

METER-RELAY MAINTENANCE INFORMATION	TITLE DISTANCE RELAYS	Page
		No. (Inf) 6533-1
Date August 7, 1962		

TRANSMITTAL LETTER NO. M&R(Inf) 62-4

The two attached articles explain the basic fundamentals in application and operation of distance relays. They are particularly appropriate for a new man on the job but also provide an excellent review of distance relaying for all concerned.

Charles Slatt

X
Enclosures

INTRODUCTION TO DISTANCE RELAYING

With the rising demand for power the problem of discrimination on distribution systems using inverse-time overcurrent relays becomes more difficult. In the past it has been possible to obtain discrimination on a time/current basis, but with the growing load and the increase in clearing time at substations, it has become necessary to employ alternative means of protection. Protective gear engineers are now turning to distance measuring relays, and this article shows that such protection not only reduces the clearing times at all substations, but gives two or three stages of back-up to the whole network, including the substation busbars

By R W NEWCOMBE
AMIEE*

FOR those who are not familiar with distance relaying, it is essential to appreciate that since impedance is an electrical measurement of distance along the transmission line, it is expedient to use a relay capable of measuring the impedance of the line up to a given point, operating only for faults occurring between the relay and the selected point, so obtaining discrimination for faults occurring in different line sections.

The basic principle of measurement involves the comparison of the fault current seen by the relay and the voltage at the relaying point. Referring to Fig. 1, it will be seen that a relay connected at position R will receive the secondary current equivalent to the primary fault current and a secondary voltage equal to the fault current times the impedance of the line up to the point of fault. If the operating torque of the relay is proportional to the current and its restraining torque proportional to the voltage then, depending upon the relative number of ampere-turns applied to each coil, there will be a definite ratio at which the torques will be equal. This is termed the balance point of the relay.

Any increase in the current coil ampere-turns without a corresponding increase in the voltage coil ampere-turns will cause the relay to become unbalanced, so that below a given ratio of $\frac{V}{I}$ the operating torque will be strengthened in relation to the restraining torque, and the relay will close its contacts. Above a given ratio of $\frac{V}{I}$ the restraining torque will be greater than the operating torque and the relay will restrain and the contacts will remain open.

Relays have been designed so that it is possible to adjust their ohmic setting by changing the relationship of the ampere-turns of the operating coil with respect to those on the restraint coil, making it possible to select a setting comparable with the length of line to be protected.

As the fault volts seen by the relay in Fig. 1 depend upon the ratio between the source and line impedance, it is important to understand the effect of their relationship, as it is usual for the manufacturer to express the relay performance in either of these terms. Fig. 2 represents a relay voltage/reach curve, declaring an accuracy of measurement within ± 5 per cent down to 8 V on a secondary basis. A relay having such a characteristic would only be

applicable within the specified accuracy to transmission lines where the value of the source/line impedance ensured that the volt drop to the point of fault would be no less than 8 V secondary.

As the relationship between the operating current and restraint volts directly affects the relay operating time, it follows that the position of the fault along the line in relation to the relay in combination with the source/line impedance ratio must inevitably decide the relay speed. It is usual to express relay performance in these terms as illustrated in Fig. 4, which shows that the nearer the fault is to the relay, the faster the operating time, and the more closely the fault approaches the relay reach point the greater the time becomes. It becomes infinite at the relay

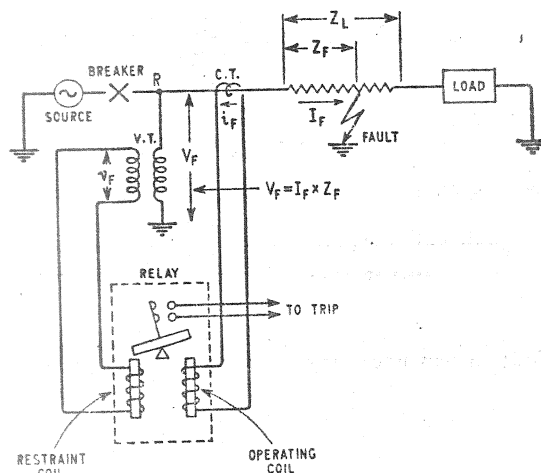


Fig. 1.—Simple impedance relay of the balanced beam type

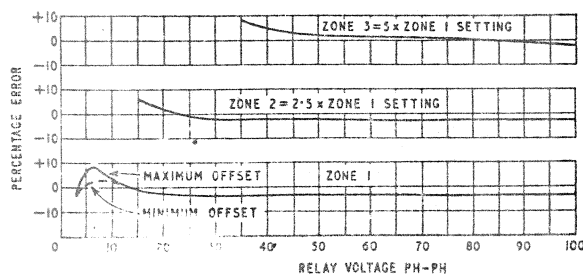


Fig. 2. Voltage/reach curves for phase relays

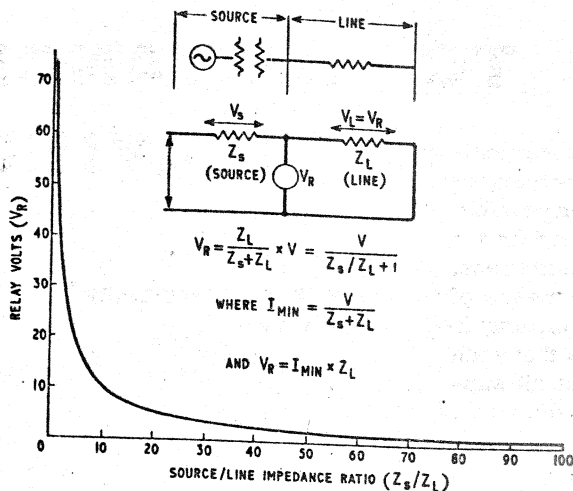


Fig. 3.—Relationship between source/line ratio and relay volts

reach point, i.e. where the ampere-turns on the operating coil balance those of the restraint coil.

Fig. 5 illustrates the relay performance in terms of fault position and source/line impedance ratio, indicating that accuracy of measurement up to a source/line ratio of 12/1 can be achieved within the limits of ± 5 per cent, and further that the operating time for various fault positions gets greater as the fault approaches the relay balance point. This is an alternative method of declaring the relay performance to that illustrated in Figs. 2 and 4.

Fig. 3 shows the relationship between the source/line impedance ratio and relay voltage. Provided the value of

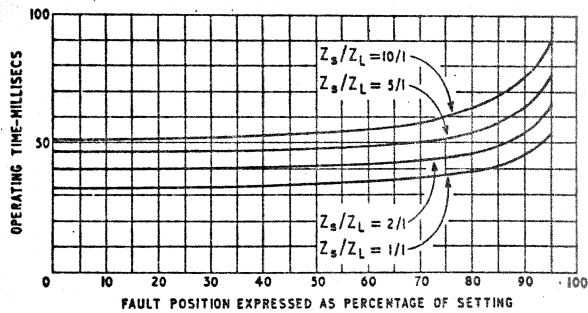


Fig. 4.—Typical operating time; reach per cent/impedance ratio curves

fault current under minimum plant conditions is known, then together with the impedance of the line to be protected it is possible to obtain the information required by applying Figs. 2 and 4, or alternatively the source/line impedance ratio by applying Fig. 5.

This information may not always be readily available and may be presented in terms of line make-up, fault current, or source MVA, but where there is some measure of standardisation in the distribution system it may be advantageous to build up a family of monograms as a quick reference by which to judge the performance of a relay to known system parameters.

Impedance Measuring Relay

Essentially, an impedance measuring relay consists of a beam balanced on a fulcrum (Fig. 1) with an operating coil on one side of the beam and a restraint coil on the other.

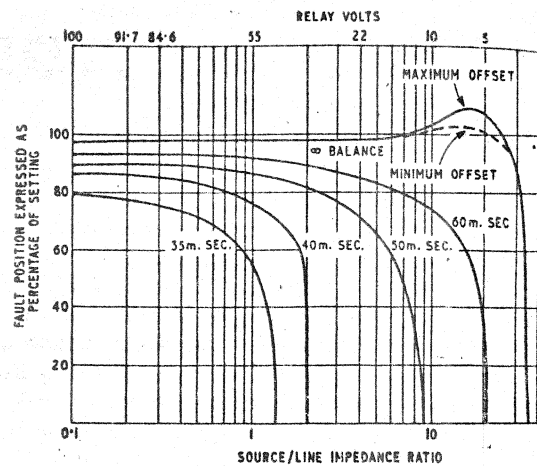


Fig. 5.—Contour curve of a mho relay characteristic

If a constant current is applied to the operating coil and the voltage applied to the restraint coil varied in magnitude and phase until the relay just operates, the values of impedance at which the relay operates can be found. This can be done with the aid of a voltmeter, ammeter and phase shifter.

If the values of impedances at the various angles are plotted on an X/R diagram they fall on the circumference of a circle with the origin as its centre (Fig. 6), signifying that a simple impedance relay would operate for any value of impedance lying within the circle.

As a transmission system is made up of X and R quantities we can represent a transmission line on the same X/R diagram as Fig. 6 by letting A-B represent one line and A-C a second line in series, then with a relay situated at A, the line A-B would represent a transmission line in front of the relay and A-C a transmission line behind the relay.

As the relay will operate for any impedance falling within the circle, it cannot discriminate between faults occurring on lines AB or AC. As it is necessary in most applications to discriminate between these two lines, it is essential to add a directional relay to limit the relay operation to one line. The characteristic of this relay is represented by the line D-D so that the relay is now only capable of operation for faults occurring within the shaded portion of the circle.

Admittance Relay

The next type of distance measuring relay is generally known as an admittance relay (mho) and combines, by the addition of a polarising winding, the characteristics of the impedance relay and the directional relay. The characteristics of this relay can be found in a similar manner to that described for the impedance relay.

When the values of Z are plotted on an X/R diagram, they fall on the circumference of a circle passing through the origin (Fig. 7), showing that the relay is inherently directional and can only detect faults on line A-B. Furthermore, the reach point setting varies with the fault angle, as the impedance measurement is not constant for all angles.

As the line to be protected is made up of resistance and inductance its fault angle would depend upon the relative values of X and R, but under an arcing fault condition the value of the relative component would increase and

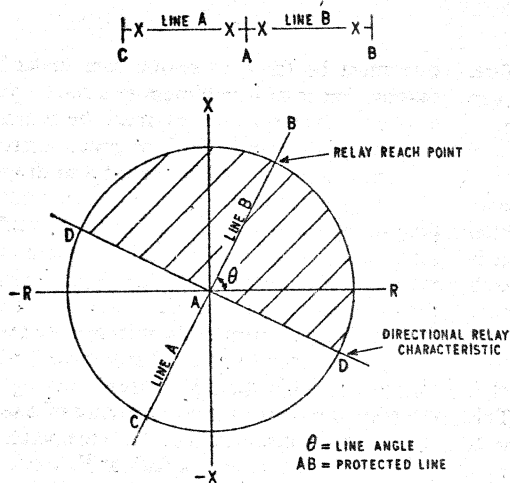


Fig. 6.—Impedance and directional characteristic

change this fault angle, so that a relay having a maximum torque angle equivalent to the line angle would, under arcing conditions, under-reach. It is usual, therefore, to apply a relay with its maximum torque slightly leading the line angle as illustrated in Fig. 7, so that it is possible to accept a small amount of arc resistance without causing under-reach.

However, when setting the relay, the difference between the maximum torque angle at which the relay is calibrated and the line angle must be known, and it will be appreciated from Fig. 7 that the length A-B corresponds to the length of the line to be protected which would be equal to the relay setting if the maximum torque were the same as the line angle. However, it is usual to make the relay maximum torque angle smaller than the line angle in order to accept a small amount of arc resistance. It follows that the actual amount of line protected would be equal to the relay setting value A-D divided by $\cos(\theta - \phi)$ where θ is the line angle and ϕ is the relay maximum torque angle.

The arc resistance bears no relation to the neutral earth resistance in regard to the relay setting value, as this is in the source at the back of the relay and only modifies the source angle and source to line impedance ratio, and would, therefore, only be taken into account when considering the minimum reach of the relay.

The effect of arc resistance can be quite important on short lines, depending upon the source MVA, which if variable at light load periods could cause inaccuracies in measurement. On long lines, arc resistance can usually be neglected on steel tower lines with overhead earth wires, but where the transmission line is carried on wooden poles without overhead earth wires, the earth fault resistance can have serious consequences in the application of mho type relays used for earth fault measurement. This is because it reduces the effective first zone reach to a point where the majority of faults are only detected in second zone time.

Reactance Relay

The reactance type of distance relay does not vary its setting with the introduction of arc fault resistance as it is designed to measure the reactance component of the line only. It will be appreciated from the relay characteristics (Fig. 8) that any increase in the resistance component of

fault current will have no effect upon the relay reach, as the relay will continue to measure the same value of X . However, due to the falling off of torque at the very high values of fault resistance there is a limit at which the relay will maintain accurate measurement. When the fault current approaches the value of the load current, the relay characteristics are modified by the value of load and its power factor.

The criticism of this relay is often applied to the case where a high resistance fault is fed from both ends of a ring main feeder through lines having a different X/R ratio on either side of the fault. In that event one relay end will over-reach and the other relay end will tend to under-reach. The effect is simply explained; as the fault current is fed from both line ends, it is the vector sum of the two currents which traverses the fault resistance path, the latter being clearly a path common to both currents. So long as there is a difference in phase between the two fault currents, the current flowing in the common fault resistance path must have a different phase to either of the individual currents. The phase of the common current will in fact be such that it leads the current from one feeder end and lags the current from the other feeder end.

It will be clear that each reactance-measuring relay will be supplied with a potential corresponding not only to the voltage drop along the overhead line as far as the fault point, but also to an additional voltage drop corresponding to that across the fault path. As the current in the fault resistance is not in phase with the current in either line, then the fault resistance itself, pure resistance though it may be, will appear to the relay as a complex impedance consisting of so much equivalent reactance. The reactance component of this complex impedance will be positive in the case of

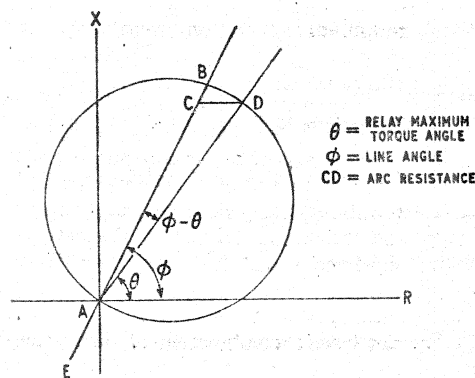


Fig. 7.—Mho characteristic

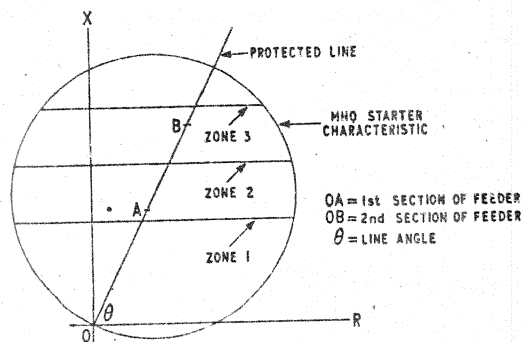


Fig. 8.—Reactance relay characteristics

the relay on the higher source angle side and will, therefore, cause under-reaching, but will be negative on the lower source angle side and will therefore cause over-reaching.

Zones of Protection

In the following calculations of the relay voltage only 80 per cent of the line length has been considered within the instantaneous zone of protection. This limitation is necessary to ensure an ample margin against over-reach due to current transient, current and voltage transformer errors and variation of the line impedance. As this leaves 20 per cent of the line unprotected, it is necessary to extend the reach of the measuring relay to cover all faults within this section of the line and maintain discrimination. This is achieved by extending the reach of the relay to zone 2, so that it covers the first section plus 50 per cent of the next section, and to discriminate with the first zone relay of the second line, time is added to the zone 2 reach of the first line relay. As it is a simple matter of extending the reach still further to zone 3 with another step of time, it is usual to carry this zone into part of the third section to give back-up protection to the second line.

The relays are usually designed to give a maximum second zone reach of $3\frac{1}{2}$ times the first zone, and a maximum third zone reach of five times the first zone. Such an extensive reach might appear unwarranted, but it must be remembered that the first line may be short and followed by two long lines, making this extended reach necessary (Fig. 9).

To detect faults in the second and third zones it is necessary to include a starting relay sensitive enough to detect faults occurring beyond the third zone under minimum generation conditions, but capable of discriminating between this and normal load conditions at the end of the first section of line.

Starting Relays

The relays used for this purpose are sometimes referred to as fault detectors. Their primary function is to control the timing relay for extending the reach of the measuring relay into the second and third zones, and they must have directional features when used with impedance and reactance measuring systems. Thus, we can have a combination of directional and overcurrent relays for use with impedance measuring systems and overcurrent units only, for use with mho systems, or mho measuring starters for any distance scheme including reactance.

These mho starters have a very wide range, as they must be capable of measuring faults well beyond the third zone reach of the measuring relays and like the measuring relays of the same type have either partial cross-polarisation when applied to reactance schemes, or alternatively an offset characteristic to cater for mho schemes. Where such a unit is used as a common starter for both phase and earth faults, compensation is necessary for the correct detection of earth faults, as in the case of the earth fault measuring relay previously described. Where overcurrent starting units are used,

care must be taken to ensure that under light load conditions, that is with minimum generating plant, the setting of the overcurrent starters must be sensitive enough to detect faults beyond the third zone. Furthermore, these starters should have a high pick-up to drop-off ratio, as it is possible without this feature to have indiscriminate tripping where the load is fed off in the second or third zone reach, and hence does not allow the overcurrent units to reset after a second or third zone fault which is cleared by the first zone relay in the faulty section. This is important as these overcurrent starting units operate the timer for controlling the second and third zone reach, which if allowed to run on would modify the reach setting of all relays in the system so that on the occurrence of a second fault, any relay in this system would be likely to operate. From Fig. 9 it will be seen that with a fault at F, breaker E would trip on first zone distance, but the overcurrent starting relays would pick-up at breakers A and C and may be held closed by the load fed off at L_1 and L_2 respectively. If breaker E is then reclosed on to the fault, breakers A, C or E might trip, if sufficient time has elapsed to allow the distance relay at breakers A and C to extend their reach into the fault.

Relay Application

When applying relays to a system the two main factors which must be known are the line impedance and the minimum fault current. When considering phase faults the positive and negative sequence impedance only is necessary, but for earth faults the positive, negative and zero sequence impedance is required. It is then possible to calculate the volt drop along the line up to the reach point of the relay as this will be the voltage appearing on the relay, so that for phase faults:—

$$V_R = \sqrt{3} \times 0.8 Z_1 L \times \frac{I_f}{kV} \times \frac{110}{1,000}$$

Similarly, for earth faults:—

$$V_R = 0.8 Z_0 L \times \frac{I_f}{kV} \times \frac{110}{1,000}$$

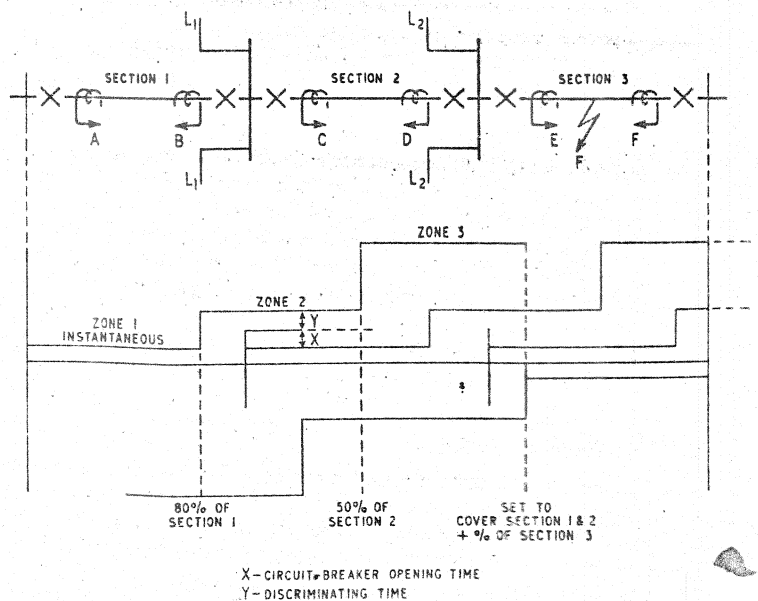


Fig. 9.—Typical time/distance characteristic

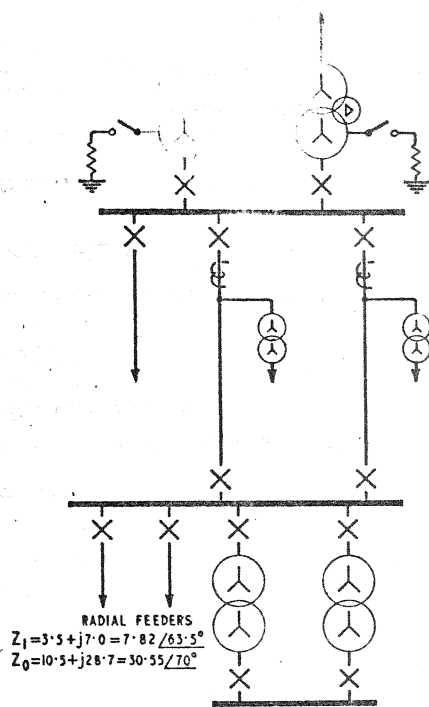


Fig. 10.—Typical 33 kV system

where kV=line volts, L=length of line, I_f =minimum fault current, Z_1 =positive sequence impedance in ohms/mile, and $Z_e = \frac{Z_0 + Z_1 + Z_2}{3}$ =earth loop impedance in ohms/mile.

The measuring relay can be designed to measure the positive sequence impedance of the line for all types of faults. For phase faults and double line to earth faults, the relay restraint coil should be supplied with the voltage across the faulted phase pair, while the operating coil is supplied with a vectorial difference between the current in the two conductors involved in the fault. For earth fault measurement the relay must be supplied with phase to neutral voltage for the restraint coil and the current in the faulted phase; and because the zero sequence impedance is always greater than the positive sequence impedance, a proportion of the residual current at the relay location must be added. A simple way of determining the amount of zero sequence compensation necessary to give the correct measurement, is to consider a three-phase line with a single earth fault. This would give a voltage across the relay of $I_1 Z_1 + I_2 Z_2 + I_0 Z_0$ while the current in the relay would be $I_1 + I_2 + I_0$.

$$\text{Thus, the impedance} = \frac{V}{I} = \frac{I_1 Z_1 + I_2 Z_2 + I_0 Z_0}{I_1 + I_2 + I_0} = \frac{I(Z_1 + Z_2 + Z_0)}{3I}$$

Then the impedance measured $Z_e = \frac{Z_1 + Z_2 + Z_0}{3}$ = the earth loop impedance.

As Z_0 for a 33 kV line is about four times Z_1 and as the negative sequence impedance is equal to the positive sequence impedance Z_2 , it follows that the earth loop

MINIMUM FAULT LEVEL AT 66kV
IS 500MVA = $j2.18$ ON 33kV BASE

66/33kV TRANSFORMERS 30MVA
AT 10% = $j3.64$ ON 33kV BASE

EARTHING RESISTANCE = 36Ω
33kV SUBSTATION 'A'

C.T. RATIO 400/1

V.T. RATIO $33,000/\sqrt{3} / 110/\sqrt{5}$ V

TRANSMISSION LINES
 $Z_1 = 2.5 + j5.0 = 5.6 / 63.5^\circ$
 $Z_0 = 7.5 + j20.5 = 21.8 / 70^\circ$

LINE 'A'

33kV SUBSTATION 'B'

33/11kV TRANSFORMERS 10MVA
AT 10% = $j10.9$ ON 33kV BASE

11kV BUSBARS

$$\text{impedance } Z_e = \frac{Z_1 + Z_2 + 4Z_1}{3} = 2Z_1.$$

The relay is therefore presented with an impedance of twice the setting and without compensation it would under-reach by 50 per cent, since the current in the loop is halved. Hence it is necessary to apply 100 per cent residual compensation for correct measurement.

Where a system is earthed at more than one point the above method of calculation would be unsatisfactory as the value of I_0 is unknown and may change with switching conditions. It is, therefore, impossible to have a fixed value of compensation, but it

can be shown that by adding $\frac{1}{3} \left(\frac{Z_0 - Z_1}{Z_1} \right) I_R$

to a compensating transformer connected in the residual circuit, automatic adjustment of the amount of compensation can be achieved with the changing value of I_0 so that correct measurement can be maintained.

It has already been shown that $V_R = I_1 Z_1 + I_2 Z_2 + I_0 Z_0$ and that $I_R = I_1 + I_2 + I_0$ where I_0 is unknown.

$$\text{In this case } Z_1 = \frac{2I_1 Z_1 + I_0 Z_0}{2I_1 + I_0 + C}$$

where C is the compensation required, $I_1 = I_2$, and $Z_1 = Z_2$

$$\therefore Z_1(2I_1 + I_0 + C) = 2I_1 Z_1 + I_0 Z_0$$

$$Z_1 C = 2I_1 Z_1 + I_0 Z_0 - 2I_1 Z_1 - I_0 Z_1$$

$$C = \frac{I_0 Z_0 - I_0 Z_1}{Z_1} = I_0 \left(\frac{Z_0 - Z_1}{Z_1} \right)$$

As $I_0 = \frac{1}{3}$ residual current, then $C = \frac{1}{3} \left(\frac{Z_0 - Z_1}{Z_1} \right) I_R$

where I_R = c.t. residual current.

Application to Typical 33 kV System

The system diagram (Fig. 10) indicates a simple 33 kV network supplied from a 66 kV system through two step-down transformers and the following example shows the calculations necessary to check the suitability of applying distance relays to the two parallel feeders interconnecting substations A and B, line A being selected for this purpose. All relevant data are given in the diagram.

It is usual for the manufacturer to declare the minimum voltage at which the relay will maintain its accuracy in terms of secondary volts, for faults at the relay reach point. For phase faults in terms of phase to phase volts, and for earth faults in terms of phase to neutral volts, and as the relays have a limited reach, it is necessary to check that 80 per cent of the line length in secondary ohms is within the setting range. Minimum volts will occur when both lines are in service and fed from one transformer, earthed through one resistance with the fault level at the 66 kV busbars at the minimum.

(1) Check setting range of relay.

$$80 \text{ per cent of line impedance} = 5.6 \times 0.8 = 4.48 \text{ ohms.}$$

$$Z_s = Z_p \times \frac{\text{c.t. ratio}}{\text{v.t. ratio}} = 4.48 + \frac{400}{I} \times \frac{110}{33,000} = 5.98 \text{ ohms.}$$

This value should fall within the relay setting.

(2) Check minimum volts at relay for fault at zone 1 reach point.

$$\text{Total } Z_1 \text{ to fault} = j2.18 + j3.64 +$$

$$\frac{0.8(2.5 + j5) \times 1.2(2.5 + j5)}{0.8(2.5 + j5) + 1.2(2.5 + j5)}$$

$$= j5.82 + \frac{0.96(2.5 + j5)(2.5 + j5)}{2(2.5 + j5)} = 1.2 + j8.22$$

$$\text{Fault current } \frac{E}{Z_L} = \frac{33,000}{\sqrt{3}(1.2 + j8.22)} = \frac{19,050}{1.2 + j8.22} = 2,290 \text{ A.}$$

Volts at relay $I \times Z_L$ where $I = 2,290 \text{ A.}$

$$Z_L = \frac{0.8(5.6) \times 1.2(5.6)}{0.8(5.6) + 1.2(5.6)} = 2.69 \text{ ohms.}$$

$$V = I \times Z_L = 2,290 \times 2.69 = 6,160 \text{ volts primary.}$$

Converting to phase to phase secondary,

$$\frac{6,160 \times \sqrt{3} \times 110}{33,000} = 35.5 \text{ V.}$$

Check with manufacturers' curves (Fig. 2).

(3) Check minimum volts at relay for phase/earth faults at zone 1 reach point.

$$\text{Line } Z_0 \text{ to fault} = \frac{0.8(7.5 + j20.5) \times 1.2(7.5 + j20.5)}{0.8(7.5 + j20.5) + 1.2(7.5 + j20.5)}$$

$$Z_0 = 0.48(7.5 + j20.5) = 3.6 + j9.84.$$

From previous calculation $Z_1 = 1.2 + j8.22$ for static equipment.

$$Z_1 = Z_2 \therefore Z_1 + Z_2 + Z_0 = 2(1.2 + j8.22) + (3.6 + j9.84)$$

$$= 6.0 + j26.28$$

Total earth fault impedance with one earthing resistance in service = $3 \times 36 + 6.0 + j26.28 = 114 + j26.28$

$$\text{Fault current } \frac{E}{Z_1 + Z_2 + Z_0 + 3N_R} = \frac{3 \times 19,050}{114 + j26.28} = 489 \text{ A.}$$

Volts at relay = $I \times Z_e$ where $I = 489$ and Z_e = earth loop impedance.

$$Z_e = \frac{1}{3}[(1.2 + j8.22) + (1.2 + j8.22) + (3.6 + j9.84)] = \frac{6.0 + j26.28}{3} = 9 \text{ ohms}$$

$$V = I \times Z_e = 489 \times 9 = 4,401 \text{ volts primary.}$$

Converting to secondary phase to neutral =

$$\frac{4,401 \times 110}{33,000} = 14.67 \text{ V}$$

Check with manufacturers' curves (Fig. 2).

(4) Determination of relay settings.

NOTE.—All relays are calibrated in positive sequence impedance.

To set zone 1 to cover 80 per cent of protected line.

Primary impedance $Z_1 = 2.5 + j5.0$ converted to secondary impedance.

$$\text{Impedance } 0.8 \times (2.5 + j5.0) \times \frac{400}{1} (\text{c.t.}) \times \frac{110}{33,000} (\text{v.t.})$$

$$= 2.67 + j5.34 = 5.96/63.5^\circ$$

Reactance relay setting = 5.34 ohms.

Mho relay max torque angle 45° , line angle 63.5° .

$$\text{Mho relay setting} = \frac{5.96}{\cos(63.5^\circ - 45^\circ)} = 6.3 \text{ ohms.}$$

To set zone 2 to cover protected line plus 50 per cent of the next line section (see Fig. 10).

$$\text{Primary impedance } Z_1 = (2.5 + j5.0) + 50\%(3.5 + j7.0) = 4.25 + j8.5$$

$$\text{Converted to secondary} = (4.25 + j8.5) \times \frac{400 \times 110}{33,000} =$$

$$5.66 + j11.33 = 12.7/63.5^\circ \text{ ohms.}$$

Reactance relay setting 11.33 ohms or 212% of zone 1.

Mho relay setting $\frac{12.7}{\cos(63.5^\circ - 45^\circ)} = 13.4$ ohms or 212 per cent of zone 1.

To set zone 3 to cover protected line plus 125 per cent of the next line section.

$$\text{Primary impedance } Z_1 = (2.5 + j5.0) + 1.25(3.5 + j7.0) = 6.87 + j13.75 \text{ ohms.}$$

$$\text{Converted to secondary} = (6.87 + j13.75) \times \frac{400 \times 110}{33,000}$$

$$= 9.18 + j18.35 = 20.5/63.5^\circ \text{ ohms.}$$

Reactance relay set 18.35 ohms or 344 per cent of zone 1.

Mho relay setting $\frac{20.5}{\cos(63.5^\circ - 45^\circ)} = 21.6$ ohms or 344 per cent of zone 1.

(5) Starting relays.

Check for positive operation of overcurrent starter under minimum fault conditions for faults at or just beyond zone 3 reach point.

$$Z_1 = j2.18 + j3.64 + \frac{(2.5 + j5.0) \times (2.5 + j5.0)}{(2.5 + j5.0) + (2.5 + j5.0)} + 1.25(3.5 + j7.0)$$

$$= (1.25 + j8.32) + (4.37 + j8.75) = 5.62 + j17.07$$

$$\text{Fault current} = \frac{\text{Line volts}}{\text{Loop impedance}} = \frac{33,000}{2(5.62 + j17.07)} = \frac{33,000}{37.1} = 890 \text{ amps.}$$

$$\text{Current down one line only} = \frac{890}{2} = 445 \text{ amps primary.}$$

Current transformer 400/1 given minimum secondary current 1.11 amps.

Should this setting be considered too low in relation to the feed off at substation "B" then mho type starters should be used, with setting the same or just greater than third zone setting, i.e. 21.6 ohms or above.

(6) Third zone discrimination.

Check discrimination of third zone reach with protection on the low voltage side of transformers in station "B."

$$\text{Parallel impedance of transformer} = \frac{10}{100} \times \frac{(33 \text{ kV})^2}{20 \text{ MVA}} = 5.45 \text{ ohms.}$$

Impedance from relaying point to fault on 11 kV bars.

$$Z_1 = (2.5 + j5.0) + j5.45 = 2.5 + j10.45 = 10.75 \text{ ohms primary.}$$

$$\text{Converting to secondary } (2.5 + j10.45) \times \frac{400 + 110}{33,000} =$$

$$3.35 + j13.9 = 14.33 \text{ ohms.}$$

Reactance relay setting = 18.35 ohms against 13.9 ohms fault.

Mho relay setting = 21.6 ohms against 14.33 ohms fault.

It is clear that both relays would operate for faults on the 11 kV busbars and therefore the time setting of zone 3 must be adjusted to discriminate with the 11 kV protection.

(7) Effect of parallel lines.

To calculate the under-reach of zones 2 and 3 when both lines are in service,

Under-reach =

(Impedance of following line included in zone of protection)

$$\times \left(\frac{\text{Fault current in parallel line}}{\text{Fault current in protected line}} \right) \text{ ohms,}$$

therefore, per cent under-reach =

$$\frac{\text{Under-reach} \times 100}{\text{Total impedance of protected zone}}$$

As both lines are of the same impedance, the current will be shared equally:

$$\therefore \text{Under-reach of zone 2 setting} = \left(\frac{7.82 \times 50}{100} \right) \times 1 = 3.91 \text{ ohms.}$$

$$\therefore \% \text{ under-reach of zone 2 setting} = \frac{3.91}{13.4} \times 100 = 29.2\%$$

$$\text{and under-reach of zone 3 setting} = \left(\frac{7.82 \times 12.5}{100} \right) \times 1 = 9.87 \text{ ohms.}$$

$$\therefore \% \text{ under-reach of zone 3 setting} = \frac{9.87 \times 100}{21.6} = 45.7\%$$

Distance Relay Schemes

The foregoing has dealt individually with measuring and starting relays, but as distance protection is made up of a combination of these relays a little must be said about their make-up. Where the system is not effectively earthed, or is earthed through an arc suppression coil, it is only necessary to apply phase fault relays so that a three-step distance scheme would consist of a fault detector and a measuring relay for each phase, with a common timing relay for extending the reach of the measuring relay into the second and third zones.

A cheaper arrangement is achieved by switching a single mho measuring unit, controlled and selected, into the faulted phase by over-current detectors (Fig. 11). This arrangement shows a considerable saving in cost and panel space, but it must be remembered that the operating times inevitably increase.

Where systems are effectively earthed, the above arrangement must be supported either by a time delayed earth fault relay or, where this is not possible, a reactance measuring relay, as the earth fault resistance on these distribution systems is generally too high for the application of mho or impedance measuring relays, unless second zone times are acceptable for faults within the major part of the first line section, with possible lack of discrimination.

For short transmission lines, there are advantages in using reactance relays for both phase and earth faults as the effect of arc resistance is more pronounced, and constitutes a larger proportion of the fault impedance.

With wood pole line transmission, and the system effectively earthed at the substation, a combination of mho and reactance, or reactance only for both phase and earth faults can be used. As reactance relays are used in either combinations, mho starting units would be necessary,

which together with a timing unit makes up a complete scheme. This combination can be extended to a single reactance measuring relay switched to measure both phase and earth faults using a mho fault detector to select the faulted phase and to give the necessary directional features. This arrangement shows a considerable saving in panel space and interconnecting wiring, and would be applicable to most 11 kV and 33 kV distribution networks, regardless of line length or methods of earthing. Although this is an admirable scheme, the overall operating time is extended due to the switching arrangement as in the case of the switched mho scheme.

Test Equipment

Type testing of distance measuring relay systems is most important as it is necessary to ensure their correct behaviour on all types of faults including the effect of current and voltage transients, changing faults on double and single end feed, loaded and unloaded lines. To do this an artificial transmission line is necessary and should be designed as a miniature power system into which the relays can be connected. A typical equipment consists of two three-phase parallel transmission lines into which controlled power can be applied at either or both ends.

The line and source impedances are capable of variation in both phase and magnitude, and all types of faults can be applied on a controlled time basis with respect to the supply voltage wave. The transient duration can be controlled by adjusting the angle of source impedance so that true dynamic test conditions can be simulated to reproduce transient over-reach effects.

Tappings on the source and line choke give a wide range of adjustments to the source/line impedance ratio, and by the introduction of series resistance into the line impedances a true representation of the various line angles can be achieved. It is also possible to vary the Z_1/Z_0 ratio by tapped neutral chokes. By switching banks of resistors into the faulted circuit and by connecting other resistors to the end of the lines, it is possible to simulate the effect of high arcing or ground resistance combined with loaded lines.

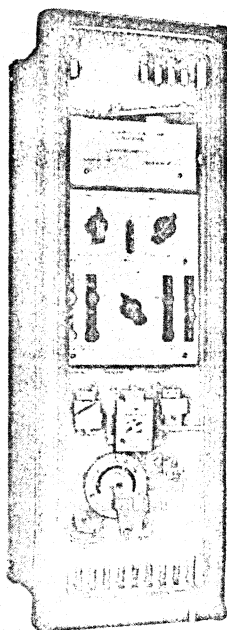


Fig 11.—English Electric type SSM3V distance protection scheme

"APPLICATION GUIDE FOR THE USE OF DISTANCE RELAYS"

John Berdy and Kenneth Winick

The natural growth of power systems today has resulted in a greater need for high speed distance type protection against all kinds of faults on transmission lines. While for economic reasons, the greatest demand in the past has been for those distance type relays that protect against multi-phase faults, modern power systems have indicated a sharp increase in the use of ground as well as phase distance relays. The many ramifications in system design and special user requirements have resulted in a significant increase in the available types of distance relays. It is the purpose of the following sections of this paper to assist the Application Engineer in his endeavor to select the proper relay for the job at hand.

In general the points discussed in this paper apply to phase distance relays. However, to complete the picture, the different models of ground distance relay are tabulated at the end of the paper along with typical application information. Basic material on the theory of operation of the simple (or directional) mho units, offset mho units, and reactance (or ohm) units form the background. From there, the paper proceeds to discuss the significance of such terms normally associated with distance relays as memory action, offset, angle of maximum torque, transient overreach, blinders, and arc resistance and to relate these terms to the desired relay characteristics for the various different protective functions. Finally each of the different popular models will be described and standard recommended packages will be grouped for such schemes of protection as straight distance directional comparison and transferred tripping. Special applications such as out-of-step blocking and out-of-step tripping will also be discussed.

PHASE DISTANCE RELAY TORQUE EQUATIONS

In order to establish a sound basis for applying mho and reactance type relays, it is important to have some understanding of the torque equations that define the characteristics of these relays. Since the mho and reactance units are basically single-phase units that are used to protect against faults between pairs of phases, three units are required for the protection of all three phases. An AB unit is required for faults involving phases A and B. For phase B to phase C faults, a phase BC unit is required and for phase C to phase A faults, a phase CA unit is needed. For three-phase faults all three units will operate.

By virtue of their construction, the reactance and mho units have the same ohmic reach on phase-to-phase faults as they have on three-phase faults. The following equations describe the reactance, mho and offset mho units of any one pair of phases. The voltages and currents designated as E and I with subscripts are actually dual quantities. For example, in the case of the mho unit, I_o - the operating coil current - for say the phase BC unit is actually the vector difference between I_B and I_C . The restraint voltage E_R is the phase B to C voltage. The same applies to the polarizing voltage E_p .

MHO UNIT

Operating Torque

$$KI_0E_P \cos(\theta - \phi)$$

Restraining Torque

$$TE_RE_P + K_S$$

- where:
- K - Design Constant (100 times the minimum reach)
 - T - Relay Tap Setting in Percent
 - K_S - Control Spring Torque Constant
 - I_0 - Operating Coil Current
 - E_R - Restraint Circuit Voltage (These are actually the same voltage fed to two separate circuits.)
 - E_P - Polarizing Circuit Voltage
 - θ - Angle by which I_0 lags E_P (Transmission Line Impedance Angle)
 - ϕ - Maximum Torque Angle (Design Constant)

By equating the operating and restraining torque, cancelling E_P from both sides of the equation recognizing that $E_R/I_0 = Z$ and assuming K_S to be negligible, the mho unit characteristic in the R-X plane is obtained. See Figure 1 below.

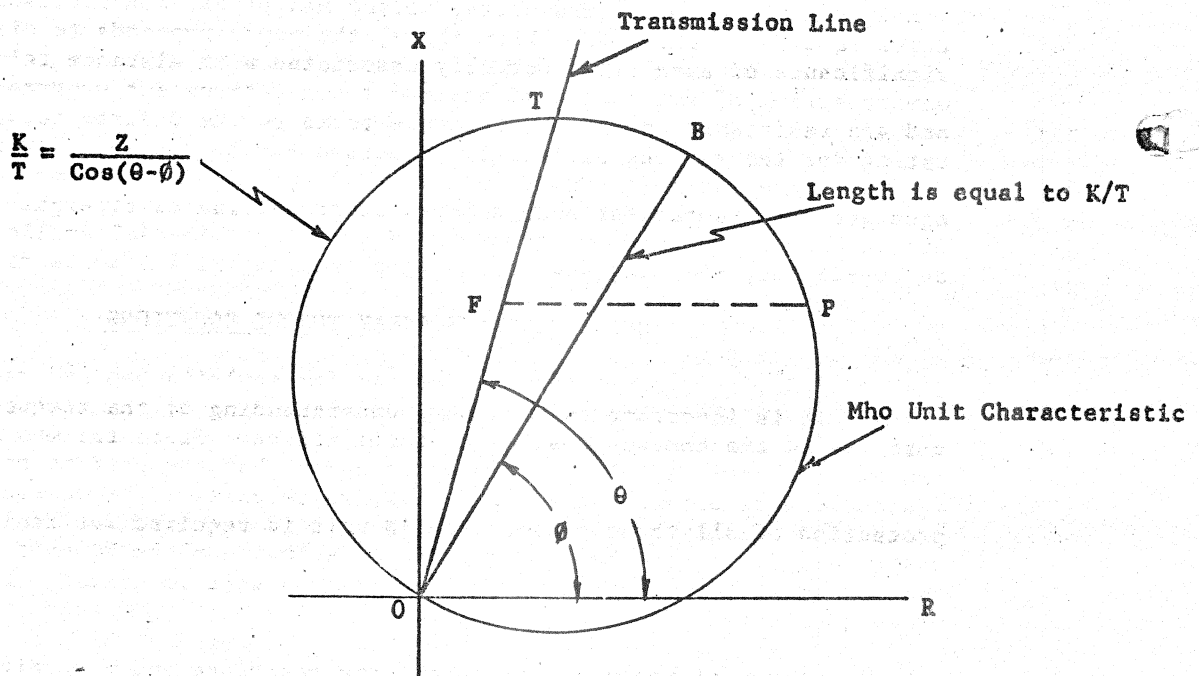


FIGURE 1

It is important to note that the mho unit is inherently directional because its characteristic always passes through the origin in the R-X diagram. This unit will operate for faults that plot anywhere inside the circular characteristic. The amount of arc resistance that this type of unit can accommodate for a fault on the transmission line is represented, on the R-X diagram, by the horizontal distance from the fault to the relay

characteristic. For example, for a fault at point F on the protected line in Figure 1 this unit will accommodate an arc resistance equal to \overline{FP} .

The operating torque of the mho unit is proportional to the product of the operating current and the polarizing voltage. For first zone faults that are close to the relay terminals, the polarizing voltage can get quite small and in some instances actually approach zero. In order to insure positive high-speed operation for these conditions, the polarizing circuit is designed with memory action so that a substantial torque persists for several cycles after the fault occurs, even if the polarizing voltage actually goes to zero. This is based on having normal voltage prior to the fault. As the fault moves away from the relay location, the voltage at the relay increases until sufficient voltage is available to insure operation on a steady-state basis. This is what permits the mho unit to be used in conjunction with time delay for second and third zone faults. The mho unit should not be used in conjunction with time delay if it is desired to detect zero voltage faults.

The mho unit is available in several different ohmic ranges and angles of maximum torque. Since the restraint circuits are essentially the same for all ranges, the difference in range is obtained by changing the design constant K in the operating circuit. Actually, the minimum reach of a mho unit is directly proportional to K. For this reason, the higher range mho units operate at a higher torque level per unit of fault current than do the lower range units.

REACTANCE (OHM) UNIT

Operating Torque

$$KI_0 I_p$$

Restraining Torque

$$TE_R I_p \sin \theta + K_S$$

where:

- K - Design Constant (100 times minimum reach)
- T - Relay Tap Setting in Percent
- K_S - Control Spring Torque Constant
- I₀ - Operating Coil Current (These are actually the same current
- I_p - Polarizing Coil Current fed to two separate circuits.)
- E_R - Restraint Circuit Voltage
- θ - Angle by which I_p lags E_R (Transmission Line Impedance Angle)

By equating the operating and restraining torques, cancelling I_p from both sides of the equation, recognizing that

$$\frac{E_R}{I_0} \sin \theta = X$$

and assuming K_S to be negligible, the reactance or ohm unit characteristic in the R-X plane is obtained. See Figure 2 on the following page.

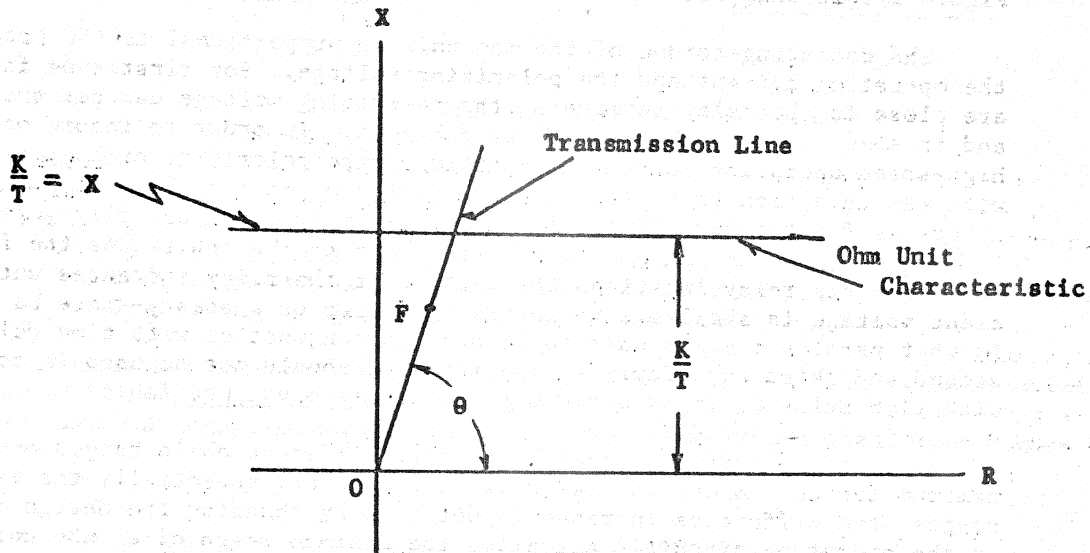


FIGURE 2

It is important to note that the ohm unit will operate for faults that plot anywhere below its characteristic line on the R-X diagram. Thus, the unit is not directional in itself and therefore is always used in conjunction with a (directional) mho unit. Its horizontal characteristic makes this unit insensitive to resistance and so it measures only the reactive portion of the impedance from the relay location to the fault. It operates to trip if this reactance is less than the relay setting. The measurement of this unit is unaffected by arc resistance in the fault.

While the operating torque is given as the product of two currents, I_0 and I_p , these are actually the same current supplied to two different poles in the magnetic circuit of the relay. Thus, the operating torque of the ohm unit is proportional to the fault current squared. Since no voltage term appears in the operating torque equation for this unit, it will operate on zero voltage faults without memory action.

The ohm unit is available in several different ohmic ranges. However, regardless of the range, the restraint circuits are essentially the same for all relays. The difference in range is obtained in the operating circuit by changing the design constant K. The minimum reach of an ohm unit is directly proportional to K. For this reason, the higher range reactance units operate at a higher torque level, per unit of fault current, than do the lower range units.

OFFSET MHO UNIT

Operating Torque

$$KI_0(E + I_0Z_T) \cos(\delta - \theta)$$

Restraining Torque

$$T(E + I_0Z_T)(E + I_0Z_T) + K_s$$

where:

- K - Design Constant (100 times the minimum reach)
- T - Relay Tap Setting in Percent
- K_s - Control Spring Torque Constant
- I_o - Operating Coil and Transactor Primary Current
- Z_T - Transactor (offset) Impedance
- E - Voltage supplied to relay (PT secondary voltage)
- θ - Maximum Torque Angle (Design Constant)
- ϕ - Angle by which I_o lags $(E + I_o Z_T)$

It will be noted that the equations for the operating and restraining torques of the offset mho unit are the same as those for the simple mho unit except that $I_o Z_T$ is now a part of the polarizing and restraining voltages.

By equating the operating and restraining torques and assuming K_s to be negligible, the offset mho unit characteristic in the R-X plane is obtained. Figure 3 below is a plot of this characteristic illustrating that the diameter of the circular characteristic is still K/T as in the case of the simple mho unit but the entire circle is offset by an amount equal to the transactor impedance Z_T in the direction of the impedance angle of the transactor. Note that in Figure 3, the mho unit characteristic is offset along the maximum torque angle θ . Some offset mho units are offset vertically along the X axis.

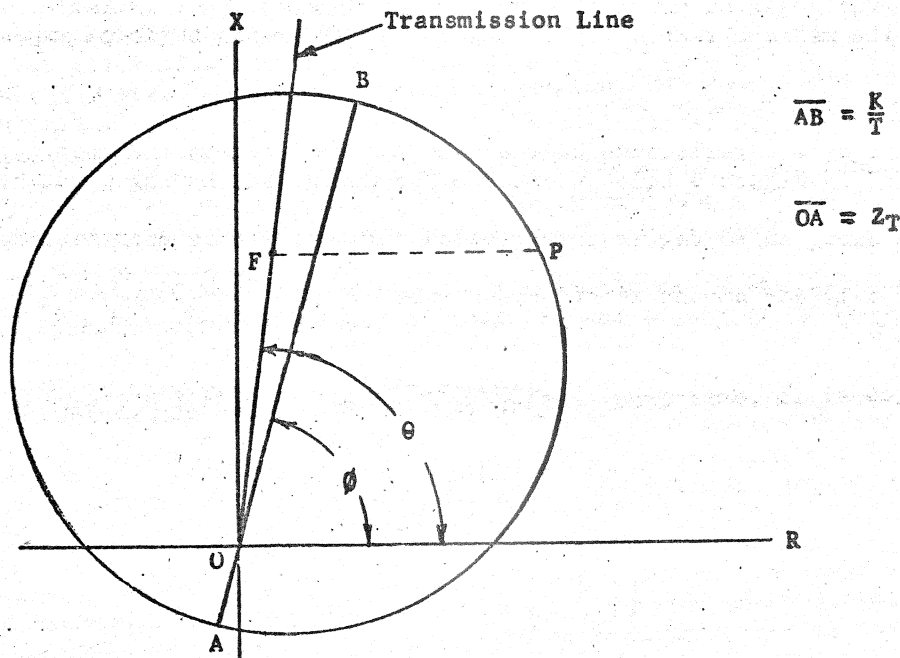


FIGURE 3

From Figure 3 it is apparent that the offset mho unit is not directional inasmuch as its characteristic does not pass through the origin of the R-X diagram. This unit will operate for faults that plot anywhere inside the circular characteristic. The amount of arc resistance that this type of unit can accommodate for a fault on the transmission line is represented on the R-X

diagram by the horizontal distance from the fault to the relay characteristic. For example, for a fault at point F on the line (in Figure 3) this unit will accommodate an arc resistance equal to FF.

The operating torque of the offset mho unit is proportional to the product of the operating current (I_o) and the polarizing voltage ($E + I_o Z_T$). In this case, the voltage is composed of two components, the system voltage (E) and the transactor voltage ($I_o Z_T$). For faults at the relay location where the voltage E can go to zero, $I_o Z_T$ still exists. Thus, a polarizing voltage is present even for zero voltage faults and for this condition, the operating torque is proportional to I_o^2 . Because of this, the offset mho unit will operate on a steady-state basis for zero voltage faults and therefore may be used in conjunction with time delay to operate for these faults.

The offset mho unit is available in several different ohmic ranges, offset ranges and angles of maximum torque. Since the restraint circuits are essentially the same for all ohmic ranges, the difference in range is obtained by changing the design constant K in the operating circuit. Actually, the minimum diameter of an offset mho unit is directly proportional to K . For this reason, the higher range units operate at a higher torque level than do the lower range units.

ANGLE OF MAXIMUM TORQUE

The angle of maximum torque of a simple mho unit is the angle at which it has its maximum reach. Referring to Figure 1, the angle of maximum torque (θ) is the angle between the diameter (OB) of the characteristic and the R axis.

This angle is significant in two respects. First, it determines the amount of arc resistance that can be accommodated by the unit. This is illustrated in Figure 4 below where two mho units, one having a maximum torque angle of 60 degrees and the other 75 degrees, are both set to reach the same distance (OD) along an 80 degree transmission circuit. It is apparent from this sketch that the characteristic with the smaller angle of maximum torque will accommodate a larger amount of arc resistance.

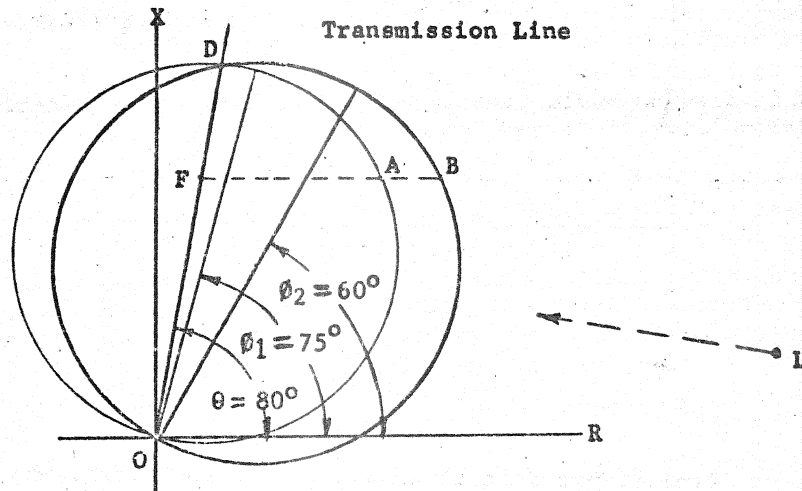


FIGURE 4

For example, for a fault at Point F on the transmission lines, the 60 degree characteristic will accommodate an arc resistance that is greater by an amount \overline{AB} than that which the 75 degree characteristic will accommodate. Note that the magnitude of this difference varies with the fault location along the protected line.

The performance of the mho unit under heavy load conditions and system swings is also related to the angle of maximum torque. Referring back to Figure 4, let point L represent the apparent load impedance on the R-X diagram. As the reach of the mho unit is increased, the characteristic will expand and approach the apparent impedance of the load. Thus, increasing the reach setting of the mho unit makes it more susceptible to operation on system swings which cause the apparent load impedance to move in the direction of the dashed arrow of Figure 4. It is interesting to note, that on a secondary basis, a load current of 5 amperes at rated volts (66.3) represents an apparent load impedance of $66.3/5$ or 13.3 secondary phase-to-neutral ohms. The angle of this impedance is, of course, determined by the power factor of the load.

In a protective relaying scheme that utilizes mho units for three zones of protection, the first zone unit is set for the shortest reach (generally not longer than 90 percent of the protected line length) while the third zone unit is set with the longest reach and the second zone is set somewhere in between. With such an arrangement, the first zone will accommodate the least amount arc resistance and will be least subject to operate on system swings. The third zone unit will accommodate the most arc resistance and will be most susceptible to operation on system swings. Thus, where these factors are important, it may be desirable to use a first zone mho unit with a relatively small angle of maximum torque while the second and third zone units have a larger maximum torque angle. This will permit the first zone unit to accommodate more arc resistance but, because of its short reach setting, its susceptibility to system swings will be minimized. On the other hand, the second and third zone units, because of their longer reach settings, will accommodate considerable arc resistance but their larger angles of maximum torque will minimize their susceptibility to system swings.

When a mho unit is used to protect a short line, it is especially desirable to use a unit with a small angle of maximum torque in order to insure maximum arc resistance accommodation. For this reason, the very short reach mho units are available with 45 degree maximum torque angles.

The angle of maximum torque of the offset mho unit is defined as its angle of maximum torque when set with zero offset. In other words, the angle of maximum torque of the offset mho unit is obtained by assuming that the unit is set with zero offset and the angle of maximum torque is then the angle at which it has its maximum reach. In general, an offset mho unit is a second or third zone unit. A first zone unit never has offset because high-speed first zone tripping units must have directional characteristics except on radial, or essentially radial circuits. The same comments relating to arc resistance and system swings apply to the offset mho unit as do to the simple mho unit.

The maximum torque angle of the ohm unit characteristic illustrated in Figure 2 is 90 degrees. This is the standard ohm unit that is used in the type GCX relays for transmission line protection. It is obvious, that this type of characteristic will accommodate considerably more arc resistance than a first-zone mho unit with the same reach setting along the transmission line.

Ohm units are also available with other angles of maximum torque. These are discussed under the headings "Out-of-Step Tripping" and "Blinders".

OFFSET

Offset, as used with transmission line relays, is that feature which is incorporated into certain mho units that permits the simple directional mho characteristic to be displaced from its position of passing through the origin in order to make it include the origin in an offset position on the R-X diagram. While the offset can theoretically take any direction, there are only two offset directions generally employed. The first, and probably the most common is to offset the characteristic in the direction of the angle of maximum torque of the unit. The second is to offset the characteristic along the X axis in the R-X plane. These are illustrated in Figures 5a and 5b below.

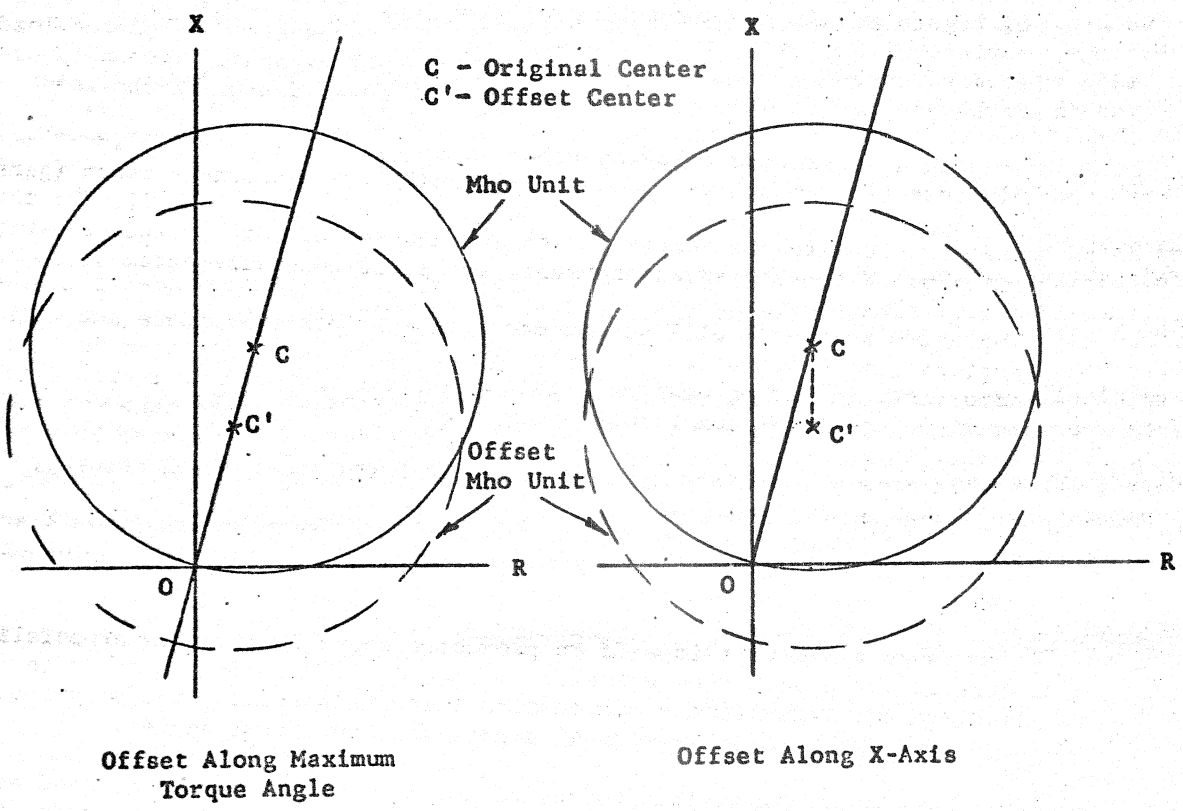


FIGURE 5a

FIGURE 5b

It is apparent from Fig. 5 that offsetting a simple mho unit converts it from a true directional unit to a non-directional unit. In standard relaying schemes, for the protection of transmission lines, this offset is provided for one single purpose. This is to embody the unit with the ability to pick up and stay picked up, on a steady-state basis, for as long as a zero voltage fault persists. Thus, the difference between the two types of offset is insignificant.

In directional comparison schemes using carrier current or microwave

channels for the protection of transmission lines, it is essential for the unit that keys the transmitter and sends a blocking signal on external faults to have an offset characteristic. The reason for this may be derived from Figure 6 below by assuming that the line section between breakers 1 and 2 is protected by a directional comparison carrier relaying scheme. If a fault were to occur at F_1 , immediately adjacent to circuit breaker 3, the carrier starting relays at circuit breaker 1 must operate to start carrier and send a blocking signal to circuit breaker 2 in order to prevent a false trip at circuit breaker 2. This blocking signal must be continued until the fault is cleared by circuit breaker 3. Since this fault can result in very low voltage (and conceivably zero voltage) to the relays associated with circuit breaker 1, the carrier starting units at circuit breaker 1 must have an offset characteristic so that after they pick up fast due to the memory action, they stay picked up due to their offset characteristics until circuit breaker 3 clears the fault.

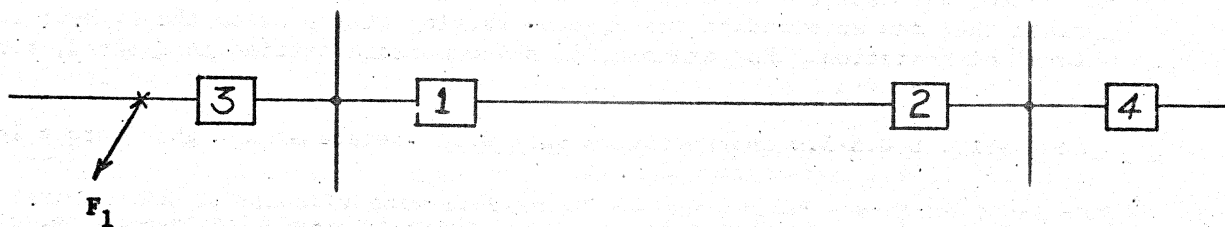


FIGURE 6

The amount of fault current that is required to pick up or maintain pick up of an offset mho unit with zero voltage applied decreases as the offset is increased just as long as the offset does not exceed one half of the diameter of the characteristic. Thus, a mho unit set for a three-ohm diameter will operate for zero voltage faults at a lower fault current when it has a 1.0 ohm offset than when it has a 0.5 ohm offset.

In general, there is no reason to offset a mho unit more than necessary to insure positive steady-state operation for zero voltage faults.

MEMORY ACTION

Memory action is that feature which is designed into the potential polarizing circuit of the simple and offset mho units in order to prolong the polarizing flux at a high level for some short time after the voltage disappears. This memory action is required in the simple mho unit to insure positive high-speed operation on close-in faults that result in very low or even zero voltage being supplied to the relay polarizing circuit. This is explained for the Mho Unit under the section on Relay Torque Equations. Since memory action persists for only several cycles, it serves no practical purpose in a mho unit when that unit is used in conjunction with a time delay auxiliary relay. Thus, memory action is required only on mho units that are used for high-speed first zone tripping and on mho units that are used for high-speed functions in directional comparison and transferred tripping schemes.

As discussed in the sections under "Relay Torque Equations", memory action is not required for the reactance unit because this type of unit operates on current alone. The offset mho unit will also operate on current alone even for

zero voltage faults. However, the memory action is desirable in the offset mho unit to provide for maximum speed when the unit is used as a transmitter keying (carrier starting) unit in directional comparison relaying schemes. In such schemes, it is important that the transmitter be keyed-on as quickly as possible to provide a blocking signal on external faults. Once the unit picks up, it will continue to stay picked up, as long as the fault persists, even for zero voltage faults.

SELECTION OF RANGE

When selecting the ranges of a terminal of distance relays, the major consideration is that the ranges should encompass the desired settings. Another consideration is that future tapping or splitting of the line should, if practical, still permit the use of the same relays. However, still another more subtle consideration should be evaluated. This deals with the torque level of operation of the relays.

For any desired ohmic reach setting, the unit having the highest minimum reach that can accommodate the desired setting will provide the highest torque level of operation. For example, if a 4-ohm reach setting is desired, a 3-30 ohm mho unit with a 4-ohm setting will operate at a higher torque level than a 2-20 ohm mho unit with a 4-ohm reach setting. If a 0.75 ohm reach setting is necessary, a 0.5-5.0 ohm reactance unit will operate at a higher torque level than a 0.25-2.5 ohm reactance unit.

Thus, all other things being equal, there is some advantage in selecting the highest range units that can accommodate the desired settings.

TRANSIENT OVERREACH

In general, distance relays are calibrated and set in terms of applied sinusoidal voltages and currents. When these same relays are installed on the Power System they are often called on to operate for conditions that are considerably different from those used in setting their reach. When a fault occurs on a transmission circuit, the resulting fault current generally contains a d-c offset in addition to the a-c power frequency component. The ratio of this d-c offset to the a-c component of current depends on the instant in the cycle at which the fault occurred while the rate of decay of the offset is a function of the impedance angle (or L/R ratio) of the system. This offset condition exists only for several cycles after the inception of the fault.

The effect of the offset is to cause the relays to "see" an impedance that is somewhat smaller than the actual impedance to the fault. This can result in the relay overreaching its setting. Since the offset decays rapidly, the overreach is transient in nature and so is termed Transient Overreach. When a distance relay is used in conjunction with time delay (RPM relay) for second and for third zone protection, the transient overreach characteristics on the measuring units so used are of no significance because the d-c offset transient will have disappeared long before second or third zone time expires.

On the other hand, the first zone distance measuring units operate at high speeds without any intentional time delay. These units are usually set so that they do not reach beyond the remote terminal(s) of the protected line section and so they are designed with limited transient overreach characteristics.

Summing up, all first zone relays, or units of relays, have limited transient overreach characteristics while second and third zone relays, or units of relays, do not. Conversely, when selecting a relay for a first zone application it should have limited transient overreach characteristics. For second and third zone applications limited transient overreach is not required.

ARC RESISTANCE

It is well known that arc or fault resistance will affect the reach of a mho unit but not that of a reactance unit. From Figure 1 it is evident that for the fault at F on the transmission line, the mho unit will operate for arc resistances up to a magnitude equal to FP . However, for a fault at T even the smallest amount of arc resistance will cause the fault to appear outside the mho characteristic. Thus, the magnitude of the arc resistance and the location of the fault as well as the actual setting will determine whether or not the mho unit "sees" the fault.

From Figure 2 it is apparent that the reach of the ohm unit itself is not affected by arc resistance just as long as the fault is within the reactance reach setting of the unit. This is true because for a fault on the line (at point F for example) the arc resistance will plot horizontally-parallel to the relay characteristic. The amount of arc resistance that the ohm unit can accommodate is actually only limited by the setting of the directional mho unit (not shown in Figure 2) that is used in conjunction with the ohm unit. Since this mho unit generally takes a third zone setting, the combination can accommodate considerably more arc resistance than a mho unit set for the same first zone reach as the reactance unit.

Since arc or fault resistance is not related to the length of the protected line section, it is quite possible for the magnitude of the arc resistance on a short line to approach or actually exceed the impedance of the line. Such applications demand a first zone reactance unit rather than a mho unit for optimum protection. In the case of longer lines, the arc resistance tends to be smaller relative to the line impedance and for such cases the mho unit may be satisfactorily used.

Arc resistance in faults is difficult to evaluate. However, it is known that the resistance of an arc increases with the length of the arc and has an inverse relationship to the current in the arc. As a rough approximation, assuming fault currents in excess of 1,000 primary amperes, the arc voltage may be assumed relatively constant at about 500 volts per foot of arc. If it is further assumed that the arc length per phase is essentially equal to one half the spacing between adjacent phases for all types of multi-phase faults, then the arc voltage at the inception of the fault can be roughly approximated by the following equation

$$V_{\text{arc}} = \frac{d \times 500}{2} \text{ primary volts per phase.}$$

where d is the spacing between adjacent conductors. .

If we assume further that line conductor spacing is roughly one foot per

10KV then the above equation becomes.

$$V_{\text{arc}} = \frac{50}{2} (\overline{KV}) = 25(\overline{KV}) \text{ primary volts per phase}$$

where \overline{KV} is the rated voltage of the line in kilovolts.

Since the potential transformers have a ratio of $(\overline{KV})(1000)/115$ volts, the secondary arc voltage is

$$V_{\text{arc}} = 25(\overline{KV}) \frac{115}{1000(\overline{KV})}$$

2.9 secondary volts per phase.

Thus it appears, for fault currents in excess of 1,000 primary amperes, roughly 3 secondary volts per phase of arc voltage can be present. This voltage divided by the secondary fault current will yield an arc resistance that may be plotted on the R-X diagram along with the protected line to provide a rough estimate as to the adequacy of the protective relay settings.

It is important to note that for a second or third zone time delay trip the fault arc may elongate with time so that the fault resistance at the time the relay is called on to operate is larger than that value calculated above.

BLINDERS

The term blinders as it applies to phase distance relays has the same significance as when it is applied to a horse. In the case of the horse, blinders limit his vision to a narrow beam in the direction in which he is facing. In the case of a distance relay, blinders limit the operation of the distance relays to a narrow beam that parallels and encompasses the protected line. In general, relay blinders are required with mho units only where long lines are involved and the resulting mho unit settings are large enough to pick up on maximum full load currents or minor system swings. Figure 7 on following page.

The blinder and mho unit contacts are interlocked in the trip circuit in such a way that tripping can only occur in the fault impedance plots inside the mho characteristics and between blinders A and B. Actually the blinders are nothing more than reactance units similar to those of Figure 2 that have been rotated by modifying the power factor angle of the restraint circuit of the units. The A blinder operates for faults that plot to its right. The B blinder operates for faults that plot to its left. The overall effect of the blinders is to restrict the operating zone to an area on the R-X diagram that parallels the protected line and thus makes the combination relatively insensitive to system swings and immune to operation on full load.

One pair of blinders is required per phase. Thus, three pairs are needed per terminal on a three-phase system.

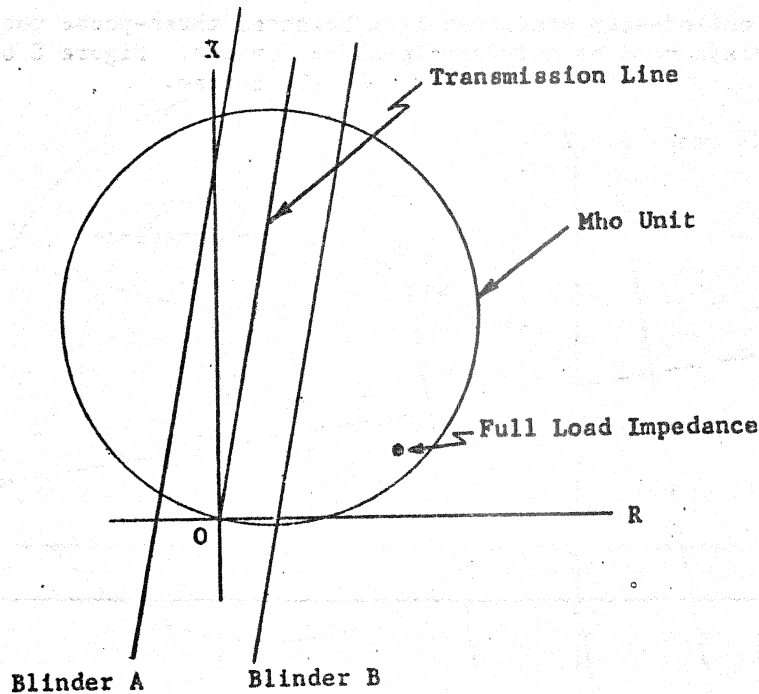


FIGURE 7

OUT-OF-STEP TRIPPING AND OUT-OF-STEP BLOCKING

Experience has indicated that for certain system operating conditions a severe system disturbance can cause system instability and result in a loss of synchronism between different generating units on an interconnected system. Such a condition is termed "Out of Step". Since a prolonged out-of-step condition can result in a partial, or in the extreme case, a complete system shut down, it is desirable to detect this condition as soon as possible and take the appropriate action.

There are two basic tools available to do this job. First, and probably the most common is the out-of-step-blocking relay. Out-of-step-blocking relays operate in conjunction with the mho-type tripping relays to prevent a terminal from tripping during severe system swings and out-of-step conditions. This prevents the system from separating in an indiscriminate manner. Next is the out-of-step-tripping relay. This device operates independently of the other protective devices to detect the out-of-step condition during the first pole slip and initiates tripping of the desired circuit breakers. It is important to recognize that the out-of-step-tripping relays must be installed on the system where they will be able to detect the out-of-step condition and that they should trip the proper local or remote circuit breakers. In this case, the proper breakers would be those that would separate the system in such a way as to balance the load with the available generation on any isolated portion of the system. Needless to say, the application of out-of-step-tripping relays must be coordinated with the out-of-step-blocking relays and both types of out-of-step protection should be based on the results of system studies.

Since an out-of-step condition is a balanced three-phase phenomenon, the out-of-step relays need be only single-phase devices. Figure 8 below illustrates the principles of operation on the R-X diagram.

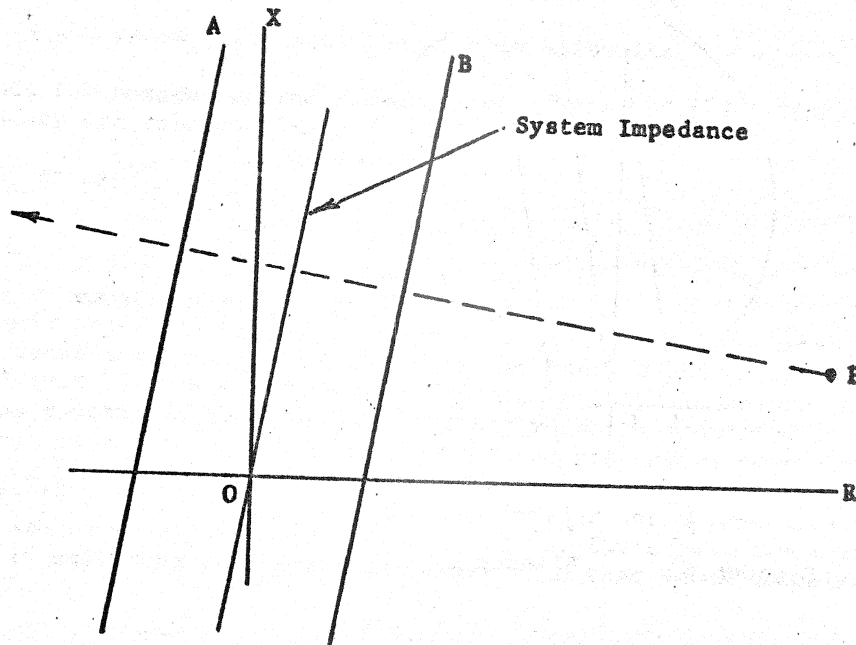


FIGURE 8

The out-of-step-tripping relay is made up of two rotated reactance type units the characteristics of which are labeled A and B in Figure 8. These units are essentially the same as those used as blinders with mho units. When an out-of-step condition occurs and the apparent impedance as viewed by these units moves from, say point P to the left along the dashed path, this impedance is first to the right of both characteristics. Next it is between the two characteristics and finally it emerges to the left of the characteristic A. This sequence of events is "evaluated" by an associated auxiliary relay to ascertain that an out-of-step condition exists and a trip signal is given either to local breakers or over some suitable communication channel to remote breakers. If the locus of the out-of-step impedance proceeded from left to right, the same result would be produced.

The out-of-step-blocking relay operates in a somewhat different manner. It is a single-phase distance type unit that operates in conjunction with the standard mho tripping units that are used in the various different protective schemes. Figure 9 on the following page illustrates how this is accomplished.

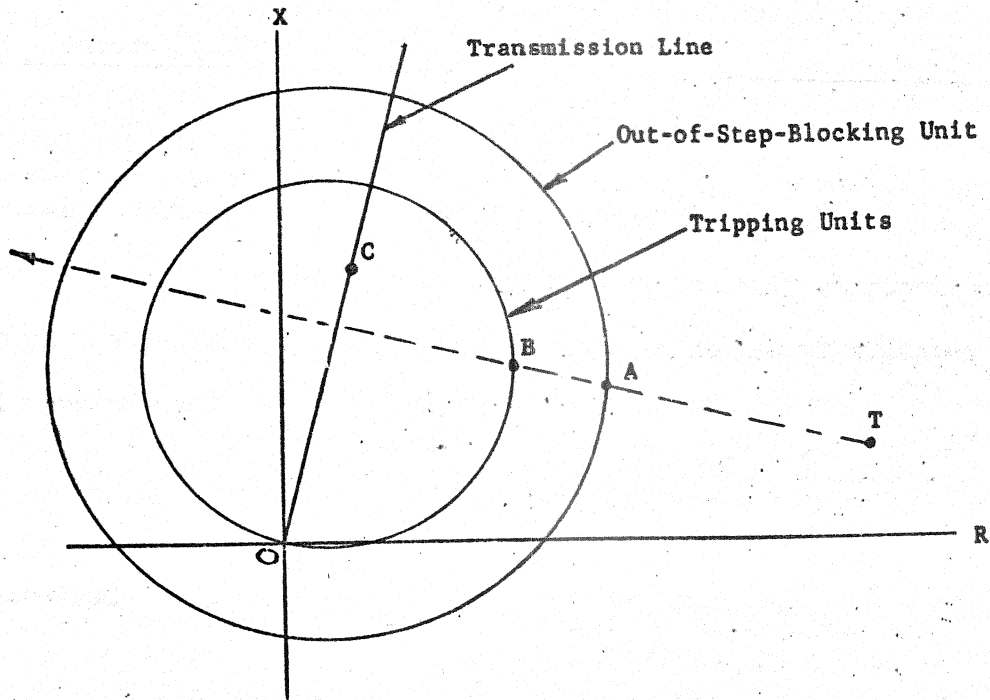


FIGURE 9

Assume that the apparent system impedance, as viewed by the relays prior to an out-of-step condition, plots at T on the R-X diagram. As this apparent impedance moves toward the relay characteristics, during or immediately after a system disturbance, it will first enter the out-of-step-blocking unit circle. Then, in continuing on its path, some short time later it will enter the tripping units characteristics. If the transit time of this locus between points A and B exceeds a few cycles, the out-of-step-blocking unit will operate an auxiliary device to block the tripping unit from tripping. It is because the out-of-step-blocking unit picks up some few cycles prior to the tripping unit that indicates a smooth change in impedance as viewed by these units.

For the same initial load impedance, if a fault were to occur on the protected line, at say Point C, the impedance as viewed by these units would change abruptly from T to C. For this condition, both the trip units and the blocking unit would operate simultaneously. For this situation, the trip unit incapacitates the blocking auxiliary unit before it can set up blocking. Thus, tripping is permitted.

One out-of-step-blocking relay could be used at each line terminal that would be subject to undesired out-of-step tripping. In some instances users apply the out-of-step-blocking relay as in Figure 8 above but use it to block automatic reclosing after an out-of-step trip by the distance tripping units. In this scheme, the tripping units are not blocked but are permitted to trip on out-of-step and automatic reclosing is blocked.