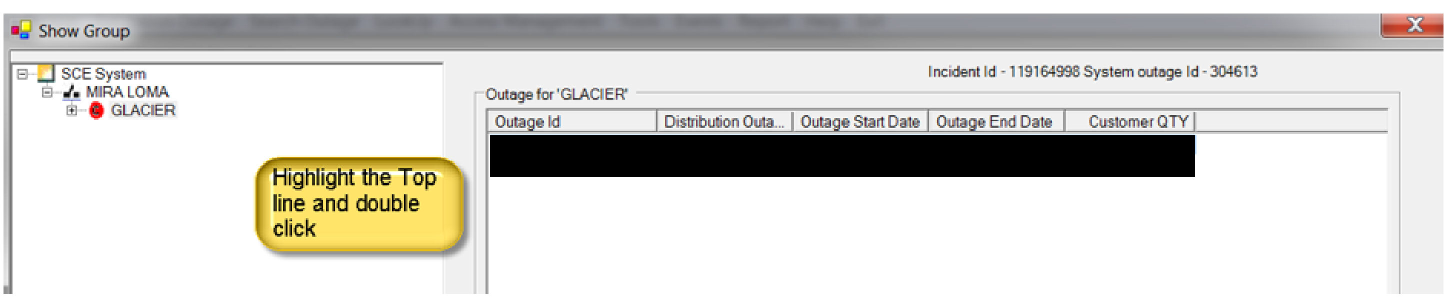
7.0 BASIC STEPS FOR VALIDATING SINGLE LOCATION INCIDENTS ON ODRM

Once the dispatcher has approved the reportable outage incident in OMS it will migrate into ODRM where the dispatcher will have to confirm data accuracy one more time and add other specific data. (NOTE: we may need to input the steps to open ODRM here.)

To find the Outage once you launch ODRM and it opens, use the drop downs to select: **1.** **Switching Center** **2.** **Outage From Date** **3.** Check the box next to **Outage To Date** and select date **4.** Confirm **Outage Status** is set to Pending **5.** Click **Search** **6.** Highlight the incident you wish to ODRM and double click or **7.** Click the Update button

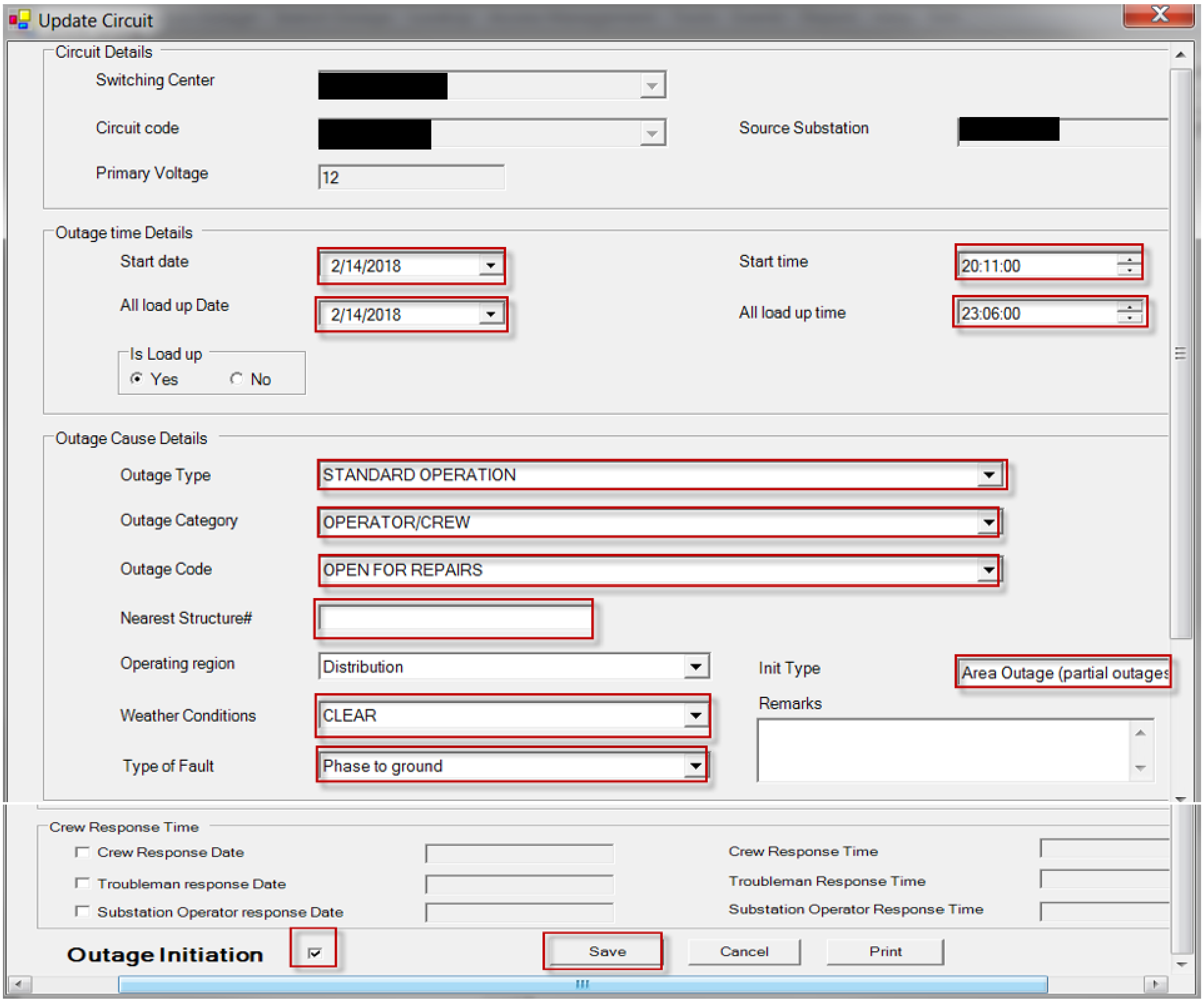


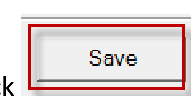
The screen below will display, Highlight the Top line and double click

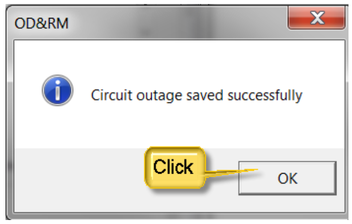


The next Screen will display. The validator should confirm that the **Start date**, **Start time**, **All load up Date** and **All load up time** are accurate as well as all 3 components of the Cause code. ~~Next the dispatcher needs to input the **Nearest Structure #** this should be the nearest Structure Mapped in OMS to the Fault (many times it will be the Structure/Device used to report the outage).~~ The **Operating**

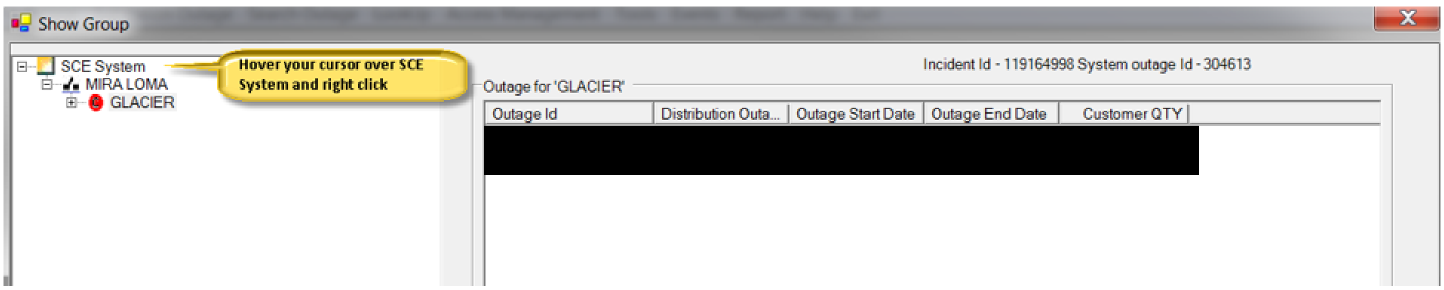
region should default to Distribution for all single location distribution outages. **Weather conditions** should be auto-populated with what was selected as part of the Occurrence Code, but can be updated if the dispatcher realizes that a better condition applies. **Init Type** should default to Area Outage (partial outages) for all Area Outs approved. If Single Location outage is at the CB or RAR level it will default to Distribution (mainline/AR). **Type of Fault** will default to Phase to ground, but can be updated using the drop down if the Dispatcher knows a better selection. If **Type of Fault** is unknown select **unknown.** The **Outage Initiation** box at the bottom left hand corner of the screen defaults as blank **and must** be checked.



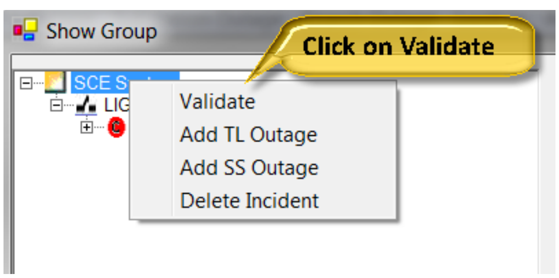
Once all data has been confirmed accurate and all extra data has been added click 

The following Pop up will display-Click **OK**: 

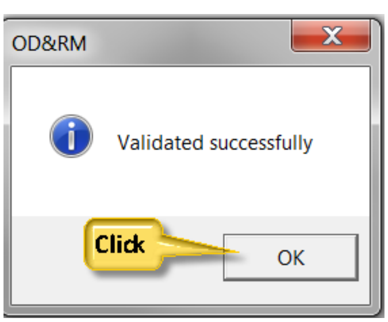
The initial screen will reappear. Hover your cursor over SCE System and right click



The options will display. Click Validate.



The pop up below will display. Click OK. **This completes your ODRM validation** and sends the outage to the Completed Status table.



OMS Outage Cause Codes

Weather/Incident Status	Occurrence Description
Cancel-False Incident	Customer Delay
Fire	Denied Access
Fog	Non-TDBU
Heat	OH Equip
Ice/Snow	PSPS Delay
Lightning	Public Safety
Not Reportable-Planned Outage	SOP
Not Reportable/Already Reported	Source Lost
Not Reportable/Secondaries Or Service	Structure
Rain/Lightning	UG Equip
Rain/Wind	Unknown
Rain	
Wind	

Cause Description	Equipment/Source Type
Denied Access	Already Reported
Non TDBU Source	Burd Switch
Not Reportable	Burd Trnsfrmr
OH Equip	Cable
Planned Outage	Cable
Pub Safety	Cable Splice
SOP	Cap Bank
Source	CB/Switch/Discon/RAR
Strctr	Conductor/Wire
UG Equip	Crossarm
Unknown	Customer Problem
	Distribution Line
	Elbow/Junction Bar
	Foreign Utility
	Fuse/BLF/Cutout
	Fuse/Iso Device
	Gas Switch
	Generation
	Insulator
	Insulator
	Insulator Assy…
	Lighng Arrest
	Maintenance
	New Construction
	Non Outage
	Not Patrolled
	Oil Switch
	Operator/Crew
	Other OH Equip-See Notes

Oth-See Notes
Patrolled
PM Trnsfrmr
PM/UG Strctr
PMH/PME Switch
Pole
Poletop Sub
Pothead
Protective Device
Regulator
Secondaries
Secondary out greater than 24 Hours
SPLC/Connector/TAP
Steel Lattice
Sub Strctr/Rack
Substation
Switch/Disconnect/AR
Telecomm
Tower…
Transformer
Transmission Line

Cause
3rd Party
Animal
Avoid Overload
Balloon
Contract Crew
De-Energize for Pub Agency
Digin Contractor
Digin Private
Digin SCE
Fire
Foreign Material
Lightning
Lost
Low Voltage
N/A
No Cause Found
Oth-See Notes
Overload/Fatigue
Overloaded
Priv Tree Trimmer
Pub Safety Power Shutdown
Public Agency
SCE unable to access
Test/Troubleshoot
Toppled/Broken
Utility Contact
Vandalism
Veg Blown
Veg Grown

Vehicle Hit
Wind

Cause Description Combinations
Denied Access-CB/Switch/Discon/RAR-Public Agency
Denied Access-CB/Switch/Discon/RAR-SCE Unable To Access
Denied Access-Conductor/Wire-Public Agency
Denied Access-Conductor/Wire-SCE Unable To Access
Denied Access-Fuse/BLF/Cutout-Public Agency
Denied Access-Fuse/BLF/Cutout-SCE Unable To Access
Denied Access-Insulator-Public Agency
Denied Access-Insulator-SCE Unable To Access
Denied Access-Other OH Equip-See Notes-Public Agency
Denied Access-Other OH Equip-See Notes-SCE Unable To Access
Denied Access-Poletop Sub-Public Agency
Denied Access-Poletop Sub-SCE Unable To Access
Denied Access-Pole -Public Agency
Denied Access-Pole-SCE Unable To Access
Denied Access-Pothead-Public Agency
Denied Access-Pothead-SCE Unable To Access
Denied Access-Transformer-Public Agency
Denied Access-Transformer-SCE Unable To Access
Non TDBY Source-Foreign Utility -N/A
Non TDBY Source-Generation-N/A
Non TDBY Source-Telecomm-N/A
Not Reportable-Already Reported-
Not Reportable-Customer Problem-
Not Reportable-Non Outage-
Not Reportable-Oth-See Notes-
Not Reportable-Secondaries-
Not Reportable-Secondary Out Greater Than 24 Hrs.-
OH Equipment-Cap Bank-3rd Party
OH Equipment-Cap Bank-Animal
OH Equipment-Cap Bank-Balloon
OH Equipment-Cap Bank-Fire
OH Equipment-Cap Bank-Foreign Mat
OH Equipment-Cap Bank-Lightning
OH Equipment-Cap Bank-Oth-See Notes
OH Equipment-Cap Bank-Vandalism
OH Equipment-Cap Bank-Veg Blown
OH Equipment-Cap Bank-Veg Grown
OH Equipment-Conductor/Wire-3rd Party
OH Equipment-Conductor/Wire-Animal
OH Equipment-Conductor/Wire-Balloon
OH Equipment-Conductor/Wire-Fire
OH Equipment-Conductor/Wire-Foreign Mat
OH Equipment-Conductor/Wire-Lightning
OH Equipment-Conductor/Wire-Oth-See Notes
OH Equipment-Conductor/Wire-Overload/Fatigue
OH Equipment-Conductor/Wire-Utility Contact

OH Equipment-Conductor/Wire-Vandalism
OH Equipment-Conductor/Wire-Veg Blown
OH Equipment-Conductor/Wire-Veg Grown
OH Equipment-Conductor/Wire-Vehicle Hit
OH Equipment-Conductor/Wire-Wind
OH Equipment-Fuse/BLF/Cutout-3rd Party
OH Equipment-Fuse/BLF/Cutout-Animal
OH Equipment-Fuse/BLF/Cutout-Balloon
OH Equipment-Fuse/BLF/Cutout-Foreign Mat
OH Equipment-Fuse/BLF/Cutout-Lightning
OH Equipment-Fuse/BLF/Cutout-Oth-See Notes
OH Equipment-Fuse/BLF/Cutout-Overloaded
OH Equipment-Fuse/BLF/Cutout-Veg Blown
OH Equipment-Fuse/BLF/Cutout-Veg Grown
OH Equipment-Insulator-3rd Party
OH Equipment-Insulator-Animal
OH Equipment-Insulator-Lightning
OH Equipment-Insulator-Oth-See Notes
OH Equipment-Insulator-Vandalism
OH Equipment-Lightning Arrest-3rd Party
OH Equipment-Lightning Arrest-Animal
OH Equipment-Lightning Arrest-Balloon
OH Equipment-Lightning Arrest-Fire
OH Equipment-Lightning Arrest-Lightning
OH Equipment-Lightning Arrest-Oth-See Notes
OH Equipment-Lightning Arrest-Vandalism
OH Equipment-Lightning Arrest-Veg Blown
OH Equipment-Oth-See Notes-3rd Party
OH Equipment-Oth-See Notes-Animal
OH Equipment-Oth-See Notes-Balloon
OH Equipment-Oth-See Notes-Fire
OH Equipment-Oth-See Notes-Lightning
OH Equipment-Oth-See Notes-Oth-See Notes
OH Equipment-Oth-See Notes-Priv Tree Trimmer
OH Equipment-Oth-See Notes-Utility Contact
OH Equipment-Oth-See Notes-Vandalism
OH Equipment-Oth-See Notes-Veg Blown
OH Equipment-Oth-See Notes-Veg Grown
OH Equipment-Poletop Sub-3rd Party
OH Equipment-Poletop Sub-Animal
OH Equipment-Poletop Sub-Balloon
OH Equipment-Poletop Sub-Fire
OH Equipment-Poletop Sub-Foreign Mat
OH Equipment-Poletop Sub-Lightning
OH Equipment-Poletop Sub-Oth-See Notes
OH Equipment-Poletop Sub-Overloaded
OH Equipment-Poletop Sub-Vandalism

OH Equipment-Poletop Sub-Veg Blown
OH Equipment-Poletop Sub-Veg Grown
OH Equipment-Pothead-3rd Party
OH Equipment-Pothead-Animal
OH Equipment-Pothead-Balloon
OH Equipment-Pothead-Lightning
OH Equipment-Pothead-Oth-See Notes
OH Equipment-Pothead-Vandalism
OH Equipment-Pothead-Veg Blown
OH Equipment-Pothead-Veg Grown
OH Equipment-Regulator-3rd Party
OH Equipment-Regulator-Animal
OH Equipment-Regulator-Balloon
OH Equipment-Regulator-Lightning
OH Equipment-Regulator-Foreign Mat
OH Equipment-Regulator-Oth-See Notes
OH Equipment-Regulator-Vandalism
OH Equipment-Regulator-Veg Blown
OH Equipment-Regulator-Veg Grown
OH Equipment-Splc/Connectr/Tap-3rd Party
OH Equipment-Splc/Connectr/Tap-Animal
OH Equipment-Splc/Connectr/Tap-Balloon
OH Equipment-Splc/Connectr/Tap-Lightning
OH Equipment-Splc/Connectr/Tap-Oth-See Notes
OH Equipment-Splc/Connectr/Tap-Overloaded
OH Equipment-Splc/Connectr/Tap-Veg Blown
OH Equipment-Splc/Connectr/Tap-Veg Grown
OH Equipment-Switch/Discon/AR-Animal
OH Equipment-Switch/Discon/AR-Balloon
OH Equipment-Switch/Discon/AR-Fire
OH Equipment-Switch/Discon/AR-Foreign Mat
OH Equipment-Switch/Discon/AR-Lightning
OH Equipment-Switch/Discon/AR-Low Voltage
OH Equipment-Switch/Discon/AR-Oth-See Notes
OH Equipment-Switch/Discon/AR-Overloaded
OH Equipment-Switch/Discon/AR-Vandalism
OH Equipment-Switch/Discon/AR-Veg Blown
OH Equipment-Switch/Discon/AR-Veg Grown
OH Equipment-Switch/Discon/AR-Vehicle Hit
OH Equipment-Switch/Discon/AR-Wind
OH Equipment-Transformer-3rd Party
OH Equipment-Transformer-Animal
OH Equipment-Transformer-Balloon
OH Equipment-Transformer-Fire
OH Equipment-Transformer-Foreign Mat
OH Equipment-Transformer-Lightning
OH Equipment-Transformer-Oth-See Notes

OH Equipment-Transformer-Overloaded
OH Equipment-Transformer-Vandalism
OH Equipment-Transformer-Veg Blown
OH Equipment-Transformer-Veg Grown
Planned Outage-Maintenance-
Planned Outage-New Construction-
Pub Safety-CB/Switch/Discon/RAR-De-Energize for Pub Agency
Pub Safety-CB/Switch/Discon/RAR-Pub. Safety Power Shutdown
Pub Safety-Fuse/BLF/Cutout-De-Energize for Pub Agency
Pub Safety-Fuse/BLF/Cutout-Pub. Safety Power Shutdown
Pub Safety-Other OH Equip-See Notes-De-Energize for Pub Agency
Pub Safety-Other OH Equip-See Notes-Pub. Safety Power Shutdown
Pub Safety-Pole-De-Energize for Pub Agency
Pub Safety-Pothead-De-Energize for Pub Agency
Pub Safety-Transformer-De-Energize for Pub Agency
SOP-Cable-3rd Party
SOP-Cable-Animal
SOP-Cable-Avoid Overload
SOP-Cable-Digin Contractor
SOP-Cable-Digin Private
SOP-Cable-Digin SCE
SOP-Cable-Fire
SOP-Cable-Low Voltage
SOP-Cable-Other-See Notes
SOP-Cable-Private Tree Trimmer
SOP-Cable-Test/Troubleshoot
SOP-Cable-Vandalism
SOP-Cable-Vegetation Grown
SOP-Cable-Vegetation Blown
SOP-Cable-Vehicle Hit
SOP-Conductor/Wire-3rd Party
SOP-Conductor/Wire-Animal
SOP-Conductor/Wire-Balloon
SOP-Conductor/Wire-Contract Crew
SOP-Conductor/Wire-Fire
SOP-Conductor/Wire-Foreign Material
SOP-Conductor/Wire-Lightning
SOP-Conductor/Wire-Other-See Notes
SOP-Conductor/Wire-Private Tree Trimmer
SOP-Conductor/Wire-Test/Troubleshoot
SOP-Conductor/Wire-Vandalism
SOP-Conductor/Wire-Vegetation Grown
SOP-Conductor/Wire-Vegetation Blown
SOP-Conductor/Wire-Wind
SOP-Crossarm-3rd Party
SOP-Crossarm-Animal
SOP-Crossarm-Balloon

SOP-Crossarm-Contract Crew
SOP-Crossarm-Fire
SOP-Crossarm-Foreign Material
SOP-Crossarm-Lightning
SOP-Crossarm-Other-See Notes
SOP-Crossarm-Private Tree Trimmer
SOP-Crossarm-Test/Troubleshoot
SOP-Crossarm-Toppled/Broken
SOP-Crossarm-Vandalism
SOP-Crossarm-Vegetation Grown
SOP-Crossarm-Vegetation Blown
SOP-Crossarm-Wind
SOP-Elbow/Junction Bar-3rd Party
SOP-Elbow/Junction Bar-Animal
SOP-Elbow/Junction Bar-Balloon
SOP-Elbow/Junction Bar-Digin Private
SOP-Elbow/Junction Bar-Fire
SOP-Elbow/Junction Bar-Lost
SOP-Elbow/Junction Bar-Other-See Notes
SOP-Elbow/Junction Bar-Test/Troubleshoot
SOP-Elbow/Junction Bar-Vandalism
SOP-Elbow/Junction Bar-Vegetation Grown
SOP-Elbow/Junction Bar-Vegetation Blown
SOP-Elbow/Junction Bar-Wind
SOP-Fuse/BLF/Cutout-3rd Party
SOP-Fuse/BLF/Cutout-Animal
SOP-Fuse/BLF/Cutout-Avoid Overload
SOP-Fuse/BLF/Cutout-Balloon
SOP-Fuse/BLF/Cutout-Fire
SOP-Fuse/BLF/Cutout-Foreign Material
SOP-Fuse/BLF/Cutout-Lightning
SOP-Fuse/BLF/Cutout-Other-See Notes
SOP-Fuse/BLF/Cutout-Private Tree Trimmer
SOP-Fuse/BLF/Cutout-Test/Troubleshoot
SOP-Fuse/BLF/Cutout-Toppled/Broken
SOP-Fuse/BLF/Cutout-Vandalism
SOP-Fuse/BLF/Cutout-Vegetation Grown
SOP-Fuse/BLF/Cutout-Vegetation Blown
SOP-Fuse/BLF/Cutout-Wind
SOP-Insulator-3rd Party
SOP-Insulator-Animal
SOP-Insulator-Balloon
SOP-Insulator-Fire
SOP-Insulator-Foreign Material
SOP-Insulator-Lightning
SOP-Insulator-Other-See Notes
SOP-Insulator-Private Tree Trimmer

SOP-Insulator-Test/Troubleshoot
SOP-Insulator-Toppled/Broken
SOP-Insulator-Vandalism
SOP-Insulator-Vegetation Grown
SOP-Insulator-Vegetation Blown
SOP-Insulator-Wind
SOP-Operator/Crew-Avoid Overload
SOP-Operator/Crew-Oth-See Notes
SOP-Operator/Crew-Test/Troubleshoot
SOP-Other See Notes-3rd Party
SOP-Other See Notes-Animal
SOP-Other See Notes-Balloon
SOP-Other See Notes-Fire
SOP-Other See Notes-Other-See Notes
SOP-Other See Notes-Toppled/Broken
SOP-Other See Notes-Vandalism
SOP-Other See Notes-Vegetation Grown
SOP-Other See Notes-Vegetation Blown
SOP-Pole-3rd Party
SOP-Pole-Animal
SOP-Pole-Balloon
SOP-Pole-Contract Crew
SOP-Pole-Fire
SOP-Pole-Foreign Material
SOP-Pole-Lightning
SOP-Pole-Other-See Notes
SOP-Pole-Test/Troubleshoot
SOP-Pole-Toppled/Broken
SOP-Pole-Vandalism
SOP-Pole-Vegetation Grown
SOP-Pole-Vegetation Blown
SOP-Pole-Vehicle Hit
SOP-Pole-Wind
SOP-Pothead-3rd Party
SOP-Pothead-Animal
SOP-Pothead-Balloon
SOP-Pothead-Fire
SOP-Pothead-Foreign Material
SOP-Pothead-Lightning
SOP-Pothead-Other See Notes
SOP-Pothead-Private Tree Trimmer
SOP-Pothead-Test/Troubleshoot
SOP-Pothead-Vandalism
SOP-Pothead-Vegetation Grown
SOP-Pothead-Vegetation Blown
SOP-Pothead-Wind
SOP-Protective Device-3rd Party

SOP-Protective Device-Animal
SOP-Protective Device-Avoid Overload
SOP-Protective Device-Balloon
SOP-Protective Device-Contract Crew
SOP-Protective Device-Digin Private
SOP-Protective Device-Fire
SOP-Protective Device-Foreign Material
SOP-Protective Device-Lightning
SOP-Protective Device-Low Voltage
SOP-Protective Device-Oth-See Notes
SOP-Protective Device-Overload
SOP-Protective Device-Private Tree Trimmer
SOP-Protective Device-Test/Troubleshoot
SOP-Protective Device-Toppled/Broken
SOP-Protective Device-Vegetation Grown
SOP-Protective Device-Vegetation Blown
SOP-Protective Device-Vehicle Hit
SOP-Protective Device-Wind
SOP-Splice/Connector/Tap-3rd Party
SOP-Splice/Connector/Tap-Animal
SOP-Splice/Connector/Tap-Balloon
SOP-Splice/Connector/Tap-Fire
SOP-Splice/Connector/Tap-Foreign Material
SOP-Splice/Connector/Tap-Lightning
SOP-Splice/Connector/Tap-Other See Notes
SOP-Splice/Connector/Tap-Private Tree Trimmer
SOP-Splice/Connector/Tap-Test/Troubleshoot
SOP-Splice/Connector/Tap-Toppled/Broken
SOP-Splice/Connector/Tap-Vandalism
SOP-Splice/Connector/Tap-Vegetation Grown
SOP-Splice/Connector/Tap-Vegetation Blown
SOP-Splice/Connector/Tap-Wind
SOP-Switch/Disconnect/AR-3rd Party
SOP-Switch/Disconnect/AR-Animal
SOP-Switch/Disconnect/AR-Balloon
SOP-Switch/Disconnect/AR-Fire
SOP-Switch/Disconnect/AR-Foreign Material
SOP-Switch/Disconnect/AR-Lightning
SOP-Switch/Disconnect/AR-Other See Notes
SOP-Switch/Disconnect/AR-Test/Troubleshoot
SOP-Switch/Disconnect/AR-Toppled/Broken
SOP-Switch/Disconnect/AR-Vandalism
SOP-Switch/Disconnect/AR-Vegetation Grown
SOP-Switch/Disconnect/AR-Vegetation Blown
SOP-Switch/Disconnect/AR-Vehicle Hit
SOP-Switch/Disconnect/AR-Wind
SOP-Transformer-3rd Party

SOP-Transformer-Animal
SOP-Transformer-Avoid Overload
SOP-Transformer-Balloon
SOP-Transformer-Fire
SOP-Transformer-Foreign Material
SOP-Transformer-Lightning
SOP-Transformer-Other See Notes
SOP-Transformer-Overloaded
SOP-Transformer-Private Tree Trimmer
SOP-Transformer-Test/Troubleshoot
SOP-Transformer-Vandalism
SOP-Transformer-Vegetation Grown
SOP-Transformer-Vegetation Blown
SOP-Transformer-Vehicle Hit
SOP-Transformer-Wind
Source-Distribution Line-Lost
Source-Distribution Line-No Cause Found
Source-Distribution Line-Pub Safety Power Shutdown
Source-Foreign Utility -Pub Safety Power Shutdown
Source-Substation-Lost
Source-Substation-No Cause Found
Source-Transmission Line-Lost
Source-Transmission Line-No Cause Found
Source-Transmission Line-Pub Safety Power Shutdown
Structure-Crossarm-3rd Party
Structure-Crossarm-Animal
Structure-Crossarm-Fire
Structure-Crossarm-Lightning
Structure-Crossarm-Oth-See Notes
Structure-Crossarm-Utility Contact
Structure-Crossarm-Veg Blown
Structure-Guywire-3rd Party
Structure-Guywire-Animal
Structure-Guywire-Lightning
Structure-Guywire-Oth-See Notes
Structure-Guywire-Utility Contact
Structure-Guywire-Vandalism
Structure-Guywire-Vehicle Hit
Structure-Insulator Assy-Animal
Structure-Insulator Assy-Balloon
Structure-Insulator Assy-Lightning
Structure-Insulator Assy-Oth-See Notes
Structure-Insulator Assy-Vandalism
Structure-Oth-See Notes-3rd Party
Structure-Oth-See Notes-Animal
Structure-Oth-See Notes-Balloon
Structure-Oth-See Notes-Fire

Structure-Oth-See Notes-Lightning
Structure-Oth-See Notes-Oth-See Notes
Structure-Oth-See Notes-Toppled/Broken
Structure-PM/UG Strctr-3rd Party
Structure-PM/UG Strctr-Oth-See Notes
Structure-PM/UG Strctr-Vandalism
Structure-PM/UG Strctr-Vehicle Hit
Structure-Pole-3rd Party
Structure-Pole-Animal
Structure-Pole-Balloon
Structure-Pole-Fire
Structure-Pole-Lightning
Structure-Pole-Other See Notes
Structure-Pole-Toppled/Broken
Structure-Pole-Vandalism
Structure-Pole-Veg Blown
Structure-Pole-Vehicle Hit
Structure-Steel Lattice-3rd Party
Structure-Steel Lattice-Animal
Structure-Steel Lattice-Fire
Structure-Steel Lattice-Lightning
Structure-Steel Lattice-Oth-See Notes
Structure-Steel Lattice-Toppled/Broken
Structure-Steel Lattice-Vandalism
Structure-Steel Lattice-Vehicle Hit
Structure-Sub Strctr/Rack-3rd Party
Structure-Sub Strctr/Rack-Animal
Structure-Sub Strctr/Rack-Balloon
Structure-Sub Strctr/Rack-Fire
Structure-Sub Strctr/Rack-Lightning
Structure-Sub Strctr/Rack-Oth-See Notes
Structure-Sub Strctr/Rack-Toppled/Broken
Structure-Sub Strctr/Rack-Vandalism
Structure-Sub Strctr/Rack-Vehicle Hit
Structure-Tower-3rd Party
Structure-Tower-Animal
Structure-Tower-Balloon
Structure-Tower-Fire
Structure-Tower-Lightning
Structure-Tower-Oth-See Notes
Structure-Tower-Toppled/Broken
Structure-Tower-Vandalism
Structure-Tower-Vehicle Hit
UG Equip-Burd Switch-3rd Party
UG Equip-Burd Switch-Oth-See Notes
UG Equip-Burd Switch-Vandalism
UG Equip-Burd Switch-Veg Grown

UG Equip-Burd Transfrmr-Animal
UG Equip-Burd Transfrmr-Oth-See Notes
UG Equip-Burd Transfrmr-Overloaded
UG Equip-Burd Transfrmr-Vandalism
UG Equip-Burd Transfrmr-Veg Grown
UG Equip-Cable Splice-Oth-See Notes
UG Equip-Cable-Animal
UG Equip-Cable-Dig In Contractor
UG Equip-Cable-Dig In Private
UG Equip-Cable-Dig In SCE
UG Equip-Cable-Oth-See Notes
UG Equip-Cable-Overload
UG Equip-Cable-Vandalism
UG Equip-Cap Bank-Animal
UG Equip-Cap Bank-Oth-See Notes
UG Equip-Cap Bank-Veg Grown
UG Equip-Cap Bank-Vehicle Hit
UG Equip-Elbow/Junction Bar-Oth-See Notes
UG Equip-Fuse/ISO Device-Overloaded
UG Equip-Fuse/ISO Device-Veg Grown
UG Equip-Gas Switch-Oth-See Notes
UG Equip-Gas Switch-Veg Grown
UG Equip-Oil Switch-Oth-See Notes
UG Equip-Oil Switch-Veg Grown
UG Equip-Oth-See Notes-3rd Party
UG Equip-Oth-See Notes-Animal
UG Equip-Oth-See Notes-Oth-See Notes
UG Equip-Oth-See Notes-Vandalism
UG Equip-Oth-See Notes-Veg Grown
UG Equip-Oth-See Notes-Vehicle Hit
UG Equip-PM Trnsfrmr-3rd Party
UG Equip-PM Trnsfrmr-Animal
UG Equip-PM Trnsfrmr-Oth-See Notes
UG Equip-PM Trnsfrmr-Vandalism
UG Equip-PM Trnsfrmr-Veg Grown
UG Equip-PM Trnsfrmr-Vehicle Hit
UG Equip-PMH/PME Switch-3rd Party
UG Equip-PMH/PME Switch-Animal
UG Equip-PMH/PME Switch-Oth-See Notes
UG Equip-PMH/PME Switch-Vandalism
UG Equip-PMH/PME Switch-Vehicle Hit
Unknown-Not Patrolled-No Cause Found
Unknown-Patrolled-No Cause Found

Logging Refresher Training

Southern California Edison Company

[redacted] Daily Log Sheet

Monday August 10, 2020

CLEARANCE & PERSONNEL AT WORK SECTION

Learning Objectives

This course will refresh your knowledge regarding:

- Clarity regarding how logging impacts other departments and SCE.
- Understanding a System Operator's role in recording and maintaining reliability metrics.
- Identifying when to log an area out.
- Identifying when an Interruption Log Sheet is required.
- Explaining the expectations surrounding what should be included in an Interruption Log Sheet or log entry.
- Recognizing the most common mistakes made regarding creating Interruption Log Sheets and logging area outs.
- Locating the documentation supporting the expectations

Why is logging important?

OMS, ODRM and Substation Logs

- The California Public Utilities Commission (CPUC) requires SCE to report all unplanned primary outages timely and accurately.
- Outages are managed in the Outage Management System (OMS) and then sent to the Outage Database and Reliability Metric System (ODRM) or created separately in ODRM for instances when information is not completely captured by OMS. The history of these outages is also tracked in the Substation Logs.
- Information contained in Substation Logs and ODRM is legally binding information that ultimately decides our reliability metrics.
- The CPUC reviews data from these outages to verify accuracy.

How is reliability measured?

SAIDI	=	Total minutes every SCE customer was without power due to sustained outages (CMI)	÷	Total number of customers	"What's the total time my power service will be unexpectedly interrupted this year?"

System Average Interruption Duration Index

SAIFI	=	Number of sustained customer outages experienced by all SCE customers (CI)	÷	Total number of customers	"How many times will my power service be unexpectedly interrupted this year?"

System Average Interruption Frequency Duration Index

CAIDI	=	System Average Interruption Duration Index (SAIDI)	÷	System Average Interruption Frequency Index (SAIFI)	"How long will it take to restore my power after an unexpected interruption?"

Customer Average Interruption Duration Index

CMI- Customer Minutes of Interruption

- **Definition**: A calculated figure that relates the number of interrupted customers and the amount of time that their service was interrupted, indicating localized electrical system reliability.
- Accurate interruption data captured in OMS, ODRM, and the Substation Log/Interruption Log, provides the basis for Customer Minutes of Interruption (CMI) calculations, equipment performance data, statistical compilation, and historical analysis.
- This data defines reliability to our customers and is reported to the California Public Utilities Commission (CPUC).
- The accuracy of this data is critical since it reflects our performance and will be audited by outside parties at some point in the future.

Reportable Outages

- As a result of an agreement with the CPUC, SCE tracks all interruptions to customers at the level of the distribution transformer and higher.
- Customers interrupted as a result of secondary voltage line problems or individual service problems will not be tracked or reported to the CPUC as part of our annual reliability report.

Roles and Responsibilities

General Responsibilities in Recording/Reporting Reliability Information

- **System Operator**
  - Provide sufficient information on the Interruption Log Sheet (ILS) or Substation Log so that a reliability event can be validated for accuracy and provide a historical record of the event.
  - Create ODRM entry for all transmission line, substation equipment, and substation outages.
  - Operate graphics and create an incident for each device operated in the field. OMS graphics should always match real time status. This include any piece of equipment, even tap-line devices and individual transformers.
  - Validate ODRM entries that do not include distribution load.
- **Field Personnel (Transmission Patrolman/Troubleman/Substation Operator/Distribution Line Crews)**
  - It is important for the field personnel to provide all required data to System Operators and DOC personnel in a timely manner and maintain communications throughout the restoration process.
  - Field personnel must ascertain the cause, conductor type, pole number, tower type and any other pertinent information regarding an interruption and communicate this information in a timely manner to System Operators and DOC personnel.
  - It is critical to not only know the "what", but also the "why". (Example: Wire down - was it a result of fatigue, connector failure, etc.? If a tree branch is in the line, did it fall, blow, or grow. This interaction needs to happen in the field for the System Operator to accurately record the correct cause code)

General Responsibilities in Recording/Reporting Reliability Information

DOC Dispatcher

- Verify outage is being properly recorded real time including correct customer counts, start times, end times, correct locations, and appropriate cause/occurrence in the incident based on field input.
- Provide sufficient information on the Incident Manager Crew Repair Remarks/Outage Alert Note (OAN) to communicate effectively to customers and record relevant information.
- Responsible for validating all reportable customer interruptions involving one device in OMS.

ROC

- Responsible for validating all ODRM entries that involve distribution load.
- Responsible for validating all reportable customer interruptions involving multiple devices in OMS

When and how should I record an Area Out in the Daily Log?

What constitutes an Area-Out?

- All outages where a CB or RAR/AR did not operate but customer load was interrupted due to a fault or an unplanned operation. This also includes field personnel requests to open a distribution device to isolate and/or reconnect new equipment.
- Area outs do not require Interruption Log Sheets but are reportable outages, therefore all switching must be logged in the official Substation Main Log.
- It must not include the circuit's CB or an RAR/AR on the affected circuit as a switching/interruption location.
- Secondary interruptions are not included. Area outs include outages at the distribution transformer or above.

Area Outs – Daily/Published Log

- Log entries in the daily or published log are essentially Interruption Log Sheets for Area Outs.

Landing NTO

1610 [redacted] reporting to work on structure [redacted], Topoc 16kV line.

1611 Made Topoc 16kV recloser solid by EMS

1612 [redacted] has No Test Orders on the Topoc 16kV line.

1622 [redacted] opened position [redacted] de-energizing a secction of the Topoc 16kV line to the end of the line for an emergency outage

.

22:45 Closed position [redacted] energizing and testing a section of the Topoc 16kV line. All load up.

23:34 Opened position [redacted] de-energizing a section of the Topoc 16kV line. Emergency outage. This item to be forwarded.

[redacted]

What should be included in the Area Out Log Entry

- All devices operated in the field down to the transformer level.
- Operation and restoration times for each device.
- Fault/Incident location, weather, reported cause, and equipment damaged.
- Field personnel operating equipment.
- System Operator responsible for log entry.
- Circuit status at beginning and end of event.
- Remember you are telling a story when writing a log, the easier to understand the story, the better job we can all do regarding recording reliability events.

When do I need an Interruption Log Sheet?

What requires an ILS?

- A circuit interruption with CB and/or RAR/AR relay or emergency open operation.
- A transmission line interruption.
- A substation interruption.
- When an interruption occurs the System Operator will make an entry in the general log. This entry should note the time of the interruption, the station name(s), and the circuit(s) involved. This information should be followed with the direction to “See Interruption Report”.

Listed below are what Grid Operations enters as an "interruption", which potentially have no impact on customers or CMI:

- Loop Transmission/Sub-transmission/Distribution lines that relay at one or both ends.
- Any banks at stations where load is not split, and each bank has enough capacity to carry the entire station load.
- Station capacitor banks.

What information is required in an Interruption Log Sheet?

General Information

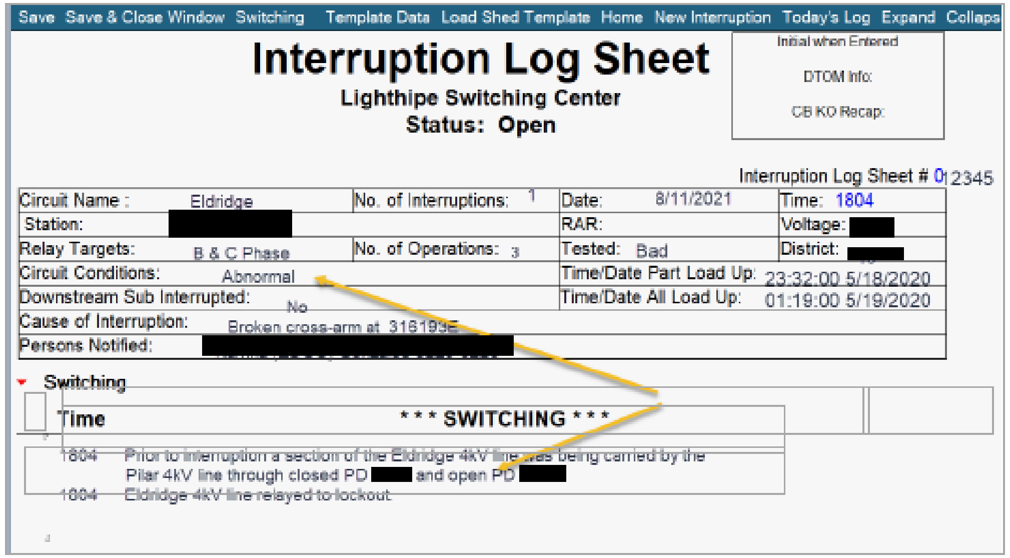
- The interruption log sheet will ensure that information is available for every interruption event that meets requirements.
- The interruption log sheet will give detailed information of the event or relay operations and the steps taken to remedy any resulting problems.
- Including the above information in an ILS will aid in the creation of a reliability event for tracking purposes.
- A complete and accurate ILS is the first step in making sure your ODRM entry is filled out correctly when you are required to create one.
- Provide sufficient information on the Interruption Log Sheet (ILS) so that a reliability event can be re-created for the purpose of analysis or calculating reliability.
- Remember you are telling a story when writing an Interruption Log Sheet, the easier to understand the story, the better job we can all do regarding recording reliability events.

The information provided shall include:

- Status of lines and equipment at the start of the outage event.
- Weather condition/Reported Cause
- Relay Targets/Persons Notified
- Circuits, substations (including downstream load), lines or equipment affected.
- Restoration steps in the exact order performed. (Including ALL devices operated down to the transformer level)
- Individual All Load Up (ALU), Part Load Up (PLU), and More Load Up (MLU) times
- Status of all lines and equipment upon completion of the reliability event.

Status of lines and equipment

- Document the status of the circuit (Abnormal vs. Normal) when interruption occurred in the header of the Interruption Log Sheet under "Circuit Conditions".
- Include appropriate detail in the first log entry. (See Example Below)



Save Save & Close Window Switching Template Data Load Shed Template Home New Interruption Today's Log Expand Collaps

Interruption Log Sheet

Lighthipe Switching Center

Status: Open

Initial when Entered

DTOM Info:

CB KO Recap:

Interruption Log Sheet # 012345

Circuit Name : Eldridge	No. of Interruptions: 1	Date: 8/11/2021	Time: 1804
Station: [redacted]		RAR:	Voltage: [redacted]
Relay Targets: B & C Phase	No. of Operations: 3	Tested: Bad	District: [redacted]
Circuit Conditions: Abnormal		Time/Date Part Load Up: 23:32:00 5/18/2020	
Downstream Sub Interrupted: No		Time/Date All Load Up: 01:19:00 5/19/2020	
Cause of Interruption: Broken cross-arm at 318193E			
Persons Notified: [redacted]			

Switching

Time	*** SWITCHING ***
1804	Prior to interruption a section of the Eldridge 4kV line was being carried by the Pilar 4kV line through closed PD [redacted] and open PD [redacted]
1804	Eldridge 4kV line relayed to lockout

- Document the status of the circuit (Abnormal vs. Normal) when interruption occurred in the header of the Interruption Log Sheet under "Circuit Conditions".
- Include appropriate detail in the first log entry. (See Example Below)

Weather condition/Reported Cause

- Make sure to list the current weather condition in your Interruption Log Sheet
- Record the appropriate Outage Cause Details and Type. ILS should provide enough information to make a choice in ODRM. See options in ODRM below:
  - **Error-** Unintentional interruption due to SCE or Contractor personnel
  - **Non TDBU Source-** This is used when a Transmission line becomes de-energized due to loss of generation or a foreign utility
  - **Source-** The line that feeds it was de-energized or a transmission substation was de-energized, select appropriate drop downs in category and code
  - **Standard Operation-** This is most used for a manual de-energizing of a Substation, line, piece of equipment or a relay at test. Select Operator/Crew in category and appropriate outage code. (Example: Emergency Outage due to hazard or MADEC
  - **Note**: if a Protective Device relays on infrequency, high or low voltage select that category and appropriate outage code
  - **Structure-** This is used if the cause is a problem (or something across) a rack in the station, transmission poles, cross arms, guy wires and towers.
  - **Substation Equipment-** This covers a wide variety of substation equipment including CB's and transformer banks. Once you have selected the equipment type select the appropriate outage code.
  - **Unknown-** A cause was not found.

Weather condition/Reported Cause

- Remember:
  - When recording the outage cause details, do your best to record the **ROOT cause** reported to you by the field, not an effect.
  - If the outage is animal caused-the animal type must be listed including the bird species if known.
  - If the outage is a manual open, the reason must be listed (for example: **To clear damaged or dangerous field equipment**)
  - All transmission line outages with no cause found must list whether the line was patrolled. (**It's a best practice to leave the ILS open until patrol is complete**)
  - Include all details provided by field personnel. (Example: **Tree branch broke and fell onto line near pole 1234567E)**

Relay Operations/Persons Notified

- Make sure to list any reported relay targets.
- Record all persons notified and involved, including:
  - **System Operator**
  - **Substation Operator**
  - **Field Personnel**
  - **GCC**
  - **DOC Dispatcher**
  - **ETC.**

Persons Notified: GCC([redacted], 1521 [redacted](Ltp Maint.Sup)

Cause of Interruption: Stage 3 emergency declaration by CAISO

Persons Notified: [redacted] (GCC), [redacted] (El Nido), Vaca (Sub Operator), [redacted](WDOC), [redacted] (Supervisor)

Circuits, substations (including downstream load), lines or equipment affected.

- It is important to list all circuits and substations affected in an outage. This includes downstream circuits and substation. (Examples: Distribution Substations with circuits and Pole Top/Padmount Substations)

1845	Load shed complete for groups A57 and A58. The following circuits have been interrupted: [redacted]

1008	Inner and Outer 12kV Operating Buses relayed, momentarily dropping all 12kV load at Railroad sub. Dispatched substation operator. Inner bus circuits interrupted: [redacted] Outer bus circuits interrupted: [redacted]

0216	16kv Operating bus relayed and tested good. The #1 and #2 Bank 66/16kv run in parallel. The following 16kv circuits were momentarily interrupted out of Fruitland: [redacted] and [redacted] 16kv lines The Pulp and Transit 16kv lines feed [redacted] sub with the following 4kv circuits out of [redacted] momentarily interrupted: [redacted] 4kv lines.

Restoration steps in the exact order performed. (Including ALL devices operated)

- Log all switching or other types of isolation (such as isolators or open taps, distribution transformers, or distribution devices) sequentially in the order they are performed in the field. (Do not show times out of order)

- All devices restored should be recorded in the ILS, this includes tap-line devices and transformers. It is important for field personnel to report this information out to the system operators to keep logs accurate.

Individual All Load Up (ALU), Part Load Up (PLU), and More Load Up (MLU) times

- Use SCADA device operation times from EMS/DMS event summaries. There is no need to round. For a relay and reclose, disregard the seconds column. Record the seconds at the start of the outage at :**00** and the seconds at the energize time at :**30**.

Time/Date Part Load Up:	1547:00 08/16/2020
Time/Date All Load Up:	1547:30 08/16/2020

- Use times given by field personnel for Non-SCADA device operations.

- Provide as close to accurate times as possible for each individual operation or restoration step.

Status of all lines and equipment upon completion of the reliability event.

- If equipment is going to remain in an abnormal status for an extended period, it is important to document the status the circuit is left in when all load is restored.

1343	[redacted] 4kV line relayed and locked out. [redacted] 4kV line is carrying a portion of the [redacted] 4kV line via Closed PD[redacted] and Open PD[redacted] [redacted] 4kV line is carrying a portion of the [redacted] 4kV line via Closed [redacted] and Open P[redacted]

Other things to consider:

- **Interruptions within 5 minutes** of each other may be included in the same ILS; interruptions longer than 5 minutes apart must be on a separate ILS, regardless if due to the same cause (reference SOB 12)
- If a Troubleman is clearing trouble or debris following an interruption with all load restored and a CB or RAR/AR is operated, you must create a new ILS.
- Any switching that occurs past midnight should reflect the new date in the body of the interruption log sheet.
- Confirm time stamps with EMS/DMS when logging operations (Get time-stamps from SCADA summary. Use :**00** or :**30** in seconds column)
- **Do not close the ILS if a patrol is pending**, instead leave open to facilitate documenting findings of the patrol.
- Add language in each ILS to demonstrate times for **Part Load Up (PLU), More Load Up (MLU), and All Load Up (ALU)**
- **NERC requirements mandate an ILS is submitted for all bulk power circuit breakers (100kV and above) that open/operate non-manually.**

Most Common Logging Mistakes

Most common general logging mistakes:

- Forgetting to create an Interruption Log Sheet.
- Not recording circuit status (normal or abnormal conditions).
- Missing devices/equipment operated, including tap-line devices and individual transformers.
- Missing restoration steps, including tap-line devices and individual transformers.
- Not providing accurate description of root cause of interruption.
- Providing inaccurate times. Not using SCADA device operation times from EMS/DMS event summaries.
- Not including of all personnel involved in restoration or notification process. (TM, Substation Operator, DOC, ROC, GCC if applicable)

Common Interruption Log header errors:

- 1. **Sys Op leaves start time at default** instead of changing to actual start time
- 2. **District #** is used in Station Field
- 3. **Circuit conditions is left blank** or if abnormal, no additional details in body of log
- 4. **Downstream Sub is left blank** or if yes, no additional details in body of log
- 6. **Cause is left blank**
- 7. **ALU is left blank**, most commonly when a single transformer remains de-energized.
- 8. **Abnormal conditions require details be logged** in the body of the Interruption Log Sheet listing any abnormal opens and/or closed devices and associated circuits
- If Downstream is interrupted, **please list**
  - **for Transmission- Station names**
  - **for Substations- either All circuits or if partial, which circuits were de-energized**
  - **for Distribution circuits- names of downstream Substations (including PT/Padmount Subs), and circuits involved.**

Documentation

Documentation

To reference documentation supporting the expectations of logging, see the links provided below:

- General Instructions For Recording Interruptions, SOB 1100
- Reports to the GCC- SOB 12
- Operators Manual- 6.10 Logging
- SOM G:5- Substation Logs

Assessment Questions- Must get 80% to pass

Question 1

- What is a reportable outage?

- An outage on the secondary side of the transformer.
- An outage on equipment 33kV and above.
- An outage at the distribution transformer level or higher.

Question 2

- What is CMI?

A. A calculated figure that relates the number of interrupted customers and the amount of time that their service was interrupted.

B. A calculated figure that relates the number of times customers were interrupted during a specified duration.

C. A calculated figure that relates the number of SCADA operations in a particular area.

Question 3

- When is an Interruption Log Sheet required?

- For all emergency or unplanned manual operations of CB’s or RAR/AR’s under the Switching Center's jurisdiction.
- Only when there is a relay operation
- Emergency operations for equipment under the Switching Center's jurisdiction on the main-line.

Question 4

- Which of these options should be included in an Interruption Log Sheet?

A. Weather condition/Reported Cause
B. Circuits, substations (including downstream load), lines or equipment affected.
C. Restoration steps in the exact order performed. (Including ALL devices operated)
D. Status of all lines and equipment upon completion of the reliability event.
E. All of the above

Question 5

- Who are the Grid Operations personnel responsible for recording and reporting reliability data?

A. System Operators ONLY

B. System Operators, Field Personnel, and RPPM

C. System Operators, Field Personnel, DOC Dispatchers, ROC

Question 6

- What is the system operator's role in recording and reporting interruptions? Pick the best answer.

A. Provide good information in the ILS, Notify GCC, Update remarks in Incident Manager, and Validate ODRM entries when necessary

B. Provide good information in the ILS, Create ODRM entries when necessary, Create incidents in OMS, and Validate ODRM entries when necessary

C. Provide good information in the ILS, Notify the GCC for every interruption, Update the OAN, and Validate ODRM entries when necessary

Question 7

- What's the first step to an accurate ODRM entry?

A. Creating Incidents on the Map

B. A complete Interruption Log Sheet

C. Correct CMI

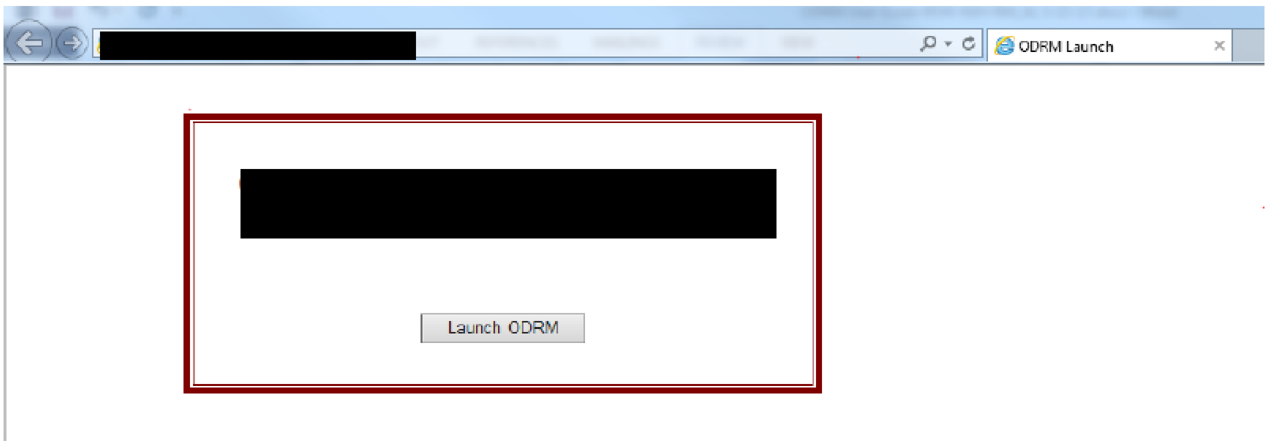
ODRM is a database that is used by our Company to track and report interruptions at all levels from Transmission voltage to primary voltage transformers for reliability reporting and tracking to various regulatory agencies. Therefore, it is very important this information is accurate. It is also used throughout the Company for planning and analysis.

TABLE OF CONTENTS **PAGE #**

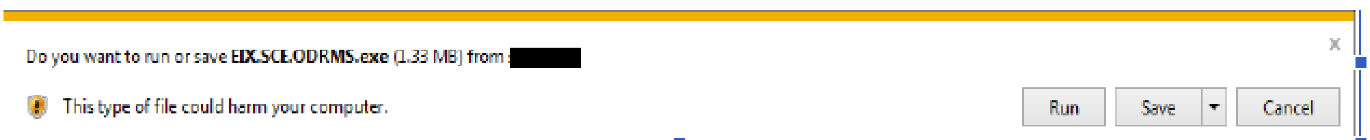
1.0 Launching ODRM

1.1 Go to ODRM link - http:/XXXXXXXXXXXXXXXXX

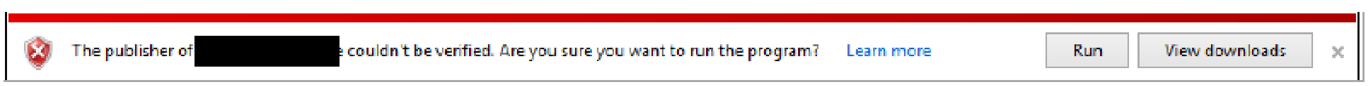
And the ODRM window will open. Click on Launch ODRM button



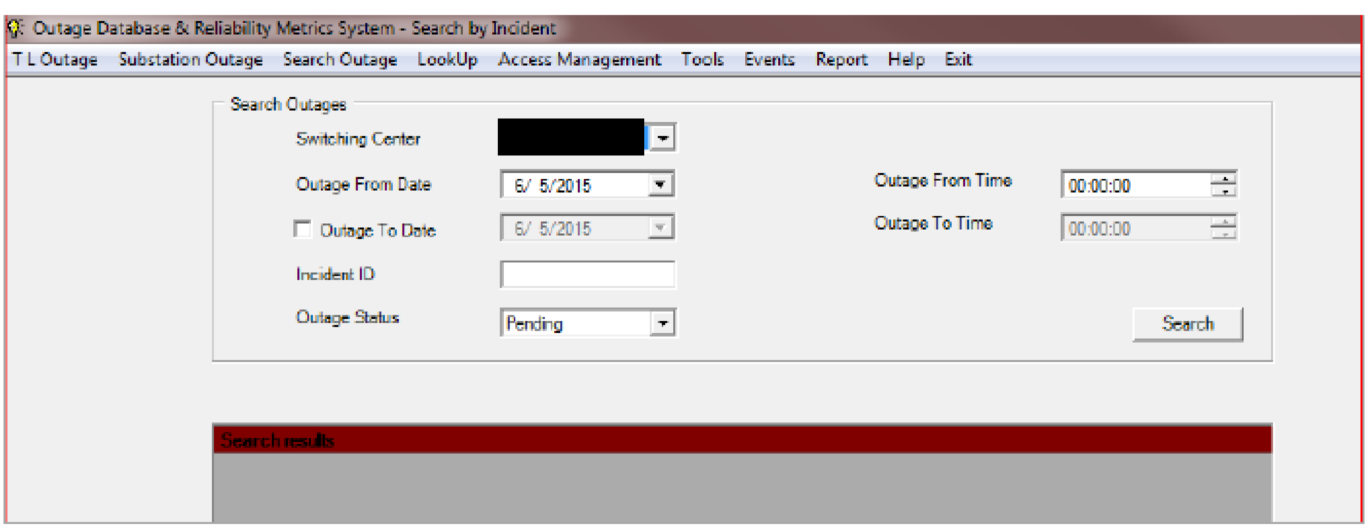
a popup will then appear at the bottom asking if you want to run or save. Select Run.



A second popup will appear and select Run again.

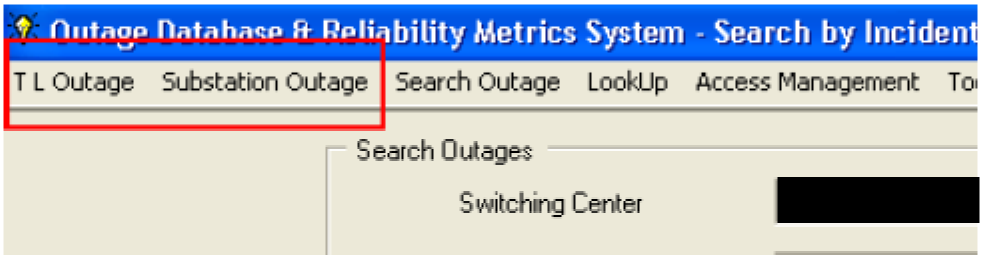


Then the Search by Incident Window will open.

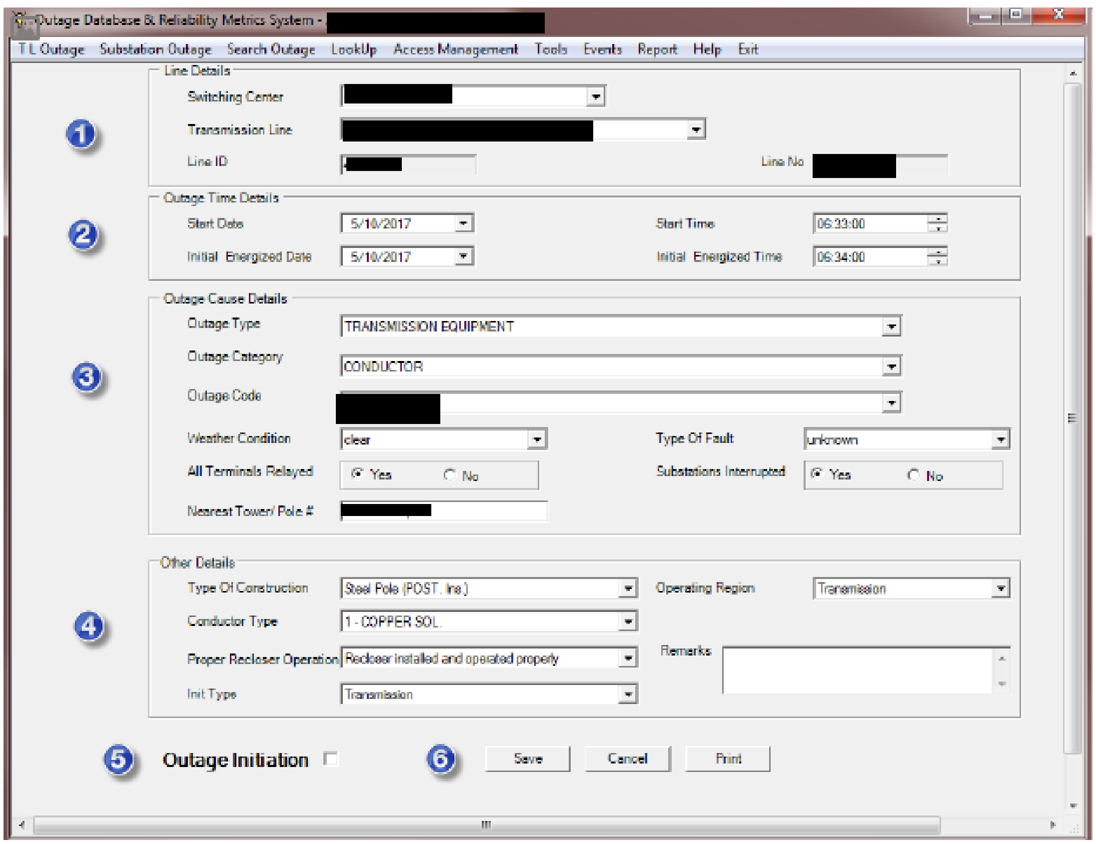


2.0 ADDING AN OUTAGE

2.1 Select the appropriate outage type **T L Outage (Transmission Line)** or **Substation Outage**. Instructions for entering Transmission lines follow, Substation instructions begin on page 8.



2.2 T L Outage Page

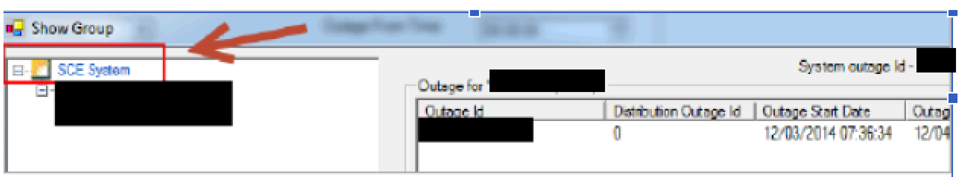


- 1. **Line Details:** Use the Drop Down menus to select Switching Center and Transmission Line.
- 2. **Outage Time Details:** Input Dates and Times. Note; the initial energized date and time is the ALU.

- 3. **Outage Cause Details:** Use the Drop Down menus to select Outage Type, Cause, and Code. Please see the appendix for additional information about the outage type, cause and code. Proceed to Weather Conditions, Type of Fault, Terminals Relayed, and Substation Interrupted field all have defaults settings that need to be changed as necessary. Fill in the Nearest Tower/ Pole # field if known.

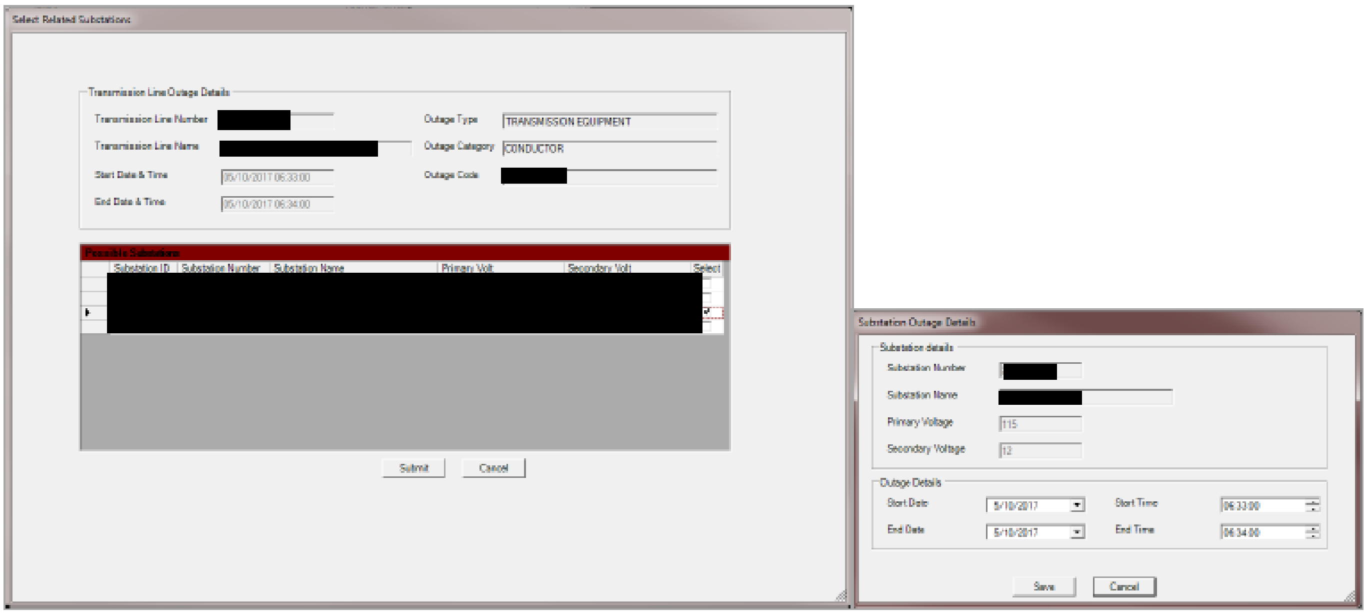
  Note: If downstream substation interrupted check "Yes" to ensure that the Select *Related Substation window* opens – this will happen after your click the save button and allows you to add downstream Substations.

- 4. **Other Details:** Use the Drop Down menus to update the fields, if you do not know the details it is okay to leave the defaults. Add any remarks as needed for clarification.
- 5. **Outage Initiation:** Check the box.
- 6. **Save:** Click the save button (or cancel)
- 7. THIS IS A DECISION POINT…
- <u>If NO downstream Substation was interrupted</u>, this interruption should now be "validated" in ODRM following the instructions below.
- <u>If a downstream Substation WAS interrupted,</u> skip to the next page and follow the instructions for entering the Substation
- .Locate the outage using the search function and select the update button. The outage will then open.
    - Right click on "SCE System".



Then select validate from the popup window and that will complete the process.

- If downstream substation(s) interrupted and "Yes" was checked under Subtation Interrupted, the Select *Related Substation* window will open allowing you to select the downstream substation(s)



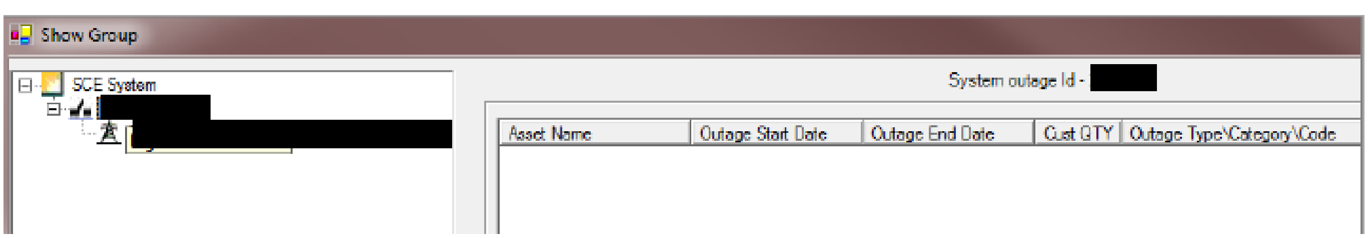
- 1. **Select the** affected downstream substation(s)**.**
- 2. The **Substation Outage Details** window will pop up. **Confirm Date and Time the substation was interrupted, editing as appropriate, then save.**

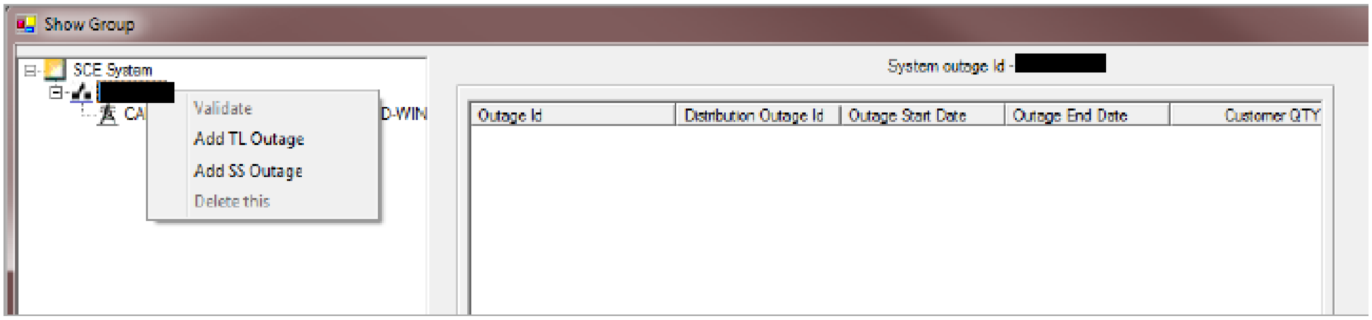
  Note: Only <u>energize</u> times should be different from the transmission line times

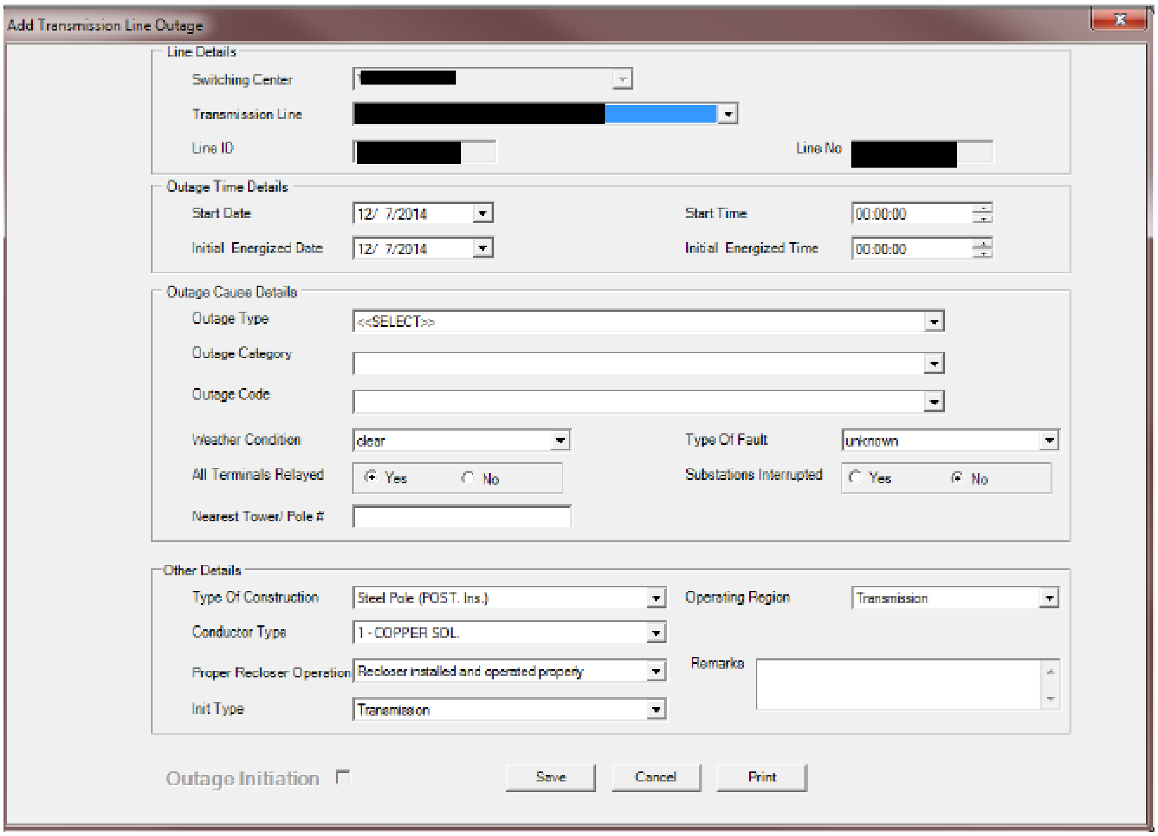
- 3. Repeat *"Steps 1&2"* if more than one substation was interrupted
- 4. When complete, click Submit.

2.2.2 Adding additional Transmission Lines to an TL Outage

- Once you have saved your Transmission Line information and additional Transmission Lines need to be added to the same ODRM – Right click on the Switching Center in the root directory and click on "Add TL Outage".



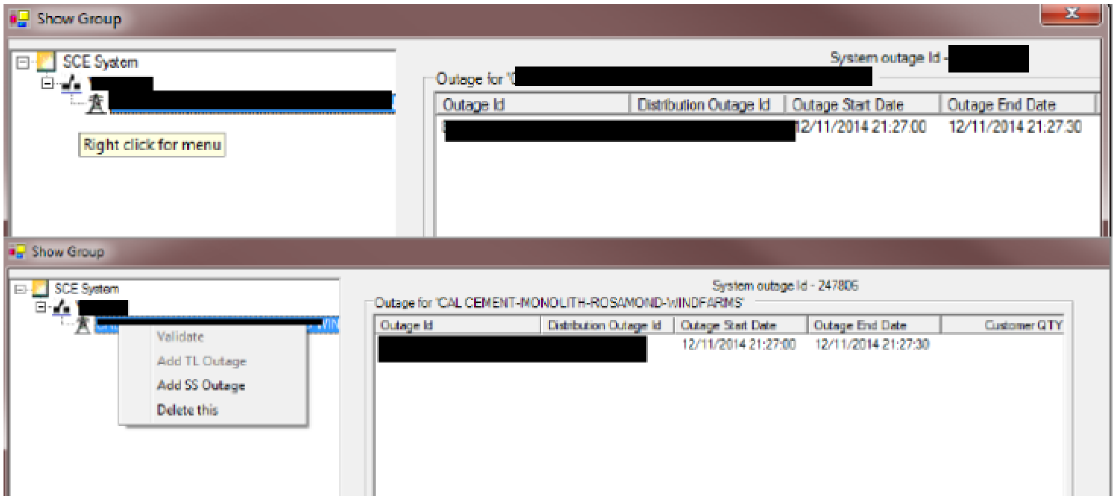


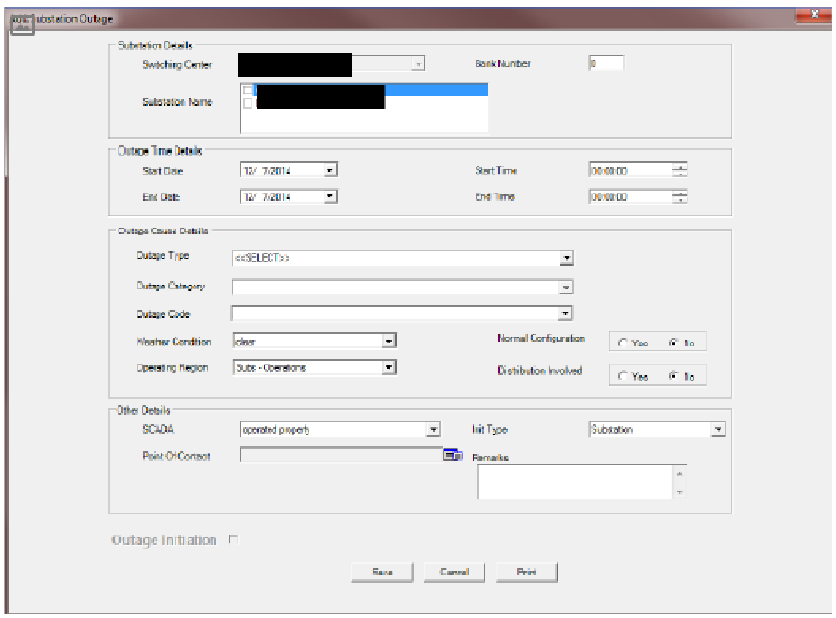


➢ From here follow the steps for TL Outage Page (on page 3).

2.2.3 Alternative way to add a Downstream Substations to existing TL Outage if needed

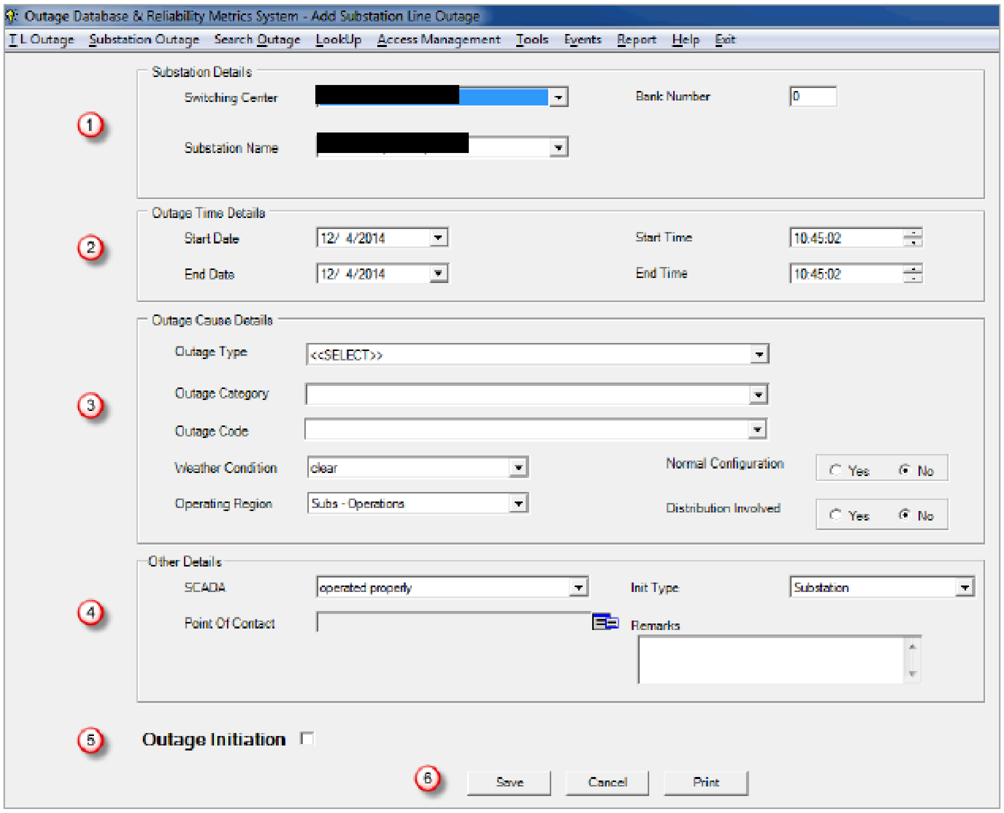
➢ If Transmission Line outage has been created without Downstream Substations but a Downstream Substation was interrupted and still needs to be added to the same ODRM, you may go back to the TL Outage page, check "Yes" and go thru the steps on page 4 or you can do the following – Right click on the Transmission Line in the root directory and click on "Add SS Outage" and check the desired substation



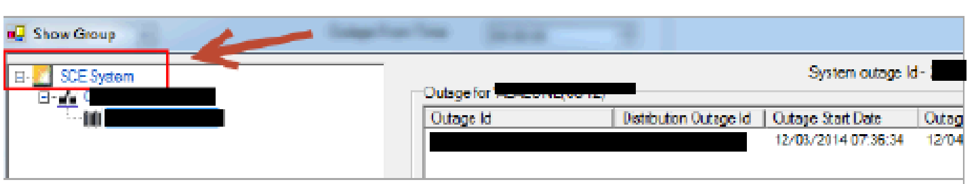


➢ From here follow the steps for downstream Substation Outage (on page 5).

2.2.4 Substation Outage Page:



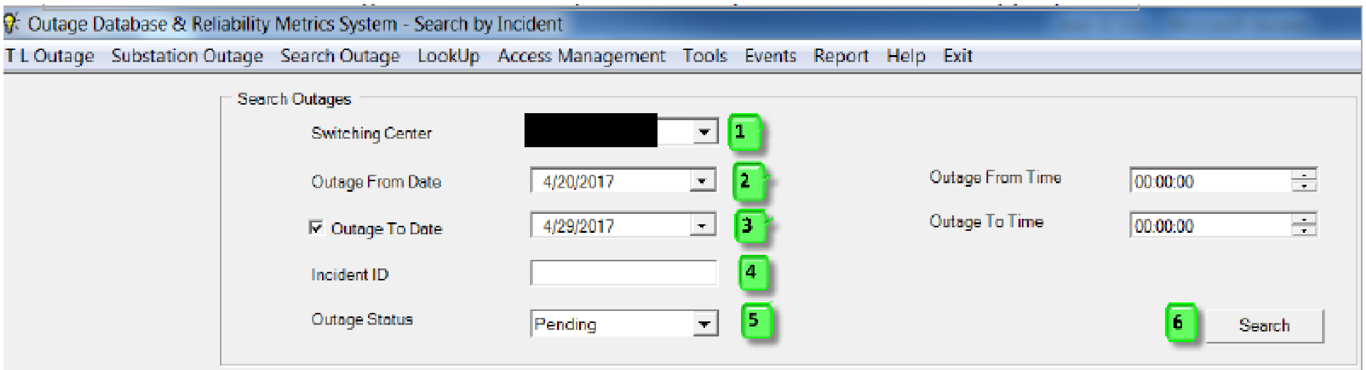
- 1. **Substation Details:** Use the Drop Down menus to select Switching Center and Substation Name. Add the Bank Number if appropriate
- 2. **Outage Time Details:** Input Dates and Times.
- 3. **Outage Cause Details:** Use the Drop Down menus to select Outage Type, Cause, and Code. The Weather Condition, Operating Region, Normal Configuration, Distribution Involved fields all have defaults settings that need to be changed as necessary.
- 4. **Other Details:** Use the Drop Down menus to update the SCADA and Init Type fields. Add any remarks as needed for clarification.
- 5. **Outage Initiation:** Check the box.
- 6. **Save:** Click the save button (or cancel).
- 7. If no downstream distribution was interrupted, this interruption should now be “validated” in ODRM .Locate the outage using the search function and select the update button. The outage will then open. Right click on “SCE System”.



Then select “validate” from the popup window and that will complete the process.

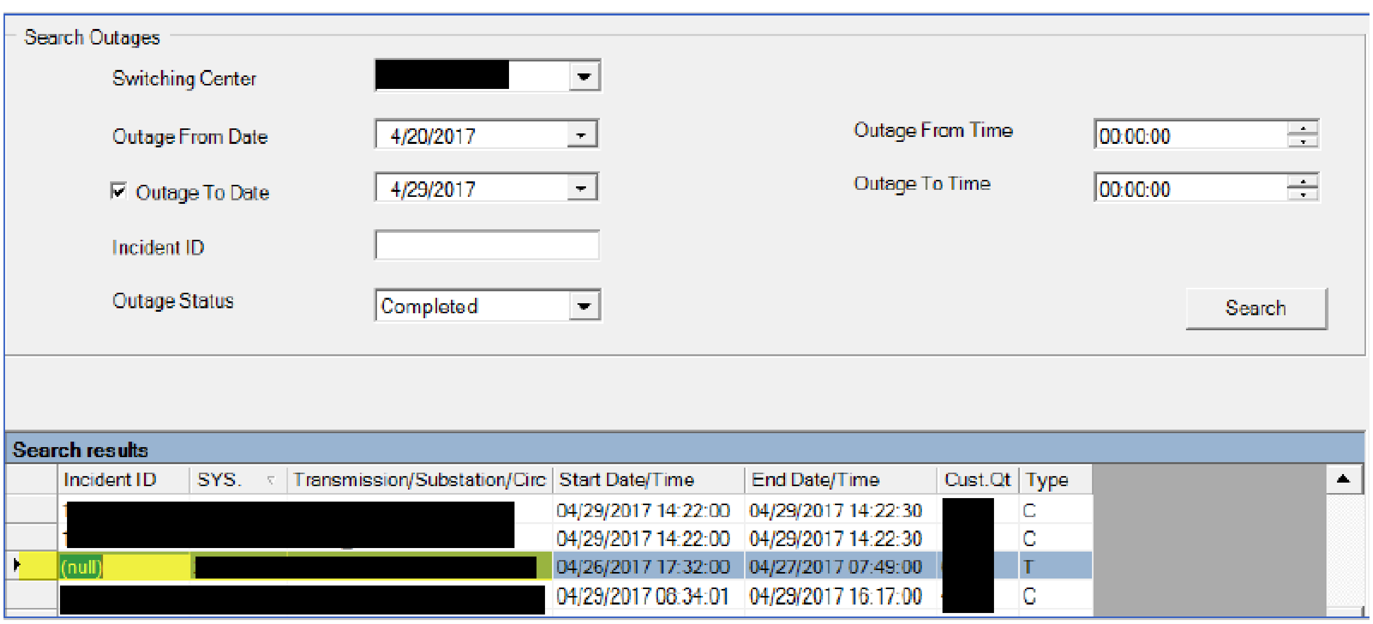
SEARCHING FOR AN OUTAGE

2.3 Select Search Outage and then complete the dropdown windows as appropriate.

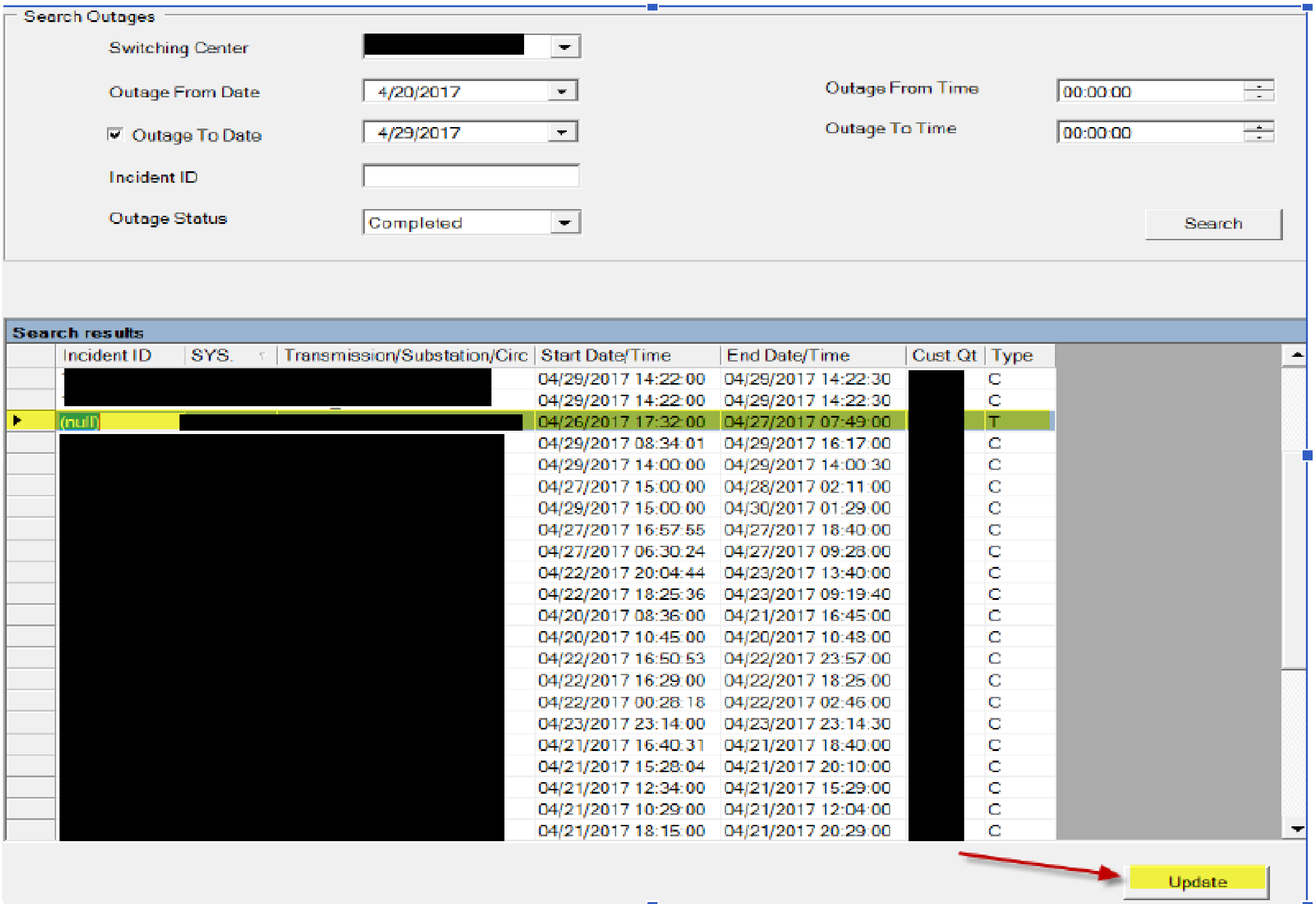


- 1. **Switching Center:** Use the drop down to select the Switching Center.
- 2. **Outage From Date/Time:** Use the date field to find an outage on a specific day, add a time to narrow to outages the started after a specific time on that day.
- 3. **Outage To Date/Time:** Check the check box to search for outages in a date range between the Outage From Date/Time and the Outage To Date/Time, maximum search period is 9 days.
- 4. **Incident ID:** You can use this field to search for a specific Incident by ID number.
- 5. **Outage Status:** Use the Drop Down menu to select either pending or completed.
- 6. **Search:** Click the search button to initiate the search.

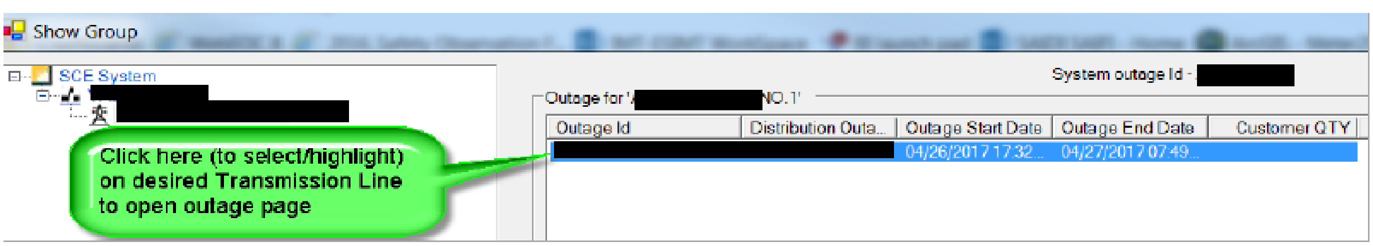
2.4 Example of a search between two dates (note that not all outages have an incident number).



2.5 To edit existing records or to view details – Double Click on desired line item, on the very left of the Search Results window or highlight desired line item and then click on "Update" button at the bottom right.



➢ Click here (to select/highlight) on desired Transmission Line, Substation or Circuit in the root directory (left part of window) and then double click on the top line item of outage record (right part of window) to open Outage Page.

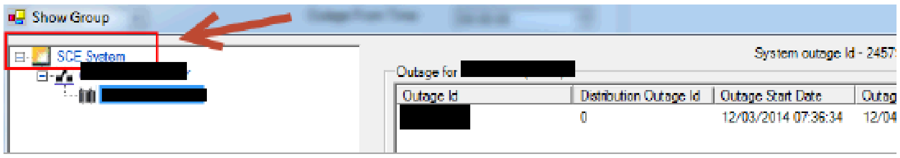


Edit and re-save the outage as necessary.

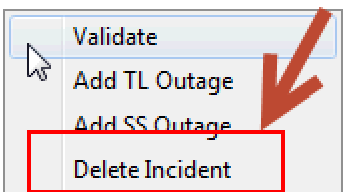
3 DELETING AN OUTAGE

Perform a search as outlined under 2.3, then double click the outage from the search results.

3.2 Right click on "SCE System".

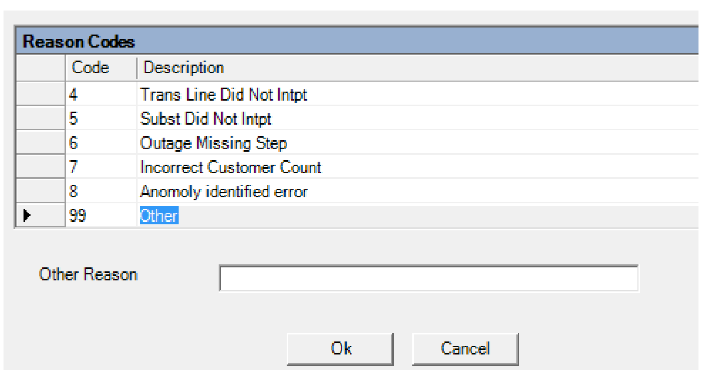


3.3 Choose "Delete Incident".



3.4 A confirmation box will appear, choose Yes to confirm the deletion.

3.5 A Reason Codes window will appear. Choose a reason code, if you select "other" you are required to give a brief explanation. Click the Ok button to complete the deletion.



Validating a previouslycreated ODRM

Locate ODRM
From the ODRM Home page (http:/XXXXXXXXXXXXX select the Search Outage tab. You need to select the 'Search By Incident Tab' however this is not available. A work around to this is to select one of the other two options, followed by again selecting the Search Outage tab and you may now select "Search by Incident"

Switching Center – will default to your home Switching Center and must match the ILS and previously created ODRM

Outage From Date – is the start date of the interruption and must match the ILS and previously created ODRM

Outage From Time– is the start time of the interruption and must match the ILS and previously created ODRM

You are now ready to locate the ODRM in need of Validation, select the Search Tab

Search results

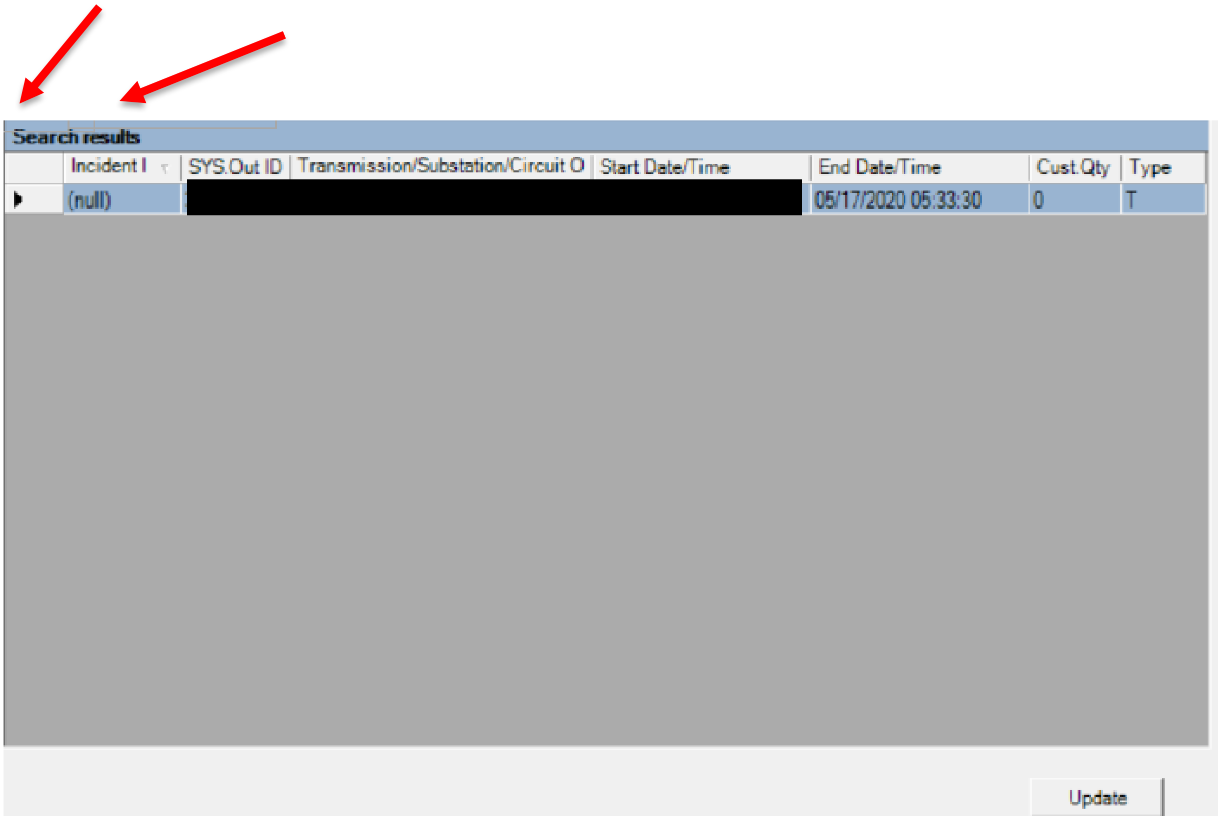
	Incident I	SYS.Out ID	Transmission/Substation/Circuit O	Start Date/Time	End Date/Time	Cust.Qty	Type
▸	(null)	[redacted]		05/17/2020 05:33:00	05/17/2020 05:33:30	0	T

The search results will appear, this includes the SYS. OUT ID # which must be manually entered in the ODRM Info box on the Original ODRM and Interruption Log Sheet

Interruption Log Sheet
Vista Switching Center
Status: Closed

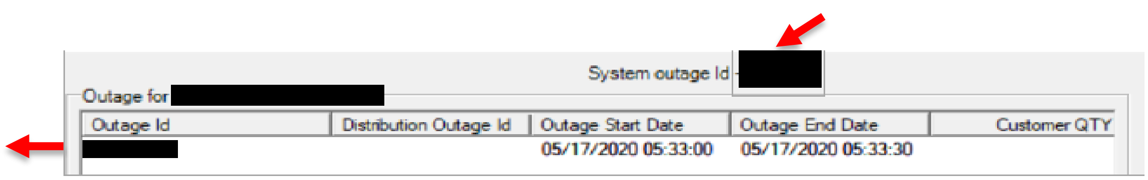
Initial when Entered
ODRM Info: [redacted]
CB KO Recap:

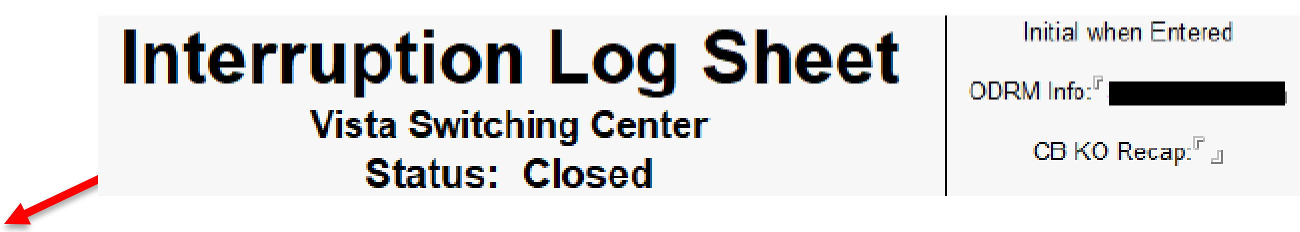
Next is to select the line item to be validated by mouse clicking on the line item (it will now be highlighted) and selecting update



The system will now open the overview of the previously created ODRM:
System outage ID - will match the number entered on the ODRM Info space on the ILS.

Outage ID – this number is required to be entered onto the ILS in the ODRM Info area as the second number associated with this ODRM





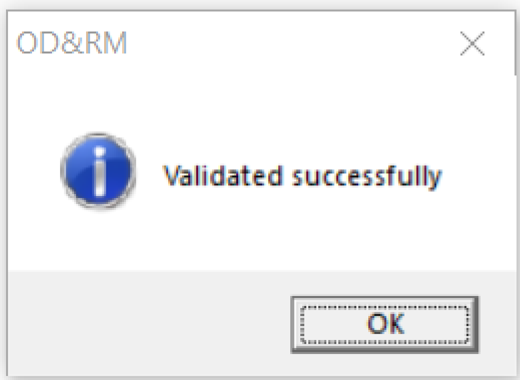
Double check the accuracy of the ODRM

This is your last opportunity to ensure the ODRM is accurate and complete

Double click on the Outage ID Number will open the original ODRM, the ODRM will open and you can double check all information against the corresponding ILS. After proof reading the ODRM you cannot close it out by selecting the **X** in the upper right corner

You are now ready to validate the ODRM

Hover the mouse pointer over the SCE System verbiage in the top left corner, right click the mouse and select Validate. A Validated successfully box will appear



The ODRM is now validated and the system will return to the home page. You can now close out the ORDM Page.

Log ODRM Process completion on your ILS

The final step is to amend the ILS with a statement of ODRM Completion (refer to ILS below)

Interruption Log Sheet

Vista Switching Center

Status: Closed

Initial when Entered

ODRM Info: 3[redacted]

CB KO Recap:

Interruption Log Sheet # 13035

Circuit Name : [redacted]	No. of Interruptions: [redacted]	Date: 05/17/2020	Time: 0533
Station: Vista		RAR:	Voltage: 66
Relay Targets: (See Table Below)	No. of Operations: 1	Tested: ◉ Good ○ Bad	District: [redacted]
Circuit Conditions: ○ Abnormal ◉ Normal		Time/Date Part Load Up: 0533:30 05/17/2020 Insert Time/Date	
Downstream Sub Interrupted: ◉ No ○ Yes		Time/Date All Load Up: 0533:30 05/17/2020 Insert Time/Date	
Cause of Interruption: No cause found, light wind Find Cause			
Persons Notified: GCC, Rinaldi			

Station	Targets	Station	Targets
[redacted]	HCB		
[redacted]	HCB		

Time	* * * SWITCHING * * *
0533	[redacted] 66kv Line R&R No Load Interupted Notified GCC Notified Transmission [redacted]
0637 1231	[redacted], Operator Karna found CBs closed, HCB target, 1 operation each CB, equipment checks OK. [redacted] Transmission reports patrol completed. no cause found., light wind in area. [redacted]
05/18/20 1232	At [redacted], Operator reports CB closed, 1 operation, HCB target, reset ok, equipment checks ok [redacted]
5/19/2020 1000	Completed and Validated ODRM [redacted]

APPENDIX

How to record causes of Substation and Transmission Line Interruptions

When recording the outage cause details, do your best to report the ROOT cause, not an effect. For example an animal gets across transmission lines resulting in a relay operation would be reported as; Transmission Equipment-Conductor-Animal, NOT Standard Operation-Protective Device-High voltage, that would be the effect, not the root cause.
There is a free form field for remarks associated with the cause, this must contain an entry in three scenarios;

1. If the outage is animal caused-the animal type must be listed in remarks including the bird species if known.
2. If the outage is a manual open, the reason must be listed in remarks (for example- to clear failed breaker)
3. If you use a cause of “other see notes”, you must detail the cause in remarks.

NOTE: if the cause of an outage is bird droppings or a bird nest, the cause is considered to be animal and a note explaining the detail is to be included in the remarks field.
All transmission line outages must either record a cause or Patrolled, no cause found. Therefore, it is a good idea to leave the Log Sheet in an open status until the patrol is completed and the Patrolman has communicated the cause, if one is found upon completion of his patrol.

Substation Outage

Outage Cause Details and Type
Below are explanation of the different Substation outage causes and how to properly record them in ODRM.
Error-self-explanatory, select appropriate drop downs in category and code
Source-self-explanatory, select appropriate drop downs in category and code
Standard Operation-this is most commonly used for a manual de-energizing of a Substation or a relay at test. Select Operator/Crew in category and appropriate outage code.
Note: if a **Protective Device** relays on infrequency, high or low voltage select that category and appropriate outage code
Structure-this is used if the cause is a problem (or something across) a rack in the station, select that category and the appropriate outage code
Substation Equipment this covers a wide variety of substation equipment including CB’s transformer banks. Once you have selected the equipment type select the appropriate outage code.
Unknown-self explanatory

Transmission Line Outage

Outage Cause Details and Type

Below are explanation of the different Transmission line outage causes and how to properly record them in ODRM.

Error-self-explanatory, select appropriate drop downs in category and code

Non TDBU Source- this is used when a Transmission line becomes de-energized due to loss of generation or a foreign utility, select the appropriate drop downs in category and code.

Source- this should only be used when the cause is loss of a transmission substation, select appropriate drop downs in category and code.

Standard Operation-this is most commonly used for a manual de-energizing of at transmission line or when a line relays at test. Select Operator/Crew in category and appropriate outage code.

Note: if a **Protective Device** relays on infrequency, high or low voltage select that category and appropriate outage code

Structure-used for transmission poles, cross arms, guy wires and towers. Select appropriate drop downs in category and code

Transmission equipment-used for conductor, hardware, lightning arrestors, insulators, potheads/terminations and switches/disconnects. Select appropriate drop downs in category and code.

Unknown- as mentioned previously, this should only be recorded after the patrol has been completed and the patrolman has communicated no cause found.

ODRM User Guide

Outage Database and Reliability Metrics

ODRM User Guide, Objectives

- At the end of this training you should be able to:
  - **Explain how to launch to ODRM application**

    How to add ODRM as a favorite.
  - **Describe when to create an ODRM.**
  - **Describe how to add an outage.**

    Add Transmission or Sub Transmission line event. (all variations).

    Add a Substation event. (all variations).

    Add an additional Transmission or Sub Transmission Line to an existing event.

    Add a downstream substation to an existing event.
  - **Describe how to search for an outage**.

    Both Pending and Completed outages.
  - **Describe how to edit an outage.**
  - **Describe how to delete an outage.**
  - **Explain how to validate an outage.**

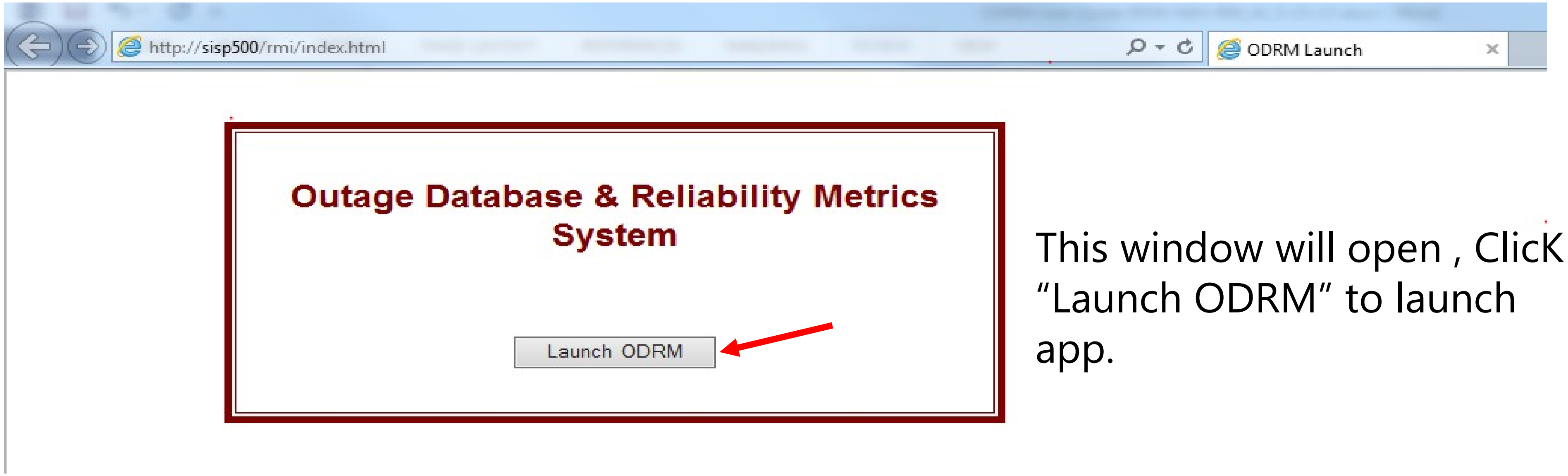
    Roles and responsibilities and expectations pertaining to validating outages for both System Operators and their SOS.

    Update Interruption Log Sheet once ODRM has been completed and validated.

Launching ODRM

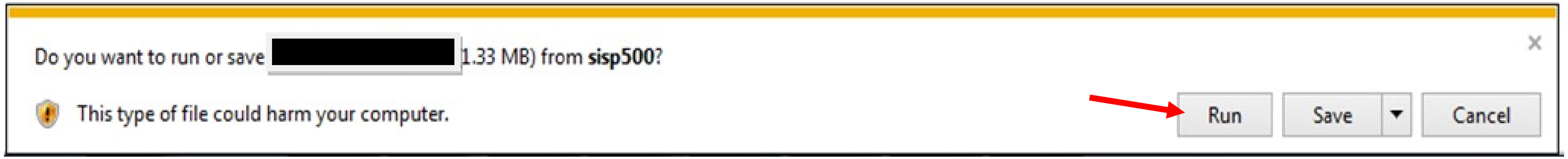
Launching ODRM:

- Click Here to launch ODRM link : [XXXXX]

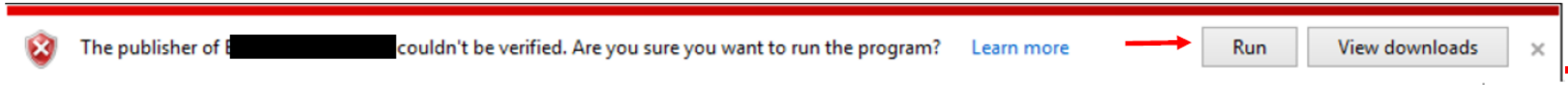


This window will open , ClicK "Launch ODRM" to launch app.

- A popup will then appear at the bottom asking if you want to run or save. Select Run.



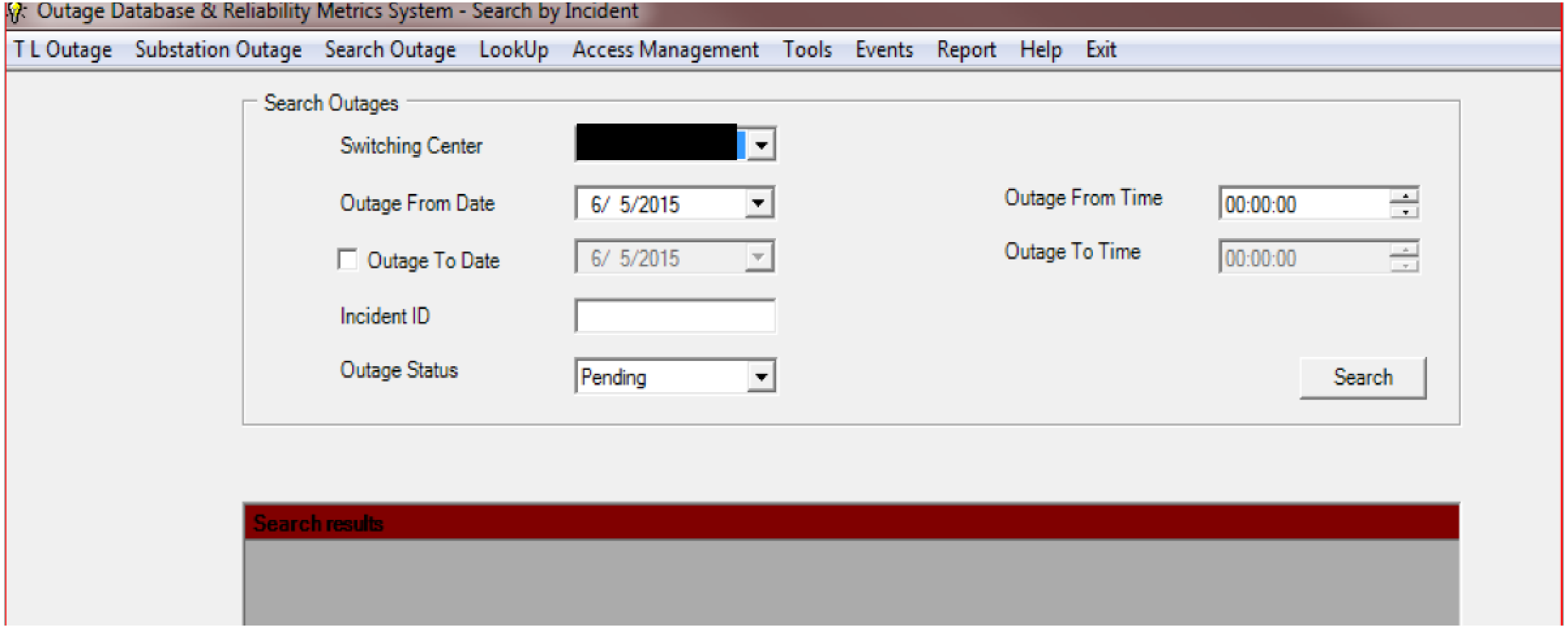
- A second popup will appear at the bottom of the screen. Select Run.



Energy for What's Ahead℠

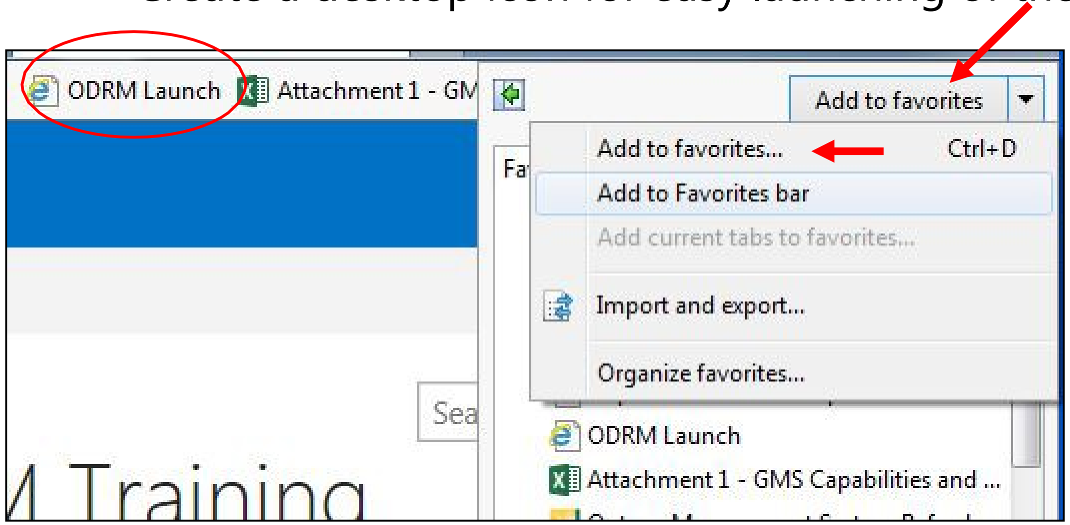
Launching ODRM:

- Once launched, the Search by Incident Window will open by default.



Adding ODRM Launch as a Favorite:

- Once you have successfully started the ODRM program you can either:
  - Add the start-up link to you favorites bar in Internet Explorer or
  - Create a desktop icon for easy launching of the application.



- When in Internet Explorer click on Add to favorites. Use the drop-down arrow to select Add to Favorites bar. The link will then be populated on the favorites bar at top of your Internet Explorer screen.

- Once ODRM is successfully launched right click and select Create Shortcut to save it to your desktop for easy launching of the application.

Creating an ODRM Roles and Responsibilities- System Operator

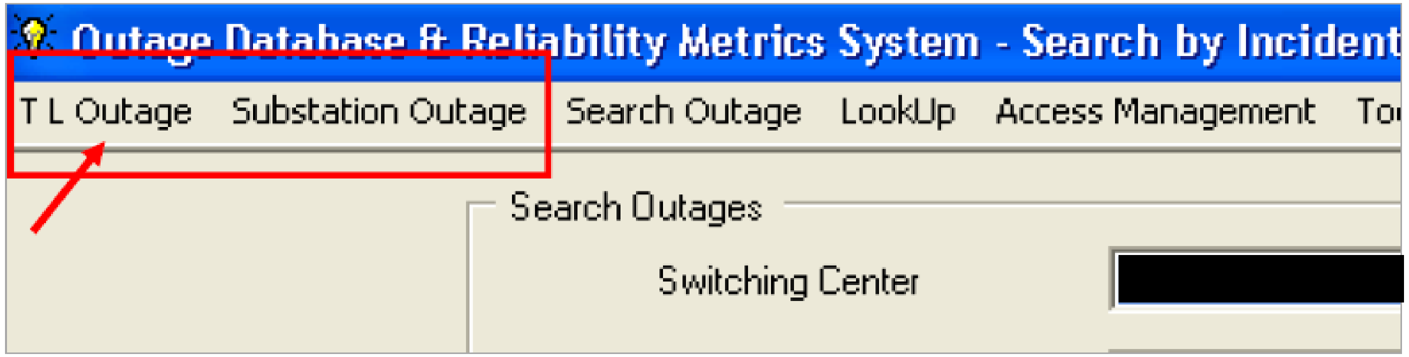
Creating ODRM Roles and Responsibilities - System Operators

- System operators are responsible to create an ODRM for ALL Transmission and Sub-Transmission line Outages (with or without load affected).
- System operators are responsible to create an ODRM for all Substation Equipment Outages (with or without load affected).
- System operators are required to create an ODRM for any open-ended bulk power CB non-manual operation.
- System operators are responsible to create the ODRM with most accurate information as possible in order to capture reliability information.

Creating a Transmission Line Outage in ODRM

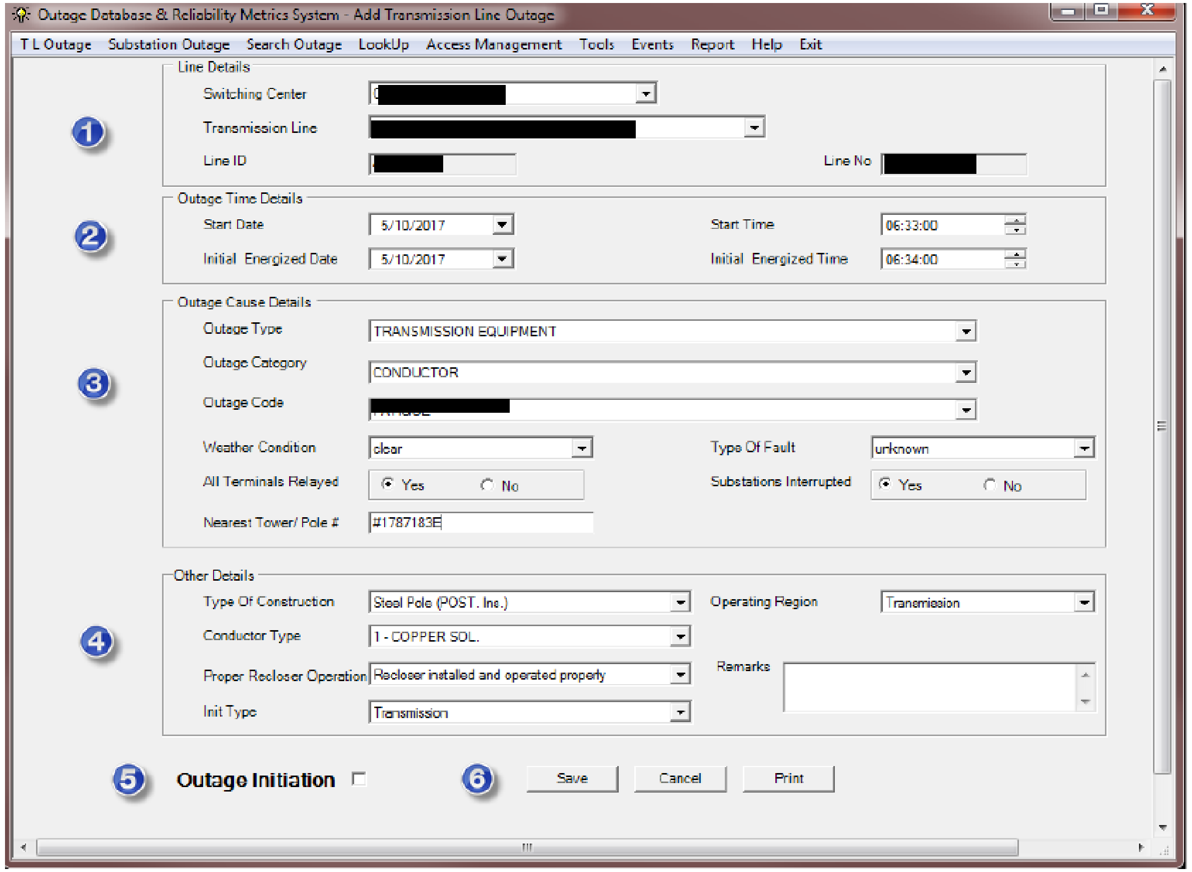
Creating a Transmission Line Outage

- Select the appropriate outage type : T L Outage (Transmission Line)



Creating a Transmission Line Outage

T L Outage Page



- 1. **Line Details**: Use the Drop-Down menus to select Switching Center and Transmission Line.

- 2. **Outage Time Details**:

Input Dates and Times.

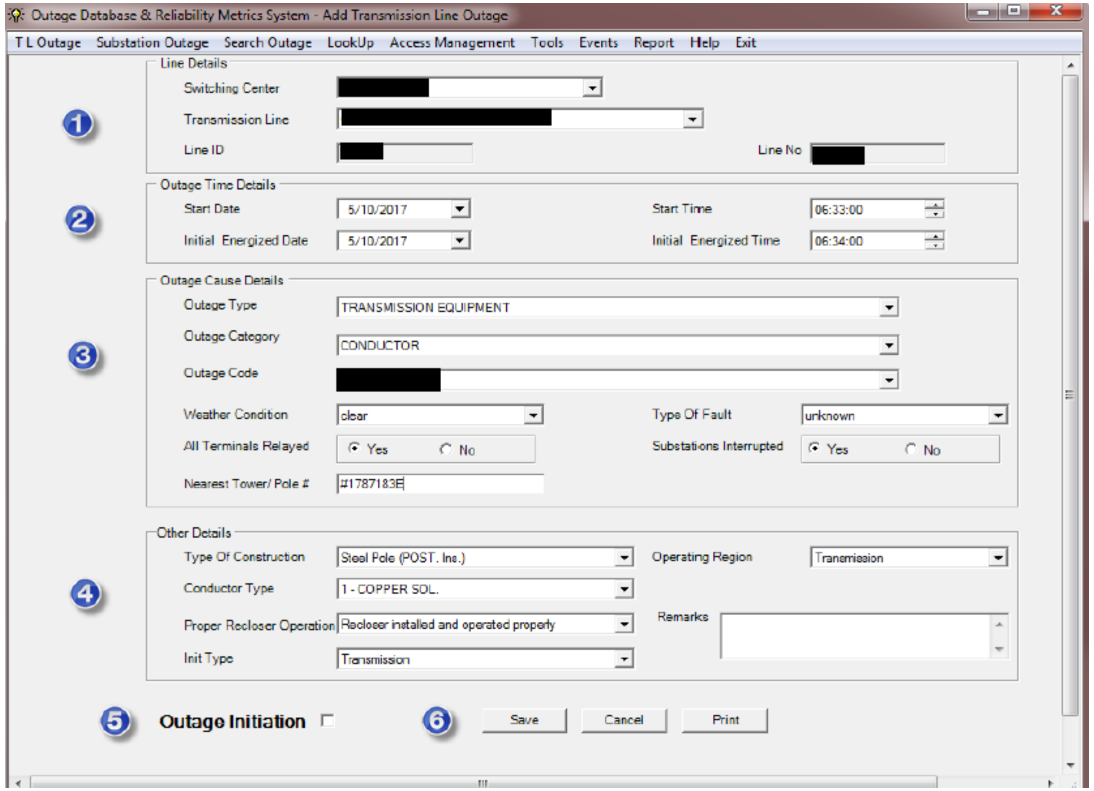
- Use SCADA Times when available.
- The initial energized date and time is the ALU time.
- For R&R's, always record the times in this format:

Start Time- **XX:XX:00**

Initial Energized Time- **XX:XX:30**

Creating a Transmission Line Outage

T L Outage Page



- 3. **Outage Cause Details**: Use the Drop- Down menus to select Outage Type, Category and Code.
  - Adjust default settings as necessary for the Weather Conditions, Type of Fault, Terminals Relayed, and Substation Interrupted fields. It is very important to document the correct weather in the area and not just select the default for reliability reporting purposes.
  - Always fill in the Nearest Tower/ Pole # field. The best way to get this information is from the field personnel patrolling the line.

Note: If a downstream substation is interrupted check "Yes". The selected related substation window will open after the <u>save</u> button has been clicked. Once saved you will be able to enter the downstream substations.

Recording Outage Cause:

- The System Operator's responsibility is to accurately represent the cause that has been reported to them by the field personnel. When recording the outage cause details, do your best to report the ROOT cause, not an effect. For example, if an animal gets across a transmission line resulting in a relay operation, it would be reported as Transmission Equipment-Conductor-Animal, NOT Standard Operation-Protective Device-High voltage, that would be the effect, not the root cause.

There is a free form field for remarks associated with the cause, this must contain an entry in three scenarios;

  - If the outage is animal caused-the animal type must be listed in remarks including the bird species if known.
  - If the outage is a manual open, the reason must be listed in remarks (for example- to clear failed breaker)
  - If you use a cause of "other see notes", you must detail the cause in remarks.

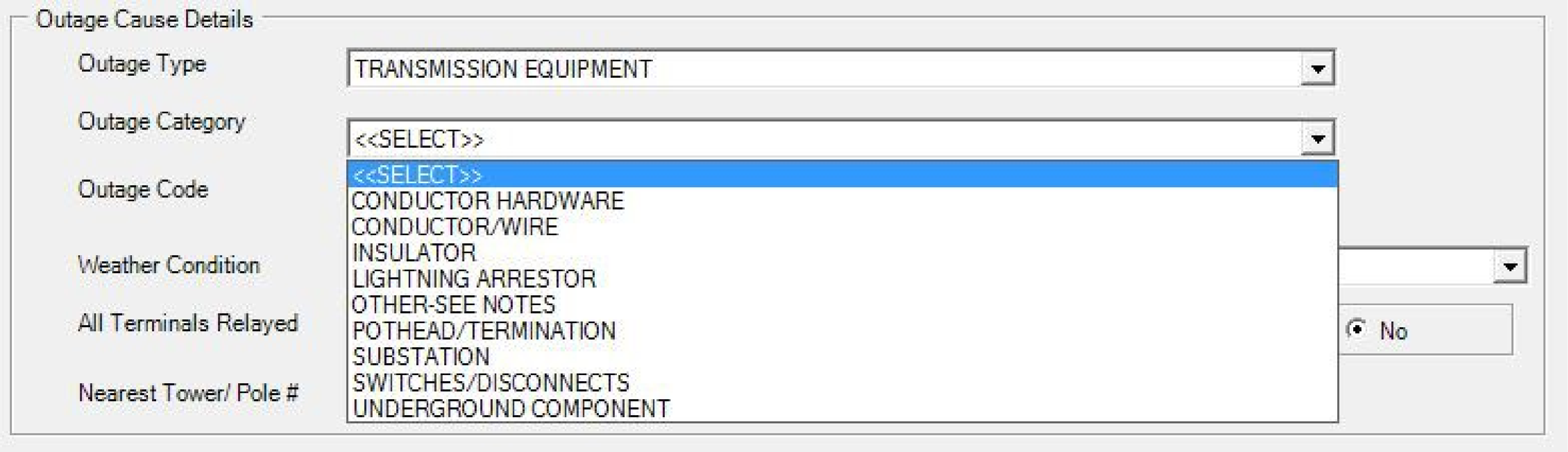
- **NOTE: if the cause of an outage is bird droppings or a bird nest, the cause is considered to be animal and a note explaining the detail is to be included in the remarks field.**
- All transmission line outages must either record the root cause or unknown (patrolled or not patrolled). Therefore, it is a good idea to leave the Log Sheet in an open status until the patrol is completed and the Patrolman has communicated the cause, if one is found upon completion of his patrol.

Outage Type:

Below are explanation of the different Substation outage causes and how to properly record them in ODRM :

- **Error-** Unintentional interruption due to SCE or Contractor personnel
- **Non TDBU Source-** This is used when a Transmission line becomes de-energized due to loss of generation or a foreign utility
- **Source-** The line that feeds it was de-energized or a transmission substation was de-energized, select appropriate drop downs in category and code
- **Standard Operation-** This is most used for a manual de-energizing of a Substation, line, piece of equipment or a relay at test. Select Operator/Crew in category and appropriate outage code. (Example: Emergency Outage due to hazard or MADEC)
- **Note**: if a Protective Device relays on infrequency, high or low voltage select that category and appropriate outage code
- **Structure-** This is used if the cause is a problem (or something across) a rack in the station, transmission poles, cross arms, guy wires and towers.
- **Substation Equipment-** This covers a wide variety of substation equipment including CB's and transformer banks. Once you have selected the equipment type select the appropriate outage code.
- **Unknown-** A cause was not found. (Patrolled or not Patrolled)

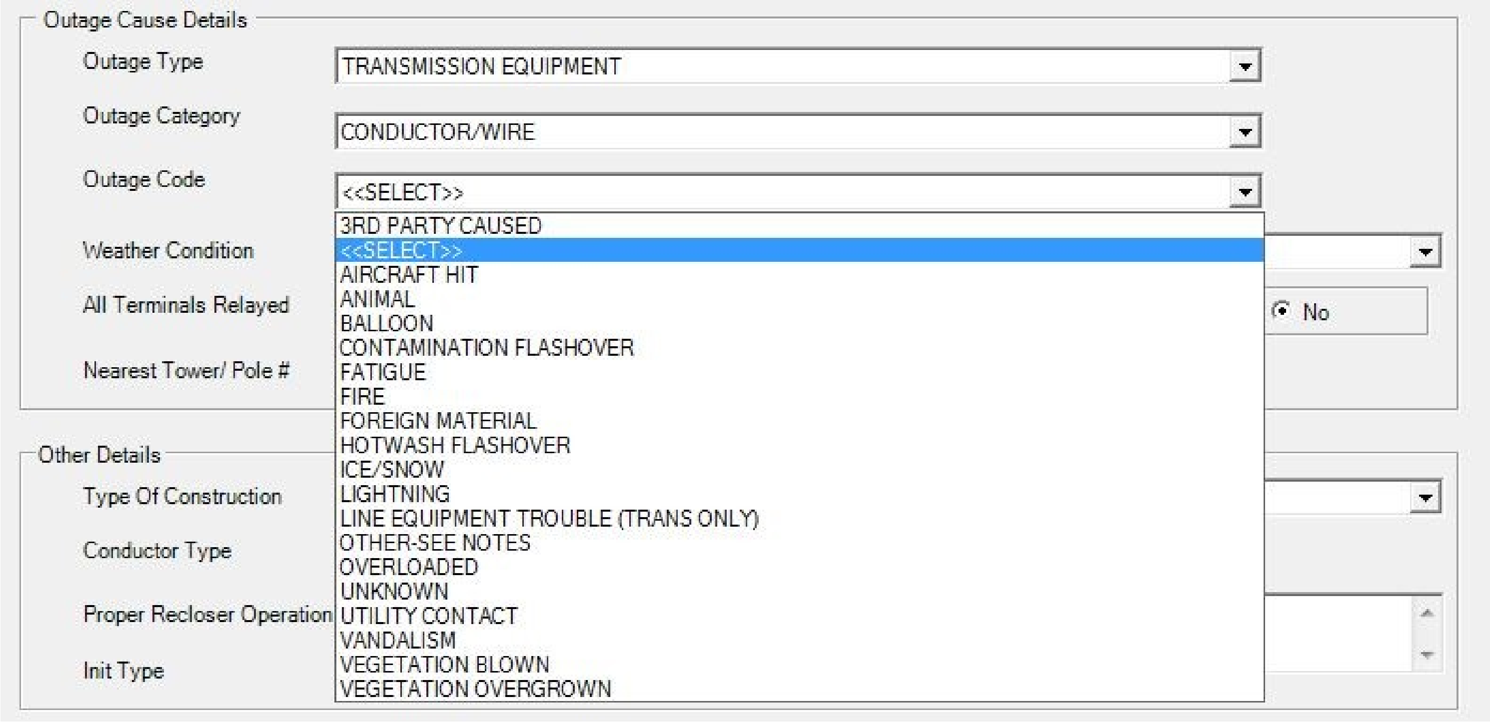
Outage Category:



- Once you have selected an Outage Type, a unique set of set of available categories will be listed for you to choose from. You want to select the device that failed or is broken if the cause has been identified by field personnel. If no cause was found the outage type should be unknown, and the Outage Category will indicate whether a patrol was performed.

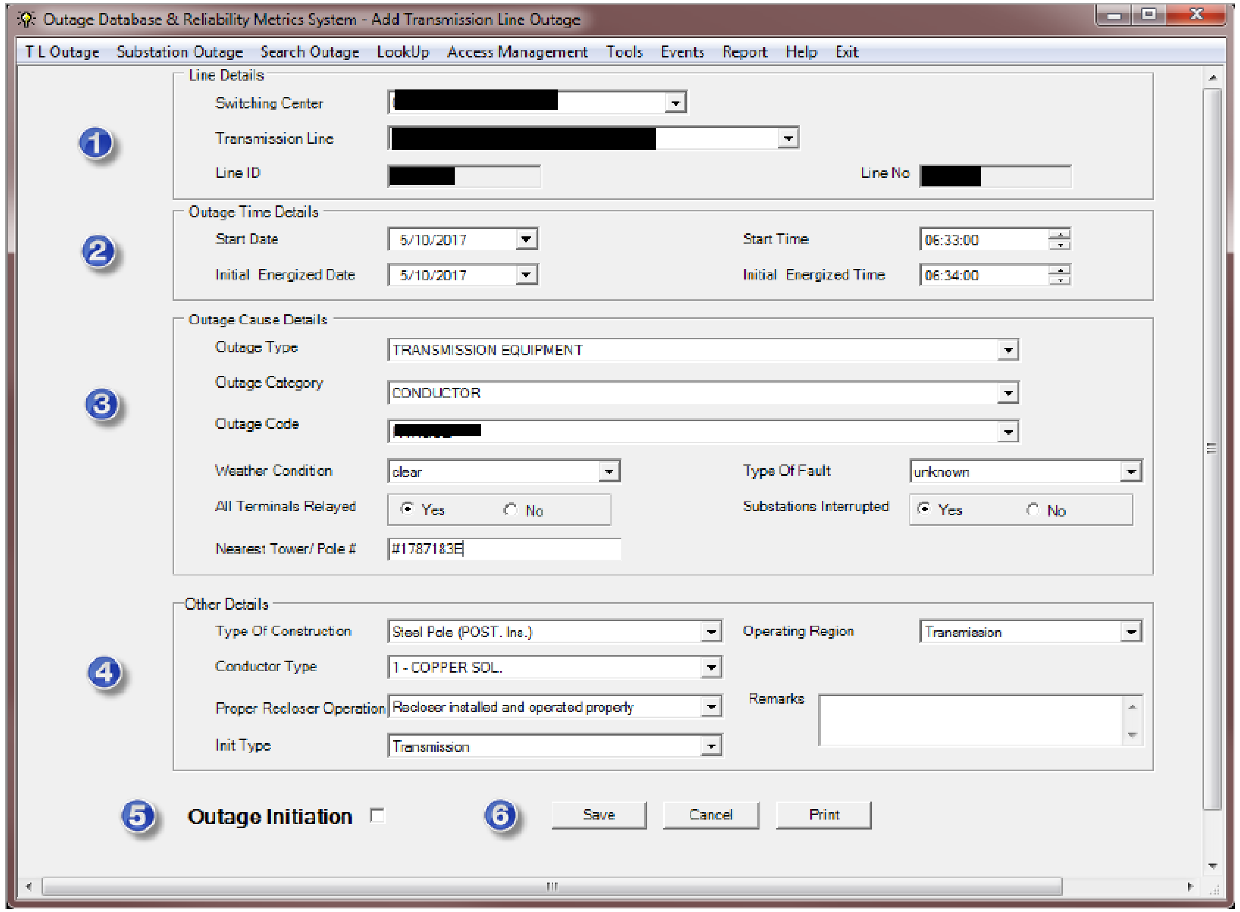
Outage Code:

- Once you have selected an Outage Category, a unique set of available codes will be listed for you to choose from. If a cause has been found, select the best description for what caused the equipment to fail or relay.



Creating a Transmission Line Outage

T L Outage Page



- 4. **Other Details**: Use the Drop-Down menus to update all fields. If you do not know the details it is okay to leave the defaults. Add any remarks as needed for clarification.
- 5. **Outage Initiation**: Check the box.
- 6. **Save**: Click the save button

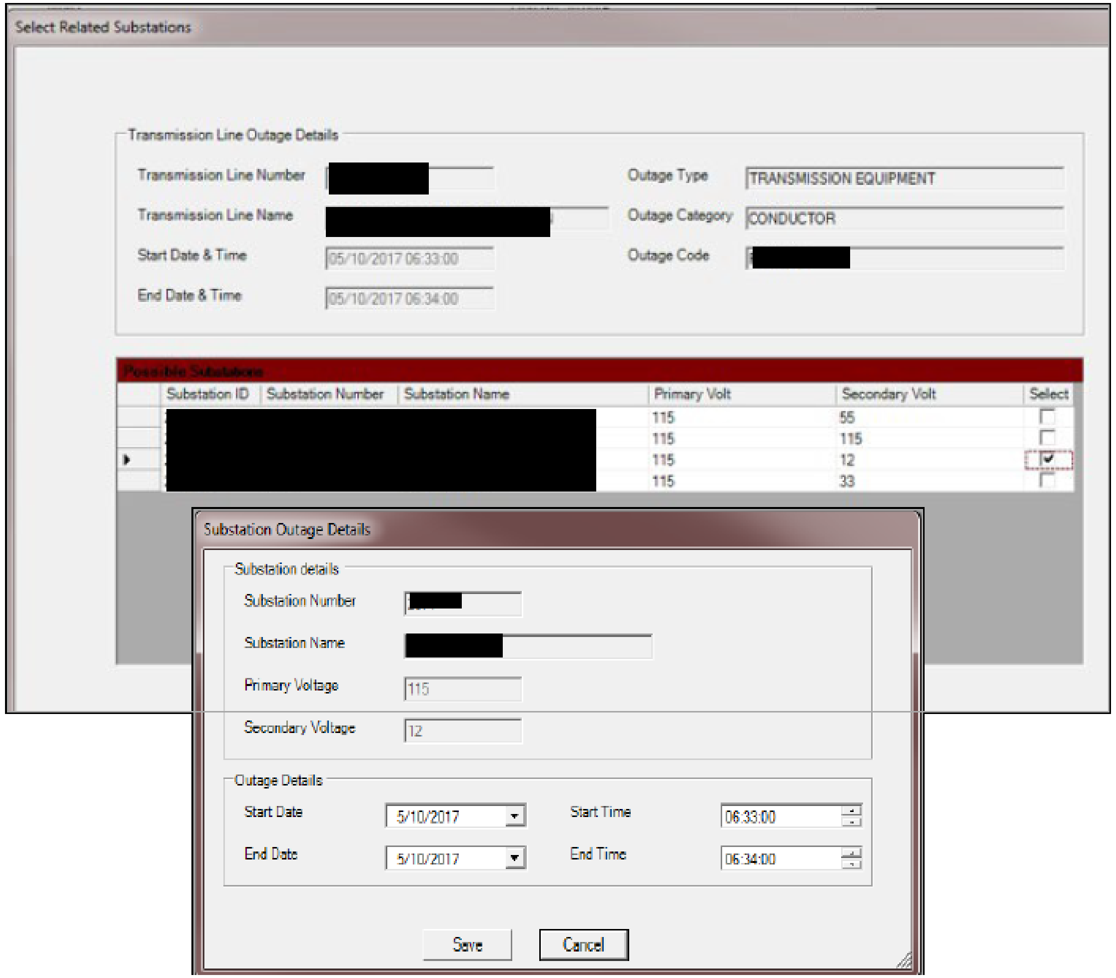
Please click on the following links for video examples of filling out transmission line outages in ODRM:

Beverly Macneil 66kV

Eagle Rock Garfield Wabash 66kV

Adding a Downstream Substation to an existing ODRM

Adding a Downstream Substation to an existing Transmission Line ODRM



- **If "Yes" was selected that a substation was interrupted in the Outage Cause Details, the related substation window will open after the <u>save</u> button has been clicked on the original TL Outage.**

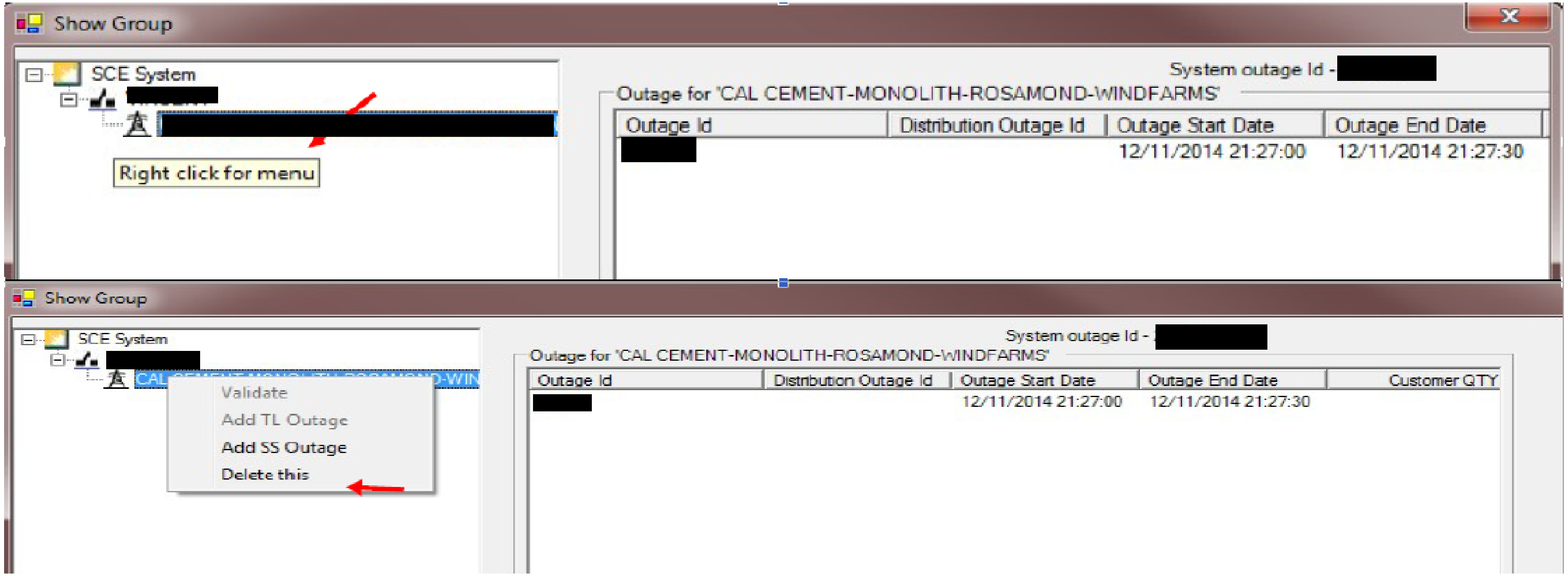
- 1. **Select the** affected downstream substation(s).
- 2. The **Substation Outage Details** window will pop up. Confirm Date and Time the substation that was interrupted, edit as appropriate and then save.

  Note: Only the energize times should be different from the transmission line times

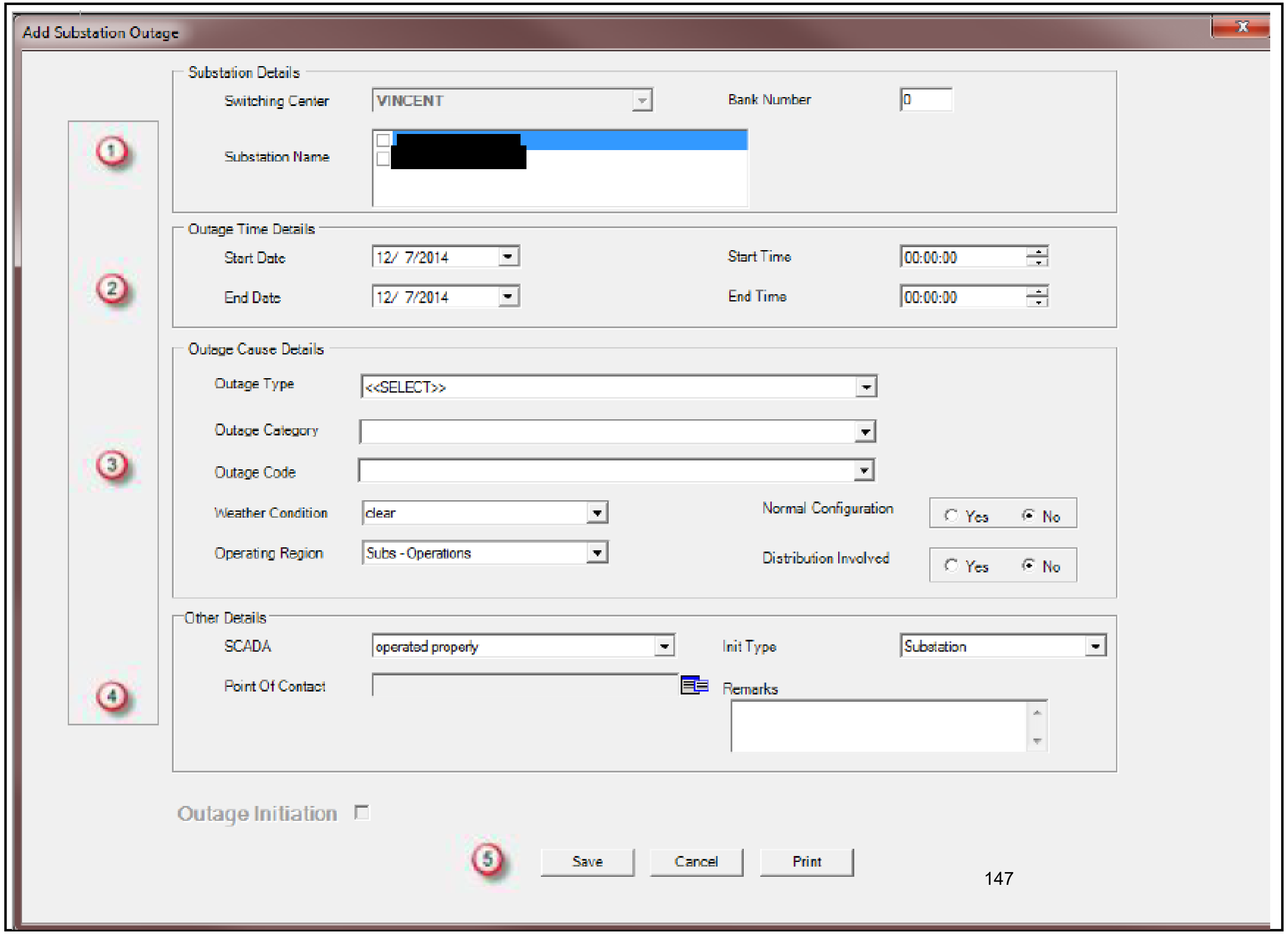
- 3. **Repeat** "Steps 1&2" if more than one substation was interrupted
- 4. When complete, click Submit.

Alternative way to add Downstream Substations to an existing TL Outage (if needed)

- If a Transmission Line outage has been created without adding Downstream Substations – Right click on the Transmission Line in the root directory. Then click on “Add SS Outage” and check the desired substation.



Alternative way to add Downstream Substations to an existing TL Outage (if needed)

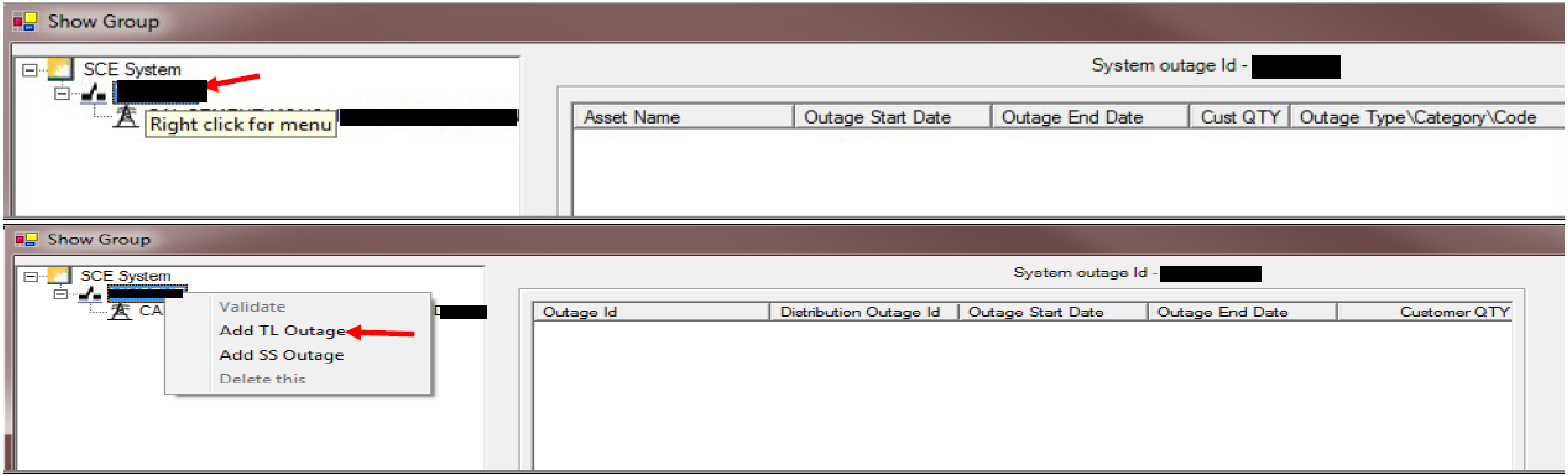


- From here follow the steps for downstream Substation
- 1. **Substation Details**: Use the Drop-Down menus to select the Switching Center and Substation Name. Add the substations transformer Bank Number if appropriate.
- 2. **Outage Time Details**: Input Dates and Times of the outage.
- 3. **Outage Cause Details**: Use the Drop-Down menus to select Outage Type, Category and Code.
- 4. **Other Details**: Use the Drop-Down menus to update the SCADA and Init Type fields. Add any additional remarks as needed for clarification.
- 5. **Save**: Click the save button.

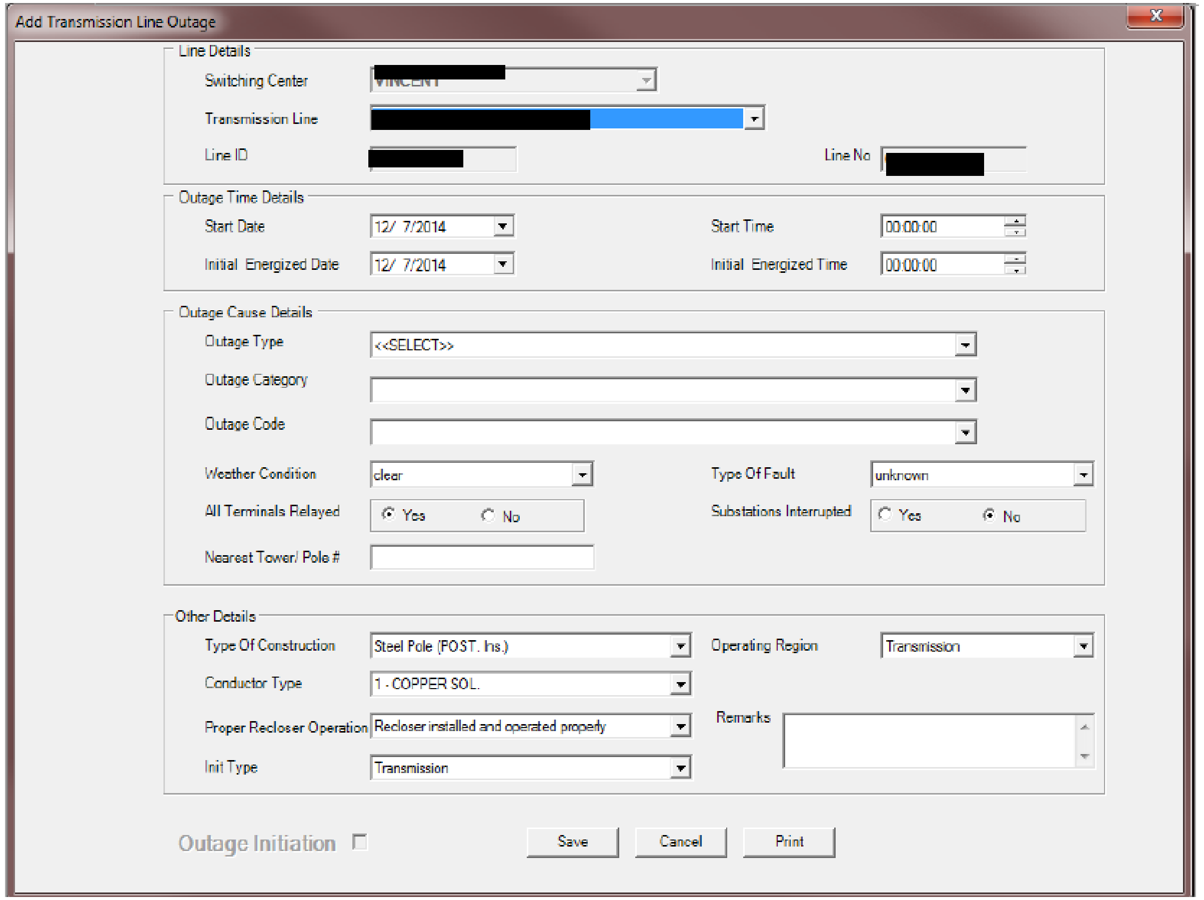
Adding an additional Transmission Line Outage to an existing ODRM

Adding additional Transmission Lines to an existing ODRM

- Once you have saved the Transmission Line information as well as any additional Transmission Lines needed to the same ODRM. Right click on the Switching Center in the root directory and left click on “Add TL Outage”.



Adding additional Transmission Lines to an TL Outage (Cont.)



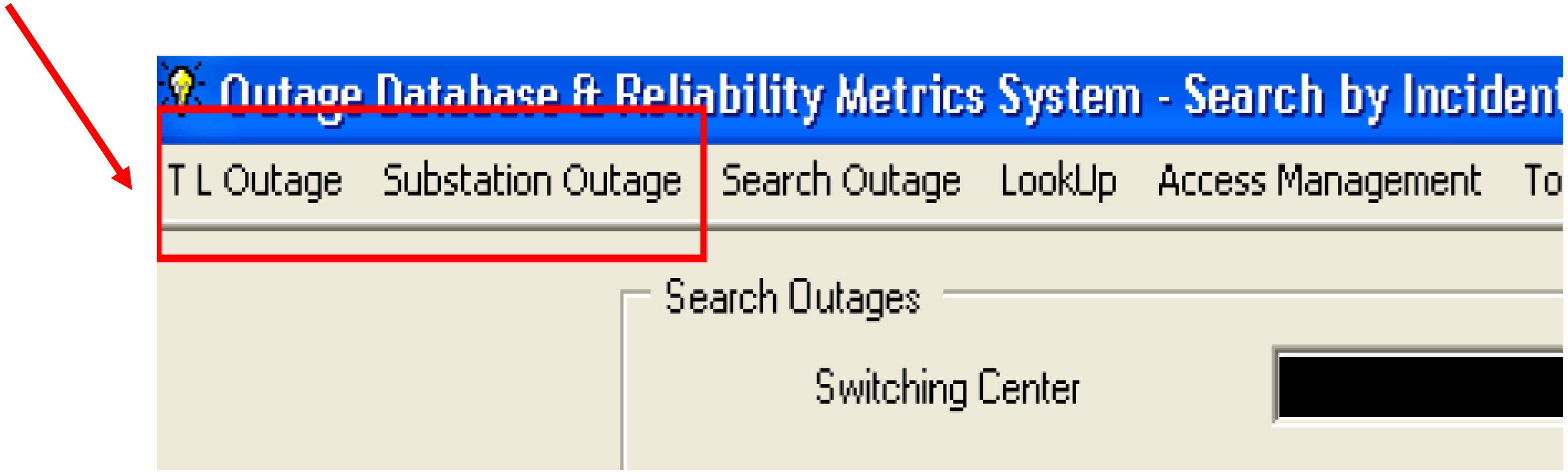
- From here we will follow the same steps for TL Outage as earlier stated.
- **Please click on the following link for a video example of adding an additional Line or Substation to an existing outage in ODRM:**

[ODRM: adding an additional Line or Sub to an existing outage.]

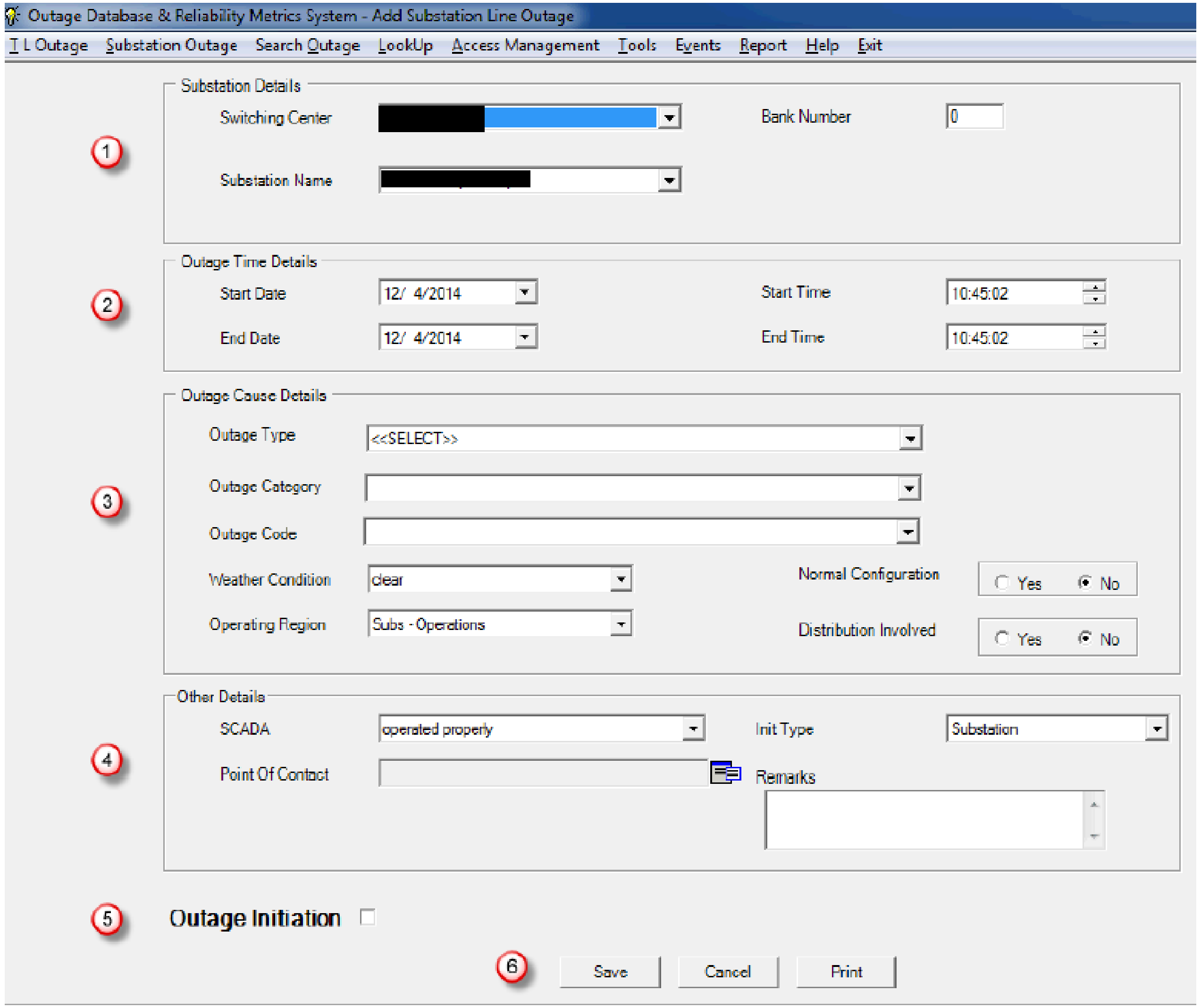
Creating a Substation Outage ODRM

Adding a Substation Outage:

- Select the appropriate outage type : **Substation Outage**

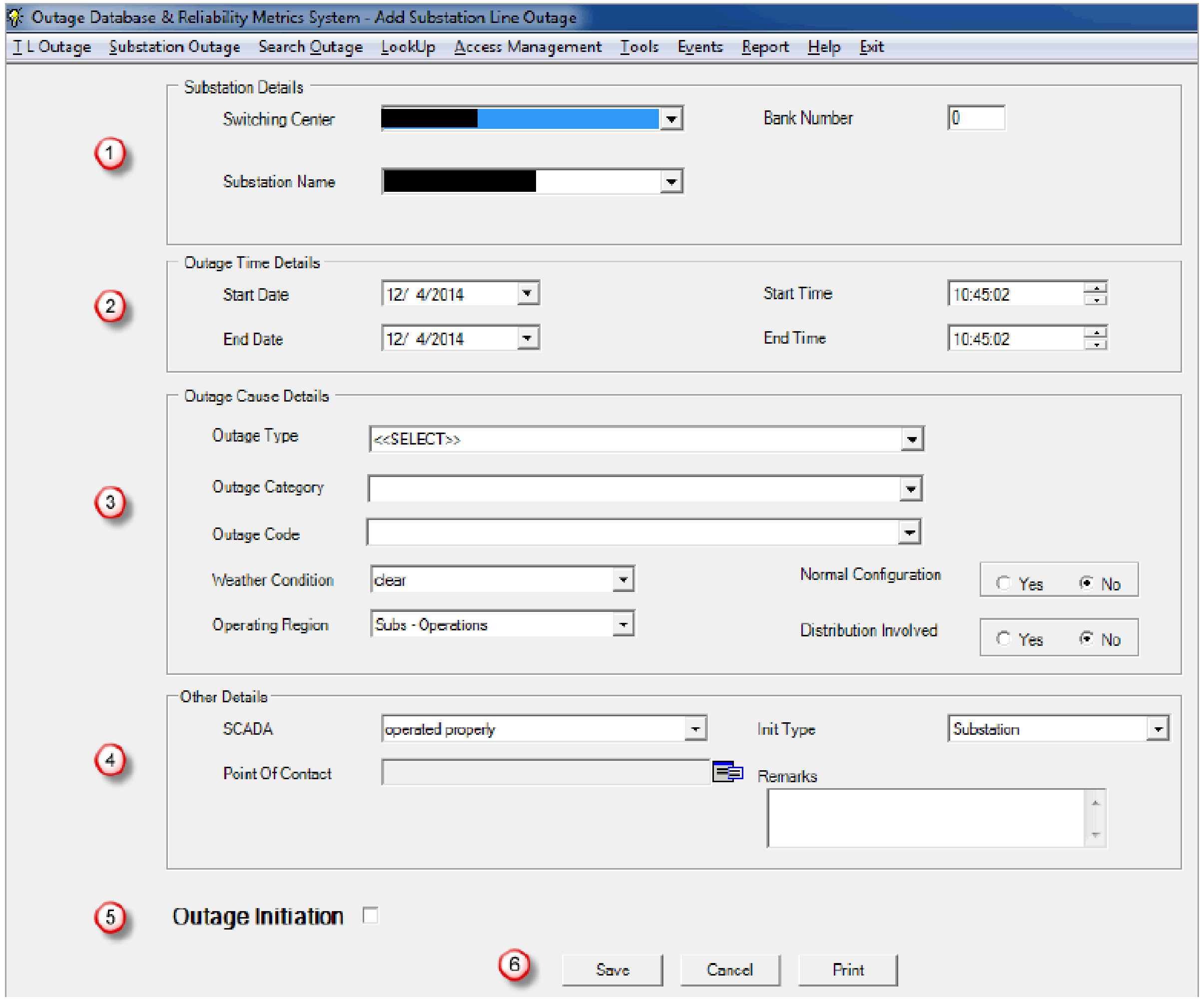


Adding a Substation Outage:



- 1. **Substation Details**: Use the Drop Down menus to select the Switching Center and Substation Name. Add the substations transformer Bank Number if appropriate.
- 2. **Outage Time Details**: Input Dates and Times of the outage.
- 3. **Outage Cause Details**: Use the Drop Down menus to select Outage Type, Category and Code. (Reference Previous Training)
- **Note : The Weather Condition, Operating Region, Normal Configuration, Distribution Involved fields all have defaults settings that need to be adjusted as necessary.**

Adding a Substation Outage:



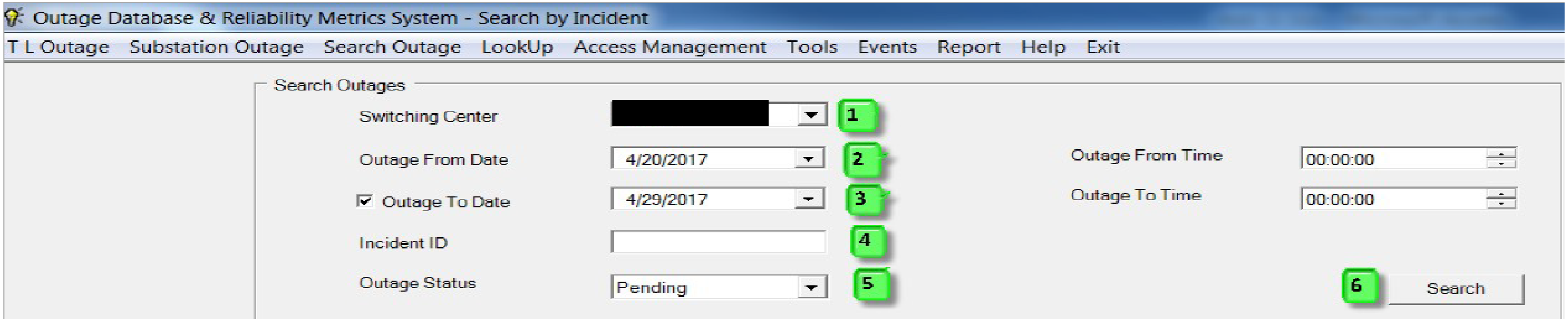
- 4. **Other Details**: Use the Drop Down menus to update the SCADA and Init Type fields. Add any additional remarks as needed for clarification.
- 5. **Outage Initiation**: Check the box.
- 6. **Save**: Click the save button.

Please click on the following link for a video example of adding a Substation outage to ODRM:

[Arroyo # 2 Bank]

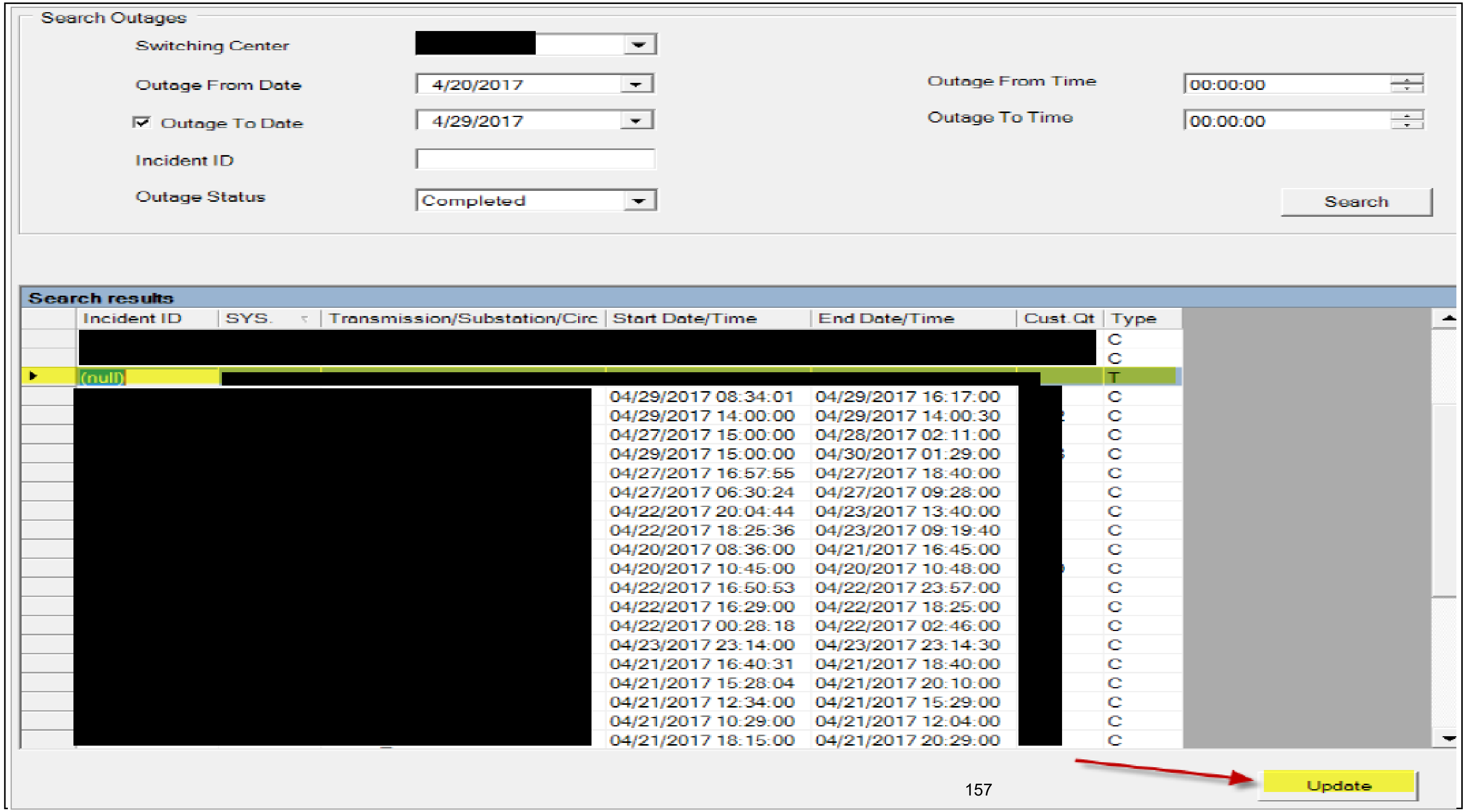
Searching For an Outage in ODRM

Search for an Outage



- 1. **Switching Center**: Use the drop down to select the Switching Center.
- 2. **Outage From Date/Time**: Use the date field to find an outage on a specific day and zero out the outage times for best results.
- 3. **Outage To Date/Time**: Mark the check box to search for outages in a date range, the maximum search period is 9 days.
- 4. **Incident ID**: You can use this field to search for a specific Incident by ODRM ID number.
- 5. **Outage Status**: Use the Drop Down menu to select either pending (Saved but not validated) or completed (validated).
- 6. **Search**: Click the search button to initiate the search.

Example of a search between two dates

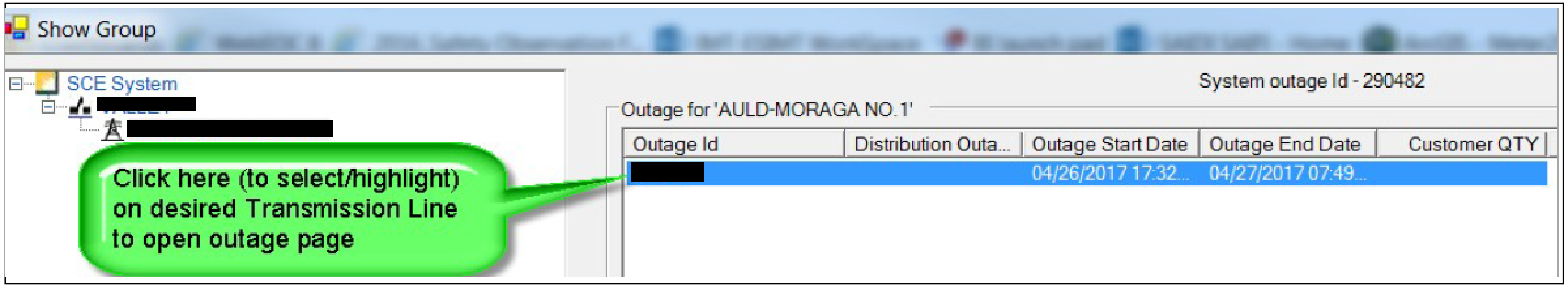


Incident ID	SYS.	Transmission/Substation/Circ	Start Date/Time	End Date/Time	Cust.Qt	Type
[redacted]						C
						C
(null)	[redacted]					T
[redacted]			04/29/2017 08:34:01	04/29/2017 16:17:00	[redacted]	C
			04/29/2017 14:00:00	04/29/2017 14:00:30		C
			04/27/2017 15:00:00	04/28/2017 02:11:00		C
			04/29/2017 15:00:00	04/30/2017 01:29:00		C
			04/27/2017 16:57:55	04/27/2017 18:40:00		C
			04/27/2017 06:30:24	04/27/2017 09:28:00		C
			04/22/2017 20:04:44	04/23/2017 13:40:00		C
			04/22/2017 18:25:36	04/23/2017 09:19:40		C
			04/20/2017 08:36:00	04/21/2017 16:45:00		C
			04/20/2017 10:45:00	04/20/2017 10:48:00		C
			04/22/2017 16:50:53	04/22/2017 23:57:00		C
			04/22/2017 16:29:00	04/22/2017 18:25:00		C
			04/22/2017 00:28:18	04/22/2017 02:46:00		C
			04/23/2017 23:14:00	04/23/2017 23:14:30		C
			04/21/2017 16:40:31	04/21/2017 18:40:00		C
			04/21/2017 15:28:04	04/21/2017 20:10:00		C
			04/21/2017 12:34:00	04/21/2017 15:29:00		C
			04/21/2017 10:29:00	04/21/2017 12:04:00		C
			04/21/2017 18:15:00	04/21/2017 20:29:00		C

- To edit existing records or to view details – Double Click on desired line item and click on the "**Update**" button
- **Note: Not all outages have an incident number.**

Example of a search between two dates (note that not all outages have an incident number).

- In the root directory select the TL outage and then double click on the desired outage record to open the Outage Page.



- Edit and re-save the outage as necessary.

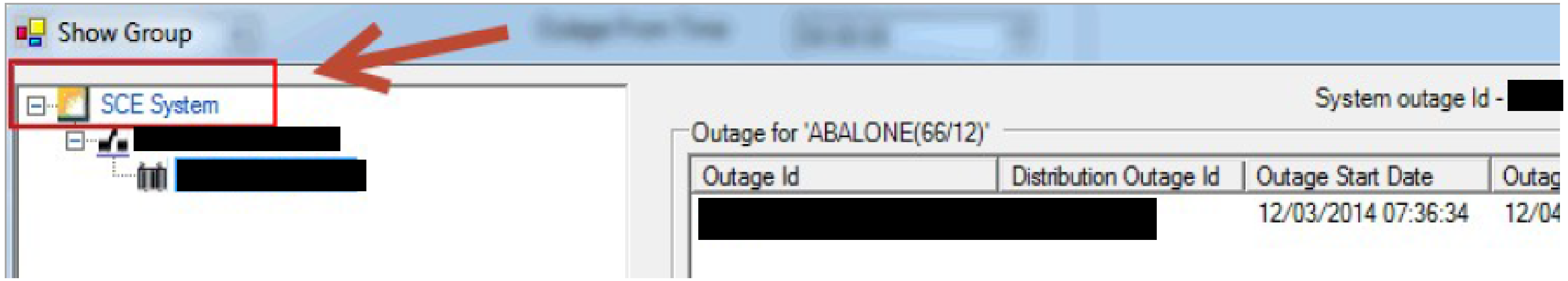
- **Please click on the following link for a video example of searching for a substation outage in ODRM:**

[ODRM, Outage Search]

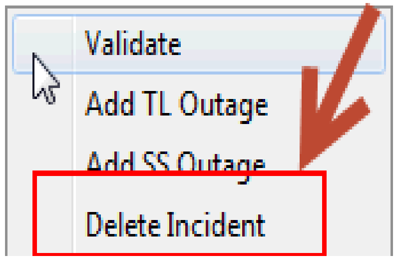
Deleting an Outage in ODRM

Deleting an Outage

- Perform a search, then double click the outage from the search results.
- Right click on “SCE System”, the AOR and then ODRM.



- Choose “Delete Incident”.



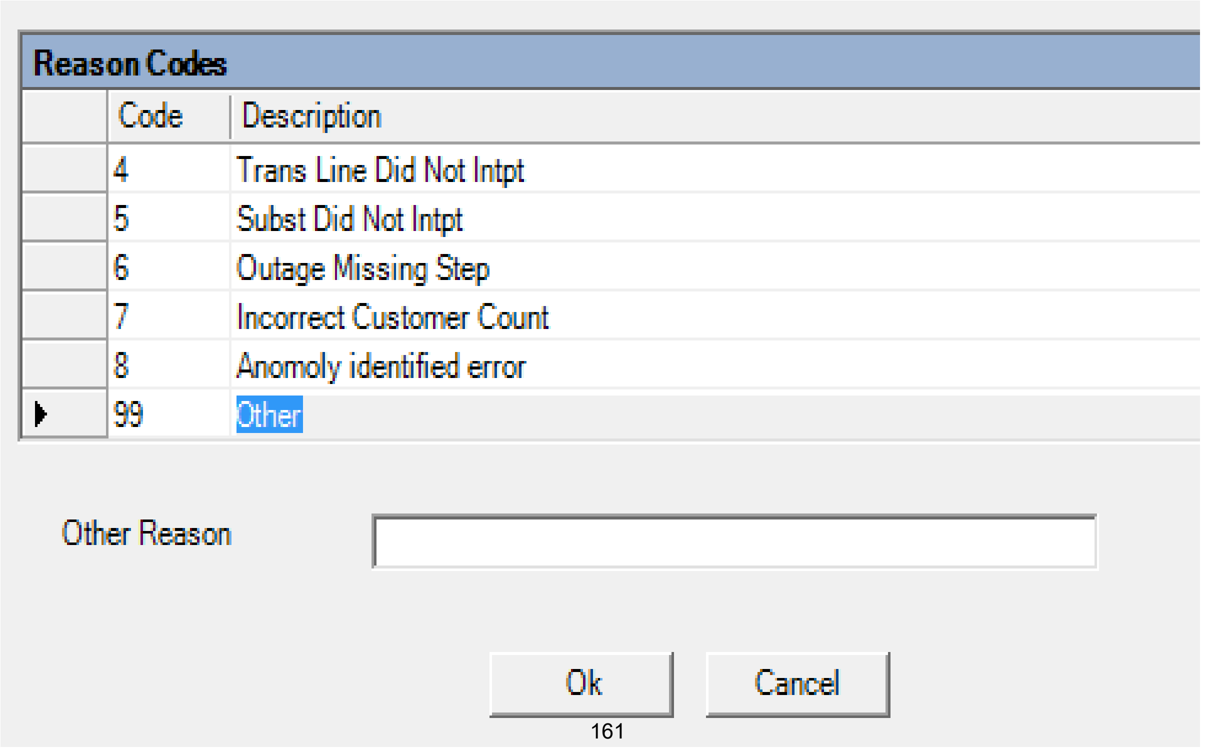
Please click on the following link for a video example of deleting an existing outage in ODRM:

[ODRM: Deleting an existing outage]

- A confirmation box will appear, choose Yes to confirm.

Deleting an Outage

- A “Reason Codes” window will appear. Choose a reason code, if you select “other” you are required to give a brief explanation.
- Click the Ok button to complete the deletion.



Validation Roles and Responsibilities

Validation Roles and Responsibilities - System Operators

- System operators are responsible to validate Transmission, Sub-Transmission lines and Substation equipment ODRM outages when no Distribution load is off.
- Sub-transmission customer ODRM outages will be validated by a System Operator or Supervisor.
- Any outage that has distribution load off will be validated be the ROC/DOC.
- It is a best practice for the ODRM to be validated by a different System Operator or SOS, other than the individual that created the initial outage when possible.

Validation Roles and Responsibilities – Substation Operations Supervisors (SOS)

- It is the responsibility of the SOS to coordinate efforts with the system operators to make sure all Transmission Line and Substation Outage entries in ODRM that do not include distribution load are validated.
- Tools available to be used by the SOS to track these efforts are:
  - The ILS Transmission Control Report that is sent out monthly
  - The SAS_Pending-Validated Outage Report that is available at all times to be viewed by SOS
  - The Search Function by Date in ODRM, comparing against the ILS entries

ILS Transmission Outages in ODRM

Found in ODRM	Not found in ODRM	Trans Line Not Found	Total Count of OMS Incident ID	Total Sum of % Found in ODRM
[redacted]	[redacted]		[redacted]	100%
				15%
				80%
		[redacted]		44%
				43%
				31%
				78%
				6%

% Pending - Validated Trans and Sub Trans Outages

Jan		Feb		Mar		Apr		May		Jun		Total % Pending	Total % Validated
% Pending	% Validated	% Pending	% Validated	% Pending	% Validated	% Pending	% Validated	% Pending	% Validated	% Pending	% Validated		
		100%	0%	50%	50%	75%	25%	82%	18%	50%	50%	75%	25%
0.00%	100%			0%	100%	0%	100%			0%	100%	0%	100%
0%	100%					0%	100%	0%	100%	0%	100%	0%	100%
		0%	100%	0%	100%	0%	100%	33%	67%	100%	0%	20%	80%
0%	100%			0%	100%	0%	100%					0%	100%
		0%	100%	0%	100%					100%	0%	60%	40%
0%	100%	0%	100%	0%	100%	0%	100%	0%	100%	50%	50%	5%	95%
		100%	0%					100%	0%	0%	100%	67%	33%
0%	100%	0%	100%	0%	100%	0%	100%	0%	100%	67%	33%	6%	94%

Validating an Outage in ODRM

Validating a previously created ODRM

- Locate ODRM by using Search feature which was discussed earlier in presentation.
- **Switching Center** – Select your home Switching Center from the drop down menu.
- **Outage From Date** – is the start date of the interruption.
- Check mark the Outage to Date if needed
- **Outage From Time** – is the start time of the interruption and must match the ILS and previously created ODRM (zeroing out the From and To Time is the best option)
- Outage Status: Select "**Pending**" option for ODRMs that need to be validated.
- Click **Search** when ready to proceed.

Validating a previously created ODRM

- The search results will appear, this includes the SYS. OUT ID # which must be **MANUALLY** entered in the ODRM Header Info box on the Interruption Log Sheet

Search results

	Incident I	SYS.OutID	Transmission/Substation/Circuit O	Start Date/Time	End Date/Time	Cust.Qty	Type
▶	(null)	[redacted]	0[redacted]	05/17/2020 05:33:00	05/17/2020 05:33:30	0	T

Interruption Log Sheet

[redacted] Center

Status: Closed

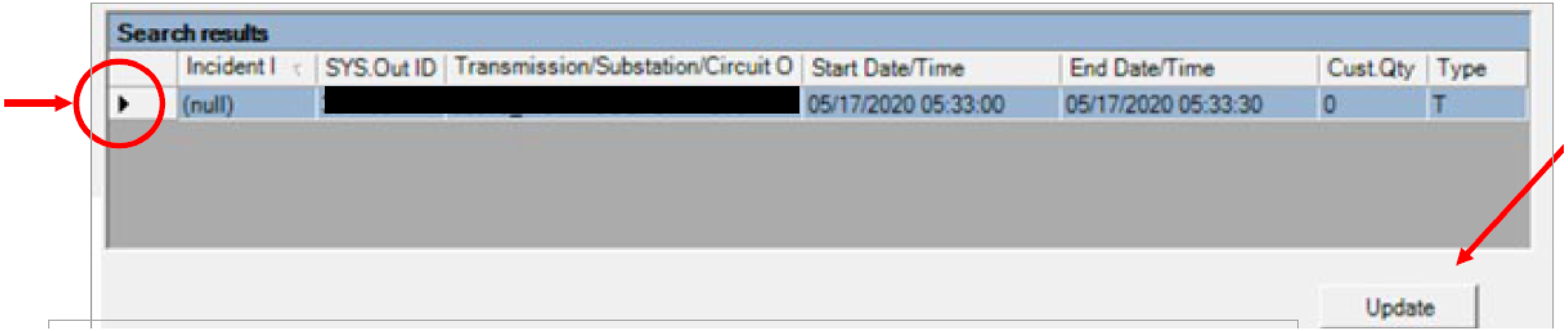
Initial when Entered

ODRM Info: [redacted]

CB KO Recap:

Validating a previously created ODRM

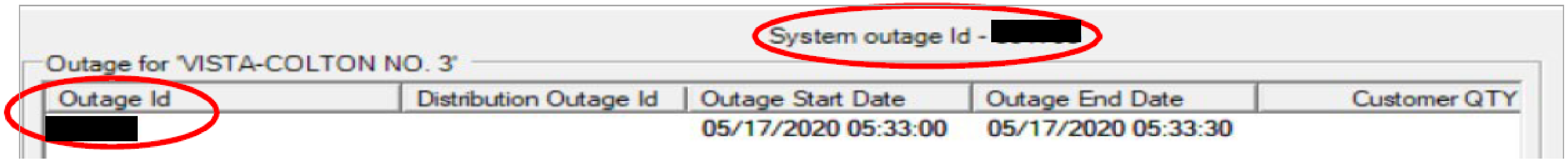
- Next is to select the line item to be validated by clicking on the line item (it will now be highlighted) and select update or double click on the arrow in the far left area.



- The system will now open the overview of the previously created ODRM.

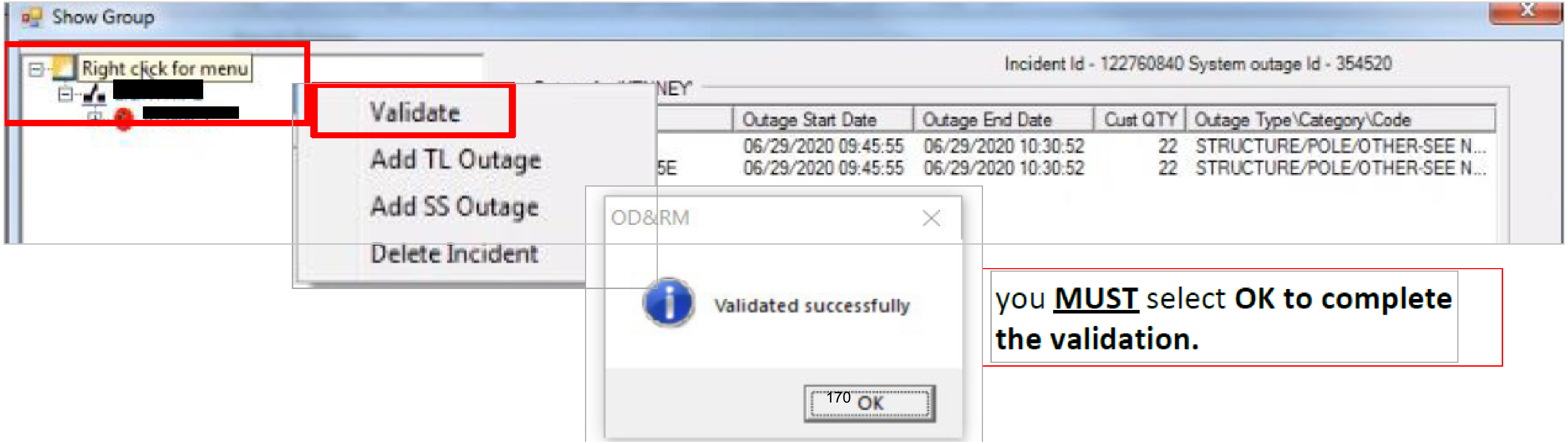
Validating a previously created ODRM

- **Outage ID** – this number is required to be **MANUALLY** entered onto the ILS in the ODRM Info area as the second number associated with this **ODRM**



Validating a previously created ODRM

- Locate the outage using the search function and select the update option. The outage will then open.
- **Double check the accuracy of the ODRM via the data entered on the ILS**
  - This is your last opportunity to ensure the ODRM is accurate and complete.
  - Select and highlight the ODRM that needs to be validated.
  - Right click on “SCE System”, then select the ORDM that needs to be validated.
  - Then select “validate” from the popup window. This will complete the process.



you **<u>MUST</u>** select **OK to complete the validation.**

Validating a previously created ODRM

Interruption Log Sheet

[redacted] Center

Status: Closed

Initial when Entered

ODRM Info: [redacted]

CB KO Recap:

Interruption Log Sheet # 13035

Circuit Name : [redacted]	No. of Interruptions: [redacted]	Date: 05/17/2020	Time: 0533
Station: Vista		RAR:	Voltage: 66
Relay Targets: (See Table Below)	No. of Operations: [redacted]	Tested: Good Bad	District: [redacted]
Circuit Conditions: Abnormal Normal		Time/Date Part Load Up: 0533:30 05/17/2020 Insert Time/Date	
Downstream Sub Interrupted: No Yes		Time/Date All Load Up: 0533:30 05/17/2020 Insert Time/Date	
Cause of Interruption: No cause found, light wind Find Cause			
Persons Notified: GCC, Rinaldi			

Station	Targets	Station	Targets
[redacted]	HCB		
[redacted]	HCB		

Time	* * * SWITCHING * * *
0533	[redacted] 66kv Line R&R No Load Interrupted Notified GCC Notified Transmission [redacted]
0637	[redacted], Operator [redacted] found CBs closed, HCB target, 1 operation each CB, equipment checks OK.
1231	[redacted] Transmission reports patrol completed. no cause found., light wind in area. [redacted]
05/18/20 1232	At [redacted], Operator reports CB closed, 1 operation, HCB target, reset ok, equipment checks ok [redacted]
5/19/2020 1000	Completed and Validated ODRM [redacted]

- The final step is to amend the ILS with a statement of “Completed and Validated ODRM”, along with the Validators name (refer to ILS), note the circled numbers discussed earlier in the presentation that need to be entered in ILS header information.

ODRM: Training Objective Recap and Knowledge Assessment.

ODRM User Guide, Objectives Summary:

- You should now be able to:
  - **Explain how to launch to ODRM application**

  How to add ODRM as a favorite.
  - **Describe when to create an ODRM.**
  - **Describe how to add an outage.**

  Add Transmission or Sub Transmission line event. (all variations).

  Add a Substation event. (all variations).

  Add an additional Transmission or Sub Transmission Line to an existing event.

  Add a downstream substation to an existing event.
  - **Describe how to search for an outage**.

  Both Pending and Completed outages.
  - **Describe how to edit an outage.**
  - **Describe how to delete an outage.**
  - **Explain how to validate an outage.**

  Roles and responsibilities and expectations pertaining to validating outages for both System Operators and their SOS.

  Update Interruption Log Sheet once ODRM has been completed and validated.

ODRM knowledge Assessment

Please Answer the following 8 questions, choose the best possible answer.

1. The XX 66kV line open ended at XX due to Mylar Balloons contacting the bank leads at XX Sub. The 66kV CB at XXis both the clearing device for the station transformer and the line. Both 12kV Distribution lines were interrupted. What action should the System operator perform?

- The System Operator will create one Substation ODRM, do NOT validate this item as there was distribution load interrupted.
- The System Operator will create one Substation ODRM and validate this item as there was distribution load interrupted.
- Notify the outage coordinator that an outage has occurred and validate the outage.
- No ODRM is required as there is distribution load off.

ODRM knowledge Assessment

2. The #3 12kV Capacitor at XX Substation relayed due to rodent contact. No load is off but the capacitors must be cleared, for the maintenance crew to make repairs. An ODRM does not need to be created.

- True
- False

ODRM knowledge Assessment

3. A Distribution line Relays due to a failed capacitor bank in the field and tests good. It is the System Operator’s responsibility to validate the ODRM?

- True
- False

ODRM knowledge Assessment

4. At XX Substation, the #3 Bank 66/12kV relayed on Sudden Pressure, the #3 and #4 Banks are in parallel. The #4 Bank carried all the load as a result, there was no load off.

- The System Operator will create and validate one Substation ODRM as there was no load interrupted as a result of the relay operation.

- True
- False

ODRM knowledge Assessment

5. The XX 66kV Line has relayed and the XX Customer substation has been interrupted. Who should validate the sub- transmission customer load outage?

- DOC
- System Operator
- ROC
- System Supervisor

ODRM knowledge Assessment

6. Which System Operator is responsible for validating ODRM outages ?

- It is a best practice for another System Operator or Supervisor who did not create the initial ILS and ODRM to validate it.
- System Operators are not required to validate ODRM outages.
- Only Supervisor is required to validate ODRM outages.

ODRM knowledge Assessment

7. The XX #1 Bank 66/12kV relayed when a tree branch contacted the low side bushing on the transformer. The #2 Bank is an emergency spare and does not carry any station load. As a result all 12kV load was interrupted. The will create the ODRM and the will validate the outage.

- System Operator - Supervisor
- Supervisor - ROC/DOC
- System Operator – System Operator
- System Operator - ROC/DOC

ODRM knowledge Assessment

8. The System Operator is responsible for both creating and validating a Transmission Line ODRM if, The XX 66kV line relays, this is a two-point line with multiple source lines at both stations. There was no load off as a result of this interruption.

- True
- False

Thank You for completing ODRM Training.

[redacted]

[redacted]	Corona	MIRA LOMA	MIRA LOMA	33.840358	-117.520942	TRUE	TRUE

[redacted]

Confirm

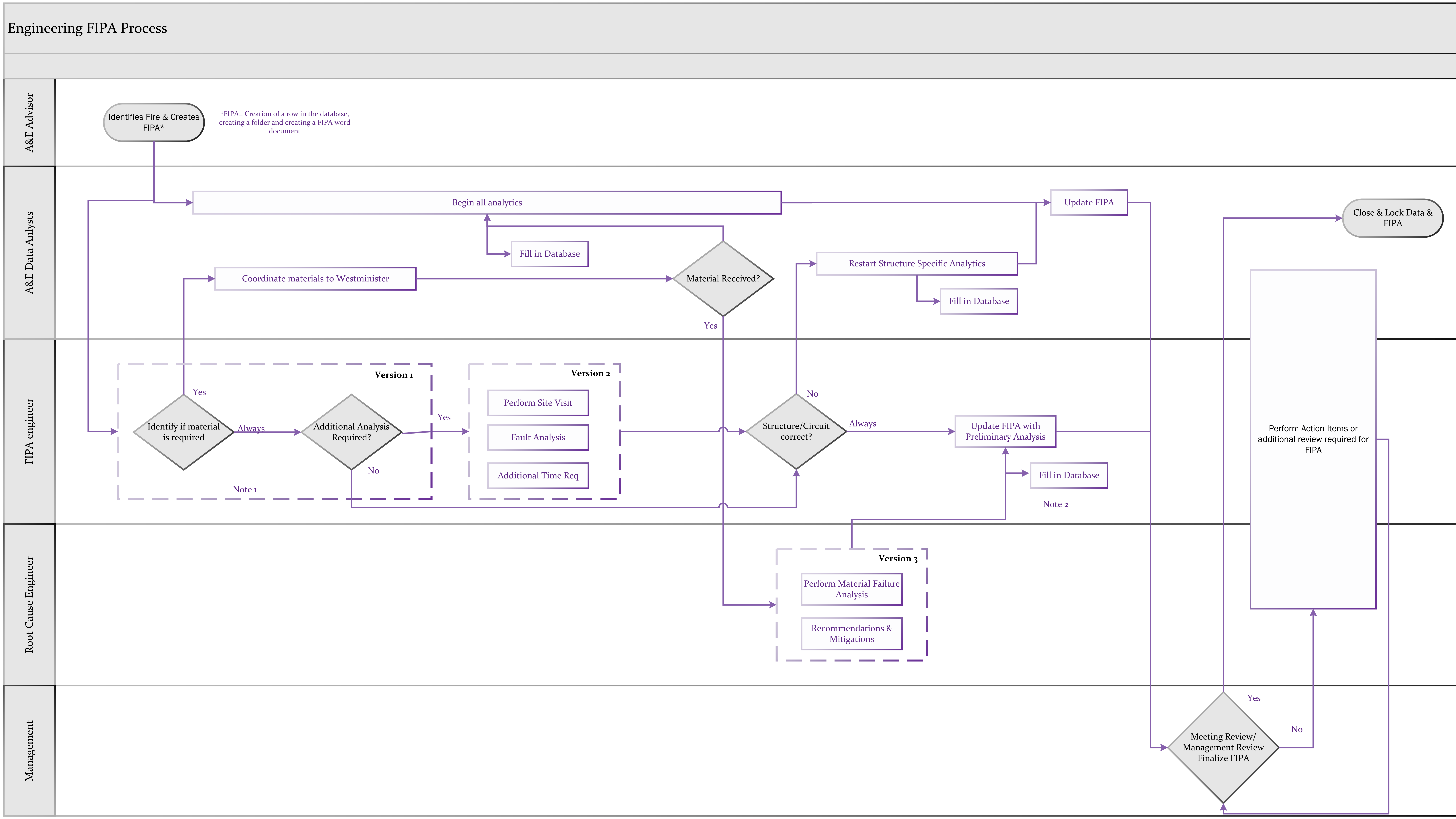
[redacted]

[redacted]

DFA	EFD	en Phase Detecti	iorated Pole Pro	migitation Requi	Approved None	Pilot None	ing Program Avai	igation Present/Fa	Failed Mitigation	CB HFRA 2	CB HFTD	HFRA	HFTD	of material Reque	Stamp Confirm C	tamp Confirm Str	am Protection Ca	ctive Mitigation	e of voltage facili	CPUC Cause	Size of Fire Category	CPUC reportable	aterial Sent to Jo	REAX 1	REAX 2	REAX 3	Field94	Field95	Field96	Max Wind	Max Gust	Humidity	Max TEMP	MIN TEMP	FPI	CKT SAIDI RANK	Last ODI/UDI	OH IR DATE
[redacted]																																						

[redacted]

[redacted]



Notes:
1. Engineer to send initial email to TM/FAO supervisor asking for material. A&E. analyst to assist in tracking materials.
2(typ): Once A&E can take the data from the database and map it to a word file, then the block can simplify to only database.

Validation Process- Dispatcher Job Aid

The California Public Utilities Commission (C.P.U.C.) requires S.C.E. to report all unplanned primary outages timely and accurately. Once validated and approved in O.M.S, the outages are sent to the Outage Database and Reliability Metric System (O.D.R.M.). The California Public Utilities Commission reviews data from these outages to verify accuracy.

The D.O.C. Dispatcher is required to validate trouble orders (including AMI's) processed by the D.O.C. on a daily basis when applicable. The validation process consist of two main categories; Reportable and Non-Reportable.

Non-Reportable

- Non-Outage Incidents

  (No SCE Load Affected)

  Examples:

  Cut non pay, de-energized for repairs/hazard,single AMI, damaged Guy Wire, customer problem at panel/ breaker/test blocks/weatherhead. Repairs being completed with no customer load affected. Planned Outages including BAD TLM.

- Secondary Outages

  (Transformer remains energized, affecting load below the transformer)

  Examples:

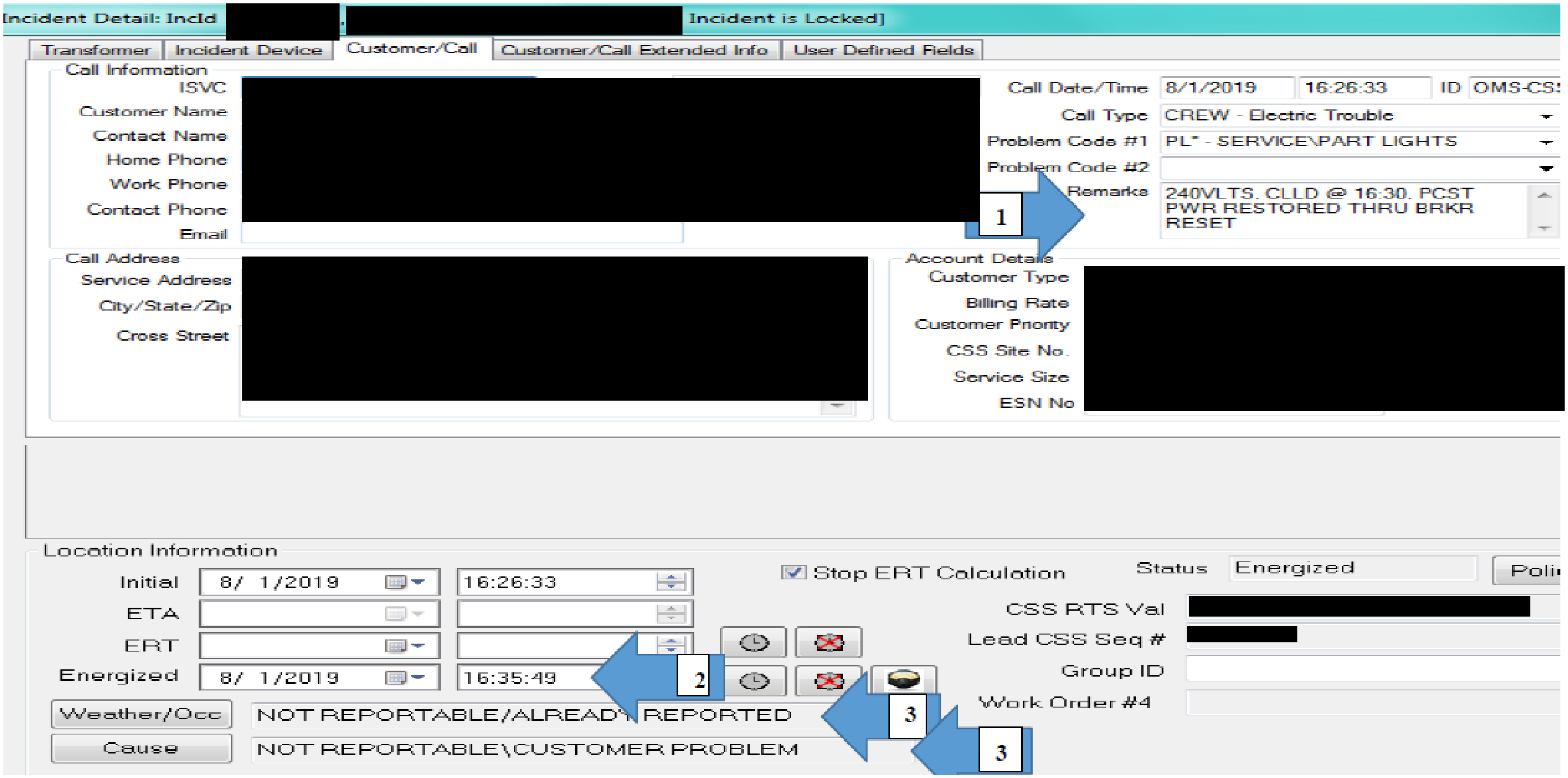
  Area outage with secondary wire down or secondary fuses blown, service wire down, replacing secondary equipment affecting secondary load only.

To process a Non-Reportable incident, verify the following information in the Incident Detail has been accurately captured;

1. Order completion remarks are accurate and thorough (Crew Remarks or Customer Remarks Tab)
2. Energize date and time
3. Cause and Occurrence codes are accurate
4. TLP (Total Loss of Power) flag is not checked on the Incident Device Tab.
5. Save information updated and send to history.

Note: Dispatchers can choose to use the Non Report button in Incident Manager on select non reportable incidents that have not been sent to CAD. Example: Single AMI with PRN or cancelled orders resolved through the QC process. The Non Report button automatically updates the cause/occurrence codes to non-reportable, removes the TLP flag, energizes the incident and sends to history. This action cannot be undone, always verify your order completion remarks have saved prior to clicking the Non Report button.

Example:


Incident Detail: IncId [redacted] Incident is Locked]
Transformer
Incident Device
Customer/Call
Customer/Call Extended Info
User Defined Fields
Call Information
ISVC
Customer Name
Contact Name
Home Phone
Work Phone
Contact Phone
Email
[redacted]
Call Date/Time 8/1/2019 16:26:33 ID OMS-CS
Call Type CREW - Electric Trouble
Problem Code #1 PL* - SERVICE\PART LIGHTS
Problem Code #2
Remarks 240VLTS. CLLD @ 16:30. PCST PWR RESTORED THRU BRKR RESET
1
Call Address
Service Address
City/State/Zip
Cross Street
[redacted]
Account Details
Customer Type
Billing Rate
Customer Priority
CSS Site No.
Service Size
ESN No
[redacted]
Location Information
Initial 8/ 1/2019 16:26:33
ETA
ERT
Energized 8/ 1/2019 16:35:49
Stop ERT Calculation
Status Energized
Poli
CSS RTS Val [redacted]
Lead CSS Seq # [redacted]
Group ID
Work Order #4
2
3
3
Weather/Occ NOT REPORTABLE/ALREADY REPORTED
Cause NOT REPORTABLE\CUSTOMER PROBLEM


ncident Detail: IncId [redacted], LocId [redacted] [Edit Detail - Incident is Locked]
Transformer
Incident Device
Customer/Call
Customer/Call Extended Info
User Defined Fields
Device Information
Device Name
Structure
Equipment No
Line Device
[redacted]
Device Type OH_TRANSFORMEF Phase ABC
Normal State CLOSED Current State CLOSED
Move Incident (via Dialog)
Move Incident (via Map)
Actual Downstream Customers
Priority Customers
kVA
Calls
[redacted]
Normal Downstream Customers
Priority Customers
kVA
[redacted]
Incident Device Properties
4
Total Loss of Power
Isolated to Customer
Planned Outage

Reportable Outages are separated into two sub categories; single line or complex. Complex Reportable outages are defined as outages consisting of more than one de-energize and/or energize date/time. These outages are sent to history by the D.O.C. to be processed and validated by the Reliability Operations Center (R.O.C.).

Example 1 Complex Reportable Outage: Lockout

Circuit Lockout at Circuit Breaker → System Operator successfully test to open RCS, partial load restored → T/M patrols, locates and isolates problem to open GS-POS 1, additional load restored → L/C completes repairs, all load restored

Example 2 Complex Reportable Outage: Transmission outage interrupting Substations and circuits

System Operator notifies dispatcher source line lost affecting multiple substations → Source line restored, substations picked up individually - part load up → RCS switches checked and/or reclosed on individual circuits-additional load restored → All load restored

Single Line Reportable outages are defined as outages with a single de-energize and energize date/time. These outages are processed and validated by the D.O.C. dispatcher.

Example 1 Single Line Reportable Outage: Single transformer area outage

Single transformer area outage (Starts at 15:00) → Trouble-man replaces burned up transformer leads and re-energizes → All load restored (Energized at 18:00)

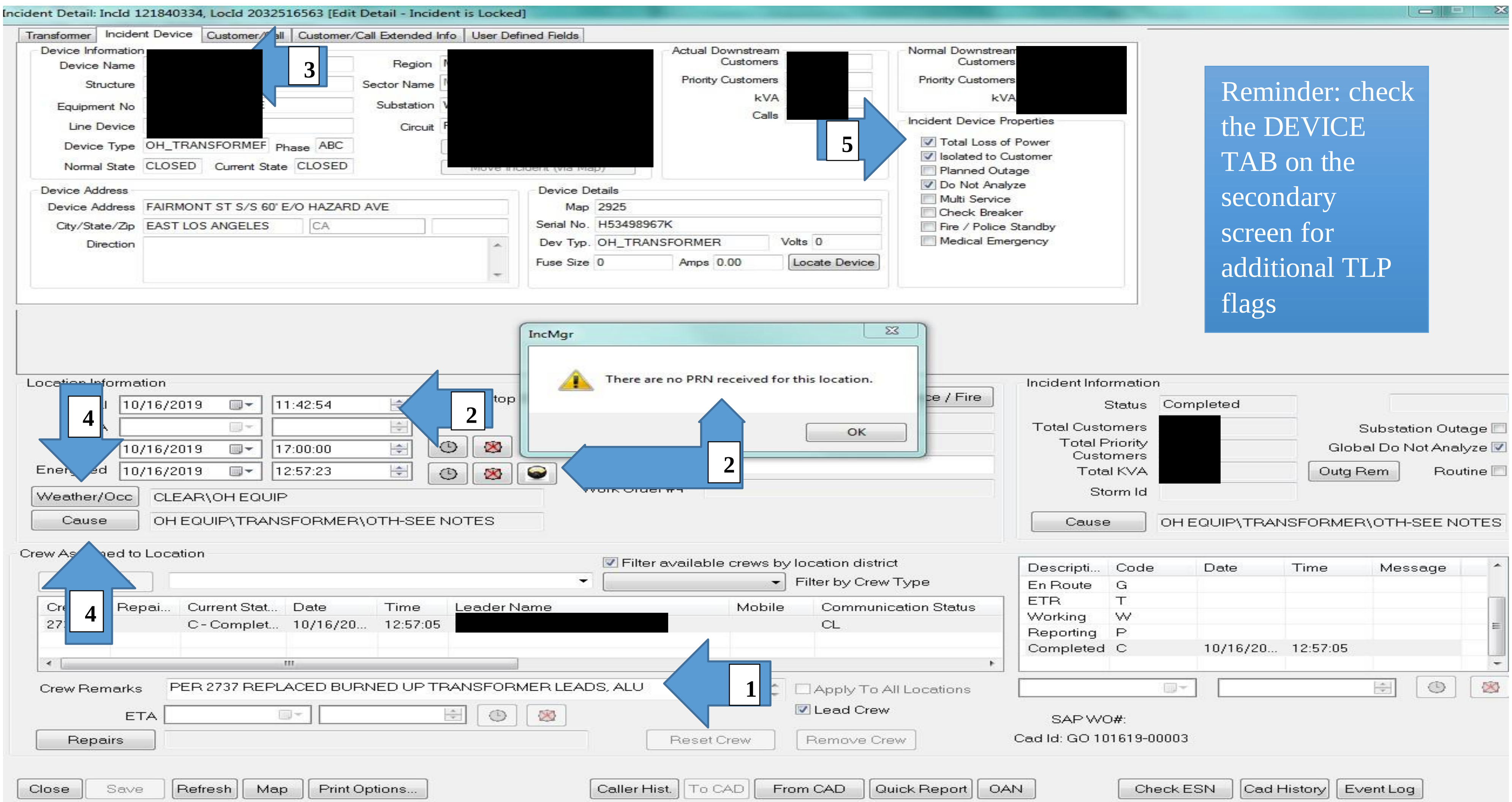
Example 2 Single Line Reportable Outage: Emergency Outage

L/C request Emergency outage beyond Branch Fuse to replace pole. (Starts at 14:00) → L/C completes repairs and re-energizes → All load restored (Energized at 17:00)

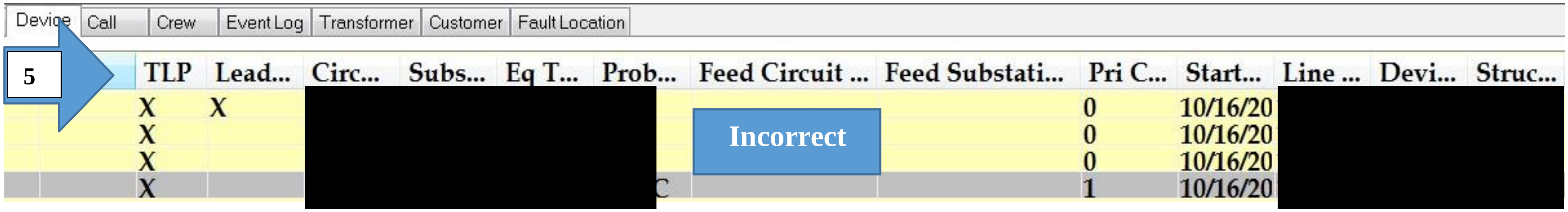
Reportable Outages <u>DO NOT</u> require customer calls or AMI notifications to be received. If you are made aware of a reportable outage by the Trouble-man or Line-crew, it is the dispatcher's responsibility to properly document the outage.

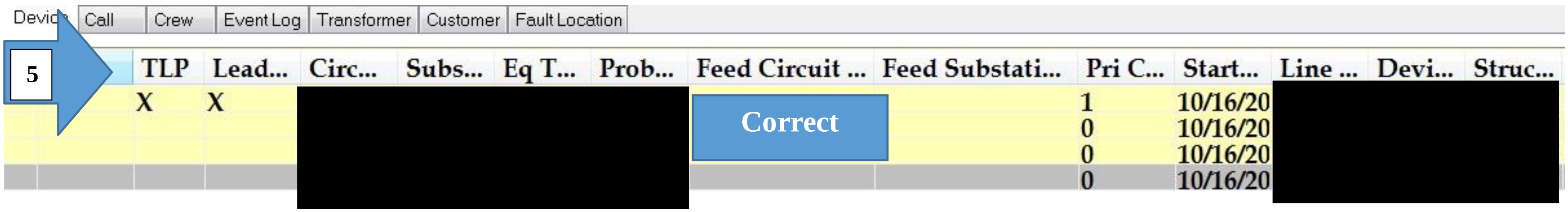
To process a Single Line Reportable incident, verify the following information has been accurately captured;

1. Field crew remarks
2. Start and energize date and time of outage (use the PRN received button if applicable)
3. Device/structure location (ensures downstream customers affected are reported)
4. Cause and Occurrence codes
5. TLP (Total Loss of Power) flag is checked on the Incident Device Tab (only 1 TLP flag should be checked per device/outage unless the transformer is banked)
6. Send to history and click the Approve button once optional to complete the validation

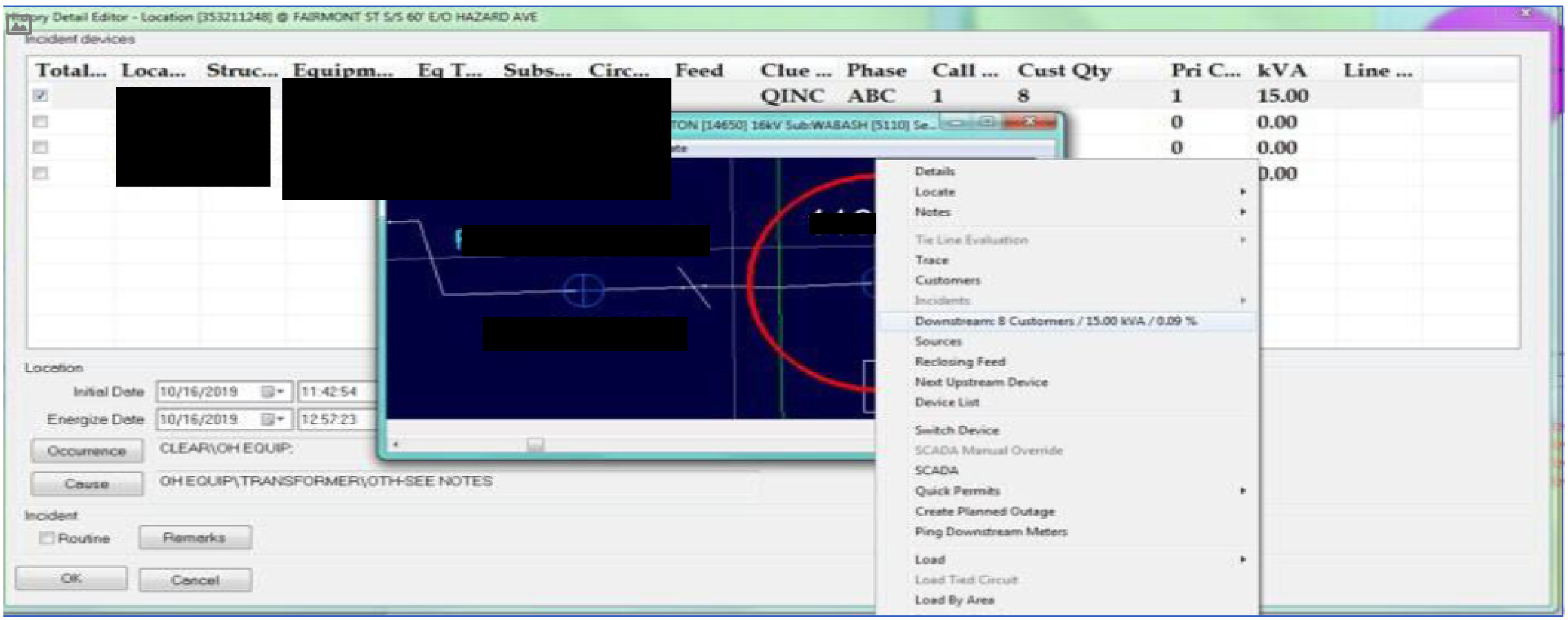


Example:



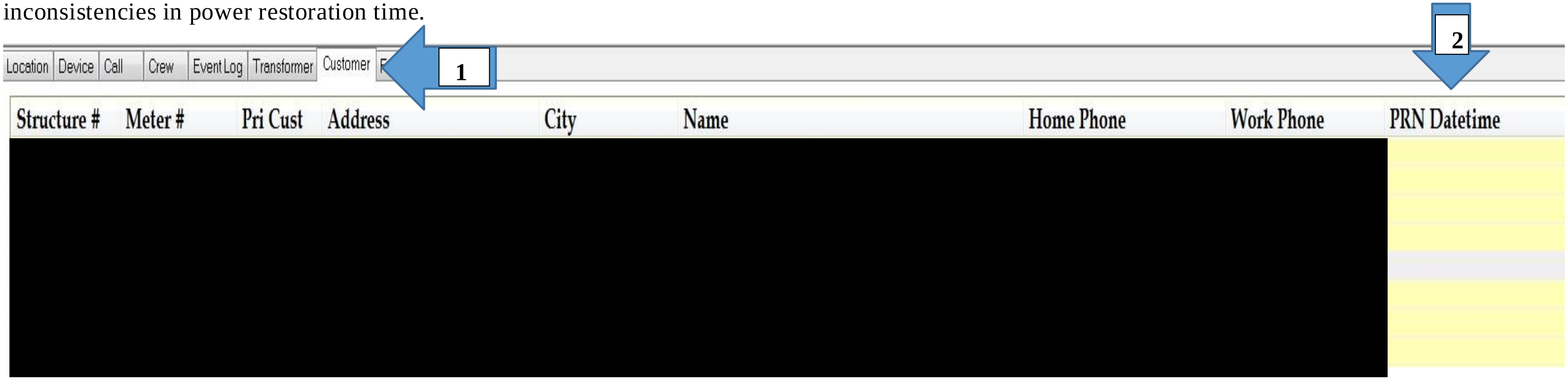


Checking the customer count is accurate:



Helpful Tip:

When verifying earliest all load up times on a reportable outage, check the PRN Datetime on the Customer tab of the secondary screen for possible inconsistencies in power restoration time.

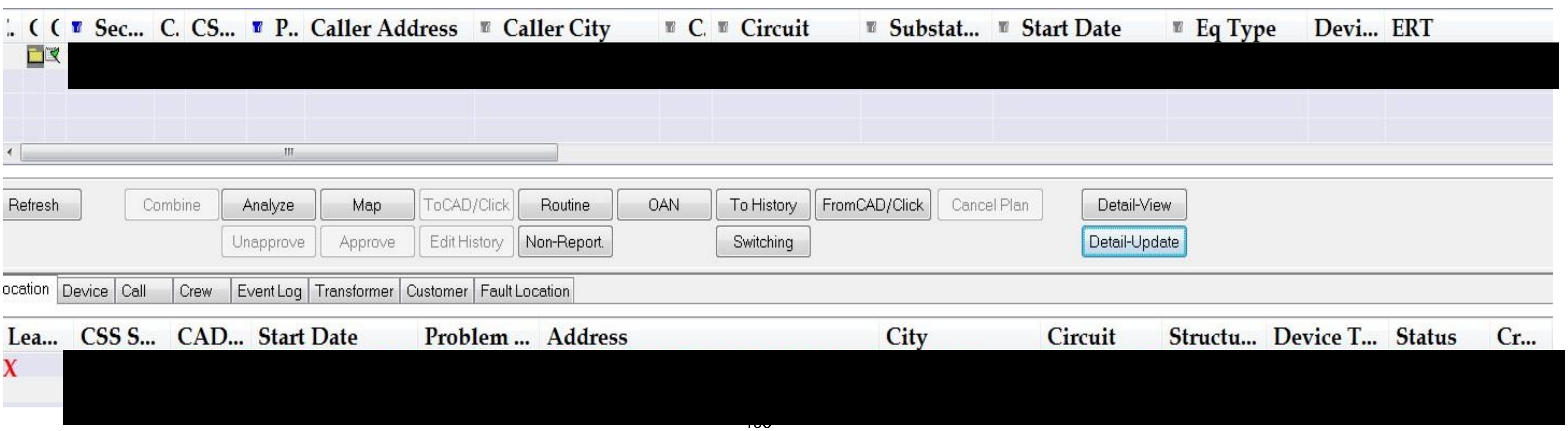


Choose the earliest PRN Datetime provided for the incident/outage.

Knowledge Check:

Question: If an outage starts as a secondary part light area and the Trouble-man takes a primary emergency outage to make repairs and restore the power; should this be processed as a complex outage or single line outage?

Answer: Complex. Due to the outage being directly related and continuous, the R.O.C. processes these outages as complex. The initial secondary part light area cause/occurrence codes will remain non-reportable. The emergency outage will be reportable and kept separate on the secondary screen.



WMP Class B Deficiency Action Statements
Guidance-1, Lack of risk spend efficiency (RSE) information

Action SCE-1: *In its 2021 WMP Update, SCE shall: 1) further describe why either ignition risk and wildfire consequence risk are calculated instead of calculating both, and 2) provide an explanation for each initiative as to why it either reduces ignition risk or wildfire consequence risk, but not both.*

Response:
(1) Guidance-1 deficiency conditions asked for a specific set of information for each mitigation:

" i. Its calculated reduction in ignition risk for each initiative in its 2020 WMP"
"ii. Its calculated reduction in wildfire consequence risk for each initiative in its 2020 WMP"

SCE provided a table which lays out, by mitigation and by ignition or consequence reduction, the incremental reduction by year. For those mitigations that reduce the probability of ignition, SCE calculated the incremental ignition reduction. For those mitigations that reduce the consequences of an ignition, SCE calculated the incremental consequence reduction.

As background, risk is defined as the product of probability and the consequence of the risk event. SCE interprets "ignition risk" as noted in the Action Statement to mean the probability/frequency of ignitions associated with various types of ignition drivers, such as contact from object (e.g., animals, vegetation, etc.) and asset related equipment (e.g., conductor, transformers, etc.). SCE also interprets "consequence risk" to mean the consequences associated with the wildfire after ignition has occurred, which is grouped into three consequence dimensions, namely safety, reliability and financial consequences. Accordingly, the wildfire risk score is a product of these two parameters, probability of ignitions and consequences.

(2) As discussed above, wildfire risk is separated into two components: a) probability/frequency of ignitions and b) consequences (measured in safety, reliability, and financial) ***after an ignition occurs that is associated with*** SCE equipment in HFRA. A system hardening initiative such as covered conductor does not directly decrease the consequence levels or impact after an ignition has started but instead it reduces the probability of ignitions. Therefore, this mitigation is only is applicable in reducing that portion of the risk equation.

In Guidance-1, Appendix A and B, SCE provided a rationale why risk reduction/RSE was not calculated for certain mitigation initiatives. In the table below, SCE describes, for those mitigation initiatives where a RSE was calculated in the 2020 WMP, why the activity reduces ignition probability or consequences of a wildfire.

Mitigation	**Rationale for ignition or consequence reduction**
SH-1, SH-10 Covered Conductor, Tree attachment remediation	Ignition reduction: For purposes of risk modeling, SCE has modeled Covered Conductor and Tree Attachment Remediation as one program. In general, these mitigations are anticipated to reduce contract-from-object and wire-to-wire ignition risks by reducing the number of faults. Because circuits that receive covered conductor

	also get brought up to current standards for related equipment, it also mitigates additional equipment failure ignition drivers.
SH-2 Undergrounding	Ignition reduction: Expected to eliminate faults and ignitions associated with overhead distribution lines where deployed.
SH-3 Fire resistant composite poles and composite crossarms (WCCP)	Ignition and consequence reduction: Composite poles and cross-arms mitigations are anticipated to reduce pole-top ignitions from risk drivers such as capacitor banks, cross arms and transformers. In addition, FR materials provide additional consequence benefits of saving equipment from fire damage and facilitating more rapid restoration of service after a wildfire, thereby reducing reliability impacts.
SH-4 Branch line protection strategy	Ignition reduction: The fusing program is intended to reduce the risk of fire ignitions with SCE's distribution lines and equipment by reducing fault energy. In the 2020 WMP, SCE modeled additional consequence reduction based on the reduced energy entering in a fault, but in the 2021 WMP has reassessed and modeled only as an ignition reduction.
SH-5 Remote Controlled Automatic Reclosers Installations	Consequence reduction: Minimize outage impacts to customers by isolating or restoring power quickly to circuit segments not impacted by the concerning weather condition.
SH-6 Circuit Breaker Fast Curve Settings	Consequence reduction: Reducing fault energy duration reduces energy at the fault location a. In the 2021 WMP, SCE has reassessed and modeled it as an ignition reduction, since it can reduce the heating, arcing and sparking for many faults.
VM-1 Hazard Tree Removal	Ignition reduction: Program will reduce vegetation caused faults from fall-ins and blow-ins and therefore is an ignition reduction mitigation program.
VM-2 Expanded Pole Brushing	Ignition reduction: Program performs brush clearance and therefore would reduce probability of ignitions by reducing the fuel needed to convert a spark from equipment failure into a wildfire.
VM-4 DRI Quarterly Inspections and Tree Removals	Ignition reduction: Reduces the probability of dead, dying or diseased trees with compromised integrity falling into lines and therefore reduce vegetation related faults that in turn reduce probability of ignitions.
IN-1.1, SH-12.1, IN-5, SH-12.3 Distribution Detailed Overhead Inspections, Remediations –	Ignition reduction: Inspections identify conditions in need of remediation, conditions are prioritized,

Distribution, Generation Inspections, Generation Remediation	and items are remediated before they fail and cause a fault. Inspections that lead to remediations help reduce ignition probability factors.
IN-3 Distribution Infrared & Corona Inspections	
IN-1.2, SH-12.2 Transmission Detailed Overhead Inspections, Remediations - Transmission	
IN-4 Transmission Infrared & Corona Inspections	
IN-6.1 Distribution Aerial Inspections	
IN-6.2 Transmission Aerial Inspections	
OP-2, SA-1, SA-3, SA-5-8, PSPS-1, PSPS-2, PSPS-3, PSPS-5, PSPS-7, SH-7 PSPS: Wildfire Infrastructure Protection Team Additional Staffing, Weather Stations, Weather forecasting, Fuel Sampling, Surface & Canopy Fuels Mapping, Remote Sensing/Satellite Fuel Moisture, Fire Science Enhancements, De-Energization Notifications, Community Resource Centers, Customer resiliency equipment incentives, MICOP Partnership, Community Outreach, PSPS driven grid hardening work	Ignition reduction: If conditions indicate fire danger is elevated — for example, if there are strong winds, low humidity, dry vegetation, there is a fire threat to public safety or electric structures — SCE may temporarily de-energize areas with a high risk of wildfires.

Action SCE-2: In its 2021 WMP Update, SCE shall: 1) rectify why it does not calculate an RSE for initiative 5.2, “Fuel management and reduction of ‘slash’ from vegetation management activities,” and 2) explain why other fuels management activities SCE performs (e.g., prescribed burns at its Shaver Lake property and weed abatement) are not included as part of this (or any) initiative and consequently do not have calculated RSEs.

Response:
SCE interprets “reduction of slash” as the practice of chipping and hauling away tree debris, when possible, from vegetation management activities such as line clearing. Reduction of slash from vegetation management activities such as line clearing is a standard practice that SCE requires, when possible, of its vegetation management contractors. The purpose of this practice is to mitigate complaints from property owners of having large pieces of vegetation debris left on the ground after clearance activities and is not a specific wildfire mitigation measure. Further, SCE has been reducing slash from its vegetation management activities as a longstanding practice and as such, SCE did not develop RSE for the activity.

Similarly, SCE performs weed abatement on SCE’s ROWs and SCE-owned land in compliance with local ordinances and regulations. This is a compliance activity that is required and has been performed for years. Thus, a risk analysis does not drive its performance and developing an RSE for it would be difficult and speculative – as such, SCE did not develop an RSE for it.

With regard to prescribed burns, SCE can only perform them on property that it owns, which is limited to approximately 20,000 acres of forested land. Given that this practice is not scalable by SCE to a larger area, SCE did not develop an RSE for it.

WMP Class B Deficiency Action Statements
Guidance-4, Lack of Discussion on PSPS Impacts

Action SCE-3: *In its 2021 WMP Update, SCE shall provide quantitative, comparable values for all "Yes" values provided in Columns D, E, F, and G of its submitted table, "Guidance-4 Appendix A.".*

Response:
See columns "I - L" of the updated "Guidance-4 Appendix A" table for quantitative and comparable values where available for reductions in the number of events (column J), number of customers impacted (Column K), duration (Column G) and threshold values for initiating PSPS (Column I).

Action SCE-4: *In its 2021 WMP Update, SCE shall: 1) explain how it determined 58 mph gusting winds to be a sufficient de-energization threshold for overhead circuits, 2) provide the percentage reduction of PSPS events based on the increased wind speed threshold, and 3) provide the range and average of historical wind speeds used for de-energization thresholds for bare overhead conductor.*

SCE Response:
1) SCE's current threshold methodology leverages the National Weather Service's High Wind Warning values of 40 mph sustained winds and 58 mph gusting winds as a baseline for circuits or circuit-segments that are fully installed with covered conductor. According to the National Weather Service, a High Wind Warning is issued "when high wind speeds may pose a hazard or [are] life threatening."[3] SCE recognizes the potential improvements that can be made to PSPS thresholds, as evidenced by the engineering-based approach that was taken during the creation of its Wildfire Risk Reduction Model-derived dynamic thresholds. As discussed in the 2021 WMP Update, Section 8.1.2, SCE is further testing and validating these new thresholds with plans to integrate them into PSPS protocols when completed.

2) In a backcast of SCE's 2020 PSPS de-energizations, SCE compared the thresholds that would be in place due to planned covered conductor work anticipated to be completed by October 1, 2021. Because SCE's forecast PSPS reduction due to covered conductor installation is based on currently planned work, it aggregates potential benefits across all of SCE's de-energized circuits. Some of these circuits are not currently forecast to have any fully covered isolatable segments in 2021, while other circuits are planned to be 100% completed with covered conductor and have most foreseeable outages mitigated.

This work is expected to fully cover more than 250 isolatable circuit segments, resulting in the PSPS reductions shown in the table below.

Scope (customer de-energizations)	Frequency (circuit de-energizations)	Duration (customer minutes of interruption)
↓9%	↓12%	↓15%

3) Below, SCE provides the requested information entailed by all 2020 PSPS outages. It should be noted that some circuits were de-energized at wind speeds lower than their thresholds. A main cause of this would be a circuit that is "downstream" or fed by another HFRA circuit that is de-energized, causing the first circuit to be de-energized at wind speeds much lower than would otherwise be the case. Also, SCE's

[3] https://www.weather.gov/lwx/WarningsDefined

PSPS IMT sometimes decides to de-energize a circuit at lower wind speeds because it serves no customers and has no reliability impacts.

In 2020, SCE de-energized bare overhead conductor at average wind speeds of 26 mph sustained and 46 mph gusting wind. The wind speed ranges for overhead bare conductor were from 8 to 65 mph sustained winds and 15 to 96 mph gusting winds, with lower values being explained by the two circumstances above.

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
RA-1	Expansion of Risk Analysis	Risk Assessment & Mapping	**Yes**	Potentially, depending on specific circumstances			High tech consequence modeling that simulates potential wildfire spread and will inform the creation of PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate PSPS thresholds	SCE is continuing to refine its Wildfire Risk Reduction Model dynamic thresholds as it further validates the model.			
OP-1	Annual SOB 322 Review	Grid Operations & Protocol	**Yes**	**Yes**	**Yes**	**Yes**	Using historical PSPS events to gather lessons learned that can inform changes to PSPS protocols in SOB322 to ensure continuous improvement Changes in Thresholds: PSPS protocols to be reviewed for lessons learned/improvements. Changes codified in this document for training/operations Reduction of Events: Codified improvements can lead to reduction once trained and put into practice Reduction of Customers: Codified improvements can lead	While SCE still performs the "Annual SOB 322 Review" activity, it does not track this activity in the 2021 WMP, and instead tracks Automatic Recloser Operations in the 2021 WMP. Tracking automatic closer operations has no impact on threshold changes. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable):			
								Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							to reduction once trained and put into practice Reduction of Duration: Codified improvements can lead to reduction once trained and put into practice				
OP-2	Wildfire Infrastructure Protection Team Additional Staffing	Grid Operations & Protocol	Potentially, depending on specific circumstances				Hiring full time staff allows the most trained, practiced men and women to execute PSPS protocols and manage events, leading to a consistent, appropriate and effective response that will serve to reduce the frequency, scope and duration of SCE's PSPS events, wherever appropriate	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
OP-3	Unmanned Aerial (UAS) Operations Training	Asset Management & Inspections	Potentially, depending on specific circumstances				Building upon aerial drone capabilities that are used to inspect HFRA assets and identify needed maintenance in order to harden the grid and raise PSPS thresholds	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be directly calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
IN-1.1	Distribution High Fire Risk Informed Inspections in HFRA	Asset Management & Inspections	**Yes**	No	No	No	Inspect HFRA assets and identify needed maintenance in order to harden the grid and raise PSPS thresholds **Change in Thresholds**: Inspections can actually lower thresholds because they alert SCE of maintenance items that are needed to harden the grid. Until fixed, those outstanding maintenance items would result in a lower threshold.	An outstanding wind-exacerbated Priority 2 (P2) notification stemming from this inspection activity would lower a circuit's trigger for de-energization by 5%	N/A		
IN-1.2	Transmission High Fire Risk Informed Inspections in HFRA	Asset Management & Inspections	**Yes**	No	No	No	Inspect HFRA assets and identify needed maintenance in order to harden the grid and raise PSPS thresholds **Change in Thresholds:** Inspections can actually lower thresholds because they alert SCE of maintenance items that are needed to harden the grid. Until fixed, those outstanding maintenance items would result in a lower threshold.	An outstanding wind-exacerbated Priority 2 (P2) notification stemming from this inspection activity would lower a circuit's trigger for de-energization by 5%	N/A		

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
IN-2	Quality Oversight / Quality Control	Asset Management & Inspections	Potentially, depending on specific circumstances				Confirm the quality and consistency of inspection program outputs to ensure the grid is appropriately maintained and hardened	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
IN-3	Infrared Inspection of Energized Overhead Distribution Facilities and Equipment	Asset Management & Inspections	No	No	No	No	High-tech inspection of HFRA assets to identify needed maintenance in order to harden the grid and raise PSPS thresholds	N/A			
IN-4	Infrared Inspection, Corona Scanning, and High Definition Imagery of Energized Overhead Transmission Facilities and Equipment	Asset Management & Inspections	No	No	No	No	High-tech inspection of HFRA assets to identify needed maintenance in order to harden the grid and raise PSPS thresholds	N/A			
IN-5	Generation High Fire Risk Informed Inspections in HFRA	Asset Management & Inspections	No	No	No	No	Inspect HFRA assets and identify needed maintenance in order to harden the grid	N/A			
IN-6.1	Aerial Inspections - Distribution	Asset Management & Inspections	**Yes**	No	No	No	Aerial inspection of HFRA assets to identify needed maintenance in order to harden the grid and raise PSPS thresholds **Change in Thresholds:** Inspections can actually lower thresholds	An outstanding wind-exacerbated Priority 2 (P2) notification stemming from this inspection activity would lower a circuit's	N/A		

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							because they alert SCE of maintenance items that are needed to harden the grid. Until fixed, those outstanding maintenance items would result in a lower threshold	trigger for de-energization by 5%			
IN-6.2	Aerial Inspections - Transmission	Asset Management & Inspections	**Yes**	No	No	No	Aerial inspection of HFRA assets to identify needed maintenance in order to harden the grid and raise PSPS thresholds **Change in Thresholds:** Inspections can actually lower thresholds because they alert SCE of maintenance items that are needed to harden the grid. Until fixed, those outstanding maintenance items would result in a lower threshold	An outstanding wind-exacerbated Priority 2 (P2) notification stemming from this inspection activity would lower a circuit's trigger for de-energization by 5%	N/A		
IN-7	Failure Modes and Effects Analysis (FMEA)	Asset Management & Inspections	Potentially, depending on specific circumstances				Identify potential modes of failure or grid vulnerabilities to ensure continuous delivery of power	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

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SH-1	Covered Conductor	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Grid hardening work that decreases the probability of phase-to-phase contact and contact from foreign object, leading to increased PSPS thresholds **Change in Thresholds:** A fully covered circuit or circuit segment would have its thresholds raised to the NWS High Wind Warning level, according to current practices **Reduction of Events:** As circuits have their thresholds raised, they are able to sustain higher wind speeds and are less likely to be de-energized **Reduction of Customers:** If circuits are de-energized less, less customers are affected by PSPS **Reduction of Duration:** If less circuits or shorter circuit segments are interrupted during a	Under current methodology, complete installation of covered conductor raises threshold a circuit or circuit-segment to 40 mph sustained or 58 mph gusts.	Based on the 254 circuit segments that SCE currently plans to have completed by 10/1/21 and a backcast of 2020 de-energizations, approximately 50 circuit de-energizations would be avoided.	Based on the 254 circuit segments that SCE currently plans to have completed by 10/1/21 and a backcast of 2020 de-energizations, approximately 13,000 customers would have reduced or no PSPS outages.	Based on the 254 circuit segments that SCE currently plans to have completed by 10/1/21 and a backcast of 2020 de-energizations, PSPS customer minutes of interruption would be reduced by approximately 40M minutes.

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							PSPS event, re-energization patrols will be quicker and events will end sooner				
SH-2	Undergrounding Overhead Conductor	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	All but eliminating catastrophic fire danger posed by an HFRA circuit, allowing it to be removed from PSPS scope **Change in Thresholds**: Undergrounding a previously overhead line will completely remove it from PSPS scope **Reduction of Events:** Undergrounding a previously overhead line will completely remove it from PSPS scope **Reduction of Customers:**	Undergrounding a circuit or circuit segment would remove that line from scope for proactive PSPS de-energization.	SCE's scoped undergrounding work for 2021 is not expected to yield any PSPS reductions. In all cases, overhead portions of each circuit will still exist and pose a wildfire risk.		

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							Undergrounding a previously overhead line will completely remove it from PSPS scope **Reduction of Duration:** Undergrounding a previously overhead line will completely remove it from PSPS scope				
SH-3	WCCP Fire Resistant Poles	Grid Design & System Hardening	No	No	No	No	Replacing traditional wood poles with fire resistant poles hardens the grid to environmental threats and means that associated hardware is replaced with new material	N/A			
SH-4	Branch Line Protection Strategy	Grid Design & System Hardening	No	No	No	No	Replace existing fuses with superior replacements that minimize potential causes of ignition and boost public safety	N/A			

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SH-5	Installation of System Automation Equipment – RAR/RCS	Grid Design & System Hardening	No	**Yes**	**Yes**	**Yes**	Increase sectionalizing capabilities on HFRA circuits to allow operational flexibility when de-energizing and reducing potential PSPS scope **Reduction of Events:** When SCE is able to limit de-energization events only to the area where potentially damaging winds are occurring, customers upstream of that de-energization will not have a PSPS event **Reduction of Customers:** When SCE uses a RAR/RCS to de-energize a portion of a circuit instead of a circuit breaker to de-energize an entire circuit, less customers are impacted **Reduction of Duration:** If less circuits or shorter circuit segments are interrupted during a PSPS event, re-energization patrols	N/A	While SCE does calculate forecast customer and de-energization reductions for all proposed installation of system automation equipment for PSPS mitigation, SCE's scope for 2021 is not yet finalized, so forecast reductions will not be available until projects are selected for implementation. Per SCE's Corrective Action Plan filing, circuit mitigation plans will be completed by April 15, 2021, and system automation scope will be known.		

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							will be quicker and events will end sooner				
SH-6	Circuit Breaker Relay Hardware for Fast Curve	Grid Design & System Hardening	No	No	No	No	Harden grid to decrease potential failures and increase public safety	N/A			
SH-7	PSPS-Driven Grid Hardening Work	Grid Design & System Hardening	Potentially, depending on specific circumstances				Evaluate distribution circuits within HFRA to determine if modifications may improve sectionalizing capability and reduce PSPS scope	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated as this activity represents an evaluation of work and not deployment of work. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
SH-8	Transmission Open Phase Detection	Grid Design & System Hardening	No	No	No	No	Harden grid to decrease potential failures and increase public safety	N/A			
SH-9	Transmission Overhead Standards (TOH) Review	Grid Design & System Hardening	Potentially, depending on specific circumstances				Continuous review of engineering standards to determine if changes can be made to reduce failure modes and reduce PSPS events	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated as this activity represents an evaluation of work and not deployment of work. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

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SH-10	Tree Attachment Remediation	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Harden the grid to decrease potential failures, increase public safety and raise PSPS thresholds **Change in Thresholds**: Remediating all know circuit health concerns leads to an increase in PSPS thresholds **Reduction of Events:** If thresholds are raised, circuits are less likely to be de-energized **Reduction of Customers:** If circuits aren't de-energized, less customers are impacted **Reduction of Duration:** If less circuits are de-energized, more resources can perform patrols and re-energization can happen more quickly	An outstanding wind-exacerbated Priority 2 (P2) notification fixed from this activity would lower a circuit's trigger for de-energization by 5%	While exact impacts are difficult to define, analysis of SCE's 2020 PSPS de-energizations showed that none of them were likely to be avoided by a 5% increase in thresholds.		
SH-11	Legacy Facilities	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Harden the grid to decrease potential failures, increase public safety and raise PSPS thresholds **Change in Thresholds:** Remediating all know circuit health concerns	An outstanding wind-exacerbated Priority 2 (P2) notification fixed from this activity would lower a circuit's	While exact impacts are difficult to define, analysis of SCE's 2020 PSPS de-energizations showed that none of them were likely to be avoided by a 5% increase in thresholds.		

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							leads to an increase in PSPS thresholds **Reduction of Events:** If thresholds are raised, circuits are less likely to be de-energized **Reduction of Customers:** If circuits aren't de-energized, less customers are impacted **Reduction of Duration:** If less circuits are de-energized, more resources can perform patrols and re-energization can happen more quickly	trigger for de-energization by 5%			
SH-12.1	Remediations - Distribution	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Harden the grid to decrease potential failures, increase public safety and raise PSPS thresholds **Change in Thresholds:** Remediating all know circuit health concerns leads to an increase in PSPS thresholds **Reduction of Events**: If thresholds are raised, circuits are less likely to be de-energized **Reduction of Customers:** If circuits	An outstanding wind-exacerbated Priority 2 (P2) notification fixed from this activity would lower a circuit's trigger for de-energization by 5%	While exact impacts are difficult to define, analysis of SCE's 2020 PSPS de-energizations showed that none of them were likely to be avoided by a 5% increase in thresholds.		

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							aren't de-energized, less customers are impacted **Reduction of Duration**: If less circuits are de-energized, more resources can perform patrols and re-energization can happen more quickly				
SH-12.2	Remediations - Transmission	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Harden the grid to decrease potential failures, increase public safety and raise PSPS thresholds **Change in Thresholds:** Remediating all know circuit health concerns leads to an increase in PSPS thresholds **Reduction of Events:** If thresholds are raised, circuits are less likely to be de-energized **Reduction of Customers:** If circuits aren't de-energized, less customers are impacted **Reduction of Duration:** If less circuits are de-energized, more resources can perform patrols and re-	An outstanding wind-exacerbated Priority 2 (P2) notification fixed from this activity would lower a circuit's trigger for de-energization by 5%	While exact impacts are difficult to define, analysis of SCE's 2020 PSPS de-energizations showed that none of them were likely to be avoided by a 5% increase in thresholds.		

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							energization can happen more quickly				
SH-12.3	Remediations - Generation	Grid Design & System Hardening	**Yes**	**Yes**	**Yes**	**Yes**	Harden the grid to decrease potential failures, increase public safety and raise PSPS thresholds **Change in Thresholds**: Remediating all know circuit health concerns leads to an increase in PSPS thresholds **Reduction of Events:** If thresholds are raised, circuits are less likely to be de-energized **Reduction of Customers**: If circuits aren't de-energized, less customers are impacted **Reduction of Duration**: If less circuits are de-energized, more resources can perform patrols and re-energization can happen more quickly	An outstanding wind-exacerbated Priority 2 (P2) notification fixed from this activity would lower a circuit's trigger for de-energization by 5%	While exact impacts are difficult to define, analysis of SCE's 2020 PSPS de-energizations showed that none of them were likely to be avoided by a 5% increase in thresholds.		

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable):			
								Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
VM-1	Hazard Tree Management Program	Vegetation Management & Inspections	No	No	No	**Yes**	Removal of potential ignition sources and fuel, boosting public safety **Reduction of Duration:** Taking care of potential foreign objects that can potentially fly into lines and require removal will mean that re-energization patrols will be shorter	N/A			Duration reductions from this category are difficult to forecast, but it likely shortens restoration patrol times, as field personnel are less likely to need to access high voltage lines to remove vegetation before re-energization. This may reasonably reduce post-patrols by 15-60 minutes for every instance avoided of foreign objects stuck on a conductor.
VM-2	Expanded Pole Brushing	Vegetation Management & Inspections	No	No	No	No	Removal of potential ignition sources and fuel, boosting public safety	N/A			
VM-3	Expanded Clearances for Legacy Facilities	Vegetation Management & Inspections	No	No	No	**Yes**	Removal of potential ignition sources and fuel, boosting public safety **Reduction of Duration**: Taking care of potential foreign objects that can potentially fly into lines and require removal will mean that re-energization patrols will be shorter.	N/A			Duration reductions from this category are difficult to forecast, but it likely shortens restoration patrol times, as field personnel are less likely to need to access high voltage lines to remove vegetation before re-energization. This may reasonably reduce post-patrols by 15-60 minutes for every instance avoided of foreign objects stuck on a conductor.

	2020-22 WMP Activity	Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
VM-4	Drought Relief Initiative (DRI) Inspections and Mitigations	Vegetation Management & Inspections	No	No	No	**Yes**	Removal of potential ignition sources and fuel, boosting public safety **Reduction of Duration:** Taking care of potential foreign objects that can potentially fly into lines and require removal will mean that re-energization patrols will be shorter	N/A			Duration reductions from this category are difficult to forecast, but it likely shortens restoration patrol times, as field personnel are less likely to need to access high voltage lines to remove vegetation before re-energization. This may reasonably reduce post-patrols by 15-60 minutes for every instance avoided of foreign objects stuck on a conductor.
VM-5	Vegetation Management Quality Control	Vegetation Management & Inspections	No	No	No	No	Inspection of HFRA circuits to identify potential ignition sources and fuel, boosting public safety	N/A			
SA-1	Weather Stations	Situational Awareness & Forecasting	No	**Yes**	**Yes**	No	Enhance situational awareness allowing more sectionalization and reduced PSPS scope **Reduction of Events:** Increased situational awareness provided by more weather station coverage allows SCE to make more granular de-energization decisions. This means that only portions of circuits can be de-energized, allowing	N/A	The PSPS reduction from weather stations is also difficult to forecast, as it relies on different weather conditions across a circuit. If SCE has multiple weather stations on a circuit and can confirm that one or more portions of a circuit are not experiencing concerning winds, sectionalization can be used to reduce the de-energization footprint.		N/A

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							certain customers to avoid de-energization **Reduction of Customers:** Smaller de-energization footprints mean that less customers will be impacted by PSPS de-energizations				
SA-2	Fire Potential Index (FPI) Phase II	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Enhance forecasting and modeling to provide more accurate PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate FPI and PSPS thresholds	These enhancements to SCE's weather and fuel forecasting capabilities will continue to improve SCE's models. However, since these upgrades are still in development and have not neared implementation, actual PSPS threshold impacts are currently unknown. These activities are	SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		
SA-3	High-Performing Computer Cluster (HPCC) Weather Modeling System	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Enhance forecasting and modeling to provide more accurate PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate FPI and PSPS thresholds		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		
SA-4	Asset Reliability & Risk Analytics Capability	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			High tech consequence modeling that simulates potential wildfire spread and will		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		

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							inform the creation of PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate PSPS thresholds	bucketed into larger deliverables with target completion dates that will be tracked under SCE's Corrective Action 2B.			
SA-5	Fuel Sampling Program	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Gather enhanced situational awareness inputs that inform PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate FPI and PSPS thresholds		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		
SA-6	Surface and Canopy Fuels Mapping	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Gather enhanced situational awareness inputs that inform PSPS thresholds **Change in Thresholds:** New modeling inputs that are used to calculate FPI and PSPS thresholds		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		
SA-7	Remote Sensing / Satellite Fuel Moisture	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Gather enhanced situational awareness inputs that inform PSPS thresholds **Change in Thresholds**: New modeling inputs that are used to		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		

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								Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							calculate FPI and PSPS thresholds				
SA-8	Fire Science Enhancements	Situational Awareness & Forecasting	**Yes**	Potentially, depending on specific circumstances			Gather enhanced situational awareness inputs that inform PSPS thresholds **Change in Thresholds**: New modeling inputs that are used to calculate FPI and PSPS thresholds		SCE is evaluating how to quantify the impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.		
PSPS-1.1	De-Energization Notifications	Grid Operations & Protocol	No	No	No	No	Information sharing to increase public safety and preparation	N/A			
PSPS-1.2	De-Energization Notifications	Grid Operations & Protocol	No	No	No	No	Information sharing to increase public safety and preparation	N/A			
PSPS-1.3	De-Energization Notifications	Grid Operations & Protocol	No	No	No	No	Information sharing to increase public safety and preparation	N/A			
PSPS-1.4	De-Energization Notifications	Grid Operations & Protocol	No	No	No	No	Information sharing to increase public safety and preparation for all members of the public	N/A			
PSPS-2	Community Resource Centers	Grid Operations & Protocol	No	No	No	No	Centers providing goods, services and information to reduce burden/impact of PSPS de-energization on the public	N/A			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
PSPS-3	Customer Resiliency Equipment Incentives	Grid Operations & Protocol	No	No	No	No	Rebates designed to encourage customer resiliency and lessen the burden of potential PSPS de-energizations	N/A			
PSPS-4	Income Qualified Critical Care (IQCC) Customer Battery Backup Incentive Program	Grid Operations & Protocol	No	No	No	No	Fully subsidized program that provides battery backup needs to power life safety equipment for select customers	N/A			
PSPS-5	MICOP Partnership	Grid Operations & Protocol	No	No	No	No	PSPS information sharing to increase public safety and preparation	N/A			
PSPS-6	Independent Living Centers Partnership	Grid Operations & Protocol	No	No	No	No	PSPS information sharing to increase public safety and publicize potentially applicable SCE programs (e.g., Medical Baseline Program)	N/A			
PSPS-7	Community Outreach	Grid Operations & Protocol	No	No	No	No	Centers providing goods, services and information to reduce burden/impact of PSPS de-energization on the public	N/A			
PSPS-8	Microgrid Assessment	Grid Operations & Protocol	No	No	No	No	Evaluation efforts to determine the feasibility of islanded microgrids that can provide power to	N/A			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable): Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
							customers during PSPS and other de-energization events				
DEP-1.1-1.3	Customer Education and Engagement	Emergency Planning & Preparedness	No	No	No	No	Information sharing to increase public safety and preparation	N/A			
DEP-2	SCE Emergency Response Training	Emergency Planning & Preparedness	Potentially, depending on specific circumstances				Strengthen rigor and core competencies to aid in the execution of PSPS protocols and decrease frequency, scope and duration of PSPS events, where appropriate	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be directly calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
DEP-3	IOU Customer Engagement	Emergency Planning & Preparedness	No	No	No	No	Information sharing to increase public safety and preparation	N/A			
DEP-4	Customer Research and Education	Emergency Planning & Preparedness	No	No	No	No	Information sharing to increase public safety and inform SCE customer programs	N/A			
AT-1	Alternative Technology Pilots – Meter Alarming for Down Energized Conductor (MADEC)	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-2.1	Distribution Fault Anticipation (DFA)	Situational Awareness & Forecasting	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable):			
								Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
AT-2.2	Advanced Unmanned Aerial Systems Study	Grid Design & System Hardening	Potentially, depending on specific circumstances				Determine efficacy of UAS patrols which can potentially be introduced to reduce PSPS duration	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-3.1	Alternative Technology Evaluations: Rapid Earth Fault Current Limiter (REFCL) - Ground Fault Neutralizer (GFN)	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-3.2	Alternative Technology Evaluations: REFCL - Resonant Grounded Substation with Arc Suppression Coil	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-3.3	Alternative Technology Evaluations: REFCL-Isolation Transformer	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-3.4	Alternative Technology Evaluations – Distribution Open Phase Detection	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-4	Alternative Technology Implementation – Vibration Dampers	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce modes of failure, boosting PSPS thresholds	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

2020-22 WMP Activity		Category	i. Does this Affect Threshold Values for Initiating PSPS (Column D)	ii. Expected to Reduce Number of Events (Column E)	iii. Expected to Reduce Customers Impacted (Column F)	iv. Expected to Reduce Duration (Column G)	How Does the Initiative Support Directional Vision of PSPS (Column H)	Action SCE-3 Quantitative / Comparable Values for (Where Applicable):			
								Threshold Values for Initiating PSPS (relates to Column D)	Reduction of Number of Events (relates to Column E)	Reduction of Customers Impacted (relates to Column F)	Reduction in Duration (relates to Column G)
AT-5	Asset Defect Detection Using Machine Learning Object Detection	Asset Management & Inspections	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-6	Assessment of Partial Discharge for Transmission Facilities	Asset Management & Inspections	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-7	Early Fault Detection (EFD) Evaluation	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			
AT-8	High Impedance Relay Evaluations	Grid Design & System Hardening	Potentially, depending on specific circumstances				Advanced technology solution that can potentially reduce public safety hazards and ignition sources	A quantifiable impact on thresholds, scope, frequency and/or duration cannot be calculated. Please see column H "How Does the Initiative Support Directional Vision of PSPS" for discussion on potential qualitative benefits.			

WMP Class B Deficiency Action Statements
Guidance-5, Aggregation of initiatives into programs

Action SCE-5: *In its 2021 WMP Update, SCE shall: 1) provide a timeline and status update for when it intends to develop quantitative evaluations for each initiative, including the status of threshold values, 2) explain why any initiatives listed in Tables 2 through 10 of the QR would not be applicable for threshold values, and 3) explain what subject matter expert (SME) expertise is being used for in the development of each quantitative value and threshold.*

Response:
SCE has identified five categories of key portfolio-level effectiveness metrics (described in its response to Guidance-5 and in SCE's 2021 WMP Update) by which most of its WMP activities may be evaluated. These effectiveness metrics proposed by SCE are:

- CPUC reportable ignitions in HFRA (total and by key drivers such as CFO, wire-to-wire, Tree Caused Circuit Interruptions, equipment failure)
- Faults in HFRA (total and by key drivers mentioned above)
- Wire down incidents in HFRA (total and by key drivers mentioned above)
- Number of customers and average duration of PSPS events
- Timeliness and accuracy of PSPS notifications

In response to Guidance 5, on September 9, 2020, SCE included all the activities in its 2020 WMP and provided effectiveness metrics for each initiative separately. In response to this Action Statement, SCE is updating its response in two ways. First, SCE is updating the response provided in Guidance 5 to reflect the 39 activities included in its 2021 WMP Update to stay consistent with the current WMP and account for new activities and eliminated activities already completed or transitioned to routine operations. SCE provided a mapping of its 2020 activities to 2021 activities in Appendix 9.3 in its 2021 WMP Update submitted on February 5, 2021. Second, SCE has linked each activity to the portfolio level key effectiveness metrics to the extent feasible as improvement in these activities is the eventual goal of our WMPs.

The 39 WMP activities are described in Table G5-SCE5-1. Also, in Table G5-SCE5-1, along with SCE's description of each activity and their 2021 program targets, SCE describes which of the five effectiveness metrics relate to the activity. The 'Quantitative Evaluation' column provides initial methods SCE may employ to measure effectiveness and thresholds thereof, subject to further refinement. As SCE analyzes the effectiveness of the WMP activities, if there are other metrics that are materially impacted, SCE will address those in future updates.

In response to parts (1) and (2) of this Action Statement, SCE notes that for all 39 WMP activities described in the Table, quantifying actual mitigation effectiveness is a complex effort that requires availability of accurate and consistent data on ignition drivers, calculation methods to be developed and normalized for weather and other exogenous factors to facilitate meaningful conclusions, and tested methods. Sufficient time is necessary to evaluate and validate real-world field performance of the mitigations over a meaningful time-period. SCE plans to build, test, and refine methods to develop threshold values for effectiveness of each of the WMP initiatives throughout Q4 2021 and will include these findings in its 2022

WMP Update. Evaluation of the initiatives themselves will occur after a sufficient volume of work has been deployed and sufficient time has passed since deployment to evaluate pre- and post-deployment changes in effectiveness metrics. For example, though covered conductor has been deployed in many areas of SCE's HFRA, we have less than two years of data which translates to very few or no incidents on any particular segment making it challenging to compare overhead conductor performance prior to and after covered conductor installation, especially when uncontrollable environmental factors are accounted for. To account for anomalies related to grid conditions, weather events, and other externalities, these results must be measured and evaluated over time. While SCE is continuing to evaluate the effectiveness of its WMP activities after deployment, SCE suggests that results may require at least 3 years of mitigation deployment in order to adequately account for these factors. Therefore, the evaluation of initiatives will be an annual exercise for SCE, with continual refinements in the measurement approaches. Finally, for those where the portfolio effectiveness metrics cannot be applied, such as digital or work management tools, SCE has provided an explanation in the Quantitative Evaluation column of the activity's role with respect to other WMP activities.

SCE has been actively investigating ways to measure and evaluate effectiveness and offers initial thoughts in the 'Quantitative Evaluation' column of the table. SCE will build upon these efforts to develop more robust and repeatable methods for assessing effectiveness in 2021. SCE also intends to investigate approaches to gauge effectiveness in targeting and deploying wildfire mitigations to the highest risk areas. An important component of these efforts will be to benchmark with other utilities and organizations on best practices and methods. For most initiatives, SCE is in the process of evaluating the appropriate methods to quantify effectiveness for each initiative, and therefore thresholds have not yet been set. Finally, SCE would appreciate the opportunity to partner with WSD in this effort and suggests that a workshop be held in early Q3 of this year to share our progress and obtain feedback from WSD in advance of the 2022 WMP Update.

Within the attached table, for those WMP initiatives which SCE has risk-scored in the 2021 WMP Update, SCE provides estimates of expected effectiveness based on the risk and RSE analysis. These are not equivalent to threshold metrics as the WMP activities are potentially effective even if they provide lesser benefits than expected. For example, though our engineering judgment might say that covered conductor is 99% effective in reducing faults associated with a particular driver, 70-80% effectiveness in reducing faults would still be a significant improvement over bare conductor performance. SCE intends to utilize these risk-informed measurements to continuously refine the assumptions that are used to model the mitigation effectiveness of each initiative, and to help inform future levels and scope of deployment of the mitigation.

3) Subject Matter Expertise: SCE has used and is continuing to use the expertise of various resources to develop the methodology by which to quantify effectiveness, perform those calculations, and establish associated thresholds. This includes:

- Engineering and technical experts associated with each initiative who are experts in how each technology performs;
- Risk modelers and data scientists with expertise in statistical analysis and evaluation who help build and calculate quantitative metrics and thresholds;
- Performance management professionals who track performance following deployment of activities and align metrics and threshold values to evaluate effectiveness;

- Customer service professionals who evaluate customers awareness, understanding and gauge satisfaction with programs intended to reduce PSPS impacts to customers;
- Meteorology and weather professionals who use advanced tools and models to evaluate and forecast weather conditions; and
- Other SMEs as needed.

WMP Class B Deficiency Action Statements
Guidance-7, Lack of detail on effectiveness of "enhanced inspection programs"

Action SCE-6*: In its 2021 WMP Update, SCE shall: 1) clearly explain how its EOI and HFRI inspections differ from its routine detailed inspections, beyond the frequency with which they are conducted, and 2) provide copies of the inspection forms used for each inspection type.*

Response:
As SCE explained in its 2021 General Rate Case – Track 2 Rebuttal Testimony and beyond the faster cadence, the enhanced overhead inspections (including EOI and HFRI) differ from traditional inspections in three key ways: (1) They have a different focus and purpose: inspections go beyond identifying the conditions of existing assets that could be safety or reliability hazards under GO 95, and extend to identifying potential upgrades or other modifications to the assets that would help mitigate ignition risks based on recent data; and (2) They are conducted in different ways: aerial inspections and high-quality image capture provide a 360-degree view of assets that was previously unachievable from the ground inspections alone. See A.19-08-013, Exhibit SCE Tr.2-01, Vol. 02, Section II.A.2 for more information.

The distribution enhanced overhead inspection checklists were attached as appendices to SCE's 2021 General Rate Case – Track 2 Testimony. See SCE Tr.2-01, Vol. 01. Additional inspection checklists are appended to this response.

Action SCE-7: *In its 2021 WMP Update, SCE shall: 1) clarify why it chose to use approximations for the number of notifications in Tables 12 and 13 and 2) provide updated tables using actual numbers rather than approximations.*

Response:

1) Given that the data was pulled at a point in time during 2020 and would vary if pulled at another point in time during 2020 due to notifications being continuously created and uploaded to the system, SCE believed that approximations would be appropriate as they would still convey the magnitude of notifications resulting from the various inspection programs without potentially creating confusion with similar data submitted at other points in time.

2) Tables 12 and 13 are presented below without the approximations. For Table 12, the original query for Table 12 had been saved and was used to populate the exact values. For Table 13, the original query was not available and was recreated with more up to date numbers.

Table 12 – Guidance-7
Number of Notifications by Priority

Inspection Program	Distribution			Transmission			Total
	P1	P2	P3	P1	P2	P3	
High Fire Risk Informed Ground Inspections (2020)	815	11,800	16,133	0	5,570	312	34,630
Aerial Inspections (2019 & 2020	396	12,696	56	54	4,877	50	18,129
EOI (2018 & 2019)	1,003	80,200	46,113	49	18,669	2,507	148,541
Long Span Inspections (2019)	0	9,196	3	0	8	0	9,207
IR/Corona (2019 and 2020)	130	319	6	10	28	24	517
Enhanced Inspection Total	**2,344**	**114,211**	**62,311**	**113**	**29,152**	**2,893**	**211,024**

Table 13 – Guidance-7
Notifications Identified in HFRA

Inspection Program	Distribution			Transmission			Total
	P1	P2	P3	P1	P2	P3	
Overall Total Notifications created in HFRA areas between December 2018 and August 2020	8,289	152,926	147,291	186	29,157	4,084	341,933
Enhanced Inspections as a Percentage of Overall	28.3%	74.7%	42.3%	60.8%	100%	70.8%	61.7%

Aerial Distribution Survey Question Change Log

EFFECTIVE: *February 1, 2021*

DATA CAPTURE QUESTIONS FOR INSPECTION

Contents

Survey Questions

General

Created Date
Last Modified Date
Submitted Date

1) Inspector Name
2) Inspector User ID
3) Inspection Date
4) FLOC
4A) Structure Number
4B) Inspection Date
4C) Display Images in GR Viewer
4D) Photo Location
5) Are you able to complete the data capture survey?

Answer choices (single select):

a. Yes (Enables Question 7)
b. No (Enables Question 6)

6) Unable to Inspect Reason: (Enabled by Question 5 - Answer b)

Answer choices (single select):

a. Incorrectly Tagged – Vendor Picture
b. Incorrectly Tagged – SCE Data
c. Missing Photo Angles (Exempt Veg Blocking View)
d. Vegetation Blocking View
e. Structure Under Repair
f. Duplicate structure
g. Unable to Inspect Comments

7) Structure Type (Enabled by Question 5 - Answer a)

Answer choices (single select):

a. Distribution Pole – ED (Enables Question 8)
b. Guy Stub/Push Pole – ED (Enables Question 9)
c. Distribution Streetlight – EDSL (survey stops)
d. Transmission / Distribution Combo Pole – EZ (Enables Question 8)
e. Transmission Pole – ET (survey stops)
f. Trans-Telecom Pole (Consult Field Specialist) (survey stops)
g. Hydro /Communication Only Pole (Consult Field Specialist)
h. None of the above (Consult Field Specialist) (survey stops)
i. Comments

8) What Circuit Type is present on Distribution pole? (Enabled by Question 7 - Answer a, d)

Answer choices (single select):

a. Primary Only (Enables Question 28, 29, 31, 32, 34, 37, 38, 43, 44, 46, 48, 49, 50, 51, 52, 53, 54, 58, 59, 60, 63, 76, 77, 79)
b. Secondary Only (Enables Question 64A, 64B, 64C, 65, 67, 67A, 71, 73, 74, 74A)
c. Both Primary and Secondary (Enables Question 28, 29, 31, 32, 34, 37, 38, 43, 44, 46, 48, 49, 50, 51, 52, 53, 54, 58, 59, 60, 63, 64A, 64B, 64C, 65, 67, 67A 71, 73, 74, 74A, 76, 77, 79)

9) What is the structure material? (Enabled by Question 7 - Answer a, b, d)

Answer choices (single select):

a. Wood pole (Enables Question 10, 12, 14A, 15, 18)
b. Composite Pole (Enables Question 10, 11, 12, 14A, 15, 18)
c. Steel Pole (Enables Question 10, 12, 14A, 15, 18)
d. Tree (Enables Question 10, 12, 14A, 15, 18)
e. None of the above (Consult Field Specialist)

Pole

10) Is the condition of the pole's structural integrity good? (Enabled by Question 9 - Answer a, b, c, d)

Answer choices (single select):

a. Yes
b. No (Notification Required)

11) Is pole-top capped? (Enabled by Question 9 - Answer b)

Answer choices (single select):

a. Yes
b. No

12) Is there equipment present? (Enabled by Question 9 - Answer a, b, c, d)

Answer choices (single select):

a. Yes (Enables Question 13, 28, 29, 31, 32, 34, 63)
b. No

13) Indicate which of the following types of Arrester material is present on pole. (Enabled by Question 12 - Answer a)

Answer choices (single select):

a. Polymer lightning arrester (Enables Question 14)
b. Polymer lightning arrester/silicon carbide (Enables Question 14)
c. Spark Prevention Unit (SPU)
d. Component/Equipment not on Structure

14) Is the ground lead attached or arrester in good condition? (Enabled by Question 13 - Answer a, b)

Answer choices (single select):

a. Yes
b. No (Notification Required)
c. Unable to Determine - Missing Photo Angle
d. Unable to Determine - Poor Photo Quality

14A) What type of Crossarm is present? (Enabled by Question 9 - Answer a, b, c, d)

Answer choices (single select):

a. Wood Only (Enables Question 19, 21)
b. Composite Only (Enables Question 24)
c. Steel Only (Enables Question xx)
d. Wood, Composite, and/or Steel (Enables Question 19, 21, 24, xx)
e. Component/Equipment not on Structure

15) List all non-exempt material present. (Enabled by Question 9 - Answer a, b, c, d)

Answer choices (multi-select):

a. Copper Vise Connectors
b. Aluminum Vice Connectors
c. Lightning Arresters (except with SPU)

d. Fuse links without an ECD
e. Box Cutouts
f. Solid Blade Disconnects (except on reclosers and regulators)
g. Split Bolt Connectors
h. Grasshopper Switches
i. Component/Equipment not on structure

16) Select all fuse types observed in the inspection (Enabled by Question 12 - Answer a)

Answer choices (multi-select):

a. Current Limiting Fuse (ELF, Fault Tamer, X-Limiter, K-Mate)
b. SMU20
c. Fuse Link
d. Liquid fuse (Enables Question 17)
e. Unable to Determine – All equipment covered
f. Component/Equipment not on Structure

17) Is liquid fuse dry? (Enabled by Question 16 - Answer d)

Answer choices (single select):

a. Yes (Notification Required)
b. No

18) Indicate if there are animal nests on the structure? (Enabled by Question 9 - Answer a, b, c, d)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

18A) Indicate if there is any communication equipment on the structure

Answer choices (single select):

a. Yes (Enables 18B)
b. No
c. Unable to Determine

18B) Indicate if any of the following communication equipment conditions are observed on the structure. Select all that apply or select "No abnormal conditions". (Enabled by Question 18B - Answer a)

Answer choices (multi-select):

a. Inadequate clearance between communication equipment or structures and SCE electrical equipment or structures (Notification Required)
b. Excessive sag of communication cables (Notification Required)
c. Loose lashing wire (Notification Required)
d. Broken or separated messenger wire (Notification Required)
e. Broken, damaged or severely strained communication guy wires (Notification Required)
f. Excessive bowing or bending of pole from potential overloading at communication equipment attachment points (Notification Required)
g. Improperly secured communication conductor or equipment (Notification Required)
h. Vegetation straining communication messenger or guy wire and/or causing structural integrity issues (Notification Required)
i. No abnormal conditions
j. Unable to Determine

Crossarms – Wood

19) How many single configuration wood crossarms are there? (Enabled by Question 14A - Answer a, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

19A) How many double configuration wood crossarms are there? (Enabled by Question 14A - Answer a, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

19B) How many triple configuration wood crossarms are there? (Enabled by Question 14A - Answer a, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

21) Are the wood crossarms and supporting members in good condition? (Enabled by Question 14A - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 22)

22) Do any of the following conditions exist on any of the wood crossarms? (Enabled by Question 21 - Answer b)

Answer choices (multi-select):

a. Bending/Bowed/Twisted (Enables Question 23a)

b. Canted
c. Tracking, charring with burn mark
d. Damaged V-braces (Enables Question 23b)
e. No bonding copper wire under cross-arm
f. Split
g. Deteriorated (woodpecker, canoeing, etc.)

23a) For bowed/twisted wood crossarms, which of the following signs are observed? (Enabled by Question 22 - Answer a)

Answer choices (multi-select):

a. Crossarm bowed and splintering
b. Crossarm bowed without splintering
c. Significant damage at a bolt

23b) For wood crossarms with V-brace damage, which of the following signs are observed? (Enabled by Question 22 - Answer d)

Answer choices (multi-select):

a. Braces broken
b. Braces loose
c. Braces missing
d. Braces worn

Crossarms – Composite

24) How many single configuration composite crossarms are there? (Enabled by Question 14A - Answer b, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

24A) How many double configuration composite crossarms are there? (Enabled by Question 14A - Answer a, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9

j. 10

24B) How many triple configuration composite crossarms are there? (Enabled by Question 14A - Answer a, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
k. 10

25) Are the composite crossarms and supporting members in good condition?

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 26)

26) Do any of the following conditions exist on any of the wood crossarms? (Enabled by Question 25 - Answer b)

Answer choices (multi-select):

a. Bending/Bowed/Twisted (Enables Question 27a)
b. Canted
c. Tracking
d. Bracket damage (Enables Question 27b)
e. Split
f. Deteriorated (woodpecker, canoeing, etc.)

27a) For bending composite crossarms, which of the following signs are observed? (Enabled by Question 26 - Answer a)

Answer choices (multi-select):

a. Significant visual fracturing
b. Significant visual buckling
c. Significantly unbalanced due to tension
d. Visual tracking, charring, burn mark
e. Bent mounting bracket and associated hardware

27b) For composite crossarms with bracket damage, which of the following signs are observed? (Enabled by Question 26 - Answer d)

Answer choices (multi-select):

a. broken
b. loose
c. cracked

Crossarms – Steel

CS1) How many single configuration steel crossarms are there? (Enabled by Question 14A - Answer c, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

CS2) How many double configuration steel crossarms are there? (Enabled by Question 14A - Answer c, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

CS3) How many triple configuration steel crossarms are there? (Enabled by Question 14A - Answer c, d)

Answer choices (single select):

a. 1
b. 2
c. 3
d. 4
e. 5
f. 6
g. 7
h. 8
i. 9
j. 10

CS4) Are the steel crossarms and hardware in good condition?

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables QuestionCS5)

CS5) Do any of the following conditions exist on any of the steel crossarms? (Enabled by Question CS4 - Answer b)

Answer choices (multi-select):

a. Bending/Bowed/Twisted
b. Canted

c. Tracking
d. Bracket damage
e. Excessive rust or corrosion

Overhead Transformers - Primary

28) How many overhead transformers are installed on this structure? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a)

Answer choices (single select):

a. 0 (Removes Question 29)
b. 1 (Enables Question 28)
c. 2 (Enables Question 28)
d. 3 (Enables Question 28)
e. 4 (Enables Question 28)

29) Is transformer in good condition? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a) (Removed by Question 28 - Answer a)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 30)

30) Indicate if any of the following signs of transformer abnormal conditions are observed. (Enabled by Question 29 - Answer b)

Answer choices (multi-select):

a. Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area (Consult Field Specialist)
b. Minor oil leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area
c. One fuse is open/down
d. Bushings damaged
e. Blown fuse
f. Signs of burn
g. Signs of swelling
h. Oil weepage indicated by oily film on tank surface
i. Red flag fault indicator is visible

Overhead Capacitors - Primary

31) How many overhead capacitor banks are installed on this structure? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a)

Answer choices (single select):

a. 0 (Removes Question 32)
b. 1 (Enables Question 32)
c. 2 (Enables Question 32)
d. 3 (Enables Question 32)

32) Is the Capacitor/Associated Equipment in good condition? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a) (Removed by Question 31 - Answer a)

Answer choices (single select):

a. Yes

b. No (Notification Required) (Enables Question 33)

33) Indicate if any capacitor or associated equipment shows signs of the following conditions. (Enabled by Question 32 - Answer b)

Answer choices (multi-select):

a. Ruptured or severely bulged capacitor units (Consult Field Specialist)
b. Capacitor bank damaged, not functioning (Consult Field Specialist)
c. Catastrophic or severely damaged capacitor switches, safety or reliability issue (Consult Field Specialist)
d. Capacitor switches not secure, damaged, not functioning
e. Capacitor controller damaged
f. One fuse is open/down (Consult Field Specialist)
g. Bushings damaged
h. Blown fuse (Consult Field Specialist)
i. Signs of burn
j. Signs of swelling
k. Loose wires
l. PT Transformer severely damaged
m. In contact with animal next
n. Oil leakage
o. Capacitor controller missing or enclosure damaged (exposed meter socket) (Notification Required)(Notification Required)

Reclosers, PE Gear, Regulators, Switches - Primary

34) Are reclosers, PE gear, regulators, or switches present on the pole? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a)

Answer choices (single select):

a. Yes (Enables Question 35, 36)
b. No

35) Are trees or vegetation interfering with operation of reclosers, PE gear, regulators, or switches? (Enabled by Question 34 - Answer a)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

36) If the switch is in the closed position, are all switch blades fully engaged?

Answer choices (single select):

a. Yes
b. No (Consult Field Specialist)
c. Switch in open position
d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality
f. Component/Equipment not on Structure

Insulators - Primary

37) What types of insulators are installed at the primary level? (Enabled by Question 8 - Answer a, c)

Answer choices (multi-select):

a. Porcelain Glass Only (Enables Question 42)
b. Porcelain Glass and Bells (Enables Question 40)
c. Armless Construction
d. Polymer Dead-end
e. Hendrix Universal (UFOs)
f. Hendrix Vice-top insulator
g. Silicon post-type insulator
h. Other (Enables Question 40, 42)

38) Are Insulators in good condition? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 39)
c. Unable to Determine – All Equipment Covered

39) Indicate if any of the following types of damaged/abnormal conditions are observed on any portions of the Insulator or its associated hardware. (Enabled by Question 38 - Answer b)

Answer choices (multi-select):

a. Missing parts (nuts, bolts, etc.) or sheer ring not torqued off
b. Insulator broken/worn out
c. Insulator cracked, damaged or loose
d. Insulator chipped
e. Insulator floating
f. Insulator squatting
g. Upward strain (lift) on pin in tangent area

40) Do the insulators connect to the structure using a C or J hook? (Enabled by Question 37 - Answer b, g)

Answer choices (single select):

a. Yes (Notification Required) (Enables Question 41)
b. No
c. Unable to Determine - Missing Photo Angle
d. Unable to Determine - Poor Photo Quality

41) Is there visible wear on the hook or structure where it attaches? (Enabled by Question 40 - Answer a)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No
c. Unable to Determine - Missing Photo Angle
d. Unable to Determine - Poor Photo Quality

42) Is the tie wire in good condition? (Enabled by Question 37 - Answer a, g)

NOTE: Check for Tie Wire broken /loose/coming off the ears of the insulator

Answer choices (single select):

a. Yes
b. No (Notification Required)
c. Component/Equipment not on Structure

d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality

Conductors - Primary

43) Are primary conductors in good condition? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required)

44) Are all tree branches and foliage at least 4ft way from conductors? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 45)
c. Unable to Determine - Missing Photo Angle
d. Unable to Determine - Poor Photo Quality

45) Does it appear imminent that veg may come in contact with the primary level to include conductors, equip, or structure? (Enabled by Question 44 - Answer b)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

46) Is the primary circuit vertical or horizontal construction? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Horizontal
b. Vertical (Enables Question 47)

47) Is there indication of the primary conductor rolling/transposing from vertical-horizontal or horizontal-vertical? (Enabled by Question 46 - Answer b)

Answer choices (single select):

a. Yes
b. No

48) Does the span have the same conductor types (all aluminum or all copper)? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No

49) What type(s) of primary conductors are installed? (Enabled by Question 8 - Answer a, c)

Answer choices (multi-select):

a. Covered/insulated
b. Copper
c. Aluminum
d. Aerial cable

50) Are any conductors smaller than 1/0 or 2 strand copper? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No

51) Indicate if any of the following types of foreign objects are observed. (Enabled by Question 8 - Answer a, c)

Answer choices (multi-select):

a. Metal debris in conductors (Enables Question 51A)
b. Non-metal debris in conductors(Enables Question 51A)
c. No abnormal conditions

51A) Is there a potential phase to phase or phase to ground condition present during a wind event? (Enabled by Question 51 - Answer a, b)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

52) Is there any indication that there is imminent contact of primary conductor with other conductors or public? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

52A) Are there visible signs of tracking or damage on the outer jacket of the covered conductor?

Answer choices (single select):

a. Yes (Notification Required)
b. No

53) Are jumper wires adequately separated and supported to avoid contact or fatigue during high wind events? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required)
c. Component/Equipment not on Structure
d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality

Hardware/Framing - Primary

54) Is the Hardware/Framing in good condition? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 55)

55) Indicate if any of the following types of damaged/abnormal conditions are observed. (Enabled by Question 54 - Answer b)

Answer choices (multi-select):

a. Severely corroded
b. Missing
c. Broken hardware
d. Fuse holders burned
e. Tracking
f. Brackets or braces damaged

Animal Guard - Primary

56) Does all primary equipment have appropriate animal guard installed per SCE DC535 Wildlife Protection Requirements?

Answer choices (single select):

a. Yes
b. No (Enables Question 56)
c. Unable to Determine - Missing Photo Angle
d. Unable to Determine - Poor Photo Quality

57) Indicate which of the following are identified. (Enabled by Question 56 - Answer b)

Answer choices (single select):

a. Burned (Consult Field Specialist)
b. Falling/Fell off (Notification Required)
c. Came apart (Notification Required)
d. Foreign objects inside animal protection (Notification Required)
e. Missing

Guy Wires - Primary

58) How many span guy wires are in parallel with the primary span? (Enabled by Question 8 - Answer a, c)

Answer choices (single select):

a. 0 (Removes Question 59)
b. 1
c. 2
d. 3
e. 4
f. 5
g. 6
h. 7
i. 8
j. 9
k. 10

59) Are any Span Guys cracked, damaged, deflected, frayed, or loose? (Enabled by Question 8 - Answer a, c) (Removed by Question 58 - Answer a)

Answer choices (single select):

a. Yes (Notification Required)
b. No

60) Are existing guy wires appropriately installed? (Enabled by Question 8 - Answer a, c)

NOTE: Select No if guy wire is damaged. Consider Side/Arm Guys as Down Guys. Check all visible attachments of Guy Wire

Answer choices (single select):

a. Yes (Enables Question 61, 62)
b. No (Notification Required) (Enables Question 61, 62)
c. Component/Equipment not on Structure
d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality

61) Are there signs of contact between guy wire and conductors? (Enabled by Question 60 - Answer a, b)

Answer choices (single select):

a. Yes (Notification Required)
b. No

62) What type of Guy Wire attachment is attached at the Primary Structure Level? (Enabled by Question 60 - Answer a, b)

Answer choices (multi-select):

a. Automatic / Bump (Pickle)
b. Pre-Form
c. Other (2-Bolt,3-Bolt, Choker)

Risers/Terminations - Primary

63) Are risers installed at this structure? (Enabled by Question 8 - Answer a, c; and Question 12 – Answer a)

Answer choices (single select):

a. Yes (Enables Question 64)
c. No

64) Indicate if the Pothead shows signs of any of the following conditions in the primary level. (Enabled by Question 63 - Answer a)

Answer choices (multi-select):

a. Pothead not properly attached to supporting structure (Notification Required)
b. Pothead leaking (Notification Required)
c. Pothead arcing (Notification Required)
d. Pothead swollen (Notification Required)
e. Porcelain pothead insulators chipped or broken (Notification Required)
f. In contact with animal nest (Notification Required)
g. Signs of damage or discoloration (Notification Required)
h. No abnormal conditions

Insulators - Secondary

64A) How many insulators are installed at the secondary level? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. 0 (Removes Question 64C)
b. 1
c. 2
d. 3
e. 4
f. 5
g. 6
h. 7
i. 8
j. 9
k. 10
l. 11

m. 12
n. 13
o. 14
p. 15

64B) Is Tie Wire in good condition? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. Yes
b. No (Notification Required)
c. Component/Equipment not on Structure
d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality

64C) Indicate if any of the following types of damaged/abnormal conditions are observed on any portions of the insulator or its associated hardware. (Enabled by Question 8 - Answer b, c) (Removed by Question 64A - Answer a)

Answer choices (multi-select):

a. Missing parts (nuts, bolts, etc.) or sheer rings not torqued off
b. Insulator broken/worn out
c. Insulator cracked, damaged, loose or chipped
d. Insulator floating
e. Insulator squatting
f. Bolt head sheared off
g. No abnormal conditions

Conductors - Secondary

65) What type(s) of secondary conductors are installed? (Enabled by Question 8 - Answer b, c)

Answer choices (multi-select):

a. Open and bare wire (Enables Question 66)
b. Open and insulated wire (WOVEN / WAL) (Enables Question 66)
c. insulated Multiplex with a messenger

66) Are any conductors smaller than 1/0 or 2 strand copper? (Enabled by Question 65 - Answer a, b)

Answer choices (single select):

a. Yes
b. No

67) Are there any foreign materials in the line? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

67A) Are the conductors in good condition? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. Yes
b. No (Notification Required)

68) Indicate if any of the following signs of inadequate clearance distances are observed at this level.

Answer choices (multi-select):

a. Bare conductors in rack construction and through tree (Consult Field Specialist)

b. Tree condition causing significant strain and/or visible abrasion damage - either open wire or triplex (Notification Required)
c. Conductor has less than appropriate radial clearance with contact, no public safety hazard (Notification Required)
d. Immediate danger concerning palm fronds falling or blowing into conductors (Consult Field Specialist)
e. Vines, branches, or foliage presenting an overhang or other imminent threat (Consult Field Specialist)
f. Cannot determine through aerial
g. No abnormal conditions

70) Indicate if any of the following signs of inadequate clearance distances are observed

Answer choices (single select):

a. Tree condition causing significant strain and/or visible abrasion damage — either open wire or triplex (Notification Required)
b. Cannot determine through Aerial
c. No abnormal conditions

Hardware/Framing - Secondary

71) Is the secondary framing in good condition? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. Yes
b. No (Notification Required) (Enables Question 72)

72) Indicate if any of the following types of damaged/abnormal conditions are observed. (Enabled by Question 71 - Answer b)

Answer choices (multi-select):

a. Severely corroded
b. Missing
c. Broken hardware
d. Fuse holders burned
e. Tracking
f. Brackets or braces damaged

Guy Wires - Secondary

73) How many span guy wires are in parallel with the secondary span? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. 0 (Removes Question 74)
b. 1
c. 2
d. 3
e. 4
f. 5

74) Are any Span Guys cracked, damaged, deflected, frayed, or loose? (Enabled by Question 8 - Answer b, c) (Removed by Question 73 - Answer a)

Answer choices (single select):

a. Yes (Notification Required)
b. No

74A) Are existing down guy wires appropriately installed? (Enabled by Question 8 - Answer b, c)

Answer choices (single select):

a. Yes (Enables Question 75, 75A)
b. No (Notification Required) (Enables Question 75, 75A)
c. Component/Equipment not on Structure
d. Unable to Determine - Missing Photo Angle
e. Unable to Determine - Poor Photo Quality

75) Are there signs of contact between guy wire and conductors (arcing marks)? (Enabled by Question74A - Answer a, b)

Answer choices (single select):

a. Yes (Notification Required)
b. No

75A) Is vegetation approaching (within 4 ft.) or in contact above the down guy wire strain insulator? (Enabled by Question 74A - Answer a, b)

a. Yes (Notification Required)
b. No

Public Level

76) Is there at least 10 feet of clearance between vegetation and the base of the pole, up to 8 feet high? (Enabled by Question 8 - Answer a, b, c)

Answer choices (single select):

a. Yes
b. No

77) Are there suspected illegal attachments? (Enabled by Question 8 - Answer a, b, c)

Answer choices (single select):

a. Yes (Consult Field Specialist)
b. No

79) Which of the following generally describes the area surrounding the pole within 100 feet? (Enabled by Question 8 - Answer a, b, c)

Answer choices (multi-select):

a. Vegetation
b. Residential
c. Sand, gravel/rock, or water
d. Concrete and/or Pavement
e. Debris, Trash, or other combustible material
f. Homeless encampment
g. Unable to determine

Notification

80) Notification Needed, if any?

Answer choices (single select):

a. Yes
b. No

Inspection Work Status Comments

Photos

81) Photos required for corrections needed.

Answer choices (single select):

a. Yes
b. No

82) Photos

Answer choices (single select):

a. Photo Type:
b. Pole Tag/Structure Number
c. Brand/Button/Plate
d. Overall Structure
e. Notification
f. Vegetation
g. Unable to Inspect

Inspect App Survey Question Log

EFFECTIVE: MAY 12, 2020

DATA CAPTURE QUESTIONS FOR INSPECTION – V3.9

Contents

Structure Verification

0.000A Are you able to complete the data capture survey?

Answers (single select)

- o Yes
- o No (Note: if user picks survey stops)

0.013 What is the structure type?

Answers (single select)

- o Distribution Pole – ED
- o Transmission / Distribution Pole – EZ
- o Hydro Pole/Communication Only Pole (Note: if user picks survey stops)
- o Distribution Streetlight Pole – EDSL (Note: if user picks survey stops)
- o Transmission Pole – ET (Note: if user picks survey stops)
- o Trans-Telecom Pole – ER (Note: if user picks survey stops))
- o None of the above (Note: if user picks survey stops)

0.004 What is the structure material?

Answers (single select)

- o Wood Pole
- o Composite Pole
- o Steel Pole
- o Tree
- o None of the above (Note: if user picks survey stops)

X.XXX What level exist on this structure?

Answers (multi-select)

- Primary level
- Secondary level
- Communications level
- Public level

X.XXX Take the following photos, vertically and no zoom

- ✓ Take a photo of the entire structure
- ✓ Take a photo of the TOP HALF of the structure
- ✓ Take a photo of the BOTTOM HALF of the structure
- ✓ Take a photo of the structure number

Primary Level

POLES - WOOD (0.017, 0.021A, 0.021B, 0.021C, 0.021D, 0.014G, 1.002)

0.017 Will 6 feet of clearance between conductors and trees remain during wind events?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.021A Indicate which of the following types of non-exempt SWITCH material are present on the pole. *Select all that apply or "None of the above"*.

Answers (multi-select)

- Grasshopper Air Switch
- Solid Blade Disconnect
- In-Line Disconnect
- None of the above

0.021B Indicate which of the following types of non-exempt FUSE material are present on the pole. *Select all that apply or "None of the above".*

Answers (multi-select)

- Universal Fuse
- Enclosed cutout w/universal fuse
- Open Link Fuse
- None of the above

0.021C Indicate which of the following types of non-exempt ARRESTER material are present on the pole. *Select all that apply or "None of the above"*.

Answers (multi-select)

- Surge arrester/Lightning arrester
- Non-porcelain lightning arrester
- None of the above

0.021D Indicate which of the following types of non-exempt CONNECTOR material are present at this level. *Select all that apply or "None of the above".*

Answers (multi-select)

- Hot Line Clamp
- Split Bolt Connector
- LM/Fargo Connector
- None of the above

0.014G How many surge arrester/lightning arresters are installed on this structure?

Answers (single select)

- Answer choices will be 0-10, and 10+

1.002 Indicate if any of the following types of structural failure are observed at this level. *Select all that apply or select "No abnormal conditions"*

Answers (multi-select)

- Hole approximately > 2 inches
- Hole approximately > 2 inches near through bolt
- Three or more holes approximately >2 inch diameter, within approximately 18 inches vertical of a through bolt
- Exterior damage approximately >2 inch depth and approximately > 1/4 pole circumference
- Exterior damage approximately 1–2 inch depth and approximately > 1/4 pole circumference
- No abnormal conditions

POLES - COMPOSITE (0.017, 0.021A, 0.021B, 0.021C, 0.021D, 0.014G)

0.017 Will 6 feet of clearance between conductors and trees remain during wind events?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.021A Indicate which of the following types of non-exempt SWITCH material are present on the pole. Select all that apply or "None of the above".

Answers (multi-select)

- Grasshopper Air Switch
- Solid Blade Disconnect
- In-Line Disconnect
- None of the above

0.021B Indicate which of the following types of non-exempt FUSE material are present on the pole. Select all that apply or "None of the above".

Answers (multi-select)

- Universal Fuse
- Enclosed cutout w/universal fuse
- Open Link Fuse
- None of the above

0.021C Indicate which of the following types of non-exempt ARRESTER material are present on the pole. Select all that apply or "None of the above".

Answers (multi-select)

- Surge arrester/Lightning arrester
- Non-porcelain lightning arrester
- None of the above

0.021D Indicate which of the following types of non-exempt CONNECTOR material are present at this level. Select all that apply or "None of the above".

Answers (multi-select)

- Hot Line Clamp
- Split Bolt Connector
- LM/Fargo Connector
- None of the above

0.014G How many surge arrester/lightning arresters are installed on this structure?

Answers (single select)

- Answer choices will be 0-10, and 10+

OVERHEAD TRANSFORMERS (0.014C, 3.001, 3.002, 3.003, 3.004)

0.014C How many overhead transformers are installed on this structure?

Answers (single select)

- Answer choices will be 0, 1, 2, 3

3.001 Indicate if any of the following signs of transformer oil leakage or weepage are observed. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area
- Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area
- One fuse is open/down
- Bushings damaged
- Blown fuse
- Signs of burn
- Signs of swelling
- Oil weepage indicated by oily film on tank surface
- Red flag fault indicator is visible
- No abnormal conditions

3.002 Indicate if transformer has any of the following conditions at the time of inspection. Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Brackets damaged
- Scott Brackets fiberglass pads present
- Visibly loose hardware
- Secondary leads in contact with the case
- Secondary leads are bare
- Transformers are humming
- Blown fuse
- Loose wires
- In contact with animal nest
- No abnormal conditions

3.003 Is the transformer showing any of the following signs of rust or corrosion?

Answers (multi-select)

- o Rust or corrosion compromising equipment integrity
- o Light surface rust or corrosion
- o No abnormal conditions

3.004 Are animal guards installed, intact, and adequately covering all transformers?

Answers (single select)

- o Yes
- o No

OVERHEAD CAPACITORS (0.014D, 4.001, 4.002. 4.003)

0.014D How many overhead capacitors are installed on thisstructure?

Answers (single select)

- Answer choices will be 0, 1, 2, 3

4.001 Indicate if any capacitor or associated equipment shows signs of the following conditions. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Ruptured or severely bulged capacitor units
- Capacitor bank damaged, not functioning
- Catastrophic or severely damaged capacitor switches, safety or reliability issue
- Capacitor switches not secure, damaged, not functioning
- Capacitor controller damaged
- One fuse is open/down
- Bushings damaged
- Capacitor is humming
- Blown fuse
- Signs of burn
- Signs of swelling
- Loose wires
- PT Transformer rusted/damaged
- In contact with animal nest
- No abnormal conditions

4.002 Indicate if any of the following types of capacitor oil leakage or weepage are observed. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Capacitor units leaking, oil reaches ground or public access or environmentally sensitive area
- Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area
- Oil weepage indicated by oily film on capacitor unit surface (not capacitor switches)
- No abnormal conditions

4.003 Has the capacitor equipment (i.e. fuses) broken down to a single phase condition with bank still energized?

Answers (single select)

- o Yes
- o No

CROSSARMS - WOOD (0.014H, 2.003A, 2.003C, 2.004A, 2.005B, 2.006A, 2.007A)

0.014H How many total crossarms are at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.003A How many crossarms at this level are bowed/twisted?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.003C How many crossarms at this level are deteriorated?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.004A How many crossarms at this level are canted?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.005B How many crossarms at this level are tracking?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.006A How many crossarms at this level have damaged braces?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.007A How many crossarms at this level have damaged insulators?

Answers (single select)

- Answer choices will be 0-10, and 10+

2.003B For bowed/twisted crossarms – Which of the following signs of bowing/twisting are observed at this level? *Select all that apply or select "No abnormal conditions"*.

Answers (multi-select)

- Crossarm bowed approximately >5 inches and splintering
- Crossarm bowed approximately >5 inches without splintering
- Significant damage at a bolt
- No abnormal conditions

2.006B For crossarms with brace damage – Which of the following brace damages are observed at this level at the time of inspection? *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Braces broken
- Braces loose
- Braces missing
- No abnormal conditions

CROSSARMS - COMPOSITE (0.014H, 7.002A, 7.002B, 7.004A)

0.014H How many total crossarms are at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

7.002A How many crossarms at this level show signs of bending?

Answers (single select)

- Answer choices will be 0-10, and 10+

7.002B For bending crossarms – Which of the following signs of crossarm bending observed at this level?

Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Significant visual fracturing
- Significant visual buckling
- Significantly unbalanced due to tension
- Bent mounting bracket and associated hardware
- No abnormal conditions

7.004A How many crossarms at this level are physically damaged?

Answers (single select)

- Answer choices will be 0-10, and 10+

INSULATORS (0.014A, 6.001, 6.002, 6.003, 6.004)

0.014A How many insulators are installed at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

6.001 What types of insulators are installed at this level?

Answers (multi-select)

- Porcelain
- Polymer
- Hendrix Universal
- Hendrix (vice-top)
- Other

6.002 Are any insulators at this level missing parts (nuts, bolts, etc.)?

Answers (single select)

- o Yes
- o No

6.003 Indicate if any of the following types of damage are observed on any portions of the insulator or its associated hardware. *Select all that apply, or select "No abnormal conditions."*

Answers (multi-select)

- Insulator broken
- Insulator cracked, damaged or loose
- Insulator chipped
- Insulator floating
- Insulator squatting
- Tie wire broken/missing/damaged or loose
- No abnormal conditions

6.004 Are any top/side tie insulators at this level touching a crossarm?

Answers (single select)

- o Yes
- o No

CONDUCTORS - PRIMARY (0.014B, 0.016, 0.026A, 0.026B, 0.026C, 8.000 series)

0.014B How many phases are installed at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

0.016 What is the clearance distance between trees/foliage and primary conductors?

Answers (single select)

- o 2 feet or less
- o Between 2 feet and 6 feet
- o 6 feet to 10 feet
- o Greater than 10 feet
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.026A Is the primary circuit horizontal or vertical construction?

Answers (multi-select)

- Horizontal construction
  Vertical construction

0.026A Is there any indication of the primary conductor rolling/transposing from vertical-to-horizontal or horizontal-to-vertical?

Answers (single select)

- o Yes
- o No

0.026 For rolling/transposing primary conductor – Is there at least 12 inches of clearance between conductors?:

Answers (single select)

- o Yes
- o No

8.009 What type(s) of primary conductors are installed? *Select all that apply or select "None of the above"*

Answers (multi-select)

- Covered/insulated
- Copper
- ACSR
- Aerial cable
- None of the above

8.006 Which of the following estimated sizes of primary conductors are on the span? *Select all that apply or select "None of the above".*

Answers (multi-select)

- 4 ACSR
- 1/0 ACSR
- 2 ACSR
- 336 ACSR
- 653 ACSR
- 4/0 ACSR
- 2/0 Copper
- 2 Solid Copper
- 4 Solid Copper
- 6 Solid Copper
- None of the above

8.007A **INSPECT APP:** For copper primary conductors – Is the span length greater than 240 feet?

Answers (single select)

- o No, and line spacers are installed
- o No, and line spacers are not installed
- o Yes, and line spacers are installed.
- o Yes, and line spacers are not installed.
- o N/A – primary conductors are not copper

8.007B For ACSR primary conductors – Is the span length greater than 240 feet?

Answers (single select)

- o No, and line spacers are installed
- o No, and line spacers are not installed
- o Yes, and line spacers are installed.
- o Yes, and line spacers are not installed.
- o N/A – primary conductors are not ACSR

8.011 How many automatic (bump) splices are in the primary level?

Answers (single select)

- Answer choices will be 0-10, and 10+

8.012 How many preform splices are in the primary level?

Answers (single select)

- Answer choices will be 0-10, and 10+

8.013 How many compression splices are in the primary level?

Answers (single select)

- Answer choices will be 0-10, and 10+

8.014 For covered conductor – select all applicable directions covered conductor is installed?

Answers (multi-select)

- North
- South
- East
- West
- No covered conductor installed

8.015 For covered conductor – indicate if any of the following covered conductor covers are missing

Answers (multi-select)

- Dead-end cover
- Any bare
- Connector cover
- Fuse cover
- Lightning arrestor cover
- Equipment bushing cover
- Pothead cover
- No missing covered conductor cover

8.005 Does the span have the same primary conductor types?

Answers (single select)

- o Yes
- o No

8.008 <u>For slack spans only</u> – Does the span have primary conductor spacers?

Answers (single select)

- No slack span present
- Yes
- No

8.001 Indicate if any of the following types of foreign objects are observed. *Select all that apply or select "No abnormal conditions"*

Answers (multi-select)

- Metal debris in conductors
- Non-metal debris in conductors
- No abnormal conditions

8.002A Are there inadequate clearance distances observed? *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Vegetation arcing or in contact with energized conductor
- Immediate danger concerning palm fronds falling or blowing into conductors
- Vines, branches or foliage presenting an overhang or other imminent threat
- No abnormal conditions
- Defer question to SCE Inspector – Item outside of Contractor Scope of Work

8.002B Are there estimated inadequate clearance distances between energized conductors and other structures observed? *Select all that apply or select "No abnormal conditions"*.

Answers (multi-select)

- Conductor located above a building, and is vertically less than 12 feet from top surface of building (commonly roof)
- Conductor NOT located above building, but is vertically is less than 12 feet from top surface of building (commonly roof)
- Less than 6 feet horizontally between conductor and any surface of a building
- Less than 6 feet radially between conductor and non-climbable pole (streetlight)
- No abnormal conditions

8.016 Indicate if any of the following types of conductor, span, and/or guy wire issues identified on the pole will create conductor clash. *Select all that apply or select "No abnormal conditions"*

Answers (multi-select)

- Slack primary conductor
- Span guy
- Down Guy
- Encroachment primary conductor with span/down guy
- Encroachment bare secondary conductor with span/down guy
- No abnormal conditions

8.010 If covered conductor is installed, are there visible signs of tracking or damage on the outer jacket?

Answers (single select)

- o Yes
- o No
- o N/A - this pole does not support primary covered conductor

RECLOSERS, PE GEAR, REGULATORS, SECTIONALIZERS (10.002, 10.004, 10.006)

10.002 Indicate if animal guards are missing from any of the following types of apparatus equipment. *Select all that apply or select "No animal guards missing".*

Answers (multi-select)

- Reclosers
- PE Gear
- Regulators
- Sectionalizers
- No animal guards missing

10.004 Indicate if any of the following types of oil leakage or weepage are observed. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area
- Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area
- No abnormal conditions

10.006 Are trees or vegetation interfering with operation of any reclosers, PE gear, regulators, or sectionalizers?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

HARDWARE/FRAMING (11.001, 11.002, 11.003)

11.001 Is there any corroded, missing, broken, or bending hardware at this level?

Answers (single select)

- o Yes
- o No

11.002 Are any fuse holders burned or tracking?

Answers (single select)

- o Yes
- o No

11.003 Are any equipment brackets or braces damaged at this level?

Answers (single select)

- o Yes
- o No

SPAN GUYS (0.014E, 12.001, 12.002, 12.003)

0.014E How many span guys are installed at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

12.001 Are any span guys cracked, damaged, deflected, frayed, or loose?

Answers (single select)

- o Yes
- o No

12.002 Is there inadequate clearance between span guy and any of the following? *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- SCE Energized components
- SCE non-energized electrical components
- Communication facilities
- Other
- No abnormal conditions

12.003 Are any span guys sagging or extremely slack?

Answers (single select)

- o Yes
- o No

DOWN GUYS (13.001B)

13.001B Are there signs of contact between guy wire and conductors (arcing marks)?

Answers (single select)

- o Yes

- No

RISER/TERMINATIONS (14.001, 14.002)

14.001 Are there any signs of damage such as discoloration on the Riser/Pothead?

Answers (single select)

- Yes
- No

14.002 Indicate if the Pothead shows signs of any of the following conditions in the primary level. *Select all that apply or select "No abnormal conditions"*

Answers (multi-select)

- Pothead not properly attached to supporting structure
- Pothead leaking
- Pothead sparking, arcing, or noisy during normal 'dry' weather conditions
- Pothead swollen
- Porcelain pothead insulators chipped or broken
- In contact with animal nest
- No abnormal conditions

Secondary Level

POLES - WOOD (0.017, 1.002, 0.021E)

0.017 Will 6 feet of clearance between conductors and trees remain during wind events?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

1.002 Indicate if any of the following types of structural failure are observed at this level. Select all that apply or select "No abnormal conditions"

Answers (multi-select)

- Hole approximately > 2 inches
- Hole approximately > 2 inches near through bolt
- Three or more holes approximately >2 inch diameter, within approximately 18 inches vertical of a through bolt
- Exterior damage approximately >2 inch depth and approximately > 1/4 pole circumference
- Exterior damage approximately 1–2 inch depth and approximately > 1/4 pole circumference
- No abnormal conditions

0.021E Indicate which of the following types of non-exempt CONNECTOR material are present at this level. *Select all that apply or "None of the above"*.

Answers (multi-select)

- o Split Bolt Connector
- o LM/Fargo Connector
- o None of the above

POLES – COMPOSITE (0.017, 0.021E)

0.017 Will 6 feet of clearance between conductors and trees remain during wind events?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.021E Indicate which of the following types of non-exempt CONNECTOR material are present at this level. Select all that apply or "None of the above".

Answers (multi-select)

- o Split Bolt Connector
- o LM/Fargo Connector
- o None of the above

CROSSARMS – WOOD (0.014H, 2.003A, 2.003C, 2.004A, 2.005B, 2.006A, 2.007A, 2.006B)

0.014H How many total crossarms are at this level?

Answers (single select)
- Answer choices will be 0-10, and 10+

2.003A How many crossarms at this level are bowed/twisted?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.003C How many crossarms at this level are deteriorated?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.004A How many crossarms at this level are canted?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.005B How many crossarms at this level are tracking?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.006A How many crossarms at this level have damaged braces?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.007A How many crossarms at this level have damaged insulators?
Answers (single select)
- Answer choices will be 0-10, and 10+

2.003B For bowed/twisted crossarms – Which of the following signs of bowing/twisting are observed at this level? *Select all that apply or select "No abnormal conditions"*.
Answers (multi-select)
- Crossarm bowed approximately >5 inches and splintering
- Crossarm bowed approximately >5 inches without splintering
- Significant damage at a bolt
- No abnormal conditions

2.006B For crossarms with brace damage – Which of the following brace damages are observed at this level at the time of inspection? *Select all that apply or select "No abnormal conditions".*
Answers (multi-select)
- Braces broken
- Braces loose
- Braces missing
- No abnormal conditions

CROSSARMS – COMPOSITE (0.014H, 7.002A, 7.002B, 7.004A)

0.014H How many total crossarms are at this level?
Answers (single select)

- Answer choices will be 0-10, and 10+
-

7.002A How many crossarms at this level show signs of bending?

Answers (single select)

- Answer choices will be 0-10, and 10+

7.002B For bending crossarms – Which of the following signs of crossarm bending observed at this level?

Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Significant visual fracturing
- Significant visual buckling
- Significantly unbalanced due to tension
- Bent mounting bracket and associated hardware
- No abnormal conditions

7.004A How many crossarms at this level are physically damaged?

Answers (single select)

- Answer choices will be 0-10, and 10+

INSULATORS (0.014A, 6.001, 6.002, 6.003, 6.004)

0.014A How many insulators are installed at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

6.001What types of insulators are installed at this level?

Answers (multi-select)

- Porcelain
- Polymer
- Hendrix Universal
- Hendrix (vice-top)
- Other

6.002 Are any insulators at this level missing parts (nuts, bolts, etc.)?

Answers (single select)

o Yes

o No

6.003 Indicate if any of the following types of damage are observed on any portions of the insulator or its associated hardware. Select all that apply, or select "No abnormal conditions."

Answers (multi-select)

- Insulator broken
- Insulator cracked, damaged or loose
- Insulator chipped
- Insulator floating
- Insulator squatting
- Tie wire broken/missing/damaged or loose

- No abnormal conditions

6.004 Are any top/side tie insulators at this level touching a crossarm?

Answers (single select)

- Yes
- No

CONDUCTORS – SECONDARY (0.014I, 9.000 series)

0.014IHow many phases are installed at this level? *(multi-plex is counted as 1 phase)*

Answers (single select)

- Answer choices will be 0-10, and 10+

9.006 What type(s) of secondary conductors are installed? Select all that apply or select "None of the above".

Answers (multi-select)

- Open wire
- Covered
- Multiplex
- No secondary conductors present

9.005 Which of the following sizes of secondary conductors are on the span? *Select all that apply or select* "None of the above".

Answers (multi-select)

- 4 Solid Copper
- 6 Solid Copper
- 4 ACSR
- None of the above

9.007A Is the span length for copper secondary conductors greater than 240 feet?

Answers (single select)

- Yes
- No
- No Copper

9.007B Is the span length for ACSR secondary conductors greater than 240 feet?

Answers (single select)

- Yes
- No
- No ACSR

9.008 How many automatic (bump) splices are in the secondary level?

Answers (single select)

- Answer choices will be 0-10, and 10+?

9.009 How many preform splices are in the secondary level?

Answers (single select)

- Answer choices will be 0-10, and 10+?

9.010 How many compression splices are in the secondary level?

Answers (single select)

- Answer choices will be 0-10, and 10+?

9.001 Are there any foreign materials in the lines?

Answers (single select)

- o Yes
- o No

9.003 Which of the following inadequate clearances are observed at this level at the time of inspection.

Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Bare conductors in rack construction and through tree (Defer question to SCE Inspector– Item outside of Contractor Scope of Work)
- Tree condition causing significant strain and/or visible abrasion damage – either open wire or Triplex (Defer question to SCE Inspector – Item outside of Contractor Scope of Work)
- Conductor has less than appropriate radial clearance with contact, no public safety hazard
- Immediate danger concerning palm fronds falling or blowing into conductors (Defer question to SCE Inspector – Item outside of Contractor Scope of Work)
- Vines, branches, or foliage presenting an overhang or other imminent threat (Defer question to SCE Inspector – Item outside of Contractor Scope of Work)
- No abnormal conditions

9.004 Indicate if any of the following types of part damage are observed. Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Conductors not in good condition, broken, missing
- Tie wire broken/missing/damaged or loose
- No abnormal conditions

RECLOSERS, PE GEAR, REGULATORS, SECTIONALIZERS (10.002, 10.004, 10.006)

10.002 Indicate if animal guards are missing from any of the following types of apparatus equipment. Select all that apply or select "No animal guards missing".

Answers (multi-select)

- Reclosers
- PE Gear
- Regulators
- Sectionalizers
- No animal guards missing

10.004 Indicate if any of the following types of oil leakage or weepage are observed. Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area
- Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area
- No abnormal conditions

10.006 Are trees or vegetation interfering with operation of any reclosers, PE gear, regulators, or sectionalizers?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

HARDWARE/FRAMING (11.001, 11.003)

11.001 Is there any corroded, missing, broken, or bending hardware at this level?

Answers (single select)

- o Yes
- o No

11.003 Are any equipment brackets or braces damaged at this level?

Answers (single select)

- o Yes
- o No

SPAN GUYS (0.014E, 12.001, 12.002, 12.003)

0.014E How many span guys are installed at this level?

Answers (single select)

- Answer choices will be 0-10, and 10+

12.001 Are any span guys cracked, damaged, deflected, frayed, or loose?

Answers (single select)

- o Yes
- o No

12.002 Is there inadequate clearance between span guy and any of the following? Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- SCE Energized components
- SCE non-energized electrical components
- Communication facilities
- Other
- No abnormal conditions

12.003 Are any span guys sagging or extremely slack?

Answers (single select)

- o Yes
- o No

DOWN GUYS (13.001B)

13.001B Are there signs of contact between guy wire and conductors (arcing marks)?

Answers (single select)

- Yes
- No

RISER/TERMINATIONS (14.003)

14.003 Indicate if any of the following Riser conditions are observed on the structure. Select all that apply or select “No abnormal conditions”.

Answers (multi-select)

- Cables in Riser exposed
- Non-Schedule 80 Riser installed
- Riser broken
- Riser swollen
- In contact with animal nest
- No abnormal conditions

SERVICE DROPS (15.001, 15.004)

15.001 What type of service drops are installed?

Answers (multi-select)

- Aluminum
- Copper
- 2 wire
- 3 wire
- 4 wire
- No service present

15.004 Indicate if any of the following inadequate clearances are observed at the time of inspection.

Select all that apply or select “No abnormal conditions”.

Answers (multi-select)

- Tree condition causing significant strain and/or visible abrasion damage — either open wire or Triplex (Defer question to SCE Inspector – Item outside of Contractor Scope of Work)
- Mid-span service clearance not maintained
- Does not meet G.O. 95 vertical clearances
- No abnormal conditions

Communications Level

POLES – WOOD (0.020B, 0,025)

0.020B Is there adequate climbing space at this level?

Answers (single select)

- o Yes
- o No

0.025 Are there communications lines installed on this structure?

Answers (single select)

- o Yes
- o No

1.002 Indicate if any of the following types of structural failure are observed at this level. Select all that apply or select "No abnormal conditions"

Answers (multi-select)

- Hole approximately > 2 inches
- Hole approximately > 2 inches near through bolt
- Three or more holes approximately >2 inch diameter, within approximately 18 inches vertical of a through bolt
- Exterior damage approximately >2 inch depth and approximately > 1/4 pole circumference
- Exterior damage approximately 1–2 inch depth and approximately > 1/4 pole circumference
- No abnormal conditions

POLES – COMPOSITE (0.020B, 0.025)

0.020B Is there adequate climbing space at this level?

Answers (single select)

- o Yes
- o No

0.025 Are there communications lines installed on this structure?

Answers (single select)

- o Yes
- o No

RECLOSERS, PE GEAR, REGULATORS, SECTIONALIZERS (10.006)

10.006 Are trees or vegetation interfering with operation of any reclosers, PE gear, regulators, or sectionalizers?

Answers (single select)

- o Yes
- o No
- o Defer question to SCE Inspector – Item outside of Contractor Scope of Work

Public Level

POLES – WOOD (0.005A, 0.005B, 0.008, 0.009, 0.020B, 0.022, 0.024, 0.027, 1.002, 11.007, 1.008)

0.005A Does pole number in the app match the structure number on the structure that you are inspecting?

Answers (single select)

- Yes
- No
- No structure number present
- Cannot access

0.005B Is the structure number the yellow and black style?

Answers (single select)

- Yes
- No
- No structure number present

0.008 Is the circular pole medallion present?

Answers (single select)

- Yes
- No
- Cannot access

0.009 Is the pole brand visible?

Answers (single select)

- Yes
- No
- Cannot access

0.020B Is there adequate climbing space at this level?

Answers (single select)

- Yes
- No

0.022 If Non-Exempt material is present on the pole, is there at least 10 feet of clearance between vegetation and the base of the pole, up to 8 feet high?

Answers (single select)

- Yes
- No
- No non-exempt material present on pole
- Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.024 Indicate which of the following defects are present on or around the structure. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Burn marks
- Corrosion
- Contamination
- Unauthorized attachment
- Debris (Dirt, water, trash)
- No abnormal conditions

0.027 Which of the following generally describes the area surrounding the pole within 100 feet?

Answers (multi-select)

- Vegetation (Defer this question to SCE Inspector – Item outside of Contractor Scope of Work)
- Residential or Commercial Area/Structures
- Only sand, gravel/rock, or water
- Concrete and/or Pavement

1.002 Indicate if any of the following types of structural failure are observed at this level. Select all that apply or select “No abnormal conditions”

Answers (multi-select)

- Hole approximately > 2 inches
- Hole approximately > 2 inches near through bolt
- Three or more holes approximately >2 inch diameter, within approximately 18 inches vertical of a through bolt
- Exterior damage approximately >2 inch depth and approximately > ¼ pole circumference
- Exterior damage approximately 1–2 inch depth and approximately > ¼ pole circumference
- No abnormal conditions

1.004 Indicate if there are any of the following types of construction faults. Select all that apply or select “No abnormal conditions”.

Answers (multi-select)

- Exposed decay pocket at ground line where part of shell is gone
- Evidence of soil erosion around base of pole
- No abnormal conditions

1.007 Indicate if the pole is showing any of the following signs of pole lean. Otherwise, select “Pole not leaning.

Answers (single select)

- Pole leaning - public hazard
- Pole leaning more than 1 foot per 10 feet of pole height
- Pole leaning less than 1 foot per 10 feet of pole height
- Pole not leaning

1.008 Indicate if there are animal nests on any of the following equipment on the structure? *Select all that apply or select “No animal nests observed”*

Answers (multi-select)

- Crossarm
- Switch
- Recloser
- No animal nests present

POLES - COMPOSITE (0.005A, 0.005B, 0.008, 0.009, 0.022, 0.024, 0.027, 5.001, 5.003, 5.005)

0.005A Does pole number in the app match the structure number on the structure that you are inspecting?

Answers (single select)

- Yes
- No
- No structure number present
- Cannot access

0.005B Is the structure number the yellow and black style?

Answers (single select)

- Yes
- No
- No structure number present

0.008 Is the circular pole medallion present?

Answers (single select)

- Yes
- No

0.009 Is the pole brand visible?

Answers (single select)

- Yes
- No

0.022 If Non-Exempt material is present on the pole, is there at least 10 feet of clearance between vegetation and the base of the pole, up to 8 feet high?

Answers (single select)

- Yes
- No
- No non-exempt material present on pole
- Defer question to SCE Inspector – Item outside of Contractor Scope of Work

0.024 Indicate which of the following defects are present on or around the structure. Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Burn marks
- Corrosion
- Contamination
- Unauthorized attachment
- Debris (Dirt, water, trash)
- No abnormal conditions

0.027 Which of the following generally describes the area surrounding the pole within 100 feet?

Answers (multi-select)

- Vegetation (Defer this question to SCE Inspector – Item outside of Contractor Scope of Work)
- Residential or Commercial Area/Structures
- Only sand, gravel/rock, or water
- Concrete and/or Pavement

5.001 Indicate if any of the following types of structural damage are observed on the pole. *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- Fracture or buckling of exterior wall
- Deterioration
- Bending
- Leaning
- Vandalism that affects the structural integrity (i.e. gun damage)
- Missing guy wire
- Depth of embedment less than 10% + 2 feet of the pole height
- No abnormal conditions

5.003 Indicate if any of the following signs of overloading are observed on the pole. *Select all that apply* or select "No abnormal conditions".

Answers (multi-select)

- Excessive lean (approximately 10% or more of the pole height), caused by erosion of soil at groundline or
- Excessive lean not caused by erosion of soil
- Leaning at the top of pole greater than approximately 5% of the height of the pole above ground with equipment (i.e. transformers, capacitors, etc.)
- Bowing of the pole at or near the mid-height due to from guys
- No abnormal conditions

5.005 Indicate if there are animal nests on any of the following equipment on the structure? *Select all that apply or select "No animal nests observed"*

Answers (multi-select)

- Crossarm
- Switch
- Recloser
- No nests present

POLES - STEEL (0.005A, 0.005B, 0.027)

0.005A Does pole number in the app match the structure number on the structure that you are inspecting?

Answers (single select)

- Yes
- No
- No structure number present
- Cannot access

0.005B Is the structure number the yellow and black style?

Answers (single select)

- Yes
- No
- No structure number present

If answer is Yes or No:
PHOTO: Take photo of structure number
Instructions: Portrait format, no zoom, standing less than 2 feet from pole, filling more than 75% of viewing screen

0.027 Which of the following generally describes the area surrounding the pole within 100feet?
Answers (multi-select)

- Vegetation (Defer this question to SCE Inspector – Item outside of Contractor Scope of Work)
- Residential or Commercial Area/Structures
- Only sand, gravel/rock, or water
- Concrete and/or Pavement

TREES (0.005A, 0.005B, 0.027)

0.005A Does pole number in the app match the structure number on the structure that you are inspecting?
Answers (single select)

- Yes
- No
- No structure number present
- Cannot access

0.005B Is the structure number the yellow and black style?
Answers (single select)

- Yes
- No
- No structure number present

If answer is Yes or No:
PHOTO: Take photo of structure number
Instructions: Portrait format, no zoom, standing less than 2 feet from pole, filling more than 75% of viewing screen

0.027 Which of the following generally describes the area surrounding the pole within 100feet?
Answers (multi-select)

- Vegetation (Defer this question to SCE Inspector – Item outside of Contractor Scope of Work)
- Residential or Commercial Area/Structures
- Only sand, gravel/rock, or water
- Concrete and/or Pavement

DOWN GUYS (0.014F, 13.001A, 13.0001B, 13.002, 13.003)

0.014F How many SCE down guys are installed on this structure?

Answers (single select)

- o Answer choices will be 0-10, and 10+

13.001A Indicate if any of the following types of damage to down guys are observed.

*Select all that apply **OR** select "No abnormal conditions".*

Answers (multi-select)

- Guys broken/missing/damaged, pole leaning, public hazard
- Guys broken/missing/damaged, pole not leaning
- Anchor rods broken/missing/rusted, pole leaning, public hazard
- Anchor rods broken/missing/rusted, pole not leaning
- No abnormal conditions

13.002 Is there inadequate clearance between down guy and any of the following? *Select all that apply or select "No abnormal conditions".*

Answers (multi-select)

- SCE Energized components
- SCE non-energized electrical components
- Communication facilities
- Other
- No abnormal conditions

13.003 Are down guy wires sagging or extremely slack?

Answers (single select)

- o Yes
- o No

RISER/TERMINATIONS (14.003)

14.003 Indicate if any of the following Riser conditions are observed on the structure. Select all that apply or select "No abnormal conditions".

Answers (multi-select)

- Cables in Riser exposed
- Non-Schedule 80 Riser installed
- Riser broken
- Riser swollen
- In contact with animal nest
- No abnormal conditions

Survey123 Training for Long Span Inspectors

for EOI / OCI

Hard copy is not controlled. Obtain latest versions from the portal:
T&D Training > Technology Integration > OCI Distribution

Table of Contents

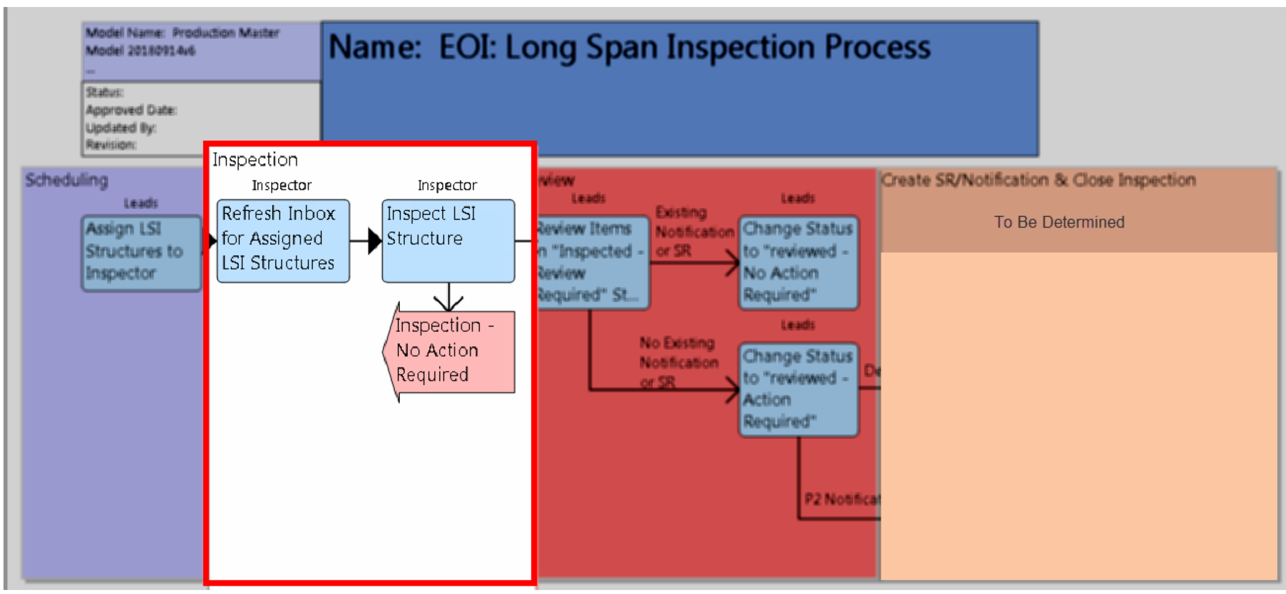
Introduction

The Long Span Inspection Survey123 Form will eliminate paper for this inspection process. Think of this as a digital inspection form.

NOTE: These screenshots were taken on a laptop. The screens may look slightly different from what you see on your iPad.

Overview

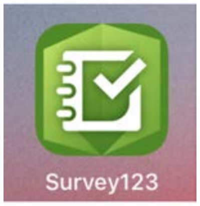
EOI: Long Span Inspection Process



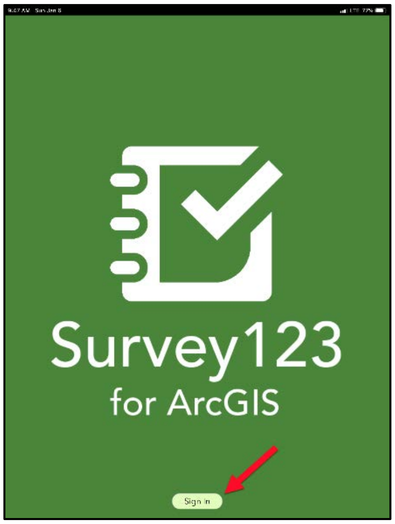
Logging In

NOTE: If you are logging in to Survey123 for the first time, see the job aid, *How to Log Into Survey123 on Your SCE iPad for the First Time*.

1. On your iPad, find the ***Survey123*** app. If you don't see it on the first screen, swipe left or right to check other screens.



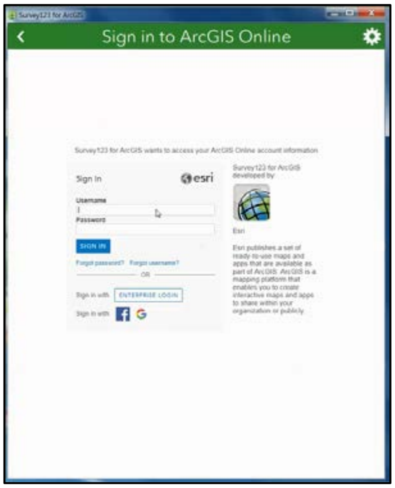
2. Tap once on the ***Survey123*** icon to launch the app.
3. When the app opens, tap **Sign In**.



4. Enter in your **ArcGIS Username** and **Password**.
    - If you have forgotten your password, tap **Forgot password?** and request that it be reset.

NOTE: The app will remember your Username and Password. The only time you will need to log out is if you are sharing the iPad with another user in your district.

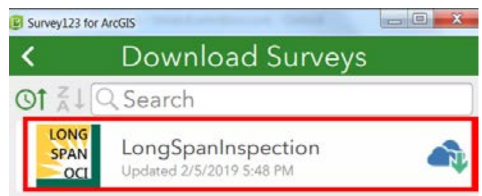
5. Tap **Sign In**.



When you log into *Survey123* for the first time, you will not see any surveys on your device because none have been downloaded yet.

2. Tap **Get Surveys.**

3. Tap the icon for the ***LongSpanInspection*** survey.

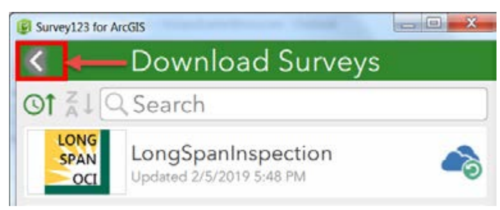


The app will download the Long Span Inspection survey form.

4. Once the download is complete, tap **Ok**.

The Download Surveys screen displays and the  *icon next to the LongSpanInspection form appears.*

5. Tap the **back arrow <** in the upper left corner next to Download Surveys to return to the home screen.



The Long Span Inspection survey now appears in My Surveys.

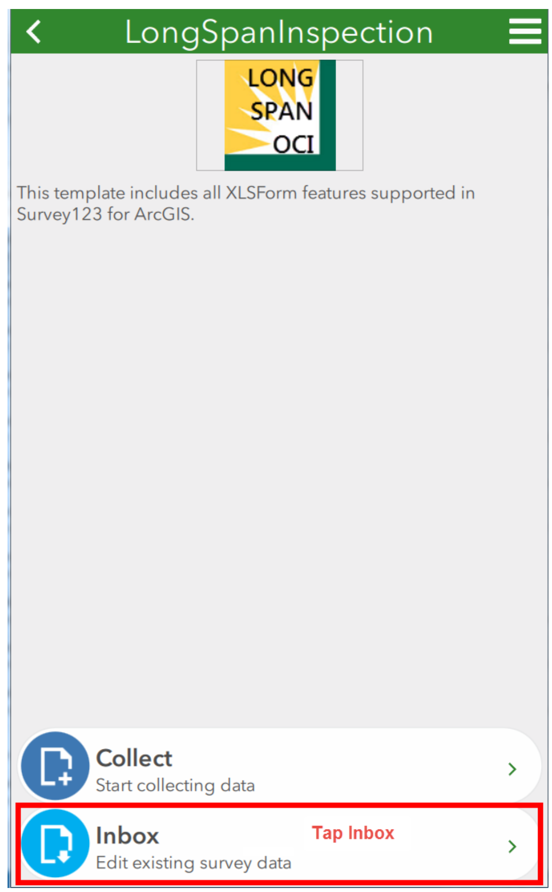
6. Tap the ***Long Span OCI*** icon.

The Long Span Inspection form displays with the Collect and Inbox folders.

Accessing Inspections through the Inbox

All inspections assigned for completion will appear in the Inbox.

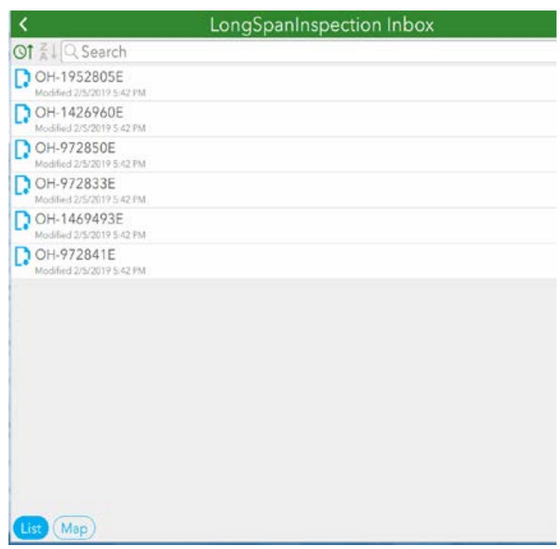
1. Tap the **Inbox** icon at the bottom of the screen.



2. The first time you log in, the Inbox will be empty. Tap **Refresh** in the lower right corner.

A list of all the inspections that have been assigned to you will be displayed in the ***List*** view.

You also have the option to view the assigned inspections in ***Map*** view.



Map View

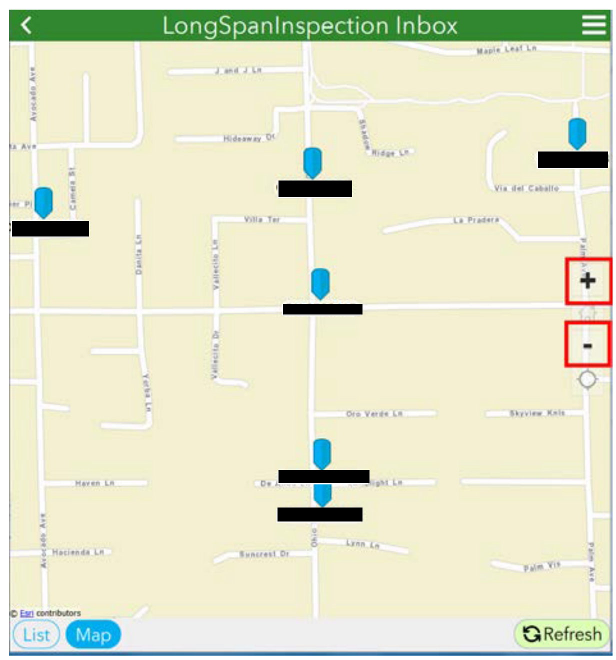
3. Tap **Map** to view the structures on a map.

The World Street map opens and the structures display in blue along with the structure numbers.

NOTE: If you have cellular service and are connected to the internet, new inspections may be pushed to your device and will automatically be added to your list. You will need to tap Refresh at the bottom right of the screen.

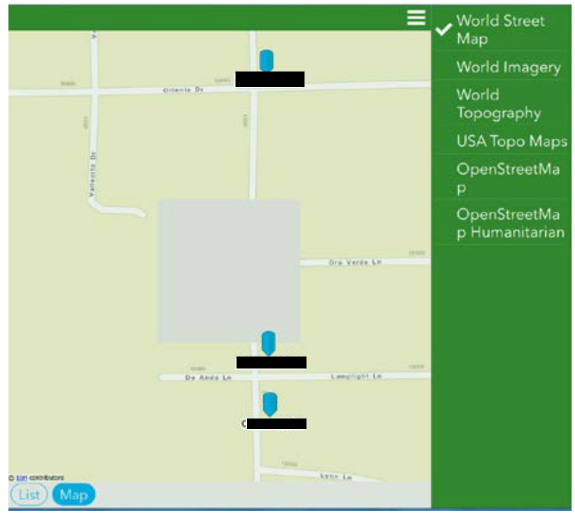
Structures assigned to you for inspection appear as blue diamonds.

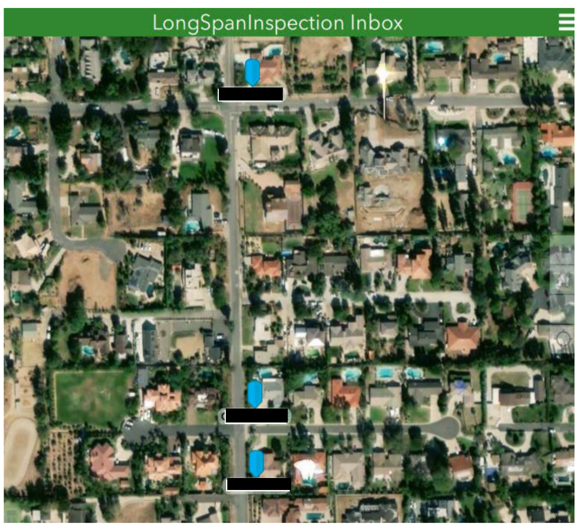
To zoom in on the map, you can pinch and drag or double-tap **+** or **--** on map.



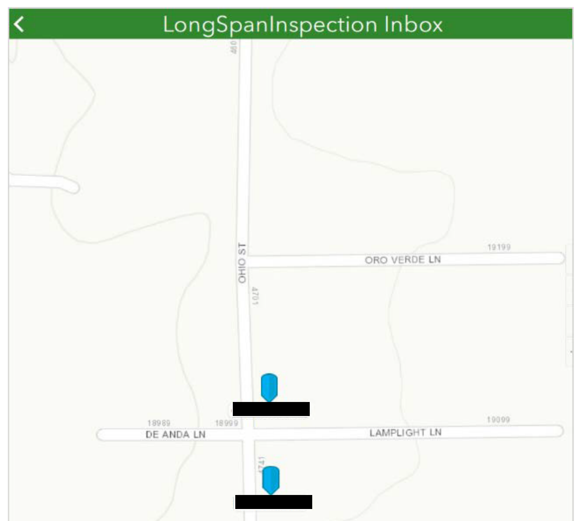
There are five other map view options:

- World Imagery
- World Topography
- USA Topo Maps
- Open Street Map
- Open Street Map Humanitarian

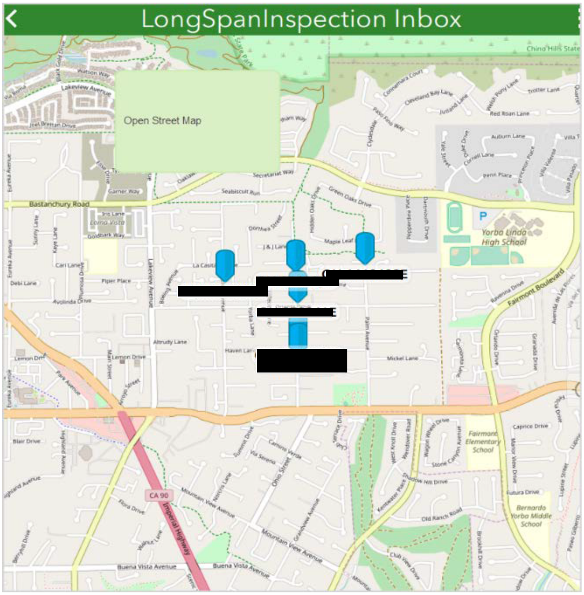




World Imagery Map

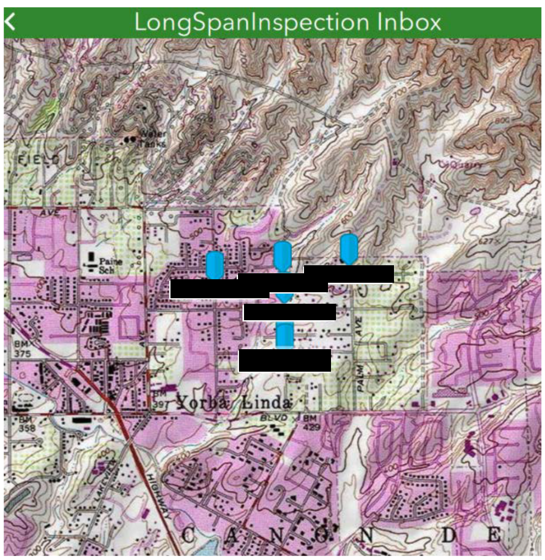


World Topography



USA Topo Maps

Open Street Map



Open Street Map Humanitarian

4. Tap on a structure (either in the list or on the map) to begin the inspection.

The Inspection form opens.

NOTE: Once you begin an inspection, the structure will disappear off the list in your Inbox and off the map.

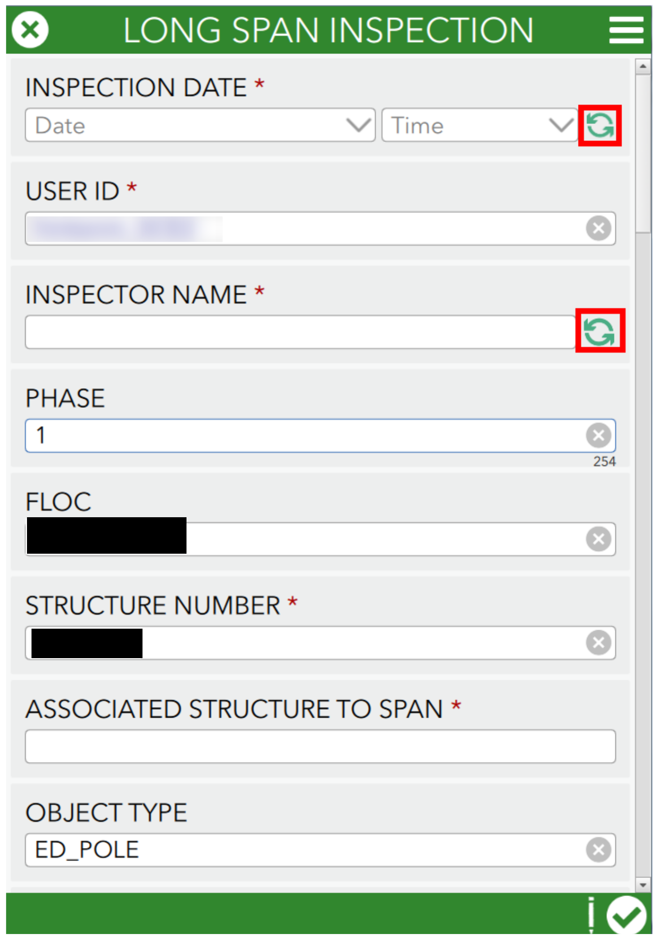
Completing the Inspection Form

Many of the fields, such as Phase, FLOC, Structure Number, etc., have been pre-populated.

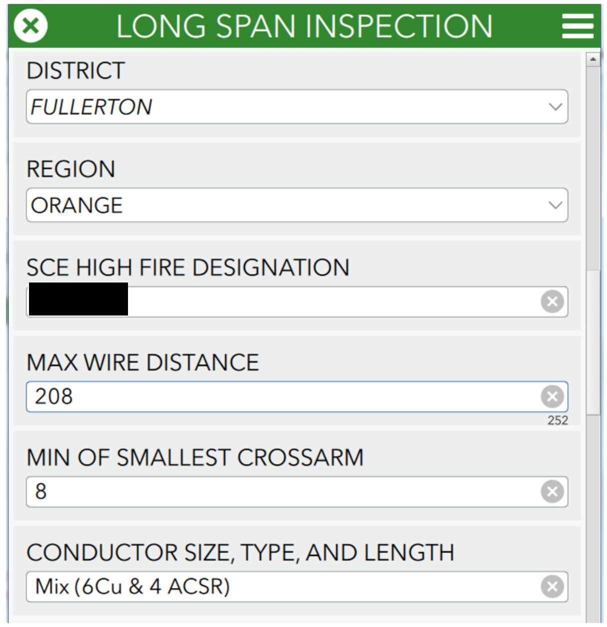
NOTE:

- Fields with **black** text are **read-only**.
- Fields marked with an * are required. You will not be able to submit the inspection form if any required fields are left empty.

5. Tap the **Refresh** icon next to the INSPECTION DATE and INSPECTOR NAME fields to auto-populate them.
6. Enter the **Associated Structure to Span**.



These fields are pre-populated and not editable.

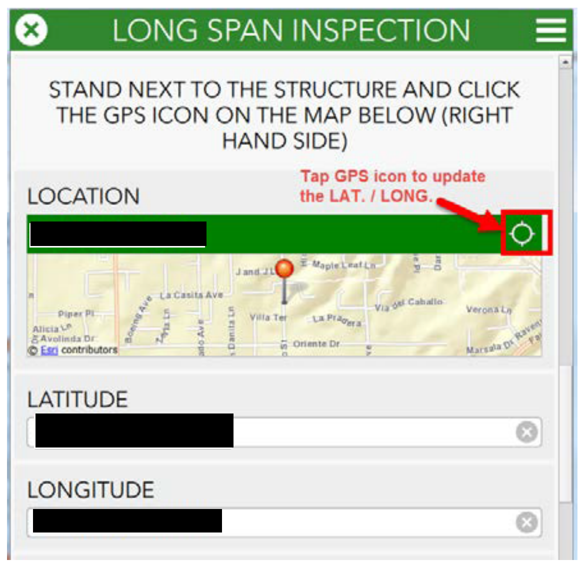


Latitude and Longitude

A map and the latitude and longitude appears, but you will need to update the latitude and longitude to ensure location accuracy.

7. Tap the **GPS icon** to update the latitude and longitude.

The Latitude and Longitude fields will update.

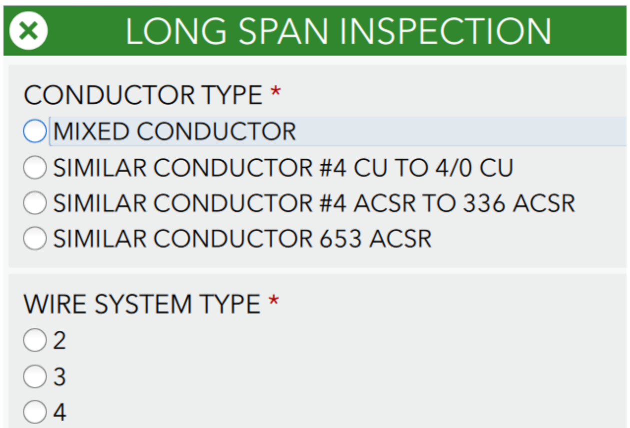


Logic has been built into the form, you will be prompted to give additional information depending on how you answer certain questions.

Conductor Type and Wire System Type

The first two question asks for Conductor Type and Wire System Type.

8. Tap the appropriate **Conductor Type**.
9. Tap the appropriate **Wire System Type**.


LONG SPAN INSPECTION

CONDUCTOR TYPE *

- MIXED CONDUCTOR
- SIMILAR CONDUCTOR #4 CU TO 4/0 CU
- SIMILAR CONDUCTOR #4 ACSR TO 336 ACSR
- SIMILAR CONDUCTOR 653 ACSR

WIRE SYSTEM TYPE *

- 2
- 3
- 4

NOTE: The next set of questions depends on your answer for the Wire System Type.

8, 10, 12 FT Crossarm?

This field displays for the following scenarios:

- Any Conductor Type
- Wire System Type = 2

If answer = **Yes**, then the *No Action Required* message displays.

If answer = **No**, then the *Is Span Longer* question displays.

8, 10, 12 FT CROSSARM? *
YES
NO

Is Span Longer?

This field displays for the following scenarios:

- Mixed Conductor, Wire System Type = 2 and when 8, 10, 12 FT Crossarm = No
- Any Conductor type and Wire System Type = 3 or 4
- Other Conductor types, Wire System Type = 3 or 4

If answer = **Yes**, the *Is The Span Bucket Truck Accessible* question appears.

If answer = **No**, the *No Action Required* message displays.

IS SPAN LONGER? *
See below table for span lengths per conductor type
YES
NO

CONDUCTOR TYPE	SPAN LENGTH
Mixed Conductor	200 ft
Similar Conductor #4 Stranded Cu to 4/0 Cu	240 ft
Similar Conductor #4 ACSR to 336 ACSR	300 ft
Similar Conductor 653 ACSR	400 ft

Is The Span Bucket Truck Accessible?

This field displays when the answer to the *Is Span Is Longer* = Yes.

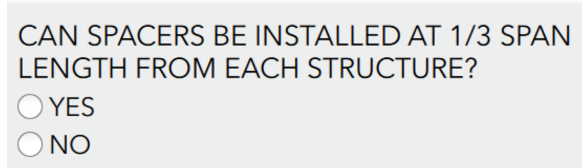
If answer = Yes, then *Action is Required*.

If answer = No, then the *Can Spacers Be Installed at 1/3 Span Length From Each Structure* question displays.

IS THE SPAN BUCKET TRUCK ACCESSIBLE? *
YES
NO

Can Spacers Be Installed at 1/3 Span Length From Each Structure?

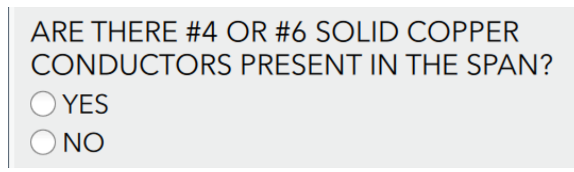
This field displays when the answer is No for the Is the Span Bucket Truck Accessible question.



Are There #4 or #6 Solid Copper Conductors Present in the Span?

This question displays when:

- Mixed Conductor Type, Wire System Type = 3 or 4, and when Is Span Longer = Yes.

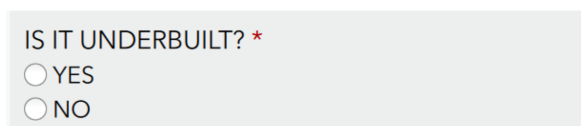


Is It Underbuilt?

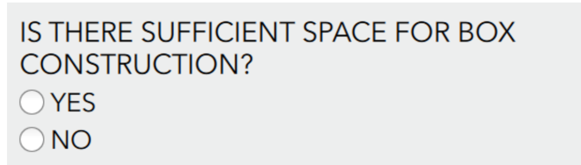
This question displays when the answer = No for Can Spacers Be Installed at 1/3 Span Length From Each Structure.

If answer = Yes, then the *Is There Sufficient Space for Box Construction* question displays.

If no, *Action is Required*.



Is There Sufficient Space for Box Construction?



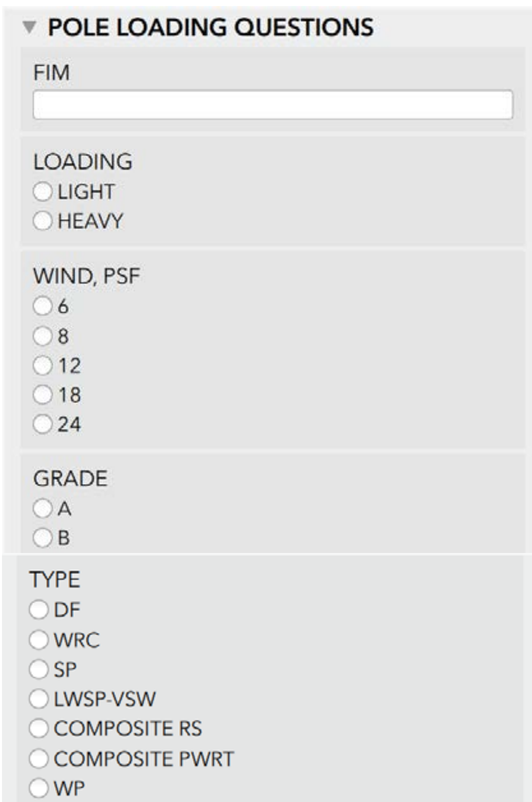
This questions displays when the answer = Yes, for the *Is There Sufficient Space for Box Construction* question.

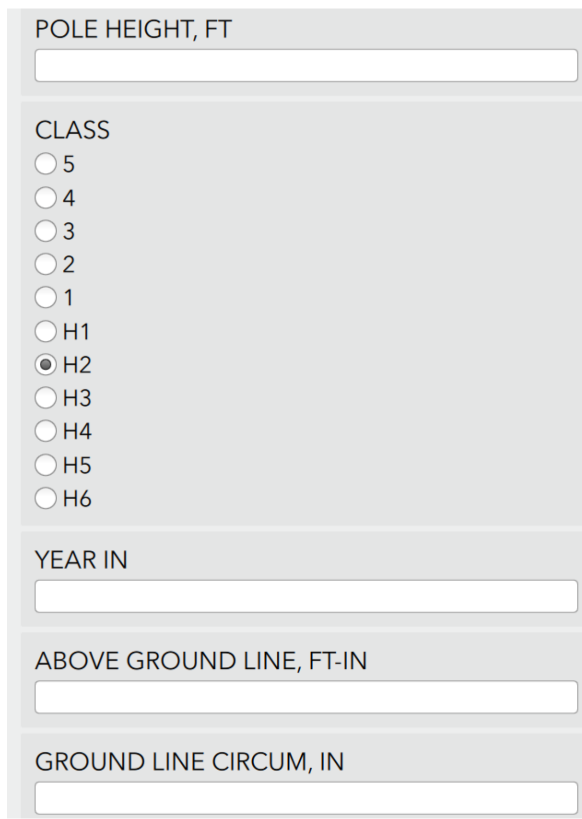
A Yes or No answer displays with Action Required.

NOTE: Optional Pole Loading questions may also display.

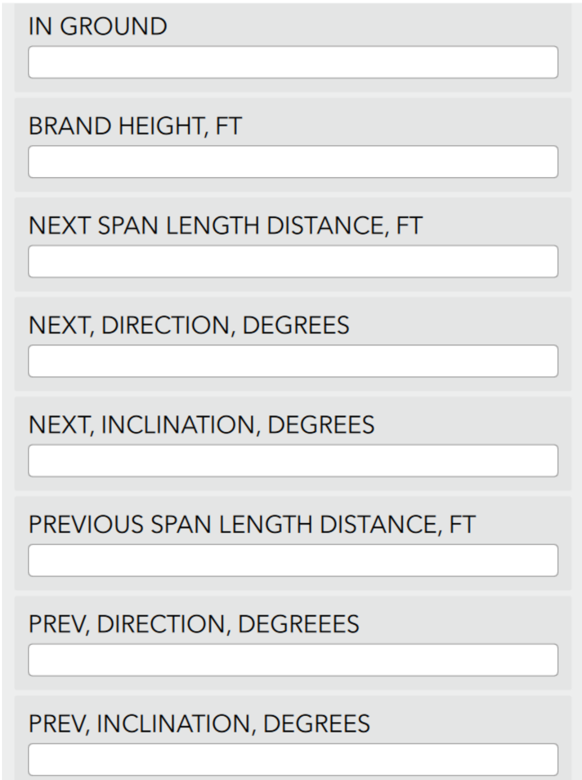
Pole Loading Questions (Optional)

A series of Pole Loading questions display when Action is Required. These are optional fields, but it will be helpful to provide pertinent information for the remediation.





Pole Loading Questions (continued)



IN GROUND

BRAND HEIGHT, FT

NEXT SPAN LENGTH DISTANCE, FT

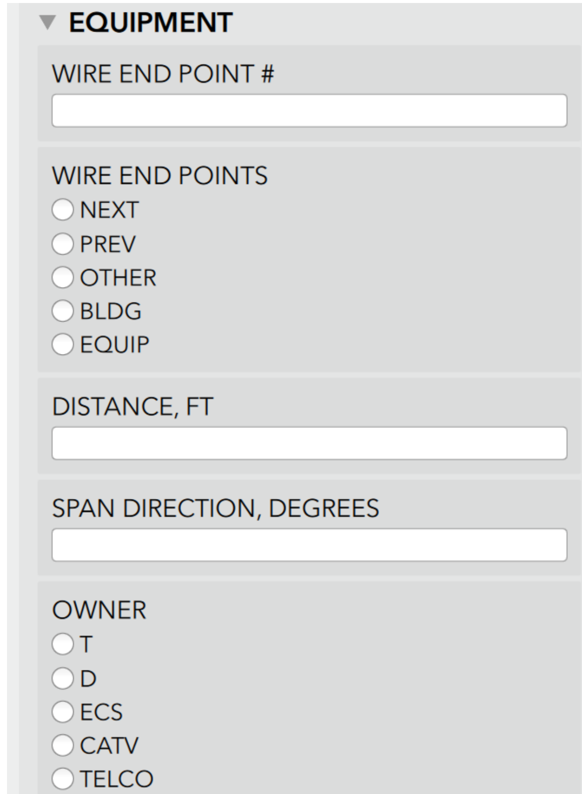
NEXT, DIRECTION, DEGREES

NEXT, INCLINATION, DEGREES

PREVIOUS SPAN LENGTH DISTANCE, FT

PREV, DIRECTION, DEGREEES

PREV, INCLINATION, DEGREES



EQUIPMENT

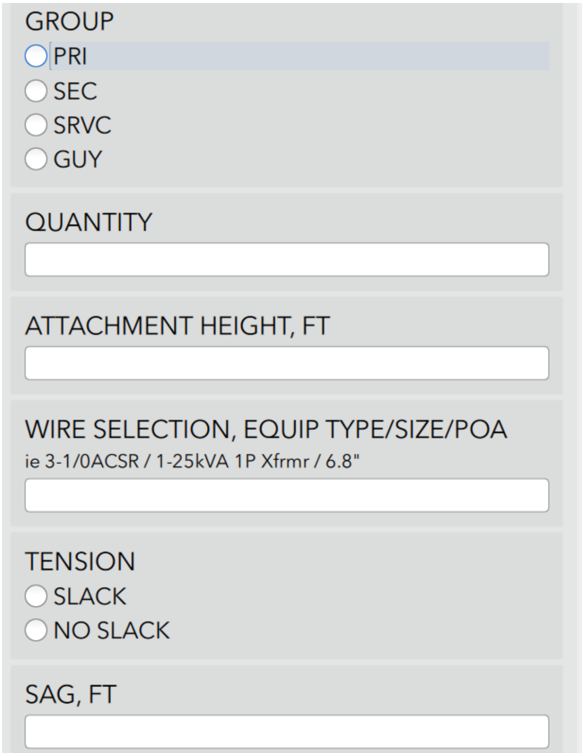
WIRE END POINT #

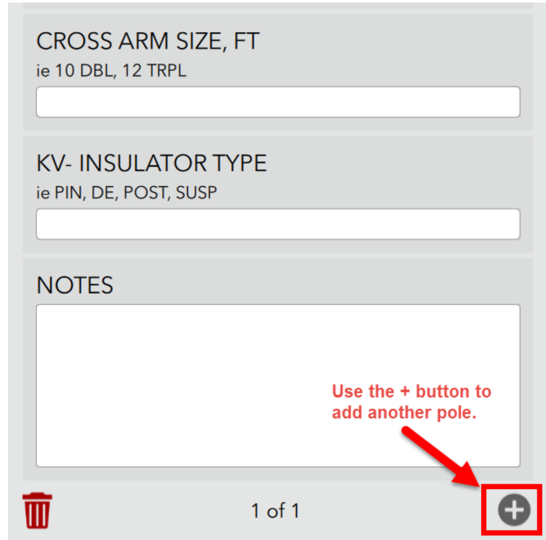
WIRE END POINTS
- NEXT
- PREV
- OTHER
- BLDG
- EQUIP

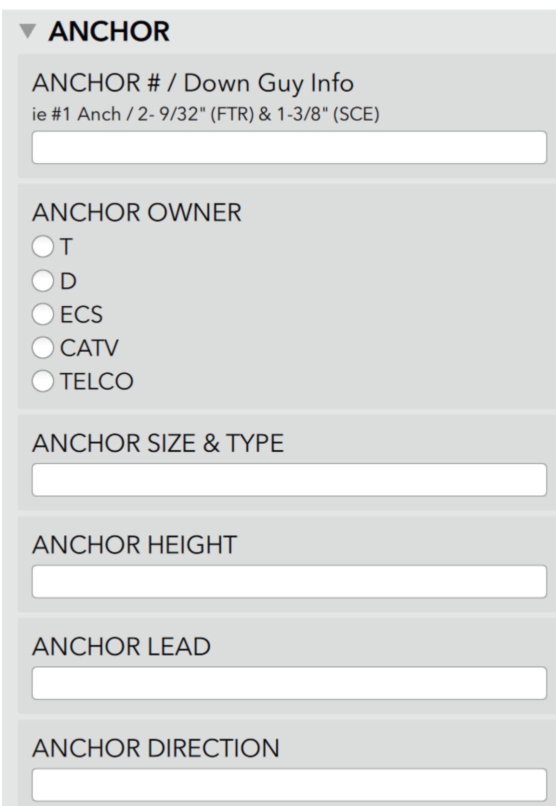
DISTANCE, FT

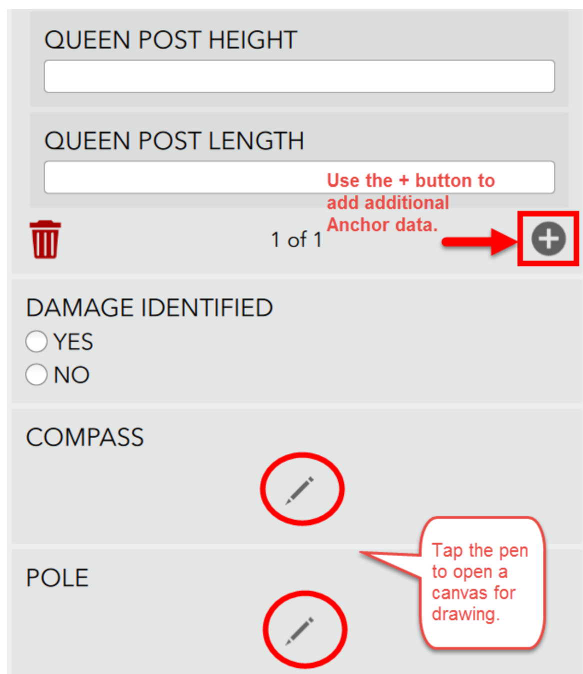
SPAN DIRECTION, DEGREES

OWNER
- T
- D
- ECS
- CATV
- TELCO


GROUP
PRI
SEC
SRVC
GUY
QUANTITY
ATTACHMENT HEIGHT, FT
WIRE SELECTION, EQUIP TYPE/SIZE/POA
ie 3-1/0ACSR / 1-25kVA 1P Xfrmr / 6.8"
TENSION
SLACK
NO SLACK
SAG, FT


CROSS ARM SIZE, FT
ie 10 DBL, 12 TRPL
KV- INSULATOR TYPE
ie PIN, DE, POST, SUSP
NOTES
Use the + button to add another pole.
1 of 1

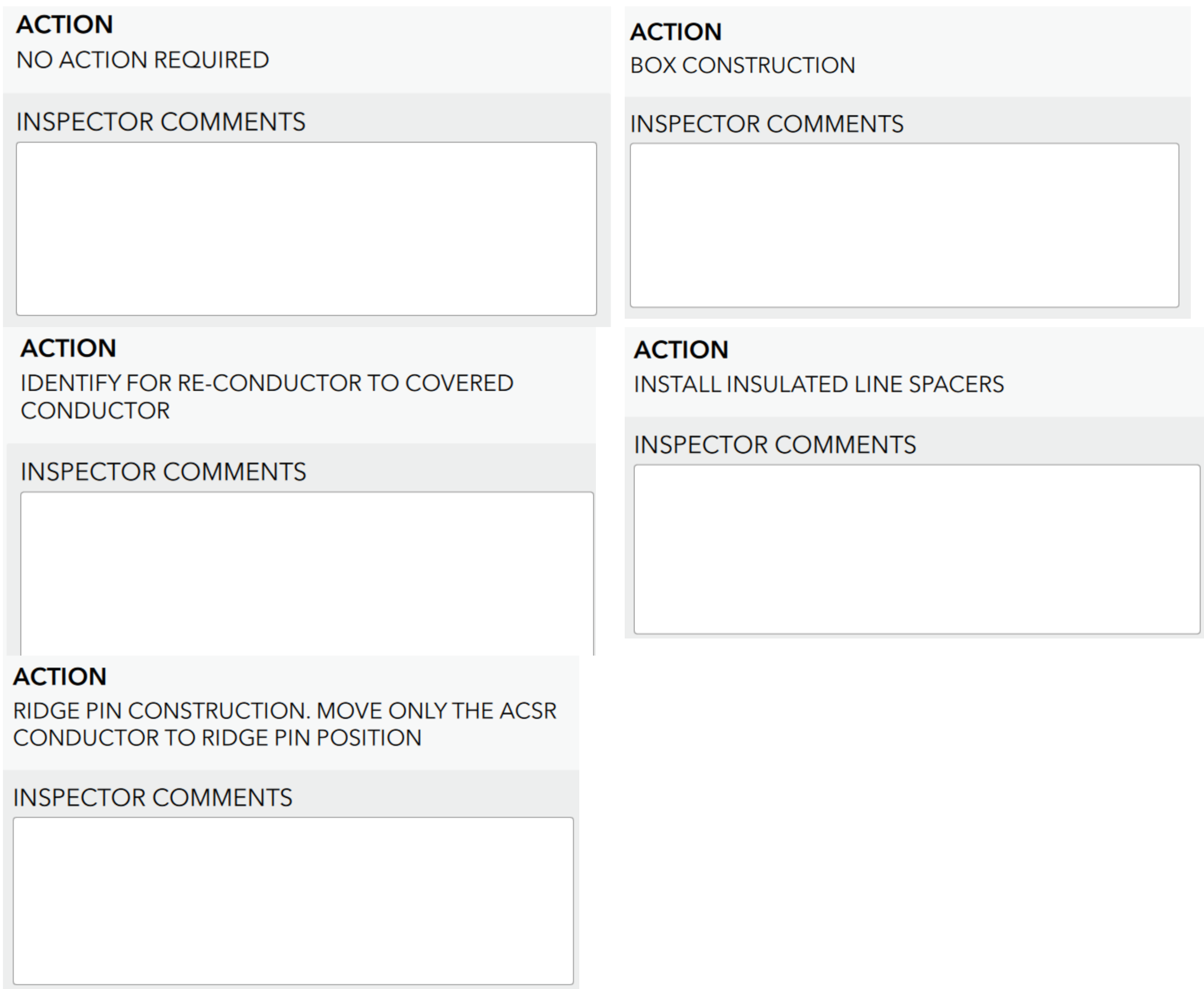

ANCHOR
ANCHOR # / Down Guy Info
ie #1 Anch / 2- 9/32" (FTR) & 1-3/8" (SCE)
ANCHOR OWNER
T
D
ECS
CATV
TELCO
ANCHOR SIZE & TYPE
ANCHOR HEIGHT
ANCHOR LEAD
ANCHOR DIRECTION


QUEEN POST HEIGHT
QUEEN POST LENGTH
Use the + button to add additional Anchor data.
1 of 1
DAMAGE IDENTIFIED
YES
NO
COMPASS
POLE
Tap the pen to open a canvas for drawing.

Action Field

The Action field indicates whether there is any action required or not depending on how you answer the series of questions.

Below is are examples of the Action Required. An Inspector Comments field is used to provide additional information pertaining to the remediation.



NOTE: If you are entering in a comment, you can use the Voice-to-Text feature to speak your comments instead of typing them in.

Photos(s)

Photos are required as follows:

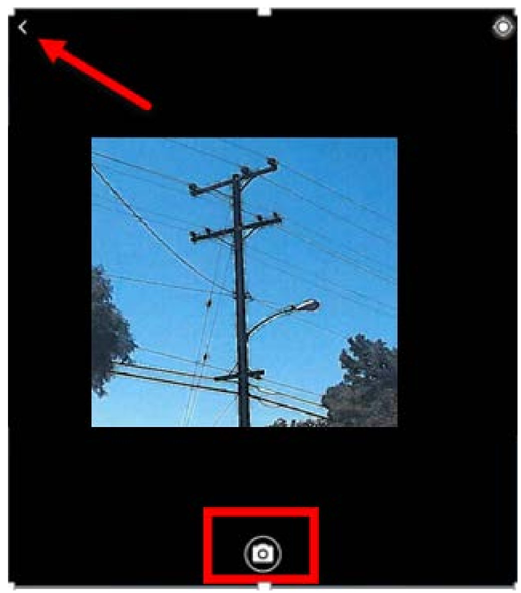
- One full pole picture is always required.
- If remediation is needed for the pole, take additional photos at multiple angles that are pertinent to action required.

1. Tap the **camera icon** to open the iPad camera.

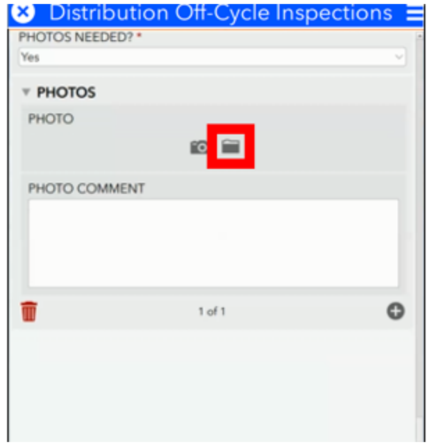
The camera opens and is ready for you to take the photo.

2. Tap the **Capture button** at the bottom of the screen to take the picture.
3. Tap the **x** at the top left of the screen to close the camera without taking a photo.
4. Enter comments related to the photo taken (optional).
5. To add additional photos, tap the sign and enter any necessary photo comments.

NOTE: If you are entering in a comment, you can use the Voice-to-Text feature to speak your comments instead of typing them in.



NOTE: You can also tap the *folder* icon to browse for photos in you iPad gallery.

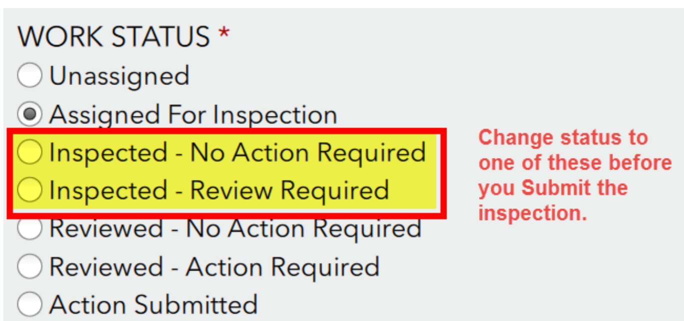


Work Status

Use this section to change the work status for the completed inspection.

NOTE: The status is defaulted to “Assigned for Inspection”.

Work Status	Description
Inspected – No Action Required	Use this status when “Action = No Action Required”.
Inspected – Review Required	Use this status when “Action = Action Required”.

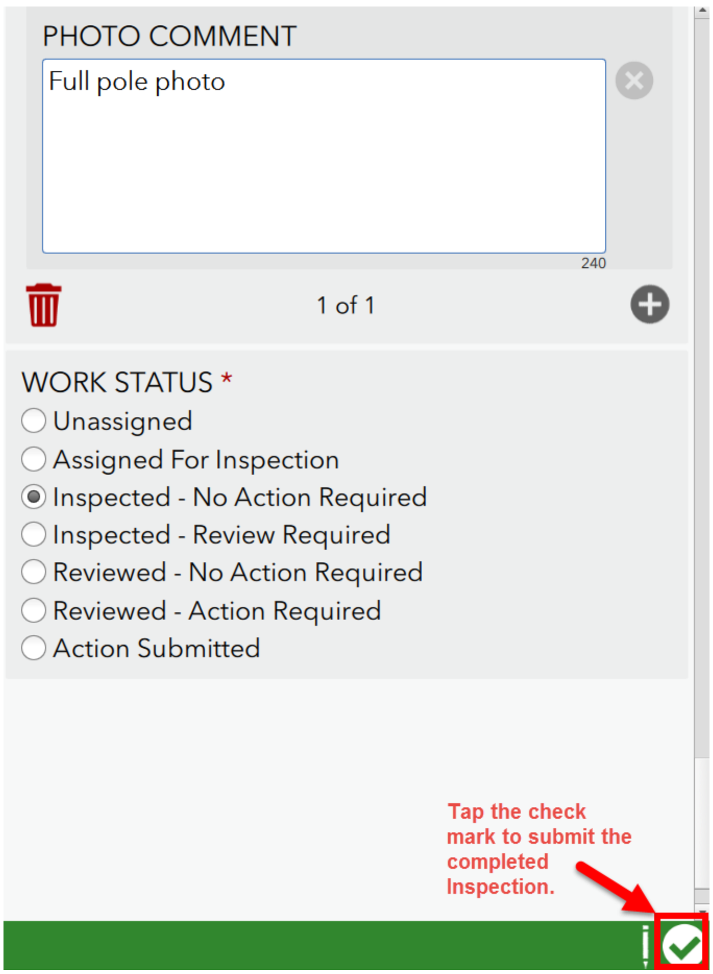


Submitting the Inspection Form

The **Submit** button appears as a checkmark in the bottom right corner.

1. Tap the checkmark to submit the completed inspection.

REMEMBER: You cannot submit a form if required fields have been left blank. You will be prompted to fill out each required field.

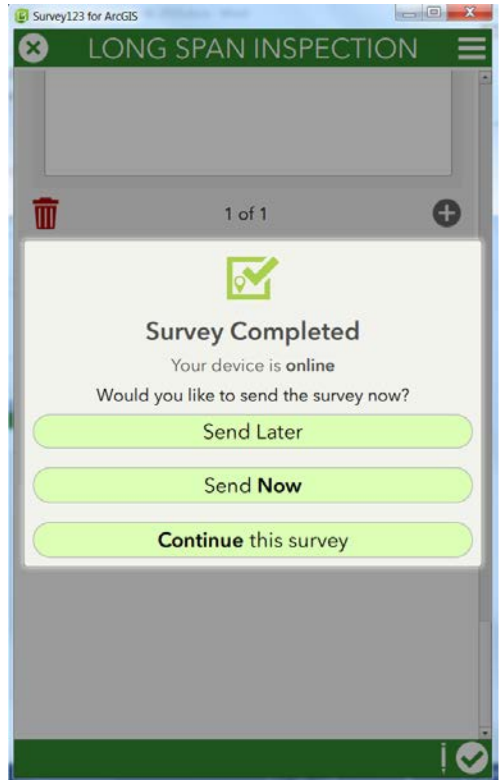


If your device is online and all the fields have been filled out, you have two options for submitting:

1. You can "Send Later" if you are not ready to send yet.
2. The form will be sent immediately if you tap, "Send Now."

NOTE: If your device is offline, you will only have the option to save the form to your device.

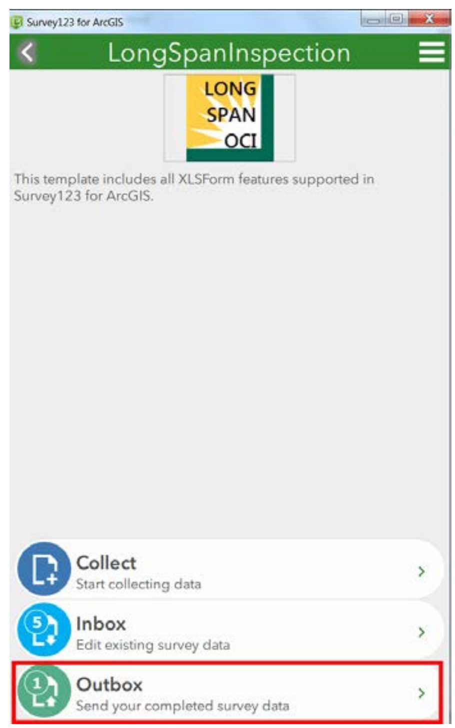
IMPORTANT: Your iPad should be online and inspections should be sent as they are completed, if at all possible, so that the inspection progress is as accurate as possible.



Outbox

If you see the **Outbox** folder, that means that you have completed inspections that needs to be submitted when cellular service resumes.

1. To clear the **Outbox** folder when cellular service resumes, you will need to tap the Outbox and tap **Send All** button to submit.



Closing a Form Before it has been Completed

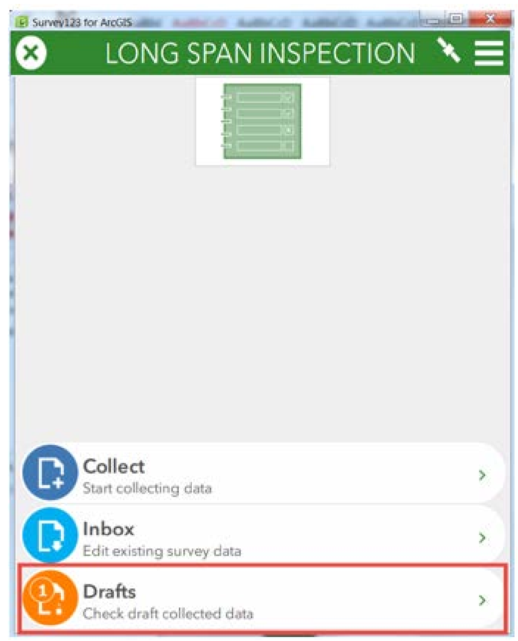
If you need to close a form before you have completed or submitted it, you have the following options.

- You can close the survey and lose all changes.
- Continue the survey and not close it at this time.
- Or you can save the survey in a draft.

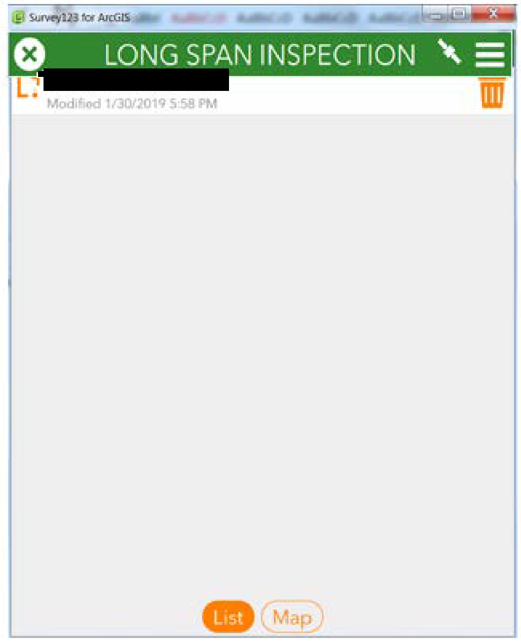
To view draft inspections:

1. Open the *Long Span Inspection* screen.
2. Tap the ***Drafts*** folder.

NOTE: This folder is only visible if you have saved draft version(s) of inspections.



All saved inspections can be accessed here.

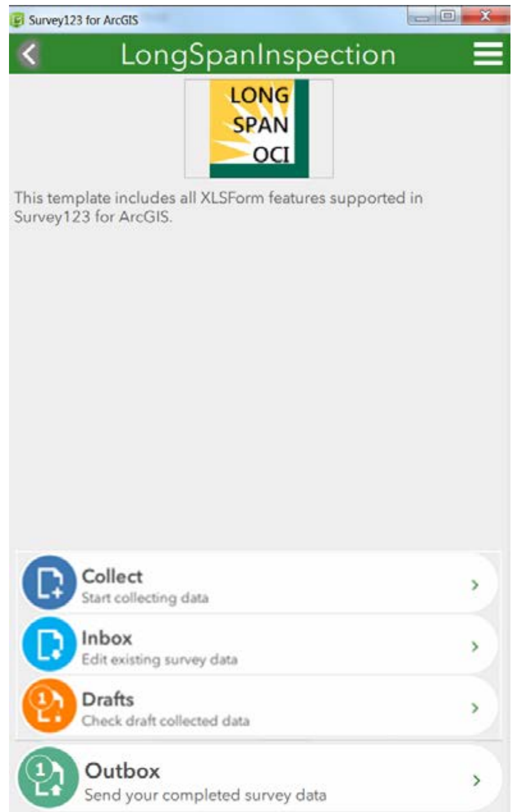


Signing Out of Survey123

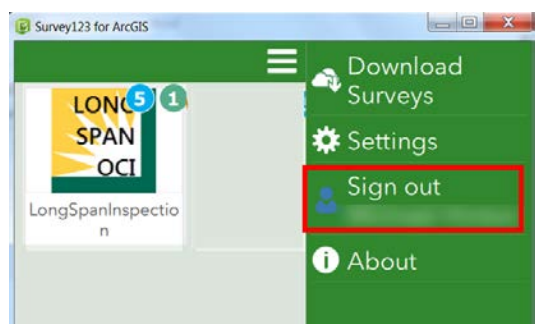
Follow the steps below to sign out of Survey123.

- Check your Long Span Inspection Survey screen. You should only see the **Collect** and **Inbox** buttons.
- If you see the **Drafts** folder, that means you have work saved that needs to be completed, submitted, and synced.
  - Open the **Drafts** folder and resolve all saved forms located there.
- If you see the **Outbox** folder, that means that you have completed inspections that needs to be submitted when cellular service resumes.
  - To clear the **Outbox** folder when cellular service resumes, you will need to tap the Outbox and tap **Send All** button to submit.

NOTE: You can edit completed inspections in your Draft and Outbox folders.



1. Return to the *My Surveys* screen.
2. Tap the menu (three bars in the upper right corner).
3. Tap **Sign out**.

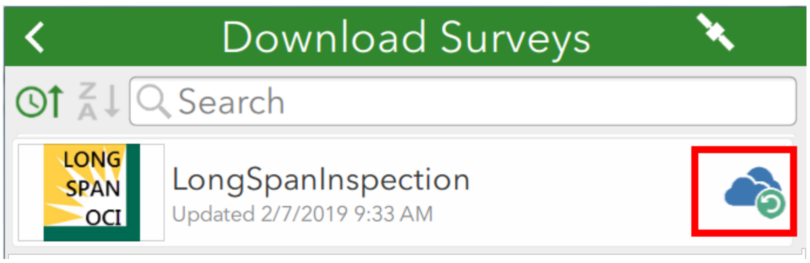


Downloading the Latest Version of Loan Span Inspection Survey Form

The Survey123 application is being updated frequently.

IMPORTANT: You should download the Survey once a day, preferably first thing in the morning before you start performing inspections so that you are always using the most up-to-date form.

To refresh the survey, in the *Download Surveys* screen, tap the download icon, located on the right side of the screen.



Technical Support Contacts

Field Tool User Support Hotline is available 7 days a week 24 hours a day.

(Leave voicemail with your name and contact number and you call will be returned immediately)

- Phone: (909) [redacted]-[redacted]
- PAX: [redacted]

IMPORTANT: Do not call the SCE Help Desk for this effort.

Training related questions:

- Email: [redacted]@sce.com

Transmission Condition Assessment Form

Ground and Aerial Inspections

Effective Date:
2-3-2021

Table of Contents

✪ This symbol and blue text indicate that the question/option is for ground only
■This symbol and purple text indicate that the question/option is for aerial only

Survey Questions

General Inspection Information

1. Inspection Date
2. Inspection Method
    a. Ground
    b. Helicopter (Ground Inspections)
    c. HEC
    d. Aerial Footage
    e. ■Helicopter (Aerial)
    f. ■UAV/Drone
    g. ■Climb
3. Accounting Type
4. User ID
5. Inspector First Name
6. Inspector Last Name
7. Inspector SCE User ID
8. Grid Name
9. Circuit
10. ✪ Is circuit information correct?
    a. Yes
    b. No
        i. Circuit List Drop Down
        ii. Circuit Not Listed (check box)
        iii. Open Comment Field
11. Voltage
12. FLOC
13. ✪ Is the Structure Number correct on structure?
    a. Yes
    b. No
        i. Select "Are you able to proceed with this inspection" - No "Incorrect Structure Number"
    c. NA (Tower)
14. Mile Tower Number
15. SCE High Fire Designation
16. SCE High Fire Sub Area
17. Latitude
18. Longitude
19. Object Type

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Structure Information

1. Are you able to proceed with this inspection?
   ✪Note: Incorrect Number, No Access, Obstructed, Incorrect Grid, Non-Transmission, Pole Removed
   ■Note: Incorrectly Tagged, Missing Photo Angles, Poor Photo Quality, Structure Media Issue, Structure Under Repair
   a. Yes
   b. No
      i. Incorrect Structure Number
         1. Number in the field
         Note: "Use Collect feature to complete inspection for Number in Field"
      ii. No Access
         1. Property Owner
         2. Responsible Patrolman
         3. Brush Overgrown
         4. Helicopter Only
      iii. Obstructed View
      iv. Non-Transmission
         1. Telecommunication
         2. Foreign
         3. Distribution
      v. Duplicate Record
      vi. Non-HF
      vii. Removed Structure (Not in field/active in SAP)
      viii. ■Incorrectly Tagged (Heli/UAV)
      ix. ■Missing Photo Angles (Heli/UAV)
      x. ■Poor Photo Quality (Heli/UAV)
      xi. ■ Structure Media Issue
      xii. ■Structure Under Repair

2. Structure Type

   Steel Lattice/Tower
   a. Lattice Tower
   b. Lattice H-Frame/Pole
   c. Aesthetic/A-Frame
   d. Portal Tower
   e. Other (comment)

   Pole
   a. Monopole/Single Pole
   b. H-Frame
      a. ■Add Associated FLOC to other Structures
   c. 3-Pole
   d. Flying Berry Pole

e. Guy Stub
    a. ■Note: Disallow the following questions from showing up: "Do visible bonds/bonding require a notification" and "Is the removal of tree/foliage required to prevent contact with transmission conductors"
f. Other (comment)

Main Pole Material Type:

a. Wood
b. Light Weight Steel (LWS)
c. Engineered Tubular Steel Pole (TSP)
d. Composite
e. Concrete
f. Hybrid (Concrete/Steel)
g. ✪ Other (comment)

✪ *Supporting Members Material Type:*

a. Wood
b. Light Weight Steel (LWS)
c. Composite
d. Concrete
e. Hybrid (Concrete/Steel)
f. Steel Crossarm
g. Post Insulators Only
h. Other/Guyed Deadend/Jumper Pole (comment)

3. Structure Attachments
    - ☐ Bulk Transmission (220kV and up)
    - ☐ Sub-Transmission (33kV-161kV)
    - ☐ Distribution (<33kV)
    - ☐ Telecommunication
    - ☐ ✪Transmission Pilot Wire/Open Wire
    - ☐ ✪Foreign Electrical Utility

4. Transmission Attachment Details
    - ☐ Single Circuit
    - ☐ Double Circuit
    - ☐ ■Multi Circuit (3 or more)
    - ☐ Bundled Conductor
    - ☐ Transposition Structure (■Phase rotation occurs on the same structure)
    - ☐ Bird Nest/Wildlife Debris at or above Bulk/Sub-Trans facilities, including equipment
    - ☐ Transmission Down Guy
    - ☐ Transmission Span Guy
    - ☐ Equipment (switches, arrestors, pothead/risers, etc.)
    - ☐ Suspension Structure
    - ☐ Deadend Structure

- ☐ Post Type Structure
- ☐ Porcelain/■Glass Insulators
- ☐ Polymer Insulators
- ☐ Tough Glass Insulators
- ☐ Dampers
- ☐ Overhead Shield/Optical/Ground Wire (OPGW/OHGW)
- ☐ Fault Return Conductor (FRC)
- ☐ Transmission Riser
- ☐ Fault Indicator
- ☐ ■Line Hose/Bird Deterrent/Bird Guard
- ☐ ■Transmission Crossarm/X-Brace
- ☐ Antenna/Microwave
- ☐ Solar
- ☐ FAA Lights
- ☐ Wind Turbine
- ☐ Distribution 4th Wire/Neutral
- ☐ Distribution Riser
- ☐ Shared Crossarm
- ☐ ■Distribution Span/Down Guy
- ☐ Telecomm Conductive Wire/Messenger/Lashing Wire (non-ADSS)
- ☐ Telecomm Riser
- ☐ Telecomm Span/Down Guy
- ☐ ■Crossarm/X-Brace Material Type
  - Wood
  - Steel
  - Composite

Data Collection

5. Is there a FLOC number on the structure?
    a. Yes
    b. No
    c. Unable to Determine
6. Construction Type
    a. Suspension
    b. Post Type
    c. Dead End
    d. N/A
7. Is there a Buddy Pole?
    a. Yes
        i. What is attached to Buddy Pole?
            1. ✪TTC Cable
            2. ✪3rd Party Cable
            3. ■ Communication
            4. Distribution
            5. Nothing (Bare Pole)
    b. No
8. ✪Describe the area surrounding the structure within 100 feet?
    a. Concrete and/or Pavement
    b. Sand, Gravel/Rock, or Water
    c. Residential or Commercial Area/Structures
    d. Vegetation
9. ✪Is the Structure within an Enclosed Area?
   Example: Behind private fencing/gate, in backyard, in orchards, etc.
    a. Yes
        ii. Behind Private Fence/Gate
        iii. In Backyard
        iv. In Orchards
        v. Customer Facilities
    b. No
10. ✪Type of Footing
    a. Foundation/Concrete
    b. Direct Bury (Wood/LWS)
    c. Grillage
    d. Cassion
    e. Other - Specify (open text field)
    f. Unable to Determine
        i. No Access
        ii. Property Owner
        iii. Obstructed
        iv. Brush Overgrown
11. ✪Does foundation have a ground to the structure?

✪ This symbol and blue text indicate that the question/option is for ground only
■This symbol and purple text indicate that the question/option is for aerial only

a. Yes
b. No
c. Unable to Determine

12. ✪Identify the appearance of the Footings/Foundations
    a. Erosion
    b. Buried Footing (excluding direct bury)
    c. Corrosion of the Steel at the Structure Base
    d. Exposed decay pocket at ground line where part of shell is gone
    e. Cracked/Broken Concrete
    f. Footings/Foundation is in good condition

Priority 3 Needed

if 'Equipment (switches, arrestors, pothead/risers, etc.)'...

13. Indicate the Equipment Type(s) and attachments on the Structure
    a. Switch
        i. ✪KPF
        ii. ✪Turner
        iii. ✪Cleveland Price
    b. Risers/Potheads/Arresters
    c. RTS
14. How many Transmission Lightning Arresters are installed on this structure?
    a. 10+,9,8,7,6,5,4,3,2,1,0
15. Do the insulators connect to the structure using a hook?
    a. Yes
    b. No
16. ■Are All Cotter Keys Visible?
    a. Yes
        i. Cotter Key(s) Missing (Notification Required)
        ii. Cotter Key(s) Do Not Belong to Structure
        iii. Cotter Key(s) is blurry/does not zoom/obstructed
            1. Where Are Cotter Keys Not Visible?
                a. Cold-Side
                b. Within Insulator String
                c. Hot-Side
                d. Shield Wire Hardware
                e. Structure Hardware
    b. No
17. ■Are All Pins Visible?
    a. Yes
        i. Pin(s) Not Applicable to the Structure
    b. No
        i. Where Are Cotter Keys Not Visible?
            1. Cold-Side
            2. Within Insulator String

3. Hot-Side
4. Shield Wire Hardware
5. Structure Hardware

18. How many LEVELS are Crossarms installed on Transmission voltages?
    Example: Crossarms on top, middle and bottom phases equals 3 levels
    a. 10+,9,8,7,6,5,4,3,2,1,0
19. Is Transmission Line hose/Bird Deterrent present?
    a. Yes
        i. Line Hose
        ii. Bird Deterrent
        iii. Bird Guard
    b. No

if 'Bulk Transmission (220kV and up)'...

20. If Shield Wires are on a 500kV Structure, is the Shield Wire:
    Note: Pertains to circuits built to 500kV standards and energized at 220kV
    a. Grounded to the tower (may or may not have an insulator)
    b. Insulated and Continuous
    c. Insulated and Open
    d. N/A (220kV tower)
    e. N/A (OPGW)
21. ✪Indicate the type(s) of Conductor Splice present on the Span
    Note: Only in span to the North or West
    a. Wrap
    b. Twist/Mac
    c. Quickie
    d. Compression
    e. Implosive
    f. Not Present

    How many?

if 'Deadend/Jumper Structure'...

22. Indicate the type(s) of Splice present on the Jumper Loop (includes Parallel Grove Clamps)?
    a. Wrap
    b. Twist/Mac
    c. Quickie
    d. Compression
    e. Implosive
    f. Parallel Grove / Bolted Clamp
    g. Not Present
    h. Unable to Determine

    How many?

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if Conductor splice present on span/jumpers

23. ✪What is the distance of Line Splices from point of support?
    a. Bulk (if Bulk Transmission (220kV and up))
        i. At least 100 feet from pint of support? (Y/N)
    b. Sub Trans (if Main Pole Material Type)
        i. Wood
            1. At least 3 feet from point of support? (Y/N)
        ii. LWS
            1. At least 20 feet from point of support? (Y/N)

if 'Transmission Down Guy'…

24. How many Transmission DOWN guys are installed?
    a. User selects from: 10+,9,8,7,6,5,4,3,2,1,0

if 'Transmission Span Guy'…

25. How many Transmission SPAN guys are installed?
    a. User selects from: 10+,9,8,7,6,5,4,3,2,1,0

if Span Guy

26. Are Span/Arm Guys installed parallel to the line conductor?
    a. Yes
        i. How many?
    b. No

if 'Distribution (<33kV)'

27. Do Guys pass near/through Distribution circuits?
    a. Yes
    b. No

If down guy or span guy

28. Do Guys have insulation between structure and ground?
    Examples: Johnny balls, strain insulators, fish rods, etc.
    a. Yes
        i. Strain Insulators/Johnny Balls
        ii. Fish Rods
    b. No

If down guy or span guy

29. Indicate Guy Type and Attachments
    a. Preformed
    b. Automatic/Quickie
       *Notification Build Out Required
    c. ■Automatic Quickie Bypassed with Preformed
    d. ■3-Bolt Clamp
    e. Other (comment)

if 'Distribution (<33kV)

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30. ✪Is the 4th Wire bonded to the structure?
    a. Yes
    b. No
    c. Unable to Determine

Notification

Main Structure & Supporting Members:

Bird Nest/Wildlife Debris at or above Bulk/Sub-Trans facilities, including equipment

31. Does bird nest/wildlife debris require notification?
    Examples: Fire hazard, reduced electrical clearances, above energized facilities, on or near equipment, blocking view, etc.
    a. Yes ✪(P2)
        i. Fire Hazard
        ii. Reduced Electrical Clearances
        iii. Above Energized Facilities
        iv. On or Near Equipment
        v. Blocking View

        *Notification Build Out Required
    b. ✪Yes (P3)
        *Notification Build Out Required
    c. No
    d. ✪Duplicate
        i. ✪Duplicate Notification Number

Default

32. Does Main Structure require notification (cross arm/arm/x-braces)?
    Examples: Signs of damage, loss of material, burn/flash/arc marks, bowing, leaning, or out of plum, etc.
    a. Yes ✪(P2)
        Steel:
        i. Corrosion
        ii. Bent/Broken
        iii. Missing Members or Bolts
        iv. Connections
        v. Bowing
        vi. Leaning
        vii. Out of Plum

        Wood:
        i. Rot
        ii. Bending/Splitting/Twisting
        iii. Woodpecker

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iv. Bowing
v. Leaning
vi. Out of Plum

Composite:
i. Unraveling of Fibers

Concrete:
i. Spalling/Cracks

*Notification build out required

b. ✪Yes (P3)
*Notification Build Out Required
c. No
d. ✪Duplicate
i. Duplicate Notification Number

default (should not show for Tower)

33. Do Supporting Members (braces/crossarms/arms/hardware) require notification (excluding guys/guying)?
Examples: Signs of damage, loss of material, braces worn, burn/flash/arc marks, etc.
a. Yes ✪(P2)
Steel:
i. Corrosion
ii. Bent/Broken
iii. Missing Members or Bolts
iv. Connections

Wood:
i. Rot
ii. Bending/Splitting/Twisting
iii. Woodpecker
iv. Bowing
v. Leaning
vi. Out of Plum

Composite:
i. Unraveling of Fibers

Concrete:
i. Spalling/Cracks

*Notification build out required

b. ✪Yes (P3)
*Notification Build Out Required
c. No
d. ✪Duplicate

            i. Duplicate Notification Number

If 'Steel Lattice/Tower' or 'TSP' or 'LWS'...

34. ✪Does Structure Base require notification due to clearance (<5ft) from non-SCE metallic objects? Examples: Conductive objects, metallic fencing, gates, etc.
    a. Yes (P2)
        i. Conductive Objects
        ii. Metallic Fencing
        iii. Gates
        iv. Other (comment)
        *Notification build out required
    b. ✪Yes (P3)
    *Notification build out required
    c. No
    d. Unable to Determine
        ii. No Access
        iii. Property Owner
        iv. Obstructed
        v. Brush Overgrown
    e. ✪Duplicate
        i. Duplicate Notification Number

Guys/Guying

if 'Transmission Down Guy'...

35. Do DOWN guys/guying require notification (excluding anchors)?
    Examples: Signs of corrosion/fraying, slack, broken/loose attachments/supports, inadequate clearances during wind events, burn/flash/arc marks
    a. Yes✪(P2)
        i. Corrosion/Fraying
        ii. Slack
        iii. Broken/Loose Attachments Supports
        iv. Inadequate Clearances During Wind Events
        v. Burn/flash/arc marks
        *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. Unable to Determine
        i. No Access
        ii. Property Owner
        iii. Obstructed
        iv. Brush Overgrown
    e. ✪Duplicate
        i. Duplicate Notification Number

if 'Transmission Span Guy'...

36. Do SPAN guys/guying require notification (excluding anchors)?
    Examples: Signs of corrosion/fraying, slack, broken/loose attachments/supports, inadequate clearances during wind events, burn/flash/arc marks
    a. Yes ✪(P2)
        i. Corrosion/Fraying
        ii. Slack
        iii. Broken/Loose Attachments Supports
        iv. Inadequate Clearances During Wind Events
        v. Burn/flash/arc marks

        *Notification Build Out Required

    b. ✪Yes (P3)
    c. No
    d. Unable to Determine
        i. No Access
        ii. Property Owner
        iii. Obstructed
        iv. Brush Overgrown
    e. ✪Duplicate
        i. Duplicate Notification Number

if 'Transmission Down Guy'...

37. ✪Do Anchors require notification?
    Examples: Signs of damage, corrosion, buried, too many attachments, etc.
    a. Yes (P2)
        i. Damage
        ii. Corrosion
        iii. Buried
        iv. Too Many Attachments

        *Notification Build Out Required

    b. Yes (P3)
    c. No
    d. Unable to Determine
        i. No Access
        ii. Property Owner
        iii. Obstructed
        iv. Brush Overgrown
    e. Duplicate
        i. Duplicate Notification Number

if 'Down Guy' or 'Span Guy' or ' 'Steel Lattice/Tower' or 'TSP' or 'LWS'…"

38. ✪Do Guys/Anchors require notification due to Clearance (<5ft) from non-SCE metallic objects?
    Example: conductive/metallic fencing/gates, other conductive objects
    a. Yes (P2)
        i. Is the Object in Direct Contact with Guys/Anchors?
       *Notification Build Out Required
    b. Yes (P3)
    c. No
    d. Unable to Determine
        v. No Access
        vi. Property Owner
        vii. Obstructed
        viii. Brush Overgrown
    e. Duplicate
        i. Duplicate Notification Number

Equipment

if Equipment (switches, arrestors, pothead/risers, etc.)

39. Does Equipment require notification?
    Examples: Switch blades not fully closed/open, whisker/arrestor/riser/pothead issues, etc.
    a. Yes ✪(P2)
        i. Loose/Corroded Hardware
        ii. Cotter Keys/Bolts Missing/Loose
        iii. Excessive Wear on Structure Attachments and Yoke Plates
        iv. In contact with Animal Nest
        v. Porcelain Pothead Insulators Chipped or Broken
        vi. Pothead swollen/leaking
        vii. Blades not fully engaged
       *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

if 'Transmission Riser'…

40. ✪Does the Riser require a notification?
    Examples: In contact with animal nest, Riser swollen, Riser broken, Non-Schedule 80 Riser installed, Cables in Riser exposed
    a. Yes (P2)
        i. In Contact with Animal Nest
        ii. Riser Swollen
        iii. Riser Broken
        iv. Cables in Riser Exposed
        v. Unable to Determine
            1. No Access
            2. Property Owner

3. Obstructed
4. Brush Overgrown

*Notification Build Out Required

b. Yes (P3)
c. No
d. Duplicate
    i. Duplicate Notification Number

if Equipment (switches, arrestors, pothead/risers, etc.)

41. Do the Equipment Brackets or Braces require a notification?
    Examples: Worn, missing, loose, broken
    a. Yes ✪(P2)
        i. Braces Worn
        ii. Braces Missing
        iii. Braces Loose
        iv. Braces Broken

        *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

Insulators/Hardware/Wires/Misc:

default

42. Do Insulators require notification?
    Examples: Polymer: Tracking, missing/loose corona rings, ripped sheds, burn/flash/arc marks, excessive pollution/contamination, chalking
    Porcelain/glass: Broken chipped bells, missing/loose corona rings (500kV only), burn/flash/arc marks, excessive pollution/contamination, deadend bell skirts facing up, severe rust on insulator caps, out of plumb (in line with span), missing/loose cotter keys, wear on structure (slotting holes), hook shows visible wear/loss of material
    a. Yes ✪(P2)

        Polymer:
        i. Tracking
        ii. Missing/Loose Corona Rings
        iii. Ripped Sheds
        iv. Burn/Flash/Arc Marks
        v. Excessive Pollution/Contamination

        Porcelain/Glass:
        i. Broken/chipped bells
        ii. Missing/loose corona rings (500kV only)
        iii. Burn/flash/arc marks
        iv. Excessive pollution/contamination
        v. Deadend bell skirts facing up, etc.)

    *Notification Build Out Required

b. ✪Yes (P3)
c. No
d. ✪Duplicate
   i. Duplicate Notification Number

if 'Do the insulators connect to the structure using a hook?'...

43. Does the Hook or the structure where it attaches require a notification?
    a. Yes ✪(P2)
       *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. Unable to Determine
    e. ✪Duplicate
       i. Duplicate Notification Number

if 'Wood' or 'Composite' Poles & Supporting Members...

44. Do visible Bonds/Bonding and/or copper grounding require notification?
    Examples: Signs of damage, missing/loose connections, etc.
    a. Yes ✪(P2)
       i. Damage
       ii. Missing/Loose Connections
       iii. Unable to Determine
          1. No Access
          2. Property Owner
          3. Obstructed
          4. Brush Overgrown
       *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
       i. Duplicate Notification Number

if 'Deadend Structure'...

45. Do Jumpers require notification?
    Note: Inadequate shape/clearance, needs I-string/stiffener/weights, missing/damaged spacers, loose connections
    a. Yes ✪(P2)
       i. Inadequate Shape/Clearance
       ii. Needs I-string/stiffener/weights
       iii. Missing/damaged spacers
       iv. Loose connections
       *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
       i. Duplicate Notification Number
    e. ■Covered Equipment
       *Notification Build Out NOT Required

if 'Dampers'...

46. Do Dampers require notification?
    Examples: Signs of damage, drooping, missing weights, broken strands at attachment
    a. Yes ✪(P2)
        i. Damage
        ii. Drooping
        iii. Missing weights
        iv. Broken strands at attachment
        *Notification Build Out Required
    b. ✪ Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

Default

47. Does Line Hardware require notification?
    Examples: Signs of corrosion/loss of material, wear/tear/grooving, slotted holes, burn/flash/arc marks, missing/damaged cotter keys/nuts/bolts, etc.
    a. Yes ✪(P2)
        i. Corrosion/loss of material
        ii. Wear/tear/grooving
        iii. Slotted holes
        iv. Burn/flash/arc marks
        v. Missing/damaged cotter keys/nuts/bolts
        *Notification Build Out Required
    b. ✪ Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number
    e. ■ Covered Equipment
        *Notification Build Out NOT Required

Default

48. Do Wires or Splices require notification?
    Examples: Signs of birdcaging, broken strands, span splices is automatic/quickie, corrosion, burn/flash/arc marks, etc.
    a. Yes ✪(P2)
        i. *Birdcaging*
        ii. *Broken strands*
        iii. *Span splice is automatic/quickie*
        iv. *Corrosion*
        v. *Burn/flash/arc marks*
        **Notification Build Out Required*
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

if 'Suspension Structure'...

49. ✪Does Suspension Insulator plum require a notification?
Examples: Out of plum, no uplift, float
   a. Yes (P2)
      i. Out of plum
      ii. No Uplift
      iii. Float
      *Notification Build Out Required
   b. Yes (P3)
   c. No
   d. Duplicate
      i. Duplicate Notification Number

if 'SCE Telecommunication' or 'Transmission Pilot Wire/Open Wire

50. ✪ Does Pilot Wire/Open Wire require notification?
Examples: Broken, Corroded, Hardware, etc.
   a. Yes (P2)
      i. Broken
      ii. Corroded
      iii. Hardware Issues
      *Notification Build Out Required
   b. Yes (P3)
   c. No
   d. Duplicate
      i. Duplicate Notification Number

if Telecommunication…

51. Does Communication Cable and/or Equipment (Non-SCE) require a notification?
   a. Yes ✪(P2)
      i. Inadequate clearance between communication equipment or structures and SCE electrical equipment or structures
      ii. Excessive sag of communication cables
      iii. Loose lashing wire
      iv. Broken or separated messenger wire
      v. Broken, damaged or severely strained communication guy wires
      vi. Excessive bowing or bending of pole from potential overloading at communication equipment attachment points
      vii. Improperly secured communication conductor or equipment
      viii. Vegetation straining communication messenger or guy wire and/or causing structural integrity issues
      ix. Unauthorized Attachment
      x. Other
   *Notification Build Out Required
   b. No
   c. Unable to Determine
   d. ✪Duplicate
      i. Duplicate Notification Number

if "Bundled Conductor"

52. ✪Does Conductor Spacers require a notification?
    Examples: Uneven sag or uneven sub-conductors in bundle circuits, Poor condition of spacers for bundled conductors (in spans ahead and back), etc.
    a. Yes (P2)
        i. Poor condition of spacers for bundled conductors (in spans ahead and back)
        ii. Other

        *Notification Build Out Required

    b. Yes (P3)
    c. No
    d. Duplicate
        i. Duplicate Notification Number

if 'Is Transmission Line hose/Bird Deterrent present?

53. Does Transmission Bird Avian Guard/Deterrent require a notification?
    Examples: Incorrectly installed, damaged
    a. Yes ✪(P2)
        i. Incorrectly Installed
        ii. Damaged
        iii. ■Missing

        *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

if 'Are All Cotter Keys Visible?'

54. ■Do Visible Cotter Keys Require Notification?
    a. Yes
        i. Cotter Key Missing
        ii. Cotter Key Backing Out

        *Notification Build Out Required
    b. No
    c. Unable to Determine
    d. Covered Cotter Keys

        *Notification Build Out NOT Required

55. ■Do Pins Require Notification?

    a. Yes
        i. Pin Backing Out
        ii. Significant Corrosion
        iii. Misaligned Insulator

        *Notification Build Out Required
    b. No
    c. Unable to Determine

d. Covered Pins
*Notification Build Out NOT Required

Grounding/Other

if 'Overhead Shield/Optical/Ground Wire (OPGW/OHGW)'...

56. Does Shield Wire require notification?
    Examples: Signs of damaged strands, hardware, dampers, attachment points, loose tails, etc.
    a. Yes ✪(P2)
        i. Damaged strands
        ii. Hardware
        iii. Dampers
        iv. Attachment Points
        v. Loose Tails
        *Notification Build Out Required
    b. ✪Yes (P3(
    c. No
    d. ✪Duplicate
        i. Duplicate Notification Number

if 'Fault Return Conductor (FRC)'...

57. Does FRC require notification?
    Examples: Signs of damaged strands, hardware, attachment points, loose tails, etc.
    a. Yes ✪(P2)
        i. Damaged Strands
        ii. Hardware
        iii. Attachment Points
        iv. Loose Tails
        *Notification Build Out Required
    b. ✪Yes (P3)
    c. No
    d. Duplicate
        i. Duplicate Notification Number

Footings/Foundations:

58. ✪Does the Footing/Base require a P3 notification?
    Examples: Erosion, Corrosion of the steel at the structure base, Exposed decay pocket at ground line where part of shell is gone
    a. Yes (P2)
        i. Erosion
        ii. Burried Footing (excluding direct bury)
        iii. Corrosion of the Steel at the Structure Base
        iv. Exposed decay pocket at ground line where part of shell is gone
        v. Unable to Determine
            5. No Access
            6. Property Owner
            7. Obstructed
            8. Brush Overgrown
        *Notification Build Out Required
    b. Yes (P3)
    c. No

d. Unable to Determine
    i. No Access
    ii. Property Owner
    iii. Obstructed
    iv. Brush Overgrown
e. Duplicate
    i. Duplicate Notification Number

Vegetation Management

59. Is vegetation trimming or removal required to prevent contact above and/or below transmission conductor and equipment?
Examples: Vines, branches, or foliage presenting an overhang or other imminent threat, Immediate danger concerning palm fronds falling or blowing into conductors, Vegetation arcing or in contact with energized conductor, contact with vegetation above the insulator/Johnny Ball or guying
    a. Yes ✪(P2)
        ☐ Vines, branches, or foliage presenting an overhang or other imminent threat
        ☐ Immediate danger concerning palm fronds falling or blowing into conductors
        ☐ Vegetation arcing or in contact with energized conductor
        ☐ Vegetation or trees (10ft or greater) encroaching on structure or underbuild
        ☐ Vegetation contact on guying above the insulator/Johnny Ball
    *Notification Build Out Required
    b. No
    c. ✪ Duplicate
        i. Duplicate Notification Number

Transmission ROW

60. ✪Is a notification required for brush clearing?
Examples: Access Road to Structure (do we need to take it out from both or just aerial), Pole/Footing Base, Anchors
Note: Anchors should be treated like structure bases for weed abatement/clearing
    a. Yes (P2)
        i. Access Road to Structure
        ii. Pole/Footing Base
        iii. Anchors
    *Notification Build Out NOT Required in GIS, will be created on backend
    b. No

Priority 1

61. Was a Priority 1 Notification identified during this inspection?
    a. Yes
        i. Notification Number
    b. No

Inspection Form End

62. Work Status

WMP Class B Deficiency Action Statements
Guidance-9, Insufficient discussion of pilot programs

Action SCE-8: *In its 2021 WMP Update, SCE shall: 1) detail how risk reduction benefits are calculated or measured for individual pilot programs, 2) provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs, and 3) discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.*

Response:

<u>**Meter Alarming for Downed Energized Conductor (MADEC)**</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
   Detection and prevention of downed energized covered conductor is an important aspect of public safety and of wildfire risk reduction. Covered conductor deployment is an important wildfire mitigation activity for SCE. Though it is expected to reduce the probability of downed wire incidents, it will not eliminate them. The MADEC system can potentially help avoid downed covered conductor remaining energized for extended periods of time, thus reducing public safety risks. The observed effectiveness in detecting downed covered conductor will be used to estimate expected reduction in the probability of a safety incident or ignition due to reduced time that downed conductor stays energized.

   This project is not a pilot but rather an assessment that was communicated in prior WMPs to highlight SCE capabilities with the MADEC system. The objective of this assessment was to evaluate if a change in the current algorithm for bare conductor can be made to make the MADEC system more effective at detecting downed energized covered conductor events. If required, the project also entails making the necessary modifications and testing its efficacy on covered conductors.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs**
   The project will be deemed successful when it can be demonstrated that the current or modified MADEC system performs as well in identifying and mitigating covered conductor wire down incidents as it does for bare conduct down incidents.

   Quantitative pass/fail criteria were not established for the assessment of MADEC improvements. Rather, SCE considers the assessment and potential improvements to MADEC as normal work aligned with continuous improvement. The MADEC system presently works for both bare and covered conductor. The system algorithm is based on machine learning principles therefore, improvements to the system functionally require event occurrences to be fed to the model. SCE expects to continue to improve MADEC for both bare and covered conductor related energized downed wire events.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
   Broad implementation of the algorithm will follow once the success criteria described above is reached. SCE is unable to provide a timeline as testing, validating and modifying the current algorithm is dependent on collection of sufficient covered conductor wire down events to test the current

algorithm, and test the new algorithm if modifications are necessary. The expected effectiveness of covered conductor in reducing wire down events makes the timeline more unpredictable.

<u>Distributed Fault Anticipation (DFA)</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
   DFA provides incipient fault detection alerts for various equipment failure (EFF) events, such as shunt or series arcing that may be linked to precursors for equipment failures. Additionally, DFA provides access to remote data to help minimize fault event re-occurrences, which are generally associated with temporary fault events. The DFA system targets a collection of ignition sub-drivers for both contact with foreign objects (CFO) or EFF related categories which can reduce risks for wildfires ignitions associated with electrical lines and equipment. This includes targeting insulator, connector, splice, switch, clamp, transformer, and capacitor EFF related ignitions as well as benefits in some wire-to-wire contacts and vegetation CFO. The following data captured though this program is used to perform risk analysis: 1) mitigation effectiveness of sub drivers that may lead to wildfires by performing this program/activity; 2) Risk reductions by performing this program/activity; and 3) costs.

   DFA provides increased awareness of incipient faults on circuits which will minimize ignition risk with remediation. DFA aids in locating fault events not previously identified allowing inspection and potential repair actions to prevent future fault re-occurrences. DFA also measures electrical disturbances where the alerts may also inform circuit operational decisions during elevated risk conditions. The observed effectiveness in detecting faults pre-emptively will be used to estimate expected reduction in the probability of faults and potential ignition.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
   - **Incipient Event Detection:** Project will track and analyze incipient events. Scenarios will be analyzed, including determining potential for ignition risk, that will lead to improved identification and location of incipient events. This technology is expected to identify incipient and re-occurring with 75%-85% accuracy. Incipient Event Detection will acquire the highest weighting of the proposed pass/fail criteria.
   - **Operational Awareness**: Project will track DFA Grid Event notifications where DFA provides additional circuit conditions/awareness not typically found with other engineering/operational tools. This allows SCE Operations to proactively configure the system or reactively confirm issue is resolved. Event location will be weighted less but is expected to be within the range of 75%-80% accuracy.
   - **Equipment Failure Ratio:** Track DFA device failure ratio. Equipment received should be free of damage, defects, and in-service failures. Expected failures identified during installation shall not exceed 1% for the 150 planned units to be installed in 2021.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
   Further expansion of 150 units was deemed necessary to continue evaluating the technology performance including the capture of additional data for analysis and refinement of the algorithm. Overall performance metrics are expected to be maintained above 80% using all pass/fail criteria to determine success.

Advanced Unmanned Aerial Systems (UAS) Study

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
   Patrolling overhead lines prior to potential PSPS events to determine asset conditions is necessary to determine ignition risks and validate the need for PSPS so that it is only used as a last resort. Likewise, and consistent with industry standard practice, conducting a patrol prior to re-energizing lines after PSPS events will reduce the potential for ignitions since dangerous weather conditions may have damaged or otherwise compromised SCE infrastructure. Pre- and post-patrols look for issues such as bird nests, encroaching vegetation, properly seated conductors, damaged or leaning/canted cross arms and poles, and other debris in the lines (e.g., metallic balloons). Currently, SCE performs these pre- and post-patrols using trucks or helicopters. UAS patrols are expected to decrease the time it takes to conduct the patrol and re-energize the lines, to reduce outage duration. This technology is not to reduce risk, but to improve efficiency.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
   SCE has completed the study and validated that the technology is effective. The following criteria were used to validate the performance of the Advanced UAS:
   - The video quality was high enough such that the inspector is able to see the same (or better) level of detail that he/she would see via traditional means (via truck, foot, or helicopter) in order to render an 'all-clear' designation using their professional judgment. No quantitative criteria exist for this metric as it is a professional pass/fail judgment. The UAS team responsible for conducting the patrol missions was able to deploy/mobilize to the subject PSPS circuit location in less than 48 hours of SCE call-out
   - During the final UAS patrol missions, the time to complete patrol and render all clear designation did not exceed the time it took to conduct the patrol via traditional means (via truck, foot, or helicopter). During the latest simulated patrol conducted in late 2020, the UAV was able to complete the patrol in half the time it took the inspectors to drive the line in a truck. Though the difference in time required using traditional patrol versus UAS can vary depending on the circuit and event conditions, the technology was deemed successful as this difference is expected to be positive under most circumstances.
   - SCE was able to secure the proper FAA waivers/authorizations to legally conduct BVLOS missions. No quantitative criteria exist for this basic legal requirement in order to complete BVLOS missions.
   - UAS teams were able to maintain reliable command, control, and video streaming communication with the aircraft during the duration of the mission. No quantitative criteria exist as this is a basic operational requirement.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase**
   Given that the technology has been proven, the next step prior to broad implementation is performing detailed cost-benefit and make-buy analyses. A make-buy analysis should help SCE determine if it needs to bring these capabilities in-house or if SCE should rely on vendors to complete these missions as technology and industry rapidly evolves in the UAS market.

Ground Fault Neutralizer (GFN)

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
GFN uses Rapid Earth Fault Current Limiter (REFCL) technology to reduce the energy from ground faults, thus reducing the sparking which can lead to ignitions. This technology also capable of detecting low magnitude faults, thus increasing the sensitivity of faults that can be detected and remediated. Extensive testing in Australia suggests GFN can reduce the energy produced from ground faults by approximately 90% and can clear 0.5 Amp faults. As part of this project, SCE has deployed this technology at one substation which feeds 180 miles of circuitry. The objective is to validate the expected effectiveness in reducing fault energy and detecting low magnitude faults effectiveness, evaluate need to replace or upgrade equipment on the circuits, and potential damage to existing equipment and associated service reliability impact. These will be measured directly during GFN operations. In addition, SCE is observing the impact on training for field personnel and system operations.

The observed effectiveness in reducing fault energy and clearing low magnitude faults will be used to estimate expected reduction in the probability of faults leading to ignitions.

2) Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.

The objective the project is not to determine success or failure of the technology, but to collect information that will enable SCE to perform risk spend efficiency (RSE) calculations to determine whether GFN should be deployed to other substations, and if yes, the scope of broader deployment.

- **Effectiveness in reducing fault energy:** More than 90% reduction would indicate success. Even if less than 90% reduction, the observed benefits will inform the RSE calculations at the end of the project.
- **Detecting and clearing low magnitude faults:** Consistently clear 0.5 Amp faults within two seconds will be considered success. Even if this is not achieved, the benefits observed will inform RSE calculations at the end of the project.
- **Evaluate need to replace or upgrade equipment on the circuits:** Costs of replacements or upgrades will be measured for RSE calculations at the end of the project. No threshold values or pass/fail criteria has been set on this metric.
- **Potential damage to existing equipment and associated service reliability impact:** Costs to replace damaged equipment and reliability metrics (SAIDI/SAIFI) associated with outages will be measured to inform RSE calculations at the end of the project. No threshold values or pass/fail criteria has been set on these metrics.
- **Impact on training:** Evaluated qualitatively based on observation and feedback from field personnel. There are no success thresholds. If challenges are identified, appropriate training has to be developed and implemented.
- **System operations:** Evaluated qualitatively based on observation and feedback from operations personnel. There are no success thresholds. If challenges are identified, appropriate operational guidelines have to be developed and implemented.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**

SCE plans to energize the GFN at one substation in the second quarter of 2021 and conduct evaluations through the end of 2021. Based on observed effectiveness in reducing ground fault energy, low magnitude fault clearing capability, costs and service reliability impacts, SCE will perform RSE analysis in 2022 to determine whether GFN should be added to the portfolio of wildfire mitigation activities. There is no pre-determined threshold RSE value. Rather, the calculated RSE will be compared to the RSEs of ongoing activities to determine relative ranking. If selected, resource and funding requirements and availability will be evaluated to determine the scope of broader deployment.

<u>Resonant Grounded Substations (RGS)</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**

The GFN technology discussed above has been used and evaluated in Australia for ground fault reduction. RGS is a different approach that if proven effective, can reduce the cost and complexity of deployment. The project objectives are the same as that described for GFN. Simulations suggest that this approach may be more suitable for smaller substations.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs**

Since RGS is a different and untested approach, more experimentation is needed with different protection schemes to improve the effectiveness of the technology. The metrics measured will be the same as than for GFN which will be used to inform RSE calculations at the end of the project. Along with cost of implementation, the complexity of implementation will also be evaluated to compare to GFN.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**

As with GFN, RSEs will be calculated at the end of the project based on observed effectiveness in reducing fault energy and clearing low magnitude faults quickly, and implementation costs. If the effectiveness is comparable to GFN, RSE is comparable or better than GFN, and implementation complexity is lower, RGS could be deployed more broadly at smaller substations. Broad deployment will also depend on comparison of RSEs to other ongoing WMP activities and availability of funding and resources. Since the evaluation will be based on RGS RSE relative to the RSEs of other activities and resource needs relative to resource availability, threshold values cannot be set at this time.

<u>Isolation Transformer REFCL Scheme</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**

The Isolation Transformer scheme is yet another approach for REFCL Technology that is expected to be lower cost and less complex implementation compared to GFN. SCE is further along in evaluating this technology compared to RGS discussed above and is reasonably confident that it can meet the effectiveness described in the GFN section above. The project objectives are the same as that described for GFN.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
Since Isolation Transformer is a different and untested approach compared to GFN, more experimentation is needed to validate the effectiveness of the technology. The metrics measured will be the same as than for GFN which will be used to inform RSE calculations at the end of the project. Along with cost of implementation, the complexity of implementation will also be evaluated to compare to GFN.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
As with GFN and RGS, RSEs will be calculated at the end of the project based on observed effectiveness in reducing fault energy and clearing low magnitude faults quickly, and implementation costs. If the effectiveness is comparable to GFN, RSE is comparable or better than GFN, and implementation complexity is lower, the Isolation Transformer scheme could be deployed more broadly. Such deployment will also depend on comparison of RSEs to other ongoing WMP activities and availability of funding and resources. Since the evaluation will be based on Isolation Transformer RSE relative to the RSEs of other activities and resource needs relative to resource availability, threshold values cannot be set at this time.

<u>**Distribution Open Phase Detection (D-OPD)**</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
This project is to evaluate if D-OPD is capable of de-energizing a circuit or circuit segment when a conductor breaks before the conductor hits the ground. SCE has currently installed this technology on five locations to validate the technology before pilot scale or broader deployment. The observed effectiveness and speed in de-energizing wires during wire-down events will be used to estimate expected reduction in the probability of faults leading to ignitions.

   Depending on the sensitivity, D-OPD settings can lead to false detection that de-energizes a line when no fault exists. The project will include evaluation of the probability of false detections and the reliability impact from these. If multiple OPD devices detecting a false/correct OPD condition are triggered simultaneously, it can lead to a “scheme operation” that results in widespread outages. Any scheme operation would be unacceptable and will disqualify SCE’s use of this technology.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
The quantitative pass/fail criteria used to determine the performance of the D-OPD project is focused on two areas. The two areas are (1) whether D-OPD can detect and alarm for open phase events (2) the probability of false detections and scheme operations.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**

- Review relay event data and determine if the relay alarmed correctly for D-OPD detections (at least 80% of the events detected by D-OPD device were correct).
- Review relay event data and determine ratio of detected D-OPD events versus non-detected events (at least 80% of total events on the system were detected by the D-OPD device).

Only after the technology has been proven, will SCE consider quantifying benefits and costs for future broader implementation.

Vibration Dampers

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
Significant research and benchmarking were performed to understand the effect of Aeolian Vibration on covered conductor. From this research, it is clear that the risk of Aeolian Vibration, unmitigated, could lead to premature conductor failure. The installation of vibration dampers reduces the effects of aeolian vibrations that may lead to conductor fatigue failure or abrasion damage, therefore preventing in-service failure/downed wires. The objective of this project was to evaluate vibration damper models that could be deployed in SCE's distribution lines in HFRA. This project was successfully concluded and installation of vibration dampers during covered conductor installation is the construction standard going forward. SCE is also evaluating covered conductor segments already deployed to see if vibration dampers should be installed in high risk locations.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs**
The criteria used for vibration dampers selection was whether it would fit all distribution conductor sizes, would not need customized engineering for installation (as needed for transmission conductor dampers) and would not damage the conductor.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
SCE assessed the effectiveness of dampers developed for covered conductor with the below threshold values through lab and field testing. Lab testing measured the energy dissipated by the damper. Field testing involved monitoring the frequency and amplitude of vibration in a damped and undamped span. The following were success criteria for damper effectiveness:
   - Lab testing illustrated that the power dissipated by the vibration damper is higher than the Wind Input Power.
   - Field testing illustrated that the vibration damper significantly reduced high frequency (above 5 Hz), low amplitude vibrations.
   - Field testing illustrated that the vibration damper significantly reduced strains higher than the 150 micro strain peak-peak value.

   In addition, as described above, SCE selected a vibration damper model that met the required criteria prior to broad deployment.

Asset Defect Detection Using Machine Learning Object Detection

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
The objective of this project is to train and test a machine learning (ML) algorithm that can detect asset defects more efficiently that can help prioritize inspections and remediation, which in turn will

reduce the probability of faults that can lead to ignitions. Currently SCE is building the data library for its distribution assets which can then be used for the ML algorithm.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
For data collection efforts, the effectiveness metric will be determined by whether or not at least 80% of the inspection imagery collected and stored is accessible for developing the machine learning algorithms. The ability of AI/ML to detect defects in utility assets inspections will be evaluated by the success rate of detecting true positives in the dataset. An acceptable success measure for the ML engine is a detection rate above 80%. The computer vision engine's detection rate will be heavily dependent on the quality of the input data and the duration of the algorithm's learning. The detection rate and accuracy if the algorithm will improve as time passes since the algorithm will improve its detection as it processes a growing number of images.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
Once the pass/fail criteria above are met, the operational strategy will be to integrate the ML model analytics to augment existing inspection management and desktop inspector tools. Continued feedback between inspectors and the ML team is key to successful evaluation of the model. ML models are expected to be valuable in prioritizing work for human inspectors by shortening the time between image capture and review and subsequent issue remediation. Scaling will take place by expanding defect use cases and refining the ML model/process via inspector feedback/calibration and continuous improvement of the model.

<u>**Transmission Partial Discharge**</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
Helicopter mounted partial discharge detection has the potential to assess asset health to determine if there may be indication of damaged or failing equipment allowing for proactive remediation prior to in-service failures. SCE has decided not to proceed with this pilot as other inspection practices (e.g., infrared and corona) provide similar information. In addition, the initial data indicated that the technology only provides the physical location, i.e. GPS location, of where partial discharge is happening but does not provide any information regarding the actual component, failure indication, or intensity. This requires additional crew/inspections and tools to travel to each site to identify the component of the source of the partial discharge.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
Not applicable as SCE has decided not to proceed with this pilot.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
Not applicable as SCE has decided not to proceed with this pilot.

<u>**Early Fault Detection (EFD)**</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs**
EFD is an early-stage technology that if proven and successfully integrated into utility operations can provide broad benefits in monitoring asset performance on the distribution system and detecting

undesirable circuit conditions early allowing repair and replacement actions to be proactively completed prior to component or conductor failure. The sensors continuously monitor the system and provide location information when issues are detected. The EFD system detection is anticipated to help to detect internal arcing in transformers, degraded insulators, failing clamp or connectors, degraded conductor stranding, and temporary vegetation contacts. This phase of the project is limited in scope and focused on understanding how the technology can be deployed in SCE's distribution system and how the data generated can be communicated and integrated into SCE's systems. SCE is also testing the frequency of false alarms to determine if the manufacturer needs make additional modifications to the devices. Therefore, this phase of the project is to determine feasibility of this technology for SCE system and operations. The next phase will be to have a pilot to quantify benefits in terms of accuracy in determining potential fault conditions early and to quantify costs which can be used to inform RSE analysis and impacts of allocation of resources and funding if this is added to SCE's WMP.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
As discussed above, the success criteria for this project is if and how the technology can be integrated with SCE's electric, communication and data systems based on engineering and operational analysis. These are not quantitative criteria, but rather a determination by SMEs that SCE is technically ready to move to the pilot phase for analyzing benefits and costs.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
As discussed above, the purpose of this project phase is not to determine risk reduction benefits, but technical feasibility. Broad deployment is not contemplated till a successful pilot can be conducted to compile the necessary data. Therefore, it is pre-mature to have quantitative thresholds at this time.

<u>**High Impedance Relays (Hi-Z)**</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
The objective of this project was to develop a protection scheme to detect high impedance faults (such as downed energized conductors) that may not be detected by conventional protection and determine how to integrate this into our system and operations. SCE has determined that this is a relatively low-cost option and the next step is to determine the frequency of false alarms, work with the vendor to reduce instances of false alarm if necessary and conduct SCE analysis prior to considering broad scale deployment.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
The quantitative pass/fail criteria used to determine the performance of the Hi-Z project is focused on two areas. The two areas are (1) false detections, and (2) the accurate detection and alarm for Hi-Z events.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
    - Review relay event data and determine if the relay alarmed correctly for Hi-Z events (at least 80% of the events detected by the device are correct).

- Review relay event data and determine ratio of detected Hi-Z events versus non-detected events (at least 80% of detected events on the system were detected by the device).

<u>Satellite and Other Imaging Technology for Fire Spotting</u>

1) **Detail how risk reduction benefits are calculated or measured for individual pilot programs.**
   Early detection of fires can help SCE's Fire Management Officers make more informed decisions about how to respond to the fire including deploying resources and coordinating with fire authorities and other SCE stakeholders. Satellite and other imaging technology can be used to help determine the point of ignition origin quickly and perform threat assessments. Risk reduction benefits can be estimated using the expected reduction in ignition consequence based on the number and timeliness of ignitions detected.

2) **Provide the quantitative pass/fail criteria used to determine the performance of individual pilot programs.**
   If any fire is detected early using these imaging technologies, this project would be considered a success.

3) **Discuss what threshold values are required to initiate broad implementation of pilot programs beyond the pilot phase.**
   SCE will evaluate the expected reduction is risk along with the cost of deploying this technology. A threshold value is not applicable as the benefits and costs of this technology have to be compared to other wildfire mitigation activities to determine if this should be broadly deployed. Funding availability at the time of deployment has to be assessed as well.

WMP Class B Deficiency Action Statements
SCE-3, Failure of Commitment

Action SCE-11*: In its 2021 WMP Update, SCE shall: 1) report on whether it achieved its expected 2020 reduction in PSPS frequency, scope, and duration, 2) commit to achieve these, or further, reductions in 2021 and beyond, and 3) set measurable, year to year, goals for reduction of the frequency, scope, and duration of PSPS events for 2021 and 2022.*

Response:
1) SCE's 2020 PSPS reduction forecast stated "With the improvements SCE has made since last year, under the same conditions we would expect to see a 30% reduction in the number of customers affected by future PSPS events." Due to different weather patterns and SCE mitigation activities, only 54 percent of the circuits de-energized in 2019 were de-energized again in 2020. When those circuits were impacted, SCE interrupted 36 percent fewer customers. While SCE did achieve the reductions expected for circuits impacted in 2019, overall there were more circuits and customers de-energized due to the differences in weather patterns experienced in 2020 as compared to 2019. The weather conditions experienced in 2020 required 16 percent more PSPS de-energizations as compared to 2019, affecting 13 percent more customers during the year. Certain customers and communities were particularly hard hit, with nearly 12,000 customers being de-energized five or more times.

So, while SCE made some positive progress in PSPS execution in 2020, more frequent Santa Ana wind conditions and less precipitation created widespread wildfire risk in 2020. SCE realizes that the resulting PSPS impacts did not meet the expectations of regulators or customers and will discuss forecasted improvements below. See the table below for a comparison of PSPS impacts from 2019 and 2020.

2020 PSPS Impacts Compared to 2019 (year over year comparison)

Total Circuits De-energized	Total Customers De-energized	Same Circuits De-energized in Both Years	Same Customers De-energized in Both Years
↑16%	↑13%	↓46%	↓36%

2) SCE recognizes the serious and ongoing impacts of PSPS on customers and is committed to programmatic improvements targeted at reducing de-energizations and reducing the burden of de-energizations, should they be necessary. In 2021, SCE expects to see a more than 15 percent reduction in the number of customers who were affected by PSPS de-energizations in 2020 to be affected in 2021 PSPS events, based on the PSPS protocol improvements and grid hardening completed since last year and with the same weather conditions as in 2020. More than half of that reduction, or almost 13,000 customers, are not expected to experience PSPS again. This customer reduction would equate to a more than 20 percent reduction in the number of circuit de-energizations due to PSPS in 2021 over 2020, and those avoided circuit de-energizations would lead to a more than 35 percent reduction in the total customer minutes of interruption (CMI). This commitment is based on known scope of improvements and mitigations, as of January 2021, and SCE will analyze opportunities for further improvements as part of its 2021 readiness process.

2021 Anticipated PSPS Reductions

Scope	Frequency	Duration
↓15%+	↓20%+	↓35%+

(~27,000 Customers)	*(~100 Circuits)*	*(~100M Customer Minutes of Interruption [CMI])*

These anticipated benefits are driven primarily by three key PSPS mitigations: SCE's circuit exception process, deployment of backup power, and circuit threshold adjustments. SCE's circuit exception process entails a detailed periodic review of circuits and circuit-segments located in HFRA to identify those with sufficiently low wildfire risk based on the latest information to warrant removal from future PSPS scope altogether. Wildfire risk changes on this scale can be brought about through deployed PSPS mitigations such as asset upgrades or circuit reconfiguration, or through fuel loading changes driven by processes like urbanization. In addition, SCE is continuing to re-evaluate alternatives and refinements to its circuit exception process which was included in SCE's Corrective Action Plan submission to the Commission on February 12, 2021. SCE will include any changes in approach, scope or cost in Change Order Reports to this WMP.

SCE expects to raise circuit windspeed thresholds to the National Weather Service's High Wind Warning thresholds based on covered conductor installation. While few circuits have full covered conductor coverage currently, SCE expects a large number of isolatable segments to be fully covered in 2021.

The above reduction forecast was calculated and filed before SCE's Corrective Action Plan Filing on February 12, 2021. Corrective Action 1 of this plan describes ongoing work that is incremental to the above forecasts and should serve to further reduce PSPS impacts in 2021 and beyond. As stated in the filing, SCE will develop metrics to reflect each reduction and report these to the Commission in its bi-weekly reports.

3) The 2021 mitigations outline above are expected to yield the same PSPS reduction benefits in 2022 as well, though SCE will continue to monitor PSPS execution and perform analysis for further improvements that can be made based on 2021 performance.

Initiatives like modeling enhancements and the creation of switching playbooks can be implemented relatively quickly across all HFRA circuits. Many of these "quick win" type of projects have already been completed, and incremental changes in PSPS reduction will take longer. Grid hardening is one of, if not, the most important mitigations that SCE can deploy to reduce PSPS. Small increases to thresholds and triggers can be expected as circuits undergo modernization and hardening, but significant adjustments can only be undertaken over a longer period of time, once all of the necessary upgrades have been performed on isolatable segments throughout HFRA.

WMP Class B Deficiency Action Statements
SCE-5, Detailed timeline of WRRM implementation not provided

Action SCE-13: *In its 2021 Update, SCE shall: 1) list the 2020 WMP initiatives being reevaluated using WRRM and the results of that reevaluation, and 2) show how the new WRRM risk scores compare to those from the previous REAX+ model.*

Response:
1) The WRRM did not impact in-flight work in scope in 2020 nor early 2021. Changes to SCE's 2020-2022 WMP initiatives' scope or priority as a result of WRRM implementation is discussed in the 2021 WMP update, please see the Table below. Each in-flight initiative that has in the past used some form of risk informed decision process such as the WRM, Reax only, or an alternative prioritization method is being evaluated for WRRM applicability. Programs that have not yet initiated 2021 activities will use the revised risk scores from the WRRM while those where it is operationally not feasible to transition to the new scores in 2021 will begin doing so in 2022.

As the WRRM is now SCE's corporate standard model for calculating wildfire risk, all new programs will be evaluated and prioritized using this model where applicable. The WRRM is being used to make risk informed decisions throughout our wildfire programs, however where the model is not able to accurately assess a risk, other methods will be used. For example, in this WMP SCE is presenting a program to replace vertical switches. These switches have not experienced high numbers of faults historically and therefore have low POI values in the model. However, through inspections, evidence of sparking was discovered. In this case, the RSE values produced by using the WRRM would not be considered as the main driver for evaluating this program within the portfolio of programs, but the order in which we replace these switches would utilize the consequence component of the WRRM.

While the WRRM is the primary tool used to make risk prioritized decisions for wildfire mitigation, SCE uses subject matter expertise and qualitative enterprise level risk tools to help make risk informed decisions when quantitative methods are not available or sufficient in and of themselves. The risk bowtie, fault trees, decision trees, failure modes and effects analysis (FMEA), and probabilistic risk assessment (PRA) are some examples of these methods. For SCE's RAMP risks and for the WMP, SCE translates the outputs of these methods into MARS units to calculate RSEs and compare across different risks and mitigation alternatives.

Initiative / Activity	Risk-Informed Prioritization	Risk Models Used (2020)	Current Risk Models Used (2021)	Future Risk-Informed Decision Making Enhancements (2022)
Weather forecasting and estimating impacts on electric lines and equipment: Fire Spread Modeling (SA-4)	Yes	Reax (Consequence)	WRRM	WRRM
Mitigation of impact on customers and other residents affected during PSPS event	Yes	WRRM	WRRM	WRRM
Other corrective action - Long Span Initiative (SH-14)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Transmission tower maintenance and replacement: C-Hooks (SH-13)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Undergrounding of electric lines and/or equipment: Undergrounding Overhead Conductor (SH-2)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Legacy Facilities (SH-11)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Circuit breaker maintenance and installation to de-energize lines upon detecting a fault: Circuit Breaker Relay Hardware for Fast Curve (SH-6)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Covered conductor installation: Covered Conductor (SH-1)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Covered conductor installation: Tree Attachment Remediation (SH-10)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Crossarm maintenance, repair, and replacement	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Distribution pole replacement and reinforcement, including with composite poles: WCCP Fire Resistant Poles (SH-3)	Yes	RAMP model; Reax (Consequence)	WRRM	WRRM

Expulsion fuse replacement: Branch Line Protection Strategy (SH-4)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Grid topology improvements to mitigate or reduce PSPS events: Circuit Evaluation for PSPS Driven Grid Hardening Work (SH-7)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other corrective action: Distribution Remediations (SH-12.1)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other corrective action: Transmission Remediations (SH-12.2)	Yes	Reax (Consequence)	WRRM	WRRM
Other corrective action: Generation Remediations (SH-12.3)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations: Aerial Inspections - Transmission (IN-6.2)	Yes	Reax (Consequence)	WRRM	WRRM
Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations: Aerial Inspections - Distribution (IN-6.1)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Detailed inspections of distribution electric lines and equipment: Distribution HFRA Detailed Inspections + Remediations (previously ODI)	Yes (Re-mediations)	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations: Transmission Risk-Informed Inspections in HFRA (IN-1.2)	Yes	RAMP model; Reax (Consequence)	WRRM	WRRM
Infrared inspections of distribution electric lines and equipment: Infrared Inspection of Energized Overhead Distribution Facilities and Equipment (IN-3)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM

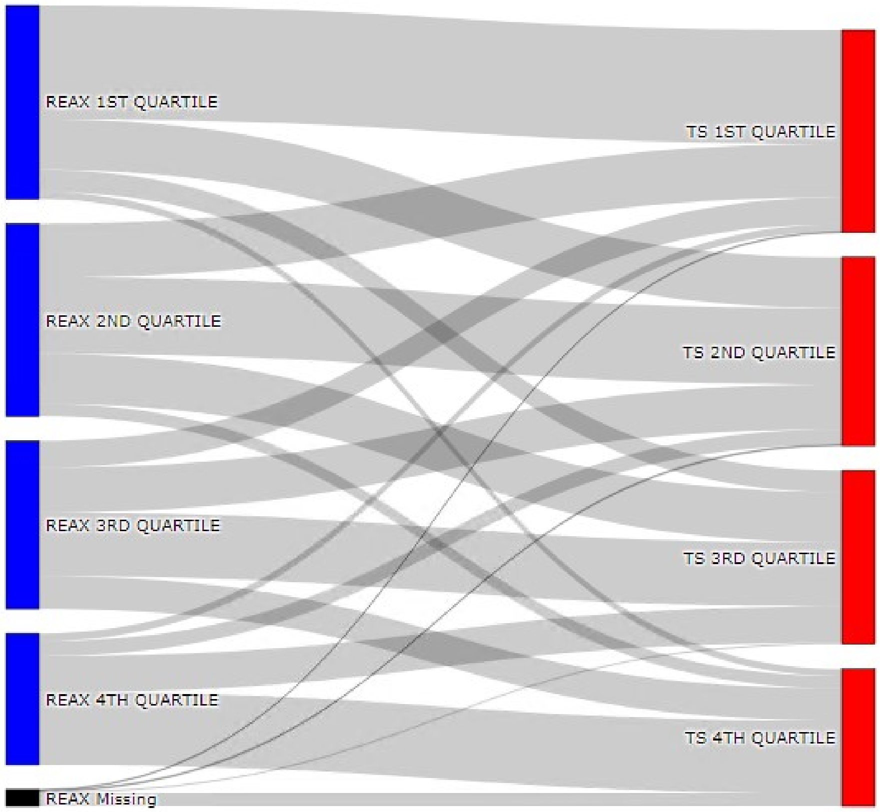
Infrared inspections of transmission electric lines and equipment: Infrared Inspection, Corona Scanning, and High Definition Imagery of Energized Overhead Transmission Facilities and Equipment (IN-4)	Yes	RAMP model; Reax (Consequence)	WRRM	WRRM
LiDAR inspections of distribution electric lines and equipment	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
LiDAR inspections of transmission electric lines and equipment	Yes	Reax (Consequence)	WRRM	WRRM
Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations: Distribution High Fire Risk-Informed Inspections (IN-1.1)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations: Generation Risk-Informed Inspections in HFRA (IN-5)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM
Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations	Yes	RAMP model; Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Patrol inspections of vegetation around distribution electric lines and equipment	Yes	RAMP model; Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Patrol inspections of vegetation around transmission electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Quality assurance / quality control of inspections: Quality Control (VM-5)	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Remediation of at-risk species	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index

Removal and remediation of trees with strike potential to electric lines and equipment: Hazard Tree (VM-1)	Yes	RAMP model; Reax (Consequence); Tree Risk Calculator	Reax (Consequence) transitioning to WRRM/ Tree Risk Calculator	WRRM; Tree Risk Calculator
Removal and remediation of trees with strike potential to electric lines and equipment: Dead and Dying Tree Removal (VM-4)	Yes	RAMP model; Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM
Substation inspections	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Substation vegetation management	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Detailed inspections of vegetation around distribution electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Vegetation management to achieve clearances around electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Detailed inspections of vegetation around transmission electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM; Tree Risk Index
Fuel management and reduction of "slash" from vegetation management activities: Expanded Pole Brushing (VM-2)	Yes	RAMP model; WRM (POI)/ Reax (Consequence)	WRRM	WRRM
Fuel management and reduction of "slash" from vegetation management activities: Expanded Clearances for Legacy Facilities (VM-3)	Yes	N/A	WRRM	WRRM
LiDAR inspections of vegetation around distribution electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM
LiDAR inspections of vegetation around transmission electric lines and equipment	Yes	Reax (Consequence)	Reax (Consequence) transitioning to WRRM	WRRM

Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Yes	RAMP model; Reax (Consequence); Tree Risk Calculator	Reax (Consequence) transitioning to WRRM/ Tree Risk Calculator	WRRM; Tree Risk Calculator
PSPS events and mitigation of PSPS impacts: Battery Backup Programs (PSPS-3)	N/A	N/A	WRRM	WRRM
PSPS events and mitigation of PSPS impacts: Income Qualified Critical Care (IQCC) Customer Battery Backup Incentive Program (PSPS-4)	N/A	N/A	WRRM	WRRM
PSPS events and mitigation of PSPS impacts	Yes	N/A	WRRM	WRRM
PSPS events and mitigation of PSPS impacts: Community Resource Centers (PSPS-2)	Yes	RAMP Model	WRRM	WRRM
Installation of system automation equipment: installation of system automation equipment - Vertical Switches (SH-15)	Yes	WRM(POI)/Reax (consequence)	WRRM	WRRM

2) The Sankey chart below shows the changes from Reax to Technosylva from a quartile ranking perspective. The left side shows the risk ranking from using Reax consequences, and the right side shows the risk ranking from using Technosylva consequences. The arrows in the middle reflect the movement across the four quartiles. For example, X% from top quartile based on Reax remains on the top quartile using Technosylva; Y% from top quartile based on Reax moves to the second quartile using Technosylva. Similar logic applies for all other quartiles. Reax Missing data represents segments of conductor that Reax was unable to provide consequence values for, but Technosylva does have consequence scores, which highlights one of the benefits of the implementation of Technosylva in 2020.

Reax to Technosylva Consequence Comparison – Sankey Chart



The table below shows the data for the Sankey chart plot:

Observed Changes in Ranking When Comparing Reax and Technosylva Consequence Scores

Reax Quartile	Technosylva Quartile	% Observations
REAX 1ST QUARTILE	TS 1ST QUARTILE	58.65%
REAX 1ST QUARTILE	TS 2ND QUARTILE	26.26%
REAX 1ST QUARTILE	TS 3RD QUARTILE	11.34%
REAX 1ST QUARTILE	TS 4TH QUARTILE	3.75%
REAX 2ND QUARTILE	TS 1ST QUARTILE	27.89%
REAX 2ND QUARTILE	TS 2ND QUARTILE	39.68%
REAX 2ND QUARTILE	TS 3RD QUARTILE	26.03%
REAX 2ND QUARTILE	TS 4TH QUARTILE	6.40%
REAX 3RD QUARTILE	TS 1ST QUARTILE	15.91%
REAX 3RD QUARTILE	TS 2ND QUARTILE	26.79%
REAX 3RD QUARTILE	TS 3RD QUARTILE	38.12%
REAX 3RD QUARTILE	TS 4TH QUARTILE	19.17%
REAX 4TH QUARTILE	TS 1ST QUARTILE	5.77%
REAX 4TH QUARTILE	TS 2ND QUARTILE	11.50%

REAX 4TH QUARTILE	TS 3RD QUARTILE	27.53%
REAX 4TH QUARTILE	TS 4TH QUARTILE	55.20%
REAX Missing	TS 1ST QUARTILE	4.90%
REAX Missing	TS 2ND QUARTILE	6.72%
REAX Missing	TS 3RD QUARTILE	10.20%
REAX Missing	TS 4TH QUARTILE	78.18%

WMP Class B Deficiency Action Statements SCE-8
SCE-16, Lack of detail on hotline clamp replacement program

Action SCE-16: *In its 2021 WMP Update, SCE shall: 1) explain whether its POI models account for splices, clamps or connectors, 2) if so, provide information detailing the impact of hotline clamp (HLC) replacements on POI, and 3) if not, explain why.*

Response:
1) SCE's current POI models include the splice/clamps/connectors failures by including historical failures caused by splice/clamps/connectors.

2) SCE does not have a dedicated WMP activity for HLC replacements. However, we provided details regarding how our inspection and maintenance activities replace HLCs when they are found in need of repair. SCE's data systems do not track connector type at the level of detail to differentiate an HLC replacement from other connector replacements. As such, SCE does not have impact details of HLC replacements on the POI.

3) As noted in response to part 1 above, SCE's POI model applies connector-related failures, including HLC connectors, equally across all connection types and does not distinguish HLC clamps. Because the total population of HLCs is not tracked, SCE is not able to detail the impact of HLCs on the POI.

WMP Class B Deficiency Action Statements
SCE-9, Lack of detail regarding Pole Loading Assessment Program

Action SCE-17: *In its 2021 WMP Update, SCE shall: 1) report how many PLP assessments have been completed between August 1 and November 30, 2020 and 2) if SCE's forecast of 1,250 assessments was not met, explain why there is a discrepancy between the forecast and work completed.*

Response:

1) SCE completed 345 PLP assessments between August 1 and November 30, 2020.

2) SCE did not meet its 1,205[4] forecasted target during this period due to operational constraints as outlined in its quarterly reports.[5] As SCE nears the end of PLP assessments, the remaining poles present customer and other access challenges which increase scheduling and planning uncertainty. SCE is working to actively resolve these challenges. Customers sometimes deny admission to their properties where poles are located or are not available when needed, requiring additional process steps to negotiate access or resolve disputes, sometimes through litigation. SCE has also experienced access issues due to customer COVID-19 concerns and anticipate these concerns will continue until the pandemic has subsided.

   Weather and fires have also limited access to poles. Additionally, some pending poles are inaccessible due to hazardous terrain and will need to be assessed via helicopter LiDAR pilot.

   Outstanding pole assessments are carried forward to the work plan for the following quarter and completion will be dependent on resolving access issues as described above.

[4] The reference in Action SCE-17 to "1,250 assessments" appears to be a typographical error.
[5] See SCE's Q4 2020 Quarterly Data Report, available at:
https://www.sce.com/sites/default/files/AEM/Wildfire%20Mitigation%20Plan/2021/SCE%20Q4%202020%20QDR.pdf.

Responses to WSD Action Statement on Remedial Compliance Plan
SCE-12, Insufficient justification of increased vegetation clearances

Action SCE-18*: In its 2021 WMP update, SCE along with PG&E and SDG&E shall submit a joint, unified plan that reflects collaborative efforts and contains uniform definitions, methodology, timeline, data standards, and assumptions.*

Response:
SCE requested and received an extension from the WSD to file its reply to this Action Statement by February 26, 2021, in lieu of submitting this response as part of its 2021 WMP Update. SCE has participated in joint meetings with PG&E and SDG&E to discuss opportunities for IOU alignment to provide the CPUC with uniform definitions, methodology, timeline, data standards, and assumptions. SCE believes the best effectiveness measure regarding enhanced clearances is the overall reduction in vegetation-caused outages on an annual basis.[6]

DEFINITIONS
Although the IOUs use slightly different terminology, PG&E, SDG&E and SCE are aligned on the definition of "Enhanced Clearance." For PG&E and SDG&E, Enhanced Clearance is considered part of their Enhanced Vegetation Management (EVM) portfolio. All utilities consider Enhanced Clearance as clearance to at least the CPUC recommended clearance in GO 95, Rule 35, Appendix E, (12 feet) at time of maintenance in areas of elevated wildfire risk. Anything less than the CPUC-recommended clearance in GO 95, Rule 35, Appendix E, (12-feet) that still meets the minimum regulatory clearance of 4 feet is considered non-Enhanced Clearance.

The IOUs have agreed to other uniform definitions, including the understanding that clearances are measured by radial clearance from the conductors. These definitions include focusing on areas of elevated fire risk areas that are consistent with Tier 2 and 3 HFTD and State Responsibility Areas, as well as vegetation-caused outages which include all known outage types, regardless of storm-caused, fall-in, blow-in, or grow-in risk. While the definitions are the same, the terminology differs for each IOU. PG&E's "Vegetation Caused Outages," SDG&E's "Vegetation Risk Events," and SCE's "Tree Caused Circuit Interruptions" are terms the IOUs use to describe data sets that document and track known vegetation related power outages.

METHODOLOGY
SCE's methodology includes reviewing and comparing total enhanced clearance work performed with total TCCIs and is based on the premise that an inverse relationship exists between the two variables. SCE will also have the ability to drill down into specific regions, and species type, to account for variations in environmental or agency permitting constraints associated with enhanced clearances.
SCE will take the following steps to measure the effectiveness of its enhanced clearances:

[6] Although outages in some instances may lead to an ignition, for the purposes of this analysis the effectiveness of this mitigation is measured by its direct impact on outages and not its indirect impact on ignitions.

Step 1: Quantify vegetation-caused outage data for calendar years from outage investigation reports before the implementation of enhanced clearances.

Step 2: Collect vegetation-caused outage data for calendar years from outage investigation reports after implementation of enhanced clearances.

Step 3: Analyze trends in outages in Steps 1 and 2 to determine the nature of the trend and whether it was related to enhanced clearances.

SCE's and PG&E's current approaches are aligned; however, SDG&E will take a slightly different approach due to data availability. SDG&E's outage data is directly linked to its tree inventory, whereas SCE and PG&E do not have this information directly mapped. SCE has implemented processes to begin mapping this information and may refine its approach to this analysis, similar to SDG&E, over time.

TIMELINE

To measure enhanced clearance effectiveness, SCE and PG&E are comparing outage and vegetation management data from the "pre" and "post" enhanced clearances time frames.[7] Pre-enhanced clearance work is defined as all work performed prior to the implementation of enhanced clearances sometime in 2019 (accounting for variation in implementation times between IOUs). Post-enhanced clearance work is defined as work performed after the implementation of new clearance standards intended to achieve the CPUC recommended GO 95 clearances.

All IOUs have concluded that a multi-year analysis is required to normalize against exogenous events, and address variation year-to-year in environmental and weather conditions, to make a determination about the effectiveness of enhanced clearances. Since inspection cycles occur on an annual basis, multiple inspection cycles will be required to collect adequate data for effective analysis. All IOUs have the ability to review outage data dating back at least 3 years, and enhanced clearance tracking data beginning sometime in 2019 and throughout 2020. SCE has agreed to joint IOU, semi-annual reviews as effectiveness measures cannot reasonably be determined in shorter time periods. SCE will internally review TCCI trends on a quarterly basis.

DATA

In alignment with the other IOUs, SCE will utilize data as captured at the time of work completion, from the electronic tools used by field crews. SCE and the other IOUs have secondary data sets gathered from Post Work Verification and Quality Control (which is conducted on a sample after work completion) that may differ from field-collected data. In order to provide the CPUC with consistent data and reporting practices, the IOUs will use the field crew collected data, which is the source data, for analysis.

ASSUMPTIONS

All IOUs have agreed to reporting and data standards for the analysis, including limiting the analysis to only trees in inventory, reporting on known outage data regardless of outage type (e.g., grow-in, fall-in, storm condition, etc.) and reporting work only performed in areas of elevated fire risk for the full calendar

[7] SDG&E's Vegetation Risk Events are directly mapped to the trees in its tree inventory, whereas SCE's and PG&E's outage and tree inventory are not; therefore, SDG&E will take a slightly different approach in its comparison.

year. SCE and PG&E will only report on enhanced and non-enhanced clearances and vegetation-related outages for all species types for the Distribution System, whereas SDG&E will report on five species for both Transmission and Distribution.

WMP Class B Deficiency Action Statements
SCE-14 SCE relies only on growth rate to identify "at-risk" tree species

Action SCE-20: *In its 2021 WMP Update, SCE shall: 1) shall explain why it does not include long-term species vulnerability factors in evaluating "at-risk" tree species (e.g., climate change, water stress/drought), 2) use a scientifically and governmentally accepted definition of "invasive" to assess vegetation attributes as it relates to utility VM activities, 3) provide an evaluation of "at-risk" tree species, rather than tree types, 4) explain the purpose of the Top 10 list and how tree types and/or species are selected for (or excluded from) the list, 5) clarify what is meant by "Subject to improper pruning practices when in proximity to high voltage lines" and explain how SCE trains its VM staff and contractors to identify and avoid improper pruning, and 6) define and/or quantify attributes of "at-risk" tree species, as listed in Table 26 – SCE-14,36 and explain how these factors are weighted.*

Response:
(1) Long-term species vulnerability related to attributes such as climate change and water stress/drought are captured in SCE's HTMP and Dead and Dying Tree Removal programs to address fall-in threats outside of any required clearance distances. Tree species risks associated with SCE's routine compliance line clearing program are mostly focused on grow-in conditions which are typically associated with faster growing species. That being said, all personnel involved in routine compliance work are trained to inspect dead, rotten or diseased trees caused by long-term vulnerability factors such as climate change, drought, water stress, etc., and, therefore, these were not included in the "at-risk" tree species attributes.

(2) For the purposes of the Known Risk Attributes List, SCE's use of the term "invasive" is aligned with the United States Department of Agriculture (USDA) definition. SCE adopts the USDA definitions of invasive plants, with modifications appropriate to the utility. According to the USDA, an *invasive plant* is "[a] plant that is both non-native and able to establish on many sites, grow quickly, and spread to the point of disrupting plant communities or ecosystems."[8] Since SCE's Vegetation Management program addresses plants that have grow-in potential and involves the increased risk of fire in our corridors, SCE modifies the USDA definition as appropriate to assess vegetation attributes as it relates to utility VM activities as follows:

Invasive: A plant that is both non-native and able to establish on many sites, grow quickly, and spread to the point of disrupting plant communities in utility Rights of Way (ROW) or electric systems.

SCE also treats native plants, which may grow within the utility ROW and have the potential to disrupt electrical systems by promoting fire and/or making contact with the electrical lines.

(3) In Table 27, SCE uses the term tree "type" but this actually refers to tree "species." To clarify, SCE's tree species are captured at the higher level (genus) and records common names not scientific names. The list provided is SCE's evaluation of at-risk species.

[8] Natural Resources Conservation Service of the United States Department of Agriculture (n.d.). Native, Invasive, and Other Plant-Related Definitions, retrieved Feb 16, 2021 from https://www.nrcs.usda.gov/wps/portal/nrcs/detail/ct/technical/ecoscience/invasive/?cid=nrcs142p2_011124

Table 27 – SCE-14 Known Risk Attributes by Type

Type	Attribute #'s
Ailanthus	1,3,6,7,11
Ash	1,3,4,6,11
Athel / Salt Cedar	1,3,6,7,10,11,12
Bamboo	1,6,7,8,12
Eucalyptus	1,2,3,4,6,8,11,12
Mulberry	1,3,6,8
Palm	1,6,7,8,9,11,12
Pepper	1,2,3,6,8,12
Poplar/Aspen/Cottonwood	1,2,3,6,8,10,11
Vine	1,7,12

(4) SCE's decision to include particular tree species in the lists took into account overall tree inventory volume, historic tree-caused circuit interruptions, supplemental inspection data, arboricultural science and practices, and subject matter expert knowledge. Historically, SCE tree crews focused their inspection and mitigation efforts based primarily on tree growth rate categories of fast, medium and slow. With the increased focus on wildfire mitigation, and the need to reduce ignition and outage events attributed to vegetation, SCE identified the top ten tree types/species which were the main contributors to Tree Caused Circuit Interruptions (TCCIs) between 2015 and 2020 and the other factors as described above.

(5) Tree crews cut back tree limbs or other vegetation to obtain the appropriate clearances within a tree canopy on an annual basis; however, some species grow faster than expected, creating the need for tree crews to revisit the site again to provide supplemental trimming. Additionally, in most cases, SCE does not own the vegetation being maintained and cannot remove all desired species types without property owner authorization. Therefore, SCE is often left with only the option to trim but not remove the vegetation. SCE's contractors are provided technical pruning training, such as ANSI A300 Pruning Standards, and SCE's Quality Control inspectors review and record quality trimming standards by contractors.

(6) The risk factor attributes identified in Table 26 are all equally weighted for this analysis. Once SCE is able to operationalize the WRRM model outputs for the Tree Risk Index, this list has the potential to be risk prioritized.

Table 26 – SCE-14 Known Risk Attributes

#	Attributes: Definition
1	Fast growing
2	Prone to trunk failure
3	Prone to branch failure
4	Prone to insect or nuisance infestation
5	Incompatibility with hardiness zone
6	Subject to improper pruning practices when in proximity to high voltage lines
7	Invasive (does not promote native plant life)
8	Prone to limb sway during windy conditions (whipping)
9	Prone to frond drop
10	Prone to root failure
11	Large maturing tree height
12	Wood and material flammability (high risk)

Action SCE-21: *In its 2021 WMP Update, SCE shall: 1) discuss how additional measures taken for "at-risk" and fast-growing tree species fit into the statistical analysis of effective tree clearance, both regulatory and enhanced, 2) explain if SCE's VM management systems record the species (in contrast to species type) of a tree, and if not, explain why, and 3) explain why analysis of clearance distance using tree "types" has adequate granularity considering the impact to future VM-related decisions and initiatives throughout SCE's large, geographically and biologically diverse, service territory.*

Response:
(1) SCE addresses at-risk species by prescribing enhanced clearances and/or removals where achievable. Therefore, enhanced clearances are an appropriate way to measure the effectiveness of at-risk species work. Additional measures taken for at-risk tree species are part of SCE's larger effort to mitigate encroachment--and ultimately outage--probability. Through increased training and focused attention on at-risk species, SCE aims to incrementally obtain property owner permission and prescribe greater clearances or removal of vegetation. These greater clearances should result in the overall reduction of outages, thus showing the effectiveness of greater clearances for at-risk species. At this time, SCE is planning to correlate the trends in vegetation-caused outages with the amount of enhanced clearances achieved at the time of trim and is not performing a statistical analysis of the data.

As discussed in the 2021 WMP Update, SCE provides below a report of the TCCIs by its list of highest risk species for the same period as collected for the enhanced clearances:

Count of TCCI by At-Risk Species 2016-2020

Year (1/1 – 12/31)	Total TCCIs	TCCIs in HFRA
2016	365	82
2017	304	87
2018	259	54
2019	307	72
2020	119	21

(2) SCE's VM work management systems (WMS) capture tree species at the higher level (genus) and records common names not scientific names. Species-level information such as specific epithet level is not captured in the WMS. The current species list in SCE's WMS includes approximately 100 items. To expand into further species data collection can pose resource constraints. Even most seasoned certified arborists can have difficulty in identifying species beyond the common level.

(3) The evaluation of trees at a "type" level is valid for the reason that tree types share more commonality than dissimilarity. Trees of the same genus typically have similar growth rate characteristics and risk potential. SCE agrees that *SCE's large, geographically and biologically diverse, service territory* can lend factors into some species variations from area-to-area, but SCE's analysis will provide the ability perform additional analytics into territorial regions to analyze varying trends.

WMP Class B Deficiency Action Statements
SCE-15, Lack of detail on how SCE addresses fast growing species

Action SCE-22*: In its 2021 WMP Update, SCE shall describe any ongoing or planned efforts to address at-risk and/or fast-growing tree species using community outreach and education, so that SCE might reduce the number of at-risk, fast growing, and/or exceptions trees it encounters while performing VM activities.*

Response:
Along with the existing planned outreach, training, and education efforts described in SCE's 2021 Wildfire Mitigation Plan Update (Section 7.3.5.1), SCE is currently planning to include more specific language in its community outreach and education to raise awareness of Palm tree hazards near power lines as part of its Palm tree campaign. Targeted postal mailers, emails, and notices will be refined or developed to emphasize the inherent risk of palm trees near wires.

Action SCE-23*: In its 2021 WMP Update, SCE shall: 1) clarify which inspection program(s) encompasses the "as needed" re-inspections for "Exception Trees," 2) detail how it is determined when an "Exception Tree" needs to be re-inspected, including who makes the determination, 3) explain how these re-inspections are prioritized (e.g., by tree species, by circuit, etc.), and 4) detail the methods for how SCE determines the effectiveness of these "as-needed" re-inspections.*

Response:
1) Exception trees apply to SCE's routine compliance program and not to HTMP or DRI. SCE's goal is to achieve the enhanced clearances recommended by GO95 Rule 35 Appendix E for all trees in SCE's HFRA.

2) SCE schedules and performs annual supplemental patrols on all trees in inventory approximately six months into the annual cycle to provide added assurance that trees will not encroach upon the minimum regulatory clearance distance required by the regulator. This applies to all trees in inventory including, fast-growing and exception trees. When the re-inspection identifies work that is required to maintain clearances, then prescriptions are made in the work management system. If no work is required, the supplemental inspection is not documented.

3) Regarding prioritization, the re-inspection is performed in accordance with an annual schedule where the last scheduled trim date is used as the basis for the reinspection date. Thus, the re-inspections prioritize according to oldest trim date.

4) Regarding effectiveness, because of varying annual seasonal weather patterns, vegetation regrowth rates differ from region to region and supplemental mitigations are observed sporadically throughout the vast SCE territory. Typically, less than 20% of overall trees in inventory may grow faster than expected at the time of trim on account of these conditions; however, the locations where the regrowth is discovered may differ from year to year. These trees are documented for supplemental work prescriptions during the supplemental inspection process, suggesting that re-inspections are effective at capturing regrowth that is faster than expected throughout SCE's service territory.

WMP Class B Deficiency Action Statements
SCE-20, Potential Notification Fatigue from Frequency of PSPS Communications

Action SCE-27: *In its 2021 WMP Update, SCE shall: 1) describe the lessons learned during the implementation of its 2020 PSPS events, and 2) detail the corrective actions it has taken to resolve the issues (i.e., both issuance of false-positive and false-negative notifications) associated with its PSPS event notifications in 2020.*

1) Describe the lessons learned during the implementation of its 2020 PSPS events associated with its PSPS event notifications in 2020.

In 2020, SCE initiated 12 PSPS events with 16 periods of concern, i.e., periods of time when de-energization was likely to occur due to forecast weather and fuel conditions. Through the course of these events, SCE continued to revise its processes and protocols to incorporate lessons learned during previous de-activations and re-energization activities.

i. **Rationalize Customer Notification Process**
In recent feedback received from customers, their representatives, agency partners and the Commission, SCE learned that SCE should rationalize the customer notifications process to mitigate communication fatigue and confusion.

ii. **Vulnerable Customer Notifications**
SCE also learned that it can and should do more to ensure that vulnerable customers receive proper and timely PSPS notifications. Fundamental to success in reaching vulnerable customers is ensuring that customers are properly identified as Medical Baseline (MBL) so we can provide the services and care they need.

iii. **Customer Information for Public Safety Partners**
SCE has also learned that it can provide better support its public safety partners, including local and tribal government entities, in providing streamlined access to data about customers and facilities at risk of de-energization. Currently, SCE provides information about impacted customers, including GIS mapping data, to public partners manually during PSPS events. SCE understands that these partners are looking for an easier experience than our current process.

iv. **Exceptions in Customer Notifications**
The CPUC noted there was significant variance between the number of advance customer notifications and the actual number of customers de-energized in a PSPS event. SCE heard it should research and document the root cause of any instance in which SCE's notification process failed to notify customers in advance of a PSPS event and implement appropriate corrective actions. If the notification deficiency was due to the weather, processes should be established to fully demonstrate the rapidity of the change in weather conditions that led to a de-energization without being able to notify customers in advance. If due to other reasons, such as internal processes, database or vendor issues, SCE should immediately act upon those issues to address the problem.

v. **Duplicate Notifications**
SCE provides notifications through many channels in order to ensure all customers are receiving appropriate notifications. This resulted in customers receiving multiple notifications that in some

cases appeared to provide conflicting information. One known source of this confusion has been account holders subscribing to ZIP code alerts in addition to, or instead of, SCE customer alerts. ZIP code alerts have been made available to reach transient populations who do not have premise-level accounts in the area, but wish to receive notifications because they may be visiting, have a business in the area or have other reasons to be notified of events in that zip code. However, ZIP code alerts cover multiple circuits, and customers who sign up for ZIP code alerts instead of premise-level alerts receive separate notifications for all circuits within a single ZIP code. This can lead to account-holding customers receiving conflicting notifications that may not be relevant to them because they may receive a unique notification for every circuit within the zip code that is being considered for PSPS.

vi. Unclear Language on Customer Notifications

Customer feedback informed us that multiple notifications during a PSPS event created confusion and the perception of "over-notification." Additional customer concerns indicated that SCE's notifications contained unclear language, missing information, and provided worst-case, rather than realistic, estimated restoration times, significantly overstating how long most customers should plan on being without power.

President Batjer's letter to SCE dated January 19, 2021 stated, "advanced and accurate notifications are vital for customers, critical facilities and public safety partners to prepare for a de-energization."

2) Detail the corrective actions it has taken to resolve the issues (i.e., both issuance of false-positive and false-negative notifications) associated with its PSPS event notifications in 2020.

SCE is committed to improving the clarity, cadence, and accuracy of notifications to better meet our customers' needs, and to evaluate and improve the effectiveness of our notification delivery systems.

i. Rationalize Customer Notification Process

SCE is performing an end-to-end analysis of in-event notification (imminent de-energization, de-energization, imminent re-energization, and re-energization) gaps experienced in 2020 and using these results to develop process and technical solutions to continue improving notification accuracy. Missed initial (72-hour, 48-hour and 24-hour) notifications will be addressed through improvements in weather forecasting.

ii. Vulnerable Customer Notifications

SCE has a comprehensive process to validate that notices have been delivered to our Critical Care customer population, including follow up calls and messages, and sending SCE representatives to knock on doors when other outreach is not successful. SCE is able to confirm that approximately 96% of all notifications to this population, including follow up calls and door knocks, are delivered in each event. While we are reaching most of the most vulnerable population, we currently do not follow a similar process for all MBL customers.

iii. Customer Information for Public Safety Partners

Going forward, SCE intends to better monitor and ensure delivery of notifications for all MBL customers in HFRA. SCE will engage its partners, including the AFN Advisory Council, and collaborate on solutions such as an online portal, for easier access to data during PSPS events.

SCE will develop a customer-facing data portal in 2021 to address this need. SCE expects to implement Phase 1 of this portal by June 1, 2021 and Phase 2 by September 13, 2021.

iv. Exceptions in Customer Notifications

The gap between number of customers notified and number of customers de-energized reflects the difference between SCE's long-range weather forecasting at the circuit level, which is the basis of initial (e.g., 72-hour, 48-hour and 24-hour) customer notifications, and in-event de-energizations, which are based on real-time decision-making at the circuit-segment level. This targeted real-time decision-making allows SCE to de-energize as few customers as possible, based on actual weather conditions and as a last resort; however, it is the main source of the gap between initial notifications and actual de-energizations. SCE will narrow this gap through improved resolution in weather forecasting. For instances where rapidly changing weather disrupts SCE's logical sequence of customer notifications, SCE will demonstrate the rapidity of the weather change in its PSPS post-event reports.

v. Duplicate Notifications

SCE is working on a process to allow customers to opt-out to move customers from ZIP code alerts to premise-level alerts.

vi. Unclear Language on Customer Notifications

SCE is reviewing means to revise the notification content for clarity and transparency. The process will map current-state customer notification experience to understand where we are falling short from the customer perspective, through both direct customer research and work with third-party communication experts.

Additional details of our corrective actions related to customer notifications to incorporate changes from the lessons learned in 2020 are provided in SCE's Corrective Action Plan shared with the Commission on February 12, 2021. Some of SCE's key activities planned for 2021 as noted in the PSPS Corrective Action Plan to improve customer notifications include:

A. Improve In-Event Notification Accuracy

SCE will assess and improve its accuracy and adherence to timing interval guidelines for notifications that are sent after the onset of extreme weather by performing an end-to-end assessment of the process gaps that have led to some instances of missed or inaccurate notifications.

In 2020, both SCE's practice of de-energizing at the circuit-segment level, which reduced customer impacts, and the use of processes that were manually driven, slowed the notification process and resulted in missed or conflicting notifications. The root-cause analysis will help SCE better coordinate the handoff between operational and notification teams by integrating operational (grid) and customer (notification and communications) workflows.

SCE will also complete design and initiate development of a broad technical solution to increase automation. This system will integrate PSPS, customer and field data, further reducing the need for manual operations. This will also reduce data conflicts and improve efficiency. The automated system should provide significant improvements to accuracy and timeliness, as well as improved overall situational awareness.

B. Reduce Notification Redundancy and Improve Clarity

SCE has initiated a re-evaluation of the PSPS notification experience, analyzing the cadence, content, language and delivery methods to more closely align with customer expectations.

SCE will continue to engage with customers to clarify how much information customers want, how frequently they want it, and the best way to message the notification content for clarity and transparency. The process will map current-state customer notification experience to understand where we are falling short from the customer perspective, through both direct customer research and work with third-party communication experts.

SCE will also meet with CPUC staff to discuss how to best interpret the regulatory requirements to meet customer needs.

C. Address Preferred Channels

To reduce notification duplications and potential for conflicting information, SCE will perform data analytics on customer notification channel subscriptions to identify customers who can be moved from ZIP code alerts to premise-level alerts and Identify and employ proactive measures to enroll customers into customer alert channels, while directing non-account holders into a different notification option that will reduce the potential for confusion.

D. Consider Use of Public Radio Broadcasts Where Appropriate

Customers in certain remote locations with poor cellphone access have difficulty communicating during power outages. To improve their ability to receive emergency messages, SCE will coordinate with County Offices of Emergency Management to identify remote locations that could require the use of Emergency Radio Broadcasts during PSPS events and develop messaging for these areas where appropriate.

Appendix A
GUIDANCE 5 ACTION STATEMENT
SCE-5 Table G5-SCE5-1

Table G5-SCE5-1

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
SA-1	Weather Stations	SCE expects to install 375 weather stations but will attempt to install as many as 475	Information from weather stations directly provide localized data on wind speed and FPI which are two of the factors which inform PSPS trigger thresholds and affect when PSPS events are called. Data from additional weather stations helps improve weather forecasting capabilities at a circuit and sub-circuit level. Additionally, by installing weather stations on specific segments of circuits, SCE is able to monitor and forecast weather at higher granularity that in turn can help decisions to sectionalize circuits and reduce the scope of PSPS events to fewer circuit segments. This improves the # of impacted customer and average duration, and timeliness and accuracy of PSPS notifications.	- Number of customers impacted and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE intends to measure the effectiveness of weather stations in improving the accuracy of weather models that drive PSPS de-energization decisions. The model results from the weather station installations will be compared with the model results from the alternative, which is to use Live Field Observations (LFO) to measure weather. The comparison will be used to draw conclusions about the effectiveness of this activity before and after deployment of additional weather stations. SCE intends to utilize data from 2018 to compare current and future years to measure the improvements in restoration time and duration over time. See parts (1) and (2) of action statement for evaluation timeline.
SA-2	Fire Potential Index (FPI)	1) Backcast 20 years of FPI using FPI 2.0 before typical height of fire season (Q3) to determine historical performance compared to current FPI 2) Run FPI 2.0 in parallel with the current FPI and compare outputs for the 2021 fire season	FPI estimates conditional fire potential at the circuit level; as accuracy of the FPI increases, it will lead to improvements in the accuracy, timeliness, and precision of PSPS decision making. By integrating historical weather and vegetation data into the FPI, SCE will improve the accuracy of this index which is a direct input into PSPS decision making. This will better inform PSPS decision-making by better estimating the potential risk of fire ignition and spread at the PSPS circuit level. Accurate FPI improves timeliness and accuracy of PSPS notifications to help better identify areas in scope for a PSPS event by more accurately targeting the number of circuits in scope and, hence, reducing number of customers who may need to be de-energized.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE intend to measure the effectiveness of the new FPI by comparing the historical performance of new and current FPI for critical and non-critical events by the end of Q3 2021; the results will be leveraged to validate or calibrate the FPI equations appropriately. Accurate FPI improves timeliness and accuracy of PSPS notifications to help better identify areas in scope for a PSPS event by more accurately targeting the number of circuits in scope and, hence, reducing the number of customers who may need to be de-energized (SCE anticipates updating the risk model ties to this metric by end of Q1 2022). See parts (1) and (2) of action statement for evaluation timeline.
SA-3	Weather and Fuels Modeling	Install two additional High-Performance Computing Clusters (HPCCs) to facilitate the installation and operationalization of the Next Generation Weather Modeling System allowing for more precise, higher resolution output	The installation of two additional HPCCs will enable SCE to produce ensemble forecast output at a 1 km resolution. This improved granularity ensemble output will provide SCE with more accurate forecasts of wind speed and FPI at the circuit level, which will ultimately improve the decision making of PSPS.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	As the Weather and Fuels Modeling will double the resolution of SCE's weather modeling, SCE intends to measure the effectiveness of this initiative by comparing the accuracy of forecasts of wind speed and FPI at the circuit level at 2km versus 1km. This would impact the number of de-energization circuits in scope and the number of customers impacted who may not need to be de-energized due to lower resolutions. See parts (1) and (2) of action statement for evaluation timeline.
SA-4	Fire Spread Modeling	Develop a methodology and a strategy to test FireCast/FireSim implementation into PSPS decision making based on backcast information by Q3	The Technosylva products allow SCE to simulate "what if scenarios" to predict various fire ignition and consequence outputs such as fire perimeter size, structures impacted, populations affected, injury and death, etc. This output will help SCE coordinate response during active wildfire events and may be used as an input to inform PSPS decision making.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE intends to measure the effectiveness of Fire Spread Modeling in improving timeliness and accuracy of PSPS notifications by evaluating how fire spread calculations would have affected de-energization decisions made historically (evaluations expected to be implemented by the start of Q3 2021). SCE intends to utilize the output to calibrate de-energization decisions as needed by end of Q3 2021. Similar to SA-2 and SA-3, this activity increases granularity to improve identification of areas in scope for a PSPS event, which will affect accuracy of PSPS notifications and number of customers de-energized. See parts (1) and (2) of action statement for evaluation timeline.
SA-5	Fuel Sampling Program	Maintain periodic fuel sampling across SCE's HFRA and evaluate the need to sample additional locations	This semi real-time measurements of vegetation moisture for 15 sites is an additional input which helps calibrate FPI which in turn increases the precision of PSPS decision making. This data can also be used to adjust inputs for fire spread calculations which will help improve the accuracy of fire consequence modeling.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE plans to track observed live fuel moisture to make appropriate adjustments to the FPI. SCE intends to measure the effectiveness of Fuel Sampling Program, by measuring the FPI accuracy before and after the live fuel moisture from the Fuel Sampling Program is incorporated, in impacting the accuracy of PSPS notifications and the number of customers impacted by a PSPS event. See parts (1) and (2) of action statement for evaluation timeline.
SA-7	Remote Sensing / Satellite Fuel Moisture	Initiate wind profiler pilot project to validate weather model performance for potential improvements to weather models	While this initiative does not reduce ignition risk or consequence directly, it enhances SCE's overall capability in our risk modeling and has the potential to improve FPI which is a direct input to PSPS decision making. Additionally, it can help improve Technosylva's fire consequence models that can help better target and prioritize WMP deployment.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE intends to measure the effectiveness of Remote Sensing in improving real-time de-energization decisions, by comparing the accuracy before (using in-house weather model forecasts) and after the implementation of the pilot to develop site-specific information about winds. This activity directly impacts the number of impacted customers and imminent notifications. See parts (1) and (2) of action statement for evaluation timeline.

Table G5-SCE5-1

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
SA-8	Fire Science Enhancements	Evaluate current wildfire events in context of 40-year history of wildfires	While this initiative does not reduce ignition risk or consequence directly, it will help put current events into a historical perspective.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE intends to measure the effectiveness of Fire Science Enhancements in improving the accuracy of the PSPS event. This will help to better understand a PSPS event (whether typical or anomaly), given the historical context. Initial results are expected by the end of Q4 2021. See parts (1) and (2) of action statement for evaluation timeline.
SA-9	Distribution Fault Anticipation (DFA)	Complete installation of 120 DFA units on circuits in SCE's HFRA and continue evaluation of DFA technology which may result in SCE installing up to 150 units	DFA systems have the potential to provide awareness of arcing events and draw attention to unique fault events which may be precursors to future fault events using electrical signatures. Early detection to allow time to take proactive remedial action(s) is expected to reduce faults, potential ignitions, and indirectly reduce wire down events as a proportion of faults reduced.	- CPUC reportable ignitions in High Fire Risk Area (HFRA) - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics for risk drivers that DFA is effective in mitigating (e.g. CFO-driven faults, wire downs and ignitions) in the areas where DFA has been deployed, prior to and after deployment of DFA. See parts (1) and (2) of action statement for evaluation timeline. In addition, DFA reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 2% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
SH-1	Covered Conductor	SCE expects to install 1,000 circuit miles of covered conductor in SCE's HFRA but will attempt to install as many as 1,400 circuit miles of covered conductor in SCE's HFRA, subject to resources constraints and other execution risks	Covered conductor is anticipated to significantly reduce contact-from-object and wire-to-wire ignition risks as well as indirectly reduce the frequency of wire down events by reducing the number of faults. CC deployment on an entire circuit segment impacts the PSPS threshold, but only when installed on an entire segment	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA - Number of impacted customers and average duration of PSPS events	SCE intends to measure the number of incidences of each of these metrics for risk drivers that covered conductor is effective in mitigating (e.g. CFO-driven faults, wire downs and ignitions) in the areas where covered conductor has been deployed, prior to and after deployment of covered conductor. See parts (1) and (2) of action statement for evaluation timeline. In addition, covered conductor (and fire resistant poles) reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 66% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA. SCE intends to measure the ability for covered conductor to reduce the number of customers impacted and the average duration of PSPS events by comparing a circuit prior to and after SCE has fully covered that circuit or circuit segment with covered conductor. In order for SCE to increase the wind thresholds by which PSPS de-energization events are called, an entire circuit segment must be covered. SCE anticipates completely covering numerous isolatable circuit segments and circuits that are within PSPS deenergization scope in 2021. Therefore, SCE expects to be able to show actual results of the effectiveness of this mitigation after such time as the circuit is completely covered and there are potential PSPS events on that circuit that can incorporate these updated thresholds.
SH-2	Undergrounding Overhead Conductor	Install 4 miles of undergrounded HFRA circuits SCE will attempt to install 6 miles of undergrounded HFRA circuits, subject to resource constraints and other execution risks, such as permitting, environmental or coordinating with other utilities	Undergrounding is expected to nearly eliminate faults and ignitions associated with overhead distribution lines where deployed.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA - Number of impacted customers and average duration of Public Safety Power Shutoff events	SCE intends to measure the number of incidences of each of these metrics for risk drivers that underground construction is effective in mitigating (e.g. CFO-driven faults, all wire downs and all ignitions) in the areas where undergrounding facilities has been deployed, prior to and after deployment of the undergrounding construction. See parts (1) and (2) of action statement for evaluation timeline. In addition, undergrounding reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 91% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA. SCE expects undergrounding to be fully effective in mitigating PSPS de-energization events on circuits that are fully undergrounded, removing them from PSPS deenergization scope. SCE is currently evaluating locations that may be within scope for PSPS.
SH-4	Branch Line Protection Strategy	Install or replace fusing at 330 fuse installation locations SCE will strive to install or replace fusing at 421 locations, subject to resource constraints and other execution risks	Ignition probability is expected to be reduced by the installation of branch line circuit protection, such as current limiting fuses. As described in the WMP Section 5.3.3.17, the fusing program is intended to reduce the risk of fire ignitions associated with SCE's distribution lines and equipment by reducing fault energy.	- CPUC reportable ignitions in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that current limiting branch line protection/fuses are effective in mitigating (e.g. ignitions caused by equipment failure by replacing existing fuses with new current limiting fuses) in the areas where current limiting fuses have been deployed, prior to and after deployment of current limiting fuses. See parts (1) and (2) of action statement for evaluation timeline. In addition, current limiting fuses reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 4% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
SH-5	Installation of System Automation Equipment – RAR/RCS	N/A – If RARs/RCSs are determined to be necessary based on the SH-7 analysis, SCE will develop appropriate project plans	As stated in the WMP Section 5.3.3.9, SCE is expanding its system automation equipment strategy to target both RARs and additional sectionalizing devices such as RCSs to provide important isolating capabilities that could minimize the frequency of customer outages during PSPS and other outage events.	- Number of impacted customers and average duration of PSPS events - Timeliness and accuracy of PSPS notifications	SCE expects automation equipment to provide important isolating capabilities that could minimize the frequency and duration of PSPS deenergization events for customers. At this time, SCE is determining the 2021 scope for RARs/RCS based upon SH-7 analysis, and currently there is no 2021 target for deployment.

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
SH-6	Circuit Breaker Relay Hardware for Fast Curve	Replace/upgrade 60 relay units in HFRA SCE will strive to replace/upgrade 86 relay units in HFRA, subject to resource constraints and other execution risks	Reducing fault current duration will reduce arcing and fault energy helping reduce wildfire ignition risk.	- CPUC reportable ignitions in HFRA - Wire down incidents in HFRA	SCE activates Fast Curve relay settings during elevated fire risk conditions that generally vary based on weather conditions and other factors. SCE plans to further assess threshold values throughout 2021 for the SH-6 program. While we expect there is directional improvement for reducing wire down events, we have not established metrics in the wire down category. SCE intends to measure the number of incidences of each of these metrics that CB fast curve settings are effective in mitigating (e.g. ignitions and wire down events) prior to and after deployment of circuits with CB fast curve settings. See parts (1) and (2) of action statement for evaluation timeline. In addition, CB fast curve settings reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 4% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
SH-7	PSPS-Driven Grid Hardening Work	SCE will develop a methodology to project probability of PSPS de-energization and impact. Utilizing this methodology, SCE will adopt a more targeted approach by evaluating highly impacted circuits from the remaining 50% circuits in HFRA (50% was completed in 2020). The outcome of this evaluation will identify mitigations/projects that could be implemented in other system hardening activities such as SH-1 and SH-5.	This initiative constitutes an evaluation and will not on its own reduce risk. The grid hardening projects recommended by SH-7 are expected to reduce PSPS frequency and scope	- Number of impacted customers and average duration of PSPS events	The effectiveness of this activity can only be measured when the recommendations by SH-7 are implemented. The effectiveness quantification of these recommendations is covered under SH-1, SH-2, and SH-5.
SH-8	Transmission Open Phase Detection	Install transmission open phase detection devices on 10 transmission circuits	By detecting and isolating lines prior to contacting ground when conductors and conductor related hardware (such as splices) fail, the TOPD system is expected to reduce ignition risk associated with wire down events.	- CPUC reportable ignitions in HFRA	The Transmission Open Phase Detection (TOPD) scheme will be implemented onto existing assets (Relays) for 10 Transmission lines residing within HFRA by Q4 of 2021. Upon implementation of said scheme, the TOPD will follow a 6-month evaluation period leading into Q2 of 2022. During the evaluation period, the Transmission line relays will be in Alarm mode only rather than trip mode. This approach will allow SCE to monitor the performance of our relay schemes while maintaining reliable operation of the network. In Q3 of 2022, with acceptable results from the TOPD scheme, SCE intends to configure the TOPD scheme to allow operational flexibility to transition between Alarm mode to Alarm/Trip mode when required. SCE is anticipating a 90% effectiveness rate for detection and isolation of separated conductor on the 10 targeted Transmission Line installations. However, it is important to recognize lower detection thresholds are also improvements over present systems which do not currently detect conductor separation events.
SH-10	Tree Attachment Remediation	Remediate 500 tree attachments; SCE will strive to complete over 600 tree attachment remediations, subject to resource constraints and other execution risks	Reducing tree attachments reduces the probability of conductors failing from compromised tree integrity or vegetation contact which in turn reduces the probability of ignitions.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that tree attachment remediations are effective in mitigating (e.g. wire down events that are caused by failure of the tree attachment) in the areas where tree attachments have been remediated, prior to and after remediation of tree attachments. See parts (1) and (2) of action statement for evaluation timeline.
SH-11	Legacy Facilities	Hydro Control Circuits – Perform evaluation on 5 circuits for possible system hardening improvements Low Voltage Site Hardening – Create 2 project plans based on 2020 engineering assessments Grounding Studies/Lightning Arrestor Assessments: Complete 12 additional assessments	This initiative will identify system hardening at these facilities, which will reduce faults and in turn probability of ignitions.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE is currently evaluating legacy facilities for this activity and expects to complete the evaluation in 2022. Additional evaluation or threshold values would be established to align with the actions from the evaluation.
SH-12	Microgrid Assessment	Perform internal assessment of vendor bid and location options. If assessment is favorable, SCE will issue an engineering, procurement, construction (EPC) contract to a vendor that meets SCE's design requirements	This initiative does not directly reduce the probability or consequence of ignitions but can provide PSPS resilience to multiple customers in areas expected to be frequently impacted by PSPS.	- Number of impacted customers and average duration of PSPS events	The system will be evaluated by the reduction in customer minutes of interruption for the supported circuit. Evaluation will not begin until system is operational in 2022.

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
SH-13	C Hooks	Replace C-Hooks on at least 40 structures in HFRA SCE will strive to replace all C hooks in HFRA, currently estimated between 50-60 structures	Failure of a C-hook could lead to a risk event with ignition probability	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that C hook replacements are effective in mitigating in the areas where C hooks have been replaced, prior to and after replacement of C hooks. See parts (1) and (2) of action statement for evaluation timeline. In addition, C hook replacement reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be less than 1% against the overall set of ignition-causing risk drivers.
SH-14	Long Span Initiative (LSI)	Complete all field assessments for locations and corresponding remediations Remediate the highest risk locations, estimating that 300, and up to 600, locations will be remediated in 2021, subject to the completion timeline for inspections, resource constraints and other execution risks	Remediation of the highest-risk locations will reduce conductor clashing (wire-to-wire contact), and in turn the probability of ignitions	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Long Span Initiative (LSI) is effective in mitigating in the areas where LSI has been deployed, prior to and after deployment of LSI. See parts (1) and (2) of action statement for evaluation timeline. In addition, LSI reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 7% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
SH-15	Vertical Switches	Install 20 switches in HFRA SCE will strive to install 30 switches in HFRA	Replacement of vertical switches in HFRA targets reducing risk with vertical switch failure events which can produce incandescent particles, and therefore reduce the risk of ignitions that can lead to wildfires.	- CPUC reportable ignitions in HFRA - Faults in HFRA	SCE fault event data is extrapolated from outage events. The switch failures of concern many times occur when a downstream fault event occurs. This type of switch failure event commonly only produces a single outage scenario and therefore switch replacement may not have an appreciable change to outage or fault quantities. See parts (1) and (2) of action statement for evaluation timeline. SCE intends to measure the number of incidences of each of these metrics that vertical switches are effective in mitigating in the areas where vertical switches have been deployed, prior to and after deployment of vertical switches. In addition, vertical switches reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 2% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
IN-1.1	Distribution High Fire Risk Informed Inspections in HFRA	Inspect between 163,000 and 198,000 structures in HFRA, via both ground and aerial inspections. This target includes HFRI, compliance-due structures in HFRA and emergent risks during the fire season	Inspections identify conditions in need of remediation (i.e. priority notifications), notifications are prioritized, and notifications are expected to be remediated before they fail and cause a fault/wire down/ignition. Inspections lead to remediations, and these remediations help reduce ignition probability factors.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Distribution OH inspections identify and are ultimately remediated to reduce risk ("Distribution OH Inspections & Remediations") are effective in mitigating in the areas where Distribution OH Inspections & Remediations have been completed, prior to and after completion of Distribution OH Inspections & Remediations. See parts (1) and (2) of action statement for evaluation timeline. In addition, Distribution OH Inspections & Remediations reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 37% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
IN-1.2	Transmission High Fire Risk Informed Inspections in HFRA	Inspect between 16,800 and 22,800 structures in HFRA, via ground and aerial inspections. This target includes HFRI, compliance-due structures in HFRA and emergent risks during the fire season.	Inspections identify conditions in need of remediation (i.e. priority notifications), notifications are prioritized, and notifications are expected to be remediated before they fail and cause a fault/wire down/ignition. Inspections lead to remediations, and these remediations help reduce ignition probability factors.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Transmission OH inspections identify and are ultimately remediated to reduce risk ("Transmission OH Inspections & Remediations") are effective in mitigating in the areas where Transmission OH Inspections & Remediations have been completed, prior to and after completion of Transmission OH Inspections & Remediations. See parts (1) and (2) of action statement for evaluation timeline. In addition, Transmission OH Inspections & Remediations reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 3% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
IN-3	Infrared Inspection of energized overhead distribution facilities and equipment	Inspect approximately 50% of distribution circuits in HFRA	Inspections identify conditions in need of remediation, conditions are prioritized, and items are remediated before they fail and cause a fault. Inspections that lead to remediations help reduce ignition probability factors.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Infrared Inspection of Energized OH Distribution Equipment identify and are ultimately remediated to reduce risk ("Distribution OH Infrared Inspections & Remediations") are effective in mitigating in the areas where Distribution OH Infrared Inspections & Remediations have been completed, prior to and after completion of Distribution OH Infrared Inspections & Remediations. See parts (1) and (2) of action statement for evaluation timeline. In addition, Distribution OH Infrared Inspections & Remediations reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 1% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
IN-4	Infrared Inspection, Corona Scanning, and High Definition imagery of energized overhead Transmission facilities and equipment	Inspect 1,000 transmission circuit miles on HFRA circuits	Inspections identify conditions in need of remediation (i.e. priority notifications), notifications are prioritized, and notifications are expected to be remediated before they fail and cause a fault/wire down/ignition. Inspections lead to remediations, and these remediations help reduce ignition probability factors.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Infrared Inspection, Corona Scanning and HD image capture of energized OH Transmission equipment identify and are ultimately remediated to reduce risk ("Transmission OH Infrared Inspections & Remediations") are effective in mitigating in the areas where Transmission OH Infrared Inspections & Remediations have been completed, prior to and after completion of Transmission OH Infrared Inspections & Remediations. In addition, Transmission OH Infrared Inspections & Remediations reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be less than 1% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
IN-5	Generation High Fire Risk Informed Inspections in HFRA	Complete inspection of 181 generation-related assets in HFRA	Inspections identify conditions in need of remediation (i.e., priority notifications), notifications are prioritized, and notifications are expected to be remediated before they fail and cause a fault/wire down/ignition. Inspections lead to remediations, and these remediations help reduce ignition probability factors.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	Deterioration of electrify equipment in generation facilities pose the same fault and ignition risks described in the Distribution HFRI Inspection program (IN-1.1). Because SCE's generation facilities are often located in or near heavily forested areas, wildfire propagation in these areas could affect critical power generation infrastructure and equipment. Consistent with our RSE calculations, effectiveness of this activity will be evaluated through to IN-1.1.
IN-8	Inspection Work Management Tools	Transition Aerial and Transmission Ground inspection processes to a single digital platform with at least 75% of inspectors trained to use the tool by year end 2021 Key AI/ML models leveraged by the Aerial inspection process; Deploy scope mapping tool with GIS visualization to Distribution Planning and Engineering users Deploy remediation mobile software and iPad devices for transmission and distribution	The Inspection Work Management Tools are enabling activities to the inspection and remediation activities described in IN-1.1 and IN-1.2.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	Because IN-8 is an enabling activity for IN-1.1 and IN-1.2, the effectiveness is measured by the effectiveness of IN-1.1 and IN-1.2.
VM-1	Hazard Tree Management Program	Assess between 150,000 and 200,000 trees for hazardous conditions and perform prescribed mitigations in accordance with program guidelines and schedules	HTMP will reduce vegetation caused faults from fall-ins and blow-ins and therefore reduce probability of ignition.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Hazard Tree Mitigation Program (HTMP) are effective in mitigating in the areas where HTMP have been deployed, prior to and after deployment of HTMP. See parts (1) and (2) of action statement for evaluation timeline. In addition, HTMP reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 8% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
VM-2	Expanded Pole Brushing	SCE plans to pole brush between 200,000 and 300,000 Distribution poles	Performing brush clearance prevents fires spreading to and from poles, reducing probability and consequence of ignitions.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Hazard Tree Mitigation Program (HTMP) are effective in mitigating in the areas where HTMP have been deployed, prior to and after deployment of HTMP. See parts (1) and (2) of action statement for evaluation timeline. In addition, HTMP reduces risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 8% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
VM-3	Expanded Clearances for Legacy Facilities	Treat 46 sites	These assessments and treatments will help ensure SCE maintains vegetation clearance requirements per NERC, ANSI, and CALFIRE ordinances in all identified legacy facilities in HFRA. Reducing vegetation and fuel will reduce probability of ignition and reduce spread in the case of ignition.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	Expanded clearances for Legacy Facilities began in 2020 and SCE was able to treat 46 sites throughout the year. When comparing vegetation-related findings from the inspection activity (IN-5) for 2019 and 2020, SCE saw a decrease of 23% in findings. SCE expects findings to continue to decrease and remain low as we treat additional sites and maintain clearances in accordance with our annual vegetation maintenance plan. The focus of this activity is to reduce fuel, provide a defensible space and slow the spread of fire in the case of a future ignition. In addition, Expanded Clearances reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be less than 1% against the overall set of ignition-causing risk drivers.
VM-4	Dead and Dying Tree Removal	Perform Drought Relief Initiative (DRI) annual inspections and perform prescribed mitigations in accordance with program guidelines and schedules	Reducing the probability of dead, dying or diseased trees with compromised integrity falling into lines will reduce vegetation related faults and in turn reduce probability of ignitions.	- CPUC reportable ignitions in HFRA - Faults in HFRA - Wire down incidents in HFRA	SCE intends to measure the number of incidences of each of these metrics that Drought Relief Initiative (DRI) are effective in mitigating in the areas where DRI have been deployed, prior to and after deployment of DRI. See parts (1) and (2) of action statement for evaluation timeline. In addition, DRI reduce risk across specific sub-drivers that cause ignitions. Based on SCE's risk modeling used in the 2021 WMP Update, SCE estimates the overall mitigation effectiveness of this activity to be approximately 7% against the overall set of ignition-causing risk drivers, assuming deployment across HFRA.
VM-6	VM Work Management Tool (Arbora)	Continue Work Management Tool (Arbora) agile development and releases in accordance with project plan – complete full rollout of Dead & Dying Tree Removal and Hazard Tree Mitigation, and conduct discovery and design architecture associated with Line Clearing	Aligns workstreams to improve visibility to high risk areas across VM programs & increases work efficiency through aligning in-flight capital work. Improving work processes and work management can lead to reduced ignitions and faults from vegetation-contact with conductors.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	Because VM-6 is intended to be an enabling activity for all VM activities, its effectiveness is measured through VM activities.
PSPS-2	Customer Care Programs	Community Resource Centers (CRC): Enable up to 15 remote CRCs with a backup transfer switch. Community Resiliency Programs: Resiliency Zones: Targeting to obtain 5 to 10+ additional agreements, pending community leaders identifying potential customer sites. Customer Resiliency Equipment Incentive: Complete installation of microgrid islanding (CREI) capability on second pilot customer. CCBB: Expand the CCBB program to all eligible Medical Baseline customers (CARE/FERA & HFRA) and increase outreach activities to increase enrollment Well Water & Residential Battery Station Rebates: Increase customer participation by 20% - 40%	These activities do not directly reduce ignition probability or wildfire consequence, but are necessary for supporting SCE's customers during PSPS events. CRCs help mitigate the impacts of PSPS events by providing customers with information about SCE's PSPS resiliency programs and incentives, the ability to update contact information and enroll in outage alerts, as well as other amenities such as bottled water and light snacks, ice and ice vouchers, restroom access, and the ability for customers to charge personal devices. During the COVID-19 pandemic, CRC services have been altered to protect public safety further (social distancing, Resiliency kits with PPE). The Resiliency Zones Pilot will equip essential services (gas stations, markets, etc.) in remote zones that participate in the pilot with the electrical equipment for back-up generation, and SCE will deploy back-up power during PSPS events. The Critical Care Backup Battery (CCBB) Program is designed to assist SCE's most vulnerable customers by providing a free portable backup battery to temporarily power medical devices during an outage. By expanding the program to target a larger eligible customer population, SCE will increase back-up batteries deployed to vulnerable customers in HRFA that may not otherwise have the resources to procure necessary resiliency equipment. Well water generator rebates are designed to help mitigate the impact of the de-energization by enabling ongoing access to water that would	- Reduces consequence of PSPS de-energization events	CRCs: The effectiveness of CRCs will be measured by survey assessments taken by customers that visit CRCs during PSPS events. Resiliency Zones: SCE will assess the effectiveness of the Resiliency Zones pilot through post-event utilization learnings, as well as the receptiveness of the program with county and community leaders as evidenced by participation in identifying site locations. CCBB Program: SCE will measure the effectiveness of the CCBB program through customer participation and battery deployment volume, as well as through customer satisfaction surveys post battery deployment. Well Water & Residential Battery Station Rebates: Effectiveness will be measured by total customer rebate redemption against our target of increasing redemption by 20 to 40%.

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
DG-1	Wildfire Safety Data Mart and Data Management (WiSDM / Ezy)	WiSDM: - Complete the WisDM solution analysis and design phase for centralized data repository - Initiate staggered consolidation of datasets from SCE Enterprise systems Ezy Data: - Implement the cloud platform infrastructure for Ezy Data - Build a solution for data consumption, storage and visualization of inspection data (LiDAR, HD video, photograph) - Enable an environment for Artificial Intelligence (AI) assisted analytics	Improves accessibility of wildfire data across all WMP activities (inspection, mitigation, system hardening, vegetation management and PSPS efforts) and improves efficiency of reporting, among many other benefits.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	DG-1 is an enabling activity for data management, improved reporting and data sharing of other WMP activities, and its effectiveness is measured through other WMP activities in these areas.
DEP-1.2	Customer Education and Engagement - Community Meetings	Host at least nine virtual community meetings SCE will complete additional meetings as needed in 2021, based on PSPS impact to communities, up to 18	This activity is not intended to directly reduce ignition probability or wildfire consequence; however, it can help customers and communities be better prepared thus reducing the impacts of wildfire and PSPS events. Collaboration with the communities can also facilitate timely completion of wildfire mitigation work which would reduce wildfire risks in turn.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	While the community meetings do not reduce ignition probably or wildfire consequences, they help external stakeholders and customers better understand and be prepared for SCE's wildfire mitigation activities, including PSPS, as well as the customer programs and resources available to support them. The effectiveness of DEP-1.2 will be determined through DEP-4, as described in the entry for DEP-4.
DEP-1.3	Customer Education and Engagement - Marketing Campaign	PSPS Customer Awareness goal: 50%	While not intended to reduce ignition probability or wildfire consequence, the marketing campaign seeks to educate customers about PSPS and emergency preparedness and reduce impact of a PSPS or wildfire event through customers' preparedness.	- PSPS Customer Awareness goal	Effectiveness of the marketing campaign is measured by the PSPS customer awareness goal. The threshold to determine whether SCE is effective in its outreach is set to 50%, a higher percentage would indicate SCE's outreach is meeting the objective of the marketing campaign. SCE is continuing to refine its methodology for measuring the effectiveness of this activity. This is an enabling activity, and does not directly impact the five effectiveness metrics nor reduces wildfire risk. The effectiveness of DEP-1.3 will be determined through DEP-4, as described in the entry for DEP-4.
DEP-2	SCE Emergency Responder Training	IMT – Have all PSPS IMT and Task Force members fully trained and qualified or requalified by July 1, 2021 UAS – In 2021 SCE plans to expand the program by an additional 50 operators over 2020 levels	IMT - A trained and qualified incident management team is more effective in PSPS operations, thus mitigating the risk of wildfires along with frequency and scope of PSPS. Additionally, a well-trained team provides greater consistency and precision across each PSPS event. UAS - SCE develops technical training programs to train qualified personnel in the use of unmanned aircraft to perform activities such as pre-patrol inspections which can provide quicker and greater precision in identifying potential hazard on system equipment in areas that can be difficult to accurately detected from ground, thus reducing the risk of ignitions, faults and wire-downs. Additionally, this training program ensures qualified personnel can operate unmanned aircraft safely for post-patrol inspections during PSPS events, as circuits must patrolled to identify potential hazards before energization, which can reduce the overall PSPS durations and number of customer impacted.	IMT and UAS - These activity serve the purpose of enabling a number of the remaining WMP activities and therefore maps indirectly to all outcome-based metrics	IMT - While this is an enabling activity, SCE will continue to evaluate whether there is a direct correlation to PSPS average duration and accuracy of PSPS notification metrics. SCE aims to have 100% passing rate for trainings of all PSPS IMT and Task Force members who will be fully trained and qualified by July, 2021; with an additional 50 operators over 2020 levels who will be included in the program in 2021. Additionally, SCE will continue to explore the effectiveness of this activity and potentially leverage the datapoints included in after-action reports (populated post PSPS event) to measure the improvements made over time related to corrective actions and lessons learned which may have an impact on increasing accuracy and timeliness of PSPS notifications. UAS - By certifying additional resources to be able to operate drones, SCE is positioned to mitigate wire down, ignitions and faults through pre-patrol inspections by identifying anomalies more quickly (e.g., broken cross-arms, malfunctioning equipment, trees touching or falling into lines). For post-patrol inspections, drones can be utilized to evaluate the field conditions faster and perform inspections prior to re-energizing the circuits during the PSPS events. This may be especially beneficial for areas that are difficult to access. By utilizing drones in post-patrol, this may increase the efficiency and reduce the outage durations during PSPS events.
DEP-4	Customer Research and Education	Administer at least 4 PSPS-related surveys (PSPS Tracker Survey to capture feedback on the 2020 events, wildfire community meeting feedback survey, CRC/CCV feedback survey, In-Language Wildfire Mitigation Communications Effectiveness Pre/Post Survey)	This initiative is not intended to reduce ignition probability or wildfire consequence, but information from customer surveys will measure how effective we are at educating customers of WMP initiatives and communicating with them about PSPS events, where we can help improve customer communication channels, materials, and other resources, thus helping customers' preparedness for wildfires and PSPS events.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	Surveying stakeholders is a support function to collect customer insights and serves as a feedback mechanism for other WMP activities (DEP-1.2, DEP-1.3, PSPS-2) to improve their effectiveness. For the PSPS Tracker survey, SCE aims to receive completed survey responses from at least 500 customers in each of the 4 sample groups targeted in the Residential survey, and aims to receive completed survey responses from at least 100 customers in each of the 4 sample groups targeted in the business customer survey. For community meetings and CRC/CCV deployment feedback surveys, there is not a target response rate as it is entirely based on a customer's choice to respond to the survey request. For the In-Language Wildfire Mitigation Communications Effectiveness Pre/Post Survey, there are separate surveys for residential customers and business customers. For the residential survey, SCE aims to receive completed survey responses from a minimum of 2,000 Residential customers per survey wave. For the Business customer survey, SCE aims to receive completed survey responses from a minimum of 400 Business customers in each survey.

GUIDANCE 5 ACTION STATEMENT SCE-5

Table G5-SCE5-1

Activity #	Initiative / Activity	Projected Target by End of 2021	Describe the effectiveness of each initiative at reducing ignition probability or wildfire consequence	Metrics Impacted	Quantitative Evaluation
DEP-5	Aerial Suppression	Enter a Memorandum of Understanding (MOU) with CAL FIRE and local county fire departments to provide standby cost funding for up to 5 aerial suppression resources strategically placed around the SCE service area	While aerial suppression resources will not be able to stop a fire at the onset, they can be used to reduce the area and assets burned and enable faster response times. In addition, aerial suppression resources help lower emergency response support costs and help minimize the impact of redirecting work crews from previously scheduled maintenance and construction work to emergency response.	- These activities serve the purpose of enabling a number of the remaining WMP activities and therefore map indirectly to the outcome-based metrics	Based upon SCE's preliminary risk modeling results, SCE expects that aerial suppression activities are able to reduce the expected consequence of ignitions that materialize into large wildfires. Aerial suppression is estimated to reduce the consequence risk of ignitions. See parts (1) and (2) of action statement for evaluation timeline.