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PROTECTION COORDINATION PLANNING WITH DISTRIBUTED GENERATION

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PROTECTION COORDINATION PLANNING WITH DISTRIBUTED GENERATION

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DISCLAMER

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EXECUTIVE SUMMARY

The main purpose of this report is to serve as a guideline for assessing the impact of distributed generation (DG) on the protection coordination of the distribution network. In particular, the report details and presents a generalized assessment procedure for determining the impact of the integration of DG on the protection practices of distribution systems. The reported assessment procedure enables the utility engineer to arrive at the suitable DG penetration limit in typical Canadian distribution systems, considering the most important protection impacts, such as the impact on coordination, de-sensitisation, nuisance fuse blowing, bi-directional relay requirements, and the impact of interconnection transformers and grounding practices on overvoltages. In addition, special attention has been given to the islanded mode of operation and various mitigation strategies have been proposed. The assessment method is demonstrated on typical Canadian urban and suburban benchmark distribution systems, which are recently published by Natural Resources Canada. To ensure the relevancy and the compatibility with the existing utility practices, demonstrations are carried out using CYMDIST and CYMTCC, which are the commonly used software for distribution system protection planning in Canada. This development will facilitate a safe integration of DGs as well as increase the penetration of DG in existing distribution systems through better understanding of the requirements and upgrades required to achieve this goal. This study was conducted as part of the *Grid Integration of Distributed Energy Resources* program managed by CETC-Varennes, Natural Resources Canada.

Different types of energy sources can be utilized in DG systems; however, the impact on the protection of the distribution system is dependent on whether the interfacing scheme is based on the direct coupling of rotary machines, such as synchronous or induction generators, or whether the DG system is interfaced via a power electronic converter. Depending on the type of DG interface, the contribution to the short circuit and consequently, the impact on protection will change. In the present study, all types of DG interfacing technologies are modeled, including: 1) synchronous generators, 2) induction generators, and 3) inverter-based generation.

The generalized assessment method relies on breaking the DG impact on distribution system protection to a number of sub-studies. Namely, they are: loss of coordination, de-sensitisation, nuisance fuse blowing, bi-directional relay requirements, and overvoltage studies. Also, impact studies in the islanded mode of operation are considered. Figure I(a) shows the overall structure of the assessment method, whereas Figure I(b) summarizes the methodology. The detailed methodology for different impact studies can be traced in Figures 43, 47, 48, 54, and 56.

A sample result of the outcome of the assessment method is shown in Tables I and II. Table I reports on the penetration limits obtained in the suburban benchmark distribution system for each protection issue. Four candidate points have been selected for DG installation. It is obvious that the impact of DG on the coordination is the most significant in the suburban system. Therefore, it

determines the overall protection-based penetration limit for this system. Table II reports on the penetration limits obtained in the urban benchmark distribution system for each protection issue. Four candidate points have been selected for DG installation. The original coordination charts of the urban system were quite clear with almost no intersections between the time-current characteristics of different protection devices. Therefore, an infinitely large DG size is required to upset the coordination. The results reveal that there is no impact on the coordination as depicted in Table II. However, the impact on the bi-directionality is the most pronounced and it is the one that dictates the overall penetration limit of the feeder under study.

Although the assessment method is general, the calculated penetration limits are very much system dependant, i.e. depending on the original protection characteristics, settings, and short circuit levels. For example, in the suburban benchmark system, the impact of DG on the bi-directionality is the weakest; then comes the impact on sensitivity. The most obvious impact was on the coordination. On the contrary, the impact on bi-directionality leads the list in the urban benchmark system; followed by the impact on the sensitivity. The impact on fuse saving strategy is not applicable in the urban benchmark system due to the absence of the recloser.

The presented method can be simply extended to the case of multiple DG by considering the most updated coordination charts, short circuit levels, and protection settings imposed by the presence of initial DG installations. Then, the assessment method can be applied to determine the protection-based penetration limit for additional DG on a given feeder. Due to the diversity of possible scenarios, a detailed study for a given system should be carried using the presented guideline.

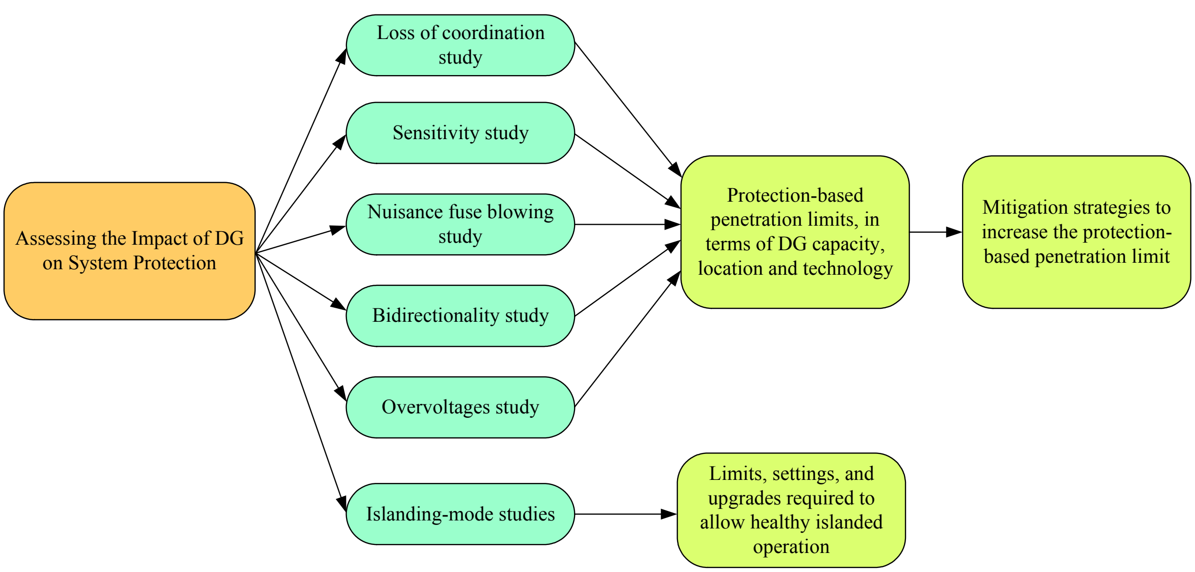


Figure I(a) - The overall structure of the assessment method.

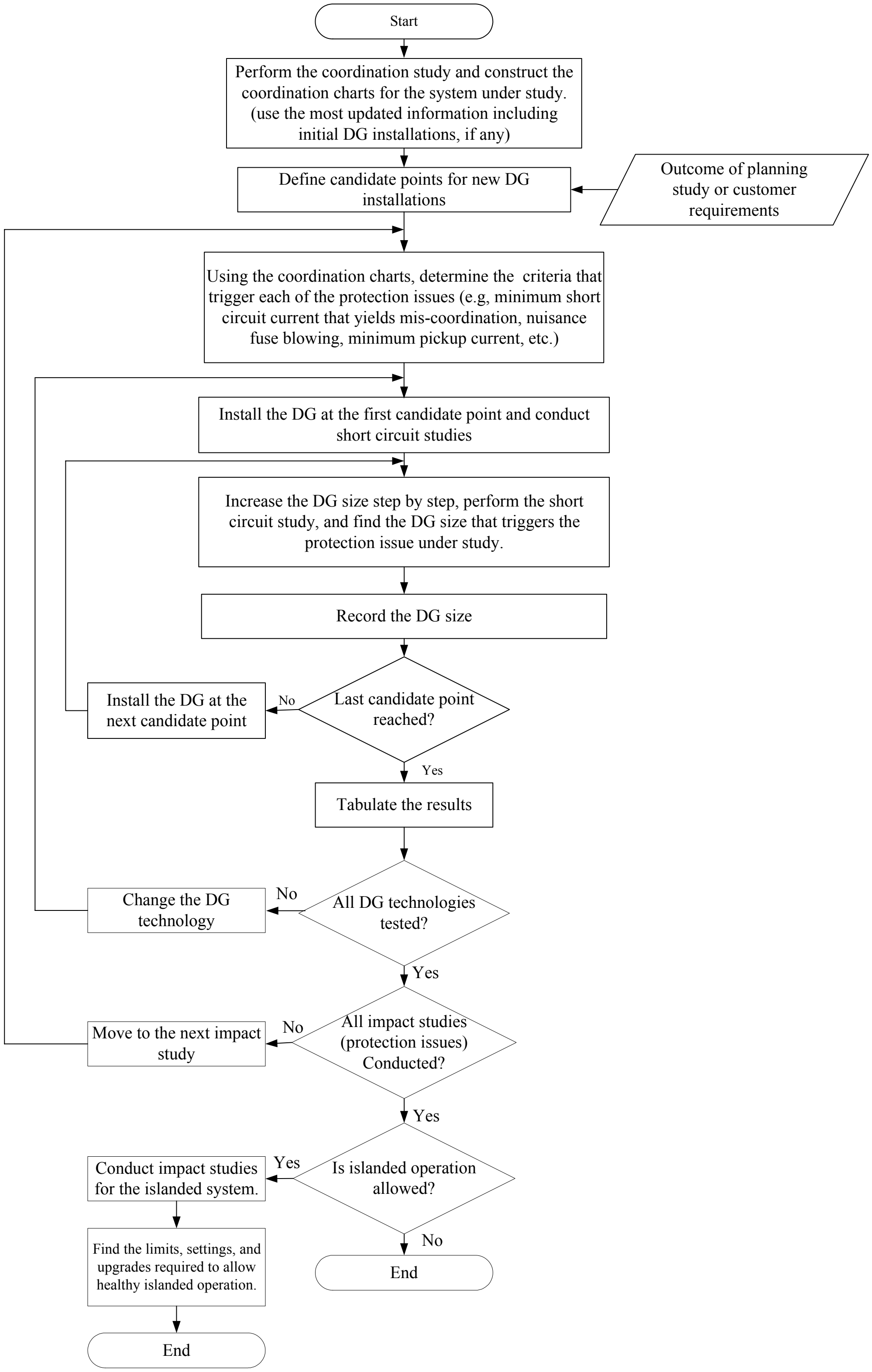


Figure I(b) - A generalized procedure to assess the impact of DG integration on distribution system protection.

Table I - Protection-based penetration limits **in the suburban benchmark system for the synchronous DG technology.**

Installation Point	P1	P2	P3	P4
Loss of Coordination Penetration Limit (DG Size in kVA)	760	755	1550	2800
Loss of Sensitivity Penetration Limit (DG Size in kVA)	No effect	17000	15000	12000
Nuisance Fuse Blowing Penetration Limit (DG Size in kVA)	760	755	1550	2800
Bi-directionality Penetration Limit (DG Size in kVA)	40000	37000	33000	31000
Overvoltage Penetration Limit for a DG with solidly grounded Y-Y interconnection transformer (DG Size in kVA)	No effect	No effect	No effect	No Effect

Table II - Protection-based penetration limits **in the urban benchmark system for the synchronous DG technology.**

Installation Point	P1	P2	P3	P4
Loss of Coordination Penetration limit (DG Size in kVA)	No effect	No effect	No effect	No effect
Loss of Sensitivity Penetration limit (DG Size in kVA)	No effect	20000	18000	14000
Fuse Blowing Penetration Limit (DG Size in kVA)	Not Applicable	Not Applicable	Not Applicable	Not Applicable
Bi-directionality penetration limit (DG Size in kVA)	950	900	900	900
Overvoltage penetration limit for a DG with solidly grounded Y-Y interconnection transformer (DG Size in kVA)	No effect	No effect	No effect	No Effect

1 Introduction

1.1 Preamble

Driven by economic, technical and environmental reasons, the energy sector is moving into an era where large portions of increases in electrical energy demand will be met through widespread installation of distributed resources or what's known as Distributed Generation (DG) [1]-[3]. Generally, DG introduces new possibilities, but at the same time, challenging planning and operation issues. Among these possibilities, DG can give commercial consumers various options in a wider range of reliability-price combinations. Therefore, DG could appear as an autonomous power system, which meets customer requirements, such as compensation of reactive power and higher harmonic components, compensation of power quality events, correction of system and load power factor, shaving of peak loads, and providing means in backup generation and reliability enhancement [1]-[5]. On the other hand, existing distribution systems have not been designed to accommodate DG. Therefore, the connection of DG to utility systems may violate existing planning and operation practices. Critical among these, the integration of distributed generation and other storage devices into the utility grid will alter the contemporary practice of having a unidirectional power flow, which remarkably affects the coordination of the utility protection systems [6]-[12].

In the context of the impact of DG on the utility protection system, a number of protection issues, such as loss of coordination, de-sensitisation nuisance fuse blowing, bidirectional relay requirements, and overvoltages, have been identified and documented [6]-[12]. However, the critical question, which centers on arriving at the penetration limits for DG in terms of location, capacity and technology, considering the most important protection impacts, remains unanswered. The criticality of this question arises from the bulky utility-infrastructure in place that it is generally unfeasible to consider major changes to provide more accommodation to DG. Therefore, a generalized assessment procedure for determining the impact on distribution practices and evaluating the penetration limit for DG in existing distribution systems, in terms of location, capacity, and DG technology, must be developed. This development will facilitate the safe integration of DG units on existing distribution systems through better understanding of the requirements and upgrades required to achieve this goal. The direct result of this development is huge financial saving for utilities by capturing the salient features of deploying DG into existing utility networks.

This study presents and demonstrates a generalized assessment procedure for determining the impact of the integration of DG on the protection practices of distribution systems. The developed method enables arriving at the penetration limit for DG, considering the most important protection impacts in terms of DG size, location and technology. The assessment considers the impact on coordination, de-sensitisation, nuisance fuse blowing, bidirectional relay requirements, and the impact of interconnection transformers and grounding practices [2]. In addition, special attention has been made to the islanded mode of operation. The method is demonstrated using different types of distribution system configuration (urban, suburban and rural) based upon Canadian benchmark systems.

To fulfill study objectives, the following tasks have been accomplished:

1. Distribution networks modeling and documenting original protection coordination curves.

2. DG modeling.

3. Considerations of interface transformer and grounding strategy.

4. Conducting the impact studies to develop the generalized assessment procedure.

An overview of each task with the associated background is highlighted below.

1.2 Distribution Networks Models

Modern distribution systems are now facing many challenges. Deregulation of the power market and the installation of DG in the system are among the most recent challenges that have to be addressed effectively in order to ensure reliable and efficient operation of the distribution system.

The electric power is supplied to the customer via the distribution network. The design of the distribution network is very much dependent on the type of customer, the geography of the area, the level of the required reliability of service, standards and national electric code. Traditionally, there are a number of distribution systems that can be implemented. The following are the major types of distribution systems [51]:

1. Simple radial

2. Loop-primary system - radial secondary system

3. Primary selective system – secondary radial system

4. Two source primary - secondary selective system

5. Simple spot network

6. Medium-voltage distribution system design

The distribution network models are basically equivalent electrical circuits consisting of multiple resistors, capacitors and inductors. However, for the equivalent circuits to allow the assessment of the protection system functionality, they must account for the additional components that facilitate the security and reliability of the distribution protection system. Two distinct popular types for distribution systems are considered in this study:

1.2.1 Suburban and rural overhead lines

For suburban areas, overhead distribution lines, either radial or meshed configurations, are used with distribution transformers connected to the poles. This type of distribution system is usually equipped with re-closers that are capable of breaking and making the circuit in order to avoid nuisance tripping due to temporary faults.

1.2.2 Urban systems

Urban distribution systems mainly consist of underground cables that are protected using circuit breaker and fuses; where re-closers are typically not used. The main incoming line is usually connected through a disconnect pad mounted switch and then to the main distribution board. Here the issue is primarily ensuring that the substation breaker will be able to see the fault.

Recently, Natural Resources Canada has published a report defining benchmarks for urban and suburban distribution systems in Canada to facilitate carrying out simulation studies of the impact of DG on distribution system operation [2]. According to [2], the reported benchmark systems can reasonably represent urban and suburban distribution systems in Canada. Also, local variations seen in Toronto, Halifax, Montreal, Calgary and Vancouver have been reported. Therefore, the urban and suburban benchmarks reported in [2], have been selected in this study. Chapter 2 details the benchmark systems and documents the original protection coordination study.

To ensure relevancy and compatibility with existing utility practices, modeling and demonstrations are carried out using CYMDIST and CYMTCC software package, which is commonly used for distribution system protection planning in Canada [3].

1.3 Distributed Generation Models

Distributed generation behind the customer's meter provides an excellent opportunity to displace load from the local distribution system's grid in a very effective manner. Load displacement technology, such as combined heat and power systems, provides increased power efficiency. This may include technology such as thermal storage systems. Combined with an existing or new district heating/cooling distribution system, this technology contributes to the development of sustainable energy networks within Ontario's communities. Other technologies such as micro-turbines, wind, biomass fuels and solar provide additional options to meet the customer's needs. The benefits of interconnecting a DG include additional capacity within the grid and cleaner technologies resulting in reductions in green house gas (GHG) emissions. Other benefits include improved system reliability, reduced harmonics, backup power possibilities and transmission congestion relief.

Different types of energy sources can be utilized in DG systems as stated earlier; however, the impact on the protection of the distribution system is dependent on whether the interfacing scheme is based the direct coupling of rotary machines, such as synchronous or induction generators, or whether the DG system is interfaced via a power electronic converter. Depending on the type of DG interface, the contribution to the short circuit and consequently, the impact on protection will change. In the present study, all types of DG interfacing technologies are modeled, including: 1) synchronous generators, 2) induction generators, and 3) inverter-based generation. Detailed modeling of these generators can be found in Chapter 3.

1.4 Interconnection Transformer and Grounding

The selection of the interconnection transformer plays an important role in how the DG will interact with the utility system. There is no universally optimal connection. All connections have advantages and disadvantages that need to be addressed by the utility and distributed generation owner. A distribution system could be solidly grounded, ungrounded or grounded through grounding impedance. The choice of transformer connection and grounding impedance will affect the magnitude of overvoltages following single-phase faults and also on the magnitude of the fault current supplied from the substation. Consequently, the choice of transformer connection will have a profound impact on ground fault detection. These factors should be considered in order to properly assess the impact of DG on system protection. Chapter 3 discusses different connections of the interconnection transformer and analyzes the associated overvoltage and sensitivity issues.

1.5 DG Impact Studies and Development of a Generalized Assessment Method

Protection is one of the most important issues that are affected by the interconnection of DG. Further, distribution system protective devices (re-closers, fuses and overcurrent relays) are normally designed based on the short circuit currents. The interconnection of DGs, interconnection transformers, as well as the grounding impedances, will all affect the value of the fault currents. Therefore, it is anticipated that all protection devices will be affected by DG integration. Hence, impact studies are conducted to develop a generalized assessment procedure for assessing the impact of the DG integration on the distribution system protection and coordination. The studies are conducted by considering the most important protection impacts in terms of DG size, location and technology. The following protection issues are considered: 1) Loss of Coordination, 2) Nuisance Fuse Blowing, 3) Loss of Sensitivity, 4) Bi-directionality, 5) Variability of Fault Current, and 6) Overvoltages. Chapter 4 presents the impact studies and outlines the assessment procedure.

To account for the islanded mode of operation, the aforementioned impact studies are revisited in the islanded mode. Chapter 5 presents the impact studies in the islanded mode of operation.

The outcome of the impact studies along with the islanded mode recommendations are utilized to establish the protection-based penetration limit of DG in a given distribution system. Figure 1 shows the overall structure of the assessment method. The presented assessment method is demonstrated on the urban and suburban benchmark distribution systems.

Finally, Chapter 6 suggests mitigation techniques to relax the impact of DG on system protection.

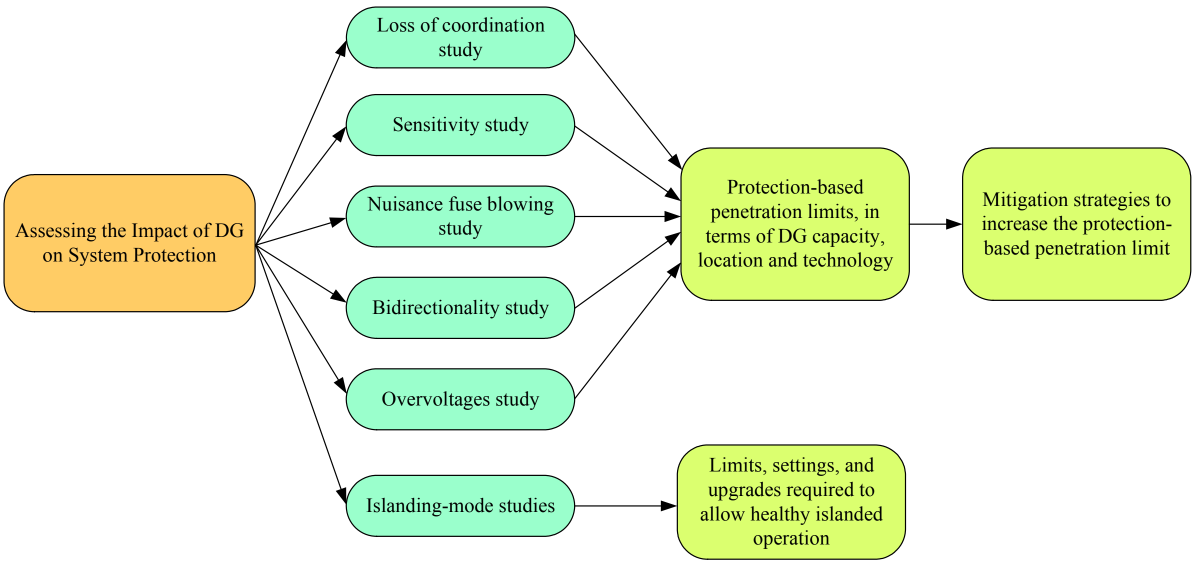


Figure 1 - Overall structure of the generalized assessment method.

2 Distribution System Models

2.1 Different Types of Distribution Systems

There are three types of distribution systems in Canada, which are urban, suburban, and rural distribution systems. Each type of them has its own features regarding the length of the backbone, types of protection devices used, types of laterals, load density, and voltage level. Table 1 summarizes the main features of each type.

Table 1 - General features of urban, suburban and rural distribution systems.

	Urban	Suburban	Rural
System voltage	7.2/ 12.5 or 8/13.8 kV	14.4 /25 or 16/27.6 kV	16/27.6 kV
Feeder Rating	6-10 MVA	12-20 MVA	10-30 MVA
Feeder construction	Little/ no overhead	Mostly overhead	Overhead
Backbone	Shorter backbones with fewer laterals	Longer backbone with large number of laterals	Much longer backbone with large number of laterals
Load density	High	Medium	Low
Voltage regulators	Not used	May be used	Used
Protection	Feeder head end overcurrent relay, lateral fuses, no recloser	Feeder head end overcurrent relay, lateral fuses, with recloser	Feeder head end overcurrent relay, lateral fuses, with recloser

Recently, Natural Resources Canada (NRCan) has published a report defining benchmarks for urban and suburban distribution systems in Canada to facilitate carrying out simulation studies of the impact of distributed generation on distribution system operation [2]. According to [2], the reported benchmark systems can reasonably represent urban and suburban distribution systems in Canada. Also, local variations seen in Toronto, Halifax, Montreal, Calgary and Vancouver have been reported. Therefore, the study team has selected the urban and suburban benchmarks reported in [2]. In addition, a typical Canadian rural distribution feeder has been utilized as a rural benchmark distribution system. The salient features of rural distribution systems, such as long backbone with large number of laterals, overheads backbone, higher voltage level, the presence of voltage regulators, and the utilization of reclosers, are obvious in the selected rural system.

Being based on the Canadian distribution system practices, the chosen benchmarks can effectively fit and extend the applicability of the impact studies. Figures 3, 4 and 5 show the one-line diagram for the chosen urban, suburban, and rural distribution networks, respectively. A detailed description of the components of each network can be found in Appendix A

2.2 Current Distribution System Protection Practices

2.2.1 Protection Devices

There are several protection devices used in the protection of the different types of distribution systems. A List of the most common current protection devices is shown below:

1. Instantaneous phase overcurrent relay (50P): it is used at the main feeder head end.

2. Timed phase overcurrent relay (51P): it is also used at the main feeder head end.

3. Timed ground overcurrent relay (51G): it is also used at the main feeder head end.

4. Timed negative sequence overcurrent relay for phase-phase faults (46): it is also used at the main feeder head end (not used as recommended in the Canadian benchmark distribution systems [2]).

5. Impedance relay (21) (not used as recommended in the Canadian benchmark distribution systems [2]).

6. Reclosers (70).

7. Current limiting fuses.

8. Differential protection for station bus only.

The selection of the relay settings differs from utility to utility. But there are general rules are used to select the setting of each relay. For example, the pickup setting of the timed phase overcurrent relay is selected to be secure under normal loading condition and to be dependable under over loading or short circuit conditions. Some utilities prefer to use lower pickup setting for the relay to ensure dependability under overloading condition and other utilities prefer to use slightly higher pickup setting of the relay to ensure reliability in case of temporary overloading. The time dial setting (TDS) and the curve type of the relay is selected according to coordination criteria of utility.

2.2.2 Coordination of Protection Devices

Almost all electric utilities use the concept of overlapped zones in the coordination of the overcurrent protection devices. This means that each zone should have its own primary protection and a backup protection facility that operates in case of primary protection failure. In most of the cases, the backup protection is the next upstream protection device to the protected zone. Backup protection should operate only when the primary protection stuck and didn't operate. Figure 2 shows a typical radial distribution system. For the fault shown, the fuse F1 should respond very fast to this fault, as this fuse is the primary protective device of this zone.

The relay –circuit breaker set (R1-B1) are considered the backup protection for the marked zone that should operate in case of F1 failure. This implies that operating time of R1 should be larger than that of F1 for any fault in the marked zone.

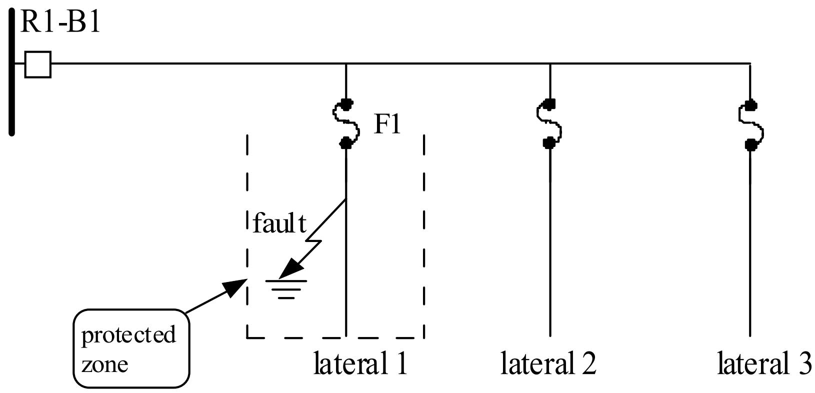


Figure 2 - A typical radial distribution feeder.

There are some issues that should be considered during the preparation of any coordination study:

1. Mis-coordination problem: this means that the coordination study should avoid any mis-coordination between the protective devices. For example, for the system shown in Figure 2, the fuse F1 (primary protection) should operate before the relay R1 (backup protection) for any fault on the protected zone. This ensures the selectivity.

2. Fuse saving strategy: this strategy saves the fuse from blowing during temporary faults. This strategy is done using a recloser that opens the circuit and recloses it again very fast to clear the temporary fault and save the fuse. This is done in rural and suburban distribution systems.

3. Sensitivity of the main head end relay: this means that the main feeder head end relay should sense any fault in the main feeder under any condition. The addition of the DG, for example, to the distribution system might reduce the fault current level drawn from the main substation. This will in turn affect the operation of the substation breaker or recloser especially on their ability to "see" the fault. This will be highly dependant on the type, size and location of the DG. The main relay of the feeder should be designed to overcome such problems.

4. Bi-directionality: this issue is obvious for radial feeders that are fed from the same substation. Protection devices on one feeder may respond to faults in the other feeder due to back feed especially if DG is installed in the healthy feeder. Also, this issue should be considered during the design stage of the protection system.

5. Overvoltage considerations: overvolatges may occur during faults if the system is ungrounded. This problem is obvious if a DG is installed and interfaced via ungrounded transformer with the main feeder.

These issues will be explained in detail in Chapter 4.

2.3 Urban Distribution System

The benchmark of the urban (Metro) distribution system is selected according to [2]. Figure 3 shows the one line diagram for the selected urban distribution system. A detailed description of system components can be found in Appendix A.1.

The metro system, as shown in Figure 3, has been modeled in CYMDIST environment. The utility substation is modeled by an equivalent source behind impedance. The station is rated at 100 MVA with a station bus feeding twelve feeders. The 12.5 kV substation bus is a split-bus type with a normally open tie-breaker. A 1-Ohm series current-limiting reactor is used to limit the short circuit current flowing through the system. Due to the similarity in all feeders, the remaining 5 feeders on each bus are modeled as a lumped load connected at the main station bus with a total power demand of 42 MVA and an overall power factor of 0.95 lagging. A 10 MVAR delta connected capacitor bank is interconnected at the main station bus for reactive power compensation.

A detailed steady state analysis of the metro system could be found in Appendix B.1.

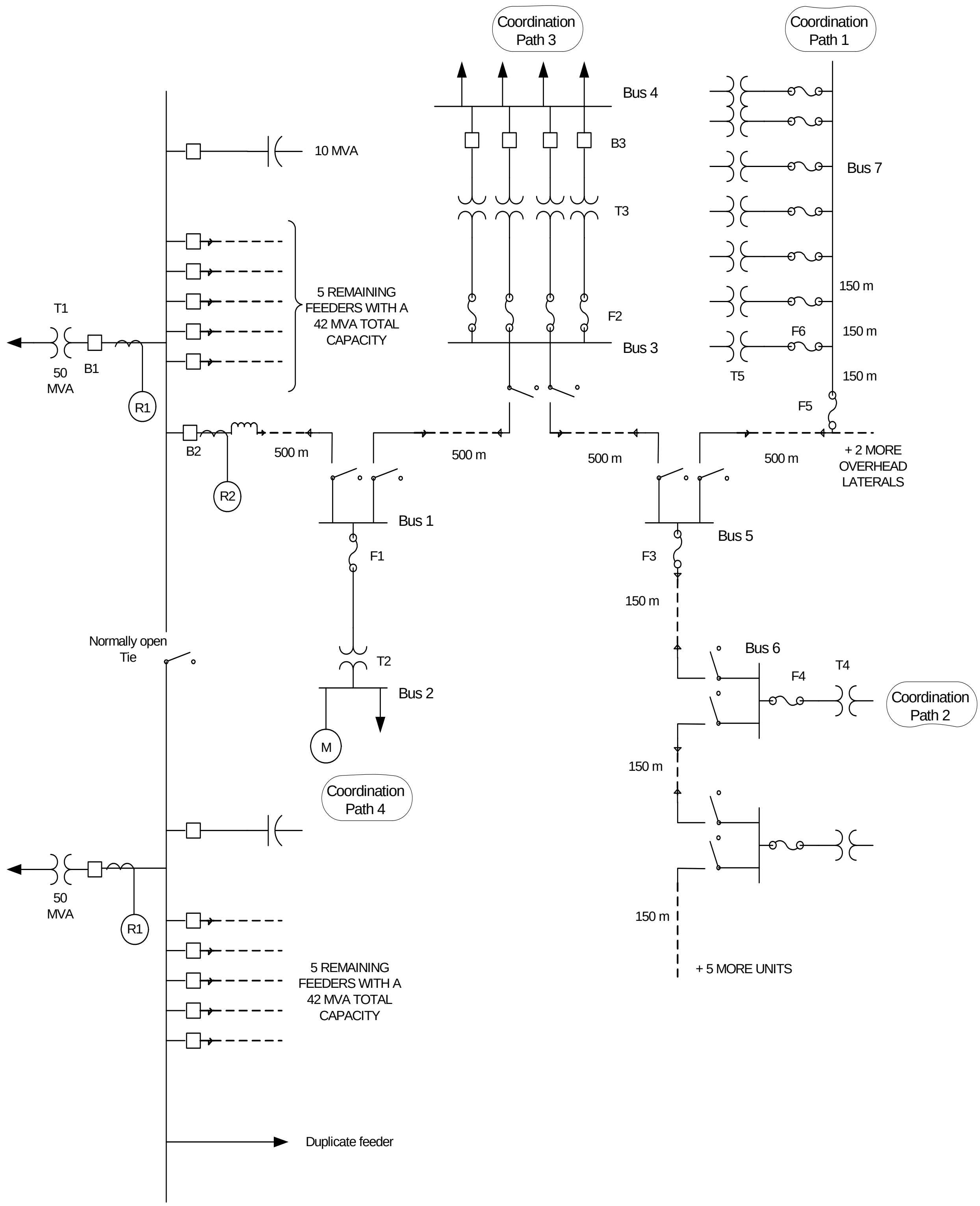


Figure 3 - Single line diagram for the metro benchmark distribution system under study [2].

2.4 Suburban Distribution System

The benchmark of the suburban distribution system is selected according to [2]. Figure 4 shows the one line diagram of the urban distribution network under study. A detailed description of system components is presented in Appendix A.2

The suburban system, as shown in Figure 4, has been modeled in CYMDIST environment. The utility was modeled by an equivalent source behind impedance. The substation is a double-ended type with one transformer on each side, each rated at 100 MVA. The rated bus voltage is 24.9kV. Each bus feeds six feeders and the tie-breaker is normally closed. Normally closed circuit breaker would allow feeding from separate transformers; however, a normally closed circuit breaker leads to a considerable increase in the short circuit level. For this reason a 2-Ohm air-core fault-current limiting series reactor is introduced at feeder head end. The presence of the 2-Ohm series reactor remarkably decreases the symmetrical short circuit level from around 38 kA to 6 kA. On the other hand, the introduction of the series reactor would introduce large voltage drop. Therefore, the sending end voltage should increase with equivalent amount to insure that the voltage drop at the end of the main feeder and at the end of all laterals is within the acceptable limit (5%). Therefore, the substation voltage is adjusted at 1.024 p.u. Due to the similarity in all feeders, the remaining 5 feeders on each bus are modeled as a lumped load connected at the main station bus with a total power demand of 84 MVA and an overall power factor of 0.95 lagging. A 20 MVAR delta connected capacitor bank is interconnected at the main station bus for reactive power compensation.

A detailed steady state analysis of the suburban system could be found in Appendix B.2.

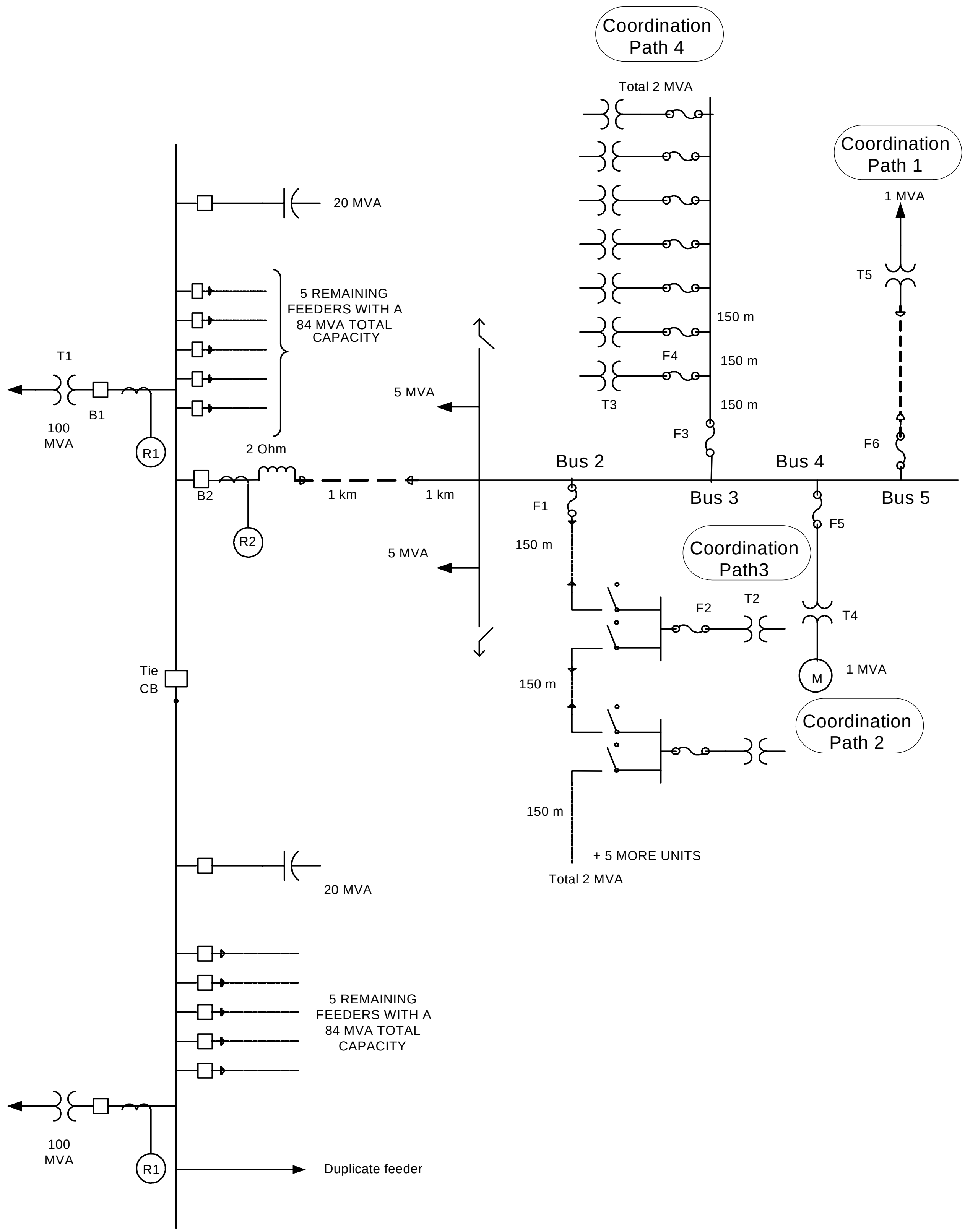


Figure 4 - Single line diagram of the suburban distribution system under study [2].

2.5 Rural Distribution System

A typical Canadian rural distribution feeder has been utilized as a rural benchmark distribution system. Figure 5 shows the one line diagram of the urban distribution network under study. A detailed description of system components is presented in Appendix A.3

The rural system, as shown in Figure 5, has been modeled in CYMDIST environment. The utility was modeled by an equivalent source behind impedance. The substation rating is 20 VA, and the feeder rated voltage is 27.6 kV. A regulating station is located around 12 km along the main feeder. The regulating station setting is adjusted to boost the voltage by 2.5%.

A detailed steady state analysis of the rural system could be found in Appendix B.3.

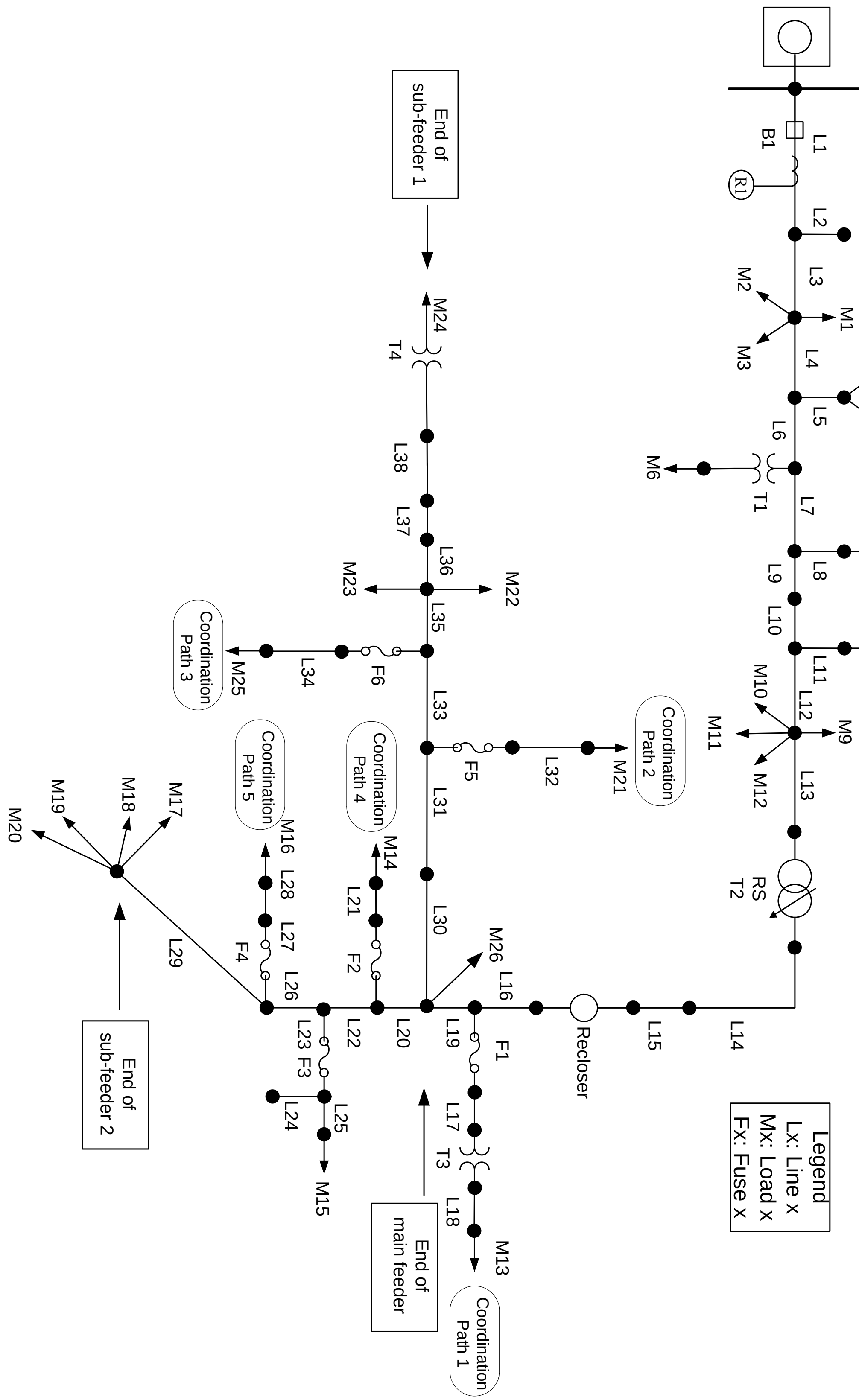


Figure 5 - Single line diagram of the rural system under study.

2.6 Protection Coordination Studies

With the short circuit analysis results available, the next step is to study the protective device coordination and document the protection system. CYMTCC is characterized by its comprehensive protective device library, which will facilitate efficient analysis of the protection devices coordination. Firstly, to verify the accuracy of CYMTCC database, a benchmark case study, extracted from ANSI/IEEE std. 242-1986 [13], pp. 432, have been modeled and tested against the coordination results reported in [13]. Then, the protection coordination studies for urban, suburban and rural distribution system have been conducted.

2.6.1 CYMTCC Software Validation

The industrial distribution system shown in Figure 6 (source: ANSI/IEEE std. 242-1986 [13], pp. 432) is used to verify the accuracy of the CYMTCC database. Figure 6 shows the system as implemented in CYMTCC software. The characteristics of the protective devices used in the coordination study of the typical industrial system are given in Appendix C.1.

Figure 7 shows the coordination chart generated from CYMTCC for a path starting from CB1 upstream to F2 in the industrial system under study. Figure 7 includes the coordinated protective devices curves, ANSI and inrush points and cable damage curves for the abovementioned path. Figures 8 shows the corresponding coordination chart reported in [13]. The results obtained from CYMTCC in Figure 7 closely match the original coordination charts in Figure 8. This verifies the accuracy of the coordination chart generated by CYMTCC software.

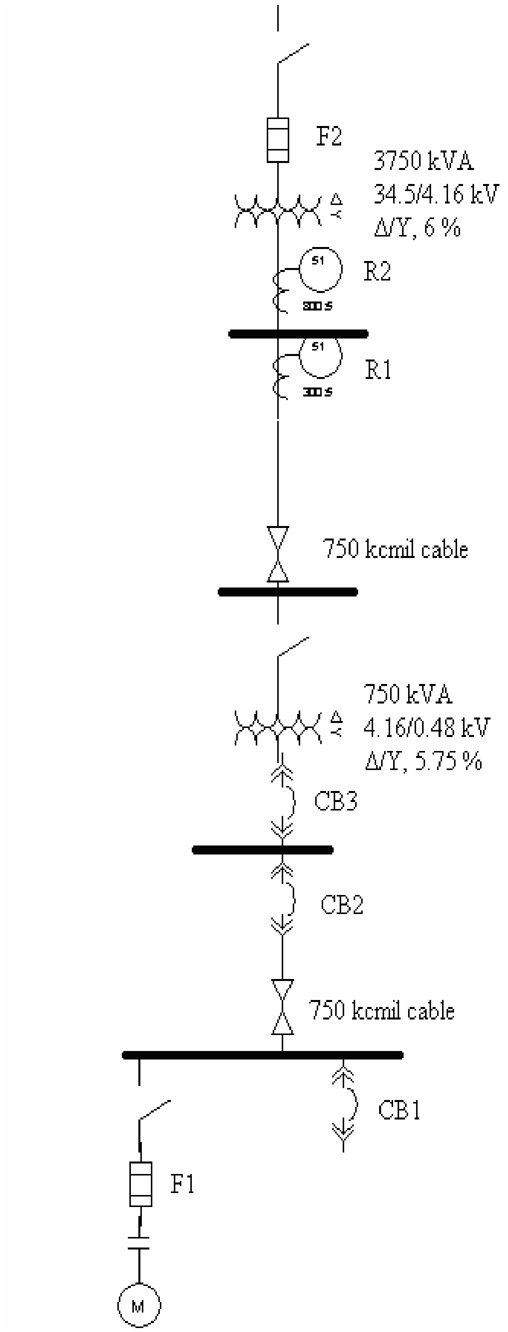


Figure 6 - Typical industrial system used for CYMTCC software validation.

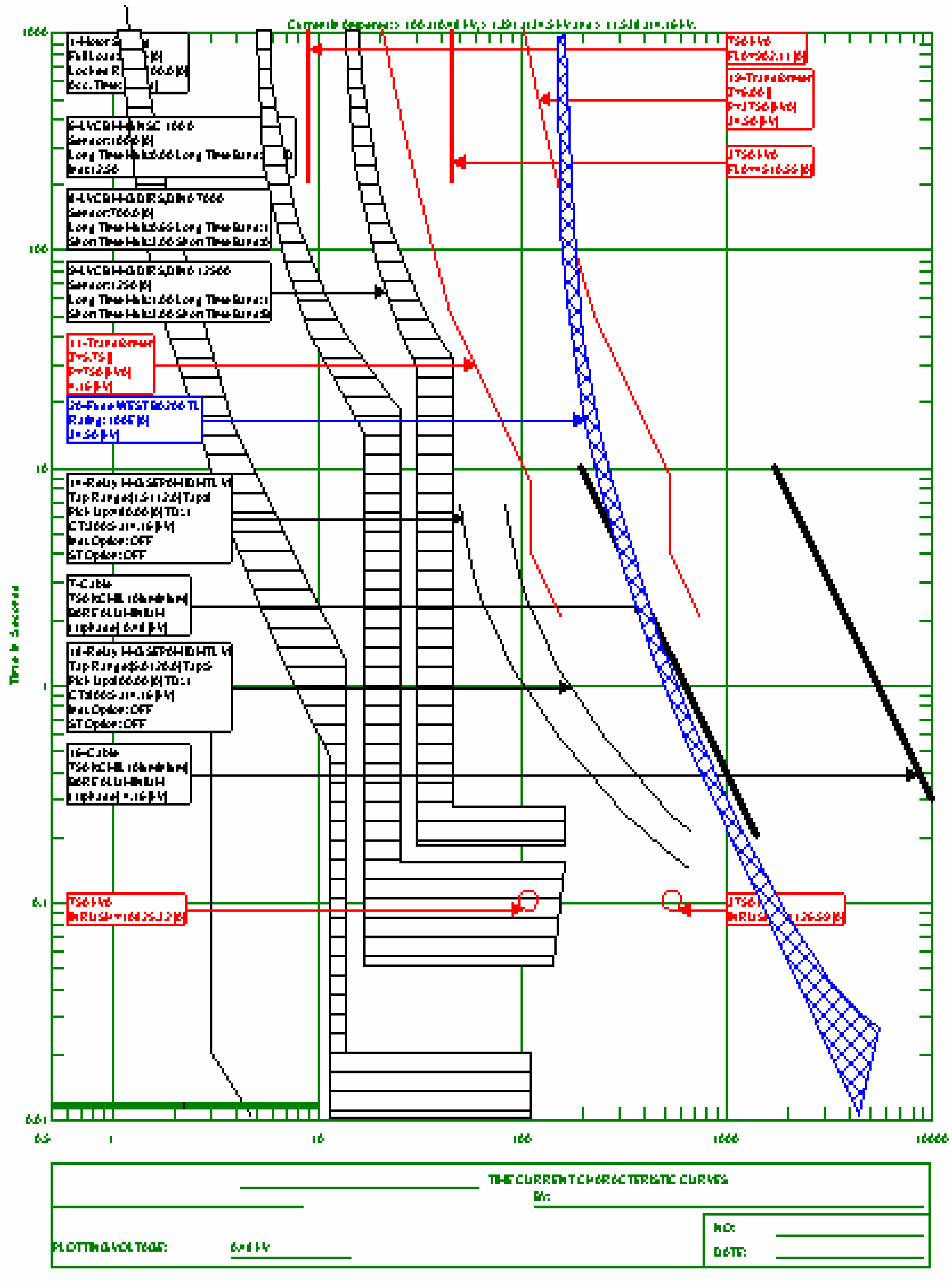


Figure 7 - Coordination chart generated from CYMTCC for CB1 path.

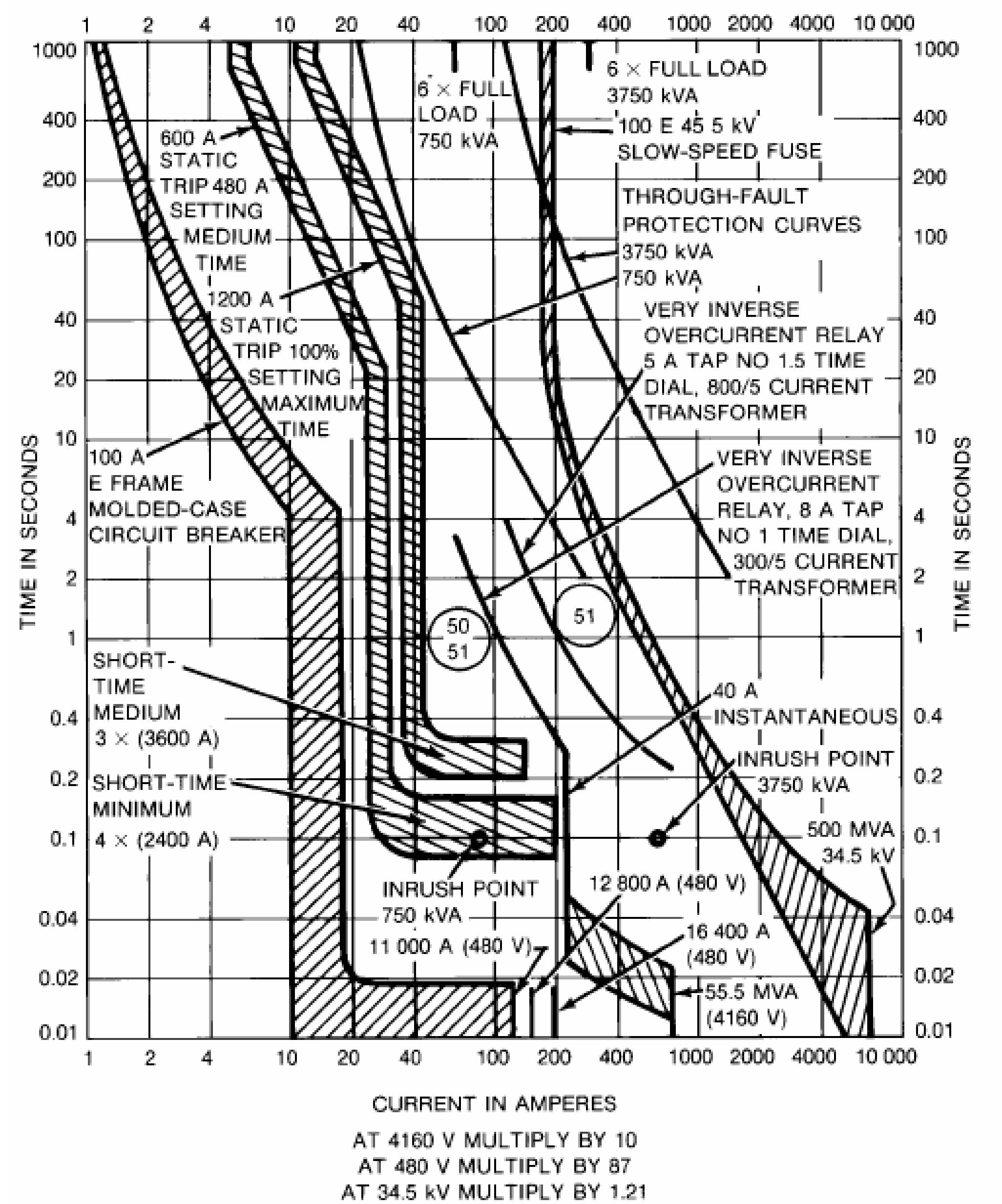


Figure 8 - Original coordination chart for CB1 path as reported in [13].

2.6.2 Urban Distribution System Protection Coordination

Short circuit analysis was performed on the urban distribution system given in Figure 3. The short circuit currents vary according to system configuration. When conducting the protective devices coordination study, it is mandatory to consider the configuration, which results in maximum short circuit currents to make sure that the protective devices are rated to withstand the worst case scenario fault currents. The case where the tie-breaker is closed was considered for protective devices coordination. In addition, if protection devices coordinate for high fault currents (with the tie breaker is closed) then the protective devices will be coordinated for lower faults current, i.e. when the tie breaker is open. For this reason, the case where the tie-breaker is closed was considered for protective devices coordination. A 1-Ohm series current-limiting reactor was used to reduce the short circuit current levels. The different feeder paths are examined to assure proper coordination between various protective devices. The characteristics of the protective devices used in the coordination study of the urban benchmark system are given in Appendix C.2. In order to ensure proper coordination, different circuit paths are studied.

Path 1: From Station Bus → Bus 7

This circuit starts from the main substation and extends towards the last bus on the system (Bus 7). This path includes the main feeder relay as well as the main overhead lateral fuse and other individual fuses of each connected load on the lateral. Figure 9 shows the one line diagram as well as the protective device coordination chart. As seen in Figure 9, the S&C SMU K fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. The S&C SMU 20 K fuse was designed to operate as a backup for the S&C SMU K fuse where the coordination time interval is approximately 0.1 seconds. The main feeder relay acts as a backup for the S&C SMU 20 K fuse where the coordination time interval is 0.9 seconds. In addition, the ground settings of the main feeder relay have been coordinated with the S&C SMU 20 K fuse and the coordination time interval is approximately 0.3 seconds. Furthermore, Figure 9 indicates that the ground-over current coordination is fulfilled.

Path 2: From Station Bus → Bus 5 → Bus 6

This circuit starts from the main substation and extends towards bus 5, which is connected to Bus 6 (underground lateral). This path includes the main feeder relay as well as the main underground lateral fuse and the individual fuses of each connected load on the lateral. Figure 10 shows the one line diagram as well as the protective device coordination chart. As seen from Figure 10, the S&C SMU 40 fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. The S&C SMU K fuse was designed to operate as a backup for the S&C SMU 40 fuse where the coordination time interval is approximately 0.1 seconds. The main feeder relay acts as a backup for the S&C SMU K fuse where the coordination time interval is 0.6 seconds. In addition, the ground settings of the main feeder relay have been coordinated with the S&C SMU K fuse and the coordination time interval is approximately 0.4 seconds.

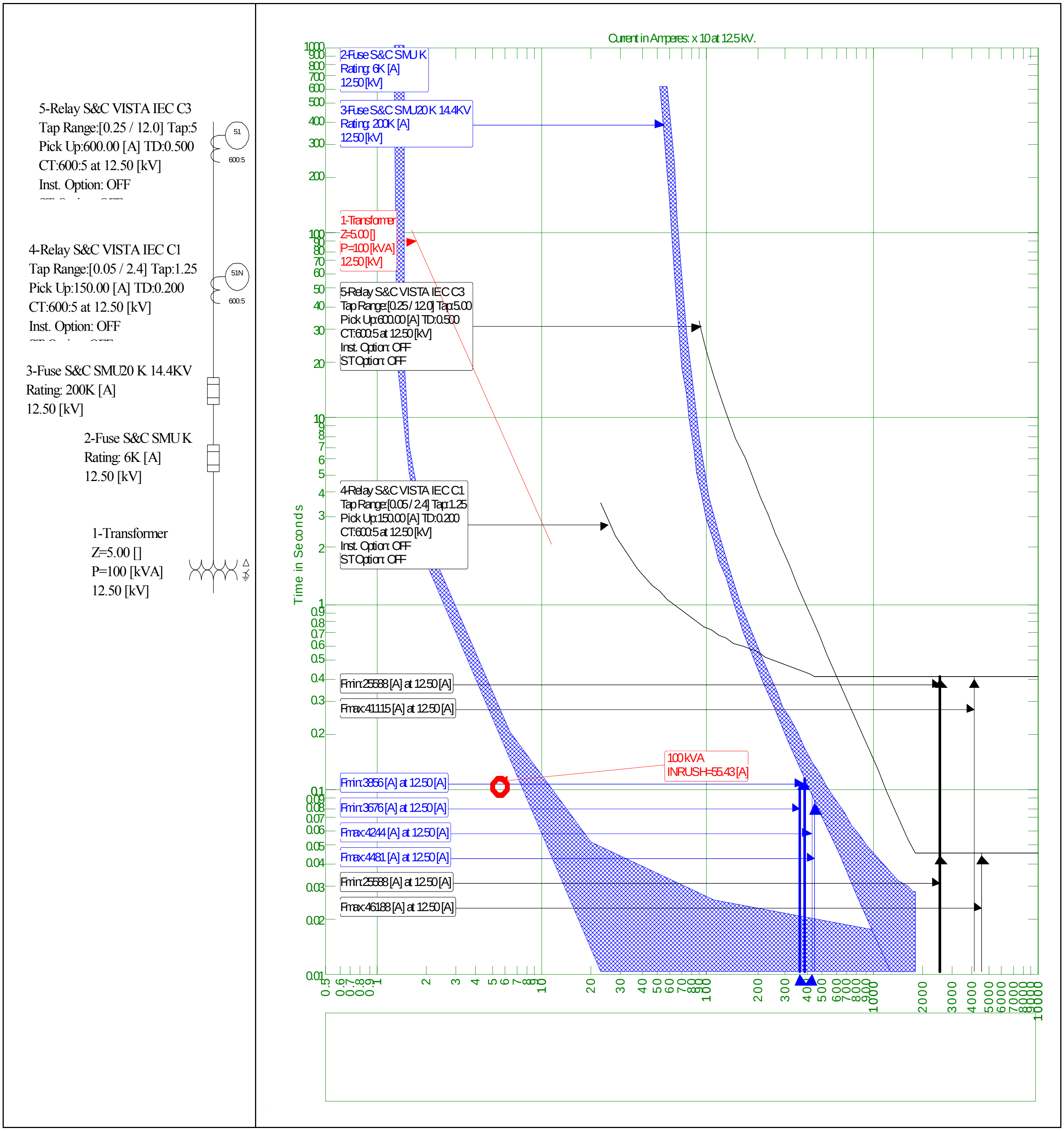


Figure 9 - Urban system coordination chart - path 1: station Bus → Bus 7.

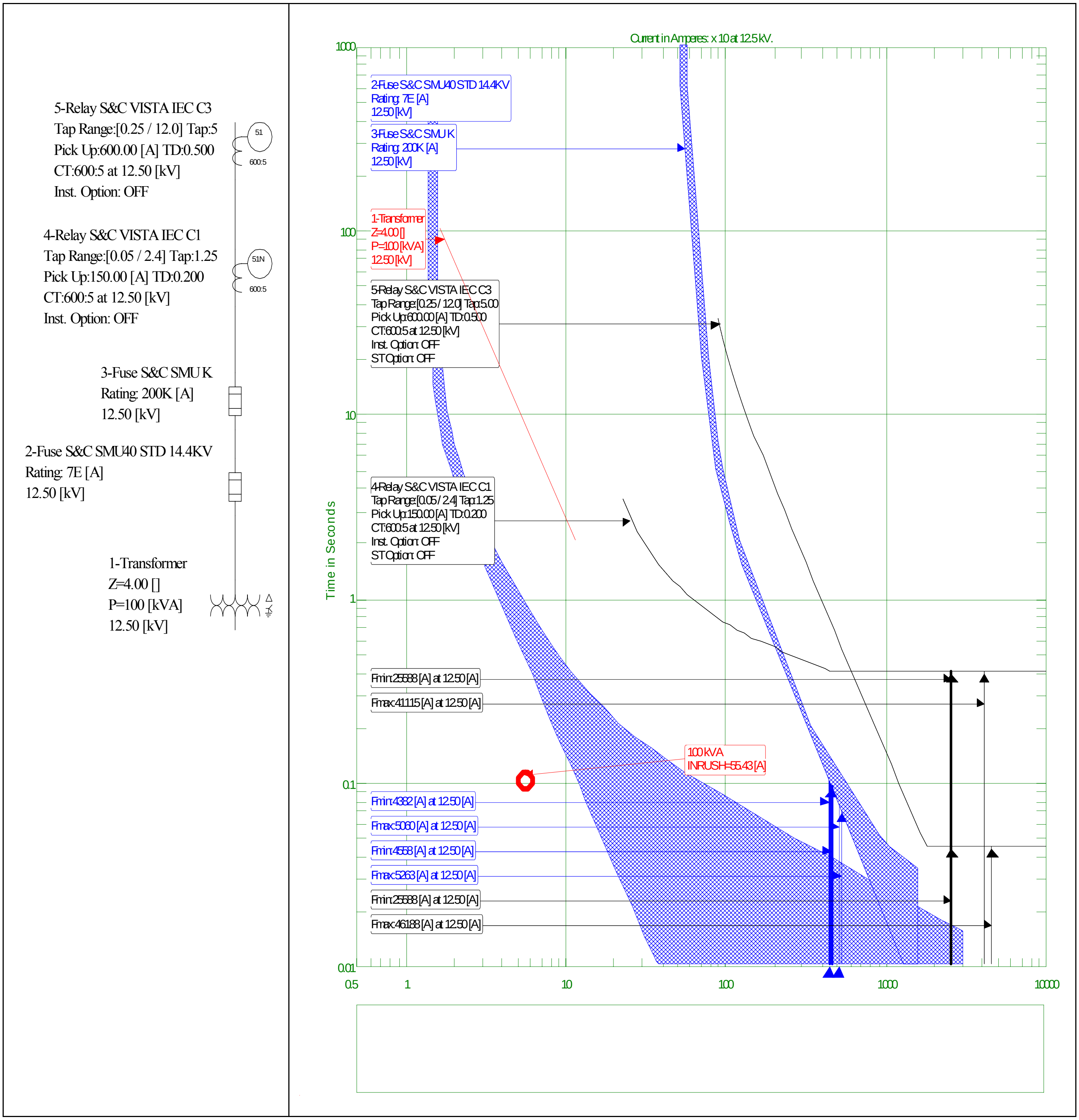


Figure 10 - Urban system coordination chart - path 2: station Bus → Bus 5 → Bus 6.

Path 3: From Station Bus → Bus 3 → Bus 4

This circuit starts from the main substation and extends towards bus 3, which is connected, to Bus 4. This path includes the main feeder relay as well as the main transformer fuse. Figure 11 shows the one line diagram as well as the protective device coordination chart. As seen in Figure 11, the C-H DBU fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. The main feeder relay acts as a backup for the C-H DBU fuse where the coordination time interval is approximately 0.4 seconds. In addition, the ground settings of the main feeder relay have been coordinated with the C-H DBU K fuse and the coordination time interval is approximately 0.4 seconds.

Path 4: From Station Bus → Bus 1 → Bus 2

This circuit starts from the main substation and extends towards bus 3, which is connected, to Bus 4 (motor and spot load). This path includes the main feeder relay as well as the main transformer fuse. Figure 12 shows the one line diagram as well as the protective device coordination chart. As seen in Figure 12, the S&C SMU 20 fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values, motor starting currents and at the same time coordinates with the transformer damage curve. The main feeder relay acts as a backup for the S&C SMU 20 fuse where the coordination time interval is approximately 0.4 seconds. In addition, the ground settings of the main feeder relay have been coordinated with the S&C SMU 20 fuse and the coordination time interval is approximately 0.4 seconds.

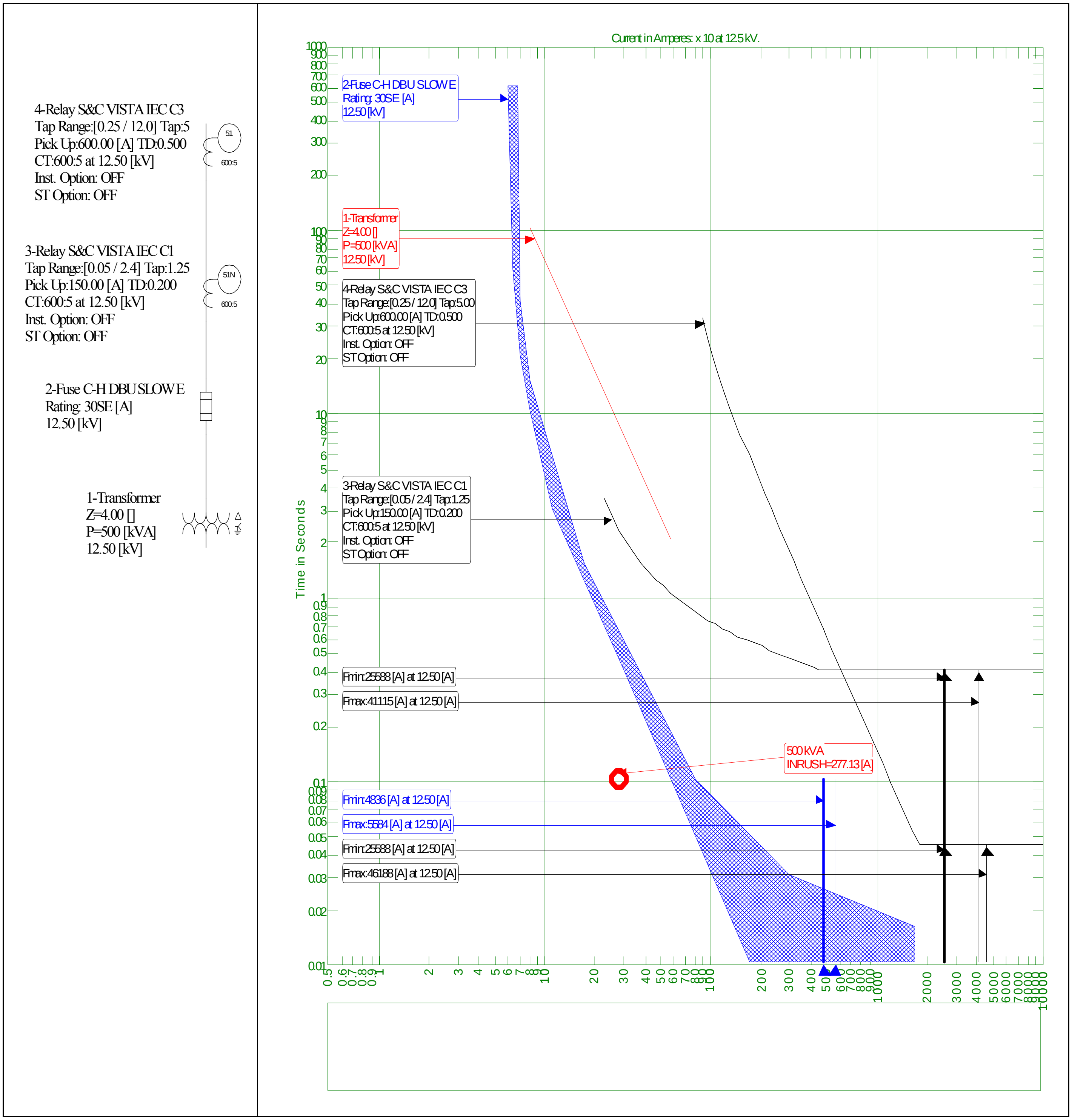


Figure 11 - Urban system coordination chart - path 3: station Bus → Bus 3 → Bus 4.

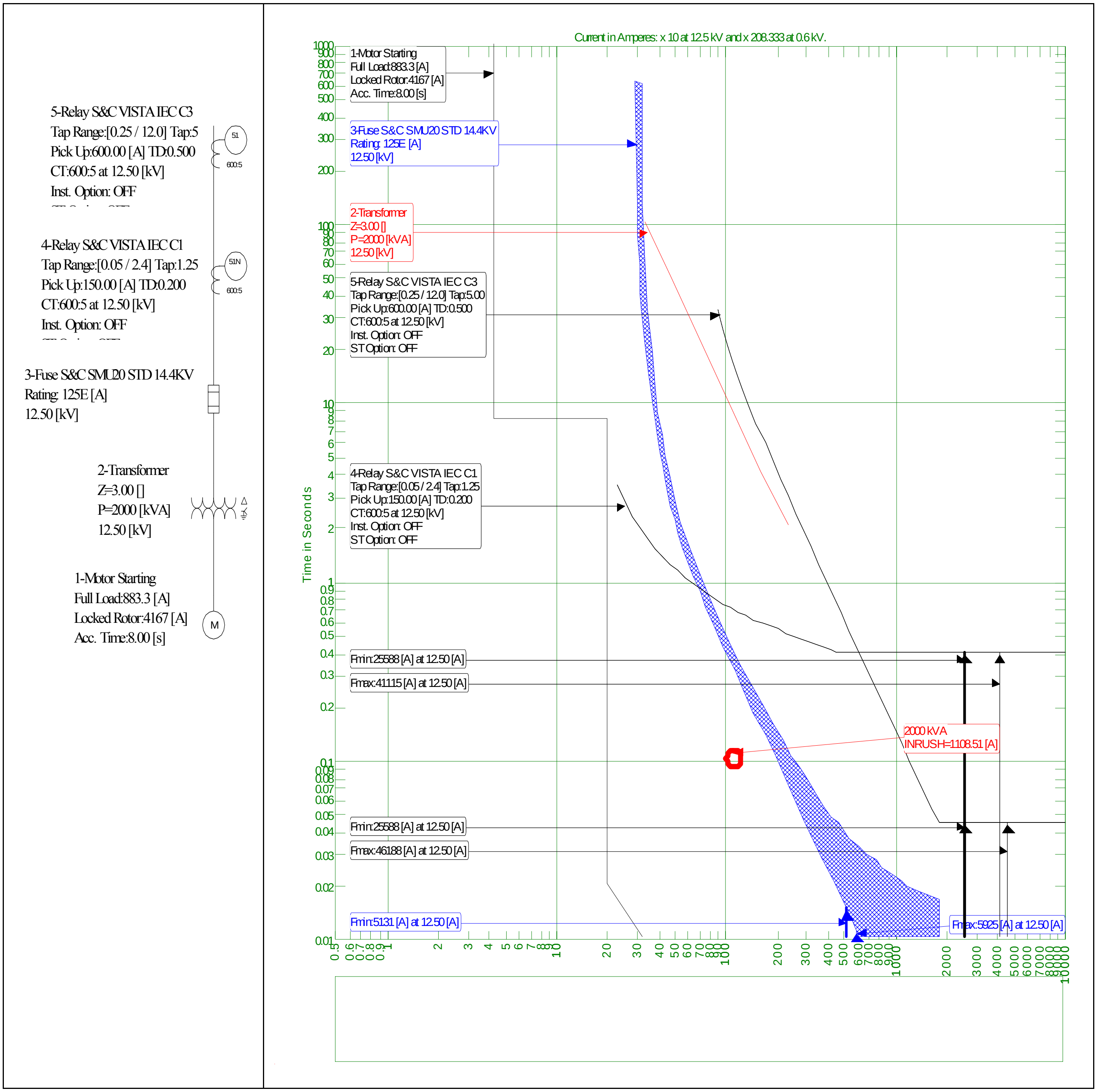


Figure 12 - Urban system coordination chart - path 4: station Bus → Bus 1 → Bus 2.

2.6.3 Suburban Distribution System Protection Coordination

Short circuit analysis was performed on the suburban distribution system given in Figure 4. Protective device coordination is based on the assumption that the station tie-breaker is closed and a 2-Ohm, 400 A, series air core reactor is placed on feeder end head to reduce the short circuit level under 8 KA. The maximum short circuit current with series reactor installed is around 6 kA AMP for three phase bolted fault at the feeder head end. The characteristics of the protective devices as used in the coordination study of the urban benchmark system are given in Appendix C.3. The different feeder paths are examined to assure proper coordination between the various protective devices.

Path 1: From Station Bus → 1 MVA Commercial Load

This circuit starts from the main substation and extends towards the last bus on the system (Bus 5). This path includes the main feeder relays, the recloser, the main underground lateral fuse (F6), and the 1 MVA transformer. Figure 13 shows the one line diagram as well as the protective device coordination chart. As seen from Figure 13, Kearney 40T fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. The T fuse-family is more preferred than the K family in this application, this because the slower response of the T family allows better coordination with the fast curve of the recloser. The fault current setting of the feeder head end instantaneous relay is 1500 A. The recloser is coordinated with the fuse for fuse saving up to 1600 A. Over current relay with delayed time setting and pickup current of 600 A is adjusted to allow for two recloser operations before it clears the fault. So for fault on laterals, which is almost double lateral peak load current and under 560 A, the Kearney 40T fuse will clear the fault. For faults on laterals with short circuit current levels in the range 560 A to 1500 A, the recloser will operate once to allow for fuse saving for non-permanents fault. If the fault persists after the first operation of the recloser, the Kearney 40T fuse will clear the fault. For faults with short circuit current equal to or larger than 1500 A, the instantaneous relay would operate to interrupt the fault. The over current relay time delay is adjusted to allow for two recloser operations during fault before it interrupts the fault. Using the same approach, the ground overcurrent coordination study can be conducted for path 1 as shown in Figure 14.

Path 2: From Station Bus → Bus 4 (Motor Bus)

This circuit starts from the main substation and extends towards (bus 4) which is then connected to the1 MVA induction motor load. This path includes the main feeder relay, the recloser, the main lateral fuse (F5), and the 1 MVA transformer and 1 MVA motor. Figure 15 shows the one line diagram as well as the protective device coordination chart. As seen from Figure 15, the Kearney 40T fuse was chosen such that it will not operate for transformer inrush current, induction motor starting current values and at the same time coordinates with the transformer damage curve. The Kearney 40T fuse would clear faults in laterals for any short circuit current levels ranging from almost the double peak load value up to 560 A. For faults on laterals with short circuit current levels in the range 560 A to 1500 A, the recloser will operate once to allow for fuse saving for non-permanent faults. If the fault persists after the first operation of the recloser, the Kearney 40T fuse will clear it. For faults with short circuit current equal to or larger than 1500 A, the instantaneous relay would operate to interrupt the fault. The over current relay time delay is adjusted to allow for two recloser operations during fault before it interrupts the fault.

Path 3: From Station Bus → Bus 2

This circuit starts from the main substation and extends towards bus 2 which is then connected to residential load areas via underground cable to 21 single phase transformers rated 100 KVA each. This path includes the main feeder relay, the recloser, the main lateral fuse, and the 100 KVA transformer fuse. Figure 16 shows the one line diagram as well as the protective device coordination chart. Similar to previous paths, protection devices coordinate.

Path 4: From Station Bus to 3

Coordination along this path is identical to Path 3.

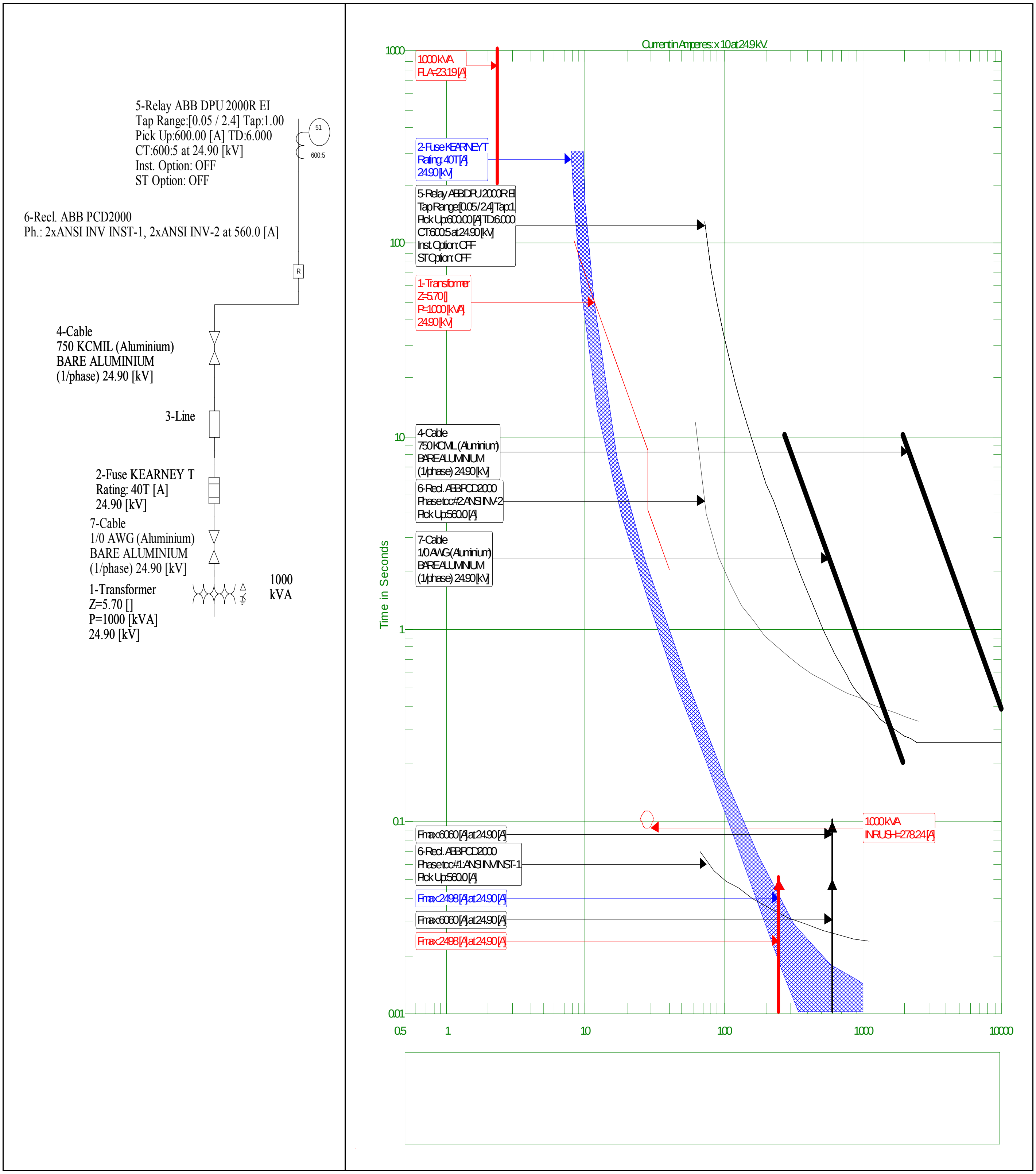


Figure 13 - Suburban system coordination chart - path 1: station Bus → 1 MVA commercial loads.

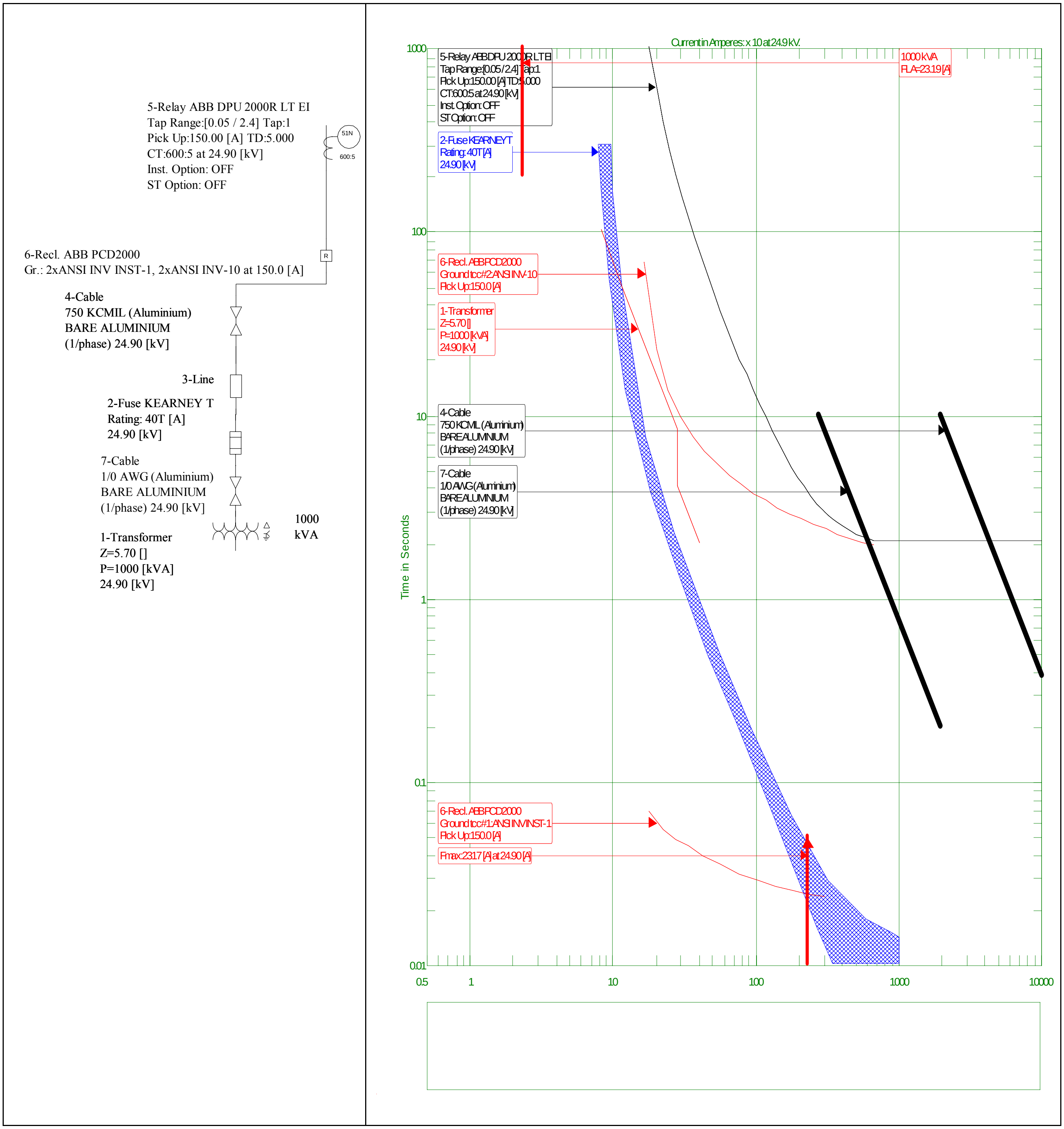


Figure 14 - Suburban system coordination chart - path 1: station Bus → 1 MVA commercial loads – ground coordination.

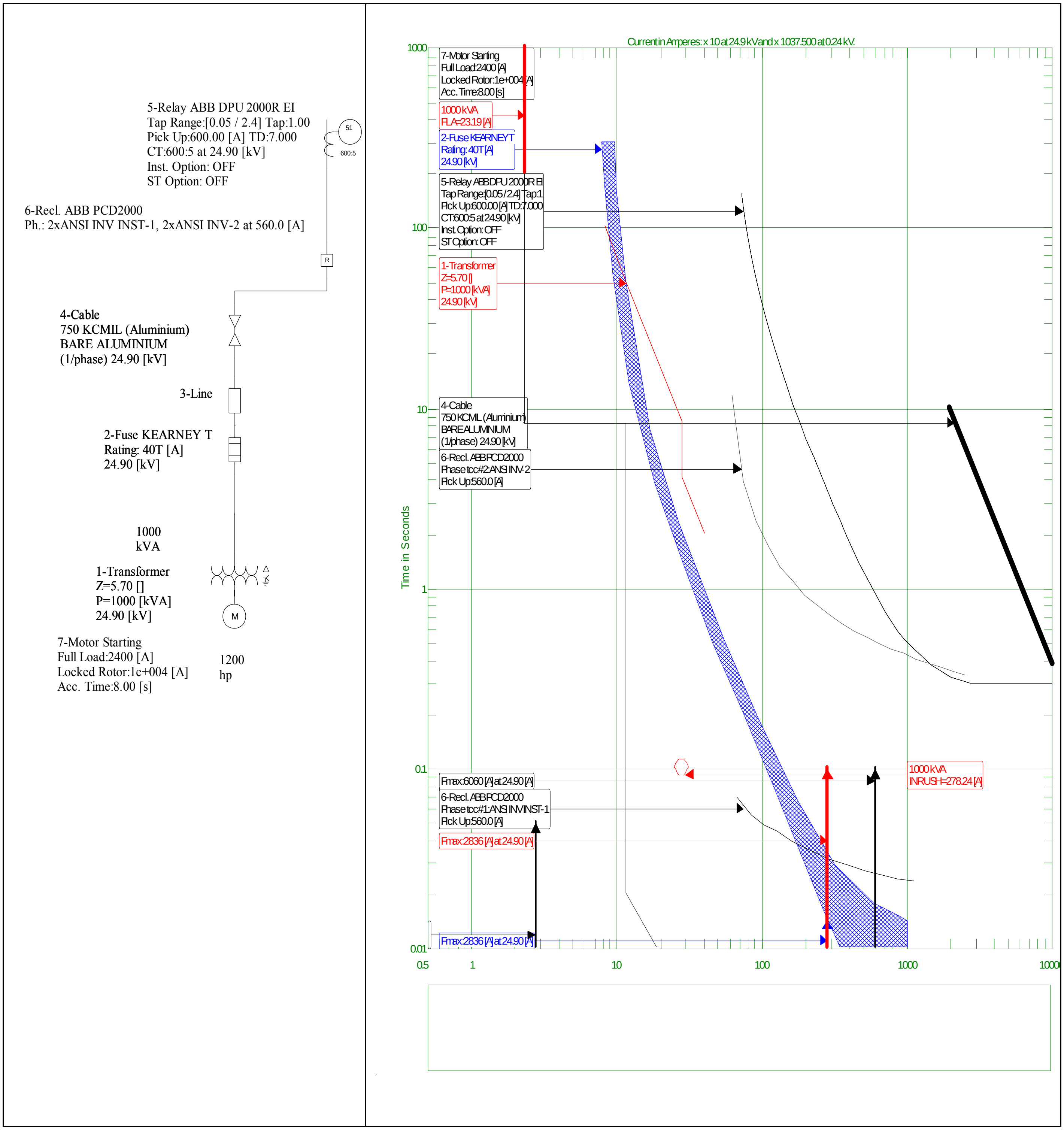


Figure 15 - Suburban system coordination chart - path 2: station Bus → Bus 4 (motor bus).

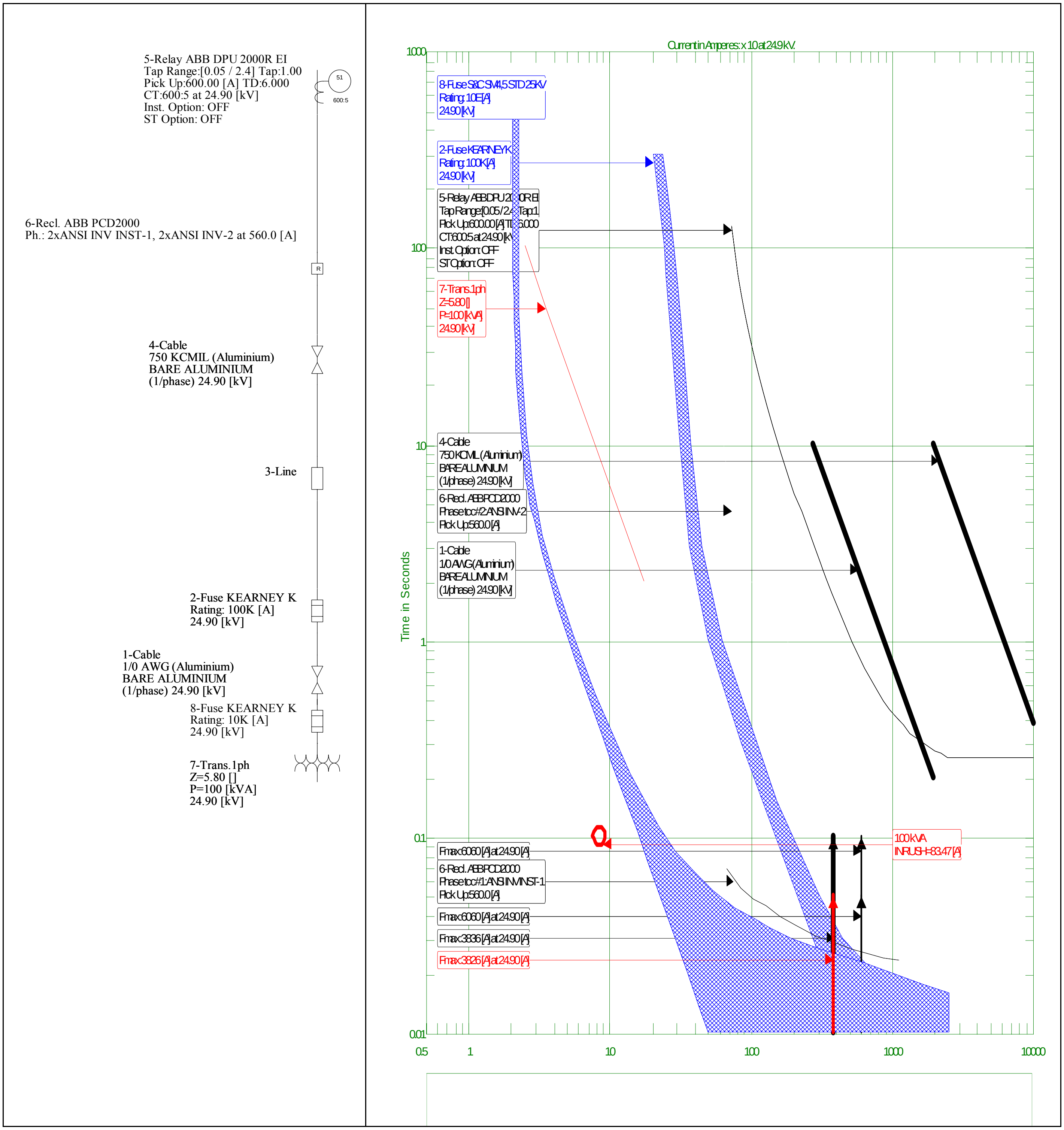


Figure 16 - Suburban system coordination chart - path 3: station Bus → Bus 2.

2.6.4 Rural Distribution System Protection Coordination

Short circuit analysis was performed on the rural distribution system given in Figure 5. The maximum short circuit current was around 19 kA for three phase bolted fault at the feeder head end. The characteristics of the protective devices as used in the coordination study of the rural benchmark system are given in Appendix C.4. The different feeder paths are examined to assure proper coordination between the various protective devices.

Path 1: From Station Bus → Load M13

This circuit starts from the main substation and extends towards load M13. This path includes the main feeder relay, the recloser, the main lateral fuse (F1), and the transformer (T3). Figure 17 shows the one line diagram as well as the protective device coordination chart for this path. As seen in Figure 17, the 40 K fuse (primary transformer fuse) was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. Also, the majority of the through-fault curve of transformer (T3) (including the damage point, which is at the end of the curve) is located over the clearing curve of the fuse. This guarantees safe operation of the transformer under through-fault conditions. Furthermore, the fast curve of the recloser and the fuse coordinate up to 2625 A for the phase protection curve. This band-limited coordination is sufficient for the maximum short circuit current at the fuse location 2128. Furthermore, Figure 17 indicates that the upstream relay totally coordinates with the slow curve of the recloser. Similar observations can be extracted from Figure 18, which illustrates the ground-overcurrent coordination for path 1.

Path 2: From Station Bus → Load M21

This circuit starts from the main substation and extends towards load M21. This path includes the main feeder relay, the recloser, and the main lateral fuse (F5). Figure 19 shows the one line diagram as well as the protective device coordination chart for this path. For this single-phase lateral, the maximum short circuit current is around 1188 A. The band-limited coordination between the recloser and the fuse is very sufficient for the maximum short circuit at the fuse location in this case. Furthermore, the upstream relay totally coordinates with the slow curve of the recloser.

Path 3: From Station Bus → Load M25

Coordination along this path is similar to Path 2 with 1003 A short circuit current at the fuse location.

Path 4: From Station Bus → Load M14

Coordination along this path is similar to Path 2 with 954 A short circuit current at the fuse location.

Path 5: From Station Bus → Load M16

Coordination along this path is similar to Path 2 with 893 A short circuit current at the fuse location.

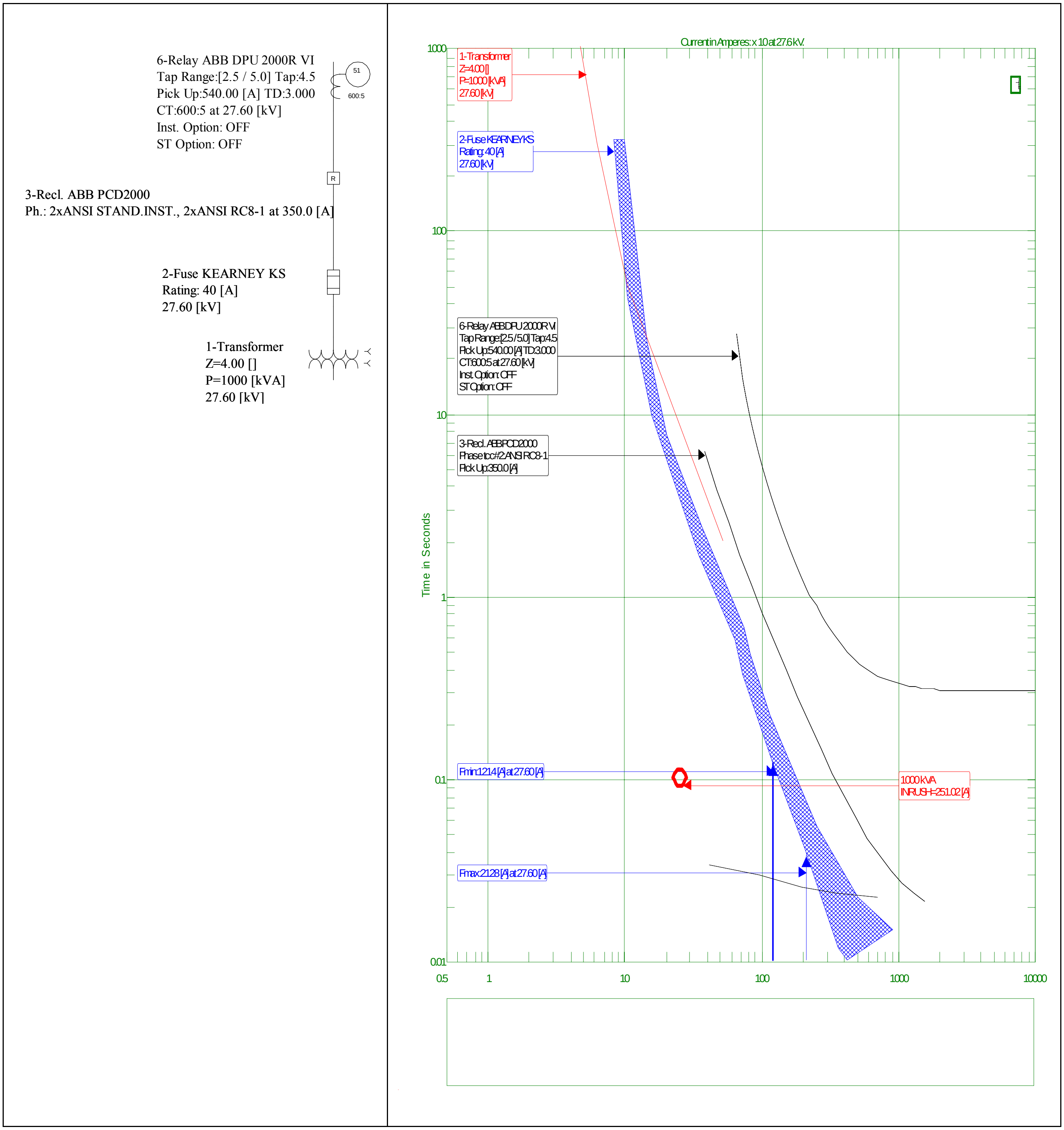


Figure 17 - Rural system coordination chart - path 1: station Bus → Load M13.

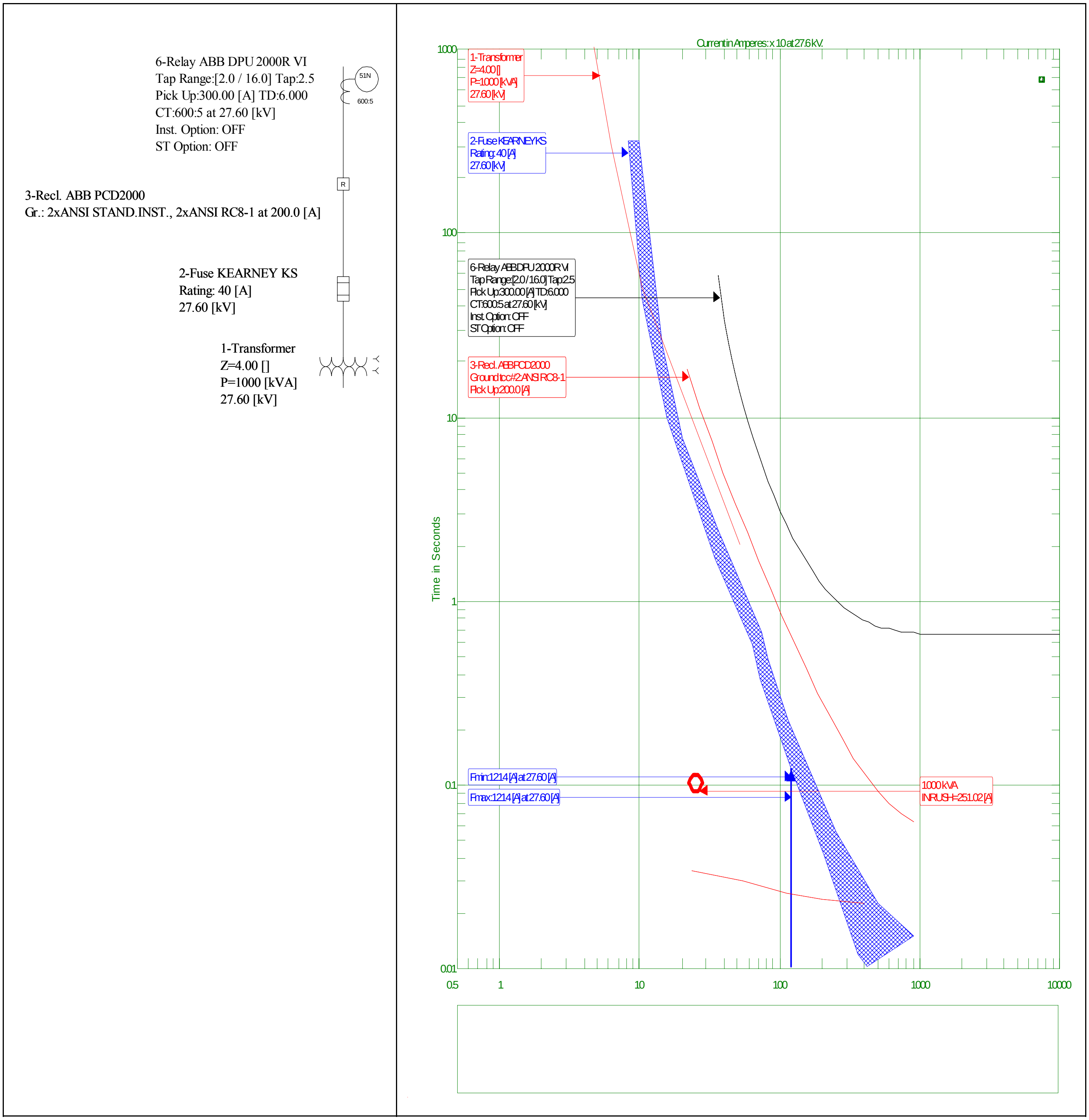


Figure 18 - Rural system coordination chart - path 1: station Bus → Load M13 – ground coordination.

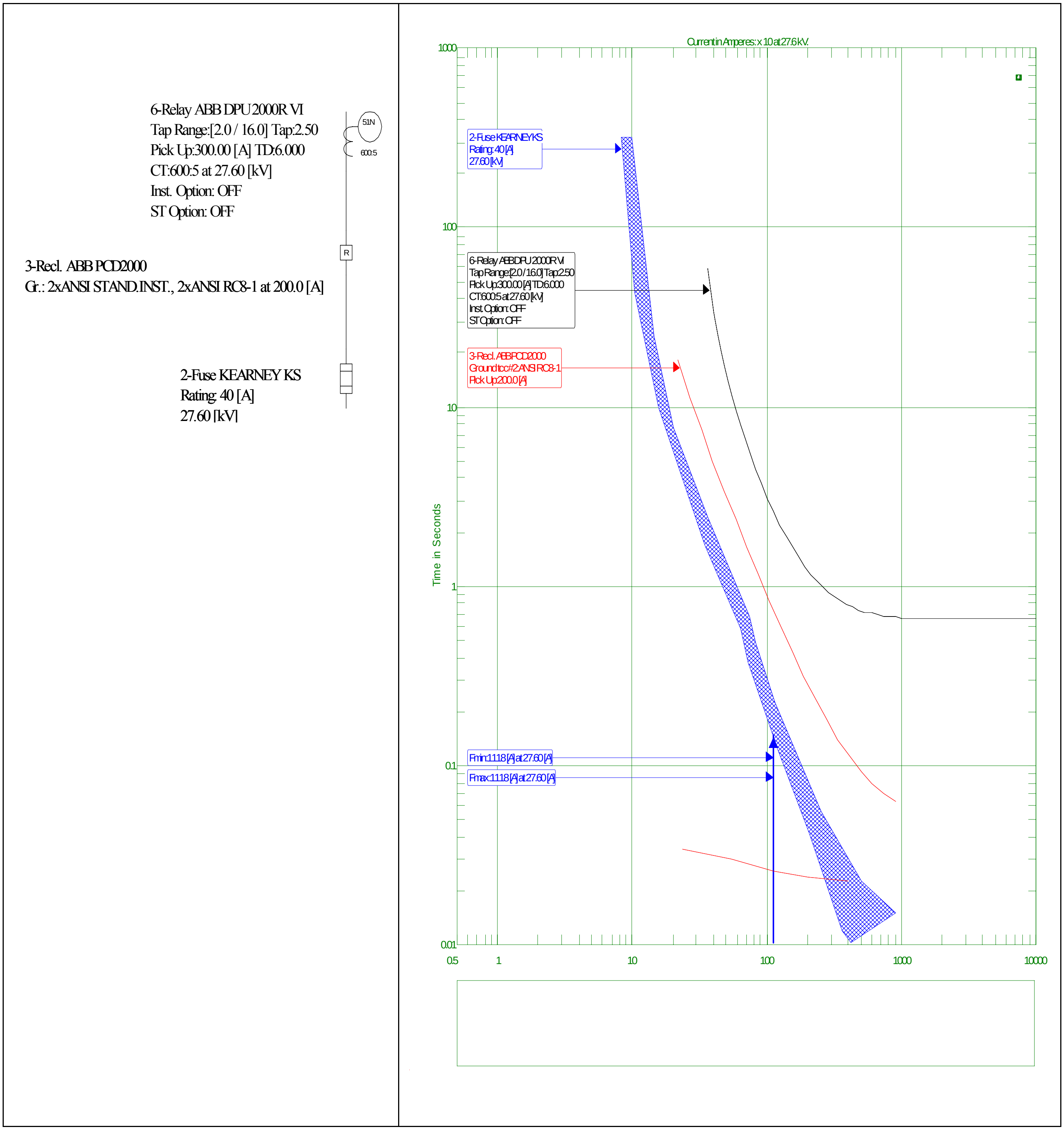


Figure 19 - Rural system coordination chart - path 2: station Bus → Load M21.

2.6.5 Concluding Remarks on Coordination Studies

This section introduces some concluding remarks regarding coordination studies for urban, suburban, and rural distribution networks. Discussion presented in this section is common for urban, suburban, and rural coordination studies.

Transformer protection

- The magnetizing inrush point is modeled on CYMTCC diagrams by 12 times the rated full current of the transformer at 0.1 sec [14]. In all cases, the fuse characteristics was to the right of the inrush point with a safe margin which takes into account any TCC adjustment for pre-load ambient temperature.

- Cold load pick up is not of concern since all fuses have been sized based on peak load conditions with diversity factor equal to unity.

- When transformers carrying load current are subjected to a momentary interruption, fuses will have been carrying the load and will melt slightly faster than when at room temperature [14]. The integrated heating effect of this inrush is considered as that of a current having a magnitude of 14 times the full-load current for duration of 0.1 s [14]. This effect is referred to as hot-load pickup and in all coordination studies discussed above the TCC curve of the fuse is located to the right of the hot-load pickup.

- The primary fuse, selected for transformer protection in all coordination studies, is sized to carry overload currents safely. In addition, it has been sized large enough to coordinate with secondary-side devices. The upper limits for the size of fuse are selected such that it does not exceed three times the transformer's full-load rating [15].

Coordination of fuses and surge arresters

All utilized fuses are cutouts K (Fast) and T (slow) fuses, which don't produce high arc voltages. So the study team found that there is no need to consider the coordination between the utilized cutout fuses and the implemented surge arrestors on urban, suburban, and rural feeders

Coordination of fuses and motor starters

In all applicable cases, the motor starting characteristics are located to the left of the feeding transformer protecting fuse with an acceptable margin. This would insure no unnecessary tripping of the circuit with motor start up. However, it is important to point out that at this stage motor circuit protection is not included at this stage of work.

Ground-faults overcurrent coordination

The ground-overcurrent coordination of current-actuated protective devices has been carried out for different systems under study.

3 Distribution Generation Modeling for Protection Studies

3.1 DG Technologies

There are different types of DGs from the constructional and technological points of view as shown in Figure 20. These types of DGs must be compared to each other to help in taking the decision with regard to which kind is more suitable to be chosen in different situations.

Different types of energy sources can be utilized in DG systems as depicted in Figure 20; however, the impact on the protection of the distribution system is dependent on whether the interfacing scheme is based the direct coupling of rotary machines, such as synchronous generators or induction generators, or whether the DG system is interfaced via a power electronic converter. Table 2 shows the common types of energy resources and the corresponding interfacing technology in DG systems.

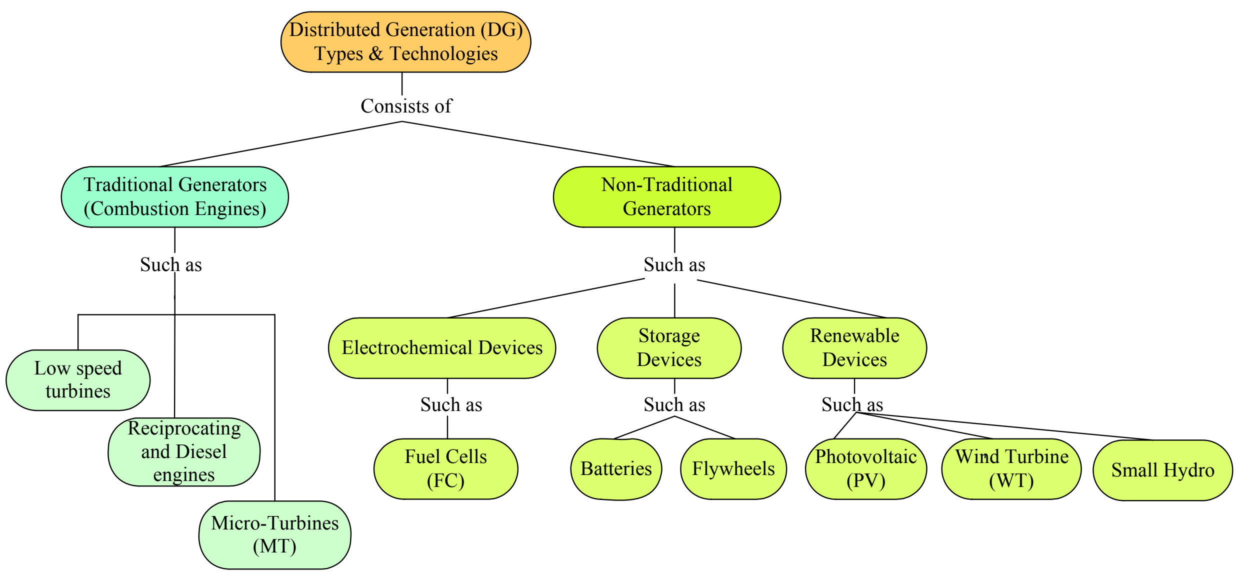


Figure 20 - Distributed generation energy types and technologies.

Table 2. Grid-interfacing technology in DG systems.

Energy Source	Grid-Interfacing Technology
Micro-turbines	Power electronic converter
Fuel cells	Power electronic converter
Photovoltaic	Power electronic converter
Wind turbines Type A: Constant speed wind turbine. Type B: Limited variable speed wind turbine. Type C: Variable speed wind turbine partial-scale frequency converter. Type D: Variable speed wind turbine with full-scale frequency converter.	 Rotary machines (Mainly induction generator) Rotary machines (Mainly induction generator) Rotary machines (Mainly induction generator) Power electronic converter
Traditional internal combustion engines	Rotary machines (Mainly synchronous generator)

3.1.1 Traditional combustion-based energy sources

These traditional sources include: low speed turbines, reciprocating engines, diesel engines, and micro-turbines (MT). In particular, micro-turbine technologies are expected to have a bright future [16]-[18]. They are small capacity combustion turbines, which can operate using natural gas, propane, and fuel oil. In a simple form, they consist of a compressor, combustor, recuperator, small turbine, and generator. There are different types of MTs according to their operation such as gas turbines and combustion turbines.

3.1.2 Non-traditional energy sources

Electrochemical devices: Fuel Cell (FC)

The fuel cell [19]-[21] is a device used to generate electric power and provide thermal energy from chemical energy through electrochemical processes. It can be considered as a battery supplying electric energy as long as its fuels are continued to supply. Unlike batteries, FC does not need to be charged for the consumed materials during the electrochemical process since these materials are continuously supplied. FC is a well-known technology from the early 1960s when they were used in the United States Space Program and many automobile industry companies. FCs can use a variety of hydrogen-rich fuels such as natural gas, gasoline, biogas or propane FCs operate at different pressures and temperatures which varies from atmospheric to hundreds of atmospheric pressure and from 20 to 200oC, respectively.

Renewable devices

Green power is a new clean energy from renewable resources like; sun, wind, and water. Its electricity price is still higher than that of power generated from conventional oil sources. Some types of renewable resources are discussed below:

a) Photovoltaic (PV)

The basic unit of PV is a cell that may be square or round in shape, made of doped silicon crystal. Cells are connected to form a module or panel and modules are connected to form an array to generate the required power. Figure 21 shows a hardware structure of a grid-connected PV system.

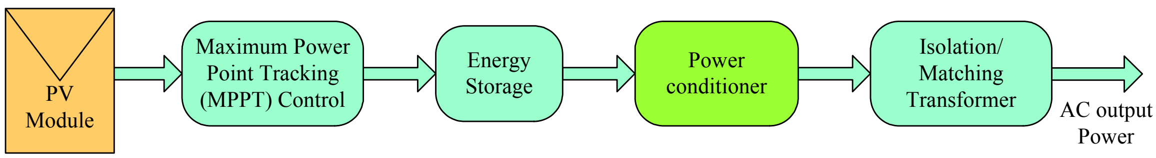


Figure 21 - A hardware structure of a grid-connected PV system.

b) Wind-turbines (WT)

Wind energy is not a new form; it has been used for decades in electrical energy production. A WT consists of a rotor, turbine blades, generator, drive or coupling device, shaft, and the nacelle (the turbine head) that contains the gearbox and the generator drive. Modern wind turbines can provide clean electricity as individuals or as wind farms.

3.2 Benefits and Impacts of DG

DG implementation in the distribution system has many benefits. Some DGs benefits are discussed below [5], [22]-[27]:

From the economical point of view:

- DGs can provide the required local load increases by installing them in certain locations so they can reduce or avoid the need for building new T&D lines, upgrade the existing power systems and reduce T&D networks capacity during planning phase.

- DGs can be assembled easily anywhere as modules (FC-MT and MT-batteries) which have many advantages as

  - They can be installed in a very short period at any location. Each modular can be operated immediately and separately after its installation independent of other modules arrival and not affected by other modular operation failure.

  - The total capacity can be increased or decreased by adding or removing more modules, respectively.

- DGs are not restricted by the centralization of the power as they can be placed anywhere. Thus, DG location flexibility has a great effect on energy prices. However, renewable DGs technology such as hydro, wind, and solar units require certain geographical conditions.

- DGs are well sized to be installed in small increments to provide the exact required customer load demand.

- Remote or stand-alone CHP DGs can be more economical. CHP DGs can use their waste heat for heating, cooling or improving their efficiency by generating more power, which is not applicable in the situation of centralized generation alone.

- DGs can reduce the wholesale power price by supplying power to the grid, which leads to reduction of the demand required.

- Due to deregulation DGs will be of great importance in generating power locally especially if the location margin pricing (LMP) is applied for independent transmission operators (ISO's) and regional transmission organizations (RTO's). LMP can give an indication of where DGs should be installed.

- DGs increase the system equipments, transformers, lifetimes, and provide fuel savings.

- Installing DGs reduce the construction schedules of developing plants. Hence, the system can track and follow the market's fluctuations and/or the peak-load demand growth.

- According to different DGs technologies, the types of energy resources and fuels used are diversified. Therefore, there is no need for certain type of fuels more than others.

From the operational point of view:

- DGs have a positive impact on the distribution system voltage profile and power quality problems.

- DGs can reduce the distribution network power losses distribution loads requirements by supplying some of the distribution load demand, reduce power flow inside the transmission network to fit certain constraints and improve its voltage profile.

- DGs can help in "peak load shaving" and load management programs.

- They can help in system continuity and reliability, as there are many generation spots not only one centralized large generation. Especially in the case of end-user customers with low reliability since when combined with DGs there will be new customer classifications between high need for reliability with high service cost and others with less service cost and relatively lower reliability.

- DGs can be used as on-site standby to supply electricity in case of emergency and system outages (provide local reliability).

- DGs maintain system stability, supply the spinning reserve required.

- DG's capacities vary from micro to large size so they can be installed on medium and/or low voltage distribution network, which give flexibility for sizing and location of DGs into the distribution network.

- They provide transmission capacity release.

- With regard to, environment and society, renewable DGs eliminate or reduce the output process emission.

Impacts of DG

Remarkable benefits can be gained through the utilization of DG in power distribution systems. However, existing distribution systems have not been designed to accommodate DG. Therefore, the connection of DG to utility systems may violate existing planning and operation practices. Critical among these:

- A DG installation may affect the protection system coordination and as result, some modifications of the coordination between the protection devices should be made or a complete replacement of some protection devices should be done.

- Existing distribution system planning practices should be revised to account for DG sizing, location and penetration levels.

- A DG installation changes the traditional routine of distribution planning and engineering by increasing the scope and complexity of what must be considered. Many traditional rules of thumb and guidelines may no longer be valid.

- The integration of DG and other storage devices into the utility grid will alter the contemporary practice of having a unidirectional power flow, which remarkably affects the coordination of the utility protection systems.

- The integration of DG and other storage devices into the utility grid will affect the power quality. Positive and negative impacts on power quality should be studied.

- With higher penetration levels of DG, system stability is highly affected. Stability studies should be conducted to ensure stable operating conditions.

- The dynamic interaction between DG and grid dynamics should be identified.

- The managerial impracticability of small DG installations participating in the hourly markets similar to large centralized generating facilities should be addressed. A robust energy market model including DG should be developed.

3.3 Modeling of Distributed Generators for Protection Coordination Studies

Depending on the nature of the study, different models of a DG unit can be developed. In protection coordination studies, the main objective is to identify and model the short circuit contribution of the DG unit at fault conditions.

As seen in Section 2, three main types of generators can be used to convert the energy produced by all types of distributed resources into useful electrical energy, namely they are: 1) synchronous generators, 2) induction generators, and 3) inverter-based generators. Modeling of these generators, for protection coordination studies, is presented in the following subsections.

3.3.1 Synchronous Generators

Synchronous generators are mainly utilized in grid interfacing of diesel and gas-fired engines and small hydro DG systems.

Synchronous generators approximate models, which are represented by a single driving voltage in series with equivalent impedance, are utilized for short circuit studies. The value of the equivalent impedance considered in the analysis depends mainly on time frame of the analysis. To explain this point a brief discussion on short circuit current characteristics is given below.

When a three-phase fault occurs at the generator terminals, a short circuit current can be represented by the following equation [28].

$$i(t) = E\sqrt{2}\left[\left(\frac{1}{X_d''} - \frac{1}{X_d'}\right)e^{-t/T_d''} + \left(\frac{1}{X_d'} - \frac{1}{X_d}\right)e^{-t/T_d'} + \frac{1}{X_d}\right]\cos\omega t - \frac{E\sqrt{2}}{X_d''}e^{-t/T_a} \tag{1}$$

where,

E: single-phase r.m.s. voltage before fault
X_d'': subtransient reactance
X_d': transient reactance
X_d: synchronous reactance
T_d'': subtransient time constant
T_d': transient time constant
T_a: aperiodic time constant

From the short circuit current point of view, the electrical variables evolve as if the machine reactance was variable and developed according to the three following periods:

– X_d " period (Direct-axis saturated subtransient reactance period): The X_d " is the apparent reactance of the stator winding at the instant short-circuit occurs with the machine is producing its rated voltage and at no load condition. This reactance determines the current flow during the first few cycles after short-circuit initiation. The duration of this period is around 1-3 cycles after the initiation of the fault.

– X_d ' period (Direct-axis saturated transient reactance). The X_d ‘ is the apparent reactance of the stator winding several cycles after initiation of the fault with the machine at rated voltage and at no load condition. The time period for which the reactance may be considered X_d' can be up to a half second or longer, depending upon the design of the machine and is determined by the machine direct-axis transient time constant.

– X_d period (Direct-axis synchronous reactance): The X_d is the direct-axis synchronous reactance to be considered after the transient period. It is the ratio of the fundamental frequency component of reactive armature voltage (E_d) to the fundamental-frequency direct-axis positive-sequence component of armature current (I_d) under sustained balanced conditions with rated field current applied.

In the order given, these reactances take a higher value for each period:

$X_d'' < X_d' < X_d$

This leads to a gradual decrease in the short circuit current. A typical short circuit waveform is given in Figure 22.

As it can be seen from the above analysis, the most important characteristics of synchronous machines when calculating short circuit currents are the internal reactances and resistances. In practice, a single machine reactance is assumed to vary (with time) from a subtransient to a transient to a sustained or steady state impedance; these variations control the ac component of the fault current. The resistance controls the rate of decay of the dc component. The machine time constants determine the rate of decay of the ac current components.

One simplified calculation technique of increasing the reactance from X_d" in increments as time passes after the short circuit is initiated accounts for the ac current decay, assuming the voltage is constant. This model obtains the machine decaying ac current contributions in the equivalent circuit without changing the circuit driving voltage. This technique is widely used and accepted by the industry. Typical reactance multiplying factors to be applied to X_d" depend on whether the synchronous machine is a generator or a motor. Typical reactance multiplying factors are given in [29]. Figure 23 shows the short circuit model of a synchronous machine [28]-[29].

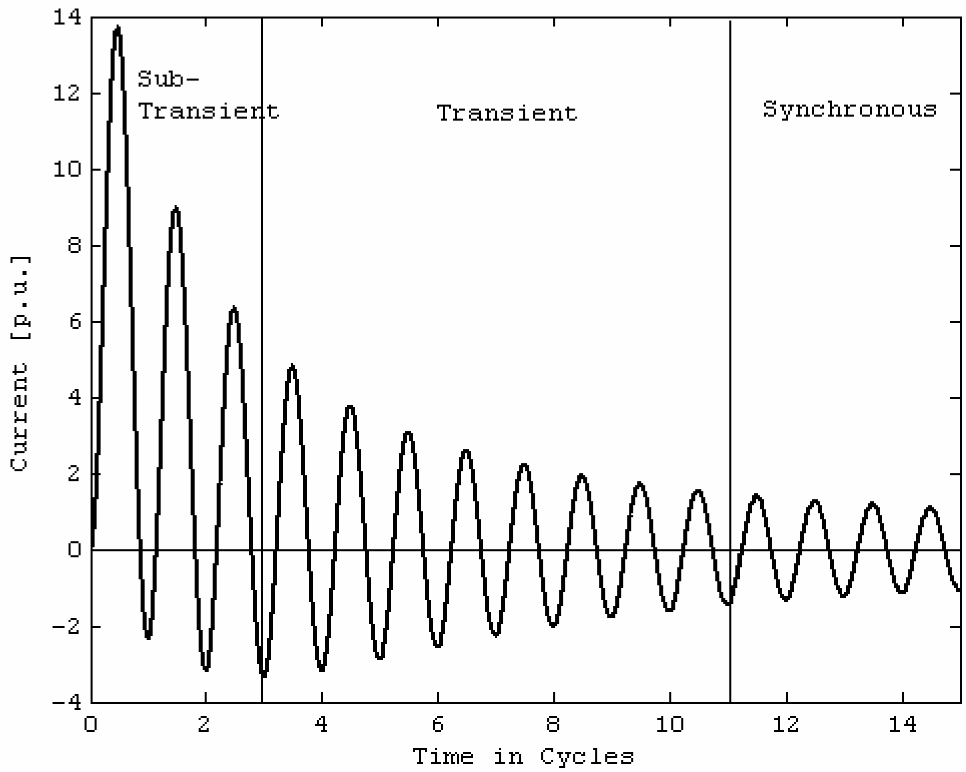
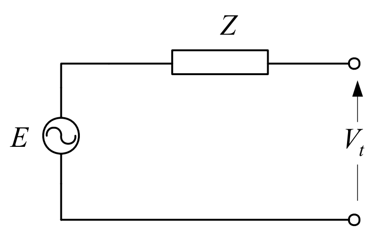


Figure 22 - A typical short circuit current of a synchronous generator.



V_t = Stator terminal voltage

E = Internal back EMF voltage

Z = Machine reactance at (X_d", X_d', or X_d)

Figure 23 - Synchronous machine positive sequence model for short circuit studies.

The initial magnitude of the ac component is calculated using the subtransient reactance X_d" of the machine. The initial magnitude of the dc component for short-circuit calculations is equal to the crest value of the initial ac component, assuming the fault current in one phase has the maximum possible asymmetry. Depending on the synchronous machine time constants, the transition of fault current from subtransient to transient to synchronous will vary. If the field to the machine remains energized, then a steady-state fault current will exist due to continuous replenishing of stator flux energy that is removed by the fault. Otherwise, the fault current from a synchronous machine will decay to zero.

In Short circuit studies, the theory of symmetrical component is utilized to calculate the value of short circuit current; this introduces the concept of negative sequence reactance and zero sequence reactance of synchronous machine. Negative sequence reactance is the apparent reactance determined by placing a line-to-line fault on the terminal of the generator at rated voltage. Zero sequence reactance is the apparent reactance determined by placing a line-to ground fault on the terminal of the generator so that rated current flows. IEEE STD 115-1995 describes how to obtain values of negative sequence and zero sequence reactances of synchronous generators [28].

CYMDIST software utilizes the model shown in Figure 8 to represent the short circuit contribution of a synchronous generator. The synchronous generator model available within CYMDIST allows the user to input the value of subtransient reactance, transient reactance, steady state reactance as well as the zero sequence reactance and grounding impedance for star connected generators [30]. Also, the software provides an impedance estimation function, which might help in the case of unknown machine parameters.

3.3.2 Induction Generators

3.3.2.1 Overview of Induction Generators Types in Wind Turbines

Induction generators are most commonly used in wind turbines for wind generation. The induction generator has several advantages, such as robustness, simple structure, and relatively low price. The major disadvantage is that the stator needs a reactive magnetizing current. The reactive excitation power is supplied by the grid (this might include local VAR generation at the point of coupling) or by a power electronic system.

In the case of AC excitation, the created magnetic field rotates at a speed determined by the number of poles in the winding, the frequency of the current, and the synchronous speed. When the rotor spins at a speed that is higher than the synchronous speed, an electric field is induced between the rotor and the rotating stator field due to the relative motion, which induces a current in the rotor windings. The interaction between the rotor and stator magnetic fields results in the torque acting on the rotor.

The rotor of an induction generator can be short-circuited (squirrel cage rotor) or it could be a wound rotor. Figure 24 shows four different dominating types of induction generators used in wind turbines [31].

A. Squirrel Cage Induction Generator (SCIG)

The SCIG is commonly used in direct-connected wind turbines, which are characterized by constant speed operation (Type A – wind turbine). The generator and the wind turbine rotor are coupled via a gearbox as the optimum rotor and generator speed ranges are different. The generator is connected to the grid via a transformer as seen in Figure 24.a. Since the SCIG always draws reactive power form the grid, a capacitor bank, for reactive power compensation, is used with this configuration. A soft-starter is normally used to achieve smooth grid-connection.

The main drawback of this configuration is that the wind fluctuations are converted into electrical power fluctuations through the direct grid-connection. These lead to voltage fluctuations at the point of common coupling; particularly in weak grids. Also, the mechanical structure of must be able to tolerate high mechanical stress imposed by variable speed operation.

B. Wound Rotor Induction Generator (WRIG)

In the case of a WRIG, the electrical characteristics of the rotor can be externally controlled, and thereby a rotor voltage can be applied. The windings of the wound rotor can be externally connected through slip rings and brushes or by means of power electronics converters, which may or may not require slip rings and brushes. By using power electronics converters the machine can be treaded as a doubly excited system, where the power can be extracted or injected to the rotor circuit. Therefore, the generator can be magnetized from either the stator circuit or the rotor circuit. It is also possible to recover the slip energy from the rotor circuit and feed it into the stator circuit. In wind turbine technology, the following WRIG configurations are commonly used:

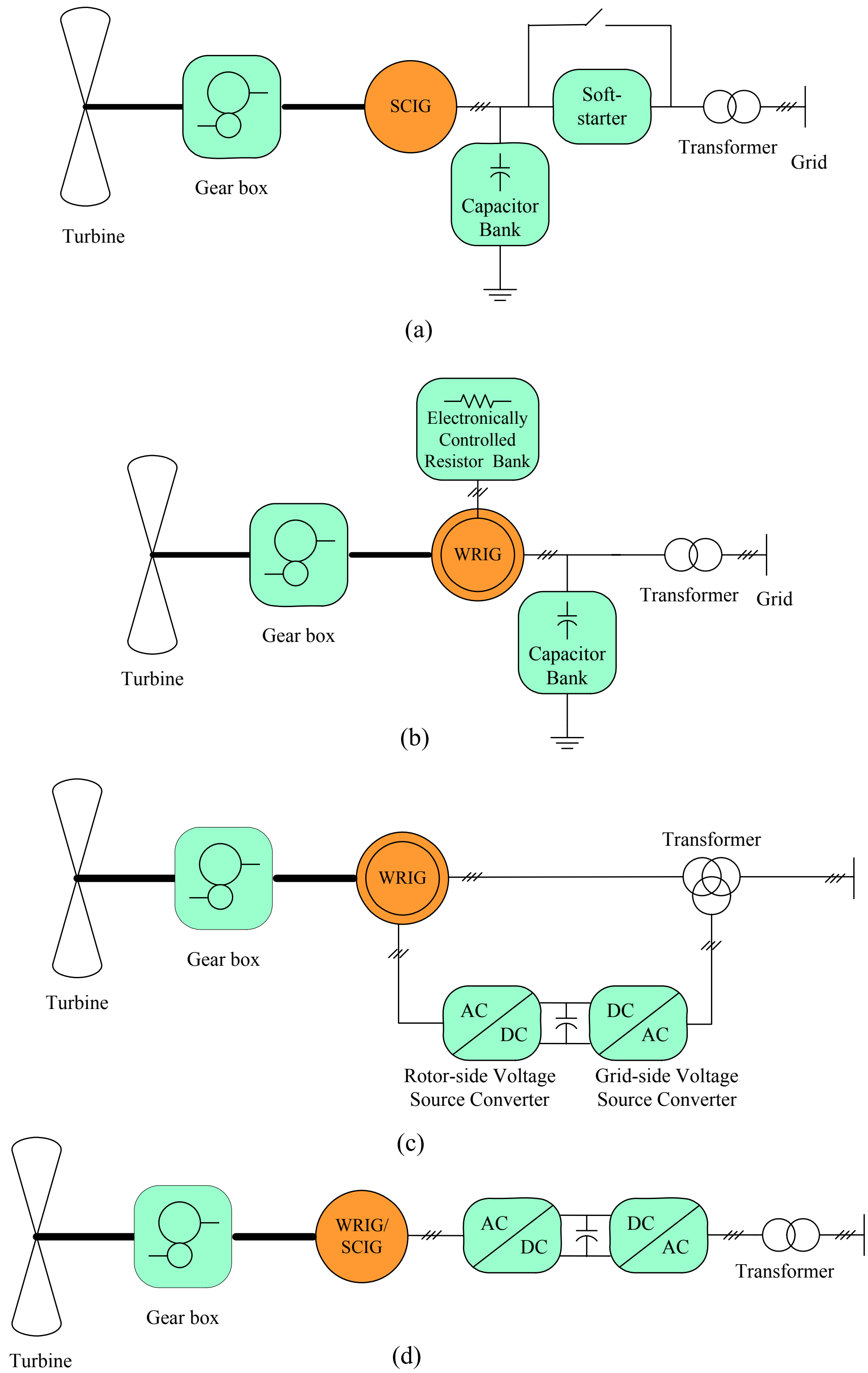


Figure 24 - Induction generators in wind turbine. (a) SCIG in constant speed wind turbine (Type A). (b) WRIG in a limited variable speed wind turbine (Type B). (c) WRIG (DFIG configuration) in a variable speed wind turbine (Type C). (D) WRIG in a full-scale converter topology (Type D).

WRIG with variable external rotor resistance

In this configuration, a variable external rotor resistance is attached to the rotor windings as depicted in Figure 24.b. This configuration is commonly used in Type – B wind turbine (limited variable speed). The slip of the generator is controlled through the variable resistance attached to the rotor circuit. The resistance is changed by means of an electronic converter mounted on the rotor shaft. The stator of the generator is directly connected to the grid.

The advantages of this generator configuration are: a simple circuit topology, the absence of the slip rings, and improved speed control range as compared to the SCIG. To a certain extent, mechanical and electrical fluctuations, caused by gusts, can be reduced. However, it still requires reactive power compensation system. Therefore, local VAR generation is usually used with this configuration. Among other disadvantages, 1) the speed control range is limited as it depends on the size of the variable rotor resistance, 2) the slip power is dissipated in the rotor resistance as losses, and 3) only poor control of active and reactive power is achieved.

Doubly-fed Induction Generator (DFIG)

The DFIG is an interesting concept and it has a widespread utilization. The DFIG consists of a WRIG with the stator winding directly connected to grid and with the rotor windings connected to a bi-directional back-to-back voltage source converter. The term "doubly-fed" refers to the fact that the voltage on the stator is applied from the grid and the voltage on the rotor is induced by the power converter. With this configuration, variable speed operation is allowed over a wide range. The converter compensates the difference between the mechanical and electrical frequency by injecting a rotor current with a variable frequency. The power converter consists of two converters, the rotor-side converter and the grid-side converter, which are controlled independently. The main idea is that the rotor-side converter controls the active and reactive power by controlling the rotor current components, while the grid-side converter controls the DC link voltage and ensures a unity power factor operation (zero reactive power).

The DFIG has several advantages, such as, independent active and reactive power control, the ability to work at a unity power factor (doesn't need to be magnetized from the grid), and it is capable of generating reactive power that can be delivered to the stator by the grid-side converter. A drawback of the DFIG is the inevitable need for slip rings and the lower robustness as compared to the SCIG.

The DFIG is normally used with Type – C wind turbine (variable speed with partial scale frequency converter) as shown in Figure 24.c.

WRIG/SCIG with Full-Scale Frequency Converter

This configuration utilized a WRIG or a SCIG with a full variable speed wind turbine. This is achieved by connecting the generator to the grid via a full-scale frequency converter as seen in

Figure 24.d. The frequency converter performs the reactive power compensation. The main drawback of this configuration is the high cost of the converter, as it has to carry the full power injected to the grid. On the other hand, this configuration enables the direct drive connection between the turbine and the generator; therefore, the gearbox can be eliminated.

4.3.3.2 Modeling of an Induction Generator for Short Circuit Studies

In protection coordination studies, short circuit analysis is the starting point. In short circuit analysis, wind turbine representation (model) will depend on the specific generator technology applied. In general, the short circuit model must include the component that will contribute to the fault current. For fixed-speed wind turbines (Types A and B) with induction generators, the machine itself is an appropriate representation as it is directly connected to the grid [31]-[33]. From the point of view of short circuit studies, connection of these types of wind turbines to the distribution feeders is very similar to serving very large motor loads. For variable speed wind turbines with DFIG (Type C), the machine itself is an appropriate representation as well [31]-[33]. Even though the DFIG utilizes a power electronic converter to control the rotor quantities, the majority of the generated power is injected to the grid via the machine stator winding. Since the rotor power is much smaller than the injected grid power, the machine itself is an appropriate representation in short circuit studies [31]-[33]. For variable speed wind turbines with full-load converters (Type D), the generator is decoupled from the grid, as the machine is connected to the grid via a converter. The contribution of the converter to the short circuit depends on the control mode. Since, the thermal time constants of semiconductor devices are very short, the grid-connected converter can be easily damaged by fault currents, and overcurrent protection is essential for the converter. The overcurrent protection rapidly disconnects the converter from grid. Generally, the converter will be disconnected if the short current reaches 150%-200% of the rated current for half a cycle [34], [2].

Based on the abovementioned discussion, types A, B and C wind turbines can be represented by the machine model during the short circuit. During a thee-phase short circuit, the terminal voltage of the induction generator remarkably decreases (it becomes zero for a fault at the generator terminals). Since the stator flux is directly proportional to the grid voltage, the stator flux vector slows down or stops rotating (if the terminal voltage is zero). This produces a dc component in the rotor flux, which is stationary with respect to the rotor and it continue to rotate with the rotor by the input wind torque. This will thus add an alternating component to the dc component of the stator flux. The maximum value that the currents reach depends mainly on the stator and rotor leakage inductance. The combination of these inductances is represented by the subtransient reactance of an induction machine. The speed at which the dc component will decay is mainly determined by the subtransient time constants, which corresponds to the subtransient reactance. Since the machine does demagnetize, the fault contribution lasts over the subtransient period only (around 3 cycles). The three-phase short circuit current of at the terminals of an induction machine can be represented by the following equation [33]:

$$i(t) = \frac{V\sqrt{2}}{X_s^{"}}\left[e^{-t/T_s"} \cos\alpha - (1-\sigma) e^{-t/T_r"} e^{j\omega s} \cos(\omega_s t + \alpha) \right] \quad (2)$$

where,

V: single-phase r.m.s. voltage before fault
X_s ": subtransient reactance
T_s": subtransient stator time constant
T_r": subtransient stator time constant
α: phase angle of stator voltage at the instant of short circuit
ω_s: synchronous angular speed
σ: machine leakage factor

Figure 25 shows a typical three-phase short circuit waveform of an induction machine.

It should be noted that the aforementioned facts apply for both types, the SCIG and the WRIG [33]. In the case of the WRIG with doubly feed technology, the voltage dip will cause large (oscillating) currents in the rotor circuit of the DFIG to which the power electronic converter is connected. A high rotor voltage will be needed to control the rotor current. When this required voltage exceeds the maximum voltage of the converter, it is not possible any longer to control the current as desired. This implies that large currents can flow, which can destroy the rotor-side converter. In order to avoid breakdown of the converter switches, a crowbar is connected to the rotor circuit. This can, for example, be done by connecting a set of resistors to the rotor winding via an electronic circuit upon the detection of a fault. When the rotor currents become too high, the electronic circuit is fired and the high currents do not flow through the converter but rather into the crowbar resistors. In this case, the damping of the rotor increases and short circuit current level and duration are reduced.

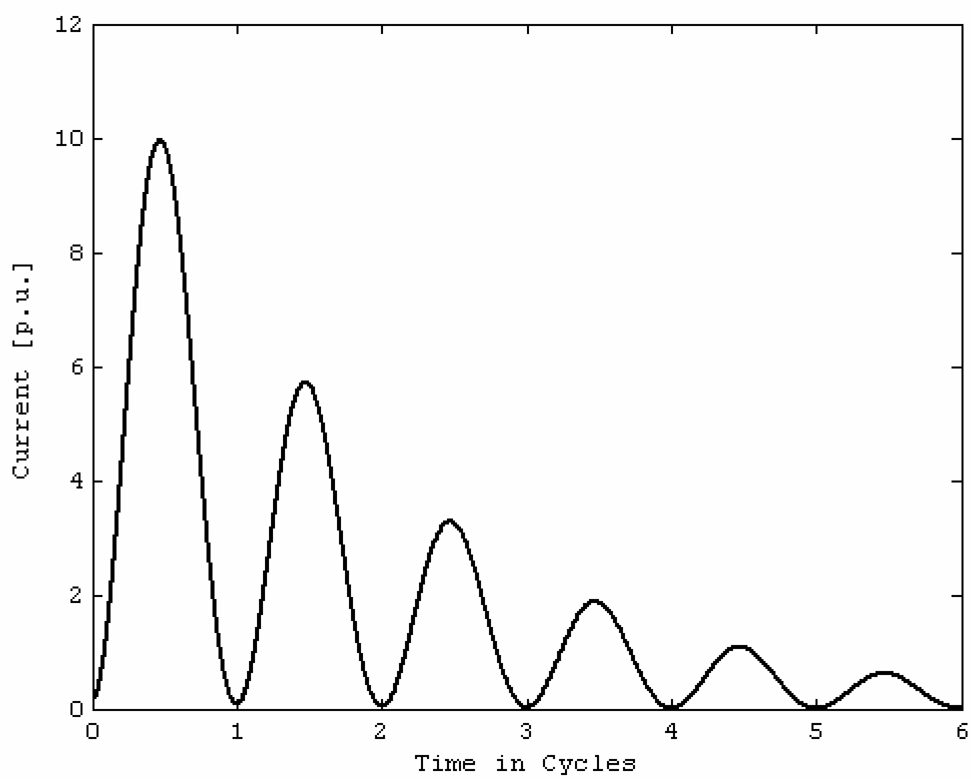
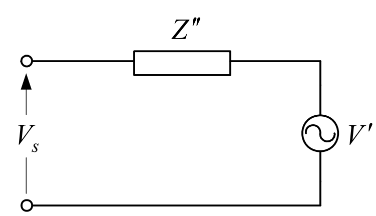


Figure 25 - A typical short circuit current of an induction generator.



V_s = Stator terminal voltage

V' = Voltage behind transient impedance

Z'' = Subtransient impedance at the subtransient reactance X''

Figure 26 - Induction machine transient equivalent circuit.

Based on the aforementioned discussion, the induction generator can be represented by a back EMF behind the machine subtransient impedance. Figure 26 depicts the induction generator representation in short circuit calculations [29], [32]. The machine contributes to the short circuit current during the subtransient period as discussed above. The value of the subtransient impedance (along with the pre-fault voltage) determines the initial amplitude of the short circuit current in the subtransient period (normally in the range of 6-10 p.u. for wind turbine generators). The initial magnitude of the dc component for short-circuit calculations is taken to be equal to the crest value of the initial ac component. This is based on the conservative assumption that the current in one of the phases will have the maximum possible asymmetry. It is accepted practice to use the known or estimated locked rotor reactance as the subtransient reactance in case of unknown subtransient reactance. The IEEE – Violet Book® [29] gives a very useful guideline in estimating the subtransient reactance of an induction machine, in case of unknown machine parameters.

CYMDIST software utilizes the model shown in Figure 26 to represent the short circuit contribution of an induction generator (this includes the SCIG, WRIG, and DFIG). The induction generator model available within CYMDIST allows the user to input the value of subtransient reactance [30]. Also, the software provides an impedance estimation function, which might help in the case of unknown machine parameters.

3.3.3 Inverter-Based Generators

3.3.3.1 Overview of Inverter-Based Generators

Unlike large generators, which are almost exclusively 50/60Hz synchronous machines, DG include variable frequency (variable speed) sources (such as wind energy), high frequency (high speed) sources (such as micro-turbine generators), and direct energy conversion sources producing dc voltages (such as fuel cells and photovoltaic). In these types of DGs, a voltage source inverter is necessary to facilitate DG interfacing to the utility, as shown in Figure 27. Current inverter technologies enable ratings from 1 kW to 1000 kW. The inverter is considered the most important functional block in the inverter-based DG. Beside converting DC voltage to AC voltage and controlling the power flow form the DG source to the utility grid, it is also might be used to: [35]-[36]

supply controlled reactive power and mitigate power quality problems such as voltage deviation, total harmonic distortion, and flickering.

provide means to anti-islanding detection. The IEEE Std. 929-2000 necessitates that the DG should be equipped with an anti-islanding detection algorithm, which could be effectively performed using the inverter interface control.

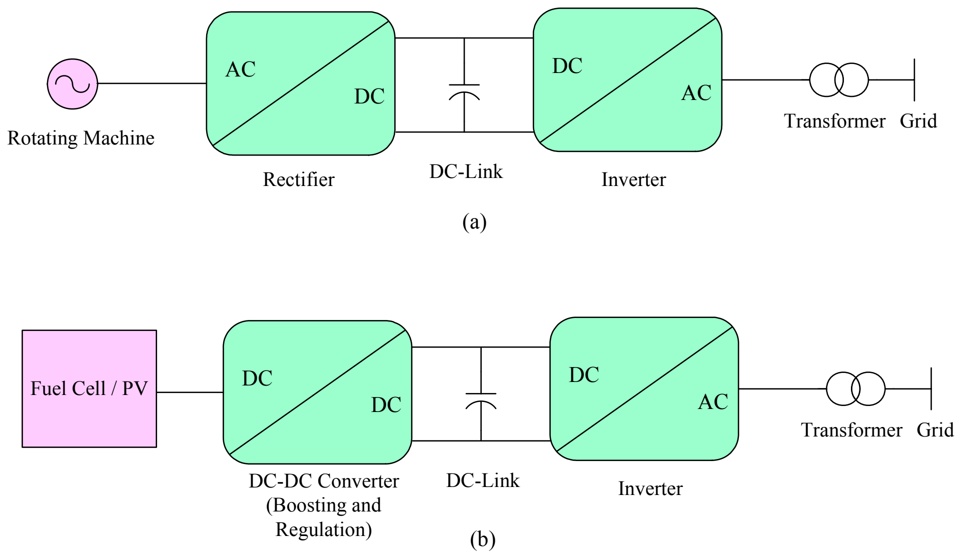


Figure 27 - Inverter interface topologies for DG technologies.
(a) AC sources interface. (b) DC sources interface.

Generally, inverters can be classified as line-commutated and self-commutated inverters as shown in Figure 28. The line-commutated inverter uses a switching device such as a thyristor. The thyristor can be switched on by a control signal but for switching it off, an external commutation voltage is required. In a three-phase grid-connected line-commutated inverter, the grid voltage can produce the necessary commutation voltage to turn of the switching device. Line commutated inverters generate significant low order harmonics; hence extensive filtering is required to meet power quality requirements. In addition it is not capable of operating in a standalone mode (islanded) since it relies on the distribution system waveform for commutation. For these reasons, line-commutated inverters are not used in DG interfacing.

The self-commutated inverter type utilizes fast switching devices such as IGBT and MOSFET. These switching devices are characterized by their ability to turn on and off using a control signal. Current technologies enable high switching frequencies (up to 20 kHz for grid-connected inverters)1; hence the switching harmonics can be easily filtered. Unlike line-commutated inverters, due to phase cancellations, the total distortion of the self-commutated inverters doesn't increase in proportionality to the number of installed units. For these reasons, most inverter interfaces for DG utilize self-commutated inverters.

[1] It should be noted that the switching frequency is limited by the switching power losses of the converter.

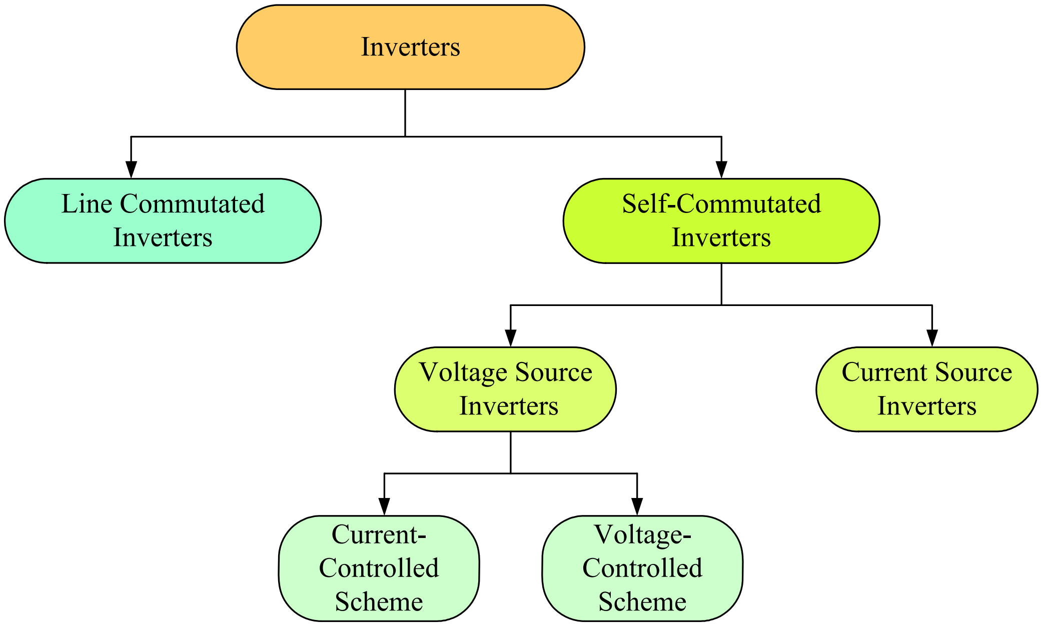


Figure 28 - A possible classification of inverters.

The self-commutated inverter can be further divided into two main types based on the nature of the DC link: current source inverter and voltage source inverter. Current source inverters are equipped with a large inductor on the DC side and act as a current source. On the other hand, voltage source inverters are normally equipped with a large capacitor on the DC side to act as a voltage source. Current source inverters exhibit higher losses and require a bulk DC-side inductor. Since DG sources resemble voltage sources more than sources, voltage-source inverters are typically used in DG interfacing.

4.3.3.2 Modeling of Inverter-Based Generators for Short Circuit Studies

To understand how inverter-based generators contribute to the short circuit current, it is necessary to discuss different control modes and associated control schemes.

For voltage source inverters there are two types of interfacing: the voltage controlled and the current controlled interface [37]. In the voltage-controlled interface, the inverter is operated as a controlled voltage source. By emulating the operation of a synchronous generator (through controlling the phase and the angle of the output voltage), the output active and reactive power components can be controlled. On the other hand, the current controlled interface utilizes the inverter as a current source, where the injected current vector is controlled to track a reference current vector. The current-controlled voltage source inverter offers potential advantages over the voltage-controlled inverter. Important among these: 1) higher power quality as the current-controller inverter is less affected by grid harmonics and disturbances, 2) the active and reactive power controls are decoupled, 3) inherent overcurrent protection is yielded, and 4) the control mode can be easily extended to compensate for line harmonics and power quality issues. For these reasons, current-controlled inverters are more commonly used. In [38], it has been reported that 81% of the DG interface inverters are current-controlled.

A. Voltage Controlled Voltage Source Inverter

A system configuration of a voltage controlled 3-phase two-level voltage-source inverter-based DG unit is shown in Figure 29. The system consists of a DG source, in which the DC voltage is boosted and regulated to an appropriate level. A 3-phase voltage-controlled voltage source inverter is used for grid interfacing. A coupling inductor is necessary in the voltage-controlled inverters to make the power flow possible.

In a voltage-controlled voltage source inverter, the power flow is controlled by adjusting the amplitude and the phase (power angle (δ)) of the inverter output voltage with respect to the grid voltage. The actual power angle is calculated from the terminal quantities and compared to the desired power angle, which is calculated form the desired active power. The error in the power angle is processed by a power angle controller (normally a proportional plus integral (PI) controller) to generate the reference phase angle of the modulating signal. In a similar manner, the error between the actual and desired reactive power is processed by a reactive power controller to generate the reference magnitude of the modulating signal. The Phase Locked Loop (PLL) is responsible for synchronizing the inverter output voltage vector with the grid voltage vector to enable controllable power transfer. Using the grid phase angle, the reference-modulating vector (magnitude and angle) is generated and dispatched to the Pulse Width Modulator (PWM), which in turns generates the inverter switching signals. The commonly used Sinusoidal PWM can effectively locate the switching harmonics in the inverter output voltage around the carrier frequency (normally in the range of 3-10 kHz). The interfacing filter is designed to provide enough attenuation to the switching harmonics, so that the Total Harmonic Distortion (THD) is less than 5% as dictated by the IEEE Std. 1547 [39].

In many applications, the control scheme is adjusted to injected active power at unity power factor while interconnected to the utility grid. However, reactive power can be injected to allow a PQ mode of operation. Furthermore, a controlled reactive power can be injected to regulate the voltage at the point of common coupling by adding an external voltage control loop.

In the sense of the sinusoidal PWM, the switching harmonics are located at the carrier frequency and the inverter can be modeled as a controlled voltage source behind the coupling impedance as depicted in Figure 30 [35], [37], [40]. The rms value of the fundamental phase voltage component can be calculated as

$$V_{inv} = m\frac{V_{dc}}{2\sqrt{2}} \tag{3}$$

where V_{inv} is the RMS value of the fundamental voltage component generated by the inverter, m is the modulation index, and V_{dc} is the DC link voltage.

The aforementioned model can effectively describe the steady-state operating conditions of the inverter [35], [37], [40]. Therefore, the model can be used to in short circuit studies as well. The short circuit level for this type of interface depends on the DC link voltage and the value of the filter impedance. Such interfaces could be represented by a voltage source behind impedance for short circuit analysis. Since the modulation index is limited to 1, the maximum output voltage of the inverter is limited to $V_{dc}/2\sqrt{2}$. This value will represent the short circuit driving voltage during a short circuit. The short circuit impedance of the DG unit will be mainly its coupling and filter impedance.

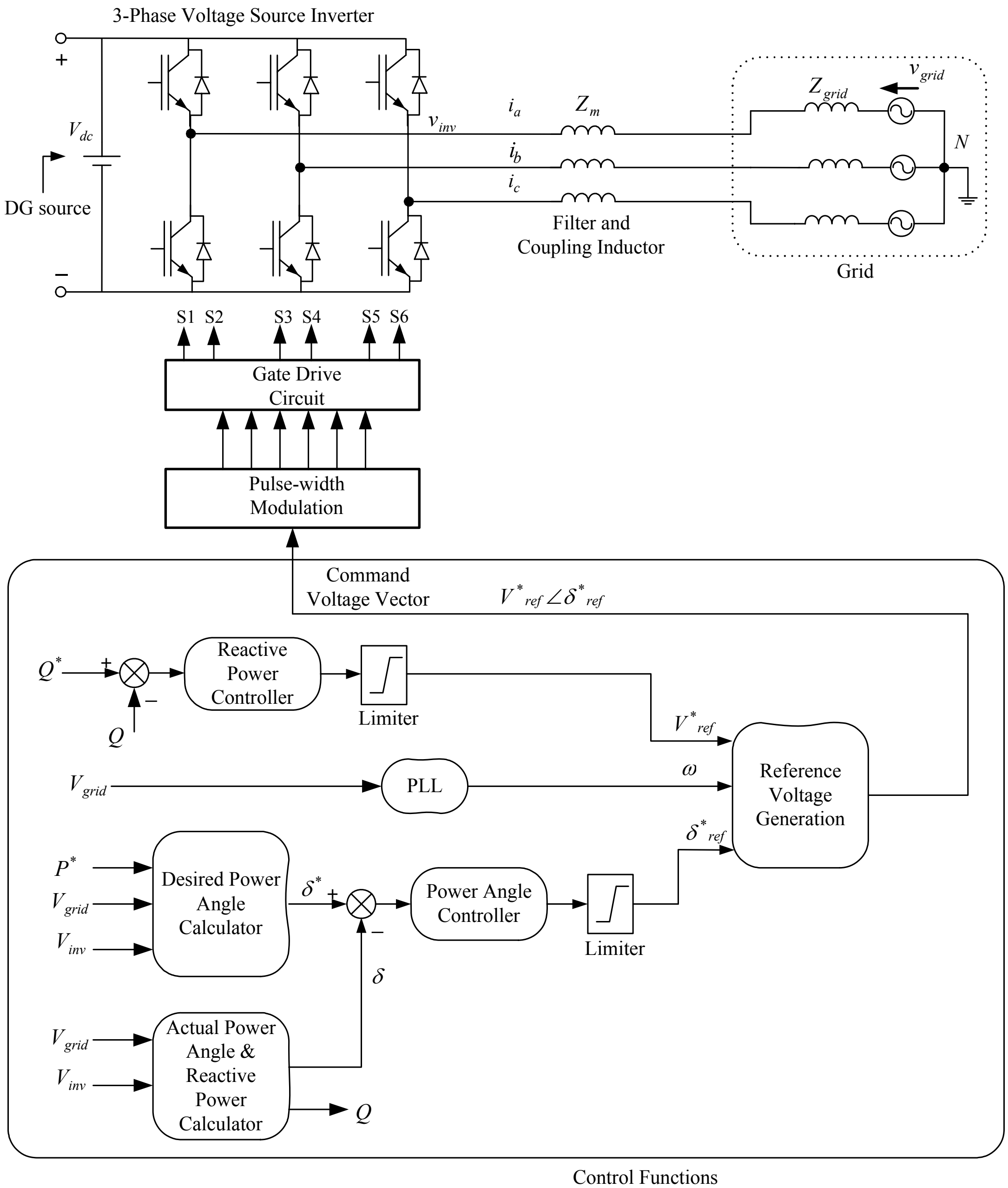


Figure 29 - A system configuration of a grid-connected voltage-controlled inverter.

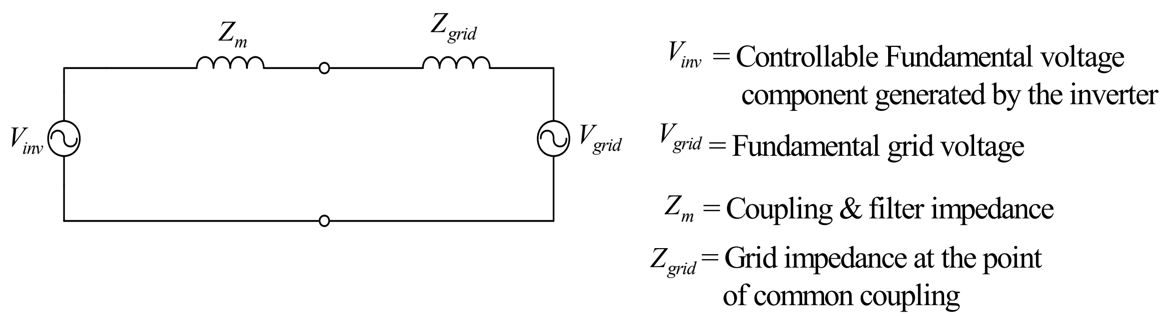


Figure 30 - Equivalent circuit of a voltage-controlled inverter at the fundamental frequency.

B. Current-Controlled Voltage Source Inverter

A system configuration of a current-controlled 3-phase two-level voltage-source inverter-based DG unit is shown in Figure 31. The system consists of a DG source, in which the DC voltage is boosted and regulated to an appropriate level. A 3-phase current-controlled voltage source inverter is used for grid interfacing. A filter inductor is necessary to smooth the injected current.

In a current-controlled voltage source inverter, the power flow is controlled by controlling the current injected to the utility grid. The reference active power and reactive power components are used along with the grid voltage information to calculate the reference current components to be injected into the grid. These are compared to the actual current components to generate a current error signal. The error signal is process by a high bandwidth current controller, which in turns generates the reference voltage vector. Normally, the current control process is carried in the synchronous reference frame, which rotates synchronously with the grid fundamental angular speed. This technique offers higher bandwidth characteristics and eliminates the phase tracking errors as the controller is working against pseudo-stationary quantities. The PLL is responsible for synchronizing the inverter output voltage vector with the grid voltage vector to enable controllable power transfer. The reference voltage vector is synthesized through the pulse-width modulated voltage source inverter. The commonly used Sinusoidal PWM can effectively locate the switching harmonics in the injected current around the carrier frequency (normally in the range of 3-20 kHz). The interfacing filter is designed to provide enough attenuation to the switching harmonics, so that the THD is less than 5% as dictated by the IEEE Std. 1547 [39].

In many applications, the control scheme is adjusted to injected active power at unity power factor while interconnected to the utility grid. However, reactive power can be injected to allow a PQ mode of operation. Furthermore, a controlled reactive power can be injected to regulate the voltage at the point of common coupling by adding an external voltage control loop.

In current-controlled inverters, the current controller is normally designed with high bandwidth characteristics (in the range of 1-2 kHz) to ensure accurate current tracking, to shorten the transient period as much as possible and to force the voltage source inverter to equivalently act as a current source amplifier within the current loop bandwidth. Under these conditions, which are inherently satisfied in a well-designed current controlled inverter, the closed loop current dynamics can be represented by the following transfer function:

$$G(s) = \frac{1}{1 + \tau s} \tag{4}$$

where $1/\tau$ is the closed loop bandwidth. The transfer function in (4) has a unity gain over the closed loop bandwidth. Therefore, the current controlled inverter can be represented by a current source over its control bandwidth. Figure 32 represents the equivalent circuit of the current-controlled inverter. Since the short circuit studies are conducted at the power frequency, which is much lower than the current loop bandwidth, the model in Figure 32 can be used to model the short circuit contribution of the inverter at the fault condition. The contribution of this mode of operation to the short circuit level is equal to the value of the current injected at the pre-fault condition (normally, the rated current).

Since the thermal time constant of semiconductor devices is very small, the current contribution of both the voltage-controlled and the current-controlled inverters to faults is terminated very quickly once the fault is detected. Simply, this is achieved by stopping the switching signal. This usually occurs before the current reaches 150%-200% of the rated current to protect the transistor switches. Therefore, the duration of the fault current of the inverter is less than half a cycle [34], [2].

In CYMDIST software, the inverter-based generator is modeled as a current source for short circuit calculation [30]. CYMDIST allows the user to input the value of the short circuit current of the inverter. This general model fits both the voltage- and current- controlled inverters, where in both cases, the short current of the inverter can be calculated and passed to the model.

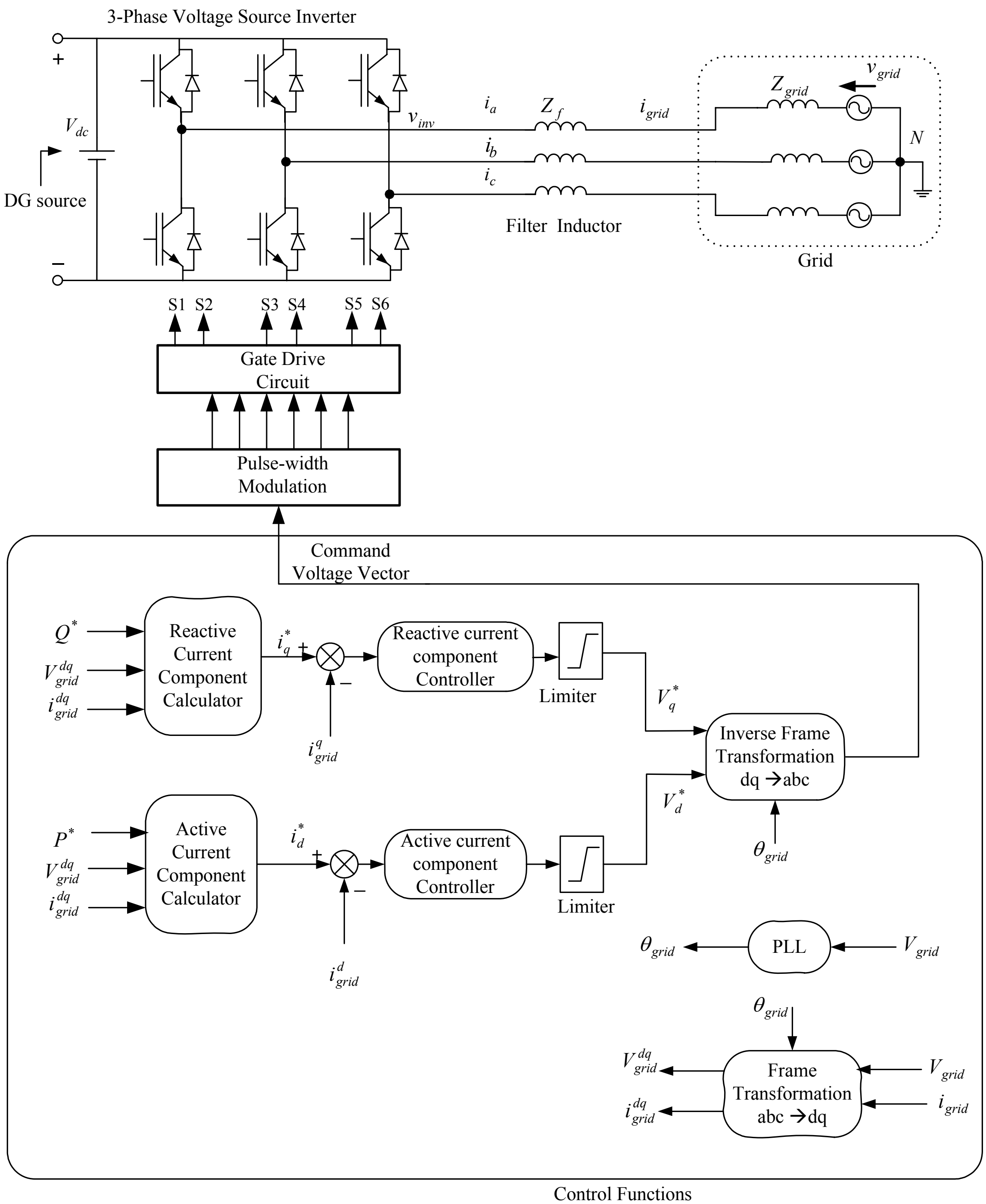


Figure 31 - A system configuration of a grid-connected current-controlled inverter.

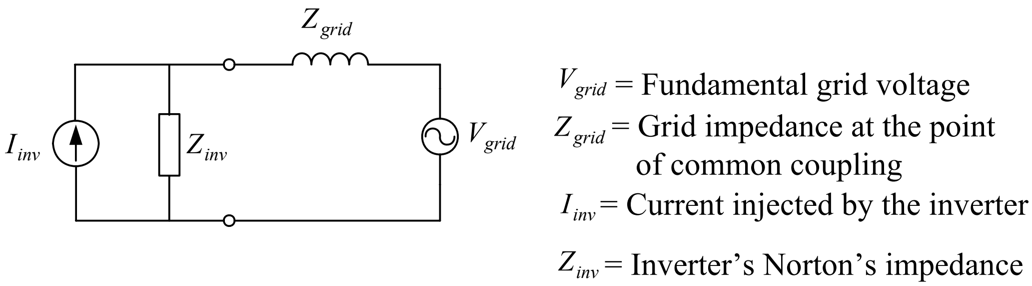


Figure 32 - Equivalent circuit of a current-controlled inverter at the fundamental frequency.

3.4 Modeling of Transformer Connection for DG Interface

Interconnection transformers are used to interface a DG unit with an existing power system, and to provide the necessary isolation. Utilities recommend using an interconnection transformer to eliminate possible zero sequence or dc components in the generated voltages, and to increase the protection. Furthermore, the transformer can be considered as a filter inductor, hence, it improves the quality of the current injected by the DG unit. Transformer connections play a key role in how the DG unit affects the utility system and how the utility system affects the DG unit. There is no universally accepted "best" connection for the interconnection transformer. Each connection has its own advantages and disadvantages. The advantages and disadvantages of the various configurations depend on the local installation, the generator, and the utility system grounding requirements [6].

3.4.1 Typical Connections

Five typical transformer connections are widely used to interconnect DG's to the utility system [6]-[8]; namely they are: Delta (HVS)/Delta (LVS), Delta (HVS)/Wye-Gnd (LVS), Wye-Ungnd (HVS)/Delta (LVS), Wye-Gnd (HVS)/Delta (LVS) and Wye-Gnd (HVS)/ Wye-Gnd (LVS), where (HVS) indicates the primary winding and (LVS) indicates the secondary winding.

To illustrate the impact of each transformer connection on the system protection, let us consider a simple system as shown in Figure 33 A DG unit it interfaced to the utility via an interconnection transformer as depicted in Figure 33. Two possible locations (F1 and F2) for a single-line to ground fault are considered.

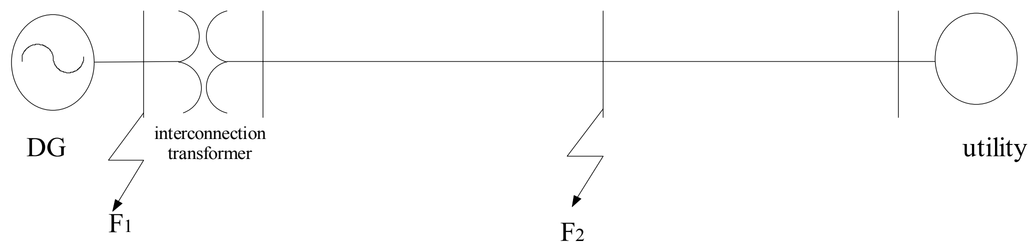


Figure 33 - Sample distribution system used to illustrate the impact of various transformer connections on the ground fault current and overvoltages.

3.4.1.1 Ungrounded Primary Side (HVS)

Consider the first three connections: Delta (HVS)/Delta (LVS), Delta (HVS)/Wye-Gnd (LVS) and Wye-Ungnd (HVS)/Delta (LVS). Figure 34 shows the zero sequence current contributions from these connections in the case of a ground fault at F_2 in the sample distribution system shown in Figure 33. It is clear form Figure 34 that for a ground fault at F_2, there will be no path for the zero sequence current from the DG and interconnection transformer side. The complete fault current will be fed from the utility. Accordingly, as an advantage, there is no impact on the utility ground relay coordination for these types of connections. Another advantage of these connections is that any ground fault on the secondary of the interconnection transformer (at F_1) will not be seen by the utility protection system and as result; the ground coordination system will not be affected [6]-[7].

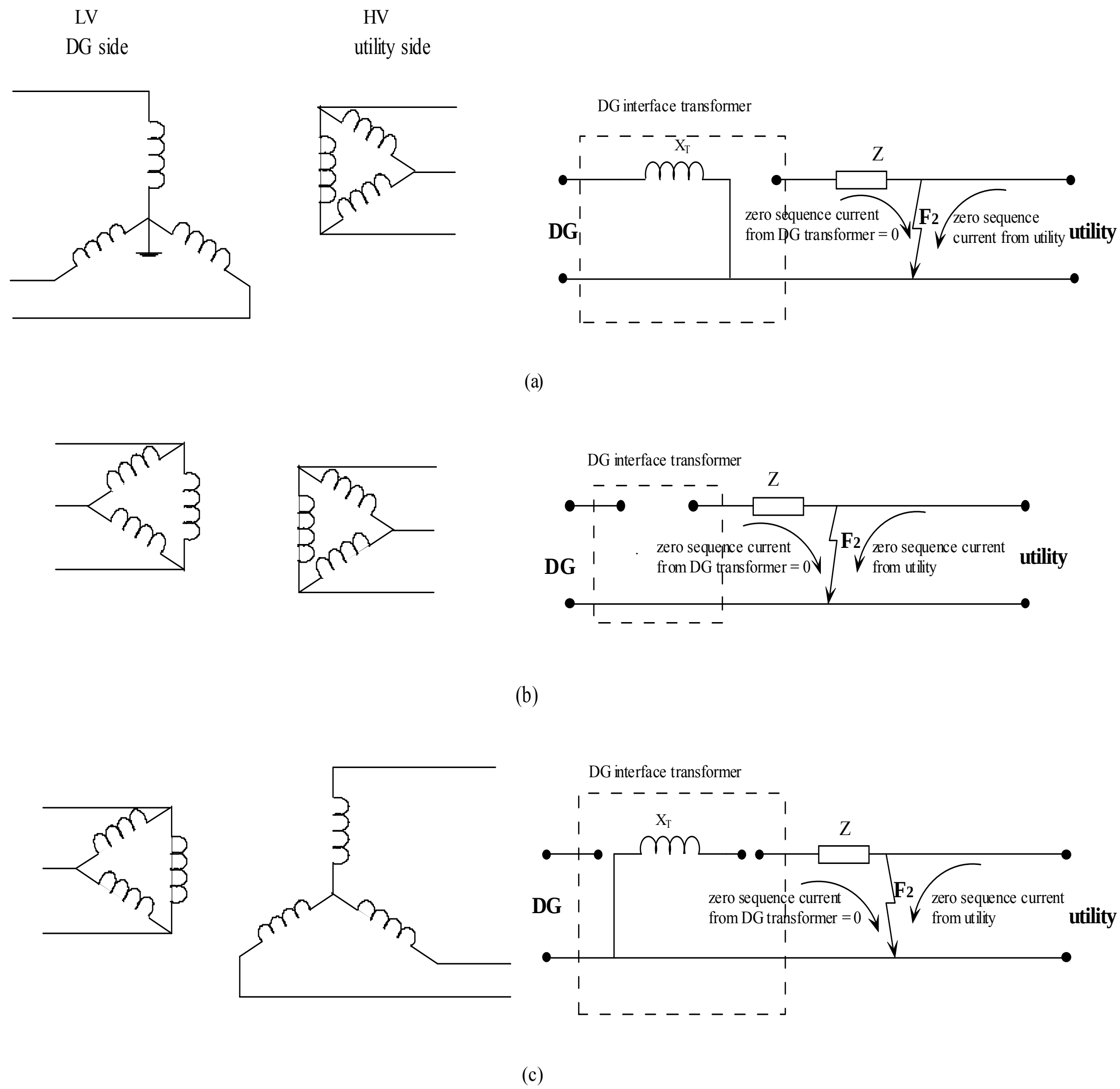


Figure 34 - Contribution of zero sequence current from DG interface transformer in the distribution system ground faults. (a) Delta (HVS)/Delta (LVS), (b) Delta (HVS)/Wye-Gnd (LVS) and (c) Wye-Ungnd (HVS)/Delta (LVS).

The major concern with an interconnection transformer with an ungrounded primary winding is that after the utility breaker is tripped for a permanent ground fault, the system will be fed from an ungrounded source. This subjects the unfaulted phases to an overvoltage that will approach the line-to-line voltage. This occurs if the DG is near the capacity of the load on the feeder when utility breaker trips. The resulting overvoltages will saturate the transformer, which normally operates at the knee of the saturation curve. Many utilities use ungrounded interconnection transformers only if a 200% or more overload on the DG occurs when utility breaker trips. During ground faults, this overload level will not allow the voltage on the un-faulted phases to rise higher than the normal line-to-neutral voltage; hence avoiding transformer saturation. For this reason, ungrounded primary windings should generally be reserved for DG's where overloads of at least 200% are expected when the substation breaker is tripped [6].

To understand how DG can generate an overvoltage during a ground fault, consider the situation given in Figure 35. In this example, we have a four-wire multigrounded-neutral distribution circuit that has one conductor (phase-A) faulted to the neutral. Once this occurs, a high fault current is generated until the substation circuit breaker opens. Once the substation source is cleared, and the DG is still feeding the system, then the voltage of the neutral (earth) becomes that of phase A of the DG. Any loads or equipment connected between an unfaulted phase (C or B) and neutral will suddenly be subjected to voltages that are equivalent to the line-to-line voltage that is about 1.73 times higher than the pre-fault voltage. The distribution transformers serving customers on these phases are connected line to neutral and thus would saturate and subject customer equipment to such overvoltages. Moreover, since the nominal pre-fault voltage may be as high as 105% due to the ANSI voltage regulation allowance, as a result, the voltage may reach 182% of nominal during the faulted condition, which increases of possibility damaging the equipment [12].

3.4.1.2 Grounded Primary Side (HVS)

A- Wye-Grounded (Primary)/Delta (Secondary)

Consider a Wye-Grounded (Primary)/Delta (Secondary) connection. For a ground fault at F1 in the system of Figure 33, the utility will not contribute any zero sequence current to the fault as shown in Figure 36.a, and as result, this arrangement prevents the utility protection system to respond to ground faults at the DG side.

However, the disadvantage of this arrangement is that it acts as a zero sequence current source; hence, establishing a zero sequence current for ground faults on the distribution system. This is the case for a ground fault at F2 in the system in Figure 33. This could have a significant impact on the utility's ground relay coordination as shown in Figure 36.b. Also, this zero-sequence current from the high voltage side will circulate in the delta winding on the low voltage side, and possibly causing heating problems within the transformer.

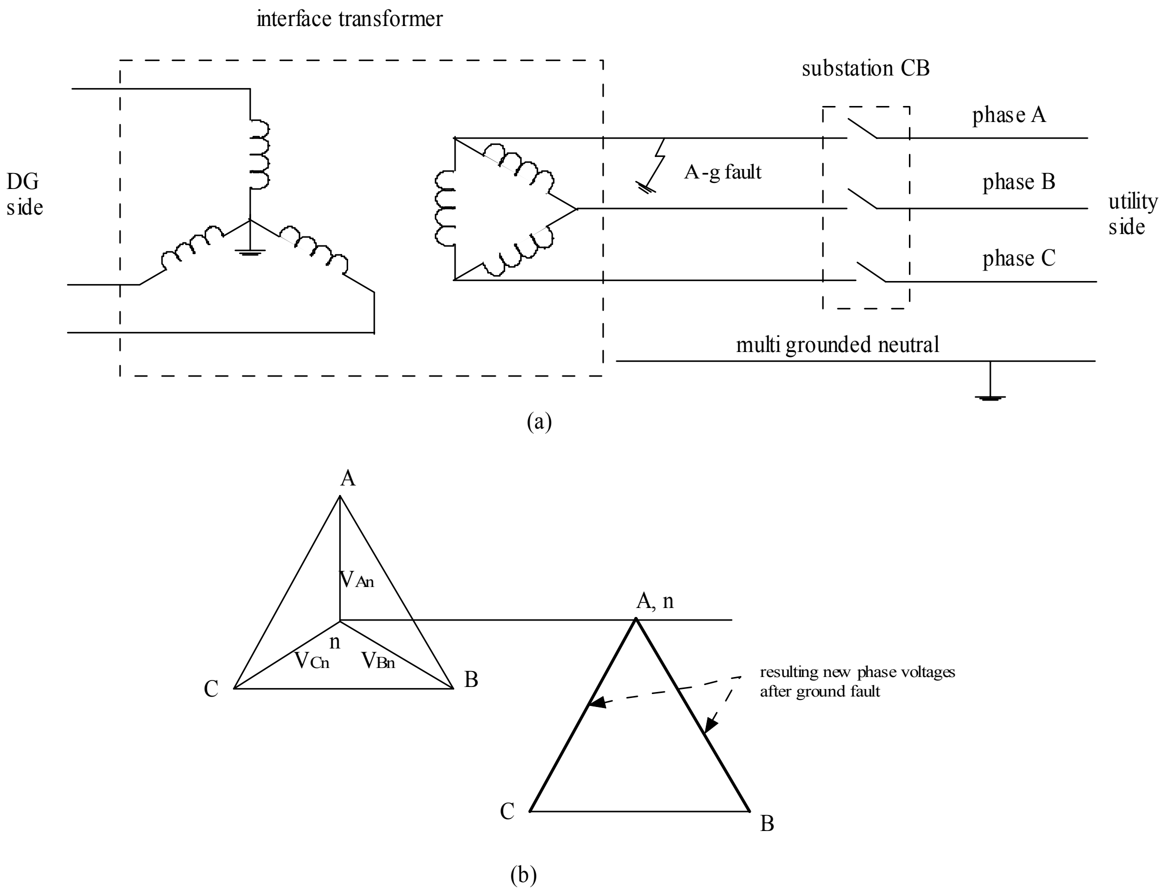


Figure 35 - Overvoltage due to ground faults.
(a) Circuit configuration. (b) Phasor Diagram.

A commonly practiced solution to this problem is to place grounding impedance in the high-side neutral connection to limit the flow of excessive circulating currents. The ground impedance should be high enough to limit the circulating current but low enough to maintain effective grounding of the DG unit [6]-[8].

In addition, any unbalanced load on the distribution circuit would normally return to ground through the utility transformer neutral. With the addition of the generator interconnection transformer, this unbalance will be divided between the utility transformer neutral and the generator interconnection transformer. During serious unbalance conditions such as a blown lateral fuse, the load carrying capability of the interconnection transformer can be reduced.

The use of a grounded-wye winding on the high side and delta on the low side has the advantage of limiting the overvoltages that can be developed when the utility beaker opens; thereby sparing lightning arresters and feeder loads from damage.

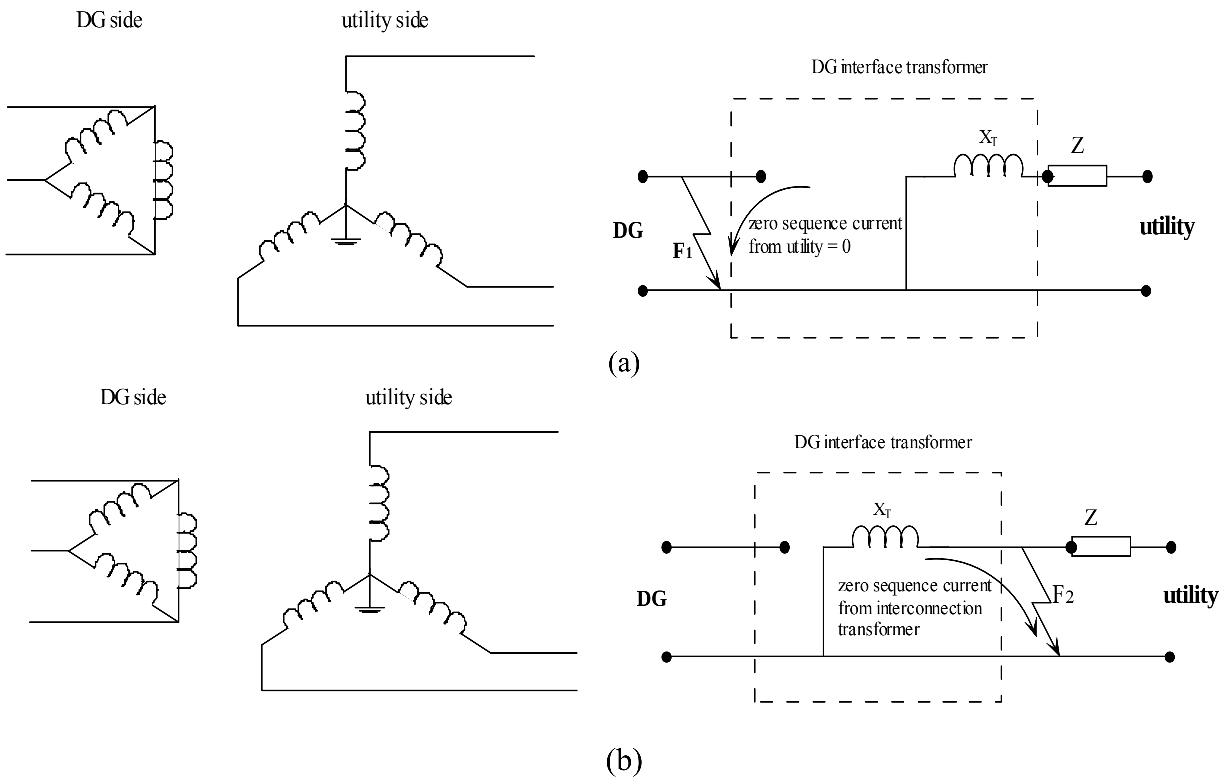


Figure 36 - Zero sequence current contribution from DG interconnection transformer in ground fault at utility system side for Wye-Grounded (Primary)/Delta (Secondary) transformer connection. (a) ground fault at F_1. (b) ground fault at F_2.

B- Wye-Grounded (Primary)/Wye-Grounded (Secondary)

Consider a Wye-Grounded (Primary)/Wye-Grounded (Secondary) connection. For a ground fault at F1 in the system of Figure 33, the DG together with the utility will feed the fault as shown in Figure 37.a. As a result, the fault current level will increase and this may affect the ground relay coordination. The same impact will be yielded for a ground fault at F2, as shown in Figure 37.b.

The main advantage for this connection is that no overvoltages will be developed when the utility beaker opens (for a solidly grounded connection). The major disadvantage of this connection is that it provides a source of unwanted ground current for utility feeder faults similar to that described in the previous section.

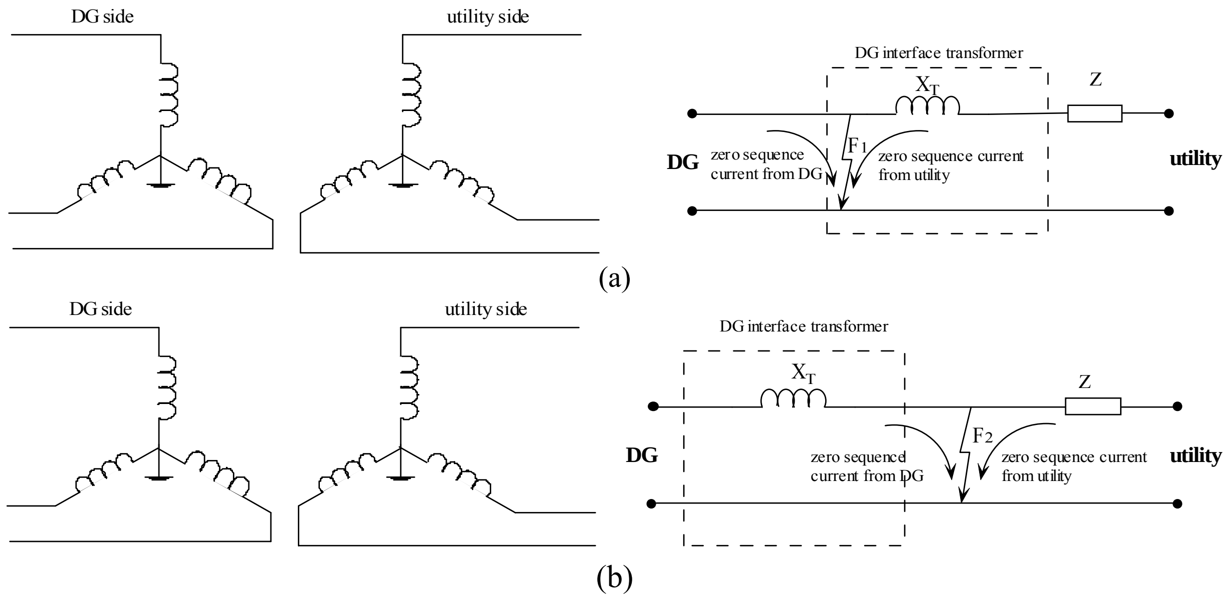


Figure 37 - Zero sequence current contribution from DG in a ground fault at utility system side for Wye-Grounded (Primary)/ Wye-Grounded (Secondary) transformer connection. (a) ground fault at F_1. (b) ground fault at F_2.

3.4.2 Case Study: The effect of the Interconnection Transformer on the Ground Fault Current

To show the effect of the DG interface transformer on the ground fault current and overvoltages, a sample distribution system, shown in Figure 38, is simulated in CYMDIST environment. The system consists of a 13.8 kV, 10 MVA utility substation, three loads at buss 2, 3 and 4, a 0.48 kV DG with its interconnection transformer connected between bus 1 and 2. Different DG sizes with different transformer connections are used in the simulation scenarios. Three ground fault positions, at bus 2, 3 and 4, are considered, where one fault is considered at a time. Table 3 gives the short circuit currents seen at the faulted bus for different configurations.

Table 3 shows that the DG doesn't affect the ground fault current value if the interconnection transformer has ungrounded primary-side. It can be noticed that the ground fault current values, with no DG installed, are slightly less than those obtained when the DG is installed. This is due to higher pre-fault voltages yielded by the power injected by the DG. Also, it is clear that a DG with a Gnd-Wye/ Delta interconnection transformer has the largest effect on the ground fault current, as this connection contributes the largest zero sequence current to the ground fault current. The effect of the DG size on ground fault current is obvious from the results obtained. As the DG size increases, its contribution to the short circuit current increases.

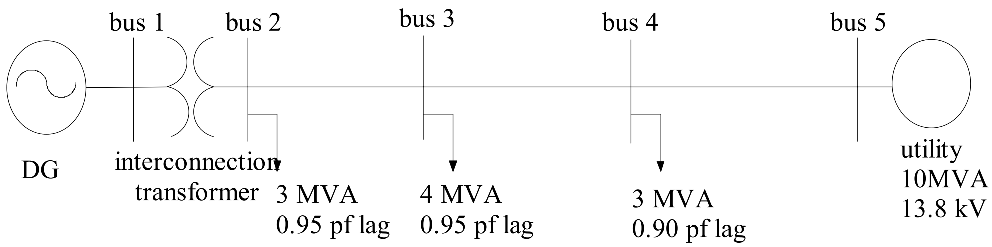


Figure 38 - A sample distribution system used for a case study on the impact of various transformer connections on the ground fault current and overvoltages.

Table 3 - Case study results: Effect of DG size and connection of the interconnection transformer on the ground fault current.

Interconnection Transformer		**Ground fault current (A)**								
		Small DG (100 kVA)			**Medium DG (500 kVA)**			**Large DG (2 MVA)**		
DG side	Utility side	Bus 4	Bus 3	Bus 2	Bus 4	Bus 3	Bus 2	Bus 4	Bus 3	Bus 2
Without DG – transformer set		9338	7271	6544	9338	7271	6544	9338	7271	6544
Delta	Delta	9340	7273	6546	9347	7281	6554	9364	7301	6575
Gnd-Wye	Delta	9340	7273	6546	9347	7281	6554	9364	7301	6575
Delta	Wye	9340	7273	6546	9347	7281	6554	9364	7301	6575
Gnd-Wye	Gnd-Wye	9379	7310	6582	9459	7386	6657	9535	7461	6732
Delta	Gnd-Wye	9446	7391	6662	9894	7795	7059	11046	8920	8182

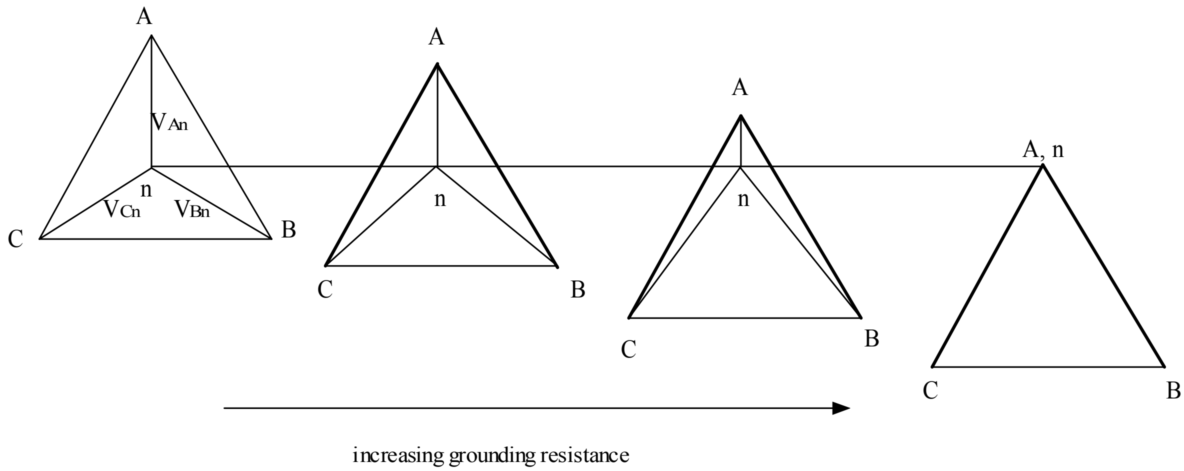


Figure 39 – Effect of increasing grounding resistance on the value of phase voltages.

To show the effect of changing the grounding impedance on the fault current and overvoltage, the same system shown in Figure 38 has been used. As stated earlier, in the case of an ungrounded system, the line to neutral voltage of the healthy phases during a ground fault is 1.73 times the rated phase voltage. For a grounded transformer, and assuming that the utility breaker is opened, the voltage of the healthy phases during a ground fault varies according to the value of the grounding impedance as shown in Figure 39. It is clear from Figure 39 that in a ground fault condition, the line-to-neutral voltages of the healthy phases don't change if the system is solidly grounded and they increase as the grounding impedance increases.

To calculate the healthy phases' voltages in a ground fault condition, the phasor diagram shown in Figure 40 is used. During a ground fault, the point F is connected to the ground and as result, the loop AnGFA is closed. For the sake of illustration, the fault is assumed to be on the terminals of the primary winding of the intercommunion transformer, and the fault is assumed to be a bolted type. Under these conditions, one can write,

$$V_{An} = V_{Gn}, \tag{5}$$

Also,

$$V_{Gn} = I_F \times Z_g \tag{6}$$

where;

Z_g: the transformer grounding impedance,

I_F: the ground fault current when the utility breaker opens, and it is equal to $\frac{3V_{prefault}}{(Z_0 + Z_1 + Z_2 + 3Z_g)}$,

where $V_{prefault}$ is the pre-fault voltage and Z_0, Z_1, and Z_2 are the Thevenin's equivalent impedances of the system seen by the fault.

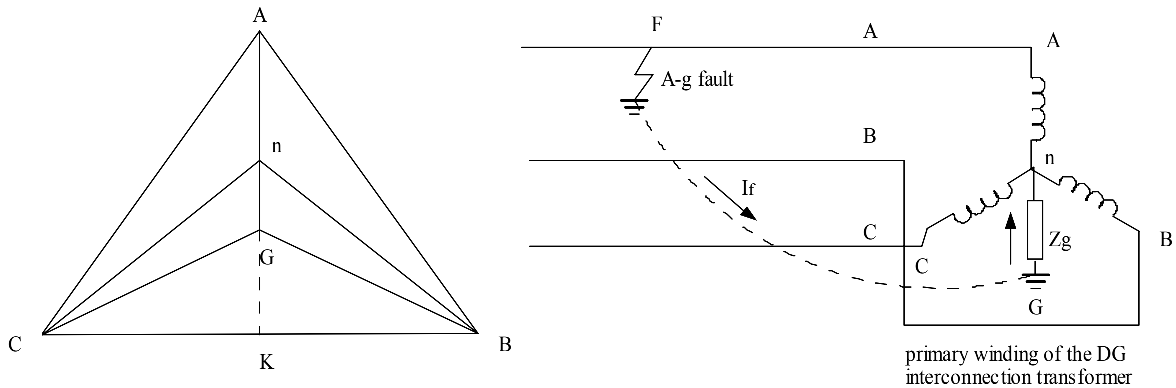


Figure 40 - Calculation of phase voltages during ground fault.

V_{An}: phase A to neutral voltage and

V_{Gn}: the voltage difference between the ground and the neutral.

After calculating V_{Gn}, the values of V_{Bn} and V_{Cn} can be calculated from the geometry of Figure 40 as follows:

$$|V_{Bn}| = \sqrt{(|V_{KG}| + |V_{Gn}|)^2 + (|V_{KB}|)^2} \tag{7}$$

$$|V_{Cn}| = \sqrt{(|V_{KG}| + |V_{Gn}|)^2 + (|V_{KC}|)^2} \tag{8}$$

For the system shown in Figure 40, the line voltage = 13.8 kV and accordingly,

$V_{KC} = V_{KB} = \frac{13800}{2} = 6900V$ and $V_{GK} = \frac{V_{AK}}{3} = 3983.7\ V$,

Also,

$V_{BG} = V_{CG} = \frac{13800}{\sqrt{3}} = 7967\ V$

So, if the grounding impedance = 0, VGn will be equal to zero and the three line to neutral voltages will be equal to line to ground voltage = 7967 V irrespective of the ground fault. As the transformer grounding impedance increases, the line to neutral voltages of the healthy phases increase during a ground fault condition. Ultimately, if the transformer is ungrounded, i.e., $Z_g \to \infty$, the voltages of the un-faulted phases will reach the line-to-line voltages.

Table 4 summarizes the effect of changing the grounding impedance of the interconnection transformer on the value of the phase voltages and the fault current during a single phase to ground (A-G) fault at the primary terminals of the interconnection transformer (bus 2 in Figure 38). For the sake of illustration, the case when a large DG with gnd wye (primary)/ delta (secondary) interconnection transformer is presented.

The grounding impedance of the interconnection transformer increases the zero-sequence impedance of the DG side and, therefore, reduces the zero sequence current supplied by the DG. It, thereby, reduces the contribution of the DG on the ground fault current and, as a result, restricts the reduction in ground protection sensitivity [9]. The utility protection sensitivity is affected when the transformer connection allows the DG unit to contribute to the ground fault current. On the other hand, for a fault at the DG side (the secondary of the transformer), if the transformer connection limits the ground fault current in the DG side and the transformer secondary winding, the DG protection sensitivity will be affected by the value of the grounding impedance. In both cases, a tradeoff between overvoltage and protection sensitivity is considered when designing the grounding impedance. Table 5 shows the effect of increasing the grounding impedance of the DG interconnection transformer on the ground fault current at different buses of the system shown in Figure 38 with the current measured at the faulted bus. For the sake of illustration, the case when a large DG with gnd wye (primary)/ delta (secondary) interconnection transformer is presented.

As a conclusion, ungrounding the interconnecting transformer causes unwanted temporary overvoltages during ground fault conditions when the utility breaker opens. On the other hand, solid grounding of the interconnection transformer increases the contribution of the zero-sequence current from the DG side and as a result, the protection sensitivity of the overcurrent protection devices at the substation may be decrease to an unacceptable level during ground faults, and also the coordination between the various protection devices in the system may be missed. Therefore, the value of the grounding impedance should be chosen in a tradeoff between the overvoltage and sensitivity constraints. Some utility practices prefer the delta-wye grounded transformers for larger DG interconnection. These preferences are based on that blocking the relatively large ground fault current by the delta-primary winding in the case of a large DG unit is more important than allowing temporary overvoltages for a few cycles until the DG is disconnected. Therefore, the miss-coordination and sensitivity problems associated with large a DG interconnected to the system by a grounded primary-winding interconnection transformer are avoided.

In addition, it should be noted that simulation studies are not required in any transformer connection case. Simulation studies are required in cases of a transformer with a high voltage side grounded through grounding impedance. In this case, the ground fault current can be obtained from simulation results and the corresponding overvoltages can be analytically computed as shown in equations (7) and (8) for given grounding impedance.

Table 4 - Case study results: Effect of transformer grounding impedance on healthy phases' line to neutral voltages for a fault at the primary terminals of the interconnection transformer with A 2 MVA DG.

Interconnection Transformer impedance (ohm)	Fault current supplied by the DG (I_F) in A	Phase A voltage (V)	Phase B voltage (V)	Phase C voltage (V)
Solidly grounded	252	0	7967	7967
0.2	250	50	7992	7992
0.5	248	124	8030	8030
1	244	244	8092	8092
2	237	474	8214	8214
100	61	6100	12218	12218

Table 5 -Case study results: Effect of transformer grounding impedance on ground fault current.

Interconnection transformer impedance (ohm)	Ground fault current measured at the faulted bus (A)		
	Bus 4	Bus 3	Bus 2
Solidly grounded	11046	8920	8182
0.2	10908	8782	8042
0.5	10738	8614	7873
1	10525	8405	7663
2	10248	8136	7396

3.4.3 DG Interface Transformer: Practices of Some Canadian Utilities

Canadian utilities have their experience in the DG interface (interconnection) transformer. A sample of typical practices is given as follows.

3.4.3.1 SaskPower Practices

Saskpower [10] has identified rules for interface transformers for two types of DGs smaller than 100 kW and larger than 100 kW. For DGs smaller than 100 kW, the transformer connection on utility side would be gnd-Wye and the DG side is grounded or ungrounded Wye. For installations, which are larger than 100 kW, Saskpower requires that the DG installation not to contribute for the zero sequence current to avoid affecting main feeder ground protection coordination. For that reason Saskpower requires one of the following options to be fulfilled in DG installation larger than 100 kW [10]:

- Delta on 25 KV side with grounded wye in the low-tension side.
- Grounded wye on 25 KV side with grounded or ungrounded wye in the low voltage side (LVS). For the grounded wye in the low voltage side the Generator should be delta connected.

3.4.3.2 BC Hydro Practices

BC Hydro distribution feeders are a four-wire, three phases, and one neutral system. As a tradeoff, BC Hydro typically specifies high-impedance grounded interconnecting transformers, which would limit the temporary voltage rise below 22% and the reduction in ground protection sensitivity below 5% [9].

3.4.3.2 Hydro One Practices

Table 6 lists the preferred configurations for a DG step-up interface transformer for Hydro One distribution utility [11].

Table 6 - Preferred configurations for a generator's step-up interface transformer for Hydro one distribution utility.

System Voltage (kV) (Secondary)	Generation Size	Preferred Interface Transformer high voltage side : low voltage side (HVS:LVS)
27.6 kV	1 – 2 MW	Gnd-wye: Delta
		Delta: Gnd-wye
		Gnd-wye: Gnd-wye
27.6/12/8 kV	200 kW - 1 MW	Gnd-wye: Gnd-wye
		Gnd-wye: Delta
		Delta: Gnd-wye
27.6/12/8/4 kV	50 kW - 200 kW	Gnd-wye: Gnd-wye
27.6/12/8/4 kV	10 kW – 50 kW	Gnd-wye: Gnd-wye

4 Impact Studies and a Generalized Method to Assess the Impact of DG on System Protection

A number of protection issues, such as loss of coordination, de-sensitisation, nuisance fuse blowing, bidirectional relay requirements and overvoltage, should be addressed in order to arrive at the penetration limits of DG in an existing distribution system. In this section, a generalized method to assess the impact of DG on distribution system protection is developed. To simplify the study, each protection impact is studied individually to determine the penetration limit that triggers this issue. The method is demonstrated using the suburban and urban benchmark distribution systems and the DG models presented in Section 3. The DG locations might be dictated according to customer requirements. The penetration limit will be calculated for these specific points.

4.1 Loss of Coordination

4.1.1 Impact definition

In normal operation, protection devices are coordinated such that the primary protection operates before the backup can take action. Interconnecting the DG increases the short circuit level. Depending on the original protection coordination settings along with the size, location and type of the DG, uncoordinated situations may be yielded. In these situations, the backup operates before the primary, which results in nuisance tripping to some of the loads.

To illustrate the impact of DG on the loss of coordination, consider the suburban benchmark system, with a 2 MVA synchronous-type DG connected at bus 4 through a Gnd Wye (pri)/Delta (sec) interconnection transformer. Figure 41 depicts the coordination chart for the coordination path from the utility to bus 4. As shown in Figure 41, the short circuit current at bus 4 before installing the DG was 2836 A, so, the recloser and the fuse are fully coordinated at this value of short circuit current. For the coordination chart in Figure 42, the coordination is maintained up to a short circuit current level equals to 3051A, which is the intersection point between the fast curve of the recloser and the clearing curve of the fuse. If the short circuit current is increased beyond this limit, the coordination between the recloser and the main lateral fuse will be lost. This is the case when the 2 MVA DG is installed, where the short circuit current at bus 4 increases to 3604 A, as shown in Figure 4, and as a result the fuse will blow up and the service will be interrupted at this section.

Depending on the system configuration, the loss of coordination can take place between any pair of protective devices, i.e., fuse-recloser, fuse-fuse, and so on. In each case, the minimum short circuit current that leads to the loss of coordination will help in identifying the permissible penetration level of DG.

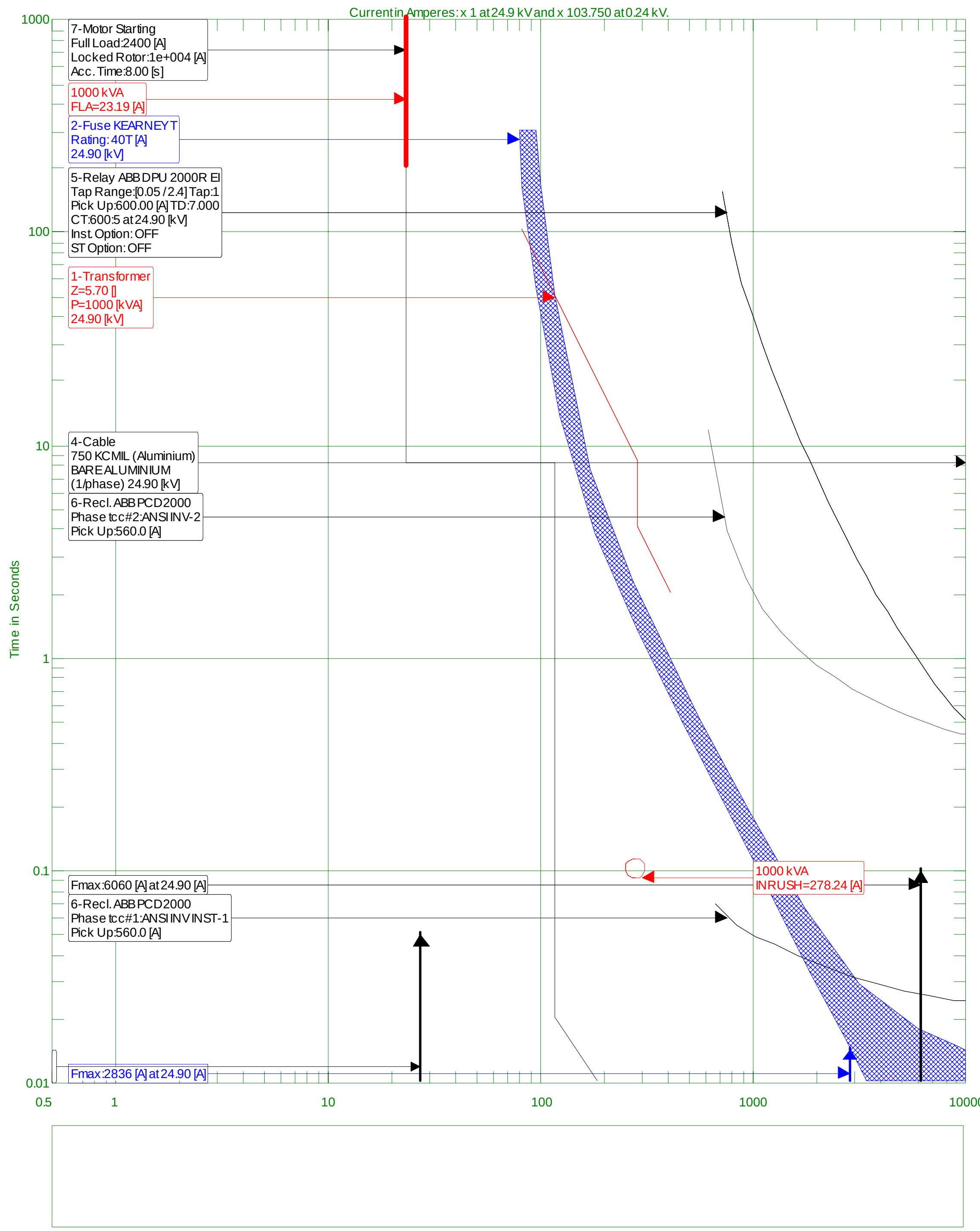


Figure 41 - Coordination chart for the path from the utility to bus 4 without DG in the suburban system.

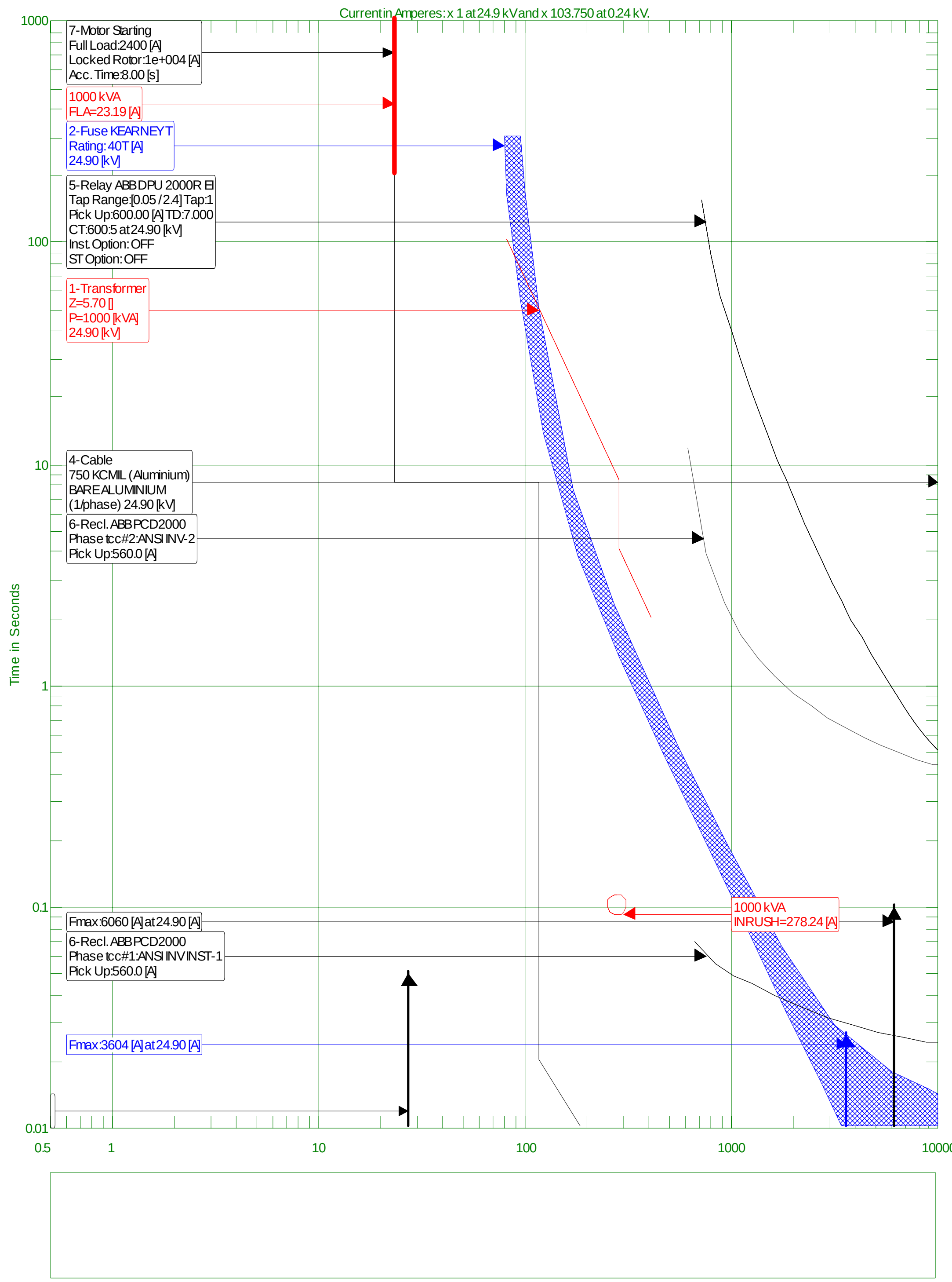


Figure 42 - Coordination chart for the path from the utility to bus 4 with a 2 MVA DG installed in the suburban system.

4.1.2 A generalized method to assess the loss of coordination penetration limits

The goal of this section is to develop a generalized procedure that determines the penetration limit of DG, in terms of size, location, and technology, from the point of view of loss of coordination. The general procedure can be summarized in the following steps:

1. In a given system, define different coordination paths. A coordination path can be defined as a set of protective devices located along a circuit path starting from the main feeder breaker to the most down stream protective device. The fact that most of the lateral (or sub-laterals) fuses are selected to be similar (to ease the maintenance), leads to a limited number of different coordination paths. A single coordination path might represent many laterals utilizing the same types of fuses.

2. Perform the coordination study and construction the coordination charts for different protection paths for the system under study.

3. Observe the minimum short circuit current at which the loss of coordination may occur among all protection coordination paths. This current may be the intersection between the coordination curves of two successive protection devices. It should be noted this minimum current might not exist in the case where there is no intersection between the coordination curves. In such a case, there will be no limit for the installed DG to violate the system coordination.

4. Define the candidate points at which the DG may be installed. The penetration limit will be calculated for these specific points. These candidate points may be obtained from a planning study to determine the optimum location of DG to minimize system losses and improve the voltage profile, or it might be dictated by the customer.

5. Simulate the installation the DG at the first candidate point, then increase the DG size and its interfacing transformer step by step until reaching the minimum short circuit current for the loss of coordination, then record the DG size. It should be noted that increasing the size of the DG and its interfacing transformer inherently increases the short circuit MVA capacity of the combined DG/transformer set. The DG impedance estimation function in CYMDIST provides a useful tool to determine the DG impedance based on its rating. The impedance estimation tool is based on the IEEE Violet Book guidelines [29]. In addition, the interfacing transformer impedance can be estimated based on its rating parameters. This function is available in CYMDIST as well.

6. Repeat step 5 for other candidate points.

7. Tabulate the results.

8. Change the DG technology by considering the cases of synchronous, inverter or induction-based generators, and then repeat steps 5 to 7, tabulate the results at each case.

A flow chart representing aforementioned procedure is shown in Figure 43.

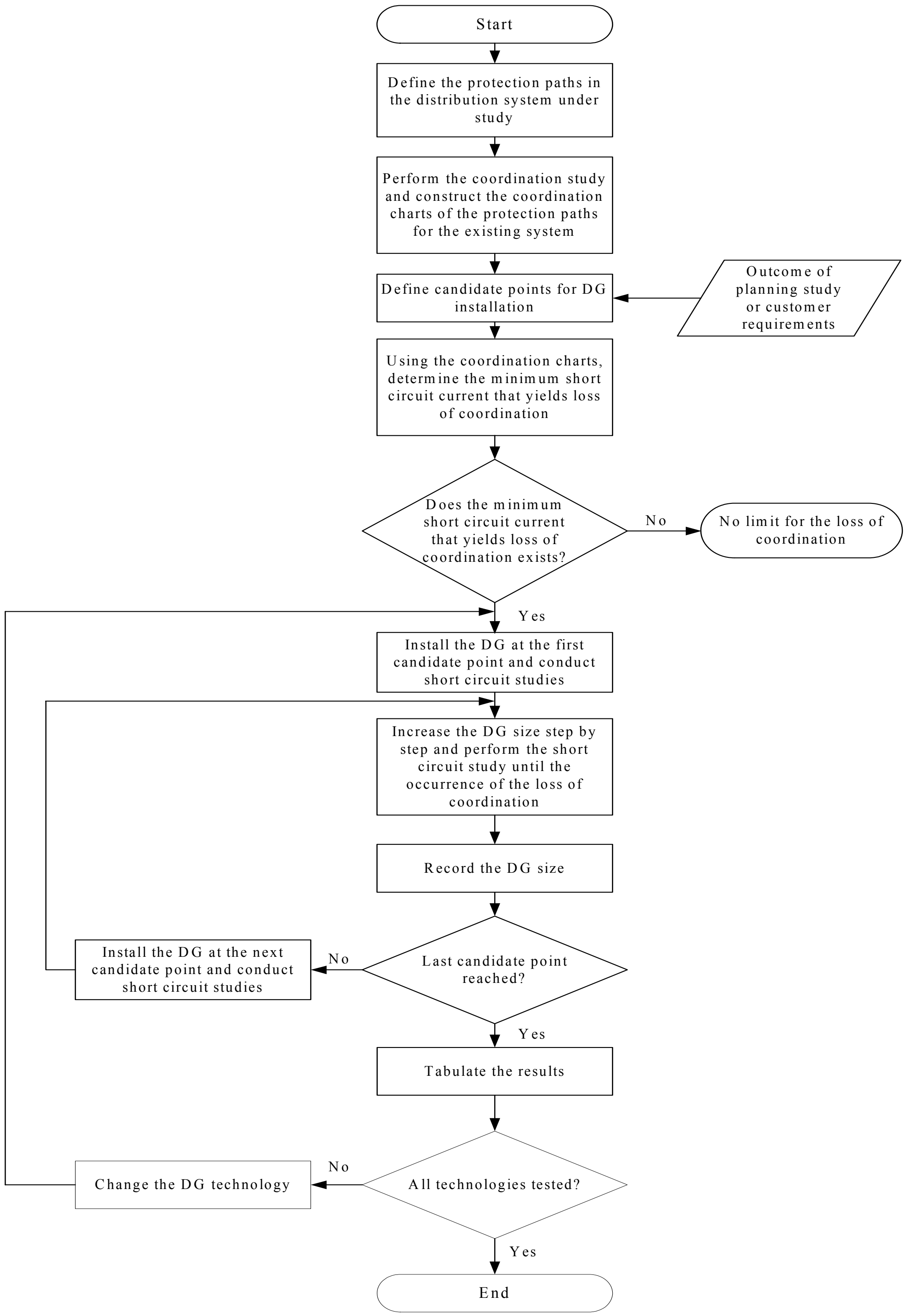


Figure 43 - A generalized method to assess the loss of coordination penetration limits.

4.1.3 Case studies

The aforementioned procedure is applied to the suburban and urban systems to demonstrate the applicability of the procedure. The initial coordination studies are documented in Chapter 2. Figure 44 shows the suburban system with four candidate points (P1 to P4) for the DG installation. In the suburban system, there are 3 different coordination paths; namely coordination paths 1, 2, and 4 as shown in Figure 4. Coordination path 3 is similar to 4 as the same fuses are utilized. The loss of coordination takes place in the coordination charts of the suburban system under study at the intersection of the "fast" curve of the recloser with the clearing curve of the main lateral fuses. These intersections occur at 3051 A for the coordination chart of path 1, 3051 A for the coordination chart of path 2, and 5200 A for the coordination chart of path 3. Therefore, the minimum short circuit that yields loss of coordination is 3051A. Tables 7 to 9 show the loss of coordination penetration limits at different candidate points and for different DG technologies. As shown in Table 9, the capacity of the inverter-based DG that yields loss of coordination is "no effect" or "no limit"; this is because the inverter based DG technology contribute to the fault current with a value equal to 1: 1.5 of its full load current and for a limited duration (to protect the semiconductor devices, which are characterized by their low thermal time constant. This means that a tremendously large inverter-based DG should be installed to trigger the loss of coordination. For considerable ratings of the inverter-based DG, "no effect" on the loss of coordination is observed.

In the urban benchmark system, there are four different coordination paths as shown in Figure 45. There is one intersection point between the ground coordination curve of the main feeder relay and the lateral fuse. Therefore, for the phase-coordination, there is no limit for the loss of coordination in this system.

Table 7 - The loss of coordination penetration limits **in the suburban system for the synchronous DG technology.**

Installation Point	P1	P2	P3	P4
DG size (kVA)	760	755	1550	2800

Table 8 - The loss of coordination penetration limits in the suburban system for the induction DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	3800	3700	6500	9000

Table 9 - The loss of coordination penetration limits in the suburban system for the inverter-based DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

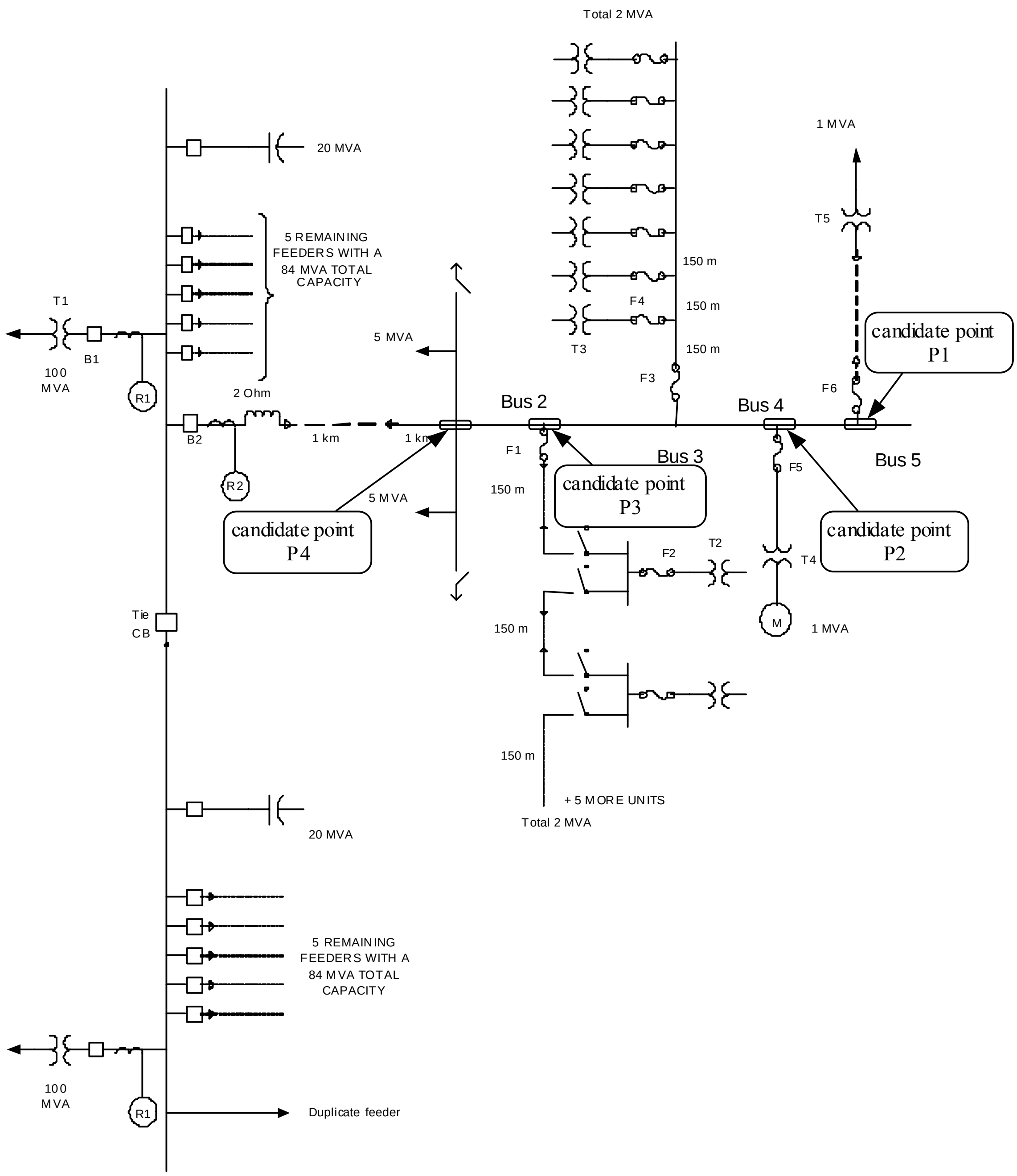


Figure 44 - Suburban benchmark system with the DG installation candidate points.

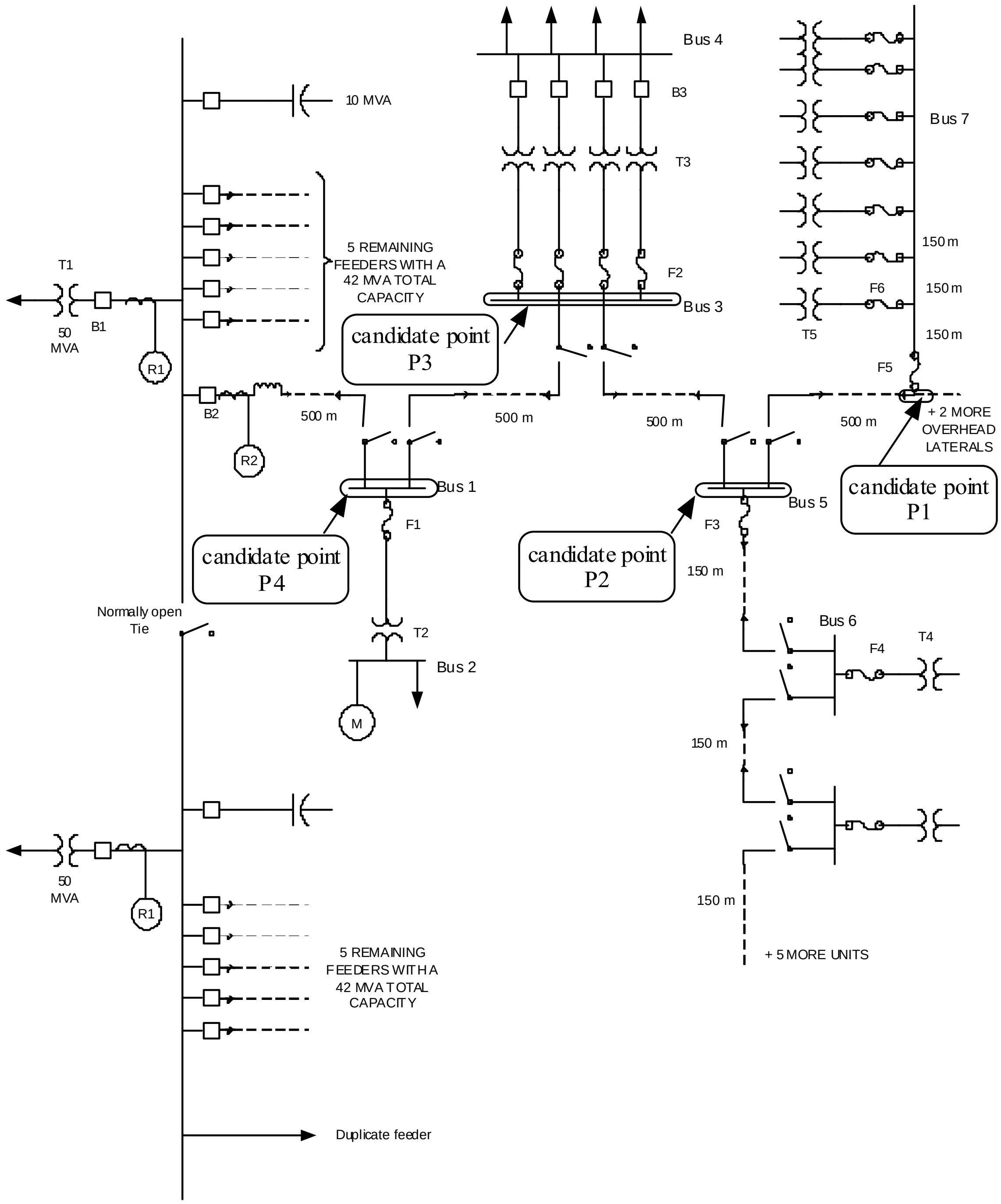


Figure 45 - Urban benchmark system with the DG installation candidate points.

4.2 Loss of Sensitivity

4.2.1 Impact definition

The addition of the DG to the distribution system might reduce the fault current level drawn from the main substation. This will in turn affect the operation of the substation breaker or recloser especially on their ability to "see" the fault. This will be highly dependant on the type, size and location of the DG.

To illustrate the impact of DG on the sensitivity of the substation breaker or recloser, let us consider a general radial feeder as shown in Figure 46. Without DG installation (Figure 46(a)), and under the fault condition, the fault current is totally supplied from the utility substation. In this case, the main feeder relay should be adjusted to respond to the lowest short circuit current. In Figure 46 (b), the DG is installed and at the fault condition, both the substation and the DG feed the fault. Depending on the source-to-fault impedances, the contribution of each source will be determined. From the circuit theory principles, the closer the DG to the substation, the lower the substation contribution to a fault beyond the DG installation point. For a fault location between the substation and the DG (Figure 46(c)), the utility contribution becomes independent of the DG size. The extreme effect of the DG is to decrease the main feeder sensitivity to the limit, at which it doesn't "see" the fault.

4.2.2 A generalized method to assess the loss of sensitivity penetration limits

The goal of this section is to develop a generalized procedure that determines the penetration limit of DG, in terms of size, location, and technology, from the point of view of loss of sensitivity. The general procedure can be summarized in the following items:

1. In a given system, determine the point, which is directly protected by the main feeder breaker/recloser and has the lowest short circuit current.

2. Determine the phase and ground pick-up currents of the feeder head-end relay.

3. Define the candidate points at which the DG might be installed. The penetration limit will be calculated for these specific points. These candidate points may be obtained from a planning study to determine the optimum location of DG to minimize system losses and improve the voltage profile, or it might be dictated by the customer.

4. Simulate the installation the DG at the first candidate point and establish the fault conditions at the point defined in step 1 above, then increase the DG size and its interfacing transformer step by step and observer the substation contribution to the fault current until it reaches the pick-up level, and then record the DG size. It should be noted that increasing the size of the DG and its interfacing transformer inherently increases the

short circuit MVA capacity of the combined DG/transformer set. The DG impedance estimation function in CYMDIST provides a useful tool to determine the DG impedance based on its rating. The impedance estimation tool is based on the IEEE Violet Book guidelines [29]. In addition, the interfacing transformer impedance can be estimated based on its rating parameters. This function is available in CYMDIST as well.

5. Repeat for the next candidate points.

6. Tabulate the results.

7. Change the DG technology and then repeat steps 5 to 7, tabulate the results at each case.

A flow chart representing aforementioned procedure is shown in Figure 47.

It is helpful to note that:

- The maximum reduction in sensitivity can be obtained when the DG installed at the closest candidate point to the substation and with the fault conditions at point defined in step 1.

- Since most of distribution systems have relatively high fault impedance, fault impedance might be assumed, then repeat step 5.

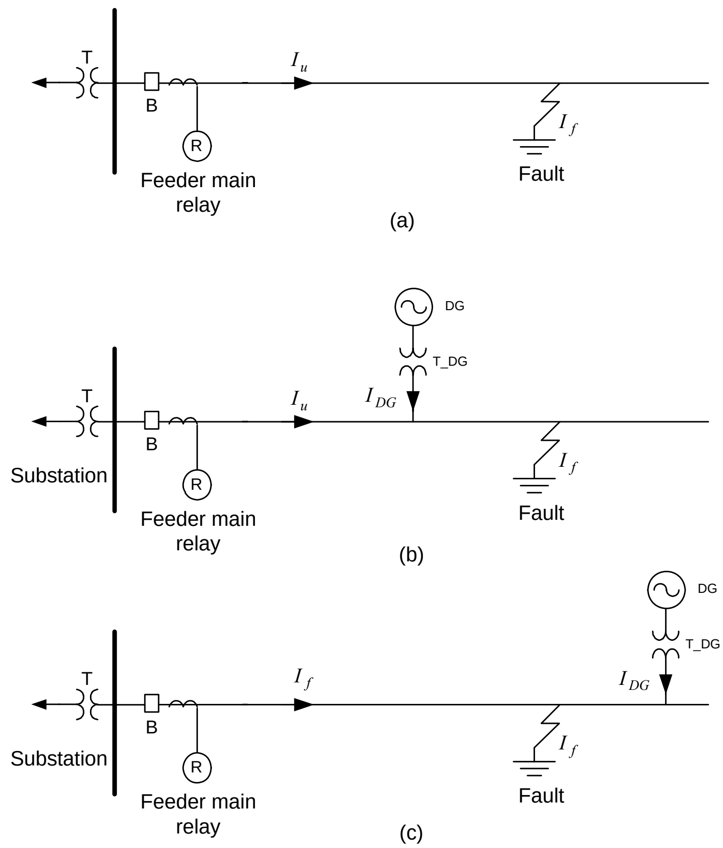


Figure 46 - Sample radial feeder with DG.

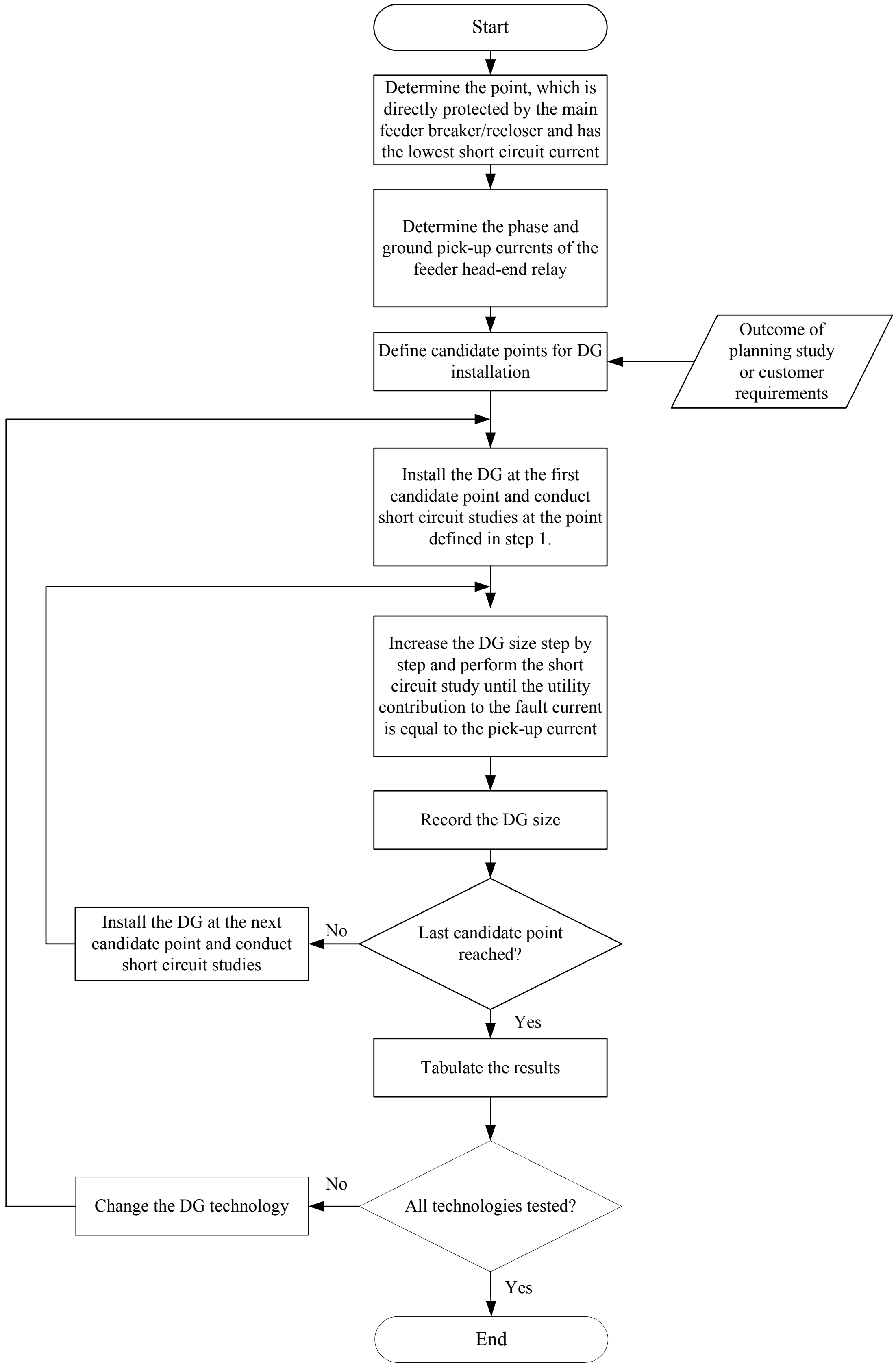


Figure 47 - A generalized method to assess the loss of sensitivity penetration limits.

4.2.3 Case studies

The aforementioned procedure is applied to the suburban system to demonstrate the applicability of the procedure. Figure 44 shows the suburban system with four candidate points (P1 to P4) for the DG installation. Through short circuit simulation studies, it can be seen that point (P1) is the point with the lowest short circuit current and it is directly protected by the main feeder relay. The pick-up level of the relay is 600 A. The closest candidate point to the substation is point P4. Therefore, the lowest DG size that violates the sensitivity is expected to be at P4. Tables 10-12 establish the sensitivity-based penetration limit for the feeder under study. When the DG is installed at P1, at which the fault is located, the DG size has no impact on the sensitivity, as the source-to-fault impedance is not affected by the installed DG.

Table 10 - The loss of sensitivity penetration limits **in the suburban system for the synchronous DG technology.**

Installation Point	P1	P2	P3	P4
DG size (kVA)	No effect	17000	15000	12000

Table 11 - The loss of sensitivity penetration limits in the suburban system for the induction DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	No effect	21000	16000	14000

Table 12 - The loss of sensitivity penetration limits in the suburban system for the inverter-based DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

4.3 Fuse Nuisance Blowing

4.3.1 Impact Definition

Fuse saving strategies are usually applied by utilities to save lateral fuses from temporary faults by de-energizing the line and re-energizing it again using auto recloser before the fuse has a chance to be blow. It is commonly adopted in suburban and rural distribution systems. Many faults are temporary in nature, so, the purpose of reclosing is to try and clear temporary faults without having any unnecessary permanent service interruption, and also to save fuse and prevent unnecessary fuse blow up. However, adding a DG to the distribution system could affect the timing coordination between the recloser and the fuse due to the additional fault current contribution from the DG and as result the coordination between the recloser and the fuse may be missed and the fuse could blow first or both the fuse and interrupting device could operate at the same time. In other words, fuse nuisance blowing is a form of the mis-coordination due to the presence of DG.

To illustrate the impact of DG on the fuse saving strategy, consider the suburban benchmark system with a 2 MVA synchronous-type DG connected at bus 4 through a gnd wye (pri)/delta(sec) interconnection transformer. Figure 41 depicts the coordination chart for the coordination path from the utility to bus 4. As shown in Figure 41, the short circuit current at bus 4 before installing the DG was 2836 A, so, the recloser and the fuse are fully coordinated at this value of short circuit current. For the coordination chart in Figure 42, the coordination is maintained up to a short circuit current level equals to 3051A, which is the intersection point between the fast curve of the recloser and the clearing curve of the fuse. If the short circuit current is increased beyond this limit, the coordination between the recloser and the main lateral fuse will be lost. This is the case when the 2 MVA DG is installed, where the short circuit current at bus 4 increases to 3604 A, as shown in Figure 42, and as a result the fuse will blow up and the service will be interrupted at this section.

4.3.2 A generalized method to assess the nuisance fuse blowing penetration limits

The goal of this section is to develop a generalized procedure that determines the penetration limit of DG, in terms of size, location, and technology, from the point of view of nuisance fuse blowing. Being a consequence of mis-coordination, the general procedure will be quite similar to that developed for the loss of coordination and it can be summarized in the following items:

1. Define different protection coordination protection paths in the system under study.

2. Perform the coordination study and construct the coordination charts for the protection paths without installing the DG.

3. Observe the current at which the fuse nuisance blowing may occur. This current is obtained by observing the intersection between the recloser fast curve and the fuse-clearing curve.

4. Define the candidate points at which the DG may be installed.

5. Simulate the installation the DG at the first candidate point, and then increase the DG size step by step until the occurrence of the nuisance fuse blowing problem. Record the DG size.

6. Repeat for the next candidate points.

7. Tabulate the results.

8. Change the DG technology and then repeat steps 5 to 7, tabulate the results at each case.

A flow chart representing aforementioned procedure is shown in Figure 48.

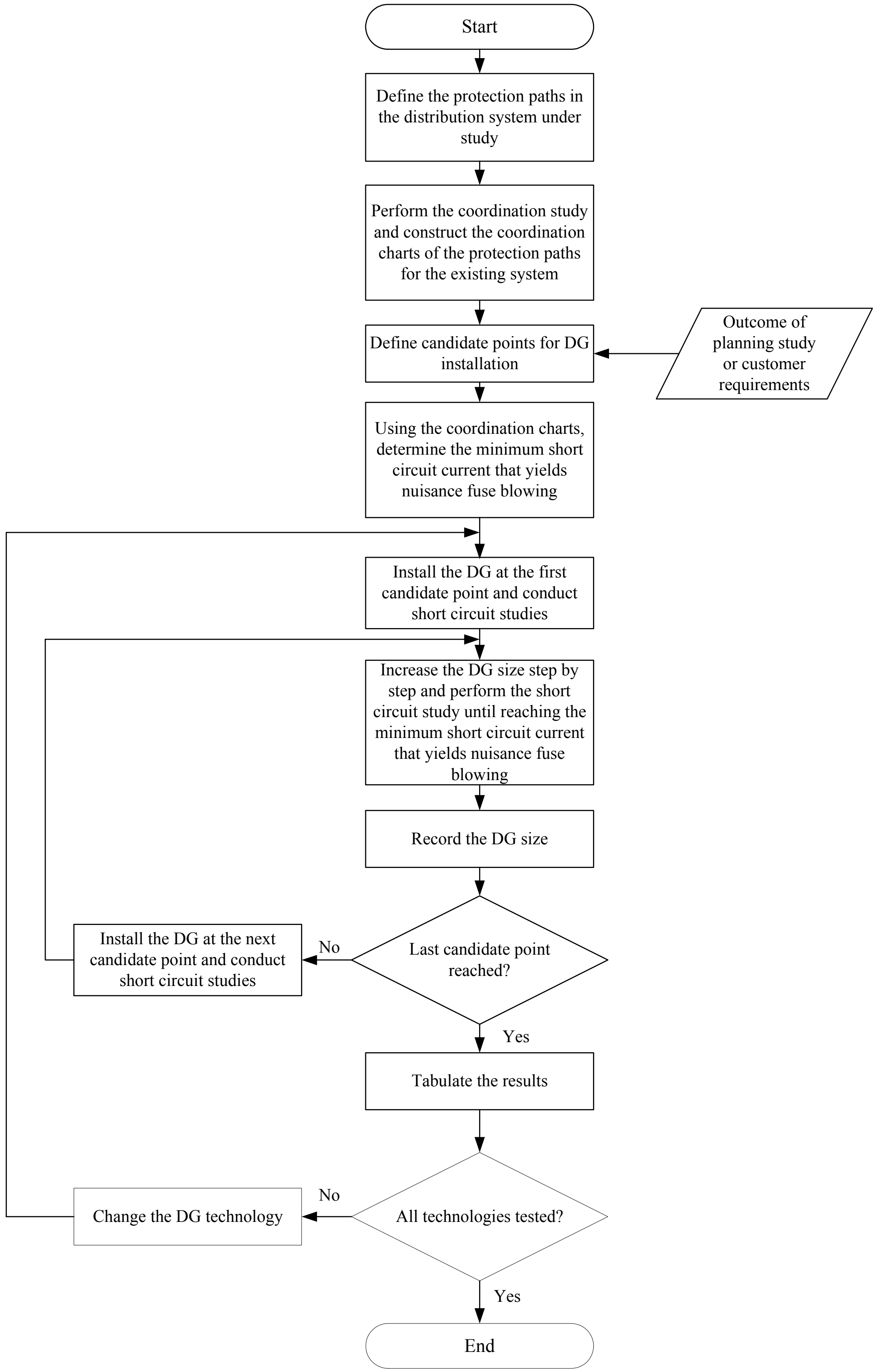


Figure 48 - A generalized method to assess the fuse nuisance-blowing penetration limits.

4.3.3 Case studies

The aforementioned procedure is applied to the suburban to demonstrate the applicability of the procedure. Fuse saving strategy is not applicable in the urban benchmark system. The initial coordination studies are performed in Chapter 2. Figure 44 shows the suburban system with four candidate points (P1 to P4) for the DG installation. In the suburban system, there are 3 different coordination paths; namely coordination paths 1, 2, and 4 as shown in Figure 2. Coordination path 3 is similar to 4 as the same fuses are utilized. Nuisance fuse blowing takes place in the coordination charts of the suburban system under study at the intersection of the “fast” curve of the recloser with the clearing curve of the main lateral fuses. These intersections occur at 3051 A for the coordination chart of path 1, 3051 A for the coordination chart of path 2, and 5200 A for the coordination chart of path 3. Therefore, the minimum short circuit that yields loss of coordination is 3051A. Tables 13 to 15 show the loss of coordination penetration limits at different candidate points and for different DG technologies. As shown in Table 15, the inverter-based DG has a minimum effect on the loss of coordination; this is because the inverter based DG technology contribute to the fault current with a value equal to 1: 1.5 of its full load current and for a limited duration (to protect the semiconductor devices, which are characterized by their low thermal time constant). This means that a tremendously large inverter-based DG should be installed to trigger the loss of coordination.

Table 13 - The loss of coordination penetration limits in the suburban system for the synchronous DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	760	755	1550	2800

Table 14 - The loss of coordination penetration limits in the suburban system for the induction DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	3800	3700	6500	9000

Table 15 - The loss of coordination penetration limits in the suburban system for the inverter-based DG technology.

Installation Point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

4.4 Bi-directionality of protection devices

4.4.1 Impact Definition

DG installation in distribution system may cause un-wanted bi-directionality for the protection devices, which may cause malfunctioning of the protection devices, and as a result a healthy part from the distribution system may be unnecessarily interrupted. The bi-directionality issue can be obviously observed in the radial feeders that are fed from the same source. Also, this issue is relevant for DG on a lateral-backfeed from DG to the adjacent lateral. Consider two parallel radial feeders fed from one source as shown in Figure 49. With no DG installed, if a short circuit occurs on one feeder of the two radial feeders, the short circuit will be completely fed from the utility source and the contribution from the feeder in the short circuit will be zero as shown in Figure 49. As a result, the current in the breaker B2 will not be reversed and the relay at B2 will not respond to the short circuit at feeder 1.

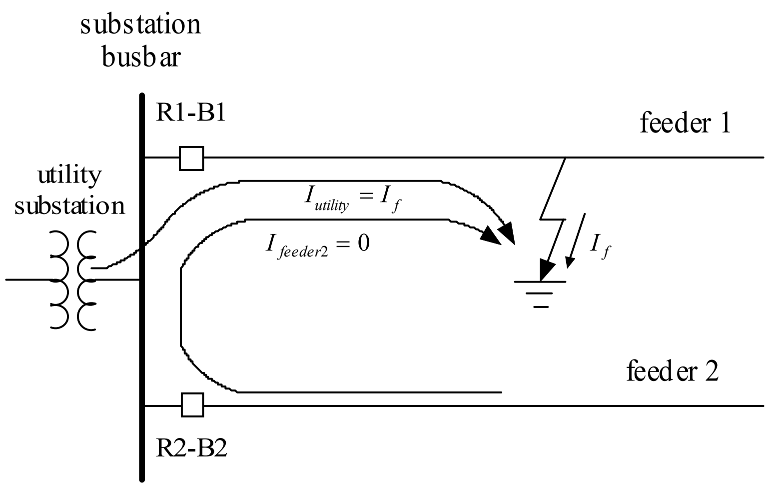


Figure 49 - Short circuit contribution on a radial distribution system without DG.

On the other hand, if a DG is installed on the healthy feeder (feeder 1), the short circuit contribution from the healthy feeder to the short circuit current will not be zero as shown in Figure 50. In this case, if the relay at B2 has faster characteristics than the relay at B1, the relay at B2 may respond to the fault at feeder 1 un-necessarily and interrupt the loads of feeder 2.

In addition, the bi-directionality issue may occur in the presence of reclosers, which are installed in sub-urban and rural systems to save fuses during temporary faults. Two feeders are installed and fed from the same supply as shown in Figure 51. Both of the feeders contain main relay and recloser to save the fuses for down stream temporary faults. If there is no DG on feeder 2, neither the main relay nor the recloser will respond to a fault on feeder 1, similar to the case shown in Figure 12. On the other hand, if a DG is installed in feeder 2, the DG will feed part of the total fault current as shown in Figure 14. This fault current contribution from the DG will be seen by the recloser, which is designed to respond very fast to through currents over its pickup value. And thus it may operate before R1 and make un-necessarily interruption to the healthy feeder.

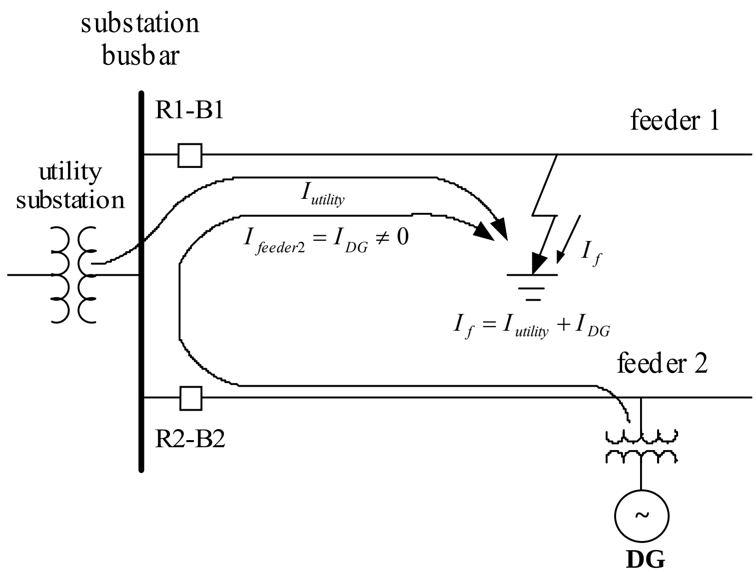


Figure 50 - Short circuit contribution on a radial distribution system with a DG installed.

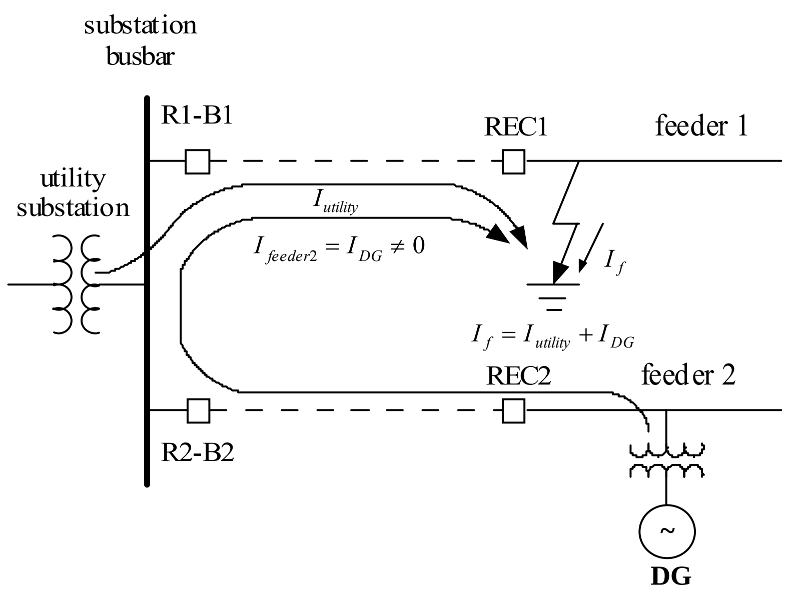


Figure 51 - Short circuit contribution on a radial distribution system contain reclosers with a DG installed.

For further illustration, consider the case when a 900 kVA synchronous DG connected at the most downstream candidate point (P1) of the feeder under study of the urban system as shown in Figure 8. Also, another higher load feeder is assumed to be fed from the same source as shown in Figure 52. From the coordination study of feeder2, the main relay characteristics at the main breaker B2 is S&C VISTA IEC C1 600 A pickup, TDS 5 for phase protection and S&C VISTA IEC C1 150 A pickup, TDS 0.2 for ground protection. If the ground protection of main relay at the main breaker of feeder1 is taken as S&C VISTA IEC C1 300 A pickup, TDS 0.55, the relative characteristics will be as shown in Figure 53. Before the installation of the DG, the main relay at B2 will not respond to any short circuit on feeder 1 as shown in Figure 49. After the installation of a 900 kVA synchronous DG at point (P1) of feeder 2, and for short circuit in the middle of feeder 1, the short circuit current will be fed from two sources; the utility and the DG as shown in Figure 50, and then the relay at B1 will sense 4707.8 A while the relay at B1 will sense 413.8 A and as result the two operating times of the two relays will be the same and the two relays will operate at the same time causing the feeder2 to be un-necessarily interrupted for a fault in feeder1.

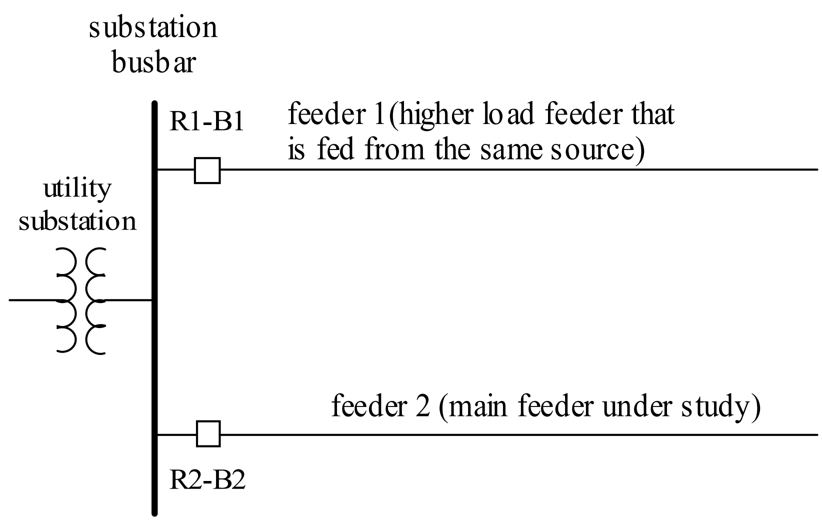


Figure 52 - Two feeder fed from the same source.

4.4.2 A generalized method to assess the bi-directionality penetration limits

The goal of this section is to develop a generalized procedure that determines the penetration limit of DG, in terms of size, location, and technology, from the point of view of bi-directionality of protection devices. The general procedure will be quite similar to that developed for the loss of coordination and it can be summarized in the following items:

1. Define different protection coordination protection paths in the system under study.

2. Perform the coordination study and construct the coordination charts for the protection paths without installing the DG.

3. Define the candidate points at which the DG may be installed.

4. Simulate the installation the DG at the first candidate point, and then increase the DG size step by step until the occurrence of the bi-directionality of protection devices problem. Record the DG size.

5. Repeat for the next candidate points.

6. Tabulate the results.

7. Change the DG technology and then repeat steps 5 to 7, tabulate the results at each case.

A flow chart representing aforementioned procedure is shown in Figure 54.

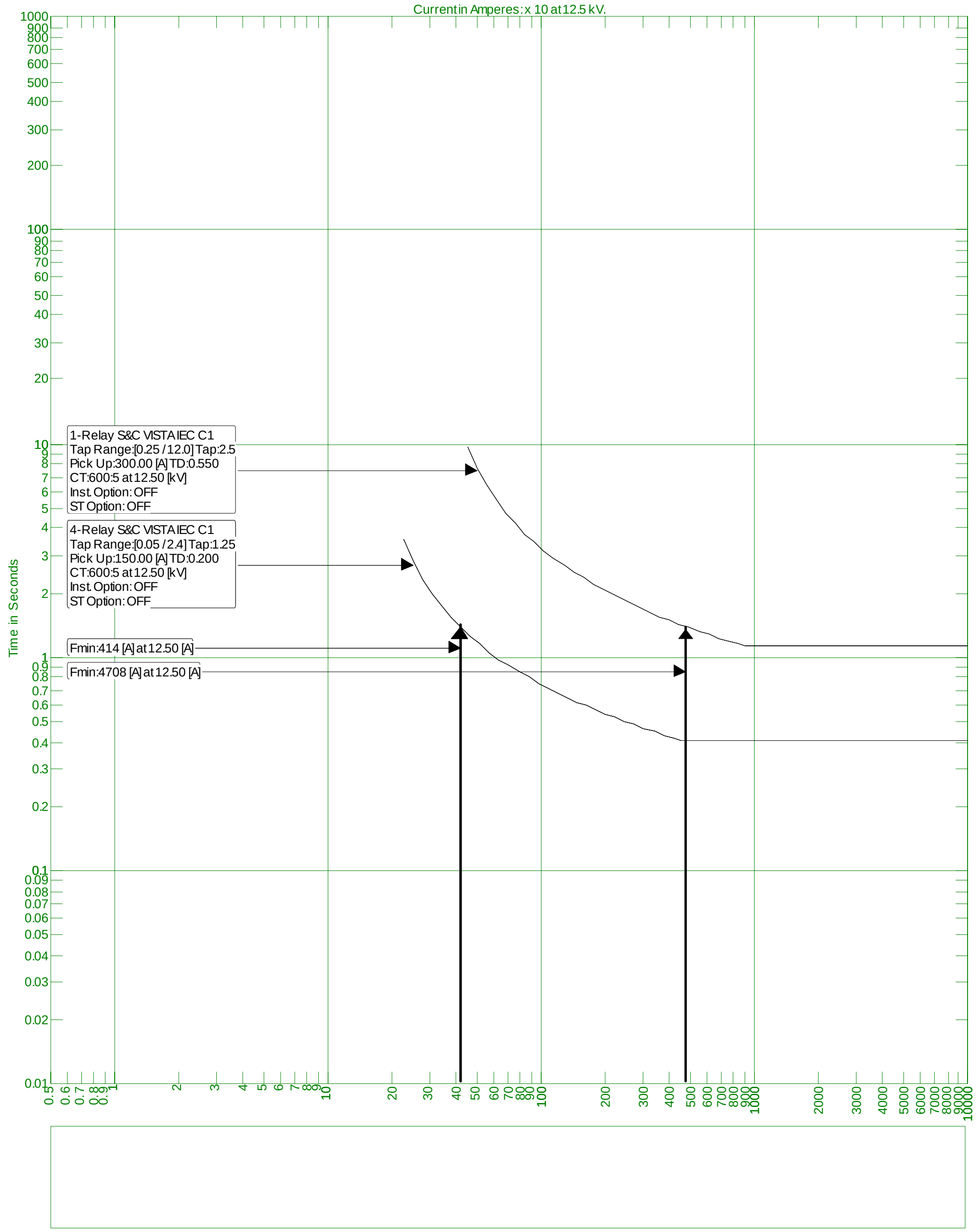


Figure 53 -The ground characteristics of feeder1 and feeder 2.

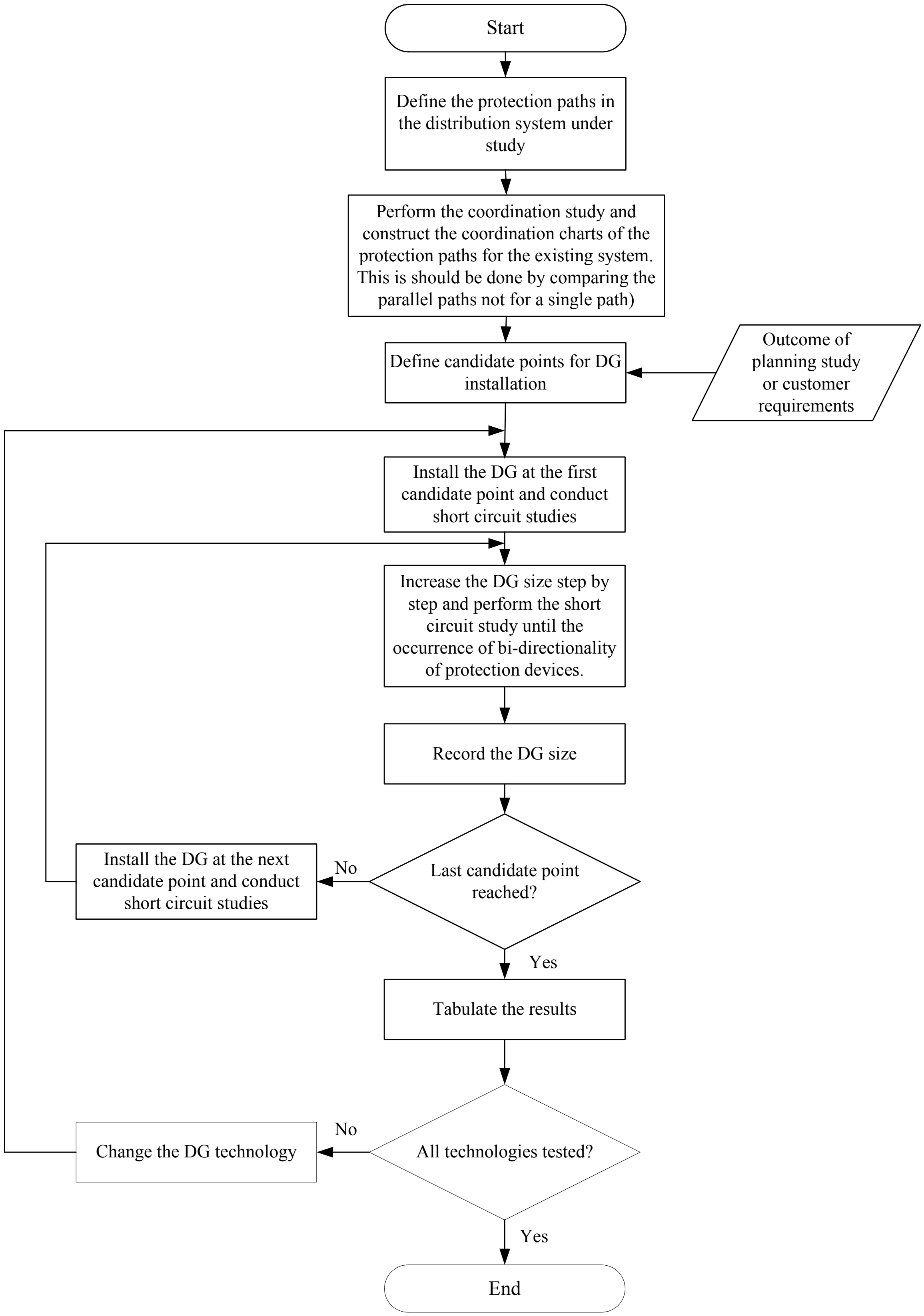


Figure 54 - A generalized method to assess the **bi-directionality penet**ration limits.

4.4.3 Case Studies

4.4.3.1 Case study on the urban system

The aforementioned procedure is applied to the urban system to demonstrate the applicability of the procedure. As stated above, the procedures here are nearly the same as that in the loss of coordination and fuse nuisance blowing study. The coordination paths are determined and the initial coordination studies are considered. The relay at B2 is S&C VISTA IEC C1 600 A pickup, TDS 5 for phase protection and S&C VISTA IEC C1 150 A pickup, TDS 0.2 for ground protection and the relay at B1 is S&C VISTA IEC C1 1200 A pickup, TDS 5 for phase protection and S&C VISTA IEC C1 300 A pickup, TDS 0.55 for ground protection. Figure 44 depicts the urban system with DG installation candidate points. Tables 16 to 18 show the bi-directionality limits at different candidate points and for different DG technologies.

Table 16 - The bi-directionality penetration limits in the urban system for the synchronous DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	950	900	900	900

Table 17 - The bi-directionality penetration limits in the urban system for the induction DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	12000	11600	11600	11600

Table 18 - The bi-directionality penetration limits in the urban system for the inverter-based DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

4.4.3.2 Case Study on the suburban System

The same procedures can be followed for the suburban system. The two main feeders' relays characteristics are: for the feeder under study (feeder 2) ABB, Pickup 600A, TDS 6, CT: 600/5 for phase protection, Pickup 1500 A and ABB, as instantaneous relay, and ABB Pickup 150A, TDS: 0.2, CT:600/5 for Ground protection. For the other radial feeder (feeder 1), ABB, pickup 1200 A, TDS 6, CT: 600/5 for phase protection and ABB RET 316 LT E FLT, pickup at 300 A, TDS 4.1 and instantaneous relay, Pickup 5600 A. A synchronous DG was simulated on the first candidate point (P1) and its size was step by step increased, until the occurrence of the bi-directionality problem. It can be found that a 40 MVA synchronous DG size will trigger the bi-directionality issue. With this size, and for a short circuit at feeder 1, the two relays at B1 and B2 will respond nearly at the same time as shown in time-current curve of Figure 55. The same steps are repeated for the rest of the candidate points and DG technologies. Tables 19 to 21 show the DG sizes for all candidate points.

Table 19 - The bi-directionality penetration limits in the suburban system for the synchronous DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	40000	37000	33000	31000

Table 20 - The bi-directionality penetration limits in the suburban system for the induction DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

Table 21 - The bi-directionality penetration limits in the suburban system for the inverter-based DG technology.

DG installation point	P1	P2	P3	P4
DG size (kVA)	No effect	No effect	No effect	No effect

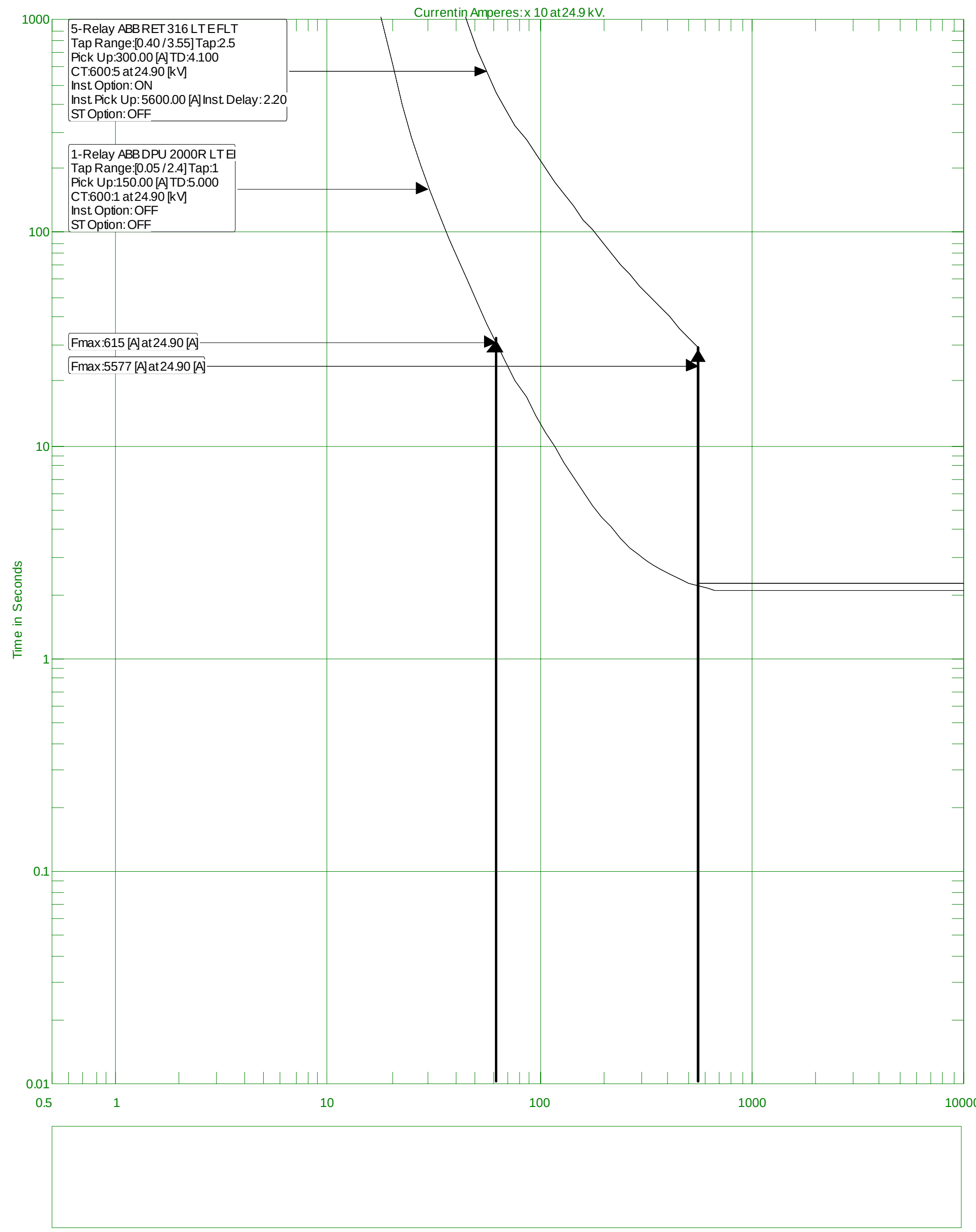


Figure 55 - The operation time of R1 (B1) and R2 (B2) for a fault in feeder 1 with a synchronous DG installed at candidate point (P1).

4.5 Overvoltages

4.5.1 Impact Definition

The main overvoltage-related issues associated with DG include [7]-[12]:

1. Temporary Overvoltage due to ground fault conditions caused by improper application of DG grounding or interface transformer connection.

2. Overvoltage, which originates from the utility side and surrounding environment and does affect the Distributed generation scheme.

3. Resonant over-voltages which may arise during islanding conditions

4. Over voltages which may arise due to high DR power injection

Temporary overvoltage due to ground fault conditions caused by improper application of DG grounding or interface transformer connection is addressed in this section. The correct sizing of surge arrestors would prevent damage of the DG installation because of high voltage surges originating from surrounding environment. The resonant overvoltages, which may arise because of interaction of transformer and DG combination inductance with a system capacitance is an operational problem which should be addressed in different context utilizing a detailed dynamic simulation programs such as EMTDC or EMTP. Similarly, overvoltage, which may arise due to high DG power injection is also an operational issues which should be addressed in different context.

As discussed in the Chapter 3, five typical transformer connections are widely used to interconnect DG's to the utility system; namely they are: Delta (HVS-utility side)/Delta (LVS-DG side), Delta (HVS-utility side)/Wye-Gnd (LVS-DG side), Wye-Ungnd (HVS-utility side)/Delta (LVS-DG side), Wye-Gnd (HVS-utility side)/Delta (LVS-DG side) and Wye-Gnd (HVS-utility side)/ Wye-Gnd (LVS-DG side), where (HVS-utility side) indicates the primary winding and (LVS) indicates the secondary winding.

For the first three connections: Delta (HVS-utility side)/Delta (LVS-DG side), Delta (HVS-utility side)/Wye-Gnd (LVS-DG side), Wye-Ungnd (HVS-utility side)/Delta (LVS-DG side), the main advantages are as follows: there is no impact on the utility ground relay coordination; and any ground fault on the secondary of the interconnection transformer will not be seen by the utility protection system and as result; the ground coordination system will not be affected. However, the major concern with an interconnection transformer with an ungrounded primary winding is that after the utility breaker is tripped for a permanent ground fault, the system will be fed from an ungrounded source. This subjects the un-faulted phases to an overvoltage that will approach the line-to-line voltage. These advantages and disadvantages have been addressed in detail in the second progress report of this study.

Considering the fourth connection which is a Wye-Grounded (HVS-utility side)/Delta (LVS-DG side) connection: for a ground fault at the DG side, the utility will not contribute any zero sequence current to the fault, and as result, this arrangement prevents the utility protection system to respond to ground faults at the DG side. However, the disadvantage of this arrangement is that it acts as a zero sequence current source; hence, establishing a zero sequence current for ground faults on the distribution system. This could have a significant impact on the utility's ground relay coordination. Also, this zero-sequence current from the high voltage side will circulate in the delta winding on the low voltage side, and possibly causing heating problems within the transformer. A commonly practiced solution to this problem is to place grounding impedance in the high-side neutral connection to limit the flow of excessive circulating currents. The ground impedance should be high enough to limit the circulating current but low enough to maintain effective grounding of the DG unit. In addition, any unbalanced load on the distribution circuit would normally return to ground through the utility transformer neutral. With the addition of the generator interconnection transformer, this unbalance will be divided between the utility transformer neutral and the generator interconnection transformer. During serious unbalance conditions such as a blown lateral fuse, the load carrying capability of the interconnection transformer can be reduced. The use of a grounded-wye winding on the high side and delta on the low side has the advantage of limiting the overvoltages that can be developed when the utility beaker opens; thereby sparing lightning arresters and feeder loads from damage.

For the fifth connection which is a Wye-Grounded (Primary)/Wye-Grounded (Secondary) connection: the main advantage for this connection is that no overvoltages will be developed when the utility beaker opens (for a solidly grounded connection). The major disadvantage of this connection is that it provides a source of unwanted ground current for utility feeder faults similar to that described in the previous section.

4.5.2 A generalized procedure to assess temporary overvoltage

As it can be seen from the above mentioned discussion, not grounding the DG interconnecting transformer exposes the feeder and its connected customers to unsafe temporary overvoltages, whereas solid grounding may limit the protection sensitivity to an unacceptable level during ground faults. Impedance grounding can offer a tradeoff. The impedance grounding can be selected such that to give an acceptable temporary overvoltage (around 25% higher than the rated value) with a small decrease (around 5%) in sensitivity to minimum fault current. Reference [9] has suggested that a reactor placed in transformer ground with a typical value between 1.0 -1.5 of the transformer zero sequence impedance would satisfy this tradeoff.

The following is a generalized procedure to assess temporary overvoltage associated with DG:

1. Define and simulate distribution network under consideration.

2. Define the candidate points at which the DG may be installed along with transformer connection configuration and grounding details.

3. For ungrounded transformer connection, the DG protection scheme design logic and hardware should insure that the DG installation should be disconnected before the main feeder circuit breaker.

4. For grounded DG installation, simulate the single line to ground fault and calculate percentage change in ground fault sensitivity. If the change in sensitivity is greater than 5%, insert a grounding reactance in transformer ground.

5. Calculate the overvoltage due to insertion of the ground reactance and check that it is within acceptable range (25% higher than rated voltage for example)

6. Repeat step 4, and check the change in the sensitivity.

7. If sensitivity and overvoltage are acceptable, stop, otherwise repeat step 5 and 6.

8. Repeat for the next candidate points.

9. Tabulate the results.

The flowchart in Figure 56 illustrates the procedure.

A simple procedure to estimate the expected value of overvoltage due to the insertion of a reactance in transformer grounding path is presented in Chapter 3 (section 3.4).

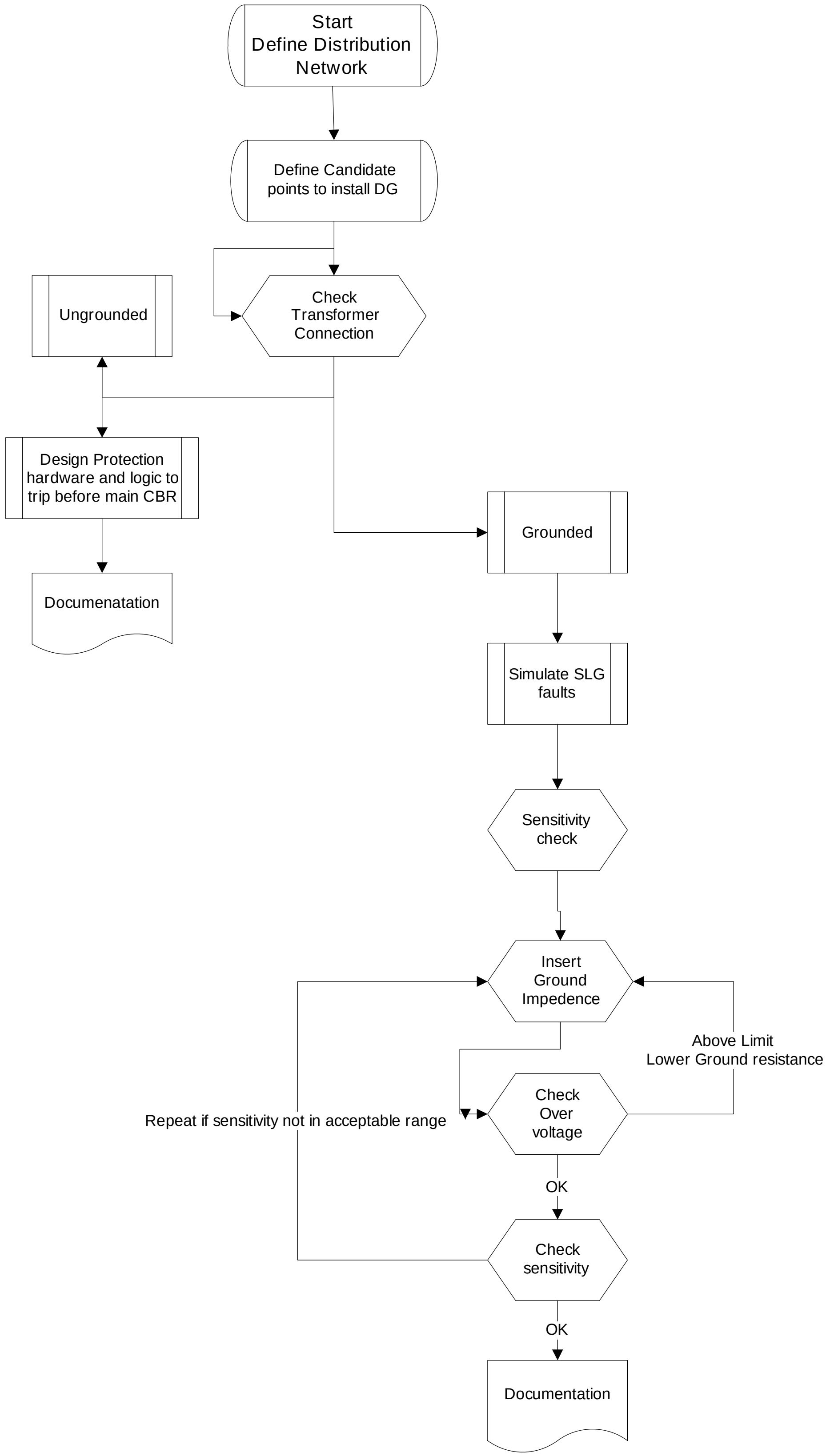


Figure 56 - A generalized procedure to assess temporary overvoltages associated with DG integration

4.5.3 Case Studies

Case Study 1: DG near substation bus

To show the effect of changing the grounding impedance on the fault current and overvoltage, the suburban system shown in Figure 2 has been used. However, to simplify numerical calculations, all sub-lateral connected loads has been assumed concentrated load originating directly from the main feeder as seen in Figure 57. As stated earlier, in the case of an ungrounded system, the line to neutral voltage of the healthy phases during a ground fault is 1.73 times the rated phase voltage. For a grounded transformer, and assuming that the utility breaker is opened, the voltage of the healthy phases during a ground fault varies according to the value of the grounding impedance. In a ground fault condition, the line-to-neutral voltages of the healthy phases don't change if the system is solidly grounded and they increase as the grounding impedance increases.

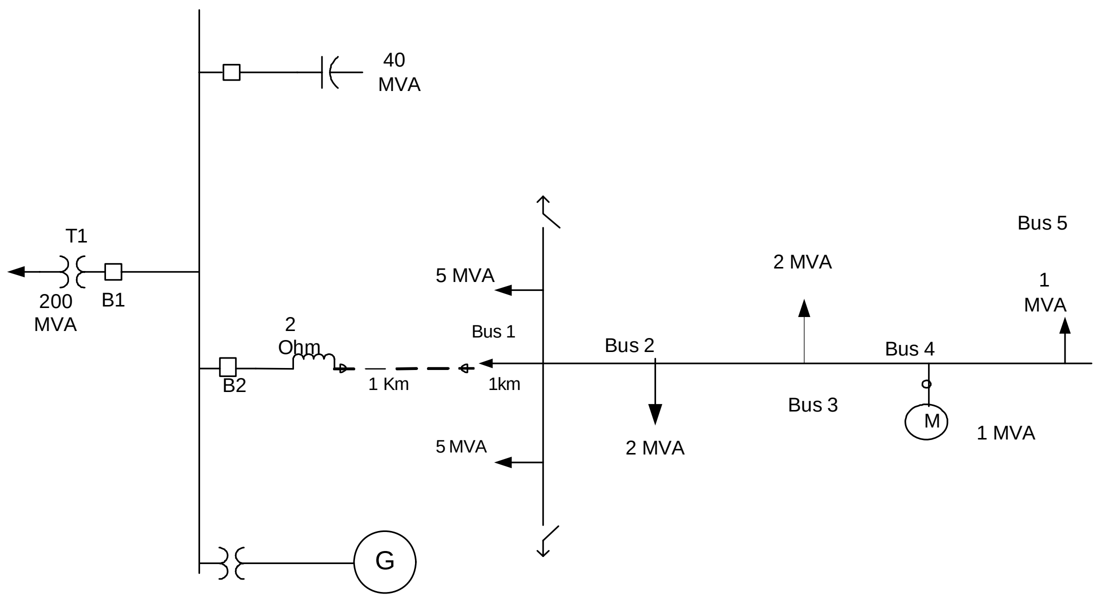


Figure 57 -A simplified suburban distribution network showing DG near the substation bus.

Table 22 shows that the DG does not affect the ground fault current value if the interconnection transformer has ungrounded primary-side. It can be noticed that the ground fault current values, with no DG installed, are slightly less than those obtained when the DG is installed. This is due to higher pre-fault voltages yielded by the power injected by the DG. Also, it is clear that a DG with a Gnd-Wye/ Delta interconnection transformer has the largest effect on the ground fault current, as this connection contributes the largest zero sequence current to the ground fault current. The effect of the DG size on ground fault current is obvious from the results obtained. As the DG size increases, its contribution to the short circuit current increases.

Table 22 - Case study results: Effect of DG size and connection of the interconnection transformer on the ground fault current, DG is located near substation bus.

Interconnection Transformer		Small DG (6000kVA DG) Ground fault current (A) at				
Utility side	DG side	Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
No DG		3663.4	2942.7	2444	2083.7	1813.1
Delta	Delta	3663.4	2942.7	2444	2083.7	1813.1
Delta	Gnd-Wye	3663.4	2942.7	2444	2083.7	1813.1
Wye	Delta	3663.4	2942.7	2444	2083.7	1813.1
Gnd-Wye	Gnd-Wye	3716.5	2975.5	2465.8	2099.1	1824.5
Gnd-Wye	Delta	3798	3026.3	2499.8	2123.2	1842

Medium Size DG (9000 KVA DG) Ground fault current (A) at				
Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3722.9	2979.4	2468.3	2100.9	1825.8
3840.6	3052.4	2517.2	2135.4	1851.4

Large Size DG (12000 kVA DG) Ground fault current (A) at				
Bus 1	Bus 2	Bus 3	Bus 4	Bus 5
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3663.4	2942.7	2444	2083.7	1813.1
3726.8	2981.7	2469.9	2101.9	1826.6
3846.2	3055.9	2519.4	2137.1	1853

For the system shown in Figure 57, the line voltage = 24.9 kV and accordingly,

$$V_{KC} = V_{KB} = \frac{24900}{2} = 12450V \text{ and } V_{GK} = \frac{1}{3} * \frac{\sqrt{3}}{2} V_L = 7188\,V,$$

Also, $V_{BG} = V_{CG} = \dfrac{24900}{\sqrt{3}} = 14376\,V$

So, if the grounding impedance = 0, V_{Gn} will be equal to zero and the three line to neutral voltages will be equal to line to ground voltage = 7967 V irrespective of the ground fault. As the transformer grounding impedance increases, the line to neutral voltages of the healthy phases increase during a ground fault condition. Ultimately, if the transformer is ungrounded, i.e., $Z_g \rightarrow \infty$, the voltages of the un-faulted phases will reach the line-to-line voltages.

Table 23 summarize the effect of changing the grounding impedance of the interconnection transformer (Gnd Wye/Gnd Wye) on the value of the overvoltage at the primary terminals of the interconnection transformer and the fault current during a single phase to ground (A-G) fault at five locations across main feeder (bus 1 to bus 5)

The grounding impedance of the interconnection transformer increases the zero-sequence impedance of the DG side and, therefore, reduces the zero sequence current supplied by the DG. It, thereby, reduces the contribution of the DG on the ground fault current and, as a result, restricts the reduction in ground protection sensitivity. However, this will results in increasing overvoltage seen at the terminals of the DG as depicted in Table 23.

Table 23 - Case study results: Effect of transformer grounding impedance on healthy phases' line to neutral voltages, DG near substation.

Interconnection Transformer Grounding Impedance (p.u.)	xg Ohm	Xg/X0	Large DG (12000 kVA)																				
			I_F Bus 1	I_FZ_G	Vph	OV %	I_F Bus 2	I_FZ_G	Vph	OV %	I_F Bus 3	I_FZ_G	Vph	OV%	I_F Bus 4	I_FZ_G	Vph	OV %	I_F Bus 5	I_FZ_G	Vph	OV %
Solidly Gnd	0	0	3726.8	0	14.4	0	2982	0	14.4	0	2470	0	14.4	0	2101.9	0	14.4	0	1827	0	14.4	0
0.06	3.2	1	3708.7	11867.7	22.8	8.4	2971	9506	20.8	6.4	2463	7881	19.5	5	2096.9	6710	18.7	4.3	1823	5833	18	3.6
0.12	6.4	2	3699.6	23677.6	33.3	18.9	2965	18977	29	14.6	2459	15738	26.1	12	2094.33	13404	24.1	9.7	1821	11654	22.6	8.2
0.18	9.6	3	3694.3	35464.8	44.4	30	2962	28434	37.7	23.3	2457	23586	33.2	19	2092.77	20091	30	15.6	1820	17471	27.6	13.2

Case Study 2: DG near the end of the feeder

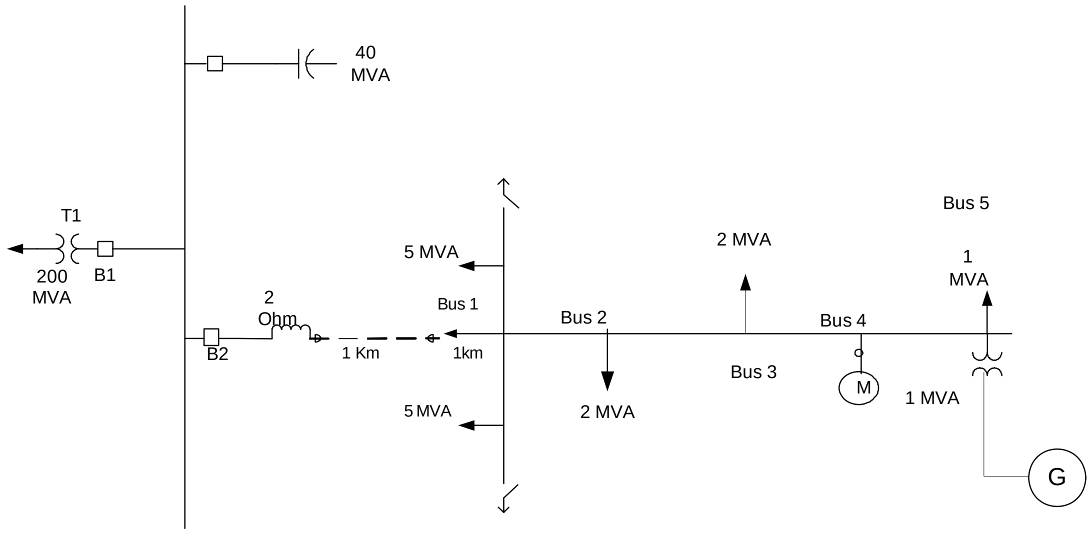


Figure 58 - A simplified suburban distribution network showing DG near the end of the feeder

In this scenario, to study the effect of the location on the generated overvoltage following a single line to ground fault, the DG is assumed to be located near the end of the distribution feeder as shown in Figure 58.

Similar to Table 23, Table 24 shows that the DG does not affect the ground fault current value if the interconnection transformer has ungrounded primary-side. It can be noticed that the combination of the location of the installed DG as well as the transformer connection play a key role in the contribution of the DG toward fault current for the same utilized transformer connection and DG size. Figure 59 shows the effect of the location and the transformer connection on the contribution of DG toward fault current. As it can be observed from the figure a DG with (Gnd Y/ Delta) connection placed at the far end of the feeder will provide the largest contribution toward ground fault current.

Similar to the previous case study, Table 25 summarize the effect of changing the grounding impedance of the interconnection transformer (Gnd Wye/Gnd Wye) on the value of the overvoltage at the primary terminals of the interconnection transformer and the fault current during a single phase to ground (A-G) fault at five locations across main feeder (bus 1 to bus 5)

Similar to the conclusion made in the first case study, the grounding impedance of the interconnection transformer increases the zero-sequence impedance of the DG side and, therefore, reduces the zero sequence current supplied by the DG. It, thereby, reduces the contribution of the DG on the ground fault current and, as a result, restricts the reduction in ground protection sensitivity. However, this will results in increasing overvoltage seen at the terminals of the DG as depicted in Table 25, a grounding impedance with a value equal to 3 Xo may lead to 30 % overvoltage during a single line to ground fault at bus 1, so in that case it is advisable to have the ratio between Xg/X0 between 2 to insure that overvoltage would be within acceptable margin. An additional means is to use an overvoltage relay together with a grounding impedance to prevent overvotlages [50].

Table 24- Case study results: Effect of DG size and connection of the interconnection transformer on the ground fault current, DG is located near feeder end

Interconnection Transformer		Small DG (6000kVA DG)				
Utility side	**DG side**	**Bus 1**	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**
No DG		3663.4	2942.7	2444	2083.7	1813.1
Delta	Delta	3725.6	3005.2	2506.5	2146.1	1875.4
Delta	Gnd-Wye	3725.6	3005.2	2506.5	2146.1	1875.4
Wye	Delta	3725.6	3005.2	2506.5	2146.1	1875.4
Gnd-Wye	Gnd-Wye	3773.8	3059.9	2565.5	2208.3	1940.2
Gnd-Wye	Delta	4458.3	3866.3	3490	3258.1	3131.3

Medium Size DG (9000 KVA DG)				
Bus 1	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**
3663.4	2942.7	2444	2083.7	1813.1
3725.6	3005.2	2506.5	2146.1	1875.4
3725.6	3005.2	2506.5	2146.1	1875.4
3725.6	3005.2	2506.5	2146.1	1875.4
3774.6	3060.9	2566.8	2209.7	1941.7
4430.3	3850.9	3485.7	3265.4	3152.3

Large Size DG (12000 kVA DG)				
Bus 1	**Bus 2**	**Bus 3**	**Bus 4**	**Bus 5**
3663.4	2942.7	2444	2083.7	1813.1
3725.6	3005.2	2506.5	2146.1	1875.4
3725.6	3005.2	2506.5	2146.1	1875.4
3725.6	3005.2	2506.5	2146.1	1875.4
3774.6	3061	2566.8	2209.7	1941.7
4483.5	3922	3577.3	3382.4	3302.8

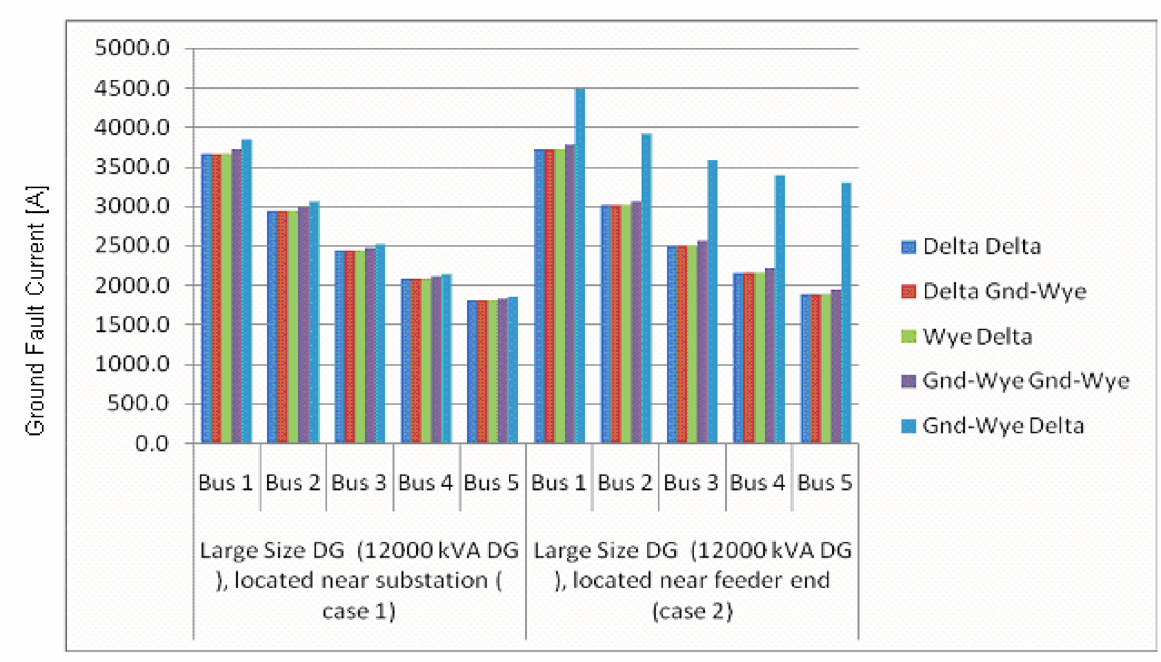


Figure 59 - Effect of transformer connection and DG location on single line to ground fault current.

Table 25 - Case study results: Effect of transformer grounding impedance on healthy phases' line to neutral voltages, overvoltage, and short circuit current DG near feeder end.

Interconnection Transformer Ground impedance (p.u.)	X_g Ohm	X_g/X_0	Large DG (12000 KVA)																			
			I_F Bus 1	I_FZ_G	V_{ph}	OV%	I_F Bus 2	I_FZ_G	V_{ph}	OV%	I_F Bus 3	I_FZ_G	V_{ph}	OV%	I_F Bus 4	I_FZ_G	V_{ph}	OV%	I_F Bus 5	I_FZ_G	V_{ph}	OV%
Solidly Gnd	0	0	3774.6	0	14.4	0	3061	0	14.37	0	2567	0	14.4	0	2209.7	0	14.37	0	1942	0	14.37	0
0.06	3.2	1	3773.9	11867.7	22.8	8.4	3060	9792	21.05	6.68	2566	8210	19.8	5.4	2208.3	7066.56	18.92	4.55	1940	6209	18.28	3.91
0.12	6.4	2	3771.7	23677.6	33.3	18.9	3058	19568	29.5	15.1	2563	16403	26.7	12	2205.7	14116.4	24.67	10.3	1937	12400	23.2	8.83
0.18	9.6	3	3770.1	35464.8	44.4	30	3056	29334	38.58	24.2	2561	24585	34.1	20	2203.5	21153.2	30.95	16.6	1935	18577	28.61	14.2

4.6 Summary

A generalized method to assess the impact of DG on distribution system protection, by considering the most important protection impacts, such as loss of coordination, de-sensitisation, nuisance fuse blowing, bidirectional relay requirements and overvoltage, has been presented. To simplify the study, each protection impact is studied individually to determine the penetration limit that triggers this issue. The method is demonstrated using the suburban and urban benchmark distribution systems and the DG models presented in this report.

5 Protection Impacts in the Islanded Mode of Operation

5.1 Introduction

Distributed Generation can potentially increase the distribution system reliability and provide additional technical and economical benefits by allowing intentional islanding or so called micro-grid operation of DGs. The current IEEE Standards (IEEE 929 and IEEE 1547) [41]-[42] and UL 1741 do not address this issue but consider it as one of the tasks to be addressed in future revisions. Currently, there is a rich and growing literature in this area. Many countries are trying to meet the targets set in the Kyoto Protocol to reduce greenhouse gas emissions. DG provides an attractive option to accomplish this task. Besides environmental benefits, technical and economical benefits could be gained by allowing micro-grid operation of DGs.

Performing intentional islanding or microgrid operation of DGs can improve the power system service quality and increase the power system reliability [43]-[44]. In some cases, expanding traditional centralized generating systems maybe so tight and it might be expected that it will not be capable of meeting future electricity demand growth at acceptable cost. In this case DGs provide a valuable solution to this problem by grouping DGs with loads in a semi-autonomous neighborhood that could be termed as Microgrid. Allowing the DG to operate during an islanding situation could potentially bring economical benefits to the DG owner, Distribution Network Operator (DNO) and the customer. The main benefit to the DG owner is the additional revenue since it is selling power during utility outage. As for the DNO, an improvement in the overall security of the supply could be achieved. Lastly, a reduction in the frequency and duration of interruptions resulting from outages in the distribution network contributes in the reduction of the overall cost [45].

Despite the many advantages that could be gained from DG islanded operation, many challenges and technical issues constraint its operation. For safe and efficient operation of micro-grids, these challenges must be addressed and well established. One of the major challenges, that is of main focus in this work, is distribution system protection.

5.2 DG Islanding

In general, islanding is a condition in which a DG is operating isolated from the utility. This scenario could occur during a utility outage. The current IEEE standards necessitate the disconnection of the DG during a utility outage. Thus, a DG is usually equipped with an islanding detection method responsible for disconnecting the DG once an islanded condition occurs.

Islanding detection methods can be divided into three main groups: communication based methods, passive methods and active methods. Communication based methods mainly depend on transmitting signals to and from the utility and DG sides. These methods are considered much more expensive than passive and active methods. Passive methods depend on monitoring a certain parameter and comparing it with a threshold value. Once the parameter exceeds the threshold, an islanding condition is declared. The third category of islanding detection methods, active methods, interferes with the power system operation by creating an abnormal condition once the DG is islanded. This could be done by providing a positive feedback in the interface control circuit to either the frequency or voltage, varying the active and reactive power output of the DG continuously, or by injecting a known waveform (frequency, voltage, or power) from the DG side [46]. Figure 60 shows an islanded situation where the utility switch opens and the DG operates independently, feeding an RLC load.

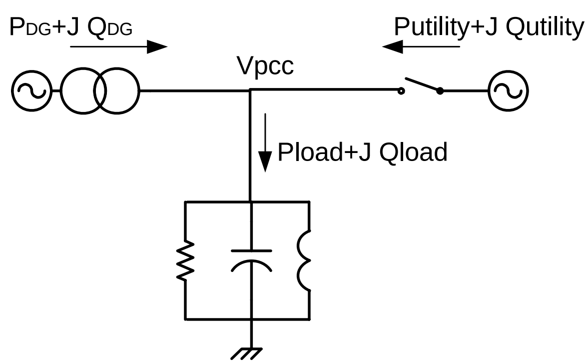


Figure 60 -System highlighting an islanded situation.

5.3 Intentional Islanding (Micro-grid)

With the increasing penetration of DG in the distribution system, intentional islanded operation becomes an attractive option. Intentional islanding offer the potential to maximise the level of generation that can be connected at the lower voltage levels of the distribution network and at the same time provide consumers with improved levels of supply security. A microgrid can be temporarily operated in an intentional islanded mode in response to significant disturbances within the upstream grid system (e.g. outage of circuits or power quality disturbances). The adoption of such a strategy effectively creates a cellular configuration within the distribution network. Since distribution system protection is of the main concern in this work, it is assumed that the DG on the island will be capable of supplying the loads on the island within standard voltage and frequency levels. The potential DG candidates for islanded operation are the synchronous and inverter based DG. The only means by which an asynchronous DG can support the voltage on an island is by self-excitation and in such cases voltage control becomes a challenging issue.

5.4 Islanded Operation Protection Issues

Under normal interconnected operation, the network will have a coordinated scheme of protection. This scheme will be arranged to clear faults in a manner that the minimum number of customers is disconnected. Such a scheme will almost certainly be making full use of the range of fault levels on the network to optimize the discrimination between protective devices on a circuit. When a DG island is created, it is required that any faults occurring will be cleared quickly to minimize damage or danger to personnel. However, the fault contribution of the DG will be significantly lower than that of the interconnected network.

Since fault currents in the islanded region might change, this can cause mis-operation of the currently installed protective devices [47]. Most of the distribution system protection is based on sensing the current. Synchronous based DGs will contribute to the fault during micro-grid operation and thus current sensing protective devices can be used in this case. Unfortunately, the current sensed by the protective devices will be different during grid connected and micro-grid operation and this can affect the operation and coordination of protective devices.

Inverter based DGs do not provide the levels of short circuit current sufficient to operate current sensing protective devices such as overcurrent relays [48]. The tripping range of the relays has to guarantee the same selectivity as in parallel operation. Yet, there is a need to assure that the protection scheme designed is operating in a fast, selective and reliable manner for both grid and islanded operation. Due to the small contribution of inverter based DGs during a fault; two concerns are presented in [49]. The first concern is that fuses and relays that depend on large fault currents to operate, will not be capable of operating during micro-grid operation. The second concern is that if the protective relays were designed for small fault currents to satisfy the micro-grid operation, nuisance tripping could occur due to motor operations.

This part of the report analyzes the impact of islanded operation on the distribution system protection. As previously mentioned, intentional islanding is becoming a hot topic and this is due to the increasing penetration of the DG in the system. In order to perform intentional islanding, the DG paralleling switchgear or interface control must be capable of maintaining both the voltage and frequency levels within the standard permissible levels. This issue is out of the scope of this work. This work focuses on the impacts of such operation on the coordination, sensitivity, fuse blowing and bi-directionality. The analysis will include both synchronous and inverter based DG. Both the DG location and penetration level are varied to thoroughly analyze the different possible scenarios for both the urban and suburban distribution systems. Furthermore, two DG will be located on each system at two different locations. The analysis is performed using the CYMTCC and CYMEDIST software packages.

5.5 Loss of Coordination and Sensitivity

5.5.1 Impact Definition

The Short circuit current levels passing through the protective devices will be different than those flowing during grid connected operation. Depending on the capacity of the DG and the DG technology, the short circuit levels could be either sufficient to operate the protective devices and could be too small to operate the protective devices and thus coordination would be affected.

The DG is located at different points on the system and its capacity is varied in order to satisfy the following:

- Intentional islanding with a DG capacity greater than the island load.
- Intentional islanding with a DG capacity approximately equal to the island load.
- Intentional islanding with a DG capacity less than the island load.

5.5.2 Case Studies

5.5.2.1 Intentional Islanding of a lateral (Fuse-Fuse Coordination) With Synchronous DG on Metro Distribution System

For the metro distribution system shown in Figure 3, the DG was located at the head of fuse F5. Figure 61 shows the lateral under study. The synchronous based DG has a solidly grounded neutral and is connected through a delta-wye grounded transformer. Three DG sizes have been chosen such that the island satisfies one of the following operations:

a. Intentional Islanding with a DG capable of exporting power. The DG capacity was chosen to be 5940 kVA and thus the DG feeds the overhead laterals as well as the laterals at bus 5 (backfeed of power)

b. Intentional islanding with a DG capable of supplying all island loads. The DG capacity was chosen to equal 2970 kVA and thus capable of supplying the overhead lateral loads.

c. Intentional islanding with deficit DG capacity. In such a case, some of the loads would be shed. The DG capacity was chosen to be 1200 kVA.

Table 26 shows the maximum and minimum short circuit currents for the three cases.

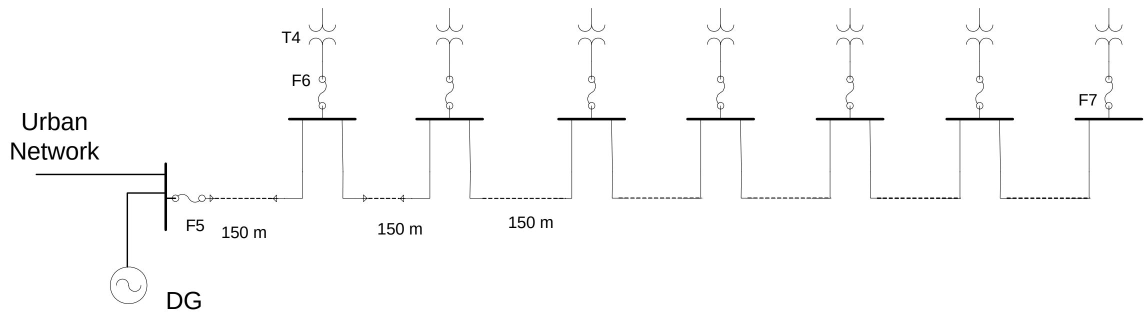


Figure 61 -Overhead Lateral on the metro distribution system

Table 26 - Maximum and minimum fault currents during an islanded situation with synchronous based DG.

	Grid-Connected Without DG			**Islanding with 5940 kVA DG**			**Islanding with 2970 kVA DG**			**Islanding with 1200 kVA DG**		
Fault	F5	F6	F7	F5	F6	F7	F5	F6	F7	F5	F6	F7
Max	4452	4244	3231	1673	1627	1380	914	900	820	527	523	496
Min	3856	3676	2748	1182	1167	1082	629	625	600	358	357	349

Figures 62, 63, and 64 present the coordination curves showing the maximum and minimum fault current values for an islanded situation. Fuse F5 is the S&C SMU 20K model and fuse F6 is the S&C SMU k model. Table 27 presents a summary of results obtained in this scenario. In general, it can be seen that as the DG capacity on the island decreases, the probability that coordination and protective device sensitivity failure increases. The protective devices experience an increase in time of operation due to the decrease in fault current values. The fuse that is affected the most is the upstream (backup) fuse F5.

Table 27 - Coordination and sensitivity in islanded mode: summary of results.

	Coordination	Sensitivity	Relay time of Operation
5940 kVA DG	Fuses F5 and F6 are still coordinated. F5 operates as a backup to F6.	F5 and F6 are capable of detecting a fault during an islanded situation.	Increased time of operation for F5. F5 time of operation increased from 0.1 s to more than 1 s. F6 operates in less than 0.02 s.
2970 kVA DG	Fuses F5 and F6 are still coordinated. F5 operates as a backup to F6.	F5 and F6 are capable of detecting a fault during an islanded situation. Fuse F5 is less sensitive to fault currents.	Increases time of operation for F5. F5 time of operation increased from 0.1 s to 50 s. F6 operates in approximately 0.03 s.
1200 kVA DG	F5 does not operate for minimum fault currents. In this case coordination fails.	F5 is not sensitive to minimum fault levels.	F5 does not operate properly. F6 operates in less than 0.05 s.

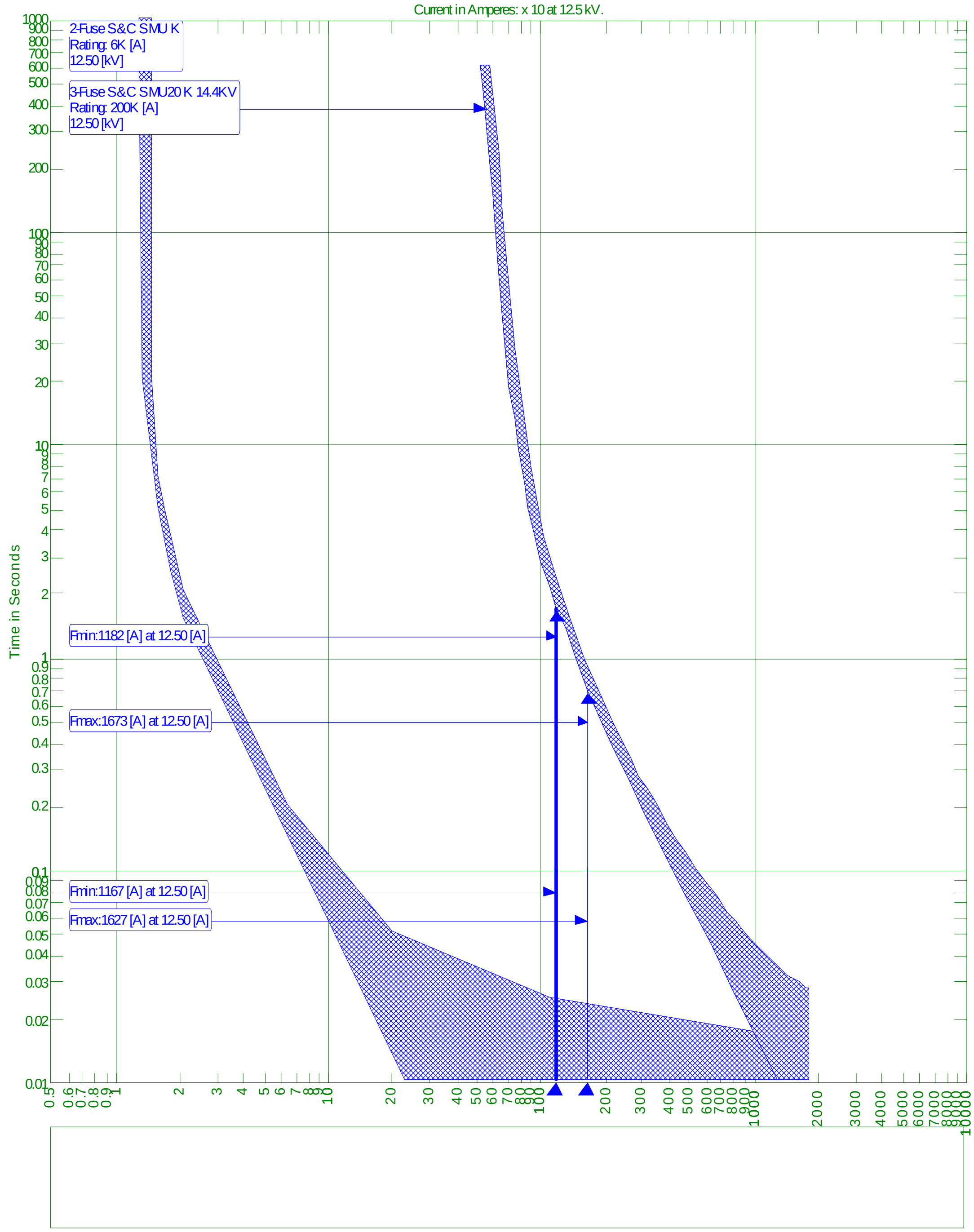


Figure 62 - Fault currents with a synchronous DG rated at 5940 kVA for fuses F5 and F6.

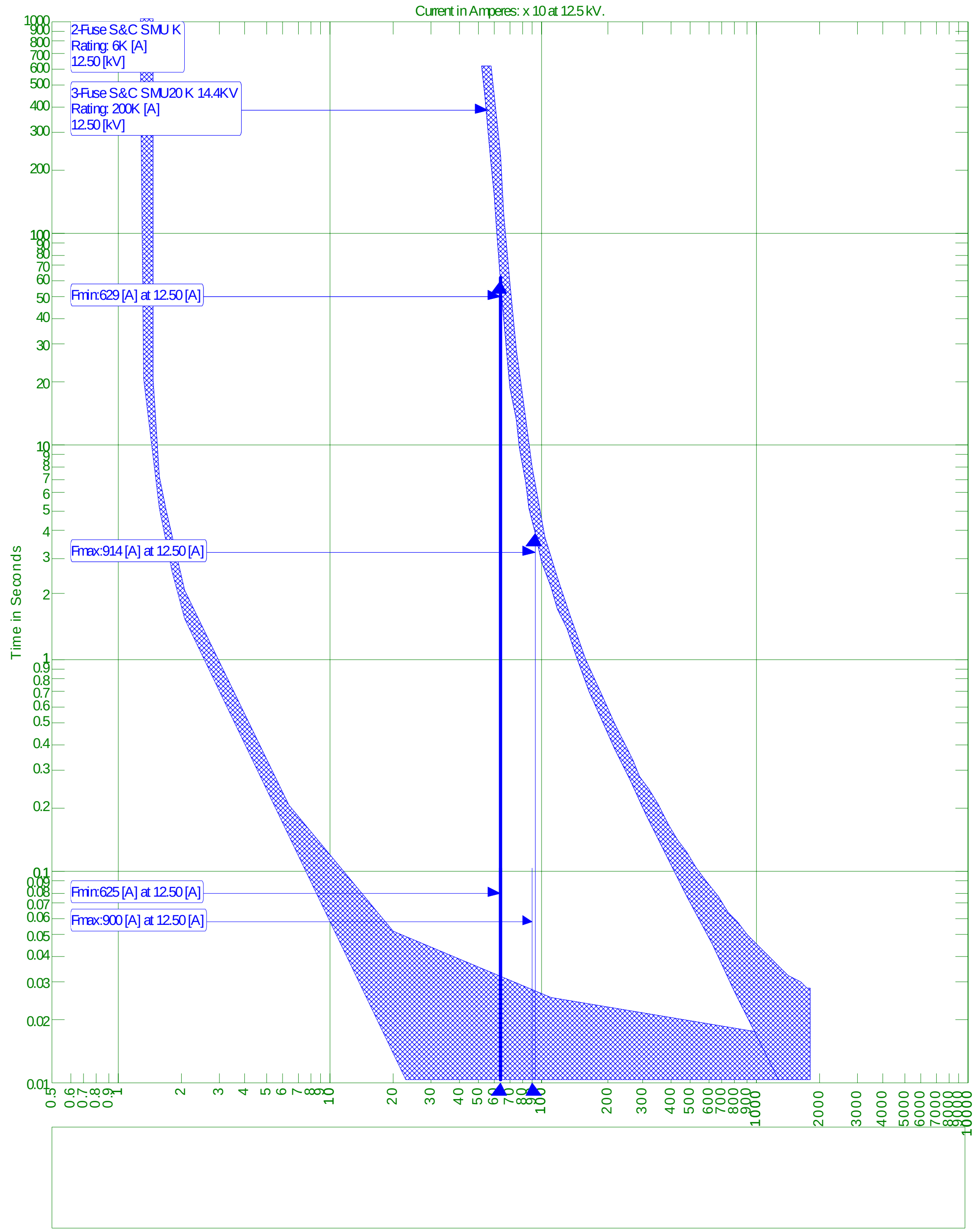


Figure 63 - Fault currents with a synchronous DG rated at 2970 kVA for fuses F5 and F6.

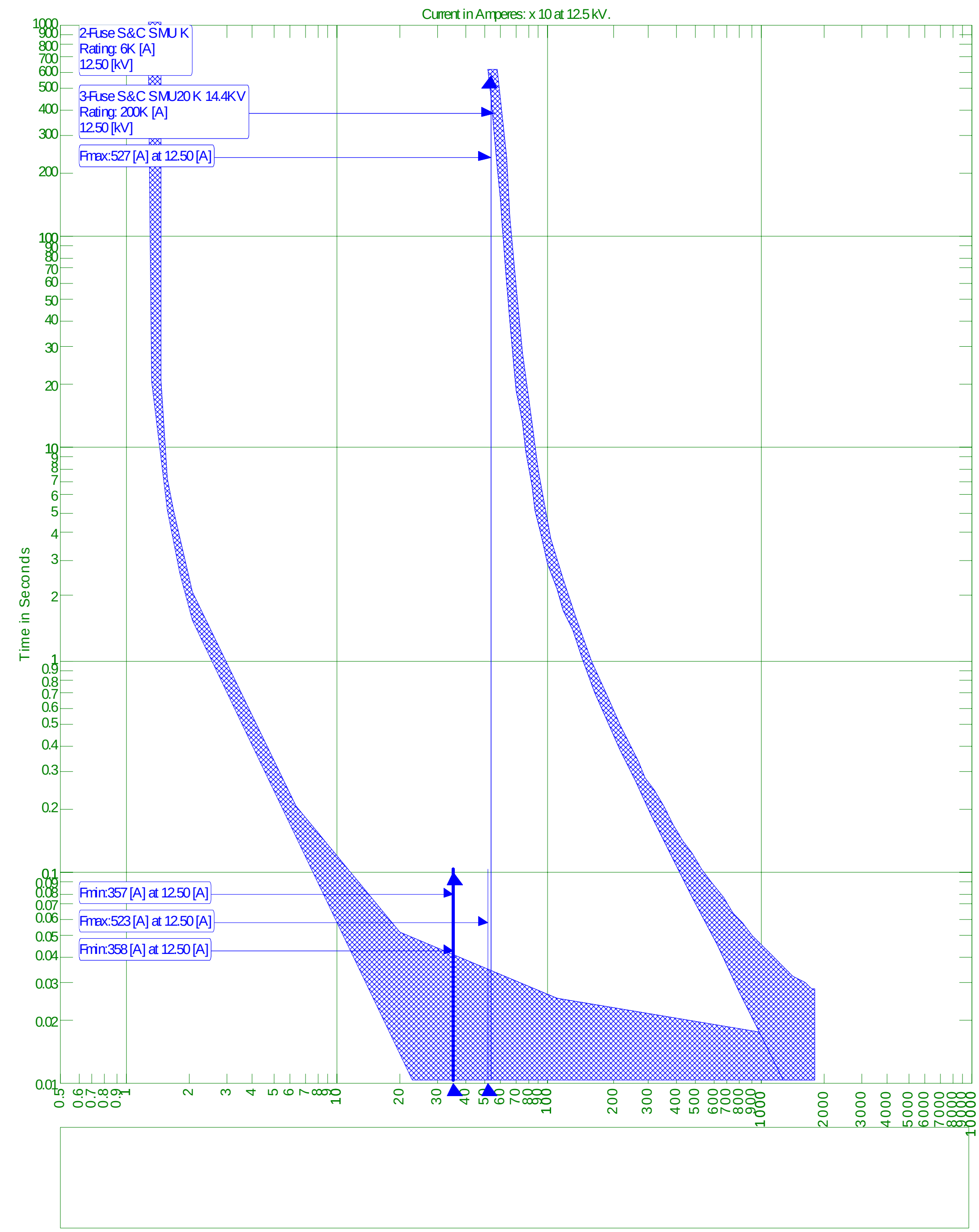


Figure 64 - Fault currents with a synchronous DG rated at 1200 kVA for fuses F5 and F6.

Figures 65, 66, and 67 present the coordination curves for fuses F5 and F7. F5 is the SMU 20K fuse model and fuse F7 is the SM 20K fuse model. Table 28 presents a summary of results. Similarly, it can be seen that as the DG capacity on the island decreases, the probability that coordination and protective device sensitivity increases. In comparison to the previous case, it can be seen that fuse F7 experiences more time delay in its operation. This is as a result of the low fault currents at the most downstream fuse (F7) in comparison with the fault currents in the most upstream fuse F6.

Table 28 - Coordination and sensitivity in islanded mode: summary of results.

	Coordination	Sensitivity	Relay time of Operation
5940 kVA DG	Fuses F5 and F7 are still coordinated. F5 operates as a backup to F6.	F5 and F7 are capable of detecting a fault during an islanded situation.	Increased time of operation for F5. F5 time of operation increased from 0.1 s to 2 s. F7 operates in less than 0.03 s.
2970 kVA DG	Fuses F5 and F7 are still coordinated. F5 operates as a backup to F7.	F5 and F7 are capable of detecting a fault during an islanded situation. F7 is less sensitive to faults.	Increases time of operation for F5. F5 time of operation increased from 0.1 s to 50 s. F7 operates in less than 0.04 s.
1200 kVA DG	F5 does not operate for minimum fault currents. In this case coordination fails.	F5 is not sensitive to minimum fault levels.	F5 does not operate properly. F7 operates in less than 0.05 s.

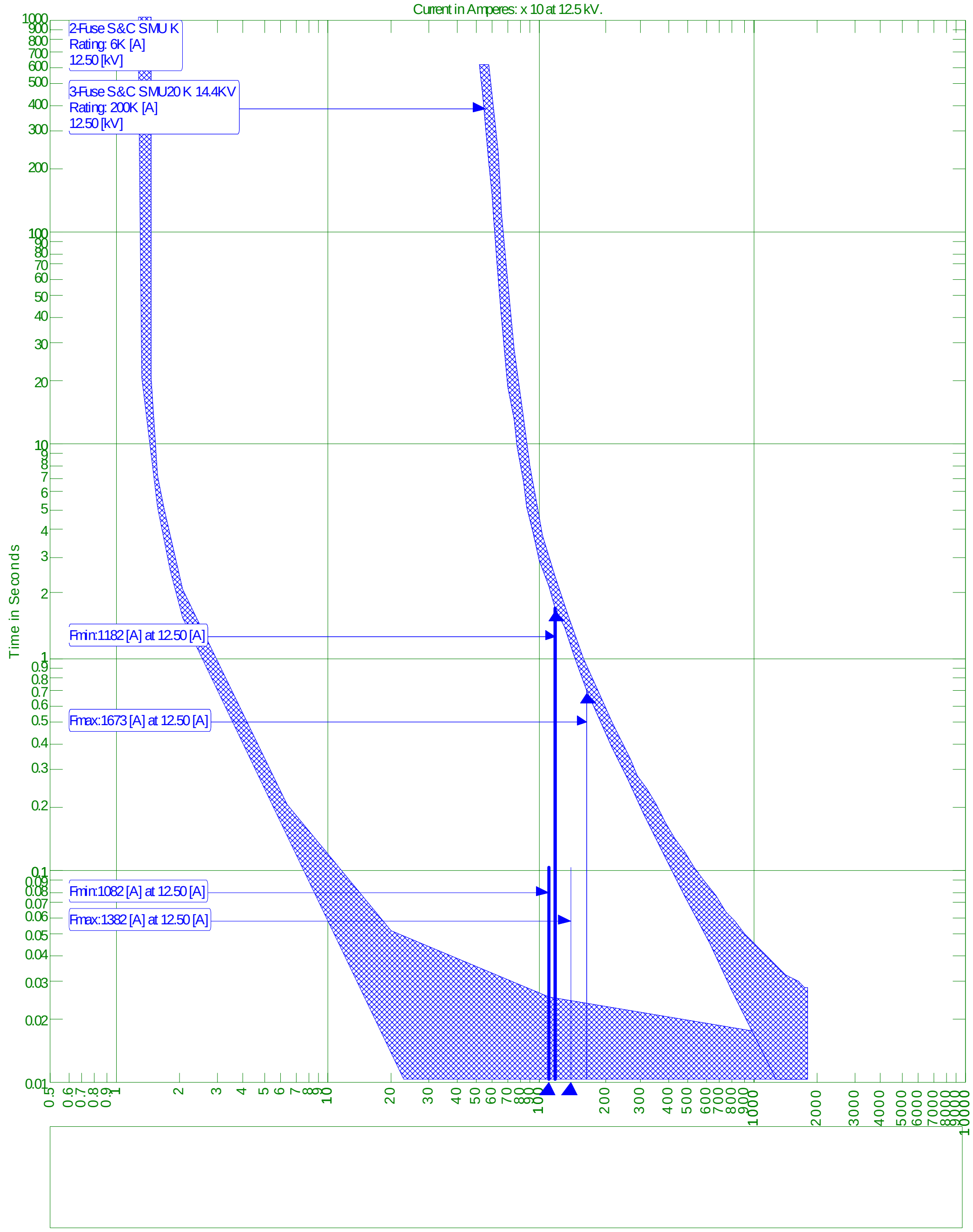


Figure 65 - Fault currents with a synchronous DG rated at 5940 kVA for fuses F5 and F7.

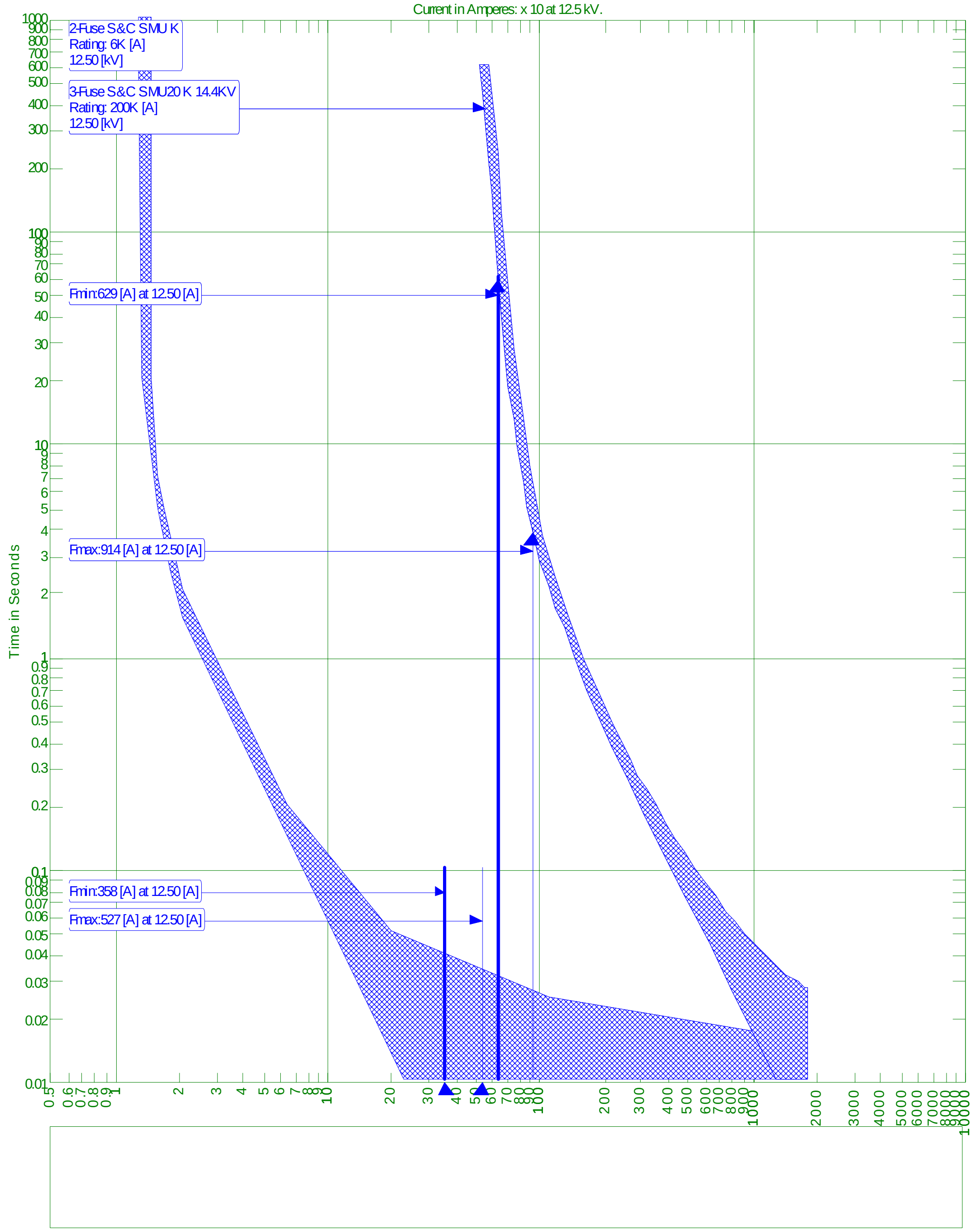


Figure 66 - Fault currents with a synchronous DG rated at 2970kVA for fuses F5 and F7.

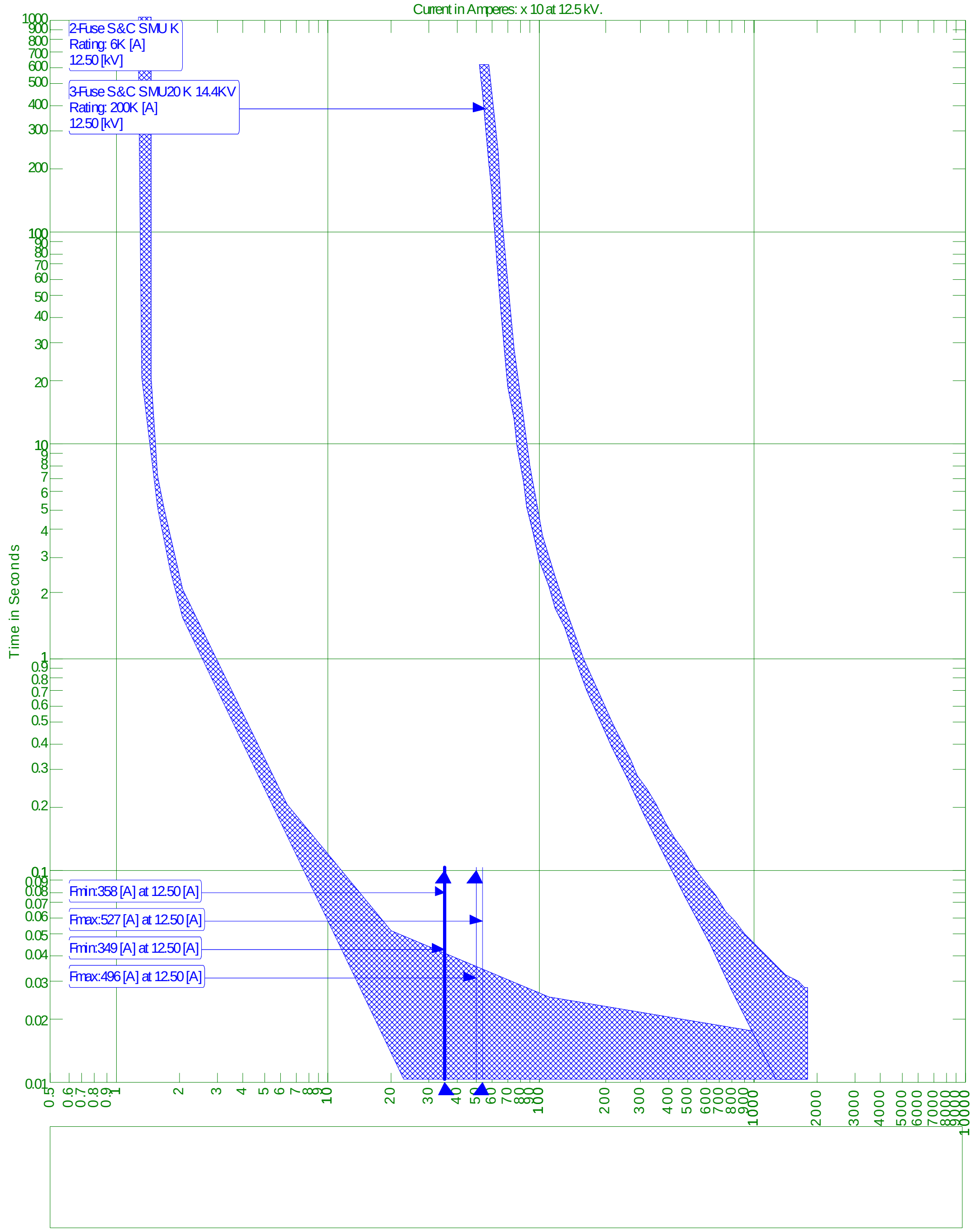


Figure 67 - Fault currents with a synchronous DG rated at 1200kVA for fuses F5 and F7.

5.5.2.2 Intentional Islanding of a feeder (Relay-Fuse Coordination) With Synchronous DG on Metro Distribution System

A group of 480V, 2.970 MVA wye solidly grounded generators are connected in parallel and are connected to the main station bus through a 12.5kV/480V delta-wye grounded transformer, as shown in Figure 68. Three different DG capacities are examined and it is assumed that the DG capacity on the island is sufficient to meet the load requirements on the island. For cases, where the DG capacity is less than the island load, it is assumed that a load shedding scheme will be adopted. Table 29 presents the maximum and minimum fault currents passing through the protective devices. Table 30 presents the summary of results. Figures 69, 70, and 71 show the coordination curves.

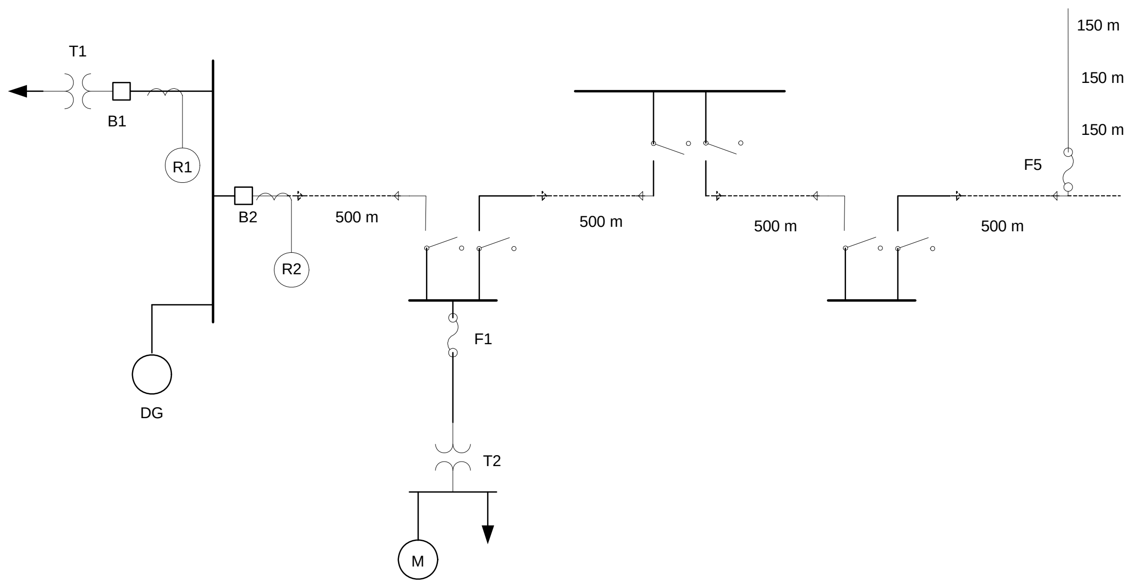


Figure 68 - System under study.

Table 29 - Maximum and minimum fault currents during an islanded condition with synchronous based DG.

	Grid Connected Without DG			**Islanding with 8910 kVA DG**			**Islanding with 5940 kVA DG**			**Islanding with 2970 kVA DG**		
Fault	B2	F1	F5	B2	F1	F5	B2	F1	F5	B2	F1	F5
Max	46188	5925	4452	2314	1731	1600	1673	1340	1269	914	808	780
Min	25588	5131	3856	1673	1340	1252	1182	1000	956	629	575	560

Table 30 - Summary of results.

	Coordination	Sensitivity	Relay time of Operation
8910 kVA DG	Relay R2 and fuse F1 are still coordinated. R2 operates as a backup to F1.	R2 and F1 are capable of detecting a fault during an islanded situation.	Increased time of operation for R2. R2 time of operation increased from 0.04 s to 5 s. F1 operates in approximately 0.2 s.
5940 kVA DG	Relay R2 and fuse F1 are still coordinated. R2 operates as a backup to F1.	R2 and F1 are capable of detecting a fault during an islanded situation. R2 is less sensitive to fault.	Increases time of operation for R2. R2 time of operation increased from 0.1 s to 10 s. F1 operates in less than 0.4 s.
2970 kVA DG	R2 does not operate for minimum fault currents. In this case coordination fails.	R2 is not sensitive to minimum fault levels.	R2 does not operate properly. F6 operates in less than 2 s.

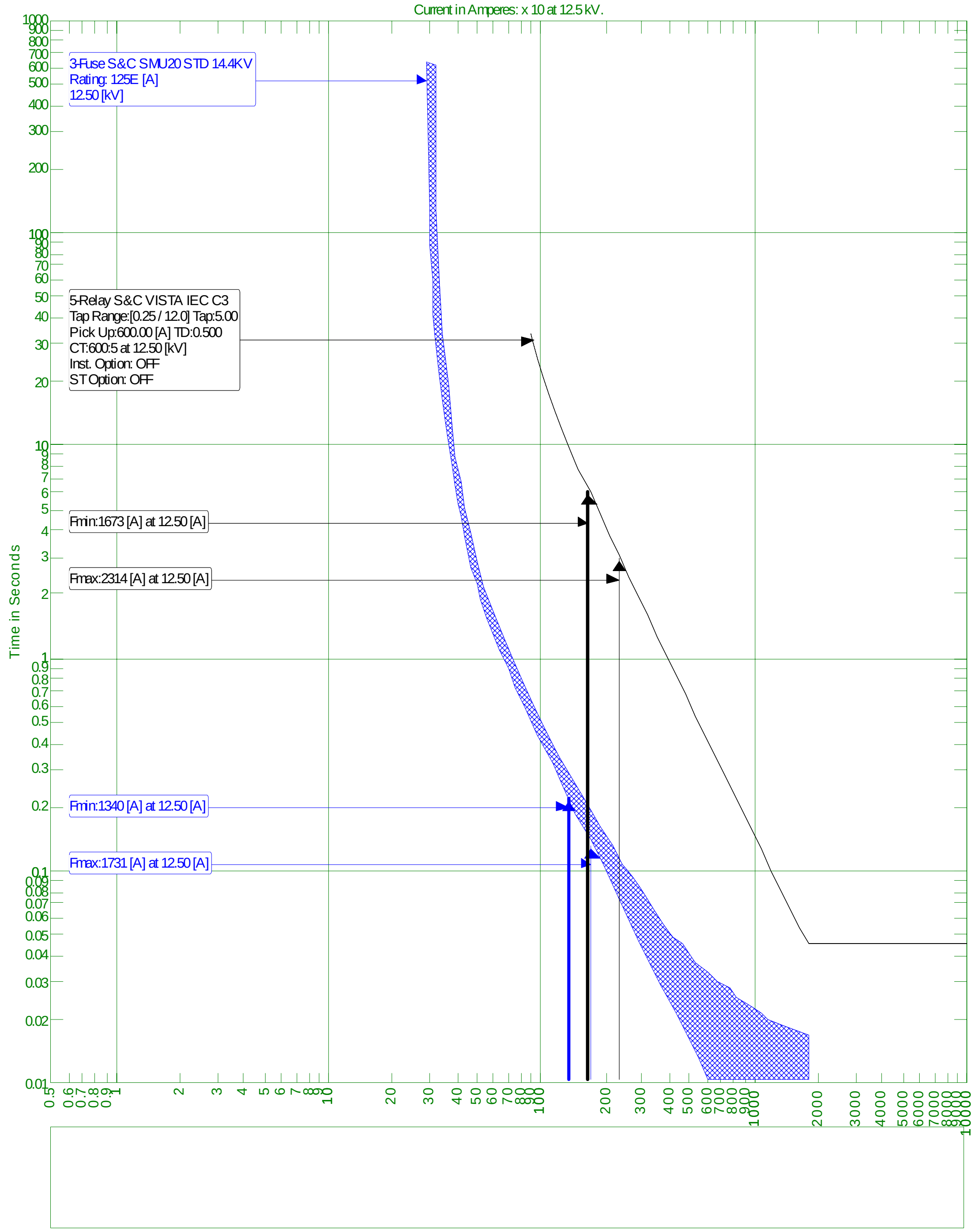


Figure 69 - Fault currents passing through R2 and F1 with a 8910 kVA synchronous DG.

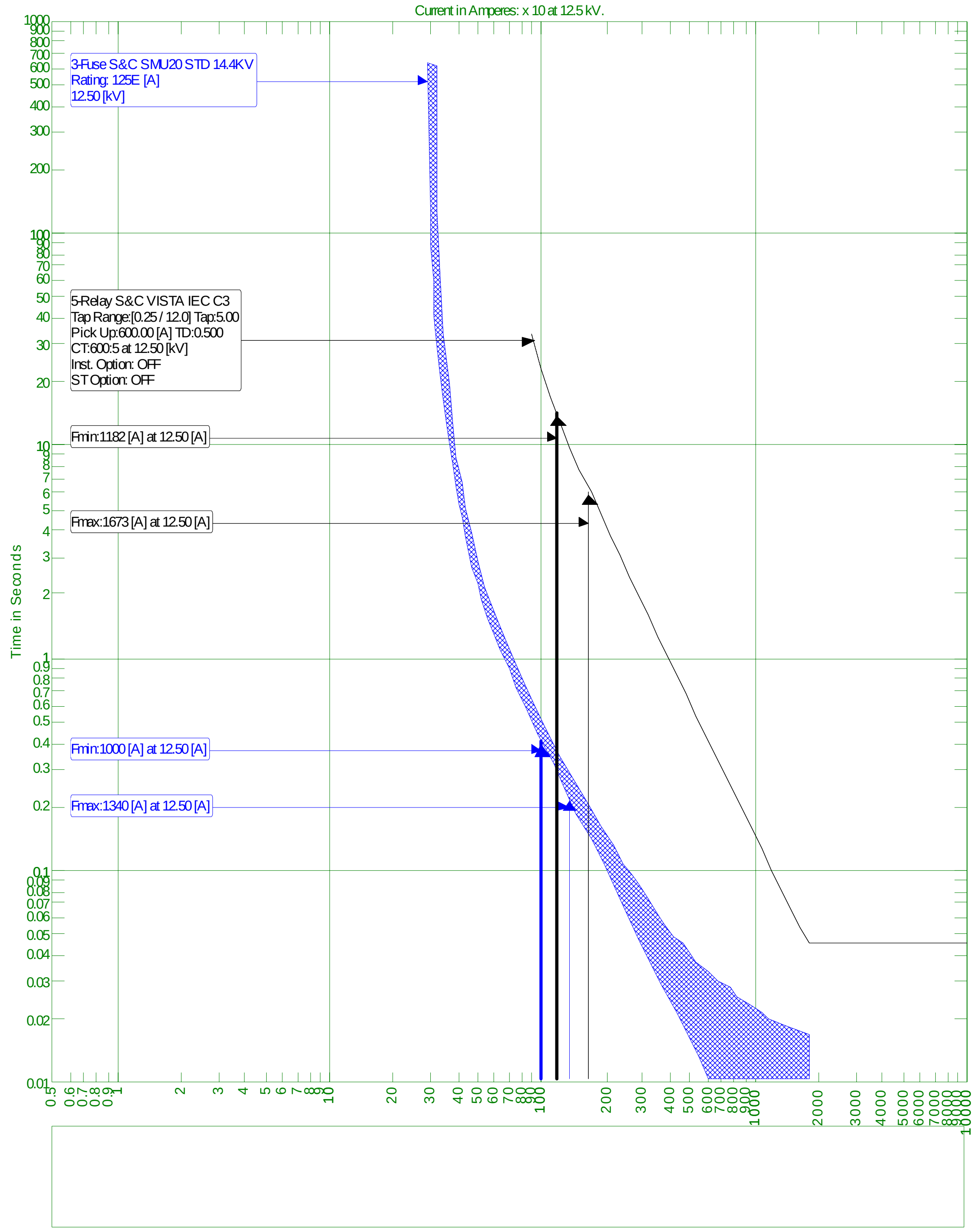


Figure 70 - Fault currents passing through R2 and F1 with a 5940 kVA synchronous DG.

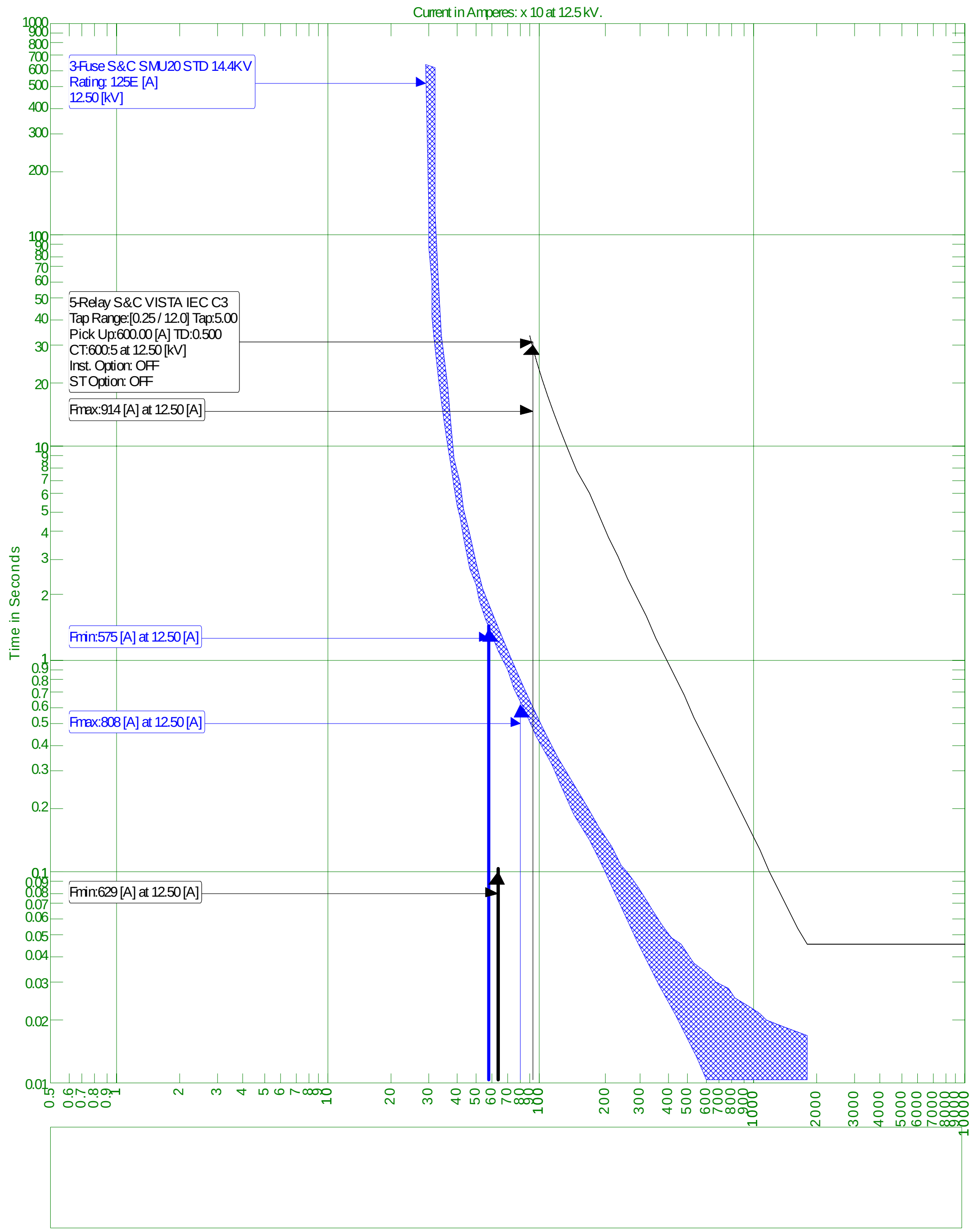


Figure 71 - Fault currents passing through R2 and F1 with a 2970 kVA synchronous DG.

Similar results are obtained for the relay R2 and fuse F5 path. Figures 72, 73, and 74 show the fault currents on the coordination curve. It can be seen that for this path, the protective devices take much more time to operate. This is due to the fact that fuse F5 is further away from the DG source than fuse F1 and thus lower magnitudes of short circuit levels currents are obtained. From the curves, as the DG capacity decreases, protective device sensitivity to fault and coordination becomes of a more concern.

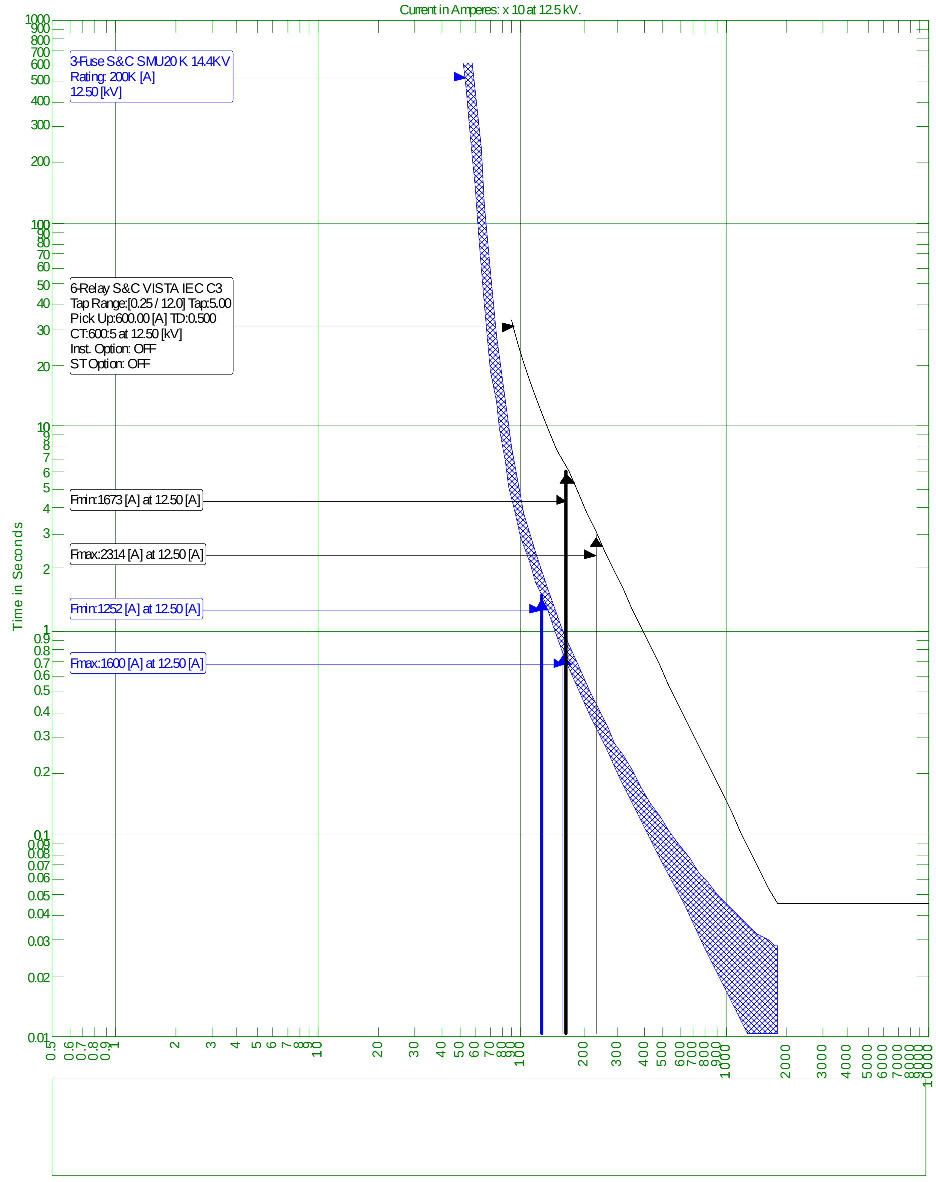


Figure 72 - Fault currents passing through R2 and F5 with a 8910 kVA synchronous DG.

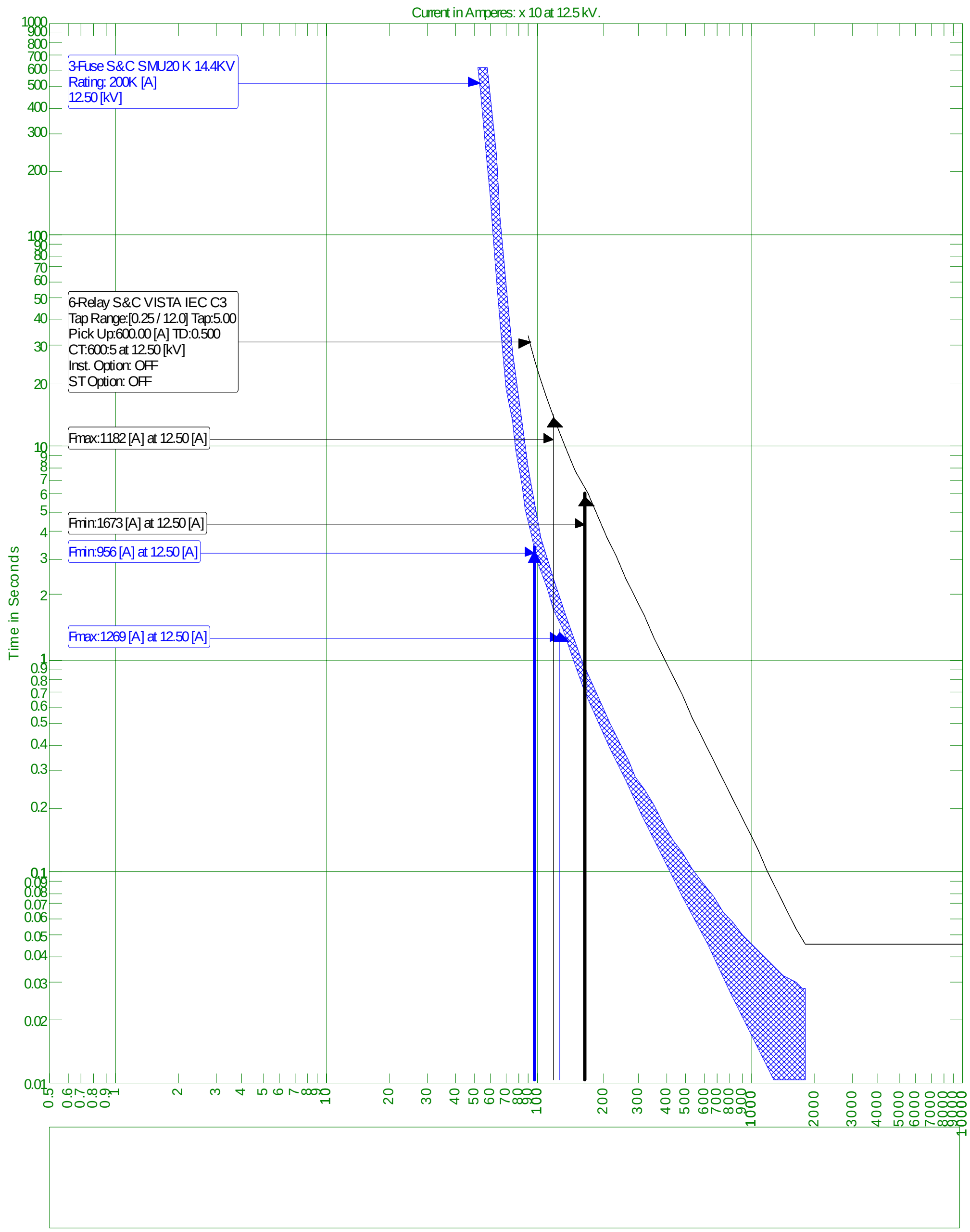


Figure 73 - Fault currents passing through R2 and F5 with a 5940 kVA synchronous DG.

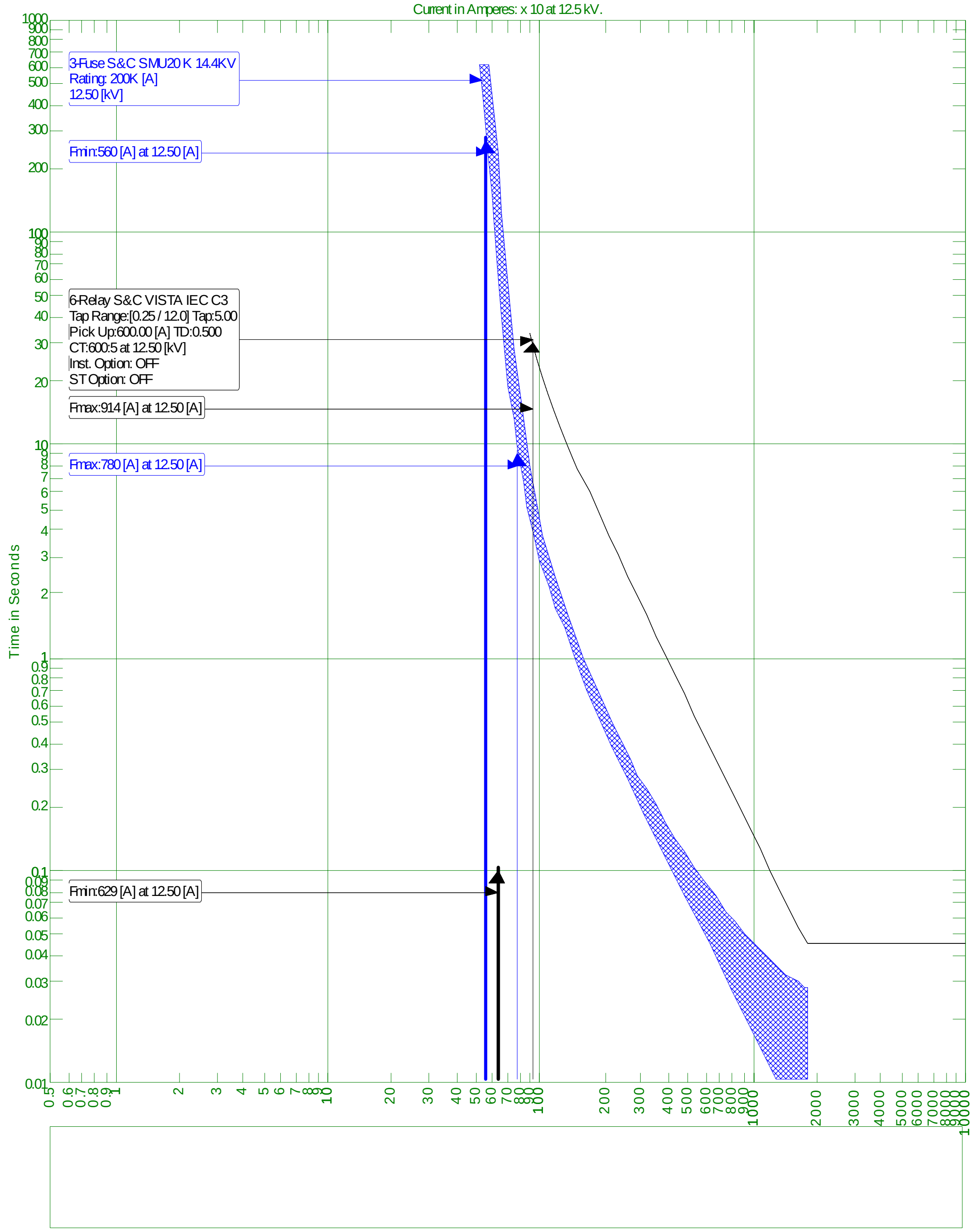


Figure 74 - Fault currents passing through R2 and F5 with a 2970 kVA synchronous DG.

5.5.2.3 Intentional Islanding with Inverter based DG on Urban Distribution System

For the urban (metro) distribution system shown in Figure 3, the DG was located at the head of fuse F5 (refer to Figure 61). The inverter based DG is connected through a delta-wye grounded transformer. Three DG sizes have been chosen such that the island satisfies the previously highlighted scenarios. Table 31 shows the maximum and minimum short circuit currents for the three cases.

Table 31 - Fault currents during an islanded situation with a inverter based DG.

	Grid-Connected Without DG			Islanding with 5940 kVA DG			Islanding with 2970 kVA DG			Islanding with 1200 kVA DG		
Fault	F5	F6	F7	F5	F6	F7	F5	F6	F7	F5	F6	F7
Max	4452	4244	3231	274	274	274	137	137	137	55	55	55
Min	3856	3676	2748	274	274	274	137	137	137	55	55	55

Based on the above results, it can be seen that the DG during a short circuit acts as a current source and the short circuit current will be limited to its rated full load current. By referring to the coordination curves previously shown in Chapter 2, it can be concluded that both the protective device coordination and sensitivity will be affected during an islanded condition. For cases where there is low DG capacity on the island, the use of current sensing devices is questionable due to the low fault current values.

5.5.2.4 Islanding With Synchronous DG on Suburban Distribution System

For the suburban distribution system, the DG was located at bus 2. The synchronous DG is connected through a delta-wye grounded transformer. Three DG sizes have been chosen such that the island satisfies one of the following operations:

a. Intentional Islanding with a DG capable of exporting power. The DG capacity was chosen to be 11880 kVA and thus the DG feeds some of the upstream loads (located upstream with respect to BUS 2)

b. Intentional islanding with a DG capable of supplying all downstream loads. The DG capacity was chosen to equal 8910 kVA.

c. Intentional islanding with deficit DG capacity. In such a case, some of the loads would be shed downstream of the DG. The DG capacity was chosen to be 5940 kVA.

Table 32 shows the maximum and minimum short circuit currents for the three cases.

Table 32 - Fault currents during an islanded situation with a synchronous based DG.

	Grid-Connected Without DG				Islanding with 11880 kVA DG				Islanding with 8910 kVA DG				Islanding with 5940 kVA DG			
Fault	F1	F2	F3	F4	F1	F2	F3	F4	F1	F2	F3	F4	F1	F2	F3	F4
Max	3827	3780	3264	3209	1400	1397	1290	1215	1333	1131	1065	1008	820	819	784	753
Min	2943	2911	2444	2394	1034	1033	1000	970	820	819	780	777	580	579	568	558

For brevity, the coordination curves are presented for F1-F2 path. Similar results could be obtained for fuses F3-F4 path. Figures 75, 76, and 76 present the coordination curves. Fuse F1 is the SMU 20 VSLO model and fuse F2 is the S&C DR model. Table 33 presents a summary of the simulation results.

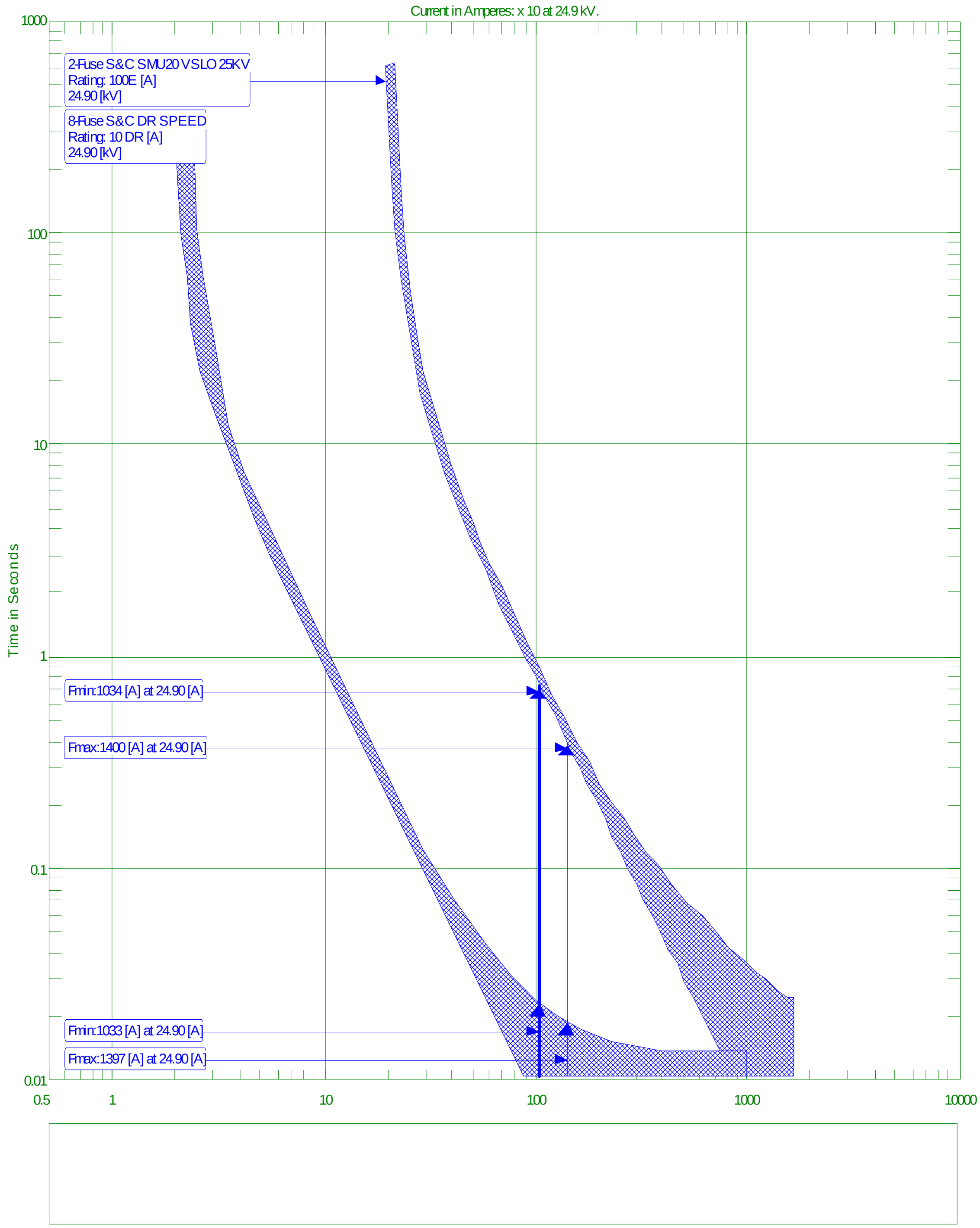


Figure 75 - Fault currents passing through F1 and F2 with a 11880 kVA synchronous DG.

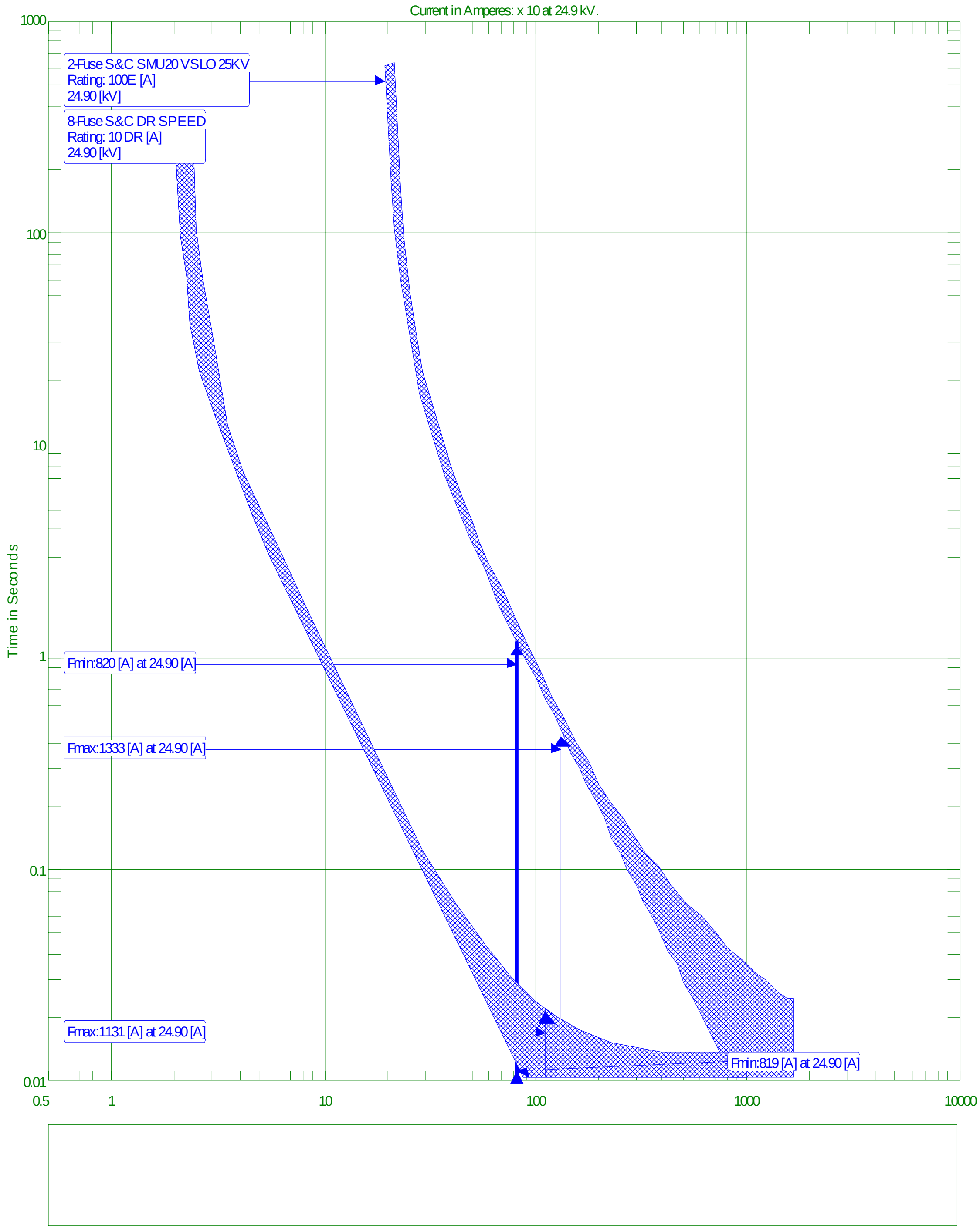


Figure 76 - Fault currents passing through F1 and F2 with an 8910 kVA synchronous DG.

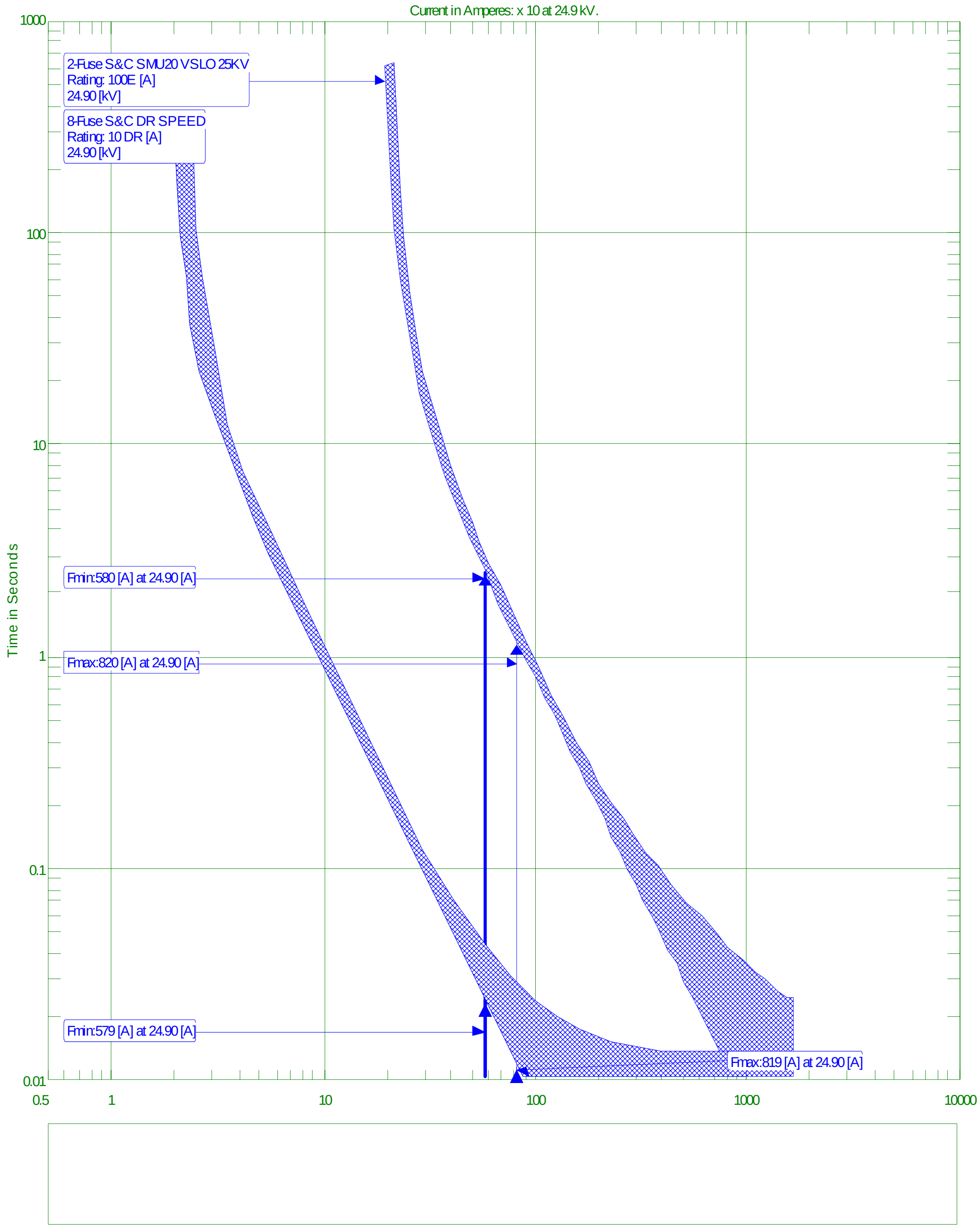


Figure 77 - Fault currents passing through F1 and F2 with a 5490 kVA synchronous DG.

Table 33 - Summary of results.

	Coordination	Sensitivity	Relay time of Operation
11880 kVA DG	Fuse F1 and fuse F2 are still coordinated. F1 operates as a backup to F2.	F1 and F2 are capable of detecting a fault during an islanded situation.	Increased time of operation for F1. F1 time of operation increased to 0.7 s. F2 operates in approximately 0.02 s.
8910 kVA DG	Fuse F1 and fuse F2 are still coordinated. F1 operates as a backup to F2.	F1 and F2 are capable of detecting a fault during an islanded situation. Both fuses are still sensitive to fault currents	Increases time of operation for F1. F1 time of operation increased 1 s. F2 operates in less than 0.03 s.
5940 kVA DG	Fuse F1 and fuse F2 are still coordinated. F1 operates as a backup to F2.	F1 and F2 are capable of detecting a fault during an islanded situation. Both fuses are still sensitive to fault currents	Increases time of operation for F1. F1 time of operation increased to 1.1 s. F2 operates in less than 0.04 s.

5.6 Nuisance fuse blowing

5.6.1 Impact Definition

The change in fault currents during an islanded condition could have an impact on re-closer-fuse (fuse saving scheme) operation. Depending on the fault current values as well as the coordination curves (whether there are any overlapping or intersection), nuisance fuse tripping could occur as well as coordination failure.

The system under study is the suburban system due to the presence of a re-closer in such systems. The DG capacity on the island is varied and the fault currents levels are determined. The coordination curves are used to assess the impact.

5.6.2 Case Study

The DG is located at the main substation bus of the suburban distribution system and is connected through a delta-wye grounded transformer. Table 34 presents the short circuit analysis results. Figures 78, 79, and 80 present the coordination curves.

Table 34 - Maximum and minimum faults currents during an islanded situation with synchronous based DG.

	Grid-Connected Without DG		**Islanding with 17820 kVA DG**		**Islanding with 8910 kVA DG**		**Islanding with 5940 kVA DG**	
Fault	Re-closer	F1	Re-closer	F1	Re-closer	F1	Re-closer	F1
Max	6060	3826	1672	1371	943	841	640	591
Min	5048	2942	1305	1171	716	674	483	464

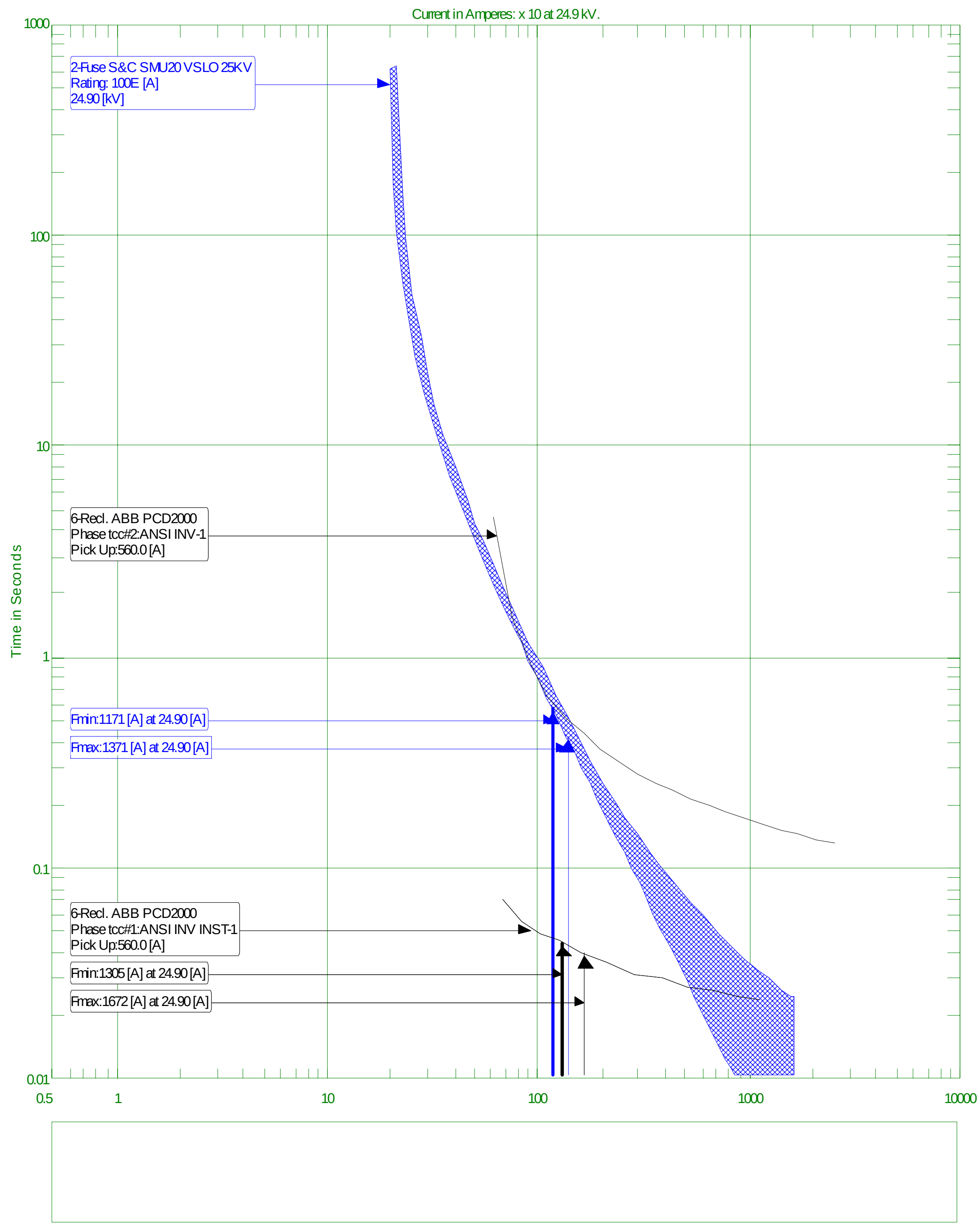


Figure 78 - Fault currents passing through recloser and F1 with a 17820 kVA synchronous DG.

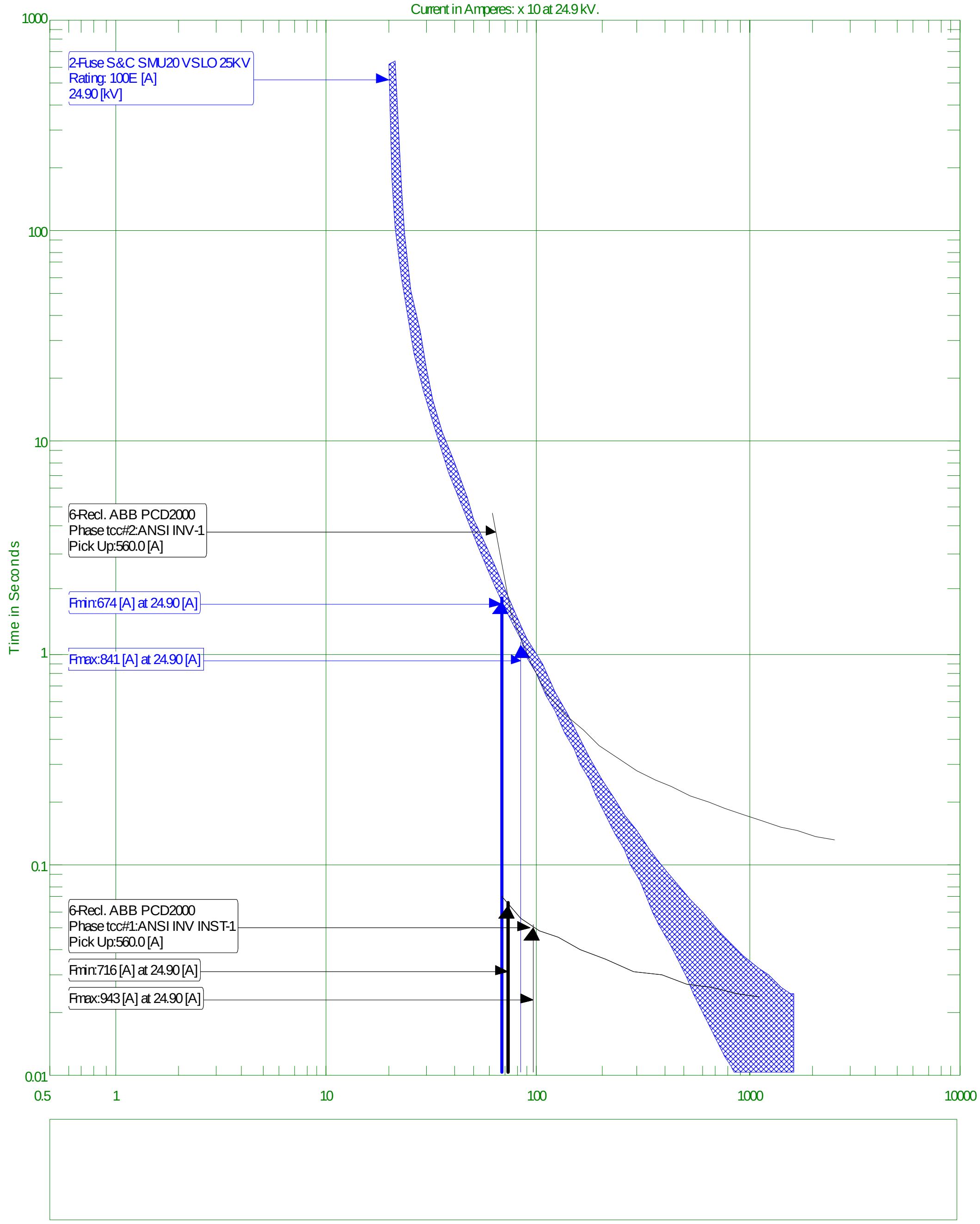


Figure 79 - Fault currents passing through recloser and F1 with a 8910 kVA synchronous DG.

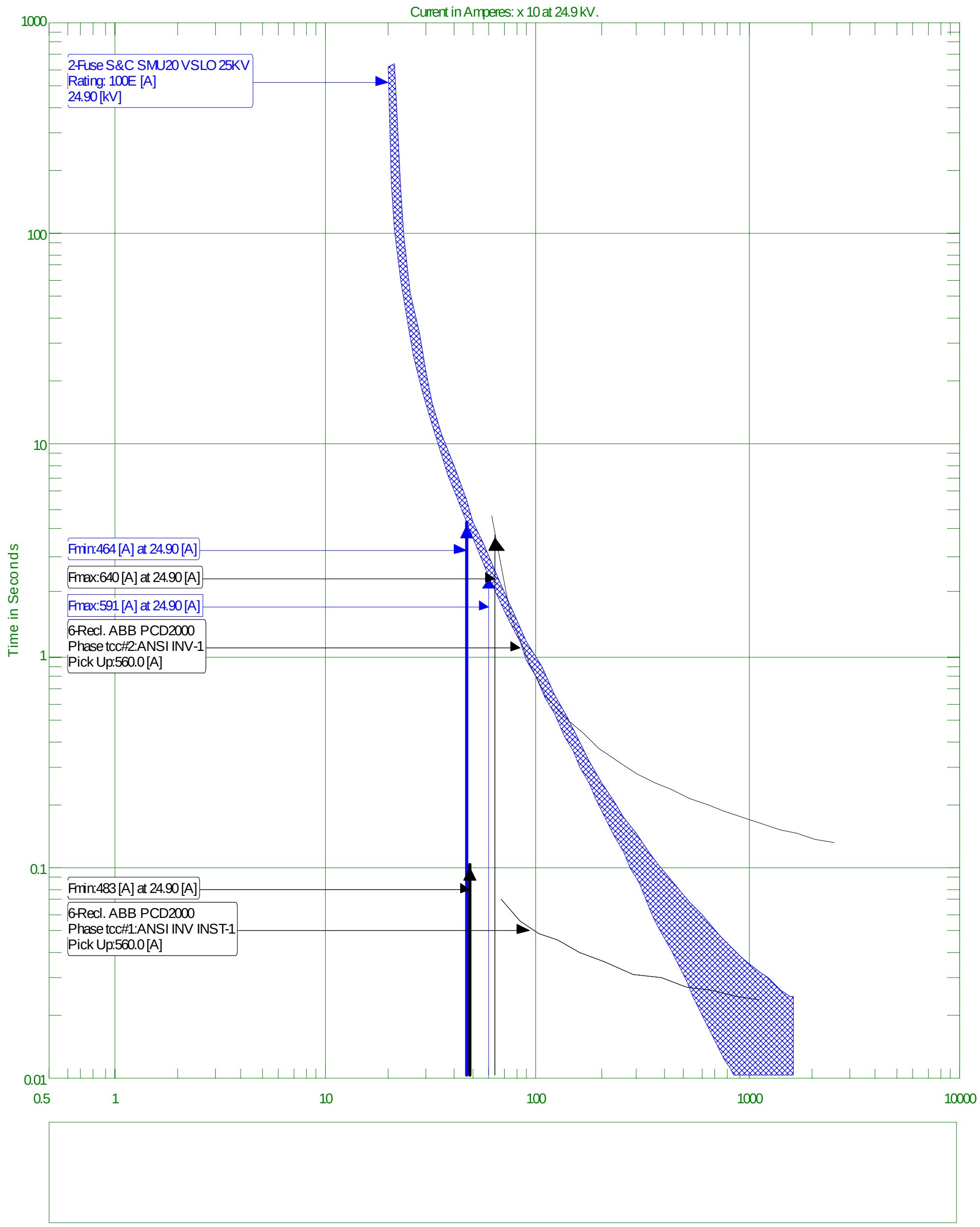


Figure 80 - Fault currents passing through recloser and F1 with a 5490 kVA synchronous DG.

During DG parallel operation, the coordination was designed such that the fuse would not blow for temporary faults (fuse saving approach). Thus, the recloser would operate first, for a fault downstream of the fuse, and if the fault still exists, the fuse would blow. The sequence of operation works well when the DG is operating in parallel with the utility. Once the DG is islanded, fault currents change as seen in Table 33. It can be seen from Figure 77 that the recloser-fuse coordination will be affected. For a permanent fault, the recloser fast curve will operate and then the slow curve. The fuse is no longer coordinated properly with the recloser slow curve (fuse should operate before the recloser slow curve). In addition, the sensitivity of the protective devices decreases as the DG capacity decreases. A solution to this problem would be to avoid any overlapping between the re-closer slow curve and the fuse as will be discussed latter.

Another possible set of coordination curves for both the re-closer and fuse is shown in Figure 81. The re-closer curves have been modified to highlight another possible situation that could occur. The re-closer curve is coordinated properly with the fuse for islanded condition. Unfortunately during utility operation, the fuse will blow before the recloser operates and thus the fuse saving scheme is affected. For this reason, it is important to try to coordinate the protective devices such that coordination is satisfied for all system configurations.

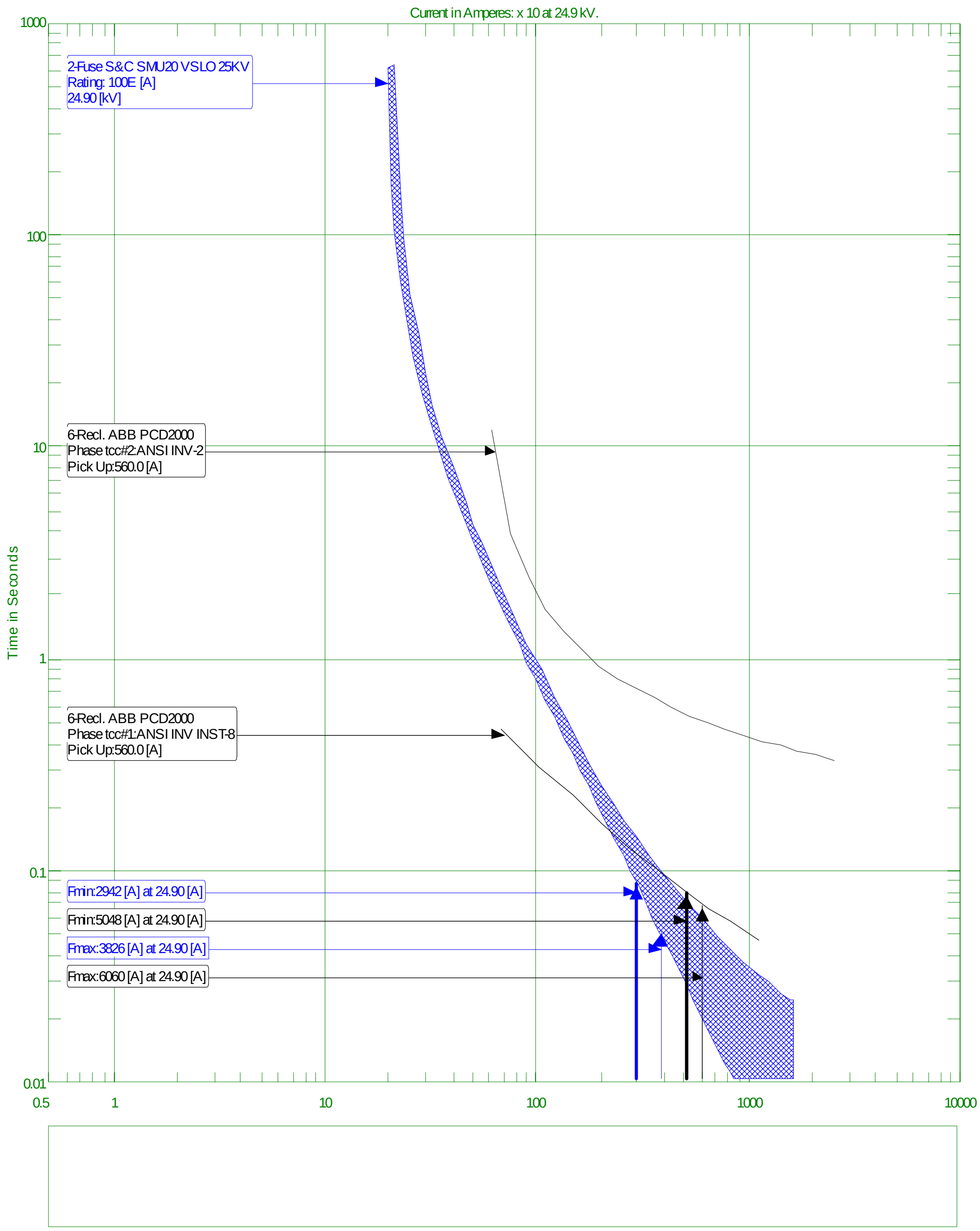


Figure 81 - showing original curve with fault currents.

5.7 Fault Back-feed During Island Operation (Bi-directionality)

5.7.1 Impact Definition

Intentional islanding of DG could lead to fault currents flowing in reverse directions through the protective devices. This will depend on the system configuration. For example, this could occur if a DG is located on a feeder and is designed to feed an adjacent feeder. Any fault on the adjacent feeder will lead to reverse fault currents passing through some of the protective relays. Similarly, reverse fault current could occur if there are more than one DG on the island. The DG is connected to the system and fault current flow is determined through the protective devices.

5.7.2 Case Study

The synchronous based DG is located at Bus 1 on first feeder and connected through a Delta – Wye grounded transformer. The fault occurs on the second feeder on Bus 1 as shown in figure. DG is designed to supply some of the loads on second feeder and third feeder. Breaker 1 “B1” is open to simulate an islanded case. Figure 82 shows part of the urban distribution system under study with a DG located bus 1. Table 35 presents the fault current levels in both feeder relays. It can be seen that both relays will sense the fault current but one of them will experience a reverse fault current. Since the settings of both relay R2 and relay R3 are identical, both relays will operate at the same time as shown in Figure 83 and thus, after a fault, the DG will feed only the loads of feeder 1. The proper procedure would be to disconnect the fault feeder (feeder 2) and leave both feeder 1 and feeder 3 being fed from the DG. Relays R2, R3, and R4 need to be coordinated properly to provide proper fault discrimination. In addition, it can be seen that as the DG rating decreases, the fault current decreases and thus the settings of the relays need to be changed to assure fast fault clearing.

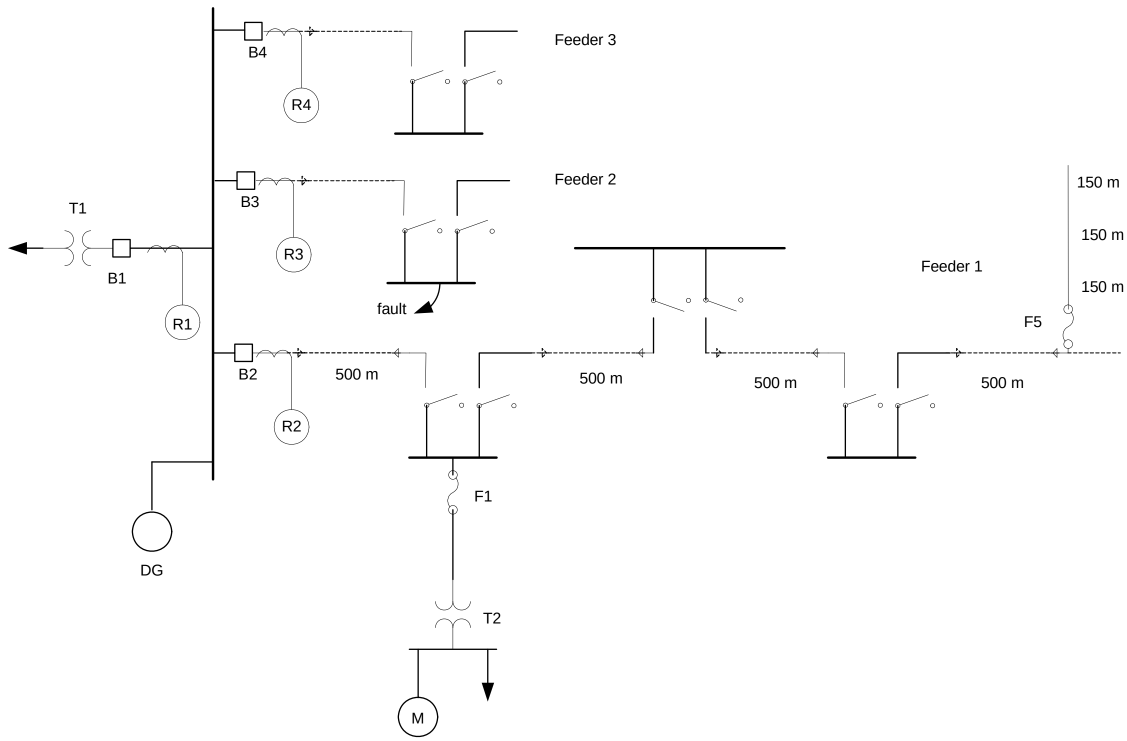


Figure 82 - Metro distribution system under study.

Table 35 - Maximum and minimum fault currents with a synchronous based DG.

	Grid-Connected Without DG		**Islanding with 11880 kVA DG**		**Islanding with 8910 kVA DG**		**Islanding with 5940 kVA DG**	
Fault	B3	B2	B3	B2	B3	B2	B3	B2
Max	46188	46188	1552	1552(reverse)	1338	1338(reverse)	1006	1006(reverse)
Min	25588	2558	1295	1295(reverse)	1092	1092(reverse)	803	803(reverse)

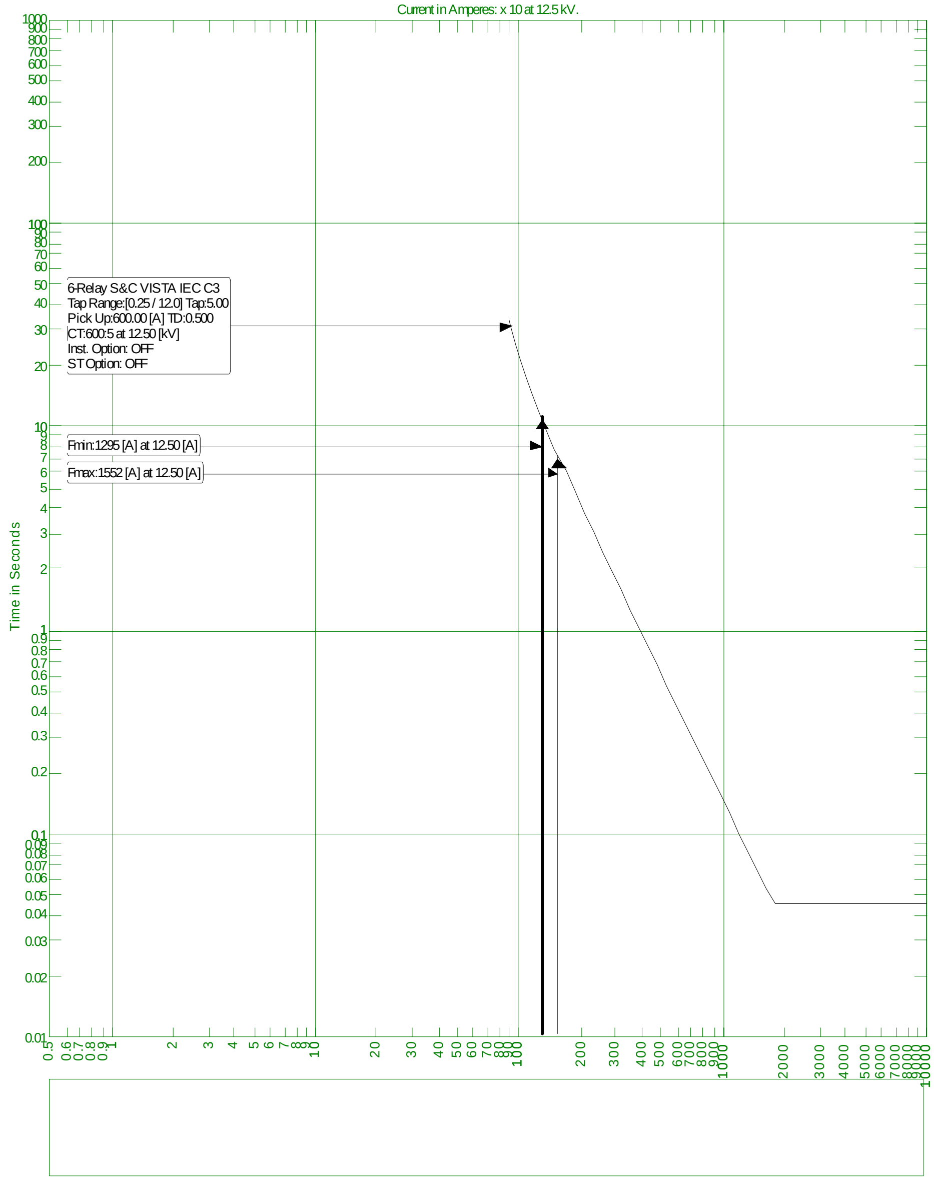


Figure 83 - Relay R2 and R3 coordination curves with a DG capacity of 11880 kVA.

A second case is presented in Figure 84, where a 6 MVA DG located at Bus 6 and another 6 MVA at Bus 1 and the fault current through fuse 3 is analyzed for a fault at different buses. Table 36 presents the fault currents through fuse F3 during an islanded operation.

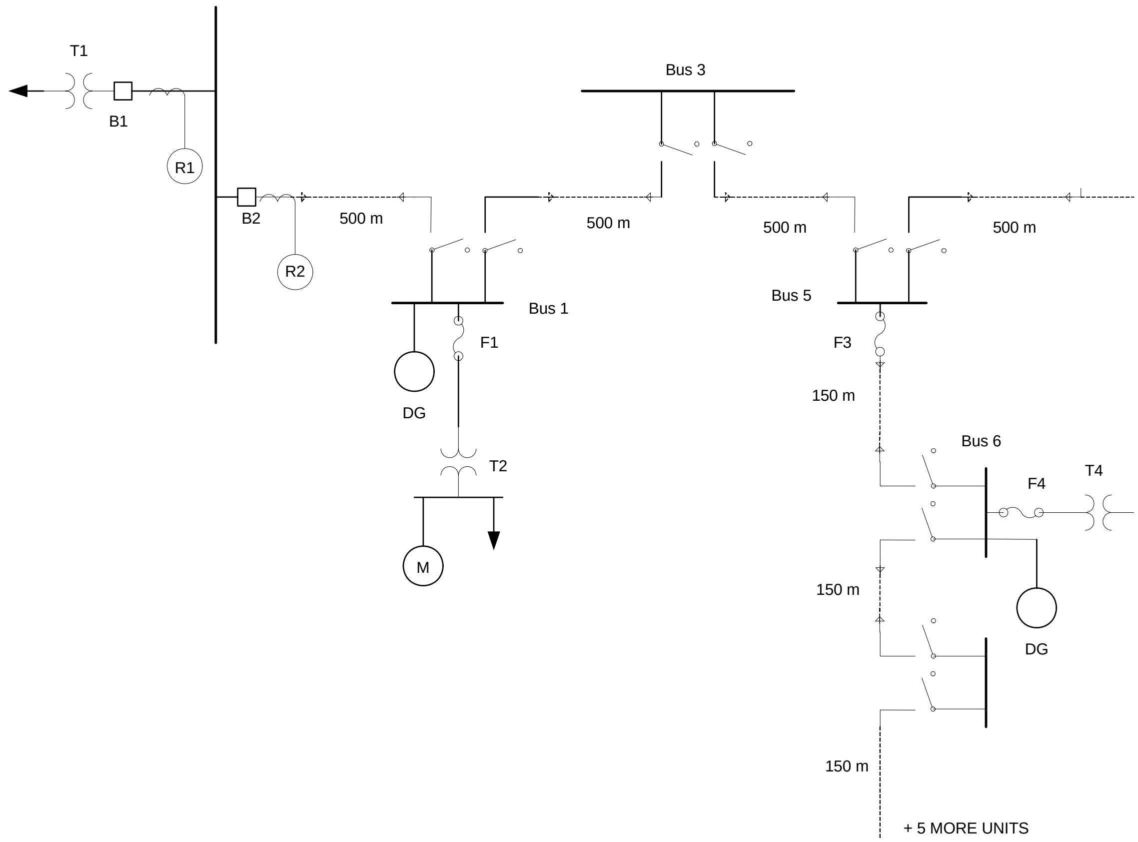


Figure 84 - System under study with two DGs.

Table 36 - Maximum and minimum short circuit currents for an islanded condition with two DG.

	Grid-Connected Without DG	**Fault at Bus 6**	**Fault at Bus 5**	**Fault at Bus 1**
Fuse	F3	F3	F3	F3
Max	5265	1370	1415 (reverse)	1364 (reverse)
Min	4558	1026	1048 (reverse)	1026.6 (reverse)

The results show that a protective device during an islanded situation could be exposed to fault currents flowing in both directions with an island consisting of more than one DG at different locations. The current protective device layout is not sufficient to isolate faults during an islanded condition. A simple approach would be to disconnect all DG once a fault occurs during islanding. For increased reliability, some additional protective devices would be needed to isolate the faulted parts of the island. In such case, an island would be created within the original island. For such islanded cases, protective devices based on overcurrent protection only would not be sufficient.

5.8 Summary

The above results indicate that the islanding scenario is very complex and requires comprehensive studies to determine the necessary settings and changes needed for healthy islanded operation. In fact, the protection philosophy for islanded systems will be different. Therefore, two separate approaches might be needed to address the parallel and islanded modes of operation, respectively. Based on the two approaches, some impacts can be mitigated by component upgrade, whereas other impacts can be addressed by utilizing microprocessor relays and communication-based protection practices to yield an adaptive protection scheme that can fit both modes of operations.

6 Mitigation Methods

From the discussion in the previous chapters, it was found that the installation of DGs may cause some problems in the protection system like loss of coordination, fuse nuisance blowing, problems with relay sensitivity, relay bi-directionality, and temporary overvoltages. These impacts are defined and generalized methods to assess the impact of DG on distribution system protection were developed in Chapter 4. In this chapter, some ideas for possible mitigation of these impacts are suggested. It should be noted that comprehensive studies are needed to analyze and evaluate the most appropriate mitigation techniques.

6.1 Suggested Solutions

6.1.1 Loss of Coordination

Upgrading some components can mitigate the loss of coordination. A new coordination study with the DG installed can be conducted to determine the appropriate sizing and upgrades of protection devices; most probably fuses. The new protection coordination study will ensure no loss of coordination even with the increase of the short circuit current by moving the intersection point of the primary and backup protection coordination curves to the right hand side on the time-current coordination curve. Figure 85 shows the short circuit current level before and after the installation of the DG in both the old and new coordination studies. It is clear from Figure 85 (a) that the backup protection will operate before the primary protection after installing the DG. Figure 85 (b) shows the new coordination study for the same system. The movement of the intersection point between the two curves to the right hand side ensures the operation of the primary protection even after installing the DG.

6.1.2 Fuse Nuisance Blowing

Examples of possible methods to mitigate this impact are:

1. Re-performing the coordination study between the recloser and the downstream fuses, and replacing the fuses with new ones with slower curve. This will give the recloser a chance to save them from the unnecessarily operation during temporary faults. The direct result is moving the intersection point between the fast curve of the recloser and the fuse to the right hand side on the time-current plane.

2. Re-performing the coordination study between the recloser and the downstream fuses, and readjusting the setting of the fast curve of the recloser to be faster in operation or even changing the whole recloser by a new one. This will also ensure the operation of the recloser first to save the fuse.

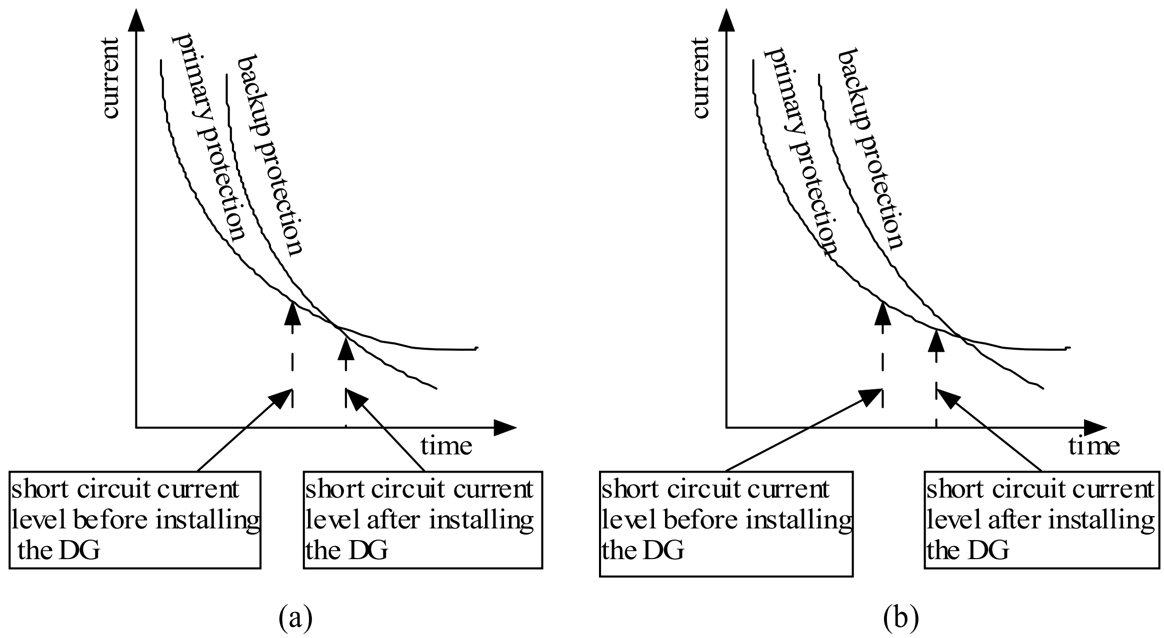


Figure 85 - Short circuit current level before and after the installation of the DG (a) old coordination study (b) new coordination study.

6.1.3 Main Feeder Relay Sensitivity

Examples of possible methods to mitigate this impact are:

1. Using a high impedance for grounding the interface transformer of the DG. This ensures high source to fault impedance for the DG, and as a result, increases the current drawn from the utility during short circuits. This in turn causes the main feeder relay to sense any fault in its primary protection zone. It should be noted here that the unnecessary increase of the grounding impedance would increase the temporary overvoltage upon opening of the main feeder breaker. Therefore, a tradeoff should be made in designing the grounding impedance.

2. Replacement of the main feeder relay with a microprocessor based relay with special fault sensing elements, such as using the high frequency transients superimposed on the current waveform during short circuits. As a result, even with low short circuit currents, the short circuit can be sensed and a trip signal can be issued. The sensed fault could be lower or greater than the relay pickup current. For the first case, the relay should issue a trip signal after a pre-determined time interval that is selected to be high enough to avoid wrong operation for out of zone faults. Further studies may be done to differentiate between in-zone faults and out of zone faults to avoid this time interval before issuing a trip signal, however, this will increase the complexity of the relay and of course its cost. For the second case, the sensed fault current is higher than the relay pickup current, the relay may operate according to the ordinary inverse time-current characteristics.

3. Prevent any installation of the DG's near the head end of the feeder, if it is possible.

6.1.4 Bi-directionality

Examples of possible methods to mitigate this impact are:

1. Usage of interlocking system between the main relays of the feeders fed from the same substation. The main idea of the interlocking system is that the main relay of the feeder with DG has an interlocking system that blocks its operation upon a locking signal from the other main relays of other feeders. The locking signal will be sent from the relay, which senses a short circuit current, to the main relay of the feeder with DG. This locking signal will prevent the relay from wrong operation even with the back feeding from the DG to the fault.

2. Using a directional element with the main relay of the feeder with DG to avoid wrong operation during the back feeding.

3. Readjust the time settings of the main feeder's relays to ensure faster relay settings for the feeder with no DG's and relatively slower time settings of the main relay of the feeder with DG. This should be done without affecting the coordination of these relays with their corresponding down stream devices.

6.1.5 Overvoltage

Examples of possible method to mitigate this impact is:

Grounding the transformer, which interfaces the DG by impedance with a low value to avoid such overvoltages, however, the grounding impedance shouldn't be very small to avoid under sensitivity problems mentioned above. The sensitivity and the overvoltage problems should be considered when deciding the value of the grounding impedance.

6.2 Summary

Some ideas for possible mitigation of these impacts have been suggested in this section. It should be noted that comprehensive studies are needed to analyze and evaluate the most appropriate mitigation techniques.

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Appendix A

Benchmark Distribution Systems Parameters

A.1 Urban System Parameters

Table A1 - Urban system parameters.

Component	Description
Substation Parameters	Number of transformers per substation: 4, Transformer rating "T1": 50MVA, Voltage ratings: 120kV/12.kV (Line), Connection: ΔY, Impedance: 10%, Grounding details: reactor grounded neutrals (1.5 Ohm)
Substation Bus	Bus rated voltage: 120 KV/ 12.5 kV, Configuration: Breaker tied bus, Voltage rating: 120kV/12.5kV, Number of feeders per bus: 6, , Breaker rated: 1200A, No. of Capacitor band/bus: 1 rated at 10 MVA, Protection: differential bus protection, Surge arrestor: Station class - 9 KV Duty Cycle.
Feeder	*Feeder head end:* The distribution feeder is fitted with the following protection elements: Timed phase overcurrent (51P)- 600 A, Timed ground overcurrent - 150 A. *Feeder Egress:* Underground cable, rated 400 AMP, 8.7 MVA. 600 kcmil shielded copper cable in 100 mm duct, Length of feeder is 1 Km.
Single-phase underground laterals (Residential loads)	Length: 1 km, Cable: XPLE 53 mm^2 Aluminum (AWG 1/0), Protection: Head end fuse 200K, Transformers "T4": 21 units, 100 KVA, 4% Impedance, 3-Phase 12.5kV/120V/208V, Surge Arrestor: Normal class 9kV duty cycle.
Single-phase overhead laterals "Residential loads"	Length: 1 km, Line: AWG 1/0 , AAC Aluminum Conductor, Protection: Head end fuse 200K, Transformers "T5": 21 units, 100 KVA, 5% Impedance, 3-Phase 12.5kV/120/208V, Surge arrestor: Normal class 9kV duty cycle.
Three-phase substation in basement of office tower	This consists of a 2 MVA, 12.5 kV/600V, 3-ph, 4 wire, ΔY transformers "T2" with an impedance of 3%, surge arrestor (Normal class 9 KV duty cycle), fuse (125E). Loads include a 1 MVA motor load in addition to a 1 MVA fixed impedance load operating at 0.95 power factor lagging.
Three-phase secondary street network	This consists of 4 parallel 500 kVA, 12.5 kV/120/208V, 3-ph, 4 wire, ΔY transformers "T3" per feeder with an impedance of 4 %. Fuse rated 30SE. The total connected load is 2 MVA with an overall power factor of 0.95 lagging.
Modeling of the rest of feeder loads	Due to the similarity in all feeders, the remaining 5 feeders on each bus are modeled as a lumped load connected at the main station bus with a total power demand of 42 MVA and an overall power factor of 0.95 lagging. A 10 MVAR delta connected capacitor bank is interconnected at the main station bus to provide reactive power compensation.

A.2 Suburban System Parameters

Table A2 - Suburban system parameters.

Component	Description
Substation Parameters	Number of transformers per substation: 2, Transformer rating: 100MVA, Voltage ratings, 240kV/25kV, Connection: YY, 10% Impedance, Reactor grounded (1.5 Ohm)
Substation Bus	Bus rated voltage: 25 kV, Configuration: Breaker tied bus, Voltage ratings, 230kV/25kV, Number of feeders per bus: 6, Breaker rated: 1200A. No. of capacitor bank/bus: 1 rated at 10MVA, differential bus protection, Surge arrestor: Station class - 18 KV duty cycle.
Feeder	*Feeder head end:* The distribution feeder is fitted with the following protection elements: Instantaneous phase overcurrent relay (50P)- 1500 A, Timed phase overcurrent (51P)- 600 A, Instantaneous ground overcurrent relay (50G)-300 A, Timed Ground overcurrent- 150 A, Reclosing 70, 2 Ohm series reactor to limit feeder fault current to under 8 KA. *Feeder Egress:* Underground cable, rated 400 AMP, 16 MVA. 380 mm^2 triplexed XPLE cable in 125 mm duct. Neutral is sized 30% of the main phases. Single point sheath ground with 107 mm^2 (AWG 4/0) bond, Length of express feeder from station to overhead line (1 km), Riser Pole surge arrestor (riser pole class, 18 KV duty cycle)
Suburban backbone Overhead Section	The suburban backbone overhead section is 5 Km long, made from ASC Aluminum stranded conductors with 170 mm2 cross-section, armless construction. Open loop primarily distribution system. There exists also another two laterals with same construction as backbone, each is 3 Km long and fed a concentrated load of 5 MVA.
Single-phase underground laterals (Residential loads)	Length: 1 km, Cable: XPLE 53 mm^2 (AWG 1/0). Protection: Head end fuse 200K, Transformers: 21 Units, Pad mounted, 100kVA single phase, 4 % Impedance, Surge Arrestor: Normal class 18kV duty cycle, Fuse including current limiting (10), Secondary (240,120 V) three wires, individual 54 mm^2 AL, Each transformer fed 15 building with 50 m UG cable.
Single-phase overhead laterals "Residential loads"	Length: 1 Km, Line: 107 mm^2, AAC All Aluminum Conductor, Protection: Head end fuse 100 K,Transformers: 21 Units, Pad mounted, 100kVA single phase, 4 % Impedance, Surge Arrestor: Normal class 18kV duty cycle, Fuse including current limiting (10) , Secondary (240,120 V) three wires, individual 54 mm^2 AL, Each transformer fed 15 building.
Three phase commercial or condominium transformers and loads	Rated 1 MVA, impedance 3%, secondary (3phase, ΔY 120,208 V, four wire) surge arrestor (Normal class 18 KV duty cycle), fuse including current limiting 40 K, secondary at load center 1 MVA, pf 0.95

Three phase industrial transformers and loads	Rated 1 MVA, impedance 3%, secondary (3phase ΔY, 120,208 V, four wire) surge arrestor (Normal class 18 KV duty cycle), fuse including current limiting 40 K, secondary at load centre 1 MVA, pf 0.9
Modeling of the rest of feeder loads	Due to the similarity in all feeders, the remaining 5 feeders on each bus are modeled as a lumped load connected at the main station bus with a total power demand of 84 MVA and an overall power factor of 0.95 lagging. A 20 MVAR delta connected capacitor bank is interconnected at the main station bus to provide reactive power compensation.

A.3 Rural System Parameters

Table A3 - Rural system parameters.

Component	Description
Source Parameters	Nominal capacity: 20MVA, Nominal voltage: 27.6kVA (line), Positive sequence equivalent resistance: 0.027 Ohm, Positive sequence equivalent reactance: 0.86 Ohm, Zero sequence equivalent resistance: 0.07796 Ohm, Zero sequence equivalent reactance: 2.85 Ohm, Equivalent three-phase short circuit MVA: 885.33. X/R=31.8519
Transformers	“T1”: 3.6MVA, 3-phase, 16kV/4.8kV (phase), ΔY, 6 % Impedance “T2”: 15MVA, 3-phase, 16kV/16kV (phase), YY , 7.3 % Impedance, Regulating station transformer. “T3”: 1.0MVA, 3-phase, 16kV/4.8kV, YY, 4 % Impedance “T4”: 3.6MVA, 3-phase, 16kV/4.8kV, ΔY, 5.65 % Impedance
Overhead Lines	“L1” 336AL427 5700m “L2” 336AL427 1010m “L3” 336AL427 400m “L4” 336AL427 380m “L5” 336AL427 130m “L6” 336AL427 170m “L7” 336AL427 260m “L8” 336AL427 140m “L9” 336AL427 380m “L10” 336AL427 560m “L11” 336AL427 300m “L12” 336AL427 3330m “L13” 336AL427 1030m “L14” 336AL427 1080m “L15” 336AL427 470m “L16” 30ASR427 1940m “L17” 30ASR427 470m “L18” 4ASR- 48 960m “L19” 30ASR427 190m “L20” 30ASR427 1940m “L21” 30ASR427 2450m “L22” 30ASR427 1630m “L23” 10ASR427 1200m “L24” 10ASR427 820m “L25” 10ASR427 1550m “L26” 30ASR427 2120m “L27” 10ASR427 750m “L28” 10ASR427 1070m “L29” 30ASR427 2540m

	“L30” 40ASR427 360m “L31” 40ASR427 260m “L32” 10ASR427 3580m “L33” 40ASR427 770m “L34” 30ASR427 2080m “L35” 40ASR427 4510m “L36” 336AL427 3240m “L37” 336AL427 300m “L38” 336AL427 500m
Voltage regulator	15MVA, 27.6kV, Boost setting: 2.5%
Load data	See Table 5 below.
Protective Devices	Timed phase overcurrent (51P)- 560 A, Timed ground overcurrent - 240 A., Recloser: 27.6kV, Phase trip current: 350A, Ground trip current: 280A., Lateral Fuses: 27.6kV, 40A.

Table A4 - Rural system load parameters.

Name	Phase	S(A) (kVA)	pf(A)	S(B) (kVA)	pf(B)	S(C) (kVA)	pf(C)
M3	ABC	0.00	1.00 Lag	10.00	0.95 Lag	0.00	1.00 Lag
M2	C	0.00	1.00 Lag	0.00	1.00 Lag	160.00	0.95 Lag
M1	ABC	2,193.67	0.95 Lag				
M11	ABC	170.00	0.95 Lag	0.00	1.00 Lag	0.00	1.00 Lag
M12	ABC	0.00	1.00 Lag	25.00	0.95 Lag	0.00	1.00 Lag
M9	ABC	0.00	1.00 Lag	0.00	1.00 Lag	20.00	0.95 Lag
M10	ABC	50.00	0.95 Lag				
M26	ABC	10.00	0.95 Lag	0.00	1.00 Lag	0.00	1.00 Lag
M14	B	0.00	1.00 Lag	50.00	0.95 Lag	0.00	1.00 Lag
M18	ABC	130.00	0.95 Lag	0.00	1.00 Lag	0.00	1.00 Lag
M19	ABC	0.00	1.00 Lag	110.00	0.95 Lag	0.00	1.00 Lag
M20	ABC	0.00	1.00 Lag	0.00	1.00 Lag	155.00	1.00 Lag
M17	ABC	50.00	0.95 Lag				
M13	ABC	216.67	1.00 Lag	216.67	1.00 Lag	216.67	1.00 Lag
M15	A	160.00	0.95 Lag	0.00	1.00 Lag	0.00	1.00 Lag
M16	C	0.00	1.00 Lag	0.00	1.00 Lag	205.00	1.00 Lag
M23	ABC	60.00	0.95 Lag	0.00	1.00 Lag	0.00	1.00 Lag
M22	ABC	0.00	1.00 Lag	0.00	1.00 Lag	50.00	0.95 Lag
M25	B	0.00	1.00 Lag	85.00	0.95 Lag	0.00	1.00 Lag
M21	C	0.00	1.00 Lag	0.00	1.00 Lag	215.00	0.95 Lag
M6	ABC	1,099.00	0.95 Lag	946.00	0.95 Lag	1,310.00	0.95 Lag
M24	ABC	749.00	0.95 Lag	710.00	0.95 Lag	821.00	0.95 Lag
M5	ABC	274.00	0.87 Lag				
M4	ABC	72.00	0.87 Lag				
M7	ABC	256.00	0.75 Lag				
M8	ABC	6.33	1.00 Lag				

Appendix B

Steady State Analysis for Different Benchmark Systems

B1. Urban Benchmark System

Power flow and short circuit analysis were performed on the urban distribution system given in Figure 3. The per unit voltage was measured starting from the substation point to the furthest load on the main feeder, underground and overhead laterals as shown in Figures B1, B3, and B5, respectively. It should be noted that the phase voltages shown in the aforementioned figures coincide due to the assumption of balanced loading conditions. The sudden drop in voltage level is as a result of the voltage drop across the current limiting reactor. It can be seen that the voltage drop, for all cases, is less than 3% on main feeder, underground and overhead lateral, which is within the 5% permissible design levels.

Figures B2, B4, and B6 show the short circuit current for bolted 3-phase Line to Line to Line (LLL) fault, Line to Line to Ground (LLG) fault, Line to Line (LL) fault and Line to Ground fault (LG) fault along the main feeder, underground and overhead laterals, respectively. The maximum short circuit current anticipated on the main start of the main feeder for LLL fault is around 6.5 kA, and the minimum short circuit current anticipated at the end of the feeder for LG fault is equivalent to 5.4 kA. Similarly, a sudden drop in short circuit levels occurs due to the presence of the current-limiting reactor.

Figures B7 and B8 depict the apparent and reactive power profile along the main feeder. The total kVA feeder consumption per phase is approximately 2300 kVA, which results in a maximum load current of 318 Amperes (passing through the main feeder). This current is less than 400 A, and thus the 600 kcmil AL conductor (rated at 400 A) will be sufficient to carry the normal load current. From Figure B8, it can be seen that the total feeder reactive power consumption is approximately 800 kVAR, thus making the overall power factor around 0.94 lagging.

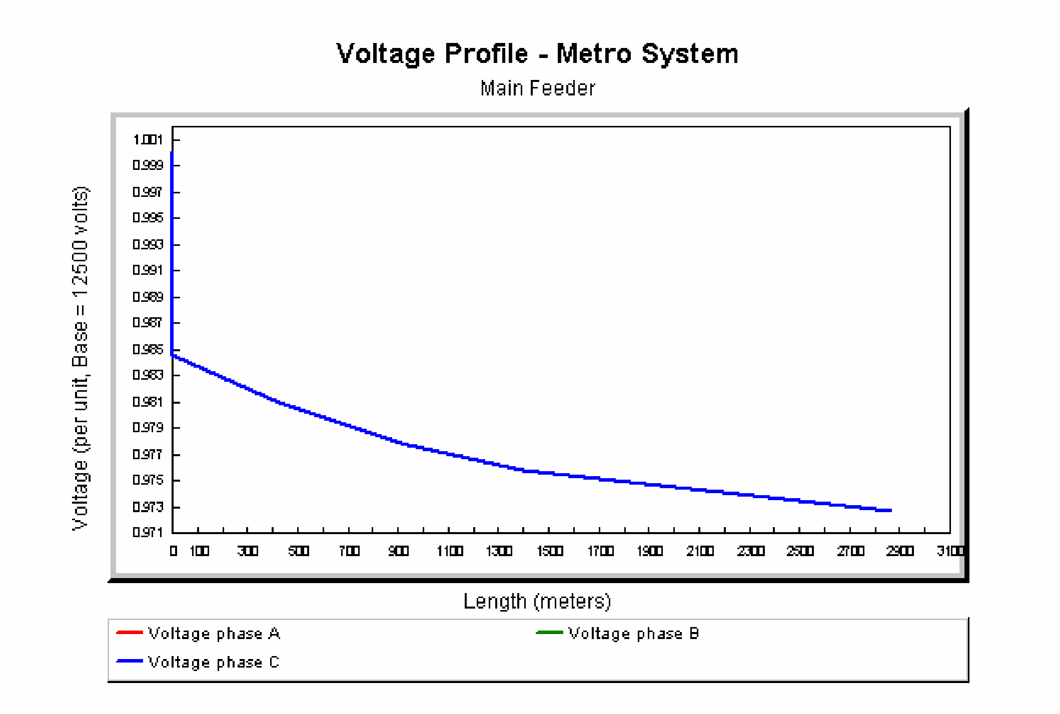

Figure B1 - Voltage profile along the main feeder of the metro distribution system.

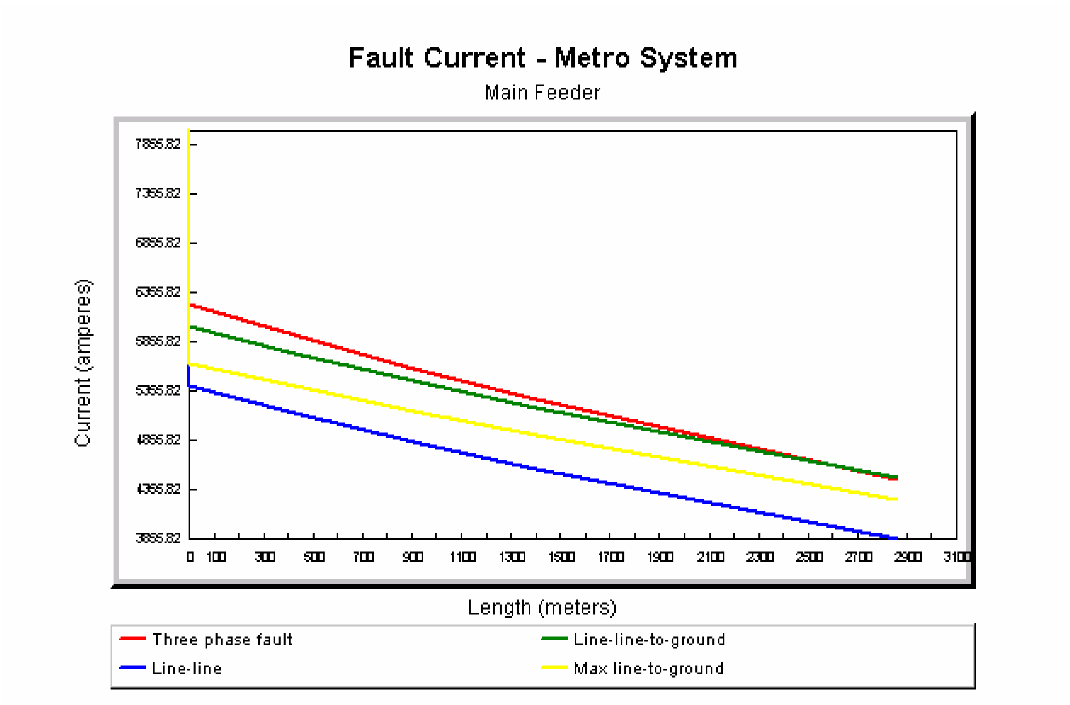

Figure B2 - Short circuit current along the main feeder of the metro distribution system.

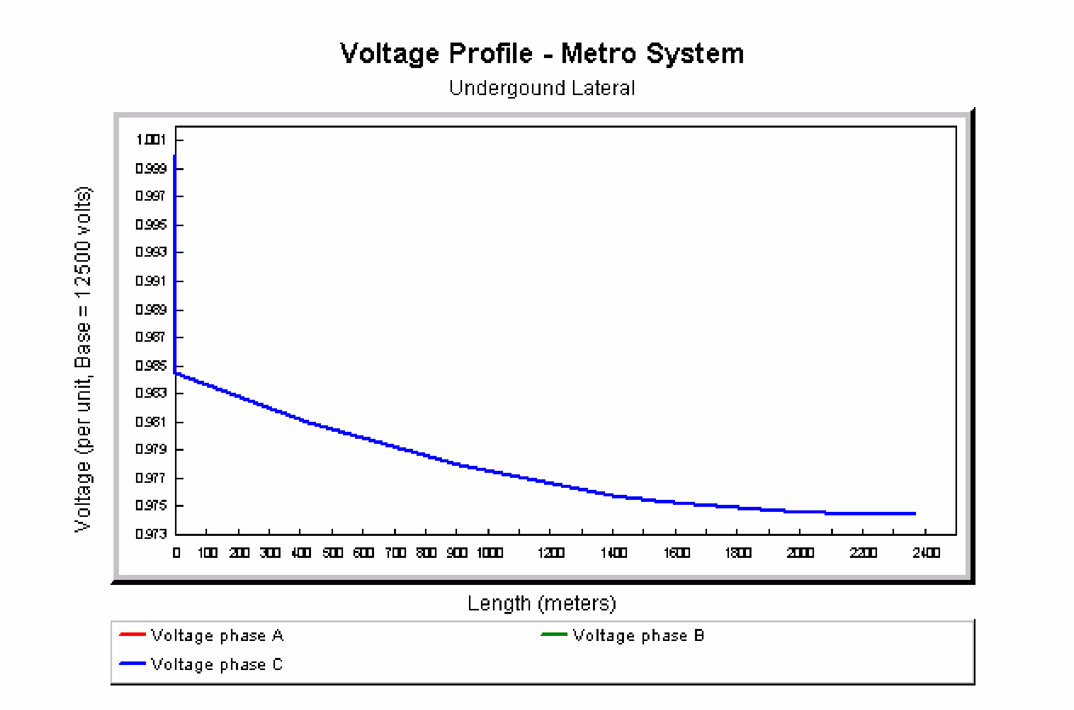

Figure B3 - Voltage profile up to the underground lateral in the metro distribution system.

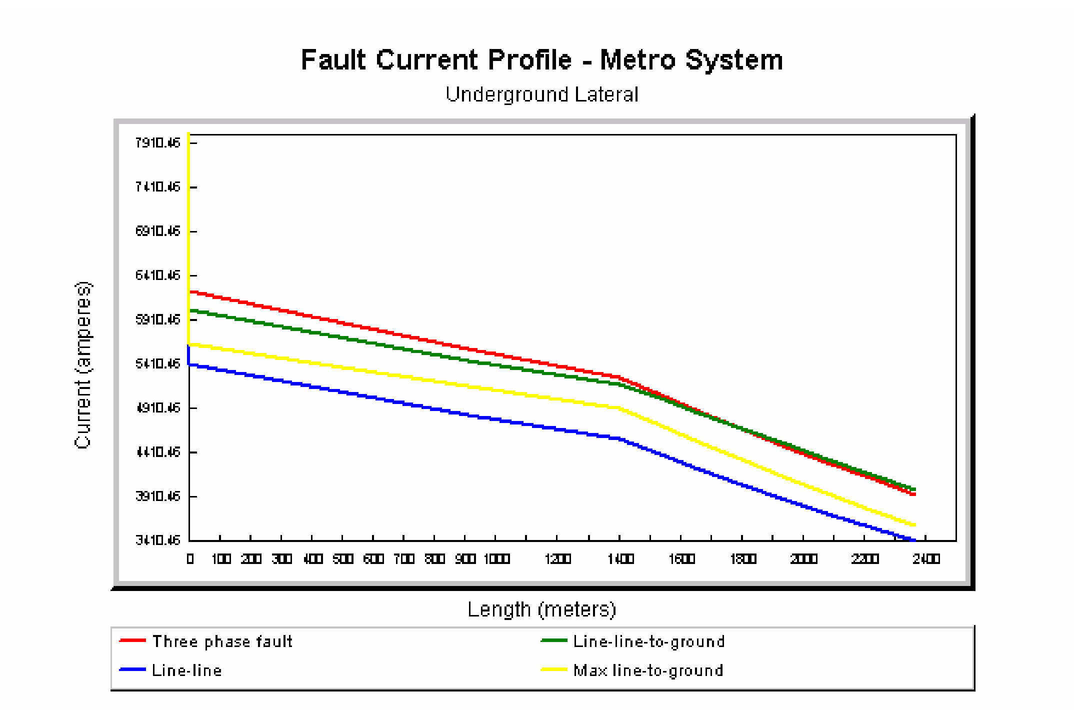

Figure B4 - Short circuit current up to the underground lateral in the metro distribution system.

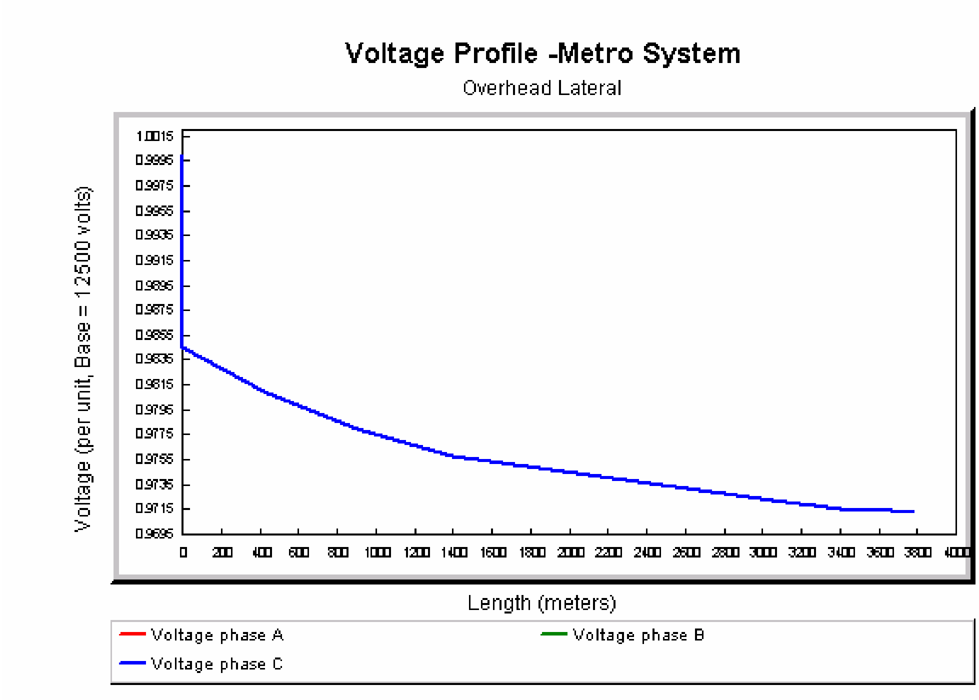

Figure B5 - Voltage profile up to the overhead lateral in the metro distribution system.

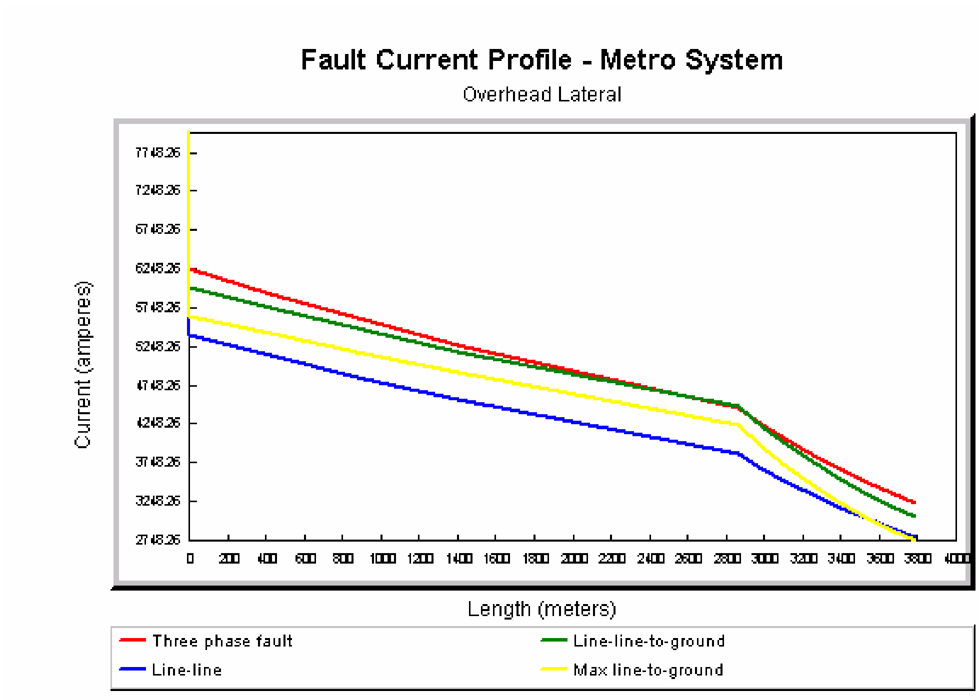

Figure B6 - Short circuit current profile up to the overhead lateral in the metro distribution system.

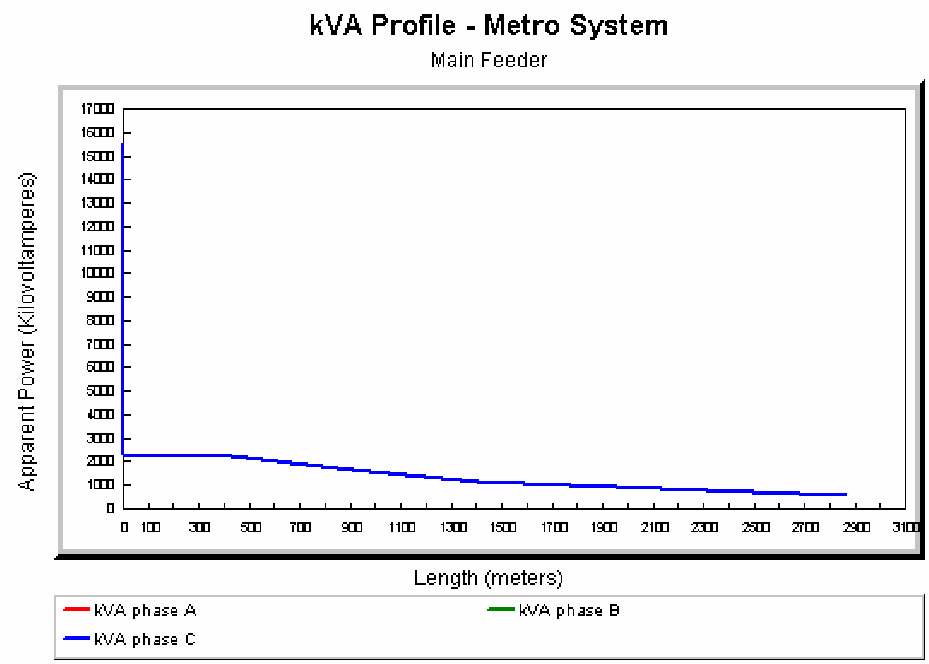

Figure B7 - Apparent power profile along the main feeder in the metro distribution system.

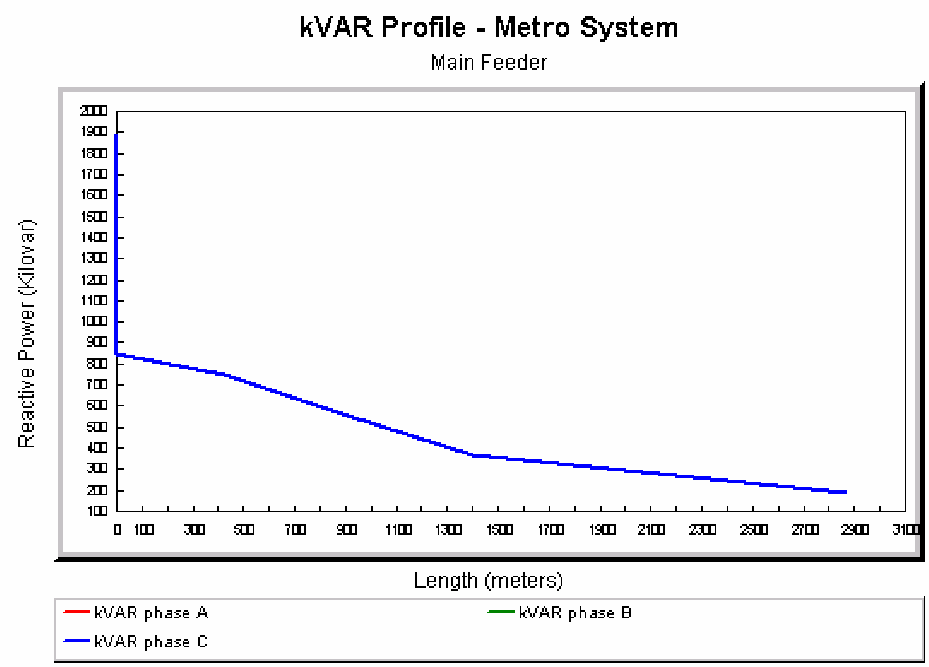

Figure B8 - Reactive power profile along the main feeder in the metro distribution system.

B2. Suburban Benchmark System

Figures B9, B11, and B13 show the voltage drop across the main feeder, lateral 1 (2MVA lateral), and lateral 2 (1 MVA lateral), respectively. Similarly, the phase voltages coincide due to balanced load conditions. Simulations have shown that the voltage drop across the main feeder and all laterals is within the 5% limits. Figures B10, B12, and B14 show the short circuit profile for LLL, LLG, LL, and LG faults along the main feeder, lateral 1, and lateral 2, respectively. Due to the presence of the series reactor, the maximum short circuit current at the feeder head end is reduced from 38 kA to around 6 kA. Figures B15 and B16 depict the apparent and reactive power profile along the main feeder, respectively.

Simulation results introduced in this section indicate that the suburban benchmark distribution feeder is working within the permissible steady state limits. Short circuit currents obtained from this analysis will be utilized in conducting the coordination study of the protective devices.

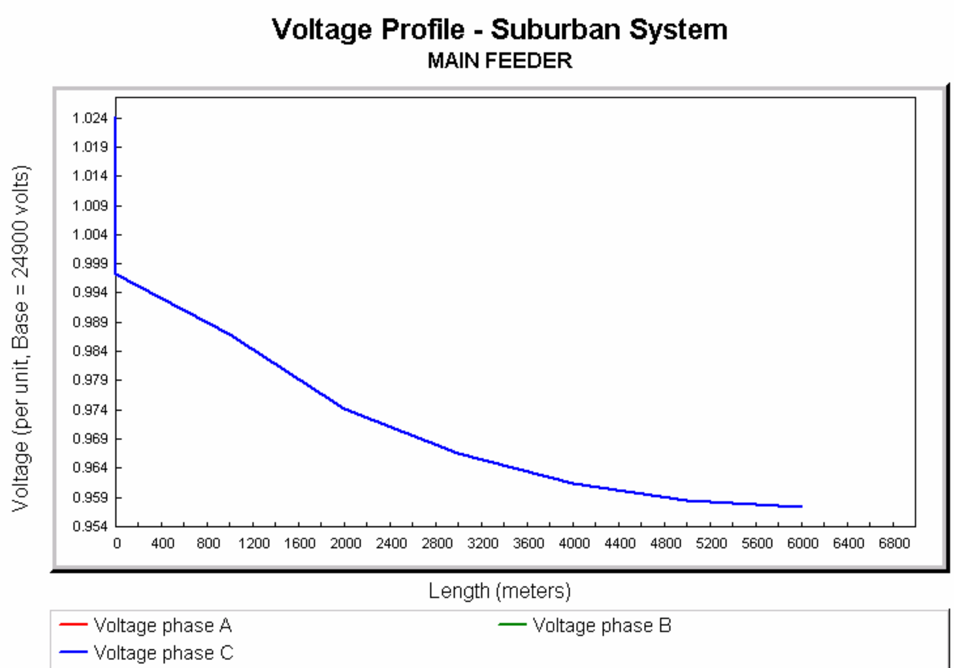

Figure B9 - Voltage profile across the main feeder in the suburban distribution system.

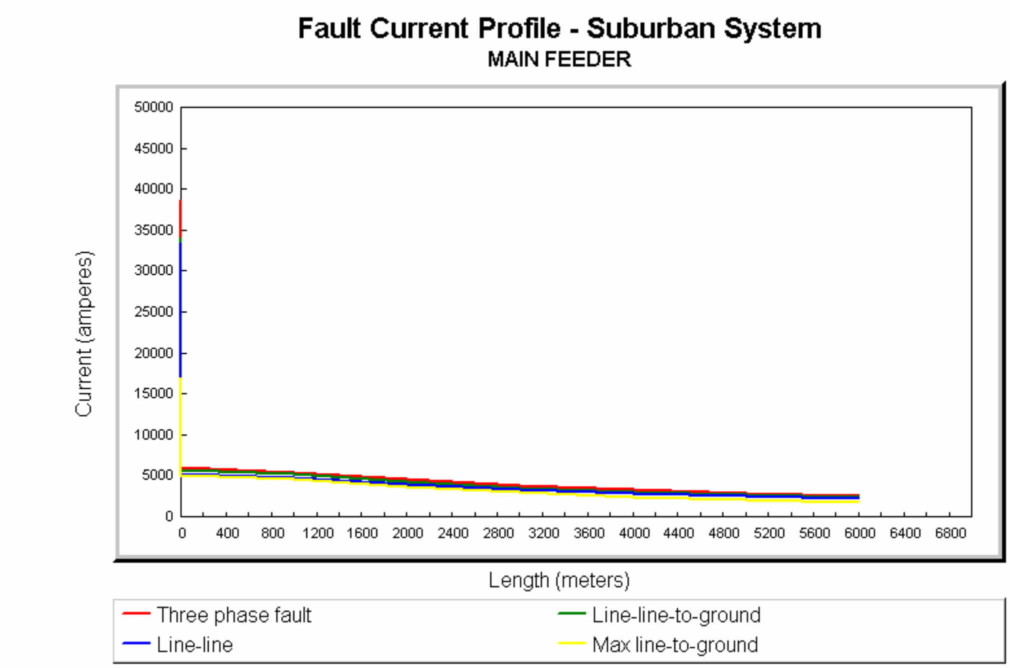

Figure B10 - Short circuit current along main feeder of the suburban distribution system.

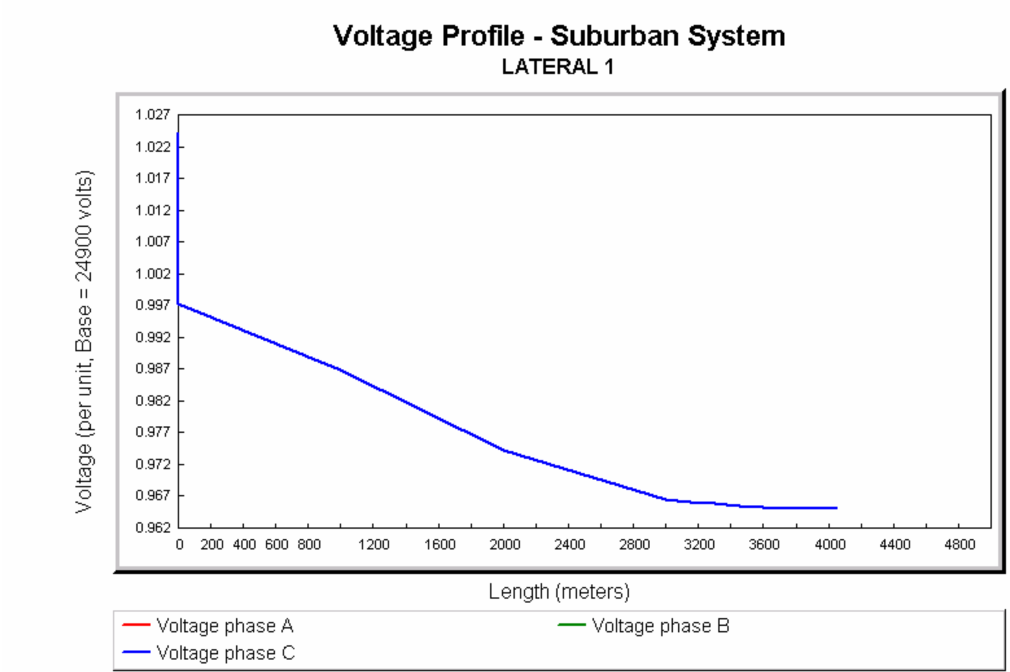

Figure B11 - Voltage profile up to lateral 1 in the suburban distribution system.

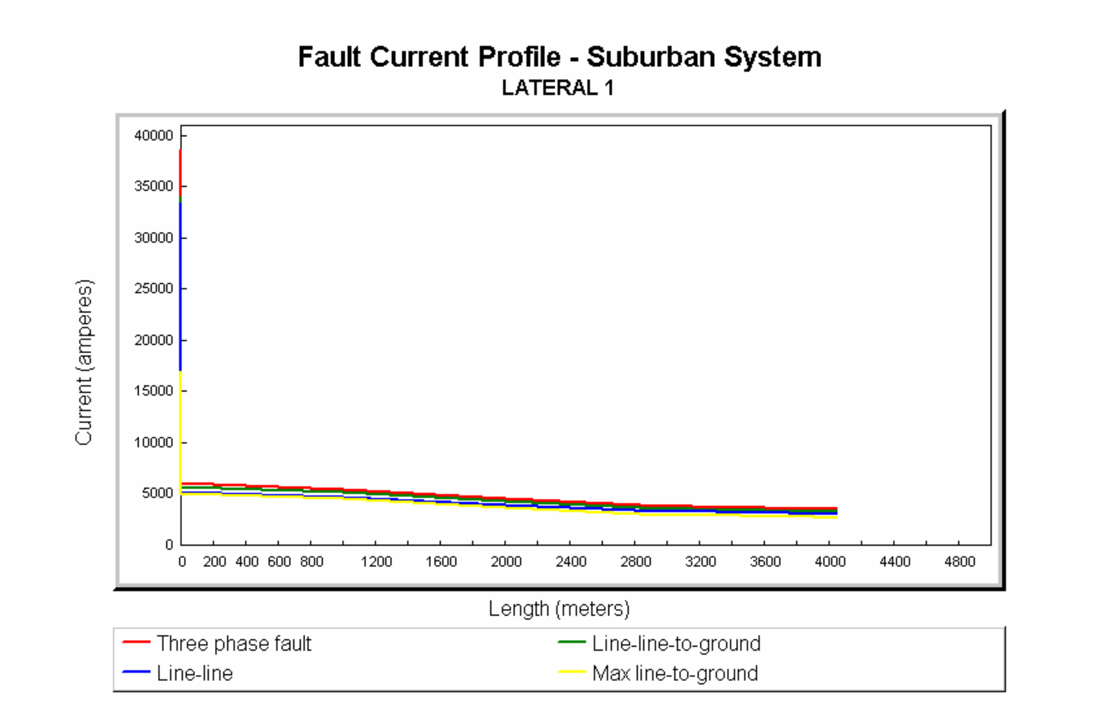

Figure B12 - Short circuit current up to lateral 2 in the suburban distribution system.

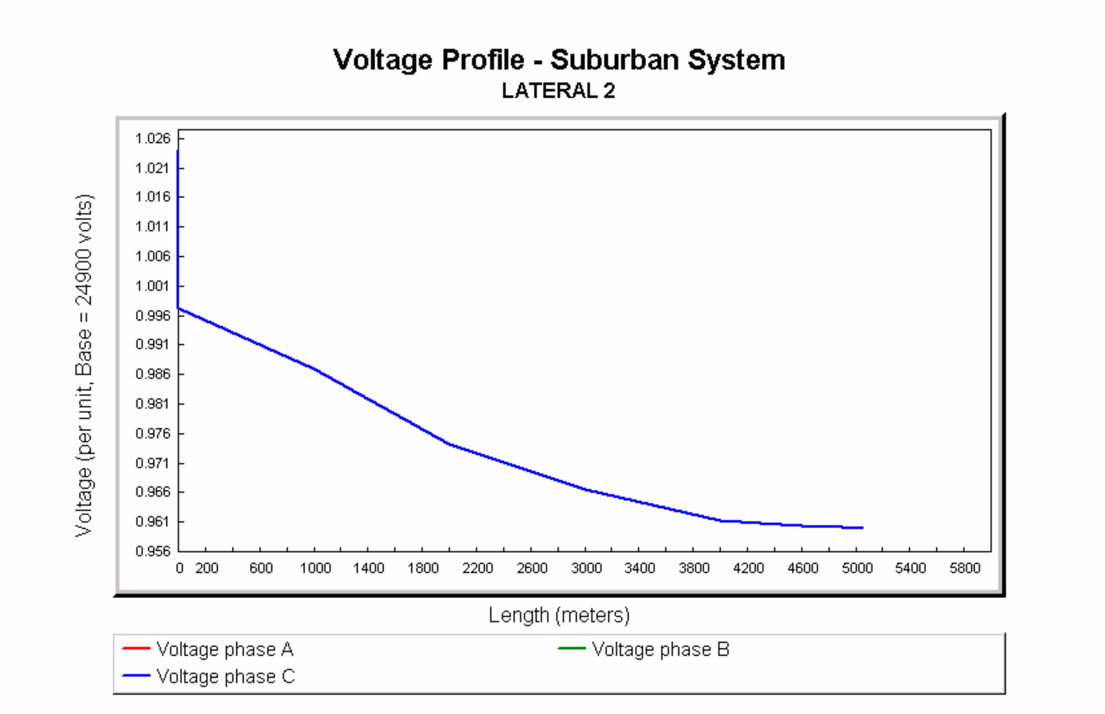

Figure B13 - Voltage profile up to lateral 2 in the suburban distribution system.

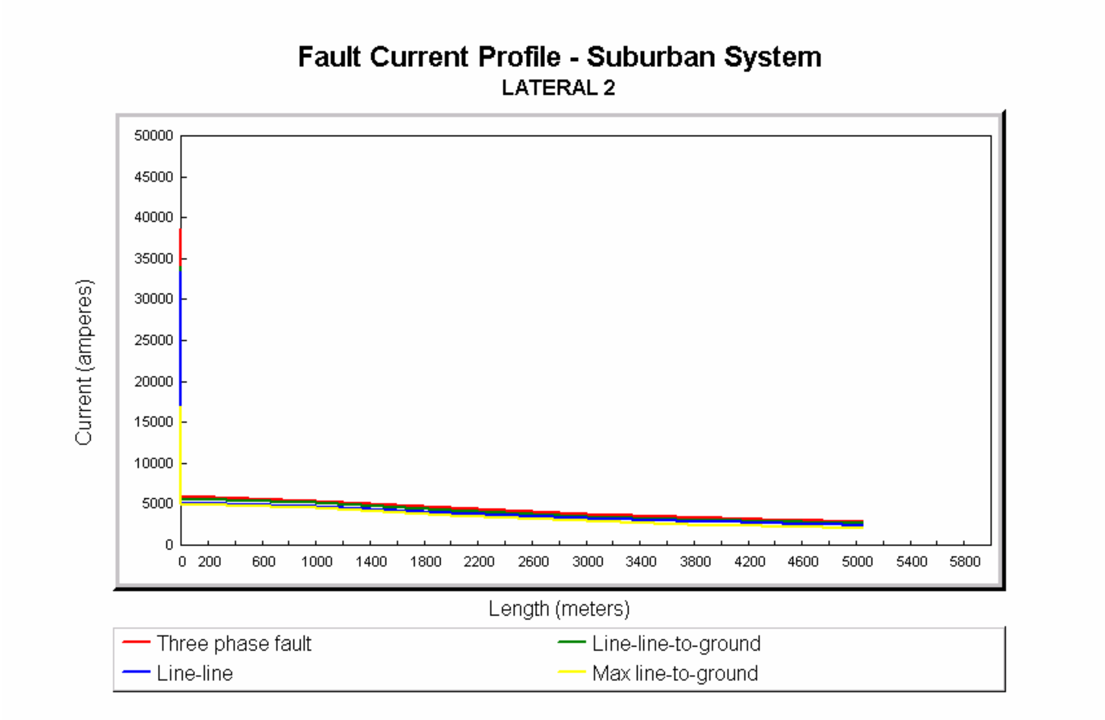

Figure B14 - Short circuit current up to lateral 2 the suburban distribution system.

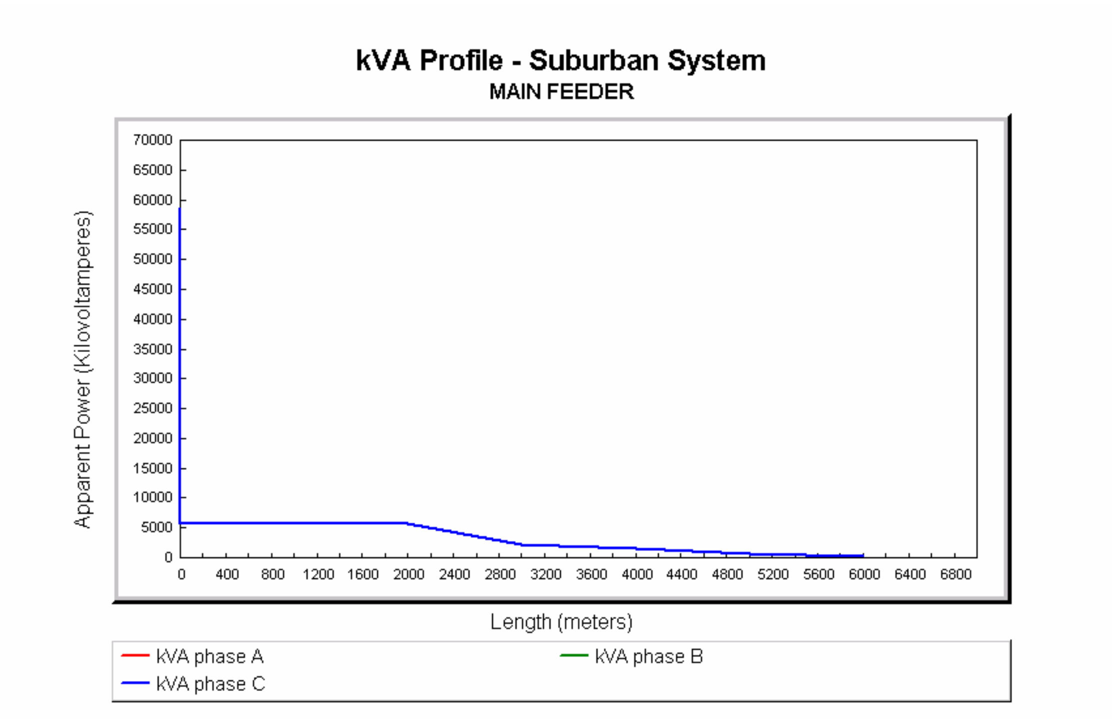

Figure B15 - Apparent power profile along the main feeder in the suburban distribution system.

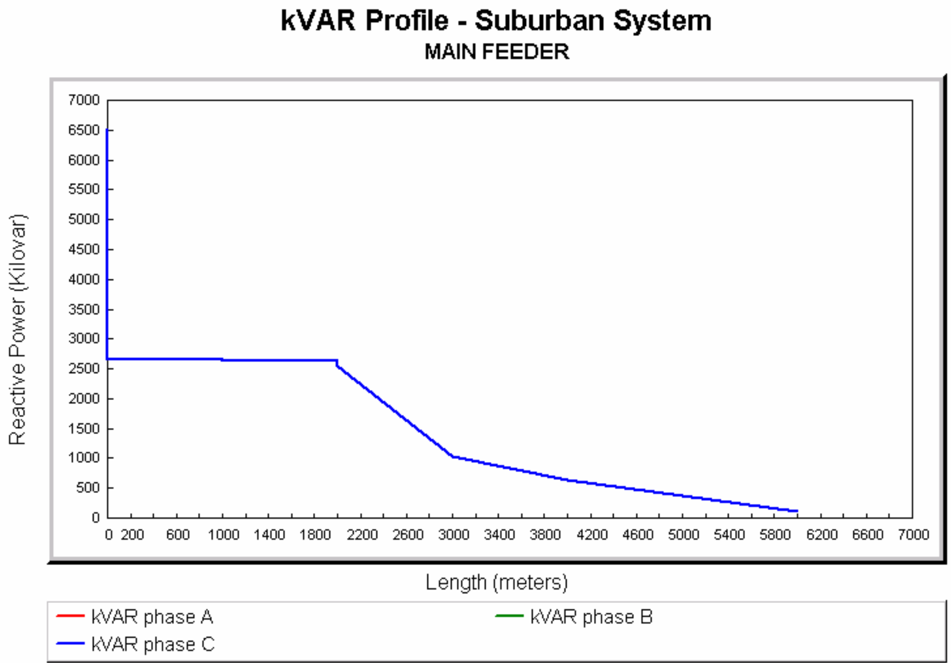

Figure B16 - Reactive power profile along the main feeder in the suburban distribution system.

B3. Rural System

The per unit voltage was measured starting from the substation point to the end of the main feeder, sub-feeder 1 and sub-feeder 2 as shown in Figures B17, B19, and B21, respectively. Due to the unbalanced nature of the feeder loading, the voltage drop among different phases is different. Phase C is the most loaded phase and it exhibits the largest voltage drop, which is around 6.2% just before the regulating station. Simulation studies reveal that sub-feeder 2 (around 25 km from the mains) exhibits the largest voltage drop, which is around 5.75% for phase C. The maximum voltage drop for other phases in different locations is less than 5%.

The voltage boosting action of the voltage regulator is obvious in the Figures B17, B19, and B21. The voltage drop indices obtained are acceptable for a typical rural distribution system. Figures B18, B20, and B22 show the short circuit current for bolted 3-phase LLL, LLG, LL, and LG faults along the main feeder, sub-feeder 1 and sub-feeder 2, respectively. The maximum short circuit current anticipated on the main start of the main feeder for LLL fault is less than 19 kA, and the minimum short circuit current anticipated at the end of the feeder for LG fault is around to 10 kA.

Figures B23 and B24 depict the apparent and reactive power profile along the main feeder. The total kVA feeder consumption is approximately 6250 kVA for phase C and around 5500 kVA for phases A and B. which results in a maximum load current of 391 A in phase C, 355 A in phase A, and 350 A in phase B. The total power consumed from the source is around 16160 kW, 6585 kVAR, and 17500 kVA. The total supply power factor is around 0.93 lagging.

Simulation results introduced in this section closely match the actual system analysis results provided with the system; hence model validity is ensured.

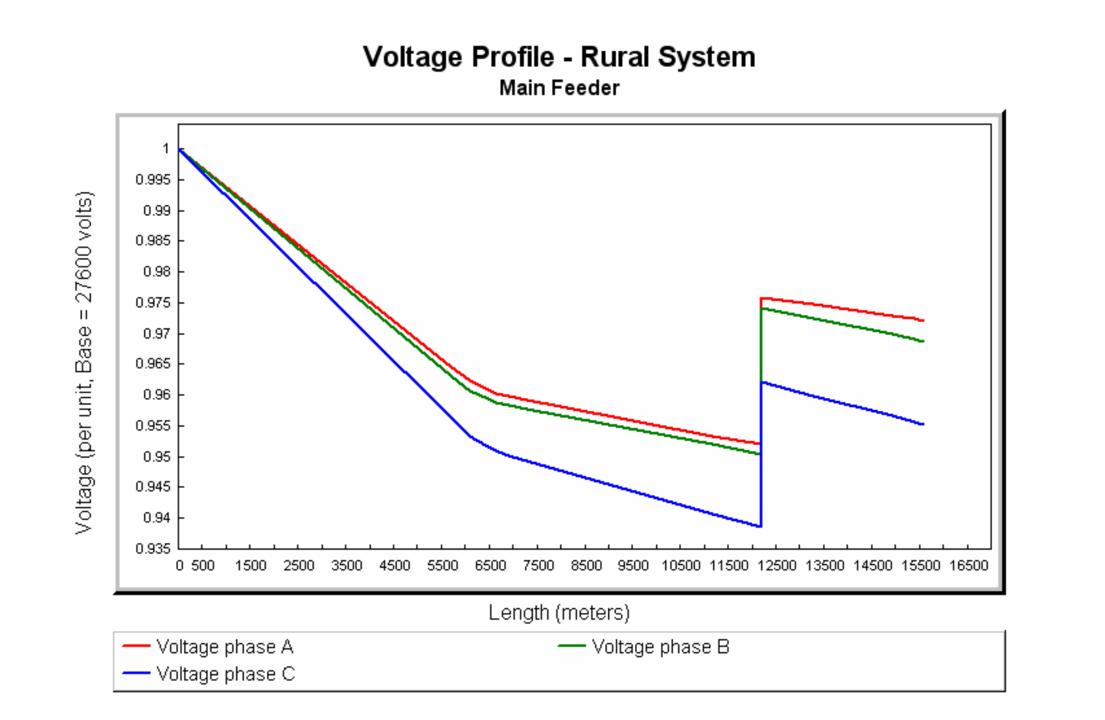

Figure B17 - Voltage profile across the main feeder in the rural distribution system.

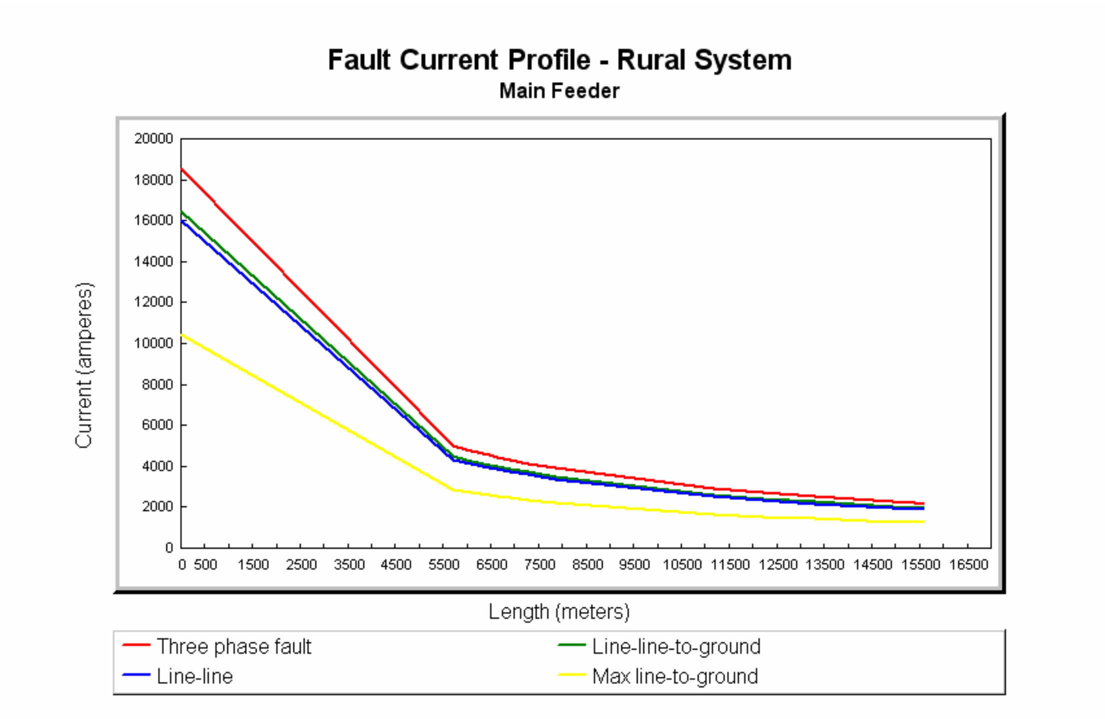

Figure B18 - Short circuit current along main feeder of the rural distribution system.

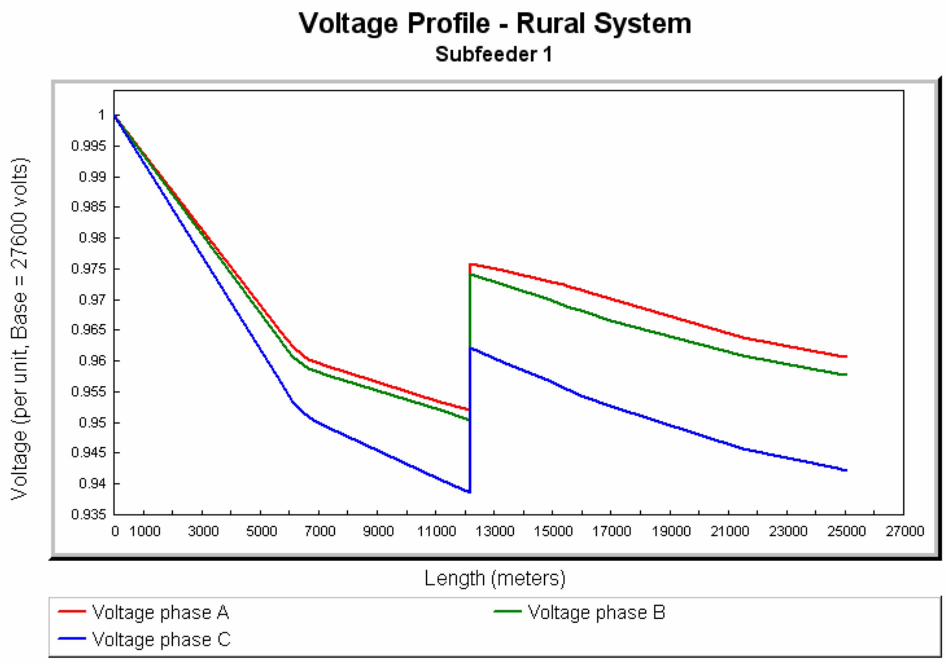

Figure B19 - Voltage profile across sub-feeder 1 in the rural distribution system.

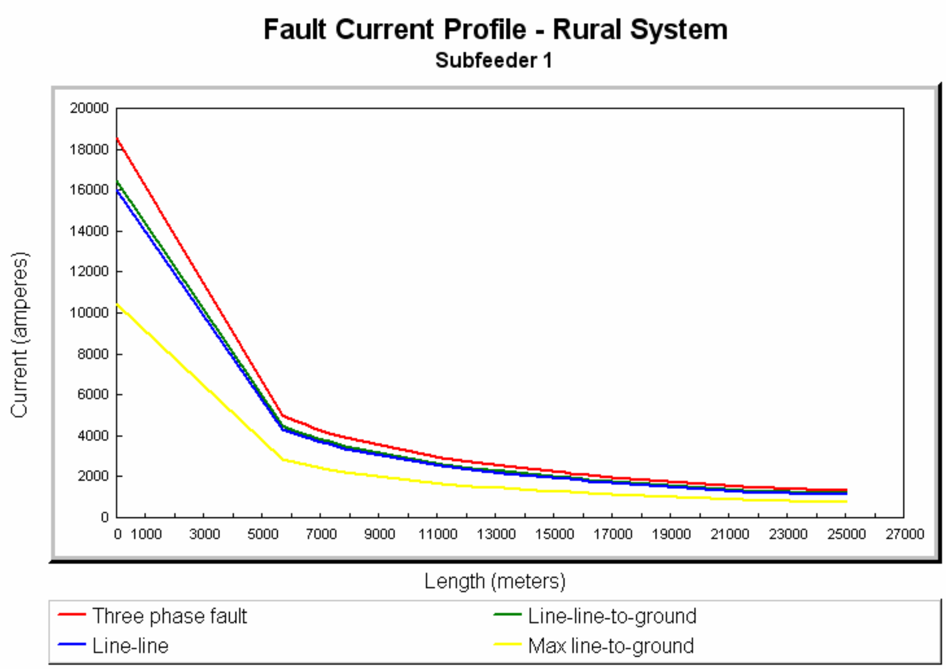

Figure B20 - Short circuit current along sub-feeder 1 in the rural distribution system.

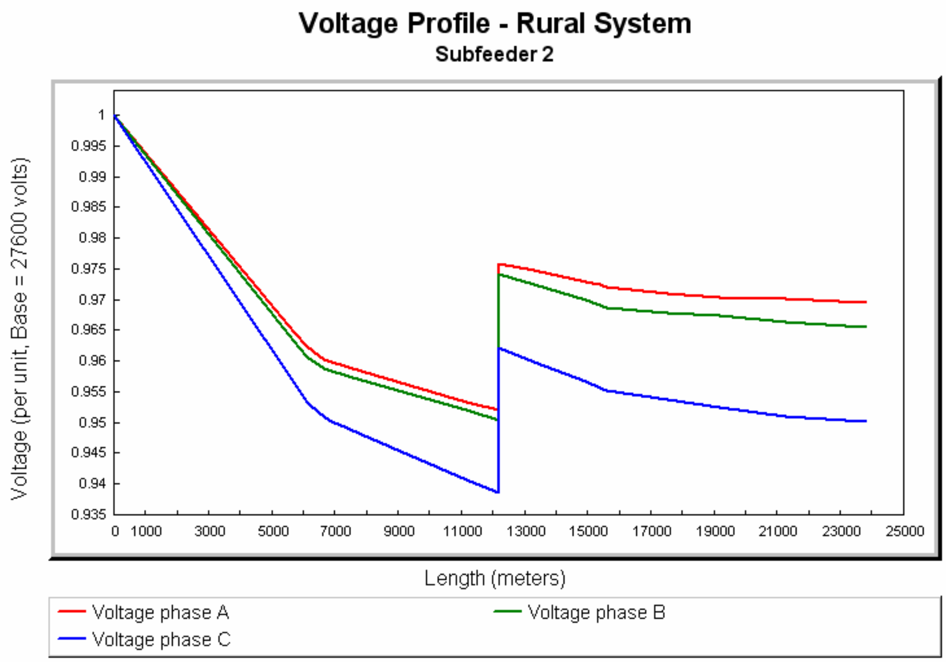

Figure B21 - Voltage profile across sub-feeder 2 in the rural distribution system.

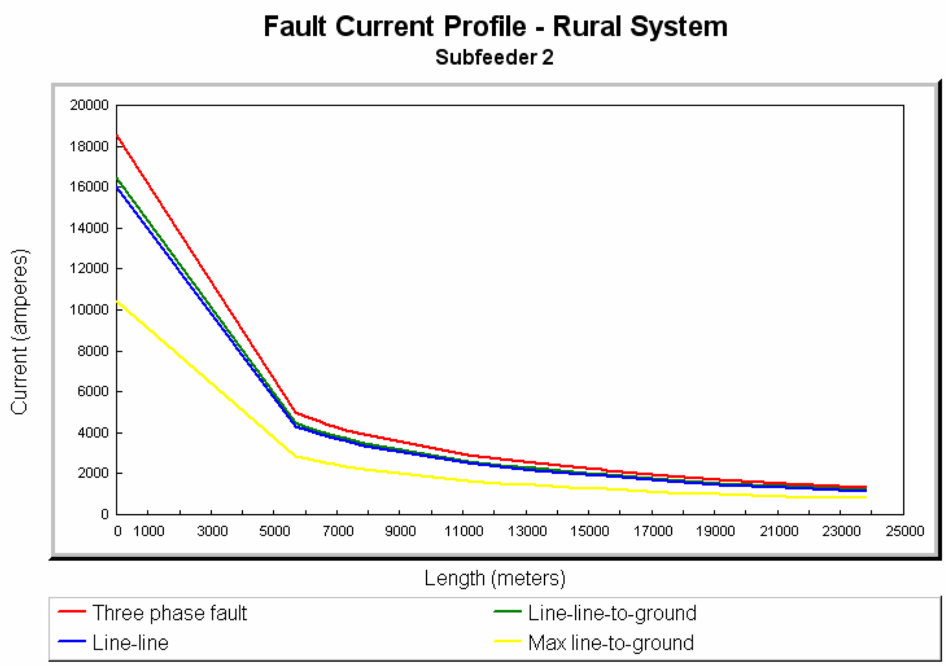

Figure B22 - Short circuit current along sub-feeder 2 in the rural distribution system.

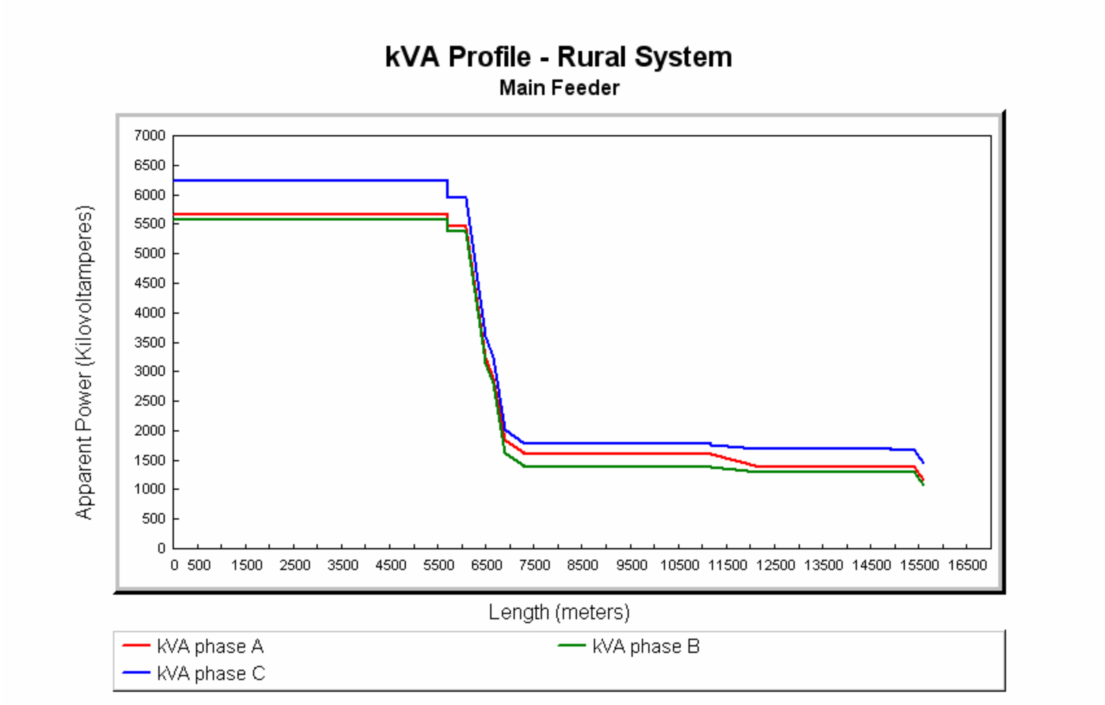

Figure B23 - Apparent power profile along the main feeder in the suburban distribution system.

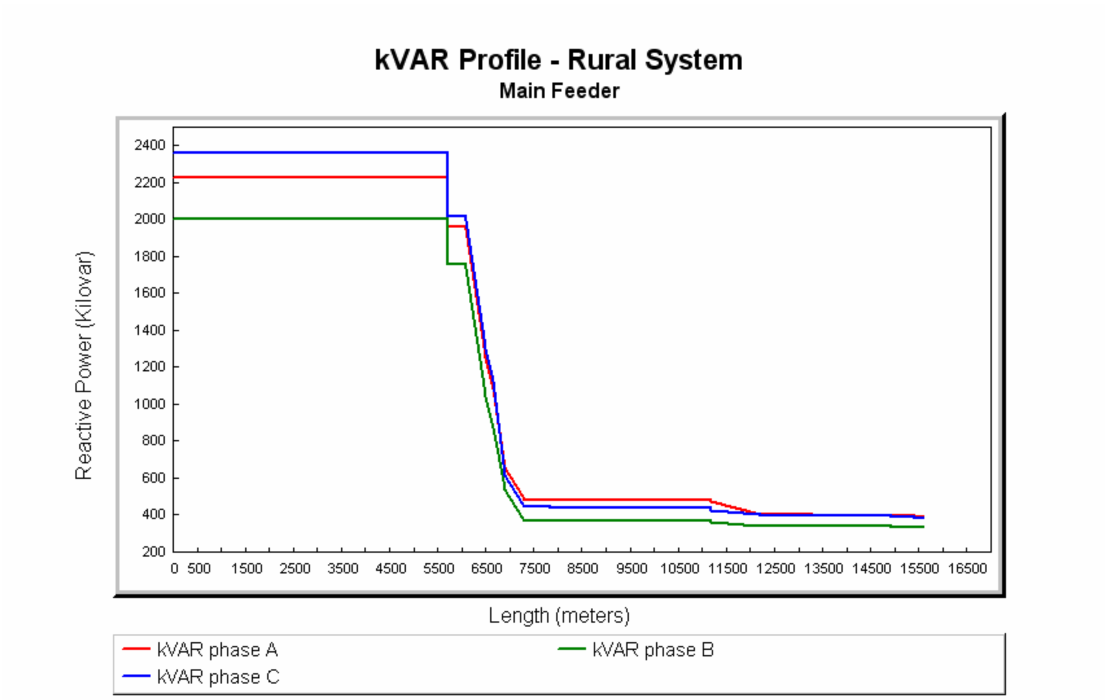

Figure B24 - Reactive power profile along the main feeder in the suburban distribution system.

Appendix C

Protective Devices Characteristics in Different Benchmark Systems

C.1. Protective devices characteristics in the ANSI/IEEE std – 242 – 1986, pp. 432, sample industrial distribution system

Table C1 - Protective devices characteristics in the industrial plant shown in Figure 28.

Protective device name	Protective device characteristics
CB1	100 A E- frame molded case circuit breaker
F1	100 A current limiting fuse
CB2	600 A long time- delay trip element set at 0.8 (480 A)
CB3	1200 A longtime- delay trip element set at 1.0 short time 3.0
R1	300/5 CT ratio with 8 A TS, 1 TDS, VI characteristics
R2	800/5 CT ratio with 5 A TS, 1.5 TDS, VI characteristics
F2	Rating 100 E, 34.5 kV

C.2. Protective devices characteristics in the urban distribution system

Table C2 - Protective devices characteristics in the urban distribution system in Figure 1.

Protective device name	Protective device characteristics
R2	S&C Vista IEC C3 Phase Overcurrent Relay: TAP: 5 (Pickup 600A), TDS: 5, CT:600/5 Ground Overcurrent Relay TAP: 1.25 (Pickup 150A), TDS: 0.2, CT:600/5
F1	S&C SMU-20 STD, Rating 125E
F2	Cutler Hammer DBU Slow E, Rating 30SE
F3	S&C SMU K, Rating 200K
F4	S&C SMU-40 STD, Rating 7E
F5	S&C SMU-20K, Rating 200K
F6	S&C SMU-K, Rating 6K

C.3 Protective devices characteristics in the suburban distribution system

Table C3 - Protective devices characteristics in the suburban distribution system in Figure 10.

Protective device name	Protective device characteristics
B2	Feeder Breaker rated 1200 Amp.
R2	Electronic Relay Asea Brown Boveri: Pickup 600A, TD 6, CT:600/5 Ground Overcurrent Relay Pickup 150A, TDS: 0.2, CT:600/5 Instantaneous relay Pickup 1500 Amp
Recloser	Electronic ABB PCD2000 Fast curve: ANSI INV INST -1 Slow curve: ANSI INV-2 Trip rating: 560 AMP
F1 and F3	Kearney expulsion fuse 100 K
F2 and F4	Kearney expulsion fuse 10 K
F5 and F6	Kearney expulsion fuse 10 K

C.4 Protective devices characteristics in the rural distribution system

Table C4 - Protective devices characteristics in the rural distribution system in Figure. 19.

Protective device name	Protective device characteristics
R1	Electronic Relay Asea Brown Boveri: Pickup 540A, TD 3, CT: 600/5 Ground Overcurrent Relay Pickup 300A, TD 6, CT: 600/5
Recloser	Electronic ABB PCD2000 Fast curve: ANSI INV INST Slow curve: ANSI RC8-1 Phase trip rating: 350 A
F1 to F6	Kearney expulsion fuse 40 A at 27.60 kV