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

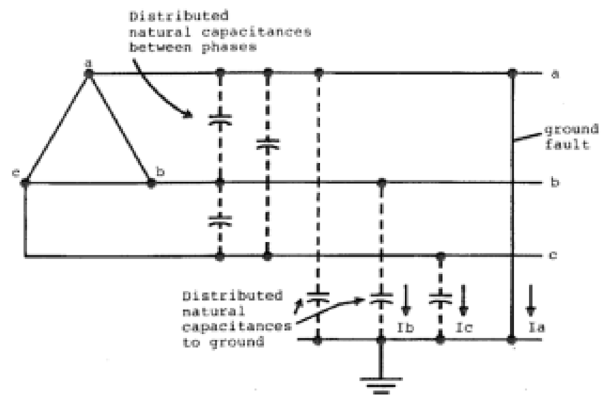
- Motor Protection
  - Motor Failure Rates
  - Induction Motor Protection
  - Thermal Overload
  - Overvoltage and Undervoltage
  - Current Unbalance
  - Ground Fault
  - Short Circuit
  - Differential
  - RTD Monitoring/Protection
- Arc Flash Mitigation

System Grounding

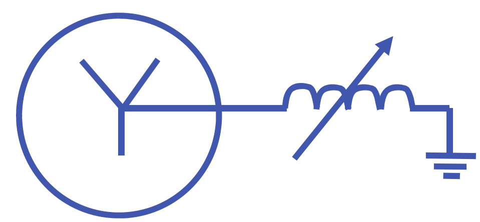
- Limits overvoltages
- Limits difference in electric potential through local area conducting objects
- Several methods
  - Ungrounded
  - Reactance Grounded
  - High Impedance Grounded
  - Low Impedance Grounded
  - Solidly Grounded

System Grounding

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.**

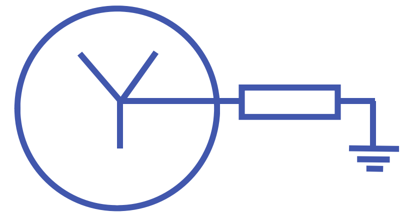


$X_0 <= 10 * X_1$

System Grounding

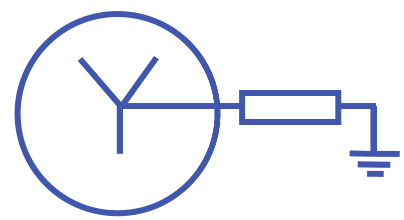
3. **High Resistance Grounded: Limits ground fault current to 5A-10A. Used to limit transient overvoltages due to arcing ground faults.**

   $R_0 <= X_{0C}/3$, X_{0C} is capacitive zero sequence reactance



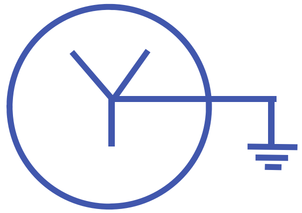
4. **Low Resistance Grounded: To limit current to 25-400A**

   $R_0 >= 2X_0$



System Grounding

5. **Solidly Grounded: There is a connection of transformer or generator neutral directly to station ground.**
   - **Effectively Grounded: $R_0 <= X_1$, $X_0 <= 3X_1$, 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

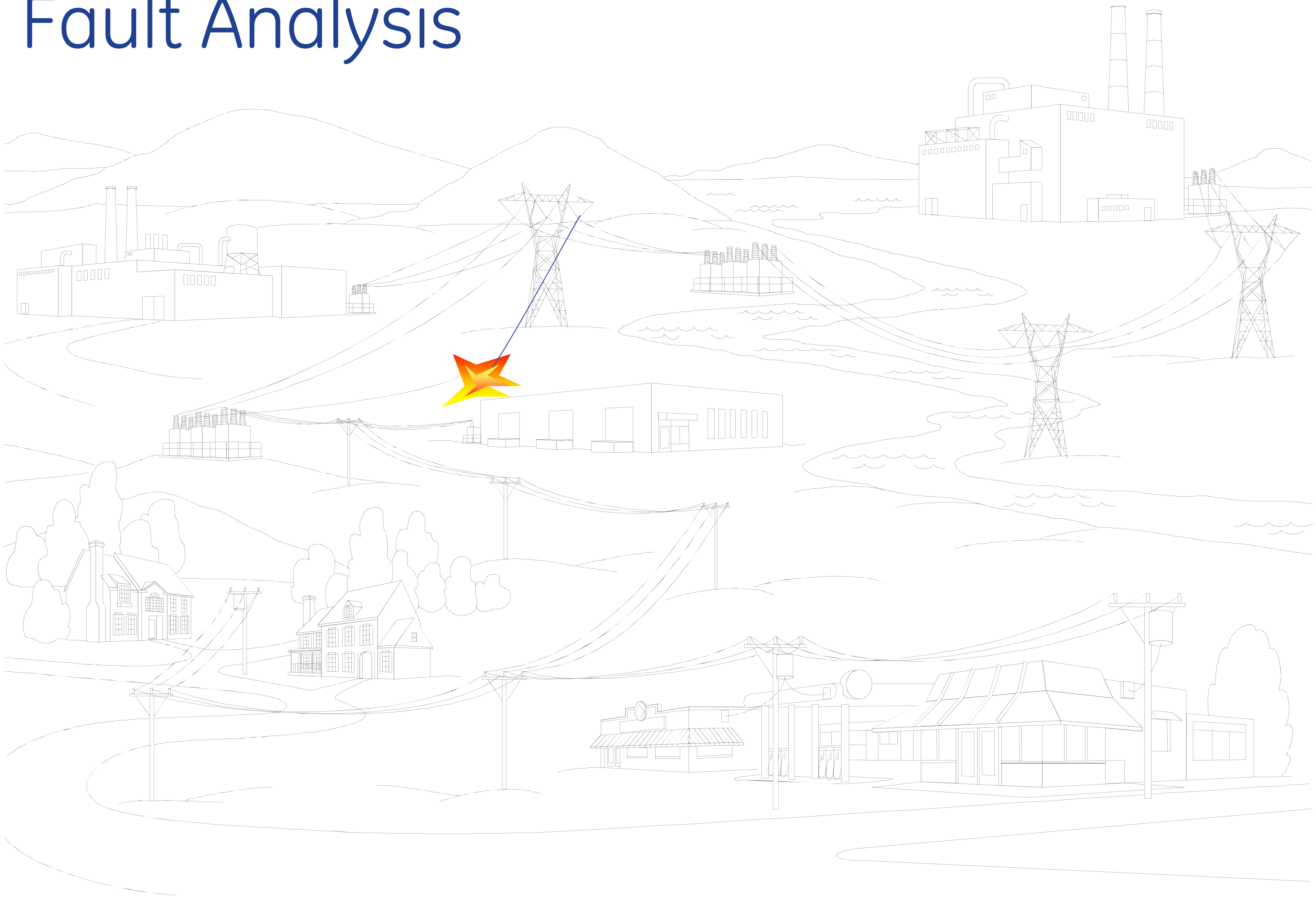
Causes for Faults

- 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:

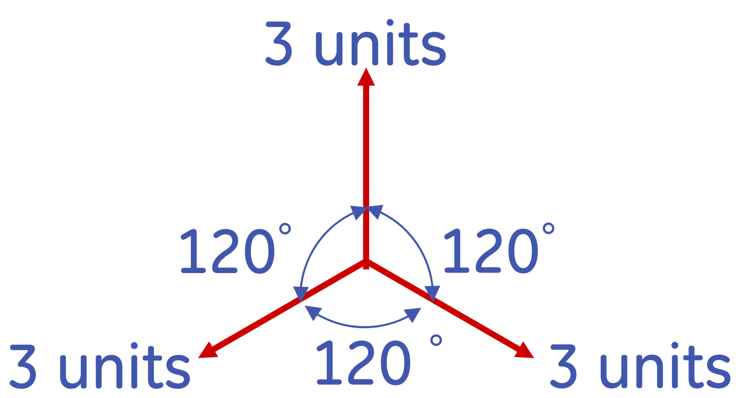
Fault Analysis



Symmetrical and Non-Symmetrical Systems

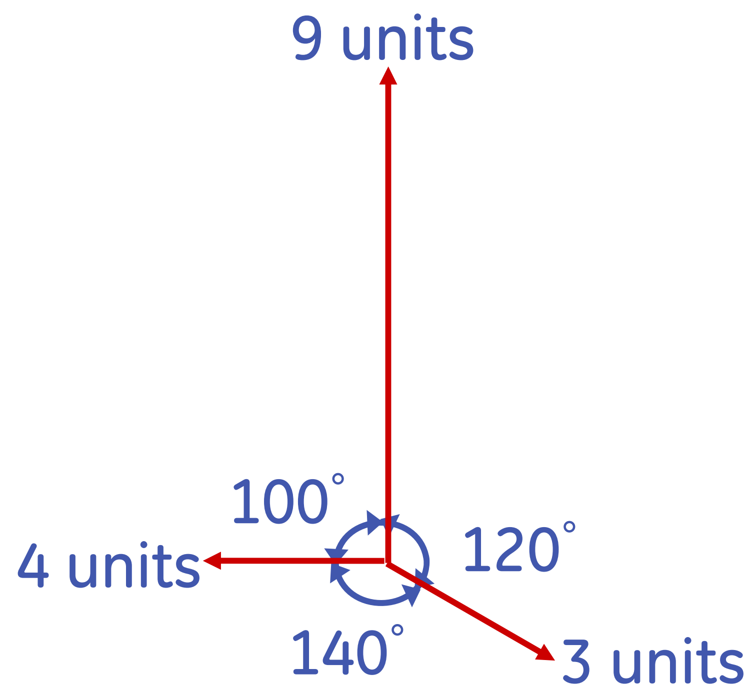
Symmetrical System:

- 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.



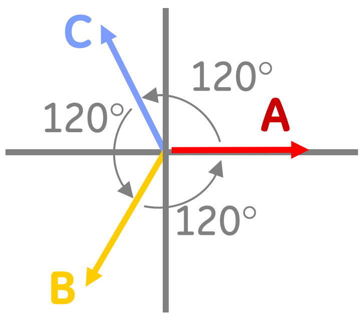
Non-Symmetrical System:

- Fault or Unbalanced condition
- If one or more of the symmetrical system conditions is not met



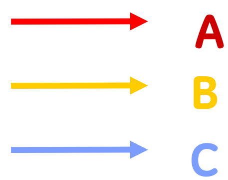
Symmetrical Components

Positive Sequence
(Always Present)



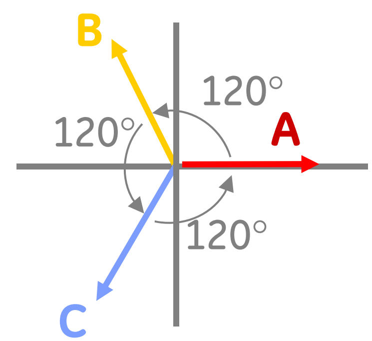
- A-B-C **Counter-clockwise** phase rotation
- All phasors with equal magnitude
- All phasors displaced 120 degrees apart

Zero Sequence



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

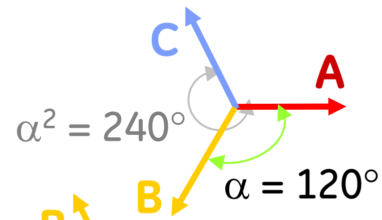
Negative Sequence



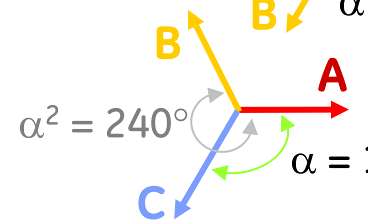
- A-C-B **counter-clockwise** phase rotation
- All phasors with equal magnitude
- All phasors displaced 120 degrees apart

Symmetrical Components

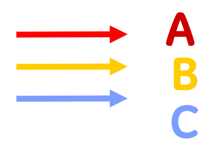
Positive Sequence Component: $I_1 = \frac{1}{3}(I_a + \alpha I_b + \alpha^2 I_c)$ $\quad V_1 = \frac{1}{3}(V_a + \alpha V_b + \alpha^2 V_c)$



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:

$I_a = I_1 + I_2 + I_0$ $\quad V_a = V_1 + V_2 + V_0$

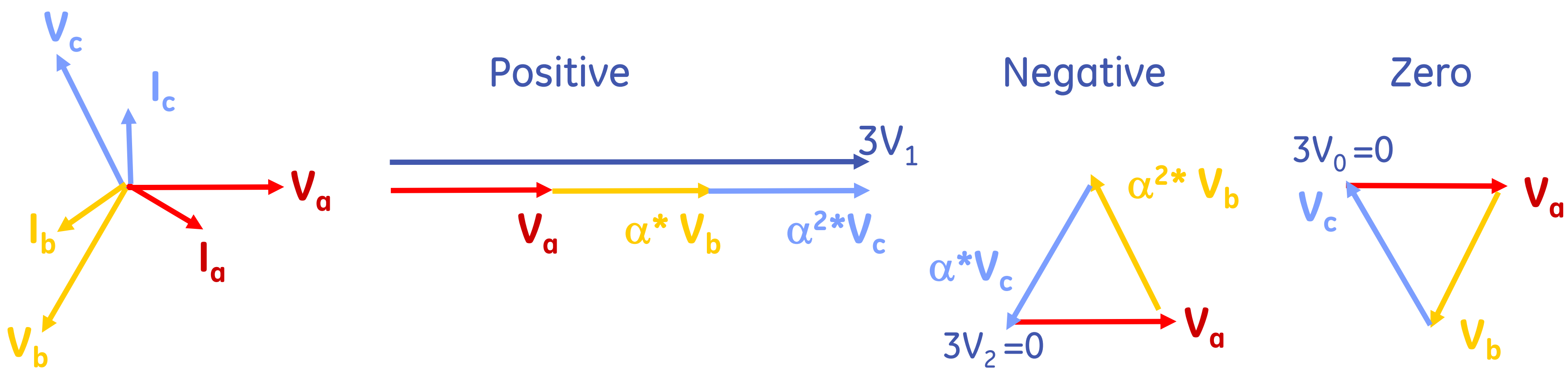
$I_b = \alpha^2 I_1 + \alpha I_2 + I_0$ $\quad V_b = \alpha^2 V_1 + \alpha V_2 + V_0$

$I_c = \alpha I_1 + \alpha^2 I_2 + I_0$ $\quad V_c = \alpha V_1 + \alpha^2 V_2 + \alpha V_0$

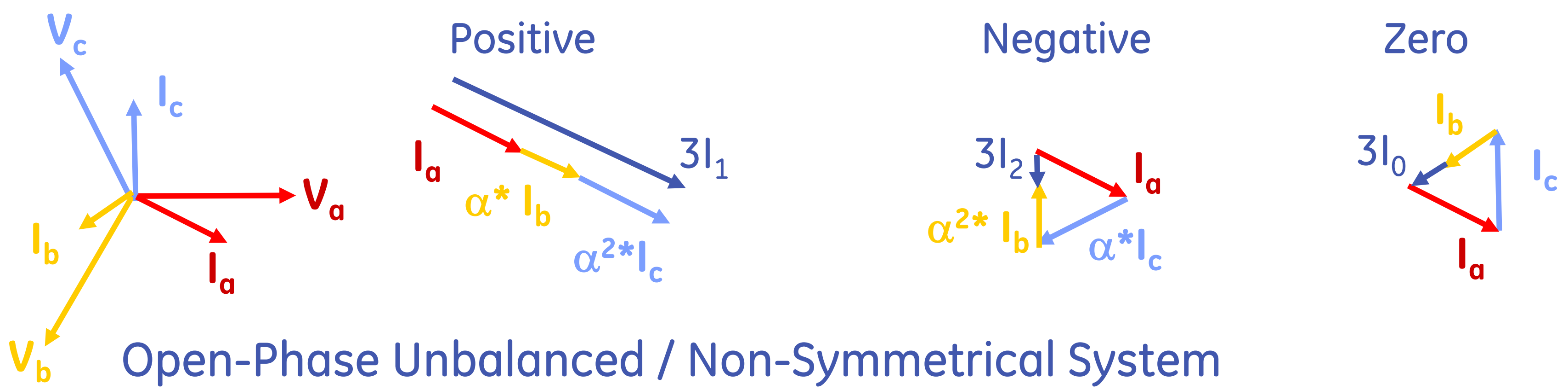
α =Phasor @ +120°

α^2 =Phasor @ 240°

Calculating Symmetrical Components



Three-Phase Balanced / Symmetrical System



Open-Phase Unbalanced / Non-Symmetrical System

Symmetrical Components

Example: Perfectly Balanced & ABC Rotation

$I_0 = 1/3(I_a + I_b + I_c)$

$I_1 = 1/3(I_a + aI_b + a^2I_c)$

$I_2 = 1/3(I_a + a^2I_b + aI_c)$

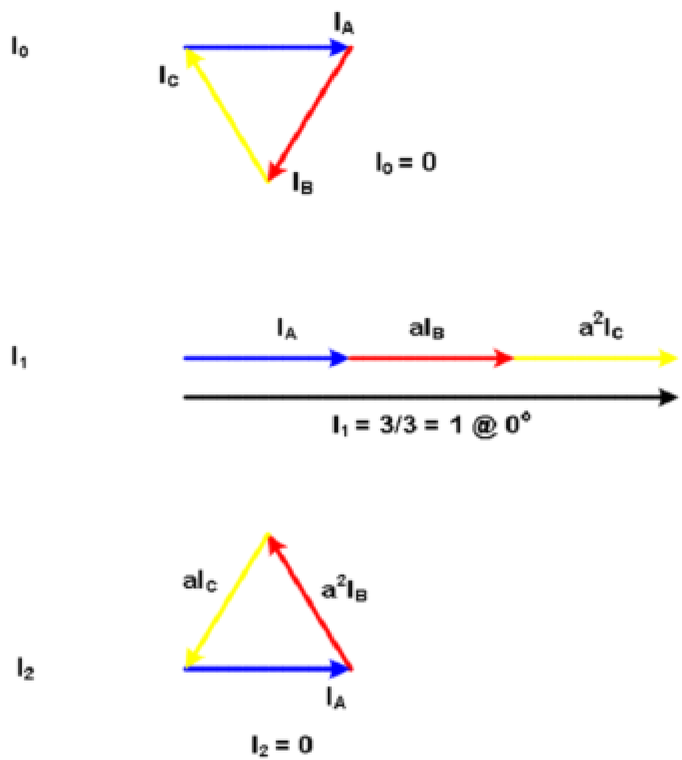
$a = 1 \angle 120^o$

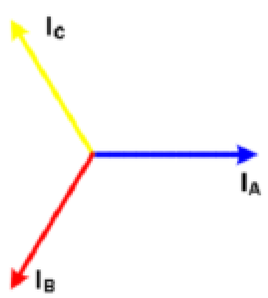
$V_0 = 1/3(V_a + V_b + V_c)$

$V_1 = 1/3(V_a + aV_b + a^2V_c)$

$V_2 = 1/3(V_a + a^2V_b + aV_c)$

$a^2 = 1 \angle 240^o$





Result: 100% I1 (Positive Sequence Component)

Symmetrical Components

Example: B-Phase Rolled & ABC Rotation

$I_0 = 1/3(I_a + I_b + I_c)$

$I_1 = 1/3(I_a + aI_b + a^2I_c)$

$I_2 = 1/3(I_a + a^2I_b + aI_c)$

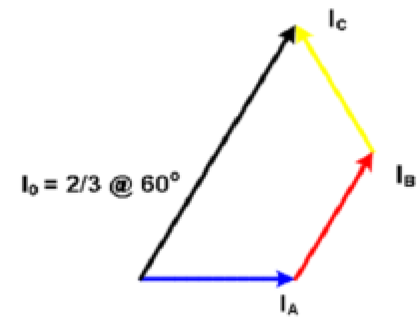
$a = 1 \angle 120^o$

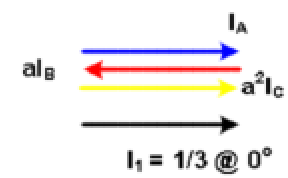
$V_0 = 1/3(V_a + V_b + V_c)$

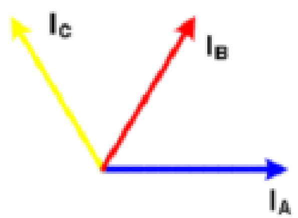
$V_1 = 1/3(V_a + aV_b + a^2V_c)$

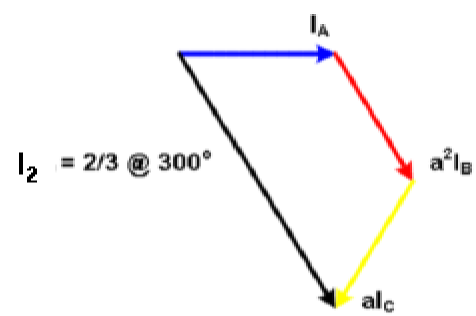
$V_2 = 1/3(V_a + a^2V_b + aV_c)$

$a^2 = 1\angle 240^o$









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

Symmetrical Components

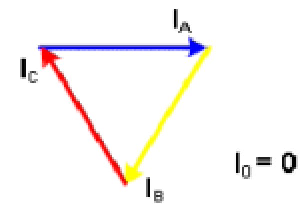
Example: B-Phase & C-Phase Rolled & ABC Rotation

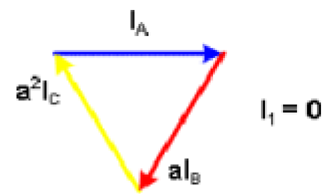
$I_0 = 1/3(I_a + I_b + I_c)$ $\qquad$ $V_0 = 1/3(V_a + V_b + V_c)$

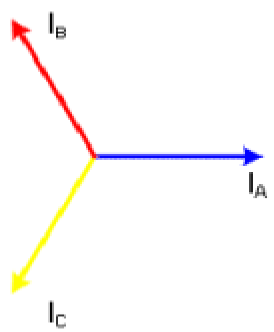
$I_1 = 1/3(I_a + aI_b + a^2I_c)$ $\qquad$ $V_1 = 1/3(V_a + aV_b + a^2V_c)$

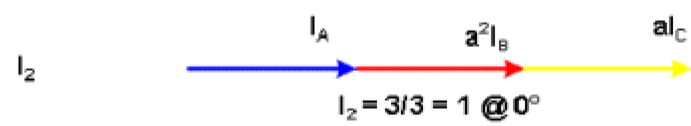
$I_2 = 1/3(I_a + a^2I_b + aI_c)$ $\qquad$ $V_2 = 1/3(V_a + a^2V_b + aV_c)$

$a = 1 \angle 120^o$ $\qquad$ $a^2 = 1 \angle 240^o$







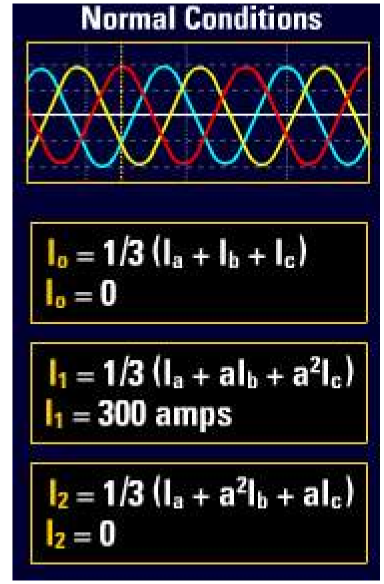


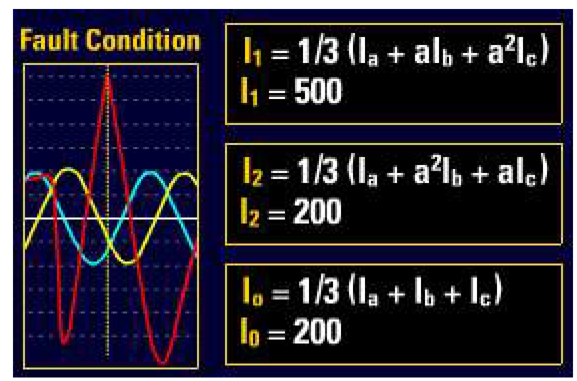
Result: 100% I2 (Negative Sequence Component)

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.
  - In = Ia + Ib + Ic = 3 I0





ANSI / IEEE C37.2 - Device Numbers

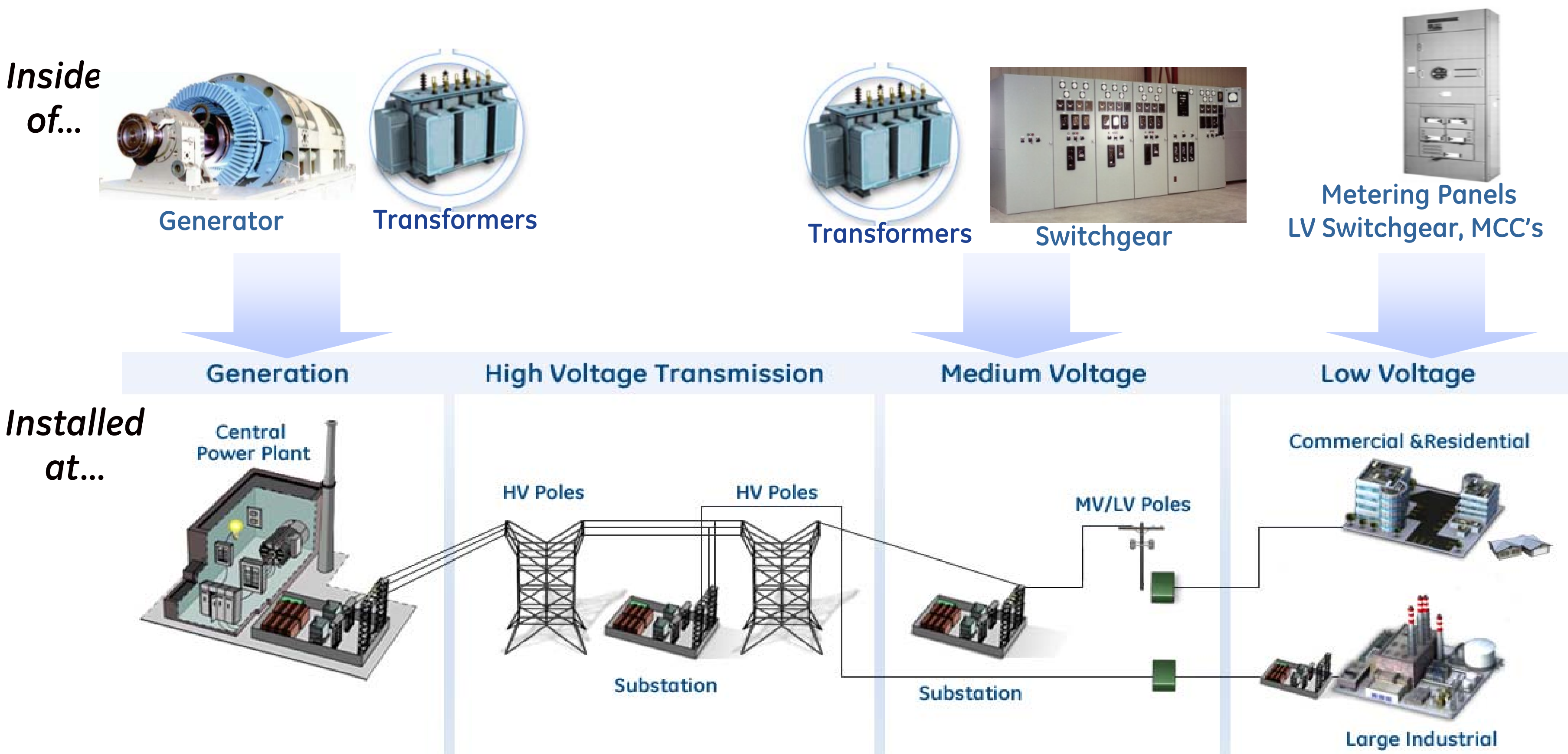
1	Master Element	26	Apparatus Thermal Device
2	Time Delay or Closing Relay	27	Undervoltage Relay
3	Checking or Interlocking Relay	28	Flame Detector
4	Master Contactor	29	Isolating Contactor
5	Stopping Device	30	Annunciator Relay
6	Starting Circuit Breaker	31	Separate Excitation Device
7	Rate of Rise Relay	32	Directional Power Relay
8	Control Power Disconnect	33	Position Switch
9	Reversing Device	34	Master Sequence Device
10	Unit Sequence Switch	35	Brush Operating or Slip Ring Shorting
11	Multifunction Device	36	Polarity or Polarizing Voltage Device
12	Overspeed Device	37	Undercurrent or Underpower Relay
13	Synchronous-Speed Device	38	Bearing Protective Device
14	Underspeed Device	39	Mechanical Condition Monitor
15	Speed or Frequency Matching	40	Field Relay
16	Reserved for Future Use	41	Field Circuit Breaker
17	Shunting or Discharge Switch	42	Running Circuit Breaker
18	Accel or Decel Device	43	Manual Transfer or Selector Device
19	Start to Run Transition Contactor	44	Unit Sequence Starting Relay
20	Electrically Operated Valve	45	Atmospheric Condition Monitor
21	Distance Relay	46	Reverse Phase or Phase Balance Relay(I)
22	Equalizer Circuit Breaker	47	Phase Sequence Voltage Relay
23	Temperature Control Device	48	Incomplete Sequence Relay
24	Volts/Hz Relay	49	Machine or Transformer Thermal Relay
25	Synch Device or Synch Check	50	Instantaneous Overcurrent Relay

ANSI / IEEE C37.2 - Device Numbers

51	AC Time Overcurrent Relay	71	Level Switch
52	AC Circuit Breaker	72	DC Circuit Breaker
52a	Contacts Open when Main Contacts Open	73	Load Resistor Contactor
52aa	High Speed a contacts	74	Alarm Relay
52b	Contacts Open when Main Contacts Closed	75	Position Changing Mechanism
52bb	High Speed b contacts	76	DC Overcurrent Relay
53	Exciter or DC Generator Relay	77	Telemetering Device
54	Turner Gear Engaging Device	78	Phanse Angle Measuring Relay
55	Power Factor Relay	79	Reclosing Relay
56	Field Application Relay	80	Flow Switch
57	Shorting or Grounding Device	81	Frequency Relay
58	Rectification Failure Relay	82	DC Load Measuring Reclosing Relay
59	Overvoltage Relay	83	Automatic Selective Control or Transfer Relay
60	Voltage or Current Balance Relay	84	Operating Mechanism
61	Density Switch or Sensor	85	Carrier or Pilot Wire Relay
62	Time Delay Stopping or Opening Relay	86	Lockout Relay
63	Pressure Switch	87	Differential Protective Relay
64	Ground Detector Relay	88	Auxiliary Motor or Motor Generator
65	Governor	89	Line Switch
66	Notching or Jogging Device	90	Regulating Device
67	AC Directional Overcurrent Relay	91	Voltage Directional Relay
68	Blocking or Out-of-Step Relay	92	Voltage and Power Directional Relay
69	Permissive Control Device	93	Field Changing Contactor
70	Rheostat	94	Tripping or Trip-Free Relay

Instrument Transformers

Instrument Transformer Locations



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:

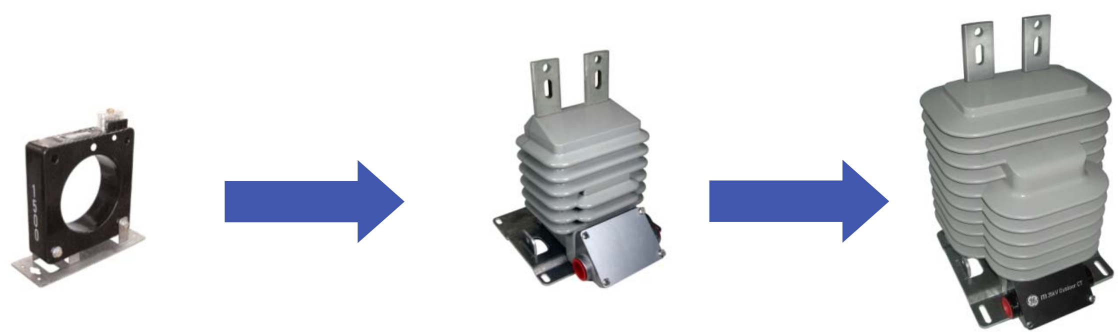
Transformer – a device that can raise or lower the ac voltage of the original source

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

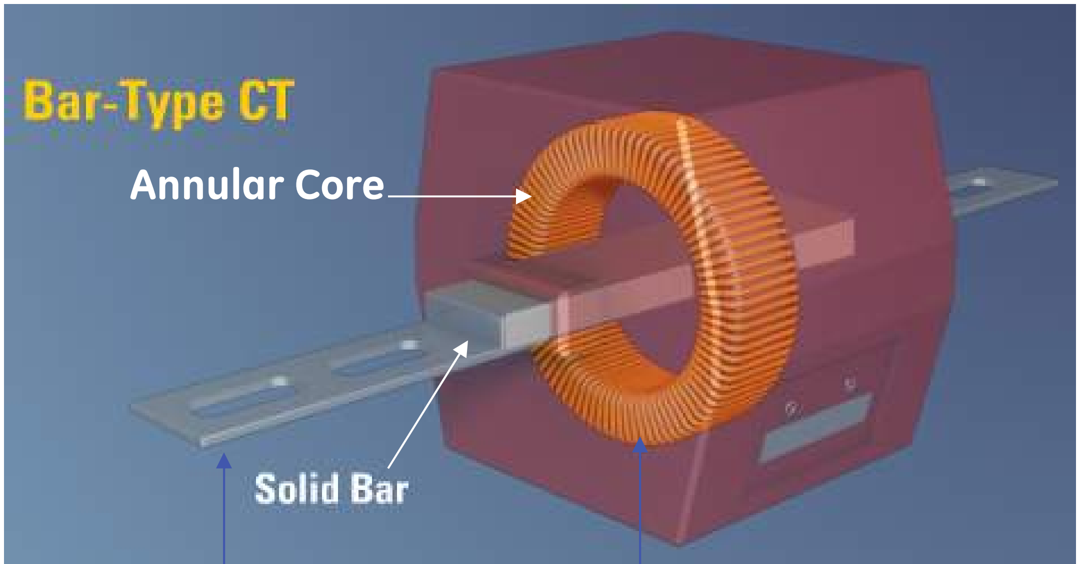
Standard Voltage Classes

Voltage Class V	.6	5	8.7	15	25	34.5
BIL Rating (BIL)	10	60	75	110	150	200



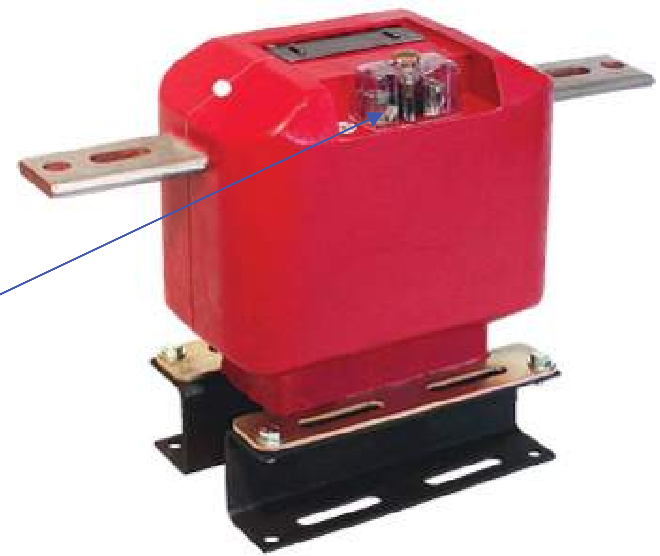
BIL = Basic Impulse Level

Current Transformer Types - Bar

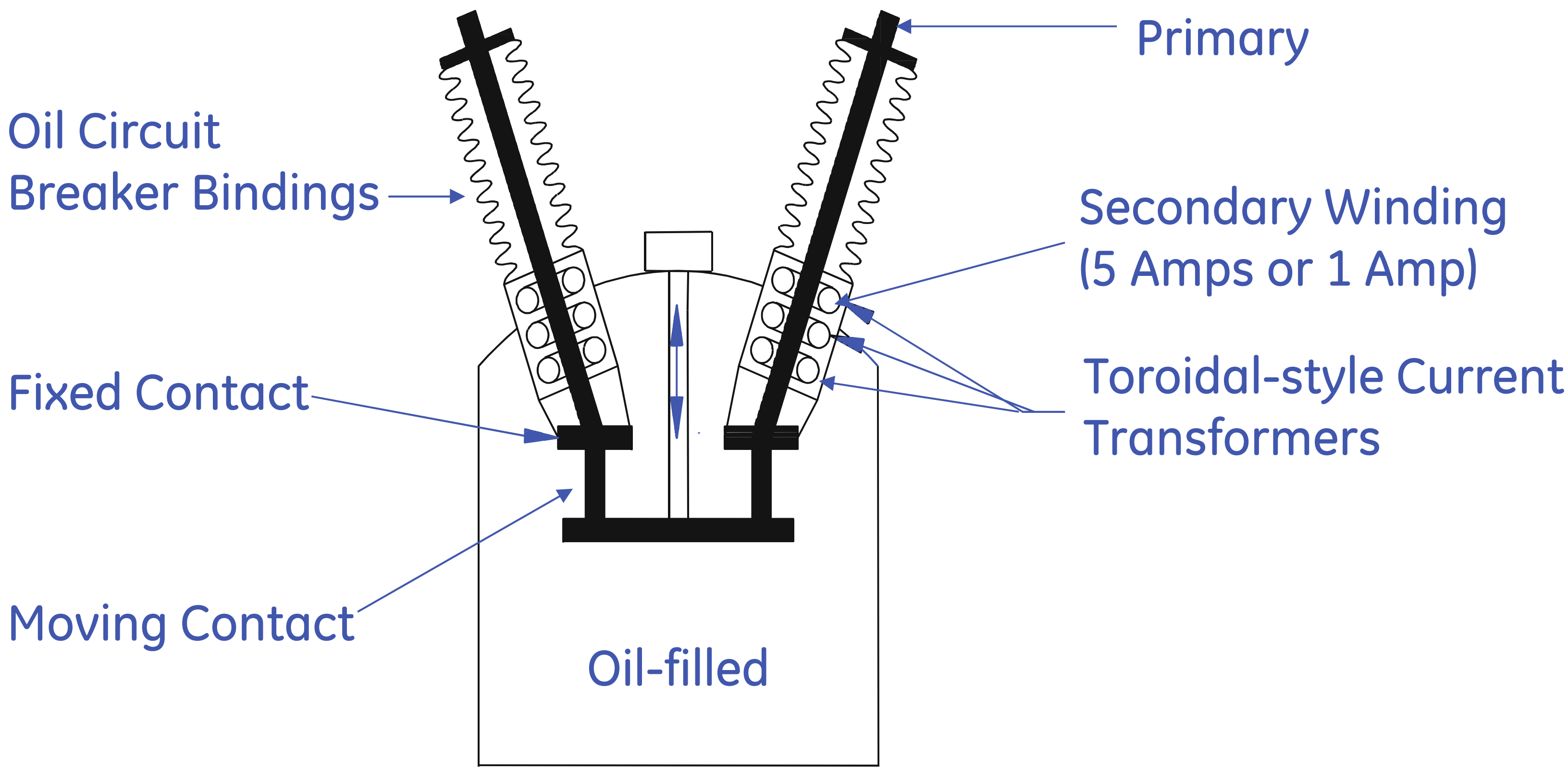


Primary

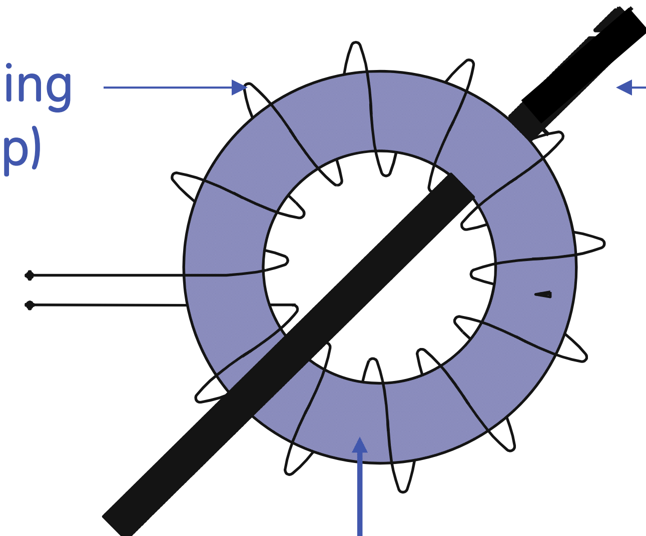
Secondary Winding
(5 Amps or 1 Amp)



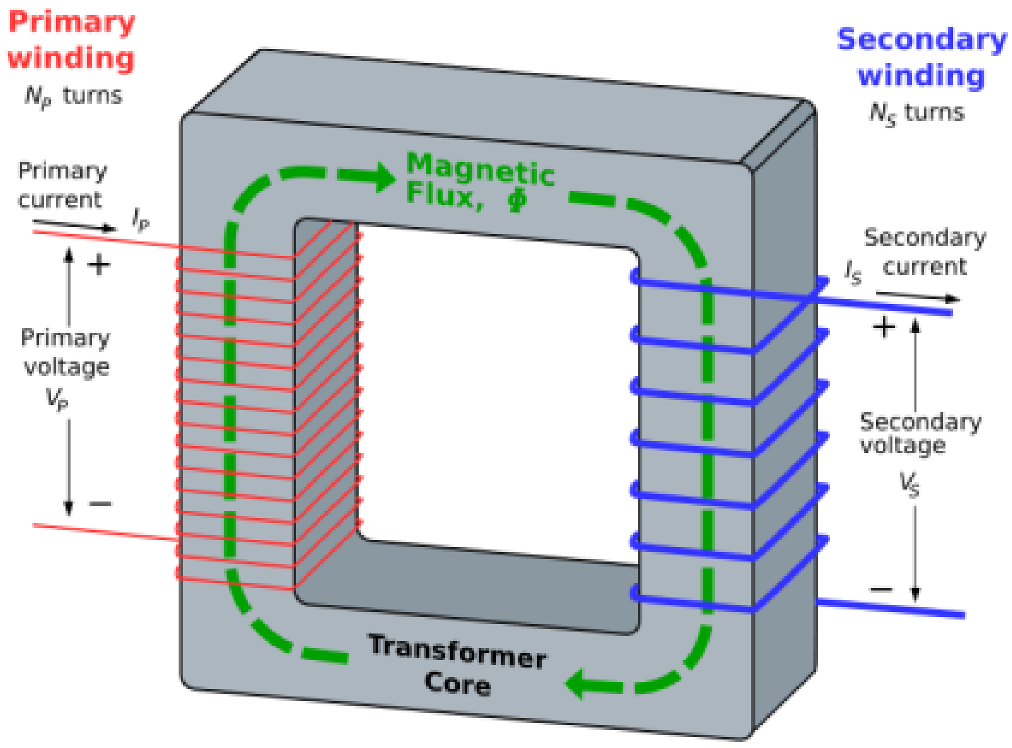
Current Transformer Types - Bushing



Current Transformer Types – Toroidal (Donut):



Current Transformer Basics



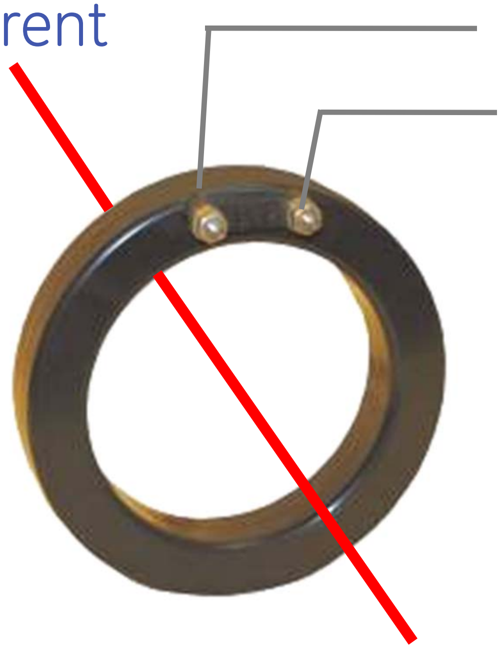
$$\int \mathbf{J} \cdot d\mathbf{A} = \oint \mathbf{H} \cdot d\mathbf{l}$$

Transformer Ratio (TR)

$$\text{Transformer Ratio} = \frac{\text{Primary Current}}{\text{Secondary Current}}$$

Primary Current
(100 amps)

Secondary Current
(5 amps)



$$\frac{100}{5} = 100{:}5 \text{ or } 20{:}1$$

Turns Ratio

Formula: $$\frac{Ip}{Is} = \frac{Ns}{Np}$$

Where:
- Ip – Primary Amperage
- Is – Secondary Amperage
- Np – Number of Primary Turns
- Ns – Number of Secondary Turns

Example: A 300:5 Current Transformer –

$$\frac{300\ p}{5\ s} = \frac{60\ s}{1\ p}$$

Turns Ratio Modification

Example: Window CT wound as a 300:5

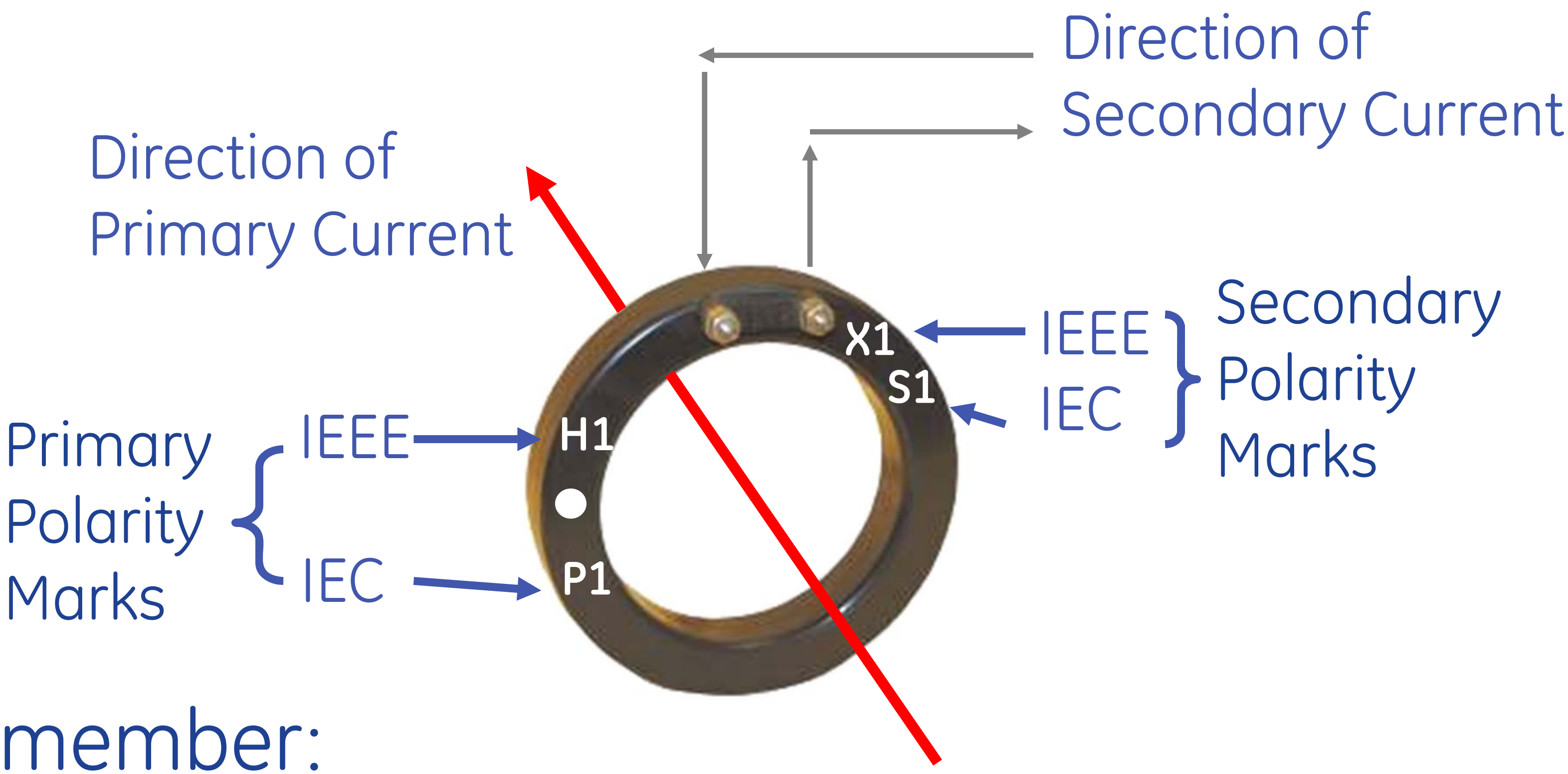
Use as a 300:5 with one primary conductor turn

Use as a 150:5 with two primary conductor turns

Use as a 100:5 with three primary conductor turns

Remember: $I_p = I_s \times N_p/N_s$

Polarity

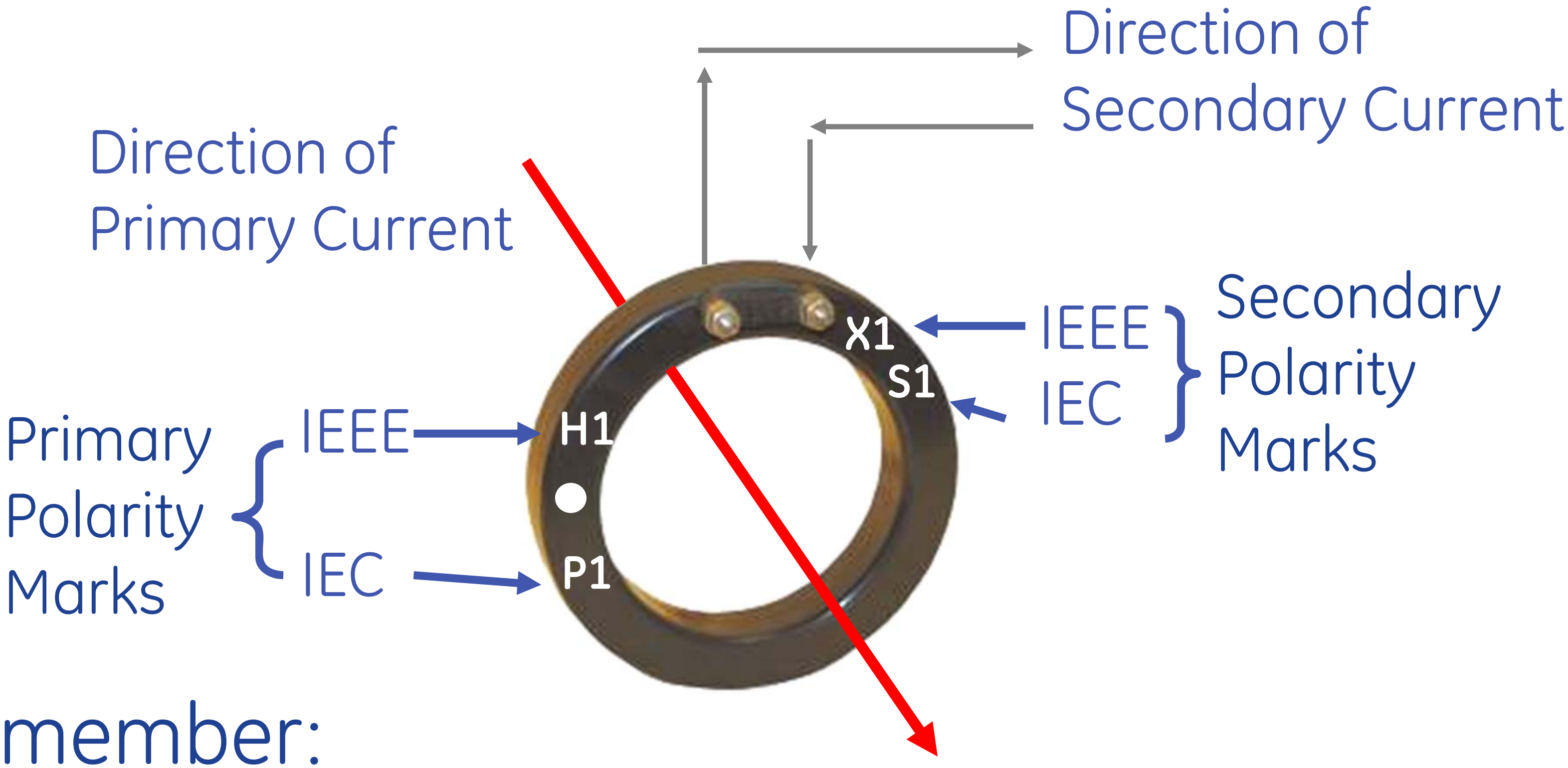


Remember:

Primary current <u>into</u> "polarity" =

Secondary current <u>out of</u> "polarity"

Polarity

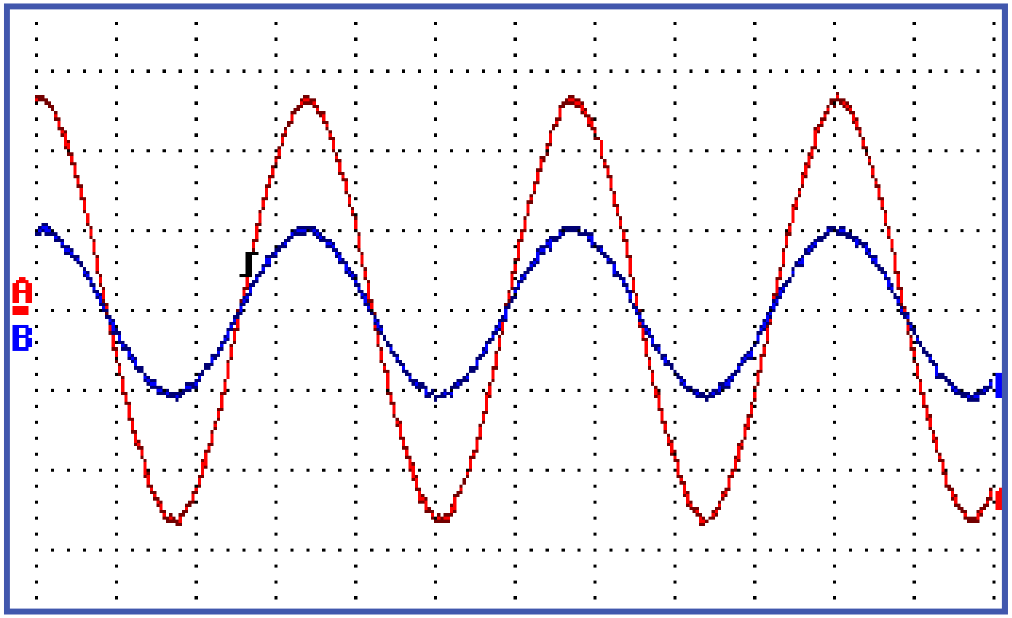


Remember:

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?

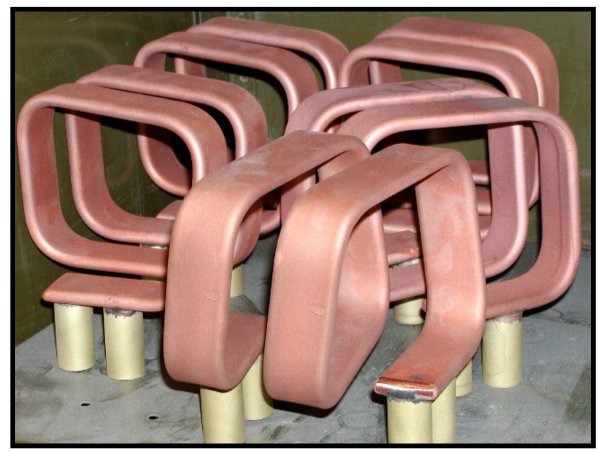
Meters and protection relays are able to sense direction of current/power flow

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

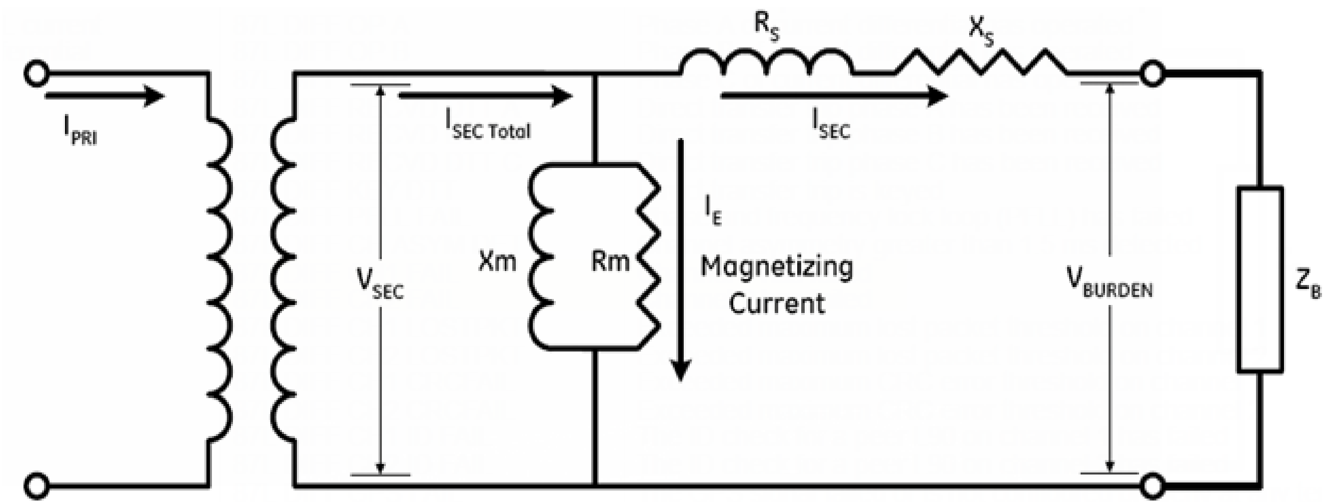


CT Accuracy

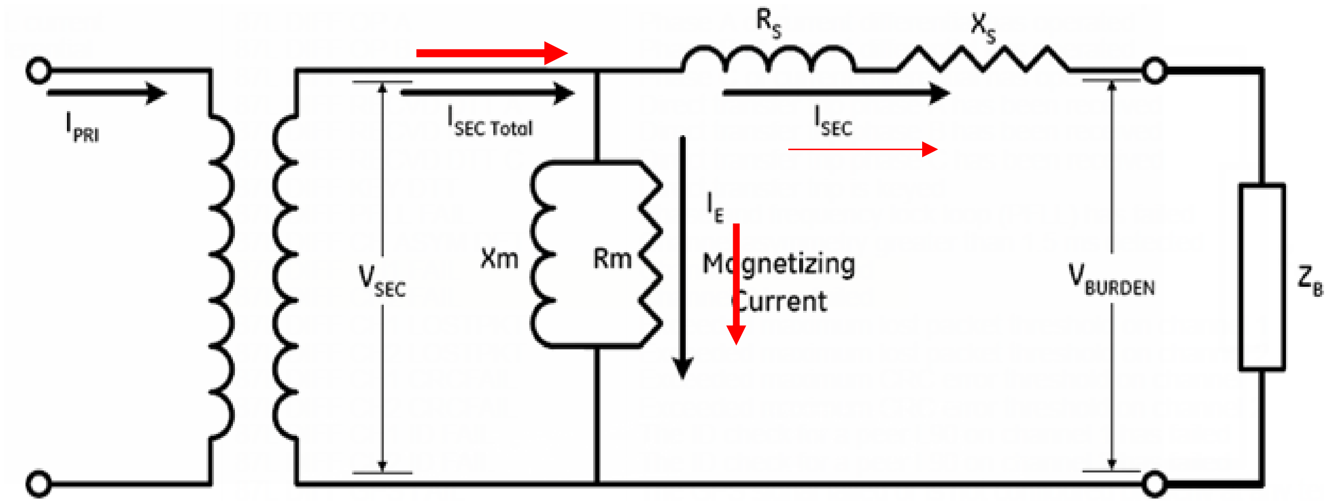
$$I_{relay} \neq I_{primary} * N_1/N_2$$

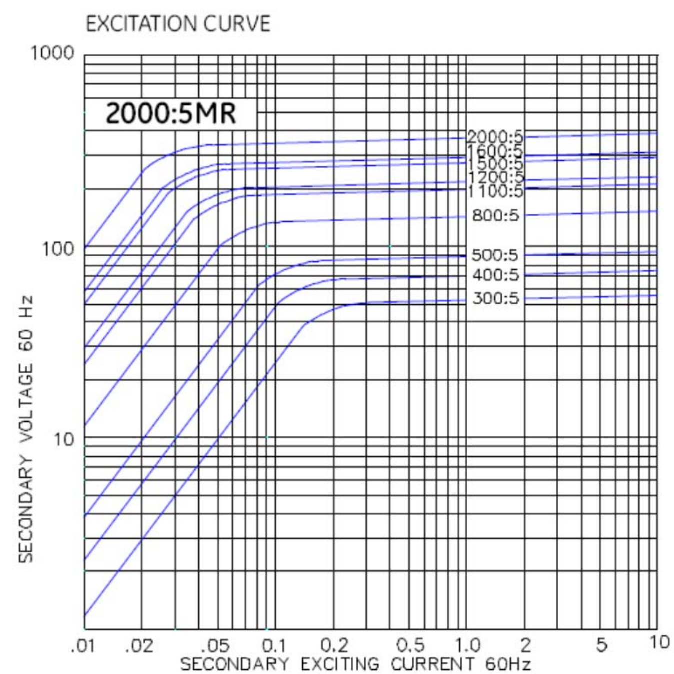
$$I_{relay} = I_{primary} * N_2/N_1 - I_{exciting}$$

CT Equivalent Circuit



CT Equivalent Circuit





Model 115-202MR

CT Metering Accuracy

Actual secondary current ≠ **Rated** secondary current

Difference in % is known as the **"Accuracy"** of the CT

IEEE CT Metering Accuracy

Accuracy Class (*)	Application
0.15	High Accuracy Metering
0.15S	"Special" High Accuracy Metering
0.3	Revenue Metering
0.6	Indicating Instruments
1.2	Indicating Instruments

* 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)

Application	Burden Designation	Impedance (Ohms)	VA @ 5 amps	Power Factor
Metering	B0.1	0.1	2.5	0.9
	B0.2	0.2	5	0.9
	B0.5	0.5	12.5	0.9
	B0.9	0.9	22.5	0.9
	B1.8	1.8	45	0.9
	E0.2	0.2	5	1.0
	E0.04	0.04	1	1.0

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

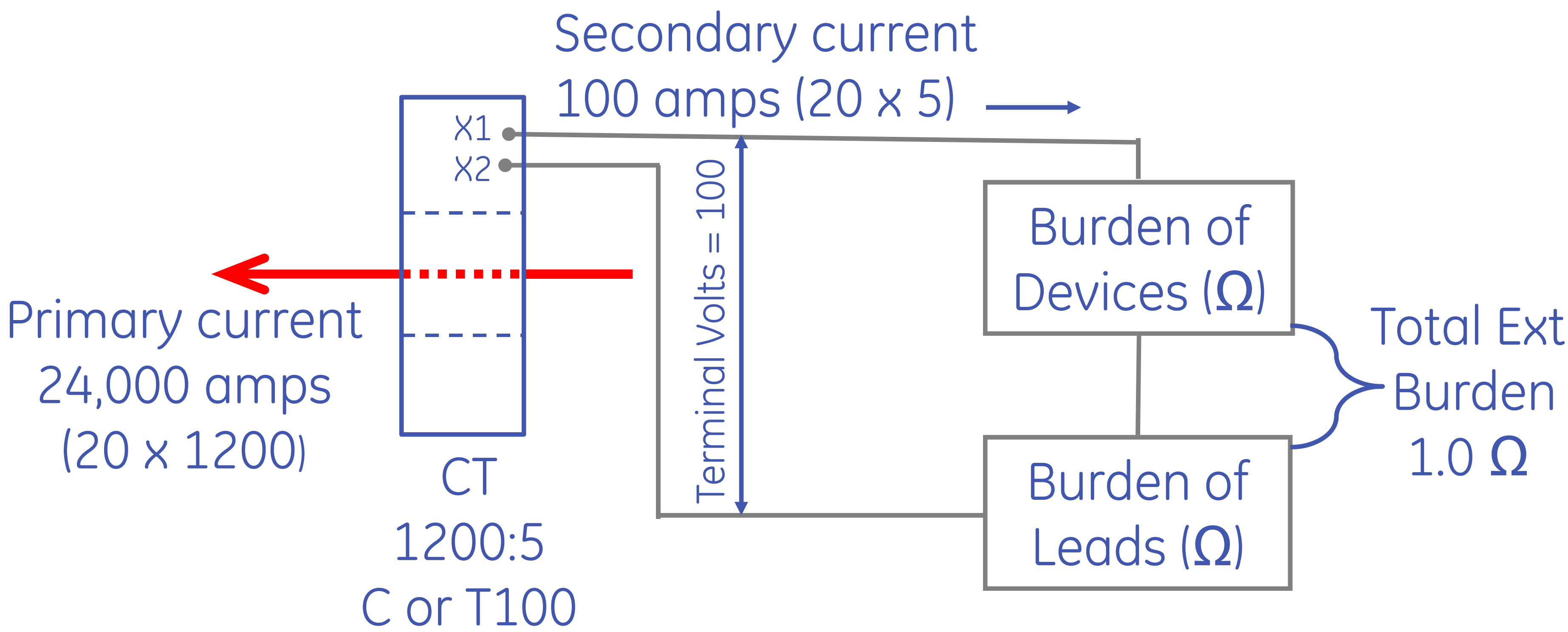
Relay class (C or T____) designates minimum secondary terminal volts…

- 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

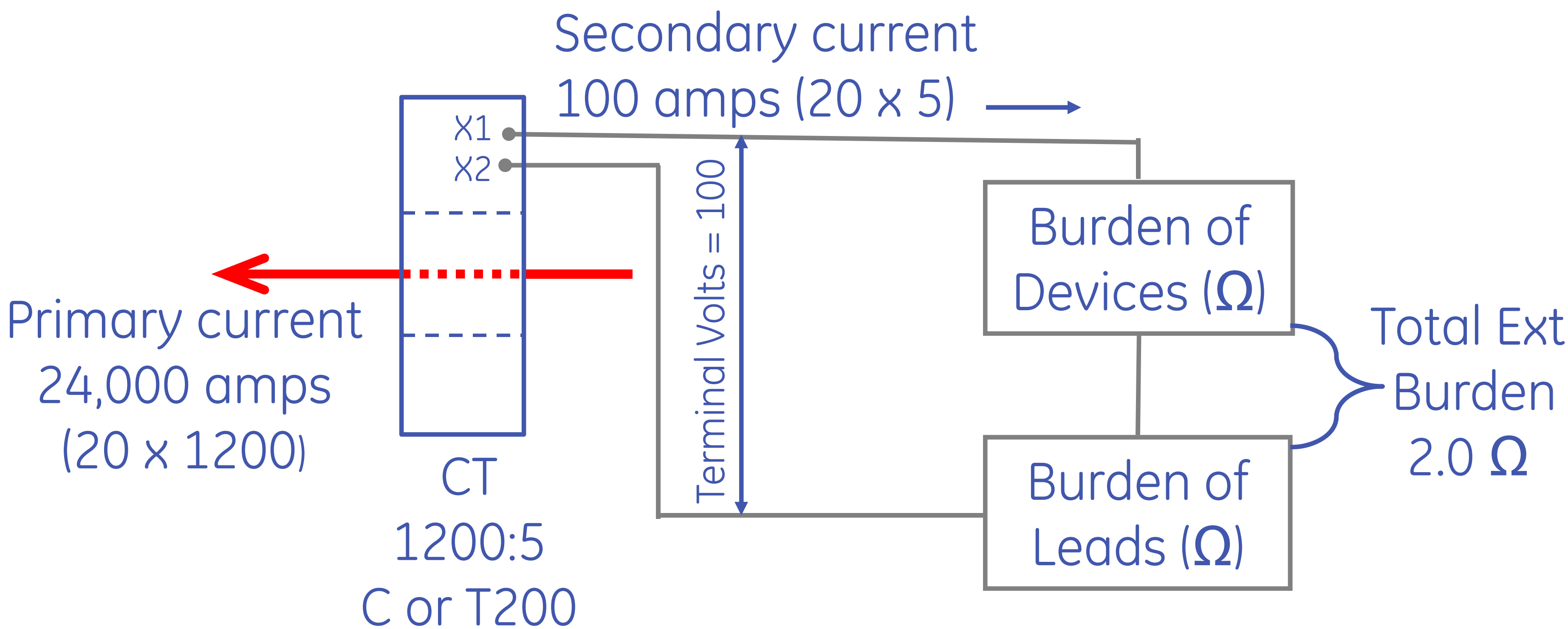


Terminal Volts = (20 times rated) (Total external burden)

100 Volts = (100 amps) (1.0 Ω)

IEEE CT Relay Accuracy

C or T200 example



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

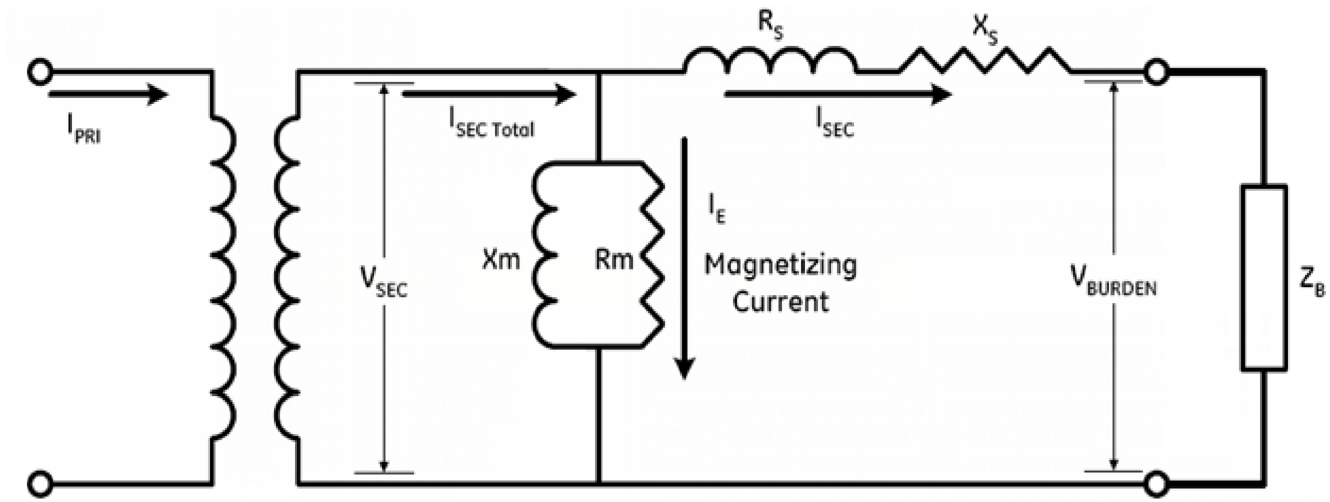
IEEE CT Relay Accuracy

Standard IEEE CT Burdens (5 Amp)

(Per IEEE Std. C57.13-1993)

Application	Burden Designation	Impedance (Ohms)	VA @ 5 amps	Power Factor
Relaying	B1	1	25	0.5
	B2	2	50	0.5
	B4	4	100	0.5
	B8	8	200	0.5

IEEE CT Relay Accuracy



C___ : a guarantee that with

I_{SEC} = 20*CT_{sec} and

Z_B = standard burden that

I_E < 0.10*20*CT_{sec}

I_S > 0.90*20*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 x (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)

CATALOG NUMBER	CURRENT RATIO	RELAY CLASS	ANSI METERING CLASS AT 60HZ					SECONDARY WINDING RESISTANCE	CONTINUOUS THERMAL RATING FACTOR	
			BO.1	BO.2	BO.5	BO.9	B1.8	(OHMS @ 75°C)	@ 30°C	@ 55°C
143—500	50:5	C20	4.8	4.8	—	—	—	0.014	2.0	2.0
143—750	75:5	C20	2.4	2.4	—	—	—	0.042	2.0	2.0
143—101	100:5	C20	1.2	2.4	4.8	4.8	—	0.056	2.0	2.0
143—151	150:5 *	C50	0.6	0.6	1.2	2.4	4.8	0.121	2.0	2.0
143—201	200:5 *	C50	0.3	0.3	0.6	1.2	2.4	0.161	2.0	2.0
143—251	250:5 *	C50	0.3	0.3	0.6	1.2	2.4	0.175	2.0	2.0
143—301	300:5 *	C100	0.3	0.3	0.3	0.6	1.2	0.241	2.0	2.0
143—401	400:5 *	C100	0.3	0.3	0.3	0.3	0.6	0.322	2.0	2.0
143—501	500:5 *	C100	0.3	0.3	0.3	0.6	0.6	0.441	2.0	2.0
143—601	600:5 *	C200	0.3	0.3	0.3	0.3	0.3	0.530	2.0	1.5
143—751	750:5 *	C200	0.3	0.3	0.3	0.3	0.3	0.662	2.0	1.5
143—801	800:5 *	C200	0.3	0.3	0.3	0.3	0.3	0.706	2.0	1.5
143—102	1000:5 *	C200	0.3	0.3	0.3	0.3	0.3	0.883	1.5	1.33
143—122	1200:5 *	C400	0.3	0.3	0.3	0.3	0.3	1.059	1.5	1.0
143—152	1500:5 *	C400	0.3	0.3	0.3	0.3	0.3	1.324	1.5	1.0
143—162	1600:5 *	C400	0.3	0.3	0.3	0.3	0.3	1.413	1.33	1.0
143—202	2000:5 *	C400	0.3	0.3	0.3	0.3	0.3	1.678	1.33	1.0
143—252	2500:5 *	C400	0.3	0.3	0.3	0.3	0.3	2.097	1.0	0.8
143—302	3000:5 *	C800	0.3	0.3	0.3	0.3	0.3	2.516	1.0	0.8
143—322	3200:5 *	C800	0.3	0.3	0.3	0.3	0.3	2.684	1.0	0.8
143—352	3500:5 *	C800	0.3	0.3	0.3	0.3	0.3	2.936	1.0	0.8
143—402	4000:5 *	C800	0.3	0.3	0.3	0.3	0.3	3.355	1.0	0.6
143—502	5000:5 *	C800	0.3	0.3	0.3	0.3	0.3	3.983	1.0	0.6
143—602	6000:5 *	C800	0.3	0.3	0.3	0.3	0.3	4.780	0.8	0.6

CT Sizing

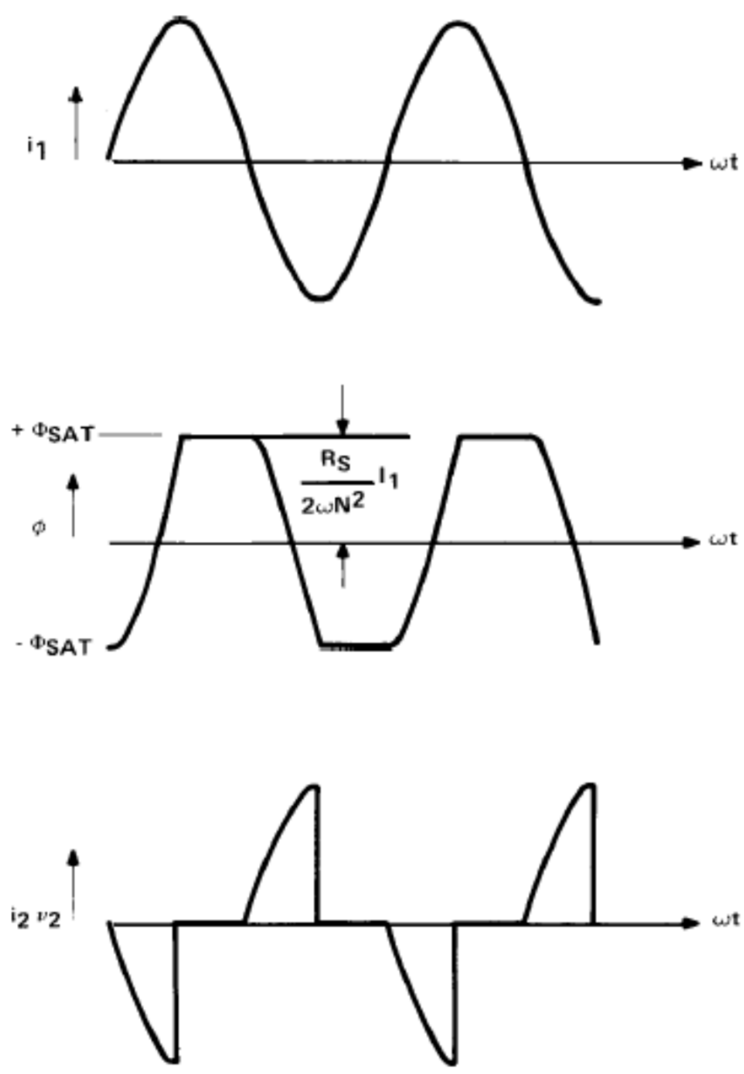
$CT_{primary}$ > maximum expected load current * rating factor
$CT_{primary}$ < maximum expected fault current/20
CT primary should be sized to avoid saturation
CT accuracy class should be sized to avoid saturation
CT insulation should be sized for the application
CT BIL should be sized to coordinate with station BIL

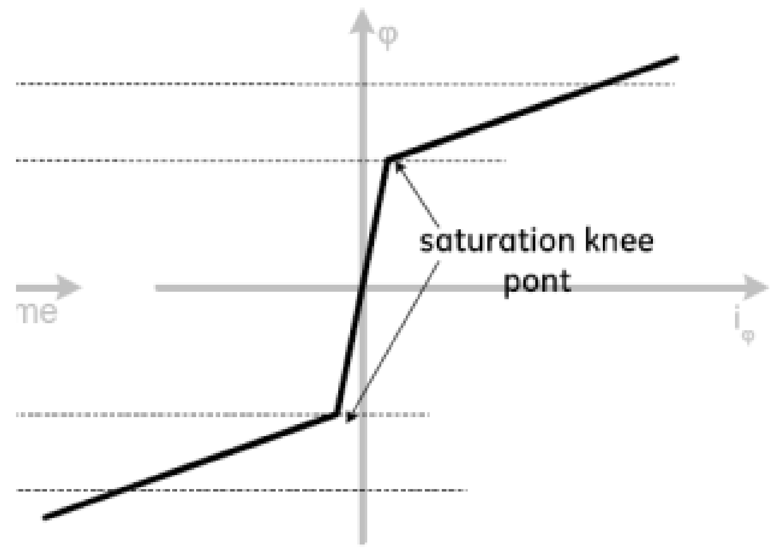
CT Saturation

CT Saturation Concepts

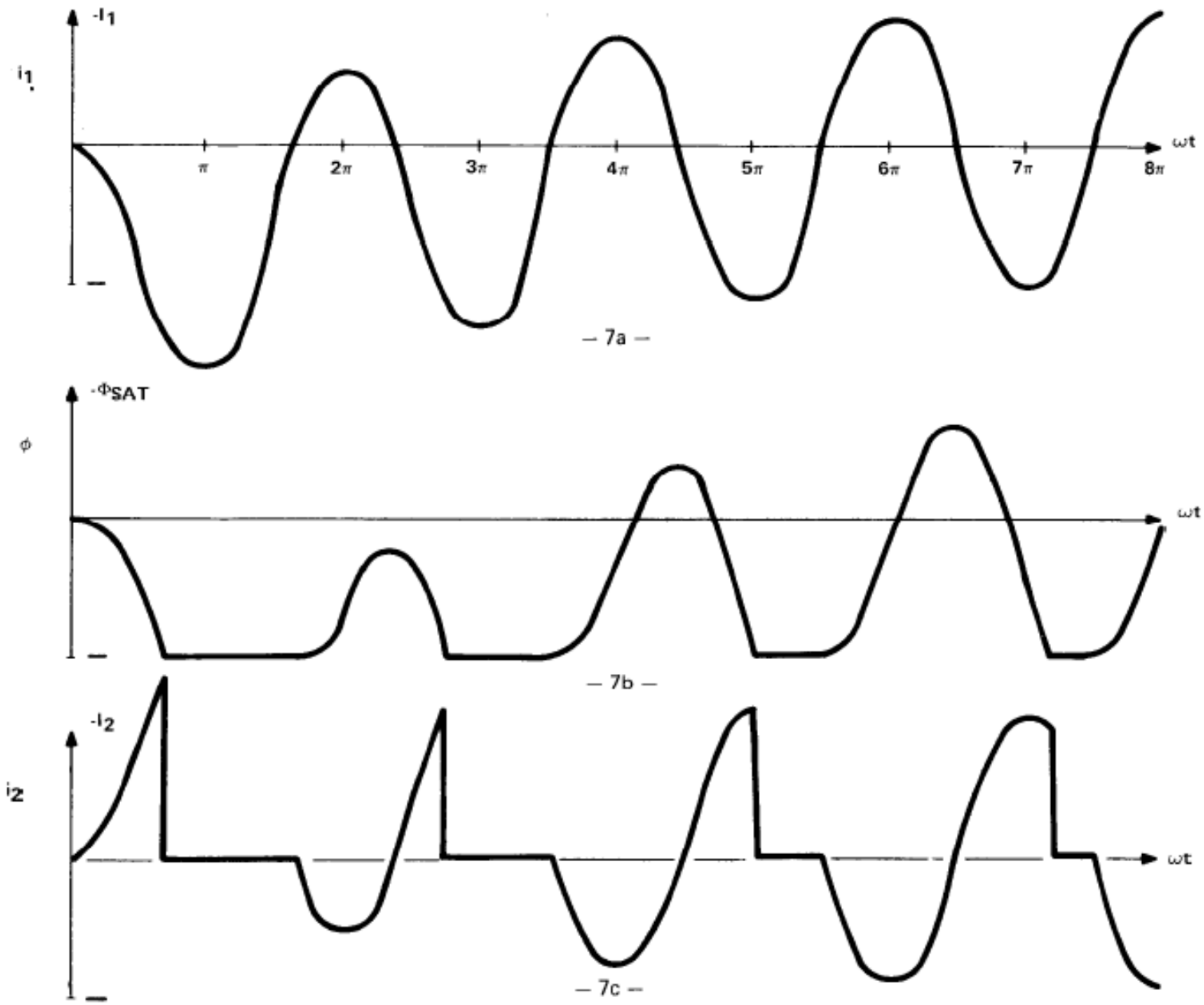
- CT saturation depends on a number of factors
  - Physical CT characteristics (size, rating, winding resistance, saturation voltage)
  - Connected CT secondary burden (wires + relays)
  - Primary current magnitude, DC offset (system X/R)
  - Residual flux in CT core
- Actual CT secondary currents may 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** from Figure 2.)

$$T_S = \frac{-X/R}{2\pi f} \times \ln\left(1 - \frac{K_S - 1}{X/R}\right)$$

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

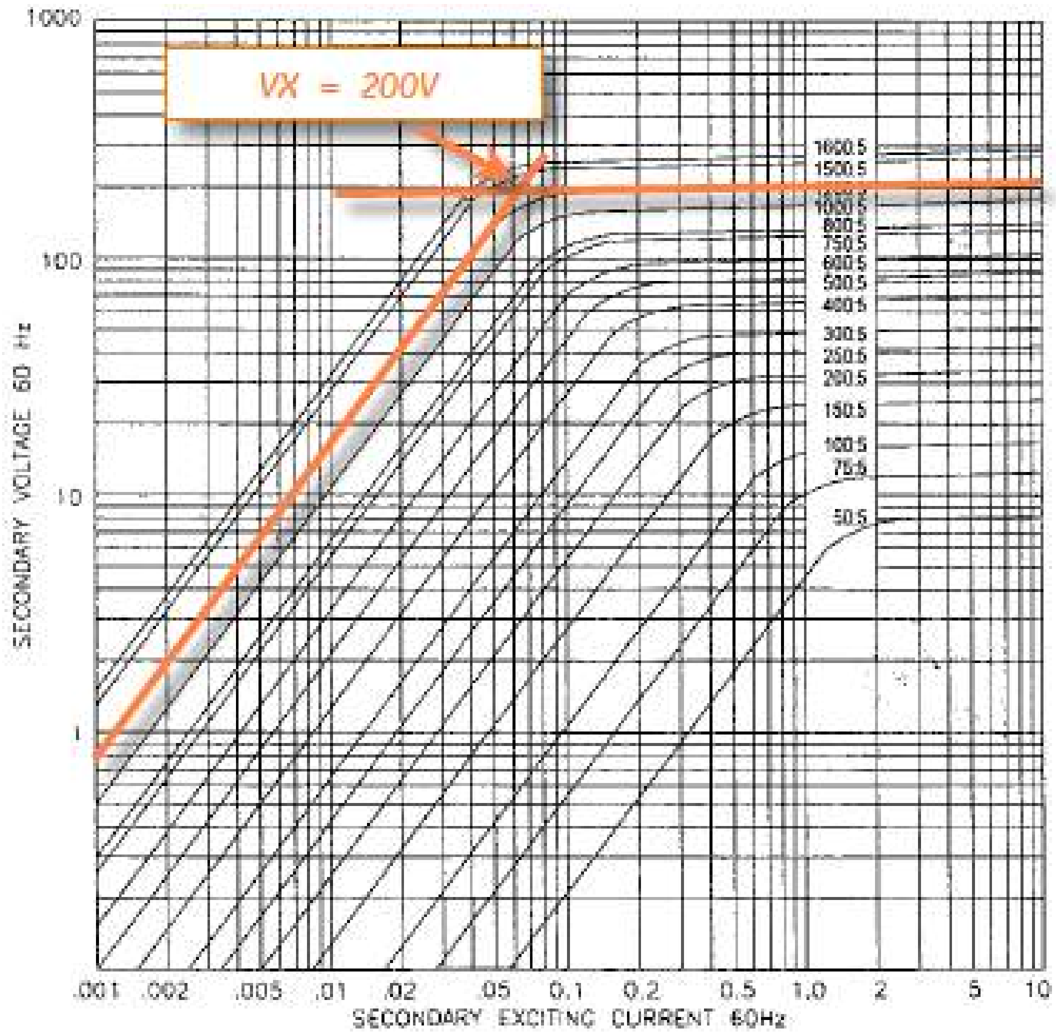
C37.110 Method

C37.110 uses this relation:

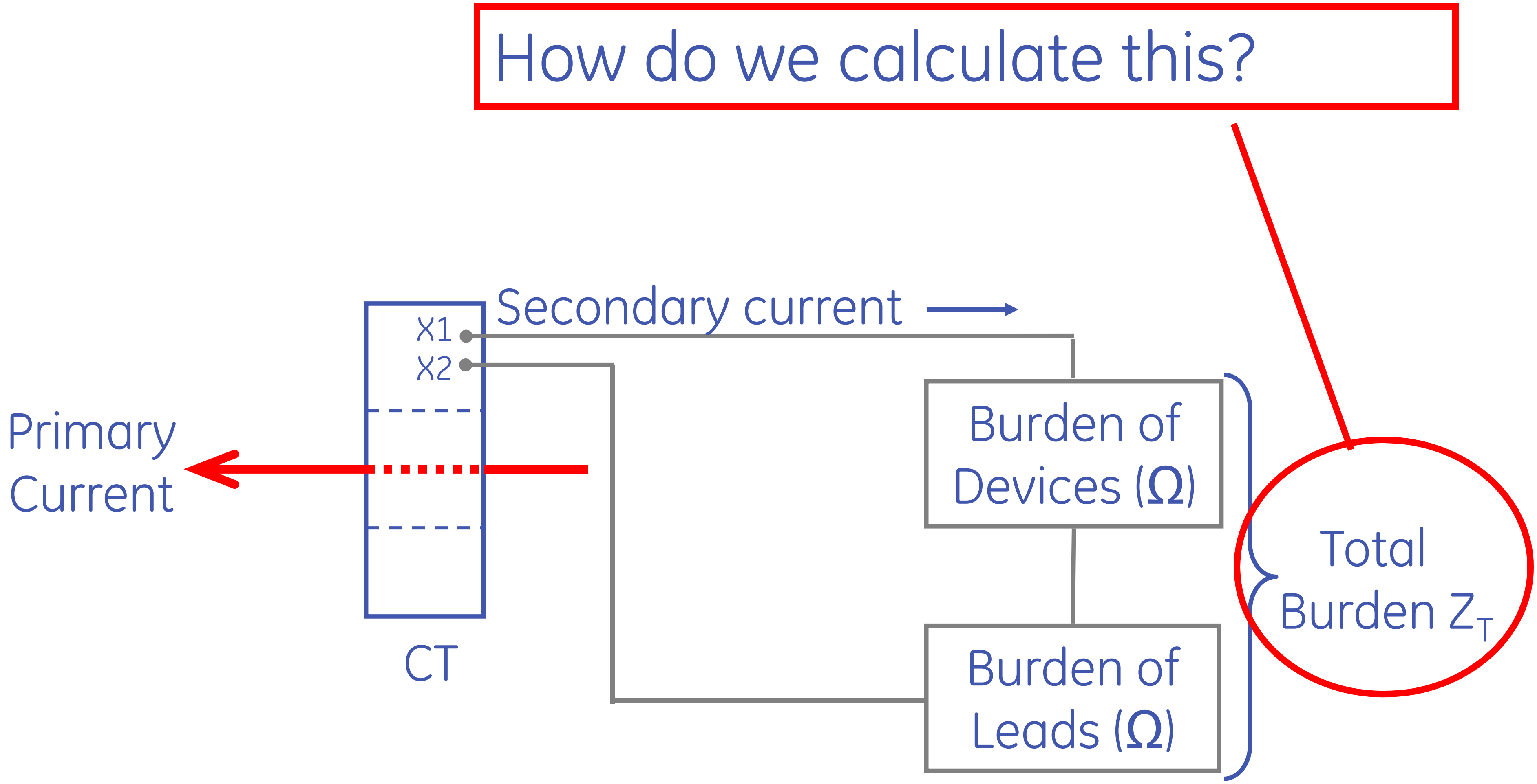
$$V_X > I_{AC} \times Z_S \times \left(1 + X/R\right)$$

(Assuming a resistive burden)

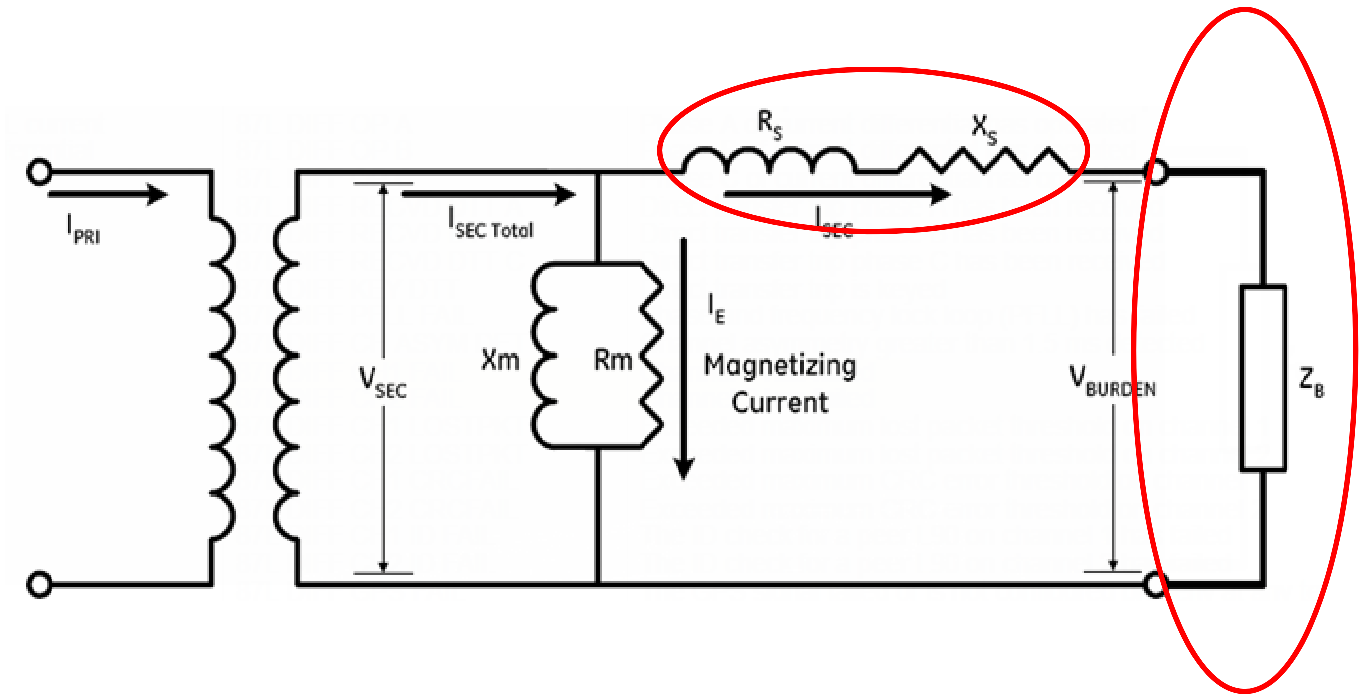
CT Saturation Voltage



CT Burden Calculation



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} = CT secondary resistance in ohms

Best Source for R_{CT} is from the Manufacturer

CATALOG NUMBER	CURRENT RATIO	RELAY CLASS	ANSI METERING CLASS AT 60HZ					SECONDARY WINDING RESISTANCE (OHMS @ 75°C)
			BO.1	BO.2	BO.5	BO.9	B1.8	
143–500	50:5	C20	4.8	4.8	–	–	–	0.014
143–750	75:5	C20	2.4	2.4	–	–	–	0.042
143–101	100:5	C20	1.2	2.4	4.8	4.8	–	0.056
143–151	150:5 *	C50	0.6	0.6	1.2	2.4	4.8	0.121

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:
Ohms/1000' = $e^{0.232G-2.32}$
Where G is AWG

CT Burden Calculation

$$Z_T = R_{CT} + R_L + Z_B$$

Z_B = **Relay resistance**

Microprocessor Burden < 0.2VA at rated secondary

Z = 0.2/25 = 0.008 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

CT Saturation Calculator

Excel Spread Sheet
See IEEE publication C37.110: "IEEE Guide for the Application of CurrentTransformers Used for Protective Relaying Purposes"

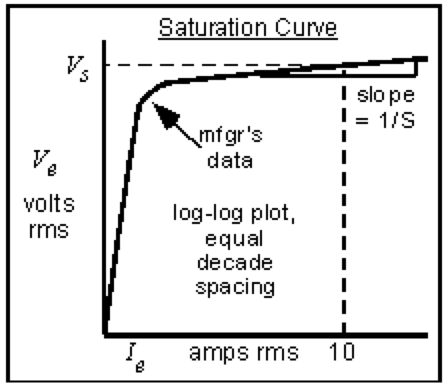
A document of the
IEEE Power Systems Relaying Committee
Contact: gswift@nxtphase.com
Refer also to "CT SAT Theory (PSRC)".

VERSION:
30 Dec 2002

ASSUMPTIONS: CT core losses and sec'y reactance zero (thru-hole primary). Frequency: 60 Hz
CT primary current is zero for t<0. CT is 5 amp nominal Time step = 1/12,000 second.

INPUT PARAMETERS:

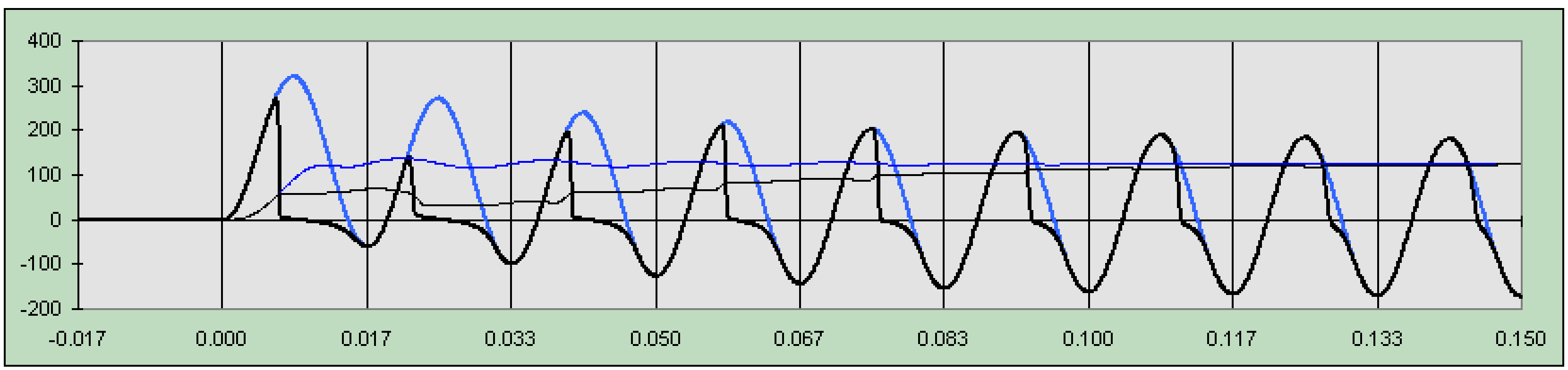
		ENTER:	
Inverse of sat. curve slope =	S =	30	---
RMS voltage at 10A exc. current =	Vs =	210	volts rms
Turns ratio = n2/n1 =	N =	240	---
Winding resistance =	Rw =	0.387	ohms
Burden resistance =	Rb =	0.700	ohms
Burden reactance =	Xb =	0.000	ohms
System X/R ratio =	XoverR =	15.0	---
Per unit offset in primary current =	Off =	1.00	-1<Off<1
Per unit remanence (based on Vs) =	λrem	0.00	---
Symmetrical primary fault current =	Ip =	30,000	amps rms



CALCULATED:

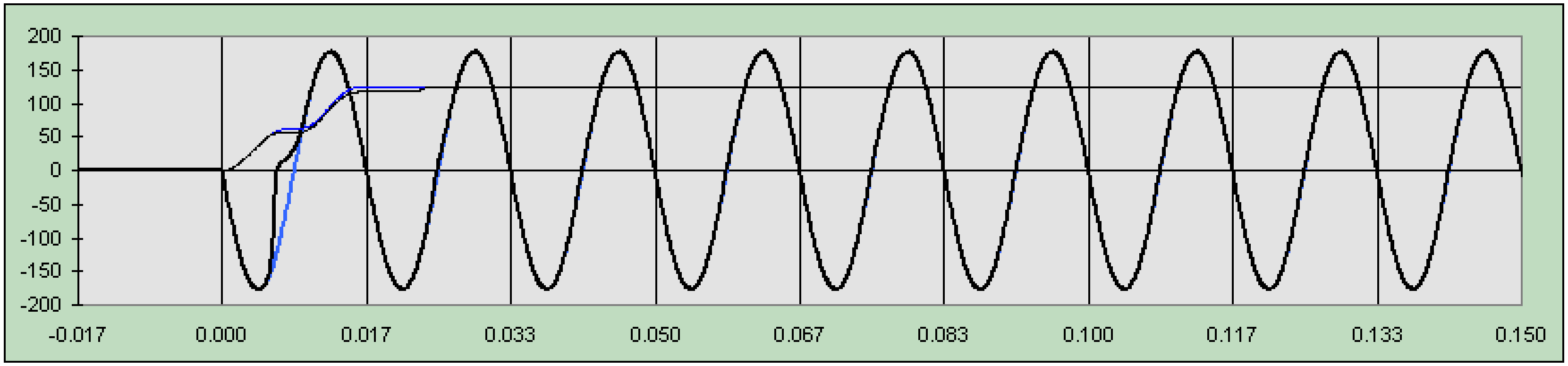
Rt =	Total burden resistance = Rw + Rb =	1.087	ohms
pf =	Total burden power factor =	1.000	---
Zb =	Total burden impedance =	1.087	ohms
Tau1 =	System time constant =	0.040	seconds
Lamsat =	Peak flux-linkages corresponding to Vs	0.788	Wb-turns
ω =	Radian freq =	376.99	rad/s
RP =	Rms-to-peak ratio =	0.32028	
A =	Coefficient in instantaneous ie versus lambda curve: ie = A * l^S :	4.00E+04	---
dt =	Time step =	0.000083	seconds
Lb =	Burden inductance =	0.00000	henries

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.

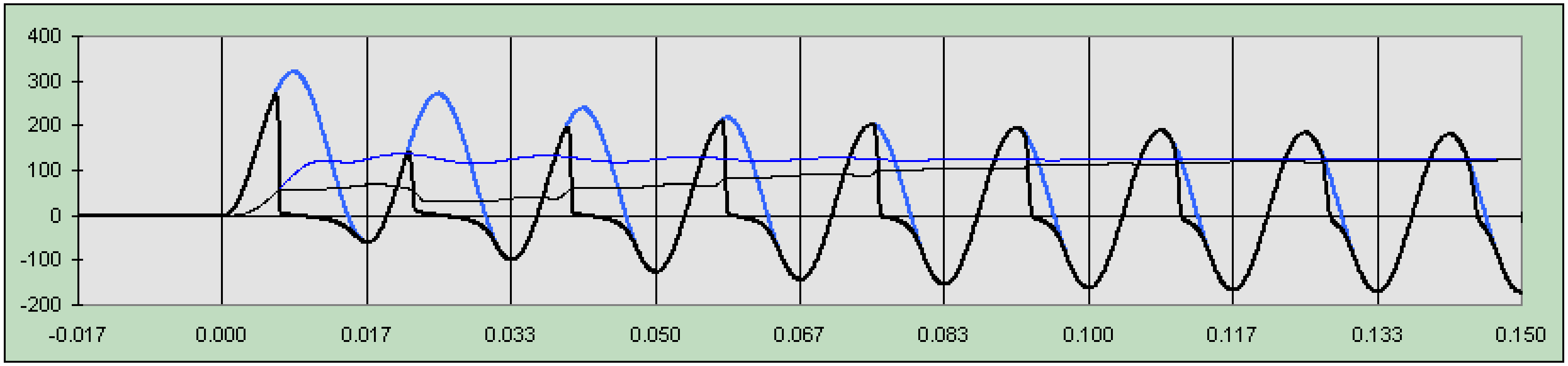


Model of CT Performance

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

IEEE VT Accuracy Class

Metering Accuracy Class Burdens	VA	PF
W	12.5	0.10
X	25	0.70
M	35	0.20
Y	75	0.85
Z	200	0.85
ZZ	400	0.85

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%

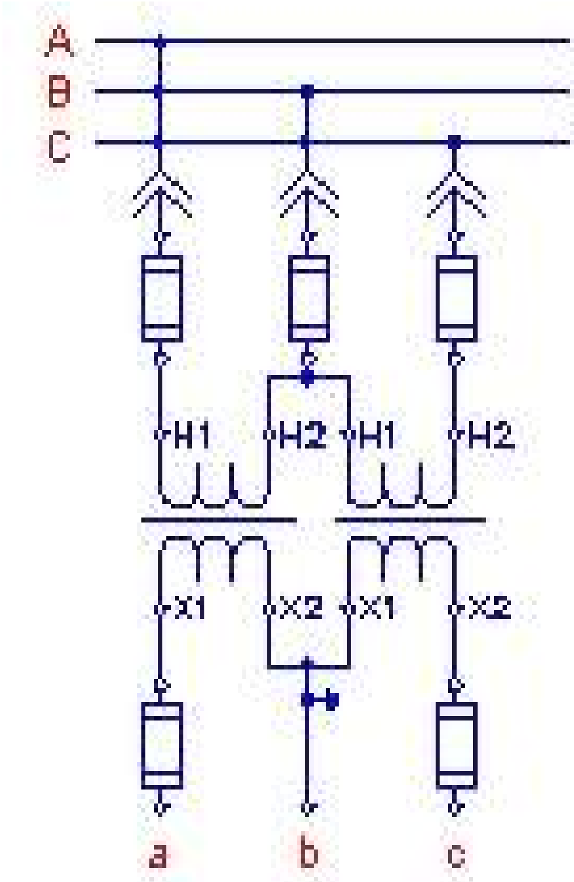
Line to ground rated:

Do not connect line to line

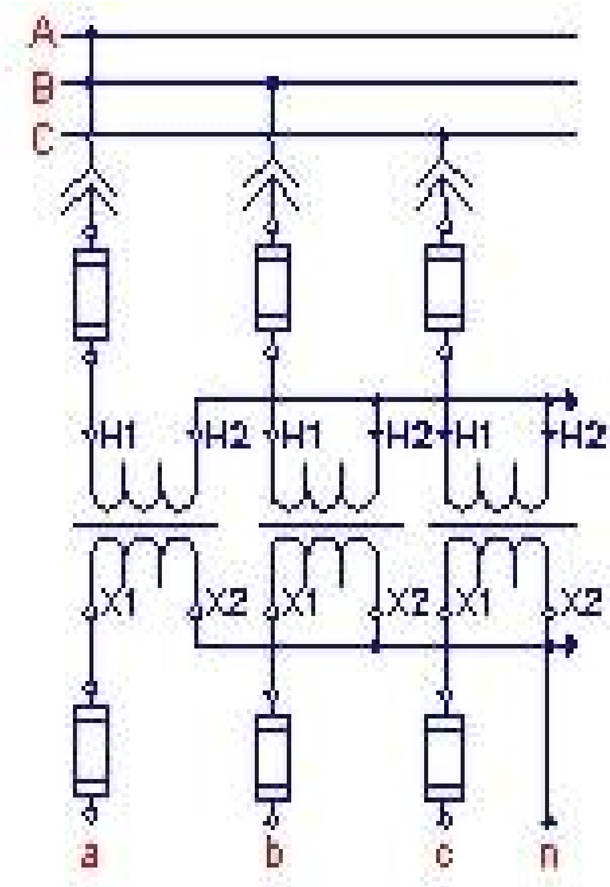
Do not use on ungrounded systems w/o consulting factory

Rated Frequency: Do not operate below rated frequency w/o consulting factory

Typical VT Connections

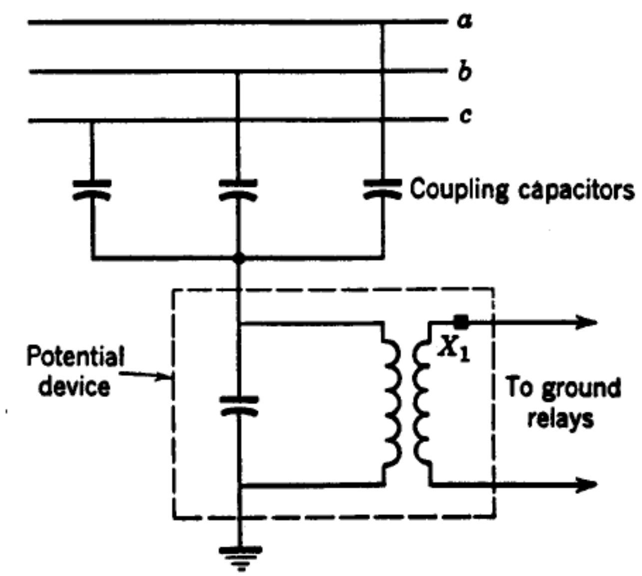


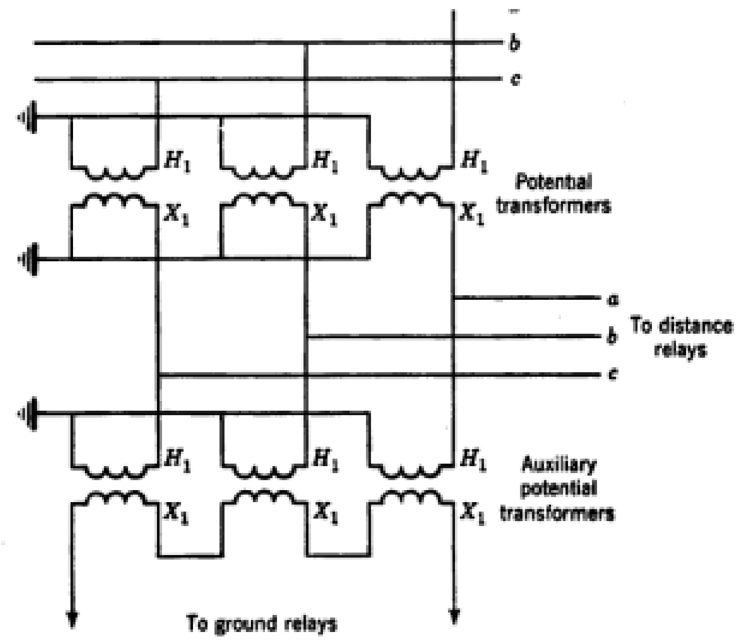
Open Delta Connection
(2) Double Bushing VTs



Y – Y Connection
(3) Single Bushing VTs

Typical VT Connections for Directional Ground





$$
\begin{aligned}
V_{nm} &= V_a + V_b + V_c \\
&= (V_{a1} + V_{a2} + V_{a0}) + (V_{b1} + V_{b2} + V_{b0}) + (V_{c1} + V_{c2} + V_{c0}) \\
&= V_{a0} + V_{b0} + V_{c0} = 3V_{a0} = 3V_{b0} = 3V_{c0}
\end{aligned}
$$

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
<u>do not</u> 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.

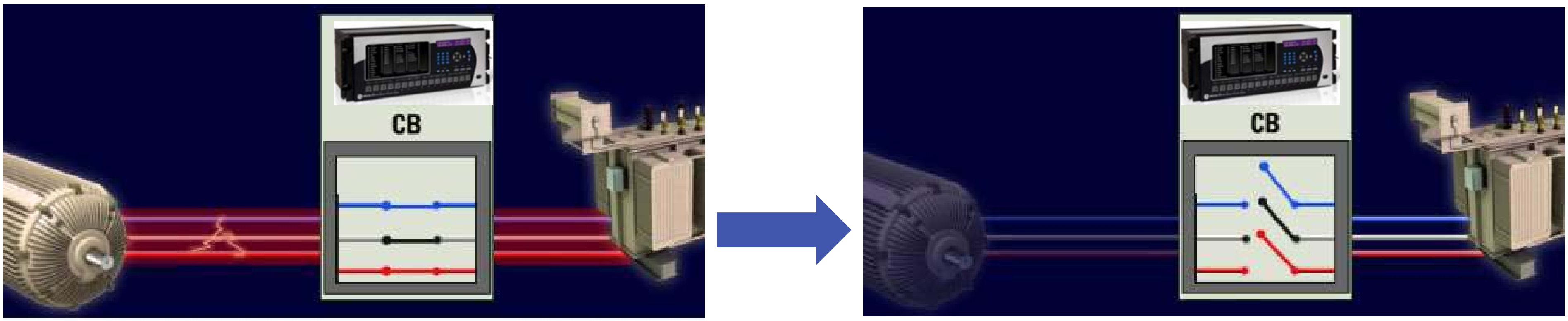
Take Home Rule # 7

Check and Double Check Polarity

Proper meter and protective relay operation is based on correct current and voltage polarities.

Relaying Fundamentals

Relaying Fundamentals
Function

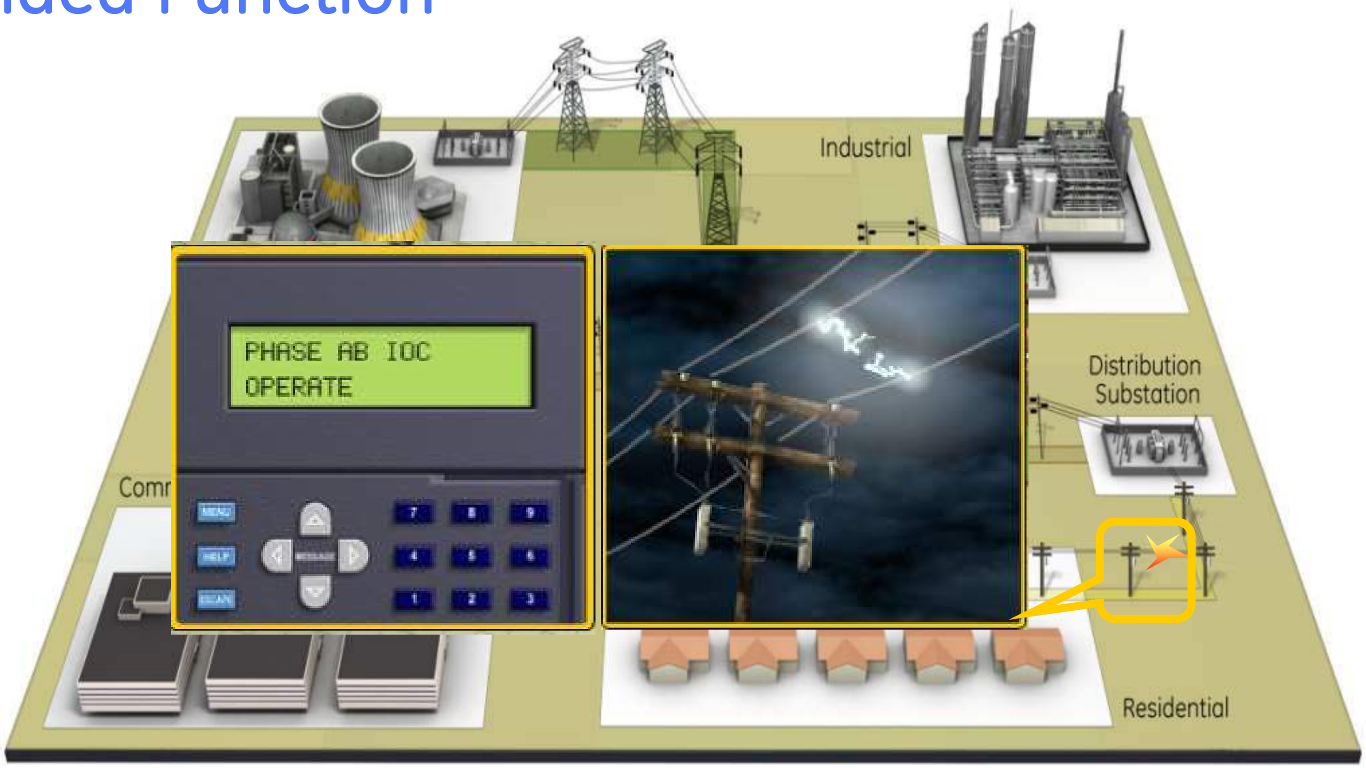


Protective Relays locate faults and trip circuit breakers to interrupt the flow of current into the defective component. This quick isolation provides the following benefits:

- 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

Relaying Fundamentals

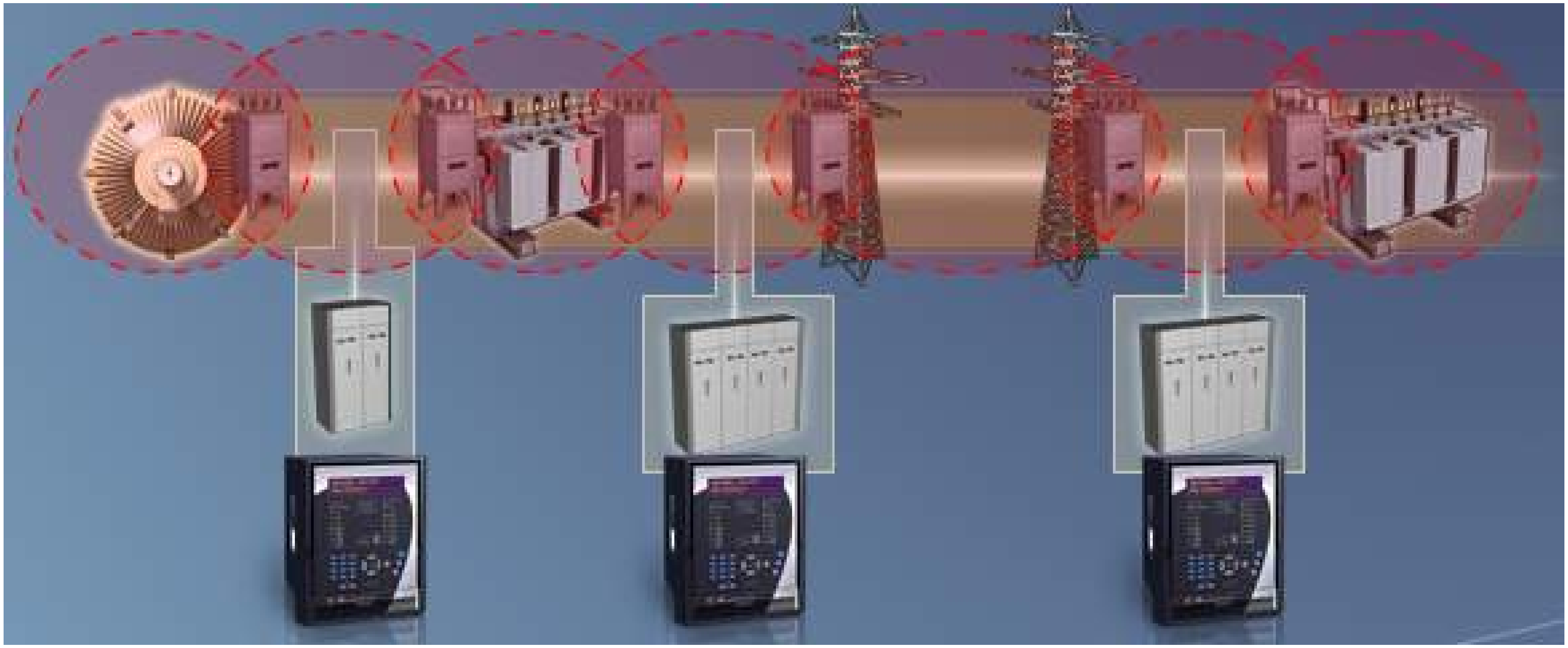
Expanded Function



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

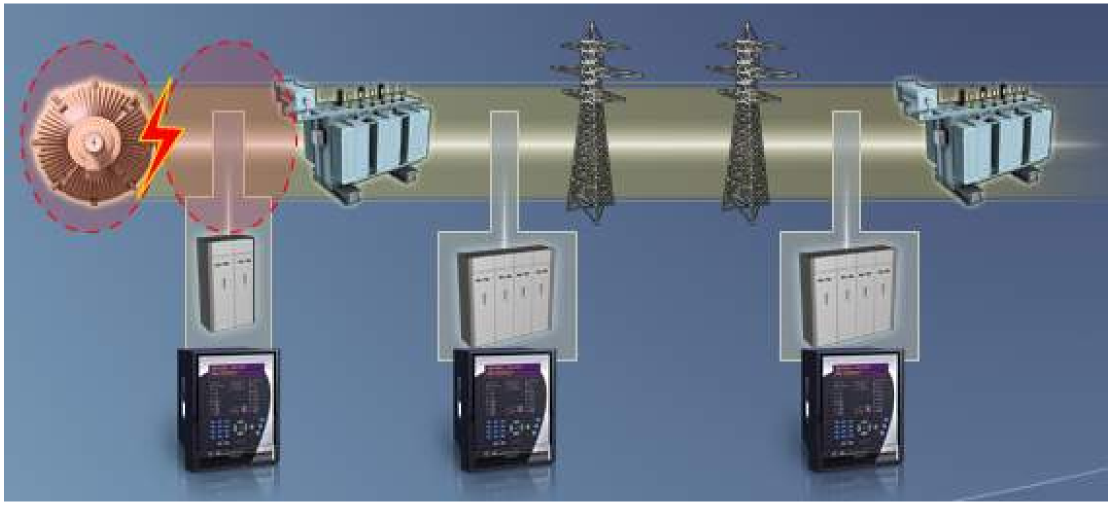


- Protective Zones around each Major Power System Component and Circuit Breaker
- Overlapping Zones around Circuit Breakers

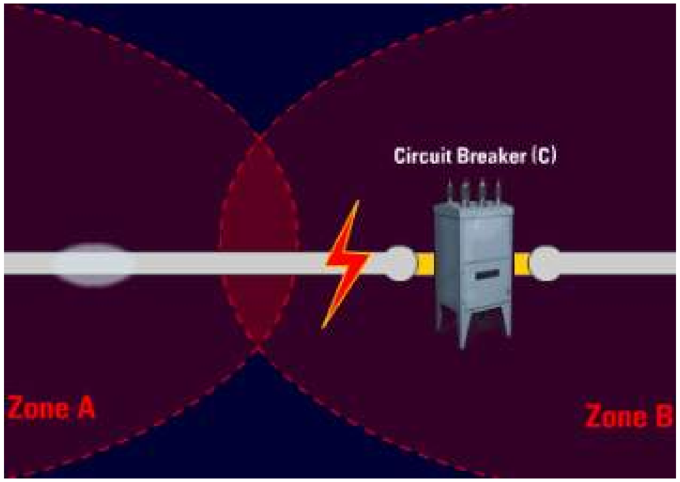
Relaying Fundamentals

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

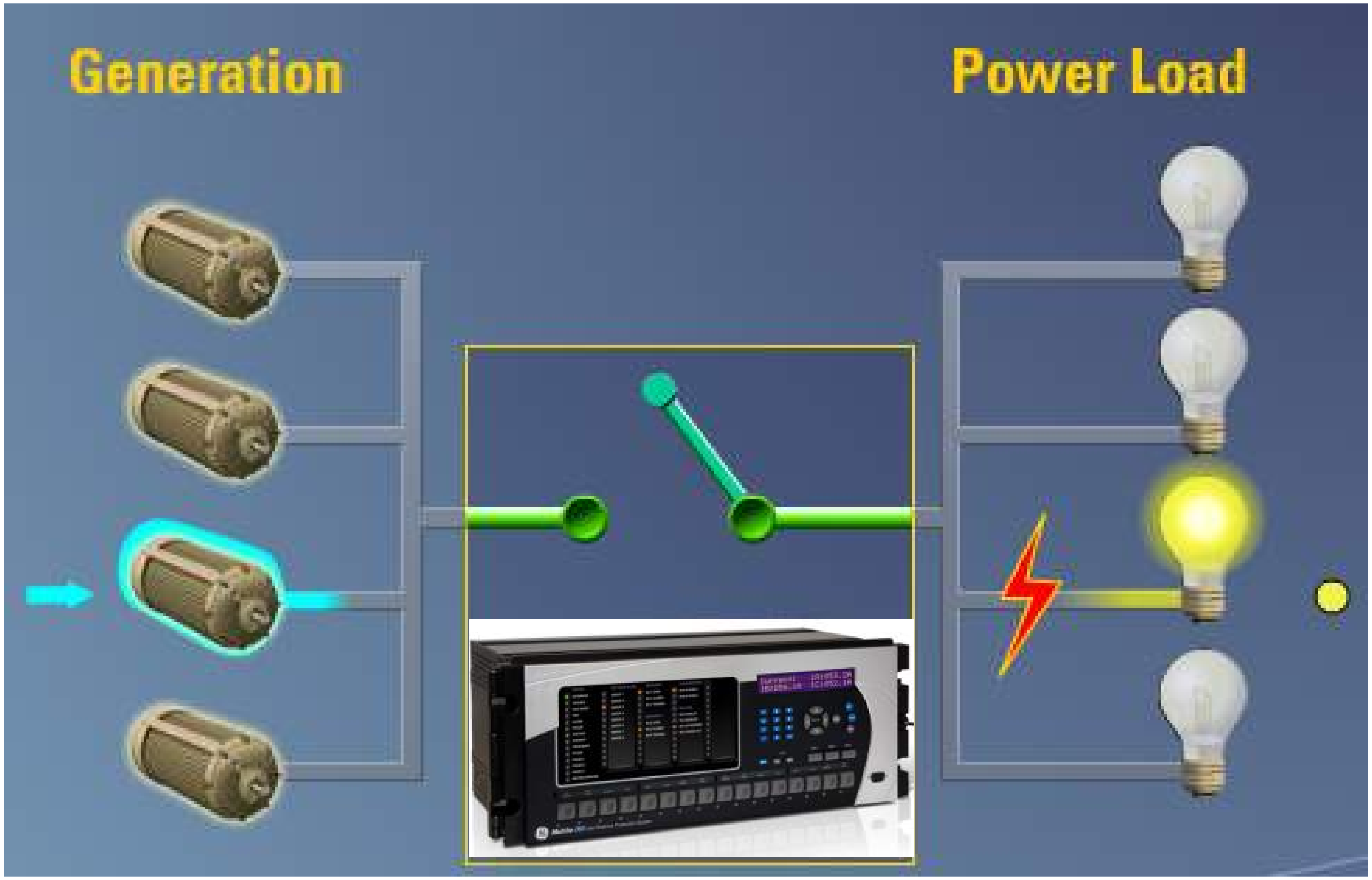
Requirements

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:



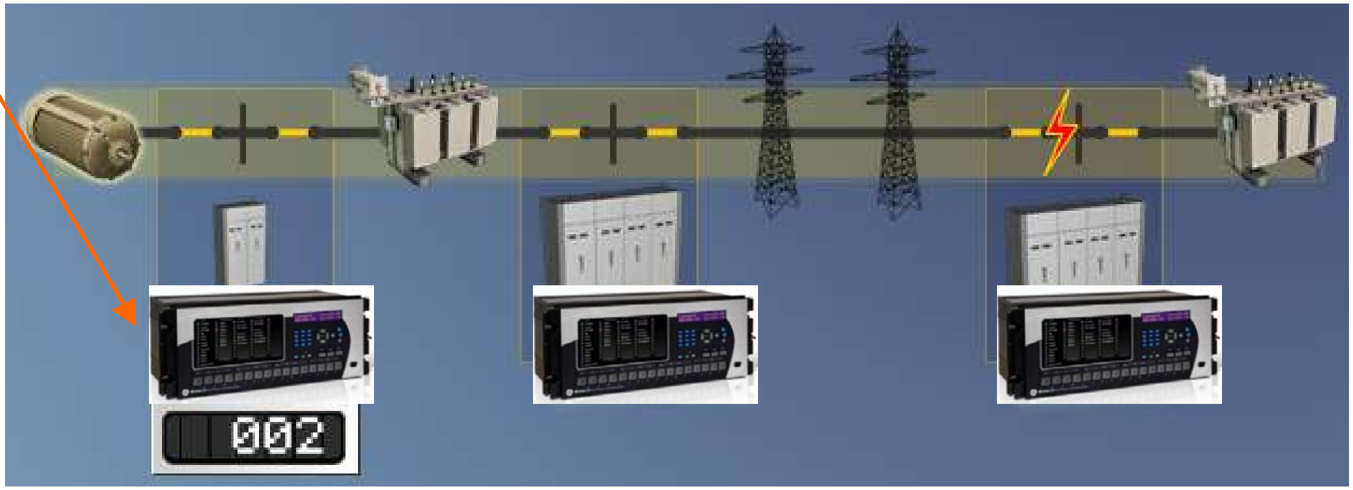
Relaying Fundamentals
Requirements

- **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:

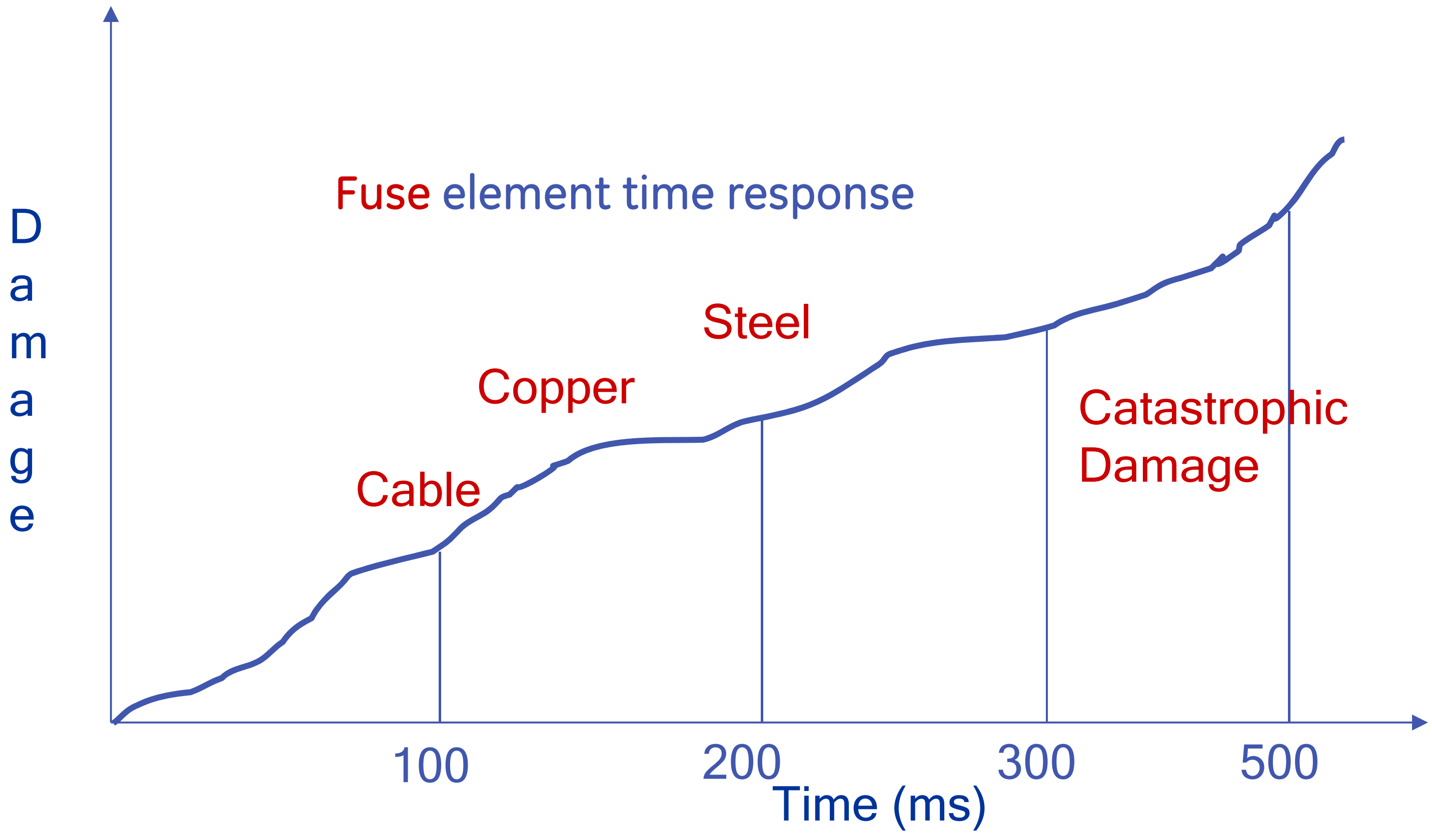
- Inherently Selective – relay is unaffected
- Relatively Selective – relay operates with time delay



Relaying Fundamentals

Requirements

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



Relaying Fundamentals
Catastrophic Damage

Relaying Fundamentals

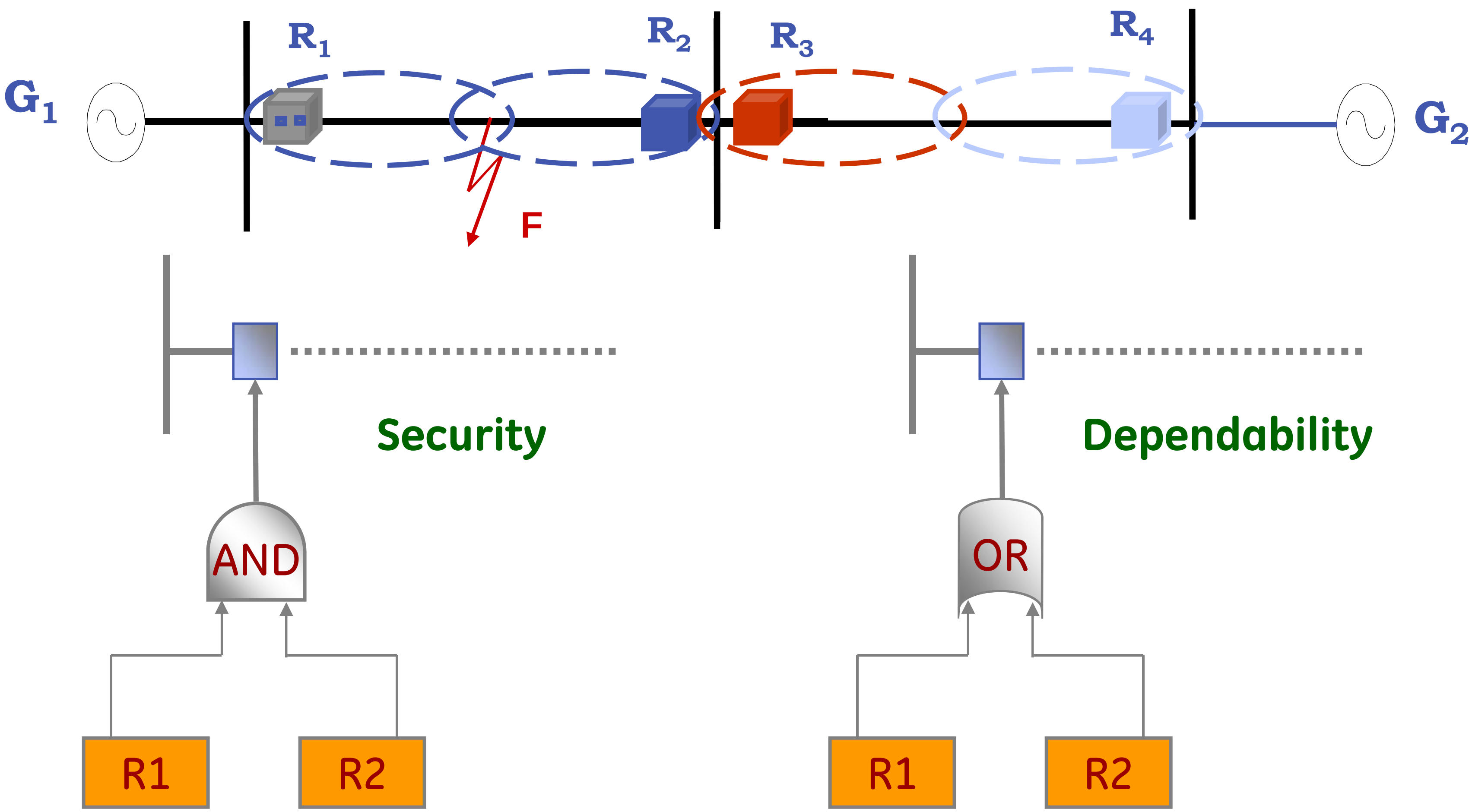
Requirements

- 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

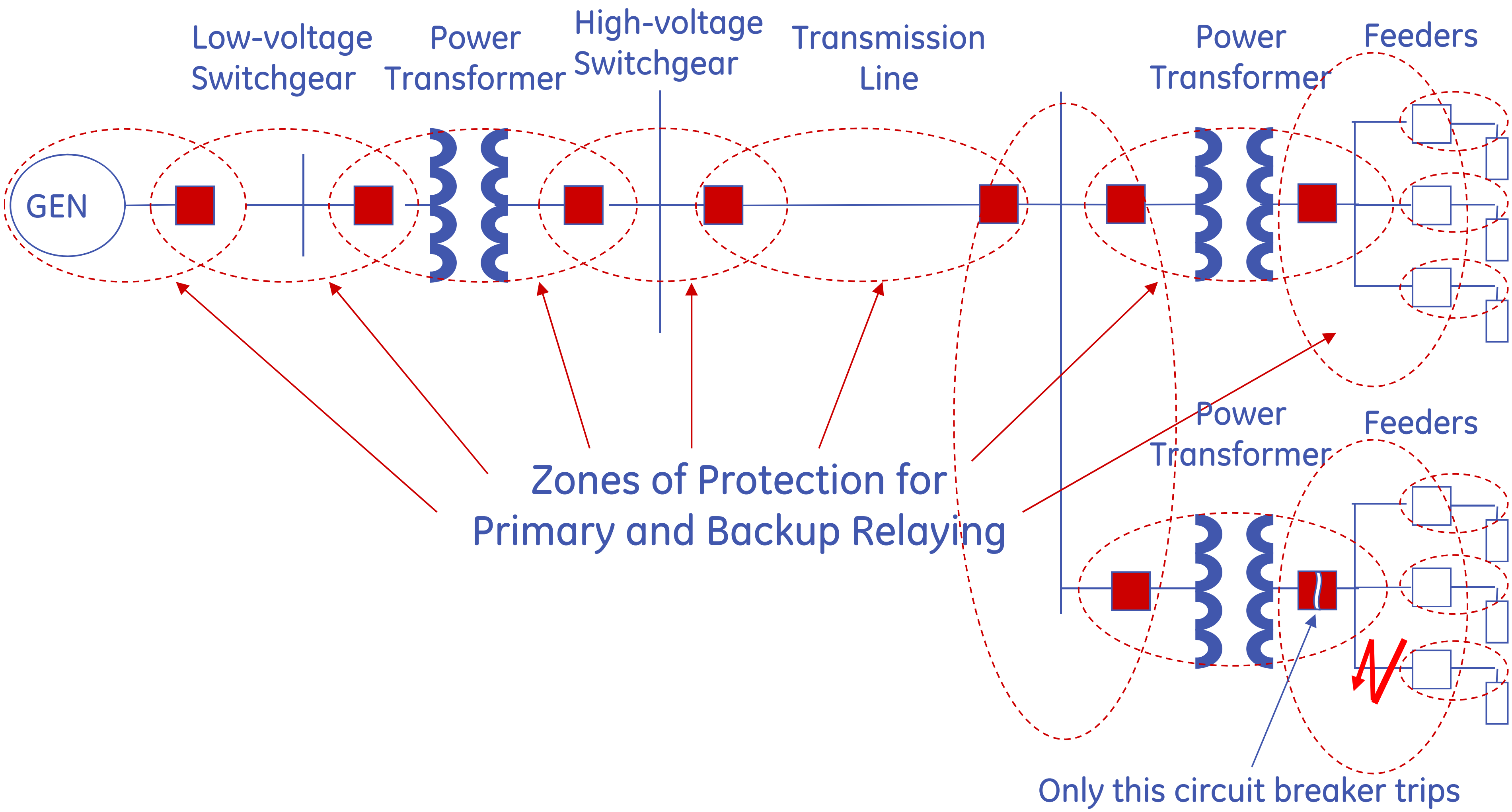
Requirements

Reliability Example:



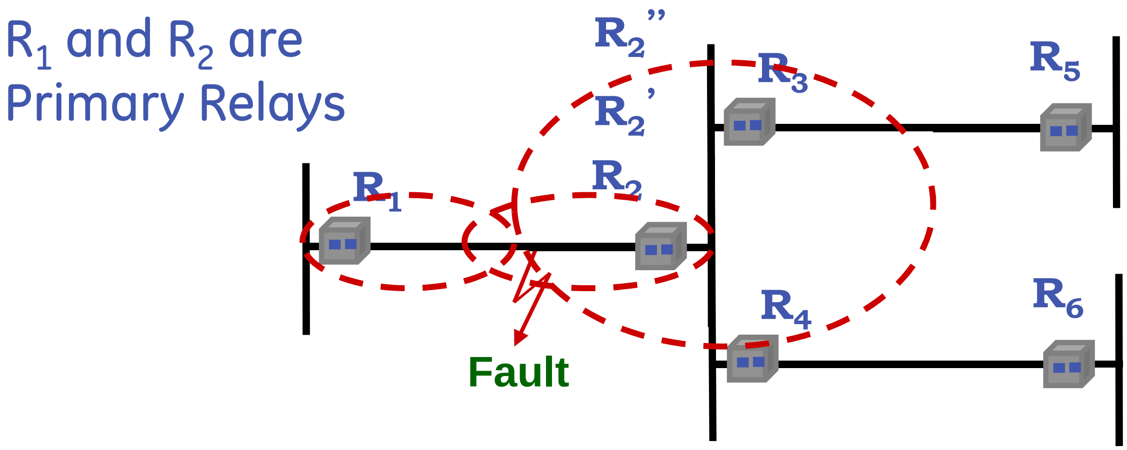
Relaying Fundamentals

Primary & Backup Relaying



Relaying Fundamentals

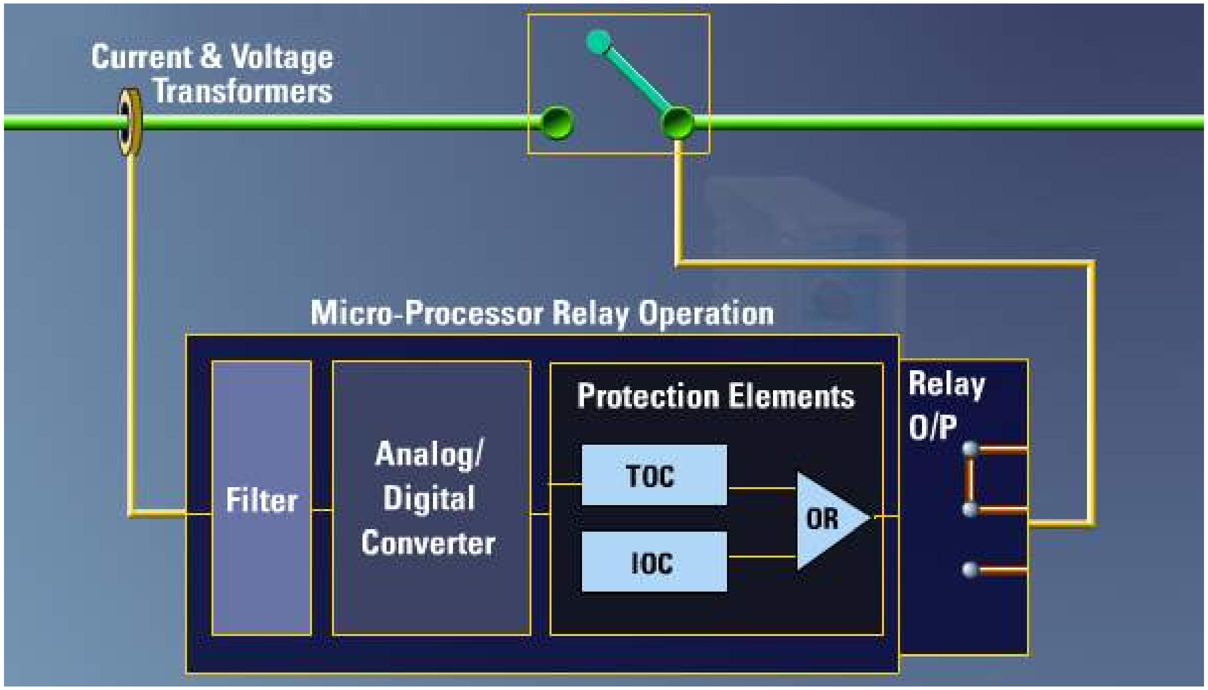
Backup Relaying Example



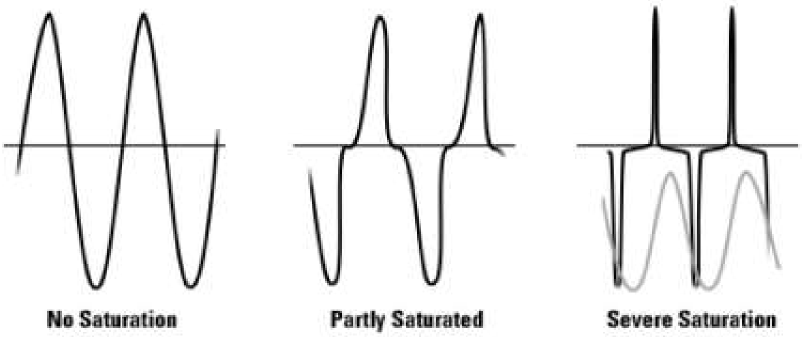
- Duplicate Relay: backup relay (R_2') located on same component for primary relay failure
- Local Backup Relaying: backup relay (R_2'') located on same component
- Remote Backup Relaying: backup relays (R_3 - R_6) located on different component

Relaying Fundamentals

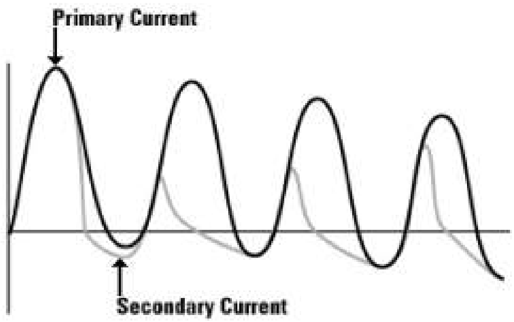
Requirements



AC Saturation:



DC Saturation:



Common Protection Methods

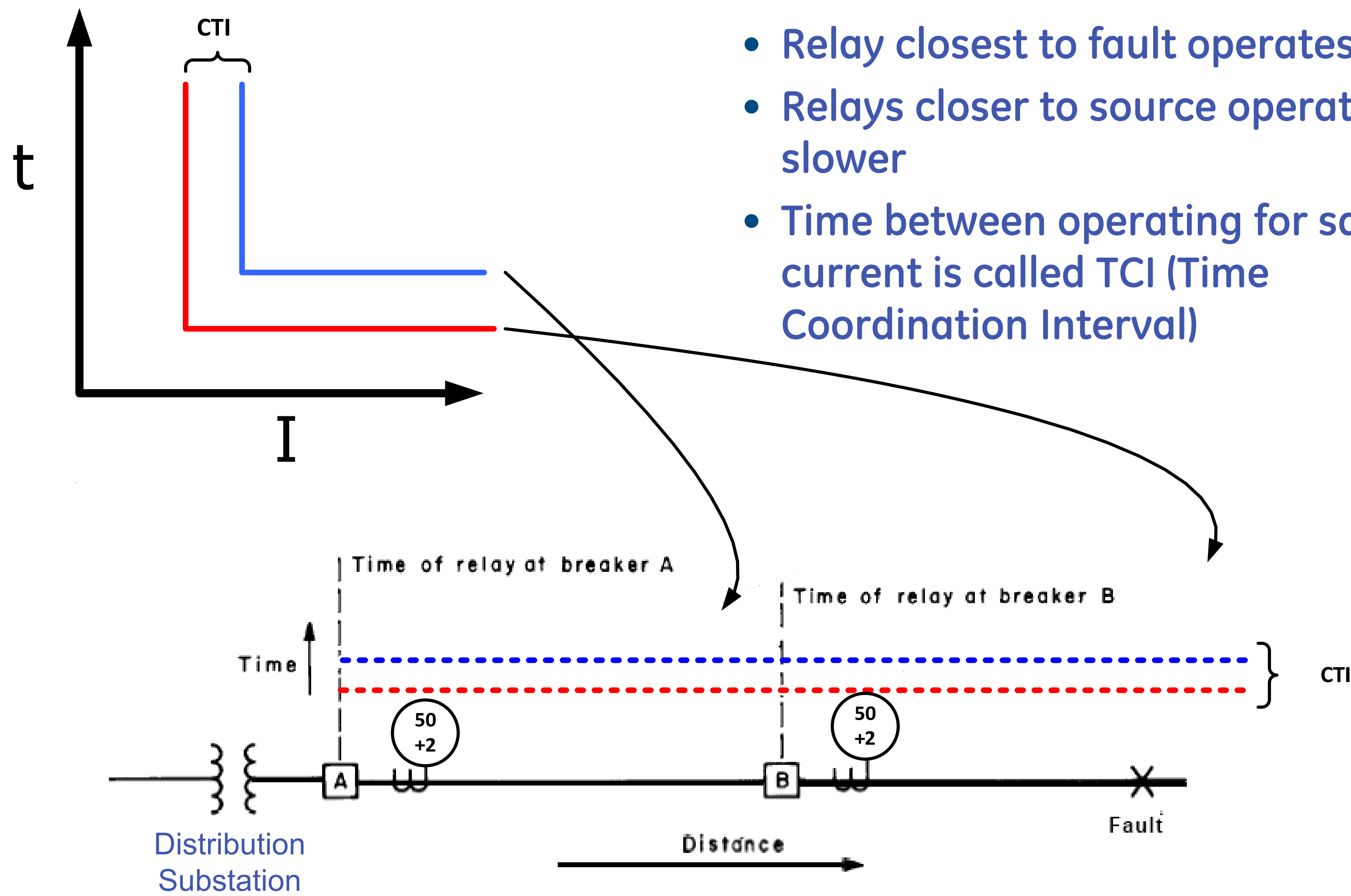
Types of Protection

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

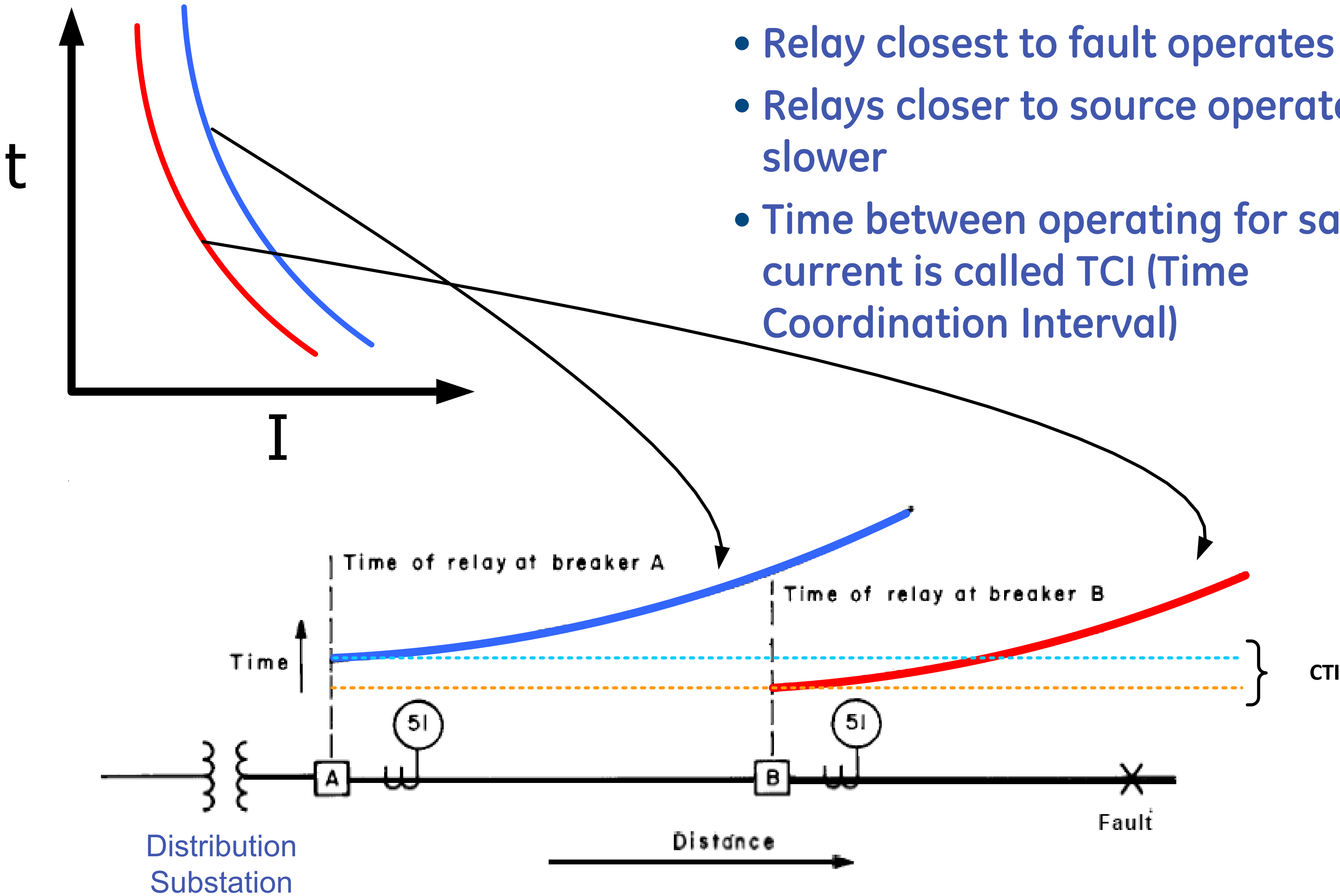
Instantaneous Overcurrent & Definite Time Overcurrent



- 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)

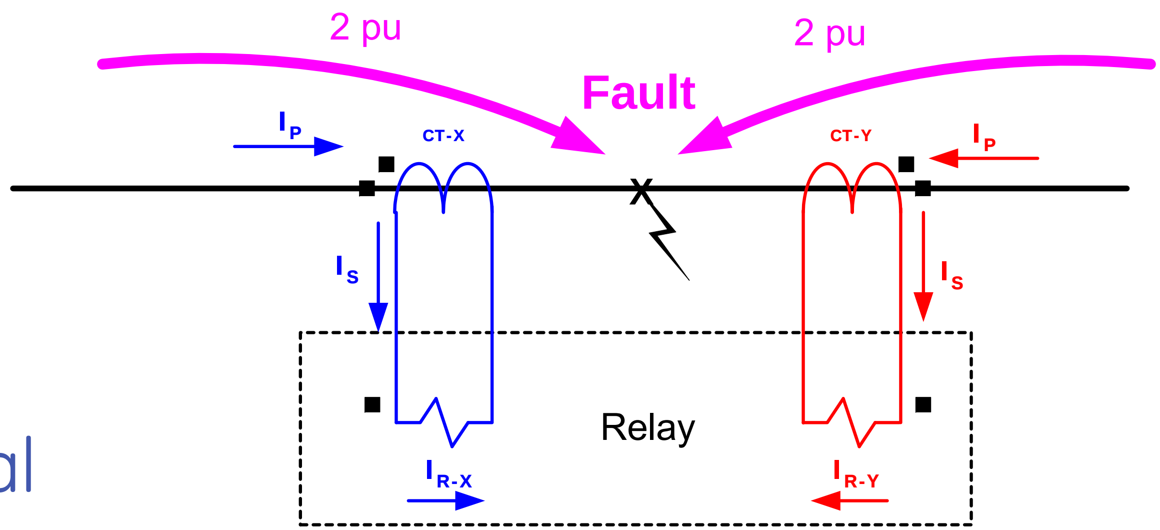
Types of Protection
Differential

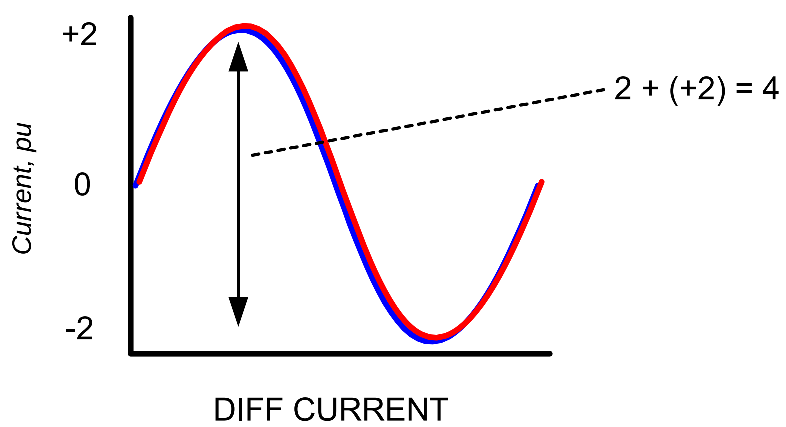
- Electricity in = electricity out
- Simple
- Very fast
- Very defined clearing area
- Expensive
- Practical distance limitations
  - Line differential systems overcome this using digital communications

Types of Protection

Differential

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

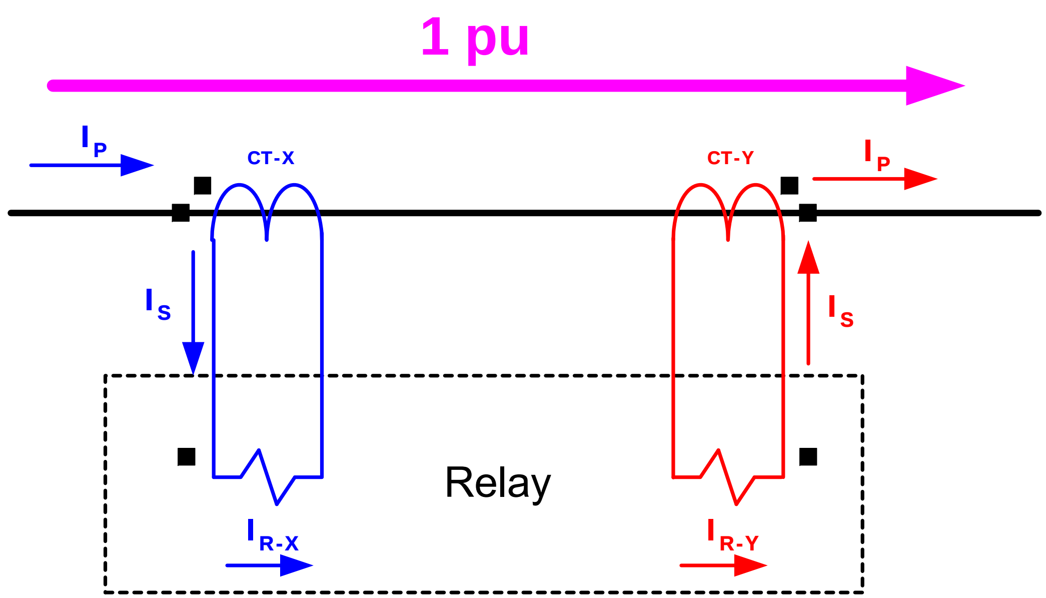


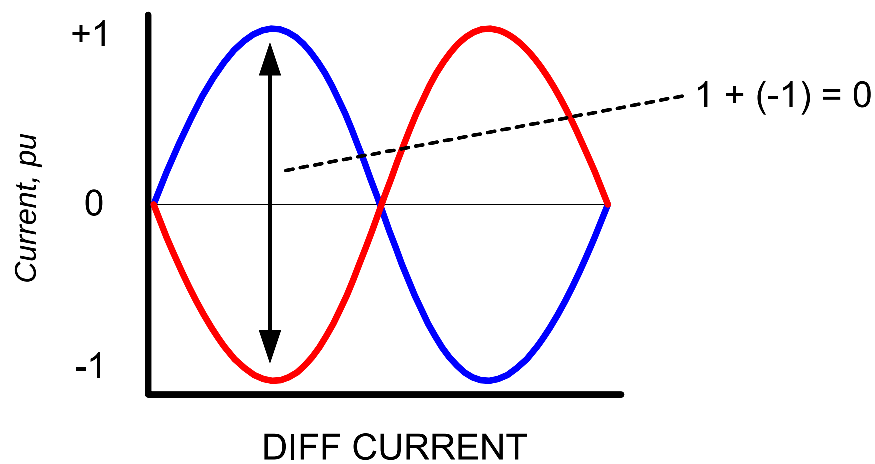


Types of Protection

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

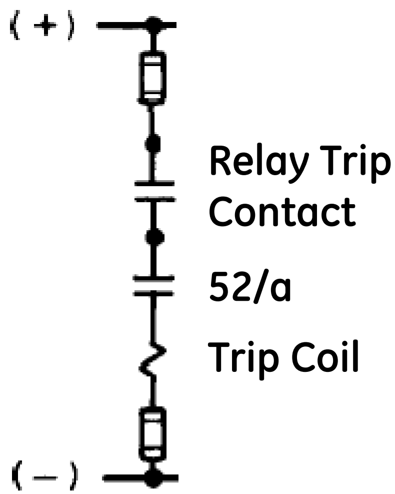
- Uses frequency of voltage to detect power balance condition
- May employ definite time or inverse time curves
- Used for load shedding & machinery under/overspeed protection
  - Simple
  - May be slow
  - Selectivity at the cost of speed can be expensive

Types of Protection
Power

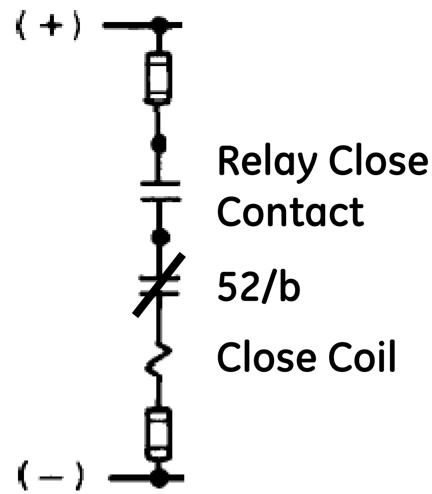
- Uses voltage and current to determine power flow magnitude and direction
- Typically definite time
  - Complex
  - May be slow
  - Accuracy important for many applications
  - Can be expensive

Trip & Close Circuits

Trip Circuit

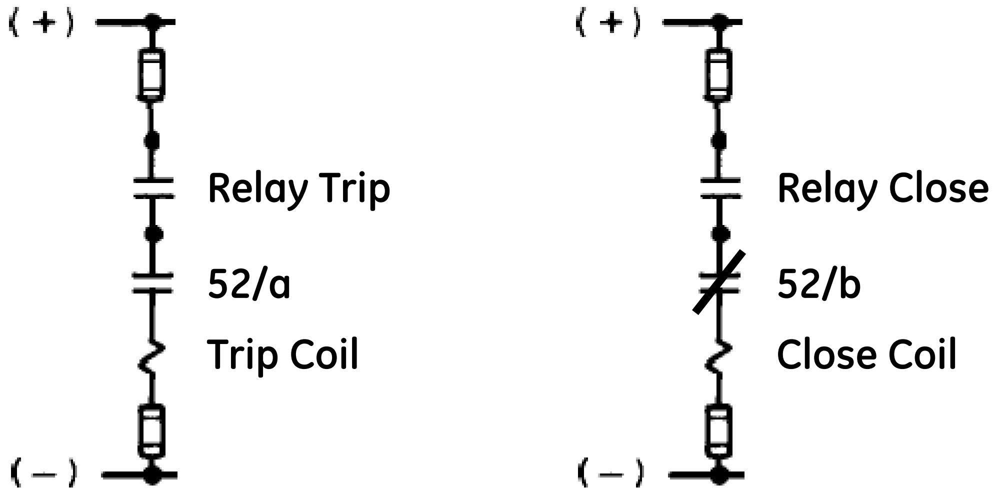


Close Circuit



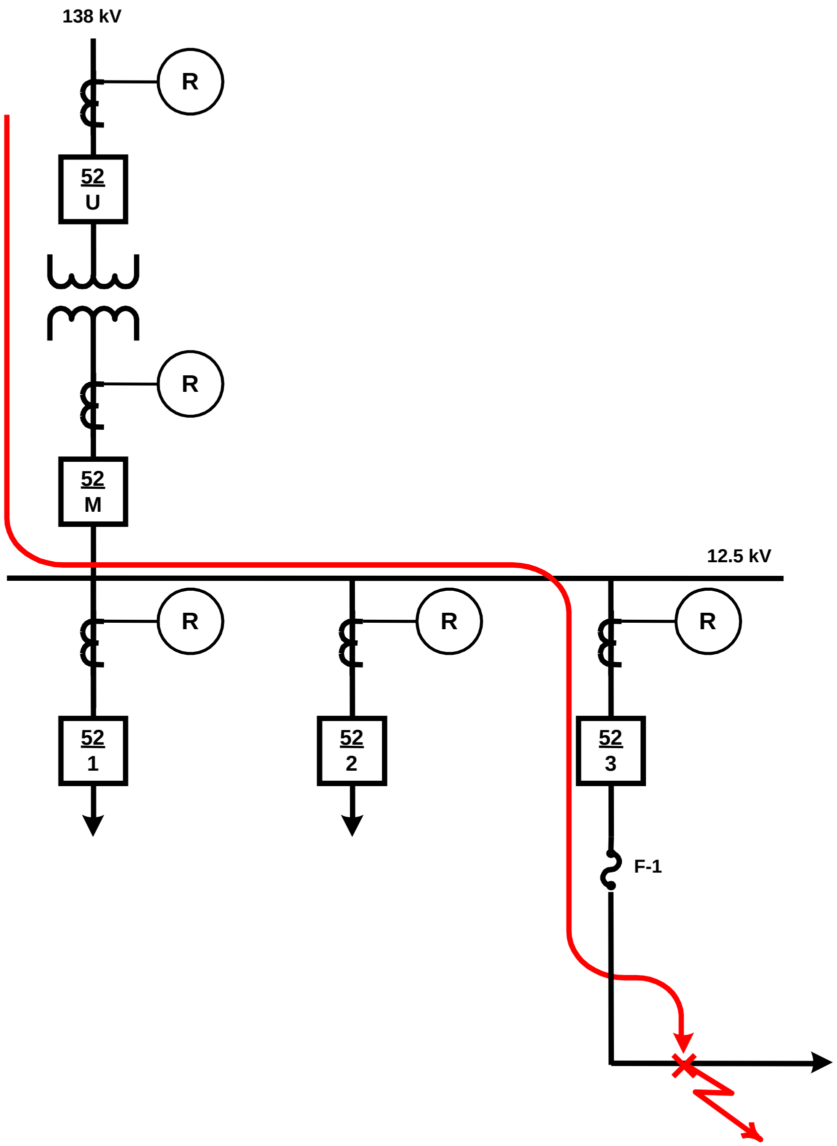
Protective Device Contact Ratings

- 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



Feeder Protection

The Protection Problem



Fault is seen by

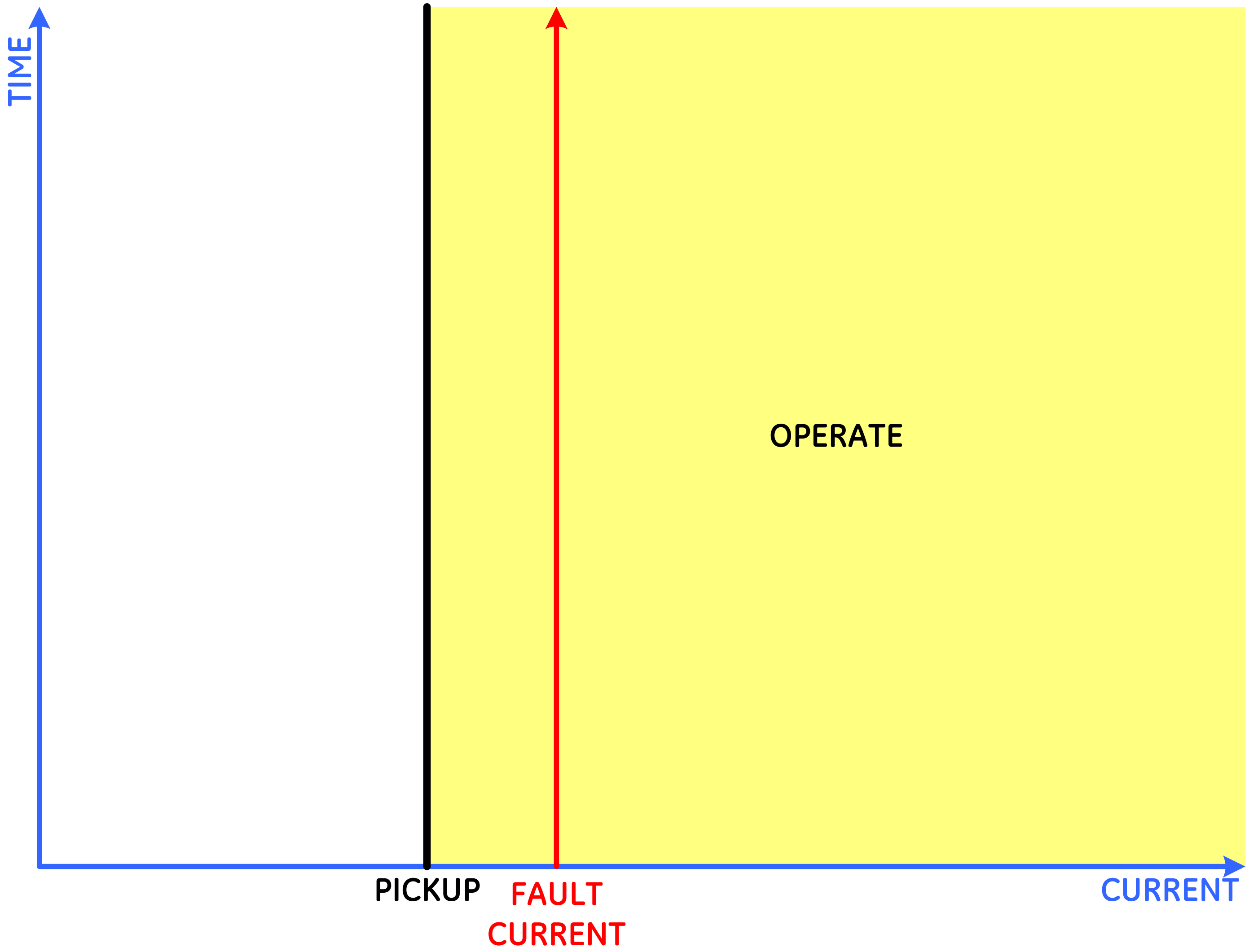
- Fuse F-1
- Feeder 3 relay
- Main Feeder relay
- Utility Provider relay

Overcurrent Protection

Types of Overcurrent Devices

- Instantaneous relays
- Inverse time relays
- Fuses

Instantaneous Overcurrent Protection

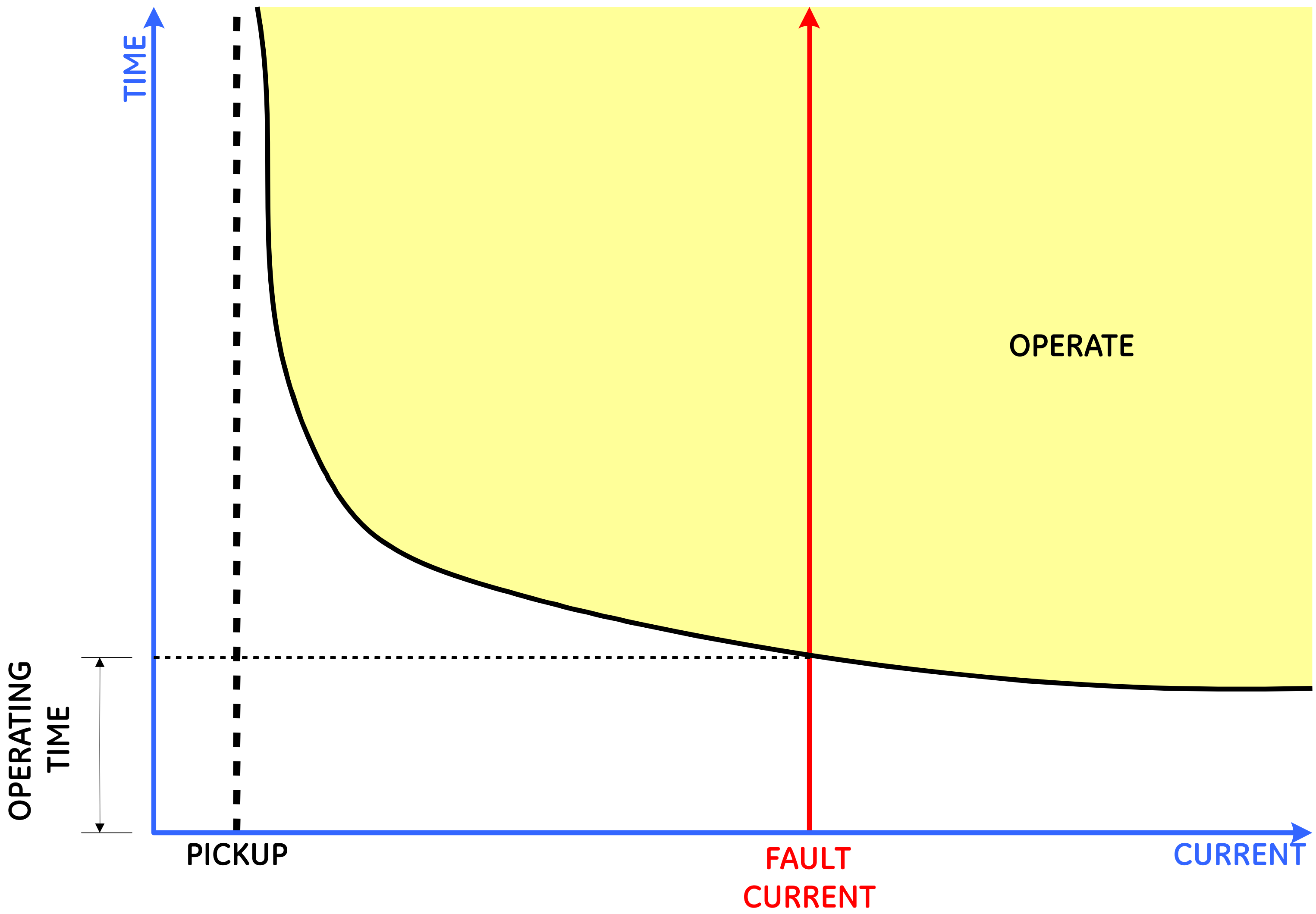


Multiples of pick-up

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

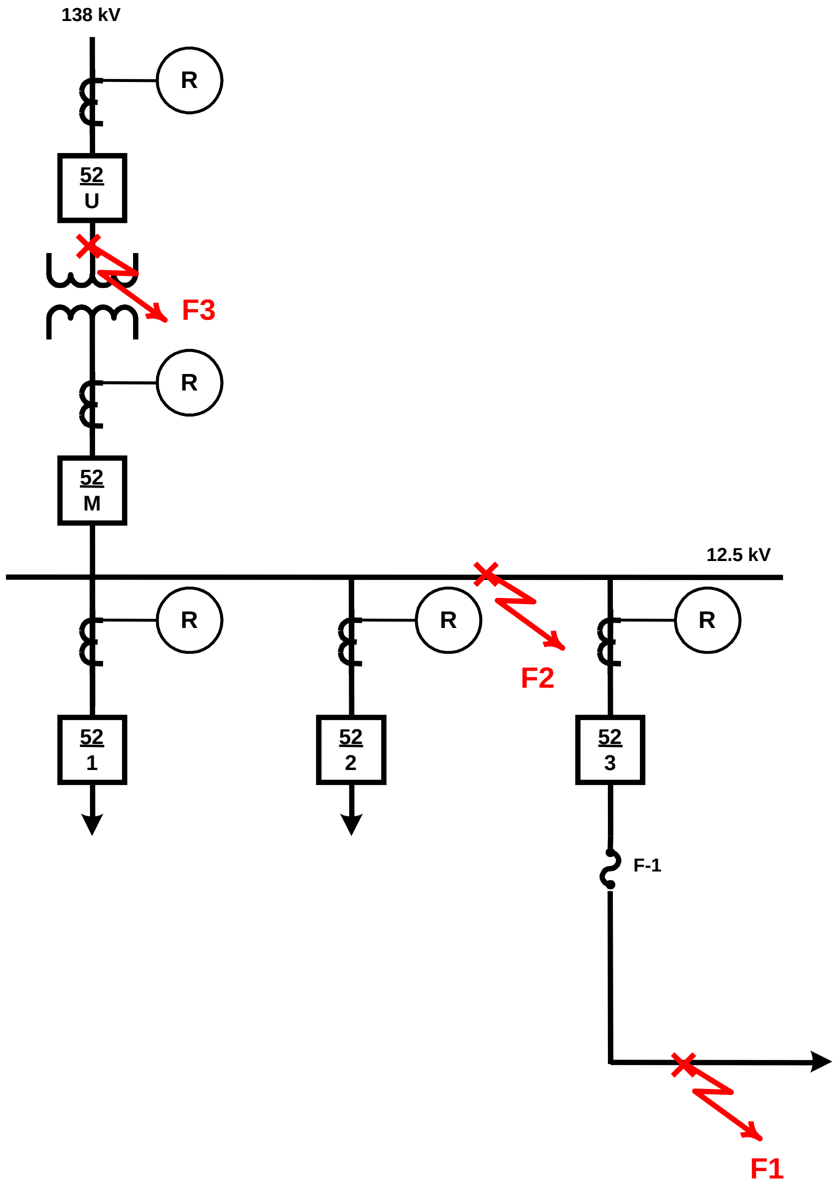


Multiples of pick-up

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



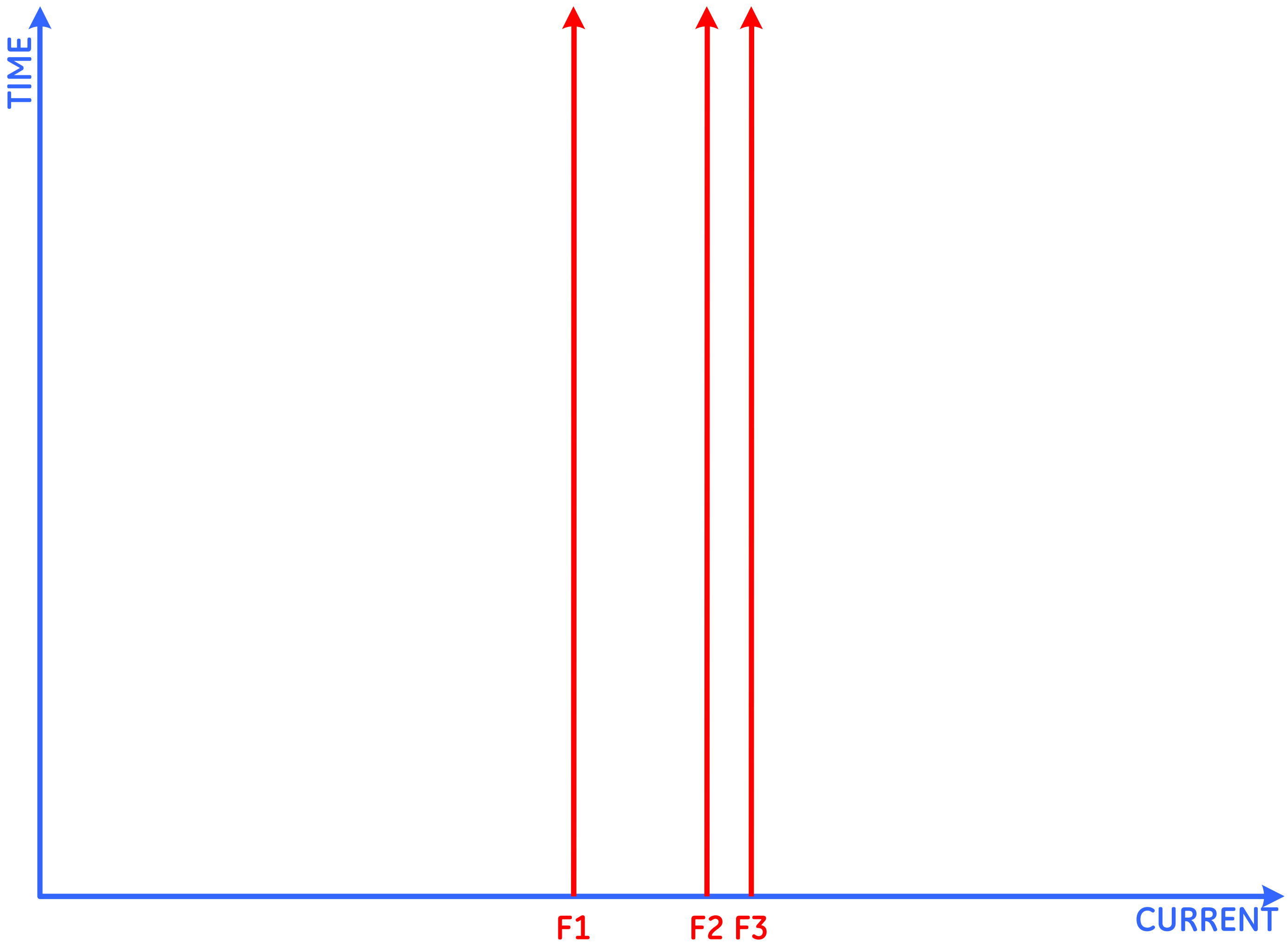
Fault magnitude

- F3 > F2 > F1

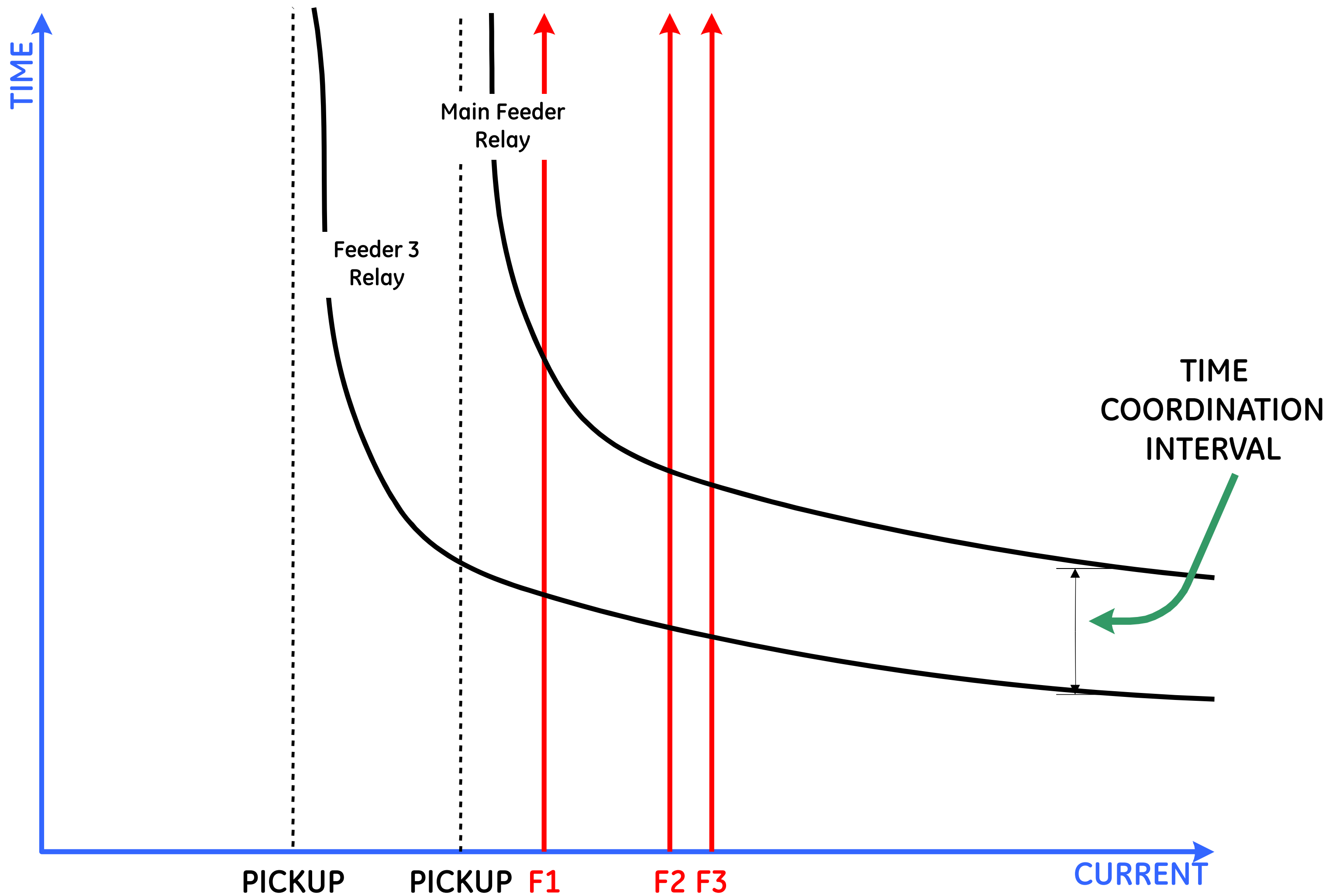
Why?

- Impedance
- I = V/Z

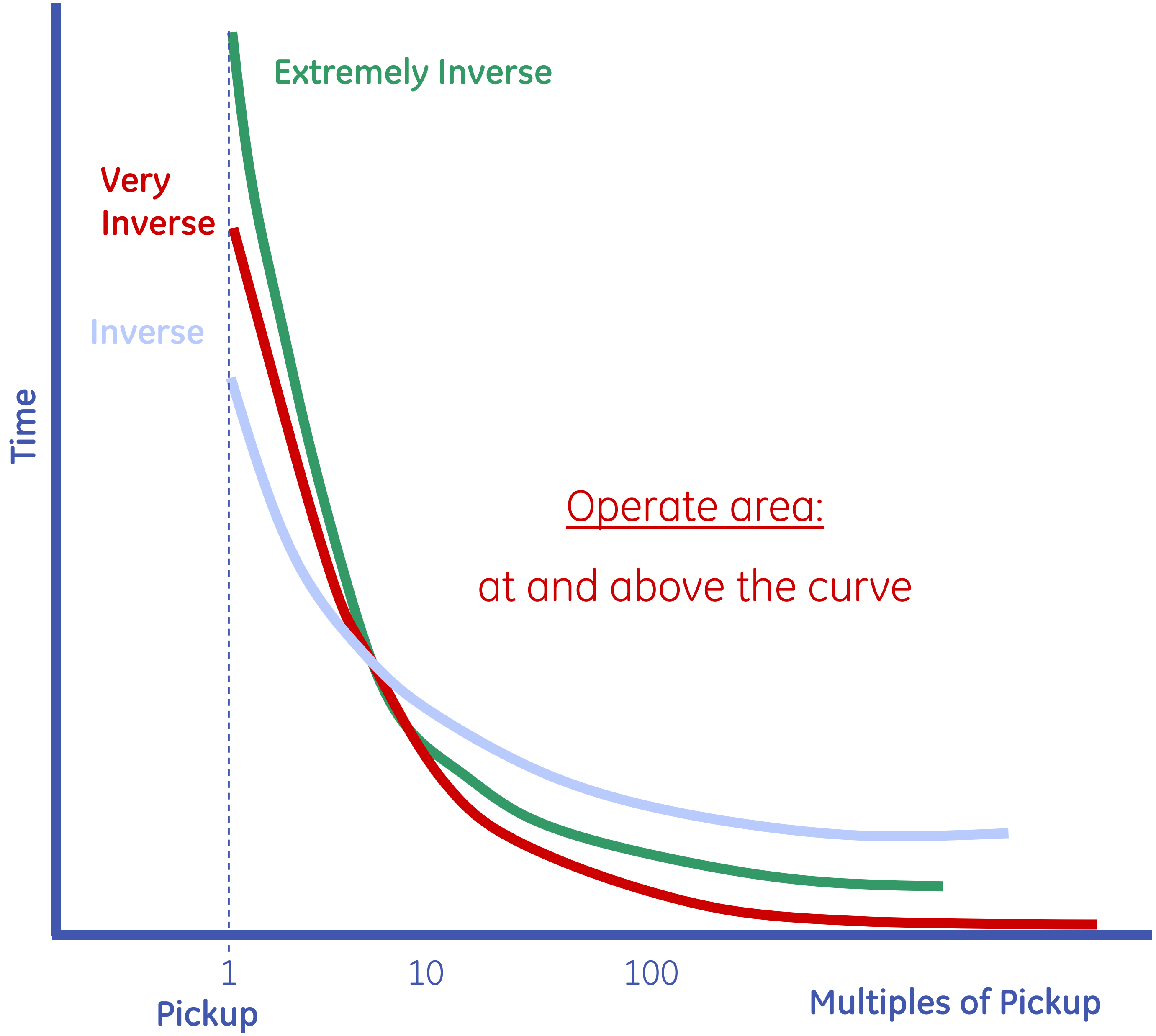
Fault Currents



Time Coordination Interval (TCI)

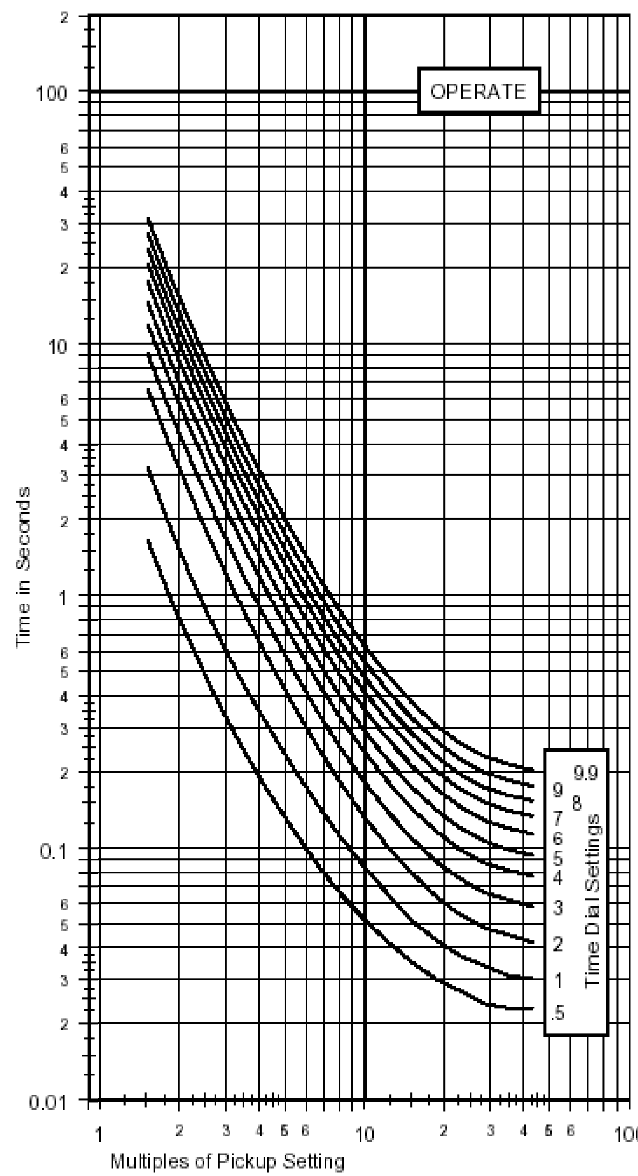


Time Overcurrent Protection



Time Overcurrent Protection

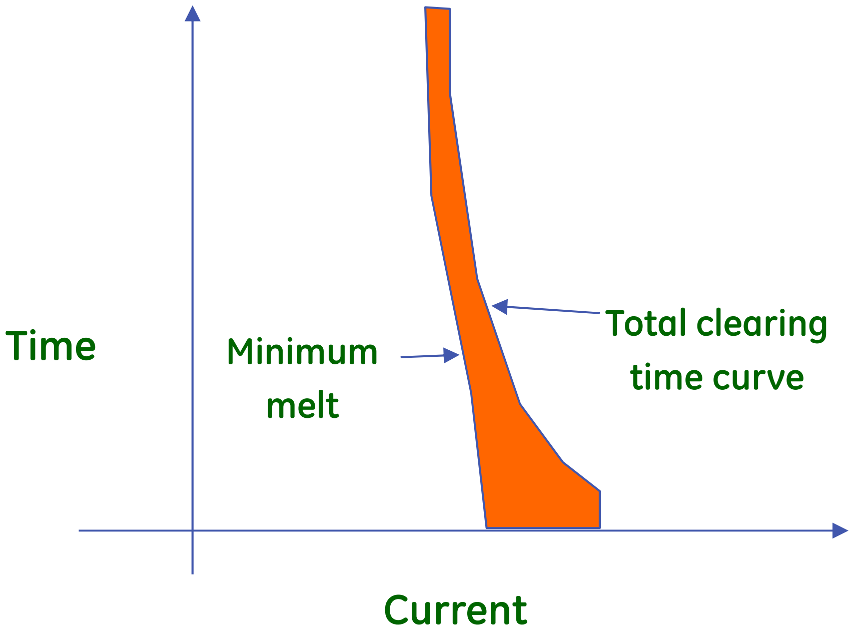
- During the selection of the curve, the protection engineer will use what is termed as a “ **time multiplier**” or “**time dial**” to effectively shift the curve up or down on the time axis
- Operate region lies above selected curve, while no-operate region lies below it
- **Pickup** used to move curve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



Fusing and Coordination

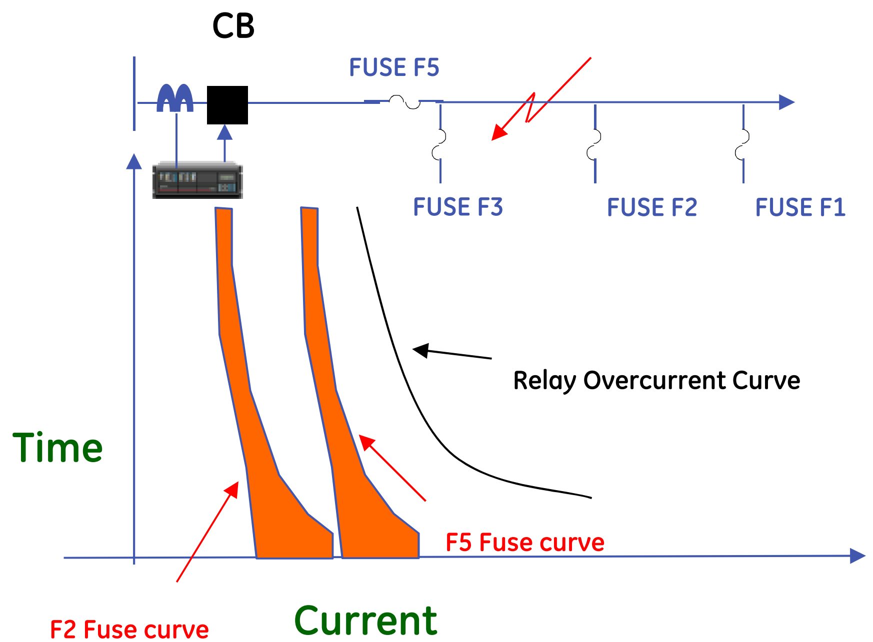
<u>Fuse time verses current characteristic</u>

- 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.



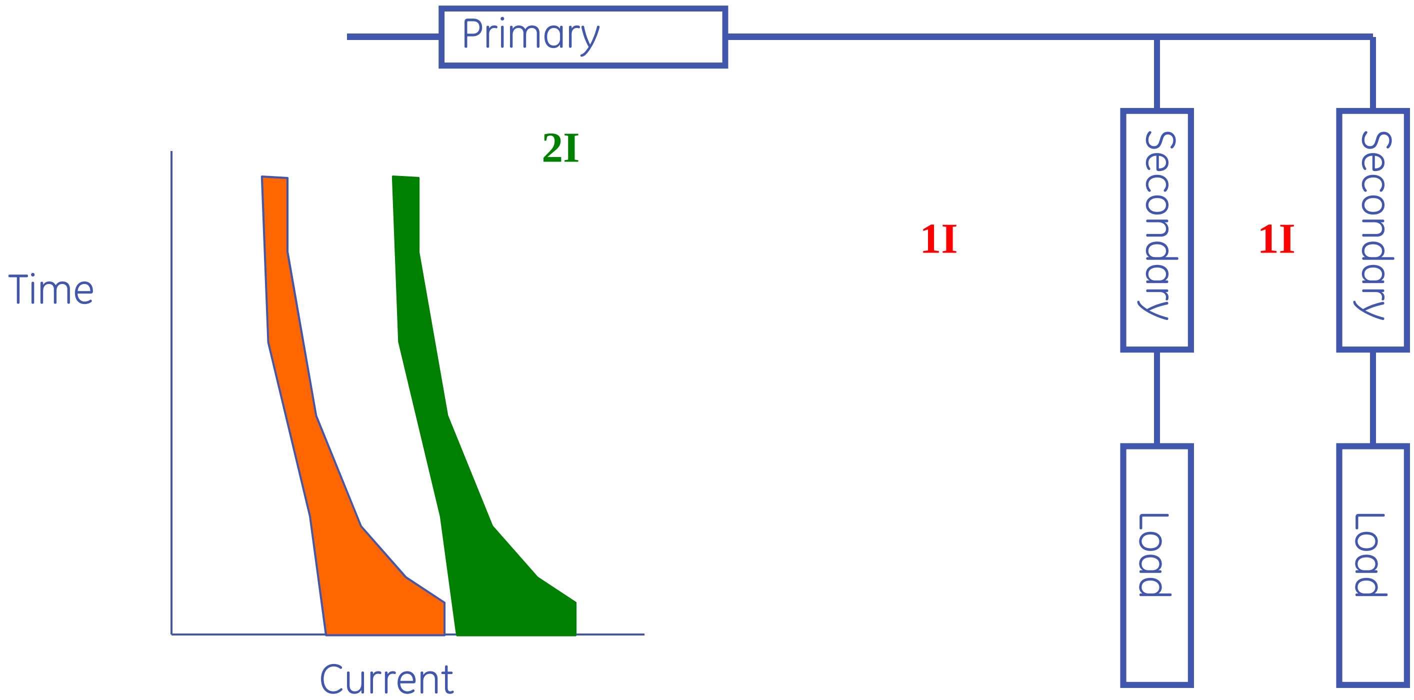
Protective Element Coordination

- 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 down stream 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



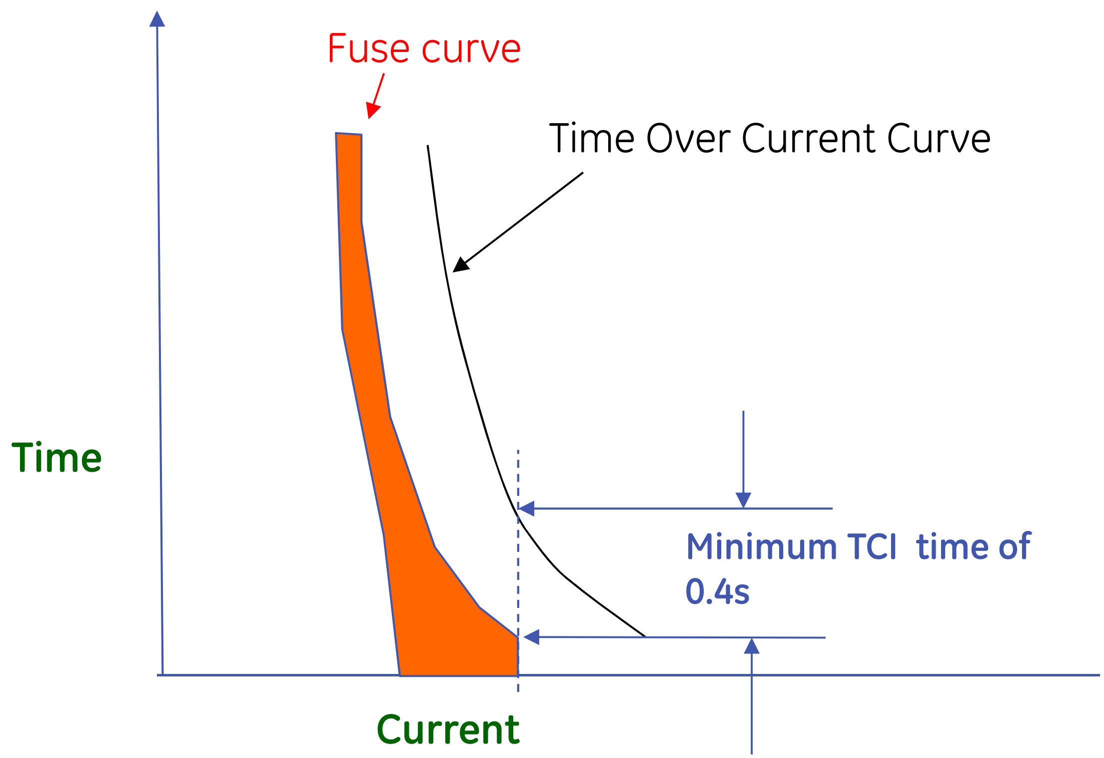
Coordination – Between Fuses

- 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.



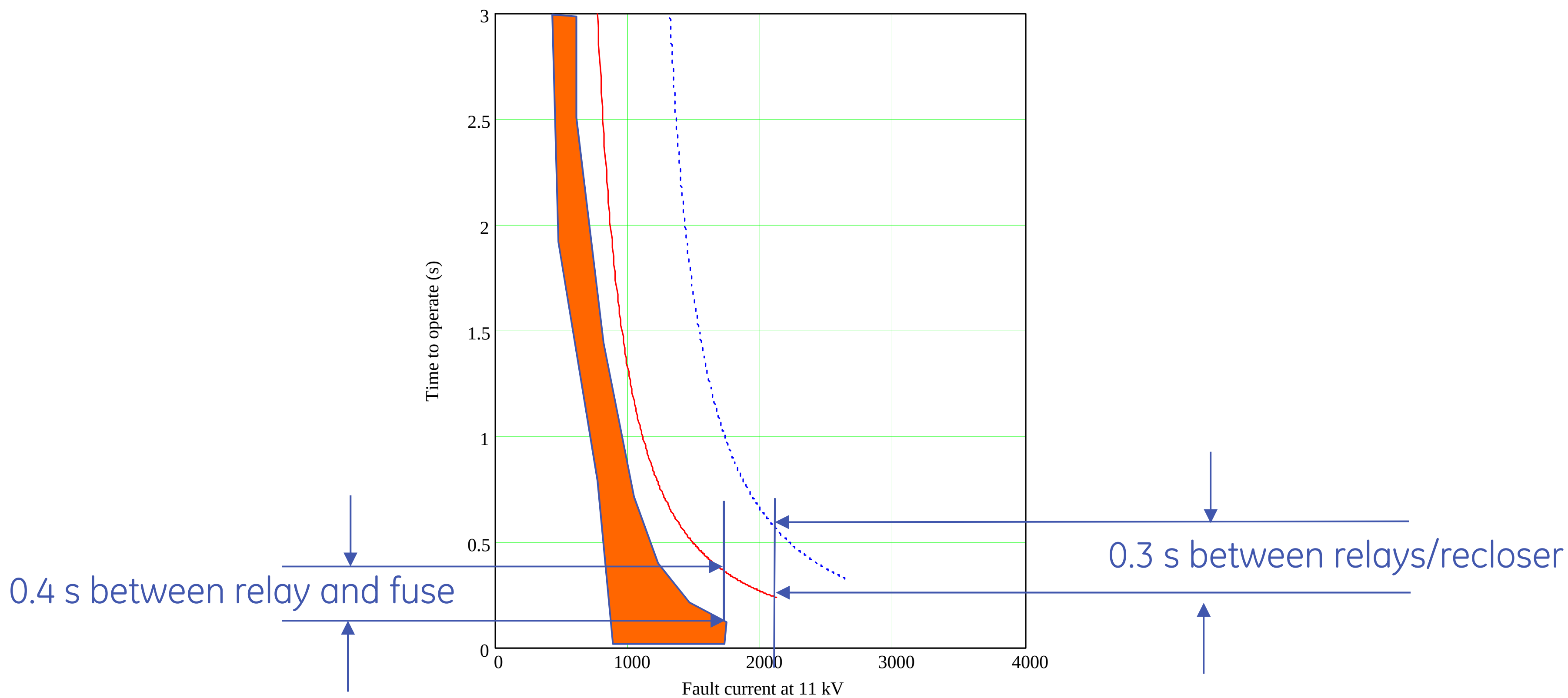
Coordination – Between Fuses & Relays

- 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.

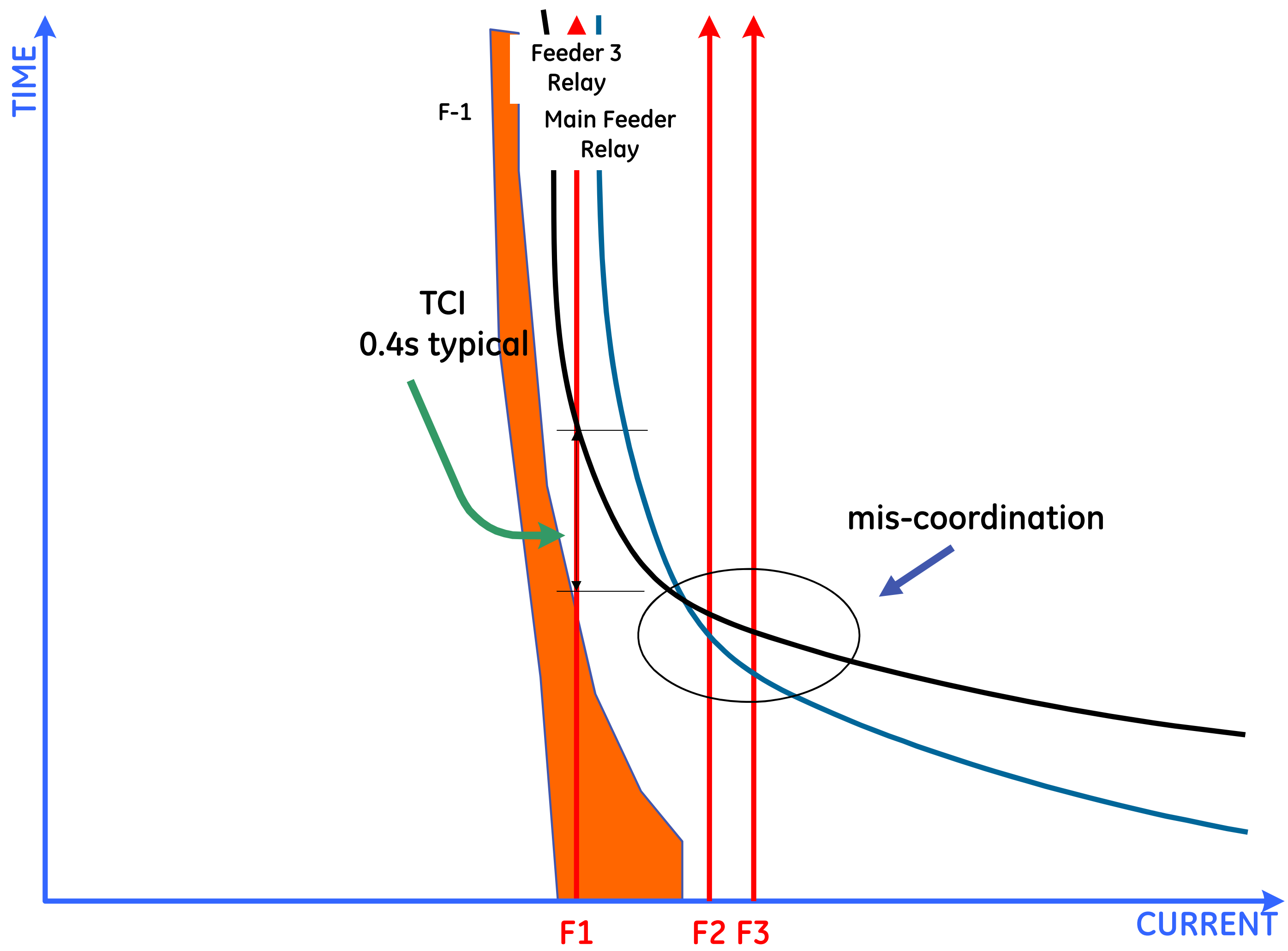


Coordination – Between Fuses & Relays

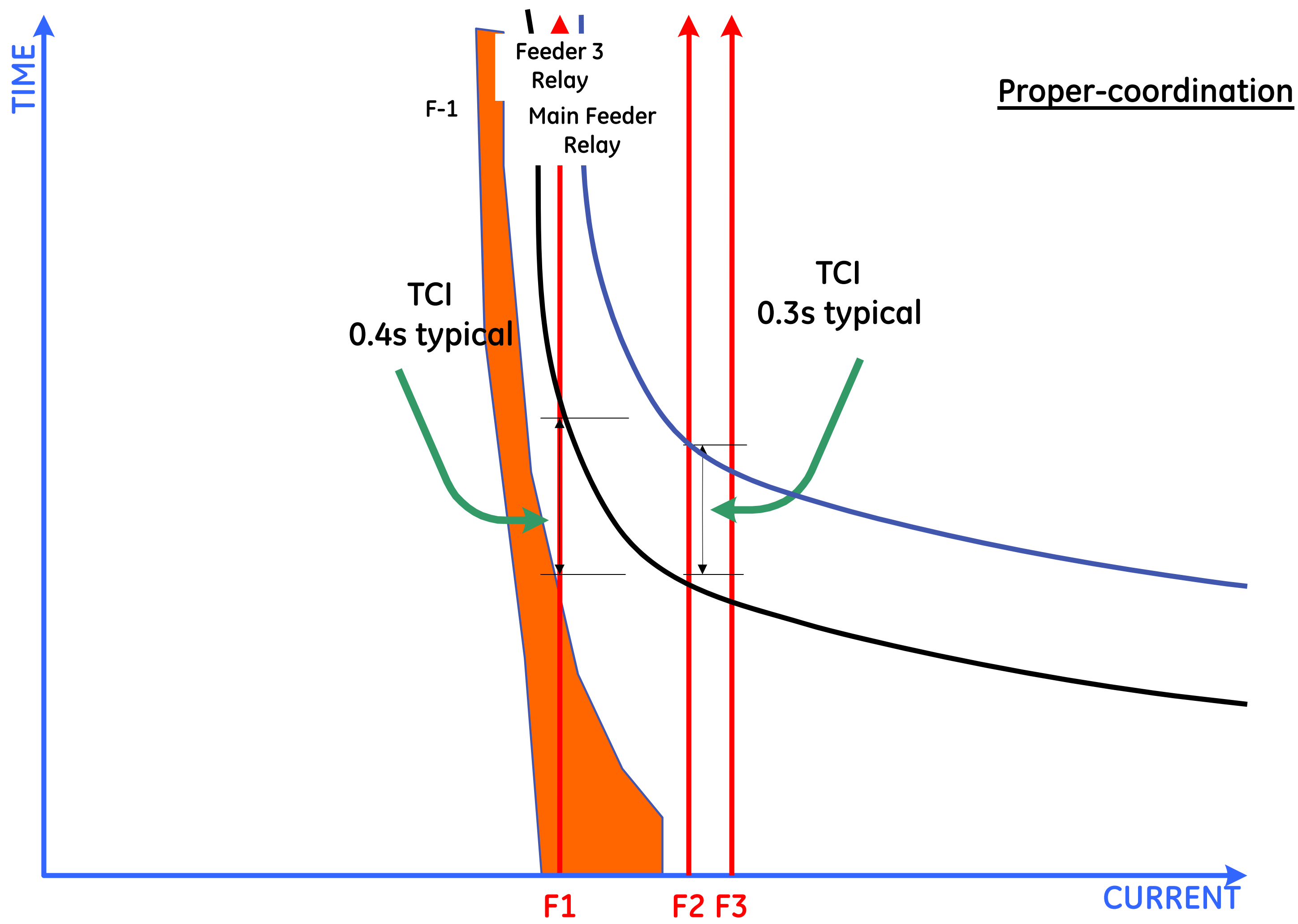
- The following is recommended TCI to ensure proper coordination



Device Coordination



Device Coordination



Device Coordination

Typical Discrimination Times based on Technology (Standard Normal Inverse Curves):			
	Relay Technology		
Error Source	Electro-Mechanical	Static	Digital / Numeric
Typical basic Timing Error [%]	7.5 %	5 %	3.5 %
Overshoot Time [s]	0.05 s	0.03 s	0.02 s
Safety Margin [s]	0.1 s	0.05 s	0.03 s
Total typical Coordination Time [s]	0.4s	0.35s	0.3s

Note: CT measurement error will add to the above times

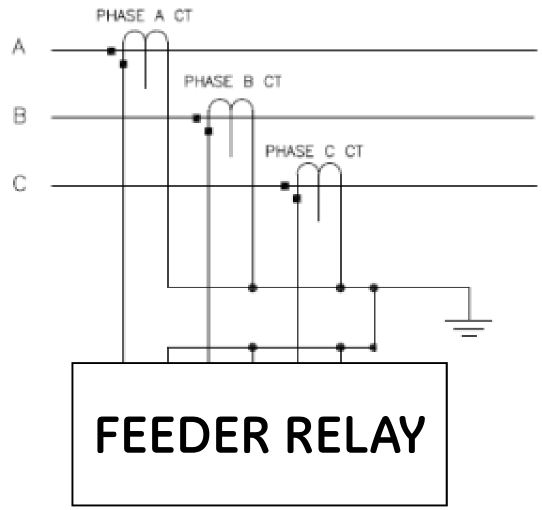
Time Overcurrent Protection

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

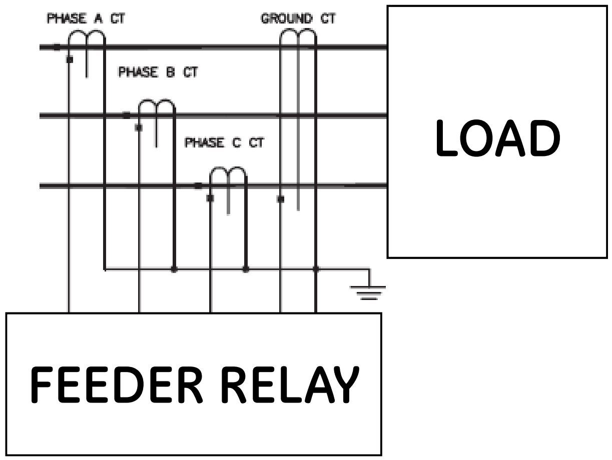


Residual Ground Fault Connection

- Less sensitive
- Drawbacks due 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.

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.

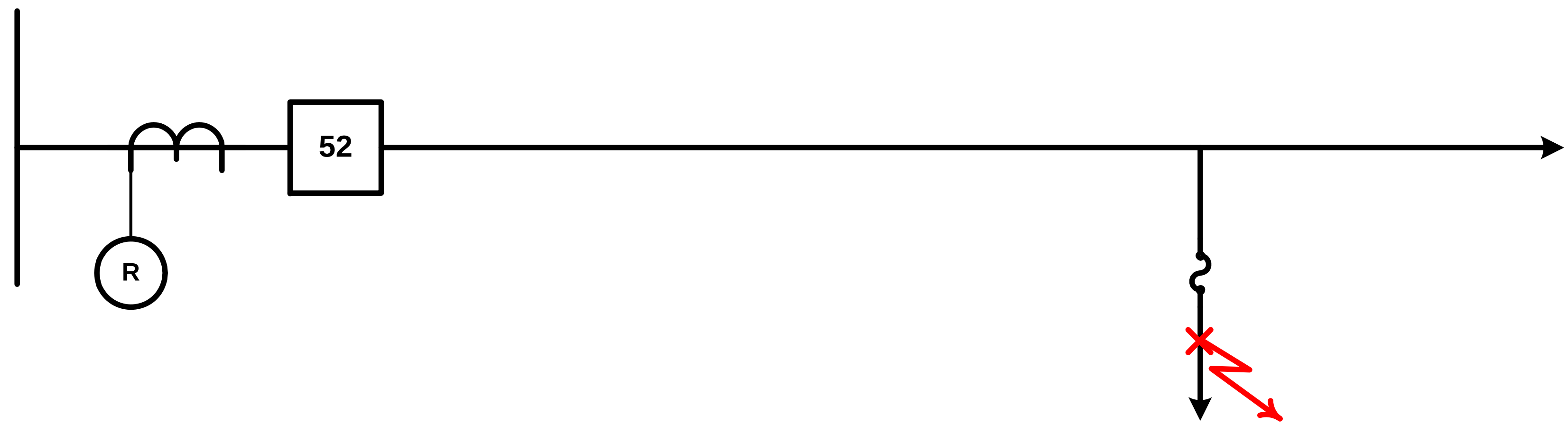
High Impedance Fault Protection

- 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



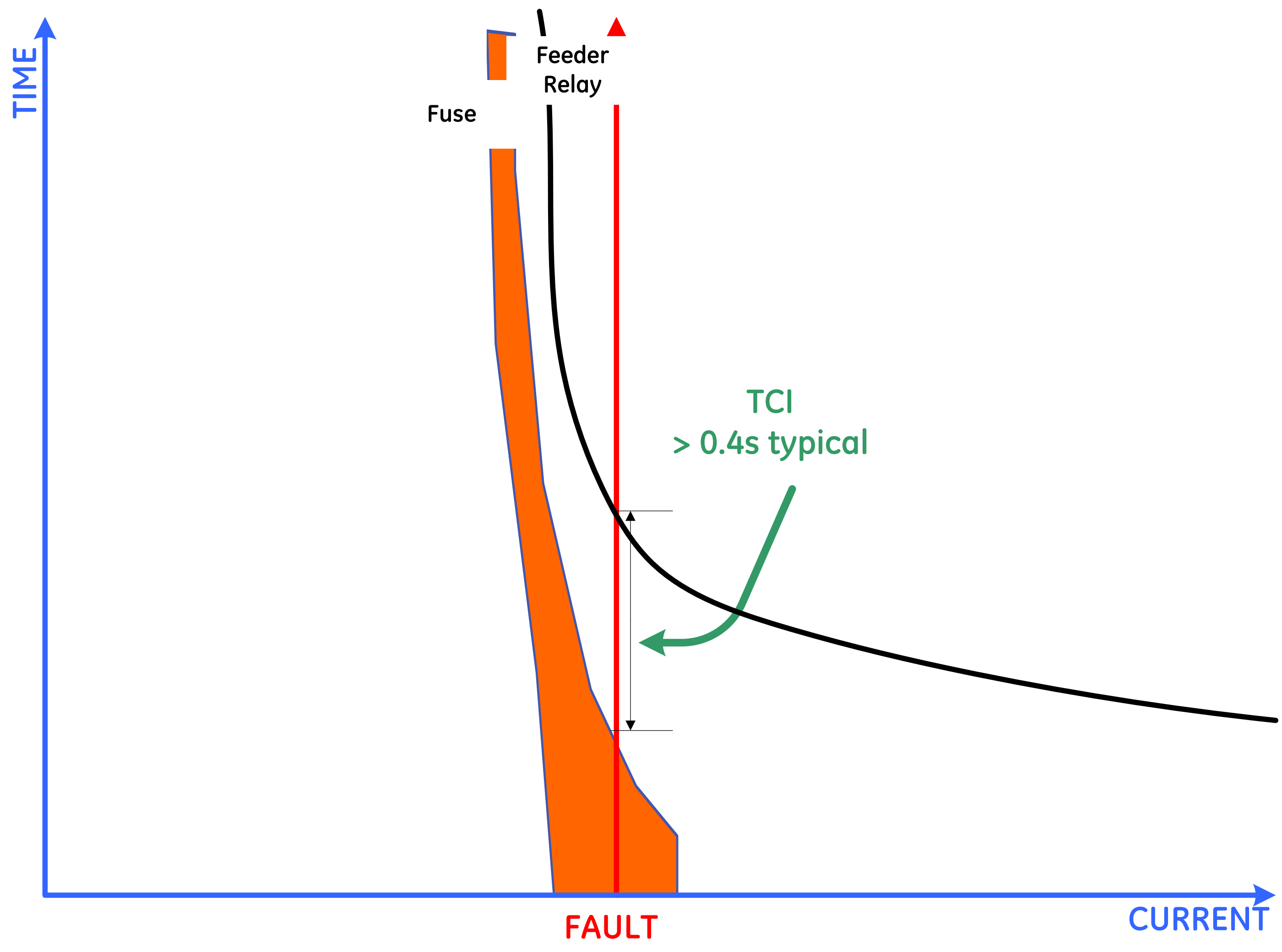
Two methods:

- Fuse Blowing
  - Fuse blows for any fault, including temporary fault
- Fuse Saving
  - Use automatic reclosing to try and save fuses for temporary faults

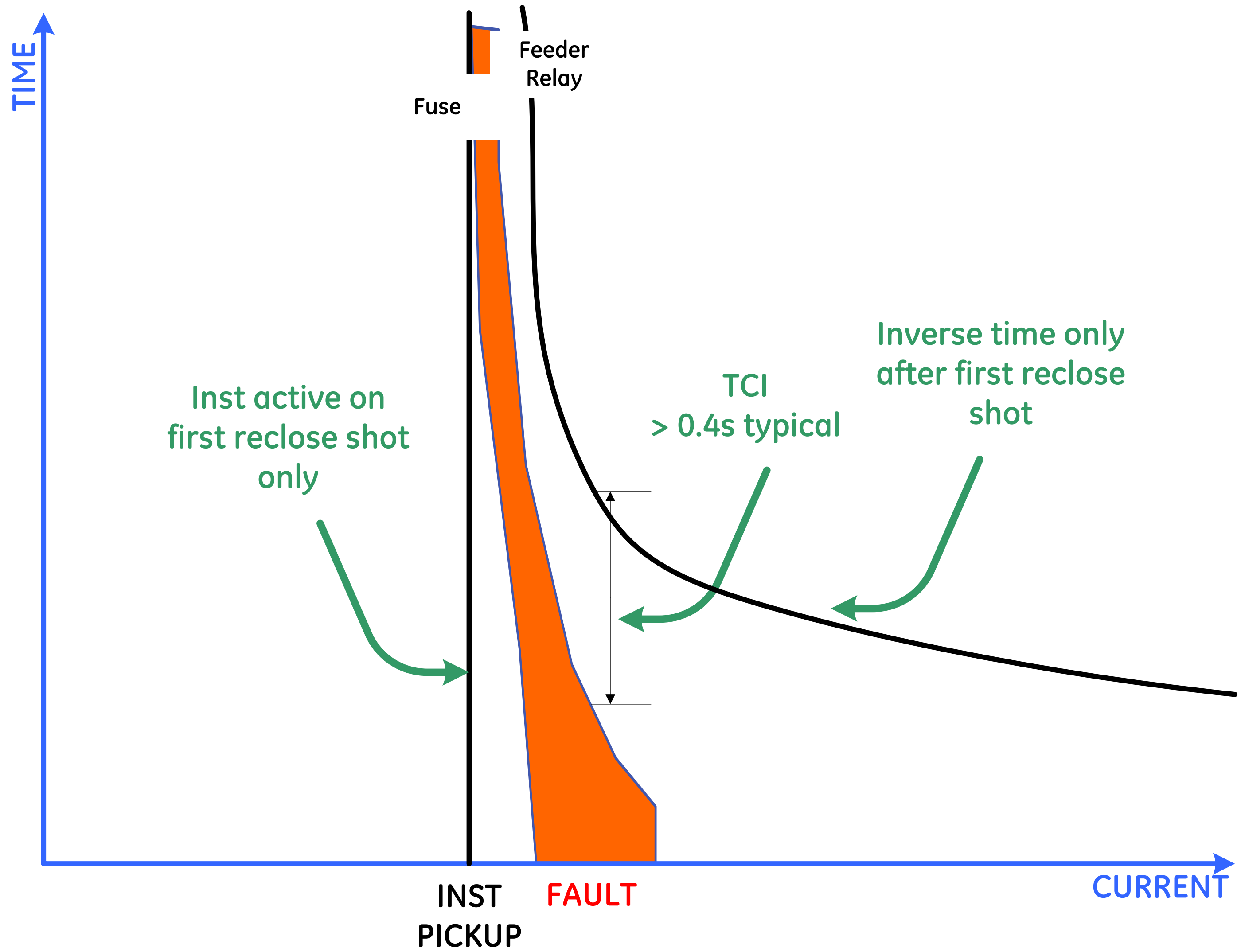
Automatic Reclosing
Coordinate with Branch Fuses

- 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

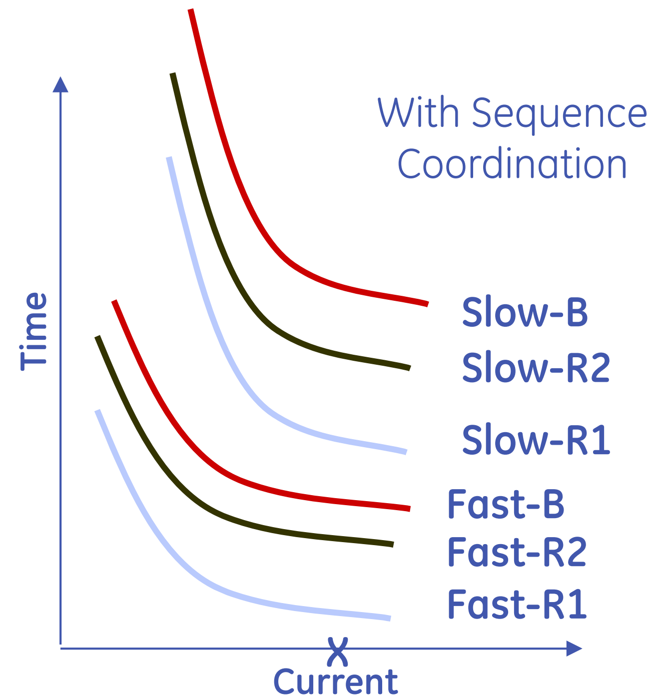


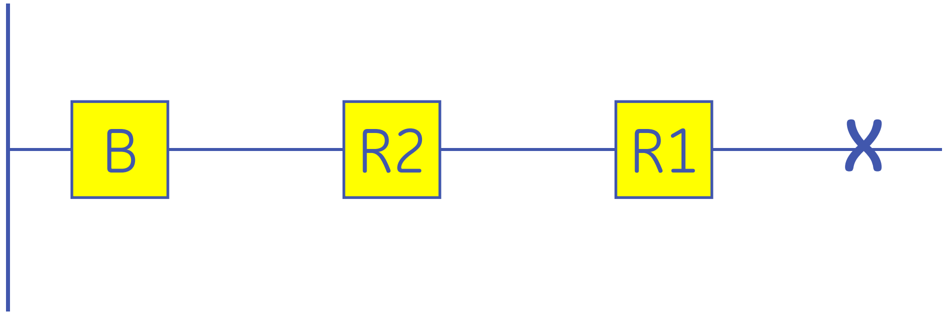
Fuse Saving for Temporary Faults



Sequence Coordination

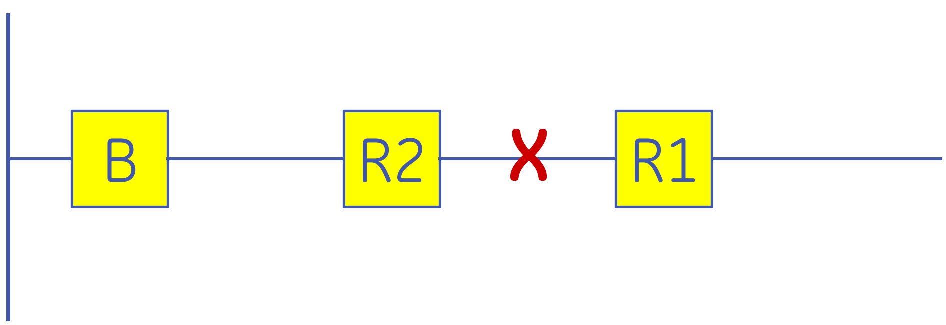
- Substation breakers & upstream reclosers should be coordinated to operate if downstream reclosers or fuses do not successfully interrupt the fault.
- Sequence coordination eliminates nuisance tripping through trip coordination. This allows coordination between substation breaker and downstream reclosers 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)

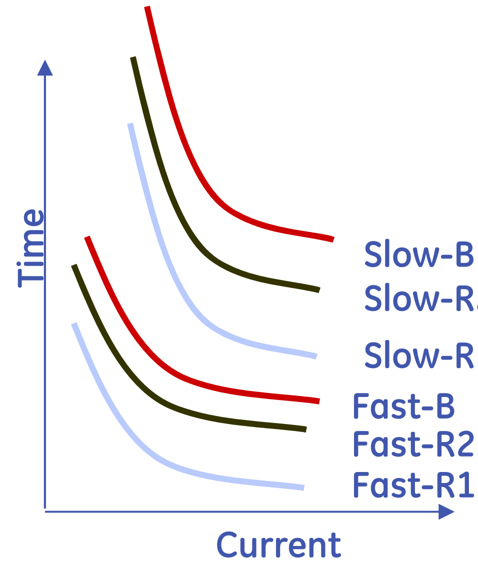


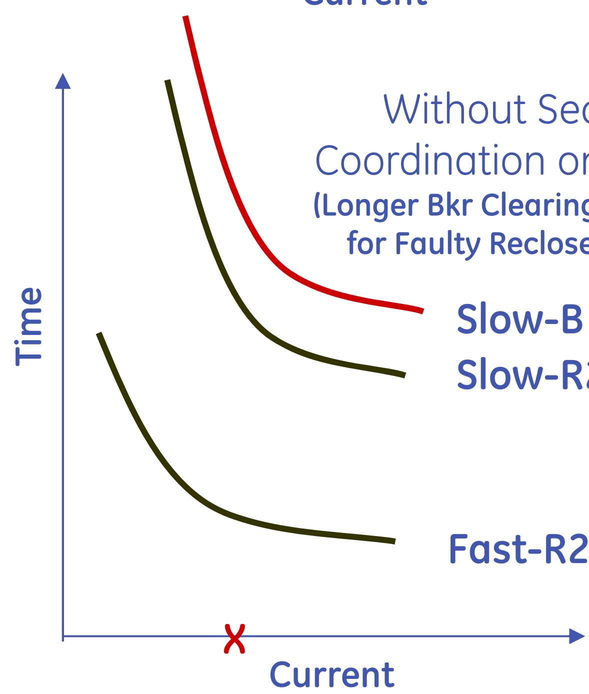


Breaker/Recloser Trip Curve Selections

- 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.



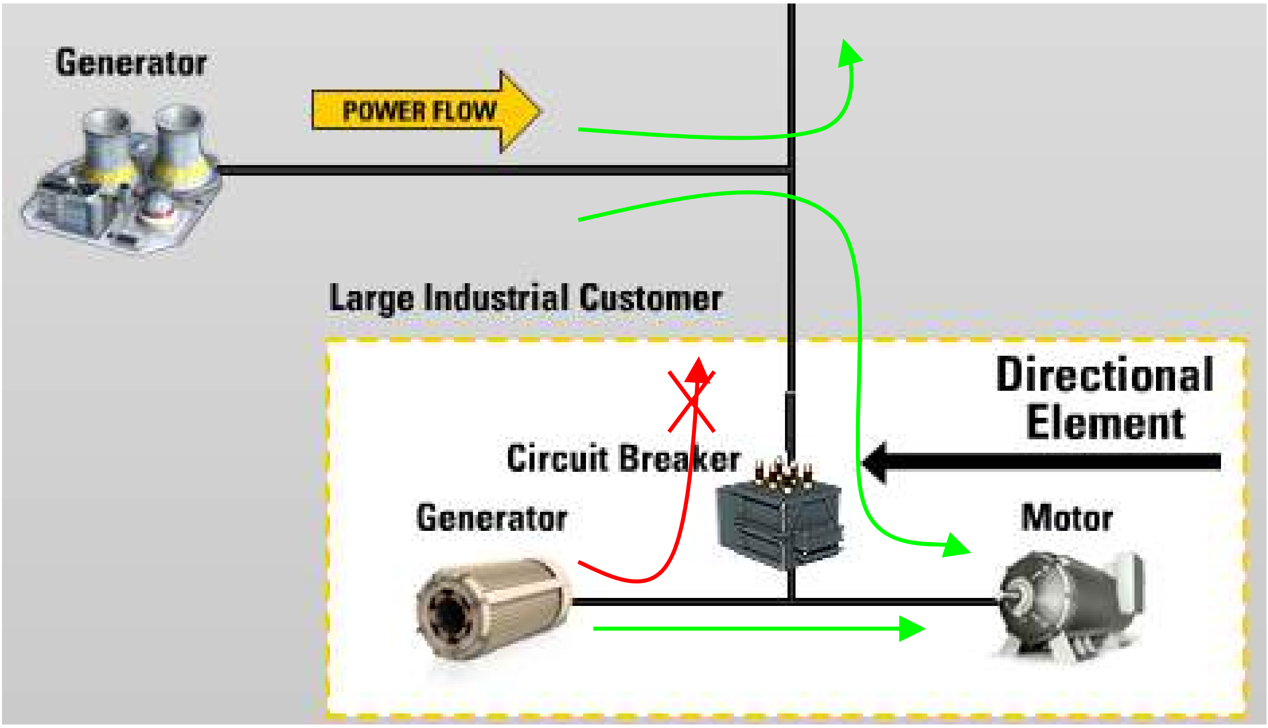




Directional Protection

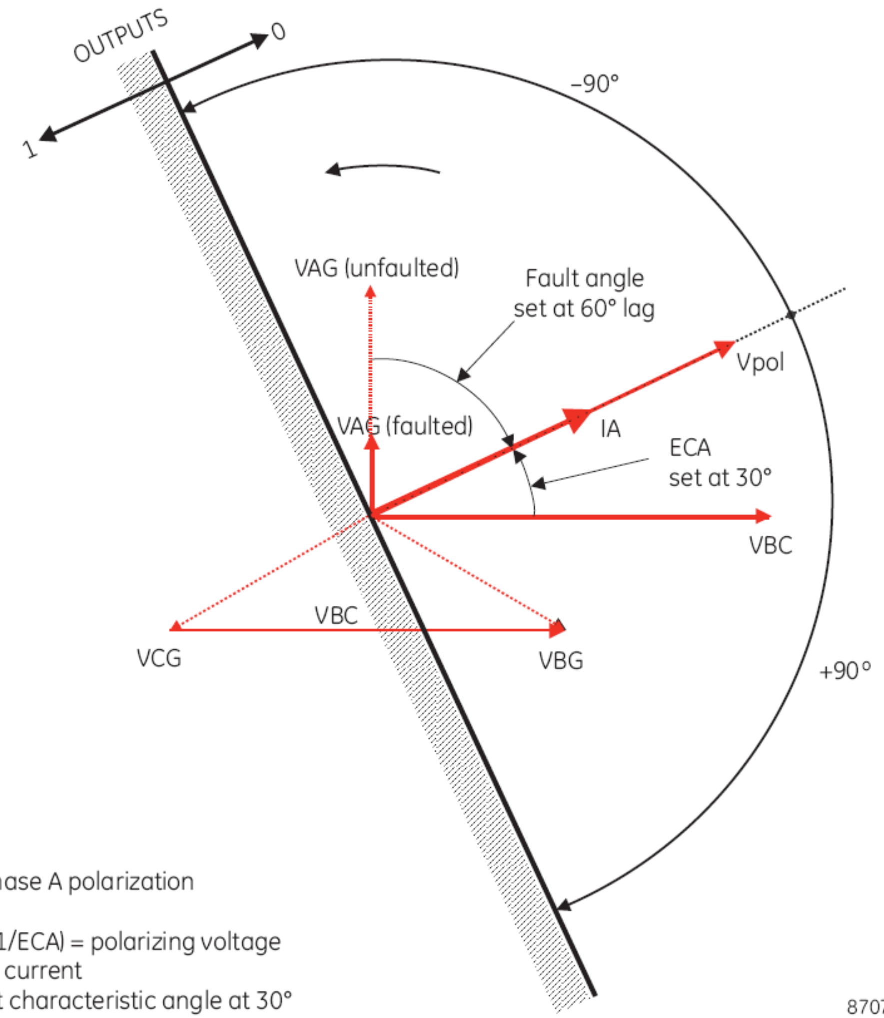
- Directional element **67** determines the direction of power flow to disable or enable the overcurrent element
- Uses the phase relationship of voltage and current to determine direction to a fault

<u>Example:</u>
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



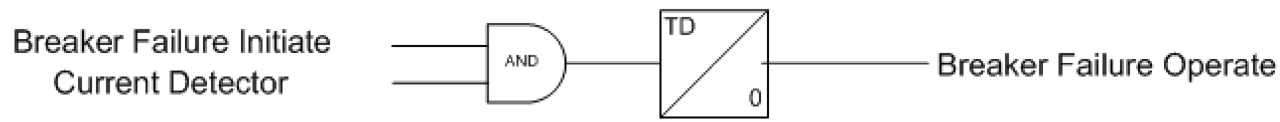
Phasors for phase A polarization

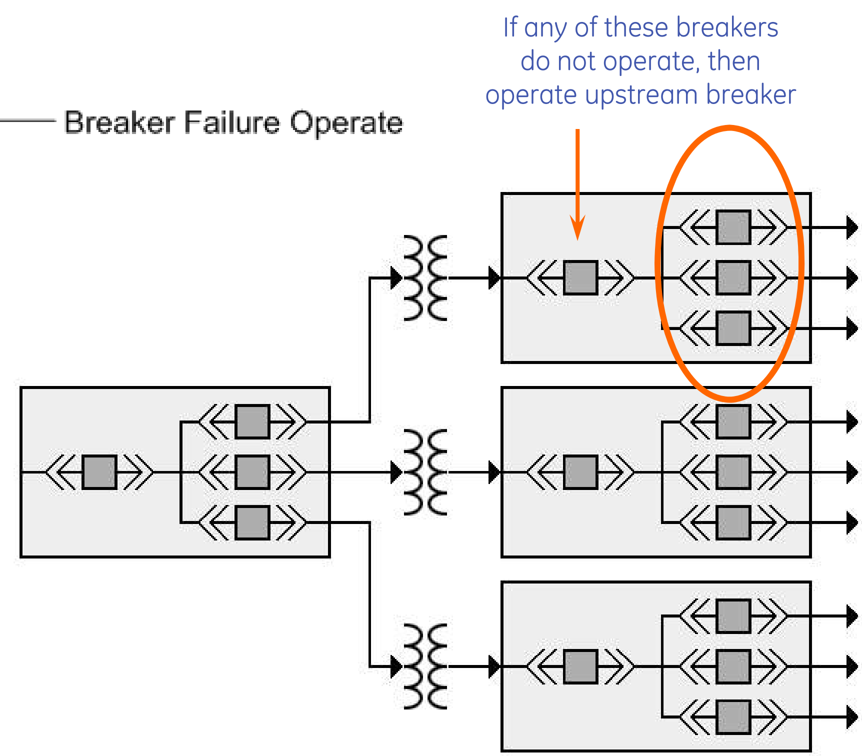
Vpol = VBC × (1/ECA) = polarizing voltage
IA = operating current
ECA = element characteristic angle at 30°

870773A1.CDR

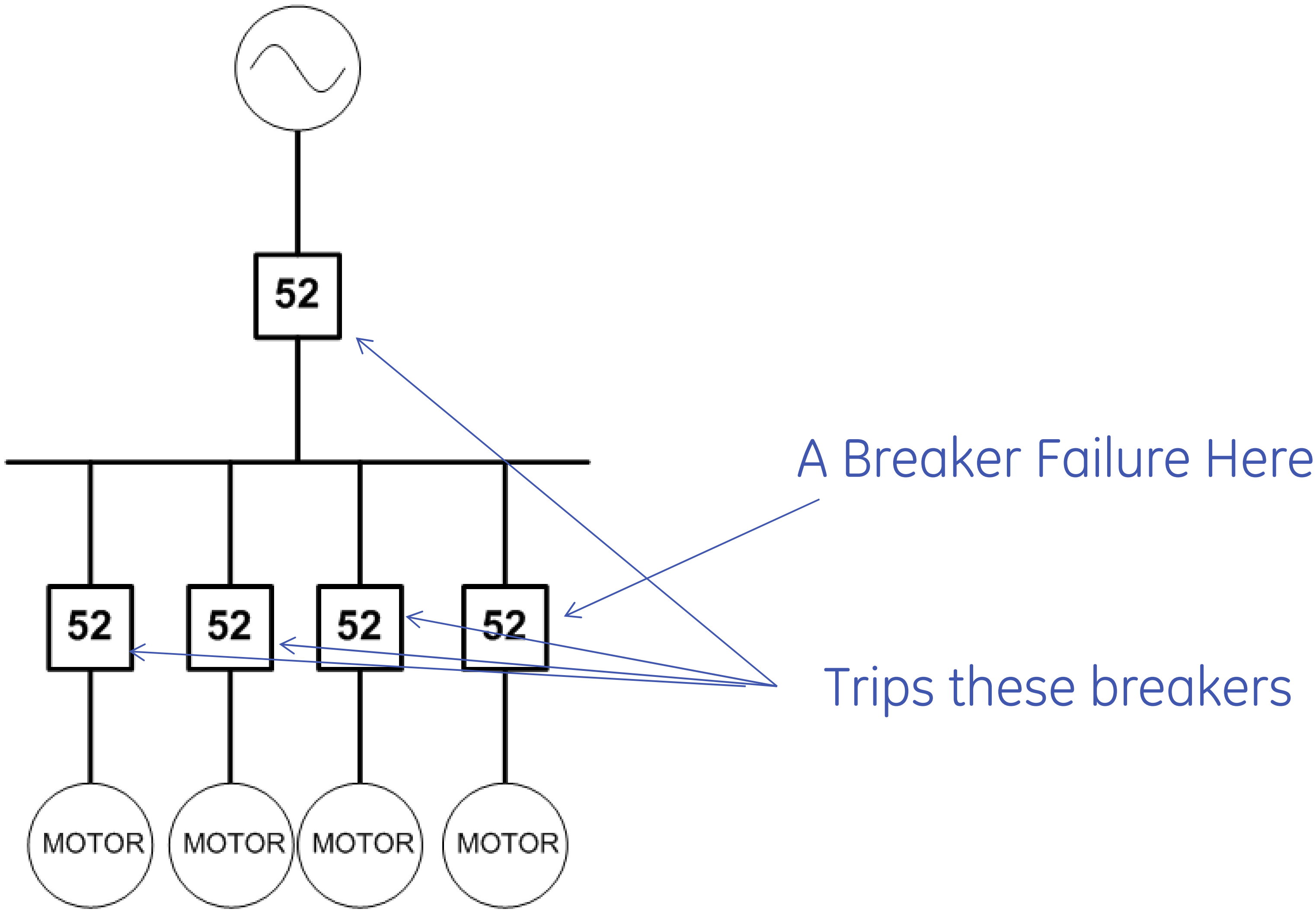
Breaker Failure Protection

- 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)





Breaker Failure Operate Example

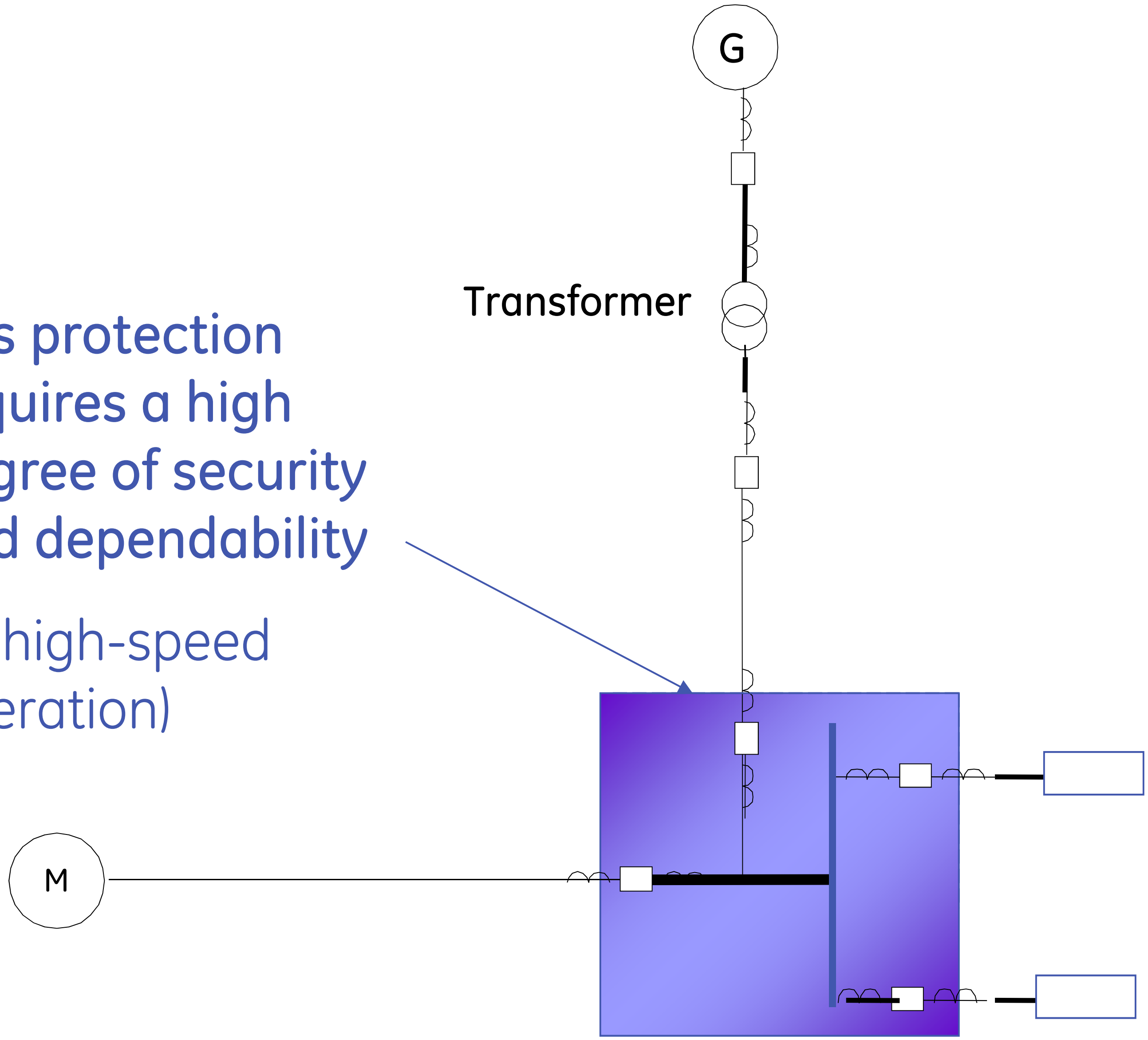


Bus Protection

Secure Bus Protection

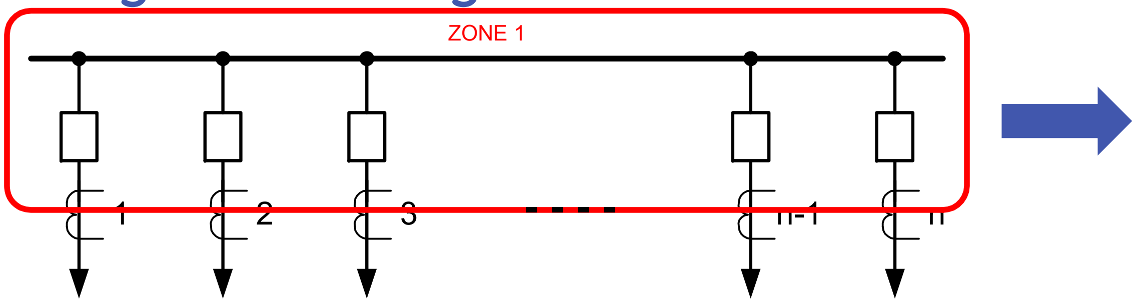
Bus protection requires a high degree of security and dependability

(or high-speed operation)



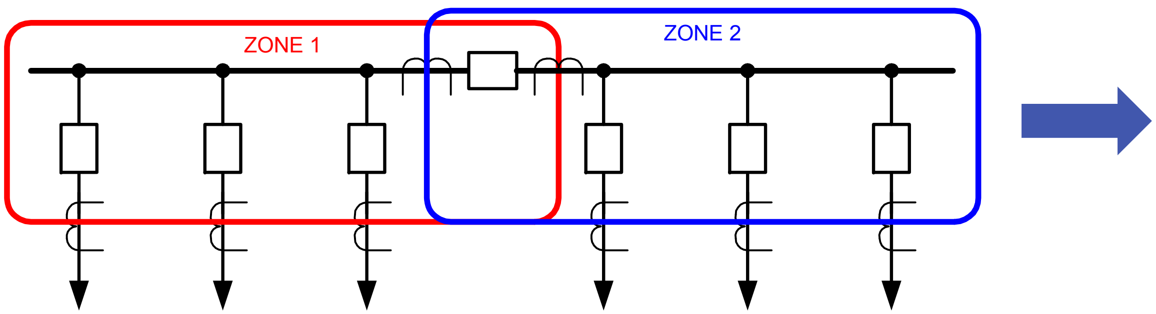
Bus Configurations

Single bus - single breaker



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

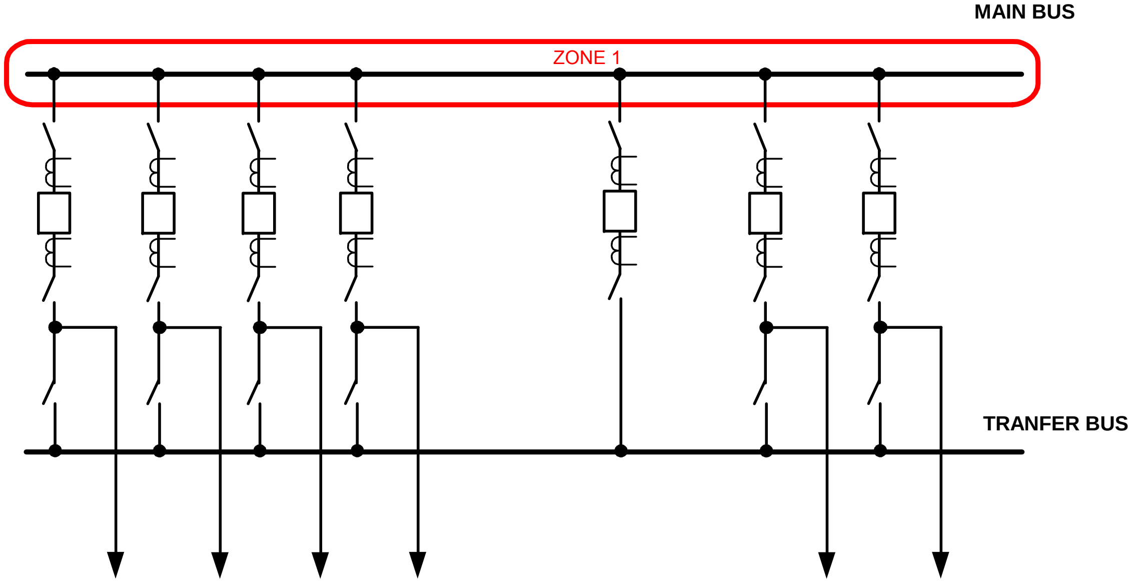
Multiple bus sections - single breaker with bus tie



- 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 <u>bus</u> 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:

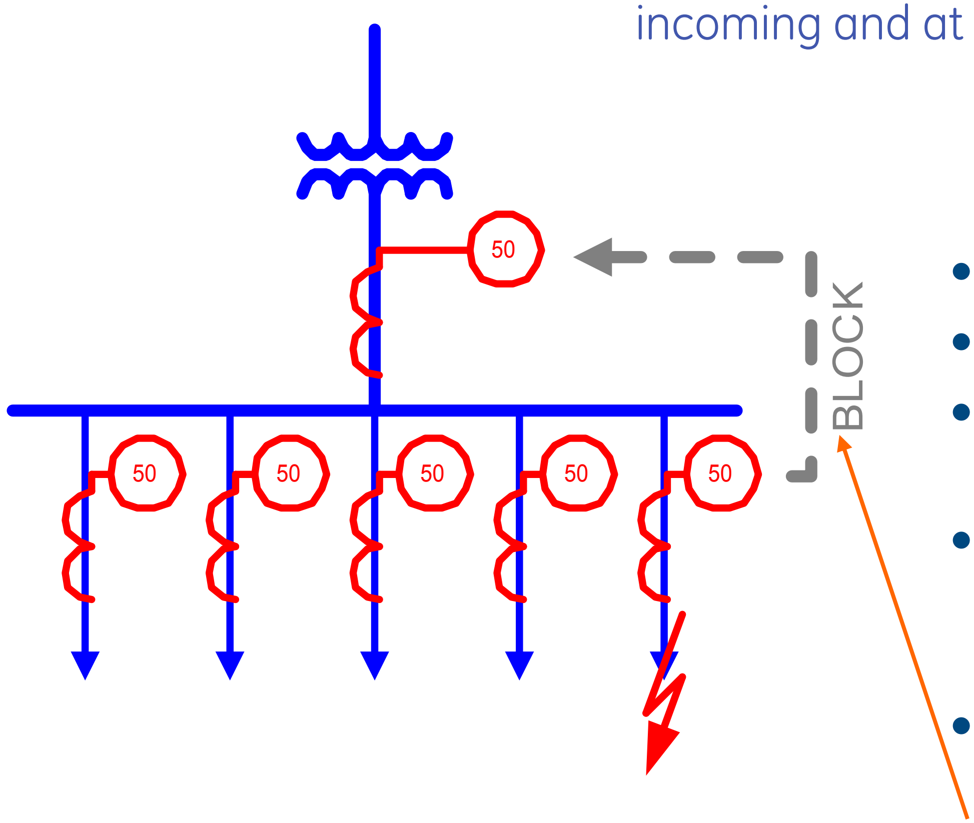
- Service interruption to a large number of customers (distribution and sub-transmission voltage levels)
- System-wide stability problems (transmission voltage levels fluctuations)

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



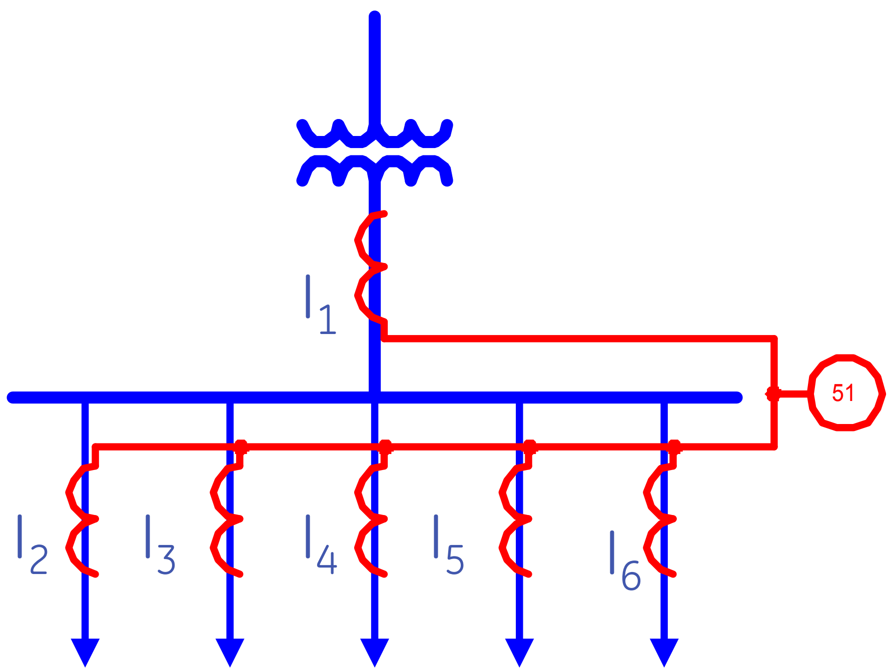
- Blocking scheme typically used
- Short coordination time required
- Practically, not affected by CT saturation
- The blocking signal could be sent over microprocessor-based relay communication ports
- This technique is limited to simple one incoming distribution bus

50 Instantaneous Overcurrent

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

Bus Protection Techniques

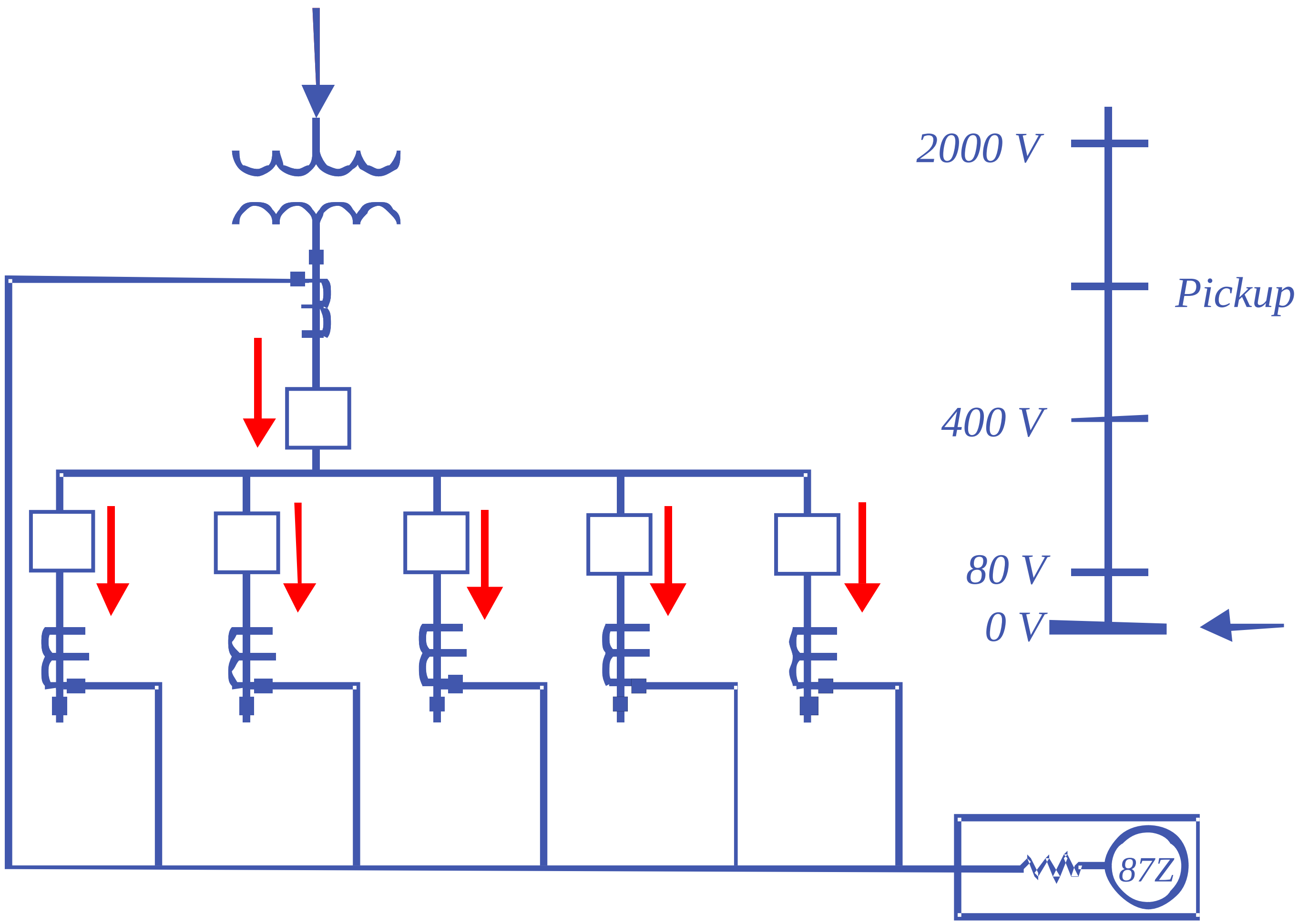
Overcurrent Differential



- 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

Bus Protection Techniques

High Impedance



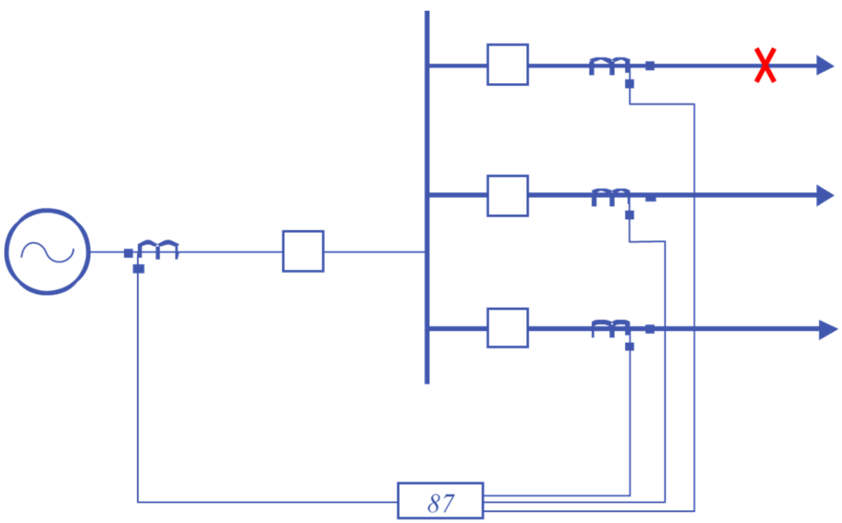
Bus Protection Techniques

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

Sum $$i_R = |i_1| + |i_2| + |i_3| + \ldots + |i_n|$$

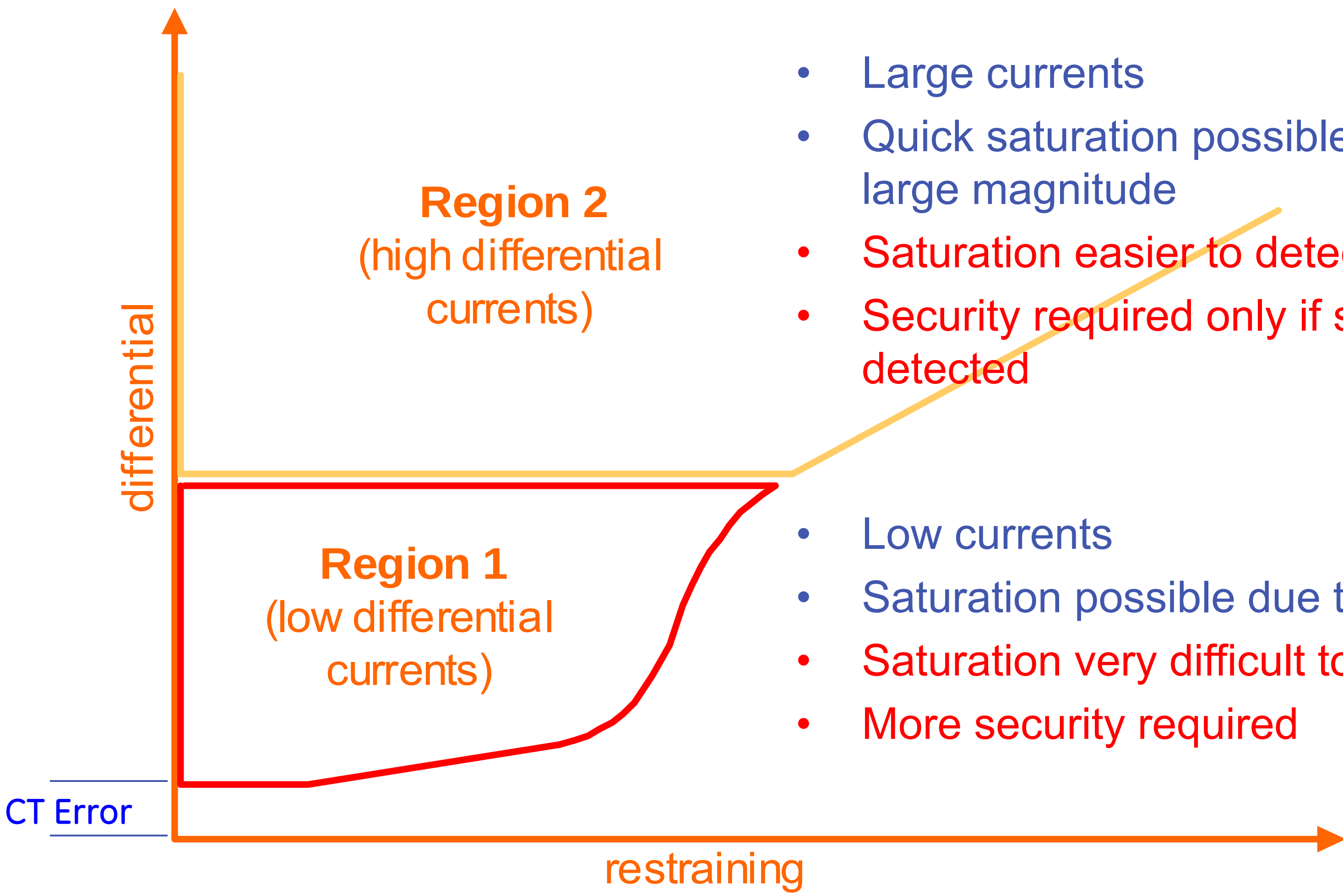
Avg $$i_R = \sqrt[n]{|i_1| \cdot |i_2| \cdot |i_3| \cdot \ldots \cdot |i_n|}$$

Max $$i_R = Max(|i_1|, |i_2|, |i_3|, \ldots, |i_n|)$$

$$I_{DIF} = |I_1 + I_2 + \ldots + I_n|$$

Bus Protection Techniques

Percent Differential - Low Impedance



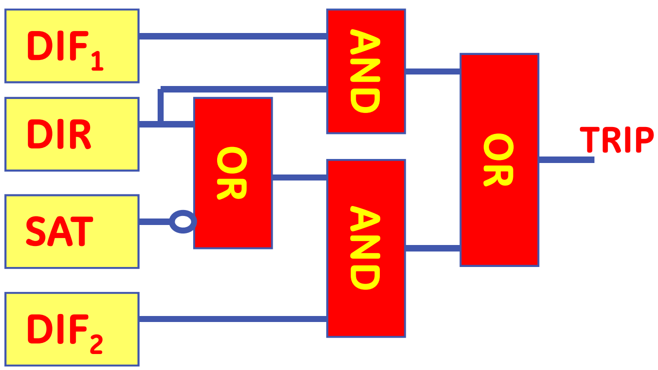
- Large currents
- Quick saturation possible due to large magnitude
- Saturation easier to detect
- Security required only if saturation detected

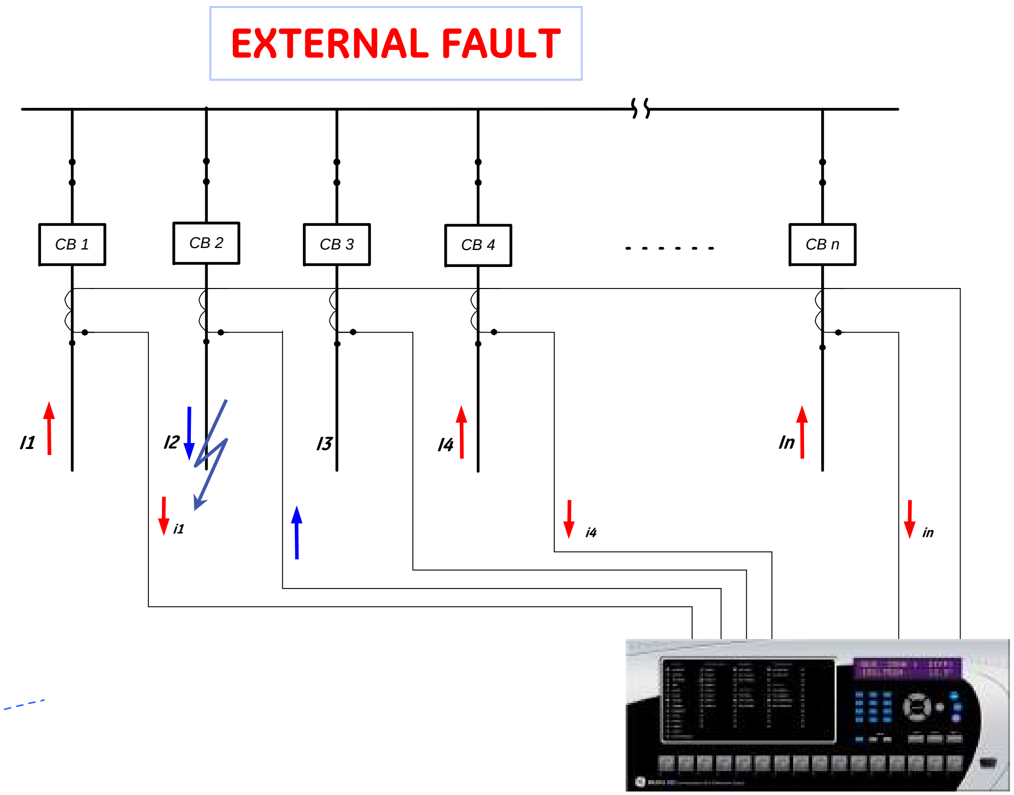
- Low currents
- Saturation possible due to dc offset
- Saturation very difficult to detect
- More security required

Bus Protection Techniques

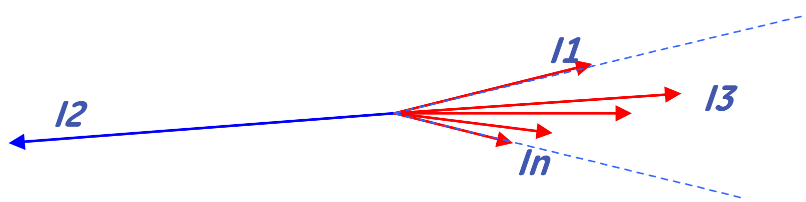
Percent Differential - Low Impedance

Protection logic





Directional flag

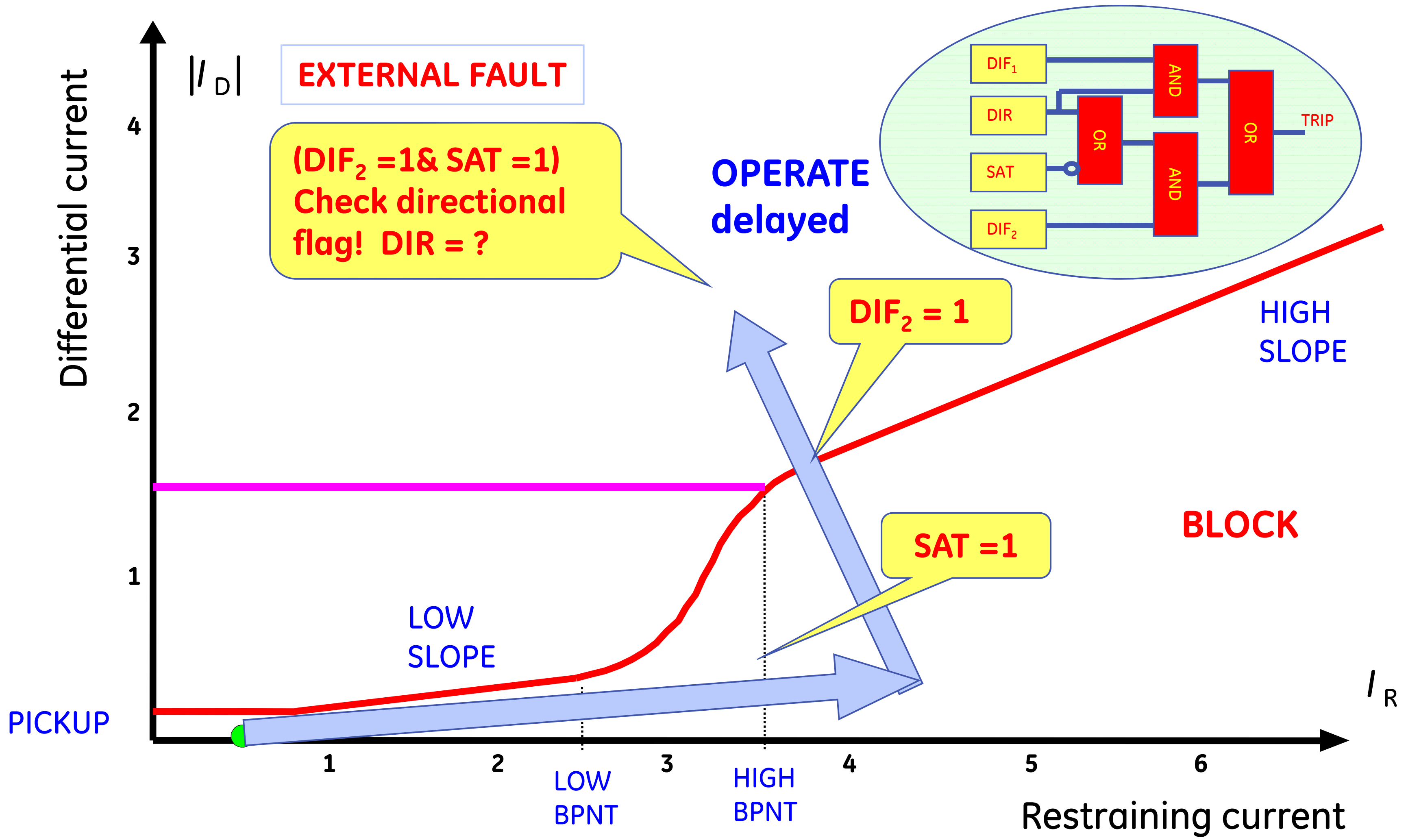


DIR = 0

Saturation flag

SAT = 1

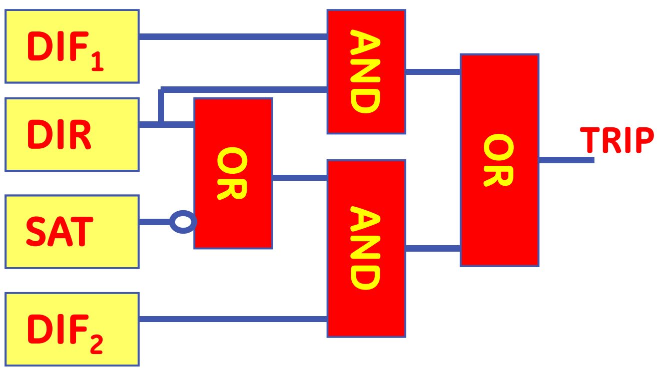
Bus Protection Techniques
Percent Differential - Low Impedance



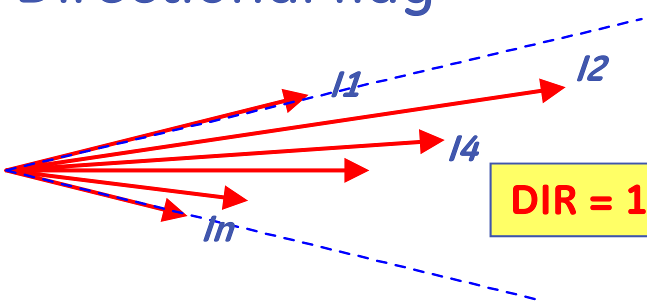
Bus Protection Techniques

Percent Differential - Low Impedance

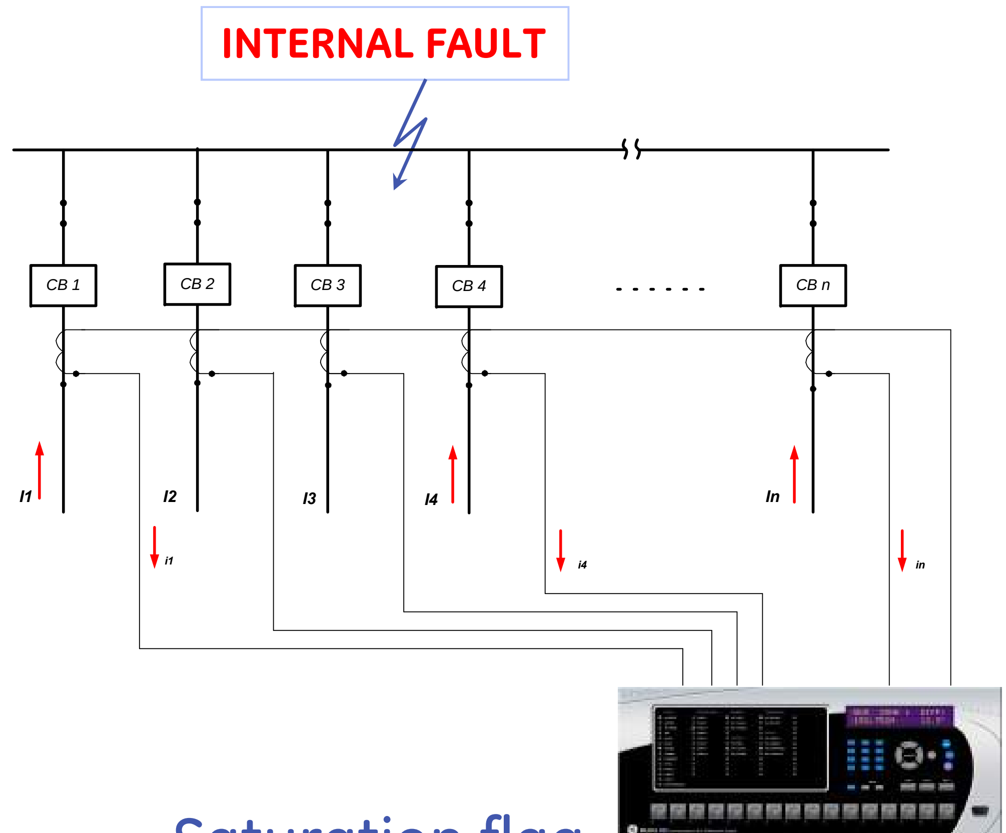
Protection logic



Directional flag



DIR = 1

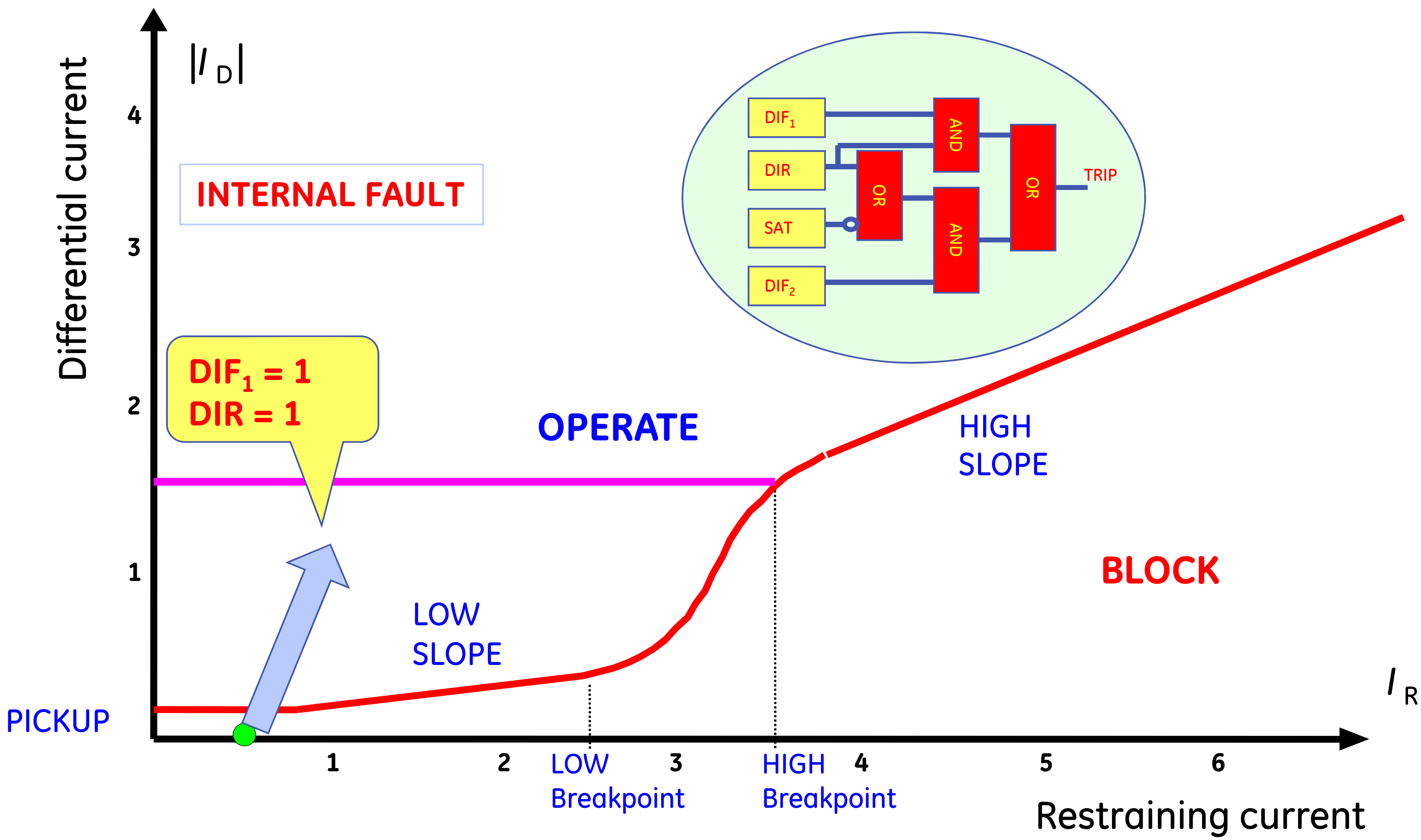


Saturation flag

SAT = 0

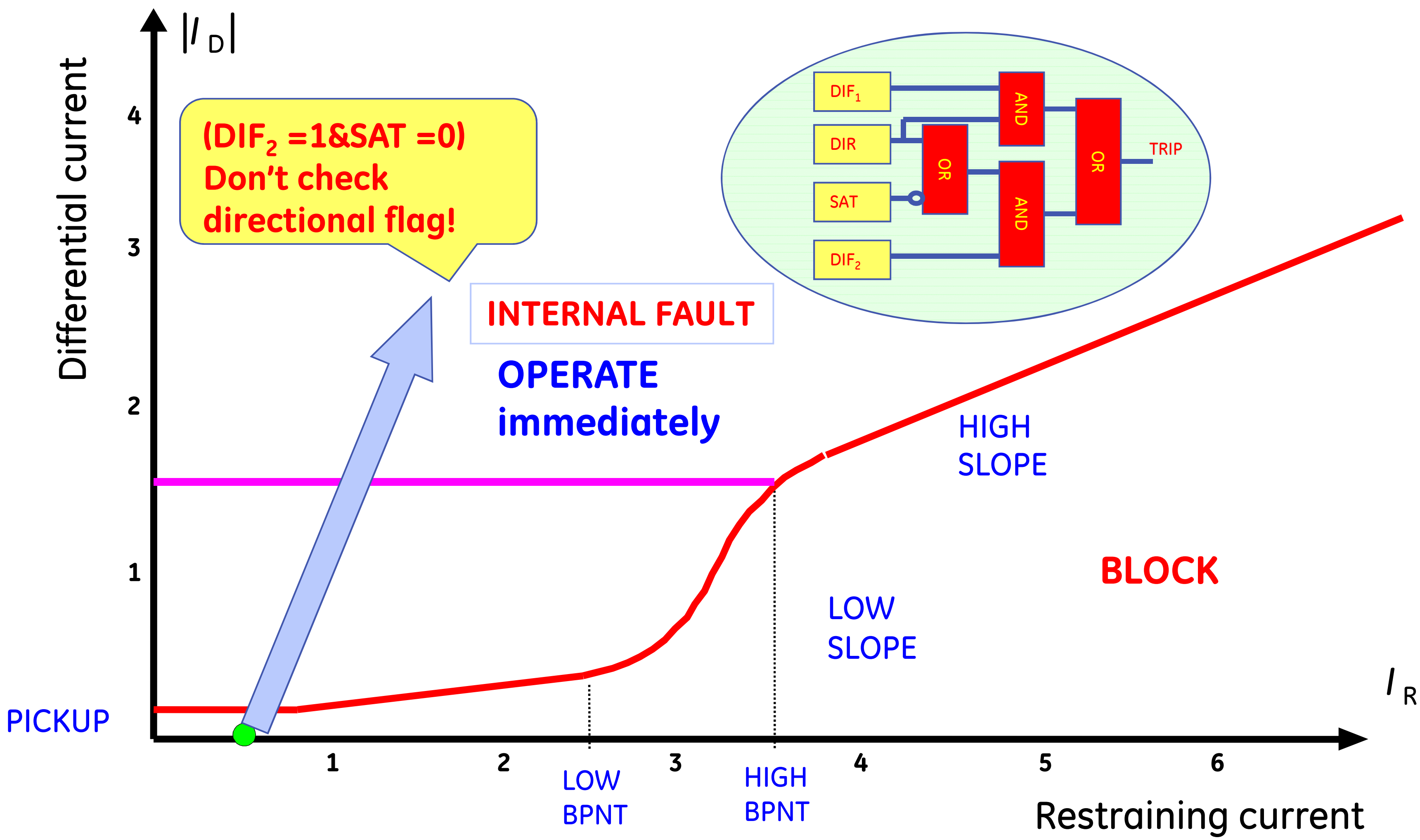
Bus Protection Techniques

Percent Differential - Low Impedance



Bus Protection Techniques

Percent Differential - Low Impedance



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**

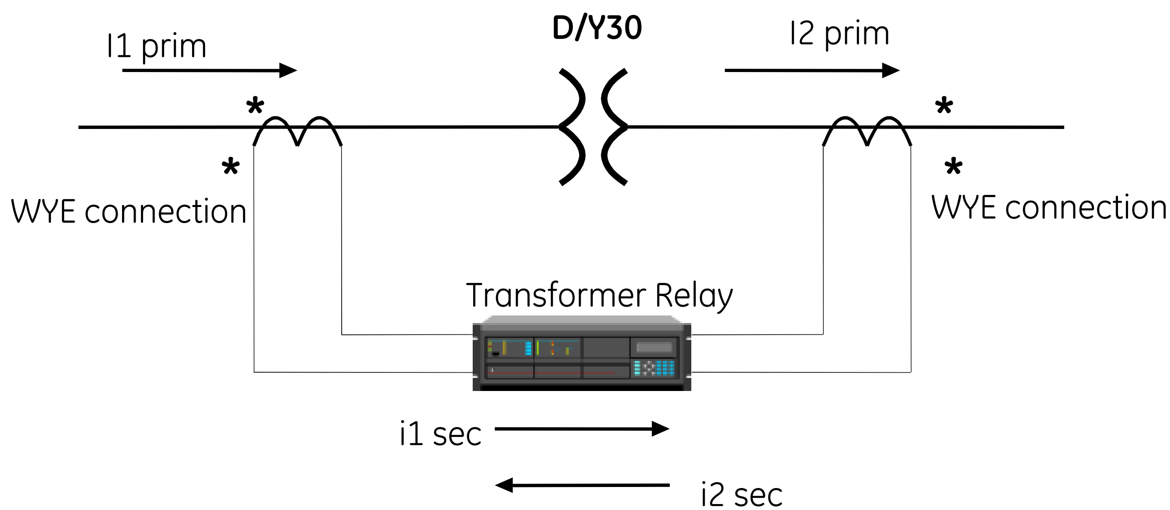
Causes of Transformer Failures

• 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**

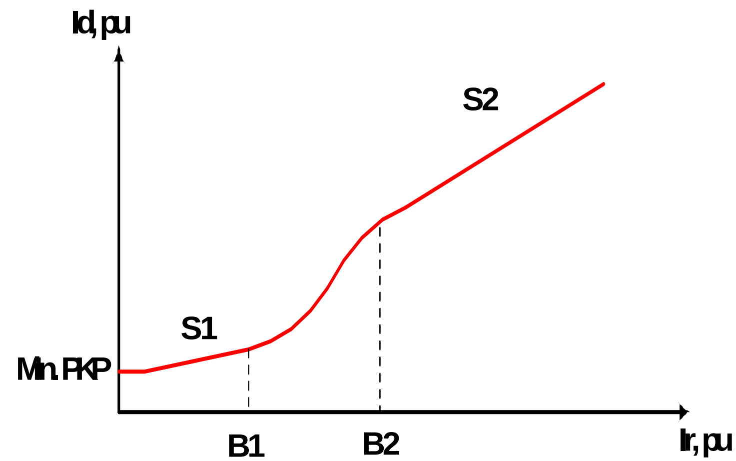


DIFFERENTIAL SIGNAL:

$$I_{DIFF.} = I1_{COMP} + I2_{COMP}$$

RESTRAINING SIGNAL:

$$I_{RESTR.} = \max\left(|I1_{COMP}| , | I2_{COMP}| \right)$$

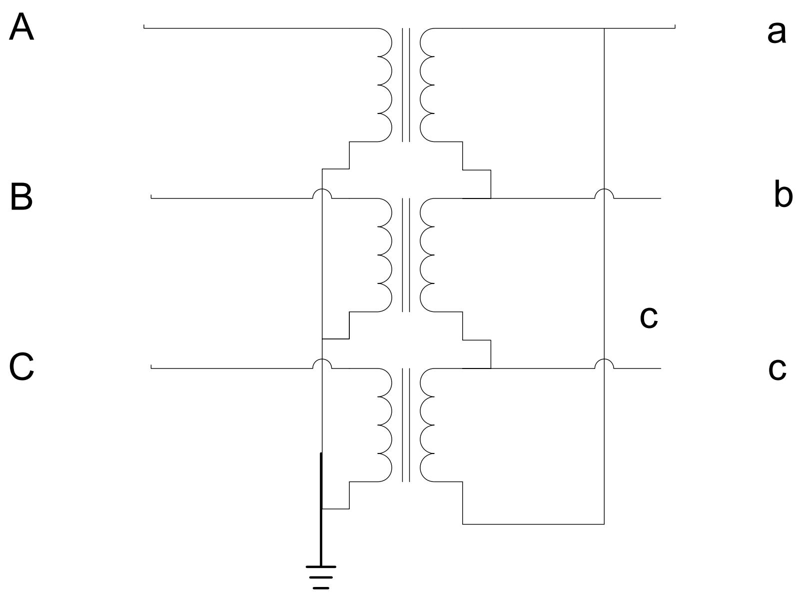


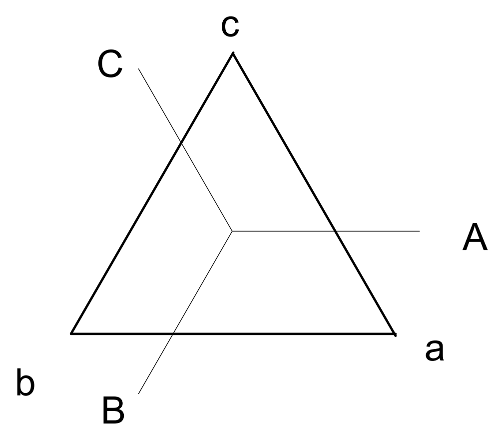
Current Differential Challenges

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

Current Differential Challenges

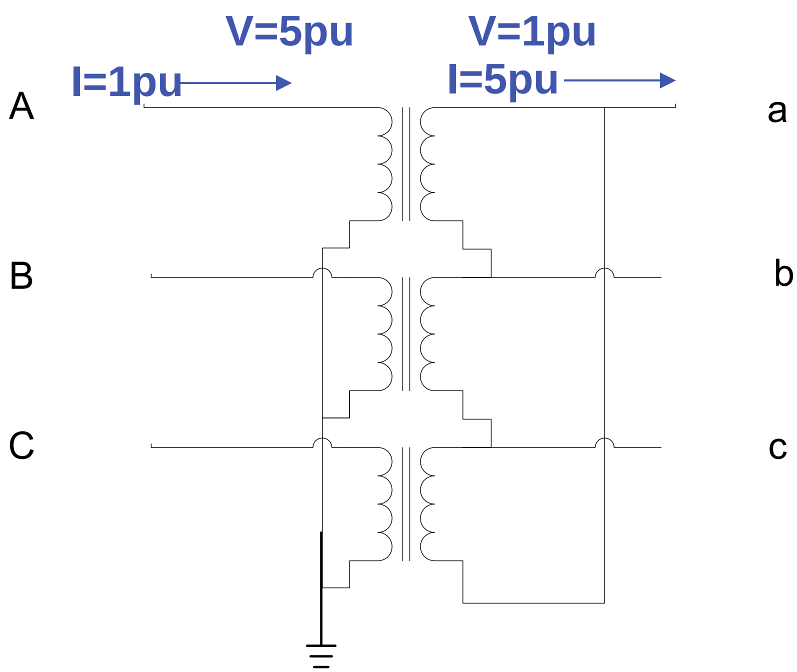
– Phase Compensation





Current Differential Challenges

– Magnitude Compensation/Mismatch



Phase & Magnitude Compensations

EM relay setup:

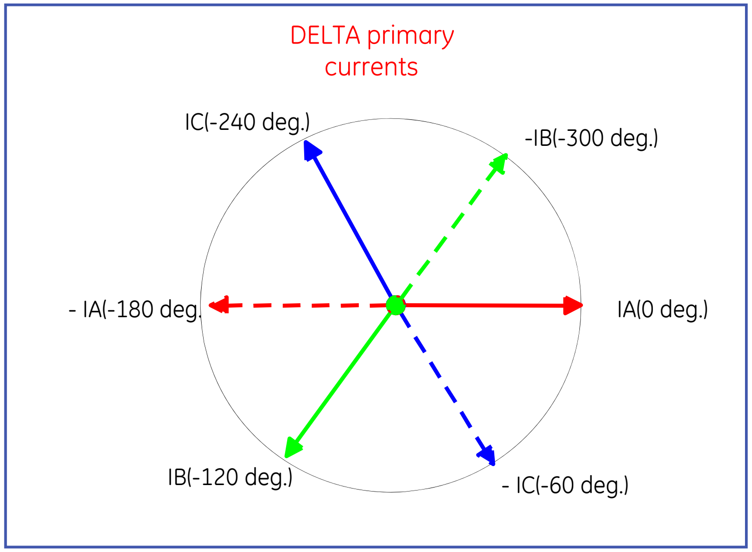
- Magnitude compensation:
  - Relay tap calculation per CT input (***introduces inaccuracy due to approximation matching the field CT with relay tap setting***)
- Phase shift compensation:
  - External Delta connected CTs on Wye, and Wye connected CTs on Delta windings ***(increases the chance of making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

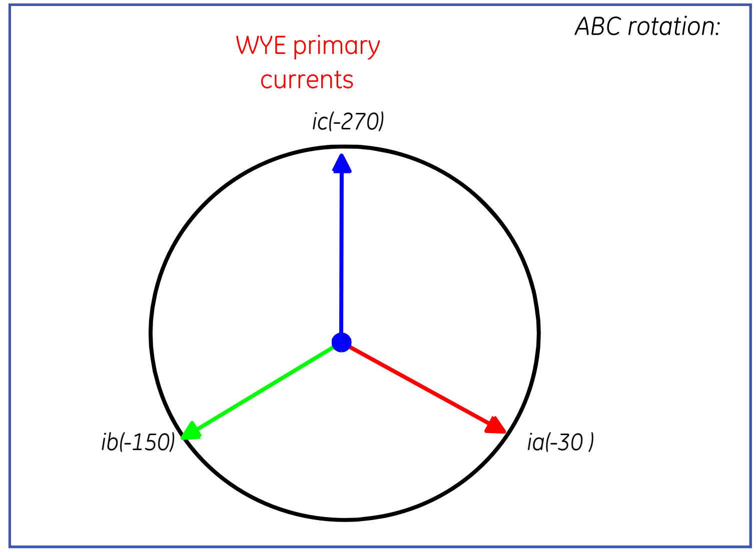
Digital relay setup:

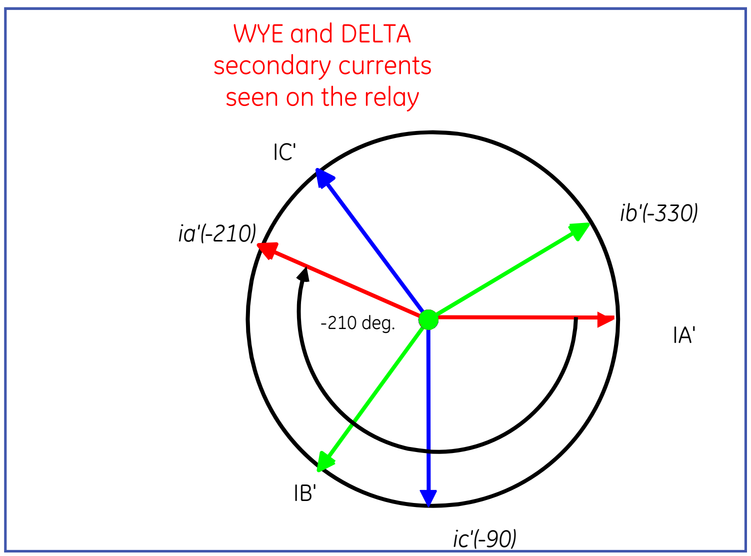
- Automatic magnitude compensation:
  - Firmware computes magnitude compensation factors for all winding currents, and scales them internally
- Phase shift compensation:
  - Firmware detects the phase shift setting entered in the transformer windings menu, and compares it to the actual phase shift between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

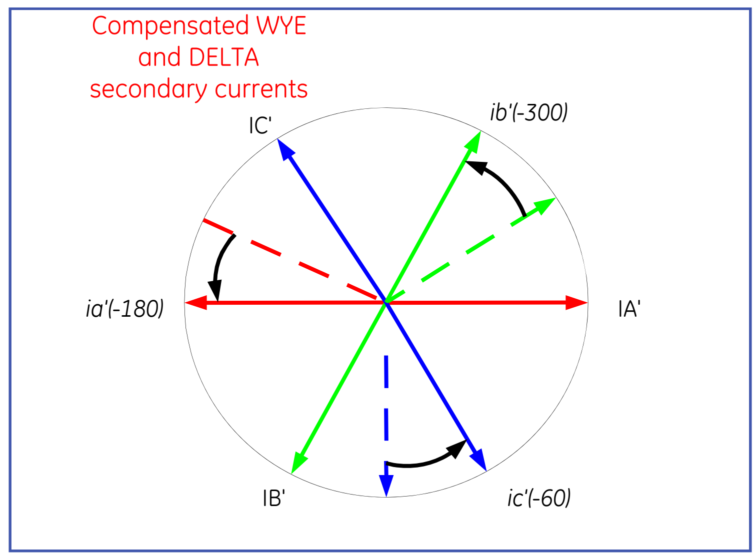
Phase Compensation

Transformer: D/Y30



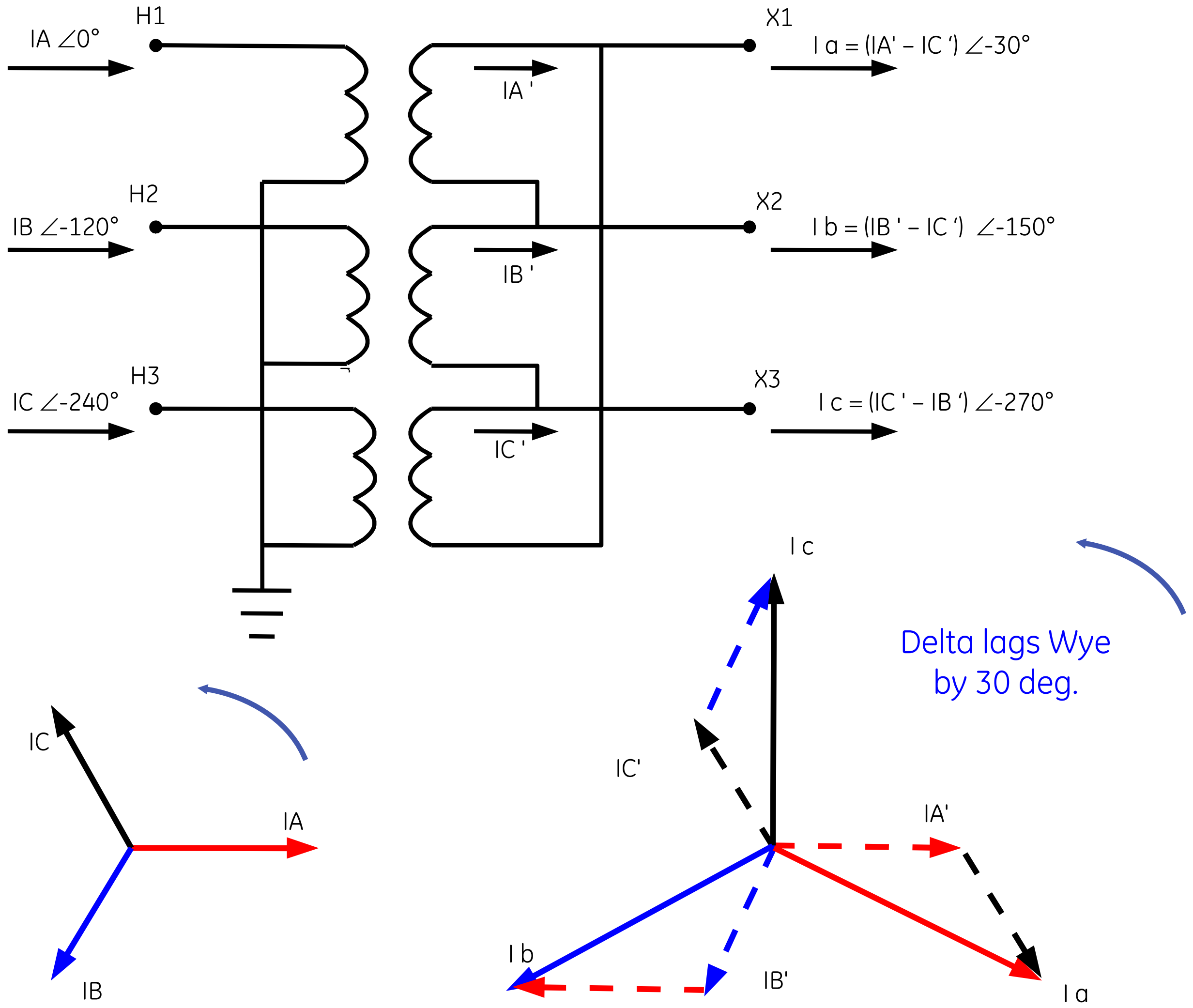






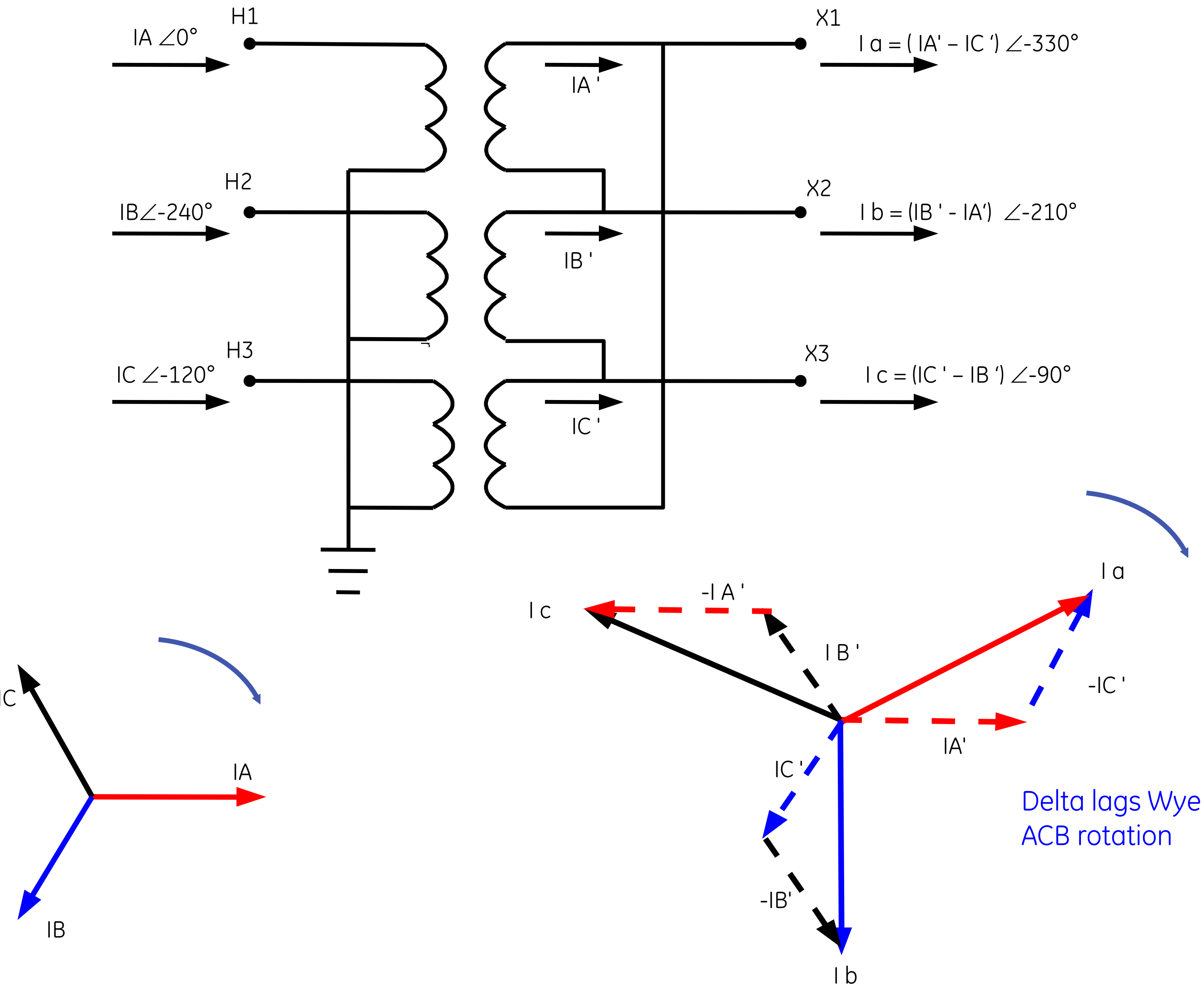
Phase Compensation

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



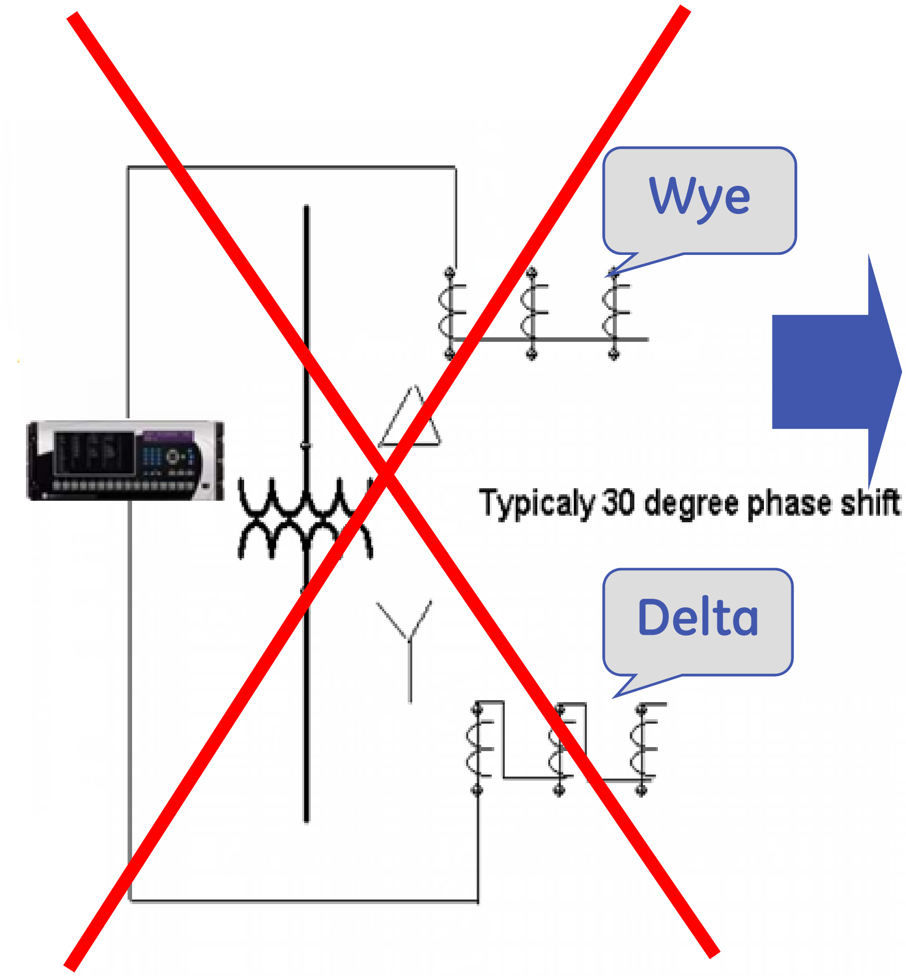
Phase Compensation

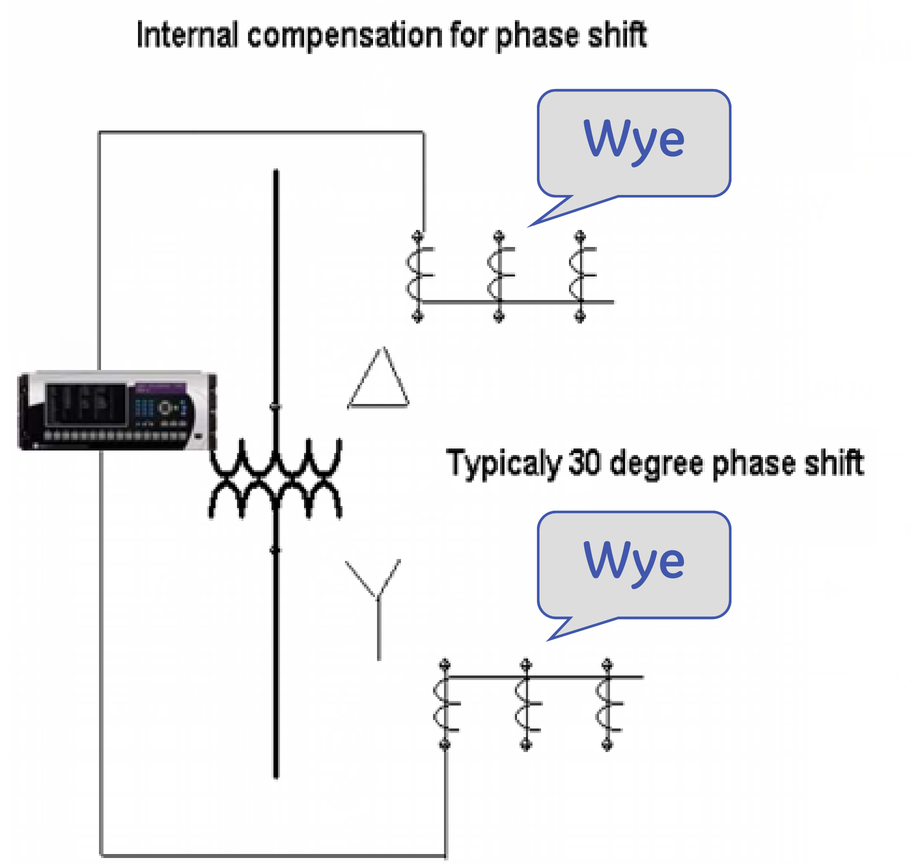
ACB rotation : compensation angle = 0 – (- 330) = 330 = 30 lag



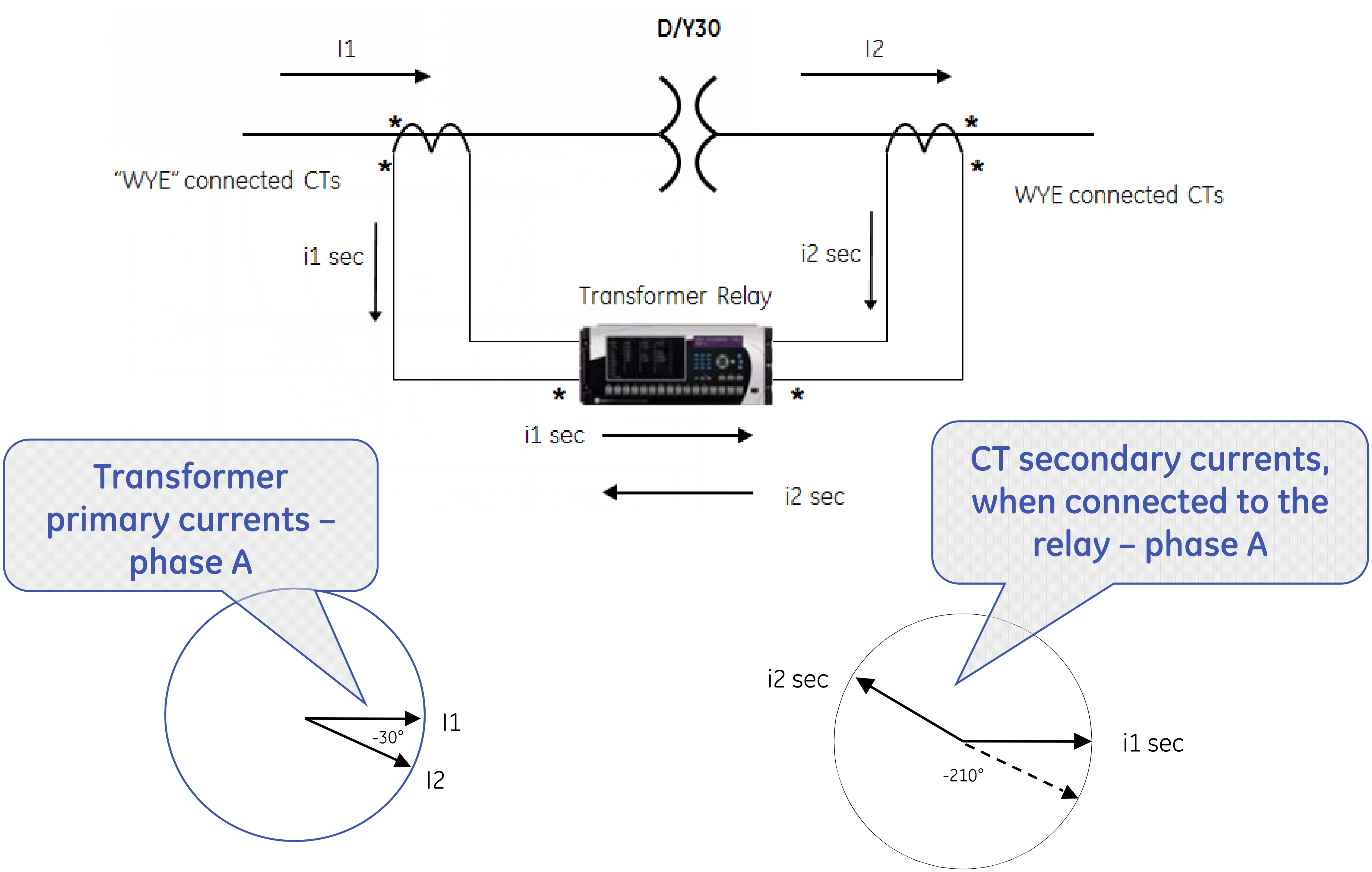
Delta lags Wye by 30 deg. for ACB rotation

Wiring & CT Polarity





Wiring & CT Polarity



CTs and Transformer Windings Setup

Current // Network: UR T60: Settings: System Setup: AC Inputs

PARAMETER	CT F1	CT F5	CT M1	CT M5
Phase CT Primary	500 A	1000 A	1 A	1 A
Phase CT Secondary	5 A	5 A	1 A	1 A
Ground CT Primary	1 A	1000 A	1 A	1 A
Ground CT Secondary	1 A	5 A	1 A	1 A

STEP 1. Define CT inputs

Signal Sources // Network: UR T60: Settings: System Setup

PARAMETER	SOURCE 1	SOURCE 2	SOURCE 3
Name	SRC 1	SRC 2	SRC 3
Phase CT	F1	F5	None
Ground CT	F1	F5	None
Phase VT	U5	U5	None
Aux VT	U5	U5	None

STEP 2. Source configuration (if applicable)

General // Network: UR T60: Settings: System Setup: Transform...

SETTING	PARAMETER
Number Of Windings	2
Phase Compensation	Internal (software)

UR T60 | Settings: System Setup: Transformer

STEP 3. Number of windings

PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	100.000 MVA	100.000 MVA
Nominal Phs-phs Voltage	230.000 kV	69.000 kV
Connection	Delta	Wye
Grounding	Not within zone	Within zone
Angle Wrt Winding 1	0.0 °	-30.0 °

STEP 4. Define Transformer windings

Step 4 – Transformer Windings Setup

Source (SRC) for Winding 1 currents per Step 3

Source (SRC) for Winding 2 currents per Step 3

Winding capacity (MVA) per transformer nameplate – same across transformer

Winding phase-to-phase voltage rating as per transformer nameplate

Windings // T60 for 4_6 fw - sample.urs : C:\Program Files\GE Power Management\...

Save Restore Default Reset

PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	100.000 MVA	100.000 MVA
Nominal Phs-phs Voltage	230.000 kV	69.000 kV
Connection	Delta	Wye
Grounding	Not within zone	Within zone
Angle Wrt Winding 1	0.0 °	-30.0 °
Resistance	10.0000 ohms	10.0000 ohms

Winding connection type

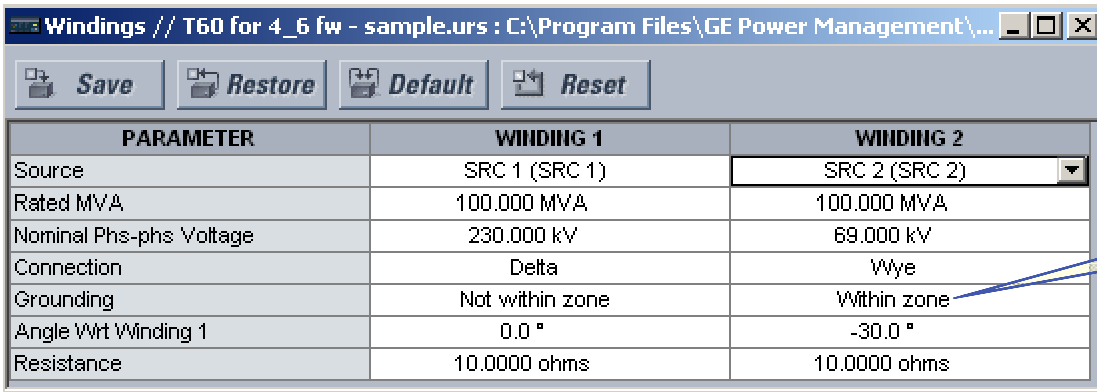
Winding grounding within 87T protection zone

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

Step 4 – Transformer Windings Setup



Windings // T60 for 4_6 fw - sample.urs : C:\Program Files\GE Power Management\...

Save | Restore | Default | Reset

PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	100.000 MVA	100.000 MVA
Nominal Phs-phs Voltage	230.000 kV	69.000 kV
Connection	Delta	Wye
Grounding	Not within zone	Within zone
Angle Wrt Winding 1	0.0 °	-30.0 °
Resistance	10.0000 ohms	10.0000 ohms

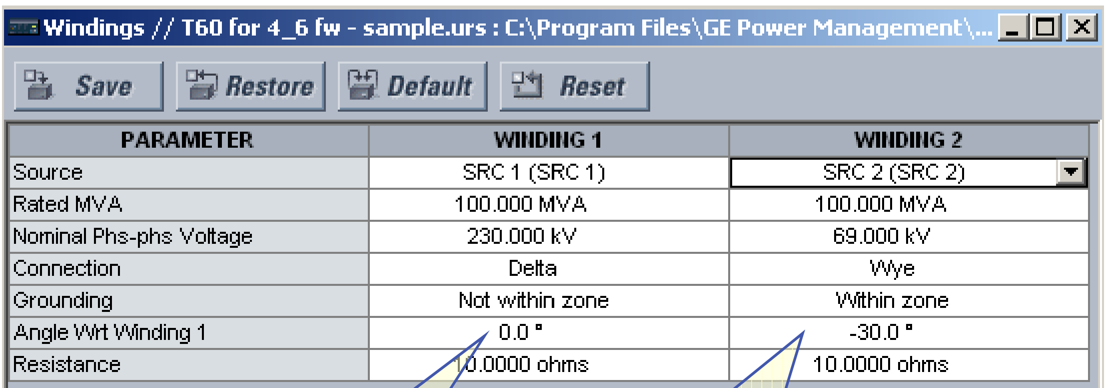
Winding grounding within 87T protection zone

"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

Step 4 – Transformer Windings Setup



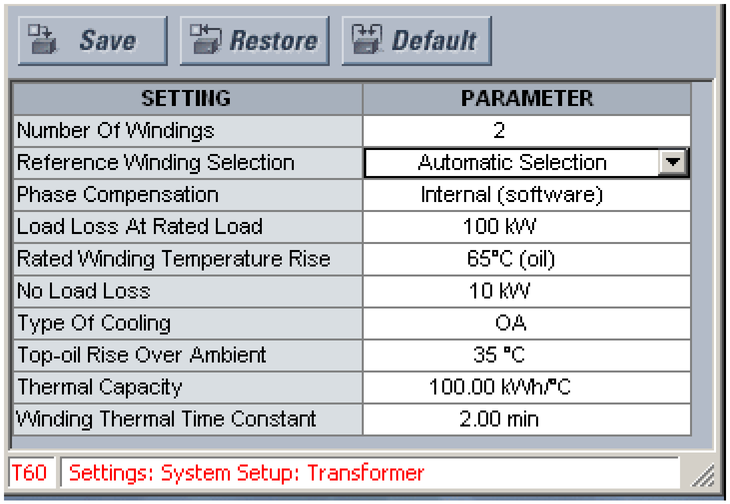
PARAMETER	WINDING 1	WINDING 2
Source	SRC 1 (SRC 1)	SRC 2 (SRC 2)
Rated MVA	100.000 MVA	100.000 MVA
Nominal Phs-phs Voltage	230.000 kV	69.000 kV
Connection	Delta	Wye
Grounding	Not within zone	Within zone
Angle Wrt Winding 1	0.0 °	-30.0 °
Resistance	10.0000 ohms	10.0000 ohms

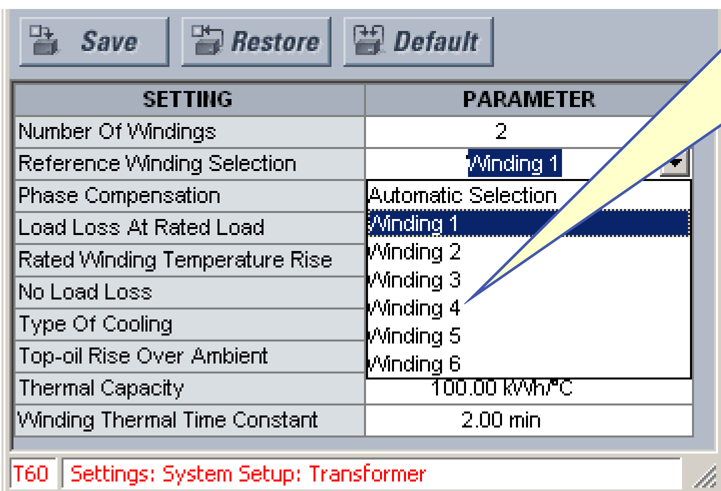
The angle of Winding 1 must be entered as 0° for any transformer setup

Angle, by which winding 2 currents lag winding 1 currents With Respect To (WRT) winding 1 angle of 0° degrees

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.

Magnitude Compensation





"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 :**
   Irated(w1)= MVA/(kV(w1)*√ 3)
   Irated(w2)= MVA/(kV(w2)*√ 3)

2. **Calculates the CT margin for each winding:**
   L margin(w1) = CT primary(w1)/I rated (w1)
   L margin(w2) = CT primary(w2)/I rated (w2)

3. **Finds the lowest CT margin:**
   REFERENCE CT: = **min [**L margin(w1), L margin(w2)**]**

4. **Finds the magnitude coefficients, by which the currents from the corresponding winding are multiplied**
   M(W)= [CT prim(W) * V nom(W)] / [CT prim(Wref) * 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)= [CT prim(W) *V nom(W)] / [CT prim(Wx) * V nom(Wx)]

Differential & Restraint Currents

COMPENSATED CURRENTS:

$$\overrightarrow{I1_{COMP}} = C1*M1(w1)*(\overrightarrow{I1_{SEC}}*CT1_{RATIO})$$

$$\overrightarrow{I2_{COMP}} = C2*M2(w2)*(\overrightarrow{I2_{SEC}}*CT2_{RATIO})$$

where,

C1, C2 - phase shift coefficients (C = 1 for the phase reference winding)

M1, M2 - magnitude coefficients (M = 1 for the magnitude reference winding)

DIFFERENTIAL SIGNAL:

$$\overrightarrow{I_{DIFF.}} = \overrightarrow{I1_{COMP}} + \overrightarrow{I2_{COMP}}$$

RESTRAINING SIGNAL:

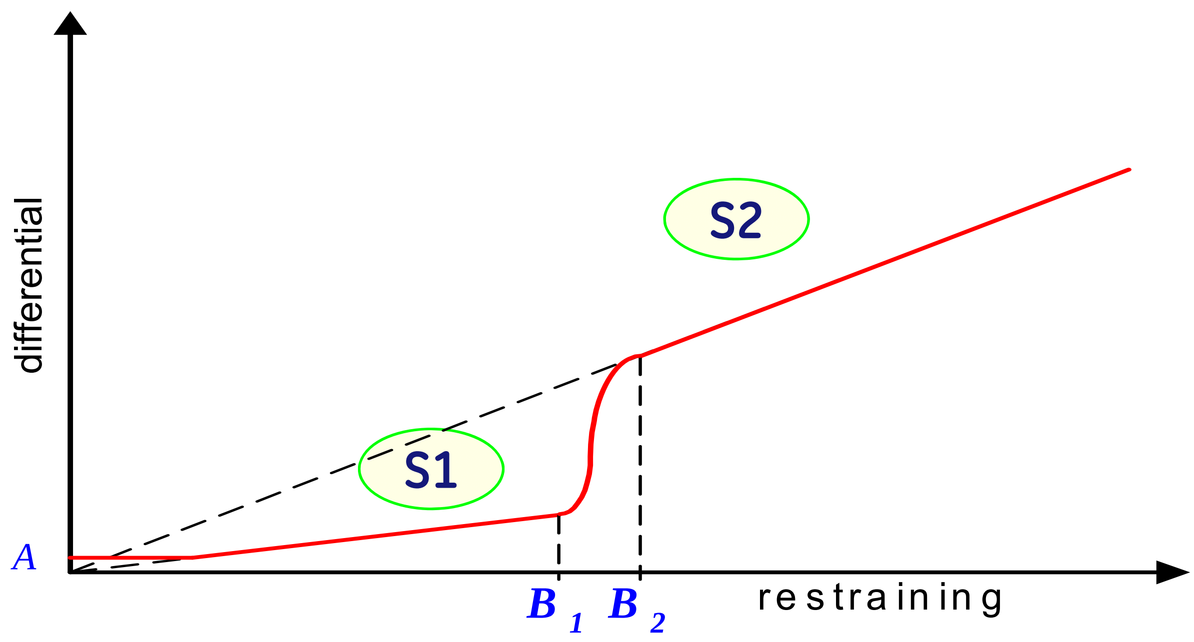
$$I_{RESTR.} = \max\left(\left|\overrightarrow{I1_{COMP}}\right| , \left|\overrightarrow{I2_{COMP}}\right| \right)$$

Differential - Restraint Characteristic

Two slopes used to cope with:

> Small errors during linear operation of the CTs (S1) and

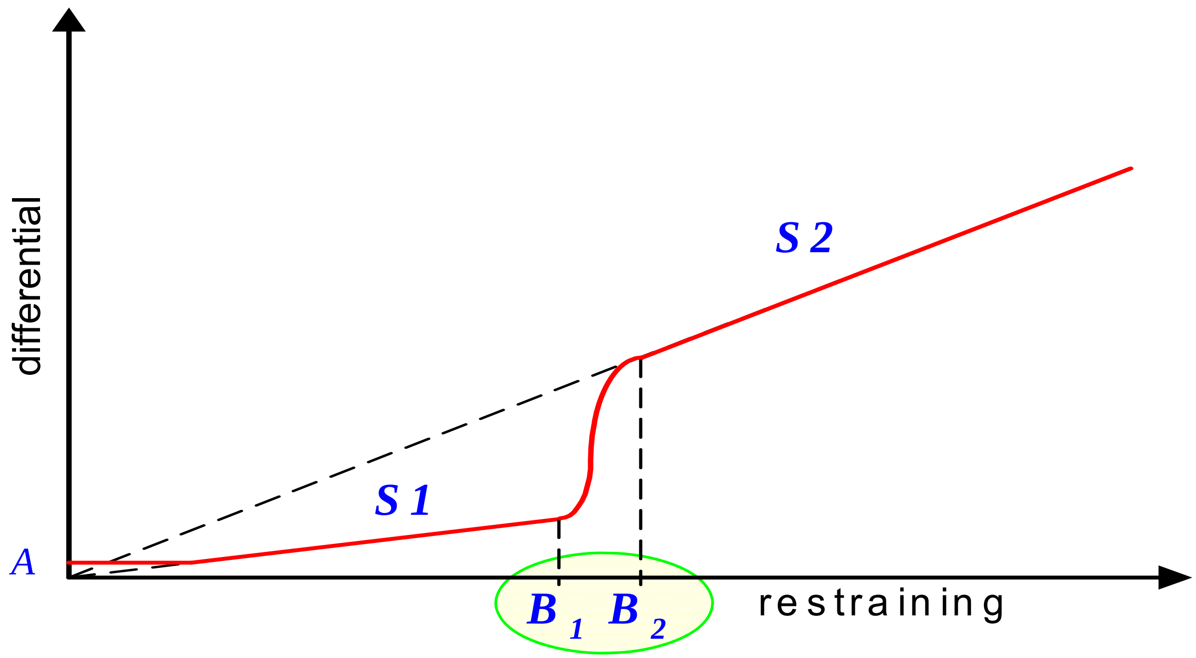
> Large CT errors (saturation) for high through currents (S2)



Differential - Restraint Characteristic

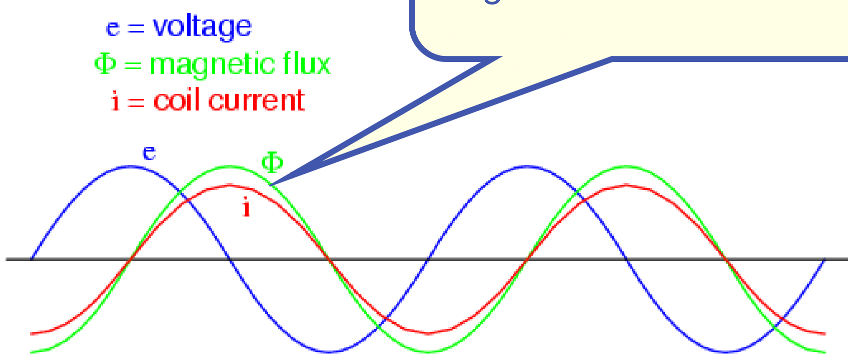
Two breakpoints used to specify:

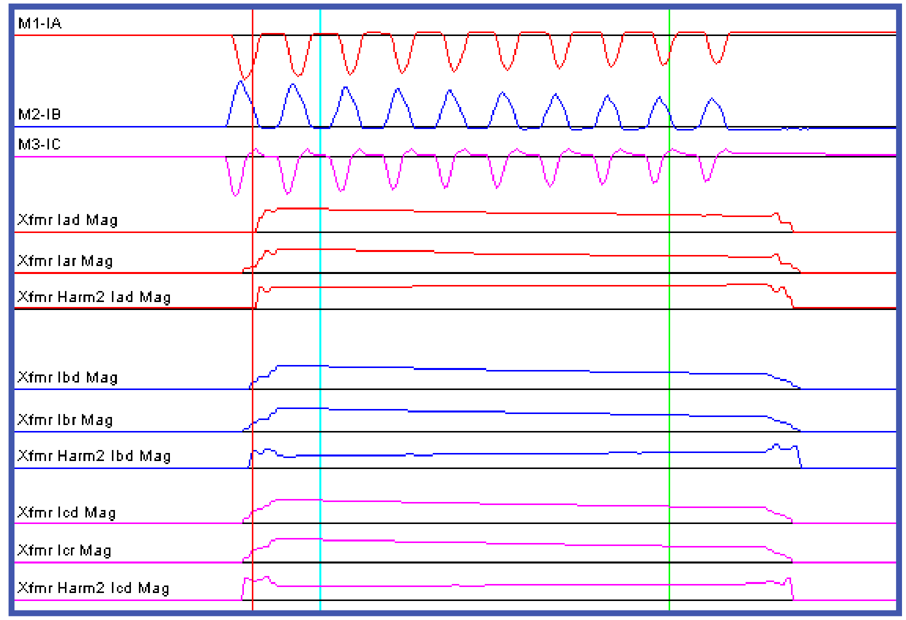
- The safe limit of linear CT operation (B_1) and
- The minimum current level that may cause large spurious differential signals due to CT saturation (B_2)



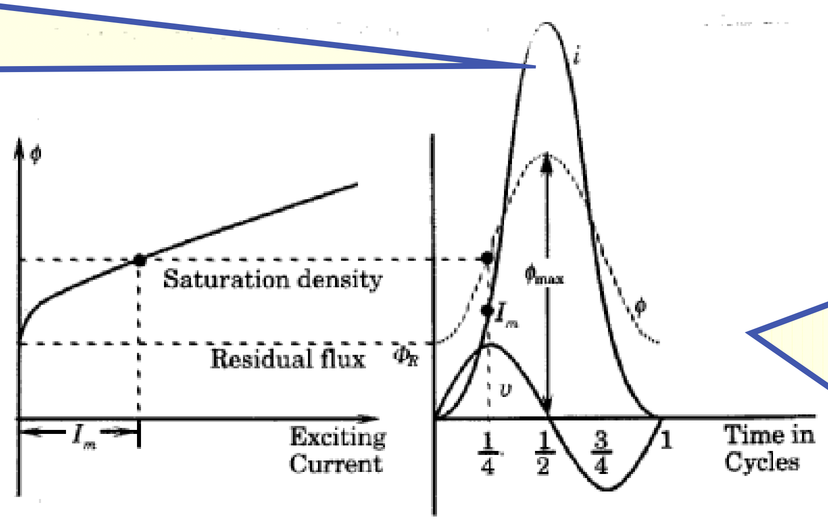
Transformer Inrush

The steady state flux lags the voltage by 90° degrees





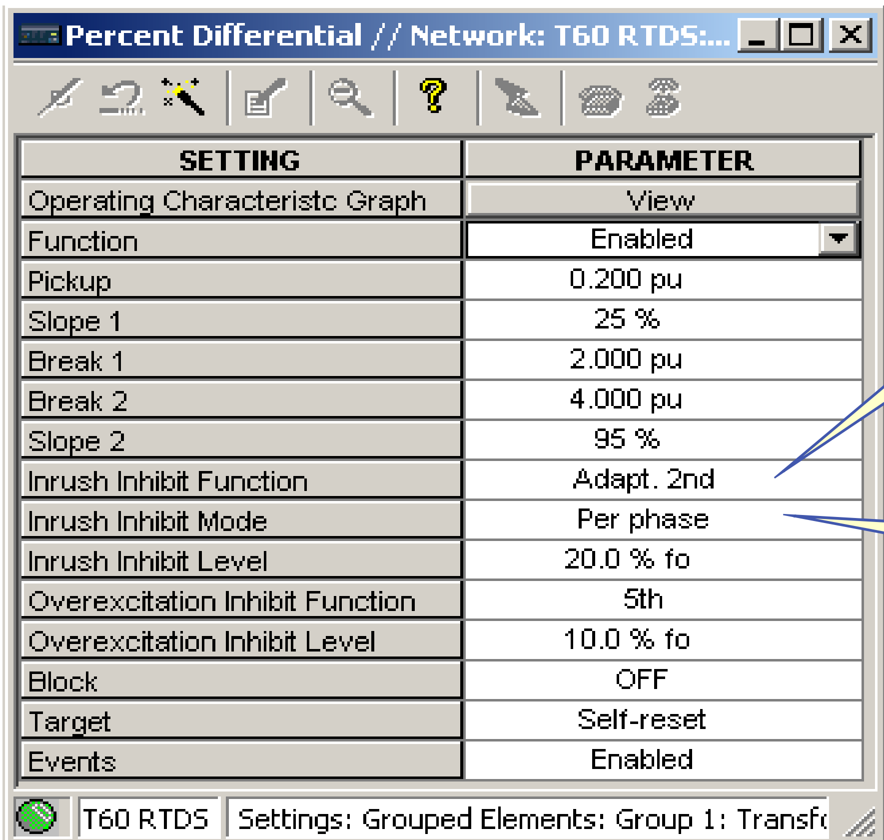
As the flux builds, the exciting current grows with the flux.



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

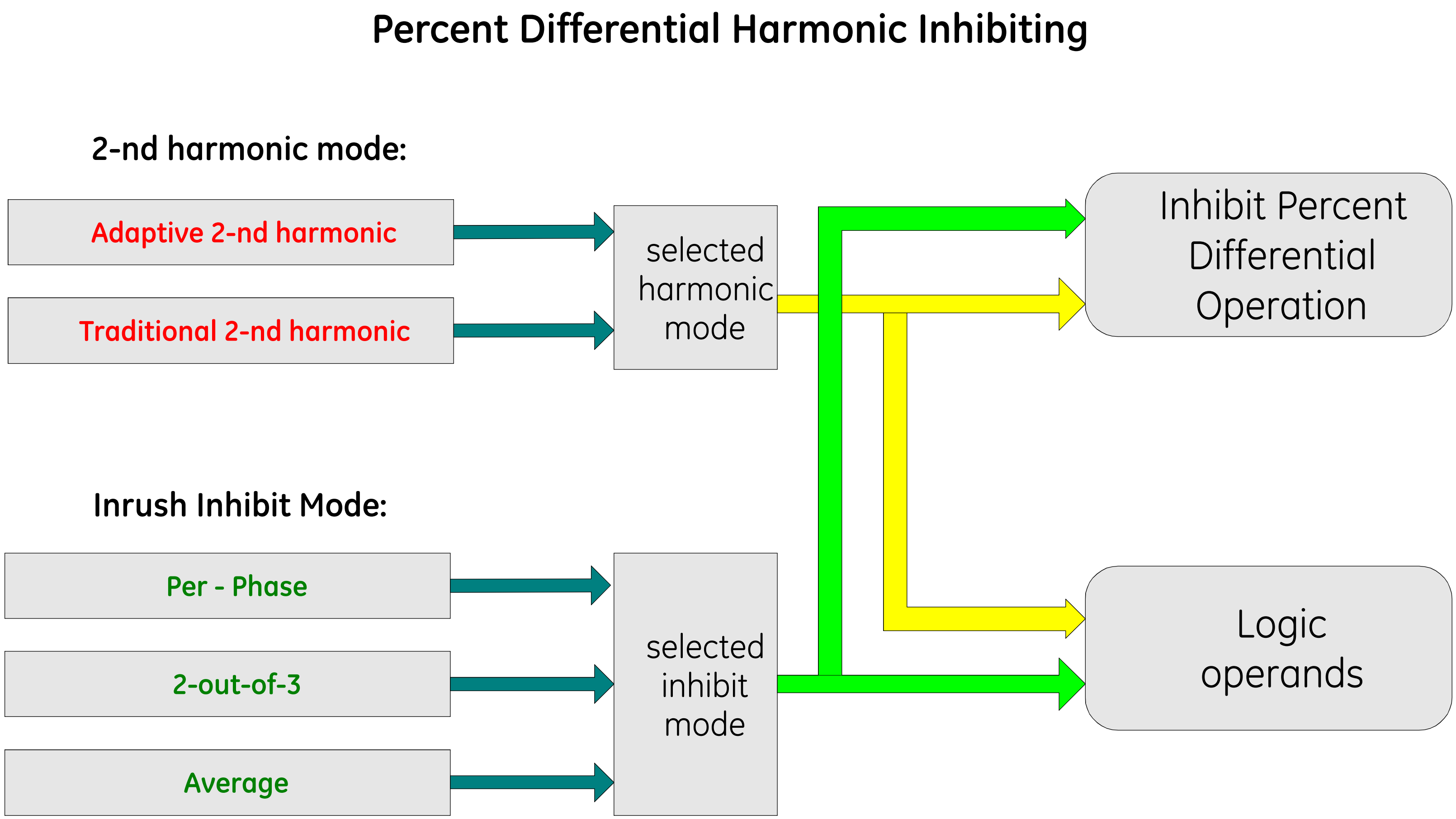
When Transformer is Energized (current applied on only one side of transformer), the 2nd Harmonic content of the current can be used to block the differential element from operating during energization



- Adapt. 2nd
- Trad. 2nd

- Per phase
- 2-out-of-3
- Average

87T – 2nd Harmonic Inhibit



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

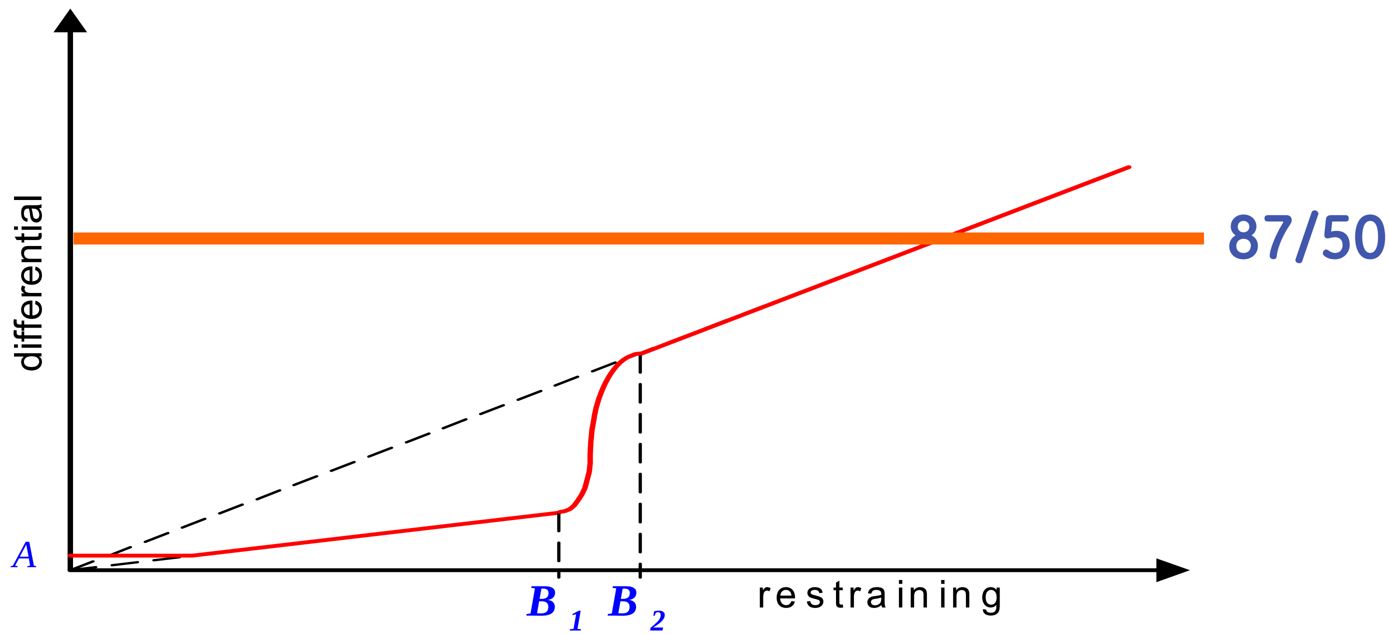
The detection of 2nd harmonic on any two phases that is higher than the setting, blocks the differential protection on all three phases

Average

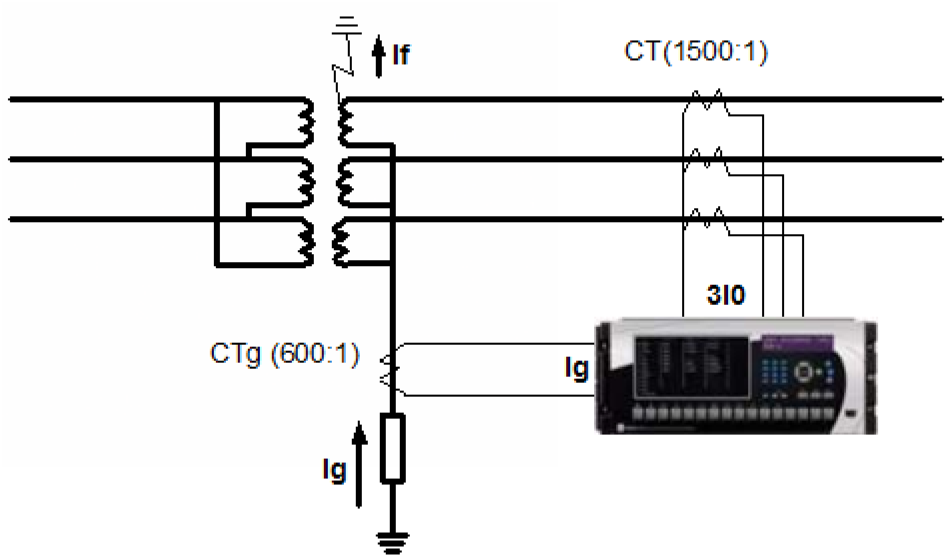
The averaged amount of 2nd harmonic from the three phases, blocks the differential protection for all of them, if above the setting

Instantaneous Differential Protection

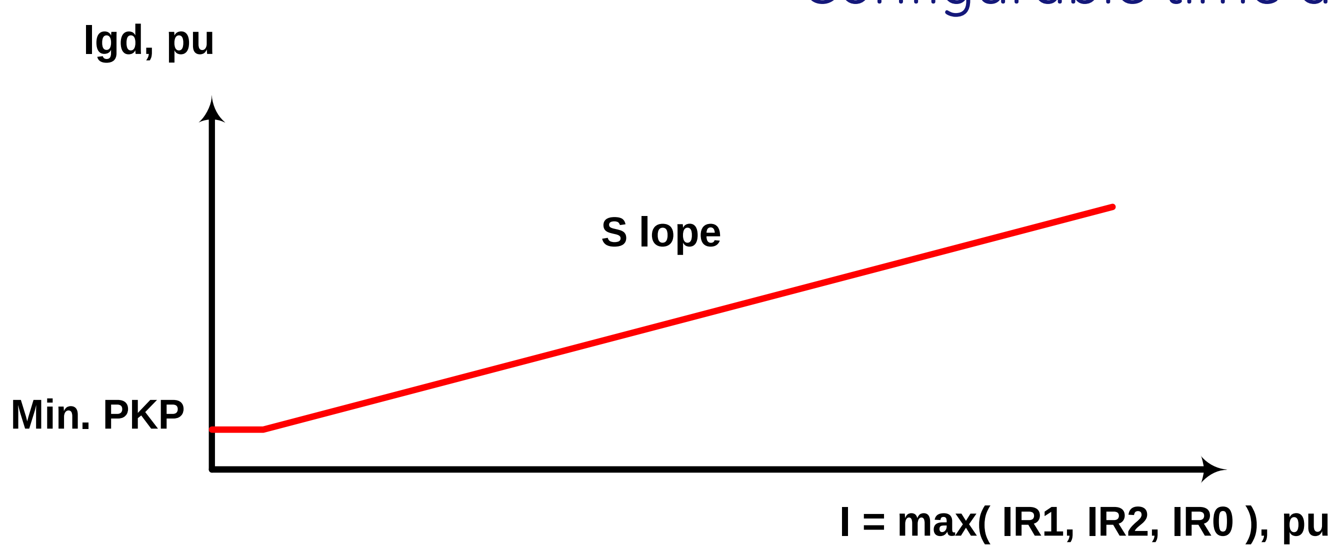
- Defined as function **87/50** and operates with no time delay
- The setting must be higher than maximum differential current the relay may detect on through fault accounting for CT saturation
- The setting must be higher than maximum inrush current during energization
- The setting must be lower, than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



Restricted Ground Fault Protection



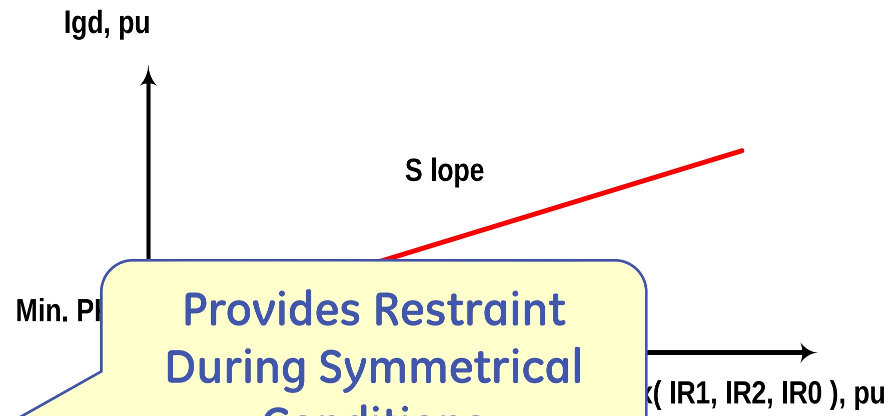
- Low impedance ground differential protection
- Adjustable pickup and slope settings to cope with unbalances during load and through fault currents
- Configurable time delay



Restricted Ground Fault Protection

Save | Restore | Default

PARAMETER	RGF1
Function	Enabled
Source	SRC 1 (SRC 1)
Pickup	0.080 pu
Slope	50 %
Pickup Delay	0.00 s
Reset Delay	0.00 s
Block	OFF
Target	Self-reset
Events	Disabled



Provides Restraint During Symmetrical Conditions

Positive sequence based restraint:
IR1 =3*(|I1| - |I0|), if |I1| > 1.5 pu,
and |I1| > |I0|
else IR1 = |I1| / 8

Ground differential current:
Igd =| IG + IN | =| IG +IA + IB + IC) |

Ground restraint current:
Igr = max (IR1, IR2, IR0)

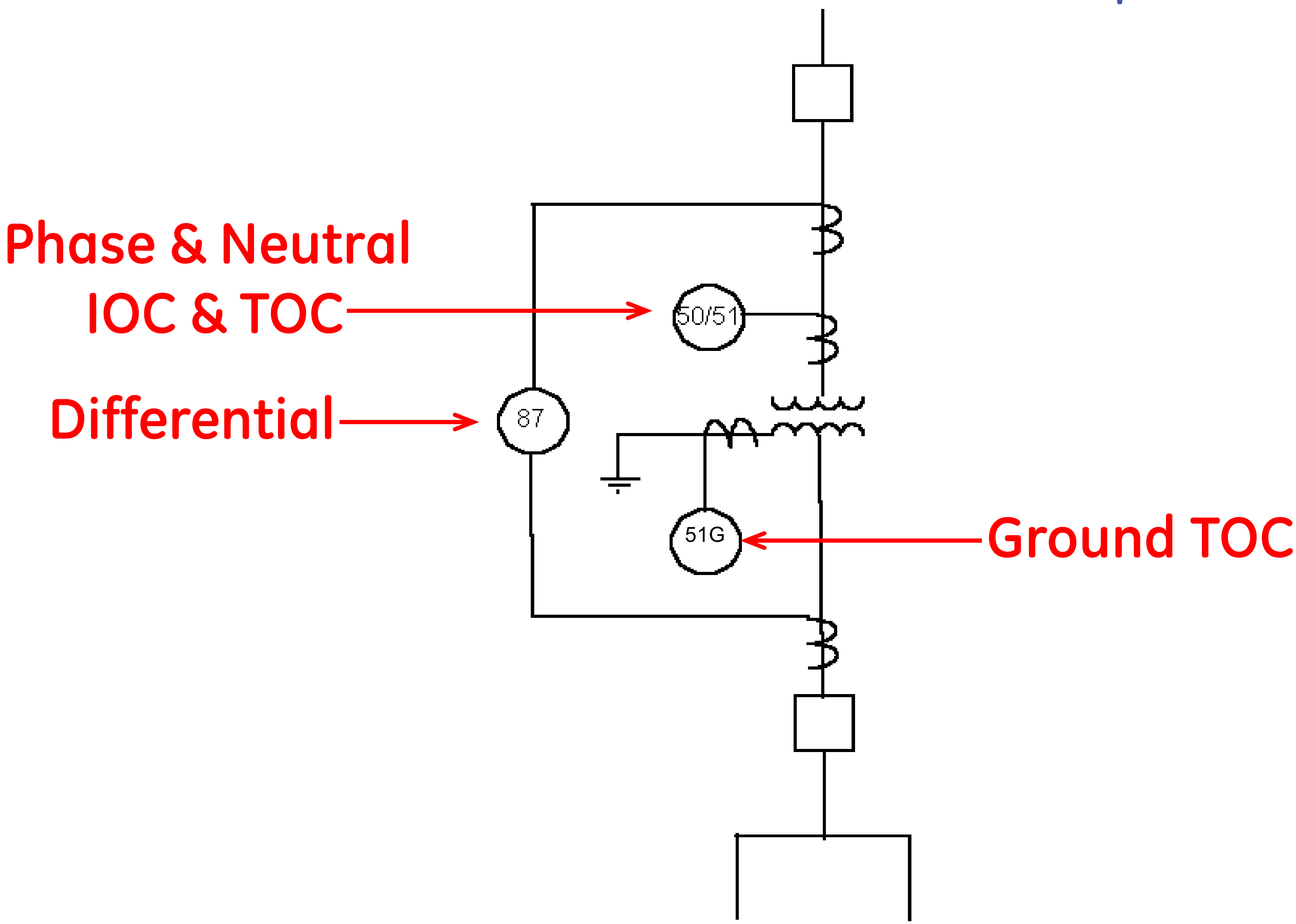
Negative sequence based restraint:
IR2 =| I2 | for first 2 cycles on transformer energization
IR2 =3*| I2 | - in normal conditions

Provides Restraint During External Phase to Phase Faults

Zero sequence based restraint:
IR0 =| IG - IN | =| IG – (IA + IB + IC) |

Provides Restraint During External Ground Faults

Transformer Overcurrent Backup



Overexcitation (V/Hz) Protection

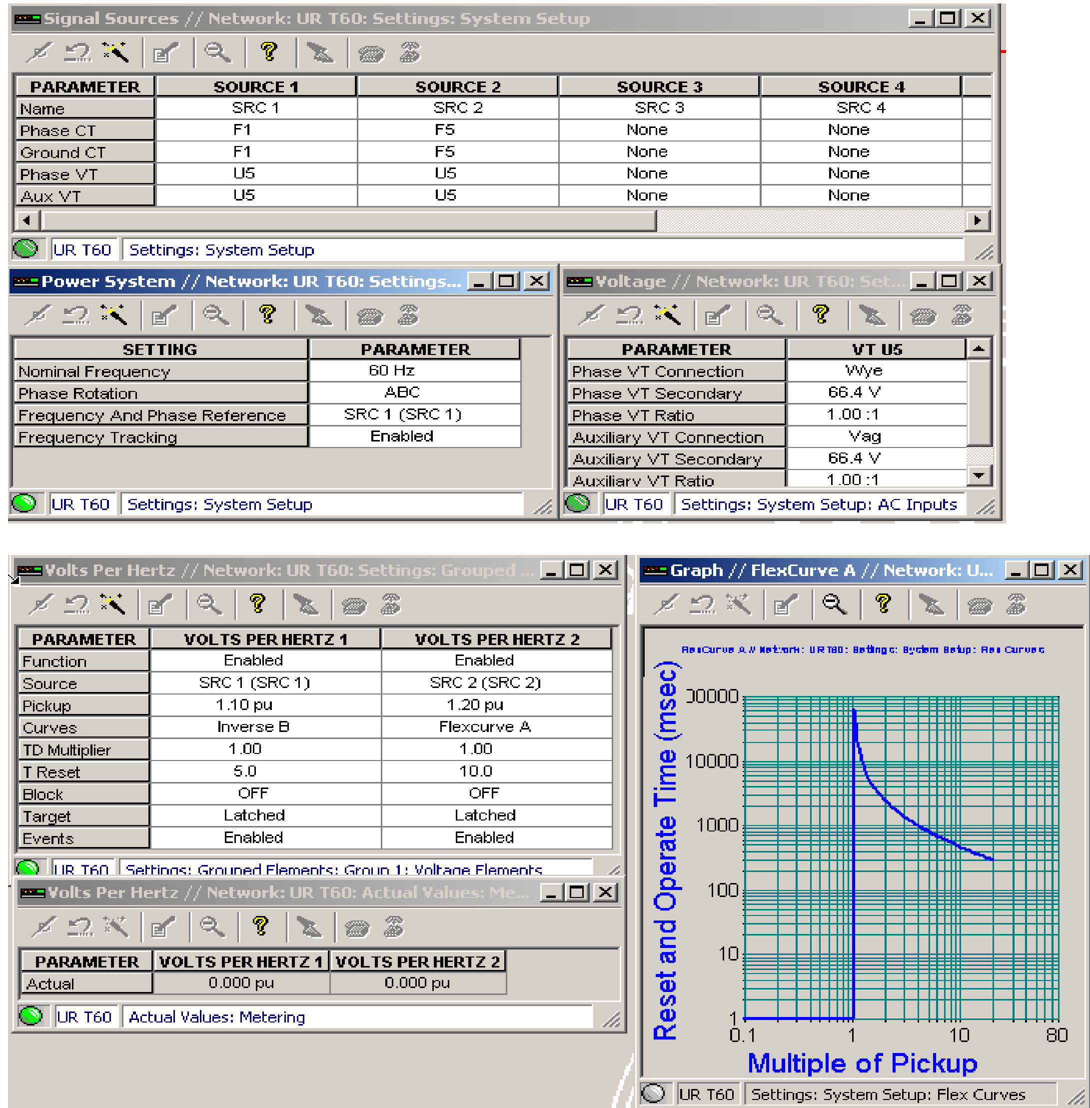
- ANSI function **24**
- Overflux protection - a result of system overvoltages, or low system frequency
- A transformer is designed to operate at or below a maximum magnetic flux density in the transformer core
- Above this design limit the eddy currents in the core and nearby conductive components cause 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

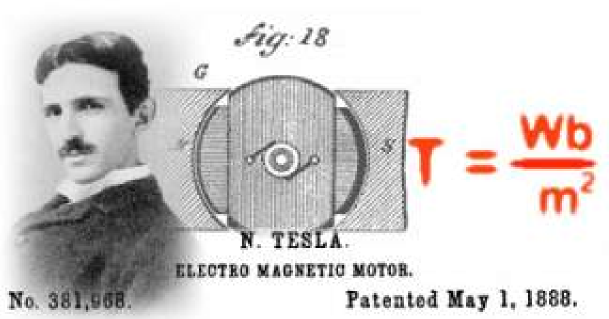


Motor Protection

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

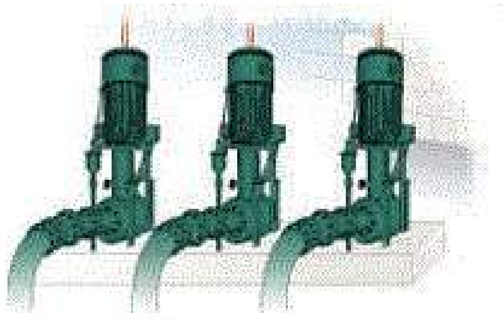
- Motors consume 25% of electricity in North America

- 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

IEEE STUDY		EPRI STUDY		AVERAGE
FAILURE CONTRIBUTOR	%	FAILED COMPONENT	%	%
Persistent Overload	4.20%	Stator Ground Insulation	23.00	Electrical Related Failures
Normal Deterioration	26.40%	Turn Insulation	4.00	
		Bracing	3.00	
		Core	1.00	
		Cage	5.00	33%
Electrical Related Total	30.60%	Electrical Related Total	36.00%	
High Vibration	15.50%	Sleeve Bearings	16.00	Mechanical Related Failures
Poor Lubrication	15.20%	Antifriction Bearings	8.00	
		Trust Bearings	5.00	
		Rotor Shaft	2.00	
		Rotor Core	1.00	31%
Mechanical Related Total	30.70%	Mechanical Related Total	32.00%	
High Ambient Temp.	3	Bearing Seals	6.00	Environmental, Maintanence & Other Reasons Related Failures
Abnormal Moisture	5.8	Oil Leakege	3.00	
Abnormal Voltage	1.5	Frame	1.00	
Abnormal Frequency	0.6	Wedges	1.00	
Abrasive Chemicals	4.2			
Poor Ventilation Cooling	3.9			
Other Reasons	19.7	Other Components	21.00	
Environmental Related & Other Reasons: Total	38.70%	Maintanence Related & Other Parts: Total	32.00%	36%

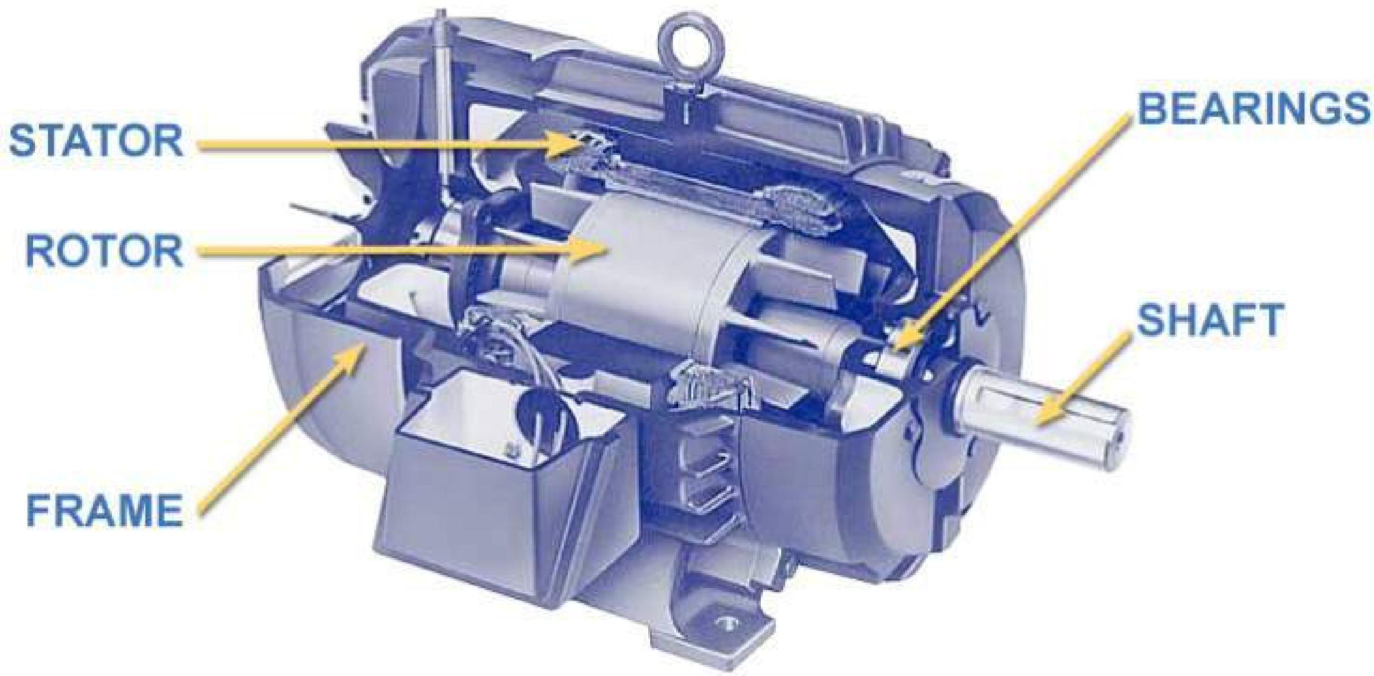
Motor Electrical Protection

- 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

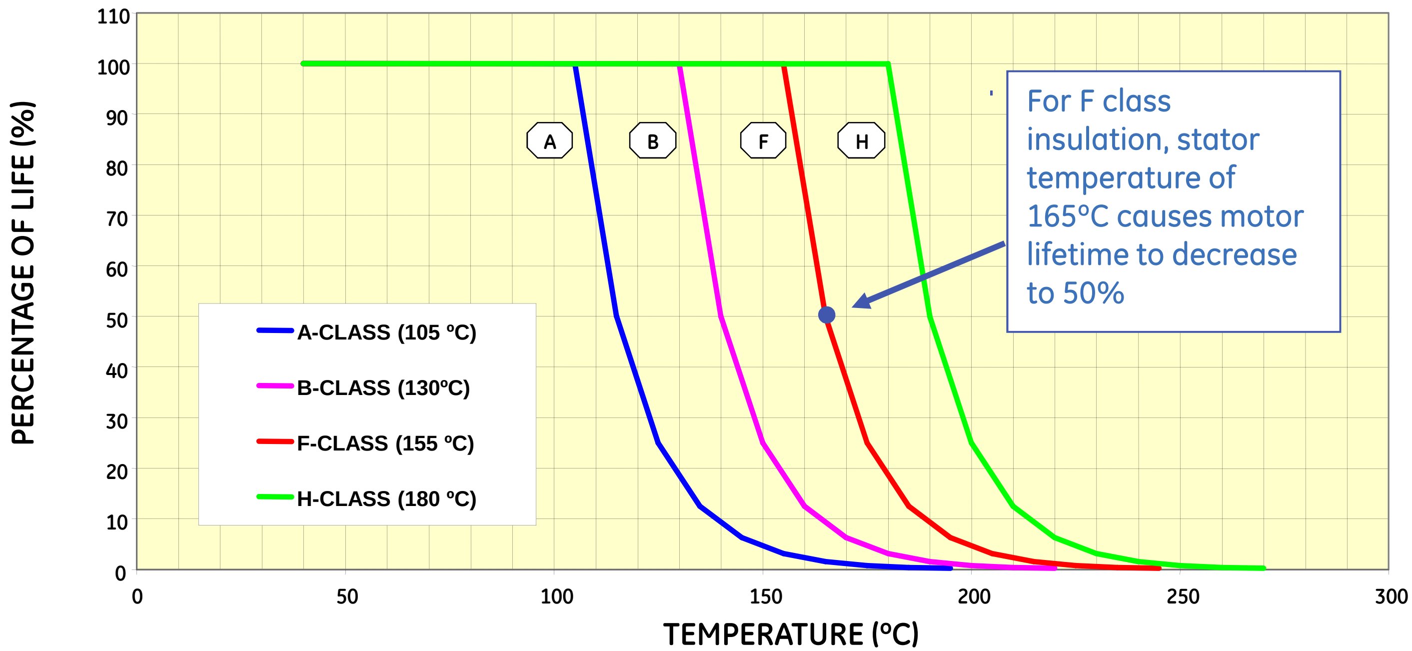
- Thermal stress potentially can cause the failure of all the major motor parts: Stator, Rotor, Bearings, Shaft and Frame



Risks for an Overheated Motor

- Stator Windings Insulation Degradation (for stator limited motors)

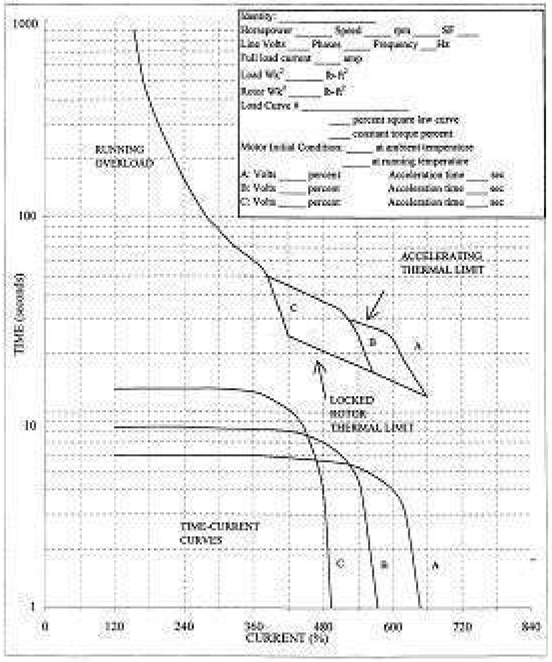
  Insulation lifetime decreases by half if motor operating temperature exceeds thermal limit by 10ºC for any period of time



- 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:**

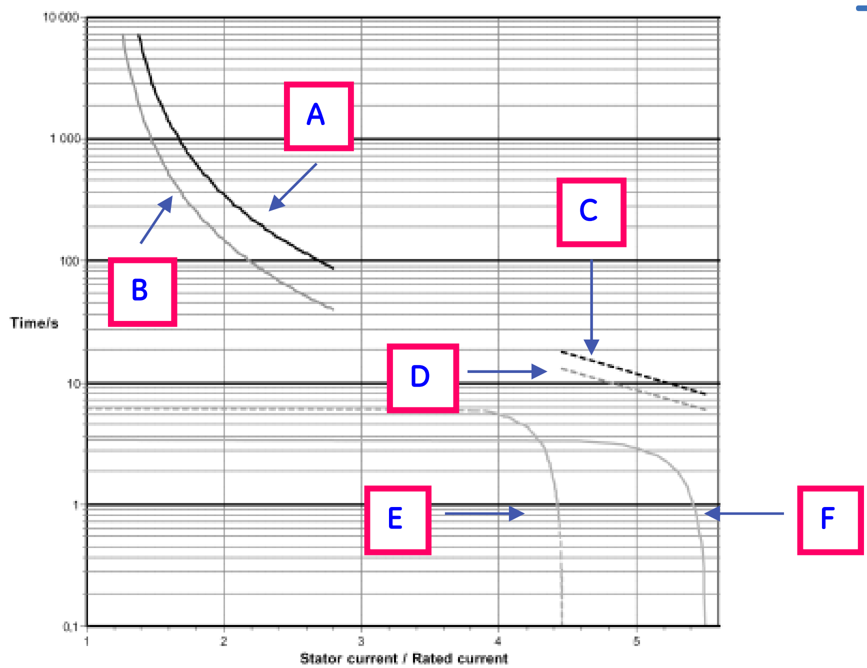
  Previous state is "Starting" or "Overloading" & Current drops below overload pickup level

- **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%

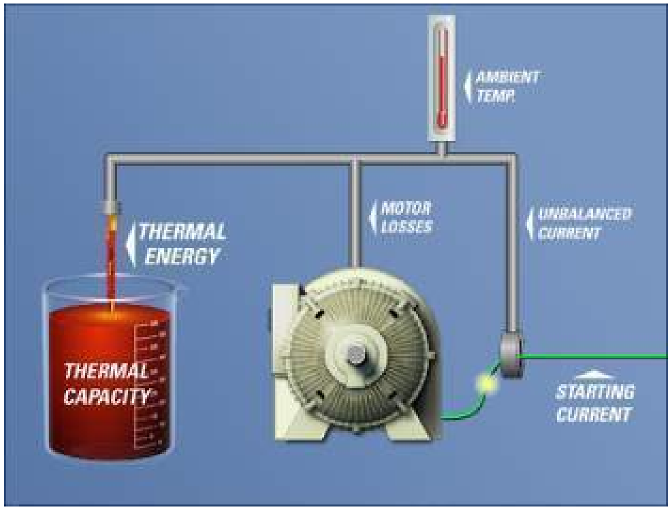
```
POWER        :8000 HP                           TYPE          :K
POLES        :4                                 FRAME         :8713Z
VOLTAGE      :13200 V                           ENCLOSURE     :WPII
FREQUENCY    :60  Hz           PHASES   :3      SERVICE FACTOR  :1.00
                                                INSULATION CLASS:F    (POLYSEAL)
TEMPERATURE RISE:80  C /RTD @ SF 1.0

DRIVEN LOAD       :FAN CLOSED VALVE
MAX. ALTITUDE     :3300 Ft
LOAD WK2 REF. TO MOTOR SHAFT : 49249 Lbft2
                                       Calculated Performance
                                       NEMA STARTING CODE    :F
RATED RPM           :1780              LOCKED ROTOR CURRENT  :540      %
RATED CURRENT       : 297 A            LOCKED ROTOR TORQUE   :77       %
RATED TORQUE        :23571   lbft      PULL UP TORQUE        :77       %
RATED KVA           :6790              BREAKDOWN TORQUE      :245      %
STATOR CONNECTION   :Y                 COUPLING TYPE         :DIRECT
MIN. STG. VOLTAGE   :70% V             ARRANGEMENT           :F1
TIME RATING         :CONTINUOUS
                                       ROTATION              :DUAL
AMB. TEMP. (MIN/MAX)    :-18/40 C      MAX. BRG.VIBR.(PK-PK) :0.0016   in
TOTAL WEIGHT (calc.)    :53700  lb     BEARING TYPR          :SLEEVE
ROTOR WK2 (calculated)  :10422 Lbft2   BEARING LUBRICATION   :OIL
                                       END PLAY              :0.50     in
NOISE LEVEL (dBA)       : 85.0 @ 3.3 ft  LOCKED ROTOR TIME
MAX CAPACITOR KVAr      :1000                     COLD       :35 Sec
STATOR RESIST. @ 25C    :0.1910 Ohms L-L          HOT        :30 Sec
X/R  RATIO              : 33.960       NUMBER OF STARTS (NEMA MG1-20.43)
OPEN CIRC. CONSTANT     :1.5680 S                 COLD       :2
ACCELERATION TIME       :15   Sec              OR HOT        :1
```

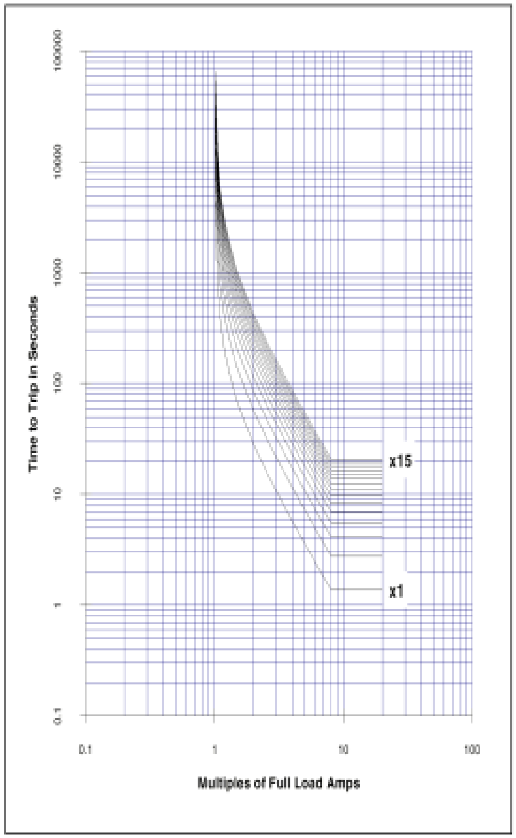
SF	Thermal Overload Pickup
1.0	1.1
1.15	1.25

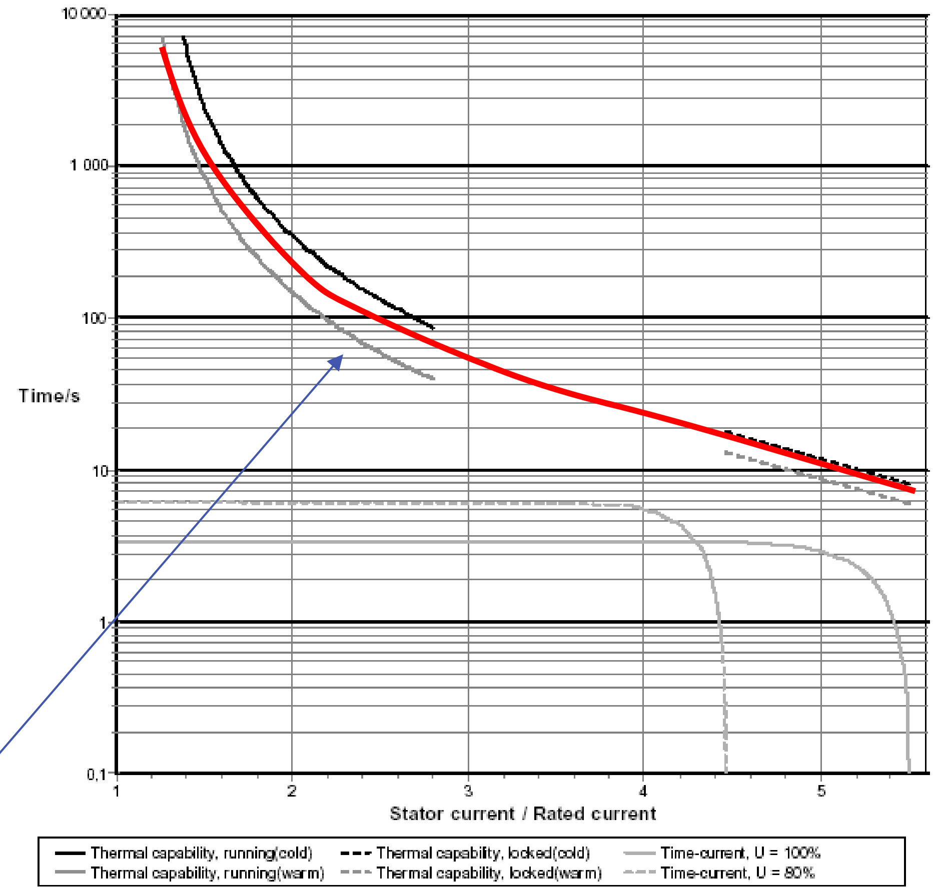
Thermal Model – Thermal Capacity Used

- 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 Selection





Overload Curve

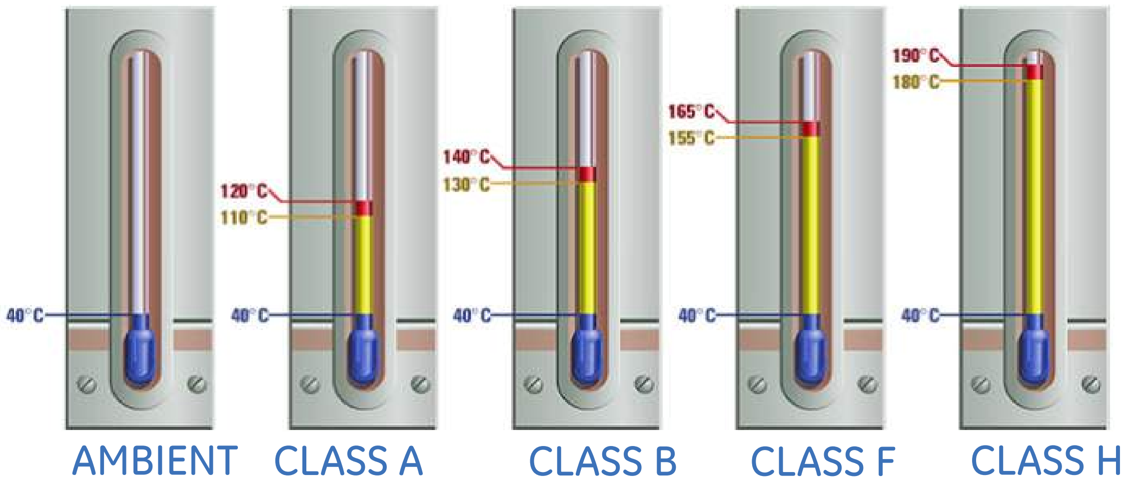
Set the overload curve below cold thermal limit and above hot thermal limit

If only hot curve is provided by mfgr, then must set below hot thermal limit

Thermal Model

Hot/Cold Stall Time Ratio (HCR)

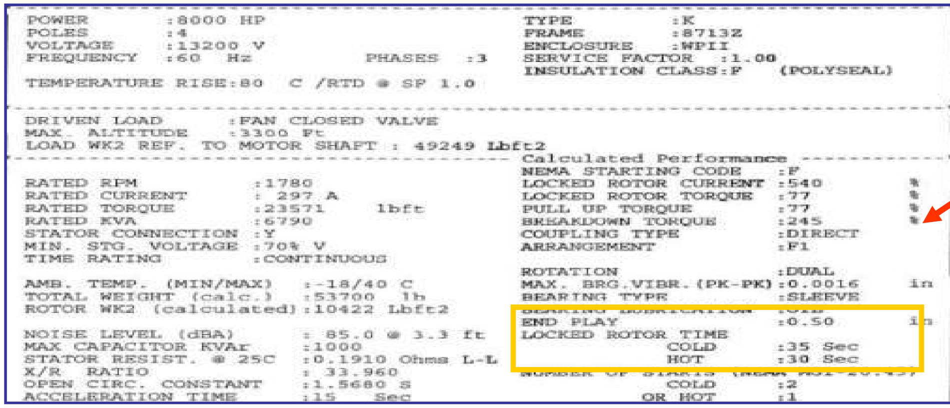
- Typically motor manufacturer provides the values of the locked rotor thermal limits for 2 motor conditions:
  - *COLD* : motor @ ambient temperature
  - *HOT* : motor @ rated temperature for specific class and service factor.
- NEMA standard temperature rises for motors up to 1500HP and Service Factors 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.

Thermal Model

Hot/Cold Safe Stall Ratio


POWER :8000 HP
POLES :4
VOLTAGE :13200 V
FREQUENCY :60 Hz PHASES :3
TEMPERATURE RISE:80 C /RTD @ SF 1.0

TYPE :K
FRAME :8713Z
ENCLOSURE :WPII
SERVICE FACTOR :1.00
INSULATION CLASS:F (POLYSEAL)

DRIVEN LOAD :FAN CLOSED VALVE
MAX. ALTITUDE :3300 Ft
LOAD WK2 REF. TO MOTOR SHAFT : 49249 Lbft2

RATED RPM :1780
RATED CURRENT : 297 A
RATED TORQUE :23571 lbft
RATED KVA :6790
STATOR CONNECTION :Y
MIN. STG. VOLTAGE :70% V
TIME RATING :CONTINUOUS

AMB. TEMP. (MIN/MAX) :-18/40 C
TOTAL WEIGHT (calc.) :53700 lb
ROTOR WK2 (calculated):10422 Lbft2

NOISE LEVEL (dBA) : 85.0 @ 3.3 ft
MAX CAPACITOR KVAr :1000
STATOR RESIST. @ 25C :0.1910 Ohms L-L
X/R RATIO : 33.960
OPEN CIRC. CONSTANT :1.5680 S
ACCELERATION TIME :15 Sec

Calculated Performance
NEMA STARTING CODE :F
LOCKED ROTOR CURRENT :540 %
LOCKED ROTOR TORQUE :77 %
PULL UP TORQUE :77 %
BREAKDOWN TORQUE :245 %
COUPLING TYPE :DIRECT
ARRANGEMENT :F1

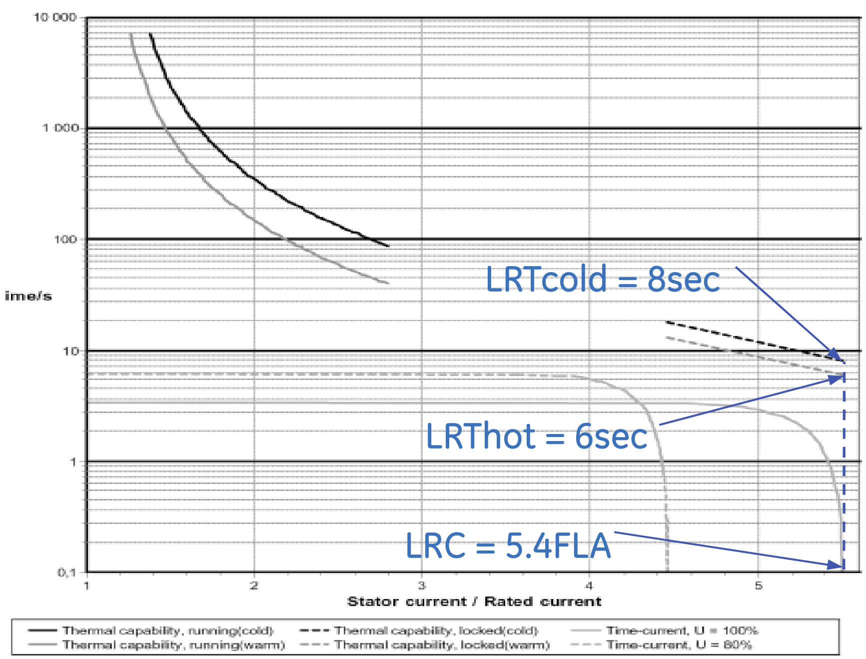
ROTATION :DUAL
MAX. BRG.VIBR.(PK-PK):0.0016 in
BEARING TYPE :SLEEVE
END PLAY :0.50 in
LOCKED ROTOR TIME
COLD :35 Sec
HOT :30 Sec
COLD :2
OR HOT :1

$$HCR = \frac{LRT_{HOT}}{LRT_{COLD}}$$

Hot/Cold Ratio = 30/35

=> 0.86

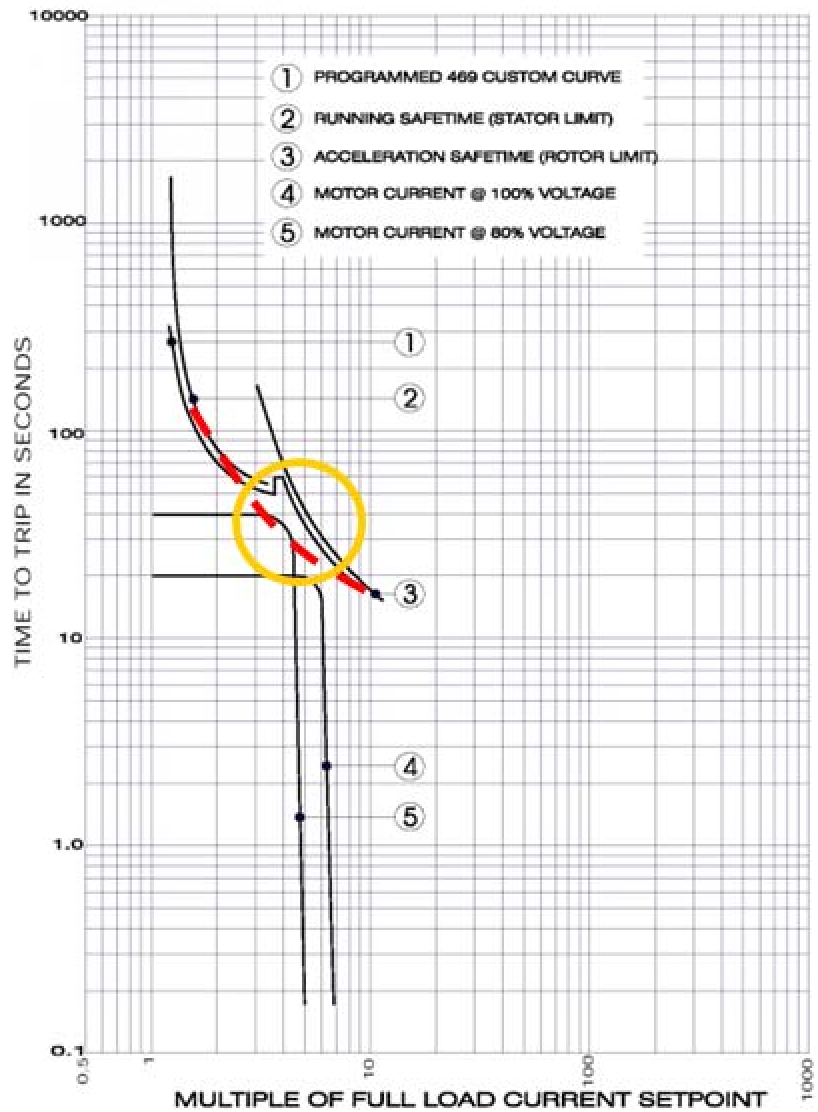
Overload Curve Method



- 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: = 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

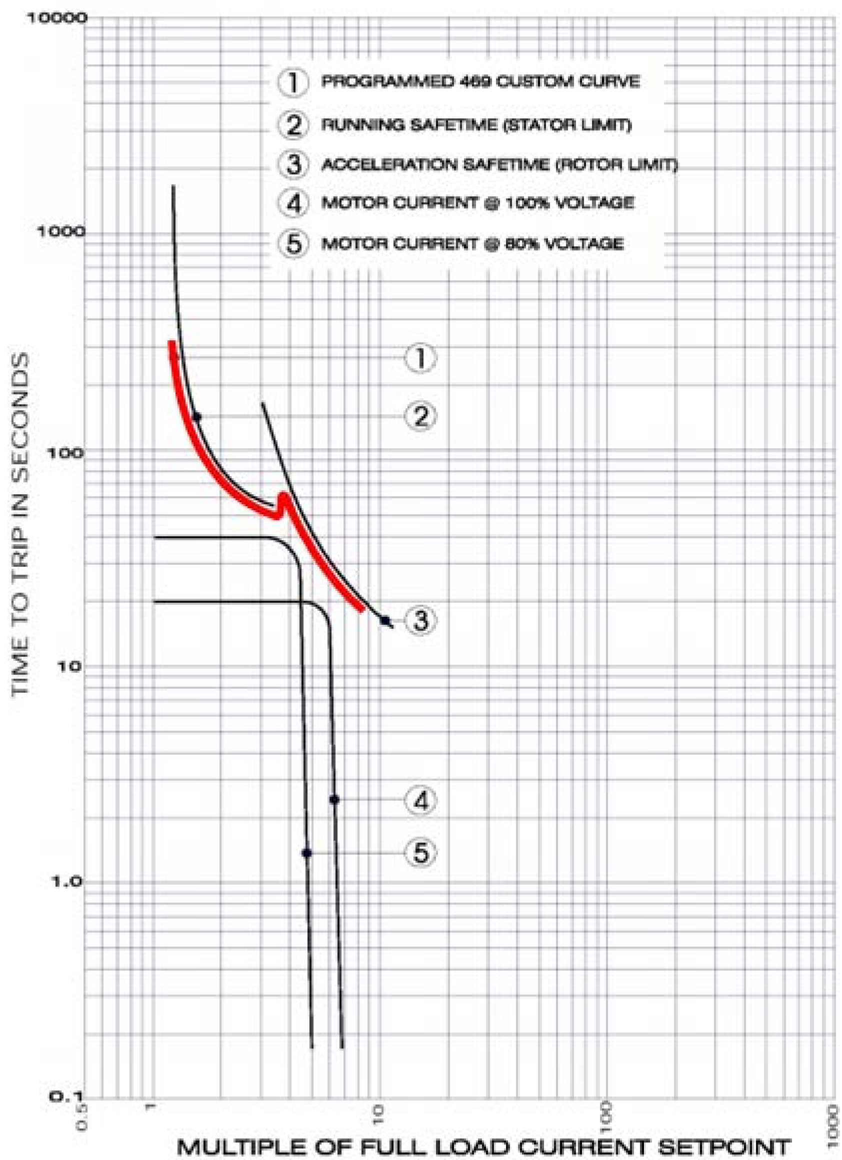
Overload Curve Selection

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



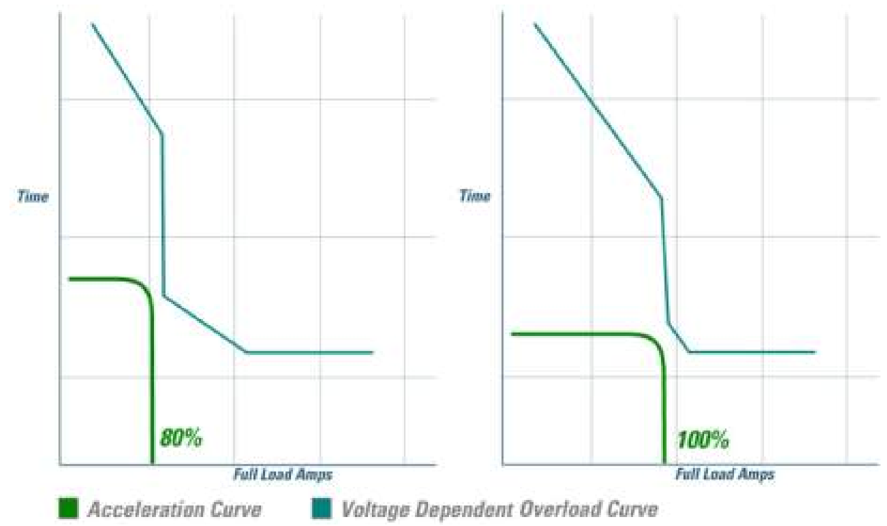
Overload Curve Selection

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

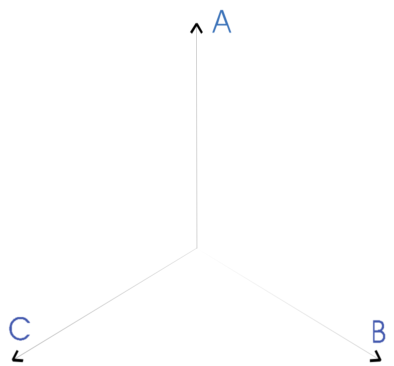
- Issue ➔Duration of a high inertia load start is longer than the allowed motor safe stall time
  - For these starts, thermal model must account for the current change during acceleration and also use the acceleration thermal limits for TCU calculations
  - Motor thermal limit is growing along with motor 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



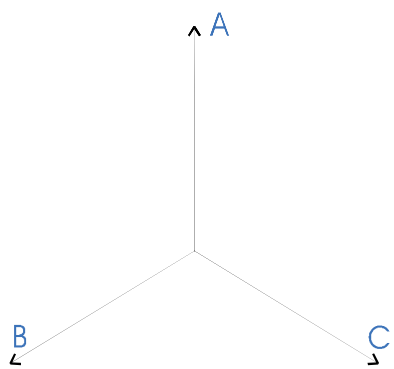
Thermal Model

Current Unbalance Bias

Negative sequence currents (or unbalanced phase currents) will cause additional rotor heating that will be accounted for in Thermal Model

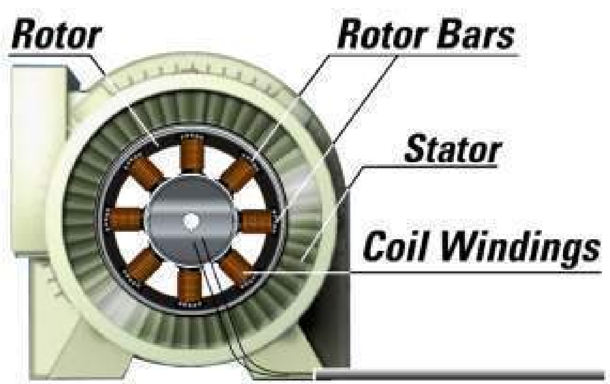


Positive Sequence



Negative Sequence

- <u>Main causes of current unbalance</u>
  - Blown fuses
  - Loose connections
  - Stator turn-to-turn faults
  - System voltage distortion and unbalance
  - Faults



Thermal Model

Current Unbalance Bias

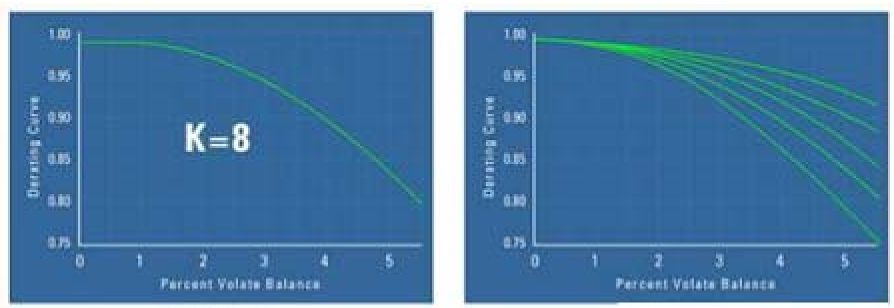
- **Equivalent heating motor current** is employed to bias thermal model in response to current unbalance

$$I_{EQ} = \sqrt{I_M^2 \times (1 + K \times (I_2 / I_1)^2)}$$

- Im - 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

$K = 175 / I_{LRC}^2$ TYPICAL

$K = 230 / I_{LRC}^2$ CONSERVATIVE



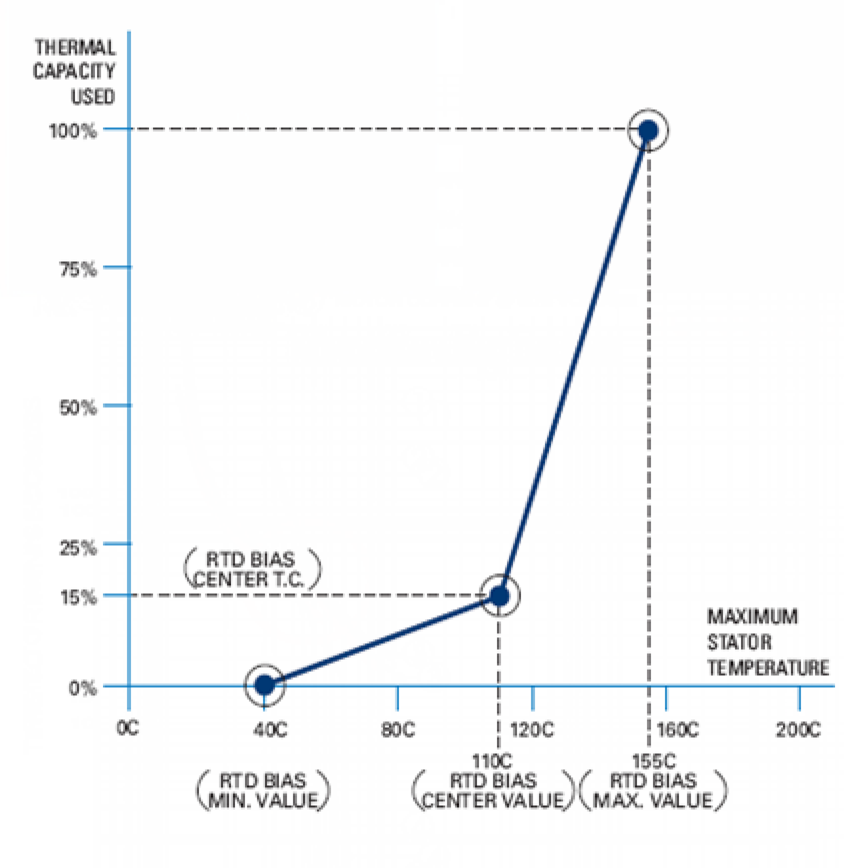
NEMA MOTOR RELAY

Motor Derating Curves

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

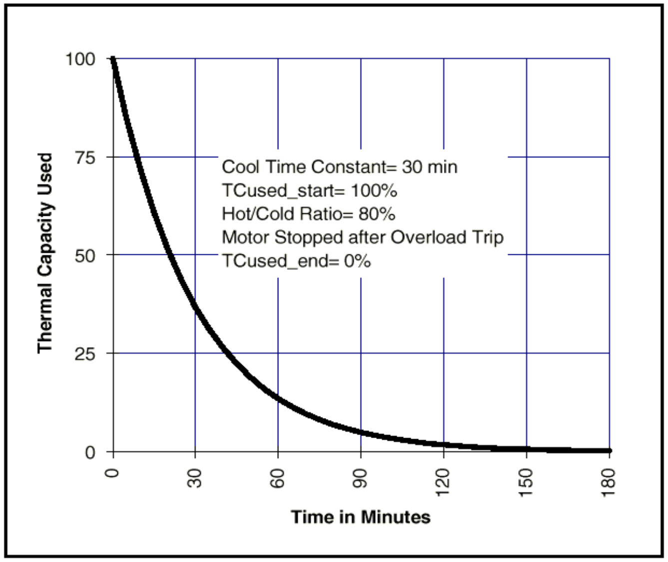


Thermal Model

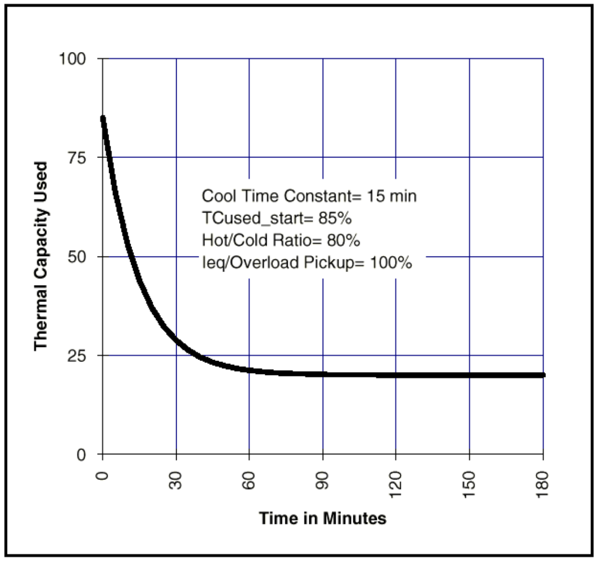
Motor Cooling

- 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

Thermal Model Cooling Motor Tripped



Thermal Model Cooling100% load - Running



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

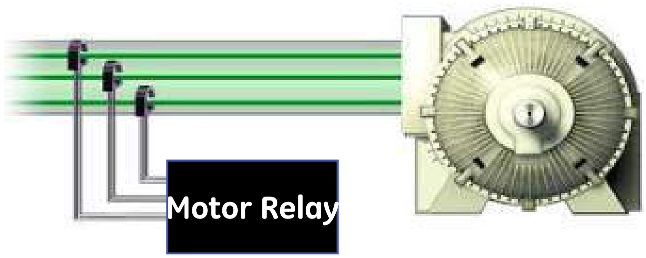
Undervoltage Protection

- 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

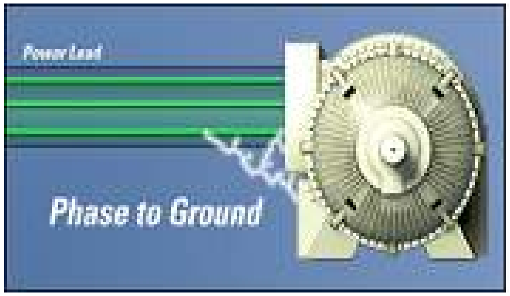
- Current unbalance can also be present due to:
  - Loose or bad connections
  - Incorrect phase rotation connection
  - Stator turn-to-turn faults



- 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.

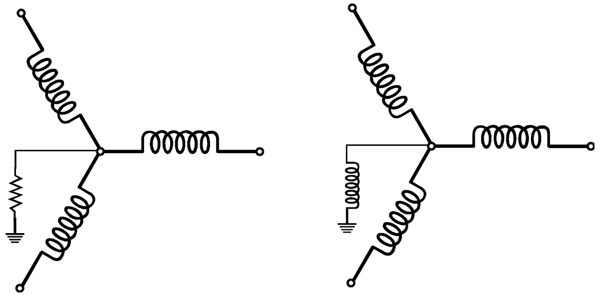
Ground Fault Protection

- 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

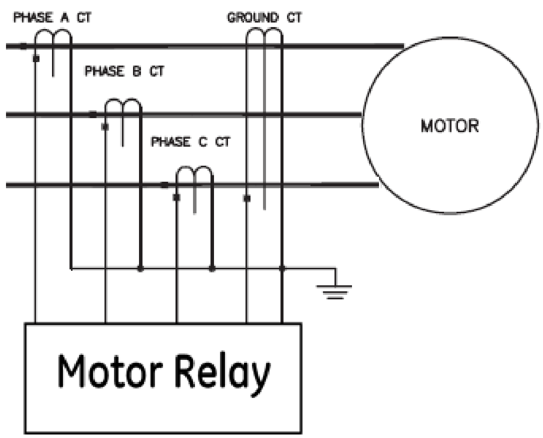


- Ground faults in a motor occur:
  - When its phase conductor's insulation is damaged for example due to voltage stress, moisture or internal fault occurs between the conductor and ground

- 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

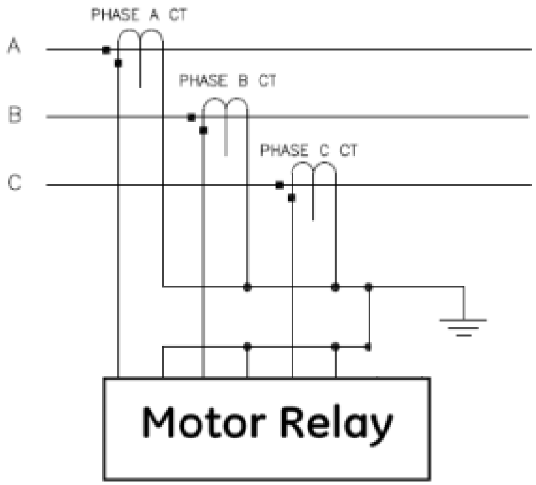


Zero Sequence CT Connection

- 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

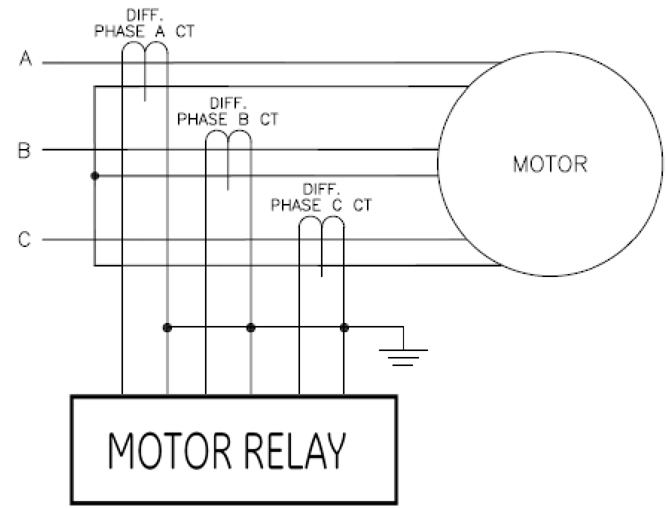
- For large cables that cannot be fit through the zero sequence CT's window, the residual ground fault configuration can be used
- This configuration is inherently less sensitive than that of the zero sequence configuration owing to the fact that the CTs are not perfectly matched
- During motor starting, 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:

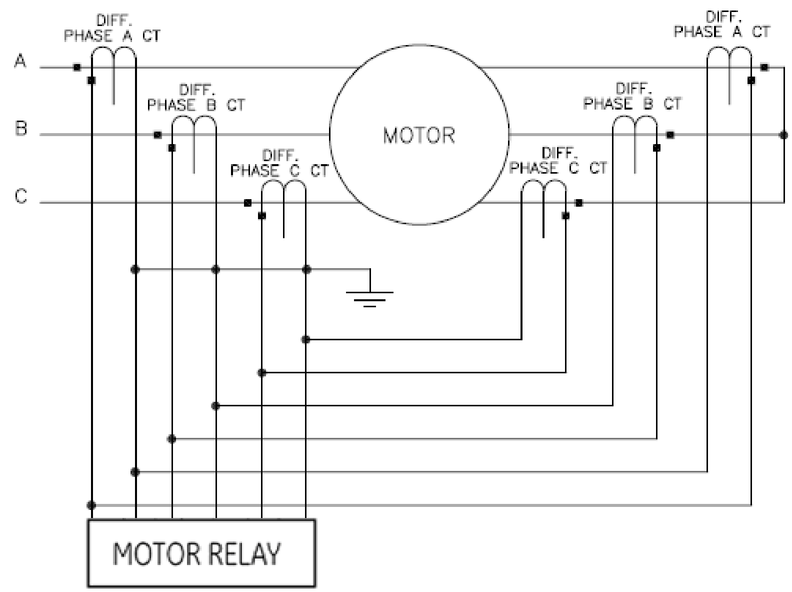
- Two sets of CT's, one at the beginning of the motor feeder, and the other at the neutral point
- Alternatively, one set of three core-balance CTs can also be used
- The differential element subtracts the current coming out of each phase from the current going into each phase and compares the result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



Differential Protection

Summation method with six CTs:

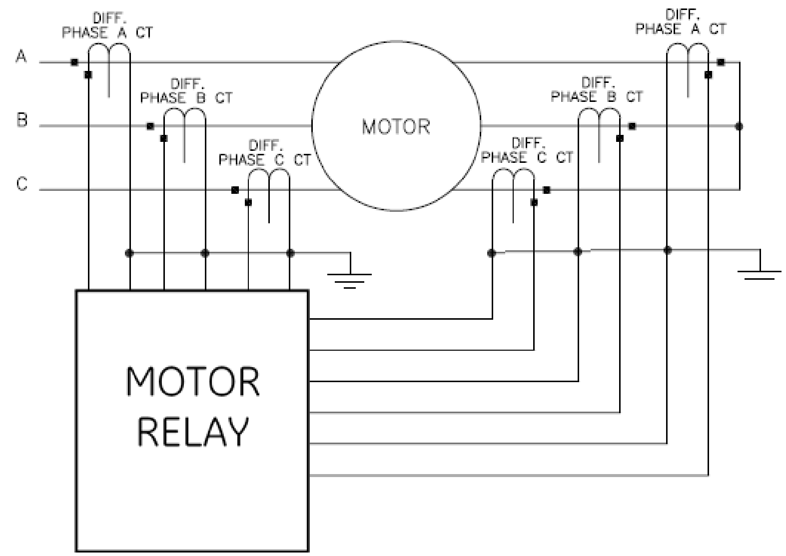
- If six CTs are used in a summing configuration, during motor starting, the values from the two CTs on each phase may not be equal as the CTs are not perfectly identical and asymmetrical currents may cause the CTs on each phase to have different outputs
- To prevent nuisance tripping in this configuration,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

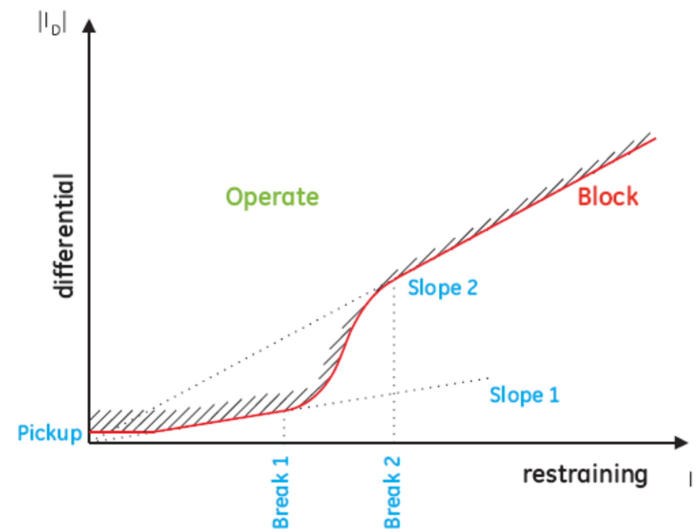


Differential Protection

Biased differential protection - six CTs:

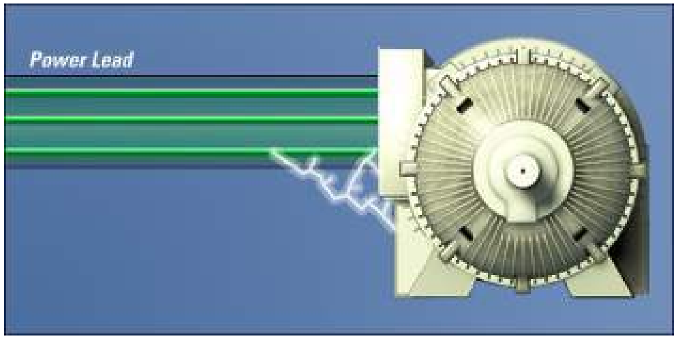
- Biased differential protection method allows for different ratios for system/line and the neutral CT's
- This method has a dual slope characteristic. Main purpose of the percent-slope characteristic is to prevent a mis-operation caused by unbalances between CTs during external faults. CT unbalances 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

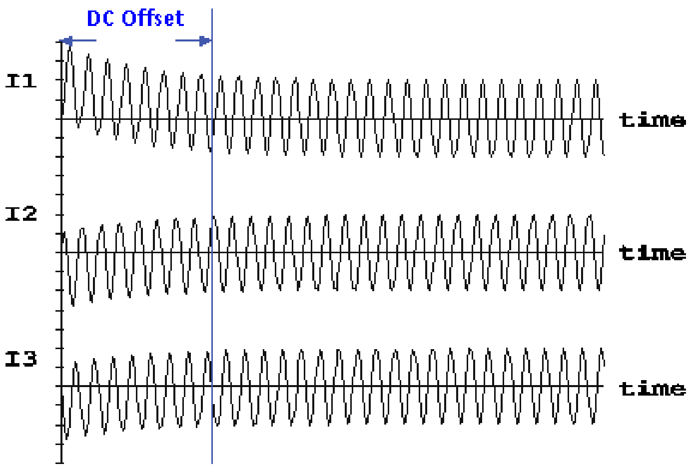




Short Circuit Protection

- 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 then 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

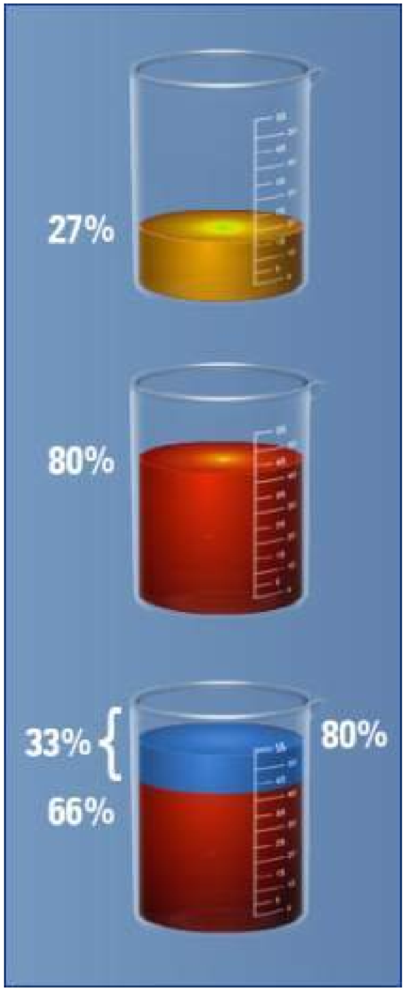
- Time Between Starts (Jogging)

- 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

TCU / Start Inhibit Example



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% × 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

Start Inhibit

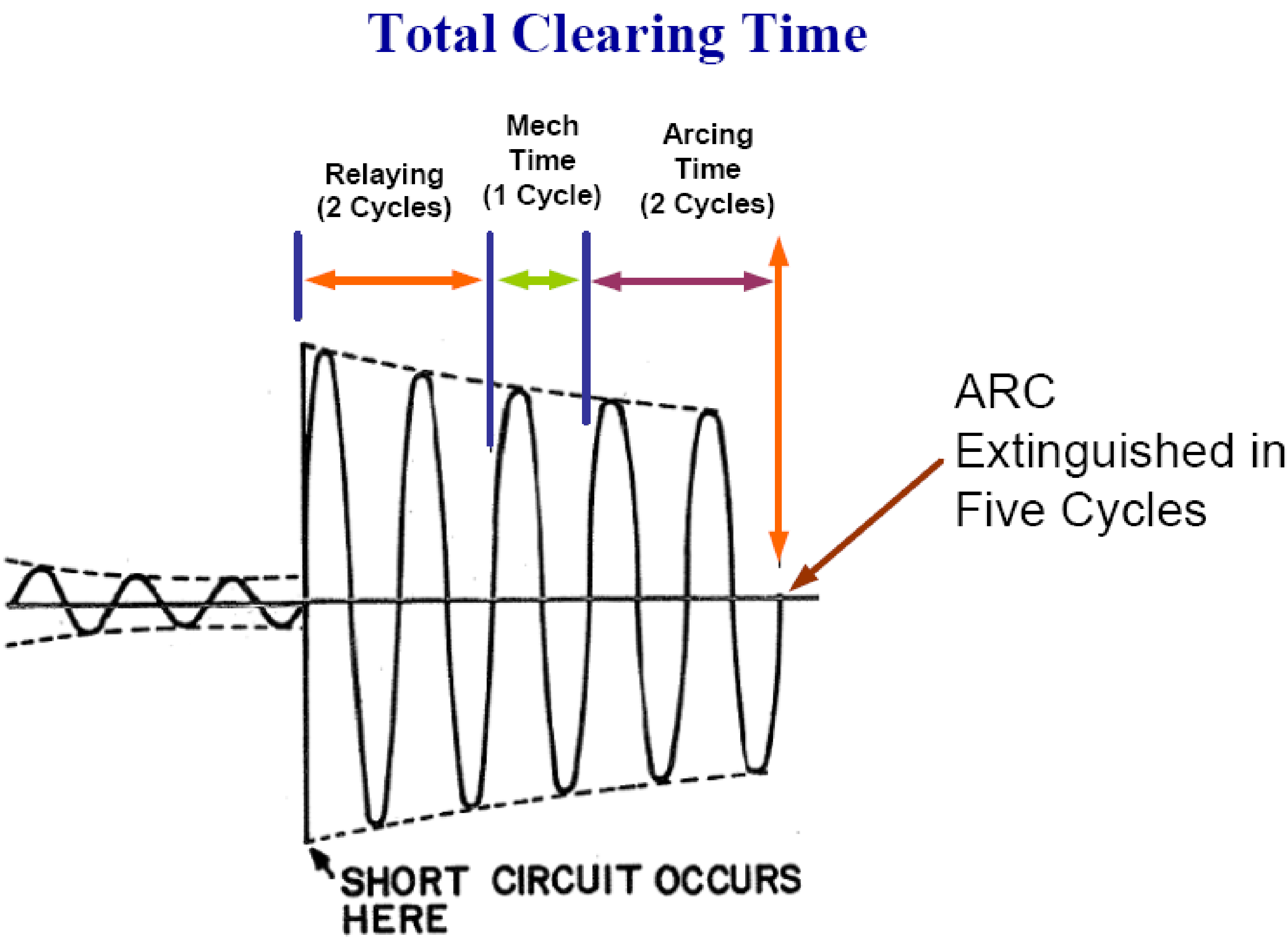
SETTING	PARAMETER
Start Inhibit Block	On/Yes
Thermal Capacity Used Margin	25 %

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…….



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 $\mathbf{I^2t}$ 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"

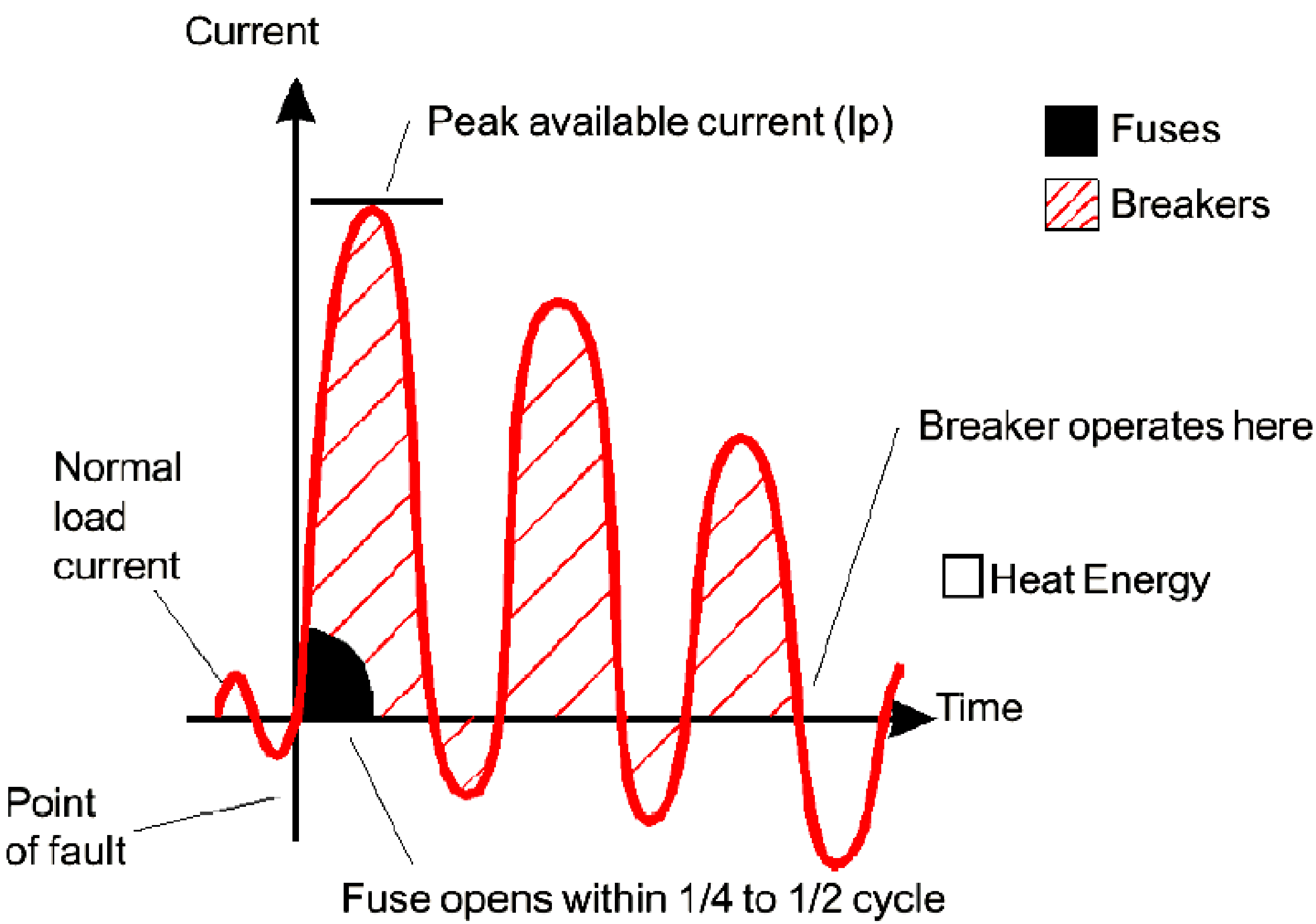
Non-Protective Relaying Methods of Reducing Arc Flash Hazard

- 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



Arc Flash Hazards

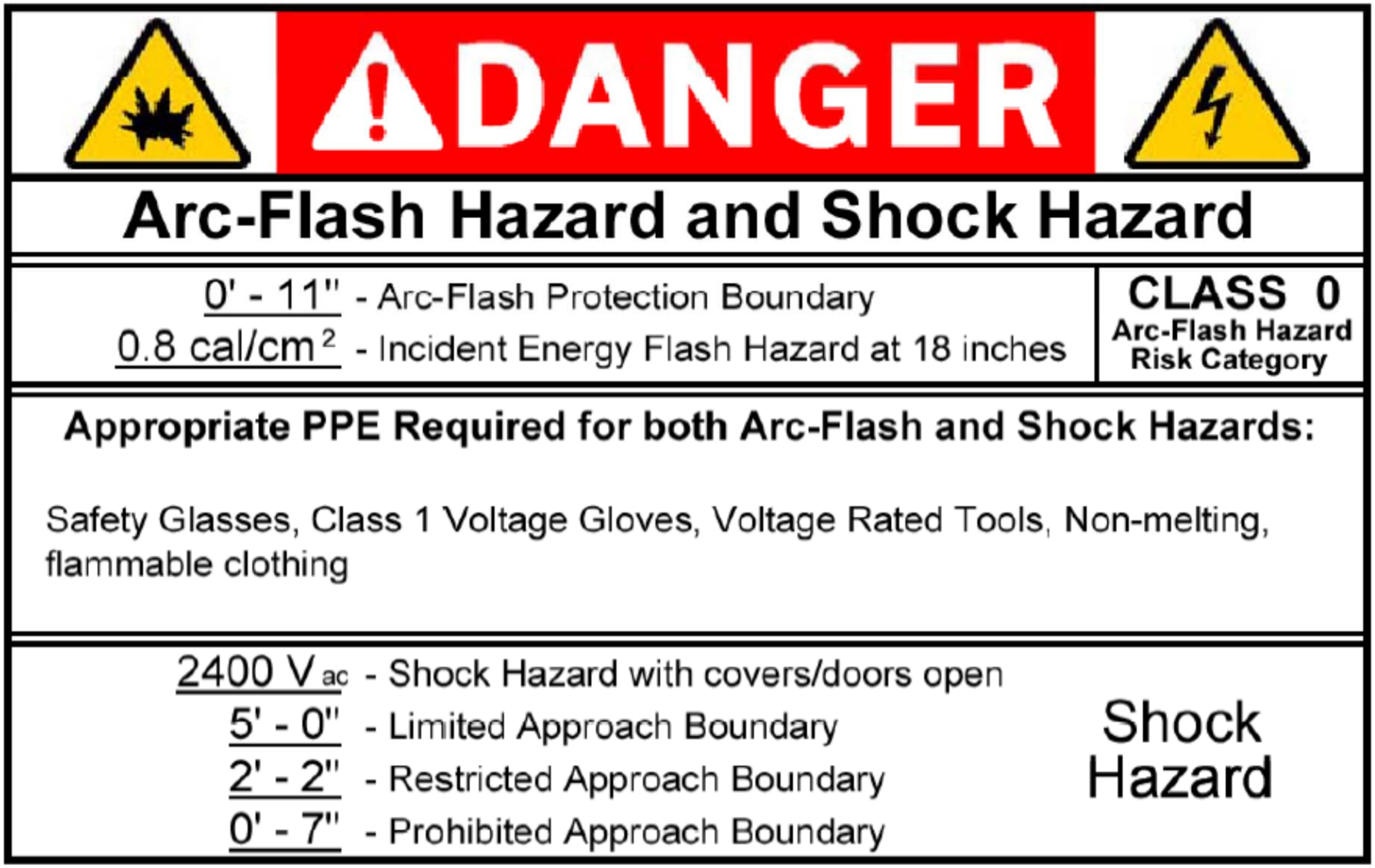
Skin Temperature	Time of Skin Temp.	Damage Caused
110 °F	6 Hours	Cell breakdown starts
158 °F	1 sec.	Total cell destruction
176 °F	0.1 sec	Curable burn
200 °F	0.1 sec	Incurable burn

NFPA-70E 2004 Equipment Requirements

Category	Energy Level	Typical Personal Protective Equipment required
0	1.2 cal/cm^2	Non-melting flammable materials
1	5 cal/cm^2	Fire Resistant (FR) shirt and FR pants
2	8 cal/cm^2	FR shirt, FR pants, cotton underwear
3	25 cal/cm^2	Two layers FR clothing, cotton underwear
4	40 cal/cm^2	FR shirt, FR pants, multilayer flash suit, cotton underwear

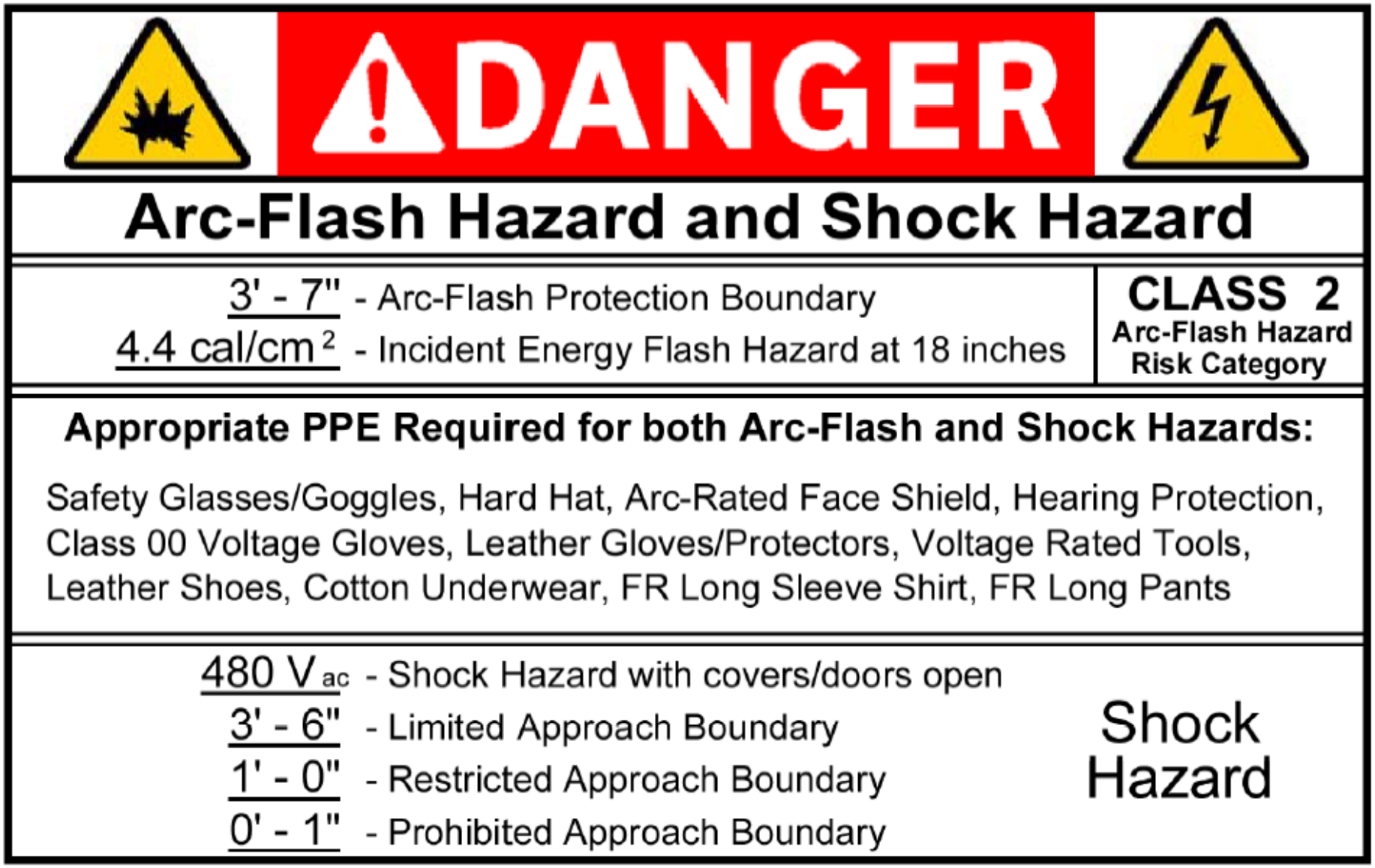
Other:
Face Protection Face Shield and/or safety glasses
Hand Protection Leather over rubber for arc flash protection
Leather work boots above 5 cal/cm^2

Arc Flash Warning Example 1



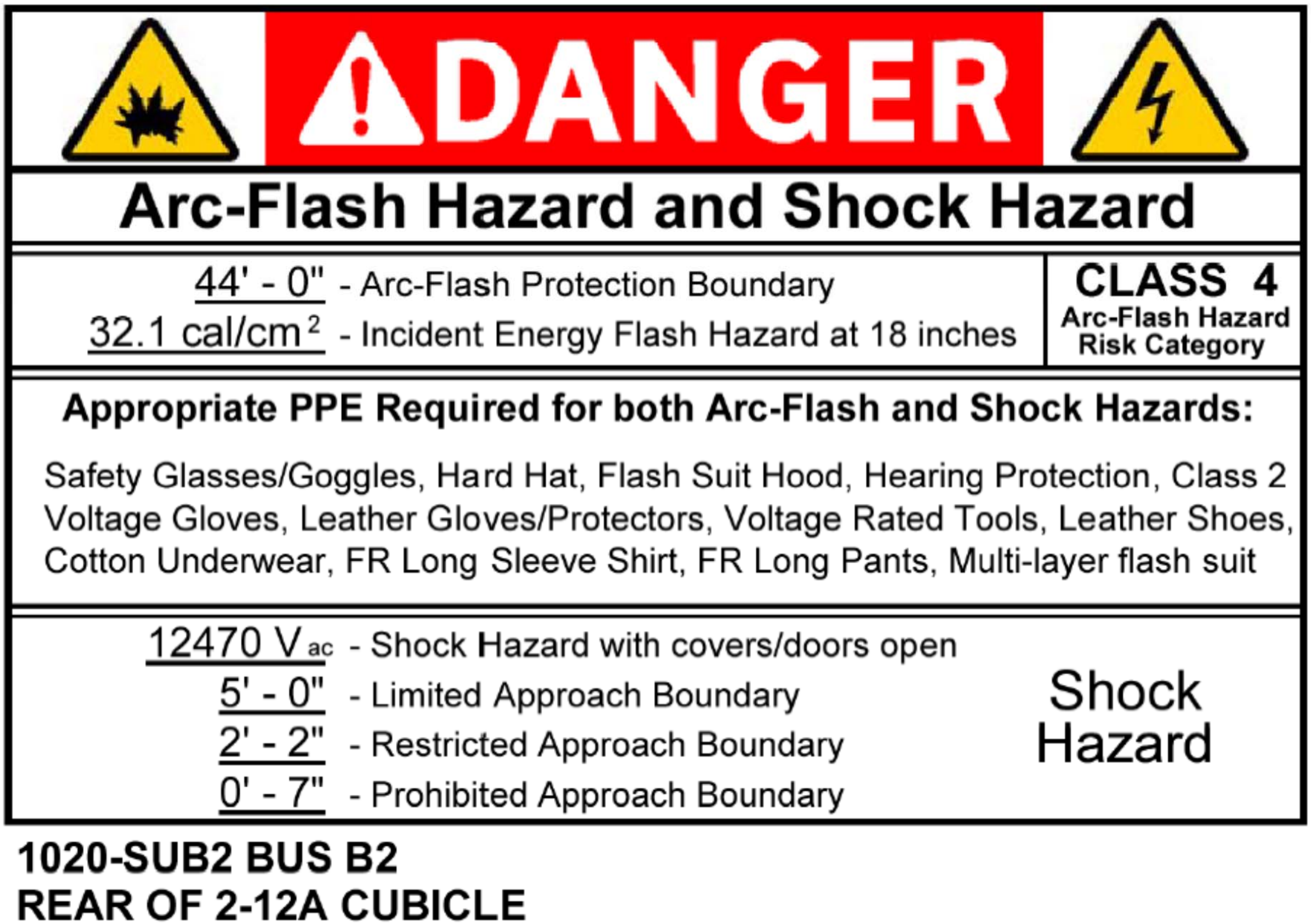
1106-MCC 2-1
STARTER DOOR OF AIR COMPRESSOR #1

Arc Flash Warning Example 2



1806-MCC G
AHU #2

Arc Flash Warning Example 3



Arc Flash Solutions

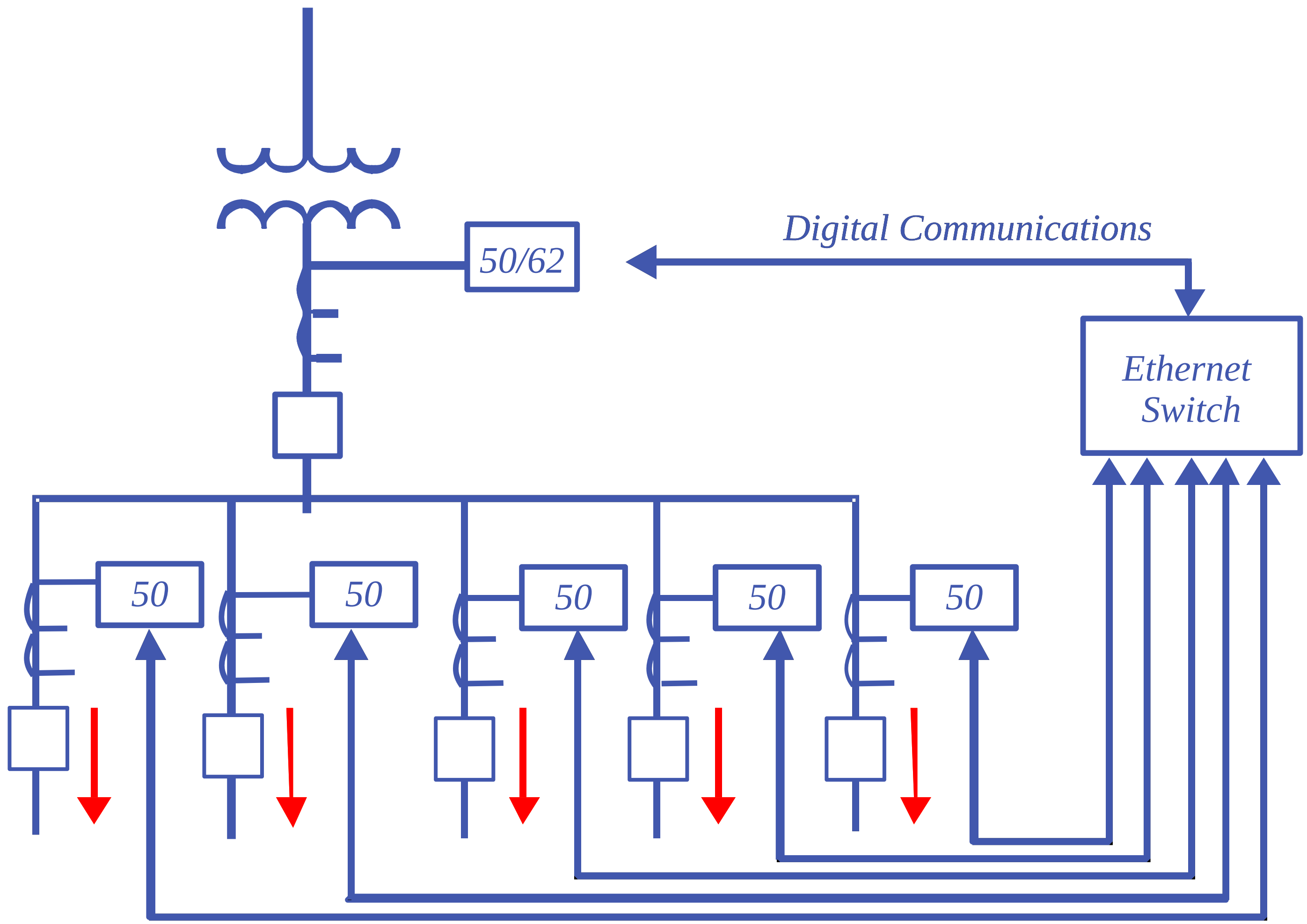
Relaying Techniques to Reduce Arc Flash Energy

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

Time to clear saves lives

Arc Flash Solutions

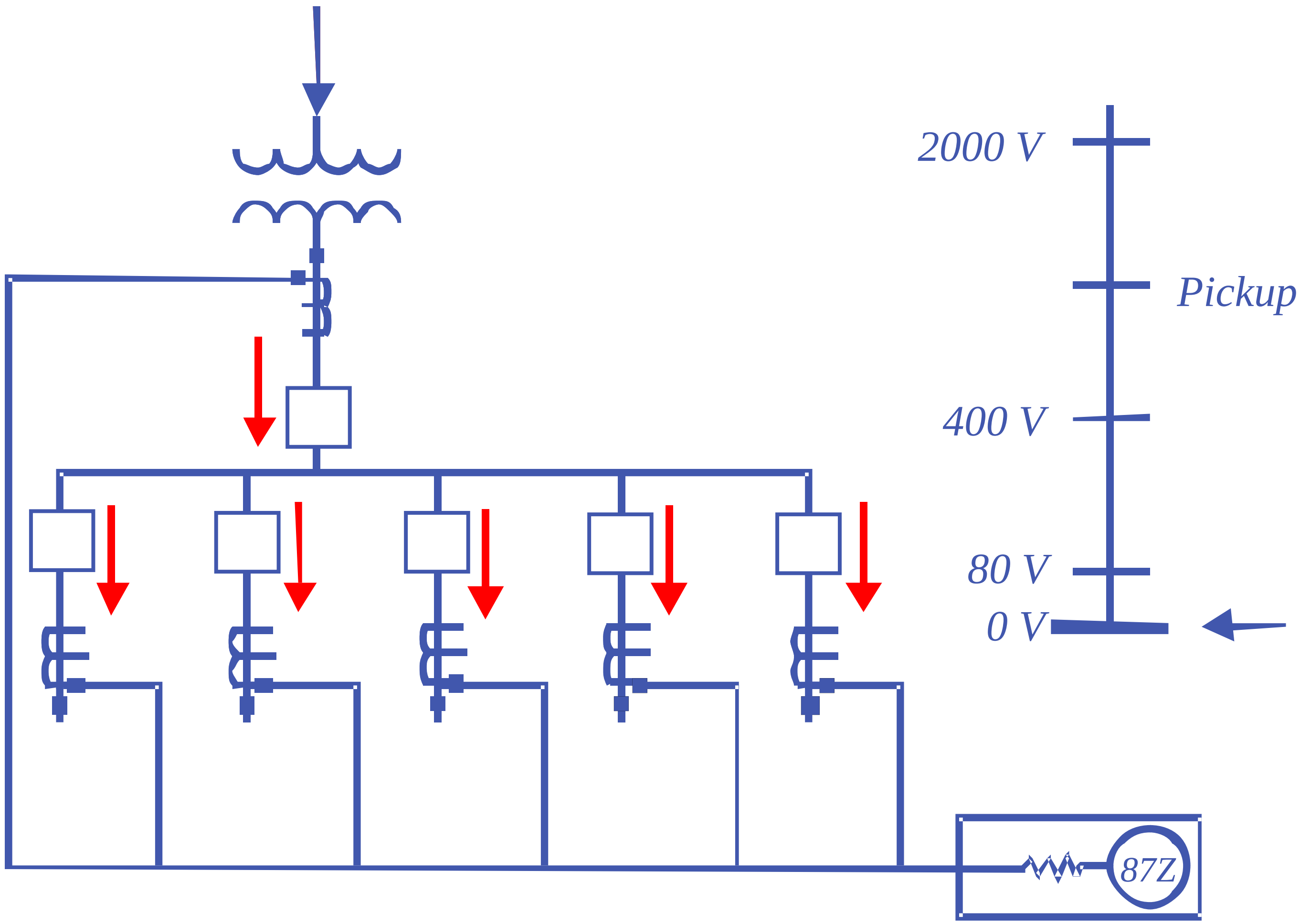
Bus Zone Interlocking Scheme



3-4 Cycles Detection

Arc Flash Solutions

High Impedance Bus Differential



1.5 to 2 Cycles Detection

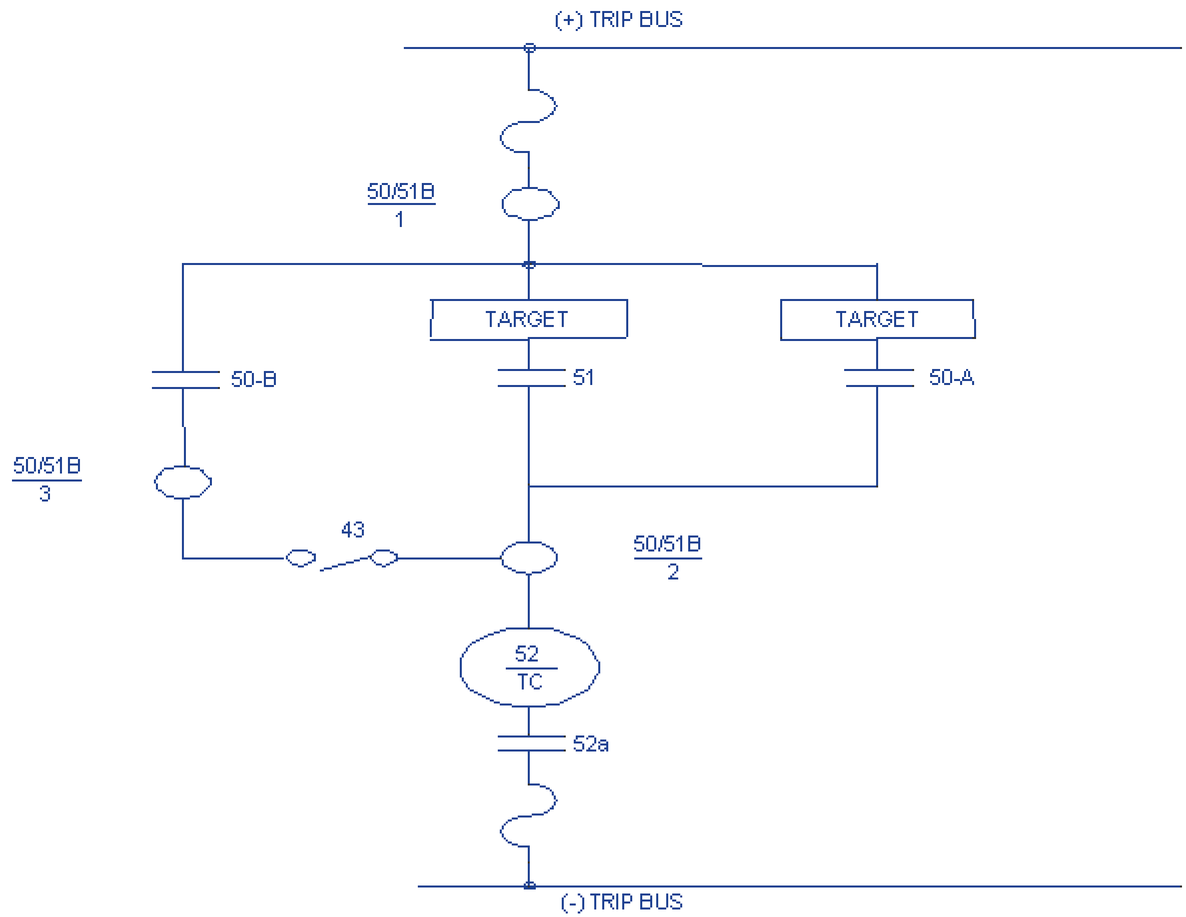
Arc Flash Solutions
Enable Maintenance Mode

- 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

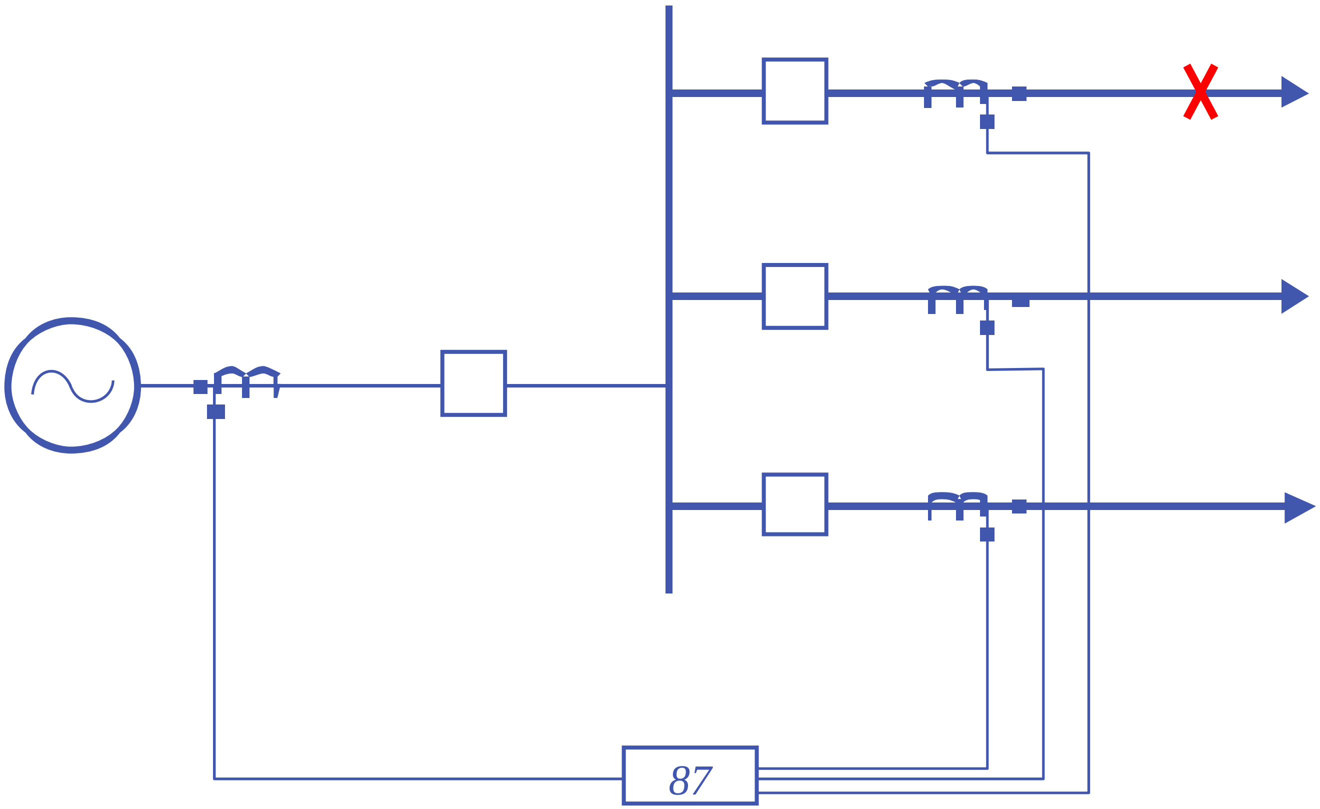
2nd Instantaneous Overcurrent Element



1.5 to 2 Cycles Detection

Arc Flash Solutions

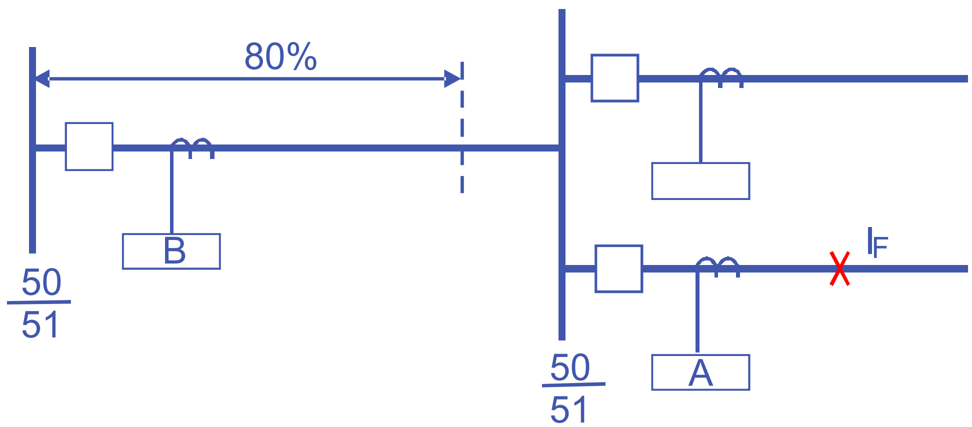
Low Impedance Bus Differential



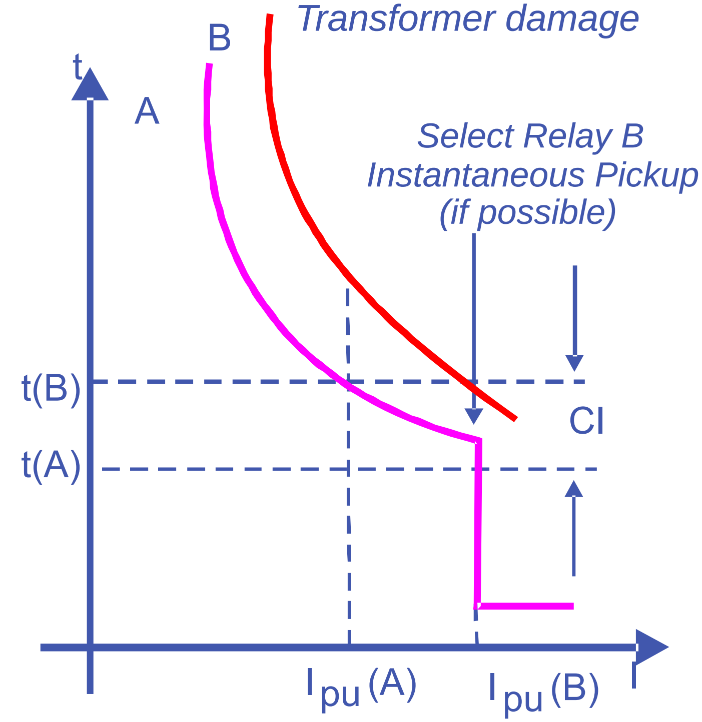
1 Cycle Detection

Arc Flash Solutions

Time Current Coordination



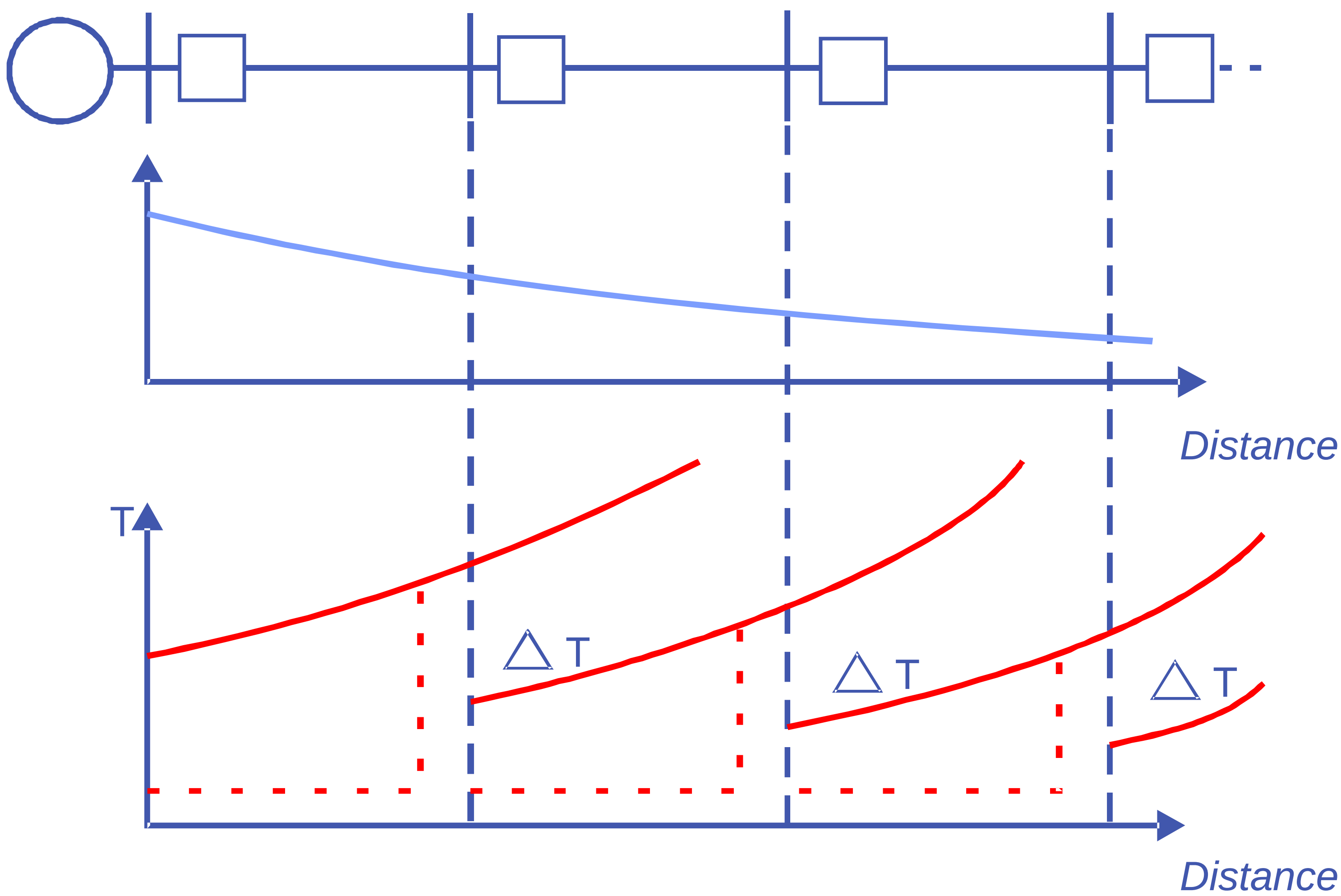
A = Downstream feeder relay with the highest settings



Use Ipu (A) for coordination

Arc Flash Solutions

Fault Current and Operate Time



Appendix

References

IEEE Protective Relaying Standards

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

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