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OVERCURRENT COORDINATION GUIDELINES FOR INDUSTRIAL POWER SYSTEMS

For industrial applications in the United States, overcurrent coordination is generally performed in accordance with the “IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems”, Standard 242 (Buff Book) with protective device settings conforming to the applicable sections of the National Electrical Code (NEC). Guidelines for achieving good coordination are outlined in this document.

1.0 PHILOSOPHY

Overcurrent protection schemes are generally designed with a primary means of clearing a fault, as well as one or more backup methods. Where possible, it is preferred that instantaneous methods of detecting overcurrent be used as the primary protection method on all of the major equipment associated with the power system. Instantaneous clearing of a fault is desirable:

- to minimize the damage due to the fault,
- to minimize the potential exposure of personnel to the hazards of an arc flash, and
- to avoid long clearing times that could result in the entire system becoming unstable, resulting in a complete loss of power to the system.

Instantaneous methods of relaying generally include differential, pilot wire, and impedance relays. Backup protection is generally accomplished with time overcurrent relays and impedance relays with a time delay.

Good objectives for clearing times are:

- that the primary protection clear a fault in less than 0.25 seconds for the maximum available fault current and
- that the backup protection clear a fault in less than 1.00 seconds for the maximum available fault current.

Faster clearing times are desirable whenever it is possible for the three reasons given above.

2.0 CONTINUOUS CURRENT SETTINGS

Protective device continuous current settings conform to the following requirements:

1. Overcurrent protective devices at 480V are set to open at or below the downline cable or busway ampacity per NEC Section 240.3; except when the ampacity does not correspond to a standard rating, the next higher standard rating may be used as long as this rating does not exceed 800 amps. (See Section 5.3 for more details.)

2. Transformer overcurrent protective device settings comply with the requirements of NEC Section 450.3.
3. Long time settings of overcurrent devices are above the maximum expected full load current for that device.

3.0 MARGINS FOR SELECTIVITY

Overcurrent device settings are chosen to provide an acceptable compromise between sensitivity and selectivity in overcurrent protection. Selective coordination is generally achieved by using the following minimum recommended margins between device characteristics:

1. **Relay - Relay** coordination requires (1) that there be a minimum of 0.25 to 0.40 seconds time margin between the relay curves at the maximum fault current to account for the interrupting time of the circuit breaker, relay over-travel time, relay tolerances, and a safety factor or (2) that the downline relay curve be less than 90% of the upline relay curve.

For induction disk relays, the minimum desired time margin for a 5 cycle breaker is generally 0.30 seconds:

5 cycle breaker	0.08 seconds
relay over-travel	0.10 seconds
CT ratio & safety factor	<u>0.12 seconds</u>
	0.30 seconds

For digital relays, the minimum desired time margin for a 5 cycle breaker is generally 0.25 seconds:

5 cycle breaker	0.08 seconds
relay accuracy \pm .02 sec.	0.04 seconds
CT ratio & safety factor	<u>0.13 seconds</u>
	0.25 seconds

Margin between pickup levels of $\geq 10\%$ for two devices in series.

2. **Electromechanical Relay - Fuse** coordination requires a minimum 0.22 second time margin between the curves.
3. **Electromechanical Relay - Low Voltage Breaker** coordination requires a minimum 0.22 second time margin between the curves.
4. **Static Relay - Fuse** coordination requires a minimum 0.12 second time margin between the curves.
5. **Static Relay - Low Voltage Breaker** coordination requires a minimum 0.12 second time margin between the curves.
6. **Fuse - Fuse** coordination requires that the total clearing time of the downline fuse curve be less than 75% of the minimum melt time of the upline fuse curve to account for pre-loading.
7. **Fuse - Low Voltage Breaker** coordination requires that the down-line breaker maximum time curve be less than 75% of the minimum melt time of the up-line fuse curve to account for pre-loading.

8. **Fuse - Relay** coordination requires a minimum 0.3 second time margin between the curves.
9. **Low Voltage Breaker - Fuse** coordination requires a minimum 0.1 second time margin between the curves to allow for temperature variations in the fuse.
10. **Low Voltage Breaker - Low Voltage Breaker** coordination requires only that the plotted curves do not intersect since all tolerances and operating times are included in the published characteristics.
11. **Low Voltage Breaker - Relay** coordination requires a minimum 0.2 second time margin between the curves.

4.0 GUIDELINES FOR RELAY SETTINGS

Guidelines for setting relays are summarized as follows:

1. **Relays for breakers on the primaries of transformers:**
 - A. Pickup is typically chosen at approximately 140% of nominal transformer current or higher if coordination considerations dictate that. Values up to 600% are allowed by the NEC, depending upon the system parameters and what other protective devices are used.
 - B. The instantaneous pickup is $> 1.6 \times I_{sc}$ for maximum fault downstream of transformer to avoid the tripping of the primary breaker for an asymmetrical secondary fault. A multiplier of 1.8 is used for larger transformers.
 - C. The instantaneous pickup is $> 1.3 \times I_{sc}$ for maximum fault downstream of transformer to avoid the tripping of the primary breaker for an asymmetrical secondary fault, if the relay is equipped with a DC filter that will filter out the offset portion of an asymmetrical fault current.
 - D. The instantaneous pickup is $> 2 \times$ the transformer inrush point at 0.1 seconds in order to avoid tripping of the primary breaker during normal energization of the transformer. The inrush point is defined as follows:
 - i. For transformers > 2500 kVA, the inrush current is 12 x nominal full load current at 0.1 seconds.
 - ii. For transformers ≤ 2500 kVA, the inrush current is 8 x nominal full load current at 0.1 seconds.
 - E. The instantaneous pickup is $> 1.3 \times$ the transformer inrush point at 0.1 seconds in order to avoid tripping of the primary breaker during normal energization of the transformer, if the relay is equipped with a filter that filters out all harmonics and DC offset, such as an SEL relay. The transformer inrush point is defined above in D.
2. **Relays for breakers on induction motors:**
 - A. Pickup is at approximately 115% of nominal motor duty factor. (The pickup is generally set at 5% to 25% above the motor duty factor.)

- B. The instantaneous pickup is $> 1.6 \times 1.1 \times$ locked rotor current to avoid tripping the breaker for the maximum asymmetrical current for starting the motor or for a nearby fault. The total factor of 1.8 is due to asymmetry and motor saturation during starting.
- C. The instantaneous pickup is $> 1.3 \times$ locked rotor current to avoid tripping the breaker for the maximum asymmetrical current for starting the motor or for a nearby fault, if the relay is equipped with a DC filter that will completely filter out the offset portion of an asymmetrical current.
- D. For relays that do not completely filter out the offset portion of an asymmetrical current, such as Multilin 469 relays, use the following guidelines:
 - i. Enable the Overreach (DC) Filter and set the Short Circuit Trip (instantaneous) pickup setting $\geq 1.5 \times$ locked rotor current.
 - ii. Enable the Overreach (DC) Filter, set the Short Circuit Trip delay setting ≥ 10 ms, and set the Short Circuit Trip (instantaneous) pickup setting $\geq 1.3 \times$ locked rotor current.

3. **Ground fault relaying:**

- A. Ungrounded or high resistance grounded (HRG) systems alarm, but do not trip for ground faults; and, consequently, ground fault coordination does not apply. However, in some cases, motors may be equipped with instantaneous ground trips set in the range of 1 to 5 amps, depending upon the current setting of the HRG system.
- B. Low resistance grounded (LRG) systems generally limit ground fault currents to 200 to 800 amps, with 400 amps being quite common. Typically, motor circuits use core-balance CT's to detect ground faults. The use of these CT's allows very sensitive ground fault settings to be used with a high degree of accuracy. However, during a ground fault, ground current (or zero sequence current) flows in the circuit breakers on the unfaulted circuits fed from the same system due to the charging current of the cables or due to the motor surge capacitors (if they have any) on that circuit. The core-balance CT's on those circuits would see $3I_0$ current or three times the normal charging current while the fault is on the system. For example, on a 2400V system, with a typical .5 uf surge capacitor on a motor, $3I_0$ would be less than 1 amp. A pickup of 10 amps would be well above the currents that would be expected on the unfaulted circuits. A delay of at least 0.05 seconds is generally preferred at these low current levels to avoid spurious trips.
- C. Residual relays (50/51N) are often used to detect ground currents on solidly grounded or LRG medium voltage systems. When using the residual relays an allowance is to be made for the possible inaccuracy among the CT circuits due to unequal high-magnitude transformer inrush currents. This can generally be accomplished by setting the 50N at four times the self-cooled full load rating of the transformer, and setting the 51N at the minimum tap with a time delay > 0.1 second at the instantaneous setting.

For LRG medium voltage systems, a minimum delay of 0.35 seconds is chosen for electromechanical relays and 0.30 seconds for static relays to allow coordination with the motor relays that are typically set with a 0.05 second delay. For LRG systems, the pickup for the relay on the main breaker is generally at 10% of the maximum single line-to-ground fault current.

- D. When ground relays (50/51G) are used to detect ground currents on the main breakers, faster clearing times are possible since the criteria of item 3C above for residual relays does not apply. A delay of 0.4 seconds is chosen to allow coordination with the downline motor relays that are typically set with a 0.05 second delay.

4. **Low voltage breakers:**

Whenever possible, maintain fast fault clearing down to 30% of maximum available fault current.

5.0 GUIDELINES FOR LOW VOLTAGE BREAKER SETTINGS

This discussion focuses specifically on the guidelines for and the setting of low voltage breakers on 480V systems. Many of these comments can be extrapolated to other low voltage systems as well.

5.1 Overview of Faults at the 480V Main Bus

The incident energy associated with three phase arcing faults on the 480V main bus generally determines the PPE label that is needed for each of the feeder fused switches or breakers that are fed from the main 480V bus. For transformers in the range of 1500 to 3000 kVA, the following observations are generally true:

1. If a 480V main class L fuse is used with a rating on the order of 125% of the transformer rating, the incident energy for faults on the main bus will be $> 100 \text{ cal/cm}^2$.
2. If a main 480V breaker is used with a long time pick up (LTPU) on the order of 125% of the transformer rating, a short time pickup (STPU) in the range of 2 to 3 times the LTPU, and a short time delay of 0.3 to 0.4 seconds, the incident energy will generally be $< 40 \text{ cal/cm}^2$ (i.e. PPE Level = 4).
3. If a main 480V breaker is used with an instantaneous setting in the range of 2 to 3 times the LTPU, the incident energy could be $< 8 \text{ cal/cm}^2$ (i.e. PPE Level = 2).
 - A. However, the instantaneous setting would not coordinate with the down-line breakers or fuses and this could result in the main breaker tripping for down-line faults. This is usually not acceptable.
 - B. Many new trip units have the option to include a two-position switch which would allow one to change to an instantaneous setting when doing a down-line task and then to change back to the short time setting for the normal condition when the down-line task is complete. This is sometimes referred to as 'Maintenance Mode.' This allows coordination for normal conditions and lower incident energy for the rare case when a down-line task is being performed.
4. Based on item #1, replacing a main fuse with a main breaker could significantly lower the incident energy from $> 100 \text{ cal/cm}^2$ to $< 40 \text{ cal/cm}^2$. With the Maintenance Mode option on the trip unit, the incident energy could even be reduced to $< 8 \text{ cal/cm}^2$ for certain down-line tasks, as discussed in item #3 above.

5. When there is a main breaker (or possibly a main fused switch) other considerations that can reduce the incident energy include:
 - A. Bus differential relaying
 - B. Zone selective interlocking
 - C. Remote tripping
 - D. Not paralleling of transformers
 - E. The use of non-louvered doors and panels, which can reduce the exposure to the qualified worker.

5.2 Detailed Low Voltage Circuit Breaker Settings

The basic system for these guidelines is illustrated in Figure 1 and is described as follows:

- 480V double ended substation
- Generator on one transformer
- Tie breaker normally open
- Two transformers are not operated in parallel
- The generator can operate in parallel with one transformer or independently

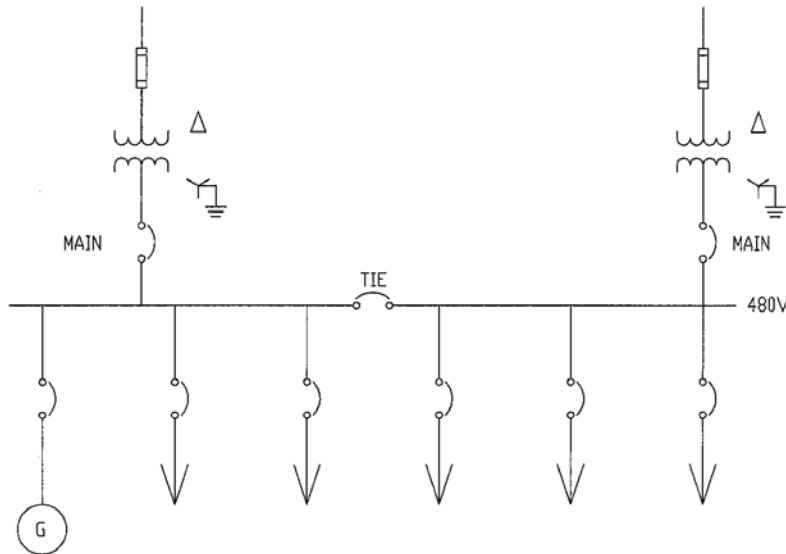


Figure 1

Objectives in coordination:

- Main and tie breakers coordinate with all feeders
- Main and generator breakers coordinate in fault current region
- Generator breaker coordinates with feeders as much as possible
- Achieve PPE = 4 at main bus with margin
- Achieve PPE = 2 at remote MCCs and PDPs with margin
- Coordination of the tie breaker with the main and generator breakers is not critical

The setting band must be considered when selecting the pickup and instantaneous settings. In many cases the tolerance on the LVCB settings are in the range of +/- 10 to 20%. The defined margins need to include these tolerances.

The guidelines for setting low voltage breakers are summarized as follows. Where coordination and protection are not compromised, lower pickup settings for short time and instantaneous functions can and should be used. (See Qual-Tech Document QT-629 for other options in accounting for the variation in the arcing current.)

1. **Main Breakers:**

- LTPU: \leq Bus Rating. Typically set no higher than 125% of transformer rating.
- LT Delay: Minimum to allow coordination with tie and generator breakers.
- STPU: Set low enough to trip for 85% of the 85% arcing current. This setting is generally in the range of 2 to 3 times the LTPU.
- ST Delay: \leq 0.33 seconds to achieve PPE = 4. It must coordinate with all feeders. Delay should be set with the I²t characteristic OFF or OUT.
- Instantaneous: None
- Ground PU: 1200 A (This is the maximum allowed by the NEC.)
- Ground Delay: 0.5 seconds

2. **Tie Breakers:**

- LTPU: \leq Bus Rating. Set ~10% less than main breaker for coordination.
- LT Delay: Minimum to allow coordination with feeder breakers. Coordinate with main and feeders if possible – if not, let overlap with main.
- STPU: Coordinate with main and feeders if possible – if not, let overlap main.
- ST Delay: Coordinate with main and feeders if possible – if not, let overlap main. Delay should be set with the I²t characteristic OFF or OUT.
- Instantaneous: None
- Ground PU: Coordinate with main and feeders if possible – if not, let overlap main.
- Ground Delay: Coordinate with main and feeders if possible – if not, let overlap main.

3. **Generator Breakers:**

LTPU:	≤ Cable Rating. (See 'Notes on Overcurrent Device Ratings and Standard Ampere Ratings.')
LT Delay:	Minimum to allow coordination with feeder breakers
STPU:	Low enough to trip for 85% of the 85% arcing current without main transformer. Due to the decaying generator current for a fault, this can be difficult if not impossible. Usually the lowest setting of 1.5 times the LTPU is used.
ST Delay:	Coordinate with main. Coordinate with instantaneous on all (or nearly all) of feeders. Delay should be set with the I ² t characteristic OFF or OUT.
Instantaneous:	None (or set at Max)
Ground PU:	Coordinate with main and feeders if possible – if not, let overlap main.
Ground Delay:	Coordinate with main and feeders if possible – if not, let overlap main.

4. **Feeder Breakers:**

LTPU:	≤ Cable Rating. (See 'Notes on Overcurrent Device Ratings and Standard Ampere Ratings.')
LT Delay:	7 to 24 seconds to allow starting of largest motor.
STPU:	≥ feeder load amps plus 6 x FLA of the largest down-line motor to allow for its starting. Set low enough to trip for 85% of the 85% arcing fault current. Must coordinate with main and tie breakers. Coordinate with generator breaker if possible. If required to reduce the arc flash, lower settings may be used if there is no large motor downline of the breaker.
ST Delay:	Allow coordination with downline devices. A maximum delay of 0.2 seconds is typical to achieve PPE = 2 at remote MCCs and PDPs. Delay should be set with the I ² t characteristic OFF or OUT.
Instantaneous:	Set at Max or less than 10 kA, whichever is lower. This typically gives a PPE = 2 for down-line faults, which are greater than 10 kA.
Ground PU:	To allow coordination with downline devices, set at maximum which coordinates with main and tie breakers. If there are no downline devices set at minimum.
Ground Delay:	To allow coordination with downline devices, set at maximum which coordinates with main and tie breakers. If there are no downline devices set at a minimum delay of at least 0.05 seconds.

5.3 Notes on Overcurrent Device Ratings and Standard Ampere Ratings

From NEC 240.4 (B) and (C), for protective devices rated 800 A or less, the next higher standard overcurrent device rating, above the ampacity of the conductors being protected, is allowed if the following conditions are met:

1. The conductors are not part of a branch circuit supplying more than one receptacle for cord-and-plug-connected portable loads.
2. The ampacity of the conductors is not the same as a standard ampere rating of a protective device.
3. The next higher standard rating is not higher than 800 A.

For protective devices rated over 800 A, the conductor ampacity shall be greater than or equal to the overcurrent device.

Section 240.91 (B) allows for higher overcurrent device ratings if the facility is a supervised industrial installation. For overcurrent devices rated over 800 A, the ampacity of the conductors it protects shall be equal to or greater than 95% of the rating of the device, with the following conditions met:

1. The conductors are protected within recognized time vs. current limits for short-circuit currents.
2. All equipment in which the conductors terminate is listed and marked for the application.

From NEC 240.6, the standard protective device ampere ratings are: 15, 20, 25, 30, 35, 40, 45, 50, 60, 70, 80, 90, 100, 110, 125, 150, 175, 200, 225, 250, 300, 350, 400, 450, 500, 600, 700, 800, 1000, 1200, 1600, 2000, 2500, 3000, 4000, 5000, 6000.

6.0 COORDINATION PRIORITIES

With the above criteria considered, there are cases where complete selectivity is not achievable. For these cases, the following priorities (level 1 being the highest) are used to determine the overcurrent device settings:

Priority Level 1:

- a. Transformer primary overcurrent device coordinates with the inrush current point.
- b. Transformer secondary overcurrent device coordinates with the transformer damage curve.
- c. Overcurrent device characteristic coordinates with downline cable damage curve. In virtually all cases, if the long time setting of the device is not above the cable ampacity, then the damage curve will not be exceeded.
- d. In a switchgear lineup, the main overcurrent device coordinates with all feeder overcurrent devices.
- e. For a normally closed tie breaker with two normally closed main breakers, the tie breaker coordinates with the main breaker. With a normally open tie breaker, the tie breaker is set the same as the mains.
- f. Ground fault protection conforms to the National Electrical Code, Section 230-95 for solidly grounded 480V systems.
- g. The first of three devices in series in a fault current path coordinates with the third device in the path.

Priority Level 2:

- a. Transformer primary overcurrent device coordinates with the transformer damage curve.
- b. Transformer primary overcurrent device coordinates with secondary main overcurrent device.
- c. MCC main overcurrent device coordinates with individual downline overcurrent devices.
- d. The first of two devices in series in a fault current path coordinates with the second device in the path.
- e. For a fused breaker, the breaker settings should be such that the breaker clears low and intermediate magnitude fault currents while the fuse operates to clear the high magnitude fault currents.