

# Requirements of a New Substation based Protective Relay Coordination

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**Abstract:** This paper brings together experiences of three years effort toward implementing an Overcurrent and Earth fault relay coordination software. A substation based coordination method has been developed by using the programming language, Vb.net and connection to the database, Microsoft Access. By this, sufficiency of the new proposed view is evaluated. Since short circuit calculation programs are usually available, a substation including all the current protective relays plus distance relays is considered in this applied research. A special attention is paid to define a few relevant short circuit scenarios and different rules are developed based on this methodology to achieve optimal settings and to cover instructions and standards. The resulted software program facilitates all the calculations of current relays for any high voltage substation with any configuration and offers detailed calculations. The results have been tested frequently on a large power system grid in a regional electric company for about 10 years.

**Keywords:** Computer aided; Coordination; Protective position; Overcurrent.

## 1. Introduction

The vital part of a power system is the protection, including many types of protective devices, while some of them operate individually and some in accordance together. They must protect grid in general including all parties (Sources, power system and loads) to keep grid continuity and reliability. Growing the grids, the protection knowledge and techniques have been developed. Recent products are offered with more options to handle new requirements which at the same time yield more complexity of calculating protective relay settings.

Protection Specialists believe that it is a combination of knowledge and art and no computer based method can cover all the needs and there is a long way to achieve optimal settings even using computerized methods. Therefore, in addition to the scientific knowledge available in this engineering area, one needs a good understanding of the power system requirements to dare offering protective relay settings in practice. Relay men try to cover peripheral factors influencing accuracy and responsiveness of the settings. However, they need to have a road map, pre-defined methods to consider known alternatives before applying their experiences. Consequently, Computer-aided techniques should be developed to be able to cover both scientific and practical influencers.

Correct operation of most protective relays depends on the relays being supplied with correct and sufficient information from the grid under control [1]. Some of important parameters, impacting the calculation are listed here:

- Topology of grid may change from time to time intentionally or due to failures.
- Interconnections of the substation under study can change during the operation due to maintenance service, faults or failures, or number of feeders in use.
- Type and/or age of relevant equipment installed in the grid under study are usually different. This happens e.g., when

there are varieties of components such as circuit breakers in different locations in a substation, posing different performances.

- Accuracy of grid model used for Short Circuit (SC) analysis can affect calculation. Grid changes outside the part under study might be out of control. This can influence all the SC values in the grid.
- Different generation of relays such as fast numerical, digital and electromechanical relays might be installed and utilized together.

Overcurrent (O/C) and Earth fault (E/F) relays play important role in different protective positions from outgoing load feeders to lines in a substation. To coordinate these relays instructions from references and standards such as [2]-[5] are used. There are also new theoretical methodologies in [6] and [7] that are not still used in computer-aided methodologies. Under the substation based view, this paper integrates practical guidelines into the calculations and also applies two internal reports and instructions [8], [9]. This paper is organized as follows: primarily the proposed technique of coordination which mixes theory and practice is briefly given in the next section. Then, different alternatives which possibly affect calculation are listed. Another classification is assigned to O/C and E/F relays in different protective positions. Some other considerations to make computer based method as much as possible capable is introduced later on and finally, a case study is considered and due graphical results is represented.

## 2. Substation vs grid based used for coordination

Advanced Computer-aided solutions consider a grid view to do typical power system studies such as SC analysis, load flow etc. They apply the standards for coordination calculations. The experiences represent that they work as black box modelers for a grid and user cannot get things under control. This limits the capabilities and trustfulness and in some cases they cannot offer optimal settings particularly for non-standard parts of grids. For instance user cannot change the way program calculates minimum SC values to be used in the coordination procedure.

The main focus of the present work is to summarize rules and calculate settings for current protective relays according to user needs, considering rules and standards. User can change the way calculation is done until it is not exceeding standards. Furthermore, if a short circuit software program is available, coordination

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algorithm is independent of whole grid model as will be discussed in the next sections. The calculation based on the substation view gets key influence of grid by having accurate SC scenarios applied in:

- Different positions of a substation.
- Lines connected to the Low Voltage (LV) side.
- Lines connected to the High Voltage (HV) side.
- Protective position that sees SC currents occurred in the lines. These are typically the protective positions that connect a substation to the whole grid directly or indirectly. The method also takes coordination with distance relays to account.

The program core calculator looks in the same direction as relay looks and feels maximums and minimums as relay feels. This helps to do correct calculation even for ring grids without need for the whole grid. Important note is that in all referred cases, maximum and minimum values are considered in the scenarios for SC. For the sake of simplicity, among all configurations of a substation a typical H-type configuration with two parallel transformers is considered in this paper.

Fig 1 illustrates a scheme of protective allocation (P1,...P9) where each position (feeder) may have O/C and/or E/F relays.

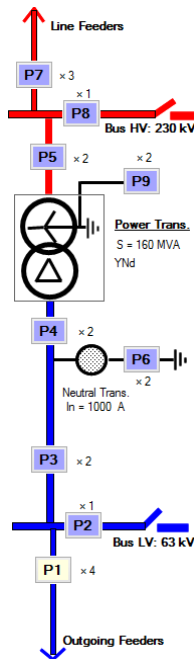


Figure 1. Symbolic diagram representing protective positions

The diagram includes 4 outgoing feeders, represented by (×4) equipped with O/C and E/F relays, one Bus-coupler protection and two transformer feeders (×2) each including incoming protection, neutral transformer protection (×2), transformer HV-side protection, transformer HV-side neutral protection (×2), three line feeders (×3) protections etc.

### 3. Some Applications

#### 3.1. Applications for Determination of Disease Risk

### 4. Alternatives Affecting calculation

#### 4.1. Alternatives of Feeders and relays

According to the proposed solution, two major categories for O/C and E/F relays are distinguished where they are coordinated separately. The following overview shows alternatives a computer-based solution is dealing with:

#### 1) Type of relays to be coordinated together:

- O/C with O/C.
- O/C with distance (ANSI 21) which is applied to some relays that see line phase faults.
- E/F with E/F.
- E/F with distance (ANSI 21) which is applied to some relays that see line earth faults.

2) In some positions O/C and/or E/F relay might be absence.

3) Types of SC currents used on the calculations which might be more complex for ringed connected configurations.

4) To achieve maximum and minimum fault currents one should switch on or off some components (lines, transformers, loads and/or sources).

5) Different Current Transformer Ratio (CTR) in different protective positions.

6) Furthermore, different brands of relays offer different setting requirements for example:

7) Different setting ranges including min, max and steps. There might be several ranges for an Inverse Definite Minimum Time (IDMT) characteristic.

8) Some units like instantaneous or normal pickup units may exist or not exist in a relay.

9) Available standard Timing characteristics (DT, SI, EI, VI, LT, etc.) can be different for some relays.

10) Some time there are different setting types. For instance, current setting ( $I_s$ ) might be set according to Ampere (A), Nominal Current ( $I_n$ ) or proportional to ' $I_s$ '.

11) Some units may have different settings. For example 'Inst' can be set differently in terms of 'A', 'In' or 'Is'.

12) Relays might have different nominal currents ( $I_n$ ).

13) Directional relays may have been set to different direction. This changes the strategy of coordination. For example type of coordination for a Busbar-side directional E/F relay is different with coordination of Line-side relays.

14) There might be different CT ratios in different feeders.

#### 4.2. Alternatives for Transformer type

The type of transformer grounding affects the coordination method. This is because it affects SC current penetration in the grid. If for instance YNd transformers are used in a 63/20 sub-transmission substation, there will be no earth fault current transferred from Low voltage side (LV-side) to HV-side. Despite, if for example an autotransformer is used in a transmission 400/230 kV substation, earth fault in the LV-side will be seen by some of relays in the HV-side and vice versa.

#### 4.3. current Relays, Overcurrent protection

While programming for coordination of O/C relays, we categorize feeders from lower levels to higher in a standard H-type substation as:

#### 1) Outgoing feeders

- Normal load feeders
- Line feeders
- Lines with infeed
- Lines feeding other neighbour substations

#### 2) LV side Bus-couplers

#### 3) Incoming feeders

#### 4) LV-side protections

- 5) *HV-side protections*
- 6) *HV-side Bus-couplers*
- 7) *HV-side Line directional O/C protection*

- Non-directional
- Busbar-side
- Line-side

In general, some of above mentioned feeders may be either including some relays or they may not. For example in a 230/63 kV substation, HV-side line feeders are not protected by O/C relays. They may just be equipped by Distance and Directional E/F relays.

The following instructions summarize the required coordination for all O/C relays in a substation in the beneath:

1) *Outgoing feeders (P1):*

- For load feeders: To be set according to load requirements. Load permissible demand for short lines.
- For outgoing line feeders, line thermal and maximum permissible line current can be considered.
- To be coordinated with distance relays (if any)
- To be coordinated with connected remote substation current relay.

2) *Bus-coupler/s (P2):* This is simpler in a way that this O/C relay needs to be coordinated with outgoings. In the coordination we need to note that required SC currents depending on the characteristic used for relays. For example if IDMT is used for outgoing feeders and if Definite Time (DT) is used for Bus-coupler protection (in old days it was used), minimum SC currents are needed in the coordination.

3) *Incoming (P3):* This relay should be coordinated with the first existing downstream protection.

4) *LV-side (P4):* This relay in some of old protective schemes exists and should be coordinated with the first downstream protection.

5) *HV-side (P5):* This relay in all transformer types should be coordinated with the LV-side protection.

6) *HV-side line protection (P7):Non-directional*

- To be coordinated with downstream.
- To be coordinated with its own distance relay.
- To be coordinated with the distance relays of other lines.
- To be coordinated with O/C of other lines (non-directional and line-side). This can also be coordinated with the remote substation relays.

7) *HV-side line protection (P7):Busbar-side*

- To be coordinated with downstream.
- To be coordinated with O/C of other lines (non-directional and line-side).
- To be coordinated with the distance relays of other lines.
- Can be coordinated with the remote substation relays, seen by this relay.

8) *HV-side line protection (P7):Line-side*

- To be coordinated with its own line distance relay.
- Can be coordinated with the remote substation relay connected to the same line, seen by this relay.

9) *HV-side Bus-coupler (P8):*

- To be coordinated with distance relay of all lines.
- Can be coordinated with the remote substation relays.

#### 4.4. current Relays, Earth fault protection

While programming for E/F relays, we categorize feeders as such:

1) *Outgoing feeders*

- Normal load feeders
- Line feeders
- Lines with infeed
- Lines feeding other neighbour substations

2) *Bus-couplers*

3) *Incoming feeders*

4) *Neutral protections*

5) *LV-side protections*

6) *HV-side protections*

7) *HV-side Neutral protections*

8) *HV-side Bus-couplers*

9) *HV-side Line directional E/F protections*

- Non-directional
- Busbar-side
- Line-side

The following instructions summarize the required coordination for all E/F relays in the following

1) *Outgoing feeders (P1):*

- For load feeders: To be set according to instructions.
- For line feeders
- To be coordinated with distance relays (if any)
- Can be coordinated with the connected remote substation current relay.

2) *Bus-coupler/s (P2):* This is simpler in the way that we just need to be coordinated with outgoings. In the coordination we need to note that required SC currents depending on the characteristic used for relays. For example if IDMT is used for outgoing feeder and in Definite Time (DT) is used for Bus-coupler protection (in old days it was possible), minimum SC currents are needed in the coordination.

3) *Incoming (P3):* This relay should be coordinated with the first downstream protection.

4) *LV-side (P4):* This relay in some of schemes exists and should be coordinated with the first downstream protection.

5) *HV-side (P5):* Only in some of transformer types that there is a reflection of LV-side fault current seen in the HV-side, should be coordinated with the LV-side protection. There is a need for fault current ratio where we transfer it to HV-side (if any). Furthermore HV-side fault current is also needed. If faults in the LV-side are not seen in the HV-side, settings should be according to instructions.

6) *LV-side neutral (P6):* Only in YNd- type transformers, neutral transformer is used. It should be coordinated with downstream.

7) *HV-side line protection (P7), Non-directional*

- To be coordinated with down stream
- To be coordinated with own distance relay ()
- To be coordinated with distance relays of other lines
- To be coordinated with E/F of other lines (non-directional and line-side)
- Possibly coordinated with the remote substation relays seen by this relay.

8) *HV-side line protection (P7), Busbar-side*

- To be coordinated with down stream
- To be coordinated with E/F of other lines (non-directional and line-side)
- To be coordinated with distance relays of other lines
- Possibly coordinated with the remote substation relays, seen by this relay.

- 9) *HV-side line protection (P7), Line-side*
- To be coordinated with its own line distance relay.
  - To be coordinated with the remote substation relay connected to the same line, seen by this relay.
- 10) *HV-side Bus-coupler (P8):*
- To be coordinated with the distance relays of all lines.
  - Possibly coordinated with the remote substation relays.
- 11) *HV-side neutral (P9):* Only in some of transformer types like autotransformers, or those with grounding in the HV-side might be used. For coordination this E/F relay needs:
- To be coordinated with distance relay of all lines.
  - Possibly coordinated with the remote substation relays, seen by this relay.

#### 4.5. Definition of fault currents, Phase fault currents

- 1) *SC currents required for outgoing feeders:*
- IP1Max: Maximum 3-ph short circuit at forward Line beginning seen by this Relay.
  - IP2Max: Maximum 3-ph short circuit at forward Line end seen by this Relay.
  - IP3Min: Minimum 2-ph short circuit at forward Line end seen by this Relay.
- 2) *SC currents required for Bus-coupler:*
- IP1Max: Maximum 3-ph short circuit at forward Line beginning seen by this Relay.
- 3) *SC currents required for incoming:*
- IPMax(Bus-coupler): 3-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders.
- 4) *SC currents required for LV-side protection (if any):*
- IPMax(Incoming): 3-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders.
- 5) *SC currents required for HV-side protection (if any):*
- IPMax(HV-side): Translation of 3-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders to HV-side of transformer. This uses fault ratio already defined for the transformer.
- 6) *SC currents required for HV-side Lines, Line-side:*
- If1: Maximum 3-ph short circuit at forward Line beginning seen by this Relay.
  - If2: Maximum 3-ph short circuit at forward Line end seen by this Relay.
  - If5: Minimum 2-ph short circuit at forward Line end seen by this Relay.
  - If6: Maximum common 3\_ph short circuit with the remote Substation.
- 7) *SC currents required for HV-side Lines, Busbar-side:*
- If3: Maximum 3-ph short circuit at reverse Line beginning (if any) seen by this Relay.
  - If4: Maximum 3-ph short circuit at reverse Line end (if any) seen by this Relay.
  - If5: Minimum 2-ph short circuit at forward Line end seen by this Relay.
  - If6: Maximum common 3\_ph short circuit with the remote Substation.
- 8) *SC currents required for HV-side Lines, Non-directional:*
- If1: Maximum 3-ph short circuit at forward Line beginning seen by this Relay.
  - If2: Maximum 3-ph short circuit at forward Line end seen by this Relay.

- If3: Maximum 3-ph short circuit at reverse Line beginning (if any) seen by this Relay.
- If4: Maximum 3-ph short circuit at reverse Line end (if any) seen by this Relay.
- If5: Minimum 2-ph short circuit at forward Line end seen by this Relay.
- If6: Maximum common 3\_ph short circuit with the remote Substation seen by this Relay.

#### 4.6. Definition of fault currents, Earth fault currents

- 1) *SC currents required for outgoing feeders:*
- Ie1Max: Maximum 1-ph short circuit at forward Line beginning seen by this Relay.
  - Ie2Max: Maximum 1-ph short circuit at forward Line end seen by this Relay.
  - Ie3Min: Minimum 1-ph short circuit at forward Line end seen by this Relay.
- 2) *SC currents required for Bus-coupler:*
- Ie1Max: Maximum 1-ph short circuit at forward Line beginning seen by this Relay.
- 3) *SC currents required for incoming:*
- IeMax(Bus-coupler): 1-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders.
- 4) *SC currents required for LV-side protection (if any):*
- IeMax(Incoming): 1-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders.
- 5) *SC currents required for HV-side protection (if any):*
- IeMax(HV-side): Translation of 1-ph Short Circuit value at Bus Coupler with Maximum SC and single Transformer without effects from substations feeding output feeders to HV-side of transformer. This uses fault ratio already defined for the transformer. In some transformer types there will be no current flown in the HV-side due to fault in the LV-side.
- 6) *SC currents required for HV-side Lines, Line-side:*
- Ie1: Maximum 1-ph short circuit at forward Line beginning seen by this Relay.
  - Ie2: Maximum 3-ph short circuit at forward Line end seen by this Relay.
  - Ie5: Minimum 2-ph short circuit at forward Line end seen by this Relay.
  - Ie6: Maximum common 3\_ph short circuit with the remote Substation.
- 7) *SC currents required for HV-side Lines, Busbar-side:*
- Ie3: Maximum 1-ph short circuit at reverse Line beginning (if any) seen by this Relay.
  - Ie4: Maximum 1-ph short circuit at reverse Line end (if any) seen by this Relay.
  - Ie5: Minimum 1-ph short circuit at forward Line end seen by this Relay.
  - Ie6: Maximum common 3\_ph short circuit with the remote Substation.
- 8) *SC currents required for HV-side Lines, Non-directional:*
- Ie1: Maximum 1-ph short circuit at forward Line beginning seen by this Relay.
  - Ie2: Maximum 1-ph short circuit at forward Line end seen by this Relay.
  - Ie3: Maximum 1-ph short circuit at reverse Line beginning (if any) seen by this Relay.
  - Ie4: Maximum 1-ph short circuit at reverse Line end (if any) seen by this Relay.

- Ie5: Minimum 1-ph short circuit at forward Line end seen by this Relay.
- Ie6: Maximum common 1-ph short circuit with the remote Substation seen by this Relay.

9) SC currents required for HV-side Bus-coupler:

- Ie1Max(Bus\_HV): Maximum 1-ph short circuit at Line beginning seen by this Relay
- Ie2Max(Bus\_HV): Maximum 1-ph short circuit at smallest Line end seen by this Relay
- Ie3Min(Bus\_HV): Minimum 1-ph short circuit at forward Line end seen by this Relay

10) SC currents required for Transformer HV-side Neutral:

- Ie1Max(HV\_Neutral): Maximum 1-ph short circuit at Line beginning seen by this Relay
- Ie2Max(HV\_Neutral): Maximum 1-ph short circuit at smallest Line end seen by this Relay
- Ie3Min(HV\_Neutral): Minimum 1-ph short circuit at forward Line end seen by this Relay

#### 4.7. Fault current transfer Ratio

As written in [6], Fault current transfer ratio is needed in the coordination procedure when we calculate settings of HV-side relays. We need to know whether an earth fault in the LV-side is seen at the HV-side or not? If yes we need to coordinate the relay under study with downstream. Otherwise, we just assign a predefined time value for it. Further reason to have fault current ratio is that the fault may path through a grid including neutrals with different zero sequence impedances which in turn causes different current ratios for a transformer in different situations.

#### 4.8. Coordination with a remote substation

A line protection device might be needed to be coordinated with a remote relay located in the neighbor substation. This may happen for instance when there is no distance relay protecting the line as is in distribution lines. Then Directional E/F relay must protect the line alone. It may need to be coordinated with another relay in the remote substation. This is also another flexibility that connects the substation under study to the neighbor substations and makes substation based methodology as powerful as the grid view method.

#### 4.9. Discrimination times

There will be specific discrimination times for coordination with any protective devices. This should be set by the user to add extra flexibilities that mainly affect time settings value. This can resolve coordination problem with grids including different types of relay generation (old and new).

#### 4.10. Setting validation

In practice, there should be many tests to validate the calculated settings since there are some situations that standard rules don't work. This is the most important point that art and science of relaying coincides. This may happen for instance when a relay aims to protect a long transmission line where minimum SC currents at the end of the line under protection cannot cause starting up of the relay. Since the main startup current settings are calculated according to the maximum values, the minimums might be missed. Therefore, the program should check such vague cases to lead designer to think how to compensate the weakness accordingly.

### 5. Managing database according to needs

Fig 2 represents a graph of two databases that we use for

coordination, Substation database and Relay database.

The main program, substation creator, makes connection with both databases. It is because while defining configuration, program needs to define relays according to relay data base and needs data from substation database. However, it doesn't change data in relay database. Therefore its relation is in one way toward substation creator. However, another program, relay creator can change data in relay database instead.

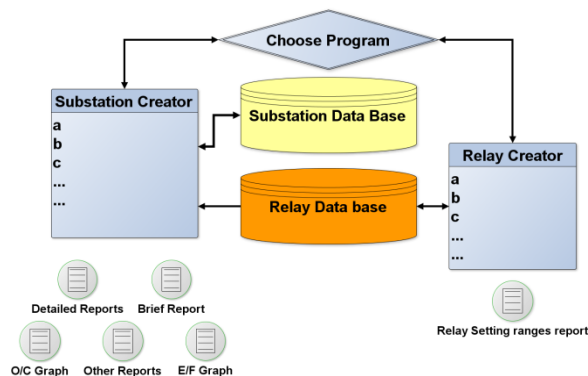


Figure 2. Schematic diagram of Databases for PRC

### 6. A case study

#### 6.1. Single Line Diagram (SLD)

Fig 3 represents a simplified SLD for a 230/63 kV substation which is the case study evaluated in this paper. The proposed substation is including the following feeders and relays:

- *O/C Relays in:* Outgoing feeders: (F1, F2, F3, F4), Bus-couplers: (Bus\_LV\_1), Incoming feeders: (Incoming\_1, Incoming\_2), LV-Side feeders: (Trans\_1, Trans\_2), HV-side protections: (HV\_1, HV\_2), HV-side Bus-couplers, HV-side Line directional O/C protections: (Abhar, Boein, Eshragh).
- *E/F Relays in:* Outgoing feeders: (F1, F2, F3, F4), Bus-couplers: (Bus\_LV\_1), Neutral protections: (LV\_Neutral, LV\_Neutral\_2), LV-Side feeders: (Trans\_1, Trans\_2), HV-side protections: (HV\_1, HV\_2), HV-side Neutral protections(HV\_Neutral\_1, HV\_Neutral\_1), HV-side Bus-couplers, HV-side Line directional E/F protections: (Abhar, Boein, Eshragh).

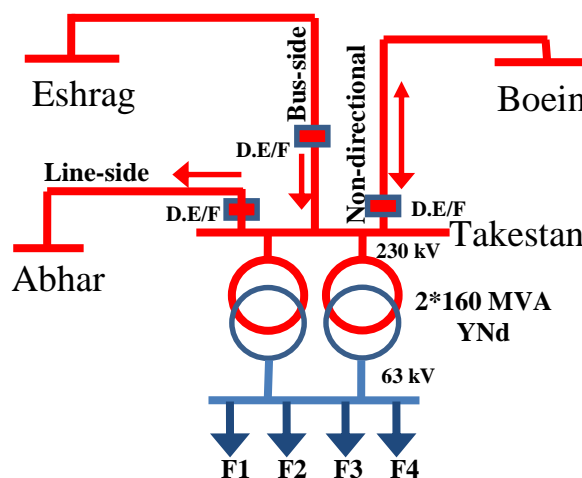


Figure 3. SLD for a 230/63 kV substation

The list of detailed calculation is too long and cannot be included in this paper due to the page limitation. Therefore, calculation for

just one outgoing feeder (F1) is represented in the appendix and time-current graphs for both O/C and E/F relays are shown in the following.

## 6.2. Time-current graphs

Time-Current diagrams for all O/C and E/F relays in a 230 kV substation are illustrated in Fig 4 and 5 respectively.

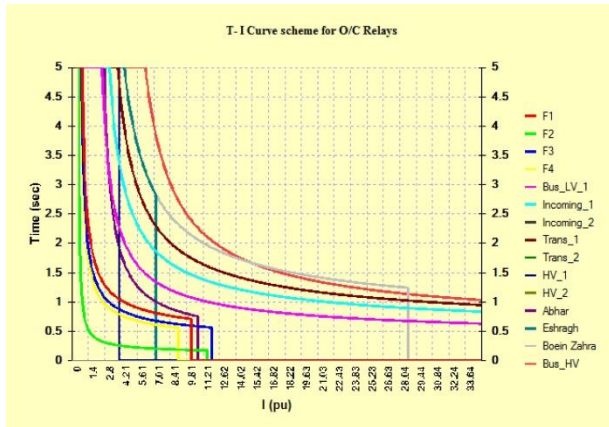


Figure 4. Time-Current diagram for O/C relays in substation under study

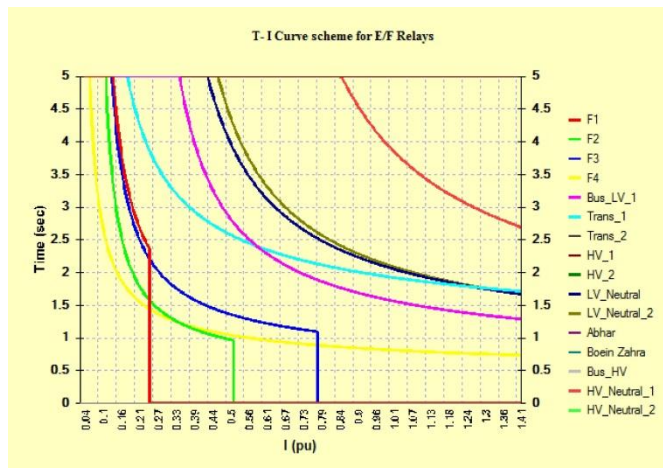


Figure 5. Time-Current diagram for E/F relays in substation under study

## 6.3. Output report, Detailed Report

This calculation is just for one of outgoing feeders as such:

Outgoing Feeder Name: F1

Overcurrent Protective Relay R1(1) = R1(F1) for 63 kV Outgoing Feeder , Direction: Line side

Relay Type: MCGG82

Selected Characteristic: SI

Generic Formula:  $T = (TMS/1) * \{K / [(I/Is)^{\alpha} - 1]^{\gamma} + \beta\} = (TMS/1) * \{0.14 / [(I/Is)^{0.02} - 1]^1 + 0\}$

$\alpha = 0.02$  ;  $\beta = 0$  ;  $\gamma = 1$  ;  $K = 0.14$  ;  $M = 1$

$I_n = 1$  A ; Relay Nominal Current

C.T Ratio =  $I_1CT / I_2CT = 800 / 1$

$I_{L Max} = I(\text{Load Max}) = 560$  A

$I(LTR) = 549$  A

First Choice of Relay Current Setting:  $ISR(F1) = 1 * I(\text{Load Max}) = 560$  A

$ISR(F1) \gg I(LTR)$  Therefore  $ISR(F1) = I_{LTR} = 549$  A

$\{1 * I_{L Max} \leq ISR(F1) \leq \text{Min}[I_1CT, I(LTR)]\} \implies ISR(F1) = 549$  A

$I_s = [ISR(F1) / 800] * I_n = 0.686 * I_n$  ; Low Norm  $\implies 0.65 * I_n$

$ISR(F1) = 0.65 * 800 = 520$  A

$I_{base} = 916.43$  A

$IP1Max(F1) = 12.58$  pu = 11528.68 A ; Maximum 3-ph short circuit at forward Line beginning seen by this Relay

$IP2Max(F1) = 7.545$  pu = 6914.46 A ; Maximum 3-ph short circuit at forward Line end seen by this Relay

$IP3Min(F1) = 1$  pu = 916.43 A ; Minimum 2-ph short circuit at forward Line end seen by this Relay

Checking:  $IP3Min(F1) / ISR(F1) = 1.76$

TMS according to required Relay Operating time for Faults in the Forward Line Beginning (Zone 1):

$TMS1 = 0.4 * 1 / \{0.14 / [(IP1Max(F1) / ISR(F1))^{0.02} - 1] + 0\} = 0.183$

TMS according to required Relay Operating time for Faults in the Forward Line End (Zone 2):

$TMS2 = 0.8 * 1 / \{0.14 / [(IP2Max(F1) / ISR(F1))^{0.02} - 1] + 0\} = 0.304$

$TMS(\text{Final}) = \text{Maximum of all defined or calculated Time Multiplying Settings (TMS)} = 0.304$  ; Low Norm  $\implies > 0.3$

Operating time of this Relay for different fault currents:

$TR(F1)$  for  $(IP1Max = 11528.68$  A) = 0.657 sec

$TR(F1)$  for  $(IP2Max = 6914.46$  A) = 0.791 sec

$TR(F1)$  for  $(IP3Min = 916.43$  A) = 3.685 sec

$TR(F1)$  for [Fault current (Max) at LV side Buscoupler with Parallel Trans. =  $IPMax(1) = 11510.35$  A] = 0.657 sec

$TR(F1)$  for [Fault current (Min) at LV side Buscoupler with single Trans. =  $IPMin(1) = 4133.1$  A] = 0.992 sec

$I_{inst} = 0.8 * [IP1Max / ISR(F1)] * I_s = 17.74 * I_s$  ; Norm  $\implies > 18 * I_s$

$T_{inst} = 0$  sec; Norm  $\implies > 0$  sec

Permissible Load according to Relay Current Setting:

$I = 520$  A ,  $S = 56.7$  MVA

## A. Output report, Abstract

$I_s = 0.65 * I_n$  ,  $TMS = 0.3$  ,  $I_{inst} = 18 * I_s$  ,  $T_{inst} = 0$  sec

## 7. Conclusions

We proposed results of implementing a big software, an Applied Relay Coordinator (ARCO) to attain overcurrent and earth fault relays settings in detail. In addition to some practical points considered in the program, we defined some specific short circuit scenarios in different points of a grid under study. It was shown that having the whole grid model is not a serious requirement if some specific fault results are used in the program calculations. Many instructions were provided to guide users to understand how to proceed and calculate all the settings of a substation in detail and with different alternatives taken in to account.

The proposed substation based method has been applied to a big power system in practice and has been showing sufficiency vs. grid view for more than a decade.

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