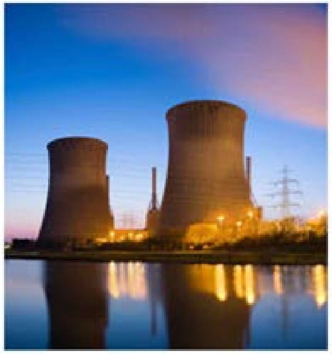
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Event Analysis Reporting

Protection System Misoperation Snapshot

Matt Lewis, Manager of Event Analysis
BES Protection System Misoperation Reduction Workshop
October 25, 2023

RELIABILITY | RESILIENCE | SECURITY

Statutory Performance Monitoring

NERC Rules of Procedure (Section 800 and Appendix 8)

- Flexible discretionary risk and/or impact analysis authorities
- Major event response

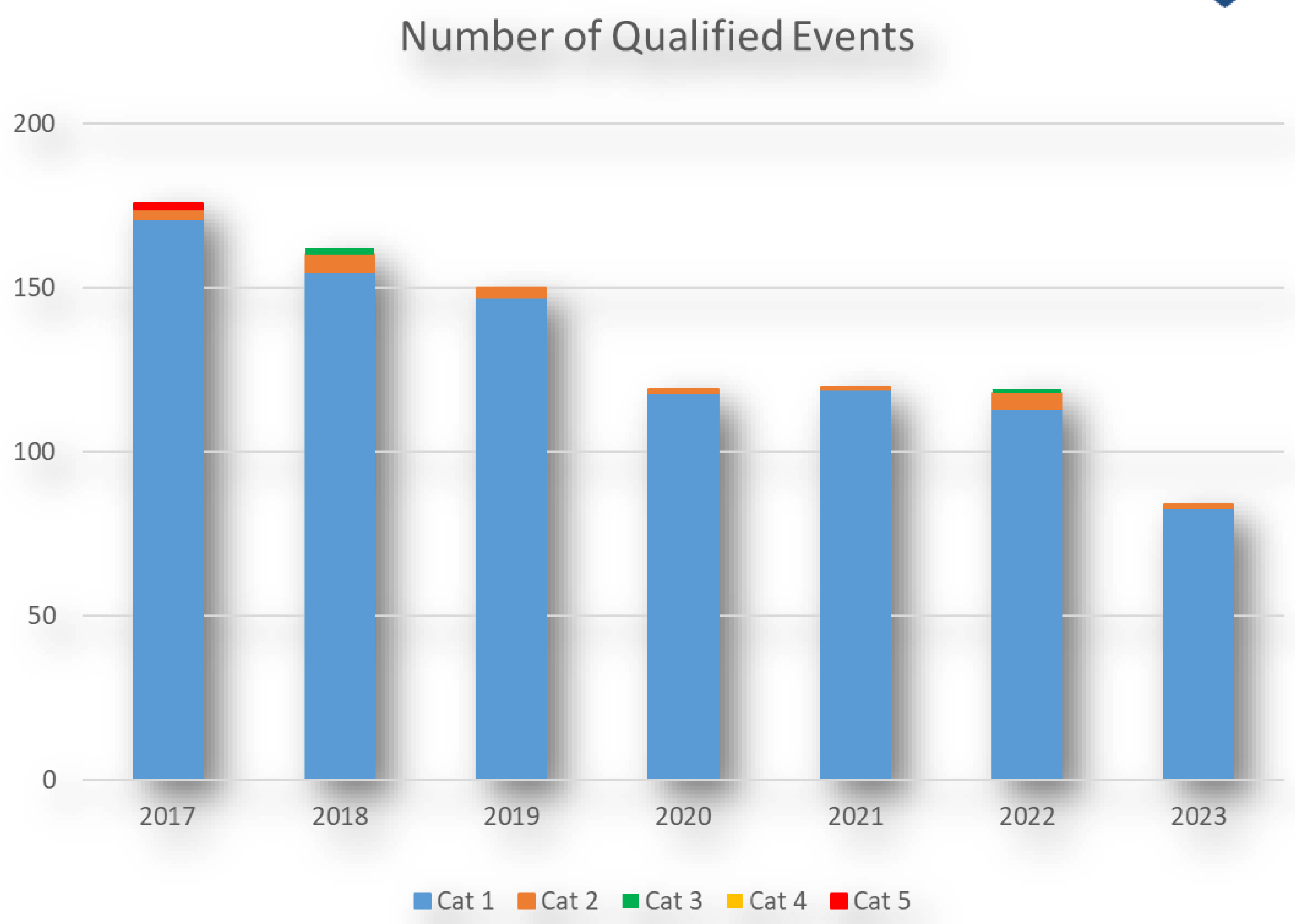
ERO Event Analysis Process (EAP)

- System operating criterion-based risk and/or impact monitoring
- Off-normal to major system event spectrum

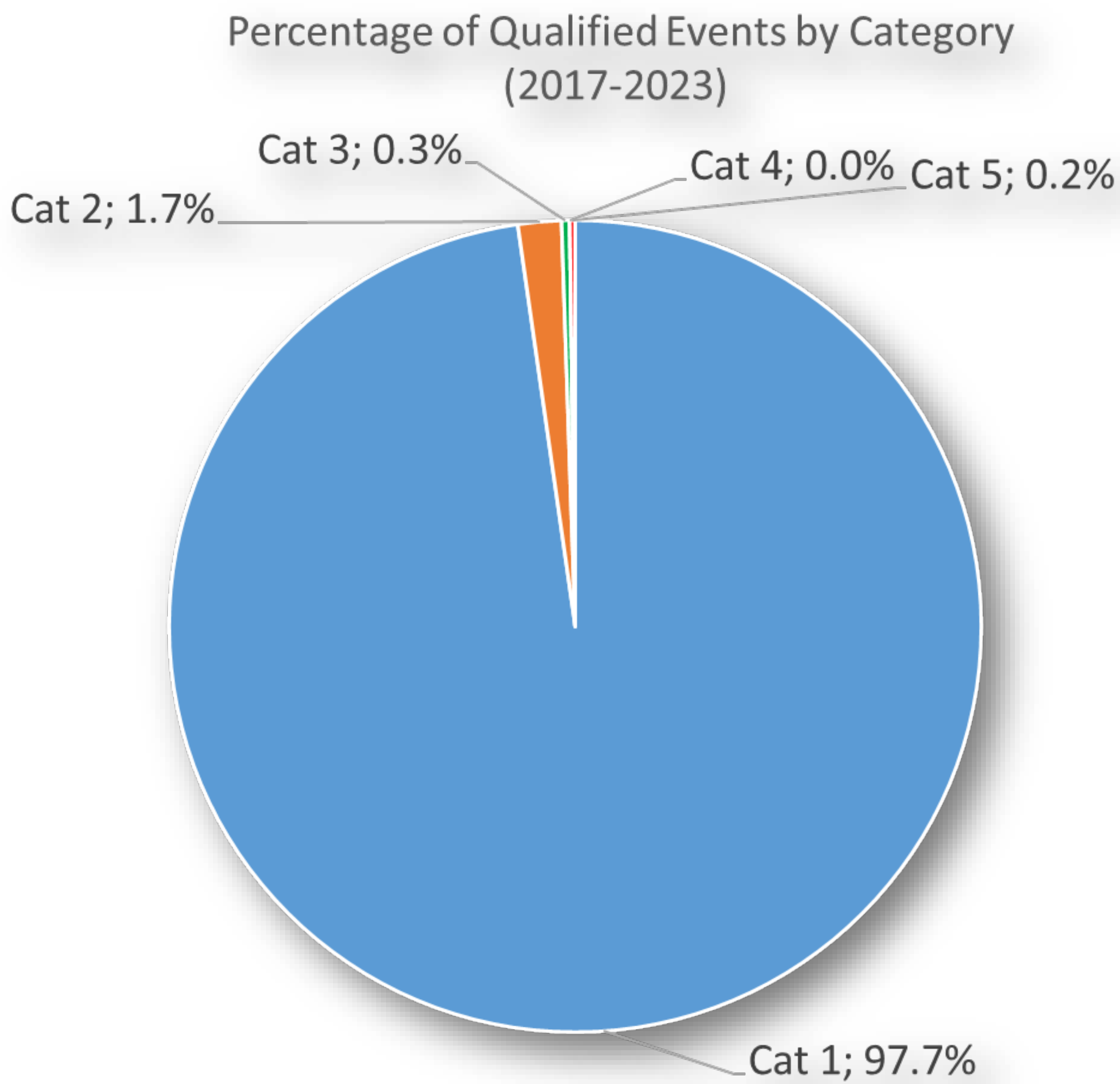
ERO Cause Code Assignment Process (CCAP)

- System risk and/or impact trending

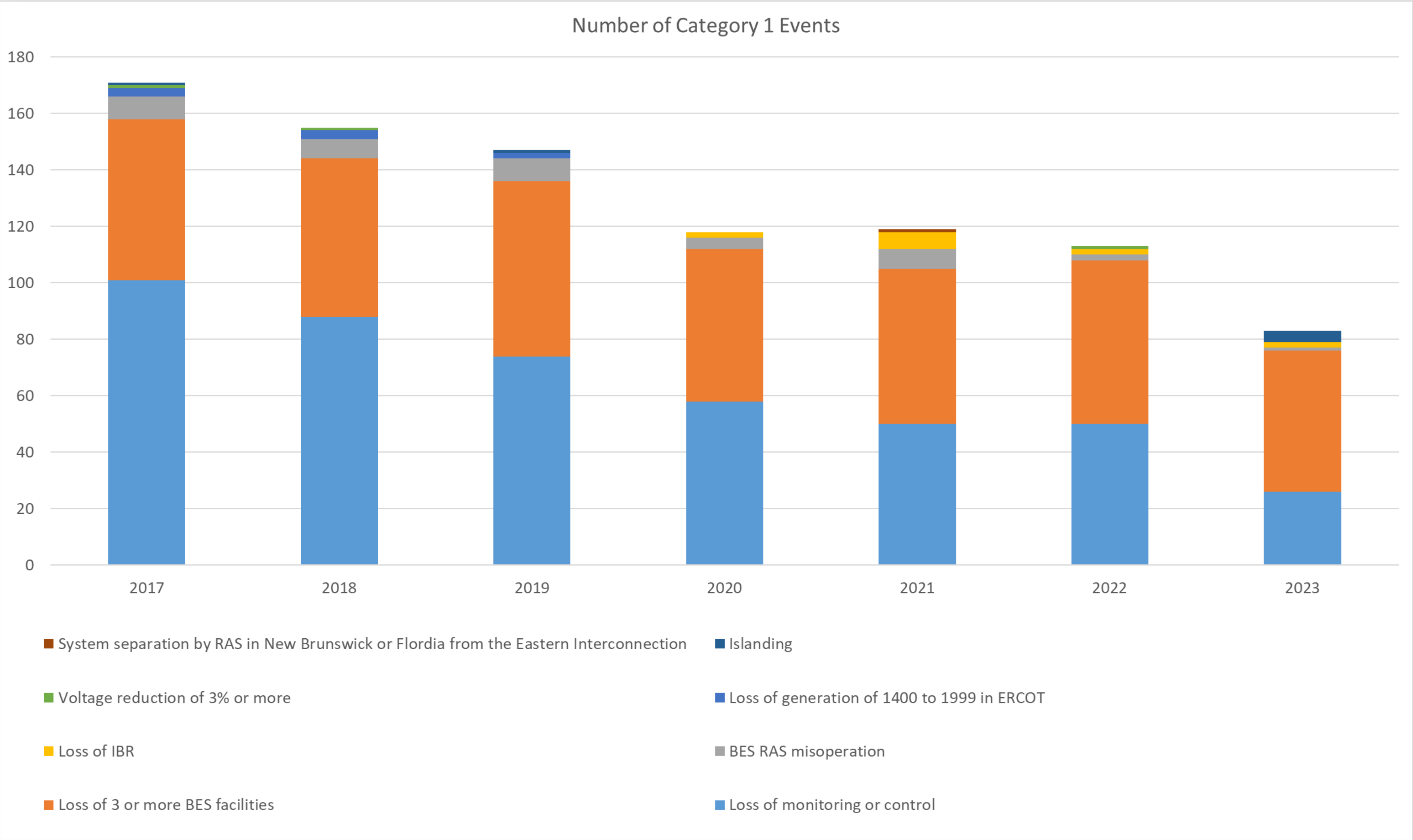
Qualified Event Trending



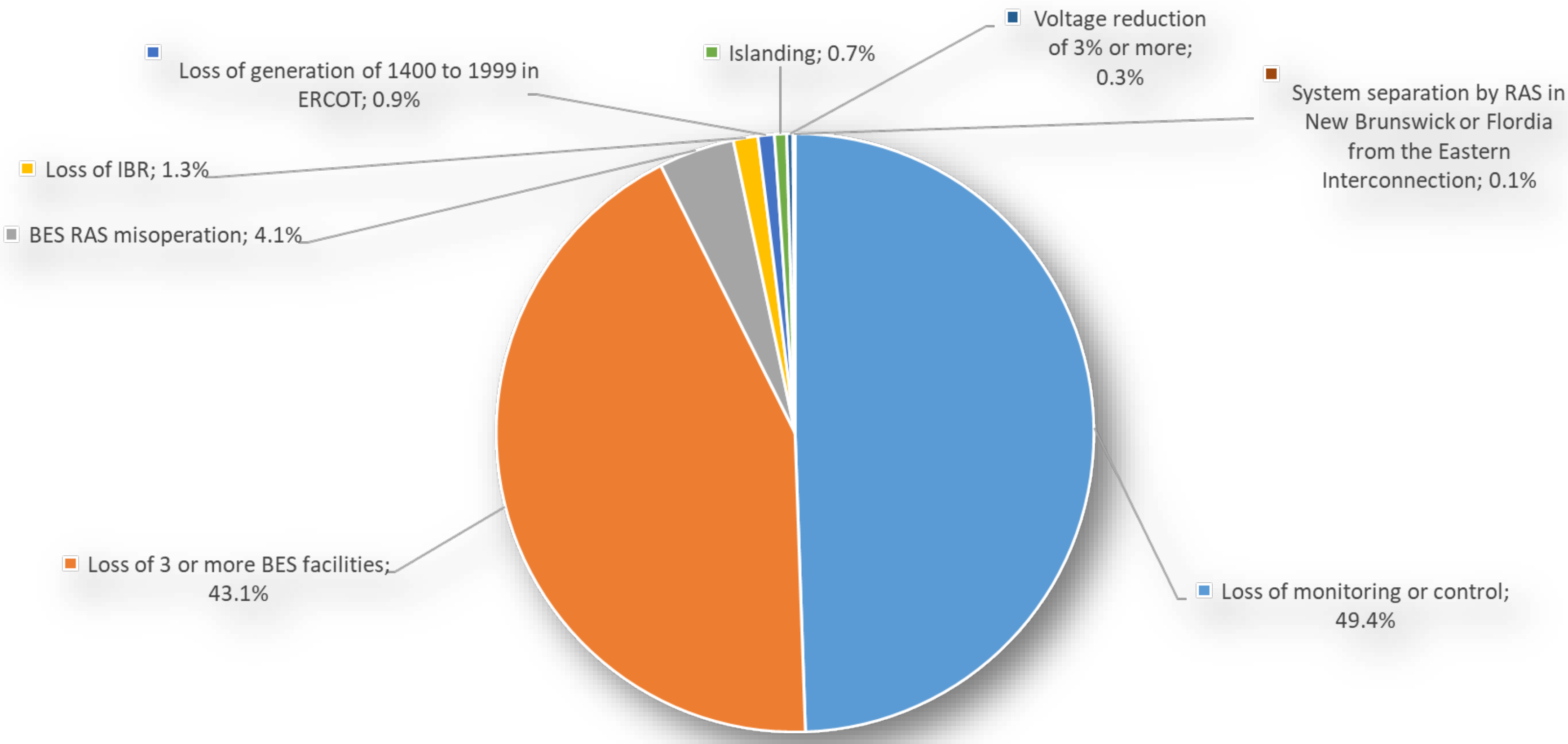
Qualified Event Trending (cont'd)



Category 1 Event Type Trending



Category 1 Event Type Trending (Cont'd)



Percentage of Catergory 1 Events by Event Type (2017-2023)

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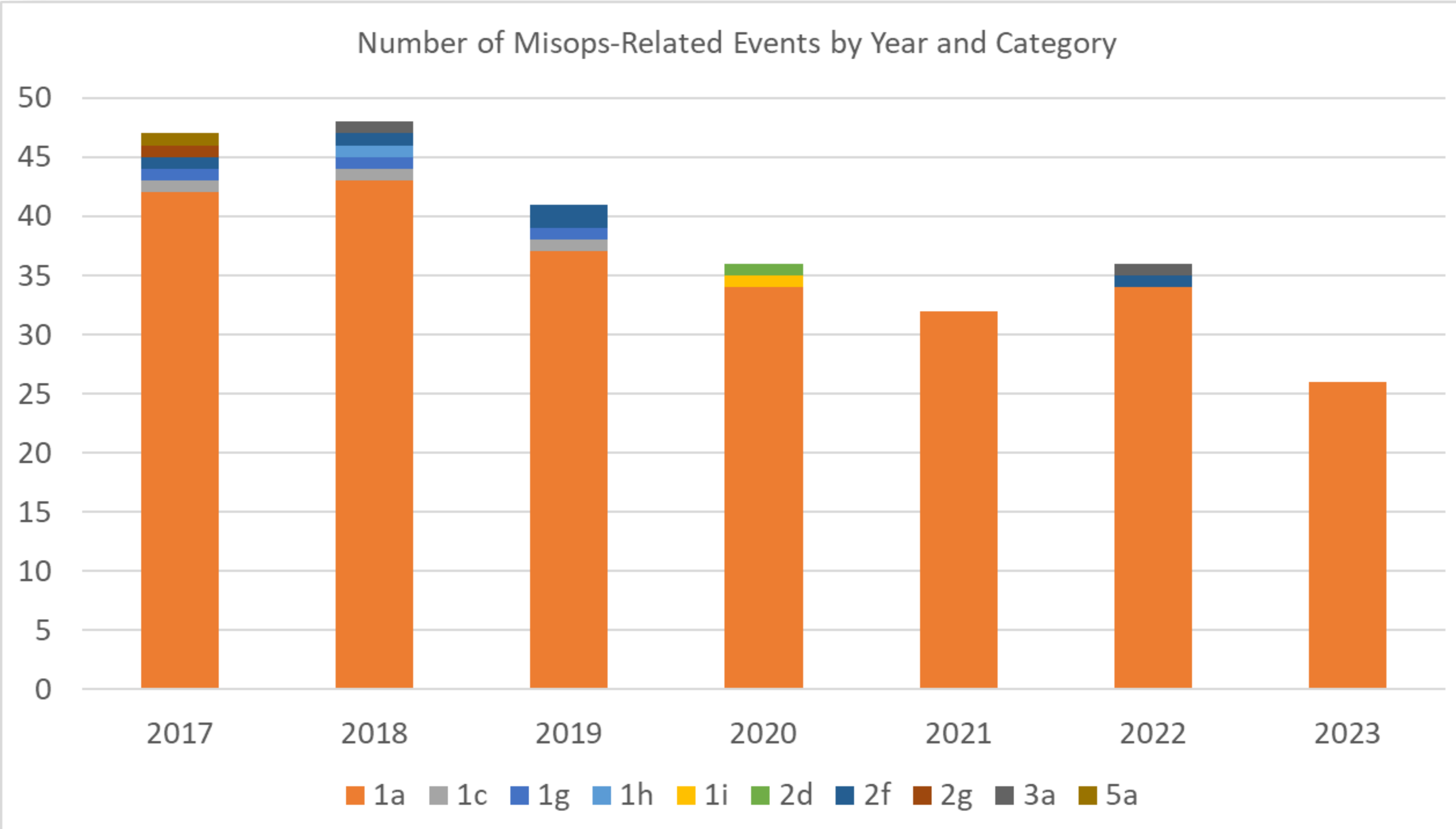
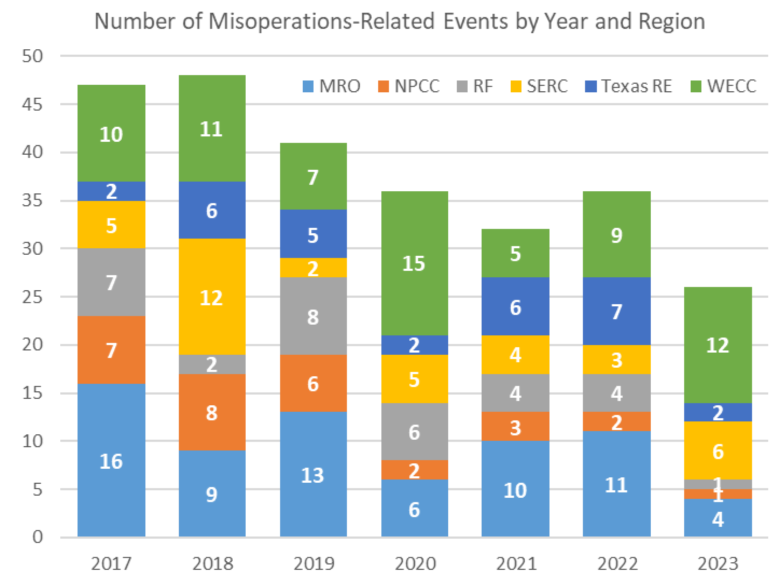
Misoperation Event Type by Year



Category 1a: An unexpected outage, that is contrary to design, of three or more BES facilities caused by a common disturbance...

Misoperation Snapshot



- Gold: incorrect settings
- Silver: relay failures
- Bronze: medley of reasons
- Good news -- related event totals are headed in a downward direction
- Seeking better understanding of why

Total Events (2017-present)	928	Percentage of Total Events (2017-present)
Misops-related Events (2017-present)	266	29%
Reasons		Percentage of Misops-related Events
Incorrect Settings	104	39%
Relay Failure	40	15%
Others	122	46%
Start-up testing		
Inspection testing		
Post maintenance/modification testing		
Mis-wiring		
Human performance		
Organization performance		

Questions and Answers

Reference

- Event Analysis Program
- ERO Event Analysis Process Document - Version 4.0
- Cause Code Quick Reference Guide
- Cause Code Assignment Process
- Event Reports
- Lessons Learned

EAP Category

Category 1: An Event that Results in One or More of the Following:

a. An unexpected outage, that is contrary to design, of three or more BES Facilities caused by a common disturbance[4]:

   i. The outage of a combination of three or more BES Facilities (excluding successful automatic reclosing)

   ii. The outage of an entire generation station of three or more generators (aggregate generation of 500 MW to 1,999 MW)[5]; each combined-cycle unit is counted as one generator.

b. Intended and controlled system separation by the proper operation of a remedial action scheme (RAS) in New Brunswick or Florida from the Eastern Interconnection

c. Failure or misoperation of a BES RAS

[3] ERO Enterprise Guide for the Multi-Region Registered Entity Coordinated Oversight Program, March 2018, Section IX: System Events

[4] As defined in the NERC Glossary of Terms: Disturbance - 1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

[5] Gross MW output of the generators at the time of the outage.

d. System-wide voltage reduction of 3% or more that lasts more than 15 continuous minutes due to a BES Emergency

e. Unintended BES system separation that results in an island of 100 MW to 999 MW. This excludes BES radial connections and non-BES (distribution) level islanding

f. ~~Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.~~ Retired on January 1, 2016

g. In ERCOT, unintended loss of generation of 1,400 MW to 1,999 MW

h. Loss of monitoring or control at a control center such that it significantly affects the entity's ability to make operating decisions for 30 continuous minutes or more.

   Some examples that should be considered for EA reporting include, but are not limited to the following:

   i. Loss of operator ability to remotely monitor or control BES elements

   ii. Loss of communications from SCADA remote terminal units (RTU)

   iii. Unavailability of ICCP links, which reduces BES visibility

   iv. Loss of the ability to remotely monitor and control generating units via automatic generation control (AGC)

   v. Unacceptable state estimator or real time contingency analysis solutions

i. A non-consequential interruption[6] of inverter type resources[7] aggregated to 500MW or more not caused by a fault on its inverters, or its ac terminal equipment.

j. A non-consequential interruption[6] of a dc tie, between two separate asynchronous systems, loaded at 500 MW or more, when the outage is not caused by a fault on the dc tie, its inverters, or its ac terminal equipment.

Category 2: An Event that Results in One or More of the Following:

a. Complete loss of interpersonal communication and alternative interpersonal communication capability affecting its staffed BES control center for 30 continuous minutes or more.

b. ~~Complete loss of SCADA, control or monitoring functionality for 30 minutes or more.~~ Retired on January 01, 2016 refer to Category 1h

c. BES Emergency resulting in a voltage deviation of ≥ 10% difference of nominal voltage sustained for ≥ 15 continuous minutes.

d. Complete loss of off-site power (LOOP) to a nuclear generating station per the Nuclear Plant Interface Requirement

e. Unintended system separation that results in an island of 1,000 MW to 4,999 MW

f. Unintended loss of 300 MW or more of firm load for more than 15 minutes

g. Interconnection Reliability Operating Limit (IROL) violation for time greater than T_v

[6] Interruption of resources caused by action of control systems on the resources in response to perturbations in voltage and/or frequency on the Interconnection, not including the control actions of a RAS.

[7] In most cases, inverter-based generating resources refer to Type 3 and Type 4 wind power plants, and solar photovoltaic (PV) resources. Battery energy storage is also considered an inverter-based resource. Many transmission-connected reactive devices such as STATCOMs and SVCs are also inverter-based. Similarly, HVDC circuit also interface with the AC network though converters.

EAP Category (cont'd)

Category 3: An Event That Results in One or More of the Following:

a. Unintended loss of load, generation (including inverter type resources), or dc tie to asynchronous resources of 2,000 MW or more.

b. Unintended system separation that results in an island of 5,000 MW to 10,000 MW

c. Unintended system separation (without load loss) that islands Florida from the Eastern Interconnection

Category 4: An Event that Results in One or More of the Following:

a. Unintended loss of load, generation (including inverter type resources) from 5,001 MW to 9,999 MW

b. Unintended system separation that results in an island of more than 10,000 MW (with the exception of Florida, as described in Category 3c)

Category 5: An Event that Results in One or More of the Following:

a. Unintended loss of load of 10,000 MW or more

b. Unintended loss of generation of 10,000 MW or more

Event Analysis Planning Meeting/Coordination Call (Step 2)

Following an event, the RE and/or NERC will determine if a planning or coordination meeting is required between the registered entity(ies) and the applicable RE. More than one planning meeting may be conducted based on the registered entity's experience level with the EAP, the scope of the event, or the number of registered entities involved.

The planning meeting (when held) should:

1. confirm the event category;
2. determine the level of analysis;[8]
3. identify the roles for the registered entity(ies), REs, and NERC;
4. establish milestones, coordination of target dates, and determine reporting entity(ies) for completing reports, lessons learned, and other necessary analysis for events requiring detailed analysis, or the analysis itself would take longer to complete than the target dates set in the appendices. Should additional time be needed beyond the target dates to complete the analysis, this can be granted by the RE on a case-by-case basis as necessary;
5. identify the need for a data retention hold; and
6. identify data and information confidentiality issues.

Registered entities should capture relevant data for the event analysis. REs will formally send a Data Retention Hold[9] Notice for events in Category 3 or higher, if deemed necessary by the RE(s) or NERC.

The Appendix B: Planning Meeting Scope Template can be used as an outline in the planning meeting.

[8] Although the category of the event provides general guidance on the level of analysis needed, these guidelines may be adjusted by the EA team, based on the overall significance of the event and the potential for valuable lessons learned.

[9] BPS users, owners, and operators are required, upon request, to produce any requested data pursuant to Title 18 of the Code of Federal Regulations (CFR) Part 39.

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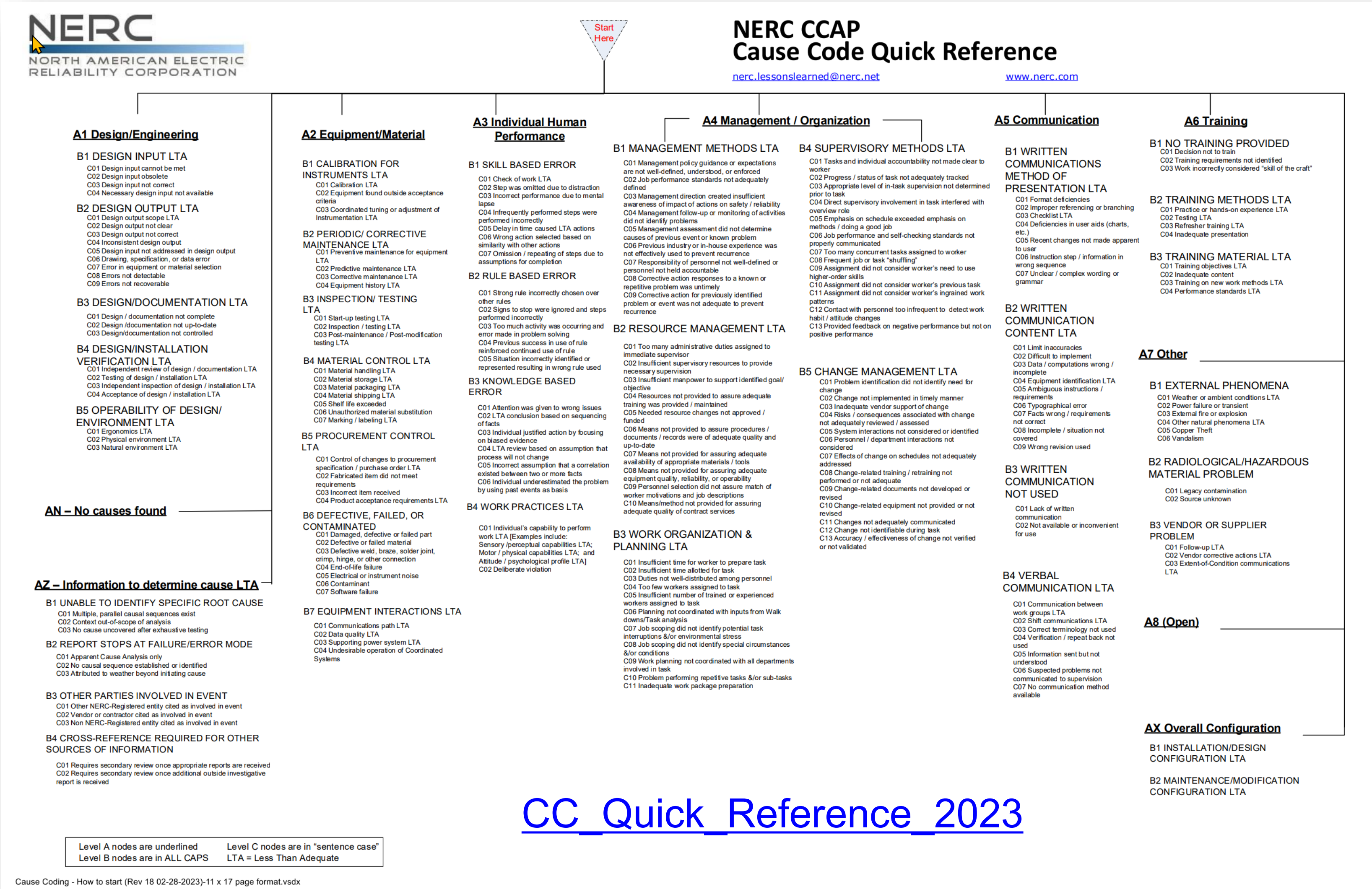
Cause Code Reference



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Start Here

NERC CCAP
Cause Code Quick Reference

nerc.lessonslearned@nerc.net   www.nerc.com

A1 Design/Engineering

B1 DESIGN INPUT LTA
- C01 Design input cannot be met
- C02 Design input obsolete
- C03 Design input not correct
- C04 Necessary design input not available

B2 DESIGN OUTPUT LTA
- C01 Design output scope LTA
- C02 Design output not clear
- C03 Design output not correct
- C04 Inconsistent design output
- C05 Design input not addressed in design output
- C06 Drawing, specification, or data error
- C07 Error in equipment or material selection
- C08 Errors not detectable
- C09 Errors not recoverable

B3 DESIGN/DOCUMENTATION LTA
- C01 Design / documentation not complete
- C02 Design /documentation not up-to-date
- C03 Design/documentation not controlled

B4 DESIGN/INSTALLATION VERIFICATION LTA
- C01 Independent review of design / documentation LTA
- C02 Testing of design / installation LTA
- C03 Independent inspection of design / installation LTA
- C04 Acceptance of design / installation LTA

B5 OPERABILITY OF DESIGN/ ENVIRONMENT LTA
- C01 Ergonomics LTA
- C02 Physical environment LTA
- C03 Natural environment LTA

AN – No causes found

AZ – Information to determine cause LTA

B1 UNABLE TO IDENTIFY SPECIFIC ROOT CAUSE
- C01 Multiple, parallel causal sequences exist
- C02 Context out-of-scope of analysis
- C03 No cause uncovered after exhaustive testing

B2 REPORT STOPS AT FAILURE/ERROR MODE
- C01 Apparent Cause Analysis only
- C02 No causal sequence established or identified
- C03 Attributed to weather beyond initiating cause

B3 OTHER PARTIES INVOLVED IN EVENT
- C01 Other NERC-Registered entity cited as involved in event
- C02 Vendor or contractor cited as involved in event
- C03 Non NERC-Registered entity cited as involved in event

B4 CROSS-REFERENCE REQUIRED FOR OTHER SOURCES OF INFORMATION
- C01 Requires secondary review once appropriate reports are received
- C02 Requires secondary review once additional outside investigative report is received

A2 Equipment/Material

B1 CALIBRATION FOR INSTRUMENTS LTA
- C01 Calibration LTA
- C02 Equipment found outside acceptance criteria
- C03 Coordinated tuning or adjustment of Instrumentation LTA

B2 PERIODIC/ CORRECTIVE MAINTENANCE LTA
- C01 Preventive maintenance for equipment LTA
- C02 Predictive maintenance LTA
- C03 Corrective maintenance LTA
- C04 Equipment history LTA

B3 INSPECTION/ TESTING LTA
- C01 Start-up testing LTA
- C02 Inspection / testing LTA
- C03 Post-maintenance / Post-modification testing LTA

B4 MATERIAL CONTROL LTA
- C01 Material handling LTA
- C02 Material storage LTA
- C03 Material packaging LTA
- C04 Material shipping LTA
- C05 Shelf life exceeded
- C06 Unauthorized material substitution
- C07 Marking / labeling LTA

B5 PROCUREMENT CONTROL LTA
- C01 Control of changes to procurement specification / purchase order LTA
- C02 Fabricated item did not meet requirements
- C03 Incorrect item received
- C04 Product acceptance requirements LTA

B6 DEFECTIVE, FAILED, OR CONTAMINATED
- C01 Damaged, defective or failed part
- C02 Defective or failed material
- C03 Defective weld, braze, solder joint, crimp, hinge, or other connection
- C04 End-of-life failure
- C05 Electrical or instrument noise
- C06 Contaminant
- C07 Software failure

B7 EQUIPMENT INTERACTIONS LTA
- C01 Communications path LTA
- C02 Data quality LTA
- C03 Supporting power system LTA
- C04 Undesirable operation of Coordinated Systems

A3 Individual Human Performance

B1 SKILL BASED ERROR
- C01 Check of work LTA
- C02 Step was omitted due to distraction
- C03 Incorrect performance due to mental lapse
- C04 Infrequently performed steps were performed incorrectly
- C05 Delay in time caused LTA actions
- C06 Wrong action selected based on similarity with other actions
- C07 Omission / repeating of steps due to assumptions for completion

B2 RULE BASED ERROR
- C01 Strong rule incorrectly chosen over other rules
- C02 Signs to stop were ignored and steps performed incorrectly
- C03 Too much activity was occurring and error made in problem solving
- C04 Previous success in use of rule reinforced continued use of rule
- C05 Situation incorrectly identified or represented resulting in wrong rule used

B3 KNOWLEDGE BASED ERROR
- C01 Attention was given to wrong issues
- C02 LTA conclusion based on sequencing of facts
- C03 Individual justified action by focusing on biased evidence
- C04 LTA review based on assumption that process will not change
- C05 Incorrect assumption that a correlation existed between two or more facts
- C06 Individual underestimated the problem by using past events as basis

B4 WORK PRACTICES LTA
- C01 Individual's capability to perform work LTA [Examples include: Sensory /perceptual capabilities LTA; Motor / physical capabilities LTA; and Attitude / psychological profile LTA]
- C02 Deliberate violation

A4 Management / Organization

B1 MANAGEMENT METHODS LTA
- C01 Management policy guidance or expectations are not well-defined, understood, or enforced
- C02 Job performance standards not adequately defined
- C03 Management direction created insufficient awareness of impact of actions on safety / reliability
- C04 Management follow-up or monitoring of activities did not identify problems
- C05 Management assessment did not determine causes of previous event or known problem
- C06 Previous industry or in-house experience was not effectively used to prevent recurrence
- C07 Responsibility of personnel not well-defined or personnel not held accountable
- C08 Corrective action responses to a known or repetitive problem was untimely
- C09 Corrective action for previously identified problem or event was not adequate to prevent recurrence

B2 RESOURCE MANAGEMENT LTA
- C01 Too many administrative duties assigned to immediate supervisor
- C02 Insufficient supervisory resources to provide necessary supervision
- C03 Insufficient manpower to support identified goal/ objective
- C04 Resources not provided to assure adequate training was provided / maintained
- C05 Needed resource changes not approved / funded
- C06 Means not provided to assure procedures / documents / records were of adequate quality and up-to-date
- C07 Means not provided for assuring adequate availability of appropriate materials / tools
- C08 Means not provided for assuring adequate equipment quality, reliability, or operability
- C09 Personnel selection did not assure match of worker motivations and job descriptions
- C10 Means/method not provided for assuring adequate quality of contract services

B3 WORK ORGANIZATION & PLANNING LTA
- C01 Insufficient time for worker to prepare task
- C02 Insufficient time allotted for task
- C03 Duties not well-distributed among personnel
- C04 Too few workers assigned to task
- C05 Insufficient number of trained or experienced workers assigned to task
- C06 Planning not coordinated with inputs from Walk downs/Task analysis
- C07 Job scoping did not identify potential task interruptions &/or environmental stress
- C08 Job scoping did not identify special circumstances &/or conditions
- C09 Work planning not coordinated with all departments involved in task
- C10 Problem performing repetitive tasks &/or sub-tasks
- C11 Inadequate work package preparation

B4 SUPERVISORY METHODS LTA
- C01 Tasks and individual accountability not made clear to worker
- C02 Progress / status of task not adequately tracked
- C03 Appropriate level of in-task supervision not determined prior to task
- C04 Direct supervisory involvement in task interfered with overview role
- C05 Emphasis on schedule exceeded emphasis on methods / doing a good job
- C06 Job performance and self-checking standards not properly communicated
- C07 Too many concurrent tasks assigned to worker
- C08 Frequent job or task "shuffling"
- C09 Assignment did not consider worker's need to use higher-order skills
- C10 Assignment did not consider worker's previous task
- C11 Assignment did not consider worker's ingrained work patterns
- C12 Contact with personnel too infrequent to detect work habit / attitude changes
- C13 Provided feedback on negative performance but not on positive performance

B5 CHANGE MANAGEMENT LTA
- C01 Problem identification did not identify need for change
- C02 Change not implemented in timely manner
- C03 Inadequate vendor support of change
- C04 Risks / consequences associated with change not adequately reviewed / assessed
- C05 System interactions not considered or identified
- C06 Personnel / department interactions not considered
- C07 Effects of change on schedules not adequately addressed
- C08 Change-related training / retraining not performed or not adequate
- C09 Change-related documents not developed or revised
- C10 Change-related equipment not provided or not revised
- C11 Changes not adequately communicated
- C12 Change not identifiable during task
- C13 Accuracy / effectiveness of change not verified or not validated

A5 Communication

B1 WRITTEN COMMUNICATIONS METHOD OF PRESENTATION LTA
- C01 Format deficiencies
- C02 Improper referencing or branching
- C03 Checklist LTA
- C04 Deficiencies in user aids (charts, etc.)
- C05 Recent changes not made apparent to user
- C06 Instruction step / information in wrong sequence
- C07 Unclear / complex wording or grammar

B2 WRITTEN COMMUNICATION CONTENT LTA
- C01 Limit inaccuracies
- C02 Difficult to implement
- C03 Data / computations wrong / incomplete
- C04 Equipment identification LTA
- C05 Ambiguous instructions / requirements
- C06 Typographical error
- C07 Facts wrong / requirements not correct
- C08 Incomplete / situation not covered
- C09 Wrong revision used

B3 WRITTEN COMMUNICATION NOT USED
- C01 Lack of written communication
- C02 Not available or inconvenient for use

B4 VERBAL COMMUNICATION LTA
- C01 Communication between work groups LTA
- C02 Shift communications LTA
- C03 Correct terminology not used
- C04 Verification / repeat back not used
- C05 Information sent but not understood
- C06 Suspected problems not communicated to supervision
- C07 No communication method available

A6 Training

B1 NO TRAINING PROVIDED
- C01 Decision not to train
- C02 Training requirements not identified
- C03 Work incorrectly considered "skill of the craft"

B2 TRAINING METHODS LTA
- C01 Practice or hands-on experience LTA
- C02 Testing LTA
- C03 Refresher training LTA
- C04 Inadequate presentation

B3 TRAINING MATERIAL LTA
- C01 Training objectives LTA
- C02 Inadequate content
- C03 Training on new work methods LTA
- C04 Performance standards LTA

A7 Other

B1 EXTERNAL PHENOMENA
- C01 Weather or ambient conditions LTA
- C02 Power failure or transient
- C03 External fire or explosion
- C04 Other natural phenomena LTA
- C05 Copper Theft
- C06 Vandalism

B2 RADIOLOGICAL/HAZARDOUS MATERIAL PROBLEM
- C01 Legacy contamination
- C02 Source unknown

B3 VENDOR OR SUPPLIER PROBLEM
- C01 Follow-up LTA
- C02 Vendor corrective actions LTA
- C03 Extent-of-Condition communications LTA

A8 (Open)

AX Overall Configuration

B1 INSTALLATION/DESIGN CONFIGURATION LTA

B2 MAINTENANCE/MODIFICATION CONFIGURATION LTA

Level A nodes are underlined	Level C nodes are in "sentence case"
Level B nodes are in ALL CAPS	LTA = Less Than Adequate

Cause Coding - How to start (Rev 18 02-28-2023)-11 x 17 page format.vsdx

CC_Quick_Reference_2023

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

MIDAS Overview

Jack Norris, Performance Analysis Engineer II
BES Protection System Misoperation Reduction Workshop
October 25, 2023

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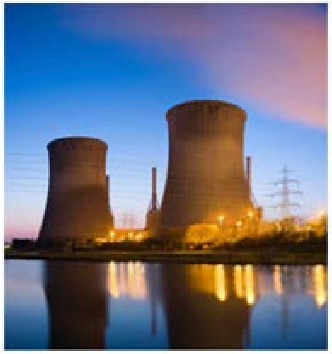


History

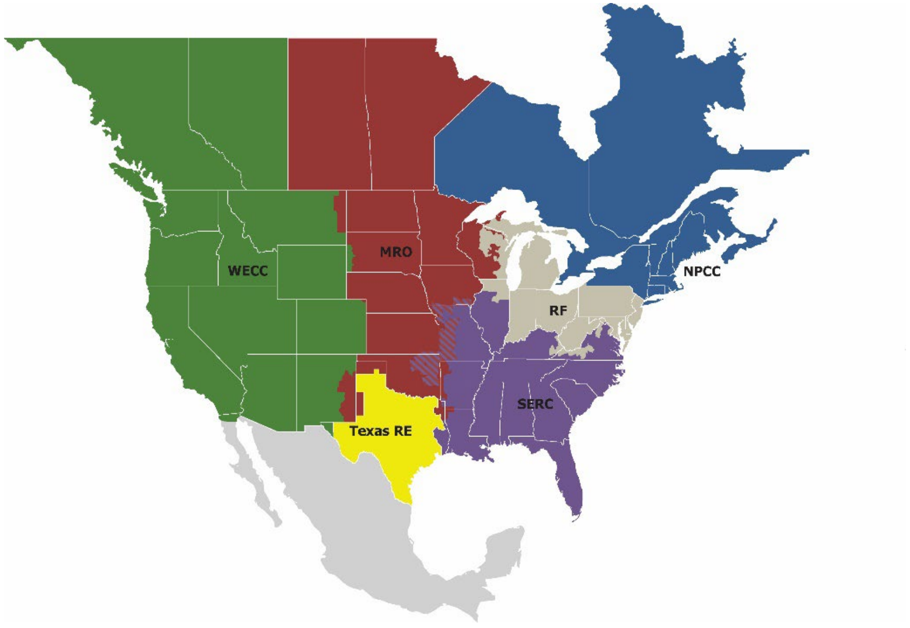
- On November 9,1965 there was a large black out in the Northeast
  - 30 million people were affected
  - It is estimated that $100 million in economic losses occurred
- In 1967 a Federal Power Commission investigation recommended forming a “council on power coordination”
- In 1968 the Regional Entities formed the National Electric Reliability Council (NERC) which later became the North American Electric Reliability Corporation.
- In 2006, NERC was made the ERO (Electric Reliability Organization) for the US by act of Congress

Mission of NERC

NERC assesses and reports on the reliability and adequacy of the North American bulk power system

- It is divided into the six Regional Entities as shown on the map
- Users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council



What is Performance Analysis and MIDAS?

NERC Rules of Procedure (Section 1600)

- Formal, confidential, mandatory BES data collection
- Separate from PRC-004 and compliance

Performance Analysis (PA)

- Study and analyze historical general BES trends for patterns and signals

Misoperation Information Data Availability System (MIDAS)

- Simple BES composite protection system operation (or lack there-of) counts
- Comprehensive individual BES Misoperations
- Used to assess industry-wide protection system performance

Composite Protection System Operations (PSOPs)

- Protection System: Protective relays, associated communication systems, voltage and current sensing devices, station batteries, and DC control circuitry

Voltage Class	Total CPSOPs Occurred in MRO	Total CPSOPs Occurred in NPCC	Total CPSOPs Occurred in RF	Total CPSOPs Occurred in SERC	Total CPSOPs Occurred in TRE	Total CPSOPs Occurred in WECC
<100 kV	0	0	0	0	0	0
100 kV	0	0	0	0	0	0
115 kV	0	0	0	0	0	0
120 kV	0	0	0	0	0	0
138 kV	0	0	0	0	0	0
161 kV	0	0	0	0	0	0
230 kV	0	0	0	0	0	0
345 kV	0	0	0	0	0	0
500 kV	0	0	0	0	0	0
735 kV	0	0	0	0	0	0
765 kV	0	0	0	0	0	0
HVdc	0	0	0	0	0	0
region)	0	0	0	0	0	0

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

Misoperation Data Collected

Who?

- Region, NCR, jurisdiction, reporter’s info

What?

- Event description, fault type, category, protection system components that Misoped, GADS/TADS?

When?

- Date & time of Misoperation

Where?

- Facility name, equipment name, equipment type,

Why?

- Cause code, event description

How?

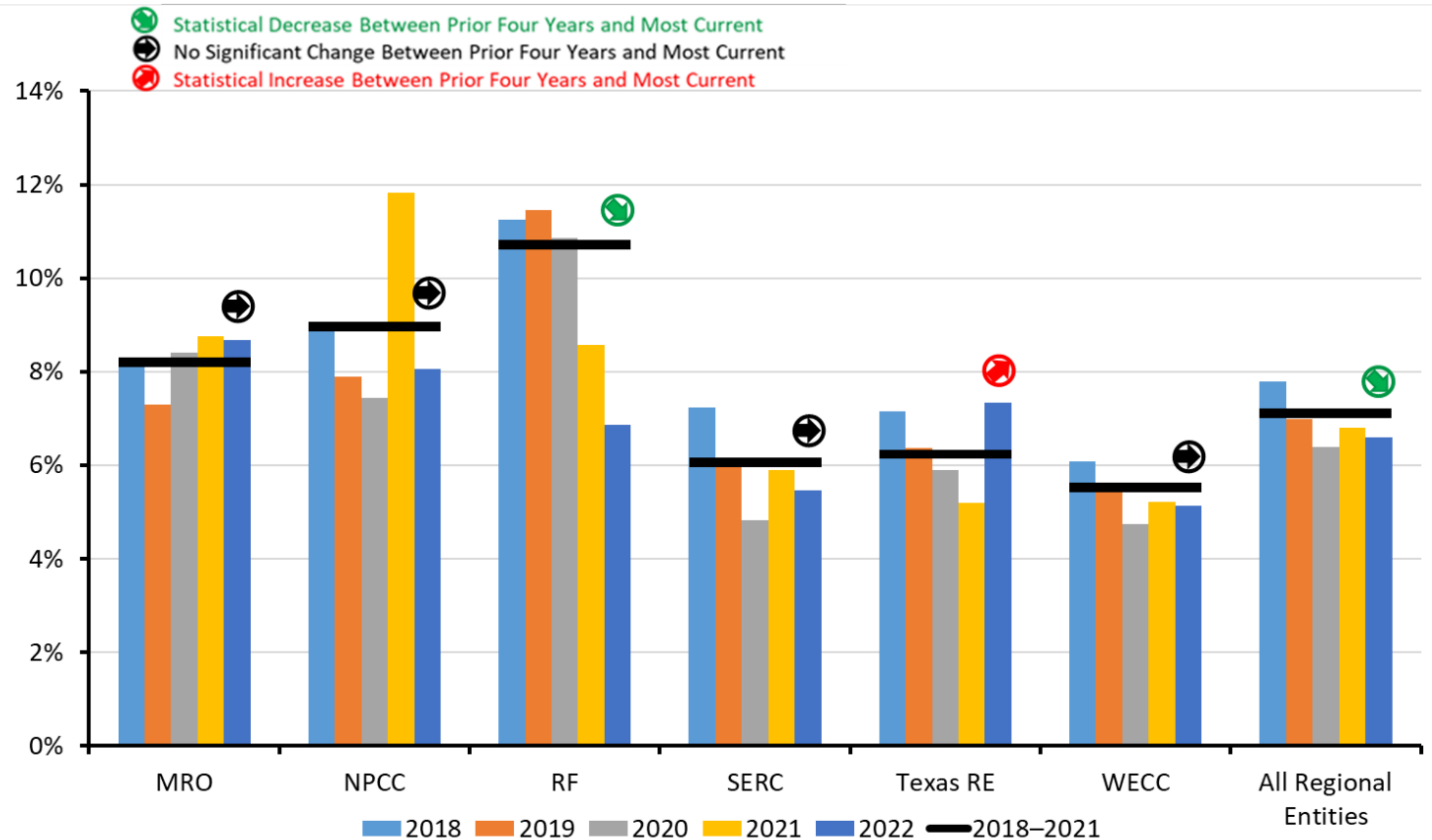
- Event description, corrective action plan

Generalized Metrics

$$\textbf{Misop Rate} = \frac{Count\ of\ Misoperations}{Count\ of\ PSOP}$$

$$\textbf{Misoperation Impact Score} = \left[Voltage\ Class\ Factor\right] * 0.3 + \left[Equipment\ Type\ Factor\right] * 0.2 + \left[Cause\ Factor\right] * 0.1 + \left[Category\ Factor\right] * 0.4$$

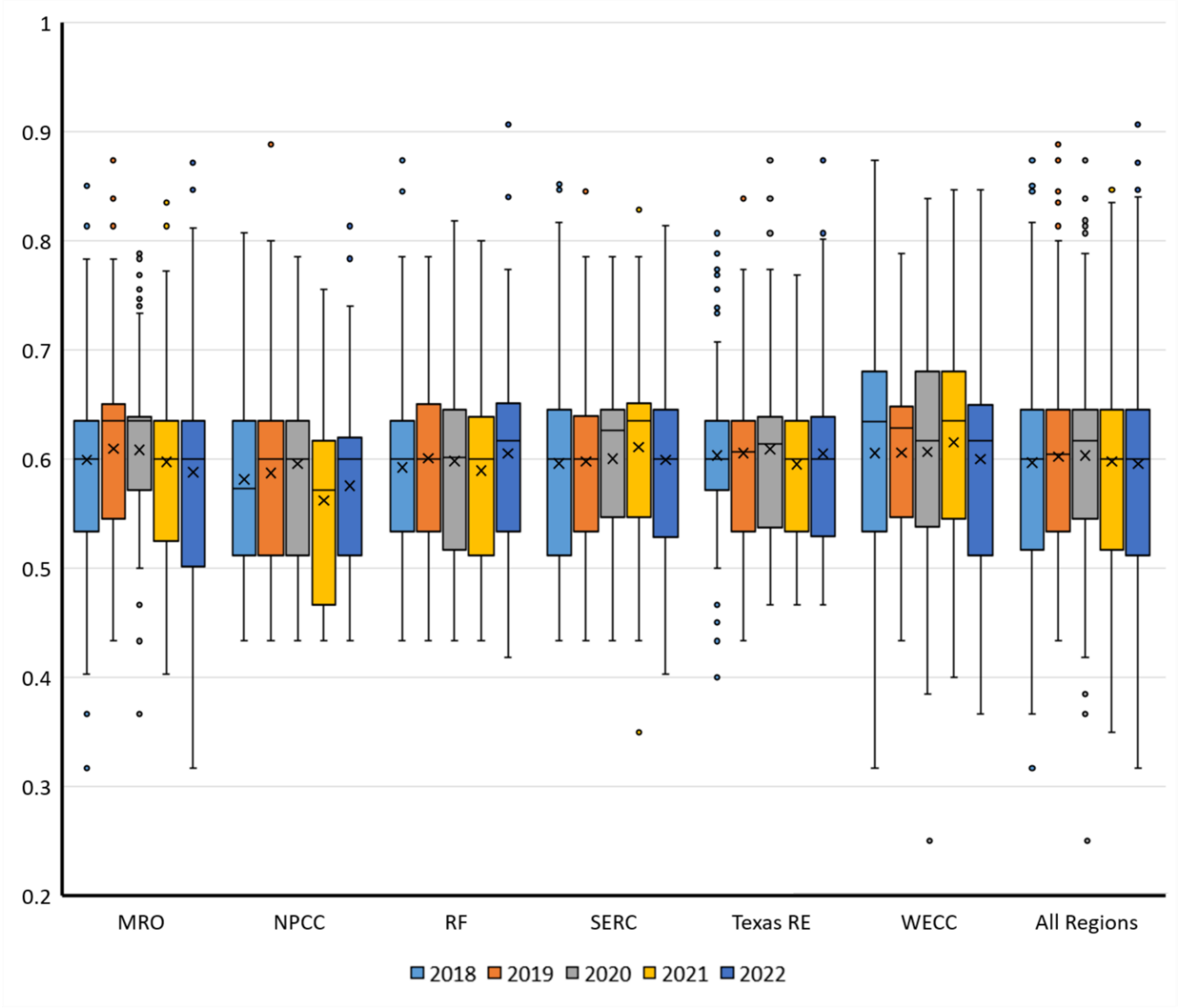
Annual Regional Misoperations Rate



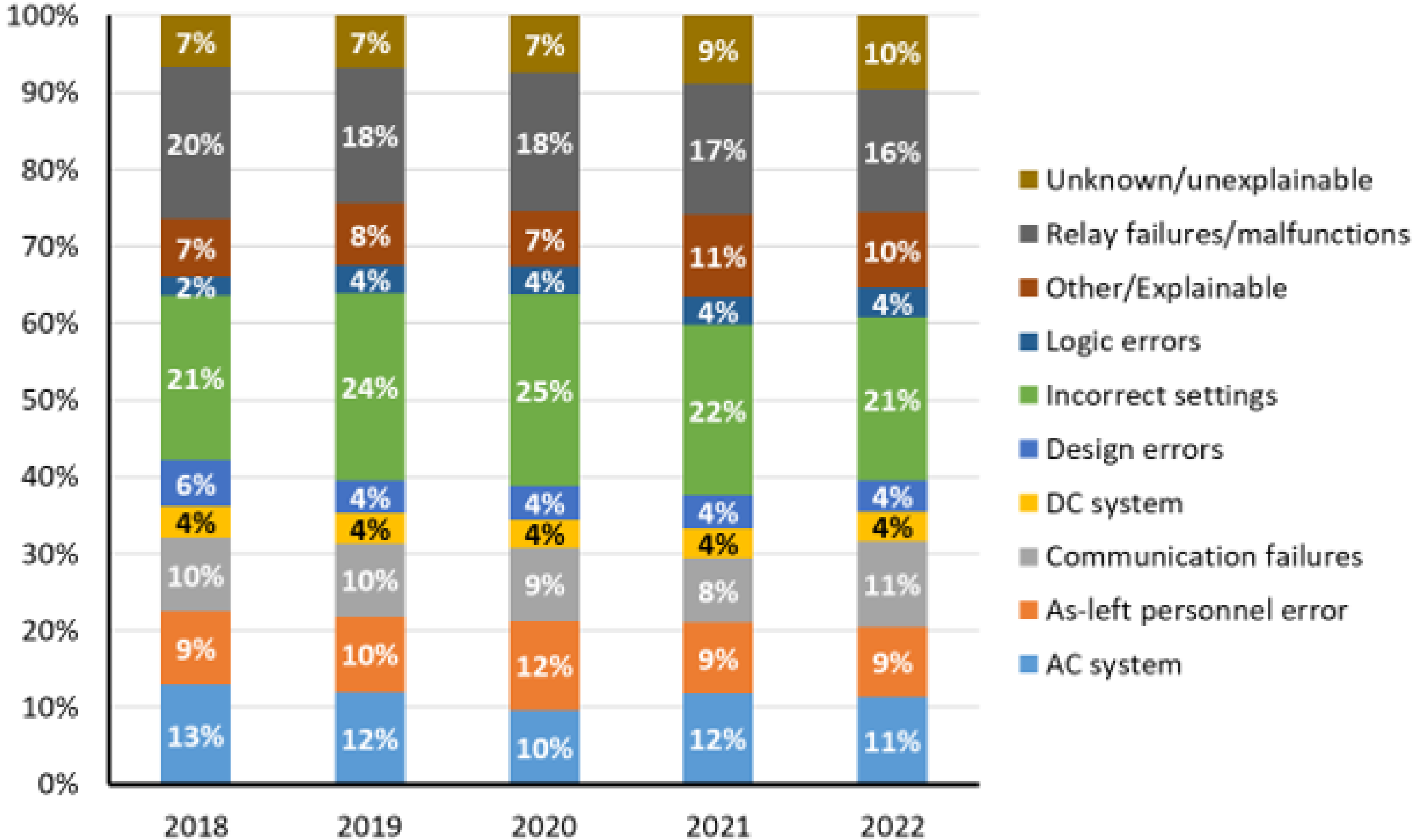
PSOP and Misoperation Counts

Area	Protection System Operations					Misoperations				
	2018	2019	2020	2021	2022	2018	2019	2020	2021	2022
All Regional Entities	19,744	19,283	18,296	17,448	17,769	1,536	1,346	1,170	1,186	1,170
MRO	3,740	3,734	3,054	2,617	3,240	306	272	257	229	281
NPCC	2,105	1,658	1,774	1,362	1,652	187	131	132	161	133
RF	2,275	2,146	1,878	1,866	2,055	256	246	204	160	141
SERC	4,873	4,736	5,267	4,614	4,764	352	284	254	272	260
Texas RE	2,280	2,640	2,000	2,599	1,992	163	168	118	135	146
WECC	4,471	4,369	4,323	4,390	4,066	272	245	205	229	209

Regional Misoperation Impact Score



Misoperations by Cause



Year	2018	2019	2020	2021	2022
Misoperation Count	1,536	1,346	1,170	1,186	1,170

NERC Proposed MIDAS Section 1600 Minor Revision

MIDAS Section 1600 Minor Revisions

[MIDAS Section 1600 Minor Revisions]

MIDAS Stakeholders:

This announcement is to inform you that the North American Electric Reliability Corporation (NERC) is posting the following minor revisions for MIDAS data reporting.

The fields **TADS Elements** and **GADS Elements** are being revised to **Count of Transmission Lines Removed From Service**, **Count of Transformers Removed From Service**, and **Count of Generator Plants Removed from Service.** NERC views these as minor changes because the information required for the revised fields is already being collected as free-form text. The intent of the revision is to improve accuracy of data reported, collect the data in a more analyzable format, and reduce resource use for intercompany communications.

The change above will become effective for Misoperations that occur on or after January 1, 2024, with the first applicable reporting deadline being May 30, 2024.

Complete details about these changes are included in the MIDAS Section 1600 Minor Revisions document linked above.

NERC's Rules of Procedure (Section 1602.5) permits NERC to make minor changes to an approved Section 1600 Data Request:
"NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented."

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FERC/ERO Protection System Commissioning Program Review Project

Rich Bauer
Atlanta, Ga
Misoperation Workshop
October 25, 2023

RELIABILITY | ACCOUNTABILITY

Background

- Efforts to reduce Misoperations resulting from less than adequate Protection System Commissioning
  - 2015-2021 NERC SPCWG Issued Lessons Learned – Verification of AC Quantities
  - 2017 IEEE WG I-25 guide Commissioning Testing of Protection Systems
  - 2019 Analysis of Protection System Misops

FERC staff review of MIDAS data

- **Process: Sample ‘Event Description’ and ‘Corrective Action’ MIDAS fields to determine PSC impact on Misops.**
- **Finding: 18 – 36% of Misops could be attributed to issues that PSC should have detected.**

Commission Testing Review

Joint Review of Protection System Commissioning Programs

2021 FERC, NERC and REs Report

November 2, 2021

FEDERAL ENERGY REGULATORY COMMISSION

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation and its Regional Entities

The matters presented in this staff report do not necessarily represent the views of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

Review Process

- Eight registered entities and one PSC contractor.
- Selected based on geographical locations and performance data such as events and Misop rates.
- Surveys and Interviews on participants' PSC programs and Procedures.
- Used the IEEE PSRC WG I-25 guide as a benchmark.
- Team discussed and agreed upon the best practices, opportunities for improvement, and related recommendations.

WG I-25

- NERC request to IEEE PSRC
- IEEE PSRC I-25 Working Group
- Report on Commission Testing Practices
- Report to serve as Industry Reference

IEEE PSRC, WG I-25 May 10, 2017

Commissioning Testing of Protection Systems

Assignment:

To create a report, at the request of the North American Electric Reliability Corporation (NERC) System Protection and Control Subcommittee (SPCS), to serve as an industry reference document on protection system testing practices. The SPCS believes that it would be beneficial for IEEE to produce a document on commissioning testing in an effort to help reduce the number of misoperations resulting from improper commissioning.

Working Group Members:

R. Garcia (Chair); K. Donahoe (Vice-Chair); R. Aguilar; A. Apostolov; H. Ashrafi; J. Barsch; N. Bilimoria; J. Brown; C. Bryant; D. Buchanan; E. Carvalheira; N. Casilla; G. Halt; W. Knapek; A. Lee; B. Mackie; H. Malson; B. Moores; G. Moskos; A. Newman; L. Polanco; S. Saminfni; E. Schock; T. Seegers; M. Siira; M. Stojak; A. Uribe; J. Verzose; D. Ware; M. Wright; V. Yedidi

PSC Programs

- **All participants but one had a formal commissioning program; however, none of the participants' programs were as comprehensive as the IEEE WG I-25 guide recommends.**
- **No participant maintained a centralized document that contained all five key elements of an effective PSC program.**
- **Recommendation**
  - **All entities should document a formal PSC program. Having a formal, documented program in a central location (e.g., a single document) allows easy reference to all the elements of the program.**

PSC Programs 5 key elements

- Stated goals and objectives
- Well-defined plans to perform commissioning
- Clearly identified lines of responsibility
- Authority given to responsible parties
- Feedback methods to improve the plan

Stated Goals and Objectives

- Three participants failed to document their PSC program goals and objectives in a program document.
- These participants embedded the goals and objectives in the procedures and activities outlined in their equipment commissioning processes.
- Recommendation:
  - All Entities should have a formal company PSC program that includes the goals and objectives of the program. Having a company-wide document that clearly describes the commissioning goals and objectives provides employees clear direction for their tasks.

Well Defined Plans to Perform Commissioning

- **Plans ranged from standard form-type checklists to tests and forms for specific types and models of equipment. Observations included:**
  - **a detailed internally developed testing guideline listing the different tests to perform based on the equipment being commissioned**
  - **No instructions on what the commissioning team should look for when performing a commissioning test on equipment**
  - **no guidance with equipment specific checklist**
  - **one participant reported that it did not develop any checklists**

Well Defined Plans to Perform Commissioning (cont.)

- **Recommendation**
  - **All Entities should review their PSC programs for adequate detail. Entities should consider including how to perform the commissioning tests that are required for each specific project. All Entities should follow the guidance provided in the Annex A of the IEEE WG I-25 guide.**
- **Best Practice**
  - **One participant included with every project a detailed commission testing plan specific to that project in terms of depth, scope, type of equipment involved, level of complexity, and each plan detailed how to perform required tests and checks.**

Clearly Identified Lines of Responsibility

- For the seven participants with formal programs, director/manager was the most common level of management required for approval.
- Some participants required personnel to complete formal training to qualify to perform commissioning and some participants only required on the job training. Two participants required a licensed PE to lead the PSC process.

Clearly Identified Lines of Responsibility (cont.)

- **Recommendation**
  - Have well-documented training requirements of classroom and on-the-job training coupled with some type of proficiency assessment to ensure well-qualified commission testing personnel.
- **Best Practice**
  - Some participants designated senior management from different departments of the company to collectively share responsibility for approval of the PSC program. Senior management involvement is likely to draw attention to and support commission testing programs.

Authority Given to Responsible Parties

- Best Practice
  - One participant reported that during contractor selection, it used a multi-layer selection process. Initially, the participant vetted the contractors for required qualifications. Then the participant's protection and control personnel vetted the contractor employees who would perform the actual commission testing.
- Best Practice
  - Some participants reported that their oversight personnel have frequent meetings with the contractor to review work performance, as this allows for prompt resolution of issues.

Feedback Methods to Improve the Plan

- **Best Practice**
  - Some participants used a standardized form to document lessons learned made available through a network application.
  - The review of the lessons learned was required in a documented scope development process for new projects.
  - Shared lessons learned information with external industry groups

8 Core Elements of PSC Process

- Planning and sequencing
- Print and technical review
- Preparing installed equipment for modification
- Equipment and device acceptance testing
- Equipment isolation
- Functional testing
- Operational (or in-service load) checks
- Documentation

Planning and Sequencing

- Participants reported similar organization process for coordinating PSC testing when other facility owners are involved
- Best Practice
  - As part of the commissioning process on tie lines, some participants employed back-to-back relay testing (i.e., in a testing in a laboratory environment) and end-to-end testing onsite.
  - Back-to-back testing was also performed when installing unfamiliar relay models, configurations, and or firmware editions.

Print and Technical Review

- **Recommendation**
  - Entities should ensure that a design review is performed prior to the start of construction activities.
  - When using third-party contractors, all Entities should ensure that the contract requires this design review. This is even more important in instances where the project involves multiple owners and separate design groups.
  - The independent design review allows the correction of any identified errors with the concurrence of the design group(s) while keeping the objectivity of the commissioning group.

Preparing Installed Equipment for Modification

- Best Practice
  - One participant reported that the engineering package identified all equipment that needed to be isolated or shorted to ensure adequate in-service protection throughout all stages of the project.
  - The participant explained that it also required the commissioning group to perform a peer-check of the isolations and shorted equipment on drawings and review any discrepancies or questions prior to the outage.

Equipment and Device Acceptance Testing

- **Recommendation**
  - All Entities should compare their acceptance testing practices to those listed in Section 3 (Commissioning Testing of Protection Schemes) of the IEEE WG I-25 guide and incorporate practices that provide opportunities for process improvement.
  - Thorough acceptance testing can help ensure that the correct equipment has been provided; that the equipment is in good working order; and that it is functioning as designed.

Equipment Isolation

- **Recommendation**
  - All Entities should maintain a documented isolation log. The contents of the isolation log should be standardized and include, at a minimum, the repositioning of test switches, temporary jumpers, and shorting blocks; who made the changes; time and date of the change; and when the equipment was returned to normal.
- **Best Practice**
  - Some participants maintained an isolation log and tagged the circuits at the point of isolation for equipment isolation.

Functional Testing

- Recommendation
  - All Entities should implement end-to-end testing for all bulk electric system communication-based protection schemes as recommended by the IEEE WG I-25 guide. Communication failures are one of the top three causes for Misoperations.
- Recommendation
  - All Entities should perform current testing on all phases to ground, phase-to-phase, and 3-phase faults. This will ensure that CT ratios, CT and polarity, and polarization of ground elements is correct for all fault scenarios.

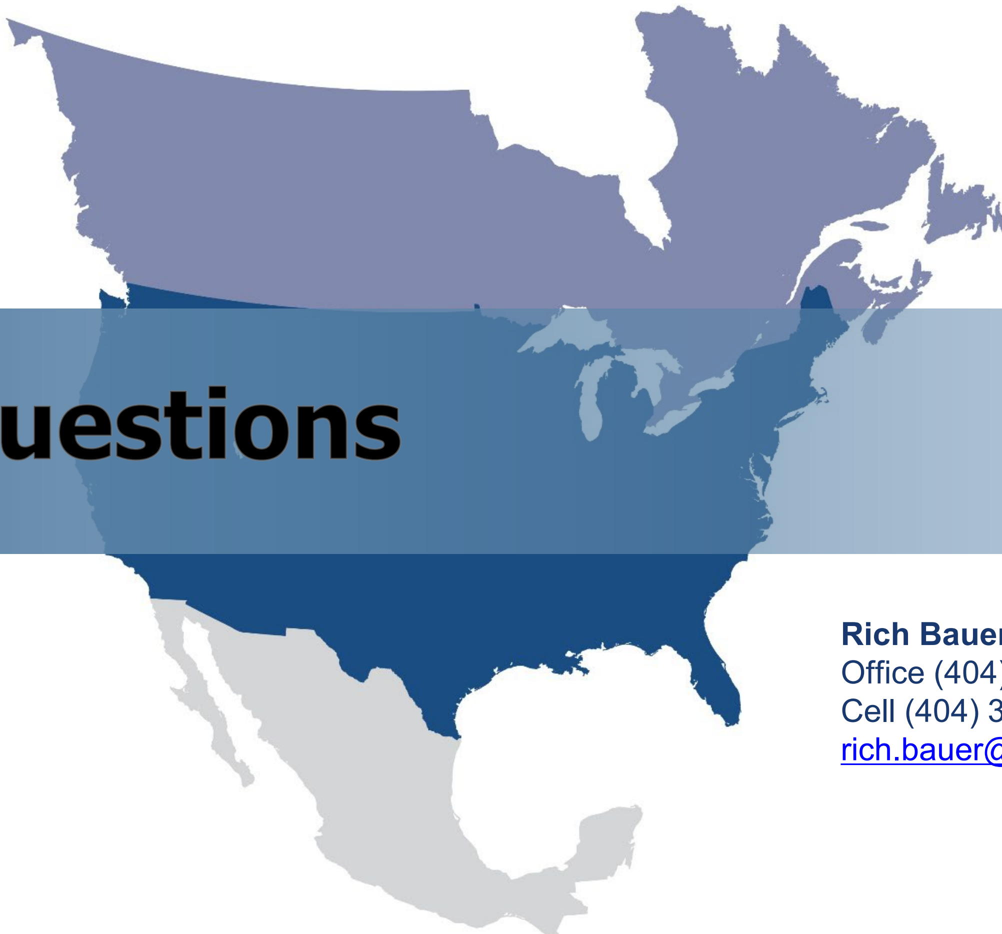
Operational Tests (in-service load checks)

- **Recommendation**
  - CT circuit errors represent a significant portion of misops primarily due to incorrect CT ratios, incorrect CT polarity, and CT's left in the shorted position. Entities should perform:
    - A final walk-down process to ensure that CT and VT circuits are correct prior to being placed in service.
    - In-service loading is above the minimum equipment requirements so that sufficient current magnitude is available for accurate measurement.
  - Operational tests and measurements include current and voltage magnitude, phase angle and polarity with respect to the primary quantities.
  - Operational measurements from different relays, meters, fault recorders, SCADA transducers, and other devices that use the same voltage and current signals should be compared with each other to ensure similar measured quantities at each device.

Documentation

- **Recommendation**
  - **All Entities should update their PSC procedure documentation as necessary to accurately reflect what is being done in the field. Entities should pay particular attention when copying documentation from other procedures.**

Questions



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WG I-25

- I-25 Report identified two areas
- PSC Programs
- PSC Process
- 8 core elements

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

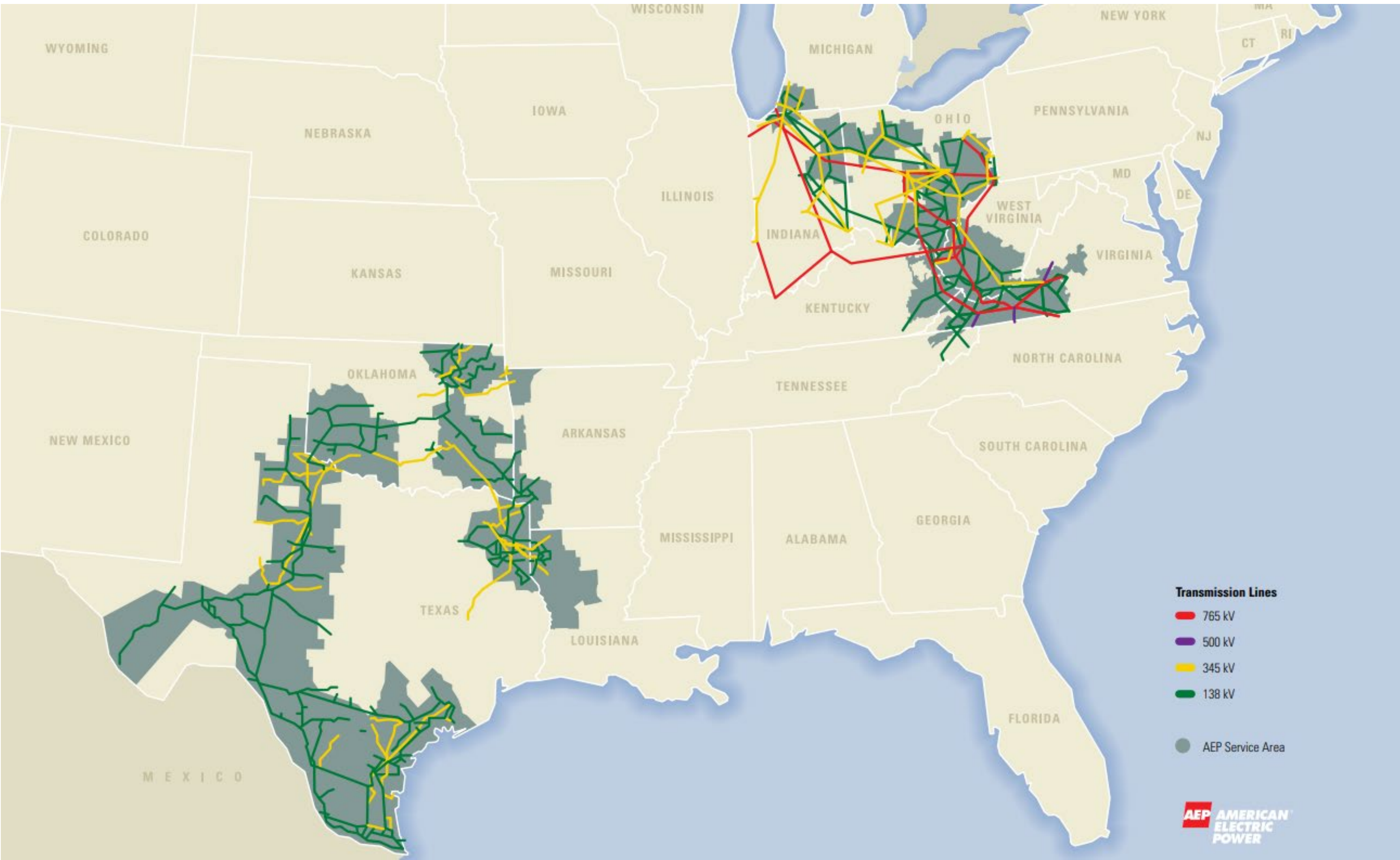
Ross D. Stienecker

(American Electric Power)

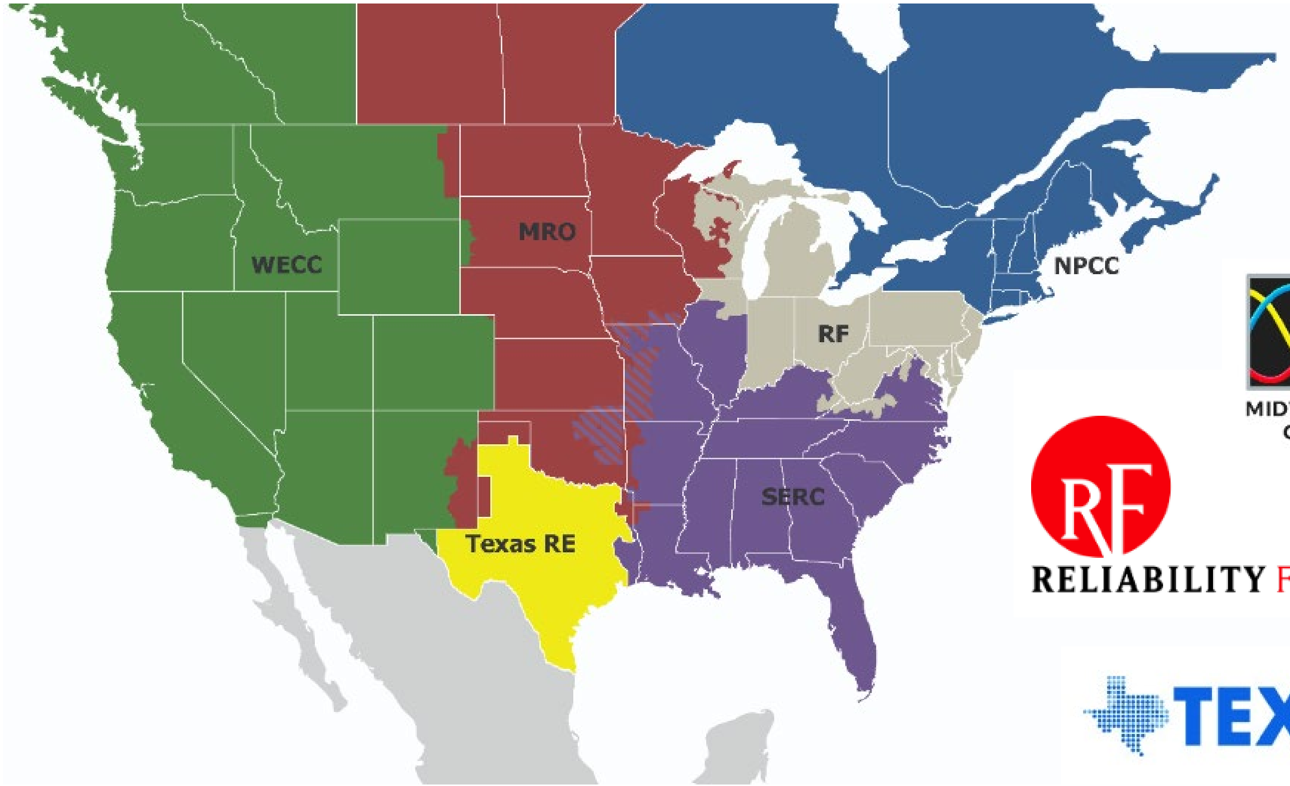
Introduction

- 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

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

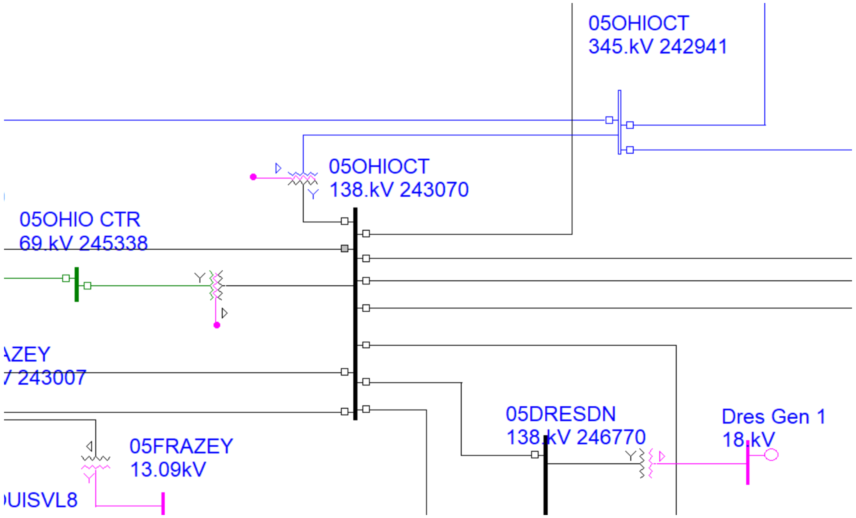
- Develop a CAP
- Implement CAP within 2 weeks (avoid repeats)
- Express Settings when applicable
- Prioritize model verification

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*				

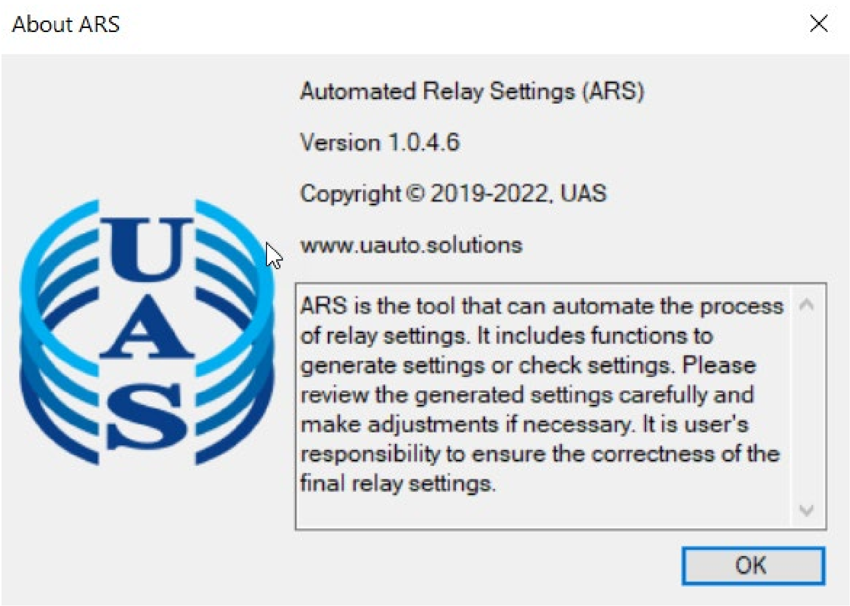
Line Settings Robust Checklist

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

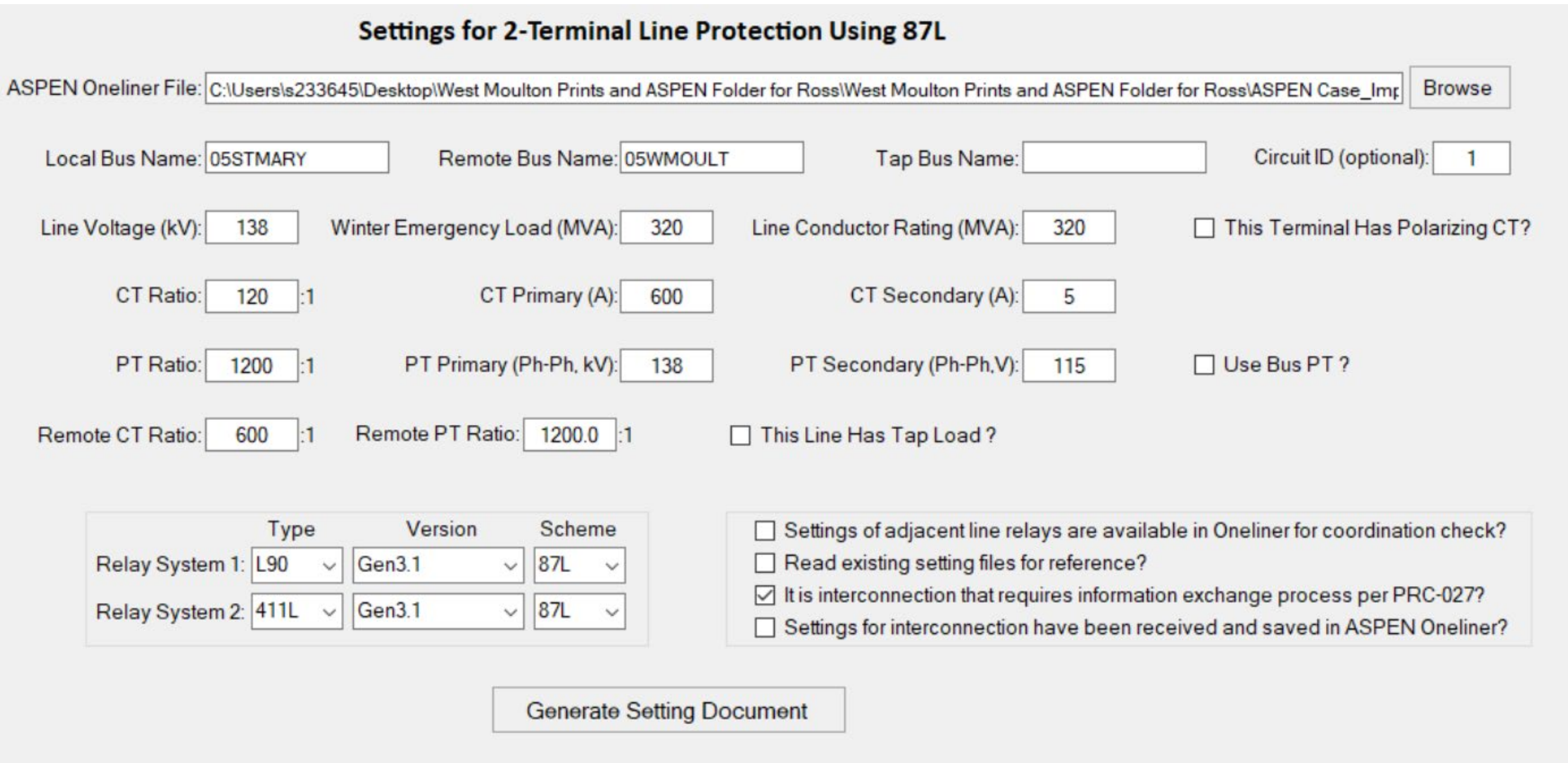
General | Revision History | Checklist | App A-L90-CS | App B-411L-CS | App C-D60-CS | App D-421-CS | App E

Automated Relay Settings

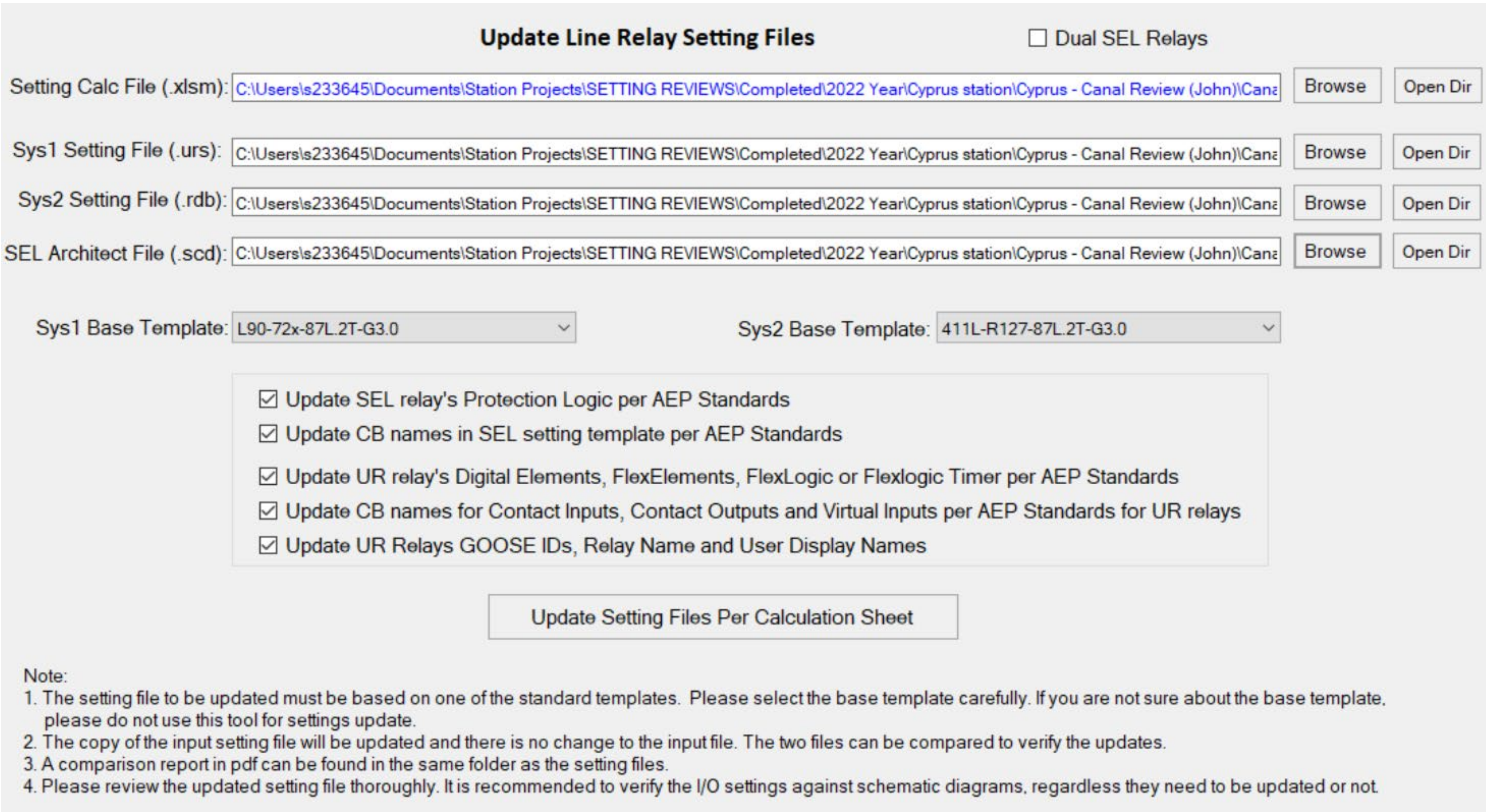
- PCE has worked with an outside consultant to development an Automated Relay Settings (ARS) tool
- ARS has many different benefits, but the three most important are its ability to **reduce human error**, its ability to **reduce engineering labor time/cost**, and its ability to **enforce consistent setting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

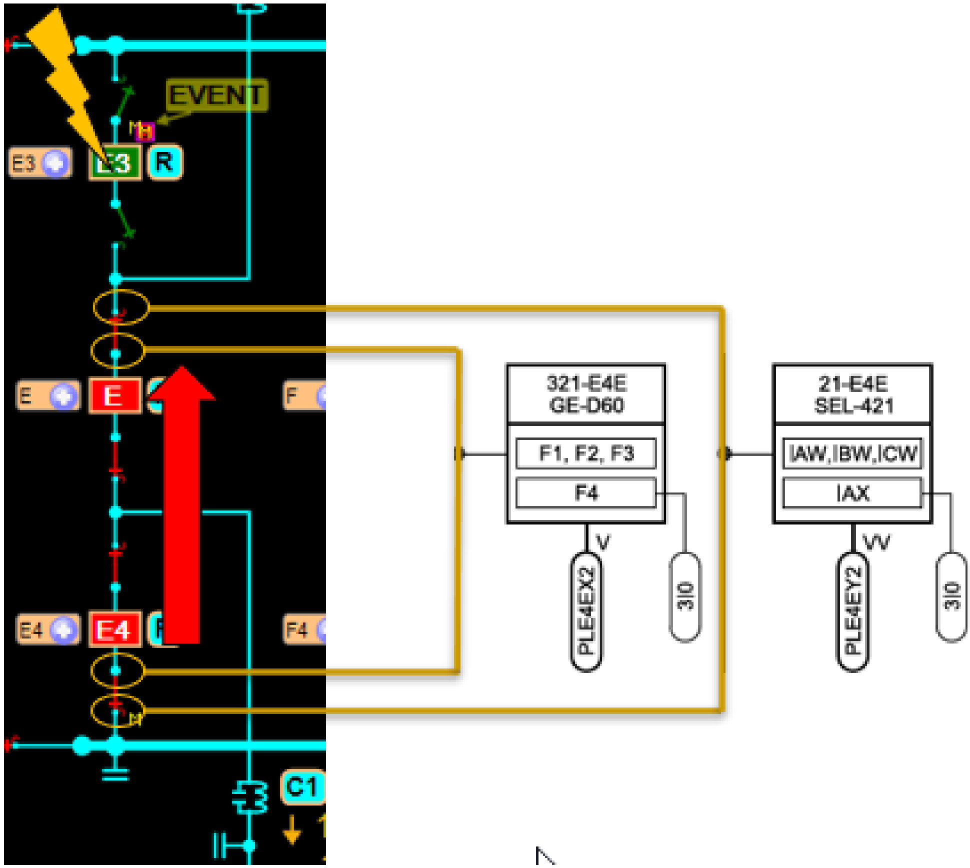
- Desensitize carrier forward ground overcurrent elements so that the schemes aren't being tested as much. The guidance is to try to set at 600 Amps primary and only reduce if you have sensitivity issues
- Delay carrier forward ground overcurrent elements by 8 cycles, to allow carrier forward ground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

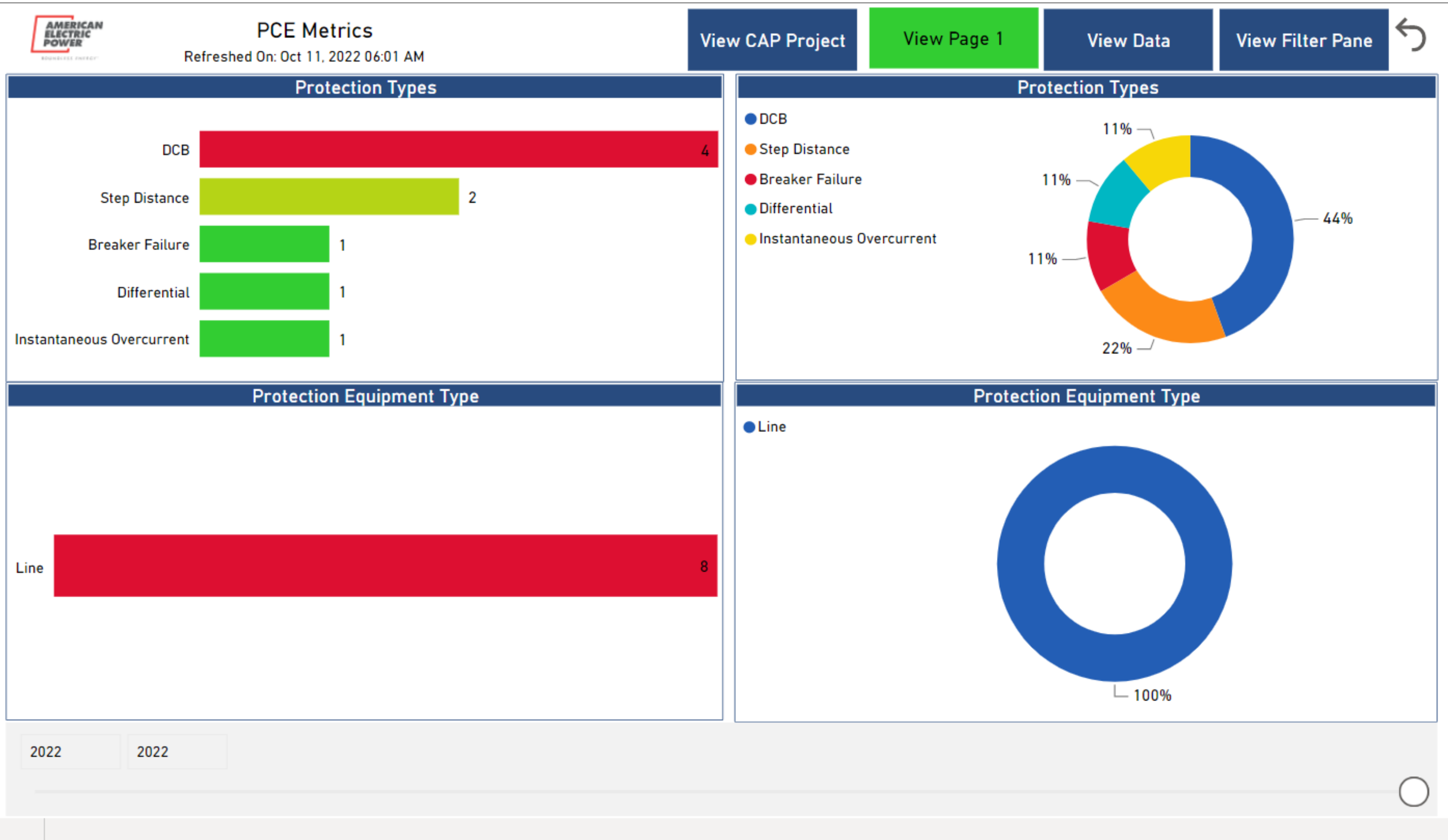
AEP SS-451010 Rev.11, Section 4.12.3.3 - Line Relay CT Ratio Selection Guidelines, page 42

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

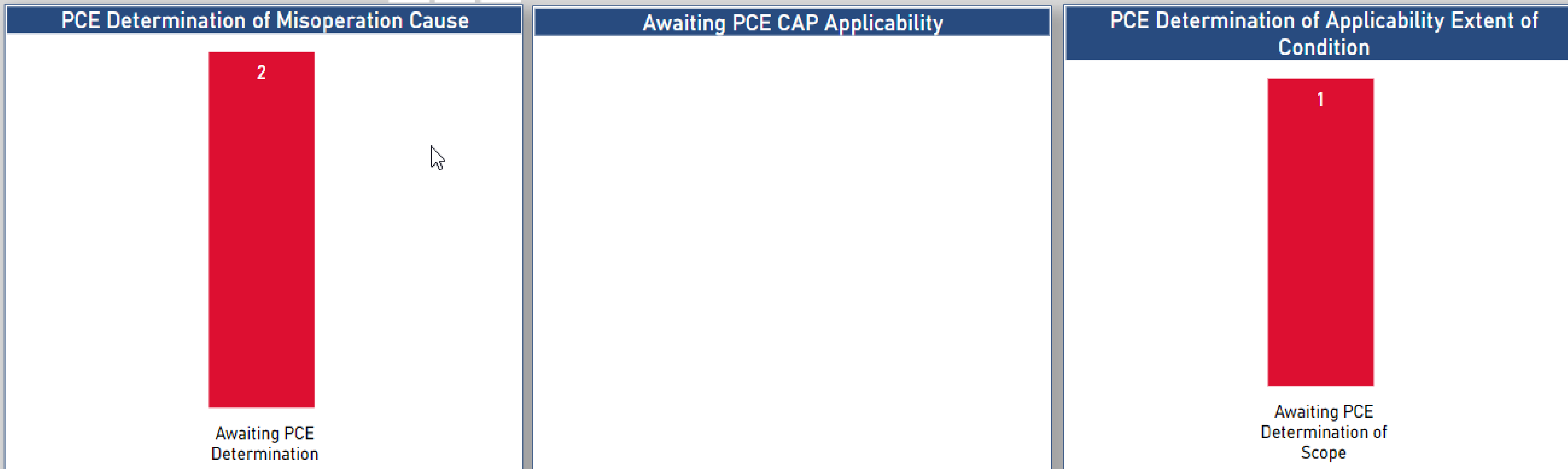
Advanced Misoperation Metrics Dashboard



Advanced Misoperation Metrics Dashboard

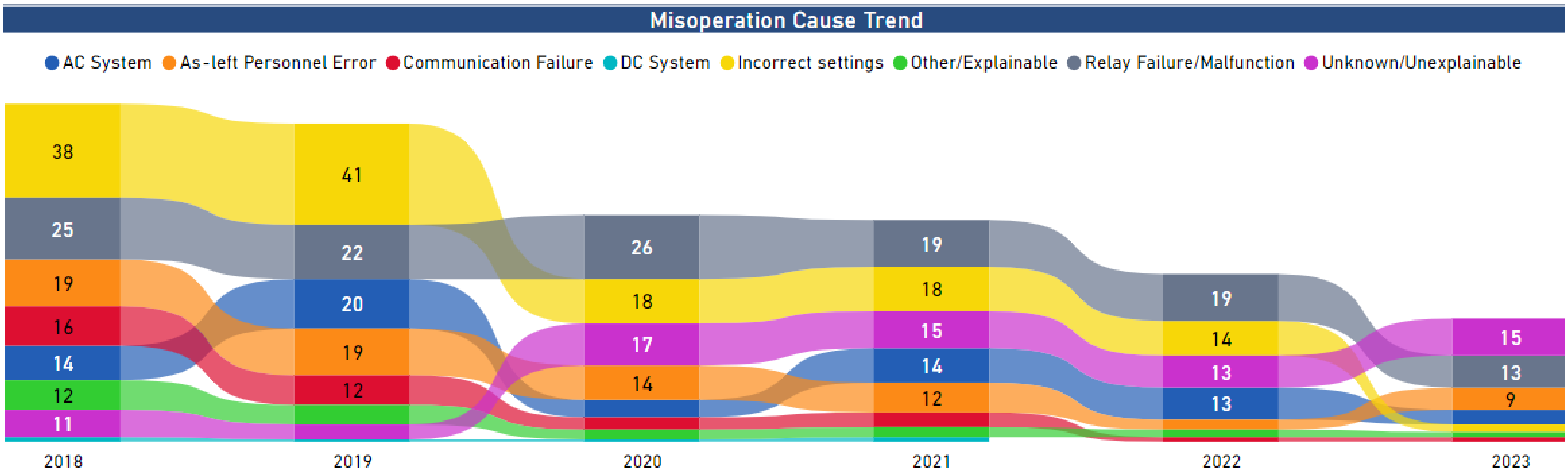
PCE Workflow

Refreshed On: Oct 11, 2022 06:01 AM



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?

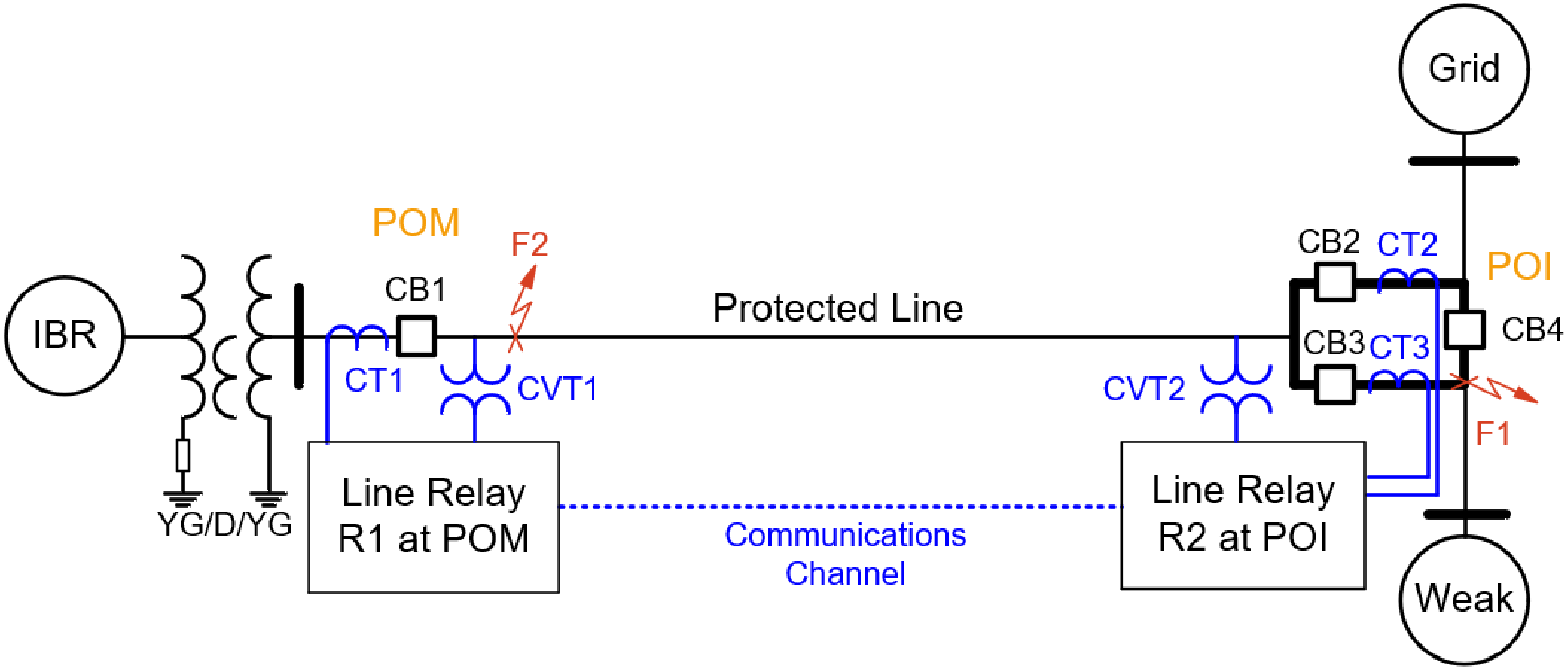
Line Protection Considerations for Systems With Inverter-Based Resources

Ritwik Chowdhury
Schweitzer Engineering Laboratories, Inc.

Overview

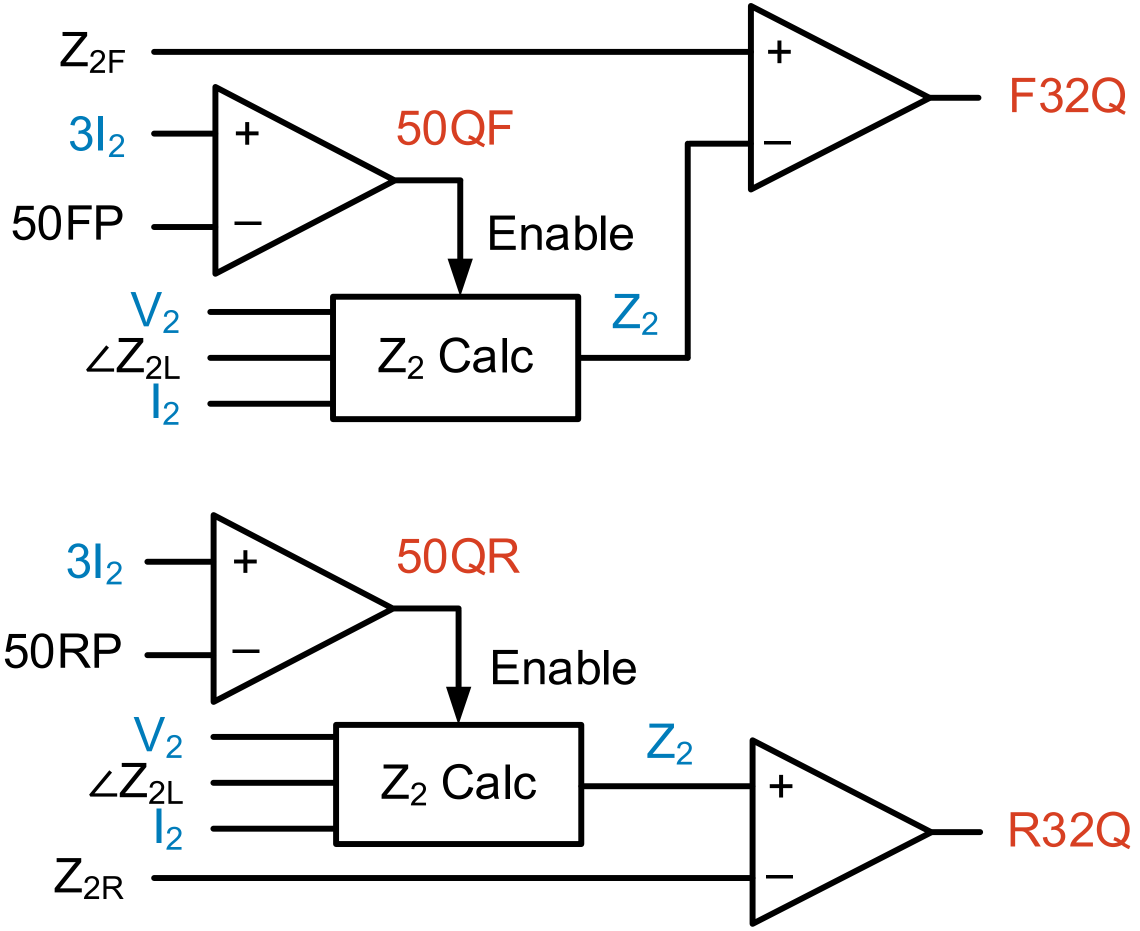
- Negative-sequence Current Challenges
  - Directional Element
  - Faulted Phase Selection
- Distance Element Considerations
- Source-to-Line Impedance Ratio (SIR)
- Directional Comparison Pilot Schemes
- Line Current Differential
- Power Swing Blocking and Out-of-Step Tripping
- Conclusion

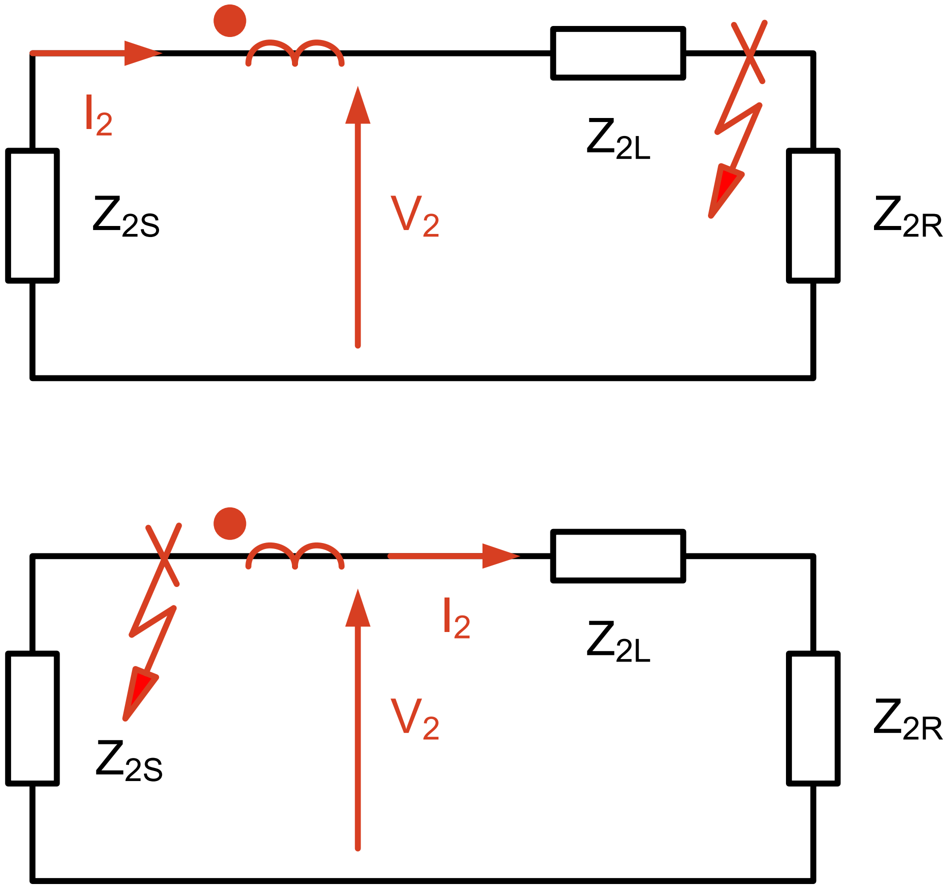
One-line Diagram



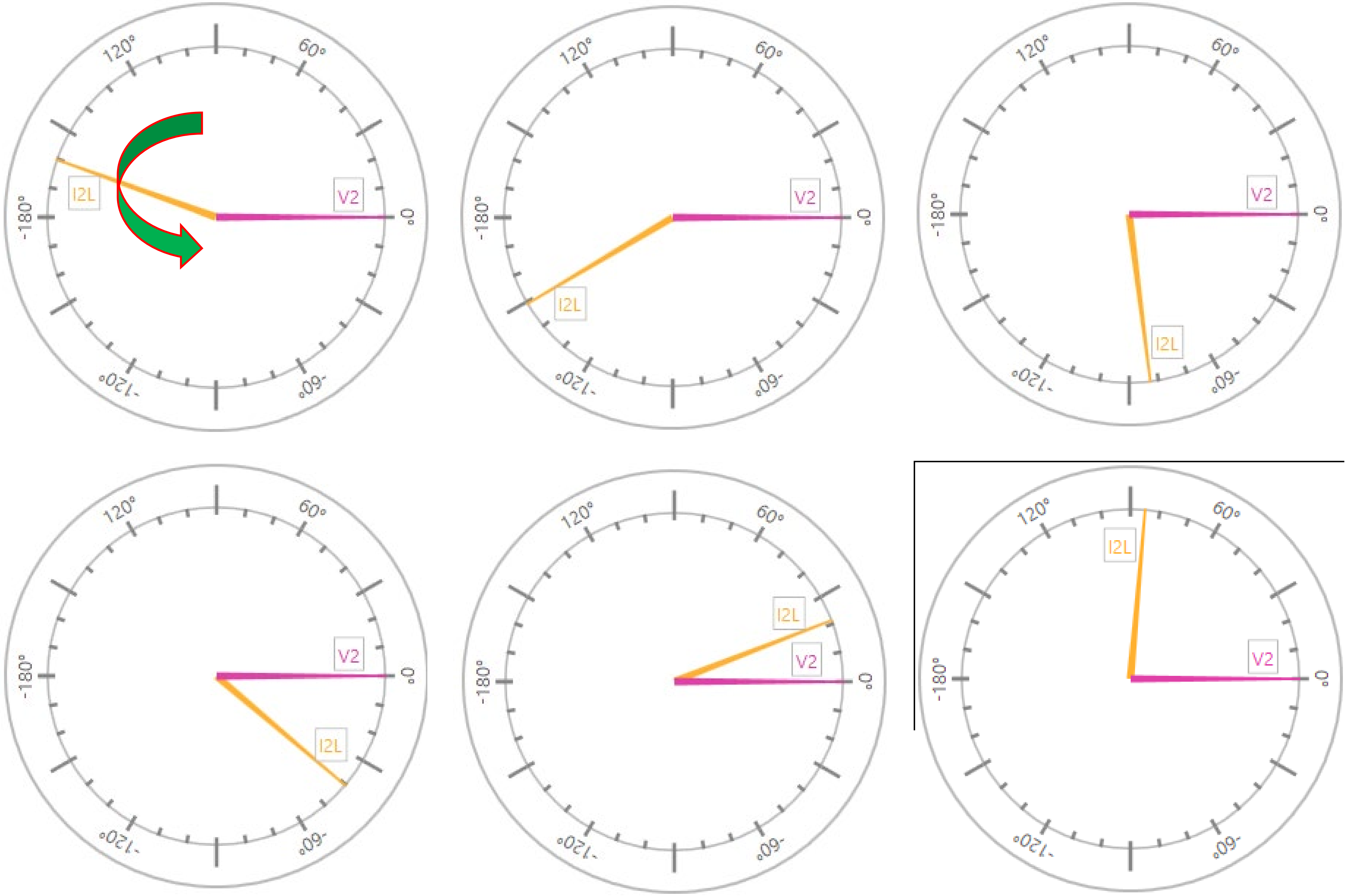
Negative-sequence current challenges

Directional element (32)

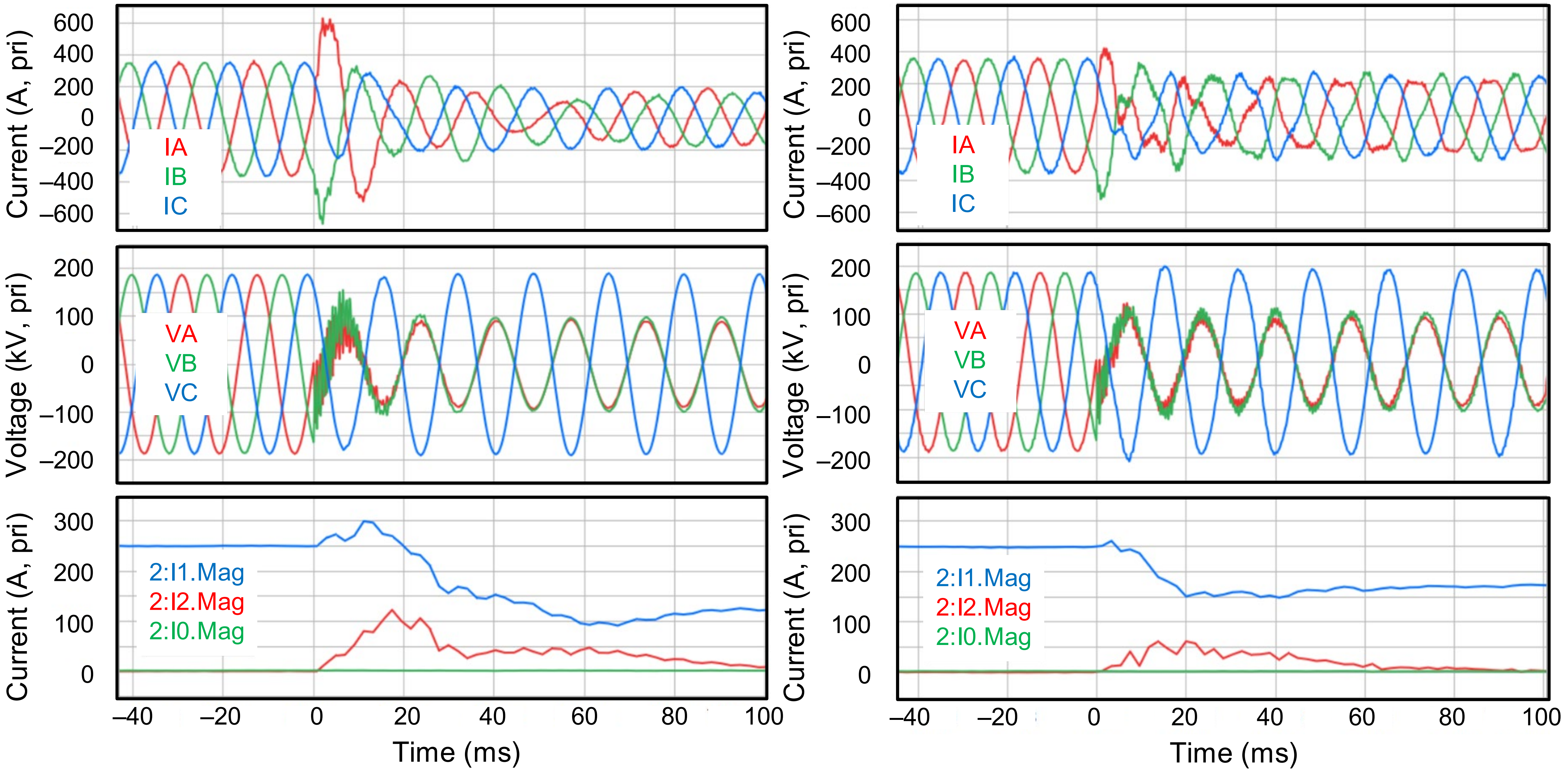




I2 vs V2



Type 4 Wind AB Fault at Remote Bus



IEEE Std 2800-2022 Performance Requirements

For unbalanced faults, in addition to increased positive-sequence reactive current, the *IBR unit* shall inject negative sequence current:

- Dependent on *IBR unit* terminal (POC) negative sequence voltage and
- That leads the *IBR unit* terminal (POC) negative sequence voltage by an allowable range as specified below:
  - 90 degrees to 100 degrees[106] for full converter-based *IBR units*
  - 90 degrees to 150 degrees for type III WTGs[107]

Table 13—Voltage ride-through performance requirements

Parameter	Type III WTGs	All other IBR units
Step response time[b, c, d]	NA[a]	≤ 2.5 cycles
Settling time[b, c, d]	≤ 6 cycles	≤ 4 cycles
Settling band	−2.5%/+10% of *IBR unit maximum current*	−2.5%/+10% of *IBR unit maximum current*

[a] The initial response from the type III WTG is driven by machine characteristics and not the control system. DC component, if present, has an impact on response, which is driven by machine parameters and time of fault occurrence. Even though the control system takes an action, it cannot control machine's natural response. As such, defining response time for type III WTGs is not necessary.

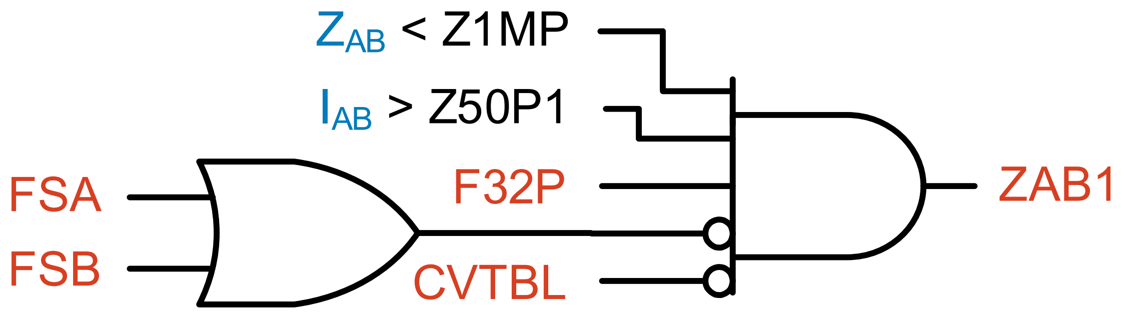
[b] System conditions may require a slower response time, or *IBR units* may not be able to meet response times noted in this table for certain system conditions. If so, greater response time and *settling time* are allowed with mutual agreement between an *IBR owner* and the *TS owner*.

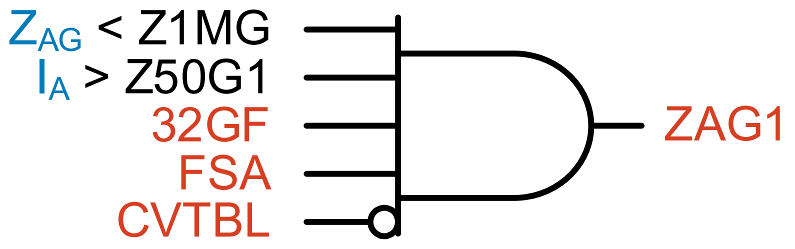
[c] The DFT with a one-cycle moving average window is used to derive phasor quantities such as active, reactive, positive-sequence, negative-sequence currents, etc. The time delay required for the DFT measurements is included in the *step response time* and *settling time* specified in this table.

[d] The specified *step response time* and *settling time* applies to both 50 Hz and 60 Hz systems.

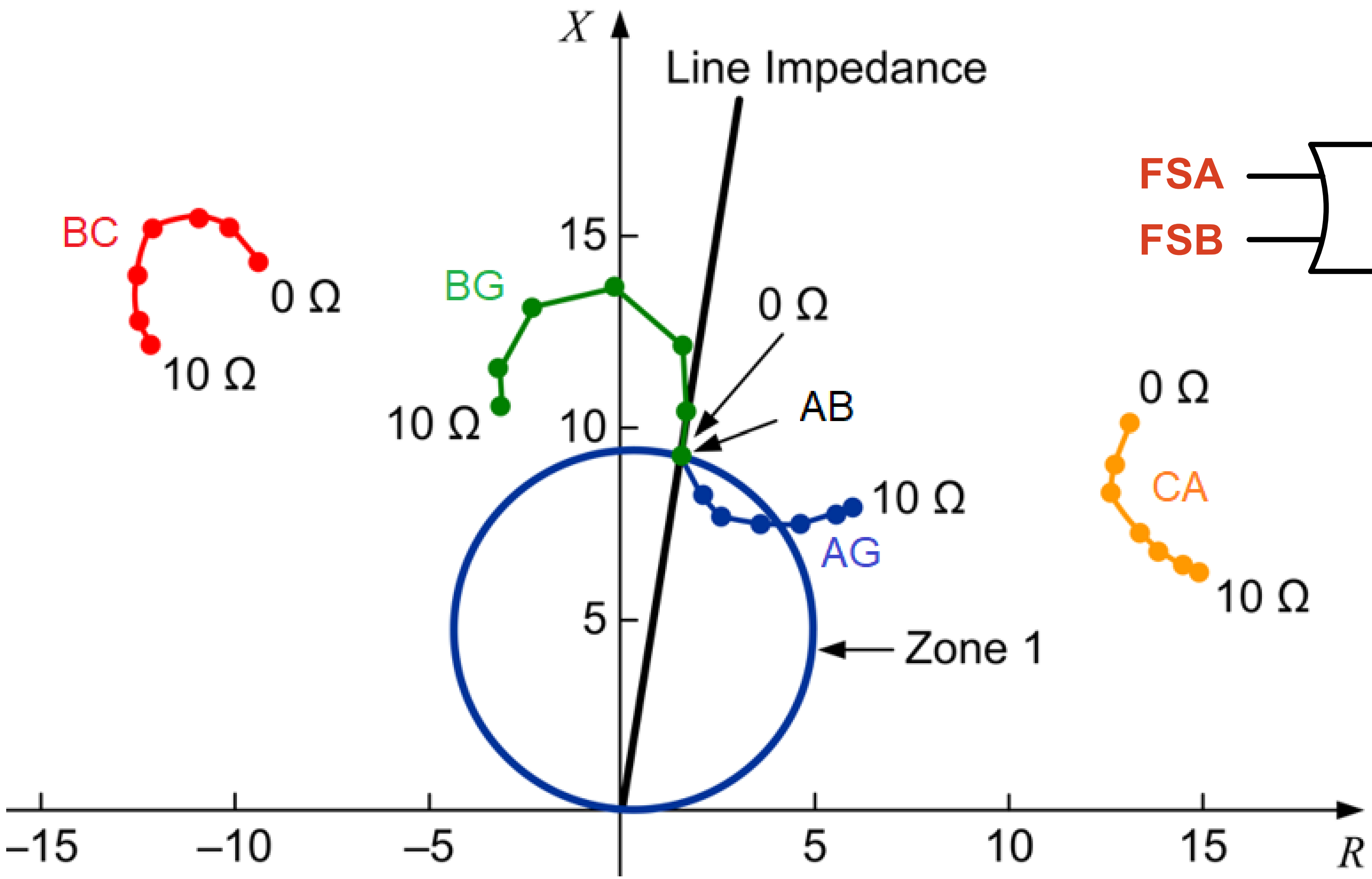
Distance element (21)

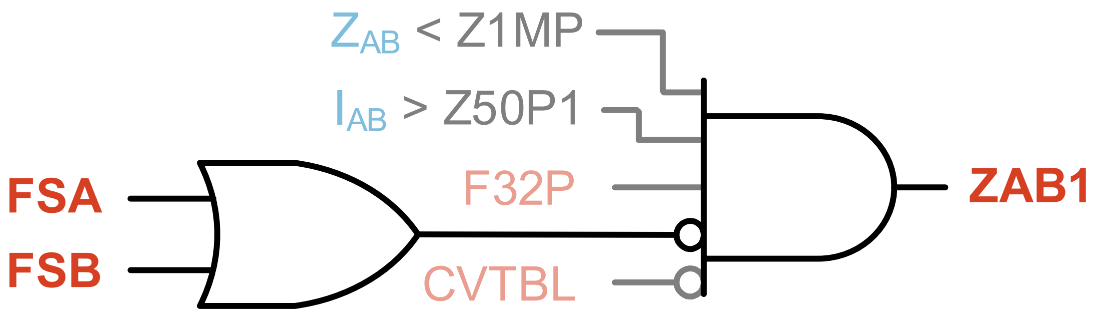
- Calculated impedance is less than set reach
- Loop current greater than fault-detector threshold (Zone 1)
- Directional element supervision (forward/reverse)
- Fault-type Identification and Selection (FIDS) logic does not block element
- No CVT transients detected (Zone 1)



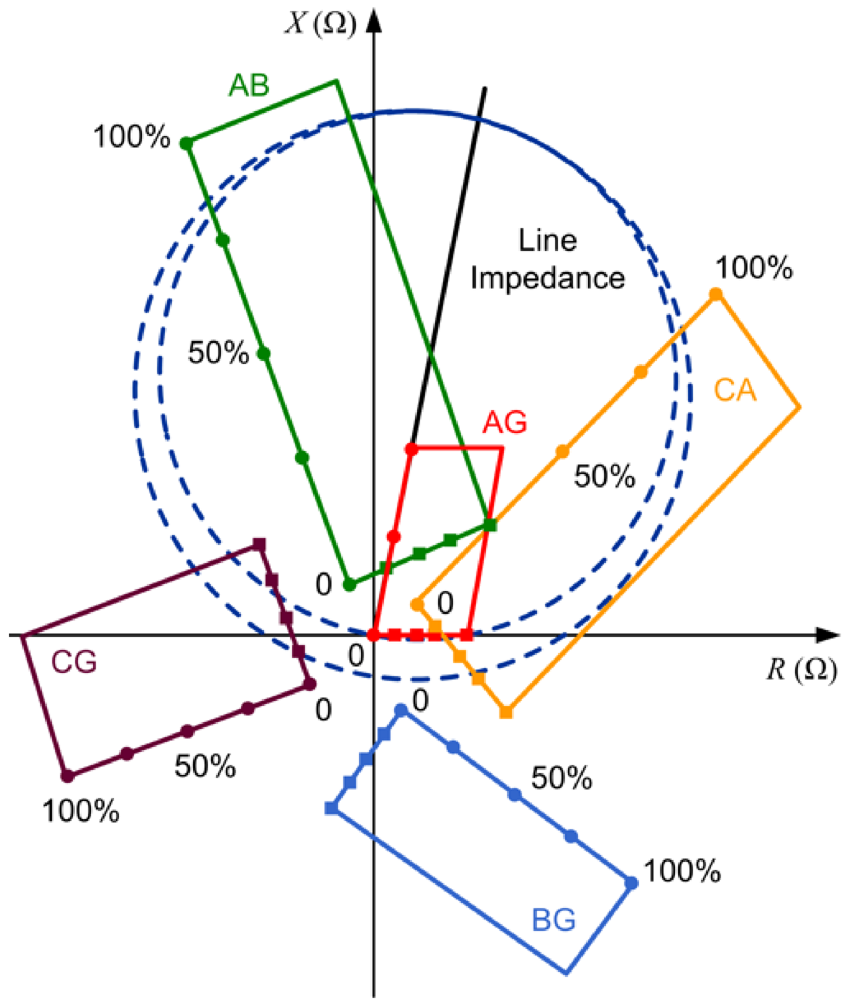


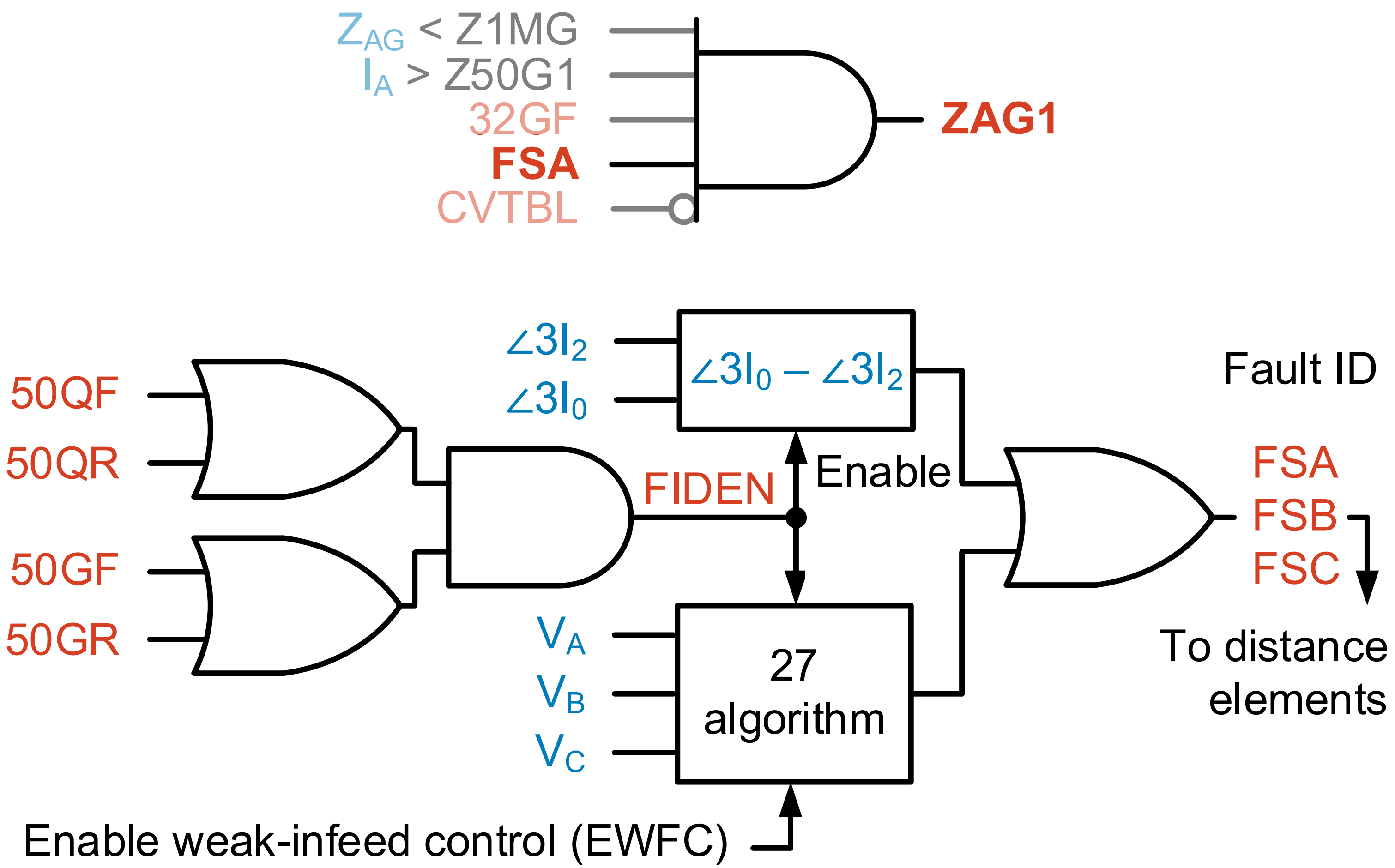
FIDS – ABG fault





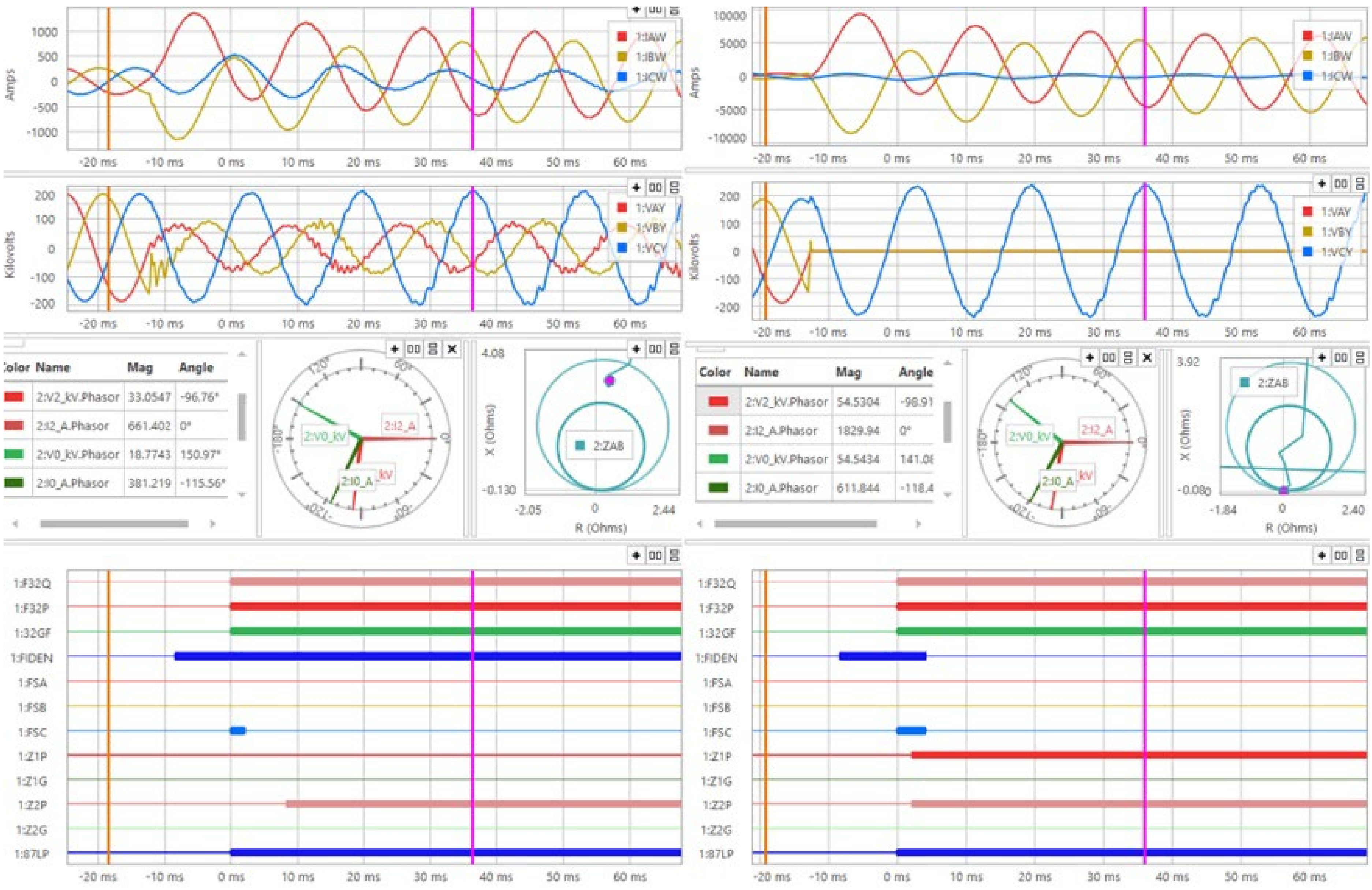
FIDS – AG fault





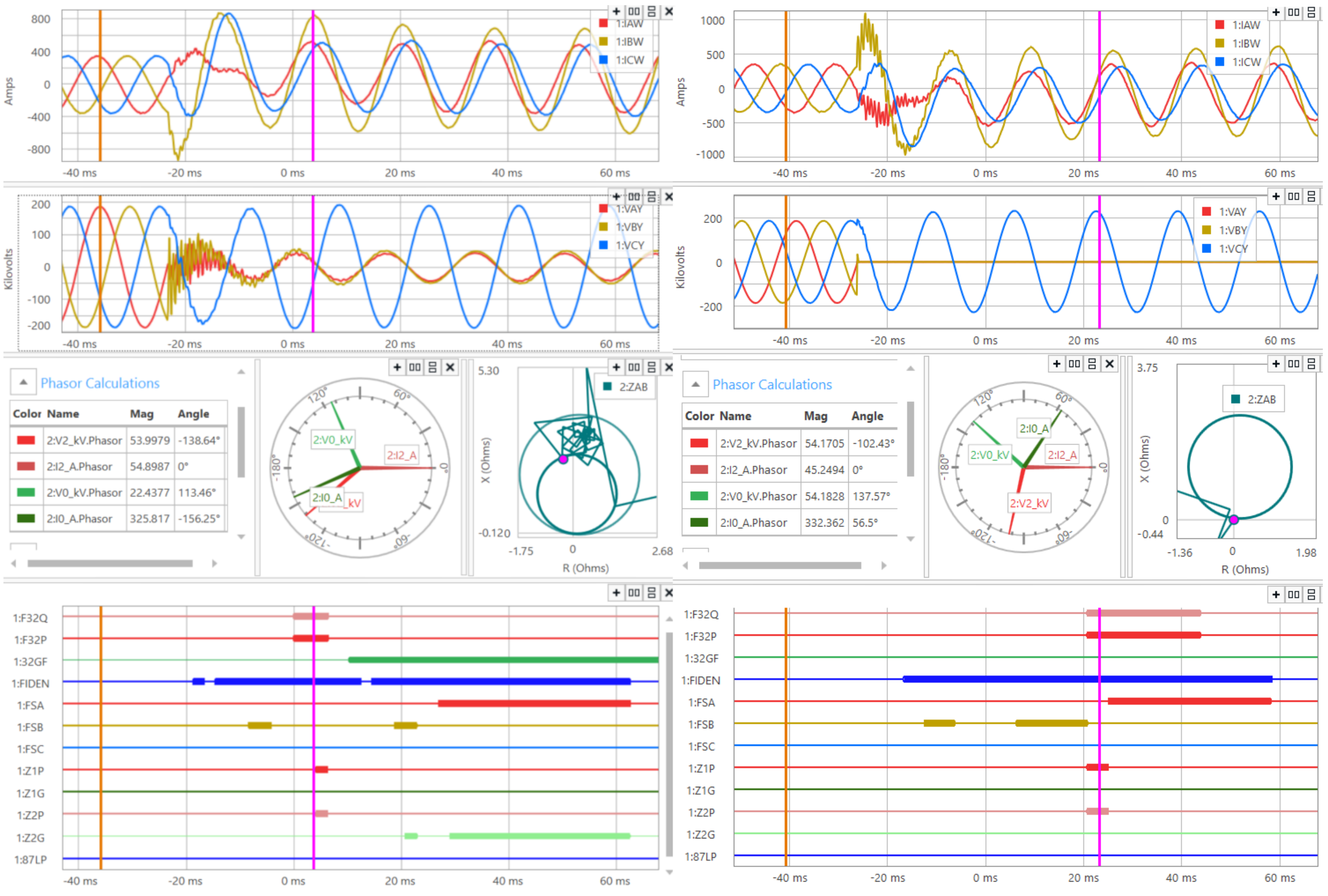
Internal ABG fault (reference)

Internal Fault



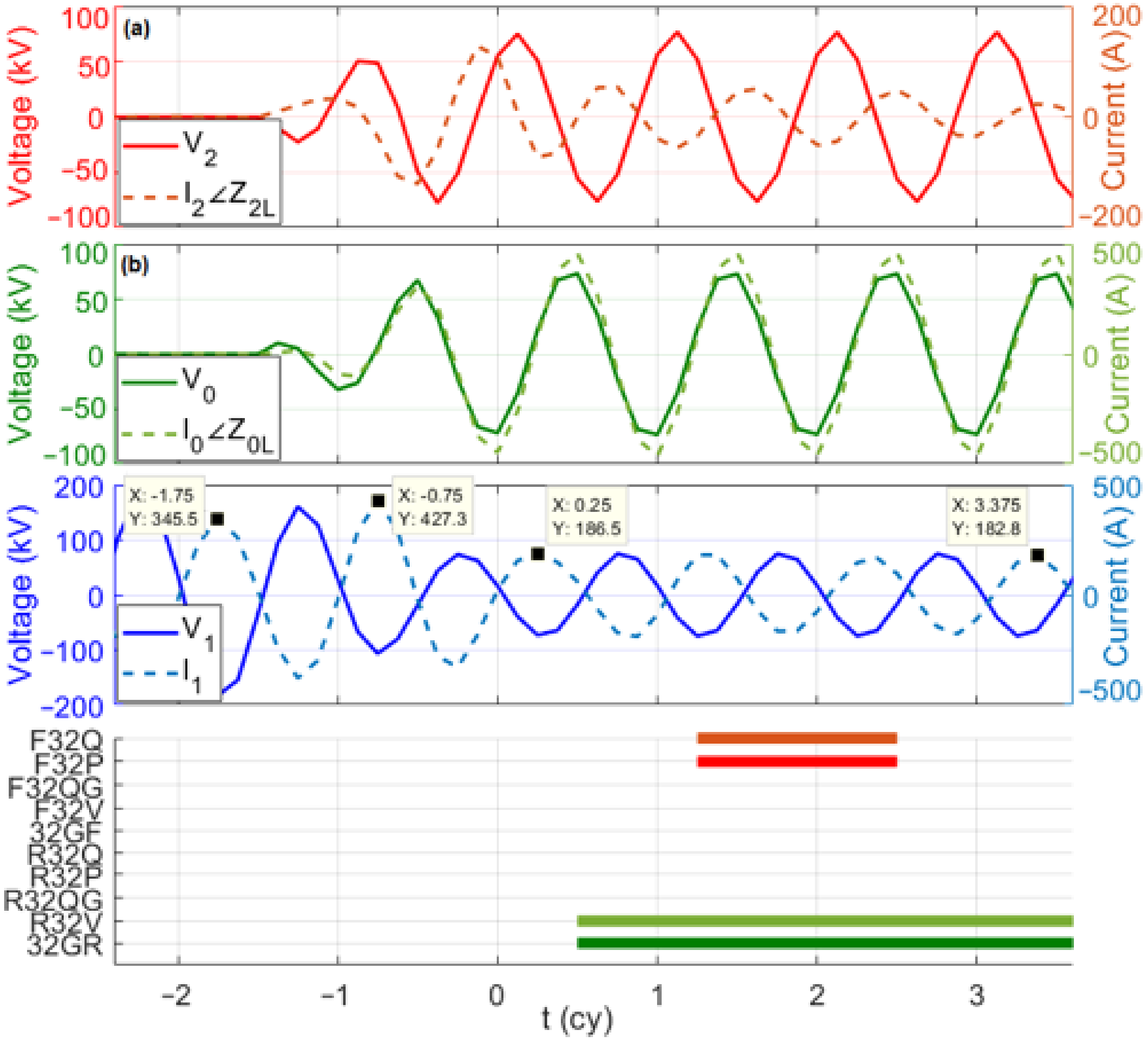
Type 4 Wind ABG fault

External Fault



Type 4 Wind ABG fault

Sequence element behavior



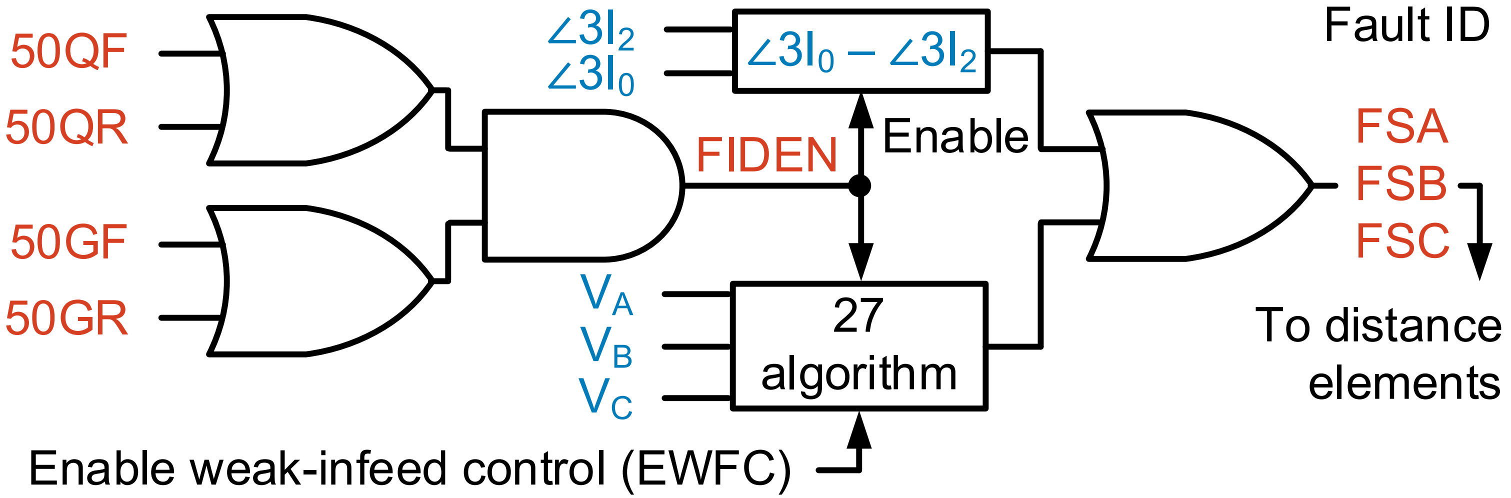
Improved Performance of Directional and Fault Type Selection

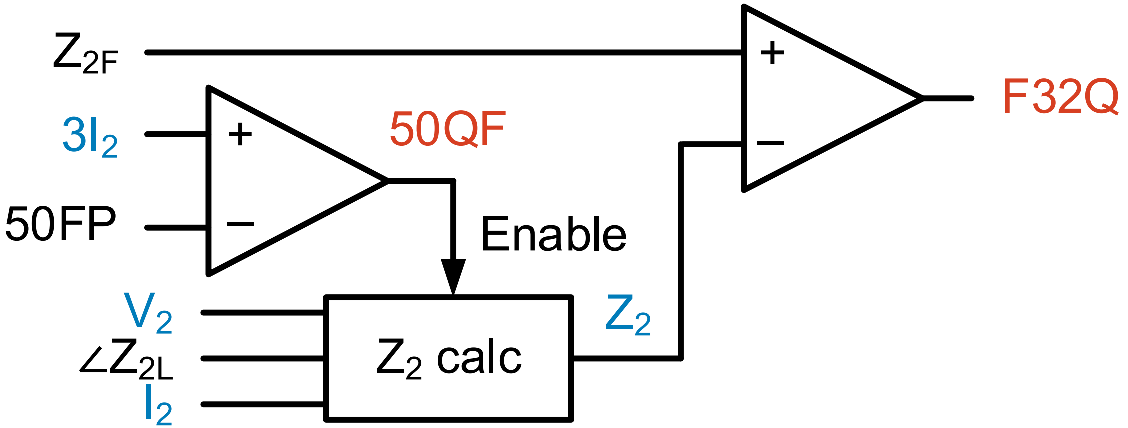
Improved performance of directional and FIDS

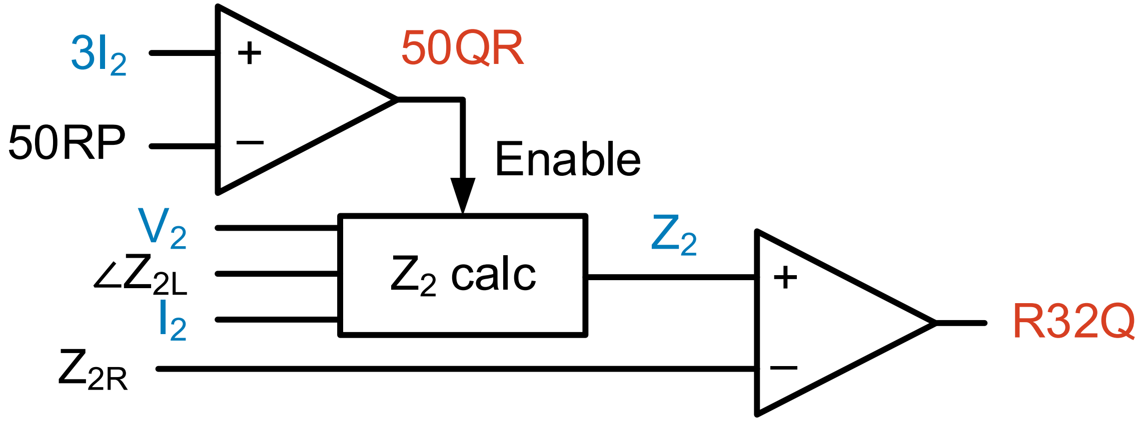
Increase overcurrent supervisory thresholds to improve 32Q security and FIDS security and dependability

$50FP = 1.25 \text{ pu} \bullet I_{MAX}$

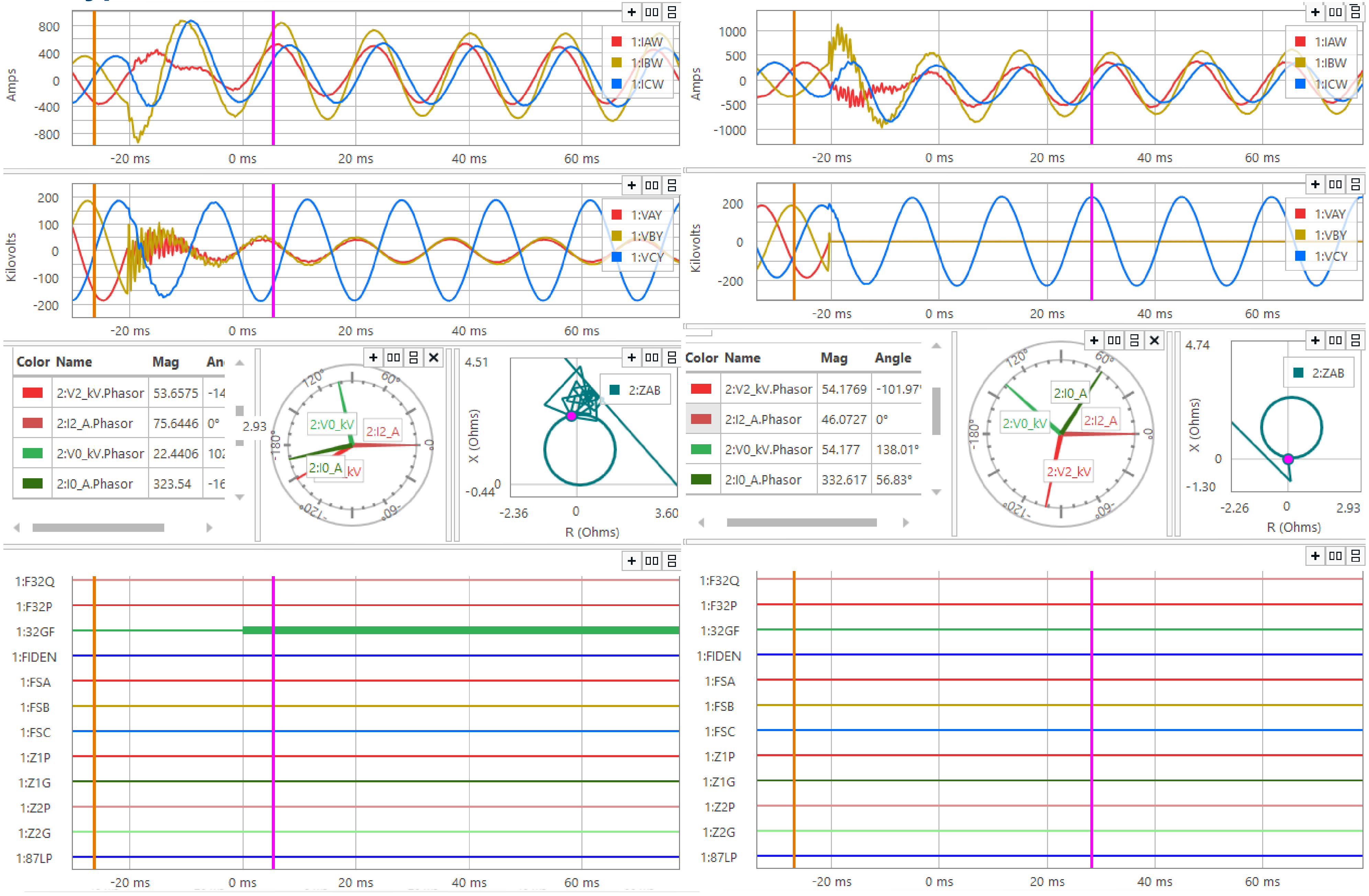
$50RP = 1.00 \text{ pu} \bullet I_{MAX}$

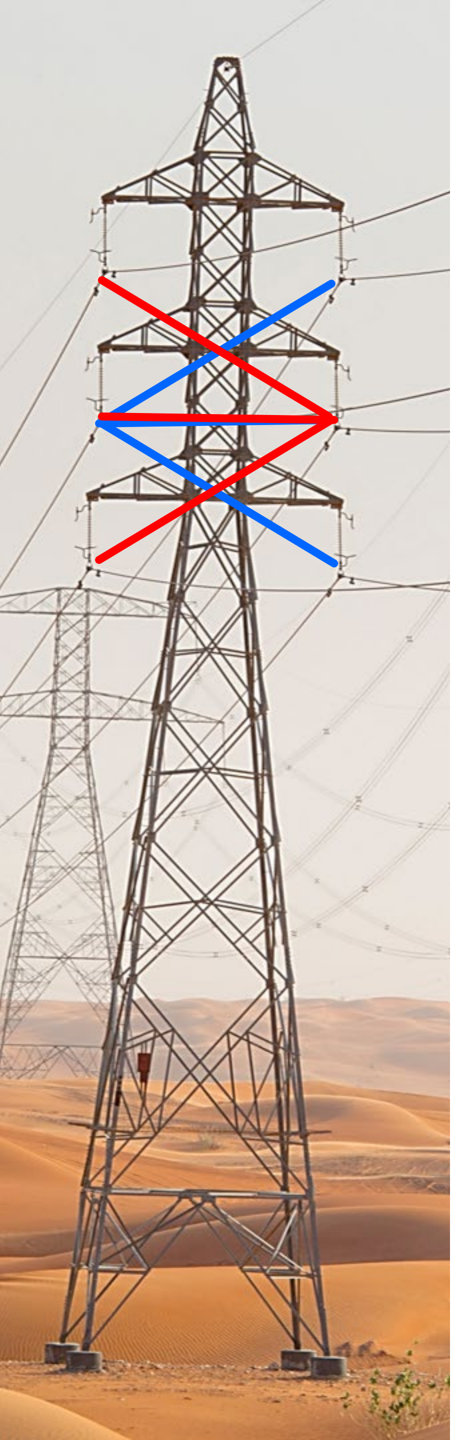




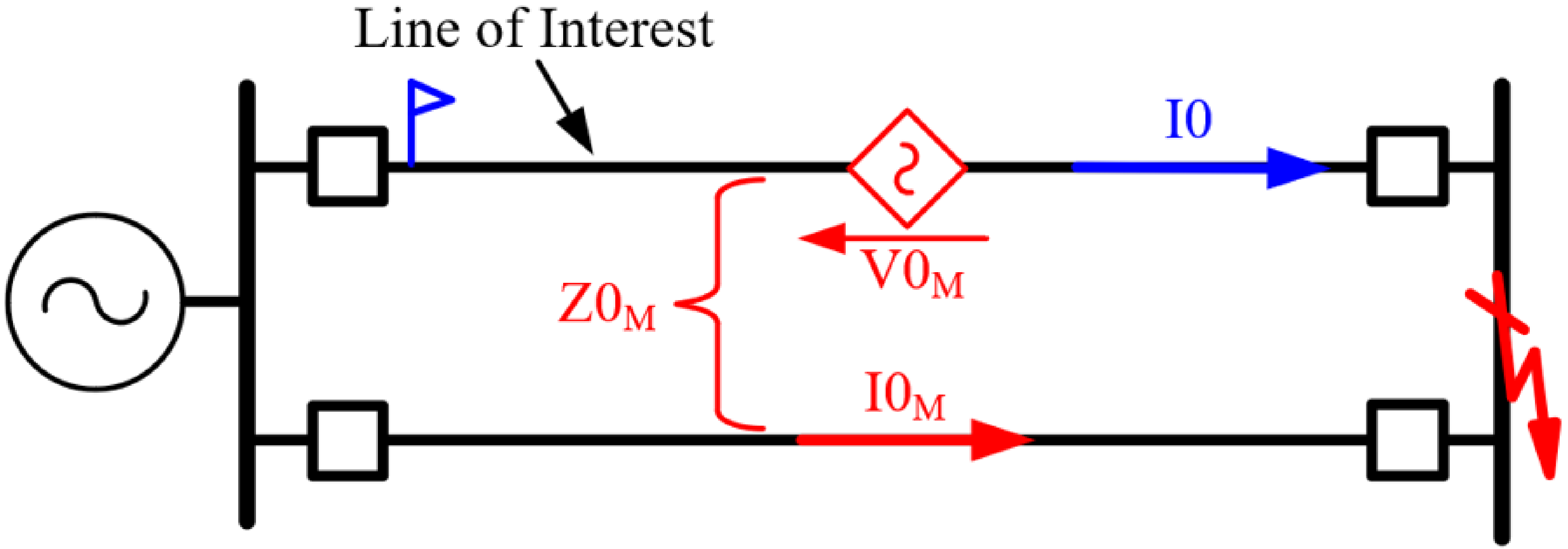


Type 4 Wind ABG fault



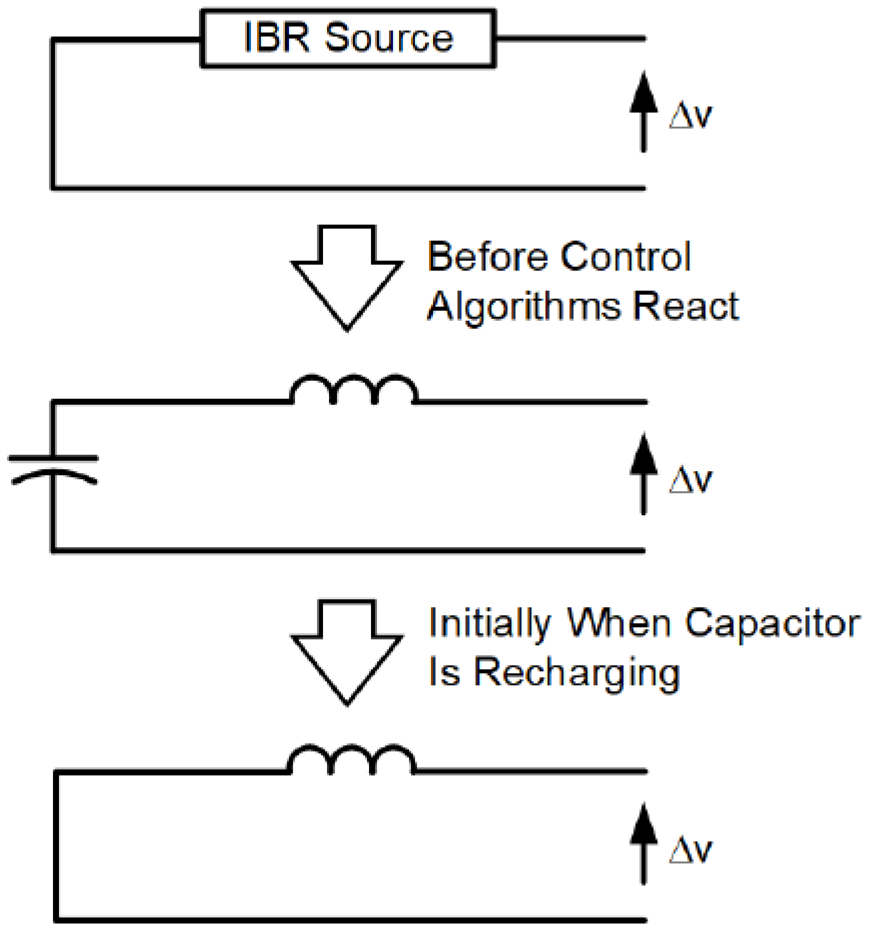


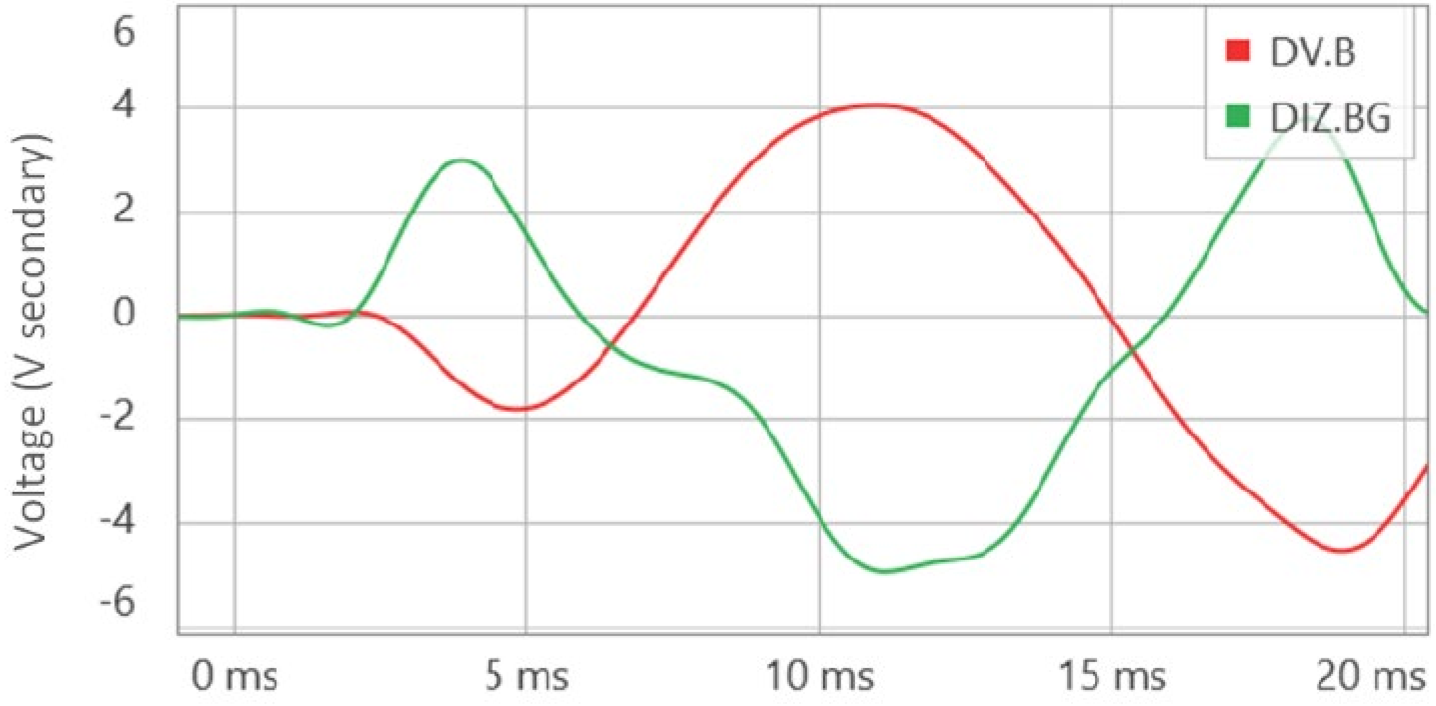
Zero-sequence Mutual Coupling



- Supervise zero-sequence directional element with low-set nondirectional negative-sequence overcurrent element
- Use security-biased thresholds
- Reclose from favorable breakers

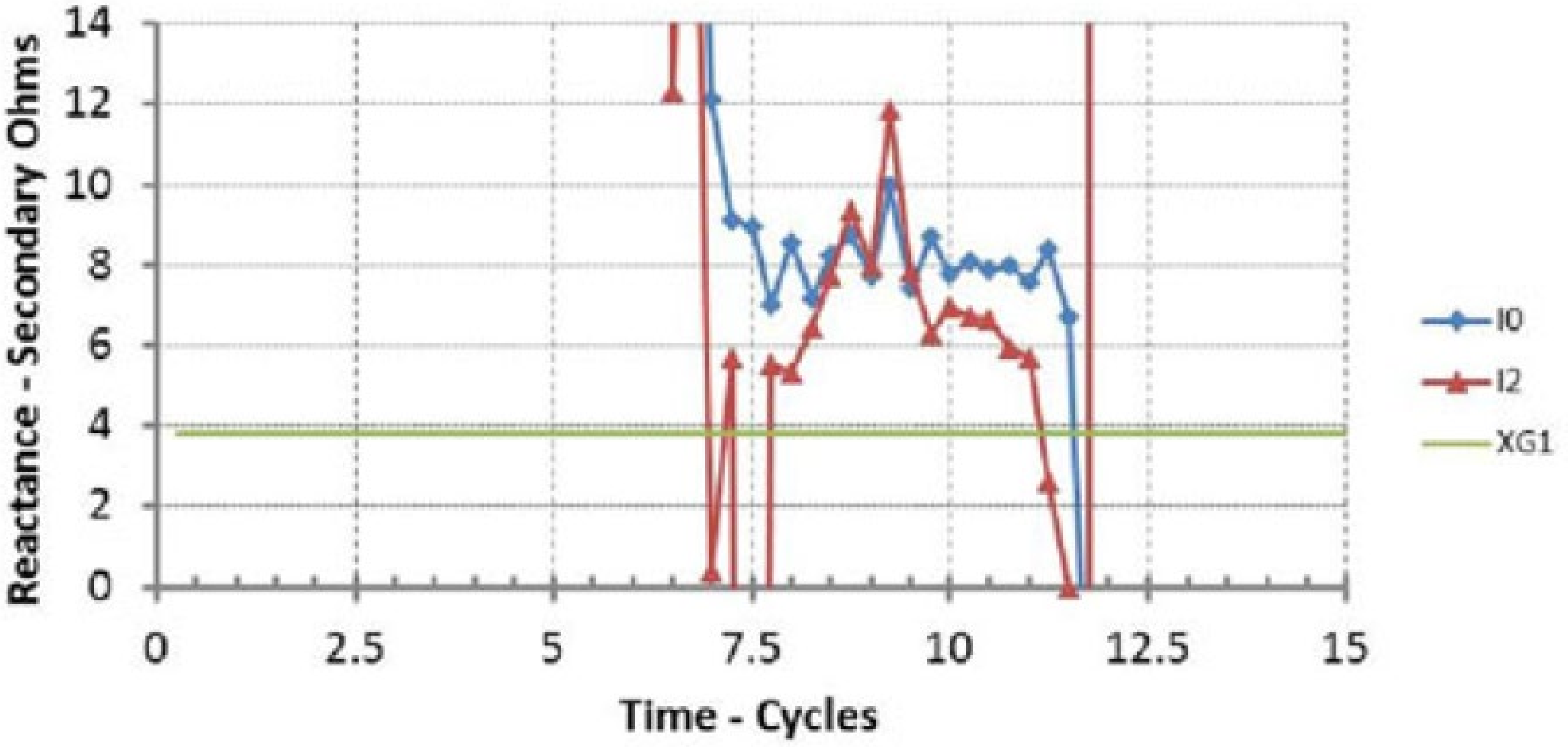
Consider use of Transient Directional Elements



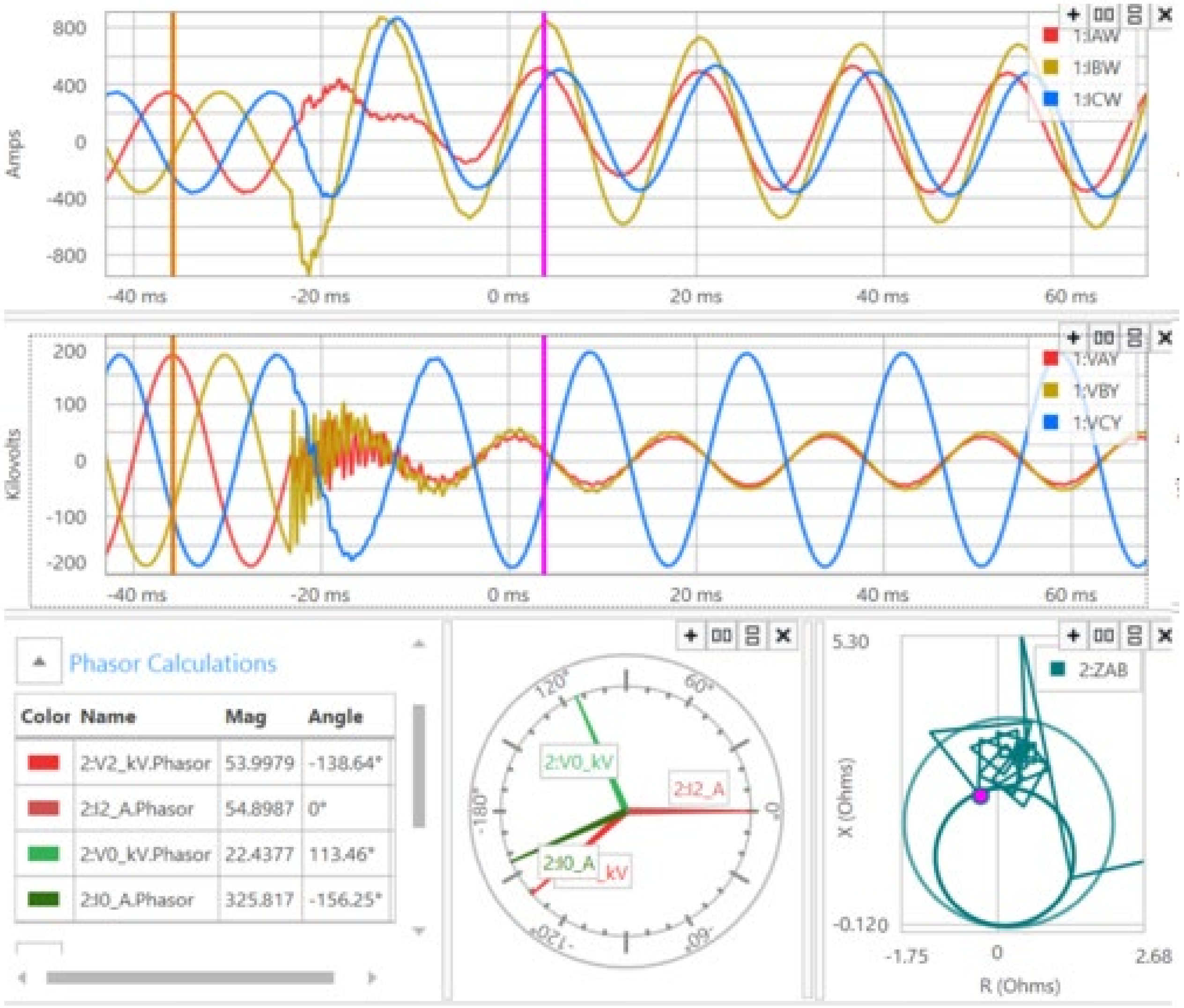


Distance Element Additional Considerations

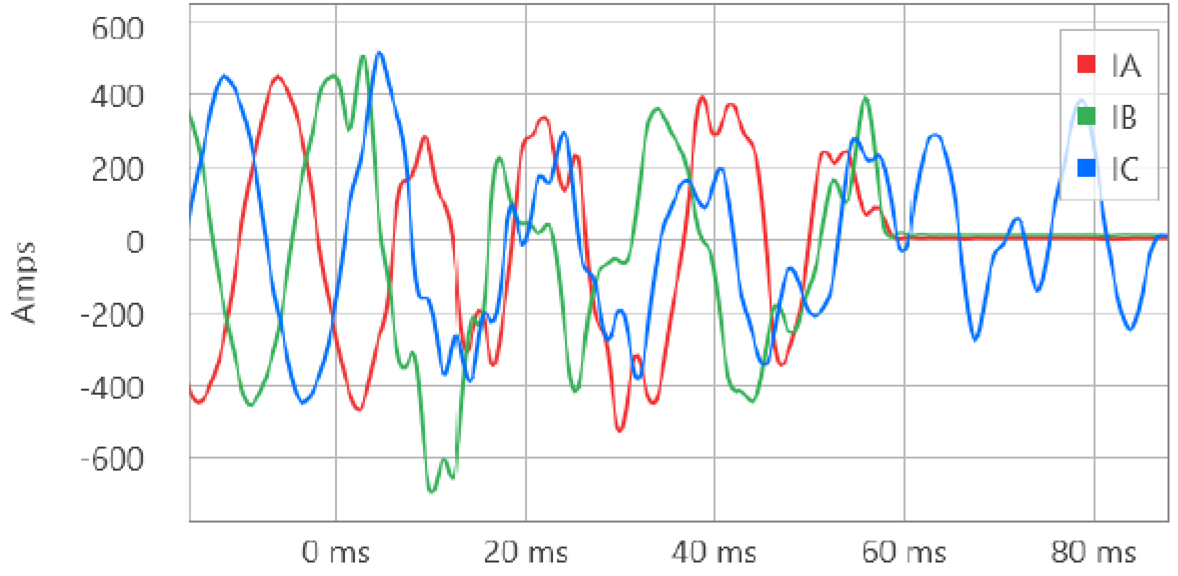
I2-polarized Ground Quadrilateral

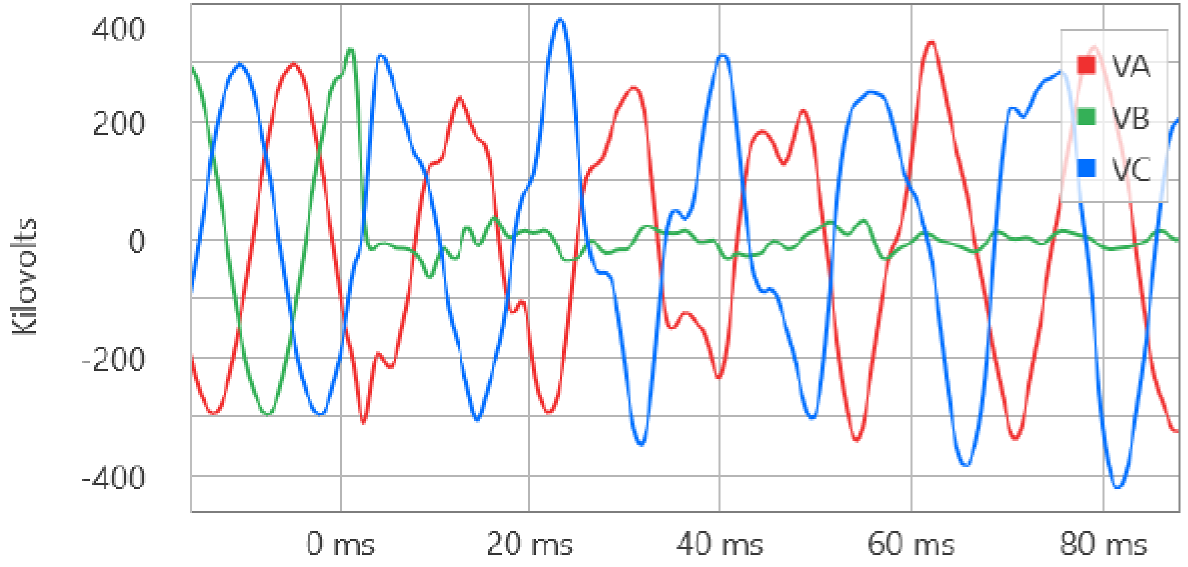


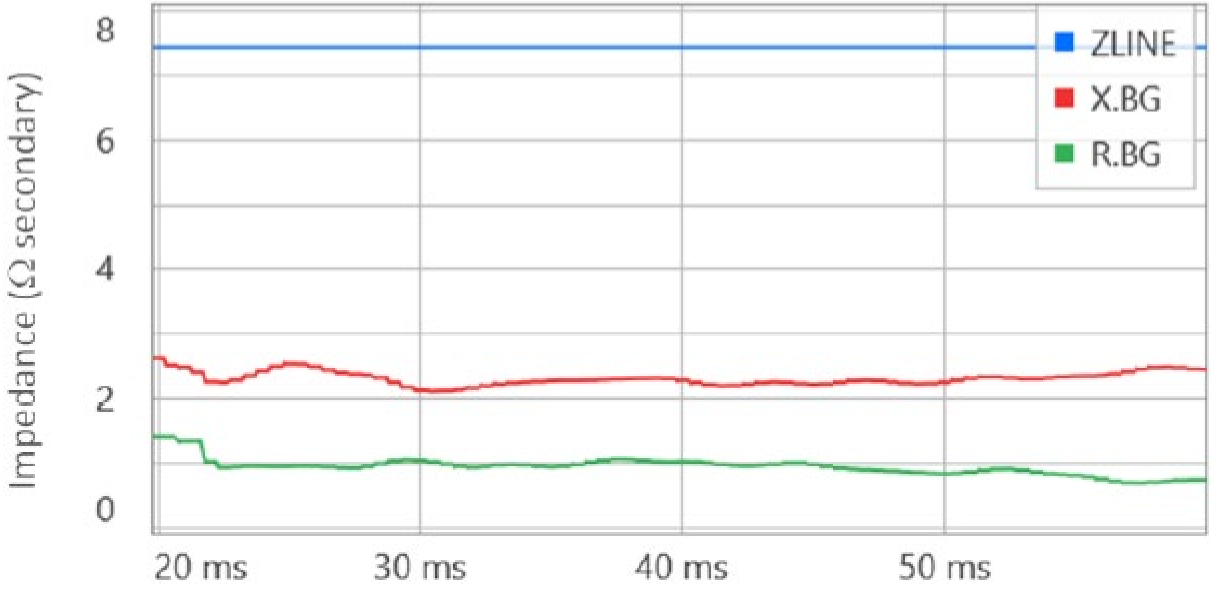
Memory-polarized Phase Mho



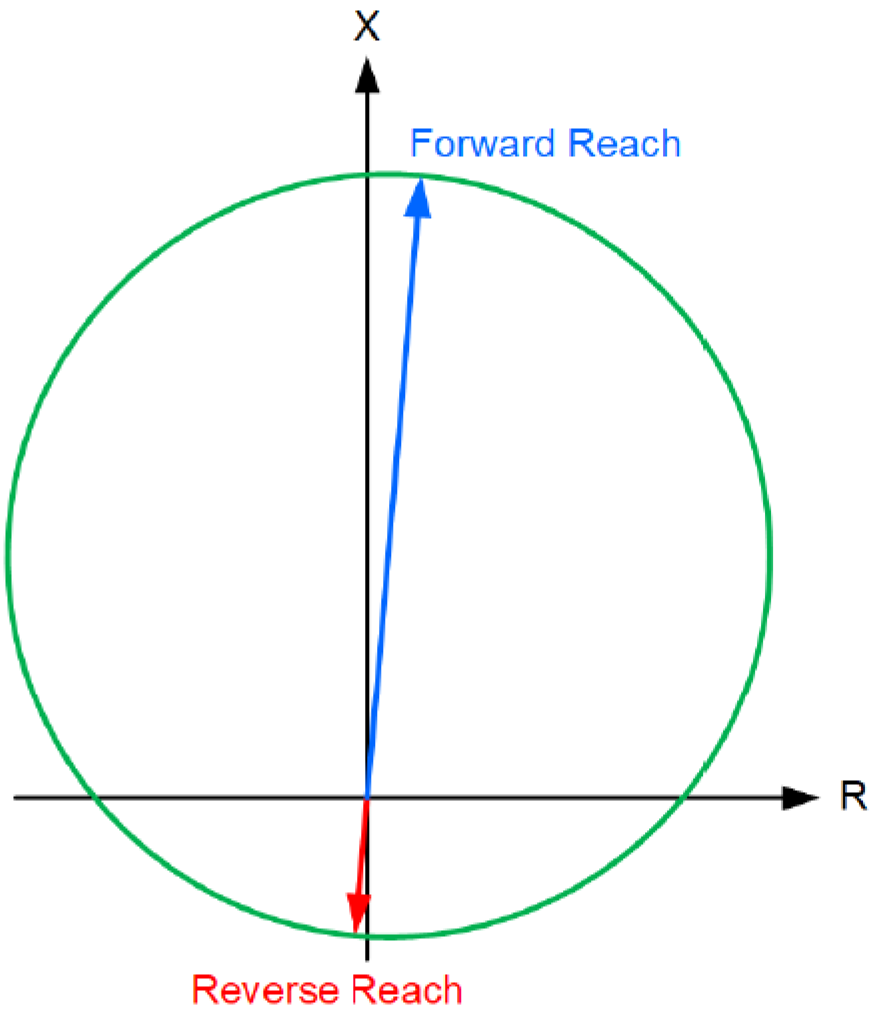
Distance Element Operating Quantity

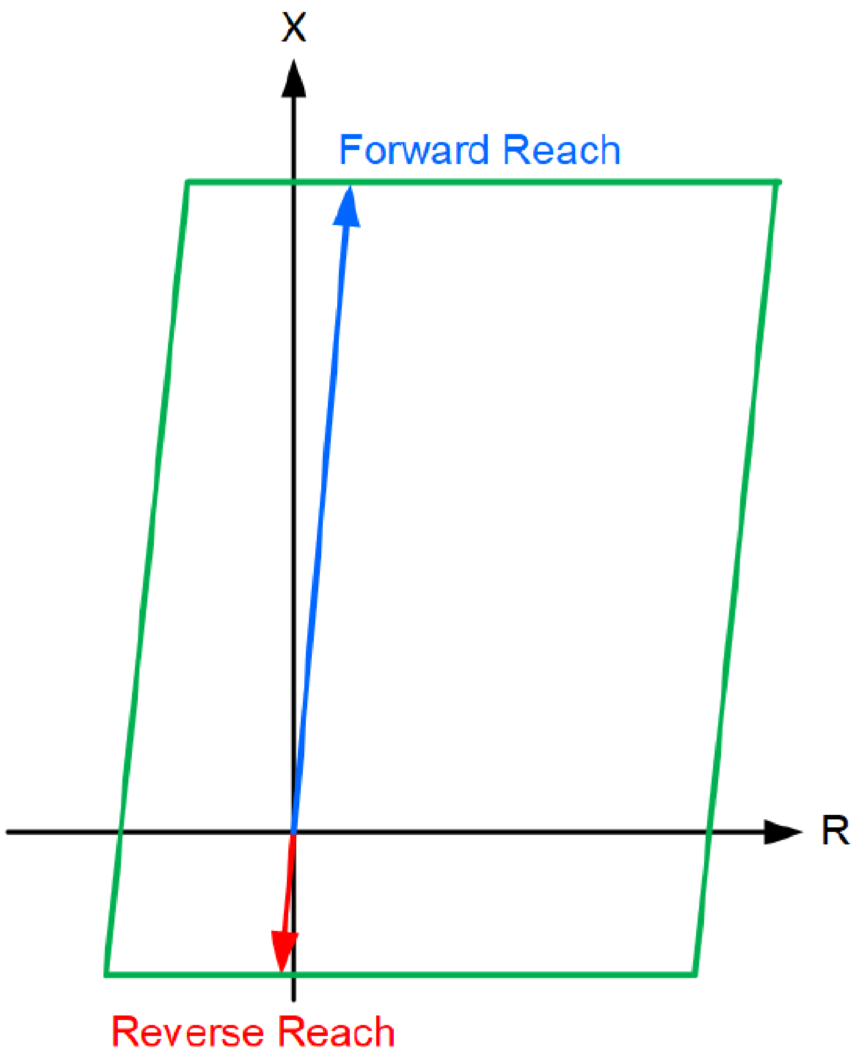




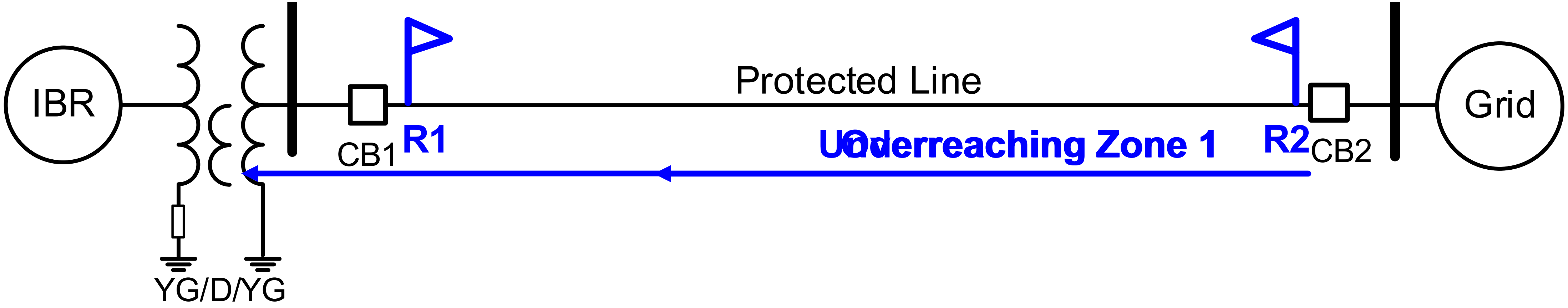


Offset Distance Elements





Increase Zone 1 Reach for Tie-Lines without Parallel Path in a Meshed Network

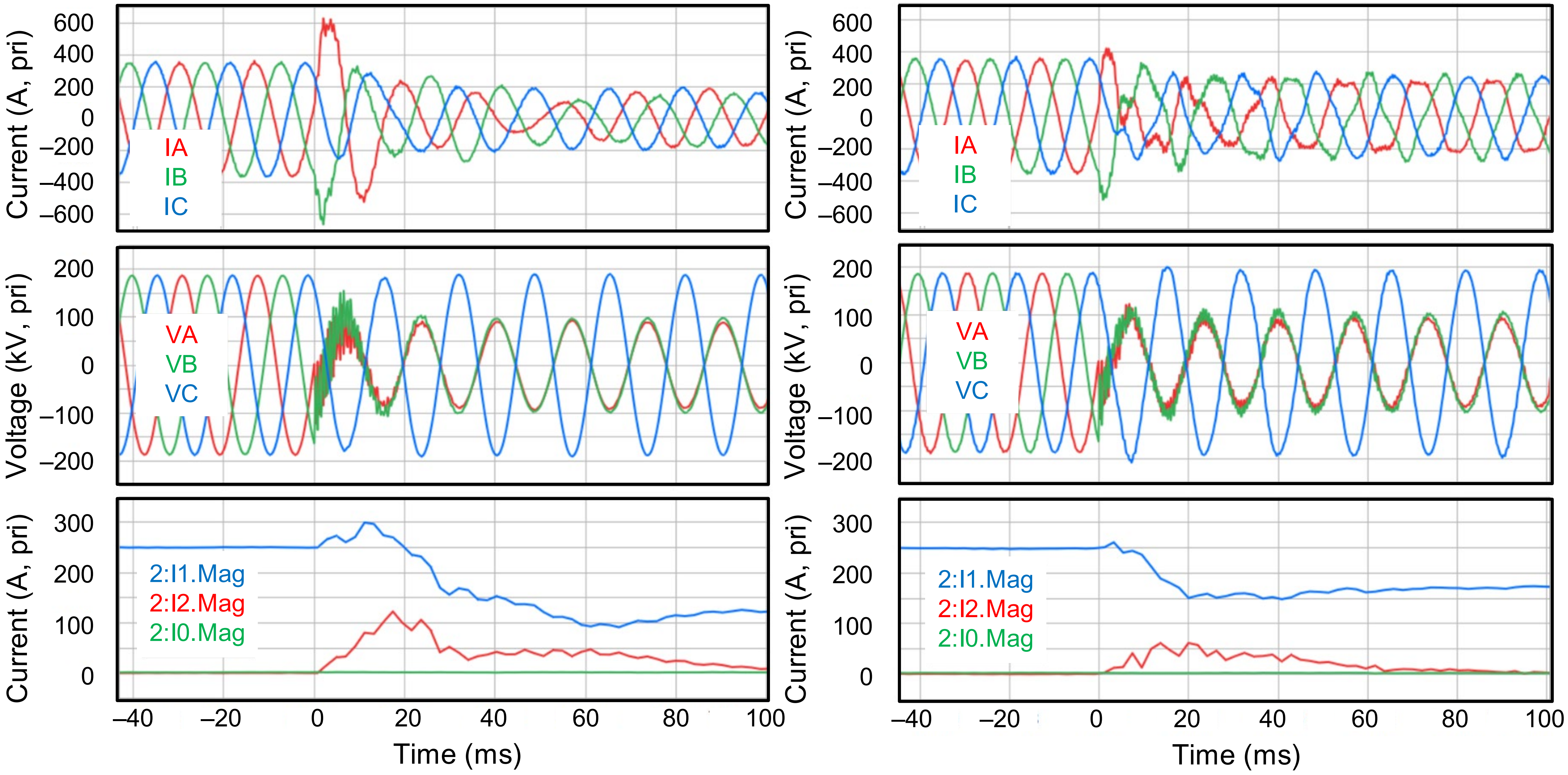


Distance Element Solutions

- Phase Distance polarization:
  - Phase mho *loop voltage* > *positive-sequence memory voltage*.
  - Phase quad *loop current* > *negative-sequence current*.
  - Use offset characteristics with transient directional elements.
- Ground Distance polarization:
  - Ground mho performs well because of the zero-sequence path presented by the IBR plant transformer.
  - Ground quad zero-sequence current > negative-sequence current.
- Increase Zone 1 Reach for tie-lines without parallel paths.

Source-to-Line Impedance Ratio (SIR)

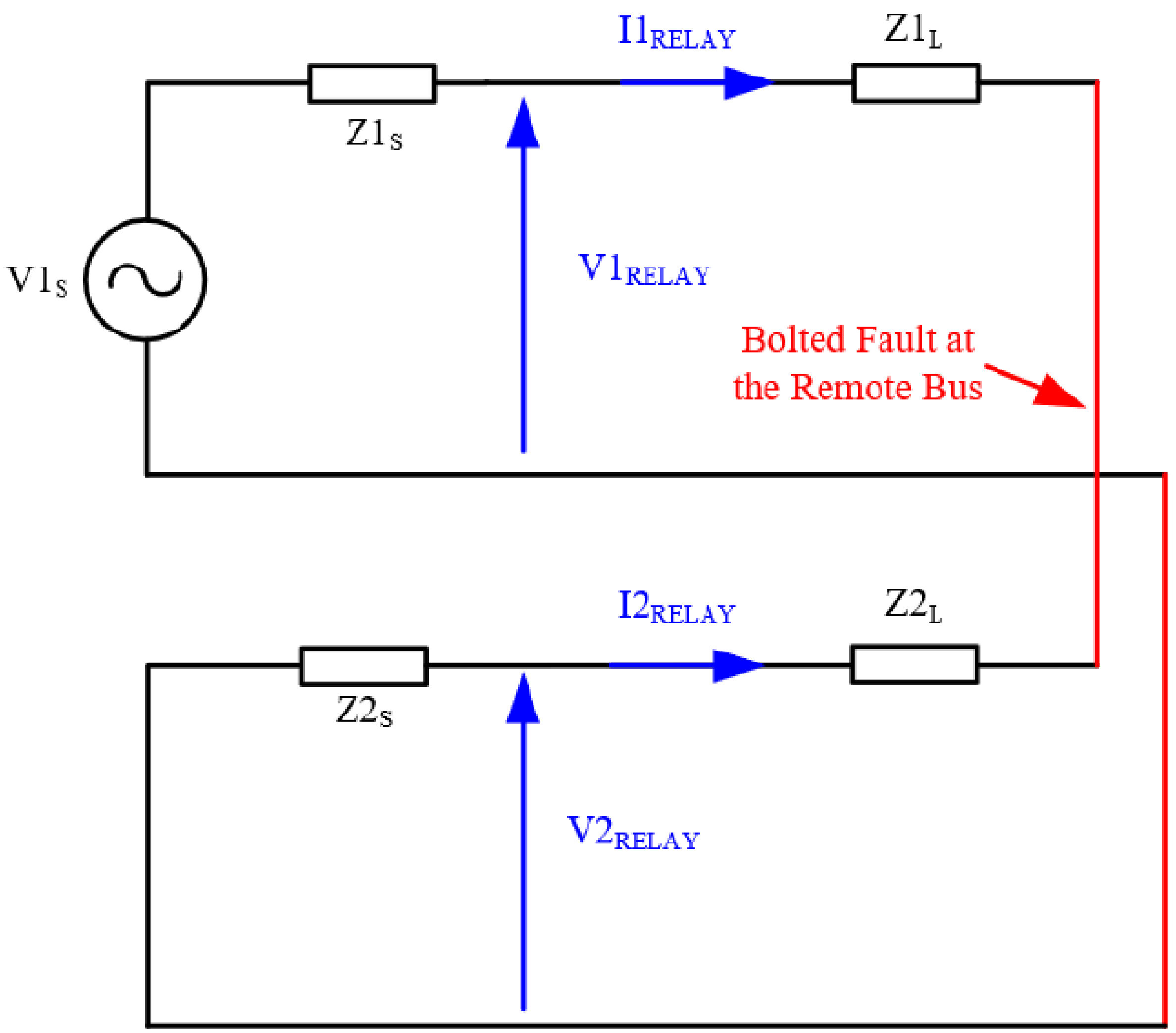
Line-to-line fault at Remote Bus



Relay Voltage for Line-to-Line faults

$$\frac{V_{RELAY\_LL\ (LL\ FAULT)}}{V_{RELAY\_LL\ (3P\ FAULT)}} = \frac{Z1_S + Z1_L}{\left(\frac{Z1_S + Z2_S}{2}\right) + Z1_L}$$

- If $Z_{1S} = 10 \cdot Z_{1L}$ and $Z_{2S} = 10 \cdot Z_{1S}$,
  - * $SIR_{P(3P\_FAULT)} = 10$
  - * $SIR_{P(LL\_FAULT)} = 50.9!$
- Consider LL faults also to calculate SIR_P!



SIR compared to synchronous generators

- Synchronous Generators X''_S = 0.10 to 0.65 pu.
  With GSU (0.05 to 0.20 pu) X''_{GEN_PLANT} = 0.15 to 0.85 pu
- IBRs I_{MAX} ~1.1 to 1.3 pu => $Z_S \gtrapprox 0.75$ pu.
  Including collector system impedance and GSU impedance:
  - Non-standardized IBRs limit I_2 => $Z_{IBR\_PLANT} \gtrapprox 3 \cdot X''_{GEN\_PLANT}$
  - Standardized IBRs provide I_2 => $Z_{IBR\_PLANT} \gtrapprox 2 \cdot X''_{GEN\_PLANT}$
- IBR modeling in short-circuit programs is an ongoing effort:
  - Tabular format with current-voltage pairs has been considered
  - IBR OEMs are working on providing DLLs to short-circuit program manufacturers

Rough Estimate SIR without use of models

$$Line\ Length > \frac{V_{BASE}{}^{2}}{S_{IBR}} \bullet \frac{Z_{PLANT\_PU}}{SIR_{MAX} \bullet Z1_{L\_PL}} \qquad (23)$$

where:

V_{BASE}	is the system line-to-line base voltage
S_{IBR}	is the rated MVA of the IBR
Z_{PLANT_PU}	is the per-unit plant impedance (e.g., 1 to 2 pu)
$Z1_{L\_PL}$	is the line impedance in ohms per desired line length unit (e.g., ohms/mile)

- 500 kV line with Z_{1L} = 0.5 Ω/mile. Interconnecting 500 MVA IBR plant has an impedance of 1.2 pu. Using (23) for an SIR_{MAX} of 4, the minimum line length is 300 miles.
- 115 kV line with Z_{1L} = 0.8 Ω/mile. Interconnecting 50 MVA IBR plant has an impedance of 2 pu. Using (23) for an SIR_{MAX} of 4, the minimum line length is 165 miles.

Improve Zone 1 Security due to High SIR

Reduce reach and/or add time-delays

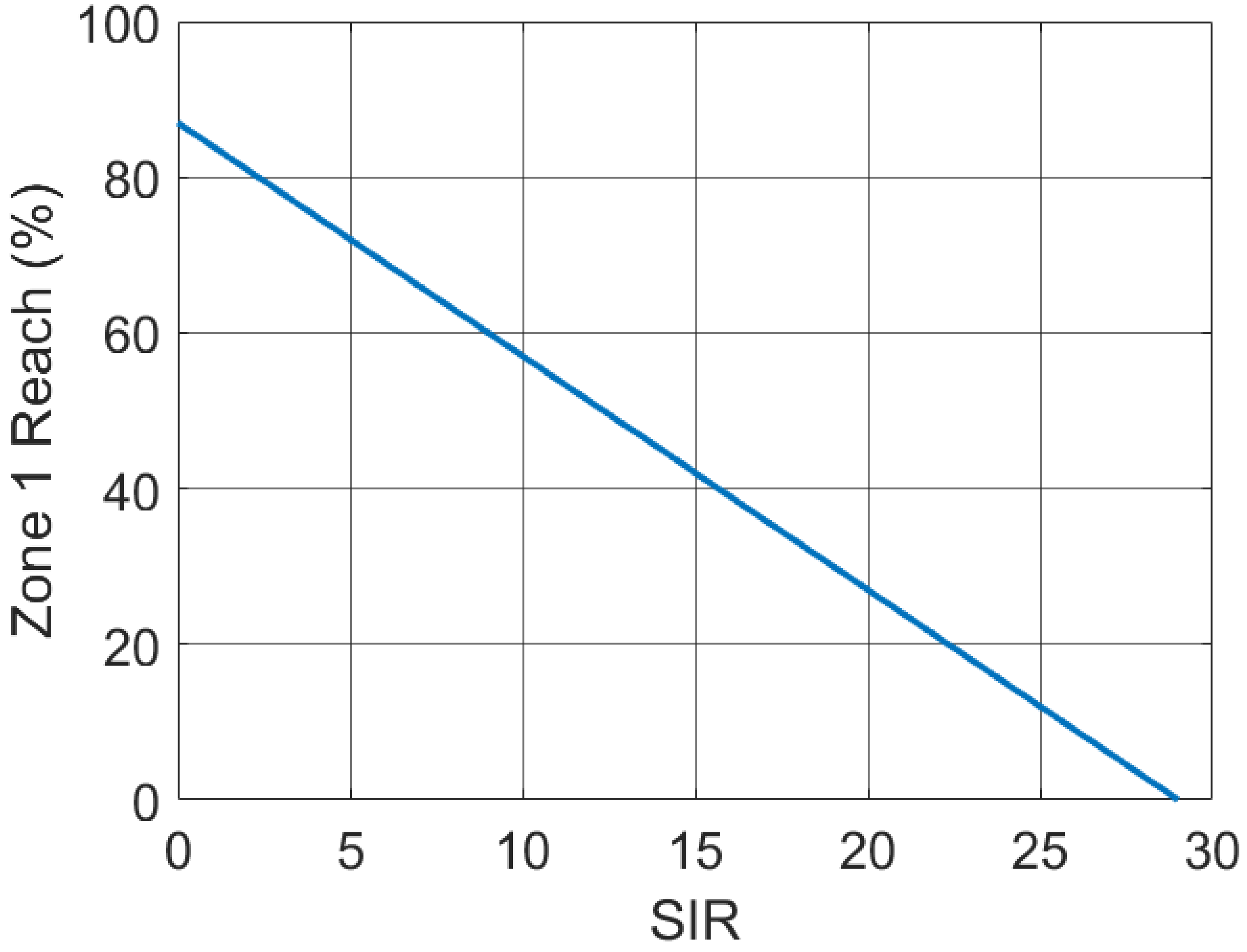
- $m_1 < m_{1RATIO} – E_{SS} \bullet (SIR + 1)$

  m_1 = Secure reach considering SIR

  m_{1RATIO} = Reach considering Ratio Errors (e.g., 0.90 pu)

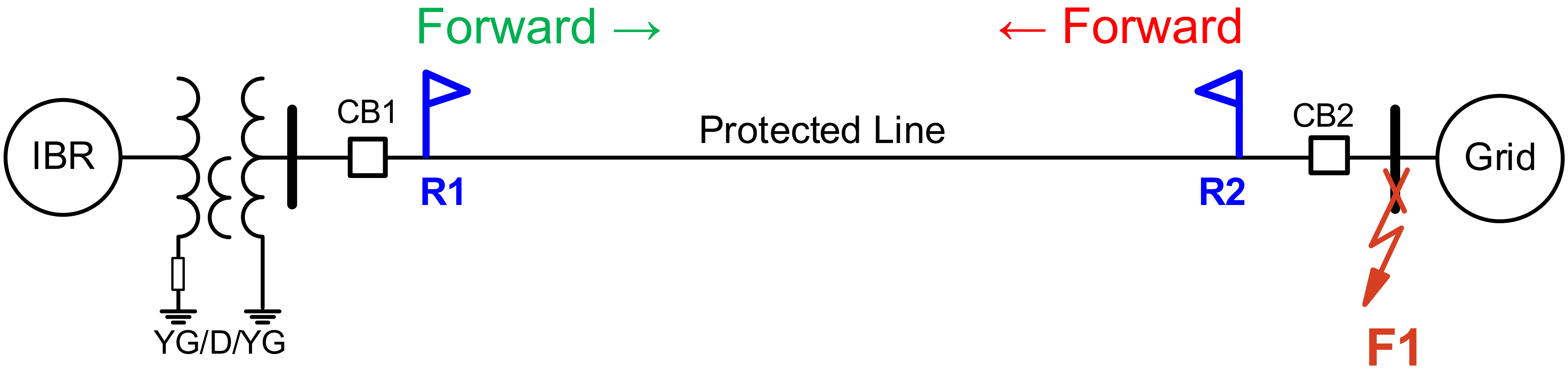
  E_{SS} = Steady-state Error (e.g., 0.03 pu)

- Consider transient CCVT errors.

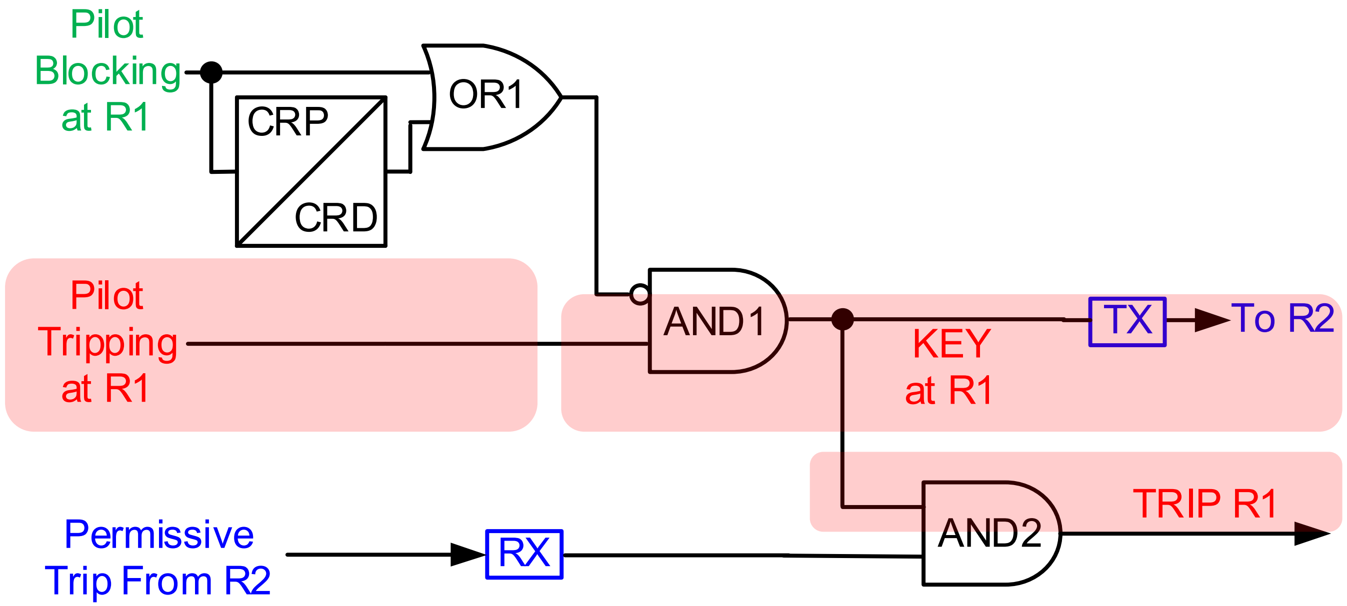


Directional Comparison Pilot Schemes

Directional Element Security

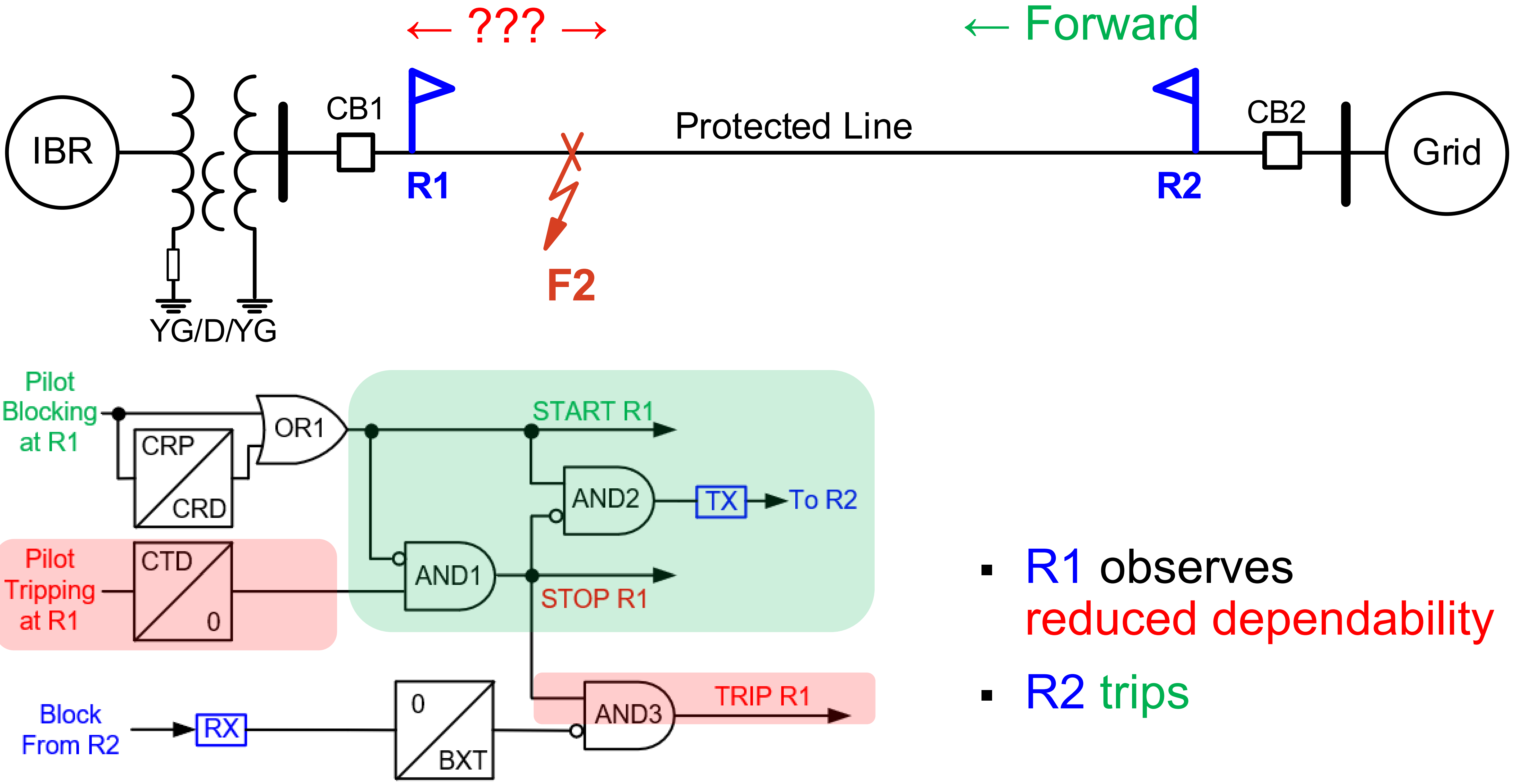


POTT Scheme Dependability



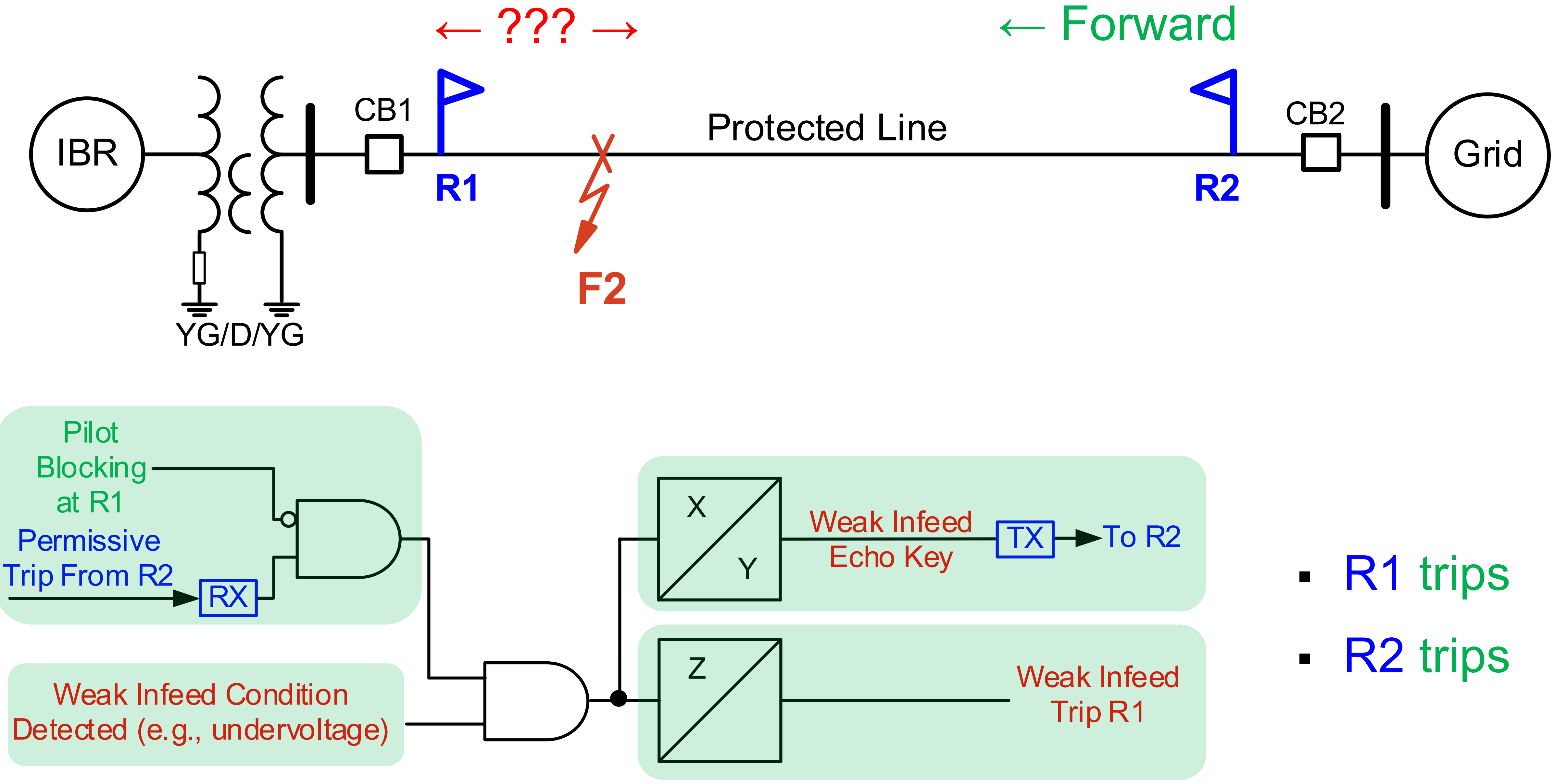
- R1 observes reduced dependability
- R2 also observes reduced dependability

DCB Scheme Dependability



- R1 observes reduced dependability
- R2 trips

Hybrid POTT With Week-Infeed Echo and Trip

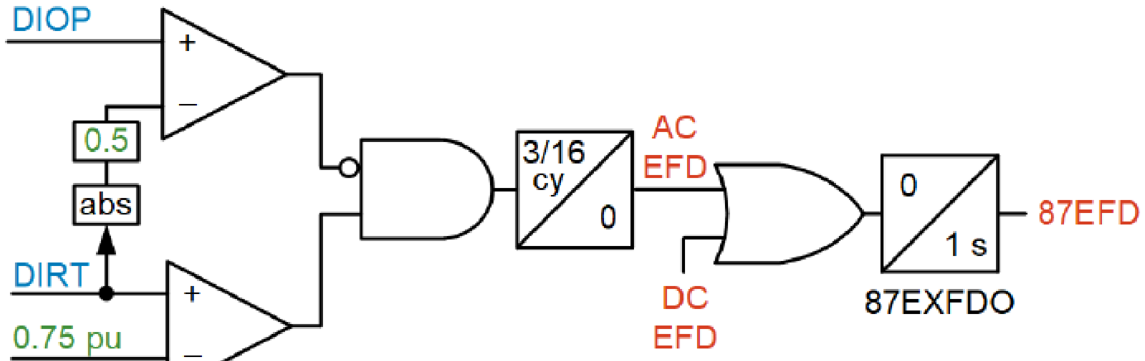


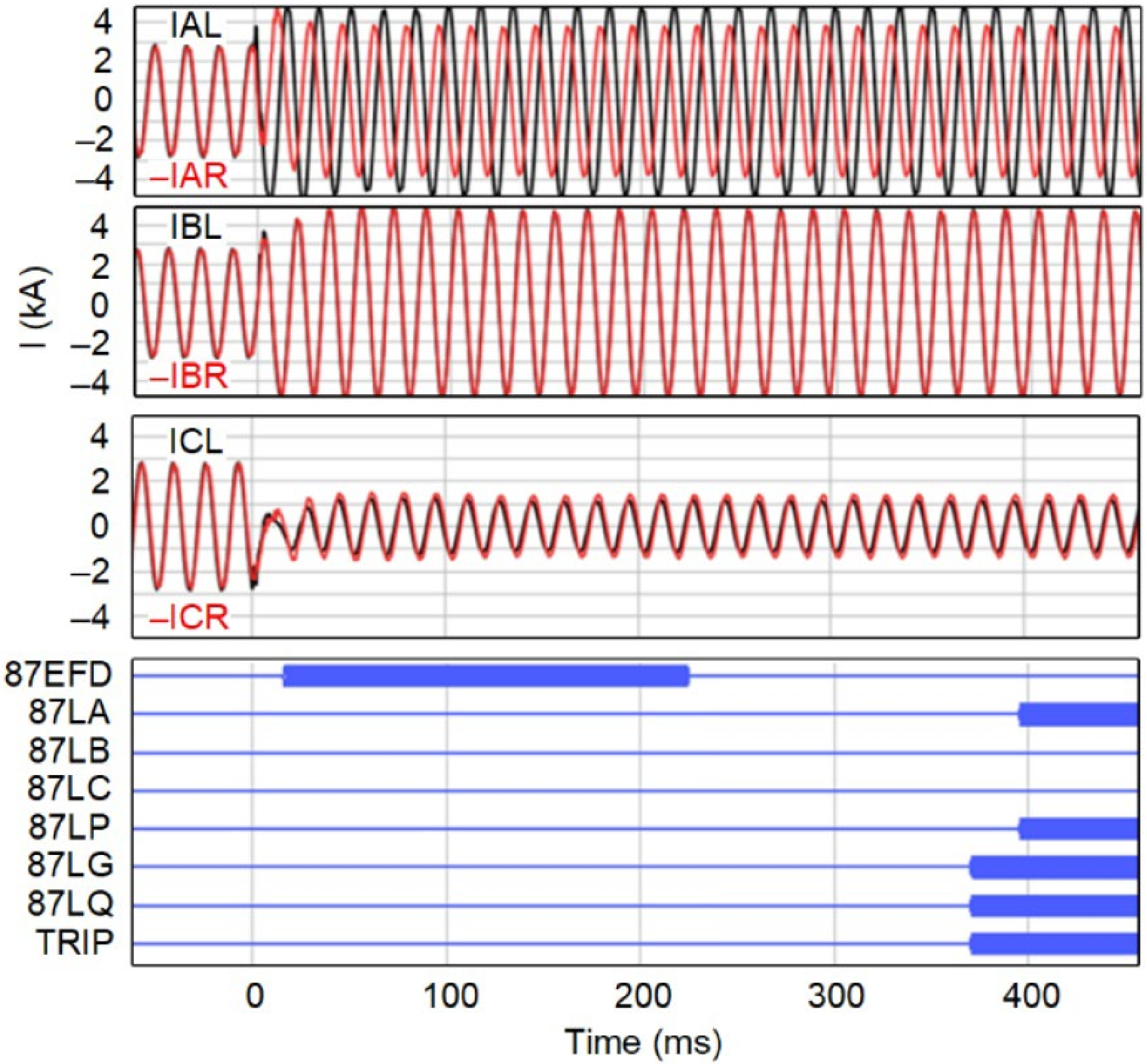
- R1 trips
- R2 trips

Line Current Differential

Internal AG fault

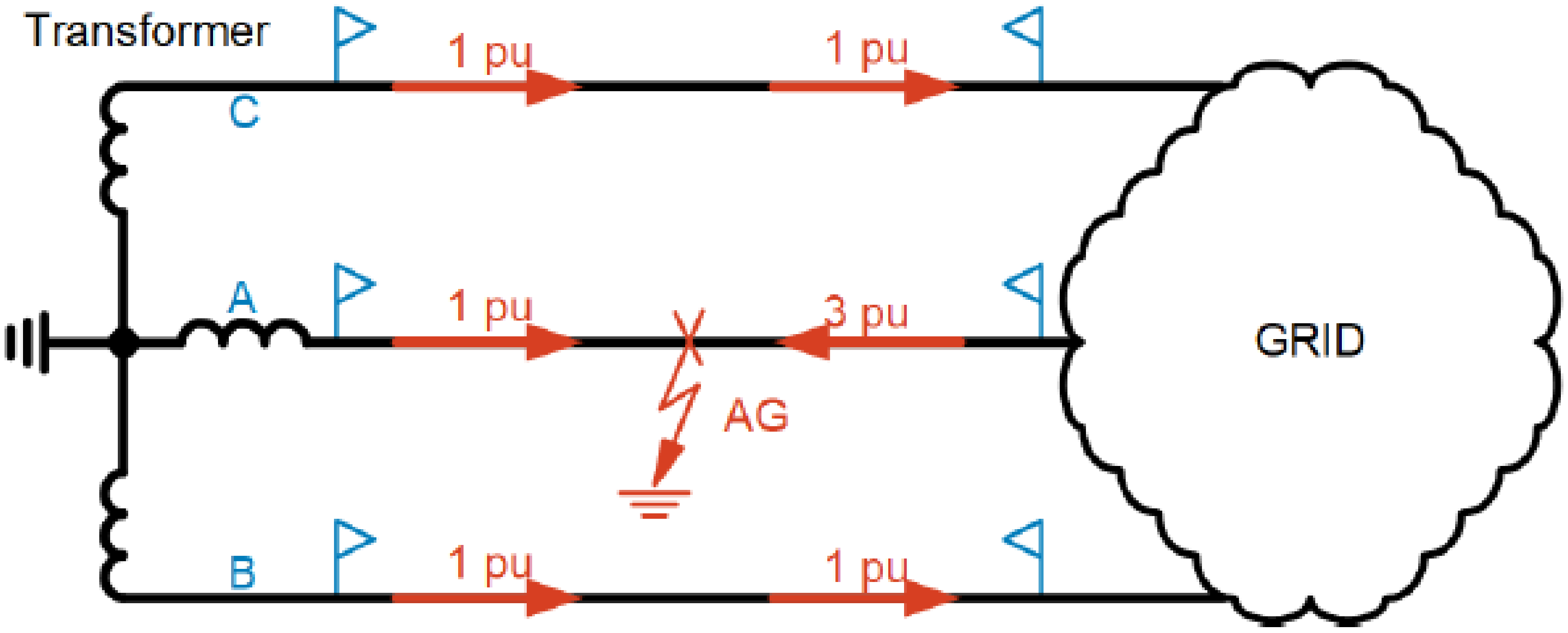
15-ohm



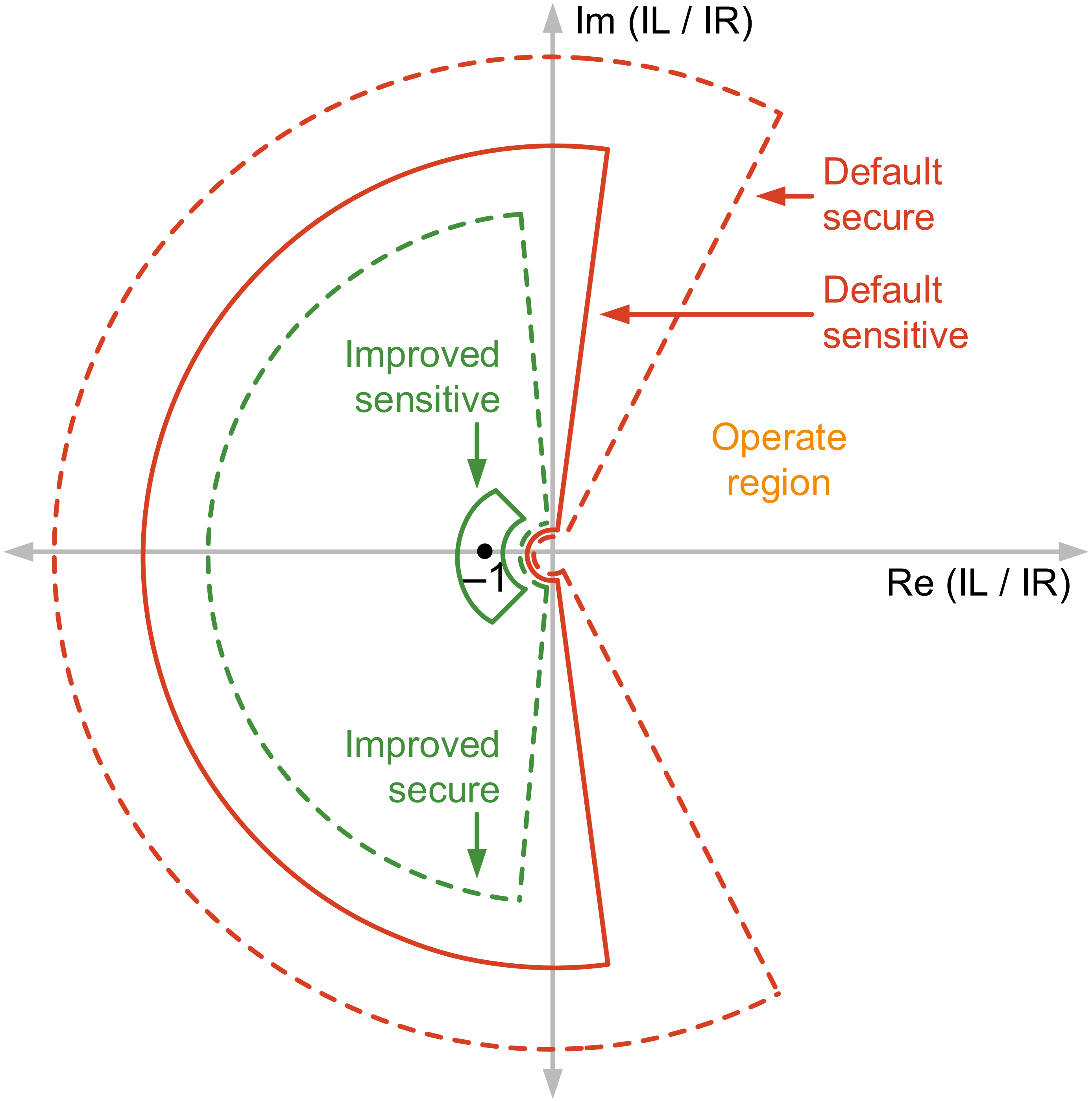


IBR fault response

Strong zero-sequence, but weak otherwise

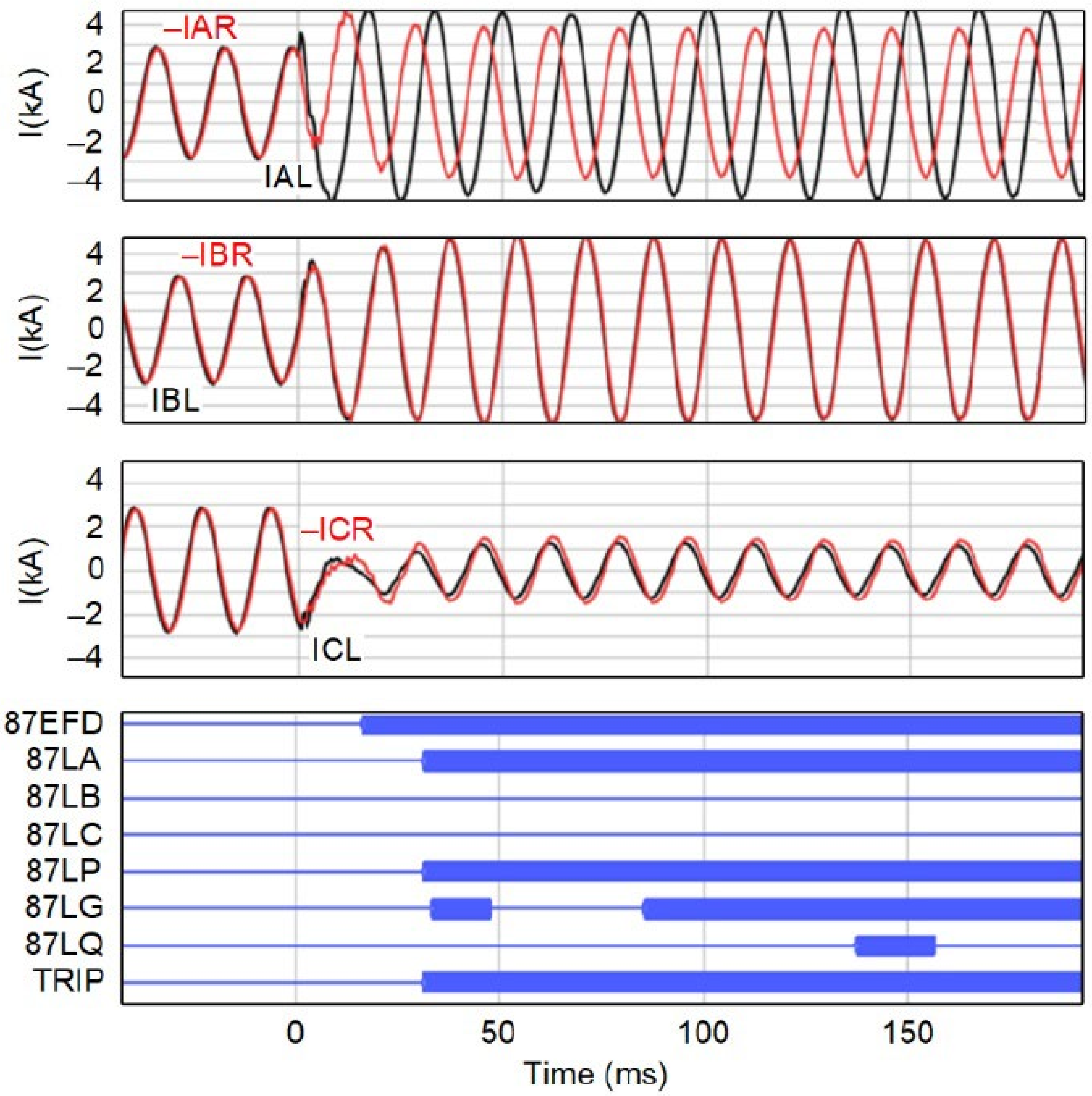


Improved dependability



Internal AG fault

Improved settings



No fault
Harmonics

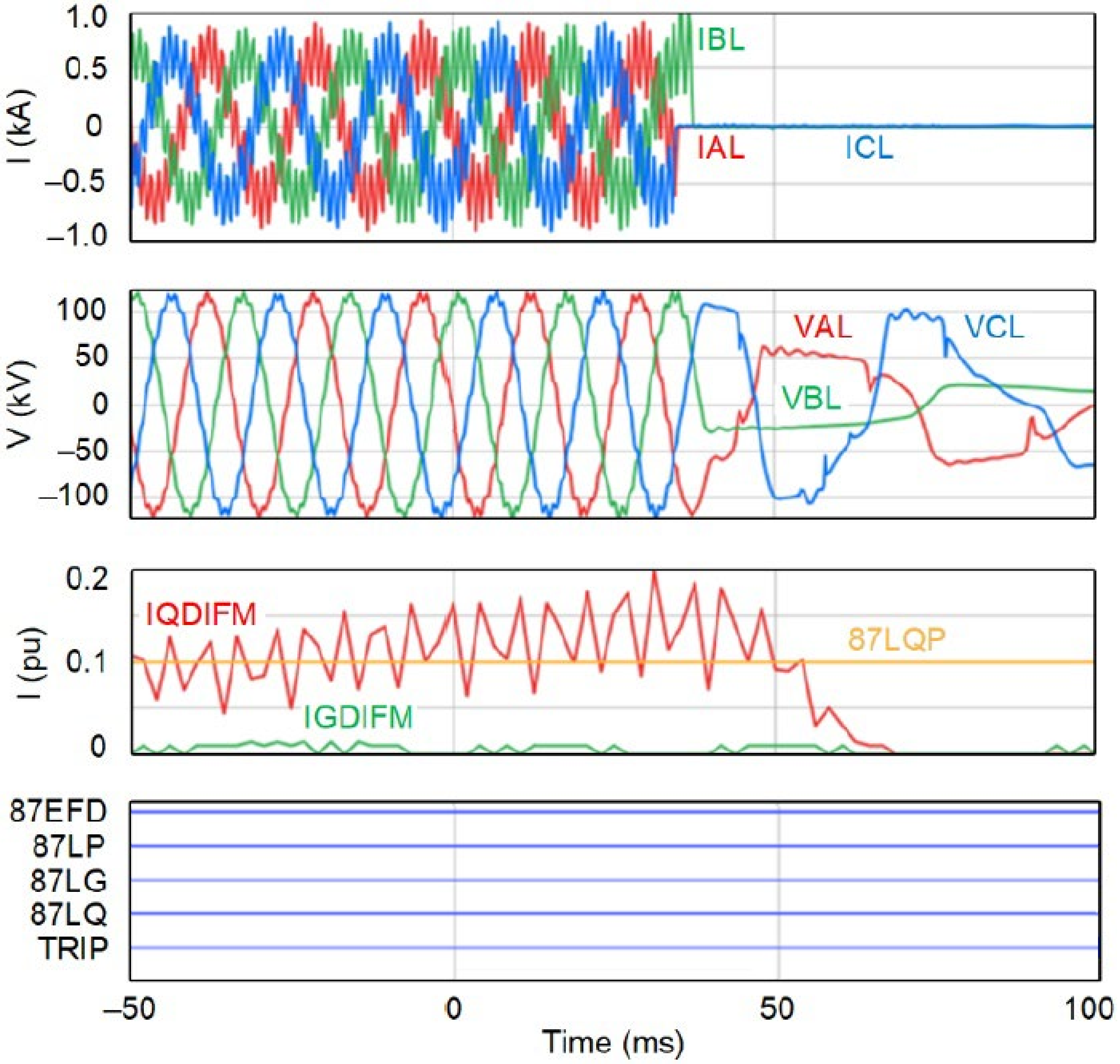
$$87LQP_{SENS} =$$

$$1.25 \cdot \frac{S_{IBR}}{\sqrt{3} \cdot V_{HV} \cdot (CTR \cdot I_{NOM})} \text{ pu}$$

$$87LQP_{SECURE} =$$

$$1.30 \cdot 87LQP_{SENS} \text{ pu}$$

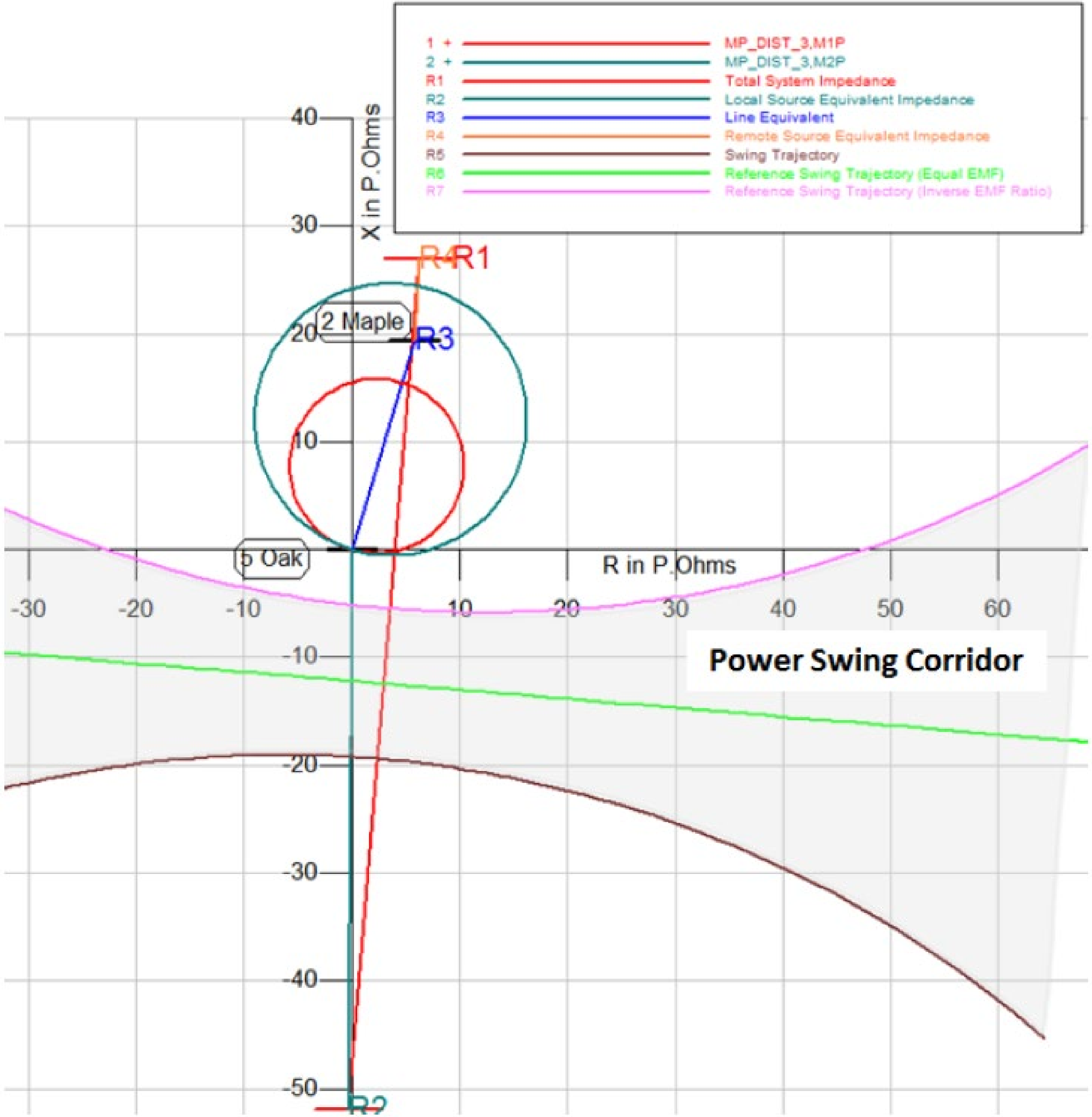
- $87LQP_{SENS}$ = 0.48 pu
- $87LQP_{SECURE}$ = 0.63 pu



Power Swing Blocking and Out-of-step Tripping

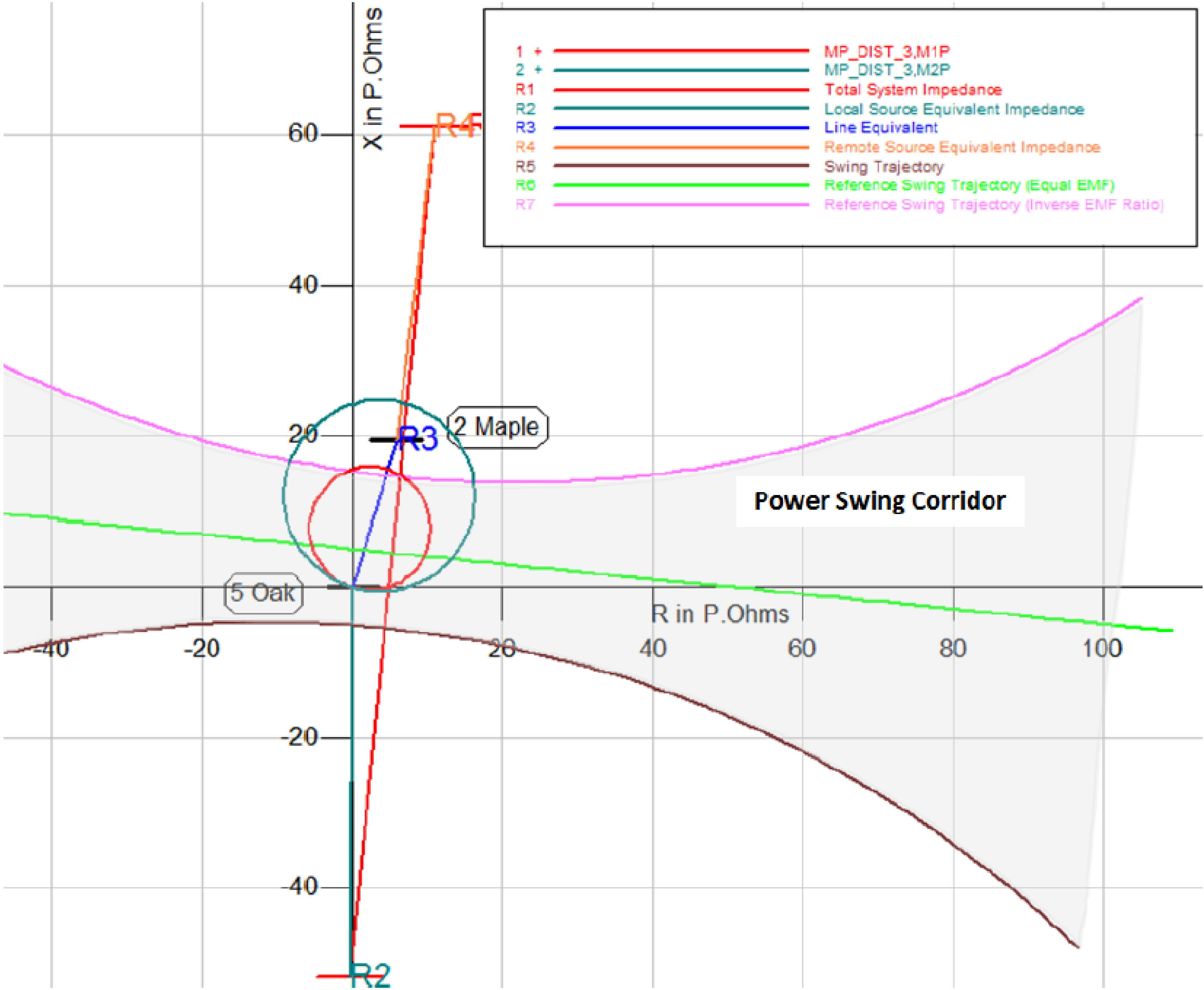
Power Swing Blocking

Corridor without IBRs

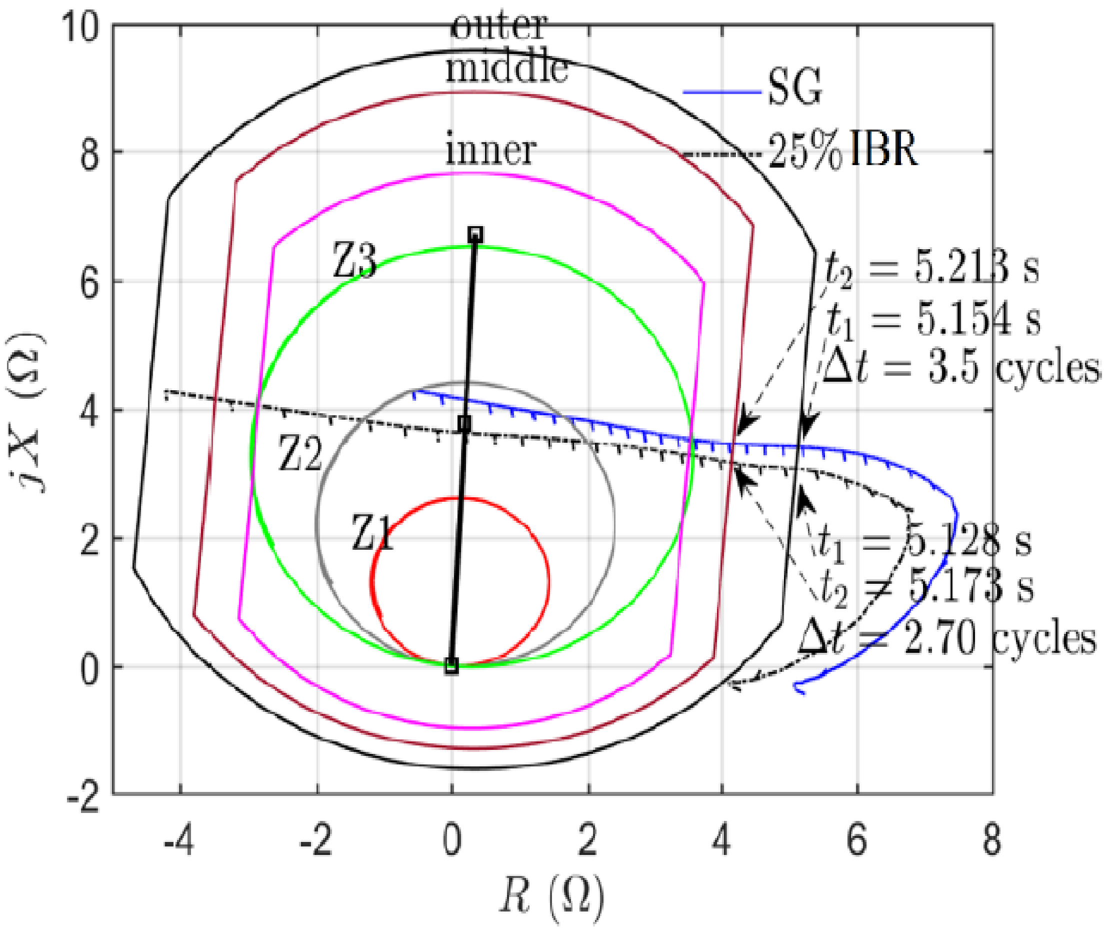


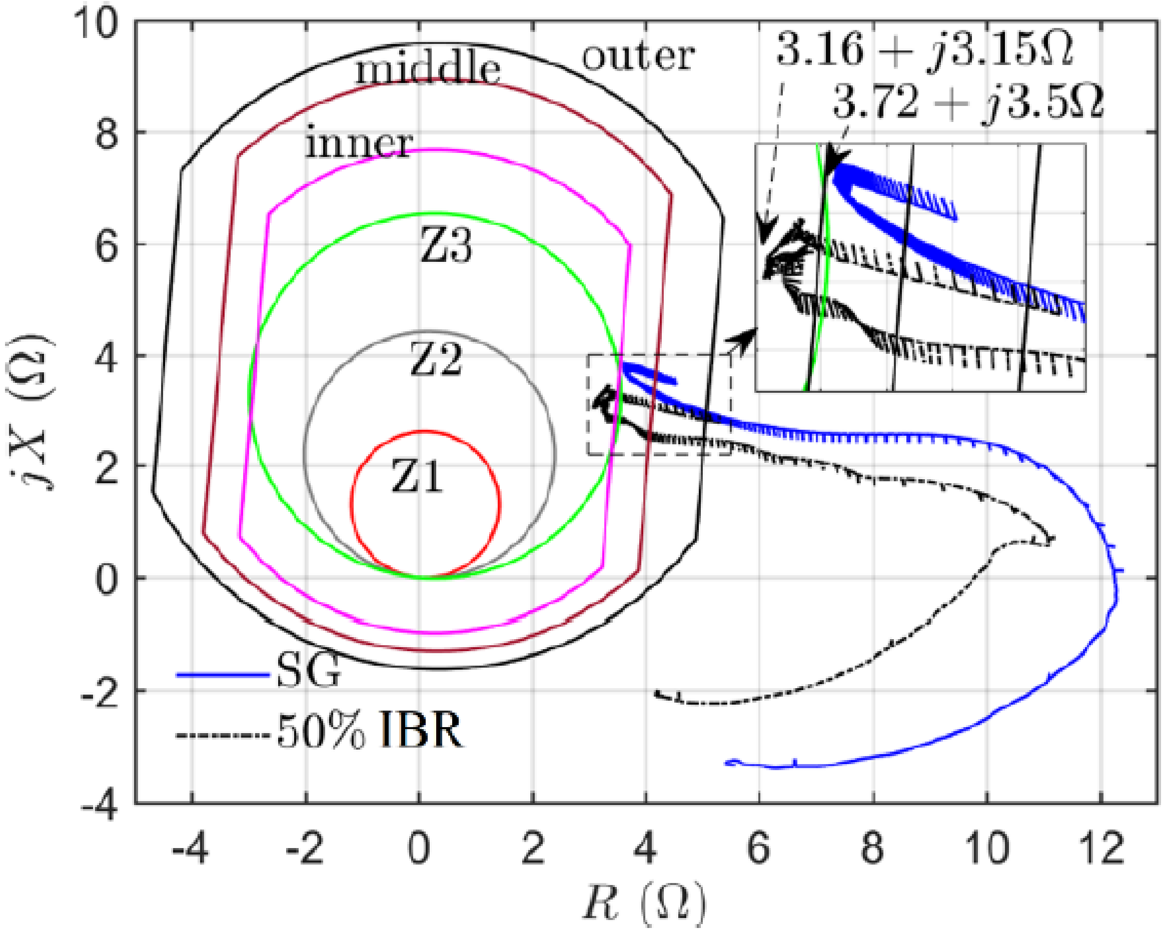
Power Swing Blocking

Corridor with IBRs



PSB and OOST Response to Faster Swings





Conclusion and References for Further Reading

Conclusion

1. Raise negative-sequence current thresholds to improve directional element and FIDS logic performance
   - Reliable directionality, especially for phase-to-phase faults in which 32Q may be the only element to provide directionality
   - Voltage-based FIDS logic adds dependability and security
2. Use self-polarized phase distance with possibly offset characteristics supplemented by transient directional elements
3. Use ground mho or zero-sequence polarized quadrilateral
4. Increase Zone 1 reach at strong terminal in tie-line applications without parallel paths.

Conclusion

5. Source-to-line Impedance Ratio (SIR) can be very high
   - Consider line-to-line faults also to calculate SIR
   - Reduce Zone 1 reach and/or add time-delay for security or, if required, Disable Zone 1 and rely on communications-assisted protection
6. Use Hybrid POTT scheme with weak-infeed echo and trip
7. Use Line Current Differential protection with improved settings
8. Re-evaluate PSB and OOST application and settings
9. Transient-based line protection elements including traveling-wave based schemes can add dependability

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8. IEEE Std 2800-2022, IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems, April 2022.

References for Further Reading

9. R. Chowdhury, R. McDaniel, and N. Fischer, “Line Current Differential Protection in Systems with Inverter-Based Resources—Challenges and Solutions,” proceedings of the 76th Annual Conference for Protective Relay Engineers, College Station, TX, March 2023.
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Questions?

Utilizing Contractors for Protection Relay Settings

NERC Bulk Electric System Protection System Misoperation Reduction Workshop - Atlanta GA

October 25-26, 2023

Harjinder Sidhu

ALTALINK
A BERKSHIRE HATHAWAY ENERGY COMPANY

SustainableElectricityApproved
Canadian Electricity Association

Utilizing Contractors for Protection Relay Settings

AltaLink

Agenda

- Introduction to AltaLink
- Parties involved when preparing Relay Settings
- Key Steps in Relay Settings development
- Relay Settings Error Examples
- Top Causes resulting in Errors
- Best Practices

Feel free to interrupt anytime you have a question during the presentation

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AltaLink

First Independent Transmission Provider in Canada – since 2002

212,000 sq km (81,854 sq miles) Service Territory

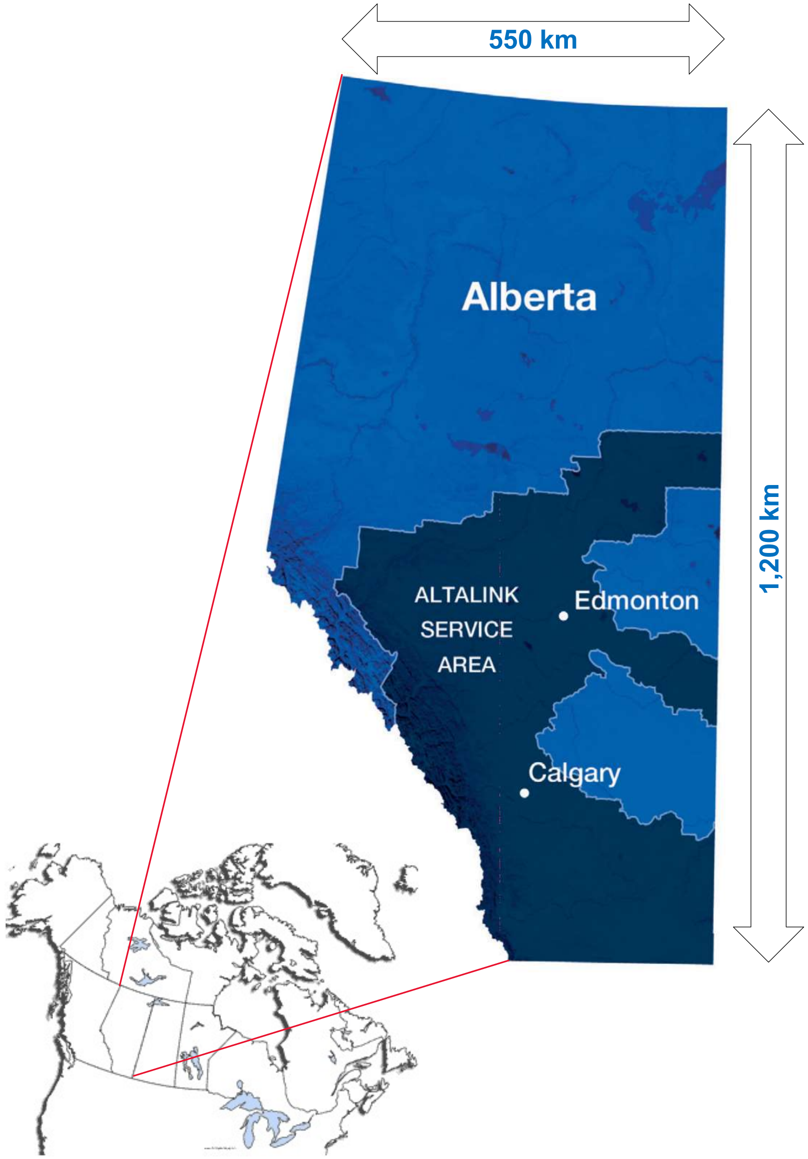
Deliver Energy to more than Three Million Albertans (85% of the Alberta's Population)

Own and Operate more than half of Alberta's Transmission Grid

Three Interties - BC, SK & MT

Approx. 730 Employees

Owned by Berkshire Hathaway Energy



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System

- Over 300 Substations
- Over 13,000 km (8,078 miles) of Transmission Lines
- 500/240/138/69 KV and one HVDC Link

Relay Base

- ~ 5300 Numerical Relays
- ~ 425 Solid State Relays
- ~ 1675 Electromechanical Relays

Relay Settings Development

- On average, AltaLink utilizes contractors for over 50% for relay settings development (new and modifications)

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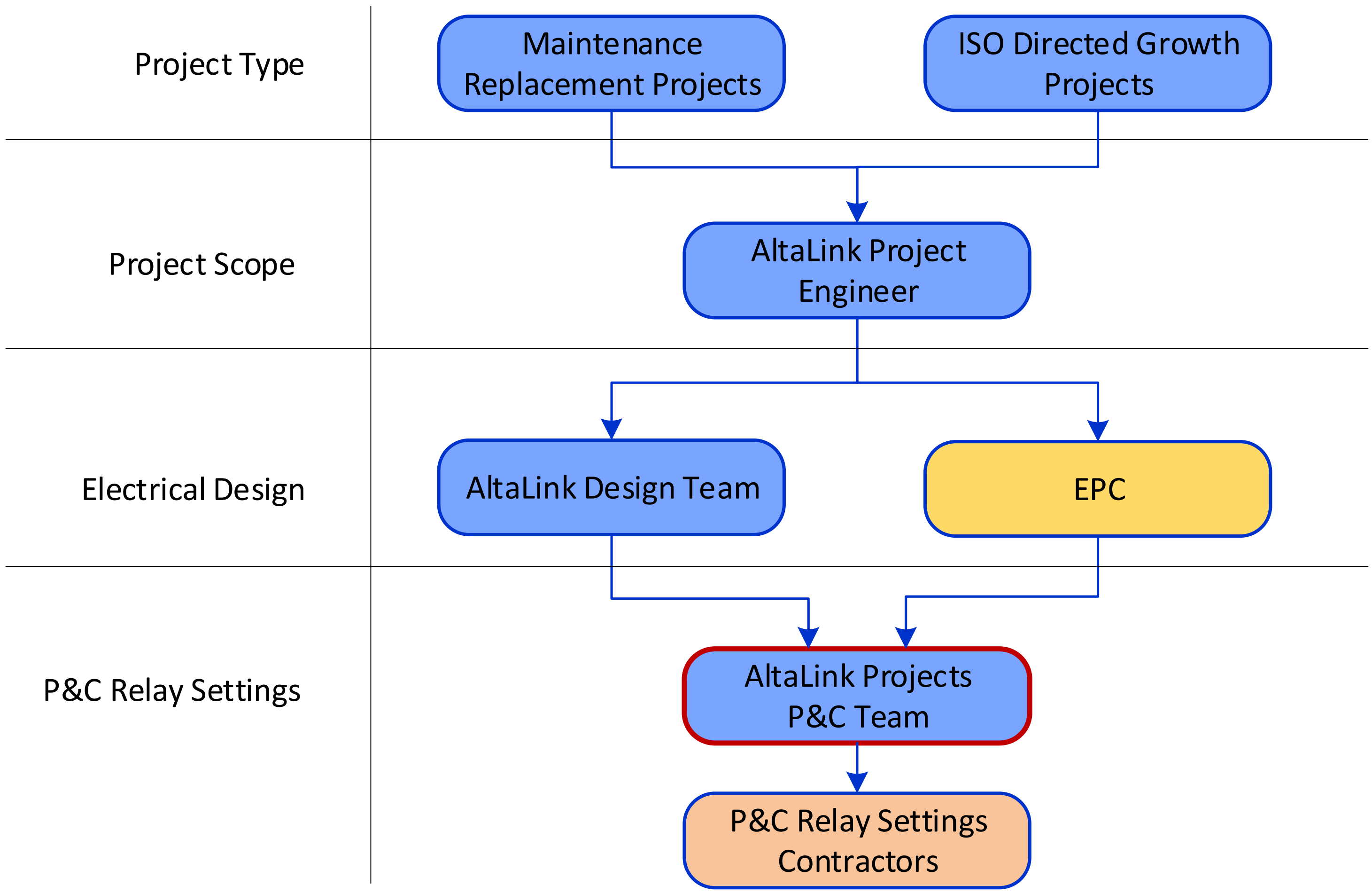
High Level Project Flow



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Key Steps and Stakeholders

- Scope - AltaLink Project Engineers

  DBM (Design Basis Memorandum) is created

- Scope Review - by all relevant domains/disciplines - P&C, SCADA, Telecom, Transmission Lines, System Operations
- Electrical Design - AltaLink Design Team or EPC
- Relay Settings - All Relay Settings requests go to AltaLink Projects P&C Team. P&C Team may hire an Approved Contractor for development of Relay Settings
- Testing & Commissioning - In Majority of cases by the same EPC (or their Sub-Contractor) that prepares Electrical Design
- Acceptance - AltaLink Field Technologists and Projects P&C Team

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Information Exchange with Relay Settings Contractors

- Project P&C Scope
- List of Deliverables and Timelines for different stages - IFR, IFC, AsLeft, AsBuilt
- AltaLink Standards and Practices
- Up to date System Short-Circuit Model and asset information pertaining to project development (inc. Line Impedances, Equipment Nameplates and Test Reports)
- Line Ratings, CT accuracy and lead lengths
- Electrical Design Drawings at different stages - IFR, IFC, AsLeft, AsBuilt
- Latest Templates - Relay Settings Calculation Reports, DC Logic Drawings and Relay Settings Files
- Existing (Approved/In-service) Relay Settings

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Other items to consider

- Key Communication Links
- Scope Changes - Projects are Dynamic
- Electrical Design Corrections/Modifications
- Concurrent Projects
- Documentation
- Access to Relay Settings Database
- Contractual Obligations and Expectations

Relay Setting Error Examples #1

Output contact not programmed in relay

Event: Transformer protection operated for an in-zone fault. Protection relay A tripped all associated breakers. Relay B tripped all but one. Relay A was wired to multiple breakers via an auxiliary, Relay B had individual output contacts wired to breaker coils.

Background: In a prior project, among several substation upgrades, a line circuit was added which required tripping for transformer faults.

Key miss: Design EPC updated drawings at IFC stage to include tripping newly added breaker, but did not request settings modifications for transformer relay B.

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Relay Setting Error Examples #1

Output contact not programmed in relay

Findings:

- Miss in P&C scope (DBM)
- Drawings were modified at IFC stage to address the missing scope, but EPC missed to request relay settings from AltaLink P&C Team.
- No record that newly added control circuit was tested on site.

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Relay Setting Error Examples #2

System backup distance zone set with no time delay

Event: Zone 3 (system backup) mis-operation for a fault on remote line

Key miss: Mistake in settings value transfer from calculation sheet to native relay settings file

Findings:

- Mistake by relay settings engineer and oversight by settings reviewer
- No record that zone 3 timing was tested on site

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Relay Setting Error Examples #3

All distance elements disabled in the relay

Event: Fortunately, this was caught before any operation (lack of operation) after the error was introduced

Background: As per CIP requirements, passwords in several relays were changed on site by a contractor. A specific relay type requires uploading complete relay settings file to the relay, even when just password is changed.

Key mistake: It is an assertion that technician at one site accidently disabled distance elements in settings while changing the password and subsequently uploaded modified settings in the relay.

Relay Setting Error Examples #3

All distance elements disabled in the relay

Findings:

- No record that on site contractor compared installed (Approved) settings with the AsLeft settings after making password change.
- This characteristic of the relay was a surprise to number of P&C engineers. The project scope had no expectation to submit AsLeft relay settings file.

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Relay Setting Error Examples #4

Erroneous Breaker Failure initiate

Event: Breaker Failure was initiated unexpectedly and as a result tripped several assets in the substation

Background: A standard numerical relay meant for RAS applications was used as an interfacing relay in a protection application. This relay initiates breaker failure via control wiring.

Key mistake: The design contractor used interfacing relay’s high-speed contact to initiate breaker failure protection in a numerical relay’s sensitive (high input impedance) input contact.

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Relay Setting Error Examples #4

Erroneous Breaker Failure initiate

Findings:

- Electrical design contractor did not follow well-known design practice (within AltaLink and it's contractors) and in fact missed to consider AltaLink Technical Bulletin that prohibits use of relay's high-speed contacts to initiate breaker failure protection in other numerical relay's sensitive input contacts.
- Settings engineer did not catch the error
- The on-site contractor followed drawings and did not catch the error

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Top Causes of Mistakes … from Years of Experience

- Contractor’s lack of competency and familiarity with AltaLink Standards and Practices
- Not establishing a strict communication channel in a project
- Failure in communicating
    - Design corrections
    - Relay settings modifications at existing sites
    - Changes in Standards/Practices
- Human error in transferring settings from calculation report to relay settings files
- Time pressure - resource challenges

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Best Practices

- Contractual obligations and expectations in regard to information exchange with contractors and their deliverables are documented
- Project specific timelines for deliverables are communicated at the project start
- P&C scope (part of DBM) is prepared, reviewed (by applicable disciplines) and authenticated by AltaLink Project Engineer (Professional Engineer)
- DBM includes list of AltaLink standards applicable at the time. Any subsequent updates are communicated by AltaLink.
- Contractor Engineers create, review and authenticate (Professional Engineer) relay settings calculation report
- Any deviation from AltaLink standards/practices requires approval from AltaLink Senior Engineer or the Principal Engineer, P&C

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Best Practices

- AltaLink keeps at least two contractor companies to develop relay settings. They go through deep technical evaluation during selection process.
- AltaLink has the requirement to review resumé and provide approval for new Engineer(s) proposed by the Contractor company to work on AltaLink projects
- For unique/special applications (e.g. SCC line, PST), AltaLink hires more specialized contractors for relay settings
- AltaLink P&C Engineer acts as a P&C Administrator when settings are prepared by a Contractor. The P&C Administrator
  - acts as a link for any communication between P&C Settings Contractor and other project stakeholders
  - provides clarification regarding AltaLink Standards and Practices
  - ensures completeness of relay settings and associated functionality (QA) as per project scope

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Best Practices

- Intend to document all P&C related information (input/output data/ calculations/decisions) by contractor in least number of documents … one if possible
- Contractors have read-only access to AltaLink relay settings database. AltaLink P&C Administrator keeps control of making additions/deletions/modifications in the database
- P&C Engineer does not issue final relay settings until IFC drawings are complete and available
- Maintain templates for relay settings reports, DC logic drawings and relay setting files
- Formal expectation from commissioning team to submit AsLeft (in-service) relay settings to AltaLink P&C Administrator within two weeks. Contractor P&C Settings Engineer to review asap and submit AsRecorded (AsBuilt) settings.

Utilizing Contractors for Protection Relay Settings

Thank You!

Questions

NERC

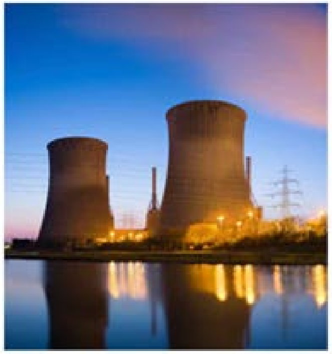
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

TECHNICAL REPORT

Inter-Entity Short-Circuit Model

System Protection and Control Working Group

RELIABILITY | RESILIENCE | SECURITY

Introduction

- Reliable operation of the power system requires accurate short-circuit models
- Updating model data at boundaries connecting to other entities (inter-entity updates) is challenging
- The increasing amount of Inverter Base Resources (IBR) requires updates at a rapid pace
- Historically, power system planners have utilized modeling software with positive sequence data to predict balanced load flow
- Correct modeling of negative and zero sequence data as well as correct transformer connections are critical for accurate short-circuit data
- Creating a network equivalent requires engineering judgment concerning the size, accuracy, and complexity of the neighboring system

Considerations

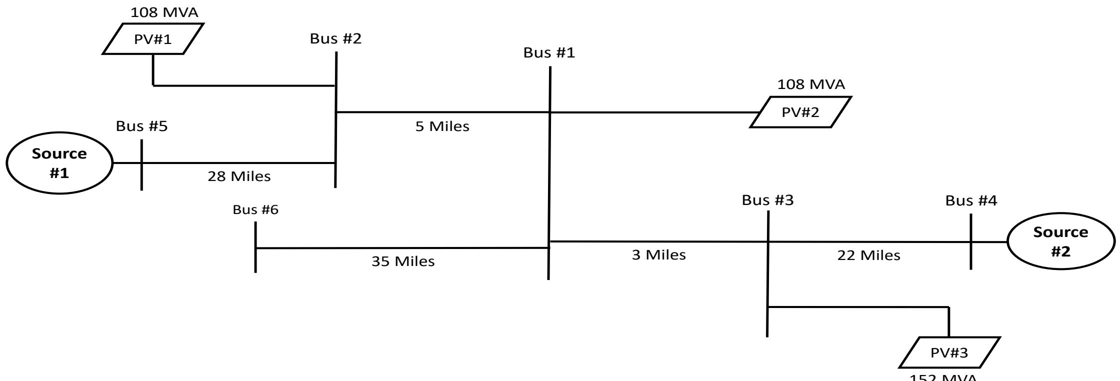
- For coordination verification, specifically those within two to three buses from the boundaries or tie lines, inter-entity model updates should be completed within the six-year period (at a minimum) set forth in PRC-027
- As a best practice, these updates should be revisited annually or more frequently if notified of a major change in a neighboring system
- Partitioning an equivalent network from its neighboring study area requires analyzing up to three buses away from the study bus for sufficient accuracy

Max and Min

- Historically, most short-circuit models were configured for system peak conditions (i.e., all generating resources)
- Network equivalent for off-peak (valley, spring, fall) load level may be of importance with increased IBR penetrations
- IBR should be correctly modeled in the system to vary its contribution based on the voltage of the interconnected system

Appendix A: IBR Network Reduction Example

- Thevenin impedance at bus #1 at 230kV = 0.23%+j 2.39 %
- Calculated three-phase fault current magnitude - inverse of the Thévenin impedance (assuming a pre-fault voltage of 100%) = 10,470 A
  - SC (calculated commercial program) matches when PV solar resources are offline
  - SC (calculated commercial program) increases to 11,045 A when PV solar resources are online
- Consider adopting the entire model rather than using boundary equivalents at tie lines until improvements are made in software tools for creating equivalents that include IBRs



Methods

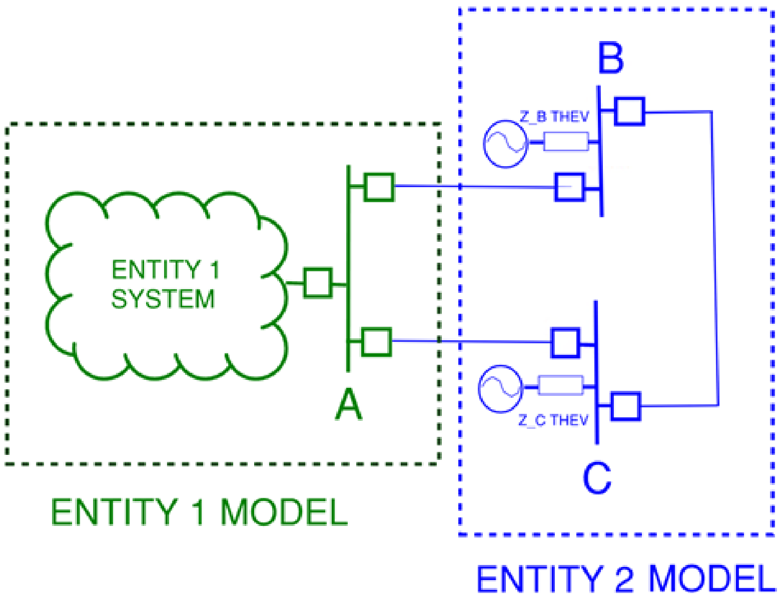
- Adopt entire model
  - Model accuracy concern when short-circuit case has been created via a software conversion of a power flow model
  - Topology (such as normal open ties between generator buses) should be verified
  - Model should contain equivalents for a minimum of three buses away from the short-circuit bus under investigation
- Keep entity model and update external ties
  - Allows a more detailed and up-to-date internal model
  - Merge Internal with entire external model OR Update boundary equivalents at external tie point

Challenges

- Different per-unit bases, different transformer modeling techniques or connection codes, or different methods of modeling elements and buses
- Different options for the fault simulations and relay solutions that might impact comparisons during validation
- Uniform conductors for transmission lines vs. tapped buses to distinguish changes in conductor type or spacing
- Buses modeled as straight buses vs. modeling the exact configuration
- Software conversion errors: Power flow to short-circuit; Short circuit to short circuit; version to version of same software
- Bus and line common format

Challenges

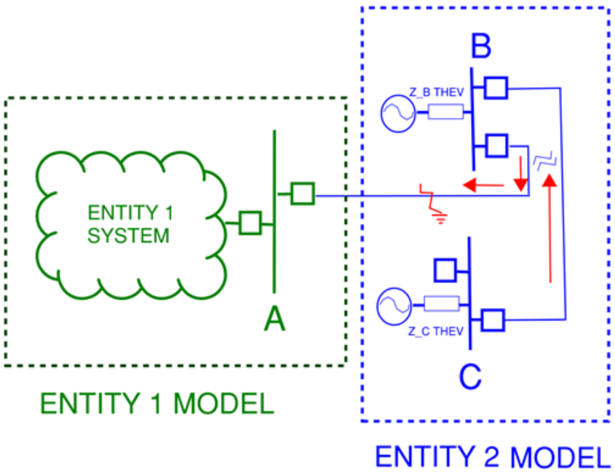
- Duplication of model parameters



If Entity 1 wishes to model the Thévenin equivalent of the tie line to B, they must account for the connection between B and C. In this simplified scenario, an accurate Thévenin equivalent at B and C requires taking not only the lines from A to B and A to C out of service to avoid inclusion of Entity 1's own system but also the line between B and C. After determining the separate Thévenin equivalent parameters for B and C, the lines should be placed back in service and remain in the simplified model.

Challenges

- Mutual impedance
  - Inclusion thresholds
  - Start/end terminal identifiers and directions
  - If entities wish to consolidate the collapsed Thévenin equivalent models, mutual coupling can be problematic because tie lines may be mutually coupled with lines solely in the neighboring entity's system



Depending on the strength of the sources and the amount of coupling, the entity may need to model the additional neighboring entity's mutually coupled lines. This portion of the neighbor's system can be simplified collapsing one or both ends of the (non-tie) coupled line using the Thévenin equivalent as an example. In many cases, this can only be done with one end of the line because the other end often terminates at the same station as the tie line. Entities must balance accuracy and simplicity when determining which mutual coupling pairs should be modeled.

Challenges

- IBR
  - The Bulk Power System has transformed with a greater number of IBRs interconnected, requiring greater consideration of their impact on reliability
  - As modeling IBRs is a recent development, available modeling software varies in the parameters used to model, and different entities may use different methods of modeling
  - Software challenge: each IBR adds more complexity and more iterations to each solution, requiring more processing power

Data Validation

- Once a model has been updated, it should be vetted prior to use
- Comparison of fault values (pre/post update)
  - < 5% Low (acceptable but could be investigated); 5–10% Medium (acceptable but should be investigated); 10–15% High (should be investigated); >15% Very High (must be investigated)
  - At a minimum, 3LG and SLG fault types should be compared. Best practice for all four fault types (three-line-to-ground, single line to ground, line-line, and two-line-to-ground) to be considered
  - Fault values for N-1 contingencies
  - Comparison of X/R bus ratios
    - Special attention should be paid to the short-circuit model's X/R preferences and any assumed X or R values the software uses when encountering an X or R equal to zero

Data Validation

- Model comparison – software routine or export data to spreadsheet
- Comparison with actual fault values
  - Approximate rather than detailed comparisons, but it still can identify major modeling errors
  - System configuration in the model must match the real-world system configuration at the time of the fault
  - If event data following a line-to-ground fault from relays at two ends of a transmission line are available then positive, negative, and zero sequence line impedances can be calculated and used to verify that transmission line's model data
  - Line impedance can be validated by using a test set in conjunction with a coupling unit that injects currents into a de-energized line and sends voltage measurements back to the test set

Possible variance issues

- Transformer connections
  - Two-winding transformers: grounded wye provides a path for zero sequence
  - Two-winding autotransformer with a delta-connected tertiary: tertiary provides a low impedance path for zero-sequence current and has a significant impact on ground fault currents
  - Converting from one software platform to another: known transformer connections and codes that do not properly convert
  - Should three-phase fault values look reasonable in a newly updated model near a transformer, but unbalanced faults look unreasonable, the transformer connection should be questioned and validated
  - Most two-winding autotransformers with a tertiary are grounded wye with a delta tertiary

Possible variance issues

- Out of tolerance zero sequence
- Generation type – Synchronous machine
  - Three different positive sequence values: sub-transient reactance (Xd''), transient reactance (Xd'), and the synchronous reactance (Xd)
  - Sub-transient reactance (Xd'') values give the highest initial current value, they are generally used in system short-circuit calculations
  - The negative sequence reactance of the turbine generator is typically equal to the sub-transient reactance (Xd'')
  - The zero-sequence reactance is much less than the others, producing a phase-to-ground fault current magnitude greater than the three-phase fault current magnitude

Possible variance issues

- Generation type – IBR
  - Expected positive sequence values should produce 1.2–2 times rated MVA as opposed to over 6 times rated MVA for synchronous machines
  - Type III - produce little negative sequence fault current and negligible zero sequence
  - Type IV (wind/solar/battery) - could be designed to provide negative sequence current although they provide little negative sequence current more commonly today
  - Historically, IBRs were sometimes modeled as current-limited synchronous machines
    - IBR resources where the positive X'' and negative sequence impedances are the same - this is expected for synchronous machines but not for IBRs
  - Consideration should be given to not only correcting any inaccurate sequence impedances but also updating IBR modeling to newer recommendations that may be available from the software manufacture

Best Practices

- Annual review of the external system model, or more frequently if notified of a major change in the neighboring system. The decision to incorporate external changes should follow a risk-based process and consider the extent of the changes and their impact to the model
- Network equivalents of neighboring systems should typically be located 2-3 buses into the neighboring system from the boundary bus
- Correlation of the two models including short circuit parameter settings, bus and line formatting, and model numbering and labeling should be completed pre-conversion
- Quality assurance checks post update for normal and N-1 system conditions include comparison of fault values and X/R ratios. All four fault types (three-line-to-ground, single line to ground, line-line, and two-line-to-ground) should be considered

Recommendations

- Regional Entities, Regional Transmission Operators, and other parties that may provide short-circuit models intended for utilization in protection system relaying should provide those models in a format compatible with industry accepted short circuit software as opposed to industry power flow software
- If creating short-circuit models by converting a power flow model, the converted model should be fully validated and corrected prior to publishing. There are many errors which can occur during conversions including out of tolerance zero sequence impedances and inaccurate power transformer connections
- Neighboring system parameters can be difficult to obtain for model validation but necessary for fault current flows into a system within a few buses from a bus under study for protection coordination

Recommendations

- Modeling of IBRs and software is evolving and requires improvement
- Consider adopting the entire model rather than using boundary equivalents at tie lines until improvements are made in software tools for creating equivalents that include IBRs
- Historically, boundary equivalent sharing has been for peak operating conditions used in short-circuit studies. Consider sharing additional operating conditions of significance as applicable. For example, minimum synchronous resources with peak IBR dispatch.
- An improved method for an efficient exchange of data between short-circuit software should be developed

Questions and Answers

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reference Documents

- *Short-Circuit Modeling and System Strength" NERC White Paper, February 2018.*
- *Validating Transmission Line Impedances Using Known Event Data. April 2016. Revised edition, SEL, inc.*
- *M. Patel, "Opportunities for Standardizing Response, Modeling and Analysis of Inverter-Based Resources for Short Circuit Studies," in IEEE Transactions on Power Delivery, vol. 36, no. 4, pp. 2408–2415, Aug. 2021.*

Relay Failures & Incorrect Settings Discussion

Rafael Sahiholamal
Manager, System Protection

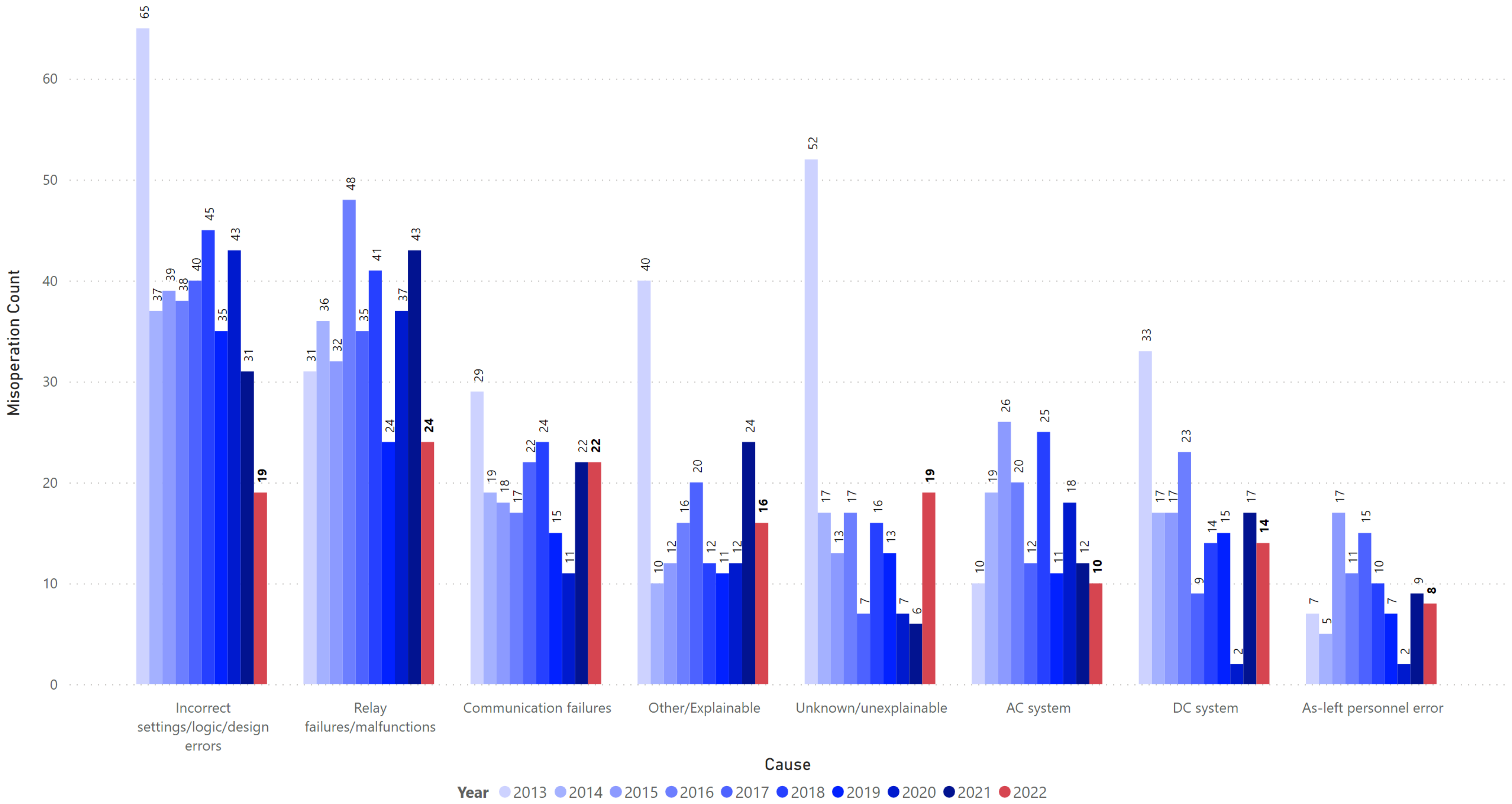
2023 NERC Bulk Electric System Protection System Misoperation Reduction Workshop

NPCC, Inc.

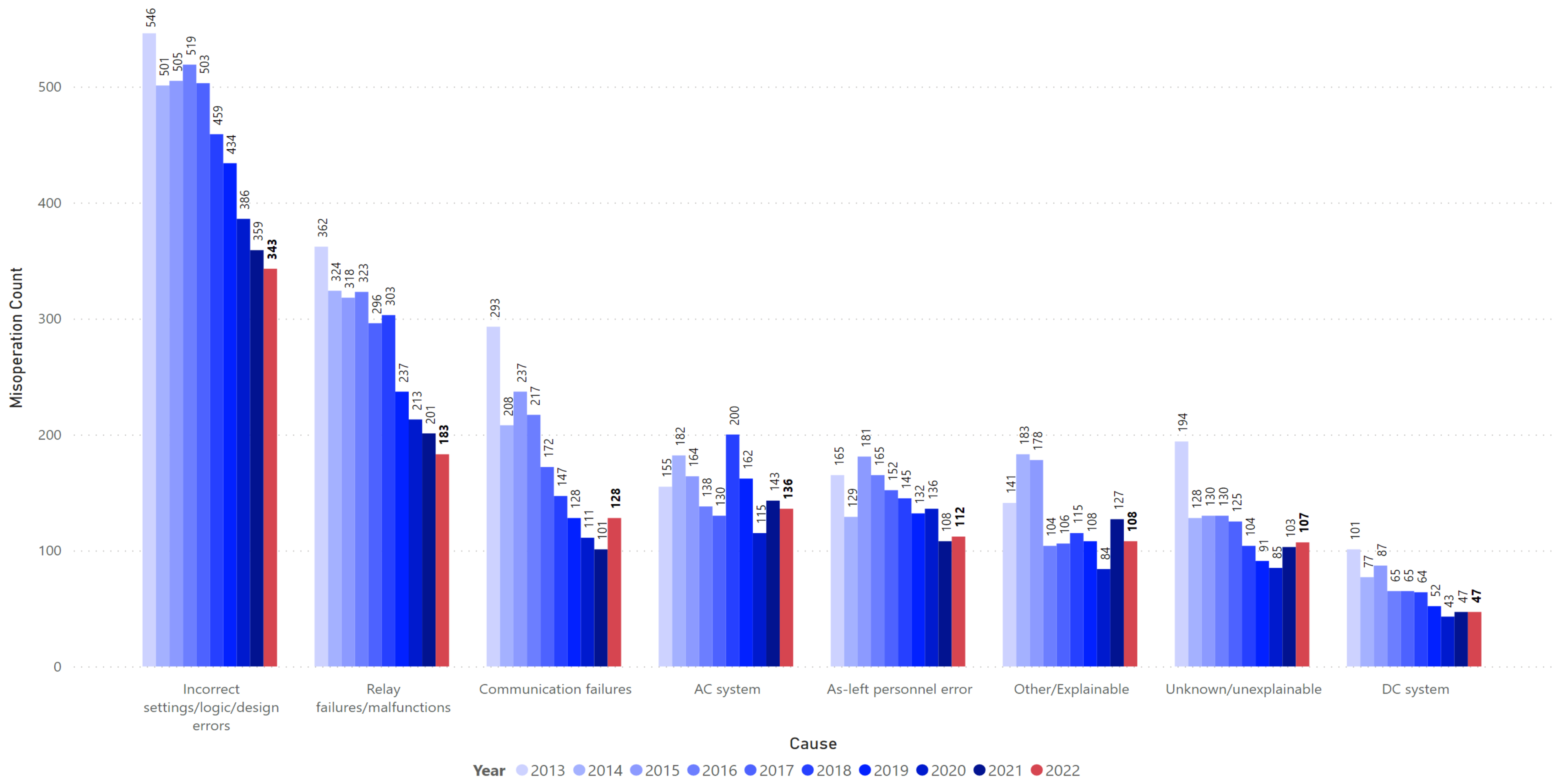
Protection System Misoperation Review Working Group (SP-07)

- Review the analysis of misoperations of protection systems on the bulk electric system
- Review the analysis of misoperations of remedial action schemes (RAS) on the bulk electric system
- Calculate statistic of protection system misoperations
- Work with the NPCC Event Analysis Team
- Share lessons learned with Members and industry from review of misoperations
- Comment as needed on NERC Misoperation Information Data Analysis System (MIDAS) Data Reporting Instruction (DRI)

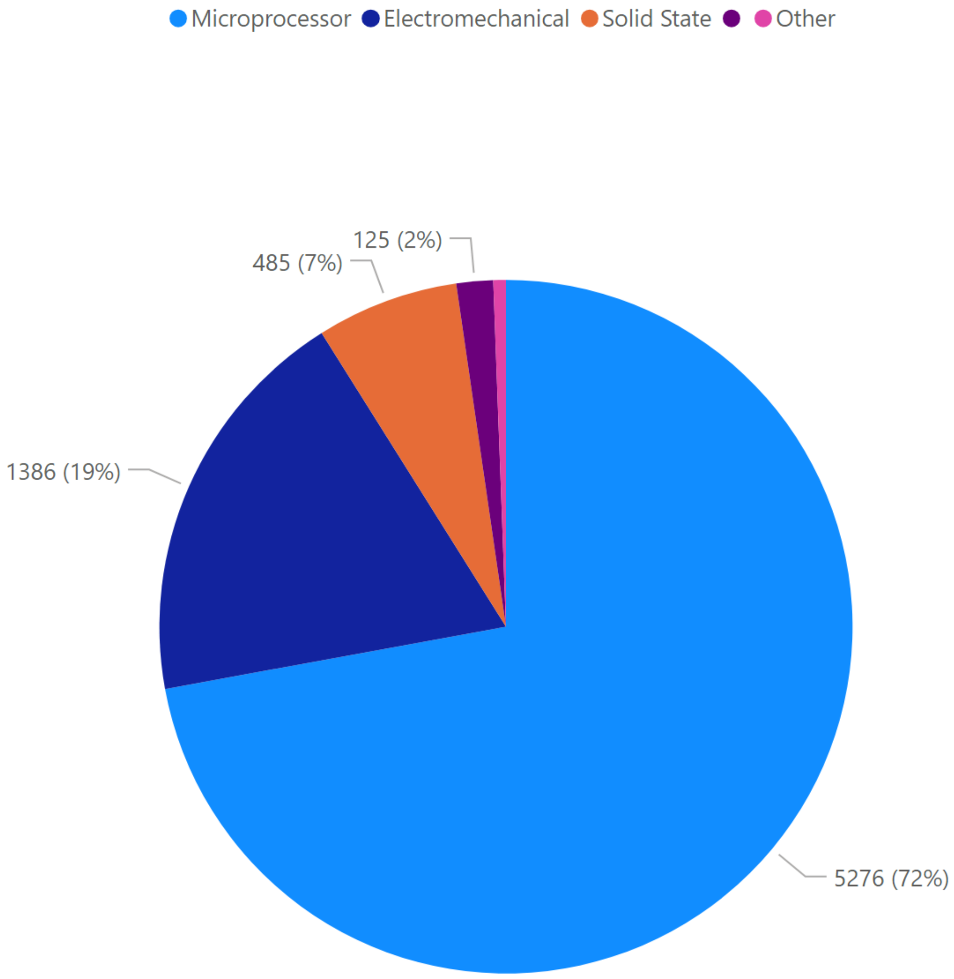
NPCC Misoperation Causes per Year



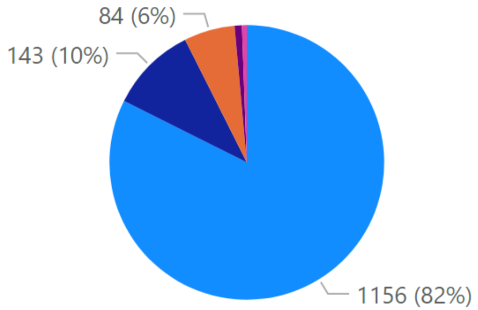
NERC Misoperation Causes per Year



NERC Relay Failures or Incorrect Setting/Logic/Design Error by Relay Technology



WECC



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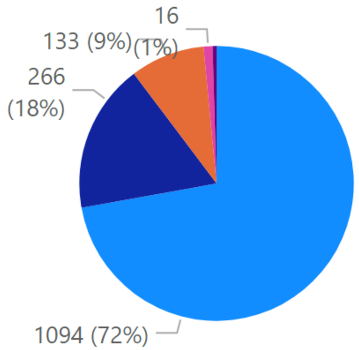

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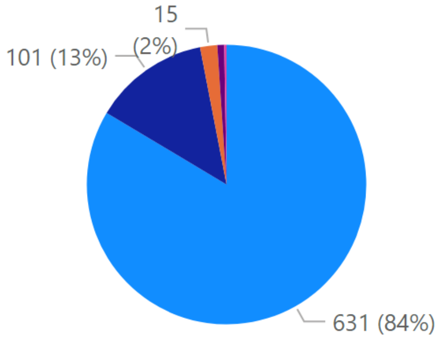

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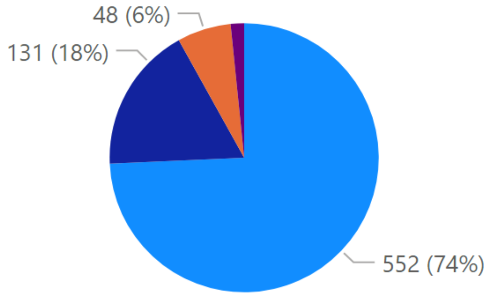

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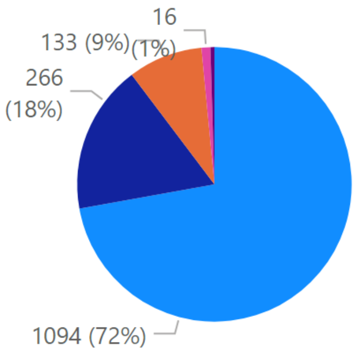
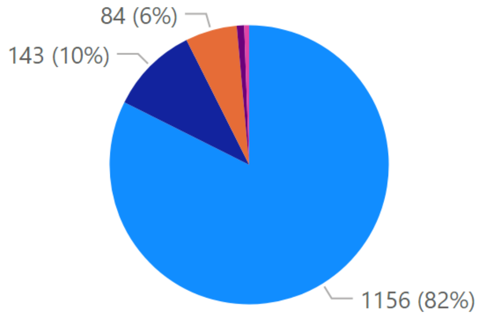


SERC



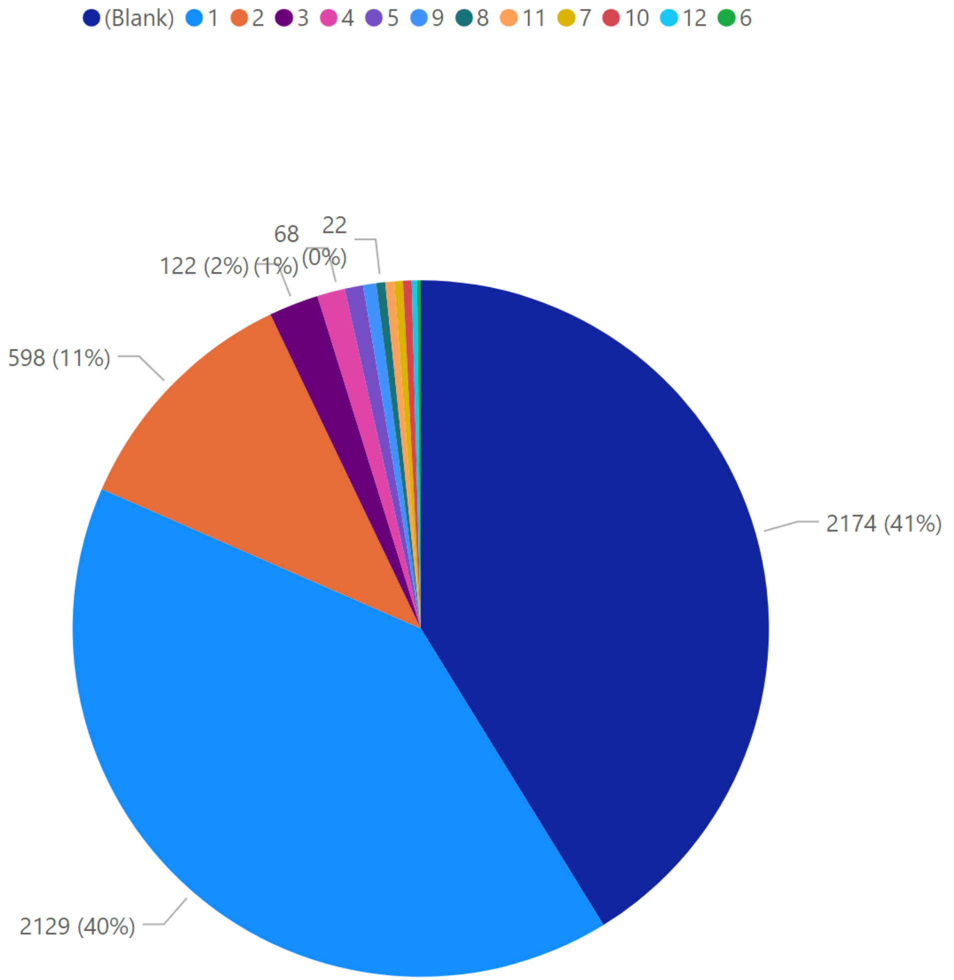
Misoperation Sub-Causes

Incorrect setting/logic/design - Incorrect Numeric Value Specified	Relay - Power Supply Failure/Malfunction
Incorrect setting/logic/design - Incorrect User-Programmed Logic Specified	Relay - AC I/O Module Failure/Malfunction
Incorrect setting/logic/design - Incorrect System Coordination	Relay - Digital I/O Module Failure/Malfunction
Incorrect setting/logic/design - Incorrect Physical Design	Relay - Communication Module Failure/Malfunction
Incorrect setting/logic/design - Failure to Update Firmware Version by User	Relay - (Communication) Loss of Synchronism
Incorrect setting/logic/design - (Communication) Programming/Logic Error	Relay - Self-Diagnostic Failure/Malfunction
Incorrect setting/logic/design - Other	Relay - CPU Processor Failure/Malfunction
	Relay - Continuous Reboot
	Relay - Incorrect Manufacturer Programming ('Bug')
	Relay - Incorrect Manufacturer Design
	Relay - Incorrect Manufacturer Documentation
	Relay - Unknown
	Relay - Other

Microprocessors Manufacturer

- ABB
- AREVA
- Basler
- GE
- RFL
- SEL/ Schweitzer
- Siemens
- Alstom
- Schneider
- Iniven
- ERL Phase
- Beckwith
- Unknown

NERC Relay Misoperations by Manufacturer



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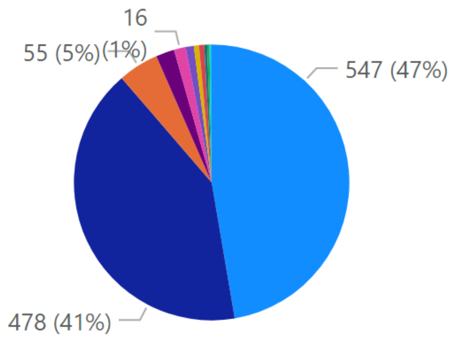

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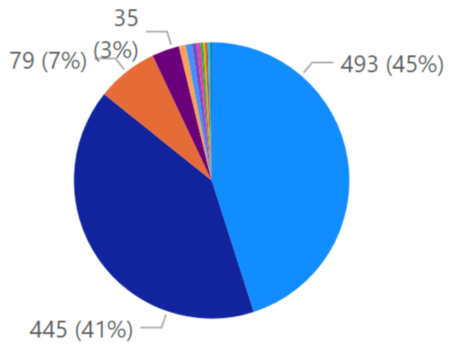
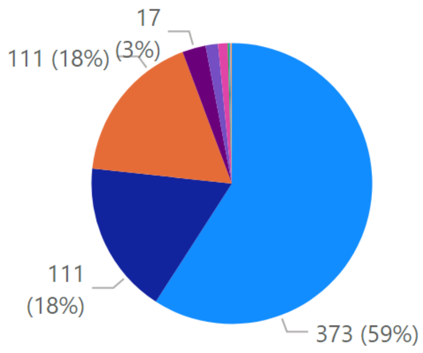


Texas RE



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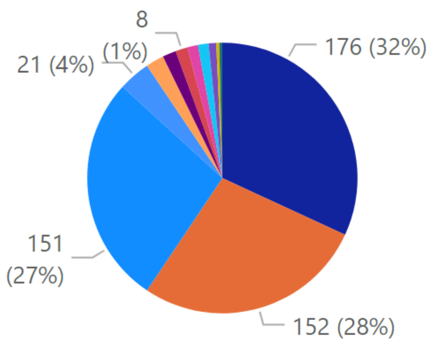

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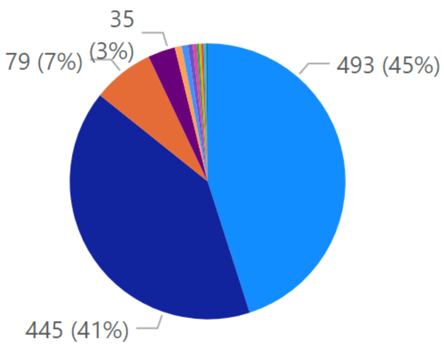

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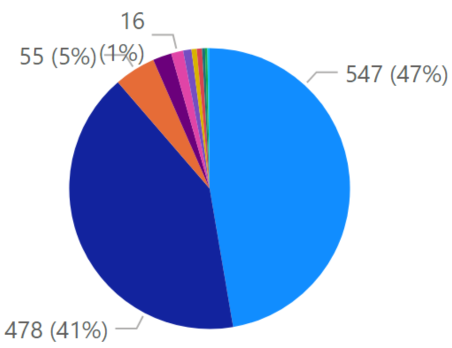

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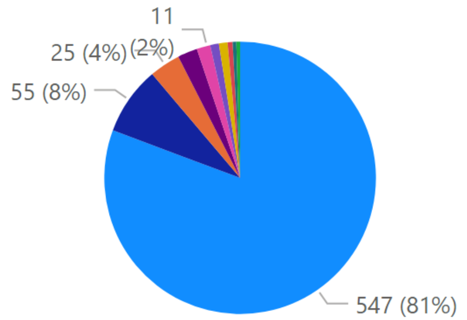

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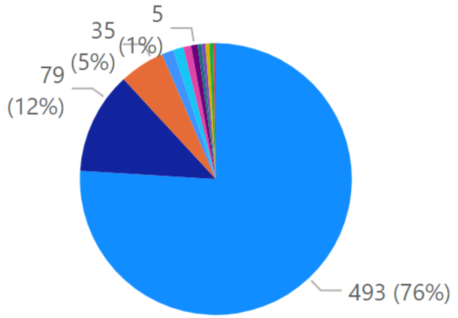

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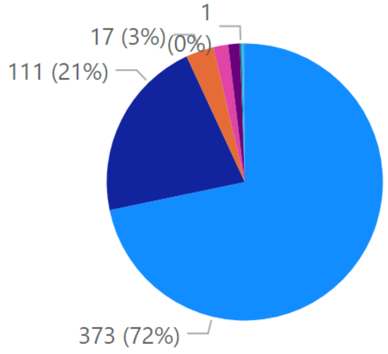
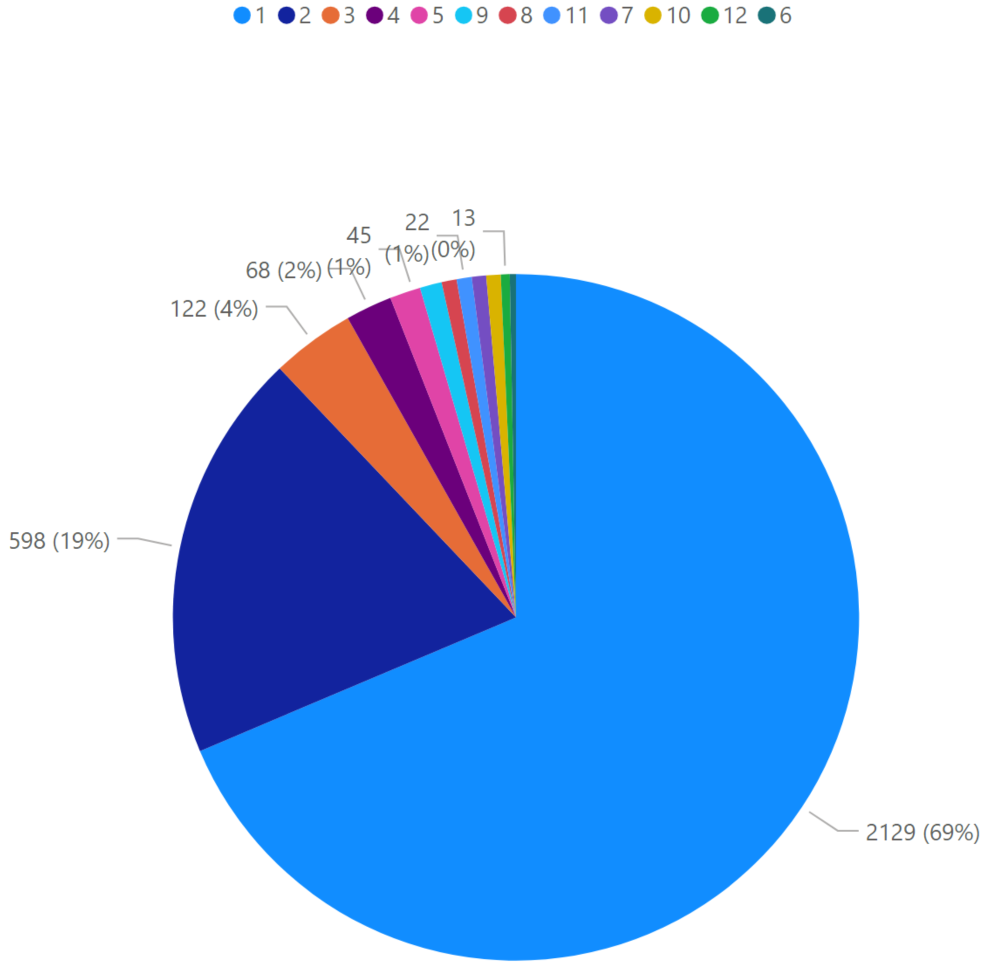


NERC Relay Misoperations by Manufacturer



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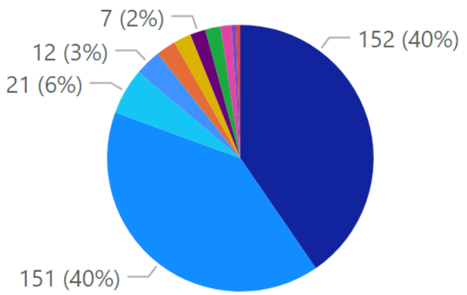

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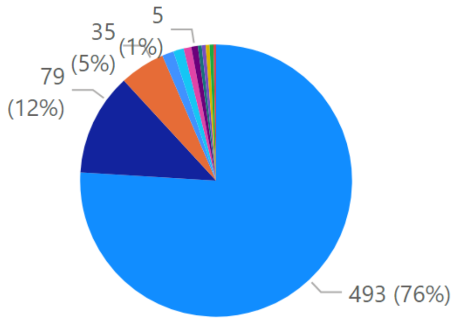

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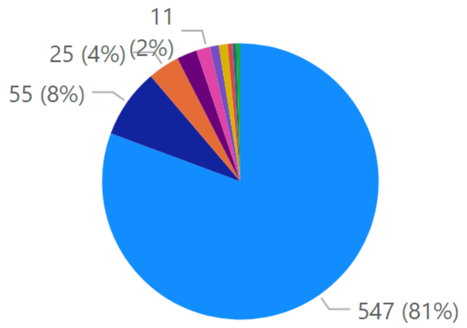
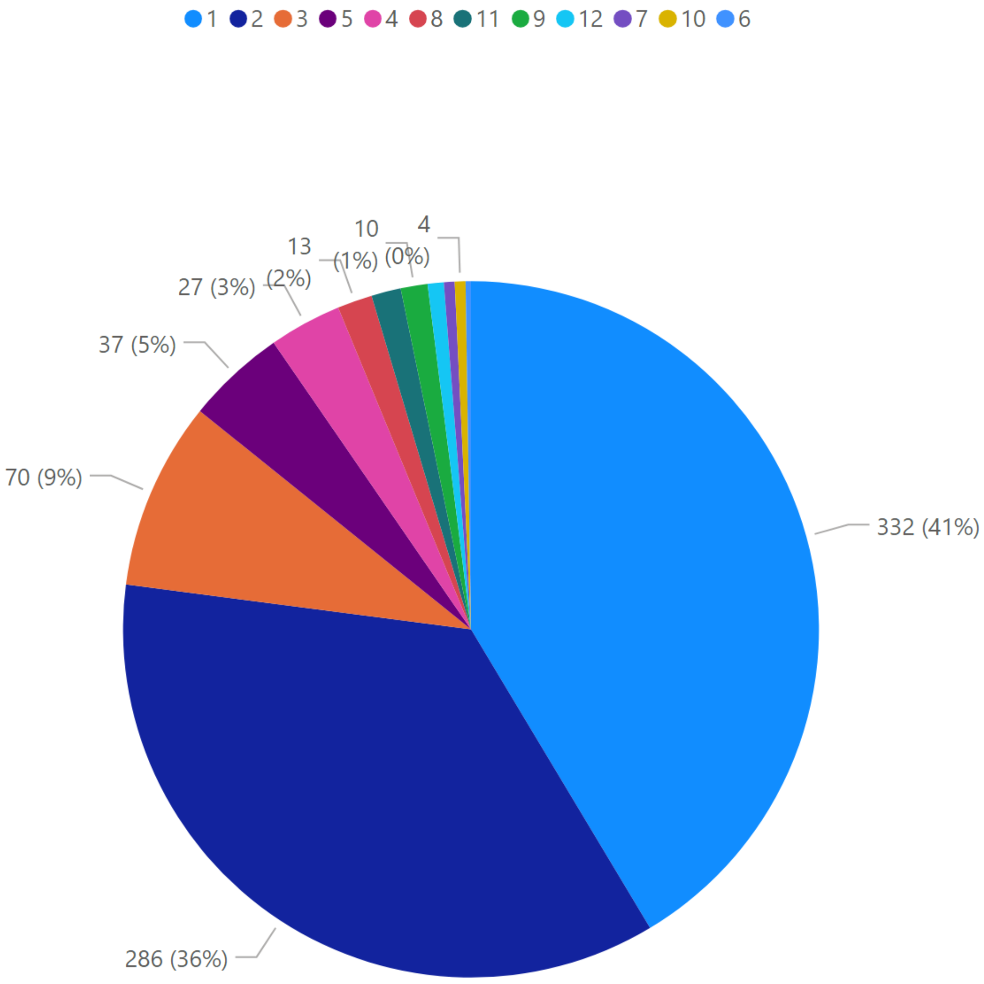


NERC Relay Failures/Malfunctions by Manufacturer



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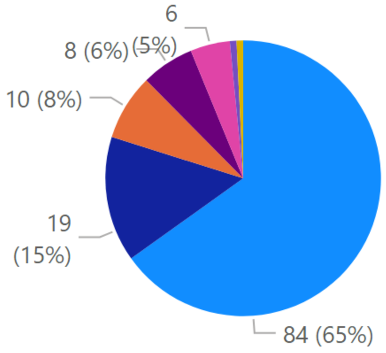

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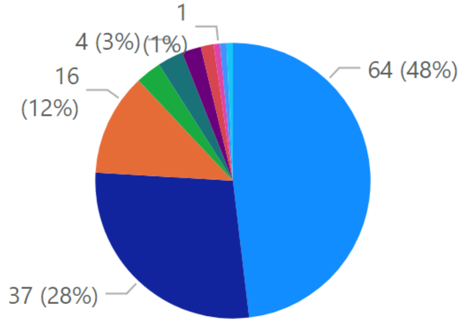

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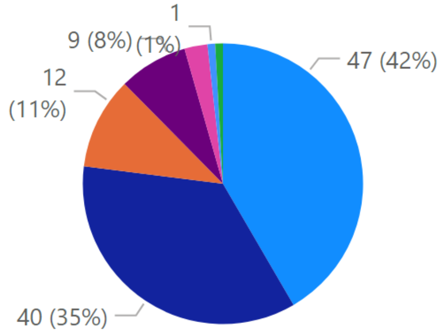

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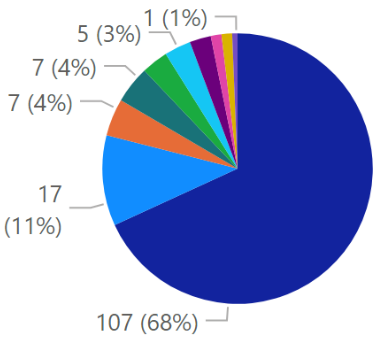

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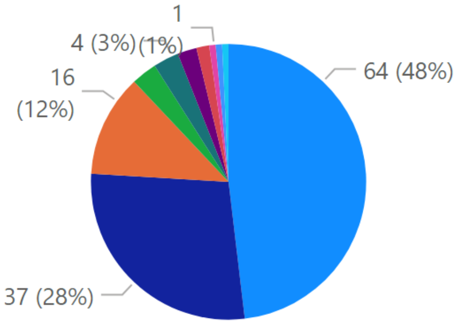

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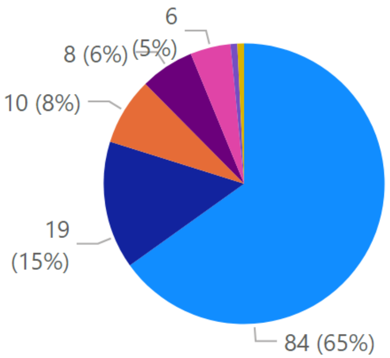

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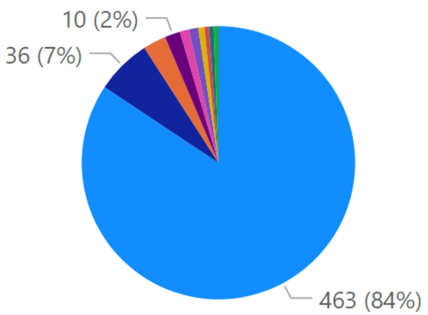
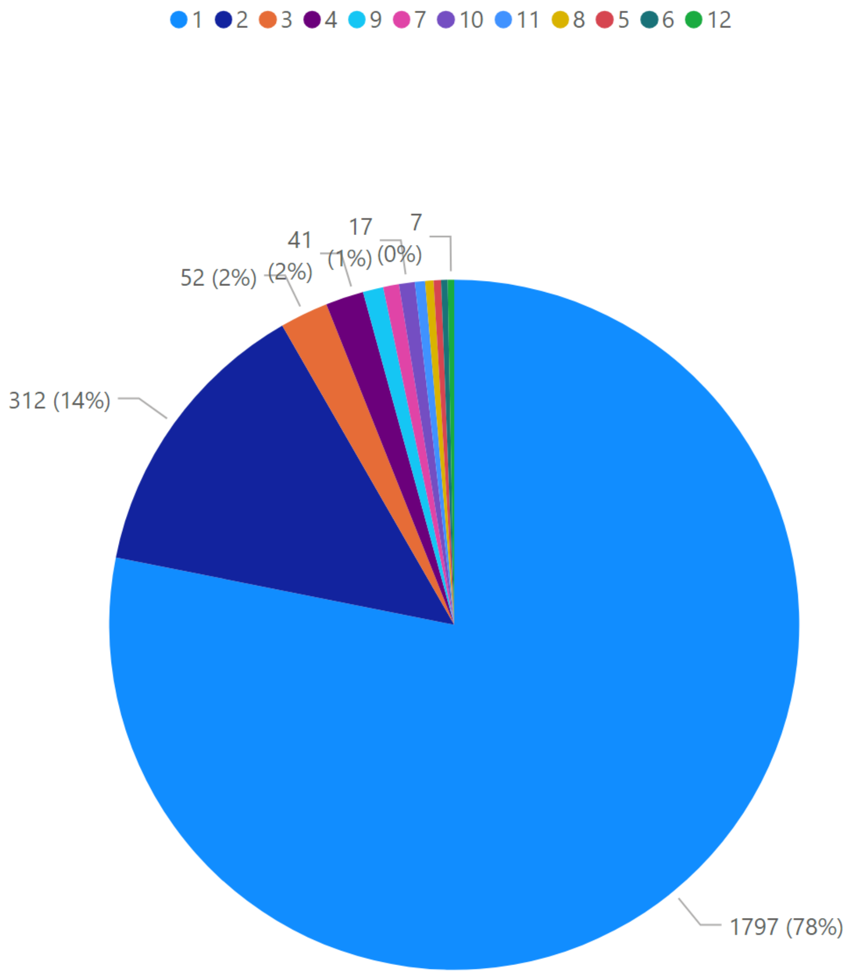


NERC Incorrect Settings/Logic/Design Errors by Manufacturer



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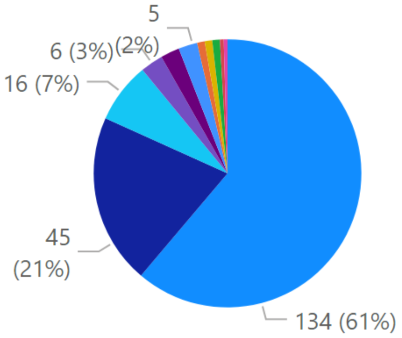

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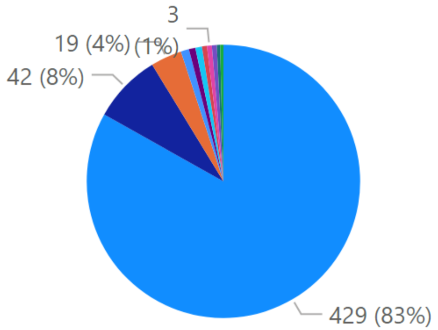

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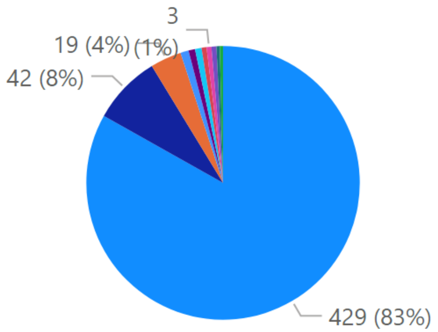
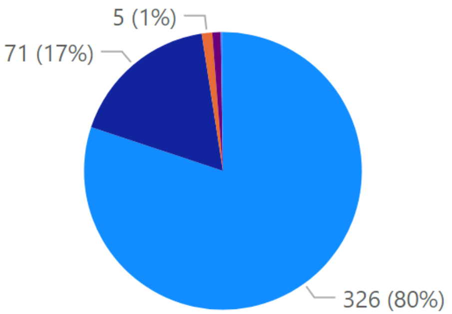


Texas RE



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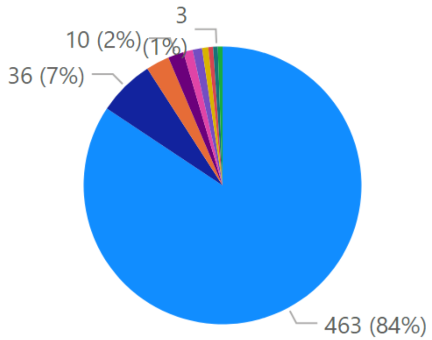
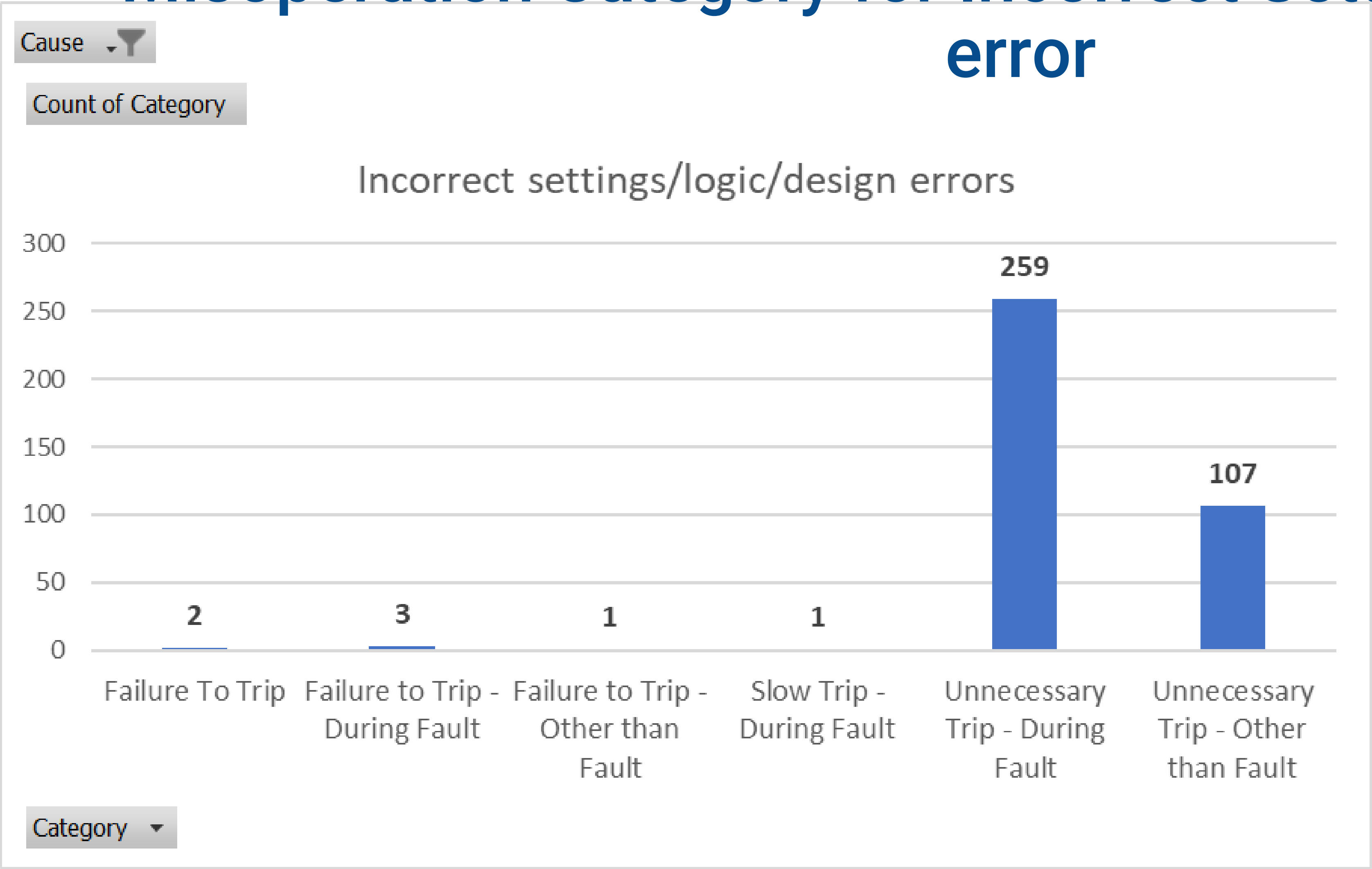
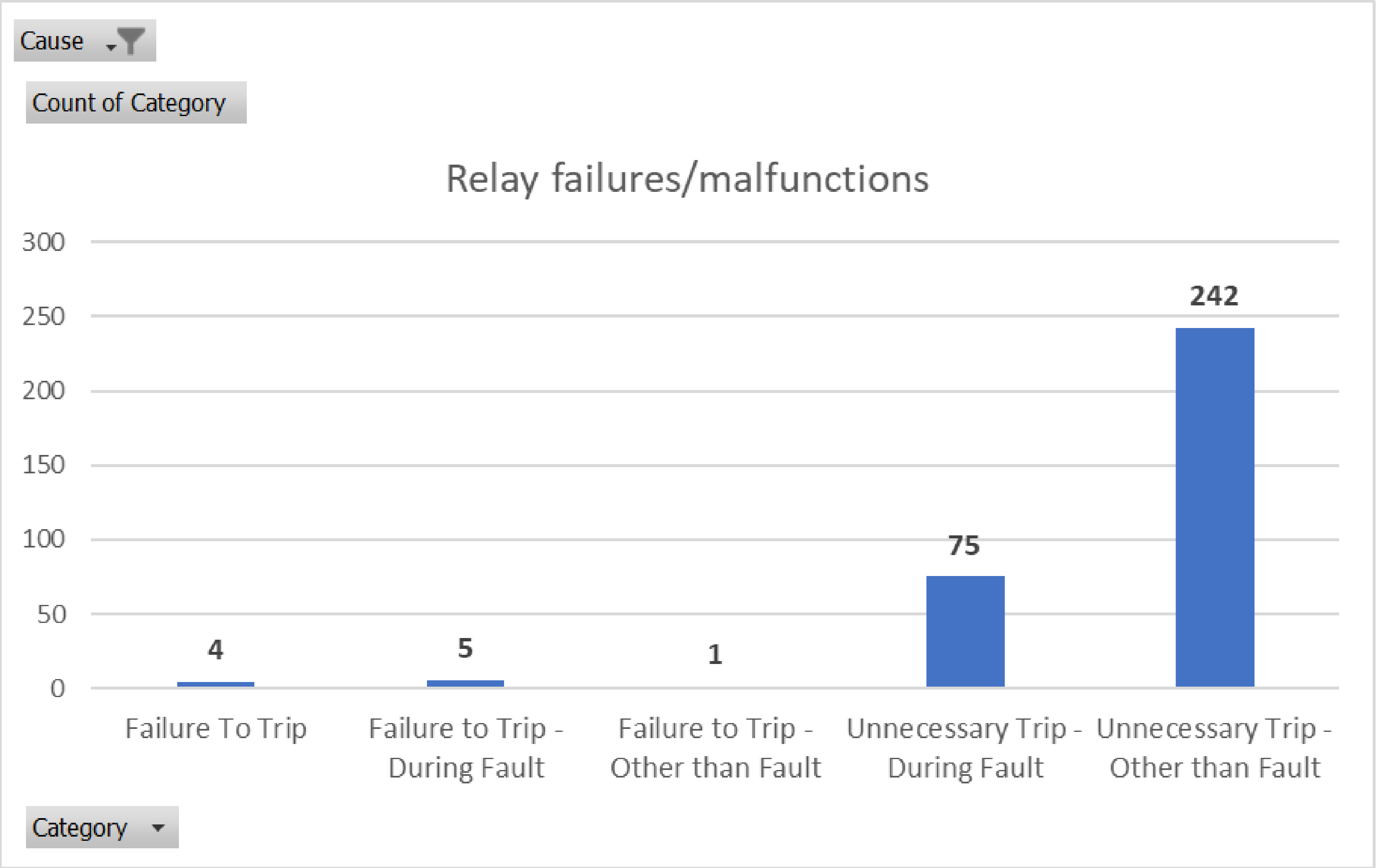


Misoperation Category for Incorrect Setting/Logic/Design error



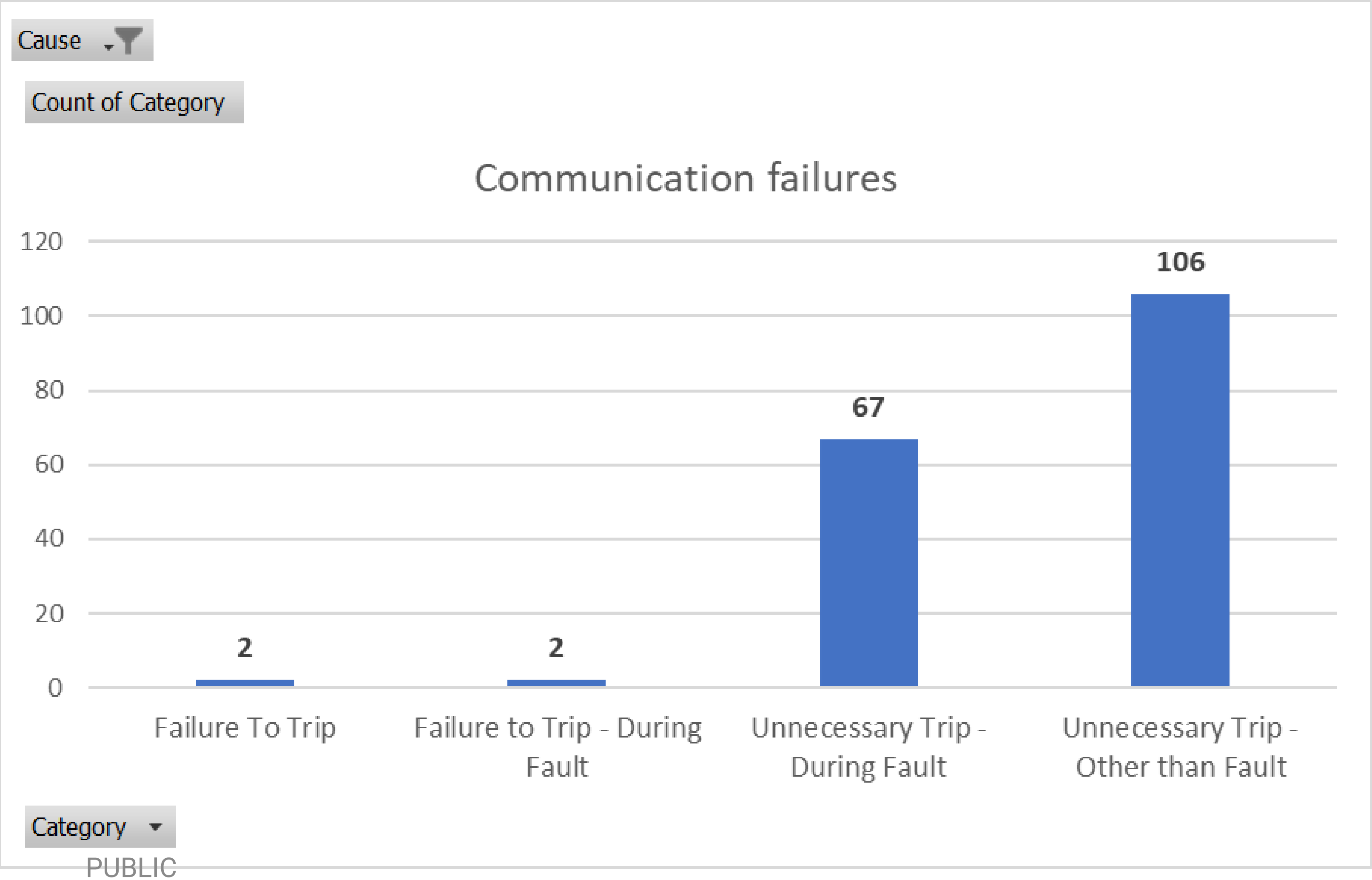
"Unnecessary Trip during Fault" which presents higher risk to the system compared to the "Unnecessary Trip- other than Fault

Misoperation Category for Relay Failure/Malfunction



"Unnecessary Trip- other than Fault" which presents lower risk to the system compared to the "Unnecessary Trip during Fault"

Misoperation Category for Communication Failure



"Unnecessary Trip- other than Fault" which presents lower risk to the system compared to the "Unnecessary Trip during Fault"

Working Group Activity-Corrective Action

Entity A	94
AC system	15
As-left personnel error	16
Communication failures	1
DC system	2
Incorrect settings	10
Incorrect settings/logic/design errors	1
Other/Explainable	6
Relay failures/malfunctions	23
Unknown/unexplainable	20
Grand Total	94

Entity B	62
AC system	7
As-left personnel error	4
Communication failures	7
DC system	10
Incorrect settings	10
Incorrect settings/logic/design errors	2
Logic errors	2
Other/Explainable	5
Relay failures/malfunctions	14
Unknown/unexplainable	1
Grand Total	62

Entity C	25
AC system	2
As-left personnel error	1
Communication failures	5
Incorrect settings	2
Incorrect settings/logic/design errors	2
Logic errors	1
Other/Explainable	4
Relay failures/malfunctions	6
Unknown/unexplainable	2
Grand Total	25

Misop Cause	Description of the Issue	Short Term Corrective Action	Long Term Corrective Action

Questions?

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The Hazards of Using Solid State Contacts for High Impedance Inputs

Rich Bauer
Misoperation Workshop - Atlanta
October 26, 2023

RELIABILITY | ACCOUNTABILITY




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Multiple Lessons Learned

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Lesson Learned
Protective Relaying Digital Input Board Loading Resistance

20120607

Primary Interest Groups
Transmission Owners (TO)
Transmission Operators (TOP)
Transmission Service Providers (TSP)

Problem Statement
The digital input board in a relay circuit tha
signals, noise, or high resistance contact bri
transmission line breaker.

Details
On two separate occasions and at two
transformers resulted in false tripping of
mounted protective relaying devices. While
design to isolate equipment, the protective
produced from an actual closure of a prote
was determined to be false in nature and un

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Lesson Learned
Use Loading Resistors When Applying Solid State Contacts to High-Impedance Input Devices

20130703

Primary Interest Groups
Generator Owners (GO)
Generator Operators (GOP)
Transmission Owners (TO)
Transmission Operators (TOP)

Problem Statement
Due to solid state-type contacts being
resistors, erroneous indications were
SPS/RAS misoperations.

Details
Modern protective devices employ th
break currents and decrease operatin
providing false contact closure indicati
of a loading resistor. NERC Event Ana
these types of contacts falsely indicatin

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Lesson Learned
Digital Inputs to Protection Systems May Need to be Desensitized to Prevent False Tripping Due to Transient Signals

20150201

Primary Interest Groups
Generator Owner (GOs)
Generator Operator (GOPs)
Transmission Operator (TOPs)
Transmission Owner (TOs)

Problem Statement
A converter station was lost due to the
transformer protection system. The op
cabinet at the time and visually inspected
current temperature and the drag hand fo
trip levels. There was no evidence found
cabinet.

Multiple events initiated by this type of
process.

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Lesson Learned
Transient Induced Misoperation: Approach I (Control Circuit Transient Misoperation of Microprocessor Relay)

20210203

Primary Interest Groups
Transmission Owners (TOs)
Generator Owners (GOs)
Transmission Operators (TOPs)
Generator Operators (GOPs)

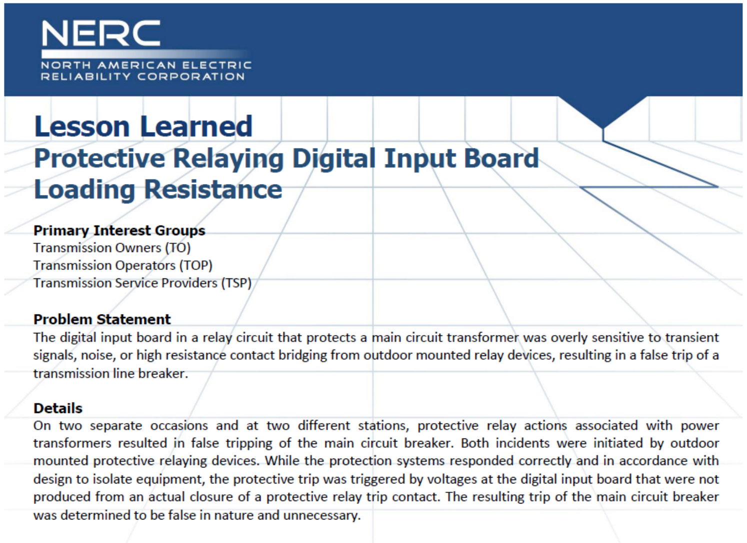
Problem Statement
Voltage transients were found to initiate protective relay digital inputs during close-in faults to a hydroelectric dam. The false inputs resulted in multiple powerhouse line protection misoperations and the unnecessarily tripping of hundreds of megawatts of generation. Due to the vintage of the equipment and a failure of the relay to properly log events, little data was initially available for troubleshooting. The powerhouse line relays at both the substation and powerhouse were owned and operated by the TOP but were connected to and powered by the GOP's control circuits and battery at the powerhouse.

Details
In 2019, a 230 kV bus fault occurred at the substation where several hydro generators interconnect with the power system. Two separate misoperations of the line protection at the powerhouse caused two powerhouse lines to trip unnecessarily, resulting in a loss of 221 MW. The relay trip was not initiated by an internal protection element; it was externally initiated via a 125 VDC direct transfer trip (DTT) input on the line relay at the powerhouse. The signal lasted less than a power system cycle and sent a direct trip to the remote end (one of the two relays failed to target it).

What is High Z?

- High Impedance Input typically ≥10 K ohm.
- Current draw typically < 10 mA.
  - Some devices less than 2 mA.

Lesson Learned 20120607



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Lesson Learned
Protective Relaying Digital Input Board Loading Resistance

Primary Interest Groups
Transmission Owners (TO)
Transmission Operators (TOP)
Transmission Service Providers (TSP)

Problem Statement
The digital input board in a relay circuit that protects a main circuit transformer was overly sensitive to transient signals, noise, or high resistance contact bridging from outdoor mounted relay devices, resulting in a false trip of a transmission line breaker.

Details
On two separate occasions and at two different stations, protective relay actions associated with power transformers resulted in false tripping of the main circuit breaker. Both incidents were initiated by outdoor mounted protective relaying devices. While the protection systems responded correctly and in accordance with design to isolate equipment, the protective trip was triggered by voltages at the digital input board that were not produced from an actual closure of a protective relay trip contact. The resulting trip of the main circuit breaker was determined to be false in nature and unnecessary.

- Sudden Pressure and Top Oil Temp inputs triggered XFMR tripping
- Neither device actually operated
  - Erroneous indication that devices operated
- Device contacts were an input into a digital input circuit board (high Z input)
- Corrective Action – add loading resistors to reduce sensitivity of digital input

Lesson Learned 20130703

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Lesson Learned

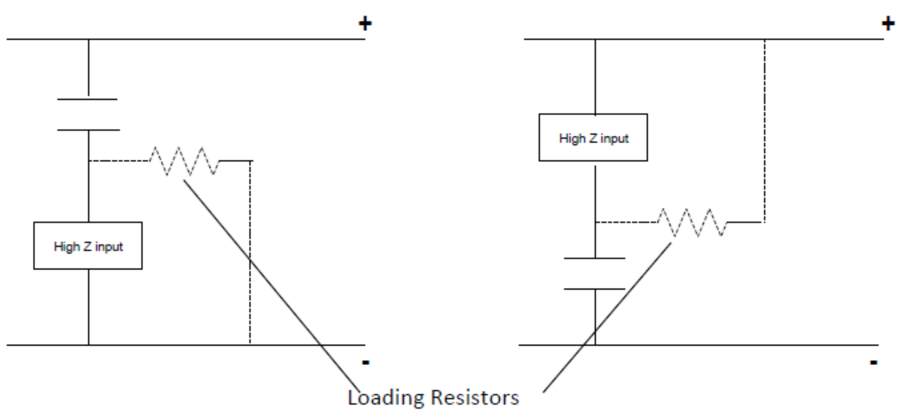
Use Loading Resistors When Applying Solid State Contacts to High-Impedance Input Devices

Primary Interest Groups
Generator Owners (GO)
Generator Operators (GOP)
Transmission Owners (TO)
Transmission Operators (TOP)

Problem Statement
Due to solid state-type contacts being applied to high-impedance input devices without the use of loading resistors, erroneous indications were introduced into the protection and control schemes and caused SPS/RAS misoperations.

Details
Modern protective devices employ the use of solid state components to increase capacity to make or break currents and decrease operating time of output contacts. These types of contacts have a risk of providing false contact closure indications when applied to high-impedance input devices without the use of a loading resistor. NERC Event Analysis received two reports in which SPS/RAS misoperated due to these types of contacts falsely indicating open breakers.

- Multiple RAS misoperations
- Erroneous inputs into logic controllers, processors and communications equipment
- Corrective action – add loading resistor



Lesson Learned 20150201

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RELIABILITY CORPORATION

Lesson Learned

Digital Inputs to Protection Systems May Need to be Desensitized to Prevent False Tripping Due to Transient Signals

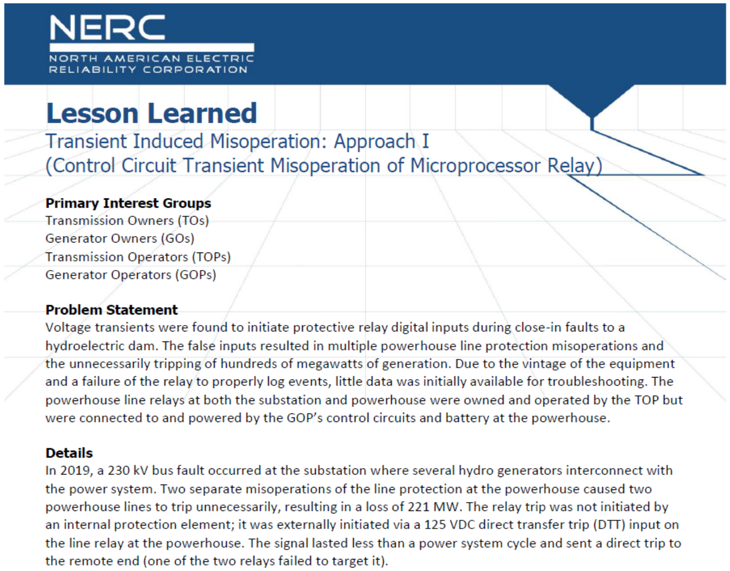
Primary Interest Groups
Generator Owner (GOs)
Generator Operator (GOPs)
Transmission Operator (TOPs)
Transmission Owner (TOs)

Problem Statement
A converter station was lost due to the erroneous initiation of a top-oil temperature trip signal from a transformer protection system. The operating entity investigated the connections in the transformer cabinet at the time and visually inspected the transformer and temperature gauges. Both the transformer's current temperature and the drag hand for the high-temperature indication were well below the alarm and trip levels. There was no evidence found to indicate any loose or corroded connections in the transformer cabinet.

Multiple events initiated by this type of erroneous input signal have been observed in the event analysis process.

- XFMR top oil temp erroneous indication
- Loading resistor applied

Lesson Learned 20210203



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Lesson Learned

Transient Induced Misoperation: Approach I
(Control Circuit Transient Misoperation of Microprocessor Relay)

Primary Interest Groups
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Generator Owners (GOs)
Transmission Operators (TOPs)
Generator Operators (GOPs)

Problem Statement
Voltage transients were found to initiate protective relay digital inputs during close-in faults to a hydroelectric dam. The false inputs resulted in multiple powerhouse line protection misoperations and the unnecessarily tripping of hundreds of megawatts of generation. Due to the vintage of the equipment and a failure of the relay to properly log events, little data was initially available for troubleshooting. The powerhouse line relays at both the substation and powerhouse were owned and operated by the TOP but were connected to and powered by the GOP's control circuits and battery at the powerhouse.

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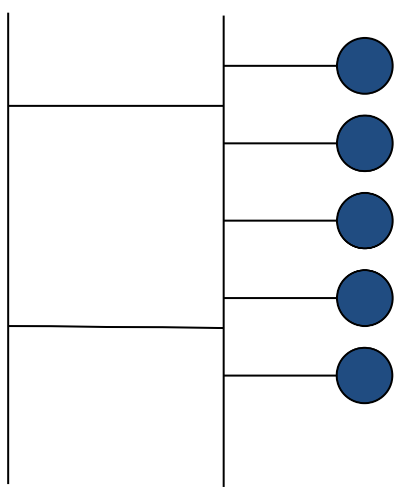
In 2019, a 230 kV bus fault occurred at the substation where several hydro generators interconnect with the power system. Two separate misoperations of the line protection at the powerhouse caused two powerhouse lines to trip unnecessarily, resulting in a loss of 221 MW. The relay trip was not initiated by an internal protection element; it was externally initiated via a 125 VDC direct transfer trip (DTT) input on the line relay at the powerhouse. The signal lasted less than a power system cycle and sent a direct trip to the remote end (one of the two relays failed to target it).



- Multiple DTT received at powerhouse during external SLG faults
- After years of research and analysis, it was determined that DTT inputs at powerhouse were triggering on transient signals
- Loading resistors previously installed were too large (47k to 23k)
- Unshielded cables contributed to problem

OEM advice

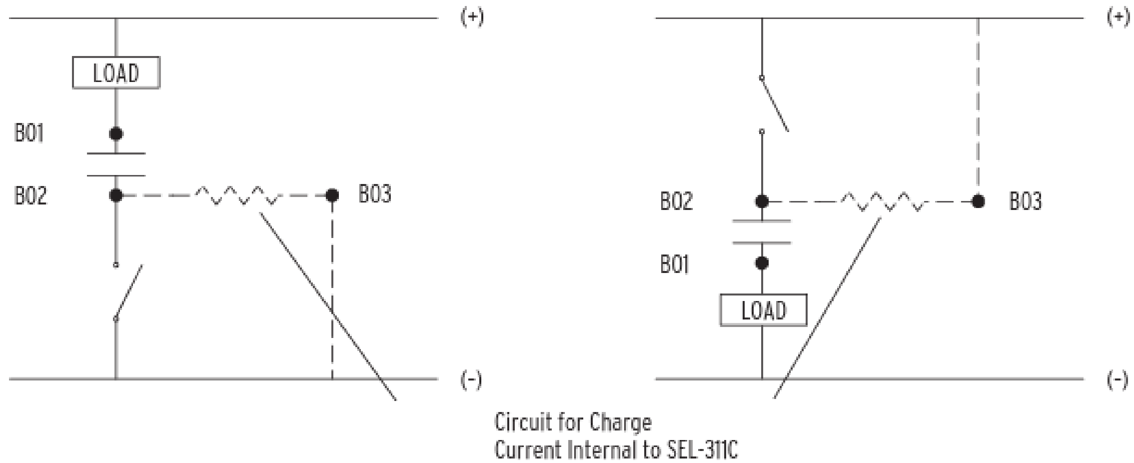
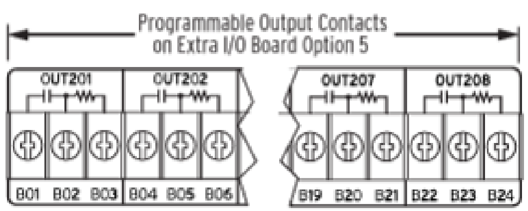


Figure 2.8 Possible Connections for Fast High-Current Interrupting Output Contacts (Third Terminal Connection Is Optional)



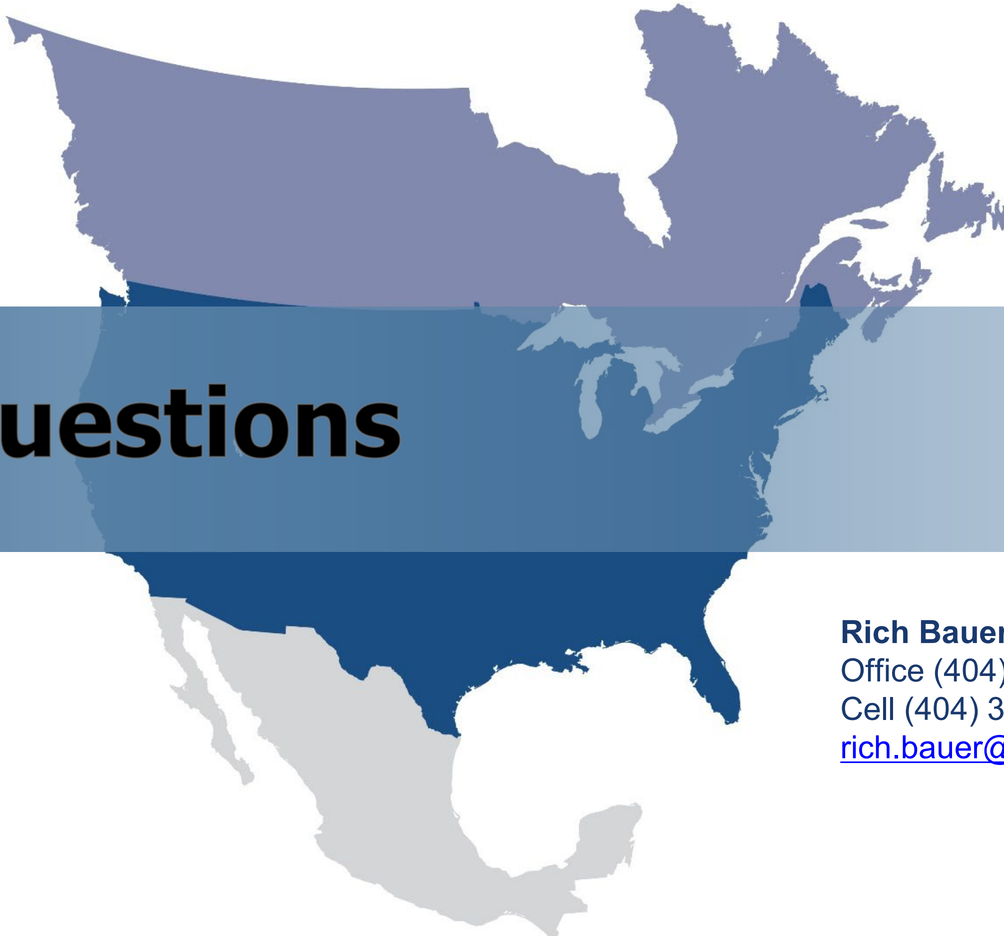
For specialized applications with sensitive auxiliary relays or digital inputs, connect the OUT201-OUT208 third terminal to provide a path for charging the circuit capacitance.

- **OEM added 3rd terminal with integral loading resistor**

OEM advice

- **OEM recommends not using solid state contacts in that application anymore**

Avoid using high-speed outputs to drive highly sensitive, high input-resistance electronic inputs (e.g., <2 mA electronic circuits) unless such inputs are connected in parallel with a low-resistance load (e.g., a breaker trip coil). The minimum current requirement is especially important for low-power signaling circuits found on SONET/SDH/MPLS multiplexers with contact I/O interfaces, power line carrier sets, and breaker failure and autoreclose initiation relay inputs. Avoid connecting multiple high-speed outputs in parallel when driving highly sensitive electronic inputs. Consider using the standard (electromechanical relay-based) Form A contact outputs, OUT201 through OUT208, for these low-power signaling applications or use digital protection signaling over Port 1, 2, or 3.



Questions

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IBR Challenges ~~and Solutions~~

Manish Patel

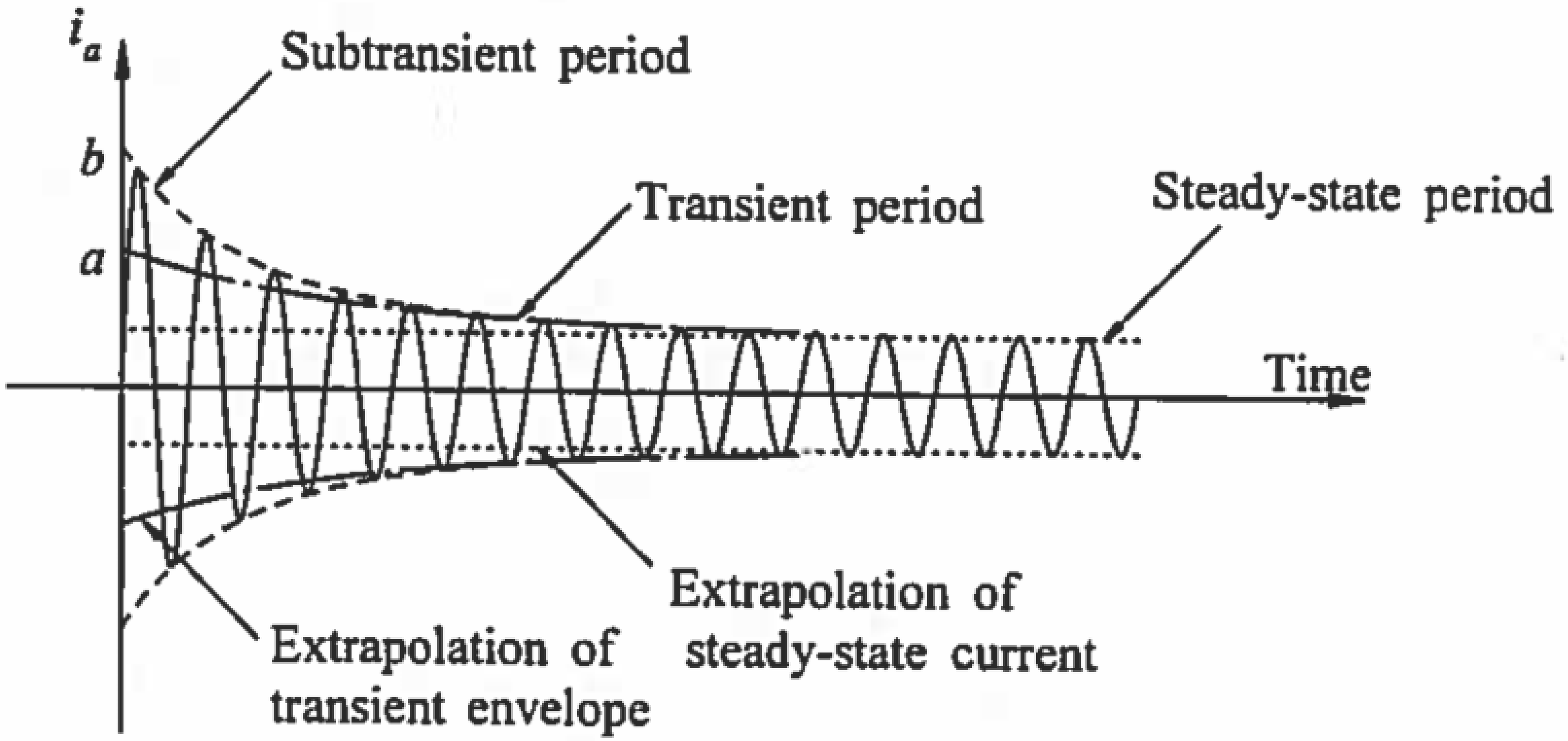
Southern Company Services

October 26, 2023

Outline

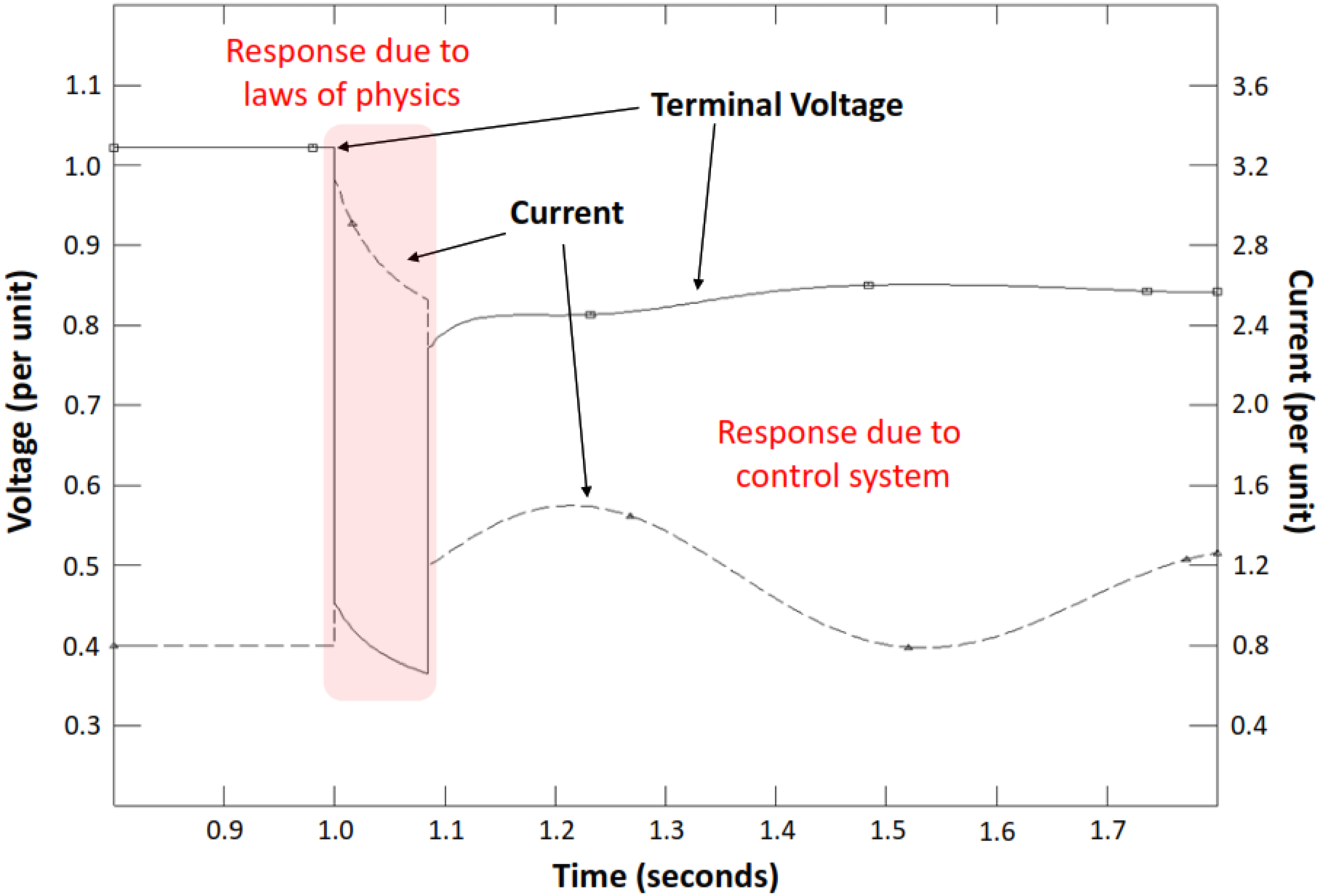
- Inverter-Based Resource (IBR) Fault Response and Opportunity for Standardization
- Impact on System Protection
- Short Circuit (SC) Modeling of IBRs
- Other Protection issues

Fault Current Contribution from Sync MCs



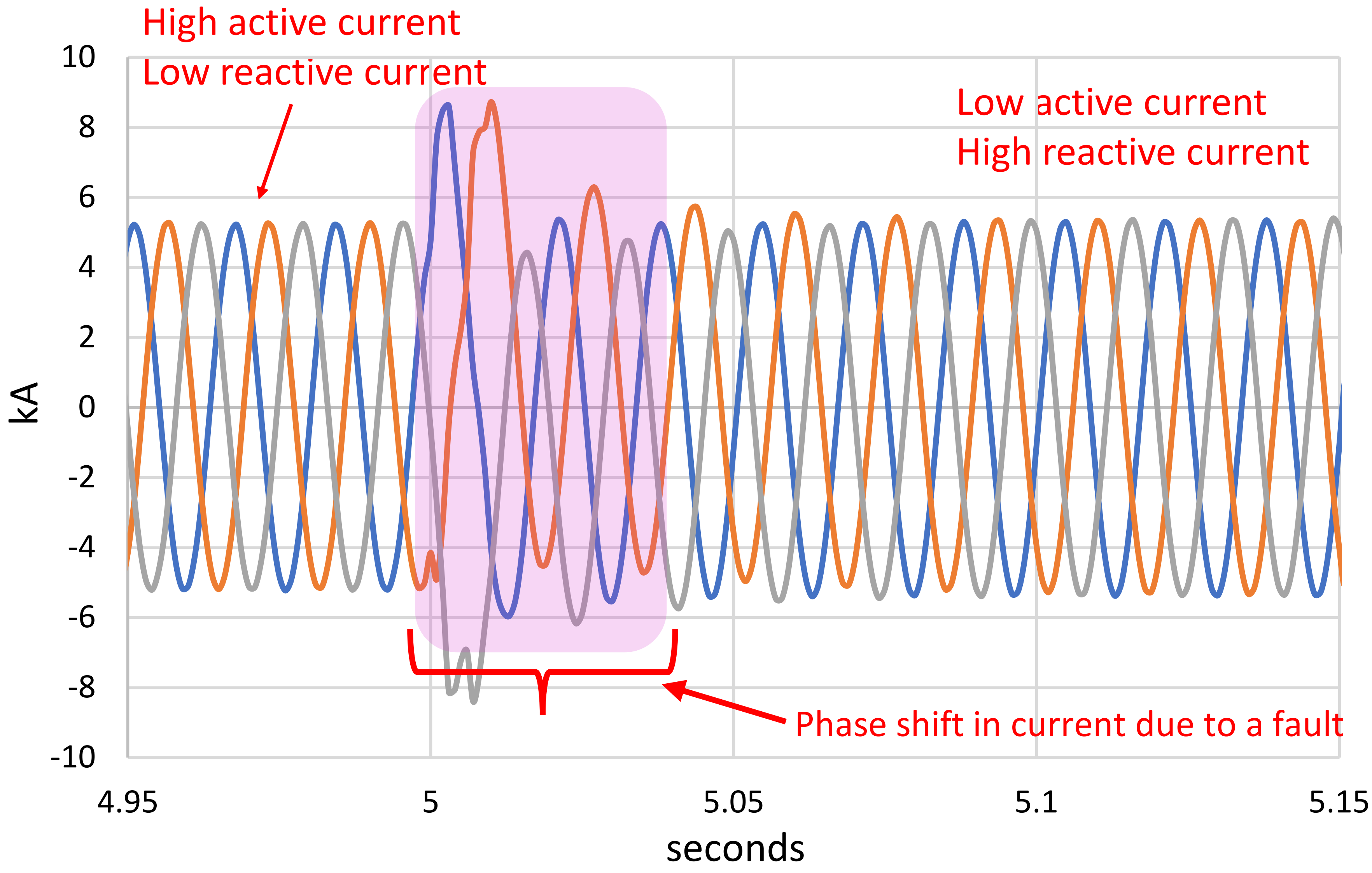
For short circuit studies, synchronous machine is represented by three snapshots in time

Response During a Three Phase Fault Sync. Mach.

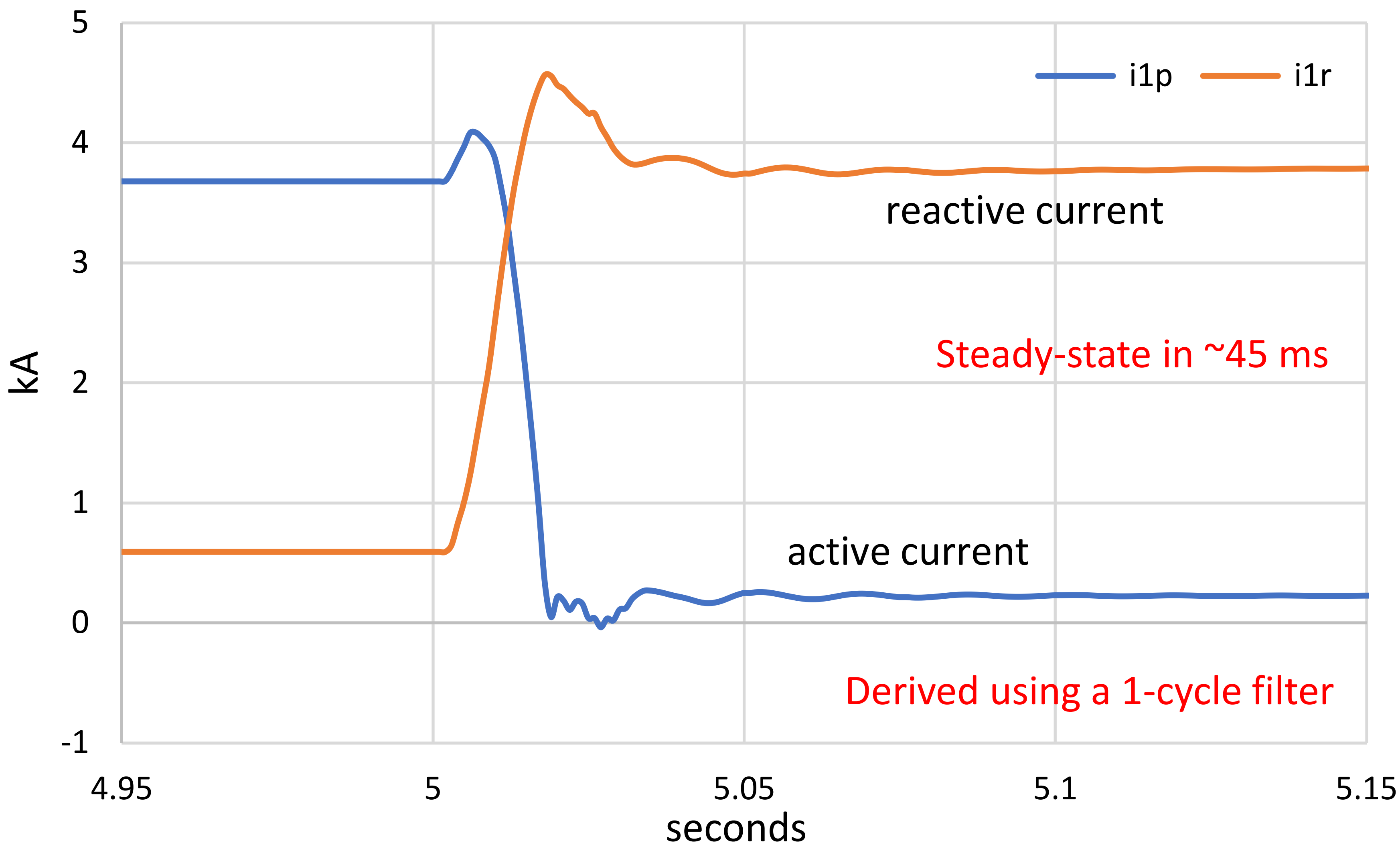


Response During a Three Phase Fault Sync. Mach.

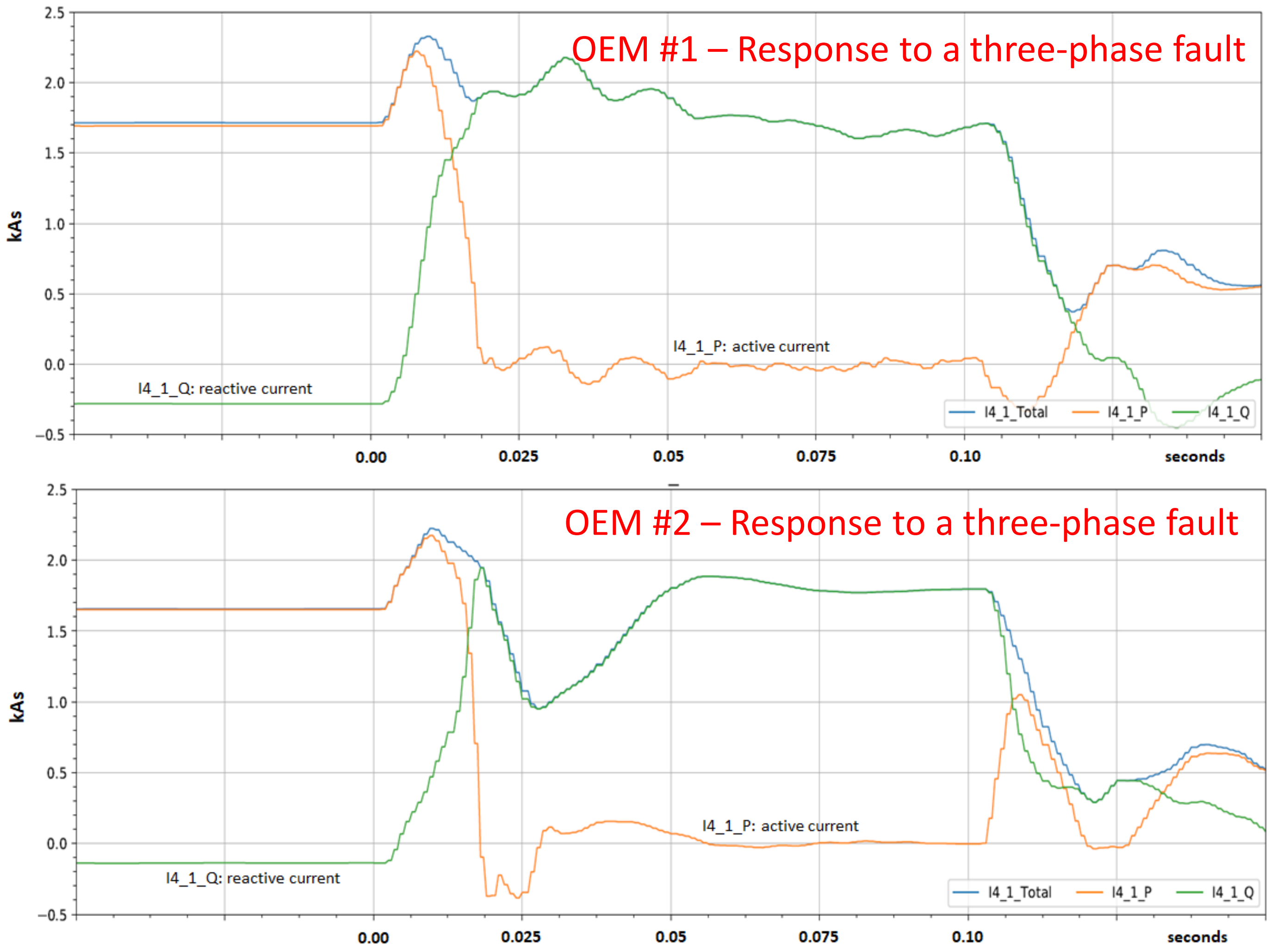
Fault Current Contribution from PV Inverter



Fault Current Contribution from PV Inverter



Opportunity for Standardization



- Response is unique and vary among OEMs.
- EMT simulations may be required.
- Standardization would help with modeling and SC analysis as well as with application of protection schemes.
- Post fault behavior equally important.

Reference: Impact of IBR I2 current injection on Transmission System Protection, Sandia Report

Fault Current Injection Requirements in IEEE 2800

- Priority shall be given to reactive current injection unless specified to operate differently.
- Balanced faults:
  - Injected reactive current shall be dependent on terminal voltage.
  - Incremental reactive current shall not be negative.
- Unbalanced faults:
  - Inject negative-sequence reactive current dependent on terminal negative-sequence voltage
  - Full converter-based resources: <u>I2 shall lead V2 by 90-100 degrees</u>
  - Type III Wind Turbine Generators (WTGs): <u>I2 shall lead V2 by 90-150 degrees</u>
- The standard also specifies fault current characteristic when current limit is reached.

Fault Current Injection Requirements in IEEE 2800

No specification of current magnitude

The 1-cycle time required for DFT (to derive phasor quantities) is included in specified response/settling time.

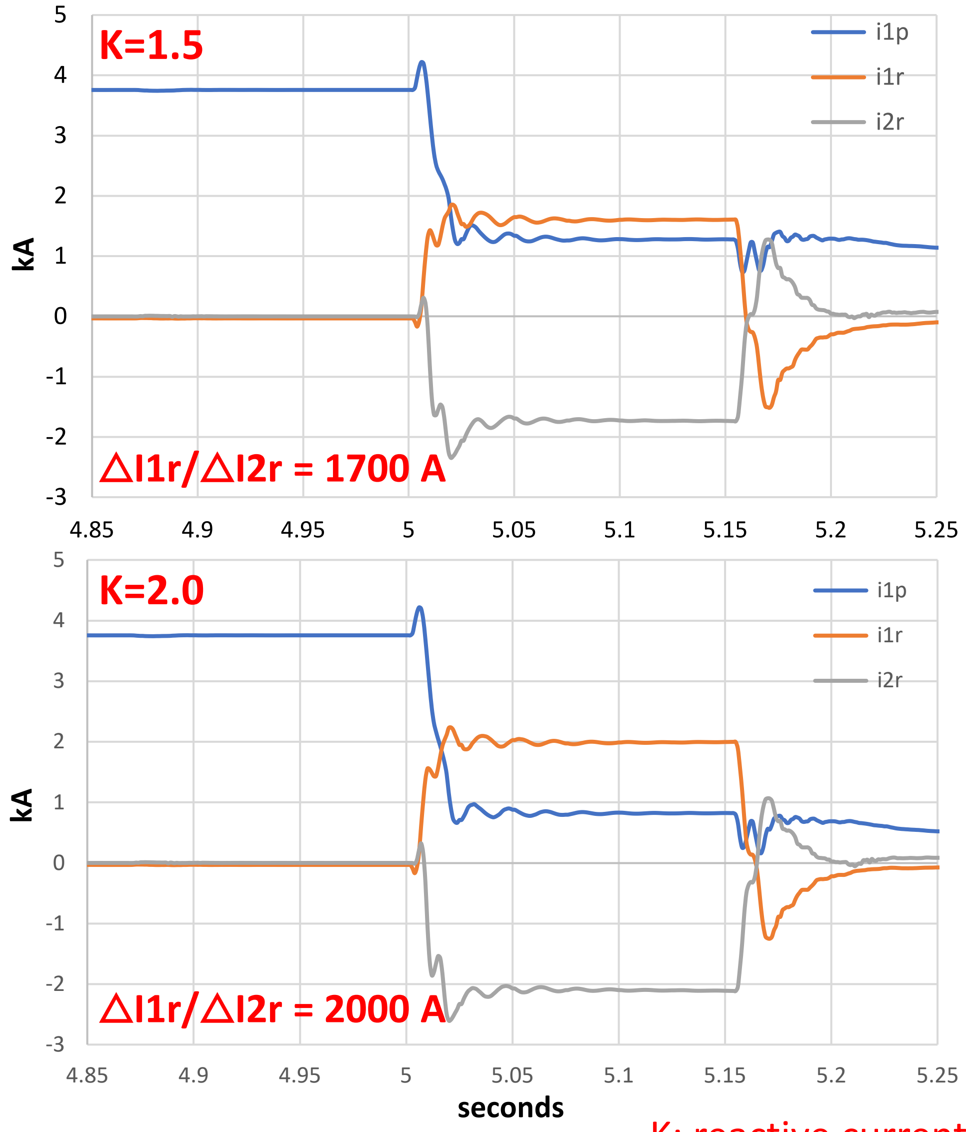
	Type III WTGs	All other IBR Units
Step Response Time	NA[1]	≤ 2.5 cycles
Settling Time	≤ 6 cycles	≤ 4 cycles
Settling Band	Max of (±10% of required change or ±2.5% of IBR unit maximum current)	Max of (±10% of required change or ±2.5% of IBR unit maximum current)

Note 1: Initial response is driven by machine characteristics, & not the control system.

IBR Units: Individual WTGs, inverters

Magnitude & Response of Fault Current?

- It is impractical to specify magnitude of incremental I1 and I2 reactive current injection during faults.
    - ➢Needs consideration of system condition
- Such specification should be based on fault studies as well as system stability studies.
- Slower response/settling time may be necessary for certain system conditions.

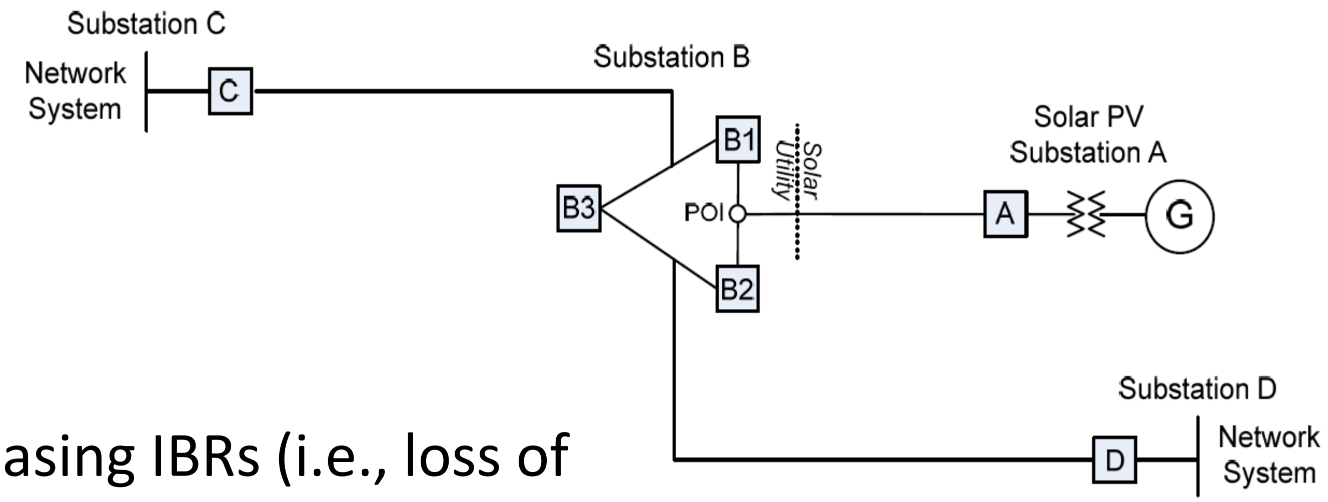


K: reactive current gain

Impact of System Protection

- As penetration of IBRs grow, emphasis on protecting tie-lines and transmission lines originating from the interconnecting substation.

- Protection for line C-B, D-B and tie-line remains challenging but configurable as far as source behind substations C and D remains strong.

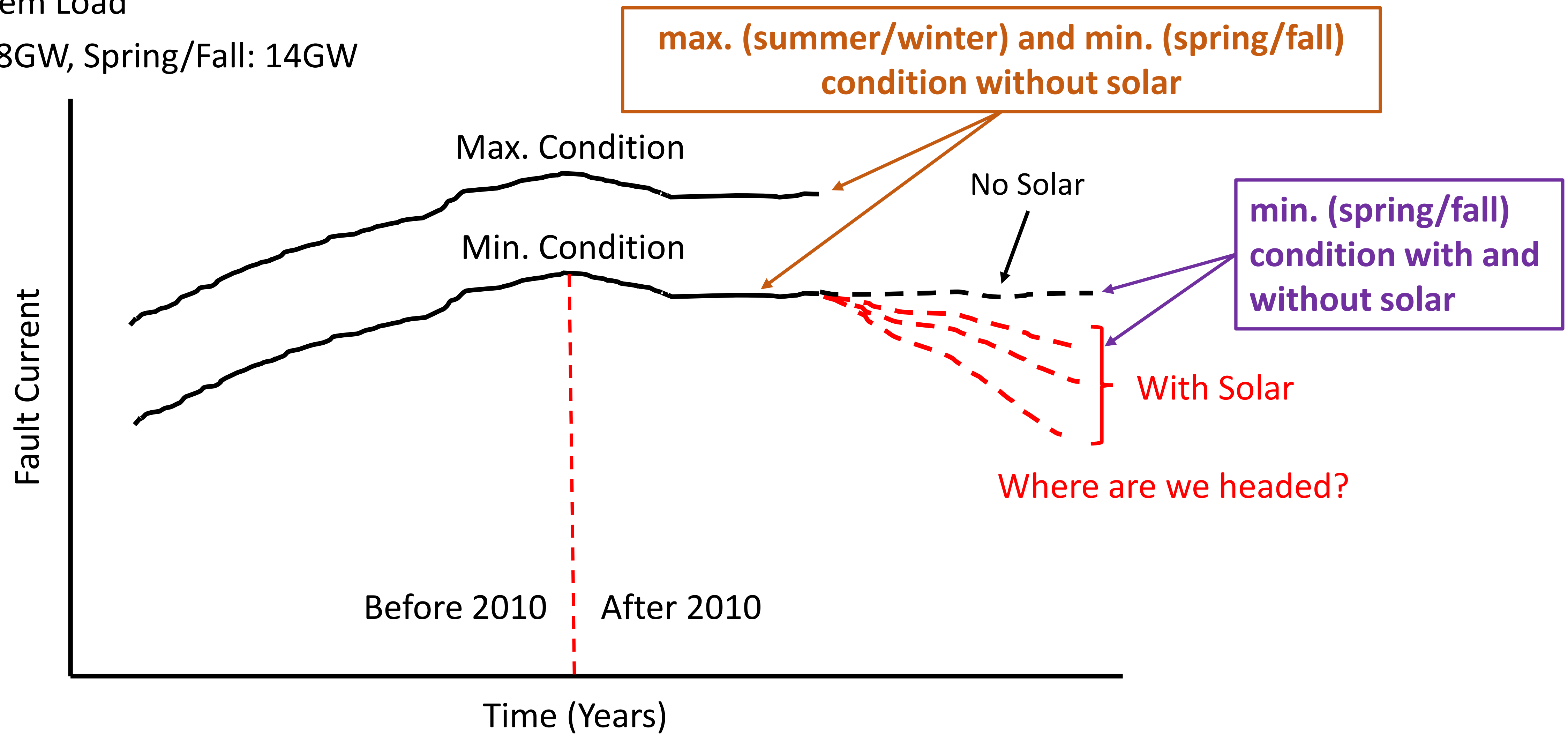


- What is the collective impact of increasing IBRs (i.e., loss of inertia, loss of fault duty)? Not only at peak condition but more importantly at off-peak condition.

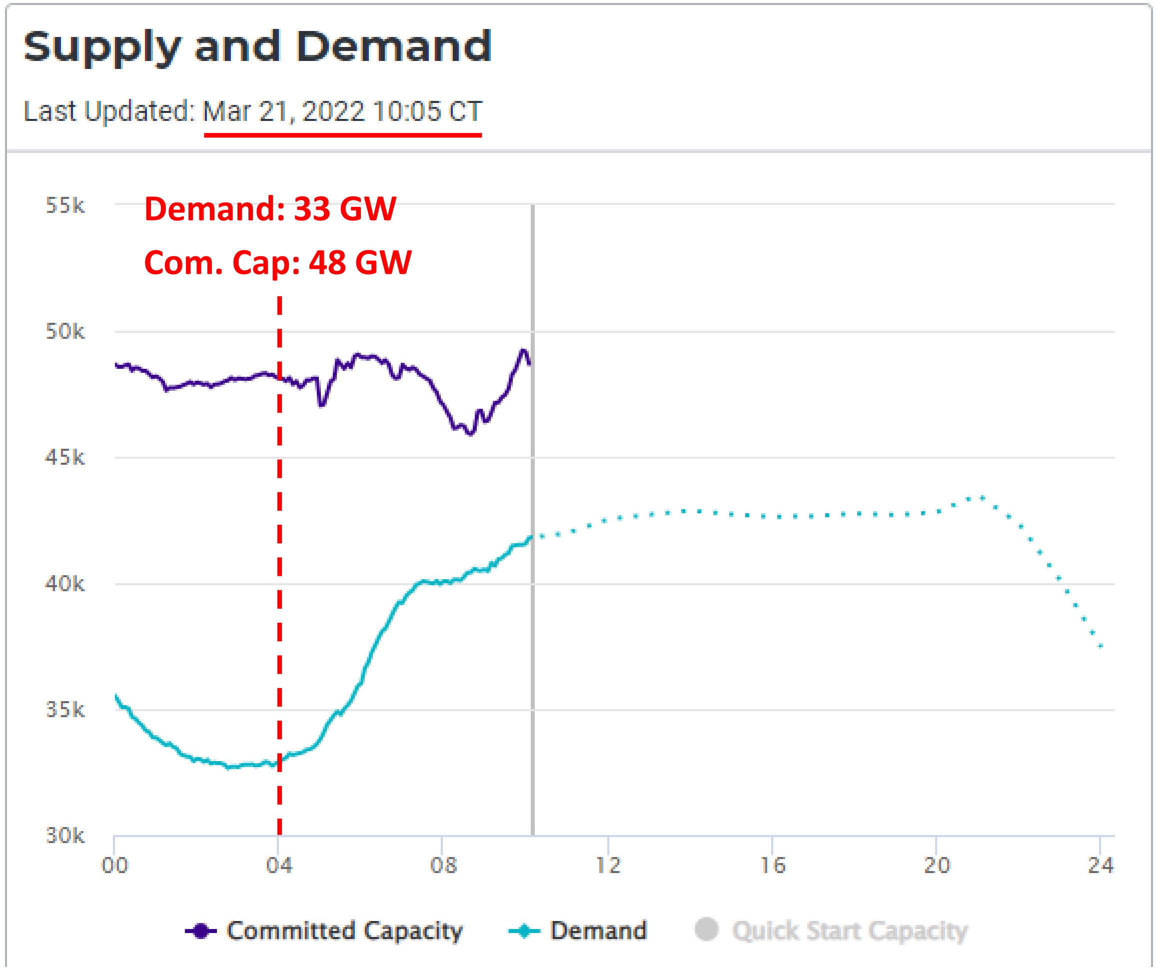
Trend in Fault Current Magnitudes

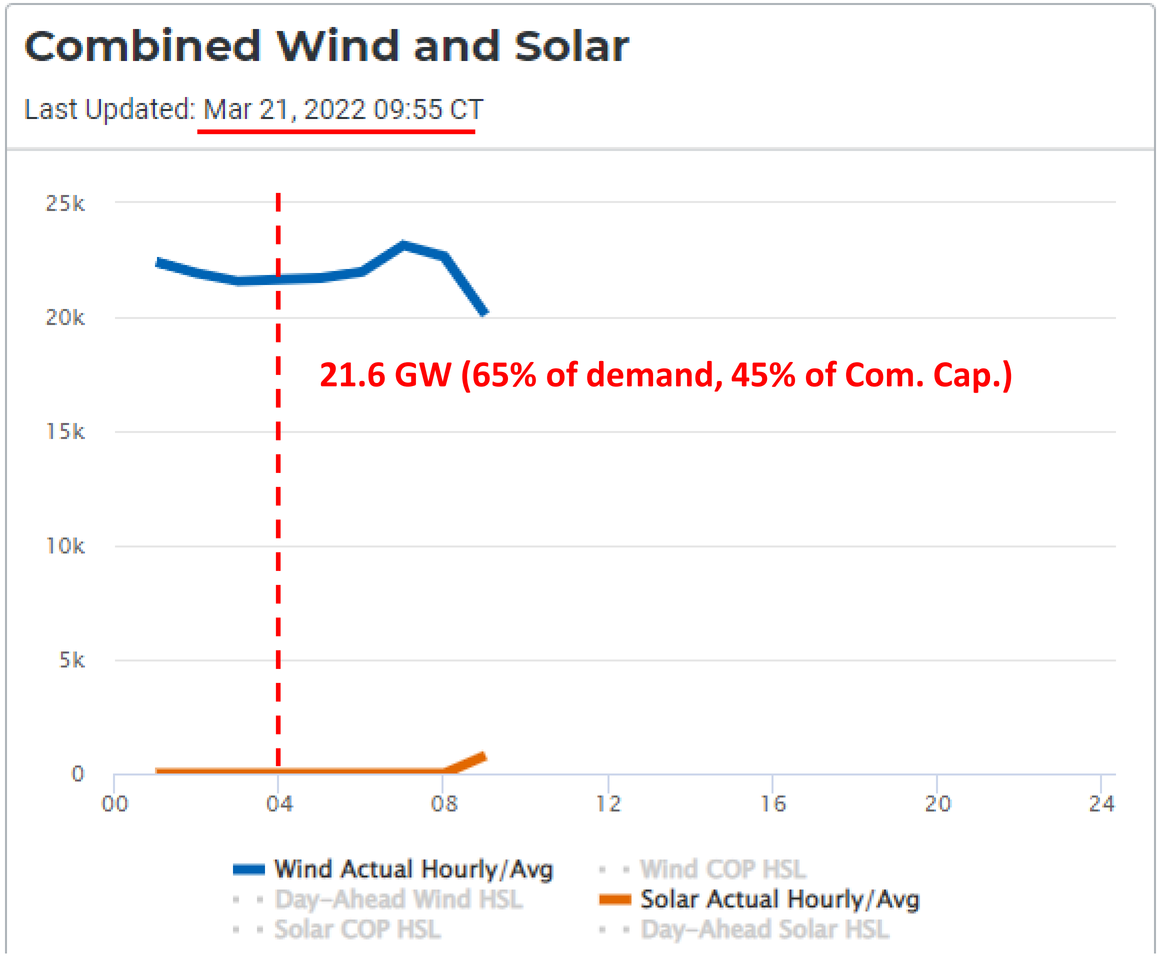
GA System Load

Peak: 28GW, Spring/Fall: 14GW



Example - ERCOT





Source: https://www.ercot.com/

Example – California ISO

April 14, 2022

Media Email | ISOMedia@caiso.com

California ISO hits all-time peak of more than 97% renewables

Electric grid breaks another record, giving glimpse of zero-carbon future

FOLSOM, Calif. – In another sign of progress toward a carbon-free power grid, the California Independent System Operator (ISO) set a new record on April 3, when 97.6 percent of electricity on the grid came from clean, renewable energy.

The peak, which occurred briefly at 3:39 p.m., broke the previous record of 96.4 percent set on March 27, 2022. Before that, the grid's record for clean power was 94.5 percent, set on April 21, 2021. The new milestone comes as the ISO integrates growing amounts of renewable energy onto the grid in support of the state's clean energy goals.

Source: http://www.caiso.com/Documents/California-ISO-Hits-All-Time-Peak-of-More-Than-97-Percent-Renewables.pdf

Example – Southwest Power Pool

March 29, 2022

SPP sets regional records for renewable energy production

LITTLE ROCK, ARK. —Southwest Power Pool (SPP) set several renewable records March 28 and 29, 2022. At 2:42 a.m. Central time March 29, SPP set a new renewable energy penetration record of 90.2%, beating the previous record of 87.5% set May 8, 2021. This means SPP served 90.2% of the demand for electricity across its 14-state service territory with renewable energy sources, and marks the first time a regional transmission organization served more than 90% of its load with renewables. Of total demand, 88.5% was served by wind, beating the previous wind penetration record of 84%, also set May 8, 2021.

Will protection schemes/relay settings operate correctly during high IBR operating conditions?

Source: https://www.spp.org/newsroom/press-releases/spp-sets-regional-records-for-renewable-energy-production/

Short-Circuit Modeling of IBRs

- Voltage controlled current sources – current injection is dependent on terminal voltage.
- IEEE PSRC WG C24 report – Recommended a tabular format for modeling.
- Data should be provided for various time instants after initiation of a fault.
- Model provides a total current injection. Typical utility scale SC models are set-up to calculate incremental currents only.
  - ➢ Total current = pre-fault current + incremental current.

Example: Steady-state current injection for a 3-ph fault

Time since initiation of a fault: Steady State			Fault Type: Three-Phase	
Pos. Seq. Volt. V1 (per unit)	Pos. Seq. Current I1 (per unit)			Angle between V1 and I1 (degrees)
	Active Current	Reactive Current	Total Current	
0.9	1.00	0.17	1.01	-9.7
0.8	1.00	0.34	1.06	-18.8
0.7	1.00	0.51	1.12	-27.0
0.6	0.80	0.68	1.20	-34.5
0.5	0.85	0.85	1.20	-45.0
0.4	0.63	1.02	1.20	-58.3
0.3	0.15	1.19	1.20	-82.9
0.2	0.0	1.20	1.20	-90.0
0.1	0.0	1.20	1.20	-90.0

Any problem with application of this model?

SC Modeling of IBRs

- Tabular SC model for IBR capable to inject negative sequence reactive current.
- Dependency between positive and negative sequence quantities.
- Depending on control scheme, dependency for angle between V1 & V2 may be needed
- How much negative sequence current?

$$\left| \underbrace{I_{load,1} + I_{fault\ (reactive),1}}_{\text{Positive Sequence}} + \underbrace{I_{fault\ (reactive),2}}_{\text{Negative Sequence}} \right| \leq I_{limit}$$

Example: IBR capable to Inject Negative Seq Current*

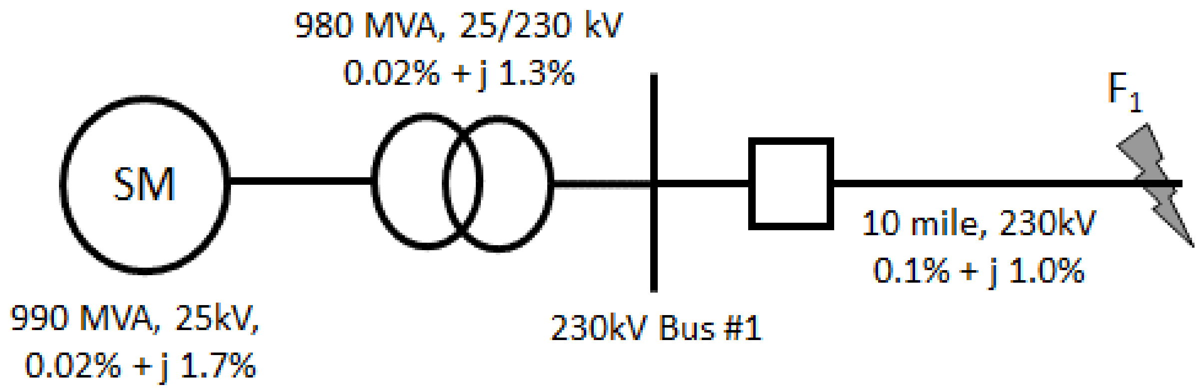
Time Frame: Steady-State					
V1 (pu)	V2 (pu)	I1 (pu)	Angle (V1/I1)	I2 (pu)	Angle (V2/I2)
0.9	0.0				
	0.1				
	0.2				
	0.3				
	0.4				
	0.5				
0.8	0.0				
	0.1				
	0.2				
	0.3				
	0.4				
	0.5				
0.7	0.0				
	….	….	….	….	….

***Some combinations may not be practical**

SC Modeling of IBRs

- Equation based model:
  - Considering various current limiting schemes, **difficult to develop** that provides a reasonable representation of an IBR
- Table based model:
  - Proven concept but table structure **might vary** depending on current limiting logic
  - **Need to run EMT studies** to populate tabular model
  - Introduces **risk of human error** when tables are large
- Dynamic Link Library (DLL) based model:
  - User-defined model, provided by an OEM
  - Should provide **accurate representation** of an IBR
  - **Efforts are ongoing** to show proof of concept

Now an Academic Exercise



<u>Ignore Resistance</u>

Fault Current $= 25\angle -90\ pu$

Fault current lags voltage by 90 degrees i.e., no active current.

<u>Considering Resistance</u>

Fault Current $= 25\angle -88\ pu$
$= 6275\angle -88\ Amps$

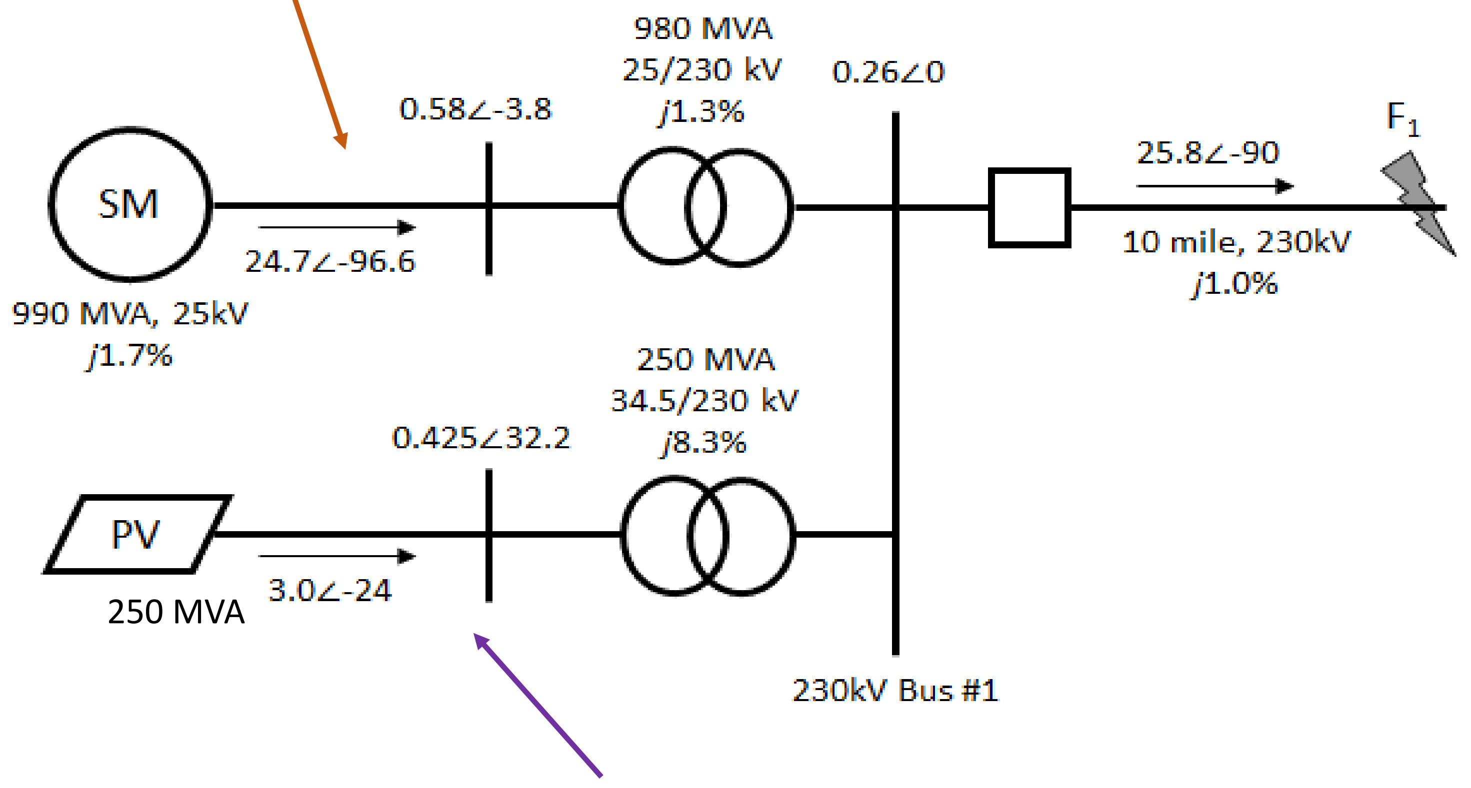
Active current $= 6275 * \cos(-88) = 219\ Amps$

Why active current?

Academic Exercise with Solar

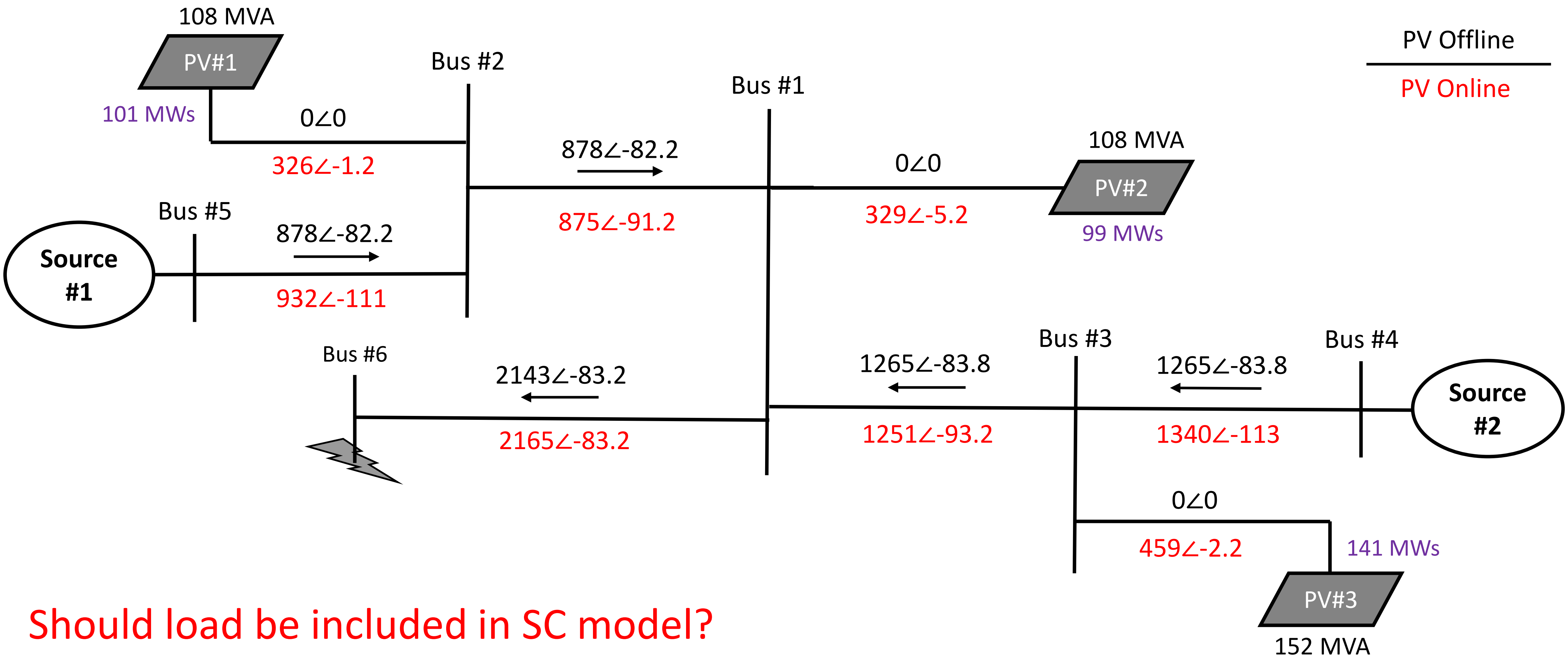
Active Power O/P $= 0.58 * 24.7 * \cos(-92.8) = -0.70\, pu = -70\, MW$

Resistance Ignored



Active Power O/P $= 0.425 * 3.0 * \cos(-56.2) = 0.71\, pu = 71\, MW$

A Real World Case



Should load be included in SC model?

Futuristic Light Load Scenario

- GA-ITS short circuit model modified to represent future light load condition.
  - Synch Machines online – 19 units, 11 GW
  - PV Solar online – 70 facilities, 5.5 GW
- Fault current reduces when PV resources are online.
  - Behavior is counterintuitive
- Synchronous machines absorb a lot of active power when PV resources are online.
- Flow of active power from PV to SM resources causes a higher voltage drop through the network.

Fault Location	Fault current (A)	
	PV Offline	PV Online
Bus #1	21727	19071
Bus #2	8472	7381
Bus #3	8279	6897
Bus #4	8866	7662
Bus #5	9549	8123
Bus #6	6817	5658

Fault Location	Active Power Contribution or Absorption (MW)			
	PV Offline		PV Online	
	SM Resources	PV Resources	SM Resources	PV Resources
Bus #1	422	NA	-1788	2499
Bus #2	324	NA	-3167	3707
Bus #3	301	NA	-3011	3622
Bus #4	358	NA	-3108	3647
Bus #5	347	NA	-2614	3271
Bus #6	229	NA	-2855	3358

Negative sign means resources absorbing active power

Should load be included in SC model?

Fault @ Bus #1 – SM Terminal Info

Unit #	PV Offline			PV Online		
	Voltage (kV)	Current (kA)	PF Angle	Voltage (kV)	Current (kA)	PF Angle
SM #1	8.2	7.93	**-87**	7.36	11.78	**-114.9**
SM #2	9.4	4.72	**-85.1**	9.09	6.49	**-107.5**
SM #3	9.4	4.72	**-85.1**	9.09	6.49	**-107.5**
SM #4	10.55	2.77	**-85.3**	10.05	3.82	**-108.9**
SM #5	7.42	18.25	**-87.5**	7.21	19.06	**-92.6**
SM #6	7.55	17.74	**-87**	7.35	18.5	**-91.8**
SM #7	6.73	23.61	**-87.6**	6.57	24.66	**-92.3**
SM #8	11.47	18.01	**-86.3**	10.5	27.54	**-115.5**
SM #9	11.05	21.14	**-86.6**	9.9	32.23	**-115.3**
SM #10	12.67	13.63	**-85.2**	12.36	16.33	**-102**
SM #11	12.31	16.34	**-86**	11.92	19.87	**-103.2**
SM #12	13.42	11.14	**-84.9**	13.14	13.34	**-101.5**
SM #13	12.96	14.39	**-85.9**	12.57	17.5	**-102.9**
SM #14	7.29	12.38	**-86.6**	7.1	12.94	**-91.5**
SM #15	7.29	12.38	**-86.6**	7.1	12.94	**-91.5**
SM #16	7.47	13.35	**-86.9**	7.1	12.94	**-91.5**
SM #17	6.21	6.53	**-86.7**	6.02	7.17	**-97.9**
SM #18	6.21	6.53	**-86.7**	6.02	7.17	**-98**
SM #19	8.2	7.93	**-87**	7.36	11.78	**-114.9**

Non-Convergence Issue

Fault Location	Fault current (A)					
	PVs offline			PVs online		
	Disp#1	Disp#2	Disp#3	Disp#1	Disp#2	Disp#3
Bus #1	21727	23817	20518	19046	21173	NC
Bus #2	8472	9467	8256	7384	8447	7105
Bus #3	8279	8662	7992	6897	7296	6547
Bus #4	8866	9152	8985	7663	8006	7724
Bus #5	17545	18837	19430	15628	16846	NC
Bus #6	24332	24698	24973	NC	NC	NC
NC: short-circuit program does not converge						

Non-Convergence Issue

Fault @ Bus #1, Dispatch #1, PVs Online

Iteration Number	IBR Terminal Voltage (per unit)	IBR Current (per unit)
0	$1.00\angle{-30}$	0.0
1	$1.35\angle{-4.6}$	$1.8\angle{-72.2}$
2	$0.87\angle 43.3$	$1.8\angle{-4.6}$
3	$0.51\angle 78.5$	$1.8\angle 31.5$
4	$0.39\angle 82.1$	$1.8\angle 34.2$
5	$0.42\angle 62.5$	$1.8\angle 21.1$
6	$0.54\angle 47.7$	$1.8\angle 7.1$
7	$0.61\angle 44.5$	$1.8\angle 6.6$
8	$0.67\angle 43.1$	$1.8\angle 10.1$
9	$0.72\angle 55.2$	$1.8\angle 14.0$
10	$0.51\angle 77.6$	$1.8\angle 29.8$

Pattern seen from iteration #6 through #9 repeats forever

Possible Reasons for Non-Convergence

- The short-circuit model does not include load. Active current/power injected by IBRs flows through the network and eventually into generating units. This may be a reason for non-convergence. If so, modeling of loads for short-circuit analysis might be necessary.
- In weak systems, IBR current could change the terminal voltage. Change in IBR terminal voltage between iterations is significant.
- Combination of above

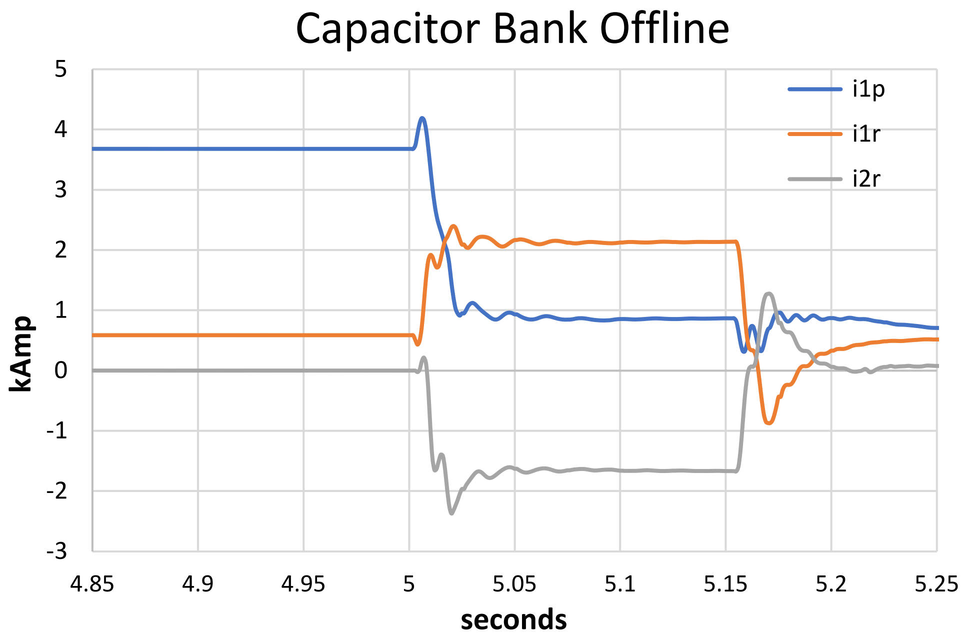
Non-Convergence Issue

What does non-convergence mean?

The non-convergence of the short-circuit program may be a sign of an unstable system. However, for synchronous machine dominated systems, the phasor domain short-circuit analysis does not indicate if generator/system would be stable or not for a given fault (type, location, and duration). In other words, given a fault/contingency, the phasor domain short-circuit analysis always provides results for next steady-state condition even though the time-domain simulations show instability for the same. For IBR dominated system, it is unclear if non-convergence of short-circuit calculation always mean system instability.

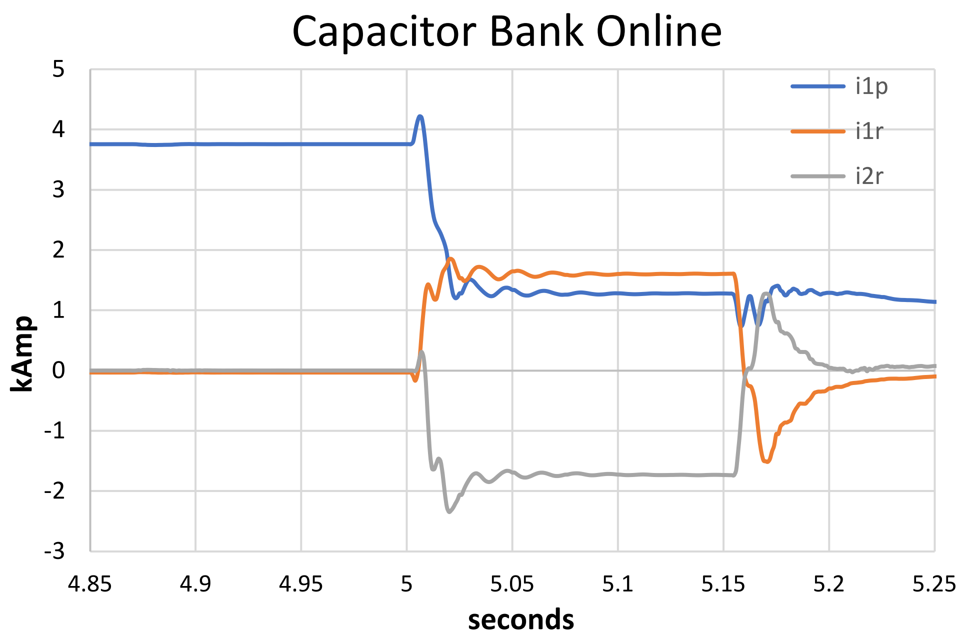
Impact of Pre-Fault Operating Condition

- 140MW PV plant with 4.4MVA, 660V Inverters & 26MVar Capacitor Bank
- Inverter Response to a LL fault on high side terminals of a main step-up transformer



Incremental pos. and neg. seq. reactive currents = 1600 A

Incremental load current = -2900 A



Incremental pos. and neg. seq. reactive currents = 1700 A

Incremental load current = -2430 A

Which pre-fault operating condition should be modeled?

Thevenin Impedance With & Without IBR

Thevenin Impedance 230kV Bus #1 (Slide #22)

Solar OFF

Source Impedance

Z1 = 0.23 + j 2.39%   100 MVA base

Fault Availability

Three-Phase = 10 470 A,   4171 MVA

Solar ON

Source Impedance

Z1 = 0.23 + j 2.39%   100 MVA base

Fault Availability

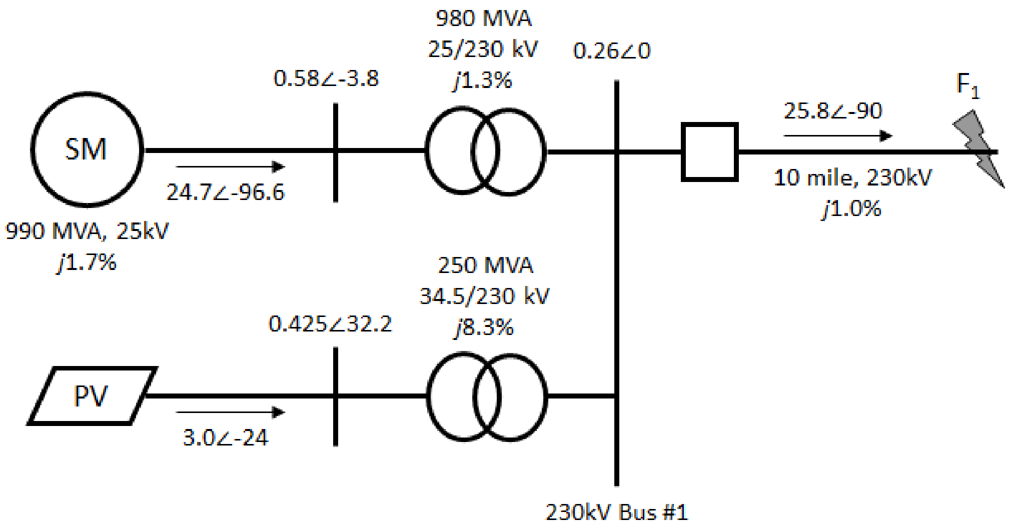
Three-Phase = 11 045 A,   4400 MVA

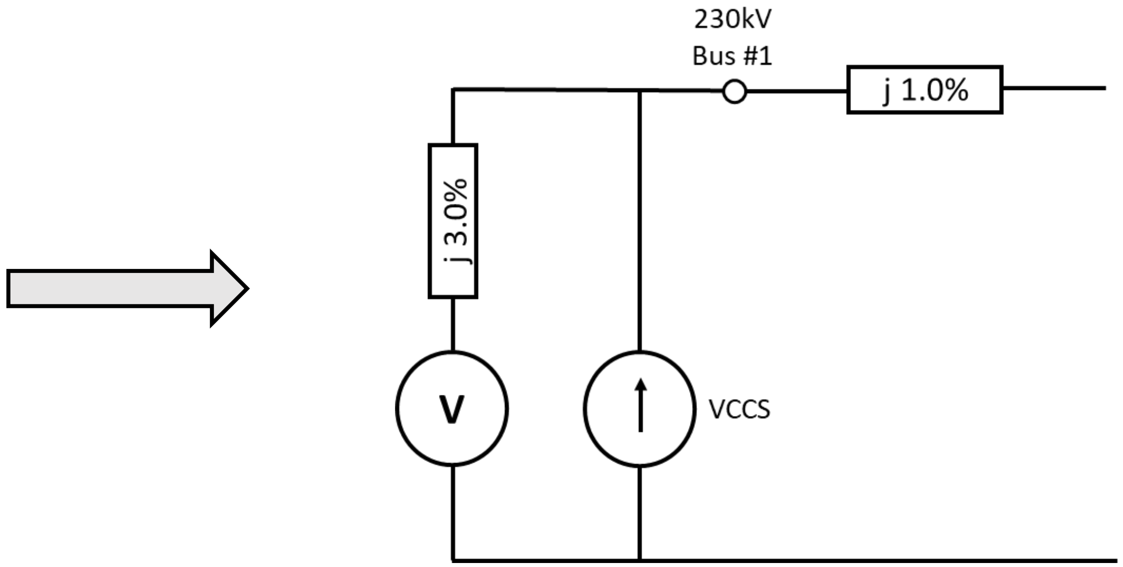
Impedance remains unchanged but fault current is different

What is an alternative for grid with IBRs?

Equivalent with IBRs

Need a methodology to develop VCCS of multiple IBRs in a system

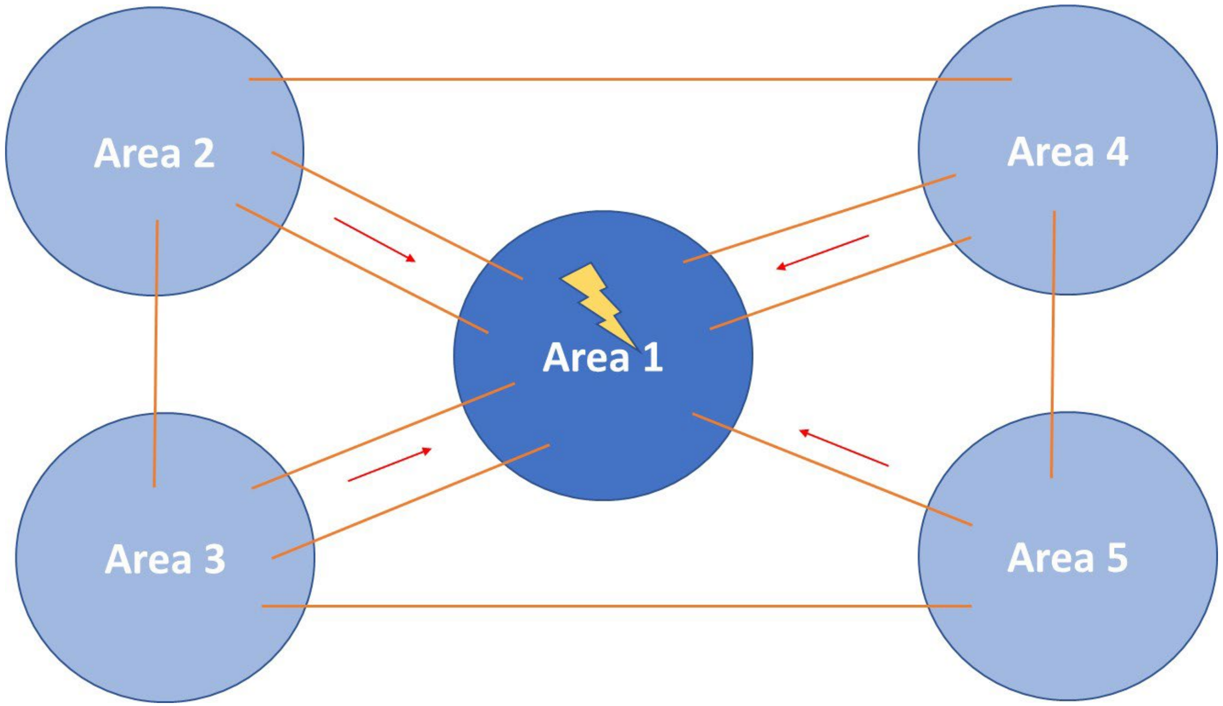




Model of Neighboring Systems

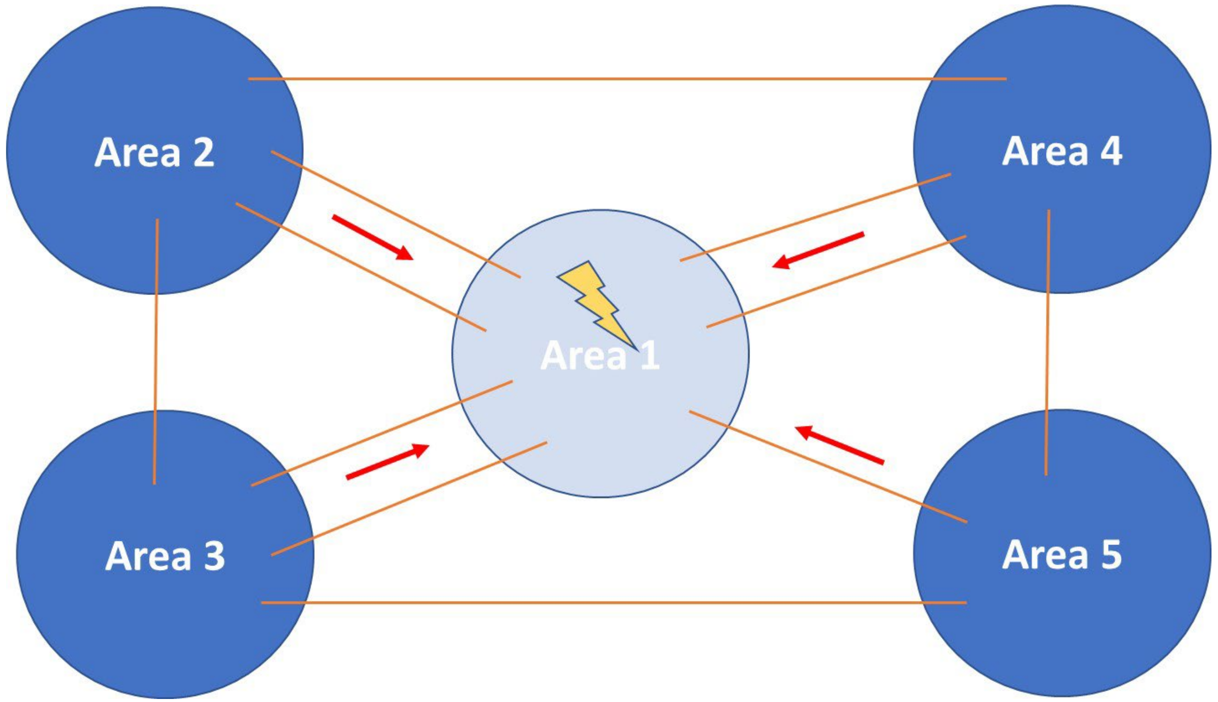
How to represent neighboring entity to study high IBR operating condition?

All areas represented with all resources online



Area 1: off-peak, high IBR operating condition

Areas 2 -5: all resources online



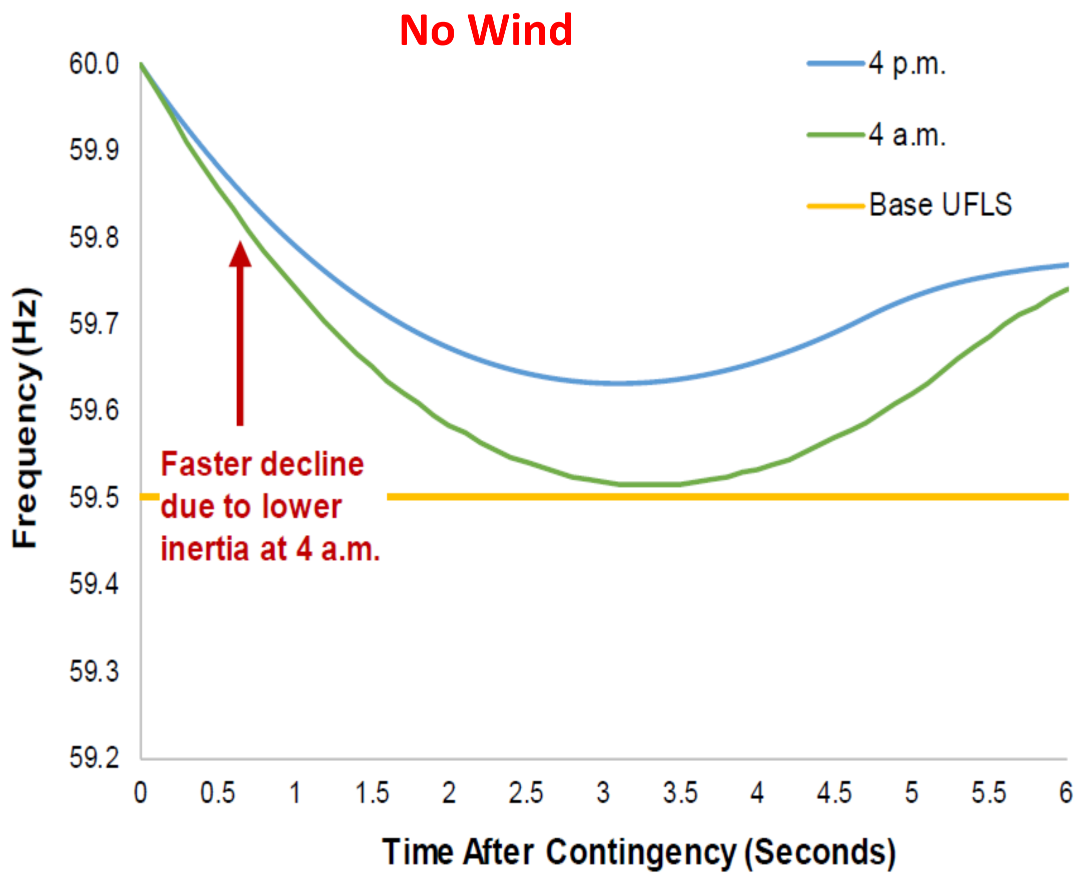
Neighboring systems become dominant, may lead to incorrect results

Impact of System Protection

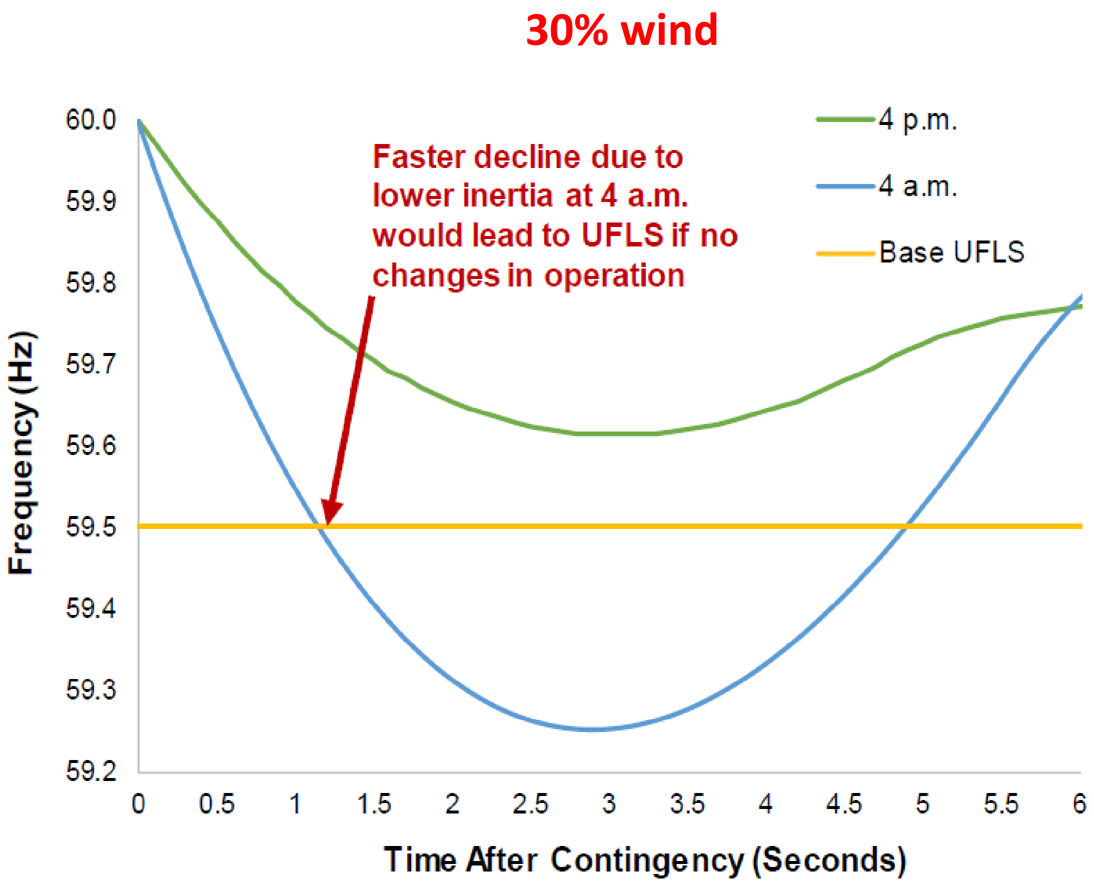
- Loss of inertia
  - Frequency deviation and ROCOF
  - Power swing (tripping & blocking)
  - Critical Clearing time
- Loss of fault duty / changing fault current characteristics
  - Impact of TL protection
  - Coordination of TL relays
- Protection of other grid components
  - Transformers, capacitor banks, reactors etc.
- Issues arising from control interactions
  - SSCI, SSR etc.

IEEE PSRC
C45 WG

Loss of Inertia – Freq Deviation, ROCOF & UFLS



b) Impact of a contingency at 4 a.m. and 4 p.m.

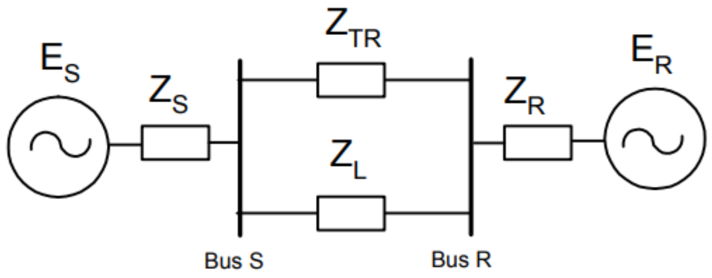


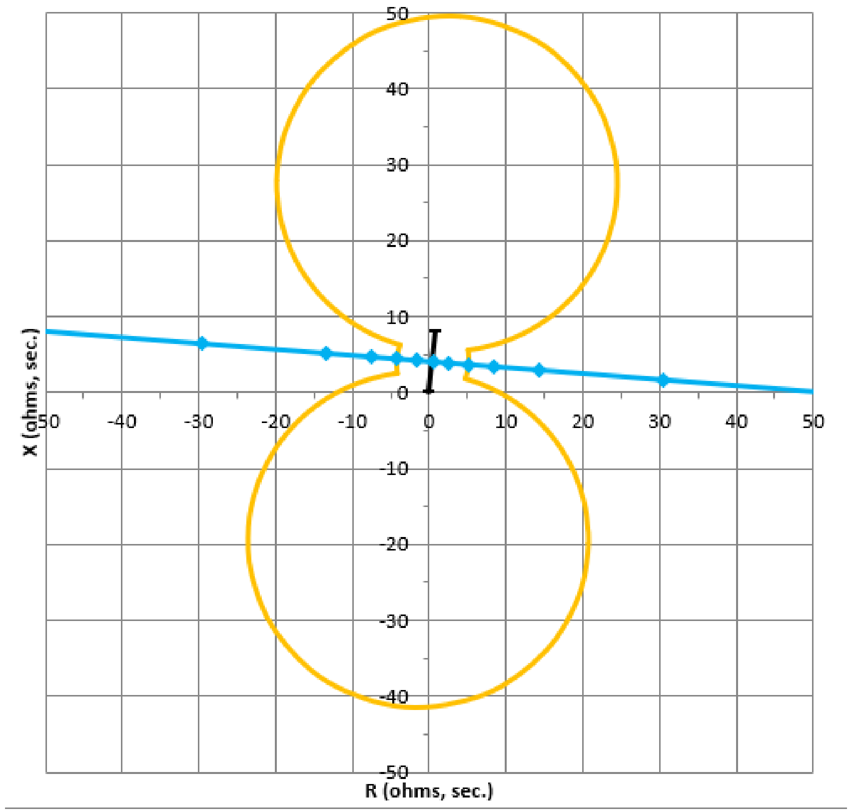
b) Frequency after a contingency at 4 a.m. or 4 p.m.

Reference: Inertia and the Power Grid: A Guide without the Spin, NREL Report.

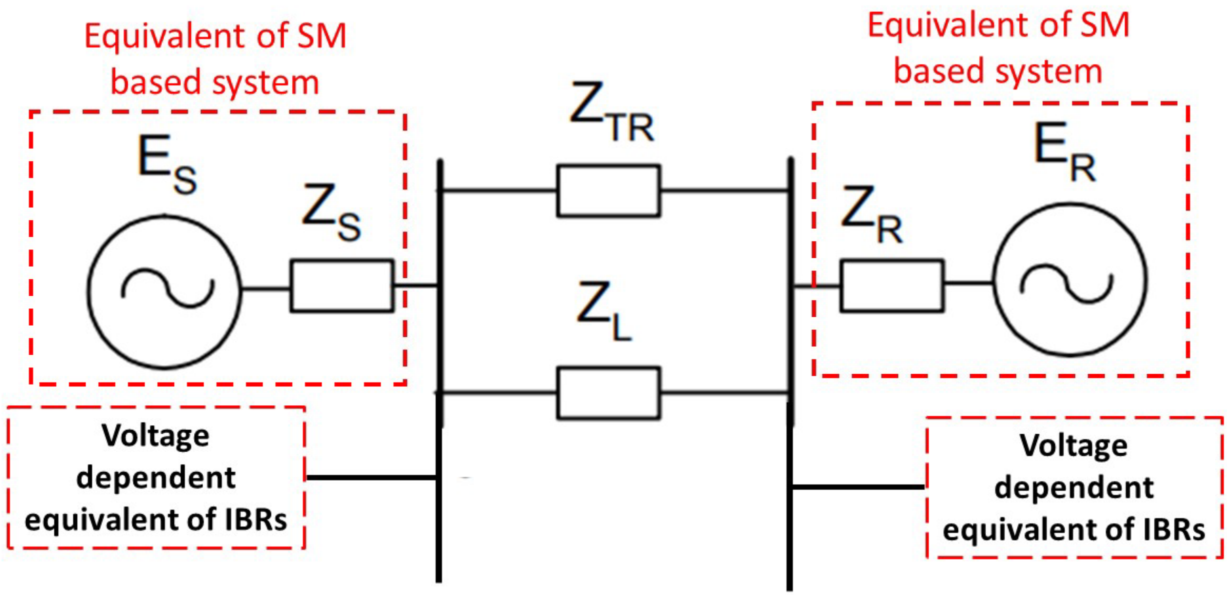
Power Swing Analysis

- **Ideal World** – Dynamic studies are used to analyze power swings and to set out of step tripping and power swing blocking elements.
- **Real World** – Two bus equivalent system is often used to for analysis.
- Even **NERC Standard PRC-026** allows for use of two bus equivalent system for setting PSB elements
  - Provides for boundary between stable and unstable regions.
- **Perhaps OK for Synch Mach dominated systems**





Analysis of Power Swings in Systems with IBRs



- The stable/unstable boundary based on two bus system **may not** be appropriate for systems with IBRs.
  - IBRs are **not** reflected in a Thevenin impedance behind a bus.
- **Not sure** if an equivalent as shown could be developed. If developed, **not sure** if it can be used for power swing analysis.

Likely that dynamic studies are necessary for analysis of Power Swings and out of step tripping and power swing blocking functions.

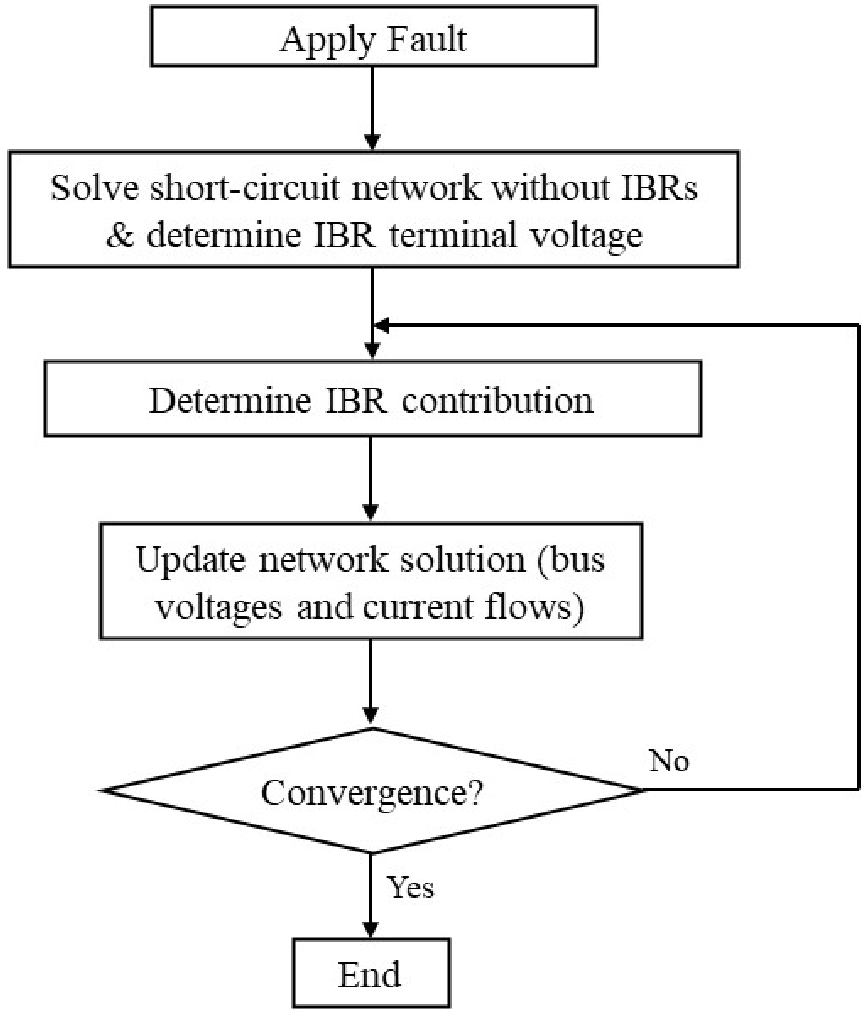
Summary

- IBR Fault response
  - Clear need for standardization
- Modeling: challenges remain
  - IBR SC model may continue to evolve
  - Need to re-evaluate assumptions made to develop traditional SC model
  - Need to re-evaluate development of network equivalents
- Need to understand and prepare for collective impact of:
  - Loss of fault duty & changing fault current characteristics
  - Loss of inertia as well as control interactions

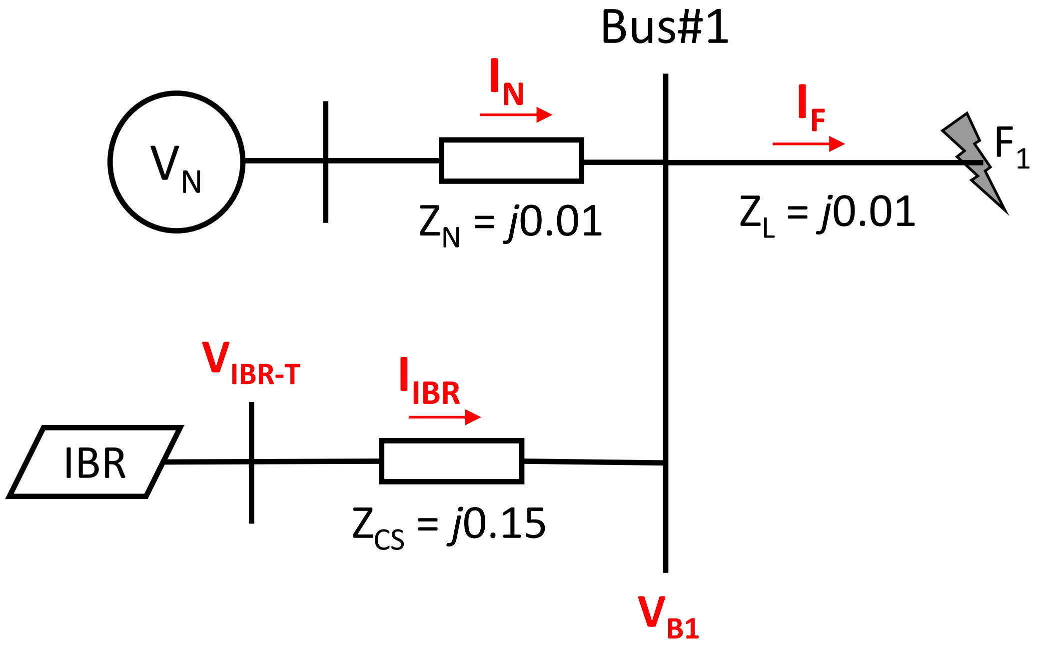
For Information Only

Calculating Current Contribution from IBRs

- The voltage controlled current source tabular model is considered output-based model.
- The IBR fault current contribution is non-linear and hence requires an iterative process to determine short-circuit current contribution for a given fault type and location.
- The actual iterative process implemented in various short-circuit programs could vary to improve computational efficiency and numerical robustness.



Calculating Current Contribution from IBRs



Iteration # 0

Network voltage V_N is a reference

$$I_F^{(0)} = I_N^{(0)} = \frac{V_N}{Z_N + Z_L}$$

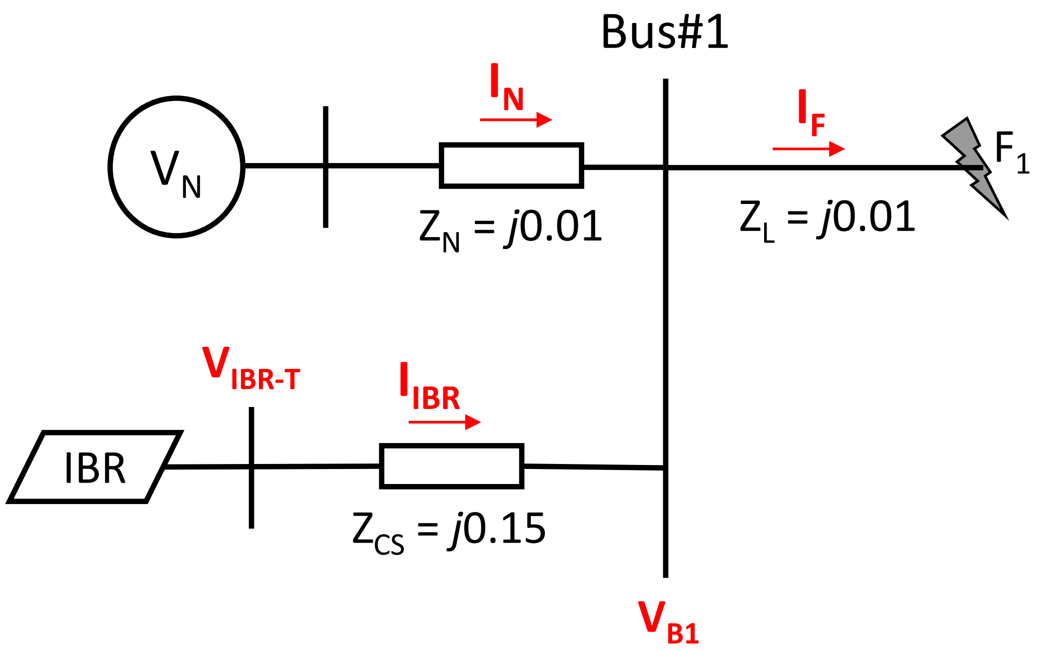
$$= \frac{1.0\angle 0}{j0.01 + j0.01} = -j50\ pu$$

$$I_{IBR}^{(0)} = 0$$

$$V_{B1}^{(0)} = \boxed{V_{IBR-T}^{(0)} = 0.5\angle 0}$$

In following iterations, this voltage is referred to as Bus #1 voltage due to current injection from the network, i.e., $V_{B1\text{-}N}$.

Calculating Current Contribution from IBRs



Iteration # 1

For an IBR terminal voltage of 0.5∠0 in iteration #0, current injection from an IBR (I_{IBR}) would be 1.2∠-45.

This current is injected into Bus#1

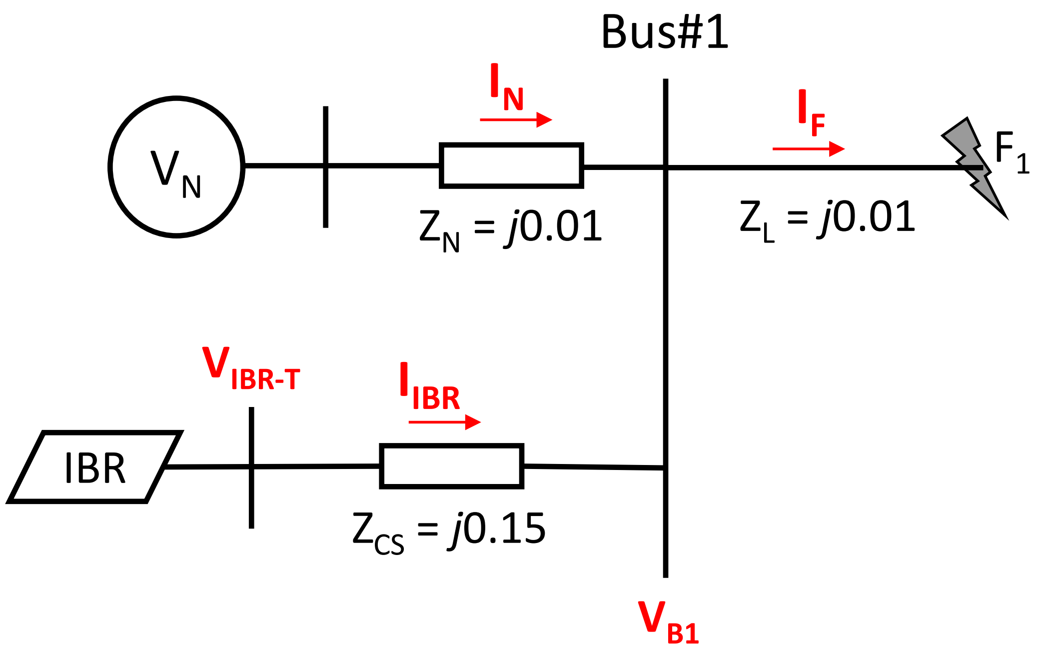
$$V_{B1,IBR}^{(1)} = I_{IBR}^{(1)} \times Z_{EQ}$$

$$= 1.2\angle -45 \times 0.005\angle 90 = 0.006\angle 45$$

Where,

$$Z_{EQ} = Z_N \,||\, Z_L = j0.01 \,||\, j\,0.01$$

Calculating Current Contribution from IBRs



Iteration # 1 (cont.)

Superimpose Bus#1 voltage due to IBR current injection on to Bus#1 voltage from iteration #0 (due to current from network).

$$V_{B1}^{(1)} = V_{B1,N}^{(0)} + V_{B1,IBR}^{(1)}$$

$$= 0.5\angle 0 + 0.006\angle 45 = 0.5042\angle 0.48$$

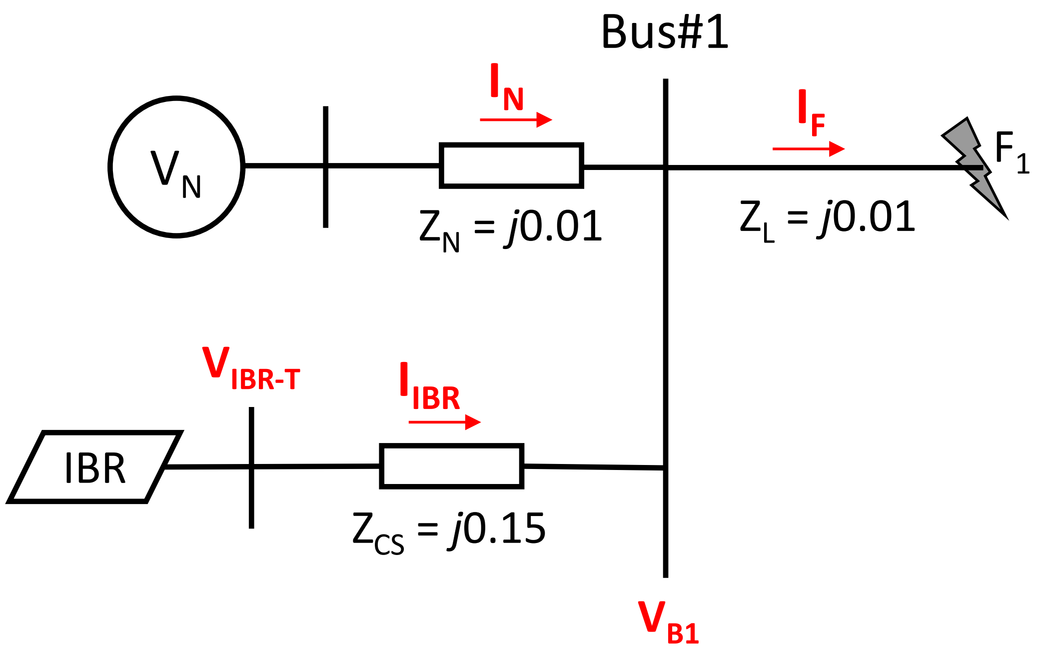
The IBR terminal voltage is then:

$$V_{IBR-T}^{(1)} = V_{B1}^{(1)} + I_{IBR}^{(1)} \times Z_{IBR,CS}$$

$$= 0.5042\angle 0.48 + 1.2\angle -45 \times 0.15\angle 90$$

$$= \boxed{0.645\angle 11.76}$$

Calculating Current Contribution from IBRs



Iteration # 2

For an IBR terminal voltage of 0.645∠11.76 in iteration #1, current injection from an IBR would be 1.2∠-18.24.

This current is injected into Bus#1

$$V_{B1,IBR}^{(2)} = I_{IBR}^{(2)} \times Z_{EQ}$$

$$= 1.2\angle -18.24 \times 0.005\angle 90 = 0.006\angle 71.76$$

$$V_{B1}^{(2)} = V_{B1,N}^{(0)} + V_{B1,IBR}^{(2)}$$

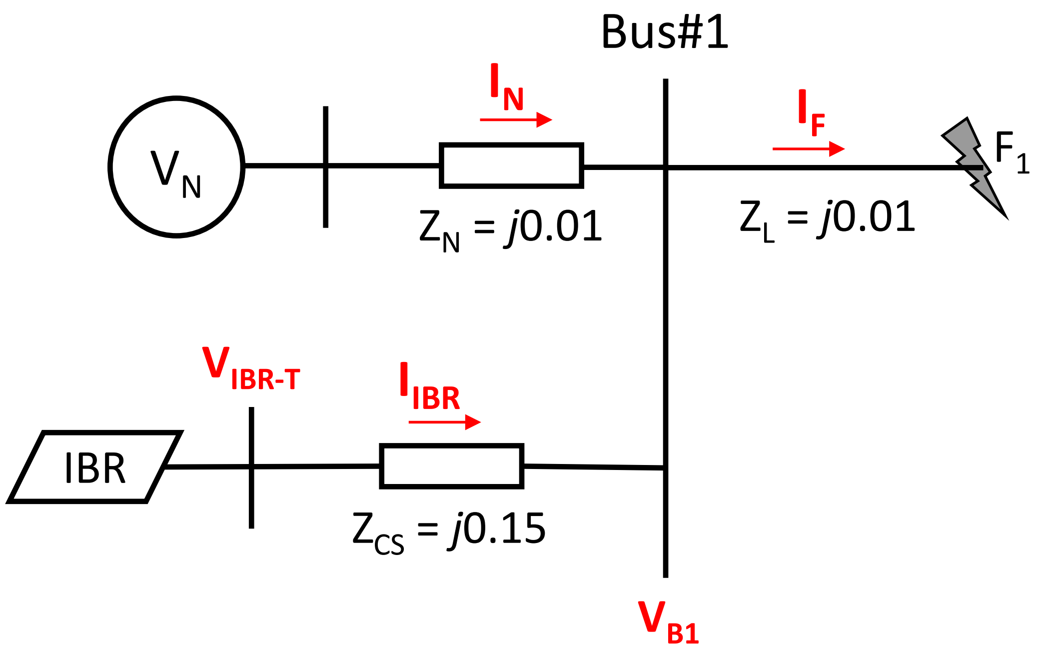
$$= 0.5\angle 0 + 0.006\angle 71.76 = 0.5019\angle 0.65$$

$$V_{IBR-T}^{(2)} = V_{B1}^{(2)} + I_{IBR}^{(2)} \times Z_{IBR,CS}$$

$$= 0.5019\angle 0.65 + 1.2\angle -18.24 \times 0.15\angle 90$$

$$= \boxed{0.585\angle 17.55}$$

Calculating Current Contribution from IBRs



Iteration # 3

For an IBR terminal voltage of 0.585∠17.55 in iteration #1, current injection from an IBR would be 1.2∠-18.45.

Follow steps in previous iterations:

$$V_{B1}^{(3)} = 0.502\ \angle 0.65$$

$$V_{IBR-T}^{(3)} = \boxed{0.59\angle 17.51}$$

Very small change compared to previous iteration, process is converged

$$I_F^{(3)} = \frac{V_{B1}^{(3)}}{Z_L} = 50.2\angle - 89.35$$

$$I_N^{(3)} = \frac{V_N - V_{B1}^{(3)}}{Z_N} = 50\angle - 90.66$$

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Lessons Learned Process

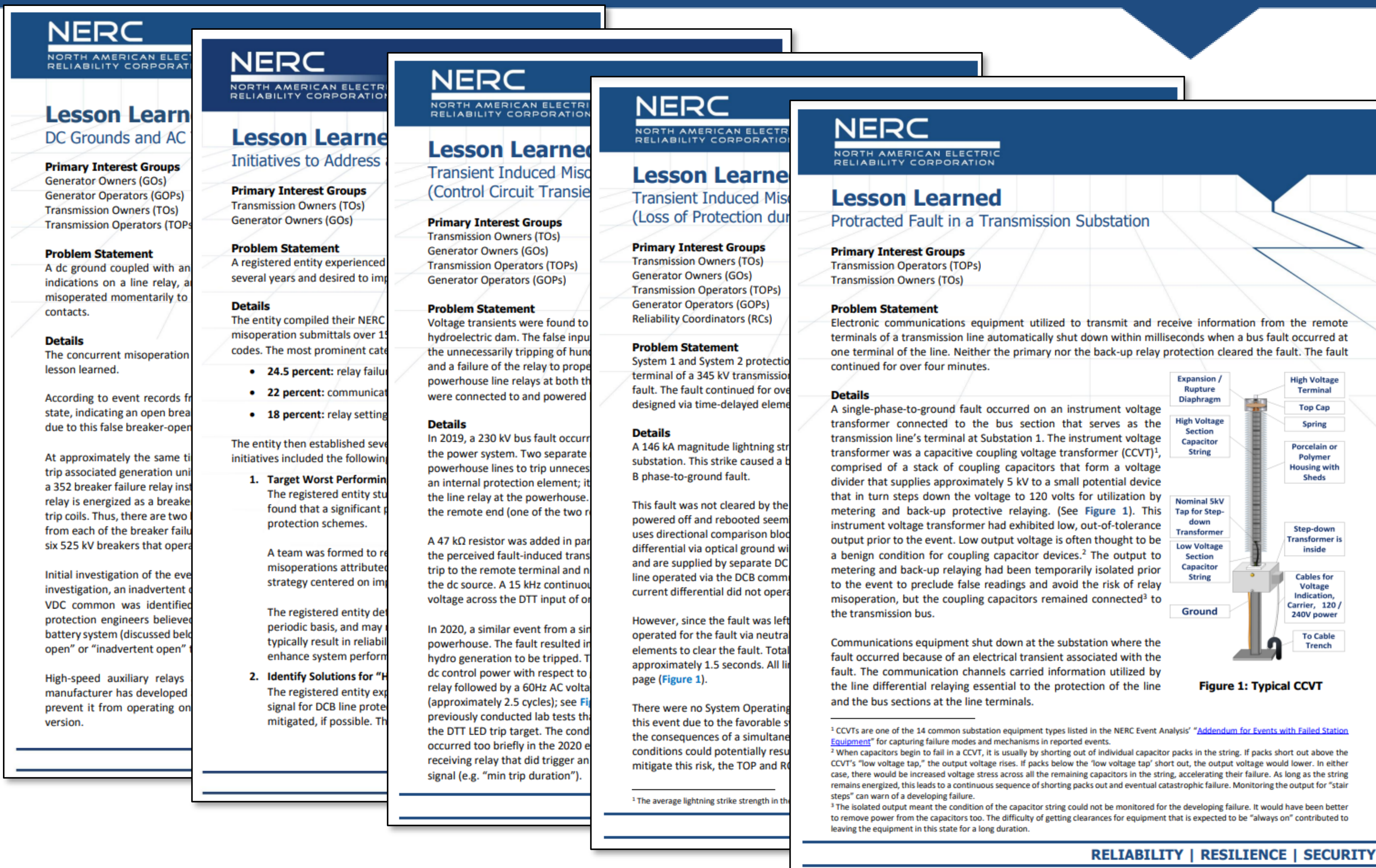
Rick Hackman, NERC Event Analysis

BES Protection System Misoperation Reduction Workshop

October 26, 2023

RELIABILITY | RESILIENCE | SECURITY

2010 – Oct 2023: 200 Lessons Learned



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Lesson Learned

Protracted Fault in a Transmission Substation

Primary Interest Groups
Transmission Operators (TOPs)
Transmission Owners (TOs)

Problem Statement
Electronic communications equipment utilized to transmit and receive information from the remote terminals of a transmission line automatically shut down within milliseconds when a bus fault occurred at one terminal of the line. Neither the primary nor the back-up relay protection cleared the fault. The fault continued for over four minutes.

Details
A single-phase-to-ground fault occurred on an instrument voltage transformer connected to the bus section that serves as the transmission line's terminal at Substation 1. The instrument voltage transformer was a capacitive coupling voltage transformer (CCVT)[1], comprised of a stack of coupling capacitors that form a voltage divider that supplies approximately 5 kV to a small potential device that in turn steps down the voltage to 120 volts for utilization by metering and back-up protective relaying. (See Figure 1). This instrument voltage transformer had exhibited low, out-of-tolerance output prior to the event. Low output voltage is often thought to be a benign condition for coupling capacitor devices.[2] The output to metering and back-up relaying had been temporarily isolated prior to the event to preclude false readings and avoid the risk of relay misoperation, but the coupling capacitors remained connected[3] to the transmission bus.

Figure 1: Typical CCVT

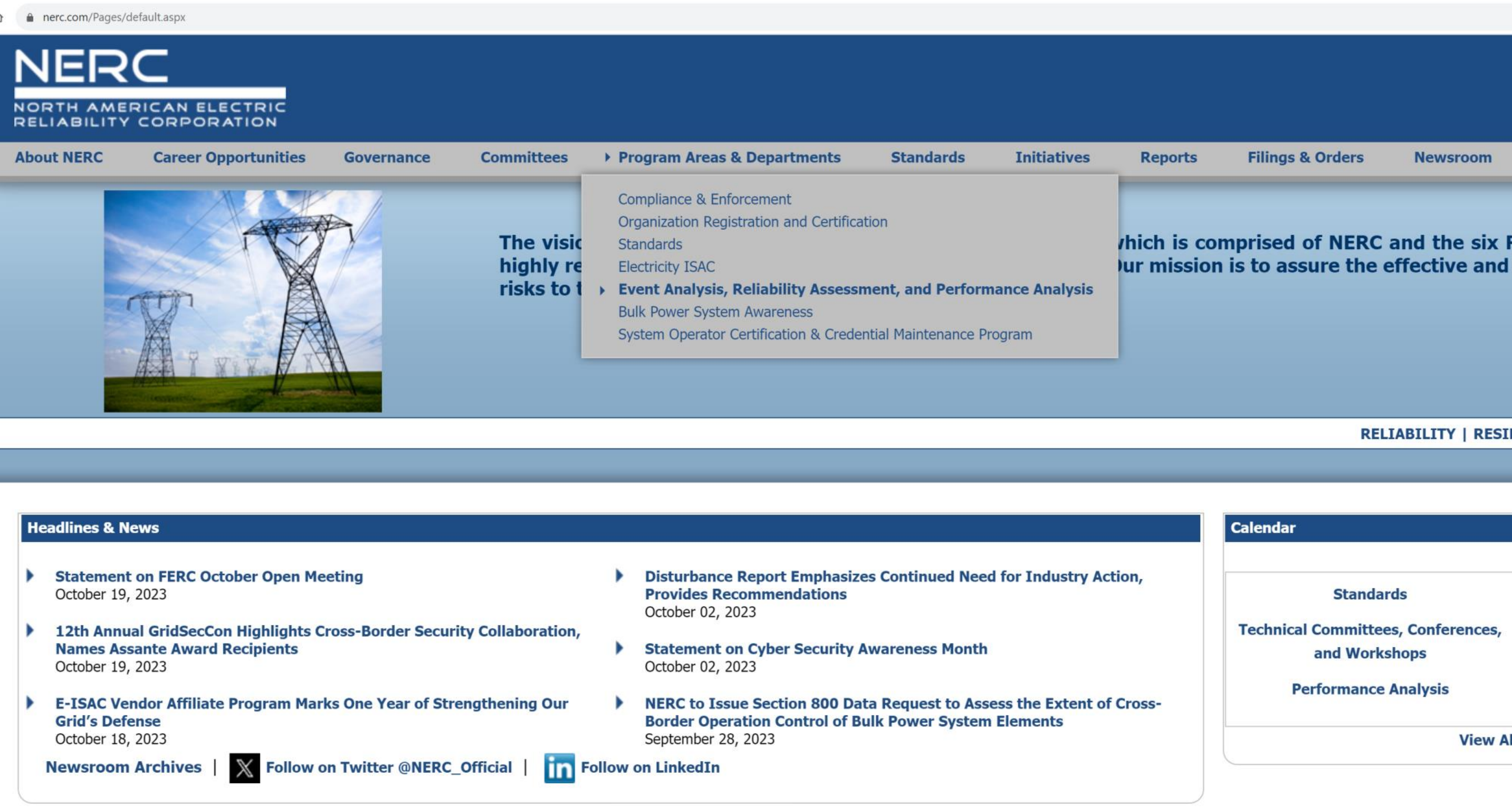
Communications equipment shut down at the substation where the fault occurred because of an electrical transient associated with the fault. The communication channels carried information utilized by the line differential relaying essential to the protection of the line and the bus sections at the line terminals.

[1] CCVTs are one of the 14 common substation equipment types listed in the NERC Event Analysis' "Addendum for Events with Failed Station Equipment" for capturing failure modes and mechanisms in reported events.
[2] When capacitors begin to fail in a CCVT, it is usually by shorting out of individual capacitor packs in the string. If packs short out above the CCVT's "low voltage tap," the output voltage rises. If packs below the 'low voltage tap' short out, the output voltage would lower. In either case, there would be increased voltage stress across all the remaining capacitors in the string, accelerating their failure. As long as the string remains energized, this leads to a continuous sequence of shorting packs out and eventual catastrophic failure. Monitoring the output for "stair steps" can warn of a developing failure.
[3] The isolated output meant the condition of the capacitor string could not be monitored for the developing failure. It would have been better to remove power from the capacitors too. The difficulty of getting clearances for equipment that is expected to be "always on" contributed to leaving the equipment in this state for a long duration.

RELIABILITY | RESILIENCE | SECURITY

35 are Relaying and Protection

Finding Lessons Learned



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Finding Lessons Learned

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  - EA Program
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- **Modeling Assessments**
- **Reliability Assessments**
- **Performance Analysis**
- **Section 1600 Data Requests**
- **Reliability Indicators**
- **Demand Response Availability Data System (DADS)**
- **Generating Availability Data System (GADS)**

Home > Program Areas & Departments > Event Analysis, Reliability Assessment, and Performance Analysis

Event Analysis, Reliability Assessment, and Performance Analysis

NERC's Event Analysis, Reliability Assessment, and Performance Analysis group identifies areas of concern regarding assessment and trend efforts and makes recommendations for their remedy. NERC cannot order construction of additional generation or transmission or adopt enforceable standards that have that effect, as that authority is explicitly withheld. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets.

NERC's assessments provide a high-level assessment of resource adequacy, an overview of projected electricity demand growth and generation and transmission additions. NERC also identifies long-term emerging issues and trends that do not necessarily pose an immediate threat to reliability but will influence future bulk power system planning, development and system analysis. Trends identified by NERC can also provide the basis for advisories, recommendations and essential action notifications. For more on these, visit the **Event Analysis** page.

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Lessons Learned

Disclaimer for Lessons Learned: These documents are designed to convey lessons learned from NERC's various activities. They are not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of these lessons learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

For a brief summary of the lessons learned that have been posted, please refer to the Lessons Learned Quick Reference Guide.

Lessons Learned

Type	LL#	Title	Category	Date
Lessons Learned 2023 (4)				
	LL20230901	Abnormal Area Control Error due to a Model Translation Error	Communications	9/28/2023
	LL20230801	Loss of Monitoring due to a "Half Failed" High Availability Switch Pair	Communications	8/10/2023
	LL20230701	Weathering the Storm: System Hardening	Facilities Design, Commission, and Maintenance, Planning and Modeling, Generation Facilities, Transmission Facilities, Bulk-Power System Operations, Emergency Response	7/5/2023
	LL20230401	Combustion Turbine Anti-Icing Control Strategy	Generation Facilities	4/19/2023
Lessons Learned 2022 (13)				
Lessons Learned 2021 (12)				
Lessons Learned 2020 (11)				
Lessons Learned 2019 (11)				
Lessons Learned 2018 (15)				

Or just click here:

Lessons Learned webpage *https://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx*

Sections of a Lessons Learned

Lesson Learned

Title — *Title*

Primary Interest Groups — *Who might need to know – GO, GOP, RC, BA, TO TOP, etc.*

Problem Statement — *Why it is important*

Details — *What happened*

Corrective Actions — *What the entity did about it*

Lesson Learned — *What was learned, and what else could be done by industry to improve reliability*

Click here for: Lesson Learned Comment Form — *Survey Link*

For more Information please contact:

NERC – Lessons Learned (via email)

Lesson Learned #:

Date Published:

Category: — *Category – use as filter on webpage*

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC Boilerplate

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Quick Reference to Lessons Learned

Lessons Learned

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Lessons Learned

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Lessons Learned Quick Reference Guide

Lessons learned are a resource enabling industry to identify problems, find what works, document the process, and share with industry. The creation of a lessons learned document is a collaborative effort between NERC, the Regional Entities, and the registered entities. A successful lessons learned document clearly identifies the lessons, contains sufficient information to understand the issues, visibly identifies the difference between the actual outcome and the desired outcome, and includes an accurate sequence of events, when it provides clarity. This document provides a brief summary of the lessons learned published since 2015 and will be regularly updated as more are published. All lessons learned published since 2010 are currently available on the Event Analysis web page.

2022 Lessons Learned				
Date	**LL #**	**Category**	**Title**	**Summary**
7/20/2022	LL20220702	Bulk-Power System Operations, Transmission Facilities	Tower Climber Incident	On an August day, a climber was reported to be on the top of a tower shared by three circuits (a 500 kV circuit, a 230 kV circuit, and a 115 kV circuit). As a result, the three circuits were required to be manually removed from service to protect the safety of the climber while taking into account system limitations that may be caused by their removal from service. They were later returned to service after the climber was reported to be safely down from the tower. **This LL is of primary interest to Transmission Owners, Transmission Operators, Reliability Coordinators, Balancing Authorities**
7/20/2022	LL20220701	Bulk-Power System Operations, Transmission	Forecasted High Winds	High-speed wind days can pose challenges to transmission, distribution, and wind-generation availability.[1] This lesson learned focuses on the implementation of coping strategies by a specific utility developed from prior experience; it is largely a success story.

[1] This Lesson Learned is about near-term (1–5 day forecast) damaging wind warnings and actions to take. There is another lesson learned under development on system hardening that is about longer term work to improve the system's resistance to damage.

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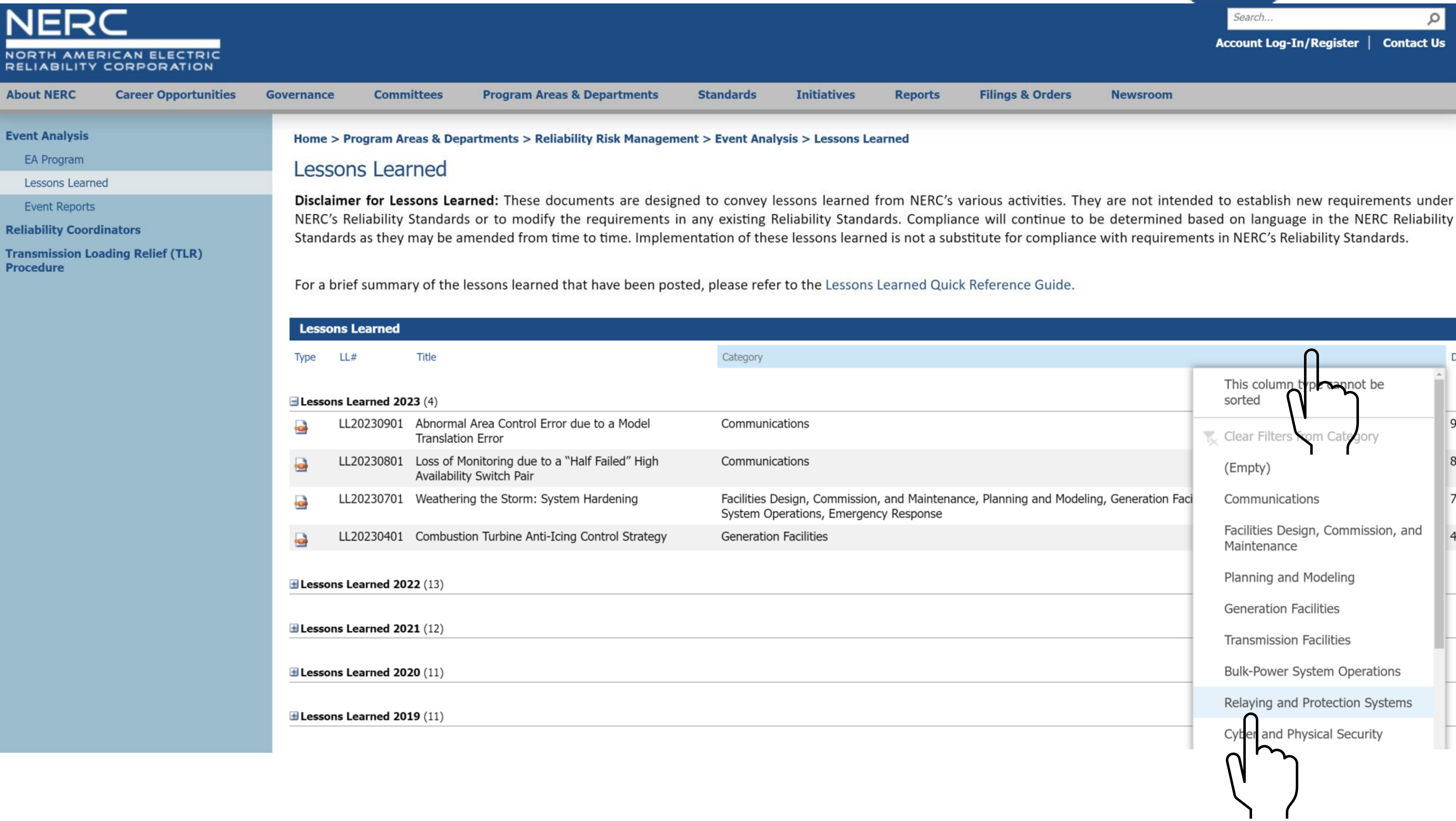
2022 Lessons Learned				
Date	**LL #**	**Category**	**Title**	**Summary**
		Facilities, Generation Facilities		**This LL is of primary interest to Transmission Owners, Transmission Operators, Reliability Coordinators, Balancing Authorities, Generator Owners, Generator Operators**
4/13/2022	LL20220406	Communications	Intermittent Network Connection Causes EMS Disruption	Intermittent disruptions of the primary network path connectivity at the backup control center (BCC) resulted in loss of access to the energy management system (EMS) and voice over internet protocol (VoIP) for 25 minutes. **This LL is of primary interest to Transmission Owners, Transmission Operators, Reliability Coordinators, Balancing Authorities**
4/13/2022	LL20220405	Transmission Facilities	Unintended Consequences of Altering Protection System Wiring to Accommodate Failing Equipment	Following standard entity practice on discovering a failing capacitor coupled voltage transformer (CCVT), the voltage sensing for the equipment protecting the CCVT line position was jumpered to a CCVT on a nearby line position, but the failing CCVT was left connected to the Bulk Electric System. The applied jumper provided a false indication of good sync voltage across the open breaker, causing the sync-check relays in the reclosing system to close the breakers into a permanent fault multiple times in rapid succession. This in turn caused relay operations at three non-faulted line terminals that were determined to be misoperations. **This LL is of primary interest to Transmission Owners, Transmission Operators, Substation Maintenance Groups, Substation Design Groups**
4/13/2022	LL20220404	Transmission Facilities	Substation Flooding Events Highlight Potential Design Deficiencies	Heavy rainfall of 5.7 inches of rain and hail over a 2.5 hour period led to the flooding of a basement relay room in the control building at a 230 kV transformer station. This led to unexpected equipment and protection operations during the event that resulted in two 230 kV circuits and six generating units (representing a total of 495

Category Filter for Lessons Learned



Category Filter for Lessons Learned

Lessons Learned

Type	LL#	Title	Category	Date
Lessons Learned 2022 (1)				
	LL20221101	Preventing Unwanted Operations during Relay Diagnostic Restarts	Relaying and Protection Systems	11/16/2022
Lessons Learned 2021 (3)				
	LL20210802	Multiple Faults in Rapid Succession Contribute to Relay Misoperations Leading to Loss of Load	Relaying and Protection Systems	8/6/2021
	LL20210204	Transient Induced Misoperation: Approach II (Loss of Protection during Severe Lightning Event)	Relaying and Protection Systems	2/25/2021
	LL20210203	Transient Induced Misoperation: Approach I (Control Circuit Transient Misoperation of Microprocessor Relay)	Relaying and Protection Systems	2/25/2021
Lessons Learned 2020 (5)				
	LL20200703	Lockout Relay Component Failure Causes Misoperation and Reportable Event	Relaying and Protection Systems	7/30/2020
	LL20200702	Verification of AC Quantities during Protection System Design and Commissioning	Relaying and Protection Systems	7/30/2020
	LL20200701	Mixing Relay Technologies in DCB Schemes	Relaying and Protection Systems	7/10/2020
	LL20200402	Protracted Fault in a Transmission Substation	Transmission Facilities, Relaying and Protection Systems	4/14/2020
	LL20200401	Misoperation of 87N Transformer Ground Differential Relays Causing Loss of Load	Transmission Facilities, Relaying and Protection Systems	4/14/2020
Lessons Learned 2018 (1)				
	LL20181201	Initiatives to Address and Reduce Misoperations	Relaying and Protection Systems	12/17/2018
Lessons Learned 2016 (3)				
	LL20161001	DC Grounds and AC Tied to DC Cause Multiple Relay Misoperations	Relaying and Protection Systems	10/4/2016
	LL20160801	Tie Line Relay Coordination	Relaying and Protection Systems	8/30/2016
	LL20160601	Transmission Relaying - Relay Setting Issue	Relaying and Protection Systems	6/7/2016
Lessons Learned 2015 (4)				
	LL20150902	Relay Design and Testing Practices to Prevent Scheme Failures	Relaying and Protection Systems	9/15/2015
	LL20150401	Detailed Installation and Commissioning Testing to Identify Wiring or Design Errors	Relaying and Protection Systems	4/21/2015
	LL20150202	Consideration of the Effects of Mutual Coupling when Setting Ground Instantaneous Overcurrent Elements	Relaying and Protection Systems	2/10/2015
	LL20150201	Digital Inputs to Protection Systems May Need to be Desensitized to Prevent False Tripping Due to Transient Signals	Relaying and Protection Systems	2/10/2015
Lessons Learned 2014 (7)				
	LL20141202	Bus Differential Power Supply Failure	Relaying and Protection Systems	12/9/2014
	LL20140903	System Protection Review Prior to Disabling Protective Relays	Relaying and Protection Systems	9/16/2014
	LL20140602	Generation Relaying - Overexcitation	Relaying and Protection Systems	6/19/2014

Typical Steps for a Lessons Learned

Draft *(from Entities, ERO, other - ?)*

Assemble Review Team *(Volunteers from EAS, various WGs, Entities, Industry, etc.)*

Improve Draft or Reject

Entity / Source Review / Concurrence

NERC Tech Writer Polishing

Review Team Check TW Changes

EAS Concurrence

NERC Management Approval to Publish

Publish to Website *(Gets LL number, publicly visible)*

Lessons Learned

- Lessons Learned help the entire industry learn from others' experiences and improves overall reliability.
- We are always wanting more Lessons Learned.
- Not all LLs have to be from adverse events – tell us how you were successful at something other entities could benefit from.
- We also need feedback on the LLs already published – how can we improve, what needs correcting, etc.

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And now for something completely different

Failure Modes and Mechanisms

4 Minute Video on Failure Modes & Mechanisms
https://vimeopro.com/nerclearning/cause-coding/video/208745179

The 2022 FMM Webinar

Click for: Presentation
or Streaming Webinar

Failure Modes & Mechanisms
Task Force webpage

*The approved FMM diagrams are in the **ERO EA data sharing site**.*

Region EA personnel can download pdfs from there to share in a controlled fashion with entity personnel.

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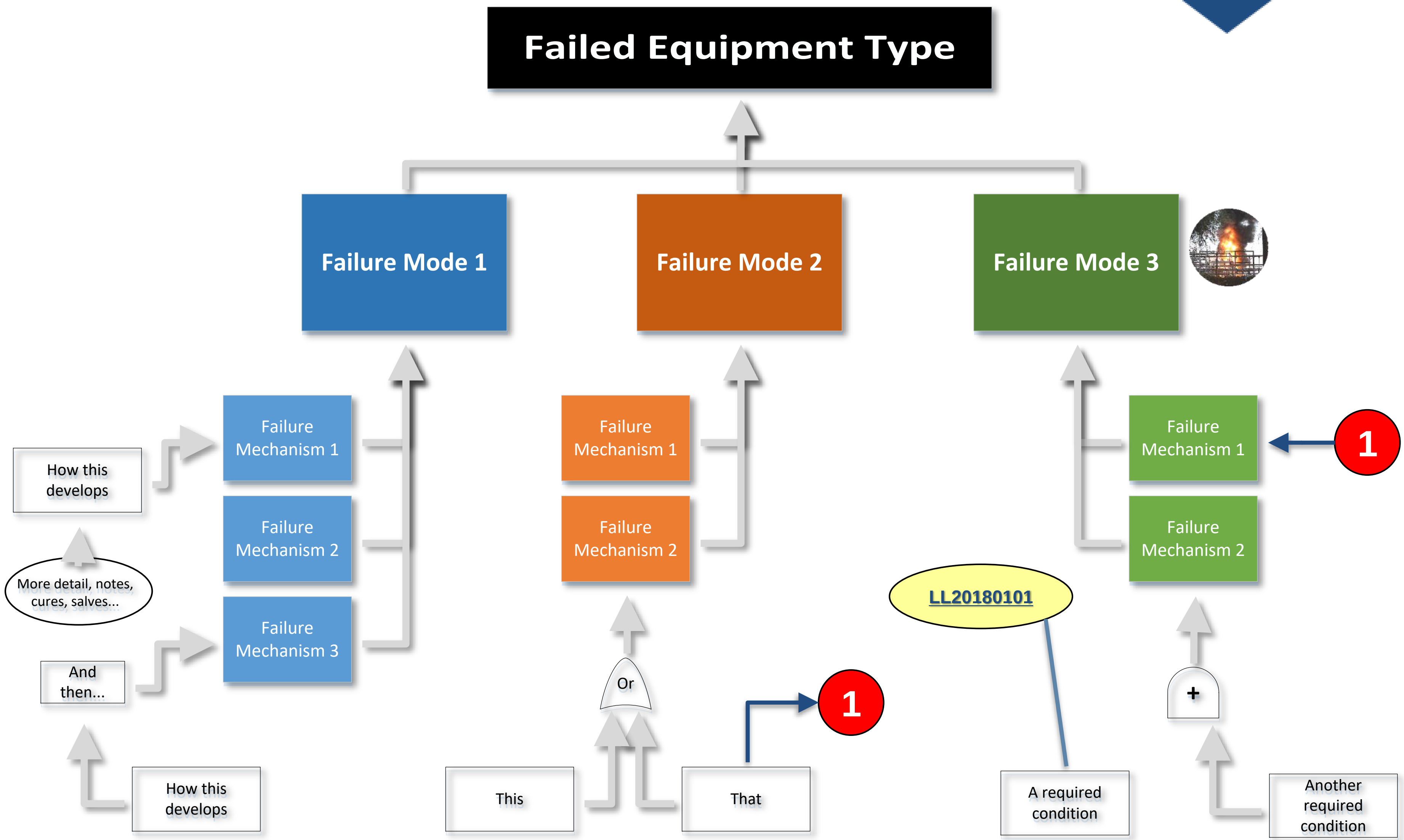
Failure Modes and Mechanisms

- Failure Modes are what gets your attention
- Failure Mechanisms are how the equipment gets going on the path to a failure
  - Equipment Failures have logical cause-and-effect relationships behind them.
  - Physical Evidence Examination and Root Cause Analysis can reveal what Failure Mechanisms were involved.
  - Aging is not a ‘cause.’ It is just a catch-all term for slow moving Failure Mechanisms.
  - Failure Mechanisms are detectable. Many can be stopped, or at least slowed down so they can be corrected before causing a failure.

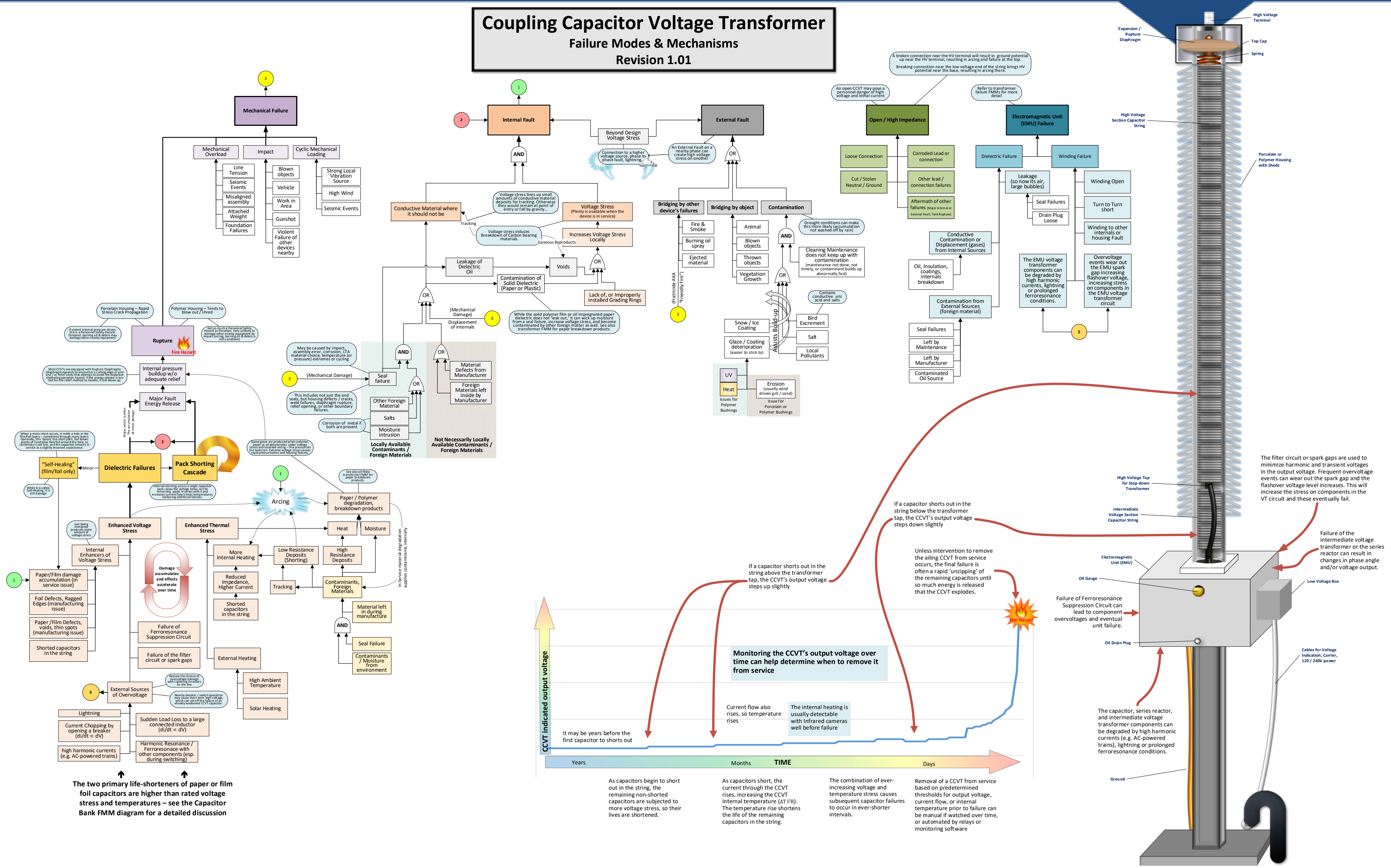
Generic Failure Modes and Mechanisms Layout



Failure Modes and Mechanisms Diagrams

Substation Equipment	Status
Generic Bushing	Release Rev 1
Oil-Filled Power Transformer	Release Rev 1.01
Wire Wound Electromagnetic Potential Transformer	Draft – nearing complete
Coupling Capacitor Voltage Transformer	Release Rev 1.01
Optical Voltage Transformer	Release Rev 1.0
Wire Wound Electromagnetic Current Transformer	Release Rev 1.0
Optical Current Transformer	Release Rev 1.0
SF6 Breaker	Release Rev 1.01
Air Blast Breaker	Release Rev 1.0
Oil Breaker	Release Rev 1.0
Switch	Release Rev 1.01
Oil-Filled Reactor (Inductor)	Release Rev 1.01
Capacitor Bank	Release Rev 1.01
Surge Arrester	Release Rev 1.01
Electromagnetic Relay	Draft
Static Relays	Draft
Microprocessor Relay	Release Rev 1.01
Large Inverters	Early Draft
New: Substation Batteries (Lead Acid)	Early Draft
New: Substation Battery Chargers	
New: Uninterruptible Power Supplies	

Failure Modes and Mechanisms Diagram



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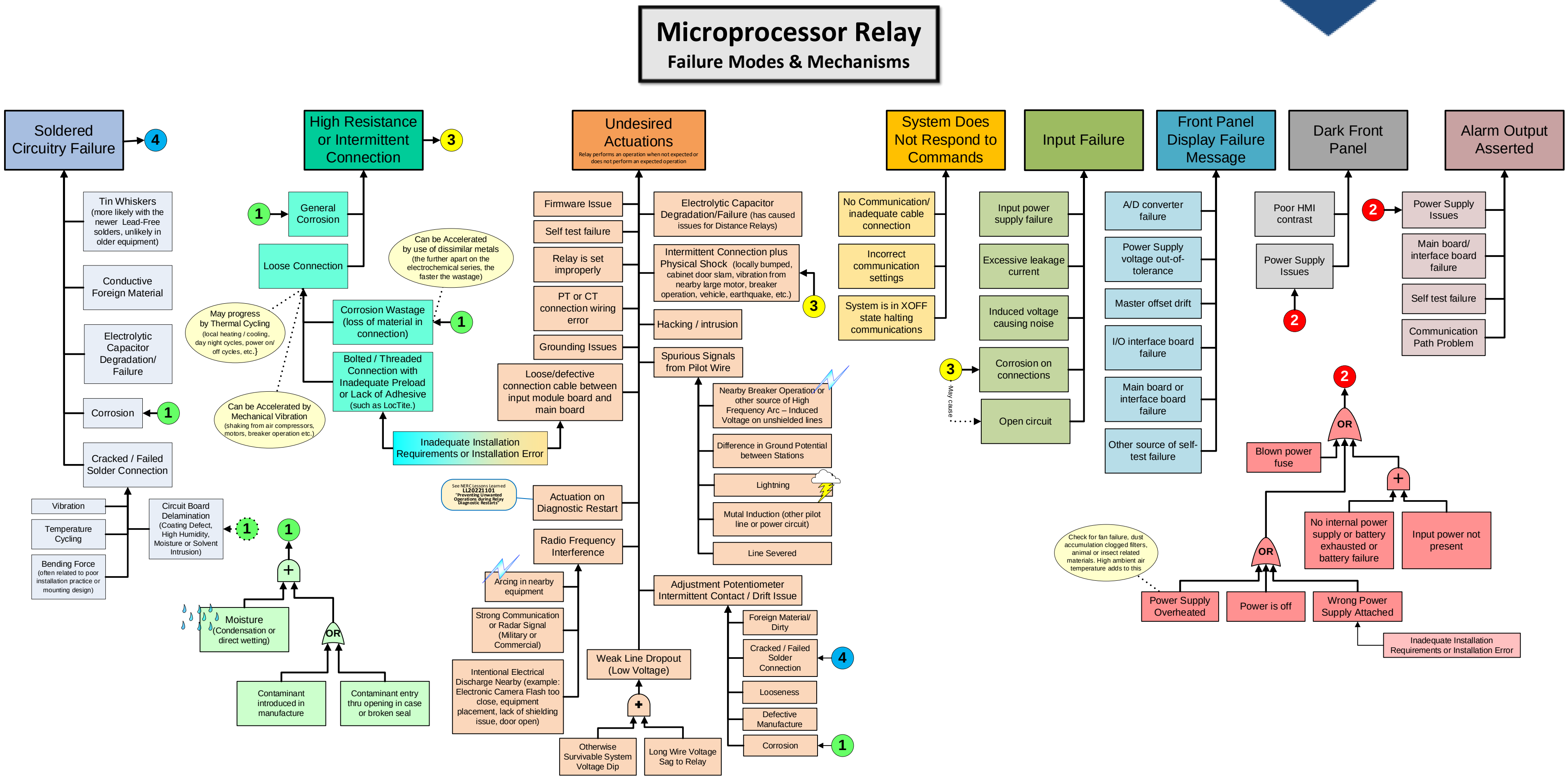
Failure Modes and Mechanisms Diagram



The FMM Task Force is looking for more volunteers!

Questions and Answers

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Sr. Event Analysis Advisor
404-576-5960 cell
Email Richard.Hackman@nerc.net

NERC Lessons Learned webpage

Failure Modes and Mechanisms Task Force

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Protection Related Standards Projects

Rich Bauer
Misoperation Workshop - Atlanta
October 26, 2023

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PRC-005-7

Standards Project 2019-04

- Draft 1 PRC-005-7 - Posted in July
- Existing definition
  - Protection System –
    - Protective relays which respond to electrical quantities,
- Proposed definition
  - Protection System – One or more of the following components:
    - Protective relays and components of control systems which respond to secondary measured electrical quantities and provide protective functions;

- PRC-005-7 proposed maintenance table changes

PRC-005-7 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance

Table 1-1 Component Type - Protective relays and Components of control systems which respond to measured electrical quantities and provide protective functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[3]**	**Maintenance Activities**
Any unmonitored protective relay/Component not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays/Components: • Verify that protective function settings are as specified For non-microprocessor relays/Components: • Test and, if necessary calibrate For microprocessor relays/Components: • Verify operation of the relay/Component inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System.
Monitored microprocessor protective relay/Component with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 Calendar Years	Verify: • Protective function settings are as specified. • Operation of the relay/Component inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values that are essential to proper functioning of the Protection System.

PRC-005-7

- Draft 1 PRC-005-7 – Poll Results

	Ballot	Non-binding Poll
	Quorum / Approval	Quorum / Supportive Opinions
PRC-005-7	90.17% / 35.33%	88.13% / 23.37%
Implementation Plan	90.78% / 41.53%	N/A

PRC-002

- Standards Project 2021-04
- Modifications to PRC-002
- 2 SARS
  - Glencoe Light SAR (Phase 1)
  - IBR SAR (Phase 2)

PRC-002

- PRC-002-4 Approved by FERC April 14, 2023
- PRC-002-4 addresses the Glencoe Light SAR only
- Glencoe SAR – clarify connected versus directly connected

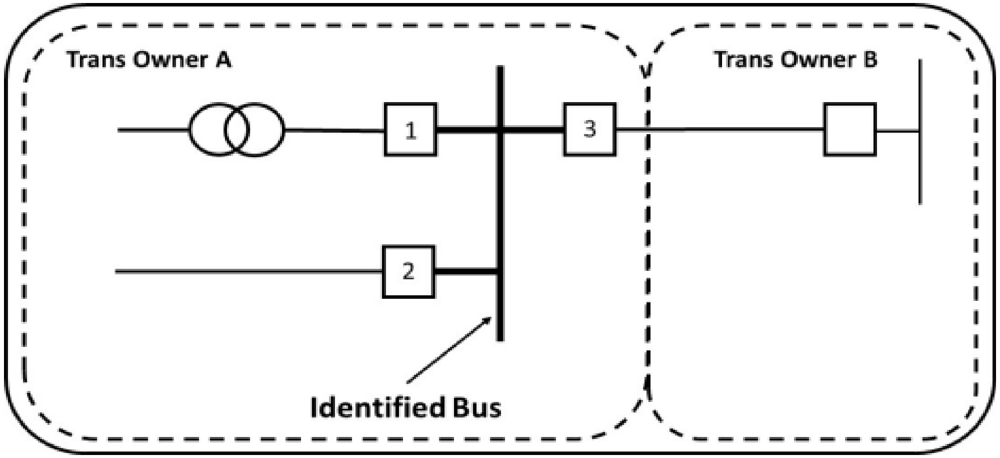


Figure 3

PRC-002

- Phase 2 addresses IBR SAR
- Draft 1 Posted for comment September 2023
- Remove IBR facilities from PRC-002
- Create new IBR Monitoring Standard – PRC-028

PRC-028-1 – Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources
2. **Number:** PRC-028-1
3. **Purpose:** To have adequate data available from inverter-based resources (IBR) to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Transmission Owner that owns equipment as identified in section 4.2
     - **4.1.2.** Generator Owner that owns equipment as identified in section 4.2
   - **4.2. Facilities:** The following Elements associated with BES generating plants (inverter-based portion of generating plant/Facility meeting the criteria set by Inclusion I2, Part (b) or Inclusion I4 of the BES definition):
     - **4.2.1** Circuit breaker(s).
     - **4.2.2** Main power transformer(s)[1].
     - **4.2.3** Collector bus.
     - **4.2.4** Shunt static or dynamic reactive device(s).
     - **4.2.5** At least one IBR unit[2] connected to last 10% of each collector feeder length (i.e., furthest from the collector bus).

- **Modifications to PRC-002 Phase 2 Ballot Results**

	Ballot	Non-binding Poll
Standard	**Quorum / Approval**	**Quorum / Supportive Opinions**
PRC-002-5	87.96% / 61.44%	86.09% / 54.45%
PRC-028-1	87.41% / 43.33%	85.44% / 28.07%
Implementation Plan	87.23 / 42.96%	N/A

PRC-019

- **Standards Project 2021-01**
- **PRC-019-3 – Draft 2 posted for comment – June 2023**

~~Standard PRC-019-2~~ PRC-019-3 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

1.2. For IBR generating Facilities, assuming the voltage control mode is enabled in the power plant controller and/or IBR unit(s)[6] and steady-state system operating conditions, verify the following coordination items:

1.2.1. The in-service control functions of the power plant controller are set to operate before the protective functions of the applicable Facilities in order to avoid disconnecting any of the Facilities listed under Section 4.2.4 unnecessarily.

1.2.2. The in-service control functions of IBR unit(s) are set to operate before protective functions of the applicable Facilities in order to avoid disconnecting any of Facilities listed under Section 4.2.4 unnecessarily.

1.2.3. The applicable in-service protective functions are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities.

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence such as a graphical representation(s) of coordination including a P-Q Diagram, R-X Diagram, Inverse Time Diagram, equivalent tables, steady-state calculations, dynamic simulation studies, or other evidence that it performed a coordination study as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

- **Draft 2 PRC-019-3 – Poll Results**

	Ballot	Implementation Plan	Non-binding Poll
	Quorum / Approval	Quorum / Approval	Quorum / Supportive Opinions
MOD-025-3	87.04% / 36.05%	86.62% / 46.46%	85.88% / 34.88%
PRC-019-3	86.99% / 46.73%	86.67% / 54.39%	85.94% / 44.07%

TPL-001 Footnote 13 d

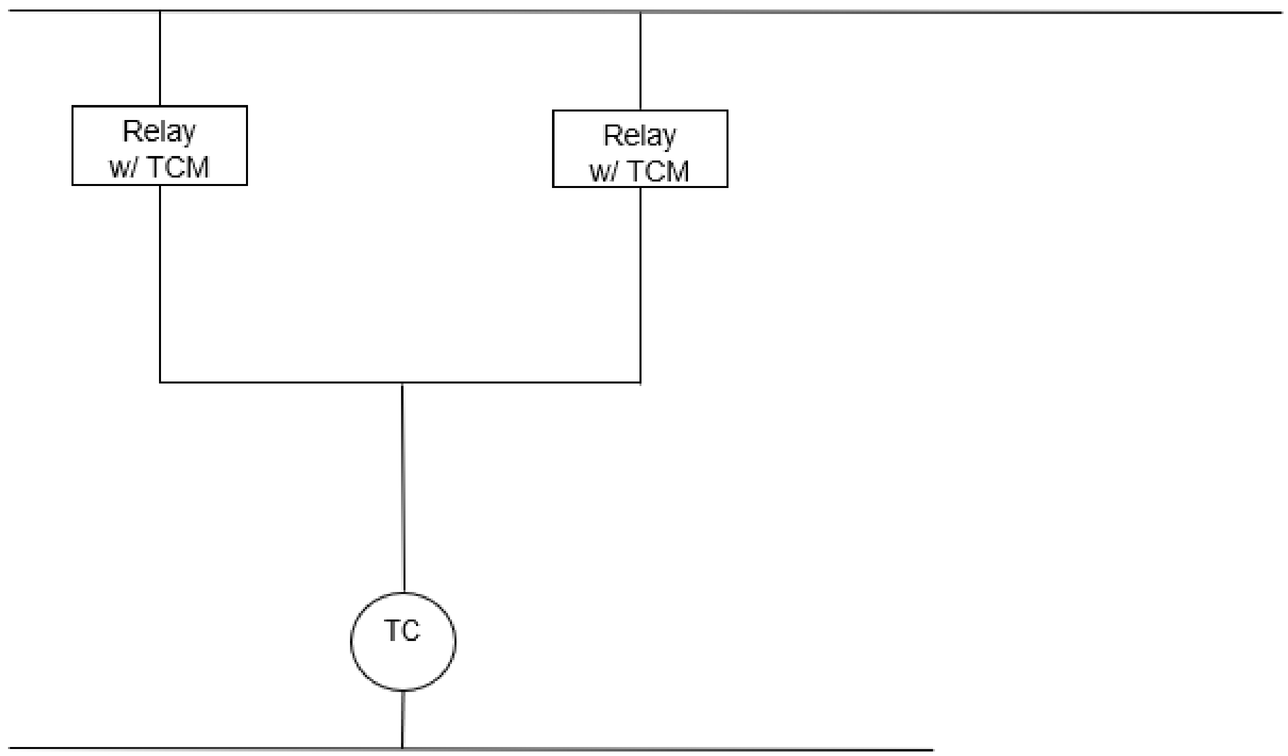
- **Standard Project 2022-02**
- **TPL-001-5 Footnote 13**
- **Single Point of Failure**

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes

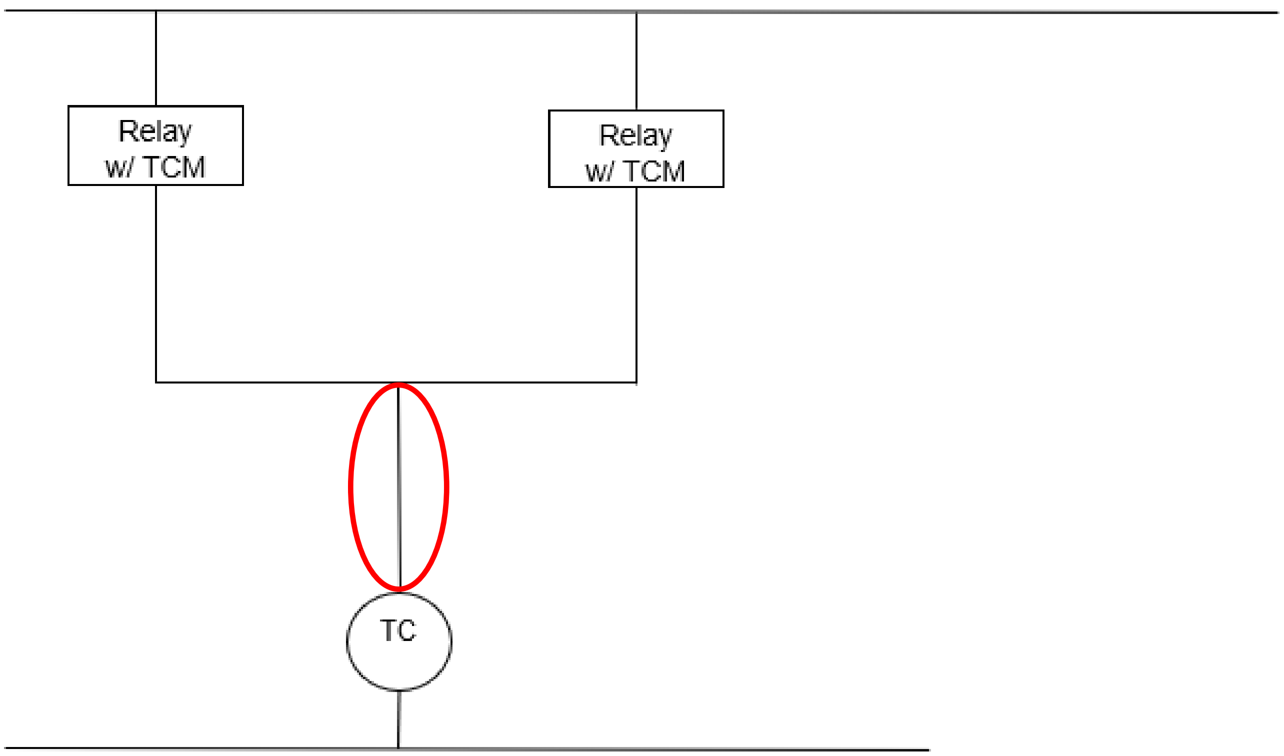
TPL-001 Footnote 13 d

- Footnote 13
  - 13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
  - d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

TPL-001 Footnote 13 d



TPL-001 Footnote 13 d



PRC-023

- PRC-023-6
- Filed with FERC March 2
- Remove R2
- Remove Attachment - 2.3

PRC-023-6 – Transmission Relay Loadability

Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 ~~through 13 and shall have evidence such as coordination curves or summaries of~~ calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

R2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~ Reserved.

M2. ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)~~ Reserved.

PRC-004

- Project 2023-02 Performance of IBRs - PRC-004
  - Clarify requirements for IBR analysis (interrupting device)

PRC-024

- Project 2020-02 Modifications to PRC-024
  - Make it a ride through Standard rather than a relay setting Standard

PRC-024

- Project 2020-06 Verifications of Models and Data for Generators
- Posted for comment 9/25 Closed 10/24

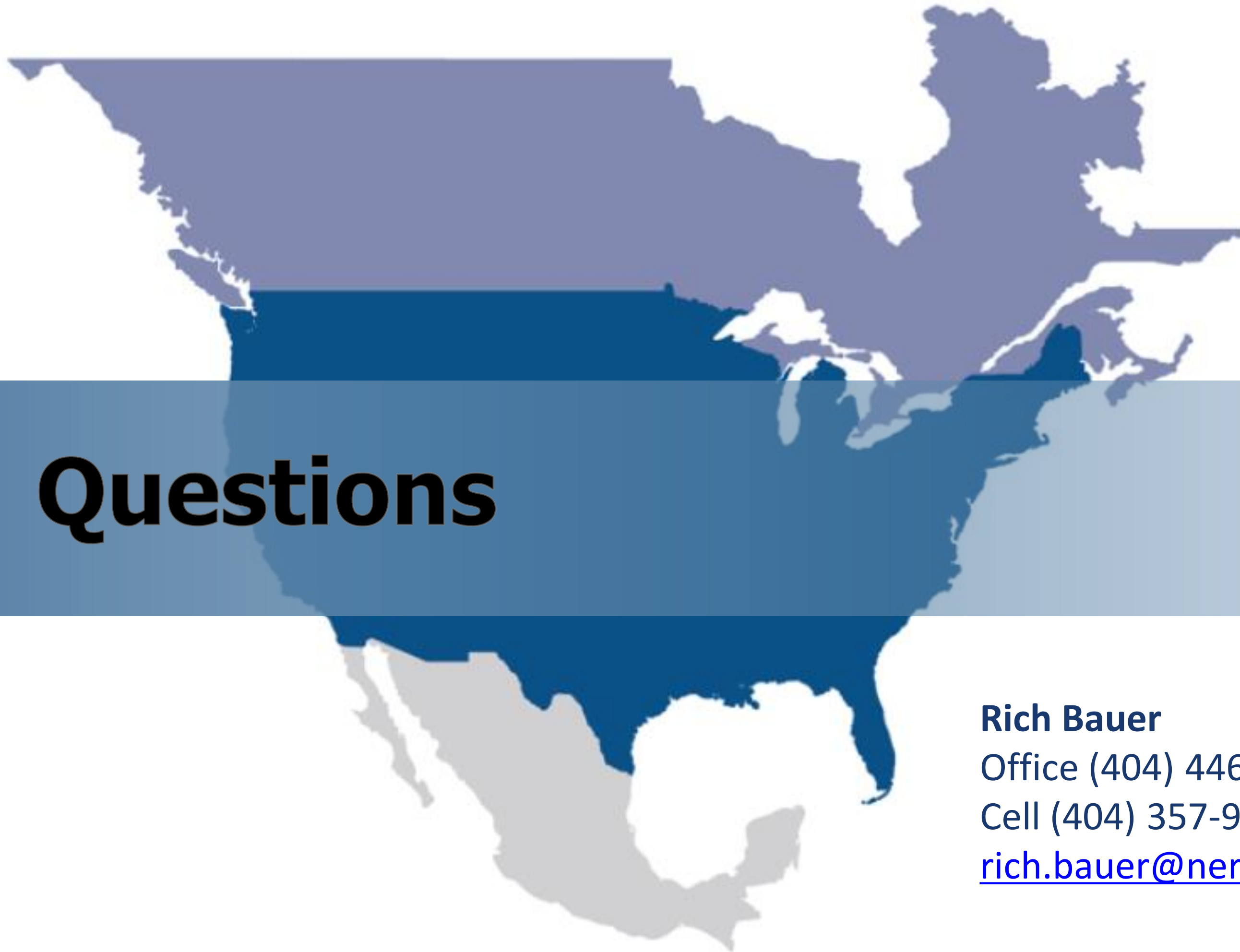
MOD-026-2 – Verification of Dynamic Models and Data for BES Connected Facilities

New or Modified Term(s) Used in NERC Reliability Standards

Background:
This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. The terms proposed below are intended to be used in MOD-026-2 and other inverter-based resource related standards.

Term(s):
Power Electronic Device (PED): Any device connected to the ac power system through a power electronic interface that generates or transmits active power or reactive power, or absorbs active power for the purposes of re-injecting it at a later time. This term excludes any load.

Inverter-Based Resource (IBR): Any source of electric power consisting of one or more Power Electronic Devices (PEDs), that operates as a single resource, supplies primarily active power, and connects to the Bulk Power System. An IBR plant/facility includes the Power Electronic Devices, and the equipment designed primarily for delivering the power to a common point of connection (e.g. step-up transformers, collector system(s), main power transformer(s), and power plant controller(s)).



Questions

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