Fundamentals of Modern Protective Relaying
(Part 1)
Your Presenters

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Course Agenda

- System Grounding
- Power System Protection
  - Why Protect?
  - Symmetrical Components
  - ANSI/IEEE Device Numbers
- Instrument Transformers
  - Current Transformers
  - Voltage Transformers
Course Agenda

- Relaying Fundamentals
- Common Protection Methods
- Feeder Protection
  - Time Overcurrent
  - Instantaneous Overcurrent
  - Directional Overcurrent
  - Breaker Failure
- Bus Protection
  - High Impedance
  - Low Impedance
  - Zone Interlocking
Course Agenda

- Transformer Protection
  - Internal and External Faults
  - Causes of Transformer Failures
  - Percent Differential
  - Transformer Inrush and 2nd Harmonic Restraint
  - Instantaneous Differential
  - Restricted Ground Fault
  - Overcurrent Protection
  - Overexcitation Protection
Course Agenda

- Motor Protection
  - Motor Failure Rates
  - Induction Motor Protection
  - Thermal Overload
  - Overvoltage and Undervoltage
  - Current Unbalance
  - Ground Fault
  - Short Circuit
  - Differential
  - RTD Monitoring/Protection

- Arc Flash Mitigation
System Grounding

- Limits overvoltages
- Limits difference in electric potential through local area conducting objects
- Several methods
  - Ungrounded
  - Reactance Grounded
  - High Impedance Grounded
  - Low Impedance Grounded
  - Solidly Grounded
1. Ungrounded: There is no intentional ground applied to the system—however it’s grounded through natural capacitance.

2. Reactance Grounded: Total system capacitance is cancelled by equal inductance. This decreases the current at the fault and limits voltage across the arc at the fault to decrease damage.

\[ X_0 \leq 10 \times X_1 \]
3. High Resistance Grounded: Limits ground fault current to 5A-10A. Used to limit transient overvoltages due to arcing ground faults.

\[ R_0 \leq \frac{X_{0C}}{3}, \quad X_{0C} \text{ is capacitive zero sequence reactance} \]

4. Low Resistance Grounded: To limit current to 25-400A

\[ R_0 \geq 2X_0 \]
5. Solidly Grounded: There is a connection of transformer or generator neutral directly to station ground.

- Effectively Grounded: \( R_0 \leq X_1 \), \( X_0 \leq 3X_1 \), where \( R \) is the system fault resistance.
Grounding Differences....Why?

- Solidly Grounded
  - Much ground current (damage)
  - No neutral voltage shift
    - Line-ground insulation
  - Limits step potential issues
  - Faulted area will clear
  - Inexpensive relaying
Grounding Differences....Why?

- High or Low Resistance Grounded
  - Manage ground current (manage damage)
  - Some neutral voltage shift
  - Faulted area will clear
  - More expensive than solid
Grounding Differences....Why?

- Ungrounded
  - Not recommend to use
  - Very little ground current (less damage)
  - Big neutral voltage shift
  - Must insulate line-to-line voltage
  - May run system while trying to find ground fault
  - Relay more difficult/costly to detect and locate ground faults
  - If you get a second ground fault on adjacent phase, watch out!
Power System Protection
Why the power system needs to be protected?

- Reduce Equipment Damage
- Reduce Power Interruptions
- Improve Power Quality
- Improve Safety for all
Causes for Faults

- Lightning
- Wind
- Ice and Snow Storm
- Flying Objects
- Contamination of Insulators
- Physical Contact by Animals
- Human Error
- Falling Trees
- Insulation Aging

Intermittent Fault:

Permanent Fault:
Fault Analysis
Symmetrical and Non-Symmetrical Systems

**Symmetrical System:**
- Counter-clockwise rotation
- All current vectors have equal amplitude
- All voltage phase vectors have equal amplitude
- All current and voltage vectors have 120 degrees phase shifts and a sum of 0.

**Non-Symmetrical System:**
- Fault or Unbalanced condition
- If one or more of the symmetrical system conditions is not met
Symmetrical Components

Positive Sequence (Always Present)

- A-B-C **Counter-clockwise** phase rotation
- All phasors with equal magnitude
- All phasors displaced 120 degrees apart

Zero Sequence

- No Rotation Sequence
- All phasors with equal magnitude
- All phasors are in phase

Negative Sequence

- A-C-B **counter-clockwise** phase rotation
- All phasors with equal magnitude
- All phasors displaced 120 degrees apart
Symmetrical Components

Positive Sequence Component:

\[ I_1 = \frac{1}{3} (I_a + \alpha I_b + \alpha^2 I_c) \quad V_1 = \frac{1}{3} (V_a + \alpha V_b + \alpha^2 V_c) \]

Negative Sequence Component:

\[ I_2 = \frac{1}{3} (I_a + \alpha^2 I_b + \alpha I_c) \quad V_2 = \frac{1}{3} (V_a + \alpha^2 V_b + \alpha V_c) \]

Zero Sequence Component:

\[ I_0 = \frac{1}{3} (I_a + I_b + I_c) \quad V_0 = \frac{1}{3} (V_a + V_b + V_c) \]

Unbalanced Line-to-Neutral Phasors:

\[ I_a = I_1 + I_2 + I_0 \quad V_a = V_1 + V_2 + V_0 \]
\[ I_b = \alpha^2 I_1 + \alpha I_2 + I_0 \quad V_b = \alpha^2 V_1 + \alpha V_2 + V_0 \]
\[ I_c = \alpha I_1 + \alpha^2 I_2 + I_0 \quad V_c = \alpha V_1 + \alpha^2 V_2 + \alpha V_0 \]

\[ \alpha = \text{Phasor } @ +120^\circ \]
\[ \alpha^2 = \text{Phasor } @ 240^\circ \]
Calculating Symmetrical Components

Three-Phase Balanced / Symmetrical System

Positive
\[ 3V_1 = V_a - \alpha V_b - \alpha^2 V_c \]

Negative
\[ 3V_2 = 0 \]

Zero
\[ 3V_0 = 0 \]

Open-Phase Unbalanced / Non-Symmetrical System

Positive
\[ 3I_1 = I_a - \alpha I_b - \alpha^2 I_c \]

Negative
\[ 3I_2 = I_a - \alpha^2 I_b + \alpha I_c \]

Zero
\[ 3I_0 = I_b - I_c \]
Symmetrical Components
Example: Perfectly Balanced & ABC Rotation

\[ i_0 = \frac{1}{3}(i_a + i_b + i_c) \]
\[ v_0 = \frac{1}{3}(v_a + v_b + v_c) \]
\[ i_1 = \frac{1}{3}(i_a + ai_b + a^2i_c) \]
\[ v_1 = \frac{1}{3}(v_a + ai_b + a^2v_c) \]
\[ i_2 = \frac{1}{3}(i_a + a^2i_b + ai_c) \]
\[ v_2 = \frac{1}{3}(v_a + a^2v_b + ai_c) \]

\[ a = 1 \angle 120^\circ \]
\[ a^2 = 1 \angle 240^\circ \]

Result: 100% I1 (Positive Sequence Component)
Symmetrical Components
Example: B-Phase Rolled & ABC Rotation

\[ l_0 = \frac{1}{3}(l_a + l_b + l_c) \quad V_0 = \frac{1}{3}(V_a + V_b + V_c) \]
\[ l_1 = \frac{1}{3}(l_a + a l_b + a^2 l_c) \quad V_1 = \frac{1}{3}(V_a + a V_b + a^2 V_c) \]
\[ l_2 = \frac{1}{3}(l_a + a^2 l_b + a l_c) \quad V_2 = \frac{1}{3}(V_a + a^2 V_b + a V_c) \]

\[ a = 1 \angle 120^\circ \quad a^2 = 1 \angle 240^\circ \]

Result: 33% I1, 66% I0 and 66% I2
Symmetrical Components

Example: B-Phase & C-Phase Rolled & ABC Rotation

\[ l_0 = \frac{1}{3}(l_a + l_b + l_c) \quad V_0 = \frac{1}{3}(V_a + V_b + V_c) \]
\[ l_1 = \frac{1}{3}(l_a + a l_b + a^2 l_c) \quad V_1 = \frac{1}{3}(V_a + a V_b + a^2 V_c) \]
\[ l_2 = \frac{1}{3}(l_a + a^2 l_b + a l_c) \quad V_2 = \frac{1}{3}(V_a + a^2 V_b + a V_c) \]

\[ a = 1 \angle 120^\circ \quad a^2 = 1 \angle 240^\circ \]

\[ l_i = 0 \]

\[ l_0 = 0 \]

\[ l_1 = 0 \]

\[ l_2 = \frac{3}{3} = 1 \angle 0^\circ \]

Result: 100% I2 (Negative Sequence Component)
Summary of Symmetrical Components

- Under a **no-fault** condition, the power system is considered to be essentially **symmetrical** therefore, only **positive sequence** currents and voltages exist.

- At the time of a **fault**, **positive**, **negative** and possibly **zero sequence** currents and voltages exist.
  - All positive, negative and zero sequence currents can be calculated using real world phase voltages and currents along with Fortescue’s formulas.
    - \( I_{N} = I_a + I_b + I_c = 3 \ I_0 \)
# ANSI / IEEE C37.2 - Device Numbers

<table>
<thead>
<tr>
<th>Number</th>
<th>Device Name</th>
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<tbody>
<tr>
<td>1</td>
<td>Master Element</td>
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<tr>
<td>2</td>
<td>Time Delay or Closing Relay</td>
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<td>3</td>
<td>Checking or Interlocking Relay</td>
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<td>4</td>
<td>Master Contactor</td>
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<td>5</td>
<td>Stopping Device</td>
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<td>6</td>
<td>Starting Circuit Breaker</td>
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<td>7</td>
<td>Rate of Rise Relay</td>
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<td>8</td>
<td>Control Power Disconnect</td>
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<td>Reversing Device</td>
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<td>10</td>
<td>Unit Sequence Switch</td>
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<td>11</td>
<td>Multifunction Device</td>
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<td>Underspeed Device</td>
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<td>15</td>
<td>Speed or Frequency Matching</td>
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<td>16</td>
<td>Reserved for Future Use</td>
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<td>Shunting or Discharge Switch</td>
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<td>18</td>
<td>Accel or Decel Device</td>
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<td>19</td>
<td>Start to Run Transition Contactor</td>
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<td>20</td>
<td>Electrically Operated Valve</td>
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<td>Volts/Hz Relay</td>
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<td>Synch Device or Synch Check</td>
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<td>26</td>
<td>Apparatus Thermal Device</td>
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<td>Undervoltage Relay</td>
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<td>Isolating Contactor</td>
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<td>Annunciator Relay</td>
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<td>Separate Excitation Device</td>
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<td>Directional Power Relay</td>
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<td>33</td>
<td>Position Switch</td>
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<td>Master Sequence Device</td>
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<td>35</td>
<td>Brush Operating or Slip Ring Shorting</td>
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<td>36</td>
<td>Polarity or Polarizing Voltage Device</td>
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<td>37</td>
<td>Undercurrent or Underpower Relay</td>
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<td>38</td>
<td>Bearing Protective Device</td>
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<td>39</td>
<td>Mechanical Condition Monitor</td>
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<td>40</td>
<td>Field Relay</td>
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<td>41</td>
<td>Field Circuit Breaker</td>
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<td>42</td>
<td>Running Circuit Breaker</td>
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<td>Manual Transfer or Selector Device</td>
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<td>44</td>
<td>Unit Sequence Starting Relay</td>
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<td>45</td>
<td>Atmospheric Condition Monitor</td>
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<td>46</td>
<td>Reverse Phase or Phase Balance Relay(II)</td>
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<td>47</td>
<td>Phase Sequence Voltage Relay</td>
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<tr>
<td>48</td>
<td>Incomplete Sequence Relay</td>
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<tr>
<td>49</td>
<td>Machine or Transformer Thermal Relay</td>
</tr>
<tr>
<td>50</td>
<td>Instantaneous Overcurrent Relay</td>
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</table>
**ANSI / IEEE C37.2 - Device Numbers**

<table>
<thead>
<tr>
<th>Device Number</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>51</td>
<td>AC Time Overcurrent Relay</td>
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<tr>
<td>52</td>
<td>AC Circuit Breaker</td>
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<td>52a</td>
<td>Contacts Open when Main Contacts Open</td>
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<tr>
<td>52aa</td>
<td>High Speed a contacts</td>
</tr>
<tr>
<td>52b</td>
<td>Contacts Open when Main Contacts Closed</td>
</tr>
<tr>
<td>52bb</td>
<td>High Speed b contacts</td>
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<tr>
<td>53</td>
<td>Exciter or DC Generator Relay</td>
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<tr>
<td>54</td>
<td>Turner Gear Engaging Device</td>
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<td>55</td>
<td>Power Factor Relay</td>
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<tr>
<td>56</td>
<td>Field Application Relay</td>
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<tr>
<td>57</td>
<td>Shorting or Grounding Device</td>
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<tr>
<td>58</td>
<td>Rectification Failure Relay</td>
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<td>59</td>
<td>Overvoltage Relay</td>
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<tr>
<td>60</td>
<td>Voltage or Current Balance Relay</td>
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<tr>
<td>61</td>
<td>Density Switch or Sensor</td>
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<tr>
<td>62</td>
<td>Time Delay Stopping or Opening Relay</td>
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<tr>
<td>63</td>
<td>Pressure Switch</td>
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<tr>
<td>64</td>
<td>Ground Detector Relay</td>
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<tr>
<td>65</td>
<td>Governor</td>
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<tr>
<td>66</td>
<td>Notching or Jogging Device</td>
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<tr>
<td>67</td>
<td>AC Directional Overcurrent Relay</td>
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<td>68</td>
<td>Blocking or Out-of-Step Relay</td>
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<td>69</td>
<td>Permissive Control Device</td>
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<td>70</td>
<td>Rheostat</td>
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<td>71</td>
<td>Level Switch</td>
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<td>72</td>
<td>DC Circuit Breaker</td>
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<td>73</td>
<td>Load Resistor Contactor</td>
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<tr>
<td>74</td>
<td>Alarm Relay</td>
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<tr>
<td>75</td>
<td>Position Changing Mechanism</td>
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<td>76</td>
<td>DC Overcurrent Relay</td>
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<td>77</td>
<td>Telemetering Device</td>
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<td>78</td>
<td>Phase Angle Measuring Relay</td>
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<td>79</td>
<td>Reclosing Relay</td>
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<td>80</td>
<td>Flow Switch</td>
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<td>Frequency Relay</td>
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<td>82</td>
<td>DC Load Measuring Reclosing Relay</td>
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<td>83</td>
<td>Automatic Selective Control or Transfer Relay</td>
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<td>84</td>
<td>Operating Mechanism</td>
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<td>85</td>
<td>Carrier or Pilot Wire Relay</td>
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<td>86</td>
<td>Lockout Relay</td>
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<td>87</td>
<td>Differential Protective Relay</td>
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<td>88</td>
<td>Auxiliary Motor or Motor Generator</td>
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<td>89</td>
<td>Line Switch</td>
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<td>90</td>
<td>Regulating Device</td>
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<td>91</td>
<td>Voltage Directional Relay</td>
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<td>92</td>
<td>Voltage and Power Directional Relay</td>
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<tr>
<td>93</td>
<td>Field Changing Contactor</td>
</tr>
<tr>
<td>94</td>
<td>Tripping or Trip-Free Relay</td>
</tr>
</tbody>
</table>
Instrument Transformers
Instrument Transformer Locations

**Inside of...**
- Generator
- Transformers

**Installed at...**
- Generation
- High Voltage Transmission
- Medium Voltage
- Low Voltage
- Commercial & Residential
- Large Industrial
Instrument Transformers

• Supply accurately scaled current and voltage quantities for measurement while insulating the relay from the high voltage and current of the power system.
Definitions

Ref IEEE 100:

**Transformer** – a device that can raise or lower the ac voltage of the original source

**Current Transformer** – a transformer intended to have its primary winding connected in series with the conductor carrying the current to be measured or controlled

**Voltage Transformer** – a transformer intended to have its primary winding connected in shunt with the voltage to be measured or controlled
Standard Voltage Classes

<table>
<thead>
<tr>
<th>Voltage Class V</th>
<th>0.6</th>
<th>5</th>
<th>8.7</th>
<th>15</th>
<th>25</th>
<th>34.5</th>
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<tbody>
<tr>
<td>BIL Rating (BIL)</td>
<td>10</td>
<td>60</td>
<td>75</td>
<td>110</td>
<td>150</td>
<td>200</td>
</tr>
</tbody>
</table>

BIL = Basic Impulse Level
Current Transformer Types - Bar

Bar-Type CT

- Annular Core
- Solid Bar
- Primary
- Secondary Winding (5 Amps or 1 Amp)
Current Transformer Types - Bushing

- Oil Circuit Breaker Bindings
- Fixed Contact
- Moving Contact
- Primary
- Secondary Winding (5 Amps or 1 Amp)
- Toroidal-style Current Transformers

Oil-filled
Current Transformer Types – Toroidal (Donut):

- **Secondary Winding (5 Amps or 1 Amp)**
- **Primary Conductor**
- **Annular Core or Ring**
Current Transformer Basics
Transformer Ratio (TR)

Transformer Ratio = \( \frac{\text{Primary Current}}{\text{Secondary Current}} \)

Primary Current (100 amps) \( \quad \quad \quad \) Secondary Current (5 amps)

\( \frac{100}{5} = 100:5 \) or \( 20:1 \)
Turns Ratio

Formula: \[
\frac{I_p}{I_s} = \frac{N_s}{N_p}
\]

Where:
- \(I_p\) — Primary Amperage
- \(I_s\) — Secondary Amperage
- \(N_p\) — Number of Primary Turns
- \(N_s\) — Number of Secondary Turns

Example: A 300:5 Current Transformer —

\[
\frac{300 \text{ p}}{5 \text{ s}} = \frac{60 \text{ s}}{1 \text{ p}}
\]
Turns Ratio Modification

Example: Window CT wound as a 300:5

Use as a 300:5 with one primary conductor turn
Use as a 150:5 with two primary conductor turns
Use as a 100:5 with three primary conductor turns

Remember: \( I_p = I_s \times \frac{N_p}{N_s} \)
Polarity

Remember:
Primary current into “polarity” =
Secondary current out of “polarity”
Polarity

Remember:
Primary current into “non-polarity” = Secondary current out of “non-polarity”
Polarity

Red = Primary Current
Blue = Secondary Current

Note:
Instantaneous current entering H1 is in-phase with instantaneous current leaving X1
Polarity

Why is polarity important?

Meters and protection relays are able to sense direction of current/power flow

What happens when polarity is wrong?

Meter spins backwards indicating power generation instead of power usage – results in decreased revenue

Relays detect power flowing in the wrong direction – results in power outages
Wound type CT - MV Primary Winding
CT Accuracy

\[ I_{\text{relay}} \neq I_{\text{primary}} \times \frac{N_1}{N_2} \]

\[ I_{\text{relay}} = I_{\text{primary}} \times \frac{N_2}{N_1} - I_{\text{exciting}} \]
CT Equivalent Circuit
CT Equivalent Circuit
CT Metering Accuracy

Actual secondary current ≠ Rated secondary current

Difference in % is known as the “Accuracy” of the CT
# IEEE CT Metering Accuracy

<table>
<thead>
<tr>
<th>Accuracy Class (*)</th>
<th>Application</th>
</tr>
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<tbody>
<tr>
<td>0.15</td>
<td>High Accuracy Metering</td>
</tr>
<tr>
<td>0.15S</td>
<td>“Special” High Accuracy Metering</td>
</tr>
<tr>
<td>0.3</td>
<td>Revenue Metering</td>
</tr>
<tr>
<td>0.6</td>
<td>Indicating Instruments</td>
</tr>
<tr>
<td>1.2</td>
<td>Indicating Instruments</td>
</tr>
</tbody>
</table>

* All accuracy classes defined by IEEE C57.13 or C57.13.6
* Accuracy classes include both ratio & phase angle error
Burden

Load connected to CT secondary
Includes devices & connecting leads
Expressed in ohms
Standard values = B0.1, B0.2, B0.5, B0.9, B1.8, E0.04, E0.2

All burdens defined by IEEE C57.13 or C57.13.6 for 60 Hz only
## Standard Burdens

**Standard IEEE CT Burdens (5 Amp)**  
(Per IEEE Std. C57.13-1993 & C57.13.6)

<table>
<thead>
<tr>
<th>Application</th>
<th>Burden Designation</th>
<th>Impedance (Ohms)</th>
<th>VA @ 5 amps</th>
<th>Power Factor</th>
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<tbody>
<tr>
<td>Metering</td>
<td>B0.1</td>
<td>0.1</td>
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<td>E0.04</td>
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<td>1</td>
<td>1.0</td>
</tr>
</tbody>
</table>
IEEE CT Relay Accuracy

Standard Relay Accuracy Classes

C or T100
C or T200
C or T400
C or T800

What do these mean?
IEEE CT Relay Accuracy

Relay class (C or T___ ) designates minimum secondary terminal volts...

At 20 times rated current
Without exceeding 10% ratio error
Into a maximum specified burden

Now that everyone is totally confused let's look at some simple examples ...
IEEE CT Relay Accuracy

C or T100 example

Primary current
24,000 amps
(20 x 1200)

Secondary current
100 amps (20 x 5)

CT
1200:5
C or T100

Burden of Devices (Ω)

Total Ext Burden
1.0 Ω

Terminal Volts = (20 times rated) (Total external burden)
100 Volts = (100 amps) (1.0 Ω )
IEEE CT Relay Accuracy

C or T200 example

Primary current 24,000 amps (20 x 1200)

Secondary current 100 amps (20 x 5)

CT 1200:5 C or T200

Burden of Devices (Ω)

Burden of Leads (Ω)

Terminal Volts = (20 times rated) (Total external burden)

200 Volts = (100 amps) (2.0 Ω)

Typical Microprocessor Relay is 0.2 VA or 0.008 Ω
# IEEE CT Relay Accuracy

Standard IEEE CT Burdens (5 Amp)
(Per IEEE Std. C57.13-1993)

<table>
<thead>
<tr>
<th>Application</th>
<th>Burden Designation</th>
<th>Impedance (Ohms)</th>
<th>VA @ 5 amps</th>
<th>Power Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relaying</td>
<td>B1</td>
<td>1</td>
<td>25</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>B2</td>
<td>2</td>
<td>50</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>B4</td>
<td>4</td>
<td>100</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>B8</td>
<td>8</td>
<td>200</td>
<td>0.5</td>
</tr>
</tbody>
</table>
IEEE CT Relay Accuracy

C___ : a guarantee that with

\[ I_{SEC} = 20 \times CT_{sec} \] and

\[ Z_B = \text{standard burden that} \]

\[ I_E < 0.10 \times 20 \times CT_{sec} \]

\[ I_S > 0.90 \times 20 \times CT_{sec} \]
Factors Influencing CT Accuracy

**Frequency**

“Low frequency” and “High accuracy” are not friends!!

**Current Ratio**

“Low ratio” and “High accuracy” are not friends!!

**Burden**

“High burden” and “High accuracy” are not friends!!
CT Sizing
CT Rating Factor (RF) - IEEE

Rated current \times (RF) =

Maximum continuous current carrying capability:

Without exceeding temperature limits
Without loss of published accuracy class

Typical rating factors -- 1.0, 1.33, 1.5, 2.0, 3.0, 4.0
## CT Sizing (Rating Factor)

<table>
<thead>
<tr>
<th>CATALOG NUMBER</th>
<th>CURRENT RATIO</th>
<th>RELAY CLASS</th>
<th>ANSI METERING CLASS AT 60HZ</th>
<th>SECONDARY WINDING RESISTANCE (OHMS @ 75°C)</th>
<th>CONTINUOUS THERMAL RATING FACTOR @ 30°C</th>
<th>CONTINUOUS THERMAL RATING FACTOR @ 55°C</th>
</tr>
</thead>
<tbody>
<tr>
<td>143–500</td>
<td>50:5</td>
<td>C20</td>
<td>BO.1 : 48, BO.2 : 48, BO.5 : -</td>
<td>0.014</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–750</td>
<td>75:5</td>
<td>C20</td>
<td>BO.1 : 24, BO.2 : 24, BO.5 : -</td>
<td>0.042</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–101</td>
<td>100:5</td>
<td>C20</td>
<td>BO.1 : 12, BO.2 : 24, BO.5 : 48</td>
<td>0.056</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–151</td>
<td>150:5*</td>
<td>C50</td>
<td>BO.1 : 0.6, BO.2 : 6, BO.5 : 12</td>
<td>0.121</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–201</td>
<td>200:5*</td>
<td>C50</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.161</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–251</td>
<td>250:5*</td>
<td>C50</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.175</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–301</td>
<td>300:5*</td>
<td>C100</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.241</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–401</td>
<td>400:5*</td>
<td>C100</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.322</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–501</td>
<td>500:5*</td>
<td>C100</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.441</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–601</td>
<td>600:5*</td>
<td>C200</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.530</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–751</td>
<td>750:5*</td>
<td>C200</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.662</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–801</td>
<td>800:5*</td>
<td>C200</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.706</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–102</td>
<td>1000:5*</td>
<td>C200</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>0.883</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–122</td>
<td>1200:5*</td>
<td>C400</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>1.059</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–152</td>
<td>1500:5*</td>
<td>C400</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>1.324</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–162</td>
<td>1600:5*</td>
<td>C400</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>1.413</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–202</td>
<td>2000:5*</td>
<td>C400</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>1.678</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–252</td>
<td>2500:5*</td>
<td>C400</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>2.097</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–302</td>
<td>3000:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>2.516</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–322</td>
<td>3200:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>2.684</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–352</td>
<td>3500:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>2.936</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–402</td>
<td>4000:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>3.355</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–502</td>
<td>5000:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>3.983</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>143–602</td>
<td>6000:5*</td>
<td>C800</td>
<td>BO.1 : 0.3, BO.2 : 0.6, BO.5 : 12</td>
<td>4.780</td>
<td>2.0</td>
<td>2.0</td>
</tr>
</tbody>
</table>
CT primary > maximum expected load current * rating factor
CT primary < maximum expected fault current/20
CT primary should be sized to avoid saturation
CT accuracy class should be sized to avoid saturation
CT insulation should be sized for the application
CT BIL should be sized to coordinate with station BIL
CT Saturation
CT Saturation Concepts

• CT saturation depends on a number of factors
  – Physical CT characteristics (size, rating, winding resistance, saturation voltage)
  – Connected CT secondary burden (wires + relays)
  – Primary current magnitude, DC offset (system X/R)
  – Residual flux in CT core
• Actual CT secondary currents may not behave in the same manner as the ratio (scaled primary) current during faults
• End result is spurious differential current appearing in the summation of the secondary currents which may cause differential elements to operate if additional security is not applied
CT Saturation Concepts
Operating with DC Offset
Operating with DC Offset

Time To Saturate

\[ K_s = \frac{V_X}{I_{SEC} \times Z_S} \]

where
- \( V_X \): saturation voltage of the CT (secondary volts)
- \( I_{SEC} \): secondary current at the CT terminals
- \( Z_S \): total secondary impedance of CT circuit \((R_s+X_s+Z_B \text{ from Figure 2.})\)

\[ T_s = \frac{-X/R}{2\pi f} \ln \left( 1 - \frac{K_s-1}{X/R} \right) \]

where
- \( f \): system frequency
- \( X \): system reactance at CT location
- \( R \): system resistance at CT location.
Modeling CT performance

- IEEE C37.110 Method
- IEEE PSRC CT Saturation Calculator
C37.110 Method

C37.110 uses this relation:

\[ V_X > I_{AC} \times Z_S \times \left(1 + \frac{X}{R}\right) \]

(Assuming a resistive burden)
CT Saturation Voltage
How do we calculate this?

CT Burden Calculation

Total Burden $Z_T$

Burden of Devices ($\Omega$)

Burden of Leads ($\Omega$)

Secondary current

Primary Current

CT $\times_1 \times_2$
CT Burden Calculation
CT Burden Calculation

\[ Z_T = R_{CT} + R_L + Z_B \]

- \( Z_T \) = Total burden in ohms
- \( R_{CT} \) = CT secondary resistance in ohms @75 deg C
- \( R_L \) = Resistance of leads in ohms (Total loop distance)
- \( Z_B \) = Device impedance in ohms
CT Burden Calculation

\[ Z_T = R_{CT} + R_L + Z_B \]

\[ R_{CT} = \text{CT secondary resistance in ohms} \]

Best Source for \( R_{CT} \) is from the Manufacturer

<table>
<thead>
<tr>
<th>CATALOG NUMBER</th>
<th>CURRENT RATIO</th>
<th>RELAY CLASS</th>
<th>BO.1</th>
<th>BO.2</th>
<th>BO.5</th>
<th>BO.9</th>
<th>B1.8</th>
<th>SECONDARY WINDING RESISTANCE (OHMS @ 75°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>143—500</td>
<td>50.5</td>
<td>C20</td>
<td>4.8</td>
<td>4.8</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>0.014</td>
</tr>
<tr>
<td>143—750</td>
<td>75.5</td>
<td>C20</td>
<td>2.4</td>
<td>2.4</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>0.042</td>
</tr>
<tr>
<td>143—101</td>
<td>100.5</td>
<td>C20</td>
<td>1.2</td>
<td>2.4</td>
<td>4.8</td>
<td>4.8</td>
<td>—</td>
<td>0.056</td>
</tr>
<tr>
<td>143—151</td>
<td>150.5 *</td>
<td>C50</td>
<td>0.6</td>
<td>0.6</td>
<td>1.2</td>
<td>2.4</td>
<td>4.8</td>
<td>0.121</td>
</tr>
</tbody>
</table>
CT Burden Calculation

\[ Z_T = R_{CT} + R_L + Z_B \]

- \( R_L \) = Lead resistance (Total run, not just one way)

- \( R_L \) Rule of thumb for CU wire:
  \[ \text{Ohms/1000'} = e^{0.232G-2.32} \]
  Where G is AWG
CT Burden Calculation

\[ Z_T = R_{CT} + R_L + Z_B \]

\[ Z_B = \text{Relay resistance} \]

Microprocessor Burden < 0.2VA at rated secondary

\[ Z = \frac{0.2}{25} = 0.008 \text{ ohms} \]
If I think my CT is going to saturate, what do I do next?
IEEE PSRC CT Saturation Tool

**CONTENTS**
Sheet 1: CALCULATOR (this sheet)
Sheet 2: INSTRUCTIONS
Sheet 4: BACKGROUND

**ASSUMPTIONS:**
- CT core losses and sec'y reactance zero (through primary).
- Frequency: 60 Hz
- CT primary current is zero for t<0.
- CT is 5 amp nominal
- Time step = 1/2,000 second

**INPUT PARAMETERS:**
- Inverse of sat. curve slope = \( S = \) 30
- RMS voltage at 10A exc. current = \( V_s = \) 210 volts rms
- Turns ratio = \( n_{2/1} = \) 240
- Winding resistance = \( R_w = \) 0.387 ohms
- Burden resistance = \( R_b = \) 0.700 ohms
- Burden reactance = \( X_b = \) 0.000 ohms
- System X/R ratio = \( X_{over R} = \) 15.0
- Per unit offset in primary current = \( \text{Off} = \) 1.00
- Per unit remanence (based on \( V_s \)) = \( \gamma_{rem} = \) 0.00
- Symmetrical primary fault current = \( I_p = \) 30,000 amps rms

**CALculated:**
- \( R_t = \) Total burden resistance = \( R_w + R_b = \) 1.087 ohms
- \( pf = \) Total burden power factor = 1.000
- \( Z_b = \) Total burden impedance = 1.087 ohms
- \( T_{at} = \) System time constant = 0.040 seconds
- \( L_n = \) Peak flux-linkages corresponding to \( V_s = \) 0.788 VA-turns
- \( \omega = \) Radian freq = 376.99 rad/s
- \( R_P = \) Rms-to-peak ratio = 0.32028
- \( A = \) Coefficient in instantaneous ie versus lambda curve: \( |e = A \cdot I_s| = \) 4.00E+04
- \( dt = \) Time step = 0.000083 seconds
- \( L_b = \) Burden inductance = 0.00000 herries

**Graphical Representation:**
Thick lines: **ideal (blue)** and **actual (black)** secondary current in amps vs. time in seconds.
Thin lines: **ideal (blue)** and **actual (black)** secondary current extracted fundamental rms value, using a simple DFT with a one-cycle window.
Model of CT Performance

Fault with no DC offset:

Fault with full DC offset:
CT Performance

• Looks like this specific CT will saturate for some fault events
• Solutions for CT saturation
  – Higher performance class CT (CTs already chosen)
  – Higher turns ratio (CTs already chosen)
  – Lower secondary burden (#10 copper with microprocessor relay)

*Must account for CT performance in calculations*
CT Performance

• Looks like this specific CT will saturate for some fault events
• Understand how novel methods relays use to cope and the limitations to the ability to cope
  – Sloped Differential Characteristics
  – Directional Algorithms

Must account for CT performance in settings and verify CTs are good enough to allow the relay method to work
Voltage Transformers
Voltage Transformer Ratings

- Basic impulse level (BIL)
- Rated primary voltage and ratio
- Frequency
- Accuracy class ratings
- Thermal burden ratings
IEEE VT Accuracy Class

Metering Accuracy Classes (% error)

0.3  Defined by IEEE C57.13
0.6  Applicable from 90% to 110% rated voltage
1.2
0.15 -- Defined by IEEE C57.13.6
IEEE VT Accuracy Class

<table>
<thead>
<tr>
<th>Metering Accuracy Class Burdens</th>
<th>VA</th>
<th>PF</th>
</tr>
</thead>
<tbody>
<tr>
<td>W</td>
<td>12.5</td>
<td>0.10</td>
</tr>
<tr>
<td>X</td>
<td>25</td>
<td>0.70</td>
</tr>
<tr>
<td>M</td>
<td>35</td>
<td>0.20</td>
</tr>
<tr>
<td>Y</td>
<td>75</td>
<td>0.85</td>
</tr>
<tr>
<td>Z</td>
<td>200</td>
<td>0.85</td>
</tr>
<tr>
<td>ZZ</td>
<td>400</td>
<td>0.85</td>
</tr>
</tbody>
</table>

These standard burden designations have no significance at frequencies other than 60 Hz.
IEEE VT Accuracy Class

Expressed as:

Accuracy Class + Burden Code

0.3 W,X,Y
0.6 Z
1.2 ZZ

These standard designations have no significance at frequencies other than 60 Hz
VT Installation Guidelines

**Caution:**

**Rated voltage:** Do not operate above 110%

**Line to ground rated:**
- Do not connect line to line
- Do not use on ungrounded systems
  - w/o consulting factory

**Rated Frequency:**
- Do not operate below rated frequency w/o consulting factory
Typical VT Connections

Open Delta Connection
(2) Double Bushing VTs

Y – Y Connection
(3) Single Bushing VTs
Typical VT Connections for Directional Ground

\[ V_{nm} = V_a + V_b + V_c \]
\[ = (V_{a1} + V_{a2} + V_{a0}) + (V_{b1} + V_{b2} + V_{b0}) + (V_{c1} + V_{c2} + V_{c0}) \]
\[ = V_{a0} + V_{b0} + V_{c0} = 3V_{a0} = 3V_{b0} = 3V_{c0} \]
Take Home Rules
Take Home Rule # 1

Never open circuit a current transformer secondary while the primary is energized

CTs are intended to be proportional current devices. Very high voltages can result from open circuiting the secondary circuit of an energized CT. Even very small primary currents can cause damage... Consult the factory if you have questions. Short or connect a burden to any CT that might be energized.
Take Home Rule # 2

Never short circuit the secondary of an energized VT

VTs are intended to be used as proportional voltage devices. Damaging current will result from short circuiting the secondary circuit of an energized VT.
Take Home Rule # 3

Metering applications do not require a “C” class CT

“C” class ratings are specified for protection purposes only. With some exceptions metering class CTs are typically smaller and less expensive.
Take Home Rule # 4

CT secondary leads must be added to the CT burden

Electronic relays usually represent very little burden to the CT secondary circuit. In many cases the major burden is caused by the CT secondary leads.
Take Home Rule # 5

Never use a 60 Hz rated VT on a 50 Hz System

60 Hz VTs may saturate at lower frequencies and exceed temperature limitations. VT failure is likely...severe equipment damage is possible.
Take Home Rule # 6

Exercise caution when connecting grounded VTs to ungrounded systems

Line to ground voltage on any VT may exceed the primary voltage rating during a fault condition... VT must be designed for application.
Take Home Rule # 7

Check and Double Check Polarity

Proper meter and protective relay operation is based on correct current and voltage polarities.
Relaying Fundamentals
Protective Relays locate faults and trip circuit breakers to interrupt the flow of current into the defective component. This quick isolation provides the following benefits:

- Minimizes or prevents damage to faulted components
- Minimizes the seriousness and duration of the fault’s interference with normal operation of the unfaulted parts of the power system
Modern protective relays also provide information on the location and type of failure to help with equipment repair and protection scheme analysis.
Relaying Fundamentals
Zones of Protection

- Protective Zones around each Major Power System Component and Circuit Breaker
- Overlapping Zones around Circuit Breakers
Relaying Fundamentals
Zones of Protection

• For No Overlapping Zones, a fault in between zone boundaries may not be properly protected

• For No Overlapping Zone around Circuit Breakers, a Fault in the breaker zone may not be properly isolated
Relaying Fundamentals

Requirements

Protective Relay System Requirements for proper functionality:

• **Sensitivity** to very small loads
• **Selectivity** operate only what is mandatory
• **Speed**
• **Reliability** - Dependability & Security
Relaying Fundamentals

Requirements

• **Sensitivity** - to operate under minimum conditions:
Relaying Fundamentals

Requirements

- **Selectivity** - to trip the minimum number of circuit breakers to clear a fault:
Relaying Fundamentals

Requirements

For faults outside of their zone of protection, if the Relaying Scheme is:

- Inherently Selective – relay is unaffected
- Relatively Selective – relay operates with time delay
Relaying Fundamentals

Requirements

- **Speed** - to isolate the damaged component and maintain stability or synchronism of the power system
Relaying Fundamentals
Catastrophic Damage
Relaying Fundamentals

Requirements

- Reliability - is determined by the following:
  - **Dependability** – degree of **certainty** that relay operates correctly to clear all faults
  - **Security** – degree of certainty that relay will not operate **incorrectly** for any fault in its zone of protection and not react to faults outside of its zone of protection
Relaying Fundamentals
Requirements

Reliability Example:

Security

Dependability
Relaying Fundamentals
Primary & Backup Relaying

Zones of Protection for Primary and Backup Relaying

Only this circuit breaker trips
Relaying Fundamentals

Backup Relaying Example

R₁ and R₂ are Primary Relays

- Duplicate Relay: backup relay \((R₂')\) located on same component for primary relay failure
- Local Backup Relaying: backup relay \((R₂'')\) located on same component
- Remote Backup Relaying: backup relays \((R₃ - R₆)\) located on different component

Fault
Relaying Fundamentals

Requirements

AC Saturation:

DC Saturation:
Common Protection Methods
Types of Protection

Overcurrent

- Uses current to determine magnitude of fault
  - Simple
  - May employ instantaneous, definite time or inverse time curves
  - May be slow
  - Selectivity at the cost of speed (coordination stacks)
  - Inexpensive
  - May use various polarizing voltages or ground current for directionality
  - Communication aided schemes make more selective
Types of Protection
Instantaneous Overcurrent & Definite Time Overcurrent

- Relay closest to fault operates first
- Relays closer to source operate slower
- Time between operating for same current is called TCI (Time Coordination Interval)
Types of Protection

Time Overcurrent

- Relay closest to fault operates first
- Relays closer to source operate slower
- Time between operating for same current is called TCI (Time Coordination Interval)
Types of Protection

Differential

- Electricity in = electricity out
- Simple
- Very fast
- Very defined clearing area
- Expensive
- Practical distance limitations
  - Line differential systems overcome this using digital communications
Types of Protection

Differential

- Note CT polarity dots
- This is an internal fault representation
- Perfect waveforms, no saturation

\[
\begin{align*}
\text{Fault} & : 2 \text{ pu} \\
\text{Fault} & : 2 \text{ pu} \\
\text{Relay} & : 2 + (+2) = 4
\end{align*}
\]
Types of Protection

Differential

• Note CT polarity dots
• This is a through-current representation
• Perfect waveforms, no saturation
Types of Protection

Voltage

- Uses voltage to infer fault or abnormal condition
- May employ definite time or inverse time curves
- May also be used for undervoltage load shedding
  - Simple
  - May be slow
  - Selectivity at the cost of speed (coordination stacks)
  - Inexpensive
Types of Protection

Frequency

- Uses frequency of voltage to detect power balance condition
- May employ definite time or inverse time curves
- Used for load shedding & machinery under/overspeed protection
  - Simple
  - May be slow
  - Selectivity at the cost of speed can be expensive
Types of Protection

Power

- Uses voltage and current to determine power flow magnitude and direction
- Typically definite time
  - Complex
  - May be slow
  - Accuracy important for many applications
  - Can be expensive
Trip & Close Circuits

Trip Circuit

(+)
Relay Trip Contact
52/a
Trip Coil

(−)

Close Circuit

(+)
Relay Close Contact
52/b
Close Coil

(−)
Protective Device Contact Ratings

- Output contacts of protective relays and controls are meant to operate trip or close of circuit breaker and not interrupt current of DC trip or close circuit.
- This is the purpose of the 52/a or 52/b contact within the trip or close circuit.
- Many protective devices offer a seal-in feature for the trip & close contacts, such they stay closed based on a time delay or presence of dc current in trip or close circuits.

![Diagram of Protective Device Contact Ratings](image.jpg)
Feeder Protection
The Protection Problem

Fault is seen by
- Fuse F-1
- Feeder 3 relay
- Main Feeder relay
- Utility Provider relay
Overcurrent Protection

Types of Overcurrent Devices

- Instantaneous relays
- Inverse time relays
- Fuses
Instantaneous Overcurrent Protection

![Diagram showing the concept of instantaneous overcurrent protection. The diagram illustrates the time-current relationship with a shaded area indicating when the protection operates.]
Instantaneous Overcurrent Protection

• ANSI function 50

• The instantaneous overcurrent protective element operates with no intentional time delay when the current has exceeded the relay setting

• There is a pickup setting.

• 50P – phase inst. overcurrent.

• 50N – neutral inst. overcurrent
  (The mathematical phasor summation of phase currents Ia, Ib, Ic equals In)

• 50G – ground inst. overcurrent – low pickup setting
  (Measured current value from a CT)

• High-set and low-set instantaneous elements are often used by electric utilities.
  Some protection engineers will block reclosing when high-set instantaneous overcurrent operates.

• A short time delay of 200ms is often used to allow downstream fuses to blow before instantaneous overcurrent element operates on utility distribution feeders
Time Overcurrent Protection

Multiples of pick-up
Time Overcurrent Protection

- ANSI function 51

- Where it is desired to have more time delay before element operates for purpose of coordinating with other protective relays or devices, time overcurrent protective element is used. The trip time varies inversely with current magnitude.

- Characteristic curves most commonly used are called inverse, very inverse, and extremely inverse. The user must select the curve type. They are said to be a family of curves and selected by the time dial.

- Curve type and time dial are separate settings. Curve type is selected so the characteristic of the relay best matches characteristics of downstream and upstream overcurrent devices. Time dial adjusts time delay of characteristic to achieve coordination between downstream and upstream overcurrent devices.

- Minimum pickup setting. Pickup setting chosen so protective device will operate on most inverse part of its time curve over the range of current for which must operate.

- 51P – phase time overcurrent

- 51N – neutral time overcurrent
  (The mathematical phasor summation of phase currents Ia, Ib, Ic equals In)

- 51G – ground time overcurrent - low pickup setting
  (Measured current value from a CT)
Fault Current Magnitude

Fault magnitude
- $F_3 > F_2 > F_1$

Why?
- Impedance
- $I = \frac{V}{Z}$
Fault Currents
Time Coordination Interval (TCI)
**Time Overcurrent Protection**

- **Extremely Inverse**
- **Very Inverse**
- **Inverse**

**Operate area:**
at and above the curve
Time Overcurrent Protection

- During the selection of the curve, the protection engineer will use what is termed as a “time multiplier” or “time dial” to effectively shift the curve up or down on the time axis.
- Operate region lies above selected curve, while no-operate region lies below it.
- **Pickup** used to move curve left and right.
Fusing and Coordination

Fuse time verses current characteristic

- The time verses current characteristics of a fuse has two curves.
- The first curve is called the pre-arcing curve
  - The pre-arcing (or melting) curve is the time between the initiation of a current large enough to cause the fusible element(s) to melt and the instant when arcing occurs.
- The second curve is called the total clearing time.
  - The total clearing time is the total time elapsing from the beginning of an overcurrent to the final circuit interruption.
- The time current characteristic curve of a fuse follows a $I^2T$ characteristic - that is to say as the current goes up, the time drops by the square of the current increase.
Protective Element Coordination

- It is very important to coordinate overcurrent protection. Take the example system shown. If a fault were to appear at position indicated, fuse F5 should open. If it were to fail, feeder circuit breaker should trip a little time later because its protection has been properly coordinated with downstream fusing.

- Properly coordinated protective devices help to:
  1. Eliminate service interruptions due to temporary faults
  2. Minimize the extent of faults in order to reduce the number of loads affected
  3. Locate the fault, thereby minimizing the service outages
The operating time of a fuse is a function of the pre-arcing (melting) and arcing time.

For proper coordination, total $I^2T$ of secondary fuse shouldn’t exceed the pre-arcing (melting) of primary fuse. This is established if current ratio of primary vs. secondary fuse current rating is 2 or greater for fuses of the same type.
Coordination – Between Fuses & Relays

- The time overcurrent relay should back up the fuse over full current range. The time overcurrent relay characteristic curve best suited for coordination with fuses is Extremely Inverse, which is similar to the $I^2t$ fuse curves. For Extremely Inverse relay curves, primary pickup current setting should be 3-times fuse rating. For other relay curves, up to 4-times fuse rating should be considered. Ensure no cross over of fuse or time overcurrent relay curves.

- To account for CT saturation and errors, electro-mechanical relay overshoot, timing errors and fuse errors a minimum TCI of 0.4s should be used.
Coordination – Between Fuses & Relays

- The following is recommended TCI to ensure proper coordination

- 0.4 s between relay and fuse

- 0.3 s between relays/recloser
Device Coordination

- Feeder 3 Relay
- Main Feeder Relay
- TCI 0.4s typical

- F-1
- F1
- F2
- F3

mis-coordination
Device Coordination

- Current Time
- F1, F2, F3
- TCI 0.3s typical
- Feeder 3 Relay
- Main Feeder Relay
- Proper-coordination
Table: Typical Discrimination Times based on Technology (Standard Normal Inverse Curves):

<table>
<thead>
<tr>
<th>Error Source</th>
<th>Relay Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Electro-Mechanical</td>
</tr>
<tr>
<td>Typical basic Timing Error [%]</td>
<td>7.5 %</td>
</tr>
<tr>
<td>Overshoot Time [s]</td>
<td>0.05 s</td>
</tr>
<tr>
<td>Safety Margin [s]</td>
<td>0.1 s</td>
</tr>
<tr>
<td>Total typical Coordination Time [s]</td>
<td>0.4s</td>
</tr>
</tbody>
</table>

Note: CT measurement error will add to the above times
Time Overcurrent Protection

Reset of Time Overcurrent Element

- There are (2) different types of resets within Time Overcurrent Protection:
  - **EM or Timed Delay Reset** – this mimics the disc travel of an electromechanical relay moving back to the reset position.
    - If the disc has not yet completely traveled back to the reset position and the time overcurrent element picks up again, the trip time will be shorter
    - If the current picks up and then dropouts many times, the disc will “ratchet” itself to the operate position
    - Be careful when coordinating with upstream or downstream devices
  - **Instantaneous Reset** – once the time overcurrent element operates, it will reset immediately
Ground Fault Protection

• For large cables that cannot be fit through the zero sequence CT’s window, the residual ground fault configuration can be used.

• This configuration is inherently less sensitive than that of the zero sequence configuration owing to the fact that the CTs are not perfectly matched.

Residual Ground Fault Connection
• Less sensitive
• Drawbacks due un-matched CTs
Ground Fault Protection

Zero Sequence CT Connection
- Best method
- Most sensitive & inherent noise immunity

- All phase conductors are passed through the window of the same CT referred to as the zero sequence CT
- Under normal circumstances, the three phase currents will sum to zero resulting in an output of zero from the Zero Sequence CT’s secondary.
- If one of the feeder phases were to shorted to ground, the sum of the phase currents would no longer equal zero causing a current to flow in the secondary of the zero sequence. This current would be detected by the feeder relay as a ground fault.
High Impedance Fault Protection

• Downed conductors or high impedance (HiZ) faults are a major safety and public hazard concern for utilities. They also disrupt the delivery of power potentially causing an economic loss to the end user and utility.

• Downed conductor faults are caused when overhead wires make unwanted contact with grounded objects (for example tree limbs). The most severe occurrence is when overhead line falls down to the ground, due to inclement weather, accident, or inadvertent contact. These events result in a downed conductor that is energized on the ground posing a significant safety and environmental hazard.

• Conventional overcurrent protection schemes are incapable of detecting these high impedance faults.

• Detection devices exist that incorporate sophisticated algorithms with expert system pattern recognition to detect high impedance faults quickly and reliably.
Automatic Reclosing

- ANSI function number 79
- Automatically reclose a circuit breaker or recloser which has been tripped by protective relaying or recloser control
- Mainly used by electric utilities
- Multi-shot reclosing for distribution circuits
  - Instantaneous shot (~0.25s)
  - Delayed reclosures (typically two delayed, for example 3s & 15s, or 15s & 30s)
- Coordinate with branch fuses
- After successful reclose, the reclosing function will reset after some adjustable time delay (typically 60s).
- If the fault is permanent, the protective device will trip and reclose several times. If unsuccessful, the protective device will go to LOCKOUT and keep the breaker open. Some devices have a separate reset time from lockout (for example 10s after the breaker is manually closed).
- Single and Three phase reclosing is available
Automatic Reclosing and Fuses

Two methods:

- Fuse Blowing
  - Fuse blows for any fault, including temporary fault
- Fuse Saving
  - Use automatic reclosing to try and save fuses for temporary faults
Automatic Reclosing
Coordinate with Branch Fuses

- After initial reclose block instantaneous overcurrent functions to allow fuse to blow
  - Instantaneous and inverse-time overcurrent relays are arranged so that, when a fault occurs, instantaneous relays operate to trip breaker before a branch fuse can blow, and breaker is then immediately reclosed
  - However, after first trip, the instantaneous relays are automatically cut out of service so that if fault should persist, inverse-time relays would have to operate to trip breaker
  - This gives time for branch-circuit fuse of faulty circuit to blow, if we assume that the fault is beyond this fuse
  - In this way, cost of replacing blown branch-circuit fuses is minimized, and at the same time the branch-circuit outage is also minimized. If breaker is not tripped within a certain time after reclosure, instantaneous relays are automatically returned to service

- Some users just decide to delay phase and ground instantaneous overcurrent elements for small time period (for example 0.2s) to allow downstream fuse to blow first and avoid main breaker operation
Fuse Blowing

Fuse Blowing

TCI > 0.4s typical
Fuse Saving for Temporary Faults

- Inst active on first reclose shot only
- TCI > 0.4s typical after first reclose shot
- Inverse time only
Sequence Coordination

• Substation breakers & upstream reclosers should be coordinated to operate if downstream reclosers or fuses do not successfully interrupt the fault.

• Sequence coordination eliminates nuisance tripping through trip coordination. This allows coordination between substation breaker and downstream reclosers and between reclosers.

• It allows the recloser control or digital protective relay to step through selected operations in the operating sequence without tripping.

• The user can select the required number of Sequence Coordination advances (1-3) to provide trip coordination with downstream recloser(s)
Breaker/Recloser Trip Curve Selections

- Reclosers will often have two fast & slow tripping characteristics.
- If sequence coordination is used on protective device within circuit breaker, then protective device of circuit breaker can also use fast and slow tripping characteristics. Optimal trip coordination is achieved.
- If sequence coordination is not used on substation circuit breaker, then a slow tripping curve is only used. This assumes that sequence coordination is used on each recloser downstream.
Directional Protection

• Directional element **67** determines the direction of power flow to disable or enable the overcurrent element

• Uses the phase relationship of voltage and current to determine direction to a fault

Example: Industrial with on-site Generator (used on main breaker)
Phase Directional Protection

- Polarizing voltage (Vpol) is established for each current
- If current is in same direction as Vpol, then element operates

Phasors for phase A polarization:

\[ V_{pol} = V_{BC} \times (1/ECA) \]

Vpol = polarizing voltage
IA = operating current
ECA = element characteristic angle at 30°
Breaker Failure Protection

- ANSI function **50BF**
- Initiated by fault condition
- Separate low-set instantaneous overcurrent element with time delay that operates if fault current is still present
- Operate upstream breaker(s)

![Diagram of Breaker Failure Protection]

If any of these breakers do not operate, then operate upstream breaker.
Breaker Failure Operate Example

A Breaker Failure Here

Trips these breakers
Bus Protection
Secure Bus Protection

Bus protection requires a high degree of security and dependability (or high-speed operation)
Bus Configurations

Single bus - single breaker

- Distribution of lower voltage levels
- No operating flexibility
- Fault on the bus trips all circuit breakers

Multiple bus sections - single breaker with bus tie

- Distribution of lower voltage levels
- Limited operating flexibility
- Overlapping zones
- Trip only breakers in faulted zone
Bus Configurations

Main and Transfer buses

- Increased operating flexibility
- A bus fault requires tripping **all** breakers
- Transfer bus for breaker maintenance
Bus Protection Requirements

High bus fault currents due to large number of circuits connected:

- CT saturation often becomes a problem as the CT may not be sufficiently rated. (False reading.)
- Large dynamic forces associated with bus faults call for fast clearing times in order to reduce damage due to a bus fault

False trip by bus protection may create serious problems:

- Service interruption to a large number of customers (distribution and sub-transmission voltage levels)
- System-wide stability problems (transmission voltage levels fluctuations)
Bus Protection Techniques

- Interlocking schemes
- Overcurrent (unrestrained, unbiased) differential
- High-Impedance schemes
- Overcurrent percent (restrained, biased) differential (Low Impedance scheme)
Bus Protection Techniques

Interlocking

Interlocking = Overcurrent (OC) relays are placed on an incoming and at all outgoing feeders

- Blocking scheme typically used
- Short coordination time required
- Practically, not affected by CT saturation
- The blocking signal could be sent over microprocessor-based relay communication ports
- This technique is limited to simple one incoming distribution bus

Instantaneous Overcurrent

If cleared the fault, block the backup from tripping too for no real need.
Bus Protection Techniques

Overcurrent Differential

- Differential signal formed by **summation** of the bus currents
- CT ratio matching may be required
- On external faults saturated CTs yield spurious differential current
- Time delay used to cope with CT saturation
- Instantaneous (unrestrained) differential OC function useful on integrated microprocessor-based relays
- No scaling and current comparison
- Low performance—should not be applied to transmission-level busbars

AC Time Overcurrent
Bus Protection Techniques

High Impedance

Diagram showing various voltage levels and components for bus protection, including 2000 V, 400 V, 80 V, and 0 V.
Bus Protection Techniques

High Impedance

- Fast (as opposed to overcurrent), secure and proven (20ms)
- Require dedicated CTs, and preferably with the same CT ratio. Cannot handle inputs from CTs set on different taps. Input from not fully distributed CT winding creates danger for the equipment, because of inducing very high voltages – autotransformer effect
- Depending on bus internal and external fault currents, they may not provide adequate settings for sensitivity and security
- Cannot be easily applied to re-configurable buses
- Require a voltage limiting varistor capable of absorbing significant energy
- Require auxiliary CTs if CT ratios are different
- Do not provide benefits of a microprocessor-based relay (e.g. metering, monitoring, oscillography, breaker fail)
Bus Protection Techniques
Percent Differential - Low Impedance

- Percent characteristic used to cope with CT saturation
- Restraining signal can be formed in a number of ways
- No dedicated CTs needed
- Can mix CT ratios
- Protection of re-configurable buses possible
- Fast 12-16ms operation

\[
\begin{align*}
\text{Sum} & \quad i_R = \left| i_1 \right| + \left| i_2 \right| + \left| i_3 \right| + \ldots + \left| i_n \right| \\
\text{Avg} & \quad i_R = \sqrt[n]{\left| i_1 \right| \cdot \left| i_2 \right| \cdot \left| i_3 \right| \ldots \cdot \left| i_n \right|} \\
\text{Max} & \quad i_R = \text{Max} \left( \left| i_1 \right|, \left| i_2 \right|, \left| i_3 \right|, \ldots, \left| i_n \right| \right) \\
I_{DIF} & = \left| I_1 + I_2 + \ldots + I_n \right|
\end{align*}
\]
Bus Protection Techniques
Percent Differential - Low Impedance

Region 1
(low differential currents)

- Low currents
- Saturation possible due to dc offset
- Saturation very difficult to detect
- More security required

Region 2
(high differential currents)

- Large currents
- Quick saturation possible due to large magnitude
- Saturation easier to detect
- Security required only if saturation detected
Bus Protection Techniques
Percent Differential - Low Impedance

Protection logic

Directional flag

Saturation flag

DIR = 0

SAT = 1
Bus Protection Techniques

Percent Differential - Low Impedance

<table>
<thead>
<tr>
<th>Differential current</th>
</tr>
</thead>
<tbody>
<tr>
<td>( I_{D} )</td>
</tr>
</tbody>
</table>

- **EXTERNAL FAULT**
  - \((DIF_2 =1\& SAT =1)\)
  - Check directional flag! \( DIR = ? \)

- **OPERATE delayed**
  - \( DIF_2 = 1 \)
  - \( SAT = 1 \)

- **HIGH SLOPE**
- **LOW SLOPE**
- **BLOCK**

- **PICKUP**
- **LOW BPNT**
- **HIGH BPNT**

- **Restraining current**

\( I_R \)
Bus Protection Techniques
Percent Differential - Low Impedance

Protection logic

Directional flag

Saturation flag

INTERNAL FAULT
Bus Protection Techniques
Percent Differential - Low Impedance

Differential current $|I_D|$

- \( DIF_1 = 1 \)
- \( DIR = 1 \)

INTERNAL FAULT

OPERATE

HIGH SLOPE

BLOCK

PICKUP

Restraining current $I_R$

1. INTERNAL FAULT
2. 
3. 
4. 
5. 
6. 

Breakpoint

Low

High

Slope

Slope

DIF$_1$

DIR

SAT

DIF$_2$

AND

OR

AND

TRIP

1. 1
2. 2
3. 3
4. 4
5. 5
6. 6

1. 1
2. 2
3. 3
4. 4
5. 5
6. 6
Bus Protection Techniques
Percent Differential - Low Impedance

(DIF₂ = 1 & SAT = 0)
Don’t check directional flag!

INTERNAL FAULT
OPERATE immediately

HIGH SLOPE
LOW SLOPE
BLOCK
Transformer Protection
Transformer Faults and Detection

- **EXTERNAL FAULTS**
  - Overloads
  - Overvoltage
  - Underfrequency
  - External system short circuits

- **INTERNAL FAULTS**
  - *Incipient faults*
    - Overheating
    - Over-fluxing
    - Overpressure
  - *Active faults*
    - Short circuit in wye-connected windings
    - Short circuits in delta windings
    - Phase-to-phase faults
    - Turn-to-turn faults
    - Core faults
    - Tank faults
External Faults

**OVERLOADS**
In most cases, no protection is provided, but an alarm is used to warn operating personnel of the condition. Time Over Current (TOC) protection with definite time delay can be set.

**OVERVOLTAGE**
It can occur either due to short term transient conditions, or long term power frequency conditions. Transient overvoltages cause end-turn stresses and possible insulation breakdown. The conditions are detected by Volts/Hertz protection.

**UNDERFREQUENCY**
Under-frequency is caused by some system disturbances resulting in unbalance between generation and load. This low frequency creates overfluxing in the transformer core, leading to overheat. Volts/Hertz protection is used with typically 1.1 pu pickup ratio setting.

**SHORT CIRCUITS**
Large external fault currents can cause high mechanical stress in transformer windings, with the maximum stress occurring during the first cycle. The transformers are not protected during such external conditions. It is a matter of transformer design, and application, to deal with these conditions.
# Incipient Transformer Internal Faults

## OVERHEATING

Caused by:

- poor internal connections in either electric or magnetic circuit
- loss of coolant due to leakage
- blockage of coolant flow
- loss of fans or pumps

*Buchholtz* relay and thermal elements protections such as
*Hottest Spot temperature, Aging Factor* and *Loss of Life*
are normally used.

## OVERFLUXING

Continuous over-fluxing can gradually lead to isolation breakdown. The detection is provided by *Volts/Hertz* protection.

## OVERPRESSURE

Overpressure in the transformer tank occurs due to released gases that accompany localized heating. An example is the turn-to-turn fault, that can burn slowly, releasing bubbles of gases, which increase the pressure.

*Sudden Pressure relay*, or *Buchholtz relay*
Causes of Transformer Failures

- Winding failures: 51%
- Tap changer failures: 19%
- Bushings failures: 9%
- Terminal board failures: 6%
- Core failures: 2%
- Miscellaneous failures: 13%

Differential protection can detect all of the types of failures above
Internal Fault Protection (87T)

- Phase-to-phase faults
- Three-phase faults
- Ground faults
- Core faults
- Tank faults

DIFFERENTIAL SIGNAL:
\[ I_{\text{DIFF.}} = I_{1\text{COMP}} + I_{2\text{COMP}} \]

RESTRAINING SIGNAL:
\[ I_{\text{RESTR.}} = \max ( |I_{1\text{COMP}}| , |I_{2\text{COMP}}| ) \]
Current Differential Challenges

- CT errors – From errors and from saturation
- With transformers
  - Unequal phase relationship
  - Inrush
  - Current Mismatch
  - Transformer Losses
Current Differential Challenges

– Phase Compensation
Current Differential Challenges

- Magnitude Compensation/Mismatch
Phase & Magnitude Compensations

EM relay setup:

- **Magnitude compensation:**
  - Relay tap calculation per CT input (*introduces inaccuracy due to approximation matching the field CT with relay tap setting*)
- **Phase shift compensation:**
  - External Delta connected CTs on Wye, and Wye connected CTs on Delta windings (*increases the chance of making connection mistakes*)

Digital relay setup:

- **Automatic magnitude compensation:**
  - Firmware computes magnitude compensation factors for all winding currents, and scales them internally
- **Phase shift compensation:**
  - Firmware detects the phase shift setting entered in the transformer windings menu, and compares it to the actual phase shift between the currents as connected on relay terminals. All winding CTs can be connected in Wye.
Phase Compensation

Transformer: D/Y30

DELTA primary currents
- IA(-180 deg.)
- IB(-300 deg.)
- IC(-60 deg.)
- IC(-240 deg.)
- IB(-120 deg.)
IA(0 deg.)

WYE primary currents
ic(-270)
i b(-150)
i a(-30)

Compensated WYE and DELTA secondary currents
IA'
IB'
IC'
ic'(-90)
ib'(-330)
ica'(-210)

ABC rotation:

WYE and DELTA secondary currents seen on the relay
ic'(-60)
i b'(-300)
i a'(-180)
-210 deg.

-210 deg.
Phase Compensation

ABC rotation: compensation angle = -30° - 0° = 30° lag

Delta lags Wye by 30 deg.
Phase Compensation

ACB rotation: compensation angle = 0 - (-330) = 330 = 30 lag

Delta lags Wye by 30 deg. for ACB rotation
Wiring & CT Polarity

Typically 30 degree phase shift

Internal compensation for phase shift

Wye

Delta

Wye

Wye
Wiring & CT Polarity

Transformer primary currents – phase A

CT secondary currents, when connected to the relay – phase A
CTs and Transformer Windings Setup

**STEP 1.** Define CT inputs

**STEP 2.** Source configuration (if applicable)

**STEP 3.** Number of windings

**STEP 4.** Define Transformer windings
Step 4 – Transformer Windings Setup

- Source (SRC) for Winding 2 currents per Step 3
- Winding capacity (MVA) per transformer nameplate – same across transformer
- Source (SRC) for Winding 1 currents per Step 3
- Winding phase-to-phase voltage rating as per transformer nameplate
- Winding connection type
- Winding grounding within 87T protection zone
- The angle of Winding 1 must be entered as 0° for any transformer setup
- Angle, by which Winding 2 currents lag Winding 1 currents “With Respect To” (WRT) Winding 1 angle of 0° degrees
- Winding series resistance – used only with thermal protection

The table shows the parameters for Winding 1 and Winding 2:

<table>
<thead>
<tr>
<th>PARAMETER</th>
<th>WINDING 1</th>
<th>WINDING 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source</td>
<td>SRC 1 (SRC 1)</td>
<td>SRC 2 (SRC 2)</td>
</tr>
<tr>
<td>Rated MVA</td>
<td>100.000 MVA</td>
<td>100.000 MVA</td>
</tr>
<tr>
<td>Nominal Ph-ph Voltage</td>
<td>230.000 kV</td>
<td>69.000 kV</td>
</tr>
<tr>
<td>Connection</td>
<td>Delta</td>
<td>Wye</td>
</tr>
<tr>
<td>Grounding</td>
<td>Not within zone</td>
<td>Within zone</td>
</tr>
<tr>
<td>Angle Wrt Winding 1</td>
<td>0.0 °</td>
<td>-30.0 °</td>
</tr>
<tr>
<td>Resistance</td>
<td>20.0000 ohms</td>
<td>10.0000 ohms</td>
</tr>
</tbody>
</table>
Step 4 – Transformer Windings Setup

"Within zone" and "Not within zone"

For “Within zone”, the relay removes the zero-sequence currents before forming its differential signal

For “Not within zone”, zero-sequence removal is not performed
The ANGLE WRT setting calls for the ‘angle with respect to’. The Winding 1 angle WRT must be zero for all transformer configurations and the angles for the other windings should be entered with respect to Winding 1. Negative values represent lagging angles.

The angle of Winding 1 must be entered as 0° for any transformer setup.

Angle, by which winding 2 current lags winding 1 current With Respect To (WRT) winding 1 angle of 0° degrees.
“Reference Winding Selection” - The user can select a winding from the menu, to be a reference winding, which automatically selects the CT of this winding (CT setup) as the unit for percent differential protection.
Magnitude Compensation

87T magnitude reference set to “Automatic Selection”

1. Calculates the rated current per each winding:
   \[\text{Irated}(w1) = \frac{\text{MVA}}{\text{kV}(w1) \sqrt{3}}\]
   \[\text{Irated}(w2) = \frac{\text{MVA}}{\text{kV}(w2) \sqrt{3}}\]

2. Calculates the CT margin for each winding:
   \[\text{L margin}(w1) = \frac{\text{CT primary}(w1)}{\text{Irated}(w1)}\]
   \[\text{L margin}(w2) = \frac{\text{CT primary}(w2)}{\text{Irated}(w2)}\]

3. Finds the lowest CT margin:
   \[
   \text{REFERENCE CT:} = \min [\text{L margin}(w1), \text{L margin}(w2)]
   \]

4. Finds the magnitude coefficients, by which the currents from the corresponding winding are multiplied
   \[
   \text{M}(W) = \frac{[\text{CT prim}(W) \times \text{V nom}(W)]}{[\text{CT prim}(W ref) \times \text{V nom}(W ref)]}
   \]
Magnitude Compensation

87T magnitude reference set to “Winding X”

REFERENCE: kV(Wx), CT(Wx)

Finds the magnitude scaling coefficients by which the currents from the corresponding windings are multiplied

\[ M(W) = \frac{\text{CT prim}(W) \times \text{V nom}(W)}{\text{CT prim}(Wx) \times \text{V nom}(Wx)} \]
DIFFERENTIAL & RESTRAINT CURRENTS

COMPENSATED CURRENTS:

\[ I_{1\text{COMP}} = C_1 \cdot M_1(w_1) \cdot (I_{1\text{SEC}} \cdot CT_{1\text{RATIO}}) \]

\[ I_{2\text{COMP}} = C_2 \cdot M_2(w_2) \cdot (I_{2\text{SEC}} \cdot CT_{2\text{RATIO}}) \]

where,

- C1, C2 are phase shift coefficients (C = 1 for the phase reference winding)
- M1, M2 are magnitude coefficients (M = 1 for the magnitude reference winding)

DIFFERENTIAL SIGNAL:

\[ I_{\text{DIFF.}} = I_{1\text{COMP}} + I_{2\text{COMP}} \]

RESTRAINING SIGNAL:

\[ I_{\text{RESTR.}} = \max (|I_{1\text{COMP}}|, |I_{2\text{COMP}}|) \]
Two slopes used to cope with:

> Small errors during linear operation of the CTs (S1) and
> Large CT errors (saturation) for high through currents (S2)
Two breakpoints used to specify:

> The safe limit of linear CT operation ($B_1$) and
> The minimum current level that may cause large spurious differential signals due to CT saturation ($B_2$)
Transformer Inrush

The steady state flux lags the voltage by 90° degrees

e = voltage
Φ = magnetic flux
i = coil current

As the flux builds, the exciting current grows with the flux.

The flux builds up from zero, when the voltage is applied at zero crossing, and can reach 2 times the maximum flux. The magnetizing current becomes even higher, if the transformer is energized at zero point of the voltage wave, and there is residual flux.
87T – 2nd Harmonic Inhibit

When Transformer is Energized (current applied on only one side of transformer), the 2nd Harmonic content of the current can be used to block the differential element from operating during energization.

- Adapt. 2nd
- Trad. 2nd
- Per phase
- 2-out-of-3
- Average
87T – 2nd Harmonic Inhibit

Percent Differential Harmonic Inhibiting

2-nd harmonic mode:
- Adaptive 2-nd harmonic
- Traditional 2-nd harmonic

Inrush Inhibit Mode:
- Per - Phase
- 2-out-of-3
- Average

selected harmonic mode

Inhibit Percent Differential Operation

Logic operands
87T – 2nd Harmonic Inhibit

**Adaptive 2nd harmonic**
- Uses both the magnitude and phase relation between the second harmonic and the fundamental frequency (60Hz) components

**Traditional 2nd harmonic**
- Uses only the magnitude of the 2nd harmonic, without considering the phase angle with the fundamental component
87T – 2nd Harmonic Inhibit

**Per-phase**

The 2nd harmonic from an individual phase, blocks the operation of the differential protection for only that phase, if above the 2nd harmonic setting

**2-out-of-3**

The detection of 2nd harmonic on any two phases that is higher than the setting, blocks the differential protection on all three phases

**Average**

The averaged amount of 2nd harmonic from the three phases, blocks the differential protection for all of them, if above the setting
Instantaneous Differential Protection

- Defined as function 87/50 and operates with no time delay
- The setting must be higher than maximum differential current the relay may detect on through fault accounting for CT saturation
- The setting must be higher than maximum inrush current during energization
- The setting must be lower, than maximum internal fault current
Restricted Ground Fault Protection

- Low impedance ground differential protection
- Adjustable pickup and slope settings to cope with unbalances during load and through fault currents
- Configurable time delay
### Restricted Ground Fault Protection

**Positive sequence based restraint:**
\[ IR_1 = 3 \times (|I_1| - |I_0|), \text{ if } |I_1| > 1.5 \text{ pu, and } |I_1| > |I_0| \]
else \[ IR_1 = |I_1| / 8 \]

**Negative sequence based restraint:**
\[ IR_2 = |I_2| \text{ for first 2 cycles on transformer energization} \]
\[ IR_2 = 3 \times |I_2| \text{ - in normal conditions} \]

**Zero sequence based restraint:**
\[ IR_0 = |I_G - I_N| = |I_G - (I_A + I_B + I_C)| \]

**Ground differential current:**
\[ I_{gd} = |I_G + I_N| = |I_G + I_A + I_B + I_C| \]

**Ground restraint current:**
\[ I_{gr} = \max (IR_1, IR_2, IR_0) \]

- Provides Restraint During Symmetrical Conditions
- Provides Restraint During External Phase to Phase Faults
- Provides Restraint During External Ground Faults
Transformer Overcurrent Backup

Phase & Neutral
IOC & TOC

Differential

Ground TOC
Overexcitation (V/Hz) Protection

- ANSI function 24
- Overflux protection - a result of system overvoltages, or low system frequency
- A transformer is designed to operate at or below a maximum magnetic flux density in the transformer core
- Above this design limit the eddy currents in the core and nearby conductive components cause overheating which within a very short time may cause severe damage
- The magnetic flux in the core is proportional to the voltage applied to the winding divided by the impedance of the winding
- The flux in the core increases with either increasing voltage or decreasing frequency
Overexcitation (V/Hz) Protection

• During startup or shutdown of generator-connected transformers, or following a load rejection, the transformer may experience an excessive ratio of volts to hertz, that is, become overexcited

• When a transformer core is overexcited, the core is operating in a non-linear magnetic region, and creates harmonic components in the exciting current

• A significant amount of current at the 5th harmonic is characteristic of overexcitation
Overexcitation (V/Hz) Protection

- The per unit setting should cope with the recommendation for the transformer
- 1.1 x Vnom continuous voltage - set just above that voltage for alarm and trip
- 66.4 V / 60 Hz = 1 PU
- Thermal curve customization through the custom curve
- Improved cooling reset time
Motor Protection
Motor History & Facts

- The first U.S. patent for a motor was issued to Thomas Davenport in 1837

- In 1888, Nikola Tesla patented the first AC poly-phase motor

- Today in North America more then 1 billion motors are in service

- Motors consume 25% of electricity in North America

- Electricity consumption by motors in manufacturing sector is 70%. In oil, gas and mining industries around 90%

- Three phase squirrel-cage induction motors account for over 90% of the installed motor capacity
Various Industry Motor Applications

- Fans, Blowers
- Pumps, Compressors
- Grinders, Chippers
- Conveyors, Shredders
- Crushers, Mixers
- Cranes, Extruders
- Refiners, Chillers
Motor Failure Rates and Costs

- Motor failure rate is conservatively estimated as 3-5% per year
  - In Mining, Pulp and Paper industry, motor failure rate can be as high as 12%

- Motor failure cost contributors:
  - Repair or Replacement
  - Removal and Installation
  - Loss of Production

- Motor failures divided in 3 groups:
  - Electrical
  - Mechanical
  - Environmental, Maintenance, & Other

<table>
<thead>
<tr>
<th></th>
<th>IEEE STUDY (%)</th>
<th>EPRI STUDY (%)</th>
<th>AVERAGE %</th>
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<td>Failure Contributor</td>
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<td>Maintenance Related &amp; Other Parts: Total</td>
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33% Electrical Related Failures
31% Mechanical Related Failures
36% Environmental, Maintainence & Other Reasons Related Failures
Motor Electrical Protection

- **Thermal Overload**
  - Process Caused (Excessive load)
  - High Ambient Conditions (Hot, Blocked Ventilation)
  - Power Supply Issues (Voltage/Current Unbalance, Harmonics)

- **Phase Fault**
- **Ground Fault**

- **Abnormal Operating Conditions**
  - Over & Under Voltage
  - Underfrequency
  - Voltage and Current Unbalance
  - Load Loss
  - Jamming
  - Jogging
Thermal Stress Causes Motor Failure

- Most of the motor failure contributors and failed motor components are related to motor overheating.

- Thermal stress potentially can cause the failure of all the major motor parts: Stator, Rotor, Bearings, Shaft and Frame.
Risks for an Overheated Motor

- **Stator Windings Insulation Degradation** *(for stator limited motors)*
  
  Insulation lifetime decreases by half if motor operating temperature exceeds thermal limit by 10ºC for any period of time.

- **Rotor Conductors Deforming or Melting** *(for rotor limited - thermal limit is defined by motor stall time)*
Overload Protection – Thermal Model

• A motor can run overloaded without a fault in motor or supply

• A primary motor protective element of the motor protection relay is the thermal overload element and this is accomplished through motor thermal image modeling. This model must account for thermal process in the motor while motor is starting, running at normal load, running overloaded and stopped. Algorithm of the thermal model integrates both stator and rotor heating into a single model.

• Main Factors and Elements Comprising the Thermal Model are:
  • Overload Pickup Level
  • Overload Curve
  • Running & Stopped Cooling Time Constants
  • Hot/Cold Stall Time Ratio
  • RTD & Unbalance Biasing
  • Motor State Machine
Thermal Model – Motor States

- **Motor Stopped:**
  Current < “0” threshold & contactor/breaker is open

- **Motor Starting:**
  Previous state is “Stopped” & Current > “0” threshold. Motor current must increase to the level higher than overload pickup within seconds otherwise motor algorithm will declare the “Running” state

- **Motor Running:**
  Previous state is “Starting” or “Overloading” & Current drops below overload pickup level

- **Motor Overloading:**
  Previous state is “Running” & Current raises above overload pickup level. Thermal Capacity Used (TCU) begins to accumulate
Motor Thermal Limit Curves

- Thermal Limit of the model is dictated by overload curve constructed in the motor protection device in the reference to thermal damage curves normally supplied by motor manufacturer.
- Motor protection device is equipped with set of standard curves and capable to construct customized curves for any motor application.

**Thermal Limit Curves:**

A. Cold Running Overload
B. Hot Running Overload
C. Cold Locked Rotor Curve
D. Hot Locked Rotor Curve
E. Acceleration curve @ 80% rated voltage
F. Acceleration curve @ 100% voltage
Thermal Overload Pickup

- Set to the maximum allowed by the service factor of the motor
- Set slightly above the motor service factor by 8-10% to account for measuring errors
- If RTD Biasing of Thermal Model is used, thermal overload setting can be set higher
- Note: motor feeder cables are normally sized at 1.25 times motor's full load current rating, which would limit the motor overload pickup setting to a maximum of 125%
Thermal Model – Thermal Capacity Used

- Thermal Capacity Used (TCU) is a criterion selected in thermal model to evaluate thermal condition of the motor.

- TCU is defined as percentage of motor thermal limit utilized during motor operation.

- A running motor will have some level of thermal capacity used due to Motor Losses.

- Thermal Trip when Thermal Capacity Used equals 100%
Overload Curve

Set the overload curve below cold thermal limit and above hot thermal limit.

If only hot curve is provided by mfgr, then must set below hot thermal limit.
Typically motor manufacturer provides the values of the locked rotor thermal limits for 2 motor conditions:

- **COLD**: motor @ ambient temperature
- **HOT**: motor @ rated temperature for specific class and service factor.

NEMA standard temperature rises for motors up to 1500HP and Service Factors 1 and 1.15 respectively

When motor is running below overload pickup, the TCU will rise or fall to value based on average current and HCR. HCR is used to calculate level of TCU by relay, at which motor will settle for current below overload pickup.
**Overload Curve Method**

- If the thermal limits curves are being used to determine the HOT/COLD ratio proceed as follows:
  - From the thermal limits curves run a line perpendicular to the current axis that intersects the hot and cold curves at the stall point or LRA.
  - The Hot/cold ratio can now be calculated as follows: $= \frac{6s}{8s} = 0.75$
  - If hot and cold times are not provided and only one curve is given verify with the manufacturer that it is the hot curve (which is the worst case), then the Hot/Cold ratio should be set to 1.0.
Overload Curve Selection

If the motor starting current begins to infringe on the thermal damage curves or if the motor is called upon to drive a high inertia load such that the acceleration time exceeds the safe stall time, custom or voltage dependent overload curve may be required.
Overload Curve Selection

A custom overload curve will allow the user to tailor the relay's thermal damage curve to the motor such that a successful start can occur without compromising protection while at the same time utilizing the motor to its full potential during the running condition.
Thermal Model Behavior – Long Starts

- Issue ➞ Duration of a high inertia load start is longer than the allowed motor safe stall time
  - For these starts, thermal model must account for the current change during acceleration and also use the acceleration thermal limits for TCU calculations
  - Motor thermal limit is growing along with motor rotation speed during acceleration
  - Starting current is proportional to system voltage during motor acceleration, thus voltage could be a good indication of the current level corresponding to the locked rotor condition.

- Voltage dependent dynamic thermal limit curve is employed to enhance the thermal model algorithm

- Motor relay will shift acceleration thermal limit curve linearly and constantly based on measured line voltage during a motor start
Negative sequence currents (or unbalanced phase currents) will cause additional rotor heating that will be accounted for in Thermal Model.

• **Main causes of current unbalance**
  - Blown fuses
  - Loose connections
  - Stator turn-to-turn faults
  - System voltage distortion and unbalance
  - Faults
Thermal Model
Current Unbalance Bias

- **Equivalent heating motor current** is employed to bias thermal model in response to current unbalance

\[ I_{EQ} = \sqrt{I_M^2 \times (1 + K \times \frac{I_2}{I_1})^2} \]

- \( I_m \) - real motor current; \( K \) - unbalance bias factor; \( I_1 \) & \( I_2 \) - positive and negative sequence components of motor current
- \( K \) factor reflects the degree of extra heating caused by the negative sequence component of the motor current
- IEEE guidelines for typical and conservative estimates of \( K \)

\[ K = \frac{175}{I_{LRC}^2} \quad \text{TYPICAL} \]

\[ K = \frac{230}{I_{LRC}^2} \quad \text{CONSERVATIVE} \]
Thermal Model

RTD Bias

- Accelerate thermal trip for hot stator windings
- RTD bias model determines Thermal Capacity Used based on temperature of Stator and is separate from overload model for calculating TCU
- Motor relay will use calculated thermal capacity unless the RTD thermal capacity is higher
- This function will not trip motor at the max point temp unless the average current is greater than the overload pickup setting
- RTD biasing is a back up protection element which accounts for such things as loss of cooling or unusually high ambient temperature
Motor cooling is characterized by separate cooling time constants (CTC) for running and stopped motor states. Typical ratio of the stopped to running CTC is 2/1.

It takes the motor typically 5 time constants to cool.
Overvoltage Protection

- The overall result of an overvoltage condition is a decrease in load current and poor power factor.
- Although old motors had robust design, new motors are designed close to saturation point for better utilization of core materials and increasing the V/Hz ratio cause saturation of air gap flux leading to motor heating.
- The overvoltage element should be set to 110% of the motors nameplate unless otherwise started in the data sheets.
Undervoltage Protection

• The overall result of an undervoltage condition is an increase in current and motor heating and a reduction in overall motor performance.

• The undervoltage protection element can be thought of as backup protection for the thermal overload element. In some cases, if an undervoltage condition exists it may be desirable to trip the motor faster than thermal overload element.

• The undervoltage trip should be set to 90% of nameplate unless otherwise stated on the motor data sheets.

• Motors that are connected to the same source/bus may experience a temporary undervoltage, when one of motors starts. To override this temporary voltage sags, a time delay setpoint should be set greater than the motor starting time.
Unbalance Protection

• Indication of unbalance ➔ negative sequence current / voltage
• Unbalance causes motor stress and temperature rise
• Current unbalance in a motor is result of unequal line voltages
  • Unbalanced supply, blown fuse, single-phasing

• Current unbalance can also be present due to:
  • Loose or bad connections
  • Incorrect phase rotation connection
  • Stator turn-to-turn faults

• For a typical three-phase induction motor:
  • 1% voltage unbalance (V2) relates to 6% current unbalance (I2)
  • For small and medium sized motors, only current transformers (CTs) are available and no voltage transformers (VTs). Measure current unbalance and protect motor.
  • The heating effect caused by current unbalance will be protected by enabling the unbalance input to the thermal model
  • For example, a setting of 10% x FLA for the current unbalance alarm with a delay of 10 seconds and a trip level setting of 25% x FLA for the current unbalance trip with a delay of 5 seconds would be appropriate.
Ground Fault Protection

• A ground fault is a fault that creates a path for current to flow from one of the phases directly to the neutral through the earth bypassing the load.

• Ground faults in a motor occur:
  • When its phase conductor’s insulation is damaged for example due to voltage stress, moisture or internal fault occurs between the conductor and ground.

• To limit the level of the ground fault current connect an impedance between the supplies neutral and ground. This impedance can be in the form of a resistor or grounding transformer sized to ensure maximum ground fault current is limited.
Ground Fault Protection

Zero Sequence CT Connection

- Best method
- Most sensitive & inherent noise immunity

- All phase conductors are passed through the window of the same CT referred to as the zero sequence CT
- Under normal circumstances, the three phase currents will sum to zero resulting in an output of zero from the Zero Sequence CT’s secondary
- If one of the motors phases were to shorted to ground, the sum of the phase currents would no longer equal zero causing a current to flow in the secondary of the zero sequence. This current would be detected by the motor relay as a ground fault.
Ground Fault Protection

Residual Ground Fault Connection
- Less sensitive
- Drawbacks due to asymmetrical starting current and un-matched CTs

- For large cables that cannot be fit through the zero sequence CT’s window, the residual ground fault configuration can be used
- This configuration is inherently less sensitive than that of the zero sequence configuration owing to the fact that the CTs are not perfectly matched
- During motor starting, the motor’s phase currents typically rise to magnitudes excess of 6 times motors full load current and are asymmetrical
- The combination of non perfectly matched CTs and relative large phase current magnitudes produce a false residual current. This current will be misinterpreted by the motor relay as a ground fault unless the ground fault element’s pickup is set high enough to disregard this error during starting
Differential Protection

- Differential protection may be considered the first line of protection for internal phase-to-phase or phase-to-ground faults. In the event of such faults, the quick response of the differential element may limit the damage that may have otherwise occurred to the motor.

Core balance method:
- Two sets of CT’s, one at the beginning of the motor feeder, and the other at the neutral point
- Alternatively, one set of three core-balance CTs can also be used
- The differential element subtracts the current coming out of each phase from the current going into each phase and compares the result or difference with the differential pickup level.
Differential Protection

Summation method with six CTs:

- If six CTs are used in a summing configuration, during motor starting, the values from the two CTs on each phase may not be equal as the CTs are not perfectly identical and asymmetrical currents may cause the CTs on each phase to have different outputs.

- To prevent nuisance tripping in this configuration, the differential level may have to be set less sensitive, or the differential time delay may have to be extended to ride through the problem period during motor starting.

- The running differential delay can then be fine tuned to an application such that it responds very fast and is sensitive to low differential current levels.
Biased differential protection - six CTs:

- Biased differential protection method allows for different ratios for system/line and the neutral CT's.
- This method has a dual slope characteristic. Main purpose of the percent-slope characteristic is to prevent a mis-operation caused by unbalances between CTs during external faults. CT unbalances arise as a result of CT accuracy errors or CT saturation.
- Characteristic allows for very sensitive settings when the fault current is low and less sensitive settings when the fault current is high and CT performance may produce incorrect operating signals.
Short Circuit Protection

- The short circuit element provides protection for excessively high overcurrent faults.
- Phase-to-phase and phase-to-ground faults are common types of short circuits.
- When a motor starts, the starting current (which is typically 6 times the Full Load Current) has asymmetrical components. These asymmetrical currents may cause one phase to see as much as 1.7 times the RMS starting current.
- To avoid nuisance tripping during starting, set the short circuit protection pick up to a value at least 1.7 times the maximum expected symmetrical starting current of motor.
- The breaker or contactor must have an interrupting capacity equal to or greater than the maximum available fault current or let an upstream protective device interrupt fault current.
Stator RTD Protection

• A simple method to determine the heating within the motor is to monitor the stator with RTDs

• Stator RTD trip level should be set at or below the maximum temperature rating of the insulation

• For example, a motor with class F insulation that has a temperature rating of 155°C could have the Stator RTD Trip level be set between 140°C to 145°C, with 145°C being the maximum (155°C - 10°C hot spot)

• The stator RTD alarm level could be set to a level to provide a warning that the motor temperature is rising
Additional Protection Methods

- **Start Inhibit**
  This function will limit starts when the motor is already hot.

- **Starts/ Hour**

- **Time Between Starts (Jogging)**

- **Bearing RTD Protection**

- **Acceleration Trip**
  Set higher than the maximum starting time to avoid nuisance tripping when the voltage is lower or for varying loads during acceleration
Thermal Capacity required to start

For example, if the THERMAL CAPACITY USED for the last 5 starts is 24, 23, 27, 25, and 21% respectively, the LEARNED STARTING CAPACITY is $27\% \times 1.25 = 33.75\%$ used

Thermal Capacity used due to Overload

If the motor had been running in an overload condition prior to stopping, the thermal capacity would be some value; say 80%

If Motor is Stopped:

When the motor has cooled and the level of thermal capacity used has fallen to 66%, a start will be permitted

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<tr>
<th>Setting</th>
<th>Parameter</th>
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<td>Start Inhibit Block</td>
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<tr>
<td>Thermal Capacity Used Margin</td>
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</table>
Motor Protection Summary

- Induction & synchronous motors are valuable assets to today’s industrial facilities
- The temperature rise of motor dictates its life
- When applied, thermal protection can prevent loss of motor life
- Additional protection elements such as overvoltage, undervoltage, unbalance, ground fault, differential, short circuit and stator RTD supplement the thermal model protection and provide complete motor protection
Arc Flash Solutions
A Study of a Fault......

Total Clearing Time

Relaying (2 Cycles)  Mech Time (1 Cycle)  Arcing Time (2 Cycles)

ARC Extinguished in Five Cycles

SHORT CIRCUIT OCCURS HERE
Arc Flash Mitigation: Problem Description

- An electric arc flash can occur if a conductive object gets too close to a high-amp current source or by equipment failure (ex., while opening or closing disconnects, racking out)
  - The arc can heat the air to temperatures as high as 35,000 F, and vaporize metal in equipment
  - The arc flash can cause severe skin burns by direct heat exposure and by igniting clothing
  - The heating of the air and vaporization of metal creates a pressure wave (arc blast) that can damage hearing and cause memory loss (from concussion) and other injuries.
  - Flying metal parts are also a hazard.
Methods to Reduce Arc Flash Hazard

- Arc flash energy may be expressed in $I^2t$ terms, so you can decrease the $I$ or decrease the $t$ to lessen the energy.
- Protective relays can help lessen the $t$ by optimizing sensitivity and decreasing clearing time.
  - Protective Relay Techniques
- Other means can lessen the $I$ by limiting fault current.
  - “Non-Protective Relay Techniques”
Non-Protective Relaying Methods of Reducing Arc Flash Hazard

- System design modifications increase power transformer impedance
  - Addition of phase reactors
  - Faster operating breakers
  - Splitting of buses
- Current limiting fuses (provides partial protection only for a limited current range)
- Electronic current limiters (these devices sense overcurrent and interrupt very high currents with replaceable conductor links (explosive charge))
- Arc-resistant switchgear (this really doesn't reduce arc flash energy; it deflects the energy away from personnel)
- Optical arc flash protection via fiber sensors
- Optical arc flash protection via lens sensors
Protective Relaying Methods of Reducing Arc Flash Hazard

- Bus differential protection (this reduces the arc flash energy by reducing the clearing time)
- Zone interlock schemes where bus relay selectively is allowed to trip or block depending on location of faults as identified from feeder relays
- Temporary setting changes to reduce clearing time during maintenance
  - *Sacrifices coordination*
- Custom TOC Curve for improved coordination opportunities
- Employ 51VC/VR on feeders fed from small generation to improve sensitivity and coordination
- Employ UV light detectors with current disturbance detectors for selective gear tripping
Fuses vs. Relayed Breakers

Current

Peak available current (Ip)

Fuses

Breakers

Normal load current

Point of fault

Fuse opens within 1/4 to 1/2 cycle

Breaker operates here

Heat Energy
# Arc Flash Hazards

## Skin Temperature vs. Time of Skin Temp. vs. Damage Caused

<table>
<thead>
<tr>
<th>Skin Temperature</th>
<th>Time of Skin Temp.</th>
<th>Damage Caused</th>
</tr>
</thead>
<tbody>
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<td>110 °F</td>
<td>6 Hours</td>
<td>Cell breakdown starts</td>
</tr>
<tr>
<td>158 °F</td>
<td>1 sec.</td>
<td>Total cell destruction</td>
</tr>
<tr>
<td>176 °F</td>
<td>0.1 sec</td>
<td>Curable burn</td>
</tr>
<tr>
<td>200 °F</td>
<td>0.1 sec</td>
<td>Incurable burn</td>
</tr>
</tbody>
</table>

## NFPA-70E 2004 Equipment Requirements

<table>
<thead>
<tr>
<th>Category</th>
<th>Energy Level</th>
<th>Typical Personal Protective Equipment required</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>1.2 cal/cm²</td>
<td>Non-melting flammable materials</td>
</tr>
<tr>
<td>1</td>
<td>5 cal/cm²</td>
<td>Fire Resistant (FR) shirt and FR pants</td>
</tr>
<tr>
<td>2</td>
<td>8 cal/cm²</td>
<td>FR shirt, FR pants, cotton underwear</td>
</tr>
<tr>
<td>3</td>
<td>25 cal/cm²</td>
<td>Two layers FR clothing, cotton underwear</td>
</tr>
<tr>
<td>4</td>
<td>40 cal/cm²</td>
<td>FR shirt, FR pants, multilayer flash suit, cotton underwear</td>
</tr>
</tbody>
</table>

Other:
- Face Protection: Face Shield and/or safety glasses
- Hand Protection: Leather over rubber for arc flash protection
- Leather work boots: above 5 cal/cm²
## Arc Flash Warning Example 1

### Arc-Flash Hazard and Shock Hazard

<table>
<thead>
<tr>
<th>Distance</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>0' - 11&quot;</td>
<td>Arc-Flash Protection Boundary</td>
</tr>
<tr>
<td>0.8 cal/cm²</td>
<td>Incident Energy Flash Hazard at 18 inches</td>
</tr>
</tbody>
</table>

**CLASS 0**

**Arc-Flash Hazard Risk Category**

**Appropriate PPE Required for both Arc-Flash and Shock Hazards:**

- Safety Glasses, Class 1
- Voltage Gloves
- Voltage Rated Tools
- Non-melting, flammable clothing

**2400 V<sub>ac</sub>** - Shock Hazard with covers/doors open

<table>
<thead>
<tr>
<th>Distance</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>5' - 0&quot;</td>
<td>Limited Approach Boundary</td>
</tr>
<tr>
<td>2' - 2&quot;</td>
<td>Restricted Approach Boundary</td>
</tr>
<tr>
<td>0' - 7&quot;</td>
<td>Prohibited Approach Boundary</td>
</tr>
</tbody>
</table>

**1106-MCC 2-1**

**STARTER DOOR OF AIR COMPRESSOR #1**
Arc Flash Warning Example 2

Arc-Flash Hazard and Shock Hazard

- **3' - 7''** - Arc-Flash Protection Boundary
- **4.4 cal/cm²** - Incident Energy Flash Hazard at 18 inches
- **CLASS 2** - Arc-Flash Hazard Risk Category

**Appropriate PPE Required for both Arc-Flash and Shock Hazards:**


**Shock Hazard**

- **480 V<sub>ac</sub>** - Shock Hazard with covers/doors open
- **3' - 6''** - Limited Approach Boundary
- **1' - 0''** - Restricted Approach Boundary
- **0' - 1''** - Prohibited Approach Boundary

1806-MCC G
AHU #2
Arc Flash Warning Example 3

Arc-Flash Hazard and Shock Hazard

44' - 0" - Arc-Flash Protection Boundary
32.1 cal/cm² - Incident Energy Flash Hazard at 18 inches

CLASS 4
Arc-Flash Hazard Risk Category

Appropriate PPE Required for both Arc-Flash and Shock Hazards:

12470 V_ac - Shock Hazard with covers/doors open
5' - 0" - Limited Approach Boundary
2' - 2" - Restricted Approach Boundary
0' - 7" - Prohibited Approach Boundary

1020-SUB2 BUS B2
REAR OF 2-12A CUBICLE
# Arc Flash Solutions

## Relaying Techniques to Reduce Arc Flash Energy

<table>
<thead>
<tr>
<th>Duration</th>
<th>Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-2 ms</td>
<td>Install discrete Arc Flash Detection device</td>
</tr>
<tr>
<td>1 cycle</td>
<td>Implement low impedance bus protection</td>
</tr>
<tr>
<td>1.5 to 2 cycles</td>
<td>Implement instantaneous overcurrent tripping using maintenance setting group in relay. Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary</td>
</tr>
<tr>
<td>1.5 to 2 cycles</td>
<td>Implement high impedance bus protection</td>
</tr>
<tr>
<td>3-4 cycles</td>
<td>Implement bus zone interlocking scheme</td>
</tr>
<tr>
<td>20.0 cycles</td>
<td>Breaker failure protection</td>
</tr>
<tr>
<td>Seconds</td>
<td>Reduce coordination intervals of existing time-overcurrent relays</td>
</tr>
</tbody>
</table>

*Time to clear saves lives*
Arc Flash Solutions
Bus Zone Interlocking Scheme

3-4 Cycles Detection
Arc Flash Solutions
High Impedance Bus Differential

1.5 to 2 Cycles Detection
Arc Flash Solutions

Enable Maintenance Mode

- Force feeder breaker protection to mis-coordinate when personnel are within flash protection boundary.
- Replacement Relays: 2nd 50 element
- Multifunction Relays: setting groups
- Multifunction Relays: multiple 50’s
Arc Flash Solutions
2nd Instantaneous Overcurrent Element

1.5 to 2 Cycles Detection
Arc Flash Solutions
Low Impedance Bus Differential

1 Cycle Detection
Arc Flash Solutions
Time Current Coordination

A = Downstream feeder relay with the highest settings

Use \( I_{pu}(A) \) for coordination
Arc Flash Solutions
Fault Current and Operate Time
Appendix
# References

## IEEE Protective Relaying Standards

<table>
<thead>
<tr>
<th>IEEE Standard</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>C37.91</td>
<td>IEEE Guide for Protective Relay Applications to Power Transformers</td>
</tr>
<tr>
<td>C37.96</td>
<td>IEEE Guide for AC Motor Protection</td>
</tr>
<tr>
<td>C37.97</td>
<td>IEEE Guide for Protective Relay Applications to Power System Buses</td>
</tr>
<tr>
<td>C37.99</td>
<td>IEEE Guide for the Protection of Shunt Capacitor Banks</td>
</tr>
<tr>
<td>C37.101</td>
<td>IEEE Guide for Generator Ground Protection</td>
</tr>
<tr>
<td>C37.102</td>
<td>IEEE Guide for AC Generator Protection</td>
</tr>
<tr>
<td>C37.110</td>
<td>IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes</td>
</tr>
<tr>
<td>C37.113</td>
<td>IEEE Guide for Protective Relay Applications to Transmission Lines</td>
</tr>
<tr>
<td>C37.119</td>
<td>IEEE Guide for Breaker Failure Protection of Power Circuit Breakers</td>
</tr>
<tr>
<td>C37.230</td>
<td>IEEE Guide for Protective Relay Applications to Distribution Lines</td>
</tr>
</tbody>
</table>
References

• ANSI/IEEE Device Numbers, C37.2
• IEEE CT Burdens (5 Amps), C57.13
• IEEE Protective Relaying Standards
• “The Art of Protective Relaying”
  – GE Publication GET-7201
• “Protective Relaying Principles and Applications”
  by J. Lewis Blackburn and Thomas J. Domin
Thank You For the Time