DISTRIBUTION FEEDER PROTECTION AND CONTROL

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Distribution Protection and Control Track
Monday, August 4, 2025
Day 1 – Session 3

Contents of IEEE C37.230 Guide for Protective Relay Applications to Distribution Lines

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  - Purpose
- Normative References
- Definitions
- Fundamentals
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  - Load Characteristics
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  - Instrument Transformers (sensing)
- Protective Schemes
  - Overcurrent Scheme
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  - Voltage Scheme
  - Impedance & Communications Assisted Schemes

Contents of IEEE C37.230 Guide for Protective Relay Applications to Distribution Lines

- Criteria and examples
  - Reach/sensitivity
  - Coordination
  - Clearing time
  - Reclosing
  - Cold load pickup

- Special applications
  - Simultaneous or Inter-circuit Feeder Faults
  - Loop Schemes
  - Underfrequency Load shedding
  - Undervoltage Load shedding
  - Adaptive relaying schemes
  - Communications assisted protection applications
  - Multiple source configurations
  - Directional overcurrent protection
  - Motors (effects of unbalance)

- Breaker failure
- Single-phase tripping
- Methods of detecting ground faults in resonant-grounded systems
- Selective ground fault protection of an ungrounded system
- Arc Flash Hazards
- Locating Faults on Distribution Lines

Outline of topics covered

- Protection Criteria and examples
  - Reach/sensitivity
  - Coordination
  - Reclosing
  - Cold load pickup
- Special applications
  - Multiple Feeder Faults
  - Loop Schemes
  - Underfrequency Load shedding
  - Undervoltage Load shedding
  - Adaptive relaying schemes
  - Communications
  - Multiple source configurations
  - Directional overcurrent protection
  - Motors (effects of unbalance)
  - Breaker failure
  - Single-phase tripping

Protection Criteria

Objectives of the electric distribution system:

Deliver electric energy to the users in a manner which is

- Safe
- Reliable and
- Economical

Protection Criteria

Objectives of Distribution System Protection

- Prevent or minimize damage to equipment and circuits
- Prevent hazards to the public and employees
- Maintain and improve continuity of service

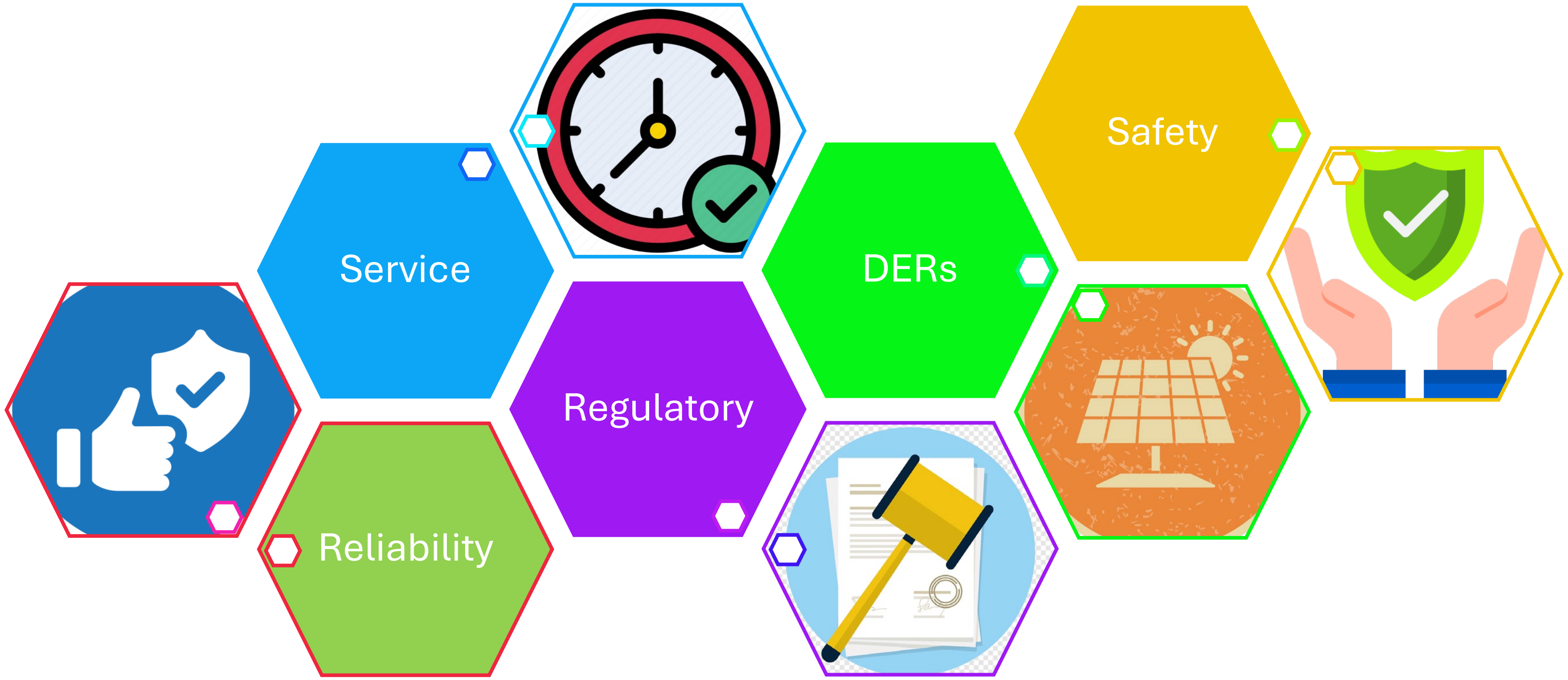
Objectives are achieved by:

- Proper application of protective devices
- Construction and maintenance practices (phase spacing, tree trimming, materials)
- System planning (radial or network, feeder backup ties, sectionalizing)

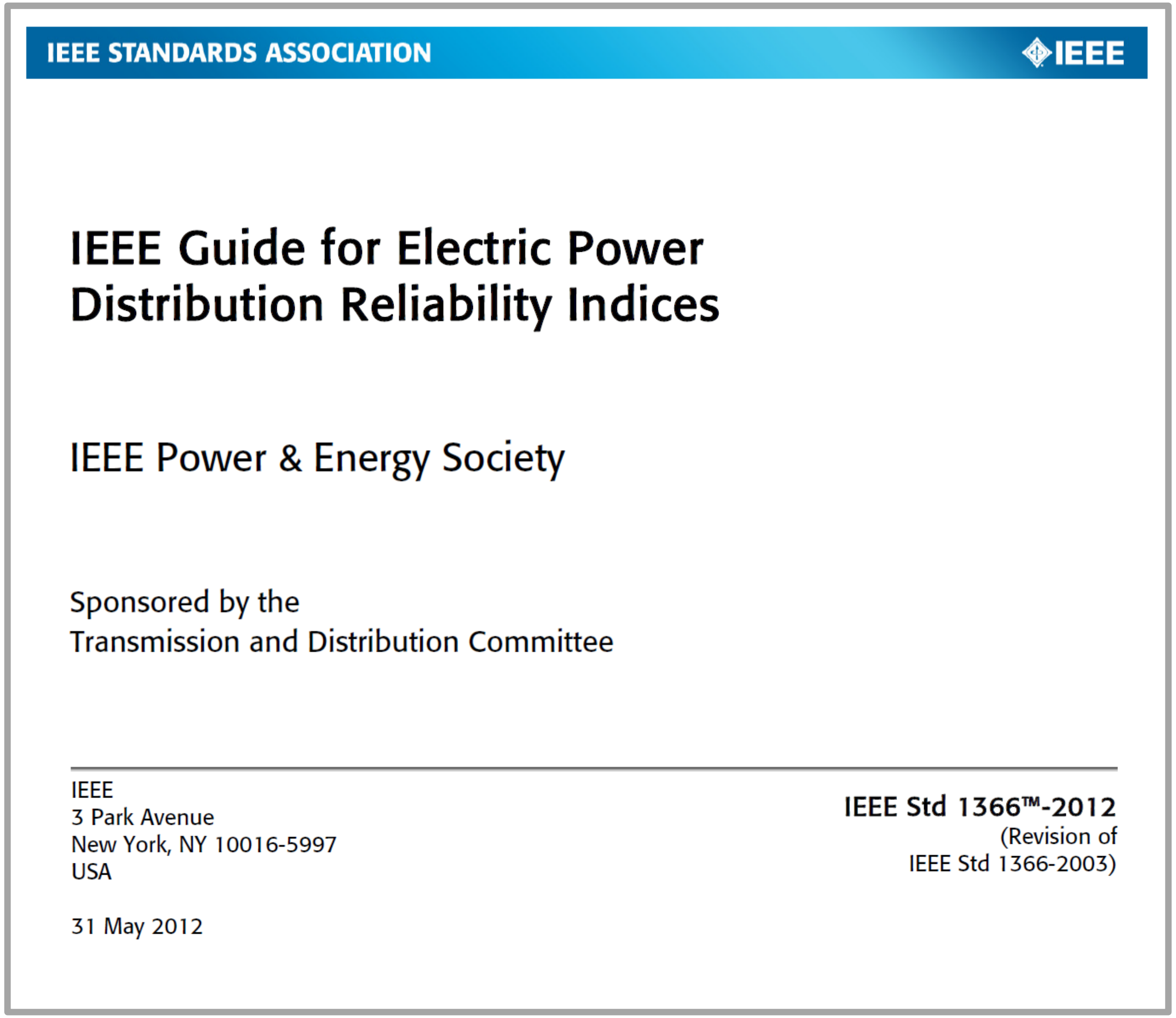
IEEE 1806-2021 Guide for Reliability-Based Placement of Overhead and Underground Switching and Overcurrent Protection Equipment, Up to and Including 38 kV – published 8/6/2021.

Why are we doing this?

Why are we doing this? What matters?



Why are we doing this? - Reliability


IEEE STANDARDS ASSOCIATION ◆IEEE

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power & Energy Society

Sponsored by the
Transmission and Distribution Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

31 May 2012

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

Performance Indices – Definitions

SAIFI: System Average Interruption Frequency Index

$$\text{SAIFI} = \frac{\sum \text{ Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

SAIDI: System Average Interruption Duration Index

$$\text{SAIDI} = \frac{\sum \text{ Customer Minutes of Interruption}}{\text{Total Number of Customers Served}}$$

CAIDI: Customer Average Interruption Duration Index

$$\text{CAIDI} = \frac{\sum \text{ Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}}$$

Performance Indices – Deeper Dive

- CTAIDI: Customer Total Average Interruption Duration Index

$$\text{CTAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Distinct Customers Interrupted}}$$

- CAIFI: Customer Average Interruption Frequency Index

$$\text{CAIFI} = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}}$$

- ASAI: Average Service Availability Index

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}}$$

- CEMI_n: Customers Experiencing Multiple Interruptions

$$\text{CEMI}_n = \frac{\text{Total Number of Customers that experienced n or more sustained interruptions}}{\text{Total Number of Customers Served}}$$

Two New Indices in IEEE Std. 1366-2012

- Customers Experiencing Long Interruption Durations
  - "CELID"
  - Major Event Days
- Indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time
  - That time is either:
    - CELID-s: The duration of a single interruption (s), or,
    - CELID-t: The total amount of time (t) that a customer has been interrupted during the reporting period.

$$\text{CELID-s} = \frac{\text{Total Number of Customers that experienced (s) or more hours duration in Reporting Period}}{\text{Total Number of Customers Served}}$$

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced (t) total hours duration in Reporting Period}}{\text{Total Number of Customers Served}}$$

- Major Event Days
- Momentary Interruption = <5 min or <1 min?

Why are we doing this? - Regulatory

- Cybersecurity – NERC CIP standards
- System optimization includes
  - Are communications involved?
    - Where do they go?
  - Got Critical Assets?
    - Load shedding?
- State Commission Rules
  - Rate case impacts
  - That is where the indices come in and why they are important

NERC and FERC

NERC

- NERC is a non-profit international regulatory authority responsible for ensuring the reliability and security of the bulk power system in North America.
- Governed by a board of directors and funded through assessments of its member utilities
- Develops and enforces mandatory reliability standards for the bulk power system, which includes transmission facilities and generators with a capacity of more than 100 MW
- Conducts assessments and audits to ensure that these standards are being followed
- Coordinates with other organizations to respond to emergencies or threats to the power system

FERC

- Independent agency of the United States government that regulates the interstate transmission of electricity, natural gas, and oil
- Responsible for licensing and regulating hydroelectric projects, including those located on federal lands
- Jurisdiction over the wholesale electricity market and is responsible for ensuring that rates for transmission and sale of electricity are just and reasonable
- Investigate and resolve disputes between utilities and other parties

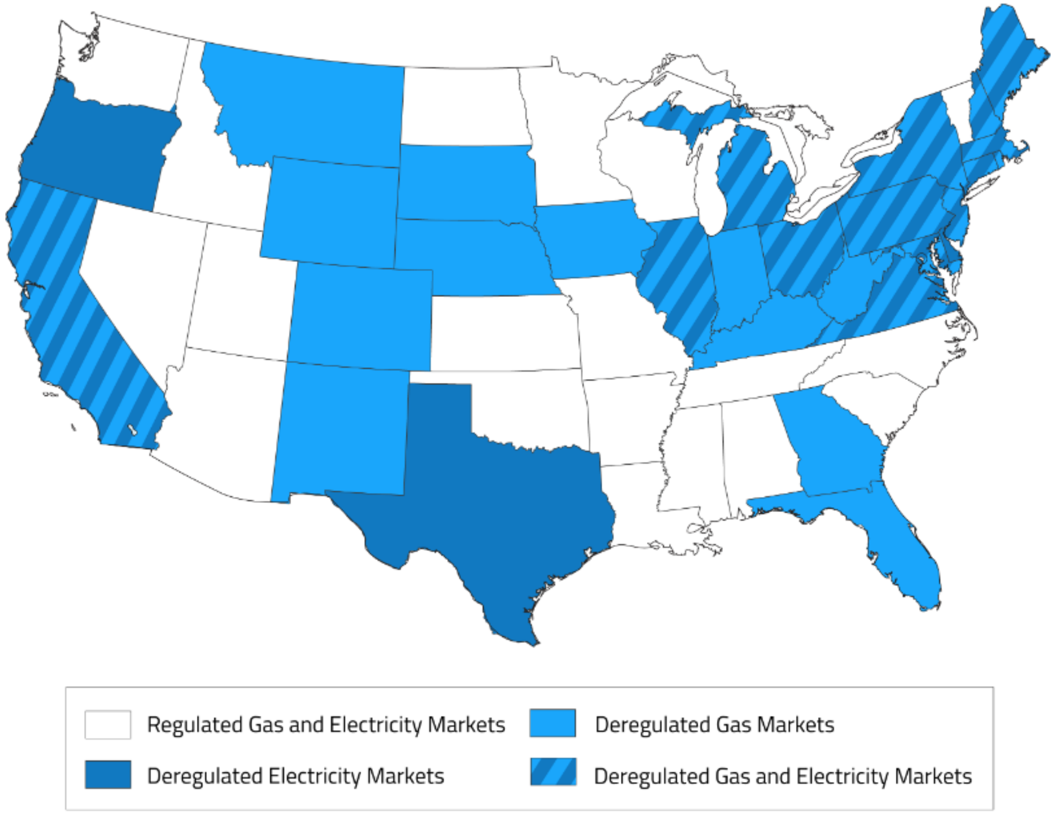
ISOs

- An independent FERC regulated non-profit organization that handles electric grid operations, market facilitation for certain electric markets, and bulk electric system planning
- Does not own the transmission system but manages equal access to it for power producers to facilitate competitive wholesale electric markets
- Schedules generation, transmission, and reserves in real time along with system planning
- Can also be referred to as RTOs (Regional Transmission Organizations)

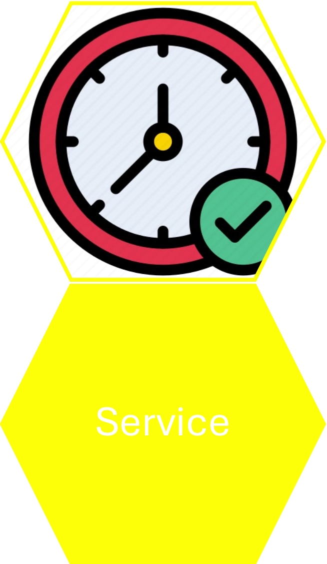
PUCs

- Public Utility Commission (PUC) is an organization that deals with rates and services provided by utility companies for their region
- Responsible for rates on not only electricity but also gas, transportation, water/wastewater, and telecommunications
- Approve and Control the utility delivery rates
- Protect the consumer from unethical energy related issues
- Manage competitive market in deregulated areas
- Also called as
  - Public service commission (PSC)
  - Utilities Commission (UC)
  - Utility Regulatory Commission (URC)

Deregulated Energy Markets in 2024



Why are we doing this? - Service



- Growing energy dependency
- Critical loads
  - Alternate feed with automatic transfer
  - On-site generation – possible DER?
- Critical Infrastructure
  - Airports
  - Data Centers, Telecom
  - Police Stations, Jails
  - Frozen/Refrigerated Warehouses
  - FEMA Facilities
  - Major venues

Why are we doing this? - Safety

- Work force
  - Aging
  - Thinning
- Lack of skills and training
- Lack of experience
- Improved information
  - Public
  - Employees
  - Work efficiency

Desirable Protection Attributes

Reliability	• Security – Not trip when not required • Dependability – Trip when required
Selectivity	• Ability to eliminate a fault by disconnecting the least number of system components
Speed	• Ability to operate in a short time after the fault or abnormal condition is detected
Sensitivity	• Ability to detect even the smallest faults and trip within the protected zone
Reach	• Trip only within the assigned zone.
Simplicity	• Achieve fault isolation without convoluted or complex logic as much as possible
Economics	• Protect the system without breaking the bank

Selection of protective relays requires compromises

- Cost of protective relays should be balanced against risks involved if protection:
  - Is not sufficient
  - Does not have enough redundancy
- Primary objectives is to have faulted zone's primary protection operate first
  - If there are protective system failures, some form of backup protection is provided
- Backup protection is local (if local primary protection fails to clear fault) and remote (if remote protection fails to operate to clear fault)

A Good Day in System Protection……

- CTs and VTs bring electrical info to relays
- Relays sense current and voltage and declare fault
- Relays send signals through control circuits to circuit breakers
- Circuit breaker(s) correctly trip

What Could Go Wrong Here????

A Bad Day in System Protection……

- CTs or VTs are shorted, opened, or their wiring is compromised
- Relays do not declare fault due to setting errors, faulty relay, CT saturation
- Cut control wiring or dead batteries so no signal is sent from relay to circuit breaker
- Circuit breakers do not have power, burnt trip coil or otherwise fail to trip

Protection Systems Typically are Designed for N-1

Protection Performance Statistics

- Correct and desired: 92.2%
- Correct but undesired: 5.3%
- Incorrect: 2.1%
- Fail to trip: 0.4%

https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Overview.pdf

Protection Performance Characterization

Correct & Appropriate

- What we all like to see

Incorrect, but Appropriate (Lucky)

- Application or settings were wrong but with unexpected contingency the correct decision was made to trip

Correct & Inappropriate (Did Not Foresee Everything)

- Setting was correct but unexpected event or contingency developed resulting in insecure trip

Incorrect & Inappropriate (Bad Luck)

- Application or settings were wrong, and relay tripped unnecessarily (insecure)
- Feeder breaker failure
- Bus endures insecure trip

Protection Criteria – Reach / Sensitivity

- Protective Relaying must:
  - Detect all possible faults that could occur
  - Isolate fault from source as fast as possible
  - Affect minimum number of customers
  - Not affect system load current capability
- Resulting in compromises
  - Fault interrupting device locations
  - Sensitivity
  - Selectivity
  - Response

Protection Criteria – Reach / Sensitivity

Assuming

- Majority of faults are temporary
- Need for continuity of service is paramount

Two basic rules of distribution protection

- Give all faults a chance to be temporary, where momentary outages are acceptable
- Remove only the smallest portion of system required to isolate fault when permanent

Protection Criteria – Reach / Sensitivity

- Overcurrent protection devices
- Incorporate inverse time-current characteristic (TCC) curves
- Defined by
  - Standards
    - IEEE C37.112: IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays
    - IEC 60255-151: Measuring Relays and Protection Equipment

Protection Criteria – Reach / Sensitivity

- The operating times defined by standards:
- IEC 60255-151 and IEEE C37.112 are:

$$t = \frac{k \cdot \beta}{\left(\frac{I}{I_s}\right)^{\alpha} - 1} + L$$

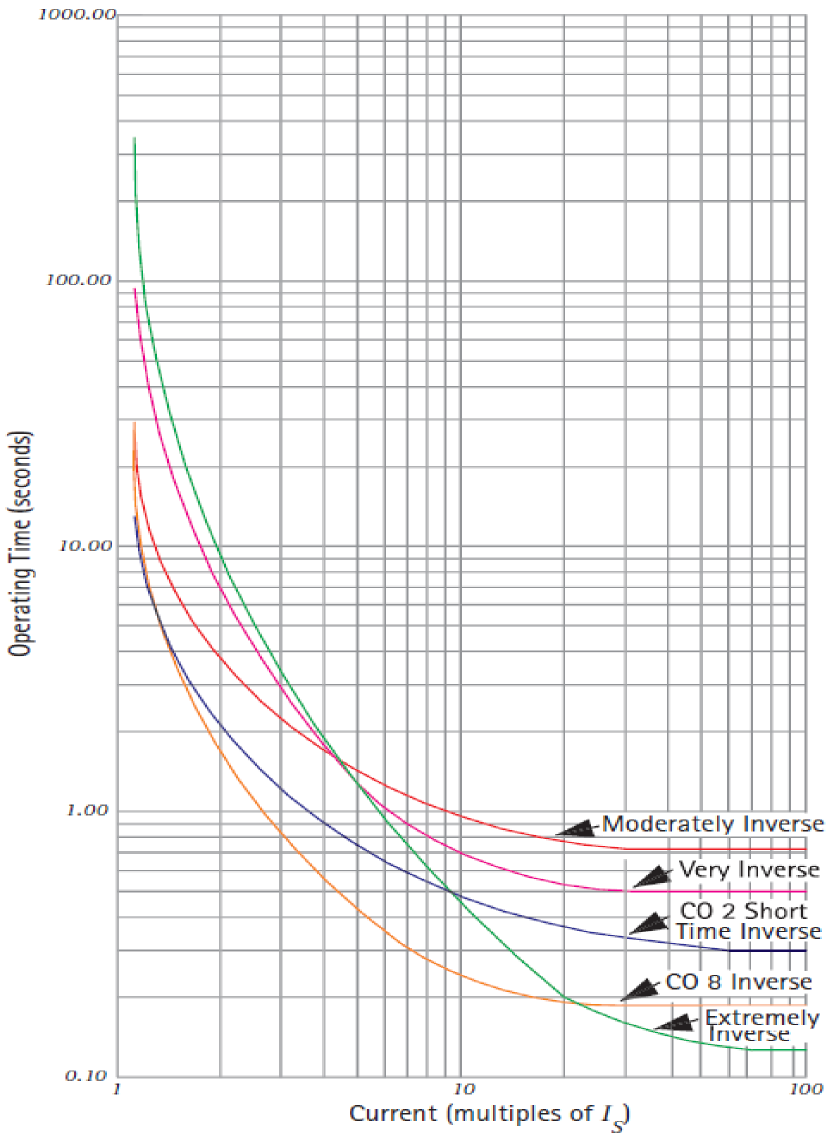
t	=	Relay operating time in seconds
k	=	Time dial, or time multiplier setting
I	=	Fault current level in secondary A
I_s	=	Pick Up (TAP) current selected
L	=	Constant
α	=	Slope constant
β	=	Slope constant

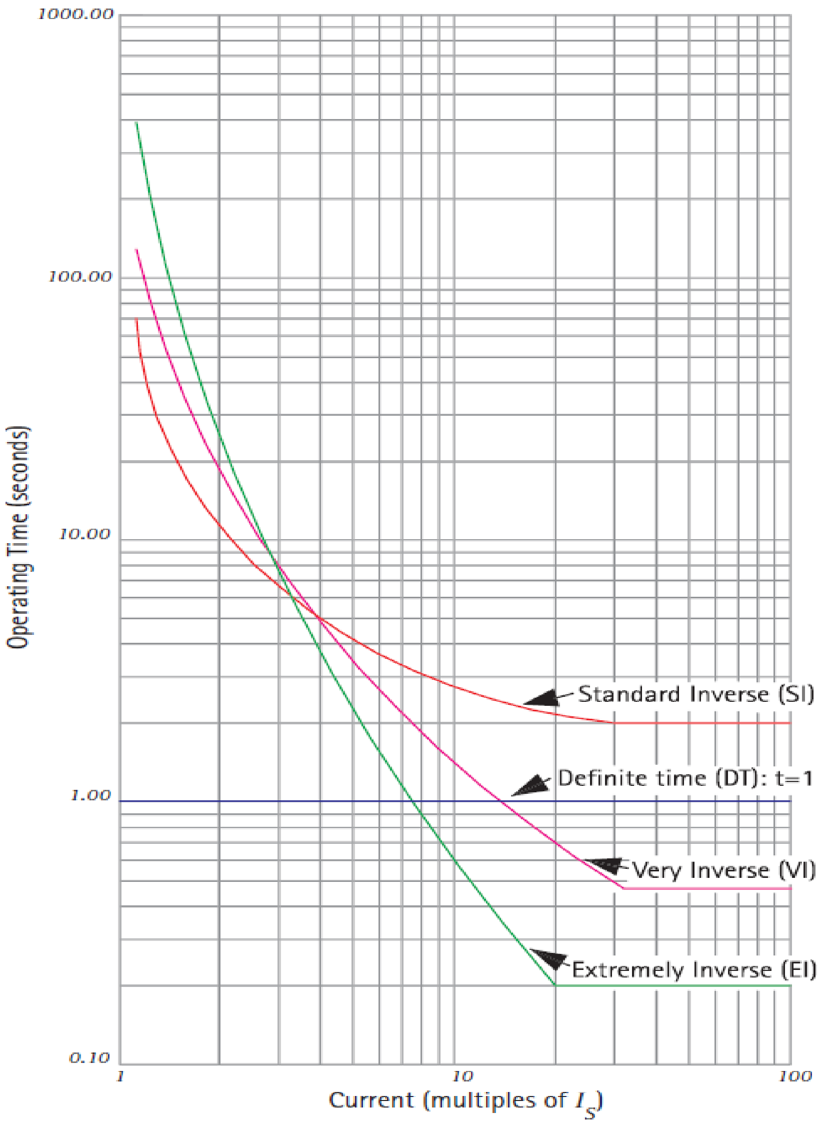
Protection Criteria – Reach / Sensitivity

IEEE and IEC constants for standard overcurrent relays

IDMT Curve Description	Standard	α	β	L
Moderately Inverse	IEEE	0.02	0.0515	0.114
Very Inverse	IEEE	2	19.61	0.491
Extremely Inverse	IEEE	2	28.2	0.1217
Inverse	US-CO8	2	5.95	0.18
Short Time Inverse	US-CO2	0.02	0.02394	0.01694
Standard Inverse	IEC	0.02	0.14	
Very inverse	IEC	1.0	13.5	
Extremely inverse	IEC	2.0	80.0	
Long Time Inverse	IEC	1	120	

Protection Criteria – Reach / Sensitivity





Protection Criteria – Reach / Sensitivity

Overcurrent protective devices are set by selecting the time/curve characteristic that is defined by two parameters for any given TCC curve

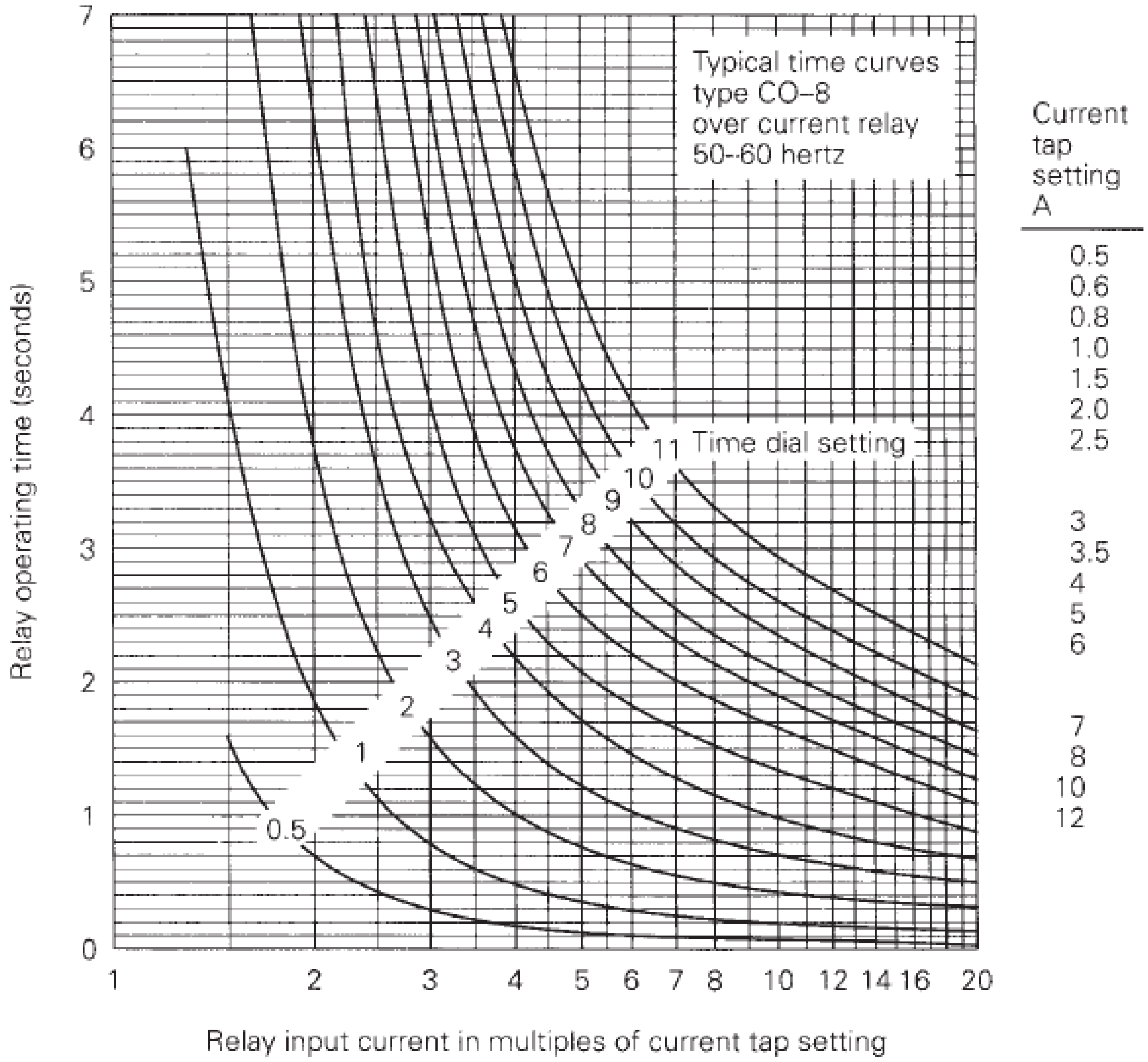
PICK UP (TAP) VALUE

- A value that defines the minimum operating current of the relay
- Current values are expressed as multiples of this value in TCC curves

TIME DIAL (sometimes called Time Lever)

- Defines the time curve at which the relay operates for any Pickup (TAP) value
- Higher values represent higher operating times

Protection Criteria – Reach / Sensitivity



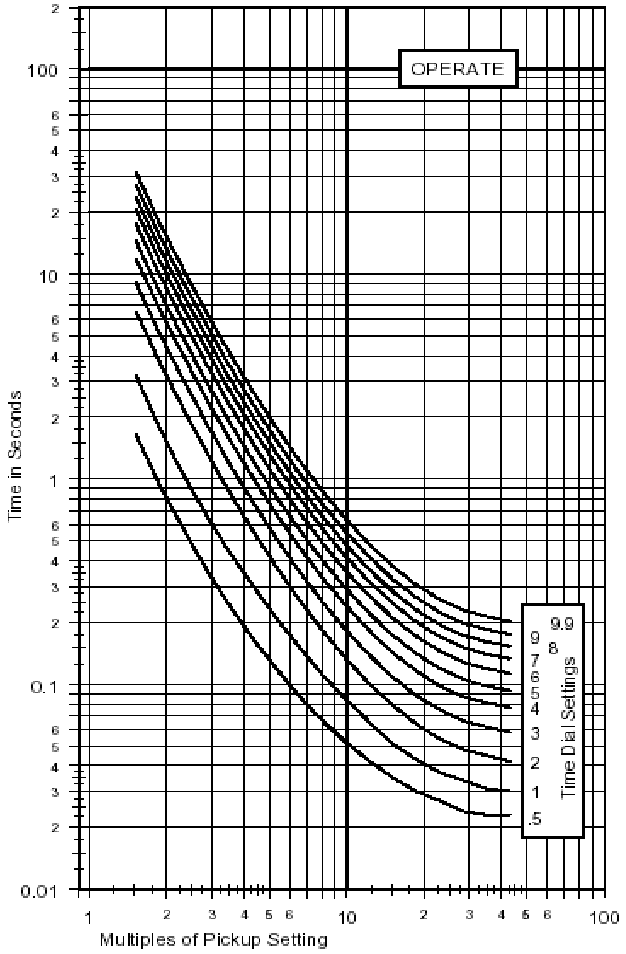
Time Overcurrent Protection - TOC Selection

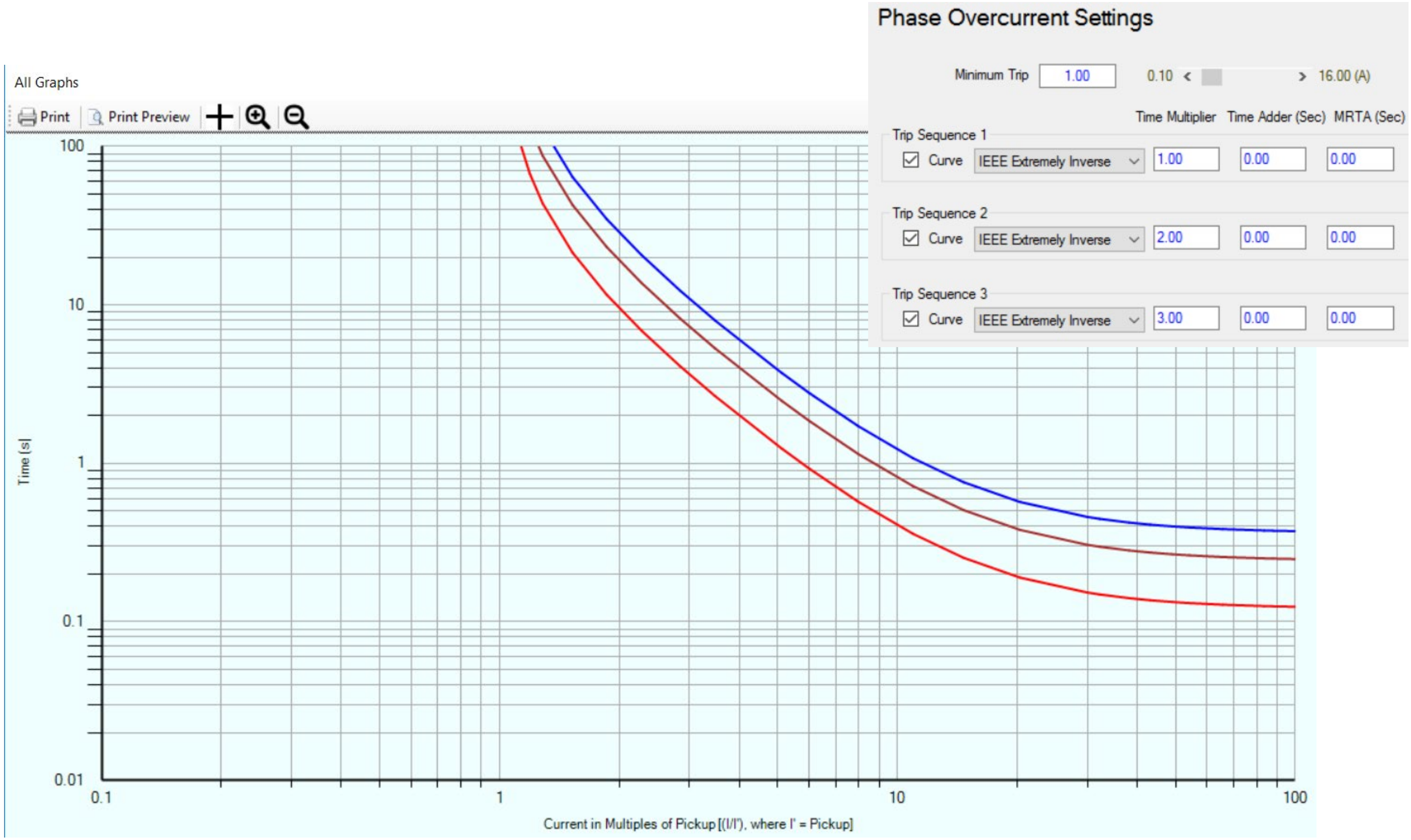
Relay and Recloser Curves

Curve Category	Curve Selection
IEC Curves (IEC 60255-151)	Inverse, Very Inverse, Extremely Inverse
IEEE Curves (IEEE C37.112)	Moderately Inverse, Very Inverse, Extremely Inverse
Traditional Recloser Curves ■NOTE: (Newer curves are shown with the older curve designations in parentheses)	101 (A); 102 (1); 103 (17); 104 (N); 105 (R); 106 (4); 107 (L); 111 (8*); 112 (15); 113 (8); 114 (5); 115 (P); 116 (D); 117 (B); 118 (M); 119 (14); 120 (Y); 121 (G); 122 (H); 131 (9); 132 (E); 133 (C); 134 (Z); 135 (2); 136 (6); 137 (V); 138 (W); 139 (16); 140 (3); 141 (11); 142 (13); 151 (18); 152 (7); 161 (T); 162 (KP); 163 (F); 164 (J); 165 (KG); 200; 201; 202
US Curves	Moderately Inverse, Standard Inverse, Very Inverse, Extremely Inverse, Short Time Inverse
Definite Time	Definite Time
User-Designed Programmable Curves	Four Programmable Curves

Time Overcurrent Protection

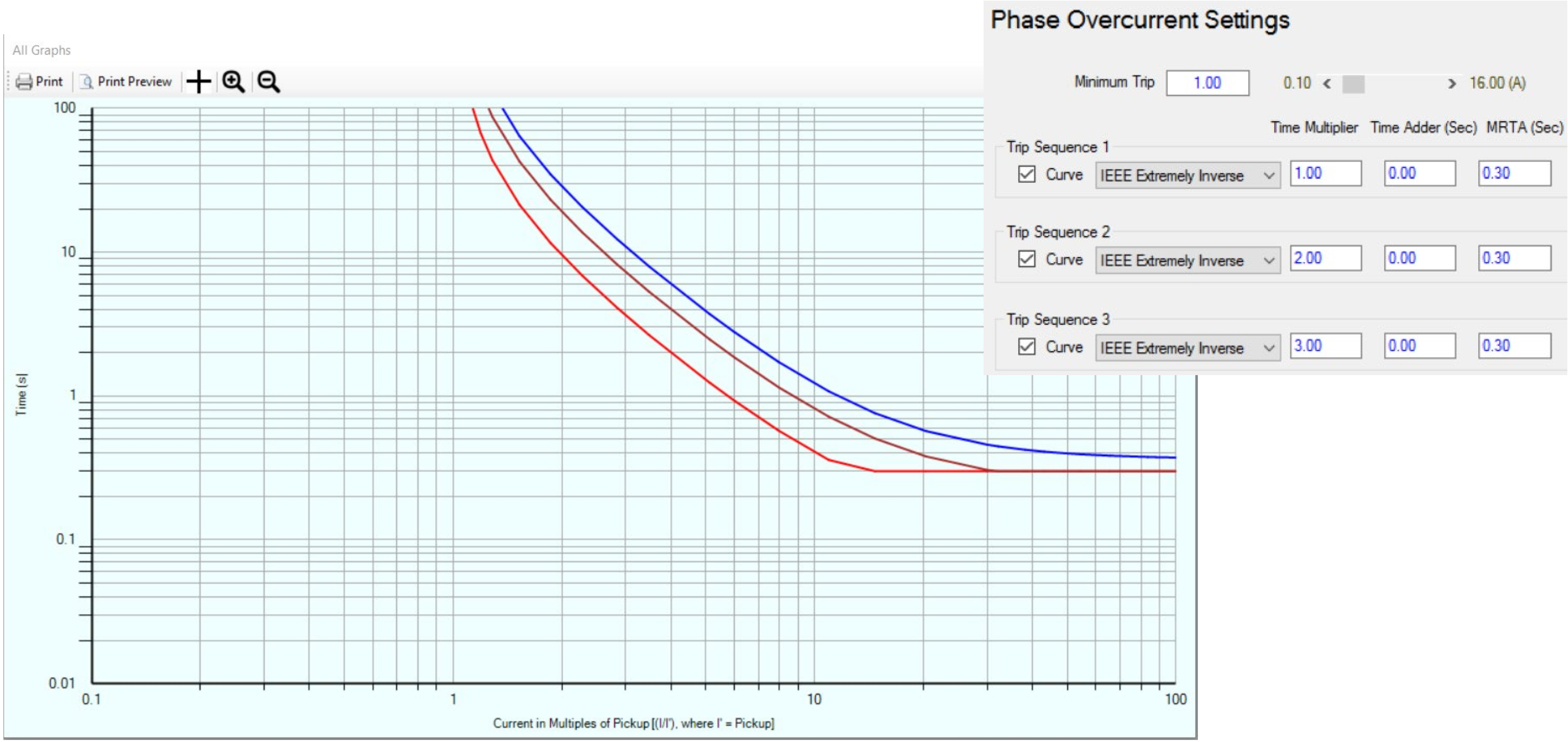
Time Multiplier (Time Dial): Increased value pushes curve up (results in longer time)





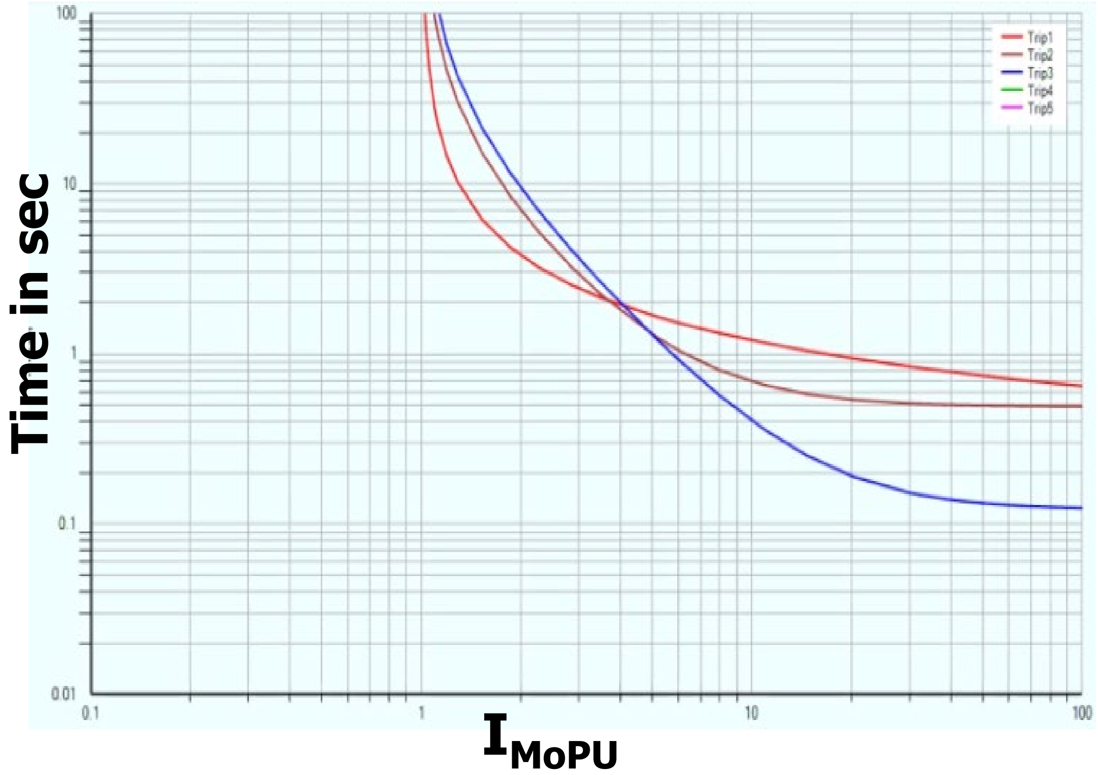
Time Overcurrent Protection

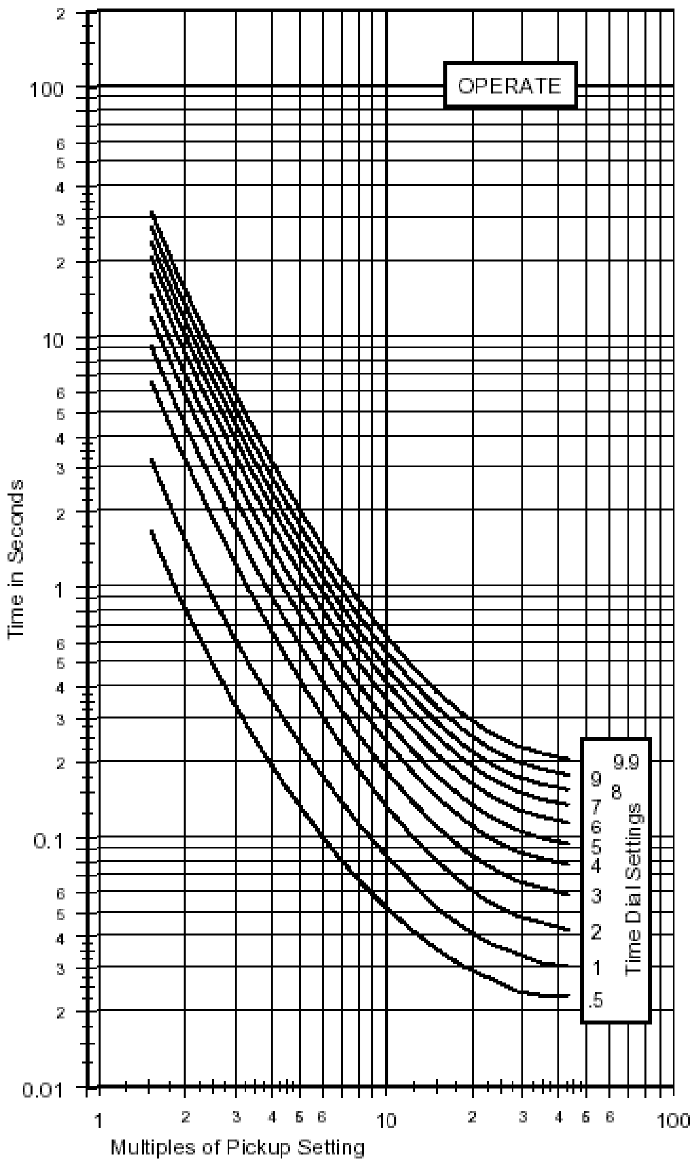
Minimum Response Time Adder



Time Overcurrent Protection

- Shape: Amount of "inverseness"
- Pickup (I_{PU}): Base line for time O/C curve
- Multiple of Pickup (I_{MoPU}): Measured fault current /I_{PU}
- Time Dial: Increased value pushes curve straight up (results in longer time)





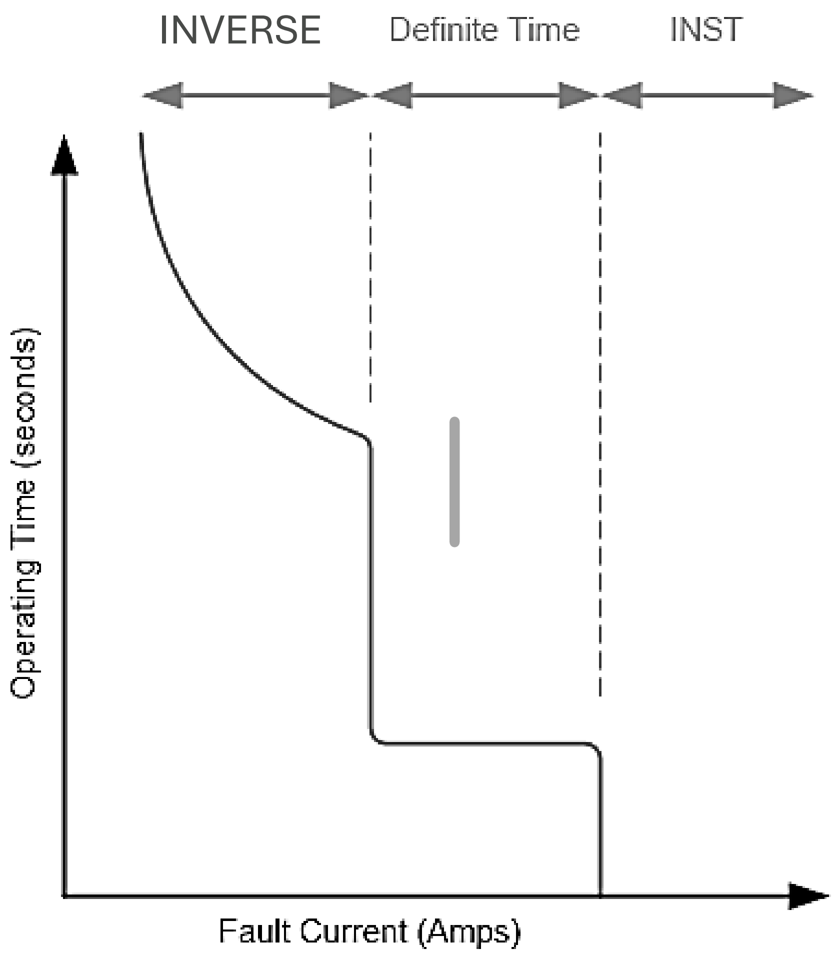
Protection Coordination

Standard Modifiers

- TCC Modifiers
- Time Multiplier
- Time Adder
- Minimum Response Time
- Definite Time
    - Instantaneous Trip
    - with Delay

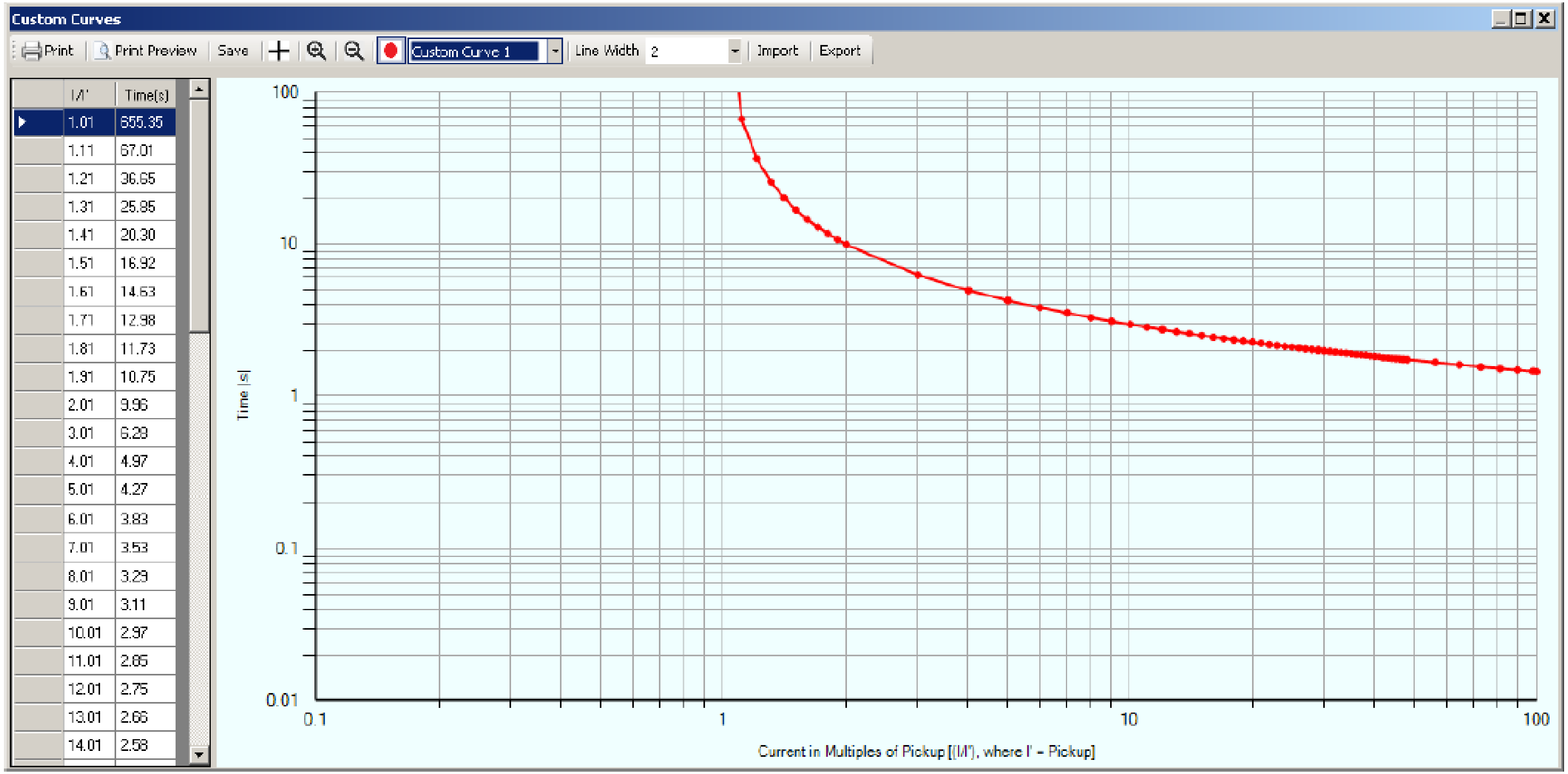
Custom TOC Curves

- Difficult time-current coordination
    - Fuse over Relay over Trip Unit
- Higher precision coordination



Custom TOC Curves

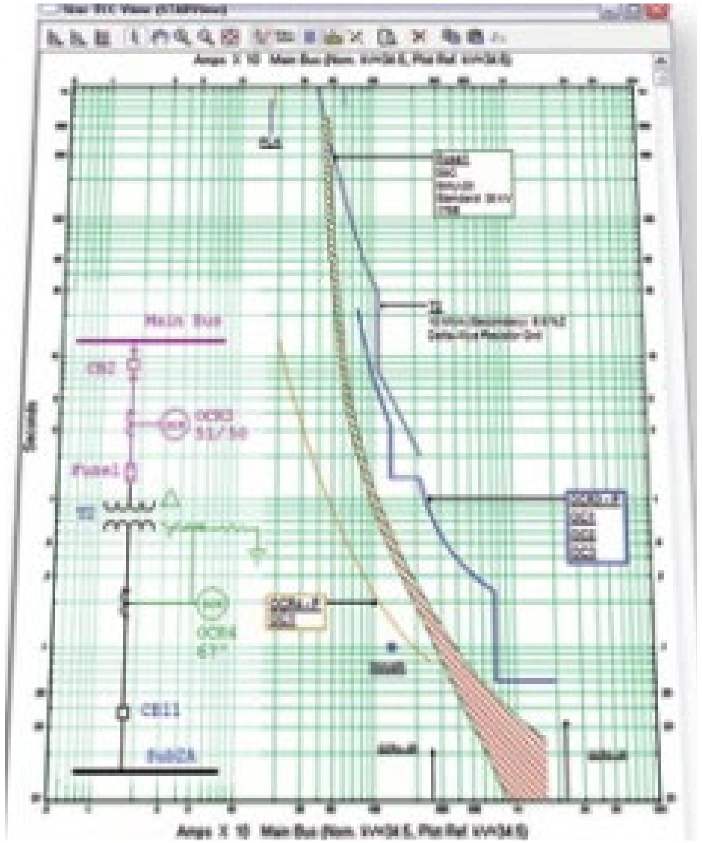
- Use Curve Editor
- Move points on curve diagram to fine tune



Protection Criteria – Reach / Sensitivity

Coordination of Protection Devices:

- Choosing pickup or time delay characteristics of protective devices such that operation of the devices will occur in a specified order for a fault
  - Minimizes service interruption
  - Minimizes area of power system isolation

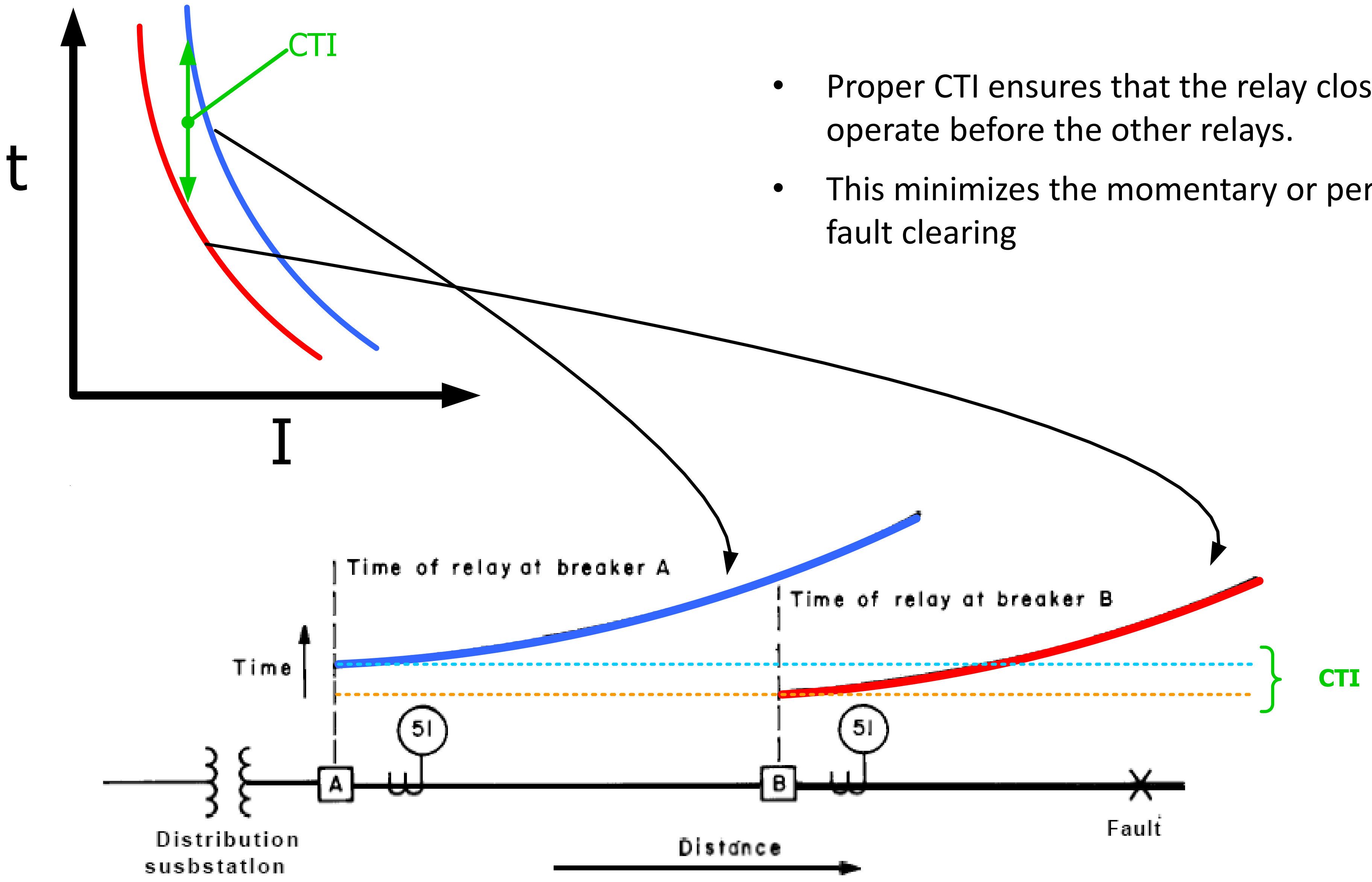


Protection Criteria – Reach / Sensitivity

Phase pickup settings

- Considerations
  - Three phase and phase-to-phase fault currents
  - Maximum line loading (with expected growth)
  - Line capacity
  - Cold load
  - Inrush
- Minimum pickup
  - > load current + margin
    - Typically, 1.25 to 3 times maximum steady state load current
  - < minimum fault current

Coordination Time Interval (CTI)



- Proper CTI ensures that the relay closet to the fault will operate before the other relays.
- This minimizes the momentary or permanent outage from fault clearing

Protection Criteria – Reach / Sensitivity

Ground Fault Sensing

- Majority of faults involve ground
- Some may include high fault impedance = lower fault current
- Phase current sensing is set above maximum load currents
  - Insensitive to high impedance faults
- Separate Ground or Residual current sensing allows lower detection settings and greater reach
- Ground current can be calculated in low impedance grounded systems or directly measured in high impedance grounded systems

Protection Criteria – Reach / Sensitivity

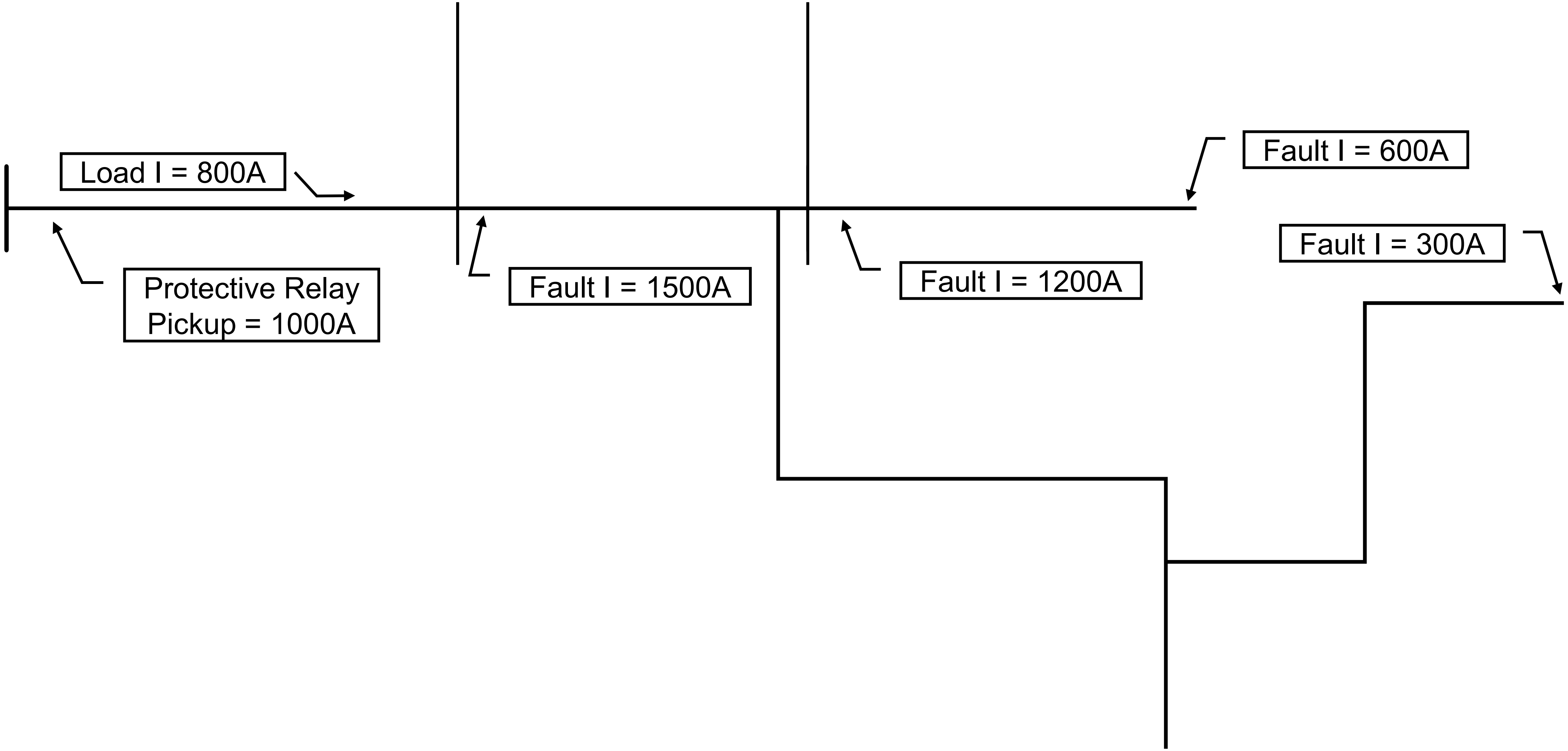
Ground Fault Sensing

- Residual current = calculated vector sum of three phases/Neutral current measurement
- Ground current = measured with Torroidal CT
  - Used with high-Z grounded systems that supply little ground current
  - Phase currents cancel leaving only ground current
  - Easy on metal-clad switchgear
  - Difficult on overhead as all 3 phase conductors have to pass through Torroidal CT

Protection Criteria – Reach / Sensitivity

- Ground faults
- Considerations
  - Grounding method
  - Fault impedance
  - Load unbalance (in multi-grounded wye system)
    - Include unbalanced cold load
- Minimum pickup
  - Different practices
    - < fault current w/o fault impedance x %margin
    - < percent of phase pickup
    - < fault current with established fault impedance
    - Based on maximum clearing time for bolted faults
  - > maximum phase unbalance load current

Protection Criteria – Reach / Sensitivity



Protection Criteria – Reach / Sensitivity

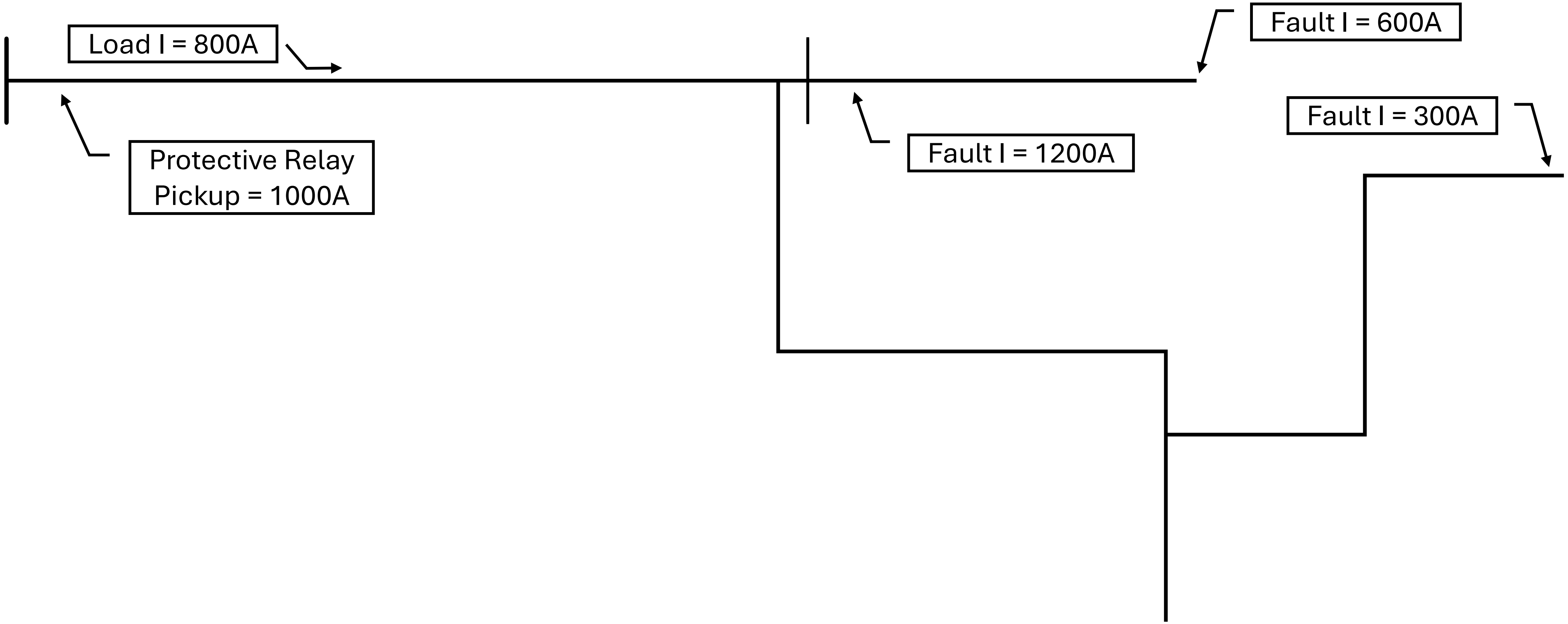
- Negative Sequence Overcurrent (46)
- More sensitive than phase overcurrent pickup
  - For phase-to-phase faults and phase-to-ground faults
  - Uses I_2 current component
- Minimum pickup
  - < phase overcurrent pickup
  - > maximum load unbalance current or loss of phase
- Considerations
  - Coordination with phase-only sensing devices such as fuses, reclosers, and ground relays
  - Unbalance phase currents for transformer inrush
- Other applications
  - Open phase or broken conductor detection
  - Low side wye phase-ground faults on transformers
  - Distribution bus protection and multi-feeder backup

Protection Coordination

- Time-current coordination
  - Allows closest overcurrent protective device to the faulted component to isolate the fault
  - Minimize extent of the outage
- Devices to coordinate
  - Transformer relays
  - Feeder relays
  - Reclosers
  - Fuses
  - Equipment Damage Curves

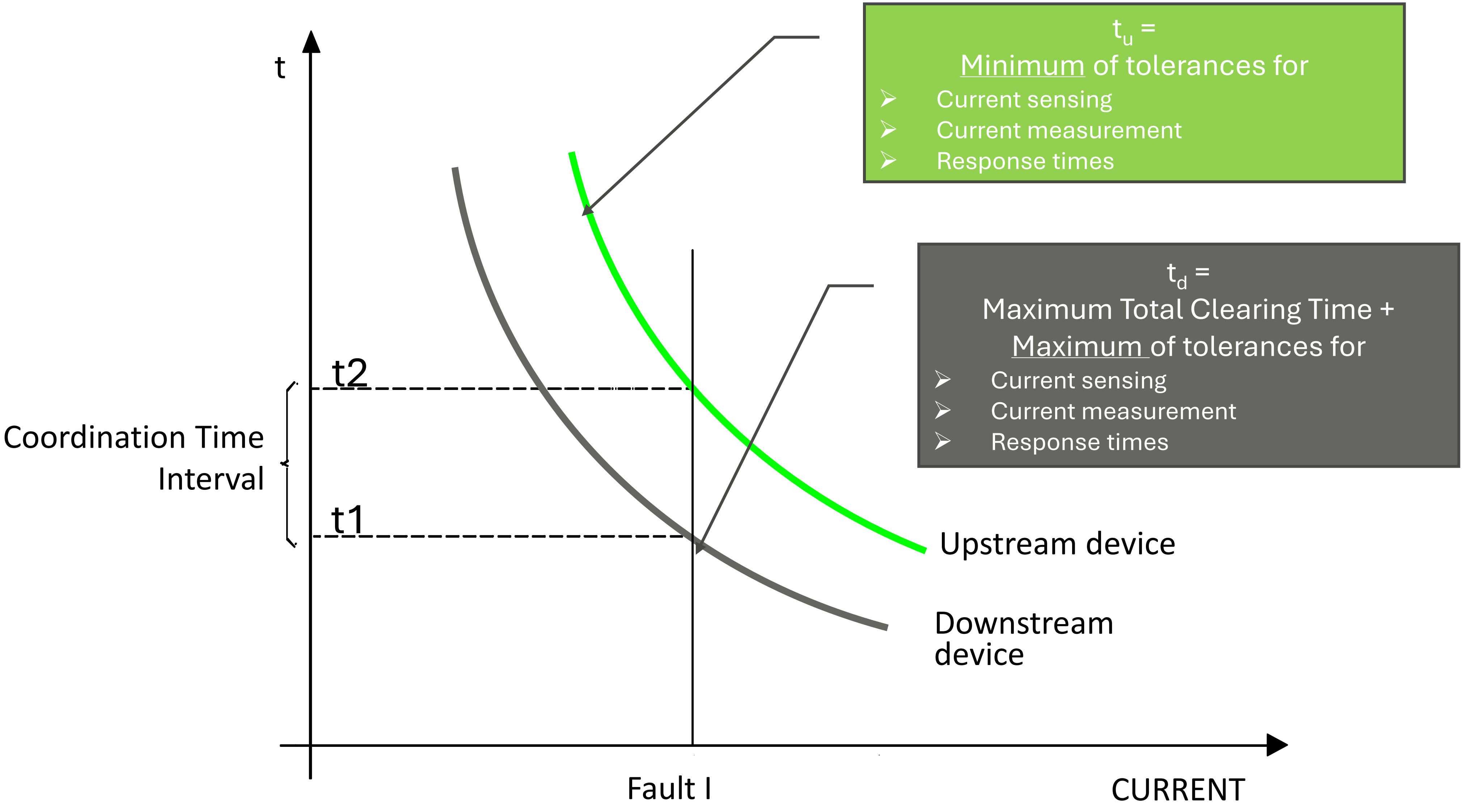
Protection Coordination

Overcurrent protective devices in series



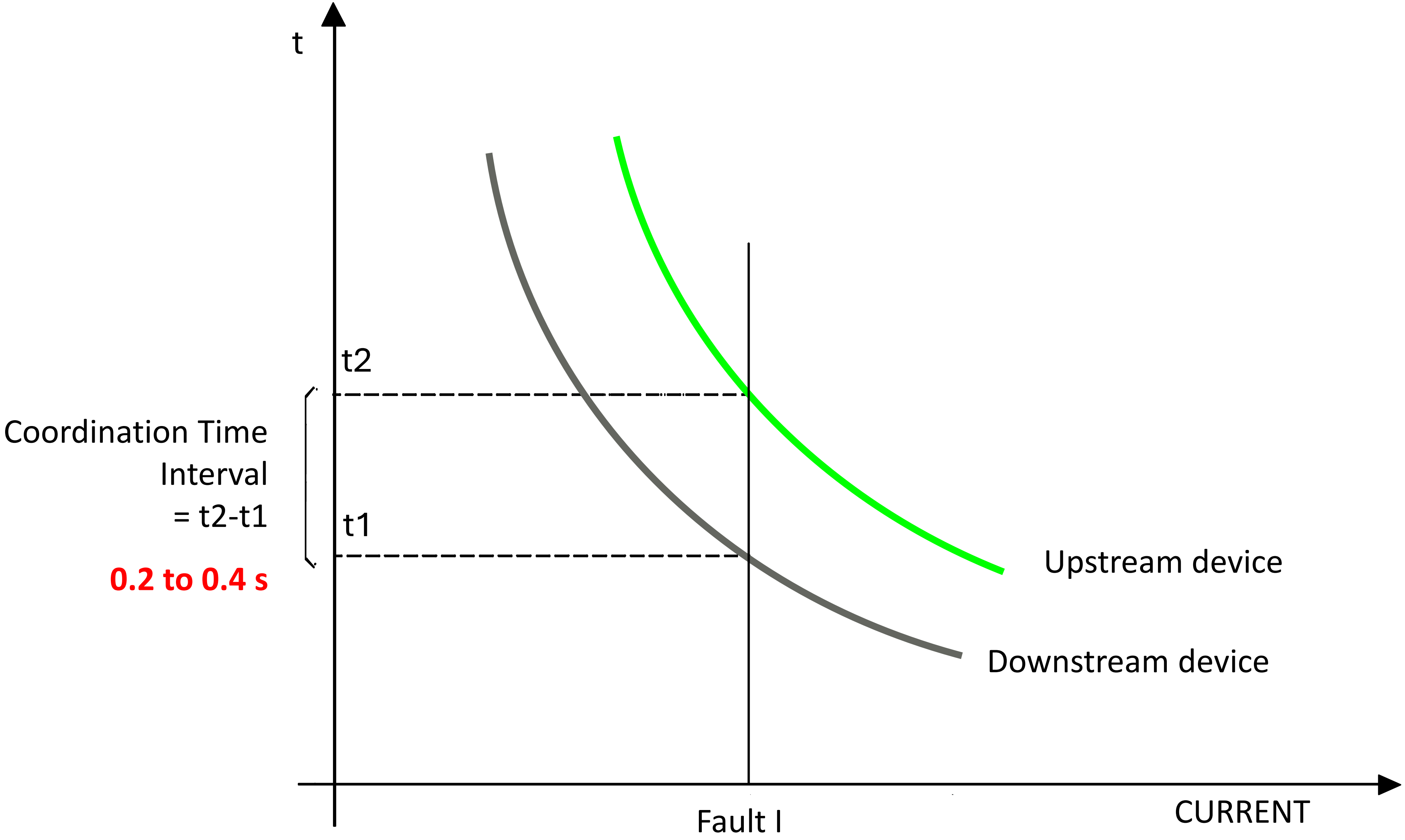
Protection Coordination

Overcurrent inverse time curves associated with two devices in series

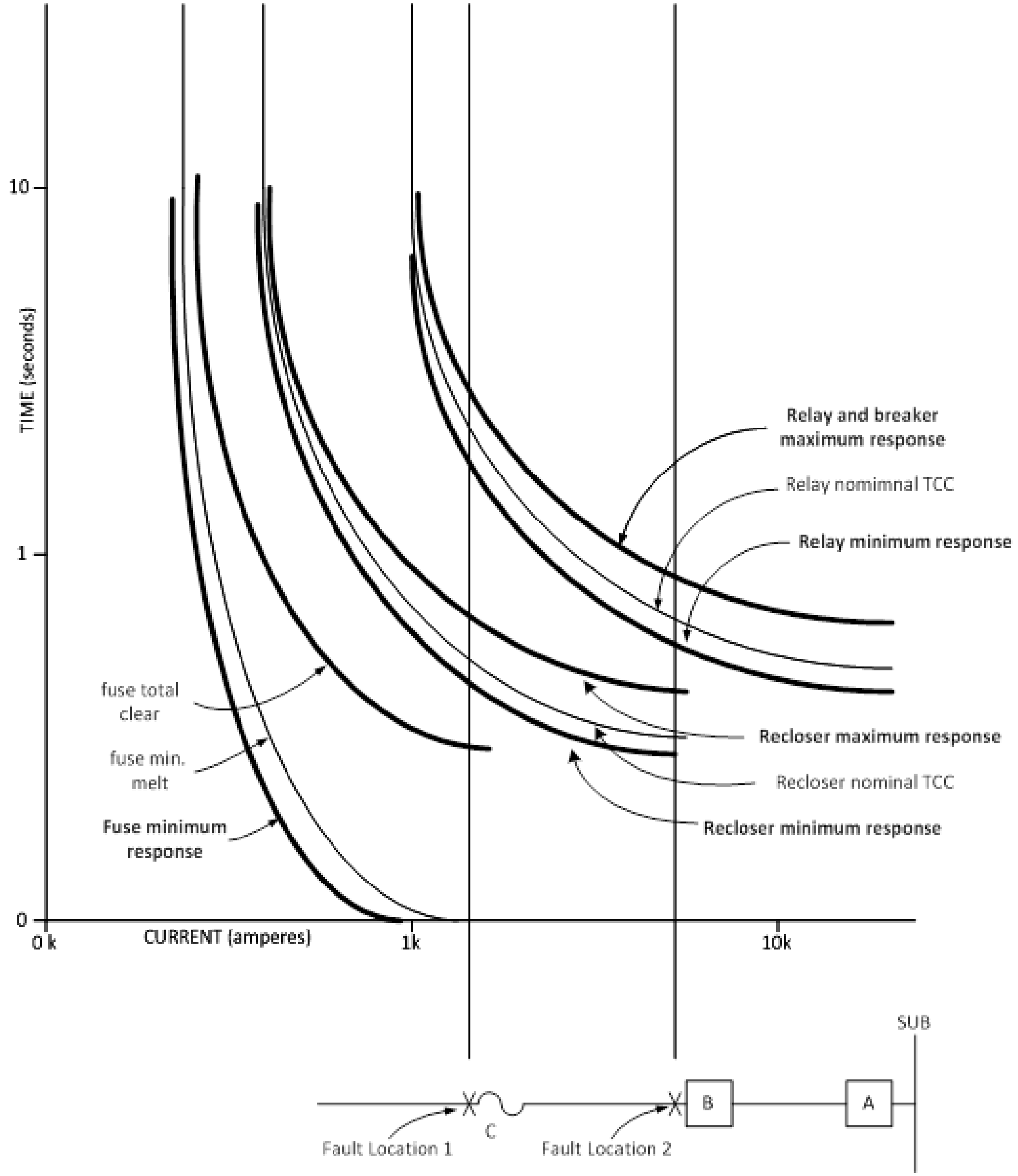


Protection Coordination

Overcurrent inverse time curves associated with two devices in series



Protection Coordination



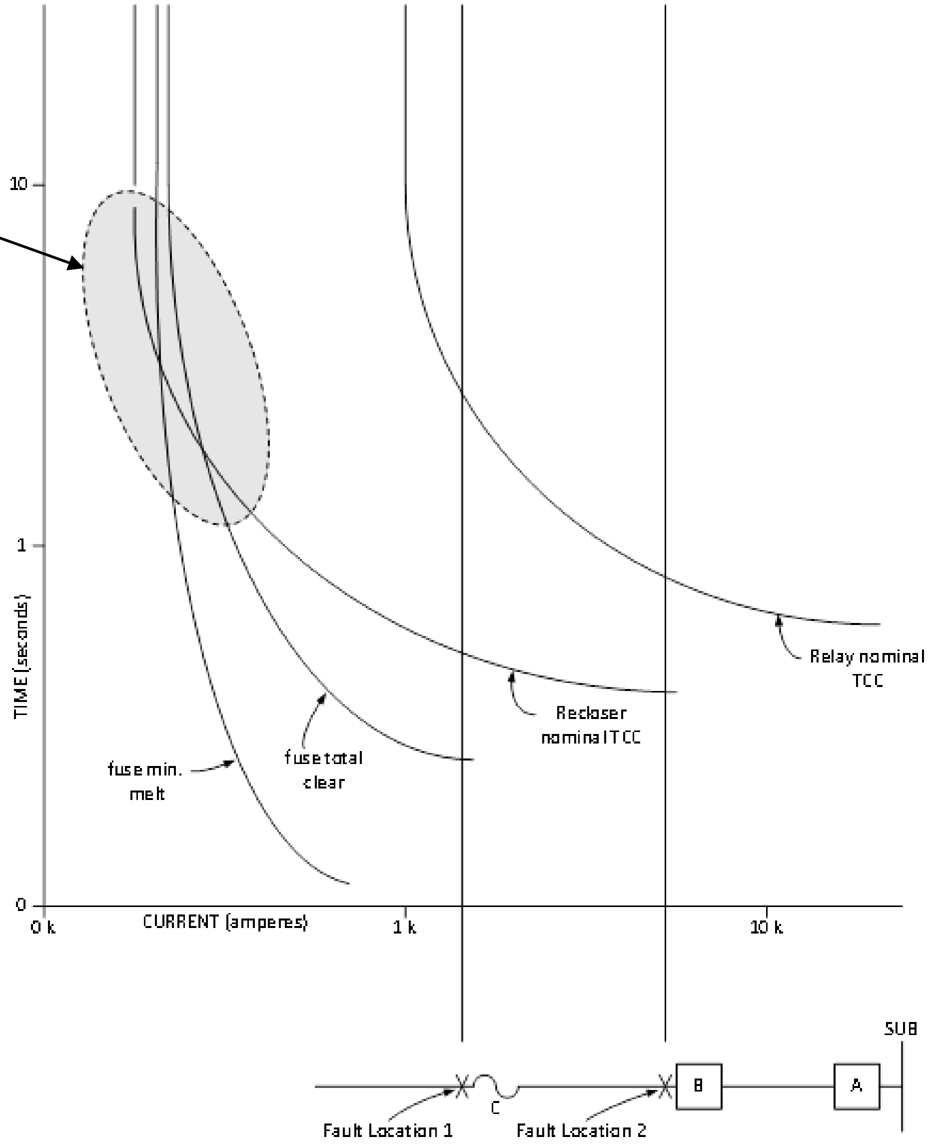
Protection Coordination

Is this Mis-coordination?

Not necessarily, as it is below the range of fault current at the location that is being considered.

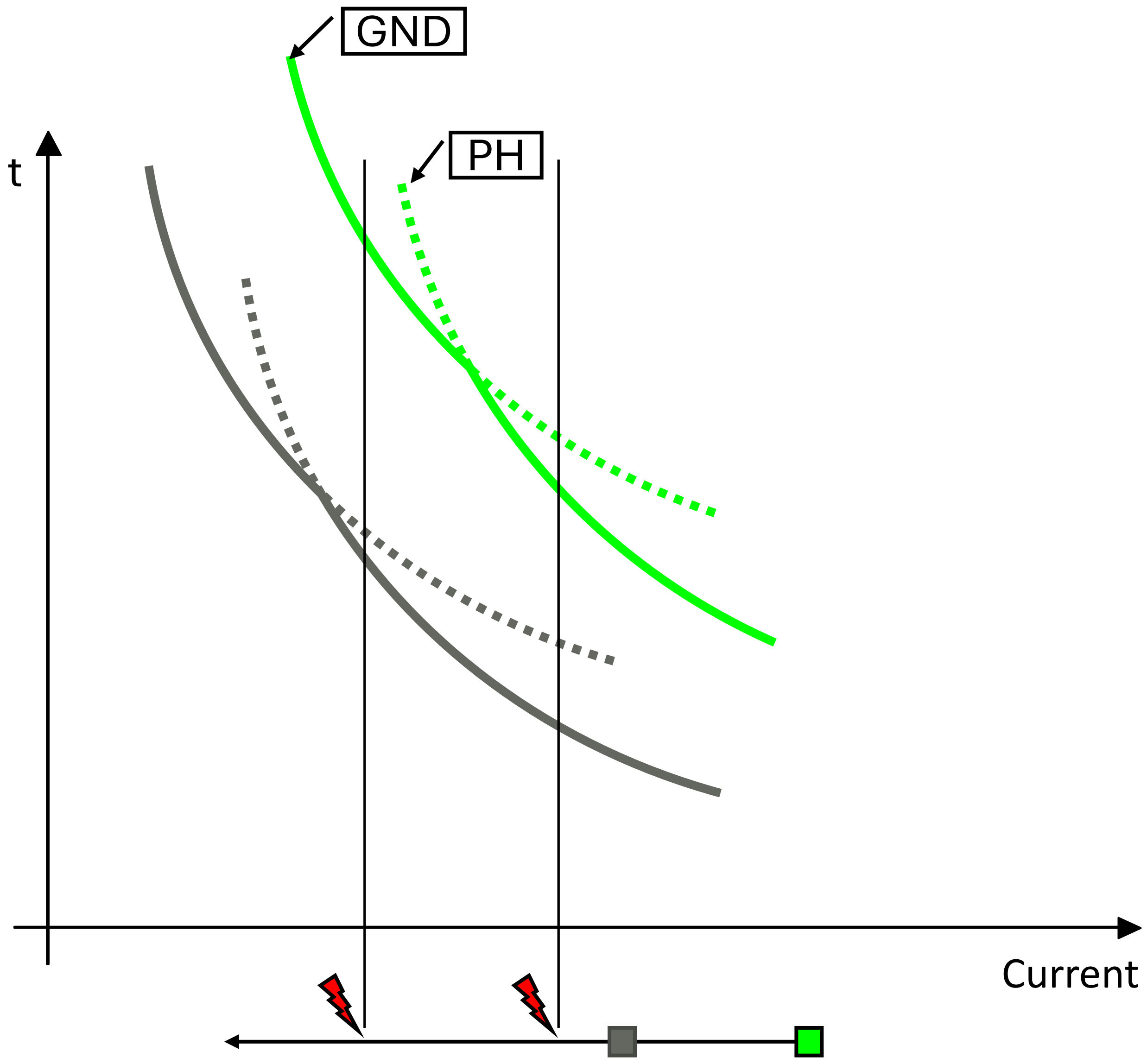
However, if there is fault resistance in the fault then the fault current would be lower, but fault resistance is less likely in a phase fault as compared to a ground fault.

Also, if the fault is located farther down the line and if the downline device fails to clear it then the relay at this location also may see this lower level of fault current meaning miscoordination could be possible as well.



Protection Coordination

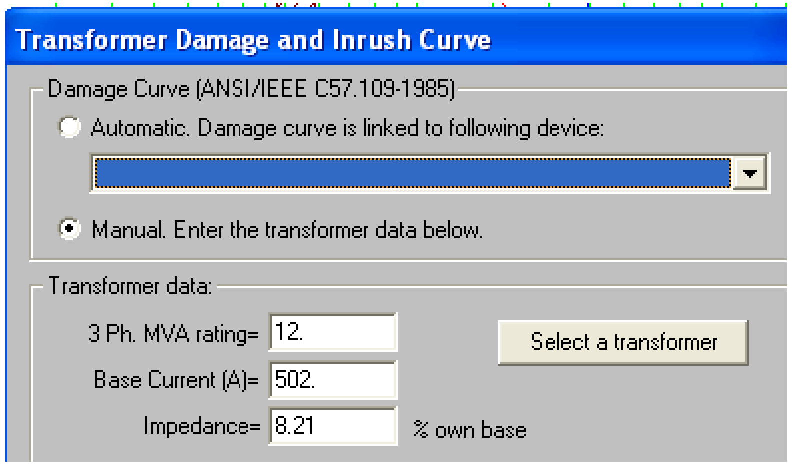
- Phase-to-Ground faults
- Phase and ground curves used
  - Both relays will pickup
- Composite curve
- Uses faster of phase or ground at each fault level

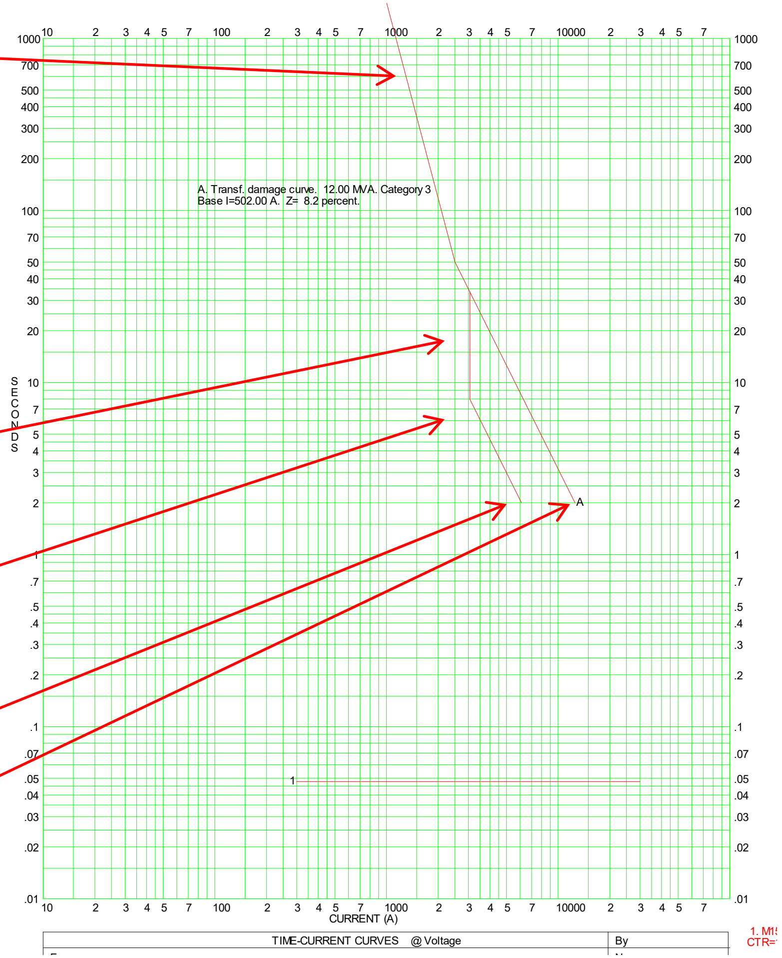


Transformer Protection - Damage Curve – ANSI/IEEE C57.109-1985

Example: Category III size (5-30MVA) Distribution Transformers in service per the above standard.

The main damage curve line shows only the thermal effect from transformer through-fault currents. It is graphed from data entered below (MVA, Base Amps, %Z):





The dog leg on the curve is added to allow for additional thermal and mechanical damage from (typically more than 5) through-faults over the life of a transformer serving overhead feeders.

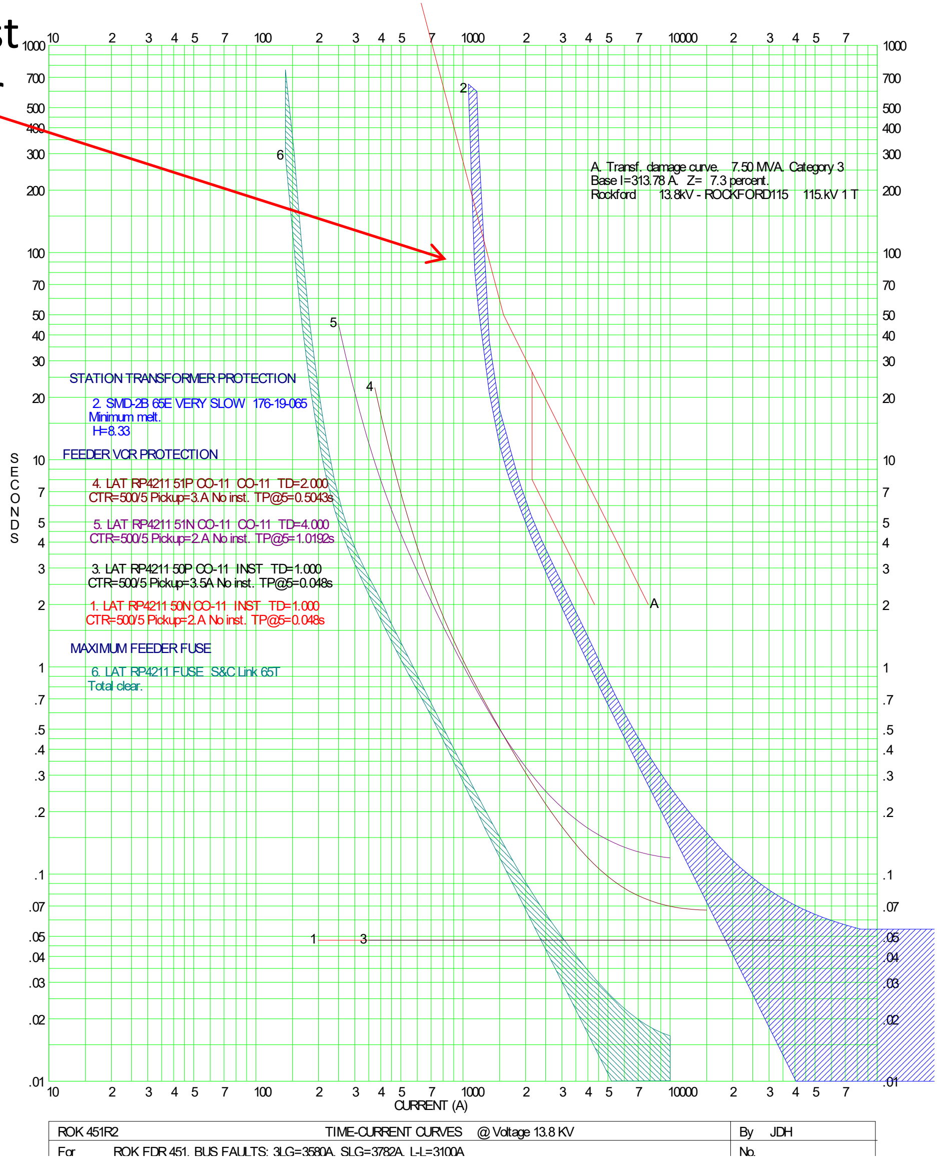
Time at 50% of the maximum per-unit through fault current = 8 seconds.

Dog leg curve - 10 times base current at 2 seconds.

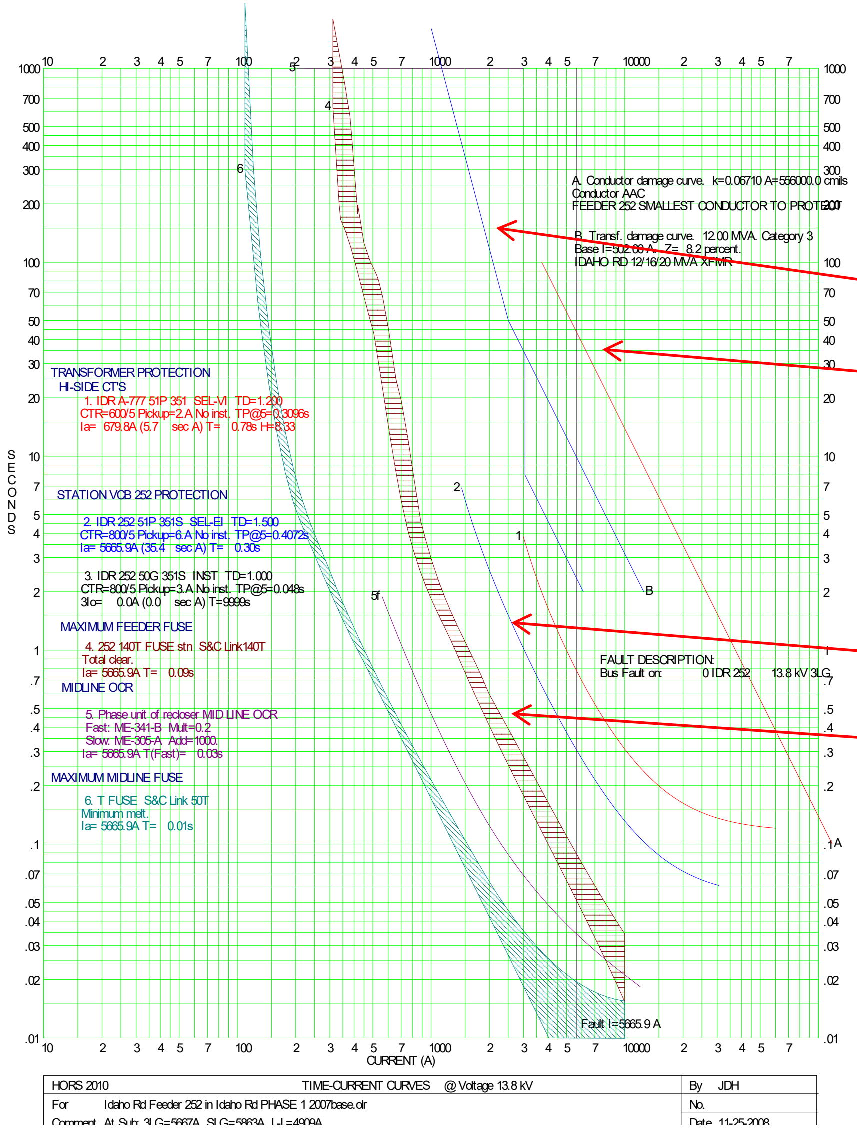
Main curve - 25 times base current at 2 seconds.

Transformer Protection using 115 kV Fuses

- Used at smaller substations up to 7.5 MVA transformer due to low cost of protection, but it may also depend on the type of load of the feeder e.g. if a hospital is on the feeder, it may warrant a breaker on the high side of the transformer with differential protection, etc..
- Other advantages are:
  - Low maintenance
  - Panel house & station battery not required
- There are also several disadvantages of using fuses:
- Low interrupting rating from 1,200A (for some older models) up to 10,000A at 115 kV.
  - By contrast a circuit switcher can have a rating of 25kA and breakers have normally 40kA.
  - The fuses are rated to blow within 5 minutes at twice their nameplate rating. Thus, a 65 amp fuse will blow at 130 A. This compromises the amount of overload we can carry in an emergency and still provide good sensitivity for faults.



System Overview



What are the types of curves?

Damage Curves:

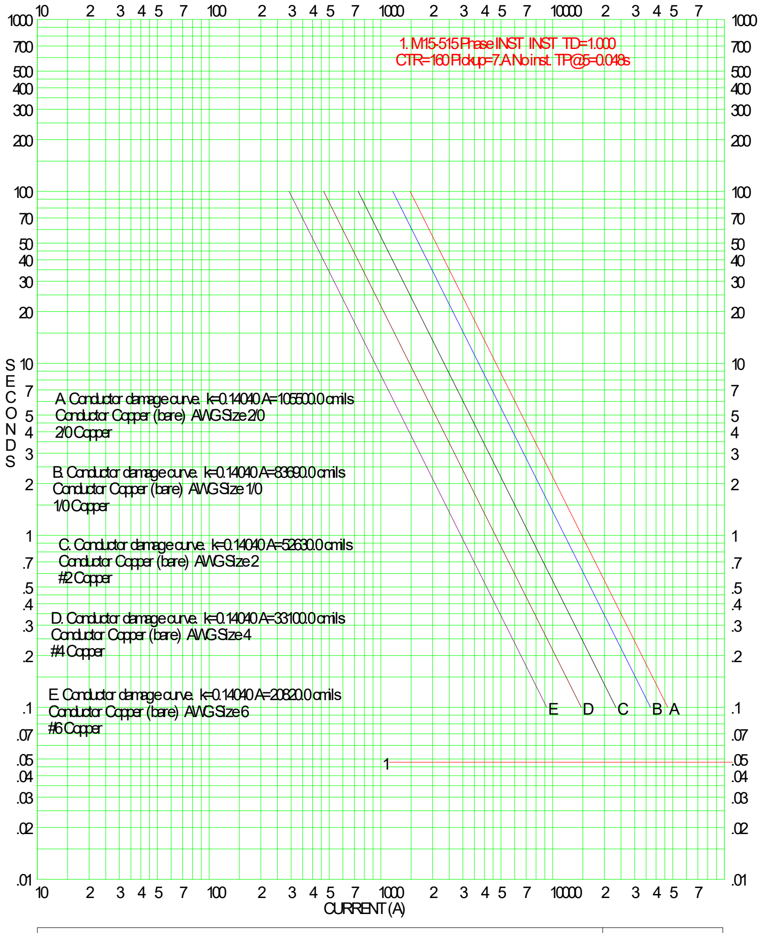
- transformer
- conductor

Protective Curves:

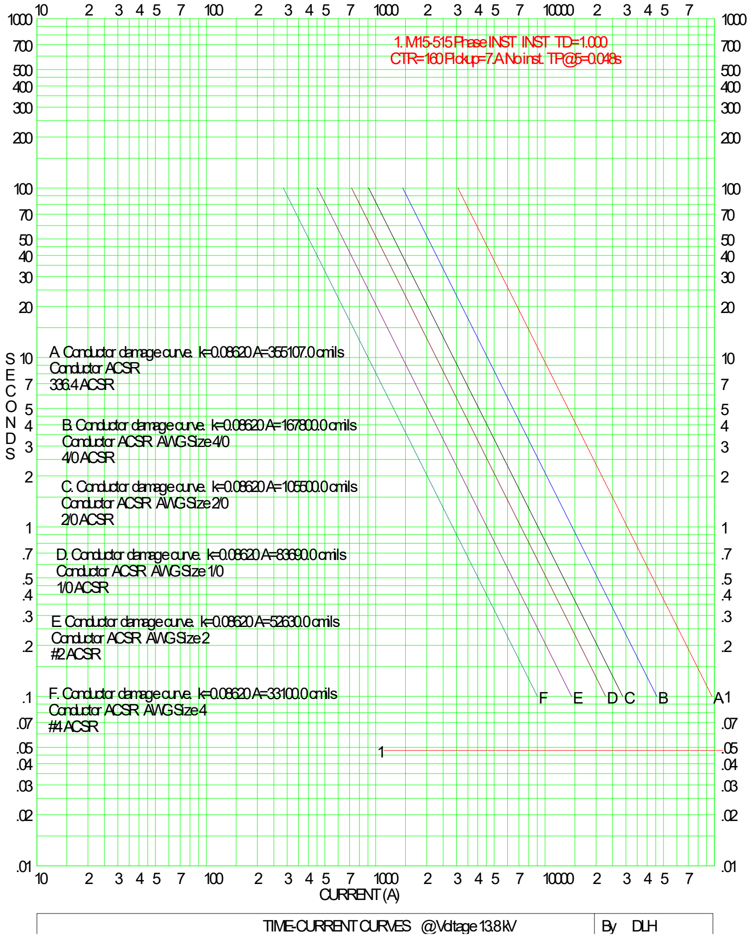
- Relay
- Fuse

Conductor Damage Curves

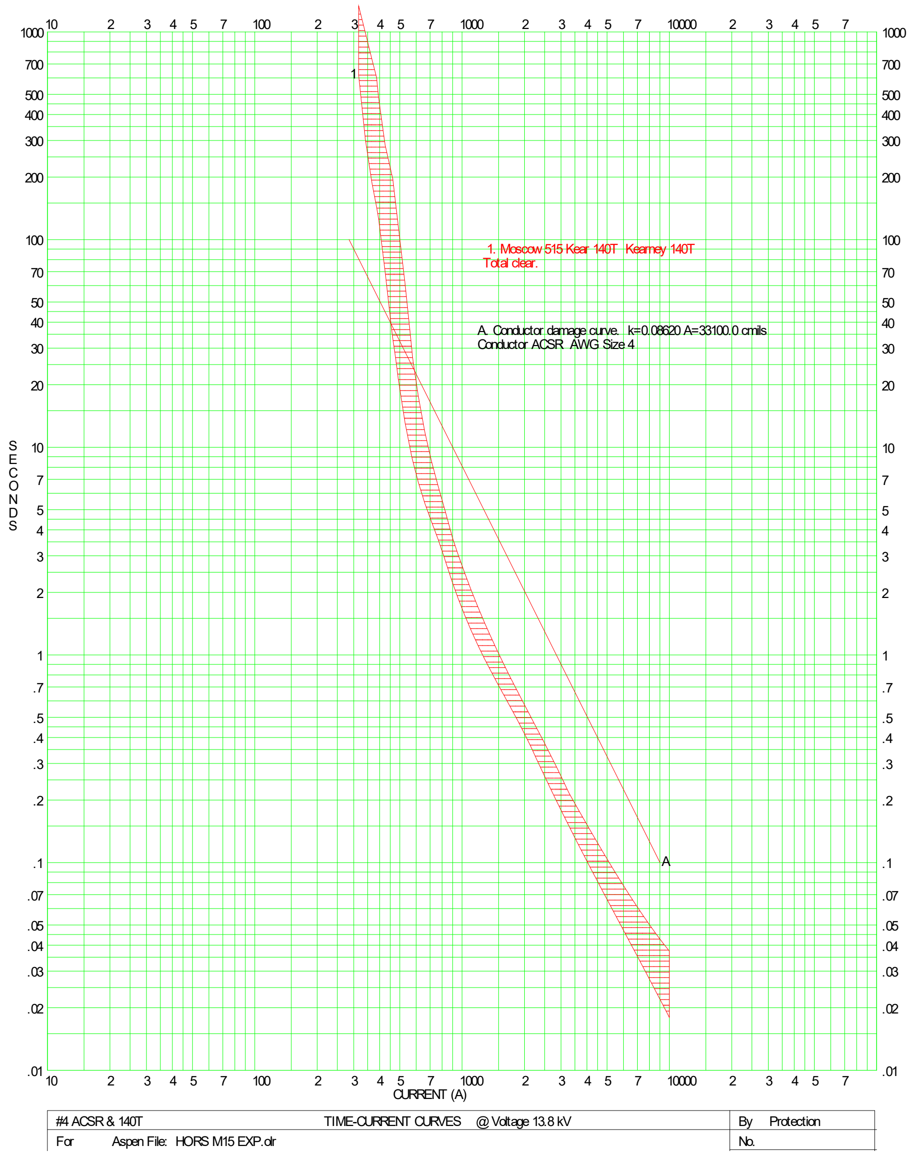
Copper Conductor Damage Curves (2/0 damage at 1500A @ 100sec.)



ACSR Conductor Damage Curves (2/0 damage at 900A @ 100sec.)



Conductor Protection Graph



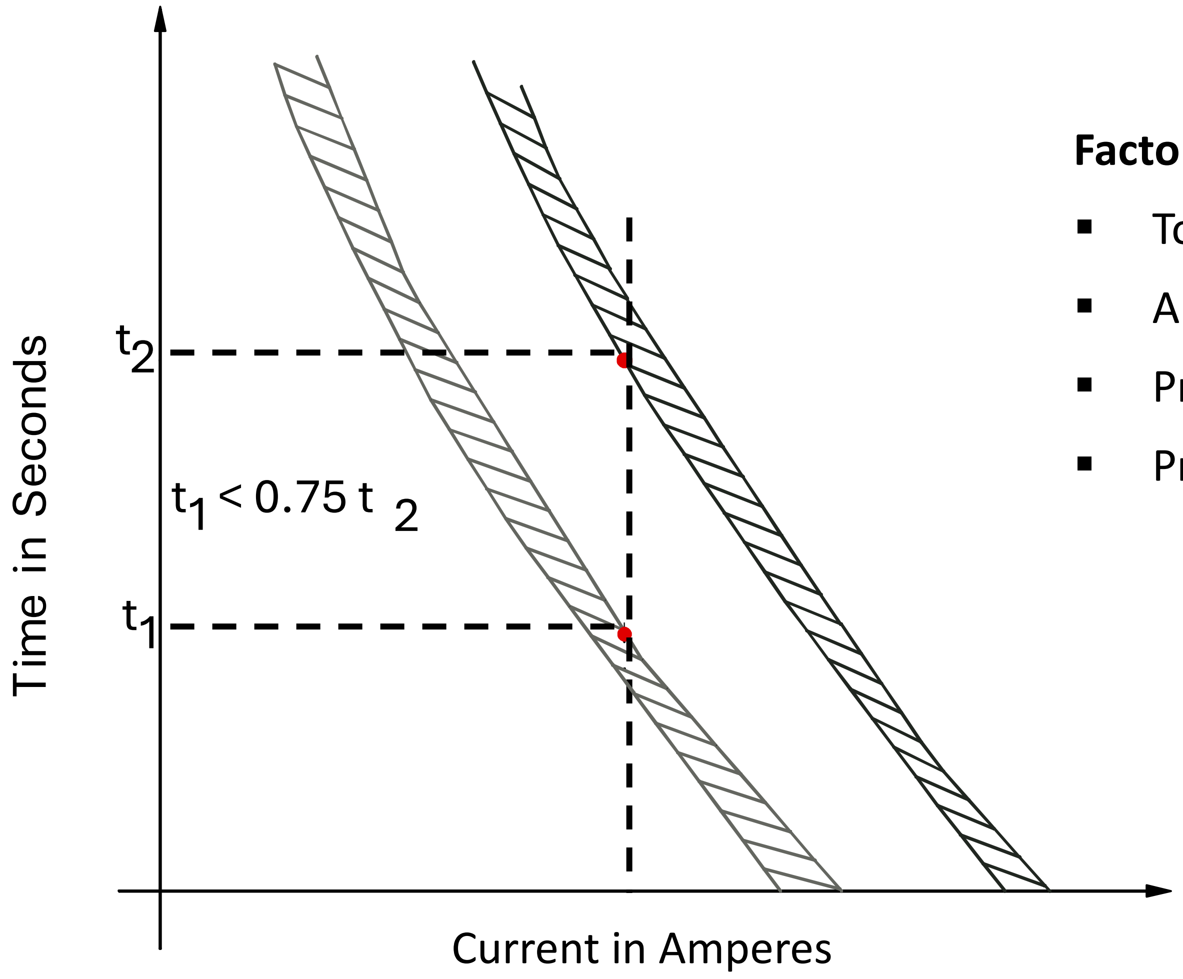
Comparing a 140T fuse versus a #4 ACSR Damage curve.

The 140T won't protect the

Conductor below about

550 amps where the curves cross.

Fuse-Fuse Coordination



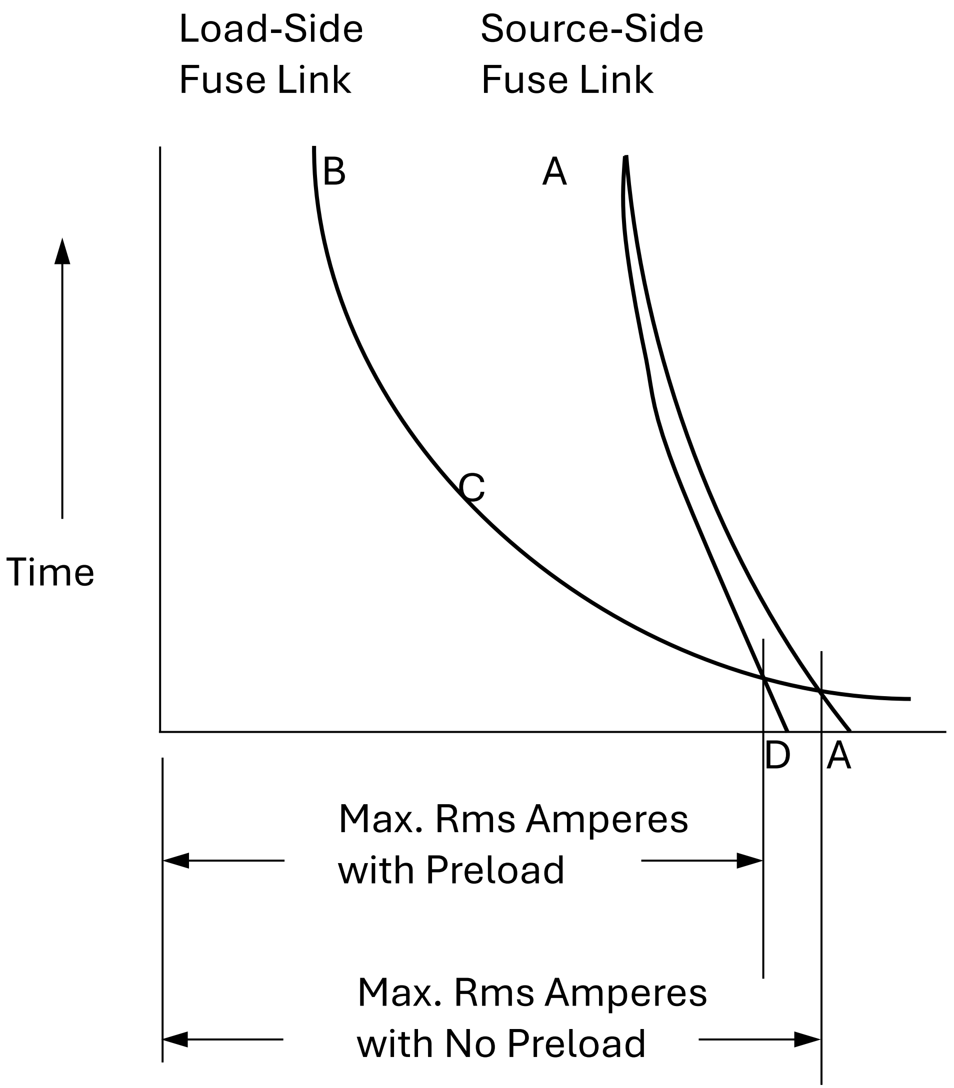
Factors affecting coordination

- Tolerances
- Ambient temperature
- Preloading
- Pre-damage due to transients and through faults

Fuse-Fuse Coordination

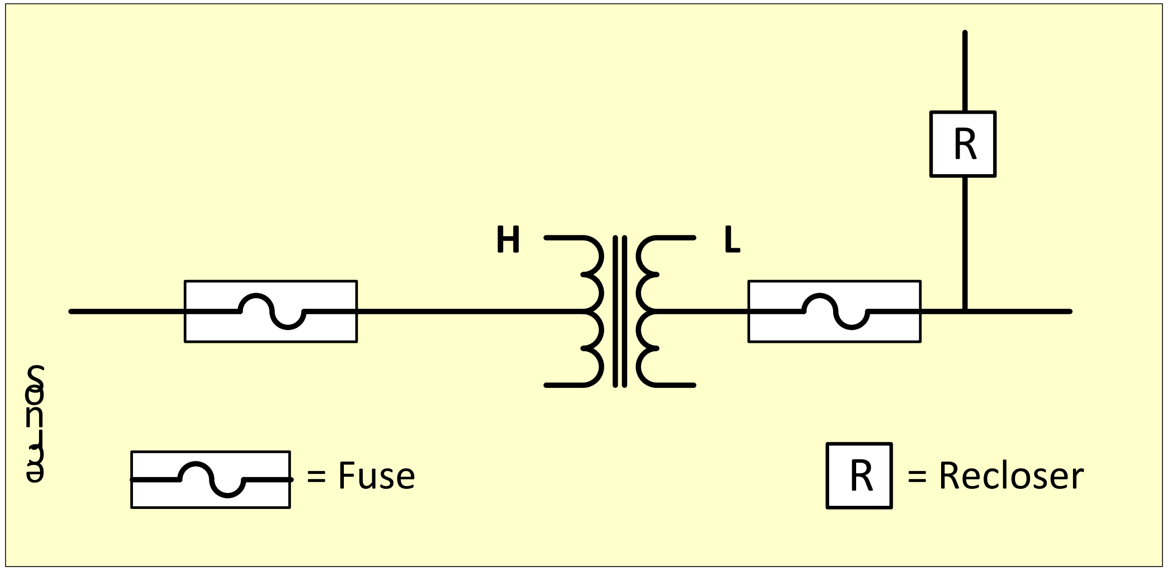
- Some manufacturers give the tables considering both preload and no preload. In the first case the curve is steeper as shown in the figure.

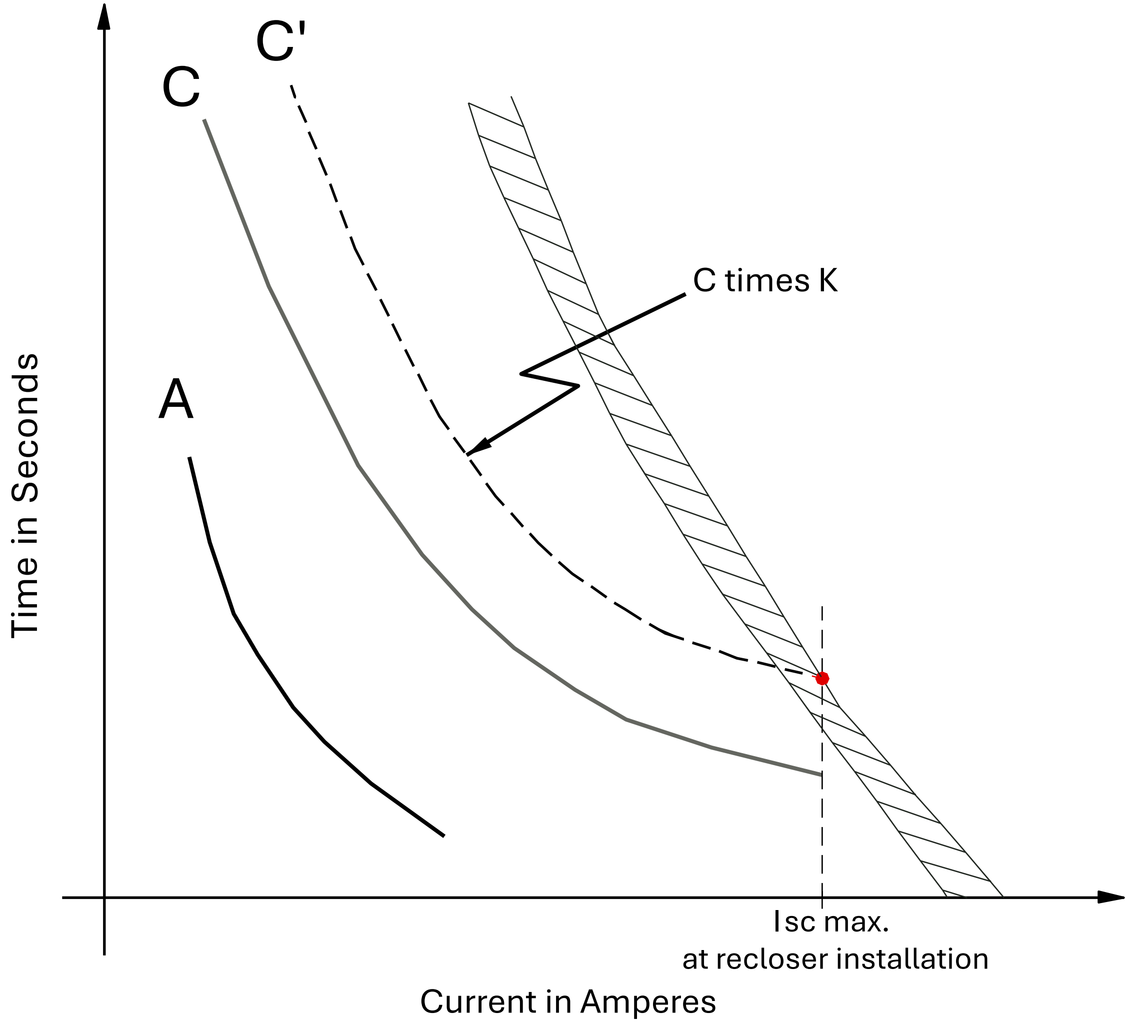
- The table on next page presents the coordination of S&C Standard Fuse Links, based on Preloading of Source Side Fuse Links.



Source-side Fuse - Recloser Coordination

Referring TCCs to Transformer Secondary



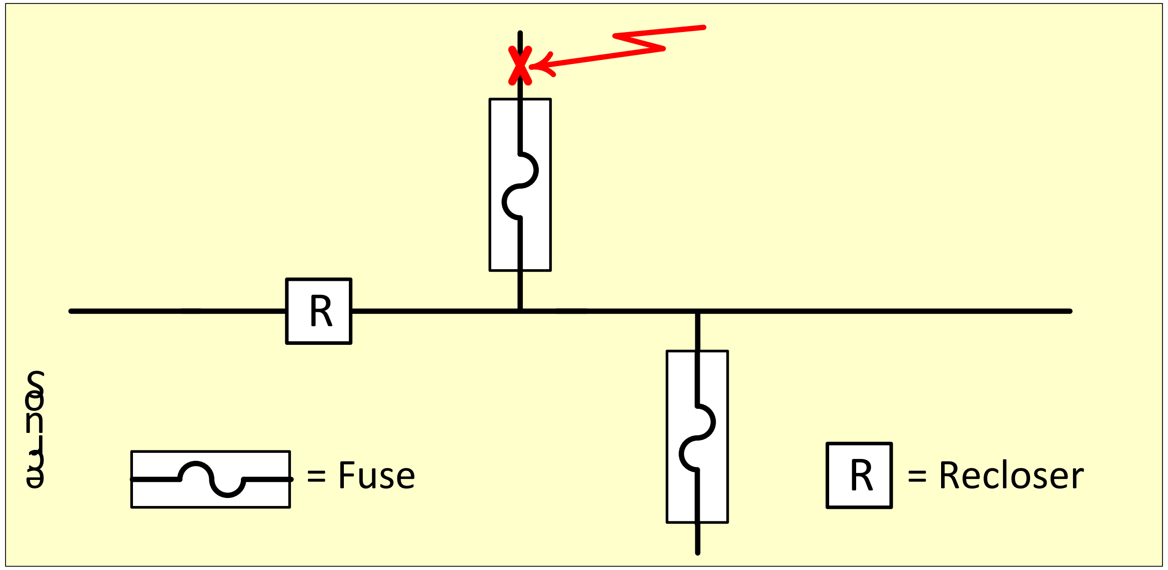


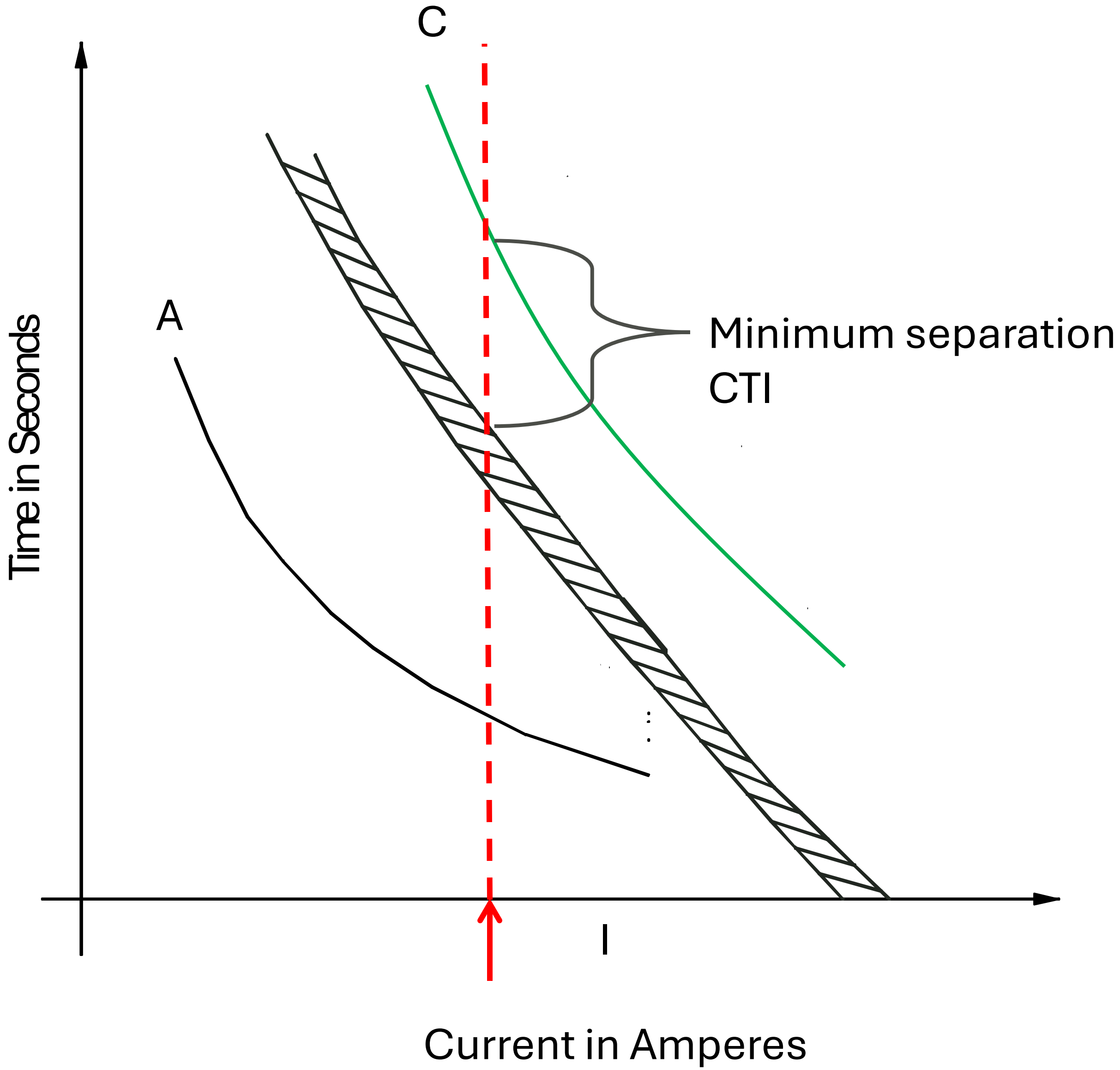
K Factor for Source Side Fuses

Multiply the time values of the delayed curve of the recloser

Reclosing time in cycles	K Factor Multipliers for		
	Two-Fast, Two-Delayed	One-Fast, Three-Delayed	Four-Delayed
25	2.70	3.20	3.70
30	2.60	3.10	3.50
50	2.10	2.50	2.70
90	1.85	2.10	2.20
120	1.70	1.80	1.90
240	1.40	1.40	1.45
600	1.35	1.35	1.35

Recloser - Load-side Fuse Coordination

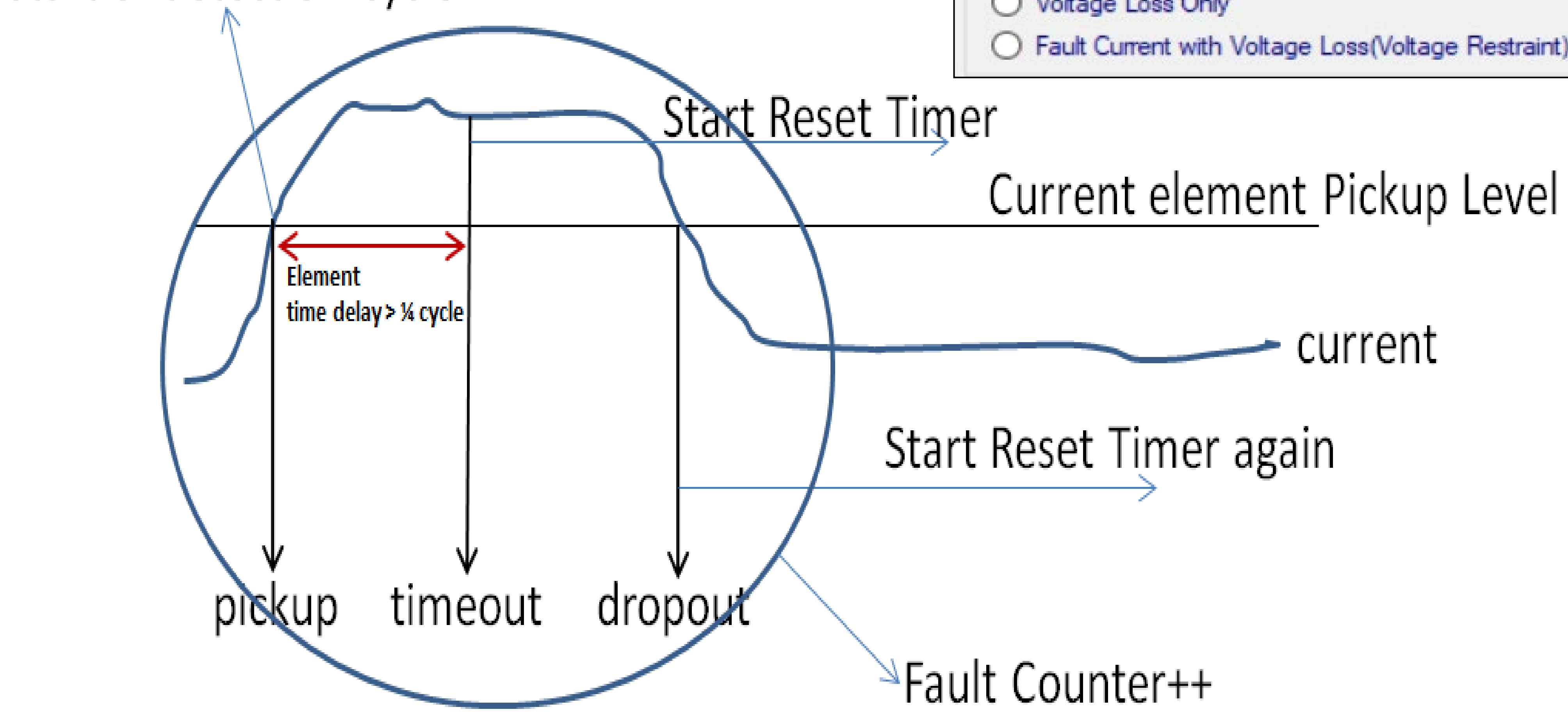




Sectionalizer

- Reclosers may coordinate with down-stream protective devices called sectionalizer
- Sectionalizer is a typically a no-load break switch equipped with a tripping mechanism triggered by a counter or a timer
  - A sectionalizer is generally not rated to interrupt fault current and is therefore less expensive than a recloser
- Each sectionalizer detects and counts fault current interruptions by the recloser (or circuit breaker).
- After a pre-determined number of interruptions, the sectionalizer will open, thereby isolating the faulty section of the circuit, allowing the recloser to restore supply to the other non-fault sections

Sectionalizer Fault Counter – Fault current

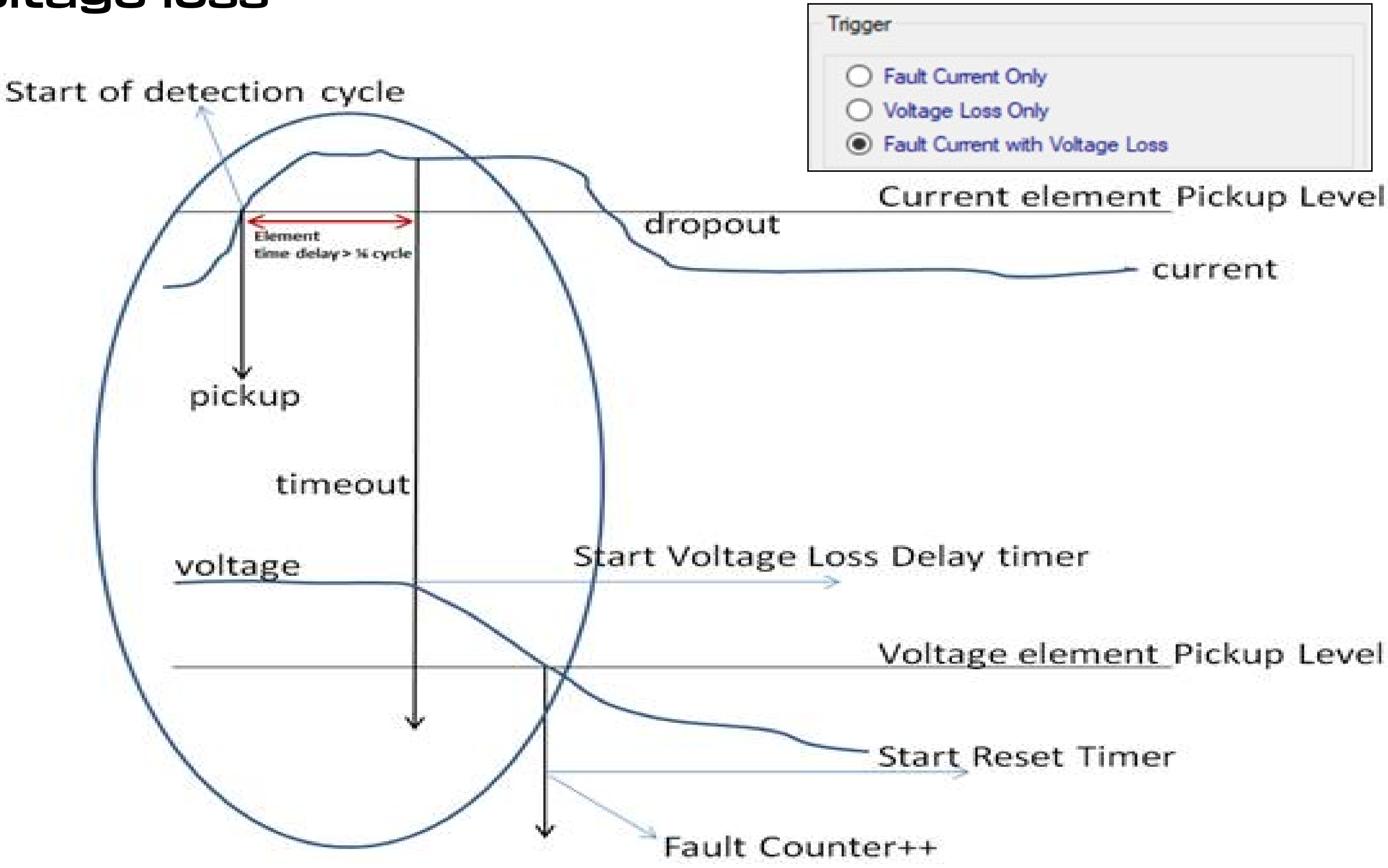


Sectionalizer Fault Counter – Voltage loss

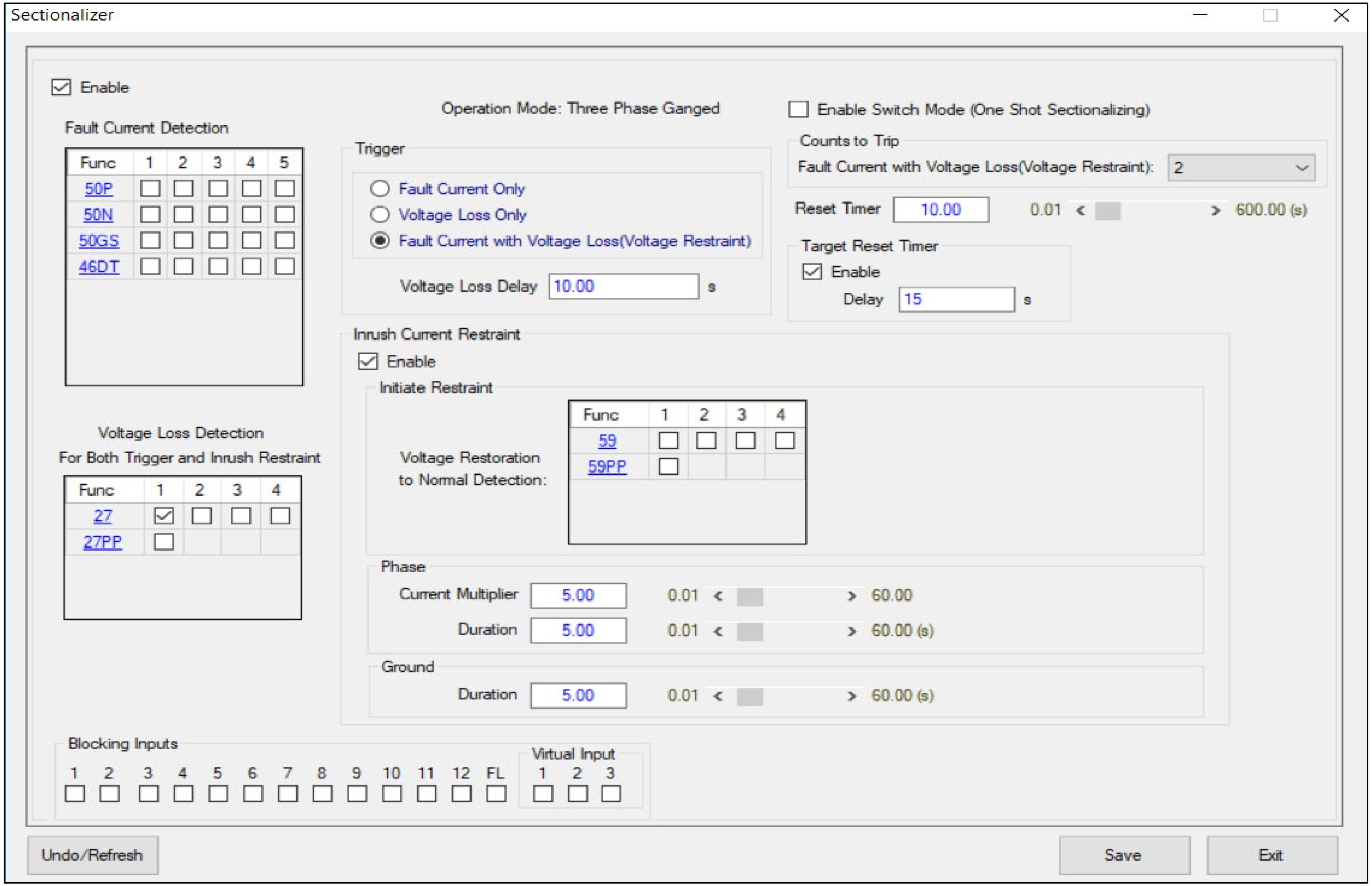
Trigger Method: Voltage Loss Only

- A count is triggered when the measured voltage drops below the selected Voltage Loss Detection element threshold.
- This applies to each voltage function you select.

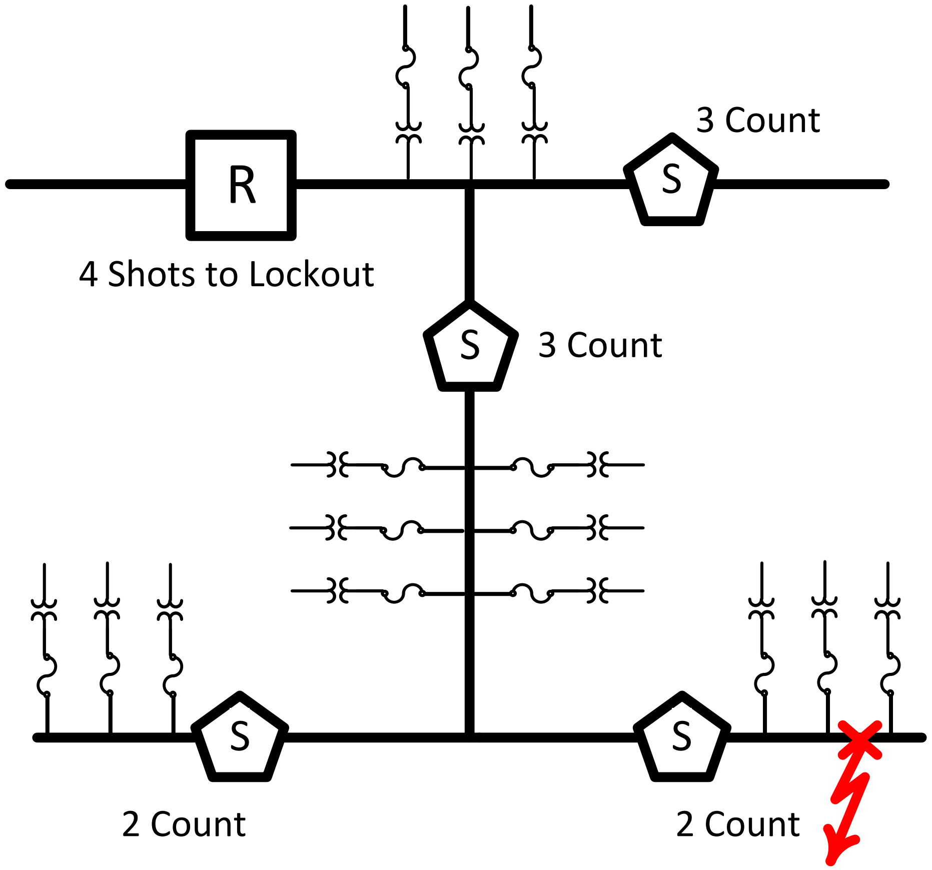
Sectionalizer Fault Counter - Fault current with voltage loss



Sectionalizer – settings screen example



Sectionalizer – operation sequence

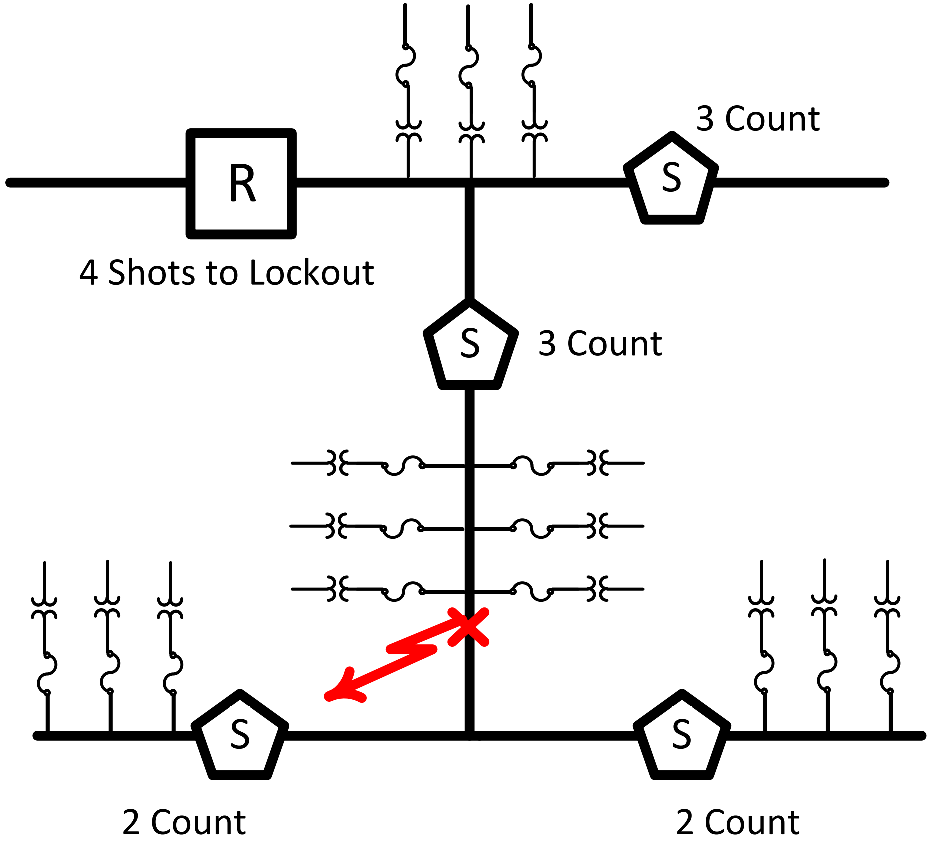


- Fault downline of 2-count sectionalizer
- Recloser trips (Trip 1), and closes (Shot 1)
- Fault still online, recloser trips again (Trip 2), waits
- 2-count Sectionalizer opens
- Recloser closes (Shot 2)
  - Recloser holds
  - Recloser resets

Sectionalizer

- Counts fault current pulses and opens during open recloser period

Sectionalizer – operation sequence

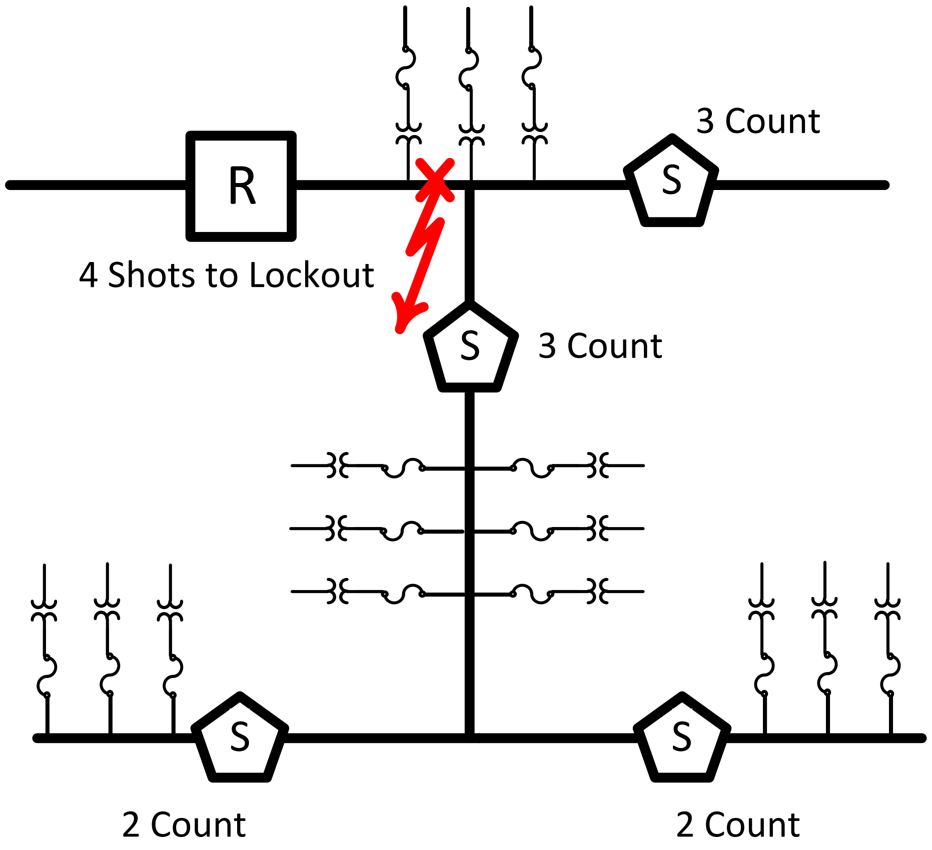


- Fault downline of 3-count sectionalizer
- Recloser trips (Trip 1), and closes (Shot 1)
- Fault still online, recloser trips again (Trip 2), waits
- Recloser closes (Shot 2)
- Recloser trips again (Trip 3), waits
- 3-count Sectionalizer opens
- Recloser closes (Shot 3)
  - Recloser holds
  - Recloser resets

Sectionalizer

- Counts fault current pulses and opens during open recloser period

Sectionalizer – operation sequence



- Fault downline of Recloser, upline of any 3-count sectionalizer
- Recloser trips (Trip 1), and closes (Shot 1)
- Fault still online, recloser trips again (Trip 2), waits
- Recloser closes (Shot 2)
- Recloser trips again (Trip 3), waits
- Recloser closes (Shot 4)
- Recloser trips, locks out

Sectionalizer

- Counts fault current pulses and opens during open recloser period

Recloser - Sectionalizer Coordination

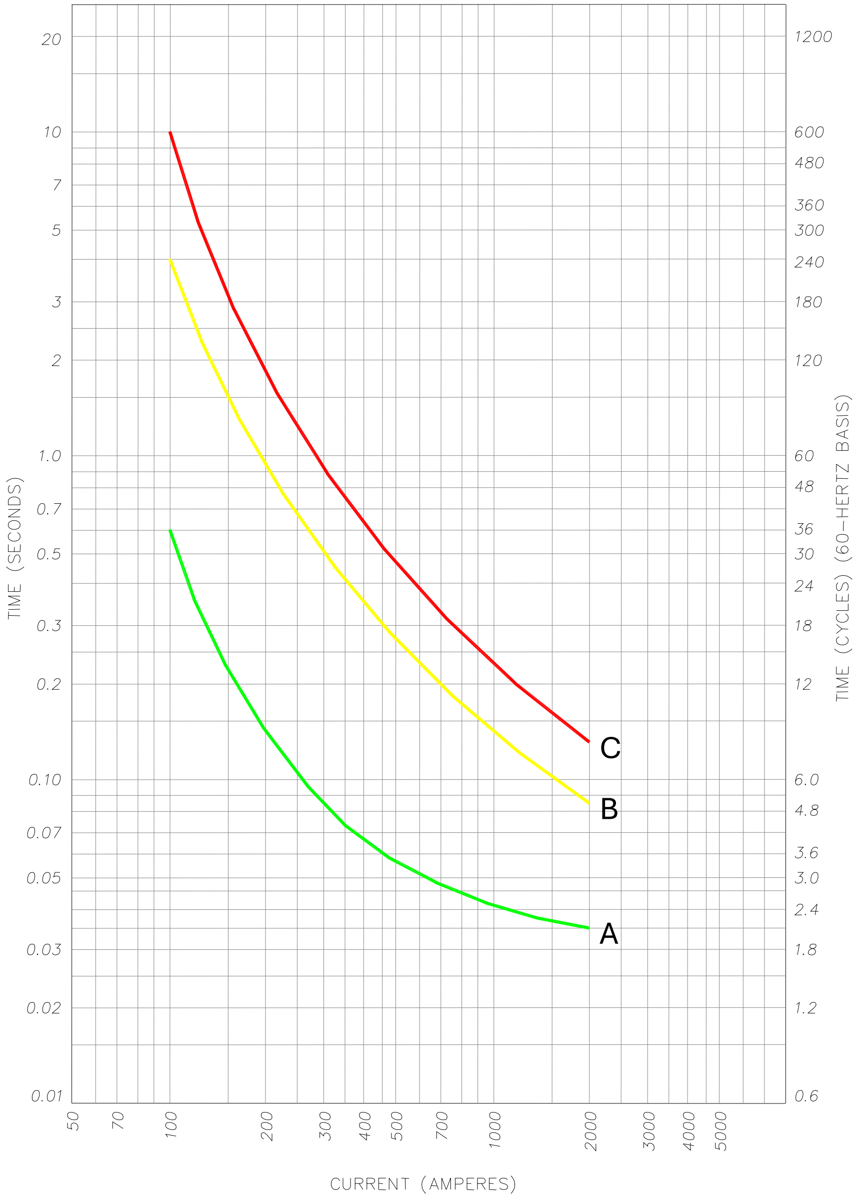
- Sectionalizers have no time/current operating characteristic
  - Their coordination does not require analysis of these curves
- Coordination criteria is based on the number of operations of the back-up recloser
- Minimum Actuating Current = 80% of back-up recloser pickup
- Count < recloser total operations to lockout
- Reset time > longest recloser open interval

Recloser - Recloser Coordination

Coordination Approach

- Set Minimum Trip levels for peak load currents and fault current reach
- Choose TCCs to coordinate with downline fuses
  - Fast and Slow curves
- TCCs must coordinate over range of fault currents in their zone of protection

Time-current curves for reclosers



- Limited choices for hydraulic controlled
- Electronic controls access to many standard, manufacturer and even custom curves

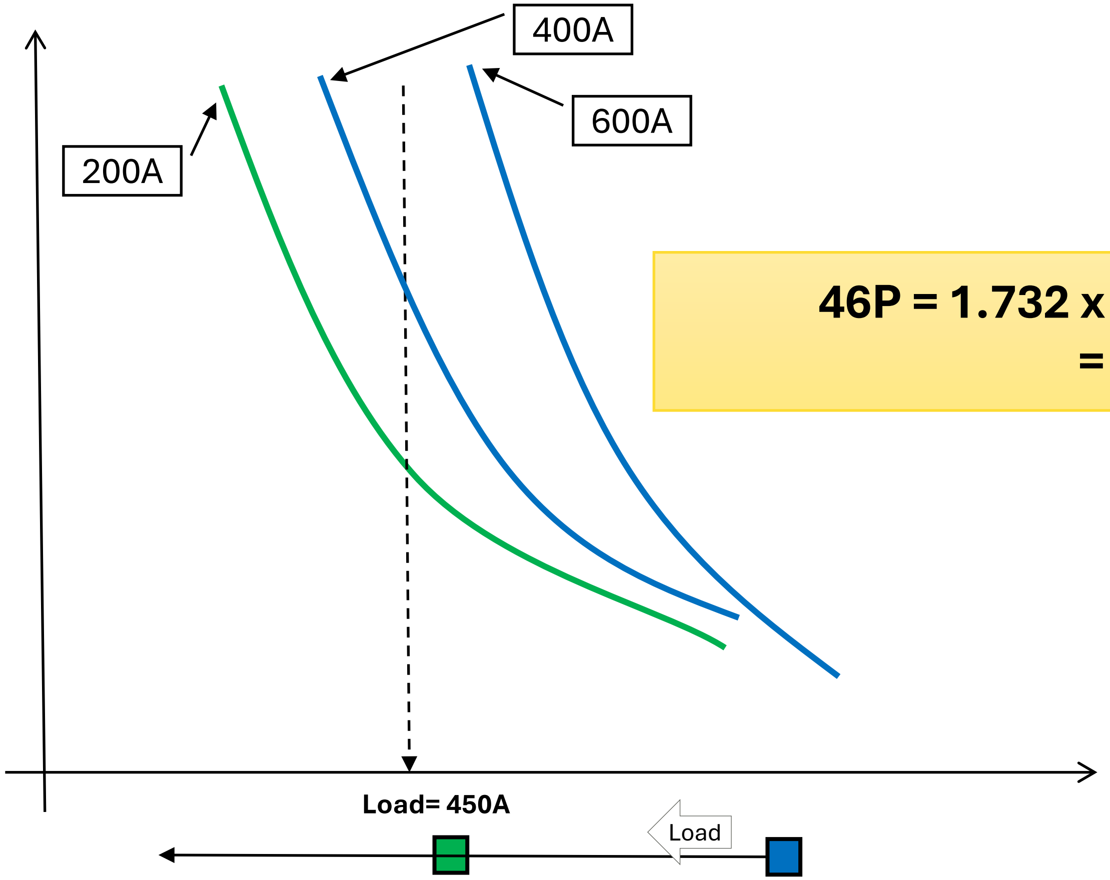
Recloser Application

Factors

- System voltage
- Maximum fault current available at recloser location
- Maximum load current, including cold load
- Minimum fault current within recloser's protection zone
- Coordination with other protective devices both source and load sides
- Ground fault sensing

Protection Coordination

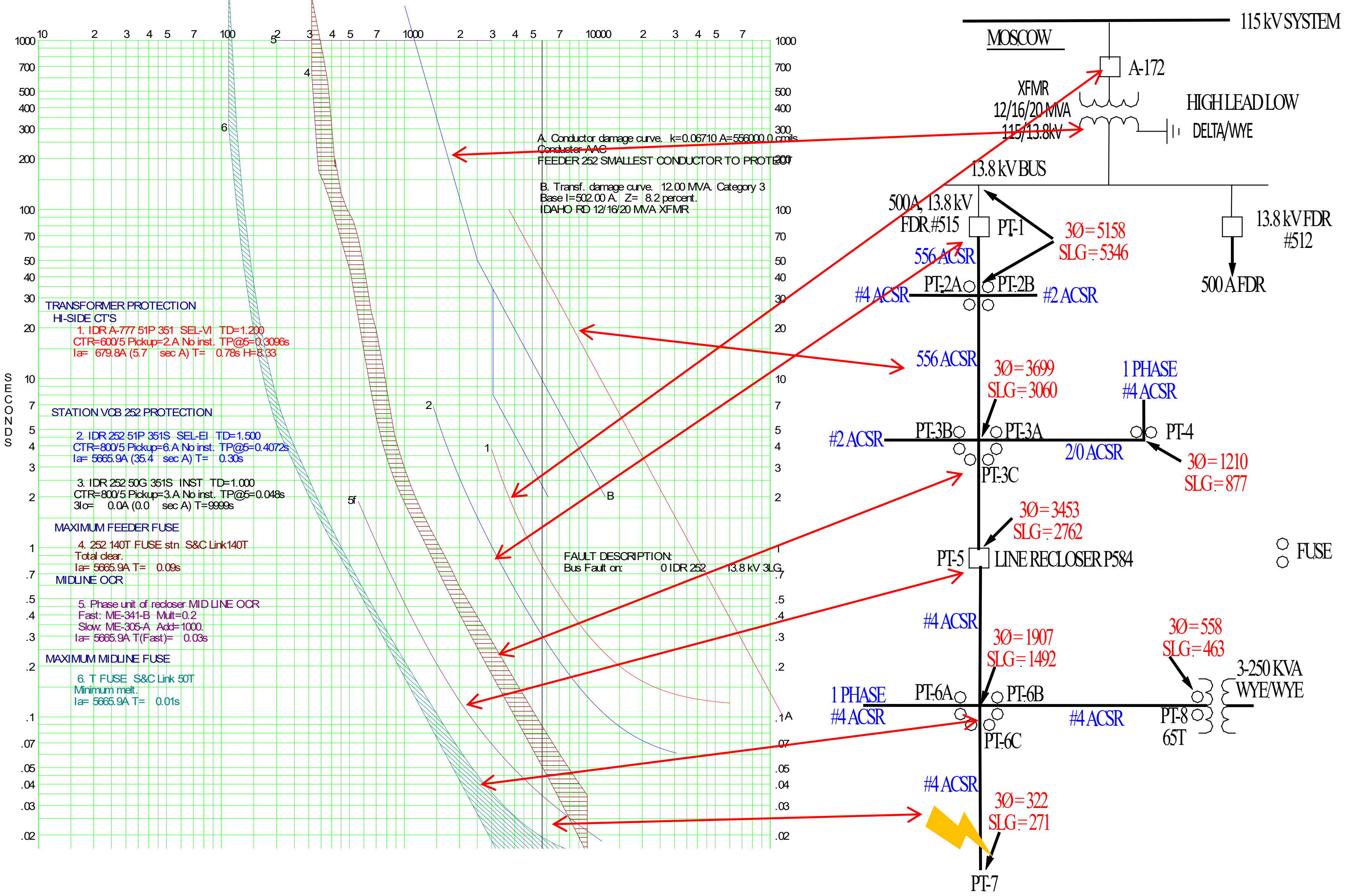
- Negative Sequence Overcurrent (46)
  - Select a pickup value ($46P_{temp}$), TCC, time dial or delay that coordinates with downline device phase OC
  - Disregard load current for pickup value
  - 46 pickup value $46P = \sqrt{3} \times 46P_{temp}$
- Further upstream devices' 46 elements set to coordinate with downstream 46 elements



46P = 1.732 x 400A
= 693A

System Overview

Each device has at least one curve plotted with current and time values on the Time Coordination Curve.



Protection Coordination – Overcurrent Reset

Current drops below pickup before timed out

- Instantaneous
- Electromechanical
- Fuses – heat dissipation
- Multiple devices in series with different reset types
    - Watch for upline devices with EM reset coordinating with downline instantaneous reset
    - Nuisance tripping on incomplete reset of upline device

Reclosing (79)

- Most distribution faults on overhead lines are temporary in nature
- Automatic reclosing is commonly applied to restore power
  - If faults are temporary, why do we need to open breakers in the first place?
  - Once a fault occurs and an arc forms, the air ionizes and provides a low impedance path for current
  - The ionized air will maintain the fault arc even if the squirrel is laying on the ground
  - Unless the circuit is de-energized, the arc will not extinguish
- Reclosing is generally NOT applied on distribution feeders that are primarily underground as the faults are typically permanent faults
- Refer to C37.104-2022 - IEEE Guide for Automatic Reclosing of Circuit Breakers for AC Distribution and Transmission Lines – published in Apr 2022.

Reclosing Definitions

- Automatic Circuit Recloser: A self-controlled device for automatically interrupting and reclosing an alternating-current circuit, with a predetermined sequence of opening and reclosing followed by resetting, hold-closed, or lock-out operation.
- Automatic Line Sectionalizer: A self-contained circuit-opening device that automatically opens a circuit through it after sensing and responding to a predetermined number of successive current pulses equal to or greater than a predetermined magnitude.
  - It opens while the main electrical circuit is deenergized.
  - It may also have provision to be manually operated to interrupt loads.

Reclosing Definitions

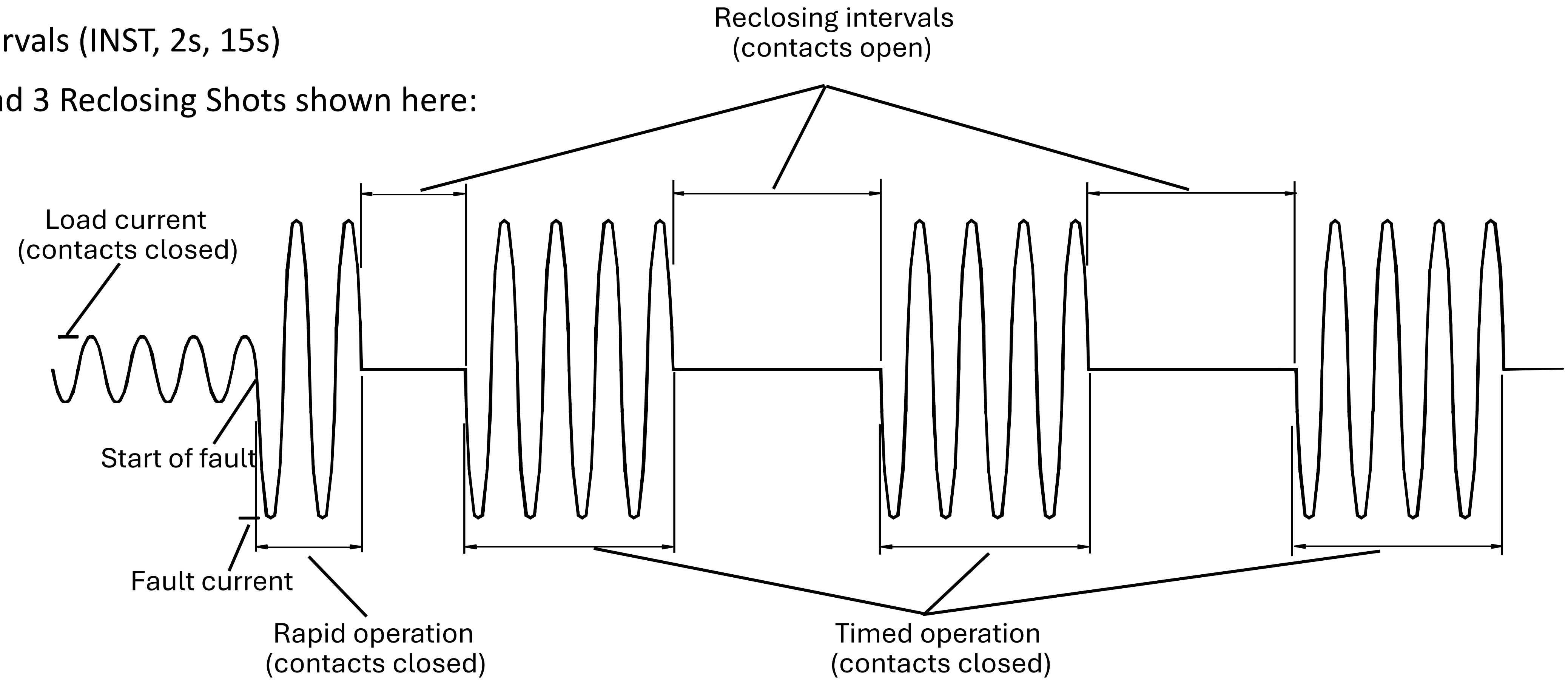
- Auto-reclosing: The automatic closing of a circuit breaker in order to restore an element to service following automatic tripping of the circuit breaker.
  - Auto-reclosing does not include automatic closing of the circuit breakers associated with shunt or series capacitor banks or shunt reactors.
- Blocking: Refers to the automatic prevention of an action following specific relay tripping operations
- Dead Time: That period of time the circuit breaker is open and the controlled circuit is deenergized following the tripping operation for a fault and before the auto-reclosing attempt
- Drive-to-Lockout: The process of forcing the auto-reclosing function to its lockout state
  - Ex., high current trip and lockout (HLC)

Reclosing Definitions

- Lockout: The state of the reclosing relay wherein the controlled line breaker is open and the relay disabled from making any further reclose attempts
- Multiple-Shot Auto-reclosing: Refers to the auto-reclosing of the circuit breaker(s) more than once within a predetermined auto-reclosing sequence
- Shot: Auto-reclose attempt that is initiated by command of the reclosing logic
- Single-Phase Auto-reclosing: Refers to the auto-reclosing of one phase of a circuit breaker following a designed single-phase trip for single-phase-to-ground faults

Reclosing (79)

- Reclosing Sequence
- Often 4 trips to lockout
  - After each trip, a reclosing “shot” is made
  - Ex., 2 trips on fast curve, 2 trips on slow or delayed curve
- Reclosing Intervals (INST, 2s, 15s)
- Initial Fault and 3 Reclosing Shots shown here:



Reclosing (79)

- A reclosing scheme typically uses several attempts or “shots”
  - Open interval time
  - This varies based upon each utility’s philosophy
- Many utilities allow for at least 3 attempts
  - 1st attempt – immediate or very short delay (this may allow for fuse saving schemes)
  - 2nd attempt – after a time delay
  - 3rd attempt – after a time delay
  - Lockout – requires human intervention either locally or remotely via a SCADA system
- How long should the first open interval be?
  - Typically, 12-18 cycles…why? **
  - At least long enough for arc extinguishing
  - If DER is present, at least long enough for downline DER disconnect in the event of a feeder fault, abnormal condition or de-energization

**** Arc deionizing time = KV/34.5 + 10.5 cycles**

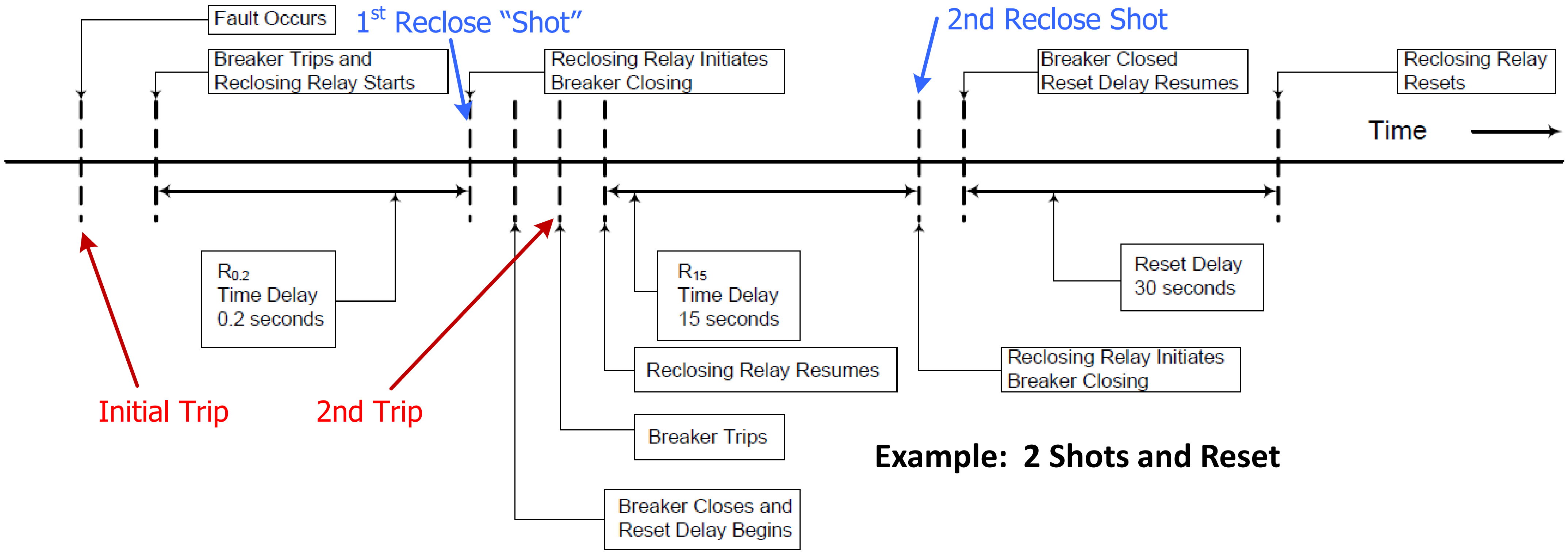
e.g. for a 24.94 KV feeder, t = 24.94/34.5 + 10.5 = 11.2 cycles

Add in some margin to get to 18 cycles for the first open interval time delay

Reclosing (79)

Reset Timer

- On Successful Reclose
  - During reclosing sequence before lockout
  - Fault cleared
- From Lockout
  - After manual closing
  - No fault present



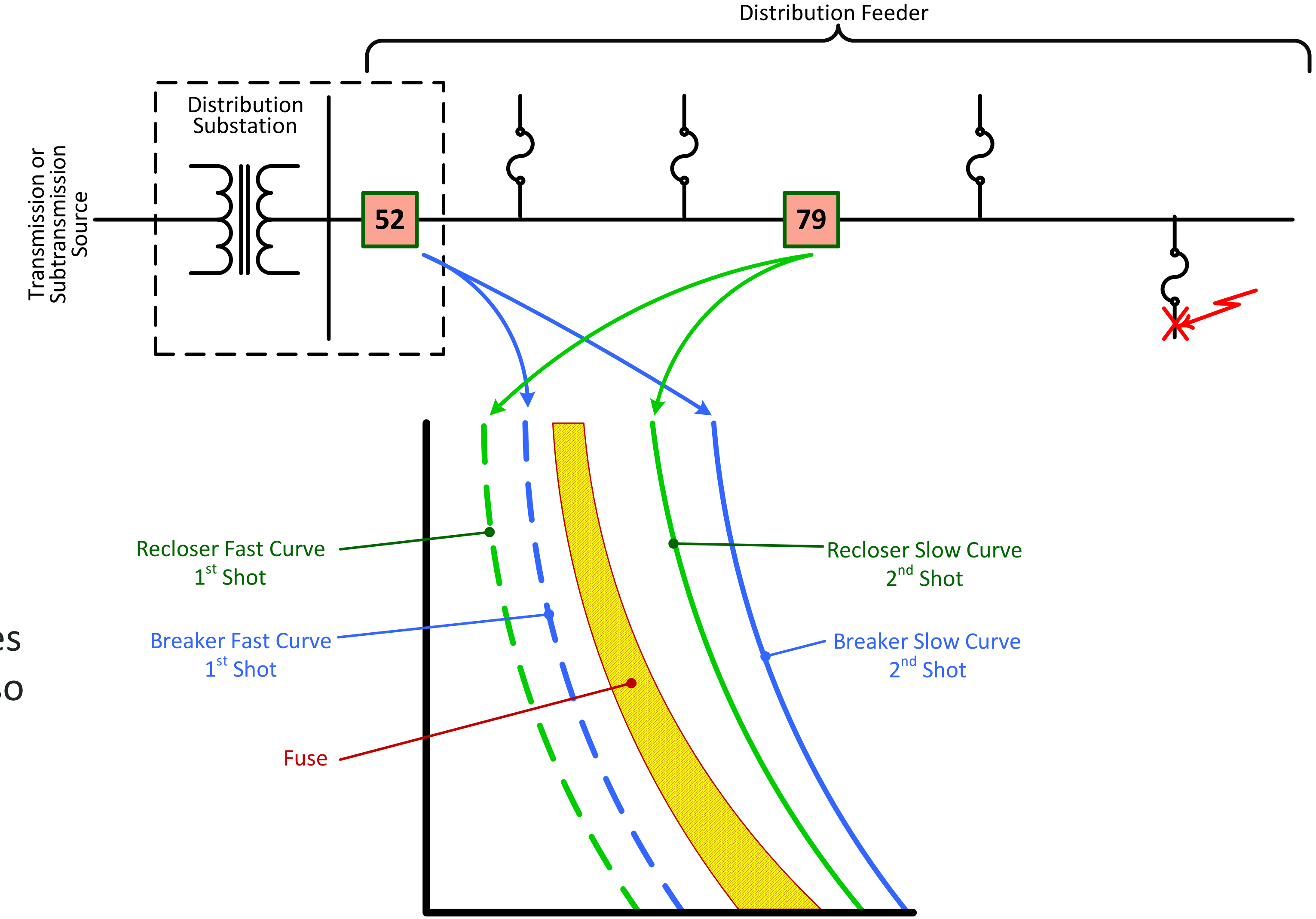
Example: 2 Shots and Reset

Reclosing (79)

- Reclosing sequence initiated by the tripping relay or by a 52 aux contact of the interrupter
- Before a breaker should reclose, several things should be considered:
  - Is the breaker locked out by some 86 device from a bus differential, transformer differential, etc.?
  - Is the control switch in the Normal-After-Close position?
  - Is auto-reclosing enabled?
  - Is the circuit TAGGED out or HOT LINE TAG on?
  - Is the recloser relay already locked out?
  - Does the breaker have enough stored energy to trip back out if the fault is still there?
  - Is the source voltage present and healthy?
  - Special fault conditions – multi-phase, high set instantaneous, etc.

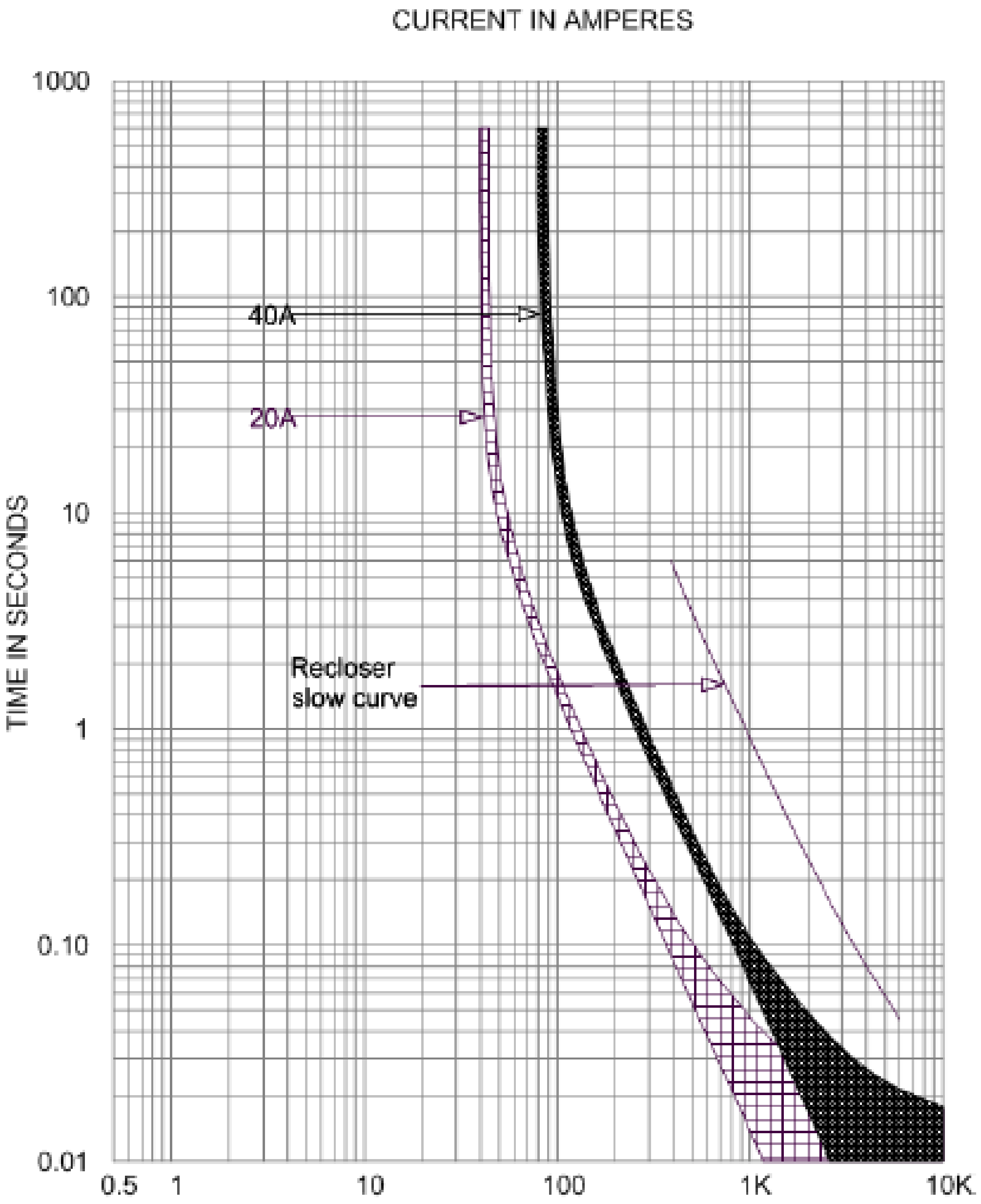
Reclosing - Sequence Coordination

- Multiple reclosers in series
  - A must with Fuse Saving Schemes
- Coordinated on fast and slow curves
  - Fast curve saves fuse
  - Slow curve blows fuse
- Reclosers detect high current pulse and advanced shot count
  - This occurs when there is a fault downline of given recloser
  - In that manner, if different TOC curves are used, all reclosers stay “in sync” so they are coordinated



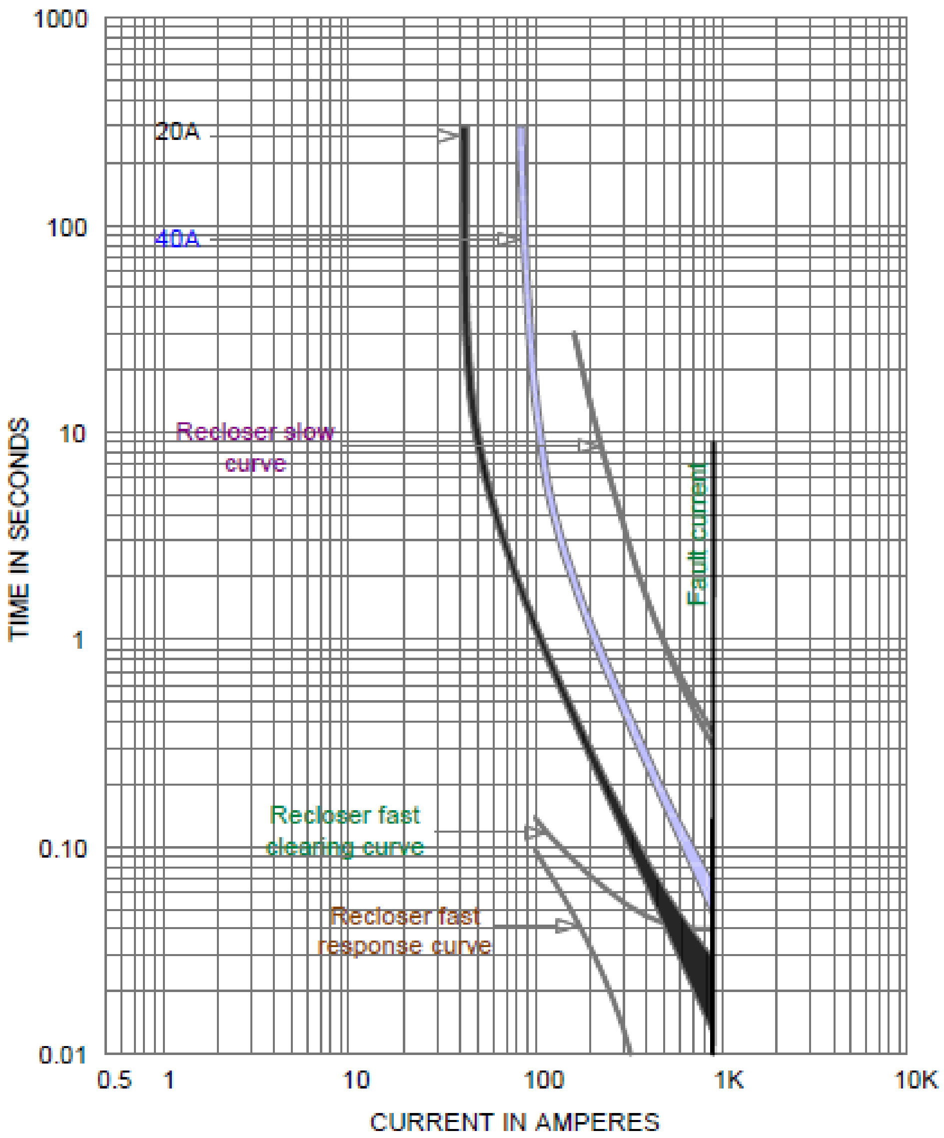
Fuse Blowing Scheme

- All Shots use "Slow Curves"



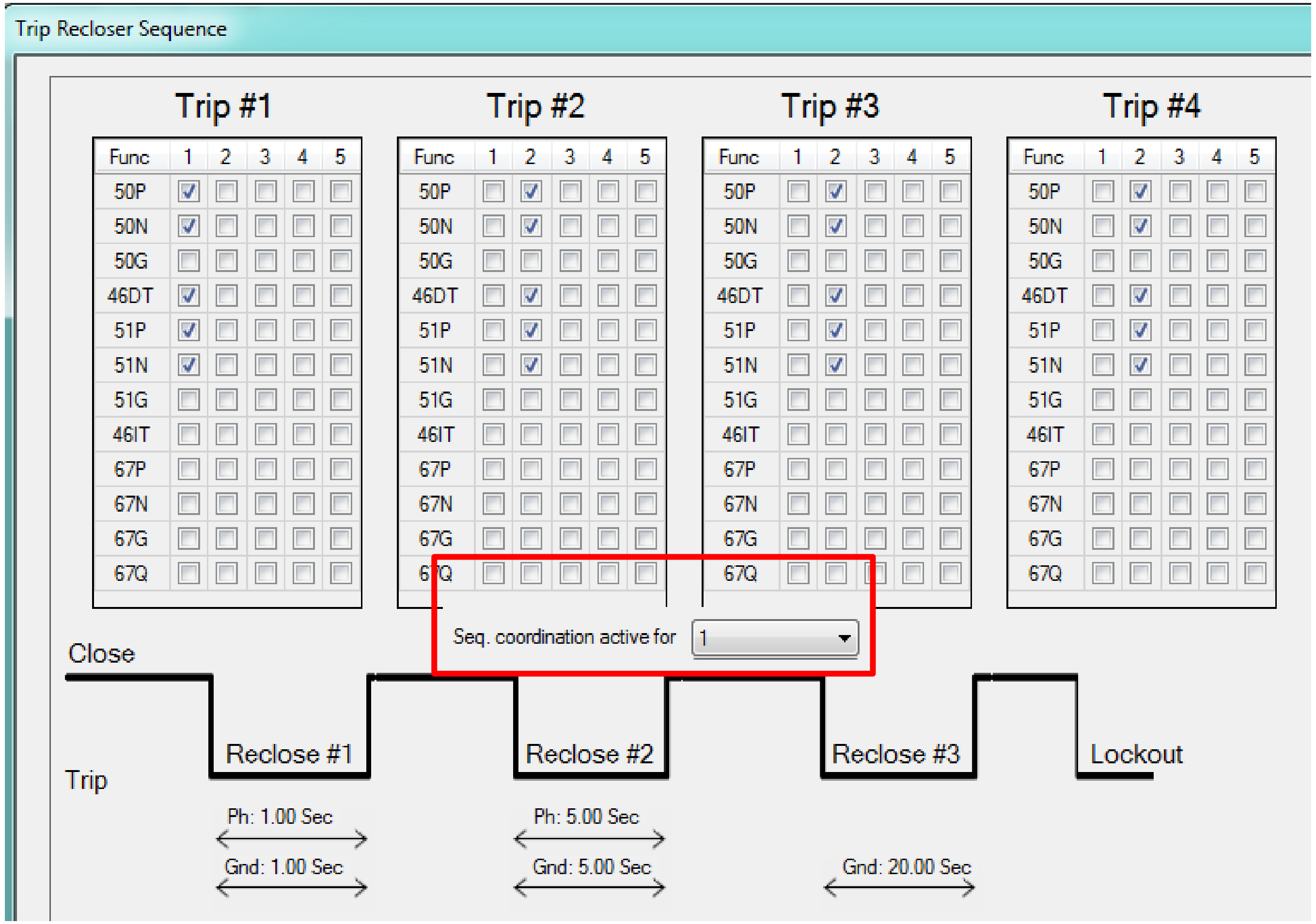
Fuse Saving Scheme

- 1st Shot use “Fast Curve” to save fuse
- 2nd+ Shots use “Slow Curves”



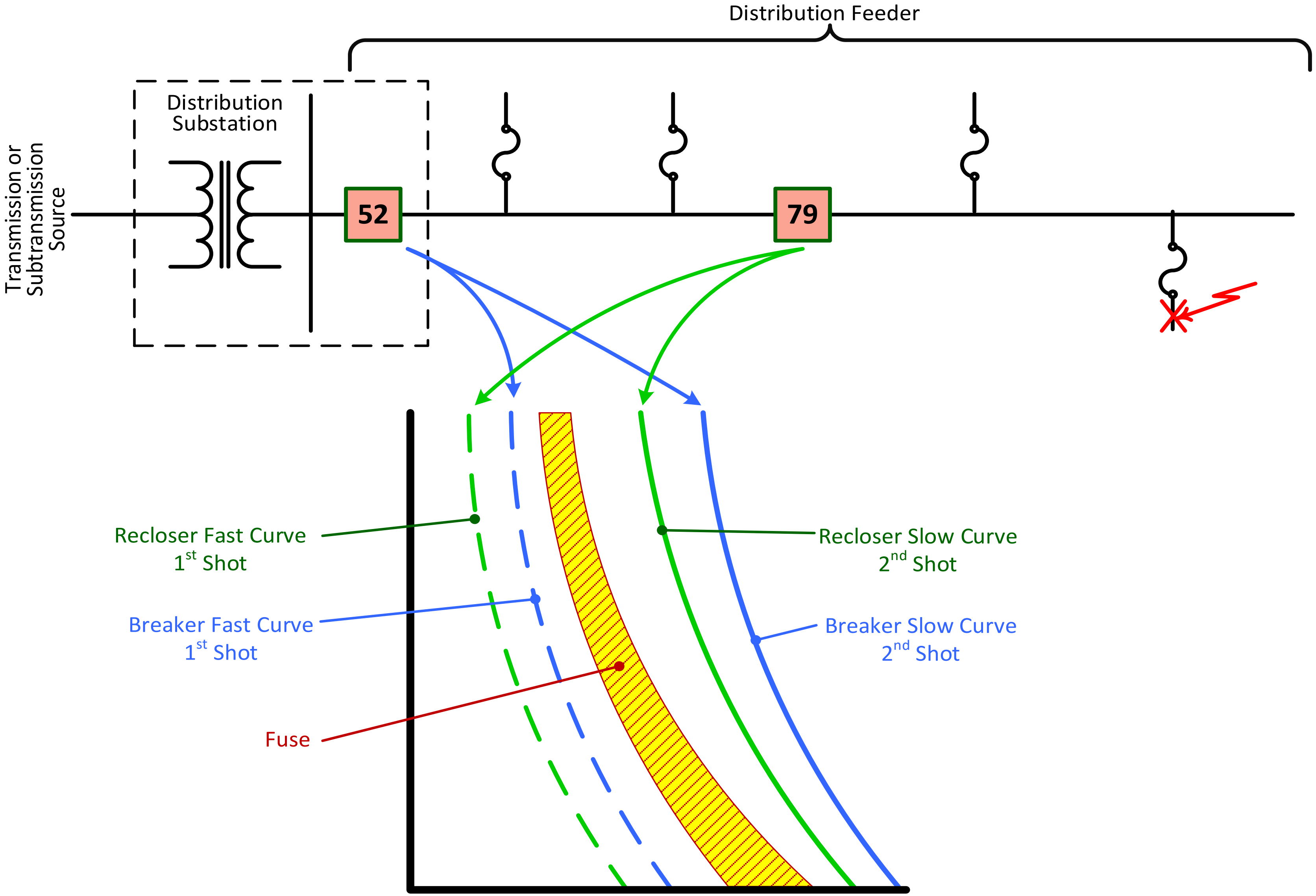
Sequence Coordination: Fuse Saving, One Shot Example

- #1 overcurrent elements used for Trip #1 are "fast trip"
- #2 overcurrent elements used for Trip #2, #3 and #4 are "slow trip"
- Sequence Coordination enabled for ONE trip cycle



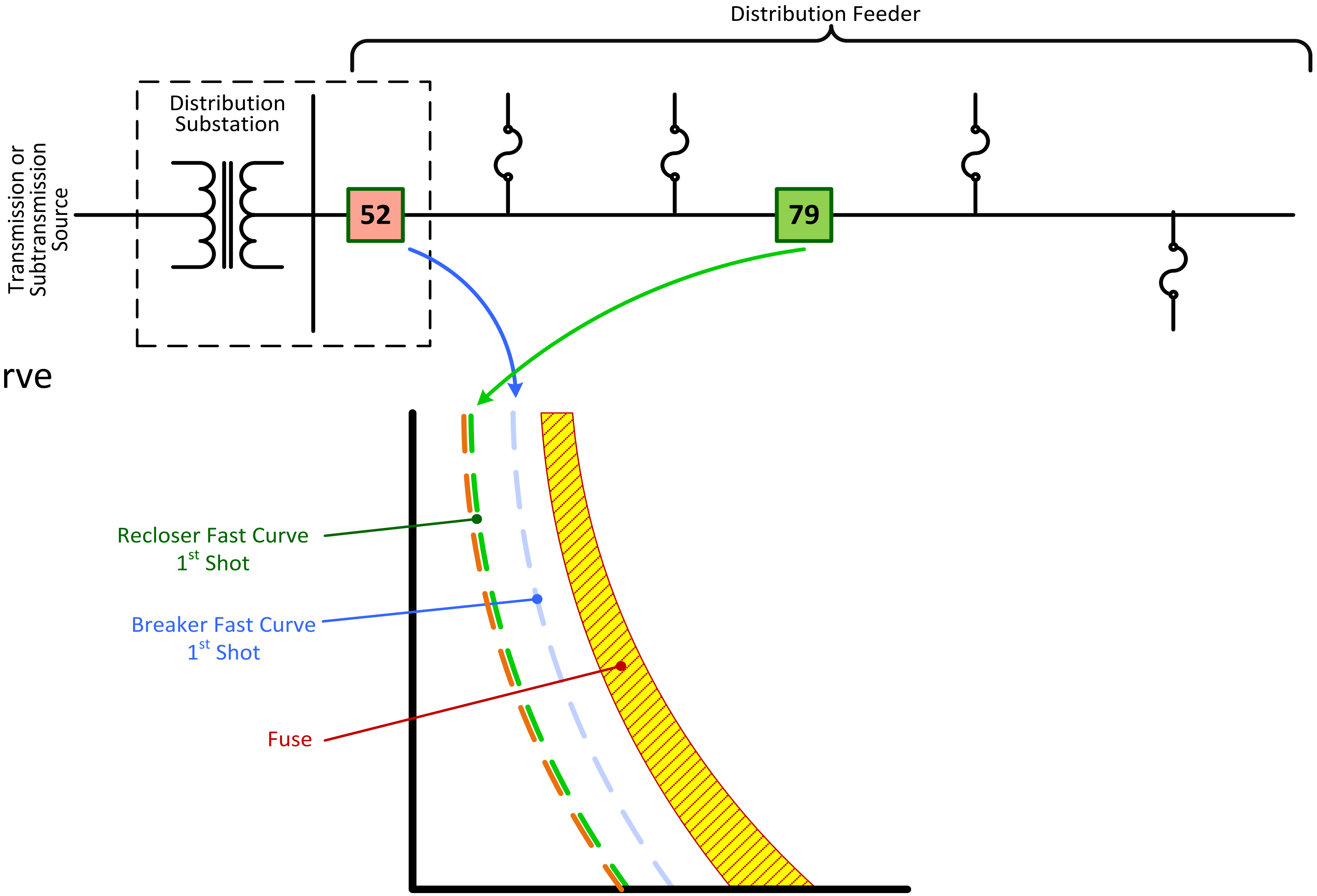
Sequence Coordination: Fuse Saving, One Shot Example

- Start
- Fault at downline fuse
- Fast Curves in play for 52 and 79 for 1st trip

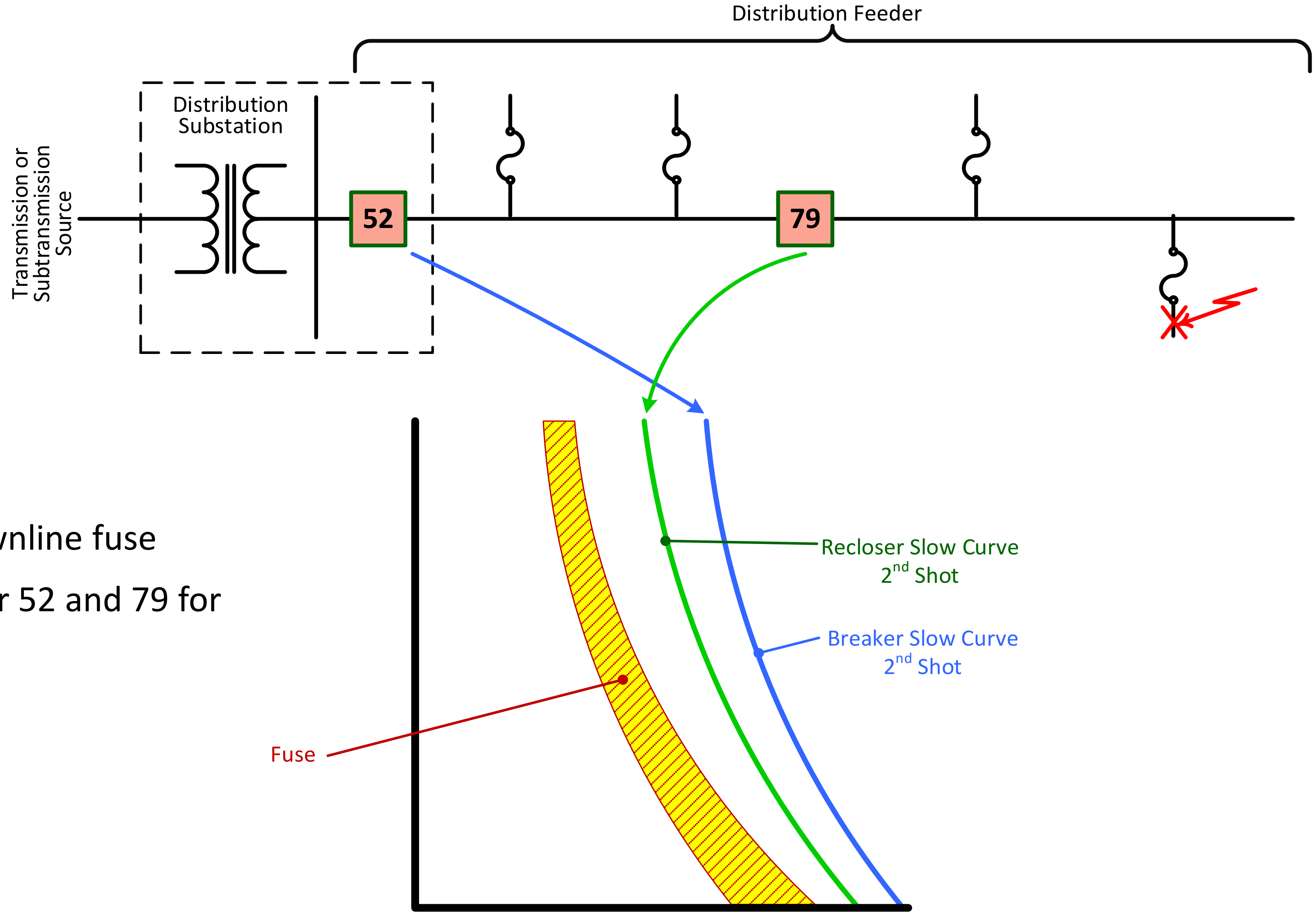


Sequence Coordination: Fuse Saving, One Shot Example

- First Trip
- Both 52 and 79 will use Fast Curve
- 79 Trips on Fast Curve
- Fault arc clears
- 52 does not trip



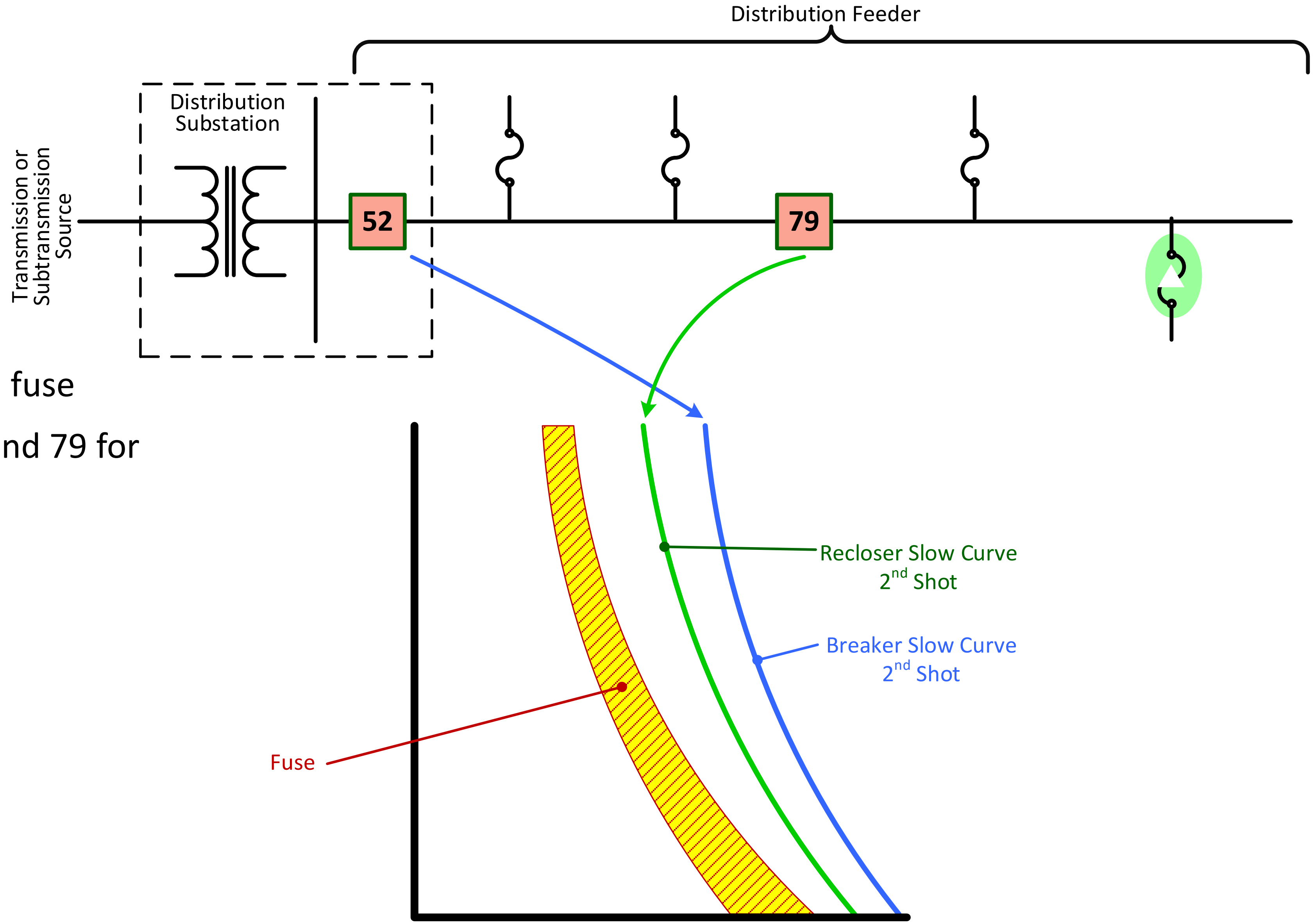
Sequence Coordination: Fuse Saving, One Shot Example



- 1st Reclose Shot
- 79 closes
- Fault still exists at downline fuse
- Slow Curves in play for 52 and 79 for 2nd trip

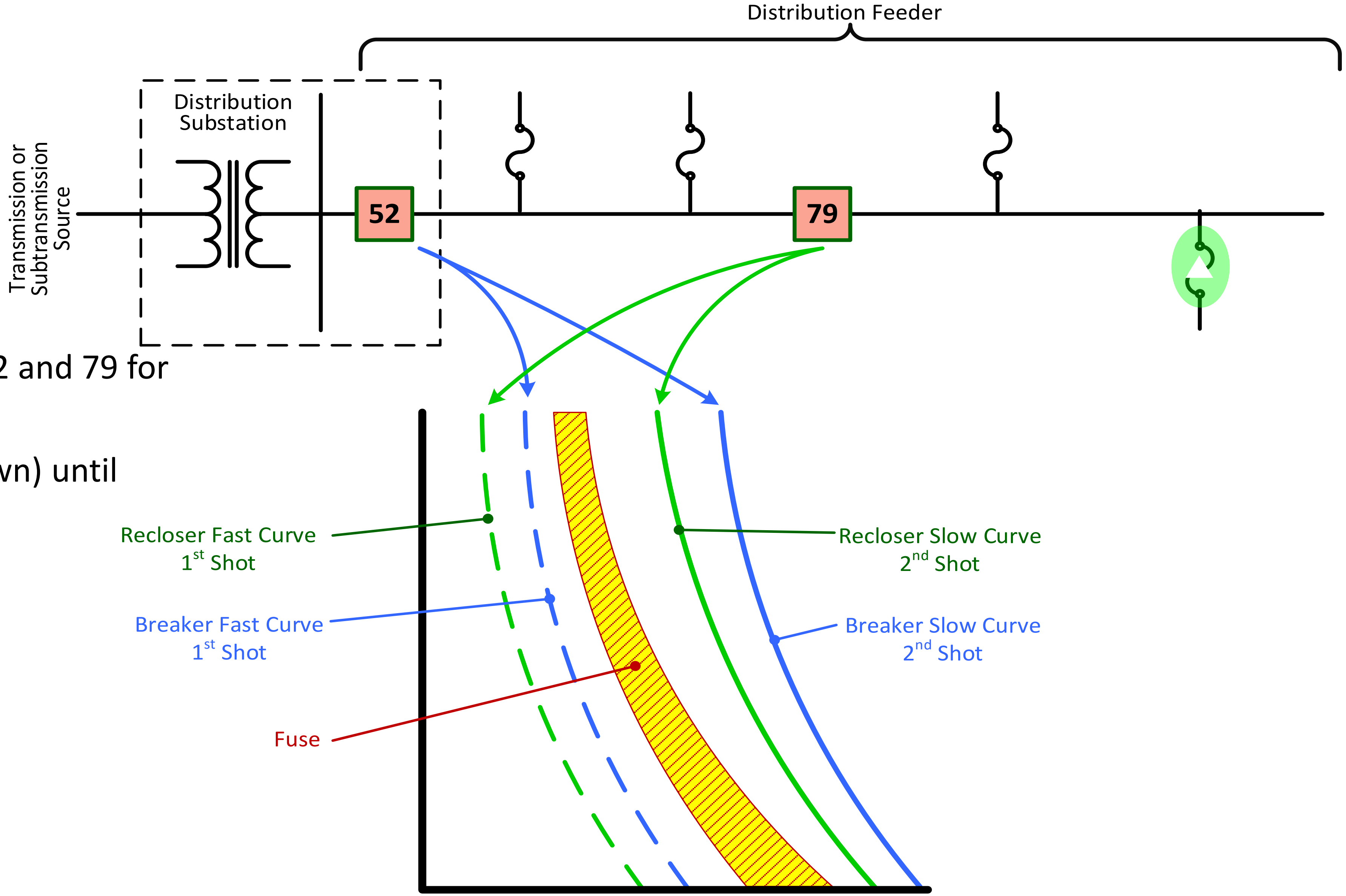
Sequence Coordination: Fuse Saving, One Shot Example

- 2nd Cycle
- 79 closes
- Fault still exists at downline fuse
- Slow Curves in play for 52 and 79 for 2nd trip
- Fuse clears
- Fault arc extinguished



Sequence Coordination: Fuse Saving, One Shot Example

- After Reclaim Time
- Fast Curves in play for 52 and 79 for 1st trip
- Fuse remains open (blown) until replaced

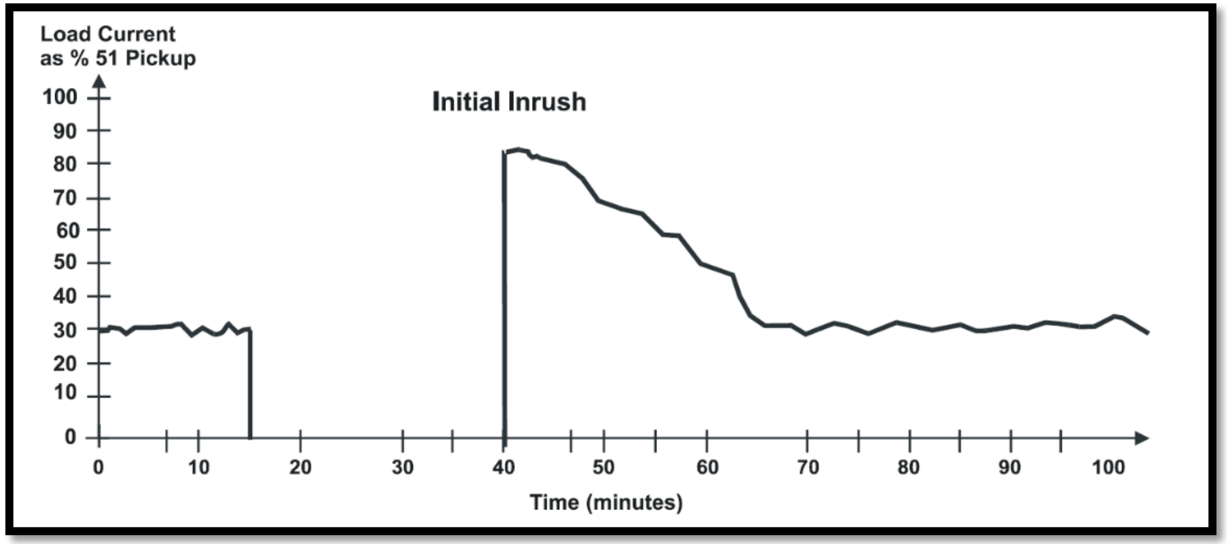


Applications – Single Phase Tripping

- Three-phase trip, three-phase lockout:
  - All three phases simultaneously trip on an overcurrent, reclose, and sequence together
- Single-phase trip, single-phase lockout:
  - Each individual phase trips, recloses and sequences to lockout independent of each other
  - Primarily for single phase residential loads and where single-phasing of three-phase loads is protected by other means
- Single-phase trip, three-phase lockout:
  - Each individual phase trips and recloses independent of each other
  - If any one phase sequences to lockout, the other two phases also trip and lockout
  - Eliminates permanent single phasing of three-phase loads
- Three-phase trip, single-phase lockout
  - All three phases simultaneously trip on an overcurrent, reclose, and sequence together and will lockout only the faulted phase
- Dynamic Phase Tripping
  - Trip and lockout all three phases when a phase-to-phase or three-phase fault is detected
- Caution on floating-wye or delta cap banks, 3 ph motors

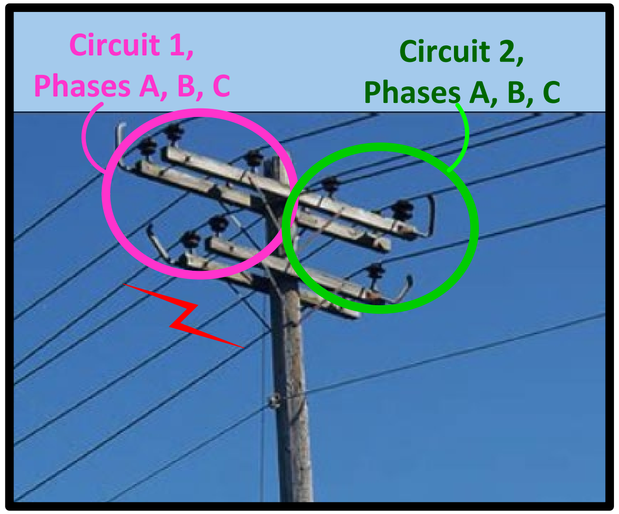
Cold Load Pickup

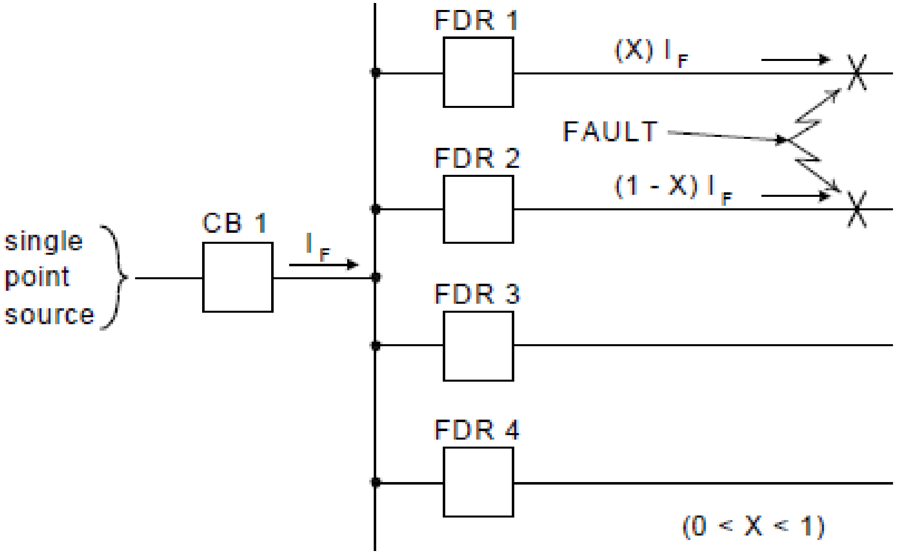
- Loss of load diversity
- Currents may exceed 10x normal
  - With transient inrush
- Diversity loss and recovery period depends on
  - Building envelopes
  - Weather and season
  - Heating and cooling equipment
- Adaptive Settings
  - Activate special protection settings and controls after device lockout for extended period
- Automatic return to normal settings
  - Timer
  - Measured current < Normal Pickup
- IEEE PSRC WG D1 Report:
  - Cold Load Pickup



Applications - Multiple Feeder Faults

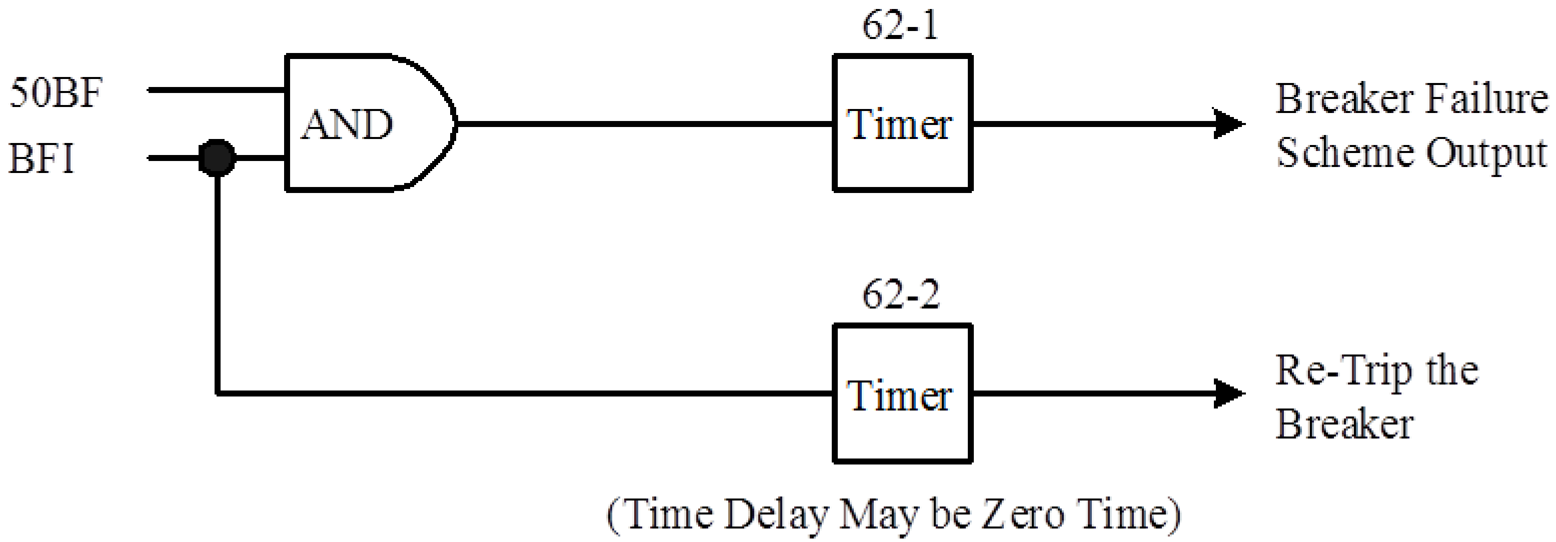
- Co-located or adjacent feeder circuits
  - Single feeder fault evolves to other feeders
  - Occurs on double circuits on same pole
  - Due to major storms, accidents by the public
- Mitigation
  - Trip blocking and interlock schemes
    - Trip one feeder, and see if the fault is removed on the other feeder
  - If two or more feeder relays pickup simultaneously, block source relay so feeders will clear
  - Coordinate reset timers
    - Fastest on main breaker
  - Larger coordination margin





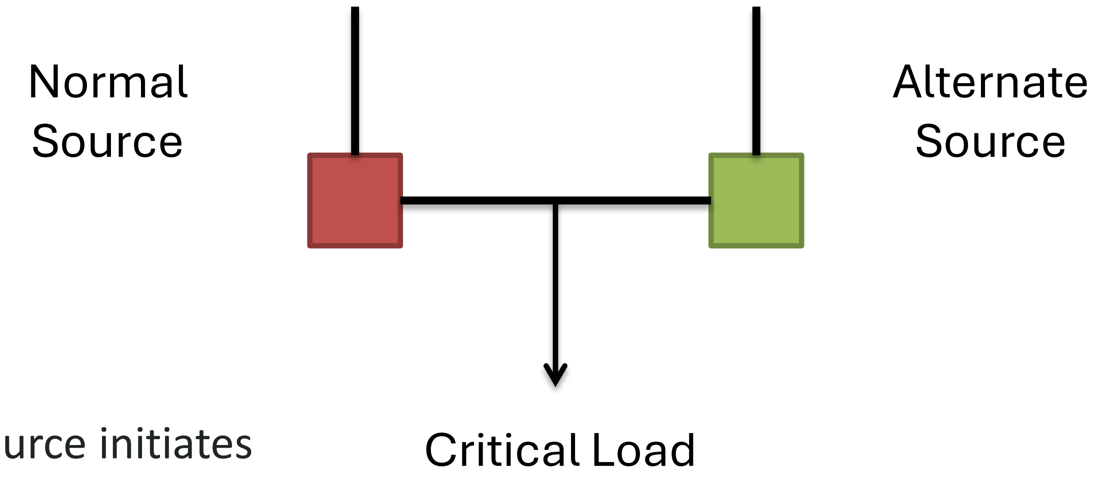
Applications – Breaker Failure

- Failure to Trip
- Failure to Close
- Often uses 2 inputs
  - Breaker aux contact position (52a or 52b)
  - Measured phase current (50BF)
- BFI – Breaker Failure Initiate
  - Trip signal
- Re-trip breaker
- Trip Breaker Failure Lockout



Applications – Multiple Sources

- Manual Transfer
  - Open or Closed Transfer
  - Open: Break-before-make
  - Closed: Make-break (Hot Parallel)
    - Requires sync check
- Automatic Transfer
  - Undervoltage loss-of-source detection on Normal Source initiates transfer to Alternate Source
    - Open: Break-before-make
  - Transfer blocked for downstream faults
- Hot Line Tag
- Auto or Manual Restoration to Normal Source

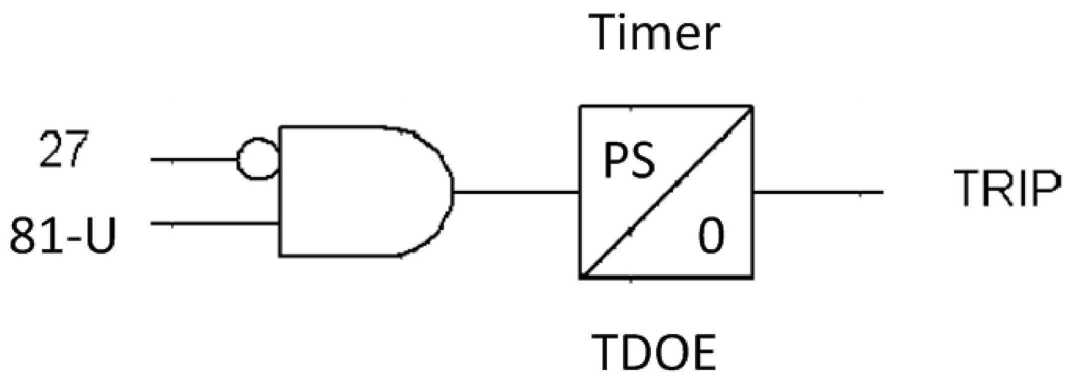


Applications – Underfrequency Load Shed (81-U/LS)

- Used to arrest bulk system frequency decline
  - Lowering frequency is an indicator of insufficient generation
  - Must react quickly to prevent system collapse
- Loads disconnected to balance generation with load
- Often deployed in several stages or setpoints
- Typically used with time delay
- May be Feeder Based or Bus Based

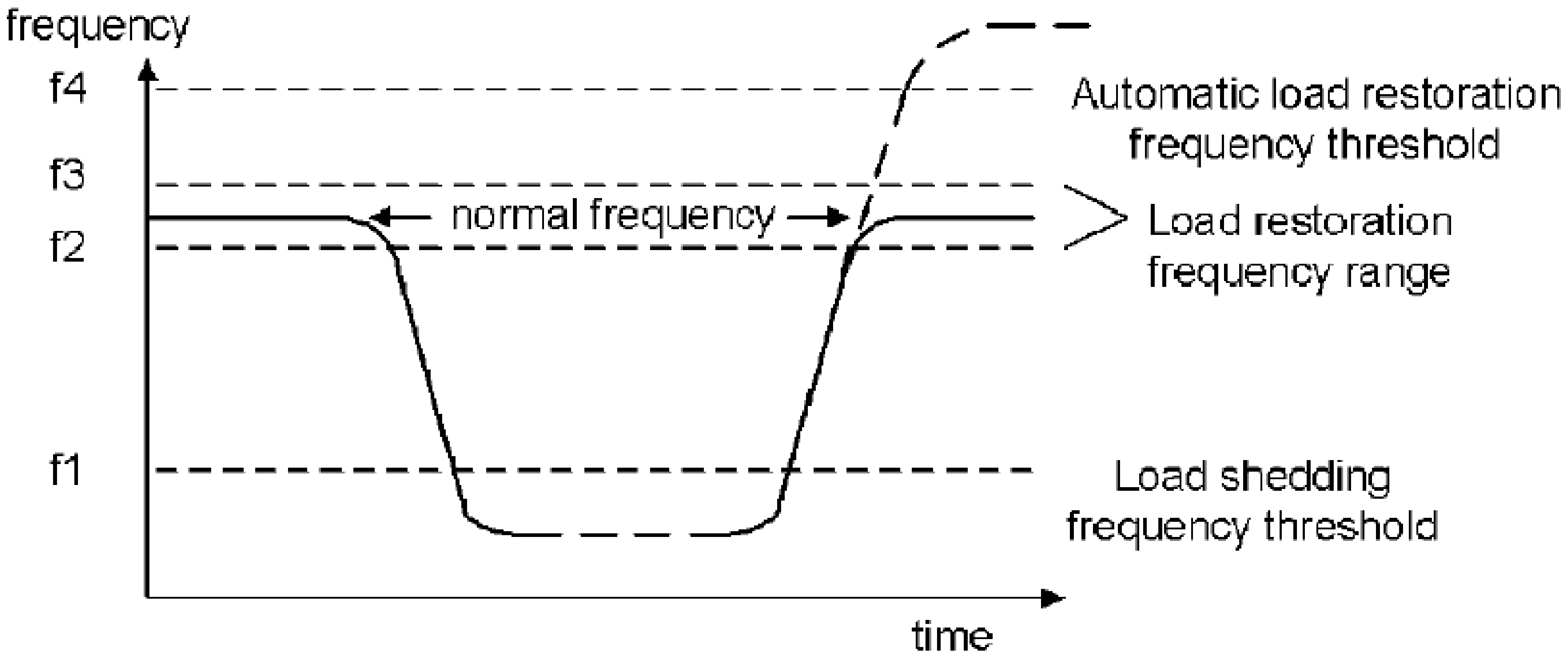
Applications – Underfrequency Load Shed (81-U/LS)

- May be supervised by an undervoltage (27) element
  - Avoids false tripping when voltage is not present



- Restoration after load shed
  - May be automatic with frequency control after delay for stabilization
  - May be manual with frequency supervision
  - Incremental restoration to match generation capacity

Applications – Underfrequency Load Shed (81-U/LS): Frequency Shed and Restore Graph



Applications – Underfrequency Load Shed (81-U/LS):

Summary of 2003 coordinating entity underfrequency load shed criteria

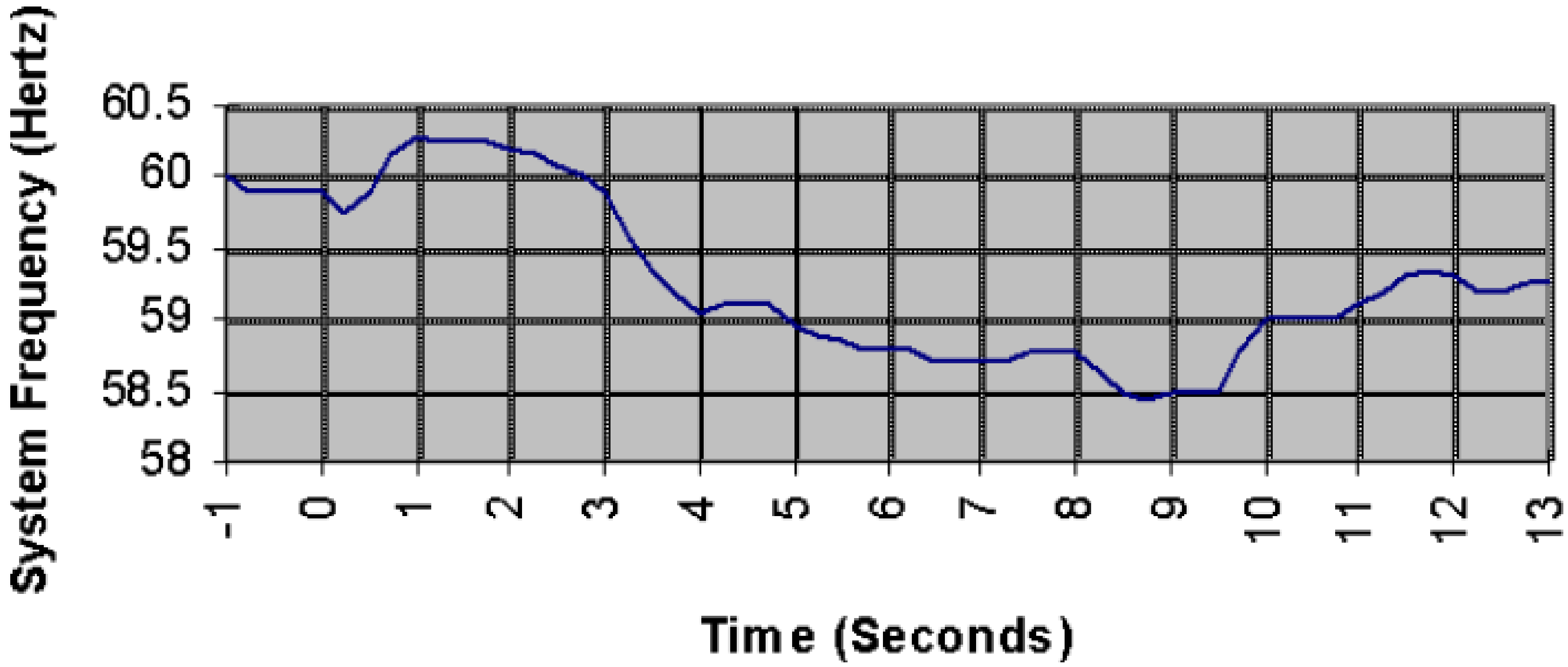
Entity	Load shed									
	F1 (Hz)	Load	F2 (Hz)	Load	F3 (Hz)	Load	F4 (Hz)	Load	F5 (Hz)	Load
Western Electricity Coordinating Council (WECC) (See Note 1)	59.1	5.3%	58.9	5.9%	58.7	6.5%	58.5	6.7%	58.3	6.7%
Mid Continent Area Power Pool (MAPP)	59.3	10%	59	10%	58.7	10%				
Electric Reliability Council of Texas (ERCOT)	59.3	5%	58.9	10%	58.5	10%				
Mid America Interconnected Network (MAIN)	59.3	10%	59.0	10%	58.7	10%				
Southwest Power Pool (SPP)	59.3	10%	59.0	10%	58.7	10%				
East Central Area Reliability coordination agreement (ECAR)	59.5	5%	59.3	5%	59.1	5%	58.9	5%	58.7	5%
Northeast Power Coordinating Council (NPCC)	59.3	10%	58.8	15%	Manual					
Mid Atlantic Area Council (MAAC)	59.3	10%	58.9	10%	58.5	10%				
Florida Reliability Coordinating Council (FRCC) (See Note 2)	59.7 (See Note 2)	9%	59.4	7%	59.1	7%	58.8	6%	58.5	5%
Northwest Power Pool (NWPP)—non -DSI load (See Note 3)	59.3	5.6%	59.2	5.6%	59.1	5.6%	59.0	5.6%	58.8	5.6%
NWPP direct service industry load	59.3	25%	59.2	25%	59.1	25%	59	25%		
Ireland ESB (50Hz)	48.5	13%	48.4	13%	48.3	13%	48.2	26%		
Nordel (50Hz)	48.8	10%	48.6	10%	48.4	10%	48.2	10%	48.0	10%

NOTE 1—WECC has additional load shed criteria from 59.5 Hz to 59.3 Hz.

NOTE 2—FRCC has intermediate steps at 0.3Hz down to 59.1 Hz with a time delays of 8 s to 10 s shedding an additional 5% per step.

NOTE 3—NWPP has one additional step of 5.6% non-DSI load at 58.6 Hz.

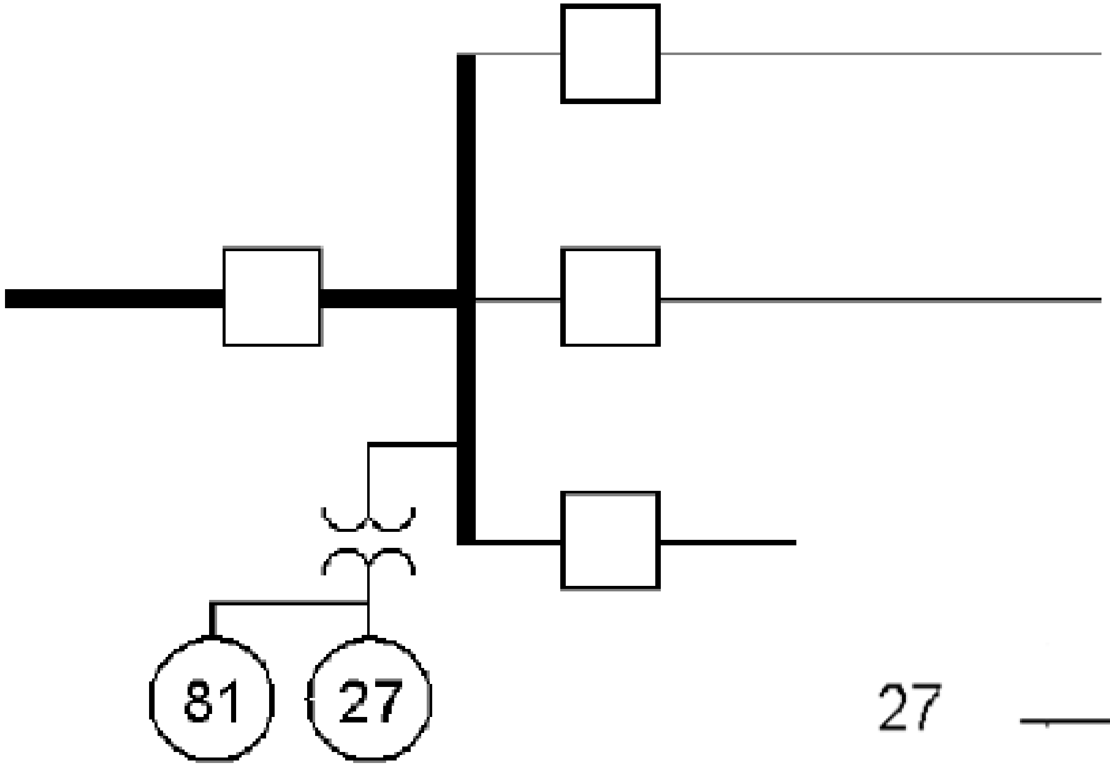
Applications – Underfrequency Load Shed (81-U/LS):

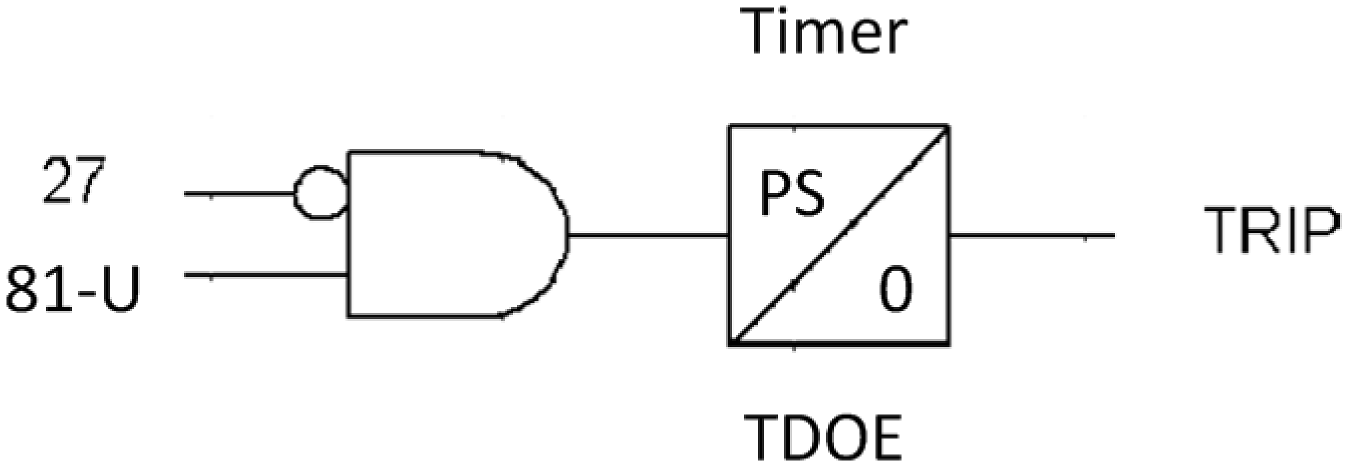


Generator frequency response for a Northern California island generator during August 10, 1996, disturbance

Applications – Underfrequency Load Shed (81-U/LS)

- Bus Based



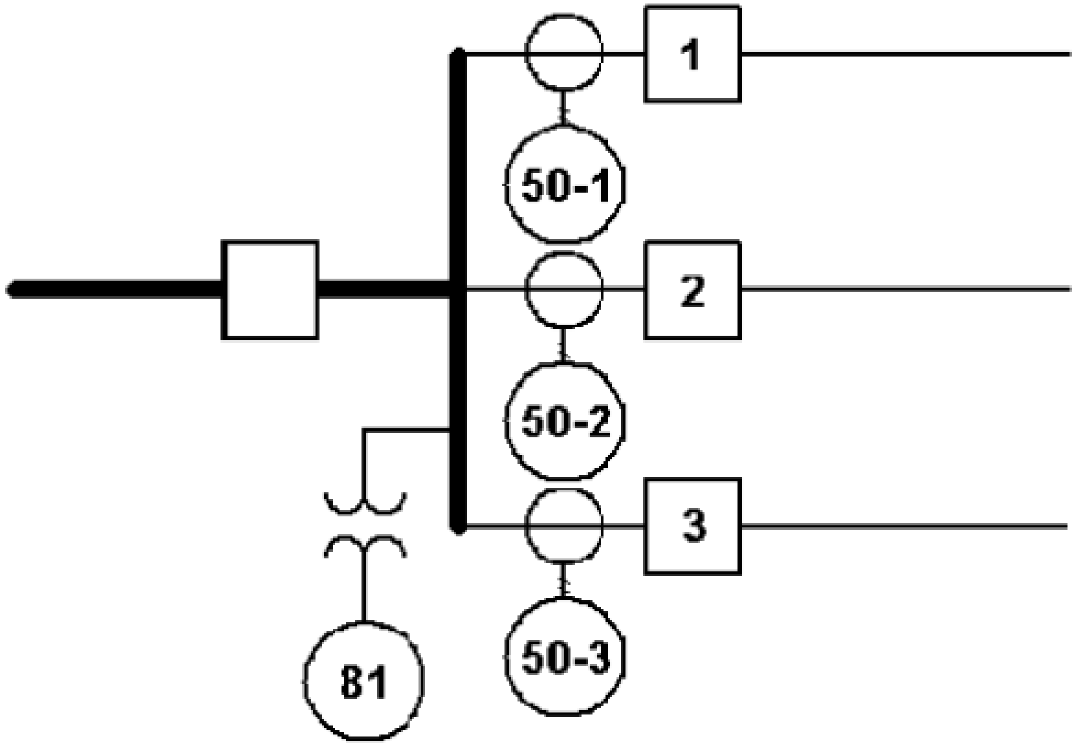


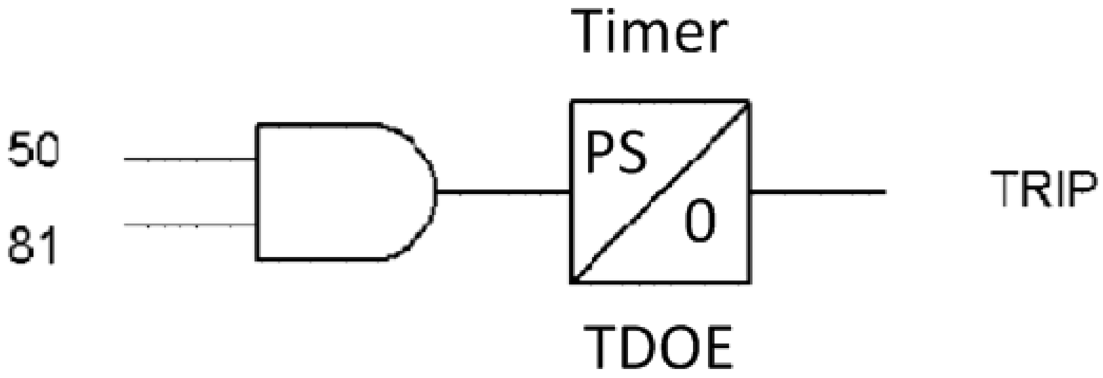
- Use of 50 element for control optional

Applications – Underfrequency Load Shed (81-U/LS)

Bus Based with Overcurrent Control

- Allow load shed with current over pickup (sheds loaded up feeders)





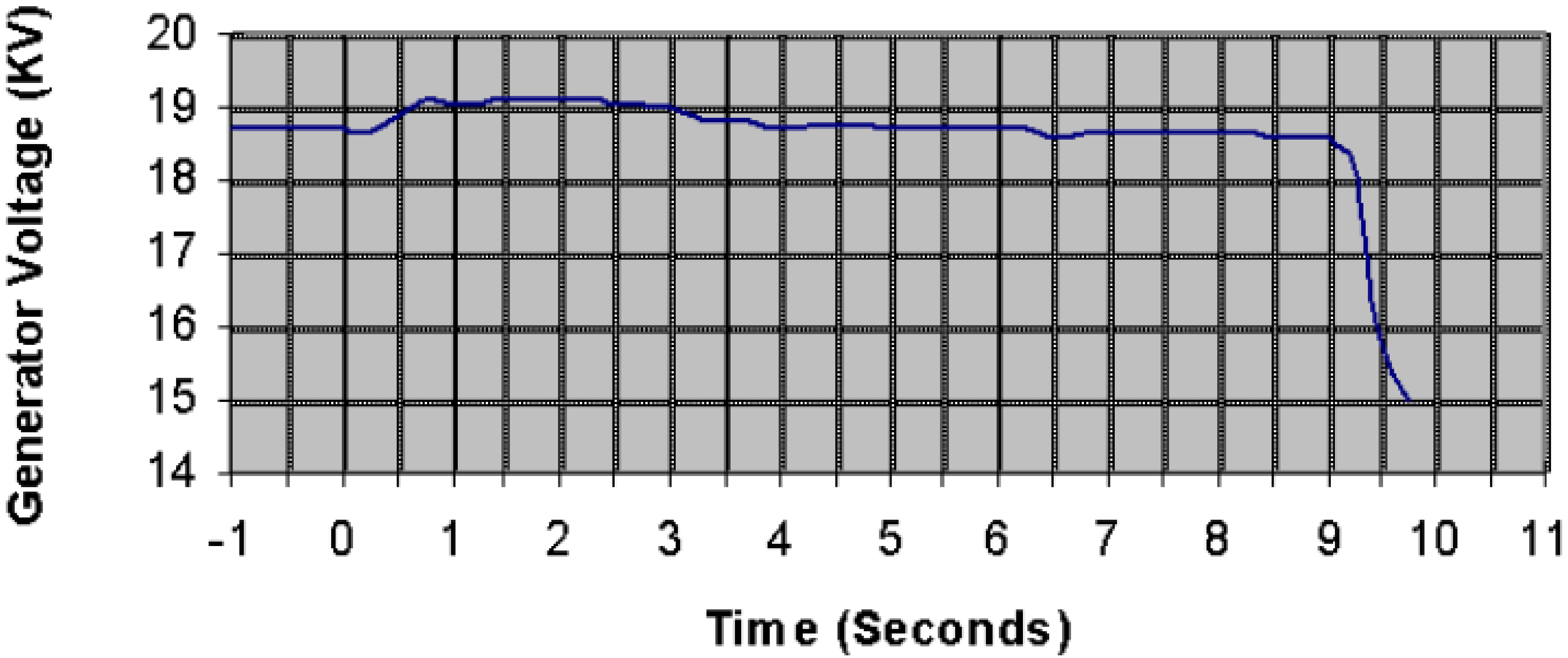
- Use of 50 element for control optional

Applications – Undervoltage Load Shed (27/LS)

- Used to halt system collapse due to low reactive supply
  - Lower voltage is an indicator of insufficient reactive supply
  - Must react quickly to prevent system collapse
- Loads disconnected to balance reactive supply with load
- Often deployed in several stages or setpoints
- Typically used with time delay
- May be Feeder Based or Bus Based

Applications – Undervoltage Load Shed (27/LS)

- Results of lack of reactive support



Generator voltage for a Northern California island unit during the August 10, 1996, disturbance

Applications – Undervoltage Load Shed (27/LS)

- Undervoltage Collapse can be sudden
- P-V Curve
- VAR Support is exponentially reduced by undervoltage to capacitors

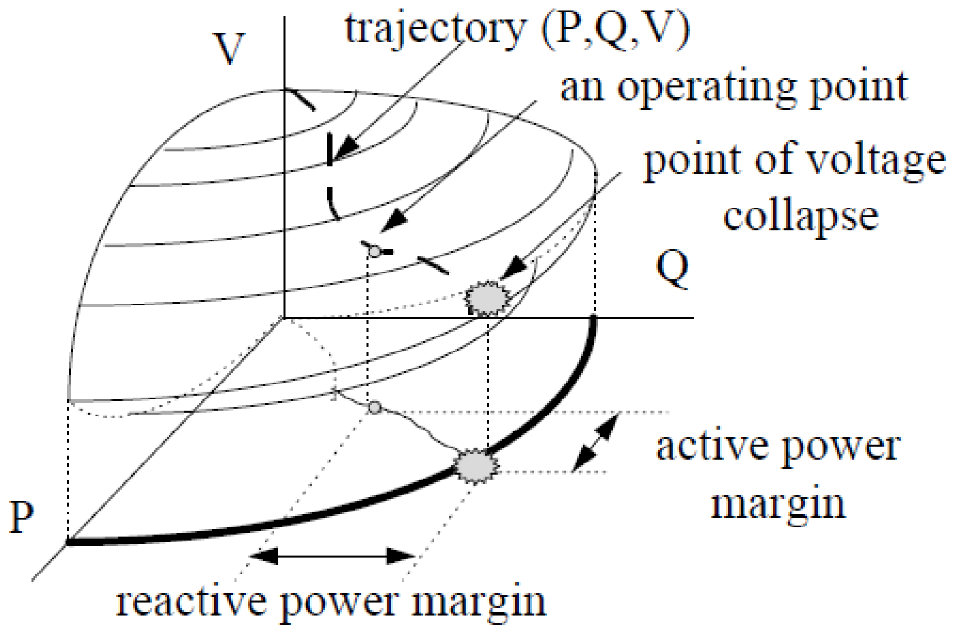
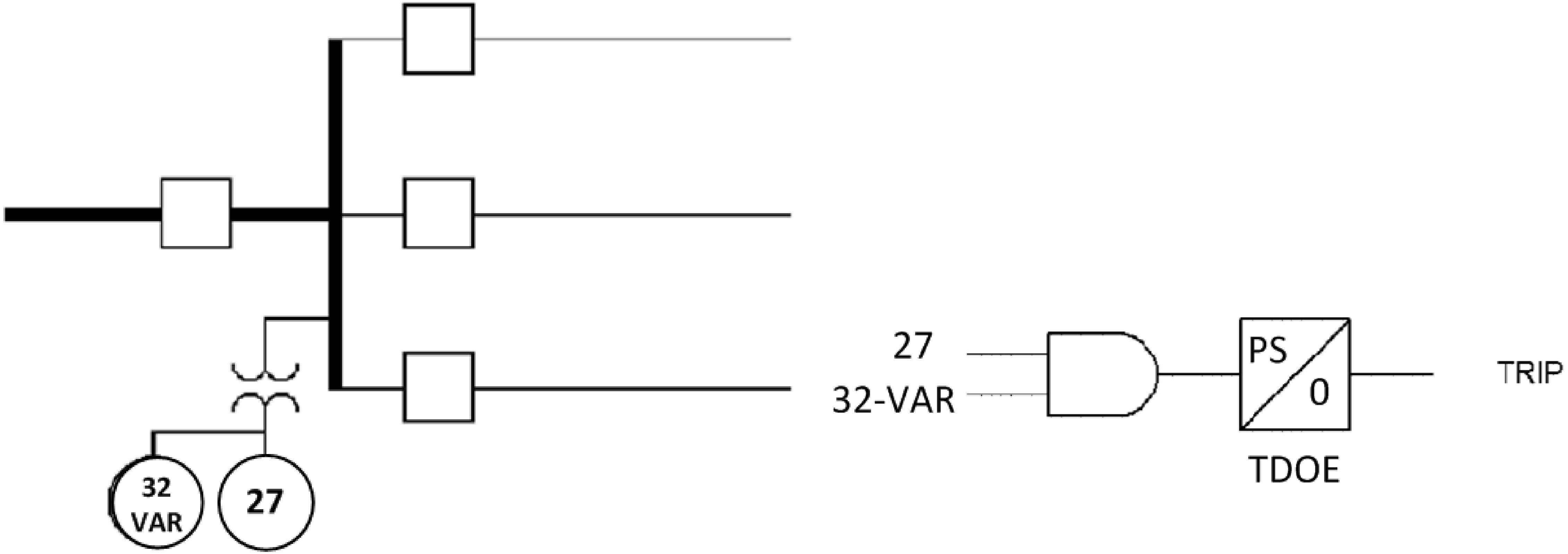


Figure II-2 VPQ Curve Representing a Trajectory Where Both Active and Reactive Power Can Change Arbitrarily

Applications – Undervoltage (UV) Load Shed (27/LS)

- UVLS with over VAR control (Bus based)
- Allow load shed during over VAR condition

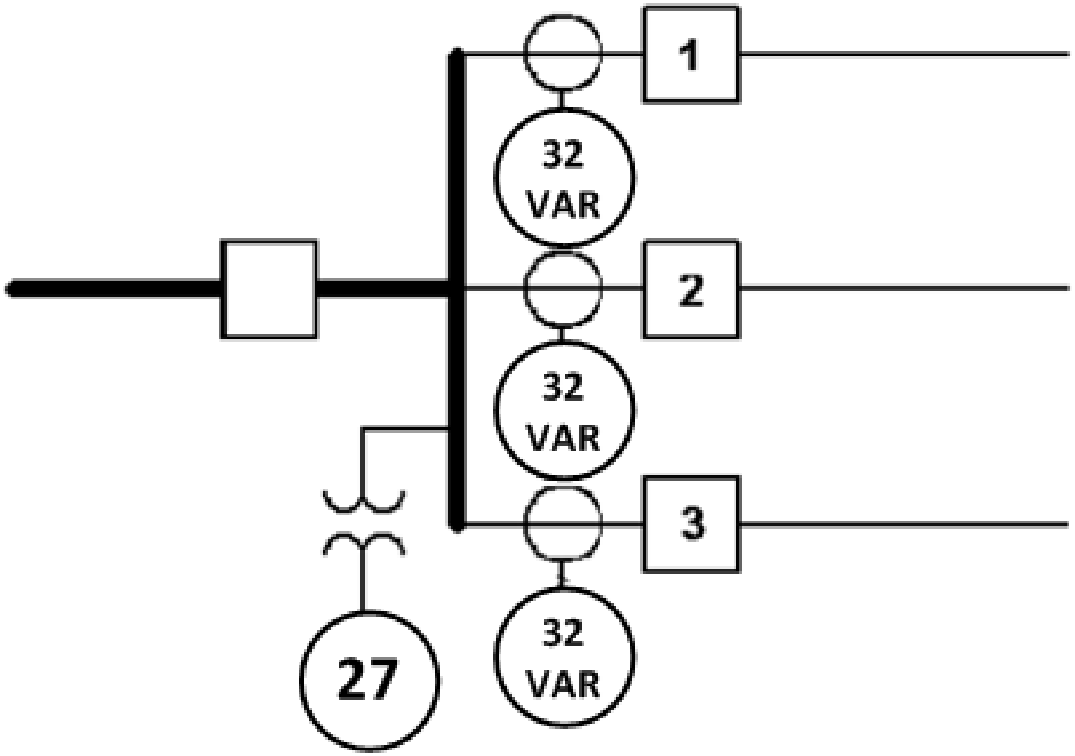


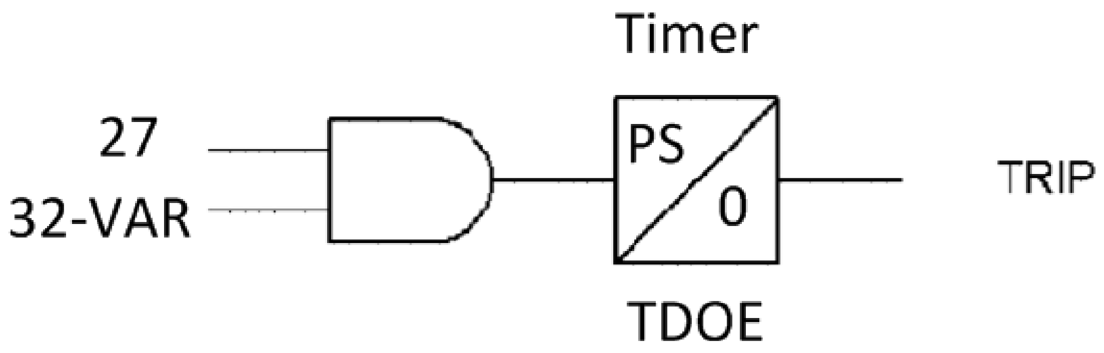
- Use of 32VAR element for control optional
- May also use 50, or no control at all

Applications – Undervoltage Load Shed (27/LS)

UVLS with over VAR control (Feeder based)

- Allow load shed with Over VAR over pickup
  - Sheds VAR-deficient feeders

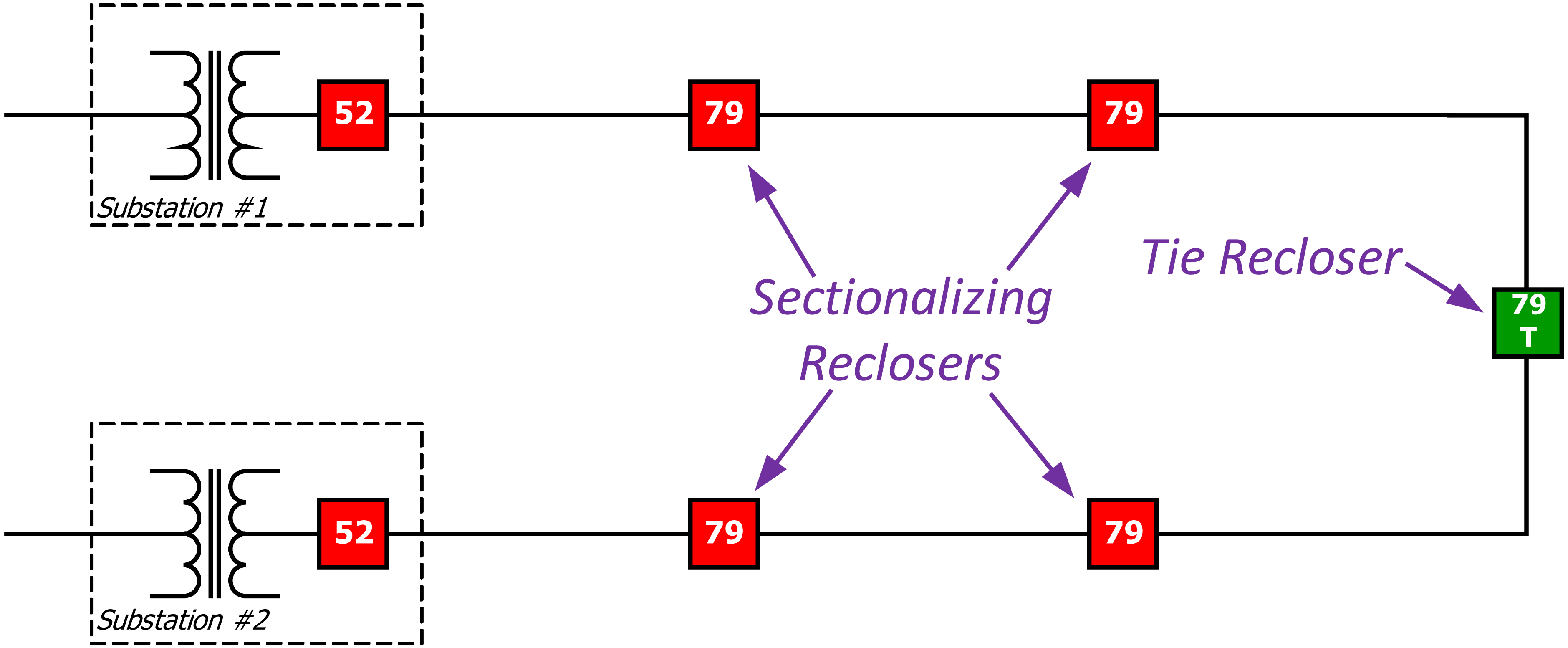




- Use of 32VAR element for control optional
- May also use 50, or no control at all

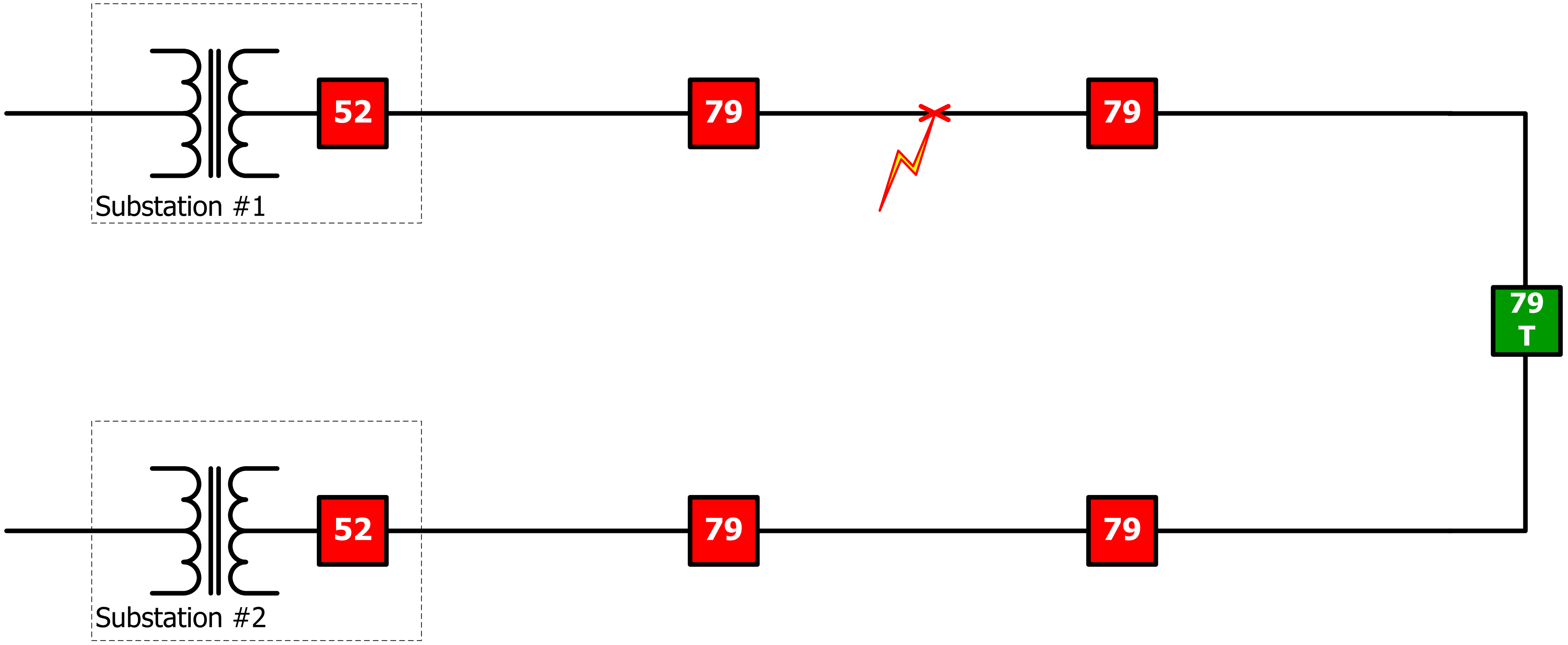
APPLICATIONS - LOOP SCHEMES

Applications - Simple Loop Scheme



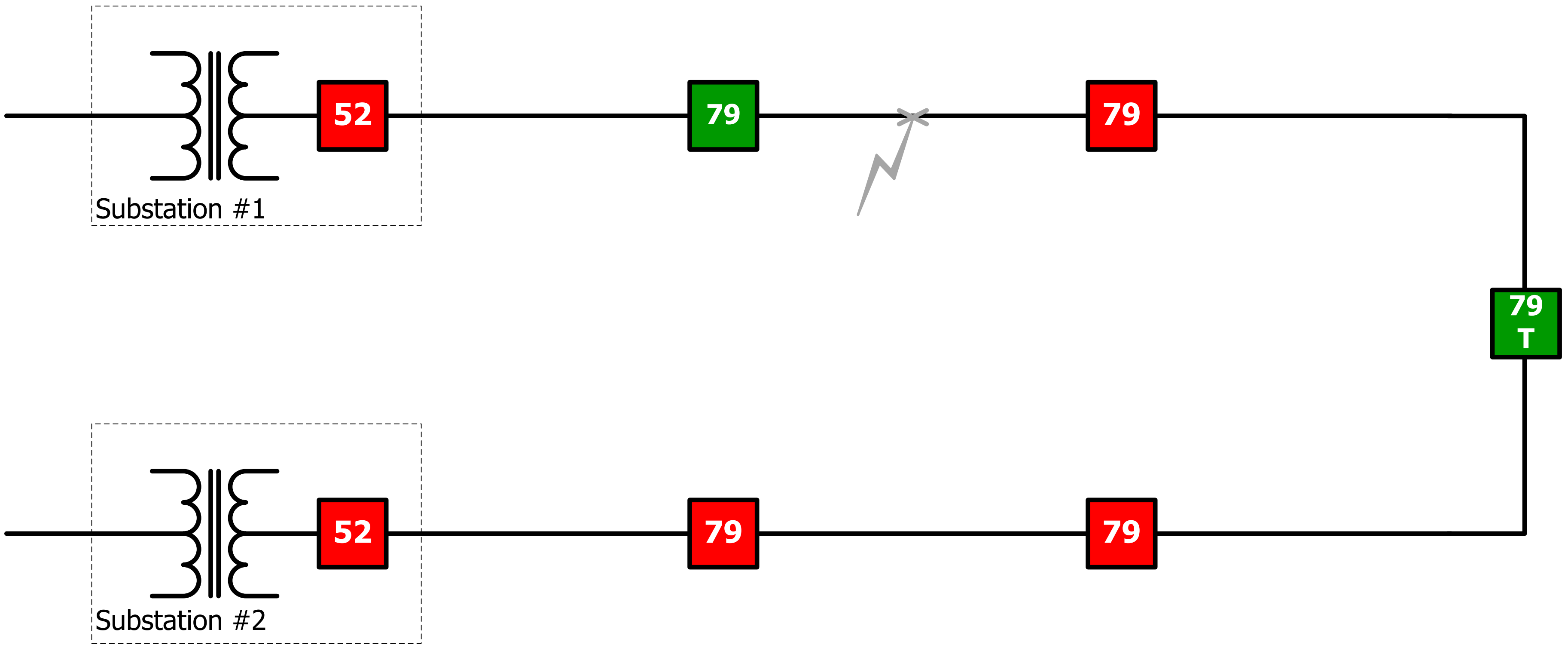
- Simple Loop Scheme Restoration
- It uses “Close and Test” as a method of determining of restoring
- Upside: No DMS/SCADA or communications required
- Downside: One “switch onto fault” operation with permanent faults

Simple Loop Scheme



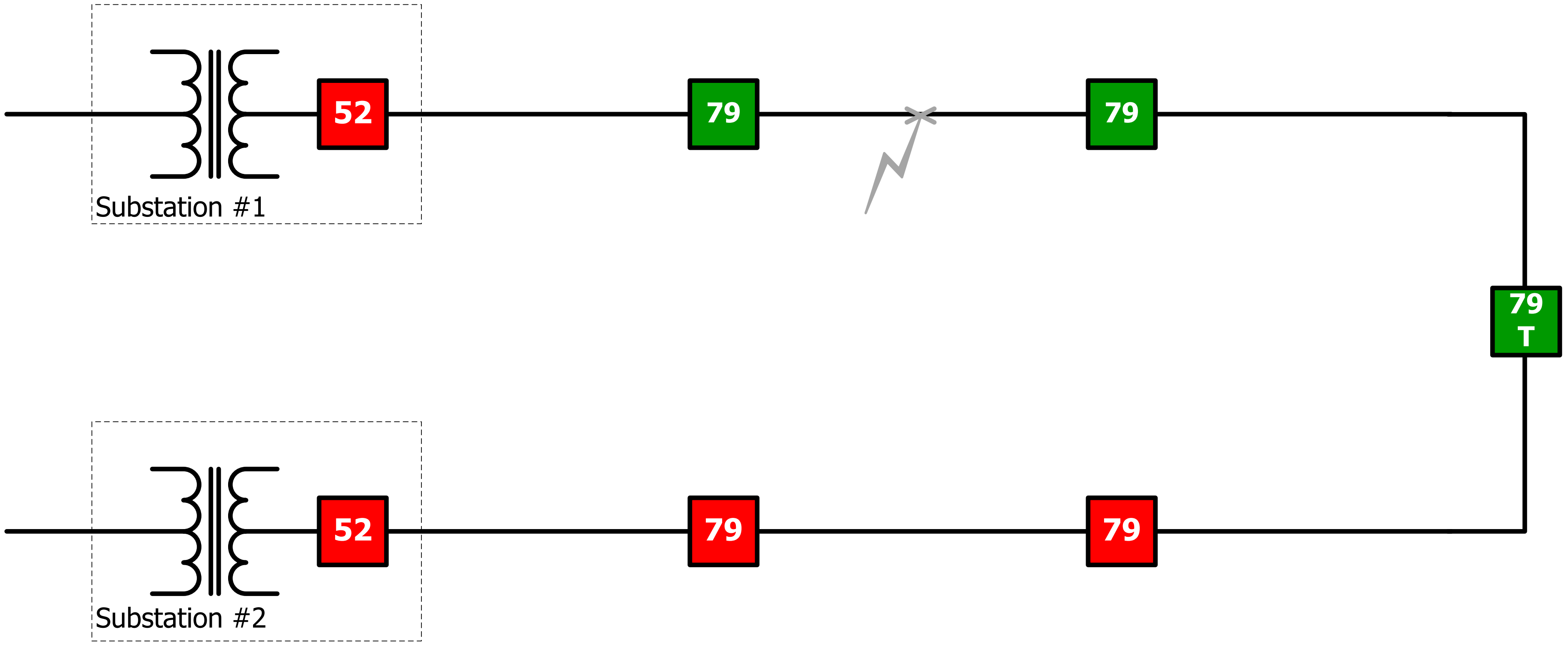
- Open Tie (79-T)
- Fault on top feeder

Simple Loop Scheme



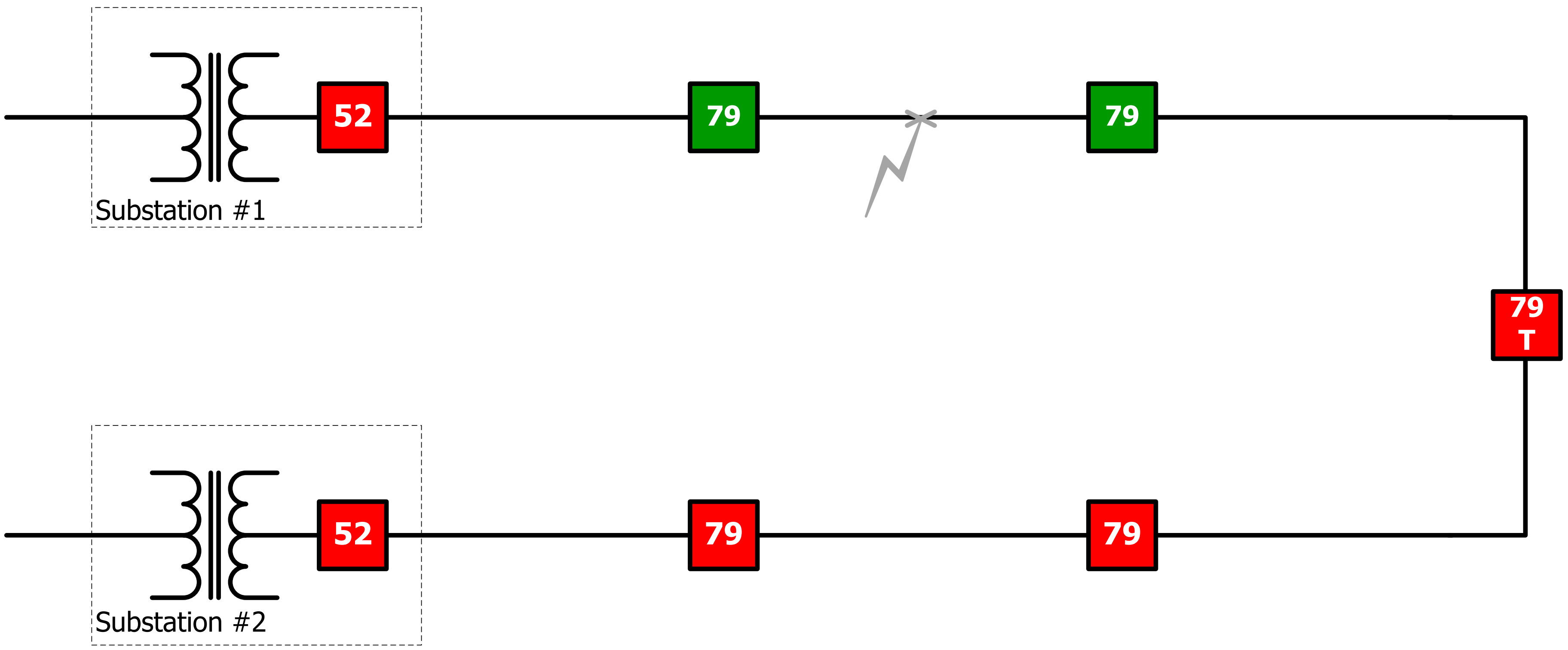
- Recloser goes through shot sequence
- Permanent fault, recloser goes into lockout

Simple Loop Scheme



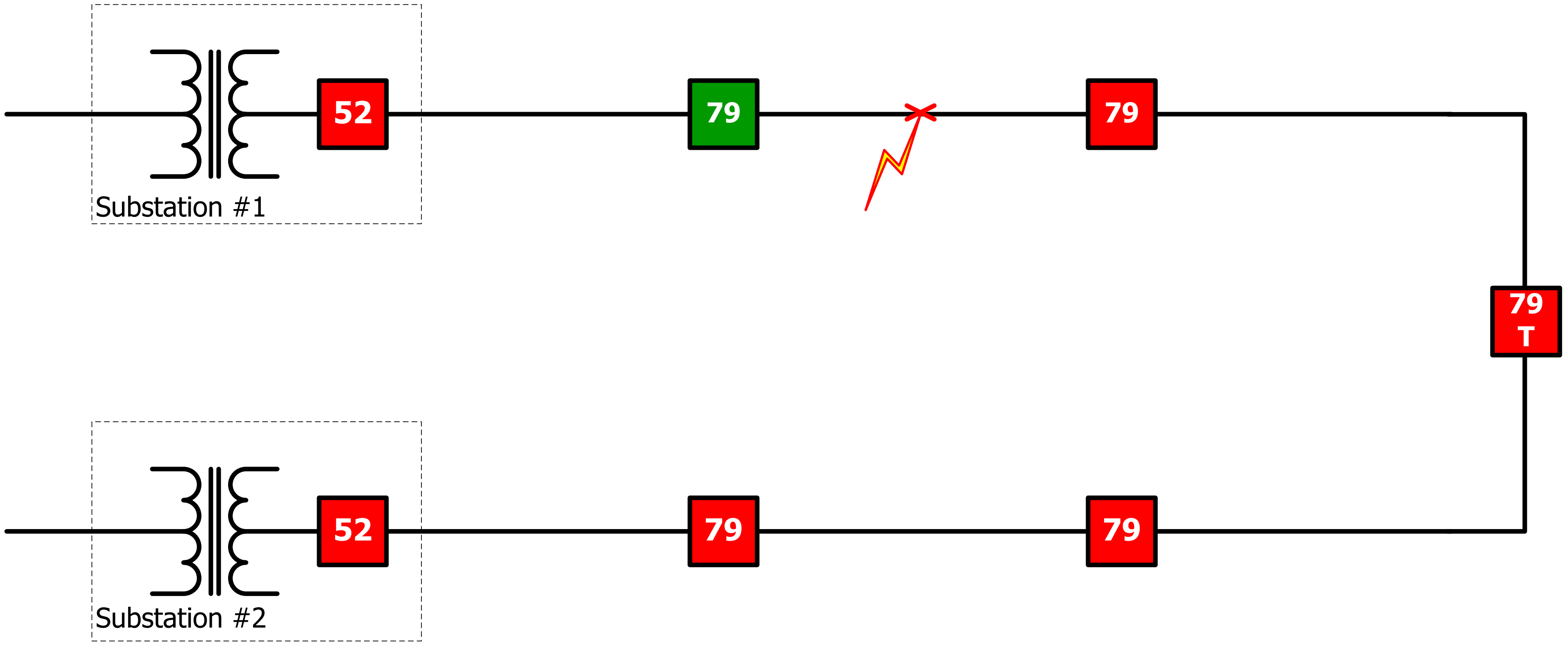
- Recloser downline of faulted section opens after delay (senses no voltage for time delay)

Simple Loop Scheme



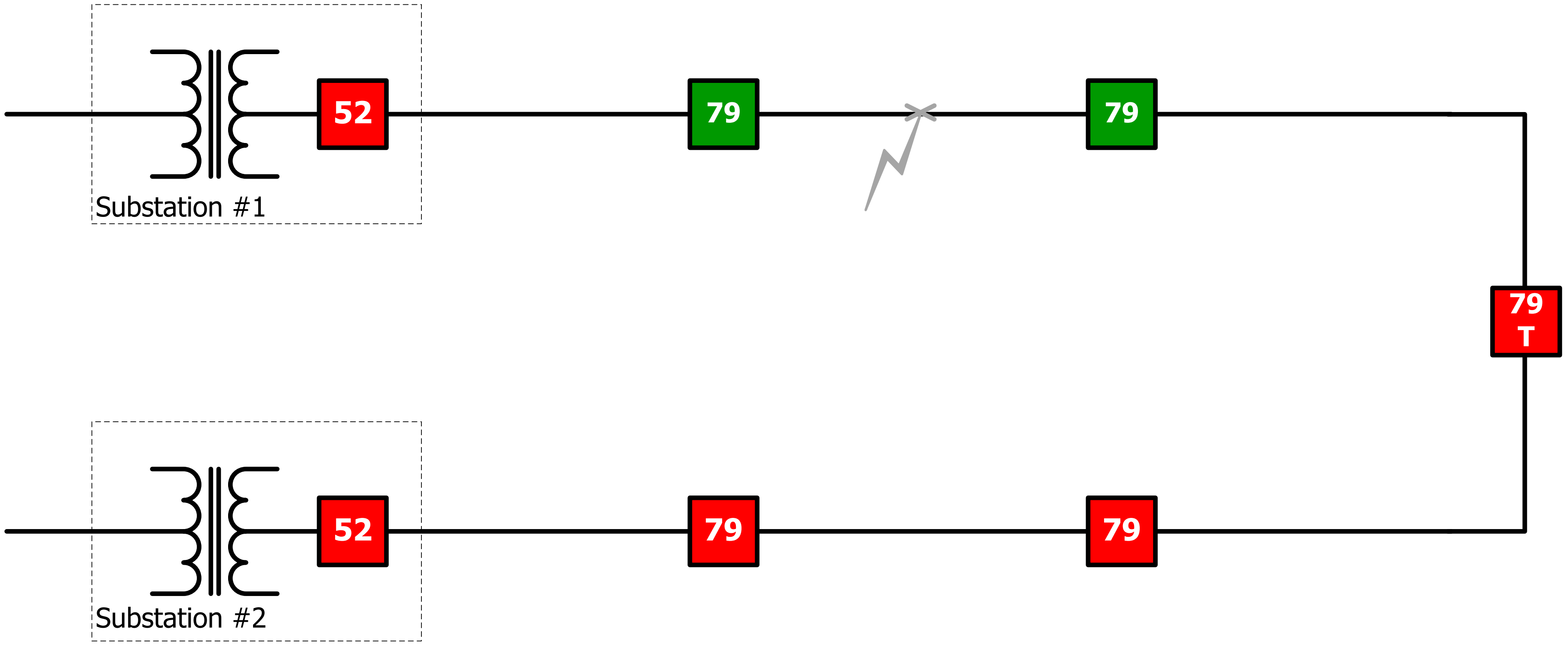
- Tie Recloser “closes and tests,” holds

Simple Loop Scheme



- Recloser adjacent to faulted section “closes and tests”
- Permanent fault exists

Simple Loop Scheme

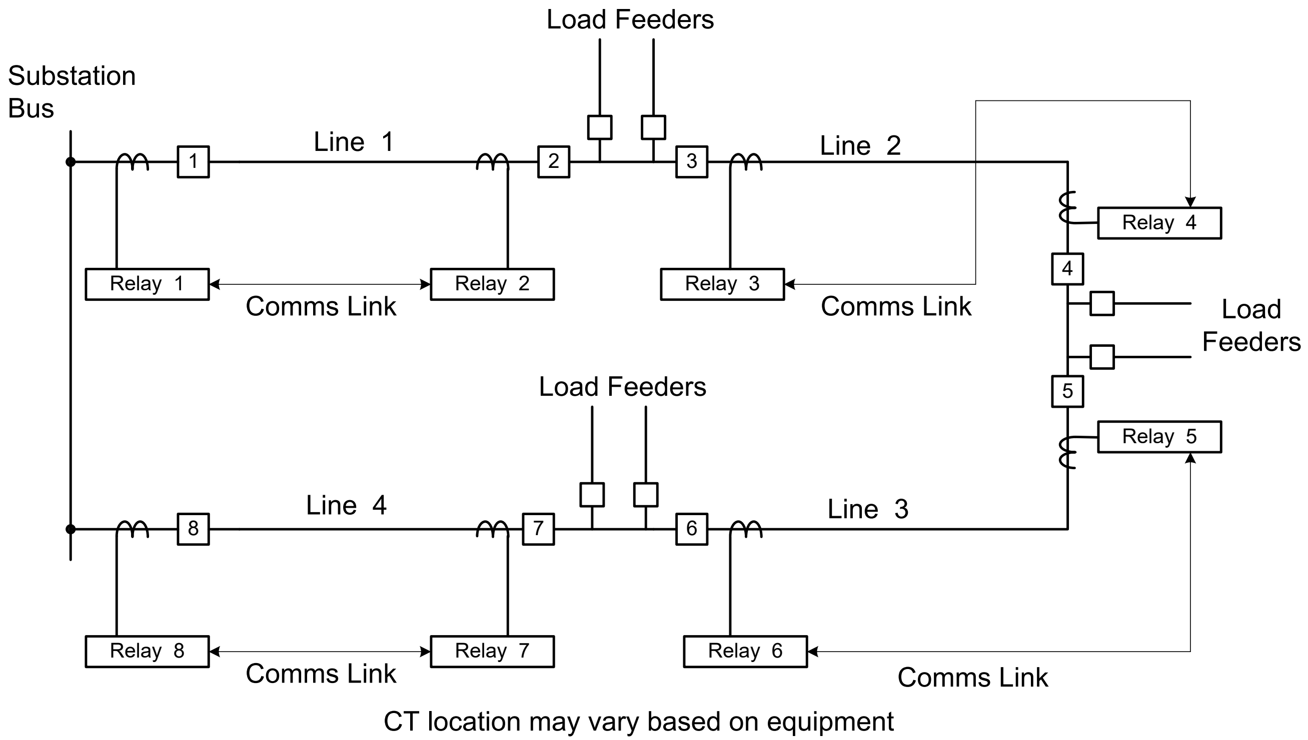


- “Close and test” fails due to permanent fault
- Switch onto fault, one shot and lockout
- Permanently faulted section is locked out
- End of sequence

Applications – Loop Schemes

Closed Loop

- Implications
  - Planning
  - Operations
  - Maintenance
  - Protection
- Non-radial system
- High service availability
- Old School: “Stacked” directional overcurrent
  - Can have slow isolation due to CTI between relays
- New School: Employ reliable communications between relays
  - High speed
  - Dedicated
- Thorough system studies for parallel operation

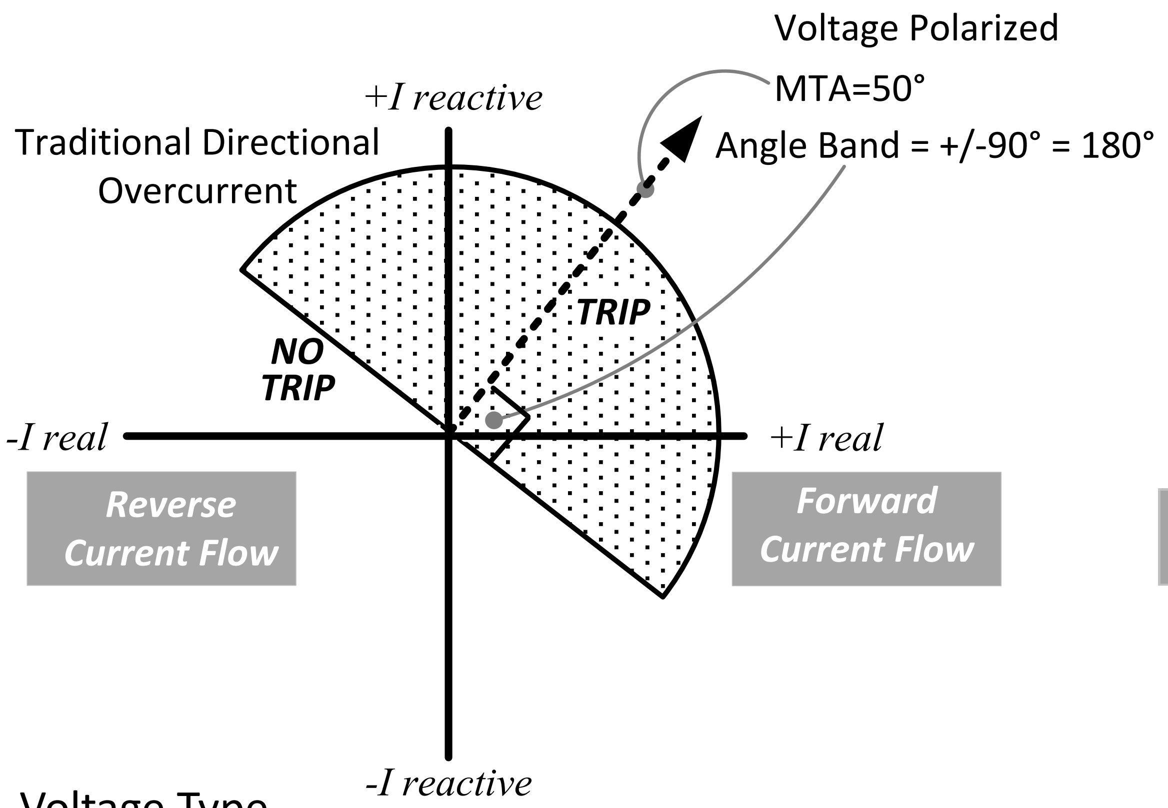


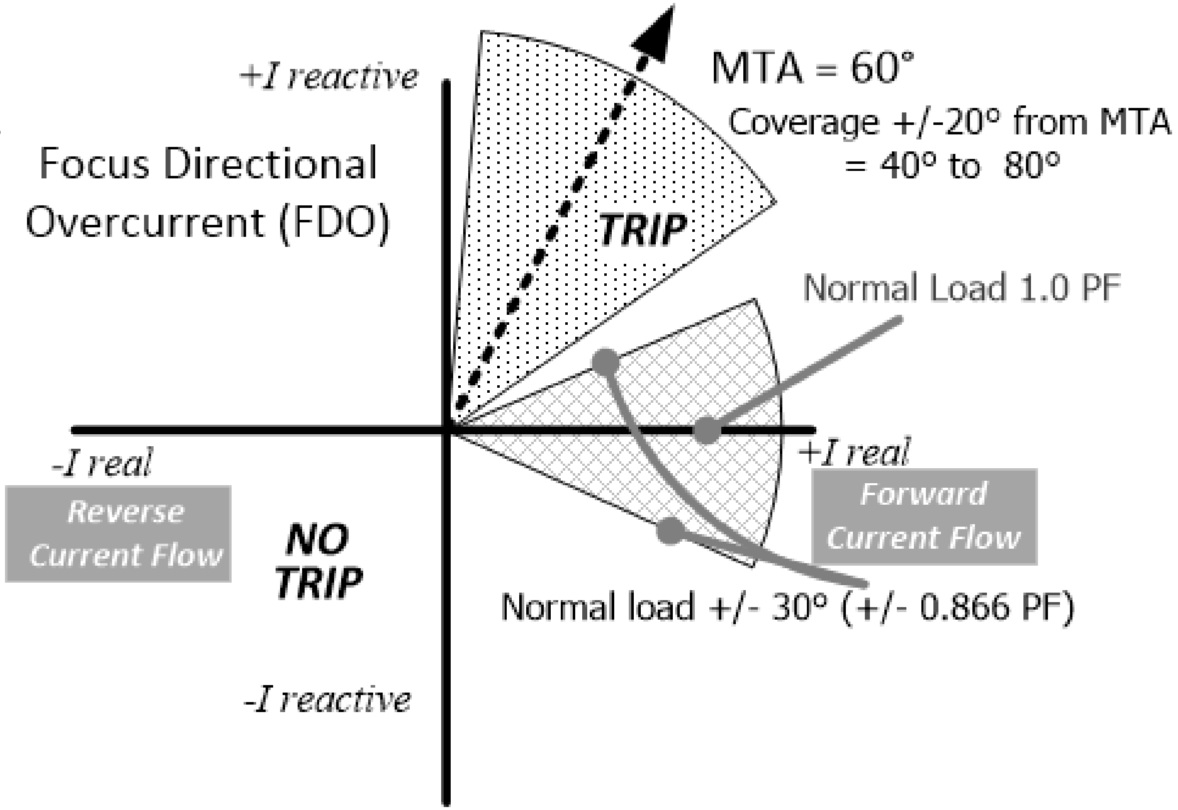
Applications – Directional Overcurrent (67)

- Overcurrent with directionality
  - When fault can be in front or behind relay
- Supervise other protection elements
  - Block
  - Delay
- Use with/without communications-based schemes
- Detect DER infeed (weak source)
- Reference (polarization) voltage or current or both gives directionality
- Instantaneous, definite time, or inverse time operation

Applications – Directional Overcurrent (67)

Voltage Polarized Directional Elements (Traditional and Focus)



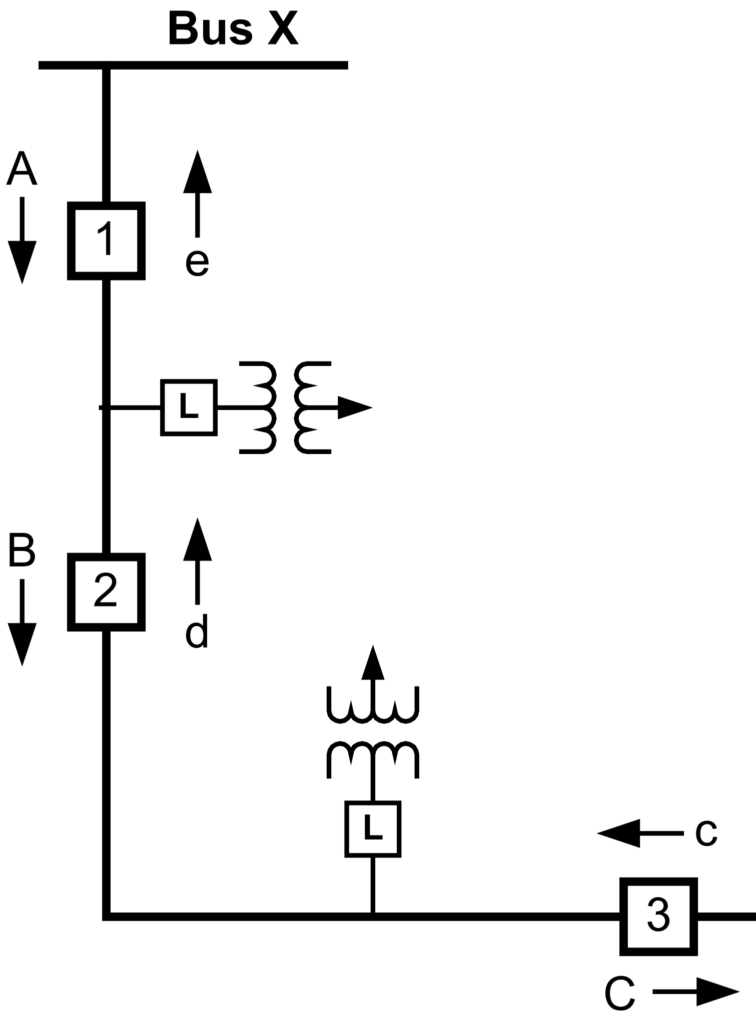


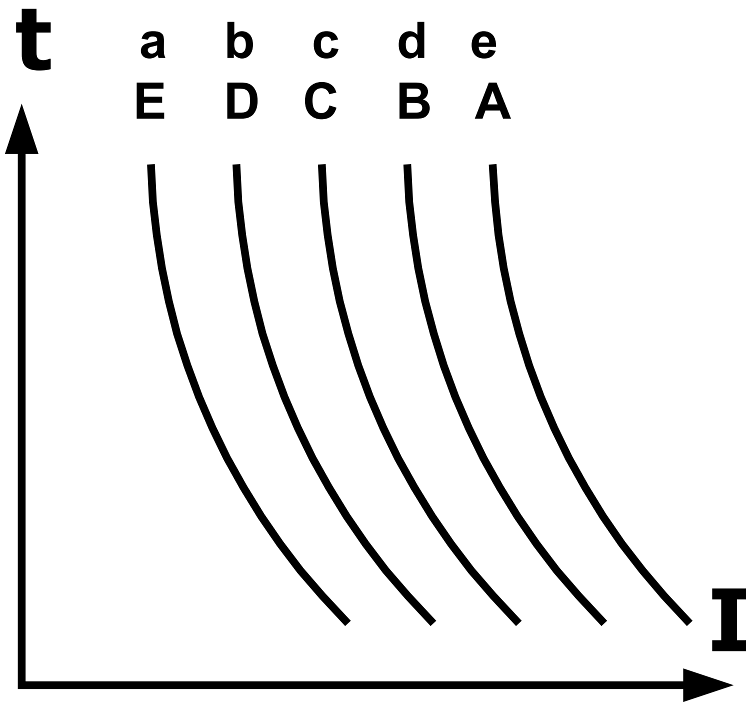
Voltage Type

- V_1 for 3-phase faults
- V_2 for 2-phase faults
- $3V_0$ for ground faults

Applications – Directional Overcurrent (67)

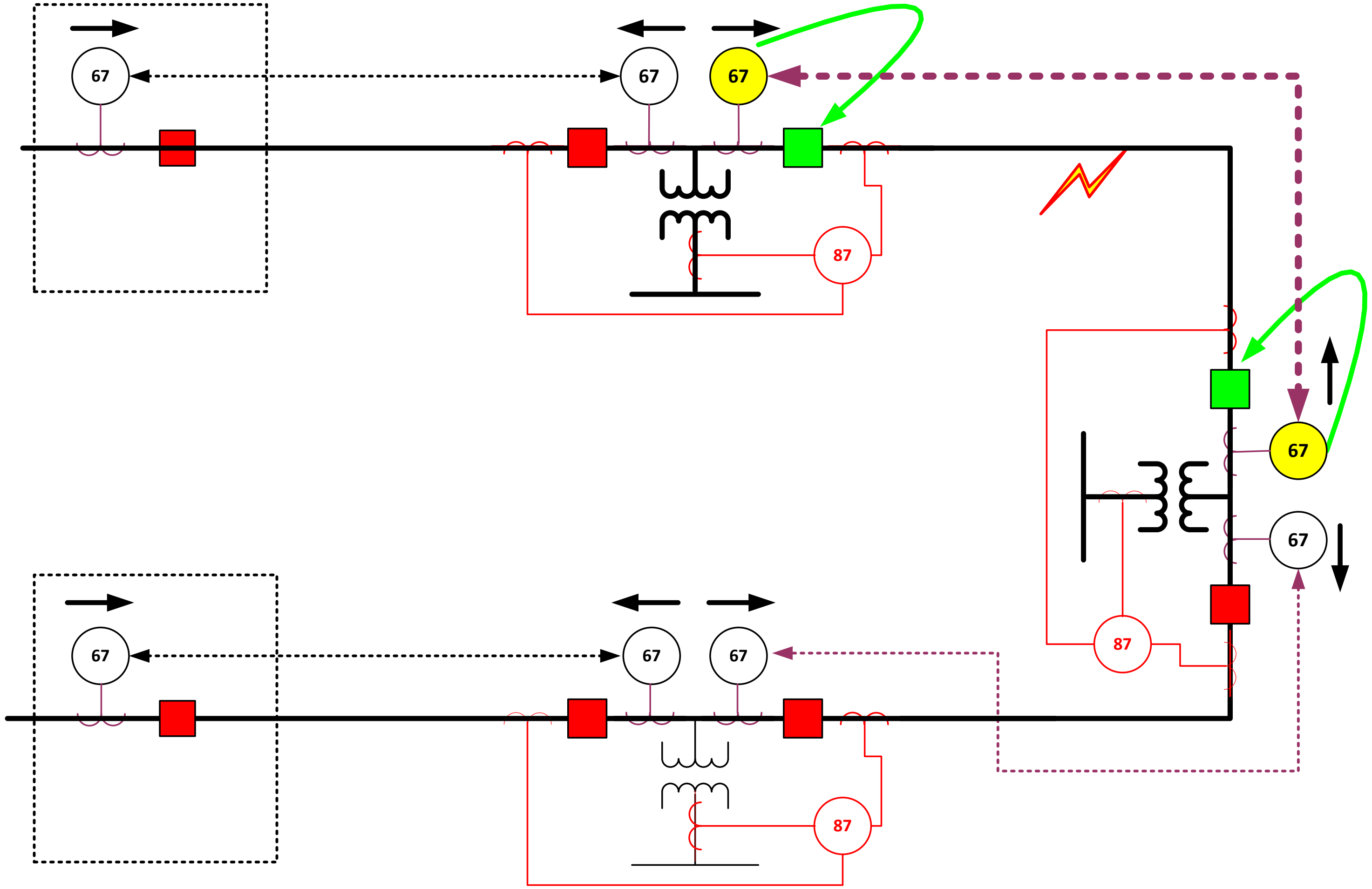
Non-Pilot Directional Overcurrent Scheme (Old School) for Looped System Protection





Applications – Loop Schemes

Use of 67, 67N for Comm Scheme Aided Protection (New School)

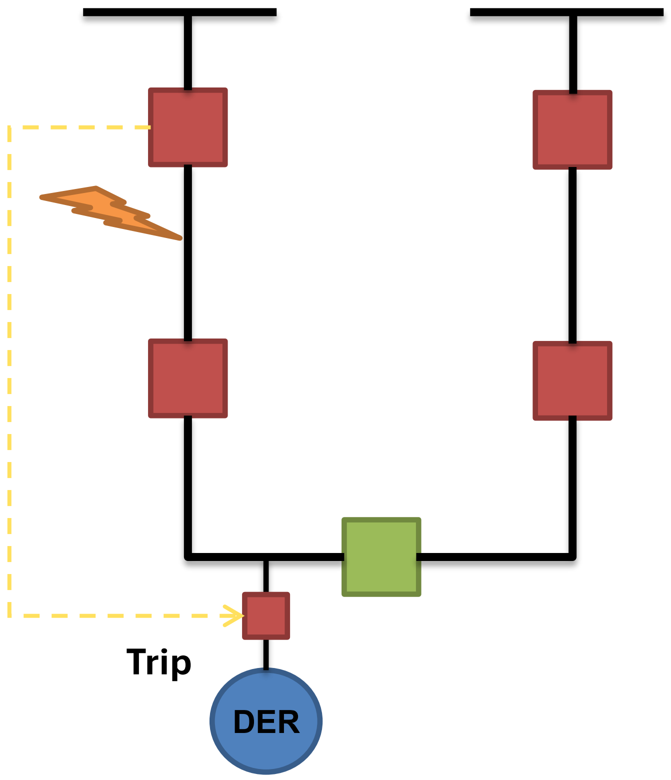


For cable fault; directional comparison trips line section

Applications – Communications

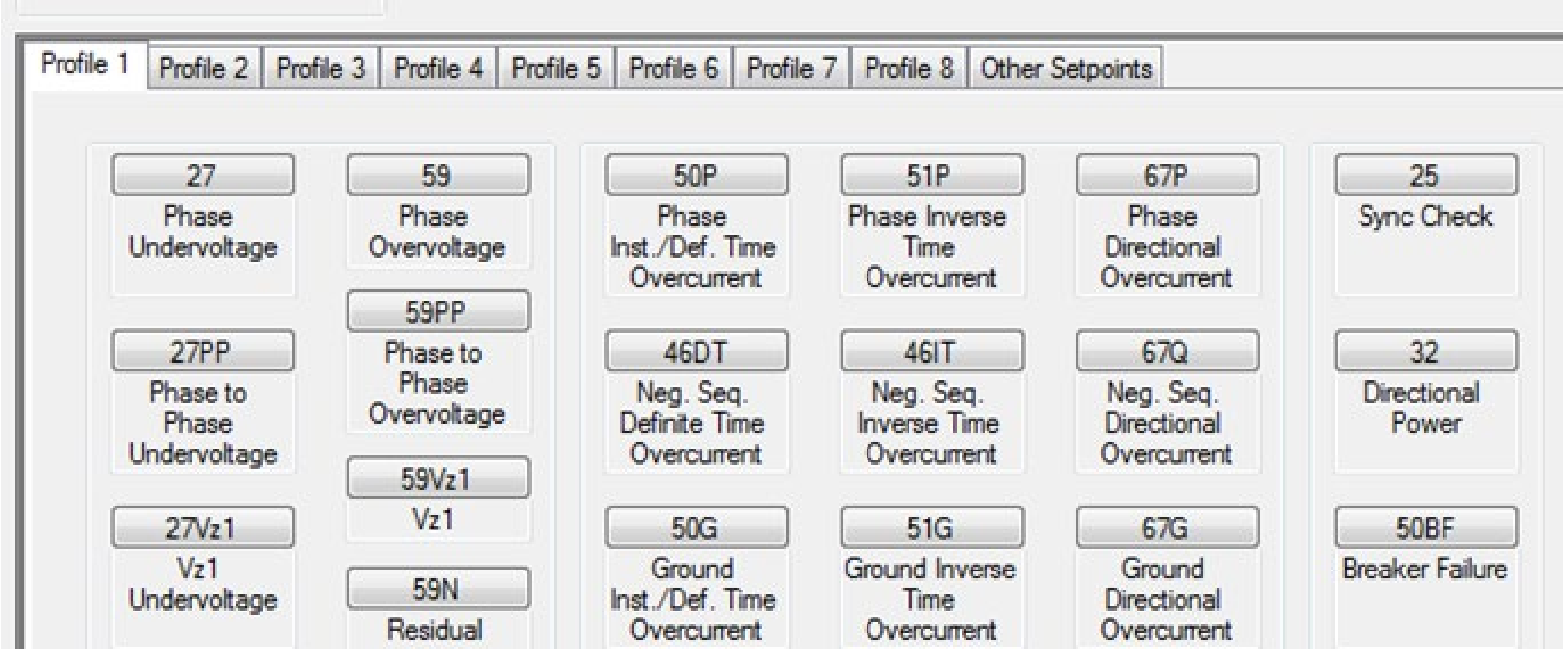
DTT

- Trips remote device when local device is tripped, as needed for the application
- Triggered by 52 contact , LOR, other device
- May be combined with other comms protection schemes



Applications – Adaptive Relaying

- Multiple Settings Profiles
  - Automated switching of settings profiles
- What can change?
  - Reclosing settings
  - Altering Pickups and Timings
  - Enabling/Disabling Elements
- Triggered with:
  - Communications
  - Internal logic
  - Measured quantities
    - Current flow direction
    - Powerflow direction
    - Load current levels
  - Other device statuses



Applications – Large Unbalanced Motors

- Induction motors with unbalanced voltages draw unbalanced phase currents
  - Worst case is single-phased motor
  - Healthy phases rise to 1.73x normal currents
- When feeder load is small relative to motor
  - Increased phase currents may false trip overcurrent relays
- Raise overcurrent pickup
- Use negative sequence overcurrent
  - Set above open phase motor current

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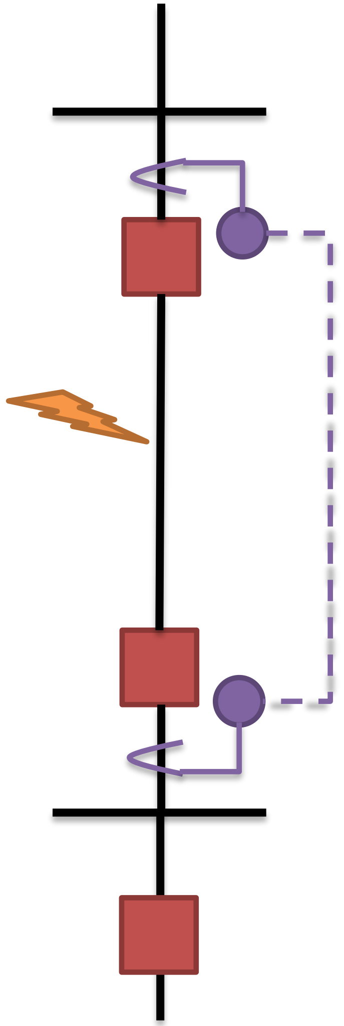
    - Set above open phase motor current

Applications – Adaptive Relaying

Current Differential

- Compares incoming to outgoing phase currents of protected object
  - INs = OUTs
- Highly selective
- Very fast, proportional to signal propagation delay time
- Virtually no coordination requirements between ends
- Minimal setting requirements
- No impact on security from load encroachment or power swings
- Applicable on any line length
- Insensitive to arcing faults, current reversal, and mutual coupling effects
- Inter-relay signaling enables secure, additional protection/control functions such as DTT and Inhibit Autoreclosing
- Scheme commissioning the local relay can display the remote relay’s quantities
- Greater bandwidth and a low error rate communications
- May need GPS time reference to coordinate sent and received data
- CT performance must be considered in application



Applications – Communications

WHY

- Improve tripping speed
- Complicated circuit topologies
- DERs
- Closed loop
- Automation schemes

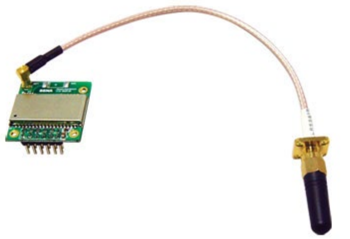
HOW

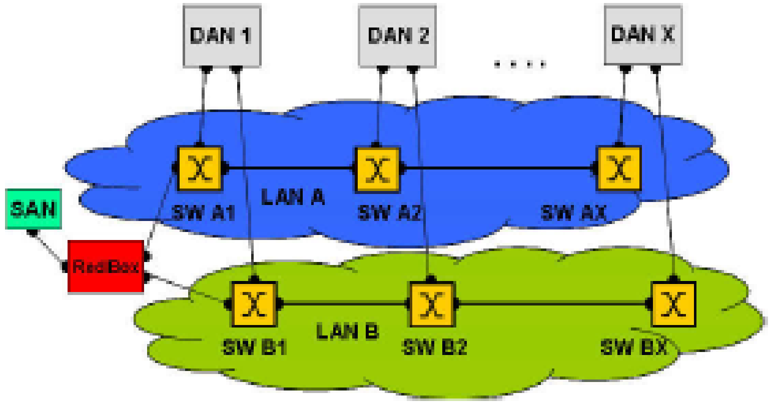
- Pilot Wire
- Power Line Carrier
- Leased Line
- Direct Fiber
- Multiplexed Fiber
- Licensed or unlicensed spread spectrum RF
- Protocols

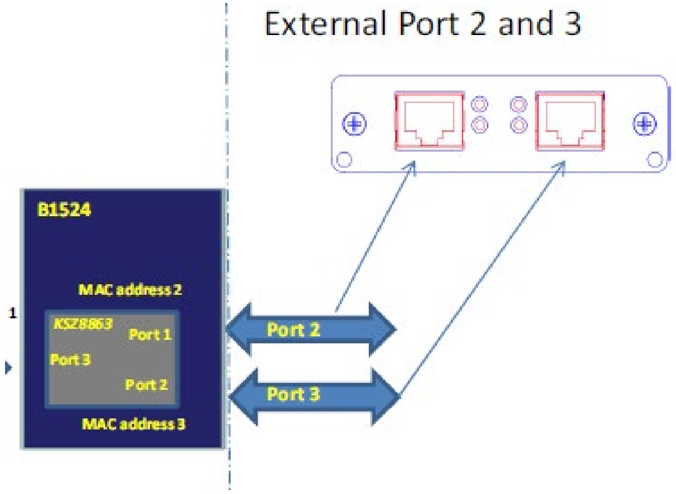
Applications – Communications

Desirable Relay Capabilities

- True Ethernet
  - Multi session/Multi protocol
  - Dual MAC
  - Redundant Network topologies
  - RSTP – Rapid Spanning Tree Protocol
  - IEC 62439
    - PRP – Parallel Redundancy Protocol
    - HSR – High-availability Seamless Redundancy
- Bluetooth
- Wi-Fi
- IEC-61850
- SD Card
- USB Programming Port
- IRIG-B, IEEE 1588 PTP
- Media
  - Copper
  - Fiber







Applications – Communications

Considerations

- Monitor communications during normal and trip conditions and alarmed for prolonged failures or degradation
- Protection scheme must consider the speed and quality of the communications system
- Backup protection must be designed with consideration of the anticipated failure mode and rate of the communication system
- Assign protection logic values for the condition of channel failure to reduce possible false trips and failures to trip

Smart Grid and Distribution Automation

FDIR / FLISR

- Fault Detection – Isolation – Restoration
- Fault Location – Isolation - Service Restoration

Distribution Automation will be covered in detail in a separate session.

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