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I. INTRODUCTION

In the majority of industrial plants built today, one encounters more numerous and expensive equipment with greater operating complexity. Also, continuity-of-service requirements are increasing and downtime for maintenance and repair must be reduced to a minimum.

The power system engineer involved in the design of the power distribution system for an industrial plant must exercise considerable engineering judgement, as all phases of industrial power system engineering cannot be expressed in numbers or solved by formulas.

In such cases one should base his considerations on facts available such as test data made under specific controlled conditions. Field reports and operating experience must always be weighed very carefully to ensure that all the facts and background information are available.

Also, the designer should consider a number of power system studies. He should think about system grounding and its influence on motor protection, give his attention to the selection of motors and its influence on system design.

This paper focusses all important points that the design engineer has to consider for his system. In chapter 2 basic ideas that the engineer has to consider before he starts his design are examined. Starting with conflicting concepts in power system design, ways for achieving optimization are examined. Also, different types of electrical equipment are compared, as well as different design schemes for parts of a system. The reason for doing so is to keep aware the design engineer with advantages, disadvantages, risks and problems involved with each case.

Chapter 3 is devoted to plants motors and voltage levels. Motor's applicaton, protection and economics are considered in this chapter. Comparison of different types of motors is also made to facilitate motor selection.

In chapter 4 a step-by-step procedure for designing a given project in an industrial power system is outlined. One of the steps which call for coordination study is elaborated to a great extent, since proper selection and coordination of clear fault devices counts for secured continuity of service. A working example in relay coordination for a sub-system is presented at the end of this chapter where every single item in coordination has been analysed.

In the last chapter the design and relay coordination of a complete industrial power system is presented in an official report form. The purpose of this chapter is to illustrate to the plant designer how a client report should be written. Also, it is believed that the reader can benefit by questioning some of the design concepts we put there and going back to this paper or to some of the references for an answer or an explanation.

Finally it is noted that this paper is based on several years personal experience with industrial power system design and coordination of clear fault devices. Experience includes: office design work, supervision or engineering consulting at field installation, field engineering check-out and trouble shooting, mill start-up, examination of field data, discussion with mill maintenance engineers and shop electricians, supervisors, etc.

2. EARLY CONSIDERATIONS AND DECISIONS

In designing a power distribution system for an industrial plant, there are a few fundamental problems the engineer must consider before he even begins his design. Also, he must decide on a few other important points as he organizes his overall plant-design plan.

2.1 Fail-Safe VS Production-Safe

In a fail-safe arrangement, failure of a component, equipment maladjustment or operating error shuts down the associated equipment without damaging it. In a production-safe arrangement, everything is set up to keep the process going. The designer needs a clear understanding of these two conflicting concepts to best balance them in the design for any specific plant process.

Several possibilities can be considered in engineering this optimum balance.

1) Advance warnings can be provided. The operator can take corrective action before a fail-safe shutdown occurs. In that way, he may entirely avoid the need for shutdown. More frequently, the operator's action cannot prevent shutdown but he may achieve an orderly one, permitting faster restart after the cause of the shutdown in corrected.

2) Choice of more reliable, time-proved equipment may lessen the need for some of the fail-safe arrangements.

3) Use of two half-sized units instead of one full-sized, or

even better, use of one full-sized unit as "stand by". This may lessen the seriousness of lost production.

4) Better annunciation systems may find the cause of shutdown faster, permit an earlier restart.

Possibilities one and four are related ones, since both deal mainly with instrumentation. Dollarwise, they are more attractive than possibilities two and three, because in most of the cases it involves some additional instrumentation. Use of "stand-by" equipment is obviously the most effective way of reducing the lose of production, but it involves a high initial cost for installation as well as a maintenance cost.

Use of more reliable, time proved equipment has been proven to be the most optimum possibility for almost ninety percent of the cases in today's industrial plants. However, the engineer has to consider every possibility available in order to get the best optimum for his particular problem.

2.2 Drawout VS Fixed Components

Almost all types of switchgear and control equipment, and many components, are available as drawout. Drawout equipment has many advantages:

1) A spare device may be quickly inserted, to replace any one of several identical devices when one of them develops trouble.

2) Maintenance men get greater accessibility and ease of repair,

as well as safety, working on a device after it is withdrawn.

3) A test arrangement is frequently available with drawout equipment, so the control can be tested with power connections de-energized and safely isolated.

4) The device may be fully withdrawn and tested on a separate control source. In that way, the source used with in-service equipment cannot be damaged.

Many of these advantages apply to relays and meters as well as circuit breakers, contactors, combination motor controllers and drawout fuse-and-switch combinations.

Major difficulties associated with drawout equipment are:

1) Misalignment between the device and its receiving compartment.

2) Inadequate current-carrying capability of the power interconnections.

3) Rapid reduction of conductivity at interconnection points, for chemically contaminated areas.

These difficulties, however, can easily be overcome by considering them in the early design stages. In case one and two, one may obtain very positive results by specifying the appropriate equipment and instructing the appropriate maintenance procedure for his particular problem. In case three, a very common practice is to build a pressurized electrical room in contaminated areas.

2.3 Fuses VS No Fuses

Fuses have centain distinct advantages. Several areas of consideration are involved here: control fuses, metering fuses, protective-circuit fuses, power-circuit fuses. Several types are available: current-limiting and non-current limiting, Form I or Form II, standard-time or time-lag, etc.

1) They supply good protection for many types of control equipment, current-limiting fuses in particular.

2) Make an economical fault-clearing device for system with high interrupting capacity.

3) They permit smaller cables in many cases, still providing adequate short-circuit protection for cables.

4) Damages from high-magnitude phase to phase faults are frequently less severe when current-limiting fuses provide the protection.

5) Their fast operation or severe faults makes the voltage dip as short as possible.

However fuses have disadvantages too:

1) They exhibit "erratic" interruption action.

2) Fuses of very high ampere rating and fuses rated above 600 Volts are relatively expensive to replace.

3) The user must rely on the fuse manufacturer's test data and reputation, since to be completely tested, the fuse would have to blow.

4) Since fuses have wide time vs current bands, they frequently limit good overcurrent protection and coordination.

5) Because of the many variations of transformer connections in use, very high voltages may result when one of several fuses blow, changing voltage distribution to the transformers.

The electrical engineer must always consider these possibilities when he applies fuses on his power distribution system. He also must carry in mind that in some situations a fuse will blow with no apparent reason. There may be several reasons. Perhaps the wrong fuse had been initially selected or the wrong replacement used. Consequently the fuse blew unnecessarily on load currents, motor starting current, transformer magnetizing inrush or an external fault which should have been cleared by another device. Perhaps the fuse connection overheated and melted the fuse. Or the fuse may simply have deteriorated with time.

2.4 System Grounding

Modern plant-distribution systems of 2.4, 4.16, 6.9 and 13.8 kV are usually resistance grounded (although sometimes they are solidly grounded, occasionally left ungrounded). Plant-600V and less systems are usually solidly grounded. Especially these of 208/120 V systems. This is because single phase 120 V systems must be grounded on one side to meet the National and Canadian Electrical Codes.

The varieties of system grounding that the engineer must consider for the various voltage levels in his particular design are the following:

a) Solidly grounded system:

The typical level of available ground-fault current that can be expected from this type of system grounding is of the same order of magnitude of fault current as that available from a three phase fault. Many industries have, in the past, utilized this method of system grounding for low voltage systems (600 V and below). One reason for this is that no expense is necessary for reactors. Another is that low-voltage switchgear almost universally uses direct acting series trip devices which usually require high current magnitudes to detect faults to ground unless supplementary ground-fault relaying is used. Provided the ground fault current is not limited to a value less than the pick-up value of the circuit breaker instantaneous trip, damage for high fault current is minimized because low-voltage protective devices are extremely fast in operation. However, although with this grounding system no intentional impedance is inserted between system neutral and ground, the impedance of this ground fault return path from faulted point is subject to many influencing variables and in fact may be so high as to limit the ground fault current to an undesirably low level. Since reliance is placed upon the phase overcurrent devices, it is possible to have a destructive arc of several thousand amperes for several minutes duration without initiating an automatic trip. This condition is know as a low level arcing ground fault. Solid grounding of the neutral is objectionable particularly in the pulp and paper industry because a ground fault can result in an immediate machine outage and subsequent loss of production.

b) Low resistance grounding system:

This type of grounding offers many of the advantages of solidly grounded system while limiting the ground fault current to a value typically in the order of 400 A . The value of resistance connected between the transformer secondary neutral and ground is calculated from the transformer phase voltage and the value of current required to relay off the defective portion of the system under ground fault conditions. The disadvantages with this type of grounding system however is that again a ground fault can result in an immediate machine outage and subsequent loss of production.

c) High resistance grounding systems:

High resistance grounding offers many of the advantages of both grounded and ungrounded systems, including practical suppression of transient overvoltages, reduction of equipment damage due to ground fault and the ability to continue production with a ground fault on one phase. The value of resistance connected between the transformer secondary neutral and ground is calculated to limit the flow of ground fault current to a value equal to or slightly greater than the capacitive charging current of the system. These current values are typically in the order of 1-2 A for 480-600 V services, 2-5 A for 2300-4160 V services and 5-30 A for 6.9-13.8 kV services.

High resistance grounding has been applied on a great many 3 phase, 3 wire system that operate in the "no trip for phase-ground fault" mode for up to and including 4160 V. Experience has proven it successful, indicating that the persistance of ground-fault current on systems at these voltages is tolerable.

While there are high resistance grounded systems at 13.8 kV levels, most are relayed off for phase-ground faults. At present, there is insufficient data to make a fair evaluation of those that operate in the "no trip" mode.

d) Ungrounded systems:

The feature of this type of grounding is that the transformer secondary neutral is not intentionally connected to ground but in fact the potential "floats" at the neutral point. In the event of a solid phase to ground fault, the ground fault current flowing will be small, typically in the order of 5 A and is determined by the system capacitance to ground. The system would not trip when only one phase is faulted to ground hence production may be maintained. A ground indicating system is generally built into the switchgear to indicate the presence of a grounded phase. The system may be tripped when a second phase is faulted. A trouble-shooting procedure must be initiated upon detection of the first phase to ground fault and corrective measures must be taken.

Although many industrial installations have used grounded systems extensively on low voltage levels (600;480 V) it has been discovered that multiple motor failures were due to severe overvoltages caused by arcing or resonant ground faults with the resulting 10 to 20 times normal voltage.

It is obvious from the above discussion that the high resistance grounding system offers many more desirable features than any other systems. But good engineering requires consideration of all systems and implementation of the one that is considered to be the best for the particular plant-system.

2.5 Control Schemes

Control schemes require some careful thinking. In the early planning stages the engineer has to commit himself to a voltage level. There are many control voltagesin use. With ac, one might choose 50 V and below, 120,230,460 or 575 V. With dc the choice runs to 6,12,24,48, 125,250 or 600 V. AC schemes at 50 V and below come in where a higher voltage might endanger human safety. However, low voltage control has the disadvantage of poor conduction when several interlock contacts are in series and dust may settle on them. Many engineers including the author feel that the optimum voltage level in ac control is at 120 V and that of dc at 125 V. These voltages are not quite as dangerous from a shock point of view as higher voltages, and this level does reasonably well in overcoming problems of dust accumulated on contacts.

If an engineer can justify the cost of the arrangement, it is recommended that control schemes include as many as possible of the following features:

a) An individual control transformer should be used with each starter in motor control centers (MCC's) and medium voltage starters (MV's).

b) All starters in MCC's and MV's should be kept "unisource" i.e. no external control power shall enter the starter compartment (Interlock accomplishments will be explained later).

c) A special process control panel (PCP) 2 phase 3 wire (120/240 V) or 3 phase 4 wire (120/208 V) should be used for powering all control devices associated with a particular process area. The PCP should be fed from an isolated control transformer of appropriate kVA rating, which in turn should be fed from any of the MCC's of that area.

d) For each process area one or more relay panel should be used to accomplish all interlock requirements and to serve as marshalling cabinet for all field instruments (switches, solenoids, etc.).

e) All switches and motors either contributing to an interlock or just to an alarm should be interfaced with a relay.

f) Firm dc control power, either for normal or emergency use, should be self-generated. Both main switchgear (SWGR) and power distribution center (PDC's) should work from it.

g) Dc control power should not leave a cubicle in SWGR nor a unit in PDC. If remote indicating lights are required, auxiliary contacts 52a and 52b may be used in conjunction with an external ac source. Also, if additional permission to close circuit or interlocks to trip circuits are required, double-voltage relays may be used inside the unit or cubicle with dc contacts across the close and trip circuit as required and ac coil in conjunction with the combination of interlocks and permissives and an external ac source.

Control schemes which include aforementioned features have certain distinct advantages:

a) They are easy for operators and maintenance people to understand and maintain.

b) They are easy for adding, eliminating or changing interlocks, if process logic is modified.

c) They are easy to change relays to micro-electronics if automation becomes more involved.

d) They ease trouble-shooting, thus permitting fast restart after a shutdown.

e) They ease intentional by-pass of interlocks for repair or replacement of an instrument or component while plant is producing, thus preventing unnecessary shutdown.

3. MOTOR SELECTION AND ITS INFLUENCE TO SYSTEM DESIGN

For most of the industrial power system, motors constitute almost 90% of the load. It is therefore important to compile a complete list of decisions associated with the plant's motors. At the top of the list, motor application is closely tied to distribution voltage, and this in turn is influenced by power rating of electric equipment.

Distribution-system voltage levels for most industrial plants utilize 575 volts (460 in U.S.A.) to operate motors of 200 hp and below. The 575 V system used in Canada for 550 V motors has some advantages: its lower amp-per-hp relation requires less conductor material.

Low-voltage power circuit breakers may have higher interrupting rating at 460 than at 575-V. For example, a breaker rated 25 000 A average assymetrical at 575-V will require a rating of up to 35000 A at 460 V. This is the interrupting range if one uses instantaneous overcurrent direct-acting trips on the breaker. When short-delay trips are employed instead, for selectivity, the rating is 25 000 A at both 460 and 575 V. However, such short-delay trip breaker can still be used a larger transformer MVA rating at 575 than at 460 V, because amperes per MVA are lower at 575 V.

Small motors should be rated 550 V (or 440 V in U.S.A.) three phase whatever their hp rating, if they are an integral part of an important process served by larger 550 V (or 440 V) motors, even though the cost of 550 V motor starters may seem high compared to the cost of a single phase starter especially for fractional hp motors.

Transformed plant-distribution voltage usually can be either 4.16 or 13.8 kV. Since maximum interrupting rating of commercially available, economic 2.4 kV equipment is 150 MVA, 2.4 kV is generally considered to place too low a limit on ultimate plant size for use in a new plant. Therefore, substations are often installed to serve local 2300-V motors above 200 hp, with total motor loads limited from about 6000 hp to 8000 hp maximum (depending on motor characteristics and the 150-MVA equipment limit).

Occasionally, where an installation has several large motors rated in the 5000 hp to 8000 hp range, 6.9 kV will be used. In general, however, 6.9 kV is no longer being used becuase it only seldom offers any real economies compared with 13.8 kV.

Equipment at 4.16 kV is usually chosen with a 250-MVA interrupting rating, although some 350- MVA equipment has been installed. In the past, 13.8 kV equipment was usually rated 500 MVA, but 750 MVA and 1000 MVA metalclad switchgear is in use.

Voltage drop caused by starting a large motor on a 4.16 kV system may be a limiting factor; in that case reduced-voltage starting can be considered. A series starting reactor is usually satisfactory although autotransformer starting is still used. Another possibility would seem to be part-winding starting. This system works for 1500 hp and below and is particularly ideal for system with high inertia (ωr^2).

Several large motors in the 250 to 1000 hp range may be served from a 575 or 2300-V substation. In fact, while usual practice limits 550-V motor ratings to 200 hp and below, one may find it pays in a plant to consider 575Vunit subs as large as 2.5 MVA serving motorsin the

250-to-1000 hp range. In such cases one should use air circuit breakers rated 600 to 1600 A as motor starters. Motors above 1000 hp are normally rated 2300 V or higher.

Individual large motors in the 500-to-5000 hp range can be conveniently served from a 13.8 kV system through their own transformers. Some times one can buy both transformer and 2.3 or 4 kV motor for about the same price as a 13.8 kV motor.

Need for surge protection should be investigated for all motors above 500 hp. Little has been published regarding the need for surge capacitors to reduce the turn-to-turn winding voltages when switching on motors. One should investigate this item with the motor supplier. Surge protection against lightning is a necessary consideration. If a plant has open distribution at the motor voltage level, or if it is served at this level from open utility lines one should install surge arresters and capacitors. It is a good idea to locate them as close to the motor terminal as possible - frequently right at the terminals. If the motors are within 100 feet of the bus, just one set of surge arresters and capacitors may be installed and connected to the bus.

Single phasing or voltage unbalance may result from a broken supply-line conductor or blown fuse. When unbalanced voltages are applied to a motor, negative sequence currents flow in the stator and rotor. In such cases it is rather uncertain whether the rotor will overheat sooner than the overload relays trip. If the motor is lightly loaded, stator currents may not be sufficient to trip the overload relays - as a result rotor damage may occur.

Single phasing or voltage unbalance protection requires some careful thinking. Beginning with data from the motor manufacturer, the effect of unbalanced voltages on operation of various motors must be studied. They may not need special protection since sometimes motor overcurrent protection or stator temperature protection may be adequate. However, if motors do need single phasing protection a phase-current or voltage-unbalance relay is recommended.

Squirrel-cage vs synchronous motor is the next decision, concerning motor selection. Frequently synchronous motors above 1000 hp, including their field control, sell for less than squirrel-cage motors. The price difference is significantly influenced by motor speed and enclosure type as well as market conditions. For large hp ratings it is always advisable to evaluate both synchronous and squirrel-cage motors as to cost, maintenance, performance and reliability.

The PF of synchronous motors is unity or leading at all loads up to the hp rating. For large squirrel-cage motors the highest PF at load is about 0.95 lagging; this may drop below 0.9 at low loads. With utility penalties for plant PF below 0.9, synchronous motors can save on power costs.

There is some maintenance involved in synchronous motors which the squirrel cage motors do not need. For example, their field brushes must be replaced at intervals of four to eight months. This can sometimes be done with the motor in service, but usually there are limitations. The field control, too, requires maintenance. To avoid maintenance for exciter-generator commutator and brushes, static exciters are now being used.

Another advantage of synchronous motors over squirrel-cage is that the torque of synchronous motors varies directly with system voltage while the torque of squirrel-cage motors varies as the square of system voltage.

4. ELECTRIC SYSTEM DESIGN FOR A GIVEN PROJECT

In chapters 2 & 3 we examined several basic considerations that determine the character of the electric power distribution. It is time now to start collecting some information and data and do some design work. The electrical project engineer shall conceive the whole project, gather the required information and order his equipment on time for efficient and accurate design of his system.

In this chapter we outline the basic steps that the design engineer shall take to properly complete his project design.

4.1 Study Process Needs, Then Talk It Over With The Utility

Because the process of a new plant determines its electric loads, the electrical engineer benefits from knowing the process and how it will be operated. Complete process information is hard for the electrical engineer to come by. The best practice is to keep constant, detailed liason with process engineers; they can give guidance in many areas.

With approximate total plant requirements determined and physical location of the major loads established, discussions with the electric utility may be started.

Typical information required from the utility includes:

1) Available supply voltages and line arrangements
2) Power-contract conditions and rates
3) Performance records: frequency, type of line faults
4) Maximum and minimum bolted 3-phase fault capacity at the

plant, referenced to initial and ultimate dates

5) Normal, emergency variations in supply voltage
6) Paralleled vs automatic-transfer service
7) Performance of utility relays with which the plant must coordinate
8) Details of utility automatic reclosing.

Once the voltage level, number of lines, etc., are decided, the utility or plant will supply the main ~~incoming~~ substation equipment. Keep future expansion in mind as you determine rating and number of main transformers. Decide whether tap changing under load is needed, and if so, the required range. What off-load taps are needed? Can HV-delta-LV-wye connections be used? (This is normal to get plant grounding via wye-neutral connection.) What transformer protection will be used - HV breakers? grounding switches? transfer trip? or fuses? What protective relaying - time-delay and instantaneous overcurrent? harmonic restraint differential? gas-pressure tripping? gas-accumulation alarm?

Other questions will have to be answered, too: will metering be on primary or secondary? What arrangements are required for supply and location of meters, pt's and ct's? You will also want to discuss right of way of incoming lines, guy wires, etc..

A single-line diagram can now be worked out in conjunction with routing studies. Diagram should show all motors, equipment, ct's and pt's, protective relays and devices.

Decisions in a number of major areas of the distribution system must be made at this time:

Protection: Select types of equipment in light of continuous-current, momentary and interrupting-capacity requirements. Settings (preferably the final ones) should be selected for all protective relays and devices.

Motor types: See chapter 3 for comparison of squirrel-cage and synchronous motors. Also investigate requirements of any special loads such as welders, arc furnaces, etc.

Voltage drops when starting motors: Special types of motor starting may be needed.

Power-factor improvement: Capacitors and change of synchronous motor pf ratings may be advisable.

Cable sizes: Consider initial and future loads, short-circuit and fault-clearing time. Cables fully rated for fault clearing are required in hazardous areas, desirable in all areas.

4.2 Write Specs for Long Delivery Items

Ideal time to order equipment from the designer's point of view is when and only when all system studiens and engineering are completed. But a lot of modern industiral plants are designed and built on a short engineering and construction schedule which may not permit this ideal approach.

If engineering is not complete, the electrical project engineer may elect to order equipment with incomplete specifications. This means serious inconvenience for the equipment manufacturer. His normal procedures are altered, engineering and procurement costs go up.

The experienced energy-systems engineer may wish to consider a different approach: order equipment with complete specs based on his experience and judgement regarding what the requirements are likely to be. With this approach he banks on not having to make too many, or major, changes in the equipment when engineering studies are finished.

While this approach involves certain risks, the author believes some engineers could use it successfully. Complete specifications aid in purchasing equipment economically. A few minor changes may turn out to cost much less than the original saving from purchasing with a complete specification.

In one particular area - the protective relaying - detailed specifications should be provided to the successful bidder. It is desirable also to specify final relay and protective-device settings to be used in the plant, and have the manufacturer incorporate them before the equipment is shippted from his factory.

4.3 Make a Short Circuit Study

Literature on short circuit philosophy, short circuit calculation procedures as well as detailed worked examples can be found in any of the References 1,2, and 3.

The important thing for the design engineer in short circuit analysis is to collect all required data, to count for all sources involved and to interpret properly his result.

The basic steps of short circuit current calculations are the following:

1) Collect all data for single-line diagram.
2) Obtain single-line diagram.
3) Make sure that single-line diagram includes all of the following data items:
   a) Utility tie sources data: MVA capacity or at least breaker rating.
   b) Generation data: kVA, voltage, speed and subtransient reactance (x"d) of all machines.
   c) Motor data (induction and synchronous): List all 2.4 kV and higher voltage machines individually hp, PF, speed, locked rotor impedance (x"d) or code letter or locked rotor current.
   d) Motor data (550 volts and less): Sum of total connected hp or each bus or feeder.
   e) Transformers data: kVA, voltage levels, winding connections and impedance.
   f) Cables and aerial lines data: Ohms per phase for total length or No. of conductors per phase, voltage rating, size of conductor, copper or aluminum, length of run, type construction.
   g) Interrupting device rating data: Momentary and interrupting rating of all significant circuit interrupters.
   h) Circuit arrangement data: Accurate circuit arrangement of system - locate and identify N.O. or N.C. tie breakers and tie lines, etc. Determine maximum and

minimum generation conditions.

4) Convert the system single-line diagram to an equivalent impedance diagram. The following calculations and conversion are required:

   a) Select base kVA and base voltage.

   b) Calculate base current for each voltages and base ohms.

   c) Convert equipment data to common study base kVA and for all items under step 3 (a) through (h).

   d) Complete impedance diagram with all per unit values in place.

   e) Select critical buses where duty is to be calculated.

   f) Rearrange diagram as required for convenience in calculation.

5) Solve for symmetrical short circuit currents.

   a) Combine series and parallel elements until one single equivalent reactance is obtained.

   b) Multiply reciprocalof reactance by base current for short circuit currents.

6) Determine duty for each interrupting or switching device.

Apply multiplying factors to symmetrical current values to determine offset or asymmetrical current values as needed for duty check or coordination.

If the fault current calculations have been performed for an existing system or if some of the equipment (Sec. 4.2) has already been ordered, the calculated duty must be checked against device rating.

4.4 Make a Coordination Study

Even on the simplest industrial power system, there will be two or more circuit breakers, or other circit protective devices, between a fault and the source of power. In order to localize the disturbance, as much as possible, these devices should be selective in operation so that the one nearest the fault on its power-source side will have the first chance to operate. If , for any reason, this protective device fails to function on schedule, the next device in the chain, that is, the next one on the upstream side, must be ready to take over the job of opening the circuit. To accomplish this objective, the fault current protective devices must be selected to operate on the minimum current that will permit them to distinguish between fault current and permissible load-current peaks. They must function in the minimum time possible and still be selective with others in series with them. When these two requirements are met, the damage to equipment, or the interference with production due to loss of power during a short circuit, or both, will also be at a minimum.

The first step required to perform a protective device coordination is to collect data for single-line diagram. The following data items are needed for the coordination calculations:

1) Go back to original single-line diagram (Sec. 4.3) and locate all significant circuit interrrupters-circuit breakers, fuses, contactors and switches.
2) Determine the rating of all of these devices - continuous current, momentary and interrupting currents as applicable.

3) Determine range of adjustments for the various devices as applicable, such as:

a) Breakers - (i) Trip coil rating

(ii) Trip coil pick-up adjustment range (long time)

(iii) Short time device - pick-up and time adjustment

(iv) Instantaneous device pick-up range.

b) Fuses - current rating

c) Relays - (i) Current tap range (time delay)

(ii) Current pick-up range (instantaneous)

(iii) Current transformer ratio

(iv) Current flow for direction of operation directional relays only.

d) Thermal overload relays for motors - range and adjustment.

4) Accumulate time-current characteristic curves for all devices listed above.

5) Locate all grounding devices - resistors and reactors and list ampere and time ratings.

After the single-line diagram has been completed and the necessary short circuit calculations made, the next step will be to examine the system for the device or devices which are the most important in the protective arrangement of the system. In general, start at the extremities which will be the load devices, and work back towards the power source.

Usually the load which will be the one of prime interest will be the largest single device having the highest normal current. Motors, because of their overcurrent condition during the starting period will, in most cases, be the critical branch circuit for coordination. However, other special loads may have higher settings, and all the various branch circuits should be surveyed to insure that the highest one will be selected.

Make a simple single-line series diagram of the specific circuit to be studied, starting with the selected end load, through the cable circuitry, low voltage bus and breakers, and the transformer, if any, back toward the power source. Identify on this simplified single-line the end load, the breakers and their type of characteristic and range of adjustment. It is a good practice to draw this specific single-line diagram in the top right hand side of the coordination paper as shown in Graph 4-1 at the end of this chapter. The sub-system illustrated in Graph 4-1 is a feeder from the general system considered in the next chapter. The short circuit and equipment dada listed in the diagram are also taken from chapter 5.

The next step is to place on the coordination paper all the significant "landmarks" which will have a bearing on the selection of settings for the protective devices. Among the "landmarks" are:

1) Low-voltage fault current levels.

The momentary short-circuit currents for the significant low voltage buses which are a part of the single-line diagram for the coordination plot. In our example, Graph 4-1 we have:

MCC BUS COORDINATION - MOM. 17 000A

PDC SWGR BUS COORDINATION - MOM. 48 900A

2) Medium or High-voltage fault current levels.

The momentary and the interrupting short-circut currents on the medium or high-voltage buses which are also a part of the single-line diagram. Note that all of the current values to be plotted on the coordination sheet must be represented at the same voltage. Therefore, the medium or high voltage short circuit currents must be multiplied by the corresponding voltage ratio to get their equivalents. In our example, Graph 4.1, we have

$$\text{MAIN SWGR. BUS: MOM.} = 16\,900\,\frac{13\,800}{600} = 390\,000 \text{ Eq. amperes}$$

$$\text{INT.} = 9060\,\frac{13\,800}{600} = 208\,000 \text{ Eq. amperes}$$

3) End device currents.

Few currents are considered here. The full load current and the overcurrent if any. Also, in the case of a motor, starting current or locked rotor current. These currents may be taken from manufacturers data or standard books in some cases. They should be indicated on the drawing, so that the setting of the protective device may be set such that it will not trip out on starting in such or on anticipated overload conditions.

4) Transformer Currents.

The next device upstream whose "landmarks" will need to be added to the coordination plot is the transformer. Because of the importance of transformers in power systems, their protective requirements have been more explicitly defined.

Whatever primary protective device is applied to a transformer, it must allow at least rated full load current of the transformer to flow continuously without tripping. Rated transformer current, in the long-time region of the curve plots, will stand as a lower limit, below which the primary overcurrent protective device must not operate.

Another lower limit point is the magnetizing inrush current which must be passed to permit energizing the transformer. For primary fused unit substation transformers, this limiting condition is observed by selecting a fuse which will not operate or be damaged by an inrush current whose integrated time-current effect is the equivalent of 8 to 15 times rated transformer current for 0.1 second, or a relay whose instantaneous device will not trip in response to this current. These two lower limiting points can broadly define a lower limiting curve below which the transformer protective device must not operate. In our example Graph 4-1 we have:

Transformer F.L.C. = 1929 | from N/P amperes @ 600V S.S.

Transf. MAG. INRUSH = 1929 x 15 | SAVE FACTOR = 29 000 A @ .1 sec

The upper limit of allowable current in the transformer is the transformer withstand (TWS) point or ANSI point. This point is provided by American Standard, which requires that a transformer must be able to withstand, without injury for a specified time interval, a short circuit on the terminal of any winding or windings. The specified time interval corresponds to the specific value of transformer impedance. Graph 4-2, at the end of this chapter, illustrates the time versus transformer impedance relationship, which is a part of finding the ANSI point. This graph gives the relationship between the multiple of full load current and the time duration that the transformer must withstand. For impedance values between 4% to 7% the per-unit current is the reciprocal of the transformer per-unit impedance on its own base. This gives the maximum possible fault level for a three-phase secondary fault.

The final part of this current calculation is to multiply the current value by a factor which is related to the transformer winding connections. This factor is 0.58 for a transformer connected in delta on the primary side and grounded-wye in the secondary side (which is a very common configuration). For any other transformer winding configuration the factor is 0.87. The reason for this factor is to provide a point on the coordination plot which will define the protective device operating zone, such that the transformer can be effectively protected. If the primary protective device characteristic lies to the left and below this point, it means that the device will operate to protect the transformer from a line to ground fault on its secondary side, which is not removed by a secondary protective interrupter. In our example, Graph 4-1, we have:

T.W.S. = 1929 (TRANSF. F.L.C.) x18.2 (MULTIPLE FOR 5.5% IMP.) = 35 100 A for 3.5 sec.

ANSI point (to count also for ground fault)

= 1929 x 18.2 x .58 (FACTOR FOR SECONDARY GRD-WYE) = 20 200 A for 3.5 sec.

5) Medium (or high) voltage relays.

The final device whose "landmarks" need to be put on the coordination plot is the medium-voltage relay and its current transformer combinations, if any. The usual approach for locating these points is to consider first the lowest pick-up point for the CT and relay combination. Then having located it, mark in the various other tap points for the relay. At the end only one tap out of a selection of six or seven will be used, but having all available pick-up points located will ease the final selection of the proper tap. The pick-up is established by multiplying the current transformer ratio by the ampere tap of the relay times the voltage ratio. The last factor is used when the high/medium voltage device is related to a diagram based on a lower voltage. This can be illustrated more clearly by considering the example we used in Graph 4-1. The 50/51 phase overcurrent relay we use in the 13.8 kv feeder circuit 1-2 is a C.G.E type IAC time o/c relay. The particular type we use has an induction unit (i.e. the time delay element of the relay) 4 to 16 A range with taps at 5.0, 6.0, 8.0, 10.0 and 12.0 A, and an instantaneous unit range from 40 to 160 A continuously adjustable. The current transformer rating is 150/5 A. The transformer ratio is 30 to 1. First establish the time delay element relay pick-up point at the minimum tap setting of 4 amperes:

$$\text{Current pick-up} = 30 \times 4 = 120\ \text{A} \quad @\ 13.8\ \text{kV}$$

$$= 30 \times 4 \times \frac{13.8}{.6} = 2760\ \text{A} \quad @\ 600\ \text{V}$$

This is the lower limit of the pick-up range. By substituting other tap values, the pick-up currents for all taps are found and shown on the coordination plot, Graph 4-1. This establishes the pick-up range available. The actual tap and time dial setting will follow later.

The instantaneous unit of the relay will have a range from Current pick-up lower limit $= 30 \times 40 \times \frac{13.8}{.6} = 27\ 600\ \text{A} \quad @\ 600\text{V}$

to

Current pick-up upper limit = $30 \times 160 \times \frac{13.8}{.6} = 110400$ A @ 600V

In looking at Graph 4.1 with only the "landmarks" in place, there are a number of "reasonableness tests" which can be applied at this point. By identifying any unusual locations in the arrangement of the "landmarks" now may lower the frustration level later when the device characteristics are to be drawn into place.

One test is to note whether the full load current values for the end device (200 hp motor in our example) and the full load amperes of the transformer are more to the left of the diagram, and the fault levels at the high and low voltage portion of the system are further to the right. Another test is to note that the inrush point of the transformer is about one decade higher than the full load current. A very important test is to note that the tap range of the CT and relay combination lies in the same zone as the one to six times full load current of the transformer. If it does not happen, calculations may be checked and, if no mistake found, it may well be that the CT ratio and relay tap range has been improperly selected. A rule of thumb for the selection of current transformer rating is: 1) the primary current rating of the CT should be about twice the full load current of the power transformer and 2) the relay tap range, in combination with CT ratio, should permit settings down close to transformer full load current.

The final step in relay coordination study is to locate the various time-current characteristics on coordination plot for protective devices used. The following comments on the step-by-step coordination procedure are to clarify the reasons for placing the characteristics of the protective devices for the example we consider at the location shown.

1) 600 V motor starter thermal overload relays and fuses -

The overload relay element is usually selected to have a continuous rating slightly more than the motor full load current for a motor carrying a steady load. In our example the motor full load current is 207 A . Looking at MCC manufacturer heater tables, a 230 ampere rated relay element is the next rating above 207 A . The pick-up point of the curve is place at 230 A and the characteristic traced on to Graph 4-1. Note that the bandwidth of the thermal overload must not intersect the motor current line. The starter fuses are used for instantaneous protection only. They are selected to have their characteristics enough above the locked rotor current to avoid nuisance trip-out. In this case the English Electric form II type C 300A fuses (Graph 4-3) have been chosen to do the job. As we see in Graph 4-1 at 5 seconds (motor's estimated acceleration time) there is enough space between the motor current line and the fuse characteristic curve.

2) MCC feeder breaker (Graph 4-4) and fuses (Graph 4-5) -

The full load current of the MCC must be somewhat less than the breaker coil rating. In our example the MCC full load current is 451 A and a trip coil of 600 A has been selected. The long time pick-up is set at 100% of coil rating and the 1B characteristic is selcted. The short time pick-up is set at (7x) and the 2B characteristic is selected. The settings and the selection of the characteristics were made for the following reasons:

a) The long time pick-up must permit MCC full load current through; Compare MCC F.L.C. 451 A vs breaker lower pick-up point 500 A . Also, it must coordinate with the motor overload relay; There must be some clearance between the long time pick-up and motor O/L curves to allow the latter to clear its own fault.

b) The short time pick-up must permit the larger motor to be started while all the other load of the MCC is on. That is, it must allow 1344 $(= 451_{\text{MCC F.L.C.}} - 207_{\text{MTR F.L.C.}} + 1100_{\text{MTR L.R.C}})$ A for five seconds through without tripping. Also it must be to the right of x_3 duty and without overlapping with motor starter fuse curve. Note that an instantaneous element might have been used for short time protection of the MCC. But since there are fuses in the 600 V air circuit breaker the characteristic of the CLF 800 A fuse coordinates properly with motor fuse and MCC duty as shown in Graph 4-1. The circuit breaker fuses provide additional protection features which will be discussed in chapter 5 where the overall system is considered.

3) The 13.8kV feeder circuit phase overcurrent relay (Graph 4.6)

The final device to be set is the high voltage relay. Setting the time delay element of the relay the following should be carried in mind:

a) Since there is no secondary breaker for the transformer the primary device must be set at 250% or less of transformer full load current (NEC requirement).

b) The time delay element must clear the inrush point and protect the ANSI point, and

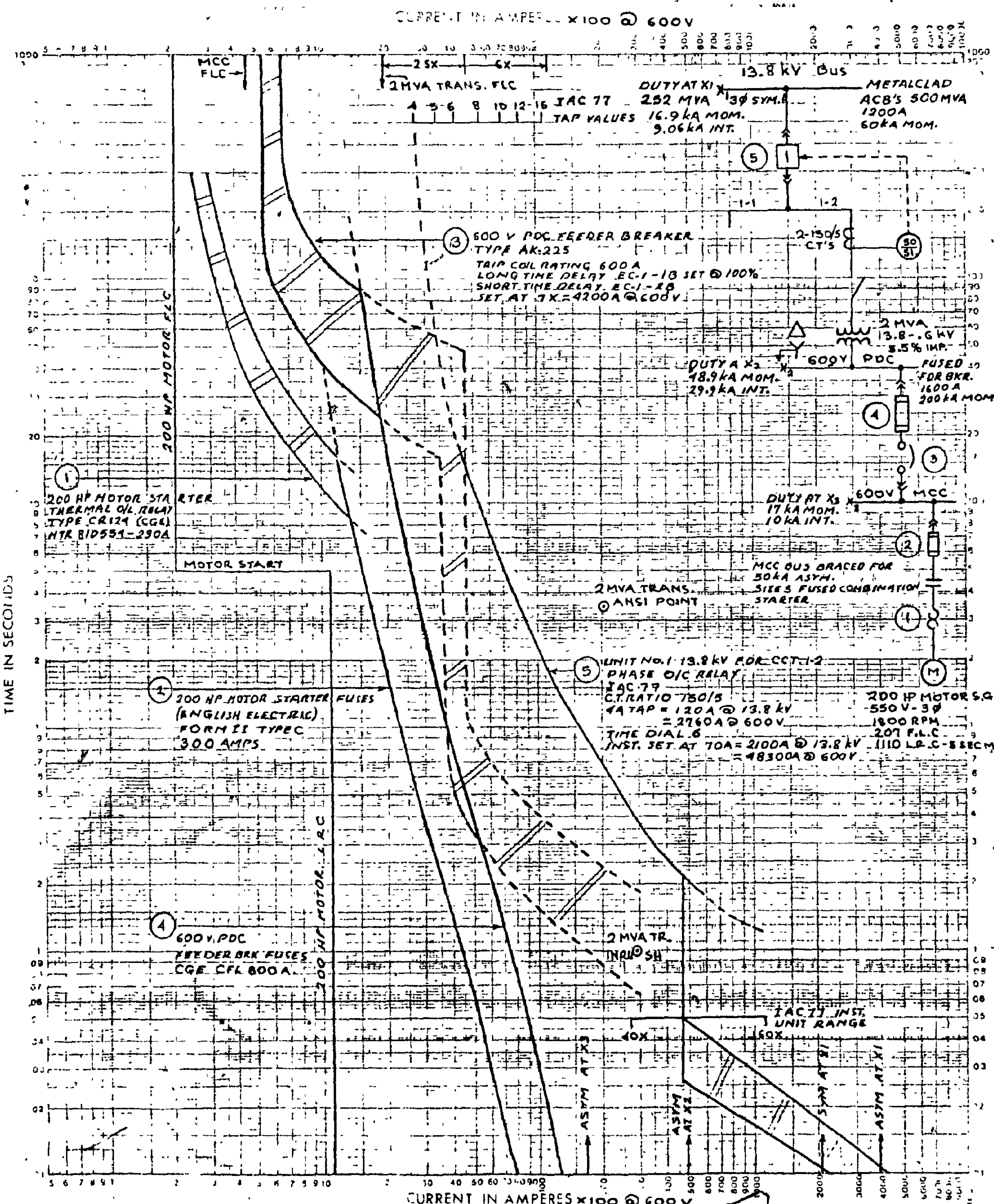
c) The o/c relay characteristics must not overlap with 600 V PDC protective element characteristics.

The instantaneous element must be set above the inrush point but not so high that it would protect the 600 V PDC bus.

In our example a type IAC77 with extremely inverse time characteristics has been used in combination with 150/5 current transformer. The time element is set at 4A taps which gives $4 \times \frac{150}{5} \times \frac{13800}{600} = 2760$ A at 600 volts, which is only 150% of transformer's full load current (Transf. F.L.C. = 1929A). The time dial is set at 6 and the characteristic curve, as shown in Graph 4-1, is safely to the right of ANSI point and enough to the left of magnetizing inrush. The little overlap with air circuit breaker characteristic curve is permissible in this case, because of the use of the fuses in the 600 V PDC.

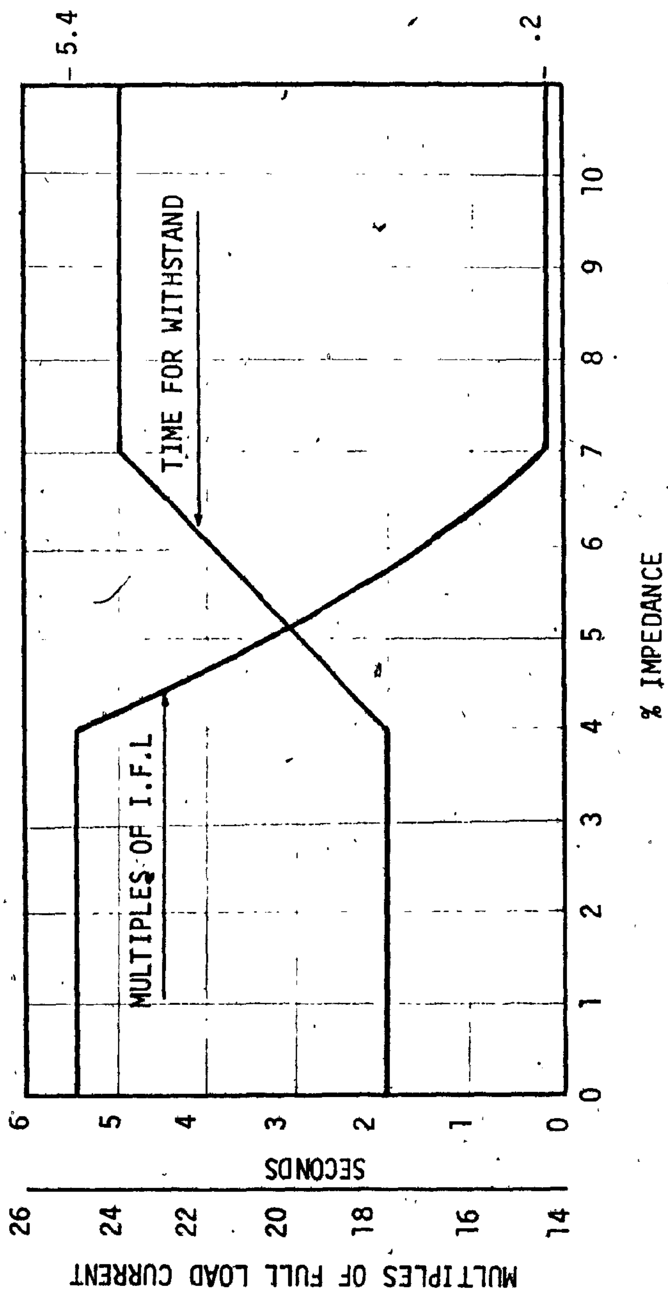
The instantaneous element is set at 70A which gives $70 \times \frac{150}{5} \times \frac{13.8}{.6} = 48\ 300$ A at 600 V which is below x_2 duty and above the magnetizing inrush of the transformer.

The coordination example we considered here is intended to provide a basic understanding of a systematic approach to obtaining protective device setting. The approach is applicable to any type of system, and if applied with good judgement, it should result in improved system protection. The example, also, will help to understand the next chapter, where a more involved and complicated system is considered and is presented in an official report form.



COORDINATION BETWEEN 13.8 kV FDR. BKR PHASE O/C RELAYS, 600 V PDC BKR & 200 HP MOTOR STARTER PROTECTIVE DEVICES. — TIME-CURRENT CHARACTERISTIC CURVES For Fuse Links In	
BASIS FOR DATA Standards Dated	
1 Tests made at Volts a-c at p-f. Starting at 25C with no initial load	No GRAPH 4-1
2 Curves are plotted to Test points so variations should be	Date

TRANSFORMER WITHSTAND POINT

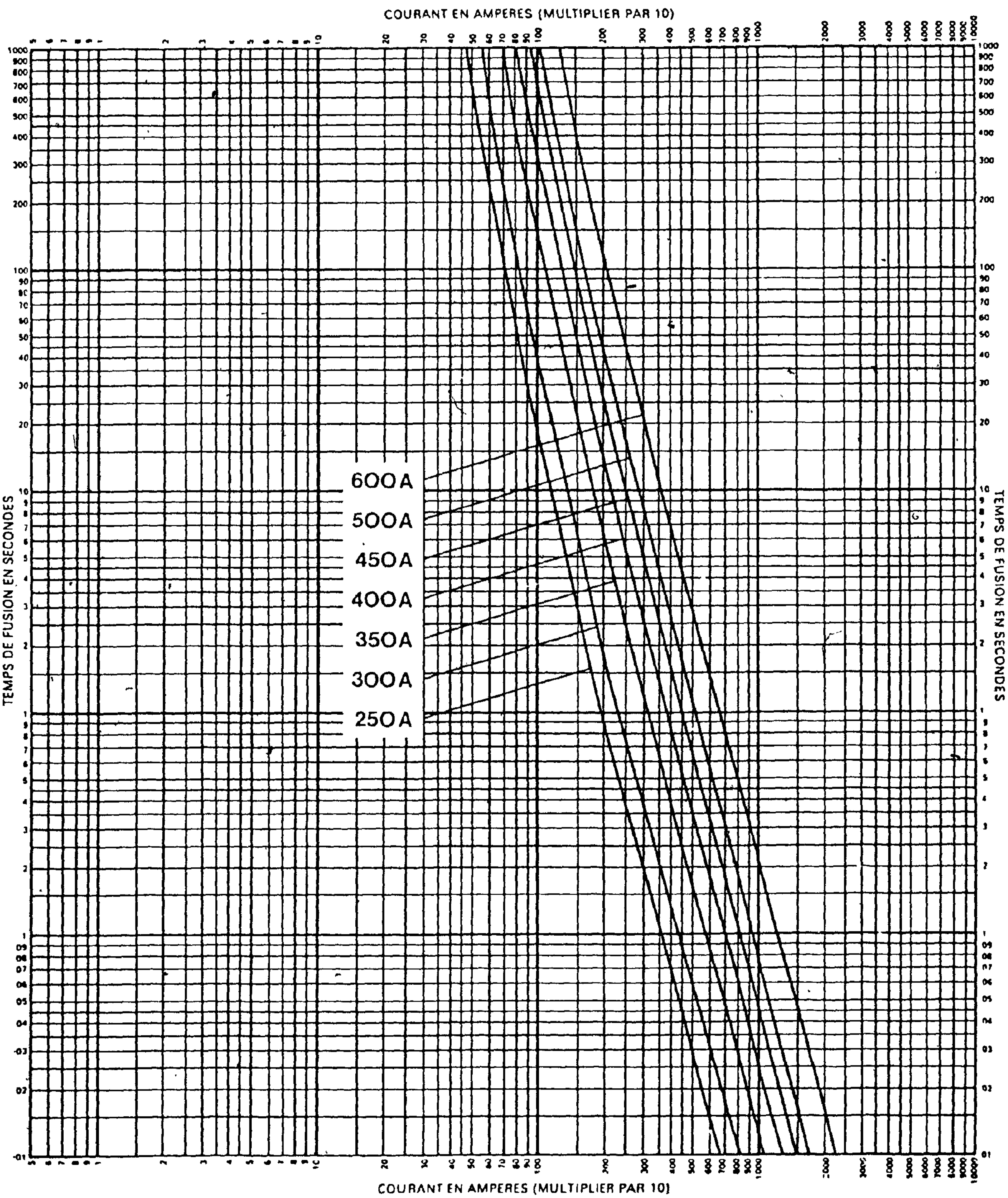


GRAPH 4-2

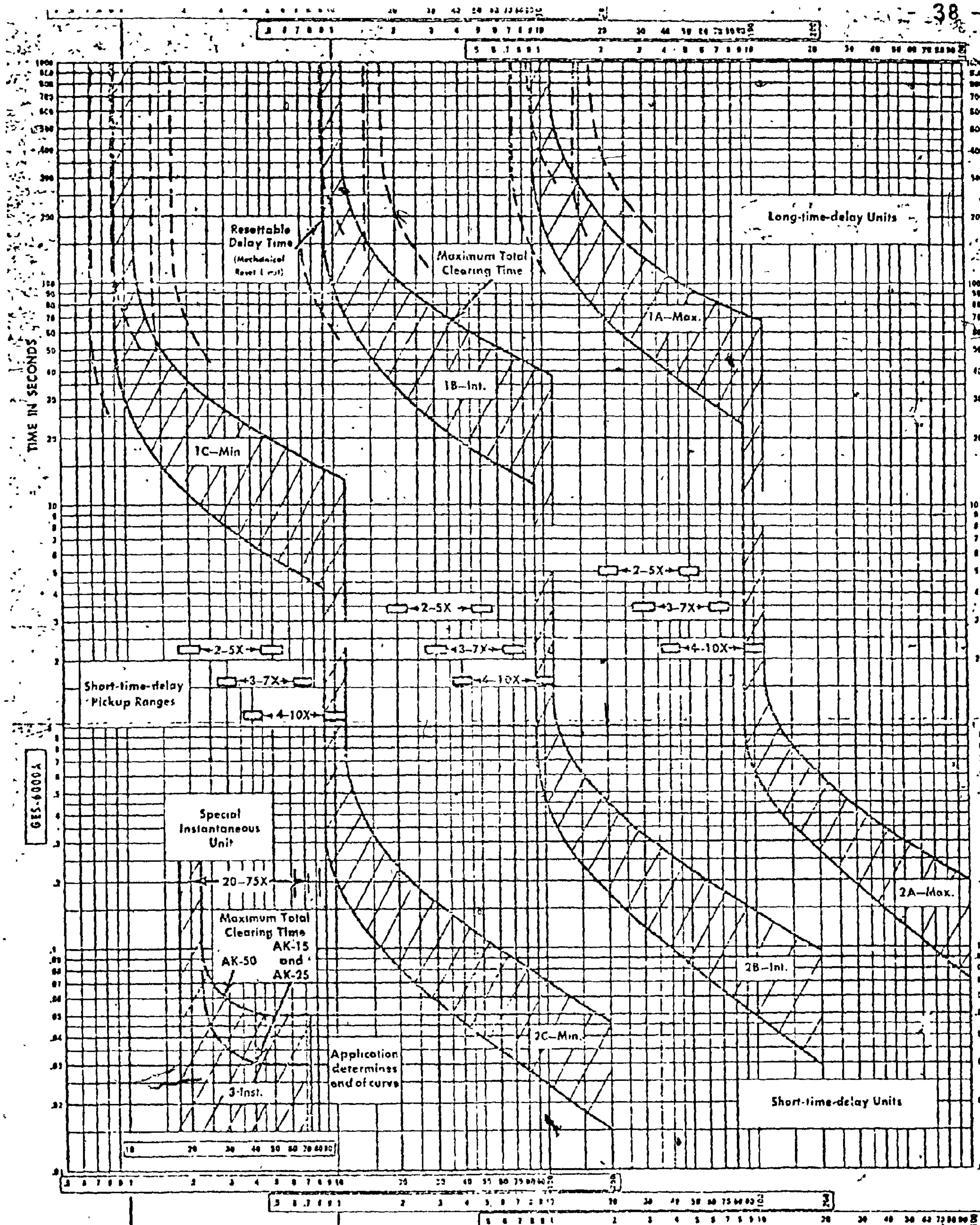
Caracteristiques de Fusion Temps/Courant

A 600 Volts ou moins

FORME II CLASSE "C" 250—600 Amp



GRAPH 4-3



MULTIPLES OF CURRENT RATING

GENERAL ELECTRIC

TYPE AK LOW-VOLTAGE POWER CIRCUIT BREAKER

EC-1 SERIES TRIP DEVICE

GES-6000A

Current Ratings (Amperes)

AK-15 15, 20, 30, 40, 50, 70, 90, 100, 125, 150, 175, 200, 225
AK-25 40, 50, 70, 90, 100, 125, 150, 175, 200, 225, 250, 300, 350, 400, 500, 600
AK-50 200, 225, 250, 300, 350, 400, 500, 600, 800, 1000, 1200, 1600
AKT-50 2000

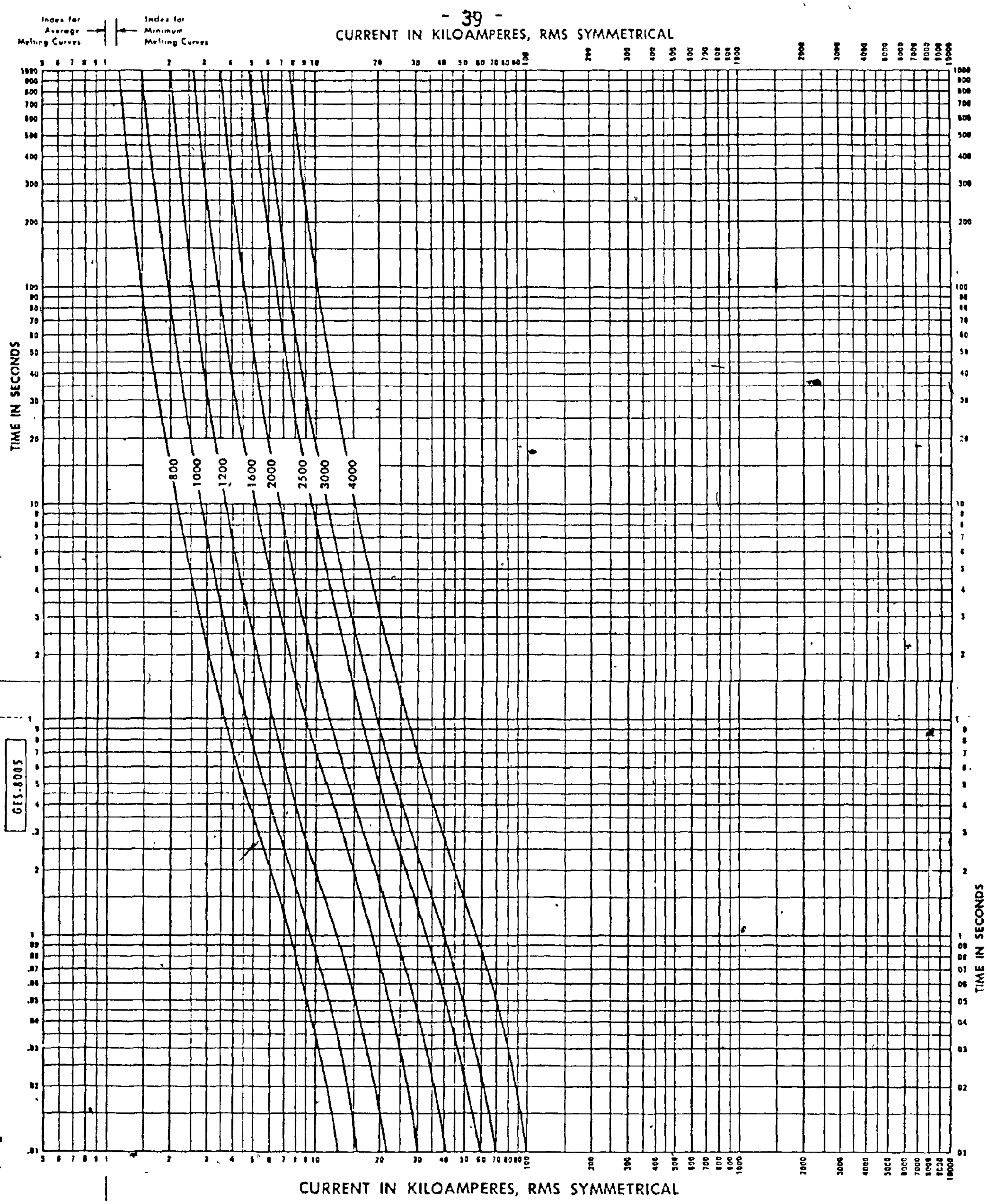
Long-time-delay, Short time-delay and instantaneous Time-current Curves.

(Curves apply at 60 Hz for ambient temperature of 25 C)

Adjustments

Long-time-delay Unit Pickup current settings are 80 to 160% of rating. (Settings higher than 100% do not increase the continuous current ratings.)
Short-time-delay Unit Pickup current settings are 2 to 5X, or 3 to 7X, or 4 to 10X of ratings.
Instantaneous Unit Special pickup current settings are 20-75X of ratings.

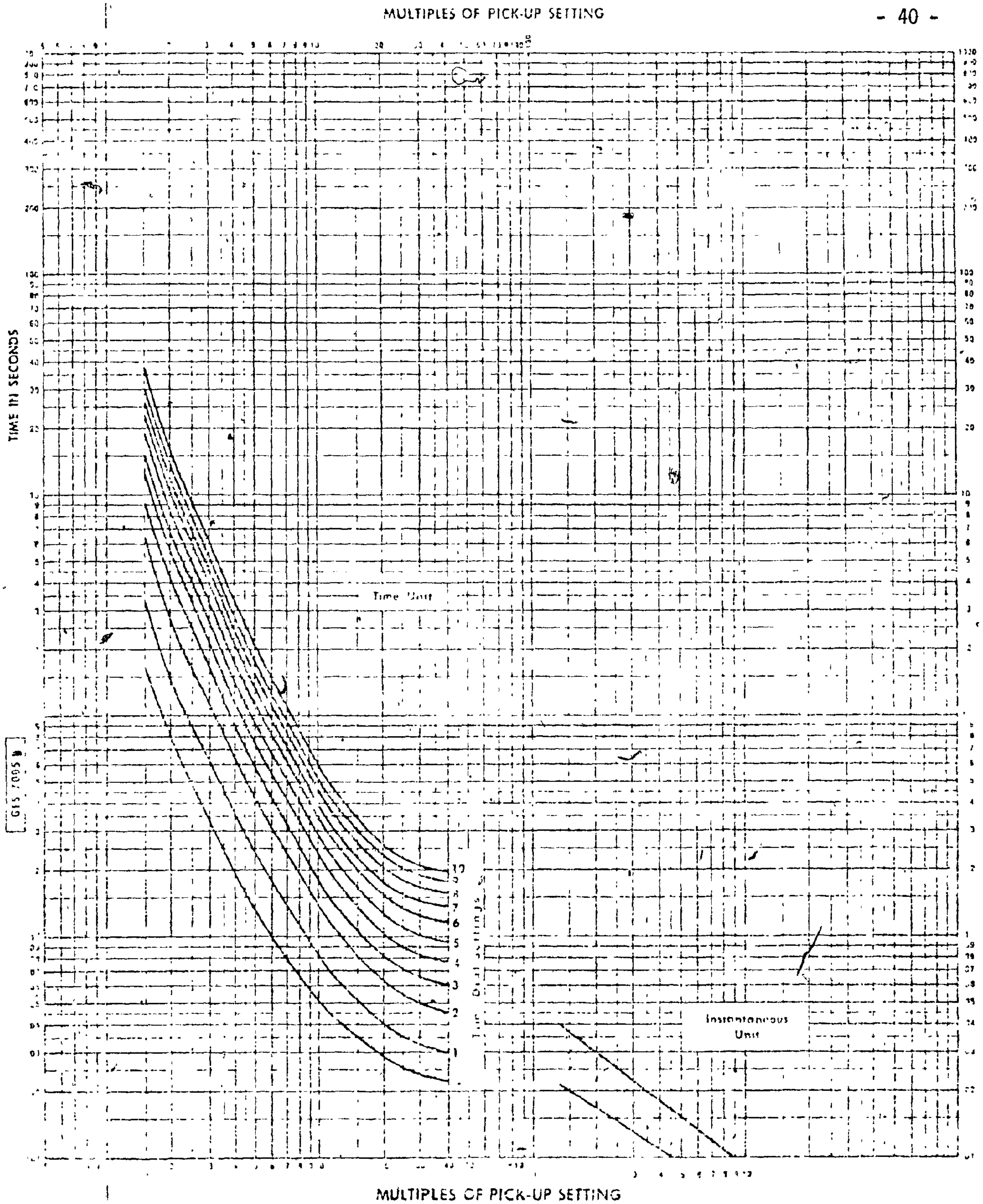
LOW VOLTAGE SWITCHGEAR DEPARTMENT, PHILADELPHIA, PA.



GENERAL ELECTRIC	LOW VOLTAGE CURRENT-LIMITING FUSE **CLF* FUSE**	GES-8005
Current Ratings 800, 1000, 1200, 1600, 2000, 2500, 3000 and 4000 Amperes **Frequency Ratings** 50 to 60 Cycles	600 Volts—NEMA Class L Average Melting Time-current Curves (At 25 C ambient in open air with no initial load)	Catalog number series—GF8B Curves plotted to average test points. Current variations 10 percent. For minimum melting curves use right hand index at top of sheet. GRAPH 4-5

LOW VOLTAGE SWITCHGEAR DEPT., PHILADELPHIA, PA

* Trade mark of General Electric Company



GENERAL ELECTRIC

TIME OVERCURRENT RELAY,

IAC 77 RELAY

Extremely Inverse Standard Time Time-Current Curves

(Other relays with the same time delay characteristic: IAC76, IBCV77 78, IBCG77 78, IBCV77 78, IBC77 78, IBCG77 78, IBCV77 78)

GES-7005 B

Ratings Amperes

Settings

Continuously Adjustable

GENERAL ELECTRIC CO, POWER SYSTEMS MANAGEMENT DEPT, PHILADELPHIA, PA. 19142

GRAPH 4-6

5. ELECTRICAL SYSTEM SHORT CIRCUIT AND PROTECTIVE DEVICES CO-ORDINATION STUDY FOR A TYPICAL PULP AND PAPER MILL

In the previous chapters we examined basic considerations that determine the character of the electric-distribution system. Also, we examined alternatives for approaching specific problems in industrial power systems and we stated the mechanics of achieving coordination with the various over-current protective devices. In this chapter a specific industrial plant is considered and the power system design and coordination of short circuit protective devices settings are worked out. The chapter itself is written in a typical industrial report format to guide the reader with the skeleton of official reports.

The concepts used apply to any kind of industrial plant and the only reason for choosing a pulp and paper mill is that the author is more familiar with that kind of process.

5.1 Purpose and Scope

The purpose of this report presented as chapter 5 in this paper is to investigate the electrical power distribution system of a typical pulp and paper mill, to determine the degree of selectivety available between the fixed and adjustable overcurrent protective devices supplied with the circuit interrupting equipment, and to recommend settings in accordance with accepted relaying practice.

The investigation of protective device selectivity includes the consideration of the characteristic curves of 600 V and 2.4 kV fused motor starter overload relays and current limiting fuses, 600 V power distribution centre feeder breaker trip devices and current limiting fuses, 13.8 kV feeder and utility tie breaker phase and ground overcurrent relays, and other special protective devices.

For clarity, the time current curves provided in this report which are associated with selectivity, between devices in the 2.4 kV and 600 V systems and devices in the 13.8 kV system, show only the coordination between the protective device having the highest rating in a particular 2.4 kV or 600 V power distribution centre or motor control centre and upstream devices. Recommended settings for the devices having lower ratings are shown in the device setting summaries and drawing provided in Appendix "B".

To aid in the selection of protective device settings and also to check the adequacy of the switchgear short circuit capability, the three phase fault availability was calculated at the mill 13.8 kV and 600 V buses. A summary of the system equipment parameters and the three phase fault levels at the various mill buses is included in report, see Table 5-1 in Section 5-2. Short circuit calculation work sheets can also be provided on demand.

Generally, it is proposed that the settings recommended in this report will provide maximum equipment protection and adequate selectivity so that faults will be isolated with a minimum of disturbance to the system.

5.2 System Short Circuit Capacity

5.2.1 System Single Line Diagram

Refer to Appendix "A" for the System Single Line Diagram upon which this study was based.

5.2.2 Mill Load

The total mill motor load is as follows:

a) <u>600 Volt System</u>

Total connected hp - 13 085 hp Induction

b) <u>2.4 kV System</u>

Total connected hp - 8450 hp Induction

1500 hp Synchronous

5.2.3 Mill Power Supply

All of the electrical power for the mill is supplied from the local Hydro 110 kV system through mill's main substation. The substation contains one 20/26/33 MVA 124-13.8 kV three phase transformer connected delta-wye. The transformer is equipped with ± 10% off load taps thus permitting operation from the present 110 kV primary system as well as from the future anticipated 13.8 kV system. The transformer will initially operate as self cooled, with provision for two stages of future fan cooling.

5.2.4 Utility and Mill Equipment Parameters

a) Mill's main substation three phase short circuit capacity on the 110 kV bus is 1000 MVA at present, with an anticipated ultimate capacity of 2500 MVA. The impedance of the utility tie transformer is 10% on its self cooled rated of 20 MVA.

b) <u>Mill Transformer Impedances</u>

2.0 MVA 13.8 kV - 600 V - 5.5% on 2 MVA Base

2.0 MVA 13.8 kV - 2.4 kV - 5.5% on 2 MVA Base

3.0 MVA 13.8 kV - 2.4 kV - 5.5% on 3 MVA Base

5.0 MVA 13.8 kV - 2.4 kV - 5.5% on 5 MVA Base

c) Estimate Mill Motor Reactance per ANSI Standards

600 volt Induction motor X"d on machine rating - 25%

2.4 kV Induction motor X"d on machine rating - 17%

2.4 kV Synchronous motor X"d on machine rating - 25%*

(*Value quoted by motor Mfgr. for 1500 hp chipper motor)

d) System Grounding

13.8 kV System - The secondary neutral of the utility tie transformer is grounded through 400 ampere resistor.

2.4 kV System - Each 13.8 - 2.4 kV transformer secondary neutral is grounded through a 400 ampere resistor.

600 Volt System - Each 13.8 - 0.6 kV transformer secondary neutral is solidly grounded.

5.2.5 Short Circuit Infeed

a) Motor Infeed

In calculating the mill motor short circuit infeed, the connected horsepowers shown on Single Line Diagram, DWG. No. 5A-1, were used. In accordance with the procedure outlined in the new ANSI Method of Calculation, the mill motor short circuit infeed was calculated as follows:

Type of Drive	Interrupting	Momentary
All synchronous motors	1.5 x"d	1.0 x"d
Induction Motors:		
Above 1000 hp @ 1800 r/min	1.5 x"d	1.0 x"d
Above 250 hp @ 3600 r/min	1.5 x"d	1.0 x"d
All others 50 hp and above	3.0 x"d	1.2 x"d
All smaller than 50 hp	Neglect	Neglect

For this Mill, approximately 75% of the connected 600 volt motor load is rated 50 hp and larger.

b) Utility System Infeed

Since the 110 kV system is supplied from generators, it is assumed that both interrupting and momentary condition will be subject ot the utility system ultimate fault availability of 2500 MVA.

5.2.6 Summary of Three Phase Short Circuit Calculation Results

Using the new ASNI Standard as the basis of calculation for bolted three phase faculty, and assuming an overall X/R ration of not greater than 12, the system momentary asymmetrical short circuit current and interrupting MVA on the 13.8 kV mill bus was calculated. Similarly, the fault level at the 2.4 kV and 600 volt buses was calculated. Table 5.1 summarizes the short circuit study results and provides a comparison with the electrical equipment short circuit capacity.

TABLE 5.1

SUMMARY OF ELECTRICAL SYSTEM THREE PHASE SHORT CIRCUIT AVAILABILITY AND SWITCHGEAR RATING.

MILL BUS	CALCULATED 3 PHASE FAULT AVAILABILITY		SWITCHGEAR RATING		
	MOMENTARY ($\frac{1}{2}$ CYCLE)	INTERRUPTING (5 CYCLES)	TYPE	MOMENTARY	INTERRUPTING
13.8 kV BUS	16.9 kA (ASYM.)	216 MVA	METALCLAD ACB's	60 kA	500 MVA
2.4 kV BUS	25 kA (ASYM.)	63 MVA	FUSED MOTOR CONTROL		230 MVA
			METALCLAD ACB	60 kA	150 MVA
600 V BUS	49 kA (ASYM.)	31 MVA	FUSED FEEDER BREAKERS	200 kA	200 kA
			MOTOR CONTROL CENTRE	BUS BRACED FOR 50 kA RMS ASYM.	100 kA

5.3 Selection and Coordination of Circuit Protective Device Settings

5.3.1 General

a) Devices Considered

This study is confined to the selection of coordinated settings for the following devices:

i) 600 volt motor starter thermal overload relays and HRC fuses.

ii) 600 volt feeder breaker trip devices and HRC fuses.

iii) 2.4 kV motor strater thermal overload relays, HRC fuses and instantaneous ground overcurrent relays.

iv) 2.4 kV chipper motor circuit breaker starter phase overcurrent relays, ground overcurrent relay, and other special purpose relaying.

v) 2.4 kV transformer secondary neutral ground overcurrent relays.

vi) 13.8 kV feeder and tie circuit phase and ground overcurrent relays and other special purpose relaying.

b) Device Setting Selection

The selection of motor strater protective device settings is determined by motor rating and operating conditions. In any particular 600 volt power distribution centre, the setting of the protective devices in the motor control supplied for the larger motor, and the motor control centre rating and loading, will determine the minimum setting which can be applied to the feeder breaker overlaod relays and also the rating of the HRC fuses. The settings of the feeder breaker protective devices are then used to aid in the determination of the associated 13.8 kV feeder breaker overcurrent relay settings.

Selectivity on the 2.4 kV system is achieved in a similar manner to that described above except that, since feeder breakers are not used, the selection of motor strater protective device settings directly affects the selection of 13.8 kV feeder breaker phase overcurrent relay settings.

In order to select satisfactory settings for the 13.8 kV system protective devices; short circuit levels, feeder transformer short circuit let-through, and system operating conditons must be considered. This subject will be discussed in detail in subsection 5.3.5 of this report.

5.3.2 Standards Used

The following accepted standards are used throughout this coordination study so that device settings will conform to the Canadian Electrical Code and to IEEE Standards.

a) 13.8 kV feeder breaker phase overcurrent relay pick up values are less than 250% of the protected transformer full load current.

b) 13.8 kV, 2.4 kV and 600 volt motor starter and/or feeder breaker short circuit protective devices are set above the inrush of the largest motor in the circuit.

Locked rotor currents were assumed to exist for not more than

10 seconds for all squirrel cage induction motors.

c) 13.8 kV breaker phase overcurrent relay operating characteristics are set below the transformer short circuit withstand as specified by NEMA, as follows:

i) 5.5% transformers - 18.2 times FLC for 3.5 seconds

ii)10.0% transformers - 10.0 times FLC for 5.0 seconds

d) 13.8 kV breaker phase overcurrent relay instantaneous pick-up is set above the highest of the following momentary currents:

i) Inrush current of the protected transformer = 15 times full load current for 0.1 seconds (estimated).

ii) Total inrush current for more than two transformers in parallel = 10 times total full load current for 0.1 seconds (estimated).

iii)Maximum asymmetrical short circuit current through each transformer on the feeder being considered.

e) A suitable time dealy and current margin is maintained between protective devices in series to allow for breaker opening time, relay overtravel, phase to phase faults, wye-delta transformations and safety factor.

f) 13.8 kV breaker phase and ground overcurrent relay settings provide short circuit protection for 13.8 kV feeder cables and transformers.

g) Since the 575 volt TEFC motors throughout the mill have 1.0 service factor, the thermal overload Relay heaters are selected so that they will ultimately trip at approximately

1.10 times the maximum rated full load current, including the 1.15 service factor. For the 2.3 k motors (induction 1.15 service factor and synchronous 1.0 service factor), the procedure recommended by the motor control manufacturer was followed in the selection of motor overload heaters.

5.3.3 Selection of 600 Volt System Protective Device Settings

a) Summary of Protective Equipment Used

Summary tables of the protective equipment which is used throughout the mill 600 volt system are shown in Appendix "B".

b) Sample Calculation of Recommended Settings

Refer to the Single Line Diagram in Appendix "A" for motor control centre loading.

Consider PDC-42 which feeds:

MCC - 421	315 hp
MCC - 422	369 hp
MCC - 423	363 hp
MCC - 424	150 hp
Larger motor	200 hp

All motors up to and including frame 445 are TEFC and have 1.0 service factor. Motors larger than 445 are ODP and have 1.15 service factor.

MCC-423 estimated normal operating load = connected hp x demand factor

Assuming:

Induction motor efficiency = 0.90

Power factor = 0.85

Demand factor = 0.75

MCC-423, estimated normal operating load =

$$\frac{363 \times 746 \times 0.75}{1.73 \times 0.9 \times 0.85 \times 600} = 256 \text{ A} \quad @ \text{ 600 volts}$$

Larger motor in the MCC = 200 hp

Motor Starter Protective Device Selection

The 600 volt motor control is supplied with Canadian General Electric Co. Ltd. fused combination starters for motors up to 200 hp. The starters are equipped with three thermal overload ampient compensated relays and English Electric Form II Class C HRC fuses. It is necessary to select a relay heater style number based on an ultimate trip of approximately 110% motor full load current, including the 1.15 service factor where applicable.

For the 200 hp motor the following device selections were made:

Approximate FLC = 209 A @ 600 volts

Approximate LRC =1100 A @ 600 volts

Use size 5 starter

Select overload relay heater type 81D554

Heater ultimate trip point = 230 A (110% motor full load current)

Select English Electric Form II Type C 300 A fuses.

For coordination curves, refer to Section 5.4, Fig. No. 8.

Feeder Breaker Protective Device Settings

The Canadian General Electric Co. Ltd. AK-2-25 feeder breaker trip devices must be set above the total load on the MCC which it is feeding and provide satisfactory coordination with the protective devices in the largest motor starter in the MCC. Also, these devices must provide satisfactory overload and short circuit protection for the feeder cables to the MCC.

Consider again MCC-423:

Estimated normal operating load = 256 A @ 600 volts

Largest motor = 200 hp

To achieve satisfactory coordination with the 200 hp motor starter thermal overload relays and fuses, the long time delay element of the feeder breaker trip device is set at 100% of coil rating and 600 A pickup.

Note that this setting is well in excess of the estimated operating load in the MCC.

The HRC fuses in the 600 volt air circuit breakers are required to limit the available fault currents to values within the rating of the circuit breakers. The fuse ratings were selected to operate before the short time delay devices in these circuit breakers to provide the following:

i) Reduce the magnitude of let-through current for a fault in the feeder circuit.

ii) Provide optimum transformer protection.

For the above reasons, 800 ampere fuses are used in the feeder breaker. For co-ordination curves refer to Section 5.4

- Fig. 8.

The calculation of settings for the protective devices in the motor control and feeder breakers throughout the remainder of the mill 600 volt distribution system is generally as described in the foregoing example, and as shown on Metering and Relaying Single Line diagram in Appendix "B".

600 Volt Bus Ground Fault Protective Device Selection

A time delay ground overcurrent relay is supplied in each PDC to provide ground fault protection for the transformer secondary circuits and the main bus in the 600 volt PDC. This type IAC51A2A relay is connected to the transformer secondary neutral CT and is wired to trip the associated 13.8 kV feeder circuit breaker.

For satisfactory co-ordination the setting of these relays must allow motor starter and feeder breaker fuses to clear "load side" faults before unnecessary tripping of the 13.8 kV breaker occurs. Also, they must clear 600 volt bus faults before the unbalanced current in the 13.8 kV feeder circuit causes the 13.8 kV breaker phase overcurrent relays to trip the breaker.

To achieve selectivity, the following settings were selected:

CT ratio 2000/5

Set pickup at 3 A tap $\frac{3x2000}{5} = 1200$ A @ 600 volts.

Set time dial at 1 and use 0.2 A tap for seal-in unit.

For coordination curve refer to Secton 5.4, Fig. 15.

5.3.4 Selection of 2.4 kV System Protective Device Settings

a) Summary of Protective Equipment Used

Summary Tables of the protective equipment which is in use throughout the Mill 2.4 kV system are shown on Metering and Relaying Single Ling Diagram in Appendix "B".

b) Sample Calculation of Recommended Settings - Circuit Breaker Starter

Consider Wood Preparation and Chip Handling MV-41

Connected hp = 4800 (all induction except chipper motor)
Larger motor is the chipper drive = 1500 hp 0.8 PF synchronous, with 1.0 service factor
Motor full load current 374 A @ 2.3 kV
Motor locked rotor current = 1570 A @ 2.3 kV
Motor current at pull out = 1216 A @ 2.3 kV
Estimated starting time = 12 seconds @ 100% voltage
Maximum allowable stall time = 14 seconds @ zero speed.

Protective Device Description and Setting

i) Short Circuit and Locked Rotor Protection

Two type IAC66K6A overcurrent relays are used to protect the motor in the event of a short circuit or stalled rotor condition, and with provision to initiate a remote alarm for overload.

The relays are set as follows:

Time overcurrent unit (51), set pickup at 4.0 A tap

CT ratio 600/5

Therefore pickup $\frac{4.0 \times 600}{5}$ = 480 A @ 2.4 kV

(approximately 128% of motor full load current)

This unit operates on auxiliary relay (51X) which will initiate a remote alarm.

Set time dial at 2.5

Use 2.0 A tap for target and sealing-in unit

Set normal dropout instantaneous overcurrent unit (51/IOC-A) pickup at 23 amps = $\frac{23 \times 600}{5}$ = 2760 A @ 2.4 kV

(approximately 176% of motor L.R.C. or 740% of motor F.L.C.)

This setting will provide satisfactory short circuit protection and also prevent false tripping either during motor starting or for external faults.

Set high dropout instantaneous overcurrent unit (51/IOC-B) pickup at 11 A = 11 x $\frac{600}{5}$ = 1320 A @ 2.4 kV

(appr. 109% of motor P.O.C., 353% of motor F.L.C. & 84% of motor L.R.C.). This unit operates in conjunction with unit 51 to trip the motor starter, and hence the combination of 11 amp high dropout instantaneous setting and the 4.0 A setting on the time overcurrent unit will protect the motor against stalled rotor damage and also prevent false tripping during start up or when the motor is subject to temporary overloads up to the magnitude of current at pull out. For coordination curve refer to Section 5.4, Fig. No. 7.

ii) Ground Overcurrent Protection

The type PJC11AV1A instantaneous ground overcurrent relay is used to provide ground fault protection for the motor feeder circuit. The relay is connected to operate from 100/5 A ground sensor CT and is wired to trip the chipper motor starter. In order to achieve coordination with the transformer neutral ground relay, the motor ground overcurrent relay is set at its lowest tap setting of 0.5 A = 0.5x100/5 = 10 A @ 2.4 kV.

iii) Current Balance Relay

A type 1JC51B3A current balance relay is used to provide protection in the event of unbalance source voltage. This relay will operate when current unbalance exceeds 25%. The pickup is set at 1 A (minimum). A time dial setting of 10 is used to allow time for other relaying to clear external phase to phase or phase to ground faults before this relay operates. 1.0 amp target and holding-in coil is supplied with this relay.

iv) Power Factor Relay

A Basler Electric Co. model No. 22900-101 power factor relay is used to provide back up protection for the Stat-X-Ator loss of synchronism relaying, as well as to provide incomplete sequence protection in conjunction with the Agastat model No. 2412AD timer, and loss of field protection. The relay is set to operate at a lagging power factor of 0.8 with a minimum time delay of 0.25 seconds. (estimated motor power factor at pull out = 0.85 lagging.) The power factor relay operating coils are isolated from the circuit during the starting period by means of the Agastat timer relay. The time delay relay is set to provide 15 seconds time delay to permit the motor to accelerate and pull into synchronism within a normal estimated starting time of 12 seconds. Failure to synchronize within 15 seconds will trip the motor circuit breaker starter due to low lagging power factor.

v) <u>AC Undervoltage Relay</u>

An type IVA54E1A ac undervoltage relay is used to trip the chipper motor starter in the event of severe undervoltage conditions. The relay is set to trip at 55 volts (approximately 46% voltage). A time dial setting of 1 is used to avoid unnecessary tripping for momentary disturbances. Use 2.0 A tap for seal-in unit.

vi) <u>Differential Relay</u>

A type PJC31D23A instantaneous current relay is used to provide motor winding differential protection, and acts to trip the motor starter through an auxiliary lockout relay. Use minimum relay tap of 0.5 A CT ratio = 100/5 Pickup 0.5 $\times \frac{100}{5}$ = 10 A @ 2.4 kV. Use 0.2 A tap for seal-in unit.

vii) Overtemperature Protection

A type IRT overtemperature relay is used to protect the stator windings against overheating caused by overload. Connect relay to the highest reading stator RTD (resistance temperature detector) and set to trip at the motor maximum allowable temperature of 120°C and reset at 110°C.

c) Sample Calculation of Recommended Setting-Contactor Starter

Consider Power, Recovery and Recausticizing MV-51

Connected hp = 3500 hp (All squirrel cage induction motors)

Larger motor is the I.D. FAN (induced draft) = 700 hp with 1.0 service factor.

Motor full load current = 164 @ 2.3 kV

Motor locked rotor current = 820 A @ 2.3 kV

Square D 2.4 kV motor control is supplied with class 9065 type CO thermal overload relays and EMP type HRC fuses. For the 700 hp motor, the following selections were made by the motor control manufacturer.

Overload relay thermal unit B4.15 - ultimate trip @ 4.11 A

CT ratio = 200/5

Pickup $4.11 \times \frac{200}{5} = 164.4$ A @ 2.4 kV

(approximately 100% of motor F.L.C.)

Fuses selected are 200R. These fuses provide satisfactory coordination and short circuit protection.

For coordination curves refer to Section 5.4, Fig. No. 9.

In addition to the above protective devices, a Class 8506 Type AO-1 instantaneous ground overcurrent relay is provided in each starter for ground fault protection of the motor and feeder cable. These relays are each connected to a ground sensor current transformer in the starter unit and each has a fixed minimum pickup of 5 A primary current. For coordination curve refer to Section 5.4, Fig. NO. 14.

2.4 kV Bus Ground Fault Protective Device Selection

A type IAC51A3A time delay ground overcurrent relay is supplied in each MV to provide ground fault protection for the transformer secondary circuit and the main bus in 2.4 kV motor control. This relay is connected to the transformer secondary neutral CT, and is wired to trip the associated 13.8 kV feeder circuit breaker.

For satisfactory co-ordination, the settings of these relays must allow the motor starter instantaneous ground fault relays to isolate faulted motor feeders before 13.8 kV feeder breaker opens. These 2.4 kV motor starter contactors have a total opening time of approximately 5.5 cycles. To achieve selectivity, the following settings were selected:

CT ratio = 100/5

Set relay pickup at 0.5 A tap $= 0.5 \times \frac{100}{5} = 10$ A ground current.

Set time dial at 2 and the 0.2 A tap for seal-in unit.

For coordination curves, refer to Section 5.4, Fig. No. 14.

5.3.5 Selection of 13.8 kV System Protective Device Settings

a) Summary of Protective Equipment Used

For a complete summary of the protective equipment used in the 13.8 kV system and the recommended settings, refer to the summary of 13.8 kV Tie Circuit Protective Device Settings and 13.8 kV Feeder Protective Device Settings as shown in DWG. No. 5B-1, TABLE 5B-1 & DWG. NO.5B-2, TABLE 5-B-2 in App. "B". Also for a complete set of time current coordination curves, refer to Section 5.4.

b) Sample Calculation of Recommended Settings

Consider Unit No. 4 which is a double feeder breaker feeding 2.4 MV-41 and 600 V PDC-42

Refer to single line diagram in Appendix "A" for system configuration.

Consider Feeder Circuit 4.1

Transformer capacity 5.0 MVA, 13.8 kV - 2.4 kV.

Transformer parameters

Full load current = 209 A @ 13.8 kV = 1203 A @ 2.4 kV

Impedance = 5.5% on 5.0 MVA Base

= 1.1 per unit on 100 MVA Base

EstimatedMagnetizing Inrush = 209 x 15 = 3135 A

@ 13.8 kV = 18 070 A @ 2.4 kV.

Transformer short circuit withstand =

= 209 x 18.2 = 3810 A @ 13.8 kV for 3.5 seconds

= 21 880 A @ 2.4 kV for 3.5 seconds.

Asymmetrical short circuit current through the transformer

$$= \frac{100 \times 10^3 \times 1.6}{1.73 \times 13.8 \times (0.427^* + 1.1)} = 4390 \text{ A} \quad @ \; 13.8 \text{ kV} = 25\,200 \text{ A} \quad @ \; 2.4 \text{ kV}$$

* System three phase short circuit impedance in per unit on 100 MVA Base.

For satisfactory phase overcurrent relay co-ordination the following must be satisfied:

1) Relay pickup should not exceed 250% of transformer full load current (code requirement), nor be less than transformer F.L.C..

2) Selectivity must be obtained with the largest protective device settings in the 2.4 kV motor control or with the feeder breaker series trip device settings in the 600 volt switchgear.

3) The supply transformer must be protected against short circuit.

4) Feeder cables must be protected against short circuit.

5) Relay instantaneous settings must exceed the asymmetrical short circuit current through the 5.0 MVA transformer.

To satisfy the above requirements, the following settings have been selected:

CT ratio = 300/5

Set IAC77B6A phase overcurrent relay pick up at 5 A tap

$= 5 \times \frac{300}{5} = 300$ A @ 13.8 kV

Set time dial at 7,

Use 2.0 A tap for seal-in unit.

Set instantaneous at 70 A $= 70 \times \frac{300}{5} = 4200$ A @ 13.8 kV

For coordination curve refer to section 5.4, Fig. No. 7.

Since it is not necessary to co-ordinate the 13.8 kV system ground relaying with the 2.4 kV system ground relaying (because the distribution transformers are connected delta-wye), the type PJC11AV1A instantaneous ground overcurrent relay in the feeder breaker can be set at the minimum pickup of 0.5 amps.

Ground sensor CT ratio = 100/5

Therefore, selected pickup $= 0.5 \times \frac{100}{5} = 10$ A ground current.

For coordination curves, refer to section 5.4, Fig. No. 13.

Consider Feeder Circuit 4-2 to PDC-42

Transformer capacity = 2.0 MVA, 13.8 kV - 600 V

Transformer Parameters

Transformer full load current = 83.6 A @ 13.8 kV = 1929 A @ 600 V

Impedance = 5.5% on 2.0 MVA Base = 2.75 per unit on 100 MVA Base

= 83.6 x 15 = 1253 A @ 13.8 kV = 28 950 A @ 600 V.

Transformer short circuit withstand

= 82.6 x 18.2 = 1253 A @ 13.8 kV for 3.5 seconds

= 35 100 A @ 600 V for 3.5 seconds.

Asymmetrical short circuit current through the transformer

$$= \frac{100 \times 10^3 \times 1.6}{1.73 \times 13.8 \times (0.401^* + 2.75)} = 2120 \text{ A @ } 13.8 \text{ kV} = 48\,900 \text{ A @ } 600 \text{ V.}$$

* System short circuit impedance in per unit on 100 MVA Base.

The principles of co-ordination for the feeder are the same as described for feeder circuit 4-1 and hence similar criteria must be satisfied. To satisfy co-ordination requirements, the following settings have been selected:

CT ratio 150/5

Set IAC77B6A phase overcurrent relay pickup at 4 A tap

$= 4 \times \frac{150}{5} = 120$ A @ 13.8 kV

Set time dial at 6

Use 2.0 A tap for seal-in unit

Set instantaneous at 70 A $= 70 \times \frac{150}{5} = 2100$ A @ 13.8 kV

For coordination curves refer to section 5.4, Fig. No. 8.

Ground fault relaying for this feeder is as described in the foregoing section for feeder 4-1.

Consider Feeder 5-1 to MV-51

Transformer capacity = 3.0 MVA, 13.8 kV - 2.4 kV.

Transformer Parameters

3.0 MVA transformer full load current = 125 A @ 13.8 kV

= 722 A @ 2.4 k V

Impedance = 5.5% on 3.0 MVA Base = 1.83 per unit on 100 MVA Base.

Estimated transformer magnetizing inrush

= 125 x 15 = 1880 A @ 13.8 kV = 10 820 A @ 2.4 kV

Transformer short circuit withstand

= 125 x 18.2 = 2280 A @ 13.8 kV for 3.5 seconds

= 13 140 A @ 2.4 kV for 3.5 seconds

Asymmetrical short circuit current through the transformer

$$= \frac{100 \times 10^3 \times 1.6}{1.73 \times 13.8 \times (0.419^* + 1.83)} = 2975 \text{ A @ } 13.8 \text{ kV}$$

= 17 100 A @ 2.4 kV

* System three phase short circuit impedance in per unit on 100 MVA Base.

For satisfactory phase overcurrent relay co-ordination, the criteria outlined for feeder circuit 4-1 must be satisfied.

Therefore the following settings have been selected:

Set IAC77B6A phase overcurrent relay pickup at 5 A tap

CT ratio = 200/5

Therefore, selected pickup = $5 \times \frac{200}{5} = 200$ A @ 13.8 kV

Set time dial at 8

Use 2.0 A tap for seal-in unit

Set instantaneous at 70 A $= 70 \times \frac{200}{5} = 2800$ A @ 13.8 kV

For co-ordination curves, refer to section 5.4, Fig. No. 9.

Set the PJC11AV1A instantaneous ground overcurrent relay at the minimum 0.5 A pickup

Ground Sensor CT = 100/5

Therefore pickup = 0.5 x 100/5 = 10 A ground current

For co-ordination curves, refer to section 5.4, Fig. No. 13.

c) <u>Selection of Protective Device Setting for Utility Tie Breaker Unit No. 7 Phase and Ground Overcurrent Relay</u>

The utility tie breaker phase and ground overcurrent relaying must be set to co-ordinate with the feeder breaker relays having the highest settings. To achieve this, the following settings have been selected:

<u>Phase Overcurrent Relay</u>

Relay type IAC77B6A

CT ratio = 2000/5

Pick up setting = 4 A tap = $4 \times \frac{2000}{5}$ = 1600 A @ 13.8 kV

Time dial setting = 2

Instantaneous should be set at 160 A , but the trip function should not be connected.

Use 2.0 A tap for seal-in unit.

For co-ordination curves, refer to section 5.4, Fig. No. 12.

Ground Overcurrent Protection

Relay type IAC53A10A (residually connected)

CT ratio = 2000/5

Pickup setting = 0.1 A tap

= $0.1 \times \frac{2000}{5}$ = 4.0 A ground current @ 13.8 kV

TIme dial = 3

Use 2.0 A tap for seal-in unit

For co-ordination curves, refer to Section 5.4, Fig. No. 13.

In addition to the above type IAC53A10A ground overcurrent relay, a type IAC53A2A time delay ground overcurrent relay is provided to protect the 15 kV conduction between the utility tie transformer and 13.8 kV breaker unit No. 7. This relay is connected to the utility tie transformer secondary neutral CT, and is wired to trip and lock out both the 13.8 kV utility tie circuit breaker and the 110 kV system oil circuit breaker.

For satisfactory co-ordination, the setting of this relay must allow the 13.8 kV utility tie circuit breaker ground over-current relay to isolate ground faults on the 13.8 kV switchgear bus before isolating the utility tie line. To achieve selectivity, the following settings have been selected:

Relay type IAC53A2A

CT ratio = 100/5

Set pickup at 2.5 A tap = $2.5 \times \frac{100}{5} = 50$ A ground current

Set time dial at 5

Use 0.2 ~~A~~ tap for seal-in unit.

For co-ordination curves, refer to section 5.4, Fig. No. 13.

Tie Circuit Transformer Differential Relaying

A General Electric type BDD15B11A transformer differential relay has been provided to protect the circuit between 13.8 kV breaker unit No. 7 and the 110 kV system oil circuit breaker. The following detail calculation is necessary to determined the optimum setting for this relay[1].

Transformer capacity = 20/26/33 MVA 124-13.8 kV with ±10% taps, connected delta-wye.

[1] Refer to relay bulletin No. GEH-2057A

Transformer full load current

Self cooled, 20 MVA	=	105 A	@ 110 kV
	=	837 A	@ 13.8 kV
Fan cooled, 33 MVA	=	173.2 A	@ 110 kV
	=	1381 A	@ 13.8 kV

For primary wye connected CT's (200/5):

$$\text{Tap current} = \frac{I_P}{N} = \frac{105}{200/5} = 2.62 \text{ A}$$

Select 3.5 A relay tap

For secondary delta connected CT's (2000/5):

$$\text{Tap current} = \frac{1.73I_S}{N} = \frac{1.73x837}{2000/5} = 3.62 \text{ A}$$

Select 5.0 A tap

To check the percent mismatch (not to exceed 5 percent)

$$\text{Ratio of relay taps } \frac{5.0}{3.5} = 1.43$$

$$\text{Ratio of tap currents } \frac{3.62}{2.62} = 1.38$$

$$\text{Mismatch} = \frac{1.43-1.38}{1.38} = 3.62\%$$

To check the short time rating of the differentail relay (should not exceed 220 A for one second)

$$\text{Available fault at 110 kV line} = \frac{2500x10^3x1.6}{1.73x110} = 20\ 950 \text{ A}$$

asymmetrical @ 110 kV.

Relaying fault current passing through 200/5 CT's for a fault at the primary terminals of the utility tie transformer=

$$= \frac{20\ 950}{200/5} = 524 \text{ A for 0.1 second.}$$

Available fault current passing through secondary CT's for fault at tie transformer secondary terminals =

$$= \frac{100x10^3x1.6}{1.73x13.8x1.50*} = 4460 \text{ A @ 13.8 kV}$$

* System three phase short circuit impedance in per unit on 100 MVA Base.

Relaying fault current passing through 2000/5 CT's for a fault at the secondary terminals of the utility tie transformer =

$$= \frac{4460}{2000/5} = 11.14 \text{ A for 1.0 second.}$$

Total relay current = 524 + 11.14 = 535.14 amps for 0.1 second.

Thermal rating of relay for 0.1 second based on 220 amps for 1 second maximum is $\frac{220}{\sqrt{0.1}}$ = 695 amps for 0.1 second.

Therefore CT fault current is within thermal rating of the relay.

To check CT ratio error (should not exceed 20% at 8 times relay rated tap current):

For wye connected CT's $\quad Z = B + \frac{N_e + 2.5f}{1000} + 2.27R$ ohms

For delta connected CT's $\quad Z = 2B + \frac{N_e + 2.5f}{1000} + 2.27R$ ohms

where B = BDD relay total burden

N = Number of turns on bushing CT

e = Bushing CT resistance per turn, milli-ohms

f = Bushing CT resistance per load, milli-ohms

R = One way lead resistance (at 75°C) from CT to relay.

For wye connected CT's located on the primary (delta) side of the utility tie transformer:

$$Z = 0.140 + \frac{(40)(3197)+(2.5)(19)}{1000} + (2.27)(0.199) = 0.799 \text{ ohms}$$

For delta connected CT's located on the secondary (wye) side of the utility transformer:

$$Z = 2(0.088) + \frac{(400)(3.0)+(2.5)(0)}{1000} + (2.27)(0) = 1.376 \text{ ohms}$$

CT secondary currents for 8 x tap setting

Is(110kv side) = 8 x 3.5 = 28.0 amps

Is(13.8 kv side) = 8 x 5.0 = 40.0 amps

CT secondary voltage at 8 x tap setting

Es(110 kV side) = 0.799 x 28.0 = 22.4 volts

Es(13.8 kV side) = 1.376 x 40.0 = 55.0 volts

From the excitation curves for CT being used:

Excitation current I_E corresponding to the secondary voltage, Es

I_E(110 kV side) = 0.034 A @ 22.4 volts

I_E(13.8 kV side) = 0.014 A @ 55.0 volts

Therefore, percent error in each CT = $\frac{I_E}{I_S} \times 100$

% error (110 kV CT's) = $\frac{0.034}{28} \times 100\% \doteq 0.12\%$

% error (13.8 kV CT's) = $\frac{0.014}{40} \times 100\% = 0.035\%$

Percent error is less than 20% and hence the CT ratio and relay taps are satisfactory.

To determine percentage slope setting:

Maximum range of transformer mannual taps = 10%

Percent of mismatch of relay taps = 3.62%

Total = 13.62%, Therefore use 25% taps.

5.3.6 Selection of 110 kV System Protective Device Settings

a) Summary of Protective Equipment Used

For summary of the equipment used in the 110 kV system utility tie circuit and for recommended settings, refer to DWG. No. 5B-1 in Appendix "B". Also for the time current coordination curves refer to section 5.4.

b) Calculation and Recommended Settings

Utility Tie Transformer Parameters

Transformer capacity p 20/26/33 MVA, 124 kV - 13.8 kV with $\pm$10% off load taps.

Impedance = 10% on 20 MVA (self cooled) Base

= 0.5 per unit on 100 MVA Base.

Full load current = 836 A @ 13.8 kV on self cool rating (20 MVA)

= 105 A @ 110 kV on self cool rating (20 MVA)

Estimated magnetizing inrush = 836 x 15 = 12 540 A @ 13.8 kV

= 105 x 15 = 1575 A @ 110 kV

Transformer short circuit withstand

= 10 x 836 = 8360 A @ 13.8 kV for 5.0 seconds

= 10 x 105 = 1050 A @ 110 kV for 5.0 seconds.

Asymmetrical short circuit current through transformer

$$= \frac{100\times10^3\times1.6}{1.73\times13.8\times(0.04^*+0.5)} = 12\ 400 \text{ A @ 13.8 kV}$$

$$= 12\ 400\ \frac{13.8}{110} = 1556 \text{ A @ 110 kV}$$

* System three phase short circuit impedance in per unit on 100 MVA Base.

<u>Phase Overcurrent Protection</u>

For satisfactory phase overcurrent relay coordination, the following must be satisfied:

1) Relay pickup should not exceed 250% of the utility tie transformer full load current (code requirement), nor be less than transformer full load current.

2) Selectivity must be obtained with the 13.8 kV utility tie circuit breaker protective device settings.

3) The utility tie transformer must be protected against short circuits.

4) Feeder cables must be protected against short circuits.

5) Relay instantaneous setting must exceed the asymmetrical short circuit current through the utility tie transformer.

To satisfy the above requirements, the following settings have been selected:

CT râtio 200/5

Set IAC77B6A phase overcurrent relay pickup at 5 A tap $= 5 \times \frac{200}{5} = 200$ A @ 110 kV (190.5% of transformer full load current) = 1595 A @ 13.8 kV.

Set time dial at 5

Use 2.0 A tap for seal-in unit

Set instantaneous at 40 A $= 40 \times \frac{200}{5} = 1600$ A @ 110 kV

$= \frac{110}{13.8} \times 1600 = 12\ 750$ A @ 13.8 kV

For coordination curves, refer to section 5.4, Fig. No. 12.

Ground Overcurrent Protection

A type IAC77B6A relay (residually connected) is used to provide ground overcurrent protection for the 110 kV circuit between the oil circuit breaker and the transformer. This relay is connected in the neutral circuit of the 200/5 A CT's on the oil circuit breaker line side bushings, and is wired to trip the 110 kV system oil circuit breaker.

Since the utility tie transformer is connected delta-wye, it is not necessary to co-ordinate the 110 kV system ground relaying with the 13.8 kv system ground rélaying. Thus the ground overcurrent relay may be set at the minimum setting to provide optimum ground fault protection.

CT ratio = 200/5

Set IAC77B6A ground overcurrent relay pick up at 4 A tap

$= 4 \times \frac{200}{5} = 160$ A @ 110 kV

$= 1275$ A @ 13.8 kV

Set time dial at 1/2

Use 2.0 A tap for seal-in unit

Set instantaneous at 40 A $= 40 \times \frac{200}{5} = 1600$ A @ 110 kV

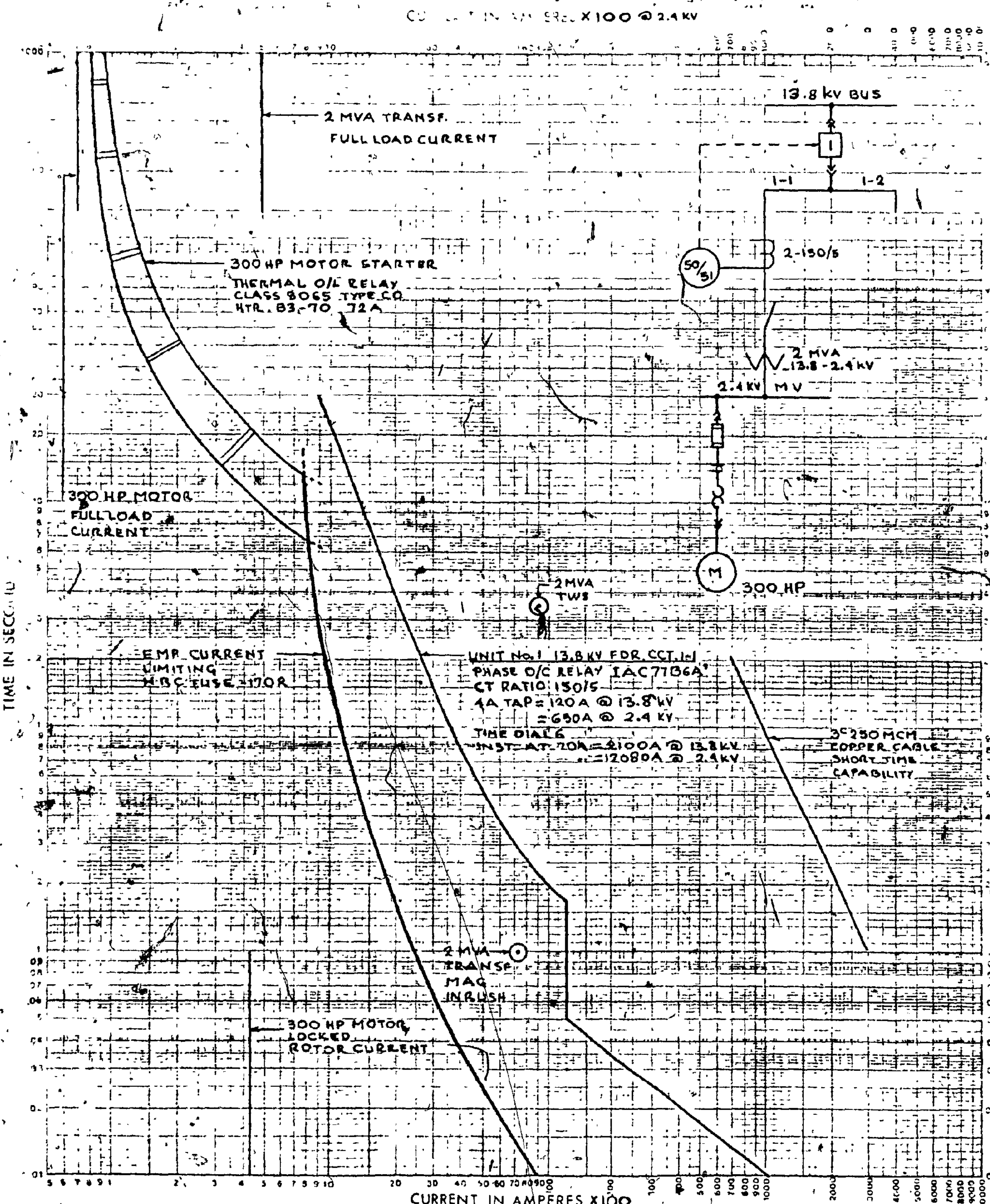
$= 12\,750$ A @ 13.8 kV.

5.4 Time-Current Characteristic Curves

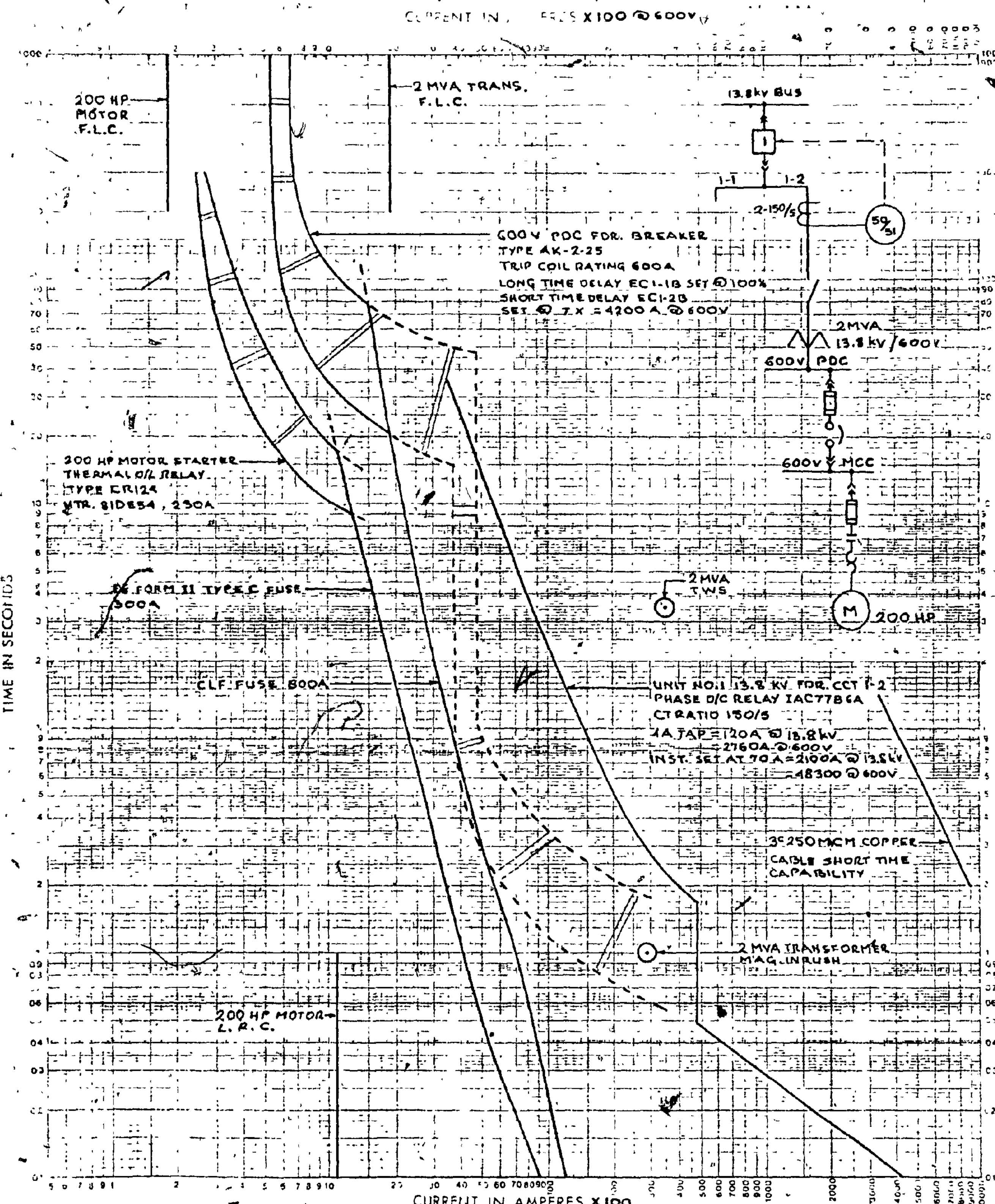
This section contains the Time-Current Characteristic Curves for all 13.8 kV feeder circuits , utility tie breaker circuit and the three voltage levels ground circuits in the following order:

Fig. 1	FEEDER 1-1
Fig. 2	FEEDER 1-2
Fig. 3*	FEEDER 2-1
Fig. 4*	FEEDER 2-2
Fig. 5*	FEEDER 3-1
Fig. 6*	FEEDER 3-2
Fig. 7	FEEDER 4-1
Fig. 8*	FEEDER 4-2
Fig. 9	FEEDER 5-1
Fig. 10*	FEEDER 5-2
Fig. 11*	FEEDER 6-2
Fig. 12	UTILITY TIE
Fig. 13	13.8 kV GROUND
Fig. 14	2.4 kV GROUND
Fig. 15	600 V GROUND

* NOTE: For the purpose of this paper Fig's designated by an asterisc are not shown in this section because they are all identical to Fig. 2. However in an official industrial report all coordination curves must be separately worked out and drawn.



CORDINATION BETWEEN 13.8 KV FDR. PHASE O/C RELAY & 300 HP MOTOR STARTER PROTECTIVE DEVICES	TIME - CURRENT CHARACTERISTIC CURVES	
BASIS FOR DATA Standards	Dated	
1. Tests made at Volts a-c at p-f, Starting at 25C with no initial load	No. FIG No. 1	FEEDER 1-1
2. Curves are plotted to Test points so variations should be	Date	



COORDINATION BETWEEN 13.8 KV FDR. BKR. PHASE O/C RELAY TIME-CURRENT CHARACTERISTIC CURVES

For 600V PDC BKR. & 200 HP MOTOR STARTER PROTECTIVE DEVICES Fuse Links ___ In ___

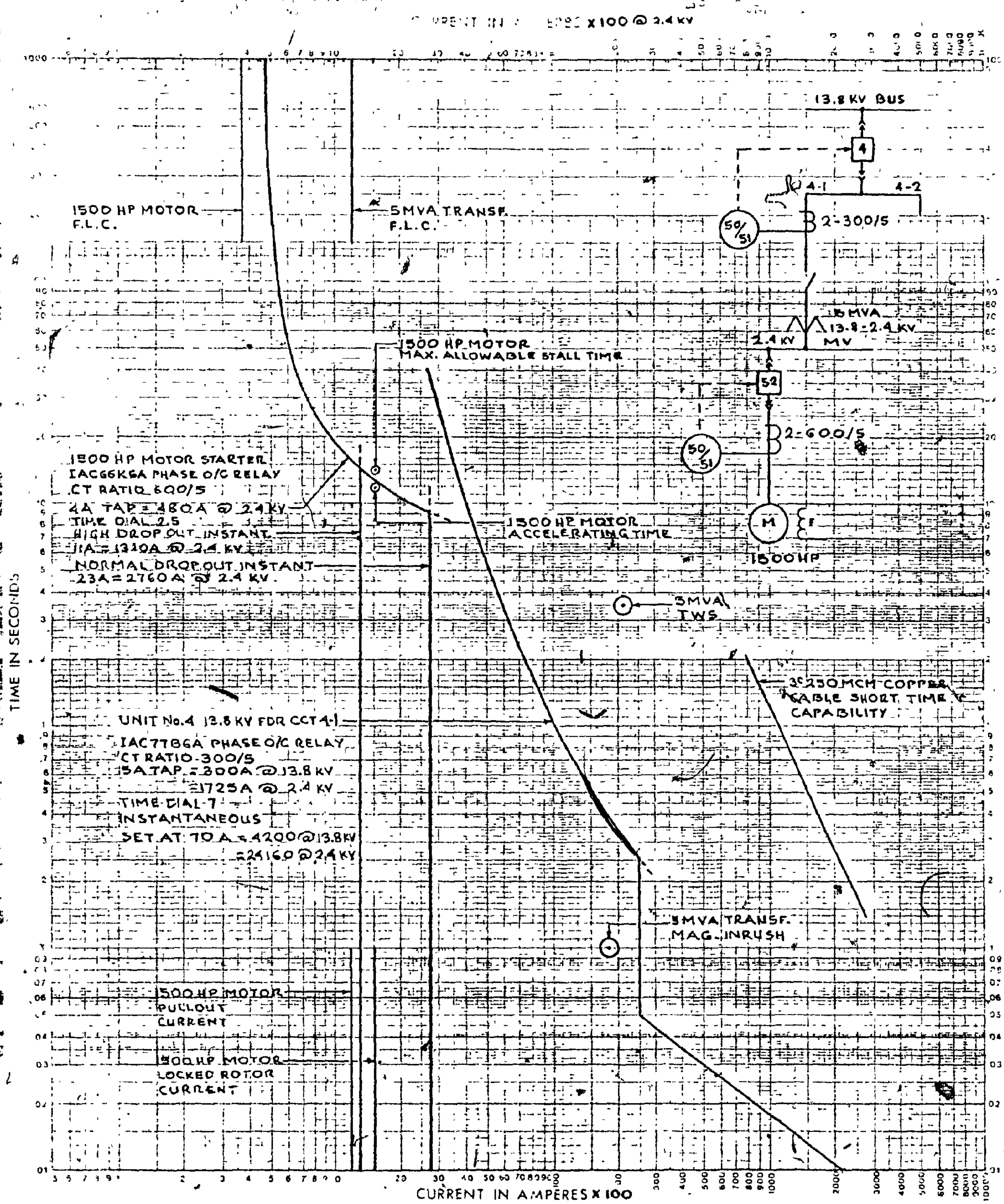
BASIC FOR DATA Standards ___ Dated ___

1 Tests made at ___ Volts ___ c at ___ p-f Starting at 25C with no initial load

2 Curves are plotted to ___ Test points so variations should be ___

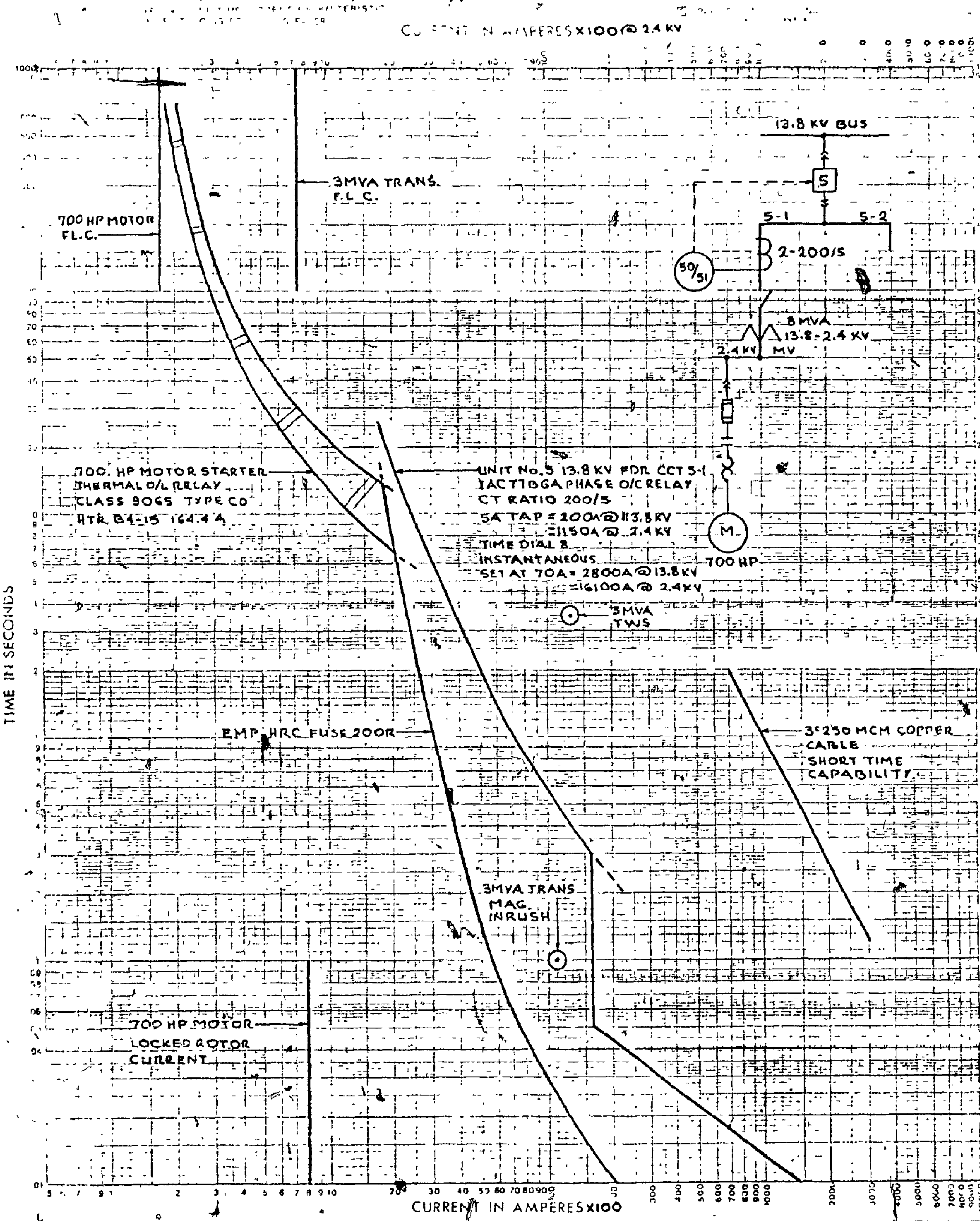
No Fig No. 2 FEEDER 1-2

Date ___



COORDINATION BETWEEN 13.8 KV FDR. BKR. PHASE O/C TIME-CURRENT CHARACTERISTIC CURVES
For RELAY & 1500 HP 2.4 KV MOTOR STARTER PROT. DEVICES Fuse Links In
BASIS FOR DATA Standards Dated
1 Tests made at volts a-c at p-f Starting at 25C with no initial load
2 Curves are plotted to Test points so variations should be

No FIG. No. 7 FEEDER 4-1
Date



COORDINATION BETWEEN 13.8 KV FDR. BKR. PHASE O/C RELAY AND 700 HP MOTOR STARTER PROTECTIVE DEVICES

TIME-CURRENT CHARACTERISTIC CURVES

Fuse Links ___ In ___

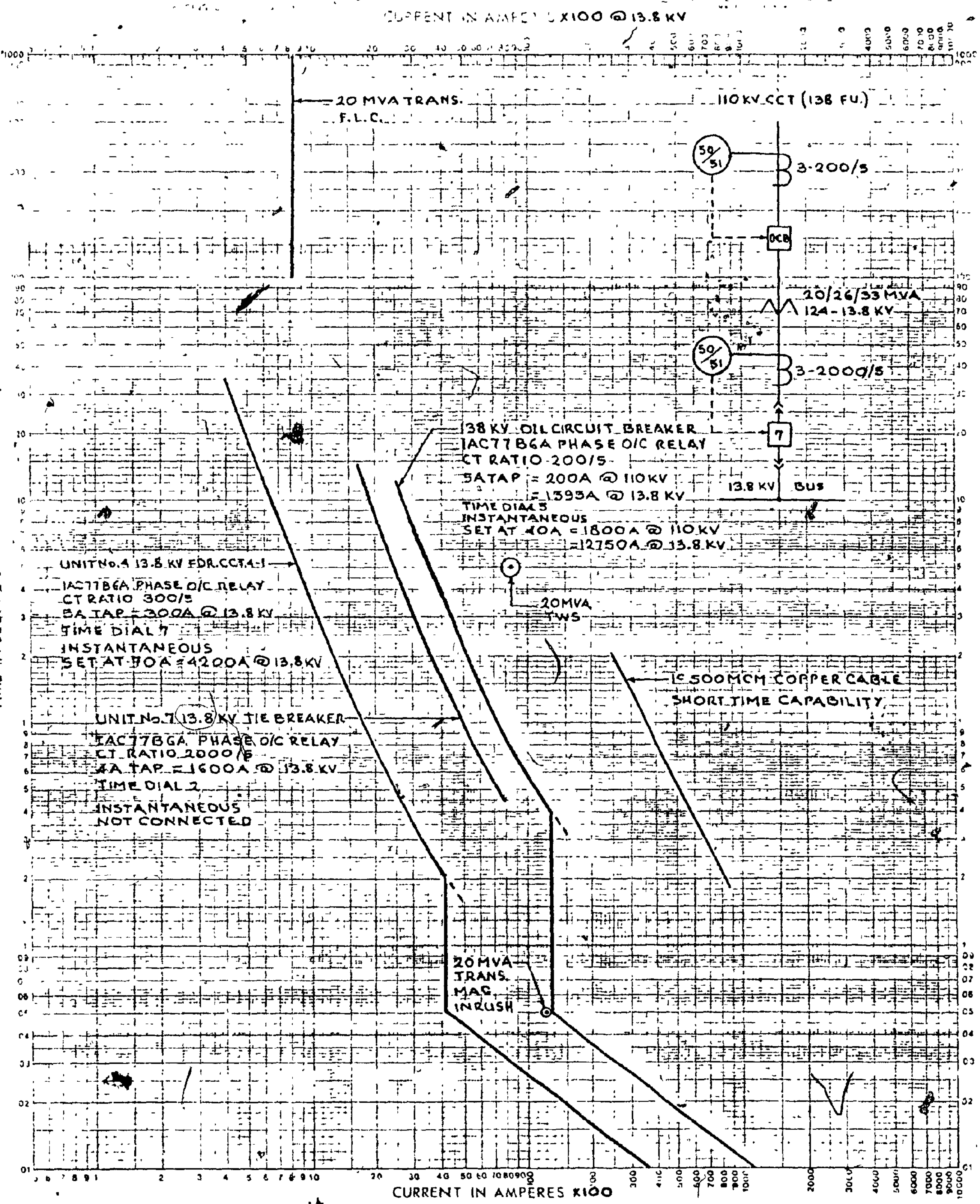
BASIS FOR DATA Standards ___ Dated ___

1 Tests made at ___ Volts a-c at ___ per Starting at 25C with no initial load

2 Curves are plotted to ___ Test points so variations should be ___

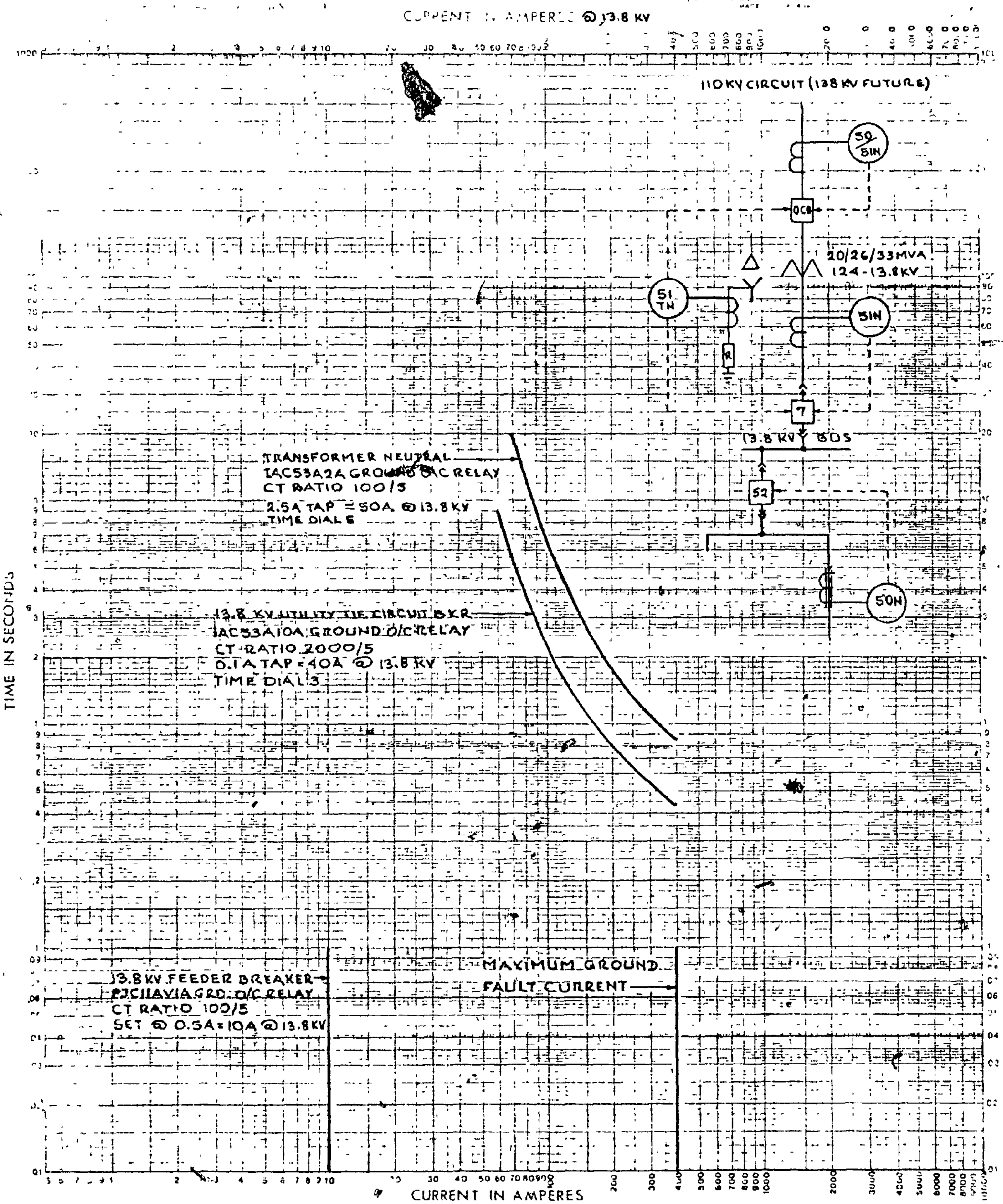
No FIG. No. 9 FEEDER 5-1

Date ___



COORDINATION BETWEEN 138 KV OCB PHASE O/C RELAY TIME – CURRENT CHARACTERISTIC CURVES
For 13.8 KV TIE BKR. PHASE O/C RELAY & 13.8 KV LARGEST FDR. BKR. Fuse Links __ In __
BASIS FOR DATA Standard __ PHASE O/C RELAY __ Dated __
1 Tests made at __ volts a-c at __ p-f Starting at 25C with no initial load __
2 Curves are plotted to __ Test points so variations should be __

No Fig. No. 12 UTILITY TIE
Date __



TIME-CURRENT CHARACTERISTIC CURVES

For 13.8 KV SYSTEM GROUND RELAYING COORDINATION

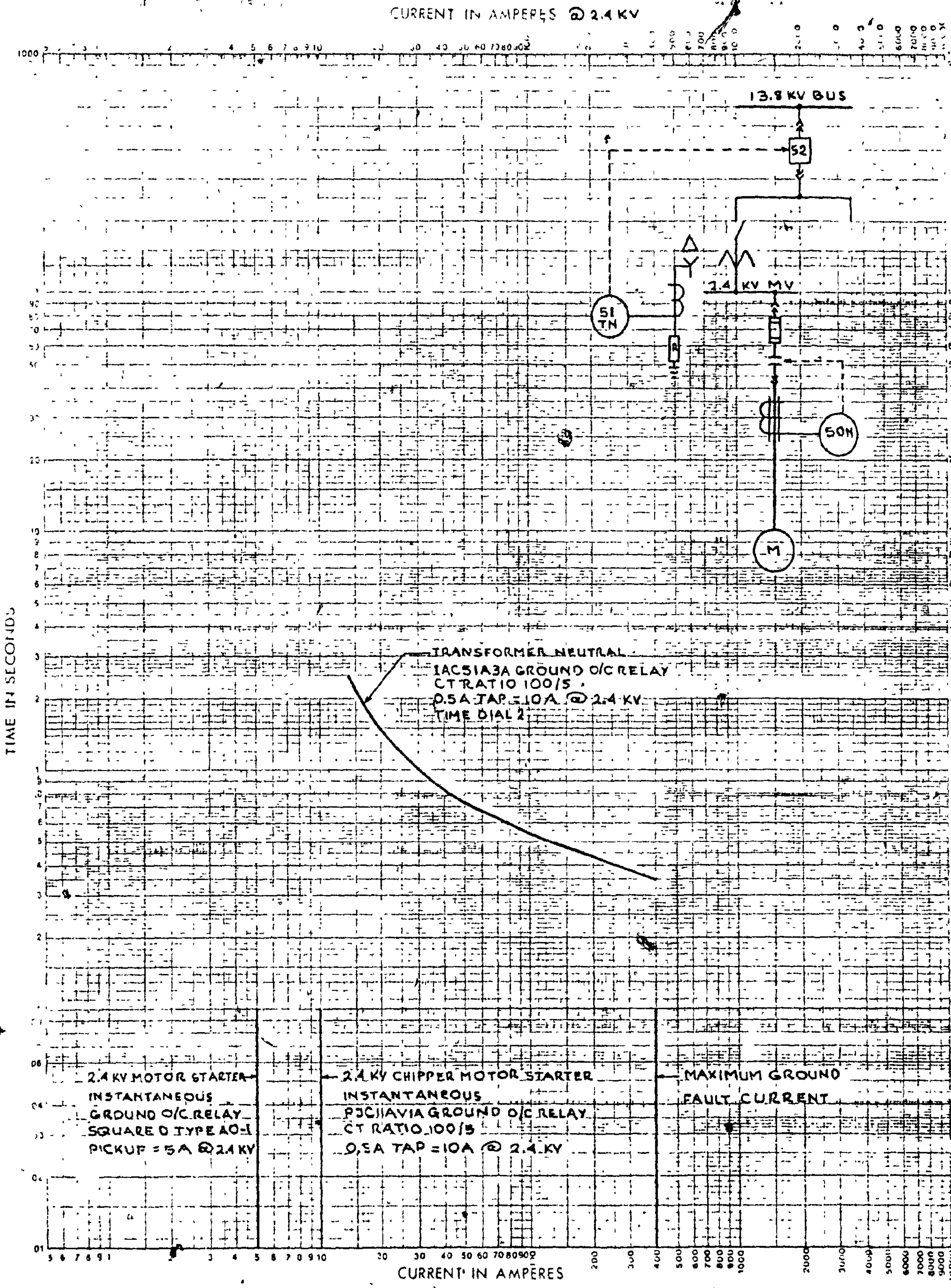
BASIS FOR DATA Standards ______ Dated ______

1 Tests made at ______ Volts a-c at ______ p-f Starting at 25C with no initial load ______

2 Curves are plotted to ______ Test points so variations should be ______

No FIG. No 13 13.8 KV GRD. RELAYING

Date ______



TIME-CURRENT CHARACTERISTIC CURVES

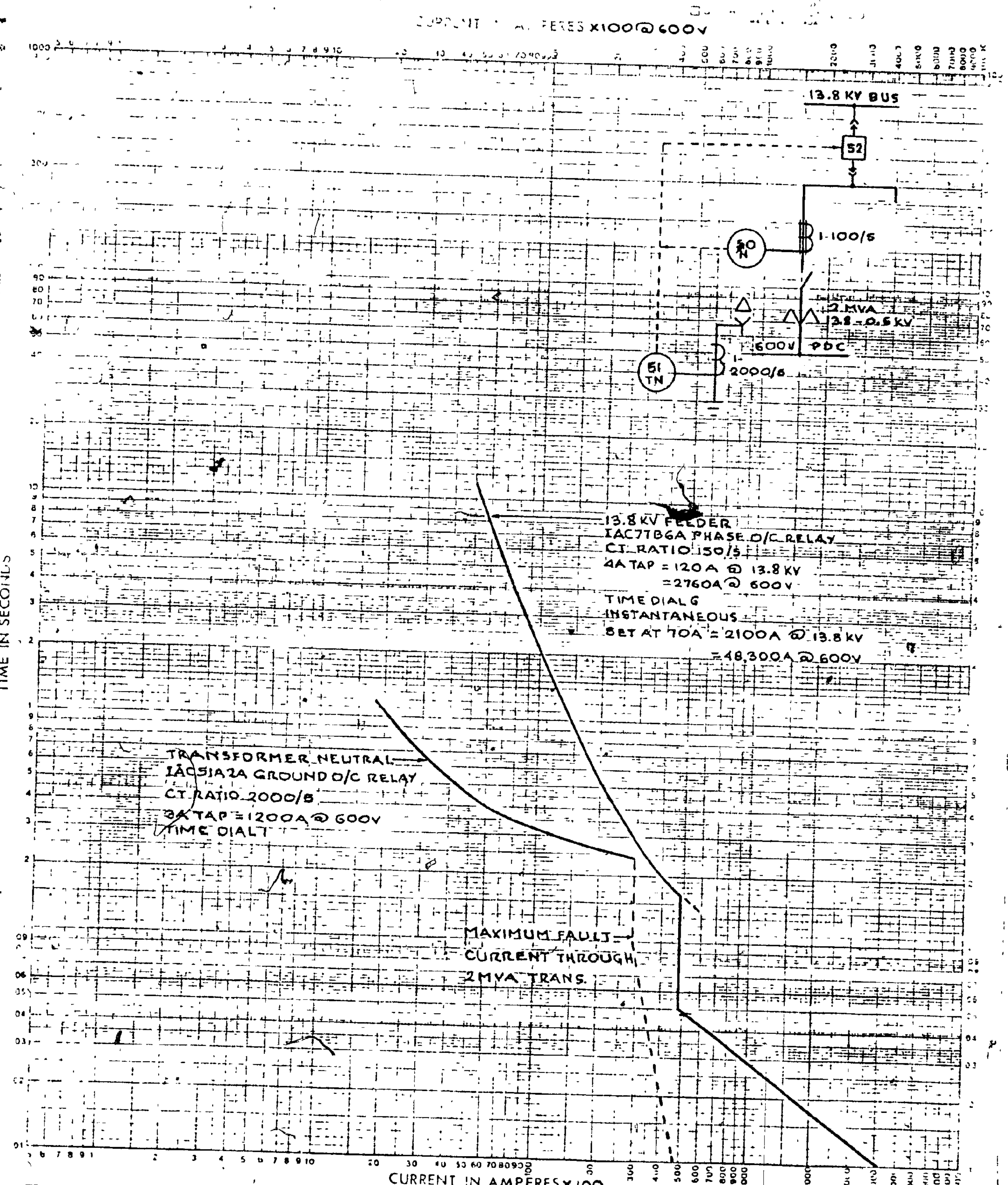
For 2.4 KV SYSTEM GROUND RELAYING COORDINATION Links ... In ...

BASIS FOR DATA Standards ... Dated ...

1 Tests made at ... Volts a-c at ... p-f. Starting at 25C with no initial load

2 Curves are plotted to ...

No. Fig. No. 14 ...



F-- 600V SYSTEM GROUND RELAYING COORDINATION — TIME-CURRENT CHARACTERISTIC CURVES — Fuse Links — In

BASIS FOR DATA Standards — Dated

1 Tests made at — Volts a-c at — p-f Starting at 25C with no initial load

2 Curves are plotted to — Test points so variations should be —

No FIG. No. 15 — 600 V GRD. RELAYING

Date

6. CONCLUSION

Analysis of the commonly encountered problems in today's industrial power distribution systems, consideration of all anticipated problems in a particular power distribution system, proper selection and coordination of protective devices, and a systematic approach to the system design are the basic principles in power system design.

The engineer designing an industrial power distribution system should evaluate all equipment and scheme options in order to select the system that best suits the plant's operations. Also, he should exercise considerable engineering judgement, as all phases of industrial power system engineering cannot be expressed in numbers or solved by formulas.

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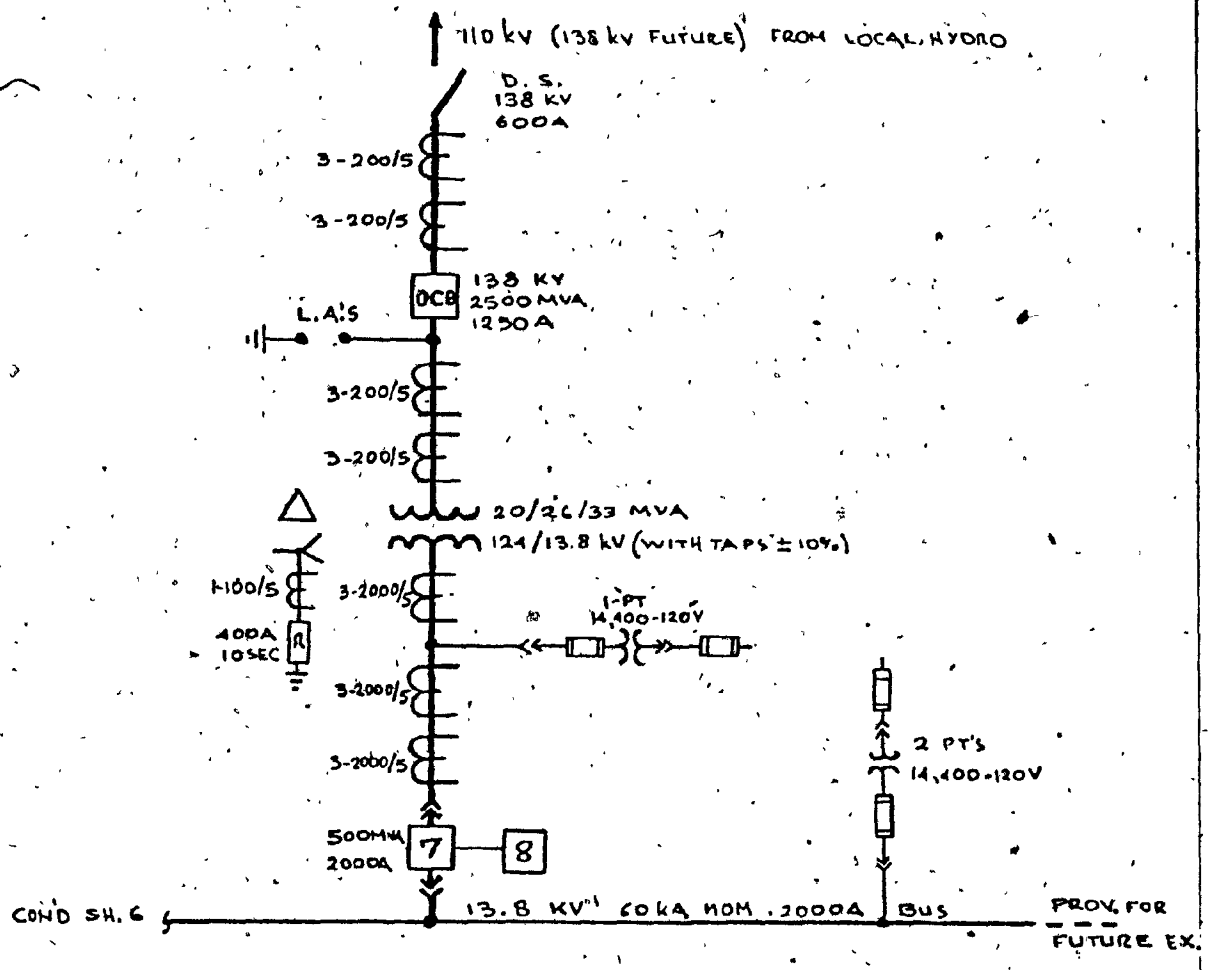
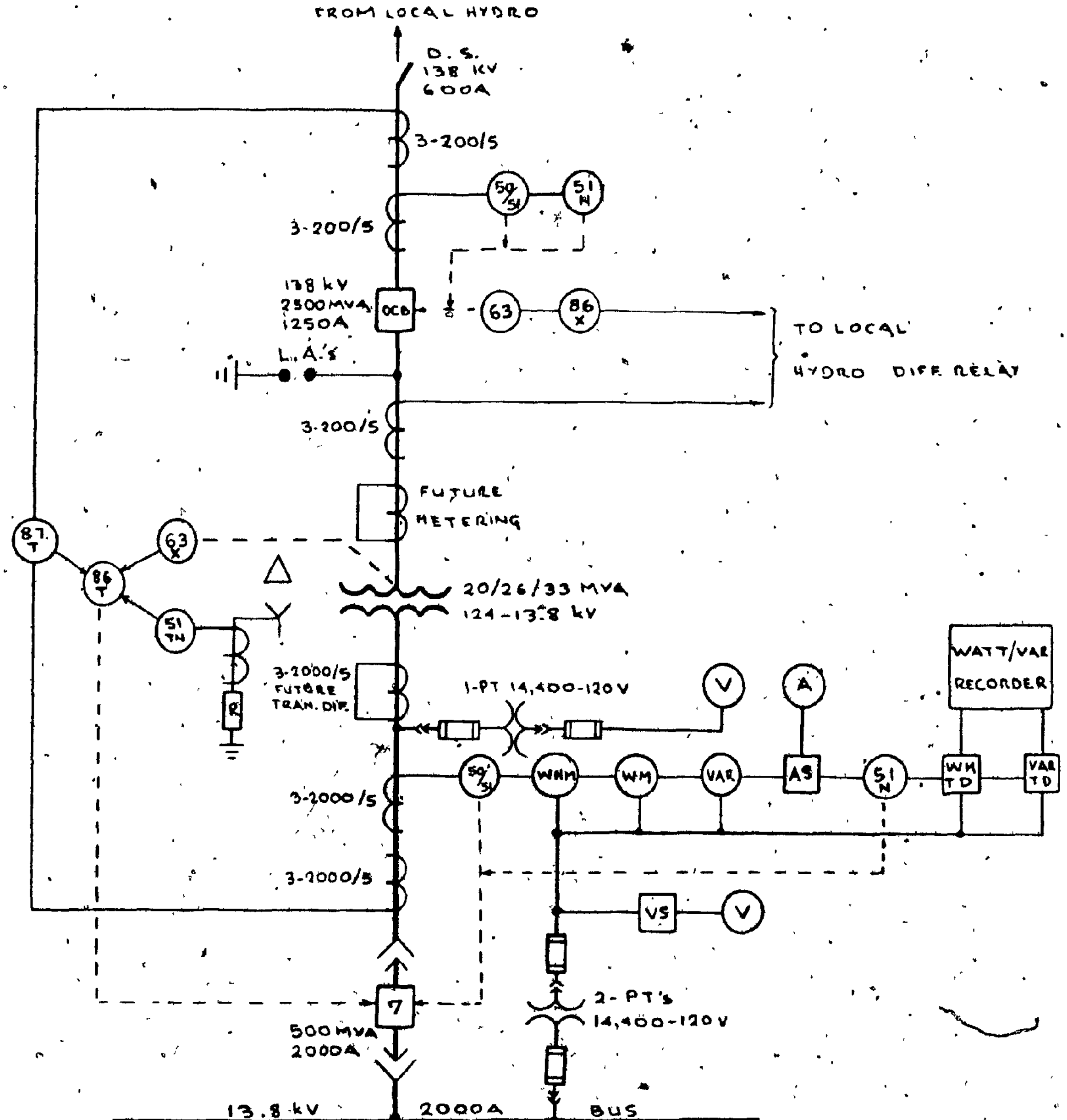


SINGLE LINE DIAGRAM

DWG. NO. 5A-1 SH.7

APPENDIX

"B"



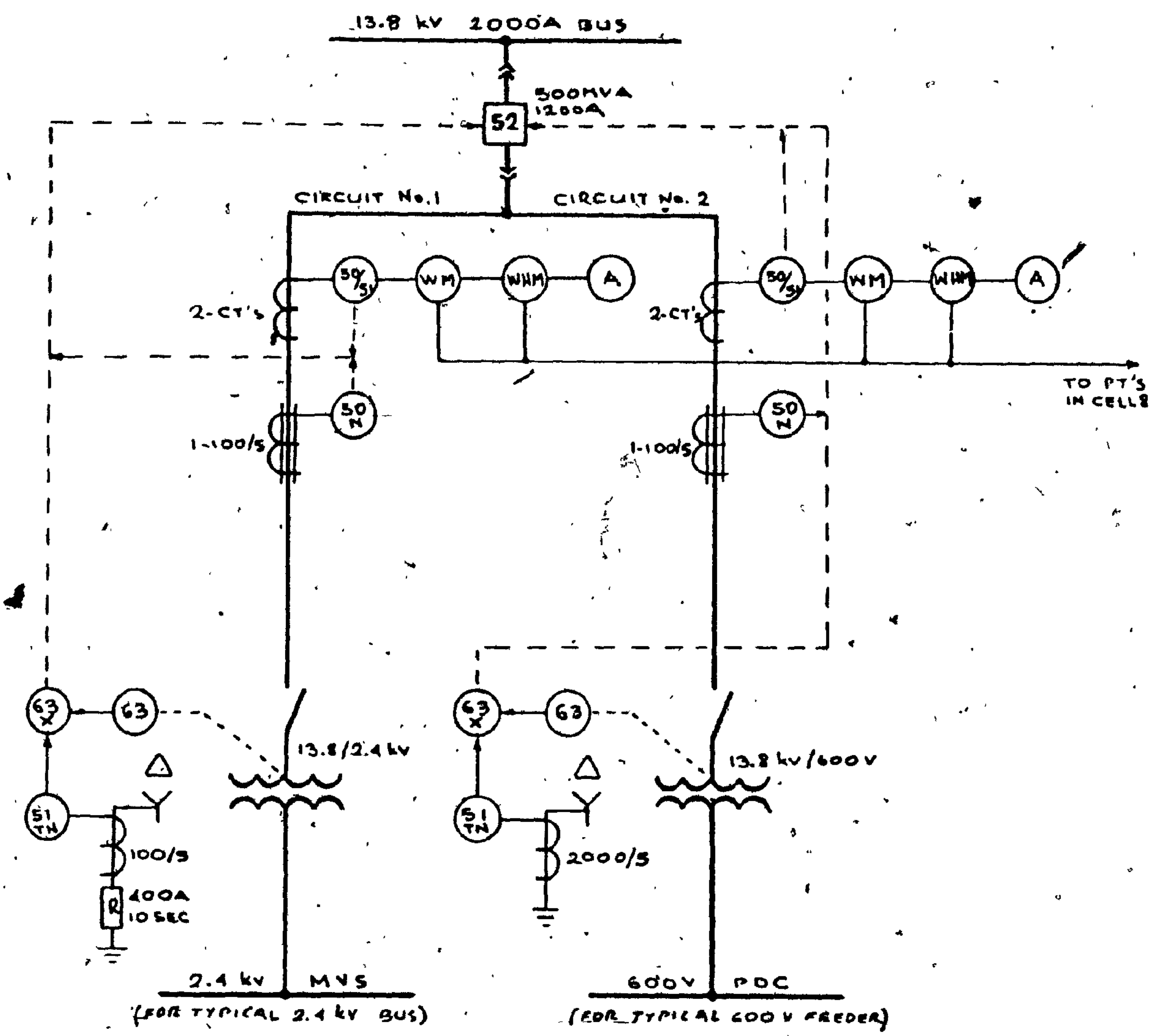
13.8 kV TIE CIRCUIT

METERING & RELAYING
SINGLE LINE DIAGRAM
DWG. NO. 5B-1

TABLE 5B-1

UNIT No.	DESCRIPTION	DEVICE No.	DESCRIPTION	RELAY TYPE	SETTINGS	REMARKS
7	13.8 kV TIE CIRCUIT	50/51	PHASE OVERCURRENT RELAY	IAC77B6A	4A TAP, TIME DIAL 2, SEALING-IN UNIT 2.0A	INST. SET 160A BUT TRIP FUNCTION DISC.
		51N	GROUND OVERCURRENT RELAY	IAC53A10A	0.1A TAP, TIME DIAL 3, SEALING IN UNIT 2.0A	
		51TN	GROUND OVERCURRENT RELAY	IAC53A2A	2.5A TAP, TIME DIAL 5, SEALING-IN UNIT 0.2A	
		87T	DIFFERENTIAL RELAY	BDD15B11A	FOR WYE CONNECTED CT'S (110 kV SIDE): USE 3.5A TAP. FOR DELTA CONNECTED CT'S (13.8 kV SIDE) USE 5.0A TAP, USE 25% RELAY TAP FOR PERCENT SLOPE SETT'G.	
		63X	REMOTE PROTECTIVE TRIP RELAY	HSA11AGA	SEAL-IN UNIT SET AT 0.2A	
8	13.8 kV TIE CIRCUIT AUXILARY	50/51	PHASE OVERCURRENT RELAY	IAC77B6A	5A TAP, TIME DIAL 5, INSTANTANEOUS 40, SEAL-IN UNIT 2.0A	
		51N	GROUND OVERCURRENT RELAY	IAC77B6A	4A TAP, TIME DIAL ½, INSTANTANEOUS 40, SEAL-IN UNIT 2.0A	
		86X	LOCAL HYDRO DIFF. AUX. TRIP RELAY	HSA11A6A	SEAL-IN UNIT 2.0A	

SUMMARY OF 13.8 kV TIE CIRCUIT PROTECTIVE RELAY SETTINGS



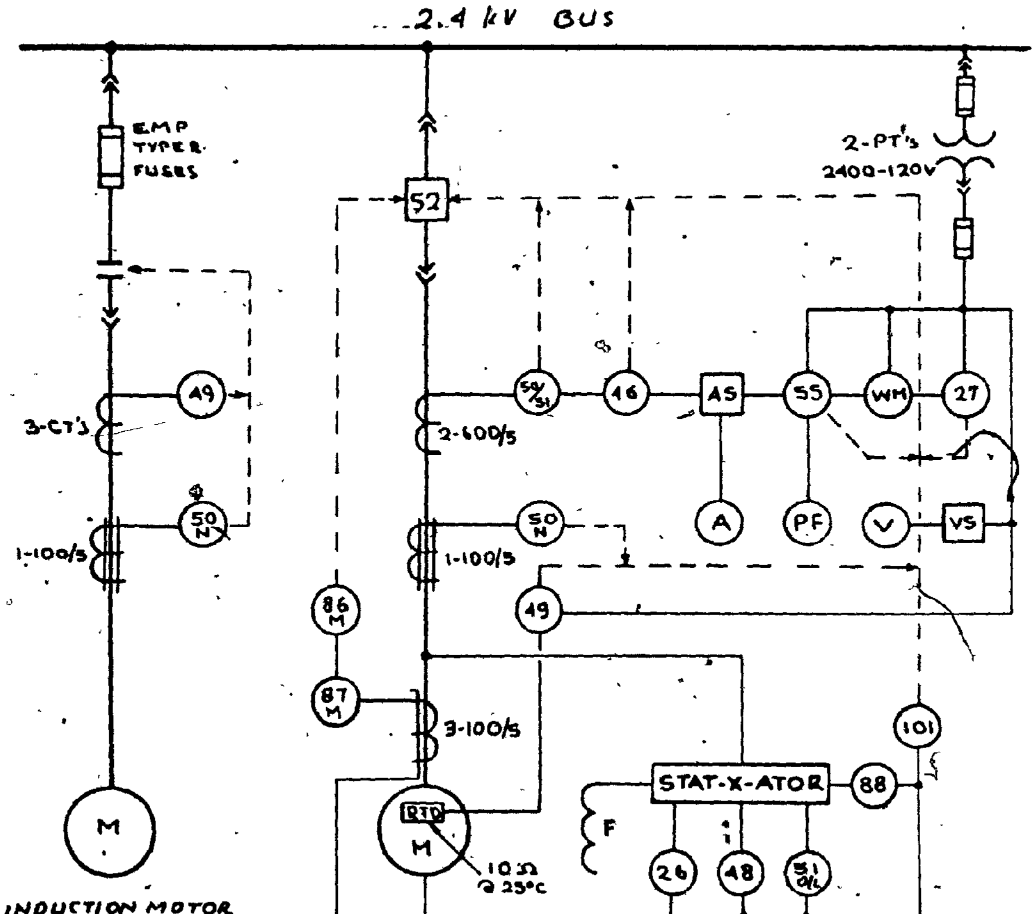
TYPICAL 13.8 kV FEEDER

METERING & RELAYING
SINGLE LINE DIAGRAM
DWG. NO. 5B-2

TABLE 5B-2

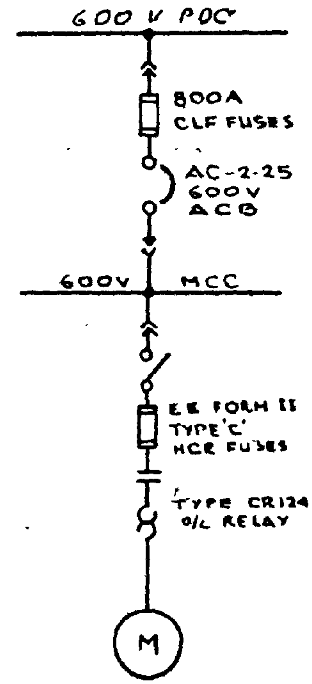
UNIT No.	CIRCUIT No.	DESCRIPTION	TRANSFORMER BANK KVA	TRANSFORMER BANK HV-LV (KV)	PHASE OVERCURRENT RELAY (50/51) CT RATIO	RELAY TYPE	TIME DELAY TAP	TIME DELAY TIME DIAL	TIME DELAY SEAL-IN UNIT	INSTANT. SET	GROUND O/C REL. (50N) RELAY TYPE	INSTANTAN. SET	TRANS. GROUND O/C REL. (51TN) RELAY TYPE	TIME DELAY TAP	TIME DELAY TIME DIAL	TIME DELAY SEAL-IN UNIT	REMOTE PROT. TRIP RELAY TYPE HSA11A&A SEAL-IN UNIT	REMARKS
1	1-1	FLASH DRYER	2000	13.8-2.4	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A3A	0.5	2	0.2A	63X/1 - 0.2A	
	1-2	WASHING & SCR'G PRIMARY CLARIFIER	2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	
2	2-1	DIGESTER BLOW HEAT RECOVERY	2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/1 - 0.2A	
	2-2	B.S. WASHING & SCREENING	2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	
3	3-1	BLEACHING	2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/1 - 0.2A	
	3-2		2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	
4	4-1	WOODROOM	3000	13.8-2.4	300/5	IAC77B6A	5	7	2.0	70	P3C11AV1A	0.5A	IAC51A3A	0.5	2	0.2A	63X/1 - 0.2A	
	4-2		2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	
5	5-1	POWER, RECOVERY RECAUSTICIZING	3000	13.8-2.4	300/5	IAC77B6A	5	8	2.0	10	P3C11AV1A	0.5A	IAC51A3A	0.5	2	0.2A	63X/1 - 0.2A	
	5-2		2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	10	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	
6	6-2	SHOPS, STORES	2000	13.8-0.6	150/5	IAC77B6A	4	6	2.0	70	P3C11AV1A	0.5A	IAC51A2A	3	1	0.2A	63X/2 - 0.2A	CIRCUIT 6-1 NOT WIRED

SUMMARY OF 13.8 kV FEEDER PROTECTIVE DEVICE SETTINGS



TYPICAL 2.4 kV MOTOR FDR.

1500 HP CHIPPER MOTOR FDR.



TYPICAL 600V MOTOR FDR.

METERING & RELAYING
SINGLE LINE DIAGRAM
DWG. NO. 5B-3

TABLE 5B-3A

13.8kV FEEDER No.	MV No.	QUANTITY OF MOTORS	MOTOR HP RATING	RPM	FLC (AMPS)	LRC (AMPS)	FUSE		THERMAL OVERLOAD RELAY (49)					50N CLASS 8506 TYPE AO-1	
							TYPE	SIZE	CT RATIO	CLASS	TYPE	THERM. UNIT No.	PICKUP (AMP) NON-ADJUST.	PICKUP NON-ADJUSTABLE	
1-1	11	1	250	1200	60	348	EMP	130R	100:5	9065	CO	83.30	57.2	5A	
		1	300	1200	71	421	EMP	170R	100:5	9065	CO	83.10	72.0	5A	
		2	250	900	61	348	EMP	130R	100:5	9065	CO	83.30	57.2	5A	
		2	300	1800	70	421	EMP	170R	100:5	9065	CO	83.10	72.0	5A	
4-1	41	2	500	1200	116	694	EMP	200R	150:5	9065	CO	84.15	123.3	5A	
		1	400	1200	93	555	EMP	200R	150:5	9065	CO	83.30	85.8	5A	
		2	600	1800	133	833	EMP	230R	200:5	9015	CO	83.10	144.0	5A	
		1	700	1800	153	1030	EMP	230R	200:5	9065	CO	84.15	164.4	5A	
5-1	51	1	400	1200	93	555	EMP	200R	150:5	9065	CO	83.70	85.8	5A	
		1	700	900	164	820	EMP	200R	200:5	9065	CO	84.15	164.4	5A	
		1	600	3600	133	950	EMP	230R	300:5	9065	CO	83.10	144.0	5A	
		2	400	514	97	485	EMP	170R	150:5	9065	CO	83.30	85.8	5A	
		2	250	1800	60	348	EMP	130R	100:5	9015	CO	83.30	57.2	5A	
		1	500	1200	116	694	EMP	200R	150:5	9065	CO	84.15	123.3	5A	

SUMMARY OF 2400 VOLT MOTOR PROTECTIVE DEVICE SETTINGS

TABLE 5B-3B

13.8 kV FEEDER No.	MV No.	MOTOR RATING	DEVICE No.	DESCRIPTION	RELAY TYPE	SETTINGS	REMARKS
4-1	41 UNIT 411	1500 HP 327 RPM SYNCH. CHIPPER MOTOR	50/51	PHASE OVERCURRENT RELAY	TACG6K6A	4A TAP, TIME DIAL 2.5, 51/10C-A NORMAL DROP OUT INST. 23 A., 51/10C-B, HI-DROP OUT INST. 11A SEAL-IN UNIT 2.0 A.	
			50N	GROUND OVERCURRENT RELAY	PJC11AV1A	SET AT 0.5A	
			46	CURRENT BALANCE RELAY	IJC51B3A	SET TIME DIAL AT 10, HOLDING-IN COIL 1 AMP	
			55	POWER FACTOR RELAY (BASLER)	22900-101	SET AT 0.8 PF LAGGING WITH 0.25 SECONDS T.D.	
			49	TEMPERATURE RELAY	IRT51A14A	HI-TEMP. PICKUP 120°C, LO-TEMP. RESET 110°C	
			27	AC UNDERVOLTAGE RELAY	IAV54E1A	55 VOLT TAP, TIME DIAL 1, SEAL-IN UNIT 2.0A.	
			PF	P.F. RELAY STARTING TIMER (AGASTAT)	2412AD	SET AT 15 SECONDS	
			87M	DIFFERENTIAL RELAY	PJC31D23A	SET AT 0.5 AMPS, SEAL-IN UNIT 0.2A	
			101	AUXILIARY TRIPPING RELAY	H5A11A4A	SEAL-IN UNIT 2.0 A	

SUMMARY OF 2400 VOLT 1500 HP CHIPPER MOTOR PROTECTIVE DEVICE SETTING

TABLE 5B-3C

SUMMARY OF 600 VOLT MOTOR PROTECTIVE DEVICE SETTINGS

13.8 KV FEEDER No.	PDC No.	MCC No.	CONNECTED HP	MISC LOAD KVA	LARGER MOTOR (HP)	600 V SWITCHGEAR TYPE & CHARACTERISTICS
1-1	11	111	320	–	125	TYPE AK-2-25 AIR CIRCUIT
		112	335	75	75	BREAKERS (EACH FEEDER)
		113	355	–	150	
		114	310	–	60	TRIP COIL RATING 600 A
		115	451	15	150	TRIP CHARACTERISTICS
2-1	12	121	456	–	125	& SETTINGS
		122	380	–	200	LONG TIME DELAY –
		123	477	–	150	ECI-18 @ 100%
		124	452	–	200	SHORT TIME DELAY –
		125	450	–	150	SET AT 7 X
2-2	22	221	350	–	125	
		222	341	–	125	FUSE TYPE – CLF
		223	540	–	100	FUSE RATING – 800 A
		224	333	–	200	
		225	465	–	100	NOTE: SAME SWITCHGEAR
3-1	31	311	332	–	150	SETTINGS AND FUSE
		312	380	–	100	RATINGS USED FOR
		313	415	–	125	EACH FEEDER IN
		314	410	–	200	ALL PDC'S.
		315	390	–	100	
3-2	32	321	470	–	125	
		322	433	–	100	
		323	413	–	125	
		324	351	–	30	
		325	87	280	30	
4-2	42	421	315	100	75	
		422	369	–	150	
		423	363	–	200	
		424	150	–	40	
5-2	52	521	288	–	50	
		522	483	–	100	
		523	11	327	1	
		524	269	–	125	
		525	151	360	40	
		526	263	–	100	
6-2	62	621	92	–	50	
		622	340	–	100	
		623	392	–	100	

SCALE:				DEPARTMENT: ELECTRICAL			
MOTOR				FUSED COMBINATION STARTER		THERMAL O/L RELAY	
HP	RPM	FULL LOAD CURRENT (AMPS)	LOCKED ROTOR CURRENT (AMPS)	STARTER SIZE	EE FORM II CLASS 'C' FUSE RATING (AMPS)	HEATER NO. 81D...	ULTIMATE TRIPPING CURRENT (AMPS)
.5	1200	0.7	8	1	6A	527	0.713
.5	900	1.2	8	1	6A	238	1.358
.75	1800	1.0	10	1	6A	530	1.08
.75	1200	1.3	10	1	6A	238	1.36
.75	900	1.6	10	1	6A	533	1.69
1	1800	1.3	12	1	6A	238	1.36
1	1200	1.6	12	1	6A	533	1.69
1	900	2.0	12	1	6A	536	2.18
1.5	3600	1.8	16	1	10A	535	2.01
1.5	1800	1.9	16	1	10A	535	2.01
1.5	1200	2.3	16	1	10A	537	2.45
1.5	900	2.6	16	1	10A	538	2.76
2	3600	2.3	20	1	10A	537	2.45
2	1800	2.4	20	1	10A	537	2.45
2	1200	2.8	20	1	10A	539	2.99
2	900	3.6	20	1	10A	542	3.84
3	3600	3.6	25.5	1	15A	542	3.84
3	1800	3.5	25.5	1	15A	542	3.84
3	1200	4.1	25.5	1	15A	543	4.28
3	900	4.9	25.5	1	15A	545	5.44
5	3600	5.4	37	1	20A	545	5.44
5	1800	5.5	37	1	20A	546	5.77
5	1200	6.3	37	1	20A	547	6.38
5	900	7.0	37	1	20A	548	7.14
7.5	3600	8.3	51	1	20A	550	8.78
7.5	1800	8.7	51	1	20A	550	8.78
7.5	1200	9.5	51	1	20A	553	10.4
7.5	900	10.0	51	1	20A	553	10.4
10	3600	10.3	65	1	25A	553	10.4
10	1800	10.5	65	1	25A	554	11.5
10	1200	12.0	65	1	25A	555	12.6
10	900	12.5	65	1	25A	555	12.6
10	720	15.0	65	1	25A	557	16.4
15	3600	15.0	93	2	40A	557	16.4
15	1800	16.0	93	2	40A	557	16.4
15	1200	18.0	93	2	40A	267	18.5
15	900	18.0	93	2	40A	267	18.5
15	720	18.0	93	2	40A	267	18.5
20	3600	20.0	116	2	50A	256	20.6
20	1800	20.5	116	2	50A	558	22.2
20	1200	23.5	116	2	50A	559	24.6
20	900	23.0	116	2	50A	559	24.6
20	720	24.0	116	2	50A	560	26.0

TABLE 5B-3C-1 SH.1

600 VOLT MOTORS FUSE & THERMAL O/L RELAY HEATER RATING