Automated Solutions and Remote Settings Changes - AEP’s Approach to Implementing PRC-027-1

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***Abstract*—Proper coordination of protective relays on the Bulk Electric System (BES) is essential to ensure a robust and reliable transmission grid. NERC established the PRC-027-1 Standard effective April 1ST 2021 in order to maintain coordination of Protection Systems on the BES by detecting and isolating faults such that the Protection System operates in the intended sequence.**

NERC PRC-027-1 Requirement 2 is intended to ensure BES Protection Systems operate in the intended sequence and remain coordinated over time. The standard provides three options to meet this requirement. Option 1 requires entities to perform a periodic Protection System Coordination Study in a time interval not to exceed six calendar years, while option 2 only requires a Protection System Coordination Study if a 15-percent or greater deviation of fault current is identified in a time period not to exceed six calendar years.

This paper discusses the pros and cons of both options for meeting PRC-027 Requirement 2 and explains why AEP selected Option 1 to meet this requirement for our network of over 2000 BES lines ranging from 765kV to 138kV. It covers the advantages to performing a coordination study on every line as well as the challenges that were encountered, including the need to mitigate past overcurrent settings practices and difficulties coordinating with interconnecting utilities, generators, and other independent power producers (IPPs). It also outlines AEP’s systematic process for performing area coordination studies, including automation of new relay settings development and new tools/methods such as remote settings changes that are essential to meet the PRC-027-1 requirements deadline of April 1, 2027 in an efficient and timely manner.

PRC-027-1 is helping utilities like AEP to mitigate frequent events/misoperations caused by incorrect relay settings (which is the highest cause category). To date, AEP has completed area coordination studies on all of its EHV lines (765kV to 345kV). Lessons learned from these studies along with AEP’s comprehensive plan to complete studies on our approximately 1600 remaining lines utilizing automation tools will also be described.

I. Introduction

American Electric Power is one of the largest electric utilities in the United States, delivering power to nearly 5.5 million regulated customers in 11 states. AEP owns the nation's largest electricity transmission system, a more than 40,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP operates more than 223,000 miles of distribution lines. Additionally, AEP is one of the nation’s largest electricity producers with approximately 30,000 megawatts of diverse generating capacity, including more than 5,300 megawatts of renewable energy. AEP operates within three NERC Regional Entities: ReliabilityFirst, Midwest Reliability Organization, and Texas Reliability Entity.

AEP has 2036 transmission lines and 3621 line terminals ranging in size from 115 to 765kV that are applicable to PRC-027. Of these line terminals, 566 of them interconnect with one of 143 different Transmission Owners (TO) or Generator Owners (GO). These terminals are shown in Table 1.

Table 1: PRC-027 Applicable Line Terminals by Voltage

Voltage (kV)	Transmission Lines	Total Line Terminals	Interconnected Terminals
765	36	68	6
500	8	8	8
345	336	506	177
230	9	11	7
161	41	68	20
138	1601	2952	346
115	5	8	2
Totals	**2036**	**3621**	**566**

II. NERC Standard PRC-027-1

The stated purpose of PRC-027-1 is *to maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.* The standard replaced PRC-001 and became effective on April 1, 2021. PRC-027 significantly expanded the scope of PRC-001 by including all BES Protection Systems, not just Protection Systems applied to interconnected Elements.

PRC-027 has three requirements. This paper will focus on Requirement 2, which is intended to ensure BES Protection Systems operate in the intended sequence and remain coordinated over time. The standard provides three options to meet this requirement. Option 1 requires entities to perform a Protection System Coordination study in a time interval not to exceed six calendar years. Option 2 requires a Protection System Coordination study when a 15-percent or greater deviation in fault current is identified in a time interval not to exceed six calendar years. Option 3 allows a combination of Options 1 and 2. The standard requires coordination of all applicable relays including transformer protection. This paper focuses on those relays that are applied for transmission line protection.

Option 1, where the Transmission Owner performs a periodic Protection System Coordination Study within a time interval not to exceed six years, has the advantage of ensuring that transmission Protection Systems are properly coordinated and remain coordinated over time. This will result in reliable Protection Systems and likely reduce the number of misoperations caused by incorrect relay settings. The disadvantage to this approach is that it may be more costly and time consuming if the coordination studies are manually performed.

Option 2, where a Protection System Coordination Study is performed only if the fault current changes by 15% or greater, requires the percent change to calculated from the present value compared to a baseline fault current. For this method to be effective, the Protection Systems must be coordinated before setting a baseline. If the Protection Systems are not coordinated, errors could go undetected until a misoperation occurs. However, this option may be less resource intensive than Option 1, especially for a system that undergoes little change, where the fault current doesn't deviate significantly over time.

During an initial review of the options, it may appear that Option 2 would be the obvious choice for a Transmission Owner with a large system. However, there are several questions to be considered:

1. How well was the system coordinated when the standard became effective? If it is believed that a system has existing coordination errors, Option 1 may be best to improve Protection System reliability.
2. Is the Protection System Coordination Study automated? If the Protection System Coordination Study is automated, there is little downside to performing a study. It provides an entity the assurance that there are no coordination issues on their system.
3. How much change occurs on the transmission system that affects the fault current? On a system that undergoes significant changes, it may be beneficial to use Option 1 if it's likely the fault current deviation will require a study anyway.

III. What is a Protection System Coordination Study?

NERC defines a Protection System Coordination Study as:

An analysis to determine whether Protection Systems operate in the intended sequence during Faults.

Attachment A in PRC-027 identifies the required protection functions to be included in a study. These are:

- Distance, if infeed or zero sequence mutual coupling is used in determining reach, and
- Overcurrent, if used in a non-communication-aided protection scheme.

The standard does not prescribe reach margins, pickup margins, or coordination time intervals; it allows Transmission Owners to define coordination criteria based on their own philosophy.

AEP includes the following checks in a Protection System Coordination Study:

<u>21 – Distance</u>

- Zone 1 reach < maximum value
- Zone 2 reach > minimum value
- Zone 2 reach coordinates with Zone 1 relays on downstream lines
- Zone 3 reach coordinates with Zone 2 relays on downstream lines

<u>50 – Instantaneous overcurrent</u>

- Instantaneous Elements have adequate margin for remote bus fault

<u>51/67 –AC overcurrent</u>

- Minimum pickup for line end fault
- Minimum pickup for line end fault with single contingency source outage
- Coordination shall be checked at the end of the instantaneous zone (distance or instantaneous overcurrent) to check for adequate coordination time interval (CTI).

An additional coordination check is also performed using the ASPEN OneLiner "Relay Operations Using Stepped Events" tool. This will validate the coordination checks performed above and may identify issues that are several busses away.

Coordination is checked at system normal (all normally energized equipment in service, all generation in service). The distance and overcurrent elements are checked together. In other words, the fastest relay function in each relay group will be used to determine whether the minimum coordination time interval (CTI) is met.

IV. Initial 765kV Area Protection System Coordination Study

In 2019, to prepare for PRC-027, AEP decided to perform a Protection System Coordination Study on our 765kV system. A total of 66 line terminals were studied on 34 lines. The purpose of the study was to determine:

1. What is the best way to perform a Protection System Coordination Study? And,
2. Is it feasible to study multiple lines in an entire area at one time?

The study was performed using the coordination checking tools within ASPEN OneLiner. The "Check Relay Settings" and "Check Relay Operations using Stepped Events" tools were used.

The expectation was that because 765KV is the highest voltage AEP operates, there would be few, if any, issues identified. The results of the study were surprising because many more coordination issues were identified than expected. There were 9 line terminals that had a setting issue that could result in a misoperation. All of these were overcurrent instantaneous settings with a low margin. An additional 32 line terminals were identified that had settings outside of AEP's settings guidance. These were unlikely to cause a misoperation but still did not coordinate based on AEP's criteria.

In addition to correcting the identified coordination issues, AEP decided to review all of the settings in these relays even though these additional settings are not required to be included in a PRC-027 Protection System Coordination Study. The reason for expanding the scope of settings reviewed is that it has been AEP's experience that the majority of Protection System misoperations are caused by settings other than those included in Attachment A of PRC-027. The opportunity was also taken to update these settings to AEP's latest settings guidance. This guidance is continually reviewed and updated in order to provide the most reliable transmission system protection possible. Some of the additional functions that were reviewed and updated include:

- Directional elements
- Directional comparison blocking (DCB) coordination time delays
- Adding a time delay to the DCB ground overcurrent tripping element and relying on DCB ground distance for clearing unless there is a high impedance fault.
- Disabling phase instantaneous overcurrent elements in digital relays if a phase overcurrent function that operates under a loss of potential condition and a switch onto fault function are enabled.

Revised settings were updated and issued for a total of 56 line terminals, which included a total of 112 digital relays.

V. Why AEP Selected Option 1

Based on the results of the initial Protection System Coordination Study of our 765kV system. AEP decided that Option 1 is the only option that would achieve reliable transmission system protection by ensuring all BES Protection Systems are properly coordinated. In addition, this option gives AEP the opportunity to go beyond the protective functions listed in Attachment A of PRC-027 and review and address all line protection settings. Over time, AEP has adjusted the guidance on how relays are set. The majority of the BES line relays do not have this latest guidance applied. This approach will help AEP significantly reduce, and potentially eliminate, Protection System misoperations caused by outdated and incorrect settings.

VI. Lessons Learned from Initial 765kV Study

Based on the initial 765kV Area Coordination Study, it was determined that up to 60% of AEP's line terminals would need revised settings. This percentage will increase further if all settings in the line relays are brought up to AEP's latest setting guidance.

The high volume of revisions needed made it necessary to enhance our relay setting and Protection System Area Coordination processes. Several changes were implemented, which are detailed in this section:

1. Updated the philosophy for setting ground overcurrent backup protection
2. Automated the development of relay settings
3. Adjusted criteria for Protection System Coordination Studies
4. Automated the execution of Area Protection System Coordination Studies
5. Began remotely applying relay settings

A. *Updated Philosophy for Setting Ground Overcurrent Backup Protection*

In the initial 765kV study, ground overcurrent settings were identified as the leading cause of coordination errors. Time overcurrent settings were found to have less than the required coordination time interval (CTI) and instantaneous overcurrent settings were found to have insufficient margin for a remote bus fault with contingency. Because of the number of coordination errors identified with ground overcurrent settings, the settings philosophy was reviewed to determine a better way to set these relay functions. The desire is to have a ground overcurrent function that is less vulnerable to system changes and still able to provide reliable backup protection.

The settings guidance was changed to meet the requirements. In the new philosophy, if the line protection is a digital relay with ground distance functions available, the instantaneous ground time overcurrent function is disabled. The ground time overcurrent function is set for a pickup of 600 amps and a trip time of 55 cycles for a line-end fault. The 600 amp setting is lowered if it does not provide adequate sensitivity for a line-end single line-to-ground fault. The intent of these changes is to allow a faster ground distance function to trip first. If there is a high impedance fault and the pilot system is out of service, the ground time overcurrent function is expected to clear the fault.

B. *Automated Relay Setting Development*

Prior to 2020, AEP used Mathcad to develop line relay settings. While this provided a consistent format for settings development, it required manual input of data. This data transfer was time consuming and prone to human error. The digital relay setting files were manually populated from the calculated settings in Mathcad, which was also time consuming and error prone. AEP decided to explore the use of automation in settings development to reduce the time to develop relay settings, reduce human error, and promote consistency in setting development.

Three key factors are necessary to successfully automate settings development: well defined setting criteria, standard schemes, and standard settings templates for each application. AEP has well documented settings guidance in the AEP Relay Settings Manual. The purpose of the manual is to ensure reliable and consistent application of protective relay settings. The manual captures the collective experience of AEP's senior P&C engineers. The manual provides settings rules and philosophy for each zone of protection. AEP's standard line protection schemes include current differential (87L), directional comparison blocking (DCB), permissive overreaching transfer trip (POTT), and step distance/overcurrent. There are standard drawings and specific relay setting templates for each scheme. The relay setting templates contain standard logic and all the necessary functions are enabled. Such standardization makes the automation of settings simpler because there is one set of rules and a limited number of setting template files that an automated software needs to support.

In 2019 AEP began to evaluate the use of an automated setting calculation software, Automated Relay Settings (ARS) developed by Utility Automation Solutions (UAS). ARS provides a single interface to calculate relay settings, update settings in ASPEN OneLiner, and populate relay setting template files for digital relays. ARS eliminates the manual transfer of data between different applications when developing settings. ARS calculates settings based on well-defined criteria that align with AEP's setting philosophy. The engineer can make manual adjustments to the automated settings as necessary.

AEP's initial PRC-027 area coordination study of the 765kV line protection discovered many relays that needed to be reset. It was decided that ARS would be evaluated by using the software to reset these relays. The software was utilized to develop settings for 56 line terminals and as a result of this trial, AEP decided to purchase ARS.

In June of 2020, the program was released for use by all AEP engineers to develop line relay settings. The program has been continually enhanced and improved based on feedback from the users and has been updated to support new standard applications as they are released for use.

ARS is now used to develop all line relay settings at AEP. The use of ARS has reduced the time to develop settings significantly. With ARS, a typical line setting can be developed within a matter of hours, including the update of the relay setting template files. ARS does not replace the engineer but simplifies the task of developing settings. The tool has been rigorously tested to ensure the calculations are accurate and correct. The settings engineer still must review the settings that are developed and a thorough peer review is also performed on the settings developed by ARS.

A drawback to automation for relay settings development is that many of the calculations are done in the background and an engineer with little experience may not understand how a setting is calculated or if the value is even reasonable. Settings engineers must be provided training on setting philosophy and calculations before they can effectively use an automation tool to assist with setting development.

1) Using ARS to Develop Line Settings

To develop a setting using ARS, the engineer must first select the protection scheme in the user interface (UI). The required information is entered, including location of the ASPEN OneLiner file, bus names, CT ratios, and relay type and scheme. Figure 1 shows the ARS UI for line setting development.

The setting can then be generated. The program produces a spreadsheet which contains all the necessary settings and a summary of the settings for each relay system. The engineer has the option to adjust any calculated value. When a setting is manually changed, a comment explaining why the setting was adjusted must be provided. The ARS calculated value is also shown next to the newly entered value. These indications make it easy for a peer reviewer to identify when a setting was changed from the ARS calculated value. ARS will provide an indication if a setting is outside an acceptable range. Figure 2 shows a phase distance Zone 2 setting where the value was changed. An indication is provided that this updated setting does not coordinate.

ARS has the ability to populate the relay setting template files from the settings calculation spreadsheet. The engineer selects the setting calculation file and the setting file template locations in the ARS UI (Figure 3). ARS performs a check to ensure the selected templates match the relay type, version, and scheme that the calculations are based on. When the setting files are populated, a comparison between the template and the populated file is automatically generated. This helps ensure that the templates were correctly populated with all the required settings.

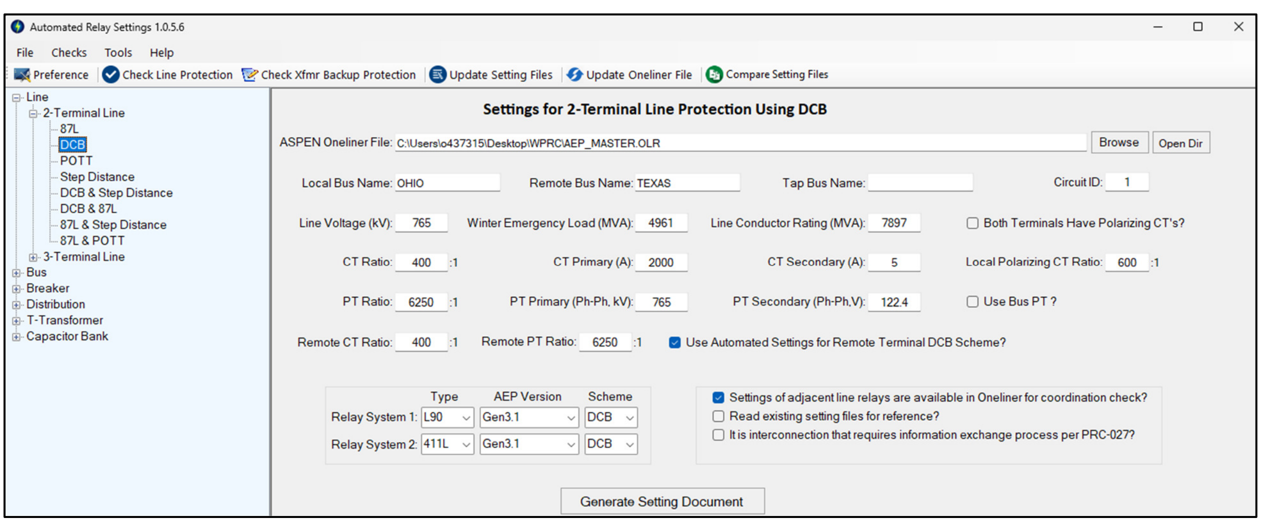

Figure 1: ARS UI for Line Setting Development

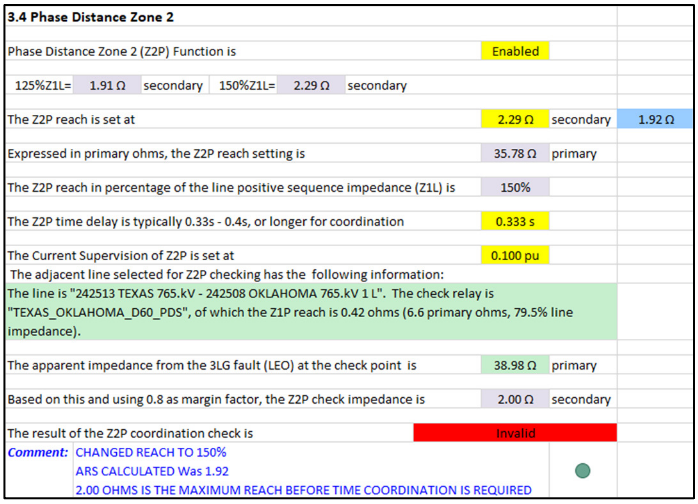

Figure 2; ARS Phase Distance Zone 2 Calculation

C. Adjusted Criteria for Protection System Coordination Studies

Another takeaway from the initial study was that the review criteria for performing Protection System Coordination Studies should be adjusted to prevent identifying coordination issues that pose little risk. AEP has well-documented relay settings criteria in the AEP Relay Settings Manual. The guidance has sufficient margins that allow a setting to be outside the target ranges and still provide a secure and dependable setting. In order to prevent having to revise settings for small changes that may occur as the system changes, the PRC-027 criteria were developed. These criteria are shown in Table 2. All new or revised settings are still set to AEP's setting criteria. The PRC-027 criteria are used when performing a Protection System Coordination Study. If it is determined that a setting falls outside the PRC-027 criteria, the relay is reset. When a revised setting is needed, all settings in the relay will be set to the AEP settings criteria.

Table 2: Relay Setting Criteria

	Element	AEP Setting Criteria	PRC-027 Criteria
345-765kV	Zone 1 Phase Distance maximum reach	85%	86%
	Zone 2 Phase Distance minimum reach	125%	120%
	Zone 1 Ground Distance maximum reach	80%	85%
	Zone 2 Ground Distance minimum reach	120%	110%
	Zone 2 Distance Z2/Zapp threshold	80%	85%
	Instantaneous overcurrent minimum margin	125%	120%
	Ground time overcurrent pickup margin	3.0x	2.5x
	Minimum Coordination Time Interval (CTI)	20 cycles	18 cycles
115 - 230kV	Zone 1 Phase Distance maximum reach	85%	86%
	Zone 2 Phase Distance minimum reach	125%	120%
	Zone 1 Ground Distance maximum reach	80%	85%
	Zone 2 Ground Distance minimum reach	120%	110%
	Zone 2 Distance Z2/Zapp threshold	80%	85%
	Instantaneous overcurrent minimum margin	120%	115%
	Ground time overcurrent pickup margin	3.0x	2.5x
	Minimum Coordination Time Interval (CTI)	24 cycles	20 cycles

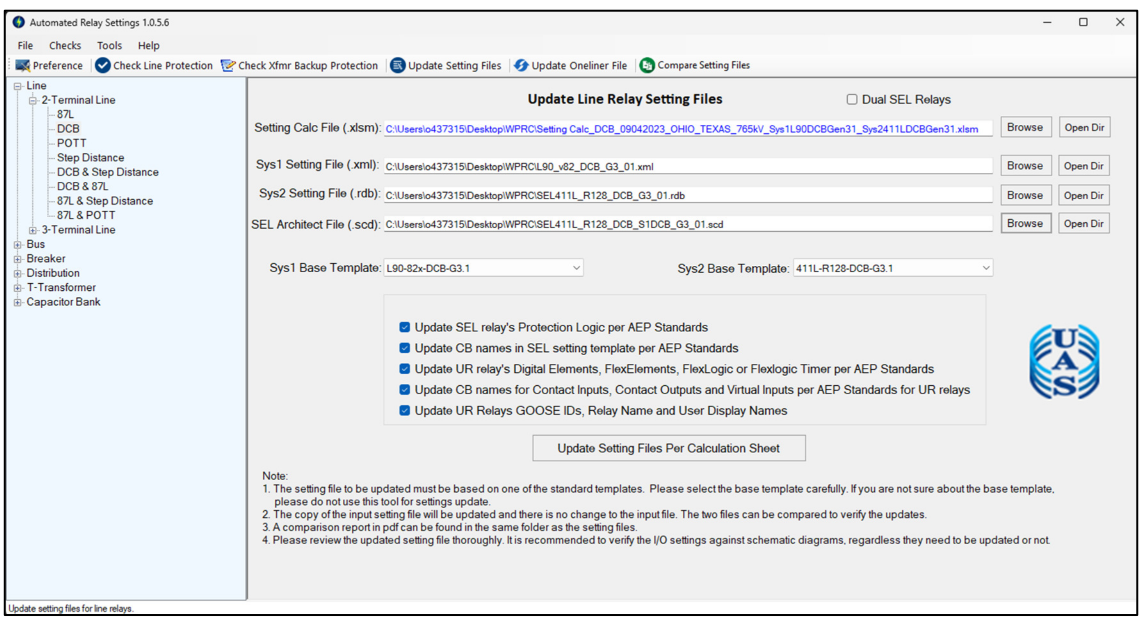

Figure 3: ARS UI for Updating Setting Files

D. *Automated Study Execution*

It was recognized that in order to efficiently perform a Protection System Coordination Study it is necessary to have an automated tool that will:

1. Perform all the checks that are required for a Protection System Coordination Study.
2. Study multiple lines at one time.
3. Have an output that easily identifies where coordination errors exist and what those errors are.

UAS developed a module in ARS to perform studies on multiple lines. ARS performs studies on a per-terminal basis and will study each relay that is modeled in ASPEN OneLiner for that terminal. A list of the line terminals to be included in a given study is needed. The list can be generated by ARS and an example is shown in Figure 4.

2-Terminal Lines			Check From Seq. #	1	To Seq. #	8	
Seq.#	Line KV	Local Bus Name	Remote Bus Name	Tap Bus Name	Relay Modelled for Both Terminals? (Y/N)	Interconnection (Y/N) ?	Circuit ID
1	765	OHIO	TEXAS		Y		1
2	765	TEXAS	OHIO		Y		1
3	765	TEXAS	VIRGINIA		Y		1
4	765	VIRGINIA	TEXAS		Y		1
5	765	KENTUCKY	TEXAS		Y		1
6	765	TEXAS	KENTUCKY		Y		1
7	765	OKLAHOMA	TEXAS		Y		1
8	765	TEXAS	OKLAHOMA		Y		1

Figure 4: ARS Check Line Protection Information File

The desired coordination check criteria are entered under the Preferences in ARS. Figure 5 shows the Check line Protection UI where the locations of the ASPEN OneLiner File, Line Information File, and the folder for the Results Files are selected.

ARS studies all the lines on the list and produces a summary output that includes each terminal checked and the result of each function that was checked. This makes it simple to determine which terminals have a coordination error. As shown in Figure 6, if an error is identified, the summary sheet will show which relay function caused the issue.

An individual settings check sheet is created for each line terminal studied. This sheet provides the details of each function that is checked. The details of the specific cause of the issue are included on the sheet. Figure 7 shows a Phase Distance Zone 2 check. This check identifies a relay with insufficient margin to coordinate with a downstream adjacent relay.

Summary of Settings Check For Multiple Line Terminals					
Oneliner File:	C:\Users\o437315\Desktop\WPRC\AEP_MASTER.OLR				
Folder for Check Files:	C:\Users\o437315\Desktop\WPRC				
Local Terminal	OHIO	Remote Terminal	TEXAS		
Number of terminals	2	Line Voltage	765 kV	Seq.#	1
Check File	OHIO_TEXAS__765kV_SettingsCheck_1_09042023.xlsm				
Type	Relay ID	Elements	Check Results		
21P	OHIO_TEXAS_421_PDS	Z1P;Z4P;Z2P	Issue Found		
21P	OHIO_TEXAS_D60_PDS	Z1P;Z3P;Z2P	OK		
21G	OHIO_TEXAS_421_GDS	Z1G;Z4G	OK		
21G	OHIO_TEXAS_D60_GDS	Z1G;Z3G	OK		
51G	OHIO_TEXAS_421_GOC	51G	OK, but issue with adjacent relay		
51G	OHIO_TEXAS_D60_GOC	51G	OK, but issue with adjacent relay		
Coordination With Downstream Relays For Adjacent Line End 1LG Fault			OK		
Coordination With Upstream Relays For Adjacent Line End 1LG Fault			Issue Found		
Coordination With Downstream Relays For Adjacent Line End 3LG Fault			OK		
Coordination With Upstream Relays For Adjacent Line End 3LG Fault			OK		
Relay Operations Check Using Step Events			Issue Found		
Local Terminal	TEXAS	Remote Terminal	OHIO		
Number of terminals	2	Line Voltage	765 kV	Seq.#	2
Check File	TEXAS_OHIO__765kV_SettingsCheck_1_09042023.xlsm				
Type	Relay ID	Elements	Check Results		
21P	TEXAS_OHIO_D60_PDS	Z1P;Z3P;Z2P	OK		
21P	TEXAS_OHIO_421_PDS	Z1P;Z4P;Z2P	OK		
21G	TEXAS_OHIO_D60_GDS	Z1G;Z3G	OK		
21G	TEXAS_OHIO_421_GDS	Z1G;Z4G	OK		
51G	TEXAS_OHIO_D60_GOC	51G	OK		
51G	TEXAS_OHIO_421_GOC	51G	OK		
Coordination With Downstream Relays For Adjacent Line End 1LG Fault			OK		
Coordination With Upstream Relays For Adjacent Line End 1LG Fault			OK		
Coordination With Downstream Relays For Adjacent Line End 3LG Fault			OK		
Coordination With Upstream Relays For Adjacent Line End 3LG Fault			OK		
Relay Operations Check Using Step Events			Issue Found		

Figure 6: Summary of Settings Check Results

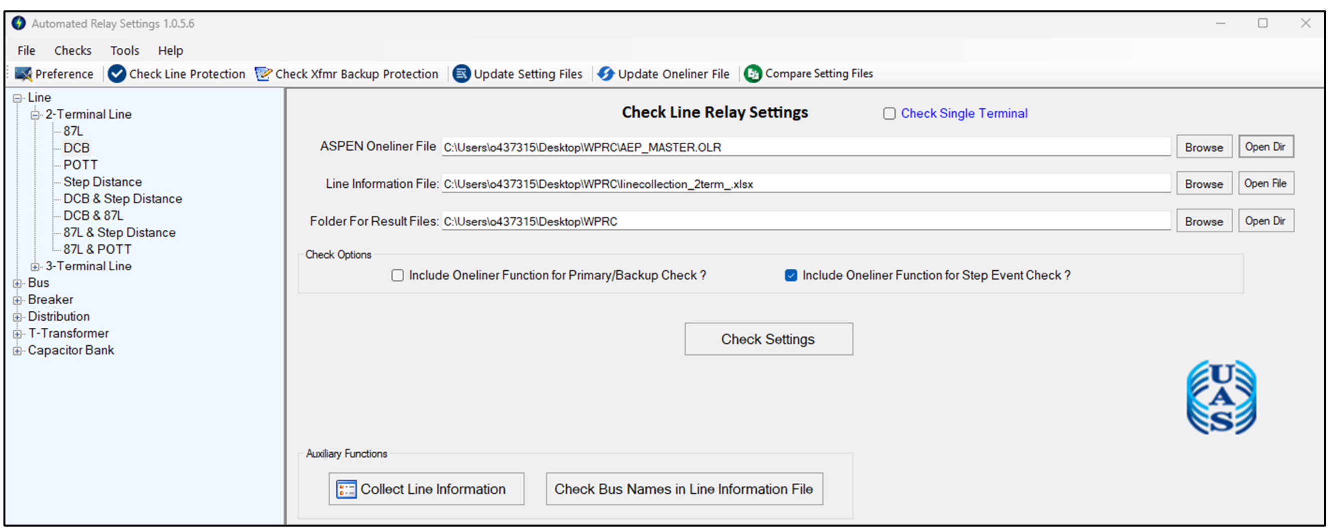

Figure 5: ARS Check Line Protection UI

4.2 Phase Distance Zone 2

From Oneliner, the main settings of Phase Distance Zone 2 (Z2P) relays are:

21P Plots

Relay ID	CTR / PTR	Reach	Primary Ω	% Z1L	Delay	I_sup	Check
OHIO_TEXAS_421_PDS(Z4P)	400 / 6250	2.29 Ω	35.78 Ω	150%	0.333 s	-	ERR
OHIO_TEXAS_D60_PDS(Z3P)	400 / 6250	1.92 Ω	30.00 Ω	126%	0.333 s	0.50 A	OK

Notes on Check Result

Downstream adjacent Relay ID	Op Time (s)	Local Relay ID	Op Time (s)	Z2P/Zapp	Check	
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	50%	OK	Plot
TEXAS_KENTUCKY_421_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	42%	OK	Plot
TEXAS_VIRGINIA_D60_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	31%	OK	Plot
TEXAS_VIRGINIA_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	26%	OK	Plot
TEXAS_VIRGINIA_421_PDS	0.333	OHIO_TEXAS_421_PDS	9999.000	31%	OK	Plot
TEXAS_VIRGINIA_421_PDS	0.333	OHIO_TEXAS_D60_PDS	9999.000	26%	OK	Plot
TEXAS_OKLAHOMA_D60_PDS	0.333	OHIO_TEXAS_421_PDS	0.670	92%	ERR	Plot
TEXAS_OKLAHOMA_D60_PDS	0.333	OHIO_TEXAS_D60_PDS	0.670	77%	OK	Plot
TEXAS_OKLAHOMA_421_PDS	0.333	OHIO_TEXAS_421_PDS	0.670	92%	ERR	Plot
TEXAS_OKLAHOMA_421_PDS	0.333	OHIO_TEXAS_D60_PDS	0.670	77%	OK	Plot

Figure 7: Phase Distance Zone 2 Check Details

E. Began Remotely Applying Relay Settings

When it was realized that the PRC-027 Protection System Coordination Studies could require a large number of revised settings, AEP decided to explore the remote implementation of these settings for digital relays. It has been a common practice to make changes to non-protective settings remotely, for example changes to alarming, oscillography, and other changes that do not affect the tripping functions in a relay. A procedure was developed for the remote application of protective setting changes.

The new procedure has specific criteria for what type of setting can be applied remotely. Some of the settings that cannot be applied remotely include settings on critical interconnects, settings associated with current transformer ratio changes, changes that requires new inputs or outputs, changes that involve firmware upgrades, and changes that modify the trip logic. The remote settings change process requires at least two qualified individuals to collaborate on the task so that they can concurrently verify that the settings were applied without error. Settings that are applied remotely do not undergo any onsite testing that could potentially uncover errors. Therefore, it is especially critical that remotely applied settings are issued to the field without errors. The use of automation to develop settings along with a thorough peer review helps eliminate any potential errors in the relay setting files.

This procedure was piloted on AEP's initial 765kV area study. A total of 55 settings were applied remotely without incident.

VII. New Study Process

After completion of the 765kV study, it was decided to perform Protection System coordination based on voltage level. The 345kV lines would be studied next and then the lines below 200kV. The transmission system was divided into manageable areas of approximately thirty lines by voltage level. A master list of line terminals by bus name was created to track the progress of the Protection System Coordination Studies. The general process for performing a study is as follows:

1. Populate the ARS Line Information file with terminals to be studied.
2. Review the short-circuit model to be used for the study. The topology at each bus is reviewed, and line impedances are reviewed to ensure they match the line impedances of record.
3. Review and update the line relay settings in the short-circuit model. If the in-service setting was issued prior to 2021, there is no need to verify this setting is correct in the model because a new setting will be required.
4. Develop settings within ARS for line terminals requiring settings. Update the new settings in the short-circuit model.
5. Run the ARS "Check Settings for the Area" tool.
6. Review the results and address any identified issues. Any coordination errors shall be corrected. If there is a legitimate reason for the error, a comment is added to check results sheet. The comment should explain why the error is acceptable. An example of an acceptable error would be a GOC element operating too fast in an area that has not been reset. This is expected to be addressed in the future.
7. Issue revised settings to the field for implementation, The Transmission Field Services group will determine whether the setting meets the criteria to be applied remotely.
8. File the study results and document that the area study is complete.

The coordination study process is shown in Figure 8.

To perform a Protection System Coordination study on a line interconnecting with another TO or GO, the relays at the non-AEP owned terminal are added to the short-circuit model. A study is performed on both terminals of the line. If errors are identified at the non-AEP terminal, the other owner is notified of the identified errors. AEP's intention is to update all settings in our relays on interconnected lines. It is recognized that other companies do not have the same relay settings criteria and may not find it necessary to make any changes or agree with the setting changes AEP wants to implement.

VIII. 345kV Studies

AEP owns all or part of 336 transmission lines at 345 kV. AEP owns the protective relays on 506 of these line terminals. 177 of these line terminals interconnect with another Transmission Owner (TO) or Generator Owner (GO).

These terminals were divided into 16 groups to perform Protection System Coordination Studies. The study of these lines began in late 2021 and continued through 2022. Based on the review and study of the 345kV system, 399 of these terminals were determined to need revised settings. No coordination issues were identified on the other 107 terminals and no updates were required for those settings because they met the latest setting guidance which was implemented in early 2021.

Most of the required settings were developed and issued in 2022. There were some remaining settings on interconnected line terminals that were issued in 2023.

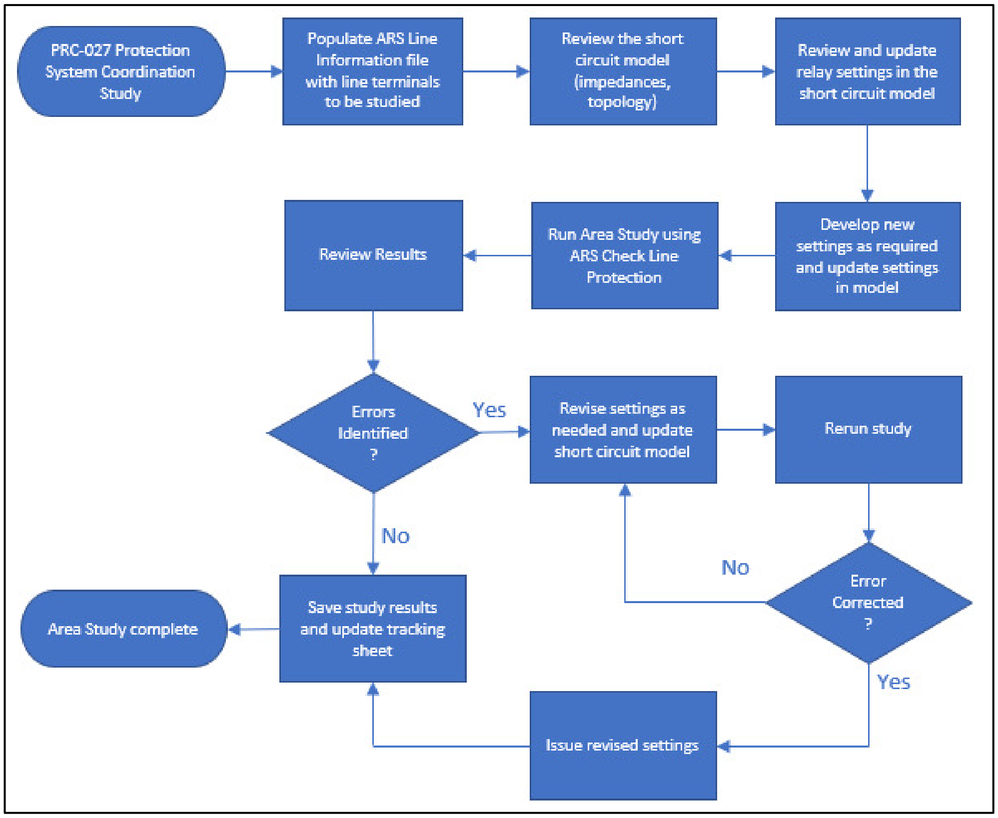

Figure 8: Process for Performing Protection System Coordination Studies

A. Lessons learned from 345kV studies

Based on the Protection System Coordination Studies performed on the 345kV system, two areas of improvement were identified and implemented in subsequent studies:

- Settings on interconnected line terminals have the added complexity of requiring agreement from the other owner before any settings changes can be made (PRC-027 Requirement 1 part 1.3), which in some cases can be very time-consuming, partly because making settings changes to a line that had previously been coordinated may not be a priority for the other company. Therefore, AEP decided to adjust the approach used when coordinating with other TOs and GOs for all subsequent studies. Moving forward, all line terminals with interconnections will still be studied, but settings will only be changed if a coordination error is identified by a PRC-027 study.

  Note: Even when settings on an interconnected line are not updated for the PRC-027 studies, they will still be updated to meet AEP's latest setting guidance during the next capital project affecting the line.

- The majority of the 345kV line setting revisions were specifically needed to meet PRC-027 and therefore were considered an O&M expense. In order to control costs, it will be necessary to coordinate PRC-027 Protection System Coordination Studies with capital projects, as much as practical, for all the remaining lines to be studied. AEP invests a tremendous amount in the transmission system annually. On average, settings for approximately 400 BES line terminals are issued for capital improvement projects each year.

IX. 161kV and 138kV Studies

AEP owns all or part of 1642 transmission lines at 161kV and 138kV. AEP owns the protective relays on 3020 of these line terminals. 366 of these line terminals interconnect with another Transmission Owner (TO) or Generator Owner (GO).

These terminals were divided into 70 groups to perform Protection System Coordination Studies, which were initiated in 2023. The initial plan was to study one-third of these line terminals per year for three years. This provides more than a year of margin before the deadline in the event of unforeseen delays. Due to some resource and budget constraints only 60% of the terminals planned to be studied in 2023 were complete. The complete date for the studies has been moved back to the end of the second quarter of 2026. This still provides a nine-month margin before the protection system coordination studies must be complete.

It is estimated that approximately 45% of these studies will be or have been completed as part of capital improvement projects. AEP typically issues relay settings for 300 line terminals per year at these voltage levels. Since PRC-027 became effective, approximately 800 line terminals have had new or revised settings issued in the context of capital projects. If this trend holds true, by the end of 2026 approximately 1500 of the 3020 terminals will have had a Protection System

Coordination Study performed when the settings were developed for the capital project.

Based on the studies that were completed in 2023, this assumption continues to be reasonable. Table 3 shows the breakdown of line terminals that were been studied in 2023. The studies indicate that 288 of the terminals (50%) will need revised settings that will be an O&M expense. 286 of the line terminals have previously been studied or will be studied as part of a capital project.

Table 3: Line Terminals Studied in 2023

Line Terminals Studied	PRC-027 Specific Settings	Setting Completed for Capital Project	Percent Capital
574	288	286	50

If a study is deferred in an area where a future capital project is anticipated, the line terminal will be studied when settings are developed for the project. All coordination issues that are identified will be corrected as part of the capital project.

X. Remotely Applied Settings Changes

AEP intends to remotely implement as many of the PRC-027 settings as possible. Approximately 31% of the settings meeting the remote application criteria have been applied remotely. This includes all settings issued for PRC-027 from 765kV to 138kV. AEP expects this percentage to increase as personnel become more comfortable with the new process. It is estimated that each setting applied remotely saves four hours per relay, or eight hours per line terminal. Table 4 shows the number of settings applied remotely.

Table 4: PRC-027 Settings Applied Remotely

Settings Meet Criteria for Remote Application?	Settings Applied at Station	Settings Applied Remotely
No - 454	454	
Yes - 512	353	159
Total - 966	807	159

XI. Challenges

AEP makes a significant number of capital improvements on the system each year. With each new transmission line added, the list of line terminals must be updated to ensure a Protection System Coordination Study is completed for the new terminals.

To perform an Area Coordination Study, the short circuit model must be accurate and up to date, including all network elements and relay settings. Incorrectly modeled relays may give a false coordination error or may mask an actual settings error. The short-circuit models must be kept up to date as the system changes.

Continually changing budgets and project schedules can make it difficult to determine which lines should be studied specifically for PRC-027 and which may be studied as part of a capital project. The process for performing Protection System Coordination Studies must be continually reviewed and adjusted.

XII. Conclusion

This initial round of Protection System Coordination studies will require many revised settings, but the end result will be a transmission system with properly coordinated line relays, in which all BES line protection settings have been updated with AEP's latest guidance. The desire is that the revised settings will be more resilient as the transmission system changes. This volume of settings adjustment is not expected to be necessary in the future.

AEP's practice is to perform a Protection System Coordination Study for every new or revised line setting. If an error is identified on an adjacent line, the error will be reviewed and corrected. A study will also be performed when any project changes the fault current in an area even if the project doesn't specifically involve line protection. For example, if an autotransformer is added to a station, a study will be performed on all lines connected to that bus and any coordination errors that are identified will be corrected. This will help the transmission system stay coordinated over time and will reduce the number of coordination errors identified when an area study is performed.

In the future, AEP plans to periodically perform Protection System Coordination studies on our entire transmission system multiple times per year. All coordination errors will be corrected when they are identified, ensuring the protective relays remain properly coordinated. It is essential to have an automated tool to efficiently perform these periodic studies.

AEP expects this initial set of costly and time-consuming PRC-027 Area Protection System Coordination Studies to reap rewards in the future by significantly reducing misoperations caused by incorrect settings. The investment in automated tools to develop relay settings and perform Protection System Coordination Studies is essential to using Option 1 to meet PRC-027 Requirement 2.

XIII. Biographies

Jeff Iler is a staff engineer in the Protection and Control Engineering group at American Electric Power (AEP) with 31 years of experience in Protection and Control (P&C). His current responsibilities at AEP include the development of P&C policies, QA/QC review of relay settings, analysis protection system operations, and development and implementation of PRC-027 compliance processes. Jeff's focus is on the automation of relay setting development and area coordination studies. Jeff is a member and past chair of the NERC System Protection and Control Working Group. Jeff received a B.S.E.E. from the University of Akron and is a registered professional engineer in the state of Ohio.

Nelson Doe is a Regional Engineer at American Electrical Power (AEP) with 11 years of experience in Protection and Control (P&C). His current responsibilities at AEP include QA/QC review of PCE transmission project deliverables, area coordination studies, misoperation analysis, mentoring PCE employees, and PCE compliance support for PRC-023 and

PRC-027. Before AEP, Nelson worked at Actalent (formally known as EASi Engineering) as a consulting engineer. Nelson received his Bachelor of Science from University of Dayton, Ohio. Nelson is a member of IEEE.

Manish Thakur is Director of Protection and Control Engineering at American Electrical Power (AEP) with 26 years of experience in Protection and Control (P&C). His current responsibilities at AEP include system protection and control, compliance and relay misoperation investigations of transmission systems up to 765kV. His areas of expertise include HiZ fault detection, series compensation application on EHV systems, transient and real time simulations, Standardization, and Digital Substation. Prior to joining AEP, Manish worked with ABB and General Electric as a P&C application and consulting engineer. Manish received his Bachelor of Science in India and Master of Science from University of Manitoba, Canada. Manish is a member of IEEE and is a Professional Engineer (PE) registered in Ohio.