Protective Equipment Maintenance Requirements

SUMMARY

This utility standard establishes the requirements for testing and maintaining protection systems, automatic reclosing, and sudden pressure relaying. This document also directs personnel to follow the utility procedures in the *Protective Equipment Standard Test Procedures (PESTP) Manual* and the *Protection System Maintenance and Testing Program (PSMP)*.

This standard lists maintenance practices that promote safe and reliable electrical service within the PG&E service territory. These maintenance practices apply to all electrical substation facilities that are owned and/or maintained by PG&E, including those under the operational control of the California Independent System Operator (CAISO) or subject to regulation by CAISO and the North American Electric Reliability Corporation (NERC).

TARGET AUDIENCE

Electric substation maintenance and construction personnel, electric power generation personnel, and onsite contractors (unless specific, alternative requirements are included in the contract) performing installation and maintenance testing on protective relays and associated equipment must comply with the requirements of this standard and follow the utility procedures in the *PESTP* Manual.

SAFETY

NA

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REQUIREMENTS

1 General Information

1.1 Protection systems must be maintained and repaired to ensure system reliability. PG&E protection systems (including automatic reclosing and sudden pressure relaying) are maintained at the scheme level, and all the protection systems are tested in accordance with a time-based maintenance program. A protection system is comprised of the following components:

- Protective relays that respond to electrical quantities.
- Communications systems necessary for the correct operation of protective functions.
- Voltage- and current-sensing devices providing inputs to protective relays.
- Station direct current (dc) supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply).
- Control circuitry associated with protective functions operating through the trip coils of the circuit breakers or other interrupting devices.

1.2 For a given protection scheme, all protection system components (protective relay, communications system, voltage- and current-sensing devices, and control circuitry) are tested at the same maintenance interval, as listed in Attachment 2, "Protection Scheme Types and Trigger Intervals," Table 1, "Protection Scheme Maintenance Activities and Trigger Intervals," with the exception of station dc supply (batteries and battery chargers).

1. For station dc supply maintenance requirements, see Utility Standard TD-3322S, "Substation Equipment Maintenance Requirements," Attachment 6, "Station Direct Current Supply Maintenance Template."

1.3 Protection scheme maintenance intervals are selected based on their respective protection system component(s) that require the shortest maintenance interval and meet or exceed the requirements of NERC Reliability Standard PRC-005-6, "Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance." As a result, some types of components may be tested more frequently than required to coincide with maintenance testing for the entire protection scheme.

1.4 PG&E communication systems used for protection schemes include either continuous monitoring or periodic, automated testing for the presence of channel function and alarming for loss of function. Therefore, maintenance activity for a 4-calendar month verification of communication system function is not required.

1.5 For each scheme listed in Attachment 2, Table 1, the maintenance interval is the maximum allowable interval for the entire scheme.

1. Maintenance intervals are in calendar years and are based on the recommendations from manufacturers, PG&E operating experience, and industry benchmarks.

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1.6 To meet regulatory requirements, maintenance activities must be completed in the calendar year of the maintenance plan due date.

2 PESTP Manual

2.1 The *PESTP Manual* provides the following required actions: installation, maintenance, and test procedures; and general specifications. Supervisors that oversee covered PG&E personnel OR contractors are responsible for ensuring that they comply with the *PESTP Manual*.

2.2 Protective equipment maintenance requirements in this standard and in the *PESTP Manual* are based on good utility practice, the recommendations of manufacturers, and the experience of PG&E personnel.

3 Maintenance Triggers

3.1 Protection system maintenance and testing are triggered by **time**, **trouble**, OR **condition**, as defined below. **Document all performed tasks in SAP**. See Section 6, "Recordkeeping," on Page 9.

- **Time-based:** Triggered by a fixed time interval, as specified in Attachment 2, Table 1.
- **Trouble-based:** Triggered by alarms, questionable relay actions, or as-found conditions (based on performance and, when conditions dictate, if protective relay[s] and/or associated equipment need to be replaced).
- **Condition-based:** Triggered by service advisories from manufacturers or when there is evidence that a particular component in the protection system is not operating as expected. (Condition-based triggers may result in more frequent testing of the protection system than is specified in Attachment 2, Table 1.)

3.2 Document all performed tasks in SAP. See Section 6.

3.3 IF any relay fails to operate properly, OR if there are concerns regarding the operation of any relay,

THEN the electrical technician must contact his or her supervisor.

3.4 IF the relay cannot be returned to working order following routine maintenance OR the discovery of a failure or malfunction,

THEN the identified "unresolved maintenance issues" (see NERC definition in Attachment 1, "Definitions of Acronyms and Terms") and their subsequent resolution must be documented in SAP.

3.5 Examples of resolution include, but are not limited to, replacing capacitors in distance relays AND replacing relays or other protective system components AND then verifying that the relay or system has been restored to working order.

3.6 Do not perform routine maintenance on protective relays or schemes that are abandoned in place or are not available for service; for example, an unmodified underfrequency load-shedding scheme. For out-of-service relays or schemes, the SAP/WMS database must indicate that the equipment is out of service AND that the maintenance plan is locked.

4 Monitoring Attributes of Protection System Components

4.1 Protective Relays

1. Transmission-Class Relays (60 kilovolt [kV] and above)

   a. PG&E protection schemes may contain both monitored and unmonitored protective relays. For the purposes of defining the maintenance intervals in Attachment 2, Table 1, the maximum maintenance interval for an unmonitored protective relay (6 calendar years) is specified for all electromechanical and solid-state transmission-class relays used on, or designed to protect, the Bulk Electric System (BES).

   b. All PG&E microprocessor protective relays or automatic reclosing relays used on, or designed to protect, the BES are monitored and include the following monitoring attributes:

      - Internal self-diagnosis and alarm functions.
      - Voltage and/or current waveform samples taken three or more times per power cycle. The waveform samples are converted to numeric values to allow the microprocessor electronics to calculate measurements. The electronics also perform self-monitoring and initiate alarms.
      - Power supply failure alarms.

   c. PG&E microprocessor protective relay or automatic reclosing relay alarms are visible to system operators either through SCADA or Station A/B alarms for initiation of corrective action upon receipt of an alarm.

   d. The maintenance intervals for protection schemes with microprocessor relays are listed in Attachment 2, Table 1. The maximum maintenance interval for a monitored microprocessor protective relay is 12 calendar years. The protection scheme may have a shorter overall maintenance interval due to the presence of unmonitored components (e.g., electromechanical lockout relays directly in the trip path) that require a maximum interval of 6 years.

2. Distribution-Class Relays (34 kV and Below)

   Distribution-class underfrequency load-shedding (UFLS) or undervoltage load-shedding (UVLS) relays also provide protection for the BES.

4.1 (continued)

a. Monitored

(1) IF the UFLS or UVLS function resides in a microprocessor feeder relay,

THEN the system is classified as monitored.

(2) Monitored UFLS and UVLS relays have a maintenance interval of 8 calendar years, chosen to coincide with the normal distribution-relay maintenance interval for distribution-class feeder-protection relays.

(3) Distribution-class, microprocessor, feeder-protection relays include the following monitoring attributes:

- Internal self-diagnosis and alarm functions.
- Voltage and/or current waveform samples taken three or more times per power cycle. The waveform samples are converted to numeric values to allow the microprocessor electronics to calculate measurements. The electronics also perform self-monitoring and initiate alarms.
- Power supply failure alarms.

b. Unmonitored

(1) IF the UFLS or UVLS function resides in a solid-state or electromechanical relay OR includes electromechanical trips or auxiliary devices,

THEN the system is classified as unmonitored.

(2) Unmonitored UFLS and UVLS have a maintenance interval of 6 calendar years.

4.2 Communication Systems

1. PG&E communication systems used for protection schemes include either continuous monitoring or periodic, automated testing. The automated testing checks for the presence of the channel function and, when there is a loss of function, for the appropriate alarms. For example, frequency shift keyed (FSK) transceivers use a loss-of-guard alarm. On/off carrier-blocking schemes use an automatic check-back to key the carrier every 8 hours and to initiate an alarm if the check-back fails. These loss-of-guard and check-back alarms are visible to system operators, either through SCADA or Station A/B alarms.

4.2 (continued)

2. Communication alarms also exist for other types of protection schemes, such as line current differential. The maintenance interval listed in Attachment 2, Table 1, for the communication system may be less than the maximum allowed by NERC because the intervals are set to coincide with the time the rest of the protection scheme is tested. Likewise, the protection scheme may have a shorter overall maintenance interval due to the presence of unmonitored components that are not part of the communication system.

4.3 Voltage- and Current-Sensing Devices Providing Inputs to Protective Relays

The maintenance intervals listed in Attachment 2, Table 1, are based on the maximum PG&E maintenance interval for unmonitored voltage- and current-sensing devices. The protection scheme may have a shorter overall maintenance interval due to the presence of unmonitored components that are not part of any voltage- and current-sensing devices providing inputs to the protective relays.

4.4 Station DC Supply

See Utility Standard TD-3322S, Attachment 6, for the maintenance requirements for station dc supply batteries and battery chargers. Utility Standard TD-3322S includes time-based maintenance requirements for all batteries associated with the station dc supply components of a protection system.

4.5 Control Circuitry

The maintenance intervals listed in Attachment 2, Table 1, are based on the maximum PG&E maintenance intervals for unmonitored control circuitry. The protection scheme may have a shorter overall maintenance interval due to the presence of unmonitored components that are not part of the control circuitry.

5 Maintenance Activities

As indicated in Attachment 2, Table 1, the maintenance activities described in this section are performed on PG&E protection systems.

5.1 Component Performance and Scheme Functional Test

1. This test determines whether protective relays, fault pressure relays, reclosing relays, reclosing supervisory relays, and associated control schemes are operating properly. The test consists of the following tasks:

   - Test and, if necessary, calibrate the relays (except for microprocessor relays) with simulated electrical inputs.
   - For fault pressure relays, verify that the pressure or flow sensing mechanism is operable.

5.1 (continued)

- For microprocessor relays, verify the operation of those relay inputs and outputs essential to the proper functioning of the protection system or automatic reclosing.
- For microprocessor relays, verify that the power-system input values are acceptable.
- For microprocessor relays, verify the alarm path conveys alarm signals to the appropriate locations where corrective action can be initiated (Grid Control Center or distribution operator).
- Verify that the current and/or voltage signal values are provided to the protective relay, reclosing relay, or reclosing supervisory relay.
- Verify that settings are as specified in the relay database or automatics database.
- Verify that each trip coil is able to operate its associated circuit breaker, interrupting device, or mitigating device.

NOTE

UFLS and UVLS relays do not require tripping circuit breakers and interrupting devices as part of testing.

- Verify the electrical operation of any electromechanical lockouts and/or auxiliary tripping devices in the direct trip path from the protective relay to the trip coil of the interrupting device.
- Verify the proper operation of the control and trip circuit paths associated with protective functions.
- Verify the proper operation AND timing of automatic reclosing functions.

5.2 Communication Component and Channel Performance Test

This test determines whether communication equipment used in association with protective relay schemes is operating properly. It consists of verifying the following items:

- Channel quality and performance meet the performance criteria that apply to the specific communications technology, such as signal level, reflected power, and data-error rate.
- Essential signals are being transmitted to and from other protection-system components.
- The alarm path conveys alarm signals to the appropriate locations where corrective action can be initiated.

5.3 Clean and Inspect

The “clean and inspect” task does not require testing relays. It consists of visually inspecting the equipment for corrosion and loose connections, replacing batteries, cleaning or replacing air filters, and performing miscellaneous cleaning.

5.4 Digital Fault Recorder (DFR) Functional Test

This test determines whether the following DFR functions are operating properly:

- Sequence of events
- Fault recording
- Dynamic disturbance recording
- Potential transformer (PT), current transformer (CT), and frequency inputs
- Time synchronization

5.5 System Test

NOTE

Because complex communication circuits, PLC control, multiple inputs, and variations make a special protection system (SPS) too complicated for problems to be identified or addressed adequately by component testing, system testing may be performed as well.

1. In addition to component testing, under certain conditions, a system test may be performed on complex SPSs and remedial action schemes (RASs).

2. IF an SPS meets even one of the following three criteria,

   THEN the SPS requires system testing:

   a. The SPS uses communications circuits for either of the following two purposes:

      (1) Non-discrete data acquisition (e.g., analog data collection).

      (2) Implementing control actions more complex than a simple control output (e.g., a trip signal).

   b. The SPS contains a programmable logic controller (PLC) OR more than four power-system terminals are monitored as inputs to the SPS.

   c. The SPS has non-trivial variations that component testing may not address adequately, such as input variations, which must be tested separately, OR its complexity makes it necessary to use system testing. For example, the Caribou Generation 230 kV SPS #1 requires system testing because it has distinctly different control actions for the same initiating event, depending on whether a monitored circuit breaker is open or closed.

5.5 (continued)

3. See the *PESTP Manual*, Section 26.1, "Special Protection System (SPS) Testing Requirements," for further information on SPS or RAS testing and documentation requirements.

6 Recordkeeping

Maintain test reports and records in accordance with Utility Procedure TD-3320P-12, "Substation SAP Work Management System (WMS) Process," Attachment 9, "Maintenance Documentation Requirements for Protection, Automation, Communication, and Control Test Reports."

7 Assistance, Error Reporting, and Revisions

7.1 IF advice or assistance is needed,

THEN personnel must contact the responsible test supervisor.

7.2 WHEN additional assistance is needed, the test supervisor or other personnel must contact the local test department transmission specialist or the appropriate protection engineer.

END of Requirements

DEFINITIONS

Definitions are provided in Attachment 1, "Definitions of Acronyms and Terms."

IMPLEMENTATION RESPONSIBILITIES

The vice president (VP) in charge of electric transmission operations and the senior director in charge of electric substations issue this standard. The VP and senior director delegate their authority to the manager responsible for system protection to revise, approve, and issue the attachments to this standard. Any changes to this standard require CAISO review before implementation.

Electric substation maintenance and construction (SM&C) superintendents and first-line test supervisors ensure that their personnel understand and comply with this standard and the *PESTP Manual*.

This standard and the *PESTP Manual* are posted in the Technical Information Library (TIL); updates are shared with appropriate personnel through tailboard conferences and meetings.

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

The requirements in this standard and in the *PESTP Manual* are designed to comply with the requirements in the following documents:

- NERC Reliability Standard PRC-005-6, "Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance"
- CAISO Transmission Control Agreement, Appendix C, "ISO Maintenance Standards"

REFERENCE DOCUMENTS

Developmental References:

NA

Supplemental References:

Protection System Maintenance and Testing Program (PSMP)

Protective Equipment Standard Test Procedures (PESTP) Manual

Utility Procedure TD-3320P-12, "Substation SAP Work Management System (WMS) Process"

- Attachment 9, "Maintenance Documentation Requirements for Protection, Automation, Communication, and Control Test Reports"

Utility Standard TD-3322S, "Substation Equipment Maintenance Requirements"

- Attachment 6, "Station Direct Current Supply Maintenance Template"

APPENDICES

NA

ATTACHMENTS

Attachment 1, "Definitions of Acronyms and Terms"

Attachment 2, "Protection Scheme Types and Trigger Intervals"

Protective Equipment Maintenance Requirements

DOCUMENT RECISION

This utility standard cancels and supersedes Utility Standard TD-3323S, “Protective Equipment Maintenance Requirements,” Rev. 1, issued 01/12/2015.

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REVISION NOTES

Where?	What Changed?
Summary	• Added reference to protection systems, automatic reclosing, and sudden pressure relaying.
Requirement 1.1	• Added parenthetical for including automatic reclosing and sudden pressure relaying. Changed elements to components. • Changed second Requirement 1.1 to Requirement 1.2.
Requirement 1.2	• Changed existing Requirement 1.2 to Requirement 1.4.
Requirement 1.3	• Added existing Requirement 1.3 to new Requirement 1.4 as second paragraph. • Added another Requirement to 1.3 to capture information from existing 1.4, since Table 1 was deleted.
Requirement 1.4	• Moved existing information in Requirement 1.4 to 1.3 and modified information, since Table 1 was deleted. • Added new Requirement to 1.4 to identify PG&E communication systems, as monitored.
Requirement 1.5	• Changed existing Requirement 1.5 to 1.6. • Moved existing Requirement from 1.3 to new 1.5.
Requirement 1.6	• Added new Requirement 1.6 with information from existing Requirement 1.5.
Table 1	• Removed Table 1.
Requirement 4.1.1	• Added text to clarify that unmonitored relays include electromechanical and solid state relays. • Added monitoring attributes for microprocessor relays to allow extending maintenance intervals beyond 6 years.
Requirement 5.1.1	• Updated “Component Performance and Scheme Functional Test” maintenance tasks for sudden pressure relaying and automatic reclosing to comply with PRC-005-6.
Reference Documents	• Removed “PSMP – Communication Component Documents” since this information is now included as Attachment B in the main PSMP document.
Attachment 1	• Added definitions for “Automatic Reclosing (BES),” “Functional test,” “Monitored,” and “Sudden Pressure Relaying (BES).” • Removed definitions for “Fully monitored” and “Partially monitored.” • Modified “Component performance and scheme functional test” definition to include sudden pressure relaying and automatic reclosing. • Modified “System test” definition for RAS or SPS.

REVISION NOTES (continued)

Where?	What Changed?
Attachment 2	• Added Section 3, “Reference Documents,” to list references that applied to all scheme types and removed those reference documents from Table 1. • Added a 3-year maintenance activity for Capacitor Protection, Series, to replace PLC battery backup and fans. • Modified Reactor Protection, Regulator Protection, and Transformer Protection scheme description to specify that pressure relays consist of sudden pressure, LTC overpressure, and bucholtz relays. • Added column to Transmission Class trigger interval for “Monitored” and set RAS to 12-year interval with footnote to indicate this is for PACIRAS, SF RAS, and Metcalf SPS. • Modified Generator Protection scheme description and added 12-year interval for monitored MP relays. For the rest of the schemes, entered “NA” in the “Monitored” column. • Modified Footnote 5 for PACIRAS, SF RAS, and Metcalf SPS interval change to 12 years. • Added Footnote 6 for generation relays. • Updated hyperlink path for PSMP in various locations.

