Relion. Thinking beyond the box.

Designed to seamlessly consolidate functions, Relion relays are smarter, more flexible and more adaptable. Easy to integrate and with an extensive function library, the Relion family of protection and control delivers advanced functionality and improved performance.
ABB Protective Relay School Webinar Series
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Topics

- System Overview
- Why is feeder protection necessary
- The Protection team
  - Fuses
  - Breakers/reclosers
  - Relays
  - CT’s
- Characteristics of protective devices
  - Fuses
  - Circuit breakers, relays and reclosers
- Principles of feeder coordination
Distribution System Voltage Class

Percent of Distribution Systems at the Nominal voltage Class

- 15 kV: 62%
- 25 kV: 20%
- 35 kV: 12%
- 5 kV: 6%

Trend to larger nominal voltage class

- Increasing load density
- Lower cost of higher voltage equipment
WHY IS FEEDER PROTECTION NECESSARY?
City Lights
Chaos and Confusion
Transmission Line Tower Flashover
Transformer Failure
Generator Failure
Overhead Distribution Feeder Faults

Temporary (non-persistent) – 85%
- Lightning causing flashover
- Wind blowing tree branches into line(s)

Permanent (persistent) – 15%
- Broken insulator
- Fallen tree
- Automobile accident involving utility pole
Typical Distribution Substation Feeder Circuit

Transformer Primary
- Rural - primary fuses
- Urban - breaker or circuit switch

Feeder Circuit
- Breaker in protective zone
- Breakers controlled by protective relays
- Reclosers
- Sectionalizers
- Lateral Tapped Fuses
Fault Current Levels

Distance in Feet (one way) From the Substation to the Fault

Fault Current Vs. Distance to Fault on the Feeder

- Function of
  - Substation transformer size (source impedance)
  - Distribution voltage
  - Fault location
- 10kA - majority
- 10-20kA - moderate number
- 20kA - few
Application

- Protection to be applied based on exposure
- Higher voltage feeders tend to be longer with more exposure to faults
- Apply downline devices . . . reclosers, fuses, based typically on 3 to 5 MVA of load per segment
Feeder protection consists of a team of coordinated devices:

- Fuses
- Breakers/Reclosers
  - Relay(s)
  - The sensors
    - PTs
    - CTs
    - Etc.
- The interconnection
Distribution Protection

Required characteristics of protective devices are:

- Sensitivity – responsive to fault conditions
- Reliability - operate when required (dependability) and no-operation when not required (security)
- Selectivity – isolate minimum amount of system and interrupt service to fewest customers
- Speed – minimize system and apparatus damage
Reliability

**DEPENDABILITY**

The certainty of correct operation in response to system trouble.

**SECURITY**

The ability of the system to avoid undesired operations with or without faults.
Reliability

**DEPENDABILITY**

The certainty of operation in response to system trouble

Main 1  Main 2

**SECURITY**

The ability of the system to avoid misoperation with or without faults

Main1

Main2
General Relaying Philosophy

“Zone Protection”
- Generator
- Transformer
- Bus
- Transmission Lines
- Motors
Zones of Protection

Station A

Station B

Station C

Station D

Generator Protection
Zones of Protection

Station A

Station B

Station C

Station D

Transformer Protection
Zones of Protection

**Station A**

**Station B**

**Station C**

**Station D**

Bus Protection
Zones of Protection

Station A

Station B

Station C

Station D

Motor/Feeder Protection
Distribution Fuses
Typical Distribution Substation Feeder Circuit: Fuses
Distribution Fuses

- Continuous current rating
- Interruption rating
- Curve characteristics
  - Minimum melt
  - Total clearing
Fuse Characteristic

Amperes

Time in Seconds

1000
100
10
1.0
1.0
0.1
0.1
10
10

Total Clearing (Interruption Time)

Minimum Melt (Response Time)

Fuse melting time (damage)

Arc Clearing
Distribution Fuses - Expulsion

- K link
- T link (slower clearing at high current)
- Common low current clearing time based on fuse rating
  - 300 sec <= 100 A rating
  - 600 sec > 100 A rating
Distribution Fuses – Current Limiting

General purpose

- Rated maximum interrupting down to current that causes melting in one hour
- Melting - 150% to 200%
Distribution Fuses – Current Limiting

Backup

- Rated maximum interrupting down to rated minimum interrupting
- Requires application with expulsion fuse for low current protection
Fuse Coordination - Rule of Thumb

Maximum clearing time of downstream fuse should be less than 75% of minimum melt time of upstream fuse (device).
Fused Cutouts

Enclosed
- Line terminal
- Porcelain Housing
- Mounting Bracket
- Fuse Tube Mounted Inside Housing Door

Fused Cutout
- Line terminal
- Silicon/Polymer Support
- Mounting Bracket
- Housing Door
- Line terminal
- Fuse Holder
- Arc Arrester
- Open Link Fuse Link

Open Link
- Line terminal
- Silicon/Polymer Support
- Mounting Bracket
- Spring Contacts
- Line terminal
Distribution Circuit Breakers and Reclosers
Typical Distribution Substation Feeder Circuit: Breakers and Reclosers
Distribution Circuit Breaker / Recloser

**Interruption medium**
- Oil
- Vacuum under oil
- Vacuum

**Operating mechanism**
- Electromechanical (spring charging)
- Magnetic actuator

**Fault sensing and control**
- Electromechanical
- Solid state
- Microprocessor
Operating Mechanisms: ESV (spring charge) vs. OVR

Spring charged mechanism
- Over 300 total parts
- Many moving parts
- 2000 Operation
- Three phase operation only

Magnetic actuator
- One moving part
- No maintenance
- 10,000 Operation
- Single and three phase
Oil Reclosers vs. Solid Dielectric

Oil

- Lower interrupting ratings
- Clearing time / coordination can vary depending on temperature and condition of oil
- Reclosing must be delayed on older units without vacuum bottles to allow for out gassing
- 2000 Operations or less
- Requires 5 – 7 year maintenance schedule

Magnetic Actuation, Solid Dielectric

- High fault interrupting capability
- High load current rating
- One size fits all amp rating (interchangeability)
- Low maintenance costs
- Environmentally friendly
Medium Voltage Vacuum Breakers

- **15kV/27kV Breaker**
  - Single Bottle design
  - 15kV & 27kV
  - Stored Energy or magnetic Mechanism

- **38kV Breaker**
  - 38kV
  - Two bottle per phase design
  - Stored Energy or Magnetic Mechanism

- Vacuum Interruption
- Definite purpose rated – ANSI C37.06 – 2000
  Table 2A
MV Breaker Ratings

<table>
<thead>
<tr>
<th></th>
<th>Type X</th>
<th>R-MAG</th>
<th>Type R</th>
<th>R-MAG</th>
<th>Type V</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage, kV</td>
<td>15</td>
<td>15</td>
<td>27</td>
<td>27</td>
<td>38</td>
</tr>
<tr>
<td>Interrupting, kA</td>
<td>12 - 25</td>
<td>12 - 25</td>
<td>12 - 20</td>
<td>12 - 25</td>
<td>25 - 40</td>
</tr>
<tr>
<td>BIL</td>
<td>110</td>
<td>110</td>
<td>125 - 150</td>
<td>125 - 150</td>
<td>150 - 200</td>
</tr>
</tbody>
</table>

BIL (Basic Impulse Level): Impulse withstand voltage

Type V two bottle design allows for back-to-back capacitor switching up to 1200 A
Automatic Recloser

- Improve reliability of service
- Pole-top mounting - eliminates need to build substation
- Three-phase unit can replace breaker in substation for lower current ratings
- Breakers and Reclosers provide the physical interruption

- Both require a protective relay to signal when to operate
Distribution Circuit Protective Relays
WHAT IS RELAYING
Relays

Relays are electromechanical, solid-state (static) or microprocessor-based (digital/numerical) devices that are used throughout the power system to detect abnormal and unsafe conditions and take corrective action.
Classification of Relays - Defined in IEEE C37.90

Classification by Function

- **Protective** - Detects intolerable conditions and defective apparatus.
- **Monitoring** - Verify conditions in the protection and/or power system.
- **Reclosing** - Establish closing sequences for a circuit breaker following a protective relay trip.
- **Regulating** - Operates to maintain operating parameters within a defined region.
- **Auxiliary** - Operates in response to other [relay] actions to provide additional functionality
- **Synchronizing** - Assures that proper conditions exist for interconnecting two sections of the power system.
Classification of Relays

Classification by Input

- Current (Generator, Motor, Transformer, Feeder)
- Voltage (Generator, Motor, Transformer, Feeder)
- Power (Generator, Motor, Transformer, Feeder)
- Frequency (Generator, Motor, Feeder)
- Temperature (Generator, Motor, Transformer)
- Pressure (Transformer)
- Flow (Generator, Motor, Transformer, Feeder)
- Vibration (Generator, Motor)
Classification of Relays

Classification by Performance Characteristics

- Overcurrent
- Over/under voltage
- Distance
- Directional
- Inverse time, definite time

- Ground/phase
- High or slow speed
- Current differential
- Phase comparison
- Directional comparison
Classification of Relays

Classification by Technology

- Electromechanical
- Solid state (Static)
- Microprocessor-based (Digital/Numerical)
Relay Input Sources
Typical Distribution Substation Feeder Circuit
Purpose

- Provide input signal (replica of power system voltage and current) to Relays
  - Reduce level - suitable for relays (typically 120V and 69V depending on line-line or line to neutral connection)
  - Provide isolation
Types

- Voltage transformation
  - Electromagnetic voltage transformer
  - Coupling capacitance voltage transformer
  - Optical voltage transformer

- Current transformation
  - Electromagnetic current transformer
  - Optical current transformer
  - Rogowski coil
Voltage (potential) Transformer (VT/PT)

- Do not differ materially from constant-potential power transformers except
  - Power rating is small
  - Designed for minimum ratio & phase angle error
Current Transformer Basics

- Current or series transformer primary connected in series with the line
- Ratio of transformation is approximately inverse ratio of turns. i.e 2000/5
- Differs from constant-potential transformer
  - Primary current is determined entirely by the load on the system and not by its own secondary load
Current Transformer Basics

- Secondary winding **should never** be open-circuited

- Flux in the core, instead of being the difference of the primary & secondary ampere-turns, will now be due to the total primary ampere-turns acting alone

- This causes a large increase in flux, producing excessive core loss & heating, as well as high voltage across the secondary terminals

\[
V_{CD} = V_S = I_L(Z_L + Z_{lead} + Z_B)
\]

Where \(Z_B\) is the load presented to the CT by the relay.
Steady State Performance of CT

- ANSI accuracy classes
  - Class C indicates that the leakage flux is negligible and the excitation characteristic can be used directly to determine performance. The Ct ratio error can thus be calculated. It is assumed that the burden and excitation currents are in phase and that the secondary winding is distributed uniformly.
Steady State Performance of CT

- ANSI accuracy classes

Figure 5-6  ANSI accuracy standard chart for class C current transformers.
Saturation of a CT may occur as a result of any one or combination of:

- Off-set fault currents (dc component)
- Residual flux in the core
D.C. Saturation Effect in Current

Figure 5-9  Dc saturation of current transformer.
Over Current Relay Characteristics
Recloser or Breaker Relay Characteristic

- **Response Time**
- **Breaker / Recloser Interruption Time**

Graph showing the relationship between Amperes and Time in Seconds for response and interruption times. The graph illustrates the decrease in time with increasing amperes for both response and interruption processes.
Overcurrent Current Device Characteristics

Current in Secondary Amperes

Time in Seconds

ANSI Numbers

50 - Instantaneous Overcurrent (No intended delay)
Recloser – Fast Curve

51 - Inverse-time Overcurrent
Recloser – Slow curve
Time Overcurrent Curves

![Graph showing time overcurrent curves with different time constants: Definite Time, Moderately Inverse, Inverse, Very Inverse, and Extremely Inverse. The x-axis represents current in multiples of pickup, and the y-axis represents time in seconds. The curves show how time varies with current for different inverse characteristics.](Image)
Time Overcurrent Curve – Time Dial

Example Time-current Characteristic

Current in Multiples of Tap (pickup)

TIME (seconds)

0.1

0.5

1

2

3

4

6

8
Recloser Curves

Variety of recloser curves are offered to match existing practices, fuses, conductor annealing, etc.
Distribution Feeder Phase Protection

- Pickup tap setting typically is 2, but never less than 1.5, times the normal maximum load interruption rating
- Or 1.25 times the short-time maximum load rating of the feeder
Distribution Feeder Ground Protection

Pickup commonly based on one of the following
- % Above estimated normal load unbalance
- % Above estimated load unbalance due to switching
- % Of the phase overcurrent pickup
- % Of the feeder emergency load rating
- % Of the feeder normal load rating

Permissible Unbalance
- Not above 25% of load current is typical rule-of-thumb, but some allow up to 50%
- Pickup setting of ground element to be 2 - 4 times the permissible unbalance
Principles of Feeder Coordination
Principles of Feeder Coordination

Fault Current Vs. Distance to Fault on the Feeder

Distance in Feet (one way) From the Substation to the Fault
Principles of Feeder Coordination

51 - Inverse time-overcurrent characteristic
Principles of Feeder Coordination

CTI - Coordination Time Interval (typical - 0.35 sec)

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Principles of Feeder Coordination

Coordination Terminology

SOURCE □ B □ R □ LOAD

Upstream
Source-side
Protected
Backup

Downstream
Load-side
Protecting
Down-line
Local
(where you are)
Principles of Feeder Coordination

1. Determine critical fault current locations and values of most downstream device, and plot
   - Maximum – $I_{f1M}$ Min $Z_s$, at device
   - Minimum – $I_{f1m}$ Max $Z_s$, end of segment
Principles of Feeder Coordination

1. Determine critical fault current locations and values, and plot.
2. Set the pickup of the most downstream device as sensitive as possible
   \[0.5 \times I_{f1m} > I_{Rpu} > 2 \times \text{LOAD}\]
1. Determine critical fault current locations and values, and plot.
2. Set most downstream device as sensitive as possible.
3. Plot operating times of Relay R based on characteristic of device selected.
Principles of Feeder Coordination

1. Determine critical fault current locations and values, and plot.
2. Set most downstream device as sensitive as possible. Plot operating times of Relay R.
3. Add Coordination Time Interval (CTI).
Principles of Feeder Coordination

Coordination Time Interval
CTI is the minimum time interval added to the local device (relay/breaker, fuse) that permits coordination with the next remote upstream device. Coordination is achieved where the remote device will not [normally] operate for faults downstream of the local device, but will operate for all faults between the two.
Principles of Feeder Coordination

Coordination Time Interval
Factors that influence CTI are:
- Breaker fault interruption time of upstream device
- Relay dropout (over-travel) time of upstream device [momentum]
- Safety margin to account for setting, tap, CT and operating time errors
- 0.35 seconds typical
4. Add CTI.
5. Determine critical fault current locations for device H, and plot:
   - Maximum – $I_{f2M}$, Min Zs, at device
   - Minimum – $I_{f2m}$, Max Zs, end of segment.
6. Plot operating times for H.
Principles of Feeder Coordination

4. Add CTI.
5. Determine critical fault current locations for device H, and plot.
6. Plot operating times of Relay H.
7. Select pickup settings for Relay H ($I_{Hpu}$) to operate for minimum fault and not operate on maximum load. ($0.5*I_{f2m} > I_{Hpu} > 2*I_{load}$ or compromise)
Principles of Feeder Coordination

4. Add CTI.
5. Determine critical fault current locations for device H.
6. Plot operating times of Relay H.
7. Select pickup settings for Relay H.
8. Select time dial for Relay H so curve passes through or above all CTI points.
Principles of Feeder Coordination

Relay at H is comparatively slow in the defined region of $I > I_{f1M}$.
Principles of Feeder Coordination

- Relay at H is comparatively slow in the defined region.
- Apply Instantaneous at H at value greater than $1.25 \times I_{f1M}$.
Fuse Coordination - Rule of Thumb

Maximum clearing time of downstream fuse should be less than 75% of minimum melt time of upstream fuse.
Fuse Coordination - Rule of Thumb

Maximum clearing time of downstream fuse should be 75% of the 51 characteristic of the upstream recloser/relay for desirable coordination. It may be necessary, however, to set the CTI down to as low as 5 cycles to achieve complete feeder coordination.
Principles of Feeder Coordination

- Most utilities require complete coordination between phase time-overcurrent elements down through customer owned protective devices.

- Those who allow miscoordination only permit it at high current levels where the result is likely to be simultaneous fuse blowing and feeder tripping.
Typical Feeder Coordination

Feeder Coordination Example
Typical Feeder Coordination

- Time-Current Curves drawn based on the 13.2kv system currents

Assumptions

- Maximum load through recloser = 230A
- Maximum load at feeder breaker = 330A
- 65T and 100T fuses used at lateral taps
Typical Feeder Coordination

- With 230A maximum load, select 560A phase pickup setting for the recloser (240%)
  - for both phase time and instantaneous units
- Select 280A pickup for ground overcurrent element (50% of phase pickup)
  - for both ground time and instantaneous units
- Select ground time-curve of recloser to coordinate with the 100T fuse
Typical Feeder Coordination

- Assuming 400:5 ct ratio for the substation relays, 330A max load = 4.125A secondary

- Select 9A tap for phase relays = 720A pickup
- Select 4A tap for ground relay = 320A pickup

- Select ground relay time-dial to coordinate with recloser ground curve. Select phase relay time dial to coordinate with recloser phase curve
Typical Feeder Coordination

- Phase overcurrent relay curve must also coordinate with transformer primary side fuses and transformer frequent-fault capability

- Primary side fuse must protect transformer per transformer infrequent-fault capability curve
Typical Feeder Coordination

Feeder Coordination Example
Typical Feeder Coordination

- Transformer fuse is the slowest (C&D)
- OC Relay and Recloser slow curves faster than 65T and 100T Fuses (3, 4, 5 & 6)
Typical Feeder Coordination

- Recloser fast curves faster than 65T and 100T Fuses
- Recloser is operating in a “fuse save” mode:
  - Fast curve (1&2) will open recloser before downstream fuses open
  - This will allow a transient fault on a fused tap to be cleared before blowing the fuse
  - After a pre-determined number of operations, usually one or two, the fast curves are blocked and the recloser allows the fuse to blow if the fault is in the fuse’s zone of protection.
  - If the fault is on the feeder the recloser will operate again, typically going to lockout after one or two more operations.
  - Each recloser operation will have a longer open time to allow the fault to clear
  - This reduces the outage time on the taps for transient faults, saving the fuse and not having to dispatch a crew to replace the fuse.
The breaker is operating in a fuse blowing mode:

- If the fault is on the tap above the recloser the 100T fuse will open before the breaker

- This reduces the number of customers affected by the outage to only those on the tap.

Typical Feeder Coordination
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Thank you for your participation

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