A STUDY OF RELAYING
FOR
THE PRIMARY TRANSMISSION SYSTEM
OF THE
MUNICIPAL LIGHT & POWER DEPARTMENT
CITY OF PASADENA

Thesis presented by

W. M. Evans

W. L. Newmeyer

In partial fulfillment of the requirements

for the degree of Master of Science

California Institute of Technology

Pasadena, California

1933

ACKNOWLEDGEMENT

We are very appreciative of the courtesy and assistance extended to us by the Municipal Light and Power Department of the City of Pasadena. In particular we wish to thank Mr. B. F. DeLanty, General Manager, for making available the files and records of the department. We also wish to thank Mr. E. L. Bettannier, Electrical Engineer, and Messrs. M. W. Edwards and K. R. Birge who greatly helped us in obtaining data on the system.

We are also very appreciative of the time and valuable suggestions given to us by Mr. E. R. Stauffacher of the Southern California Edison Company and Messrs. C. H. Hagey and F. L. Eley, of the same company, who made it possible for us to check some of our results on the calculating table.

To Dr. W. A. Lewis, Engineer for the Westinghouse Electric & Mfg. Co., we also wish to express our thanks for assisting us in making calculations by the symmetrical component method.

TABLE OF CONTENTS

CHAPTER I

THE PASADENA POWER SYSTEM

The Municipal Light & Power Department of the City of Pasadena has been operating an independent electric system for twenty seven years and now supplies all of the city of Pasadena. It's growth is shown briefly as follows:

1906	-	One 250 H. P. Generating Unit
1909	-	One 1000 H. P. Generating Unit
1914	--	One 1250 KW. Turbine Generator
1916	-	One 3000 KW. Turbine Generator
1920	-	Purchase of Southern California Edison System in Pasadena
1924	-	One 10,000 KW. Turbine Generator
1928	-	One 15,000 KW. Turbine Generator
1932	-	One 25,000 KW. Turbine Generator

Inasmuch as Pasadena is essentially a residential city and the future growth will probably be quite slow, the estimated future consumption will not exceed eighty five million kilowatt hours per year by 1940. Any planning will therefore be made on this basis and while certain changes and revisions of the existing system are quite needed, they will be made only after due consideration from the economic point of view as well as the engineering point of view.

This paper deals with the problem of revising and extending the present relay equipment for the 16.5 KV. transmission system. The present relaying consists almost wholly of line inverse time element and definite time element overload relays applied at the power and sub-stations. An attempt has been made in this paper to consider the relaying problem as a whole and to make a more or less fundamental study of the complete system, analyzing for short circuit currents and relay application by use of the symmetrical component method. However in so doing it has been necessary to limit the study to certain assumed conditions and also to assume that certain changes now planned will be consummated before the complete revision of the relaying.

The study was limited to the primary 16.5 KV. transmission system since it is not contemplated that any radical change will be made in the present relay arrangement for the secondary 2400 volt distribution. Quite complete supervisory control may be installed at a later date but since this is a problem, quite separate, discussion of this will not be made in this paper.

PRESENT POWER SYSTEM.

The present power system consists of:

(A) One power station, in which are located the following main generating units:

Unit #8 - Allis Chalmers, 31,250 KVA., 80% P.F., 16,500 volt, 50 cycle, 1500 R.P.M. Turbine Generator.

Unit #7 - Allis Chalmers, 18,750 KVA., 80% P.F., 11,000 volt, 50 cycle, 1500 R.P.M. Turbine Generator.

Unit #6 - Allis Chalmers, 12,500 KVA., 80% P.F., 2400 volt, 50 cycle, 1500 R.P.M. Turbine Generator.

Units one to five consist of smaller older generators of up to 3000 KW. capacity, but for the purpose of this paper, they are not considered since they are small, more or less obsolete and not expected to be used except in a possible emergency. As now operating and as expected to operate, Unit #8 will ordinarily supply the load since it is the most efficient. Units #6 and #7 will be standby and for use at offpeak times. From indications now at hand, unit #8 alone will be able to handle even the peak load for some years to come, so the relay calculations involving determinations of short circuit currents are made assuming this machine on the line alone.

Although the main power station is usually the only power supply, there is an arrangement with the Southern California Edison Company, whereby the load can be thrown onto their system in case of emergency. The tie-in feeder comes directly to the Pasadena Power Station 16.5 KV. bus from the Garfield Substation of the Southern California Edison Company. This feeds power from a 15,000 KVA. bank of transformers, the bank with its reactors (two in parallel) having an approximate reactance of 12%.

This tie-in is for emergency operation but is occasionally used when, on account of abundant water supply, the Southern California Edison Company can supply power at a rate which makes it advisable to shut down the steam station. The relaying for this power feeder is done at the Garfield Station so this is not considered in the present discussion. Because of the fact that this line is used only under abnormal conditions, and will practically never be operated in parallel with the power station, the calculations are based only on the actual operating conditions of the power station.

(B) Two main substations known as Raymond Substation and Lamanda Park Substation.

Each of these substations have two 3000 KVA. banks of transformers stepping down from 16,500 volts to 2400 volts. The sedondary 2400 volt distribution system radiates from these substations as well as from a 2400 volt substation located at the power plant.

At Raymond all 2400 volt feeder are controlled by automatic reclosing circuit breakers (three time close, then lockout) and this substation is practically unattended, an inspector visiting it several time a day. Any trouble causing a feeder to remain open requires the visit of a trouble man to close the breaker. The same is true if any primary circuit breaker opens. Notification of outages on the 2400 volt feeders is usually received by calls from customers reporting outages.

Lamanda Park Substation is an old manually operated substation taken over from the Southern California Edison Company in 1922. It is unattended during the day (except for inspection periods) until 3:30 p.m., at which time an inspector comes to the substation and remains until after the evening peak. This substation is quite obsolete having been built many years ago and it is only a question of a very short time until a new station will be erected on land several blocks away, this land already having been purchased.

(C) The 16.5 KV. Transmission System.

The diagram on page 8 shows the schematic layout of the system. Raymond and Lamanda Park Substations are fed by a loop line from the power station. Also fed from both Raymond and Lamanda Park is a 16.5 KV. line feeding the water pumping system. Finally there is a direct stub feeder from the power station to the California Institute of Technology. A tie-in to the Lamanda Park Feeder is also run to the Institute. On the diagram is also shown the proposed Maryland Substation and feeders to same, reference to which will be made below.

PRESENT RELAYING.

At the present time the relays (except for the differential protection of the generators) are all of the well known induction disc, time element overcurrent type. Although some attempt has been made to obtain selective breaker tripping, the method of operation today is to have all relays in the substations on the 16.5 KV. lines set for heavy overload and long time and the relays at the power station set to trip first. The reason for this is that the substations are usually unattended and it is considered better to trip at the power plant where an attendant can immediately reclose, rather than attempt to sectionlize at the substation, which would cause a line section to remain out until a man went to the substation to reclose the breaker. The present method of operation has proven fairly satisfactory as there have been few outages and the system is comparatively simple. However there is no assurance that under the present operation, some fault may not completely shut down the system whereas with proper relaying, sectionlizing would promptly take place, isolating the fault withing the smallest area possible and not putting out of service healthy parts of the system. It is for this reason that a general revision of the relaying is being contemplated, particularly so as the critical demand for nearly perfect service is growing with the increase in use of synchronous apparatus, electric clocks, etc.

PRESENT AND FUTURE DEVELOPMENTS.

The condition of load in the business section has caused several feeders to have nearly reached their capacity and because this central load is somewhat distant from the substation feeding it, proposals have been made to build a new substation adjacent to this load. This substation if built, will be known as Maryland and will be fed from the power station by a new feeder. It would also be tied in to the system by a connection to the present California Institute of Technology Line and to the Water Pump Line. The Pump Line could then receive power from any one, or mor, of the three substations, Raymond, Lamanda Park, and Maryland.

Because it is quite possible that the Maryland Substation will be built within a few years, it was considered advisable to proceed with the problem an this basis. If other developments take place, the following analysis of the problem is still applicable though the actual calculations would have to be revised.

Lamanda Park, as already mentioned, is quite obsolete so a new substation to replace this is planned for the very near future. The general scheme of connections on the 16.5 KV. side will be about as at present, though an emergency tie-in may be made with the Southern California Edison System at this point to supplement the one now at the power station. The new substation will be made as fully automatic as possible and probably supervisory control will be installed to permit control from the power station.

At present nearly all 16.5 KV. lines are overhead but much work has been done in installing conduit for placing underground both the primary 16.5 KV. lines and the secondary 2400 volt feeders. The lines from the power station to the Raymond, Lamanda Park and Maryland Sub-stations and most of the Pump Line will be underground cables. The cables used for these lines will be 500,000 c.m. and 350,000 c.m., three phase type H, 23,000 volt cables, each conductor being separately wrapped by a metallic sleeve, the three conductors being contained in a common lead sheath.

Diagram, page 8 is a single line diagram of the system as it would be when the Maryland and new Lamanda Park Substations are built. This diagram shows all 16.5 KV. lines with the distances and size of conductors used, location of apparatus, and the recommended types of relays.

CHAPTER II

TYPES OF RELAYING

At the present time induction type time element overcurrent relays are used on all feeders. However, the use of only this type in the future will cause difficulties. As an example, consider the diagram, figure 1, page 10.

If the relays shown were timed in the usual consecutive manner, it would be necessary to give #1 and #3 the longest time setting, say 1.5 seconds, #5 and #10, 1.0 second, and #7 and #8 the shortest time, say 0.5 seconds. Under these conditions, with a short circuit on line #2, relays #7 and #8 would operate before the others and clear the system. For a short circuit on line #1, however, since the same current flows through relays #7 and #8 as through #5, these relays would operate before #5, and hence as soon as relay #1 operates (1.5 seconds), Raymond Substation would be isolated from the system, though the fault is only on one side. Similarly for a short on line #3, Lamanda Park Substation would be isolated.

If, on the other hand, relay #5 is set to operate in, say 0.5 seconds, and relay #7 in 1.0 seconds, relay #5 would isolate a fault on line #1 from Raymond Substation before relay #7 operated but, of course, the operation would then be improper if the short circuit occurred on line #2 or line #3. It is therefor, obvious that

FIGURE 1

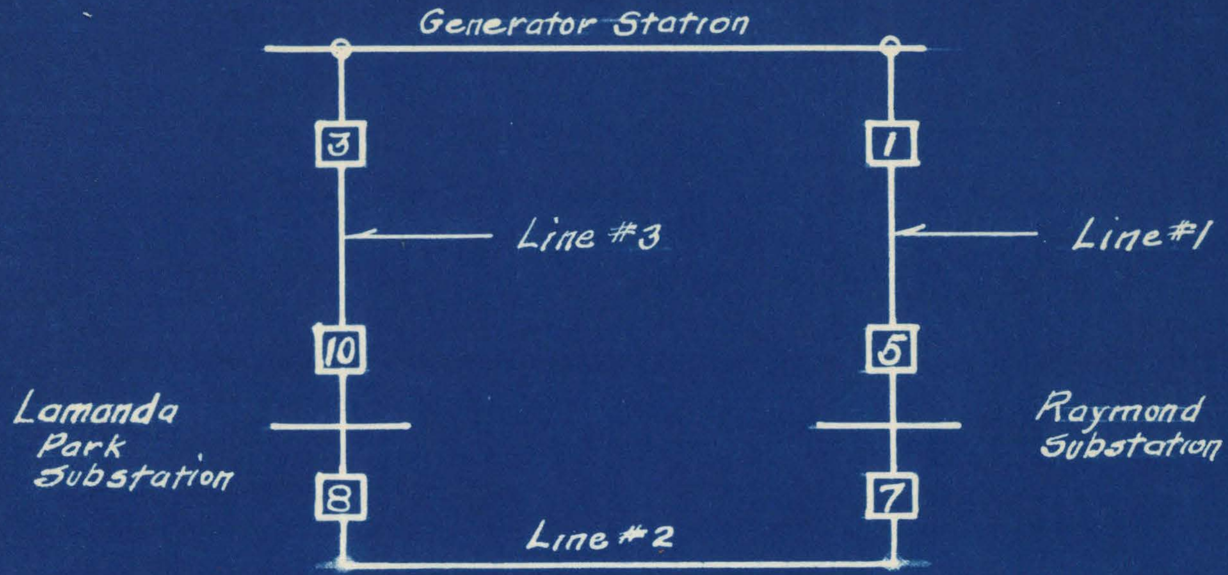
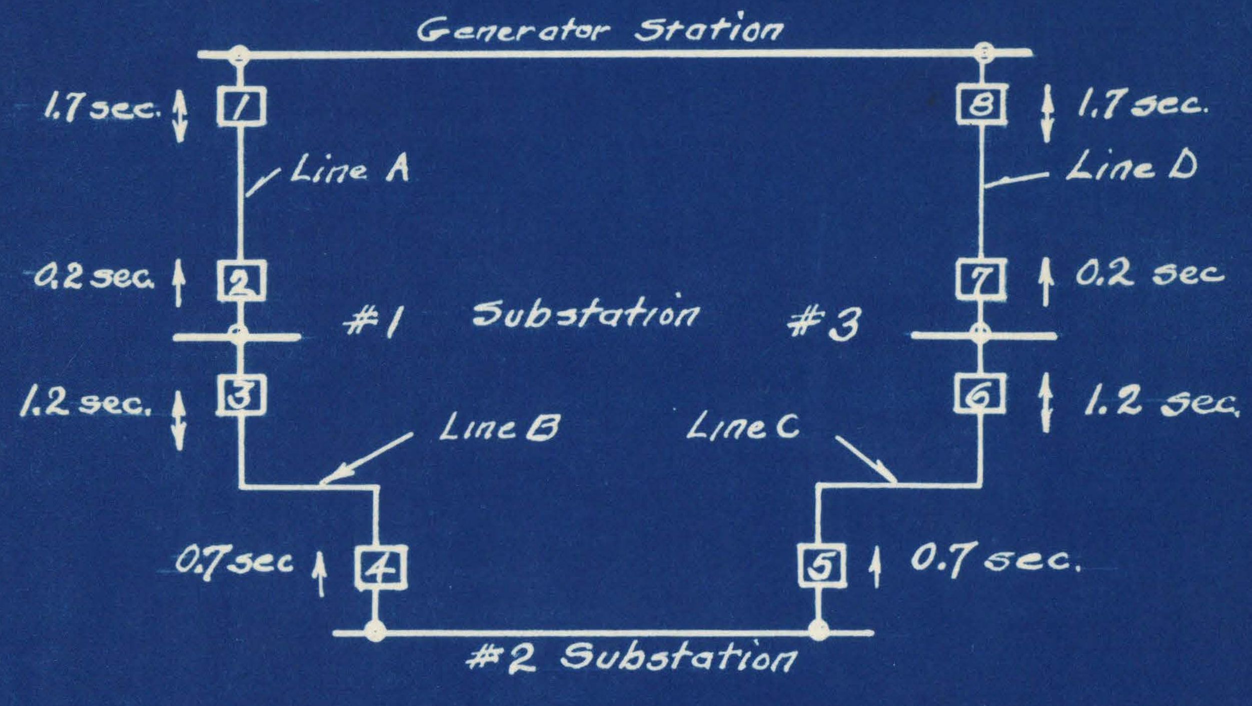


FIGURE 2



the present relaying may cause unnecessary interruptions to service.

The first step in this problem, then is to analyze the system conditions, determine what conditions must be met and pick out that method of relaying which will accomplish the desired result with the least complications and cost.

Ordinary time element non-directional overcurrent relays are often supplemented by these other general methods of relaying for transmission line protection. These methods respectively involve the following relays:

Distance type relays
Pilot wire relays
Directional current relays alone or in combination with overcurrent relays

DISTANCE TYPE RELAYS

The distance type relays work on the principle that the relay nearest the fault will operate first. This is accomplished by the use of a restraining coil operated from the potential of the line which acts in opposition to the overcurrent coil of the relay. As the voltage across the relay nearest the fault will be lowest, the restraining potential coil on this relay will be least effective and, therefore, this relay will operate before the others.

The objections to this type of relay are, first, that it is considerably more expensive than the overcurrent type; secondly, on comparatively short lines, it is sometimes difficult or impossible to get sufficient difference in potential to obtain the selectivity desired. It is also necessary to have potential for all relays.

This type of relay is used on long lines with a number of sectionalizing points, where the use of consecutively time overcurrent relays would make the maximum timing too long, or on complicated networks, where it is otherwise impossible to get proper selectivity. These relays are not intended to be used in place of overcurrent relays, but to supplement them where overcurrent relays cannot be made properly selective.

PILOT WIRE RELAYS.

The use of pilot wire relay protection systems has been considerably greater in England than in the United States because short cable lines have been used there to a comparatively greater extent than in the United States. The earlier schemes developed were known as the Merz-Price system. Of late, modifications of the pilot wire systems are coming more prominently into use in the United States, some making use of communication channels as the pilot wires. Such systems however usually have a backup relay protection in case of the failure of the pilot wires.

The advantages of such a system are:

1. Nearly instantaneous operation.

2. Can be used on any number of lines independent of the number of stations.

3. Will operate on small fault currents, thereby providing excellent protection against ground faults.

4. Potential connections not required.

The disadvantages are:

1. Cost of pilot wires and maintenance of same.

2. Necessaity of special, matched current transformers.

3. Possibility of undetected open circuit on pilot wires rendering scheme inoperable.

4. Dange of induced potentials on the pilots causing false operation.

Inasmuch as Pasadena is considering the use of supervisory control of the substations from the power station, a number of spare conductors could be included in the supervisory control cable at small cost so the first disadvantage may not be objectionable. The other disadvantage, however, are quite serious, in fact, sufficiently so to make inadvisable such a scheme for this power system.

DIRECTIONAL OVERCURRENT RELAYS

The current directional relay has one pair of contacts operated by a standard time element overcurrent relay. Another set of contacts is directional: that is this contact will close only if power flow is in a certain direction and will stay open if in the opposite direction. The two sets of contacts are either connected in series or are cascaded. That is, the overload contacts are prevented from operating if the directional contacts are open. This prevents the relay from operating on a surge because both sets of contacts would have to be closed for the time for which the relay was set. The directional element of the relay is so connected that it will operate only when power is flowing away from the substation; it will not operate when power flows into the station.

The current directional relay is suitable for use on loop systems having not more than four stations (power and substations) The reason for this is that good relay practice requires the operation of a relay withing two seconds at most, after the occurrence of the fault. Intervals should not be shorter than 0.4 seconds and preferably 0.5 to permit time for the opening of a preceding breaker before the closure of the succeeding relay contacts. Therefore, a series of more than four relays is not advisable, if they have to be progressively timed.

Figure 2 on page 10 illustrates an advantage sometimes attained by using directional relays. Relays #1, #3, #6 and #8 are non-directional overcurrent relays. Relays #2, #4, #5 and #7 are directional. The relays at the power station are set for the longest interval while #2 and #7 are set for the shortest. If a short occurs on line A relays #1 and #2 will clear the fault without interrupting service to #1 substation. It is not necessary to make #3 relay directional because it has a longer time than either #2 or #5. If, however, a fault occurs on line B relays #3 and #4 will clear the fault. #4 will operate before #6 or #8 can operate, while neither #7 nor #5 can operate since the power direction opposes their contacts closing. Likewise #3 will operate before #1, and #2 relay cannot operate with the power direction against it. Similar relay operation will take place for faults on lines C or D. In Pasadena, there are at present only two substations in the loop, while the proposed Maryland Substation can either tie in, in parallel with either substation or be operated independently. The arrangement is shown on page 8. The complete method of arriving at settings is given latter.

Some of the advantages of this system are:

1. Simple to install, check, and maintain.

2. Least expensive of satisfactory schemes.

3. Operation independent of line length.

4. Can be applied to ground relaying and can be made quite sensitive by using low energy directional relays.

Its disadvantages are:

1. Not instantaneous in operation.

2. Line relays cannot be set to operate on fault currents equal to or less than full load.

3. Requires potential transformers for directional elements.

Once having decided on the use of directional overcurrent relays on a system it is necessary to investigate the various types of directional protection so that the best and most economical plan may be submitted. The discussion will be divided into two parts; line fault protection, and ground fault protection.

For the line protection three single phase overcurrent directional relays or one polyphase power directional relay and three single phase overcurrent relays as shown on pages 69 and 72 respectively, may be used. For the connections on page 69 with a fault in the right direction for tripping, the directional contact will close almost instantaneously, and be followed by the closing of the overcurrent element at a time determined by the magnitude of the short. The polyphase power directional relay of page 72 will close its contact regardless of which phase is faulted so long as the direction of power flow is correct. The operation of the current element is the same as for the case of single phase relays. The choice between these two systems is largely a matter of opinion, some companies prefering the use of single phase relays and others the use of a polyphase relay. Since the Pasadena system has already purchased several single phase directional overcurrent relays this type has been recommended.

For ground protection, page 69 shows the use of a single phase low energy directional overcurrent relay and page 72 shows the use of a single phase low energy non-directional relay. The obvious advantage for the connections shown on page 72 is the saving in cost. A first cost comparison between the two installations using representative cost prices, which could be obtained by the City of Pasadena Light and Power Department, is as follows:

Equipment	Cost
Polyphase power directional relay	$120.00
Directional overcurrent standard relay	73.00
Non-directional overcurrent standard relay	30.00
Low energy directional overcurrent relay	77.00
Low energy non-directional overcurrent relay	34.00
2/1 ratio potential transformer	20.00
20/1 ratio potential transformer (2400 V. Primary)	45.00
100/1 ratio potential transformer (11,500 V. Primary)	100.00

Initial Cost For Setup Page 69

Relay Cost Per Line

Directional overcurrent standard relays	3 @ $73	$219
Low energy directional overcurrent relay	1 @ 77	77
		$296

For the six installations of directional relays Total Cost----$1776

Potential Transformer Cost(only one set of potential transformers are needed at each substation)

2/1 Ratio potential transformers	3 @ $ 20	$ 60
100/1 Ratio potential transformers	3 @ 100	300
		$360

For three substations, Total potential transformer cost------------$1080

Total relay and transformer cost--------$2856

Initial Cost for Setup Page 72

Relay Cost Per Line

Polyphase power directional relay	1 @ $120	$120
Non-directional overcurrent relays	3 @ 30	90
Non-directional low energy relay	1 @ 34	34
		$244

For six installations Total Cost----$1464

No additional potential transformers are necessary since the present metering transformers may be used.

If it is found that the burden on the open delta potential transformers is large enough to cause any voltage unbalance or an overload condition, it will be necessary to add a third transformer to close the delta.

Hence add:

20/1 Ratio potential transformer 3 @ \$45 \$135

For the setup page 72 Total Cost--\$1599

Resultant Saving by use of the method page 72 Saving----\$1257

From the above comparison it is evident that there is a considerable saving in cost by using the second method.

The polyphase relay as shown on page 72 is and must be designed for operation as a line relay, due to the fact that its current coils must at all times carry the line current. For this reason the polyphase relay will not operate on small ground faults. The current coils of the single phase low energy directional overcurrent relays, however, normally carry no current, hence their sensitivity can be made much greater. For this reason single phase directional relays are recommended.

Since two new substations are planned new potential transformers will be needed for one or both, hence it will be convenient to use the scheme of page 69 in which case the high tension potential transformers can be used for both metering and relaying purposes. The difference in cost between the 16.5 KV. transformers and the 2400 volt transformers, would be only the additional cost and this amount would be small enough to neglect when considering the gain in sensitivity of relay protection.

RECOMMENDATIONS FOR LINE AND GROUND FAULT PROTECTION

For Line Protection:

The use of non-directional and directional overcurrent relays of the single phase type as shown on page 69.

For Ground Fault Protection:

The use of non-directional and directional low energy relays of the single phase type as shown on page 69.

CHAPTER III

SYSTEM CALCULATIONS FOR RELAY DETERMINATION AND SETTING

With the preliminary survey completed and the type of relays determined, the next step is to make the necessary calculations to determine what abnormal conditions may occur and the required action of the relays under these conditions to:

1. Clear the fault as quickly as possible to minimize disturbance on the system.

2. Isolate only the faulty section of the line.

This information provides a basis for decision as to which relays must be directional and which may be non-directional. Also the proper setting of the relays can be made both as to current tap and lever setting.

Before making these calculations, the actual conditions under which the system will operate must be known. That is the location, capacity and characteristics of the power supply, the line characteristics and the actual network arrangement.

The calculations consist of finding the current which will flow in the different relays for several types of faults, these faults being successively assumed to occur at different points in the system. With this data, the worst conditions for each part of the system will be known and the relays can then be set for proper operation to correctly protect against such faults.

EQUIVALENT SYSTEM IMPEDANCES

Assuming the fault occuring at a certain point on the system it is necessary to find the equivalent impedance from the power source to the fault in order to determine the total current flowing over all paths to the fault. In the case of a balanced three phase fault, the equivalent impedance to be found is the single phase impedance from neutral to the fault. To do this the impedance of each part or section of the system must be found and all impedances combined according to the well known laws for electric circuits.

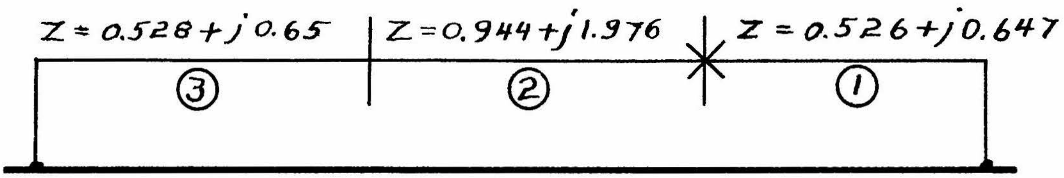
In practice three different methods of combining line impedances are used. The first is to express the impedance of each line section as a complex quantity and combine them as complex quantities. This method is rigorously correct but becomes vary laborious if the system is at all complicated, particularly if there are many parallel circuits.

The second method is to determine the impedance as a single scalar quantity, having only magnitude, the phase angle being neglected when combining them. This method is not altogether correct but in most practical solutions the amount of error is not serious for relay determinations, since at best these can be only approximate when such undeterminable factors as fault impedance but enter into the problem. Furthermore the more constant the ratio of resistance to reactance, the more correct the method will be, since the vector angle is dependant upon this ratio.

The third method is to neglect the resistance entirely and consider only the reactance component. In this case the amount of error depends upon the ratio of resistance to the reactance. If the resistance is equal to the reactance, the assumed impedance of the circuit is 70.7% of the actual impedance. If the resistance becomes less, the error decreases quite rapidly. For this reason, if the resistance is less than half the reactance, the amount of error is not sufficient to warrant the additional complication of the other methods.

For the study of the Pasadena system, the third method (neglecting resistance) is used because the generator reactance and the line reactor reactance are a very considerable part of the total impedance. Therefore the error introduced by using this method is not serious.

The following numerical example gives an idea of the variation obtained in results by the use of the three methods.



Method Used	Total Current	% Error	Current Sec. (1)	% Error	Current Sec. (2-3)	% Error
Complex Quantity	3520		2757		763	
Reactance	3570	1.4	2870	4.5	700	8.2
Impedance	3390	3.7	2660	3.6	730	4.3

D.C. SHORT CIRCUIT CALCULATING TABLE

By using the second or third method of calculation, the very helpful d.c. short circuit calculating table can be used. Numerous articles have appeared describing this equipment so space will not be taken here for that purpose. Such a calculating table was used for checking some of the results but all values were actually calculated in addition.

OPERATING CONDITIONS OF THE SYSTEM

Under normal operating conditions all power is supplied from the Pasadena Power Station. Unit #8, the 31,250KVA. turbine generator, is the most efficient unit and will therefor be used practically continuously. This unit has ample capacity for the peak loads at present and for some time to come as nearly as can be determined. It is believed logical therefor, to make all calculations relating to relay protection on the basis of this unit only. The short circuit current would of course be larger if several machines were operating in parallel on the bus or with the Edison line in parallel and such possibilities must be considered in determining circuit breaker duties. Such operation, however, must be classed as abnormal and it is neither desirable nor necessary to consider such in the relaying calculations.

Of the several different normal operating conditions possible four representative cases have been selected. Other setups, which might normally be used, will be found practically identical with one of these four. The four cases are:

Case 1. All switches closed except switches 6, 9, and 11.
(See pages 53 and 62)

Case 2. All switches closed except numbers 9 and 12.
(See pages 54 and 63)

Case 3. All switches closed except number 12.
$See pages 55 and 64)

Case 4. All switches closed.
(See pages 56 and 65)

Case 1 is a typical setup for normal operation when the pump lines (see diagram, page 8 for pump line designations) may be fed from any one of the three substations but not from more than one. In this case, therefore, there is no interconnection of substations except the loop line from Raymond to Lamanda Park.

Case 2 is the setup when the Maryland Substation is fed by the 500,000 c.m. cable and Maryland and Raymond Substations are connected through the pump lines, thus feeding the pump lines from two sources. This case is typical of any one of the three cases possible, where the pump lines are fed from two substations. It may be more usual for Maryland to be fed only through the 500,000 c.m. cable (the 350,000 c.m. cable being held for emergency) because the 350,000 c.m. cable taps the feeder to the California Institute of Technology High Tension Laboratory Feeder. This feeder is subject to severe surges so it is desirable to operate it independently, so preclude disturbance from it to other parts of the system.

Case 3 shows the system when the three substations all feed into the pump lines, thus interconnecting all three substations. Only the 350,000 c.m. cable to Maryland is open.

Case 4 is when all switches are closed, and is the case when the highest total short circuit currents may be experienced.

No case is considered with the loop tie between Raymond and Lamanda Park open, because this would be very abnormal, and not to be considered as an ordinary case of operation. Several other possible setups might be made but these also would fall in the abnormal class and need not be considered.

In studying these cases, faults are considered in turn at each of the substations. Two types of faults are considered;

1. A balanced three phase fault.

2. A single phase to ground fault.

The first type of fault was chosen because while not common, it is the severest fault that may be encountered, so that a study of this type will show us the maximum currents with which it is necessary to deal. The ground fault was chosen because it is the most common fault to occur and the type requiring the most sensitive relays. Because the Pasadena system is grounded at one point (the generator) through a reactance, the ground current will be limited but the appearance of any ground current (except a small charging current) is an indication of a fault. Therefore, particularly on a system where cables are used, the quicker the fault is recognized and isolated the better and the cheaper.

The single phase line to line fault is not considered because it is not so likely to happen as a ground fault, it is almost always preceeded by a ground fault, and it is not so severe as a three phase fault. The double ground fault is not considered because it is uncommon and is almost certain to be preceded by a single line to ground fault which would cause functioning of relays.

SYMMETRICAL COMPONENT ANALYSIS

The development of the symmetrical component method of solution of asymmetrical polyphase networks discovered by Dr. C. L. Fortescue gives a completely unique technique for the handling of relay problems on a three phase system. Use is made of this method for determining the currents flowing through the ground relays on occurrence of a ground fault. A series of articles published by Messrs. Wagner and Evans in the Electric Journal and since reprinted by the Westinghouse Electric & Mfg. Co., gives quite fully the development and application of this method.

By this method the calculation of system performance involves the setting up of three separate networks known as the positive sequence, negative sequence and zero sequence networks. Each network has balanced phases and is represented by a single line diagram, which is made up of the various impedances of the different parts of the network under consideration. These impedances are the impedances of one phase of the network, the other phases are identical. The phase voltages and currents for each network are balanced. In the first network, known as the positive sequence network, the three phases a_1, b_1, and c_1 are 120° apart and rotate in a counter clockwise direction. In the second network known as the negative sequence network the corresponding three phases a_2, b_2, and c_2 also rotate in a counterclockwise direction but in the order a_2, c_2, b_2. In the third network known as the zero sequence network, the phases a_0, b_0, and c_0 also rotate in a counter clockwise direction, but they are all in phase. In determining the actual phase quantity such as current of the actual network, the positive, negative and zero phase components are added together.

In a balanced three phase system, the zero and negative sequence components disappear, leaving only the positive sequence. The positive sequence network is in all respects similar to the usual networks considered; the resistances and reactances are the values usually given to calculate line regulation. For determination of relay calculation, the reactance of a generator is the transient reactance. The reason for this is discussed under generator reactances.

The negative phase sequence network is in general quite similar to the positive sequence network. The negative sequence reactance of the generator, however, is taken as the subtransient reactance of the generator. In the case of single phase line to line faults, the positive and negative sequence networks only need be considered, since the zero phase component disappears.

The zero phase sequence network impedances are radically different from those of either the positive or negative sequence networks. The line impedances are those obtained by imagining the three conductors connected in parallel, the ground forming the return conductor. The generator zero sequence impedance is dependent upon such design characteristics as pitch factor. It is generally much smaller than the positive or negative sequence impedances. For transformer, the impedance to zero sequence is infinite unless a path is provided for the flow of zero sequence current, that is a neutral or ground connection. Since the power transformers on the Pasadena System are all delta delta they have infinite impedance to ground and can be neglected in the zero sequence network.

The following table gives approximate values of zero sequence reactance of various part of a network in terms of positive sequence reactance.

Single Circuit Aerial Lines (no ground wires)	3.5 times positive sequence reactance.
Double Circuit Ditto	5.5 times positive sequence reactance.
Single Circuit Aerial Lines (non-magnetic ground wire)	2.0 times positive sequence reactance.
Double Circuit Ditto	3.0 times positive sequence reactance.
Three Phase Cables	3 to 5 times positive sequence reactance.
Single Phase Cables	3.0 times positive sequence reactance.
Neutral Impedance	3.0 times positive sequence reactance.
Ungrounded Transformers	Infinite Impedance.
Grounded Delta Y	Equals positive sequence reactance to neutral on the Y side and open circuit on the delta side.

GENERATOR REACTANCES

The generator reactance which limits the current at the instant of short circuit is a smaller value than after a short period. The current at the first instant may be regarded as having two components, (1) a direct component and (2) an alternating component. The direct component disappears quite rapidly, leaving the alternating component which is symmetrical about its axis. This component known as the transient component decreases more slowly until the steady state is reached, which is determined by the so called synchronous reactance of the generator. The reactance of the generator limiting the first rush of current is called the subtransient reactance, and the transient reactance is the value of reactance which gives the symmetrical r.m.s. value of current for a three phase short circuit at the terminals.

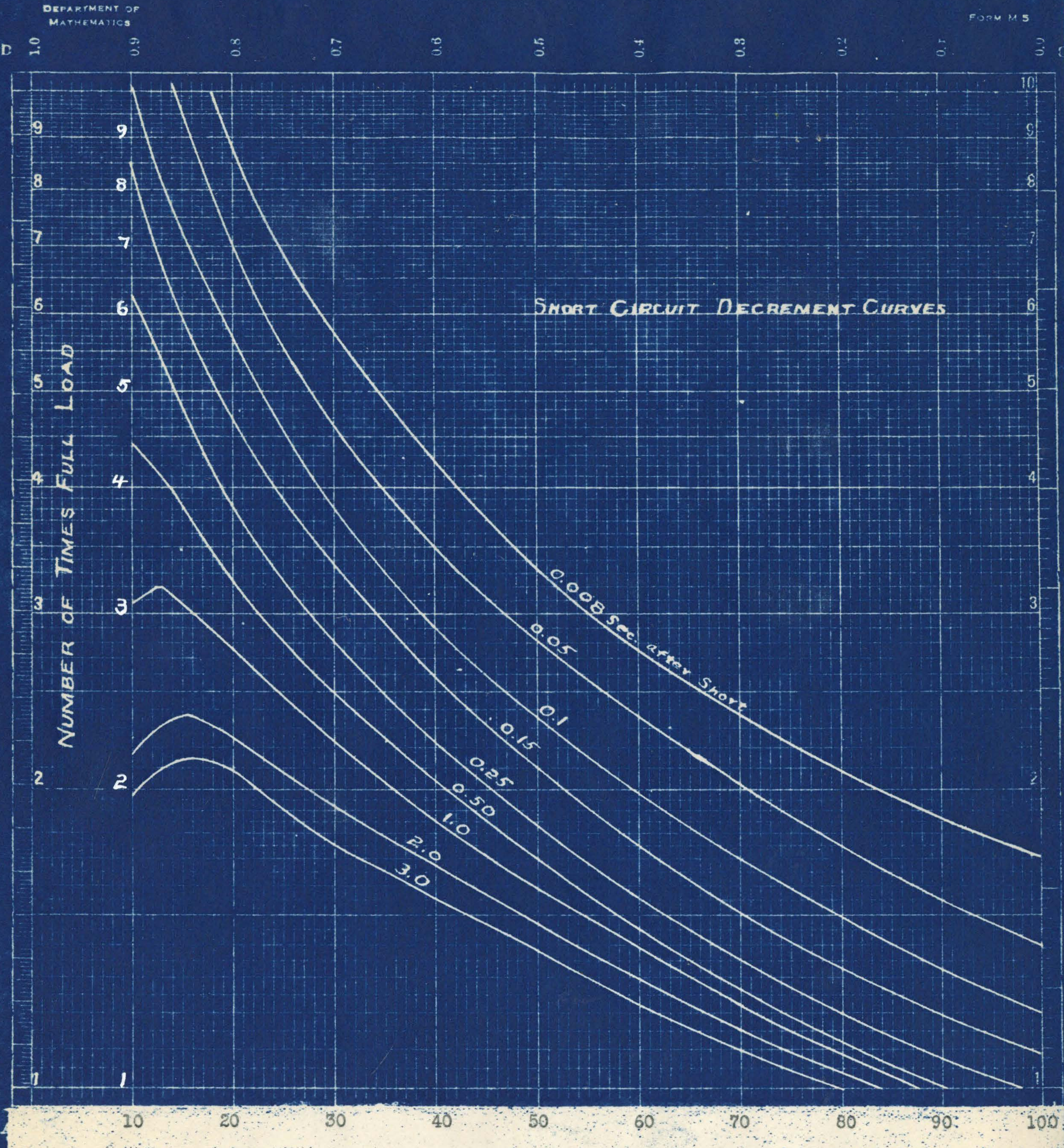
For relay operation, the value of transient reactance gives current values for which the calculated time very closely approaches the actual time of operation. However, to be strictly correct, the decaying current should be considered from the instant of short circuit until the operation of the relay and for this purpose decrement curves can be used. Decrement curves vary for different machines but the standard decrement curves now accepted are sufficiently accurate for good approximation.

To determine whether the use of the transient reactance of the generator was sufficiently accurate to make it unnecessary to use the decrement curves, the following example was worked out.

Relay 1 in Case 2 was set to operate in 1.1 seconds on a current of 1635 amperes. This is for the short circuit at Raymond Substation and is the value obtained by using the transient reactance of the generator. If however, the subtransient reactance were used this value would have been 2220 amperes, while the total current flowing at the instant of short circuit would have been 5353 amperes. (see page 31) The percent system reactance which is the full load current divided by the total short circuit current times 100, would be:

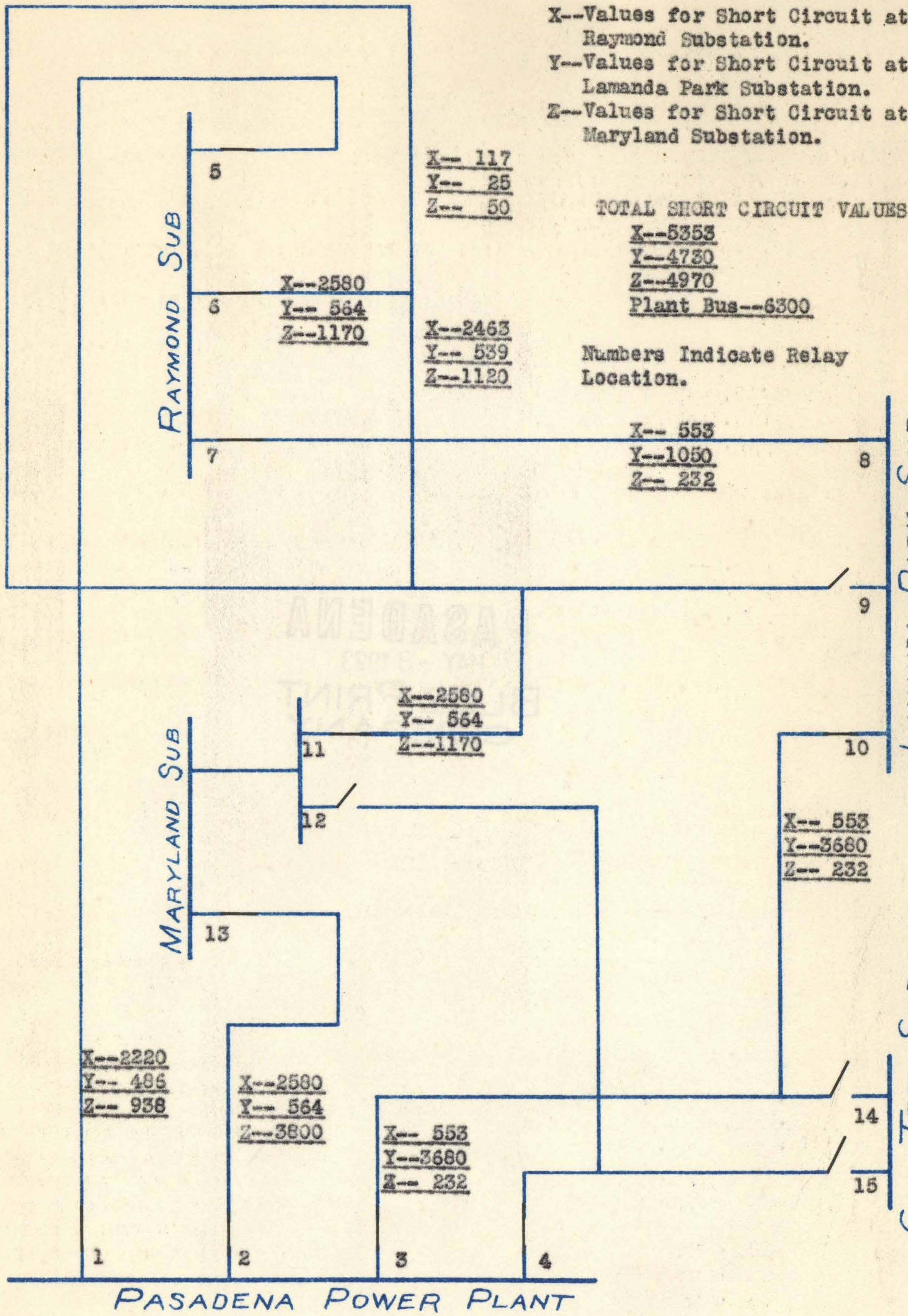
$$\frac{1090}{5353} \times 100 = 20.3\%$$

Suppose, however the decrement curves, page 30, were used instead of assuming a definite value of current flowing for the time of operation of the relay. Using the 20.3% reactance, the instantaneous (0.008 seconds) unsymmetrical short circuit current would reach a value of 8.6



DEPARTMENT OF MATHEMATICS
FORM M 5
SHORT CIRCUIT DECREMENT CURVES
NUMBER OF TIMES FULL LOAD
0.008 Sec. after Short
0.05
0.1
0.15
0.25
0.50
1.0
2.0
3.0
1
2
3
4
5
6
7
8
9
10
20
30
40
50
60
70
80
90
100
System Reactance in Percent

THREE PHASE SHORT CIRCUITS USING SUBTRANSIENT
GENERATOR REACTANCE -- CASE 2



times full load current. Actually, however, for relay operation only the symmetrical values of the current (not to include the unsymmetrical or d.c. component) is effective and this value for this reactance is 5.11 time full load current. (This value of 5.11 is given in the article by C. F. Wagner entitled Decrement Curves) This value continues for the whole interval of 0.12 seconds. The current in the line section to which the relay is connected would for this interval have been:

$$\frac{2220}{5353} \times 5.11 \times 1090 = 2320 \text{ amperes.}$$

This corresponds to 580% full load on the relay (with a current transformer ratio of 400/5 and a relay tap setting of 5). For this value of current and a time lever setting of 5, the relay would close its contacts in 1 second. However, the interval of time is actually

$$0.12 \times \frac{6.6}{5} \doteq 0.158 \text{ seconds.}$$

The factor of 6.6/5 must be introduced because the decrement curves are based on a time constant of 5 while the machine in question has a time constant of 6.6. The actual distance the contact moves in this time is:

$$\frac{0.158}{1.00} \times 5 = 0.79 \text{ divisions.}$$

Taking the next interval of time from 0.12 to 0.15 seconds, the average value of current for this interval is found to be 4.85 times the full load current. This will give:

$$\frac{2220}{5353} \times 4.85 \times 1090 = 2200 \text{ amperes in the line section.}$$

or 550% full load current in the relay. For this value of current it still takes only one second for the relay to close its contacts if starting from the #5 time lever setting. The corrected time would be:

$$(0.15 + 0.12)\ \frac{6.6}{5} = 0.04 \text{ seconds.}$$

The movement of the contact would be:

$$\frac{0.04}{1.00} \times 5 = 0.2 \text{ divisions.}$$

By continuing this integration until the relay contacts close we get the following table.

Time Interval	Time Seconds	Corrected Time	% F. L. Current	Divisions Moved
0.00 to 0.12	0.12	0.158	580	0.79
0.12 to 0.15	0.03	0.040	550	0.20
0.15 to 0.25	0.10	0.132	475	0.63
0.25 to 0.50	0.25	0.330	390	0.46
0.50 to 0.83	0.33	0.440	350	1.87
		1.100		4.95

It will thus be seen that the approximate method of using the transient reactance value is sufficiently accurate for the relay settings in this case.

The following table obtained from the paper presented by W. C. Hahn and C.F. Wagner on Standard Decrement Curves in the A.I.E.E. Transactions fro June 1932, gives the various machine unit reactance values for typical three phase 4 pole turbine generators:

Synchronous reactance	0.95 to 1.45	Average 1.10
Subtransient reactance	0.07 to 0.17	Average 0.12
Negative sequence reactance	Same as Subtransient reactance	
Zero sequence reactance	0.01 to 0.14	Average 0.075

Since the zero phase sequence reactance varies quite critically with the winding pitch, an average value is not dependable. In the study for Pasadena a value of 0.06 was taken arbitrarily since the exact value was not known. This particular factor is not sufficiently large to have a great effect upon the result so it is believed safe to assume such a value.

The value of transient and subtransient reactance for generator #8 are given on page 8. The relation between these reactance values in percentage is given as follows:

Transient reactance = (1.4 x Subtransient reactance + 2)

ZERO SEQUENCE IMPEDANCE OF THE TRANSMISSION SYSTEM

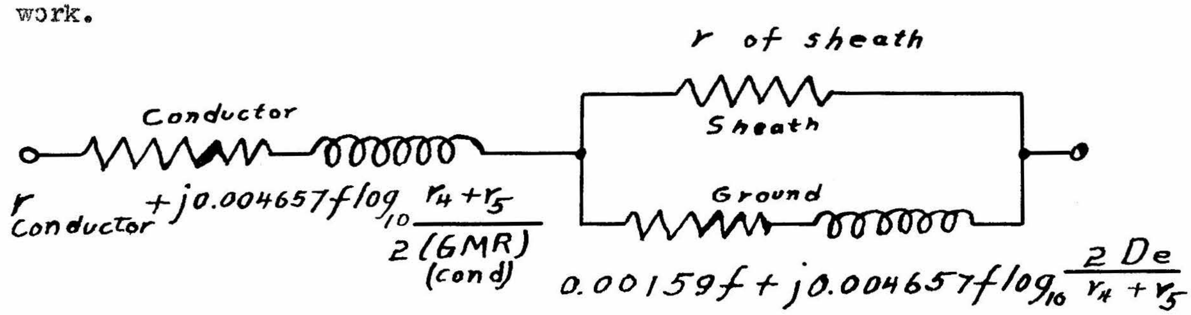
The zero sequence impedance of a single three conductor cable can be determined for either of the two cases as follows:

1. Return current through the sheath and ground in parallel.
2. Return current through the sheath alone.

In this study, the first condition is assumed because, although the cable is to be laid in fiber or glazed tile duct, it is to be frequently grounded at all underground vaults.

The impedance of the cable per conductor, including the ground return with zero fault impedance, per mile length as developed by

Wagner and Evans can be found by solution of the following network.



where:

r_4 is the radius to inside of sheath.

r_5 is the radius to outside of sheath.

$(r_4 + r_5)/2$ is the geometric mean spacing, conductor to sheath.

G.M.R. of the conductors was calculated on the basis of round conductors.

D_e is the symbolic representation of the equivalent depth of the ground return. This value was taken as 2800 feet.

$\dfrac{0.20}{\text{Mean diameter} \times \text{thickness}}$ is the resistance of the sheath in ohms per mile.

The value thus found is the value for the entire 3 conductor cable and as the zero sequence current divides equally between the three conductors the impedance per phase is three times this value.

<u>CABLE CHARACTERISTICS USED IN THIS REPORT</u>

500,000 C.M. Cable

Positive or Negative Sequence
- Resistance --- 0.0249 ohms per 1000 feet.
- Reactance --- 0.0271 ohms per 1000 feet.

Zero Sequence
- Resistance --- 0.228 ohms per 1000 feet.
- Reactance --- 0.114 ohms per 1000 feet.
- Impedance --- 0.255 ohms per 1000 feet.

350,000 C.M. Cable

Positive or Negative Sequence			
	Resistance	--- 0.031	ohms per 1000 feet.
	Reactance	--- 0.0286	ohms per 1000 feet.
Zero Sequence			
	Resistance	--- 0.263	ohms per 1000 feet.
	Reactance	--- 0.129	ohms per 1000 feet.
	Impedance	--- 0.284	ohms per 1000 feet.

It will be noted from the above table that the zero sequence values thus calculated are much greater than the positive sequence values. For 500,000 c.m. cable the resistance is approximately 9.15 times as great and the reactance is approximately 4.2 times as great. Since in this case the resistance is such a large factor it cannot be neglected as was done in the positive sequence calculations, therefore the zero sequence impedances are considered as scalar quantities.

The zero phase sequence impedance of the overhead lines is taken as 3.5 times the positive sequence values. This value is an approximate value obtained by a number of calculations for typical overhead lines. Since the amount of overhead transmission lines at Pasadena will in the future be small this approximate value was considered quite accurate enough for the purpose.

The zero phase sequence impedance of the line reactors is taken as 3.5 times the positive phase sequence value while the zero phase sequence impedance of the ground reactor must be taken as 3 times the positive phase sequence value.

SAMPLE CALCULATIONS

As stated above there have been chosen four cases of probable normal operation for which the short circuit calculations must be made. Since case 4 is the most complicated of these it has been chosen to exemplify the calculations for both three phase short circuits and single line to ground faults. For both cases the fault is considered to be at Raymond Substation.

In making any such calculations on a system it is possible to use the values of reactance or impedance (as stated above only reactance values are used for three phase short circuits and impedance values in the zero sequence network for ground faults) either as a percentage value or as an actual ohmic value. For use in this report the actual ohmic values have been chosen and are shown on page 38 for the various line sections as well as for the generator and reactor.

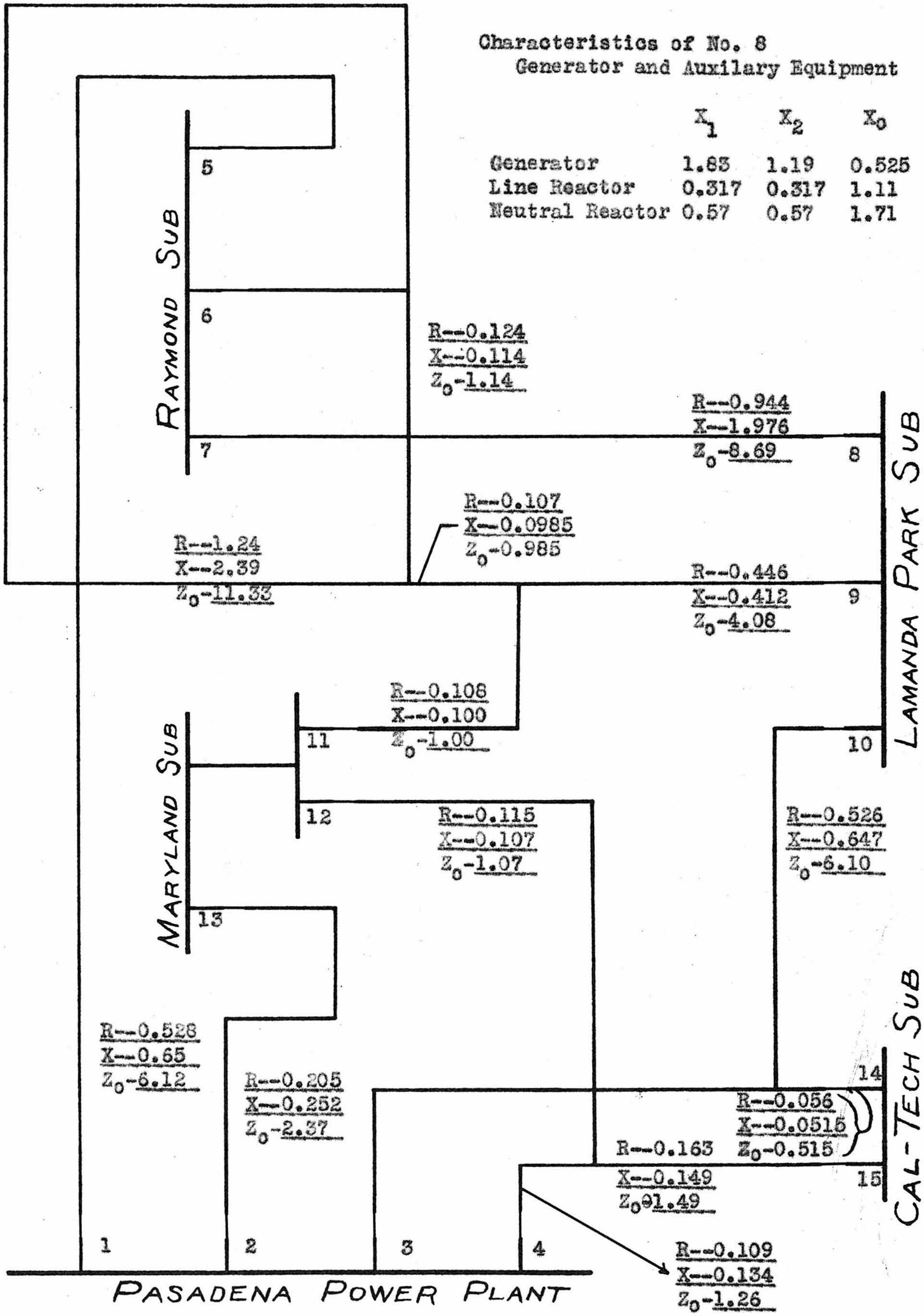
CALCULATIONS FOR A THREE PHASE FAULT ON THE BUS AT RAYMOND SUBSTATION

The positive sequence network for the faulted phase, which is all that is necessary for three phase short circuits calculations, is shown in fig. 3, page 39, in a convenient form for use. Each line section is numbered and in the following examples these numbers are used as subscripts to indicate the various line sections. The location of the short circuit is designated by X.

Once having the network set up as in fig. 3 it is then necessary to reduce it to a single impedance as shown in fig. 7; the total short circuit current may then be found and apportioned between the respective lines in the inverse ratio of their impedances.

Characteristics of No. 8
Generator and Auxilary Equipment

	X_1	X_2	X_0
Generator	1.83	1.19	0.525
Line Reactor	0.317	0.317	1.11
Neutral Reactor	0.57	0.57	1.71



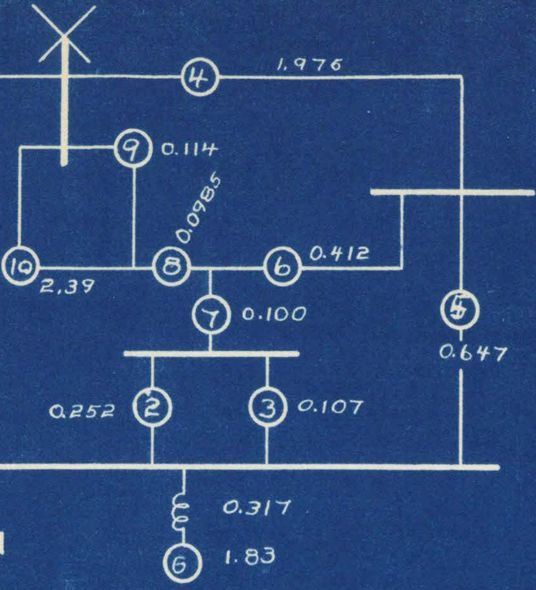


Fig. 3

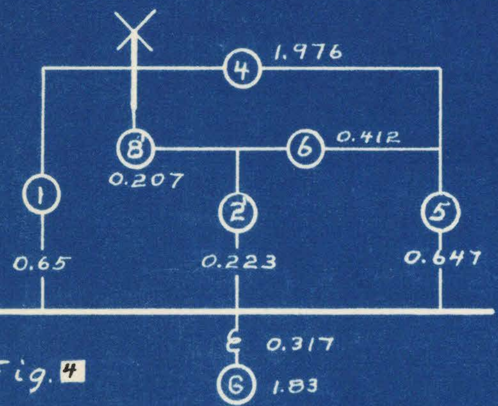


Fig. 4

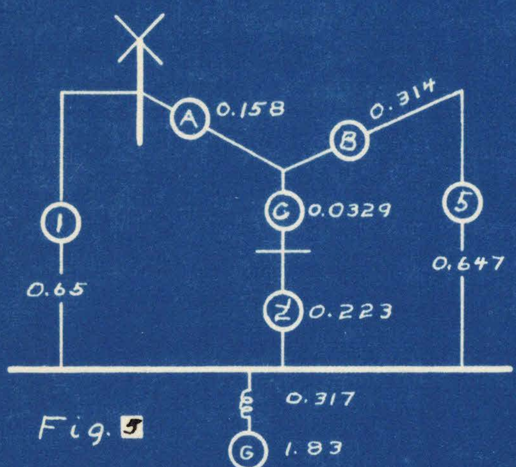


Fig. 5

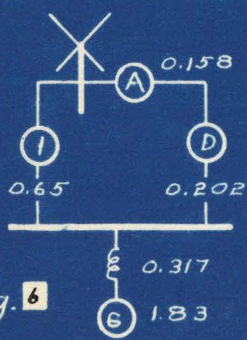


Fig. 6

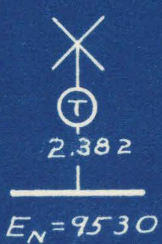


Fig. 7

Fig. 8

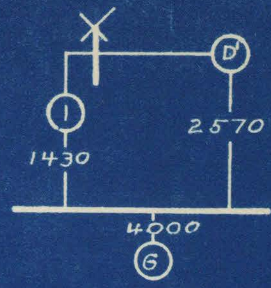


Fig. 9

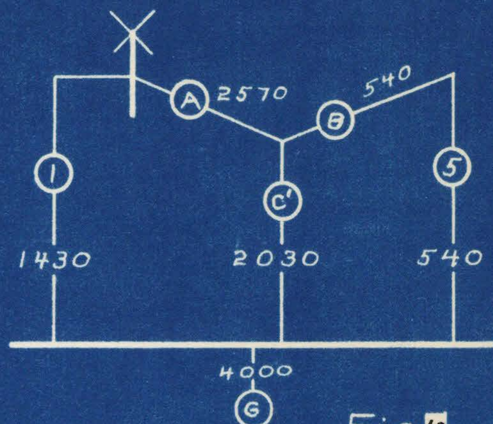


Fig. 10

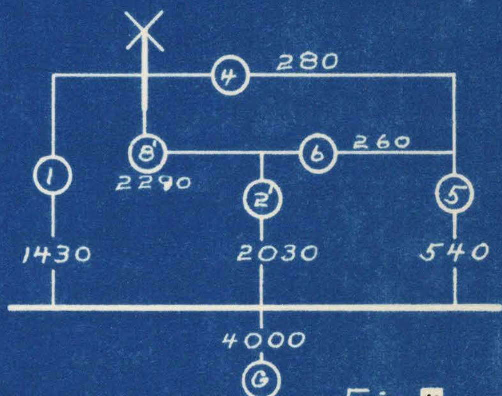


Fig. 11

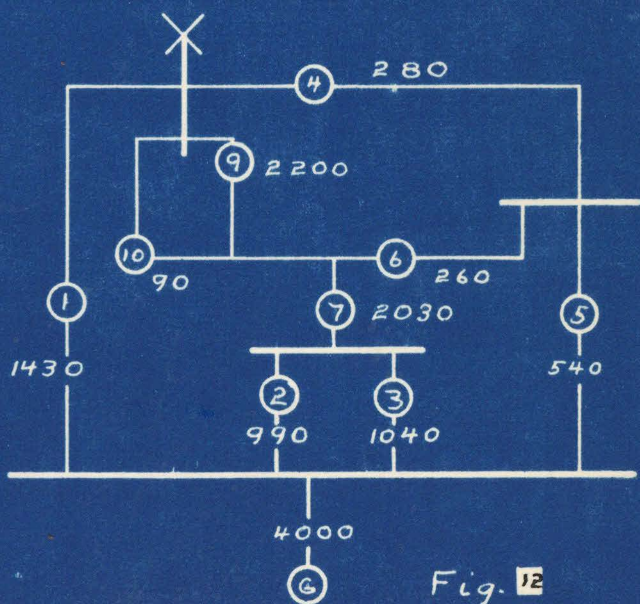


Fig. 12

Fig. 4 is obtained from fig. 3 by combining line sections (9) and (10) into an equivalent value and adding to it line section (8) thus obtaining section (8').

$$X_{8'} = \frac{X_9 \times X_{10}}{X_9 + X_{10}} + X_8 = 0.207$$

Sections (2), (3), and (7) are similarly combined to form section (2').

By inspection of fig. 4 it can be seen that line sections (4), (6), and (8') form a closed delta so that the next step in the simplification of the circuit is to convert this delta into an equivalent Y as shown in fig. 5. The formula used in making this conversion may be written as follows:

$$X_A = \frac{X_4 \times X_{8'}}{X_4 + X_5 + X_{8'}} = 0.158$$

Similar expressions may be written for the other two branches B, and C.

Fig. 6 is next obtained from fig. 5 by combining branches (C + 2') and (B + 5) to form line section (D).

$$X_D = \frac{X_{(B + 5)} \times X_{(C + 2')}}{X_{(B + 5)} + X_{(C + 2')}} = 0.202$$

The value of total reactance fig. 7 is next obtained by combining section (A + D) and (1), this value then being added to the sum of the generator and reactor values.

$$X_T = \frac{X_1 \times X_{(A + D)}}{X_1 + X_{(A + D)}} + 0.317 + 1.83 = 2.382$$

The total short circuit current is obtained by dividing the line to neutral voltage by the total reactance.

$$I_T = \frac{E_N}{X_T} = \frac{9530}{2.382} = 4000 \text{ amperes}$$

In order to determine the current in the various line sections it is now necessary to work backward through the network dividing the current at each line junction inversely as the impedance of the remaining line. The first division would be as shown in fig. 9 between line sections (1) and (D').

$$I_1 = \frac{(X_A + X_D)\ I_T}{X_1 + (X_A + X_D)} = \frac{(0.158 + 0.202)\ 4000}{0.65 + 0.158 + 0.202} = 1430$$

Fig. 10 is obtained similarly by the division of the current (D') (or (A)) into sections (C') and (B + 5).

To obtain fig. 11 from fig. 10 it is also necessary to consider fig. 5 which contains the equivalent Y. The sum of the voltage drops across sections (A) and (C) will give the voltage across one side of the delta (8'). Therefore: $E_{8'} = I_A X_A + I_C X_C$

Hence the current in section (8') will be:

$$I_{8'} = \frac{I_A X_A + I_C X_C}{X_{8'}} = \frac{(2570)(0.158) + (2030)(0.0329)}{0.207} = 2290$$

The currents in sections (4) and (6) are determined in a similar manner. Fig. 12 comes directly from fig. 11 by making the necessary divisions for line sections (9), (10), and (2), (3).

Calculations for other fault locations and system connections are made in a similar manner the final results being shown on a form similar to that of fig. 12. (See pages 62 to 65)

CALCULATIONS FOR A GROUND FAULT ON THE BUS AT RAYMOND SUBSTATION

In the case of ground fault calculations it is necessary to consider the three sequence networks connected in series through the grounded points. Since in this system there is only one point normally grounded, the generator, the connections between the networks are made from the point of fault to this grounded point of the following network. These connections are shown in fig. 13 page 44 for the faulted phase where the line values are indicated in the form of a general box network. These line values having been obtained by a series of combinations as shown for the three phase calculations figs. 3 to 12. The reactance values of the three sequences are also indicated for the generator, line reactor, and neutral reactor. Because positive sequence voltages only are generated in zynchronous machines the only voltage appearing will be that in the positive sequence network. Since these networks are now all in series the total equivalent reactance is the sum of the separate values. The current is then found by dividing the line to neutral voltage by the total reactance.

$$I_T = \frac{E_N}{X_T} = \frac{9530}{10.723} = 890 \text{ amperes}$$

From the connection of the networks it is evident that this same current of 890 amperes must flow through each network of the faulted phase. By the same procedure as followed for the three phase calculations this current may then be apportioned between the various line sections in each network. It is well to note here that the division of current in the various networks will not necessarily be the same for the respective line sections due to the fact that impedance values for the corresponding sections are not the same in each network. If it is desired to obtain the current in the faulted phase it is only necessary to add up the particular line section current values from each of the sequence networks for the faulted phase. It is also possible to obtain the sequence current in the other phases so that by the addition of these other sequence currents the current in any phase may be obtained.

For our case, however, we are interested only in the residual ground current, i.e., the current that will flow in the neutral lead of the current transformers. By definition the zero phase sequence currents in each phase are in phase, hence all the zero phase sequence currents will combine and flow through the neutral lead, i.e., three times the current in any one phase. The positive sequence currents constitute a balanced three phase system, consequently there can be no residual current flowing in the neutral lead. Similarly no negative sequence current can flow in the neutral lead. From the above it is evident that the residual ground current in the neutral lead would be three times the value found in any line section of the zero phase sequence network. Hence the total residual ground current is 3 x 890 which equals 2670 amperes. Page 56 shows the ground currents for the case considered in this example and it is seen that for the ground at Raymond Substation the total fault current is 2670 amperes while the current in the various line sections are as indicated.

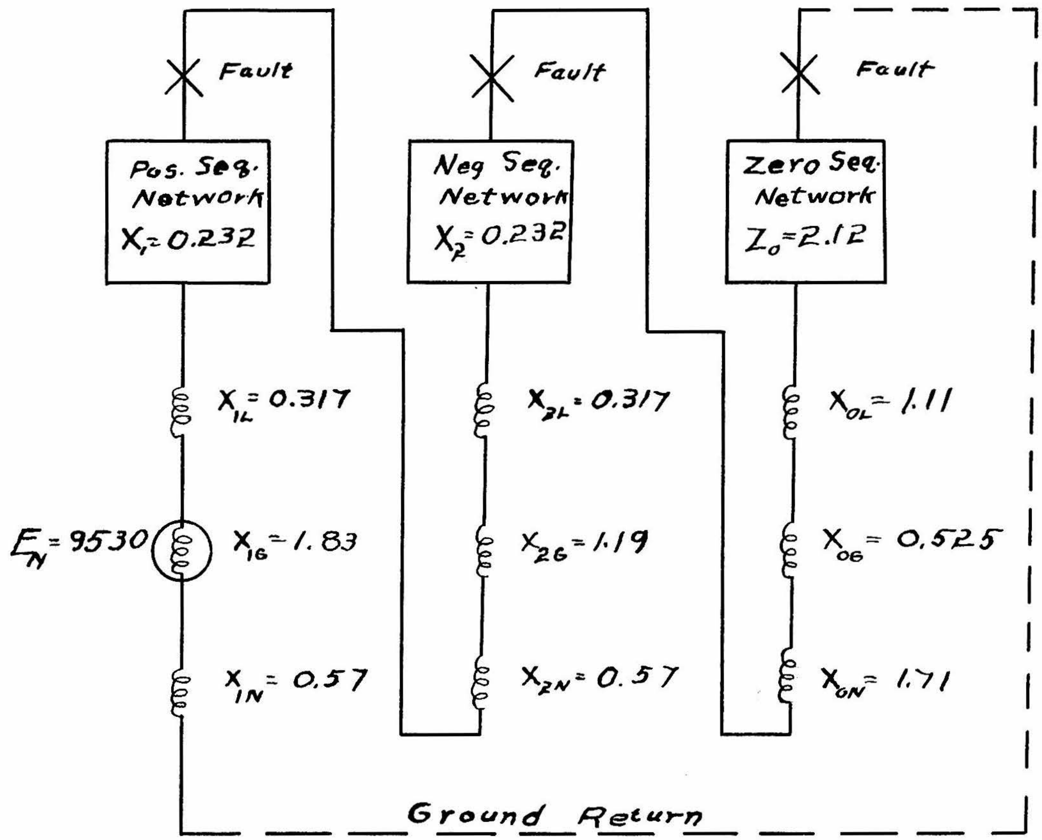

Fault
Fault
Fault
Pos. Seq. Network
X1= 0.232
Neg Seq. Network
X2= 0.232
Zero Seq. Network
Z0=2.12
X1L = 0.317
X2L = 0.317
X0L = 1.11
EN = 9530
X1G = 1.83
X2G = 1.19
X0G = 0.525
X1N = 0.57
X2N = 0.57
X0N = 1.71
Ground Return

Figure 13

CHAPTER IV

RELAYS, DESCRIPTION--CONNECTIONS--SETTINGS

The following description while applying specifically to Westinghouse Type CO induction overcurrent and Type CR overcurrent directional relays, is also generally descriptive of the General Electric Relays IA-201, IK-104 and IB-1.

The standard overcurrent relay is the induction disc type having a current coil with a number of taps. Each tap has a full load rating in amperes and these ratings are from 4 to 12 or 4 to 16 amperes depending upon the particular style of relay used. The ratings are such that the relay will not start until the current in the coil slightly exceeds the rating.

The tap settings of the relay permit the adjustment of the current flowing in the relay coil for a given value of current in the secondary of the current transformer. Another adjustment is the time lever setting. This simply consists of moving the contacts further apart or closer together so that it takes a longer or shorter time for the rotating contact to close. As the relay is designed to give as nearly constant speed of rotation as possible for a given percent load, the time of closure is directly proportional to the division setting of the relay.

The directional current relay has an overcurrent element precisely the same as the above relay. In the same case is mounted a wattmeter element having a potential coil and a current coil. The current coil is in series with the current winding of the overload element. The wattmeter element is designed to close its contacts practically instantaneously if the power flow is in the right direction. It will operate on as low as one percent of normal voltage with a reasonable excess current.

Inasmuch as great sensitivity is desirable for the ground relay, that is operation on a minimum amount of current it is desirable to use low current coils on the ground relays. The line relays must have capacity to carry the full normal line current continuously but since there is no normal ground current, a relay that will operate on the minimum current possible is desired. For this purpose the so called low energy relay with the low current coil ($\frac{1}{2}$ to $2\frac{1}{2}$ amperes) is applicable. By using a low energy relay, particularly, for the directional relays operation is obtained with great sensitivity even when the voltage at the relay is very low.

RELAY SETTINGS

Since the Pasadena System at present has mostly Westinghouse relays installed it is considered best to use the typical Westinghouse time current curves for making the relay settings. The General Electric relay curves differ slightly from those of the Westinghouse so that if such relays are purchased in the future it will be necessary to make the corresponding changes in relay settings. These curves are shown on pages 60 and 49 for the Standard and Low Energy relays. For the curves of the standard relay page 60 it can be seen that the higher the percentage of current above 100% the faster the operation of the relay up to a value of current about 400% to 900% (depending on the time lever setting) of rating. Above this value the time of operation is a definite minimum. The relay thus has an inverse time characteristic for values of current from 100% to 400% or 900% of full load rating and a definite time characteristic above this value. It is the combination of this inverse and definite time characteristic which makes possible the consecutive timing of a number of relays along any given line. The curves for the low energy relay are similar to those for the standard relay except that it takes a larger percentage of overload before the relay becomes definite time.

In order to make the necessary selective relay settings one must have at hand certain data as follows:

1. The general type of relay to be used must be known. As stated above for this system it has been decided to use non-directional and directional overcurrent relays.

2. Typical time current curves for the relays to be used. These are shown on pages 49 and 60. Since the timing mechansim of the directional and non-directional relays is the same, the curves apply equally well to both types.

3. A symplified diagram of the system on which the relay locations may be represented in some convenient manner. For this purpose, use has been made of pages showing the fault current values; also each of these sheets has numbers 1 to 15 at locations quite representative of the necessary relay location. For instance, #5 is found on any of these sheets to be on the Raymond Line at Raymond Substation; hence

relay #5 is located on the Raymond Line at Raymond Substation.

4. The allowable time interval between relay settings. For this report the minimum time is taken as 0.4 seconds. The minimum time interval necessary depends upon the rapidity of operation of circuit breakers and circuit breaker relays, because in less than this time interval the fault must be cleared or the succeeding relay sets in operation the tripping of another breaker, which should not open. This time interval is long enough for the ordinary operation of most breakers, but if it is found that the circuit breaker mechanisims are too sluggish for this timing, the time intervals will have to be increased accordingly. For Pasadena it is believed that the apparatus is sufficiently speedy, but this point should be checked by test.

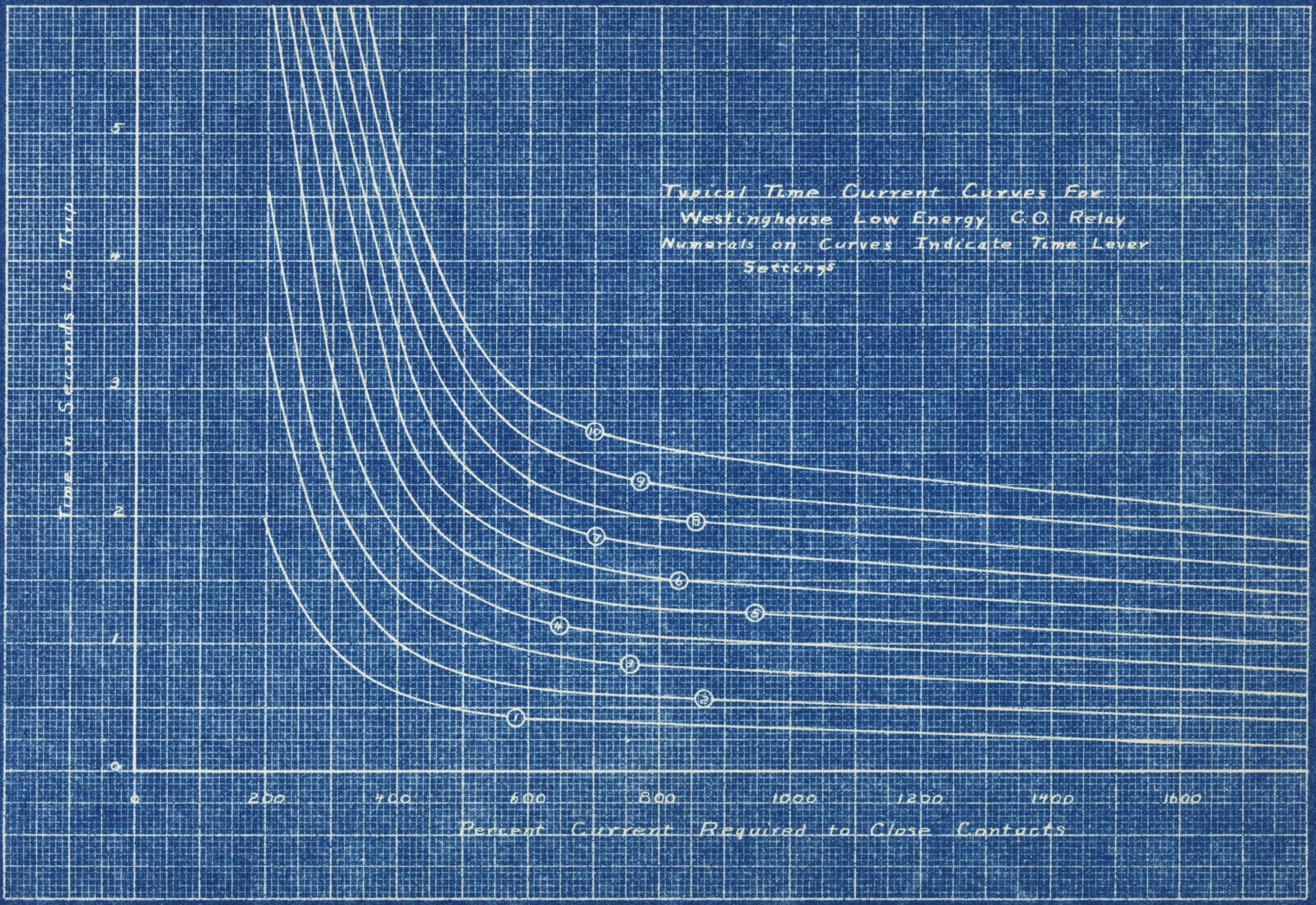
5. The current transformer ratios at all points at which relays are to be located. These can be found on the original system diagram page 8.

6. Minimum time for which a relay may be set. 0.2 seconds has been chosen as the minimum tripping time since a shorter time might allow the relay to close on a heavy surge.

GROUND RELAY SETTINGS

The setting of the ground relays has been considered first as they are somewhat simpler and show the advantage of using the inverse time part of the time current curves in setting the line relays.

As has been stated several times before it is desirable to set the ground relays so that they will operate on small values of ground


Typical Time Current Curves For
Westinghouse Low Energy C.O. Relay
Numerals on Curves Indicate Time Lever
Settings
Time in Seconds to Trip
0
1
2
3
4
5
Percent Current Required to Close Contacts
0
200
400
600
800
1000
1200
1400
1600
1
2
3
4
5
6
7
8
9
10

current, hence the $\frac{1}{2}$ ampere tap has been chosen for all such relays. From the time current curves for the low energy relay it is found that the relay will not trip for less than 200% load or the equivalent of 1 ampere in the relay. For all locations having current transformer ratios of 400/5 this would mean a line current of 80 amperes, for 250/5 --- 50 amperes; and for 170/5 ---- 34 amperes.

In setting the ground relays advantage has been taken of the fact that between each time lever setting curve, page 49, there is an interval of approximately 0.2 seconds for all values of load, hence if the relays to have the lowest time were set on lever setting #1; the next on lever setting #3 etc. it is evident that no matter what the fault current value in the relays there would always be discrimination provided directional relays are used when needed. This is the general plan used for the ground relay settings. Page 51 shows a table containing the settings as recommended.

As stated above 0.2 seconds was set as a minimum time allowable so that there would be no chance for the relay to go out on a surge but in the case of the ground currents it is not felt that the minimum time necessarily need be held to this for values of current of over about 100 amperes so the minimum time setting has been given as 0.25 seconds at 500% current; for loads greater than 500% the relay will trip much faster. This results in a lever setting of $\frac{1}{2}$ with a definite minimum tripping time of 0.1 second.

Since the relays at points 5, 10, 12, 13, have only to protect the lines coming from the power station they have been chosen of the

GROUND RELAY SETTINGS

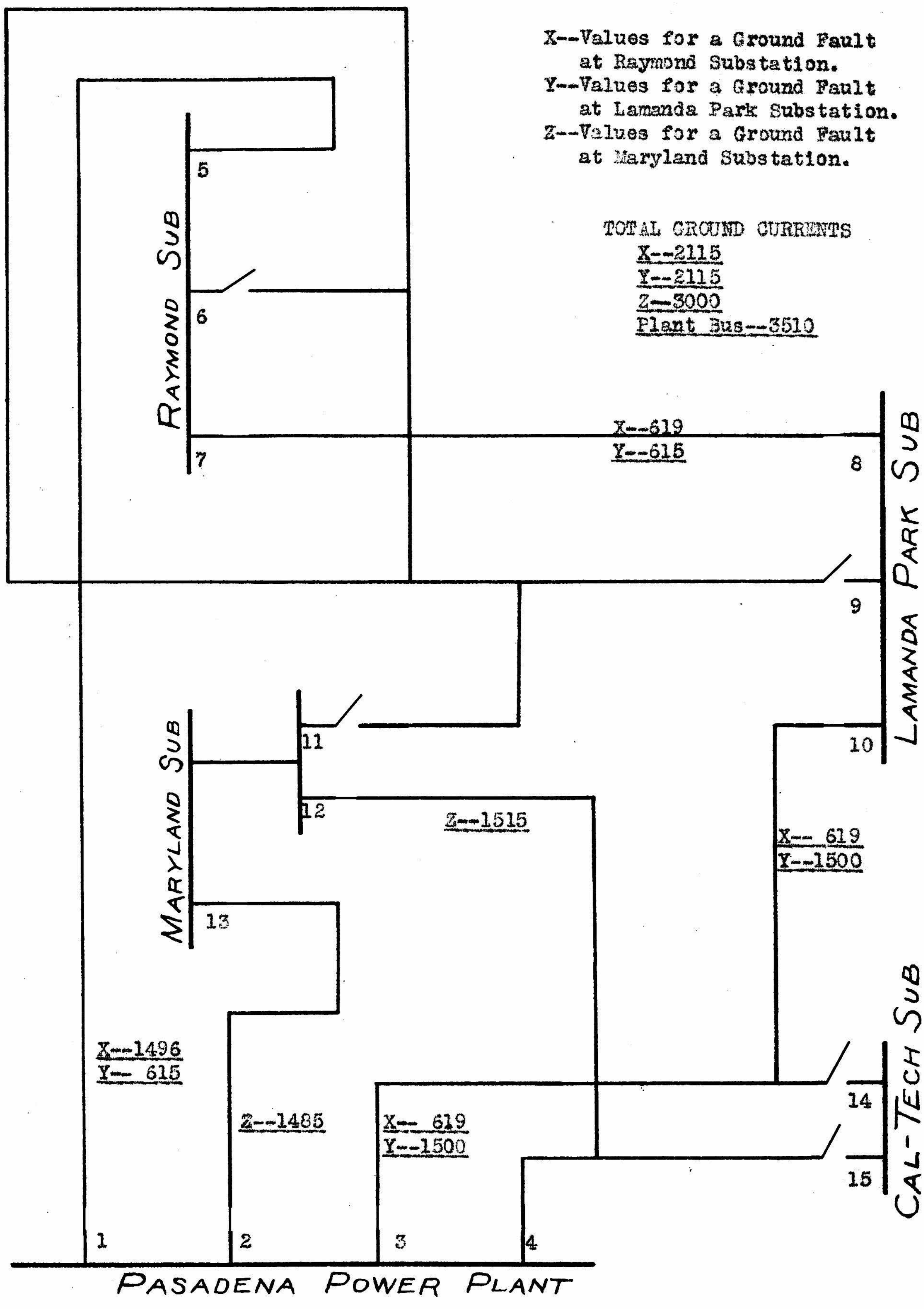
Relay	C. T. Ratio	Tap	%Load	Time Lever Setting	Time	Minimum Time
1	400/5	$\frac{1}{2}$	500	$4\frac{1}{2}$	1.60	0.9
2	400/5	$\frac{1}{2}$	500	$6\frac{1}{2}$	2.25	1.3
3	400/5	$\frac{1}{2}$	500	$4\frac{1}{2}$	1.60	0.9
4	400/5	$\frac{1}{2}$	500	$6\frac{1}{2}$	2.25	1.3
5	400/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1
6	170/5	$\frac{1}{2}$	500	$2\frac{1}{2}$	0.95	0.5
7	250/5	$\frac{1}{2}$	500	$2\frac{1}{2}$	0.95	0.5
8	250/5	$\frac{1}{2}$	500	$2\frac{1}{2}$	0.95	0.5
9	170/5	$\frac{1}{2}$	500	$2\frac{1}{2}$	0.95	0.5
10	400/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1
11	400/5	$\frac{1}{2}$	500	$4\frac{1}{2}$	1.60	0.9
12	400/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1
13	400/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1
14	170/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1
15	170/5	$\frac{1}{2}$	500	$\frac{1}{2}$	0.25	0.1

directional type and given the minimum time setting mentioned above.

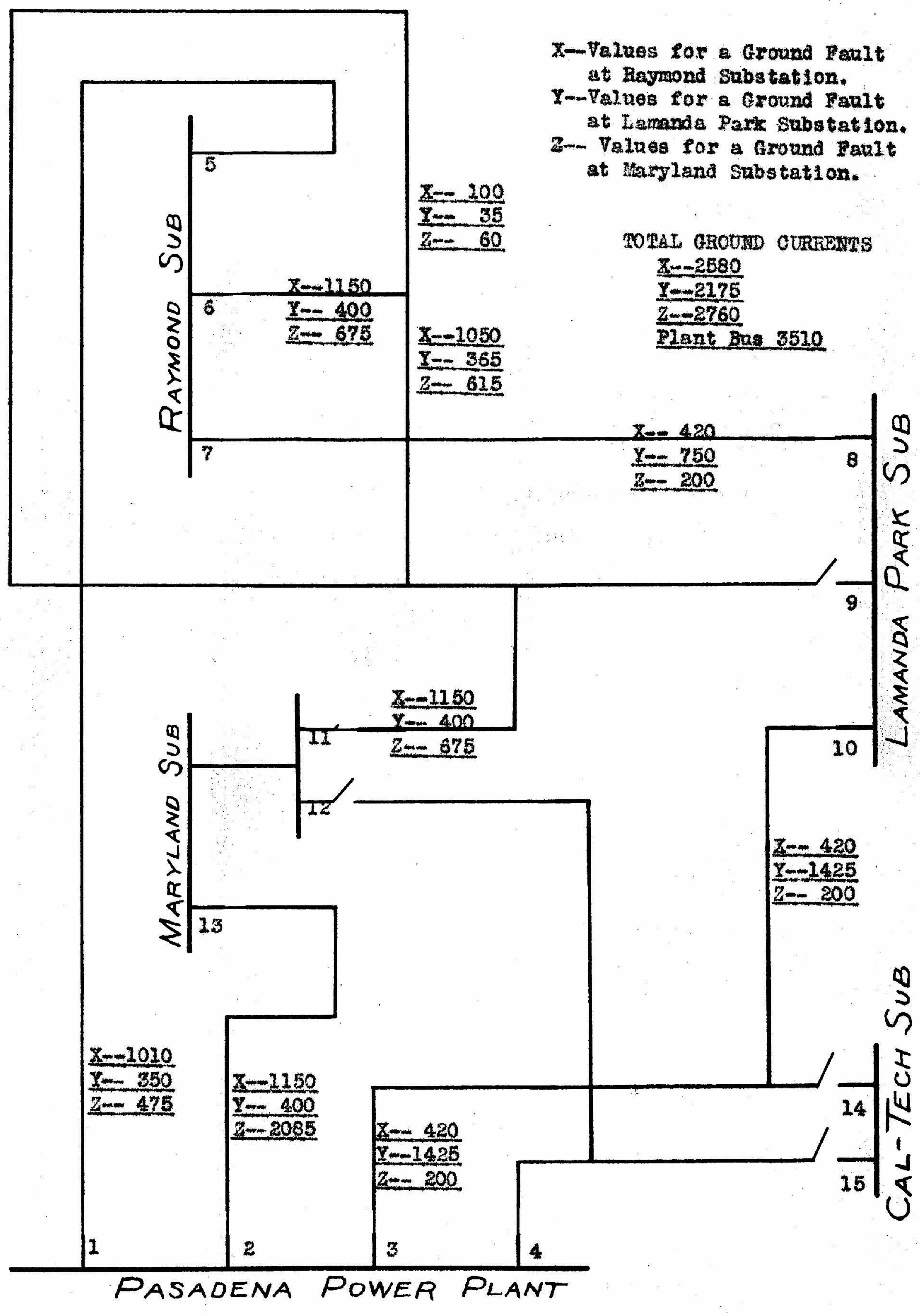
Relay 6 must be set to hold in over relays 10, 12, and 13 and relay 9 over 5, 12, and 13, so they are given a minimum setting of 0.5 seconds with the time lever setting of $2\frac{1}{2}$. These relays are made directional so that they do not have to be timed to hold in over 7 and 8.

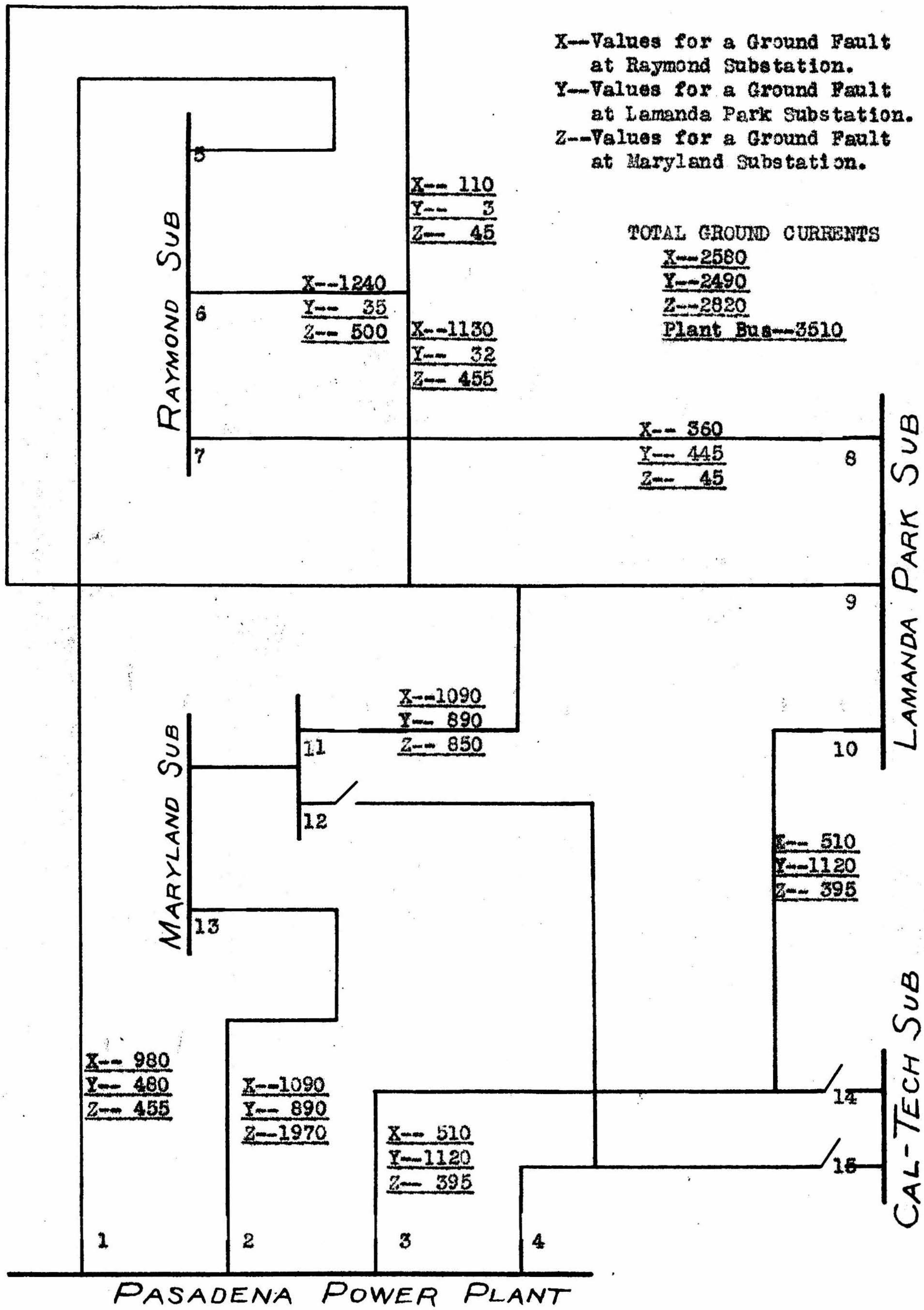
To secure correct selectivity relays 7 and 8 should be set to hold in over 6 and 9 but due to the fact that this would increase the tripping time on relays 1, 2, 3, and 4 at the power station, relays 7 and 8 have been set the same as 6 and 9. To find out just what trouble this will cause, consider the case of a fault on the water department line just outside of Raymond Substation, case 4. Relays 7 and 8 would have a primary current of 355 amperes or 1420% load which would cause these relays to trip in approximately 0.55 seconds. Relay 6 would have (355 -- 925) 1280 amperes primary current or 7500% current which would trip in the minimum time of 0.5 seconds. Hence with these settings there would be caused the false operation of relays 7 and 8 but this would be of no serious consequence since it would not isolate any part of the system from the power plant. It is felt of greater advantage to allow such false operation in this case than to increase the time another 0.4 seconds. Directional type relays have not been recommended for 7 and 8 since they would produce no greater discrimination; their only advantage would be that only relay 8 would go out, in such a case as cited above, instead of 7 and 8.

GROUND FAULT CURRENTS -- CASE 1

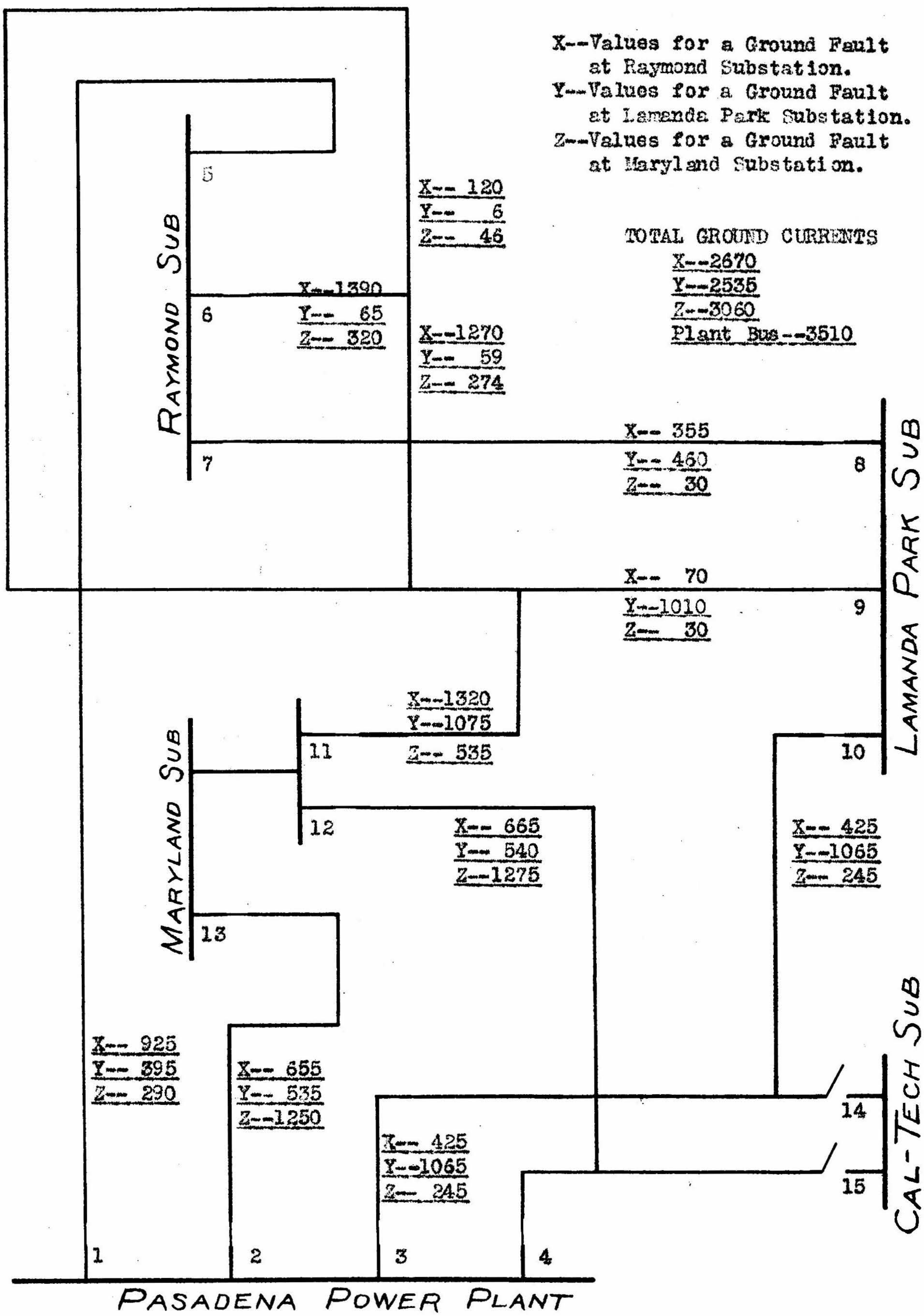


GROUND FAULT CURRENTS -- CASE 2




X--Values for a Ground Fault at Raymond Substation.
Y--Values for a Ground Fault at Lamanda Park Substation.
Z--Values for a Ground Fault at Maryland Substation.
TOTAL GROUND CURRENTS
X--2580
Y--2490
Z--2820
Plant Bus--3510
RAYMOND SUB
5
6
7
X-- 110
Y-- 3
Z-- 45
X--1240
Y-- 35
Z-- 500
X--1130
Y-- 32
Z-- 455
X-- 360
Y-- 445
Z-- 45
8
9
10
LAMANDA PARK SUB
MARYLAND SUB
11
12
13
X--1090
Y-- 890
Z-- 850
X-- 510
Y--1120
Z-- 395
X-- 980
Y-- 480
Z-- 455
X--1090
Y-- 890
Z--1970
X-- 510
Y--1120
Z-- 395
14
15
CAL-TECH SUB
1
2
3
4
PASADENA POWER PLANT

GROUND FAULT CURRENTS -- CASE 4



Relay 11 must be set to hold in over relays 7 and 8 so that it is given a minimum tripping time of 0.9 seconds on lever setting $4\frac{1}{2}$. It is of the non-directional type since the relays on both sides of it are set for shorter times.

Relays 1 and 3 at the power station must be set to hold in over 6, 7, 8, and 9 so they are set with a minimum time of 0.9 seconds and a lever setting of $4\frac{1}{2}$. Relays 2 and 4 must be set to hold in over 11 so they are given a setting of 1.3 seconds minimum time on lever $6\frac{1}{2}$. Since there is only the one source of power on this system it is obvious that only non-directional relays should be used at the power station.

Though the actual values of ground current as calculated have not been used directly in determining the relay settings it is of advantage to have the current for two reasons.

1. It can be used as a check on the operation of any doubtful relays such as was done in setting #7 and #8.

2. It is well to know the order of magnitude of the ground currents which might flow in the system.

LINE RELAY SETTINGS

In determining the setting for the line relays the actual values of current as calculated have been used as it is not considered necessary to isolate line faults until they have developed. By using the currents thus calculated for the various line sections it is possible by setting the relays on the inverse part of the time curves to obtain selectivity of operation without increasing the total time. In making the settings care must be taken so that no line will be tripped out on its full load value of current. These values are taken as 400 amperes for 500,000 c.m. cable and 300 amperes for 350,000 c.m. cable. A table showing the line relay setting is given on page 59. The time current curves are on page 60 and the short circuit current values are found on pages 62 to 65.

Relay 5 has only to protect the line from Raymond to the power station so that the directional type is used with a minimum time setting. Since the full load on that line is 400 amperes tap 5 must be used as tap 4 would allow the relay to trip on less than full load. The relay is set on division 1 as it has the allowable minimum time of 0.2 second. No actual current value need be considered in setting this relay. Relays 10, 12, and 13 are set in a similar manner as they must meet the same requirements.

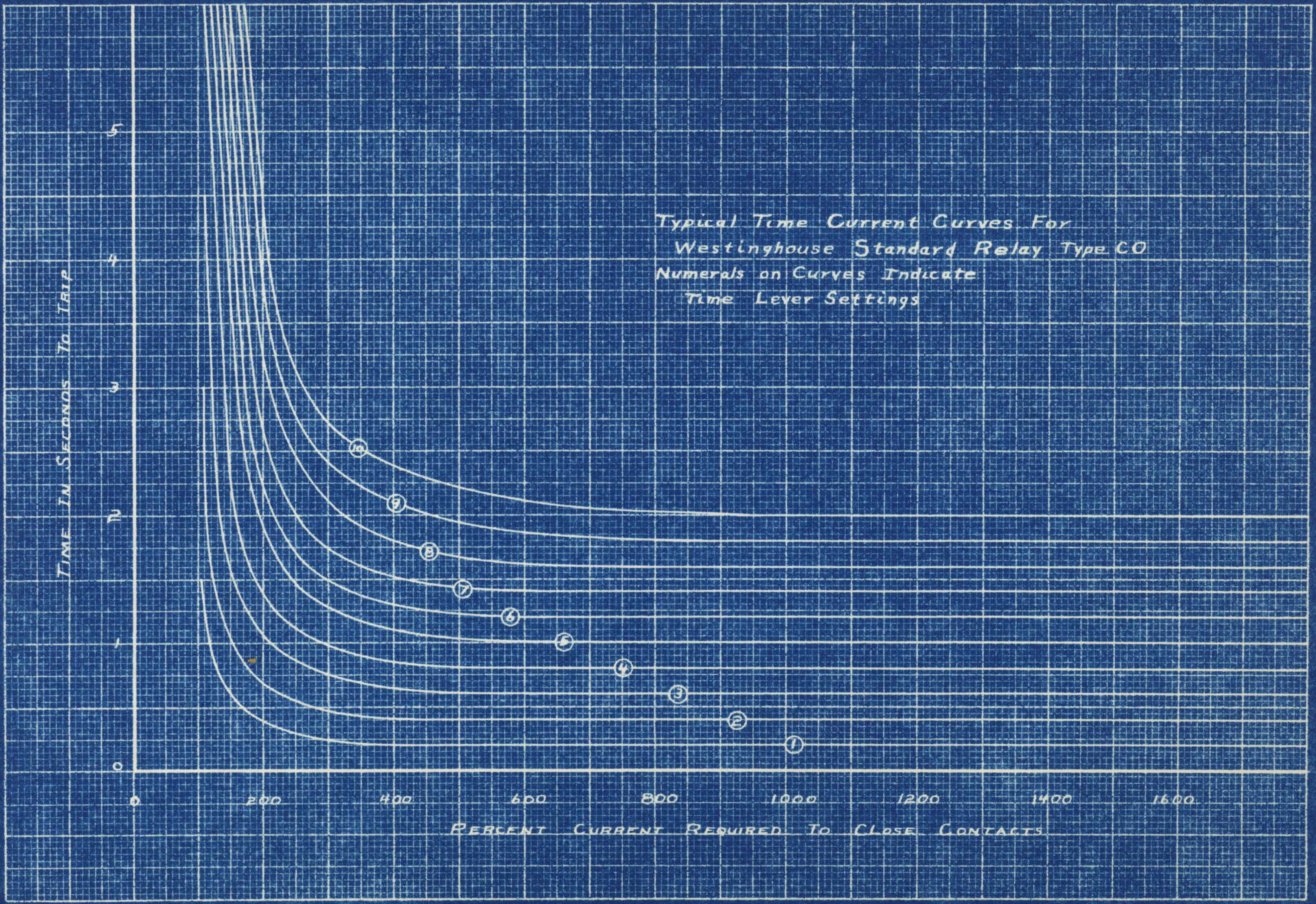
Relay 6 is next set to hold in over 10, 12, and 13. Since it is advisable to have the relay operate on the inverse part of the curve it is desirable to find the maximum value of current on which this relay will be expected to trip (and still hold in over some other relay) and for this value set it just on the beginning of the inverse part. This maximum value is found in case 2 to be 975 amperes for a short circuit adjacent to Maryland on the Maryland Line. The relay is then set to hold over 13 as shown on page 59. Relay 9 is set in a similar manner.

Next relays 7 and 8 are set to hold in over 5, 6, 9, 10, 12, and 13. In cases 3 and 4 the current values are but slightly over the full load rating of the line so that they can hardly be considered.

LINE RELAY SETTINGS

Relay	Primary Current	C. T. Ratio	Secondary Current	Tap	%Load	Approx. Lever Setting	Tripping Time*	Definite Min. Time Setting
1	1635	400/5	20.4	5	409	5	1.10	1.0
2	3095	400/5	38.6	12	322	6	1.42	1.2
3	2870	400/5	35.9	10	359	5	1.15	1.0
4	2145	400/5	26.8	8	335	6	1.40	1.2
5	695	400/5	8.7	5	175	1	0.47	0.2
6	975	170/5	28.7	9	319	3	0.72	0.6
7	695	250/5	13.9	6	232	3	0.90	0.6
8	695	250/5	13.9	6	232	3	0.90	0.6
9	530	170/5	15.6	9	173	2	0.83	0.4
10	700	400/5	8.75	5	175	1	0.47	0.2
11	1400	400/5	17.5	10	175	4	1.65	0.8
12	2045	400/5	25.6	5	511	1	0.20	0.2
13	975	400/5	12.2	5	244	1	0.30	0.2
14		170/5	16.0	4	400	1	0.20	0.2
15		170/5	This setting will be governed by the operation of the Million Volt Laboratory.					

*Tripping times are only for the primary current indicated. Since all these currents have not been chosen for one given fault condition the tripping times do not show selective operation of the relays. However, if any given fault condition is chosen and the relay tripping times checked for the corresponding tap and lever setting, selective operation will be indicated. Such a system of checking has been done for this system to assure against false operation.


Typical Time Current Curves For
Westinghouse Standard Relay Type CO
Numerals on Curves Indicate
Time Lever Settings
Time in Seconds to Trip
0
1
2
3
4
5
0
200
400
600
800
1000
1200
1400
1600
Percent Current Required to Close Contacts
1
2
3
4
5
6
7
8
9
10

Case 2 shows current values sufficiently large to trip the relays but the limiting case was found to be #1 with the condition of a short circuit on the Raymond Line at which time there would be a current of 695 amperes flowing in the primary circuit of relays 5, 7 and 8. Page 59 shows the necessary setting so that relays 7 and 8 will hold in over #5. The setting was also checked to see that it would hold in over 6, 9, 10, 12, and 13.

The settings of the remaining relays were obtained in a similar manner and can be followed through by the reader if desired. It is well to call attention to the fact that in making any such settings there are a good many more factors to consider than appear on the surface so that to really understand the why and wherefore of certain choice of tap etc. it is necessary to follow the whole story through from beginning to end.

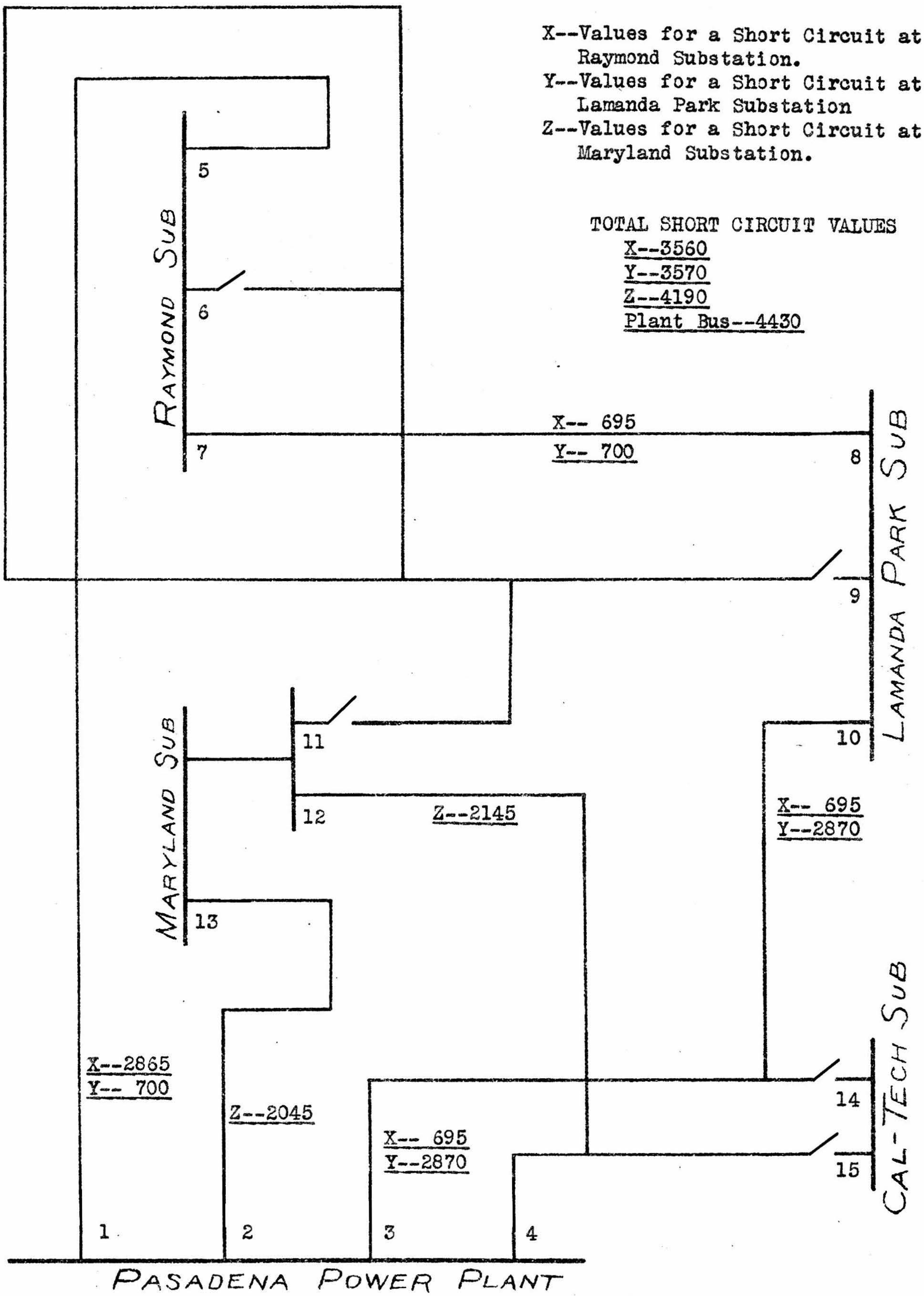
These settings for the line relays as given will allow the correct operation of all relays; there will be no false operation as in the case of the ground relays. By referring to the column of minimum times it is also seen that the time is slightly less for the line relays than for the ground relays, hence the advantage of setting on the inverse part of the curve is quite evident.

The above settings have been made so that the relays will operate correctly for any one of the normal operating conditions considered. If, however, a definite operating condition should be decided on the relays could be set for that condition only, in which case the settings might be somewhat simpler and the total time might be reduced.

THREE PHASE SHORT CIRCUITS -- CASE I

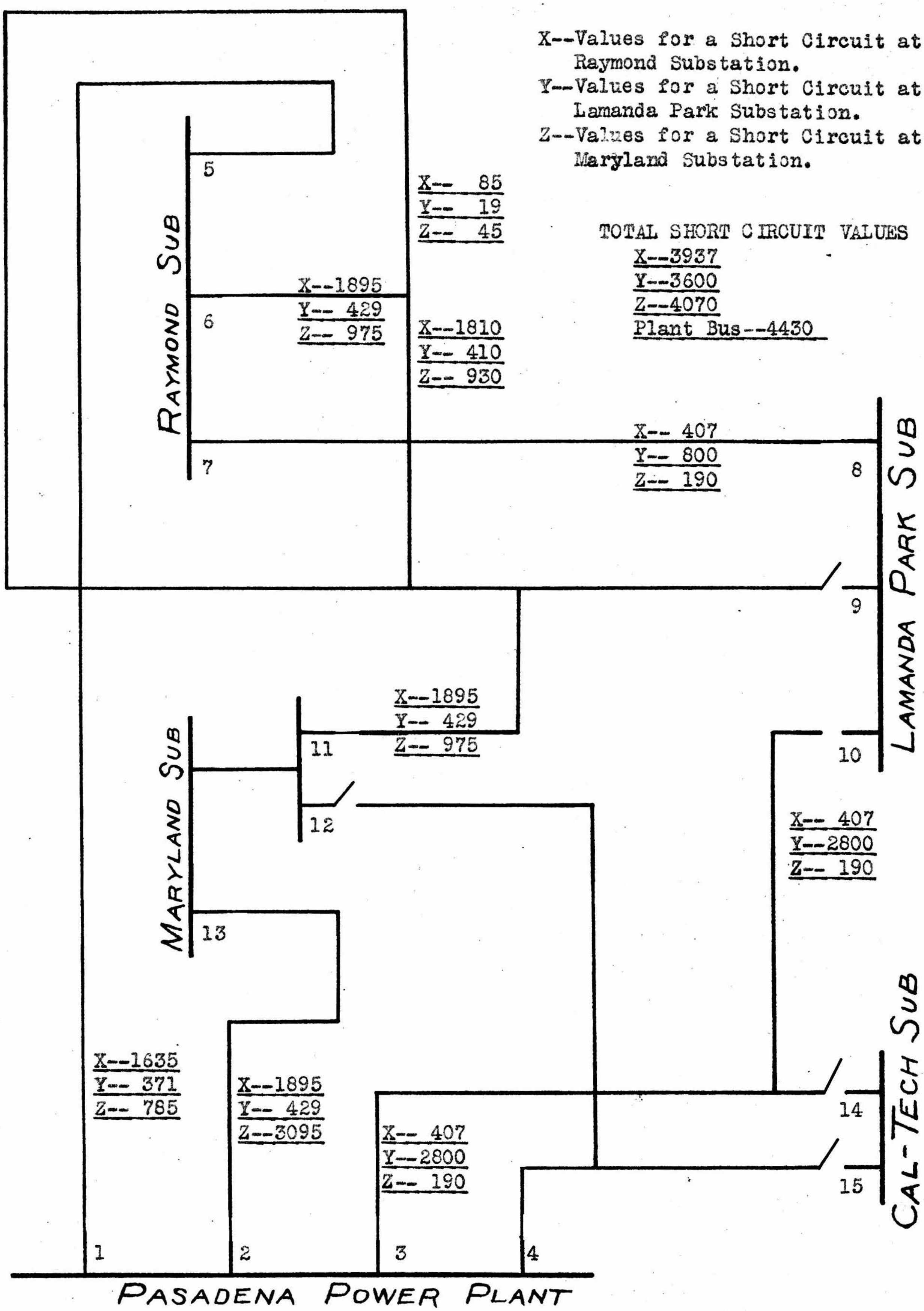
X--Values for a Short Circuit at Raymond Substation.
Y--Values for a Short Circuit at Lamanda Park Substation
Z--Values for a Short Circuit at Maryland Substation.

TOTAL SHORT CIRCUIT VALUES
X--3560
Y--3570
Z--4190
Plant Bus--4430



X--Values for a Short Circuit at Raymond Substation.
Y--Values for a Short Circuit at Lamanda Park Substation.
Z--Values for a Short Circuit at Maryland Substation.

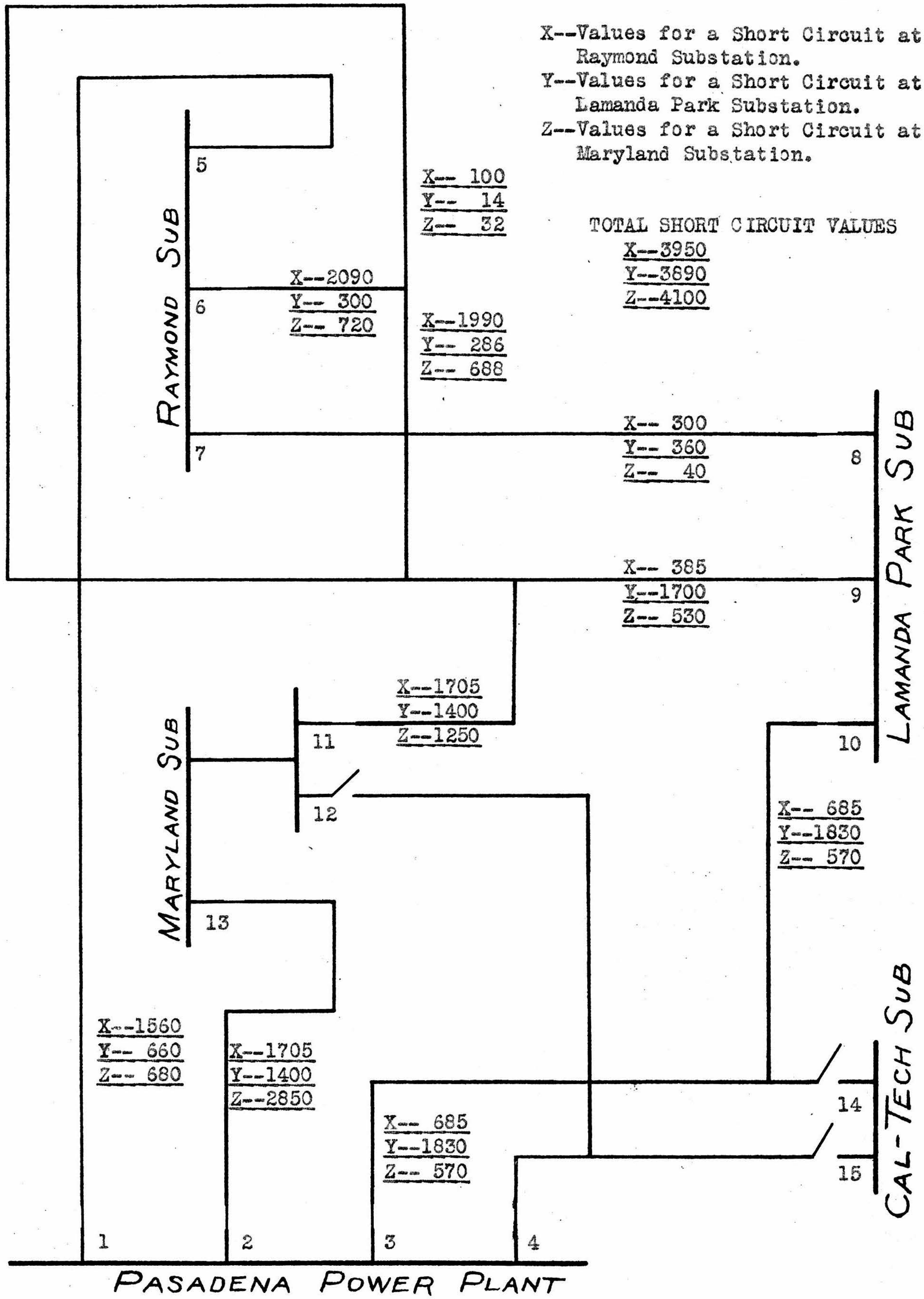
TOTAL SHORT CIRCUIT VALUES
X--3937
Y--3600
Z--4070
Plant Bus--4430



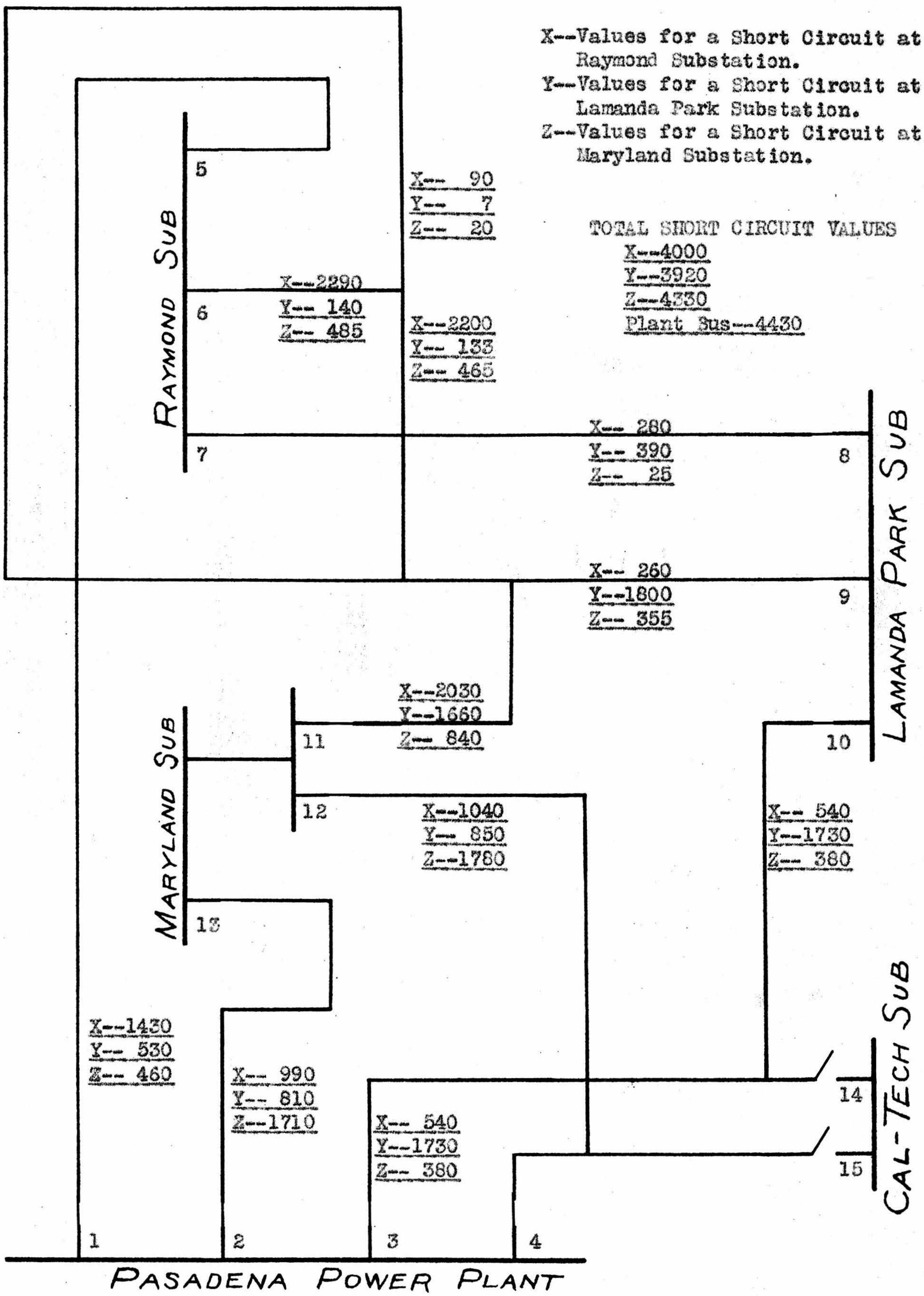
THREE PHASE SHORT CIRCUITS -- CASE 3

X--Values for a Short Circuit at Raymond Substation.
Y--Values for a Short Circuit at Lamanda Park Substation.
Z--Values for a Short Circuit at Maryland Substation.

TOTAL SHORT CIRCUIT VALUES
X--3950
Y--3690
Z--4100



THREE PHASE SHORT CIRCUITS -- CASE 4



RELAYING AT CAL-TECH SUBSTATION

So far in the discussion no mention has been made of the necessary setting for the relays at the Cal-Tech Substation and the Million Volt Laboratory. The normal operation is to feed the Cal-Tech Substation from the Lamanda Park Line and the Million Volt Laboratory from the combined Cal-Tech and Water Department Line. The reason for this operation is that the Million Volt Laboratory during periods of experimental activity causes large surges on the line which might cause disturbances at the local Cal-Tech Substation if both were fed off the same feeder.

For relay 14 on the line feeding the substation, since it is a stub feeder, it should be set as low as possible, hence tap 4 and lever setting 1 are used. For the condition of a short on the 16.5 KV. bus this relay might not operate to clear the fault before relay 10 operates. However, the chance of a short on the high tension bus is quite remote so that this operation is felt to be quite satisfactory. For any fault on the low side of the transformer operation would be selective, because the current is limited by the reactance of the transformer.

Since the ground relays are set to operate on small values of current ground relay # 14 will start to operate much before ground relay #10 and hence it will be tripped out in plenty of time. Similarly ground relay #15 will operate before #12.

The setting of line relay #15 depends on the operation of the Million Volt Laboratory. However, it is recommended here that this relay be set to trip before the one at the power station #4.

16.5 KV. RELAYING FOR POWER STATION AND SUBSTATIONS

The 16.5 KV. line relaying is not designed to relay for trouble inside the substations or on the 2400 volt distribution. Each 2400 volt feeder has relay protection at the substation and the trouble will normally be very quickly cleared by the particular 2400 volt breaker on that feeder. In case of trouble inside any bank of transformers, quick acting differential relays are recommended. These operating, will trip the breakers on either side of the transformer bank, isolating the faulty transformer but not interrupting the supply to the substation, if two banks are on.

In the power station, differential protection is recommended around each machine, and also around the autotransformer for #7 generator. This protection should overlap the differential protection recommended and shown for the bus, so that no part of the circuit in the power station is left unprotected. (See page 8)

It is felt that the possibility of trouble on the busses in the substations is so remote, that differential protection here is hardly justified. Especially so as two complete and rather complicated differential connections would be needed (because of the double bus and bus sectionalizing), one for the low bus and one for the high. Furthermore if the highly improbable trouble did occur, the line overload relays would operate to clear the station from the system.

The above analysis of the relay types and setting shows that the relay system recommended fulfills the three requisites of good relaying. These are:

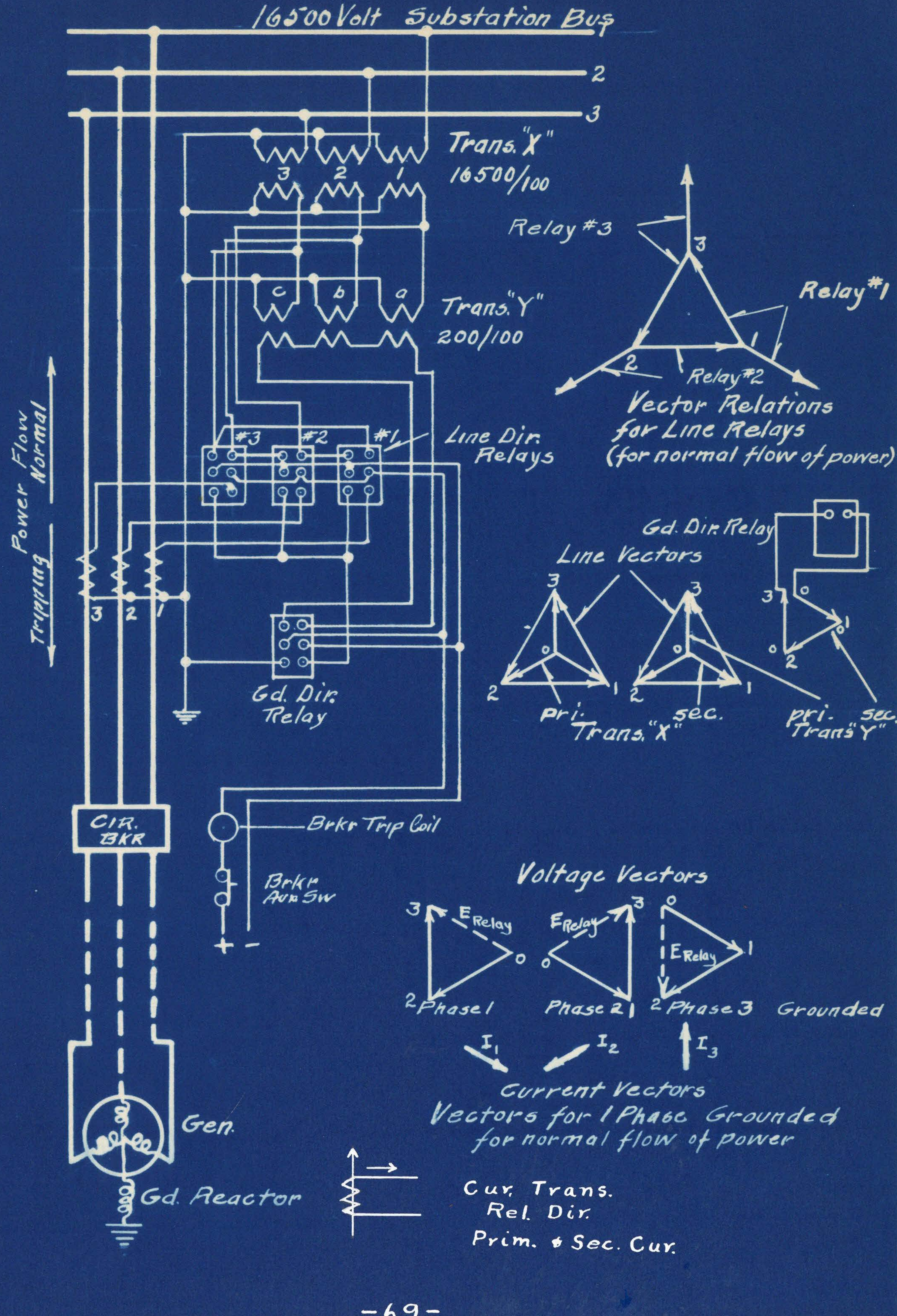
1. Isolation of fault limited to the smallest area possible by taking out of service only that section of the line on which the fault occurs.

2. As speedy operation as possible, consistent with proper selectivity.

3. Non operation of relays on legitimate loads. (Relays operate only on overloads).

RELAY CONNECTIONS AND VECTOR RELATIONS FOR SINGLE PHASE RELAYS

Referring to the vector diagram, page 69, for the line relays, it will be seen that for the relay on phase #1, the current in the relay will lag the voltage across the relay (voltage 1-3) by 150 degrees, when the power factor is unity and the power flow is in the direction to keep the relay contacts open. If the power flow is reversed in the direction for relay tripping, the current reverses with respect to the voltage and then leads the voltage by 30°, provided the power factor remains unity. Actually, however, it does not, but becomes largely lagging on account of the reactance in the circuit. The current therefor shifts to a lagging position but never more than 60° lagging. Even with this angle of lag the relay would close its directional contacts, as this element is very sensitive. If however, the angle of lag is going to be very large, a phase shifter box may be used to bring the current more nearly in phase with the voltage.


16500 Volt Substation Bus
1
2
3
Trans. "X"
16500/100
3 2 1
c b a
Trans. "Y"
200/100
Relay #3
Relay #1
Relay #2
Vector Relations
for Line Relays
(for normal flow of power)
#3 #2 #1
Line Dir. Relays
Power Flow Normal
Tripping
3 2 1
Gd. Dir. Relay
Gd. Dir. Relay
Line Vectors
pri. sec.
Trans. "X"
pri. sec.
Trans. "Y"
CIR. BKR
Brkr Trip Coil
Brkr Aux Sw
+ -
Voltage Vectors
E Relay
Phase 1
Phase 2
Phase 3
Grounded
I1
I2
I3
Current Vectors
Vectors for 1 Phase Grounded
for normal flow of power
Gen.
Gd. Reactor
Cur. Trans.
Rel. Dir.
Prim. & Sec. Cur.

For the cases of single phase ground faults, the vector relations of relay current and voltage are also shown. For this purpose three potential transformers (transformers X) are connected in Y across the 16,500 volt substation bus. The secondaries (also Y connected) feed the primaries of three auxiliary 200/100 potential transformers (transformers Y) Y connected on the primary side and delta connected on the secondary side. The ground directional relay is connected into one corner of the delta. All star connected windings are solidly grounded at the neutral points, thus preventing shifting of these points.

Now suppose phase 1 became grounded at or near the substation. There would then be no voltage across transformer 1 and likewise transformer a. The voltages of the other transformers would remain constant in magnitude and vector direction. On the delta side of transformers a, b, and c, since voltage a has disappeared and voltage b and c maintain their magnitude and direction, a voltage appears across the relay coil which is shown by the dotted line in the vectors shown in the lower side of the diagram. If the power direction is normal (i.e. in the direction to keep the contacts open) this voltage will be 180^{0} out of phase with the current in the ground lead, assuming the ground impedance is wholly resistance. If however, the power direction reverses, the relay current will reverse with respect to the relay voltage and will then be in phase, causing closure of the directional contacts.

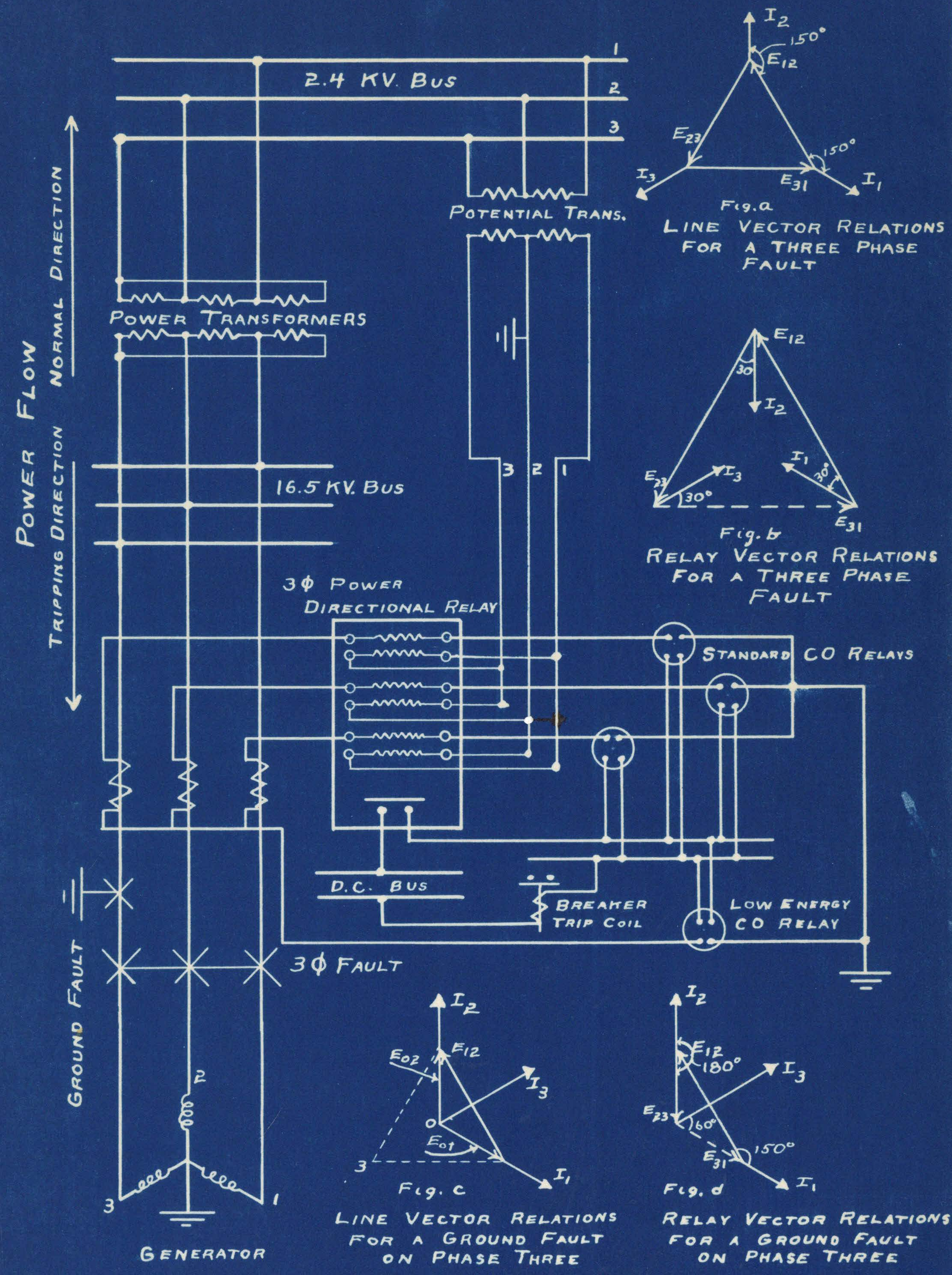
Actually the current will be very considerably lagging on account of the reactance of the grounded circuit. If this lag is too much a phase shifter box (combined resistance and reactance, external to relay) must be used which will bring the relay current more nearly in phase with the relay voltage.

By a similar analysis, it will be found that no matter which phase is grounded, the voltage appearing across the relays will have the same vector relation to the relay current as shown above. Of course, the more distant the ground fault is from the potential transformers, the greater will be the variation from this relation. But for the distance of one line section, the variation will not exceed permissible limits in the case of the Pasadena system.

It will be noted that the generator neutral is ground through a reactor, not a resistance. This has the effect of causing any ground current to be more lagging than if it were a resistance. Therefore it is very likely that a phase shifter should be used with the ground relays. This point should be carefully investigated before application of the relays is made.

RELAY CONNECTIONS AND VECTOR RELATIONS FOR USE OF POLYPHASE RELAYS.

The connections for use of one polyphase power directional relay in conjunction with three standard overcurrent relays for line protection and with one low energy overcurrent relay for ground protection is shown on page 72. Though this system of relay connection has not been recommended for Pasadena it is considered worth while to give the corresponding vector relations because so far as known such a method is not listed in any of the literature.


2.4 KV. Bus
1
2
3
Potential Trans.
Power Flow
Normal Direction
Tripping Direction
Power Transformers
16.5 KV. Bus
3 2 1
3φ Power
Directional Relay
Standard CO Relays
D.C. Bus
Breaker
Trip Coil
Low Energy
CO Relay
Ground Fault
3φ Fault
Generator
I2
150°
E12
E23
150°
I3
E31
I1
Fig. a
Line Vector Relations
For a Three Phase
Fault
E12
30
I2
I1
E23
I3
30°
30°
E31
Fig. b
Relay Vector Relations
For a Three Phase
Fault
I2
E02
E12
I3
0
E01
3
I1
Fig. c
Line Vector Relations
For a Ground Fault
on Phase Three
I2
E12
180°
I3
E23
60°
150°
E31
I1
Fig. d
Relay Vector Relations
For a Ground Fault
on Phase Three

The vector relations shown in fig. a represent the conditions on the line for normal direction of power flow in which case the current in any given element of the power directional relay is 150° out of phase with the voltage across that element, hence the relay will not operate. Now consider a three phase fault on the 16.5 KV. line outside the substation as shown on the diagram. Fig. b shows the vector relations at the relay under these conditions. Since it is a three phase fault the vectors can be considered balanced even after the fault. The voltage E_{31} is shown dotted since it is the voltage across the open side of the V connection. The currents in fig. b are reversed 180° with respect to their position in fig. a; this is due to the fact that the fault causes a reversal of current, it now flows away from the substation in the tripping direction. The above discussion has been for unity power factor so that the currents as shown lead their respective voltages by 30° . Actually, of course, the current is largely lagging but in no case may it lage the voltage by more than 60°.

Now to consider a ground fault on phase 3. In this case the line vector relations are given in fig. c which shows the fact that since phase 3 is faulted the voltage E_{03} is equal to zero (at point of fault) so that the resultant line voltages are E_{12}, E_{02}, and E_{01}; the currents are not altered except that I_3 is much greater in magnitude and is reversed. Fig. d shows the vector relations at the relay where the open V voltage is shown dotted as E_{31}. In this case the current I_3 leads the voltage by 60° at unity power factor so that with the lagging current occuring in the fault, the relay will operate correctly. The current I_1 is still 150^0 out of phase with its voltage E_{12}, and I_2 is 180^0 out of phase with its voltage E_{23}; hence these elements would not act to close their contacts; it is only necessary however, for one element to act. A similar discussion may be followed through for faults on either of the other phases as well as for a single phase line to line short.

The fact that line 2 in the V connection is grounded can make no difference in the actual vector relations; its purpose is to keep the metering equipment at ground potentials.

LOCATION OF RELAYS WITH RESPECT TO CIRCUIT BREAKERS.

On the system diagram page 8 all the directional relays have their current transformers located on the bus side of the circuit breaker. This practice has been recommended so that if a fault should occur in the circuit breaker the directional relay would operate to open the breaker and clear the fault (depending on which part of the breaker was faulted) without making it necessary to isolate the substation from the system. As an example consider a fault on the line side of the breaker contacts of the breaker on the Raymond Line at Raymond Substation. In such a case if the current transformer of the directional relay was on the line side of the breaker the power flow through the relay would be in the normal direction so that it would not operate. With the connections as recommended (with the current transformer on the bus side of the breaker) the power flow in the current transformer and relay will be in the reverse direction and hence the relay will operate to clear the fault. If the relay did not operate it would be necessary to isolate Raymond Substation before the fault could be cleared from the system.

The overcurrent relays will trip regardless of which side of the breaker they are on, though for new installations it would be advisable to locate them on the bus side of the breaker because in such a location they would be subject to the larger short circuit current and would hence operate faster. Since the Pasadena system has installed their current transformer on the line side of the breakers this change has not been recommended for the non-directional type of relay.

RECOMMENDATIONS AND CONCLUSIONS

A. RECOMMENDATIONS

The present development and probable future growth of this system indicate that the relaying protection of the 16.5 KV. lines and equipment can be most satisfactorily and economically accomplished by the combined use (Diagram, page 8, shows all recommendations listed below) of:

1. Time element, overcurrent, non-directional and directional relays for line fault protection. (See pages 13 to 19 and 66).

2. Time element, low current, low energy, non-directional and directional relays for ground fault protection. See pages 15 tp 19 and 66).

3. Overlapping differential, quick acting relays for generators, transformers and busses at the power station. (See pages 67-68).

4. Differential protection for the main transformers at the substations but no differential bus protection at the substations. (See pages 67-68).

5. Location of current transformers for all directional relays on the bus side of the circuit breakers. This same recommendation is made for all new installations of non-directional relays. It is not recommended, however, that the changes be made on the old installations for this type of relay. (See pages 74-75).

B. PILOT WIRE RELAYS

The fundamental weakness of pilot wire relaying, unless backed up by other relays, makes this type of protection somewhat hazardous.

It should not be used therefore, even if pilot wires could be obtained, at little additional cost, through the use of spare wires in a supervisory cable if such were installed. (See pages 12 and 13).

C. DISTANCE TYPE RELAYS

The system is simple enough to make it unnecessary to use a more costly or complicated relaying method, such as distance type relays.

D. ADVANTAGES OF RECOMMENDED RELAYING

The advantages of the recommended relaying scheme are:-

1. Complete protection with good selectivity.
2. Reasonably fast.
3. Easy to adjust and maintain.
4. Moderate cost.
5. Sufficiently flexible to require no extensive alterations as system expands.
6. Insures good protection for an underground cable system as well as for overhead lines, without unnecessary interruption to service.

BIBLIOGRAPHY

1. - Symmetrical Components, Parts I to X.
   By R. D. Evans and C. F. Wagner
   Electric Journal, March, April, June, July, 1928.
   September, December, 1929.
   April, May, Oct., Nov., 1931.
   Also published as a reprint by the Westinghouse Elec. & Mfg., Co.

2. - The Short Circuit Calculating Table.
   By I. T. Monseth and R. DeCamp
   Electric Journal, June 1926.

3. - Theory and Applications of Relay Systems.
   By I.T. Monseth and P. H. Robinson
   Electric Journal, Monthly from July to Dec., 1930
   " " Feb. to Dec., 1931
   Feb., Mar., 1932

4. - Standard Decrement Curves.
   By W. C. Hahn and C. F. Wagner
   Transactions of A.I.E.E., June, 1932.

5. - Development of Short Circuit Curves
   By C. F. Wagner
   Electric Journal, March, 1933.

6. - Ground and Distance Relay Trend in Practice
   Electric World, Page 398, Feb. 27, 1932.

7. - Decrement Curves
   By C. F. Wagner
   Electric Journal, April,1933.

8. - D. C. Pilot Wire Loop
   Electrical World, March 25, 1933.

9. - Transmission System Protection
   By W. W. Edson
   Transactions A.I.E.E., Oct., 1930.

10. - Directional Ground Relays
    By E. E. George and R. H. Burnett, Jr.
    Transactions, A.I.E.E., Oct., 1930.

11. - Impedance Relay Developments and Applications
    Transactions, A.I.E.E., July, 1928.

12. - Pilot Wire Relay Scheme
Electrical World, June, 1928, Page 1390.

13. - Calculation of Single Phase Short Circuits by the method of symmetrical components.
G. E. Review, 1926, Pages 218 and 468.

14. - Reactance of Transmission Lines with Ground Return.
Transactions of A.I.E.E., Sept. 1931, Page 901.

15. - Transactions, A.I.E.E.
March, 1929, Pages 183-185
Oct. 1930, Pages 1321-1334
July, 1931, Page 510
Dec. 1931, Page 942

16. - Calculating Tables
G. E. Review, 1920, Page 669.

17. - Metal Clad Switchgear, Automatic Protection, and Remote Control.
By H. W. Clothier
British Institute E.E. 1932, Page 285.

18. - Recent Developments on 3 Phase Transmission Lines and Feeders.
By Ross and Bell
B.I.E.E., 1930, Page 801.

19. - Faults and Their Clearances on Large Networks.
By Kapp and Carrothers.
B.I.E.E., 1932, Page 685.