



# Advances in Impedance Based Fault Location in Distribution Systems

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# Abstract

The transmission and distribution system is seeing an increasing penetration of embedded generation especially renewable energy sources (RES) and its resilience will be further challenged by the increasing electrification of transport and heating/air conditioning. Renewable energy sources behave differently to conventional generation systems from both a power system protection and an operation point of view. For this reason, embedding renewable energy sources and its effect on the protection of the electricity system requires more investigation.

This thesis investigates the use of the high frequency transient generated when a fault occurs to locate the faults in distribution systems (frequency range up to 3 kHz). The project considers conventional distribution systems fed from one point and the modern distribution systems with embedded distributed generation. The effect of distributed generation on the fault location process is studied in two ways. Firstly, a high frequency model is developed for both inverter based and synchronous based distributed generation types. This allows the fault location algorithm to use the measurements at the main substation only. The inverter based distributed generation transfers power at the fundamental frequency with some low order and switching harmonics also being present. On the other hand, the synchronous based distributed generation can be assumed as a fundamental frequency voltage source. Therefore, approximations in the developed model will be different for the two types. The second approach assumes measurements at the distributed sources are available and a double end fault location algorithm is introduced.

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The performance of the proposed fault location methods is evaluated through simulation of a medium voltage system. The simulation studies for different scenarios show the accuracy of the proposed concepts. The feasibility of the concepts is experimentally validated on a small scale 400 V system including the proposed single end method, the proposed high frequency model for the inverter based distributed generation and the proposed double end method.

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# Abbreviations

|                  |                                                    |
|------------------|----------------------------------------------------|
| <i>ab</i> fault  | Phase <i>a</i> to phase <i>b</i> fault             |
| <i>abc</i> fault | Three-phase fault                                  |
| <i>ag</i> fault  | Phase <i>a</i> to ground fault                     |
| <i>SRC</i>       | Second-order rate of change                        |
| AC               | Alternative current                                |
| ANN              | Artificial neural network                          |
| avg              | Average value                                      |
| DC               | Direct current                                     |
| DEWIBFL          | Double end wideband impedance based fault location |
| DG               | Distributed generation                             |
| FFT              | Fast Fourier transform                             |
| GNSS             | Global navigation satellite system                 |
| IBDG             | Inverter based distributed generation              |
| IGBT             | Insulated gate bipolar transistor                  |
| KVL              | Kirchhoff's voltage law                            |
| max              | Maximum value                                      |
| PCC              | Point of common coupling                           |
| RES              | Renewable energy sources                           |
| SBDG             | Synchronous based distributed generation           |
| SEWIBFL          | Single end wideband impedance based fault location |

# Chapter 1

## Introduction

### 1.1 Motivation for the Project

The accurate estimation of the location of a fault helps in improving power system continuity. However, this task differs between the transmission systems to the distribution systems due to variance in the system characteristics. Usually, distribution systems have limited measurements at the main substation. Moreover, the integration of renewable energy sources provides additional challenges including the possibility of changing the direction of power flow. Therefore, an accurate fault location method for distribution systems that can consider different inherent system characteristics and features of modern distribution systems as well is highly recommended.

### 1.2 Project Objectives

This thesis aims to develop a fault location method for distribution systems based on the nature of the system (radial system or system with distributed generation) and also considers the reduced number of measurement points. The main objectives of this project are:

- Review the existing fault location methods in the distribution systems and discuss their benefits and drawbacks. Highlight the areas of

possible improvements.

- Develop a new single end wideband impedance based method suitable for complex distribution systems with limited measurements available only at the main substation.
- Develop a new non-fundamental frequency model for inverter based distributed generation that will feature in future distribution grids.
- Develop a new double end wideband impedance based method for complex distribution system considering line capacitive and inductive coupling.
- Experimental validation of the proposed fault location schemes and the high frequency distributed generation model.

### 1.3 Thesis Outline

**Chapter 2** presents a literature review for fault location in power systems especially distribution networks. Firstly, importance of the fault location is provided followed by a general classification of the fault location methods. Then, a deep discussion of impedance based fault location techniques is provided. The review considers radial distribution systems fed from one point and active distribution systems where the distributed generation is incorporated to enhance the distribution system performance. The review tends to investigate the recent impedance based technologies highlighting points of strength and weakness for these technologies.

For radial distribution systems with measurements only available at the main substation, a single end wideband impedance based fault location scheme is proposed in **Chapter 3**. The proposed method uses the non-fundamental frequency components generated when a fault occurs. The method is derived and generalised for complex distribution systems with loading and laterals tapped off the main feeder at different points. An illustrative example is then provided to validate the proposed concept.

**Chapter 4** and **Chapter 5** consider distribution systems with distributed generation (active distribution systems). Based on the availability of measurement points in the system, a fault location concept is introduced.

**Chapter 4** deals with active distribution systems where the measurements available to perform the fault location function only exist at the main substation. For this purpose, a model for each distributed generator in the system is required. In Chapter 4, equivalent circuits for inverter based distributed generation and synchronous based distributed generation are developed at the non-fundamental frequencies required to apply the single end method proposed in Chapter 3.

With multiple measurement points available in the system, a double end wideband impedance based fault location scheme is proposed in **Chapter 5**. The proposed method employs two possibilities based on the nature of the available measurements. The first one assumes all measurements (at main substation and different distributed generation nodes) are synchronized. The second option uses a combination of synchronized and non-synchronized measurements. For the latter case, a concept to use the high frequency impedance measured at the distributed generation nodes is developed.

For each of the proposed concepts in Chapter 3, Chapter 4 and Chapter 5, an illustrative example over a simple distribution system is used to validate the concept. **Chapter 6** presents an extensive simulation study over a representative and more complex distribution system. The IEEE 34-bus system which is a real medium voltage feeder is simulated using the Matlab/Simulink tool and used to check the performance of different fault location concepts. The evaluation considers different factors e.g. the fault type, the fault resistance and the load uncertainty.

**Chapter 7** presents an experimental study for a 400 V laboratory scaled system. The proposed fault location schemes and the high frequency model for the inverter based distributed generation are examined. A commercial drive system is used to build the distributed generation system.

Finally, **Chapter 8** presents the conclusions on the work, summarizes the novel aspects derived and also illustrates where future work should be directed.

# Chapter 2

## Literature Review

### 2.1 Introduction

As is well known, a part of a transmission line's protection system is the distance protection function/relay [1]. In brief, the distance protection function aims to decide whether or not the fault lies inside the protection zone covered by the distance relay and accordingly takes a proper action e.g. a trip decision to the line's circuit breakers to isolate the fault. As an example with high voltage transmission lines, the travelling wave technique was used to perform this function [2]–[4]. Travelling wave techniques are applied in different ways based on the operation mode as discussed in [5], [6]. The exact fault location was not of high importance with the distance protection developed in [4]. Subsequently, a dedicated fault locator was developed by Takagi [7] to estimate the fault distance over a transmission line using fundamental frequency analysis of the system. Further research has been conducted to develop this concept and it is now being considered for distribution systems as well. The importance of locating faults can be summarized as follows [6]:

- Improving the continuity of the system by reducing the time required to locate the fault compared to a manual search by repair crews.
- Saving money as the faster the system is restored after fixing the fault,

the lower the costs incurred.

- Rescheduling maintenance by locating intermittent (temporary faults). Although these faults do not require system interruption, the ability to identify their location helps in considering a preventive maintenance policy to avoid future large scale effects when they become permanent faults.

Several fault location methodologies have been developed for transmission and distribution systems. However, the distribution system has a complicated structure compared to the transmission system. The general features for distribution systems are summarized in the following points:

- Existence of loading taps and laterals along the system
- Unbalanced operation due to presence of single phase and three-phase loads and laterals.
- Reduced number of measurements especially with conventional distribution systems where the measurements are usually available at the main substation only.
- Non-homogeneous line sections which means the same feeder may contain sections with different conductor sizing leading to different per unit length parameters, e.g. a system that combines overhead lines and underground cables.
- Asymmetrical line configuration or untransposed lines which means for a three-phase line, the line parameters are different for different phases and the coupling between phases is different as well.

In this chapter, a general description for the fault location categories is provided followed by a detailed discussion for some of recent methods regarding the radial and the active distribution systems.

## 2.2 Classification of Methods

Fault location methods can be classified into impedance based methods, travelling wave based methods, sparse measurements based methods and learning based methods as discussed in [8].

### 2.2.1 Impedance based methods

The conventional impedance based fault location methods use the voltages and currents measured at fundamental frequency to estimate the impedance between the measurement point and the fault point [7], [9]. The fault distance is calculated using the per unit length parameters of the line. Superimposed components, which are the difference between the during fault data and the steady state pre-fault data, were used to estimate the fault distance in [10]. The assumed fault distance was changed iteratively. Only at the actual fault point, the fault current in the healthy phases estimated at the fault point will be approximately zero. These methods may be applied using measurements from one point (single end impedance based methods) [11]–[22] or synchronized measurements from multiple points especially for distribution systems with distributed generation [23]–[28]. Also, non-synchronized measurements have been used in [29] to locate faults in active distribution systems.

The single end methods are cheap to implement as only the measurements at the main substation are required. However, their accuracy is affected by the fault resistance and an iterative approach is used to estimate the fault distance inside the fault section. On the other hand, the double end methods that require synchronized measurements are less affected by the fault resistance and do not require an iterative process. Measurements can be captured synchronously from different locations using GNSS time stamping (global navigation satellite system). Methods based on synchronized measurements are not suitable for conventional

distribution systems where usually the measurements are available at the main substation only.

Single end and double end impedance based methods based on high frequency analysis are reported in [30]–[32]. These methods use the high frequency components originated by the fault. In contrast to the previous impedance based method, the system analysis in [30]–[32] is applied to the high frequency components.

The common drawback of the impedance based methods using measurements from one location (single end methods) is the “multiple estimation problem” [8], [33]. As the methods in different ways estimate the impedance to the fault point then convert it to a distance and due to presence of laterals and branches in real distribution systems, several points in the system may have the same electrical distance to the measurement point. Therefore, for a single fault case, multiple points could be a valid solution for the problem. This is illustrated in Fig. 2.1.

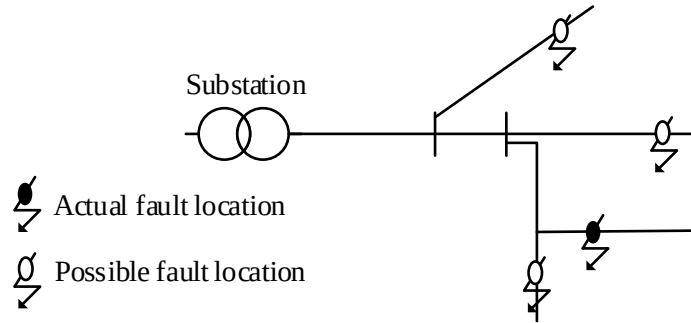


Fig. 2.1: Multiple estimation problem with a branched network

### 2.2.2 Travelling wave based methods

The inception of a fault generates high frequency waves that propagate between the fault point and the line terminals. These “Travelling Waves” can be used to estimate the fault distance. The basic concept for travelling wave based methods depends on relating the measured travelling time to the fault distance ( $distance = propagation\ speed \times time$ ) [5], [34]. These waves

are captured at either one line terminal or both line terminals [34]–[37]. Based on the measured travelling time of the reflected waves from the fault point and the propagation speed of the waves, the distance to the fault is estimated. In another way, the measured voltage at the substation is converted to the frequency domain in [38] to provide an estimate for the travelling wave frequency. The frequency spectrum shows peaks at certain high frequencies which are a function of the fault distance. An offline database is generated for recording the travelling wave frequencies for faults simulated along different branches of the system. Then, the fault branch is identified by comparing the measured frequencies with recordings in the database. After identifying the fault branch, the distance is estimated using a previously generated frequency-distance curve for the fault branch.

Travelling wave based methods require fewer system parameters to estimate the distance unlike impedance based methods [8], [39]. Also, they can estimate the distance with a high accuracy [8]. Even though travelling wave based methods are suitable for transmission systems, they become more complicated for distribution systems. Due to the presence of loading taps and laterals in the distribution systems, the generated waves face reflections at these discontinuities as well as the reflection from the fault point. Therefore, it becomes more difficult to distinguish between the waves reflected from the fault point and those reflected from other loading or lateral tapping points [40]. Also, these methods require a very high sampling frequency which increases the implementation cost. For example, a sampling frequency of 10 MHz was used in [41]. This category may be more applicable to transmission systems [40].

### 2.2.3 Sparse measurements based methods

Smart distribution grids are equipped with communication networks and also metering instruments are installed at different points along the system [40]. The availability of the data collected from the entire system allows the development of this fault location category. The fault occurrence causes

voltage sags in the system which can be obtained from the nodes equipped with measurement instruments (e.g. smart meters). Then, a fault of the same type can be simulated at all nodes of the system. The voltage sags at the measurement nodes are also calculated from the simulation process using an iterative load flow algorithm and compared to the measured sag in [42]. The node that provides the minimum difference (highest similarity) is considered as the closest node to the fault point [42]. In another way in [43], for any assumed fault node, using the system bus impedance matrix, the fault current is estimated at this node several times using the measured voltage sag at different measurement nodes, one at a time. Therefore, there will be a number of estimates for the fault current at each node equal to the number of measurement nodes. At the actual fault node (nearest node to the fault), the estimated currents using different voltage measurements will be very close to each other and ideally represent the real fault current. These methods are referred to as voltage sag based methods. In [44], fault indicators have been employed to define the fault zone. Directional fault indicators were recommended for distribution systems with distributed generation [44].

The methods based on sparse measurements can provide a single estimation for the fault location overcoming the multiple estimation problem with the impedance based methods. However, they require more measurement points. This limits the implementation in a conventional distribution system with limited measurements. Also, the accuracy of this category is a direct function of number of the sparse measurement points.

#### **2.2.4 Learning based methods**

In this category, artificial intelligence techniques such as artificial neural networks (ANNs) are trained and used to estimate the fault zone or distance [45]–[47]. Using ANNs operates in two phases. Firstly, a set of data (input-output patterns) is used to train the ANN. Then, it can be used to locate fault cases which have not been included in the training set. This

provides the advantage of generalisation. Also, system parameters such as loading data are not required. These techniques are able to operate with complex distribution systems without the need for the full system details, but their performance is dependent on the amount and quality of the training data [39]. They require a huge amount of data for training. Distribution systems have limited monitoring devices which in turn limits the information that can be used for the ANN training. Also, retraining is necessary whenever the system configuration changes [39]. The structure of the ANN is defined by trial and error e.g. the number of hidden layers. When the technique is trained to output the fault distance based on measurements from the local substation, the multiple estimation problem also arises as many points in the system may lie at the same distance from the measuring node [8].

## **2.3 Impedance Based Methods: Survey**

A detailed review of some of recent impedance based fault location methods is presented below [11]–[32]. The review has been divided based on the nature of the distribution system i.e. radial system and active system with distributed generation. The methods were discussed on a historical basis.

### **2.3.1 Survey: radial distribution systems**

In [11], direct circuit analysis has been used to develop a single end impedance based method. The method locates only phase to ground faults. It is applicable to both balanced and unbalanced systems as it employs the phase domain analysis. It has been derived assuming a short line model i.e. ignoring the line capacitance. It has been evaluated on a very simple system consists of two line sections with loads. The assessment considered only the effect of fault distance and fault resistance on the accuracy.

The work in [11] was further developed in [12] to locate line to line faults as well. However, the development still uses the short line model

to simulate the line ignoring the capacitance. The evaluation was carried out on a more complicated system compared to [11]. Although the load uncertainty has been considered in the evaluation tests, a compensation method that depends on measurements at each load was used. This is impractical for many applications.

In [13], a single end method was presented. The method was derived using a short line model. The methods in [11]–[13] are only valid for systems where the line capacitance is insignificant e.g. with short lines. Different fault types have been considered. An iterative load flow technique was used to update the loads to compensate for the load variation in the system. The pre-fault measured voltage and current at the main substation were used for the load compensation process. This work is further improved in [14].

In [14], the line capacitance has been considered by deriving the method using the  $\pi$  line model. The simulation studies showed the importance of including the effect of the line capacitance. However, the simulation studies ignored the heterogeneity of the line sections and the performance of the improved method has not been checked against load uncertainty.

The short line model was used in [15] to develop a single end method based on phase domain analysis to consider the possible unbalance in the system. It uses the pure fault equivalent circuit to provide an estimate of the fault current required by the fault location algorithm. In [15], the authors presented a solution for the multiple estimation problem for faults involving one or two phases by calculating the fault current for the healthy phase(s). The correct faulted feeder is assumed to have the minimum fault current in the healthy phase(s). The work was further generalized in [16], the multiple estimation was solved for three phase faults by comparing the actual measured fault current with the calculated fault current. The method derivation ignores the line capacitance (uses short line model). As proved in [14], this assumption significantly affects the estimation accuracy.

A distributed parameter model for the lines was used in [17] to consider the effect of the line capacitance. The method uses the measured voltage

and current to establish boundary condition equations to estimate the fault distance. Using the distributed parameter model supported the accuracy of the distance estimate. However, the evaluation process was limited to the effect of fault resistance (maximum fault resistance value is  $10\ \Omega$ ) showing a high sensitivity when increasing the fault resistance. The load uncertainty has not been considered.

In [18], the voltage and current measured were used to estimate the total reactance between the measurement device and the fault location. This presented possible candidates for the fault point (multiple estimations). Then, the information from other field devices such as fault circuit indicators is used to narrow down the possible candidate locations. The method considered non-homogeneity in feeder sections but ignored other factors e.g. the line capacitance. The method treats the healthy phases as open circuits and uses sequence components analysis. As mentioned by the authors, light load contributed to the accuracy of the method to locate the two fault cases studied. Sequence components analysis is not suitable for unbalanced systems [11].

High frequency single end and double end impedance based methods were presented in [30], [31]. These methods use the high frequency signals generated when a fault occurs to analyse the system. The analysis is carried out at the non-fundamental frequency components allowing the methods to depend on a short window of data during the fault. Both methods have been derived and evaluated on a single section system i.e. system that consists of source, one line and one load at the end of the line. This is a highly simplified system and is assumed to represent an integrated power system (such as distribution feeder in a ship or train) [48], [49]. As the system is very simple and also very short (line length is 21 m) due to the application, the mutual coupling between phases has been ignored and the line capacitance was ignored too. In [31], connecting multiple loads along the system in a simulation study significantly increased the error in distance estimation.

An improved single end method using a distributed parameter model for the line has been presented in [20]. The method considered several factors affecting the accuracy e.g. fault resistance, fault inception angle and fault type. However, the simulation process assumed all lines to be three-phase with the same line configuration ignoring heterogeneity in feeder sections. Also, the derivation of the method employs sequence components (positive, negative and zero). The sequence components are not suitable for unbalanced systems [11].

A double end method has been derived based on measurements from both feeder ends in [23]. The method considered the effect of fault type and fault resistance. It has been derived assuming a short line model. Using synchronized measurements provided a good accuracy in distance estimation. However, it may not be a possible option with conventional radial distribution systems.

In [21], a single end impedance based method has been introduced using the modal domain analysis to decouple the mutual inductive coupling between the line phases. The method considered different fault types and other factors affecting the fault location. It has been derived assuming short lines i.e. ignoring the line capacitance. Also, the evaluation process assumed the lines are perfectly transposed.

The previous review shows that no impedance based fault location method covers all fault location aspects. Many of the methods ignore the effect of the line capacitance which has a significant effect of the fault location accuracy [14]. Moreover, when the line capacitance is considered it has been approximated to a  $\pi$  model which may not reflect the actual performance of the line. Some methods considered the general distributed parameter model. However, the method has other shortfalls such as using sequence components analysis [20] or limited evaluation process [17]. Table 2.2 presents a summary for different methods reviewed and also the features of the evaluation/simulation studies carried out in each method. Table 2.1 defines different terms used in Table 2.2.

Table 2.1: Survey table legend

| item                | description                                                                                                                                                                                                                            |
|---------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>domain</b>       | phase: phase domain analysis<br>sequence: sequence components analysis<br>modal: modal domain analysis<br>combined 1: combined phase and sequence components analysis                                                                  |
| <b>measurements</b> | Sub VI: main substation voltage and current<br>Sub VI & Load: measure at main substation, also at load for load compensation<br>synchronized: using synchronized measurements<br>non-synchronized: using non-synchronized measurements |
| <b>line model</b>   | SLM: short line model<br>PLM: $\pi$ line model<br>DPLM: distributed parameter line model                                                                                                                                               |
| ✓                   | considered                                                                                                                                                                                                                             |
| ✗                   | not considered                                                                                                                                                                                                                         |
| NC                  | Not clear in the simulation study data                                                                                                                                                                                                 |
| <b>fault type</b>   | SLG: single line to ground fault<br>LL: line to line fault<br>ALL: more than one fault type                                                                                                                                            |

Table 2.2: Summary for radial distribution systems review

| method     | domain     | measurements  | line<br>model | evaluation/simulation studies |                          |                      |                     |       |                    |       |
|------------|------------|---------------|---------------|-------------------------------|--------------------------|----------------------|---------------------|-------|--------------------|-------|
|            |            |               |               | laterals                      | non-homogeneous<br>lines | asymmetrical<br>line | load<br>uncertainty | fault |                    |       |
|            |            |               |               |                               |                          |                      |                     | type  | resistance         | angle |
| [11]       | phase      | Sub VI        | SLM           | ✗                             | ✗                        | ✓                    | ✗                   | SLG   | up to 50 $\Omega$  | ✗     |
| [12]       | phase      | Sub VI & Load | SLM           | ✓                             | ✗                        | ✗                    | ✓                   | LL    | up to 50 $\Omega$  | ✗     |
| [13]       | phase      | Sub VI        | SLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 100 $\Omega$ | ✓     |
| [14]       | phase      | Sub VI        | PLM           | ✓                             | ✗                        | ✗                    | ✗                   | ALL   | up to 100 $\Omega$ | ✗     |
| [15], [16] | phase      | Sub VI        | SLM           | ✓                             | ✓                        | ✓                    | ✓                   | ALL   | up to 100 $\Omega$ | ✗     |
| [17]       | modal      | Sub VI        | DPLM          | ✓                             | ✓                        | NC                   | ✗                   | ALL   | up to 10 $\Omega$  | ✗     |
| [18]       | sequence   | Sub VI        | SLM           | ✓                             | ✓                        | ✗                    | ✗                   | ALL   | ✗                  | ✗     |
| [30]       | phase      | Sub VI        | SLM           | ✗                             | ✗                        | ✗                    | ✗                   | ALL   | up to 1 $\Omega$   | ✓     |
| [31]       | phase      | synchronized  | SLM           | ✗                             | ✗                        | ✗                    | ✗                   | ALL   | up to 3 $\Omega$   | ✗     |
| [20]       | combined 1 | Sub VI        | DPLM          | ✓                             | ✗                        | ✗                    | ✗                   | ALL   | up to 150 $\Omega$ | ✓     |
| [23]       | phase      | synchronized  | SLM           | ✓                             | ✓                        | NC                   | ✗                   | ALL   | up to 40 $\Omega$  | ✗     |
| [21]       | modal      | Sub VI        | SLM           | ✓                             | ✓                        | ✗                    | ✓                   | ALL   | up to 100 $\Omega$ | ✗     |

### 2.3.2 Survey: active distribution systems

The penetration of distributed generation especially renewable energy sources into distribution systems introduces new challenges to fault location. The challenge increases with lower communication capabilities in the system. In this section, recent impedance based methods developed for active distribution systems are reviewed.

A single end method using the measurements at the local substation is presented in [19]. The method uses the sequence components to analyse the system. A simple synchronous based distributed generation (SBDG) has been considered only. The DG is modelled as a source behind an impedance. The lines were represented by the short line model ignoring the line capacitance.

In [24], an impedance based fault location method suitable for different DG types was presented. The method considered the effect of the line capacitance and unbalanced loading. It assumes the pre-fault and during fault voltages and currents are available and synchronously measured at all sources (main substation and DG units). Dependence on synchronized measurements at all DGs eliminates the need for detailed DG parameters. Firstly, the method locates the fault by identifying all possible candidate locations. Then, a voltage matching method is used to eliminate the multiple estimation problem. The system bus impedance matrix is built assuming the fault node as a new bus with injected current equal to the calculated fault current. Then, the voltage is calculated at all measurement nodes and compared to the measured voltages. This process is repeated by assuming the injected fault current at different candidate locations. The node that provide the best match between the measured and calculated voltage is assumed to be the exact fault node.

In [25], a fault location method considering distributed generation and load uncertainty is presented. Similar to [24], the method relies on measurements at the DGs to avoid modelling the DG. Synchronously

measured pre-fault and steady state during fault voltages and currents are necessary to apply the method. The method considered several factors such as fault type, resistance, unbalanced loading and provided a compensation method for the load uncertainty. The method has been derived using the sequence components. For an asymmetric line or not perfectly transposed line, the sequence component impedance matrix will be coupled. Also, the derivation does not include the line capacitance. The evaluation process considered only a single DG unit connected to the system.

The synchronously measured voltage and current at the main substation and at the DG units, in pre-fault and fault steady states were used in [26]. The method combined both phase and sequence components analysis and considered the line capacitance by using the  $\pi$  model. Although the method depends on measurements at the DGs, the internal DG phase impedance is necessary for the calculation steps. Among the algorithm steps, the fault distance estimation step depends on representing the line impedance matrix by its sequence components. For a line with an asymmetric impedance matrix, the sequence impedance matrix will have non-zero off diagonal elements i.e. the sequence circuits are mutually coupled. The method finds the possible candidate locations for the fault. Then, the exact fault location is assumed to be the location that corresponds to the minimum estimated fault reactance.

A high frequency impedance based fault location method has been developed in [32]. This method is an extension to the single end method presented in [30] to be suitable for complex distribution systems rather than the simple system used in [30]. The method considered the presence of a double fed induction generator based DG (DFIG). To apply a single end method, it was necessary to firstly develop a high frequency model for the DFIG. The fault location method highly simplified the system by ignoring both the inductive mutual coupling between the three phases and the line capacitance. These assumptions are not valid with real distribution systems. To locate the fault considering the presence of multiple loading

taps or DGs in the system, the fault distance is estimated by applying the single end method at different measurement points. Then, the estimated distances were communicated to find the actual fault section. According to the authors, one measurement point is required for every five nodes in the system. The evaluation shows a significant effect of the fault resistance on accuracy of the distance estimation.

In [27], voltage and current measurements at the local main substation as well as synchronized current measurements from different DGs are used to locate faults in active distribution systems. The method does not require synchronized voltage measurements from DGs terminals and considered the line capacitance by using the  $\pi$  model for the lines. A ladder based load flow approach was used to estimate the downstream fault current.

In [29], non-synchronized measurements from the main substation and DGs were used to develop an impedance based method. The method eliminates the need for synchronized measurements in contrast to the methods in [24]–[27]. A synchronization angle error is assumed between measurements and is calculated using an iterative load flow technique. The method considered the effect of fault type, resistance, load uncertainty and noise in measurements. It has been derived using a short line model ignoring the effect of the line capacitance.

In [22], a single end method using only the voltage and current measurements at the local substation is developed. The method considered the presence of the inverter based distributed generation (IBDG) and a steady state DG equivalent circuit at the fundamental frequency was developed. The equivalent circuit is dependent on the DG operating mode during the fault whether the DG exhibits a current limit mode or tracks the normal pre-fault reference power. A ladder iterative technique was used to estimate the DG current. The method considered several factors such as line capacitance (using  $\pi$  model) and load uncertainty. However, the representation of IBDG under fault conditions is not a straight forward issue at the system frequency [50]. The IBDG model at the system frequency

depends on the converter operating mode particularly whether or not it exhibits a current limiting mode and also whether or not fault ride through is considered.

In [28], synchronized measurements from all sources (main source and DGs) were used. Also, the line capacitance was considered using the  $\pi$  model for the lines. The method has been evaluated on a simple system with balanced loads and a single DG unit (PV). Load uncertainty has not been checked.

As is clear from the literature review, the methods in [24]–[28] required synchronized measurements from all sources (main substation and DG units). The method in [29] can work with non-synchronized measurements but still require communication channels between the DG units and the main substation to transfer the measured non-synchronized voltages and currents at DGs to the main substation. Only [19] and [22] do not require voltage and current measurement transfer by developing a model for the DG and employing this model in the fault location algorithm. A synchronous based distributed generation was assumed in [19] and an inverter based distributed generation was used in [22]. The methods in [19], [22], [24]–[29] used either the short line model or the approximate  $\pi$  model to represent the line sections. Table 2.3 presents a summary for different methods reviewed and also the features of the evaluation/simulation studies carried out in each method. Table 2.1 defines different terms used in Table 2.3.

### 2.3.3 Survey: multiple estimation

As stated “multiple estimation” is the common drawback of impedance based fault location methods. Not only the impedance based methods but also any other method that depends on measurements at the main substation only will suffer from the multiple estimation problem due to the branched nature of distribution systems [8]. In this section, some of the research undertaken to address this problem is reviewed (in addition to the previously reviewed in [15], [16], [18]).

Table 2.3: Summary for active distribution systems review

| method | domain     | measurements     | line<br>model | evaluation/simulation studies |                          |                      |                     |       |                    |       |
|--------|------------|------------------|---------------|-------------------------------|--------------------------|----------------------|---------------------|-------|--------------------|-------|
|        |            |                  |               | laterals                      | non-homogeneous<br>lines | asymmetrical<br>line | load<br>uncertainty | fault |                    |       |
|        |            |                  |               |                               |                          |                      |                     | type  | resistance         | angle |
| [19]   | sequence   | Sub VI           | SLM           | ✓                             | ✓                        | ✗                    | ✗                   | ALL   | up to 50 $\Omega$  | ✗     |
| [24]   | phase      | synchronized     | PLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 25 $\Omega$  | ✗     |
| [25]   | sequence   | synchronized     | SLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 40 $\Omega$  | ✗     |
| [26]   | combined 1 | synchronized     | PLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 40 $\Omega$  | ✗     |
| [32]   | phase      | non-synchronized | SLM           | ✓                             | ✓                        | ✗                    | ✗                   | SLG   | up to 40 $\Omega$  | ✗     |
| [27]   | phase      | synchronized     | PLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 100 $\Omega$ | ✗     |
| [29]   | phase      | non-synchronized | SLM           | ✓                             | NC                       | NC                   | ✓                   | ALL   | up to 50 $\Omega$  | ✗     |
| [22]   | phase      | Sub VI           | PLM           | ✓                             | ✓                        | NC                   | ✓                   | ALL   | up to 100 $\Omega$ | ✗     |
| [28]   | phase      | synchronized     | PLM           | ✓                             | ✓                        | NC                   | ✗                   | ALL   | up to 100 $\Omega$ | ✓     |

In [51], the authors depended on the knowledge of the location of the protective devices and their characteristics (time-current curves) along the system e.g. recloser and fuse. The authors assumed that for different parts of the network, the protective devices have different time-current characteristics. Also, the sequence of the protective devices operation would be different for faults at different locations in the system. Therefore, a fault diagnosis process can be used to eliminate the multiple estimation problem by comparing the recorded response at the main substation with the possible responses for different fault locations. When using the same protective devices at different locations e.g. two fuses of the same type installed along two laterals, the change in the load current measured at the substation after clearing the fault was incorporated in the diagnosis process. It can give an estimation for the total load removed from the system which in turns helps to identify the fault zone. However, there are some uncontrolled uncertainties that lead to difference between the simulation and the actual observation such as obtaining the actual response (time delay) of the protective devices due to the possible tolerance and also wear and tear. Loads in the system are changing over time and may also depend on the weather conditions.

The installation of fault indicators along the laterals has been used in [52] to overcome the multiple estimation problem. Fault indicators sense the current level and can send a signal to the local substation. The limitation with this method is associated to the implementation cost (e.g. installation and maintenance costs). However, the optimal deployment of the fault indicators is currently under research [53].

In [54], the authors estimated the fault distance for faulty and healthy phases. The exact fault path is assumed to provide close distance estimation for the three phases. In other words, the error between the estimated distance for the faulty phase and the healthy phase(s) is minimum for the exact fault location. For three-phase faults, the error is estimated between the distance of each phase and average of the three distances. The authors

assumed the load current in the fault phase can be ignored. This may be acceptable for severe faults (fault with a low fault resistance).

A similar concept to that proposed in [51] has been developed in [55] which depends on current pattern diagnosis at the main substation. The difference is that the authors proposed a procedure for setting and locating the protective devices in the system. In other words, the authors do not depend on the currently installed protective devices (neither type, quantity nor setting). Instead, a procedure was developed to divide the system into parts (each part contains three laterals) and then selects the fuse type for different laterals and the recloser setting between parts of the system. This method aims to generate a unique current pattern and time delay for faults at different sections of the system. Therefore, the exact fault section can be identified by a diagnosis process at the main substation.

In [56], a combined fundamental frequency impedance based method and transient based method was used to identify the fault section. Firstly, the impedance based method finds the possible fault locations. Then, a travelling wave based analysis is used to find the fault section. The method depends on comparing the theoretically calculated characteristic frequency for different possible fault paths with that obtained for the recorded measured voltage at the local terminal.

In [57], the authors firstly used an impedance based fault location method to estimate the possible fault sections. Then, for each fault section, the same fault type is simulated at different points along the section with a step of 0.1 km. For each simulated fault case, the change in the voltage magnitude and phase angle at the substation is recorded ending with a data bank for each fault section. A relation between the distance and change in voltage magnitude and change in phase angle is derived through curve fitting (cubic equation). This process is repeated for each possible fault section. The result is two cubic formulas for each fault section. The actual recorded change in voltage and phase angle at the main substation are used with the generated formulas to provide two estimated distances for each line section

(one estimate using the voltage change formula and another estimate using the phase angle change formula). The exact fault section is assumed to provide very close estimates when using the voltage magnitude and angle formulas.

In [33], an impedance based fault location method was firstly applied to estimate the candidate fault locations. Then, smart meters installed along the system were used to prune down the estimates and find the exact fault zone. The method depends on the voltage data obtained from the smart meters where the actual fault zone would have low voltage magnitudes due to the proximity of the fault location.

This survey illustrates that there are a continuously running trials to overcome the multiple estimation problem depending on the available measurements or with adding extra devices.

## 2.4 Conclusions

It can be seen from the survey that the line's capacitance, untransposed lines and distributed parameter model for the lines with radial and also active distribution systems need to be considered in the fault location algorithms. Also, the use of a reduced number of measurements (which may only use measurements at the main substation) to perform the fault location function with active distribution systems needs further research. Therefore, as is stated in Chapter 1, the thesis aims to develop a single end fault location algorithm for both radial and active distribution systems considering the distributed parameter model and the untransposed line model. Also, a high frequency model for distributed generation will be proposed to allow the application of the single end method in active distribution systems. Furthermore, with the same line model considerations, a double end method using synchronized or a combination of synchronized and non-synchronized measurements will be introduced that can be applied in distribution systems equipped with a communication network.

# Chapter 3

## Radial Distribution Systems

### 3.1 Introduction

This chapter presents a single end impedance based fault location scheme for radial distribution systems. The method requires the measurements captured at the main substation only. It uses the high frequency components generated when a fault occurs to estimate the fault distance. Firstly, the concept of the single end wideband impedance based fault location (SEWIBFL) scheme is presented for a single line section system. Then, the deployment of the method on a more complicated distribution system is investigated. Also, an illustrative example is provided at the end of the chapter to validate the proposed concept.

### 3.2 A Single Line Section System

The SEWIBFL scheme is presented in this section for a single line section system. The proposed scheme is derived for a transmission line with significant line capacitive effect that cannot be ignored. A short distribution system with negligible capacitance will be illustrated as a special case.

In order to generalize the analysis for different line configurations, the distributed parameter line model is used. Therefore, mutual inductance and capacitance, capacitance to ground, line asymmetry and untransposed

lines are considered. To perform a general three-phase analysis, the transformation between phase domain and mode domain is used to decouple the system into three independent propagation modes (ground mode and two aerial modes). Voltage, current, impedance and admittance transformation between modes is obtained by (3.1) [6].

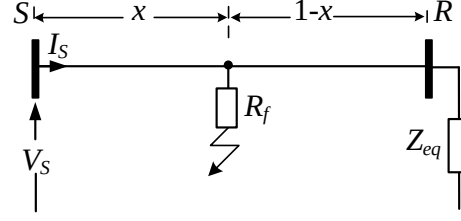
$$\begin{aligned} V_{012} &= T_v^{-1} V_{abc} & I_{012} &= T_i^{-1} I_{abc} \\ z_{012} &= T_v^{-1} z_{abc} T_i & y_{012} &= T_i^{-1} y_{abc} T_v \end{aligned} \quad (3.1)$$

where 0, 1, 2 are the ground and the two aerial modes,  $a, b, c$  are the phase components,  $z$  is the line series impedance matrix,  $y$  is the line shunt admittance matrix, the transformation matrices  $T_v$  and  $T_i$  are the eigenvectors of  $z_{abc}y_{abc}$  and  $y_{abc}z_{abc}$  respectively. For symmetrical/transposed lines, the Clarke's transformation matrix is commonly used to transform between phase and mode domains [6]. Also, the propagation constant  $\gamma$  and the characteristic impedance  $z_c$  of the line are given by (3.2), where  $j$  refers to the propagation mode.

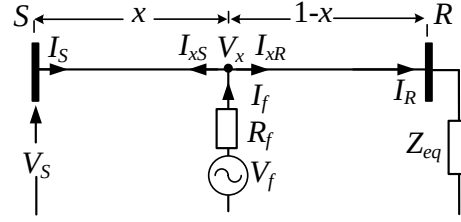
$$\gamma_j = \sqrt{z_j y_j}, \quad z_{c_j} = \gamma_j^{-1} z_j \quad (3.2)$$

Consider a line with a unity total length with a fault at distance  $x$  as shown in Fig. 3.1a. The SEWIBFL scheme employs the circuit analysis at the non-fundamental frequencies to calculate the fault distance  $x$  measured from node  $S$ . The equivalent circuit at the non-fundamental frequencies is illustrated in Fig. 3.1b where the fault is represented by a voltage source  $V_f$ . The fault voltage source is assumed to have a step change which is equal to and opposite to the pre-fault voltage at the fault point. The step value depends on the fault inception angle. In Chapter 6, the proposed method is evaluated at different fault inception angles. This voltage source injects a transient signal that contains a wideband of frequencies. The circuit is analysed at these injected frequencies. To help explain the method, the procedure is divided into three stages which are:

1. Building the fault voltage source ( $V_f$ )



(a) at fundamental frequency



(b) at non-fundamental frequencies

Fig. 3.1: System equivalent with a fault

2. Estimating the fault current
3. Estimating the fault distance

### 3.2.1 Building the fault voltage source

The measured pre-fault voltage ( $V_{Spre}$ ) and current ( $I_{Spre}$ ) at node  $S$  are used to calculate the pre-fault voltage at the fault point ( $V_{xpre}$ ) as given in (3.3) for different propagation modes, where  $j$  refers to the propagation mode [6]. Then, it can be converted to phase domain by (3.1). The fault voltage source ( $V_f$ ) is created as a step voltage source with a step change which is equal to and opposite to the pre-fault voltage at the fault point. After building  $V_f$  in the time domain, its frequency spectrum can be obtained as will be explained later and is used for the analysis of the next stages. Faults in power systems occur due to various reasons e.g. equipment failure, weather conditions and human error. Some faults result in large currents and other are staged where the fault current increases with time (not a step change). Equipment failure such as transformer or permanent insulation failure in cables and faults due to forgetting metallic

or conductive parts after maintenance can cause a step fault with high fault currents. On the other hand, high impedance faults such as vegetation faults (a tree touching the power line) have a low fault current and may turn into a severe fault causing fire. Due to the high fault impedance and low fault current of such faults, they may not cause a step change in the voltage at their inception. High impedance faults are not addressed in this thesis.

$$V_{xpre_j} = \cosh(\gamma_j x) V_{Spre_j} - z_{c_j} \sinh(\gamma_j x) I_{Spre_j} \quad (3.3)$$

### 3.2.2 Estimating the fault current

By analysing the circuit in Fig. 3.1b, the voltage and current at the fault point ( $V_x$ ,  $I_{xS}$ ) can be obtained using (3.4) [6] where  $I_{xS}$  is the portion of the fault current flowing to the sending end and  $V_S$ ,  $I_S$  are the sending end voltage and current respectively. Applying the same equation on the downstream side of the fault point results in (3.5) where  $I_{xR}$  is the portion of the fault current flowing to the receiving end and  $V_R$ ,  $I_R$  are the receiving end voltage and current respectively. Substituting for  $V_R$  in (3.5) by (3.6), the load side current  $I_R$  can be calculated using (3.7). The total fault current is obtained through (3.8) and (3.9). Note that (3.7) and (3.8) require an estimate of the load side impedance  $Z_{eq}$ . Note that, the transient in the voltage  $V_S$  due to the fault inception depends on the fault current level. For a system mainly fed by DGs especially IBDGs, the fault current will not be high. Therefore, the transient in the voltage and current signals are expected to be not significant. The proposed fault location method will be analysed with such system as a part of the future work.

$$\begin{bmatrix} V_{x_j} \\ -I_{xS_j} \end{bmatrix} = \begin{bmatrix} \cosh(\gamma_j x) & -z_{c_j} \sinh(\gamma_j x) \\ -\sinh(\gamma_j x)/z_{c_j} & \cosh(\gamma_j x) \end{bmatrix} \begin{bmatrix} V_{S_j} \\ I_{S_j} \end{bmatrix} \quad (3.4)$$

$$\begin{bmatrix} V_{x_j} \\ I_{xR_j} \end{bmatrix} = \begin{bmatrix} \cosh(\gamma_j(1-x)) & z_{c_j} \sinh(\gamma_j(1-x)) \\ \sinh(\gamma_j(1-x))/z_{c_j} & \cosh(\gamma_j(1-x)) \end{bmatrix} \begin{bmatrix} V_{R_j} \\ I_{R_j} \end{bmatrix} \quad (3.5)$$

$$V_{R_j} = Z_{eq_j} I_{R_j} \quad (3.6)$$

$$I_{R_j} = \{\cosh(\gamma_j(1-x))Z_{eq_j} + z_{c_j}\sinh(\gamma_j(1-x))\}^{-1}V_{x_j} \quad (3.7)$$

$$I_{xR_j} = \{\sinh(\gamma_j(1-x))Z_{eq_j}/z_{c_j} + \cosh(\gamma_j(1-x))\}I_{R_j} \quad (3.8)$$

$$I_{f_j} = I_{xS_j} + I_{xR_j} \quad (3.9)$$

The first two stages of the procedure require a value for  $x$  which is unknown. Therefore, for the first iteration, an initial value for the distance  $x$  is assumed to be 0.01 pu. Note that, the initial assumed distance value does not affect the final estimation. However, assuming an initial value close to the start of the line ensures a systematic forward progress in the estimation. On the other hand, assuming an initial value of 0.5 pu for example may lead to forward or backward estimation but may also reduce the number of iterations required. In the next stage, a new value for  $x$  is estimated and is used for the next iteration.

### 3.2.3 Estimating the fault distance

To estimate the fault distance  $x$ , the Taylor expansion for both  $\cosh(\gamma x)$  and  $\sinh(\gamma x)$  has been used in (3.4) by considering the first three terms of the series to represent the voltage at the fault point and  $V_x$ . From (3.4), the voltage  $V_x$  for any propagation mode can be written as (3.10).

$$V_x = \cosh(\gamma x)V_S - z_c\sinh(\gamma x)I_S \quad (3.10)$$

The representation of the cosh and sinh functions by Taylor series is as follows [58]:

$$\cosh(\gamma x) = 1 + \frac{(\gamma x)^2}{2!} + \frac{(\gamma x)^4}{4!} + \dots + \frac{(\gamma x)^{2n}}{(2n)!} + \dots \quad (3.11)$$

$$\sinh(\gamma x) = \gamma x + \frac{(\gamma x)^3}{3!} + \frac{(\gamma x)^5}{5!} + \dots + \frac{(\gamma x)^{2n-1}}{(2n-1)!} + \dots \quad (3.12)$$

Substitute in (3.10) by (3.11) and (3.12) using the first three terms for both cosh and sinh.

$$V_x = \left\{1 + \frac{(\gamma x)^2}{2} + \frac{(\gamma x)^4}{24}\right\}V_S - \left\{\gamma x + \frac{(\gamma x)^3}{6} + \frac{(\gamma x)^5}{120}\right\}z_c I_S \quad (3.13)$$

From (3.13), the voltage  $V_x$  can be written in the form (3.14) for different propagation modes.

$$V_{x_j} = A_j + B_j x + C_j x^2 + D_j x^3 + E_j x^4 + F_j x^5 \quad (3.14)$$

where  $j$  refers to the propagation modes  $(0, 1, 2)$  and the values for  $A_j$ ,  $B_j$ ,  $C_j$ ,  $D_j$ ,  $E_j$  and  $F_j$  are given as follow:

$$\begin{aligned} A_j &= V_{S_j} & B_j &= -\gamma_j z_{c_j} I_{S_j} \\ C_j &= \gamma_j^2 V_{S_j} / 2 & D_j &= -\gamma_j^3 z_{c_j} I_{S_j} / 6 \\ E_j &= \gamma_j^4 V_{S_j} / 24 & F_j &= -\gamma_j^5 z_{c_j} I_{S_j} / 120 \end{aligned} \quad (3.15)$$

The voltage  $V_x$  can be expressed in the phase domain by (3.16) using (3.1).

$$\begin{aligned} V_{x_{abc}} &= A_{abc} + B_{abc} x + C_{abc} x^2 + D_{abc} x^3 + E_{abc} x^4 + F_{abc} x^5 \\ &= [V_{xa} \ V_{xb} \ V_{xc}]^t \end{aligned} \quad (3.16)$$

where  $t$  refers to non-conjugate transpose,  $K_{abc} = T_v K_{012}$ ,  $K$  refers to  $A$ ,  $B$ ,  $C$ ,  $D$ ,  $E$  and  $F$ ,  $K_{abc} = [K_a \ K_b \ K_c]^t$  and  $K_{012} = [K_0 \ K_1 \ K_2]^t$ .

Then, the fault distance is calculated by applying Kirchhoff's voltage law (KVL) on the fault branch based on the fault type. The following two subsections illustrate the distance estimation for phase  $a$  to ground fault and phase  $a$  to phase  $b$  fault as examples.

### 3.2.3.1 Phase $a$ to ground fault

For a phase  $a$  to ground fault with a resistance  $R_{fa}$  as shown in Fig. 3.2, applying KVL on the fault branch leads to (3.17).

$$V_{xa} = V_{fa} - R_{fa} I_{fa} \quad (3.17)$$

Equating phase  $a$  voltage in (3.16) to (3.17) results in (3.18). Separating (3.18) into real and imaginary parts and assuming the fault impedance is resistive, (3.19) and (3.20) are obtained where  $re(\ )$  and  $im(\ )$  refers to real and imaginary parts respectively. By multiplying (3.19) by  $im(I_{fa})/re(I_{fa})$

and subtracting the result from (3.20), a 5<sup>th</sup> order polynomial can be obtained to calculate the fault distance  $x$  (3.21).

$$(A_a - V_{fa}) + B_ax + C_ax^2 + D_ax^3 + E_ax^4 + F_ax^5 = -R_{fa}I_{fa} \quad (3.18)$$

$$\begin{aligned} re(A_a - V_{fa}) + re(B_a)x + re(C_a)x^2 + re(D_a)x^3 + re(E_a)x^4 \\ + re(F_a)x^5 = -R_{fa}re(I_{fa}) \end{aligned} \quad (3.19)$$

$$\begin{aligned} im(A_a - V_{fa}) + im(B_a)x + im(C_a)x^2 + im(D_a)x^3 + im(E_a)x^4 \\ + im(F_a)x^5 = -R_{fa}im(I_{fa}) \end{aligned} \quad (3.20)$$

$$A_{N_a} + B_{N_a}x + C_{N_a}x^2 + D_{N_a}x^3 + E_{N_a}x^4 + F_{N_a}x^5 = 0 \quad (3.21)$$

where  $K_{N_a} = im(K_a) - re(K_a)im(I_{fa})/re(I_{fa})$ ,  $K$  refers to  $B, C, D, E$  and  $F$ , and for  $A$ ,  $K = A - V_f$ .

The value of  $x$  can be used in the next iteration starting from (3.3), and the final value of  $x$  can be obtained when the difference between two consecutive estimates is acceptable. This is further illustrated in subsection 3.2.4.

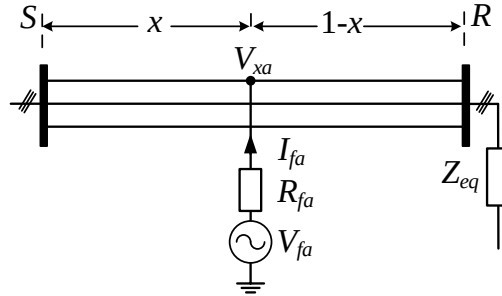


Fig. 3.2: System with phase  $a$  to ground fault

### 3.2.3.2 Phase $a$ to phase $b$ fault

For a fault between two phases  $a$  and  $b$  with a resistance  $R_{fab}$ , the system equivalent circuit will be as shown in Fig. 3.3 and applying KVL to the fault branch results in (3.22).

$$V_{xab} = V_{fab} - R_{fab}I_{fa} \quad (3.22)$$

where

$$V_{fab} = V_{fa} - V_{fb} \quad (3.23)$$

$$\begin{aligned} V_{xab} = (A_a - A_b) + (B_a - B_b)x + (C_a - C_b)x^2 + (D_a - D_b)x^3 \\ + (E_a - E_b)x^4 + (F_a - F_b)x^5 \end{aligned} \quad (3.24)$$

As with (3.21), a 5<sup>th</sup> order polynomial that combines both fault phases can be obtained to calculate the fault distance  $x$  (3.25).

$$A_{N_{ab}} + B_{N_{ab}}x + C_{N_{ab}}x^2 + D_{N_{ab}}x^3 + E_{N_{ab}}x^4 + F_{N_{ab}}x^5 = 0 \quad (3.25)$$

where  $K_{N_{ab}} = im(K_a - K_b) - re(K_a - K_b)im(I_{fa})/re(I_{fa})$ ,  $K$  refers to  $B$ ,  $C$ ,  $D$ ,  $E$  and  $F$ , and for  $A$ ,  $K = A - V_f$ .

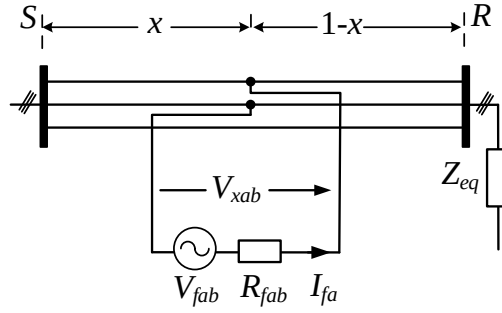


Fig. 3.3: System with phase  $a$  to phase  $b$  fault

### 3.2.4 Data processing and root selection

The proposed scheme is a single ended method which uses measurements at the main substation only. Three-phase voltages and currents are captured for a period of 40 ms composed of 20 ms pre-fault and 20 ms during the fault. The pre-fault part of the captured signals is used to create the assumed fault voltage source. For this purpose, the signals were captured at a high sampling rate of 500 kHz. Then, the full recorded window and the created fault voltage source are digitally filtered before downsampling to a lower frequency rate of 20 kHz. The signals were firstly captured at a high sampling rate to avoid aliasing [59]. Also, the same digital filter

used on the recorded signals can be applied to the created fault voltage source as well maintaining the harmony between the signals. Then, the downsampling aims to reduce the amount of data to be processed in the fault location procedure reducing the computational burden. Alternatively, the signals can be filtered using an analogue filter to avoid aliasing, then captured directly at a lower sampling rate of 20 kHz. In this case, the fault voltage source is built at a high sampling rate then a digital filter (that has the same response as the analogue filter) is applied on the created voltage source to keep the harmony between the signals. The latter case needs more care when simulating the filter as the analogue filter performance may change over time due to component tolerances and degradation. Also, as the voltage source is created at a different sampling rate from the measured signals, the assumed voltage step instant may be different from the actual instant which may affect the estimation accuracy.

Frequency domain analysis is then used to find the non-fundamental frequency components required for the fault distance estimation algorithm. The analysis includes applying a window function to remove the end effects [59], and applying the Fast Fourier Transform to find the non-fundamental components. For every frequency in the frequency range of interest, and based on the fault type, the fault distance  $x$  is calculated. A frequency range upto 3 kHz is used as it provides a good signal to noise ratio and is typical of standard instruments used for this purpose. As  $x$  refers to a distance value which is a fraction of the total line length, the correct solution should satisfy the conditions:

1. real positive value
2. less than 1 pu

After extensive simulation studies, it has been found that only one root fulfils these conditions at each frequency. However, in a very few cases, at some frequencies, two roots satisfy the conditions. In these cases for these frequencies, the average for the two roots may be used, or the results

are discarded at these frequencies. Over the frequency range of interest (up to 3 kHz), only very few frequencies have two valid roots. Therefore, the majority of the frequency bins have a single valid solution and these frequencies can be used to estimate the final distance and this has been achieved through the evaluation study. After estimating the distance over the frequency range of interest, the final distance is determined as the average over the whole frequency range. The flowchart in Fig. 3.4 illustrates the procedure of the proposed fault location method where the operation terminates when the difference between two consecutive estimates is less than an accepted tolerance.

### 3.2.5 Simplified Distance Formula

In the derivation of the method, the Taylor expansion for both  $\cosh(\gamma x)$  and  $\sinh(\gamma x)$  has been used by considering the first three terms of the series. This results in a 5<sup>th</sup> order polynomial to estimate the fault distance. A simplified cubic formula can be obtained if only the first two terms of the Taylor expansion are used. Note that ignoring more terms of the expansion means a greater approximation compared to the real distributed parameters. The approximation depends on the line parameters such as the line length. Considering this modification to the derivation, all terms related to  $x^4$  and  $x^5$  will be deleted. As an example, the final equation to estimate the distance for phase  $a$  to ground fault in (3.21) is modified to be (3.26). Using a 3<sup>rd</sup> order equation instead of 5<sup>th</sup> order reduces the computational burden. Later in this chapter through an illustrative example, the fault distance estimation using both 3<sup>rd</sup> and 5<sup>th</sup> order equations are compared.

$$A_{N_a} + B_{N_a}x + C_{N_a}x^2 + D_{N_a}x^3 = 0 \quad (3.26)$$

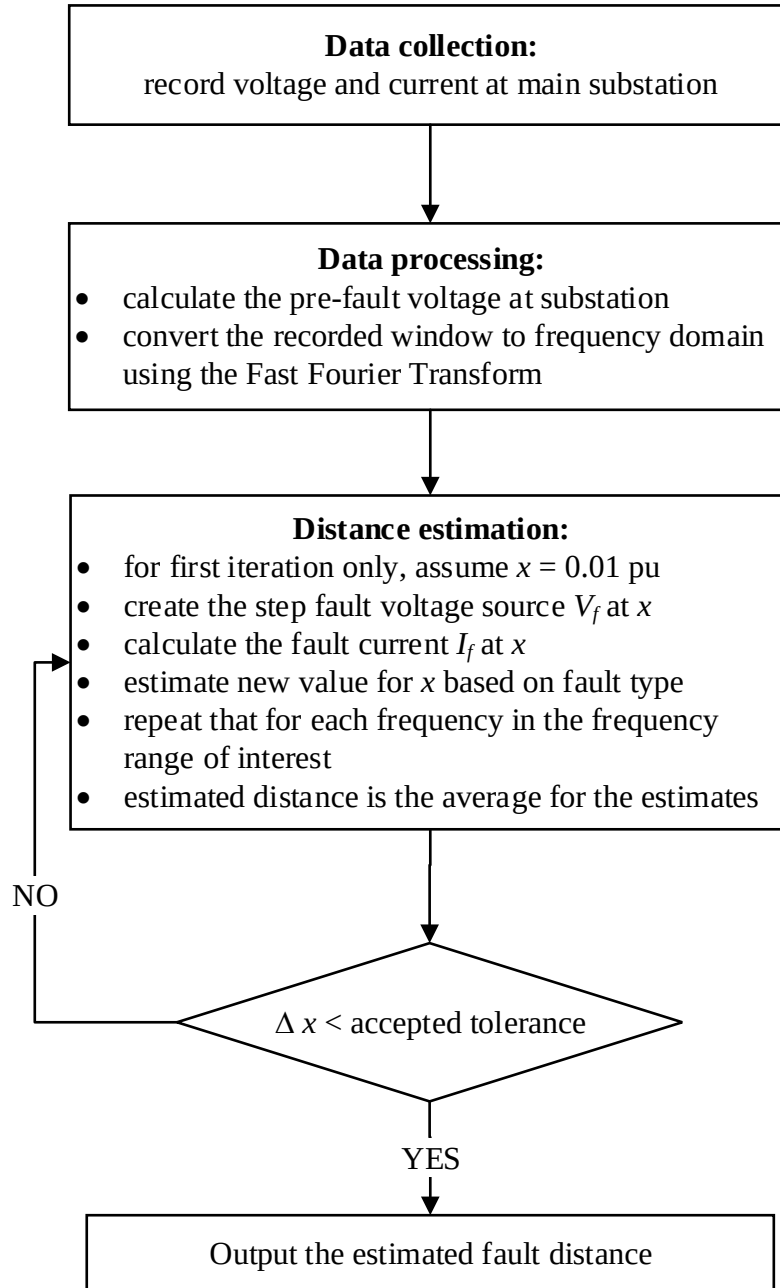


Fig. 3.4: Proposed scheme procedure for single line section system

### 3.3 A Real Distribution System

A real distribution system has loading taps and laterals along the system. The previous derivation requires the voltage and current data at the start of the fault section and also an equivalent impedance at the end of the fault section. In the following subsections, these two requirements are analysed.

#### 3.3.1 Voltage and current at start of the fault section

With measurements only available at the substation node, the voltage and current at the start of any section can be calculated by a downstream sweep along the system. Assume a section between two nodes  $k$  and  $k + 1$ , (see Fig. 3.5). The measurements can be swept from  $k$  to  $k + 1$  by (3.27) [6]. The current leaving node  $k + 1$  is calculated by (3.28). This algorithm is recursively applied starting from the substation node.

$$\begin{bmatrix} V_{k+1_j} \\ I'_{k+1_j} \end{bmatrix} = \begin{bmatrix} \cosh(\gamma_j l) & -z_{c_j} \sinh(\gamma_j l) \\ -\sinh(\gamma_j l)/z_{c_j} & \cosh(\gamma_j l) \end{bmatrix} \begin{bmatrix} V_{k_j} \\ I_{k_j} \end{bmatrix} \quad (3.27)$$

$$I_{k+1_j} = I'_{k+1_j} - Y_{L(k+1)} V_{k+1_j} \quad (3.28)$$

where  $l$  is the length of the line section and  $Y_{L(k+1)}$  is the load or equivalent admittance at node  $k + 1$  (general  $3 \times 3$  matrix that might be unbalanced). If  $Y_{L(k+1)}$  is not a single load e.g. a lateral with some lines and loads, the equivalent can be obtained as will be discussed in the next subsection.

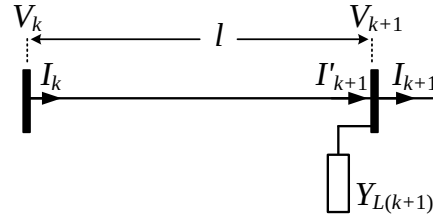


Fig. 3.5: Downstream sweep of measurements

### 3.3.2 Equivalent impedance at end of the fault section

To calculate the equivalent impedance at the end of the fault section, a recursive procedure starting from the end node of the feeder is applied. To illustrate this, consider the system in Fig. 3.6, and the target is to calculate the equivalent impedance  $Z_{eq(m)}$  knowing the impedance  $Z_{eq(m+1)}$ . The relationship between the voltage and current at the start and end of the line section is given by (3.29) and (3.30). The relationship between the voltage and current at the end of the line section is given by (3.32).

$$V_{m_j} = A_{lj}V_{m+1_j} + B_{lj}I'_{m+1_j} \quad (3.29)$$

$$I_{m_j} = C_{lj}V_{m+1_j} + D_{lj}I'_{m+1_j} \quad (3.30)$$

where

$$A_{lj} = \cosh(\gamma_j l) \quad B_{lj} = z_{c_j} \sinh(\gamma_j l) \quad (3.31)$$

$$C_{lj} = \sinh(\gamma_j l)/z_{c_j} \quad D_{lj} = \cosh(\gamma_j l)$$

$$V_{m+1_j} = Z_{eq(m+1)_j} I'_{m+1_j} \quad (3.32)$$

Substituting (3.32) in to (3.29) and (3.30):

$$V_{m_j} = (A_{lj}Z_{eq(m+1)_j} + B_{lj})I'_{m+1_j} \quad (3.33)$$

$$I_{m_j} = (C_{lj}Z_{eq(m+1)_j} + D_{lj})I'_{m+1_j} \quad (3.34)$$

The equivalent impedance  $Z_{eq(m)}$  can be represented as (3.35):

$$Z_{eq(m)_j} = \{Y_{L(m)_j} + I_{m_j}/V_{m_j}\}^{-1} \quad (3.35)$$

Therefore,  $Z_{eq(m)}$  can be derived as (3.36):

$$Z_{eq(m)_j} = \{Y_{L(m)_j} + (C_{lj}Z_{eq(m+1)_j} + D_{lj})(A_{lj}Z_{eq(m+1)_j} + B_{lj})^{-1}\}^{-1} \quad (3.36)$$

The same analysis can be used to calculate the equivalent impedance for a lateral tapped at any point along the system where the algorithm is applied starting from the end node of the lateral.

As the distribution system has many line sections, the fault is located iteratively by assuming the fault in the first section next to the substation

and applying the proposed fault location method. If the estimated fault distance exceeds the total section length, the fault location method is then applied on the next section or another section based on the estimated distance from the previous iteration until the correct distance is calculated—a distance inside the section considered. This iterative process is illustrated by the flowchart in Fig. 3.7.

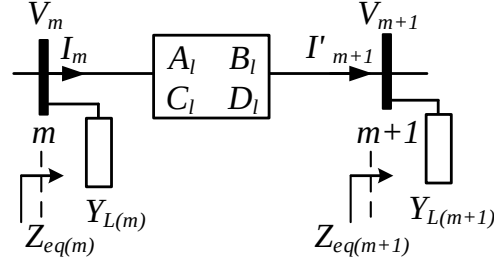


Fig. 3.6: Equivalent impedance calculation

### 3.4 A Short Distribution System

The proposed fault location scheme can be adapted for a short distribution system where the line capacitance can be ignored. This is illustrated as a special case from the derived methodology. The analysis is directly carried out in the phase domain. The line in Fig. 3.8 is represented by its total series lumped impedance  $Z$ . The pre-fault voltage at the fault point which is used to create the fault voltage source ( $V_f$ ) is given by (3.37).

$$V_{xpre} = V_{Spre} - xZI_{Spre} \quad (3.37)$$

The fault voltage and current at non-fundamental frequencies are given by (3.38) to (3.40).

$$V_x = V_S - xZI_S \quad (3.38)$$

$$I_{xS} = -I_S$$

$$I_{xR} = \{Z_{eq} + (1 - x)Z\}^{-1}V_x \quad (3.39)$$

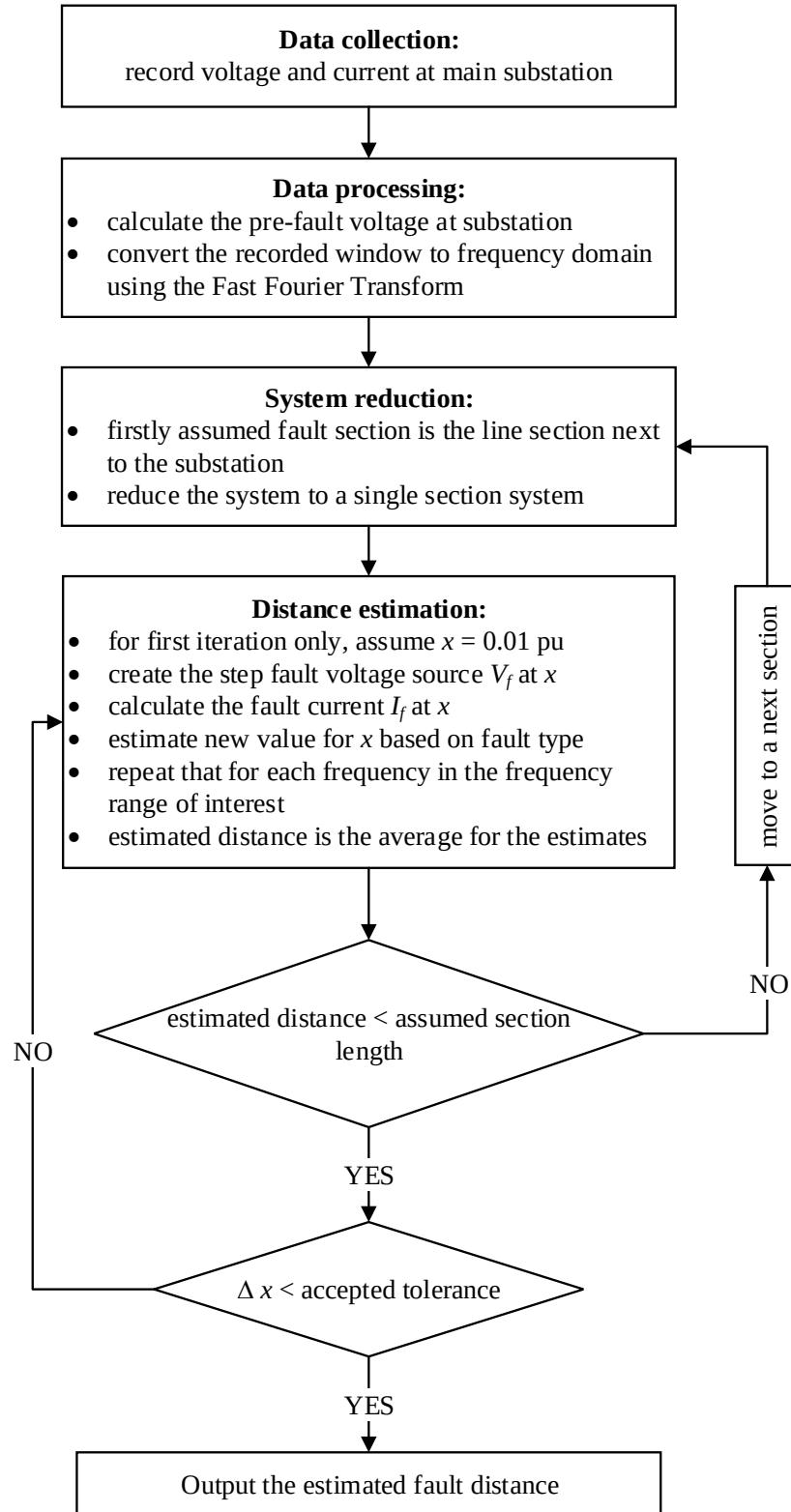
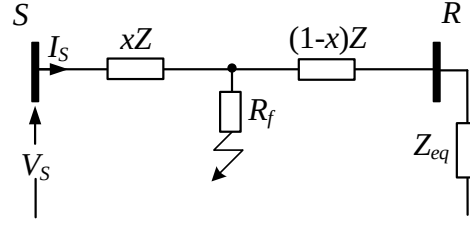


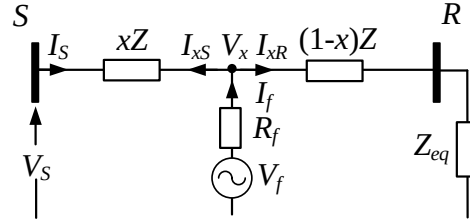
Fig. 3.7: Proposed scheme procedure for multi-line distribution system

$$I_f = I_{xS} + I_{xR} \quad (3.40)$$

Then, the fault distance can be estimated by applying KVL on the fault branch based on the fault type as has been explained with the general distributed parameter model. It is clear that the analysis is simpler for short lines where the capacitance can be ignored. A distribution feeder in a marine system is an example for a distribution system with a limited length [48].



(a) at fundamental frequency



(b) at non-fundamental frequencies

Fig. 3.8: Short distribution system with a fault (single end)

### 3.5 Detection of Fault Inception Point

As has been illustrated in the derivation of the method, a virtual fault voltage source ( $V_f$ ) is required with a step change at the fault inception point. Therefore, an algorithm to detect the fault inception point is essential. In this section, two algorithms are proposed to perform this function namely the “Second-order Rate of Change” method and the “Time Domain Subtraction” method. The two algorithms employ the fact that a discontinuity in the measured voltage occurs at the fault inception. Once a fault has been detected by any method e.g. current level detector, a time

window that combines both pre-fault and during fault data is formed and then one of the two algorithms is used to detect the actual fault inception point in this window. As explained in section 3.2.4, the fault voltage source is created at the high sampling rate used to capture the original measured voltage and current. Therefore, the detection of the fault inception point is also carried out on the signals before downsampling.

### 3.5.1 Second-order rate of change

In order to detect the fault inception point, a parameter called the Second-order Rate of Change (*SRC*) at sample number ( $n$ ), is calculated using three samples ( $n, n + 1, n + 2$ ) by (3.41).

$$SRC(n) = ||v(n) - v(n + 1)| - |v(n + 1) - v(n + 2)|| \quad (3.41)$$

where  $v(i)$  is the voltage value at sample number  $i$ .

By sweeping over the recorded voltage signal, once the fault inception point is included in the *SRC* calculation, it's value increases sharply indicating a fault inception. In (3.41), if the fault inception point is at ( $n + 2$ ) the corresponding *SRC* high value will be stored at point ( $n$ ) i.e. the detection appears 2 samples before the fault inception point.

The performance of the method may be affected by noise in the voltage signal and produces high values during the healthy period. However, at the fault inception, a significant change is obtained. The experimental studies in Chapter 7 emphasize the success of the method even with noisy signal.

### 3.5.2 Time domain subtraction

In this method, the time window that contains the fault inception point is subtracted sample by sample from a pre-fault time window of the same length. The resulting difference will have a significant value at the first fault sample point. In this case the window must match an integer number of fundamental cycles.

For both detection methods, a suitable threshold level can be determined based on the values obtained during the healthy period.

### 3.5.3 Wave propagation delay time

#### 3.5.3.1 Effect of wave propagation delay time

As previously mentioned, the fault voltage source created has a step change at the fault inception instant. In the previous subsection, the initial reaction point (sample) in the measured substation voltage to the fault can be detected using two different algorithms. However, the point estimated at the monitoring substation node may be different from the actual fault inception point. This case only appears with long distribution systems where the combination of line inductance and capacitance causes a time delay during the signal propagation from the fault point to substation point [60]. Based on the line length, line parameters and fault location, this time delay may lead to a difference between the actual fault inception sample at the fault point and the sample at the substation measuring point. Sections 3.5.1 and 3.5.2 present detection methods for the fault inception sample in the measured voltage at the substation. This inception sample may be used for creating the fault voltage source with insignificant propagation delay. Otherwise, the propagation time delay needs to be considered. This case is further illustrated by an illustrative example in Section 3.6.

#### 3.5.3.2 Compensation for wave propagation delay time

Wave propagation theory indicates that over a transmission line, the signal takes a time to propagate from point to point and this is known as the propagation/travelling time. The propagation time is dependent on the line parameters [60]. For a line with per unit length inductance and capacitance of  $L$  and  $C$  respectively, the propagation time per unit length of the line and can be calculated using (3.42).

$$t_d = \sqrt{LC} \quad (3.42)$$

Therefore, the travelling time can be calculated and considered when building the fault voltage source. As the SEWIBFL scheme assumes the fault to be in the first section next to substation and iteratively moves along the feeder until finding the fault point, the travelling time between the start node of the assumed fault section and the substation node is used to compensate for the time delay. For an incorrect assumed fault section, the calculated travelling time will also be incorrect and will not help in finding the fault distance therefore the SEWIBFL scheme moves to the next section.

It is worth noting that it might be difficult to accurately calculate the exact travelling time for the signal moving from the fault point to the substation for various reasons:

1. As the actual fault point is unknown along the assumed fault section, it is only possible to calculate the travelling time between the start node of the fault section and the substation node. Therefore, a time error will exist if the travelling time between the actual fault point and the start node of the fault section is influential.
2. The travelling time calculated depends on the line parameters which might have a tolerance and uncertainty.

Consequently, the basic travelling time between the substation and the start of the assumed fault section is calculated using (3.42) and accordingly the different number of samples to be considered between the substation voltage and the step voltage source created can be found. To compensate for these potential sources of error, this estimated number of samples should be iteratively increased and/or decreased to reflect the actual travelling time. In the following illustrative example this point is further illustrated.

### 3.6 Illustrative Example

In this section, a simple medium voltage system (24.9 kV) is used to help illustrating the proposed concept. The feeder is shown in Fig. 3.9 and consists of four line sections having the same per unit length parameters and lengths as provided in Fig. 3.9. In this illustrative example, transposed lines were assumed so the per unit length parameters matrices are as shown below where  $R$ ,  $L$  and  $C$  are the series resistance ( $\Omega/\text{km}$ ), series inductance ( $\text{mH}/\text{km}$ ) and shunt capacitance ( $\text{nF}/\text{km}$ ) respectively. These parameters are an average values obtained from the IEEE 34-bus feeder data [61]. A load of  $600 \Omega$  and  $1 \text{ H}$  has been connected at end of each line section. The system has been simulated using Matlab/Simulink packages [62].

$$R = \begin{bmatrix} 0.833 & 0.133 & 0.133 \\ 0.133 & 0.833 & 0.133 \\ 0.133 & 0.133 & 0.833 \end{bmatrix} \quad L = \begin{bmatrix} 2.589 & 1.093 & 1.093 \\ 1.093 & 2.589 & 1.093 \\ 1.093 & 1.093 & 2.589 \end{bmatrix}$$

$$C = \begin{bmatrix} 10.103 & -2.075 & -2.075 \\ -2.075 & 10.103 & -2.075 \\ -2.075 & -2.075 & 10.103 \end{bmatrix}$$

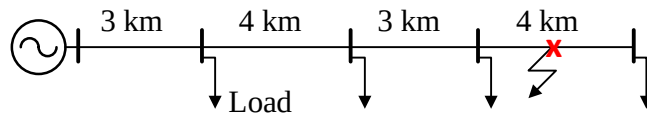


Fig. 3.9: Simple distribution system

#### 3.6.1 Detection of fault inception

A single line to ground fault has been simulated at the middle of the fourth line section. Firstly, the fault has been detected based on current level detector and the voltage at the source point has been captured for 40 ms at 500 kHz sampling rate and is shown in Fig. 3.10 for the faulted phase.

Noting that 40 ms data length equals to 20000 samples at 500 kHz. A zoomed view for the measured voltage is illustrated in Fig. 3.11 where the fault inception sample becomes clear as the sample number 9753 (first sample during the fault) or the last healthy sample number is 9752.

For the *SRC* method, as previously explained in (3.41), when the fault inception sample is included in the *SRC* calculation as sample number  $n+2$ , the corresponding high value for the *SRC* is stored in the sample number  $n$ . When employing the method on the recorded signal, the resulted *SRC* is shown in Fig. 3.12. The first high value is stored at 9751. Therefore, the fault inception point would be  $(n + 2 = 9753)$  according to (3.41) which is the actual inception point in the measured voltage. Noting that, the result in Fig. 3.12 is a zoomed view around the fault inception to make it obvious.

For the time domain subtraction method, the signal in Fig. 3.10 has been subtracted sample by sample from a healthy signal of the same length where the healthy signal is the signal measured directly before the signal in Fig. 3.10. The difference between the two signals is shown in Fig. 3.13 where at the sample number 9753 there is a sharp increase in the value indicating the fault inception in the measured voltage.

### 3.6.2 Propagation time delay

In the simulation, the voltage at the fault point has been measured as well as the voltage at the substation point and is shown in Fig. 3.14. The zoomed view is shown in Fig. 3.15 to focus on the fault inception sample. As is clear, the actual last healthy sample at the fault location is 9728 and the reaction at the substation location appears at 9752 which is 24 samples delayed. For a sampling frequency of 500 kHz, the 24 samples are equivalent to 48  $\mu$ s delay between the measured voltage and the fault point voltage.

By converting the inductance ( $L$ ) and capacitance ( $C$ ) to mode domain using Clarke's transformation matrix [6], the propagation time per unit length can be calculated by (3.42). Note that the inductance  $L$  and capacitance  $C$  matrices, used in this example, have been calculated from the

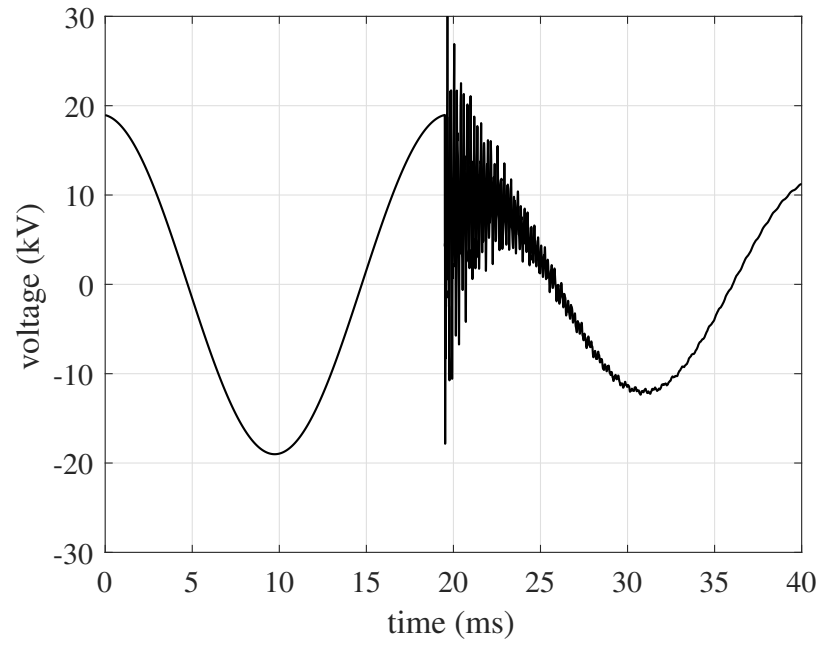


Fig. 3.10: Measured voltage at substation

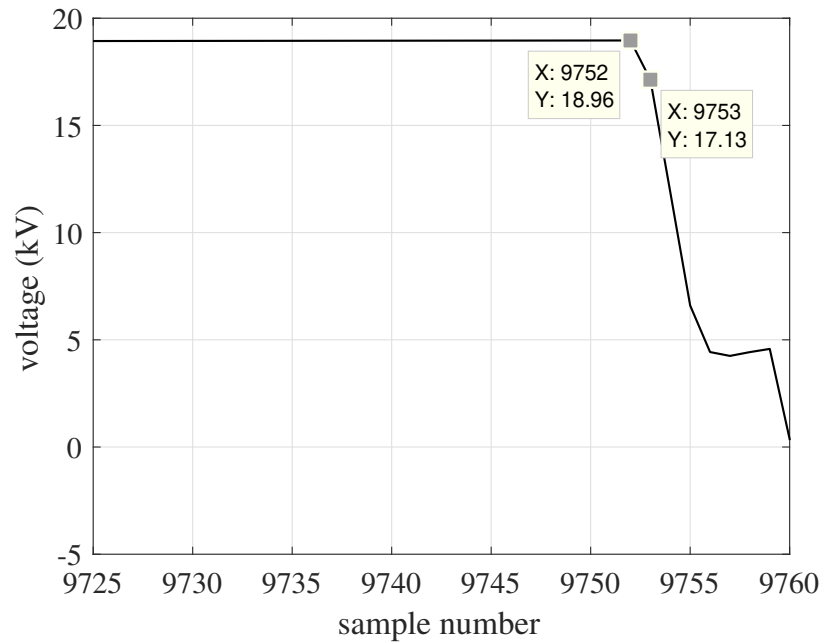


Fig. 3.11: Zoom in for measured substation voltage

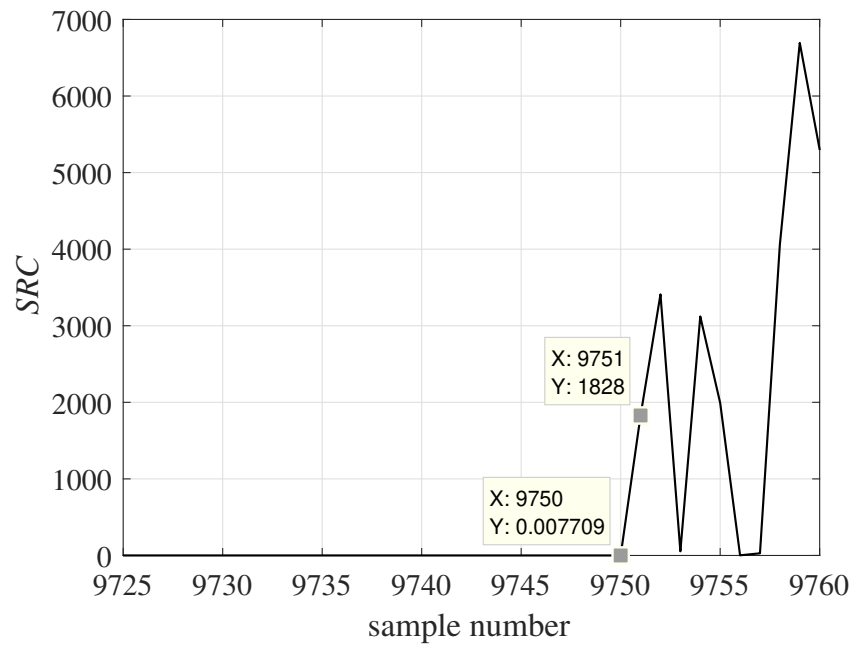


Fig. 3.12: Fault detection by second-order rate of change method (*SRC*)

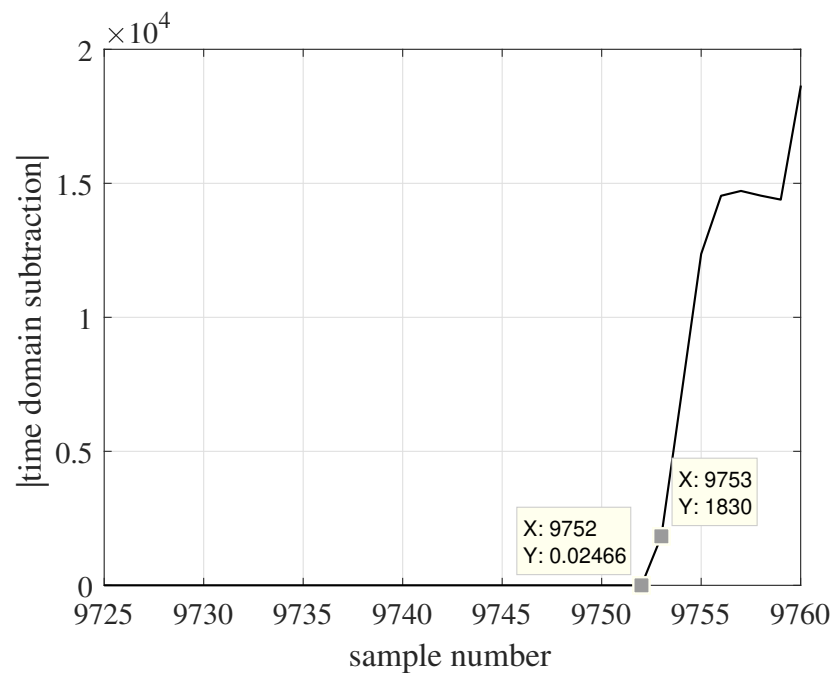


Fig. 3.13: Fault detection by time domain subtraction method

IEEE 34-bus data assuming the system frequency is 50 Hz. This results in a propagation speed which is lower than the speed of light for the aerial modes. The propagation speed for the aerial and ground modes is  $2.34 \times 10^5$  km/s and  $1.87 \times 10^5$  km/s respectively. The distance from the substation to the start of the fault section is 10 km. Using this distance and the calculated propagation speed, the travelling time has been calculated as 54  $\mu$ s for the ground mode and 43  $\mu$ s for the aerial modes. The calculated time differs from the actual delay as the calculated time represents the delay between the start of the fault section and the substation. However, it is a good starting point to be used to compensate for the travelling time effect.

### 3.6.3 Distance estimation

After detecting the fault inception sample and building the fault voltage source, the measured signals as well as the created voltage source are digitally filtered then downsampled to 20 kHz as explained in section 3.2.4. The downsampled data is used to estimate the fault distance.

#### 3.6.3.1 Effect of propagation delay time

The actual fault distance for the simulated fault is 12 km. To illustrate the effect of ignoring the propagation delay, the fault voltage source  $V_f$  has been created based on the detected fault inception in the measured substation voltage and then is used for distance estimation. In this case, the created fault voltage has 24 samples error in the time domain (24 samples at 500 kHz sampling rate). The estimated distance is presented in Fig. 3.16.

When ignoring the propagation delay, most of the frequency range does not provide an accepted solution (real positive root and less than 1 pu). Also, the error in the estimation is high and increases with increasing the frequency. This may be attributed to the same time delay ( $\Delta t$ ) reflecting a higher phase angle error ( $\Delta \theta$ ) with increasing the frequency ( $w$ ) (3.43). For instance, a time delay of 48  $\mu$ s corresponds to a phase error of  $0.86^\circ$ ,  $17.28^\circ$

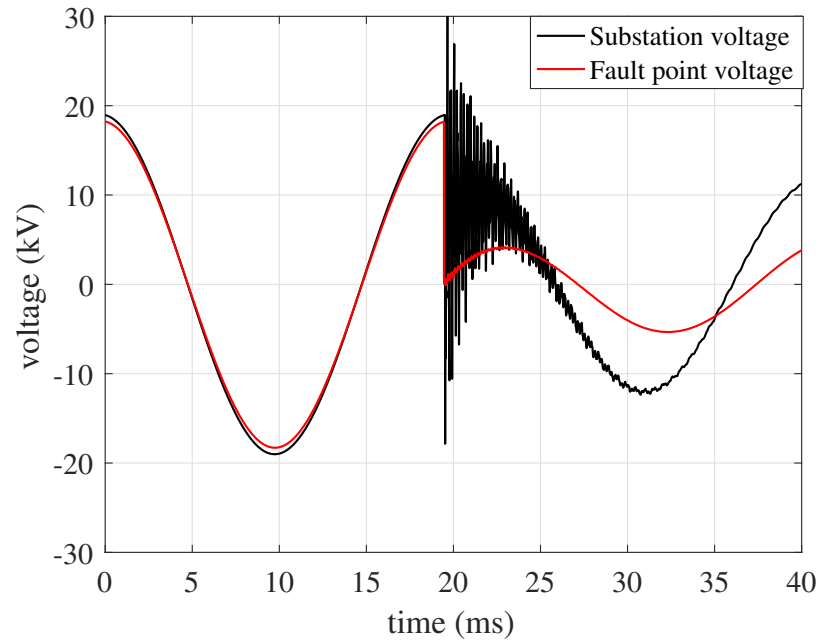


Fig. 3.14: Measured voltages at substation and fault point

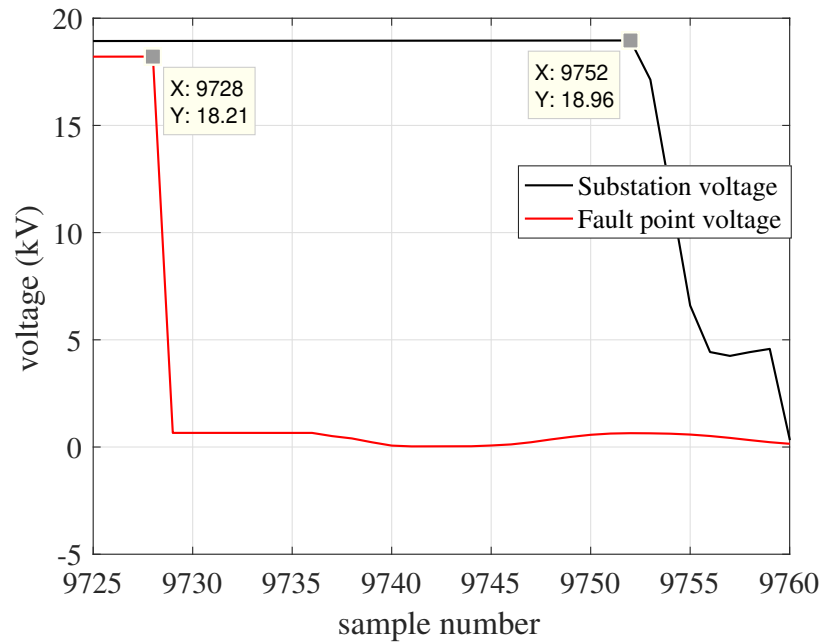


Fig. 3.15: Zoom in for measured substation and fault point voltages

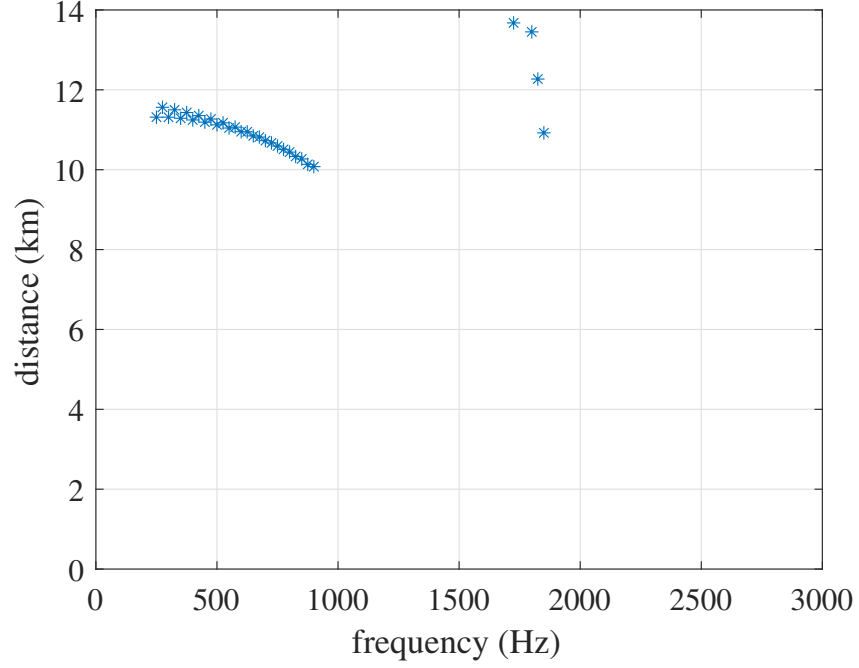


Fig. 3.16: Effect of propagation delay on the estimated fault distance

and  $34.56^\circ$  at 50 Hz, 1 kHz and 2 kHz respectively. The standard deviation between the estimates at valid frequency bins is 800 m.

$$\Delta\theta = w\Delta t \quad (3.43)$$

In order to compensate for the propagation delay, the initial compensation number of samples is calculated from the estimated delay time between the substation and the start of the fault section. So, for an assumed delay time of about  $43\mu\text{s}$ , the integer difference in samples (ds) would be 22 at 500 kHz. This number of samples is considered in building the fault voltage source, then the fault distance is estimated again. The number of samples (ds) is also increased to consider the potential sources of error discussed in section 3.5.3.2. The estimated distance at different values for (ds) is shown in Fig. 3.17. Table 3.1 presents the standard deviation between the estimates and the number of valid estimates for each value of the compensation samples (ds). As is clear, the best performance (especially lowest standard deviation) corresponds to  $ds = 24$  which reflects the actual delay samples.

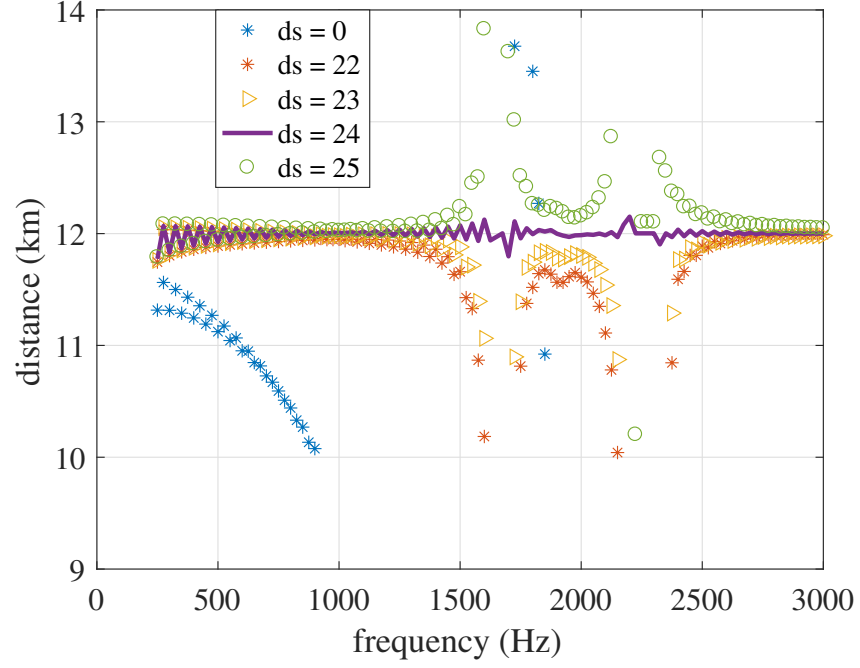


Fig. 3.17: Estimated distance for different compensation samples

Table 3.1: Compensation for the delay time

| ds | standard deviation (m) | number of valid estimates |
|----|------------------------|---------------------------|
| 22 | 363                    | 98                        |
| 23 | 220                    | 99                        |
| 24 | 55                     | 109                       |
| 25 | 345                    | 105                       |

### 3.6.3.2 Effect of line capacitance

In [32], a single end method based on the high frequency analysis has been developed for distribution systems with distributed generation. However, the method simplified the line model by ignoring the mutual coupling between the phases and also ignoring the line capacitance.

In this section, the fault distance is estimated while ignoring only the line capacitance to check its effect on the estimation accuracy. The estimated distance is shown in Fig. 3.18 while ignoring and considering the line capacitance in the fault location process. As is clear, ignoring

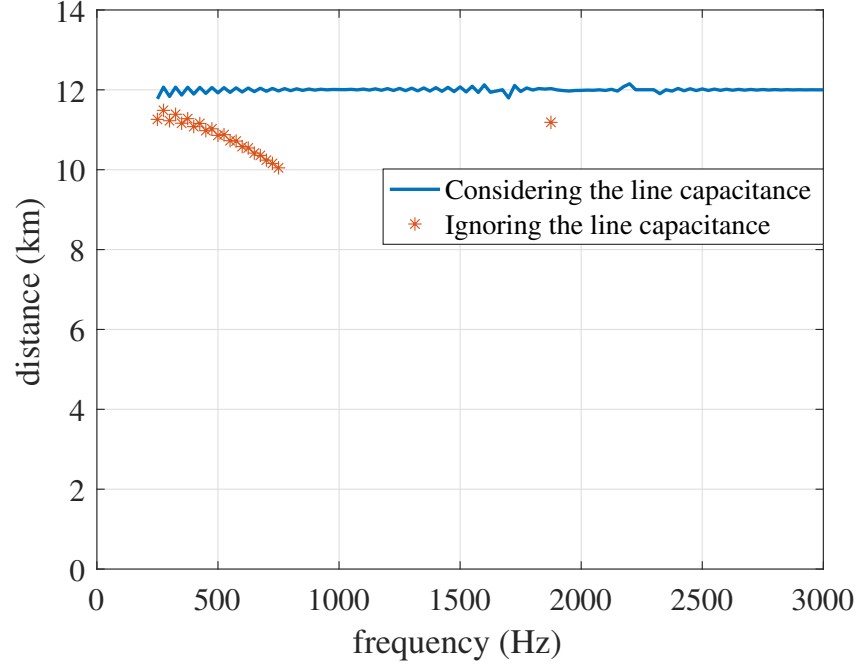


Fig. 3.18: Effect of the line capacitance

the capacitance affects the accuracy especially at higher frequencies as the ignored capacitive charging current increases with increasing frequency (as the frequency increases, the capacitive reactance decreases). Most of the frequency range above 1 kHz does not have a valid estimated root. This effect is expected to be more significant on a more complicated and longer distribution system. Noting that, ignoring the line capacitance in turn ignores the effect of the propagation time delay. Therefore, the result in Fig. 3.18 is very similar to that in Fig. 3.17.

### 3.6.3.3 Using 3<sup>rd</sup> order formula

The previous results used the 5<sup>th</sup> order equation to estimate the fault distance. The fault distance is also estimated using the simplified cubic equation and compared with that obtained in the previous results in Fig. 3.19. The two equations provide the same distance estimation which means the simplification for this system is a valid assumption. The two equations provide the same performance which means that the 3<sup>rd</sup> order representation of the line is valid over the used frequency range (up to

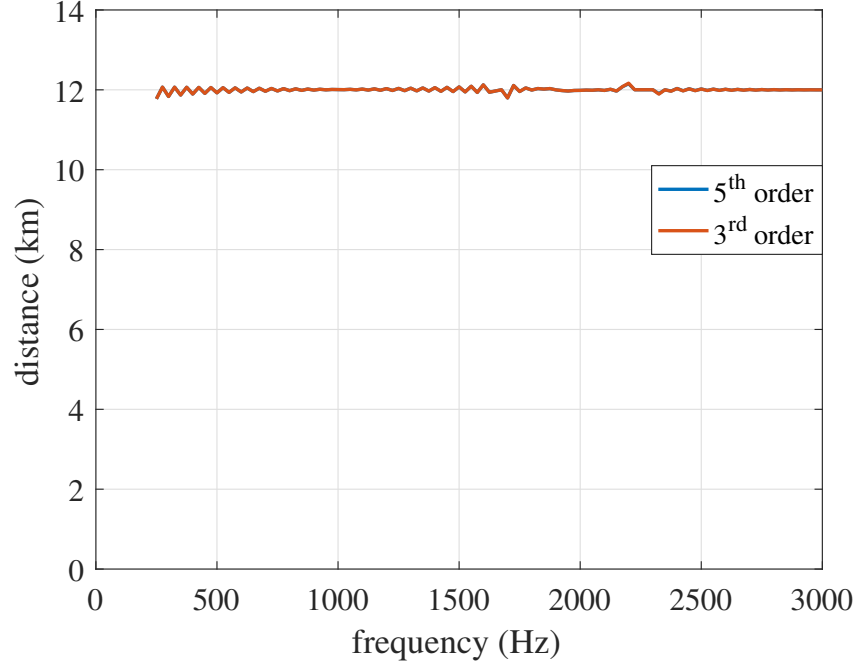


Fig. 3.19: Using fifth and third order equations (single end)

3 kHz). In the next subsection, the relation between the line representation used and the frequency range is further illustrated.

#### 3.6.3.4 Approximate $\pi$ line model

As stated, simplifying the formula used to estimate the fault distance reduces the computational burden and the validity of this approximation depends on the system parameters such as the line length. An approximation of the maximum frequency range represented by the  $\pi$  line model is given by (3.44) [63].

$$f_{maximum} = \frac{Nc}{8l} \quad (3.44)$$

where  $N$ ,  $c$ ,  $l$  and  $f_{maximum}$  are the number of  $\pi$  sections used to model the line, the propagation speed (km/s), the line length (km) and the maximum frequency (Hz) respectively.

For example, using  $N = 2$ ,  $c = 2.34 \times 10^5$  km/s and  $l = 14$  km, the maximum frequency will be 4.18 kHz. Note that, using  $N = 2$  results in a 4<sup>th</sup> order equation.

As is clear, the maximum frequency and accordingly the approximation to a single  $\pi$  line ( $N = 1$ ) instead of considering the distributed nature of the line parameters depends on the line length and the propagation speed (the propagation speed depends on the line inductance and capacitance).

In this subsection, a further approximation is tested by using the  $\pi$  line model. Using the  $\pi$  line model is equivalent to using a  $2^{nd}$  order formula to estimate the fault distance (i.e. removing the terms related to  $x^5$ ,  $x^4$  and  $x^3$  in the equation used to estimate the distance). The fault location algorithm has been tested twice. Firstly, the approximate  $\pi$  line model is employed only in the distance estimation step i.e. the sweep of measurements from the measurement node to the fault section uses the distributed parameter line model for the lines. Secondly, the  $\pi$  line model is assumed for all steps (sweep of measurements to the fault section and also the distance estimation formula). The results are shown in Fig. 3.20 where case I refers to the first case and case II refers to the second case.

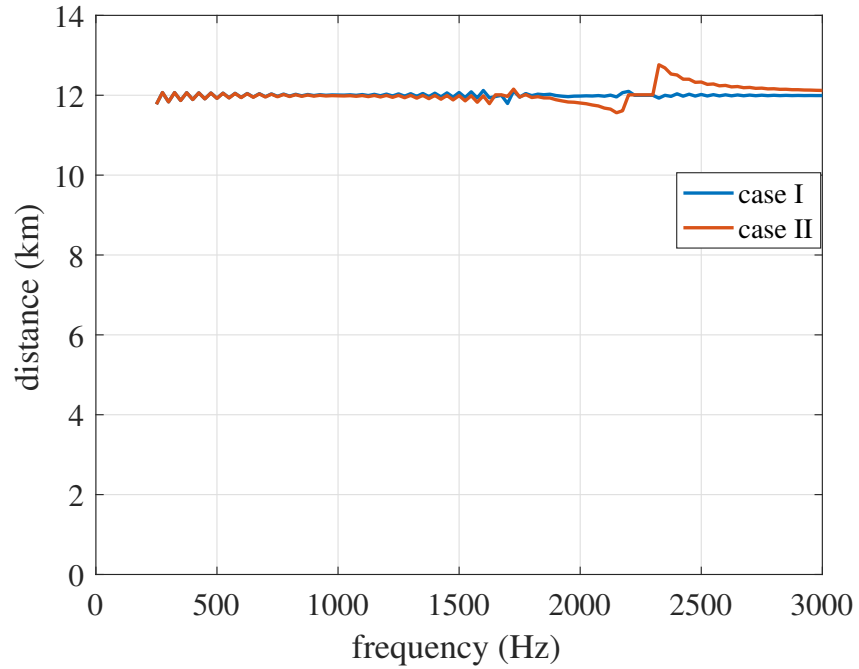


Fig. 3.20: Estimated distance using approximate  $\pi$  line model

The results show that the approximation is valid for the whole frequency range in case I and higher errors were obtained in the high frequency range

for case II. This is attributed to the total length of the approximated line in both cases. Only the faulted line with a length of 4 km is approximated to a  $\pi$  model in case I. On the other hand, the full system length (14 km) is approximated in case II leading to lower  $f_{maximum}$  according to (3.44).

From this test, it can be concluded that with a longer system that may extend to several tens of kilometres, using a single  $\pi$  line model to represent each line of the system will not provide an accurate distance estimation. Also, approximating only the fault section to a  $\pi$  model still depends on the line parameters (section length, inductance and capacitance).

### 3.7 Conclusions

A single end wideband fault location scheme has been proposed for radial distribution systems. The method uses the voltage and current transients generated when a fault occurs. It assumes the fault is a voltage source that injects high frequency components into the system. The system was analysed at the non-fundamental high frequency components to estimate the distance between the measurement point (substation node) and the fault point. The analysis considered the line's capacitance, untransposed/asymmetrical line and used the distributed parameter model for the lines. The three-phase system has been decoupled into three independent propagation modes using modal transformation. An iterative approach has been proposed to compensate for the wave propagation delay time with long lines. The proposed method has been initially evaluated using a simple symmetrical medium voltage feeder. The evaluation ensures the importance of considering the line's capacitance, the propagation delay time and the distributed parameter model for the lines.

# Chapter 4

## Active Distribution Systems: Case I

### 4.1 Introduction

This chapter presents a fault location scheme suitable for distribution system with distributed generation (DG). A model for the distributed generation in the high frequency range is proposed for both inverter based distributed generation and synchronous based distributed generation. The proposed DG model is employed in the previously proposed SEWIBFL scheme to locate faults in active distribution systems.

### 4.2 DG Equivalent Circuit

A fault location scheme which uses measurements at one end only requires an equivalent circuit to represent each DG in the system. The derivation of this circuit is presented in this section. Two types of DGs have been considered: inverter based and synchronous based distributed generation.

Many types of renewable energy sources such as PV systems produce a DC output that needs to be controlled to maximize the power transfer and then be converted to AC if connected to AC grids. To achieve that, power converters are used. Also, a filter is necessary to reduce the switching

frequency harmonics generated by the inverter penetrating into the grid [64]–[67]. High order filters such as LCL filters are usually employed instead of simple inductors as they provide better performance with lower inductor values leading to a reduced size and cost [66]. Often, a transformer is needed for interconnection with the grid for two different reasons. Firstly, if the DG is to be connected to a medium voltage or high voltage system, the transformer acts as a step up transformer as the DG output is usually low voltage. Secondly, the DG usually uses a three-phase three-leg inverter [50], [68], hence if the DG is to be connected to a low voltage four-wire microgrid, a transformer is needed as an interface between the three-wire DG and the four-wire microgrid [50]. This type of generation is known as inverter based distributed generation (IBDG) and a general circuit for the IBDG connected to AC grid at the point of common coupling (PCC) is illustrated in Fig. 4.1a. The control system and the DC side energy source are not displayed in Fig. 4.1a. Other DGs can be directly connected to the grid such as synchronous based distributed generation (SBDG), refer to Fig. 4.1b. In the subsequent sections, the DG equivalent circuit at the non-fundamental frequencies that will be employed in the fault location process is presented for both IBDG and SBDG types.

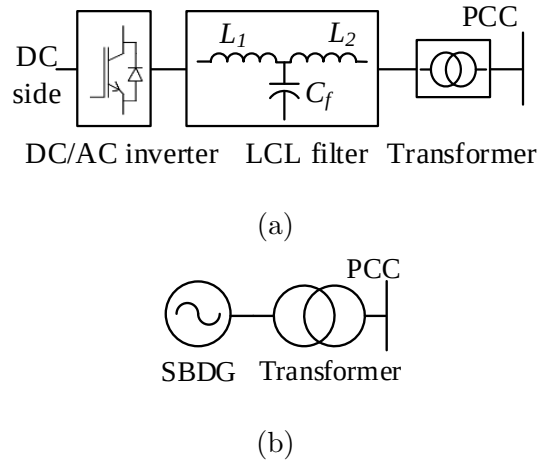


Fig. 4.1: DG connected to AC grid (a): IBDG (b): SBDG

### 4.2.1 IBDG approximate equivalent circuit

During healthy operation, the inverter transfers power at the fundamental frequency with some low order and switching harmonics also being present. The proposed fault location scheme utilizes a data window that combines a pre-fault period and part of the fault period. The frequency spectrum of the inverter output voltage over this window may contain different non-fundamental components not usually seen in the healthy case. As a first stage toward the equivalent circuit, the inverter circuit and the DC side system are approximated as a voltage source ( $V_{ab}$ ,  $V_{bc}$  and  $V_{ca}$ ) that contains a wideband of frequencies, as shown in Fig. 4.2a.

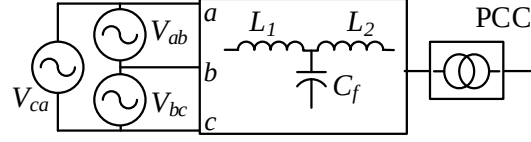
The system in Fig. 4.2a can be reduced to a Thevenin equivalent voltage source  $V_{th}$  and an impedance  $Z_{th}$  connected to the point of common coupling, refer to Fig. 4.2b. Considering the capacitor  $C_f$  of the LCL filter is connected in delta,  $V_{th}$  can be obtained as (4.1). For  $Z_{th}$ , the inverter voltage source acts as short circuit and  $Z_{th}$  is the combination of both filter and transformer impedances when using a transformer, otherwise it will be the filter equivalent impedance. The following subsections illustrate the steps to obtain (4.1) and also  $Z_{th}$ .

$$V_{th-pq} = V_{pq}Z_C/(Z_C + 3Z_{L1}) \quad (4.1)$$

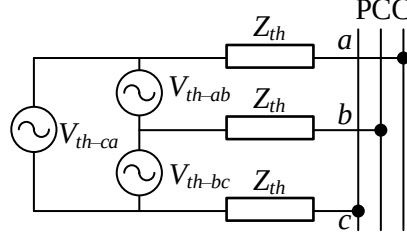
where  $p$  and  $q$  refer to the phases  $a$ ,  $b$ ,  $c$  with  $p \neq q$ ,  $Z_C$  and  $Z_{L1}$  are the impedances of the filter capacitor ( $C_f$ ) and inverter side inductor ( $L_1$ ) respectively.

#### 4.2.1.1 Analysis for $V_{th}$

The circuit analysis depends on the Thevenin's theorem and loop analysis [69]. To obtain the Thevenin equivalent voltage from Fig. 4.2a, the system connected to the point of common coupling would be an open circuit. Therefore, no current passes in the grid side inductor ( $L_2$ ) and the equivalent circuit is shown in Fig. 4.3.



(a)



(b)

Fig. 4.2: IBDG equivalent circuit

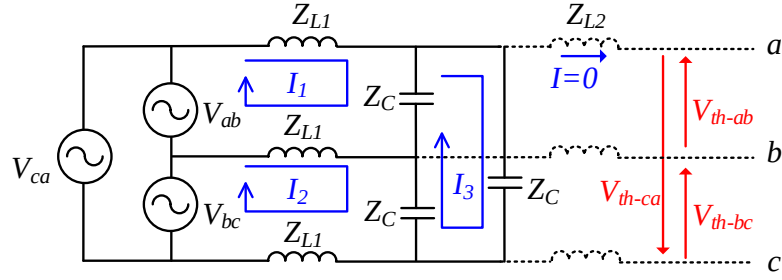


Fig. 4.3: IBDG Thevenin voltage calculation

The equivalent Thevenin voltages can be calculated using (4.2) with respect to the assumed loop currents ( $I_1$ ,  $I_2$  and  $I_3$  given in Fig. 4.3). Therefore, after calculating the loop currents using the loop analysis, the Thevenin voltages can be calculated.

$$\begin{aligned} V_{th-ab} &= Z_C(I_1 - I_3) \\ V_{th-bc} &= Z_C(I_2 - I_3) \\ V_{th-ca} &= -Z_C I_3 \end{aligned} \tag{4.2}$$

#### Loop analysis:

The loop/mesh analysis is used to estimate the assumed loop currents

by applying the KVL on each loop. Then, the equations are solved simultaneously [69].

*Loop 1:*

$$(2Z_{L1} + Z_C)I_1 - Z_{L1}I_2 - Z_CI_3 = V_{ab} \quad (4.3)$$

*Loop 2:*

$$-Z_{L1}I_1 + (2Z_{L1} + Z_C)I_2 - Z_CI_3 = V_{bc} \quad (4.4)$$

*Loop 3:*

$$-Z_CI_1 - Z_CI_2 + 3Z_CI_3 = 0 \quad (4.5)$$

From (4.5), the current ( $I_3$ ) can be represented as (4.6) then used in (4.3) and (4.4) to obtain (4.7) and (4.8) respectively.

$$I_3 = (I_1 + I_2)/3 \quad (4.6)$$

$$(2Z_{L1} + 2Z_C/3)I_1 - (Z_{L1} + Z_C/3)I_2 = V_{ab} \quad (4.7)$$

$$-(Z_{L1} + Z_C/3)I_1 + (2Z_{L1} + 2Z_C/3)I_2 = V_{bc} \quad (4.8)$$

Assuming  $h = Z_{L1} + Z_C/3$ , then (4.7) and (4.8) can be represented in the matrix form in (4.9). The currents ( $I_1$  and  $I_2$ ) can be obtained from solving (4.9) and are represented in (4.10). Substituting in (4.6), the three currents can be represented as (4.11). Finally, the Thevenin voltages are calculated by substituting with the loop currents in (4.2). The final form for the Thevenin voltages is similar to (4.1).

$$\begin{bmatrix} V_{ab} \\ V_{bc} \end{bmatrix} = \begin{bmatrix} 2h & -h \\ -h & 2h \end{bmatrix} \begin{bmatrix} I_1 \\ I_2 \end{bmatrix} \quad (4.9)$$

$$\begin{bmatrix} I_1 \\ I_2 \end{bmatrix} = \frac{1}{3h^2} \begin{bmatrix} 2h & h \\ h & 2h \end{bmatrix} \begin{bmatrix} V_{ab} \\ V_{bc} \end{bmatrix} \quad (4.10)$$

$$\begin{aligned}
 I_1 &= \frac{2V_{ab} + V_{bc}}{3h} \\
 I_2 &= \frac{V_{ab} + 2V_{bc}}{3h} \\
 I_3 &= \frac{V_{ab} + V_{bc}}{3h}
 \end{aligned} \tag{4.11}$$

$$\begin{aligned}
 V_{th-ab} &= \frac{Z_C}{3Z_{L1} + Z_C} V_{ab} \\
 V_{th-bc} &= \frac{Z_C}{3Z_{L1} + Z_C} V_{bc} \\
 V_{th-ca} &= \frac{Z_C}{3Z_{L1} + Z_C} V_{ca}
 \end{aligned} \tag{4.12}$$

#### 4.2.1.2 Reduced $Z_{th}$

To obtain the equivalent Thevenin impedance, the voltage sources are replaced by a short circuit [69]. The equivalent circuit for the LCL circuit is shown in Fig. 4.4. The following procedure summarizes the calculation steps of  $Z_{th}$

- (1) Convert the wye network  $Z_{L1}$  to delta network  $Z_{L1D}$  [69].
- (2) Calculate the parallel equivalent of  $Z_{L1D}$  and  $Z_C$ .
- (3) Convert the previous parallel equivalent from delta to wye network.
- (4) The equivalent  $Z_{th}$  for the LCL circuit results from adding the impedance calculated in the previous step to  $Z_{L2}$ .

In Fig. 4.2b, the current in different loops can be calculated using mesh analysis. The current in each phase can then be calculated with respect to the loop current. Generally, the current in each phase would satisfy the following:

$$I_{DG} \propto (V_{PCC} - V_{th})/Z_{th} \tag{4.13}$$

where  $V_{PCC}$  is the voltage at the PCC.

As the proposed SEWIBFL scheme does not use the measurements made at the DGs themselves,  $V_{th}$  cannot be calculated. Therefore we must determine under what conditions it is possible to ignore the effect of  $V_{th}$  on

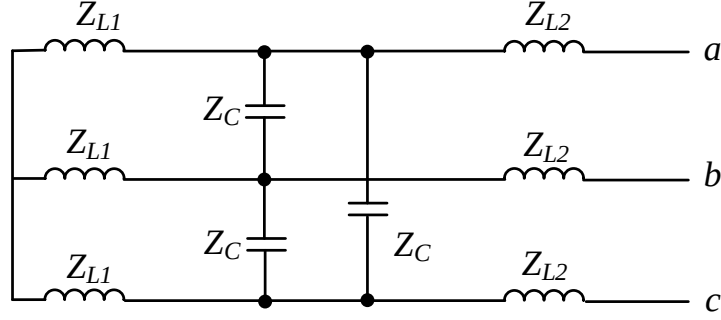


Fig. 4.4: IBDG Thevenin impedance calculation

the equivalent circuit. If  $V_{th}$  is ignored, an approximate equivalent circuit comprising the passive impedance ( $Z_{th}$ ) will be used for the fault location algorithm as shown in Fig. 4.5. It is worth noting that, ignoring  $V_{th}$  does not mean the actual equivalent circuit is a passive circuit, but it is an approximation and as a consequence an error is possible. From (4.1),  $V_{th}$  can be arranged as (4.14).

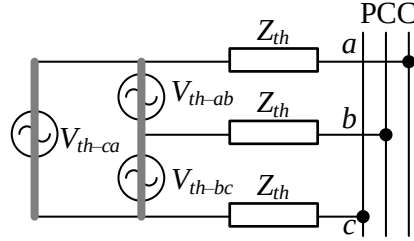


Fig. 4.5: IBDG approximate equivalent circuit

$$V_{th-pq} = V_{pq} \times Xf \quad (4.14)$$

where  $Xf = Z_C / (Z_C + 3Z_{L1})$

The magnitude of the factor  $Xf$  affects the final magnitude of  $V_{th}$  i.e. it is frequency dependent. Substituting for  $Z_C$  and  $Z_{L1}$  with  $1/j\omega C_f$  and  $j\omega L_1$

respectively while the resistive elements are ignored and  $w$  is the angular frequency,  $Xf$  can be written as in (4.15).

$$Xf = 1/(1 - (w/w_r)^2) \quad (4.15)$$

where  $w_r = 1/\sqrt{3L_1C_f}$

The magnitude of  $Xf$  changes with frequency as shown in Fig. 4.6 where the peak value lies at the resonance frequency between  $Z_C$  and  $3Z_{L1}$  (at  $w = w_r$ ). From Fig. 4.6 and (4.15), it can be concluded that:

1.  $Xf$  has lower magnitudes in the high frequency range and it is better to avoid working in the frequency range surrounding the resonance frequency of the filter capacitor and inverter side inductor.
2. In the high frequency range, a filter with a higher  $L_1C_f$  product will have a lower  $Xf$  magnitude and accordingly a lower effect on  $V_{th}$ .

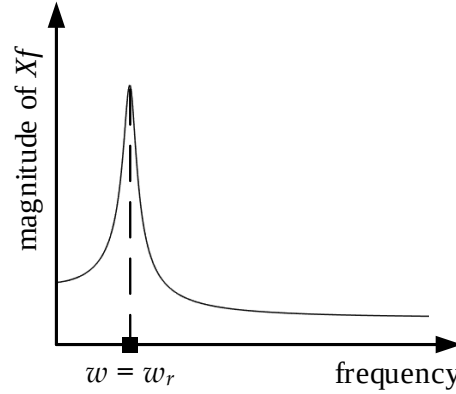


Fig. 4.6: Change of magnitude of  $Xf$  with frequency

As the magnitude of  $Xf$  in the high frequency range (above  $w_r$ ) is lower than its magnitude in the low frequency range, the high frequency range will provide a better performance.

### 4.2.2 IBDG current and fault location

It is worth noting that the DG current in the frequency range used by the fault location scheme is also determined by the value of  $Z_{th}$  as is clear from (4.13). Therefore, as  $Z_{th}$  increases, the DG current decreases and errors introduced by this current may have a lower impact on the fault location accuracy.

The magnitude of  $Z_{th}$  is minimum at the LCL filter resonance frequency. Below this resonance frequency,  $Z_{th}$  has higher magnitudes but also  $V_{th}$  cannot be ignored in the fault location algorithm. Therefore, there are two separate factors affecting fault location and which one dominates is not determinable and depends on different conditions. For this reason, even though the approximate circuit is expected to introduce high error compared to the actual circuit in the lower frequency range, the full frequency range will be used for fault location purposes due to the impact of high  $Z_{th}$ . A concept to calculate the final estimated distance based on the estimates over the full frequency range will therefore be introduced later in this chapter.

### 4.2.3 SBDG equivalent circuit

The SBDG can be modelled as a voltage source ( $E_{DG}$ ) behind an impedance ( $Z_{SBDG}$ ) at the system fundamental frequency as shown in Fig. 4.7a [70]. At the non-fundamental frequencies, the voltage source Thevenin equivalent is a short circuit as shown in Fig. 4.7b. The SBDG exhibits three operating modes during the fault: subtransient, transient and steady state [70]. The SBDG impedance  $Z_{SBDG}$  increases while transitioning from mode to mode. As the proposed fault location scheme uses data from the first cycle during the fault, the subtransient impedance is used in modelling the SBDG at the non-fundamental frequencies. Note that the detailed synchronous machine harmonic model is different from using only the subtransient impedance of the machine [71]. In [72], a detailed harmonic model was developed and simplified to the simple harmonic model reported in [73]. The approximate

simple harmonic model uses the subtransient impedance to model the machine for the harmonic studies and is employed in this thesis to simplify the fault location processing. The stray capacitance has been considered negligible in [71]–[73] and accordingly not included in the thesis as well. In the simulation studies in Chapter 6, a dynamic model for the synchronous machine from the Matlab/Simulink library has been used to reflect the transient performance of the machine during the fault. When using a transformer to connect the DG to the grid, its impedance is to be added in series to the DG impedance.

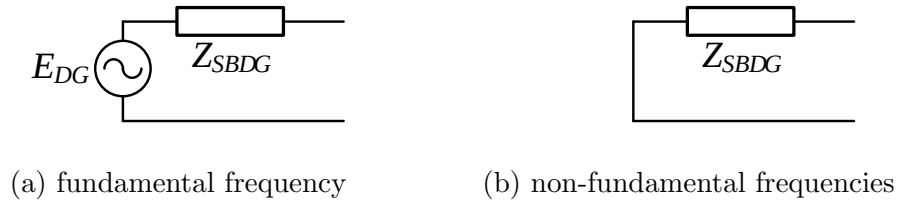


Fig. 4.7: SBDG equivalent circuit per phase

## 4.3 Fault Location and DG

### 4.3.1 SEWIBFL scheme for active distribution system

Consider a fault between two nodes  $k$  and  $k + 1$  in an active distribution system as shown in Fig. 4.8. At the non-fundamental frequencies, the DGs are represented by their approximate equivalent impedance as explained earlier. Therefore, the system equivalent at the non-fundamental frequencies will be as shown in Fig. 4.9 with the fault represented as a voltage source. When treating the DGs as passive impedances (i.e. similar to a radial distribution system with the fault acting as the only source for non-fundamental frequency components), the SEWIBFL scheme proposed in Chapter 3 can be applied to estimate the fault distance.

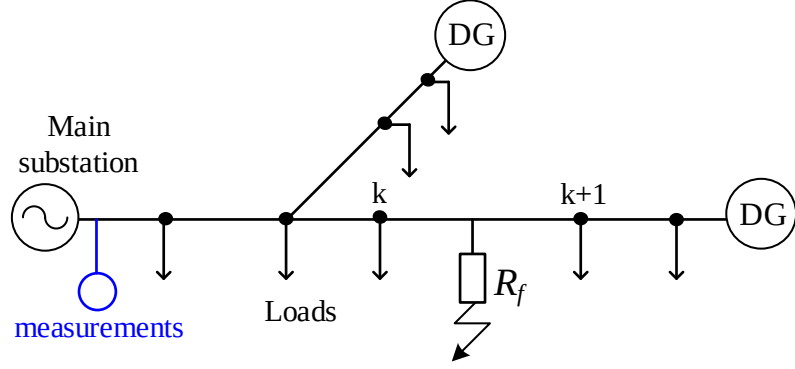


Fig. 4.8: Active system with a fault at the fundamental frequency

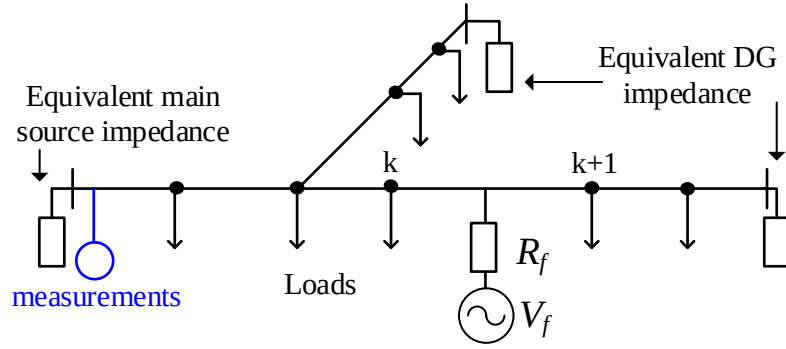


Fig. 4.9: Active system with a fault at the non-fundamental frequencies

### 4.3.2 Ignoring the presence of the DG

This section discusses two possibilities to ignore the presence of the DG during the fault location process. In the method derived in Chapter 3, the fault current in Fig. 3.1b is divided into two portions:  $I_{xS}$  that flows upstream from the fault point toward the main substation node, and  $I_{xR}$  that flows downstream to the end of the feeder. Keeping that in mind and looking at Fig. 4.9, the equivalent main source impedance is often much lower than the equivalent DG impedance. Therefore, the current  $I_{xS}$  is expected to be much higher than  $I_{xR}$ . As a result, the current  $I_{xR}$  would have a lower impact on the fault distance estimation. If the DG current is a portion of  $I_{xR}$ , it is possible to ignore the DG effect as the total current  $I_{xR}$  itself has a lower impact on the distance estimation. From this it may

be concluded that:

- DGs downstream of the fault point may be ignored in the fault location process. However, DGs upstream of the fault point should not be ignored as this would affect the estimation accuracy.

It may be not possible to generalize the previous conclusion for all systems and any number of DGs. Therefore, it is recommended to address this issue based on the system nature.

For small DG units, assuming the DG uses the same per unit filter parameters (for IBDG), the base impedance increases with decreasing the nominal DG power (4.16). Therefore, for the IBDG, the inductance value will increase with decreasing the DG unit power rating which leads to higher values for  $Z_{th}$  at the high frequency range. Also, for SBDG, the DG impedance increases too. Higher  $Z_{th}$  means lower DG impact on the fault location. Therefore, for this case also the DG effect can be ignored.

$$Z_{base} = V_n^2 / S_n \quad (4.16)$$

where  $V_n$  and  $S_n$  are the nominal line to line voltage and the nominal power of the DG unit respectively.

### 4.3.3 Average distance calculation

As previously mentioned, the fault distance is estimated over a wide frequency range. To calculate the final estimated distance (while considering that the accuracy may be bad for some frequency sub-ranges due to the approximation in the DG circuit representation as will be illustrated later in this chapter in Section 4.4 and by the experimental equivalent circuit test in Chapter 7), the full frequency range has been divided into five equal frequency zones. For each zone, the average distance, standard deviation and number of frequency bins that have a valid estimation are calculated. The calculated number of frequency bins and the standard deviation are used to calculate a weighting factor for each zone ( $FZ$ ). The final fault

distance is calculated as the weighted average for the zones. This is illustrated by (4.17) to (4.21).

$$Avg_k = average(dis_k) \quad (4.17)$$

$$f1_k = 1/std(dis_k) \quad (4.18)$$

$$f2_k = number\ of\ points(dis_k) \quad (4.19)$$

$$FZ_k = a1 \times f1_k / \sum_{k=1}^5 f1_k + a2 \times f2_k / \sum_{k=1}^5 f2_k \quad (4.20)$$

$$estimated\ distance = \sum_{k=1}^5 FZ_k \times Avg_k \quad (4.21)$$

where  $dis_k$ ,  $Avg_k$ ,  $f1_k$ ,  $f2_k$  are the vector of estimates, average value, inverse of standard deviation and number of points for zone number  $k$  and  $k$  has values from 1 to 5,  $a1$  and  $a2$  are the weights with  $a1 + a2 = 1$ . In this study, the standard deviation factor that reflects the convergence/divergence of different estimates in the zone has a higher weight. The values of  $a1$  and  $a2$  are set to 0.8 and 0.2 respectively.

## 4.4 Illustrative Example

The simple distribution system in Fig. 3.9 used in Chapter 3 has been modified by connecting a DG at the end node and is shown in Fig. 4.10. A fault between phase  $a$  and phase  $b$  has been simulated with a resistance of  $10\ \Omega$  at the middle of the last section. Regarding the IBDG, a DC source has been connected at the DC side of the DG and a controller to track a reference power has been used. Detailed parameters for the IBDG are given in Table 4.1. As advised in [65] and other work, a damping resistor is connected in series with the filter capacitor to attenuate the filter gain at the resonance frequency. The connection of filter capacitor is delta and a small resistance has been connected in series with the filter inductors to represent the inductor resistance. A step up transformer has been used to connect the IBDG to the 24.9 kV system. The transformer leakage inductance has been

considered to be the value of the grid side inductance of the LCL filter. For the SBDG, a standard three-phase, 250 kVA, 400 V synchronous generator has been used. Also, a step up transformer has been used as an interface between the DG and the system.

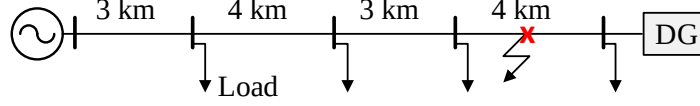


Fig. 4.10: Simple distribution system with one DG

Table 4.1: Parameters of the IBDG

|                          |             |                      |               |
|--------------------------|-------------|----------------------|---------------|
| rated power              | 250 kW      | DC side voltage      | 480 V         |
| line to line AC voltage  | 250 V       | switching frequency  | 3 kHz         |
| inverter side inductance | 0.16 mH     | grid side inductance | 0.04 mH       |
| filter capacitance       | 212 $\mu$ F | damping resistance   | 0.23 $\Omega$ |

#### 4.4.1 DG equivalent circuit

In the simulation, an IBDG has been connected at the end node. The voltage and current are measured at the DG in order to calculate the DG impedance as seen from the point of common coupling to the system and to compare this measured impedance with the proposed approximate impedance. A data window that combines pre-fault and during fault periods is used for the impedance calculation.

For a fault between phase  $a$  and phase  $b$ , the IBDG impedance between phase  $a$  and phase  $b$  is calculated from the measurements and the approximate equivalent impedance are shown in Fig. 4.11 and the change in the  $Xf$  factor using the filter parameters is shown in Fig. 4.12.

As is clear, there is a mismatch between the measured and the approximate impedances in the low frequency range as the proposed

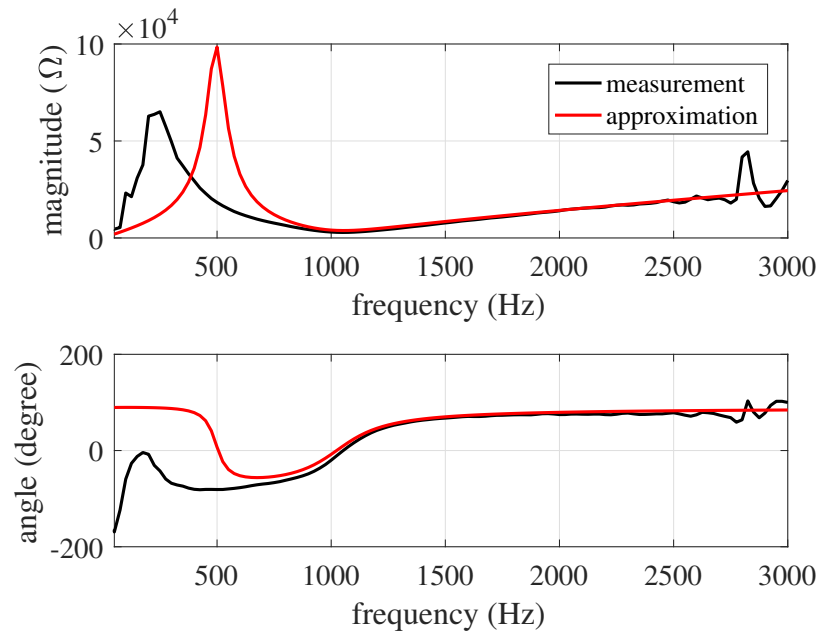


Fig. 4.11: IBDG measured and approximate impedances

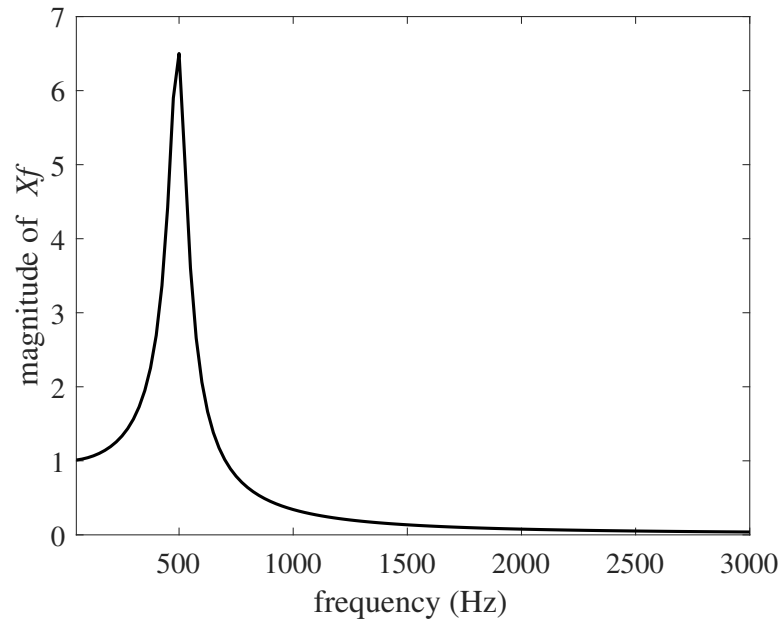


Fig. 4.12: Change of the magnitude of the  $Xf$  for the simulated system

approximation assumes a totally passive circuit (ignoring  $V_{th}$ ). As explained earlier, the matching between calculated and approximate impedances increases in the high frequency range. The deviation between the two impedances close to 3 kHz is attributed to the effect of the converter switching frequency which is 3 kHz for this example. It is clear from Fig. 4.11 that the frequency range between 1 kHz and 2.5 kHz shows a high matching between the impedances and can be selected for fault distance estimation. Alternatively, the full range is used with weighting different frequency sub-ranges as previously stated which is employed in this example.

When replacing the IBDG by a SBDG, the measured and the approximate impedances are shown in Fig. 4.13. As is clear, there is a high agreement between the two impedances for almost all of the frequency range. This is because, the SBDG naturally does not generate high order harmonics compared to the IBDG and the passive equivalent circuit becomes valid.

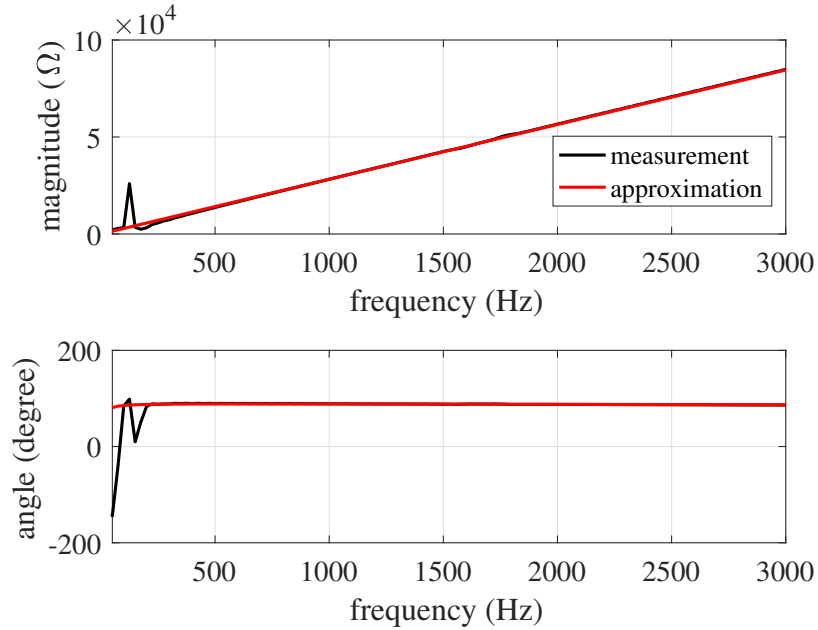


Fig. 4.13: SBDG measured and approximate impedances

#### 4.4.2 Distance estimation

The measured voltage and current at the main substation together with the proposed approximate equivalent impedance for the DG are used to estimate the fault distance. For the two simulated cases (IBDG and SBDG cases), the estimated distance at different frequencies is shown in Fig. 4.14. As is clear, the estimation for the SBDG at different frequencies looks better than the IBDG case due to the errors associated with the IBDG approximate impedance compared to the SBDG case.

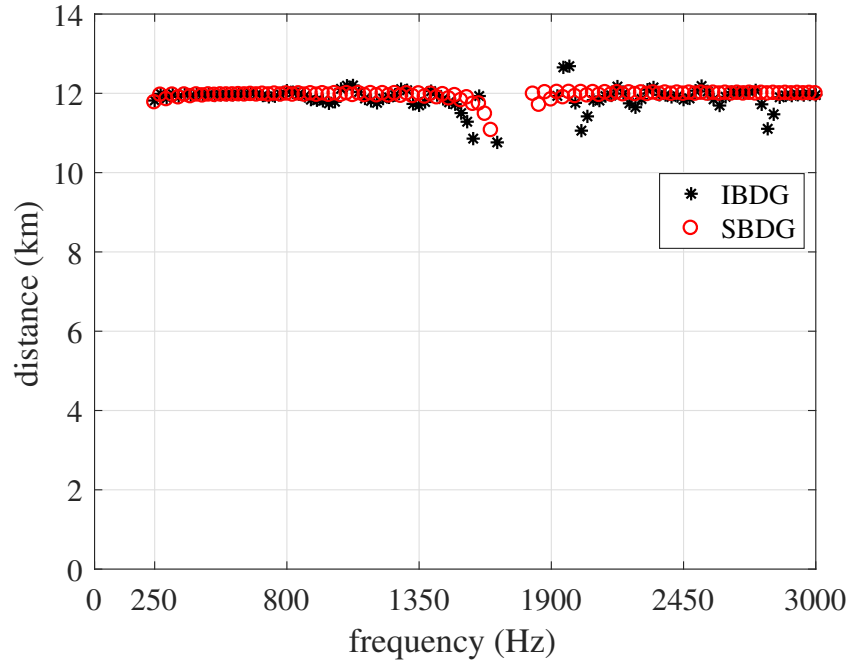


Fig. 4.14: Estimated fault distance for IBDG and SBDG

The accuracy of the distance estimation for the IBDG case in the low frequency range ( $< 800$  Hz) looks good. This is because the portion of the fault current that flows upstream to the main substation is much higher than that flows toward the DG node in this low frequency range. The ratio between the two currents (substation current / DG current) is shown in Fig. 4.15 for different phases. The high ratio at the low frequency range is clear for the faulty phases ( $a$  and  $b$ ) and this highly reduces the effect of the IBDG on the accuracy of the distance estimation. The peak value for

the healthy phase (c) around 1.7 kHz in Fig. 4.15 is expected to be due to a resonance effect for this phase. For a three-phase fault at the same fault location, no peak was found for any of the three phases.

As previously mentioned, the frequency range is divided into five zones of 550 Hz width and the fault distance is estimated as the weighted average for the five zones. The error in distance estimation as the absolute difference between the actual distance and the estimated distance is 81 m and 23 m for the IBDG case and the SBDG case respectively (actual distance is 12 km).

Also, the fault distance is estimated using the simplified 3<sup>rd</sup> order equation and the result for the IBDG case is shown in Fig. 4.16. The two equations show the same distance estimates supporting the result obtained with the radial distribution system.

### 4.4.3 Effect of ignoring the DG presence

To check the effect of ignoring the DG presence on the fault distance estimation, the system in Fig. 4.10 has been modified to have another DG connected at the end of the second line section as shown in Fig. 4.17. The power rating for each DG is 250 kVA. For a fault in the middle of the fourth line section, DG1 becomes downstream of the fault point and DG2 is upstream of the fault point. The fault location process has been repeated at different scenarios that are illustrated in Table 4.2. The first four scenarios deal with the IBDG while considering and ignoring the DG presence in the fault location process. The other cases do the same but for the SBDG.

The estimated distance for different scenarios is shown in Fig. 4.18 and Fig. 4.19 for the IBDG and the SBDG scenarios respectively. As explained earlier, ignoring the DG located downstream of the fault point (DG1) does not affect the distance estimation. This is clear when comparing the results for (sc2) to (sc1) in Fig. 4.18 and comparing the results for (sc6) to (sc5) in Fig. 4.19. On the other hand, the accuracy of the estimation decreased for the remaining scenarios either for the IBDG (sc3 and sc4) or the SBDG (sc7 and sc8) when the upstream DG (DG2) was ignored in the fault location

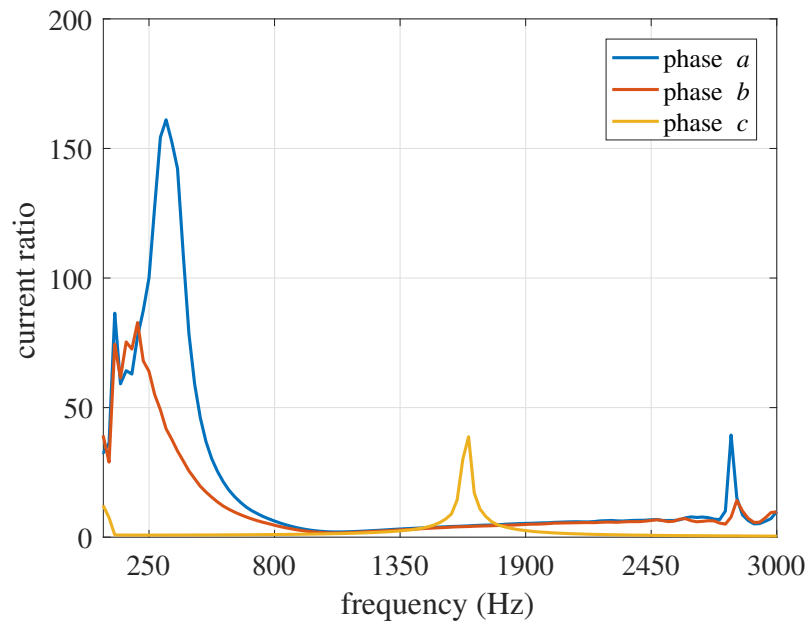


Fig. 4.15: Ratio between the substation current and the IBDG current

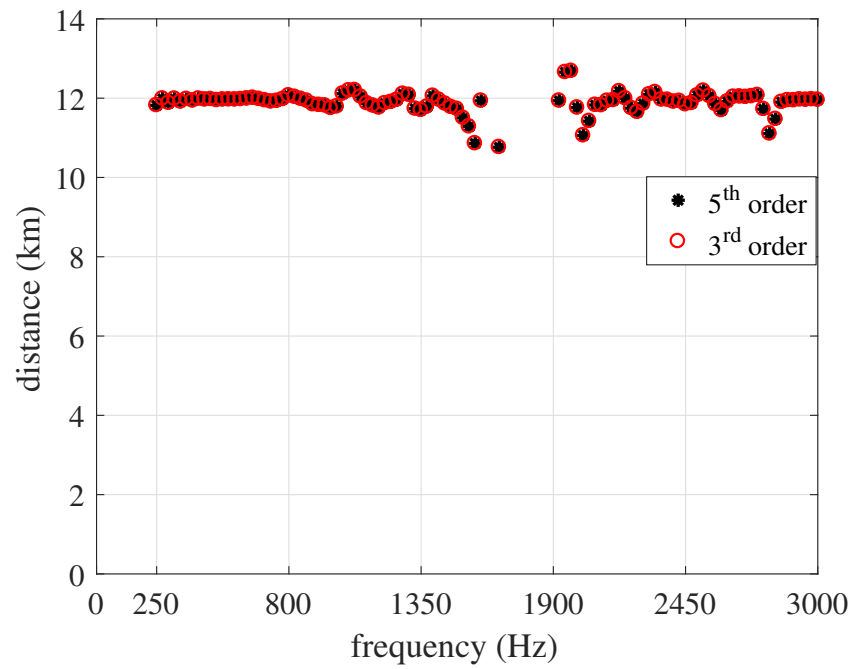


Fig. 4.16: Using fifth and third order equations (IBDG case)

process. As the upstream current is higher than the downstream current, the effect of the downstream current on the distance estimation accuracy is lower than that of the upstream current. Therefore, ignoring the downstream DG impedance that affects the downstream current would have a low or negligible effect on the estimation accuracy when compared to the upstream DG that affects the upstream current. Also, in the low frequency range, ignoring the DGs does not affect the estimation greatly due to the high ratio between the substation current and the DG current as explained earlier in Fig. 4.15. As previously explained, the system exhibits some resonance effect in the zone surrounding 1.7 kHz where valid solutions could not be estimated. The thesis will not ignore the presence of the DGs, neither the upstream nor the downstream ones with respect to a certain fault point. The illustrative example just provides an idea for the possibility of ignoring the DGs and their effect on the fault location accuracy. However, this example considers the presence of two DGs only to discuss the concept. Studying the effect of ignoring the downstream DGs on the fault location accuracy for more complicated systems is recommended before a general conclusion can be derived.

In general, the accuracy of distance estimation is better for the SBDG than that for the IBDG because of the approximations associated with the DG equivalent circuit and the harmonics generated by the IBDG and ignored by the fault location algorithm as previously explained in the DG equivalent circuit section.

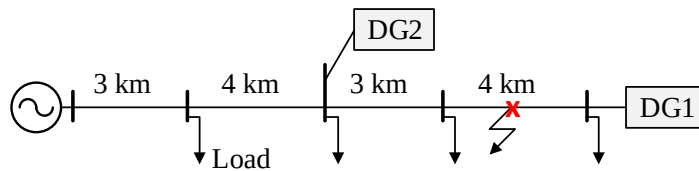


Fig. 4.17: Simple distribution system with two DGs

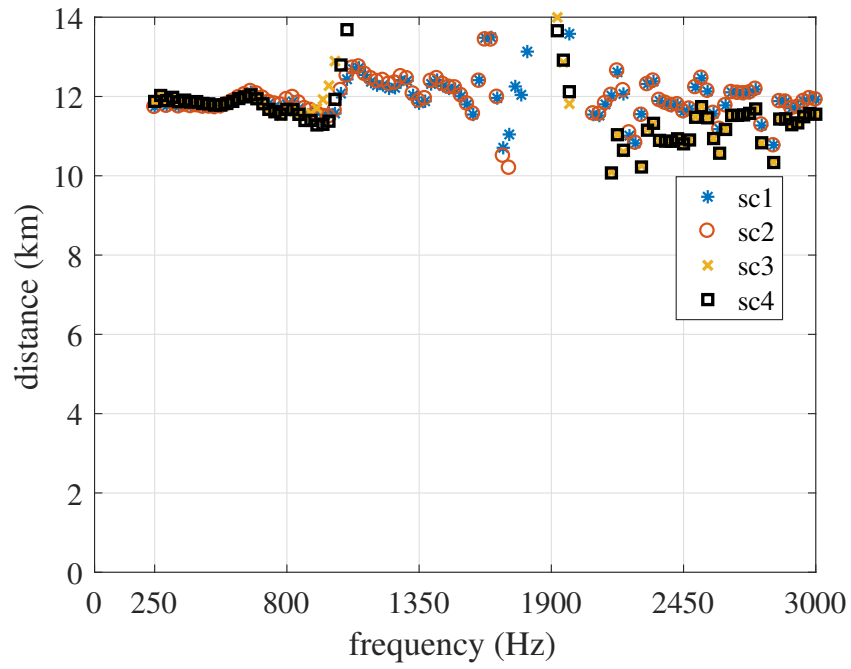


Fig. 4.18: Effect of ignoring the IBDG on the distance estimation

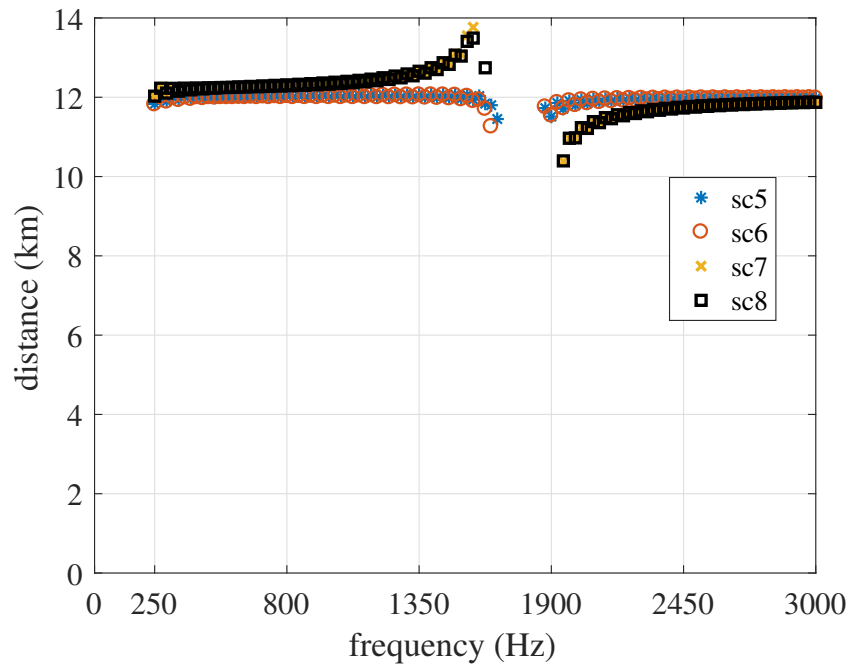


Fig. 4.19: Effect of ignoring the SBDG on the distance estimation

Table 4.2: Test scenarios for ignoring the DG presence

| #   | Description                                                          |
|-----|----------------------------------------------------------------------|
| sc1 | Both DGs are IBDG and are considered in the fault location process   |
| sc2 | Both DGs are IBDG and DG1 is ignored in the fault location process   |
| sc3 | Both DGs are IBDG and DG2 is ignored in the fault location process   |
| sc4 | Both DGs are IBDG and both are ignored in the fault location process |
| sc5 | Both DGs are SBDG and are considered in the fault location process   |
| sc6 | Both DGs are SBDG and DG1 is ignored in the fault location process   |
| sc7 | Both DGs are SBDG and DG2 is ignored in the fault location process   |
| sc8 | Both DGs are SBDG and both are ignored in the fault location process |

## 4.5 Conclusions

A fault location scheme in distribution systems with distributed generation using single ended measurements at the main substation was presented in this chapter. A high frequency model was developed for the DGs in the system. Both inverter based and synchronous based distributed generation were studied. This eliminates the need for using a communication network to transfer the measurements between the DG nodes and the main substation. The single end method proposed in Chapter 3 and the high frequency model proposed in this chapter were combined to develop the fault location scheme. The proposed model for the IBDG depends on the filter parameters used as an interface between the DG and the grid. The illustrative example used in Chapter 3 was modified by connecting DGs of different types to evaluate the proposed DG model and the fault location scheme. The evaluation shows a matching between the proposed DG model and the measured DG impedance in the high frequency range above the filter resonance frequency for the IBDG. For synchronous based distributed generation, the proposed model was valid at almost all non-fundamental frequencies. The evaluation of the single end fault location scheme results in an accurate estimate for the fault distance.

# Chapter 5

## Active Distribution Systems: Case II

### 5.1 Introduction

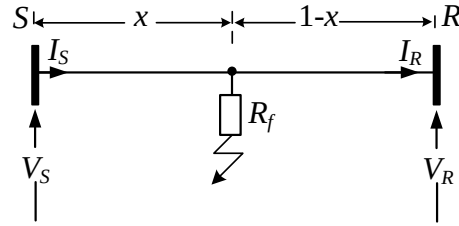
In this chapter, the measurements available at different generating nodes in the system are used to develop a double end fault location method. Two methodologies are proposed based on the nature of measurements. The first method assumes all measurements are synchronized while the other method works with combined synchronized and non-synchronized measurements.

### 5.2 Synchronized Measurements

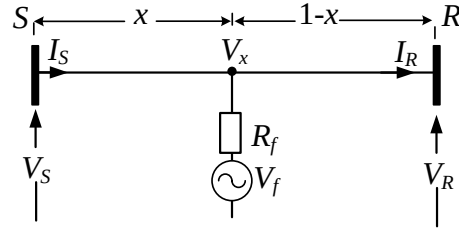
In this section, the method is derived for a system where synchronized measurements are available. Measurements from different locations can be performed synchronously if GNSS (global navigation satellite system) time stamping is available. As the synchronized measurements are available, a double end wideband impedance based fault location (DEWIBFL) scheme can be derived. Firstly, the proposed method is derived for a single line section system then generalized for a real distribution system.

### 5.2.1 A Single Line Section System

Consider a line of unity length between two nodes  $S$  and  $R$  with a fault at a distance  $x$  from node  $S$ . The equivalent circuit at the system fundamental frequency and the non-fundamental frequencies is shown in Fig. 5.1. In Fig. 5.1, the voltage at the fault point ( $V_x$ ) can be calculated based on voltage and current at both ends by (5.1) and (5.2), where  $j$  refers to the propagation mode as explained in Chapter 3.



(a) at fundamental frequency



(b) at non-fundamental frequencies

Fig. 5.1: System equivalent with a fault

$$V_{x_j} = \cosh(\gamma_j x) V_{S_j} - z_{c_j} \sinh(\gamma_j x) I_{S_j} \quad (5.1)$$

$$V_{x_j} = \cosh(\gamma_j (1 - x)) V_{R_j} + z_{c_j} \sinh(\gamma_j (1 - x)) I_{R_j} \quad (5.2)$$

Using the first three terms of the Taylor series for both  $\cosh$  and  $\sinh$  in (5.1), the fifth order polynomial in (5.3) is obtained (this analysis has been illustrated in Chapter 3).

$$V_{x_j} = A_{S_j} + B_{S_j} x + C_{S_j} x^2 + D_{S_j} x^3 + E_{S_j} x^4 + F_{S_j} x^5 \quad (5.3)$$

In a similar manner, Taylor series is used with (5.2) but instead of  $x$ ,  $(1 - x)$  is used as follows:

When looking at (5.2), it is similar to (5.1) but with  $(1 - x)$  instead of  $x$  and also the second term is positive. Therefore, an equation similar to (5.3) can be obtained considering these two modifications. This is illustrated by (5.4).

$$V_x = A_r + B_r(1 - x) + C_r(1 - x)^2 + D_r(1 - x)^3 + E_r(1 - x)^4 + F_r(1 - x)^5 \quad (5.4)$$

where

$$\begin{aligned} A_r &= V_R & B_r &= \gamma z_c I_R \\ C_r &= \gamma^2 V_R / 2 & D_r &= \gamma^3 z_c I_R / 6 \\ E_r &= \gamma^4 V_R / 24 & F_r &= \gamma^5 z_c I_R / 120 \end{aligned} \quad (5.5)$$

The expansion of  $(1 - x)^n$  is given as:

$$(1 - x)^n = 1 - nx + \frac{n(n-1)x^2}{2!} - \frac{n(n-1)(n-2)x^3}{3!} + \dots \quad (5.6)$$

Therefore, when setting  $n$  to 1, 2, 3, 4 and 5, the terms of (5.4) will be as shown below

$$\begin{aligned} B_r(1 - x) &= B_r(1 - x) \\ C_r(1 - x)^2 &= C_r(1 - 2x + x^2) \\ D_r(1 - x)^3 &= D_r(1 - 3x + 3x^2 - x^3) \\ E_r(1 - x)^4 &= E_r(1 - 4x + 6x^2 - 4x^3 + x^4) \\ F_r(1 - x)^5 &= F_r(1 - 5x + 10x^2 - 10x^3 + 5x^4 - x^5) \end{aligned} \quad (5.7)$$

From which the coefficients can be combined to produce (5.8) for different propagation modes ( $j$ ).

$$V_{x_j} = A_{R_j} + B_{R_j}x + C_{R_j}x^2 + D_{R_j}x^3 + E_{R_j}x^4 + F_{R_j}x^5 \quad (5.8)$$

where values for different constants are given in (5.9).

$$\begin{aligned}
 A_{S_j} &= V_{S_j} & B_{S_j} &= -\gamma_j z_{c_j} I_{S_j} \\
 C_{S_j} &= \gamma_j^2 V_{S_j} / 2 & D_{S_j} &= -\gamma_j^3 z_{c_j} I_{S_j} / 6 \\
 E_{S_j} &= \gamma_j^4 V_{S_j} / 24 & F_{S_j} &= -\gamma_j^5 z_{c_j} I_{S_j} / 120 \\
 A_{R_j} &= V_{R_j} & B_{R_j} &= \gamma_j z_{c_j} I_{R_j} \\
 C_{R_j} &= \gamma_j^2 V_{R_j} / 2 & D_{R_j} &= \gamma_j^3 z_{c_j} I_{R_j} / 6 \\
 E_{R_j} &= \gamma_j^4 V_{R_j} / 24 & F_{R_j} &= \gamma_j^5 z_{c_j} I_{R_j} / 120 \\
 A_{R_j} &= A_{r_j} + B_{r_j} + C_{r_j} + D_{r_j} + E_{r_j} + F_{r_j} \\
 B_{R_j} &= -(B_{r_j} + 2C_{r_j} + 3D_{r_j} + 4E_{r_j} + 5F_{r_j}) \\
 C_{R_j} &= C_{r_j} + 3D_{r_j} + 6E_{r_j} + 10F_{r_j} \\
 D_{R_j} &= -(D_{r_j} + 4E_{r_j} + 10F_{r_j}) \\
 E_{R_j} &= E_{r_j} + 5F_{r_j} & F_{R_j} &= -F_{r_j}
 \end{aligned} \tag{5.9}$$

The voltage  $V_x$  can be expressed in the phase domain by (5.10) and (5.11) using (3.1).

$$\begin{aligned}
 V_{x_{abc}} &= A_{S_{abc}} + B_{S_{abc}} x + C_{S_{abc}} x^2 + D_{S_{abc}} x^3 + E_{S_{abc}} x^4 + F_{S_{abc}} x^5 \\
 &= [V_{xa} \ V_{xb} \ V_{xc}]^t \tag{5.10}
 \end{aligned}$$

$$V_{x_{abc}} = A_{R_{abc}} + B_{R_{abc}} x + C_{R_{abc}} x^2 + D_{R_{abc}} x^3 + E_{R_{abc}} x^4 + F_{R_{abc}} x^5 \tag{5.11}$$

where  $t$  refers to non-conjugate transpose,  $K_{abc} = T_v K_{012}$ ,  $K$  refers to  $A_S$ ,  $B_S$ ,  $C_S$ ,  $D_S$ ,  $E_S$ ,  $F_S$ ,  $A_R$ ,  $B_R$ ,  $C_R$ ,  $D_R$ ,  $E_R$  and  $F_R$ ,  $K_{abc} = [K_a \ K_b \ K_c]^t$  and  $K_{012} = [K_0 \ K_1 \ K_2]^t$ .

By equating (5.10) and (5.11), the fault distance can be calculated using (5.12).

$$\begin{aligned}
 (A_{S_{abc}} - A_{R_{abc}}) &+ (B_{S_{abc}} - B_{R_{abc}})x + (C_{S_{abc}} - C_{R_{abc}})x^2 + \\
 (D_{S_{abc}} - D_{R_{abc}})x^3 &+ (E_{S_{abc}} - E_{R_{abc}})x^4 + (F_{S_{abc}} - F_{R_{abc}})x^5 = 0 \tag{5.12}
 \end{aligned}$$

The formula in (5.12) represents three equations for the three phases. It is only solved for the faulted phase(s). For a phase fault e.g. fault between

phase  $a$  and phase  $b$ , the corresponding line to line voltage from (5.10) and (5.11) is used to generate a single equation instead of solving two equations separately for the two phases. Required voltages and currents are measured with a sampling frequency of 20 kHz for a period of 40 ms. They are then transformed to the frequency domain using the Fast Fourier Transform as explained in Chapter 3.

### 5.2.2 A Real Distribution System

For a distribution system with multiple lines and loads, the voltage and the current at the fault section ends (nodes  $S$  and  $R$  in the previous derivation) can be calculated from the available measurements along the system by a downstream and upstream sweep of measurements. For any propagation mode  $j$ , to sweep downstream from the start node of the feeder, (5.13) and (5.14) can be used [6], refer to Fig. 5.2a. On the other hand, (5.15) and (5.16) can be used for the upstream sweep [6], refer to Fig. 5.2b.

$$\begin{bmatrix} V_{k+1_j} \\ I'_{k+1_j} \end{bmatrix} = \begin{bmatrix} \cosh(\gamma_j l) & -z_{c_j} \sinh(\gamma_j l) \\ -\sinh(\gamma_j l)/z_{c_j} & \cosh(\gamma_j l) \end{bmatrix} \begin{bmatrix} V_{k_j} \\ I_{k_j} \end{bmatrix} \quad (5.13)$$

$$I_{k+1_j} = I'_{k+1_j} - Y_{L(k+1)} V_{k+1_j} + I_{dg(k+1)_j} \quad (5.14)$$

$$\begin{bmatrix} V_{k_j} \\ I_{k_j} \end{bmatrix} = \begin{bmatrix} \cosh(\gamma_j l) & z_{c_j} \sinh(\gamma_j l) \\ \sinh(\gamma_j l)/z_{c_j} & \cosh(\gamma_j l) \end{bmatrix} \begin{bmatrix} V_{k+1_j} \\ I'_{k+1_j} \end{bmatrix} \quad (5.15)$$

$$I'_{k_j} = I_{k_j} + Y_{L(k)} V_{k_j} - I_{dg(k)_j} \quad (5.16)$$

where  $l$  is the length of the line section between nodes  $k$  and  $k+1$  and  $Y_{L(k)}$  and  $Y_{L(k+1)}$  are the load or equivalent admittance at node  $k$  and  $k+1$  respectively (general  $3 \times 3$  matrix that might be unbalanced). If  $Y_L$  is not a single load e.g. a lateral with some lines and loads, the equivalent can be obtained as previously discussed in Chapter 3 (section 3.3.2). If no DG is connected at node  $k$  or  $k+1$ , then the DG current in the corresponding equation is set to zero, otherwise a measurement of the DG current is required.

Unlike the proposed SEWIBFL scheme, the DEWIBFL scheme does not require the creation of the fault voltage source as it is not included in the distance estimation analysis. Also, it does not require multiple iterations for the same fault section to estimate the distance.

Similar to the case of the SEWIBFL scheme, as the distribution system has many line sections, the fault is located using the DEWIBFL scheme iteratively by assuming the fault in the first section next to the substation and applying the proposed fault location method. If the estimated fault distance exceeds the total section length, the fault location method is then applied on the next section or another section based on the estimated distance from the previous iteration until the correct distance is calculated—a distance inside the section considered. This iterative process is illustrated by the flowchart in Fig. 5.3.

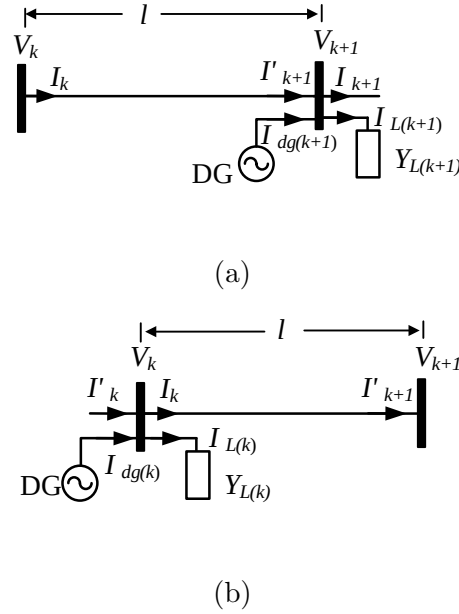


Fig. 5.2: Sweep of measurements, (a) downstream, (b) upstream

### 5.3 Combined Measurements

The proposed scheme uses the available synchronized and non-synchronized measurements in the system to locate the fault point. Therefore, DG

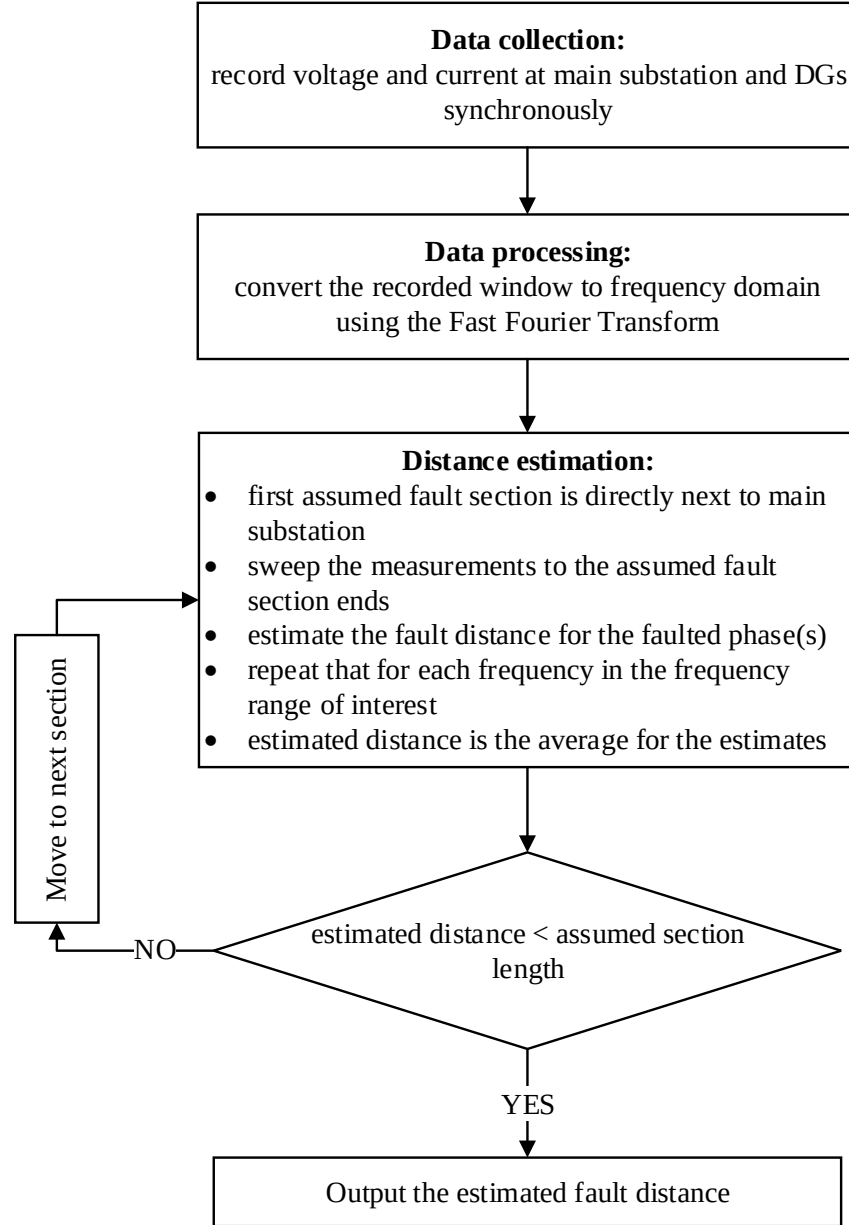


Fig. 5.3: Procedure of the proposed DEWIBFL scheme (synchronized measurements)

modelling is not necessary and also it is not necessary to synchronously measure at all generation nodes. The DEWIBFL scheme developed in the previous section will be applied between the nodes with synchronized measurements. The following subsection illustrates how the DGs with non-synchronized measurements will be treated in the fault location process.

### 5.3.1 DG representation

The method does not require synchronized measurements at all power sources (main substation and DGs) in the system. Also, voltage and current data transfer is not necessary from all DGs to apply the method. Instead, the voltage and current measurements available at each DG location are processed locally at the DG unit itself (for DGs with non-synchronized measurements). The processing aims to find the DG equivalent impedance as seen from the point of its interconnection to the grid. The impedance is calculated locally at the DG unit over the high frequency range of interest and is sent to the main substation using non-synchronized communication channels.

For this purpose, a data window that combines both pre-fault and during fault signals is used and the Fast Fourier Transform (FFT) is employed to calculate the DG impedance over the frequency range of interest (5.17). A series of values for  $Z_{dg}$  at different frequencies is locally generated. Then, it can be transferred to the main substation to be used by the proposed fault location algorithm. Assuming that the voltage and current measurements at the DG unit are not synchronized with those at the main substation, this will not affect on the calculated impedance as the error in synchronization in voltage cancels that in current and the ratio is maintained the same in (5.17). The calculated impedance can be transferred to the main substation using an asynchronous channel.

$$Z_{dg} = FFT(V_{dg})/FFT(I_{dg}) \quad (5.17)$$

## 5.4 Simplified Distance Formula

The fifth order polynomial in (5.12) can be simplified similar to the proposed single end method by ignoring the terms related to  $x^4$  and  $x^5$  resulting in a  $3^{rd}$  order equation to estimate the fault distance which is shown in (5.18).

$$(A_{S_{abc}} - A_{R_{abc}}) + (B_{S_{abc}} - B_{R_{abc}})x + (C_{S_{abc}} - C_{R_{abc}})x^2 + (D_{S_{abc}} - D_{R_{abc}})x^3 = 0 \quad (5.18)$$

## 5.5 A Short Distribution System

The proposed double end method can be adapted for a short distribution system in a similar way to that presented for the single end method. The line in Fig. 5.4 is represented by its total series lumped impedance  $Z$ . The voltage at the fault point  $V_x$  can be calculated using the measurements from both  $S$  and  $R$  nodes using (5.19) and (5.20). From these two equation, the fault distance can be calculated using (5.21).

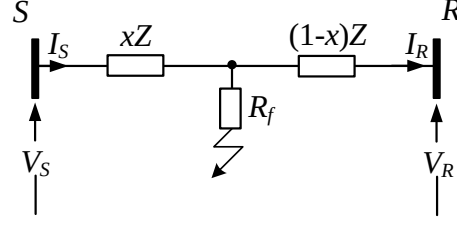
$$V_x = V_S - xZI_S \quad (5.19)$$

$$V_x = V_R + (1 - x)ZI_R \quad (5.20)$$

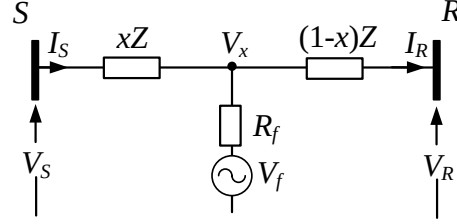
$$xZ(I_S - I_R) = V_S - V_R - ZI_R \quad (5.21)$$

## 5.6 Illustrative Example

For the same system that is shown in Fig. 4.17, a fault between phase  $a$  and phase  $b$  with a resistance of  $10 \Omega$  was simulated at the middle of the last section. The fault has been simulated twice, using both DGs in the system (DG1 and DG2) as IBDGs in one case and as SBDGs in the other case. For each fault case, synchronized measurements from the main substation and both DGs were used to check the performance of the synchronized



(a) at fundamental frequency



(b) at non-fundamental frequencies

Fig. 5.4: Short distribution system with a fault (double end)

measurements concept. To evaluate the combined measurements concept, non-synchronized measurements were assumed at DG2. The measurements at DG2 were used to calculate the DG equivalent impedance. To simulate non-synchronized measurements, the data window used at DG2 has been shifted by five samples with respect to that at the main substation and DG1.

For the four test scenarios, the estimated distance over the frequency range of interest is shown in Fig. 5.5 to Fig. 5.8 using both  $5^{th}$  and  $3^{rd}$  order formulas. Firstly, the estimated distance is almost identical whatever the formula used to calculate the distance. Also, the performance of the synchronized measurements and combined measurements methods is very close. The absolute error values in distance estimation are 1 m and 3 m for the SBDGs case and IBDGs case respectively using either the synchronized or the combined measurements method. The large error around 1.7 kHz may be attributed to the effect of resonance in the healthy phase (phase  $c$ ) as previously discussed in Chapter 4.

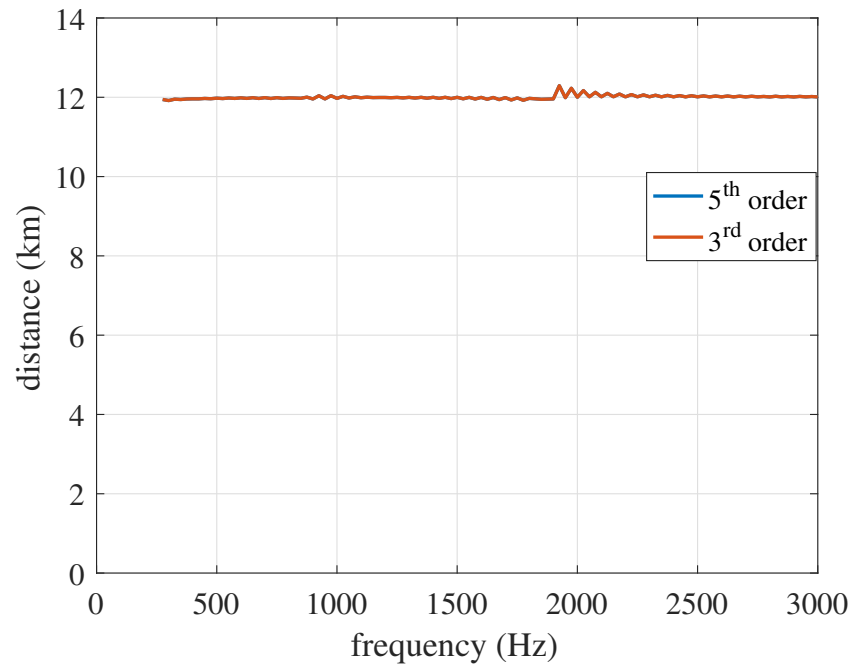


Fig. 5.5: Estimated distance using synchronized measurements with IBDGs

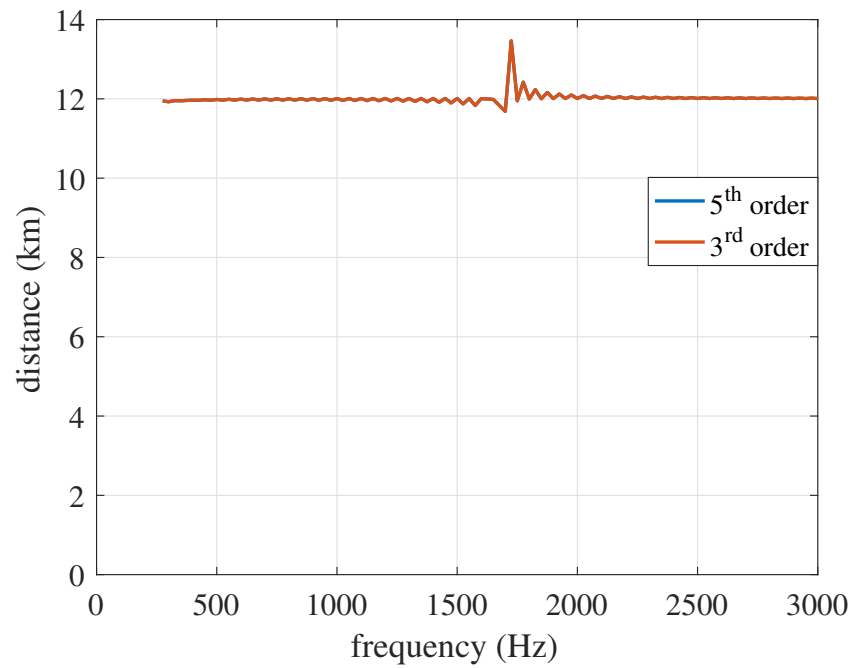


Fig. 5.6: Estimated distance using synchronized measurements with SBDGs

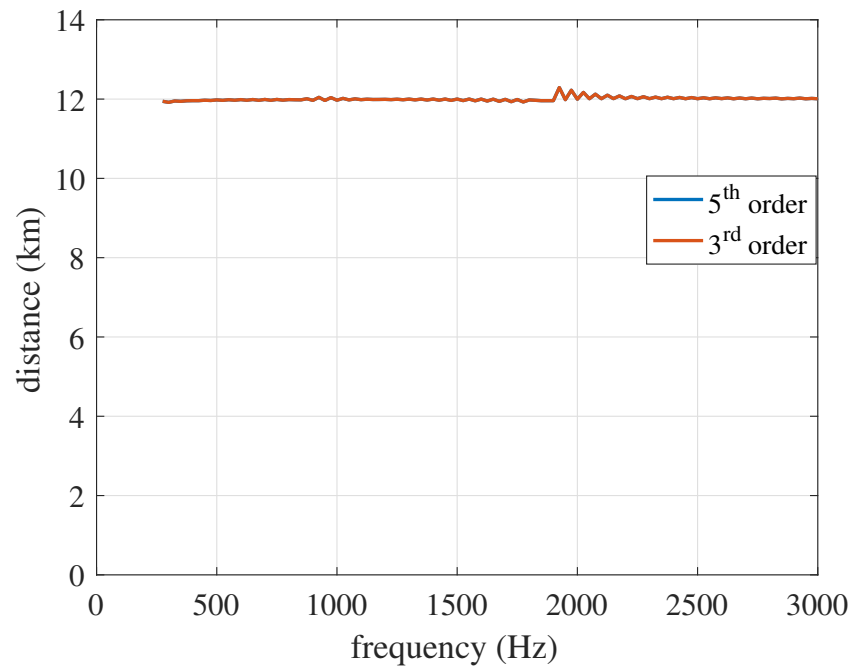


Fig. 5.7: Estimated distance using combined measurements with IBDGs

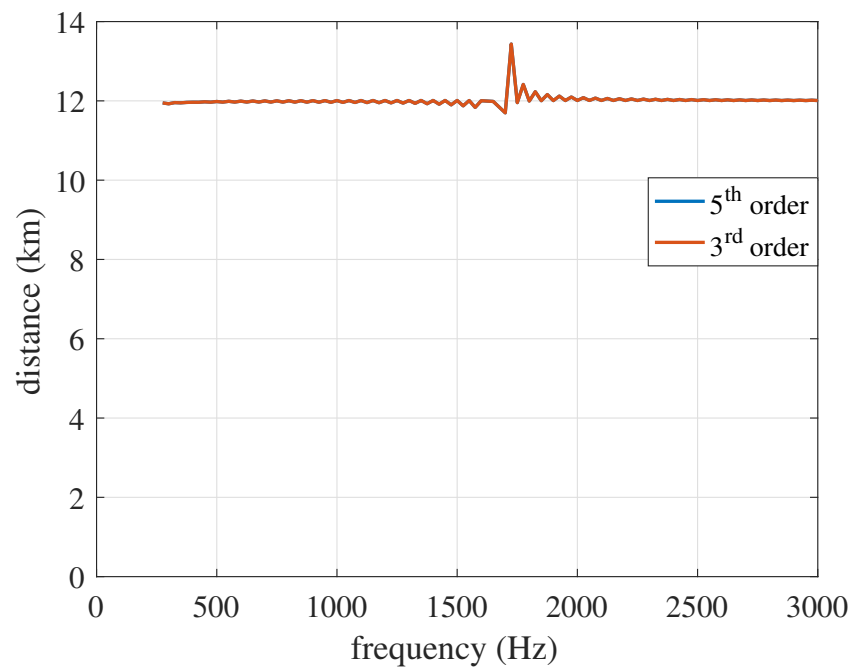


Fig. 5.8: Estimated distance using combined measurements with SBDGs

## 5.7 Conclusions

A double end wideband fault location scheme has been proposed for distribution systems with distributed generation. Similar to the proposed single end method, the double end method considered the line's capacitance, untransposed/asymmetrical line and used the distributed parameter model for the lines. Unlike the case of limited measurements assumed in Chapter 4, this chapter deals with distribution systems equipped with a communication network such that the measurements can be shared between the main substation and DGs. The proposed method can be applied using either synchronized measurements from all generation nodes or a combination of synchronized and non-synchronized measurements. For the latter case, the voltage and current measured at the DGs (non-synchronized with the main substation) were locally processed at the DGs themselves to estimate the DG impedance in the high frequency range of interest. Then, this impedance can be sent to the main substation to be used in fault distance estimation. The benefit behind that is the error in the voltage synchronization cancels the error in the current synchronization and the measured impedance is not affected by this error in synchronization. The developed double end method using either ways of measurement was evaluated showing a very high accuracy level. Also, both ways of measurement provided very close performance.

# Chapter 6

## Simulation Studies

### 6.1 Introduction

In this chapter, the performance of the fault location schemes proposed in the previous chapters is evaluated on a representative distribution system. The 3<sup>rd</sup> order formula for distance estimation is used in this study (refer to Section 3.2.5 and Section 5.4). A simulation of the IEEE 34-bus feeder is used for this study [61]. It is a real medium voltage distribution feeder located at Arizona, USA. The feeder exhibits asymmetrical non-homogeneous lines, unbalanced loads and single and three-phase laterals. In this study, line asymmetry has been considered in the simulation by using the general distributed parameters line model included in the Matlab/Simulink library [62]. The loads are modelled as constant impedance and the line regulators were removed. A single line diagram for the system is shown in Fig. 6.1. Appendix A contains the data used to simulate the IEEE system. In the subsequent sections, the proposed methods are evaluated for different fault scenarios. The error in distance estimation is calculated by (6.1). Note that in this system, the longest path (feeder path from node 800 to node 848) is 58 km and the aggregated lines length (summation of all lines' lengths) is about 93 km.

$$error = |actual\ distance - estimated\ distance| \quad (6.1)$$

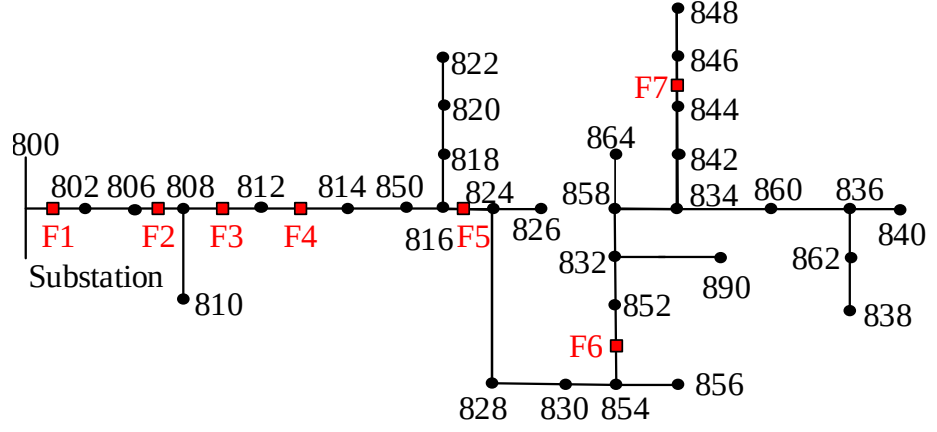


Fig. 6.1: IEEE 34-bus feeder [61]

## 6.2 SEWIBFL Scheme: Chapter 3

The proposed SEWIBFL scheme derived for a radial distribution system is evaluated considering the effect of fault point, fault type, fault resistance, fault inception angle, load uncertainty and noise in measurements. Table 6.1 illustrates the test conditions for the SEWIBFL scheme. For different scenarios, the fault is simulated at different points with different types (phase  $a$  to ground ( $ag$ ), phase  $a$  to phase  $b$  ( $ab$ ) and three-phase ( $abc$ ) faults).

Table 6.1: Evaluation scenarios for radial system

| scenario | fault resistance  | inception angle | loading   | noise level |
|----------|-------------------|-----------------|-----------|-------------|
| 1        | 0.01:100 $\Omega$ | 90°             | full load | n/a         |
| 2        | 10 $\Omega$       | 0°:180°         | full load | n/a         |
| 3        | 10 $\Omega$       | 90°             | 4 cases   | n/a         |
| 4        | 10 $\Omega$       | 90°             | full load | 0.1%:1%     |

### 6.2.1 Scenario 1: fault resistance

Fifty fault resistance values between 0.01  $\Omega$  and 100  $\Omega$  (randomly generated) have been used in this scenario to evaluate the performance of the proposed

method. The fault resistance values are shown in Fig. 6.2. For each fault resistance value, phase  $a$  to ground ( $ag$ ), phase  $a$  to phase  $b$  ( $ab$ ) and three-phase ( $abc$ ) faults were simulated at seven locations along the feeder. These locations lie at distances of 0.5, 6.2, 16.85, 27.1, 33.3, 47.1 and 57.25 km from the main substation. These locations are illustrated in Fig. 6.1 as F1 to F7. In this scenario, the fault inception angle is maintained at  $90^\circ$  and the system is running at the rated loading values as is clear in Table 6.1. Voltages and currents measured at the substation for  $ag$  fault with a resistance of  $10\ \Omega$  at 27.1 km are shown in Fig. 6.3 and Fig. 6.4.

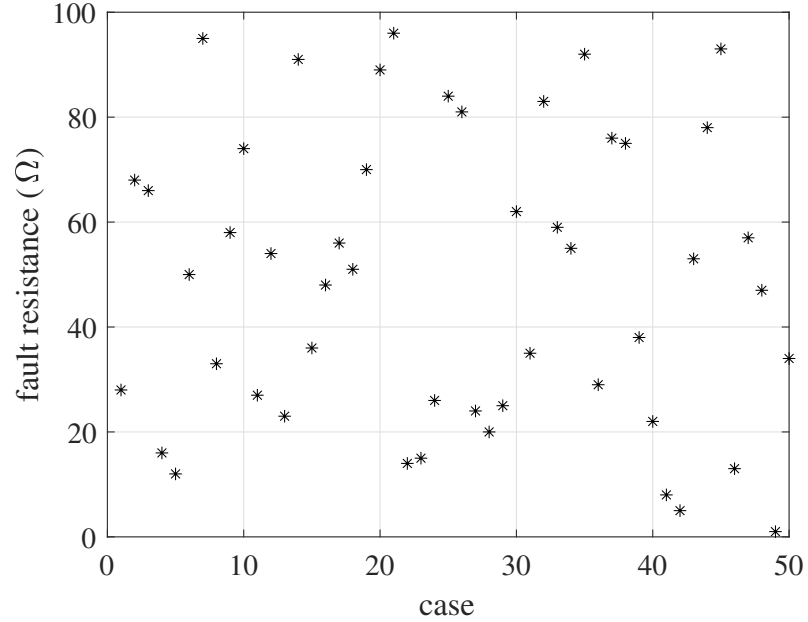


Fig. 6.2: Scenario 1, fault resistance variation

A sample of the fault location results is shown in Fig. 6.5 for different fault types to show the effect of varying the fault resistance on the error in distance estimation for faults at 27.1 km. The error in distance estimation is small for different resistance values and different fault types, where all cases have an error of less than 70 m.

For different locations, the results are grouped using a box plot for each fault type [62]. In Fig. 6.6, the definitions for the box plot parts are illustrated. The box plot helps in deriving some statistics and relationships.

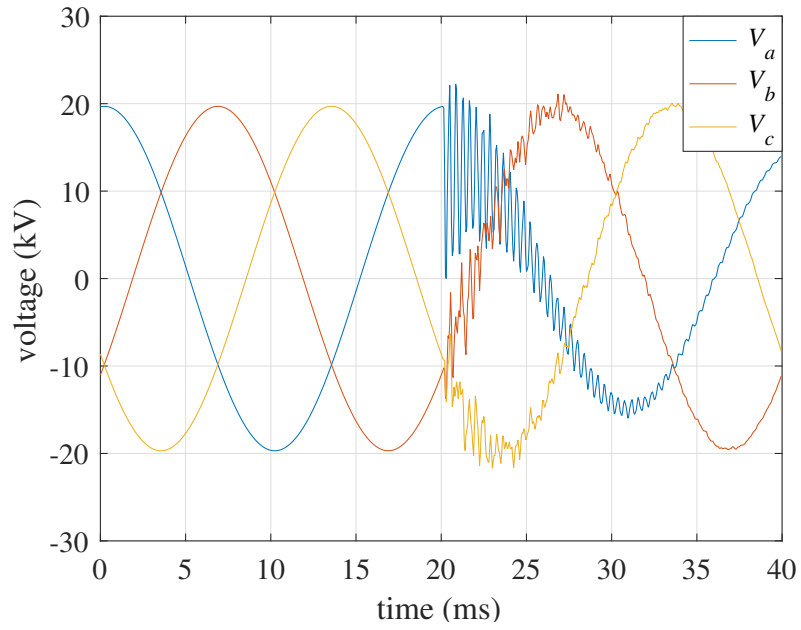


Fig. 6.3: Measured voltages for  $ag$  fault

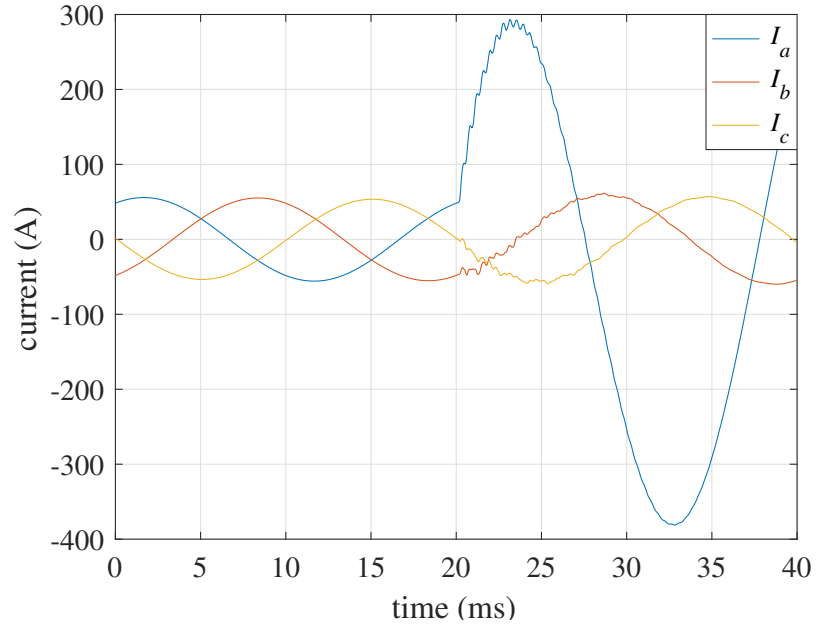


Fig. 6.4: Measured currents for  $ag$  fault

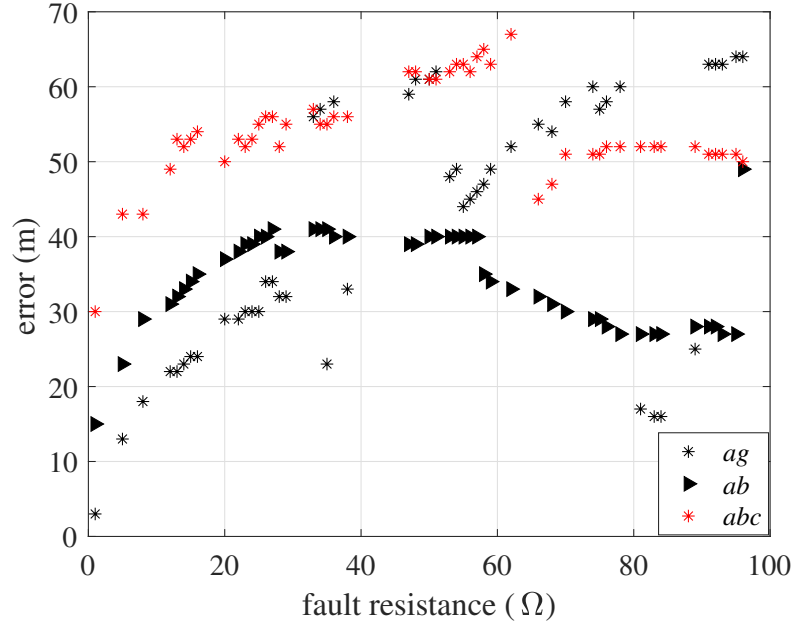


Fig. 6.5: Error in estimation for faults at a distance of 27.1 km

The box plots are shown in Fig. 6.7 to Fig. 6.9 based on the fault type. From these plots, it can be deduced that:

- Almost all fault cases are located with error of less than 100 m except for some cases for *ag* faults at 47.1 km. Faults at location 47.1 km show higher error when compared to the other locations. However, the error values for this location are still small and also the variation between the upper and lower extremes is very small.
- The distance between the upper and lower extremes is small for most locations which means the change in the error with changing the resistance value is small.
- As the error is less than 100 m for most of cases, the method is also not significantly affected by the fault point location.

### 6.2.2 Scenario 2: inception angle

The fault inception angle represents the voltage angle at the instant of the fault inception. This angle affects the step magnitude in the supply voltage.

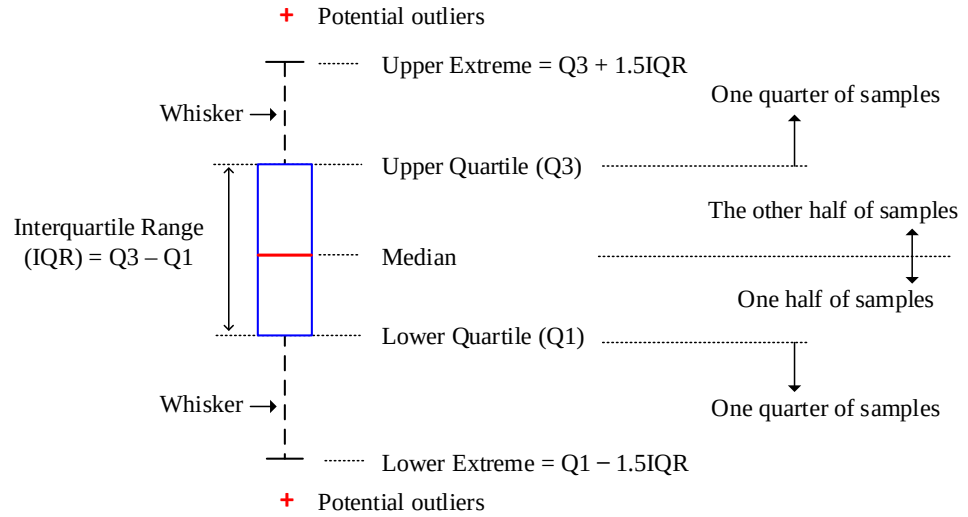


Fig. 6.6: Box plot illustration

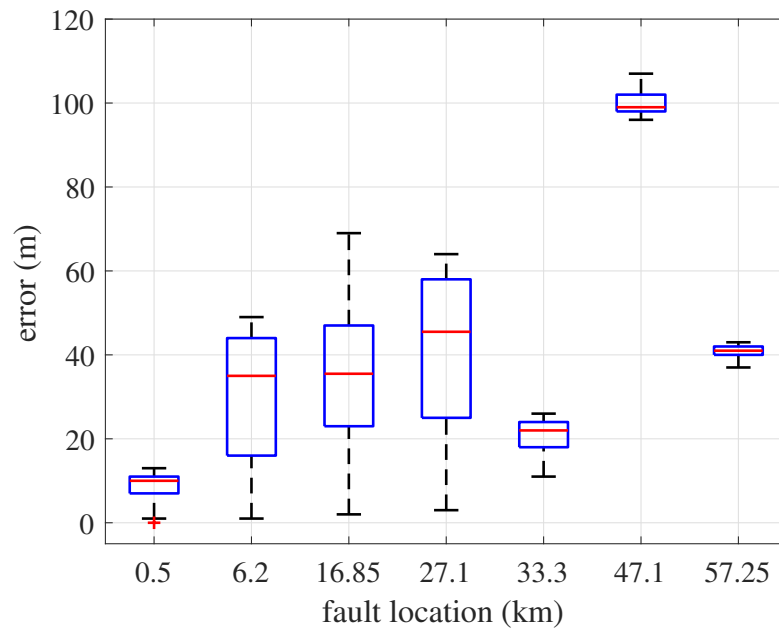


Fig. 6.7: Scenario 1, box plot for *ag* fault

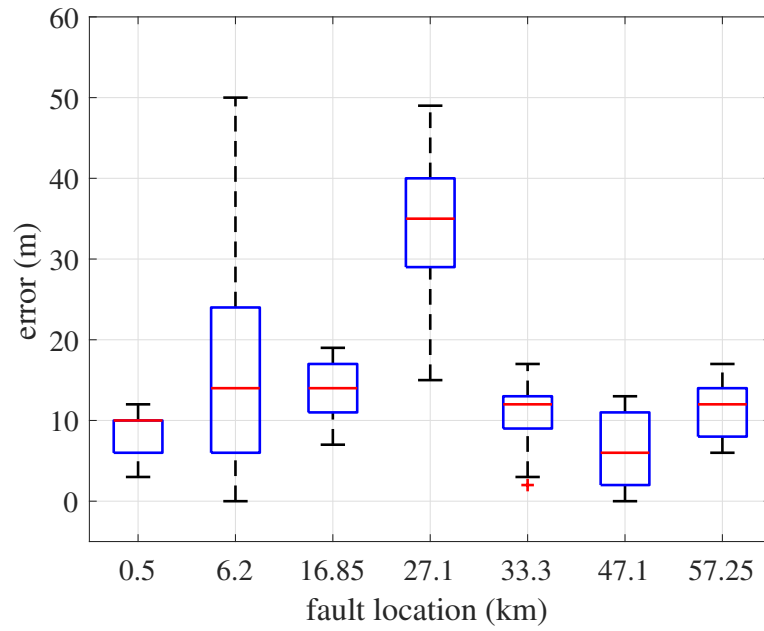


Fig. 6.8: Scenario 1, box plot for *ab* fault

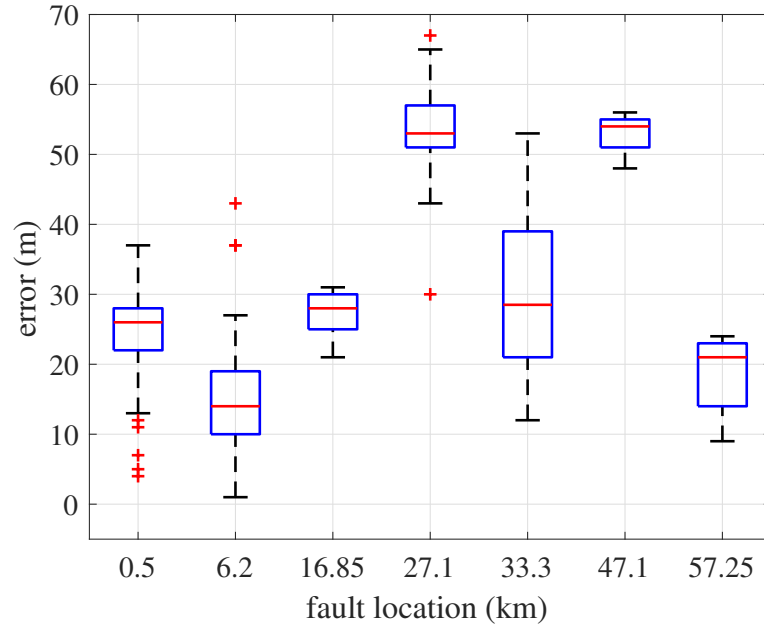


Fig. 6.9: Scenario 1, box plot for *abc* fault

Consequently the level of the high frequency components generated due to the fault occurrence. The main substation source phase angle (for phase  $a$ ) has been varied in this test to give 50 values randomly generated between  $0^\circ$  and  $180^\circ$  while keeping the fault resistance at  $10\ \Omega$ . The variation of the inception angle is shown in Fig. 6.10. Similar to the previous test, different fault types were simulated at different locations for each inception angle.

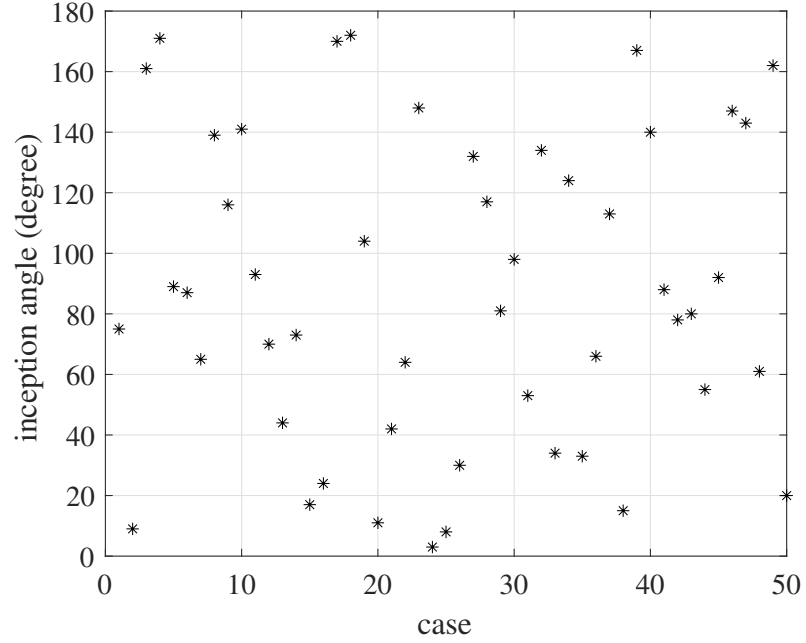


Fig. 6.10: Scenario 2, inception angle variation

A box plot is used to summarize the fifty fault cases for each fault type at each location (different inception angles). The box plots are presented in Fig. 6.11 to Fig. 6.13. From these plots, it can be deduced that:

- For  $ag$  faults, most fault cases are located with an error of less than 100 m. This is clear as the upper quartile (75% of samples) lies below 100 m for all location except for 47.1 km.
- All phase fault cases ( $ab$  and  $abc$  faults) have an error in estimation of less than 100 m.
- The distance between the upper and lower extremes is small for most of locations which means the change in the error with changing the

inception angle is not high.

- When looking at the median for different locations at the same fault type, the median values are close to each other which helps in concluding that the performance of the method is not significantly affected by the fault distance.

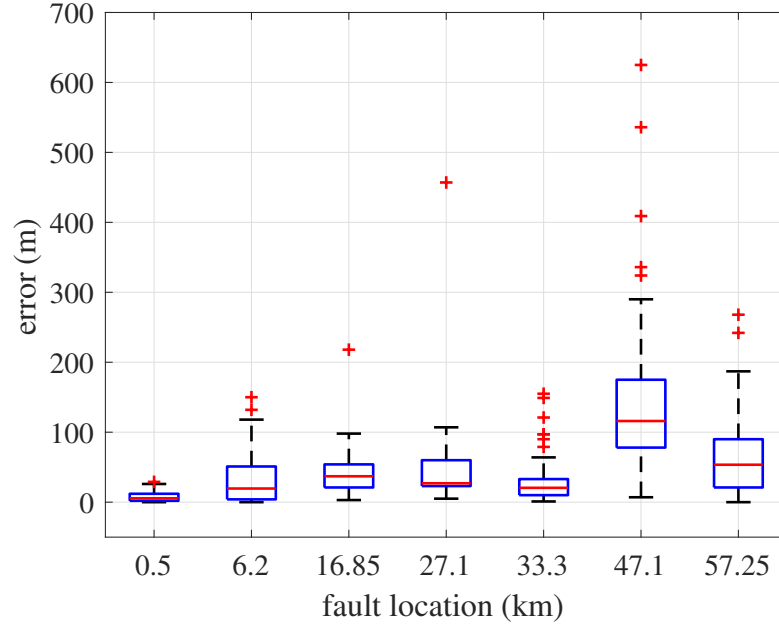


Fig. 6.11: Scenario 2, box plot for *ag* fault

In order to understand the reason for the outliers in the figures (especially those above the upper extreme point), detailed figures were plotted for some cases as examples. For *ag* faults, the locations 6.2, 33.3 and 47.1 km show some outliers. Because the error ranges for the outliers at 6.2 and 33.3 km are close, they are illustrated on the same plot as shown in Fig. 6.14a. Also, the results for 47.1 km are shown in Fig. 6.14b. It is clear that the outlier points are most likely to exist close to  $0^\circ$  and  $180^\circ$ . The step change in the faulted phase voltage is small close to these zones and this reduces the high frequency content and finally appears as an increase in the distance estimation error. Nevertheless, the error is less than 100 m for most of the cases which represent a low value for this long system.

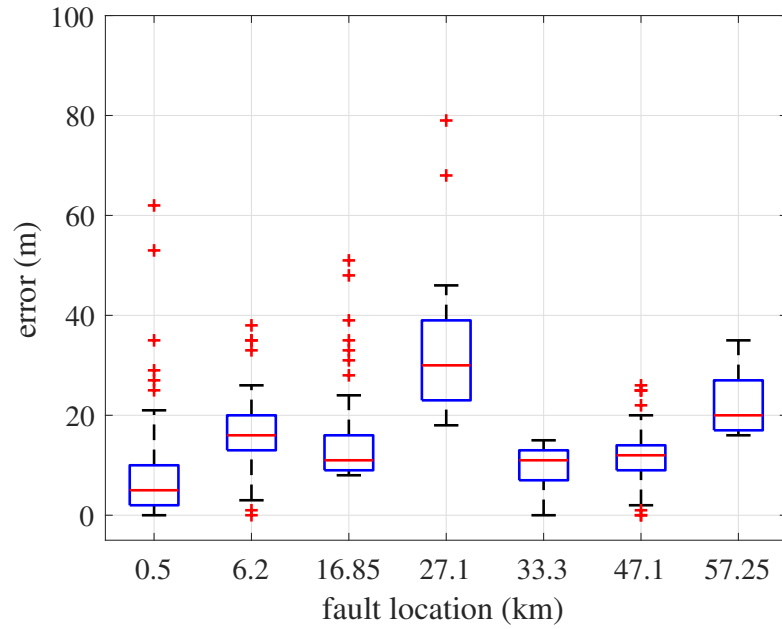


Fig. 6.12: Scenario 2, box plot for *ab* fault

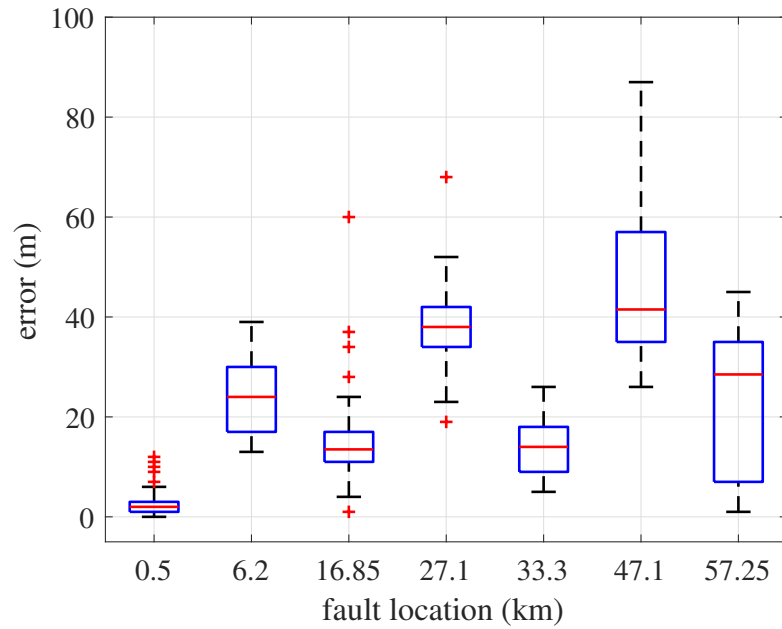
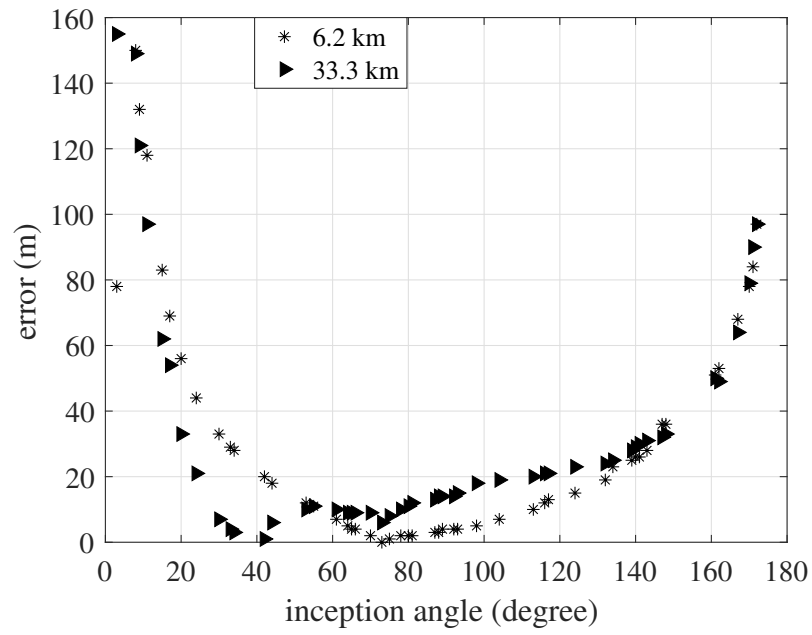
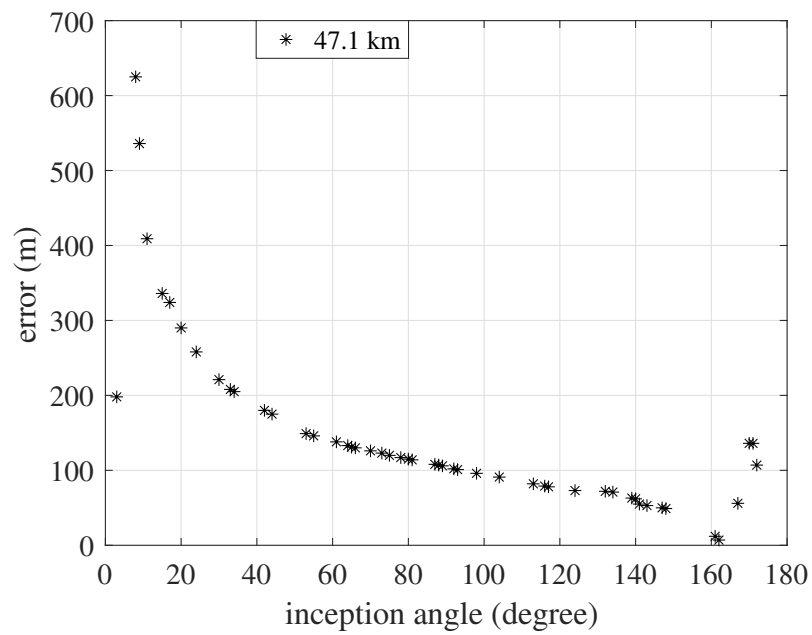


Fig. 6.13: Scenario 2, box plot for *abc* fault



(a)



(b)

Fig. 6.14: Error in estimation for  $ag$  faults at different inception angles

For  $ab$  faults, the error at different inception angles is plotted for 0.5 and 16.85 km cases as examples and is shown in Fig. 6.15. The outliers exist around  $150^\circ$ . This can be explained as the voltage between phase  $a$  and phase  $b$  leads phase  $a$  voltage by  $30^\circ$ . Therefore, when the inception angle which is the angle of the source phase  $a$  voltage is around  $150^\circ$ , the corresponding angle for the fault voltage (between phase  $a$  and phase  $b$ ) becomes around  $180^\circ$  which leads to lower high frequency contents as explained earlier with the  $ag$  faults. However, as is clear, all cases are located with an error of less than 100 m.

For all the cases (1050 cases), a histogram is plotted to show the distribution over different error ranges. A cumulative type histogram is shown in Fig. 6.16 relative to the total number of cases (1050). The height of each bar denotes the cumulative observations at this range and all previous ranges. In other words, the height of each bar represents the relative number of fault cases (relative to 1050) that are located with error less than the corresponding error bin high limit. In Fig. 6.16, for the error bin  $[80\ 100]$ , the corresponding relative cumulative observation is 0.9495. This means that 94.95% of cases are located with error of less than 100 m.

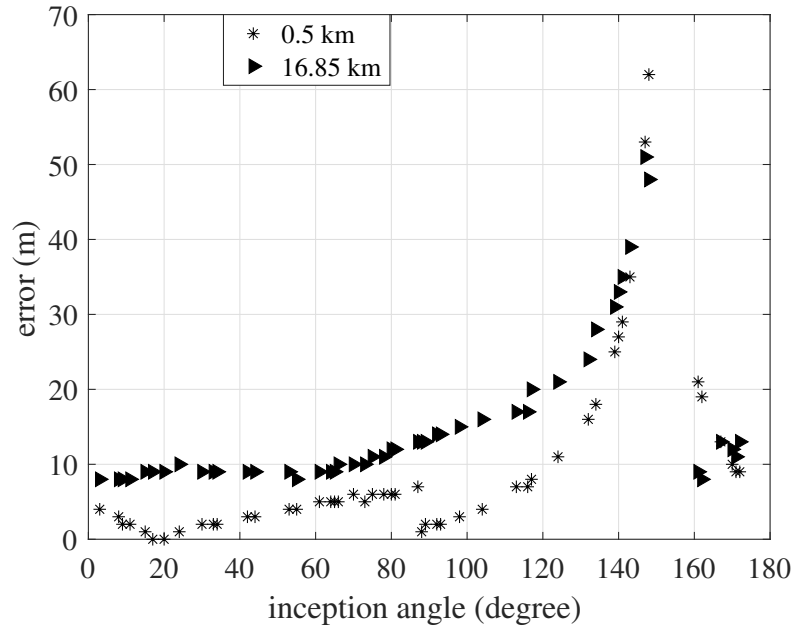


Fig. 6.15: Error in estimation for  $ab$  faults at different inception angles

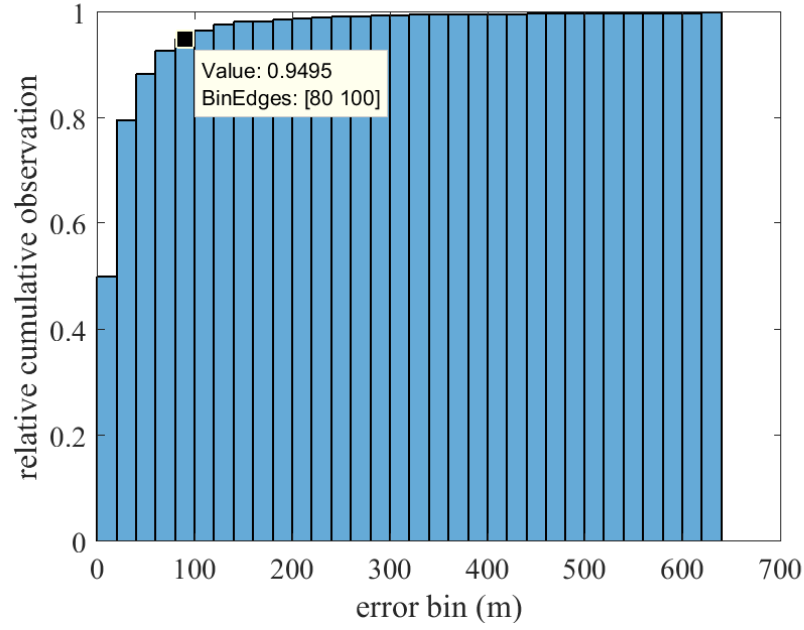


Fig. 6.16: Scenario 2, histogram for the inception angle test

### 6.2.3 Scenario 3: loading

The proposed scheme as well as the other impedance based methods depend on understanding the load configuration of the system. However, for distribution systems, loads are time varying and it might be impossible to define the exact loading value for different loads without direct measurement at each load point: this is impractical in many applications. To check the effect of load uncertainty on the proposed scheme, it has been tested for four different loading cases.

- case 1: the loads were randomly changed between 50% and normal rated load (100%) to simulate working at medium to normal load condition.
- case 2: the loads were randomly changed between 100% and 125% of the rated load to simulate operation at overload condition.
- case 3: the loads were randomly changed between 50% and 125% to allow some loads to operate below the rated value while others run at

overload condition.

- case 4: the loads were randomly changed between 0% (no load) and 50% to simulate a light loading condition for the system.

For each of these cases, the load scaling factor is different for different loads and is randomly generated. When calculating the loading for the four cases compared to the rated load (100%), the total loading was found to be 74%, 111%, 86% and 25% for the four cases respectively. Even though the loads have been varied in the simulation, the fault location algorithm is performed assuming all loads operate at the rated level e.g. the fault location scheme ignores this variation in the loading. For each loading case, the three aforementioned fault types were simulated at different points with a resistance of  $10\ \Omega$  and inception angle of  $90^\circ$ . Also, the performance of the proposed method has been checked at rated load to compare with the load uncertainty cases. The error in distance estimation for the four loading cases as well as the full load case is shown in Fig. 6.17 to Fig. 6.19.

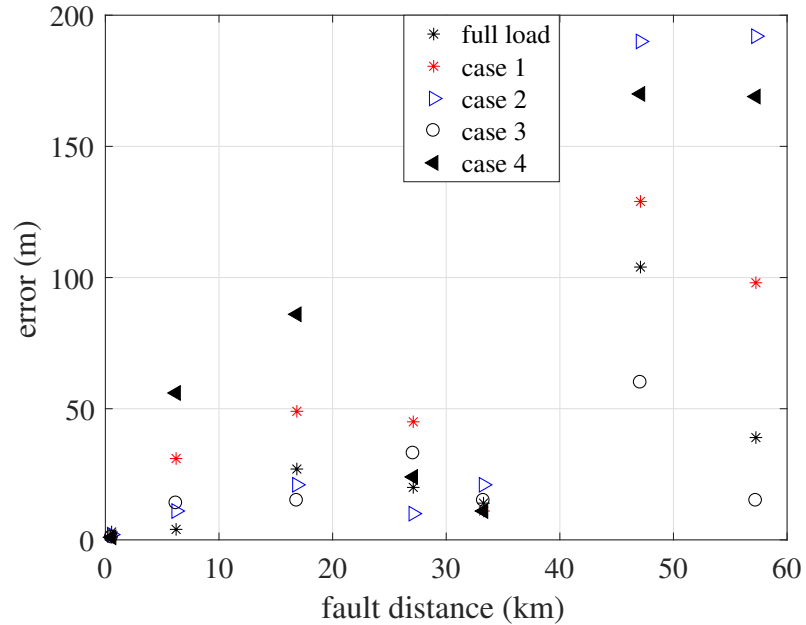
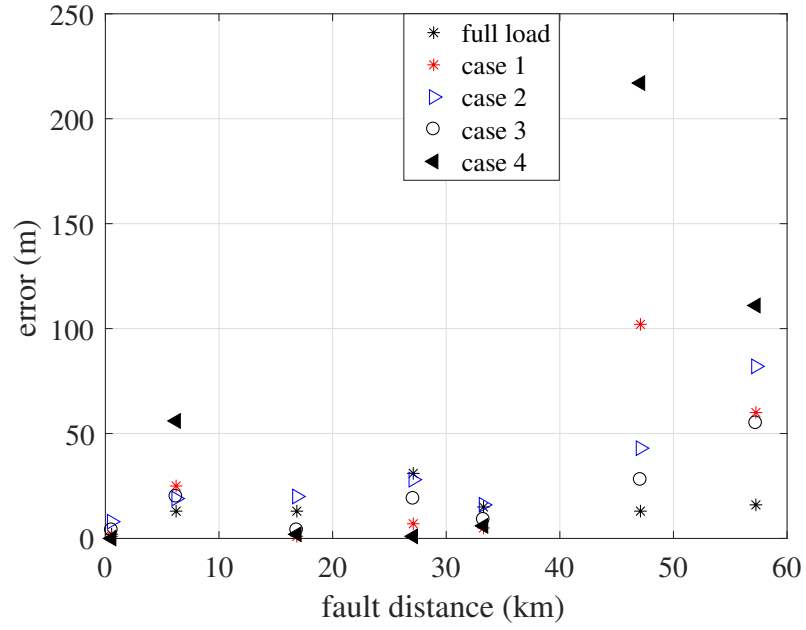
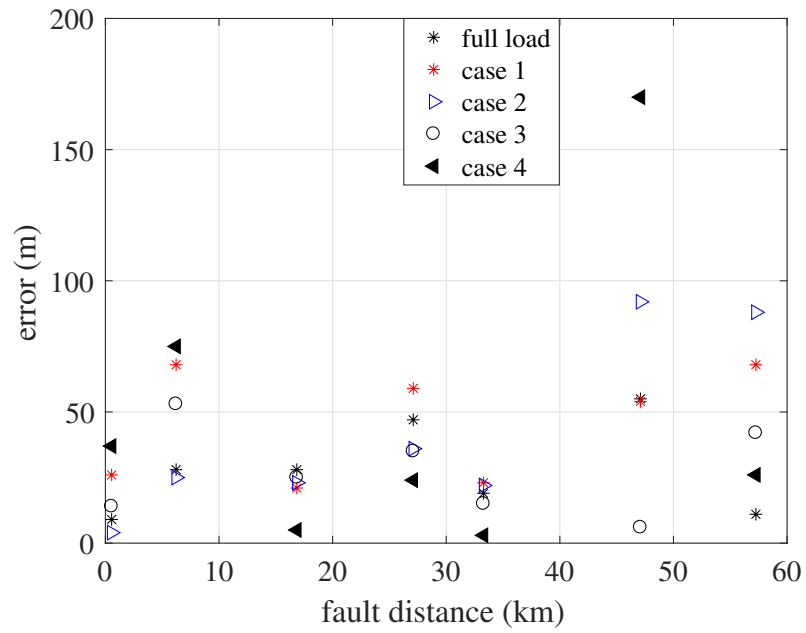


Fig. 6.17: Scenario 3, error for *ag* fault


 Fig. 6.18: Scenario 3, error for  $ab$  fault

 Fig. 6.19: Scenario 3, error for  $abc$  fault

The error in distance estimation has not significantly been affected by the load uncertainty even without using any compensation technique for the load variation. A clue to this can be found by checking Fig. 3.9. With

the fault point treated as the voltage source in the circuit, the main source Thevenin equivalent at the non-fundamental frequencies is an impedance. Therefore, the fault current coming out from the fault voltage source finds several parallel paths through the various load impedances as well as the main source Thevenin equivalent impedance. The main source equivalent impedance is much smaller than the load impedances. Therefore, the effect of the load impedance uncertainty decreases.

#### 6.2.4 Scenario 4: noise level

The measured voltages and currents are susceptible to perturbations e.g. electromagnetic interference noise and accuracy of the measuring instruments. Gaussian noise is used to add random noise to the measured signals and a 16 bit quantizer has been added to represent the analogue to digital converter used for data capture.

At seven different points along the feeder, *ag*, *ab* and *abc* faults have been simulated 50 times at each point. For each fault case, the noise level is randomly selected from the range 0.1% to 1% of the pre-fault rms value for the phase voltage and current and is shown in Fig. 6.20. Box plots that summarize the test are shown in Fig. 6.21 to Fig. 6.23. As is clear, the proposed method provides a good performance for different locations and fault types with most of cases (97.6% when calculated) having an error of less than 100 m.

The previous extensive evaluation process shows the success and accuracy of the proposed SEWIBFL scheme to locate faults in distribution systems using the available local measurements at the substation with estimation errors of less than 100 m for most of cases. For all the simulation cases carried out in the previous scenarios (3255 cases), a histogram is plotted to show the distribution over different error ranges. A cumulative type histogram is shown in Fig. 6.24 relative to the total number of cases (3255). The marked error bin in Fig. 6.24 has a relative cumulative observation of 0.9671. This means that 96.71% of cases are located with

error of less than 100 m. Noting that the aggregated lengths of the lines for the IEEE 34-bus feeder is about 93 km and the length of the longest path is about 58 km.

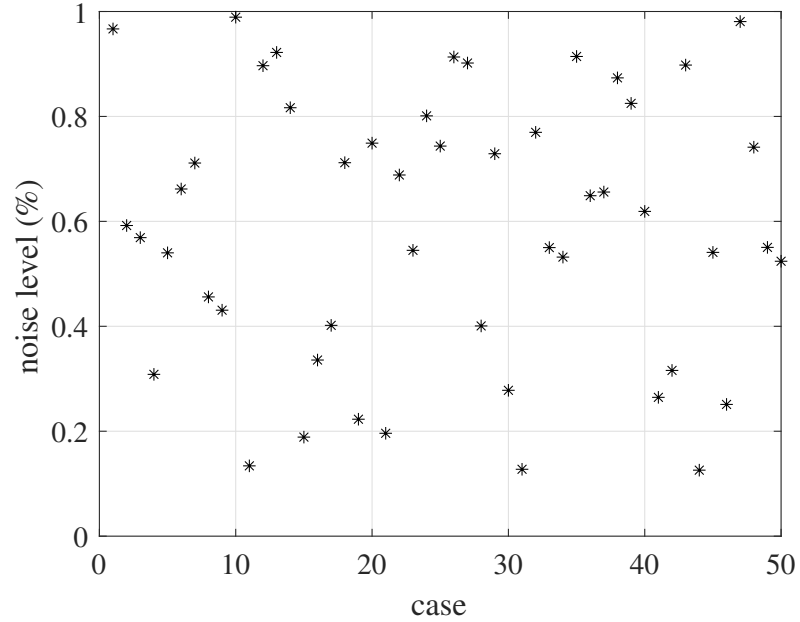


Fig. 6.20: Scenario 4, noise level variation

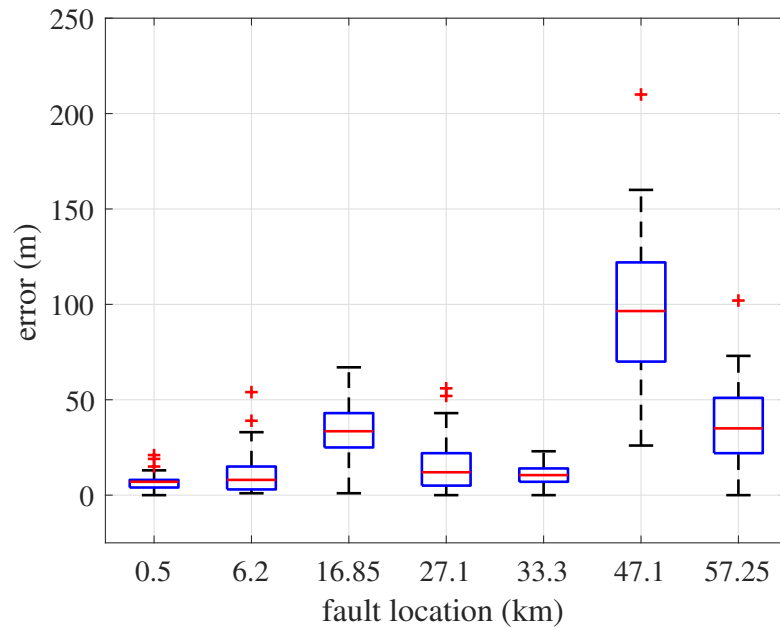


Fig. 6.21: Scenario 4, box plot for *ag* faults

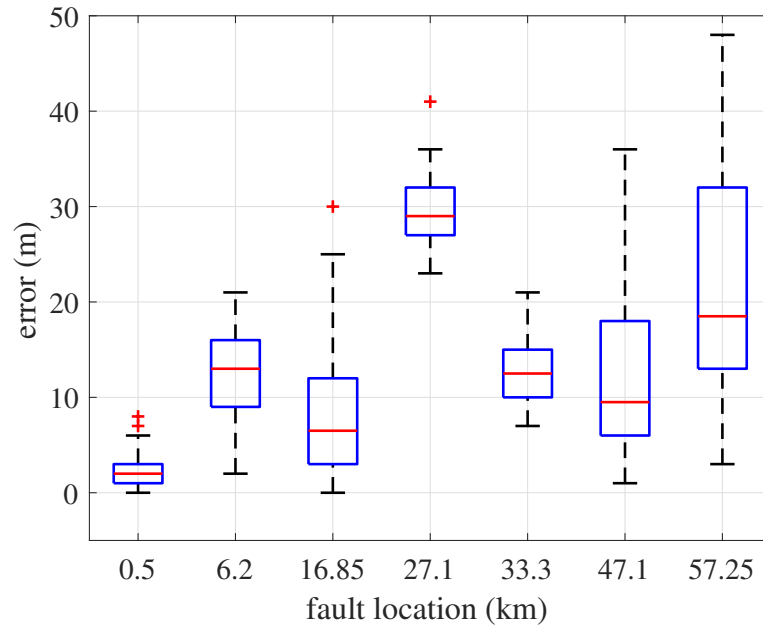


Fig. 6.22: Scenario 4, box plot for *ab* faults

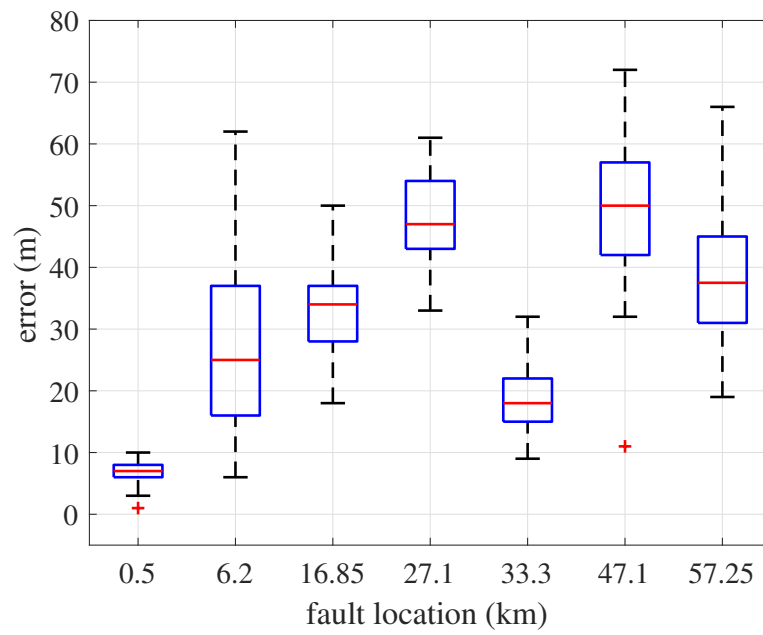


Fig. 6.23: Scenario 4, box plot for *abc* faults

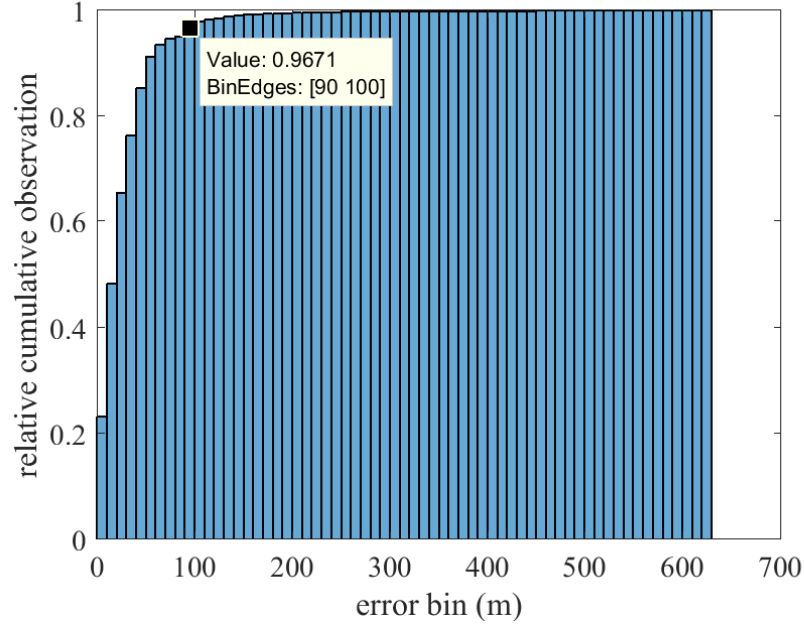


Fig. 6.24: Histogram for the whole tests, chapter 3

### 6.3 SEWIBFL Scheme: with DG

In this section, the DG equivalent circuit proposed in Chapter 4 is used in conjunction with the proposed SEWIBFL scheme to locate faults on a modified version of the IEEE 34-bus feeder. The system modification considers connecting DGs at different locations with different types. The assessment scenarios are presented in Table 6.2. Other than the third scenario, an inverter based distributed generation is connected at nodes 848 and 840 and this is defined as (2 IBDGs) in Table 6.2, column number 4. The single line diagram in Fig. 6.25 shows the nodes where the DGs were connected and the seven locations where the faults were simulated (F1 to F7). The IBDG parameters were mentioned in Table 4.1. When using a SBDG, a standard three-phase, 250 kVA, 400 V synchronous generator block from the Matlab library has been used. The different scenarios are presented in the subsequent sections in a similar way to that used previously with the radial system.

Table 6.2: Evaluation scenarios for active system

| scenario | fault resistance  | inception angle | DG       | loading   | noise level |
|----------|-------------------|-----------------|----------|-----------|-------------|
| 1        | 0.01:100 $\Omega$ | 90°             | 2 IBDGs  | full load | n/a         |
| 2        | 10 $\Omega$       | 0°:180°         | 2 IBDGs  | full load | n/a         |
| 3        | 10 $\Omega$       | 90°             | 10 cases | full load | n/a         |
| 4        | 10 $\Omega$       | 90°             | 2 IBDGs  | 4 cases   | n/a         |
| 5        | 10 $\Omega$       | 90°             | 2 IBDGs  | full load | 0.1%:1%     |

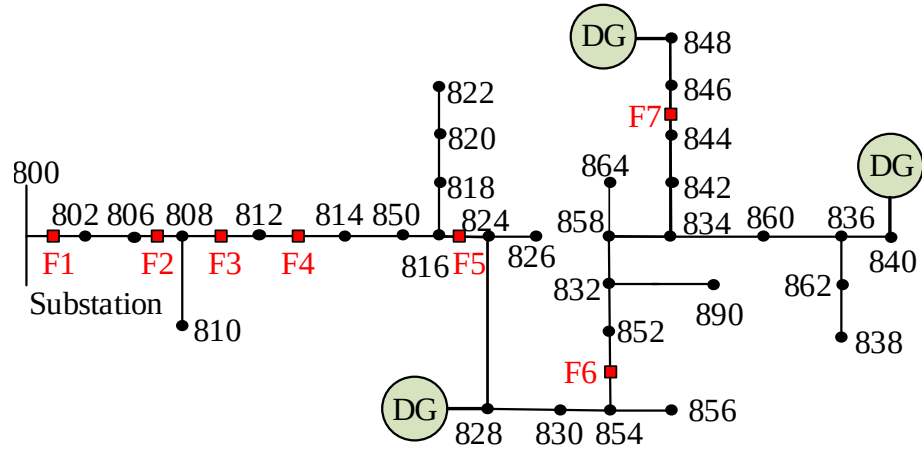


Fig. 6.25: IEEE 34-bus feeder with DG

### 6.3.1 Scenario 1: fault resistance

The fault resistance values shown in Fig. 6.2 (previously used in the evaluation of the radial distribution system) have been used to simulate faults of different types (*ag*, *ab* and *abc*) at locations 0.5, 6.2, 16.85, 27.1, 33.3, 47.1 and 57.25 km measured from the main substation. The DGs at nodes 848 and 840 are represented by their proposed equivalent circuit in the fault location process. The IBDG has been chosen as its equivalent circuit has greater approximations compared to the SBDG equivalent circuit. The other test conditions are illustrated in Table 6.2.

The error in distance estimation for different fault types at location

27.1 km is shown in Fig. 6.26. When comparing these results with those corresponding to the same location with radial system in Fig. 6.5, there are increases in the error for *ag* faults. However, the maximum error is 140 m. For most of the points, the error lies in the same range in both figures which reflects the success of the proposed DG equivalent circuit to be implemented in the fault location process but with an expected increase in the error due to the approximations associated to the DG equivalent circuit.

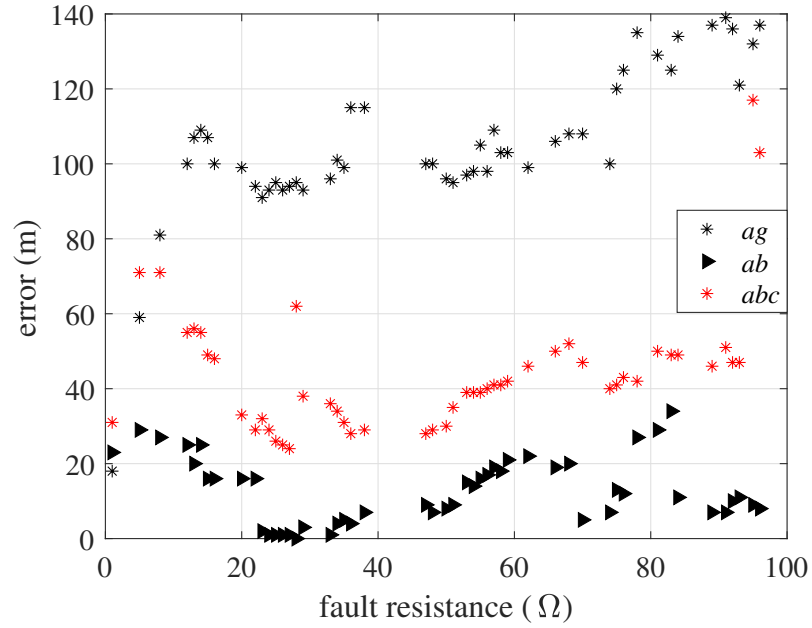


Fig. 6.26: Error in estimation for faults at a distance of 27.1 km

A box plot for all the *ag* faults has been drawn and is shown in Fig. 6.27. By comparing this box plot with the box plot in Fig. 6.7, it can be seen a noticeable difference between the two figures. Firstly, the error range is higher with the active distribution system. As stated, this increase is expected. Also, the distance between the upper and lower extremes is higher for some locations e.g. for 47.1 km the difference is 327 m. However, for many locations, this difference is small. This difference reflects the effect of fault resistance variation on the estimation accuracy. For location 47.1 km, the variation of the error against fault resistance is presented in Fig. 6.28.

As is clear, the high error values correspond mainly to the high fault

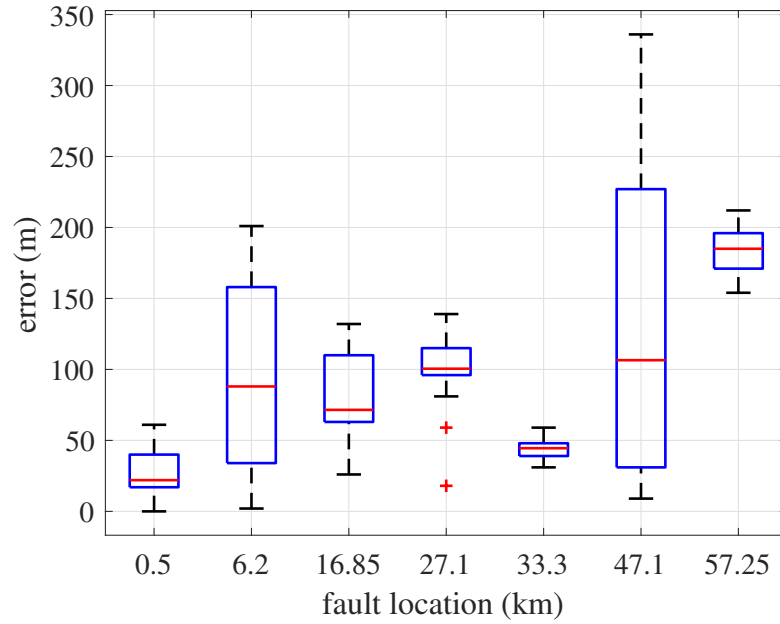


Fig. 6.27: Scenario 1, box plot for *ag* fault

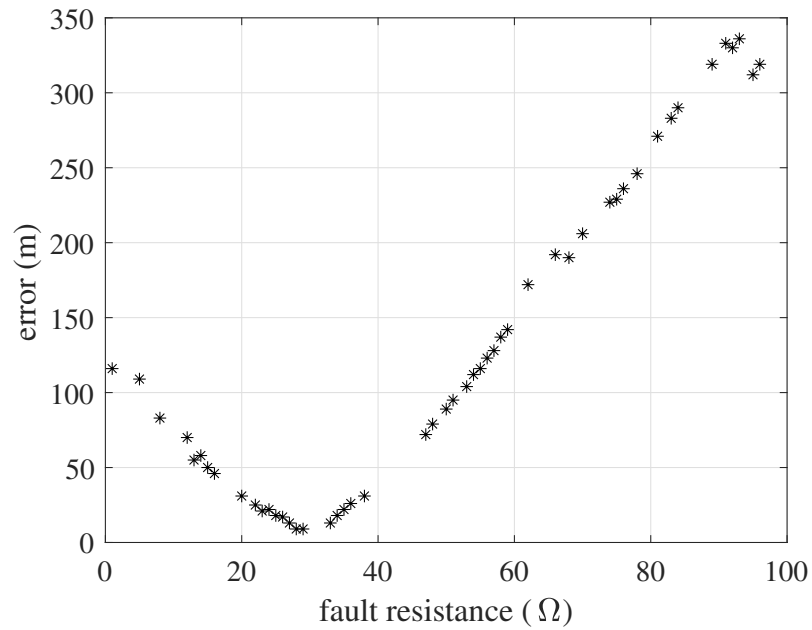


Fig. 6.28: Error in estimation for faults at a distance of 47.1 km

resistance values. The fault distance is calculated using the weighted average as explained in Chapter 4 (Section 4.3.3), the estimated fault distance at some frequencies shows an over-estimation (estimated distance is larger than the actual distance) and under-estimation at other frequencies. This results in a reduced error in the final average distance and explains the small error obtained around  $30\ \Omega$  in Fig. 6.28. In Fig. 6.27, most of cases were estimated with error of less than 200 m. The box plots for *ab* and *abc* faults are shown in Fig. 6.29 and Fig. 6.30. Also, these plots show an increase in the error compared to the corresponding ones with radial distribution system. Nevertheless, still most of the cases have an error of less than 200 m. The total average error for the whole scenario was found to be 70.4 m.

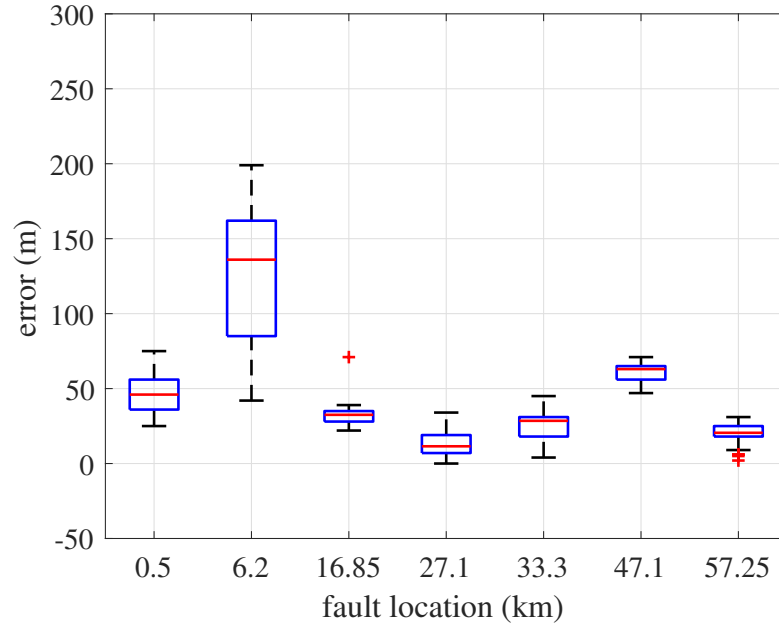


Fig. 6.29: Scenario 1, box plot for *ab* fault

A relative cumulative histogram is plotted for the 1050 fault cases and is shown in Fig. 6.31. From the histogram, 75.24% of cases were estimated with error of less than 100 m and 97.24% have an error less than 200 m. Noting that the total line length for the system is about 93 km and the longest feeder is 58 km. Therefore, the 200 m reflects a good accuracy level. Later, the comparative study between the proposed method and

other impedance based methods (Section 6.6) emphasizes that the 200 m error obtained by the proposed method reflects a good accuracy.

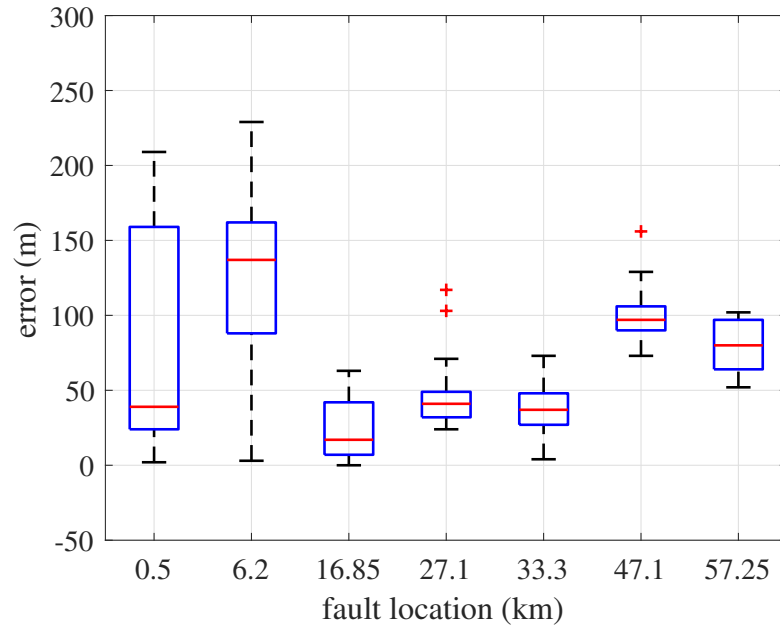


Fig. 6.30: Scenario 1, box plot for *abc* fault

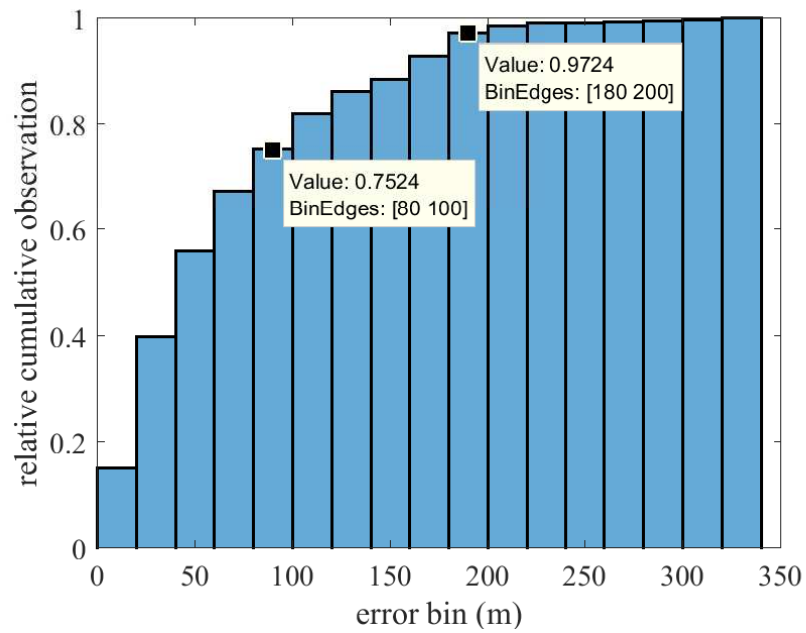


Fig. 6.31: Scenario 1, histogram for the fault resistance test

### 6.3.2 Scenario 2: inception angle

The fifty fault inception angles used with the radial distribution system evaluation have been used in this section. The three fault types have been simulated at different points for each inception angle. The box plot showing the results for *ag* faults at different fault locations is shown in Fig. 6.32. The results show the majority of cases have an error of less than 200 m. This is clear as the upper extreme for many locations lies below 200 m and all upper quartiles (75% of data) lie below 200 m. Similar to the case of the radial distribution system without DGs, some outliers exist. Interpreting the results may be not as straight forward as the case of the radial distribution system.

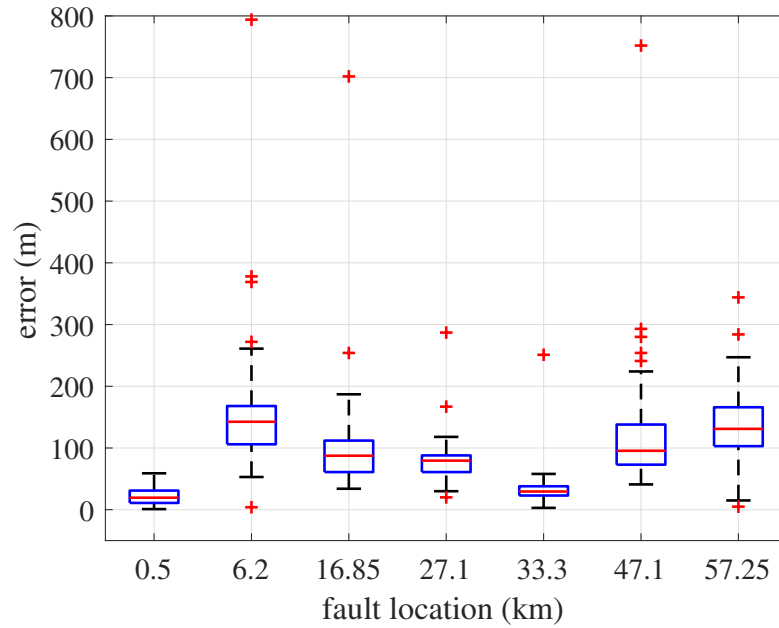


Fig. 6.32: Scenario 2, box plot for *ag* fault

The approximation regarding the IBDG equivalent circuit has an effect on all the results and this effect may be a fault condition dependent. The error for the locations 6.2 km and 47.1 km at different inception angles is presented in Fig. 6.33. The highest error case for both locations occurs at a low inception angle. This is because the low inception angle leads to a low magnitude transient and in turn lower values for the high frequency

components used to estimate the distance. Also, most of the cases where the error is more than 200 m are in the lower inception angle range. For 6.2 km, there are some points higher than 200 m but not in the low inception angle range. As mentioned, the effect of the IBDG may differ from case to case and also the method used to calculate the final average value based on dividing the whole range into zones may be a reason for these cases.

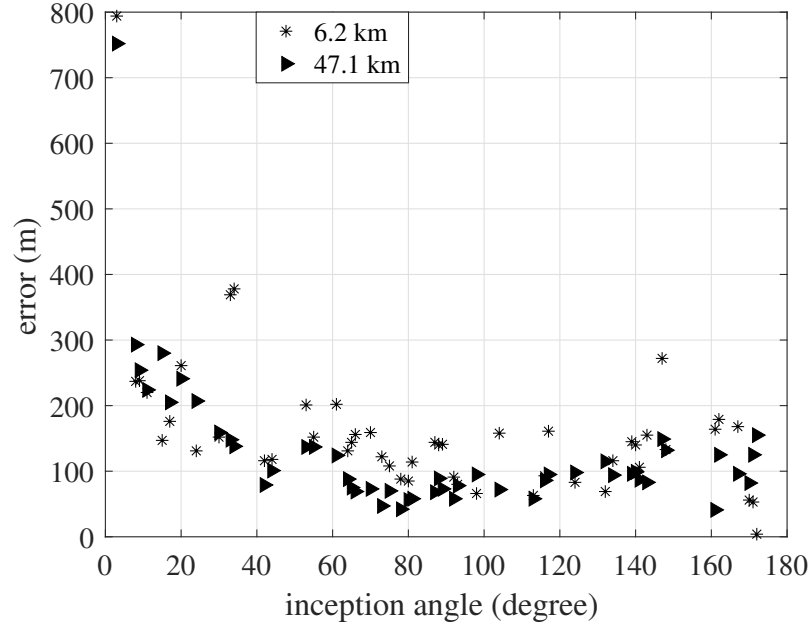


Fig. 6.33: Error in estimation for  $ag$  faults at different inception angles

The results for  $ab$  and  $abc$  faults are shown in Fig. 6.34 and Fig. 6.35 respectively. Also, a sample of the results for  $ab$  faults at locations 16.85 km and 27.1 km is shown in Fig. 6.36 which illustrates that the outliers are mainly in the zone surrounding  $150^\circ$ , similar to the case of the radial system. A conclusion regarding the effect of the fault distance on the method performance can be derived by comparing the median for different fault locations. For different fault types, the medians in the box plot at different locations are close to each other which reflects robustness of the method to changing the fault point. Also, excluding the outliers, the variation of the error for different fault inception angles is not high. Therefore, the method can be considered robust against fault inception angle variation.

For all the cases (1050 cases), a histogram is presented in Fig. 6.37 showing the relative cumulative observation for every error range. The observation for the error bin  $[80 \ 100]$  is 0.8267 which means 82.67% of cases are located with error of less than 100 m. This ratio is lower than that obtained with the radial system (94.95% with the radial distribution system). This is expected due to the approximation regarding the DG equivalent circuit. However, it is still a high percentage. Also, 96.86% of cases have an error less than 200 m which is a very high ratio with this small error level.

### 6.3.3 Scenario 3: DG

In this scenario, a combination of DG conditions is used to check the performance of the proposed method. The tests consider changing the DG type, connection node and quantity and different cases are presented in Table 6.3. For each case, *ag*, *ab* and *abc* faults were simulated with a resistance of  $10 \ \Omega$  and fault inception angle of  $90^\circ$  at seven locations.

For each fault type, the results for different cases are grouped based on the DG type. In Fig. 6.38, Fig. 6.39 and Fig. 6.40 the error in distance estimation for *ag* faults is presented for SBDG cases, IBDG cases and combined DGs cases respectively. Similarly for *ab* and *abc* faults, the results are shown in Fig. 6.41 to Fig. 6.46. From these figures, only 15 fault case have an error more than 100 m (total number of cases is 210). The total average error is 44 m and the maximum error does not exceed 200 m. For most of occasions, increasing the number of DGs (from one DG to two then three DGs) does not result in a significant change in the estimation error. For example, the first four cases with SBDG and *ag* faults in Fig. 6.38, the four points at the same location are very close. This is also valid for various locations in different figures. Note that each DG unit is running at 10% of the nominal main substation transformer power rating (main substation transformer rating is 2500 kVA [61]).

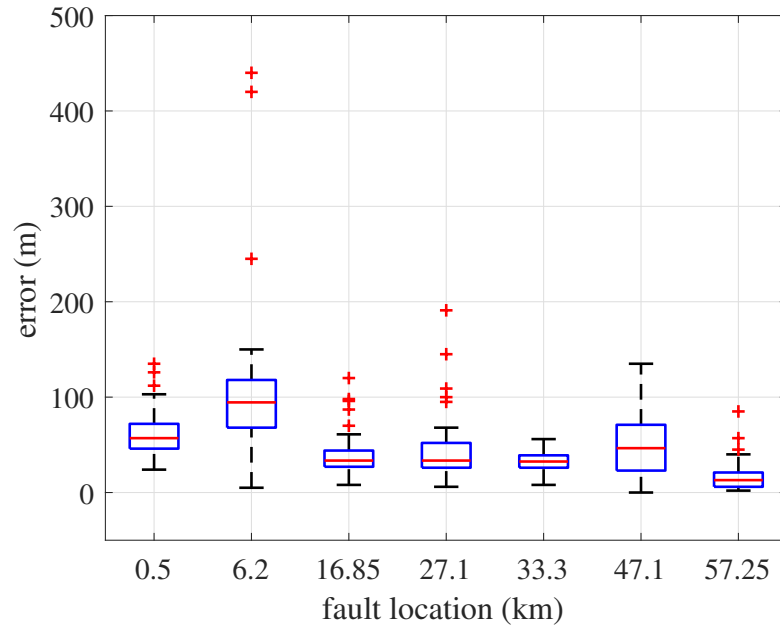


Fig. 6.34: Scenario 2, box plot for *ab* fault

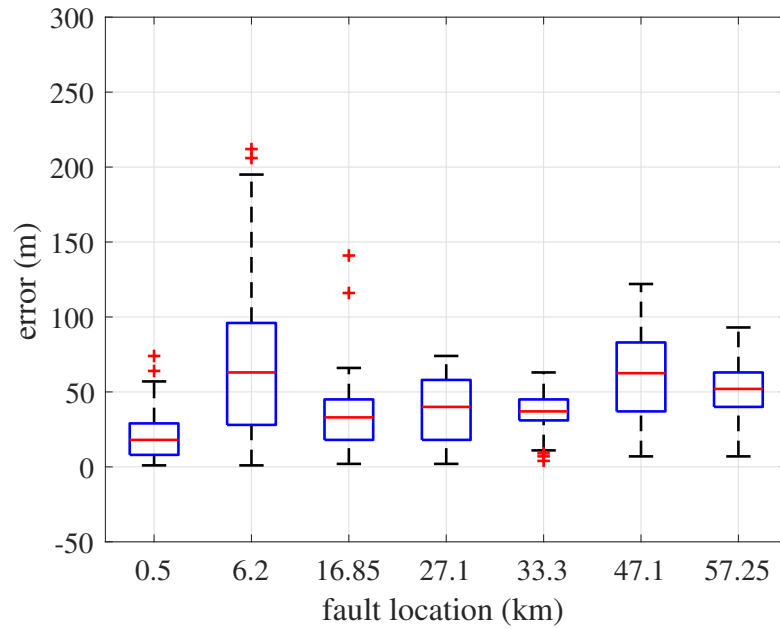


Fig. 6.35: Scenario 2, box plot for *abc* fault

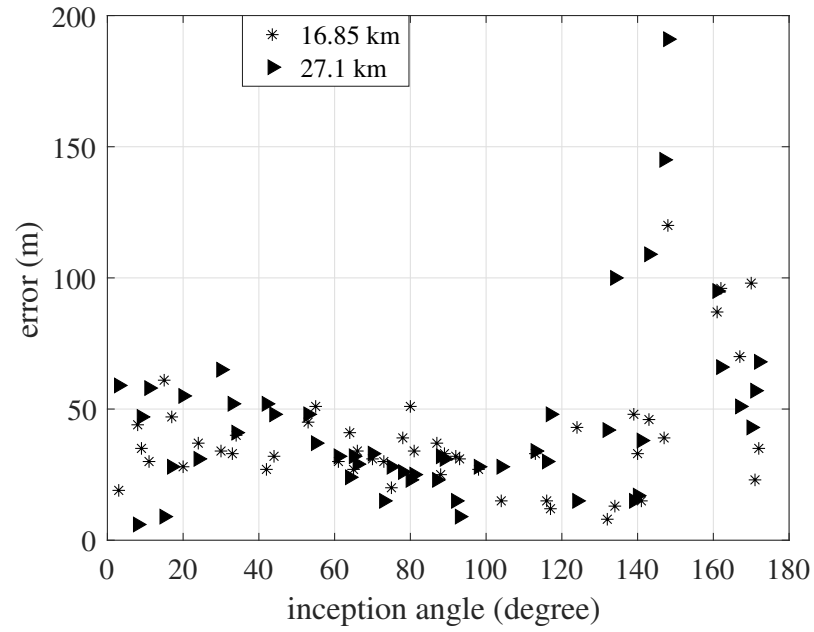


Fig. 6.36: Error in estimation for  $ab$  faults at different inception angles

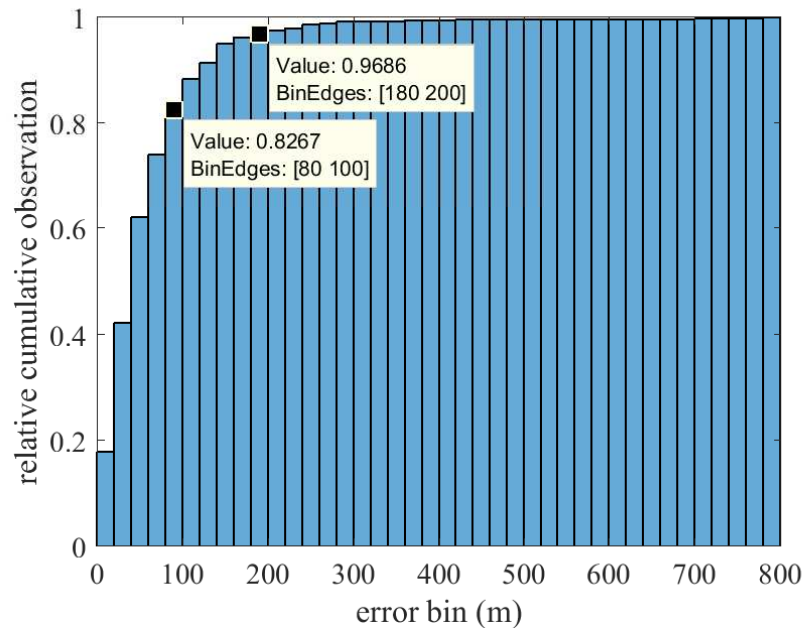


Fig. 6.37: Scenario 2, histogram for the inception angle test

Table 6.3: DG test conditions

| case | DG type | connection node(s) |
|------|---------|--------------------|
| 1    | SBDG    | 848                |
| 2    |         | 828                |
| 3    |         | 848 and 840        |
| 4    |         | 848, 840 and 828   |
| 5    | IBDG    | 848                |
| 6    |         | 828                |
| 7    |         | 848 and 840        |
| 8    |         | 848, 840 and 828   |
| 9    | IBDG    | 848                |
|      | SBDG    | 840                |
| 10   | IBDG    | 848 and 840        |
|      | SBDG    | 828                |

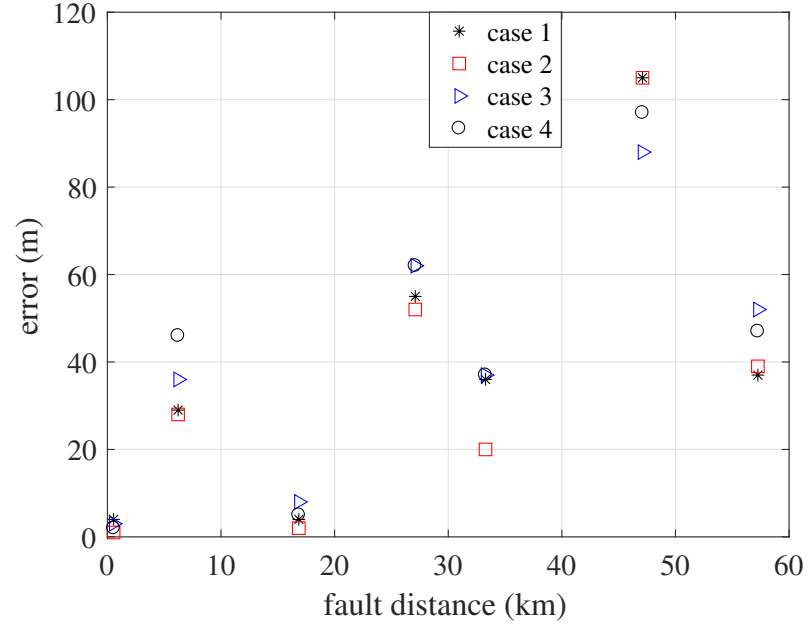


Fig. 6.38: Scenario 3, *ag* faults with cases 1 to 4

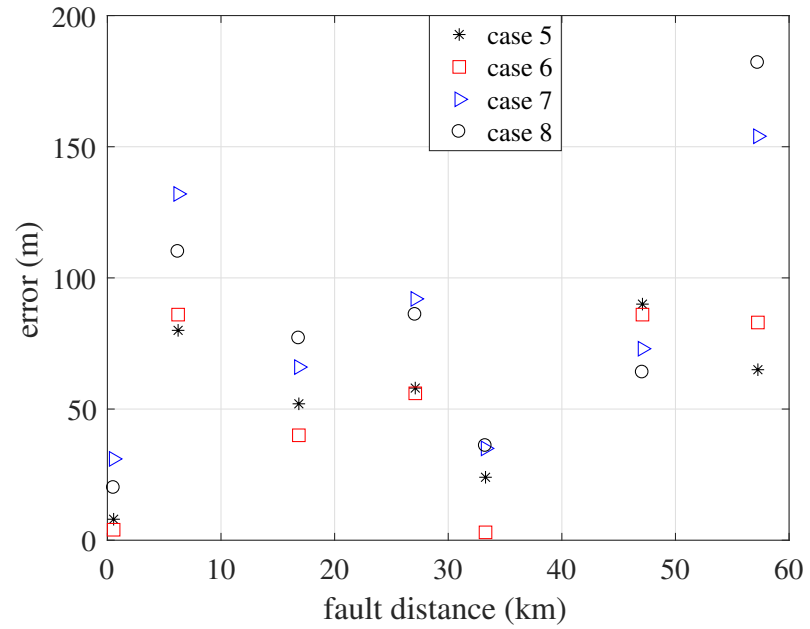


Fig. 6.39: Scenario 3, *ag* faults with cases 5 to 8

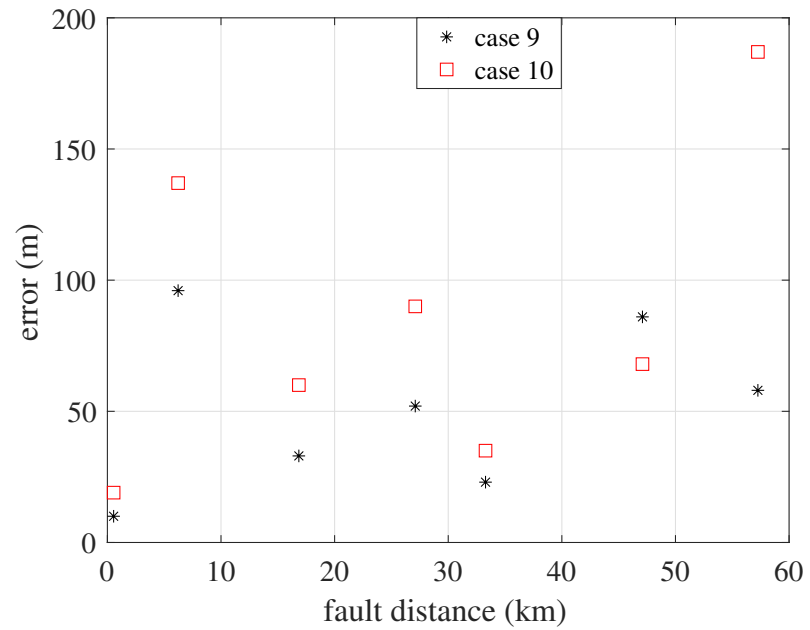


Fig. 6.40: Scenario 3, *ag* faults with cases 9 and 10

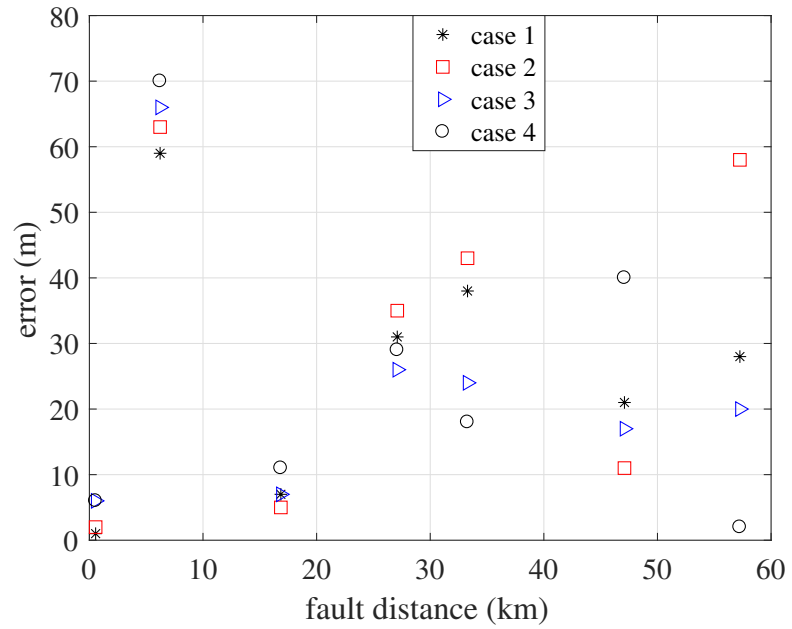


Fig. 6.41: Scenario 3, *ab* faults with cases 1 to 4

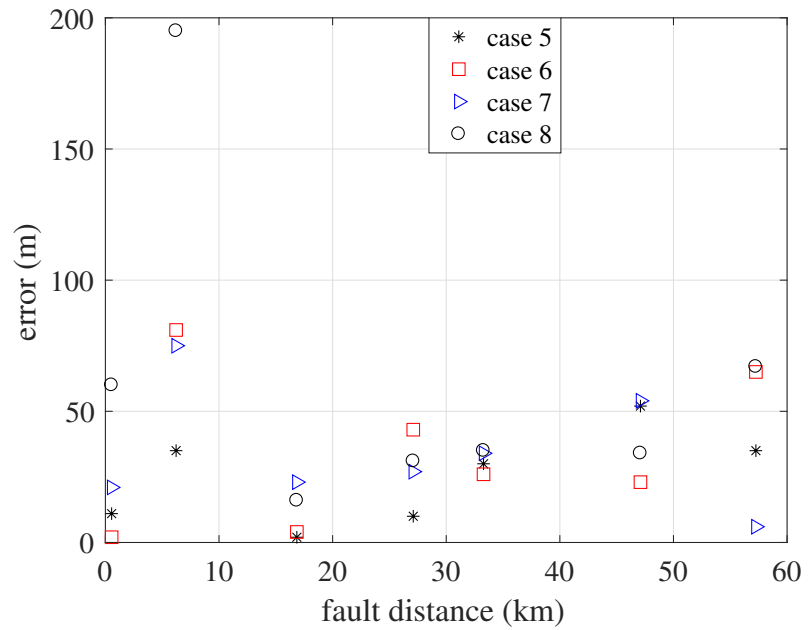


Fig. 6.42: Scenario 3, *ab* faults with cases 5 to 8

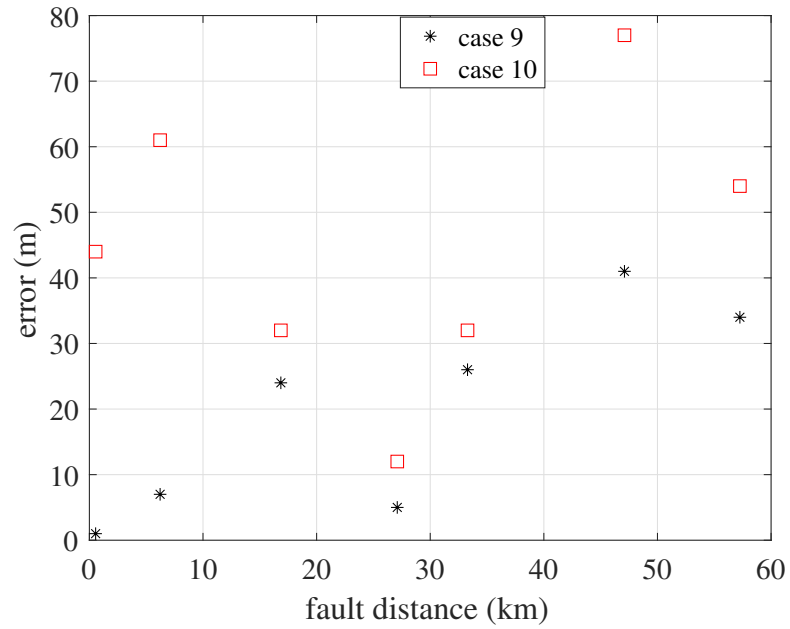


Fig. 6.43: Scenario 3, *ab* faults with cases 9 and 10

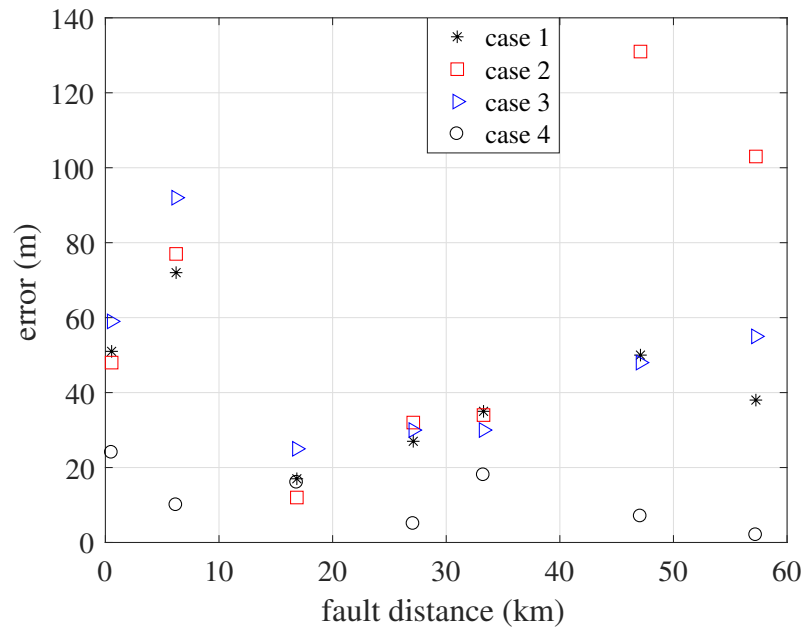


Fig. 6.44: Scenario 3, *abc* faults with cases 1 to 4

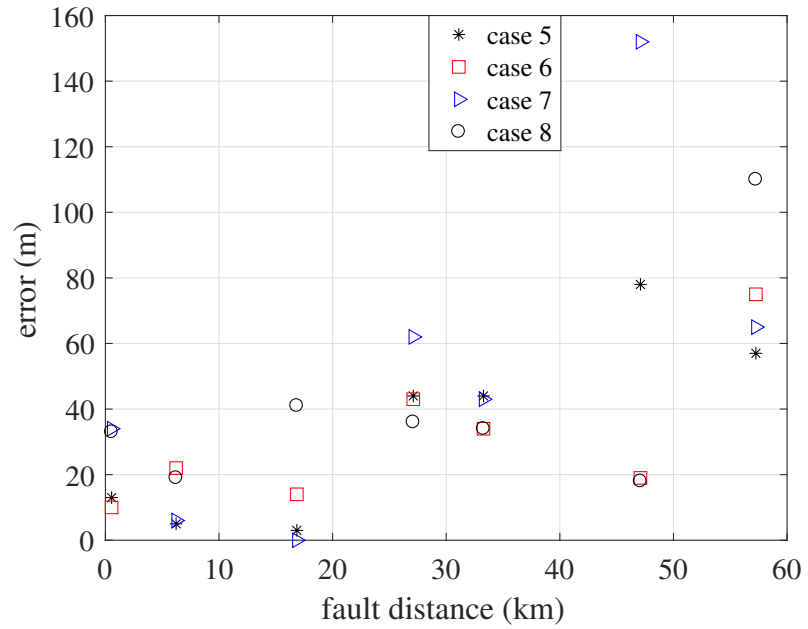


Fig. 6.45: Scenario 3, *abc* faults with cases 5 to 8

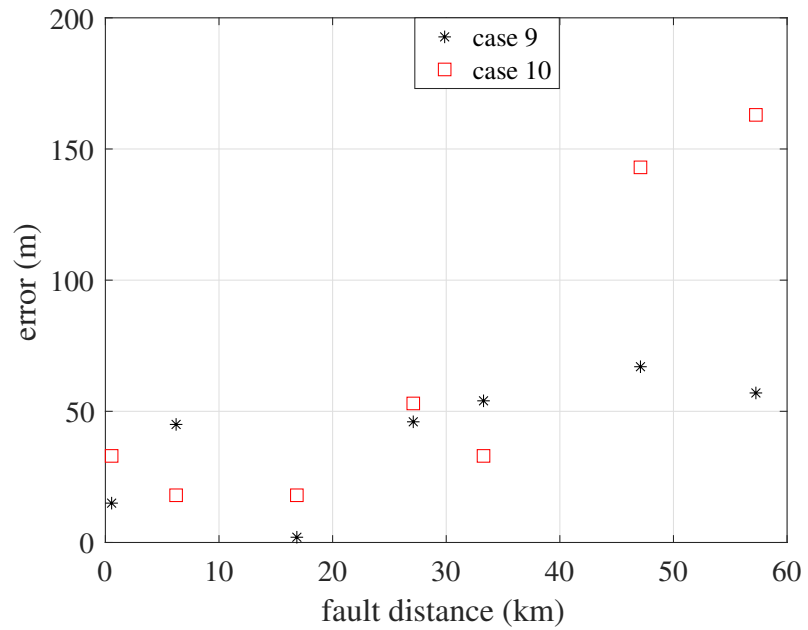


Fig. 6.46: Scenario 3, *abc* faults with cases 9 and 10

### 6.3.4 Scenario 4: loading

With two IBDGs connected at nodes 848 and 840, different loading cases were simulated to consider the load uncertainty. The four loading cases used previously with the radial distribution system have been considered as well as running at the full load. Also, the load uncertainty has been simulated but ignored by the fault location algorithm. Faults of different types have been created and the results obtained are shown in Fig. 6.47 to Fig. 6.49. In general, the estimation accuracy does not significantly deteriorate due to the load uncertainty. This result is the same as that obtained and discussed with the radial system evaluation.

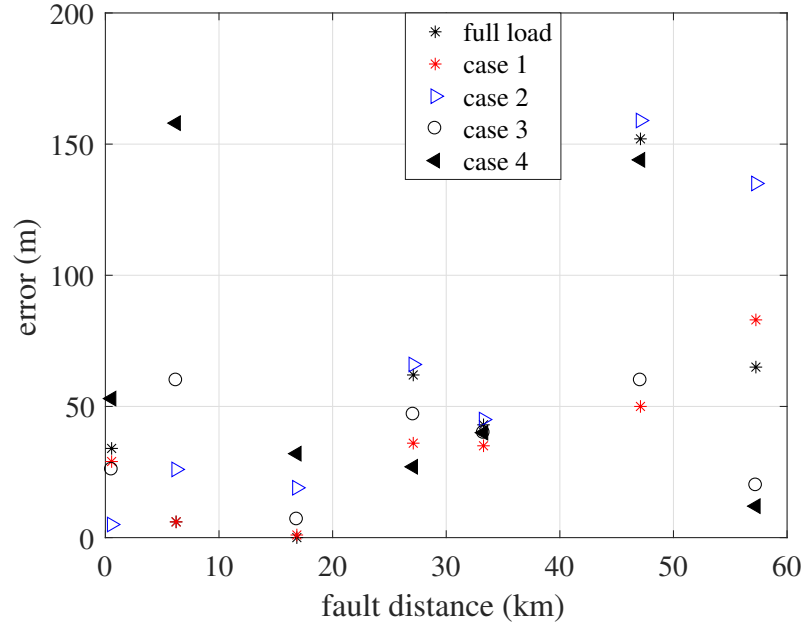


Fig. 6.49: Scenario 4, error for *abc* fault

### 6.3.5 Scenario 5: noise level

The voltage and current measured at the main substation and used in the fault location process have been subjected to randomly generated noise. The same noise levels illustrated in Fig. 6.20 have been utilized in this scenario. For each fault type, a box plot is used and the results are shown in Fig. 6.50

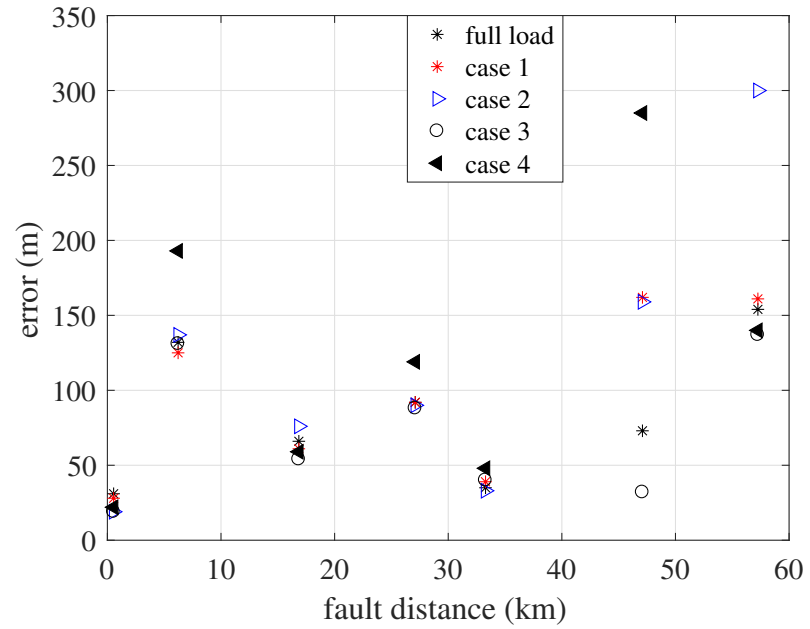


Fig. 6.47: Scenario 4, error for *ag* fault

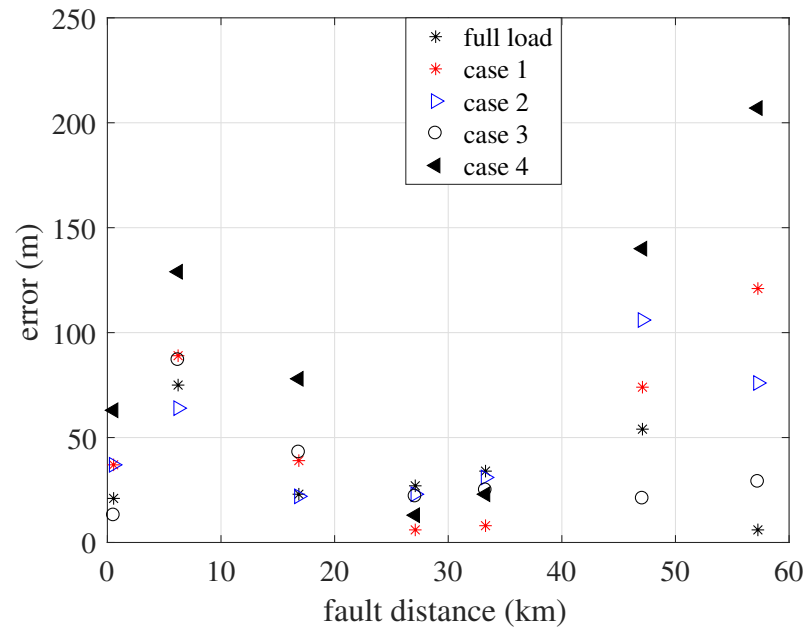


Fig. 6.48: Scenario 4, error for *ab* fault

to Fig. 6.52. The general statistics for the results show a total average error of 65 m and 79.14% of cases have an error of less than 100 m.

The previous extensive evaluation process shows the success and accuracy of the proposed fault location method as well as the proposed DG equivalent circuit. Using the available local measurements at the main substation, the estimation error is less than 100 m for most of cases. For all the simulation cases carried out in the previous scenarios (3465 cases), a histogram is plotted to show the distribution over different error ranges and is shown in Fig. 6.53. From the histogram, 79.8% of cases are located with error of less than 100 m which is lower than the value obtained with the radial distribution system (96.71%). Also, 97.66% of cases were located with error of less than 200 m which represents a low error value for this long distribution system.

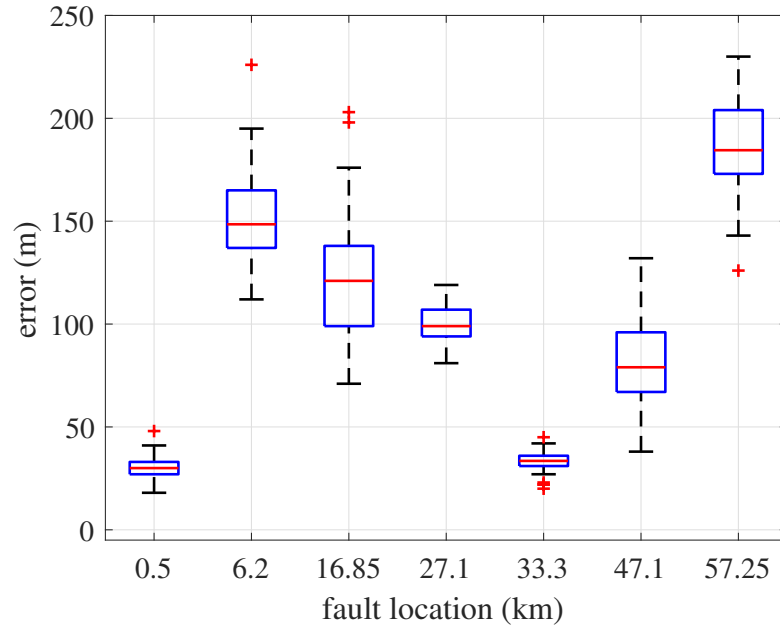


Fig. 6.50: Scenario 5, box plot for *ag* faults

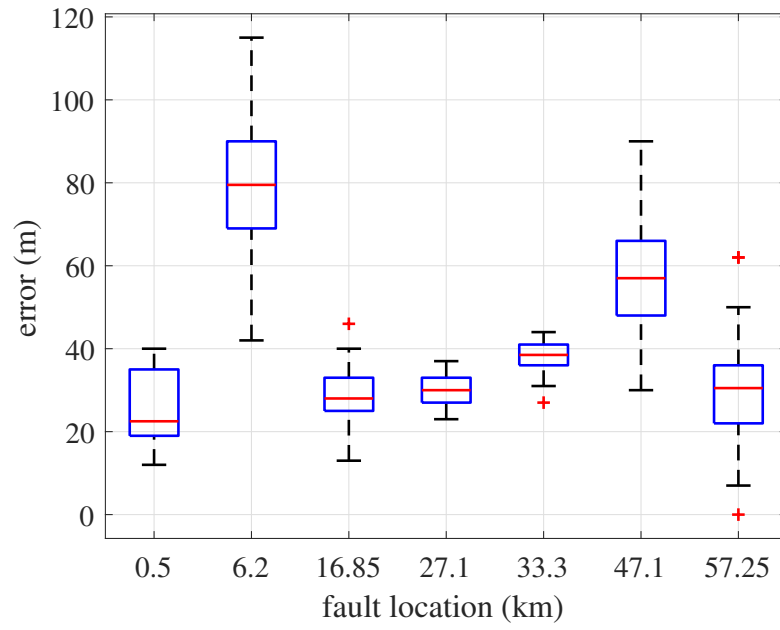


Fig. 6.51: Scenario 5, box plot for *ab* faults

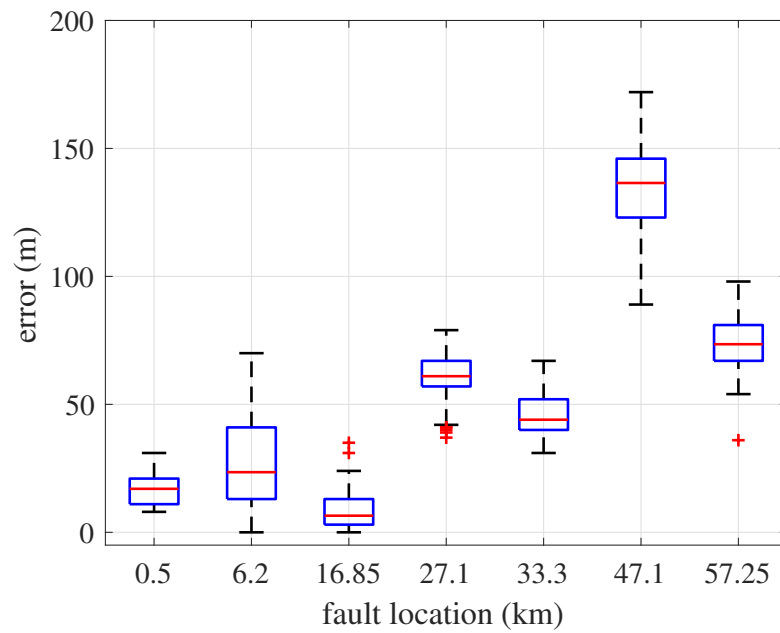


Fig. 6.52: Scenario 5, box plot for *abc* faults

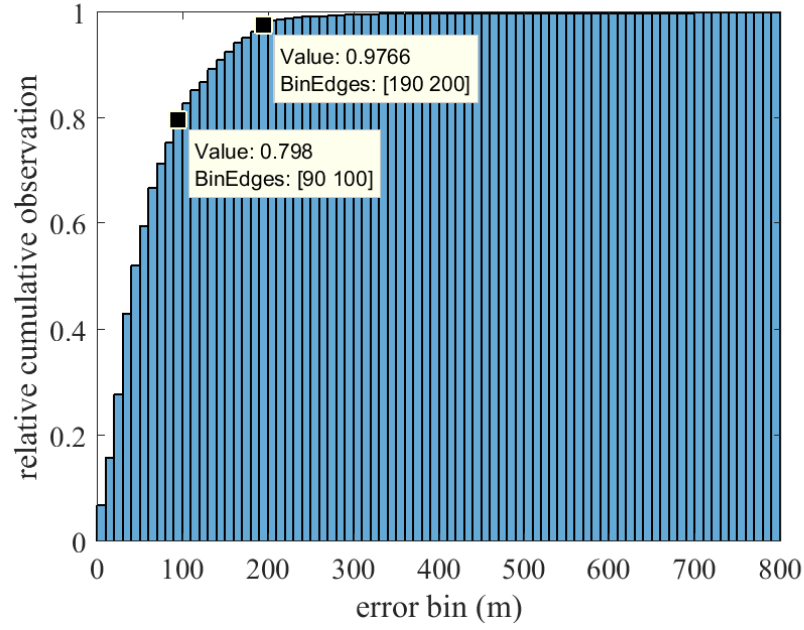


Fig. 6.53: Histogram for the whole tests, chapter 4

## 6.4 DEWIBFL Scheme

The double end method proposed in Chapter 5 using synchronized measurements or combined synchronized and non-synchronized measurements is evaluated in this section. The effect of the fault resistance and inception angle as explained in Table 6.2 (first two scenarios) are used. Also, the test cases 4 and 8 in Table 6.3 are used as a third scenario.

### 6.4.1 Scenario 1: fault resistance

The double end method has been applied for different fault types simulated with a variety of resistance values. Similar to the previous evaluation processes, the distance error values for the same fault type have been grouped in a box plot for each location. Also, samples of the results were drawn to show the variation of the error against the fault resistance at the same fault location. The box plots are presented in Fig. 6.54 to Fig. 6.56 for synchronized measurements.

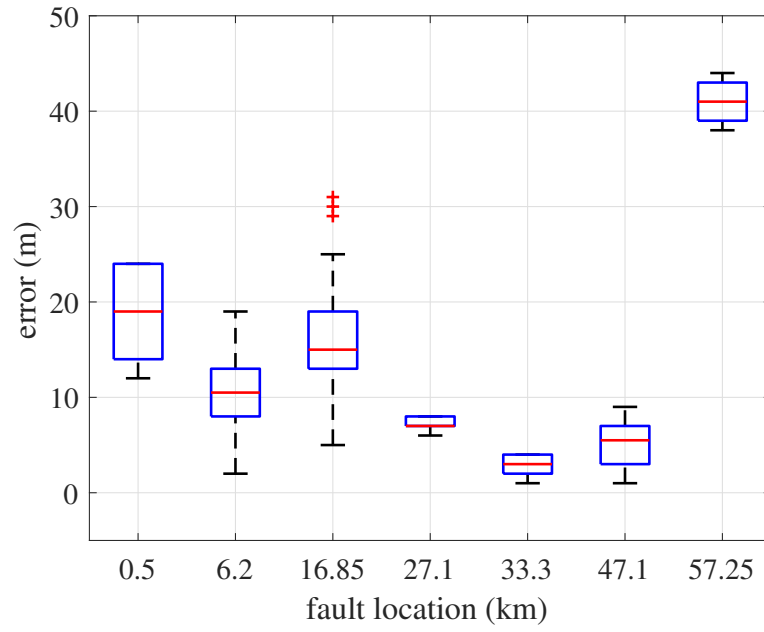


Fig. 6.54: Scenario 1, box plot for *ag* faults (synchronized measurements)

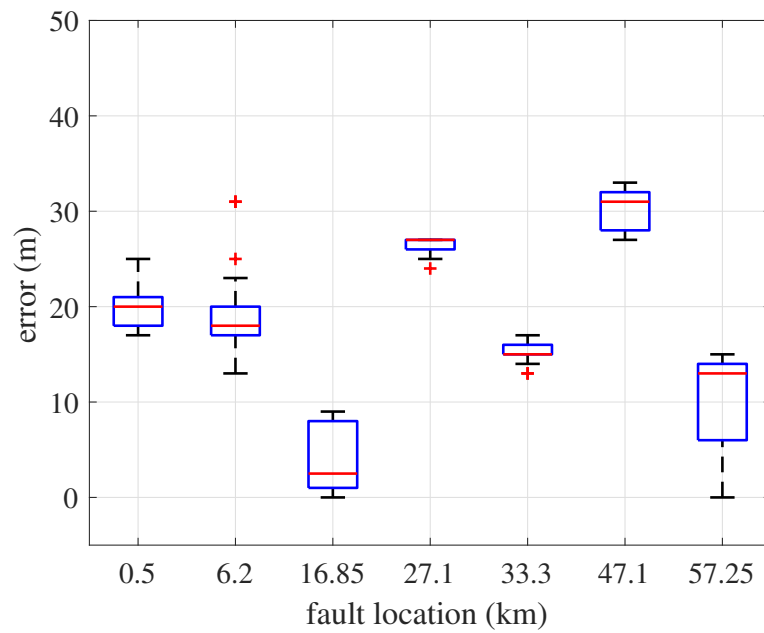


Fig. 6.55: Scenario 1, box plot for *ab* faults (synchronized measurements)

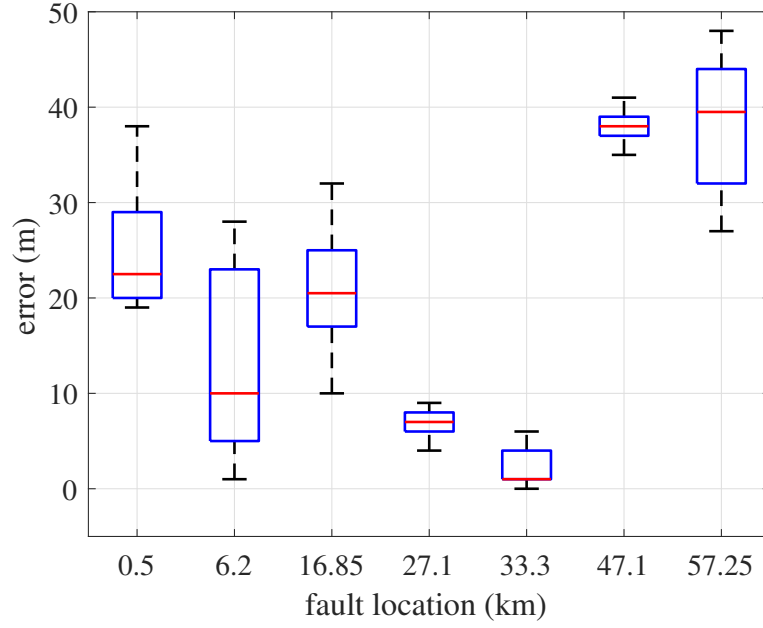


Fig. 6.56: Scenario 1, box plot for *abc* faults (synchronized measurements)

The results show a very high accuracy in distance estimation with all test cases having an error of less than 50 m. This high level of accuracy indicates that the performance of the method is not affected by either the change in the fault resistance value or the fault point.

In Fig. 6.54, the upper extreme of the box plots for locations 0.5, 27.1 and 33.3 km is not distinguishable from the upper quartile. This is attributed to the data points with the highest error values having roughly the same value. This is illustrated by plotting the error against fault resistance variation in Fig. 6.57 where the error at different resistance values is constant. When looking at the maximum error for each location, it is the same value for many fault resistance values leading to the aforementioned observation in the box plot. Also for location 27.1 km in Fig. 6.55, the upper quartile and the upper extreme lie at the median value. For this case, 31 fault cases out of 50 (more than half of points), have almost the same error value (27 m) as shown in Fig. 6.58. The sample of the results proves the robustness of the proposed method against fault resistance variation.

The results when using the combined measurements are shown in

Fig. 6.59 to Fig. 6.61 with error values of less than 50 m for all cases.

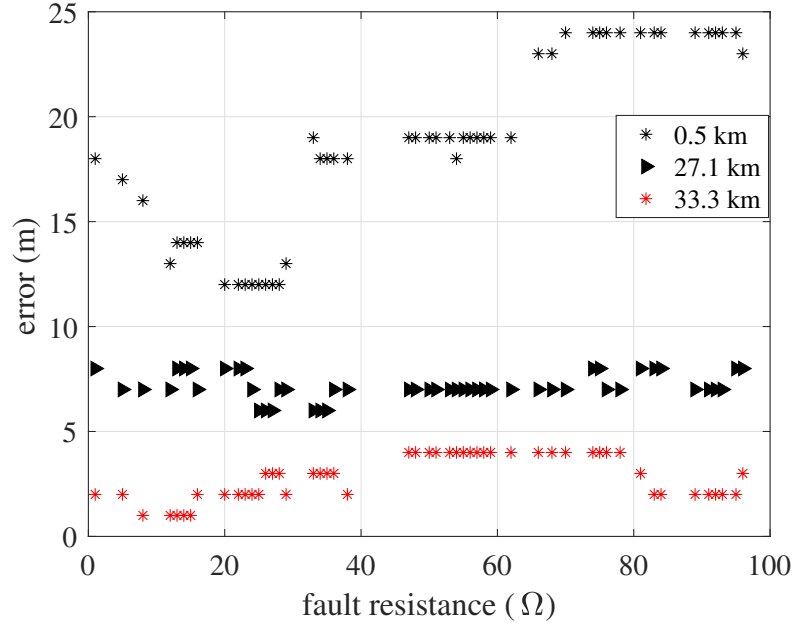


Fig. 6.57: Error in estimation for *ag* faults (synchronized measurements)

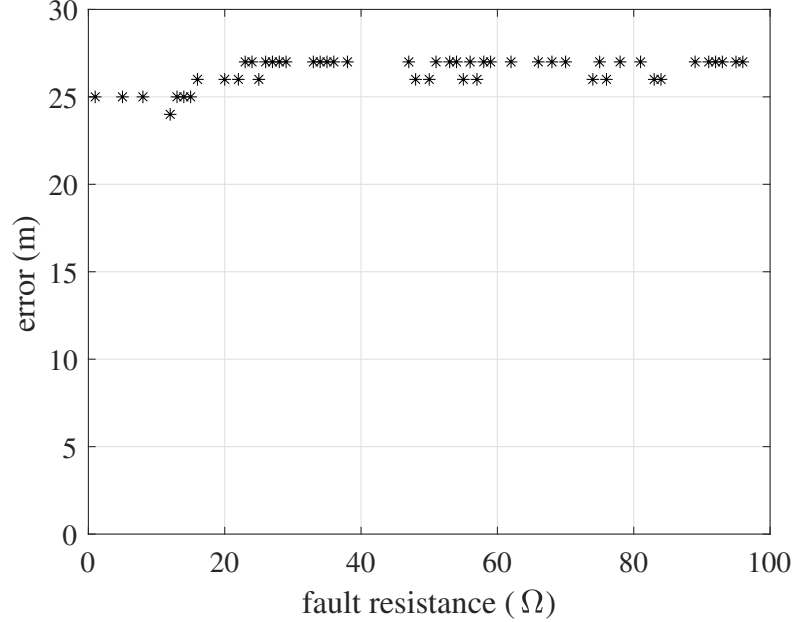


Fig. 6.58: Error in estimation for *ab* faults (synchronized measurements)

Comparing both groups of results (synchronized and combined measurements results), they provide a very close performance. As

an example, the results for *ag* faults at 0.5 km using both types of measurements are presented in Fig. 6.62 to show close performance.

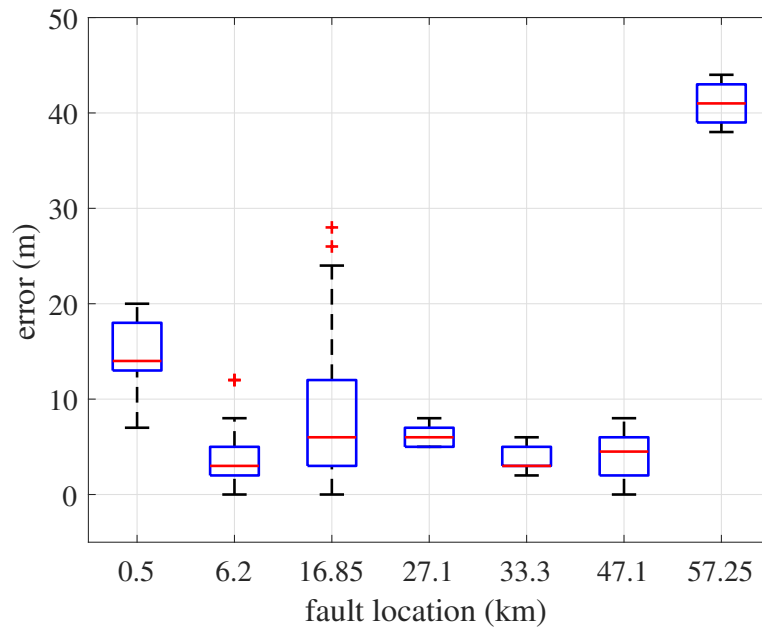


Fig. 6.59: Scenario 1, box plot for *ag* faults (combined measurements)

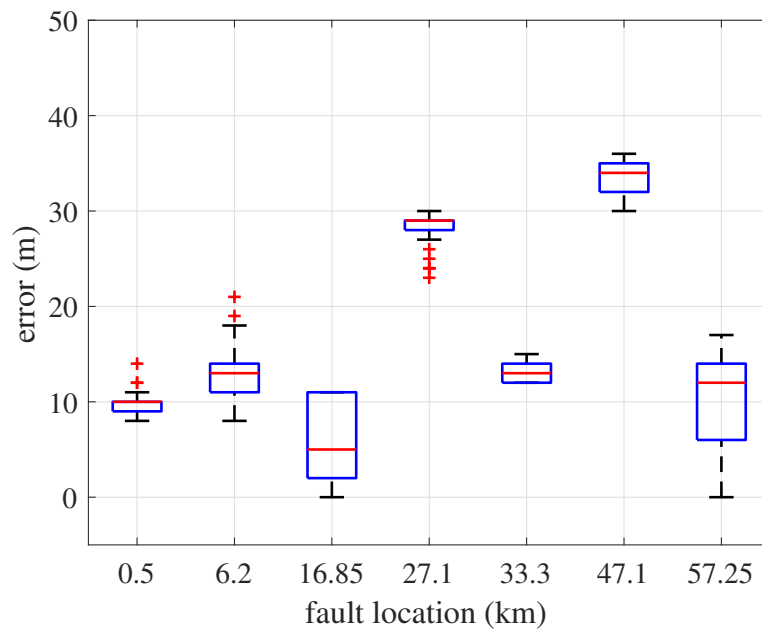
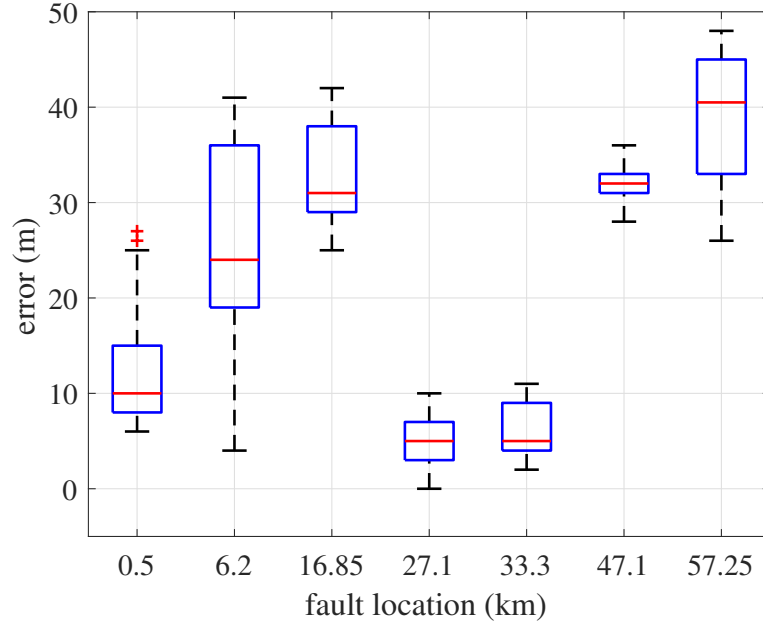
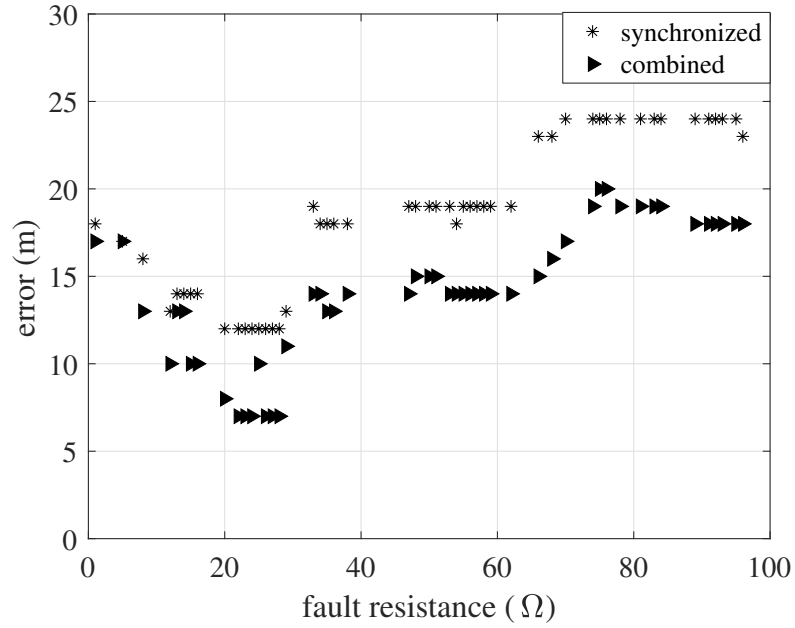


Fig. 6.60: Scenario 1, box plot for *ab* faults (combined measurements)


 Fig. 6.61: Scenario 1, box plot for *abc* faults (combined measurements)

 Fig. 6.62: Scenario 1: Error in estimation for *ag* faults (both methods)

### 6.4.2 Scenario 2: inception angle

The fault inception angles shown in Fig. 6.10 have been used for imposing each of *ag*, *ab* and *abc* faults. The results corresponding to using the

synchronized measurements are shown in Fig. 6.63, Fig. 6.65 and Fig. 6.67 for different fault types. Also, the results for the combined measurements method are shown in Fig. 6.64, Fig. 6.66 and Fig. 6.68.

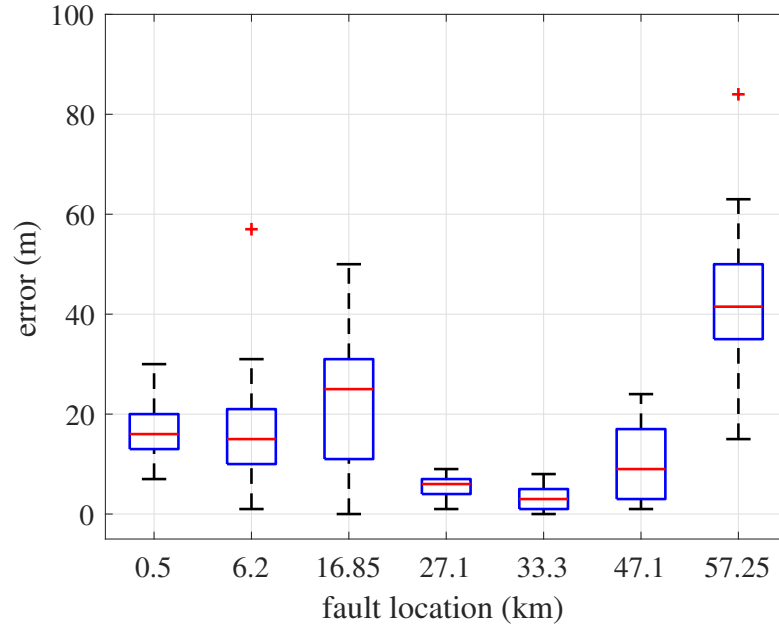


Fig. 6.63: Scenario 2, box plot for *ag* faults (synchronized measurements)

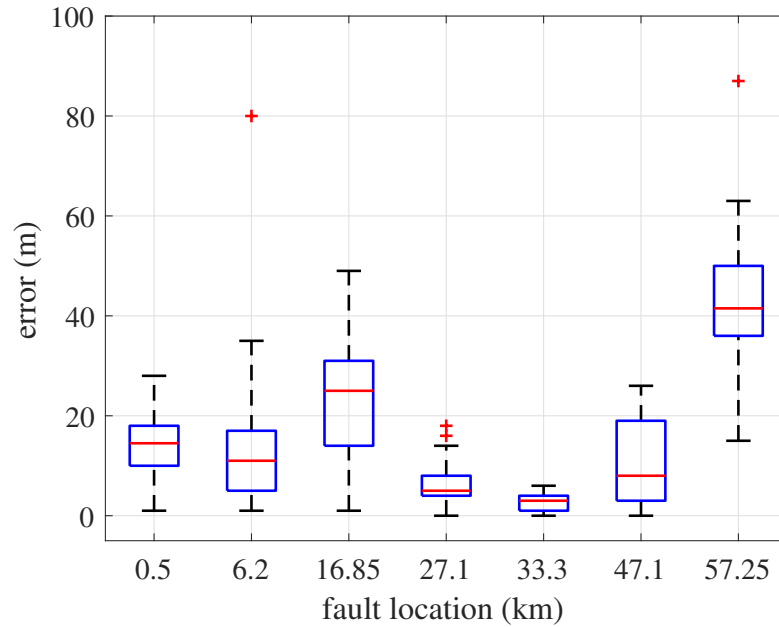


Fig. 6.64: Scenario 2, box plot for *ag* faults (combined measurements)

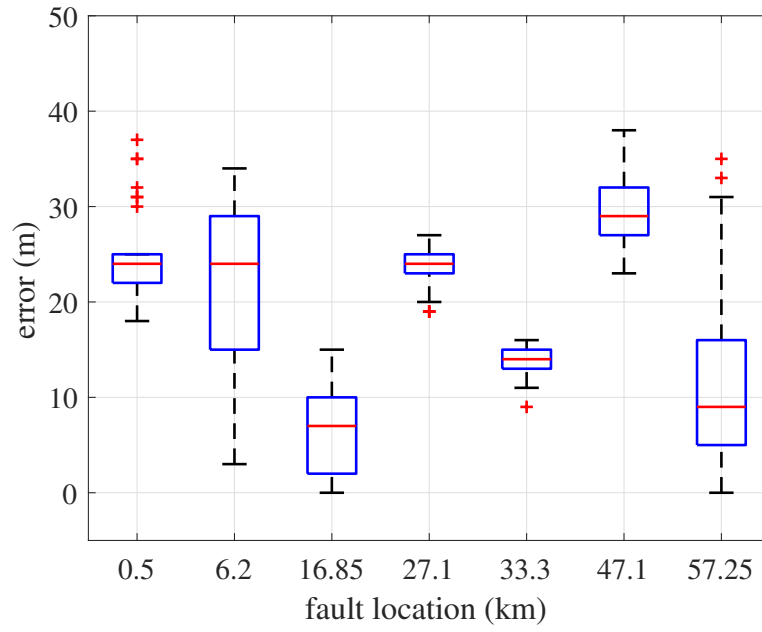


Fig. 6.65: Scenario 2, box plot for  $ab$  faults (synchronized measurements)

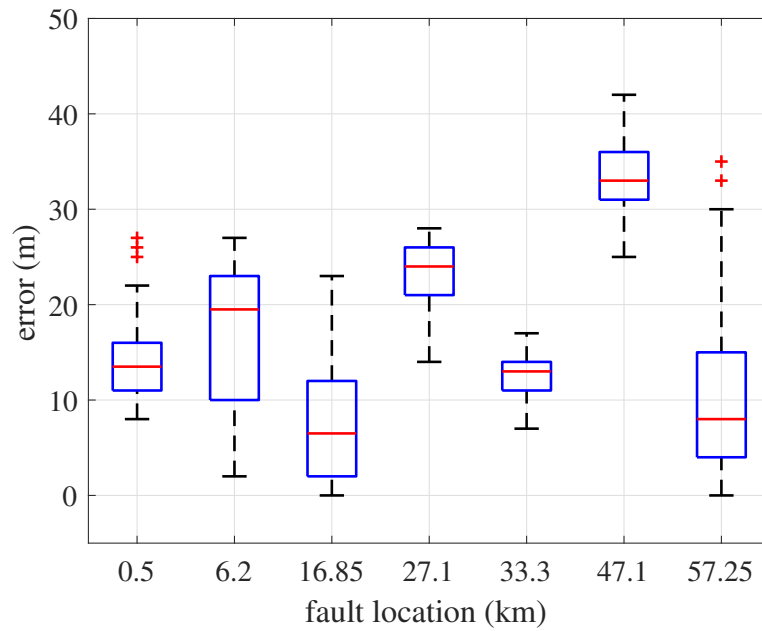


Fig. 6.66: Scenario 2, box plot for  $ab$  faults (combined measurements)

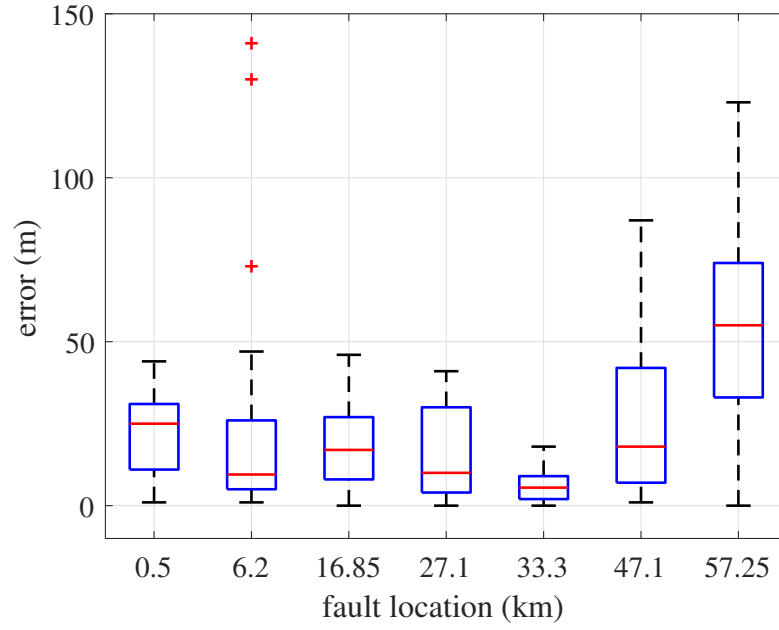


Fig. 6.67: Scenario 2, box plot for *abc* faults (synchronized measurements)

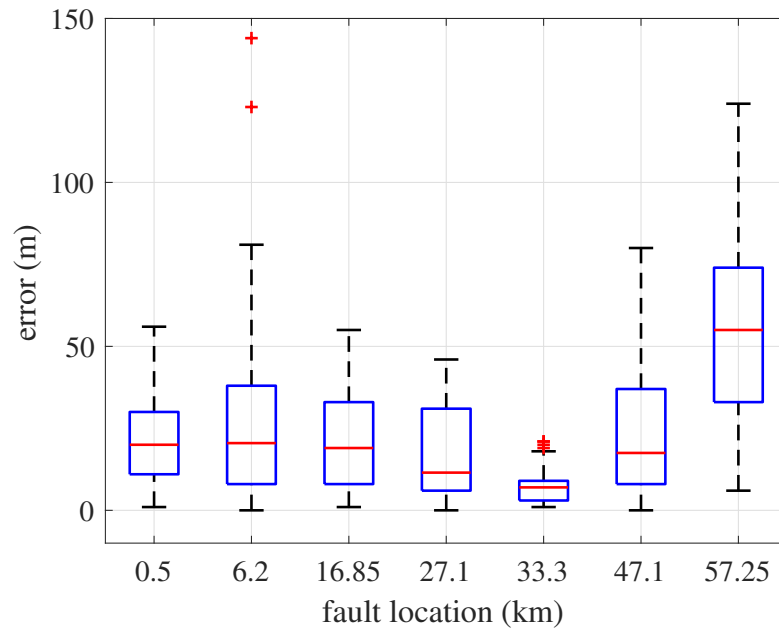


Fig. 6.68: Scenario 2, box plot for *abc* faults (combined measurements)

Firstly, the two groups of results emphasize the close performance for the two methods. The distance error versus the fault inception angle using both methods for *ag* faults at 16.85 km is shown in Fig. 6.69.

Regarding the synchronized measurements method, the box plots show that the upper extremes for five fault locations out of seven have a value less than 50 m for *ag* and *abc* faults. For the remaining two locations, the distance error is less than 100 m for most points. Moreover, all cases for the *ab* faults have an error of less than 50 m. Similarly for the other method, all *ab* faults and most of locations for *ag* and *abc* faults were estimated with a 50 m accuracy level. This very low error value for this long distribution system (longest path is 58 km) ensures the accuracy of the proposed methods and their robustness against the fault inception angle variation.

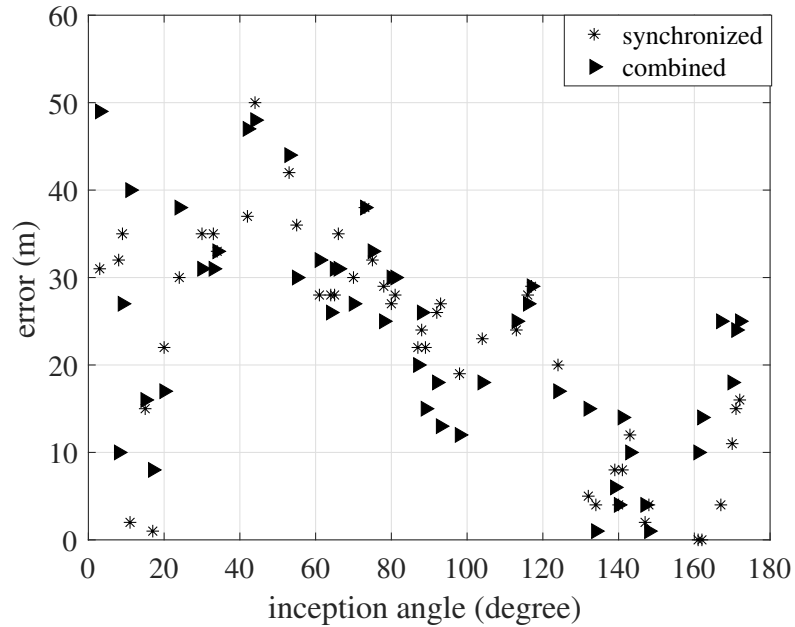


Fig. 6.69: Scenario 2: Error in estimation for *ag* faults (both methods)

### 6.4.3 Scenario 3: DG

Two cases for DG connection are used in this scenario. They are mentioned as cases 4 and 8 in Table 6.3. The three fault types with a resistance of  $10 \Omega$  and inception angle of  $90^\circ$  were simulated at the seven fault locations for each DG case (3 SBDGs and 3 IBDGs). The absolute error is illustrated in Table 6.4 and Table 6.5 for synchronized measurements and combined measurements respectively showing a close performance similar

to the conclusion derived from the previous two scenarios.

Table 6.4: Scenario 3: Error (in metres) using synchronized measurements

| <b>location</b> | <b>3 SBDGs</b> |           |            | <b>3 IBDGs</b> |           |            |
|-----------------|----------------|-----------|------------|----------------|-----------|------------|
|                 | <i>ag</i>      | <i>ab</i> | <i>abc</i> | <i>ag</i>      | <i>ab</i> | <i>abc</i> |
| 0.5             | 28             | 23        | 65         | 17             | 20        | 34         |
| 6.2             | 14             | 20        | 26         | 9              | 16        | 6          |
| 16.85           | 19             | 0         | 9          | 23             | 4         | 26         |
| 27.1            | 6              | 23        | 4          | 8              | 24        | 8          |
| 33.3            | 2              | 8         | 3          | 1              | 14        | 5          |
| 47.1            | 4              | 29        | 44         | 4              | 26        | 32         |
| 57.25           | 47             | 9         | 44         | 43             | 21        | 20         |

Table 6.5: Scenario 3: Error (in metres) using combined measurements

| <b>location</b> | <b>3 SBDGs</b> |           |            | <b>3 IBDGs</b> |           |            |
|-----------------|----------------|-----------|------------|----------------|-----------|------------|
|                 | <i>ag</i>      | <i>ab</i> | <i>abc</i> | <i>ag</i>      | <i>ab</i> | <i>abc</i> |
| 0.5             | 27             | 23        | 63         | 14             | 9         | 23         |
| 6.2             | 14             | 18        | 27         | 5              | 10        | 22         |
| 16.85           | 19             | 0         | 10         | 18             | 11        | 36         |
| 27.1            | 6              | 23        | 5          | 8              | 23        | 12         |
| 33.3            | 2              | 8         | 3          | 2              | 15        | 12         |
| 47.1            | 4              | 29        | 43         | 4              | 29        | 26         |
| 57.25           | 47             | 9         | 44         | 44             | 18        | 23         |

## 6.5 Comparison of Results

This section aims to derive overall statistics from the whole simulation studies carried out for the different proposed methods and also provides a comparison between the accuracy level obtained by different methods. Table 6.6 provides some statistics for all the simulation studies.

In Table 6.6, the total number of fault cases simulated for each category is mentioned. Also, the number of cases that satisfies a certain level of accuracy is mentioned. The cases where the distance error is less than 100 m and 200 m are mentioned as a number of cases and as a percentage of the corresponding total number of cases. Finally, the table provides the total average error (in metres) for each category.

It should be noted that the IEEE 34-bus feeder used for this study has an aggregated line length of 93 km and the longest path is 58 km. Starting with the proposed single end method with radial distribution system, the values ensure the high accuracy of the method where the percentage number of cases with error less than 100 m and 200 m are very high. Applying this method to active distribution systems sees a small reduction in the accuracy level. The reason for that is the approximations associated with the proposed DG equivalent model as discussed in the corresponding chapter. However, the majority of cases have an error of less than 200 m and the total average error is 65 m.

On the other hand, the double end method using either synchronized or combined measurements provides a very high accuracy level with the active distribution system. Almost all cases have an error of less than 100 m (99.63%). The double end method using measurements from all sources avoids using approximations in representing the DG. As an example, the results for *ag* faults for the case of 3 IBDGs using single end, synchronized measurements and combined measurements methods are grouped in Fig. 6.70. The single end method shows a clear difference in the error due to the DG model approximations. However as previously mentioned still all cases have an error of less than 200 m.

Table 6.6: Summary of the results

| <b>method</b>     | <b>system/<br/>measurements</b> | <b>total<br/>cases</b> | <b>cases<br/>&lt; 100 m</b> | <b>cases<br/>&lt; 200 m</b> | <b>total<br/>average (m)</b> |
|-------------------|---------------------------------|------------------------|-----------------------------|-----------------------------|------------------------------|
| <b>single end</b> | radial                          | 3255                   | 3148 (96.71%)               | 3239 (99.51%)               | 29                           |
|                   | active                          | 3465                   | 2765 (79.8%)                | 3384 (97.66%)               | 65                           |
| <b>double end</b> | synchronized                    | 2142                   | 2134 (99.63%)               | 2142 (100%)                 | 19                           |
|                   | combined                        | 2142                   | 2134 (99.63%)               | 2142 (100%)                 | 18                           |

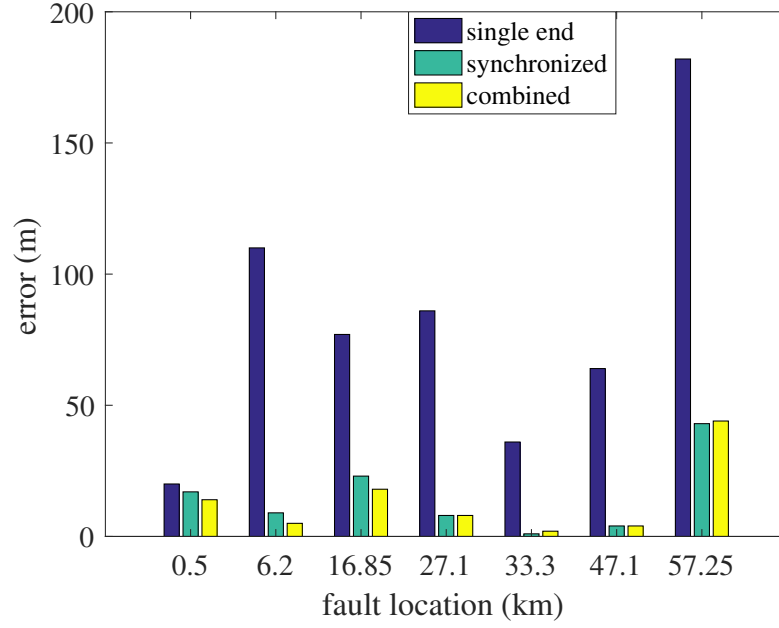


Fig. 6.70: Results using different proposed methods

## 6.6 Comparative Study

A brief comparison between the proposed methods and other impedance based fault location methods is provided in this section. The comparison considers both radial and active distribution systems.

### 6.6.1 Radial distribution system

The single end method proposed in Chapter 3 is compared to other single end impedance based methods reported in the literature. The methods introduced in [14], [20] have been used for the comparison as both of them considered the effect of the line shunt capacitance. Also, they were evaluated on the IEEE 34-bus feeder which is the same system used in this thesis.

These techniques use analysis at the system fundamental frequency. The capacitive effect of the line has been considered in [14] by using a  $\pi$  model for the lines. In [20], the technique considered the distributed parameter model and used the sequence components network to decouple the three-phase

system. However, the sequence networks will be coupled for an unbalanced system [11].

The evaluation in [14] considered the effect of the fault resistance and ignored the variation of the inception angle. In [20], three-phase faults were not simulated at different fault resistance values. Therefore, the comparison between the methods is delivered considering the common factor which is the fault resistance (phase to ground and phase to phase faults). Also, the evaluation in [14] considered many fault cases (combination of changing the fault point and the fault resistance). The average and maximum error values have been reported in [14] for the simulated cases. In [20], the number of cases was very limited. Hence, only the error values for the simulated cases were mentioned. An approximate average error value is derived for faults with resistance up to  $100 \Omega$  from the error values reported in [20].

The error in the estimated distance is converted from percentage to metres based on the total feeder length assumed in [14], [20] with the aim of comparison. Table 6.7 provides a summary for the average (avg) and the maximum (max) error values in meter obtained in [14], [20] as well as by the proposed method. This comparison shows the improved accuracy of the proposed method due to considering the distributed parameter model for the lines and also accounting for the system unbalance. Also, as is clear considering the distributed parameter line model in [20] provides better accuracy than [14] that employs the  $\pi$  model.

Table 6.7: Comparison result for radial distribution system

| fault<br>type         | [14] |      | [20] |     | proposed method |     |
|-----------------------|------|------|------|-----|-----------------|-----|
|                       | avg  | max  | avg  | max | avg             | max |
| single line to ground | 378  | 1170 | 84   | 300 | 40              | 107 |
| phase to phase        | 313  | 830  | 83   | 227 | 15              | 50  |

### 6.6.2 Active distribution system

The single end and double end concepts developed in this thesis for active distribution systems have been compared to other impedance based methods [22], [24], [25], [27]. The methods in [24], [25], [27] use synchronized measurements. Therefore, they are compared with the proposed double end method. In [22], a during fault model has been developed for the IBDG and the fault location algorithm depends on the local measurements at the main substation. The proposed single end method is compared to [22].

The IEEE 34-bus has been used as a case study in [22], [24], [25], [27]. The comparison considers the effect of the fault resistance with single line to ground ( $ag$ ), phase to phase ( $ab$ ) and three-phase ( $abc$ ) faults as they are covered by all methods [22], [24], [25], [27]. The percentage error reported in [24], [25] has been converted to metres using a total feeder length of 58 km. It was not possible to calculate an average value for phase to phase and three-phase faults in [25] as only the limits of the error obtained were mentioned. In [22], the results have been delivered in a box plot form, the maximum value and an approximate average value (average of upper and lower quartiles values) have been derived from the given box plot. The maximum fault resistance values in [25], [24], [27] and [22] are 40, 25, 100 and 100  $\Omega$  respectively.

Table 6.8 summarizes the average and maximum error reported in different references and also obtained by the proposed methods (single, synchronized measurements and combined measurements). In general, using the synchronized measurements in [24], [25], [27] as well as the proposed double end methods provides better performance than using the local measurements at the main substation in [22] and the proposed single end method. The performance of different methods using synchronized measurements is close. However, the high error in [25] may be attributed to using short line model to derive the method. On the other hand, depending on the local measurements sees an increase in the error values.

Nevertheless, the proposed single end method provides a higher accuracy than [22]. The total average error value for the proposed single end method is 70 m compared to 283 m for [22].

Table 6.8: Comparison result for active distribution system

| method   |              | <i>ag</i> |      | <i>ab</i> |      | <i>abc</i> |      |
|----------|--------------|-----------|------|-----------|------|------------|------|
|          |              | avg       | max  | avg       | max  | avg        | max  |
|          | [25]         | 272       | 580  | —         | 1740 | —          | 174  |
|          | [24]         | 29        | 58   | 29        | 52   | 6          | 12   |
|          | [27]         | 17        | 32   | 15        | 25   | 5          | 7    |
|          | [22]         | 450       | 1300 | 50        | 300  | 350        | 1225 |
|          | single       | 95        | 336  | 47        | 199  | 69         | 229  |
| proposed | synchronized | 14        | 44   | 18        | 33   | 20         | 48   |
|          | combined     | 12        | 44   | 16        | 36   | 22         | 48   |

## 6.7 Multiple Estimation Study

The literature review in Chapter 2 discussed the definition of “multiple estimation” and also showed some efforts to overcome this problem. The solutions included, but were not limited to, knowledge of the protective devices installed along the system and also their characteristics (time-current curves), the change in the system loading after clearing the fault, installing fault indicators and using information from smart meters that exist with modern distribution systems. In this section, a study that explains how to employ the measurements available at multiple points in an active distribution system can help to prune down the possible candidate locations. The idea is presented assuming availability of synchronized measurements between some nodes (i.e. synchronized or combined measurements). Then, a similar concept can be employed with non-synchronized measurements.

### 6.7.1 Combining estimates concept

The availability of synchronized measurements allows the use of the double end method to locate the fault. The double end method always defines a single fault point that exists on the feeder path connecting the two measurement nodes used to apply the method. To illustrate this, consider the system in Fig. 6.71 where the measurements at nodes N1 and N2 are used to develop the double end method. Therefore, all faults located by the method are assumed to be on the path connecting N1 and N2. Faults along a lateral tapped from this path are estimated as a fault at the lateral tapping point with the path e.g. all faults along the lateral between nodes T and L are located as a fault at node T. From that it can be concluded:

- Faults along the feeder path connecting the two measurement nodes are fully located using the double end method.
- Faults along a lateral are located as a fault at the lateral tapping point.

Therefore, the double end can either identify the fault location or the faulted lateral. In the later case, it will be necessary to find the actual location along the lateral. The process flow shown in Fig. 6.72 illustrates how the double end method can be re-applied or combined with the single end method to discriminate between faults on the main feeder and on the lateral.

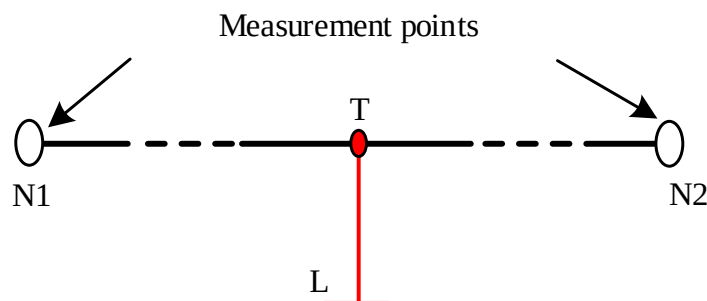


Fig. 6.71: Simple system with a lateral

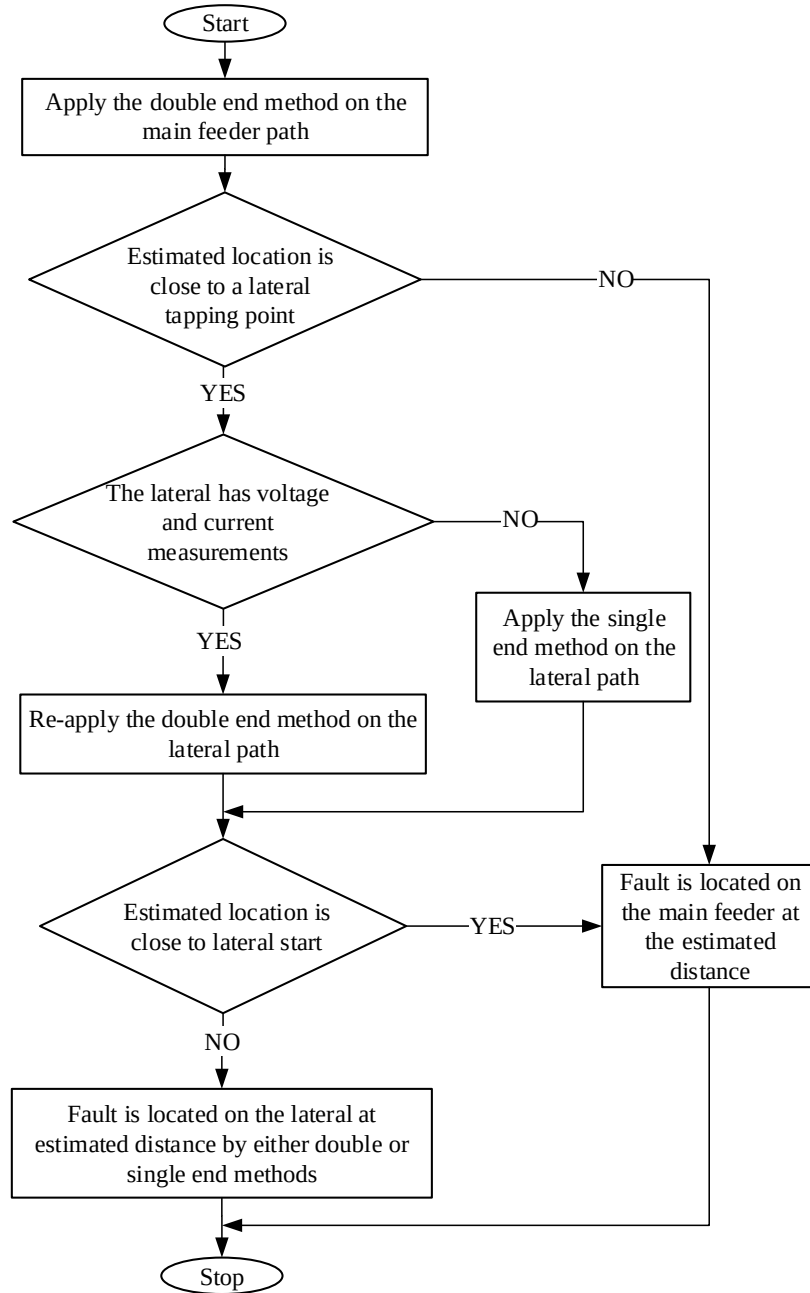


Fig. 6.72: Flowchart to discriminate between faults on the main feeder and on the laterals

To explain the process, consider the system in Fig. 6.73 with 2 DGs at nodes N2 and N3 where N1 represents the main substation. With respect to the main substation, faults at locations F1, F2, F3 and F4 are assumed to be at the same electrical distance. Also, faults F5 to F8 lie at the same

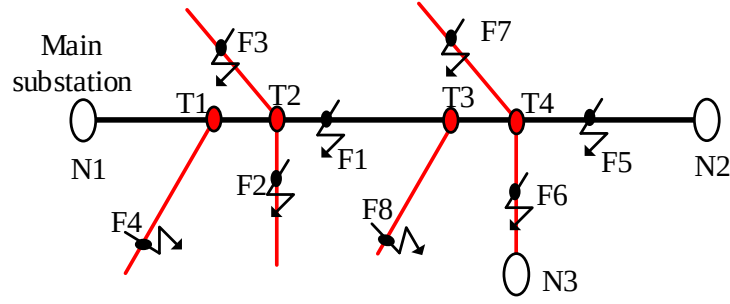


Fig. 6.73: System with multiple laterals

distance from the main substation. Therefore, a basic single end method applied using the local measurements at the main substation would have four candidate locations for each fault (F1 to F8). These faults can be located according to the previous discussion assuming the measurements are synchronized. Table 6.9 shows the application of the process in Fig. 6.72 for each fault case (F1 to F8).

It is clear that instead of four candidate locations for each fault case, the fault can be accurately located using the double end method, combined double end and single end methods or by re-applying the double end method. When there are multiple laterals tapped off from the same node, and no measurements are available along the lateral, applying the single end method results in a candidate location for each lateral (e.g. faults F2 and F3). In this case, a method from the literature with the aid of extra information can be used to locate these faults [33], [52].

In case of non-synchronized measurements, it will be only possible to apply the single end method. Therefore, the single end method is to be applied at each measurement point resulting in the possible candidate locations. Then, the estimates from different measurement points can be combined to find potential common location or locations. This process can at least reduce the candidate locations.

Table 6.9: Procedure to locate different faults

| <b>fault</b> | <b>process description</b>                                                                                                                                                                                                                                                                                                                                       |
|--------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| F1           | Fully located by applying the double end method between nodes N1 and N2.                                                                                                                                                                                                                                                                                         |
| F2           | Partially located at T2 by applying the double end method between nodes N1 and N2. As the lateral does not have measurements, the single end method, using the measurements at N1, is applied on the lateral to estimate the fault F2. However, F3 is a possible candidate that will result from the single end. Therefore, there will be 2 candidate locations. |
| F3           | Same procedure as F2                                                                                                                                                                                                                                                                                                                                             |
| F4           | Partially located at T1 by applying the double end method between nodes N1 and N2. Then, applying the single end method on the lateral can estimate the fault F4.                                                                                                                                                                                                |
| F5           | Fully located by applying the double end method between nodes N1 and N2.                                                                                                                                                                                                                                                                                         |
| F6           | Partially located at T4 by applying the double end method between nodes N1 and N2. Then, re-applying the double end method between N1 and N3 estimates the fault F6.                                                                                                                                                                                             |
| F7           | Partially located at T4 by applying the double end method between nodes N1 and N2. Then, re-applying the double end method between N1 and N3 estimates the fault F6 at the tapping T4 too. Finally, the single end provides the accurate location for F7 when applied on its lateral.                                                                            |
| F8           | Partially located at T3 by applying the double end method between nodes N1 and N2. Then, applying single end method on the lateral can estimate the fault F8.                                                                                                                                                                                                    |

### 6.7.2 Example from the simulation study

The IEEE 34-bus feeder used in the previous evaluation studies contains seven laterals. Two fault cases have been simulated and the process discussed above has been used to define the fault location. Two SBDGs were connected at nodes 848 and 840. The voltages and currents at the DGs and the main substation are synchronously measured.

The first case illustrates combining the double end and the single end methods to estimate the fault location. A single line to ground fault with a resistance of  $1 \Omega$  and inception angle of  $90^\circ$  has been simulated at a distance of 40 km from the main substation. The exact fault location lies on the lateral extending between node 816 and node 822. This is illustrated in Fig. 6.74 as the actual location. The fault distance is divided into two parts: a length of 31.726 km between node 800 (the main substation) and node 816 (the lateral tapping node with the main feeder) and 8.274 km distance along the lateral (distance from node 816 to the actual fault point).

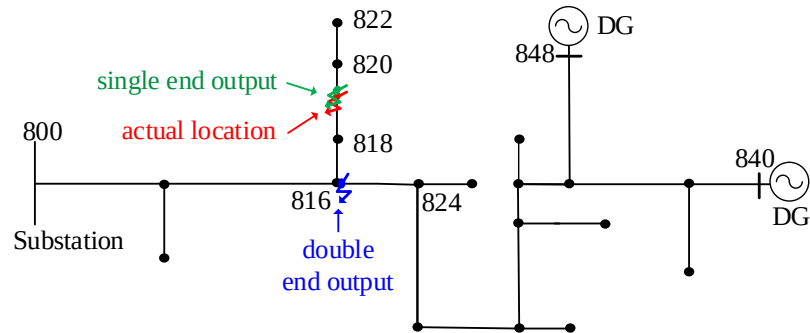


Fig. 6.74: Example for combined double and single end methods

Firstly, the double end method has been applied and the estimated distance was 31.763 km. This distance is very close to node 816 and is indicated in Fig. 6.74 as double end output. Therefore, the fault may be at this location or at any point along the lateral at node 816. As the lateral does not contain any measurements, a single end method has been applied on the lateral. The single end method estimated a fault at a distance of

8.281 km measured from node 816. This result points to the actual fault location with distance error of 7 m. Therefore, combining the double end with the single end was able to identify the fault along the lateral.

For the second case, the fault has been simulated at a distance of 57 km from the main substation. This fault lies on the lateral tapped off at node 834. The total fault distance is divided into 55.982 km from main substation to node 834 and 1.018 km from node 834 to the actual fault location as illustrated in Fig. 6.75. The double end method has been applied on the main feeder (between nodes 800 and 848) providing a fault at a distance of 55.821 km and is pointed to in Fig. 6.75 as the main double end output. The estimated location is close to node 834 which has a lateral. Therefore and similar to the first case, the fault may be either at the estimated location or along the lateral. As the lateral has measurements, a double end method is applied again between node 800 and the lateral measurement node 840 and accordingly it is not required to apply the single end method. A fault was estimated at a distance of 973 m measured from node 834 or 56.955 km from the main substation. The second double end method accurately located the actual fault point with an absolute error of 45 m.

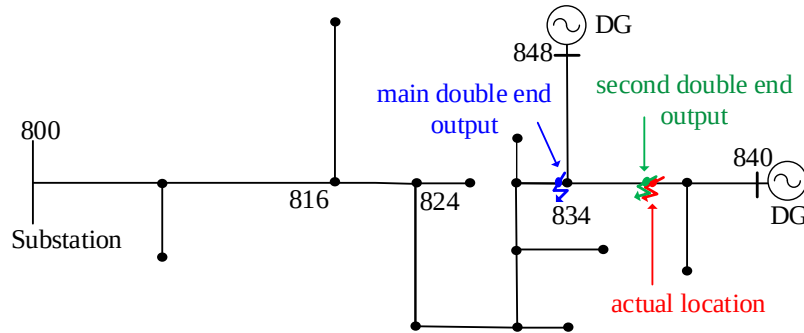


Fig. 6.75: Example for combining double end methods

It is worth noting that, if the fault point exists at the lateral tapping point, applying either the single end method or a second double end method will result in a small fault distance measured from the lateral tapping node indicating the actual fault location is around the tapping point.

## 6.8 Limits to Successful Operation

The proposed methods (single and double end) have been derived and evaluated assuming a constant fault resistance. However, the fault resistance may be time variant [74]. In this section, the performance of the proposed single end and double end methods is tested while simulating a fault with a time varying resistance.

### 6.8.1 Time varying resistance

In [74], a fault resistance trajectory of a real-world fault caused by a brush fire under a transmission line is provided and is shown in Fig. 6.76. The fault starts with a high resistance which decays to its steady state value. The shape of the fault resistance variation could be approximated as an exponential waveform. Assuming the fault initiated at 0.065 s and the steady state resistance was at time 0.09 s, therefore this period of 0.025 s can be used to provide an approximate estimate for the waveform time constant. The exponential decay requires about  $5\tau$  to arrive the steady state where  $\tau$  is the waveform time constant. Therefore, the time constant  $\tau = 0.025/5 = 0.005$  s for the fault resistance waveform in Fig. 6.76.

In order to simulate a fault with a time varying resistance, the Alternative Transient Program (ATP) has been used [75]. In ATP, the fault resistance is simulated using a TACS-controlled time-dependent resistor (type 91). The fault resistance is simulated as an exponential function which is given in (6.2). The block diagram of the simulated time-dependent fault resistance is shown in Fig. 6.77.

$$R(t) = R_{ss} + (R_{in} - R_{ss})e^{-(t-t_0)/\tau} \quad (6.2)$$

where  $R_{in}$  and  $R_{ss}$  are the initial and steady state values for the fault resistance,  $t_0$  is the fault inception time.

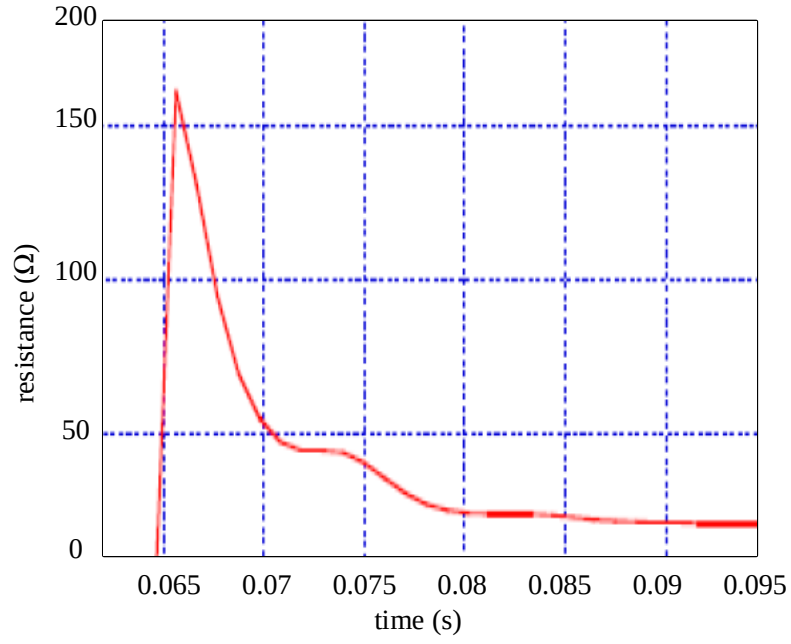


Fig. 6.76: Real-world fault resistance trajectory [74]

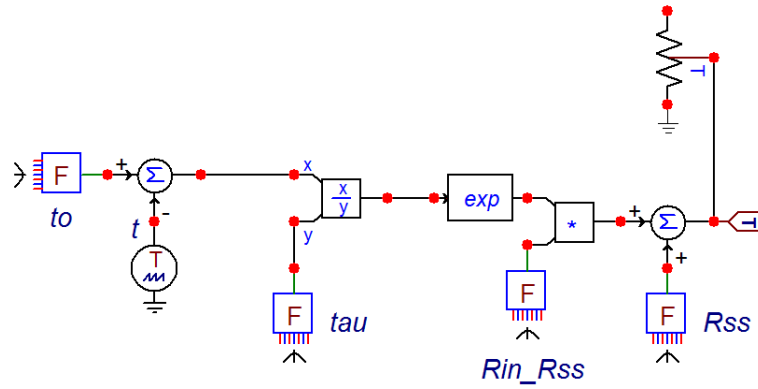


Fig. 6.77: Simulated time-dependent fault resistance

### 6.8.2 Evaluation of the methods

A simple single section system has been simulated using the ATP as shown in Fig. 6.78. The distributed parameters three-phase transposed line model has been used and the line parameters are given in Table 6.10 for two independent modes called (+ mode) and (0 mode) (as defined by the ATP

block). A star-connected load of  $600 \Omega$  and  $1 \text{ H}$  has been connected at the end of the line. The line to line source voltage is  $24.9 \text{ kV}$ .

The measurements at the source side are used with the single end method while measurements from both ends are used with the double end method. A phase  $a$  to ground fault has been imposed at  $t = 0.1 \text{ s}$  at the middle point of the line (total line length is  $4 \text{ km}$ ). For the simulated fault resistance, the initial and final values were assumed as  $150 \Omega$  and  $20 \Omega$  respectively. The time constant value was assumed as  $5 \text{ ms}$ .

The simulated fault resistance is measured using a TACS probe and is shown in Fig. 6.79. The fault is simulated also with a constant  $20 \Omega$  resistance for the aim of comparison. The fault distance is estimated using the single end and the double end methods for both time varying and constant fault resistances and the results are shown in Fig. 6.80 and Fig. 6.81.

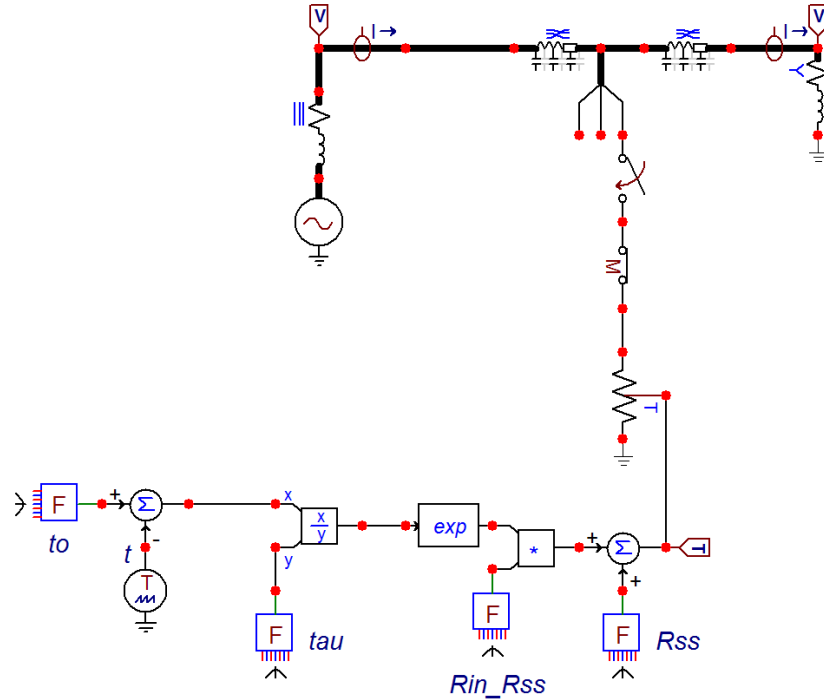


Fig. 6.78: System with a time-dependent fault resistance

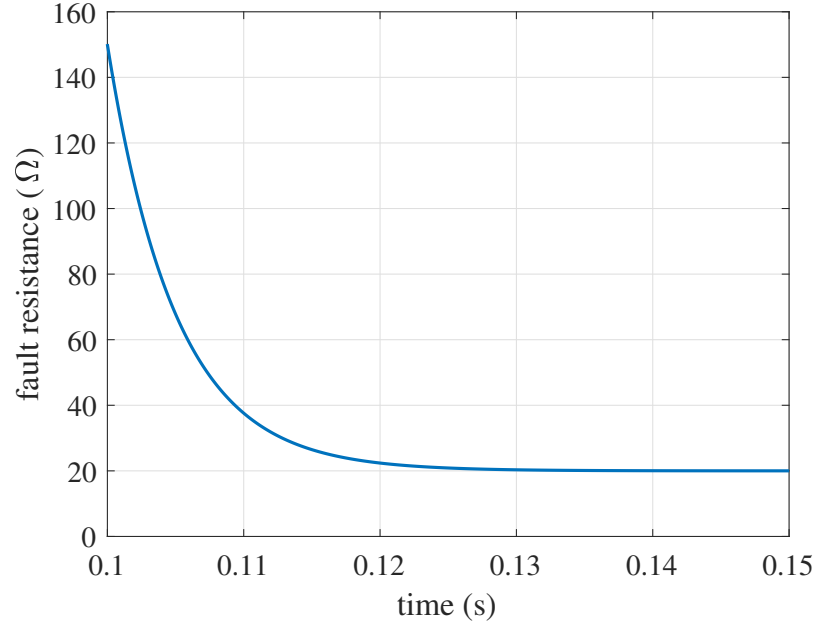


Fig. 6.79: Time-dependent fault resistance

Table 6.10: Line parameters for the ATP model

| parameter                              | + mode                 | 0 mode                |
|----------------------------------------|------------------------|-----------------------|
| resistance ( $\Omega/\text{m}$ )       | $7 \times 10^{-7}$     | $11 \times 10^{-7}$   |
| inductance ( $\text{mH}/\text{m}$ )    | $1.49 \times 10^{-3}$  | $4.77 \times 10^{-3}$ |
| capacitance ( $\mu\text{F}/\text{m}$ ) | $12.18 \times 10^{-6}$ | $5.95 \times 10^{-6}$ |

The double end method is not affected by the nature of the fault resistance because the derivation of the method is not affected by the fault resistance. On the other hand, the fault resistance nature has a significant effect on the single end method. The method performance deteriorates in the low frequency range as the time domain change of the fault resistance would be noticeable with lower frequency components. The high frequency components (short period in time domain), are less affected by the variation. To what degree the variation of the fault resistance affects the performance appears to be a function of the time constant of the time varying resistance. Fast changing resistance (low time constant) is expected to have effect on a wider frequency range.

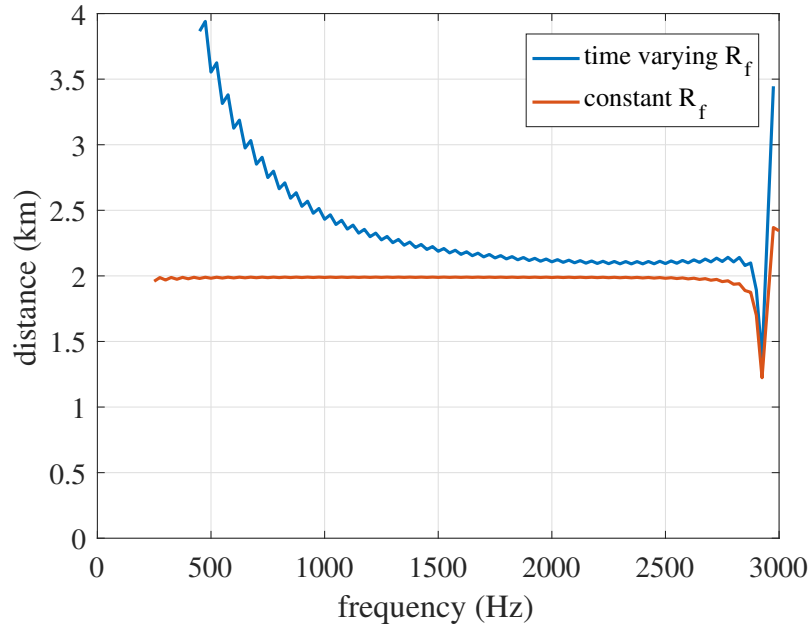


Fig. 6.80: Estimated distance using the single end method

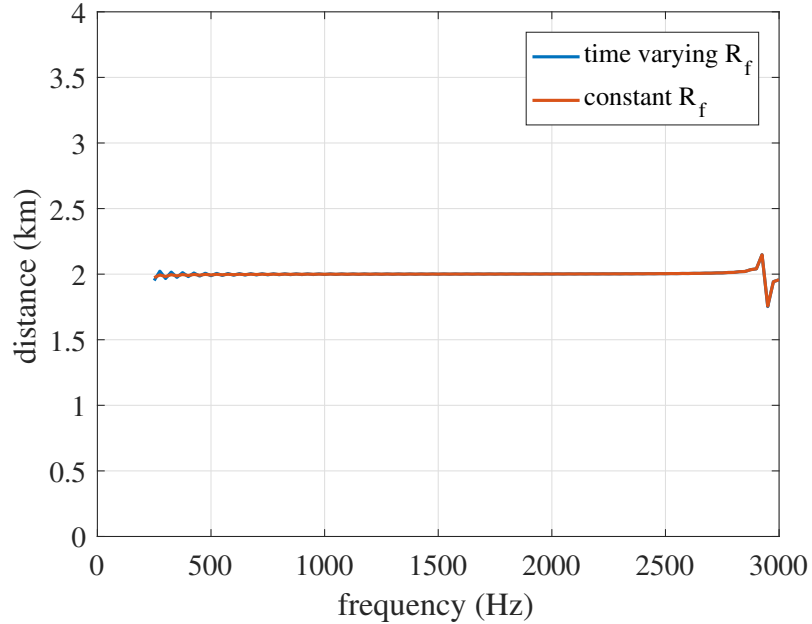


Fig. 6.81: Estimated distance using the double end method

The estimated distance values using the single end method for three different time varying resistances are shown in Fig. 6.82 where the time constant has been changed between 3 ms, 5 ms and 10 ms. As can be seen, the larger the time constant, the better the results. Large time constant introduces a slow changing resistance which appears with respect to the high frequency components (short periodical time) as a roughly constant resistance.

From this study, it becomes clear that the proposed single end method will be affected by the nature of the fault resistance if it is time varying. However, the method does not totally collapse as the fault still can be located but with a larger error in distance estimation. Also, with the case of time varying fault resistance, operating at a higher frequency range may be a good choice but will be limited to the capability of the system e.g. the available measurement devices and data acquisition system. This study requires further developments which will be a part of the future work.

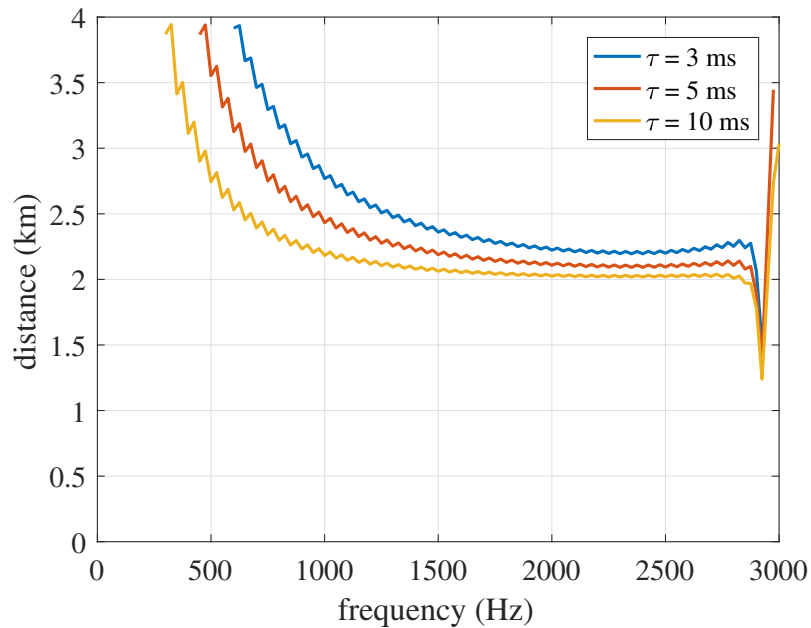


Fig. 6.82: Estimated distance for different fault resistance trajectories

## 6.9 Conclusions

The single end and double end methods proposed in the previous chapters have been evaluated on a real medium voltage feeder model. The IEEE 34-bus feeder has been simulated using the Matlab/Simulink tool. This feeder contains unbalanced loads, non-homogeneous lines, asymmetrical line configuration and single and three-phase laterals. The total lines length is about 93 km and the longest path is about 58 km. The lines have been simulated using the distributed parameter line model. The test conditions included the effect of fault type, fault resistance, fault inception angle, load uncertainty and noisy measurements. Also, the effect of DG type and quantity have been considered with active distribution system.

With radial distribution system, 3255 fault cases have been simulated at different conditions. The proposed single end method estimated 96.71% of cases with an error of less than 100 m and 99.51% of cases with an error of less than 200 m. The total average error obtained is 29 m. The accuracy level of the single end method decreased when applied to the active distribution system due to approximations associated with the proposed DG high frequency model. The percentage values of cases estimated with an error of less than 100 m and 200 m are 79.8% and 97.66% respectively. On the other hand, the double end method presented a very high accuracy level using either synchronized or combined measurements where 99.63% of cases were estimated with an error of less than 100 m and all cases having an error of less than 200 m.

The proposed methods were compared to other impedance based methods. The proposed single end method presented a better performance than the other single end methods either with radial distribution system or active distribution system. The proposed double end method presented, if not better, a similar performance to the other methods that use synchronized measurements. However, even the performance of the proposed double end method is close to the methods in the literature,

the proposed method can operate with combined synchronized and non-synchronized measurements.

Also, a proposal to locate faults along the laterals was presented by combining the estimates from applying different fault location methods. Limitation for successful operation of the proposed methods was illustrated. The performance of the single end method is affected if fault resistance is time varying. However, the double end method is not affected by the nature of the fault resistance.

# Chapter 7

## Experimental Studies

### 7.1 Introduction

A small scale laboratory system has been used to validate the single end method proposed in Chapter 3, the approximate IBDG high frequency model proposed in Chapter 4 and the double end method using synchronized measurements proposed in Chapter 5. These experiments are described in this chapter.

### 7.2 Experiment Setup

#### 7.2.1 Laboratory system

The experimental system layout is shown in Fig. 7.1. The transmission cable is a 16 mm<sup>2</sup>, 5-core cable with a total length of 50 m. The cable is connected to the main power grid at node  $S$  (400 V, 50 Hz). Node  $R$  is either connected to a load or to another power source (which represents a DG) based on the test case. At node  $F$ , a fault can be imposed.

The system is equipped with hall effect current transducers installed at nodes  $S$  and  $R$  [76]. Also, differential voltage probes are used to measure the voltage at different locations [77]. A National Instruments compact data acquisition system (NI cDAQ 9174 [78]) with analogue input modules

(NI 9222 [79]) is used for capturing signals.

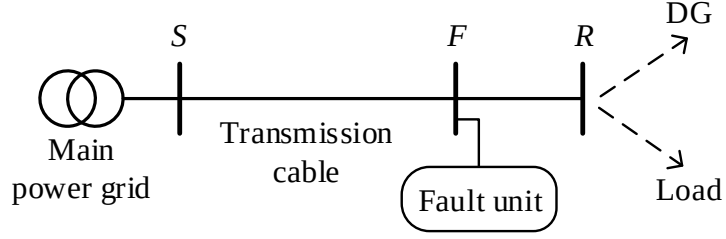


Fig. 7.1: Experimental system diagram

The cable parameters have been calibrated using an LCR meter (PSM1735 [80]). The impedance between two cores of the cable shorted from the other cable end has been measured. The resulting cable inductance and resistance per unit length are  $0.75 \mu\text{H}/\text{m}$  and  $2.82 \text{ m}\Omega/\text{m}$  respectively. For this short cable, the capacitance is ignored.

### 7.2.2 Fault unit

The fault unit used to create the fault consists of two IGBTs connected in series to a miniature circuit breaker (MCB) and a fault resistor ( $R_f$ ) as shown in Fig. 7.2. The fault unit is connected to node  $F$  in Fig. 7.1. The fault is imposed to the system by applying a signal to the gate terminal of the IGBTs and is removed by removing this gate signal. The MCB is used to protect the circuit in event of IGBT failure. A series resistor is used to limit the fault current. The experimental components used to represent the fault unit are shown in Fig. 7.3.

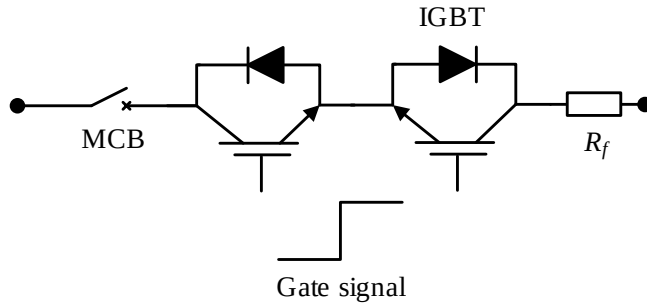
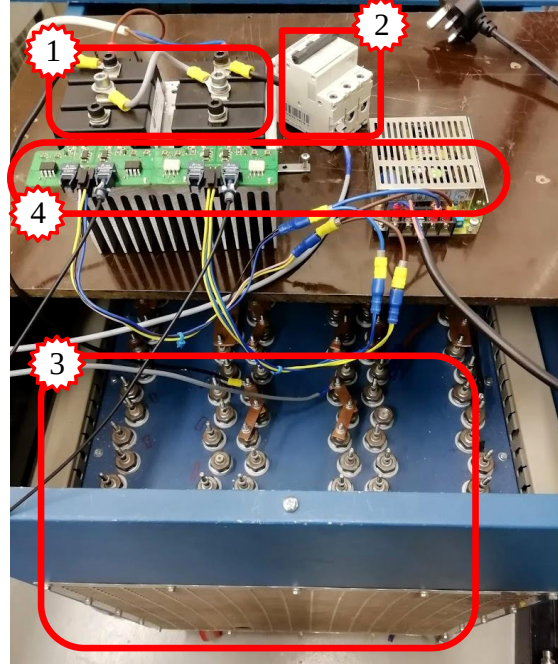


Fig. 7.2: The fault unit



1) IGBTs      2) MCB      3)  $R_f$       4) Gate drive circuit

Fig. 7.3: Experimental fault unit components

### 7.3 SEWIBFL Scheme

The SEWIBFL scheme proposed in Chapter 3 is validated in this section. The laboratory setup in Fig. 7.1 is connected to a resistive load of  $37.5 \Omega$  at node  $R$ . Node  $S$  is connected to the main power grid. A phase to neutral fault with a resistance of  $4.6 \Omega$  has been imposed at node  $F$ . The voltage and current measured at node  $S$  are shown in Fig. 7.4 and Fig. 7.5 respectively. The voltage signal during the fault shows a small reduction in the peak value compared to the pre-fault voltage. This is attributed to the small source impedance. The current signal has a step change in the magnitude due to the resistive nature of the fault circuit at the fundamental frequency (50 Hz). The total cable (50 m) resistance and reactance values at the fundamental frequency are  $141 \text{ m}\Omega$  and  $11.78 \text{ m}\Omega$  respectively (using the per unit length parameters in Section 7.2.1).

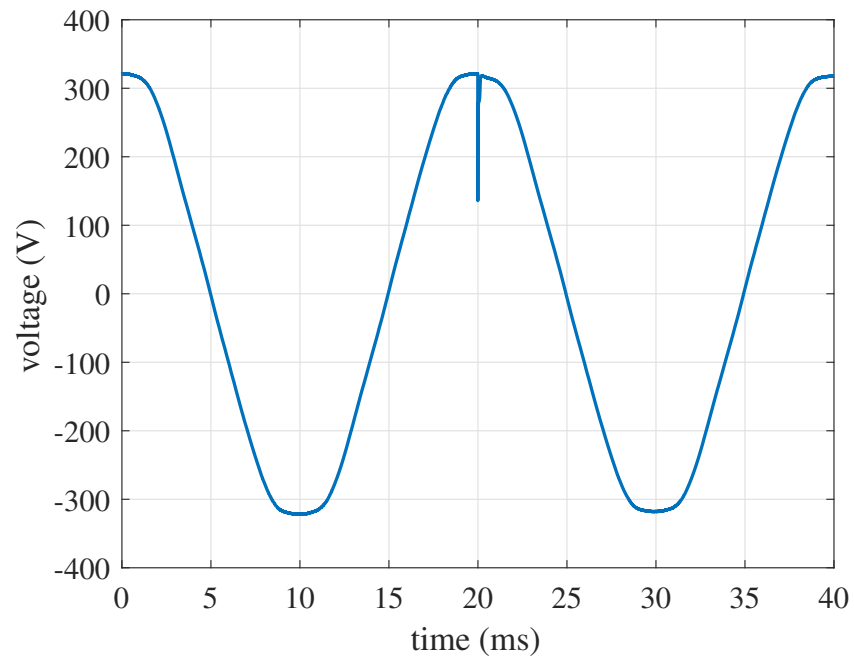


Fig. 7.4: Measured voltage signal

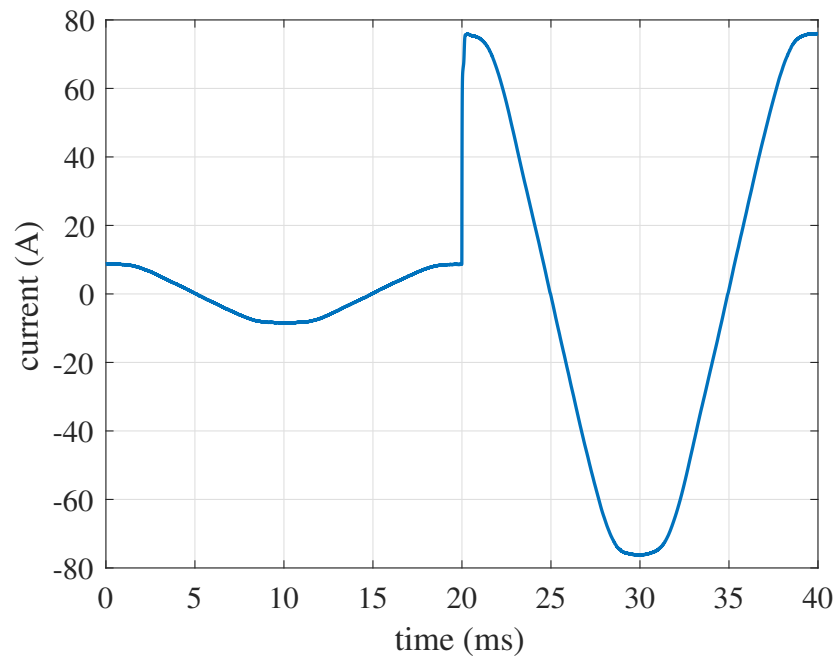


Fig. 7.5: Measured current signal

### 7.3.1 Detection of fault inception

As stated in Chapter 3, the signals are captured with a sampling rate of 500 kHz to be used for building the fault voltage source. Firstly, the fault inception sample is detected. The two methods explained in Chapter 3 to detect the fault inception have been applied (second-order rate of change and time domain subtraction). A zoomed view of the measured voltage signal to focus on the first fault sample is presented in Fig. 7.6. The last healthy sample is 9997 and the first fault sample is 9998.

Applying the second-order rate of change method to the voltage window results in Fig. 7.7. As previously explained in Chapter 3, the *SRC* has a high value two samples before the fault sample number. In Fig. 7.7, the *SRC* detects the sample number 9996. Therefore, the fault sample would be 9998 which is the actual fault inception sample. Also, the time domain subtraction method detects the correct fault sample number (9998) as presented in Fig. 7.8.

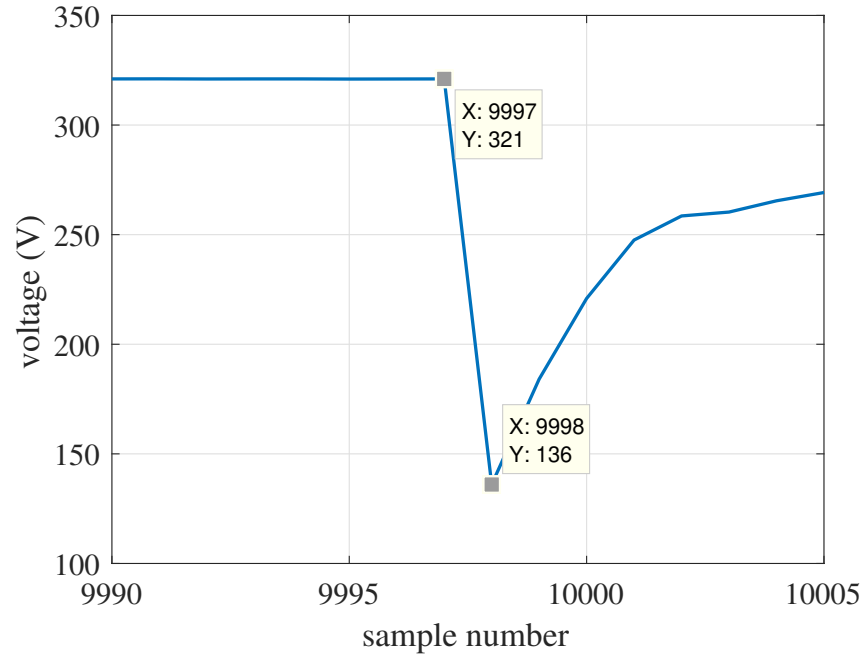
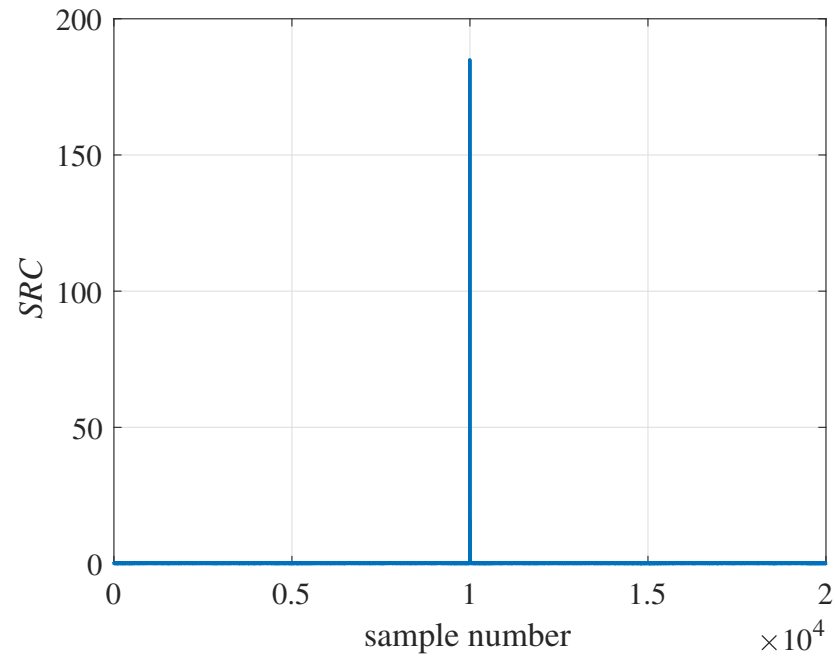
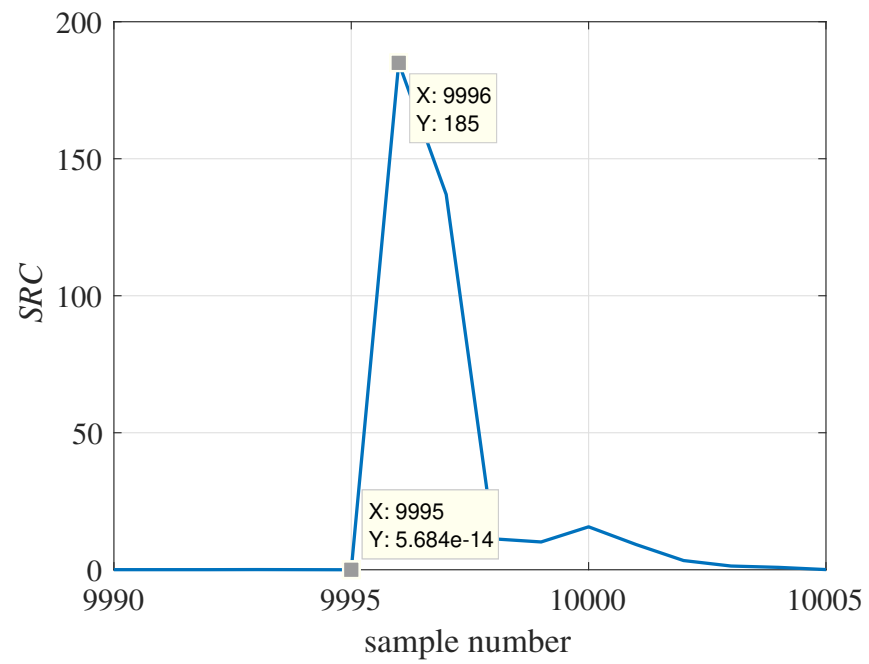


Fig. 7.6: Zoomed view for measured voltage

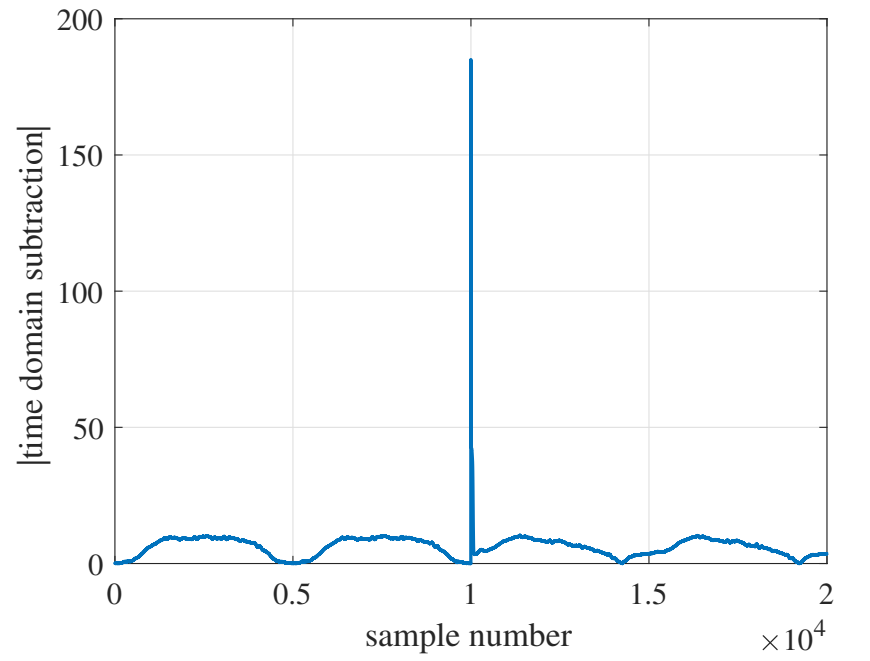


(a)

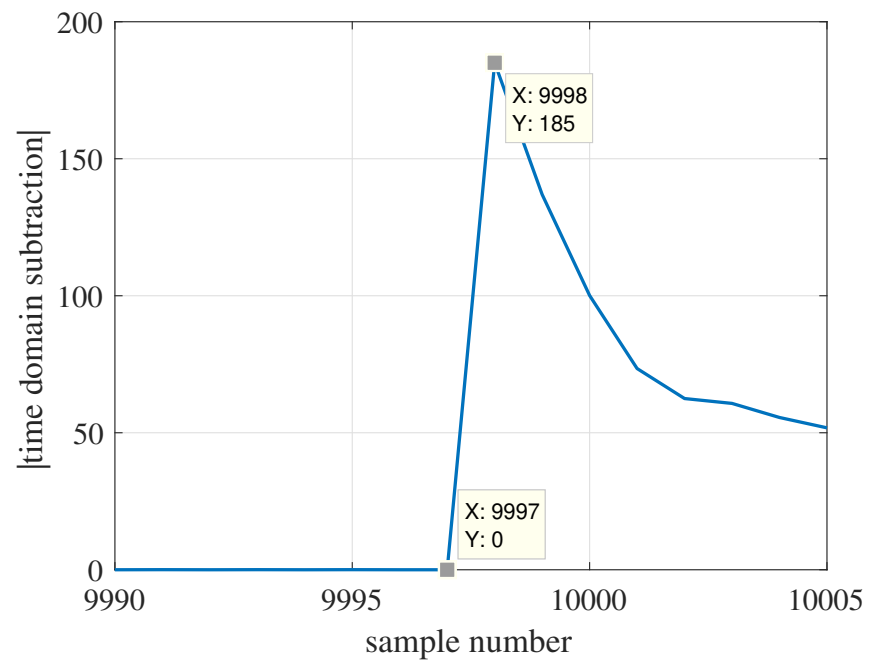


(b)

Fig. 7.7: Fault detection using *SRC*



(a)



(b)

Fig. 7.8: Fault detection using time domain subtraction

### 7.3.2 Distance estimation

After detecting the fault inception sample and accordingly creating the assumed fault voltage source, this voltage source can then be used for the distance estimation.

Before going through the fault distance estimation, the frequency spectrum has been calculated for a healthy window (pre-fault data) of the main grid voltage and is shown in Fig. 7.9 as a percentage of the fundamental 50 Hz component. As is clear, the main grid phase voltage contains 5<sup>th</sup> and 7<sup>th</sup> harmonic components with percentage values of 2.028% and 0.9802% respectively. The magnitude of these harmonics is larger than the magnitude of the high frequency components generated due to the fault transient with this system. For this reason, the frequency range below 500 Hz has been discarded from the distance estimation. Also, the upper frequency limit used is 2 kHz as this range provides a higher signal to noise ratio compared to the higher frequency range with this low transient magnitude system.

The frequency spectrum for the voltage and current signals in Fig. 7.4 and Fig. 7.5 is shown in Fig. 7.10 and Fig. 7.11 respectively for the frequency range from 500 Hz to 2 kHz. As the current waveform has a higher step change than the voltage waveform, the frequency spectrum magnitudes for the current are higher than those for the voltage. Also, the voltage magnitude over this frequency range is less than 0.6 V which is low compared to the low order harmonics in the grid voltage as explained earlier. The spectrum in Fig. 7.10 shows a voltage magnitude of 0.35 V and 0.32 V at 650 Hz and 850 Hz respectively. These frequency components are mainly due to the harmonic contents in the main grid voltage not due to the fault transient. In Fig. 7.9, the frequency components (650 Hz and 850 Hz) have a percentage value of 0.0913% which is equal to 0.3 V based on the fundamental frequency peak voltage (325 V).

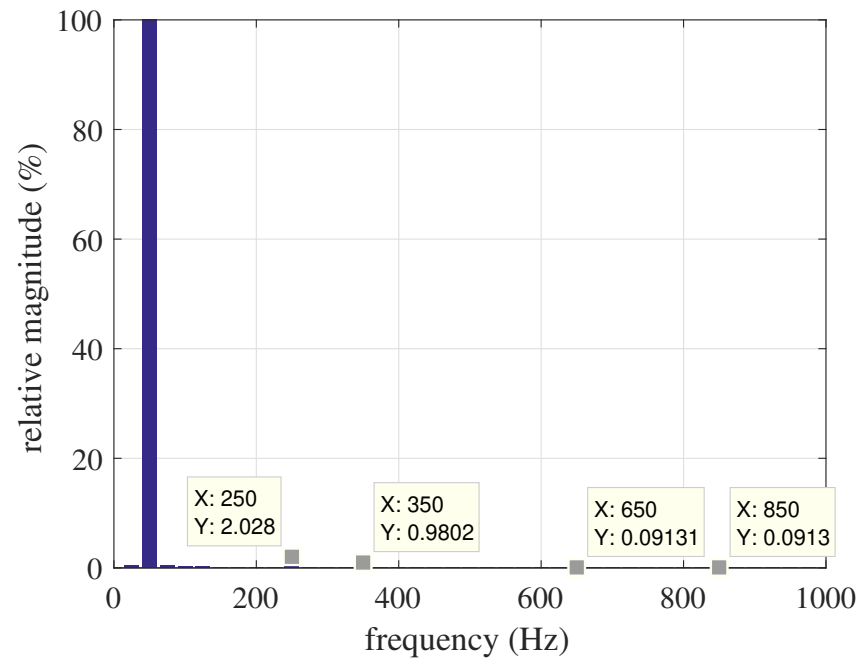


Fig. 7.9: Frequency spectrum of the grid phase voltage

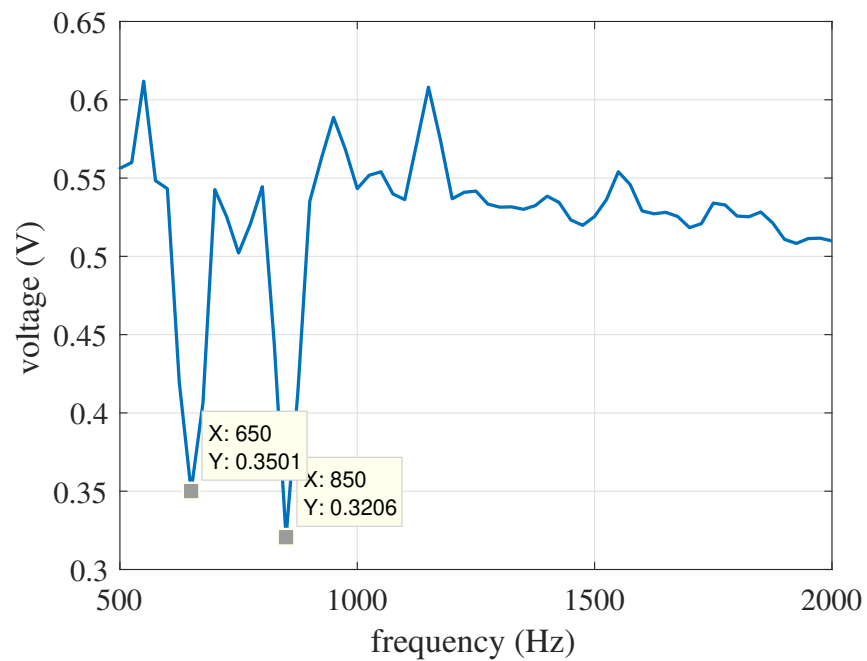


Fig. 7.10: Frequency spectrum of the measured voltage

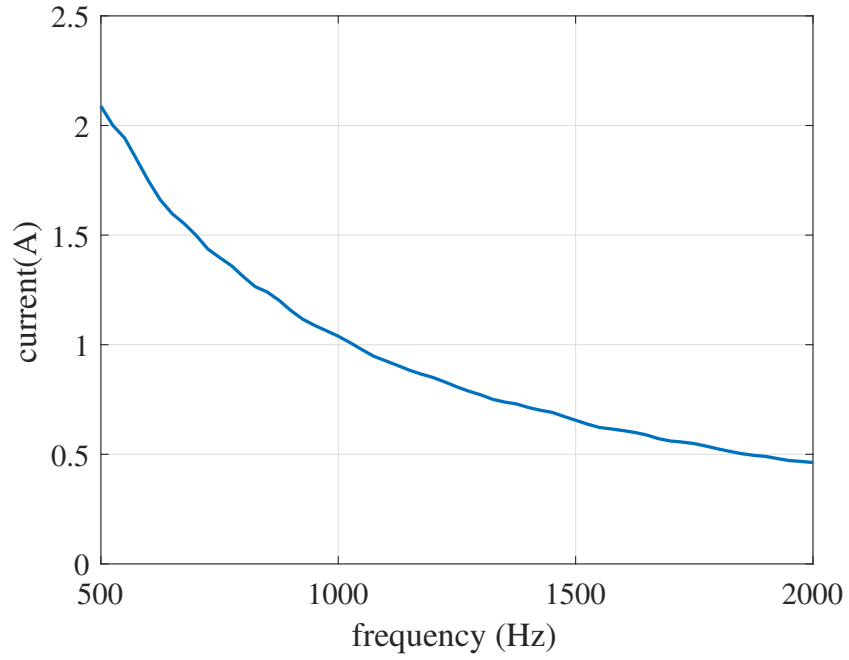


Fig. 7.11: Frequency spectrum of the measured current

For locating the fault, the cable reactance between the fault point and the measurement point (node  $S$ ) is estimated over the frequency range of interest (500:2000 Hz). Then, the estimates at different frequencies are input to a curve fitting algorithm (straight line curve fitting) to estimate the distance based on the known cable per unit parameters. The actual cable reactance to the fault point, the estimated reactance and the reactance estimated from the curve fit are shown in Fig. 7.12. The actual fault distance is 40 m and the estimated distance is 39.2 m. The method required 3 iterations to locate this fault and the estimated reactance through different iterations is presented in Fig. 7.13.

The estimated reactance in Fig. 7.12 shows high variation, although the final fitted reactance provides good accuracy. The high error at the individual frequencies results from the difference between the created fault voltage source and the actual voltage across the IGBTs during the fault. The created fault voltage source is assumed to have a zero value during the fault period. However, the actual voltage across the IGBTs when measured is a square wave which introduces the error seen at the individual

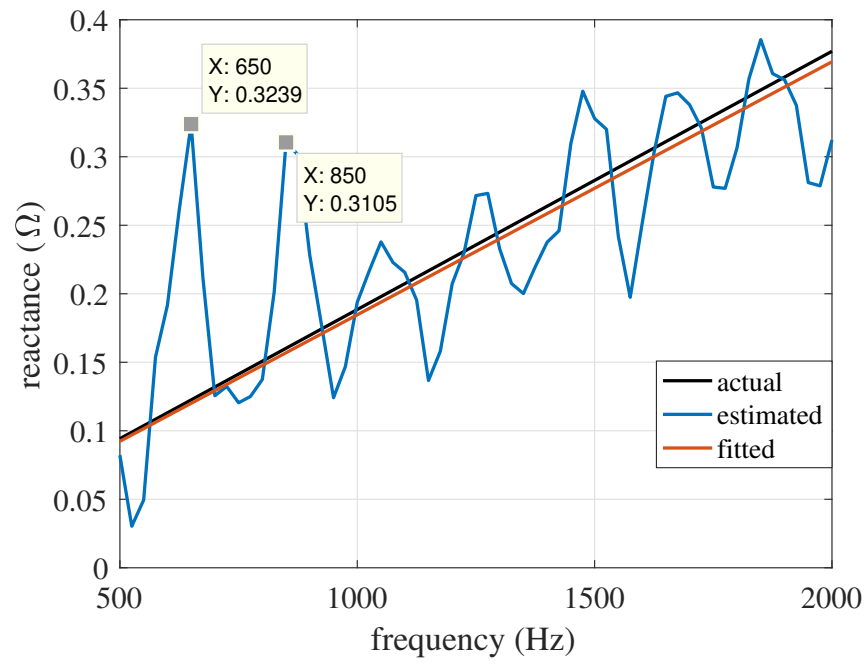


Fig. 7.12: Estimated cable reactance using the SEWIBFL

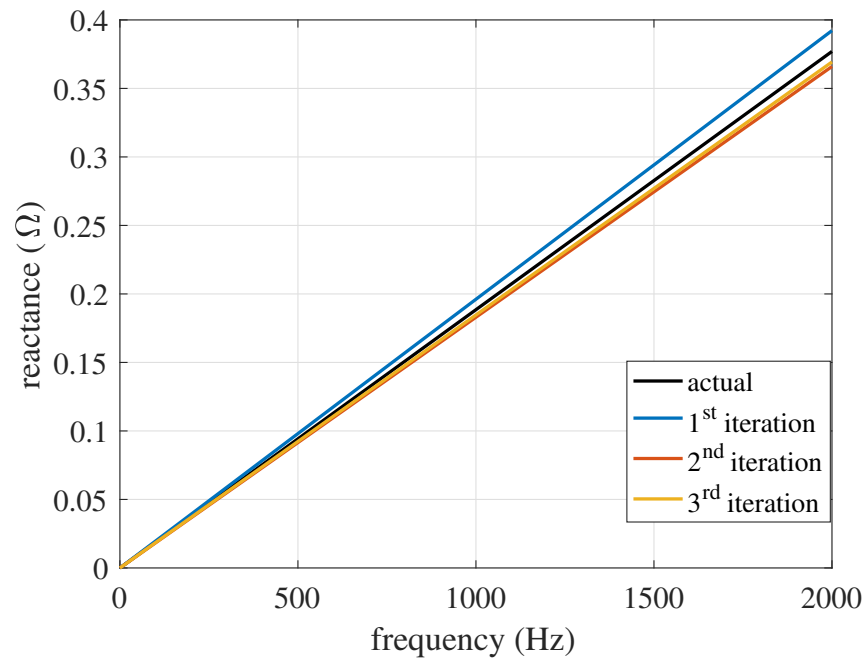


Fig. 7.13: Different iterations using the SEWIBFL

frequencies in Fig. 7.12. This may be a noticeable effect due to the very low total impedance of the cable that needs to be estimated. The total cable inductance is  $50 \times 0.75 = 37.5 \text{ } \mu\text{H}$  ( $0.4712 \text{ } \Omega$  at  $2 \text{ kHz}$ ) which is very low compared to the fault resistance. Also, the high error at  $650 \text{ Hz}$  and  $850 \text{ Hz}$  in Fig. 7.12 results from the low voltage magnitudes at these frequencies which is clear in Fig. 7.10.

## 7.4 IBDG Equivalent Circuit

In this section, the IBDG equivalent circuit proposed in Chapter 4 is validated experimentally.

### 7.4.1 DG system overview

A commercial drive system has been used to setup the experiment. To emulate an IBDG, the layout in Fig. 7.14 was used and consists of two Unidrive SP (classed as a regenerative drive and a motoring drive [81]), a brushless AC servo motor [82], a DC machine, a regen inductor and a switching frequency filter (inductor and capacitor) [81]. This combination is connected to the main power grid at the PCC. Information regarding the system components is provided in Table 7.1. The values for both inductors and the capacitor in Table 7.1 have been calibrated at  $1 \text{ kHz}$  for the components in the experimental system using an LCR meter [80]. These values are as close as possible to the recommended values in [81].

The Unidrive SP can be set to work in motoring mode or regenerative mode. It works in a regenerative mode when the power flows from the drive system to the main supply [81]. A control system has been used to run the DC machine which in turns acts as a prime mover for the AC servo motor. By controlling the torque on the DC machine while the speed of the servo motor is controlled by the motoring drive, the servo motor operates as a generator and the system runs in regenerative mode and the power flows to the main grid. This system emulates a wind turbine. The different

components of the experimental system are shown in Fig. 7.15. The DG system power circuit used and the control circuit connections are shown in Fig. 7.16 and Fig. 7.17 respectively. In [81], more details are available about the system operating procedure and the settings for both regenerative and motoring drives.

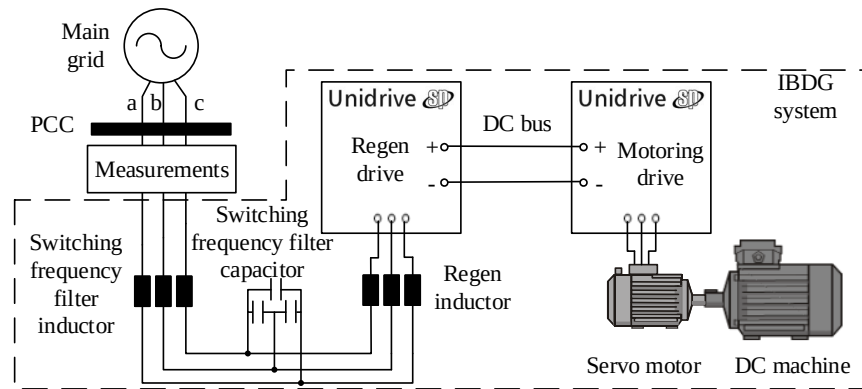


Fig. 7.14: Experimental DG system layout

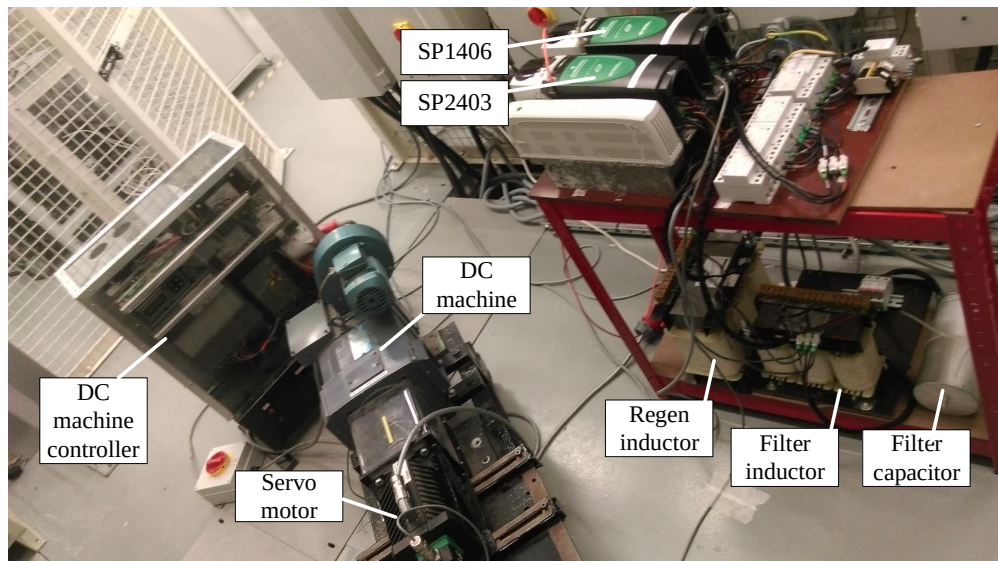


Fig. 7.15: Experimental DG system setup

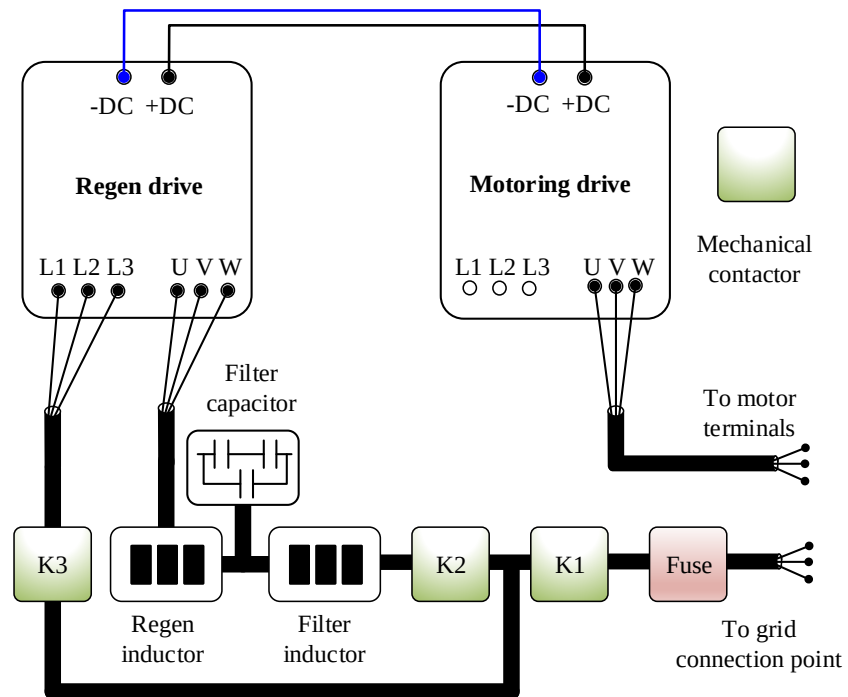


Fig. 7.16: DG system power circuit connection

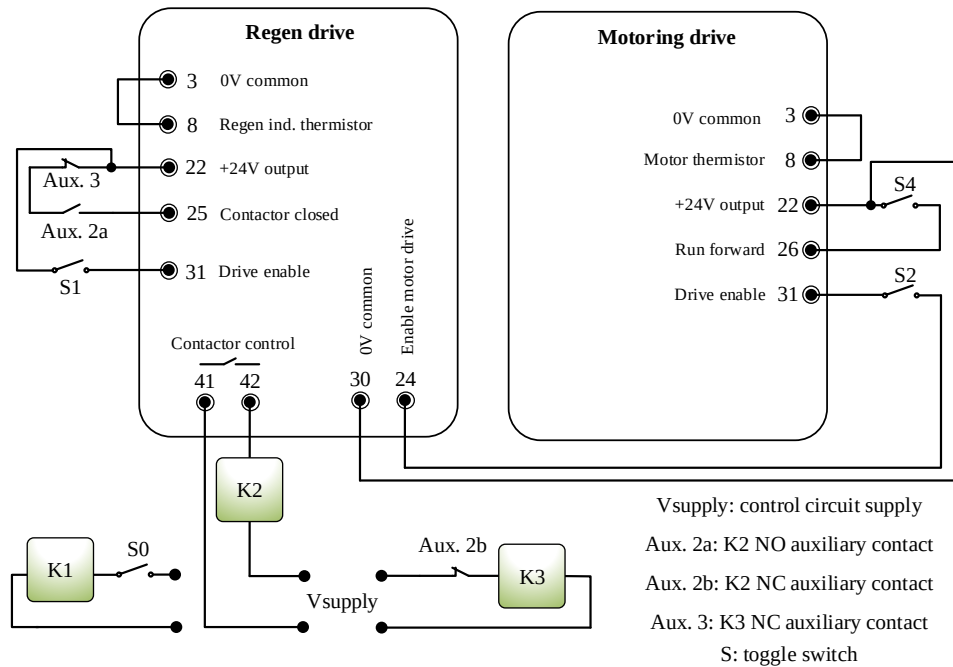


Fig. 7.17: DG system control circuit connection

Table 7.1: Parameters of the experimental DG system

|                                                    |                          |
|----------------------------------------------------|--------------------------|
| regen drive model                                  | SP2403                   |
| motoring drive model                               | SP1406                   |
| servo motor model                                  | 142UMC300CACAA           |
| regen inductor ( $L$ , $R$ )                       | 1.82 mH, 0.8 $\Omega$    |
| switching frequency filter inductor ( $L$ , $R$ )  | 0.75 mH, 0.2 $\Omega$    |
| switching frequency filter capacitor ( $C$ , $R$ ) | 40 $\mu$ F, 0.5 $\Omega$ |

### 7.4.2 System operation in healthy condition

Before working on the IBDG equivalent circuit test, this section shows the operation of the DG system in the healthy condition. As stated, the system has been set to run in the regenerative mode delivering the active power to the main grid. The line to line voltage and the phase current output from the DG are measured at the DG terminals and filtered. The voltages and currents are shown in Fig. 7.18 and Fig. 7.19.

As is clear, the measured current signal is not a pure sinusoidal waveform. The frequency spectrum for phase  $a$  current is presented in Fig. 7.20 with all values referred to the fundamental frequency component.

The current spectrum shows high  $5^{th}$  and  $7^{th}$  harmonic values (250 Hz and 350 Hz). This is not only due to non-linear converter effects but also it is due to the presence of  $5^{th}$  and  $7^{th}$  harmonics in the main grid voltage. This has been previously illustrated for the grid phase voltage in section 7.3. Furthermore, the frequency spectrum of the line to line voltage  $V_{ab}$  is shown in Fig. 7.21 where the relative percentage values for the  $5^{th}$  and  $7^{th}$  harmonics are 1.959% and 0.8514% respectively. These harmonics are applied to the switching frequency filter capacitor which leads to a noticeable harmonic content in the current due to lower capacitor impedance at these frequencies. These harmonics in the voltage would cause approximately 9.8% ( $5 \times 1.959$ ) and 6% ( $7 \times 0.8514$ ) harmonic values in the current.

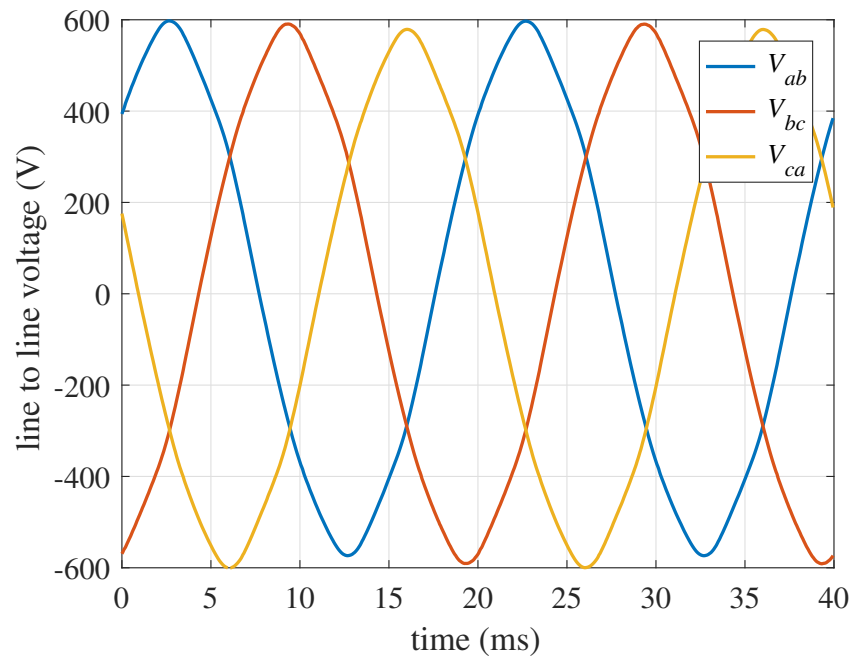


Fig. 7.18: DG output voltage in the healthy condition

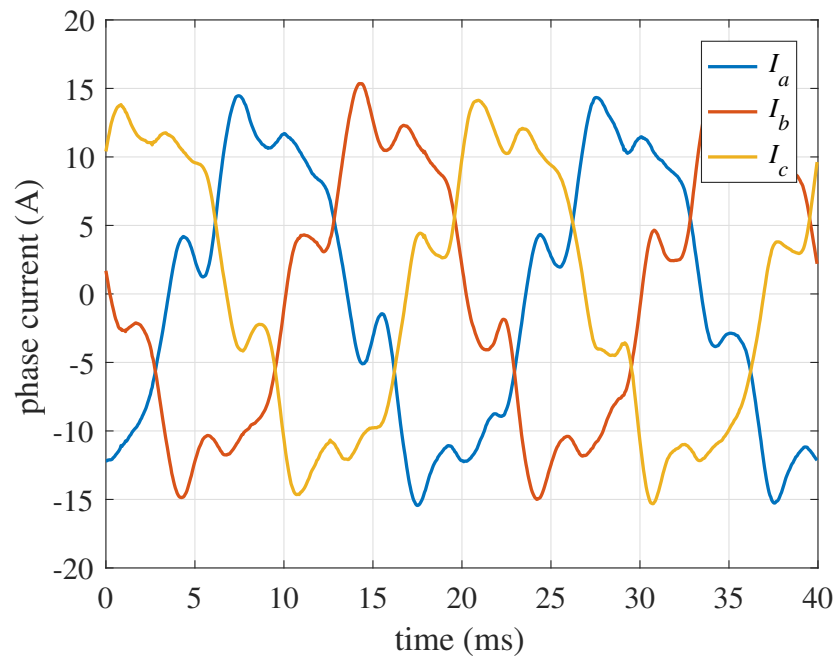


Fig. 7.19: DG output current in the healthy condition

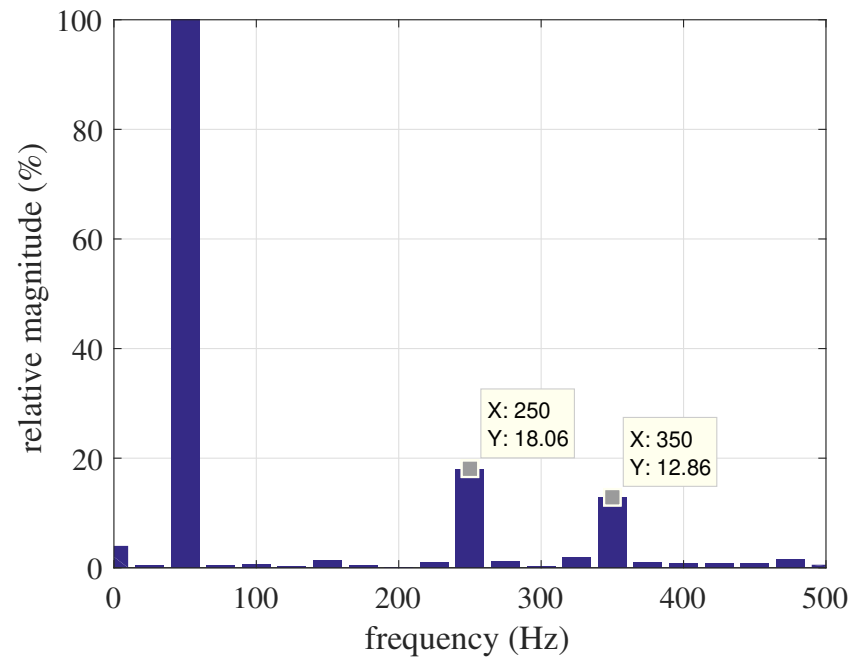


Fig. 7.20: Frequency spectrum of the DG output current

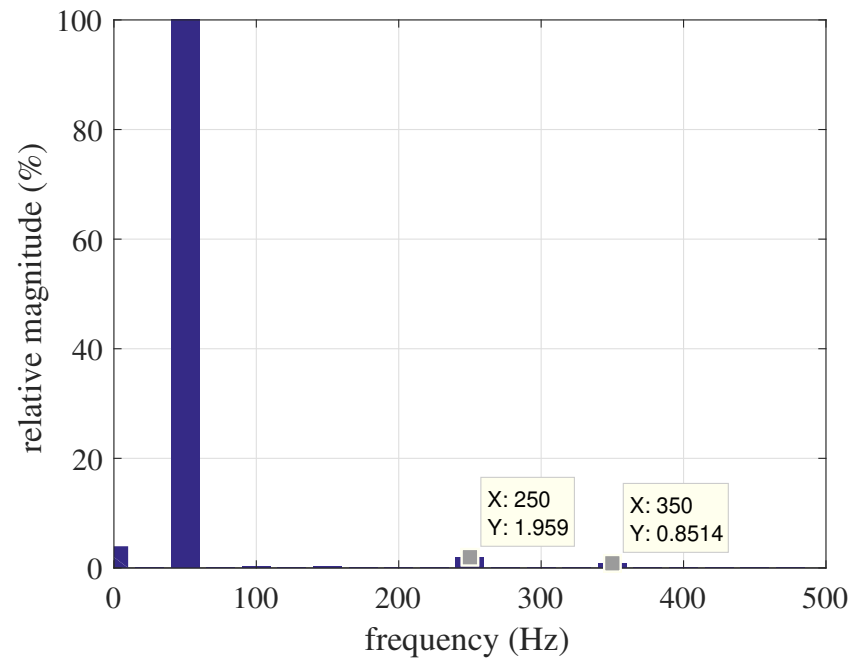


Fig. 7.21: Frequency spectrum of the grid line to line voltage

In order to verify that, the DG system has been connected to a programmable AC source (Chroma 61511) instead of direct connection to the main grid [83]. As the Chroma does not accept regenerative power, the servo motor ran as a motor not a generator. The voltage and current at the DG terminals were measured and are shown in Fig. 7.22 and Fig. 7.23. The corresponding frequency spectrum were calculated and are shown in Fig. 7.24 and Fig. 7.25. The voltage spectrum shows negligible 5<sup>th</sup> and 7<sup>th</sup> harmonics compared to connection to the main grid and this is reflected on the current spectrum as the 5<sup>th</sup> and 7<sup>th</sup> harmonic values are reduced to about 4% and 0.6% respectively (compared to 18% and 12.86% in the first case).

### 7.4.3 Equivalent circuit test

During this test, the DG system was connected to the main grid injecting power to the grid. A fault with 5.3  $\Omega$  resistance has been imposed between phase *a* and phase *b* (Note that it is a 3 wire system). The line to line voltage and the phase current at the terminals of the DG system were measured. The measured voltage between phase *a* and phase *b* and the current in phase *a* are shown in Fig. 7.26 and Fig. 7.27 where this data window combines both pre-fault and during fault periods.

The equivalent impedance of the DG as seen from the PCC can be calculated using a data length of 40 ms of the measured voltages and currents (inside the dashed rectangle in Fig. 7.26 and Fig. 7.27). The data window was converted to the frequency domain and the impedance between phase *a* and phase *b* has been calculated. The parameters in Table 7.1 were used for the proposed equivalent circuit calculation. The actual measured impedance as well as the approximate equivalent impedance are shown in Fig. 7.28. There is a high degree of matching between the two impedances in the high frequency range and a mismatch in the low frequency range which agrees with the proposed concept for the DG approximate circuit.

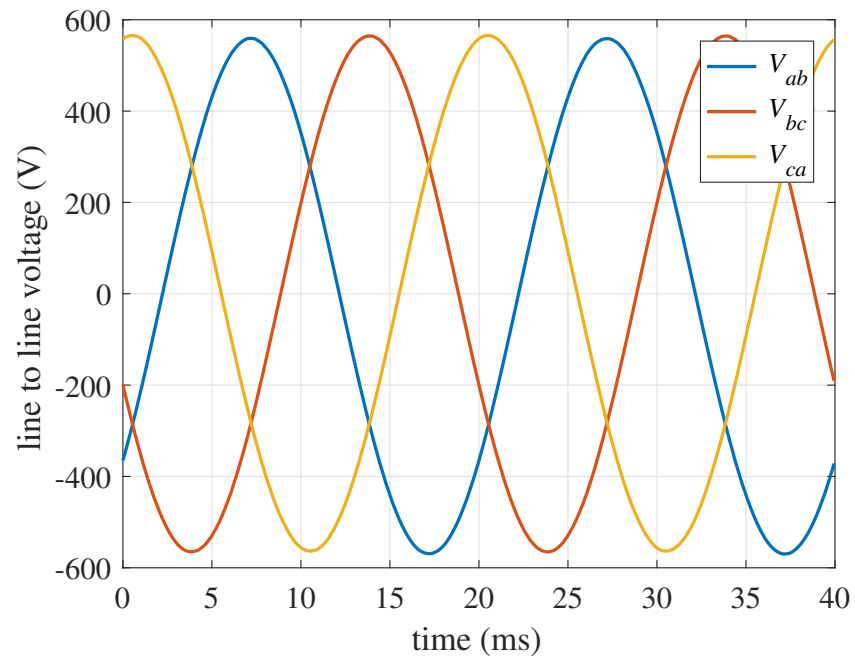


Fig. 7.22: Voltage in the healthy condition when using Chroma source

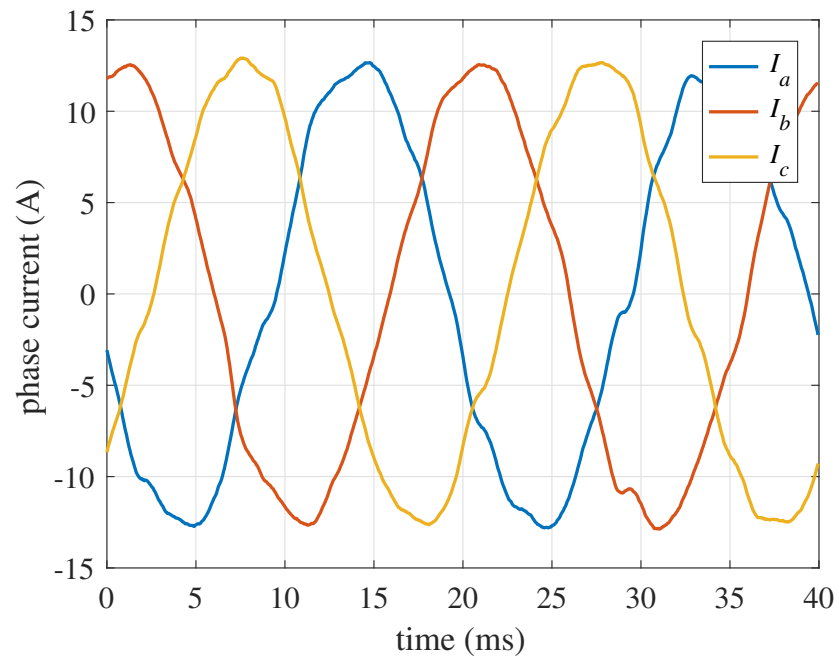


Fig. 7.23: Current in the healthy condition when using Chroma source

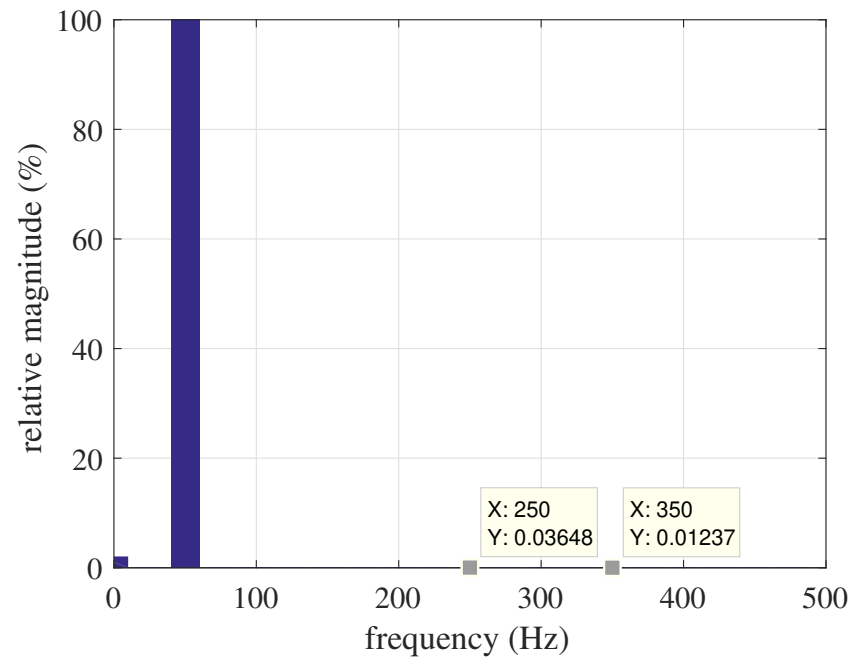


Fig. 7.24: Voltage frequency spectrum when using Chroma source

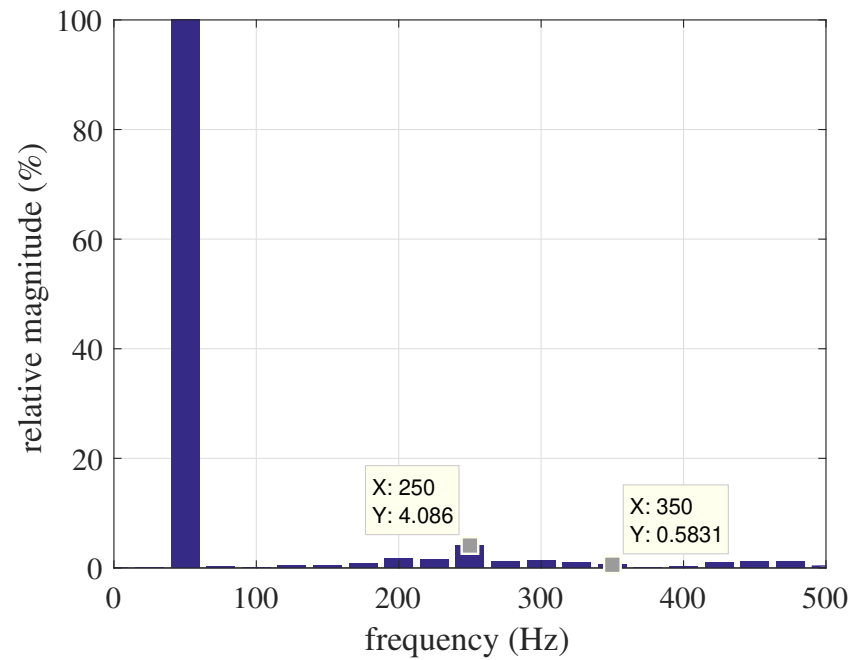


Fig. 7.25: Current frequency spectrum when using Chroma source

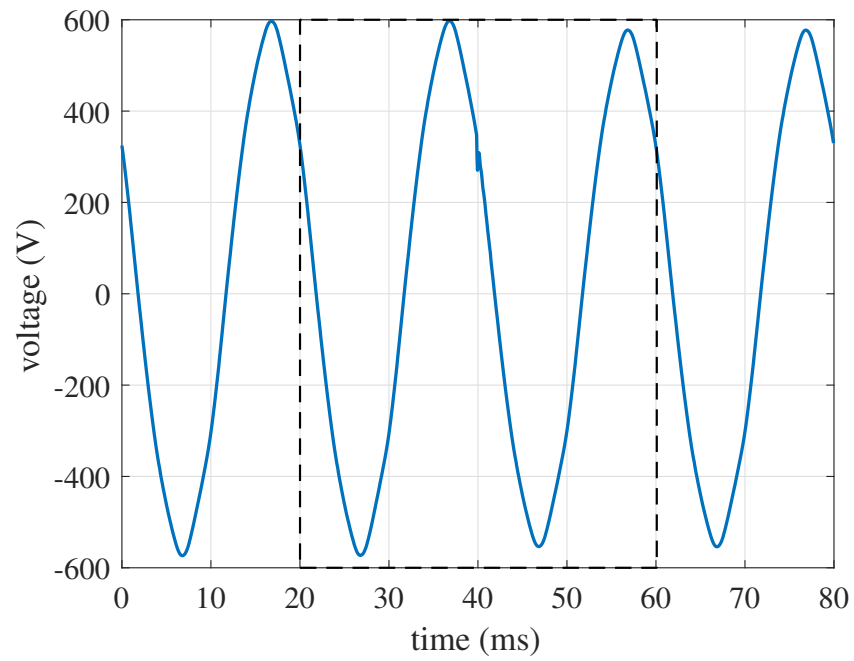


Fig. 7.26: DG output voltage during the fault condition

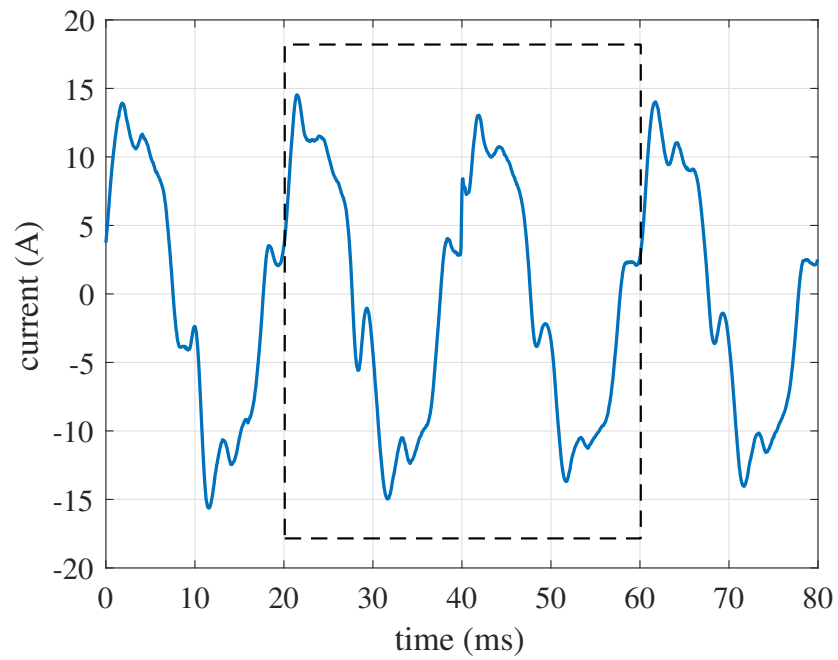


Fig. 7.27: DG output current during the fault condition

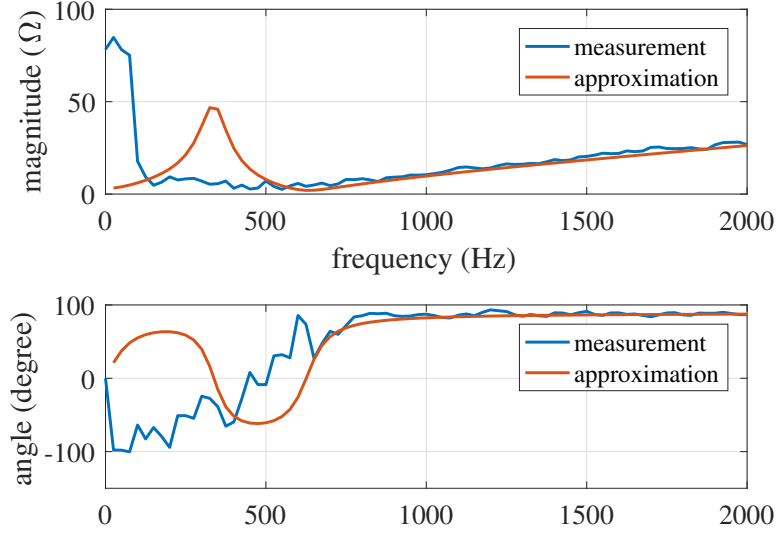


Fig. 7.28: Experimentally measured impedance and the proposed approximate impedance for the DG system

## 7.5 Fault Location with DG

With the previously described DG system connected at node  $R$  in Fig. 7.1, a fault with a resistance of  $5.3 \Omega$  has been imposed between phase  $a$  and phase  $b$  at node  $F$  in Fig. 7.1. The voltage and current are measured at both nodes  $S$  and  $R$ . The fault distance is estimated using both the proposed single end and the proposed double end methods.

### 7.5.1 SEWIBFL with DG

The measured voltage and current at node  $S$  together with the proposed approximate DG high frequency model were used to estimate the fault distance. As previously discussed, the method firstly detects the fault inception sample then estimates the fault distance. The measured voltage between phase  $a$  and phase  $b$  and phase  $a$  current at node  $S$  are shown in Fig. 7.29 and Fig. 7.30 respectively.

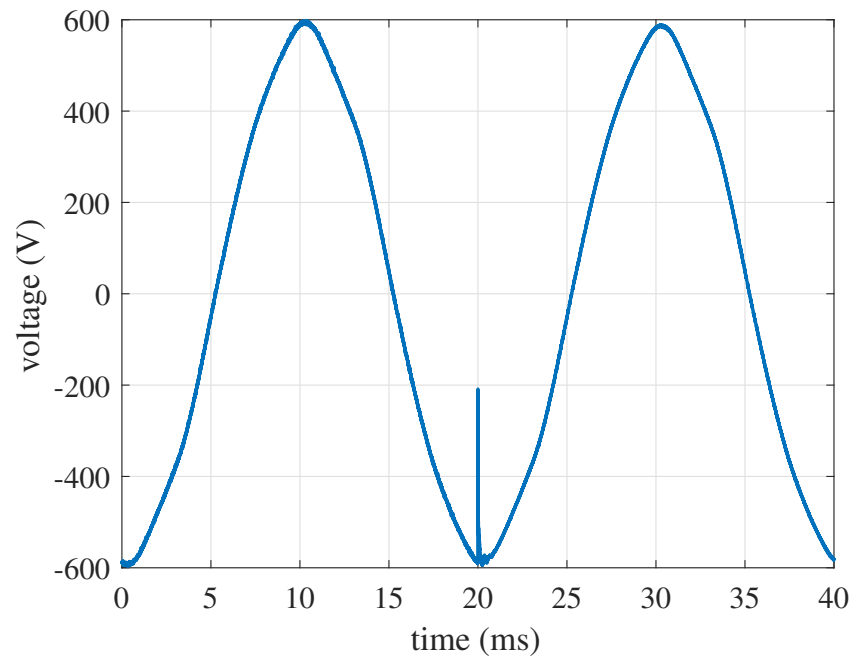


Fig. 7.29: Measured voltage at node  $S$  (system with DG)

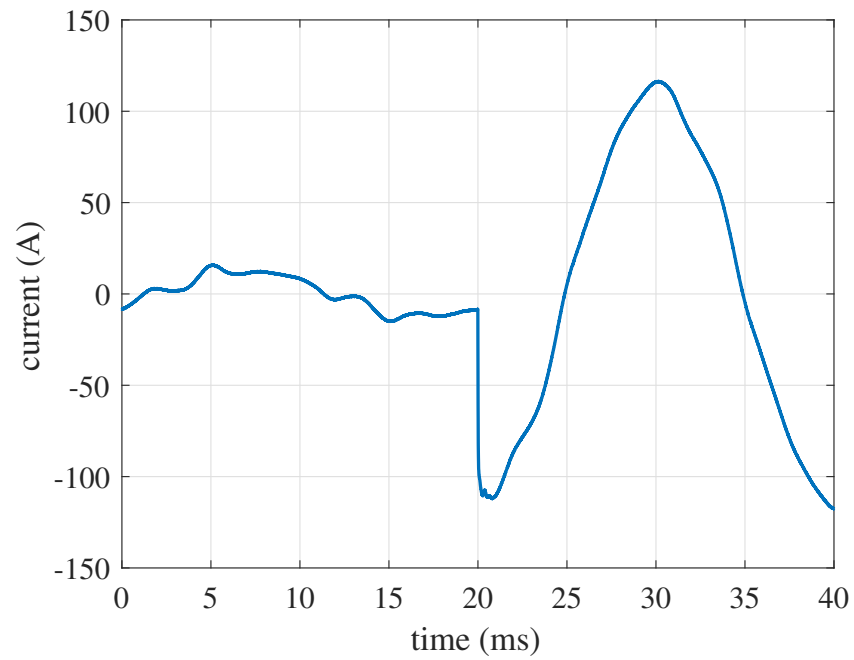


Fig. 7.30: Measured current at node  $S$  (system with DG)

### 7.5.1.1 Detection of fault inception

The fault inception detection methods have been applied on the measured voltage at node  $S$ . The first fault sample is 9998 as is clear in Fig. 7.31. The results for the  $SRC$  method and the time domain subtraction method are shown in Fig. 7.32 and Fig. 7.33 respectively. Both detection methods accurately detected the fault inception sample. As the voltage signal is noisy (as is clear in Fig. 7.29), the methods' result during the healthy part of the signal is not low. For instance, comparing the  $SRC$  output in Fig. 7.32 to its value in Fig. 7.7 shows the high values for the  $SRC$  during the healthy part when operated on a noisy signal such as that in Fig. 7.29. However, the result at the fault inception is very high and distinguishable compared to the healthy period.

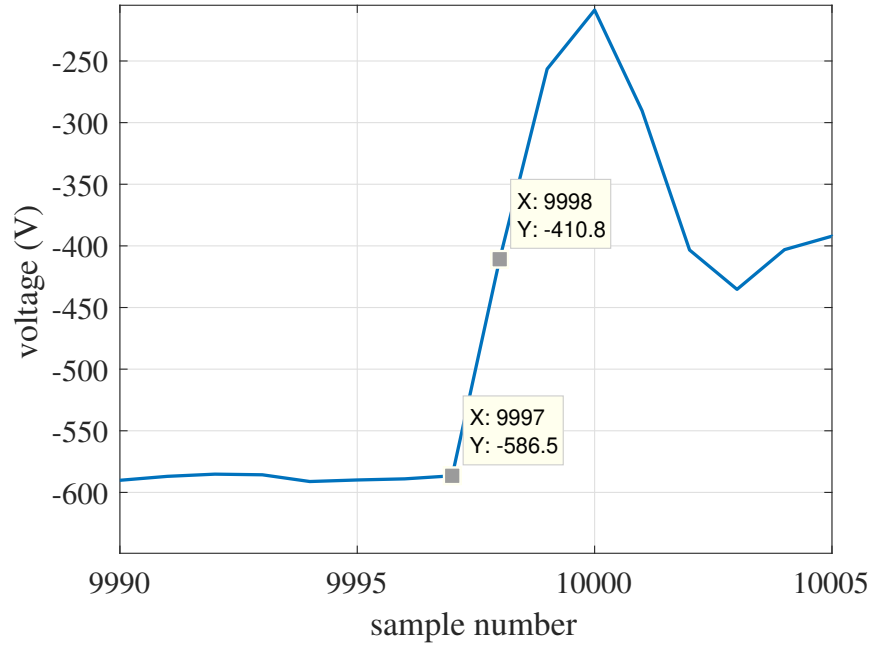
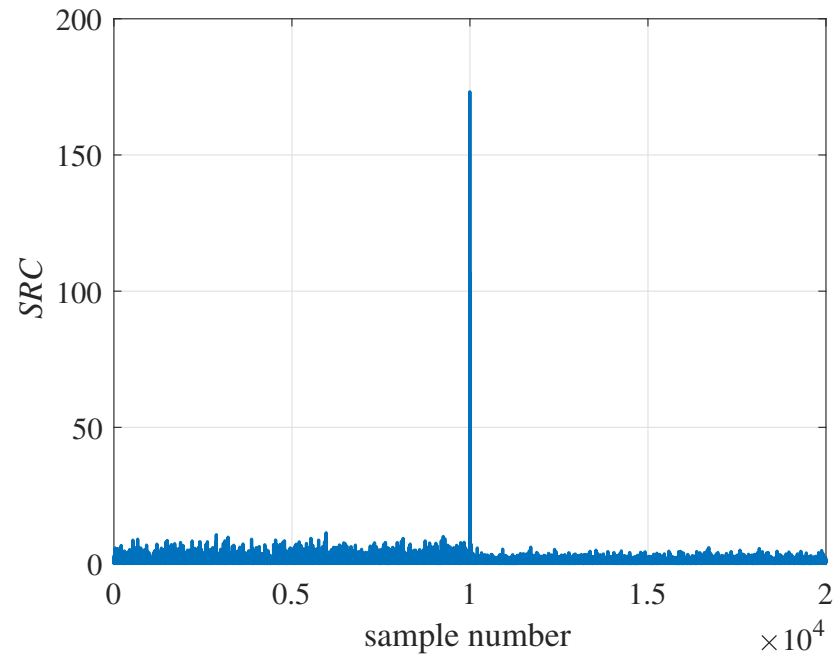


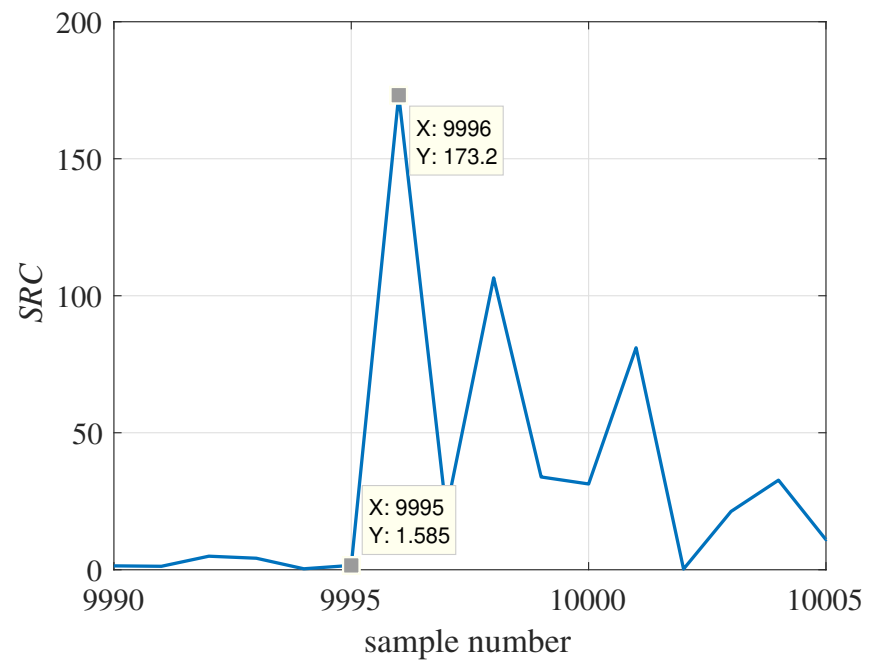
Fig. 7.31: Zoomed view for measured voltage (system with DG)

### 7.5.1.2 Distance estimation

After detecting the fault inception sample and building the fault voltage source, the fault distance can be estimated.

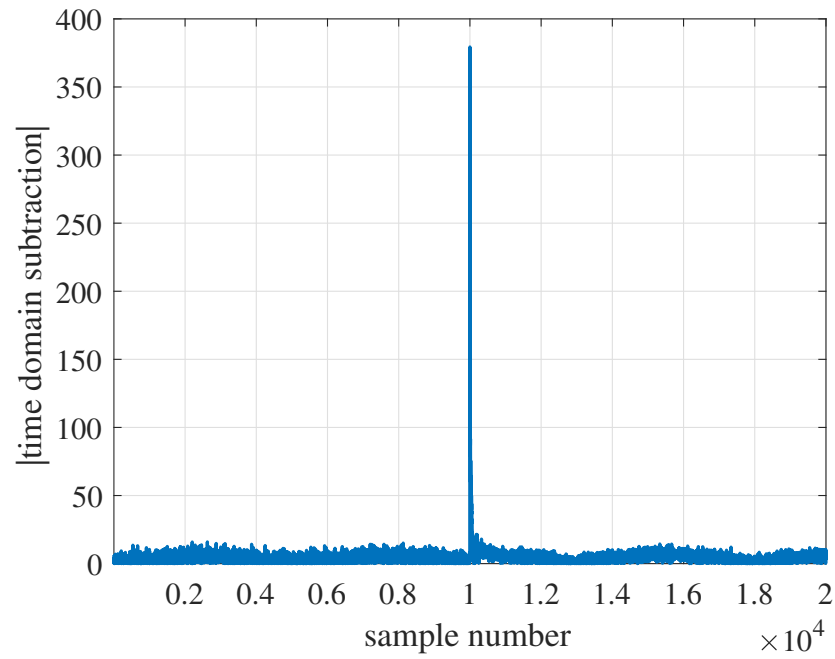


(a)

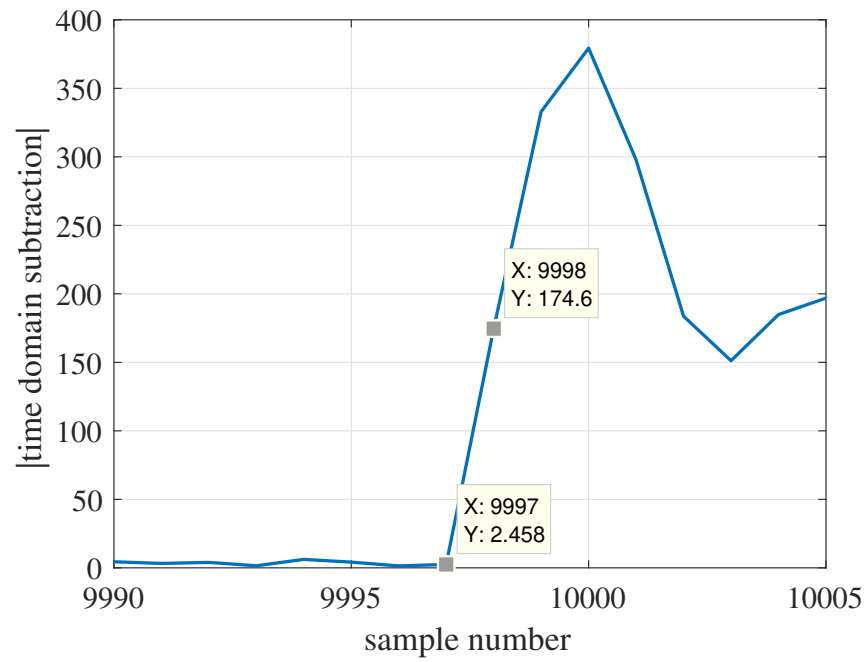


(b)

Fig. 7.32: Fault detection using *SRC* (system with DG)



(a)



(b)

Fig. 7.33: Fault detection using time domain subtraction  
(system with DG)

According to the analysis in section 7.4, the measured healthy current contains a high value of 5<sup>th</sup> and 7<sup>th</sup> harmonics (250 Hz and 350 Hz). Also, using the DG system inductors and capacitor parameters in Table 7.1 and looking at the measured and approximated equivalent DG impedance in Fig. 7.28, the resonance frequency (minimum DG impedance) is around 630 Hz. For these reasons, the frequency range below 1 kHz has been ignored in the distance estimation. The cable reactance between node  $S$  and the fault point is estimated over the frequency range from 1 kHz to 2 kHz, then fitted to a curve (straight line fitting) to estimate the fault distance.

The actual reactance, the estimated reactance and the fitted reactance are presented in Fig. 7.34. Also, the estimations over different iterations are shown in Fig. 7.35. The estimated fault distance is 39.4 m while the actual distance is 40 m.

### 7.5.2 DEWIBFL with DG

The measurements from both cable ends are used to apply the proposed double end method using synchronized measurements. The measured voltage and current at both ends are shown in Fig. 7.36 and Fig. 7.37 respectively after filtering and downsampling to 20 kHz. The cable reactance is estimated then fitted to a curve (straight line fitting) to calculate the fault distance. The estimated cable reactance is shown in Fig. 7.38. The estimated fault distance is 39.7 m. As is clear, the estimated reactance at the individual frequencies is more accurate than the case of the single end method. The single end method has assumptions related to the DG equivalent circuit and also the fault voltage source.

## 7.6 Bouncing Fault

While the IGBTs used to build the fault unit can cause a step fault, a mechanical switch can result in a bouncing fault due to the vibration of the switch contacts when the switch is closing.

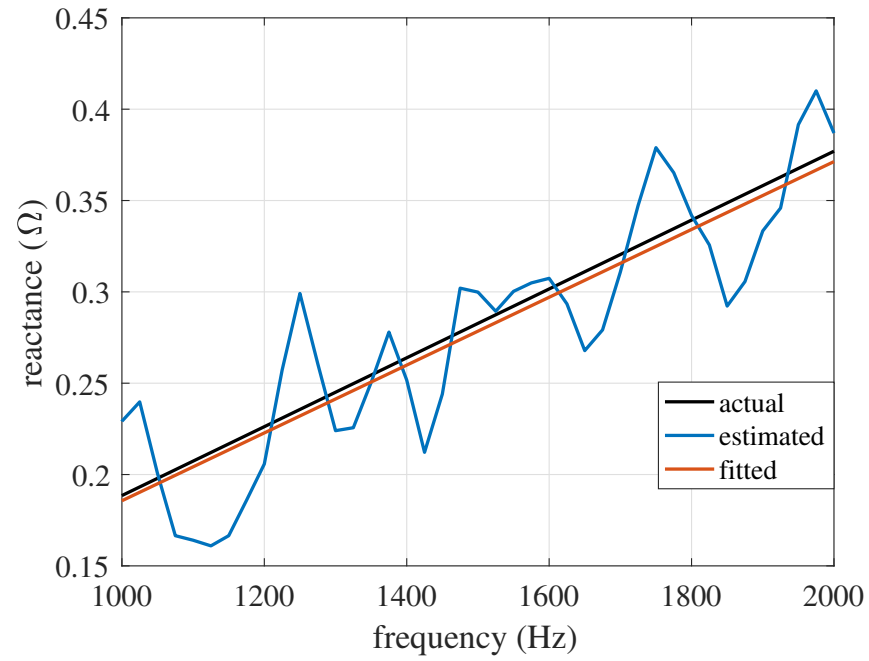


Fig. 7.34: Estimated cable reactance using the SEWIBFL (system with DG)

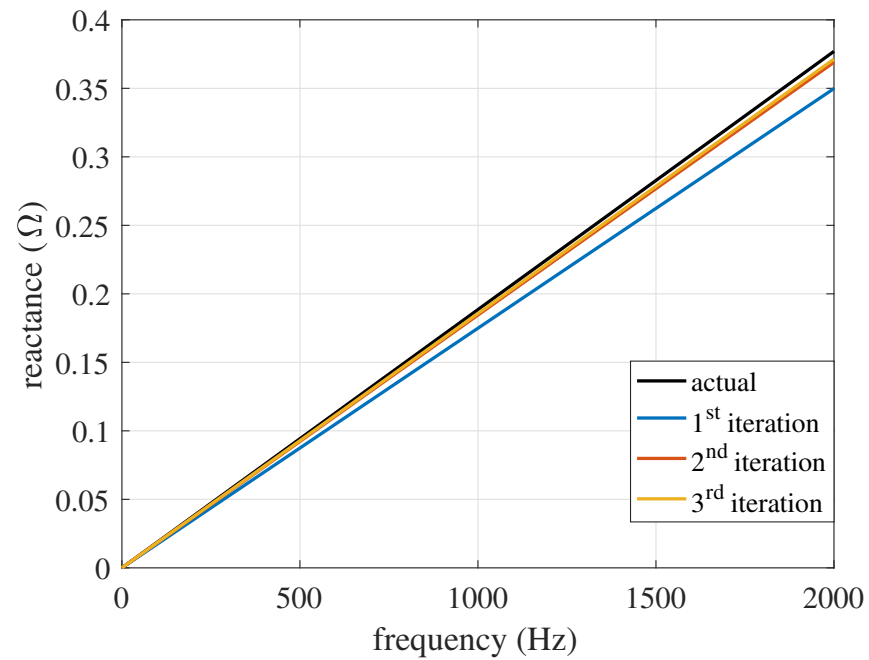
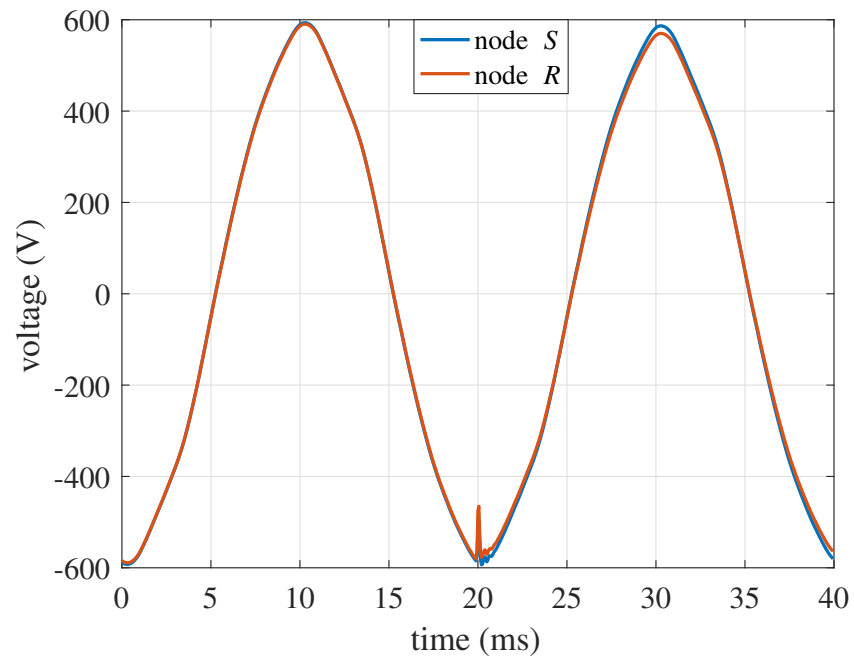
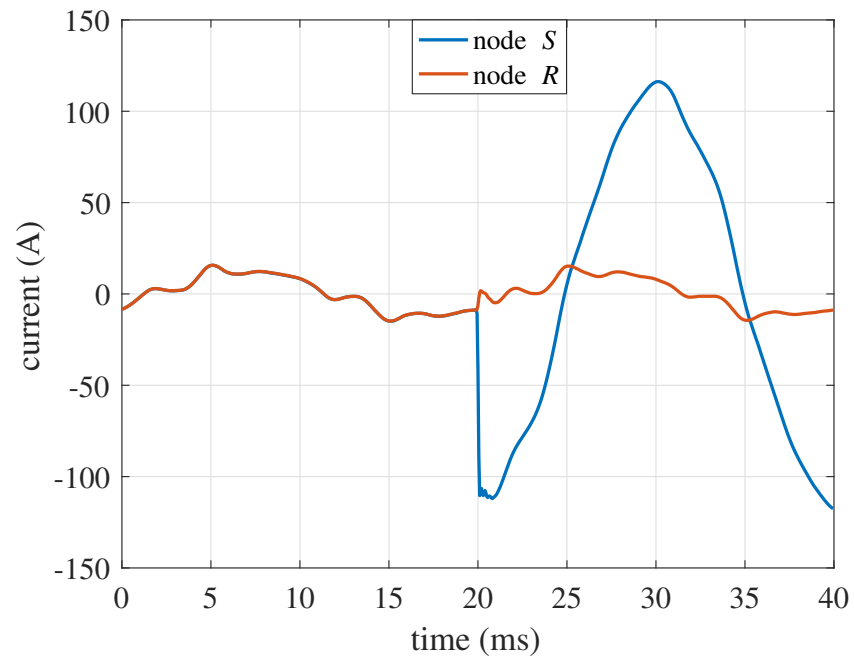


Fig. 7.35: Different iterations using the SEWIBFL (system with DG)

Fig. 7.36: Measured voltage at nodes  $S$  and  $R$ Fig. 7.37: Measured current at node  $S$  and  $R$

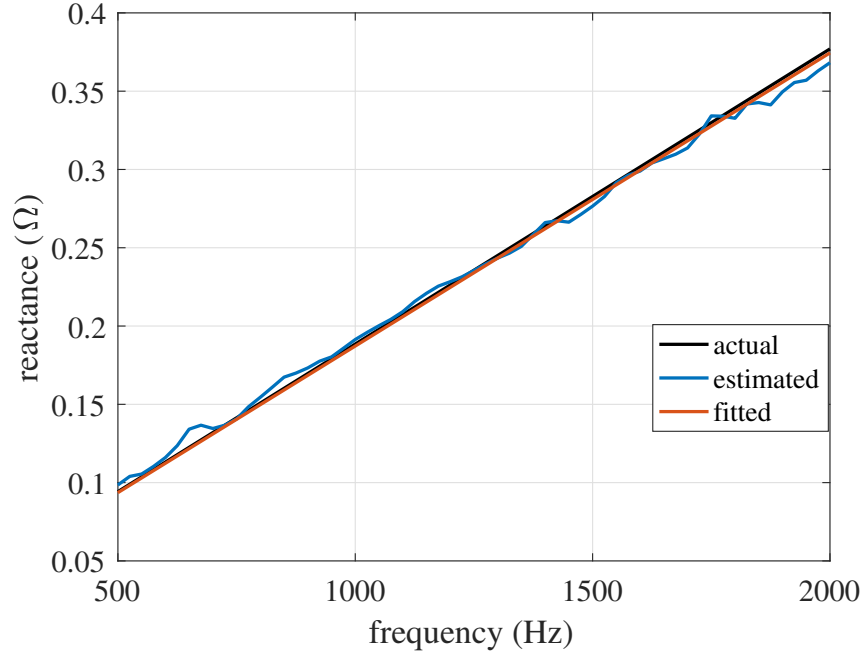


Fig. 7.38: Estimated cable reactance using the DEWIBFL  
(system with DG)

The fault unit has been modified by replacing the IGBTs with a mechanical switch. A fault with resistance of  $1.6 \Omega$  has been imposed between phase  $a$  and the neutral. The voltage and the current were measured at nodes  $S$  and  $R$  and are shown in Fig. 7.39 and Fig. 7.40.

Both single end and double end methods have been applied to estimate the fault distance. The single end method failed to locate this bouncing fault. However, the double end method succeeded and the estimated cable reactance is shown in Fig. 7.41. The single end method assumes a step change in the voltage which is not the case when using the mechanical switch. The voltage over the mechanical switch was also measured and is shown in Fig. 7.42 to illustrate the bouncing action.

## 7.7 Conclusions

The proposed single end method, IBDG model and double end method using synchronized measurements have been validated experimentally.

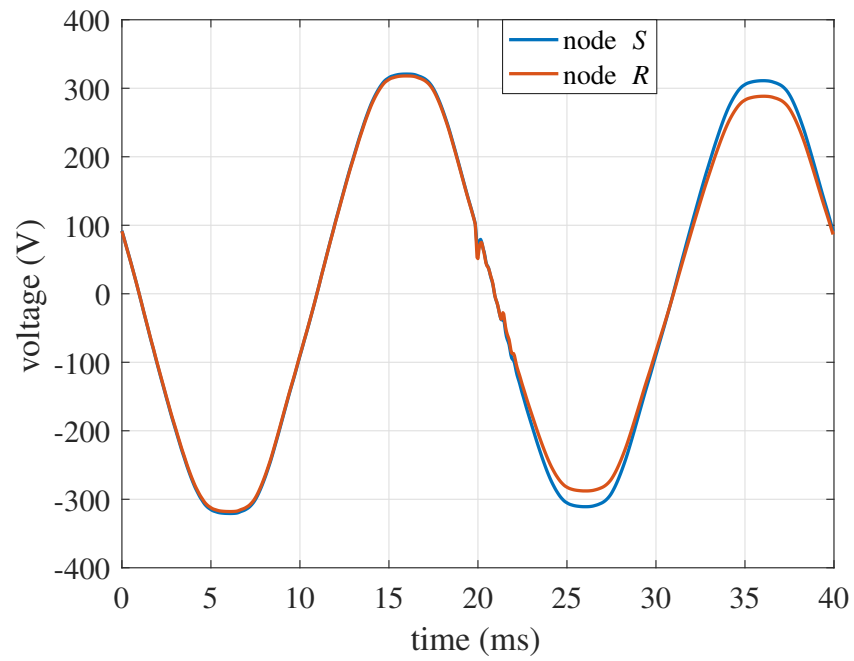


Fig. 7.39: Measured voltage during bouncing fault

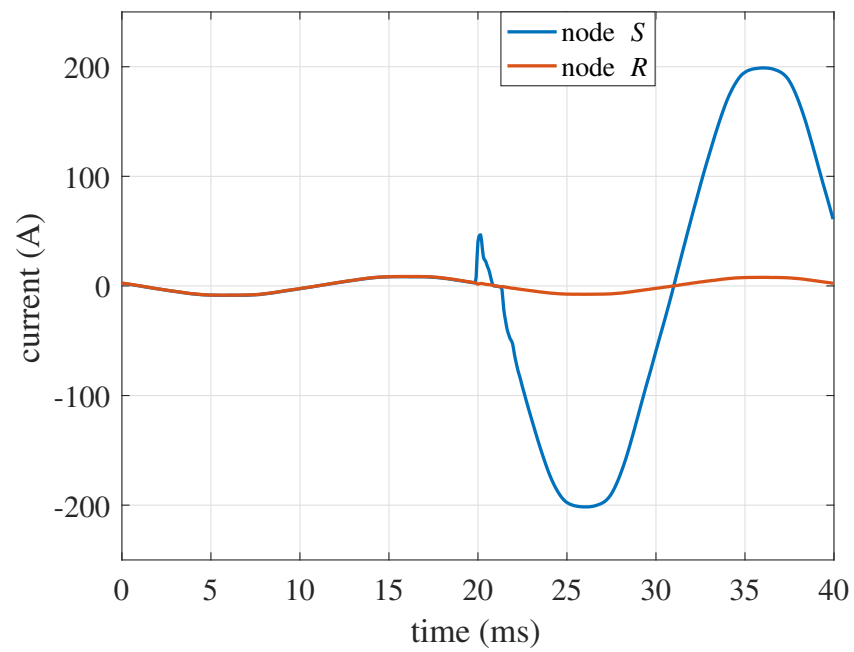


Fig. 7.40: Measured current during bouncing fault

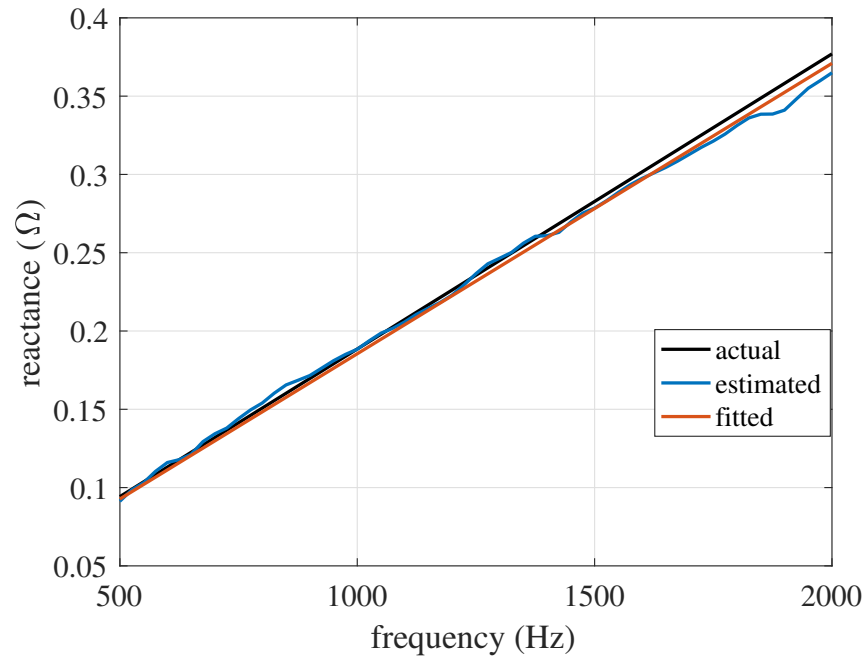


Fig. 7.41: Estimated cable reactance for the bouncing fault using double end method

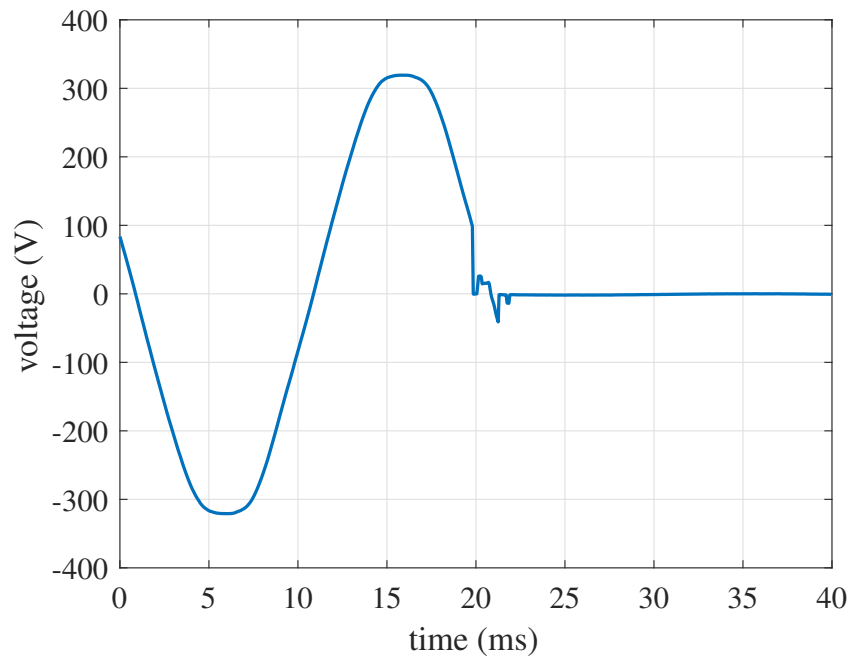


Fig. 7.42: Voltage across the mechanical switch

The experimental system consisted of a cable connected to the main power grid from one side and connected to either a load or to the DG system from the other side. A commercial drive system (Unidrive SP) has been used to build the DG system. Analysing the main grid voltage during healthy operation showed noticeable 5<sup>th</sup> and 7<sup>th</sup> harmonic components (250 Hz and 350 Hz). Therefore, the lower limit for the frequency range of interest, which is used for distance estimation, has been selected as 500 Hz (compared to 250 Hz in the simulation studies). Also, the inception of a fault caused a small change in the voltage which leads to lower magnitudes for the high frequency components. Hence, the upper limit for the frequency range of interest has been selected as 2 kHz to ensure a good signal to noise ratio (compared to 3 kHz in the simulation studies). Due to laboratory restrictions, it was not possible to create a fault with a low fault resistance such that high transient in the voltage could be obtained.

With a load connected at the end of the cable, a fault has been imposed using a fault unit at a distance of 40 m from the sending end (main grid node). The fault distance has been estimated using the proposed single end method by estimating cable reactance between the sending end and the fault. The estimated fault distance was 39.2 m.

The proposed single end method and double end method have been evaluated when connecting the DG to the end node of the cable. The harmonics in the main grid voltage produced a high current at these harmonics due to presence of the DG system filter capacitor. The proposed DG model coincided with the measured DG impedance in the high frequency range. For the single end method, the frequency range from 1 kHz to 2 kHz has been used for distance estimation to avoid errors due to harmonics in the current and also approximations in the DG model. The double end method provided a better performance at different frequencies than the single end method. The estimated distance is 39.4 m and 39.7 m using the single end method and the double end method respectively.

The single end method assumed a step change in the voltage.

Consequently, it failed to locate a bouncing fault created using a mechanical switch. On the other hand, the double end method succeeded to locate the bouncing fault as it does not require building a fault voltage source.

# Chapter 8

## Conclusions

### 8.1 Introduction

This chapter presents the core findings of the work presented in this thesis together with the contributions to the state of art. Potential areas for future research have been identified. Finally, a list of publication is presented.

### 8.2 Conclusions and Contribution

A wideband impedance based fault location technique in distribution systems has been proposed. The proposed technique uses the fault generated transient to estimate the distance to fault point. The technique has been presented based on the availability of measurements. A single end method using the measurements at the main substation has been derived for both radial distribution systems and active distribution systems (in presence of distributed generation). On the other hand, a double end method has been presented to be implemented on distribution systems equipped with multiple measurement points. For both single end and double end methods, different factors affecting the accuracy of the fault location have been considered. These factors may be system dependant such as unbalanced loads, non-homogeneous lines, single and three-phase laterals, line capacitance and untransposed lines.

The distributed parameter line model has been used to accurately represent the line (mutual coupling between phases, line capacitance, untransposed lines or asymmetrical line configuration). The analysis used the transformation between the phase domain and the modal domain to decouple the three-phase system into three independent propagation modes. The methods have been derived for different types of faults e.g. single line to ground and line to line faults.

In order to implement the proposed single end method on a distribution system with distributed generations, a model for each DG in the system is necessary. In this thesis, high frequency approximate models have been presented for both inverter based and synchronous based DGs. The inverter based distributed generation is approximated to a linear system at the high frequencies above the filter resonance frequency. A simple model for the synchronous based distributed generation represented by the machine subtransient impedance has been used. The development of the DG model allowed the application of the proposed single end method on active distribution systems. This eliminates the need for synchronized or even non-synchronized measurements from the DGs to estimate the fault distance.

With multiple synchronized measurement points available in the system, the double end method can be applied. The double end method is more accurate than the single end method. In addition to the traditional concept to apply the double end method using synchronized measurements, a new concept has been presented using a combination of synchronized and non-synchronized measurements. The voltage and current signals which are not synchronized with the main substation measurements are processed to estimate a DG impedance at the high frequency range of interest. The calculated DG impedance is not affected by the error in synchronization as the synchronization error in voltage cancels that in current.

A simulation of the IEEE 34-bus feeder has been used to evaluate the performance of the proposed single end and double end methods. This

feeder is a real medium voltage system and contains unbalanced loads, single and three-phase lines, non-homogeneous sections and asymmetrical line configurations. The test conditions included the effect of fault type, fault resistance, fault inception angle, load uncertainty, noise in measurements and DGs conditions. Note that the aggregated length of the lines is about 93 km and the total length of the main feeder is about 58 km. The evaluation of the proposed single end method with radial distribution system demonstrates the robustness and accuracy of the method against different factors. For different test scenarios, 96.71% of cases were located with an error in estimation of less than 100 m and 99.51% with an error of less than 200 m. The simulation study of an active distribution system showed a reduction in the general performance of the single end method due to the approximations assumed while developing the DG model. The percentage cases with an error of less than 100 m and 200 m are 79.8% and 97.66% respectively. This accuracy level is considered high for this long distribution system. The comparison between the proposed single end method and other impedance based methods emphasizes that the 200 m error obtained by the proposed method represents a good accuracy. The proposed double end method showed a very high accuracy level for different evaluation scenarios where 99.63% of test cases achieved an error in distance estimation of less than 100 m and almost all cases have an error of less than 200 m. To locate faults along laterals, the single end and the double end methods have been integrated to distinguish between a fault on the main feeder and that on a lateral. As a limitation for the single end method, the performance of the single end method is affected if the fault resistance is time varying.

A small scale laboratory system has been built to validate the proposed methods. The test rig consists of a 50 m cable connected to the main power grid from one side and to a load or a DG from the other side. The single end method has been verified experimentally with either load or DG connected at the end of the cable. Also, the double end method has been verified when running the system with the DG connected. The error in distance

estimation was less than 1 m. A commercial drive system has been used to build an IBDG system. The proposed IBDG approximate model has also been validated experimentally by comparing the proposed DG model with the measured DG impedance estimated using voltages and currents measured at the terminal of the DG system.

The main contributions can be summarized as follow:

- The proposed single method is the first single end wideband impedance based method that considers the distributed parameter line model and untransposed lines as well.
- A high frequency model has been developed for inverter based distributed generation that will feature in modern distribution systems. This model eliminates the need for using measurements from the DG location. Therefore, the proposed single end method combined with the developed DG model can be used to locate faults in active distribution system using only the local measurements at the main substation.
- The proposed double method can be applied using either synchronized measurements or a combination of synchronized and non-synchronized measurements.
- The thesis presented the first experimental validation for an inverter based distributed generation high frequency model. A commercial drive system has been used to build an inverter based distributed generation.

### 8.3 Future Work

To achieve full implementation of the proposed methods, further work needs to be done. Some of the areas where the future work can be directed include

- **Locating arc faults:** Arc faults are characterized by time varying fault resistance [84]–[86]. As has been explained in the simulation

studies in Chapter 6, the performance of the single end method was affected by the non-linearity of the fault resistance. However, the double end method was not. Therefore, the single end method requires further investigation to be able to locate such faults.

- **Auto-commissioning:** The proposed methods and other impedance based methods assume the line parameters are available. However, the exact line parameters cannot be ensured due to uncertainties associated to the actual line length and other tolerances. Also, a part of the line may be replaced during maintenance. Therefore, a method that can calibrate the impedance of an unknown system would improve the accuracy of the proposed impedance based methods.
- **Switching on a fault:** The proposed single end method assumes the fault causes a step change in the voltage. When the system is switched on a fault, the circuit breaker used to energize the system may cause non hard step closing (i.e. the switching causes some bouncing). In this case, the single end method would not be suitable unless the measurements at the line side of the circuit breaker are available. This aspect requires investigation.
- **DG dominant system:** In a system mainly fed by DGs especially IBDGs, the fault current will not be high. Therefore, the transient in the voltage and current signals are expected to be not significant. The performance of the proposed methods needs to be evaluated for such system e.g. with isolated microgrid network.
- **Real life application:** Installation of a high frequency monitoring system, for instance at the main substation, which is able to record transient in voltage and current would be of great benefit and would allow testing the method using real transient data. This helps to develop the method for real applications.

## 8.4 Publication List

The research related to this thesis has been published in three international conferences and one journal paper. Also, two journal papers were submitted and are currently under review.

1. F. M. Aboshady, Mark Sumner, and D. W. P. Thomas, "A double end fault location technique for distribution systems based on fault-generated transients," IEEE, *26th International Symposium on Industrial Electronics (ISIE)*, 2017.
2. F. M. Aboshady, D. W. P. Thomas, and M. Sumner, "Fast fault location scheme for distribution systems based on fault transients," IET, *International Conference on Resilience of Transmission and Distribution Networks (RTDN)*, 2017.
3. F. M. Aboshady, Mark Sumner, and D. W. P. Thomas, "A wideband fault location scheme for active distribution systems," *7th International Conference on Renewable Energy Research and Applications (ICRERA)*, 2018.
4. F. M. Aboshady, D. W. P. Thomas, and Mark Sumner, "A new single end wideband impedance based fault location scheme for distribution systems," *Electric Power Systems Research*, vol. 173, pp. 263-270, 2019.
5. F. M. Aboshady, D. W. P. Thomas, and Mark Sumner, "A wideband single end fault location scheme for active untransposed distribution systems," submitted to IEEE Transactions on Smart Grid.
6. F. M. Aboshady, D. W. P. Thomas, and Mark Sumner, "A fault location scheme for active untransposed distribution systems using limited synchronized measurements," submitted to Electric Power Components and Systems.

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# Appendix A

## Simulation Data

The system in Fig. 6.1 has been simulated using Matlab/Simulink toolbox [62]. The system data used in the simulation is provided in this appendix.

### A.1 Substation Data

The main substation is simulated as a three-phase voltage source with an impedance. The voltage source data is provided in Table A.1. The short circuit level is calculated based on the main transformer nominal power (2.5 MVA) and the transformer percentage impedance (8%) given in [61].

Table A.1: Data of the substation

|                                        |         |
|----------------------------------------|---------|
| <b>line to line voltage</b>            | 24.9 kV |
| <b>frequency</b>                       | 50 Hz   |
| <b>three-phase short circuit level</b> | 31 MVA  |

### A.2 Line Data

The system has three-phase lines of different configurations and also single phase laterals. The same line configuration was used for different single phase lines. The distributed parameter line model in Matlab/Simulink was used to model the lines. The length, phasing and configuration of the lines

are given in Table A.2. Then, the resistance, inductance and capacitance data for different configurations is provided.

Table A.2: Data of the lines

| <b>from node</b> | <b>to node</b> | <b>length (m)</b> | <b>configuration</b> | <b>phasing</b> |
|------------------|----------------|-------------------|----------------------|----------------|
| 800              | 802            | 786               | 300                  | ABC            |
| 802              | 806            | 527               | 300                  | ABC            |
| 806              | 808            | 9824              | 300                  | ABC            |
| 808              | 812            | 11430             | 300                  | ABC            |
| 812              | 814            | 9062              | 300                  | ABC            |
| 814              | 850            | 3                 | 301                  | ABC            |
| 850              | 816            | 94                | 301                  | ABC            |
| 816              | 824            | 3112              | 301                  | ABC            |
| 824              | 828            | 256               | 301                  | ABC            |
| 828              | 830            | 6230              | 301                  | ABC            |
| 830              | 854            | 158               | 301                  | ABC            |
| 854              | 852            | 11226             | 301                  | ABC            |
| 852              | 832            | 3                 | 301                  | ABC            |
| 832              | 858            | 1494              | 301                  | ABC            |
| 858              | 834            | 1777              | 301                  | ABC            |
| 834              | 842            | 85                | 301                  | ABC            |
| 842              | 844            | 411               | 301                  | ABC            |
| 844              | 846            | 1109              | 301                  | ABC            |
| 846              | 848            | 162               | 301                  | ABC            |
| 808              | 810            | 1769              | 302                  | B              |
| 816              | 818            | 521               | 302                  | A              |
| 818              | 820            | 14676             | 302                  | A              |
| 820              | 822            | 4188              | 302                  | A              |
| 820              | 822            | 4188              | 302                  | A              |

*Continued on next page*

Table A.2 – *Continued from previous page*

| from node | to node | length (m) | configuration | phasing |
|-----------|---------|------------|---------------|---------|
| 824       | 826     | 924        | 302           | B       |
| 854       | 856     | 7111       | 302           | B       |
| 832       | 890     | 3219       | 300           | ABC     |
| 858       | 864     | 494        | 302           | A       |
| 834       | 860     | 616        | 301           | ABC     |
| 860       | 836     | 817        | 301           | ABC     |
| 836       | 840     | 262        | 301           | ABC     |
| 836       | 862     | 85         | 301           | ABC     |
| 862       | 838     | 1481       | 302           | B       |

*Configuration 300:*

$$R_{300} = \begin{bmatrix} 0.8308 & 0.1306 & 0.1324 \\ 0.1306 & 0.8227 & 0.1284 \\ 0.1324 & 0.1284 & 0.8372 \end{bmatrix} \quad (\Omega/\text{km})$$

$$L_{300} = \begin{bmatrix} 2.6397 & 1.1433 & 0.9921 \\ 1.1433 & 2.6844 & 0.9082 \\ 0.9921 & 0.9082 & 2.6650 \end{bmatrix} \quad (\text{mH}/\text{km})$$

$$C_{300} = \begin{bmatrix} 10.5543 & -3.0294 & -1.9670 \\ -3.0294 & 10.0852 & -1.2289 \\ -1.9670 & -1.2289 & 9.6700 \end{bmatrix} \quad (\text{nF}/\text{km})$$

*Configuration 301:*

$$R_{301} = \begin{bmatrix} 1.1995 & 0.1446 & 0.1466 \\ 0.1446 & 1.1906 & 0.1422 \\ 0.1466 & 0.1422 & 1.1945 \end{bmatrix} \quad (\Omega/\text{km})$$

$$L_{301} = \begin{bmatrix} 2.7924 & 1.2744 & 1.1259 \\ 1.2744 & 2.8252 & 1.0362 \\ 1.1259 & 1.0362 & 2.8110 \end{bmatrix} \text{ (mH/km)}$$

$$C_{300} = \begin{bmatrix} 10.1303 & -2.8416 & -1.8600 \\ -2.8416 & 9.7046 & -1.1773 \\ -1.8600 & -1.1773 & 9.3285 \end{bmatrix} \text{ (nF/km)}$$

*Configuration 302:*

$$R_{302} = 1.74 \, \Omega/\text{km} \quad L_{302} = 2.939 \, \text{mH/km} \quad C_{302} = 8.4 \, \text{nF/km}$$

### A.3 Load Data

Table A.3 presents the loads connected at different nodes of the system. The loads are described by the nominal active power (P in kW) and nominal reactive power (Q in kVAR) for different phases.

Table A.3: Data of the loads

| node | phase A |       | phase B |      | phase C |       |
|------|---------|-------|---------|------|---------|-------|
|      | P       | Q     | P       | Q    | P       | Q     |
| 802  | 0       | 0     | 15      | 7.5  | 12.5    | 7     |
| 806  | 0       | 0     | 15      | 7.5  | 12.5    | 7     |
| 808  | 0       | 0     | 8       | 4    | 0       | 0     |
| 810  | 0       | 0     | 8       | 4    | 0       | 0     |
| 818  | 17      | 8.5   | 0       | 0    | 0       | 0     |
| 820  | 84.5    | 43.5  | 0       | 0    | 0       | 0     |
| 822  | 67.5    | 35    | 0       | 0    | 0       | 0     |
| 816  | 0       | 0     | 2.5     | 1    | 0       | 0     |
| 824  | 0       | 0     | 22.5    | 11   | 2       | 1     |
| 826  | 0       | 0     | 20      | 10   | 0       | 0     |
| 828  | 3.5     | 1.5   | 0       | 0    | 2       | 1     |
| 830  | 13.5    | 6.5   | 10      | 5    | 25      | 10    |
| 854  | 0       | 0     | 2       | 1    | 0       | 0     |
| 856  | 0       | 0     | 2       | 1    | 0       | 0     |
| 832  | 3.5     | 1.5   | 1       | 0.5  | 3       | 1.5   |
| 858  | 6.5     | 3     | 8.5     | 4.5  | 9.5     | 5     |
| 864  | 1       | 0.5   | 0       | 0    | 0       | 0     |
| 834  | 10      | 5     | 17.5    | 9    | 61.5    | 31    |
| 860  | 43      | 27.5  | 35      | 24   | 96      | 54.5  |
| 836  | 24      | 12    | 16      | 8.5  | 21      | 11    |
| 840  | 18      | 11.5  | 20      | 12.5 | 9       | 7     |
| 862  | 0       | 0     | 14      | 7    | 0       | 0     |
| 838  | 0       | 0     | 14      | 7    | 0       | 0     |
| 842  | 4.5     | 2.5   | 0       | 0    | 0       | 0     |
| 844  | 139.5   | 107.5 | 147.5   | 111  | 145     | 110.5 |
| 846  | 0       | 0     | 24      | 11.5 | 10      | 5.5   |
| 848  | 20      | 16    | 31.5    | 21.5 | 20      | 16    |
| 890  | 150     | 75    | 150     | 75   | 150     | 75    |