Protection System Coordination, Testing, and Maintenance to Comply with NERC Requirements

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ABSTRACT

Proper generation and transmission protection system operation relies on a host of critical components such as potential and current transformers, relays, and breakers along with skilled crafts to coordinate, test, and maintain this system. Recently, the North American Electric Reliability Corporation (NERC) has issued requirements regarding protection systems. NERC PRC-001-1 and PRC-005-1 requires utilities to ensure coordination of relay settings and to develop a protection system maintenance and testing program, including testing intervals. This paper provides insight into how the Bureau of Reclamation (Reclamation) addressed these new requirements by means of comprehensive protection system testing from the current and potential transformers through the relays themselves and finally to the associated breakers. Discussion of the associated NERC requirements and details from Reclamation's latest Facilities Instructions Standards and Techniques (FIST) Manual 3-8 "Operation, Maintenance, and Field Test Procedures for Protective Relays and Associated Circuits", which was recently updated to provide guidance to our facilities, will benefit other generation and transmission owners and operators developing similar internal programs.

INTRODUCTION

Powerplants and switchyard protection systems and associated circuits should be properly maintained and tested to ensure proper protection of equipment and systems. Protection systems also must function properly to protect the electric power system as well. Reclamation, as a significant generator of electricity in the Western United States, must meet the requirements established by Western Electricity Coordinating Council (WECC) and NERC. These reliability organizations define minimum requirements for protection and control systems that affect power system stability and reliability. Reclamation fully endorses and cooperates with these entities and their requirements.

NERC Reliability Standard PRC-001-1 states:

> "Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority."

NERC Reliability Standard PRC-005-1 states:

> "To ensure all transmission and generation protection systems affecting the reliability of the bulk electric system (BES) are maintained and tested."

To help insure Reclamation would meet the intent of these standards it recently has updated its protection system coordination, maintenance, and testing programs. Reclamation's tests and test intervals are included in this paper and may be helpful to other utilities that are developing or updating the protection system guideline.

Typical Protection System

The typical protection systems for generation or transmission of electrical energy are similar. Each system will have instrument transformers, protective relays, and a means to remove energy from the system, thus isolating the problem. Backup power for the protection system should also be included when performing testing to meet the NERC requirements. Typical equipment that should be tested to insure compliance with PRC-005-1 includes, but is not limited to:

- Instrument transformers and associated wiring
- Protective relays and associated wiring
- Power-interrupting devices (breakers)
- Station service battery and DC distribution system

Protective Relay Systems

Reclamation procedures for testing these systems are outlined in our FIST volumes. The newly revised FIST manual 3.8, "Operation, Maintenance, and Field Test Procedures for Protective Relays and Associated Circuits" [1] outlines the requirements to maintain relays and protection circuits. This volume summarizes the equipment to test, testing to be performed, and test intervals as outlined in appendix A, Table 1. Testing is also recommended any time a relay setting is changed. A 6-month grace period is given on all time intervals for a required maintenance or test. These intervals are not meant to supersede manufactures maintenance or testing intervals. If a specified maintenance or test interval cannot be accomplished due to some extenuating circumstances, a written variance is required. All test reports should be documented and kept on file.

Fault and Load Studies and Relay Settings

Electrical protective relays are calibrated with settings derived from system fault and load studies. Initial settings are provided when relays are installed or replaced. Electrical power systems change as generation equipment and transmission lines are added or modified resulting in relay settings that are no longer appropriate. Outdated relay settings can be hazardous to personnel and in danger the integrity of the powerplant, power system, and equipment. To ensure relay settings are not outdated, periodic reviews of the relay settings should be performed (Table 1) and adjustments to the settings should be made based on the actual configuration of the effected power system. Information regarding protective relay systems affecting interconnection operations should be routinely disseminated and settings of such relays shall be coordinated with the affected entities.

Instrument Transformers

Instrument transformer burden: Instrument transformers include current transformers (CTs), potential transformers (PTs) and coupling capacitor voltage transformers (CCVTs) which reduce current and voltage to levels useable by protective relays and other control devices. The secondary PT and CT load should be within nameplate specifications. PTs typically operate at constant secondary voltage (typically 120 volts). As devices are added in parallel to the secondary circuit, the burden (current requirement) increase. At some point, it will exceed capacity of the PT. CTs normally operate at a secondary current that typically ranges from 0 to 5 amps. As devices are added in series, the voltage requirements increase. At some point, the voltage capacity of the CT will be exceeded.

If the capacity of either a CT or PT is exceeded, the transformer cannot accurately measure current or voltage, especially CTs during a system fault, thus giving protective relays false information. The relay will misoperate or not operate at all. Therefore, instrument transformers should have their burdens checked and/or measured regularly (Table 1). In most cases, measuring the voltage and current magnitude on the system and then using ohms law will yield an estimate of the burden.

$$Z_B = \frac{V_{MEASURED}}{I_{MEASURED}}$$

This method is easy to perform with standard tools; but if more accurate values are warranted or the measured burden is greater than 50 percent (%) of the nameplate burden, then a phase angle meter is needed. The use of a phase angle meter will yield the angle between the voltage and current in the system. In this case, we will allow the voltage to have a reference angle of 0 degrees (°). The angle measured by the phase angle will be θ. Using this convention, the equation for the burden will yield:

$$Z_B = \frac{V_{MEASURED}\angle 0^\circ}{I_{MEASURED}\angle\theta}$$

This equation will yield an answer in one of the following forms:

Rectangular Coordinates: $Z_B = r + xi\ \Omega$

Polar Coordinates: $Z_B = r\angle\delta^\circ\ \Omega$

These tests can be performed either on- or off-line. For the online tests, PTs should be energized near rated voltage, and CTs should be loaded to near the equipment or CT rating. If this loading cannot be reached, then the CT should be loaded to at least 1 amp secondary current to allow for accurate measurements. Secondary current and voltage values can be measured with a digital multimeter (DMM) and clamp-on current meter rated for the values being measured.

For offline tests, current is injected into the secondary circuit as close as practical to the CT, and voltage is injected into the PT circuit by lifting the leads near the PT. The CT can remain in the circuit during these tests because it will appear as an open circuit. PT secondary leads need to be isolated from the secondary circuit and voltage injection leads. Care should be taken during the off-line test to disable the trip output of relays that may pickup. Relay operation may cause unintended consequences within the plant.

CT and PT circuits ground and insulation resistance: Relay misoperations or failure to operate can be caused by grounding the neutral at two points, such as one ground at the PT or CT and another at the relay panel. Reclamation typically grounds instrument transformers at the first control board where the signal is used. Spurious grounds may develop, or intentional grounds may be lost as insulation ages and wiring errors occur; therefore, grounds should be checked on a regular basis. [2] With the primary de-energized, the intentional ground should be lifted and the overall circuits checked for additional grounds and insulation breakdowns. Any additional grounds should be located and cleared prior to placing the circuit back into service.

While the ground is still removed from checking the grounding points of the circuits, check the insulation resistance and 1-minute DC voltage withstand between the secondary circuit of the CT or PT and ground using a standard 500-volt (V) insulation resistance meter. Before performing the test, the CT or PT circuit should be isolated from the burden/relays if these devices are not rated to withstand the test voltage, and the primary circuit should be grounded. In the test, include as much of the secondary circuit as possible. If relays or other burdens are being isolated during the test it will require removing the relay from its housing or lifting leads or opening switches at either the first terminal block in the control panel, the relay test block, the back of the relay, or at the control board fuses for the PT circuits. The lowest acceptable value of resistance to ground is 1 megohm. Readings lower than 1 megohm should be investigated carefully; insulation integrity is faulty. [3][4]

Phasing and polarity: It is assumed that instrument transformer polarities and both primary and secondary phasing were verified during design and installation. Whenever instrument transformers or their secondary circuits are modified, it is important to re-verify correct polarity and proper phasing. During periodic testing of the instrument transformers, it is important to confirm polarity and phasing on the secondary circuit of the instrument transformers to the protective relay.

Turns ratio: Instrument transformers should be verified to be operating within their **stated** accuracy class to assure the correct operation of protective relays. Relay accuracy classes have been established in ANSI/ IEEE C57.13™ [4]. Ratio tests are typically performed by comparison of the transformer under tests against a transformer with a known ratio, reference transformer. Tests typically are performed at rated primary values. However, if test equipment may not be available at these high values, it may be necessary to perform ratio tests at reduced primary values.

There are typically two accepted methods for testing ratios of CTs. *Voltage Method.* A suitable voltage, below saturation, is applied to the full secondary winding, and the primary voltage is then measured using a high-impedance voltmeter. Saturation occurs with voltages above the knee of the saturation curve. The turns ratio should be about the same as the voltage ratio. *Current Method.* This method requires a high current source, a reference current transformer to measure the primary current, a loading transformer, and two ammeters. Primary current is passed through both CTs and the secondary currents are compared.

For testing the ratio of a PT, the recommended method for field use is to use a reference PT to compare against the measured PT. Additional test methods for checking PT accuracy are outlined in IEEE Std. C57.13™. [4] A PT of known calibration is required for this method, called the reference PT, and a high voltage source. The high voltage source can be a step-up PT connected to a variable auto transformer. The primary side of the step-up PT is then connected to the primary side of the reference and PT under test. Two high-precision digital voltmeters will be used to compare the output voltage to the reference PT and the output voltage of the PT under test.

Automated primary test sets also are available to test PT and CT ratios that are all inclusive and automate these measurements.

Protective Relaying

Reclamation has powerplants that have been in service for over 100 years. The relay types and vintage installed in our facilities vary widely. At smaller facilities, it is typical to find electromechanical and solid-state relays, while some of these facilities may have installed microprocessor based relays. Our larger facilities generally have microprocessor based relays installed. The variety of equipment installed at our facilities resulted in the creation of a single FIST document that cover electromechanical, solid-state, and microprocessor based relays. Each type of relay has unique testing schedules and requirements as outlined in Appendix A, Table 1. However, this paper will only address microprocessor relay testing.

Microprocessor relays functional testing techniques: Calibration of microprocessor relays is typically not required and not possible. The relay is operated by a microprocessor that is programmed in a manner similar to electromechanical or solid-state relays. There are no user adjustable components in the relay. If a relay does not pass a specific test, often the test point or procedure is incorrect. If everything is proven to be correct, the relay may need to be repaired or replaced, which requires contacting the relay manufacturer.

Reclamation requires that each digital relay be functionally tested upon commissioning and then on a periodic interval. Protective relay functional testing includes operating the relay in place or on a bench to verify that: 1) Each function and settings are correct; 2) The appropriate output contacts close/open at the proper time and under the appropriate inputs; 3) Analog and digital outputs are accurate and reliable; 4) Indicating devices such as targets or indicating lights operate correctly; and 5) Logic functions operate as designed.

Steady-state function testing of microprocessor-based relays typically is performed locally using a laptop computer, or they may be networked together via Ethernet local area networks (LANs) to a personal computer (PC) for testing and monitoring. Steady-state testing is a process where each element of a relay is tested individually, one element at a time. If a relay element is not enabled, it does not need to be tested. However, if relay settings are changed or an element is enabled, the entire relay should be function tested at that time, independent of the testing schedule.

As microprocessor-based relays typically encompass several protection elements, it is often necessary to “isolate” a particular function to test it. This is accomplished by routing the digital element output to an unused physical output. Another method is to temporarily disable any overlapping or interfering relay functions in software when they show up during testing. Making changes to the in-service “as-found” settings for testing requires that the original settings be loaded back into the relay after testing. It is highly recommended to download a copy of the as-found settings to a safe location before testing. It is also important to compare the as-found settings in the relay with the official settings that should be in the relay and to document any discrepancies. After testing is complete, if the as-found copy has all the correct settings, reload these settings back into the relay from the saved copy instead of trying to reverse all the changes. Most manufacturers’ software allows a user to compare settings in the relay to settings on the disk. This will alleviate the possibility of file corruption during downloads and ensures the as-found settings match the as-left settings.

Digital relays are self-testing and self-diagnostic. They monitor their internal programming and can alarm if an internal error is detected. Internal monitoring alarm outputs should be wired to the annunciation system for continuous monitoring. This allows their test interval to be pushed out to 9 years. However, digital relays cannot monitor their analog or digital input or output circuitry. Thus, it is necessary to test each digital relay input and outputs functionally on a more frequent basis, every 2 years per Appendix A, Table 1. Only the inputs/outputs that are in use need to be tested. If a relay input or output is not enabled, it does not need to be tested. However, if relay settings are changed or an input or output is enabled, the entire relay should be function tested at that time, independent of the testing schedule.

Analog inputs (voltages and currents) can be calibrated offline by comparison of the relay display against a calibrated set of inputs. The relay test set can be used for these tests. The analog input can also be checked online by comparison to a second digital relay or meter connected to the same primary circuit. The accuracy of the relay values should be within manufacturer specifications.

The digital output test can be performed by connecting the relay to a PC and forcing the output to change state. The relay also can be programmed to use an unused digital input to trip the outputs. An external signal then can be manually connected to this input to function check the output circuit. It may be necessary to lift the relay trip lead to avoid the unintentional operation of plant protective devices. These tests could be performed with the equipment left in service; however, extreme care should be taken to ensure that equipment left in service is protected adequately during testing.

The programmable logic within a microprocessor-based relay allows the relay to act as numerous different electromechanical relays. The programmable logic should be documented on drawings and available while function testing relays or troubleshooting. Testing of the programmable logic is as important as functional testing. This means all inputs, outputs, relay function blocks, controls, alarms, and switches perform as intended and do not operate with unintended consequences. Logic settings should be reviewed and tested anytime settings are changed. Drawings can be updated at this time. It is essential to keep a set of "as-built" relay logic settings and drawings at the facility. A hard copy of relay settings and logic is useful in case there is a situation where a computer is not available to communicate with the relay.

Lockout Relays and Lockout Circuit Functional Testing

Functional testing should be conducted to prove that protective relay action will actually trip the lockout relays and that the lockouts will trip circuit breakers or other protective devices (e.g., governor, exciter, etc.). Steps that should be included:

- With lockout relays in the "reset" position, initiate a lockout relay trip with the protective relay contact.[1]

- Visually and electrically, verify that the lockout relay actually tripped from the protective relay action. Verify that circuit breakers actually tripped (or other protective action occurred) from the lockout relay action. Verify that every contact in the lockout relay actually has functioned properly. This may be done visually by removing the cover or with an ohmmeter from the relay terminal board.

- Activate the lockout relay from each protective device. After the first full test of the lockout relay and breakers, the trip bus may be lifted from the lockout relay so as not to repeatedly trigger the lockout coil; a meter, light, or buzzer may be substituted to verify contact operation. Reconnect the trip bus prior to the last test to verify correct operation of the final configuration.

- Visually check that all alarms, meters, lights, and other indicators have activated.

- Return all devices and wiring back to their normal "ready" positions.

Lockout relays and circuit breakers perform extremely critical functions—so much so that Reclamation standard designs for lockout relays and circuit breaker control circuits include the use of red (position/coil) status indicator lights. These lights monitor continuity through both the lockout relay coil and breaker trip coil. Microprocessor

[1] It is recommended that the protective device actually be operated where possible for best assurance. The ideal functional test is to actually change input quantities (e.g., instrument transformer primary or secondary injection) to the protective device to thoroughly test the entire protection path. However, it is often necessary to simulate contact operation with a "jumper" when device activation is not possible.

based relays can be configured to continuously monitor lockout relay and breaker trip coil continuity. It is recommended to use this whenever possible.

Power Circuit Breakers

Reclamation has a wide variety of breakers. They include low, medium, and high voltage and air blast, vacuum, and SF6. Various tests and test interval for these breaker can be found in Reclamation FIST volume 4-1B. [5] This paper will briefly cover circuit breaker testing. For a reference, Reclamation's medium voltage vacuum circuit breaker tests and test interval is included in Appendix A, Table 2. A 6-month grace period is given on all time intervals for a required maintenance or test. These intervals are not meant to supersede manufactures maintenance or testing intervals. If a specified maintenance or test interval cannot be accomplished due to extenuating circumstances, a written variance is required. All test reports should be document and kept on file.

Station Service Battery

The station service battery is often considered one of the most vital systems within a powerplant because it provides power to critical controls, protective relays, and uninterruptible power systems associated with computers that control plant operations. Failure of a DC system during a system disturbance could lead to damage of equipment and injuries to employees. Reclamation FIST volume 3-6 [6] outlines routine maintenance of the DC system. For reference purposes the flooded lead-acid battery tests and testing intervals are included in Appendix A, Table 3. A key element to these tests is a periodic battery capacity test.

The DC distribution system is another very critical system. This system includes the main and secondary DC panels. DC Breaker coordination is critical for this system to function correctly. It should be checked each time a new circuit is added to the DC system and when the battery or battery chargers are replaced. Load testing of the main and battery charging circuits are also accomplished following a capacity test. Often battery chargers will operate in a max current mode while initially recharging a battery. This helps to verify circuit breaker ratings of the battery and battery charger circuits. Addition tests include IR scanning of these panels and battery while under load, battery cell connection resistance measurements, and specific gravity readings. Ventilation of the battery room should be checked to ensure adequate diffusion of hydrogen gas during maximum gas generation conditions.

Total Plant Protection System Functional Testing

Total plant protection system functional testing is the ideal way to test the protection system in any facility. This method involves inject primary currents and voltages into CTs and PTs to test associated relays. If a trip is warranted, then the trip signal is sent to the lockout relay in turn tripping the circuit breaker and initiating annunciations and indications. This test method is capable of testing the entire system, with exception of the station service battery. This technique also tests the CT or PT ratios and can be used to verify polarity. Grounding and secondary resistance measurements should be verified in separate tests.

The primary injection technique is the preferred method to provide real assurance that emergency protective actions will take place as required. Recognizing that this technique may be impossible or impractical at some locations, it is acceptable to divide the protection components into subsets and to test each subset separately. For example, the PT and CT circuit could be tested and verified from the transformers to the control board test switches. This would verify proper ratios, phasing, and polarity. The relay then could be tested by injecting currents and voltages at the test switch and verifying the relay trip contact closes. Extreme care should be taken to verify that consistent phasing and polarity be maintained at the test switch between these two tests. Finally, the lockout and breaker circuit could be tested by shorting the trip leads at the relay.

Primary injection testing is performed by injecting primary currents and/or voltages onto the primary windings of the current transformers and potential transformers. A source(s) capable of supplying voltages and currents equal to normal and abnormal operation values should be available. Upon injecting currents and/or voltages, instrument transformers output secondary values to protective relays, annunciators, indicators, and other devices. All components connected to the outputs of the relays are then tested. This also allows the user to test for correct polarity of the system while performing ratio checks on instrument transformers. Depending upon the primary voltage and current values and the need for de-energizing primaries, this method may not be feasible. Extreme care should be taken when performing primary injection testing as high currents and voltages can be hazardous. Only personnel trained, experienced, and qualified should be testing protective relay systems.

Secondary injection testing of protection systems is the method used most often to perform routine maintenance. Secondary testing is accomplished by injecting single-phase or three-phase currents and voltages into the relay or into the current transformer or potential transformer secondary circuits that would emulate the secondary outputs both during normal and abnormal conditions. Each individual component within the protection circuit needs to be tested to ensure correct operation. Secondary voltages typically are 120 volts phase-to-phase, and secondary currents are typically 0–5 amps for timed functions of the relays. Higher currents (20 plus amps) may be required for instantaneous fault trip tests. These values can be obtained using multiple power supplies or a relay test set (also known as a secondary test set). With secondary injection techniques, a clearance of the primary circuit is not normally required, and risks are reduced due to lower required voltages and currents.

The downside to secondary injection testing is that instrument transformers should be tested separately. Extra care must be taken to insure the polarity of the system from the transformer primary to the relay is correctly interconnected. Separate tests need be performed on the instrument transformers circuits to assure the burden is within the transformer specification and to check transformer ratio and polarity.

CONCLUSION

Proper generation and transmission protection system operation relies on a host of critical components such at potential and current transformers, relays, and breakers along with skilled crafts to coordinate, test, and maintain this system. NERC requirements PRC-001-1 and PRC-005-1 requires utilities to ensure coordination of relay settings and development of protection system maintenance and testing programs, including testing intervals. Reclamation has addressed these NERC requirements in the new FIST 3-8 [1] which is available online as a reference for others.

All equipment associated with the protection system and associated wiring should be tested to meet the intent of the NERC standards. This includes, but is not limited to, instrument transformers, protective relays, power-interrupting devices, station service battery and all associated wiring. The protection system should be tested using a primary or a secondary testing scheme. A comprehensive testing procedure will need to be established if the system is tested using secondary injection. A capacity test of the station service battery should be performed to determine the condition of the battery and associated DC circuits should be examined to ensure correct wiring and DC breaker coordination. All individual components and system as a whole needs to be tested to ensure the protection system will operate as designed.

REFERENCES

[1] Bureau of Reclamation, FIST 3-8 "Operation, Maintenance, and Field Test Procedures for Protective Relays and Associated Circuits", http://www.usbr.gov/power/data/fist_pub.html

[2] American National Standards Institute (ANSI)/ Institute of Electrical and Electronics Engineers (**IEEE**®) Standard (Std.) C57.13.3™.

[3] IEEE C57.13.1-1981™, Guide for Field Testing of Relaying Current Transformers

[4] IEEE C57.13-1993™, Standard Requirements for Instrument Transformers.

[5] Bureau of Reclamation, FIST volume 4-1B "Maintenance Scheduling for Electrical Equipment", http://www.usbr.gov/power/data/fist_pub.html

[6] Bureau of Reclamation, FIST volume 3-6 "Storage Batteries Maintenance and Principles", http://www.usbr.gov/power/data/fist_pub.html

[7] DeHaan and Myers, *Protection System Coordination, Testing, and Maintenance to Comply with NERC Requirements,* Doble Client Conference; March 29-April 3, 2009, Boston, MA

APPENDIX A

Maintenance Schedule Tables

TABLE 1
Maintenance Schedule for Relays and Protection Circuits

Maintenance or Test	Required Interval	Reference
Fault/load study and recalculate settings	6 years	Reclamation Recommended Practice NERC Standard PRC-001-1 Approved by ANSI (2007)
Electromechanical relays calibration and functional testing	Upon commissioning, 1 year after commissioning, and every 2 years thereafter After setting changes	NFPA 70B, 9.9.7 and 21.10.3 2006 edition Manufacturer's instructions Reclamation Recommended Practice NERC PRC-005-1
Solid-state relays calibration and functional testing	Upon commissioning, 1 year after commissioning, and every 2 years thereafter After setting changes	NFPA 70B, 9.9.7 and 21.10.3 2006 edition Manufacturer's instructions Reclamation Recommended Practice NERC PRC-005-1
Microprocessor (digital) relays and functional testing	Upon commissioning, 1 year after commissioning, 9 years thereafter. After setting changes	Manufacturer's instructions NERC PRC-005-1 Reclamation Recommended Practice
Microprocessor (digital) relay input and output verification	Upon commissioning, 1 year after commissioning 2 years thereafter After setting changes	Reclamation recommended practice Manufacturer's instructions
Instrument transformer preventive maintenance and testing	As required by the references	Manufacturer's instructions
Instrument transformer ratio measurement	Upon commissioning, 6 years thereafter	Reclamation Recommended Practice
Instrument transformer burden measurements	6 years and before adding or replacing any	Reclamation recommended practice

	device in the secondary	
Instrument transformer secondary circuit integrity testing	6 years and after modifications	Reclamation recommended practice
Instrument transformer secondary grounding and Insulation resistance tests	6 years and after equipment or wiring modifications	NFPA 70B 21.10.3.2 2006 edition, Table H.4.C
Protection circuit functional test, including lockout relays	Immediately upon installation and/or upon any changes in wiring and every 6 years	NFPA 70B 9.4.6.3 2006 edition Manufacturer's instructions Reclamation Recommended Practice NERC PRC-005-1
Check red light lit for lockout relay and circuit breaker coil continuity Note: Some microprocessor relays can continuously monitor lockout and breaker trip coil continuity	Daily[1] (once per shift in manned plants)	Reclamation recommended practice Functional tests required by NFPA 9.4.6.3 2006 edition
Lockout relays cleaning and lubrication (When recommended by the manufacturer). Note: Electroswitch lockouts may not need to be oiled or cleaned	6 years	Reclamation Recommended Practice NFPA 70B 9.4.6.3 2006 edition Manufacturer's instructions.
Protection system communications equipment and channels required for correct operation of protection systems	6 years	Reclamation recommended practice
Drawings associated with relaying and protection current and accurate	Continuously update upon any changes in wiring or control	Reclamation recommended practice

[1] In staffed plants, in conjunction with daily operator control board checks. Otherwise, check each visit to the plant.

TABLE 2
Medium Voltage (601-15 kV Rated) Vacuum Breaker Maintenance Schedule

Maintenance or Test	Required Interval	Reference
Review equipment ratings	5* years	NERC Planning Standard FAC-009-1
Preventive maintenance	Per manufacture's instruction manual	Manufacturer's instruction manual
Record meter readings	Annually	Manufacturer's instruction manuals Western Area Power Administration (WAPA) Standard Maintenance Guidelines, Chapter 13
Record operations counter	Monthly	Manufacturer's instruction manuals
Check foundation, grounds, paint Check external screws, bolts, electrical terminals tight	Annually	Manufacturer's instruction manuals WAPA Standard Maintenance Guidelines, Chapter 13
Contact resistance measurement, motion analyzer, trip test	Per manufacturer's instructions manual	Manufacturer's instruction manuals WAPA Standard Maintenance Guidelines, Chapter 13
Doble test or AC Hipot (including across open contacts[1]) and to ground	5 years	Manufacturer's instruction manuals WAPA Standard Maintenance Guidelines, Chapter 13 NFPA 70B, 8.5.2 Annex Table I.1
Infrared scan and visual inspection, lube, clean, adjust, align control mechanisms	Annually	Manufacturer's instruction manuals WAPA Standard Maintenance Guidelines, Chapter 13

[1] Caution: Refer to manufacturer's instructions regarding safe distances (normally 6 feet or greater) to avoid X-radiation if DC Hipot tests.
* Maintenance interval may be changes to 6 years to better correlate with protection system testing intervals.

TABLE 3
Maintenance Schedule – Flooded, Wet Cell, Lead Acid Batteries

Maintenance or Test	Required Interval	Reference
Visual inspection	Monthly	Reclamation Recommended Practice
Battery float voltage	Shift (charger meter) Monthly overall battery voltage with digital meter compare with charger meter	Reclamation Recommended Practice, Table 1 Record on POM Form 133A
Cell float voltage	Monthly, pilot cells with digital meter Quarterly, all cells	Reclamation Recommended Practice, Table 1 Record on POM Form 133A
Specific gravity	Monthly, pilot cells Quarterly, 10 percent (%) of cells Annually, all cells	Reclamation Recommended Practice, Table 1 Record on POM Form 133A
Temperature	Monthly (pilot cell) Quarterly (10% of all cells)	Reclamation Recommended Practice, Table 1 Record on POM Form 133A
Connection resistance	Annually, all connections	Reclamation Recommended Practice, Table 1 Record on POM Form 134A
Capacity testing	5 years, annually if capacity less than 90%	FIST Volume 3-6 IEEE Std. 450-1995™
Safety equipment inspection	Monthly, test all wash devices and inspect all safety equipment	Reclamation Recommended Practice IEEE Std. 450-1995™
Infrared scan cells and connections	Annually	NFPA 70B 20.17
Battery monitoring system	According to manufacturer's recommendations	Manufacturer's instruction manual