American Electric Power's Experience with Protection System Misoperations and Improvements

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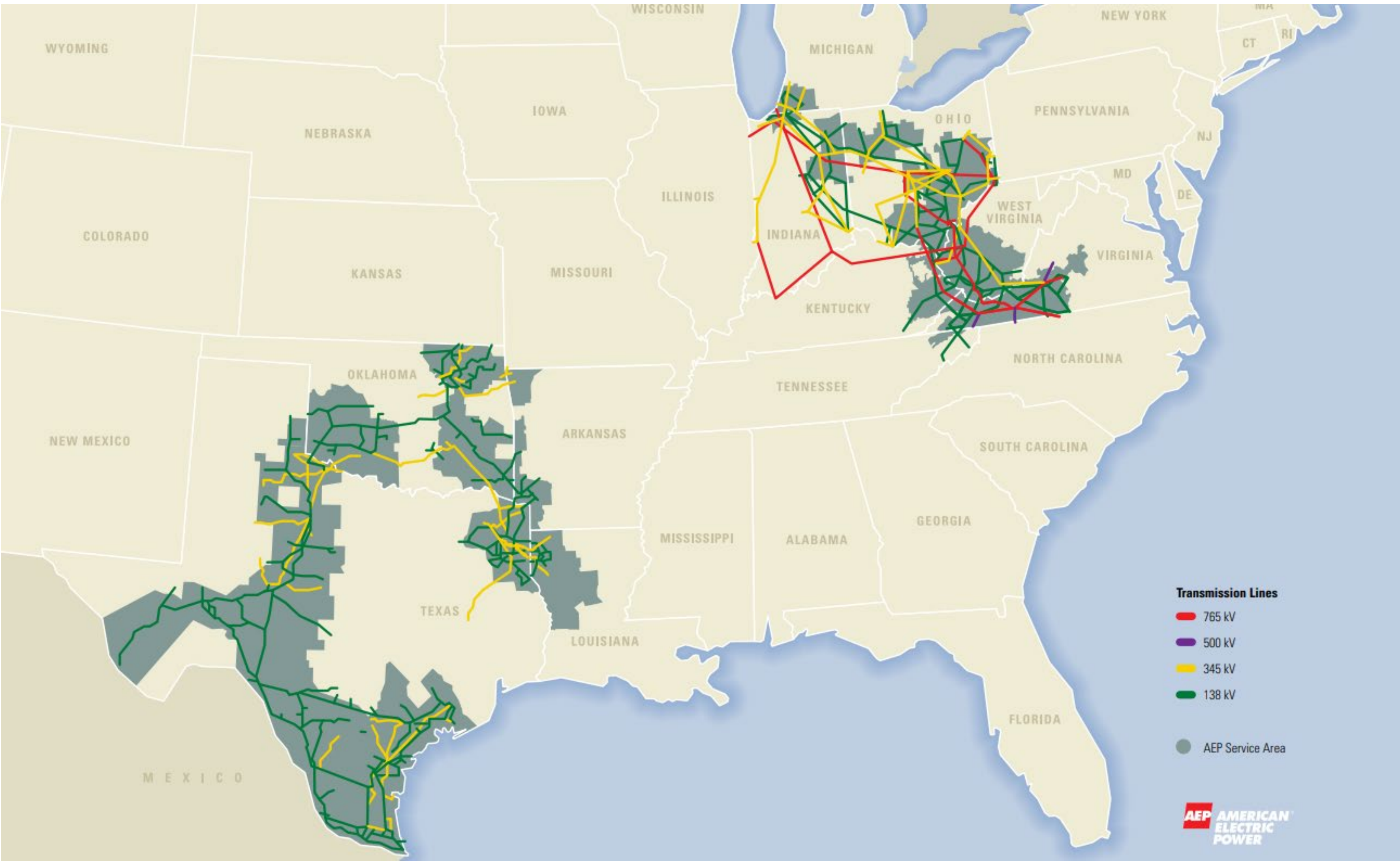
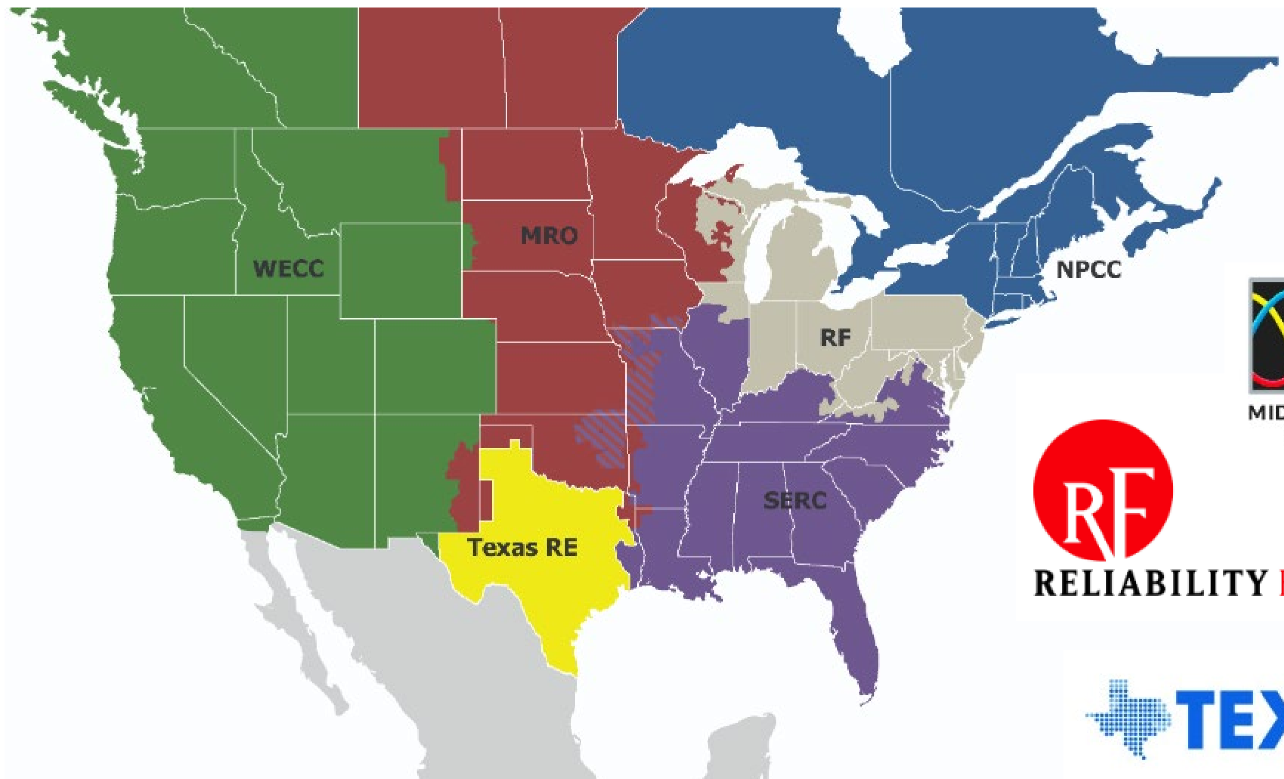
Introduction

- AEP Key Statistics:
  - 16,800 employees
  - 5.5 million regulated customers
  - 30,000 MW generation capacity
  - 40,000 miles of transmission line (including 765kV)
  - Operates in 11 different states
  - Headquartered in Columbus, Ohio

AEP Transmission Network



AEP Regional Entities



MIDWEST RELIABILITY ORGANIZATION

RF
RELIABILITY FIRST

TEXAS RE

New Technologies

Grid Transformation

Challenges

- Protection system technology changes
- Decentralized renewable generation
- Inverter based generation vs traditional inertia
- Younger experience level in the industry
- Large capital investment workplans
- FACTs transmission devices (series capacitors, SVCs, PSTs, etc…)

Reliability

- All these challenges lead to increased complexity which if not properly accounted for can lead to protection system misoperations
- Misoperations are a key risk to the Bulk Electric System's (BES) reliability
- AEP has a goal of ZERO protection system misoperations

Path to Zero Misoperations

- Leverage automation
- Embrace industry best practices
- Simplify protection and control schemes
- Incorporate lessons learned from system misoperations into key engineering processes

Identifying Misoperations

- AEP has a separate team outside of engineering (TFS P&C) that first reviews the operation
- TFS P&C reviews all available data
- If an operation is determined a misoperation, then engineering (PCE) gets involved

Cause Identification

- A group of experienced technical engineers representing all regions and departments of PCE meet to analyze the event
- Very important to find the true root cause so that the appropriate corrective action plan (CAP) can be developed (ex: Z1P overreaches; is setting bad or is model bad)
- The formal group setting helps raise awareness

Corrective Action Plan

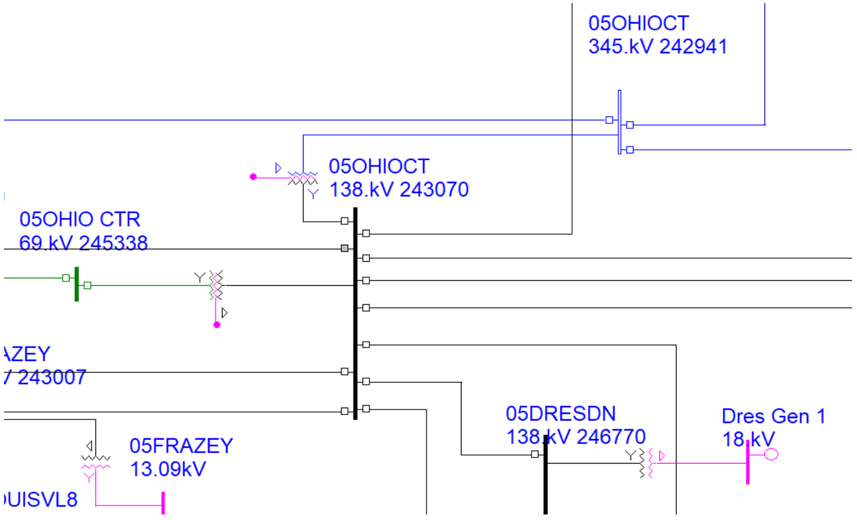
- Develop a CAP
- Implement CAP within 2 weeks (avoid repeats)
- Express Settings when applicable
- Prioritize model verification

Assessing Applicability

- Group determines if misoperation is isolated event
- Does CAP have applicability to other protection systems
- If so, filter and define list of affected assets
- Create mitigation project (proactive way to reduce risk & prevent future misoperations)
- Express Settings method speeds up mitigation

Modelling

- Formalized how power elements such as lines and transformers are modelled
- Dedicated short circuit modelling group
- Modelling process includes a peer review before given to engineering
- All settings work requires a verified model even if an existing asset and no planned changes



Formalized Settings Peer Reviews

- Human error is a top driver of settings related misoperations
- Peer review adds extra layer of protection
- Past reviews were not performed consistently and not well documented
- Have a peer review process document, defines expectations
- Review is now integrated with setting issue workflow
- BES line settings need reviewed by qualified peer reviewer

Formalized Settings Peer Reviews

- Reviews are stored electronically, and reviewer name is included
- Instituted a Line Settings Robust Checklist
- This checklist includes items that may often get overlooked and items that past experiences have deemed need extra attention from the setter and also the peer reviewer.

Formalized Settings Peer Reviews

Item	Task	Enter Value	Executed	Executed Time	User
1-	**PCE Peer Review**				
1.1.	Select the type of settings that are being peer reviewed	Line Settings	☑	9/27/2022	s233645
2-	**Aspen Model**				
2.1.	Aspen Model was reviewed and updated as per TEPD-2450	Yes	☑	9/27/2022	s233645
2.2.	*Comments*				
2.3.	Relay devices and coordination pairs are modelled correctly.	Yes	☑	9/27/2022	s233645
2.4.	*Comments*				
2.5.	Proposed settings coordinate with relay devices in the area.	Yes	☑	9/27/2022	s233645
2.6.	*Comments*				
3-	**Calculations**				
3.1.	All calculations required for this asset are accurate and complete	Yes	☑	9/27/2022	s233645
3.2.	*Calculation Comments*				
4-	**TOps Sheet**				
4.1.	*Settings match the RSRF*				
4.2.	*Comments*				
5-	**Settings Templates**				
5.1.	Correct relay settings template was used and populated accurately	Yes	☑	9/27/2022	s233645
5.2.	*Comments*				
5.3.	Relay settings file addresses legacy issues detailed in the robust checklist	Yes	☑	9/27/2022	s233645
5.4.	*Comments*				
6-	**RPA**				
6.1.	*Data points match with RPA file*				
6.2.	*RPA comments*				
7-	**Comments/Attachments**				
7.1.	Attachment any other documents that are required	Import...	☑	9/27/2022	s233645
7.2.	Settings are approved and are good to be issued for implementation	Yes	☑	9/27/2022	s233645
7.3.	*Please enter the comments on why the settings were not approved*				

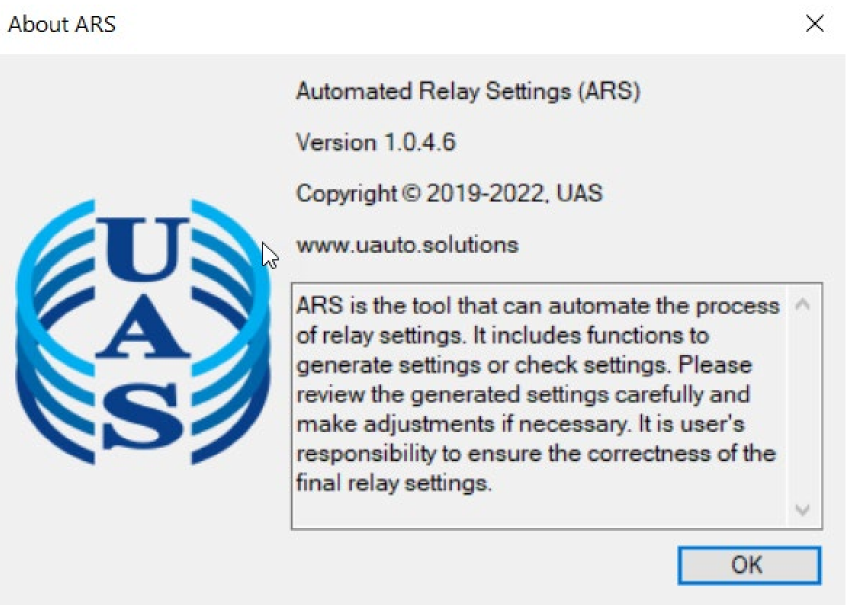
Line Settings Robust Checklist

Model	Function	Setting	Description
L90	Ph Dist Z1, Ph Dist Z2, Grd Dist Z1, Grd Dist Z2	Volt Level	Firmare version 7.x and later must set volt level to 0.001
L90	Ground Directional Elements		Verify the correct ground directional element is used per SS-451010 (zero sequence or negative sequence). Verify the Block for Neutral TOC and IOC are set to use the correct element. (It was not uncommon in the past to use Negative sequence for the DCB or POTT scheme and keep the TOC and IOC using Zero Sequence. These should all match)
L90	Neutral Dir OC1	Fwd/Rev Pickup	Verify local and remote pickup values are coordinated, in primary amps, if used in a DCB or POTT
L90	Neutral Dir OC1	Polarizing	Verify polarizing is set per SS-451010 and matches at remote terminal if used in a DCB or POTT
L90	Neutral Dir OC1	POS Seq Restraint	All terminals of a line must use the same POS Seq Restraint setting if used in a DCB or POTT scheme. Firmware version 3.x and earlier has a hard coded POS Seq Restraint of 0.0625.
L90	Neg Seq Dir (Zero seq type)	Fwd/Rev Pickup	Firmware version 5.5x and earlier based on I0 and later versions based on 3I0. Confirm remote ends are coordinated for this mismatch if used in a DCB or POTT scheme
L90	Neg Seq Dir (Zero seq type)	POS Seq Restraint	All terminals of a line must use the same POS Seq Restraint setting if used in a DCB or POTT scheme. Firmware version 3.x and earlier has a hard coded POS Seq Restraint of 0.0625.
L90	Neg Seq Dir OC2 (NEG seq type)	Fwd/Rev Pickup	Firmare V5.8x and newer uses Neg Seq Dir OC2 to supervise Neg Seq Dir OC1. If the Negative Sequence Directional elements are used in a DCB or POTT scheme verify this logic exists and remote terminal and the Fwd and Rev pickups are coordinated in primay amps.
L90	1P Blocking Scheme/1P Hybrid POTT	Grn Dir OC Fwd/Rev	All teminals of a line must use the same setting (Grd Dir OC Fwd/Rev) at all terminals of a line. Some settings are developed in Flexlogic.
L90	Phase Distance Z1	Reach	Make sure the reach is below 85% so that it does not show up during PRC-027 checks.
L90	Ground Distance Z1	Reach	Make sure the reach is below 85% so that it does not show up during PRC-027 checks. Confirm that mutuals were considered when setting was made.
L90	Phase Instantaneous (Phase IOC1)	Enable/Disable	Disable or desensitize if possible. Should be able to disable if Phase Distance Z1 and Line Pickup are enabled and set per SS-451010. Coordination must be maintanied. Update comm workbook as necessary.
L90	Ground Instantaneous (Neutral IOC1)	Enable/Disable	Disable or desensitize if possible. Should be able to desensitize if Ground Distance Z1 and Line Pickup are enabled and set per SS-451010. Coordination must be maintanied.
L90	Phase Distance trip and block supervision		Ensure that the phase distance trip supervision element at one end coordinates with the phase distance block supervision element at the other end, in primary amps, in a DCB or POTT scheme.
L90	Ground Distance trip and block supervision		Ensure that the ground distance trip supervision element at one end coordinates with the ground distance block supervision element at the other end, in primary amps, in a DCB or POTT scheme.
L90	Line Pickup	Autoreclose Coordination Bypass	Ensure that this is set to Disabled. Update comm workbook as necessary.
L90	Current Differential	Fault Detector	Confirm whether tap load exists on the circuit (ASPEN tap buses are indication of tapped load). If it does confirm whether fault detectors are enabled and set properly (fault detedtors are enabled/disabled by either flex logic or a switch).
L90	DCB	Rx Coord Pickup Delay	Set to 0.024 sec regardless of whether or not the remote relay(s) are similar or mismatched. The remote terminals do not have to be changed at the same time.
L90	DTT Trip input	S5a; S7a	If your relay has a contact input that is used for direct tripping such as DTT Trip Receive or DTT Keying the input must have a 10msec debounce time.
L90	Relay Mismatch with Remote End Relay while using DCB	EDG-20 & Ground DCB OC	If you are using DCB and your relay does not match the remote end relay, make sure all terminals are using EDG-20, if possible, and to desensitize the ground DCB overcurrent elements. Reference SS-451010 8.2.4.6

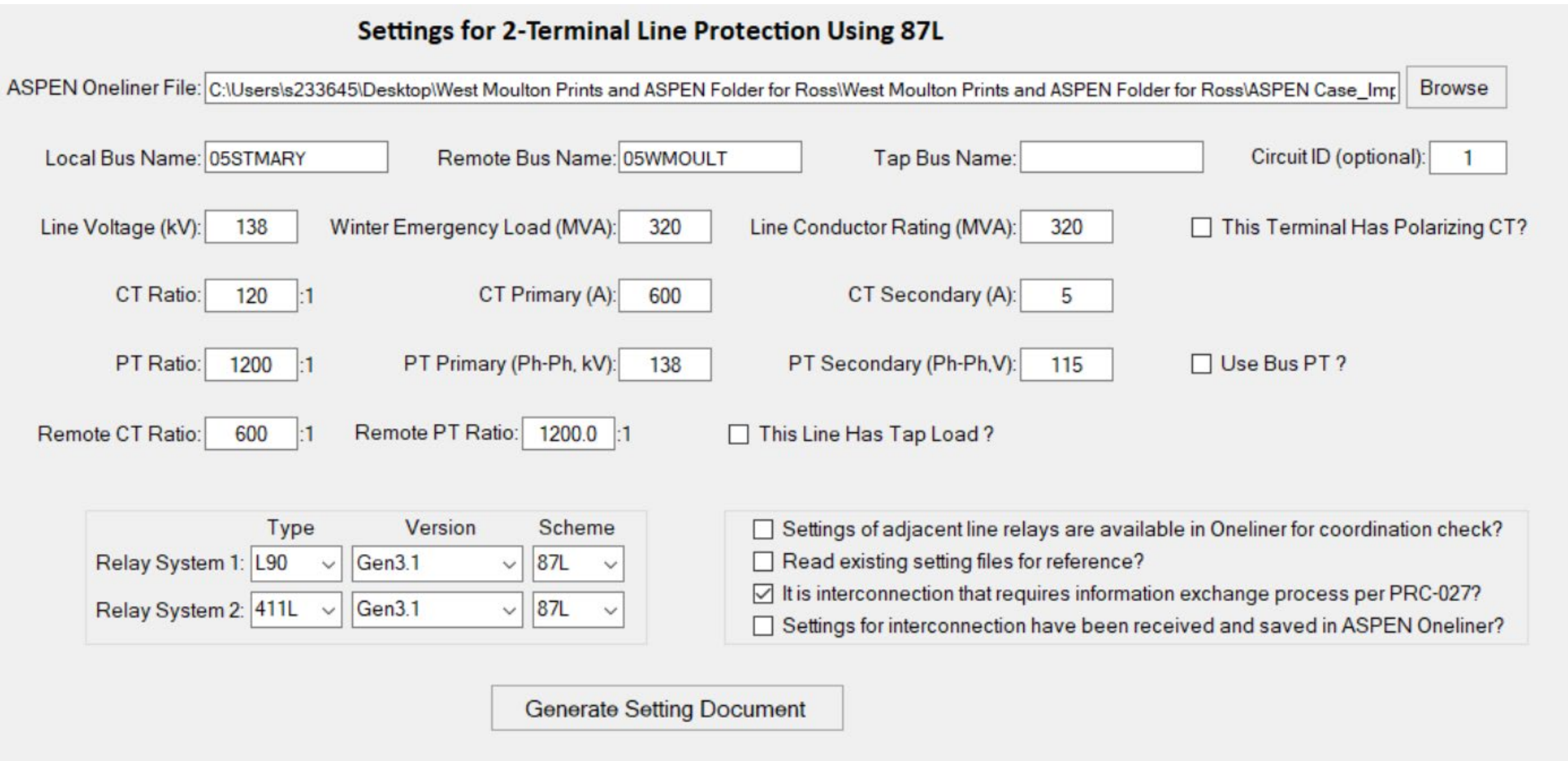
General | Revision History | Checklist | App A-L90-CS | App B-411L-CS | App C-D60-CS | App D-421-CS | App E

Automated Relay Settings

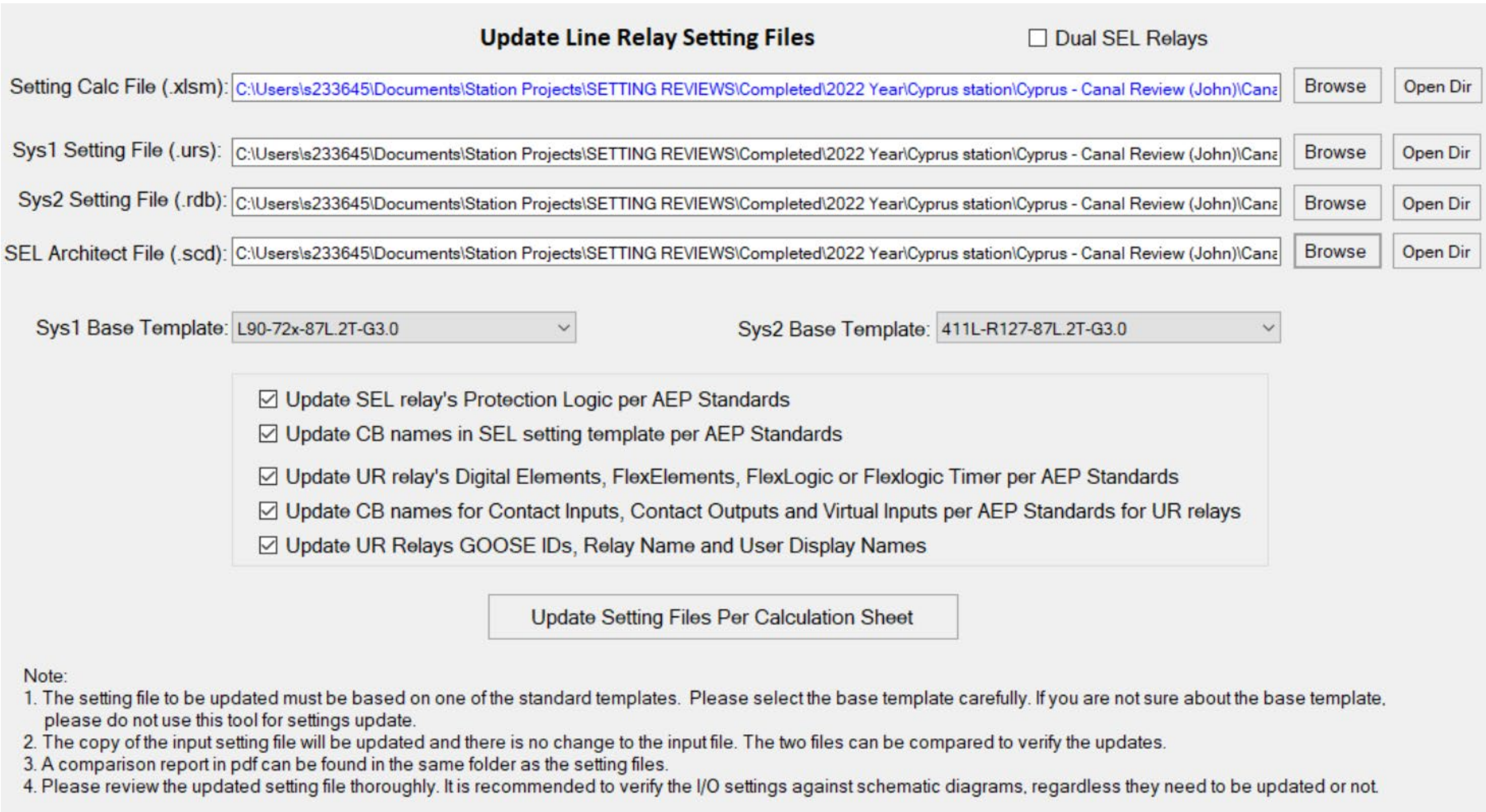
- PCE has worked with an outside consultant to development an Automated Relay Settings (ARS) tool
- ARS has many different benefits, but the three most important are its ability to **reduce human error**, its ability to **reduce engineering labor time/cost**, and its ability to **enforce consistent setting criteria/philosophies**



Automated Relay Settings



Automated Relay Settings



Automated Relay Settings

- Interfaces with short circuit software
- Interfaces with raw setting files
- Promotes consistent settings
- Easy to update software
- Is a tool, not a complete solution, still requires some engineering and sanity checks

PRC-027 Area Coordination Reviews

- One of the standard's requirements calls for performing a periodic relay system coordination review every six-calendar years.
- PCE has taken the approach of completely resetting all of its BES terminal so that they are up to modern criteria/philosophies "The Great Reset"
- 500-765kV complete, 345kV expected complete by end of 2022, 100-161kV complete by end of 2023
- Heavily proactive approach that requires a lot of resources, but will pay off in reducing risk and misoperations

Relay Failures

- Trending misoperation cause for AEP
- AEP still has a lot of Electromechanical relays that we are upgrading via capital projects
- Older first generation IED relays are now starting to reach the end of their lives and we are starting to proactively replace with newer hardware

Relay Failures

- IED relays from a particular vendor have periodically suffered from a memory corruption also referred to as a “bit flip” which results in the relay asserting protection elements during non-fault conditions.
- AEP has worked with this vendor to prevent future misoperations from “bit flips” by implementing a change in the relay firmware

Relay Settings Criteria / Philosophy Improvements

- No longer set phase or ground instantaneous overcurrents if distance elements are available
- Enhanced its directional settings guidance for carrier-based schemes that are very reliant on correct direction assessments. Rely heavily on negative sequence, force one common method at all terminals of line
- Increased carrier coordination timer to 24 milliseconds for all carrier relays

Relay Settings Criteria / Philosophy Improvements

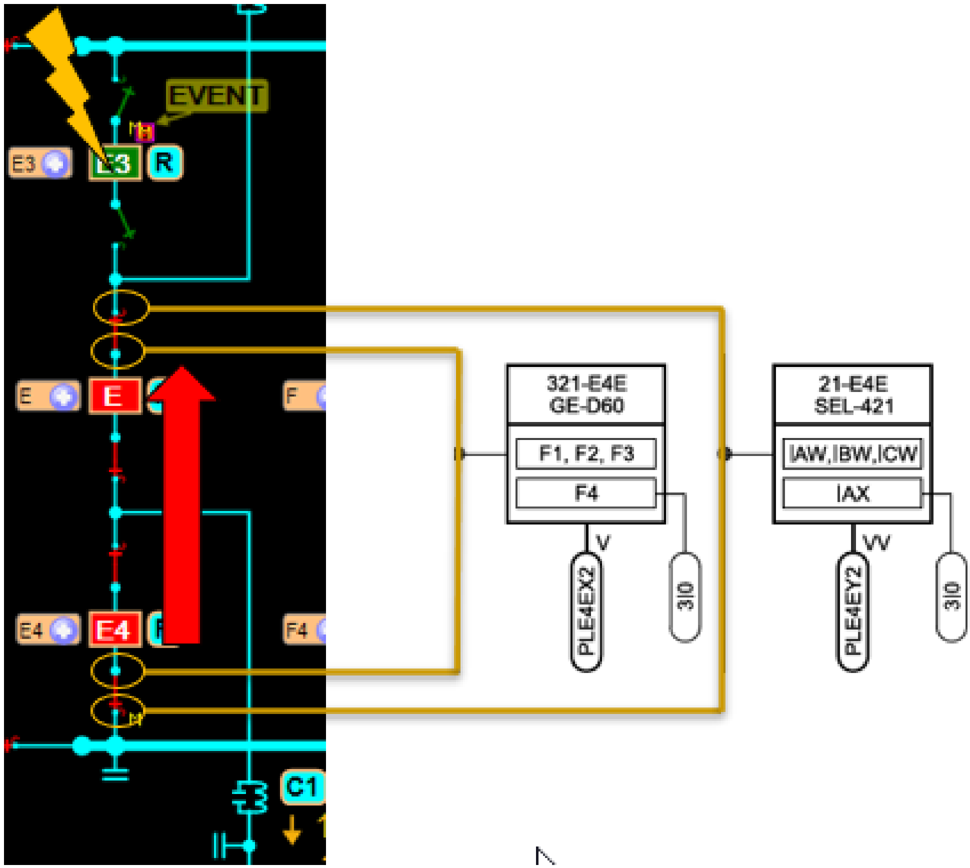
- Desensitize carrier forward ground overcurrent elements so that the schemes aren’t being tested as much. The guidance is to try to set at 600 Amps primary and only reduce if you have sensitivity issues
- Delay carrier forward ground overcurrent elements by 8 cycles, to allow carrier forward ground distance elements to act first

Relay Settings Criteria / Philosophy Improvements

- Desensitize current differential schemes by settings at 5A secondary and only lowering if needed
- No longer use negative sequence differential for lines
- Moving towards all line schemes using individual currents and summing internally as opposed to externally
- Changed our capacitor bank design from ungrounded wye to grounded wye

CT Saturation

- Trending misoperation cause for AEP
- Often when dealing with multiple CTs that sum external
- Have not been consistent in past on how CT ratios are selected



Scoping CT Sizing Calculator

- PCE has developed a formal CT sizing calculator for scoping
- Helps get correct max ratio CTs ordered
- Identifies potential problems way in advance

Fault Data Provided by Planning Engineer (Only Make Changes to Yellow Cells)					
3LG Expected Bus Fault Level (kA)	10				
3LG Expected Bus Fault X/R Ratio	5				
1LG Expected Bus Fault Level (kA)	10				
1LG Expected Bus Fault X/R Ratio	5				
Possible CT Selections					
Full Ratio	1200	2000	3000	4000	5000
Accuracy Ratio @ C800	1200	1200	2000	3000	4000
Is CT selection acceptable?	YES	YES	YES	YES	YES
Minimum Acceptable CT Cable	4C	4C	4C	4C	4C
Max CT Secondary Current @ Full Ratio	42	25	17	13	10
CT Saturation Results @ Full Ratio					
3LG (4C/#10 CT cables)	48%	22%	19%	19%	18%
1LG (4C/#10 CT cables)	77%	32%	27%	24%	22%
3LG (12C/#10 CT cables)	29%	15%	14%	15%	14%
1LG (12C/#10 CT cables)	39%	18%	17%	17%	16%

Detailed CT Ratio Selection Calculator

600A	1200A	2000A	3000A	4000A	5000A
50	100	300	300	500	500
100	200	400	500	1000	1000
150	300	500	800	1500	1500
200	400	800	1000	2000	2000
250	500	1100	1200	2500	2500
300	600	1200	1500	3000	3000
400	800	1500	2000	3500	3500
450	900	1600	2200	4000	4000
500	1000	2000	2500		5000
600	1200		3000		

CT Information				
Full Ratio	1200:5			
Connected Ratio	1200:5		CTR =	240
Accuracy Ratio	1200:5			
Accuracy Class	C800			
Thermal Rating Factor	3.0			
Winding Resistance	0.0027	ohms/turn		
Winding Connection	WYE			
Lead Conductor Size	#10		0.9989	ohms per 1000 feet
Lead Conductors per phase	1			
Lead Length (feet, one-way)	1000'			
Remnance	0	percent		

Burden Calculation (ohms secondary)	
CT Winding Resistance	0.65
CT Lead Resistance One-Way	1.00
Relay Burden	0.02
Maximum Rated CT Burden	8.00
CT Burden (3LG or LL)	1.67
CT Burden (LG)	2.67

CT Saturation for 3LG & LL Faults		
saturation current	20,752	amps primary
maximum fault current	10,000	amps primary
maximum fault X/R ratio	5	
% of saturation current	48%	

CT Saturation for 1LG Faults		
saturation current	12,976	amps primary
maximum fault current	10,000	amps primary
maximum fault X/R ratio	5	
% of saturation current	77%	

CT Loadability		
CT Thermal Limit	3,600	amps primary
Bus Voltage	138	kV
Winter Emergency Rating	400	MVA
NERC required current	2,513	amps (@ 150% WE)
% of CT Thermal Limit	70%	
AEP required current	1,675	amps (@ 100% WE)
% of CT Thermal Limit	47%	

Sensitivity Check (Remote End Fault with Strongest Source Out of Service)		
Strongest Source	Enter Strongest Source Name Here	
LG	3000	amps primary
LL	3000	amps primary
Minimum CT Current	12.5	amps secondary
Maximum CT Current	42	amps secondary

Mathcad		
Rated CT Terminal Voltage	800	volts
Max CT Secondary Current	100	amps
Rated CT Excitation Voltage	865	volts
3LG Fault CT Excitation Voltage	417	volts
% saturated	48%	
1LG Fault CT Excitation Voltage	666	volts
% saturated	77%	

Reference Documents

AEP SS-451010 Rev.11, Section 4.12.3.3 - Line Relay CT Ratio Selection Guidelines, page 42

IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes - IEEE Std C37.1110-2007

"Selecting CTs to Optimize Relay Performance" by Gabriel Benmouyal (IREQ), Jeff Roberts (SEL) and Stanley E. Zocholl (SEL)

Advanced Misoperation Metrics Dashboard

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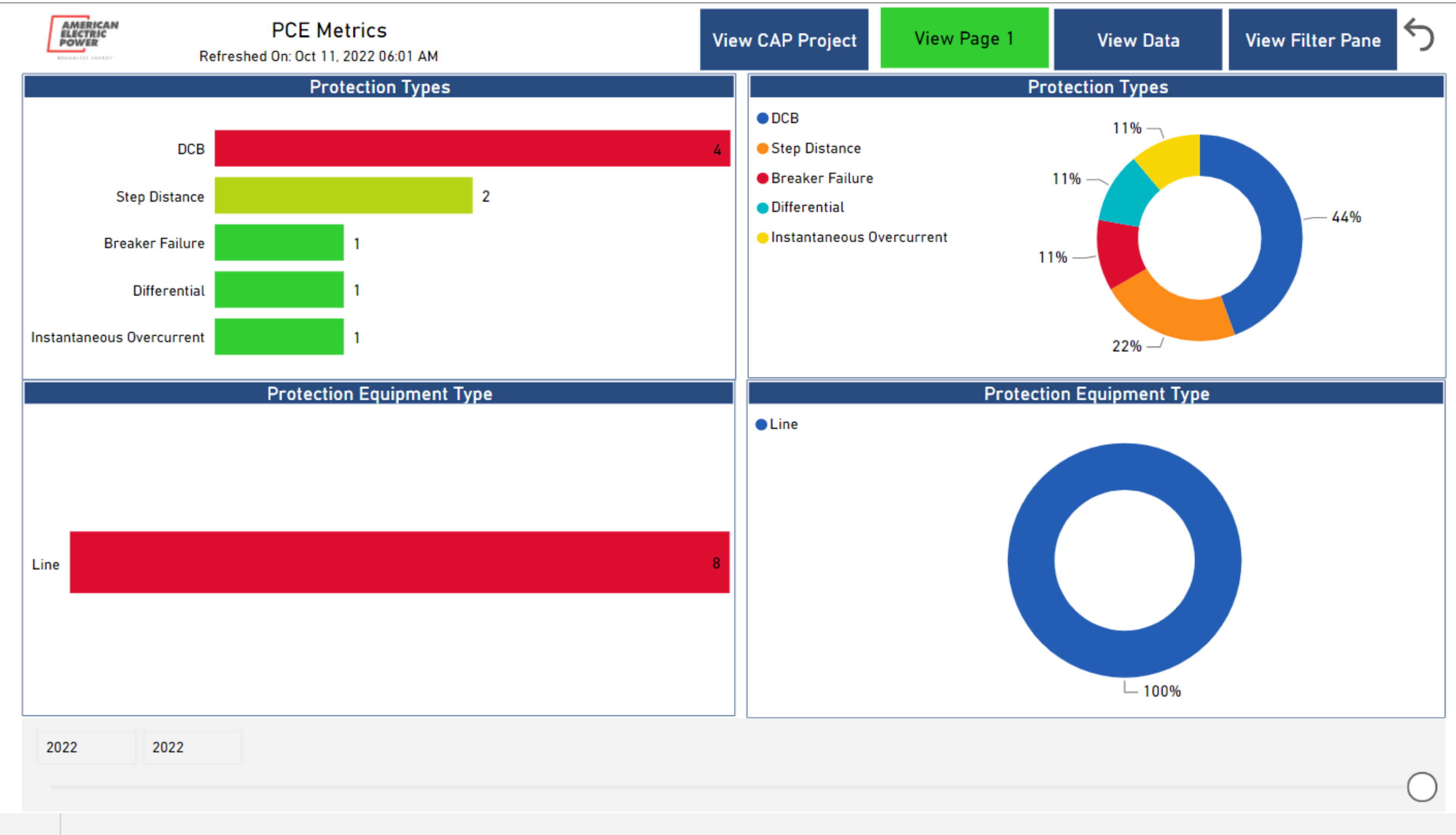
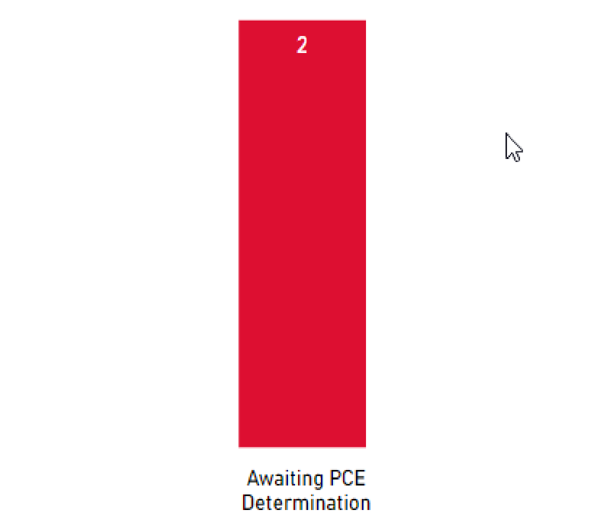


Advanced Misoperation Metrics Dashboard

PCE Workflow

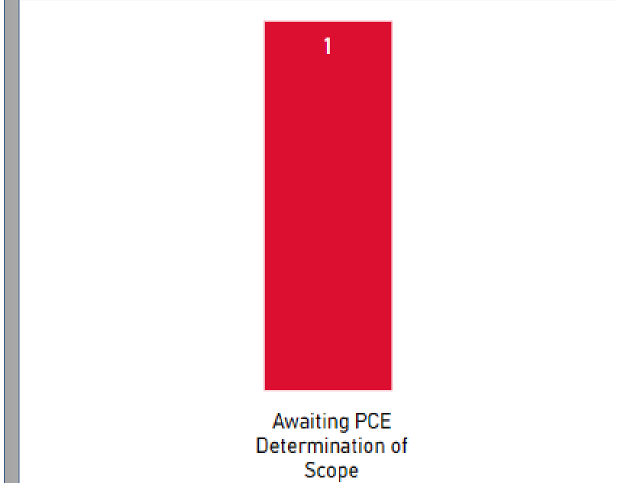
Refreshed On: Oct 11, 2022 06:01 AM

PCE Determination of Misoperation Cause



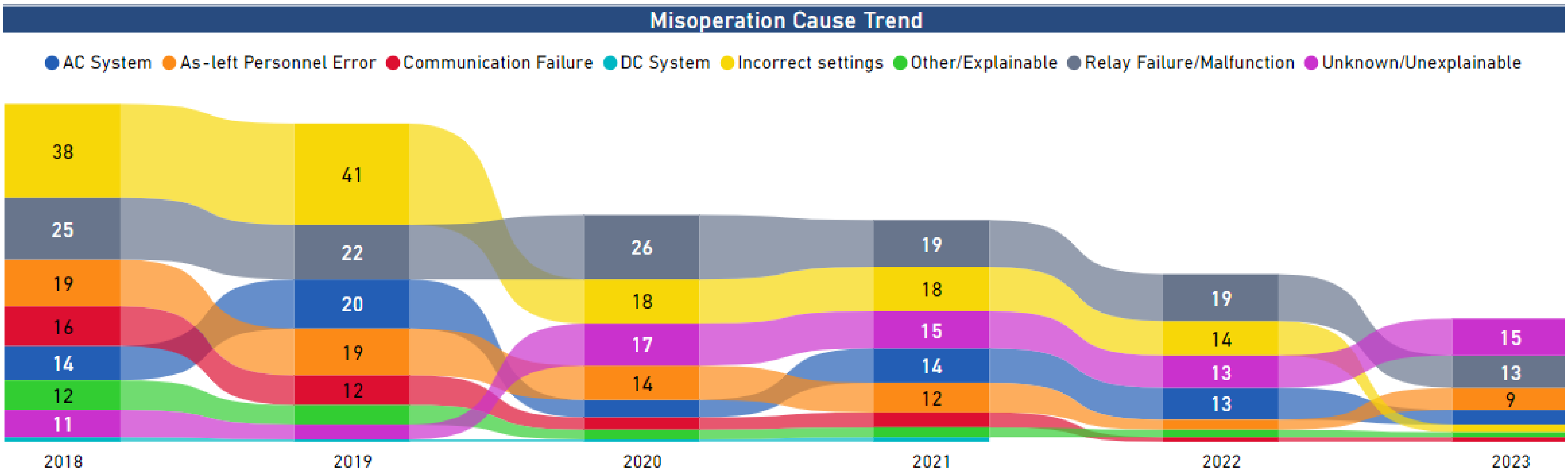
Awaiting PCE CAP Applicability

PCE Determination of Applicability Extent of Condition



AEIR ID	Event Date	Outage Category	Misop Cause	NERC Reportable	Transmission Region	Station	Protected Equipment Name	Components That Misoperated
209623	2/15/2022	Misoperation	Incorrect settings	Yes	Columbus	Clinton	Clinton - Huntley - Karl	L90 line current differential tapped load
209767	3/30/2022	Misoperation	Unknown/Unexplainable	Yes	Tulsa	Center	Center-Tenaha	
211103	9/20/2022	Misoperation	Unknown/Unexplainable	Yes	Corpus Christi	Laredo VFT South	Laredo VFT South-CAP-1417	351S SV15T (time delay UV trip)

Advanced Misoperation Metrics Dashboard




ANY
QUESTIONS?