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STANDARDS COMMITTEE

MIDWEST RELIABILITY ORGANIZATION

STANDARD APPLICATION GUIDE

PRC-005-6

VERSION 2.2a

PROTECTION SYSTEM, AUTOMATIC RECLOSING, AND SUDDEN PRESSURE RELAY MAINTENANCE

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Disclaimer

The Midwest Reliability Organization (MRO) Standards Committee (SC) is committed to providing training and non-binding guidance to industry stakeholders regarding existing and emerging Reliability Standards. Any materials, including presentations, were developed through the MRO SC by Subject Matter Experts (SME) from member organizations within the MRO Region.

In 2014, SMEs in the field of Protection System Maintenance and Testing were brought together to prepare a guide for complying with NERC Reliability Standard PRC-005-2 – *Protection System Maintenance*. Participants include representatives from Transmission Operators (TOPs), Generator Operators (GOPs) and Distribution Providers (DPs). The SMEs continued their efforts in order to meet the subsequent versions through PRC-005-6 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.

PRC-005-6 Application Guide – Subject Matter Experts Development Team

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The SMET would also like to acknowledge the contributions of Harvey Veenstra, American Transmission Company. The materials have been reviewed by MRO staff and provide reasonable application guidance for the standard addressed. Ultimately, demonstrating compliance depends on a number of factors including the precise language of the standard, the specific facts and circumstances, and quality of evidence.

Acknowledgement

This publication was developed by a SME Team from MRO member organizations within the MRO footprint. The development of SME Teams is an ongoing effort to produce unified application guides for MRO and its Registered Entities.

The PRC-005-6 SME Team Chair, Joe Livingston (Great River Energy), wishes to acknowledge and thank those who dedicated efforts and contributed significantly to this publication. The MRO, MRO SC, and their organizational affiliations include:

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INTRODUCTION

The intention of this guidance document is to assist entities to meet the requirements of and maintain compliance with NERC Reliability Standard PRC-005-6 – *Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.*

Stakeholders need to understand what is included and excluded from PRC-005-6 as it relates to the Bulk Electric System (BES) definition (effective July 1, 2014). Major changes have been made to the previous PRC-005 Standard, this guidance document will aid in further implementation of the new standard.

Description of each version of PRC-005

Version	Enforcement Date	Description
-1	6/18/2007	Entity develop PSMP with activities and intervals for five component types. Action of protection considered
-2	4/1/2015	NERC defines activities and intervals. Includes UVLS, UFLS, and SPS. Purpose of protection considered
-2i	5/29/15	Aggregate total BES Dispersed power resources > 75 MVA
-2ii	N/A superseded by V6 Implementation	SPS now RAS *
-3	N/A superseded by V6 Implementation	Added Automatic Reclosing
-3i	N/A superseded by V6 Implementation	Aggregate total BES Dispersed power resources > 75 MVA
-3ii	N/A superseded by V6 Implementation	SPS now RAS *
-4	N/A superseded by V6 Implementation	Added Sudden Pressure Relaying
-5	N/A superseded by V6 Implementation	Removal of required maintenance of dispersed generation
-6	1/1/16	Added Supervisory associated with Automatic reclosing. Combine implementation of versions -3, -4, -5, and -6

* Monitor the development of PRC-012-2 which requires that a RAS be functionally tested to verify the proper operation of all non-protection components.

The SME Team provides guidance to stakeholders on how to apply the Standard Requirements and implementation of the Protection System Maintenance Program (PSMP).

The SME Team has also prepared a presentation (see Appendix B) and example documentation from its utilities to provide a Standards Application Guide (SAG) overview to help guide entities on the applicability of BES Facilities to the Standard.

Facilities

Section 4.2 of PRC-005-6 defines the Protection Systems that are subject to the required maintenance activities and intervals.

4.2. Facilities:

> ***4.2.1*** *Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).*
>
> ***4.2.2*** *Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.*
>
> ***4.2.3*** *Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.*
>
> ***4.2.4*** *Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.*
>
> ***4.2.5*** *Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:*
>
> > ***4.2.5.1*** *Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.*
> >
> > ***4.2.5.2*** *Protection Systems for generator step-up transformers for generators that are part of the BES.*
> >
> > ***4.2.5.3*** *Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.*
>
> ***4.2.6*** *Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:*
>
> > ***4.2.6.1*** *Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.*

4.2.7 *Automatic* Reclosing[1], *including:*

4.2.7.1 *Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group*[2].

4.2.7.2 *Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.*

4.2.7.3 *Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.*

Bulk Electric System (BES)

In general, the definition of the BES is *"all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy."*[3]

Using the applicable facilities section of PRC-005-6 and the definition of the BES, the SME Team has analyzed different Protection Systems to determine whether PRC-005-6 is applicable.

Definitions

Automatic Reclosing – *Includes the following components:*

- *Reclosing relay*
- *Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or synch check functions that enable or disable operation of the reclosing relay*
- *Voltage sensing devices associated with the supervisory relay(s) or function(s)*
- *Control circuitry associated with the reclosing relay(s) or function(s)*

[1] *Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.*

[2] *The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.*

[3] See NERC Glossary of Terms for complete definition at page 18.

Protection System[4]:

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

Protection System Maintenance Program (PSMP)[5]:

An ongoing program by which Protection System, Automatic Reclosing Components are kept in working order and proper operation of malfunctioning Components is restored.[6] A maintenance program for a specific Component includes one or more of the following activities:

- *Verify — Determine that the Component is functioning correctly*
- *Monitor — Observe the routine in-service operation of the Component*
- *Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problem*
- *Inspect — Examine for signs of Component failure, reduced performance or degradation*
- *Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement*

Sudden Pressure Relaying – *A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:*

- *Fault Pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure or oil flow that are indicative of Faults within liquid filled, wire-wound equipment*
- *Control circuitry associated with a fault pressure relay*

[4] Id. at page 63.
[5] Id. at page 64-66.
[6] PRC-005-2 does not require any reference to Automatic Reclosing or Sudden Pressure Components be within the PSMP. Automatic Reclosing Components were added in PRC-005-3 (version 3, effective April 1, 2016). Sudden Pressure Components were added in PRC-005-4 (version 4 – pending FERC approval).

Protection Systems

Protection Systems Included R1

1) Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.). (Section 4.2.1 from PRC-005-2).[7]

2) If a protection zone encompasses BES and non-BES elements, the Protection System is covered by PRC-005-2.

All elements in figures 1-11 below (i.e. breakers, lines, buses, transformers. etc.) shown in:

- Blue are considered a BES element
- Green are considered Non-BES elements
- A breaker that does not operate during a fault is displayed as solid box (filled)
- A breaker that fails to operate is designated by an X over the breaker

The zone of protection of each Protection System is shown as:

- A red oval if the Protection System is included within PRC-005-2
- A green oval if the Protection System is excluded within PRC-005-2

The zone of protection of a breaker failure relay is shown as a rectangle around that breaker.

[7] Please note that this would not include out of step tripping or blocking relays.

a) Transformer Protection Systems connected to CT's on a BES-breaker (i.e., ring bus or breaker and a half). This Protection System not only protects the transformer, but also protects a BES-bus and detects Faults on BES Elements (BES-bus). (Figure 1)

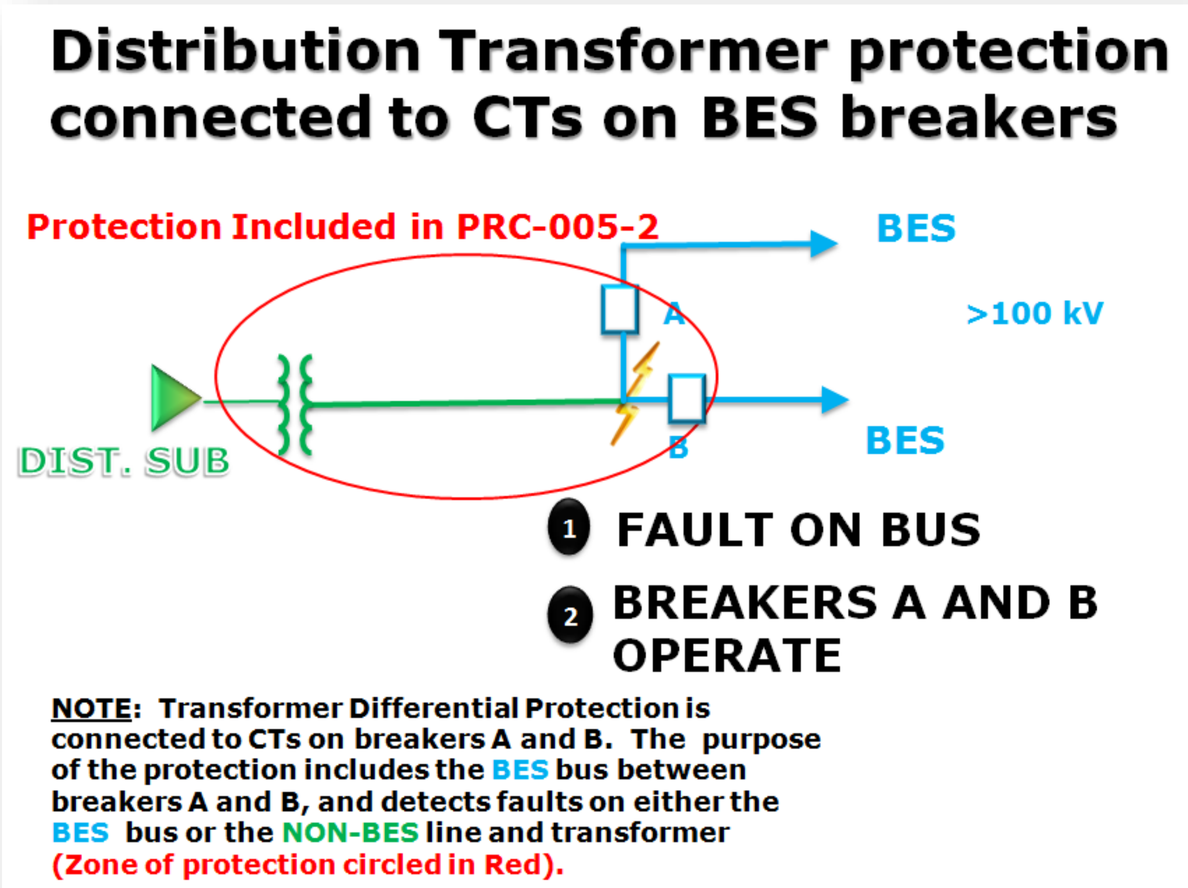

Figure 1.

b) Radial lines directly connected to BES ring bus or breaker and a half bus. (Figure 2)

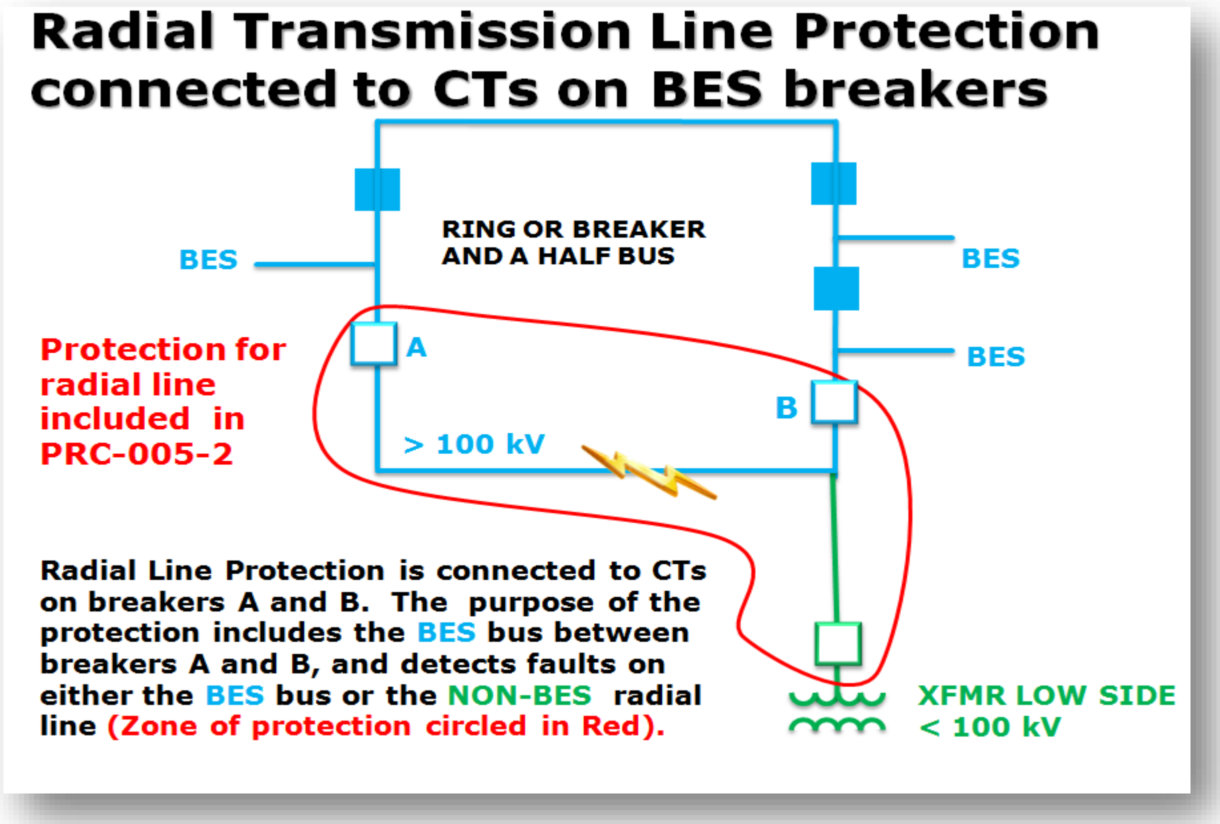

Figure 2.

3) Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays. (PRC-005-2, §4.2.5.4). (Figure 3)

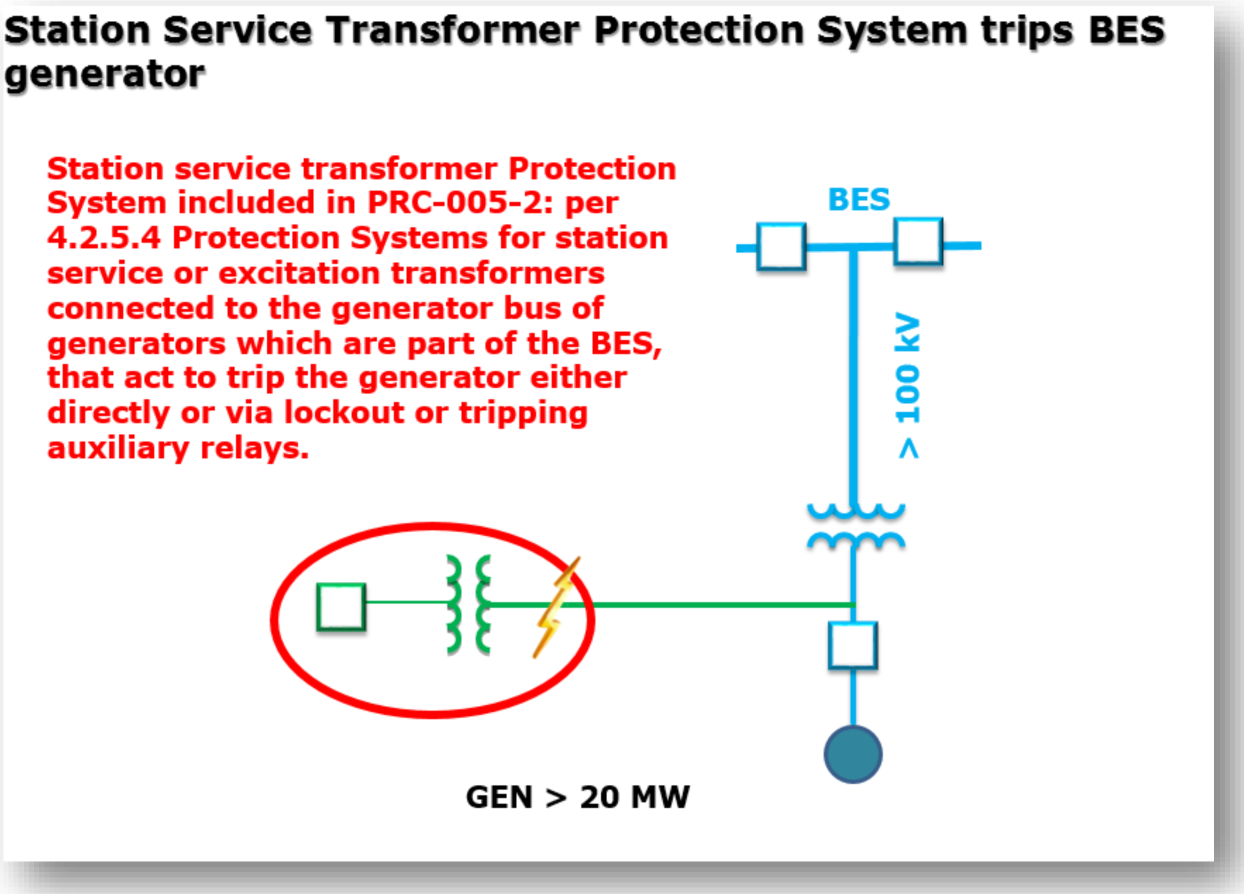

Figure 3.

4) Any breaker failure relay that detects the failure of a breaker that is defined as a BES breaker, or non-BES breaker that trips a single BES generator (Figure 4) or an aggregate of BES generators.

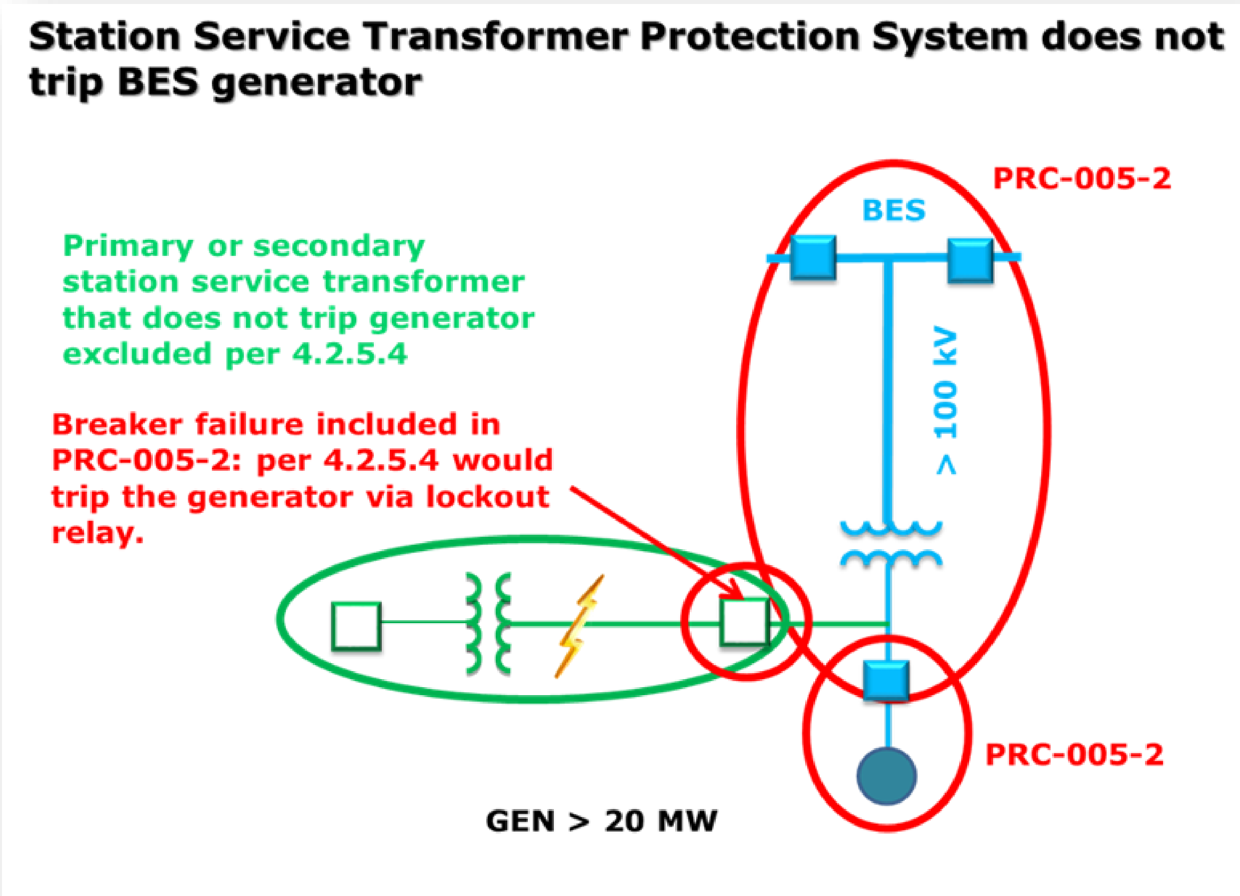

Figure 4.

Exemption for Exclusion

Through the application of the July 1, 2014 definition of the BES and the BES net process, facilities may receive a self-determined exclusion or may have been excluded through the exception process as being a BES asset. A study can be done to exclude the facilities and with that, the associated protection systems (the zone of protection shown as an orange oval see Figure 5). The study to exclude this protection system should determine if power flows in the reverse direction through the transformer into the BES under any scenario or contingency(s), or actual power flow through the transformer is measured and has not flown into the BES. Protection Systems for the excluded facilities are not subject to the application of PRC-005-2.

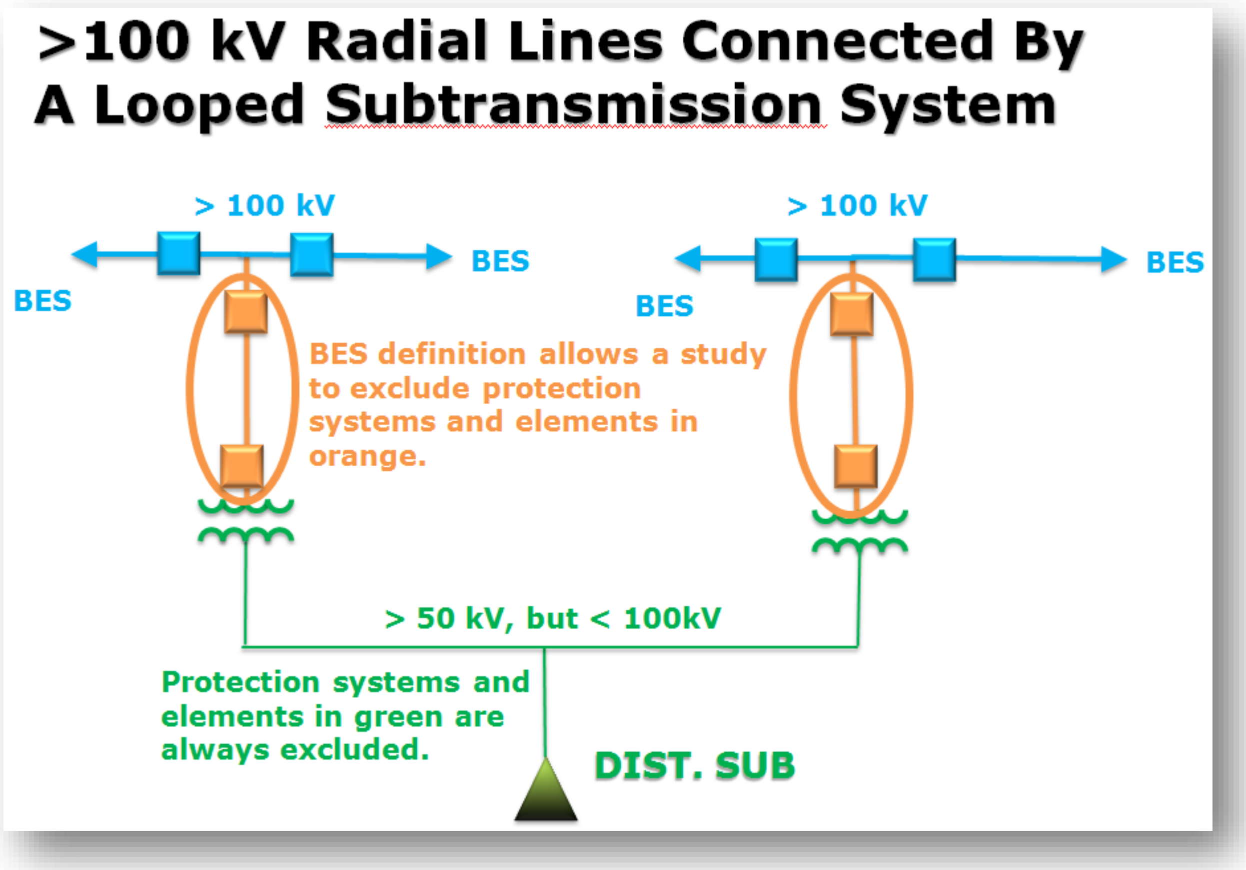

Figure 5.

Protection Systems Excluded

The SMET created four rules that help determine if a protection system is excluded from PRC-005-2. The rules are not all inclusive. However, they are described throughout this section and shown in Figures 6 through Figure 11.

1. If the protection zone covers only non-BES elements, then the protection scheme is not covered by PRC-005-2. (Figures 6 and 7)

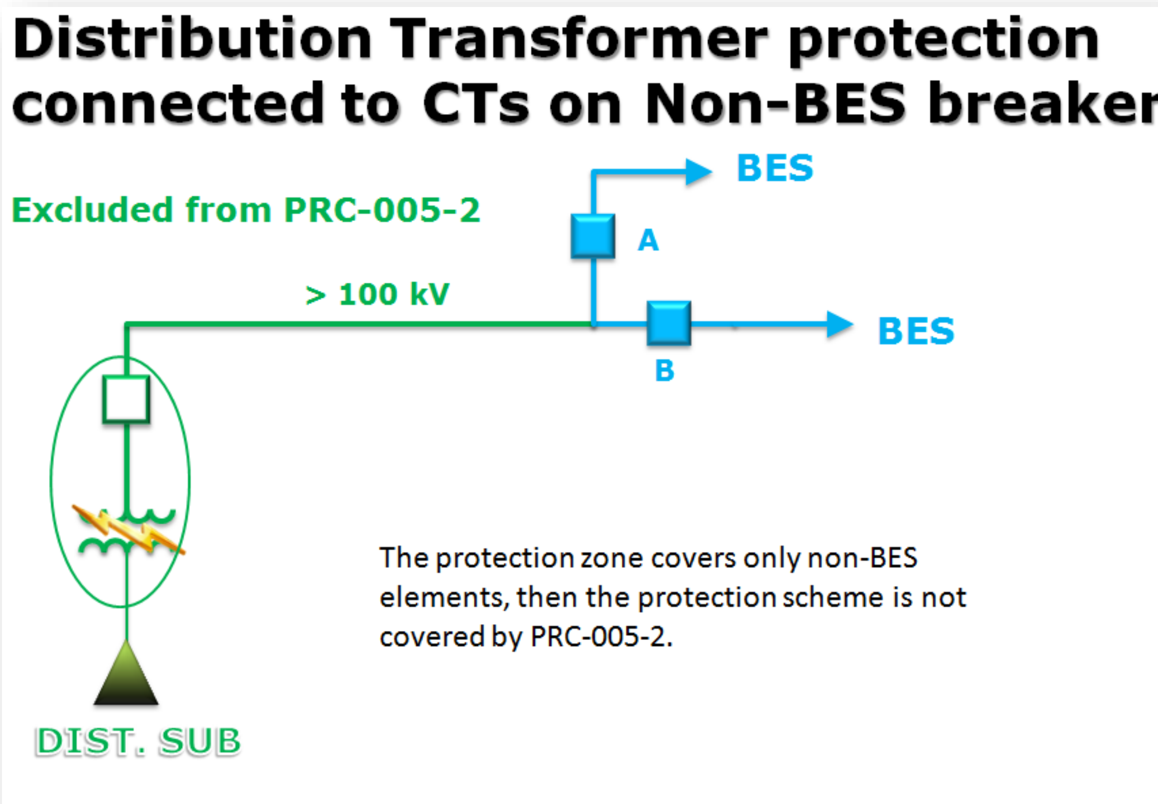

Figure 6.

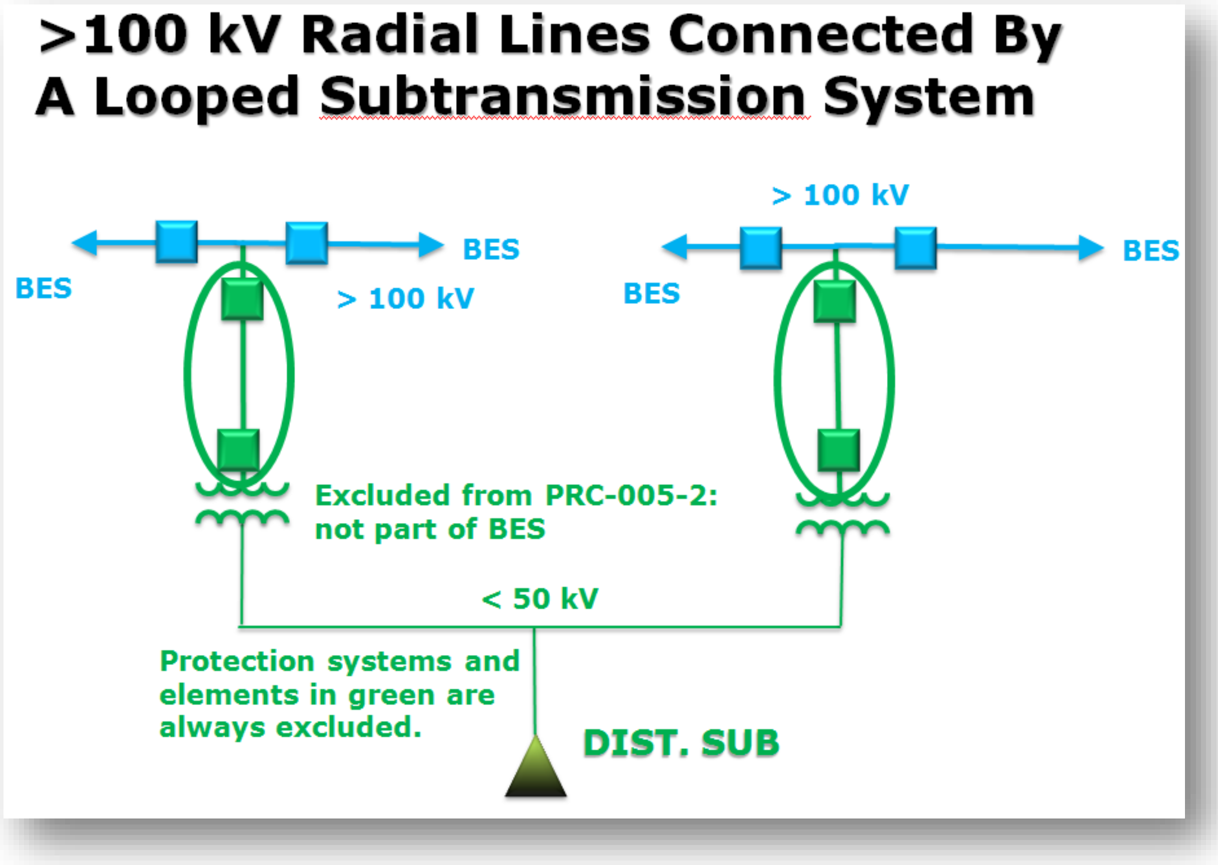
>100 kV Radial Lines Connected By
A Looped Subtransmission System
> 100 kV
BES
BES
> 100 kV
BES
BES
Excluded from PRC-005-2:
not part of BES
< 50 kV
Protection systems and
elements in green are
always excluded.
DIST. SUB

Figure 7.

2. Any breaker failure relay that detects the failure of a non-BES breaker is excluded, unless that breaker failure relay trips a BES generator. (i.e., the high-side or low-side breaker of a non-BES transformer connected to a BES bus.) Even though this relay may detect Faults on BES Elements (the BES bus), the purpose of the relay is to detect current flowing through the failed non-BES breaker. (Figures 8 and 9)

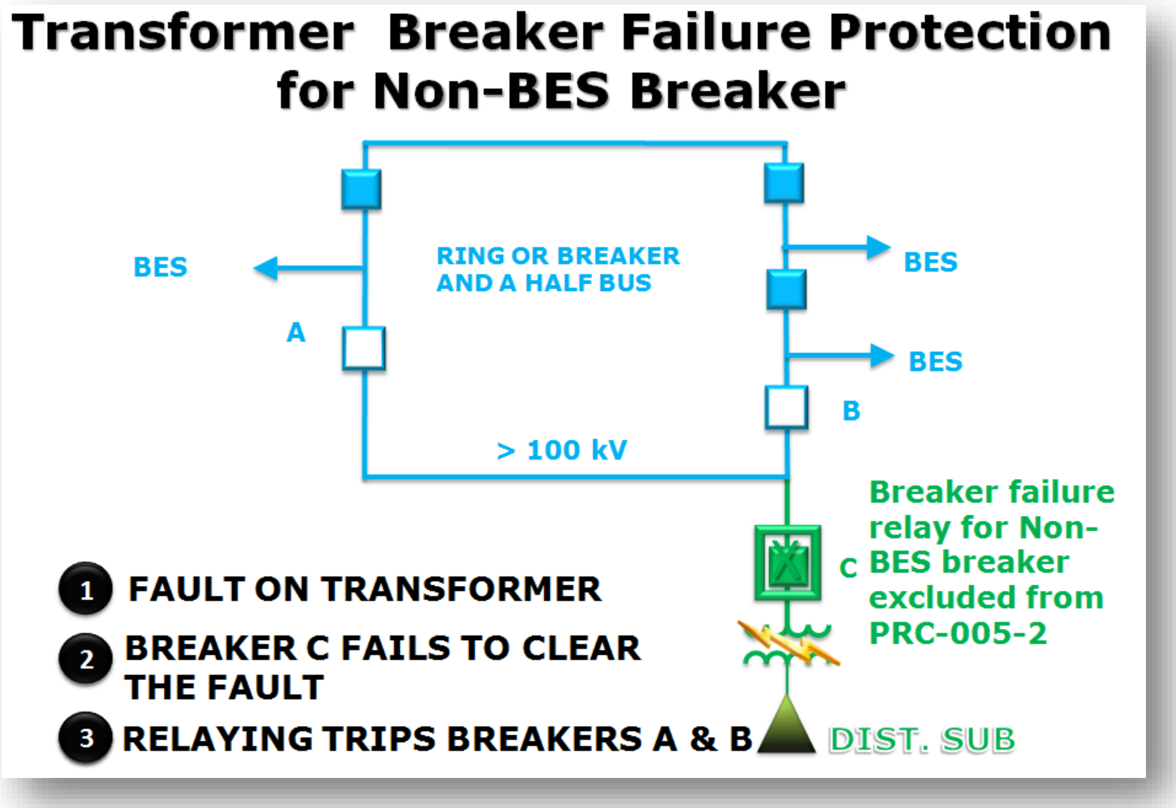

Figure 8.

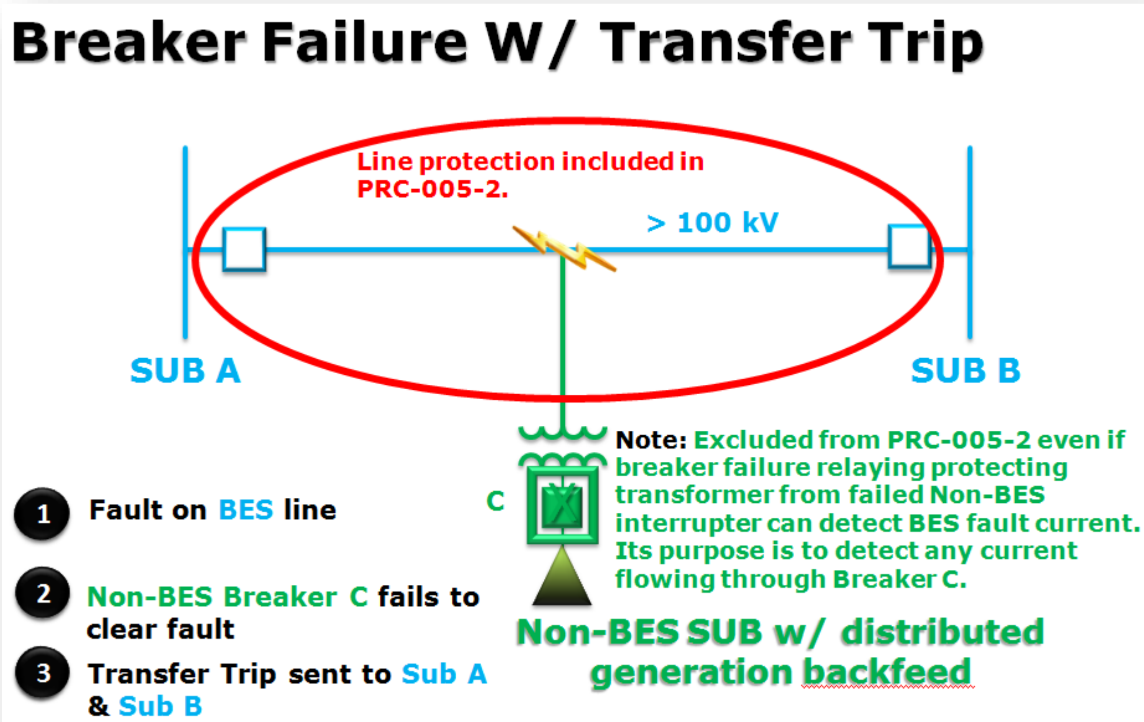
Breaker Failure W/ Transfer Trip
Line protection included in PRC-005-2.
> 100 kV
SUB A
SUB B
Note: Excluded from PRC-005-2 even if breaker failure relaying protecting transformer from failed Non-BES interrupter can detect BES fault current. Its purpose is to detect any current flowing through Breaker C.
C
1 Fault on BES line
2 Non-BES Breaker C fails to clear fault
3 Transfer Trip sent to Sub A & Sub B
Non-BES SUB w/ distributed generation backfeed

Figure 9.

3. Any Protection System installed for the purpose of detecting Faults on only non-BES Elements regardless of the actions of that Protection System opening or disconnecting a BES element. (Figures 10 and 11)

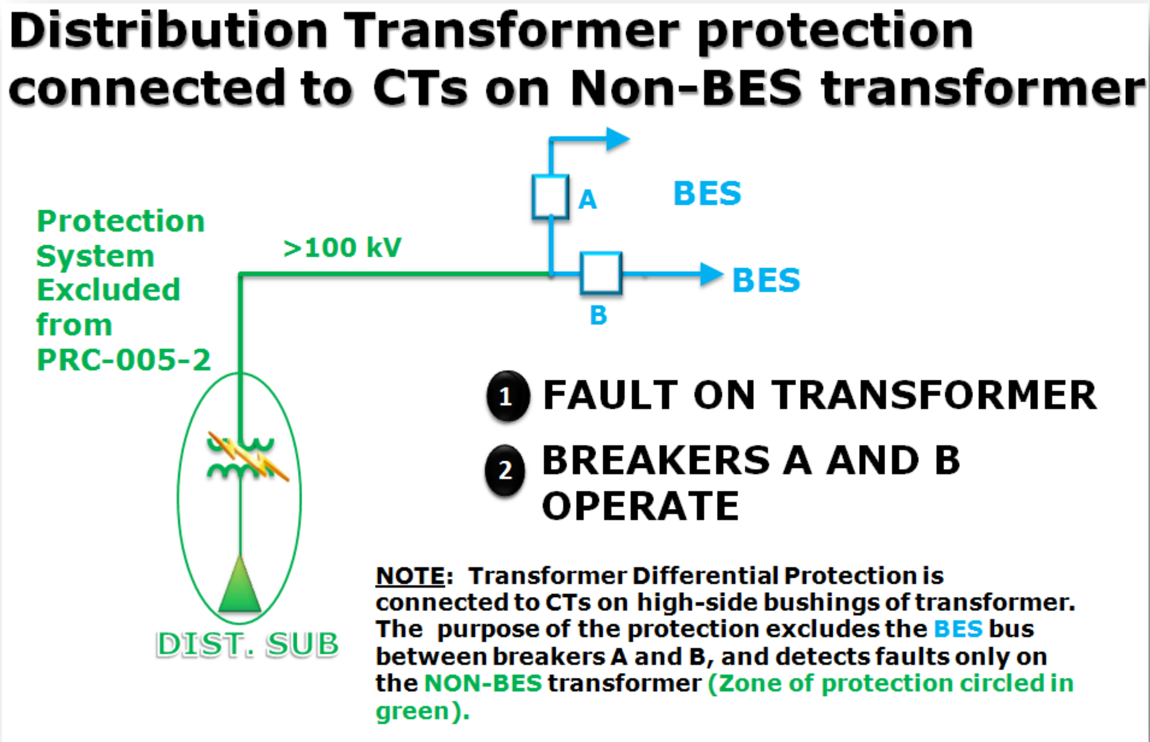

Figure 10.

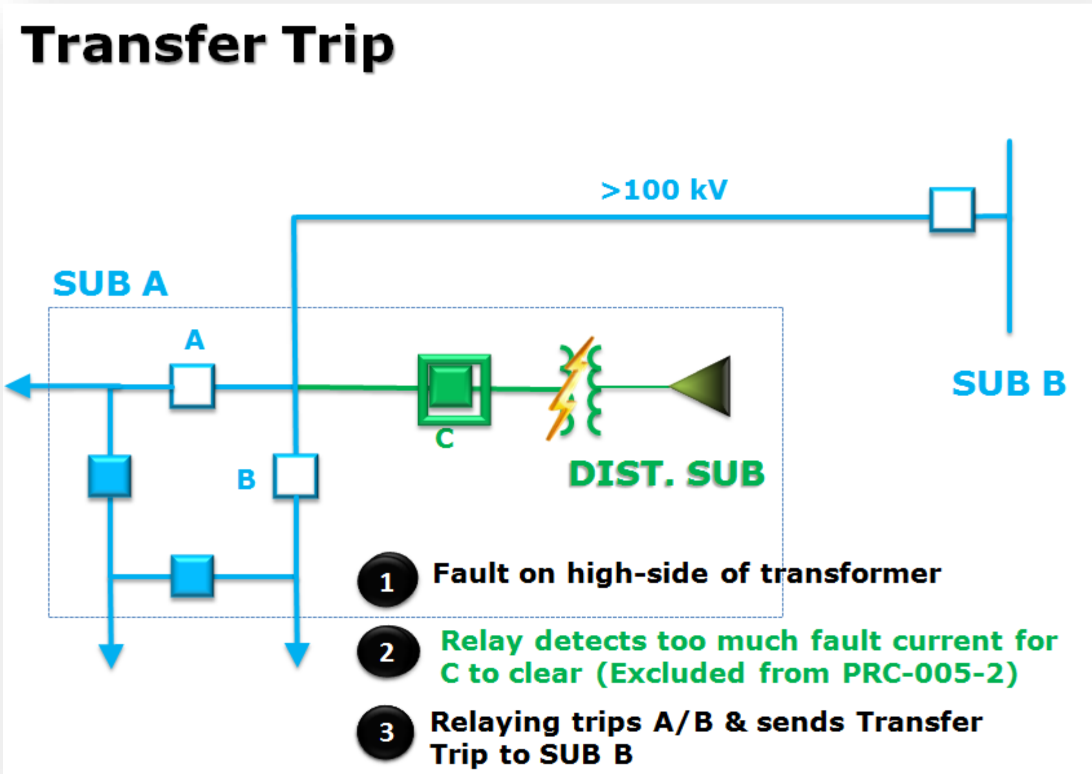

Figure 11[8]

4. A control system that acts to trip the generator is excluded from PRC-005-2. A control system is not considered a Protection System and it does not detect BES faults.

[8] The transfer trip communications to Substation B (Figure 11) would most likely be initiated by the detected failure of either BES breaker A or B and therefore would be included in PRC-005-2.

Protection Systems Maintenance Activities

Unresolved Maintenance Issue (Requirement R5)

Deficiencies identified during a maintenance activity that cause the component to not meet the intended performance, and cannot be corrected during the maintenance interval, require initiation of a follow-up corrective action. The requirement does not state how quickly a corrective action for unresolved maintenance issues needs to be resolved. A catastrophic failure may require more multiple maintenance intervals to resolve a maintenance issue (i.e., a fire, flood, or hurricane will take more than the four-month interval required for the battery maintenance). Replacing a failed electromechanical relay with a new panel of microprocessor relays may take three to four years due to budgeting, design, procurement, and scheduling outage for installation.

Once the corrective actions have been completed, the maintenance records shall be updated to reflect the successful results. Documentation of unresolved maintenance issues may include but is not limited to corrective work order, email requesting budget approval, email stating project budget approved, project work orders, replacement component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs), or purchase orders.

Failed Element Tests

Each element may have multiple types of documentation methods available to validate the completion of maintenance activities. Any time a check box is used as documentation a step or process was completed, procedural documents must be available in order to validate the significance of the check box. Any element that receives a “fail” check mark must be resolved and documented prior to the end of the maintenance interval, otherwise, the element shall be addressed as an unresolved maintenance issue (R5).

Data Retention

Data retention has been reduced from the two most recent performances to only the most recent performance in those cases where the interval of the maintenance activity is longer than the audit cycle.[9]

However, NERC Reliability Standard PRC-005-1.1b only requires that the Protection System owner shall retain evidence of the implementation of its PSMP for three years. A Protection System owner may have a longer data retention period within its PRC-005-1.b PSMP, and therefore, may require documentation for implementation prior to April 4, 2012. Keep the most recent performance of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the

[9] For elements which have been removed from service, entities shall retain maintenance records for those elements for the current audit period as described above which may pre-date the prior audit. The minimum requirement for commissioning records of the replacement element is documentation of the dates of the tests under this standard.

previous scheduled audit date, whichever is longer, dating back to June 18, 2007 (date PRC-005 initially was enforceable).

Protective Relay Maintenance Activities (Table 1-1 and Table 2)

Acceptable documentation to verify that settings are as specified

- A check box stating the relay settings were verified
- Pass/Fail relays setting verification stated in relay test report

The settings within the relay are compared to specified settings within corporate records. Microprocessor settings could be verified locally or remotely.

<u>For non-microprocessor relays</u>:

Acceptable documentation to verify relays were tested and, if necessary calibrated

- Relay test report
  - Date
  - Relay identification
  - Tester ID (not required, but is a good control)
  - Test results proving the test was performed (lock-out relay (LOR) and auxiliary relays are tested per Table 1-5 for Control Circuitry)
  - Pass/Fail-is auditor friendly but not required
- Relay calibration is not required to be documented, but this may be helpful for asset renewal

Electro Mechanical Relay.pdf

<u>For microprocessor relays:</u>

Acceptable documentation to verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System, and verification that the alarm path conveys alarm signals to a location where corrective action can be initiated (Table 2).[10]

- Relay test report
  - Date
  - Relay Identification
  - Tester ID (not required, but is a good control)
- A check box stating the essential relay outputs/inputs were verified
- Pass/Fail essential relay outputs/inputs verification stated in relay test report
- A check box stating the relay monitoring alarms were verified
- Pass/Fail essential relay monitoring alarm verification stated in relay test report

[10] Verify the actual operation of the output contact (i.e. test continuity at test switch, trip LOR, or trip breaker). Viewing an event report does not confirm the output actually closed; it only proves the logic to actuate the output picked up. Inputs can be confirmed via event reports.

The requirement to verify the proper functioning of an analog to digital (AD) converter within a microprocessor relay can be satisfied by any of the following documentation:

1. A check box stating during the CT/PT testing, if there is another CT/PT value to be compared to. (i.e., if you compare the energized system metered values within the primary relay to the secondary relay. This would satisfy both your AD converter testing and PT/CT testing.)
2. A check box stating currents or voltages measured by an independent meter were accurately measured within the relay.
3. A check box stating known currents or voltages were injected from a test set and verified to be accurately measured within the relay.
4. A test report showing known currents or voltages were injected from a test set and verified to be accurately measured within the relay.

Microprocessor Relay.pdf

Communication Systems Maintenance Activities (Table 1-2 and Table 2)

Required maintenance activities for Communication Systems (from Table 1-2):

1) Verify that the communications system is functional, by verifying a signal initiated at the sending end results in correct receiver output at the remote end

2) Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System

3) Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated (Table 2)

Acceptable documentation for the Communication Systems maintenance activities above (Examples are not all inclusive, but any would be acceptable):

- Test report
    - Date
    - Communication system identification
    - Tester ID (not required, but is a good control)
- A check box stating the verification of the required maintenance activity of Communication Systems
- Pass/Fail stated in Communication Systems test report

  (Or)
- Highlighted schematics or one-lines

Acceptable documentation for the Communication Systems maintenance activities: Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).[11]

- Communication test report
  - Date
  - Communication equipment identification or associated relay identification
  - Tester ID (not required, but is a good control)
- Check box stating transmitted/received levels were adequate or record transmitted/received levels (for power line carrier, tone, and microwave only). Not applicable to digital
- Check box stating reflective power was adequate or record Reflective power levels (for power line carrier, tone, and microwave only). Not applicable to digital
- Record propagation and/or data error rate (for fiber/digital only), unless monitored
- Pass/Fail-is auditor friendly but not required

- Communication System calibration is not required to be documented, but this may be helpful for asset renewal[12]

Communication Fiber.pdf | Communication Carrier.pdf | Communication Carrier Managemen | Communication Relays Test Procedu

Voltage and Current Sensing Devices Providing Inputs to Protective Relays Maintenance Activities- (Table 1-3)

Acceptable Maintenance Activities for online CT/PT Testing:

Acceptable documentation to verify that current and voltage signal values are provided to the protective relays. (Examples are not all inclusive, but any would be acceptable.)

- CT/PT test report
  - Date
  - CT/PT identification
  - Tester ID (not required, but is a good control)
- A check box stating "*Verify current and voltage signal are received*"
- A meter command from a microprocessor printout

[11] A check box stating a time synched end-to-end test done during preventative maintenance is acceptable documentation. However, this would typically be done during commissioning, after a scheme has been modified, after a change of power line carrier frequency, when a new component essential to the communication scheme is installed or modified, or a misoperation due to poor communication coordination. A time synched end-to-end is not required during preventative maintenance activities within PRC-005-2.

[12] SCADA points list or operator screen shot would be acceptable documentation of monitoring.

- Pass/Fail verify that current and voltage signal values are provided to the protective relays stated in test report
- Measured current or voltage values recorded

<u>Acceptable Maintenance Activities for offline CT/PT Testing:</u>

Some PT/CT's for generators, reactors, or capacitors cannot be energized during testing. If the applicable entity has a microprocessor protecting the element (generator, reactor, or capacitor), an event report can be triggered when the element is energized. Then the event report can be saved as documentation of CT/PT testing. If the element has not been energized and therefore hasn't created an event report (i.e., large capacitors that are prevented from being in service due to system conditions), then the applicable entity must:

- CT/PT test report
  - Date
  - CT/PT identification
  - Tester ID (not required, but is a good control)
- Verify the signal values (voltage or current) are provided from the CT/PT primary to the relay inputs. Testing Methods: (Test 1, test 2, or test 3 are acceptable examples but are not all inclusive).

<u>(Test1)</u>

- Inject current or voltage on primary of CT/PT and confirm signal values reach the inputs of the relay(s).

<u>Or</u>

<u>(Test 2)</u>

- Inject current or voltage at the relay terminal and confirm signal values reach the secondary of CT/PT (i.e. lamp test).

<u>And</u>

- Any test that would confirm a voltage or current applied to the primary will reach the secondary of the voltage or current sensing device as expected.[13]

<u>Or</u>

<u>(Test 3)</u>

- Using a test set inject current or voltage at the secondary of CT/PT and confirm signal values reach the inputs of the relay(s).

<u>And</u>

- Any test that would confirm a voltage or current applied to the primary will reach the secondary of the voltage or current sensing device as expected.

[13] An acceptable test but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data.

In summary as stated in the NERC Supplementary Reference and FAQ PRC-005-3: *If online testing is deemed too risky, offline tests, such as, but not limited to, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately "verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" while eliminating the risk of tripping an in service generator or transformer. Similarly, this same offline test methodology can be used to verify the relay input voltage and current signals to relays when there are no other instrument transformers monitoring available for purposes of signal comparison.*

CT/PT Test Results for voltages or currents expected to be close to 0[14]:

- CT/PT test report
  - Date
  - CT/PT identification
  - Tester ID (not required, but is a good control)
- Measure voltage induced on operating circuit quantities should appear equal to or close to 0, and verify all CT's are carrying load.
  Or
- Test against the presence of a short circuit CT, and verify all CT's are carrying load.

Current differential relays with parallel CT connections:

- CT test report
  - Date
  - CT identification
  - Tester ID (not required, but is a good control)
- Measure operating circuit quantities should appear equal to or close to 0, and verify all CT's are carrying load.

  Or
- Test against the presence of a short circuit CT, and verify all CT's are carrying load.

Line Protection neutral currents.

- Circuit report
  - Date
  - Circuit identification
  - Tester ID (not required, but is a good control)
- Measure 3IO and 3VO quantities should appear equal to or close to 0, and verify all CT's are carrying load. Typically transmission systems are not perfectly balanced and some very small value (i.e., 0.01 A) should be measured.

[14] High impedance differential relays (i.e., PVD, SBD, SEL-587Z) with parallel CT connections:

Voltage and Current.pdf

Protection System Station DC Supply Maintenance Activities (Table 1-4(a) through Table 1-4(f))

All required battery maintenance activities and documentation are fairly straight forward.

Protection System owners can verify that the station battery can perform as manufactured by performing periodic internal ohmic measurements, float current, float voltage, temperature, specific gravity, or combinations of these tests on station batteries, OR the users may elect to perform capacity tests. It is the owner's responsibility to validate a baseline from new on every make/model/type of battery. Going forward the owner must maintain a documented process using the chosen testing parameters and methodology that determines where the battery cannot perform as manufactured.

In order to verify battery continuity, you could turn off the battery charger, and clamp onto the battery load terminals and verify current is flowing to station DC load. This can be documented by either a check box or pass/fail of battery continuity verified.

Table 1-4(e) requires the DC Voltage to be measured for an unmonitored SPS tripping non-BES breakers, non-distributed UFLS systems, or non-distributed UVLS systems every 12 calendar years. This can be documented by either a check box or pass/fail of DC voltage verified, or the recording of the measured value.

Table 1-4(f) does enable exclusions from maintenance activities for monitored Station DC supplies.

4 Month Battery Inspection.pdf   18 Month Battery Test.pdf   battery 18 month.pdf   Battery 6 Year.pdf

Control Circuitry Associated With Protective Functions Maintenance Activities (Table 1-5)

Acceptable documentation for all maintenance activities of Control Circuitry (examples are not all inclusive, but any would be acceptable):

- Circuit test report
  - Date
  - Circuit identification
  - Tester ID (not required, but is a good control)
- A check box stating the verification of any required maintenance activity of Control Circuitry

- Pass/Fail stated in Control Circuitry test report
- Highlighted schematics or one-lines
- A detailed list of each trip path for a breaker, auxiliary relay, or LOR that is signed and dated

For lockout testing PRC-005-2 requires a functional trip. As an example, a test using a relay output and station battery DC to trip the LOR is adequate.[15]

DC Control Ck A.pdf

DC Control Ck B.pdf

Maintenance Activities for UFLS and UVLS Systems

Distributed UFLS/UVLS Systems are systems at one substation (distribution substations, non-BES or BES substations) that operate more than one interrupting device with an individual or multiple relays at that substation, or one device that sends a signal to operate multiple interrupting devices at multiple substations.[16]

After thorough review of UFLS/UVLS activities in PRC-005-2 Tables, the SME Team has determined there is no difference between the maintenance activities of a distributed or non-distributed UFLS/UVLS system.

UFLS/UVLS Relay:
Acceptable documentation to verify that settings are as specified

- UFLS/UVLS relay test report
    - Date
    - UFLS/UVLS relay identification
    - Tester ID (not required, but is a good control)
- A check box stating the relay settings were verified
- Pass/Fail relays setting verification stated in relay test report

For non-microprocessor relays:
Acceptable documentation to verify tested and, if necessary calibrate

- Relay test report
    - Date
    - UFLS/UVLS relay identification
    - Tester ID (not required, but is a good control)

[15] Any breaker that is determined to be non-BES does not have to be tripped, even if it is tripped by a BES protective relay or UFLS/UVLS relay that is considered included within PRC-005-2. Per Supplementary reference and FAQ Section 15.3

[16] If the UFLS/UVLS is non-distributed you must follow maintenance activities and intervals in Tables 1-1 through 1-3, Table 1-4(e), and Table 1-5. If the UFLS/UVLS is distributed you must follow maintenance activities and intervals in Tables 3.

- Pass/Fail-is auditor friendly but not required
- Relay calibration is not required to be documented, but this may be helpful for asset renewal

For microprocessor relays:
Acceptable documentation to verify operation of the relay inputs and outputs that are essential to proper functioning of the UFLS or UVLS, and verification that the alarm path conveys alarm signals to a location where corrective action can be initiated (Table 2).

- Relay test report
  - Date
  - UFLS/UVLS relay identification
  - Tester ID (not required, but is a good control)
- A check box stating the essential relay outputs/inputs were verified
- Pass/Fail essential relay outputs/inputs verification stated in relay test report
- A check box stating the relay monitoring alarms were verified
- Pass/Fail essential relay monitoring alarm verification stated in relay test report

The requirement to verify the proper functioning of an AD converter within a microprocessor relay can be satisfied by any of the following documentation:

1. A check box stating during the CT/PT testing, if there is another CT/PT value to be compared to. (i.e., if you compare the energized system metered values within the primary relay to the secondary relay. This would satisfy both your AD convertor testing and PT/CT testing.)
2. A check box stating currents or voltages measured by an independent meter was accurately measured within the relay.
3. A check box stating known currents or voltages was injected from a test set and verified to be accurately measured within the relay.
4. A test report showing known currents or voltages was injected from a test set and verified to be accurately measured within the relay.

Under Frequency Load Shedding (UFL

UFLS A.pdf

UFLS/UVLS Associated Communication Equipment:

For distributed UFLS/UVLS there is no required maintenance. For non-distributed UFLS/UVLS associated communication equipment most likely does not exist.

UFLS/UVLS Voltage sensing device:

Acceptable documentation to verify that voltage signal value is provided to the UFLS/UVLS relays. (Examples are not all inclusive, but any would be acceptable.)

- UFLS/UVLS voltage sensing device test report
  - Date
  - UFLS/UVLS voltage sensing device identification
  - Tester ID (not required, but is a good control)
- A check box verifying that voltage signal value is provided to the UFLS/UVLS relay
- A meter command from a microprocessor printout
- Pass/Fail verify that voltage signal value is provided to the UFLS/UVLS relays stated in test report
- Measured UFLS/UVLS voltage value recorded

UFLS/UVLS DC Supply:

The DC Voltage is to be verified at the output(s) that trips the interrupting device(s) for a UFLS/UVLS system. This can be documented by either a check box or pass/fail of DC voltage verified, or the recording of the measured value. The maximum maintenance interval for this is 12 calendar years. [17]

UFLS/UVLS Control Circuitry

UFLS/UVLS control circuitry which includes:[18]

1. Path from relay to LOR and/or auxiliary relay and essential supervisory logic
2. Electrical operation of electromechanical lockout and/or auxiliary relay

Acceptable documentation for all maintenance activities of UFLS/UVLS control circuitry (Examples are not all inclusive, but any would be acceptable):

- UVFLS/UVLS control circuitry test report
  - Date
  - UFLS/UVLS circuit identification
  - Tester ID (not required, but is a good control)
- A check box stating the verification of UFLS/UVLS control circuitry
- Pass/Fail stated in UFLS/UVLS control circuitry test report
- Highlighted schematics or one-lines[19]

[17] For UFLS/UVLS DC Supply that is monitored the DC voltage must be verified as described above every 12 years.
[18] A majority of distributed UFLS/UVLS relays will directly trip the trip coil of the non-BES breaker. There is no required maintenance for UFLS/UVLS control circuitry in this case.
[19] Any breaker that is determined to be non-BES does not have to be tripped, even if it is tripped by a BES protective relay or UFLS/UVLS relay that is considered included within PRC-005-2. (Per Supplementary reference and FAQ Section 15.3.1)

Automatic Reclosing

Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) still meets the critical clearing time for the generation. If both the trip-close-trip time delay and breaker failure time delay are shorter than critical clearing time, maintenance requirement for Automatic Reclosing can then be excluded.

The largest BES generating unit within the BAA or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

As an example, the largest generator in a BAA is 1550 MW. It is a nuclear plant and there is no retirement information available at this time for unit. Therefore, any Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the 1550 MW (the largest BES generating unit within the BAA for those companies within the BAA.

Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate one of the below:

1) Two buses away from generating plant where the total installed gross generating plant capacity is greater than the 1550 MW, regardless of the circuit miles.
2) Synchronizing relays for breakers without auto reclosing relays.
3) A close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of greater than 1554 MW generation. The trip-close-trip time delay should be less than breaker failure time delay. The breaker failure time delay should be less than the critical clearing time for stability. If both the trip-close-trip time delay and breaker failure time delay are shorter than critical clearing time, then maintenance requirements for Automatic Reclosing can be excluded.

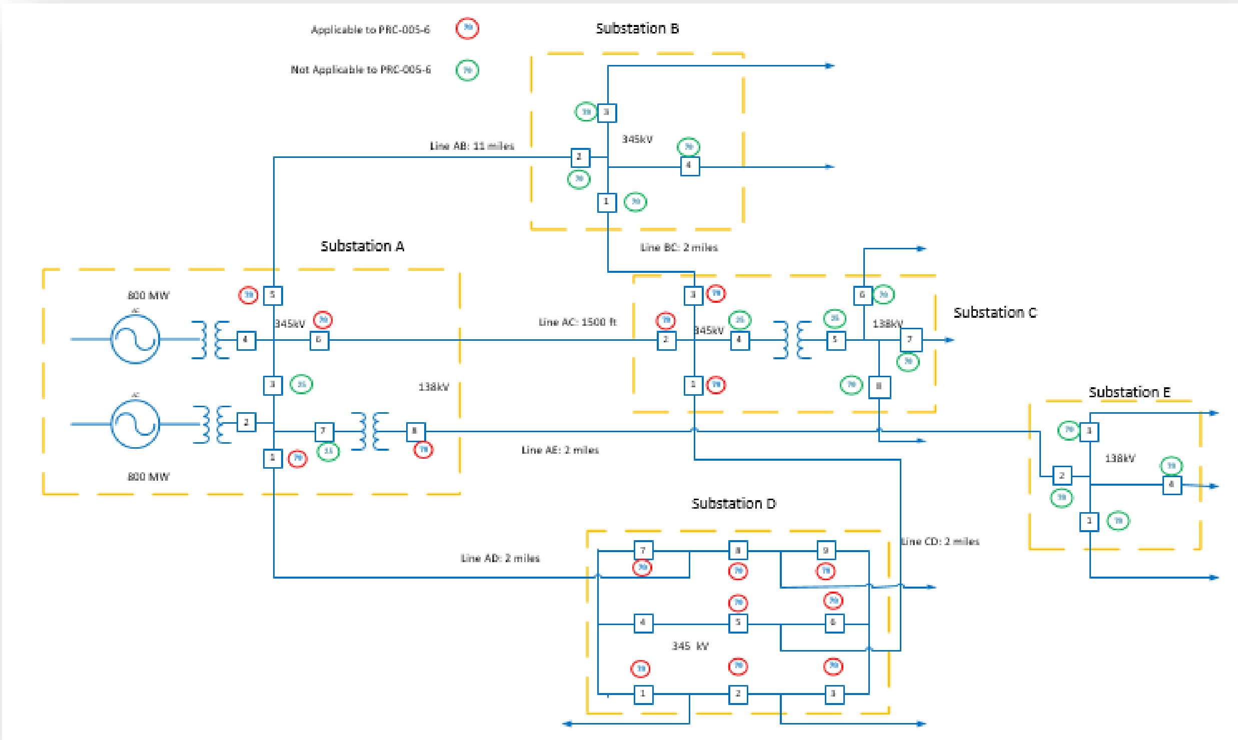

Figure 12[20]

Substation A:
In Figure 12 above, the gross capacity of the generation plant at Substation A is larger than the largest generator within the MISO's BAA, therefore all Automatic Reclosing at substation A is included within PRC-005-6. The sync check relays on breakers A3 and A7 are excluded since these breakers do not have Automatic Reclosing.

Substation B:
All Automatic Reclosing at Substation B is excluded because Line AB is greater than 10 circuit-miles. Substation B is within 10 circuit-miles from the 345 kV bus at Substation A if you add the lengths of Line AC and Line BC, but Substation B is two buses away looking at that circuit route.

Substation C:
All Automatic Reclosing at Substation C applied on the 345 kV breakers is included within since the 345kV bus is one bus away and within 10 circuit-miles of the 345 kV bus at Substation A. The sync check relay on breaker C4 is excluded since it is not associated with Automatic Reclosing. All Automatic Reclosing at Substation C on the 138 kV bus is excluded since the 138kV bus is two buses away from the 345 kV bus at Substation A.

Substation D:

[20] Each substation has its own ground grid and therefore is considered a separate bus. Each Automatic Reclosing system is shown as 79, but also includes supervisory relays (i.e. 25, 27, and 59).

All Automatic Reclosing at Substation D applied on the 345 kV breakers is included within since the 345kV bus is one bus away and within 10 circuit-miles of the 345 kV bus at Substation A. The SME Team has determined that a straight bus, ring bus, or breaker and half bus configuration is considered one bus.

Substation E:

Even though substation E is within 10 circuit-miles of Substation A, all Automatic Reclosing at Substation E is excluded because Substation E is two buses away from the 345 kV bus at Substation A.

Maintenance Activities for Automatic Reclosing (Table 4-1, 4-2a and 2b, and 4-3)

Reclosing Relay and Supervisory Relay (Table 4-1)

Reclosing Relay and Supervisory Relay maintenance activities are described in Table 4-1. All maintenance activities and documentation are the same as the protective relays. See Protective Relay Maintenance Activities (Table 1-1 and Table 2) section of the document.

Section 15.8.1 of Frequently Asked Questions (FAQ) lists the supervisory relays that may be applicable (i.e. IEEE device 25, 27, and 59 relays associated with a 79).

Automatic Reclosing Control Circuitry not integral part of RAS (Table 4-2a)

Microprocessor:

1. Confirm that the reclosing relay contact is open when that reclosing relay output logic is deactivated.[21]

Electromechanical:

1. Confirm that the reclosing relay contact is open when that reclosing relay is deactivated.
2. Initiate a reclose and verify that the Automatic Reclosing does not issue a premature closing command to the close circuitry.

Automatic Reclosing Control Circuitry for RAS schemes only (Table 4-2b)

Automatic Reclosing within a RAS (Table 4-2b):

1. A check box stating the verification of all Control Circuitry.
2. A check box stating each close coil or actuator is able to operate the circuit breaker or mitigating device.

[21] The supervisory relay will not cause a premature closing command to the close circuitry.

Automatic Reclosing Voltage Sensing Device (Table 4-3)

Automatic Reclosing Voltage Sensing Device_maintenance activities are described in Table 4-3. All maintenance activities and documentation are the same as the protective relays voltage sensing devices. See Voltage and Current Sensing Devices providing inputs to Protective Relays (Table 1-3) section of the document.

Section 15.8.1 of Frequently Asked Questions (FAQ) lists the supervisory relays that may be applicable (i.e. IEEE device 25, 27, and 59 relays associated with a 79).

Maintenance Activities for Sudden Pressure Relaying (Table 5)

Fault pressure relay:

1. Check box stating verified the pressure or flow sensing mechanism is operable with a go/no go test. [22]

- Westinghouse SPR- remove plug to actuate device per Westinghouse test procedure
- Bucholtz relay-push button to actuate the device.
- Qualitrol Sudden Pressure Relief (SPR) – use Qualitrol test kit (hand pump and pressure gage) to actuate device.
- Qualitrol Fault Pressure Relief (FPR) – reach in flip switch to actuate device, then manually reset.
- Qualitrol Rapid Pressure Rise relay (RPR) – use Qualitrol test kit (hand pump and pressure gage) to actuate.
- ABB Gas Detector Relay (GDR) – use pump to actuate device per ABB test procedure.

Note: No need to remove device from transformer from testing/maintenance. Some entities only alarm for the operation of the devices listed above, maintenance of devices listed above not required if device does not trip breakers.

Sudden Pressure Relaying Control Circuitry and LOR:

2. All maintenance activities and documentation are the same as Control Circuitry Associated with Protective Functions Maintenance Activities (Table 1-5). See Control Circuitry Associated with Protective Functions Maintenance Activities (Table 1-5) section of this document.

Performance-Based Maintenance (Attachment A of PRC-005-6)

To establish performance-based maintenance (PBM):

[22] Section 15.9.1 of FAQ Fault pressure relay may include Bucholtz relay, Westinghouse SPR, and/or Qualitrol RPR.

1. Determine the population of components in segment. Make sure that population exceeds 60.
2. Maintain per Tables 1-1 through 1-5 and Table 3 (i.e., table 1-5 for breaker trip coils or LORs - 6 years) until maintenance activity results are available for 30 components.
3. Document maintenance activities including maintenance dates and countable events.
    a. Countable event-failure requiring repair or replacement during maintenance
    b. Countable event-Misoperation due to hardware or calibration failure (i.e., for breakers: only hardware failure applies to trip coils)
4. Analyze program to determine performance.
5. Analyze countable events not to exceed 4%, for the greater of either last 30 maintained or all maintained in last year.

Assessment for confirming establishing PBM: (only required for the initial establishment of PBM program)

1. Request population size; must be greater than 60.
2. Confirm the first 30 components were maintained per Tables 1-1 through 1-5 and Table 3
3. Request number of countable events.
4. Determine maximum PBM interval where countable events will not exceed 4% of population tested. (If countable events = 0, then maintain 5% of population.)

Example Maximum PBM Interval calculation:

1,000 population
100 components tested
1 countable event

Failure rate = countable events / components tested = 1/100 = 1%
Minimum components tested at Maximum Interval = countable events / (maximum failure rate of 4%) = 1/.04 = 25
Maximum Interval = population / Minimum components tested at Maximum Interval = 1000/25 = 40 years

5. Maintain those components at or below that maximum interval. Always be sure to calculate the maximum maintenance interval with a failure rate not to exceed 4%.

To continue to use PBM the applicable entity must:

1. Annually update components and segments.
2. Prove they have tested at least 5% of the population annually.
3. Calculate the maximum interval not to exceed a 4% failure rate/countable events. (If countable events = 0, then maintain 5% of population)

4. Analyze prior year data. If the percentage countable events exceed 4% for the greater of either last 30 maintained or all maintained in last year, create an action plan to reduce the countable events below 4% within 3 years.
5. Do not exceed 4% countable events of segment tested for 3 consecutive years following the year the countable events first exceeded 4%.

Assessment to confirm entity is properly continuing PBM:

1. Request population size; must be greater than 60.
2. Request population tested. Entity must test at least 5% of population.
3. Request number of countable events.
4. Request maximum # of failures.
5. Determine maximum PBM interval where countable events will not exceed 4% of population tested. Maintain those components at or below that maximum interval.
6. If countable events exceeds 4% of population tested, request action plan to reduce countable events below 4% within 3 years.

PBM Table

Brand specific (Lockout Relay) LOR[23]

Year	Total Population	Tested	% Tested (must exceed 5%)	# of Failures	Maximum # of Failures (4%)	Maximum PBM Interval
2014	859	49	5.7%	0	1	Test 5%
2013	824	89	10.8%	1	3	32.96 Years
2012	824	62	7.5%	0	2	Test 5%
2011	824	140	17.0%	0	5	Test 5%
2010	824	266	32.3%	0	10	Test 5%
2009	824	205	24.9%	0	8	Test 5%

PRC-005-2 Implementation

This section contains suggested implementation plan to meet the requirements of NERC Standard PRC-005-2. The Implementation Plan is intended to give an applicable entity the ability to

[23] See NERC Supplementary Reference and FAQ PRC-005-3 Section 9. Performance-Based Maintenance Process.

transition from the maintenance intervals and activities according to PRC-005-1 to the required maintenance intervals and activities in PRC-005-2.

Maintenance Intervals

If an applicable entity has an existing maintenance interval that is shorter than the required maintenance intervals within PRC-005-2 and also includes all the maintenance activities within PRC-005-2, then the applicable entity can immediately transition to the new required maintenance intervals.

If an applicable entity has an existing maintenance interval that is shorter than the required maintenance intervals within PRC-005-2, but does not include all the maintenance activities within PRC-005-2, then the applicable entity can immediately transition to the new required maintenance intervals and activities.

If an applicable entity has an existing maintenance interval that is longer than the required maintenance intervals within PRC-005-2, the applicable entity can transition to the new required maintenance intervals and activities per the Implementation Plan Project 2007-17 Protection Systems Maintenance and Testing PRC-005-2. During the implementation plan you must not exceed your existing (PRC-005-1) maintenance interval.

You must be able to show when you are 30%, 60%, and 100% compliant according the implementation plan. (See table below.)[24] Your compliance percentage should be calculated on a component basis. (i.e., if you have 10,000 microprocessor relays with monitoring. 3,000 must be tested according to new required activities by 4/1/2019; 6,000 by 4/1/2023, and all 10,000 by 4/1/2027. If you had 10,000 electro-mechanical relays. 3,000 must be tested according to new required activities or replaced by 4/1/2017; 6,000 tested or replaced by 4/1/2019, and all 10,000 tested or replaced by 4/1/2021. It may be helpful to know the number of relays in service as of 4/1/2015.)

Implementation Plan Data Table V2

Max. Maintenance Interval	% Compliant	By
Less than 1 year	100%	Oct. 1, 2015 (1D/1Q 18 mo. following regulatory approval)
1–2 calendar years	100%	Apr. 1, 2017 (1D/1Q 36 mo. following regulatory approval)
3 calendar years	30%	Apr. 1, 2016 (1D/1Q 24 mo. following regulatory approval)1
3 calendar years	60%	Apr. 1, 2017 (1D/1Q 36 mo. following regulatory approval)

[24] The dates of compliance percentage are different for each Province of Canada.

3 calendar years	100%	Apr. 1, 2018 (1D/1Q 48 mo. following regulatory approval)
6 calendar years	30%	Apr. 1, 2017 (1D/1Q 36 mo. following regulatory approval)2
6 calendar years	60%	Apr. 1, 2019 (1D/1Q 60 mo. following regulatory approval)
6 calendar years	100%	Apr. 1, 2021 (1D/1Q 84 mo. following regulatory approval)
12 calendar years	30%	Apr. 1, 2019 (1D/1Q 60 mo. following regulatory approval)
12 calendar years	60%	Apr. 1, 2023 (1D/1Q 108 mo. following regulatory approval)
12 calendar years	100%	Apr. 1, 2027 (1D/1Q 156 mo. following regulatory approval)

1 Or, for generating plants with scheduled outage intervals exceeding two years, at the conclusion of the first succeeding maintenance outage.
2 Or, for generating plants with scheduled outage intervals exceeding three years, at the conclusion of the first succeeding maintenance outage.

PRC-005-6 Implementation

The Implementation Plan for PRC-005-6 includes Automatic Reclosing and Sudden Pressure Relaying. The Implementation Plan is intended to give an applicable entity the ability to transition to the new required maintenance intervals and activities according to PRC-005-6.

PRC-005-6 is effective on 1/1/2016 and all entities need to update their PSMP's by 1/1/2017.

Maintenance Intervals

If an applicable entity has an existing maintenance interval that is shorter than or equal to the required maintenance intervals within PRC-005-6 and also includes all the maintenance activities within PRC-005-6, then the applicable entity can immediately transition to the new required maintenance intervals.

You must be able to show when you are 30%, 60%, and 100% compliant according to the implementation plan. (See table below.) Your compliance percentage should be calculated on a component basis.

Example 30%, 60%, and 100% compliant dates:

If an entity has 10 microprocessor automatic reclosing and/or supervisory relays with monitoring; 3 must be tested according to new required activities by 1/1/2021; 6 components by 1/1/2025, and all 10 components by 1/1/2029. If an entity has 201 sudden pressure relays; 60 must be tested according to new required activities or replaced by 1/1/2019; 120 components must be tested or replaced by 1/1/2021, and all 201 components must be tested or replaced by 1/1/2022.

Implementation Plan Data Table V6[25]

R1, R2 , R5	100% Compliant	By January 1, 2017
Max. Maintenance Interval	**% Compliant**	**By**
6 calendar years	30%	Jan 1, 2019 (1D/1Q 36 mo. following regulatory approval)
6 calendar years	60%	Jan 1, 2021 (1D/1Q 60 mo. following regulatory approval)
6 calendar years	100%	Jan 1, 2023 (1D/1Q 84 mo. following regulatory approval)
12 calendar years	30%	Jan 1, 2021 (1D/1Q 60 mo. following regulatory approval)
12 calendar years	60%	Jan 1, 2025 (1D/1Q 108 mo. following regulatory approval)
12 calendar years	100%	Jan 1, 2029 (1D/1Q 156 mo. following regulatory approval)

Additional applicable Automatic Reclosing Components may be identified because of the addition or retirement of generating units; or increases of gross generation capacity of individual generating units or plants within the BAA. In such cases, the responsible entities must complete the maintenance activities within the maintenance intervals from the time of becoming applicable as described in Table 4, for the newly identified Automatic Reclosing Components, unless documented prior maintenance fulfilling the requirements of Table 4 is available.

[25] The dates of compliance percentage could be different for each Province of Canada.

Revision History

Revision	Effective Date	Author(s)	Approver(s)	Summary of Changes
1.0	4/8/2015	SMET	MRO SC	Original Issue
2.0	2/03/2016	SMET	MRO SC	• Added revision history and summary of changes to PRC-005 • Updated 4.2 Facilities • Added definitions from the standard • Protective Relay Maintenance Activities (Table 1-1 and Table 2) • Updated Data Retention to align with PRC-005-4 • Added SME discussion on Relay Setting Verification. • Added PRC-005-3 and -6 Automatic Reclosing facilities included and excluded • Added maintenance activities for PRC-005-3, -4, and -6 • Added PRC-005-5 facilities excluded • Added PRC-005 -6 Implementation Plan • Moved management practices to Appendix C
2.1	4/20/2017	Staff	PRC-005 SMET, MRO SC	• Added Failed Element Test page 22 • Modified Unresolved Maintenance Issue page 22
2.2	10/09/2017	Staff	PRC-005 SMET, MRO SC	• Replaced “interpret with “apply” page 7 • Removed Facility applicability 4.2.5.4 • Updated fields required on test reports for consistency
2.2a	6/4/2018	Staff		• Repaired links to attached documents

Appendix A – References

1. NERC Reliability Standard PRC-005-2(i) – Protection System Maintenance
2. NERC Reliability Standard PRC-005-6 - Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
3. Supplementary reference and FAQ PRC-005-3 - System Protection Maintenance
4. NERC Rules of Procedure Appendix 5C - Procedure for Requesting and Receiving an Exception from the Application of the NERC Definition of the BES
5. NERC Glossary of Terms used in Reliability Standards
6. Bulk Electric System Definition Reference Document
7. Implementation Plan Project 2007-17 - Protection Systems Maintenance and Testing PRC-005-2

Appendix B – Power Point Presentation

PRC-005-2 Application Guidance.

PRC-005-6 Presentation.pptx

Appendix C – Recommended Management Practices

Management practices are **<u>not required</u>** but will assist to provide reasonable assurance regarding the achievement of objectives. Listed below are practices/controls that may be utilized by utilities:

- A secure asset database is a great tool for managing the assets within a PSMP.
- A secure Protection System maintenance documentation database is a great tool for managing the documentation of testing.
- Clear reports and/or dashboard showing components approaching maximum interval or maintenance history.
- A well-documented process of issuing Protection System maintenance work orders, which includes equipment failures, corrective action plans, and asset verification.
- Peer review of all or a random sample of Protection System maintenance work order documents.
- Automated test reports that are clear and concise as to PASS/FAIL.
- Test reports clearly cover the exact activities within the standard Tables 1-1 through Table 3.
- Periodic review of PSMP and test procedures.
- A descriptive revision history of PSMP.
- Annual training of field personnel on PSMP and test procedures with attendance records.
- A well-documented process of issuing Protection System settings.

- A central database that stores the settings that are in the field.
- Automated remote verification of microprocessor settings.
- Self-audit of PSMP and Testing Documentation (described below).

PRC-005-6 Self-Audit of PSMP and Testing Documentation

Request a list of all substations that contain BES Protection Systems included within PRC-005-6.[26]

The request should provide a list of all the BES relays, relays schemes, zones of protection, or relay panels included within PRC-005-6, depending on how the entity tracks their relays. Many entities have large asset databases of 10,000+ relays and may keep track of relay schemes, zones of protection, or relay panels rather than individual relays. The list of relays should provide a list of any of the following: relays, relays schemes, zones of protection, or relay panels depending on how the entity tracks their relays. Relays, relays schemes, zones of protection, or relay panels will be referred to as relays in the paragraphs below.

After randomly selecting the relays from the acquired list of relays, request documentation of maintenance of that relay, its associated voltage or current sensing devices, communication equipment, DC circuitry, and/or DC supply.

Do **not** randomly select a voltage or current sensing device from a substation because it may be connected to multiple relays within that substation, which would mean there would be multiple test reports. There would be multiple test dates and it would be difficult to determine if the entity has met the required test intervals within Table 1-3.

[26] A request for 100 kV and above substations can be misleading.