SOUTHERN CALIFORNIA EDISON
TRANSMISSION AND DISTRIBUTION

Distribution Inspection and Maintenance Program (DIMP)

2024— FOURTH QUARTER ISSUE

October 25, 2024

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Distribution Inspection and Maintenance Program (DIMP)

Revision Summary

2024 Fourth Quarter Issue

Effective Date: October 25, 2024

Overview

The main purpose of this revision summary is to describe new revisions to this manual. (Some or all of the information may have been previously communicated to field personnel by other means.)

Table 1 lists the revisions. Clickable page/sheet numbers link directly to individual revisions or the first of a series of revisions.

Table 2 defines four types of revisions: (1) Admin (Administrative), (2) Technical, (3) New, and (4) Pilot.

Note: **Admin** *and* **Technical** *revisions to existing standards or existing* **Pilot** *projects are identified with change bars* **|** *in the left margin.* **New** *standards (as well as new pilot projects) do not receive change bars. Editorial revisions, such as corrections to spelling, do not receive change bars.*

A Getting Help section provides contact information.

Table 1: Revisions

Chapter	Page	Description	Type
IN-3	3	Renamed “Other Confined Space” to “Enclosed Space”.	Admin

Table 2: Revision Types

Type	Definition
Admin	Administrative revisions do not significantly affect design, construction, maintenance or operation of the electrical distribution, substation, and transmission systems. They do not require Standards Review Team (SRT) or management approval; however, they have been approved by other organizations, as appropriate. They may include updates to SAP codes, updates to references, updates to standards for clarity, or deletions of outdated information.
Technical	Technical revisions are engineering changes to existing standards. They affect the design, construction, maintenance or operation of the electrical distribution, substation, and transmission systems. They require SRT and management approval.
New	Refers to a new standard. New technical standards require SRT and management approval.
Pilot	A *Pilot* is an in-field evaluation of a piece of equipment or work method, with the intention of approving for standardized use. Pilot standards will have a PILOT watermark so that they are easily identified throughout this manual.

Getting Help

Technical Issues

If you have any comments, corrections, questions, or suggestions concerning manual revisions, please contact one of the following individuals at the numbers provided, or click on the name to send an email:

- Name Removed — Phone Number Removed

Address Corrections

Send address changes to:

Southern California Edison
7400 Fenwick Lane
Westminster, CA 92683-5288

Director, Asset Management Program

DI — Division Index

Section

DI: Division Index
GE: General
IN: Inspection
CG: Condition Guides

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GE–TOC: General

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GE–1: General Overview of Distribution Inspection and Maintenance Program

1.0 Introduction

1.1 Mission Statement

The Distribution Inspection and Maintenance Program (DIMP) seeks to ensure public and worker safety and regulatory compliance by completing scheduled Detailed Inspections and Grid Patrols, as described in Chapter IM-2 of the Distribution Operations Maintenance Policies and Procedures (DOM) Manual and in conformity to the California Public Utilities Commission's (CPUC) General Order (G.O.) 165 and performing Distribution Maintenance, as described in Chapter IM-3 of the DOM, in accordance with G.O. 95, G.O.128, Southern California Edison (SCE) standards, and good utility practice.

The purpose of this manual is to provide guidance to the field inspectors who perform detailed inspections and patrols. This manual also provides the guidelines for G.O. 95/128 infractions and maintenance activities to be properly identified, correctly rated, and recorded in a timely manner.

1.2 Program Overview

The DIMP is an ongoing Company-wide program established to maintain the distribution system in accordance with good utility practices and the CPUC's G.O. 95, G.O. 128, and G.O. 165.

SCE has developed and improved its various maintenance and inspection programs to ensure the safety of its workers and the general public, as well as to provide reliable service to our customers.

General Order 165 was enacted on March 31, 1997 to establish maximum time intervals of inspection frequency of all electric distribution facilities within the jurisdiction of the CPUC. The basic premise of G.O. 165 is that all distribution assets must be patrolled every year for safety and reliability issues and the identification of significant G.O. 95 and 128 discrepancies. General Order 165 also requires these same assets to have a close up detailed inspection every 5 years (or less) to identify safety and reliability issues as well as all G.O. 95 and 128 discrepancies.

DIMP is SCE's approach to combining these two worthwhile endeavors into one efficient and cost effective program. This is a very large undertaking for SCE as there are over 2 million assets to be inspected and numerous SCE organizations involved.

1.3 Organizational Responsibilities

A. Maintenance and Inspection Program Oversight

Maintenance and Inspection Program Oversight (M&IPO) is responsible for oversight and improvement of the DIMP, including:

- ☐ Resolving all CPUC audits of G.O. 95/128/165
- ☐ Strategic direction of the M&I program and governance of policies, including frequency, scope, inspection criteria, corrective action time frames, and documentation of inspection and repair requirements
- ☐ Providing technical advisory staff
- ☐ Providing annual and informal training

- ☐ Developing performance measures
- ☐ Analyzing and tracking program department performance
- ☐ Providing staff to manage and/or support audits conducted by the CPUC
- ☐ Providing oversight of notification process, including developing enhancements and oversight reports
- ☐ Responsible for Aviation, Filing, and Maintenance (AF&M) program
- ☐ Responsible for supporting aerial program quality reviews

B. Distribution Construction and Maintenance

Distribution Construction and Maintenance (DC&M) is responsible for identifying and scheduling resources to achieve program goals and seeking to ensure:

- ☐ Discrepancies are properly identified and rated per policy
- ☐ Rated discrepancies are recorded timely
- ☐ Priority 2 rated discrepancies are reviewed prior to Work Management System (WMS) upload
- ☐ Resultant Maintenance is scheduled properly
- ☐ Maintenance (DC&M) is completed safely and according to policy

C. Overhead Detail Inspections

Overhead Detail Inspections is responsible for identifying and scheduling resources to achieve program goals and seeking to ensure:

- ☐ Overhead Detail Inspections (ODIs) are completed and timely
- ☐ Annual Grid Patrols (AGPs) are completed correctly and timely
- ☐ Repair by Inspector (RBI) is performed during inspections when authorized by Labor Agreement
- ☐ Streetlight detailed inspections are completed correctly and timely
- ☐ Discrepancies are properly identified and rated correctly
- ☐ Rated discrepancies are recorded timely
- ☐ Priority 2 rated discrepancies are reviewed by a Gatekeeper after the notifications have been by the Overhead Detail Inspector.
- ☐ Inspections are completed safely and according to policy
- ☐ Complete the electronic inspection form for distribution detailed inspections.

D. Substation Construction and Maintenance Field Apparatus

Substation Construction and Maintenance (SC&M) Field Apparatus is responsible for identifying and approving equipment as described in IN–1, Attachment 1–2 to allocate resources for achieving program goals and seeking to ensure:

- ☐ Assigned inspections are completed correctly and timely
- ☐ Infractions and maintenance activities are identified, rated correctly, and recorded timely
- ☐ Maintenance is completed safely and according to policy

E. Information Technology System Support and Administration
Information Technology (IT) System Support and Administration is responsible for identifying and allocating resources to achieve DIMP goals by ensuring recording devices and the WMS are functioning properly.

F. Compliance and Quality Control
Compliance and Quality Control is responsible for administering an effective quality assurance program, assessing compliance with regulatory requirements and supporting continuous improvement of the DIMP.

G. Environmental Requirements
For equipment inspection activities that occur in open space areas and/or on public lands, activities must follow the applicable environmental requirements. Activities conducted in natural areas, areas with historic or cultural resources, or areas in or adjacent to wetlands or waters have the highest potential for impacts. It is important to avoid impacts to the greatest extent possible on private or public lands; but we must be particularly sensitive when working on public lands such as U.S. Forest Service, National or State Parks, and Bureau of Land Management properties. Of special concern are sensitive species and their habitats, waterways, associated upland areas, and archaeological resources.
To reduce potential impacts to environmental resources and to ensure public land management agencies are notified as appropriate, engage the Environmental Services Department (ESD) at [EMAIL REMOVED] or (833) 723-2362. Additionally, contact the ESD for further guidance if these guidelines cannot be followed to complete inspections in a safe manner, or if there is a change in inspection scope. For inspections occurring within public lands, contact Government Lands for applicable access requirements ([EMAIL REMOVED]).
Refer to DOM IM-8 for environmental guidelines.

H. Distribution Aerial Inspection Program
In April 2019, SCE launched a robust Aerial Inspection Program to support SCE's Wildfire Mitigation Plan (WMP) which supplements SCE's ground-based inspections. The Aerial Inspection Program was deployed to reduce wildfire risks by assessing assets in High Fire Risk Areas (HFRAs) from the air, enabling detection of Priority 1 and 2 conditions not visible from the ground.

I. Pole Program Management
The Pole Program Management (PPM) group administers the Pole Replacement Program, which encompasses the visual and intrusive testing of transmission and distribution wood poles, including necessary repair, reinforcement, and replacement in alignment with remediation time frame requirements.

J. Vegetation Management
The Vegetation Management (VM) department is responsible for all line-clearing activities occurring within SCE’s Distribution districts. VM Managers and Senior Specialists work with SCE’s vegetation contractors who are responsible for maintaining vegetation-to-line clearances in order to comply with regulations such as General Order 95, Rule 35 and 37, and California Fire Public Resources Code 4293.

2.0 Definitions

2.1 Annual (Inspection)

Twelve consecutive calendar months starting the first full calendar month after an inspection is performed, plus three full calendar months, not to exceed the end of the calendar year in which the next inspection is due.

2.2 Communication Lines

The continuous set of SCE communication cables, components, and appurtenances, located outside of substations.

2.3 Discrepancy

A noteworthy material or structural deficiency; a condition that does not meet a SCE standard or specification or General Order 95 and General Order 128 requirement; or, a condition that left unresolved (in the opinion of the inspector) presents a hazard to the public or workers; or, a condition that will negatively impact system reliability.

2.4 Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts, which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practices is not intended to be any one of a number of optimum practices, methods, or acts to the exclusion of all others; but rather acceptable practices, methods, or acts generally in practice in the region.

2.5 Inspections

A. Aerial Inspection

Performed mainly via drones to support with 360-degree inspections as well as some use of helicopters. Potential ignition risk conditions in HFRA locations are identified; Priority 1 and 2 notifications on findings and additional findings to support with data collection are created.

B. Detailed Inspection

A close proximity evaluation of an SCE distribution asset. Distribution assets subject to underground detail inspections include subsurface and pad mounted enclosures, switches, transformers, visible cables, and associated components.

Distribution assets are also subject to overhead detail inspections include poles, transformers, capacitors, regulators, visible wires and/or cables, and associated line elements.

Overhead Detailed Inspections are conducted using an electronic inspection form with prompted questions and data capture.

- Inspector duties include:
  - — Identifying discrepancies rating and recording conditions
  - — Performing minor corrective action
  - — Documenting Priority 2 rated safety and reliability conditions created by third parties on or near SCE structures.

Conditions assigned a priority rating are recorded electronically in a field tool. Additional data recorded in the field tool includes:

- Functional location (FLOC) or equipment number, problem statement, date found, and unique employee identifier.
- Electronically recorded data is uploaded to the WMS.

C. Grid Patrol

Basic visual evaluation of SCE's distribution assets located within a specified boundary. Distribution assets subject to grid patrols include above ground structures, overhead conductors and equipment; as well as entryways to subsurface enclosures and vaults. Grid Patrols are typically conducted by land vehicle; however, patrols may be conducted by foot or by aircraft (helicopter or fixed wing) in remote areas. Conditions assigned a priority rating are recorded electronically in a field tool.

Additional data recorded in the field tool includes, but not limited to:

- FLOC or equipment number
- Problem statement
- Date found
- Unique employee identifier

Electronically recorded data is uploaded to the WMS. The AGP should not be considered complete for a grid until, for all structures with required assets within the grid, SCE has either documented a successful visual inspection (by vehicle, foot, or air) or documented a permissible justification for an incomplete inspection (that is, permitting, government access restrictions, or other reasonable circumstances).

Refer to IN–2, Section 2.0 for details.

D. Emergency Patrols

Typically performed following a circuit interruption or system event to identify affected facilities and safety hazards, as well as to perform initial damage assessments. Results are reported to the responsible manager and/or Grid Control Center and recorded.

E. Infrared Thermography

The use of an infrared imaging and measurement camera to "see" and "measure" the thermal energy emitted from an object.

F. Repair by Inspectors (RBI)

Inspectors also identify and perform certain maintenance tasks during the course of a Detail Inspection or Grid Patrol. Upon completion of these tasks, the inspectors will accurately record work completed in the field tool and upload recorded data to the WMS.

G. Streetlight Inspections

Conducted as visual evaluations.

H. Intrusive Pole Inspection

Involves boring of holes at different levels to identify degradation. These inspections are categorized as either:

- Partial Dig
- Full Treatment
- OR Sound and Bore
  - — For poles set in asphalt or concrete) and performed on a 15-year cycle for poles that have been in-service for 20 years. Inspections are typically performed by contract personnel.

Visual and Intrusive test results are recorded and submitted to the responsible program administrator for review and input into a WMS.

2.6 Maintenance

As used herein, encompasses inspection, assessment, maintenance, repair, and replacement activities performed with respect to Transmission and Communication Lines.

A. Repair

The restoration or reconditioning of equipment, structures, or components.

B. Replacement

The installation of new or refurbished equipment, structures, or components.

2.7 Safety Hazard

A condition that poses a significant threat to human life or property.

2.8 Work Management System (WMS)

Any database used to collect data, schedule, and monitor pending and completed activities. Examples include SAP and Consolidated Mobile Solutions (CMS).

3.0 Action Priortization

There are three basic elements to the overall inspection program: 1) Identification of actionable items, 2) Risk assessment and action prioritization, and 3) Actual repairs.

3.1 Identification and Repair of Actionable Items

Information required to identify and repair actionable items (Items 1 and 3 in Section 3.0 above) are contained in the various SCE standards manuals as well as G.O. 95 and 128. The Condition Guides included in this document provide typical conditions, criteria and tests that have associated Priority 1 and 2 ratings. These Condition Guides are intended only to serve as aids, and do not, nor cannot, contain all the possible safety and reliability issues and/or G.O. discrepancies that the inspector is expected to identify.

- A condition that conflicts with SCE standards, G.O. 95 or G.O. 128 requirements;

- OR a condition that, left unchecked (in the opinion of the Inspector), presents a hazard to the public or utility worker, property, environment, or will negatively impact system reliability.

Discrepancies identified during detail inspections and grid patrols or while performing

associated tasks are cross-referenced with the Risk Assessment Matrix and as necessary, conditions are assigned a priority rating according to the Assigning Priority Levels.

3.2 Risk Assessment and Action Prioritization

Risk assessment and action prioritization of repair efforts for these actionable items (Item 2 in Section 3.0 above) requires evaluation of site and equipment specific conditions by the inspector to determine the appropriate priority rating and action time frame.

3.3 E1 Notification

The E1 notification provides the detailed information needed for corrective actions to be taken following the identification of a potential violation or safety hazard on SCE's facilities.

The E1 notification is also defined as:

- Repair notifications created in SAP to document and record corrective actions on SCE facilities and equipment.
- The E1 notification will provide the detailed information needed for corrective actions to be taken following the identification of a potential violation or safety hazard on SCE's facilities.
- Each condition or discrepancy identified in the field shall be assigned its own E1 notification.

3.4 Notification Priority Rating with Remediation Time Frames

Transmission and Distribution (T&D) uses a three-priority ratings system: 1) Priority 1 (E1P1) Notifications, 2) Priority 2 (E1P2) Notifications, and 3) Priority 3 (E1P3) Notifications. This system ranks the potential impact to safety or reliability of a condition. These may be conditions which present a hazard to workers or to the public or conditions which may cause a system failure. The ratings also define the maximum corrective action time frames to remediate the condition.

The three priorities are as follows:

A. Priority 1 (E1P1) Notifications

Priority 1 notification conditions are an immediate risk of high potential impact to safety or reliability and require temporary or permanent corrective action within 72 hours. The site must be made safe to the public via immediate corrective action taken by the first responder if necessary. Otherwise, T&D personnel are required to remain on-site, at a safe distance, until relieved by a company representative. It is acceptable to briefly leave the site if it is for the purpose of making the site safe as long as steps are taken to limit access to the site by the public until return. For all immediate corrective actions taken, and temporary repairs performed it shall be documented in SAP to include a description of what was done, when the work was performed, and who performed the work.

The on-site requirement does not apply to the following exclusions; however, temporary or permanent corrective action is still required for these exclusions within 72 hours:

- T&D notification derived from calculated values:
  - — Intrusive Pole Inspections (IPI)
  - — Overhead Infrared Inspections
  - — Pole Loading Calculations
- Special programs or projects such as:
  - — Aerial Inspection Program
  - — Deteriorated Vault and Manhole Program (DVMP)

1. E1P1 Remediation Time Frames

   A temporary or permanent repair is required within 72 hours of the notification date. If a temporary repair is made:

   - The E1P1 notification can be completed for the temporary repair, then an E1P2 notification is required for the permanent repair;
   - OR the E1P1 notification can remain open and a permanent repair must be made within 21-calendar days or the notification date.

   If the permanent repair extends beyond 21-calendar days of the notification date, the following actions are required:

   ☐ Complete the E1P1 notification for the temporary repair made

   ☐ Create an E1P2 notification for the permanent repair

   Exceptions to the requirement to complete the E1P1 notification and create an E1P2 notification if a permanent repair extends beyond 21 calendar days:

   Claims and Storms

   - The associated E1P1 notification may be kept open longer than 21-calendar days for a permanent repair to be made if necessary.
   - In each such instance, it shall be documented in the system of record that the E1P1 is being left open to ensure proper tracking for the purpose of Claim and/or Storm accounting.

B. Priority 2 (E1P2) Notifications

Priority 2 notifications are for conditions which pose a risk of moderate potential impact to safety or reliability. These notifications require action anywhere from the same day up to 36 months of the notification date depending on the condition and the location. Repairs completed by inspectors during an inspection are classified as Priority 9 notifications.

The Gatekeeper will review issue notifications, using the appropriate standards that are in place, and can reassess time frames, if necessary, to allow for the condition to be remediated within the required compliance time frames:

1. E1P2 Remediation Time Frames

   - Same day Find & Fix notifications require all notification dates to be the same.
   - Conditions that create a fire risk located in CPUC Tier 3 Extreme Fire Threat Area (overhead only) require corrective action within 6 months of the notification date.

- Conditions that create a fire risk located in CPUC Tier 2 Elevated Fire Threat Area / Non-CPUC HFRA (SOB322) (overhead only) require corrective action within 12 months of the notification date.
- Conditions that compromise worker safety require corrective action within 12 months of the notification date.
- All other conditions require corrective action within 36 months of the notification date.

2. Exceptions To Remediation Time Frames

Exceptions to remediation time frames are conditions in a HFRA that are identified as not creating a fire risk. These conditions are determined by Gatekeeper review, risk assessment, or an engineering analysis (that is, Intrusive Pole Inspection) and may be classified as a Non-High Fire Threat Notification with a remediation time frame up to 36 months of the notification date.

To be classified as a Non-High Fire Threat Notification, the following condition(s) must be met:

- Remove the High Fire status from the notification AND
- Enter in the Notification Long Text “NonFireRiskNotification” followed by a description of why the condition is not a fire risk.

OR

- Enter in the Notification Long Text “NonElevatedFireRiskNotification” followed by a description of why the condition is not an Elevated fire risk

Notifications created on the assets below can exceed 6 or 12 months in high fire areas, but cannot exceed 36 months:

- Underground assets
- Apparatus assets
  - — Apparatus notifications must have the Main Work Center of Apparatus

Exceptions to remediate time frames are those E1P2 notifications that are not

reviewed by a Gatekeeper due to their automation:

- Same day Find & Fix
- Notify Customer/Communication Infrastructure Provider (CIP)
- Intrusive Pole Inspection (IPI)
- Pole Loading Failures

C. Priority 3 (E1P3) Notifications

Priority 3 notifications are for conditions which pose a risk of low potential impact to safety or reliability, GO 95 or GO 128 infractions, and programmatic replacement work.

1. E1P3 Remediation Time Frames

Corrective actions necessary within these remediation time frames appear below:

- Conditions on overhead assets found on or after June 30, 2019 require corrective action within 5 years of the notification date.

- Conditions on overhead assets found prior to June 30, 2019 do not require corrective action within a specified time frame.
- Conditions on non-overhead assets do not require corrective action within a specified time frame.

D. Maintenance Priority Accuracy

Maintenance priorities will be thoroughly evaluated and accurately assigned and maintained. Training and continuing analysis will take place to prevent premature maintenance, and to prevent failure prior to repair or the next scheduled inspection.

A discrepancy not yet entered into WMS can be re-rated when being reviewed by a Gatekeeper (supervisor with qualified electrical worker knowledge) who clearly demonstrates that it was prioritized incorrectly. The discrepancy should then be entered into WMS with the appropriate priority.

3.5 Actual Repairs

Repairs shall be made in conformance with established internal standards. When performing Priority 2 maintenance work, all pending Priority 2 and Priority 3 work on the structure shall be repaired as long as it does not exceed the qualifications of the crew.

4.0 References

4.1 E1 Notification Policy

5.0 Attachments

Attachment 1–1: Assigning Priority Levels

Attachment 1–2: Risk Assessment Matrix — Things to Consider when Assessing a Condition

Attachment 1–3: Risk Assessment Matrix

Attachment 1–1: Assigning Priority Levels

Discrepancies identified during Patrols or Detail Inspections requiring remedial action are prioritized according to Table 1–1 below.

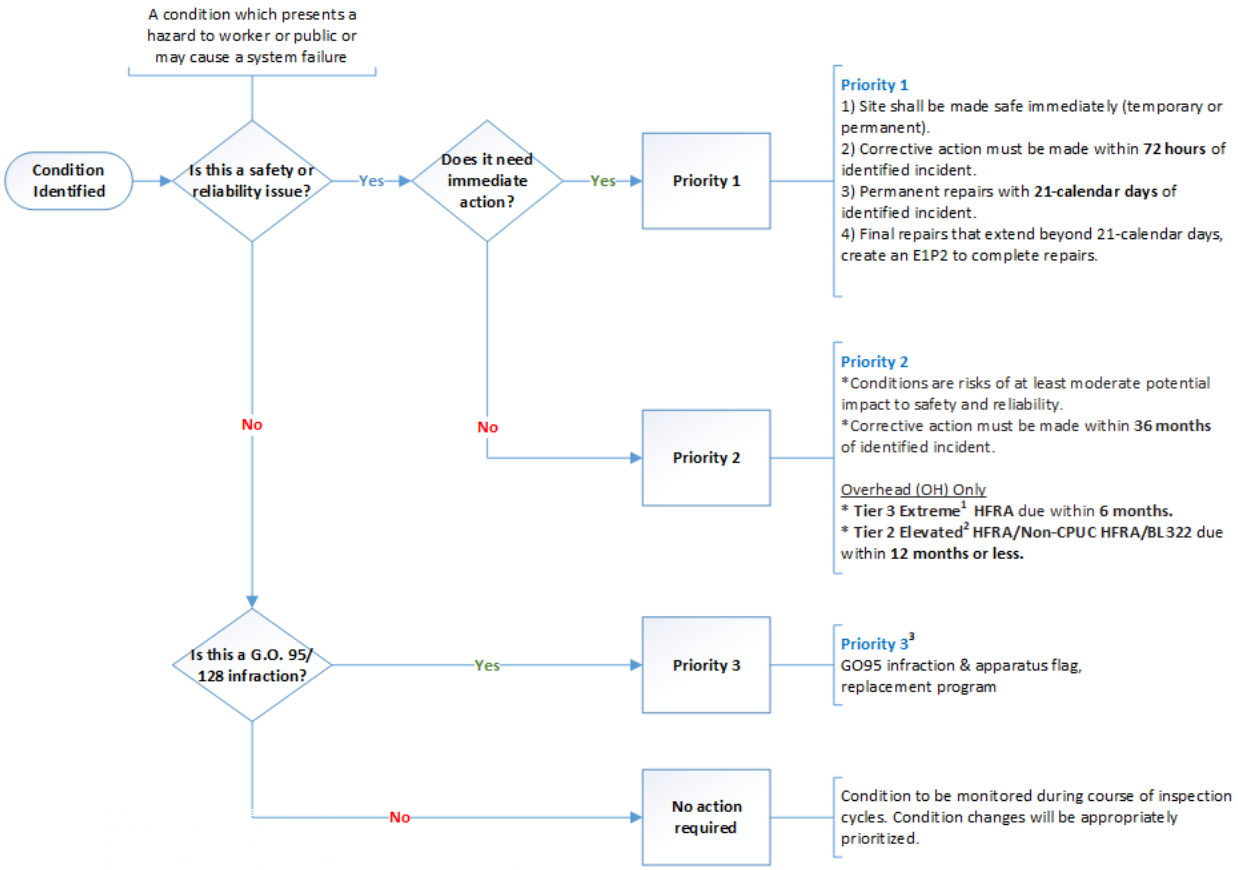
Table 1–1: Priority Rating

Priority	Overhead	Underground	Wood Poles
1	Initiative corrective action	Initiative corrective action	Initiative corrective action
2	Remedy within 36 month[1]	Remedy within 36 months[2]	Remedy within 36 months[1]
3	Remedy within 60 months[3, 4]	Re-evaluate next routine patrol cycle	Re-evaluate next routine patrol cycle

Note(s):

1. SCE HFRA repair time frame:
   - Tier 3 (Extreme) HFRA due within 6 months from the inspection/notification date
   - Tier 2 (Elevated) HFRA/ Non-CPUC HFRA/BL 322 due within 12 months from the inspection/notification date.
2. SCE HFRA Priority repair time frames are applicable only to overhead facilities/structures and underground facilities shall require remediation within 36 months and are not required to comply with HFRA Tier 3 (Extreme) and Tier 2 (Elevated) remediation time frames.
3. Unless discrepancy is exempted per G.O. 95 Rule 18 and Appendix J.
   - Priority 3 Remediation Time Frames
     — Overhead notifications prior to June 30, 2019 do not require a due date
     — Overhead notifications created on or after June 30, 2019 have up to a 5-year due date
     — Underground notifications do not currently require due dates
4. These priority levels are applicable to the maintenance and inspection requirements referenced in G.O. 95 /128/165.
   Please reference E1 Notification Policy for further definition of E1 priority levels and time frames. The Condition Guides included in this document provide typical conditions, criteria and tests that have associated Priority 1 and 2 ratings.
   These Condition Guides are intended only to serve as aids, and do not, nor cannot, contain all the possible safety and reliability issues and/or G.O. discrepancies that the inspector is expected to identify.

Figure 1–1: Priority Inspection Decision Flowchart



Once a condition has been determined to be a Priority 2, the inspector performs a risk assessment to properly establish a reasonable time frame within zero (0) to 24 months. This is done by assessing the condition through determination of the safety and reliability factors in accordance with Attachment 1–2: Risk Assessment Matrix — Things to Consider when Assessing a Condition, and then applying this information to the risk assessment, Attachment 1–3: Risk Assessment Matrix.

Note(s):

1. Tier 3 Extreme HFRA effective March 2018
2. Tier 2 Elevated HFRA effective June 2018
3. Priority 3 Remediation Time Frames:
   - Overhead notifications prior to June 30, 2019 do not require a due date.
   - Overhead notifications created on or after June 30, 2019 have up to a 5-year due date
   - Underground notifications do not currently require due dates.

Attachment 1–2: Risk Assessment Matrix — Things to Consider when Assessing a Condition

NOTE Each problem or condition is independent from one another.

Determine Safety Factors

Factors to Consider when Assessing the Safety Risk		
Public/Worker Safety	**Property**	**Environmental**
•Near a school/park •In front of a mall •Rear property line •Behind a commercial strip center •In a vacant field •Minor pedestrian traffic •Major intersection •Impossible climbing space	•In a parking lot •In an agricultural area •In a vacant field	•In the desert •In coastal areas •Mountainous •Urban/Rural •Time of season –High wind –Rainy –High heat –Snow •Protective habitats •Hazardous spills •In a high fire risk area
It is important to note that no one factor weighs more than another. Only after you have considered all your surroundings, People/Property/Environment, can you make a true assessment of the risk. Refer to DOM IM-8 for environmental guidelines.		

Identifying the Safety Risk Impact Levels	
No/Slight Safety Impact	Any Condition which has *LITTLE/NO* safety risk to public or worker safety/Property/Environment.
Minor Safety Impact	Any Condition which has *MINOR* safety risk to public or worker safety/Property/Environment.
Moderate Safety Impact	Any Condition which has *MODERATE* safety risk to public or worker safety/Property/Environment.
High Safety Impact	Any Condition which has *HIGH* safety risk to public or worker safety/Property/Environment.

Attachment 1–2: Risk Assessment Matrix — Things to Consider when Assessing a Condition
(Continued)

NOTE

Each problem or condition is independent from one another.

Determine Reliability Factors

CONSTRUCTION TYPE

- ☐ What is the component the condition is associated to?
- ☐ What is the construction type of the component?
- ☐ Is there any electrical equipment associated to the component?
- ☐ Where is the condition located on the component?
- ☐ What is the stress factor?
  - — Weight: high/medium/low
  - — Span length: long/medium/short

CIRCUIT TYPE/LOCATION

- ☐ What is the highest voltage “Directly” associated to the component?
- ☐ What is the highest voltage “Indirectly” associated to component?
- ☐ What is the load factor: High/Medium/Low
- ☐ Is the component located behind any fusing?

Attachment 1–3: Risk Assessment Matrix

Select the safety impact level to people, property, and environment aligned with the condition of the component regarding the risk to the system.

Reliability (Failure Risk)	No/Slight Impact	Minor Impact	Moderate Impact	High Impact
Component Failure could lead to System Failure	**Priority 2** Action Required 13-36 Months	**Priority 2** Action Required 4-12 Months	**Priority 2** Action Required 0-3 Months	**Priority 1** Action Required Immediately
Component Has Failed No significant risk to system	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 2** Action Required 13-36 Months	**Priority 2** Action Required 4-36 Months	**Priority 2** Action Required 0-3 Months
Potential Component Failure	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 3/No Action Required** Only 95/128 Infractions Recorded	**Priority 2** Action Required 13-36 Months	**Priority 2** Action Required 4-12 Months
	Safety (People/Property/Environment)			

Note(s):

1. This “Risk Assessment Matrix” is a reference tool intended to give inspectors guidelines to assign a reasonable time frame for the remediation of any distribution facility condition.
2. Starting March 1, 2018, Overhead Equipment in an Extreme High Fire Area has HFRA an allowed maximum of 6 months. Starting June 30, 2019, Priority 3 notifications on Overhead Equipment have an allowed maximum of 60 months.
3. System Failure is when the system no longer operates. (An interruption of service caused by damaged equipment preventing the system to perform).
4. Component Failure is when a piece of equipment can no longer perform the function it was designed for, but the system continues to operate. (Abnormal elbow temperature that is connected to the transformer.) (The elbow has failed, however, the system is still operating).

GE–2: Inspection and Maintenance Training

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GE–2: Inspection and Maintenance Training

1.0 Purpose

Training for the SCE Distribution Inspection and Maintenance Program (DIMP) will promote safety and circuit reliability on all electrical distribution facilities for both underground and overhead systems through routine inspections.

2.0 Training Objectives

Initial training and annual refresher training is mandatory and will be provided to all personnel inspecting distribution assets to ensure SCE will meet all inspection and maintenance objectives. These objectives include:

- Using proper field inspection procedures
- Accurately and timely documenting and reporting findings via the Work Management System (WMS)
- Prioritizing items identified for follow-up maintenance
- Compliance with CPUC-required maintenance cycles on structures, equipment, conductors and/or components

Inspectors will be tested at completion of training.

3.0 Operations

The Manager of Maintenance and Inspection is responsible for determination of training program requirements.

4.0 References

4.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

4.2 CPUC G.O. 128, Rules for Construction of Underground Electric Supply and Communication Systems

4.3 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.4 SCE Distribution Overhead Construction Standards (DOH)

4.5 SCE Distribution Underground Construction Standards (DUG)

4.6 SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

4.7 SCE Accident Prevention Manual (APM)

4.8 SCE Environmental Policies and Procedures (EN) and ESD Waste Management Manual

4.9 DOM IM-3, Distribution Maintenance Program

4.10 Work Management System

4.11 Underground Corrosion Inspection and Maintenance Manual

4.12 SCE Training Manual for Performing Grid Patrol, Detail Inspection and Intrusive Inspection of Wood Pole Structures

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IN–1: Overhead Detail Inspections

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IN–1: Overhead Detail Inspections

1.0 Purpose

The purpose of the Overhead Detail Inspection (ODI) is to visually evaluate SCE's overhead electrical distribution facilities with the intent to identify and document obvious discrepancies and validate accuracy of asset information and facility inventory mapping references for appropriate corrective action. Inspectors also identify and perform certain maintenance tasks during the course of a detailed inspection. Overhead detail inspections also accomplish the annual patrol of the grids, including streetlights.

2.0 Methods and Procedures

The inspector performs a close in-depth visual inspection of all the overhead electrical distribution facilities, including the streetlights and third party communication assets, within the assigned inspection area. The frequency of ODI is directed elsewhere in this chapter, and in the Distribution Operations and Maintenance Policies and Procedures (DOM) manual.

Conditions and asset data shall be documented using the electronic inspection form. Discrepancies and asset corrections shall be recorded through the field tool.

When inspecting structures with both transmission and distribution assets (e.g., combo poles), observe and identify conditions that require immediate attention (e.g., priority 1) on non-distribution assets, when authorized by the Labor Agreement. If conditions are found at the transmission level, the inspector shall notify their Supervisor who will contact the appropriate Transmission Grid Manager or Senior Patrol (if known) and provide photos and information related to the condition. If the condition is related to SCE communication, contact Telecom Control Center (TCC) - Contact (949) 587-5500.

3.0 Duties of the Inspector

The inspector performs the following tasks for each facility detailed inspection:

3.1 Identification of Discrepancies per the OH Detailed Inspection Guidelines

The ODI inspector performs an in-depth visual examination of each overhead distribution facility, including streetlights and third party communication assets, using the following Overhead Detailed Inspection Guidelines as a guideline. This list is a high level summary of the items and areas to inspect. Additional information showing typical conditions requiring corrective action (Priorities 1 and 2) is shown in the applicable overhead equipment and component Condition Guide attached.

The inspector also identifies and reports any G.O. 95/128 infractions created on or near Distribution facilities by the following:

- Third party communication providers subject to CPUC jurisdiction
- Non-utility third parties that are non-subject to CPUC jurisdiction

3.2 Establishment of Priorities per the Priority Decision Flowchart

Once the inspector has identified a condition requiring action, a risk assessment is performed using the Priority Inspection Decision Flowchart. This process helps identify the appropriate priority of the condition. The highest priorities are for those items that pose a safety hazard to the public or employees, property, environment, or could present a reliability threat to the system.

3.3 Establishment of Action Time Frames for Each Identified Priority 2 Condition per the Condition Guides, Risk Assessment Matrix

Only Priority 1 and 2 conditions have action time frames for mitigation. Priority 1 requires same day or immediate action thus no action time frame decision is required from the inspector. As discussed in the General Overview Section of this manual, Priority 2 conditions have zero (0) to 36-month time frame options depending on the severity of the situation (unless in a high fire risk area.)

3.4 Performance of Appropriate Minor Repairs at the “Public” Level

The ODI inspector makes minor repairs at the Public level, when authorized by the Labor Agreement, while at the site for the detailed inspection, rather than having other SCE personnel return at a later time to make the repairs.

The following is a list of repairs that the ODI inspector performs:

- ☐ Repair damaged ground molding.
- ☐ Install new and/or repair existing guy guard.
- ☐ Repair damaged visibility strips or install new strips in locations where necessary.
- ☐ Install or repair riser strap.
- ☐ Repair broken risers and exposed conductor.
- ☐ Repair damaged PVC separations, loose holders, and uncapped sweeps
- ☐ Install pole number.
- ☐ Remove unauthorized attachments when safe to do so.
- ☐ Repair open/damaged secondary hand hold and remove minor brush.

Overhead structures present unique public safety exposure and work conditions depending on the height of the necessary repairs from the ground level where public exposure exists.

3.5 Validation of Accuracy of Asset Information and Facility Inventory Mapping References

While at the facility site, the ODI inspector performs the following:

- ☐ Records corrections—found assets, missing assets, asset corrections.
- ☐ Mapping corrections

3.6 Document in the Field Tool

Refer to the Work Management System (WMS) procedures manual.

4.0 References

4.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

4.2 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.3 SCE Distribution Overhead Construction Standards (DOH)

4.4 SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

4.5 SCE Accident Prevention Manual (APM)

4.6 SCE Environmental Policies and Procedures (EN) and ESD Waste Management Manual

4.7 DOM, IM-3: Distribution Maintenance Program

4.8 Work Management System

5.0 Attachments

Attachment 1–1: Overhead Detailed Inspection Guideline

Attachment 1–2: Frequency of Apparatus Inspections

Attachment 1–1: Overhead Detailed Inspection Guideline

1. Condition of Equipment, Apparatus, and Hardware
   - ☐ Broken, chipped, or severely contaminated insulators/Primary insulator or pin above 750 V (cracked/damaged/loose)
   - ☐ Pole switch indicating need for repair
   - ☐ Indication of equipment oil leak
   - ☐ Bulged or discolored capacitor units
   - ☐ Blown or dry fuses, blown surge arresters, broken fuseholders
   - ☐ Streetlights broken or damaged including brackets, mast arms, and lights/globes – public hazard
   - ☐ Damaged anchor bolts
   - ☐ Insulator broken, cracked or loose, floating, squatting, chipped
   - ☐ Insulator tie wire broken/missing/damaged
   - ☐ Animals, birds, foreign material interfering with operation
   - ☐ Evidence of tracking or burning
   - ☐ Broken pins or squatters (primary or secondary)
   - ☐ Broken, bent pole steps
   - ☐ Damaged or missing ground wire molding or ground wire exposed
   - ☐ Condition of transformer's Internal Fault Detector (IFD), if so equipped; see DOM, TR–9.
2. Condition of Pole and Structures
   - ☐ Damage/deteriorated pole
   - ☐ Damage to pole foundation
   - ☐ Crossarm broken, split, or extremely canted
   - ☐ Visually check for pole leaning
   - ☐ Washout or excavation around pole or anchor
   - ☐ Check pole setting depth marked from brand. (Brands are at 10 feet on 60-foot poles and less; at 13 feet for poles taller than 60 feet.)
   - ☐ Damage down guys, guy guard missing (Install guard where required.) – public hazard
   - ☐ Excessive slack on down guys or span guys
   - ☐ Six-foot Fiberglass Guy Strain Insulator installed (upgrade to standard 12-foot version)
   - ☐ Visually check pad-mounted equipment for movement and cabinet secured or locked.
   - ☐ Visually check Buried Underground Residential Distribution (BURD) lids, vault lids, vent pipes, and handhole lids.
3. Conductors and Covered Conductors
   - ☐ Inadequate primary, secondary, or service ground clearances
   - ☐ Exposed conductor (covering falling off) – service drops, secondary, and primary
   - ☐ Excessive slack in primary conductors in high wind areas
   - ☐ Clearance from building, television or radio antenna, billboard signs, scaffolding, streetlights, communication cable or hazardous locations for primary, secondary or services
   - ☐ Trees touching or above primary conductors or covered conductors (overhangs) unless special encased aerial bundled cable (18 inches required)
   - ☐ Hazardous tree conditions, limbs over wire, dead or decaying trees, palm fronds

- ☐ Foreign objects in line, such as kites, Mylar balloons
- ☐ Bare conductors in rack construction
- ☐ Bare service drops
- ☐ Deflection, strain or abrasion on service drops and secondaries
- ☐ Abandoned conductors

4. Risers

- ☐ Riser straps, blocks broken – public hazard
- ☐ Opening in riser conduit coupling, damaged – public hazard
- ☐ Riser in climbing space in rack construction
- ☐ Missing/Damaged Warning Label on Riser Conduit

5. Climbing Space

- ☐ Obstructions in climbing space (bolts, wire)
- ☐ Climbing space obstructed by cable TV or phone, and a hazard to climb

6. General Conditions

- ☐ Unlocked substations, pole switches, equipment
- ☐ Verify circuit-to-circuit map for additional equipment and tap lines not identified.
- ☐ Check status of fault indicators with circuit map inventory.
- ☐ Validate asset information – maps, asset characteristics, location
- ☐ Unauthorized attachments
- ☐ Foreign attachments to SCE ground
- ☐ Conditions for transmission and distribution assets (e.g., combo pole), include but are not limited to:
  - — Pole broken/damaged or excessive leaning
  - — Vegetation contacting or nearly contacting energized lines (e.g., expected to imminently fail and contact energized lines, contact or arcing with bare-wire conductors is highly probable to occur in a high wind event due to vegetation proximity to power lines, appears contact has occurred with primary electric facilities, appears strain or abrasion has occurred with secondary bare open wire)
  - — Broken, damaged, burned or rotted crossarm
  - — Energized conductor with inadequate clearances, bare conductor contacting communication, burned jumpers/connectors, or burned wire
  - — SCE Communication (e.g., broken lashing wire with slack to reach into power space, attachments/repairs poorly secured with tape/rope, broken and hanging strands, down guys, primary/secondary slack and jumpers capable of contacting communication facilities, Transmission/primary/secondary broken down guys hanging in communication space, foreign objects with potential to cause arcing, shorts or conduct electricity across insulators)
  - — Loose, broken, damaged, or missing insulator
  - — Broken/damaged guy in proximity to energized conductor
  - — Leaking oil from the equipment - for transmission, 66 kV and 115 kV potheads
  - — Excessive corrosion (e.g., loss of material/holes in equipment)

- ☐ Conditions for third party communication assets include but are not limited to:
  - — Inadequate clearance between communication equipment or structures and SCE electrical equipment or structures
  - — Loose or broken lashing wire
  - — Improperly secured communication conductor or equipment
  - — Broken, damaged or severely strained communication guy wires
  - — Excessive bowing or bending of pole from potential overloading at communication equipment attachment points
  - — Excessive sag of communication cables causing G.O. 95 infraction(s) or safety issue(s)
  - — Communication messenger and/or cable sag is too tight and creating a G.O. 95 clearance violation for SCE low voltage or high voltage lines
  - — Vegetation straining communication messenger or guy wire and/or causing structural integrity issues
- ☐ Conditions for Overhead Transmission-Distribution Line Crossings include but are not limited to:
  - — Missing or damaged visibility (X) strips on any of the three distribution poles immediately preceding and following a transmission-distribution line crossing.
  - — Visibility strip(s) are not installed on the correct side of the distribution pole (opposite-facing side in relation to the transmission-distribution crossing).
  - — Visibility (X) strips are installed at a location where there is no transmission-distribution line crossing.

Attachment 1–2: Frequency of Apparatus Inspections

Facility/Equipment[a/]	Inspection Frequency (yr)	DOM Section
Apparatus		
Capacitors, Fixed (Overhead)	10	CA–1
Capacitors,. Fixed (Padmounted)	10	CA–1
Capacitors,. Switched (Overhead)	10	CA–2, CA–3, CA–4
Capacitors, Switched (Padmounted)	10	CA–2, CA–3, CA–4
Fault Interrupters (Padmounted)	5	SW–9, SW–12
Fault interrupters (Underground)	3	SW–9
Network Protectors	1	PD–3
Preferred Emergency Equipment (Overhead & Padmounted)	5	SW–8
Preferred Emergency Equipment. (Underground)	3	SW–8
Reclosers (Overhead)	5	SW–1
Reclosers (Padmounted)	5	SW–13
Regulators	5	TR–4
Remote Controlled Switches (Underground)	3	SW–11
Remote Controlled Switches (Padmounted)	5	SW–11
Remote Controlled Switches (Overhead)	7	SW–11

[a/] For inspection frequencies of equipment located in customer substations, co-generation interface sub-stations and small power-production interface substations, see DOM SC-1 Distribution Substations.

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IN–2: Inspection Procedures — Grid Patrols

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IN–2: Inspection Procedures — Grid Patrols

1.0 Purpose

The purpose of the Grid Patrol is to conduct an annual visual evaluation of SCE's Electrical distribution facilities with the intent to identify and document obvious discrepancies that require corrective action.

2.0 Methods and Procedures

The Grid Patrol inspector performs a simple visual inspection of publicly accessible electrical distribution facilities, including streetlights, within the assigned inspection area. The frequency of ODI is directed elsewhere in this chapter, and in the Distribution Operations and Maintenance Policies and Procedures (DOM) manual.

The inspections can be performed from vehicles, on foot, or by aircraft. The vehicle method is the most used as it provides the required accuracy while being cost effective. The problem conditions can generally be seen adequately by the naked eye or through the use of binoculars. The Grid Patrol does not require the climbing of overhead structures (poles)/streetlights or the opening of underground structures and equipment. Inspectors shall attempt to inspect all assigned structures from the ground when safe and practical to do so. If a portion of the circuit/streetlight cannot be safely and/or cost effectively inspected from the ground, then that portion shall be bypassed and clearly documented in red on the inventory maps for follow-up air patrol within the required compliance time frame.

Underground facilities such as pad-mounted transformers, BURD enclosures, vent pipes, handholes, and subsurface structure lids are also included as items to be visually observed for public safety hazards during a Grid Patrol. Underground portions of the circuit, including pad-mounted equipment, that are located on rear property lines, within private property, or in limited access communities do not require a patrol as these structures and equipment are in a controlled environment. In these cases the Underground Detail Inspection will be used to ensure compliance.

If the inspector is unable to complete a basic visual inspection of a given asset by vehicle or foot, then an air patrol should be used to timely complete the patrol inspection for that asset.

In the event that permitting, government access restrictions, a state of emergency, or other reasonable circumstances prevent the inspector from timely completing a basic visual inspection of a given asset by vehicle, foot, or air, the justification for the incomplete inspection of the relevant structure must be documented.

The Grid Patrol should not be considered complete for a grid until, for all structures with required assets within the grid, the inspector has either documented a successful visual inspection (by vehicle, foot, or air) or documented a permissible justification for an incomplete inspection (that is, permitting, government access restrictions, or other reasonable circumstances). This documentation should permit SCE to not only capture the percentage of required structures successfully inspected within the grid during the Grid Patrol, but to also capture, on a structure-by-structure basis, whether a given structure was successfully inspected or not, and, if not successfully inspected, the justification for the incomplete inspection.

Regardless of whether an AGP is considered complete or not for internal compliance purposes, for every structure that is not timely inspected, SCE shall make reasonable efforts to complete the inspection as soon as practical given the exception circumstances. For example, if a structure is

not able to be timely inspected because SCE needs a permit, SCE shall make reasonable efforts to obtain a permit and, once the permit is obtained, should complete the inspection of the structure as soon as practical.

When inspecting structures with both transmission and distribution assets (e.g., combo pole), observe and identify conditions that require immediate attention (e.g., priority 1) on non-Distribution assets, when authorized by the Labor Agreement. If conditions are found at the transmission level, the inspector shall notify their Supervisor who will contact the appropriate Transmission Grid Manager or Senior Patrol (if known) and provide photos and information related to the condition. If the condition is related to SCE communication, contact Telecom Control Center (TCC) - Contact (949) 587-5500. See grid patrol guideline section for condition examples.

3.0 Duties of Grid Patrol Inspector

The grid patrol inspector performs the following tasks for each facility in the grid:

3.1 Identification of Hazards and/or Discrepancies per the Grid Patrol Guideline

The grid patrol inspector shall perform annual routine visual examination of each overhead distribution facility, including streetlights, using the following Grid Patrol Guideline as a guideline. This list is a high level summary of the items and areas to inspect. Additional information showing typical conditions requiring corrective action (Priorities 1 and 2) is shown in the applicable equipment and component Condition Guide attached. Priority 3 conditions are generally not identified or documented as part of a grid patrol.

3.2 Establishment of Priorities per the Priority Inspection Decision Flowchart

Once the inspector has identified a condition requiring action, a risk assessment is performed using the Priority Inspection Decision Flowchart. This process helps identify the appropriate priority of the condition. The highest priorities are for those items that pose a safety hazard to the public or employees, property, environment, or could present a reliability threat to the system.

3.3 Establishment of Action Time Frames for Each Identified Priority 2 Condition per the Condition Guides, Condition Risk Assessment Matrix

Priority 1 and 2 conditions have action time frames for mitigation. Priority 1 requires same day or immediate action; site shall be made safe immediately and corrective action shall be made within 72 hours of reported incident. As discussed in the General Section of this manual, Priority 2 conditions have zero (0) to 36-month time frames (unless in a high fire risk area). Priority 3 (overhead) conditions have remediation time frames up to a 5-year due date if notification was created on or after June 30, 2019. Overhead notifications prior to June 30, 2019 do not require a due date.

3.4 Performance of Appropriate Routine Repairs

The inspector also repairs or installs, when authorized by the Labor Agreement, new guy guard/markers on down guys in general public proximity or exposed to pedestrians, areas easily accessible to the general public, parking lots, or areas exposed to vehicular contact. Any repair by inspector during a patrol will be recorded in the field tool.

3.5 Document in the Field Tool

Refer to the Work Management System (WMS) procedure manual.

4.0 References

4.1 CPUC G.O. 95, Rules for Overhead Electric Line Construction

4.2 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.3 Distribution Overhead Construction Standards (DOH)

4.4 Distribution Operations and Maintenance Policies and Procedures (DOM)

4.5 Accident Prevention Manual (APM)

4.6 Environmental Policies and Procedures (EN) & ESD Waste Management Manual

4.7 DOM, IM-3: Distribution Maintenance Program

4.8 Work Management System

5.0 Attachments

Attachment 2–1: Grid Patrol Guideline

Attachment 2–1: Grid Patrol Guideline

1. Condition of Equipment, Apparatus, and Hardware
   - ☐ Broken, chipped, or severely contaminated insulators/Primary insulator or pin above 750 V (cracked/damaged/loose)
   - ☐ Pole switch indicating need for repair
   - ☐ Indication of equipment oil leak
   - ☐ Bulged or discolored capacitor units
   - ☐ Blown or dry fuses, blown surge arresters, broken fuse-holders
   - ☐ Streetlights broken or damaged including brackets, mast arms, and light/globes — public hazard
   - ☐ Damaged anchor bolts
   - ☐ Insulator broken, cracked or loose, floating, squatting, chipped
   - ☐ Insulator tie wire broken/missing/damaged
   - ☐ Animals, birds, foreign material interfering with operation
   - ☐ Evidence of tracking or burning
   - ☐ Broken pins or squatters (primary or secondary)
2. Condition of Pole and Structures
   - ☐ Damage/deteriorated pole
   - ☐ Damage to pole foundation
   - ☐ Crossarm broken, split, or extremely canted
   - ☐ Visually check for pole leaning
   - ☐ Washout or excavation around pole or anchor
   - ☐ Damage down guys, guy guard missing — public hazard
   - ☐ Excessive slack on down guys or span guys — clearance problem or pole integrity issue
   - ☐ Visually check pad-mounted equipment for movement and cabinet secured or locked.
   - ☐ Visually check BURD lids, subsurface structure lids, vent pipes, and handhole lids.
3. Conductors
   - ☐ Inadequate primary, secondary, or service ground clearances
   - ☐ Excessive slack in primary conductors in high wind areas
   - ☐ Clearance from building, television or radio antenna, billboard signs, scaffolding, streetlights, communication cable or hazardous locations for primary, secondary or services
   - ☐ Trees touching or above primary conductors (overhangs) unless special encased tree cable (18 inches required)
   - ☐ Hazardous tree conditions, limbs over wire, dead or decaying trees, palm fronds
   - ☐ Foreign objects in line, such as kites, Mylar balloons
4. Risers
   - ☐ Riser straps, blocks broken, unattached — public hazard
   - ☐ Opening in riser conduit coupling, damaged conductor — public hazard
5. General Conditions
   - ☐ Unlocked substations, pole switches, equipment

- ☐ Conditions for transmission and distribution assets (e.g., combo pole), include but are not limited to:
  - — Pole broken/damaged or excessive leaning
  - — Vegetation contacting or nearly contacting energized lines (e.g., expected to imminently fail and contact energized lines, contact or arcing with bare-wire conductors is highly probable to occur in a high wind event due to vegetation proximity to power lines, appears contact has occurred with primary electric facilities, appears strain or abrasion has occurred with secondary bare open wire, etc.)
  - — Broken, damaged, burned or rotted crossarm
  - — Energized conductor with inadequate clearances, bare conductor contacting communication, burned jumpers/connectors, or burned wire
  - — SCE Communication (e.g., broken lashing wire with slack to reach into power space, attachments/repairs poorly secured with tape/rope, broken and hanging strands, down guys, primary/secondary slack and jumpers capable of contacting communication facilities, Transmission/primary/secondary broken down guys hanging in communication space, foreign objects with potential to cause arcing, shorts or conduct electricity across insulators, etc.)
  - — Loose, broken, damaged, or missing insulator
  - — Broken/damaged guy in proximity to energized conductor
  - — Leaking oil from the equipment - for transmission, 66 kV and 115 kV potheads
  - — Excessive corrosion (e.g., loss of material/holes in equipment)
- ☐ Conditions for third party communication assets include but are not limited to:
  - — Inadequate clearance between communication equipment or structures and SCE electrical equipment or structures
  - — Loose or broken lashing wire
  - — Improperly secured communication conductor or equipment
  - — Broken, damaged or severely strained communication guy wires
  - — Excessive bowing or bending of pole from potential overloading at communication equipment attachment points
  - — Excessive sag of communication cables causing G.O. 95 infraction(s) or safety issue(s)
  - — Communication messenger and/or cable sag is too tight and creating a G.O. 95 clearance violation for SCE low voltage or high voltage lines
  - — Vegetation straining communication messenger or guy wire and/or causing structural integrity issues
- ☐ Conditions for Overhead Transmission-Distribution Line Crossings include but are not limited to:
  - — Missing or damaged visibility (X) strips on any of the three distribution poles immediately preceding and following a transmission-distribution line crossing.
  - — Visibility strip(s) are not installed on the correct side of the distribution pole (opposite-facing side in relation to the transmission-distribution line crossing).
  - — Visibility (X) strips are installed at a location where there is no transmission-distribution line crossing.

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IN–3: Inspection Procedures — Underground Detail Inspections

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IN–3: Inspection Procedures — Underground Detail Inspections

1.0 Purpose

The purpose of the Underground Detail Inspection (UDI) is to give a visual evaluation of SCE's underground electrical distribution assets with the intent to identify and document obvious discrepancies and/or California Public Utility Commission (CPUC) General Order (G.O.) 128 discrepancies for appropriate corrective action.

2.0 Methods and Procedures

The UDI inspector performs a close in-depth visual inspection of all the underground electrical distribution assets per inspection orders. UDI frequency is identified in the Distribution Operations and Maintenance Policies and Procedures (DOM) manual, Chapter IM-1: Distribution Inspection and Maintenance Program (DIMP) - Overview.

3.0 Duties of Underground Detail Inspector

The UDI inspector performs the following tasks as appropriate for each facility detailed inspection:

3.1 Identification of Discrepancies per the Underground Structure Detailed Inspection Guidelines

The UDI inspector performs an in-depth visual examination of each underground distribution facility using the following Underground Detailed Inspection Guidelines (Structure, Equipment and Apparatus Equipment) as minimum guides. These lists are high level summaries of the items and areas to inspect. Additional information regarding the extent of the condition is shown in underground equipment and component Condition and Corrosion Guides attached. Inspectors will inspect and report on all equipment within a structure, and confirm the configuration numbering of the equipment.

The UDI inspector also identifies and reports any G.O. 128 infractions created on or near Distribution facilities by non-utility third parties that are not subject to CPUC jurisdiction.

NOTE

Inspectors will comply with the Confined Space Safety Initiative (CSSI), when inspectors are entering a Confined Space or Enclosed Space.

3.2 Establishment of Priorities per the Priority Inspection Decision Flowchart

Once the inspector has identified a condition requiring action, a risk assessment is performed using the Priority Inspection Decision Flowchart. This process helps identify the appropriate priority of the condition. The highest priorities are for those items that pose a safety hazard to the public or employees, property, environment, or could present a reliability threat to the system.

3.3 Establishment of Action Time Frames for Each Identified Priority 2 Condition per the Condition and Corrosion Guides, Condition Risk Assessment Matrix

Only Priority 1 and 2 conditions have action time frames for mitigation. Priority 1 requires same day or immediate action thus no action time frame decision is required from the inspector. As discussed in the General section of this manual, Priority 2 conditions have a zero (0) to 36-month time frame (unless in a high fire risk area).

3.4 Performance of Appropriate Routine Repairs

- ☐ The UDI inspector will make routine repairs while at the site for the detailed inspection, rather than having other SCE personnel return at a later time to make the repairs.
- ☐ Inspectors will perform structure cleanup of debris or materials prior to leaving the structure.

3.5 Validation of Accuracy of Asset Information and Facility Inventory Mapping references

It is extremely important that SCE's records be as accurate as possible. The UDI inspector is a valuable force in realizing this goal. While at the facility site, the UDI inspector shall perform the following:

- ☐ Records corrections—found assets, missing assets, asset corrections
- ☐ Mapping corrections

3.6 Document in the Field Tool

Refer to the Work Management System (WMS) Procedure Manual.

4.0 References

4.1 CPUC G.O. 128, Rules for Construction of Underground Electric Supply and Communication Systems

4.2 CPUC G.O. 165, Inspection Cycles for Electric Distribution Facilities

4.3 Distribution Underground Construction Standards (DUG)

4.4 The following chapters of SCE Distribution Operations and Maintenance Policies and Procedures (DOM)

- CP-3 Vault Sump Pumps
- TE-5 Infrared Heat Sensing Devices-Underground Equipment
- TE-6 Impact Pro Gas and Oxygen Monitors
- TR-7 Vault Blowers

4.5 Accident Prevention Manual (APM)

4.6 Environmental Policies and Procedures (EN) and ESD Waste Management Manual

4.7 Distribution Maintenance Program

4.8 Work Management System

4.9 Underground Corrosion Inspection and Maintenance Manual

4.10 Underground Structure Standards (UGS)

5.0 Attachments

Attachment 3–1: Underground Structure Detail Inspection Guideline

Attachment 3–1: Underground Structure Detail Inspection Guideline

EXTERNAL PROCEDURE CHECKLIST

- ☐ Prior to and after entering a structure, perform a general thermal scan for hot spots in structure and all equipment, cable, terminations, and splices.
- ☐ Check for missing or damaged manhole lid gasket/seal rope.
- ☐ Check air vents for damage and presence of shields around vent standpipe in landscaped areas.
- ☐ Check vault lid (equipment cover) seal (felt) and lifting hole plugs.
- ☐ Check manhole and vault lid for any openings where small objects can be inserted.
- ☐ Check for any visual damage to manhole cover.
- ☐ Check for evidence of water ponding on top of the structure.
- ☐ Check for missing/damaged bolts or penta bolts.
- ☐ Check for debris in or around structures.(Good Housekeeping)
- ☐ Check for visual hazards.
- ☐ Check for structure movement.
- ☐ Verify that HIGH VOLTAGE signs and the structure number are legible.
- ☐ Check for exterior damage to structure.
- ☐ Check for sufficient work space around structure.
- ☐ Check that traffic barrier(s) are in place and that adequate clearance exists in front of structure.
- ☐ Check for deterioration of concrete.
- ☐ Check for signs of corrosion (specifically inspect weld seams, corners, door hinges, and enclosure roof.).
- ☐ Check that the structure is sound and secure.]
- ☐ Check for openings in structure which may allow the passage of wire, or other conducting material into the structure from the outside.
- ☐ Check for exterior damage to adjacent service handholes or splice boxes.
- ☐ Secure lids/covers prior to leaving site.
- ☐ Check for 3-inch backfill of soil on pads.

NOTE

The above list is to be used as a guide only and inspection should not be limited to the list.

INTERNAL PROCEDURE CHECKLIST

- ☐ Check that restraint system is intact (connected per UGS MH 319, VA 410, FC 670, or FC 625).
- ☐ Check for water inside the structure.
- ☐ Check for sand, dirt, mud, signs of vermin, and debris.
- ☐ Verify cable tags.
- ☐ Verify that cable clearances are adequate, not rubbing on sharp edges.
- ☐ Check that duct plugs are installed and in good working order in all necessary ducts.
- ☐ Check if the vent is leaking, or shows signs of previous leaking.
- ☐ Check for corrosion of ground rods and cables and all ground connections are proper.
- ☐ Check for concrete spalling and exposed rebar per UGS MC 880.
- ☐ Remove debris and loose materials from inside structure.
- ☐ Inspect shoring (if present) for signs of delamination, discoloration, or corrosion of metal components.

ADDITIONAL CHECKLIST (VOLTEK STRUCTURE)

- ☐ Signs of splitting or fraying and swelling on any of the composite panels.
- ☐ Check column beams between the wall panels for signs of warping and deterioration.
- ☐ Signs of loose embedded unistrut.
- ☐ Check duct bank and grade rings for deterioration. Any part of the walks or ceiling bulging (out of plumb.)

NOTE

The above lists are to be used as guides only and inspection should not be limited to the lists.

Attachment 3–1: Underground Structure Detail Inspection Guideline *(Continued)*

EQUIPMENT CHECKLIST

- ☐ Prior to and after entering a structure, perform a detailed thermal scan for hot spots on structure and all equipment, cable, terminations, and splices.
- ☐ Check for signs of termination overheating or distortion.
- ☐ Check for signs of corrosion, oil leakage, and low oil levels.
- ☐ Check for signs of severe rusting of all restraint hardware (that is, turnbuckle, chains, anchors, and shackles).
- ☐ Check operation of vault blower (transformer structures) and perform maintenance.
- ☐ Check operation of sump pumps and perform maintenance.
- ☐ Check for scratches or abrasion to bare metal on equipment.
- ☐ Inspect weld seams.
- ☐ Inspect external operating mechanism.
- ☐ Inspect operating shaft seals.
- ☐ Inspect gaskets (cover, cableheads).
- ☐ Inspect oil fill plug and sight gauge seals.
- ☐ Inspect tightness of hold-down bails.
- ☐ Inspect condition of marine-coating.
- ☐ Inspect fuse carriers for proper locking and sealing.
- ☐ Check for sufficient work space around equipment.
- ☐ Verify appropriate signs are legible, that is, signs for ownership, clearance requirements, ferroresonant condition, switch feeding a capacitor bank.
- ☐ Check for signs of contamination, tracking, or deterioration of insulating barriers and arc interrupting chutes.
- ☐ Verify electrical clearances are maintained between barriers, live front or exposed terminations, and other insulated components.
- ☐ Verify that phase barriers are securely attached.
- ☐ Verify that the ground conductor is the correct size and is attached to the ground pad on the tank.
- ☐ Check safety barrier installation and condition on live front equipment (for example, pothead skirt in the PMH switch in contact with the protective barrier).
- ☐ In live-front equipment, verify that the fuse clips are in good condition (no signs of heating, arcing, or corrosion)
- ☐ Verify that locking devices are in place.
- ☐ Inspect mounting bolts for the correct size and number, tightness and corrosion.

The above list is to be used as a guide only and inspection should not be limited to the list.

Attachment 3–1: Underground Structure Detail Inspection Guideline *(Continued)*

APPARATUS CHECKLIST

The following list is designed for non-technicians to use while performing their normal work in and around apparatus equipment, such as network protectors, P.E. gear, fault interrupters, automatic circuit reclosers, regulators, sectionalizers, and capacitor banks.

- ☐ Check for bulging, ruptured, or discolored capacitor units.
- ☐ Inspect fuseholders, cutouts, or fused disconnects.
- ☐ Check for blown fuses.
- ☐ Check cable and cable terminations for signs of deterioration or damage (underground).
- ☐ Heat scan the cable, terminations, and equipment (underground).
- ☐ Check for corrosion or other damage.
- ☐ Check for oil or compound leaks.
- ☐ Check clearances, barriers, and grounding.
- ☐ Check weld seams.
- ☐ Inspect operating shaft seals.
- ☐ Check oil fill and sight gauge seals (underground)
- ☐ Check oil fill and sight gauge seals (underground)
- ☐ Check to see if relay tripped (if applicable).
- ☐ Check for loose connections (arcing or burning).
- ☐ Check for damaged or blown control transformer.
- ☐ Check for approved locking devices in place and locked.
- ☐ Check for exterior/interior damage to enclosure (underground).
- ☐ Check for washout or excavation around enclosure (underground).
- ☐ Check all decals for legibility.
- ☐ Check that enclosure mountings are securely bolted to structure (underground).
- ☐ Check for signs of rodents or other animals (underground).
- ☐ Check for any signs of water or oil within the apparatus housing (underground).
- ☐ Enter the status of equipment, counter and load reads, any abnormal conditions, and the names of all inspection personnel in the log provided at equipment.

NOTE

The above list is to be used as a guide only and inspection should not be limited to the list.

CG–TOC: Condition Guides

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CG–2: Overhead Component Condition Guide	07-26-2024
CG–3: Underground Equipment and Structure Condition Guide	01-28-2022
CG–4: Underground Component Condition Guide	01-28-2022
CG–5: Underground Equipment Corrosion Condition Guide	01-28-2022
CG–6: Aboveground Equipment Corrosion Condition Guide	10-23-2015
CG–7: Field Painting of Pad-Mounted Equipment	10-23-2015

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CG–1: Overhead Equipment Condition Guide

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1.0 Attachments

Attachment 1–1: Wood and Composite Poles

Attachment 1–2: Transformers

Attachment 1–3: Capacitors

Attachment 1–4: Switches

Attachment 1–5: Apparatus Equipment

Attachment 1–6: Branch Line Fuse

Attachment 1–7: Fuse Dip

Attachment 1–1: Wood and Composite Poles

Pole Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Wood Poles			
Unstable structure due to damage caused by splits, decay, hole or boring, exterior mechanical damage, or foot setting depth no longer supports the pole; failure is imminent **Priority 1**	X		
Pole leaning; public hazard **Priority 1**	X		
Leaning more than 1' per 10' pole height		X	X
Split or decay at critical attachment; bolt pulling through pole	X		
Split or decay within 6" of critical attachment; bolt not pulling through pole		X	X
Split, decay, or hole below highest attachment allows light through the pole	X		
Hole greater than 2" and extends past pole center	X		
Hole greater than 2" and possible cavity in high stress area		X	X
Three or more holes >2" diameter within 18" vertical at a high stress area	X		
Exposed decay pocket at ground line where part of shell is gone	X		
Insect borings or droppings		X	X
Compression wood peeling off, >2"	X		
Compression wood peeling off, 1–2"		X	X
Exterior damage >2" depth and > 1/4 pole circumference	X		
Exterior damage 1–2" depth and > 1/4 pole circumference		X	X
Depth in soil >20% shallow with heavy equipment	X		
Depth in soil 10–20% shallow with heavy equipment		X	X
Leaning more than 1' per 10' pole height with heavy equipment		X	X
Cavity with <1" shell thickness	X		
Decay within 6" of critical attachment; not pulling through		X	X
Three or more holes >2" diameter within 18" vertical		X	X
Rotten top		X	X
Animal/bird's nest near circuitry/equipment	X		
Steel stub banding is damaged or missing		X	X

Attachment 1–1: Wood and Composite Poles *(Continued)*

Pole Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Composite Poles			
Fracture or buckling of exterior wall	X		
Visual cracks or rupture of exterior laminates on any location of the exterior wall exposing interior laminates	X		
Excessive lean at the top of the pole due to insufficient embedment caused by erosion of soil at groundline or due to eccentricity of heavy equipment (horizontal displacement at the tip of the pole greater than 10% of the pole height above the groundline).	X		
Elongated bolt holes, cracks or rupture around the hardware connection to equipment and guy attachments (bolts pulling through, sharp edges cutting into surface of wall)		X	X
Cutting or drilling within “No-Drill-Zone”	X		
Exposed fiberglass due to exposure of fire[a/]			X
Surface gouging on exterior of pole larger than 2-inches in length		X	X
Surface discoloration or fiberblooming (“fuzzing”) greater than 20% of total exterior surface area		X	X
Pole embedded on soil with heavy ponding (accumulation of water)		X	X
Depth of embedment less than 10% + 1 ft of the pole height with heavy equipment		X	X
Leaning at the top of pole greater than 5% of the height of the pole above ground with heavy equipment		X	X
Bowing of the pole at or near the mid-height due to heavy load from guys		X	X
Animal/bird’s nest near circuitry/equipment		X	X
Missing or damaged pole cap		X	X

[a/] Contact Linear & Structural Strategies and Standards for immediate review.

Attachment 1–2: Transformers

Overhead Transformer Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area		X	X
Oil weepage indicated by oily film on tank surface			X
Transformer damaged	X		
Transformer extremely rusted or corroded		X	X

Attachment 1–3: Capacitors

Overhead Capacitor Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Ruptured or severely bulged capacitor units **Priority 1**	X		
Capacitor units or capacitor oil switches leaking, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage from capacitor units or oil capacitor switches, oil remains on equipment, does not reach ground or public access or environmentally sensitive area			X
Signs of tracking or arcing on capacitor units			X
Broken/damaged bushings or terminals on capacitor units, capacitor switches, fuseholders or control power transformer		X	
Single phase condition with bank still energized[a/] **Priority 1**	X		
Capacitor bank damaged, not functioning		X	
Floating connections **Priority 1**	X		
Catastrophic or severely damaged capacitor switches, safety or reliability issue **Priority 1**	X		
Capacitor switches not secure, damaged, not functioning		X	X
Capacitor controller damaged			X
Antenna damaged		X	
Animal nest			X
Blown fuse		X	
Incorrect fuse size		X	
Damage to control power transformer		X	

[a/] A single phase condition can occur when one phase fuse is blown or when switch position indicators are not synchronized (that is, all open or all closed).

Attachment 1–4: Switches

Overhead Switch Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Manually Operated			
Pole switch mechanism broken/missing/damaged/loose	X		
Pole switch damaged	X		
Remote Controlled			
Remote control actuator broken, missing or worn out		X	
Control damaged		X	

Attachment 1–5: Apparatus Equipment

Overhead Apparatus Equipment Condition Description (Reclosers, PE Gear, Regulators, Sectionalizers)	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Any fuse operation **Priority 1**	X		
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area			X
Oil weepage indicated by oily film on tank surface			X
Equipment damaged			X
Tree/vegetation interfering with apparatus equipment operation	X		
Equipment extremely rusted or corroded		X	X

Attachment 1–6: Branch Line Fuse

Branch Line Fuse Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Dry or low liquid levels dropped more than one inch below the bottom of the upper ferrule		X	
Corroded, missing or broken hardware		X	X
Holder burned		X	
Tracking	X		

Attachment 1–7: Fuse Dip

Fuse Dip Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Dry or low liquid levels dropped more than one inch below the bottom of the upper ferrule		X	
Corroded, missing or broken hardware		X	X
Holder burned		X	
Tracking	X		

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CG–2: Overhead Component Condition Guide

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1.0 Attachments

Attachment 2–1: HIGH VOLTAGE Signs

Attachment 2–2: Overhead Hardware/Framing

Attachment 2–3: Crossarms

Attachment 2–4: Insulators

Attachment 2–5: Grounds

Attachment 2–6: Guys

Attachment 2–7: Risers/Conduits

Attachment 2–8: Cutouts/Fuses

Attachment 2–9: Bonds

Attachment 2–10: Surge Arresters

Attachment 2–11: Overhead Terminations

Attachment 2–12: Overhead Conductors and Service Drops

Attachment 2–13: Overhead Pole-Mounted Streetlights

Attachment 2–1: HIGH VOLTAGE Signs

HIGH VOLTAGE Sign Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
HIGH VOLTAGE sign broken or missing in critical public awareness/hazardous situation		X	

Attachment 2–2: Overhead Hardware/Framing

Overhead Hardware/Framing Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Corroded, missing or broken hardware		X	X
Holder burned or tracking		X	X
Major equipment bracket broken/missing/worn out (including damaged Scott brackets)		X	X
Equipment brackets or braces cracked/damaged/loose		X	X
Scott brackets with no visible damage			X

Attachment 2–3: Crossarms

Crossarm Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Wood Crossarms			
Complete fracture or partial fracture causing significant deflection **Priority 1**	X		
Partial fracture causing <5" deflection		X	X
Primary crossarms bowed >5" and splintering	X		
Primary arm bowed >5", but no splintering		X	X
Secondary arm bowed >5" with or without splintering		X	X
Canting, through bolt pulled out **Priority 1**	X		
Canting, through bolt pulling out		X	X
Significant damage at a stress point	X		
Significant damage at insulator pin/bolt and pin/bolt ready to separate from arm	X		
Significant damage at attachment or insulator pin/bolt and pin/bolt may or may not be pulling through arm; if multiple X-arms and bolt at damaged area have not pulled through either arm, no damage on second arm		X	X
Crossarm tracking — cross section missing >50% **Priority 1**	X		
Crossarm tracking - cross section missing <50%		X	X
Braces broken/missing/worn out		X	

Attachment 2–3: Crossarms *(Continued)*

Crossarm Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Composite Crossarms			
Significant deflection (greater than 10% of overhang length) on either side of the crossarm due to fracture, buckling or excessive unbalanced tension	X		
Visual cracks or rupture of exterior laminates on any location of the exterior wall exposing interior laminates	X		
Any signs of charring, “blister”, “bubble” or distortion of exterior surface due to exposure to fire	X		
Fractured mounting bracket and associated hardware	X		
Elongated bolt holes, cracks or rupture around the hardware connection (bolts pulling through, sharp edges cutting into surface of wall)		X	X
Surface discoloration or fiberblooming (“fuzzing”) greater than 20% of total exterior surface area		X	X
Bent mounting bracket and associated hardware		X	X

Attachment 2–4: Insulators

Insulator Condition Description		Reliability/Failure Risk: Component Failure Could Lead to System Failure	Reliability/Failure Risk: Component Has Failed No Significant Risk to System	Reliability/Failure Risk: Potential Component Failure
Secondary Insulators (less than 600V)				
Secondary insulator volts cracked, damaged, or loose			X	X
Secondary insulator - squatter			X	X
Missing (Priority 2) or Improperly installed Cotter Key (Priority 3)				X
Primary Insulators (greater than 600V)				
General				
Primary insulator missing	**Priority 1**	X		
Primary insulator mechnically broken/damaged resulting in floating wire	**Priority 1**	X		
Primary insulator cracked, damaged, or loose			X	X
Signs of flashover or melting	**Priority 1**	X		X
Corroding/rusting/loose hardware		X		X
Missing (Priority 1) or Improperly installed Cotter Key (Priority 2)		X		X
Porcelain Insulators (Pin/Post Type and Dead-End)				
Tie wire missing (Priority 1) or broken/damaged/loose		X		X
Primary side tie insulator touching arm Primary			X	X
Insulator chipped (Priority 1 if >25%)			X	X
Polymer Insulators (Pin/Post Type and Dead-End)				
Exposed fiberglass rod/core	**Priority 1**	X		X
Severe tracking/erosion	**Priority 1**	X		X
Cracking at sheath or neck of pin insulators (see Note 1)	**Priority 1**	X		X
Shed damage (<25% of overall insulating material, P1 if >25%)			X	X

Note(s):

1. If a universal polymer insulator (see GR 200.7) is replaced on a structure, all remaining universal insulators on the structure shall be replaced. Universal insulators shall also be replaced on an opportunity basis where work methods and circuit status allow for such to occur.

Attachment 2–5: Grounds

Ground Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Ground wire broken/missing/worn out		X	

Attachment 2–6: Guys

Guy Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Span Guys			
Span guy cracked/damaged or loose		X	X
Span guy clearance issue		X	X
Span guy sagging or extremely slack		X	X
Down Guys			
Guys broken/missing/worn out, pole leaning, public hazard **Priority 1**	X		
Guys broken/missing/worn out, pole not leaning		X	X
Down guy clearance issue, pedestrian/vehicle traffic		X	X
Down guy sagging or extremely slack		X	X
Anchor rods broken/missing/worn out, pole leaning, public hazard **Priority 1**	X		
Anchor rods broken/missing/worn out, pole not leaning		X	X

Attachment 2–7: Risers/Conduits

Riser/Conduit Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Primary/secondary riser and cable damage in the public level **Priority 1**	X		
Primary/secondary riser damaged but cable intact		X	X
Primary/secondary riser uncoupled/gap, cable exposed, no damage		X	X
Riser coming loose from pole			X
Missing Conduit Riser Label		X	
Damaged Conduit Riser Label		X	

Attachment 2–8: Cutouts/Fuses

Cutout/Fuse Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Dry or low liquid levels dropped more than one inch below the bottom of the upper ferrule		X	
Corroded, missing or broken hardware		X	X
Holder burned		X	
Tracking	X		

Attachment 2–9: Bonds

Bond Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Bonding has loosened or separated from pole/crossarm		X	X
Damaged bonding wire		X	X
Missing bonding wire[1]		X	X

Note(s):

1. SCE construction standards identify bonding requirements for new construction. In the past, certain districts were exempted from bonding during new construction for various reasons. These districts include Blythe, Victorville, Kernville, San Joaquin, and Yucca Valley. These exemptions are no longer valid for new construction. Existing construction historically built without bonding, in these districts, does not require repair for the lack of bonding condition alone. For the purpose of inspection, historical construction shall be identified by the presence of unbonded porcelain insulators on wood crossarms. Installation locations in these districts without standard bonding should be tracked and built to current standards as part of other replacement or maintenance work in the future.

Attachment 2–10: Surge Arresters

Surge Arrester Condition Description		Reliability/Failure Risk		
		Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Blown ground lead isolator	**Priority 1**	X		
Surge arrester broken but not blown, including corroded, missing or broken hardware, housing			X	X

Attachment 2–11: Overhead Terminations

Overhead Termination Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Potheads			
Pothead sparking, arcing, or noisy during normal 'dry' weather conditions **Priority 1**	X		
Pothead swollen	X		
Pothead not properly attached to supporting structure	X		
Pothead leaking	X		
Pothead showing signs of tracking such as discoloration	X		
Porcelain pothead insulators chipped or broken	X		

Attachment 2–12: Overhead Conductors and Service Drops

Overhead Conductor and Service Drop Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Primary Conductors			
Contact with other conductors or where contact is imminent **Priority 1**	X		
Metal debris in conductors **Priority 1**	X		
Vegetation arcing or in contact with bare or covered conductor **Priority 1**	X		
Conductors not in good condition, broken, missing, worn out		X	X
More than 10% reduction in radial or vertical clearance		X	X
Vegetation <18" from energized conductors (bare or covered)	X		
Growth on pole >18" but <48" from conductors (bare or covered)		X	X
Trees with <4' clearance in high fire risk area	X		
Foreign material in lines	X		
Tie wire broken/missing/damaged or loose	X		
Secondary Conductors			
Extreme safety hazard to the public such as reachable, wire down, bare wires touching anything, wires touching each other at bare spots **Priority 1**	X		
More than 10% reduction in radial or vertical clearance		X	X
Bare conductors in rack construction and through tree		X	X
Tree condition causing significant strain and/or visible abrasion damage - either open wire or Triplex		X	X
Conductor has less than appropriate radial clearance with contact, no public safety hazard		X	X
Vegetation growth within secondary level		X	X
Conductors not in good condition, broken, missing, worn out		X	X
Tie wire broken/missing/damaged or loose	X		
Foreign material in lines		X	X

Attachment 2–12: Overhead Conductors and Service Drops *(Continued)*

Overhead Conductor and Service Drop Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Service Drops			
Greater than 15% reduction in vertical clearance **Priority 1**	X		
Bare drop with >10% reduction in vertical clearance **Priority 1**	X		
Bare drop arcing **Priority 1**	X		
Greater than 10% but less than 15% reduction in vertical clearance		X	X
Bare drop with <10% reduction in vertical clearance			
Drop with <radial clearance and contact		X	X
Tree condition causing significant strain and/or visible abrasion damage — either open wire or Triplex		X	X
Bare drop		X	X
Drop connector bare at weatherhead		X	X
Service attachment broken		X	X
Service termination damage		X	X
Mid-span service clearance		X	X

Attachment 2–13: Overhead Pole-Mounted Streetlights

Overhead Pole-Mounted Streetlight Condition Description		Reliability/Failure Risk		
		Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Access plate missing — conductor exposed	**Priority 1**	X		
Broken glass ready to fall	**Priority 1**	X		
Fixture or fixture door ready to fall	**Priority 1**	X		
Structural/mechanical failure/vehicle hit pole	**Priority 1**	X		
Fixture/door cover missing			X	X
Visible cracks in fixture			X	X
Broken/missing glass but no public safety hazard			X	X
Mast arm weak and unsecured, but no public safety hazard			X	X
Unauthorized attachments			X	X
Pole mechanical damage and may fail soon			X	
Anchor bolts missing/rusted through			X	
Large multiple holes				X
Anchor bolts corroded, unremovable				X

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1.0 Attachments

Attachment 3–1: BURD Structures

Attachment 3–2: Enclosures

Attachment 3–3: Handholes

Attachment 3–4: Manholes

Attachment 3–5: Primary Splice Boxes

Attachment 3–6: Pads

Attachment 3–7: Subsurface Structure (CST)

Attachment 3–8: Vaults

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Attachment 3–10: Underground Transformers

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Attachment 3–16: Fault Indicator

Attachment 3–17: Junction Boxes

Attachment 3–18: Oil Fuse Cutouts

Attachment 3–19: Underground PE Gears

Attachment 3–20: Fuse Cabinets

Attachment 3–1: BURD Structures

BURD Structure Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Debris or vegetation blocking proper access to structure			X
BURD cylinder damaged		X	X
Debris in structure requiring removal		X	X

Attachment 3–2: Enclosures

Enclosure Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	X		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	X		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	X		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Vent pipes cracked, damaged, loose or missing		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		
Roof/grate damaged or missing	X		
Door damaged, unsecurable or cannot lock	X		
Enclosure structure damaged	X		

Attachment 3–3: Handholes

Handhole Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Damaged handhole in public area	X		
High/low tripping hazard	X		

Attachment 3–4: Manholes

Manhole Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Pavement in street has collapsed causing dangerous traffic conditions **Priority 1**	X		
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	X		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	X		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	X		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		

Attachment 3–5: Primary Splice Boxes

Primary Splice Box Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Debris or vegetation blocking proper access		X	X
Unable to secure **Priority 1**	**X**		
Structure damaged		X	X
Debris in structure requiring removal		X	X
Pavement in street has collapsed causing dangerous traffic conditions **Priority 1**	**X**		
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	**X**		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	**X**		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	**X**		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X

Attachment 3–5: Primary Splice Boxes *(Continued)*

Primary Splice Box Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		

Attachment 3–6: Pads

Pad Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Any tilt, lean, or structure movement causing strain on electrical connectors or adverse oil level	X		
Pad Damaged — > 25% of surface area. Deep cracks were observed that propagate from one end of the pad to the other.		X	X
Grade change requiring pad relocation			X
Pad Surface Area Deterioration (< 25%) — Cracks, spalls, delamination (loose concrete), exposed rebar			X

Attachment 3–7: Subsurface Structure (CST)

Subsurface (CST) Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Pavement in street has collapsed causing dangerous traffic conditions **Priority 1**	X		
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	X		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	X		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	X		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		
Vent pipes cracked, damaged, loose or missing	X		
Debris or vegetation blocking proper access		X	X

Attachment 3–8: Vaults

Vault Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Pavement in street has collapsed causing dangerous traffic conditions **Priority 1**	X		
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	X		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	X		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	X		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		
Vent pipes cracked, damaged, loose or missing	X		

Attachment 3–9: Vault Shoring

Vault Shoring Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Wood members (columns, beams, or ceiling decking) are broken	X		
Wood members showing signs of severe deterioration, heavy discoloration present (confirmed by sounding with tool)	X		
Delamination is present on wood members	X		
Gap is present between ledger plate and structure wall (not due to curvature of wall)			X
Severe corrosion is present on steel components (metal flaking, severe pitting)			X

Attachment 3–10: Underground Transformers

Underground Transformer Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
No oil at gauge and major leakage **Priority 1**	X		
No oil at gauge and minor leakage		X	X
No oil at gauge but no evidence of leakage			X
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area		X	X
Oil weepage indicated by oily film on tank surface			X
Tank wall temperature >265°F	X		
Tank wall temperature >155°F above ambient			X
Indications of overload, past or present (burned spades, paint)			X
Hole >1/8" diameter	X		
Transformer damaged		X	X
Corrosion per Corrosion Guide		X	X
Excessive noise			X

Attachment 3–11: Underground Capacitors

Underground Capacitor Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Ruptured or severely bulged capacitor units **Priority 1**	X		
Capacitor units or capacitor oil switches leaking, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage from capacitor units or oil capacitor switches, oil remains on equipment, does not reach ground or public access or environmentally sensitive area			X
Signs of tracking or arcing on capacitor units			X
Broken/damaged bushings or terminals on capacitor units, capacitor switches, fuseholders or control power transformer		X	
Single phase condition with bank still energized[a/] **Priority 1**	X		
Capacitor bank damaged, not functioning		X	
Loose or floating connections **Priority 1**	X		
Catastrophic or severely damaged capacitor switches, safety or reliability issue **Priority 1**	X		
Capacitor switches not secure, damaged, not functioning		X	X
Capacitor controller damaged			X
Antenna damaged		X	
Animal nest			X
Thermal criteria exceeded per DOM TE–5		X	X
Obstacles restricting operating clearance/access to compartments			X
Corrosion per Corrosion Guide		X	X
Blown fuse		X	
Incorrect fuse size		X	
Damage to control power transformer		X	
Damaged fiberglass boards or plexiglas panels		X	

[a/] A single phase condition can occur when one phase fuse is blown or when switch position indicators are not synchronized (that is, all open or all closed).

Attachment 3–12: Underground Switches

Underground Switches Condition Description		Reliability/Failure Risk: Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Oil — Subsurface				
Field oil test failure (<15kV) *Priority 2 (90 days) — see DOM TS–4*		X		
No oil at gauge and major leakage	**Priority 1**	X		
No oil at gauge and minor leakage			X	X
No oil at gauge but no evidence of leakage				X
Oil leak in wet structure	**Priority 1**	X		
Oil leak in dry structure		X		
Thermal failure per DOM TE–5	**Priority 1**	X		
Mechanism frozen, inoperable		X	X	X
G&W RA style switches with aluminum cableheads manufactured from 1970–1973				X
Corrosion per Corrosion Guide			X	X
Solid Dielectric Vacuum Switch — Subsurface				
Switch Temperature >40°F above Cable Temperature	**Priority 1**	X		
Mechanism frozen, inoperable		X	X	X
Corrosion per Corrosion Guide			X	X
Oil — Padmount				
Field oil test failure (<15 kV) *Priority 2 (90 days) — see DOM TS–4*		X		
No oil at gauge and major leakage	**Priority 1**	X		
No oil at gauge and minor leakage			X	X
No oil at gauge but no evidence of leakage				X
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area	**Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area			X	X
Oil weepage indicated by oily film on tank surface				X
Thermal failure per DOM TE–5	**Priority 1**	X		
Mechanism frozen, inoperable		X	X	X
Corrosion per Corrosion Guide			X	X

Attachment 3–12: Underground Switches *(Continued)*

Underground Switches Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Gas Switches			
Gas switch: 0 psi in wet structure (DOM, SW–5) **Priority 1**	X		
Gas switch: < 5 psi or in **red zone** in wet structure (DOM, SW–5)	X		
Gas switch: < 5 psi or in **red zone** in dry structure (DOM, SW–5)		X	
Corrosion per Corrosion Guide		X	X
PMH/PME			
Hole >1/8" diameter	X		
Evidence of previous electric flashover **Priority 1**	X		
Thermal failure per DOM TE–5 **Priority 1**	X		
Vegetation or debris inside structure	X		
Electrical clearance <1-1/2" between barriers and energized parts	X		
Moisture barrier missing	X		
Mechanism frozen	X		
Corrosion per Corrosion Guide		X	X
ARC compressor caps missing or damaged		X	X
Remote-Controlled Switches			
Control damaged		X	X
Actuator damaged		X	

Attachment 3–13: Sump Pumps

Sump Pump Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Sump pump damaged and not operating		X	

Attachment 3–14: Underground Apparatus

Underground Apparatus Condition Description (Automatic Reclosers, Fault Interrupters, Network Protectors, Regulators, and Sectionalizers)		Reliability/Failure Risk		
		Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Thermal failure per DOM TE–5	**Priority 1**	X		
No oil at gauge and major leakage	**Priority 1**	X		
No oil at gauge and minor leakage			X	X
No oil at gauge but no evidence of leakage				X
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area	**Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area			X	X
Oil weepage indicated by oily film on tank surface				X
Hole >1/8" diameter		X		

Attachment 3–15: Blowers

Blower Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Blower damaged and not operating		X	

Attachment 3–16: Fault Indicator

Fault Indicator Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Unit has malfunctioned or has failed to operate when tested		X	
Visible damage that has caused a malfunction under test		X	
Units > 20 years in service			X

Attachment 3–17: Junction Boxes

Junction Box Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Debris or vegetation blocking proper access		X	X
Unable to secure **Priority 1**	X		
Structure damaged		X	X
Debris in structure requiring removal		X	X
Pavement in street has collapsed causing dangerous traffic conditions **Priority 1**	X		
Structure roof or walls in immediate danger of collapse, showing evidence of structural compromise, load cracks, flexing concrete **Priority 1**	X		
Casting frame/plug broken with dangerous traffic and/or pedestrian condition **Priority 1**	X		
Broken non-concrete covers of concrete structures in public area exposing the structure opening **Priority 1**	X		
Heavy Traffic — Roof has >20% delamination in any precast section		X	X
Heavy Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Roof has >30% delamination with exposed rebar at multiple corners and in the neck area		X	X
Light Traffic — Casting frame and plug have exposed rebar and/or failure cracking		X	X
Light Traffic — Wall concrete deteriorated with spalling, exposed rebar, and switch supports coming out of the wall		X	X
Light Traffic — Other structure conditions presenting an immediate danger to the public or workers		X	X
Structure settlement has caused pavement failure in traffic area; pavement still drivable but deteriorated			X
Light Traffic — Structure roof has spalling concrete at roof neck and/or joints with exposed rebar at any roof joint and/or delaminations in 10% or more of any roof section			X
Light Traffic — Concrete spalls have come off of walls at over 5 feet of any corner surface with accompanying areas of delamination, 25% or more in any section			X
Light Traffic — Casting frame and plug show cracking or minor spalling			X

Attachment 3–17: Junction Boxes *(Continued)*

Junction Box Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Non-Traffic — Heavily deteriorated structure has spalling concrete and delaminations on 30+% of any wall and roof section, or over 15 feet of exposed rebar in the roof section			X
Spalled concrete in danger of falling on equipment	X		

Attachment 3–18: Oil Fuse Cutouts

Oil Fuse Cutout Condition Description[a/]	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Corroded fuseholder		X	X
Oil leak not repairable		X	
Mechanism frozen	X		
Minor oil leak, but repairable			X

[a/] Oil fuse cutouts are obsolete. Replacement fuses are no longer available. The units must be replaced whenever opportunity exists.

Attachment 3–19: Underground PE Gears

Underground PE Gear Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Oil — Subsurface Type Switches			
No oil at gauge and major leakage **Priority 1**	X		
No oil at gauge and minor leakage		X	X
No oil at gauge but no evidence of leakage			X
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area		X	X
Oil weepage indicated by oily film on tank surface			X
Thermal failure per DOM TE–5 **Priority 1**	X		
Mechanism frozen, inoperable	X	X	X
G&W RA style switches with aluminum cableheads manufactured from 1970–1973			X
Corrosion per Corrosion Guide		X	X
Oil — Padmount Switches			
No oil at gauge and major leakage **Priority 1**	X		
No oil at gauge and minor leakage		X	X
No oil at gauge but no evidence of leakage			X
Excessive oil leakage, oil reaches ground or public access or environmentally sensitive area **Priority 1**	X		
Minor leakage, oil remains on equipment, does not reach ground or public access or environmentally sensitive area		X	X
Oil weepage indicated by oily film on tank surface			X
Thermal failure per DOM TE–5 **Priority 1**	X		
Mechanism frozen, inoperable	X	X	X
Corrosion per Corrosion Guide		X	X
Gas Switches			
Gas switch: 0 psi in wet structure (DOM, SW–5) **Priority 1**	X		
Gas switch: <5 psi in wet structure (DOM, SW–5)	X		
Gas switch: <5 psi in dry structure (DOM, SW–5)		X	X
Corrosion per Corrosion Guide		X	X

Attachment 3–19: Underground PE Gears *(Continued)*

Underground PE Gear Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
PMH/PME Switches			
Hole >1/8" diameter	X		
External evidence of previous electric flashover **Priority 1**	X		
Corrosion per Corrosion Guide		X	X
Remote-Controlled PE Gear			
Control damaged		X	X
Actuator damaged		X	

Attachment 3–20: Fuse Cabinets

Fuse Cabinet Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Access or load-break elbow operational issue		X	X
Door does not secure (not sealed)	X		
External visual inspection failure		X	X
Hole >1/8" diameter	X		
Corrosion per Corrosion Guide		X	X
Elbow not properly seated or attached; that is, bail is missing **Priority 1**	X		
Elbow sparking, arcing, or noisy **Priority 1**	X		
Elbow swollen	X		
Elbow showing signs of tracking such as discoloration	X		
Elbow temperature > 40°F above cable temperature **Priority 1**	X		
Elbow temperature 10–39°F above cable temperature		X	X

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1.0 Attachments

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Attachment 4–1: Underground Hardware/Framing

Underground Hardware/Framing Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Major equipment bracket broken/missing/worn out **Priority 1**	X		
Equipment brackets or braces cracked/damaged/loose		X	X
Cable, equipment, or termination failure due to lack of rack support**Priority 1**	X		
Cable racks and other equipment supports cracked, damaged or loose, or are hanging in concrete separated from the rebar		X	X
Racks and/or through bolts corroded but can still support cable and/or equipment			X
Ladder broken/missing/worn out; cracked, damaged or loose	X		
Corroded, missing or broken hardware		X	X

Attachment 4–2: Grounds

Ground Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Ground grid has lost all embeds, or ground rod connection is gone			X
Grounds/bonds broken, missing or worn out		X	
Grounding of insufficient capacity			X

Attachment 4–3: Lids and Frames

Lid and Frame Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Lids/covers broken, missing, worn out and cannot be secured; subject to pedestrian traffic**Priority 1**	X		
Grade ring broken, missing, worn out and cannot be secured; subject to pedestrian traffic**Priority 1**	X		
Lids/covers cracked, damaged or loose, structure temporarily secured		X	
Grade ring damaged or missing, structure temporarily secured		X	
Corroded restraint hardware (turnbuckle, chains, anchors, and shackles)		X	X

Attachment 4–4: Retaining Walls

Retaining Wall Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Retaining wall damaged or undermined, requiring repairs	X		

Attachment 4–5: Underground Terminations

Underground Termination Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Potheads			
Pothead sparking, arcing, or noisy during normal “dry” weather conditions**Priority 1**	X		
Pothead swollen	X		
Pothead not properly attached to supporting structure	X		
Pothead leaking	X		
Pothead showing signs of tracking such as discoloration	X		
Porcelain pothead insulators chipped or broken	X		
Elbows			
Elbow not properly seated or attached; that is, bail is missing**Priority 1**	X		
Elbow sparking, arcing, or noisy **Priority 1**	X		
Elbow swollen; subject to water intrusion between cable entrances and bushing interface	X		
Elbow showing signs of tracking such as discoloration	X		
Elbow temperature > 40F above cable temperature **Priority 1**	X		
Elbow temperature 10-39F above cable temperature		X	X

Attachment 4–6: Barrier Posts

Barrier Post Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Traffic barrier broken or missing and equipment contact imminent		X	X

Attachment 4–7: Pedestals

Pedestal Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Damaged, unable to secure or lock	X		
Corrosion per Corrosion Guide	X		

Attachment 4–8: Handholes

Handhole Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Damaged handhole in public area	X		
High/low tripping hazard	X		

Attachment 4–9: Cables

Cable Condition Description	Reliability/Failure Risk		
	Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
50% or less of concentric neutrals remain		X	X
Visual and serious damage (open cracks) on the semiconducting shield		X	X
Cable temperature exceeds 240 degrees	X		
Wet, contaminant condition that could damage cable			X
Cable temperature exceeds 175 degrees			X
Secondary/service cable damaged		X	X
Visible signs of incorrect positioning of cable causing contact and/or damage (that is, cable movement, rubbing points)			X
Visible signs of burning of materials or external heat damage to cable or any of the visible layers	X		

Attachment 4–10: Streetlights

Streetlight Condition Description		Reliability/Failure Risk		
		Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Access plate missing — conductor exposed	**Priority 1**	X		
Broken glass ready to fall	**Priority 1**	X		
Fixture or fixture door ready to fall	**Priority 1**	X		
Structural/mechanical failure/vehicle hit pole	**Priority 1**	X		
Fixture/door cover missing			X	
Visible cracks in fixture			X	X
Broken/missing glass but no public safety hazard			X	
Mast arm weak and unsecured, but no public safety hazard			X	X
Unauthorized attachments			X	X
Pole mechanical damage and may fail soon			X	
Anchor bolts missing/rusted through			X	
Large multiple holes				X
Anchor bolts corroded, unremovable				X

Attachment 4–11: Splices

Splice Condition Description		Reliability/Failure Risk		
		Component Failure Could Lead to System Failure	Component Has Failed No Significant Risk to System	Potential Component Failure
Ruptured lead splice	**Priority 1**	X		
Splice not properly seated or attached, that is, T-splice not secure	**Priority 1**	X		
Splice sparking, arcing, or noisy	**Priority 1**	X		
Splice swollen; subject to water intrusion between cable entrances and bushing interface		X		
Splice showing signs of tracking such as discoloration		X		
Splice temperature >40°F above cable temperature	**Priority 1**	X		
Splice temperature 10–39°F above cable temperature			X	X
Leaking splice		X		

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CG–5: Underground Equipment Corrosion Condition Guide

1.0 Corrosion Evaluation Overview

Listed below are guidelines to assessing corrosion conditions. Utilize the Risk Assessment Matrix to determine reasonable time frame for any required action needed.

1.1 Severe Corrosion (Priority 1)

- ☐ Severe corrosion or pitting has eroded 100% of the wall thickness.
- ☐ Cable terminations hold down bolts have corroded where they no longer support the cable.
- ☐ Equipment oil leak in a wet structure.
- ☐ Any condition that would indicate that a severe hazard exits.

1.2 Very Heavy Corrosion (Priority 2)

- ☐ There is very heavy corrosion over most of the equipment's surface, or the pitting exceeds 50% of the wall thickness.
- ☐ The cable termination hold-down bolts have corroded to a point where the threads have been obliterated.
- ☐ Equipment oil leak in a dry structure.
- ☐ Any other condition of the equipment that would indicate that a hazard exists.

1.3 Heavy Corrosion (Priority 2)

- ☐ There is discoloration, loss of paint, and deep pitting over 50% of the equipment's surface.
- ☐ There is pitting greater than 25% of wall thickness, but less than 50% of wall thickness.
- ☐ Switch operators are frozen and cannot be freed with simple field repair.

1.4 Moderate Corrosion

No action required; monitor during next inspection cycle.

- ☐ There is discoloration, some loss of paint, and slight pitting (pencil-point-sized pits less than 25% wall thickness—that is, 1/16" maximum on R.A. switches).
- ☐ No sign of oil leaks.
- ☐ Switch operators are temporarily frozen but can be made operational with a minimum amount of effort.
- ☐ Bottom of equipment, or 25% of surface area is not accessible and corrosion is likely to occur (that is, wet structure and equipment does not have marine coating).

1.5 Light Corrosion

No action required; monitor during next inspection cycle.

- ☐ Equipment may be dirty but there is no sign of corrosion.
- ☐ There is some discoloration and disruption to painted surfaces, but no serious pitting or scaling is present over 75% of the equipment's surface.
- ☐ Switch operators work freely.
- ☐ No signs of oil leaks.

NOTE Once a corrosion evaluation has been established, that evaluation should not be changed as a result of cleaning, repairing, or painting. This policy is established since pitting cannot be repaired and the back, as well as the bottom, of the switch cannot always be cleaned and repainted.

2.0 Corrosion Examples

2.1 Severe Corrosion (Priority 1)

- ☐ Severe corrosion or pitting has eroded 100% of the wall thickness.
- ☐ Cable terminations hold down bolts have corroded where they no longer support the cable.
- ☐ Equipment oil leak in a wet structure.
- ☐ Any condition that would indicate that a severe hazard exists.

NOTE Severe corrosion is described above. There are no pictures of severe corrosion in this manual revision. Corrosion conditions exceeding the conditions identified in Priority 2 images are considered Priority 1.

WARNING When a severe corrosion condition exists, the structure shall be closed and a sign shall be posted stating “DO NOT ENTER WHILE EQUIPMENT IS ENERGIZED.” The situation shall be made safe and the equipment shall be replaced as soon as possible.

2.2 Very Heavy Corrosion (Priority 2)

- ☐ There is very heavy corrosion over most of the equipment's surface, or the pitting exceeds 50% of the wall thickness.
- ☐ The cable termination hold-down bolts have corroded to a point where the threads have been obliterated.
- ☐ Equipment oil leak in a dry structure.
- ☐ Any other condition of the equipment that would indicate that a hazard exists.

WARNING When A Very Heavy Corrosion condition exists, the structure shall be closed and a sign shall be posted stating “DO NOT ENTER WHILE EQUIPMENT IS ENERGIZED.” The situation shall be made safe and the equipment shall be replaced within 90 days. See Figure 5–1.

Figure 5–1: Severe/Very Heavy Corrosion — CAUTION Sign

CAUTION

DO NOT ENTER WHILE EQUIPMENT IS ENERGIZED.

SCE 14-174-150

Figure 5–2: Very Heavy Corrosion — Example 1 of 2

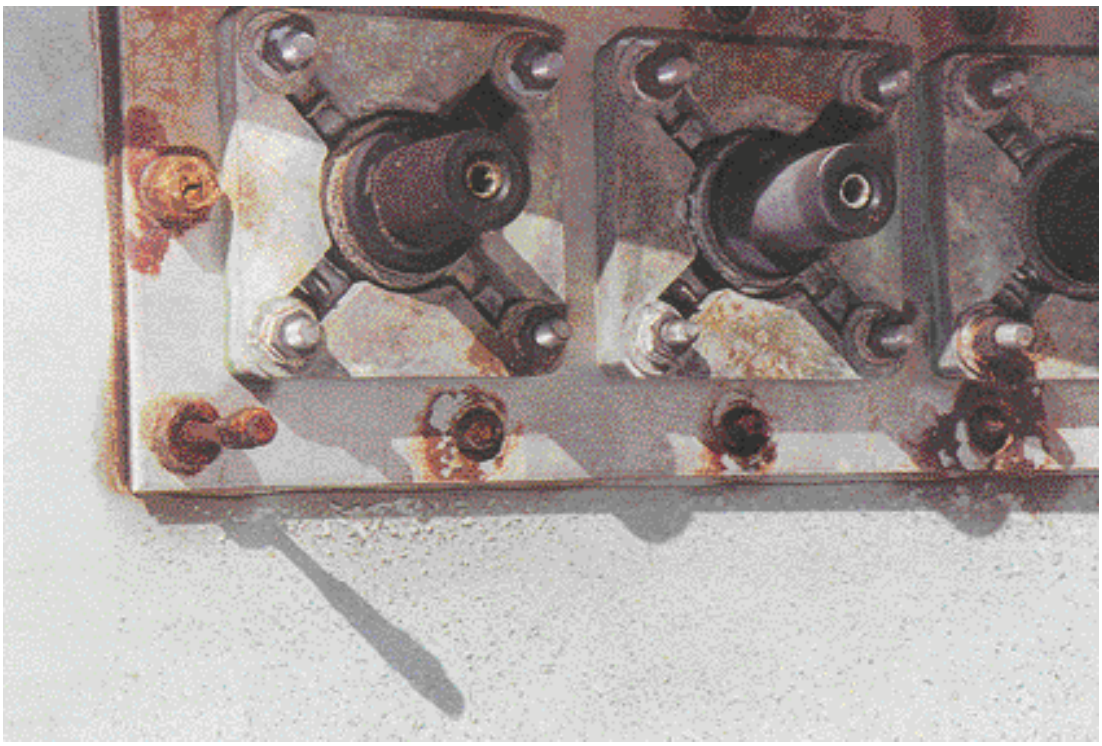
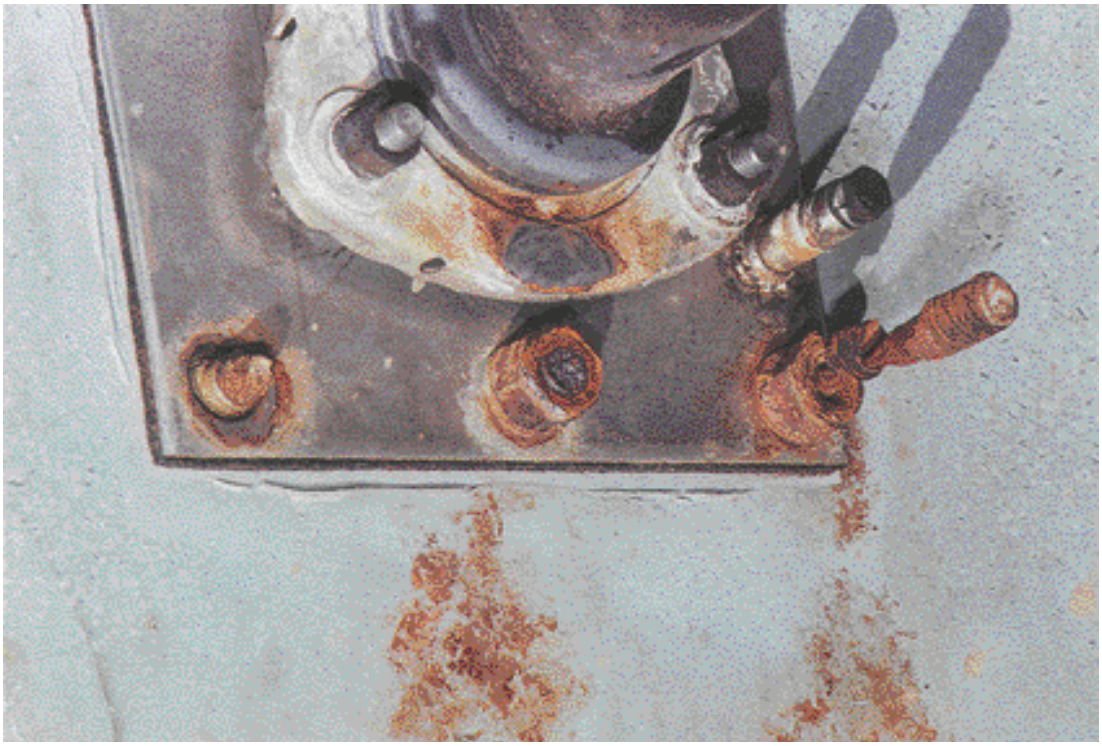


Figure 5–3: Very Heavy Corrosion — Example 2 of 2



2.3 Heavy Corrosion

- ☐ There is discoloration, loss of paint, and deep pitting over 50% of the equipment's surface.
- ☐ There is pitting greater than 25% of the wall thickness, but less than 50% of the wall thickness.
- ☐ Switch operators are frozen and cannot be freed with simple field repair.
- ☐ There is minor oil leakage, but it is repairable.

Figure 5–4: Heavy Corrosion — Example 1 of 3

Figure 5–5: Heavy Corrosion — Example 2 of 3

Figure 5–6: Heavy Corrosion — Example 3 of 3

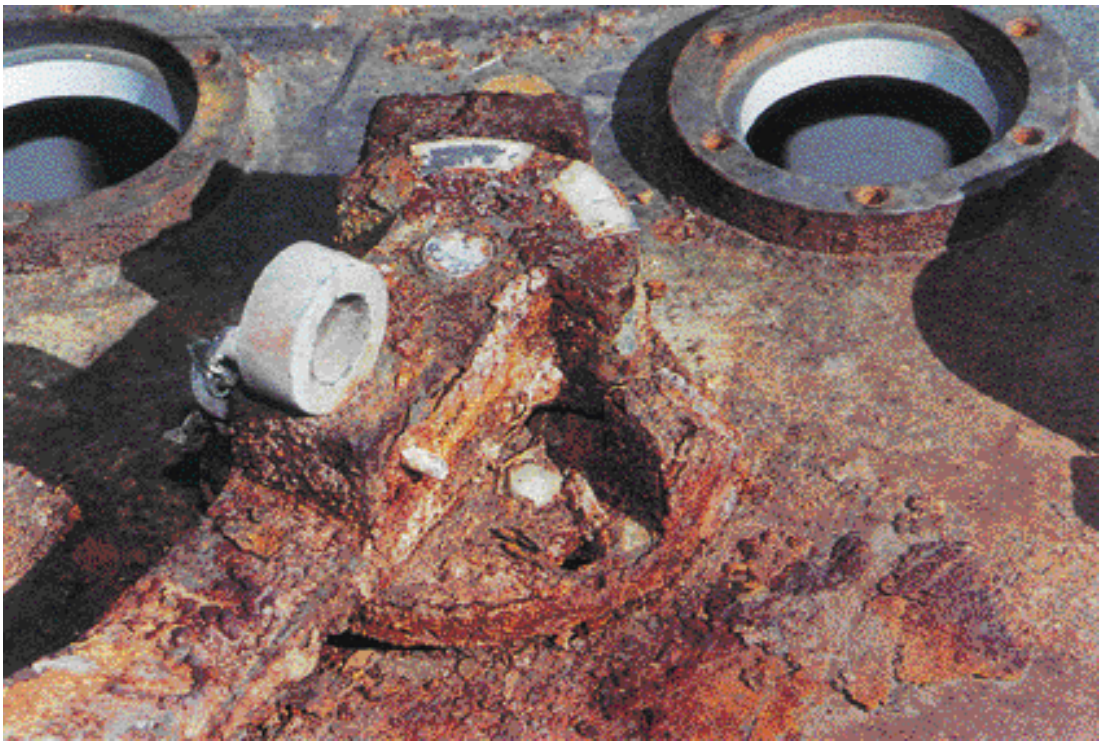
2.4 Moderate Corrosion

- ☐ There is discoloration, loss of paint, and slight pitting (pencil point-sized pits less than 25% of the wall thickness – that is, R.A. switches – 1/16" maximum depth).
- ☐ No signs of oil leaks.
- ☐ Switch operators are temporarily frozen but can be maintained and made operational with a minimum amount of effort.
- ☐ Bottom of equipment or 25% of surface area is not accessible and corrosion is likely to occur (that is, wet structure and equipment does not have marine coating).

Figure 5–7: Moderate Corrosion — Example 1 of 3

Figure 5–8: Moderate Corrosion — Example 2 of 3

Figure 5–9: Moderate Corrosion — Example 3 of 3



2.5 Light Corrosion

- ☐ There is some discoloration and disruption to painted surfaces, but no serious pitting or scaling is present over 75% of the equipment's surface.
- ☐ Switch operators work freely.
- ☐ No signs of oil leaks.

Figure 5–10: Light Corrosion — Example 1 of 3

Figure 5–11: Light Corrosion — Example 2 of 3

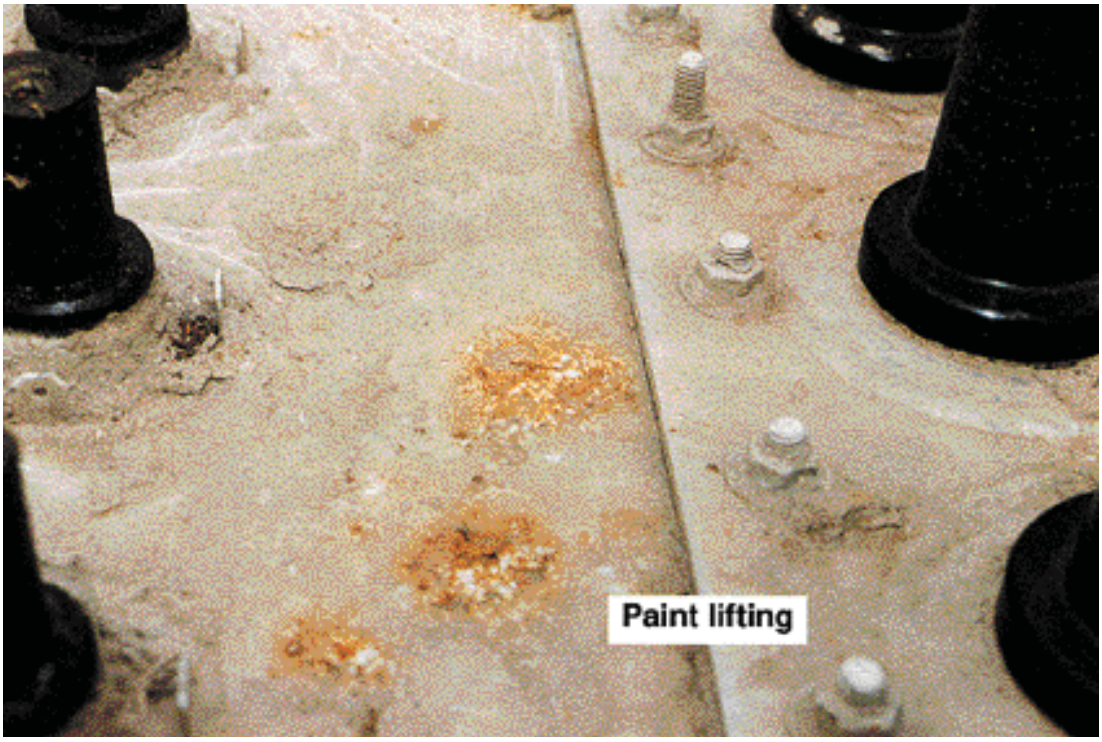


Figure 5–12: Light Corrosion — Example 3 of 3

2.6 Maintenance and Refurbishing

- ☐ Any “moderate” or “light” corrosion equipment should have the following repairs performed:
- ☐ The operating mechanism should be cleaned, greased (if required), and operate freely.
- ☐ The equipment tank, except for the back and/or bottom, should be cleaned of corrosion and coated with an approved material.
- ☐ The equipment tank, except for the back and/or bottom, should be cleaned of corrosion and coated with an approved material.
- ☐ To determine the level of corrosion and, in particular, the depth of pitting, the corroded material must be removed.
- ☐ To extend the life of equipment and ensure the operating mechanism functions properly.
- ☐ To inspire confidence in crew members when working in a vault or enclosure where the equipment has obviously been maintained.

Figure 5–13: Maintenance and Refurbishing — Example 1 of 4

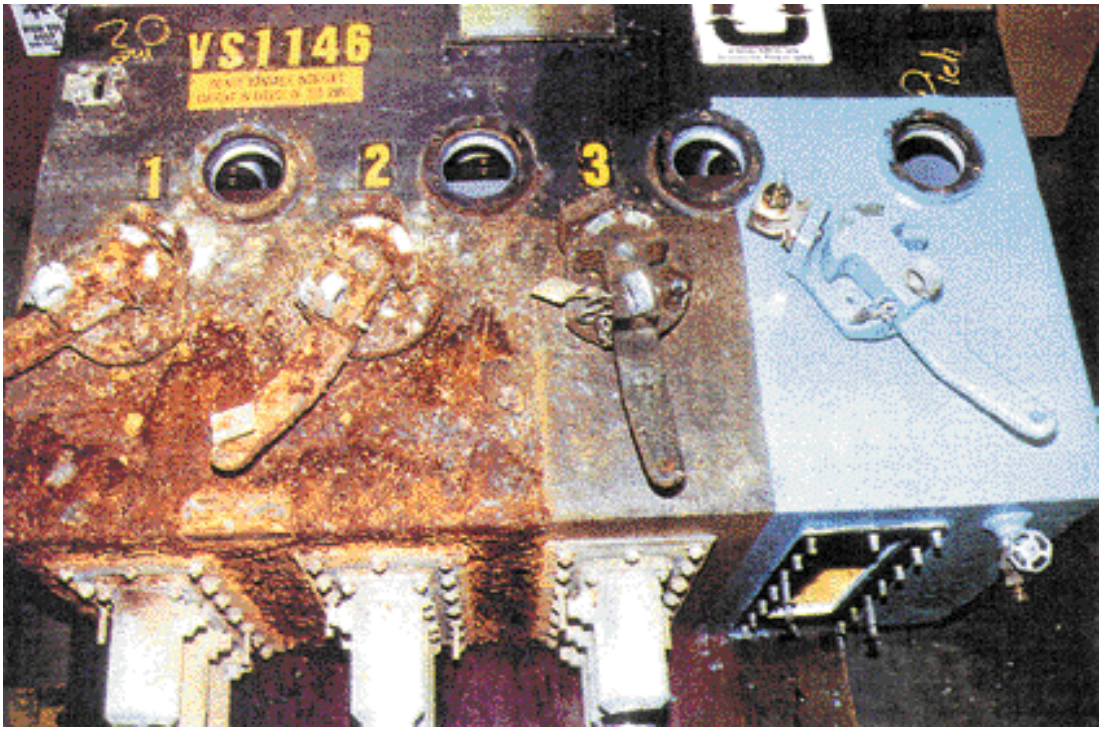


Figure 5–14: Maintenance and Refurbishing — Example 2 of 4

Figure 5–15: Maintenance and Refurbishing — Example 3 of 4

Figure 5–16: Maintenance and Refurbishing — Example 4 of 4

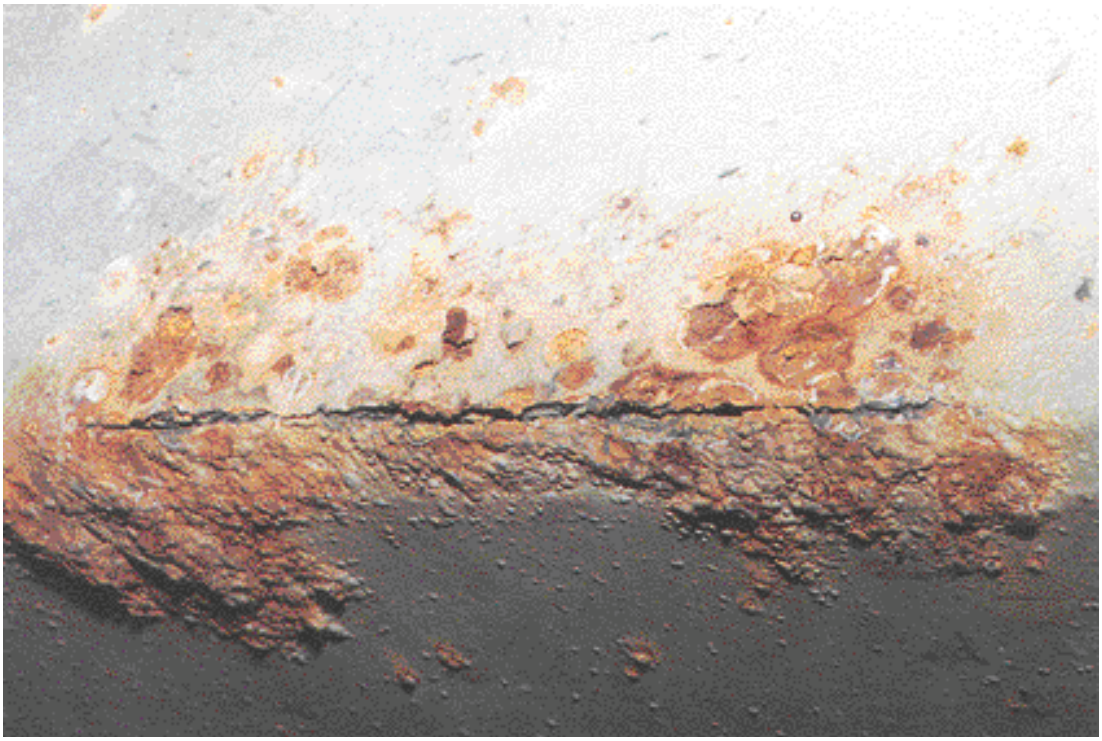
2.7 Typical Problems

A. This is an example of a switch oil drain valve assembly where the drain plug and nipple have corroded to the point that the assembly is inoperative.

Figure 5–17: Typical Problems — Example 1 of 4

B. This picture illustrates a weld seam that has possibly corroded to the extent that an oil leak may be imminent.

Figure 5–18: Typical Problems — Example 2 of 4



C. In some cases, there are aluminum-bodied terminators installed in areas where moisture is present. These terminators will normally be classified as “very heavy” or “heavy” corrosion, depending upon degree of corrosion.

Figure 5–19: Typical Problems — Example 3 of 4

Figure 5–20: Typical Problems — Example 4 of 4

CG–6: Aboveground Equipment Corrosion Condition Guide

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CG–6: Aboveground Equipment Corrosion Condition Guide

1.0 Corrosion Levels of Pad Mounts, Switch Enclosures, Transformers and Capacitors

1.1 Purpose

Listed below are guidelines to assessing corrosion guidelines. Utilize the Risk Assessment Matrix to determine reasonable time frame for any required action needed.

This procedure provides the requirements for establishing external and internal corrosion levels and the criteria for making necessary field repairs or replacements of padmounted (PMH/PME) switch enclosures, transformers, and capacitors.

1.2 Inspection

The following are the measures for detection and inspection of corrosive and deteriorating conditions of padmounted switch enclosures, transformers, and capacitors:

A. External Inspection

- ☐ Check paint for blistering, cracking, flaking, peeling, and any significant color changes.
- ☐ Check for evidence of corrosion at specific locations. These locations include but are not limited to weld seams, edges, corners, and around enclosure base.
- ☐ Open switch operating mechanism compartments in switch enclosures and check for hidden areas of corrosion.

B. Internal Inspection

- ☐ Check around door edges (including hinges), at areas where the door comes in contact with the enclosure, at base of door openings, and on component structural support members for evidence of corrosion.
- ☐ Check for evidence of standing water in structure below switch enclosure, transformer, or capacitor, and note in inspection report.
- ☐ Check for evidence of moisture condensation on internal surfaces.

1.3 Designating External and Internal Corrosion Evaluation

To evaluate the external corrosion evaluation of PMH/PME switch enclosures, transformers, or capacitors, scrape and wire brush the areas on the enclosure, operating mechanisms, and other metal components where corrosion is suspected so that the depth and extent of corrosion can be determined. Ensure proper safety measures are being taken. After scraping and cleaning, each enclosure shall have the corrosion level rated and maintenance priority established as described in the following:

NOTE

Once a corrosion evaluation has been established, that evaluation should not be changed as a result of cleaning, repairing, or painting. This policy is established since pitting cannot be repaired and the interior of the enclosure usually will not be repaired or repainted.

A. Severe Corrosion (Priority 1)

- ☐ Severe corrosion or pitting has eroded 100% of the wall thickness.
- ☐ Cable termination hold down bolts have corroded where they no longer support the cable.
- ☐ Equipment oil leakage is severe where routine repairs will not stop leakage.
- ☐ Any condition that would indicate that a severe hazard exits.

B. Very Heavy Corrosion (Priority 2)

- ☐ There is very heavy corrosion over most of the equipment, or the equipment enclosure has pits that are “near through” the wall thickness.
- ☐ There are openings completely through the enclosure wall.
- ☐ There is oil leakage that cannot be repaired.
- ☐ Any other condition exists that would indicate a hazard.

C. Heavy Corrosion (Priority 2)

- ☐ There is distinct corrosion, heavy loss of paint, and deep pitting over half of the equipment surface.
- ☐ There is pitting that exceeds one quarter of the original wall thickness.
- ☐ Metal is flaking away in nonhazardous locations.
- ☐ There is minor oil leakage, but it is repairable.

D. Moderate Corrosion

No action required; monitor during next inspection cycle.

- ☐ There is distinct discoloration and significant loss of paint and/or moderate pitting (pencil point-sized pits no deeper than one quarter of the original wall thickness).
- ☐ There is no sign of oil leakage.

E. Light Corrosion

No action required; monitor during next inspection cycle.

- ☐ There is some discoloration and disruption to painted surfaces, but no serious pitting or scaling are present.
- ☐ Switch handles and mechanism are operational.
- ☐ There is no sign of oil leakage.
- ☐ There are only minor touch-up repairs required.

2.0 Corrosion Examples

2.1 Severe Corrosion

- ☐ Severe corrosion or pitting has eroded 100% of the wall thickness.
- ☐ Cable termination hold down bolts have corroded where they no longer support the cable.
- ☐ Equipment oil leakage is severe where routine repairs will not stop leakage.
- ☐ Any condition that would indicate that a severe hazard exits.

NOTE Severe corrosion is described above. There are no pictures of severe corrosion in this manual revision. Corrosion conditions exceeding the conditions identified in "Very Heavy" images are considered Severe.

WARNING When a severe corrosion condition exists, the structure shall be closed and a sign shall be posted stating "DO NOT ENTER WHILE EQUIPMENT IS ENERGIZED." The situation shall be made safe and the equipment shall be replaced as soon as possible.

2.2 Very Heavy Corrosion

- ☐ There is very heavy corrosion over most of the equipment, or the equipment enclosure has pits that are "near through" the wall thickness.
- ☐ There are openings completely through the enclosure wall.
- ☐ There is severe oil leakage that cannot be repaired.
- ☐ Any other conditions exist that would indicate a hazard.

WARNING When a very heavy corrosion condition exists, the structure shall be closed and a sign shall be posted stating "DO NOT ENTER WHILE EQUIPMENT IS ENERGIZED." The situation shall be made safe and the equipment shall be replaced as soon as possible.

Figure 6–1: Opening Completely Through the Enclosure Wall

Figure 6–2: Very Heavy Corrosion of Locking Assembly

Figure 6–3: Another Example of Metal Flaking Away at Nonhazardous Locations

2.3 Heavy Corrosion

- ☐ There is distinct corrosion, heavy loss of paint, and/or deep pitting over half of the equipment's surface.
- ☐ There is pitting that exceeds one quarter of the original wall thickness.
- ☐ Metal is flaking away in nonhazardous locations.
- ☐ There is minor oil leakage, but it is repairable.

Figure 6–4: Wall Corrosion at Top of Compartment Door, Covered when Other Door Closed

Figure 6–5: Wall Corrosion at Bottom of Compartment Door, Covered when Other Door Closed

Figure 6–6: Pitting Exceeding One-Quarter Depth of Wall Thickness

Figure 6–7: Distinct Corrosion of Component Structural Support Members

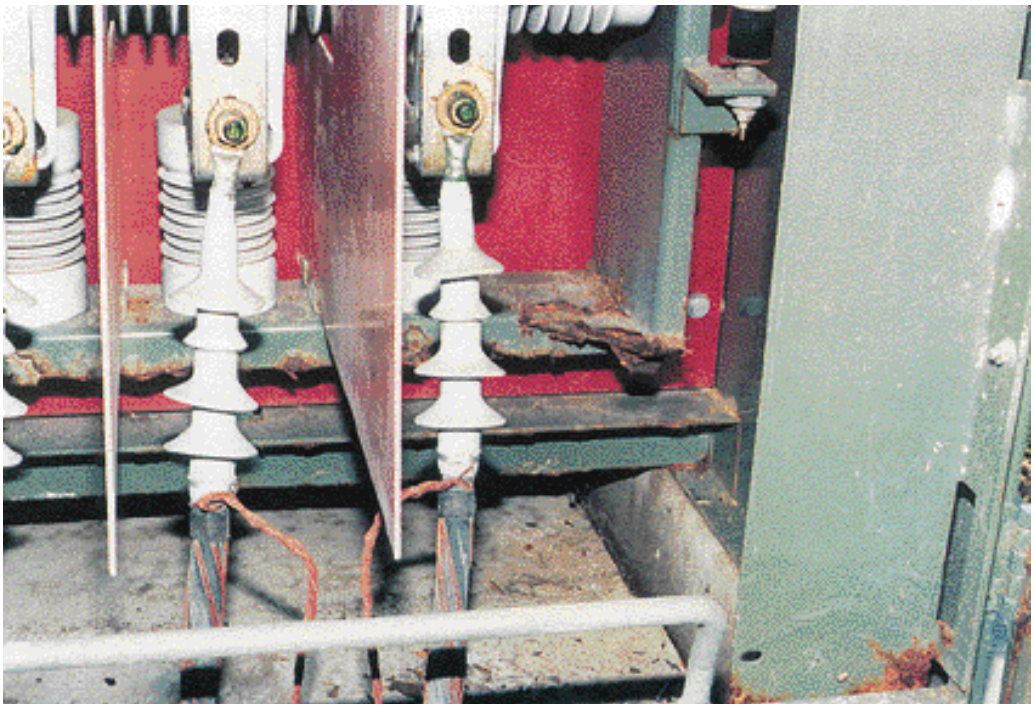


Figure 6–8: Metal Flaking Away at Nonhazardous Locations

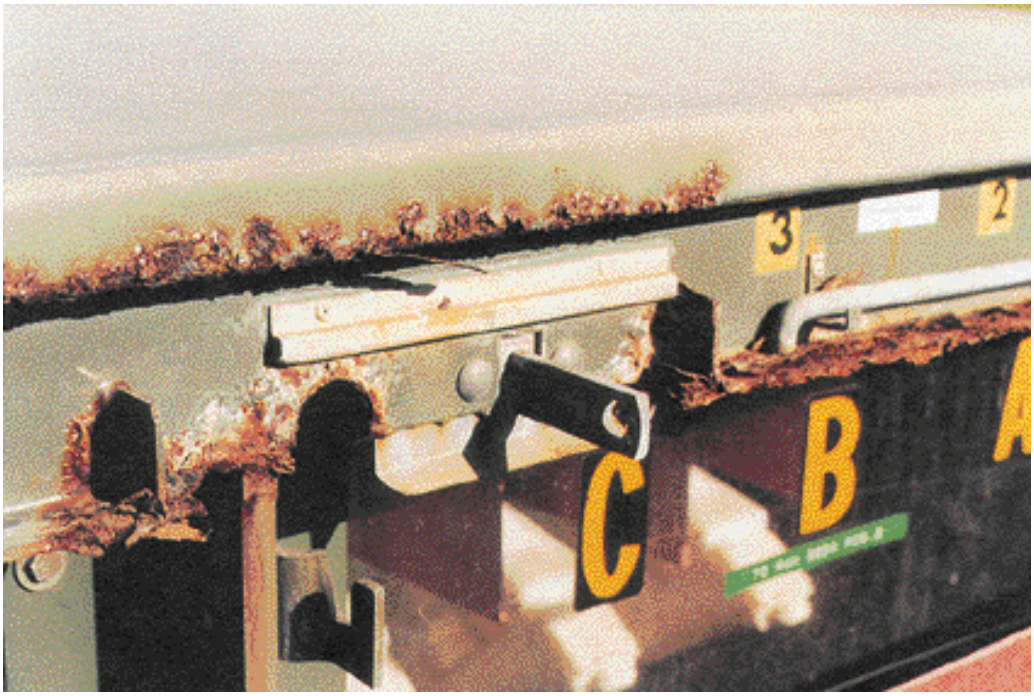


Figure 6–9: Another Example of Metal Flaking Away at Nonhazardous Locations

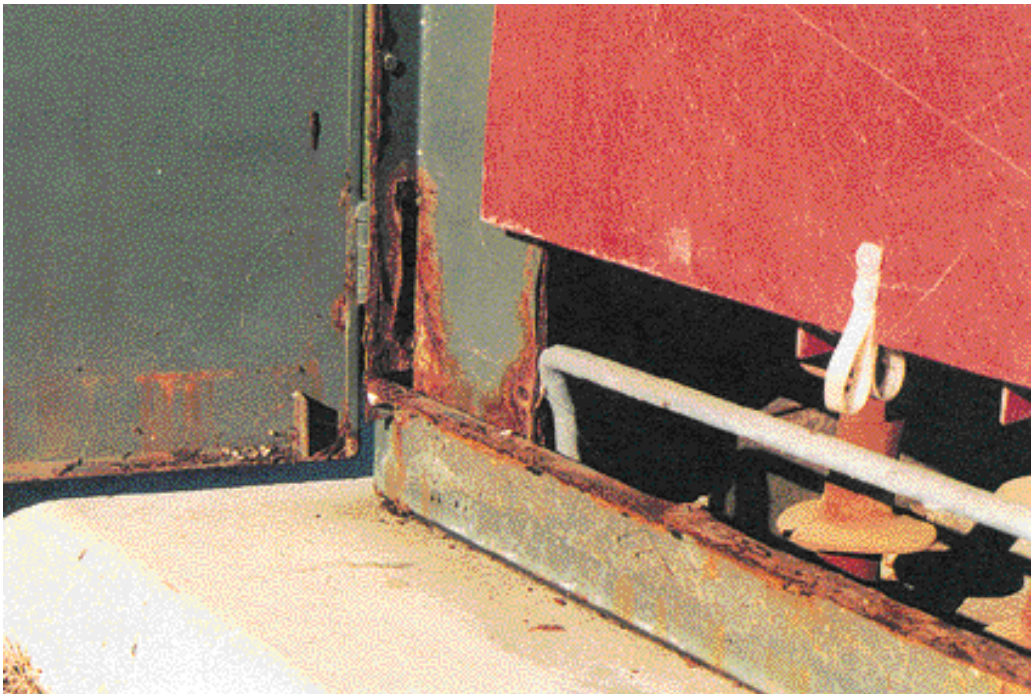


Figure 6–10: Heavy Corrosion with Deep Pitting, Exceeding One-Quarter of Original Wall Thickness

Figure 6–11: Another Example of Heavy Corrosion with Deep Pitting, Exceeding One-Quarter of Original Wall Thickness

2.4 Moderate Corrosion

- ☐ There is distinct discoloration and significant loss of paint and/or moderate pitting (pencil point-sized pits no deeper than one quarter of the original wall thickness).
- ☐ There is no sign of oil leakage.

Figure 6–12: Ineffective Prior Repairs

Figure 6–13: Significant Blistering of Paint

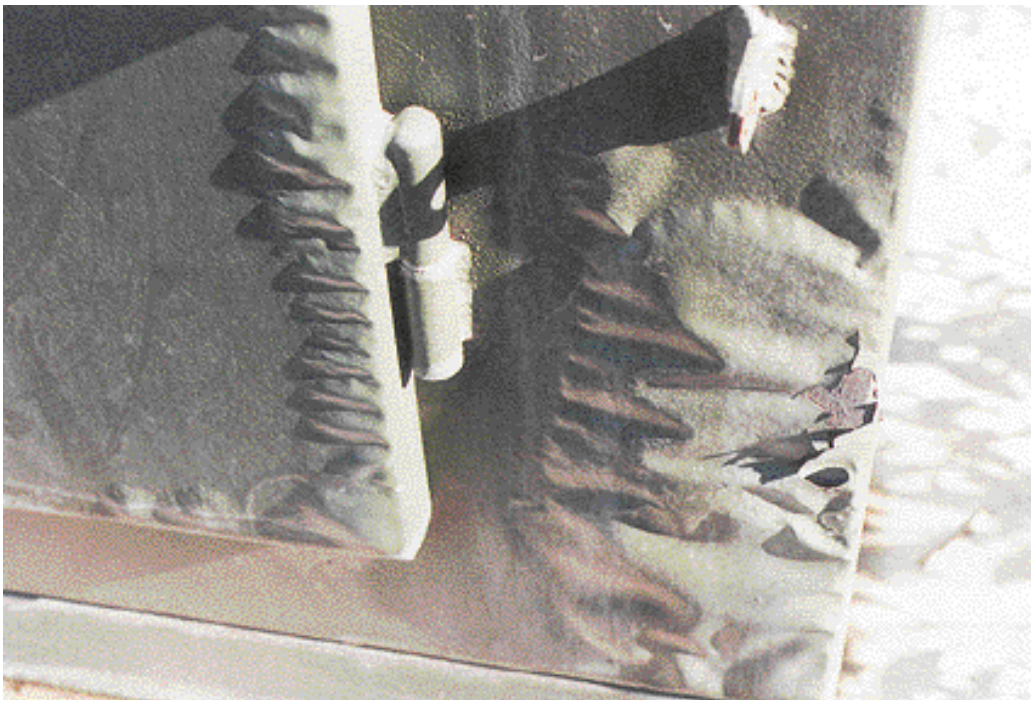


Figure 6–14: Moderate Corrosion with Pitting on Edge of Enclosure Top

Figure 6–15: Loss of Metal

Figure 6–16: Moderate Corrosion with Blistering, Pitting, and Discoloration in and around Vents

Figure 6–17: Moderate Corrosion with Pitting and Significant Loss of Paint

Figure 6–18: Moderate Corrosion with Significant Loss of Paint at Base

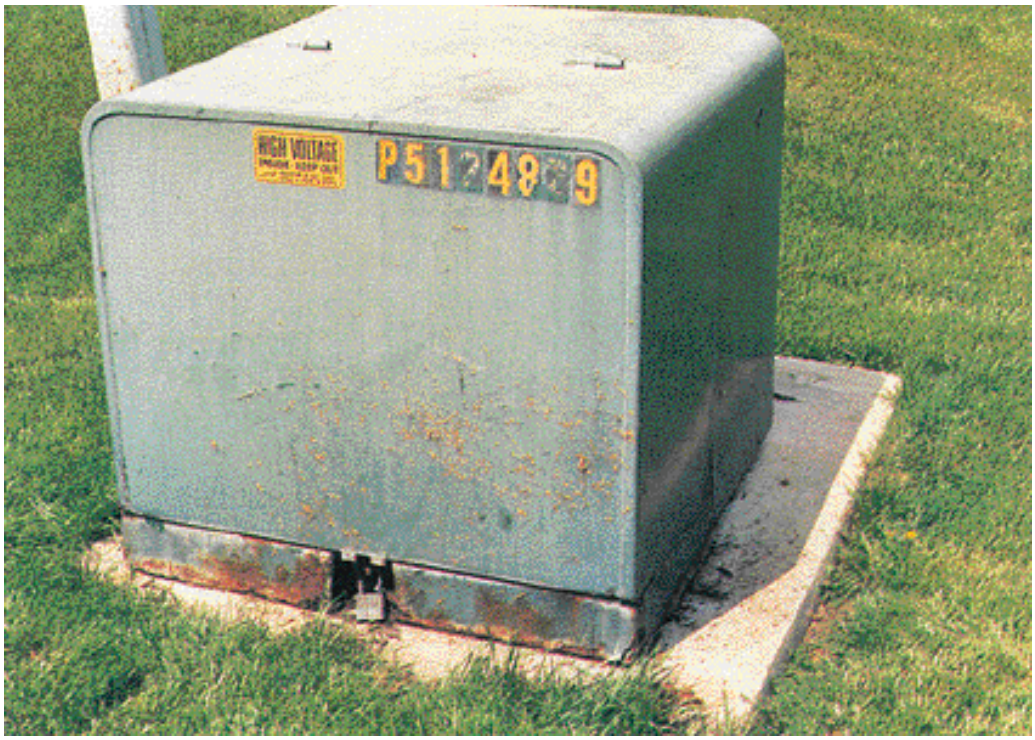


Figure 6–19: Interior Blistering, Flaking, Corrosion, and Discoloration

Figure 6–20: Peeling of Paint with Moderate Pitting

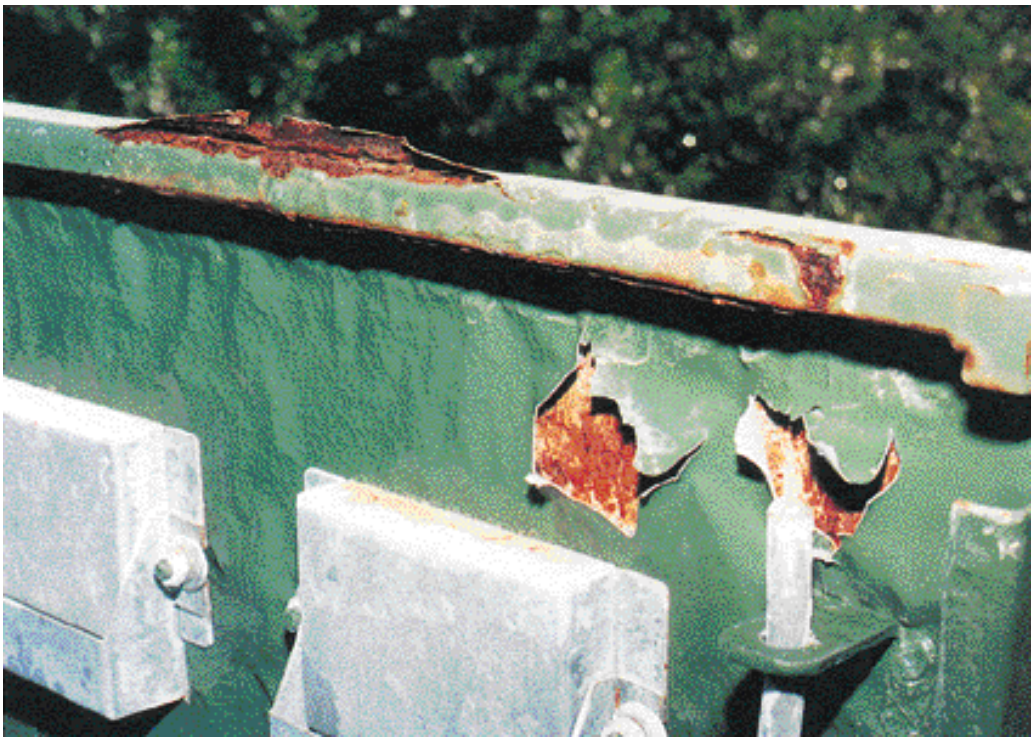
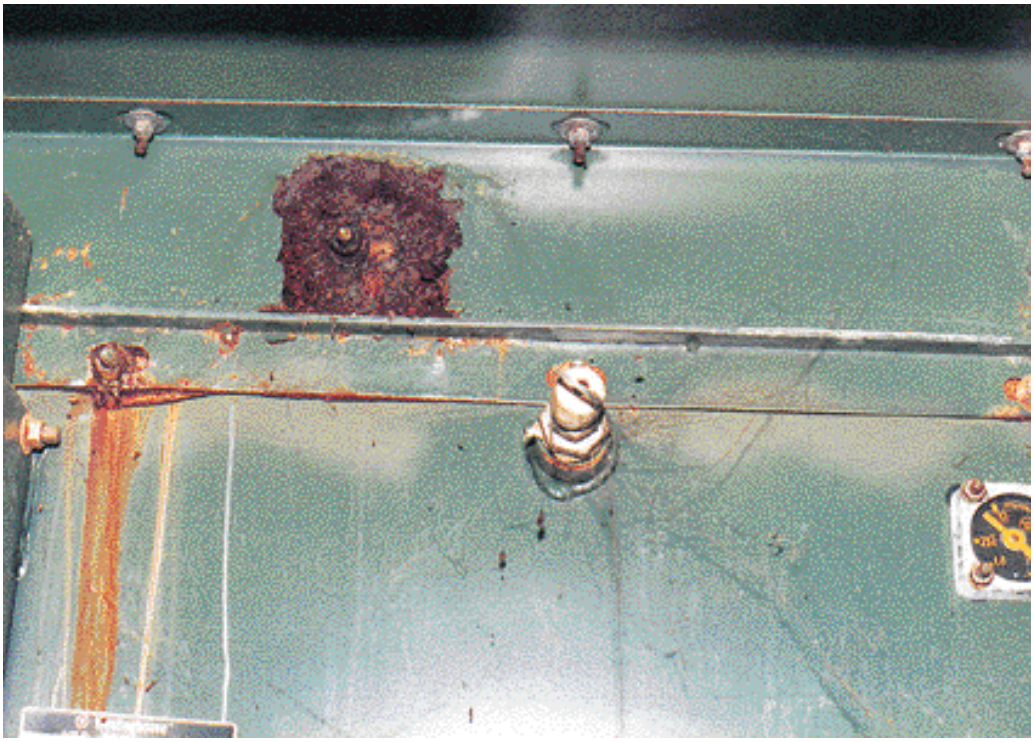


Figure 6–21: Moderate Corrosion of Interior with Significant Pitting



2.5 Light Corrosion

- ☐ There is some discoloration and disruption of painted surfaces but no serious pitting or scaling are present.
- ☐ Switch handles and mechanisms are operational.
- ☐ There is no sign of oil leakage.
- ☐ There are only minor touch-up repairs required.

Figure 6–22: Light Corrosion on Bottom of Door (No Serious Pitting)

Figure 6–23: Close-Up of Light Corrosion on Bottom of Door (No Serious Pitting)

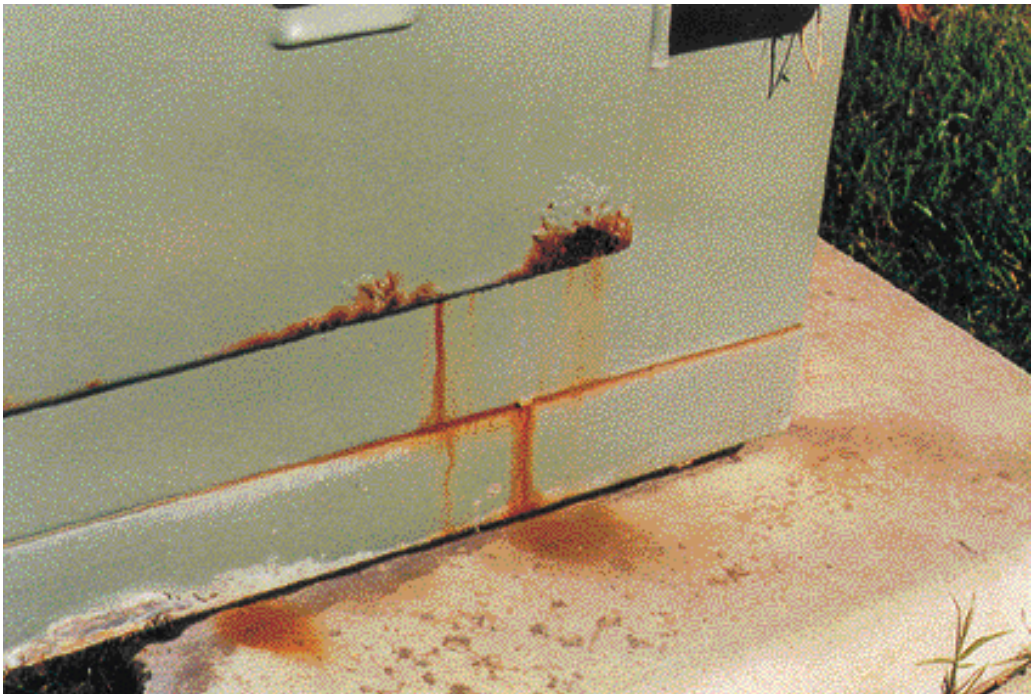


Figure 6–24: Light Corrosion within Manual Switch Operating Mechanism Compartment (No Serious Pitting)

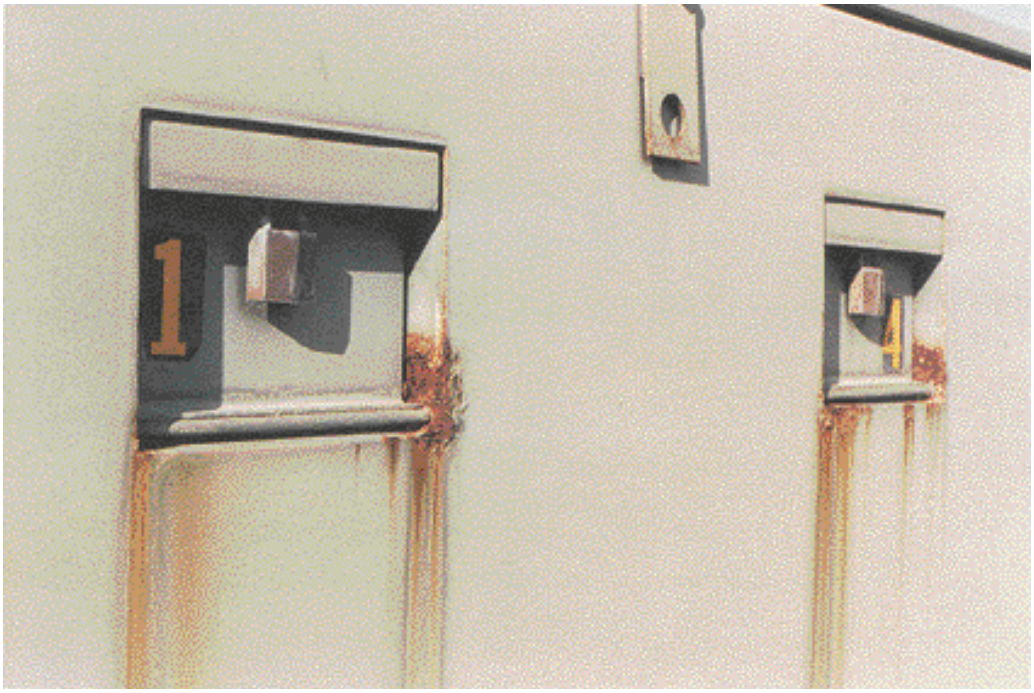


Figure 6–25: Light Corrosion at Louver Openings and at Base of Cabinet (No Serious Pitting)

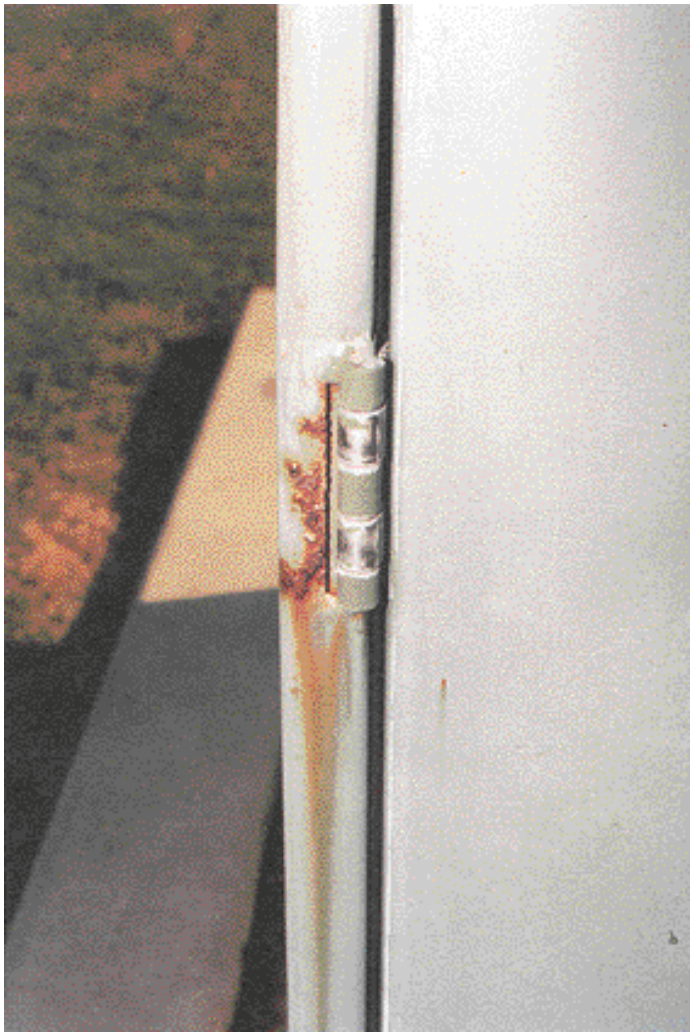
Figure 6–26: Limited Peeling of Paint

Figure 6–27: Light Corrosion of Adapter Cover Plate (No Serious Pitting)

Figure 6–28: Light Corrosion at Lower Edge of Top Cover and Brackets (No Serious Pitting)

Figure 6–29: Light Corrosion at Weld Seam
(No Serious Pitting)

Figure 6–30: Light Corrosion at Hinges



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CG–7: Field Painting of Pad-Mounted Equipment

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1.0 Moderate Corrosion

Perform routine maintenance within three years. Touch up exterior of equipment rated as Corrosion Level 4 as necessary using the following material coded items:

- Paint Thinner, SCE Item 303
- Valspar Chromox Primer, SCE Item 105 (Manufacturer's No. 13-R-50)
- Paint, SCE Item 214, Bell Telephone Green

NOTE

Refer to Corrosion Prevention maintenance instructions (CP-2, 1.0) for field repainting of padmounted equipment.

2.0 Light Corrosion

Opportunity maintenance is identified (but not required) prior to the next inspection cycle.

3.0 Surface Preparation

The following photographs illustrate three stages of surface preparation recommended for repainting of PMH/PME switch enclosures, transformers, and capacitors.

- Stage **A** — Condition as found before scraping or cleaning.
- Stage **B** — Condition after scraping and cleaning.
- Stage **C** — Finished condition with primer undercoat.

Figure 7–1: Field Painting of Pad-Mounted Equipment (1 of 12)

Figure 7–2: Field Painting of Pad-Mounted Equipment (2 of 12)

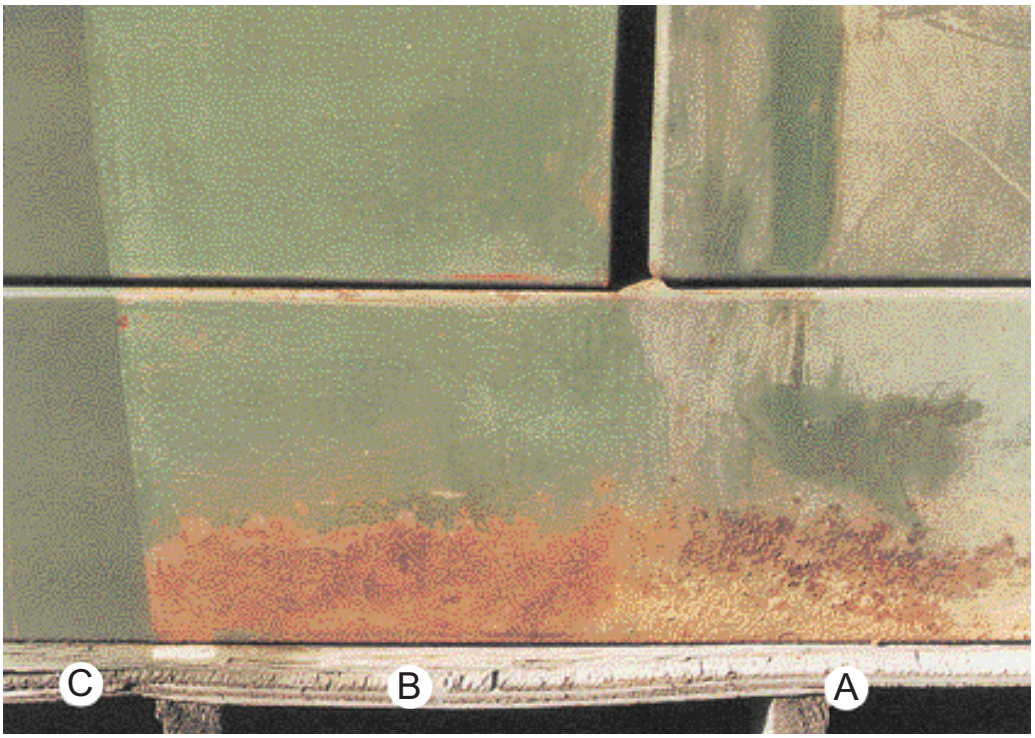

Figure 7–3: Field Painting of Pad-Mounted Equipment (3 of 12)

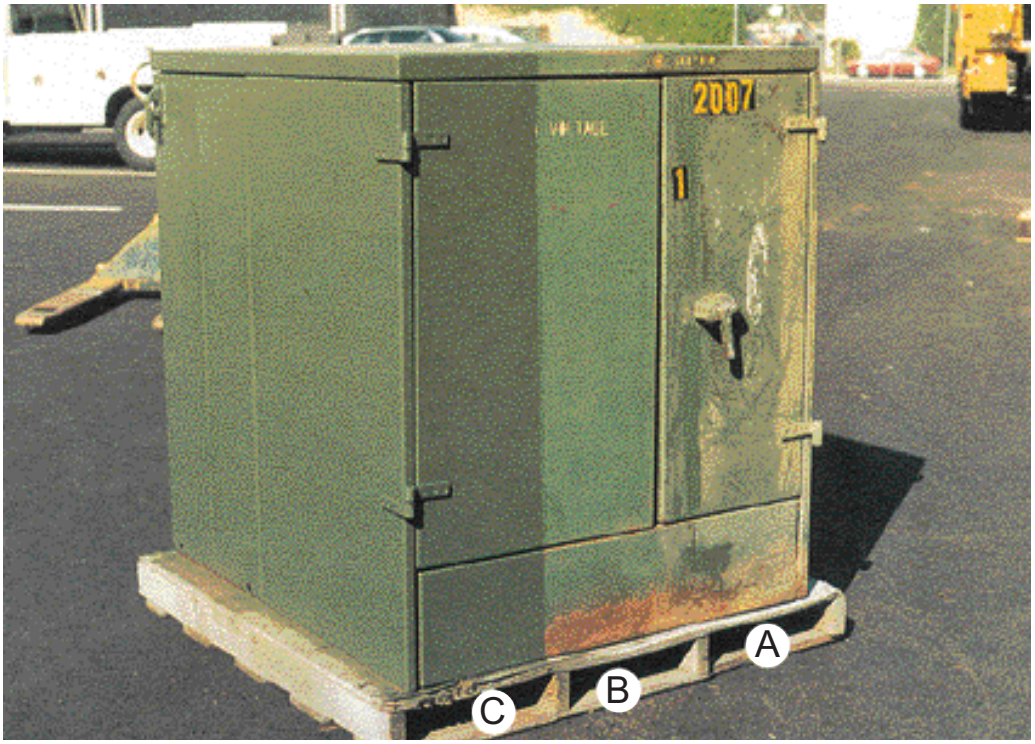

Figure 7–4: Field Painting of Pad-Mounted Equipment (4 of 12)

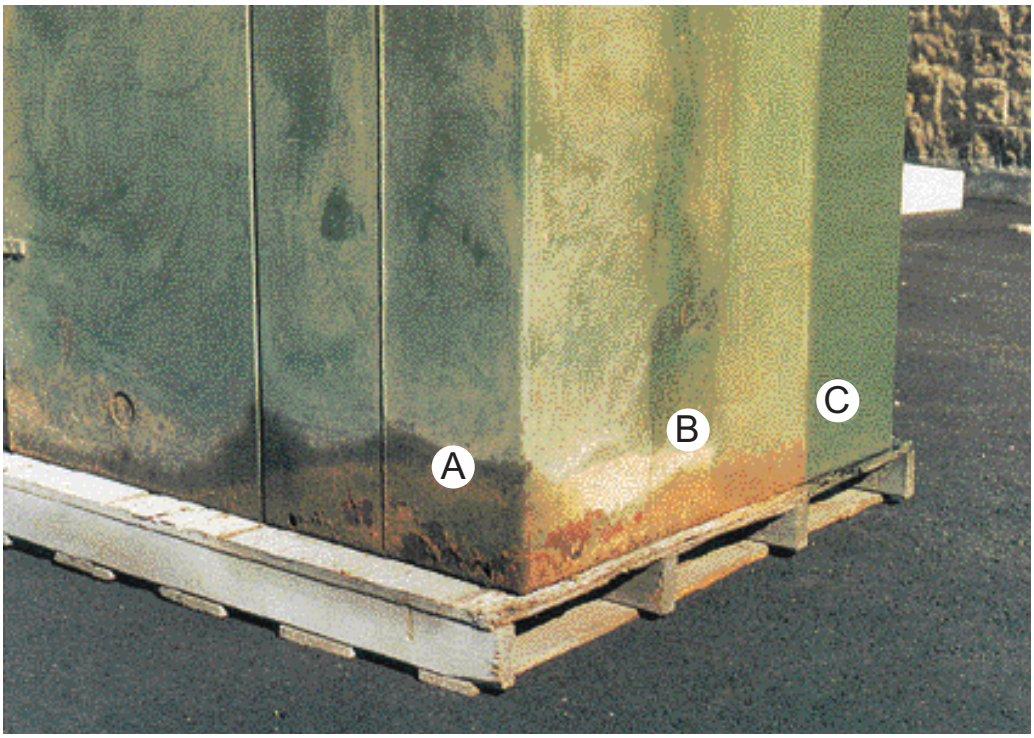

Figure 7–5: Field Painting of Pad-Mounted Equipment (5 of 12)

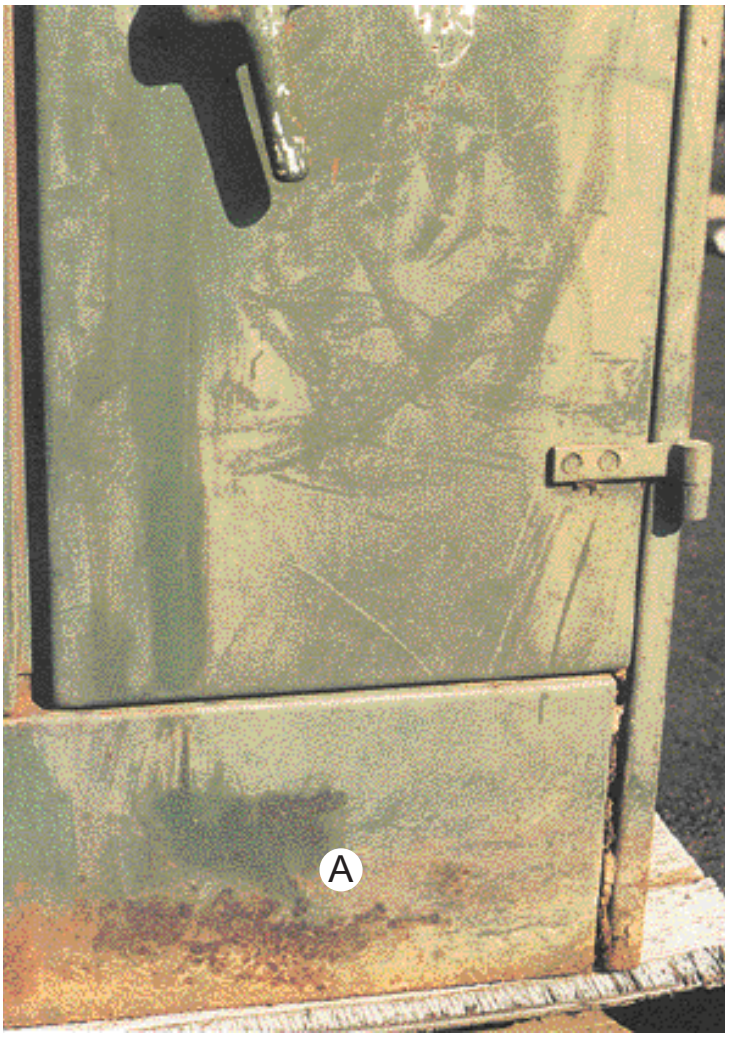

Figure 7–6: Field Painting of Pad-Mounted Equipment (6 of 12)

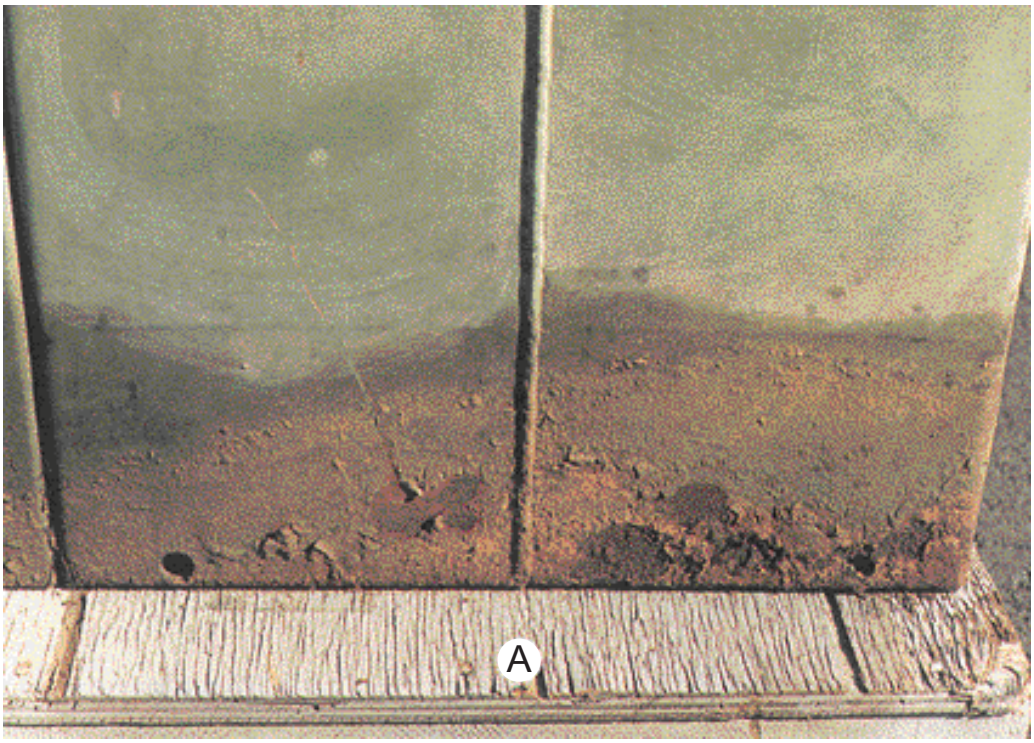

Figure 7–7: Field Painting of Pad-Mounted Equipment (7 of 12)

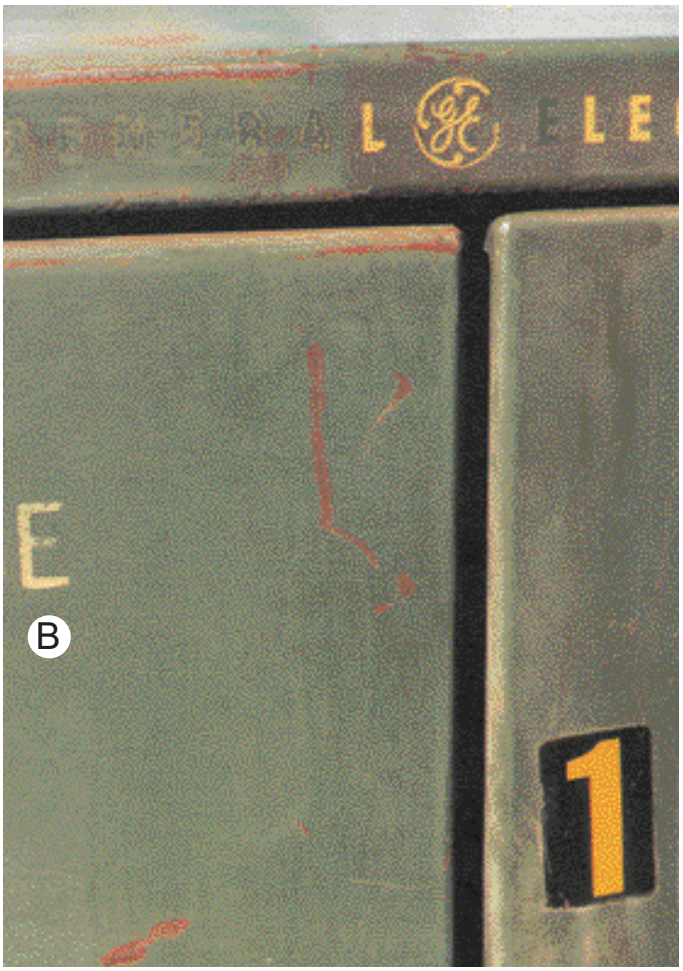

Figure 7–8: Field Painting of Pad-Mounted Equipment (8 of 12)

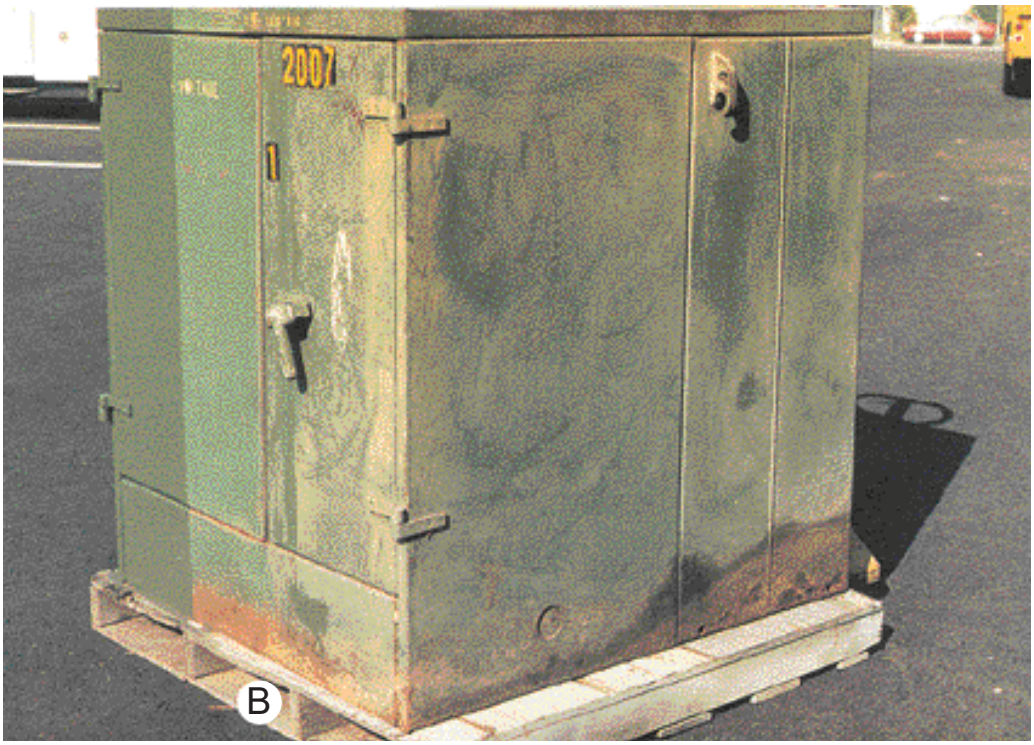

Figure 7–9: Field Painting of Pad-Mounted Equipment (9 of 12)

Figure 7–10: Field Painting of Pad-Mounted Equipment (10 of 12)

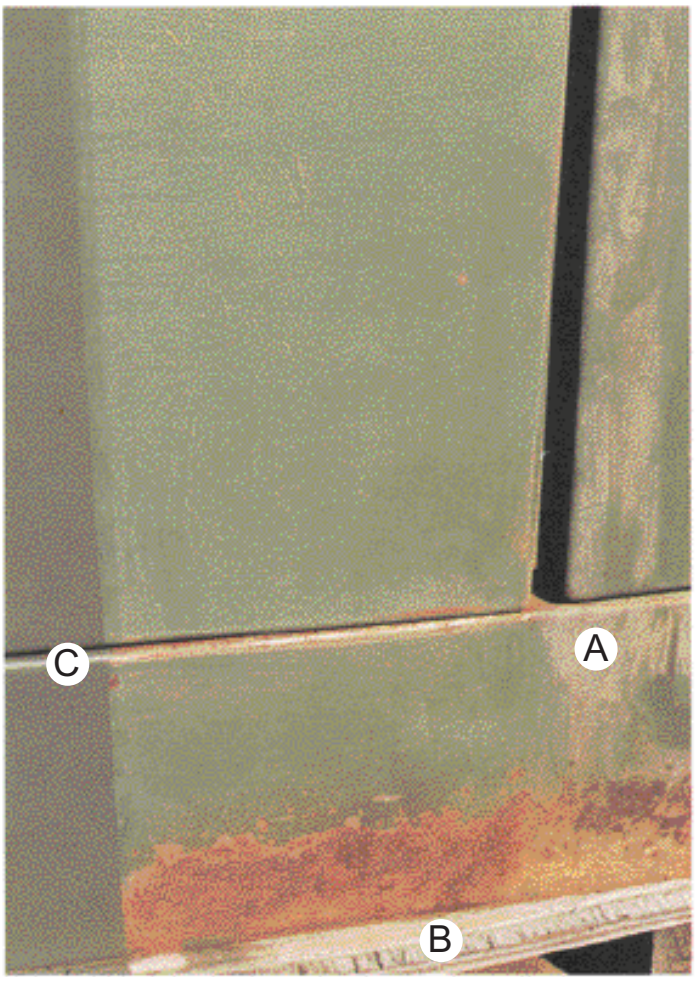

Figure 7–11: Field Painting of Pad-Mounted Equipment (11 of 12)

Figure 7–12: Field Painting of Pad-Mounted Equipment (12 of 12)