CHAPTER 4

PROTECTIVE DEVICES COORDINATION

4-1. General

Where there are two or more series protective devices between the fault point and the power supply, these devices must be coordinated to insure that the device nearest the fault point will operate first. The other upstream devices must be designed to operate in sequence to provide back-up protection, if any device fails to respond. This is called selective coordination. To meet this requirement, protective devices must be rated or set to operate on minimum overcurrent, in minimum time, and still be selective with other devices on the system. When the above objectives are fulfilled, maximum protection to equipment, production, and personnel will be accomplished. As will be seen later in this chapter, protection and coordination are often in direct opposition with each other. Protection may have to be sacrificed for coordination, and vice versa. It is the responsibility of the electrical engineer to design for optimum coordination and protection. This is sometimes more art than science.

4-2. The coordination study

A coordination study consists of the selection or setting of all series protective devices from the load upstream to the power supply. In selecting or setting these protective devices, a comparison is made of the operating times of all the devices in response to various levels of overcurrent. The objective, of course, is to design a selectively coordinated electrical power system. A new or revised coordination study should be made when the available short-circuit current from the power supply is increased; when new large loads are added or existing equipment is replaced with larger equipment; when a fault shuts down a large part of the system; or when protective devices are upgraded.

a. Time-current characteristic curves. Time is plotted on the vertical axis and current is plotted on the horizontal axis of all time-current characteristic curves. Log-log type graph paper is used to cover a wide range of times and currents. Characteristic curves are arranged so that the area below and to the left of the curves indicate points of "no operation," and the area above and to the right of the curves indicate points of "operation." The procedure involved in applying characteristic curves to a coordination study is to select or set the various protective devices so that the characteristic curves of series devices from the load to the source are located on a composite time-current graph from left to right with no overlapping of curves. The result is a set of coordinated curves on one composite time-current graph.

b. Data required for the coordination study. The following data is required for a coordination study.

(1) Single-line diagram of the system under study.

(2) System voltage levels.

(3) Incoming power supply data.

(a) Impedance and MVA data.

(b) X/R ratio.

(c) Existing protection including relay device numbers and settings, CT ratios, and time-current characteristic curves.

(d) Generator ratings and impedance data.

(e) Transformer ratings and impedance data.

(4) Data on system under study.

(a) Transformer ratings and impedance data.

(b) Motor ratings and impedance data.

(c) Protective devices ratings including momentary and interrupting duty as applicable.

(d) Time-current characteristic curves for protective devices.

(e) CT ratios, excitation curves, and winding resistance.

(f) Thermal (I^2t) curves for cables and rotating machines.

(g) Conductor sizes and approximate lengths.

(5) Short-circuit and load current data.

(a) Maximum and minimum momentary (first cycle) short-circuit currents at major buses.

(b) Maximum and minimum interrupting duty (5 cycles and above) short-circuit currents at major buses. The exact value of ground-fault current (especially arcing ground-fault current) is impossible to calculate. Methods are available for estimating ground-fault current. The application of NEMA damage curves for ground-fault current is illustrated in appendix G.

(c) Estimated maximum and minimum arcing and bolted ground-fault currents at major buses.

(d) Maximum load currents.

(e) Motor starting currents and starting times.

(f) Transformer protection points.

c. Coordination procedure. The following procedure should be followed when conducting a coordination study:

(1) Select a convenient voltage base and convert all ampere values to this common base. Normally, the lowest system voltage will be chosen, but this may not always be the case.

(2) Indicate short-circuit currents on the horizontal axis of the log-log graph.

(3) Indicate largest (or worst case) load ampaities on the horizontal axis. This is usually a motor and should include FLA and LRA values.

(4) Specify protection points. These include magnetizing inrush point and NFPA 70 limits for certain large transformers.

(5) Indicate protective relay pick-up ranges.

(6) Starting with the largest (or worst case) load at the lowest voltage level, plot the curve for this device on the extreme left side of the log-log graph. Although the maximum short-circuit current on the system will establish the upper limit of curves plotted to the right of the first and succeeding devices, the number of curves plotted on a single sheet should be limited to about five to avoid confusion.

(7) Using the overlay principle, trace the curves for all protective devices on a composite graph, selecting ratings or settings that will provide overcurrent protection and ensure no overlapping of curves.

d. Coordination time intervals. * When plotting coordination curves, certain time intervals must be maintained between the curves of various protective devices in order to ensure correct sequential operation of the devices. These intervals are required because relays have overtravel and curve tolerances, certain fuses have damage characteristics, and circuit breakers have certain speeds of operation. Sometimes these intervals are called margins.

(1) Coordination can be easily achieved with low voltage current-limiting fuses that have fast response times. Manufacturer's time current curves and selectivity ratio guides are used for both overload and short-circuit conditions, precluding the need for calculating time intervals.

(2) When coordinating inverse time overcurrent relays, the time interval is usually 0.3-0.4 seconds. This interval is measured between relays in series either at the instantaneous setting of the load side feeder circuit breaker relay or the maximum short-circuit current, which can flow through both devices simultaneously, whichever is the lower value of current. The interval consists of the following components:

(a) Circuit breaker opening time (5 cycles).	0.08 seconds
(b) Relay overtravel	0.10 seconds
(c) Safety factor for CT saturation, setting errors, contact gap, etc.	0.22 seconds

(3) This safety factor may be decreased by field testing relays to eliminate setting errors. This involves calibrating the relays to the coordination curves and adjusting time dials to achieve specific operating times. A 0.355 margin is widely used in field-tested systems employing very inverse and extremely inverse time overcurrent relays.

(4) When solid-state relays are used, overtravel is eliminated and the time may be reduced by the amount included for overtravel. For systems using induction disk relays, a decrease of the time interval may be made by employing an overcurrent relay with a special high-dropout instantaneous element set at approximately the same pickup as the time element with its contact wired in series with the main relay contact. This eliminates over-travel in the relay so equipped. The time interval often used on carefully calibrated systems with high-dropout instantaneous relays is 0.25 seconds.

(5) When coordinating relays with downstream fuses, the circuit opening time does not exist for the fuse and the interval may be reduced accordingly. The total clearing time of the fuse should be used for coordination purposes. The time margin between the fuse total clearing curve and the upstream relay curve could be as low as 0.1 second where clearing times below 1 second are involved.

(6) When low-voltage circuit breakers equipped with direct-acting trip units are coordinated with relayed circuit breakers, the coordination time interval is usually regarded as 0.3 seconds. This interval may be decreased to a shorter time as explained previously for relay-to-relay coordination.

(7) When coordinating circuit breakers equipped with direct-acting trip units, the characteristics curves should not overlap. In general only

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a slight separation is planned between the different characteristics curves. This lack of a specified time margin is explained by the incorporation of all the variables plus the circuit breaker operating times for these devices within the band of the device characteristic curve.

(8) Delta-wye transformers. When protecting a delta-wye transformer, an additional 16 percent current margin over margins mentioned previously should be used between the primary and secondary protective device characteristic curves. This helps maintain selectivity for secondary phase-to-phase faults since the per-unit primary current in one phase for this type of fault is 16 percent greater than the per-unit secondary current which flows for a secondary three-phase fault.

4-3. Primary and medium-voltage coordination

Figure 4-1 shows a single-line diagram (modified for simplicity) of the electrical distribution system at an Army Ammunition Plant. Two 115kV utility lines supply the double-ended, main substation, which transforms the voltage down to 13.8kV for distribution throughout the facility. The utility company should participate in the selection of relay protection for the incoming 115kV lines in the event of a fault in the 115kV bus or the main transformers. The 15kV switchgear is designed primarily for supplying the 480V substations, although medium and large-size motors could also be served. Primary and medium-voltage protection is covered in detail by the coordination examples in appendix G.

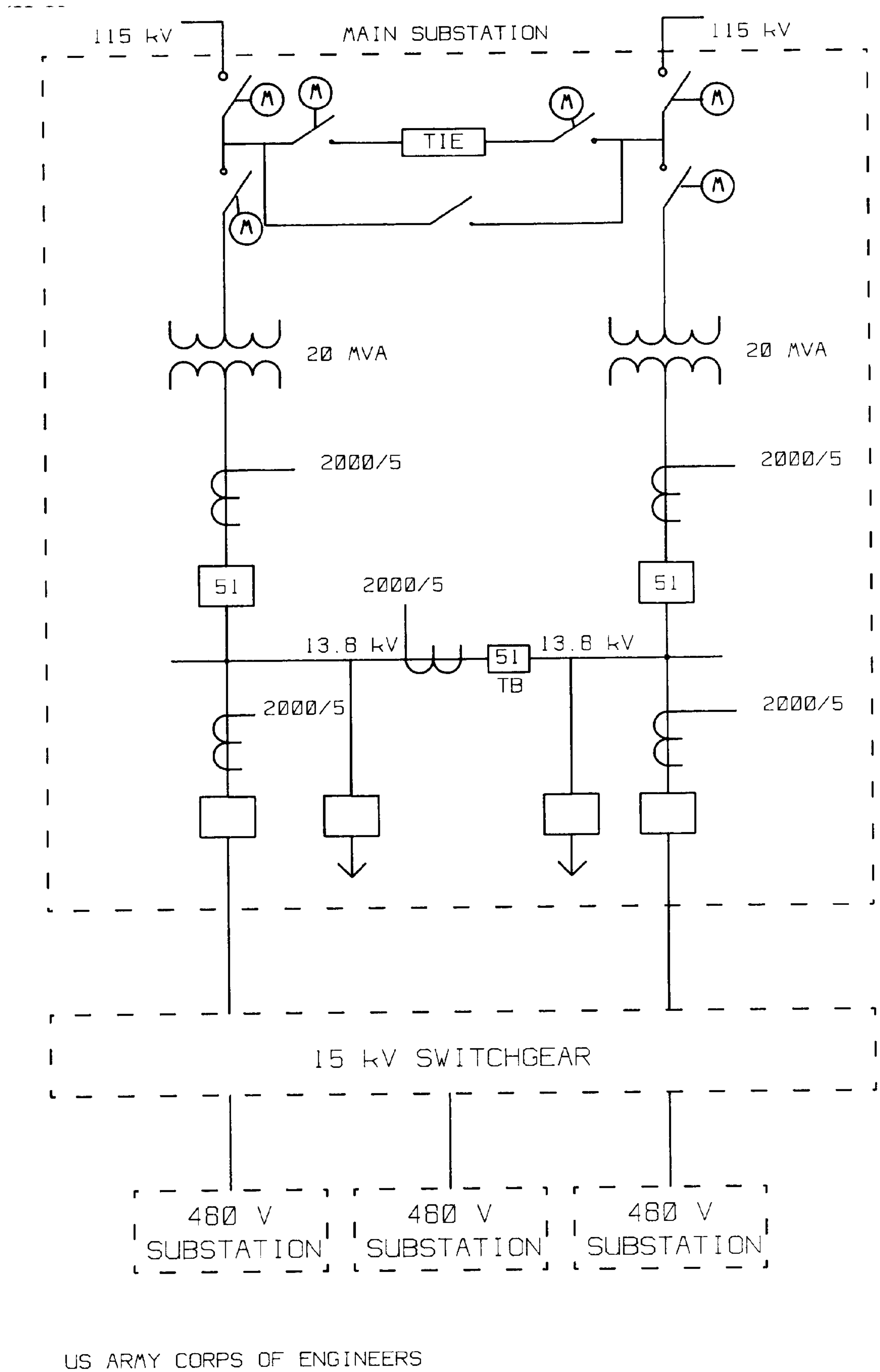

Figure 4-1. Army ammunition plant single-line diagram.

4-4. Low-voltage coordination

Low-voltage coordination involves selecting feeder-breaker, tie-breaker, main-breaker, and transformer fuse ratings and settings that provide optimum protection of equipment while maintaining selective coordination among the low-voltage, protective devices. Total system coordination with upstream medium-voltage and primary protective devices must also be incorporated. Low-voltage protection is covered in detail by the coordination examples in appendix G.

4-5. Ground-fault coordination

Most of the concern about ground-fault protection and coordination, today, centers on low-voltage systems where low-level arcing faults are a considerable problem. The phenomena of arcing faults began in the 1950's with the advent of large capacity 480Y/277V solidly-grounded systems. Medium- and high-voltage grounded systems don't experience the arcing ground fault problem common to low-voltage systems, and have employed ground current relays for years. Currently, there are three methods for achieving low-voltage arcing ground-fault protection.

a. Method 1. The non-selective, single-zone method, shown in figure 4-2a, applies ground-fault protection only at the main service disconnect. This is minimum protection as required by NFPA 70, and is required only on 480Y/277V services rated 1000A or more. Non-selective, single-zone ground-fault protection may be difficult to coordinate with downstream standard overcurrent de- vices, and additional ground-fault protection at downstream levels may have to be considered even though not required by NFPA 70.

b. Method 2. The selective, time-coordinated method, shown in figure 4-2b, applies ground-fault protection at additional levels downstream of the main service disconnect. Coordination is achieved by intentional time-delays to separate the various levels. This method achieves the coordination that Method 1 does not, but protection is sacrificed by inclusion of the time-delays. Additionally, Method 2 costs more than Method 1.

c. Method 3. The selective, zone-coordinated method, shown in figure 4-2c, applies ground-fault protection at downstream levels like Method 2 does, but includes a restraining signal which can override the time-delay. Coordination and protection are both maximized by the application of this system of restraining signals by allowing each level to communicate with other levels. This method, of course, costs more than the other methods, and should be considered only for special purpose applications.

d. Government facilities. Except for special installations requiring precise ground-fault protection and coordination, government facilities should incorporate ground-fault protection in accordance with NFPA 70 only. Where coordination is not possible with downstream feeders, main GFP devices and feeder protective devices should he set to optimize coordination as much as possible.

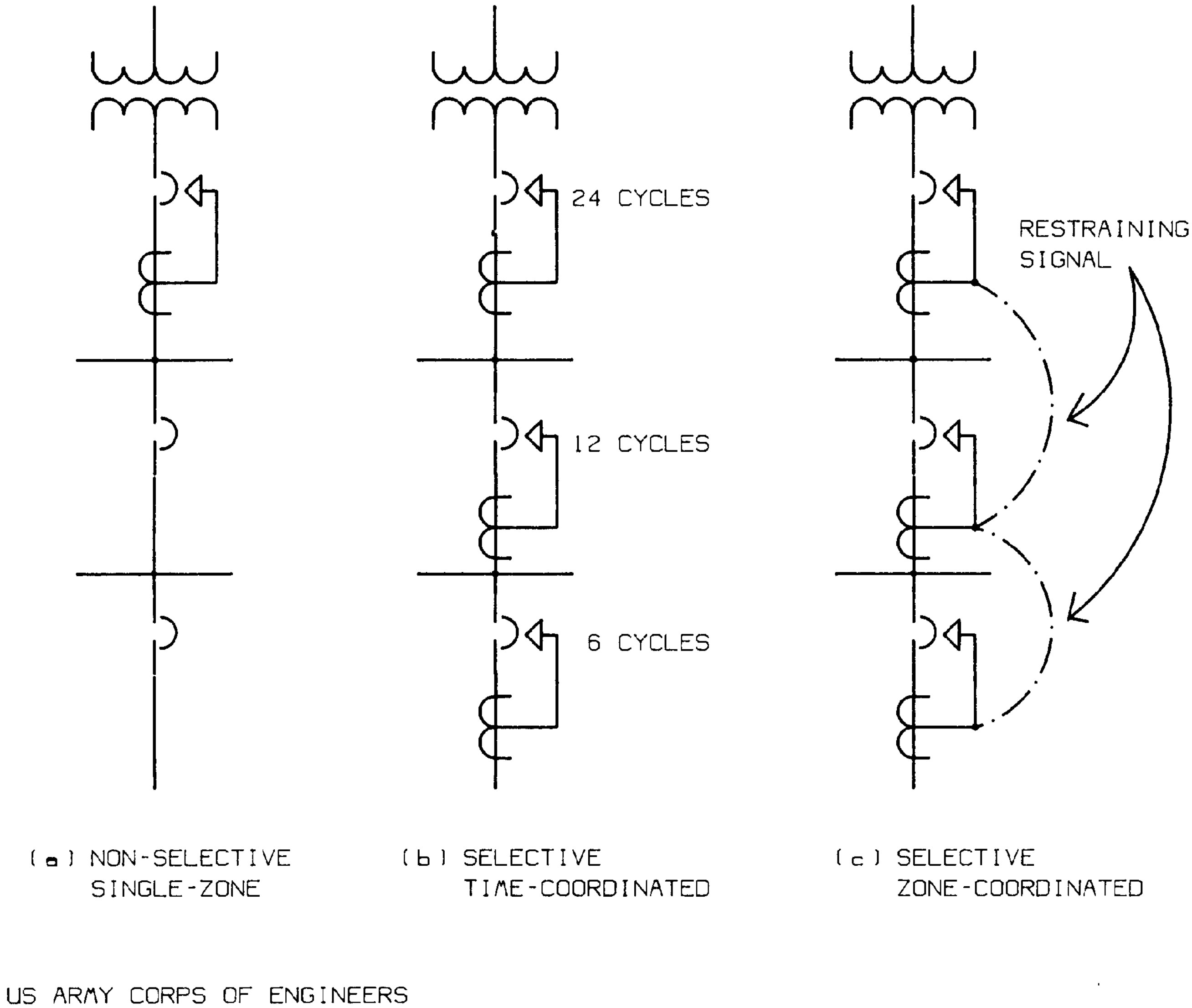

Figure 4-2. Ground-fault protection.

4-6. Coordination requirements

The primary purpose of the coordination procedure is to select the proper ratings and settings for the protective devices on an electrical distribution system. These ratings and settings should be selected so that pick-up currents and time delays allow the system to ignore transient overloads, but operate the protective device closest to the fault when a fault does occur. Proper selection of ratings and settings of protective devices requires knowledge of NFPA 70 requirements for protection of motors, transformers, and cables as well as knowledge of ANSI C57.12 requirements for transformer withstand limits. Application of the protection requirements listed in this paragraph is covered in detail by the coordination examples in appendix G.

a. NFPA 70 transformer limits. NFPA 70 specifies the maximum overcurrent setting for transformer protective devices. Table 4-1 summarizes the NFPA 70 requirements for transformers over 600V. Fuse ratings are permitted to be lower than circuit breaker ratings due to the differences in operating characteristics in the overload region.

*Table 4-1. Maximum overcurrent protection (in percent) per NFPA 70**

Transformers with Primary and Secondary Protection					
	Primary		Secondary		
	Over 600V		Over 600V		600V or Below
Transformer Impedance	Circuit Breaker	Fuse	Circuit Breaker	Fuse	Circuit Breaker or Fuse
Less than or equal to .06 per unit	600	300	300	250	125**
Greater than .06 but less than or equal to .1 per unit	400	300	250	225	125**

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**Supervised locations may be 250 percent.

b. ANSI C57.12 withstand point. At current levels greater than 600 percent of full-load, transformer withstand can be approximated by I^2t through-fault curves which have replaced the old, familiar ANSI C57.12 withstand point.

c. Magnetizing inrush. Transformer primary protective devices must be rated or set below the withstand limit but above the magnetizing- and load-inrush currents that occur during transformer energization. In-rush current magnitudes and durations vary among transformer manufacturers, but 8 to 12 times full-load current for 0.1 second are commonly used for coordination purposes.

4-7. Maintenance, testing, and calibration

Preventive maintenance should not be confused with breakdown maintenance, which is not maintenance at all, but is really repair. Preventive maintenance involves a scheduled program for cleaning, tightening, lubricating, inspecting, and testing devices and equipment. The purpose is to identify and correct problem areas before troubles arise. Maintenance, testing, and calibration procedures vary with the type of equipment, the environment, frequency of operation, and other factors. While procedures may vary, certain initial field tests and inspection areas should always be addressed. Control power and control circuits should be tested for correct operation. Protective devices should be inspected, calibrated, and proper settings incorporated. Grounding connections should be verified, instrument transformers should be tested for proper polarity and operation, and ground-fault protection systems should be performance tested.

4-8. Example of phase coordination

This paragraph, in conjunction with the referenced figures, outlines a step-by-step procedure for conducting a phase coordination study. The example includes primary protection (34.5kV), medium-voltage protection (13.8kV), low-voltage overcurrent protection (480V), and low-voltage ground-fault protection. The procedures developed in this example may be applied to any electrical distribution system regardless of the complexity or simplicity. Although both manual and computer plotting procedures are described, computer plotting was used to develop the time current curves in this TM. The use of a computer coordination plotting program will make the coordination procedure more accurate and less time consuming, and is recommended. Short-circuit current calculating procedures are not covered.

a. Single-line diagram. Draw the single-line diagram of the system under study. Include voltage levels, incoming power supply data, and other information as outlined in this chapter. Figure 4-3 shows the single-line diagram for the electrical system considered by this example.

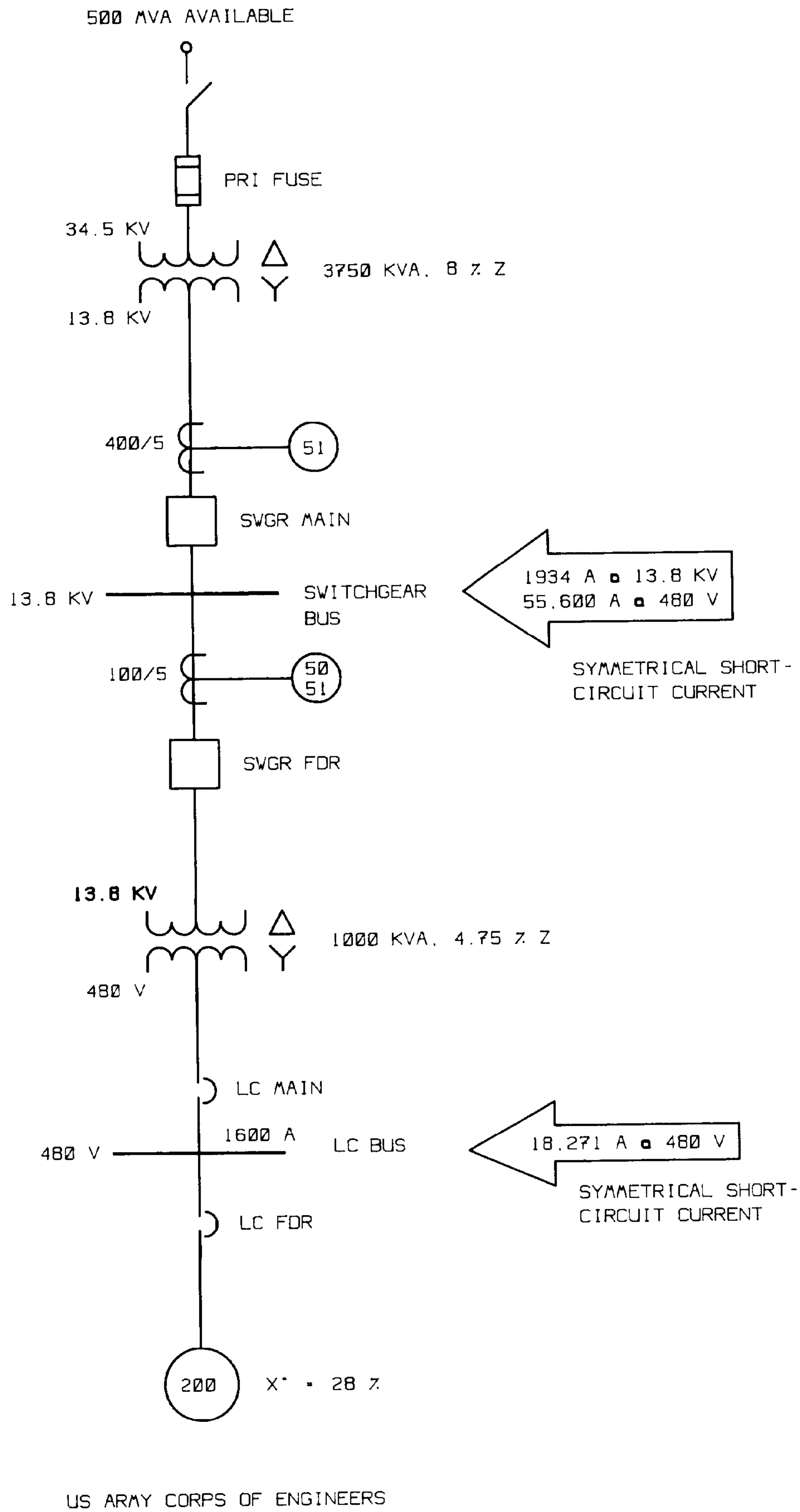

Figure 4-3. Single-line diagram.

b. Short-circuit and load currents. Short-circuit and load currents must be determined and included on the appropriate time-current coordination curves or entered into the computer plotting pro-gram.

(1) Assume that motor kVA is approximately equal to motor horsepower. This is a widely used and valid assumption for large motors. Also, for simplicity assume motor voltage is 480V, although it may actually be 460V. Motor examples using 460V ratings are covered in other examples. Calculate motor full load amperes (FLA) and motor locked-rotor amperes (LRA) as shown in equations 4-1, 4-2, and 4-3.

$$Motor_{FLA} = (kVA)/(1.73)(kV = (200)/(1.73)(.480) = 241A. \quad \text{(eq 4-1)}$$

$$Motor_{LRA(SYM)} = (FLA)/Xd'' = (241)/.28 = 861A. \quad \text{(eq 4-2)}$$

$$Motor_{LRA(ASYM)} = (Motor_{LRA(SYM)})(1.6) = (861)(1.6) = 1378A. \quad \text{(eq 4-3)}$$

(2) Determine maximum and minimum short-circuit currents and express the currents on a common base voltage. The base voltage for this example was selected to be 480V. Symmetrical and asymetrical short-circuit current values were calculated to be

I_{sym} at LC Bus = 18,271A
I_{sym} at LC Bus = 27,691A
I_{sym} at SWGR Bus = 55,600A
I_{sym} at SWGR Bus = 88,960A

Asymmetrical current is important because all instantaneous devices see the asymmetrical current. If the coordination study is being completed manually, short-circuit current values are normally shown on the current axis to remind the designer about the short-circuit current limits. For computer plotting programs, short-circuit current values, along with other data, are entered directly into the computer. The computer keeps track of all current limits, thereby simplifying the coordination procedures.

(3) Select a convenient current scale that will permit about five devices to be shown on the time-current characteristic curve. Locate the load device (motor) as far to the left as possible. Plot the motor starting curve as illustrated in figure 4-4. The motor current at time zero is LRA(asym). At about 3 cycles, it changes to LRA(sym). The transition from LRA(sym) to FLA is assumed to be made at about 10 seconds, although the exact time will depend on the actual starting time of the motor used. For simplicity, only the LRA(asym) values will be shown on the time-current curves.

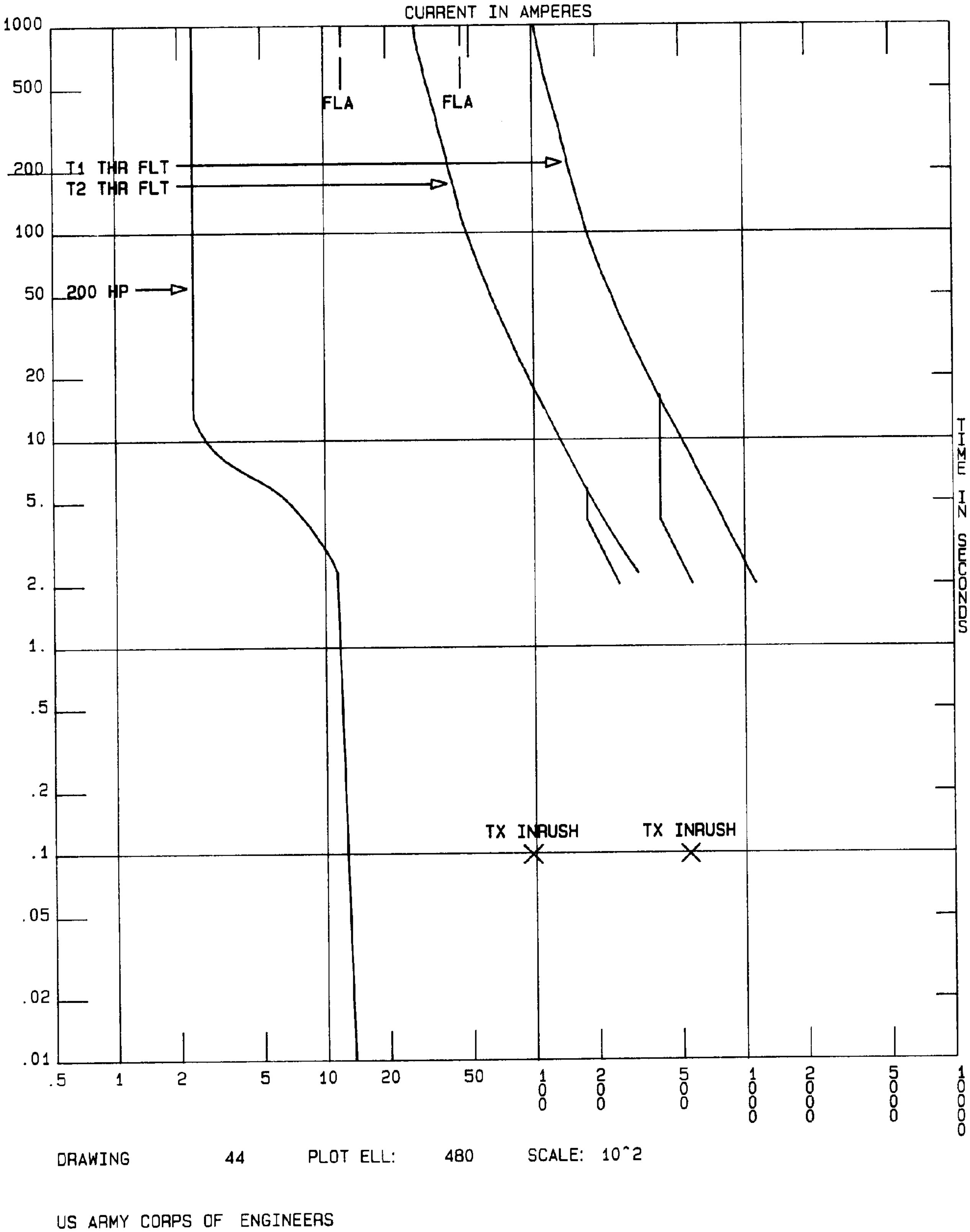

Figure 4-4. Key protection points.

c. Protection points. Determine NFPA 70 limits from table 4-1 and transformer inrush points for transformers T1 and T2. Equations 4-4 through 4-9 illustrate the required calculations.

(1) $T1_{FLA} = (kVA)/(1.73)(kV) = (3750)/(1.73)(.480) = 4511A$. (eq 4-4)

$T1_{3X} = (T1_{FLA})(3) = 13{,}533A$ .... (eq 4-5)

$T2_{FLA} = (kVA)/(1.73)(kV) = (1000)/(1.73)(.480) = 1203A$. (eq 4-6)

$T2_{6X} = (T2_{FLA})(6) = 7218A$. .... (eq 4-7)

(2) $T1_{INRUSH} = (12)(T1_{FLA}) = (12)(4511) = 54{,}132A$ for 0.1 second. (eq 4-8)

$T2_{INRUSH} = (8)(T2_{FLA}) = (8)(1203) = 9624A$ for 0.1 second. (eq 4-9)

(3) Plot the transformer through-fault protection curves and inrush points on the time-current curves as shown in figure 4-4. Transformer primary protection should always be below the through-fault curve to protect the transformer, but above the inrush point to prevent operating the protective device when the transformer is energized. Long-time rating or setting of the transformer primary protective device should he above FLA but less than the NFPA 70 limit.

d. Load center (LC) feeder circuit breaker characteristics. For manual coordination, tape the time-current characteristic curve of the first up-stream device (LC FDR) to a light table, and place figure 4-4 over this curve. Select the appropriate settings for the LC FDR circuit breaker by positioning the overlays and trace the resulting curve, as shown in figure 4-5. Although NFPA 70 will allow the LC FDR device to be set at 250 percent of FLA, or 600A, it is obvious from the characteristic curves that a lower setting, and thus better protection, can be used. Computer plotting programs allow the designer to interactively select, compare, and reselect (if necessary) curves of a wide range of protective devices. The settings shown below were selected for this example.

(1) Long-time pick-up=400A.

(2) Instantaneous pick-up=10X or 4000A. The instantaneous curve is truncated at the maximum short-circuit current seen at this point in the system (27,691A). The 10X value was selected because it is representative of commercially-available circuit breakers. As will be seen from the time-current curves, instantaneous and other settings are flexible and dependent upon many circuit variables.

(3) Separate overload protection not greater than 125 percent of motor nameplate amperes in accordance with NFPA 70.

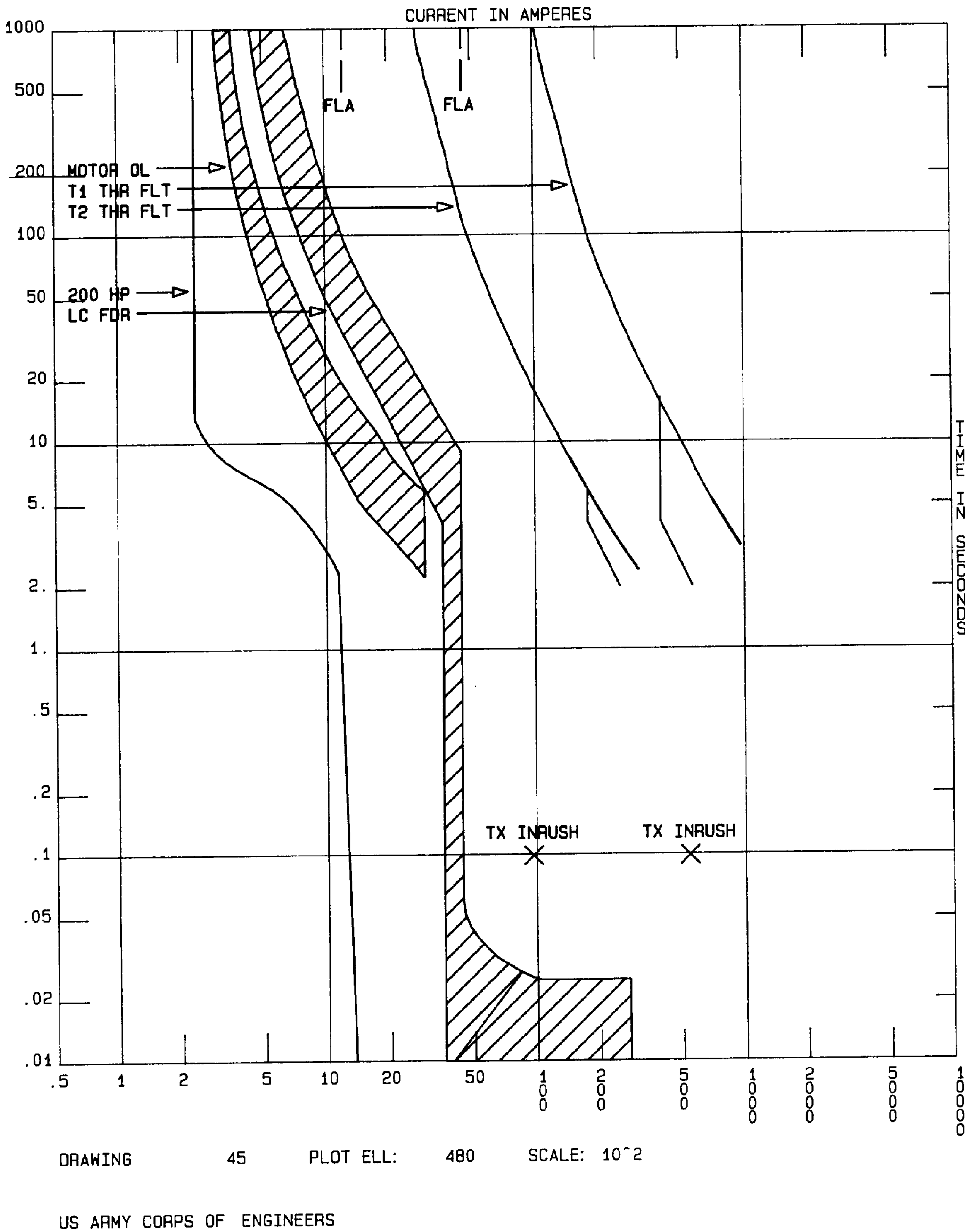

Figure 4-5. LC feeder protection.

e. LC MAIN circuit breaker characteristics. For manual coordination, tape the time-current characteristic curve of the next upstream device (LC MAIN) to the light table and place figure 4-5 over this curve. Select the appropriate settings for the LC MAIN as was done for the LC FDR. See figure 4-6. The long-time pick-up was set at 1600A to obtain full capacity from the 1600A LC bus. The LC MAIN can be set as high as 250 percent of the full-load amperes of T2 since T2 has both primary and secondary protection. See table 4-1. The following settings were selected for the Lc MAIN:

(1) Long-time pick-up = 1600A.

(2) Long-time delay=minimum.

(3) Short-time pick-up=7X or 11,200A

(4) Short-time delay=minimum. The short-time curve is truncated at the maximum short-circuit current seen at this point in the system (18,271A).

(5) Instantaneous pick-up=NONE, since it is impossible to coordinate the instantaneous curves for the two series devices, LC MAIN and LC FDR. If LC MAIN has an instantaneous element, it should be set high to coordinate with the LC FDR as much as possible.

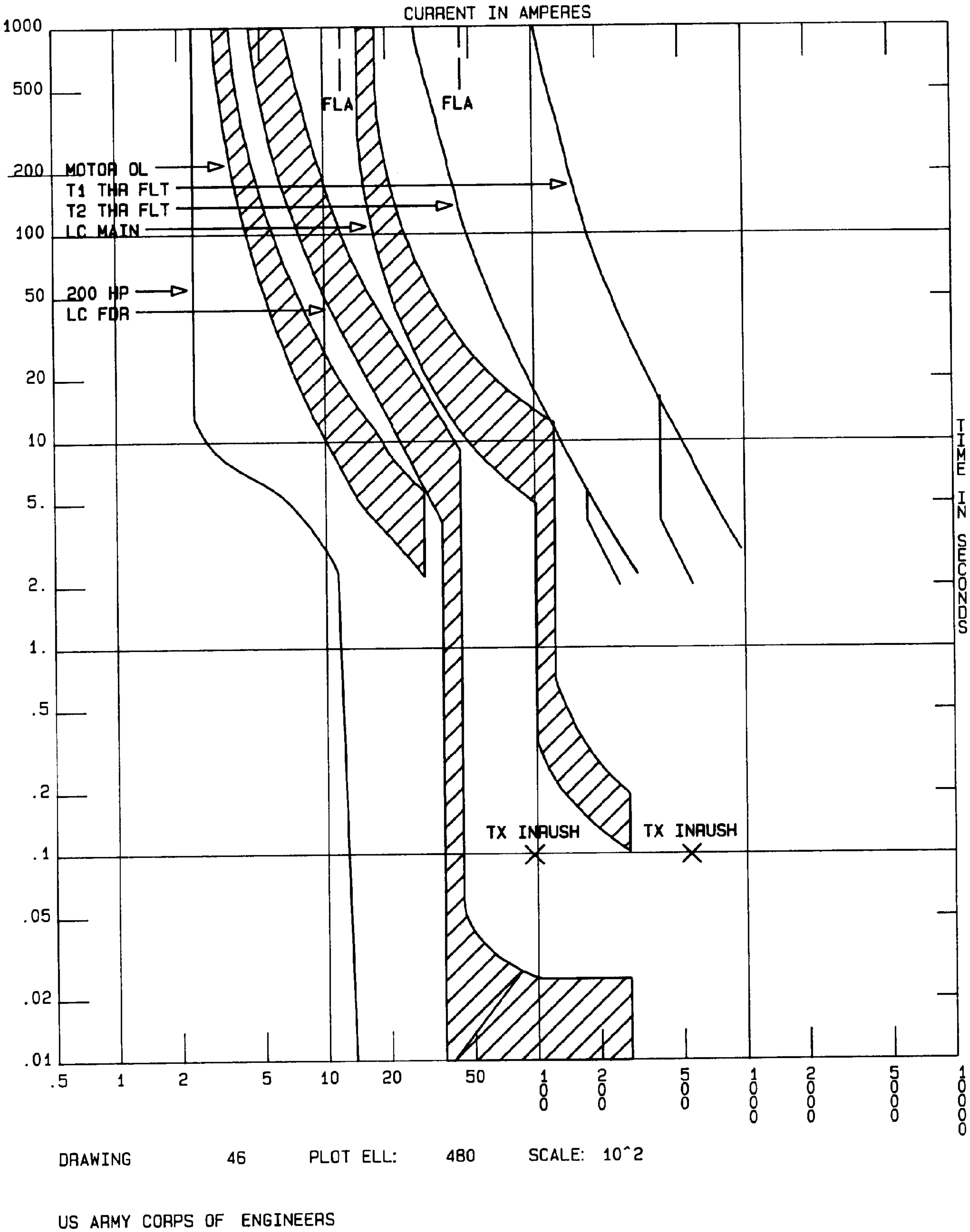

Figure 4-6. LC MAIN protection.

f. Switchgear feeder circuit breaker and relay characteristics. In this example, a 100/5A current transformer is used. On a 480V base a relay tap setting of lA will result in a primary current value of—

$$(1A)\frac{100A}{5A}\frac{13{,}800V}{480V} = (1A)(20)(28.75) = 575A. \quad \text{(eq 4-10)}$$

Other tap settings will result in the following primary currents:

$(2A)(20)(28.75) = 1150A$ .... (eq 4-11)
$(3A)(20)(28.75) = 1725A$ .... (eq 4-12)
$(4A)(20)(28.75) = 2300A$ .... (eq 4-13)
$(5A)(20)(28.75) = 2875A$ .... (eq 4-14)
$(6A)(20)(28.75) = 3450A$ .... (eq 4-15)
$(7A)(20)(28.75) = 4025A$ .... (eq 4-16)
$(8A)(20)(28.75) = 4600A$ .... (eq 4-17)
$(9A)(20)(28.75) = 5175A$ .... (eq 4-18)
$(10A)(20)(28.75) = 5750A$ .... (eq 4-19)
$(12A)(20)(28.75) = 6900A$ .... (eq 4-20)

....

The relay tap setting must be higher than the LC MAIN or 1600A, but less than the T2 NFPA 70 limit (6X), or 7200A. Sketch the usable tap settings (3A-12A) at the top of the time-current characteristic curve if the coordination study is being completed manually. Allowing an additional 16 percent current margin in addition to standard margins between the primary and secondary protective devices of the delta-wye transformer, select an appropriate pick-up (tap setting) for the SWGR FDR relay. Tape the time-current characteristic curve for the relay to the light table and place figure 4-6 over this curve as before. Line up the relay "1" vertical line with the selected tap setting previously sketched at the top of the curves. Select both tap and time-dial settings which result in the optimum protection and coordination. Remember that the relay curve must be below the T2 through-fault protection curve in addition to complying with the inrush point and NFPA 70 limits. For computer plotting programs each tap and time dial setting can be viewed on the CRT workstation screen and the optimum setting selected. The settings listed below and illustrated in figure 4-7 were selected for the SWGR FDR relay.

(1) Tap (pick-up)=8A.

(2) Time dial = 3.

(3) Instantaneous 60X or 34,500A on a 480V base, which is less than the symmetrical short-circuit current at the SWGR bus. Maximum short-circuit current seen by the instantaneous device will be I_{asym} or 88,960A. Asymmetrical current must be considered since all instantaneous devices will see asymmetrical current.

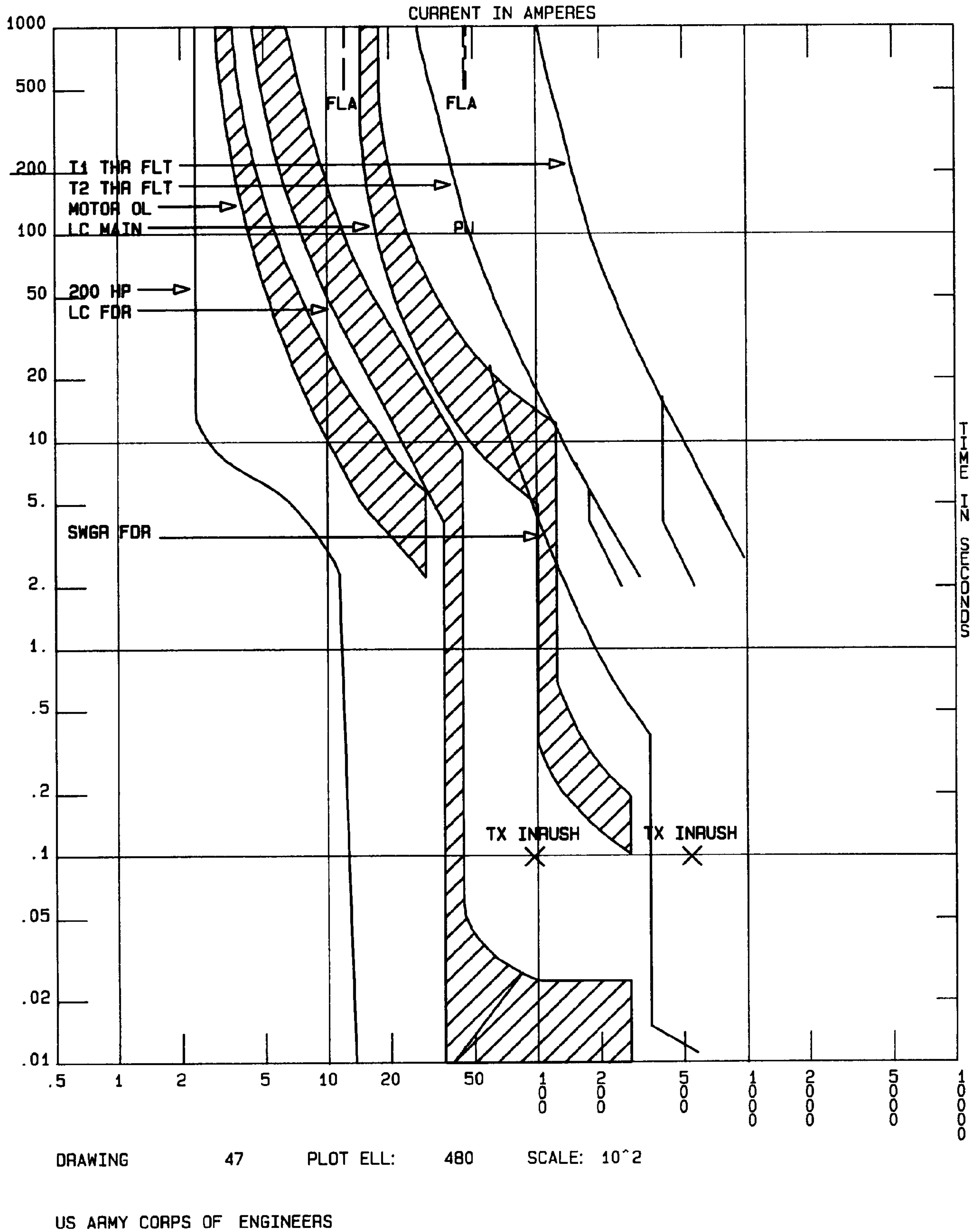

Figure 4-7. Switchgear feeder protection.

g. Switchgear main circuit breaker and relay characteristics. Allowing a convenient margin between the SWGR FDR and the SWGR MAIN, select appropriate tap and time dial settings for the SWGR MAIN relay. The following settings which are illustrated in figure 4-8 were selected:

(1) Tap (pick-up)=2.

(2) Time dial=6.

(3) Instantaneous=NONE, since instantaneous curves for the SWGR MAIN and SWGR FDR will not coordinate. Maximum short-circuit current seen at this point in the system will be I_{sym} or 55,600A.

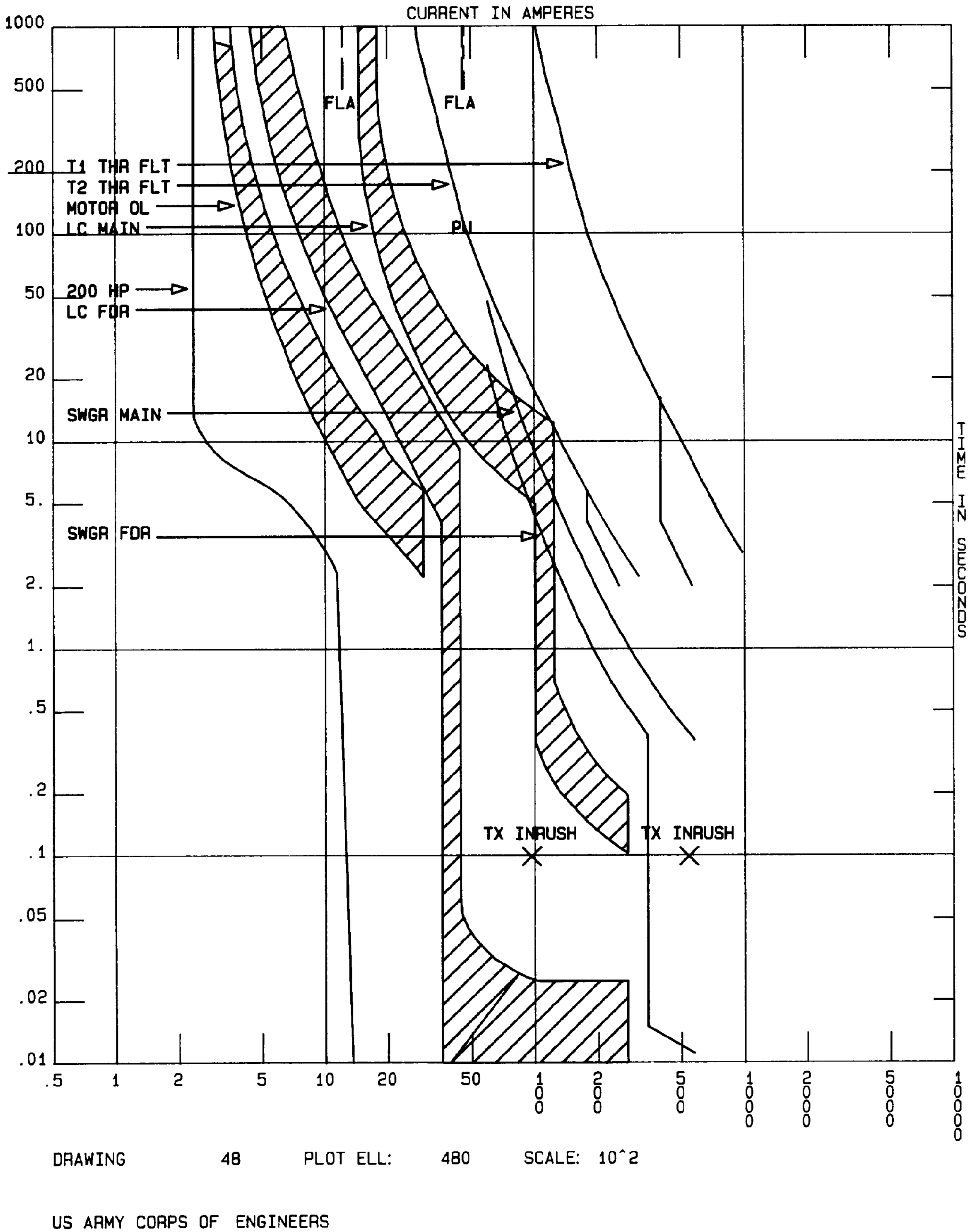

Figure 4-8. Switchgear main protection.

h. Primary fuse characteristics. Tape the characteristic curve of the primary fuse to the light table, place figure 4-8 over the curve, and sketch the fuse time-current curve. See figure 4-9. Although a standard speed, 100E fuse will protect the transformer, a slow speed, 100E fuse is selected to improve coordination with downstream de- vices.

I. Composite time-current curve. Figure 4-9 and table 4-2 show the completed, composite time-current characteristic curves for the electrical distribution system represented by this example. As you can see, protective devices coordination is often more art than science. There are no right or wrong settings, necessarily, within normal limits. There *are* optimum settings. As the system changes, through plant expansion or layaway, the settings may have to be changed. The coordination study is unique for each system, and must be a "fluid" document. That is, it changes as the electrical system itself changes. The time and current settings should be the minimum consistent with the system operating at its rating and maintaining selective coordination.

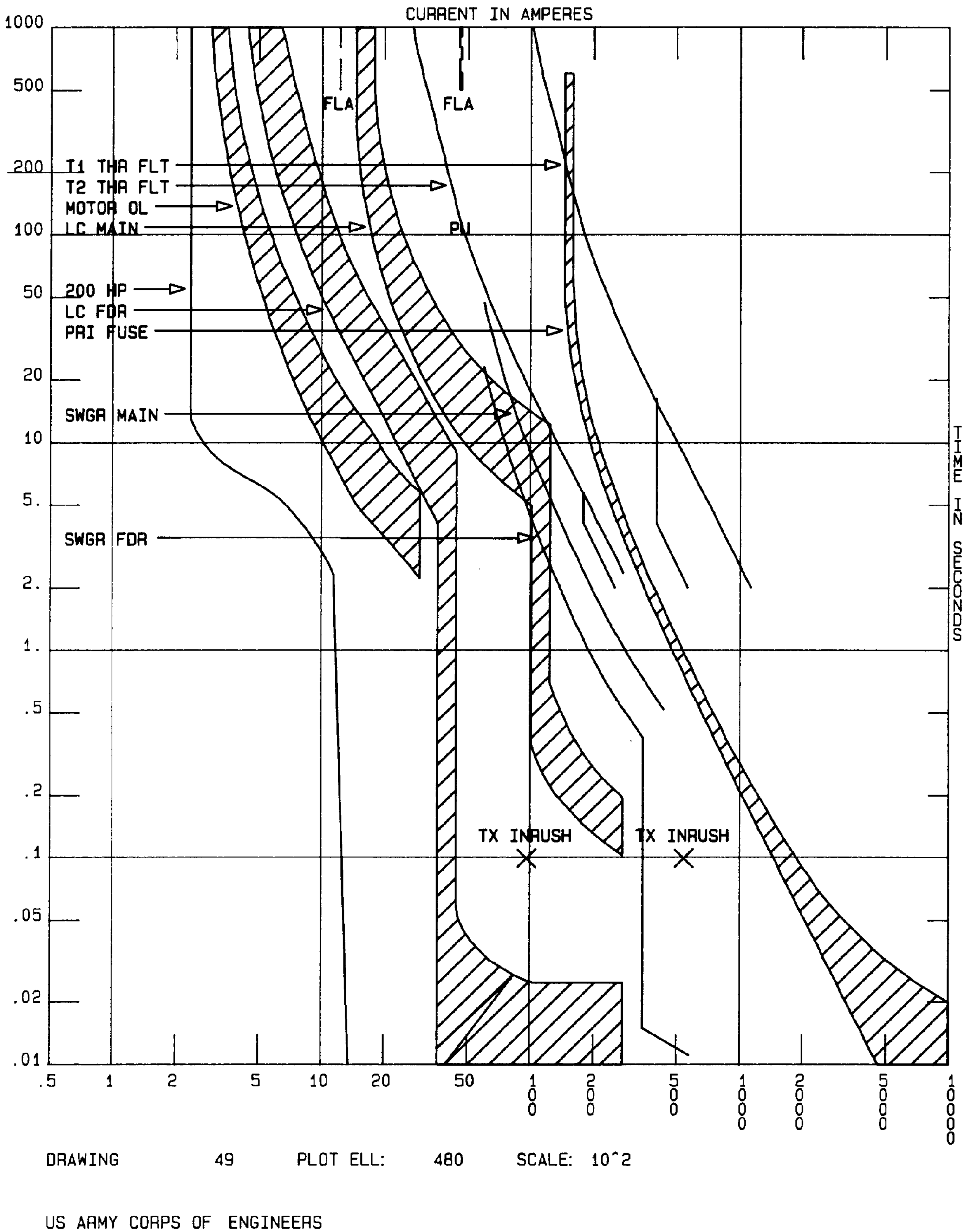

Figure 4-9. Composite time-current curve.

j. Coordination problems. Close examination of figure 4-9 reveals the following coordination problems:

(1) The SWGR FDR, which is also the primary protection for *transformer* T2, intersects with the T2 Thru-Fault curve. The settings for this device should he reduced while meeting the criteria in (a) and (b) below. The LC MAIN and IC FDR settings must also be reduced to maintain coordination.

(a) SWGR FDR relay curve is set above FLA and magnetizing inrush of T2.

(b) SWGR FDR relay curve is set below 6X FLA of T2 and below the T2 Thru-fault curve.

(2) The rating of the primary fuse should he reduced while meeting the criteria in (a) and (b) below. The setting of the SWGR MAIN may also have to be reduced or a different relay characteristic used to maintain coordination. In the final analysis, complete coordination may not be achievable. Figure 4-10 and table 4-8 illustrate improved coordination using reduced settings and solid state circuit breakers.

(a) Fuse curve is above FLA and magnetizing inrush of T1.

(b) Fuse curve is below 3X FLA of T1 and below the T1 Thru-Fault curve.

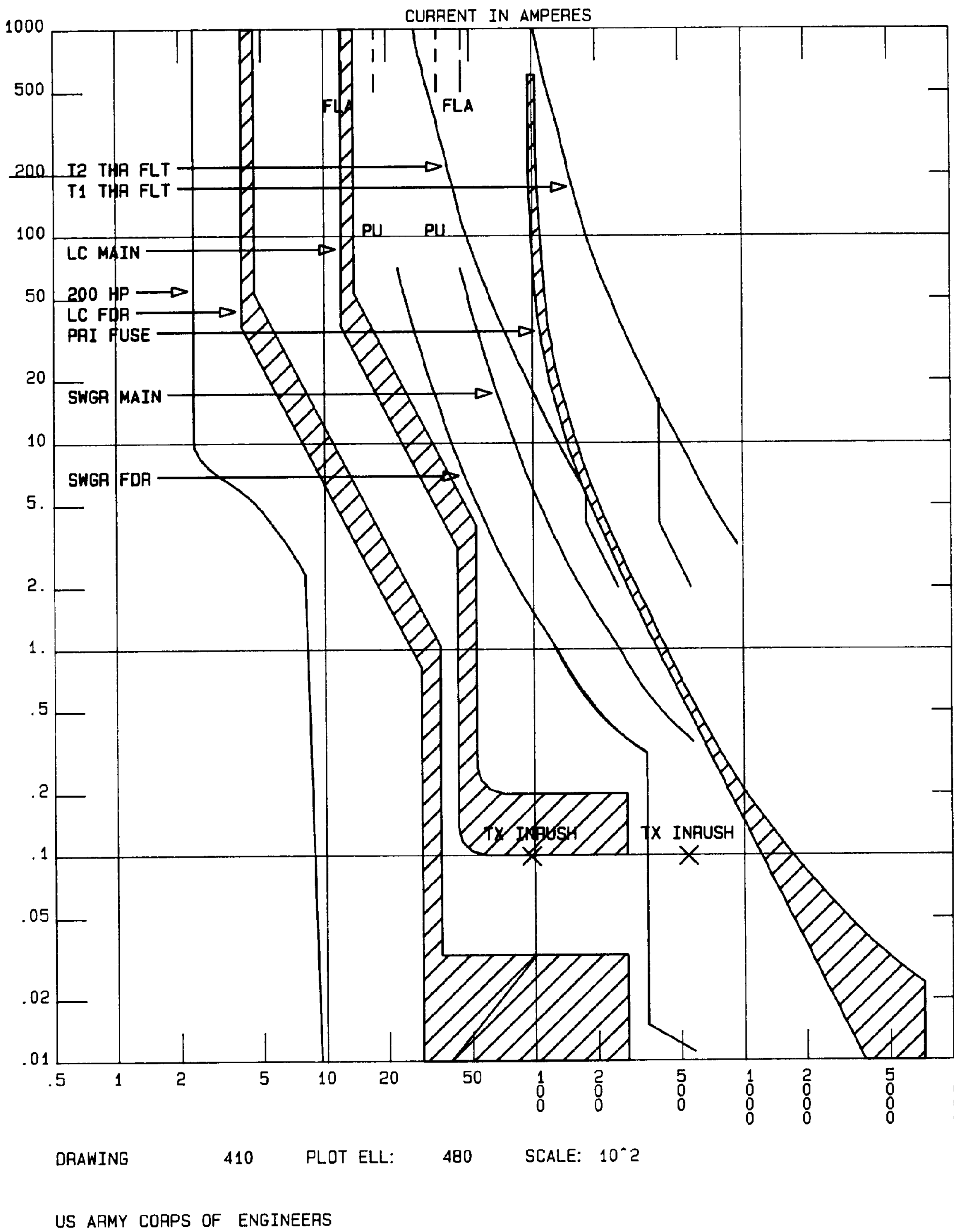

Figure 4-10. Composite time-current curve using solid-state devices.

Table 4-2. Summary of initial protective device settings

Device	ID	Setting
PRI FUSE	F1-1	100A SLOW (34.5kV)
SWGR MAIN	B3-1	Tap=2, TD=6 (400/5 CT)
SWGR FDR	B3-2	Tap=8, TD=3, INST=60 (100/5 CT)
LC MAIN	B5-1	LT=1600A, LTD=MIN, ST=7.0, STD=MIN
LC FDR	B5-2	400A, INST=10.0

Table 4-3. Summary of new settings using solid-state devices

Device	ID	Settings
PRI FUSE	F1-1	65A VERY SLOW (34.5kV)
SWGR MAIN	B3-1	Tap=1.5, TD=8 (400/5 CT)
SWGR FDR	B3-2	Tap=3, TD=8, INST=60 (100/5 CT)
LC MAIN	B5-1	LT=1200A, LTD=2.2 SEC, ST=4.0, STD=0.2 SEC

Table 4-3. Summary of new settings using solid-state devices—Continued

Device	ID	Settings
LC FDR	B5-2	LT=400A, LTD=2.2 SEC, INST=8

4-9. Example of ground-fault protection

Figure 4-11 illustrates possible settings for low-voltage ground-fault protection for the system of this example. The IC MAIN GFP can be set no higher than 1200A pick-up and one second time delay for ground-fault currents greater than 3000A. However, as discussed earlier, such a setting provides limited protection and may not coordinate with downstream standard overcurrent devices. Therefore, separate ground-fault protection at the IC MAIN and IC FDR is shown. The IC MAIN is set at 400A pick-up and 0.1 second time delay, while the LC FDR is set at 300A pickup and 0.08 second time delay.

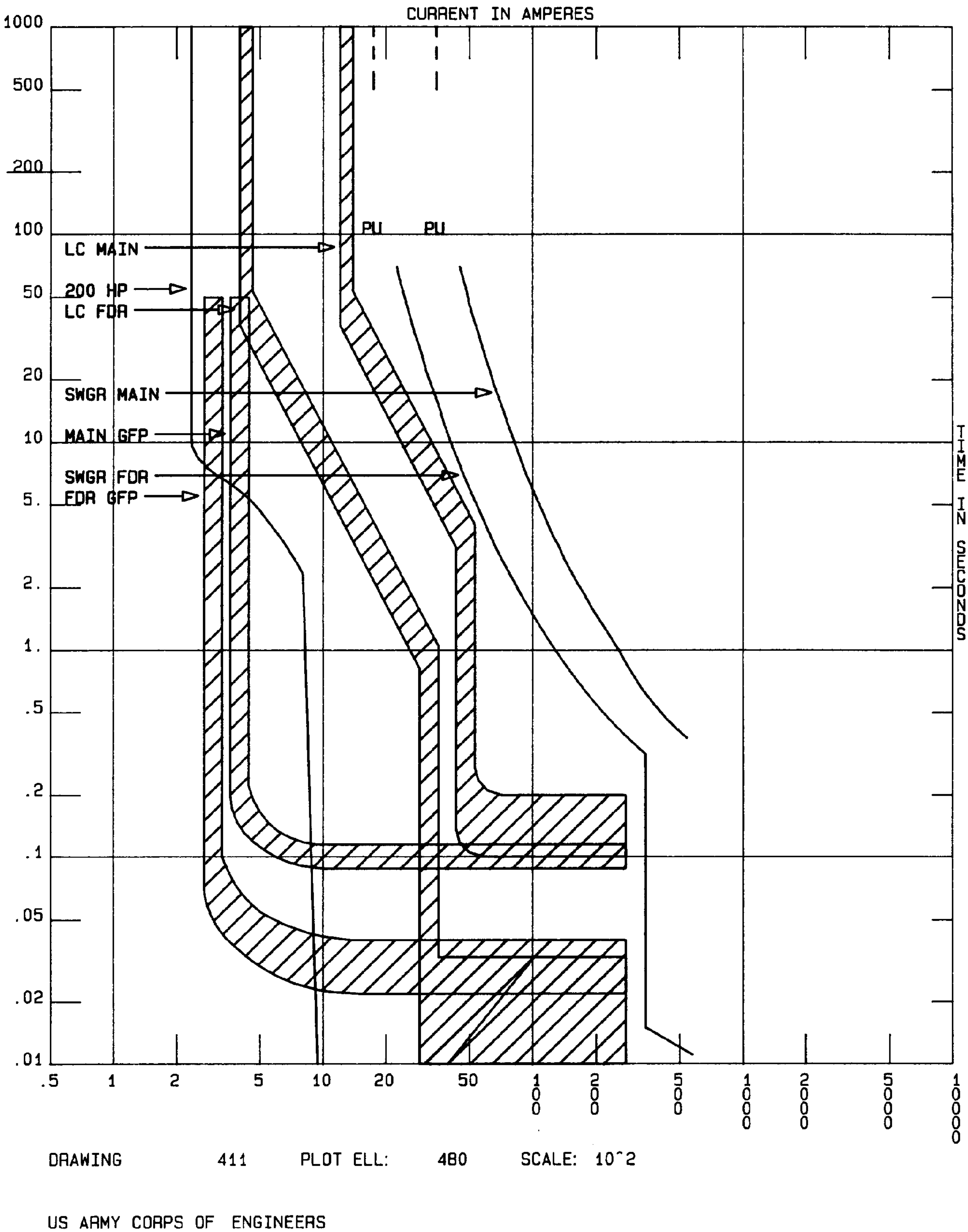

Figure 4-11. Low-voltage ground-fault protection.