Overcurrent Protection & Coordination for Industrial Applications

Doug Durand, P.E.

IEEE Continuing Education Seminar - Houston, TX
November 3-4, 2015

KBR

Agenda

Day 1

- Introduction
- Using Log-Log Paper & TCCs
- Types of Fault Current
- Protective Devices & Characteristic Curves
- Coordination Time Intervals (CTIs)
- Effect of Fault Current Variations
- Multiple Source Buses
- Partial Differential Relaying
- Directional Overcurrent Coordination

Day 2

- Transformer Overcurrent Protection
- Motor Overcurrent Protection
- Conductor Overcurrent Protection
- Generator Overcurrent Protection
- Coordinating a System
- Coordination Quizzes
- Coordination Software
- References

Introduction

Protection Objectives

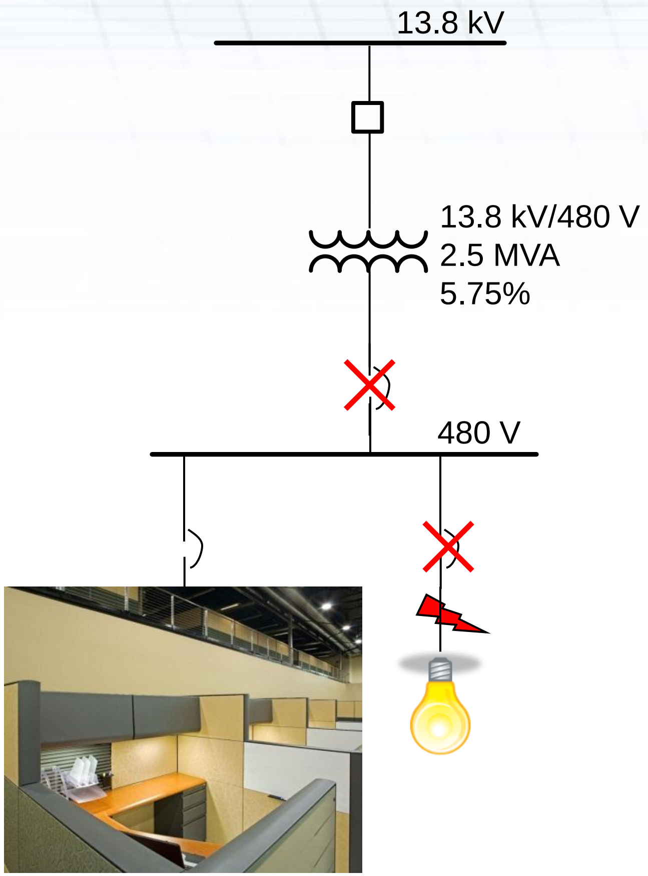
- Personnel Safety

Protection Objectives

- Equipment Protection

Protection Objectives

- Service Continuity & Selective Fault Isolation



- Faults should be quickly detected and cleared with a minimum disruption of service.
- Protective devices perform this function and must be adequately specified and coordinated.
- Errors in either specification or setting can cause nuisance outages.

KBR

Types of Protection

Protective devices can provide the following assortment of protection, many of which can be coordinated. We'll focus primarily on the last one, overcurrent.

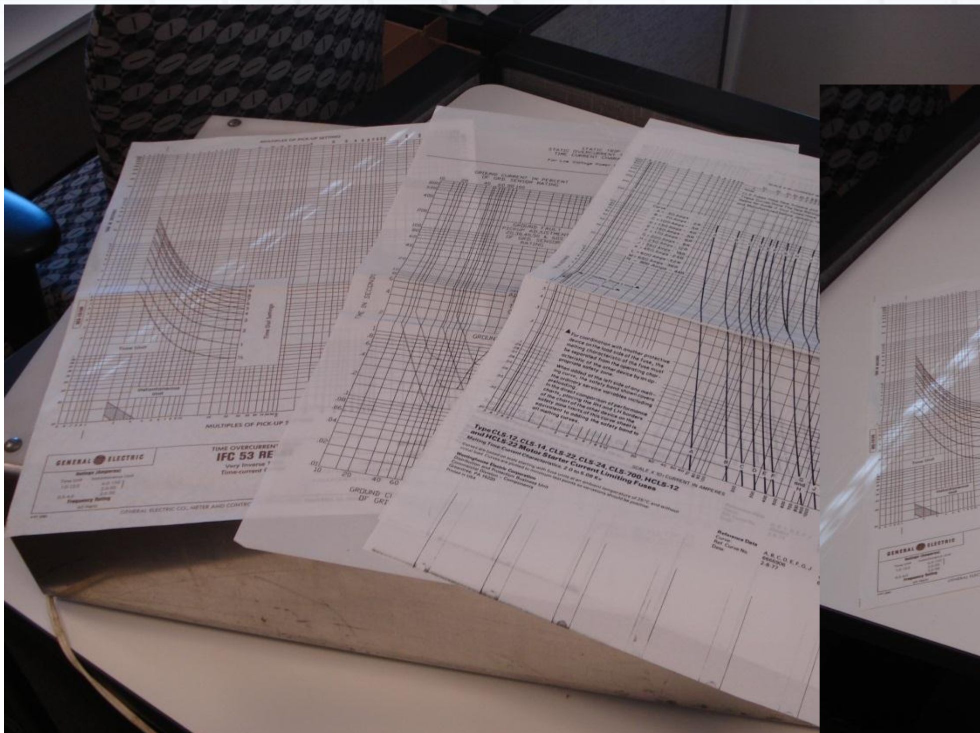
- Distance
- High-Impedance Differential
- Current Differential
- Under/Overfrequency
- Under/Overvoltage
- Over Temperature
- Overload
- Overcurrent

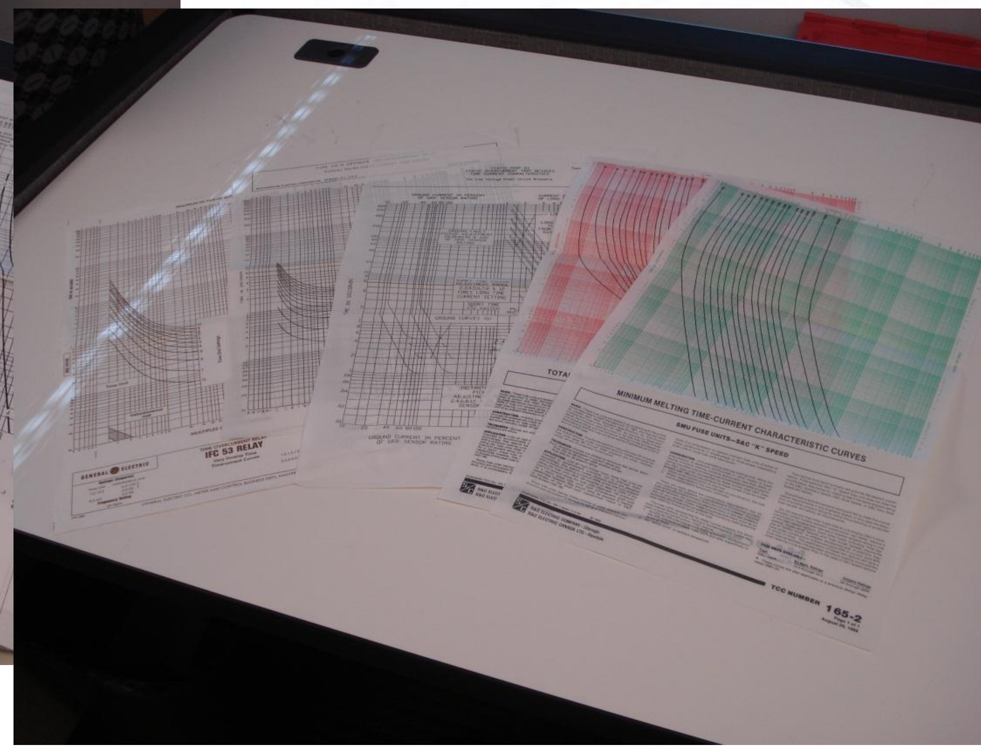
Coordinating Overcurrent Devices

- Tools of the trade “in the good old days…”

Coordinating Overcurrent Devices

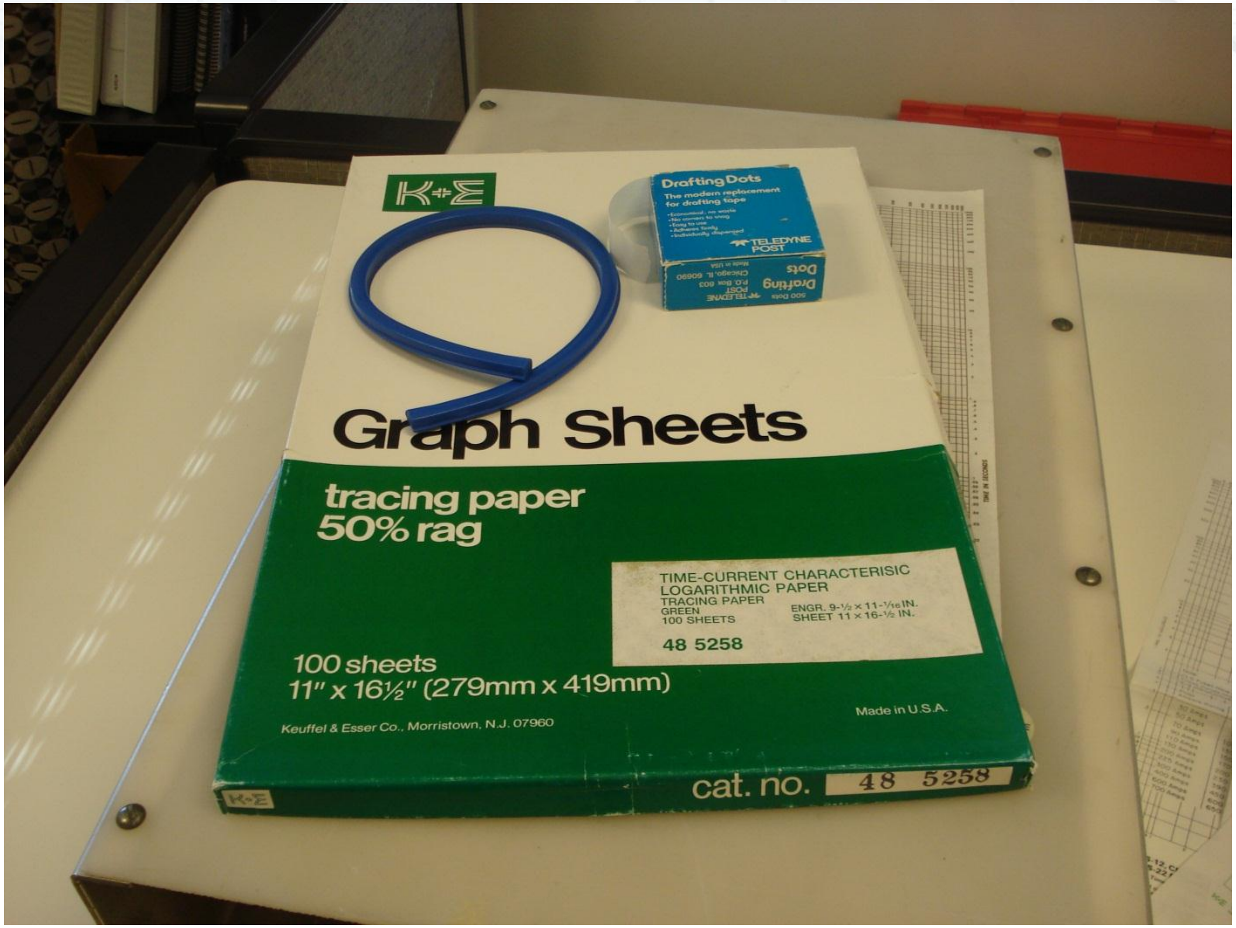
- Tools of the trade “in the good old days…”





Coordinating Overcurrent Devices

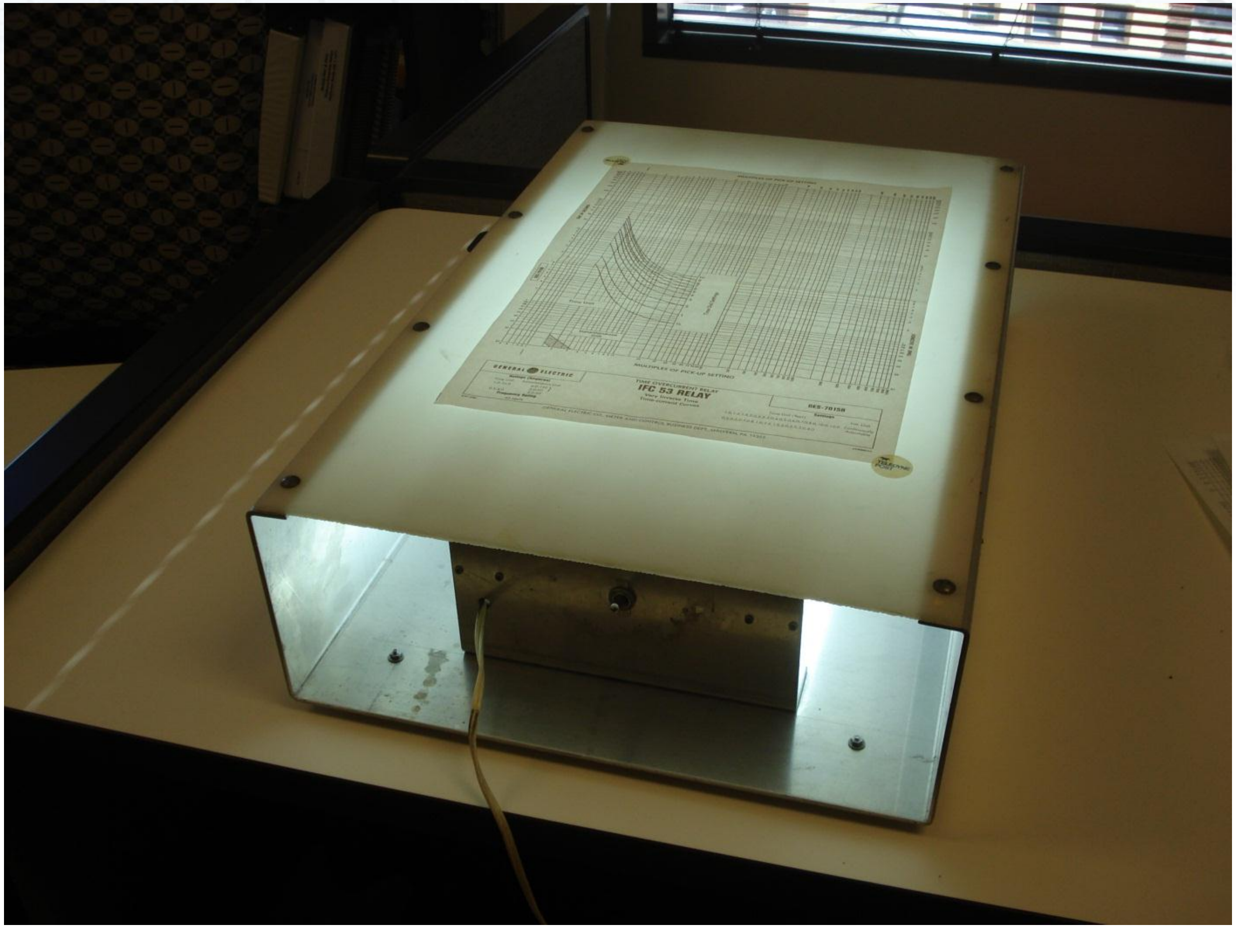
- Tools of the trade “in the good old days…”



KBR

Coordinating Overcurrent Devices

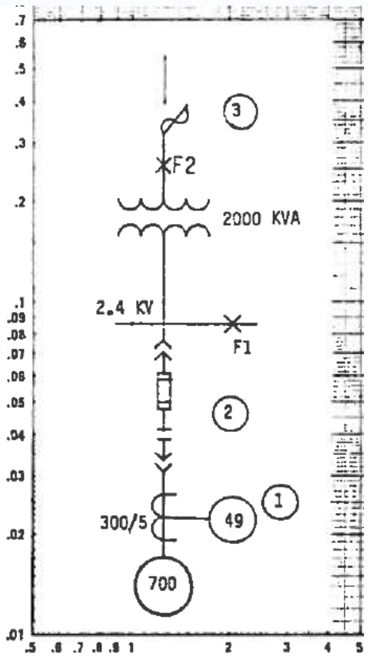
- Tools of the trade “in the good old days…”

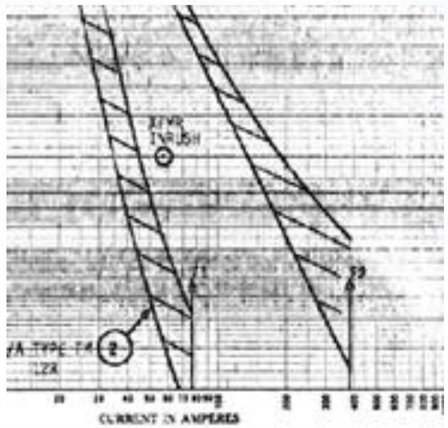


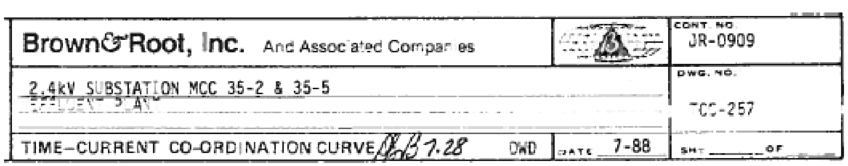
KBR

Coordinating Overcurrent Devices

- Old-world craftsmanship…





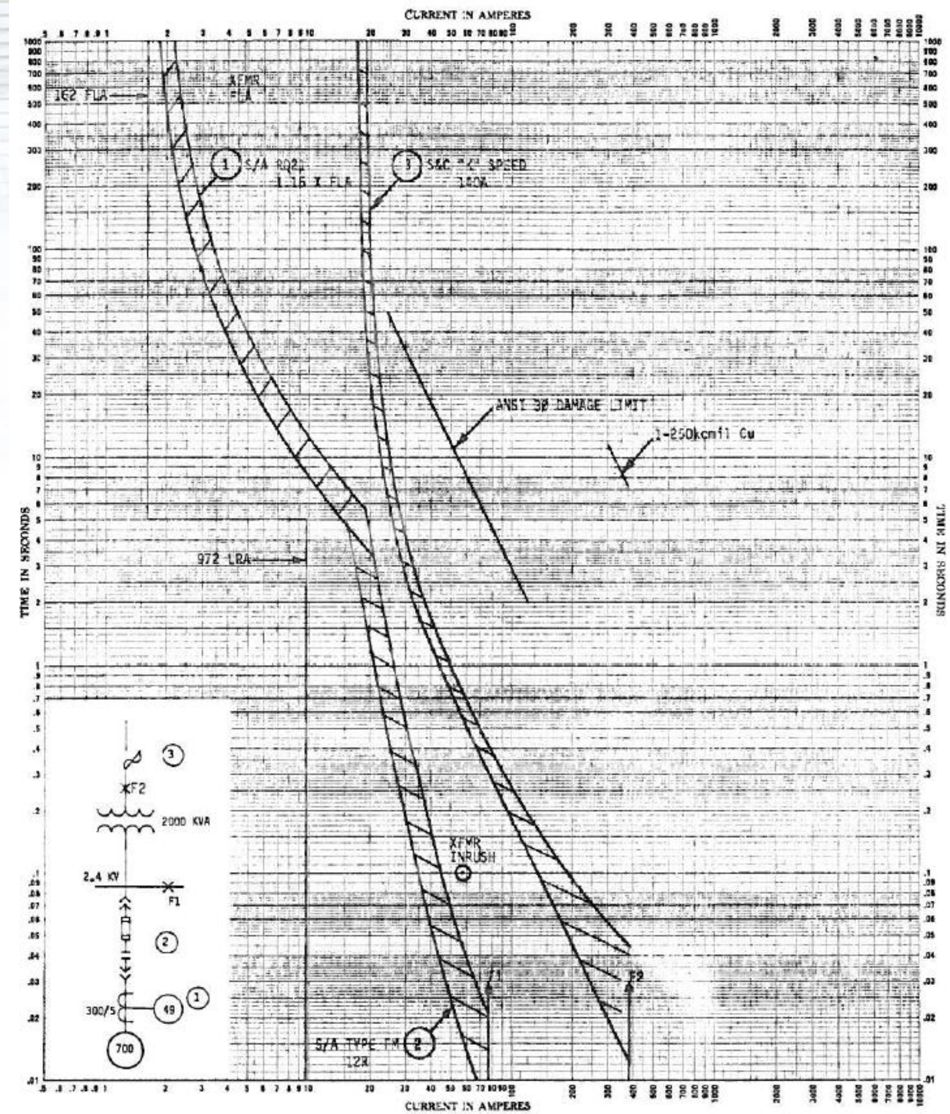

Brown&Root, Inc. And Associated Companies

CONT. NO. JR-0909

2.4kV SUBSTATION MCC 35-2 & 35-5

DWG. NO. TCC-257

TIME–CURRENT CO-ORDINATION CURVE DWD DATE 7-88 SHT ____ OF



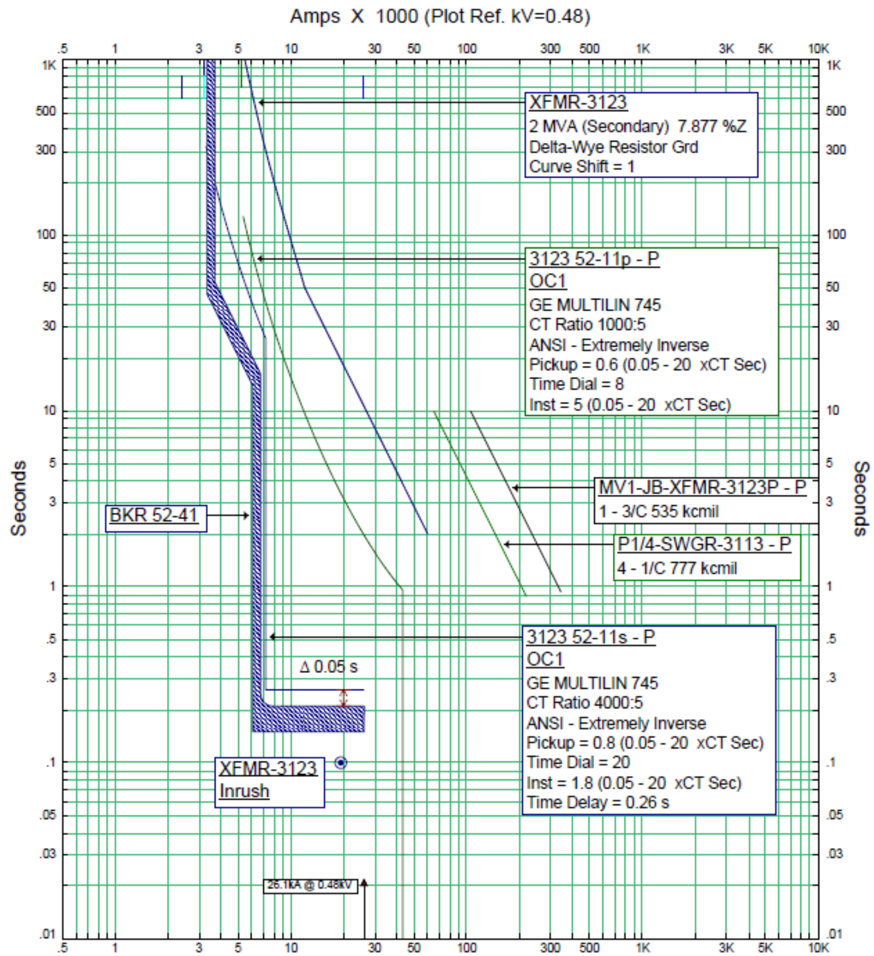
KBR

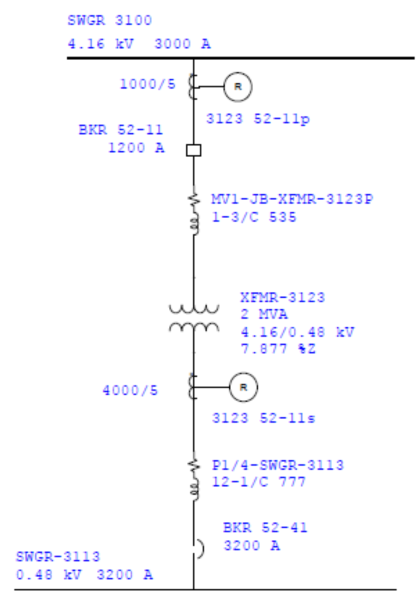
Coordinating Overcurrent Devices

- Tools of the trade today…

Coordinating Overcurrent Devices

- New-world craftsmanship…

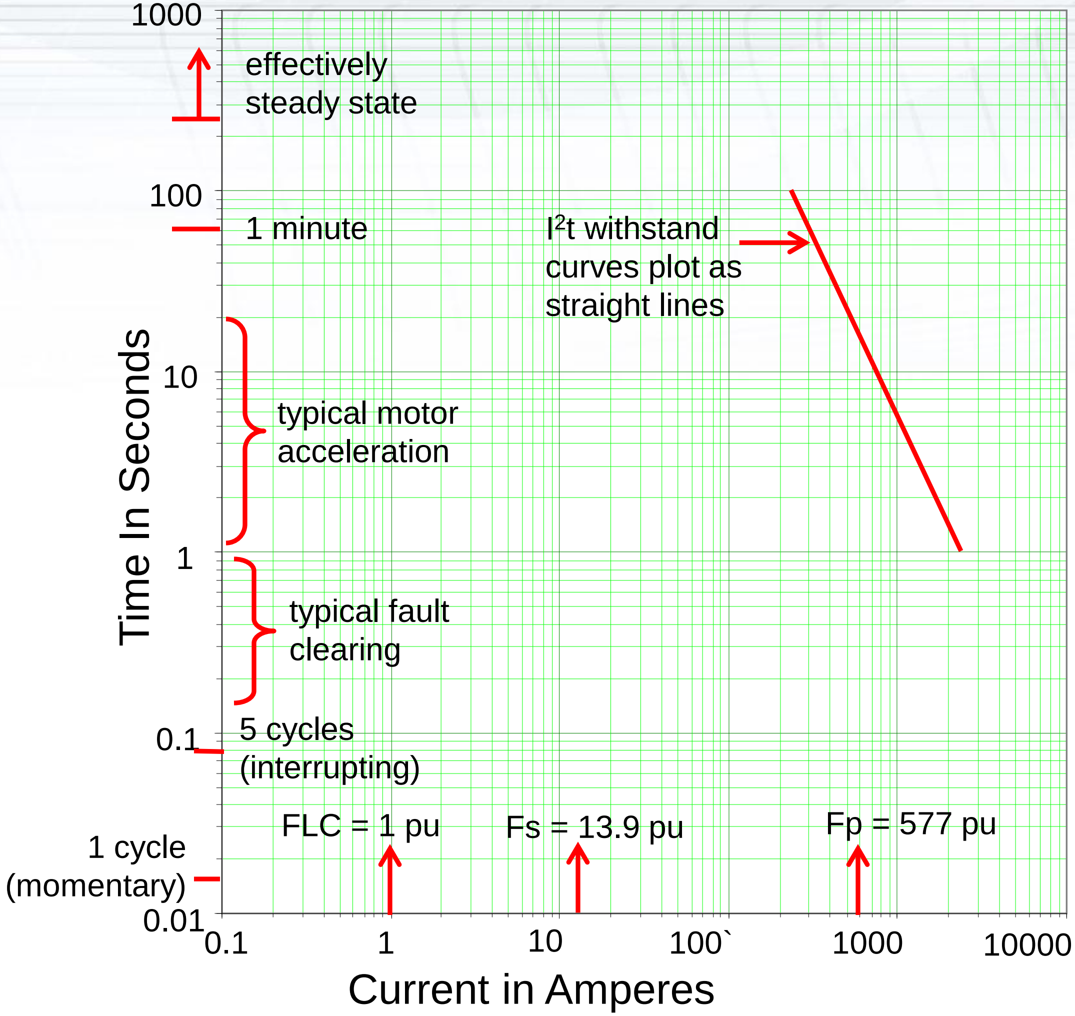




Using Log-Log Paper & TCCs

Log-Log Plots

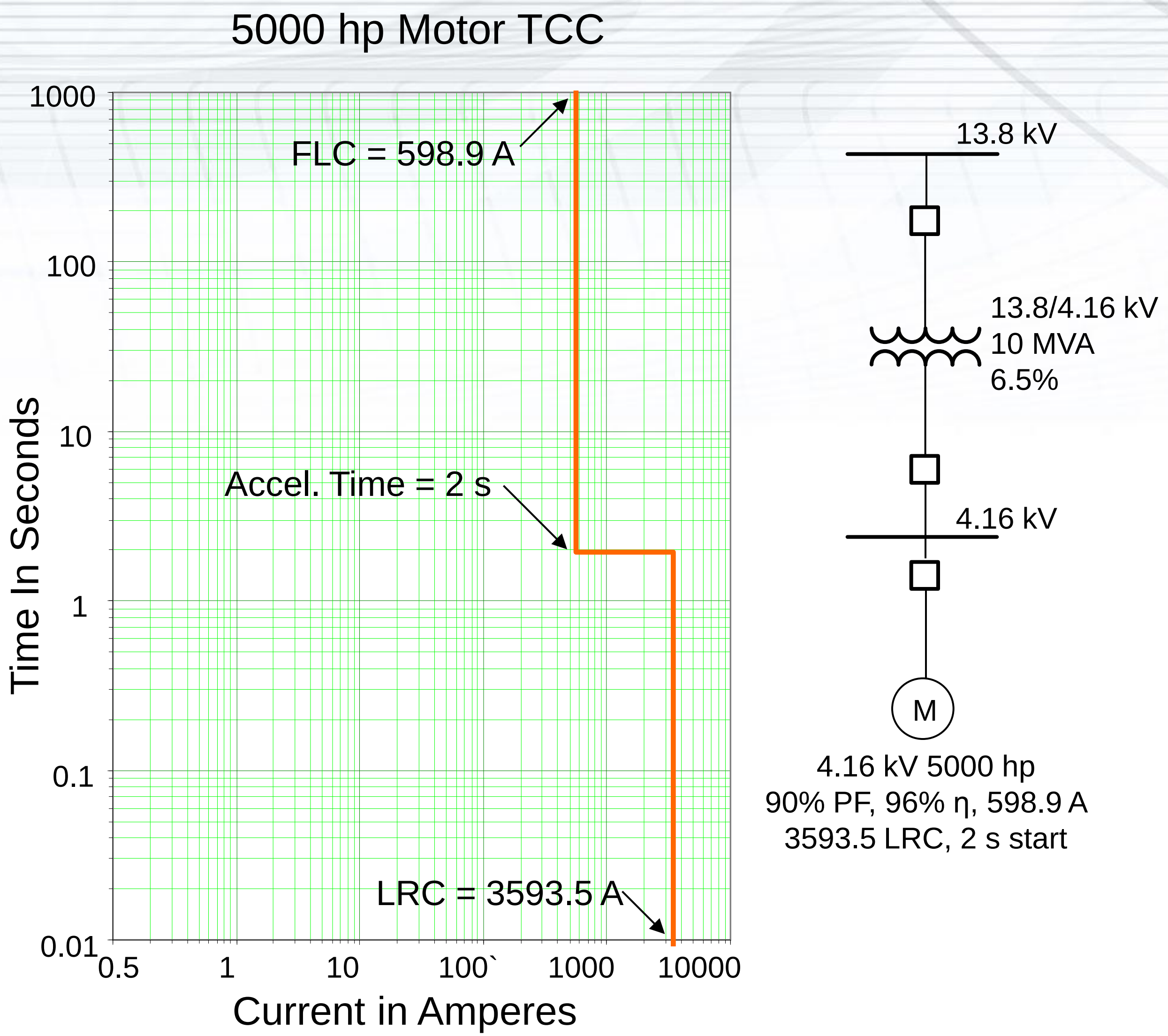
Time-Current Curve (TCC)



Why log-log paper?

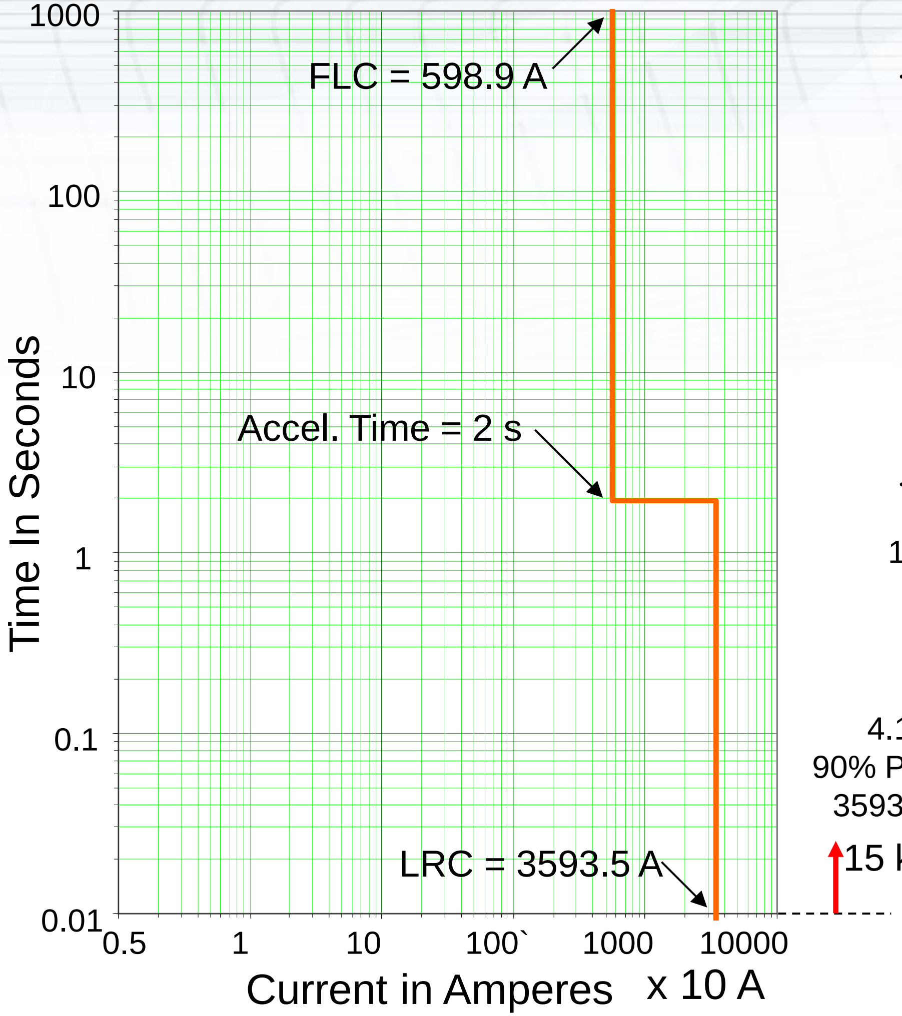
- Log-Log scale compresses values to a more manageable range.
- I^2t withstand curves plot as straight lines.

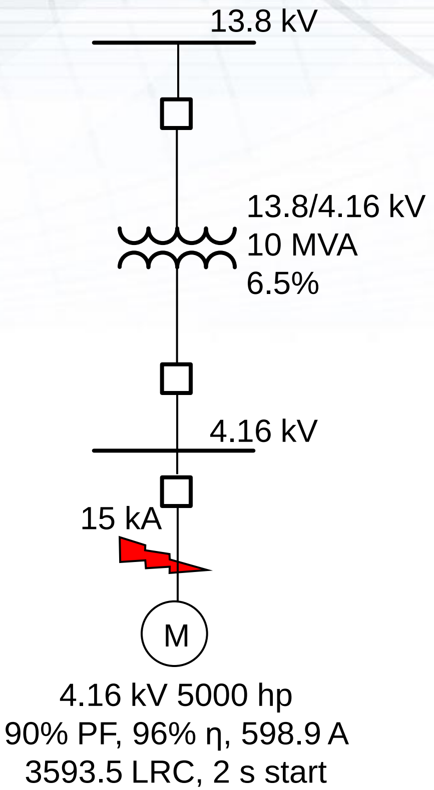
Plotting A Curve



Plotting Fault Current & Scale Adjustment

5000 hp Motor TCC with Fault on Motor Terminal





Voltage Scales

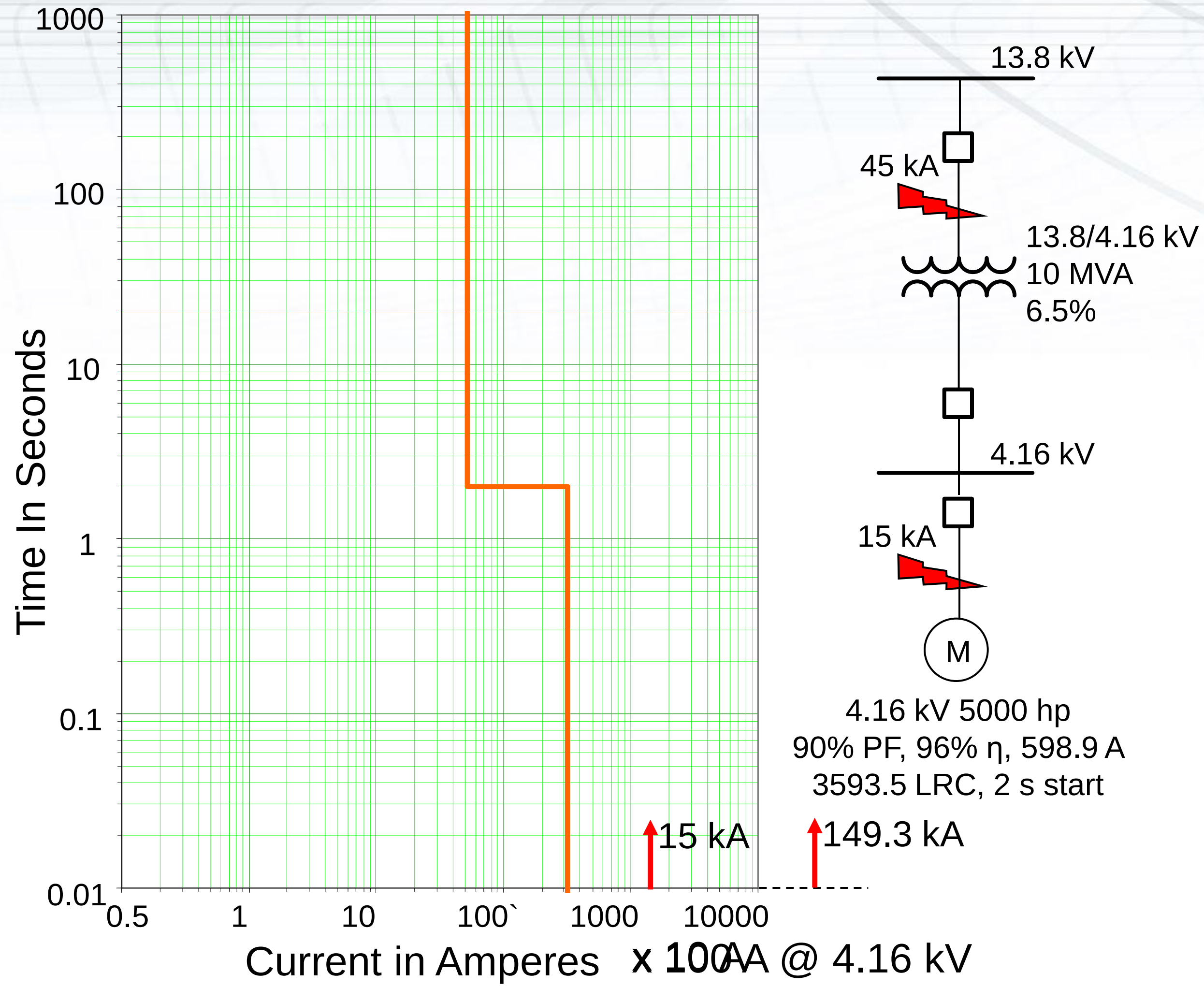
5000 hp Motor TCC with Fault on Transformer Primary

45 kA @ 13.8 kV

= ? @ 4.16 kV

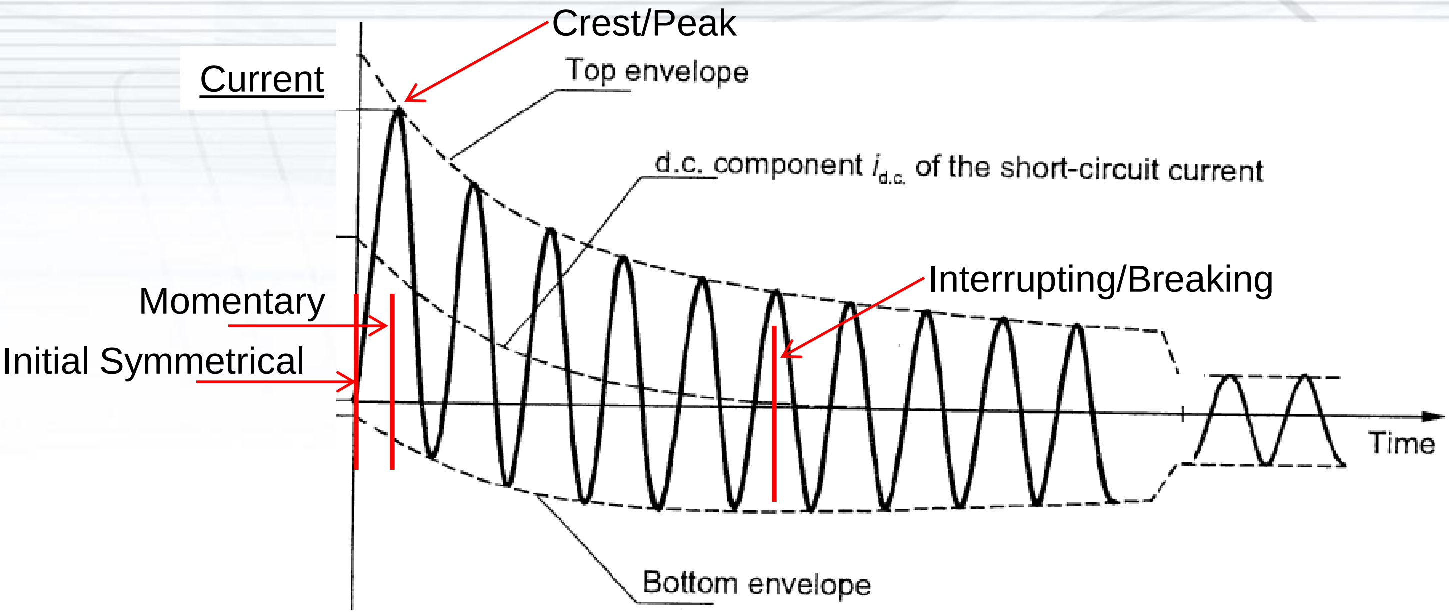
= (45 x 13.8/4.16)

= 149.3 kA @ 4.16 kV



Types of Fault Currents

Fault Current Options



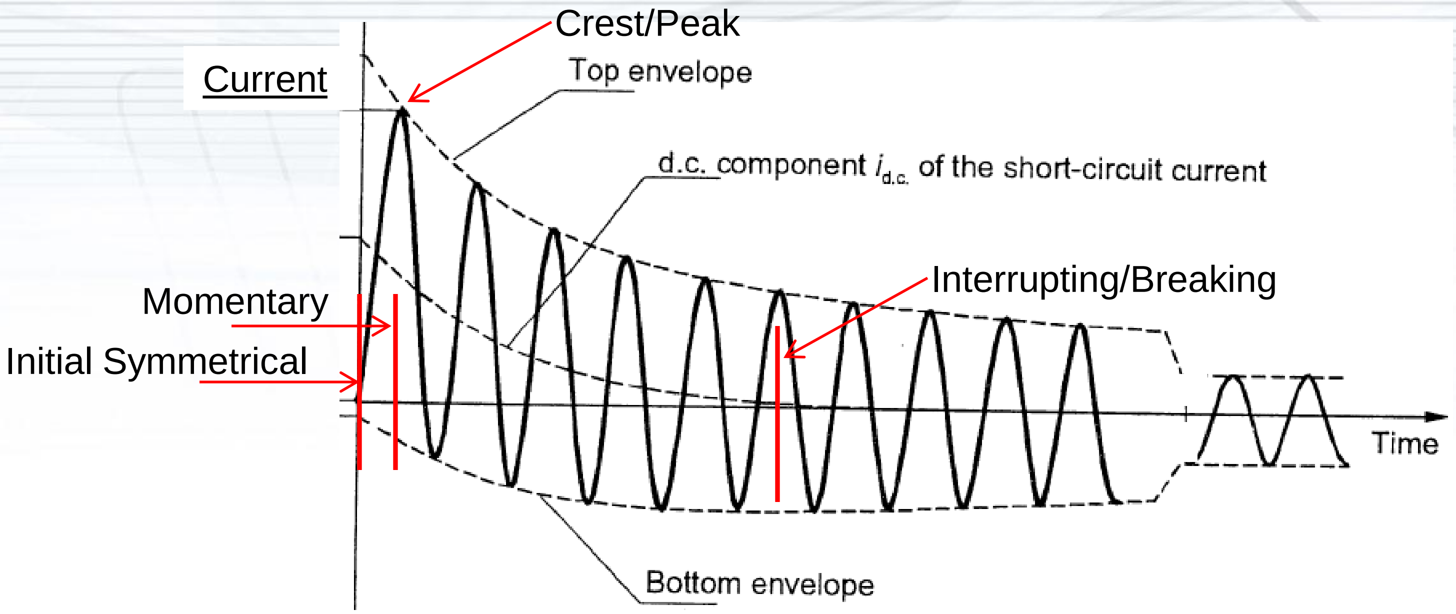
ANSI

- Momentary Symmetrical
- Momentary Asymmetrical
- Momentary Crest
- Interrupting Symmetrical
- Adjusted Interrupting Symmetrical

IEC

- Initial Symmetrical (I_k'')
- Peak (I_p)
- Breaking (I_b)
- Asymmetrical Breaking ($I_{b,asym}$)

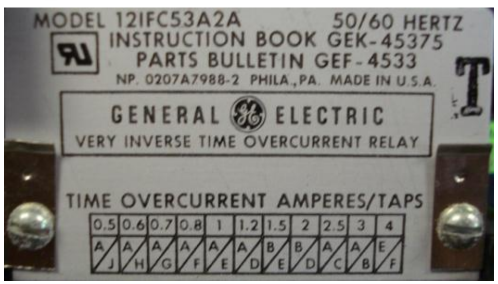
Fault Current Options

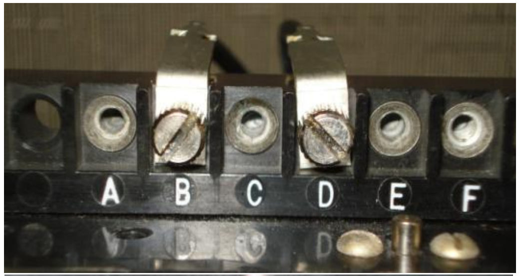


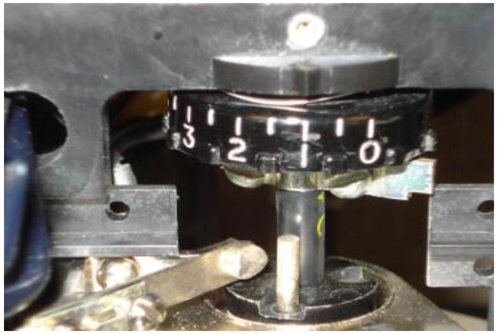
- Symmetrical currents are most appropriate.
- Momentary asymmetrical should be considered when setting instantaneous functions.
- Use of duties not strictly appropriate, but okay.
- Use of momentary/initial symmetrical currents lead to conservative CTIs.
- Use of interrupting currents will lead to lower, but still acceptable CTIs.

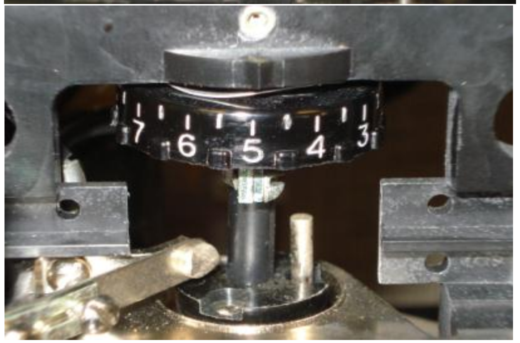
Protective Devices & Characteristic Curves

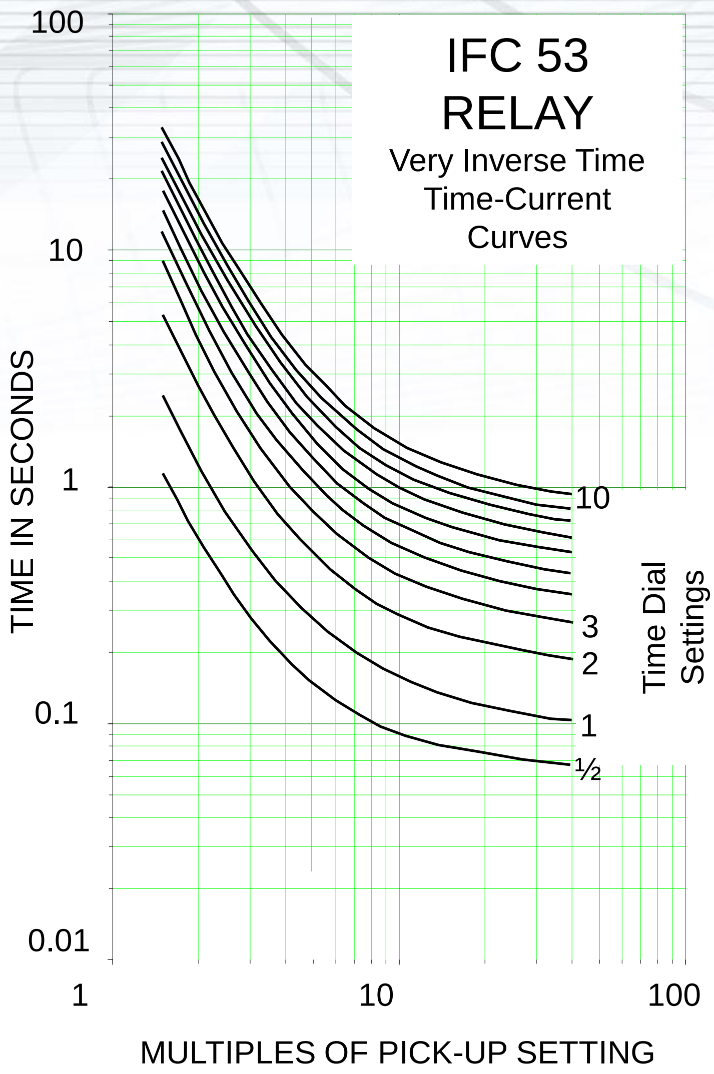
Electromechanical Relays (EM)











Electromechanical Relays – Pickup Calculation

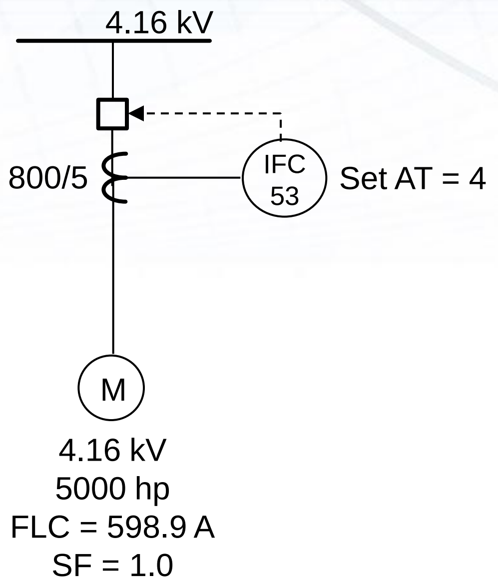
The relay should pick-up for current values above the motor FLC (~ 600 A).

For the IFC53 pictured, the available ampere-tap (AT) settings are 0.5, 0.6, 0.7, 0.8, 1, 1.2, 1.5, 2, 2.5, 3, & 4.

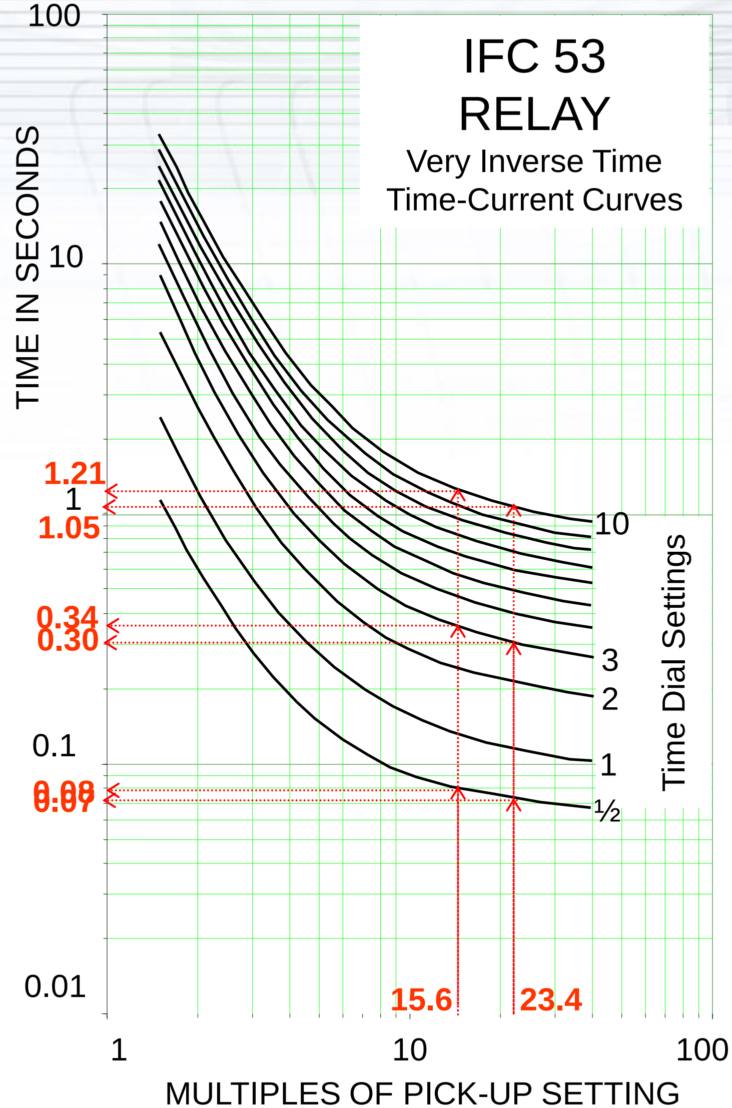
For this type of relay, the primary pickup current was calculated as:

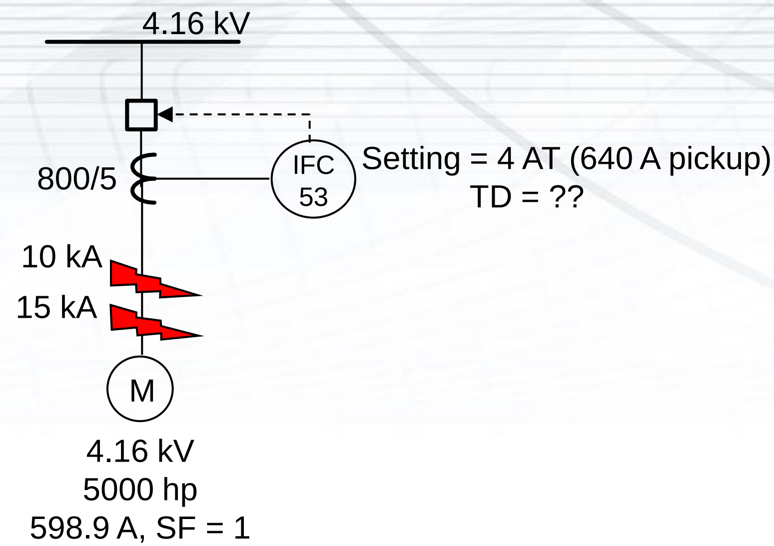
PU = CT Ratio x AT

PU = (800/5) x 3 = 480 A (too low)
= (800/5) x 4 = 640 A (107%, okay)



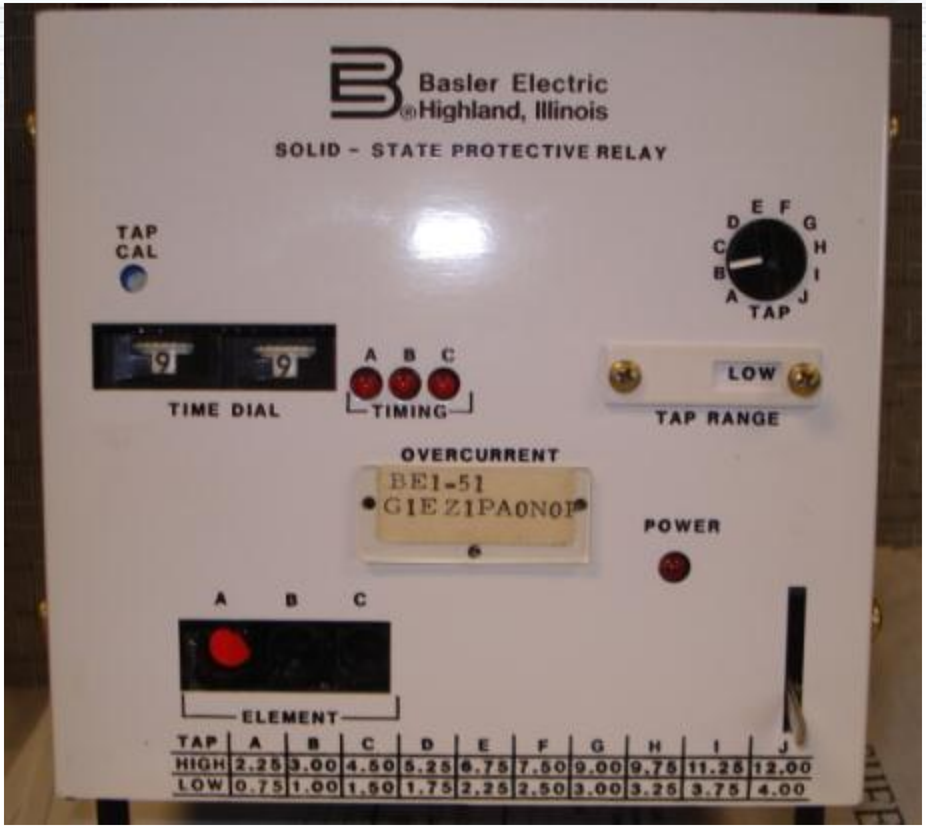
Electromechanical Relays – Operating Time Calculation

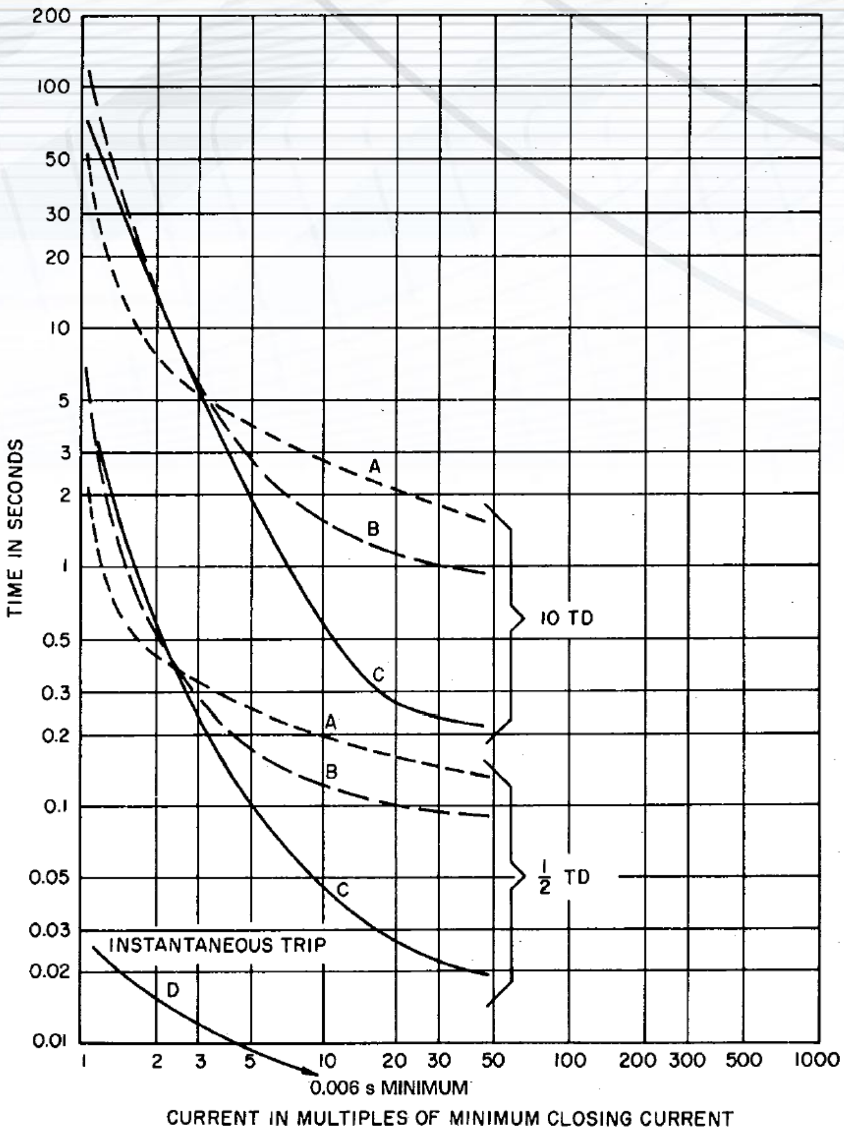




IFC 53 Relay Operating Times		
Fault Current	15 kA	10 kA
Multiple of Pick-Up	15000/640 = 23.4	10000/640 = 15.6
Time Dial ½	0.07 s	0.08 s
Time Dial 3	0.30 s	0.34 s
Time Dial 10	1.05 s	1.21 s

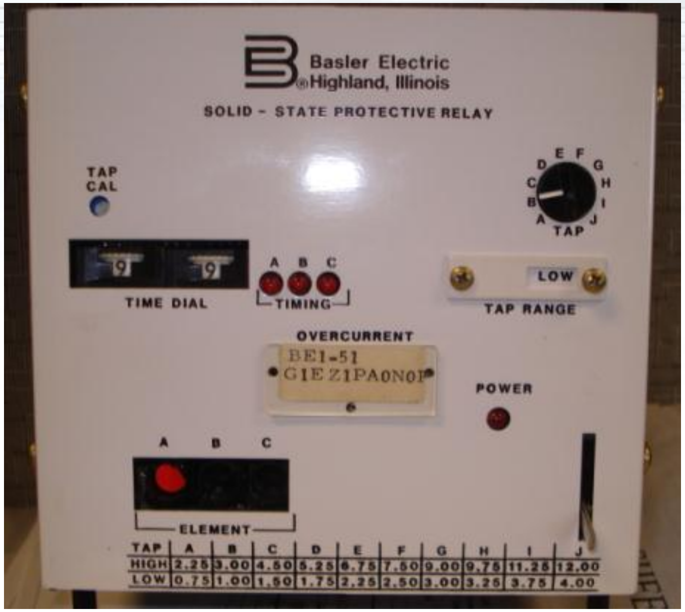
Solid-State Relays (SS)





KBR

Solid-State Relays (SS)



Curve selection made on the left-side interior of the relay.

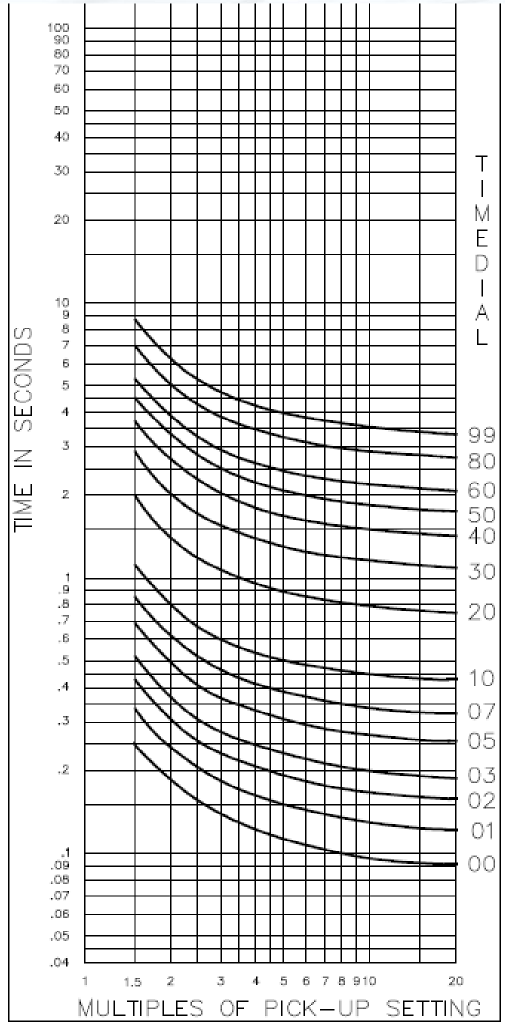


Figure A-5. Timing Type B3, Definite Time

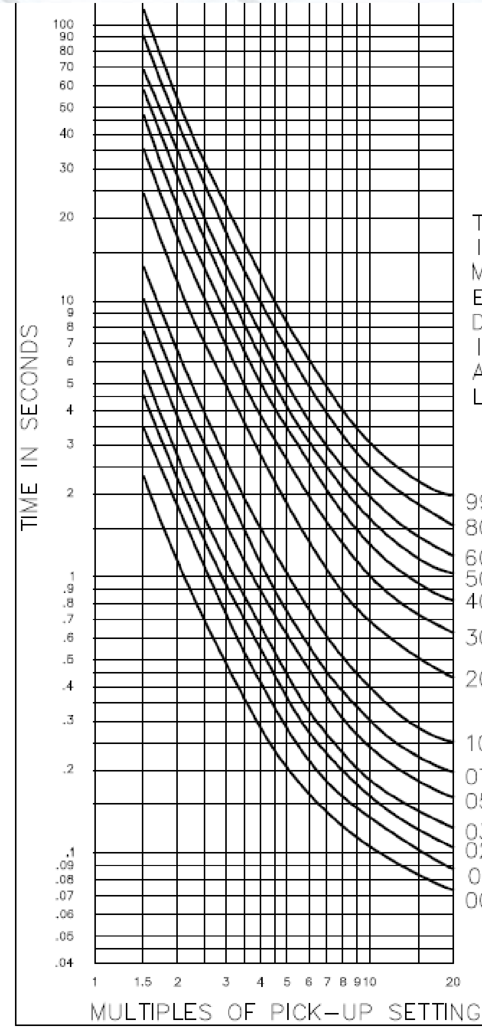
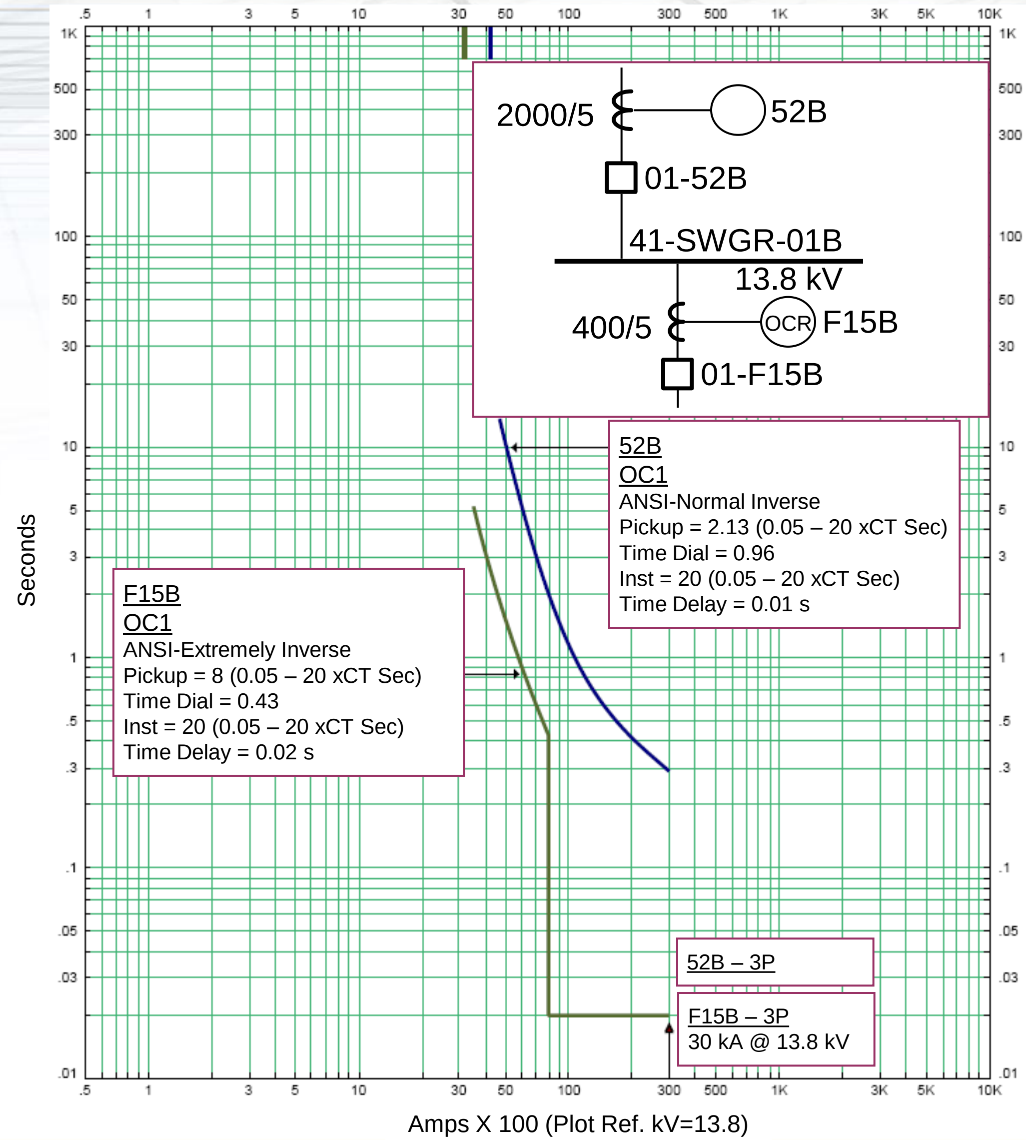


Figure A-13. Timing Type B7, Extremely Inverse

KBR

Microprocessor-Based Relays



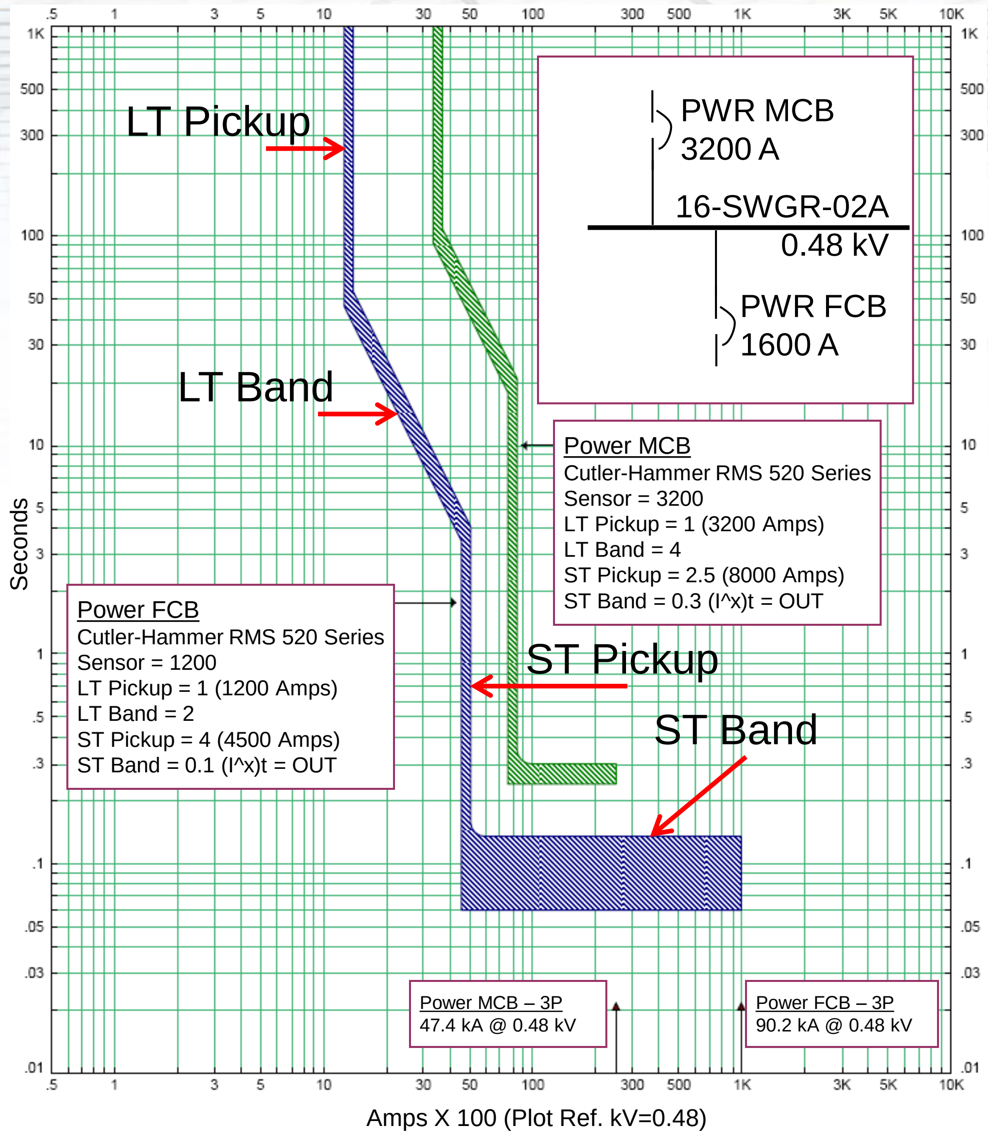
KBR

Microprocessor-Based Relays

Table 5–10: IAC Curve Trip Times

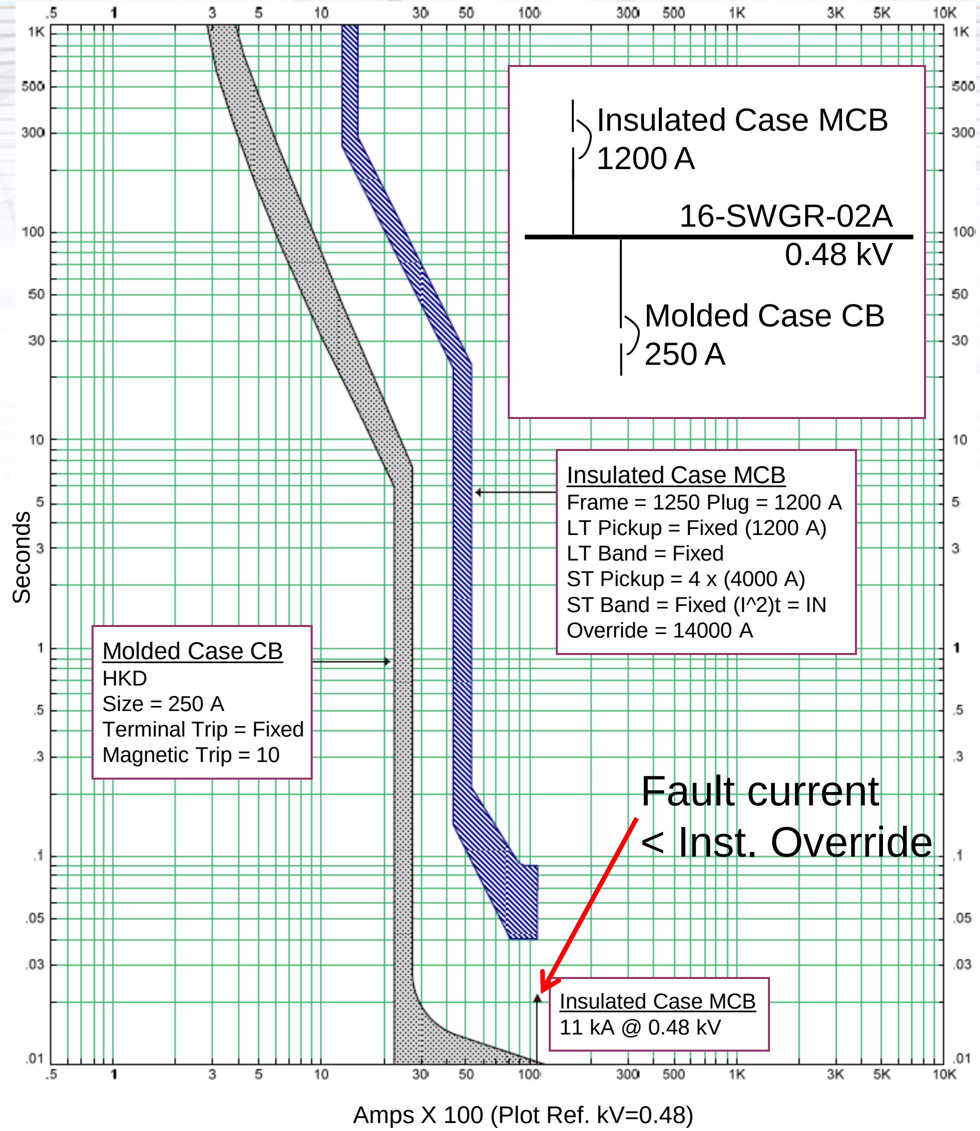
Multiplier (TDM)	Current (I / I_{pickup})									
	1.5	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0
10.0	29.012	13.121	5.374	3.434	2.663	2.266	2.025	1.862	1.744	1.654
IAC Inverse										
0.5	0.578	0.375	0.266	0.221	0.196	0.180	0.168	0.160	0.154	0.148
1.0	1.155	0.749	0.532	0.443	0.392	0.360	0.337	0.320	0.307	0.297
2.0	2.310	1.499	1.064	0.885	0.784	0.719	0.674	0.640	0.614	0.594
4.0	4.621	2.997	2.128	1.770	1.569	1.439	1.348	1.280	1.229	1.188
6.0	6.931	4.496	3.192	2.656	2.353	2.158	2.022	1.921	1.843	1.781
8.0	9.242	5.995	4.256	3.541	3.138	2.878	2.695	2.561	2.457	2.375
10.0	11.552	7.494	5.320	4.426	3.922	3.597	3.369	3.201	3.072	2.969
IAC Short Inverse										
0.5	0.072	0.047	0.035	0.031	0.028	0.027	0.026	0.026	0.025	0.025
1.0	0.143	0.095	0.070	0.061	0.057	0.054	0.052	0.051	0.050	0.049
2.0	0.286	0.190	0.140	0.123	0.114	0.108	0.105	0.102	0.100	0.099
4.0	0.573	0.379	0.279	0.245	0.228	0.217	0.210	0.204	0.200	0.197
6.0	0.859	0.569	0.419	0.368	0.341	0.325	0.314	0.307	0.301	0.296
8.0	1.145	0.759	0.559	0.490	0.455	0.434	0.419	0.409	0.401	0.394
10.0	1.431	0.948	0.699	0.613	0.569	0.542	0.524	0.511	0.501	0.493

Power CBs



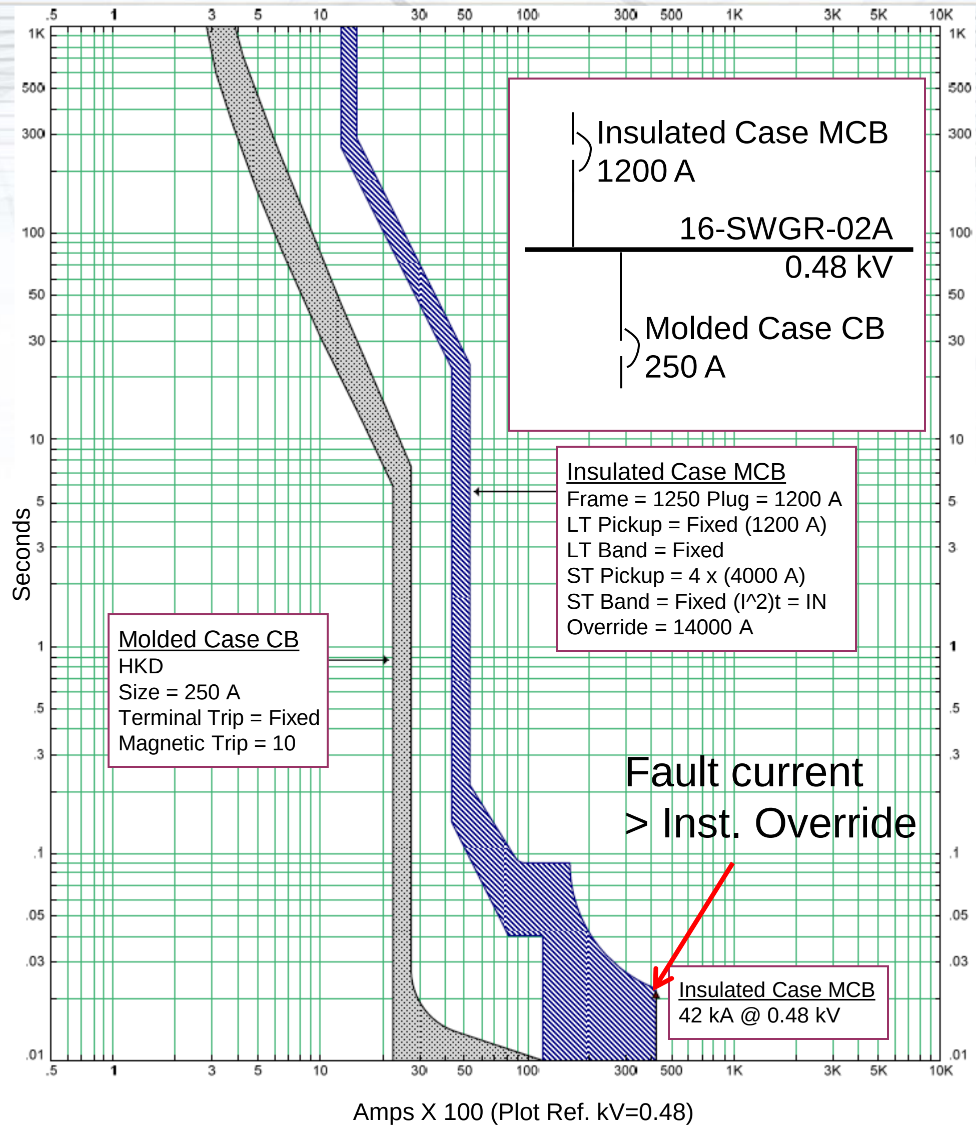
KBR

Insulated & Molded Case CB



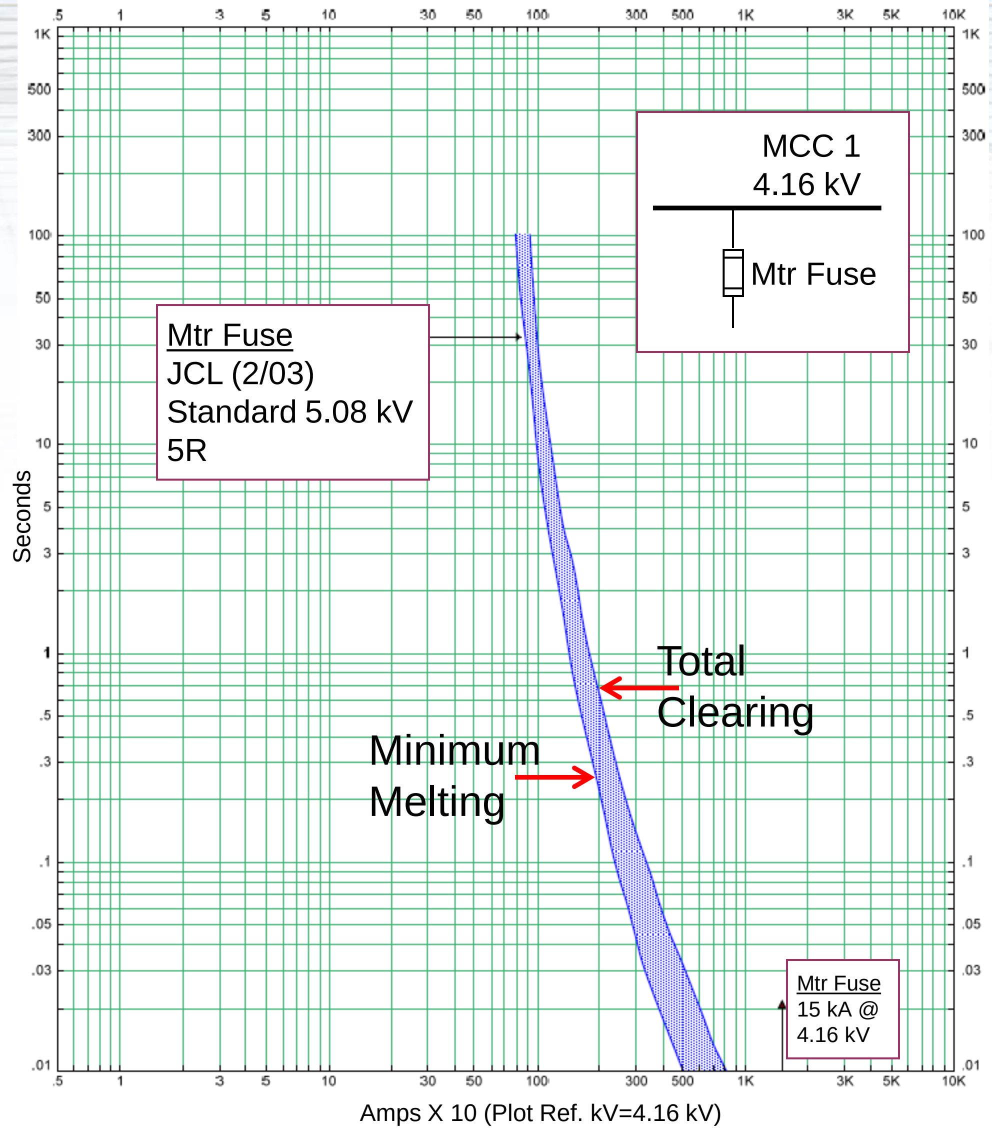
KBR

Insulated & Molded Case CB



KBR

Power Fuses



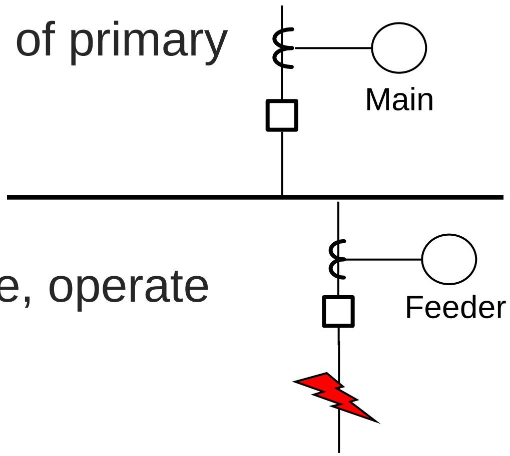
KBR

Coordination Time Intervals (CTIs)

Coordination Time Intervals (CTIs)

The CTI is the amount of time allowed between a primary device and its upstream backup.

Backup devices wait for sufficient time to allow operation of primary devices.



Primary devices sense, operate & clear the fault first.

When two such devices are coordinated such that the primary device “should” operate first at all fault levels, they are “selectively” coordinated.

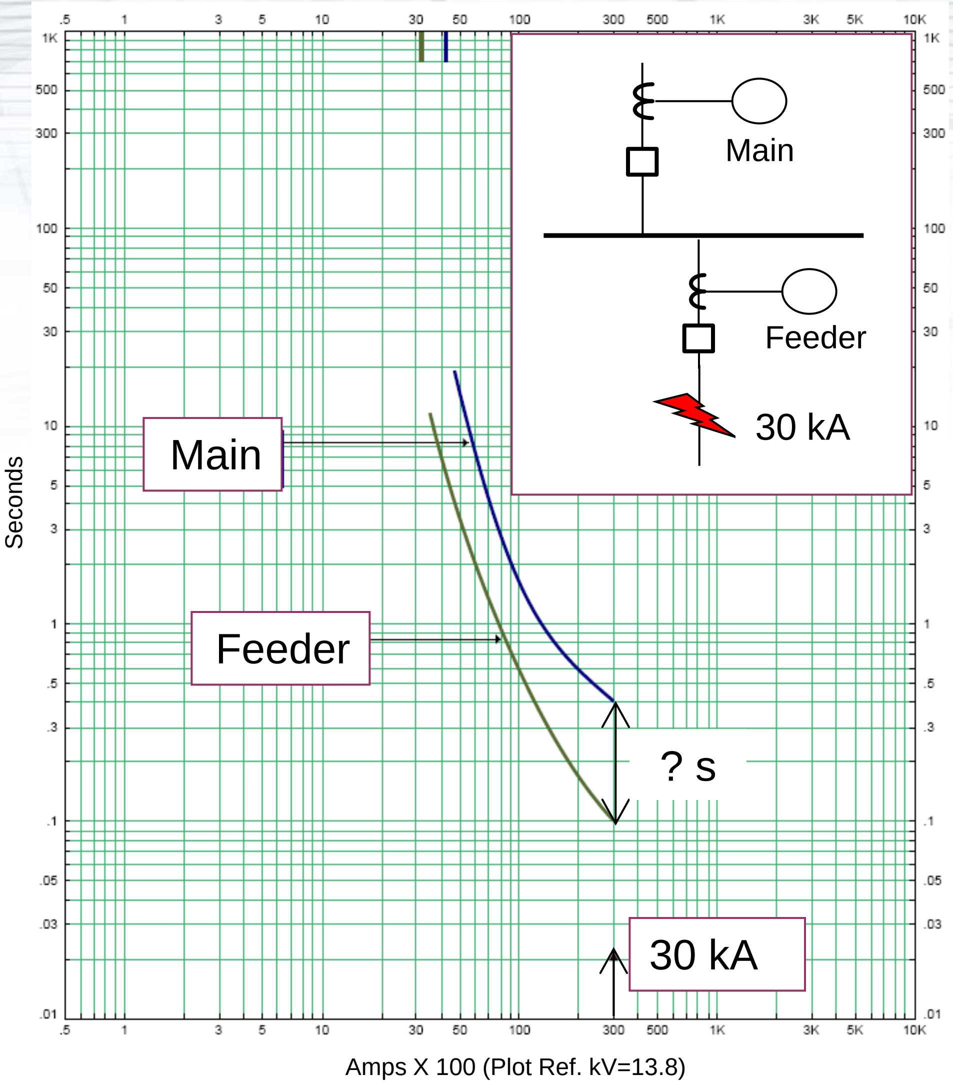
KBR

Coordination Time Intervals – EM

In the good old (EM) days,

What typical CTI would we want between the feeder and the main breaker relays?

____

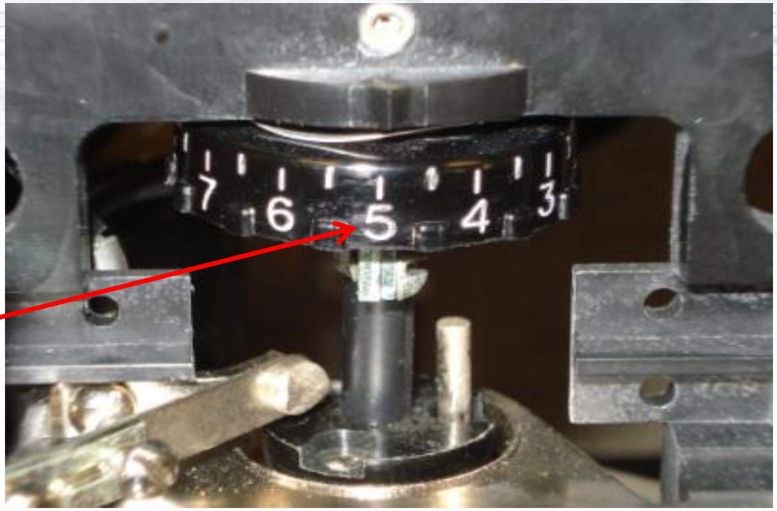


KBR

Coordination Time Intervals – EM

On what did it depend?

Remember the TD setting?



It is continuously adjustable and not exact.

So how do you really know where TD = 5?

FIELD TESTING !

(not just hand set)

Pickup = 8 (0.05 - 20 xCT Sec)

Time Dial = 5

3x = 3.3 s, 5x = 1.24 s, 8x = 0.628 s

KBR

Coordination Time Intervals – EM

Plotting the field test points.

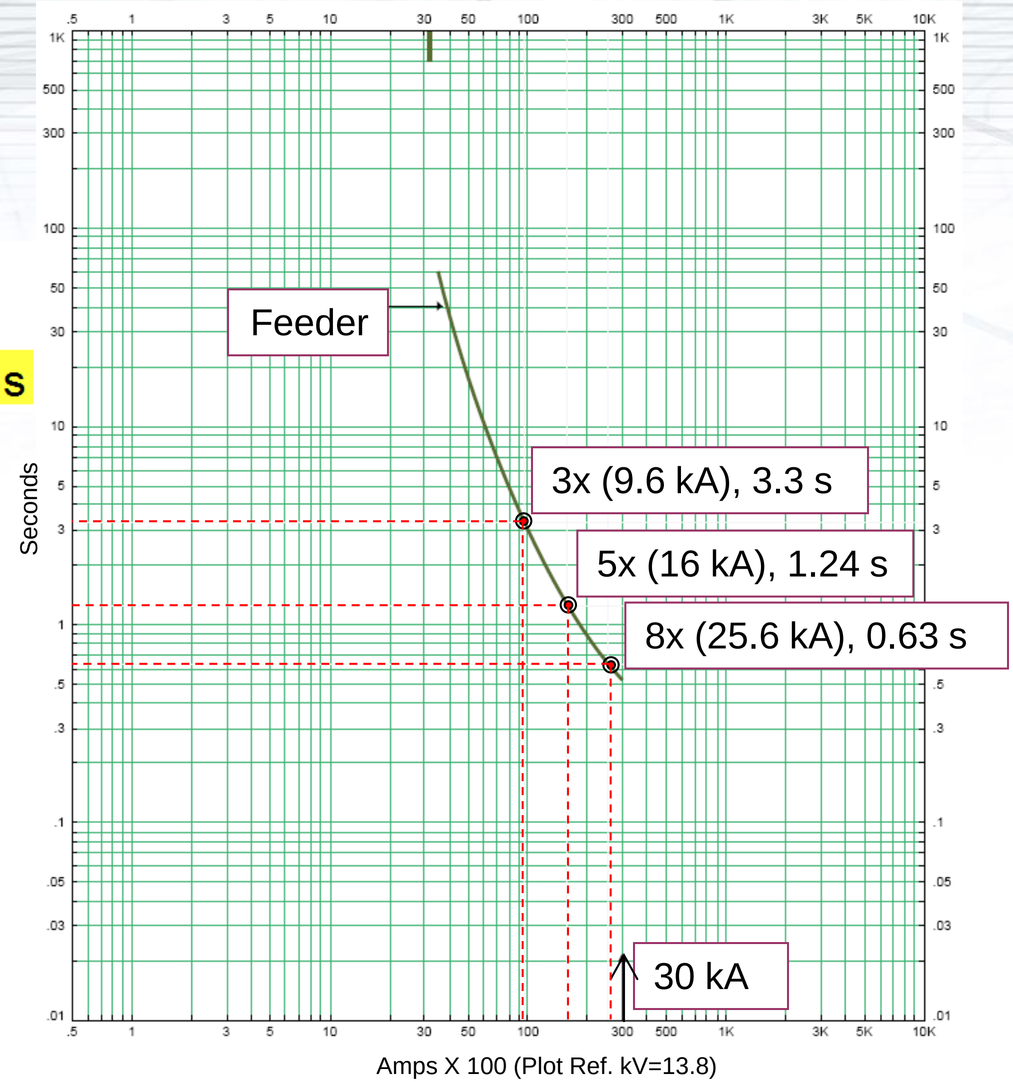
Pickup = 8 x 2000/5 = 3200 A
Time Dial = 5
3x = 3.3 s, 5x = 1.24 s, 8x = 0.628 s

“3x” means 3 times pickup

3 * 8 = 24 A (9.6 kA primary)

5 * 8 = 40 A (16 kA primary)

8 * 8 = 64 A (25.6 kA primary)



KBR

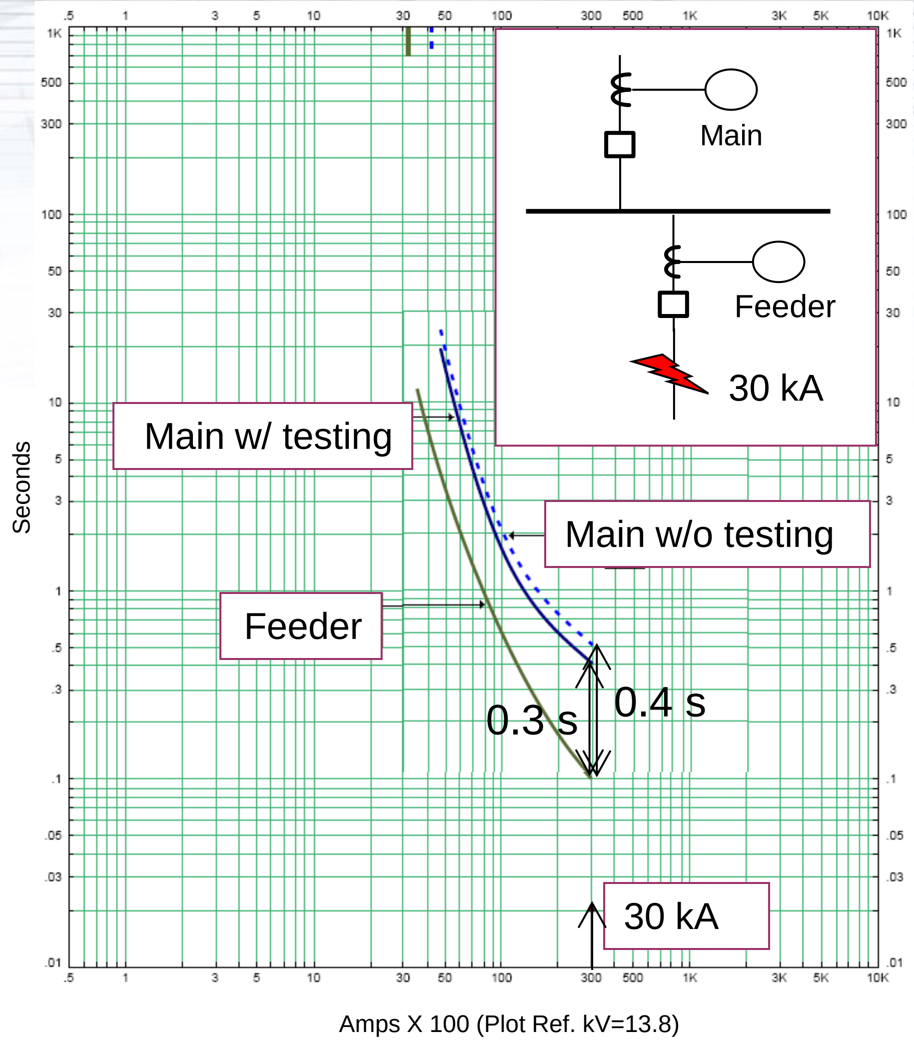
Coordination Time Intervals – EM

So now, if test points are not provided what should the CTI be?

______

But, if test points are provided what should the CTI be?

______



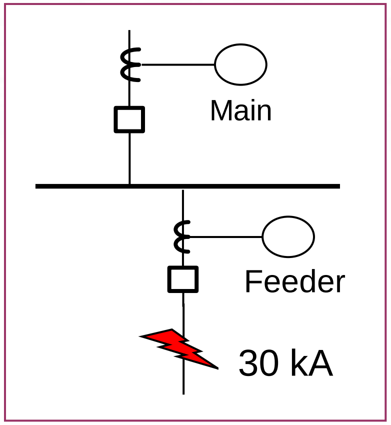
KBR

Coordination Time Intervals – EM

Where does the 0.3 s or 0.4 s come from?

1. breaker operating time (Feeder breaker)
2. CT, relay errors (both)
3. disk overtravel (Main relay only)

	Tested	Hand Set
breaker 5 cycle	0.08 s	0.08 s
Disk overtravel	0.10 s	0.10 s
CT, relay errors	0.12 s	0.22 s
TOTAL	0.30 s	0.40 s



Coordination Time Intervals – EM

Obviously, CTIs can be a subjective issue.

Red Book (IEEE 141-1993, per Section 5.7.2.1)

Components	Handset	Set using instruments
Breaker operating time (5 cycles)	0.083 s	0.083 s
Relay overtravel (disk inertia)	0.10 s	0.10 s
Relay tolerance and setting errors	0.217 s	0.117 s
Allowable time interval	0.40 s	0.30 s

Buff Book (IEEE 242-2001, taken from Tables 15-1 & 15-2)

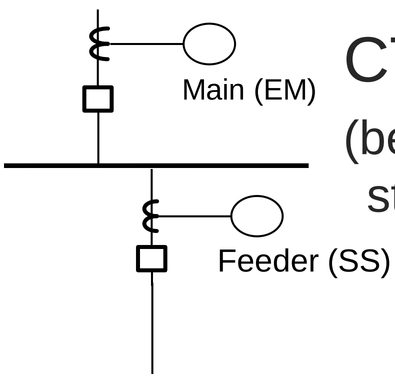
Components	Handset	Field Tested
Breaker operating time (5 cycles)	0.08 s	0.08 s
Relay overtravel (disk inertia)	0.10 s	0.10 s
Relay tolerance and setting errors	0.17 s	0.12 s
Allowable time interval	0.35 s	0.30 s

Coordination Time Intervals – EM & SS

So, lets move forward a few years….

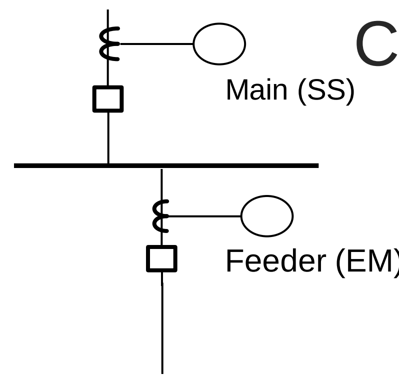
For a modern (static) relay what part of the margin can be dropped?

So if one of the two relays is static, we can use 0.2 s, right?



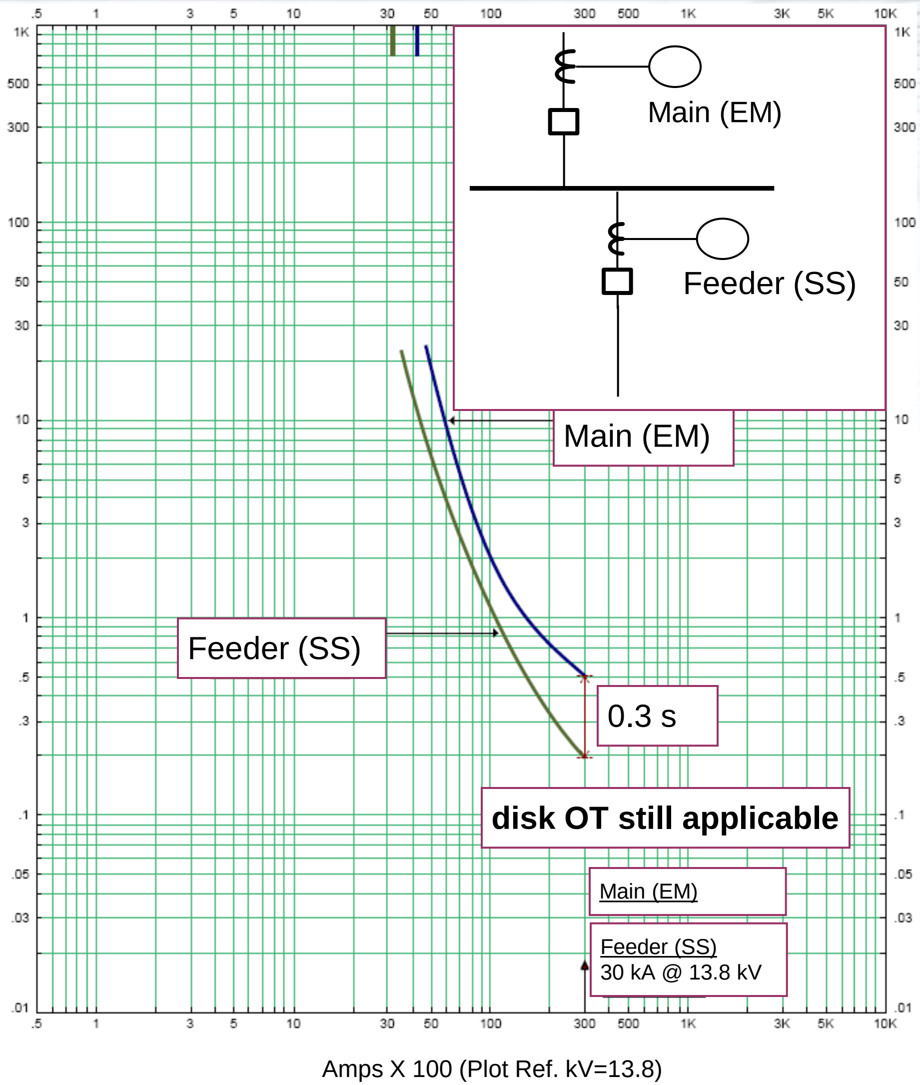
CTI = 0.3 s

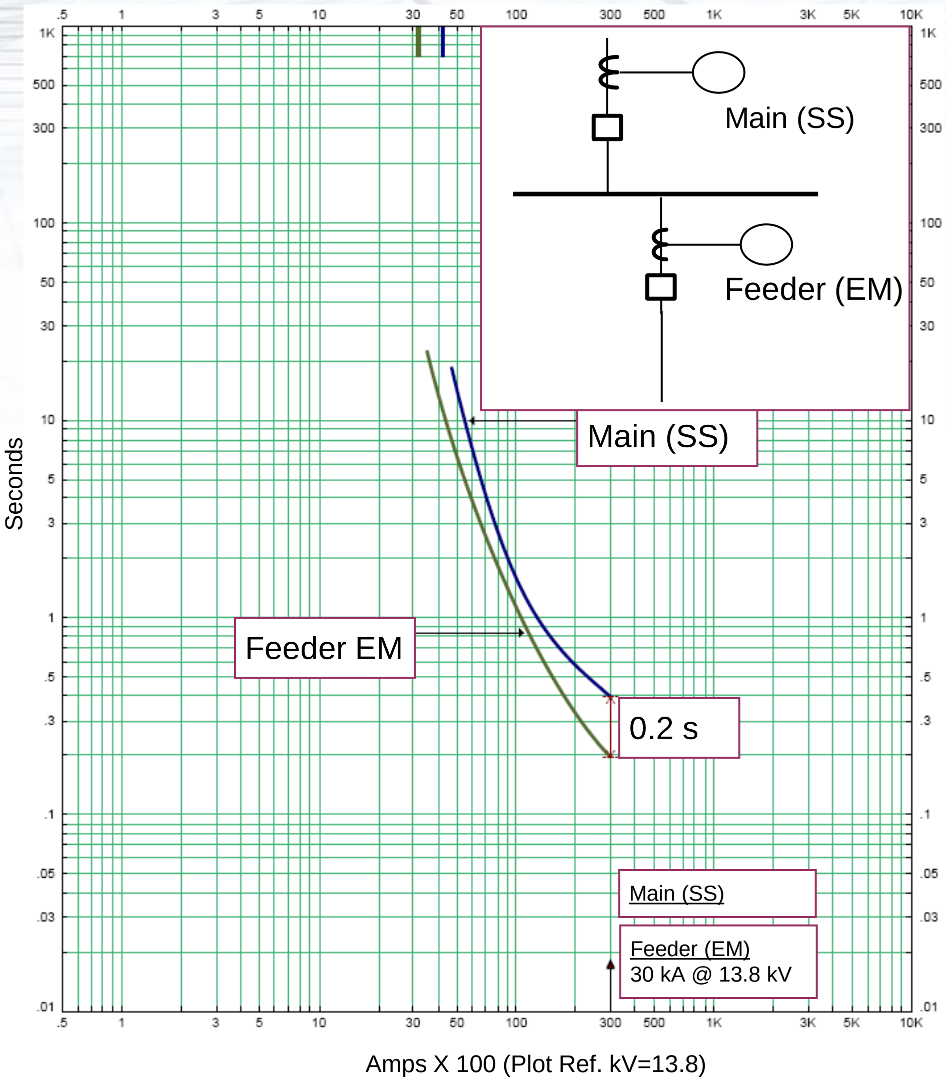
(because disk OT is still in play)



CTI = 0.2 s

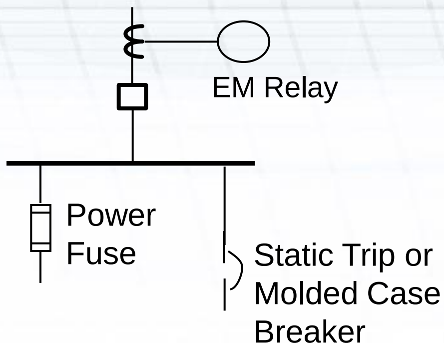
Coordination Time Intervals – EM & SS



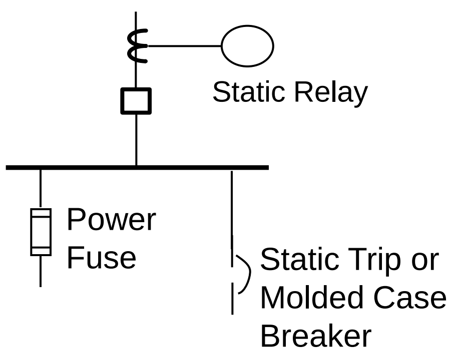


Coordination Time Intervals – EM/SS with Banded Devices

OC Relay combinations with banded devices

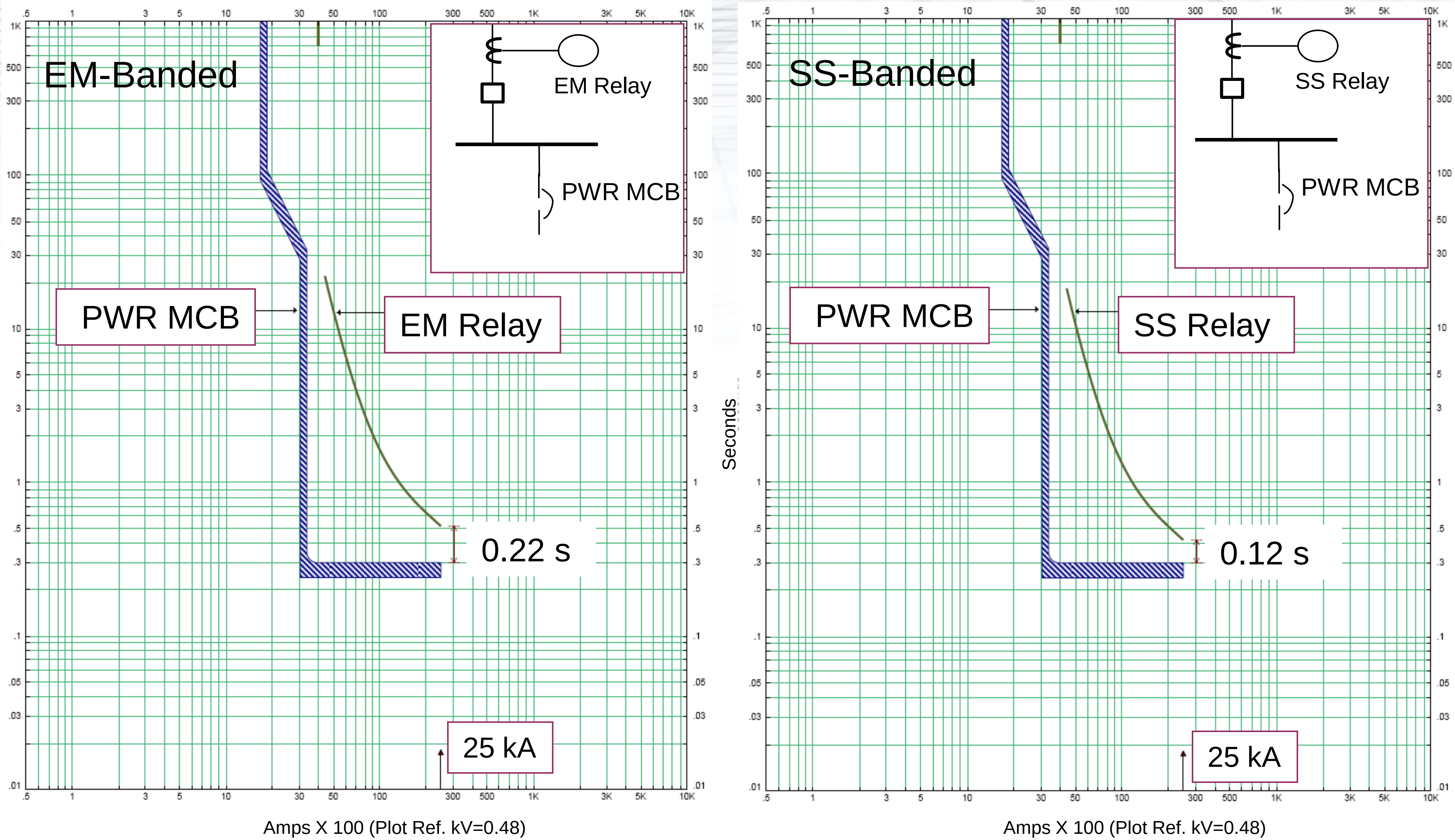


disk overtravel	√	0.1 s
CT, relay errors	√	0.12 s
operating time	X	-
CTI		0.22 s

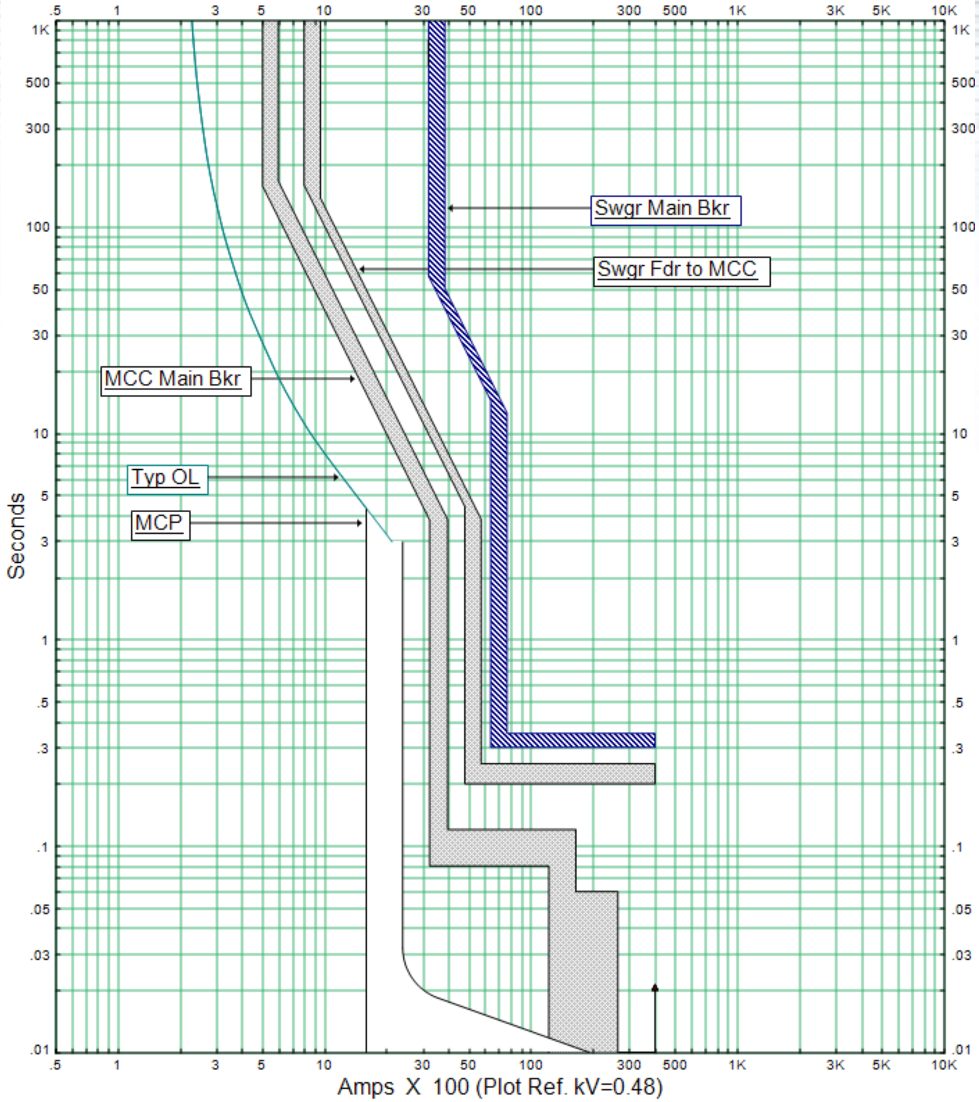


disk overtravel	X	-
CT, relay errors	√	0.12 s
operating time	X	-
CTI		0.12 s

Coordination Time Intervals – EM/SS with Banded Devices



Coordination Time Intervals – Banded Devices



- Banded characteristics include tolerances & operating times.
- There is no intentional/ additional time delay needed between two banded devices.
- All that is required is clear space (CS), except…
- coordination of instantaneous trips cannot be demonstrated on TCCs.
- Discrimination depends on type and size.

Coordination Time Intervals – Summary

Buff Book (IEEE 242-2001, Table 15-3 – Minimum CTIs [a])

Downstream	Upstream			
	Fuse	Low-voltage breaker	Electro-mechanical relay	Static relay
Fuse	CS[b,c]	CS	0.22 s	0.12 s
Low-voltage circuit breaker	CS[c]	CS	0.22 s	0.12 s
Electromechanical relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s
Static relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s

[a]Relay settings assumed to be field-tested and -calibrated.
[b]CS = Clear space between curves with upstream minimum-melting curve adjusted for pre-load.
[c]Some manufacturers may also recommend a safety factor. Consult manufacturers' time-current curves.

KBR

Effect of Fault Current Variations

CTI & Fault Current Magnitude

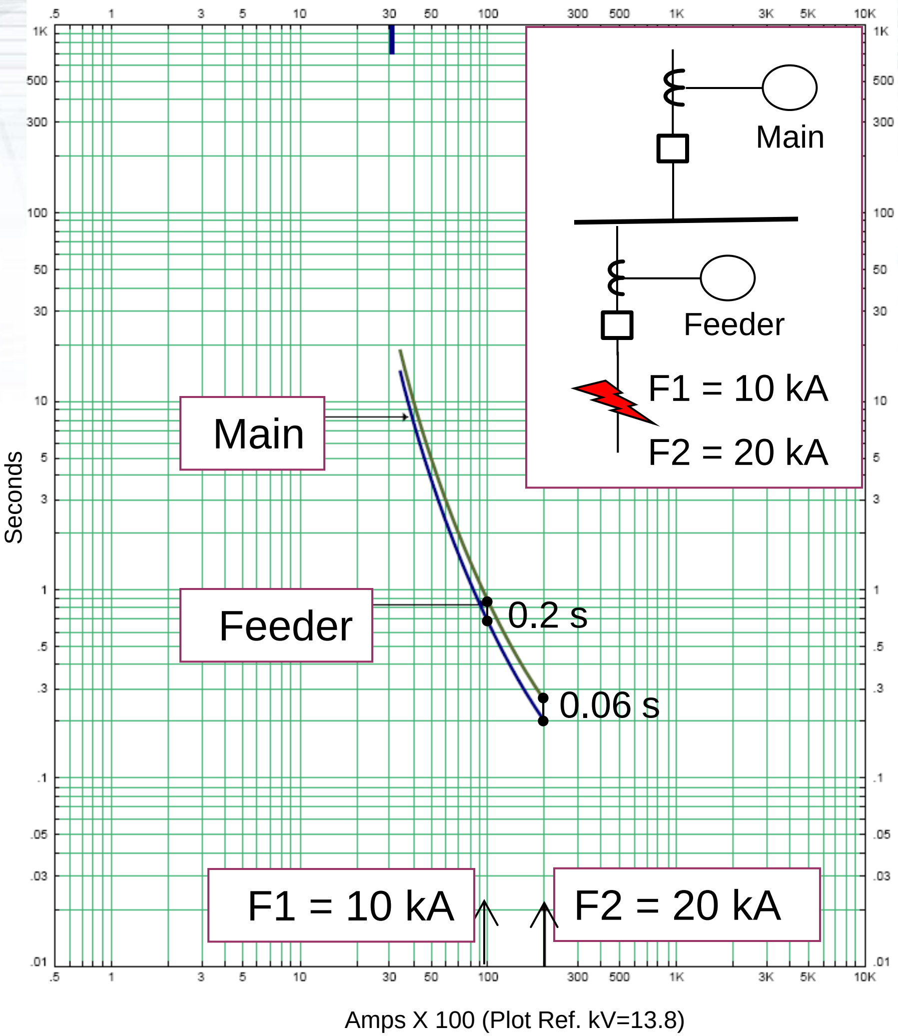
Inverse relay characteristics imply

↑ Relay Current ↓ Operating Time

For a fault current of 10 kA the CTI is 0.2 s.

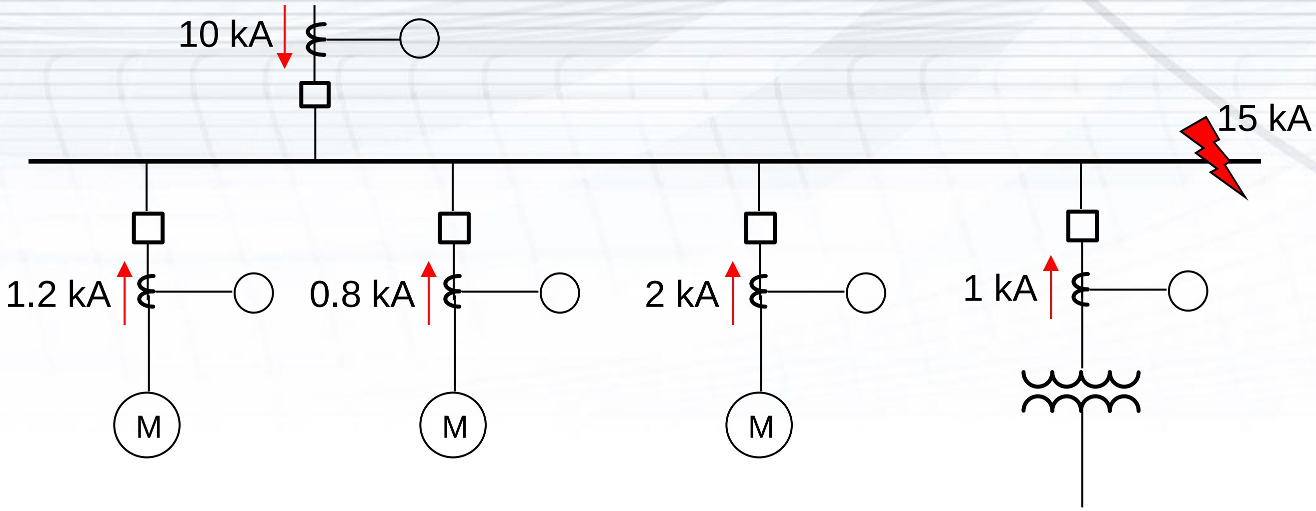
For a fault current of 20 kA the CTI is 0.06 s.

Conclusion – inverse-time curves are highly susceptible to changes in current. Add definite time when possible.



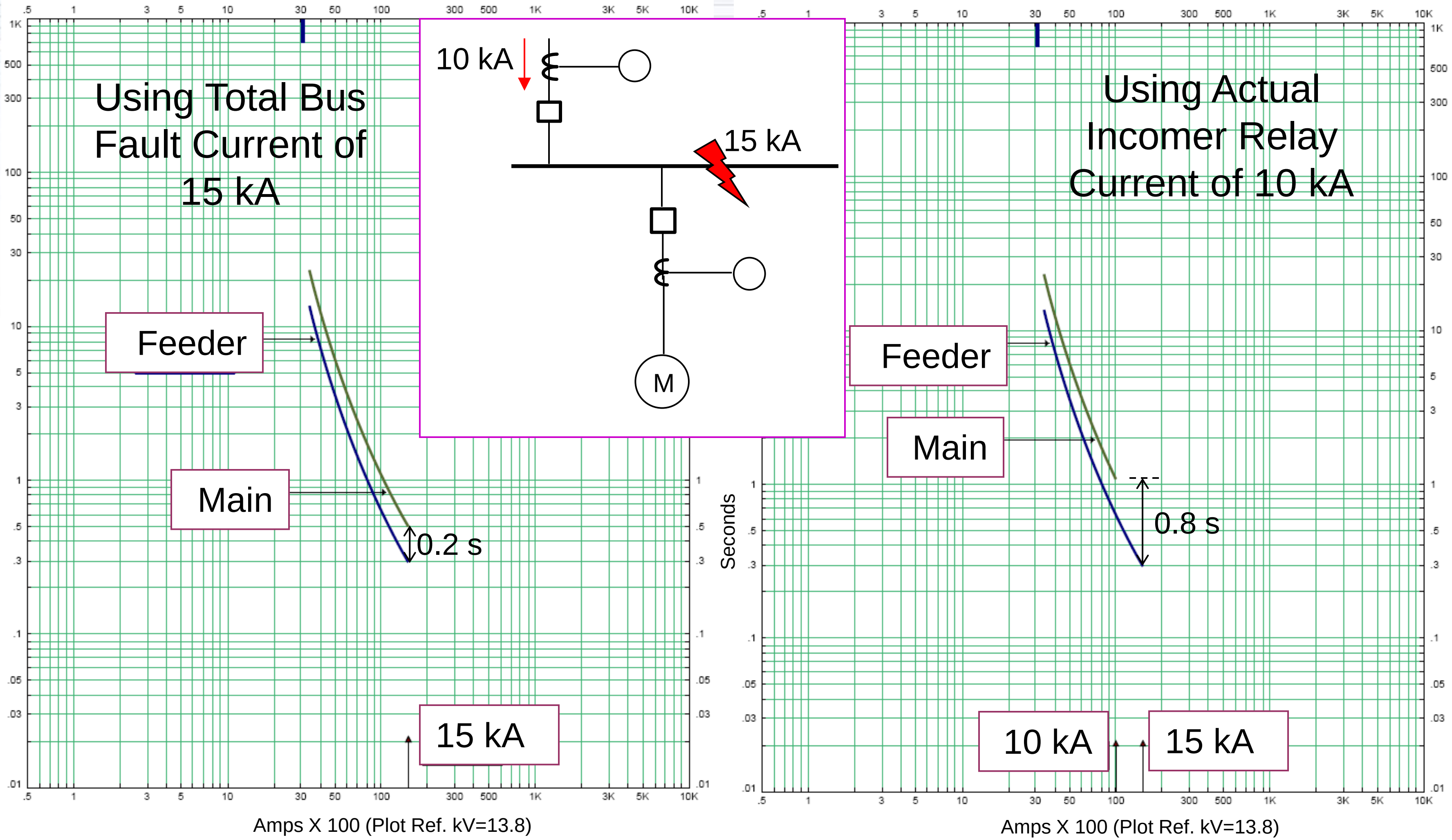
KBR

Total Bus Fault versus Branch Currents



- For a typical distribution bus all feeder relays will see a slightly different maximum fault current.
- Years back, the simple approach was to use the total bus fault current as the basis of the CTI, including main incomer.
- Using the same current for the main led to a margin of conservatism.

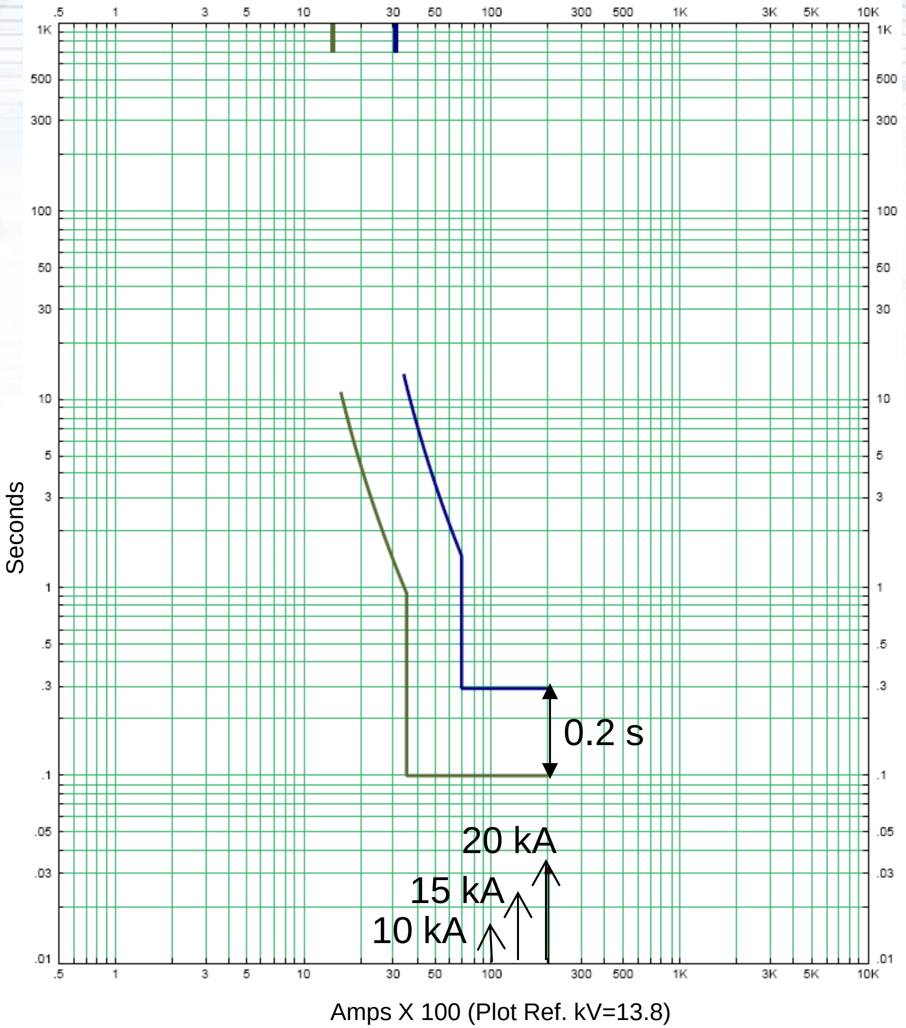
Total Bus Fault versus Branch Currents



KBR

Curve Shaping

- Most modern relays include multiple OC Elements.
- Using a definite time characteristic (or delayed instantaneous) can eliminate the affect of varying fault current levels.
- This is a highly-recommended change to old-school thinking.

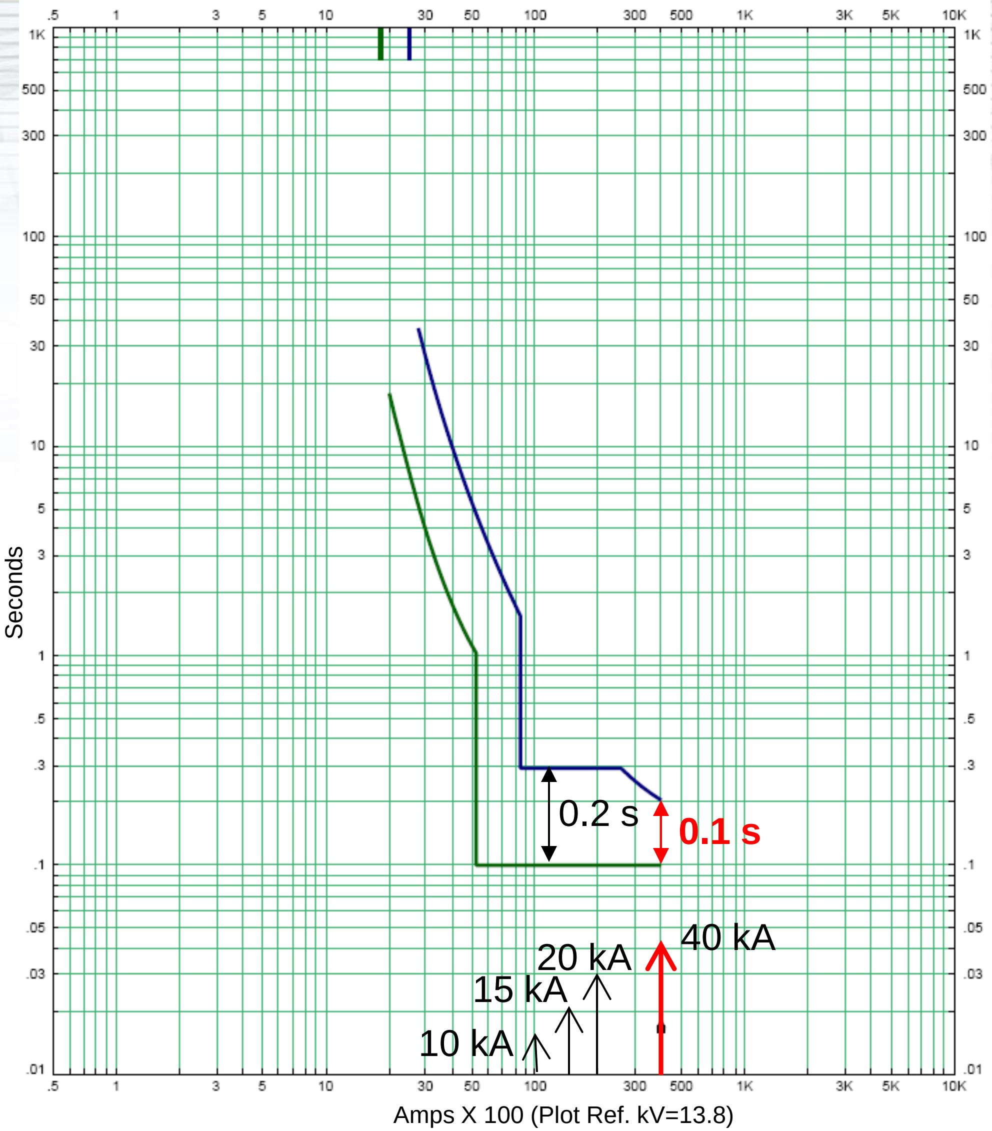


Curve Shaping – Danger of Independent OC Units

- Many software programs include the facility to plot integrated overcurrent units, usually a 50/51.

- However, the OC units of many modern relays are independent and remain active at all fault current levels.

- Under certain setting conditions, such as with an extremely inverse characteristic, the intended definite time delay can be undercut at higher fault levels.

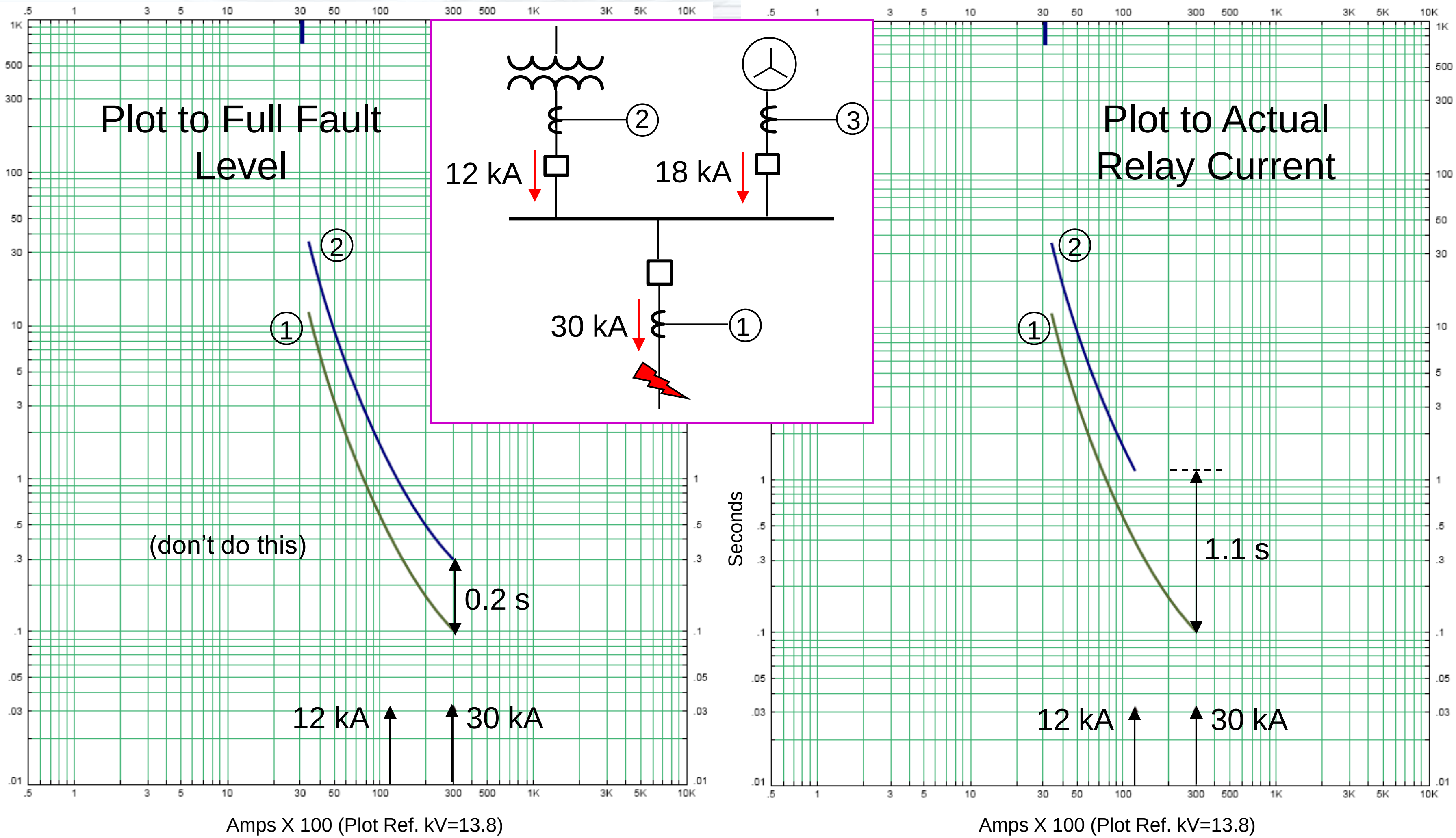


Multiple Source Buses

Multiple Source Buses

- When a bus includes multiple sources, care must be taken to <u>not</u> coordinate all source relays at the total fault current.
- Source relays should be plotted only to their respective fault currents or their “normalized” plots.
- Plotting the source curves to the total bus fault current will lead to much larger than actual CTIs.

Multiple Source Buses



KBR

Curve Shifting

- Many software packages include the facility to adjust/shift the characteristics of the source relays to line up at the bus maximum fault currents.
- Shifting allows relay operation to be considered on a common current basis (the max).
- The shift factor (SF) is calculated using:

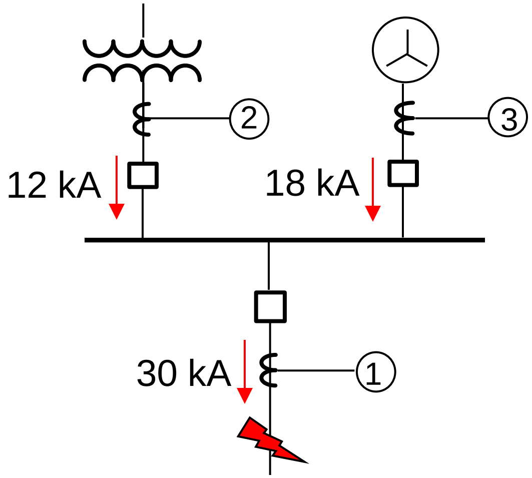
  SF = Bus Fault / Relay Current

- For example:

  Transformer relay SF = 30/12 = 2.5

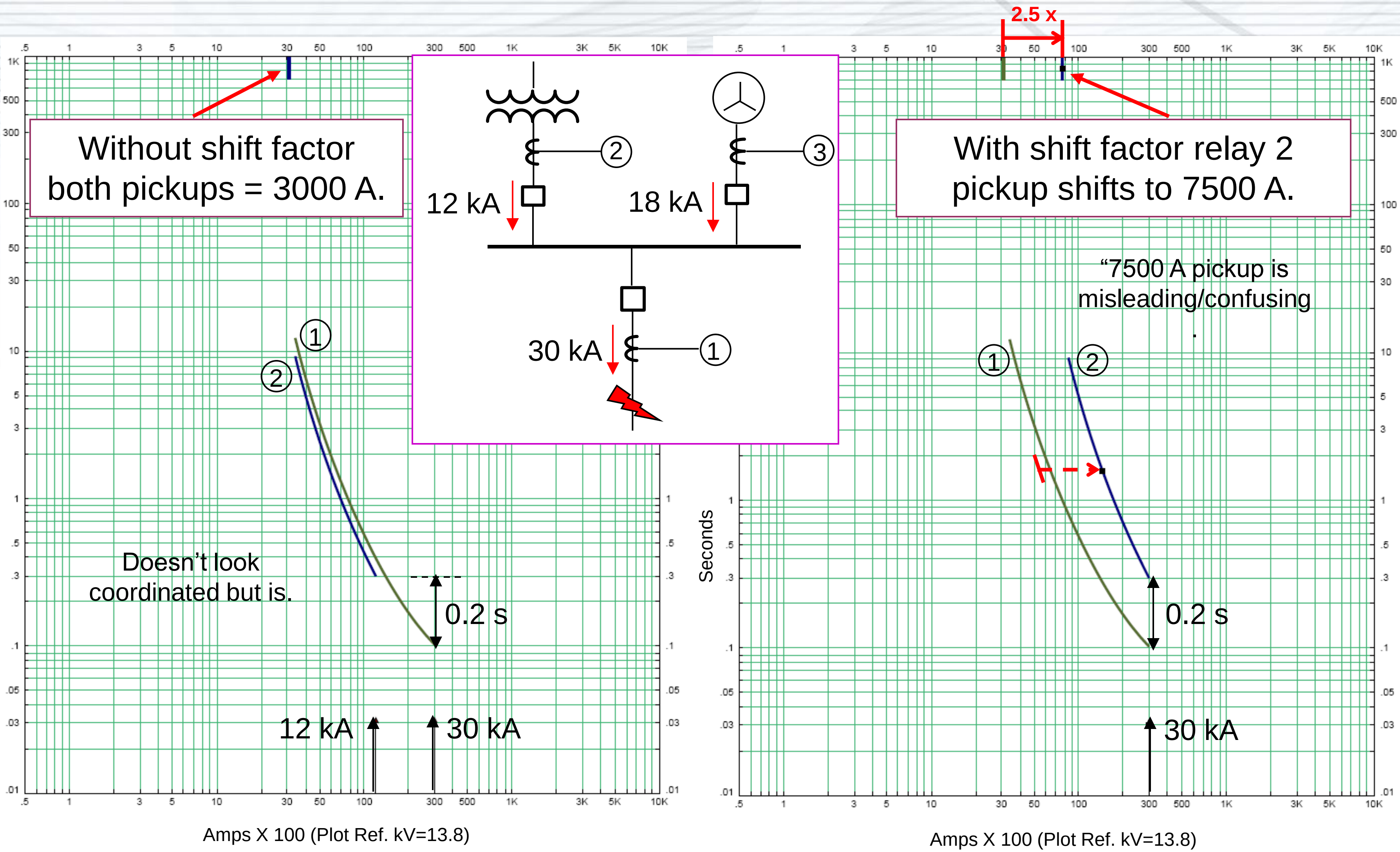
  Generator relay SF = 30/18 = 1.67

  Feeder relay SF = 30/30 = 1.0

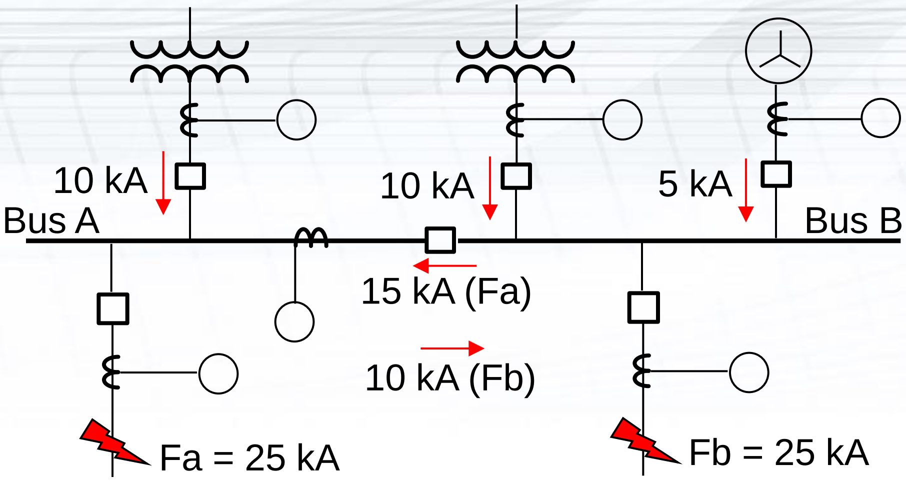


KBR

Curve Shifting



Multiple Source Buses with Closed Tie



- Different fault locations cause different flows in tie.

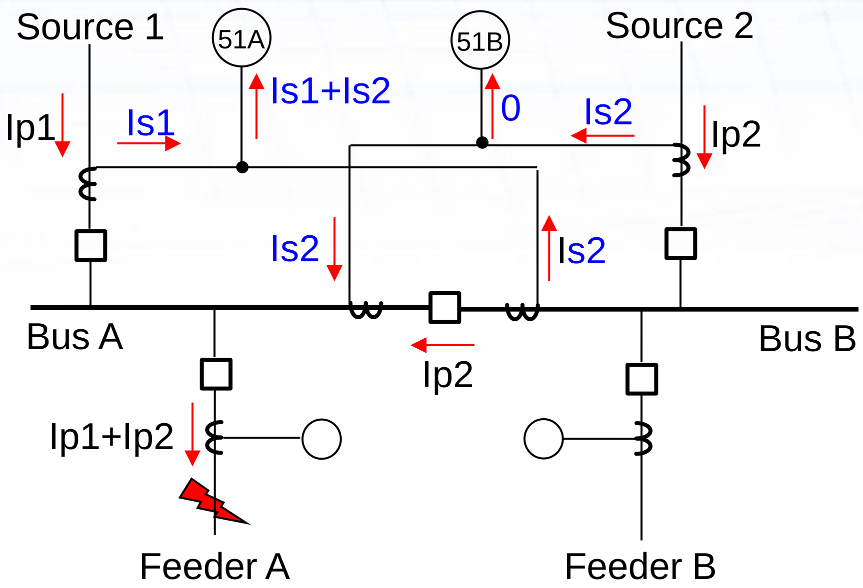
  $SF_{(Fa)} = 25 / (10 + 5) = 1.67$

  $SF_{(Fb)} = 25 / 10 = 2.5$

- Preparing a TCC for each fault unique location will determine the defining case.
- Cases can be done for varying sources out of service & breaker logic used to enable different setting groups.

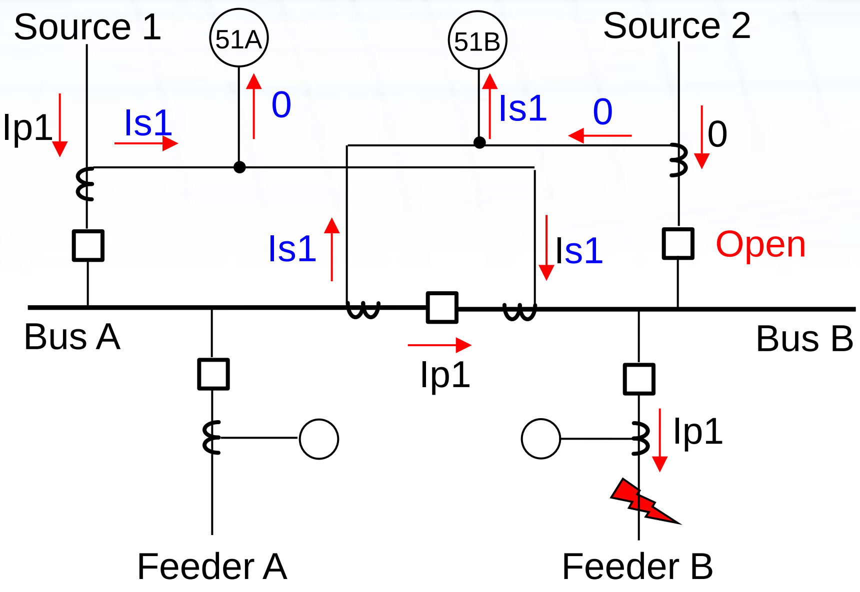
Partial Differential Relaying

Partial Differential (Summation) Relaying



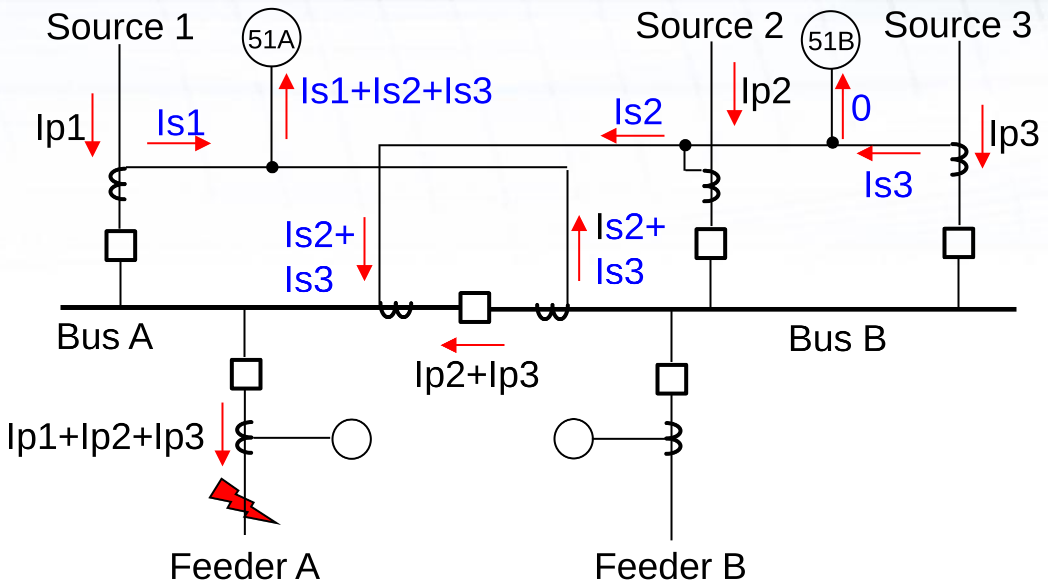
- Commonly used on secondary selective systems with normally closed tie breakers.
- CT wiring automatically discriminates between faults on Bus A and Bus B.
- CT wiring ensures that main breaker relay sees the same current as the faulted feeder.
- 51A trips Main A & tie; 51B trips Main B & tie.
- Eliminates need for relay on tie breaker & saves coordination step.

Partial Differential Relaying



- Scheme works with a source or tie breaker open.
- The relay in the open source must remain in operation.
- Relay metering functions can be misleading due to CT summation wiring.
- Separate metering must be provided on dedicated CTs or before the currents are summed.

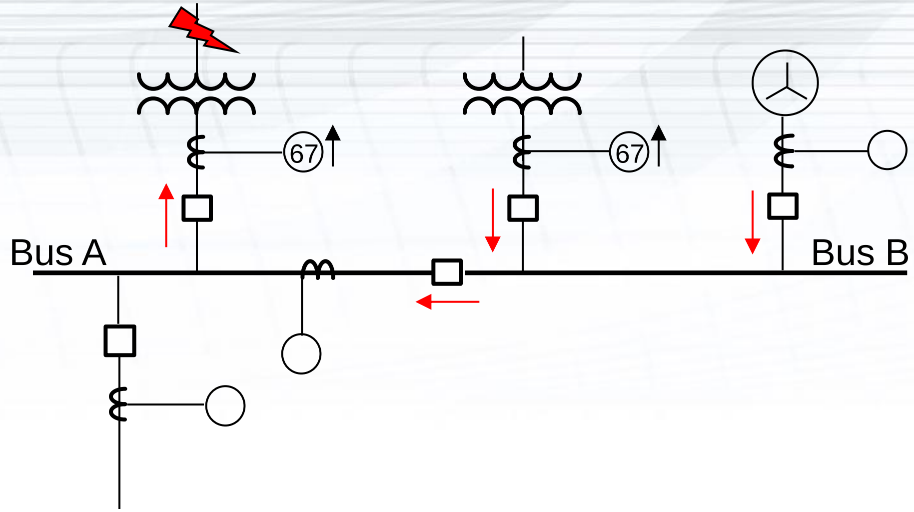
Partial Differential Relaying



- Scheme will work for any number of sources or bus ties.
- A dedicated relay is needed for each bus section.
- Partial differential schemes simplify the coordination of multiple source buses by ensuring the main relay for each bus always see the same current as the faulted feeder.

Directional Overcurrent Relaying

Directional Current Relaying



- Directional overcurrent (67) relays are required on double-ended line-ups with normally closed ties and buses with multiple sources.
- Protection is intended to provide more sensitive and faster detection of faults in the upstream supply system.
- Directional device provides backup protection to the transformer differential protection.
- Normal overcurrent devices are bidirectional. A separate set of TCCs are required to show coordination of directional units.

KBR

Transformer Overcurrent Protection

Transformer Overcurrent Protection

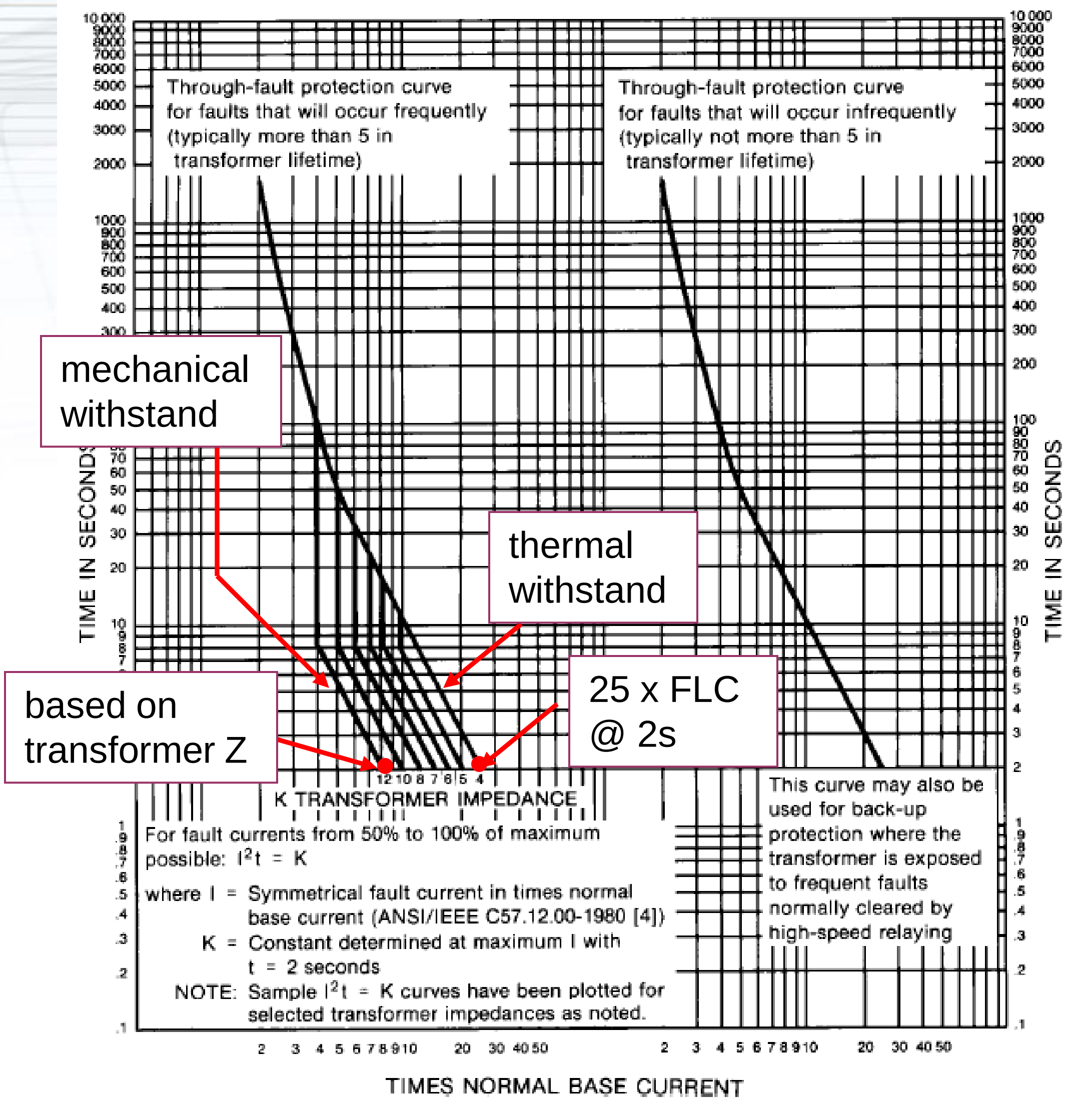
NEC Table 450.3(A) defines overcurrent setting requirements for primary & secondary protection pickup settings.

Table 450.3(A) Maximum Rating or Setting of Overcurrent Protection for Transformers Over 1000 Volts (as a Percentage of Transformer-Rated Current)

		Primary Protection over 1000 Volts		Secondary Protection (See Note 2.)		
				Over 1000 Volts		1000 Volts or Less
Location Limitations	**Transformer Rated Impedance**	**Circuit Breaker (See Note 4.)**	**Fuse Rating**	**Circuit Breaker (See Note 4.)**	**Fuse Rating**	**Circuit Breaker or Fuse Rating**
Any location	Not more than 6%	600% (See Note 1.)	300% (See Note 1.)	300% (See Note 1.)	250% (See Note 1.)	125% (See Note 1.)
	More than 6% and not more than 10%	400% (See Note 1.)	300% (See Note 1.)	250% (See Note 1.)	225% (See Note 1.)	125% (See Note 1.)
Supervised locations only (See Note 3.)	Any	300% (See Note 1.)	250% (See Note 1.)	Not required	Not required	Not required
	Not more than 6%	600%	300%	300% (See Note 5.)	250% (See Note 5.)	250% (See Note 5.)
	More than 6% and not more than 10%	400%	300%	250% (See Note 5.)	225% (See Note 5.)	250% (See Note 5.)

Transformer Overcurrent Protection

- C37.91 defines the ANSI withstand protection limits.
- Withstand curve defines thermal & mechanical limits of a transformer experiencing a through-fault.
- Requirement to protect for mechanical damage is based on frequency of through faults & transformer size.
- Right-hand side (thermal) used for setting primary protection.
- Left-hand side (mechanical) used for setting secondary protection.



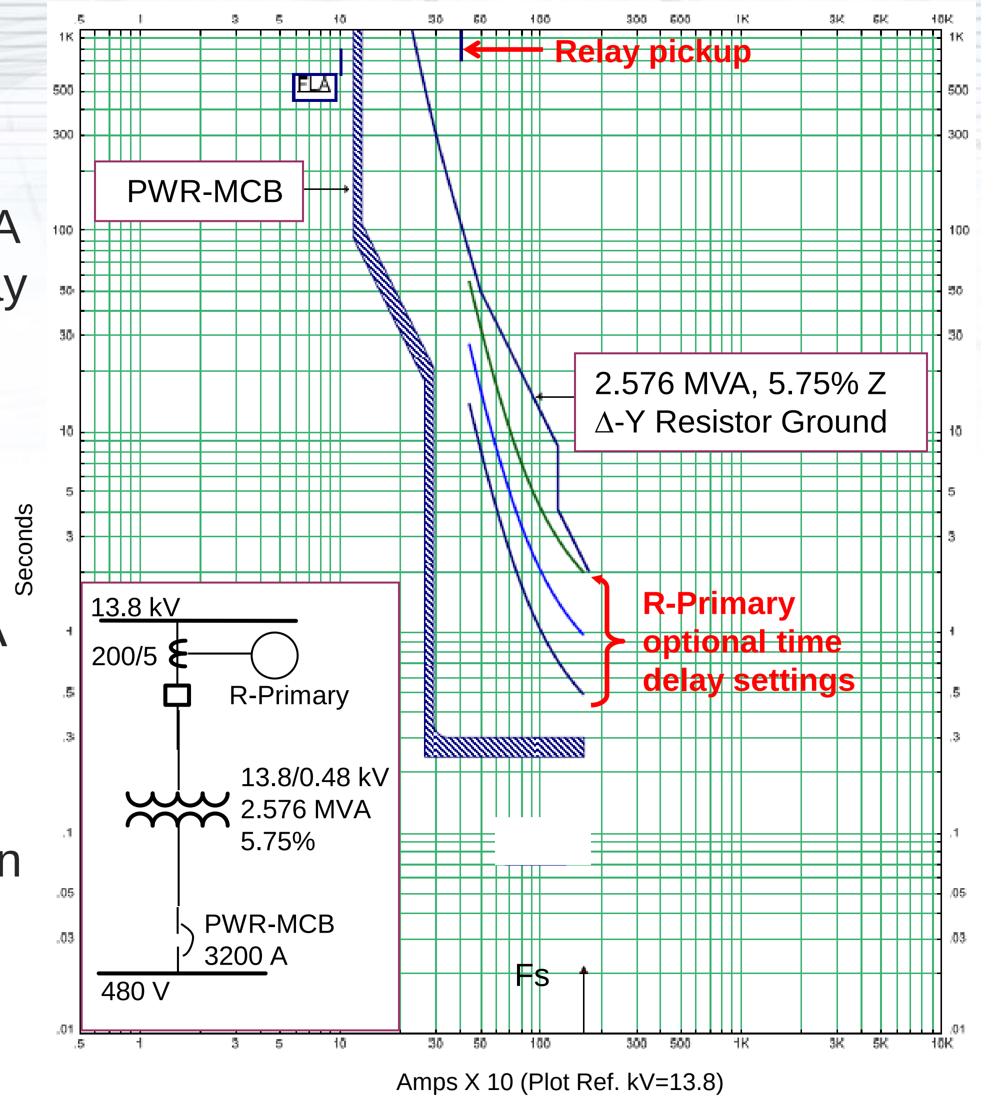
Transformer Overcurrent Protection

Primary
FLC = 2.576 MVA/(√3 x 13.8) = 107.8 A
Relay PU must be ≤ 600% FLC = 646.6 A
Using a relay setting of 2.0 x CT, the relay PU = 2 x 200 = 400 A
400 / 107.8 = 371% so okay

Secondary
FLC = 2.576 MVA / (√3 x 0.48) = 3098 A
MCB Trip must be ≤ 250% FLC = 7746 A
Breaker Trip = 3200 A per bus rating
3200 / 3098 = 103% (okay)

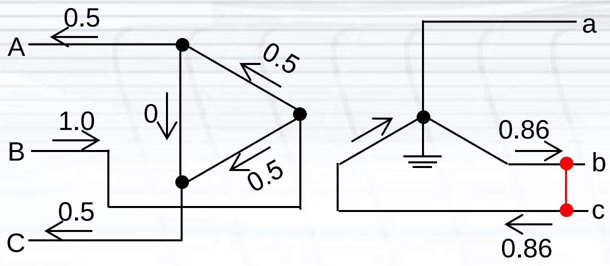
Time delay depends on level of protection desired.

(ONAN/ONAN/ONAF - 2.0 x 1.12 x 1.15 = 2.576)

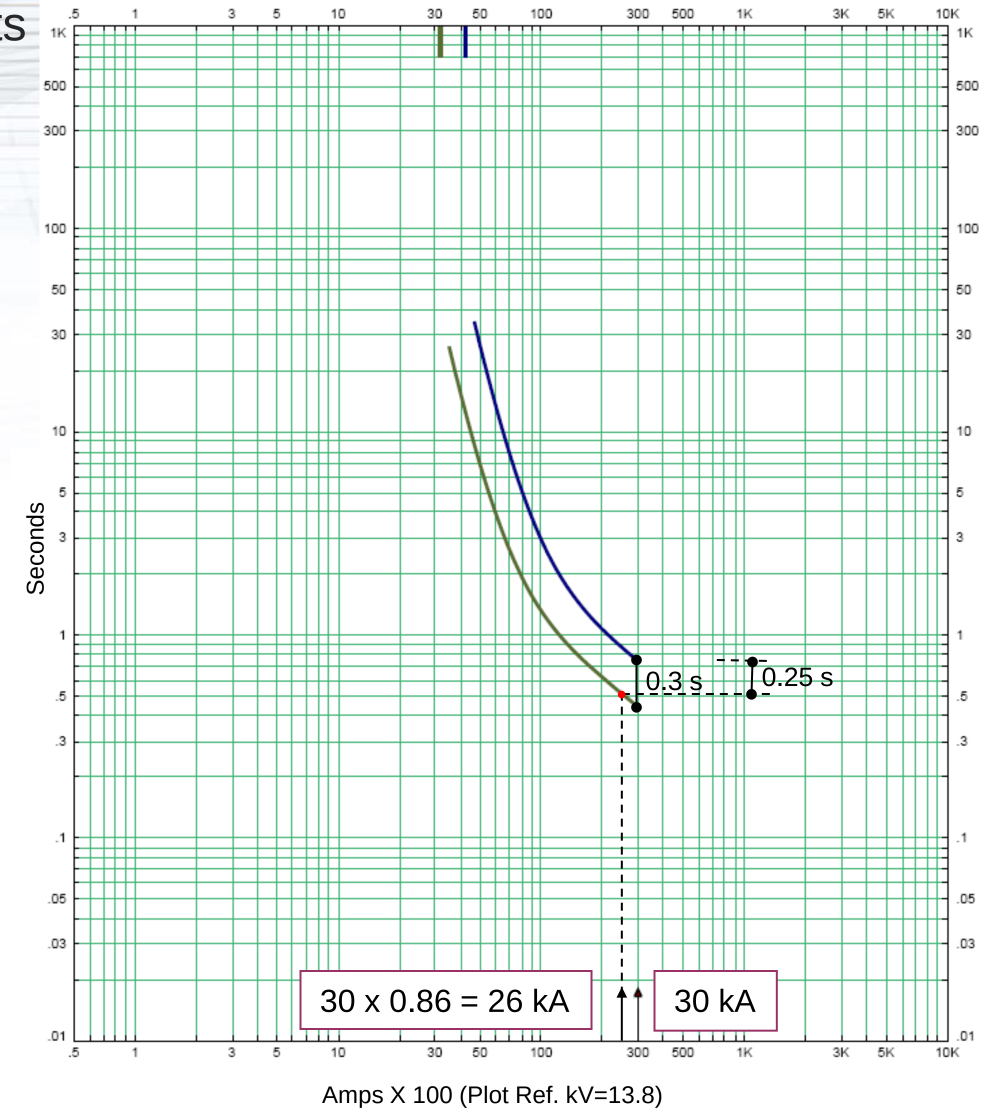


Transformer Overcurrent Protection

Δ-Y Connections – Phase-To-Phase Faults



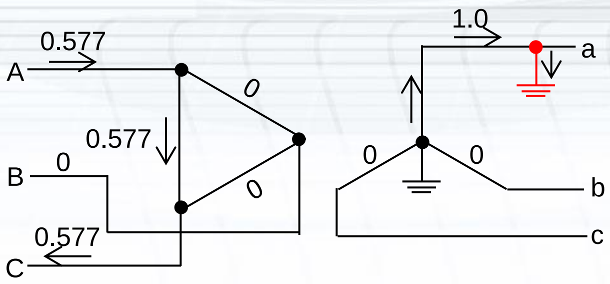
- A phase-phase fault on the secondary appears more severe in one phase on the primary.
- Setting the CTI based on a three-phase fault is not as conservative as for a phase-phase fault.
- The secondary curve could be shifted or a slightly larger CTI used, but can be ignored if primary/ secondary selectivity is not critical.



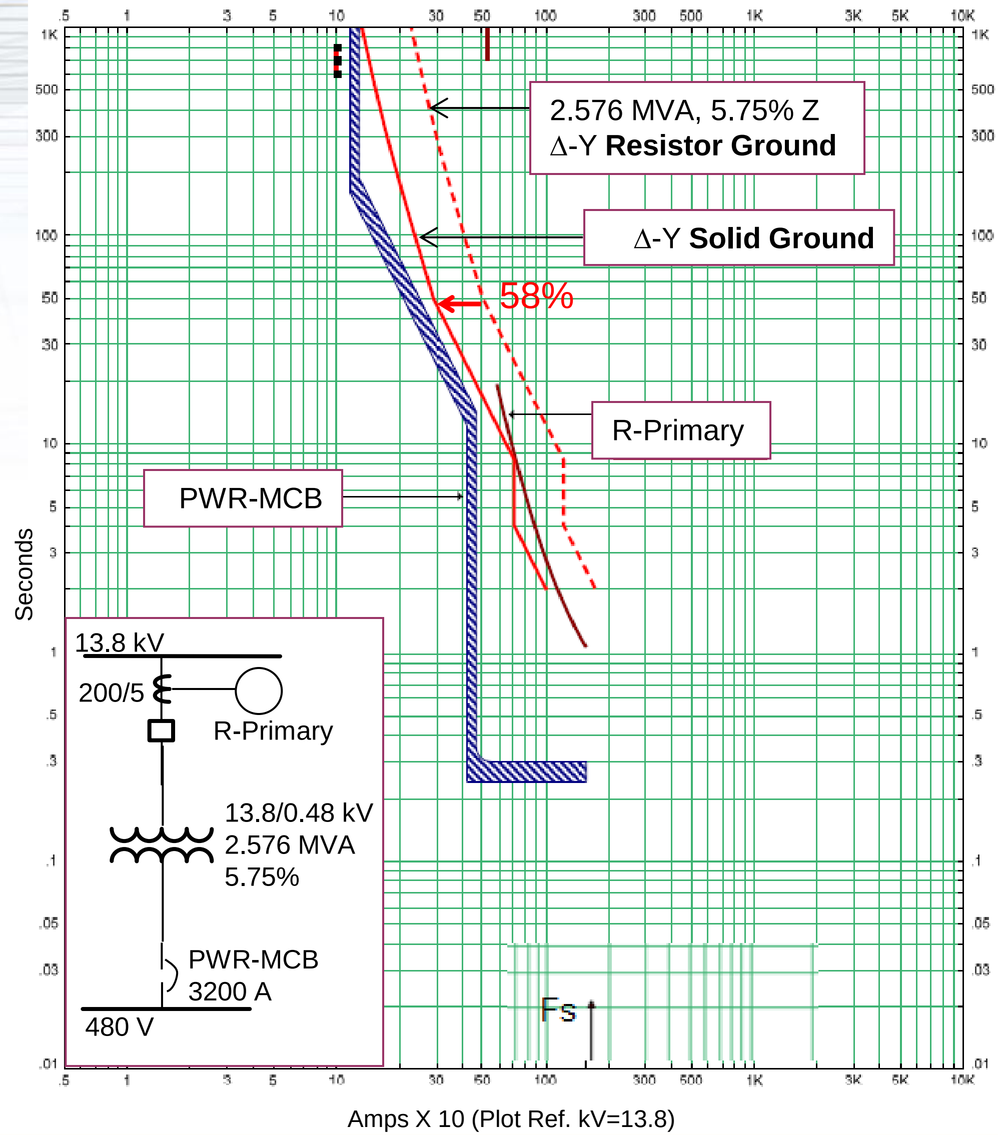
KBR

Transformer Overcurrent Protection

Δ-Y Connections – Phase-To-Ground Faults



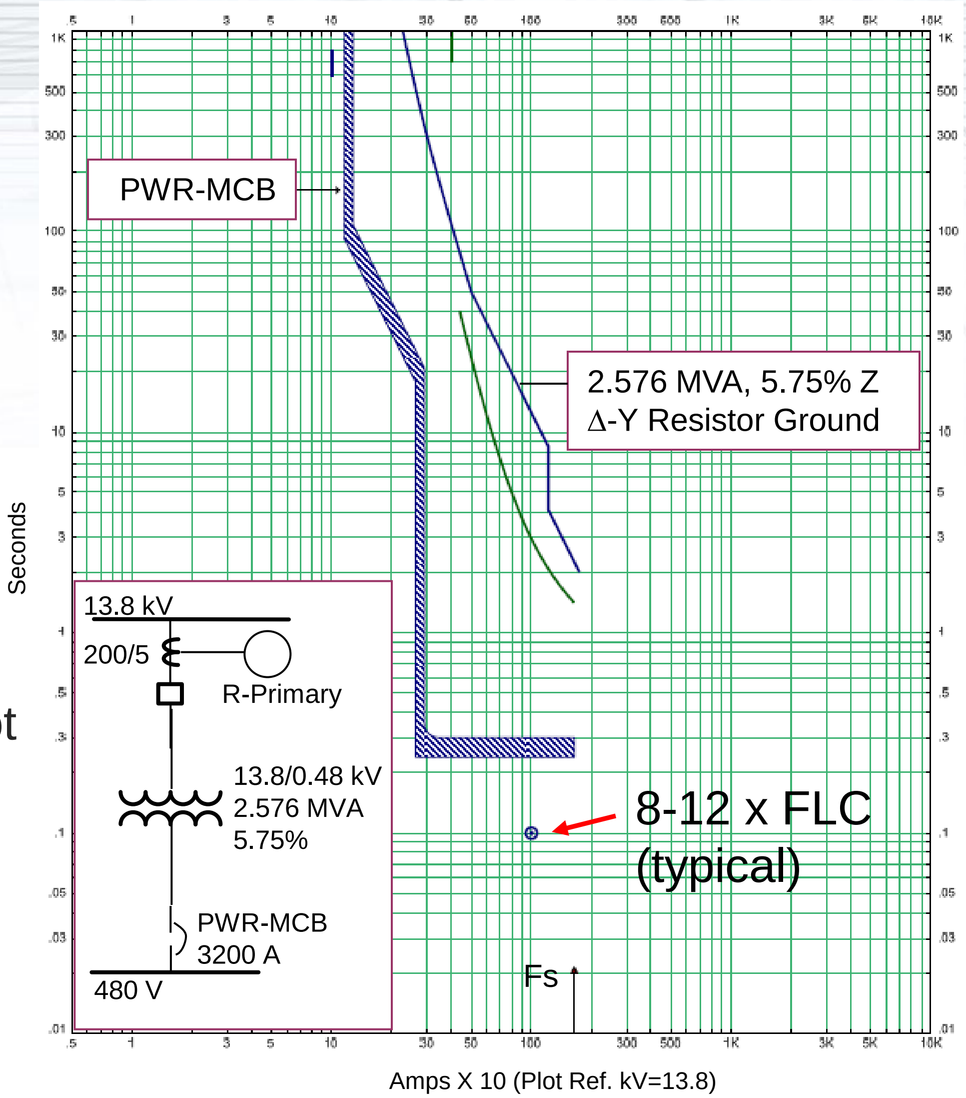
- A one per unit phase-ground fault on the secondary appears as a 58% (1/√3) phase fault on the primary.
- The transformer damage curve is shifted 58% to the left to ensure protection.



Transformer Overcurrent Protection

Inrush Current

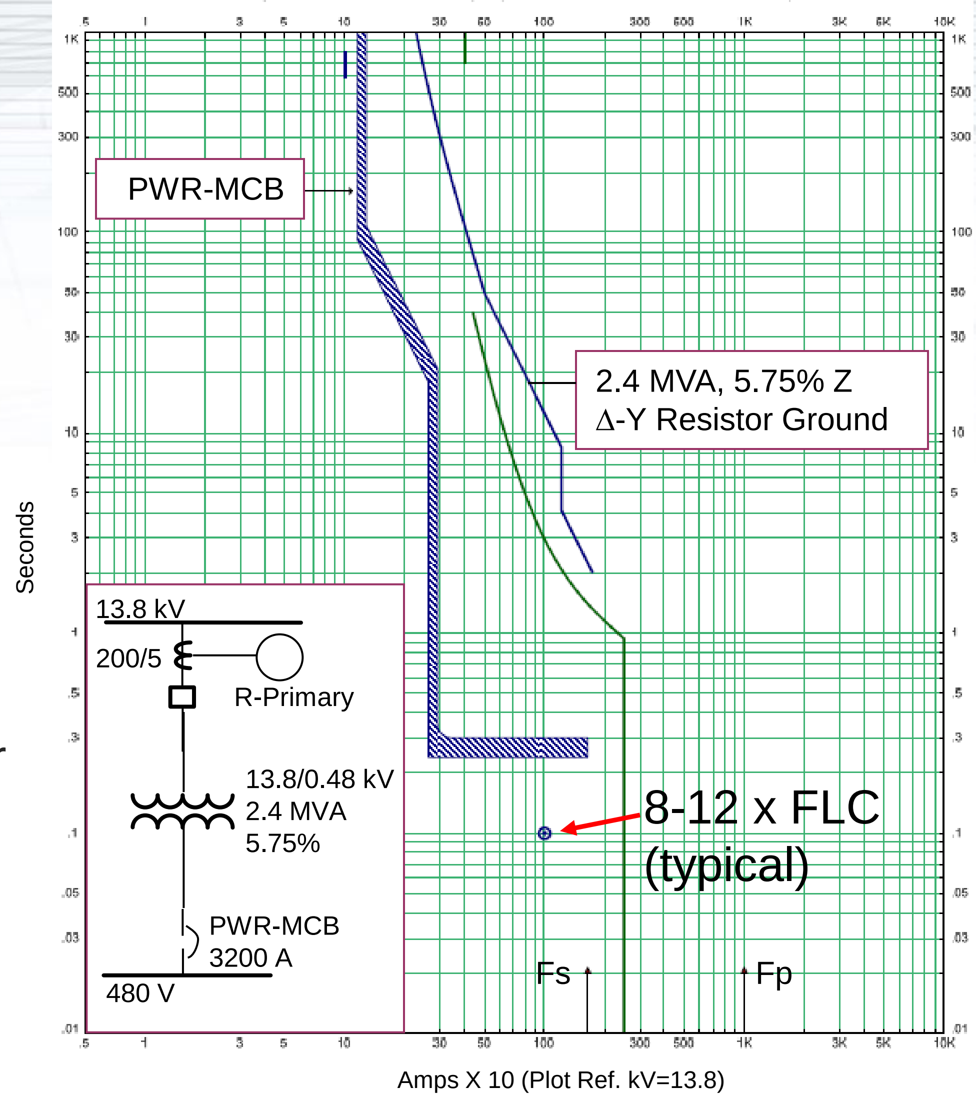
- Use of 8-12 times FLC @ 0.1 s is an empirical approach based on EM relays. (based on a 1944 AIEE paper)
- The instantaneous peak value of the inrush current can actually be much higher than 12 times FLC.
- The inrush is not over at 0.1 s, the dot just represents a typical rms equivalent of the inrush from energization to this point in time.



Transformer Overcurrent Protection

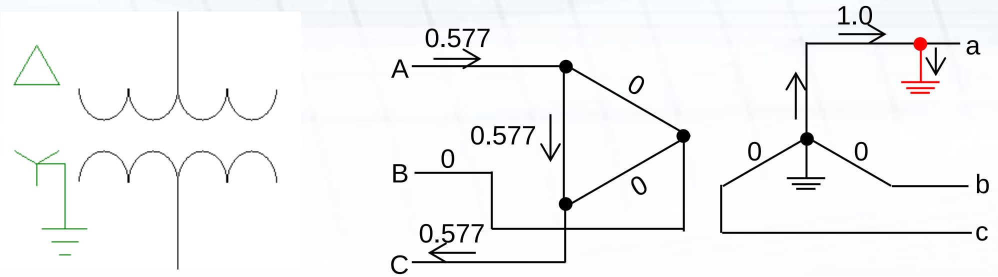
Setting the primary inst. protection

- The primary relay instantaneous (50) setting should not trip due to the inrush or secondary fault current.
- It was common to use the asymmetrical rms value of secondary fault current (1.6 x sym) to establish the instantaneous pickup, but most modern relays filter out the DC component.

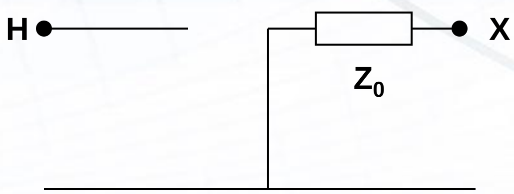


Transformer Overcurrent Protection

Δ-Y Connection & Ground Faults



Phase Currents

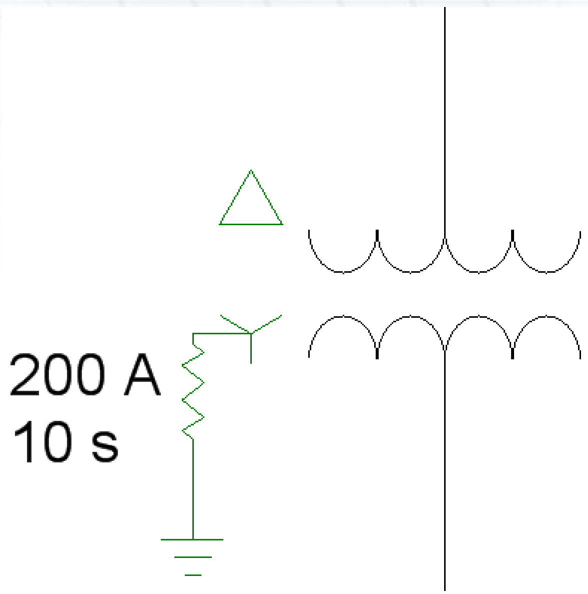


Zero Sequence Network

- A secondary L-G fault is not sensed by the ground (zero sequence) devices on the primary (Δ) side.
- Low-resistance and solidly-grounded systems on the secondary of a Δ-Y transformer are therefore coordinated separately from the upstream systems.

Transformer Overcurrent Protection

Δ-Y Connection & Ground Faults

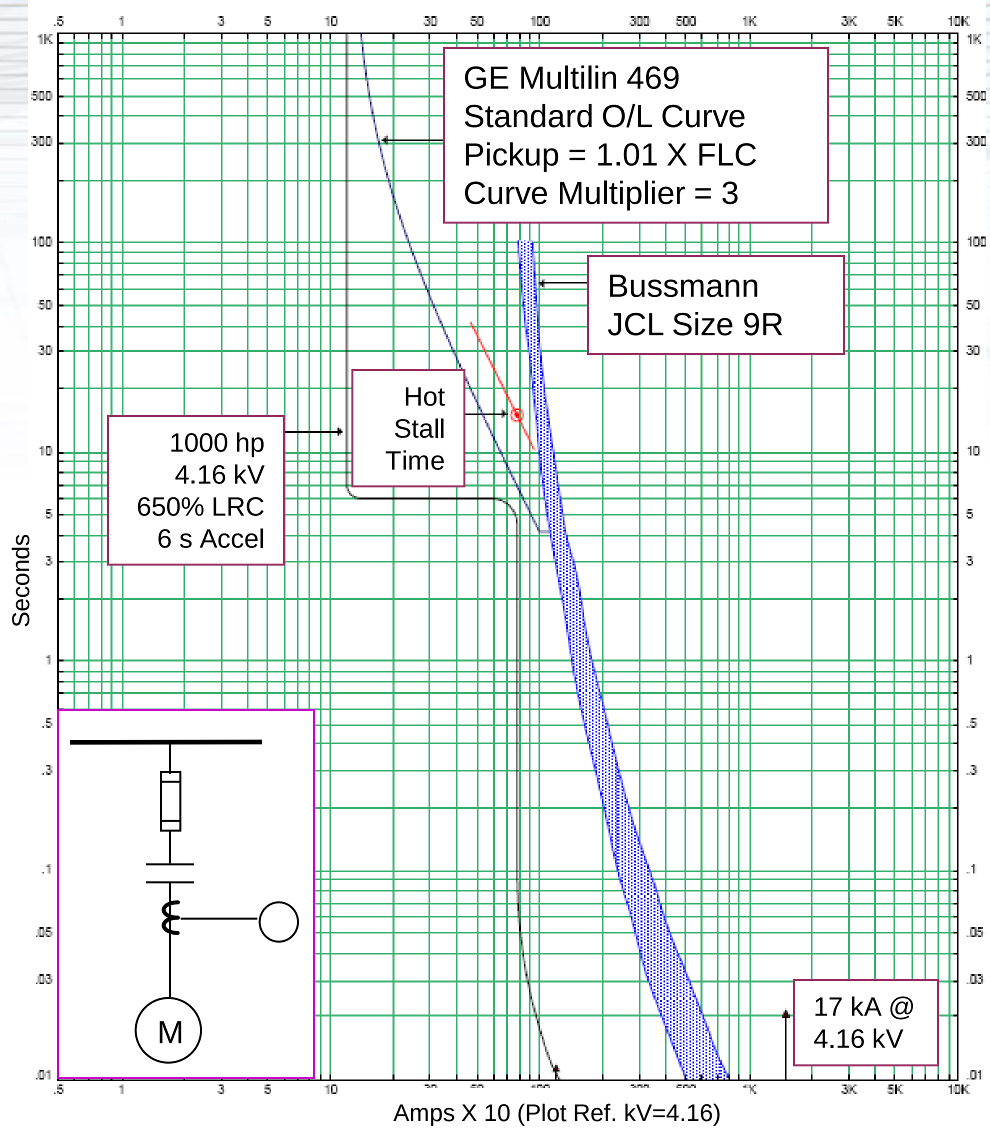


- The ground resistor size is selected to limit the fault current while still providing sufficient current for coordination.
- The resistor ratings include a maximum continuous current that must be considered. (as low as 10% of the rated current)

Motor Overcurrent Protection

Motor Overcurrent Protection

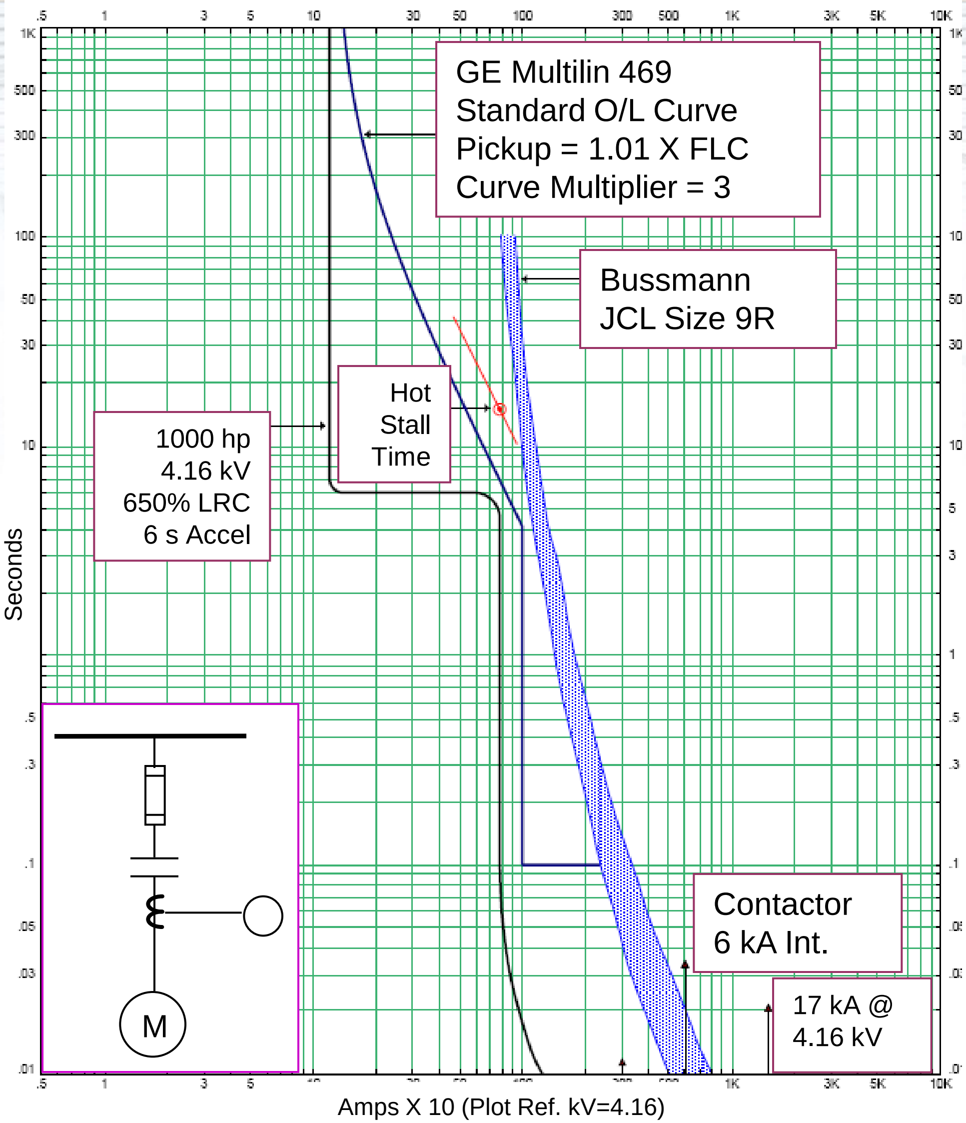
- Fuse provides short-circuit protection.
- 49 or 51 device provide motor overload protection.
- Overload pickup depends on motor FLC and service factor.
- The time delay for the 49/51 protection is based on motor stall time.



KBR

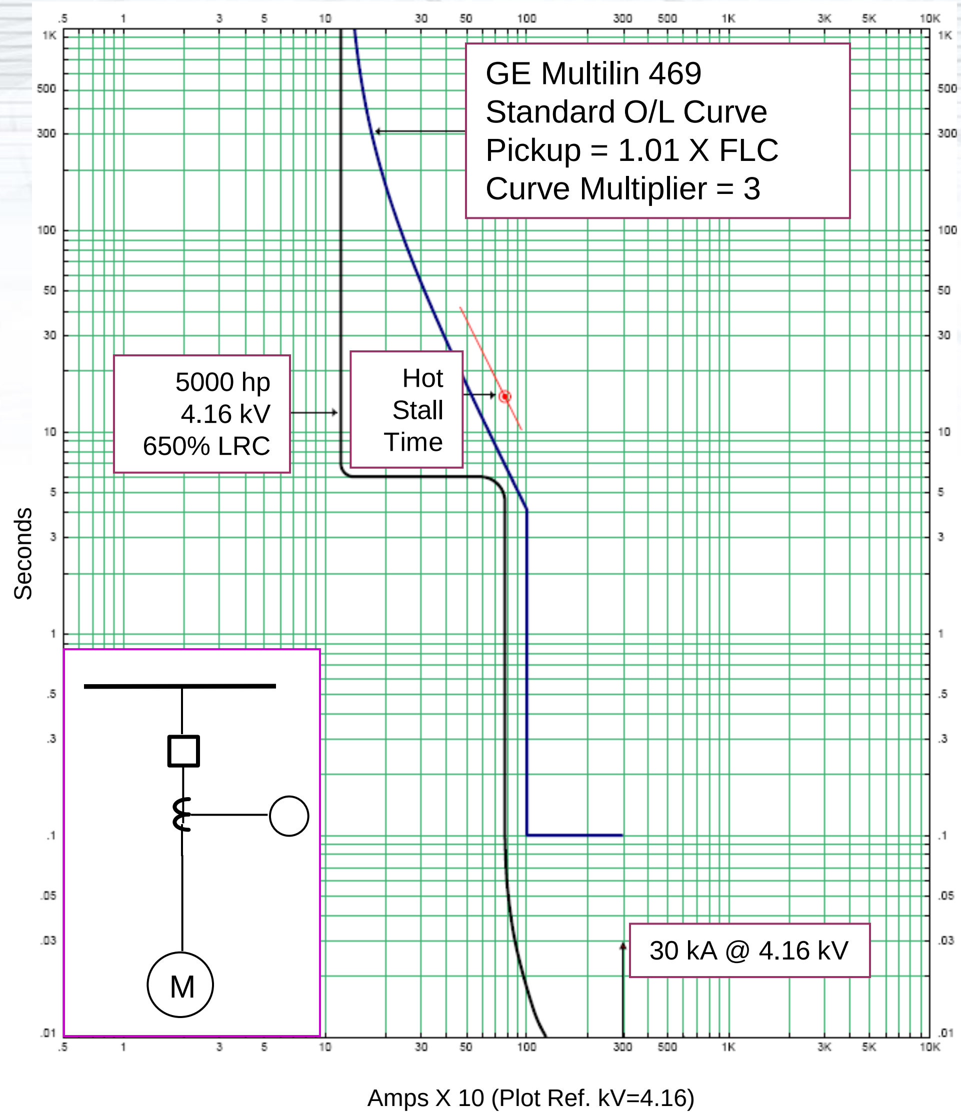
Motor Overcurrent Protection

- In the past, instantaneous OC protection was avoided on contactor-fed motors since the contactors could not clear high short-circuits.
- With modern relays, a definite time unit can be used if its setting is coordinated with the contactor interrupting rating.



Motor Overcurrent Protection

- The instantaneous or definite time setting for a breaker-fed motor must be set to not trip during motor starting.
- Electromechanical relays must be set above the asymmetrical rms current, either via the pickup or with a time delay.
- Modern relays with filtering can ignore the asymmetrical current, but it's advisable to include a generous margin such as 2 x LRC.
- Note – undervoltage protection (27) needed to trip motor on loss of power.



Conductor Overcurrent Protection

Conductor Overcurrent Protection

LV Cables

NEC 240.4 Protection of Conductors – conductors shall be protected against overcurrent in accordance with their ampacities

> **(B) Devices Rated 800 A or Less –** the next higher standard device rating shall be permitted
>
> **(C) Devices Rated over 800 A –** the ampacity of the conductors shall be ≥ the device rating

NEC 240.91 Protection of Conductors (supervised locations, new in 2011)

> **(B) Devices Rated Over 800 A –** allows ampacity of at least 95% of breaker rating to be acceptable provided I^2t withstand protection is provided.

- Means that 3/phase 500 kcmil conductors at 380 A each for a total of 1140 A can be protection by a 1200 A breaker.
- Does not mean you can operate the circuit at 1200 A.

Conductor Overcurrent Protection

NEC 240.6 Standard Ampere Ratings

- **(A) Fuses & Fixed-Trip Circuit Breakers –** cites all standard ratings
- **(B) Adjustable Trip Circuit Breakers** – Rating shall be equal to maximum setting
- **(C) Restricted Access Adjustable-Trip Circuit Breakers** – Rating can be equal to setting if access is restricted

KBR

Conductor Overcurrent Protection

MV Feeders & Branch Circuits

NEC 240.101 (A) Rating or Setting of Overcurrent Protective Devices

Fuse rating ≤ 3 times conductor ampacity
Relay setting ≤ 6 times conductor ampacity

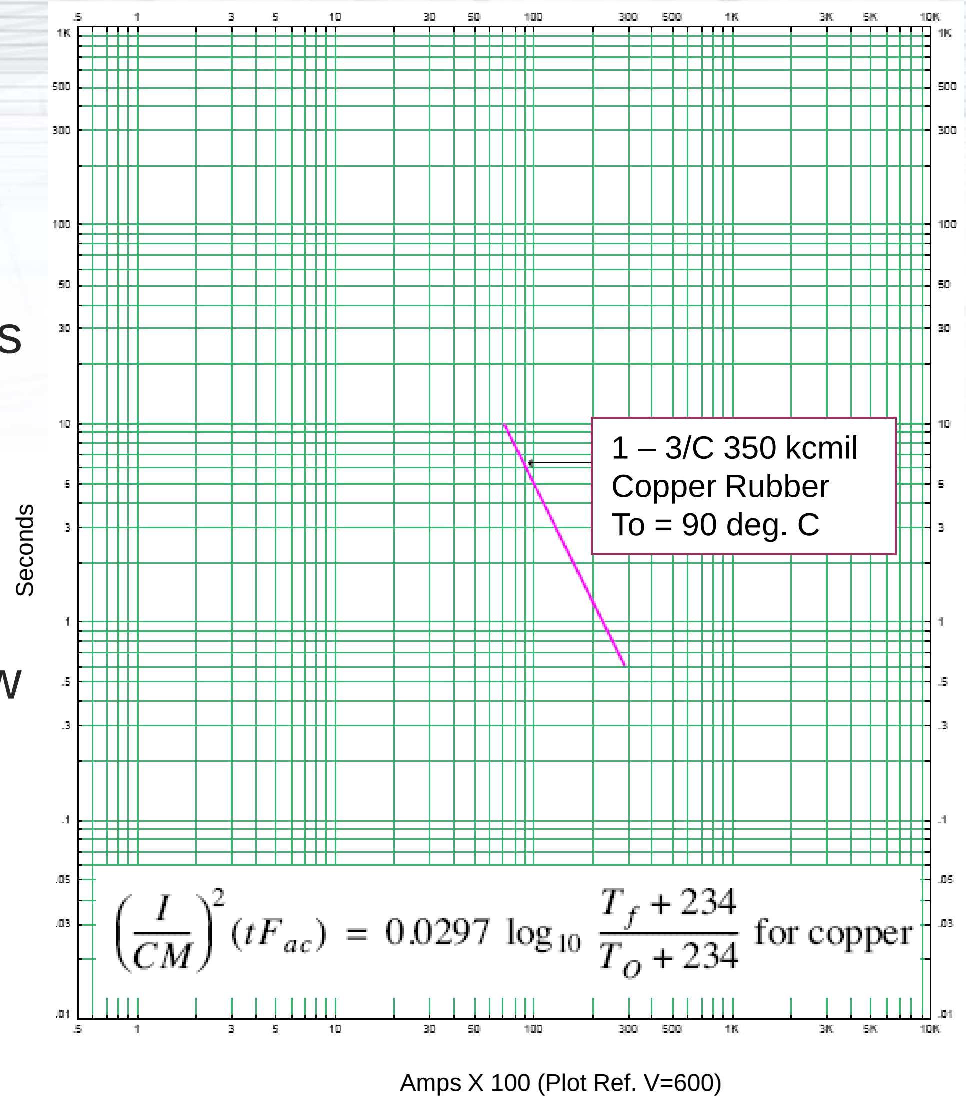
MV Motor Conductors

NEC 430.224 Size of Conductors

Conductors ampacity shall be greater than the overload setting.

Conductor Overcurrent Protection

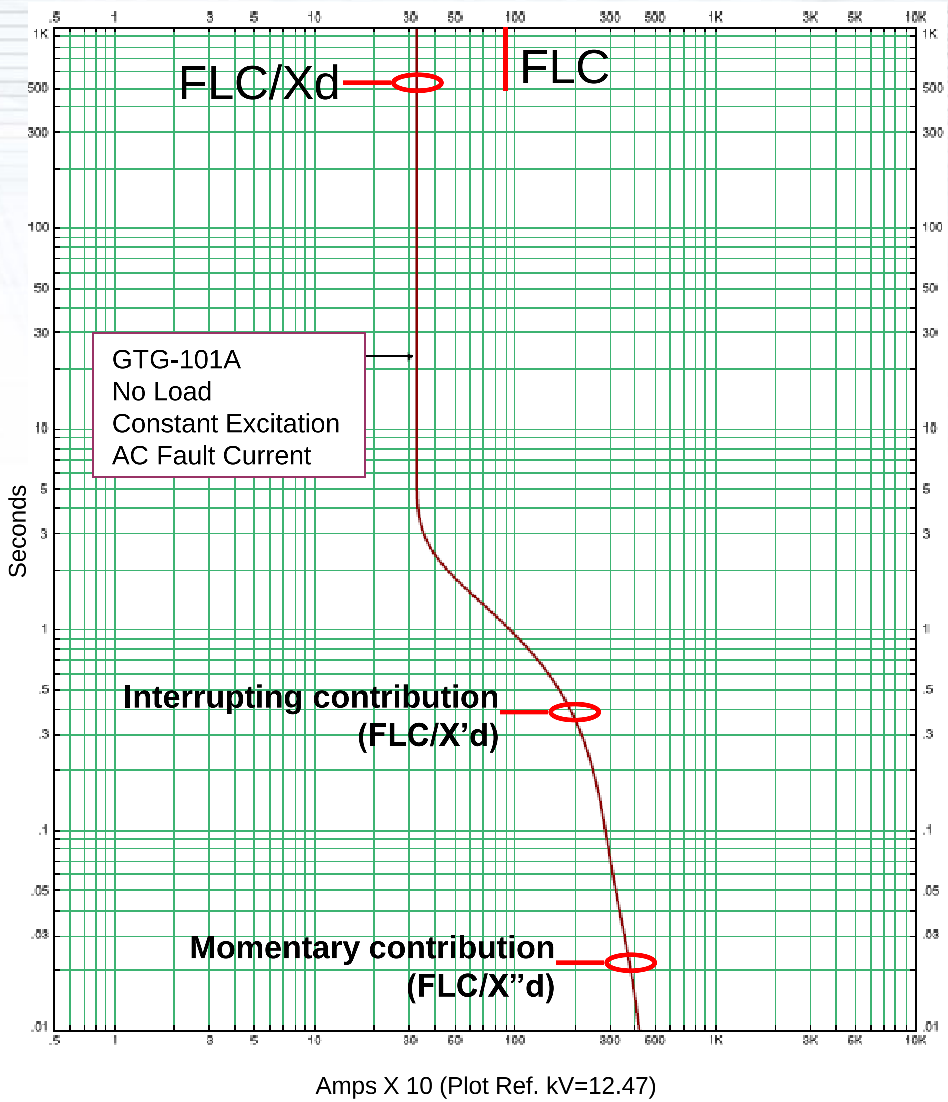
- The insulation temperature rating is typically used as the operating temperature (T_o).
- The final temperature (T_f) depends on the insulation type (typically 150 deg. C or 250 deg. C).
- When calculated by hand, you only need one point and then draw in at a -2 slope.



KBR

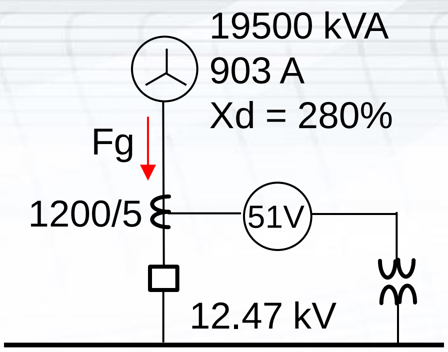
Generator Overcurrent Protection

Generator Overcurrent Protection



- A generator's fault current contribution decays over time.
- Overcurrent protection must allow both for moderate overloads & be sensitive enough to detect the steady state contribution to a system fault.
- Voltage controlled/ restrained relays (51V) are commonly used.
- Per 1986 Buff Book, the pickup at full restraint is typically ≥ 150% of Full Load Current (FLC).
- The pickup at no restraint must be < FLC/X_d.

Generator 51V Pickup Setting Example



Fg = FLC/Xd = 903 / 2.8 = 322.5 A

51V pickup (full restraint) > 150% FLC = 1354 A

51V pickup (no restraint) < 322.5 A

Generator 51V Pickup Setting Example

51V Setting > 1354/1200	= 1.13
Using 1.15, 51V pickup	= 1.15 x 1200 A = 1380 A

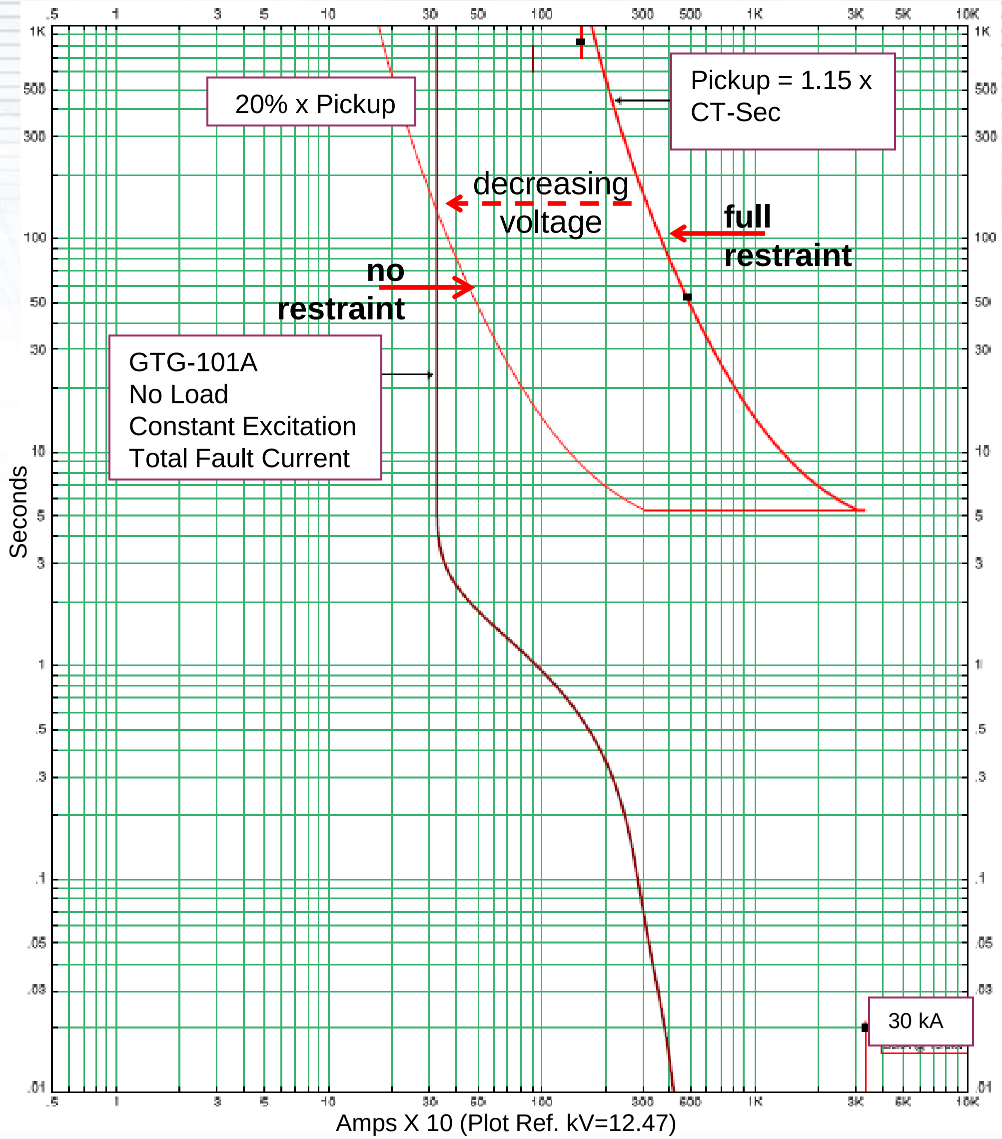
With old EM relays,

51V pickup (no restraint)	= 25% of 1380 A
	= 345 A (> 322.5 A, not good)

With new relays a lower MF can be set, such that 51V

pickup (no restraint)	= 20% of 1380 A
	= 276 A (< 322.5, so okay)

Generator 51V Settings on TCC



- At 100% voltage the overcurrent function is fully restrained.
- As the bus voltage decreases the restraint decreases and the characteristic curve shifts to the left.
- There was no guidance in the 1986 Buff Book with respect to time delay.
- Practically speaking, if the installation is not generator-limited, it is not possible to overload the generator.
- To avoid nuisance tripping, especially on islanded systems, higher TDs are better.

KBR

Generator Overload Protection per 2001 Buff Book

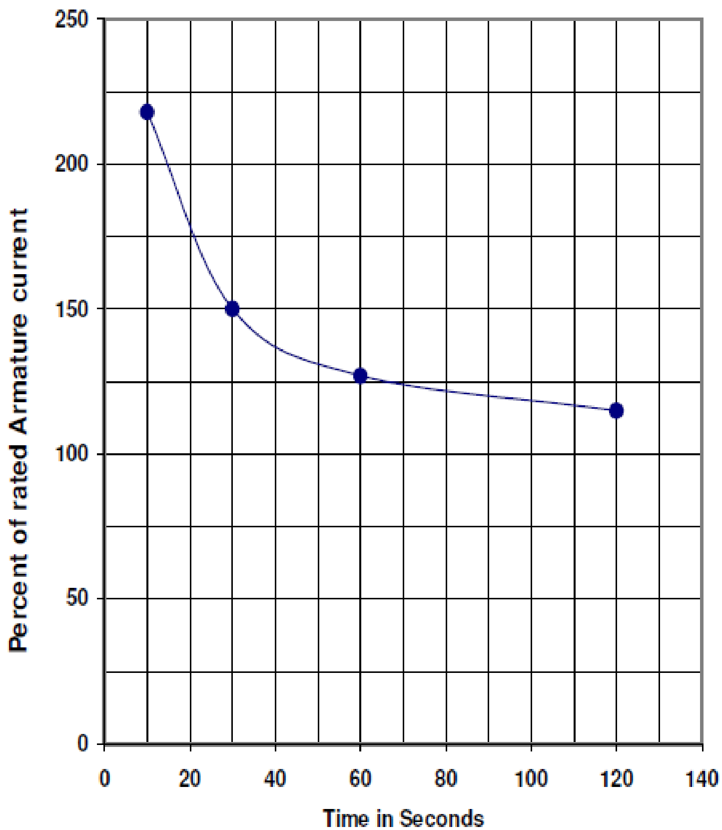


Figure 4-1—Turbine-generator short time thermal capability for balanced three-phase loading

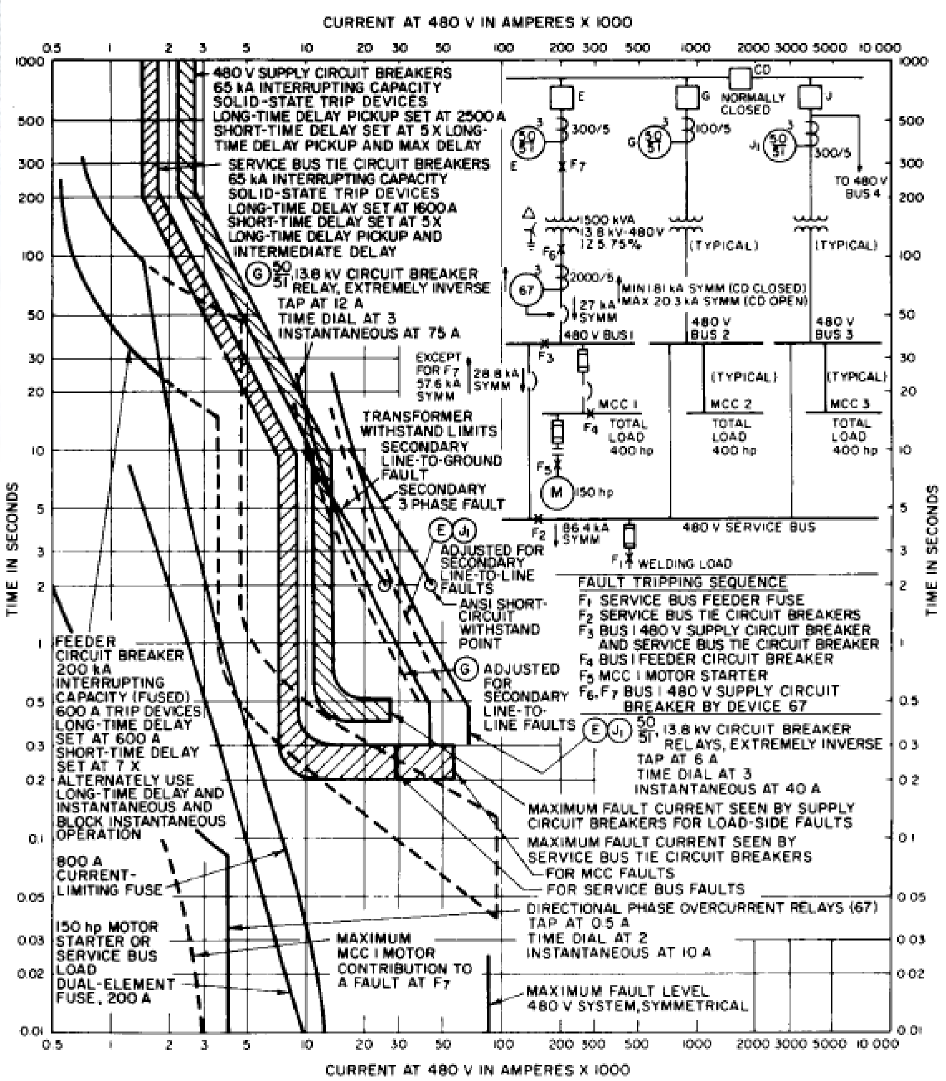
- C50.13, Section 4.2 discusses stator and rotor thermal limits.
- C37.102, Section 4.1.1 provides the associated plot.
- The 2001 Buff Book now references this discusses a different approach overload protection.
- The approach uses a 50 device to control a 51. No mention of voltage.
- Note that rotor negative sequence (I_2t^2) protection can be plotted on a TCC but is applicable to 46 protection, not 51V.

KBR

Coordinating a System

Coordinating a System

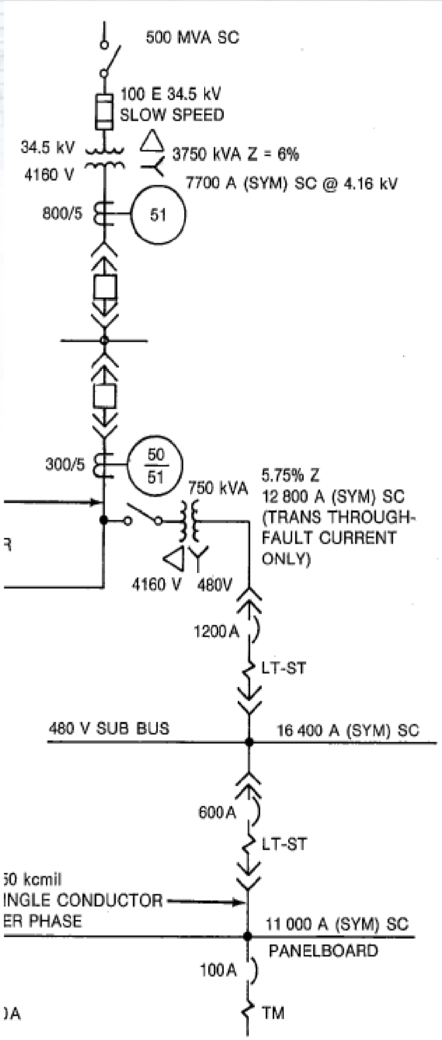
- TCCs show both protection & coordination.
- Most OC settings should be shown/confirmed on TCCs.
- Showing too much on a single TCC can make it impossible to read.

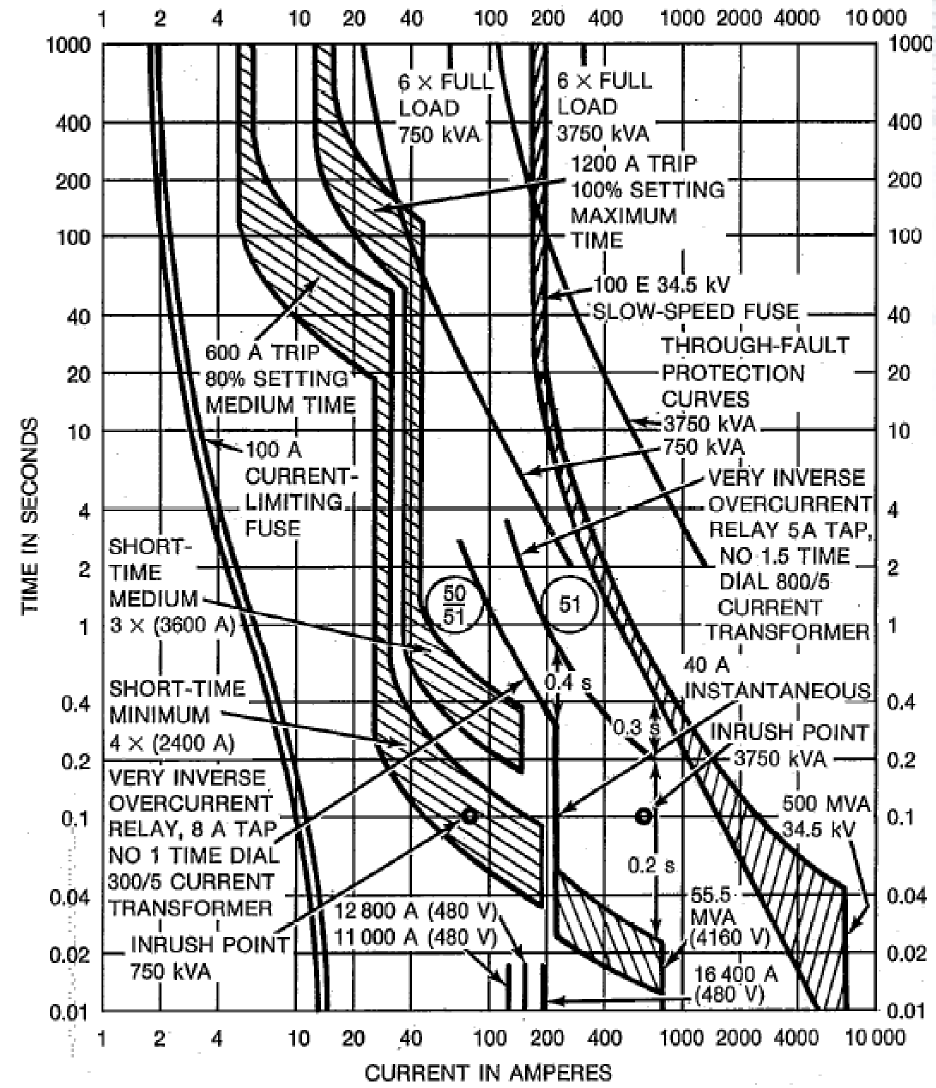


KBR

Coordinating a System

- Showing a vertical slice of the system can reduce crowding, but still be hard to read.
- Upstream equipment is shown on multiple and redundant TCCs.

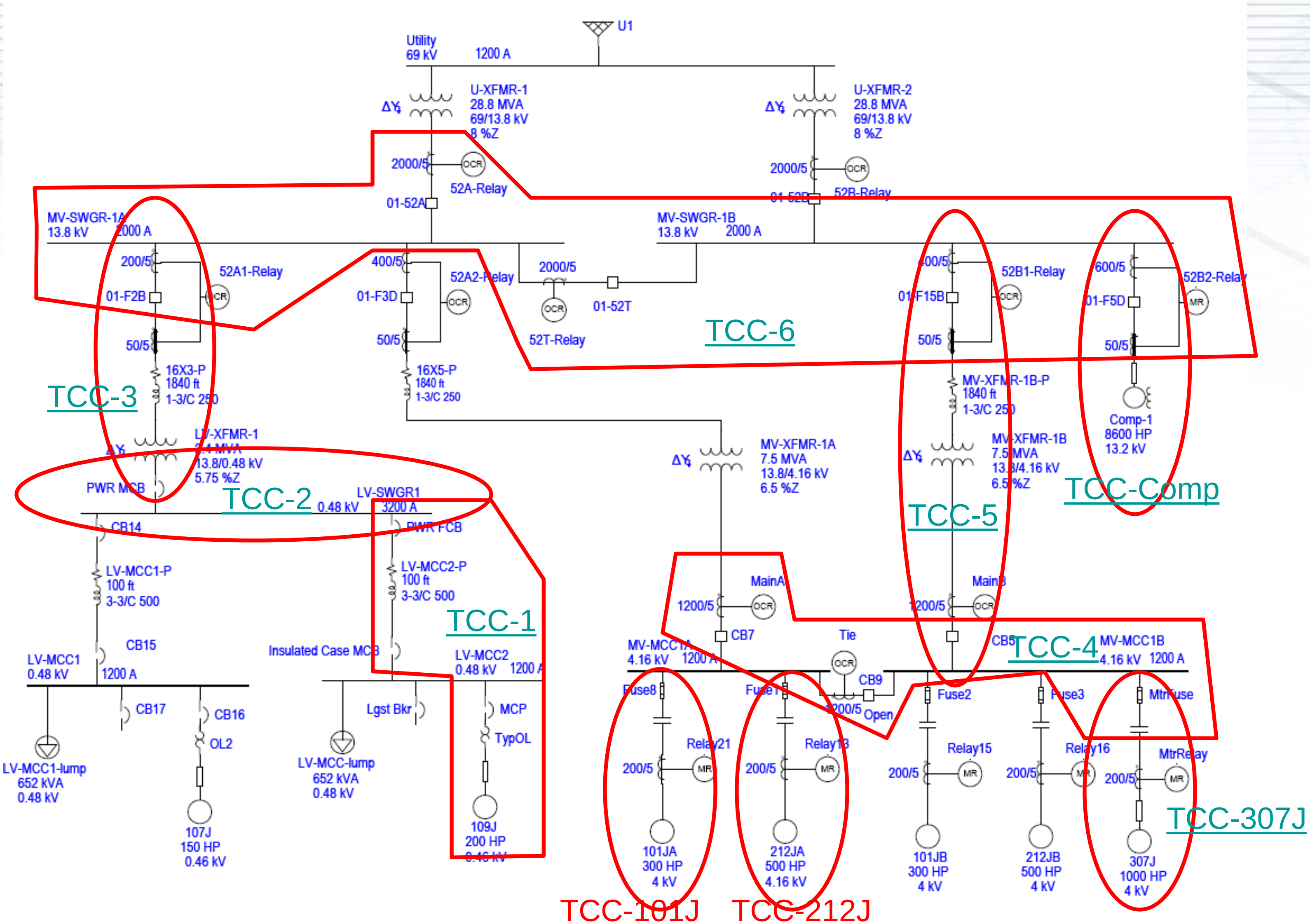




Coordinating a System

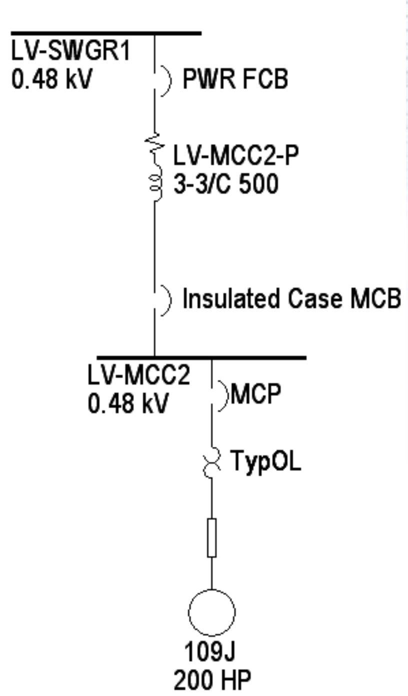
- A set of overlapping TCCs can be used to limit the amount of information on each curve and demonstrate coordination of the system from the bottom up.
- Protection settings should be based on equipment ratings and available spare capacity – not simply on the present operating load and installed equipment.
- Typical TCCs can be used to establish settings for similar installations.
- Device settings defined on a given TCC are used as the starting point in the next upstream TCC.
- The curves can be shown on an overall one-line of the system to illustrate the TCC coverage (Zone Map).

Phase TCC Zone Map

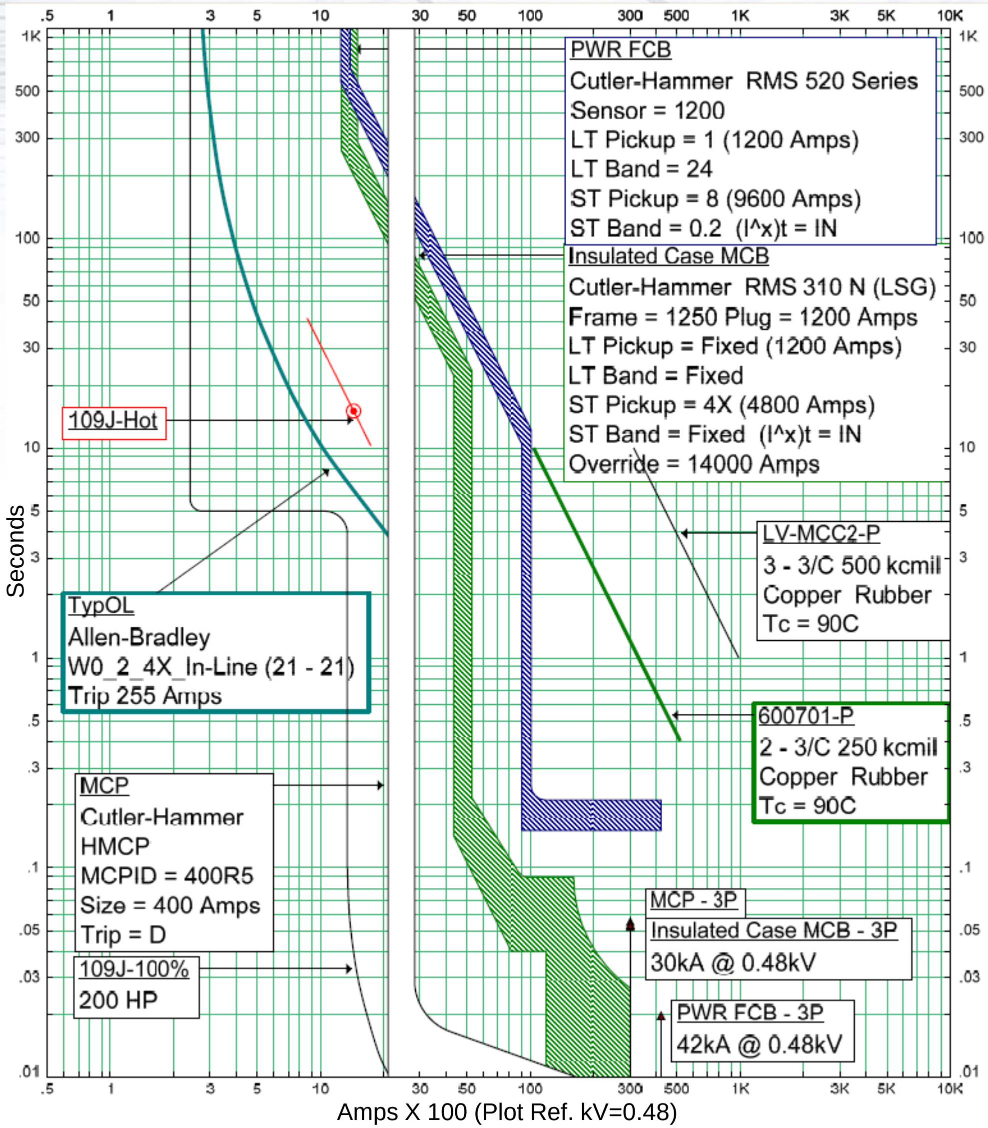


KBR

Coordinating a System: TCC-1

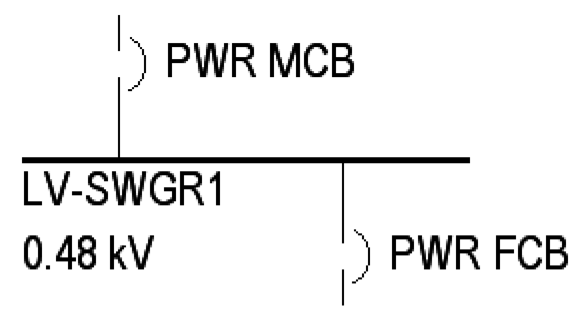


Zone Map

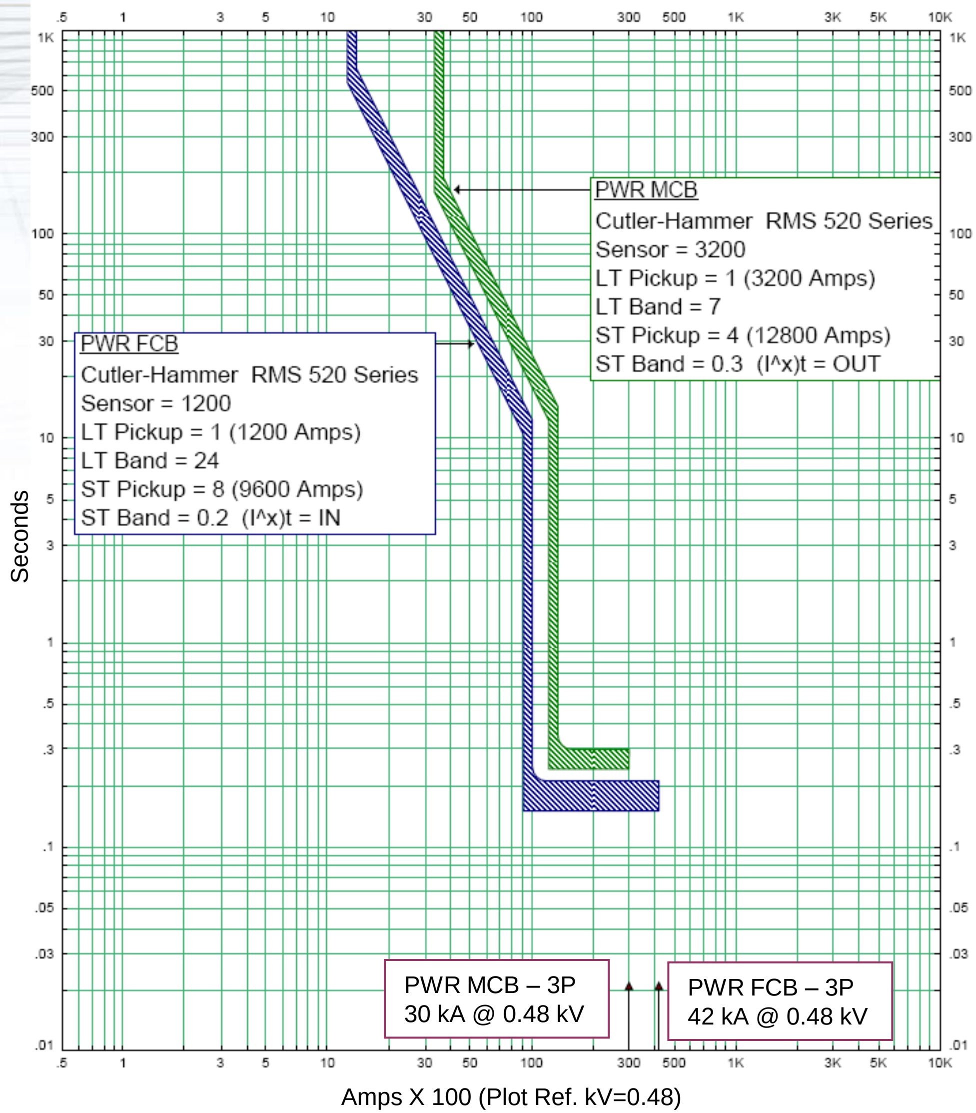


- Motor starting & protection is adequate.
- Cable ampacity & withstand protection is adequate.
- The MCC main breaker may trip for faults above 11 kA, but this cannot be helped.
- The switchgear feeder breaker is selective with the MCC main breaker, although not necessarily required

Coordinating a System: TCC-2

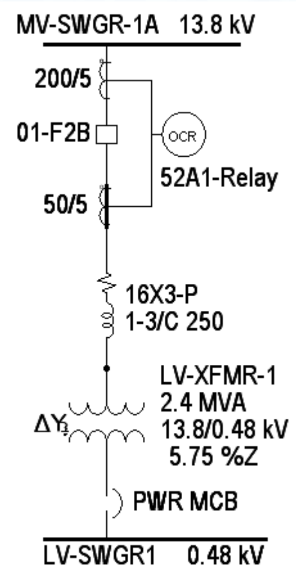


Zone Map



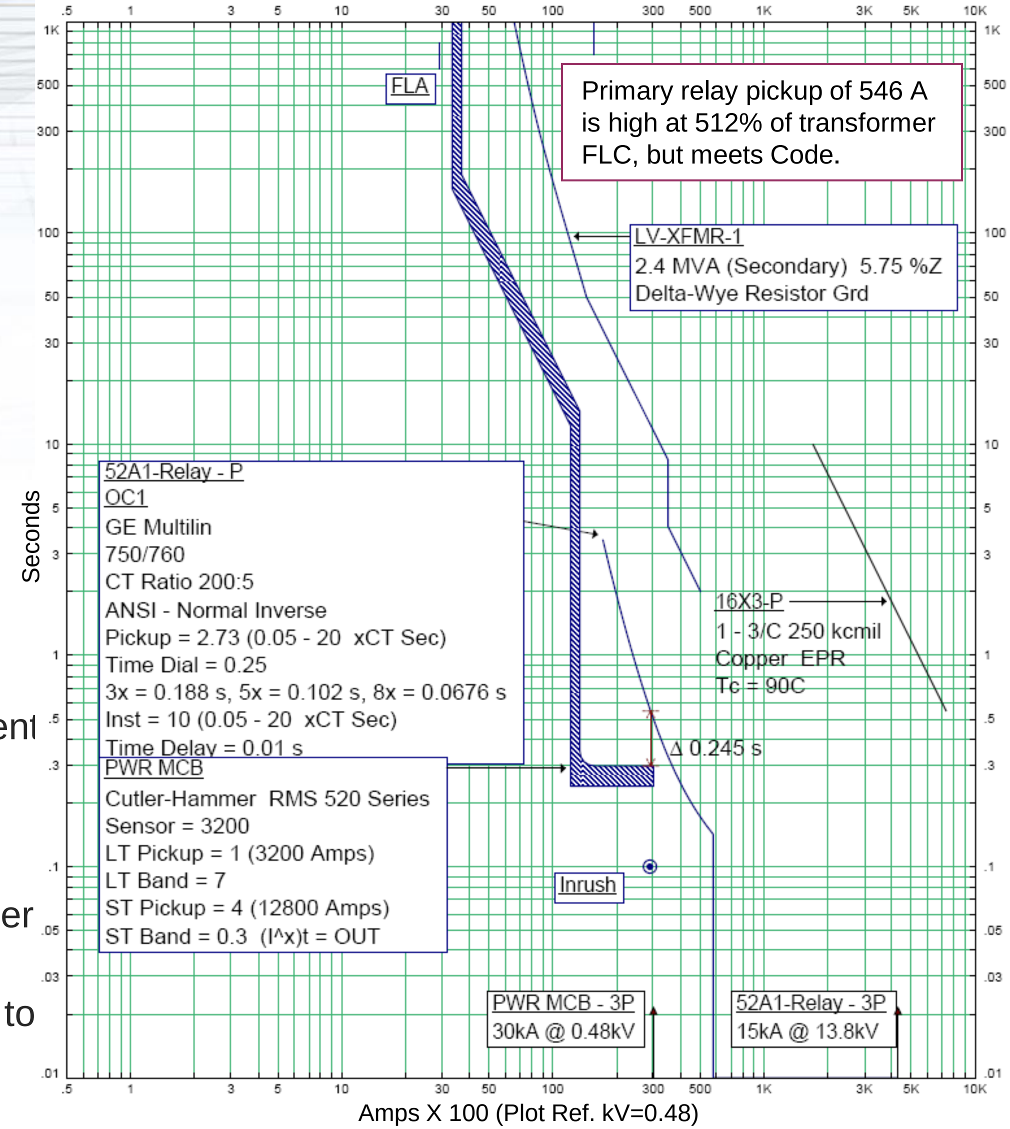
- The switchgear feeder breaker settings established on TCC-1 set the basis for this curve.
- The main breaker is set to be selective with the feeder at all fault levels.
- A CTI marker is not required since the characteristic curves include all margins and breaker operating times.
- The main breaker curve is clipped at its through-fault current instead of the total bus fault current to allow tighter coordination of the upstream relay. (See TCC-3)

Coordinating a System: TCC-3

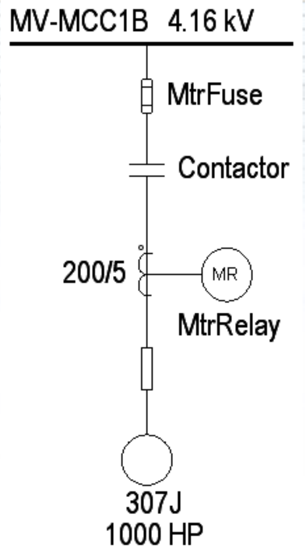


Zone Map

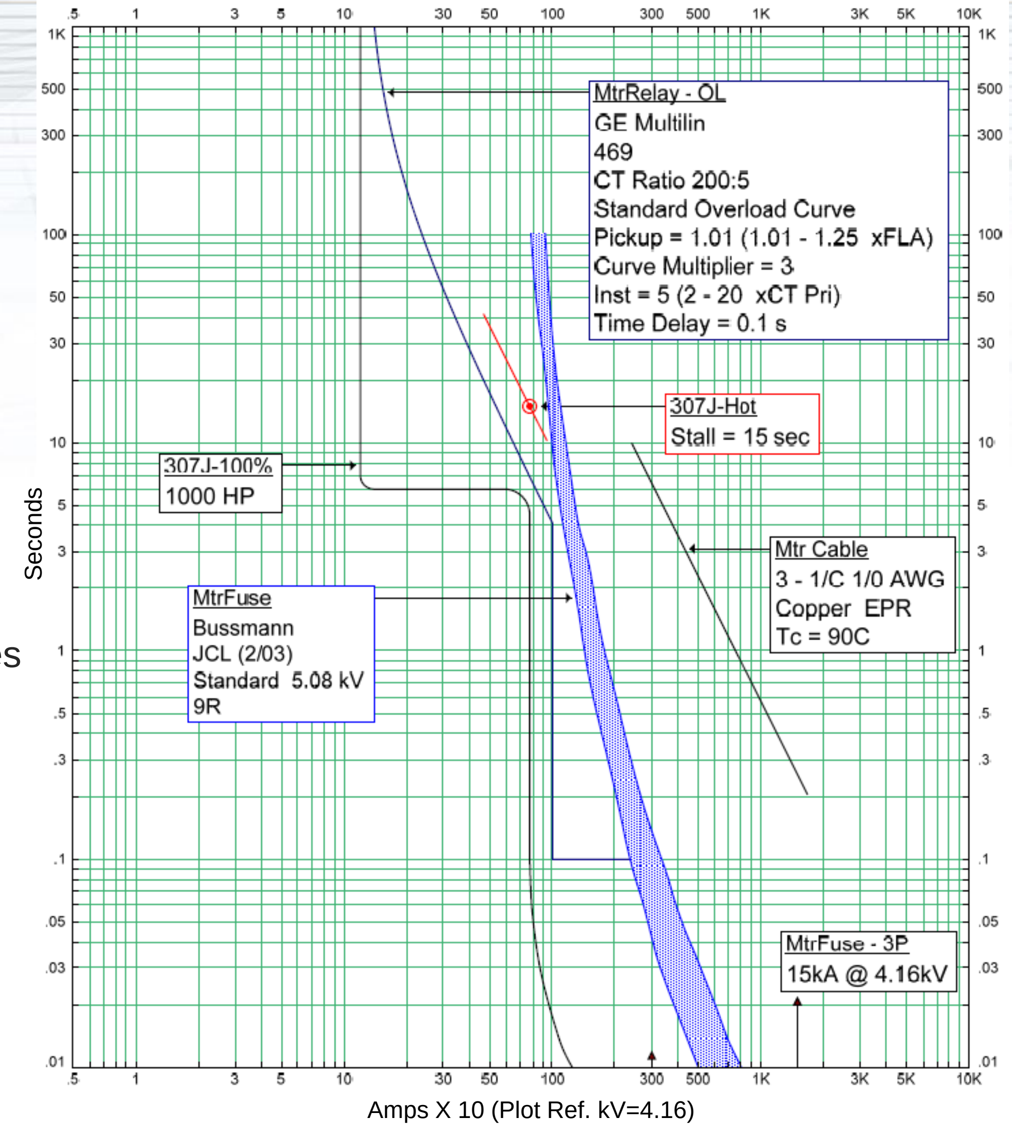
- The LV switchgear main breaker settings established on TCC-2 set the basis for this curve.
- The transformer damage curve is based on frequent faults and is not shifted since the transformer is resistance grounded.
- The primary side OC relay is selective with the secondary main and provides adequate transformer and feeder cable protection.
- The primary OC relay instantaneous high enough to pass the secondary fault current and transformer inrush current.



Coordinating a System: TCC-307J

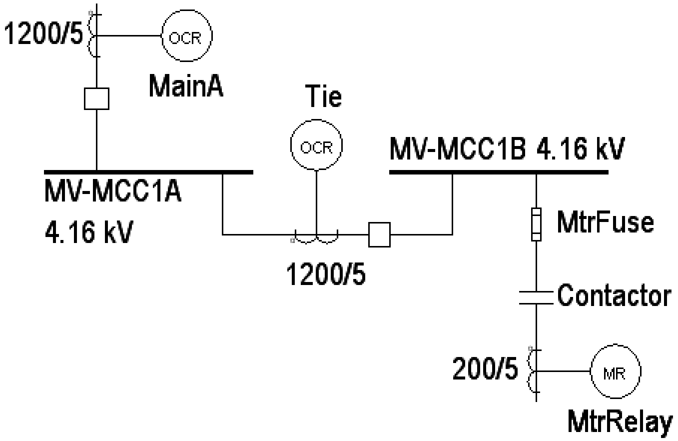


[Zone Map]



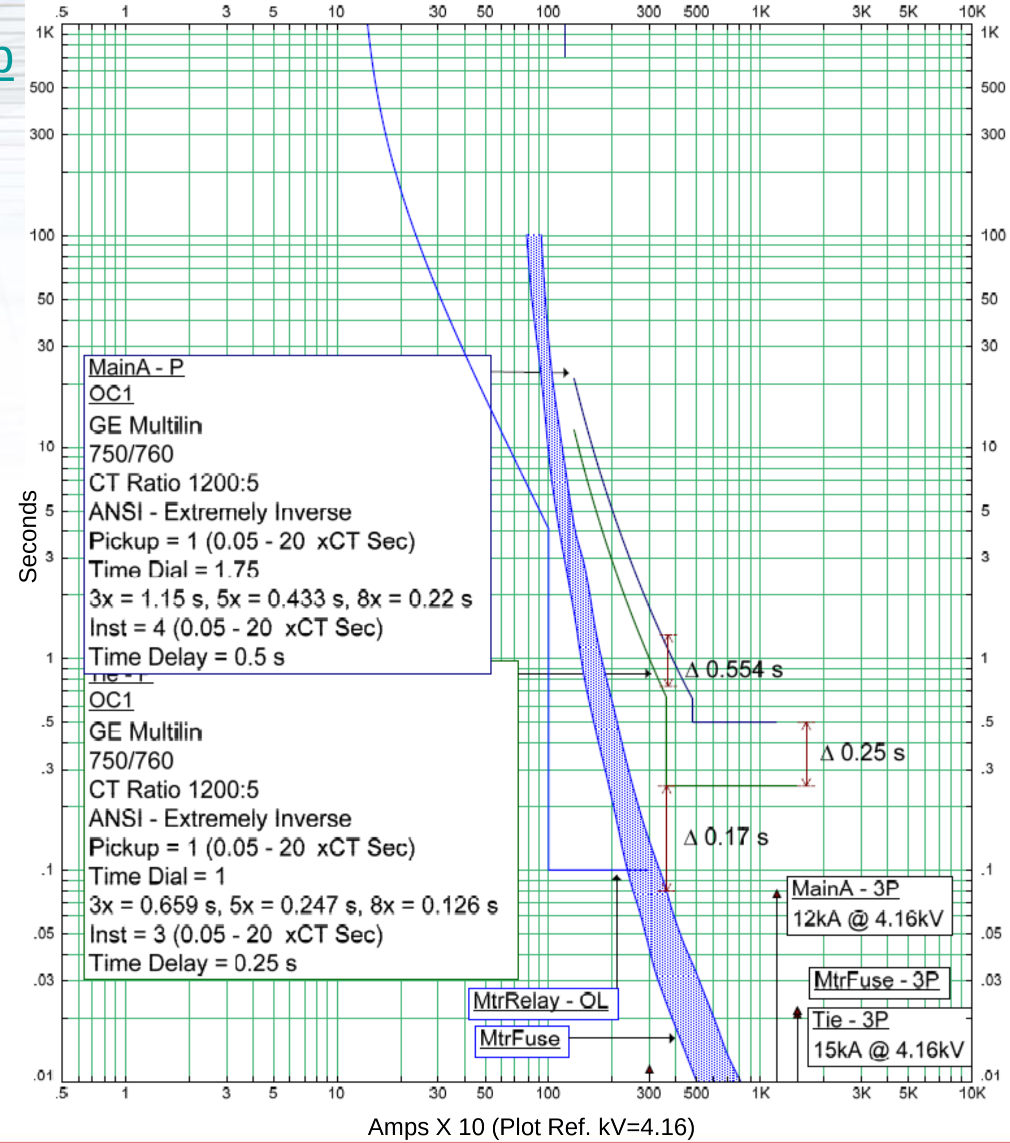
- This curve sets the basis for the upstream devices since its motor is the largest on the MCC.
- Motor starting and overload protection is acceptable.
- Motor feeder cable protection is acceptable
- The motor relay includes a definite time unit to provide enhanced protection.
- The definite time function is delayed to ensure fuse clears faults over the contactor rating.

Coordinating a System: TCC-4



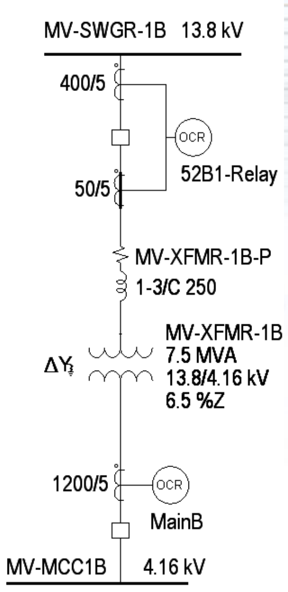
[Zone Map]

- The 307J motor relay settings established on TCC-307J set the basis for this curve.
- The tie breaker relay curve is plotted to the total bus fault current to be conservative.
- The main breaker relay curve is plotted to its let-through current.
- A coordination step is provided between the tie and main relay although this decision is discretionary.
- The definite time functions insulate the CTIs from minor fault current variations.
- All devices appear selectively coordinated at all fault current levels, but the independent OC functions may be an issue.



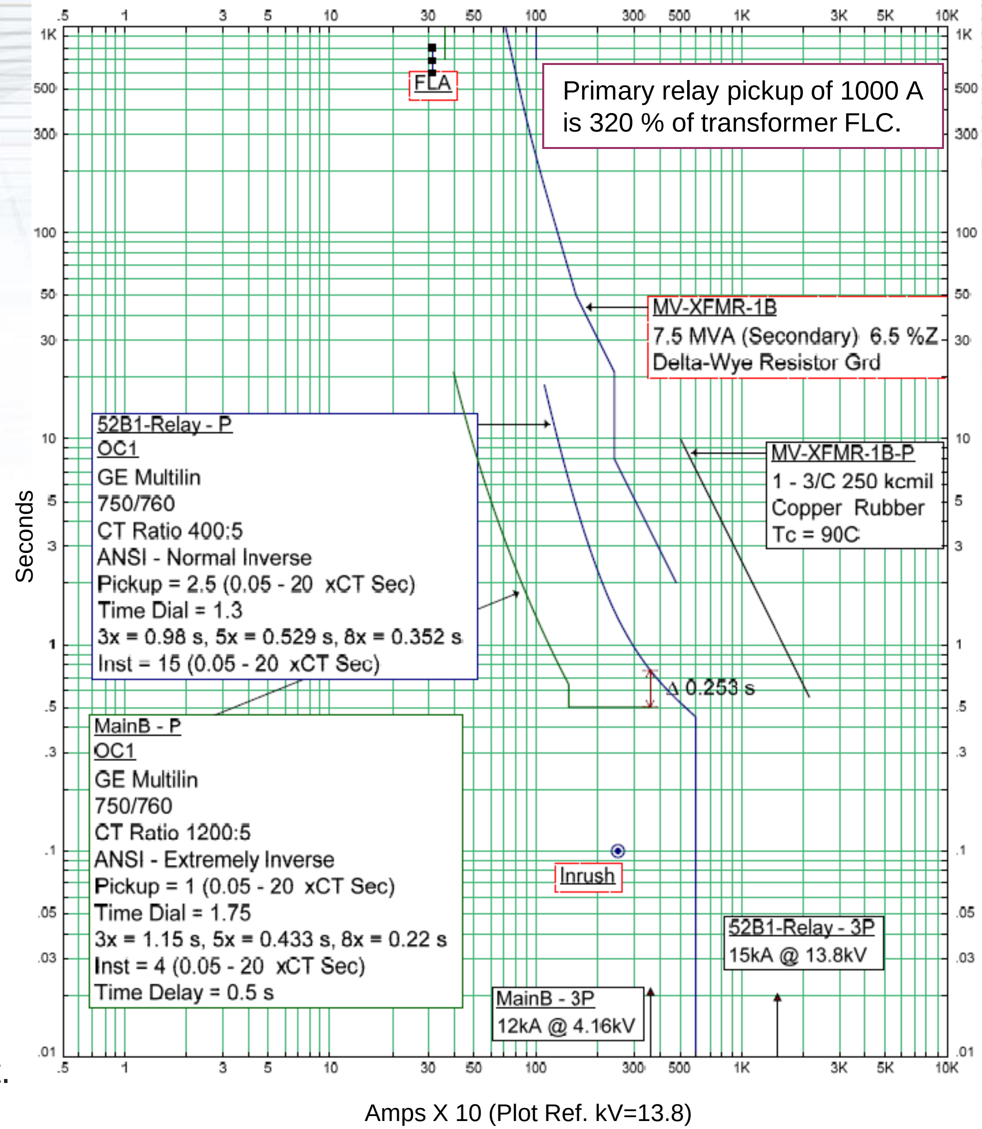
KBR

Coordinating a System: TCC-5



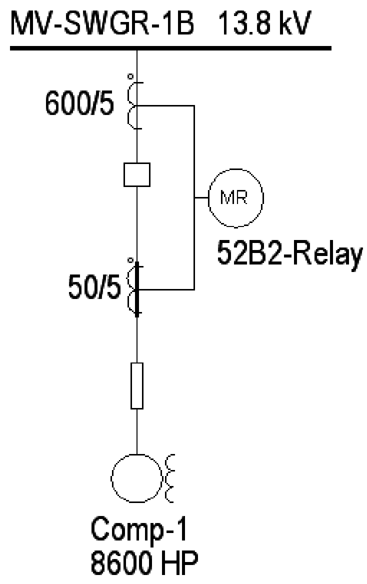
Zone Map

- The MV MCC main breaker settings established on TCC-4 set the basis for this curve.
- The transformer damage curve is based on frequent faults and is not shifted since the transformer is resistance grounded.
- The primary side OC relay is selective with the secondary main and provides adequate transformer and feeder cable protection.
- The OC relay instantaneous high enough to pass the secondary fault current and transformer inrush current.

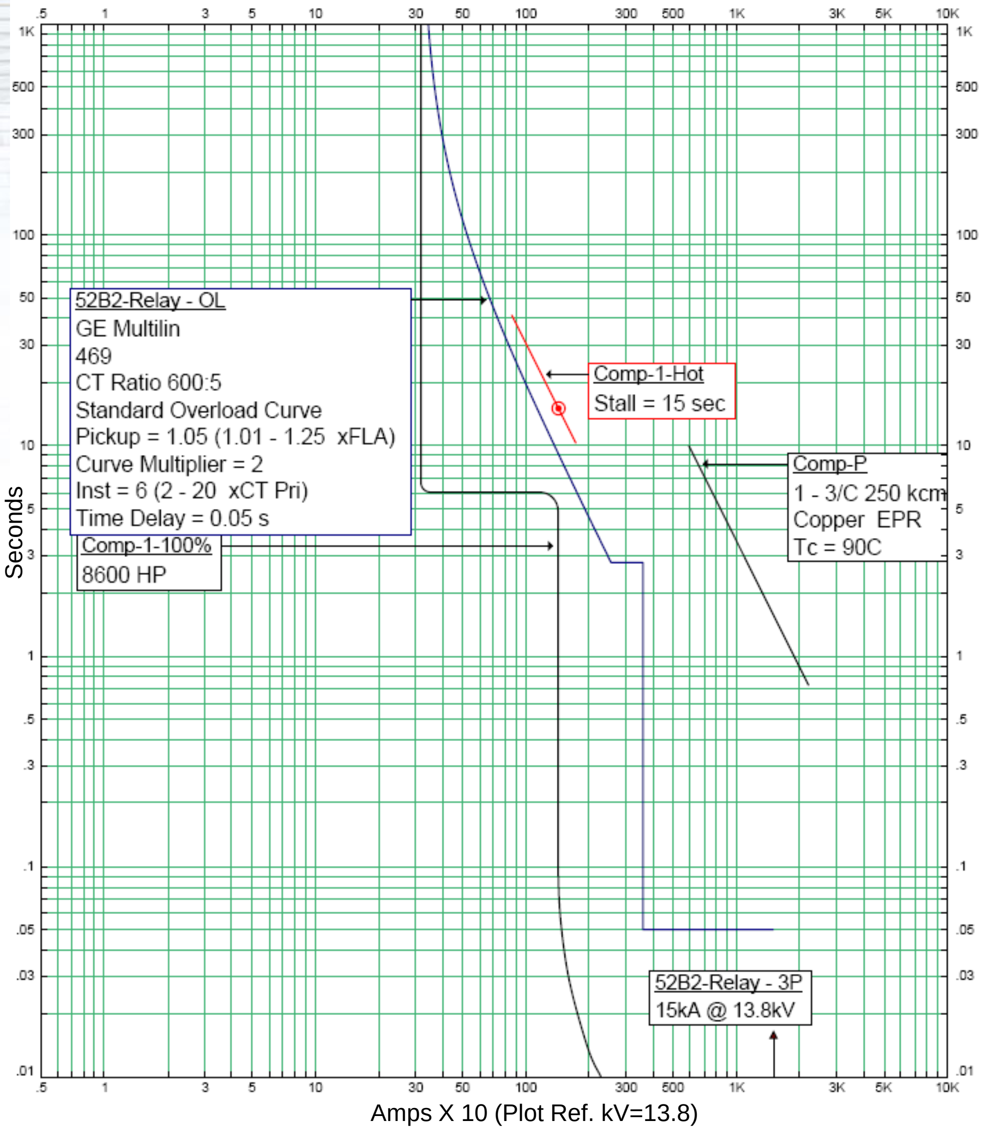


KBR

Coordinating a System: TCC-Comp



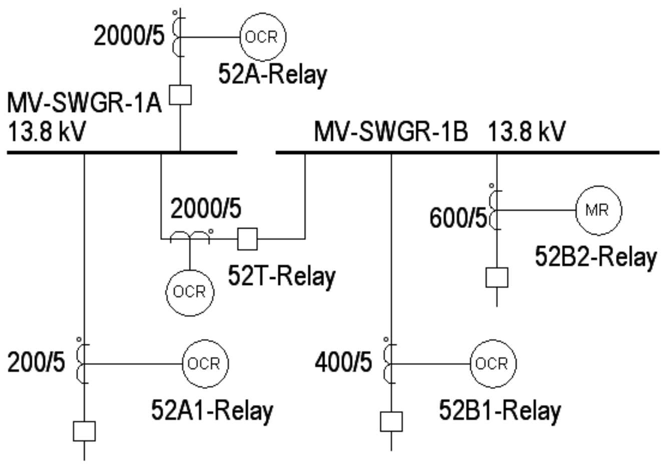
[Zone Map]



- Due to the compressor size, this curve may set the basis for the MV switchgear main breaker.
- Motor starting and overload protection is acceptable.
- Short-circuit protection is provided by the relay/breaker instead of a fuse as with the 1000 hp motor.
- The short-circuit protection is delayed 50 ms to avoid nuisance tripping.

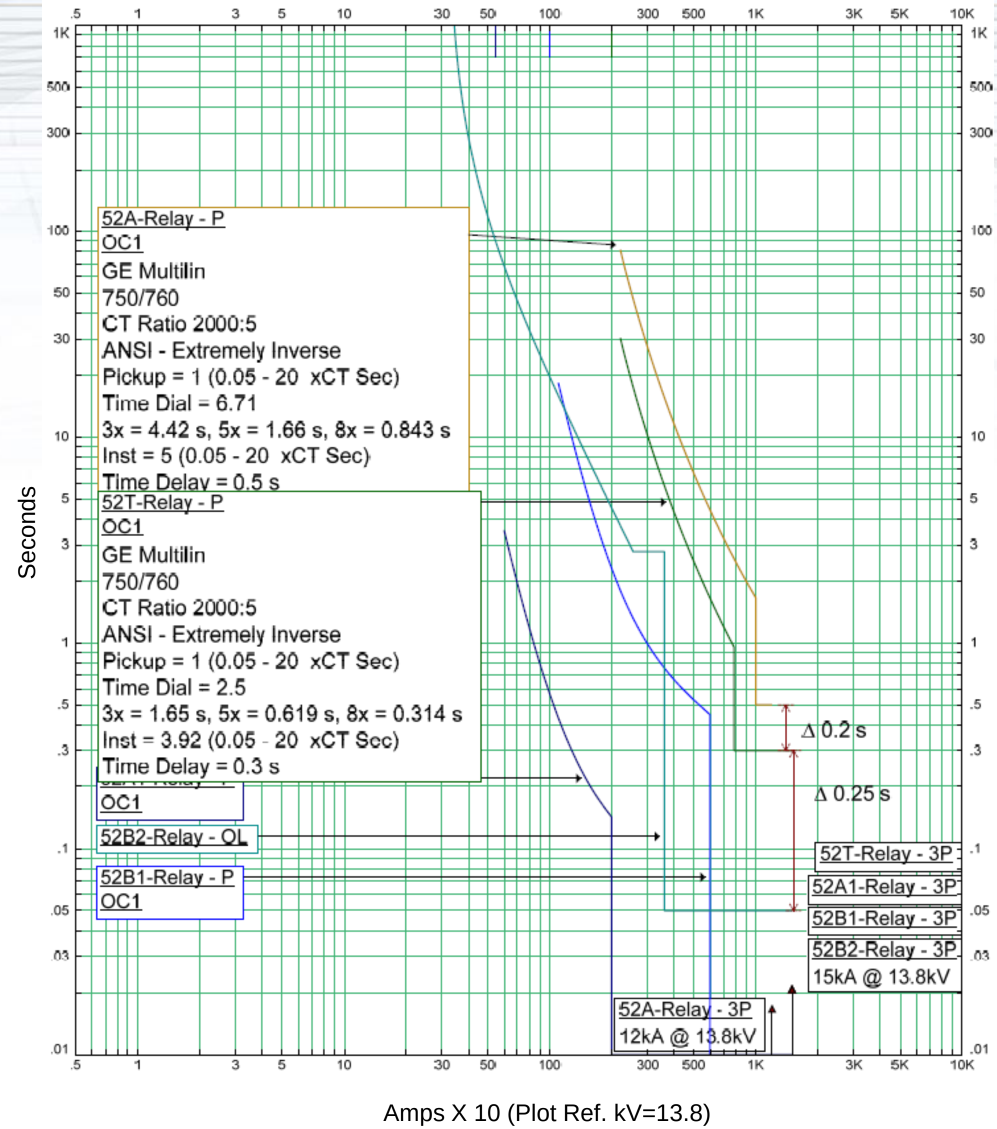
KBR

Coordinating a System: TCC-6



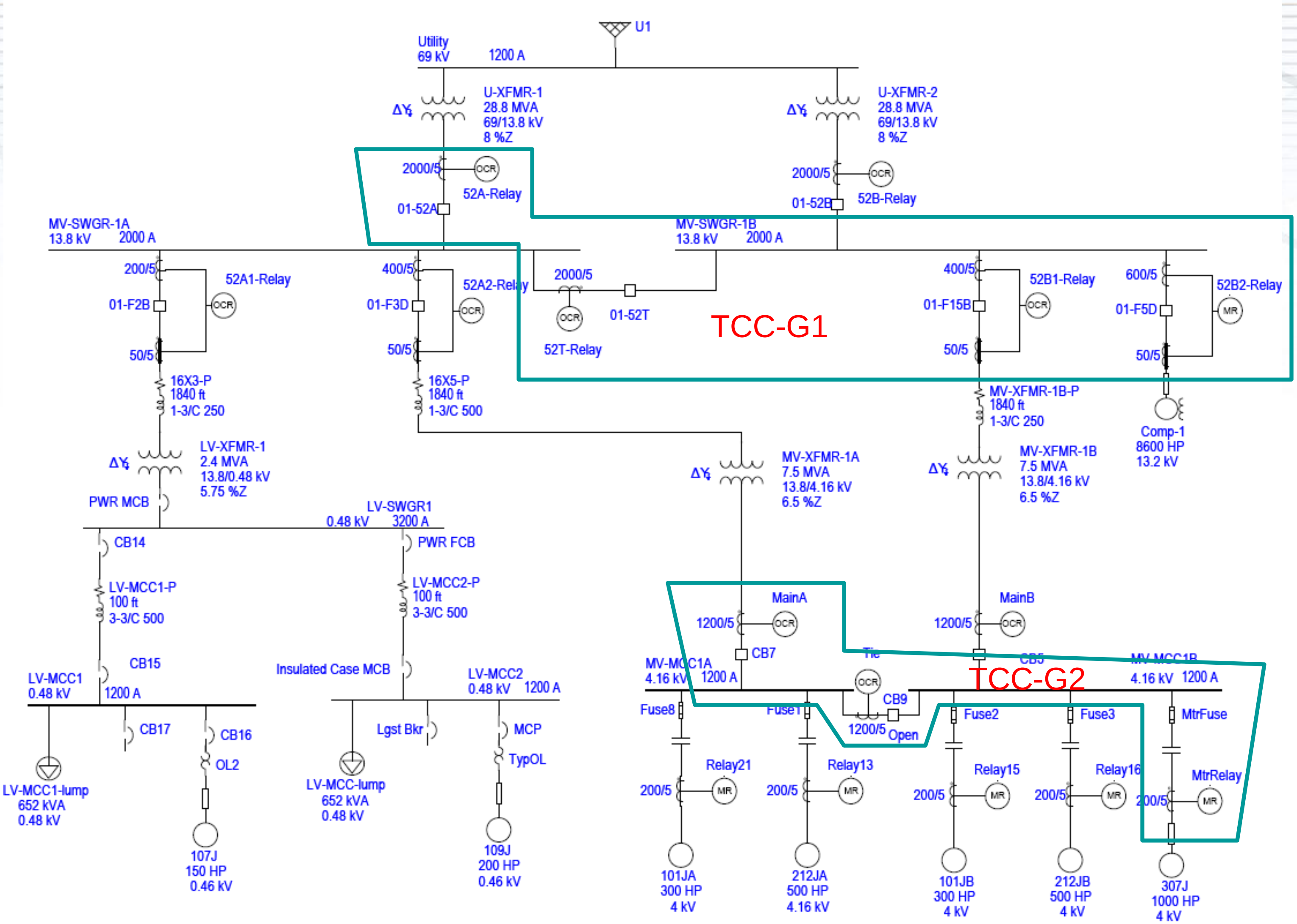
Zone Map

- The feeder breaker settings established on TCC-3, TCC-4, and TCC-Comp are shown as the basis for this curve.
- The settings for feeder 52A1 (to the 2.4 MVA) could be omitted since it does not define any requirements.
- A coordination step is provided between the tie and main relay although this decision is discretionary.
- All devices are selectively coordinated at all fault current levels.
- The definite time functions insulate the CTIs from minor fault current variations.



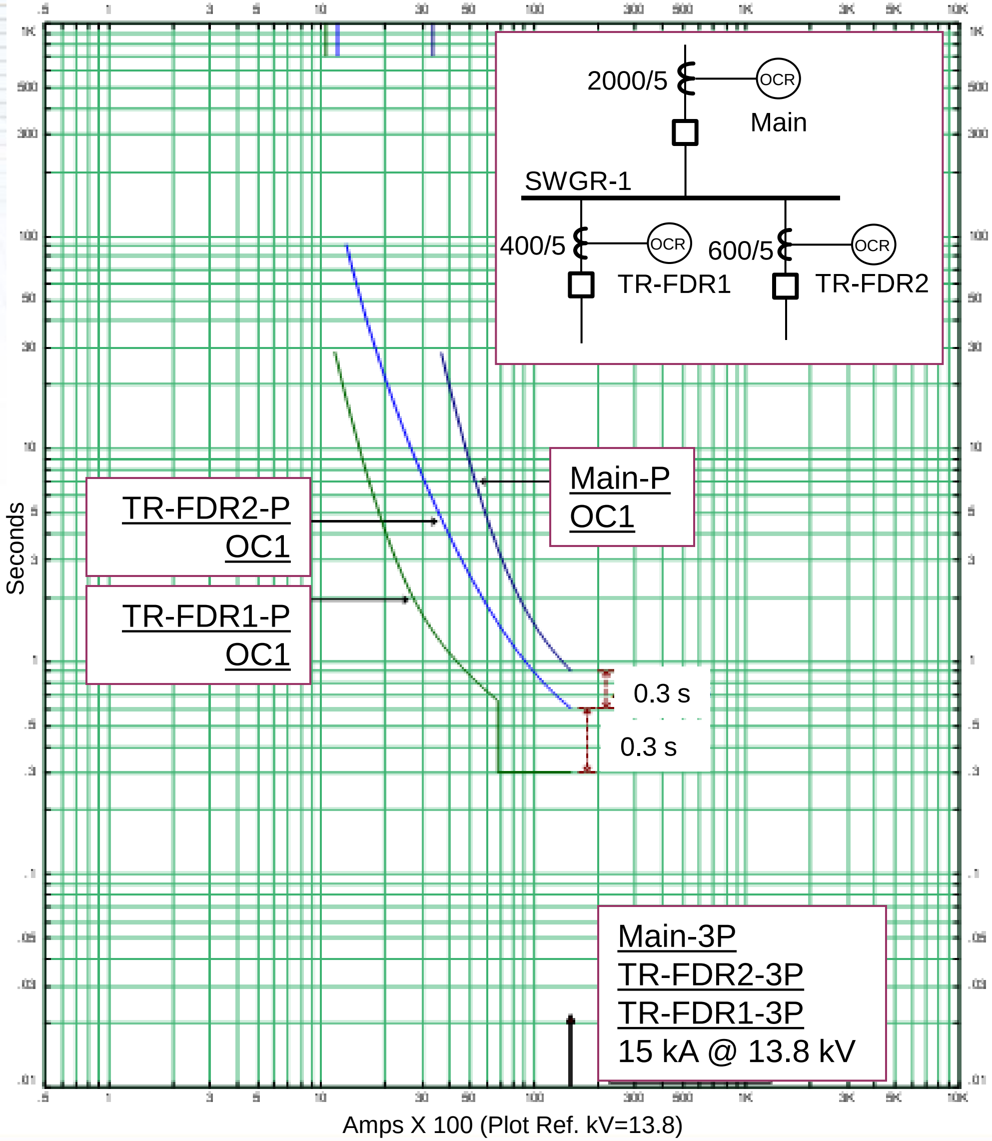
KBR

Ground TCC Zone Map



Coordination Quizzes

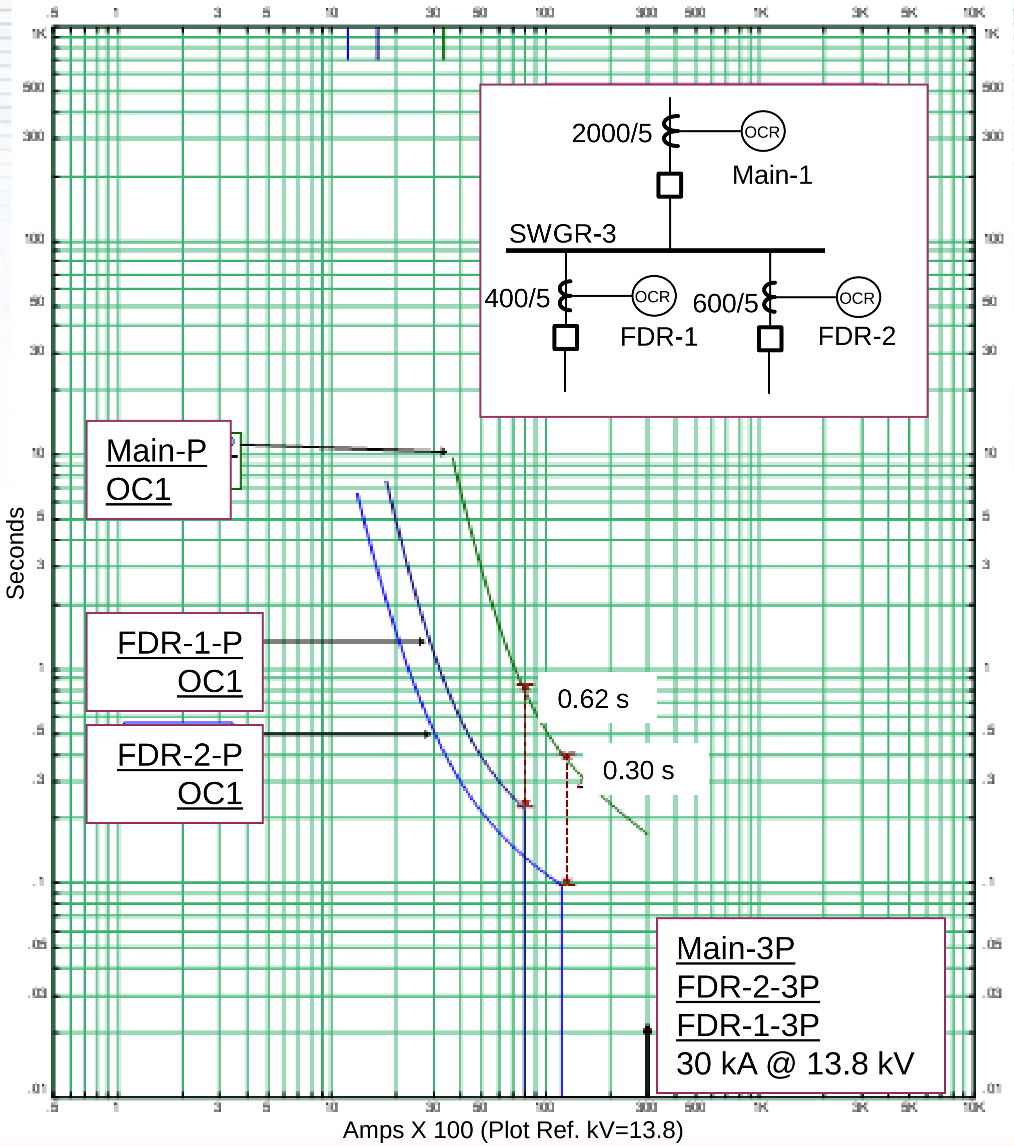
Coordination Quiz #1



Does this TCC look okay??

- There is no need to maintain a coordination interval between feeder breakers.
- The 0.3-s CTIs are sufficient unless all relays are electro-mechanical and hand set.
- Fix – base the setting of the feeder 2 relay on its downstream equipment and lower the time delays if possible.

Coordination Quiz #2

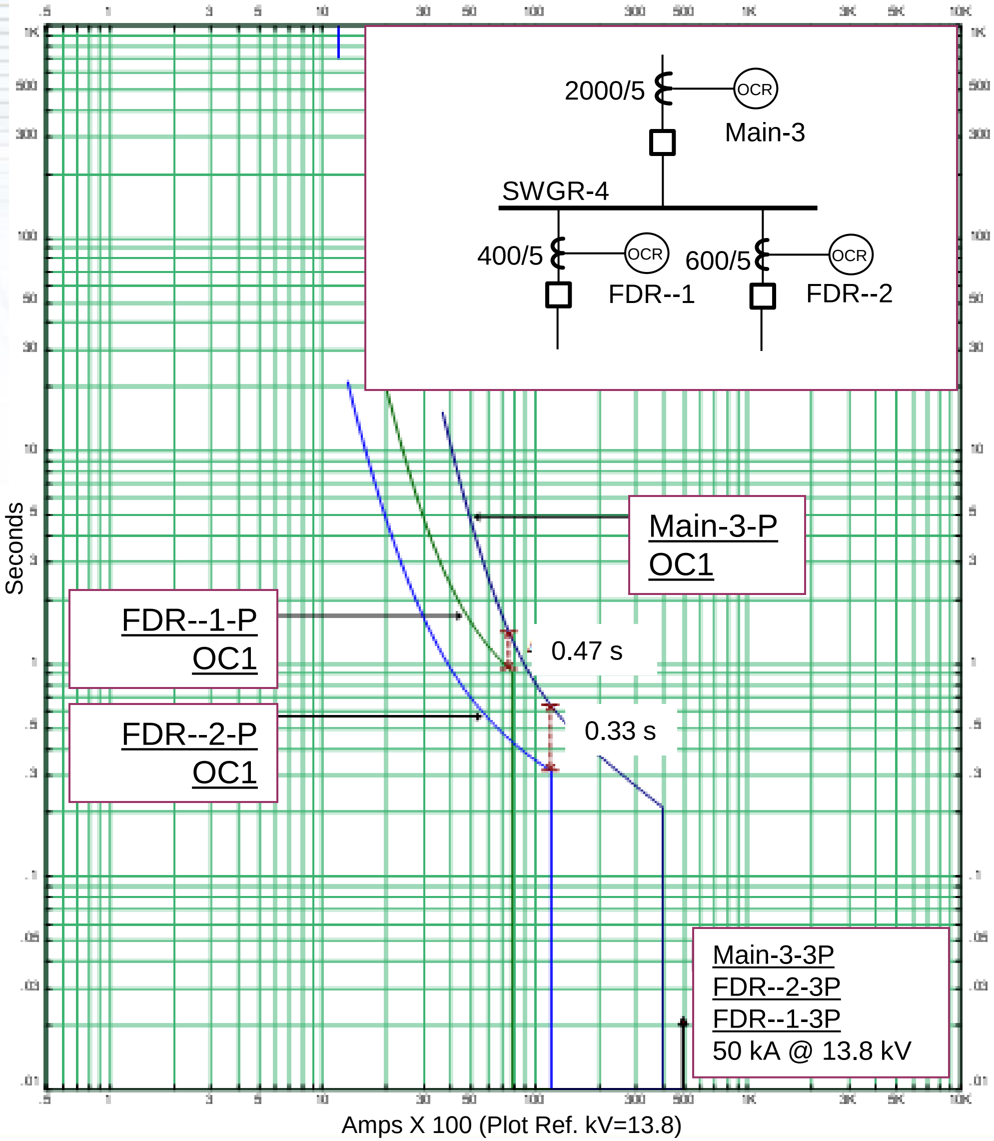


Does this TCC look okay??

- The CTIs between the main and feeders are sufficient at the fault levels noted.
- Assuming testing EM relays, the 0.62 s CTI cannot be reduced since the 0.30 s CTI is at the limit.
- The main relay time delay is actually too fast since the CTI at 30 kA is less than 0.2 s.
- Fix – raise the time delay setting of the main relay or make it less inverse.

KBR

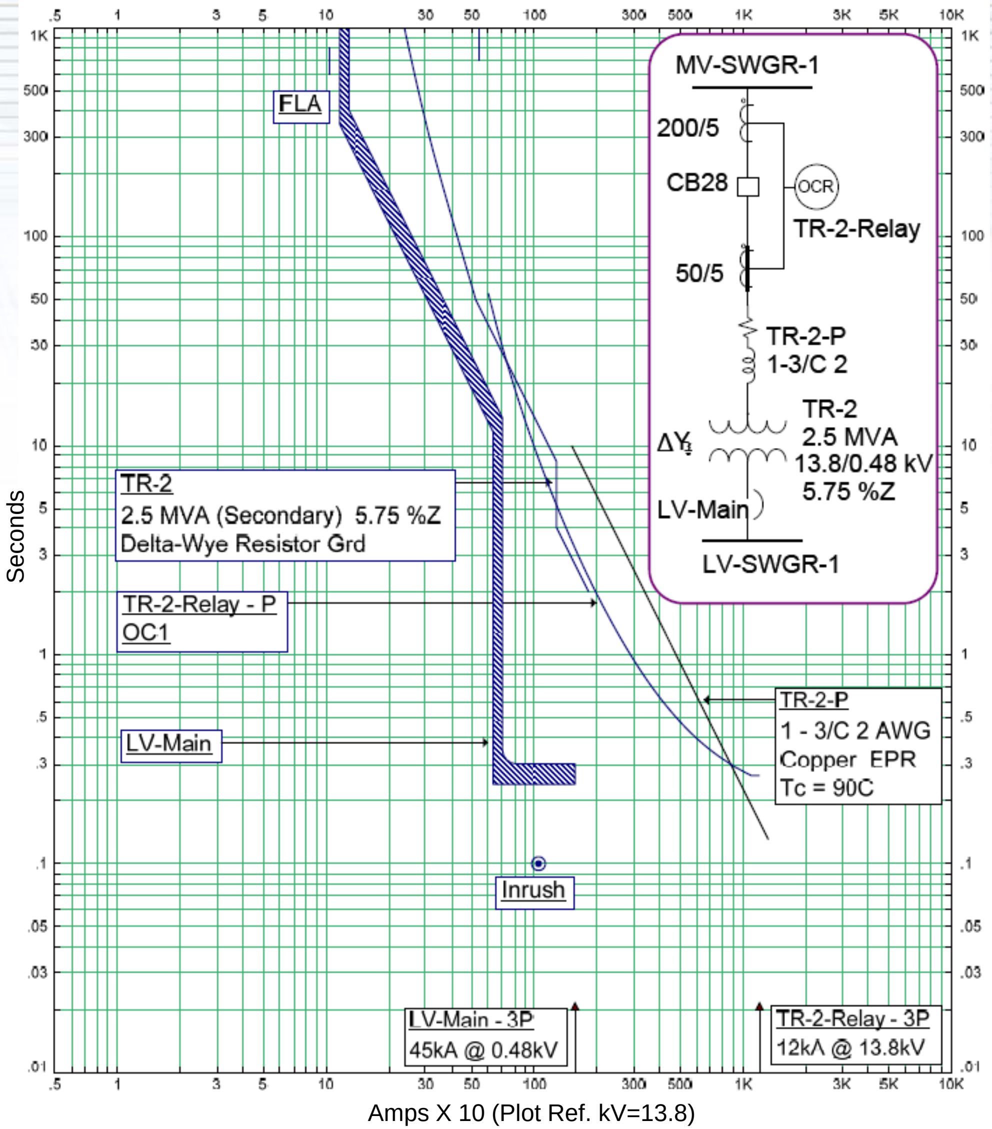
Coordination Quiz #3



Does this TCC look okay??

- The marked CTIs are okay, but….
- A main should never include an instantaneous setting.
- Fix – delete the instantaneous on the main relay (!!) and raise the time delay to maintain a 0.2s CTI at 50 kA (assuming static relays)

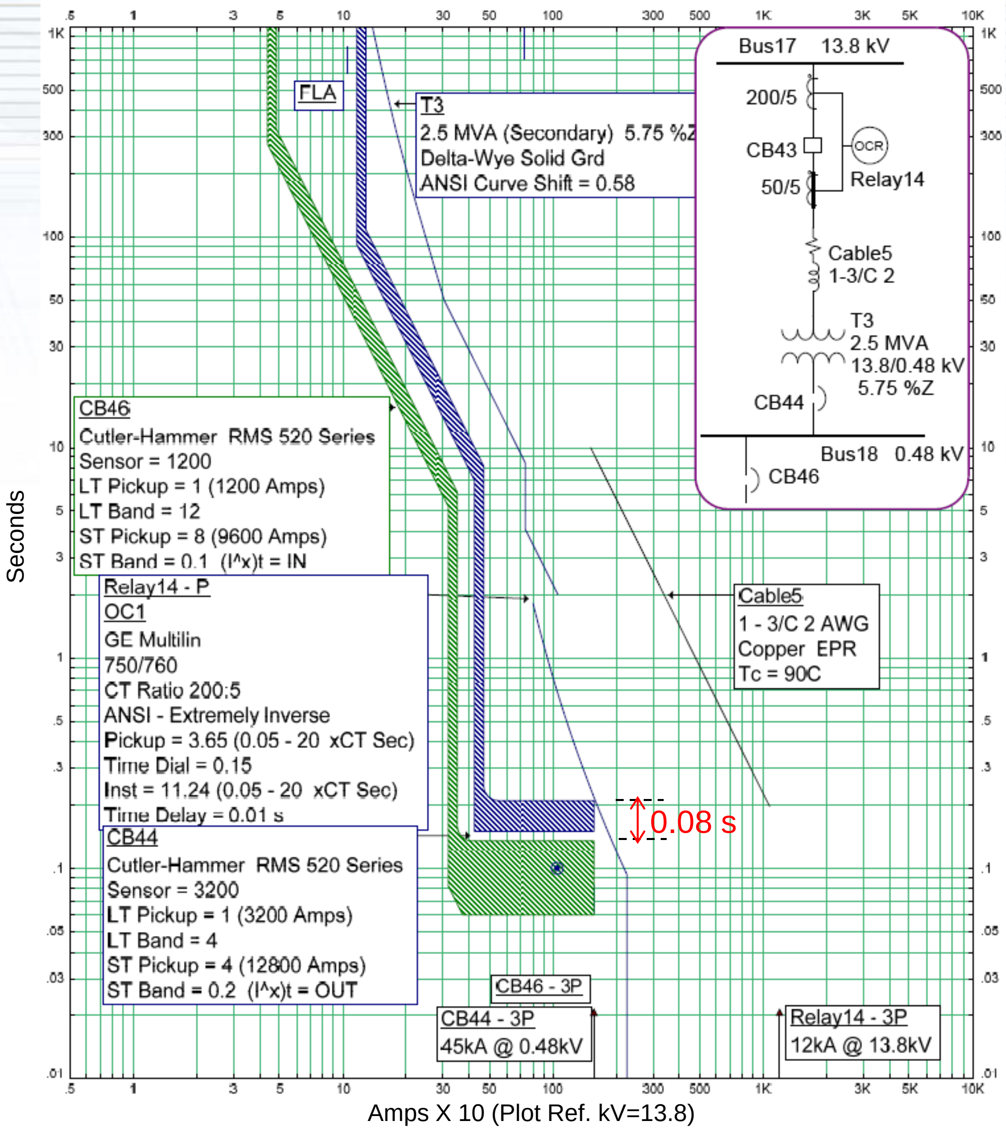
Coordination Quiz #4



Does this TCC look okay??

- Primary relay pickup is 525% of transformer FLC, thus okay.
- Transformer frequent fault protection is not provided by the primary relay, but this is okay – adequate protection is provided by the secondary main.
- Cable withstand protection is inadequate.
- Fix – Add instantaneous setting to the primary relay.

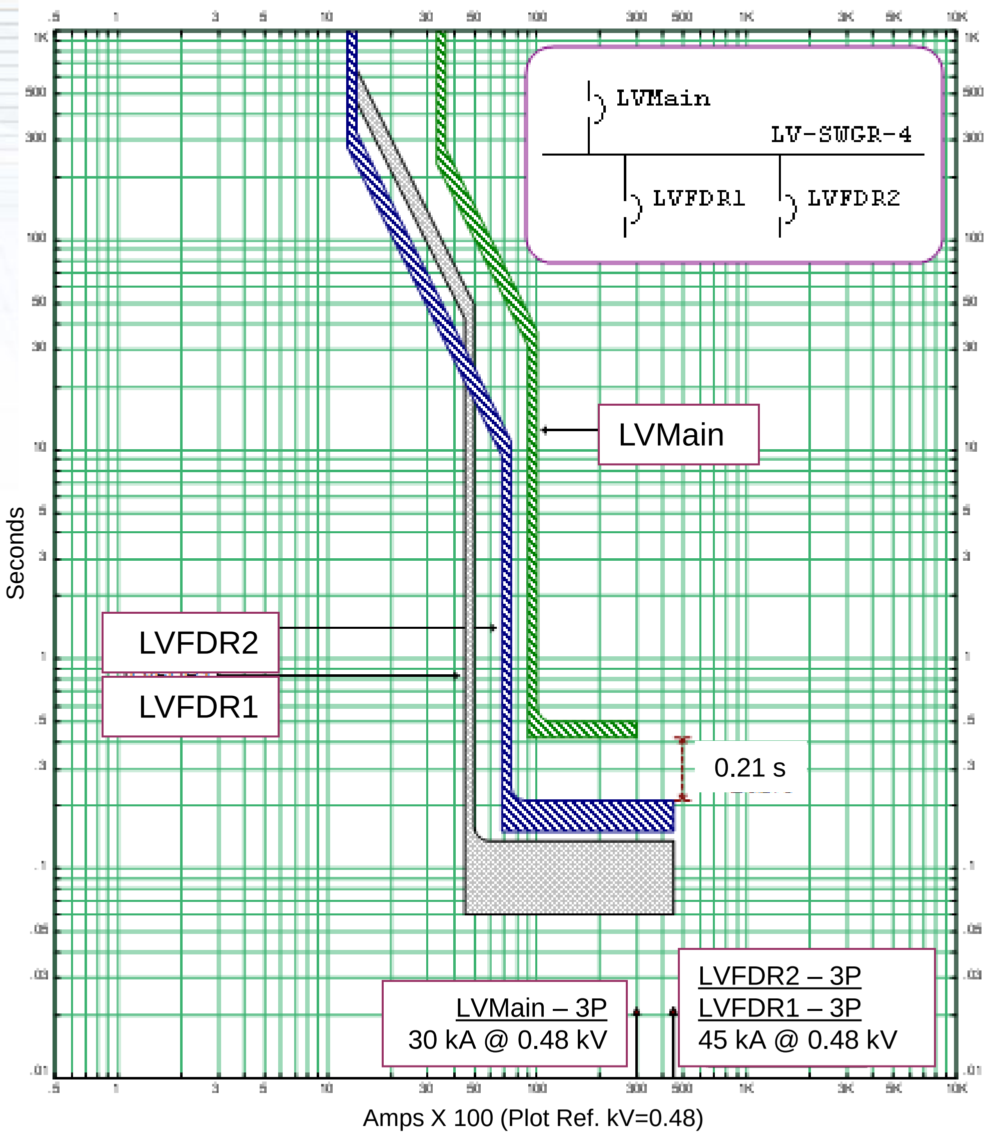
Coordination Quiz #5



Does this TCC look okay??

- Selectivity between Relay14 on the transformer primary and CB44 on the secondary is not provided, but this can be acceptable.
- Relay 14 is not, however, selectively coordinated with feeder breaker CB46.
- Fix – raise Relay14 time delay setting and add CTI marker.

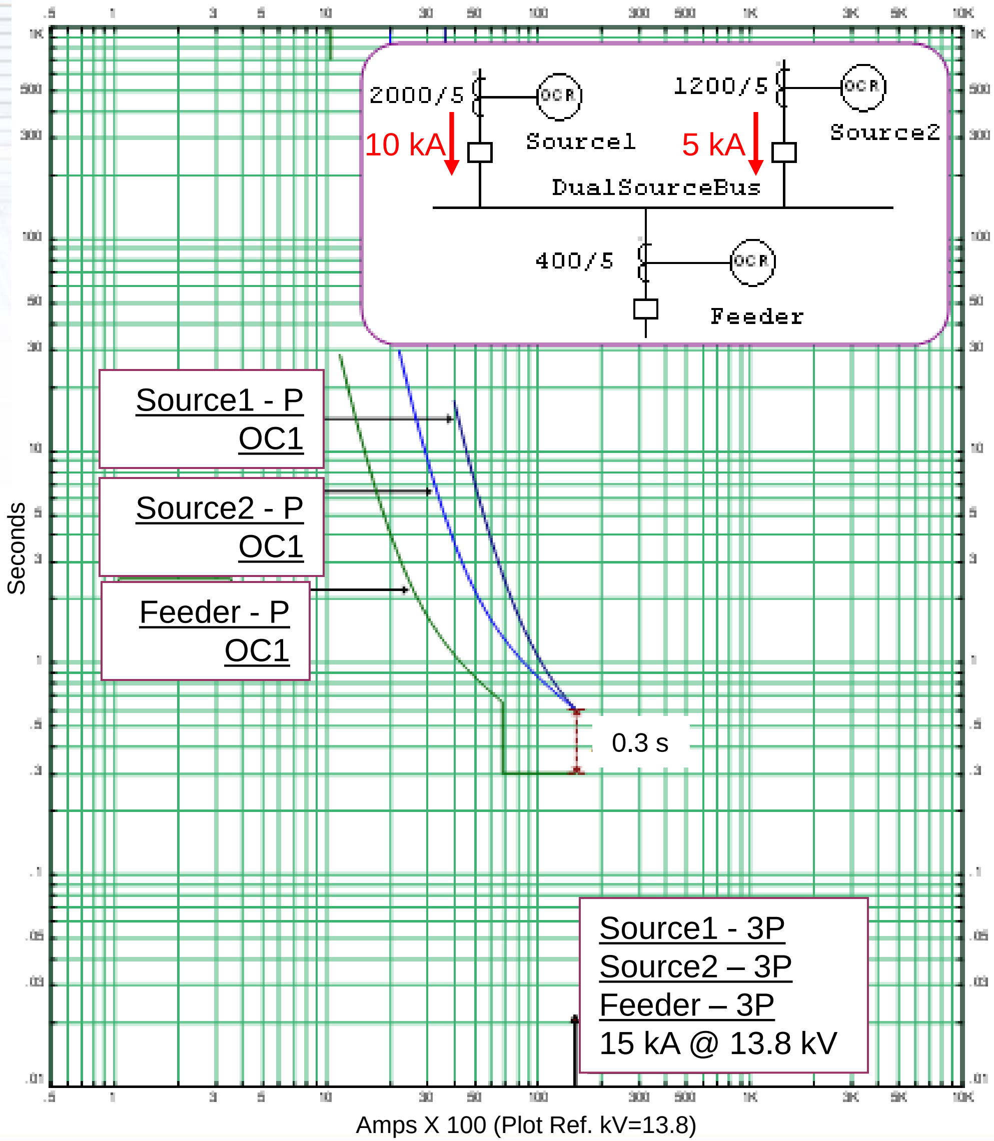
Coordination Quiz #6



Does this TCC look okay??

- Crossing of feeder characteristics is no problem.
- There is no need to maintain an intentional time margin between two LV static trip units – clear space is sufficient.
- Fix – lower the main breaker short-time delay band.

Coordination Quiz #7



Does this TCC look okay??

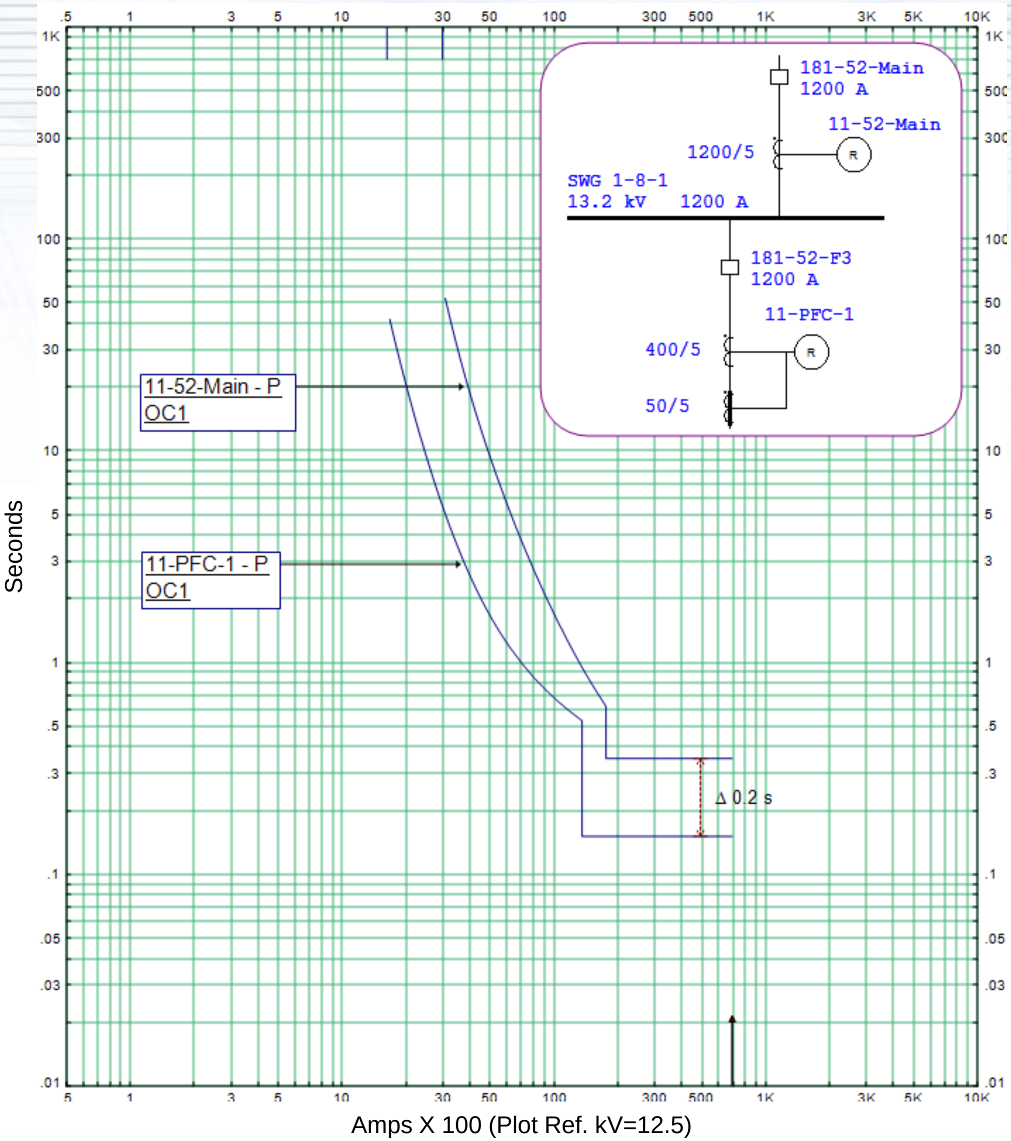
- The source relays should not be plotted to the full bus fault level unless their plots are shifted based on:

  SF = Total fault current / relay current.

- Since each relay actually sees less than the total fault current, the CTIs are actually much higher than 0.3 s.

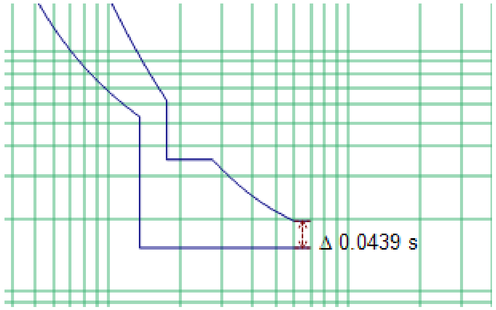
- Fix – plot the source relays to their actual fault current or apply SF.

Coordination Quiz #8



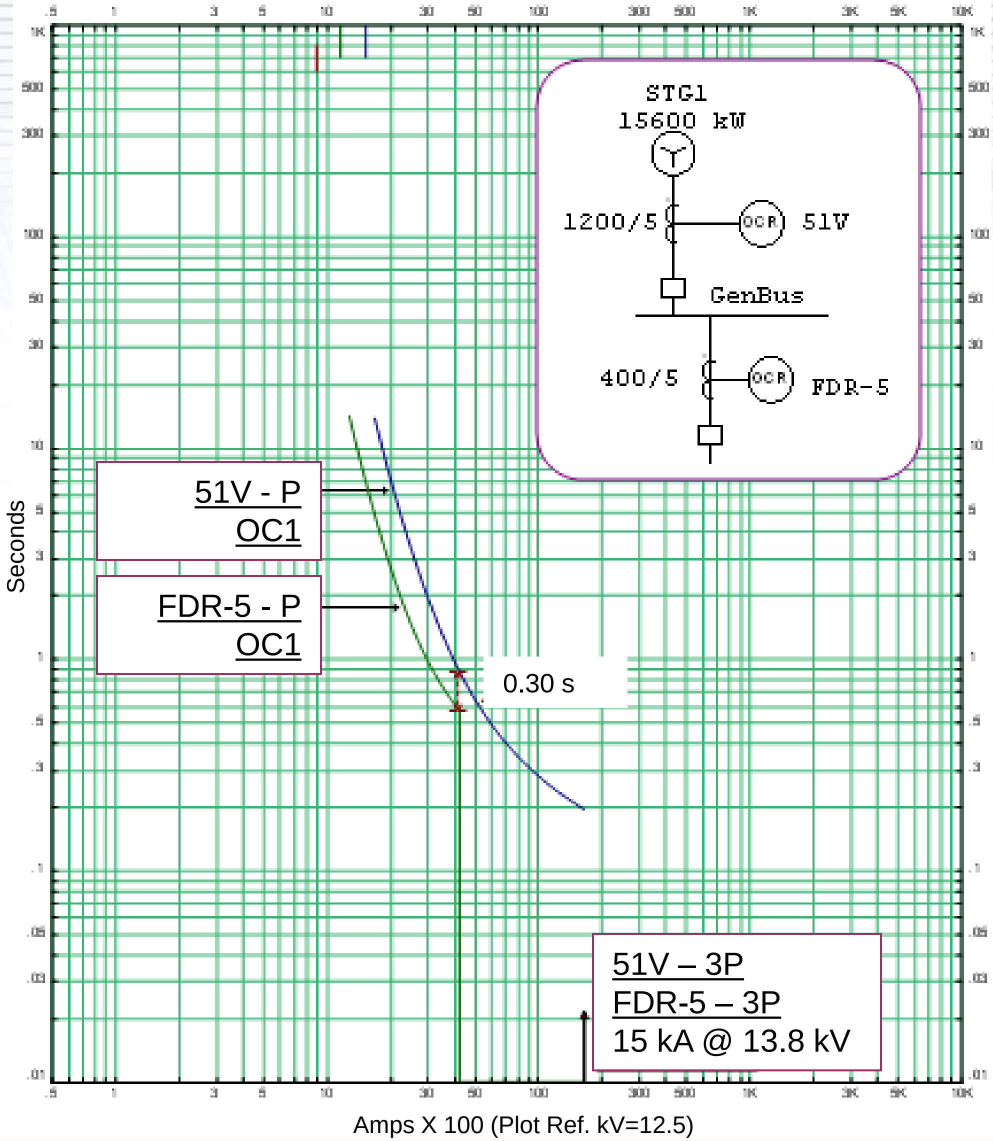
Does this TCC look okay??

- The displayed CTI of 0.2 s is acceptable.
- But, if the main relay's overcurrent elements are independent then there is miscoordination.



- Fix – set minimum response time (if available), raise TD of main, or make curve less inverse.

Coordination Quiz #9



Does this TCC look okay??

- There are two curves to be concerned with for a 51V – full restraint and zero restraint.
- Assuming the full restraint curve is shown, it is coordinated too tightly with the feeder.
- The 51V curve will shift left and lose selectivity with the feeder if a close-in fault occurs and the voltage drops.
- Fix – show both 51V curves and raise time delay.

Coordination Software

Coordination Software

- Computer-aided coordination software programs originated in the mid 1980s.

- The accuracy of the device characteristic curves was often highly questionable.

- There are numerous, much more powerful programs available today, many of which are very mature.

- Even still, the accuracy of the protective devices functions and characteristics is still extremely critical.

Coordination Software

- For many years clients maintained separate impedance models for power studies and protective device models for coordination studies.

- Integrated models are now the norm and are required to support arc-flash studies.

References

Selected References

- Applied Protective Relaying – Westinghouse
- Protective Relaying – Blackburn
- IEEE Std 242 – Buff Book
- IEEE Std 141 – Red Book
- IEEE Std 399 – Brown Book
- IEEE C37.90 – Relays
- IEEE C37.91 – Transformer Protection
- IEEE C37.102 – Guide for AC Generator Protection
- IEEE C50.13 – Cylindrical-Rotor Gens ≥ 10 MVA
- NFPA 70 – National Electrical Code