# DEVELOPMENT OF HYBRID ISLANDING DETECTION TECHNIQUE FOR DISTRIBUTED POWER GENERATION

Master of Science dissertation

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# Abstract

The utilization of distributed generation (DG) units is rapidly increasing in power system and questions are raised regarding their effect on the system, energy management and protection policies. DG can provide in some cases a significant art of the load energy requirements. Islanding operation of DG usually occur when the main utility supply is interrupted due to several contingencies (inrush currents, faults, etc) while the DG is still supplying power to the distribution network at a sustained voltage and frequency. These conditions have negative impacts on the system protection, restoration, operation and management and could be fatally harmful to line workers and power system facilities. IEEE Std. 1547TM-2003 & IEEE Std.929-2000 require that islanded DG system be shut down within a specified time. Therefore, it is necessary to detect the presence of this condition and switch off the DG from distribution network or isolate the DG with its load from the rest of the system.

Conventional detection methods for islanding conditions are based on monitoring several parameters such as voltage magnitude, phase, displacement, frequency change, voltage unbalance (VU) and total harmonic distortion (THD). However, in case of small changes in loading for DG, the contingency will be masked by normal operating condition. Conventional methods usually will not detect such an islanding condition.

Among the existing islanding detection techniques, two techniques, namely the positive feedback (PF) technique and voltage unbalance and the total harmonic distortion (VU/THD) technique are most promising ones. However, both of these tecliniques have their own flaws. In this thesis a new technique is proposed that combines the principles of those two to obtain a hybrid islanding detection technique for synchronously rotating DGs. Simulation results show that the proposed hybrid technique is more effective than each of the above schemes.

# DECLARATION

The work submitted in this dissertation is the result of my own investigation, except where otherwise stated.

It has not already been accepted for any degree, and is also not being concurrently submitted for any other degree.

UOM Verified Signature



R. P. Tilakeratne
January 2008

I endorse the declaration by the candidate.

UOM Verified Signature

Prof. Ranjith Perera
Supervisor

# CONTENTS

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# Chapter 1

## Introduction

### 1.1 General

According to IEEE STD 1547-2003[1], distributed generation (DG) is defined as electric generation facilities connected to power system through a point of coupling (PCC). Distributed generation has the potential to play a major role as a complement or alternative to the electric power grid under certain conditions. DG can also improve a utility's ability to serve peak load on a feeder. DG is fundamentally distinct from the traditional central plant model for power generation and can deliver energy close to loads within power distribution network [8].

In August 1997, the Ministry of Irrigation and Power of Sri Lanka announced policy directions for power sector, where the private sector is expected to play a key role in power sector development activities. The policy direction for power sector envisages that private sector financing will be utilized for power generation from small hydro power plants. At present, unsolicited proposals for mini hydro power projects of not more than 10 MW of individual installed capacity are entertained by The Ceylon Electricity Board (CEB). During last few years, mini hydropower industry has gained a boost in this country and 75 plants with total installed capacity of 150 MW are already in commercial operation. There are 25 projects with the total installed capacity of 55 MW are under construction, which are expected to be grid interconnected over the next few years and many more project proposals are in pipeline. As a whole it is expected that about 300 MW of mini hydroelectric plants will be developed over the next few years. Embedded generators covered by the CEB guide are those connected to distribution network, passive and dispatch their generation to the system without any control over them by the System Control Center of the CEB.



Distributed generation has the potential in Sri Lanka to play a major role in supplementing the electric grid power under certain conditions and at present capacity of following 33 kV feeders are already been utilized fully.

- Balangoda – Ratnapura feeder
- Balangoda – Haputale feeder
- Seethawaka – Karawanella feeder
- Balangoda – Nivitigala feeder
- Wimalasurendra – Gampola feeder
- Nuwara-Elliya – Hanguranketha feeder
- Ratnapura – Kuruwita/Waranagala feeder.

**The benefits of distributed generation can be summarized as given below.**

- Emergency backup
- Improved system performance
- Increased reliability
- Potential utility capacity addition deferrals
- Combined heat and power
- Green power
- Ancillary service power
- Advantageous for national security.



Although DGs are receiving a lot of attention in the recent past, the prospects of their widespread adoption is not certain. There are economic and technical concerns involved that act as hindrances in the wide spread use of DGs.

## 1.2 Economic Concerns

Since cost is a dominant factor for the survival of a technology, following economic concerns need to be addressed before the wide spread adoption of DGs.

- **Uncertainty about market potential:** Although it is believed that DG prices would fall in the future, the most widely mentioned highly efficient DG micro-turbines are not widely commercially available [13].
- **Difficulties in recovering utility costs:** If customers start setting up their own DGs for their power requirement and buy a small amount of power from the utilities, it would be very difficult for the utilities to recover past investment or

embedded costs. It would also increase the burden on customers who rely on the utility for their power demands.

## 1.3 Technical Concerns

Distribution systems have been traditionally designed as radial systems, and the time coordination of protection devices at the distribution level is a standard practice used by the utilities. However, insertion of a DG downstream of the loads or protection devices changes the traditionally radial nature of distribution system and hence may necessitate a change in protection strategy. These problems include protection issues, voltage and frequency issues, operational issues and minimizing the need to upgrade the system for accommodating DGs [9, 10 and 11].

**The following terms have been defined in consistency with IEEE STD 1547:**

- **Micro grid (MG):** The portion of the grid connected to a DG which is isolated from the utility grid by a circuit breaker (CB) at the point of common coupling.
- **Island:** A condition where a part of the grid, connected to the DG (the micro-grid or MG) is isolated from the utility-connected grid by the opening of the CB at PCC.
- **Unintentional islanding:** If the islanding was unplanned, then the islanding is called unintentional islanding. Islanding usually refers to unintentional islanding.



### 1.3.1 Protection issues

Distribution systems have been designed as radial systems [10] and therefore, as a standard practice time coordination of protective devices at distribution level are used. Insertion of a DG downstream of the loads may necessitate a change in protection strategy [11]. Some of them are discussed below.

#### 1.3.1.1 Fuse-fuse coordination

Figure 1.1 shows a DG connected to a utility distribution system through fuses excluding circuit breakers and other protective devices [11].

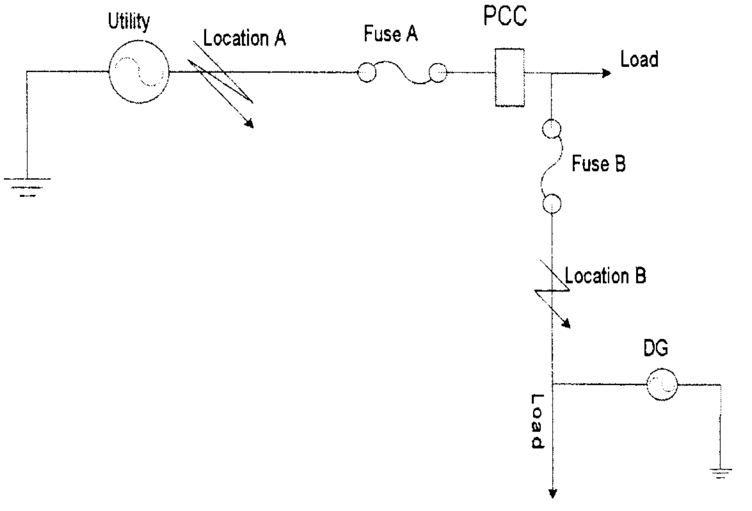


Figure 1.1 – DG connected to utility grid

For a fault occurring at location B, fuses A and B would see the same fault current injected by the utility grid. Fuse B should act faster than fuse A to isolate a minimum part of the system. In case of an abnormal condition where utility grid is faulted at location A, both fuses see the same fault current which is injected by the DG. During this situation fuse A should act faster than fuse B to isolate a minimum part of the system. It is clear that the fuse-fuse coordination for an upstream fault in the presence of DG is in contradiction with the fuse coordination requirement in the absence of DG.



### 1.3.1.2 Recloser-fuse coordination

In the distribution system circuit protection is often done by the coordination of fuses and auto reclosers [11]. Figure 1.2 shows a radial distribution line feeding a load before insertion of a DG and figure 1.3 shows after insertion of a DG. For a fault occurring at location A before insertion of DG as shown in figure 1.2; the recloser is normally programmed to make two short reclosing attempts, and if the fault persists, it will make a longer reclosing attempt before it goes to lock out. In a reliable system the fuse would operate during the long reclosing time of the auto recloser so that power will continue to be supplied to the portion of the line between the fuse and the recloser.

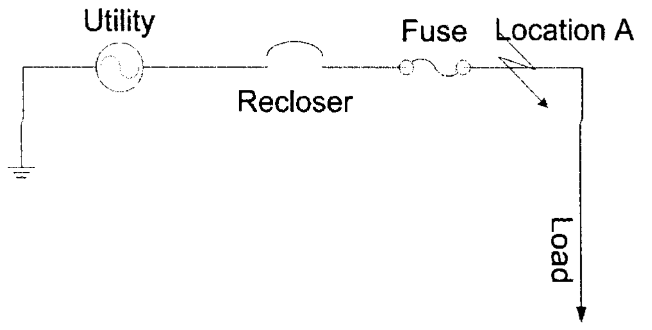


Figure 1.2 – Reclosure-fuse co-ordination before insertion of DG

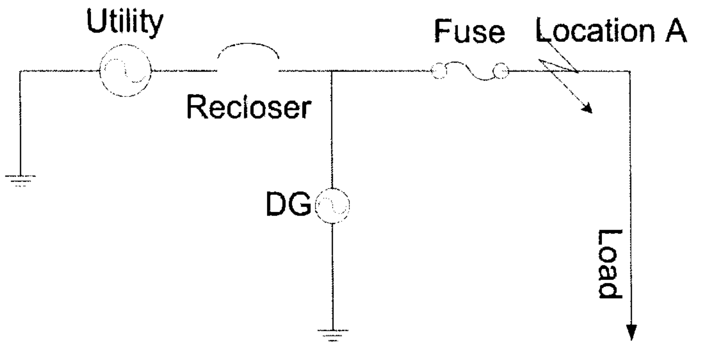


Figure 1.3 – Reclosure-fuse co-ordination after insertion of DG



Now consider the situation where DG is inserted in between fuse and recloser as appears in figure 1.3. On occurrence of a fault; at the first reclosure attempt the DG might inject sufficient current to blow the fuse. Therefore, even in case of a transient fault, the fuse may blow leading to a blackout downstream of the fuse.

### 1.3.2 Voltage and frequency issues

When unintentional island (defined in 1.3) occurs, it has to be detected within two seconds, and the PCC should disconnect the bus to which DG is connected, from the utility grid. Once this happens; an island or a micro-grid is formed and a portion of the grid is supplied solely by DGs, and utility has no control over these supplies. It is essential that the frequency and voltage of the micro-grid be quickly restored after disconnecting from the utility grid [18]. Bringing frequency and voltage within permissible limits as quickly as possible and maintaining them at right values is a technical challenge currently being investigated world-wide [5].

### 1.3.3 Modification of distribution systems

It may be necessary to do certain modifications to connect DGs to distributions systems and steps should be taken to minimize the need for such modifications. The IEEE Standard for interconnecting distributed generation to electric power systems sets the requirements which DGs should fulfill before connecting to the utility grid. The introduction of new or increased embedded generation can have following key effects on the electrical system.

- Unintentional islanding
- Increase in fault level which might make it necessary to replace the switchgear.
- Alter power flows and voltage profiles: The insertion of DG affects local voltage and power imported by the local load from utility.
- System upgrade: it may be necessary to upgrade some of the system components:
    - Switching/control arrangements
    - Protection system and setting
    - Earthing system arrangements



Among above issues unintentional islanding is the most important concern regarding the use of distributed generation. The figure 1.4 shows a DG source connected to an existing utility line near a load center.

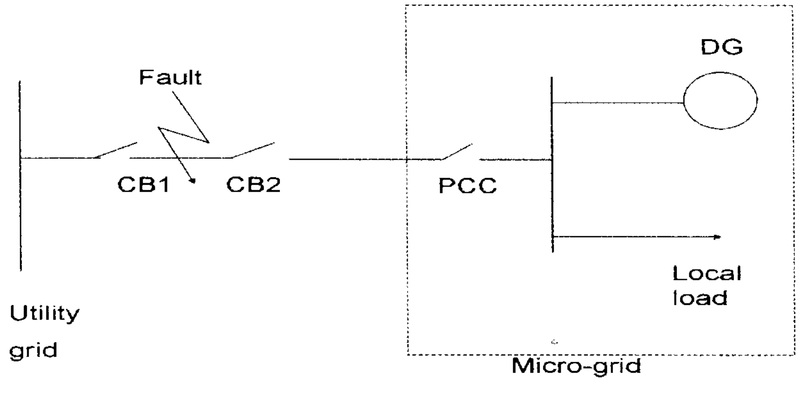


Figure 1.4 – An instance of islanding

For a fault in between CB1 and CB2; CB1 would trip, but DG may not be able to inject enough current to trip CB2. Hence, a portion of the distribution network in between CB1 and the DG is energized solely by DG and utility has no control at all. This situation is referred to as islanding.

### 1.3.4 Operational issues

DG islanding operation usually occur when the main utility power supply is interrupted due to several contingencies such as faults, inrush currents while the DG unit is still supplying power to the distribution network. This kind of condition has negative impact on the distribution system protection, reconfiguration, operation, load management and DG itself. Therefore, once an unintentional island occurs, it has to be detected within two seconds, and the PCC should disconnect the bus to which the DG is connected, from the utility grid. Unintentional islanding is the most important concern regarding the use of DGs and could have severe implications [10], some of which are given below.



- Line worker safety can be threatened by the DG sources feeding a system after the primary energy sources have been opened and tagged out
- Public safety can be compromised as the utility does not have the capability of de-energizing the DG sources energizing downed lines
- The voltage and frequency provided to the customers connected to the island are out of the utility's control, yet the utility remains responsible to those customers
- Protection systems on the island are likely to be uncoordinated, due to change in the short circuit current availability
- The island system may be inadequately grounded by the DG interconnection
- Utility breakers or circuit re-closures may reconnect the island to the greater utility system when out of phase, causing over currents and CB tripping

For safe operation of power systems to which DGs are connected, unintentional islanding should be properly detected. There are many ways to detect this condition. In the next chapter some of the common islanding detection schemes will be explored.

Based on two of these existing techniques a new hybrid islanding detection technique is proposed in this thesis and will be tested to prove the validity of the scheme.

## 1.4 Objectives

Although distributed generation offers many benefits as a nascent field of technology, it faces many obstacles due to economic and technical reasons. A technical issue called unintentional islanding is the most prominent among them, and hence is considered in more detail. This thesis reviews the prominent islanding detection techniques and studies the implementation feasibility, impact on the utility, and probability of false tripping [20]. Therefore the main objective of this research study is to develop a new hybrid technique to overcome drawbacks of existing techniques.

### 1.4.1 Methodology used to accomplish objectives

Review of anti-islanding techniques

- Identify two types of techniques for anti-islanding purpose such as remote techniques and local techniques
- Remote technique: study power line carrier communication (PLCC) and supervisory control and data acquisition network (SCADA)
- Local technique: identify active techniques and passive techniques
- Active techniques: study following protection schemes
    - Detection of islanding by adding perturbations in DG output
    - Active frequency drift method of islanding prevention
    - Positive feedback technique
    - Sandia frequency shift (SFS)
- Passive techniques: study following protection schemes
    - Loss of mains detection by system impedance monitoring
    - Detection of voltage magnitude and frequency
    - Rate of change of frequency
    - Islanding detection by monitoring phase displacement
    - Voltage unbalance (VU) and total harmonic distortion technique (THD)
- General comparison of anti-islanding techniques

- General aspects of islanding operation
- Development of hybrid islanding detection technique for synchronously rotating DGs by using active (positive feedback-PF) and passive (UV/THD) techniques
- Development of a relevant algorithm for the proposed islanding detection technique
- Test proposed islanding detection technique on two systems
- Take first system from "IEEE Transactions on Power Delivery, v20, nl, January, 2005"
- Extract second system from a part of 33 kV feeder No.08 of Ratnapura grid substation
- Simulate second system using MAT LAB

# Existing Islanding Detection Schemes

## 2.1 Classification

There are many proposed techniques for detection of an island. They can be broadly classified into remote and local techniques [24]. Local techniques can further be classified into active and passive techniques as shown in the figure 2.1.

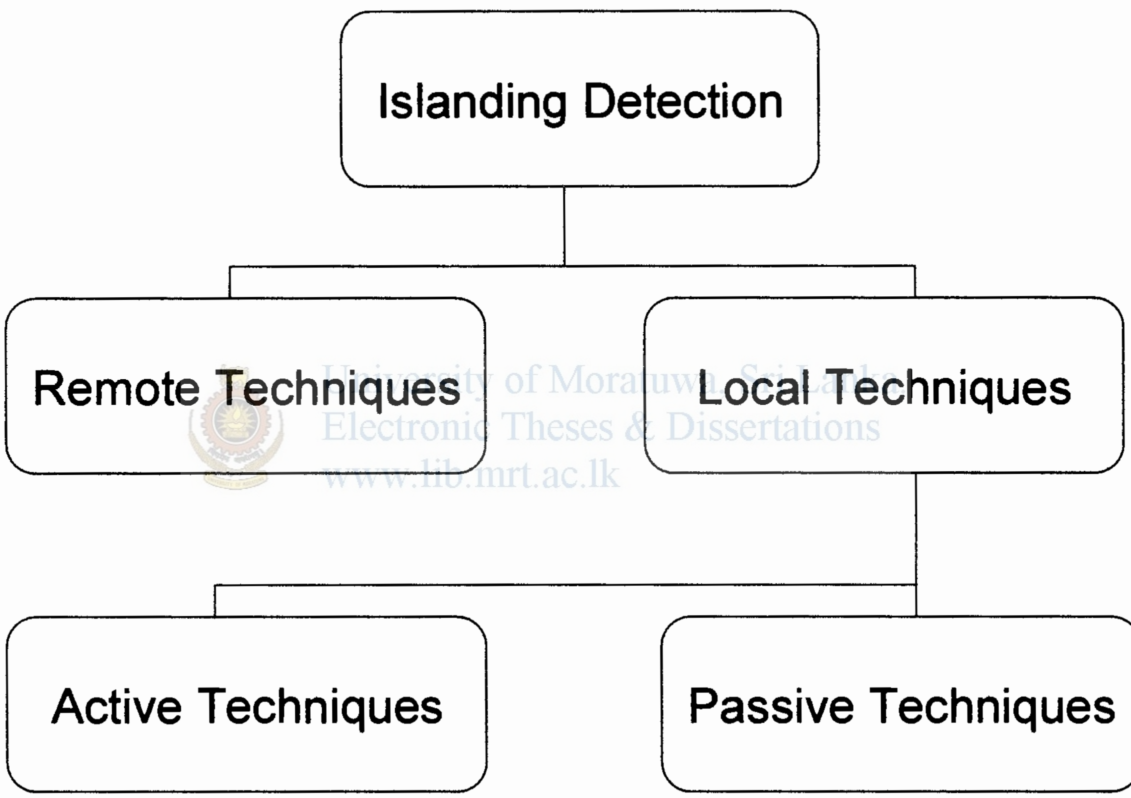




Figure 2.1 – Islanding detection techniques

Remote techniques for detection of islanding are based on communication between utility and the DGs and have better reliability than local techniques, they are expensive to implement and hence uneconomical. Local techniques rely on the information and data at DG site. Passive methods depend on measuring certain system parameters and do not interfere with DG operation. Passive techniques are based on monitoring voltage magnitude [27], rate of change of frequency [28], phase angle displacement [29] or impedance monitoring [26]. If the threshold for permissible disturbance in these quantities is set to a low value, then nuisance tripping might take place and if setting is too high, then islanding may not be detected [20]. In active methods, the DG interface control is designed to facilitate islanding detection by providing a positive feedback from either frequency or voltage [23].

## 2.2 Remote Techniques

There are two prominent methods available [24]. One is power line carrier communication (PLCC) and other one is supervisory control and data acquisition network (SCADA)

### 2.2.1 Power line carrier communications (PLCC)

The figure 2.2 shows a PLCC based system [17] where a DG is connected to utility grid.

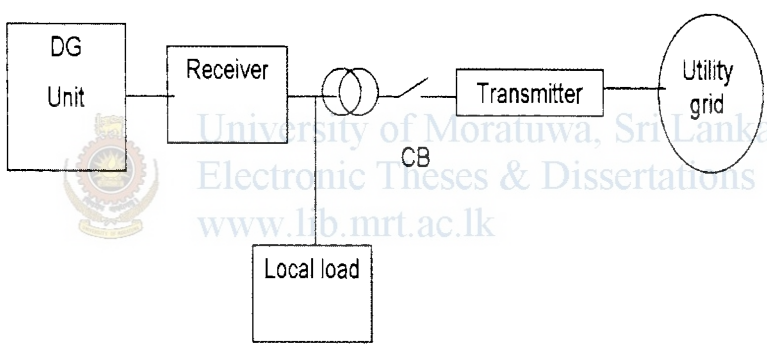




Figure 2.2 – Use of PLCC for islanding detection [24]

In this technique transmitter sends a low energy signal through the line connecting the transmitter to the receiver. Once islanding occurs, the receiver stops getting signals from transmitter, and the absence of signal from the transmitter is used to indicate islanding.

### 2.2.2 Supervisory control and data acquisition (SCADA)

In this technique, the SCADA systems monitor auxiliary contacts of a circuit breaker. When circuit breaker trips, SCADA system identifies this breaker and sends this information to a central control station and that may be used to identify islanded area and trip the PCCs in the islanded area [16].

## 2.3 Local Techniques

There are two types of local techniques namely active and passive techniques.

### 2.3.1 Active techniques

Introduce disturbance to the DG output for the islanding detection. Some of the prominent active techniques will be discussed here.

#### 2.3.1.1 Detection of islanding by adding perturbations in DG output.

In this technique perturbations or disturbances are added at regular intervals to the DG output voltage [15]. Then voltage and reactive power through PCC is measured. In the utility connected mode, these perturbations or disturbances do not cause a significant change in the voltage or reactive power export at PCC. If there is a considerable change in these measured quantities at PCC that indicates the DG is not connected to the utility grid, and hence it can be concluded that islanding has occurred. Flow chart for this technique is shown in figure 2.3 [15].



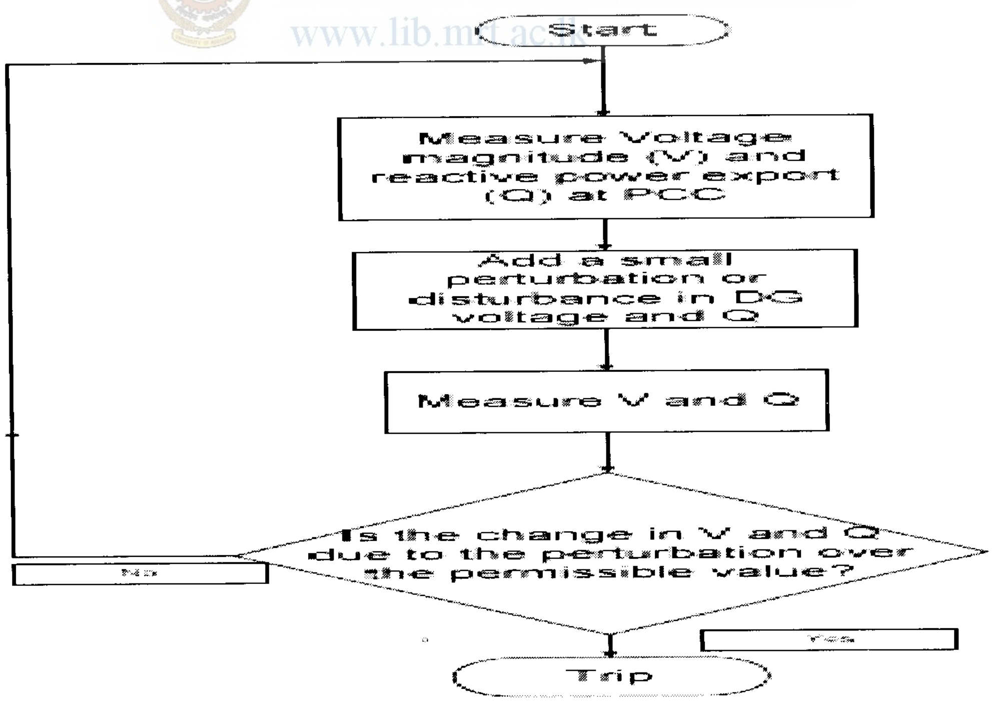


Figure 2.3 – Detection of islanding by adding perturbations

### 2.3.1.2 Active frequency drifts method of islanding prevention

Here, the DG is interfaced with grid through a power electronic inverter [14]. When the inverter converts DC input into AC, instead of converting to utility frequency, the output current waveform of the inverter has a slightly different frequency than the utility supply. Relevant current and voltage waveform are shown in figure 2.4.

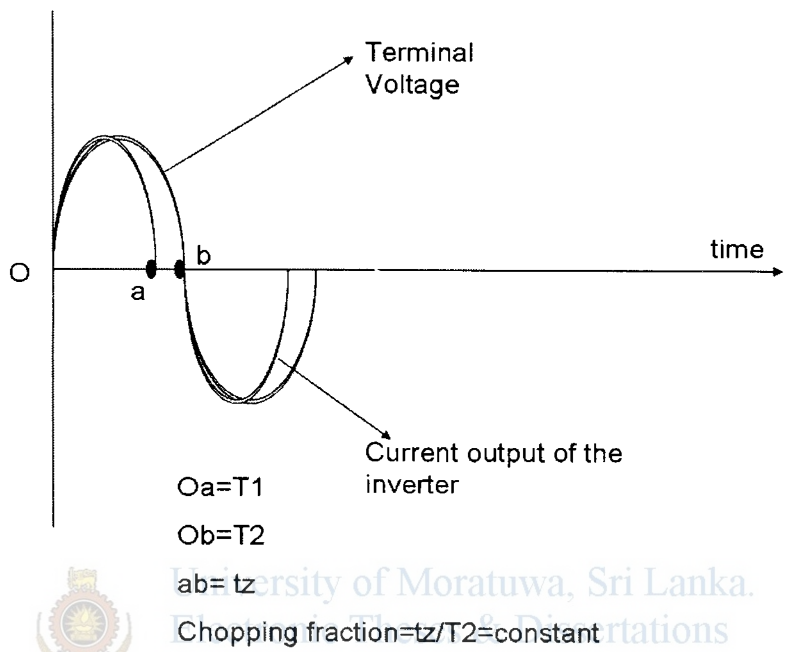




Figure 2.4 – Active frequency drift for islanding detection

Here, T1 is the half time period for inverter current output, and T2 is half time period of terminal voltage and frequency of the inverter and tz is called dead time. In the non islanded or utility connected mode, the terminal voltage and hence T2 is maintained by the utility.

The inverter tries to maintain chopping fraction at a constant value. As soon as islanding occurs, assuming a purely a resistive load, voltage at the inverter terminals would be in phase with the inverter current output. Since the inverter tries to maintain chopping fraction to a constant, it increases the output frequency of the inverter current. But voltage still remains in phase with inverter current. So the inverter tries to increase the frequency even more. This process continues until frequency crosses the permissible window of operation of the inverter.

### 2.3.1.3 Positive feedback technique

This is one of the most prominent existing islanding detection techniques. In this method, a positive feedback of voltage and frequency is given to the DG [19]. As long as DG is connected part of the grid or the micro-grid (MG) is connected to the utility grid, the frequency and voltage of the MG will stay at nominal level. However, as soon as utility supply is disconnected due to faulty conditions the positive feedback which applied to the DG would push the MG frequency and voltage beyond the permissible window of operation of the interfacing inverters and as a result they will shut down. Even though, this technique works, it has some drawbacks. That is; if there are several DGs connected to the utility, they may push the voltage and frequency error higher due to positive feedback and could destabilize the utility grid. Another draw back is that it makes it impossible for an island to have autonomous operation. Hence, in the event of a utility power outage, any consumers connected to that island will go without power.

### 2.3.1.4 Sandia frequency shift (SFS)



This is a modification of active frequency drift which was explained in (2.3.1.2) and shown in figure 2.5. In the active frequency drift technique the chopping fraction (cf) is a constant. However, in SFS technique the cf is made a function of error in the line frequency [19].

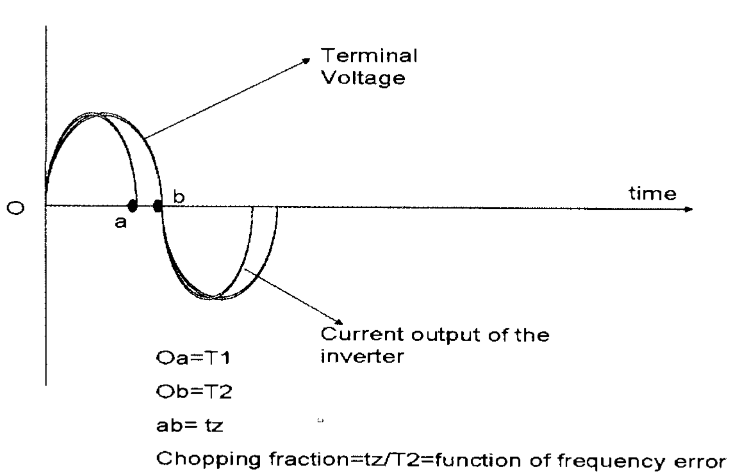


Figure 2.5 – Sandia frequency shift method of islanding detection

$$cf = cfo + K\,(fa - fline) \quad \ldots\ldots (1)$$

Where,

$cf$ = chopping fraction

$cfo$ = chopping fraction set for utility connected operation mode

$K$ = a constant to accelerate the process

$fa$ = frequency of the voltage at the inverter terminals

$fline$ = frequency of the utility supply = a constant

When the inverters connected to the utility grid, the utility maintains the frequency at 50 Hz. So, $fa - fline$ is approximately zero. Therefore $cf$ is a small value and the frequency of the inverter current is close to the utility frequency. But when utility is disconnected even though $fline$ remains at 50 Hz, $fa$ changes because the inverter frequency is slightly different from the utility frequency. According to the equation (1) this error is pushed higher and higher. At last the frequency crosses the permissible window of operation of the inverter and the inverter is shutdown.



The table 2.1 shows the set trip points for this technique.

| Set point for the frequency | Time before switching off (cycles) |
|---|---|
| 53 Hz | 0.5 |
| 50.5 Hz | 5 |
| < 49.5 | 5 |
| < 47 Hz | 0.5 |

Table 2.1 – Tripping time setting for different frequencies

### 2.3.1.5 Sandia voltage shift (SVS)

The principle of this method is similar to that of SFS method. The inverter increases the amplitude of its current output for an increase in the voltage at the terminals of the inverter and vise versa. This will cause a higher voltage error [19]. This does not happen in the utility connected mode but as soon as islanding occurs, the voltage error is pushed higher until the permissible window of operation is crossed. Then the inverter shuts down. Set points for the tripping are shown in table 2.2.

| Set point for the voltage | Time before switching off(cycles) |
|---|---|
| > 145 V | 1 |
| > 132 V | 100 |
| < 110 V | 100 |
| < 60 V | 5 |
| < 30 V | 1 |

Table 2.2 – Tripping time setting for different voltages

### 2.3.2 Passive techniques

The passive techniques detect abnormalities related to the islanding conditions.

#### 2.3.2.1 Loss of mains detection by system impedance monitoring

In this technique a sudden spike in the equivalent impedance of the system is used to detect islanding as shown in figure 2.6.



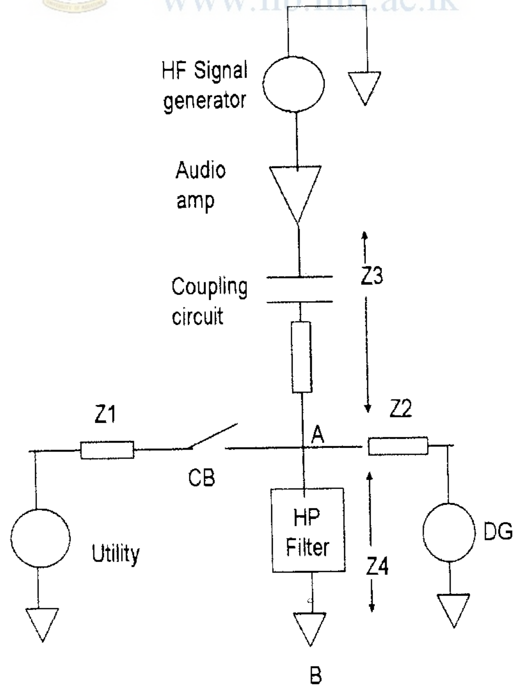


Figure 2.6 – System setup for islanding detection by impedance monitoring

In this method [26] a high frequency signal of a few kHz is injected into the system. When the utility side circuit breaker is in closed position, the impedance between points A and B consist of impedances Z1, Z4 and Z2 in parallel. This impedance is low and hence the voltage across high pass (HP) filter is low. Once the CB at the utility side opens the equivalent impedance between A and B is raised to the value of Z4 in parallel with Z2. This increase in impedance causes an increase in the voltage across the HP filter. This sudden increase in voltage across the HP filter is used to indicate islanding conditions. Main drawback of this system is that a big load switching could be mistaken for islanding.

#### 2.3.2.2 Detection of voltage magnitude and frequency

It is given that as an official guideline for islanding detection in Japan, a deviation of voltage and frequency outside the permissible window of operation can be used as a criterion for islanding detection [27].

#### 2.3.2.3 Rate of change of frequency



In this technique [28], a relay is set such that if the rate of change of frequency is higher than a preset value, the relay trips. Here, the set point for maximum permissible rate of change frequency is a critical value. It should be selected such that the change in frequency during normal utility connected operation does not cause a false tripping but an islanding should cause the relay to trip. However, trip setting for the relay depends on the size of the DG installed.

#### 2.3.2.4 Islanding detection by monitoring phase displacement

In this method [29], output voltage of the DG is monitored for a sudden change in phase. At the instant of islanding, the output current of the DG suddenly changes. This causes a jump in phase of the DG output voltage due to a change in the voltage drop across the synchronous reactance of the DG. The maximum permissible shift in phase is selected in such a way that normal load switching does not cause a false tripping but islanding is detected.

### 2.3.2.5 Voltage unbalances (VU) and total harmonic distortion technique (THD)

In this technique [22] the VU at the DG terminals and THD of the DG current are monitored and used for islanding detection. VU at DG terminals is defined as follows.

$$\text{Voltage unbalance (VU)} = \frac{V_2}{V_1} \times 100 \quad \text{......} (2)$$

Where, $V_1$ and $V_2$ are the positive and negative sequence components of the DG output voltage, respectively. This technique exploits the facts that any change in DG loading causes a spike in the THD and VU of the DG. Any significant spike in either of these monitored quantities is used to send a trip signal to the CB at PCC, which connects the MG to the utility grid. The drawback of this technique is that a load switching can cause a spike in these quantities even if the DG is connected to the utility grid, and as a result, a false tripping of the CB at PCC could occur. A more detailed explanation of the algorithm used in this technique is given below.

### 2.3.2.6 Voltage unbalances (VU)



The average value of VU over one cycle is given by

$$VU_{avg,t} = \frac{1}{N}\sum_{i=0}^{N-1} VU_{t-i} \quad \text{......} (3)$$

The variation in VU is given by

$$\Delta VU_t = \frac{VU_{avg,s} - VU_{avg,t}}{VU_{avg,s}} \times 100 \quad \text{......} (4)$$

Where, N is the number of samples taken per cycle

t is the monitoring time

$VU_{avg,s}$ is the reference value of VU.

This value is initially set to the VU under steady state conditions. If $\Delta VU_t$ remains within – 100% and 50% for one cycle, then $VU_{avg,s}$ is updated by $VU_{avg,t}$. This means that $VU_{avg,s}$ is updated only if the variation in VU is small.

### 2.3.2.7 Total harmonic distortion (THD) in current

$$THD = \frac{\sqrt{\sum_{h=2}^{H} I_h^2}}{I_1} \times 100 \quad \text{......(5)}$$

Where, $I_1$ is the RMS value of the fundamental component of current, $I_h$ is the RMS value of the $h^{th}$ harmonic component of the current.

The average value of THD over one cycle is given by

$$THD_{avg,t} = \frac{1}{N}\sum_{i=0}^{N-1} THD_{t-i} \quad \text{......(6)}$$



The variation in THD is given by

$$\Delta THD_t = \frac{THD_{avg,s} - THD_{avg,t}}{THD_{avg,s}} \times 100 \quad \text{......(7)}$$

Where, N is the number of samples taken per cycle and t is the monitoring time. $THD_{avg,s}$ is the reference value of THD.

This value is initially set to the THD under steady state conditions. If $\Delta THD_t$ remains within -100% and 75% for one cycle, then $THD_{avg,s}$ is updated by $THD_{avg,t}$. This means that $THD_{avg,s}$ is updated only if the variation in THD is small.

The simplified algorithm for VU/THD scheme is as follows.

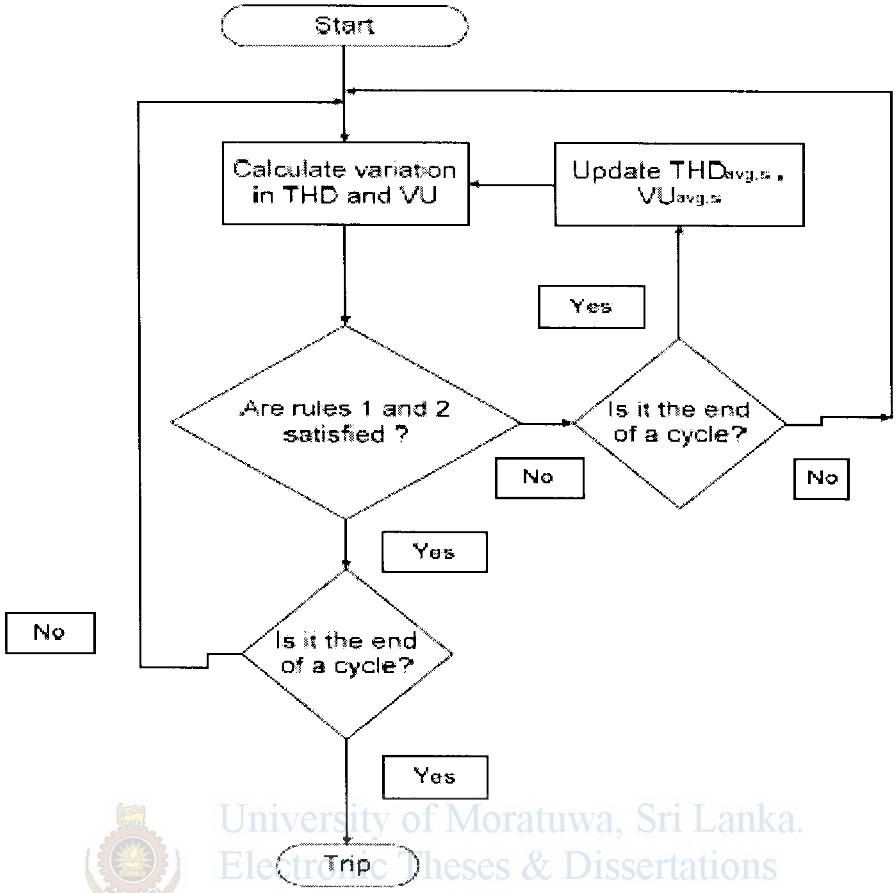




Figure 2.7 – Simplified algorithm for VU/THD scheme

The algorithm proposed above uses two rules to make the tripping decision.

Rule 1: $\Delta THD_t > 75\%$ or $\Delta THD_t < -100\%$

Rule 2: $\Delta VU_t > 50\%$ or $\Delta VU_t < -100\%$.

# Chapter 3

## Proposed Islanding Detection Scheme

### 3.1 Introduction

All techniques mentioned above are having drawbacks and unintentional islanding may take place.

Out of the existing islanding detection techniques, positive feedback (PF) technique [30] and voltage unbalance and the total harmonic distortion (VU/THD) technique [22] are combined to form the proposed hybrid technique.

Proposed method is a hybrid islanding detection technique for synchronously rotating DGs by using active [30] positive feedback-PF and passive UV/THD techniques [22] which can efficiently discriminate between load switching and islanding. Here the three phase voltages are continuously monitored at the DG terminals and VU is calculated for each DG. During disturbances VU is more sensitive than THD and hence THD is not used in this hybrid technique. Any disturbance applied to DGs, as a result of random load switching or islanding could result a spike of VU. To discriminate between VU spike due to islanding and that due to other reasons, another feature is added to this technique. Whenever a VU spike above set threshold value is observed, then set point of frequency is gradually lowered from 50 to 49 Hz within a second. Threshold value of 35 X $VU_{avg}$ is selected as the maximum permissible VU spike. Here $VU_{avg}$ is equal to average value of VU over the past one second. Once frequency set point is lowered, the frequency of DG output voltage is continuously monitored and if it falls below 49.2 Hz within next 1.5 seconds, it indicates that islanding has occurred and should disconnect DG from the grid. If frequency at the DG terminals remains close to 50 Hz; it means utility grid is energized and islanding has not occurred. The exceeding of VU could be a result of load switching or other transient disturbances that do not severely affect operation of power system. Then set point of frequency is restored back to 50 Hz. According to IEEE STD 446-1995 [13] for small engine generators, a 5% frequency change can be tolerated up to 5 seconds and this technique comply with requirement.

## 3.2 Algorithm for the Proposed Islanding Detection Technique

Relevant algorithm for the proposed islanding detection technique is shown in figure 3.1.

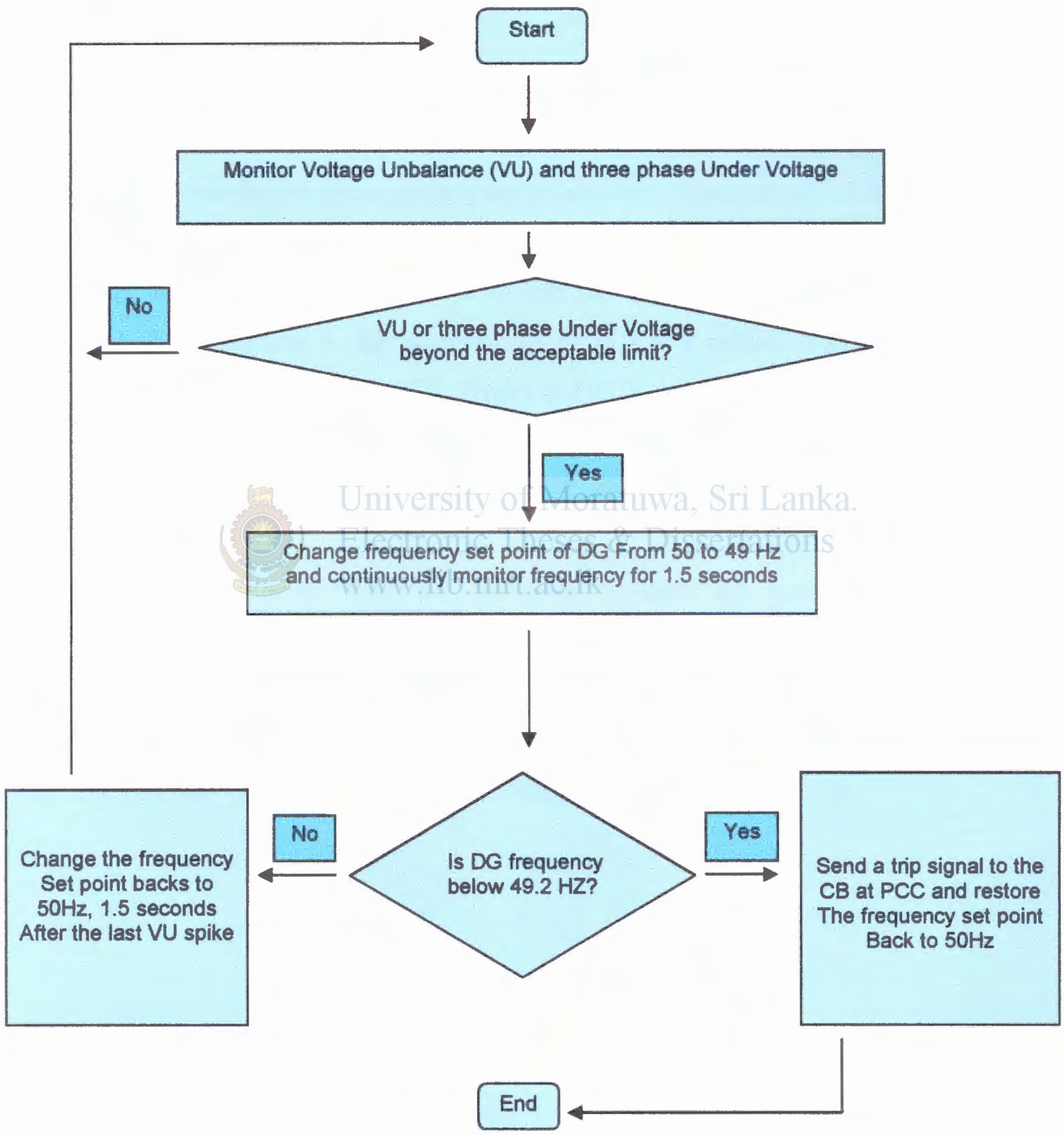




Figure 3.1 – Proposed islanding detection technique.

## 3.3 Test System

The proposed islanding detection technique was tested on two systems. The first system was taken from [12] and the second system was extracted from a part of 33 kV feeder No. 08 of Ratnapura grid substation and was simulated using MAT LAB software.

### 3.3.1 Test system (I)

The system of figure 3.2 (The details for the simulation model is shown in appendix A) is composed of a 13.8 kV, three feeder distribution systems consisting of 20 nodes. The 13.8 kV distribution substations is equipped with a three phase 1.5 MVAr, fixed shunt capacitor bank at node 7, four loads and two synchronous DG units with excitation and governor control. The load and DG capacities are given in the figure. The part of the system to the downstream of PCC1 is called MG1, and the part downstream of PCC2 is called MG2. Nodes at PCC1 and PCC2 have a synchronizing switch to check for in phase (synchronous) operation of the MG with the utility grid before closing the corresponding CB.



In the system shown in figure 3.2, the phase voltages are monitored at the DG terminals, and the positive ($V_1$) and negative sequence ($V_2$) voltages and voltage unbalance$V_2/V_1$ are calculated. Any VU spike over the permissible value given by (8) is investigated for islanding according to the algorithm given in figure 3.1. Details for the study system can be obtained from the diagram in Appendix A [12].

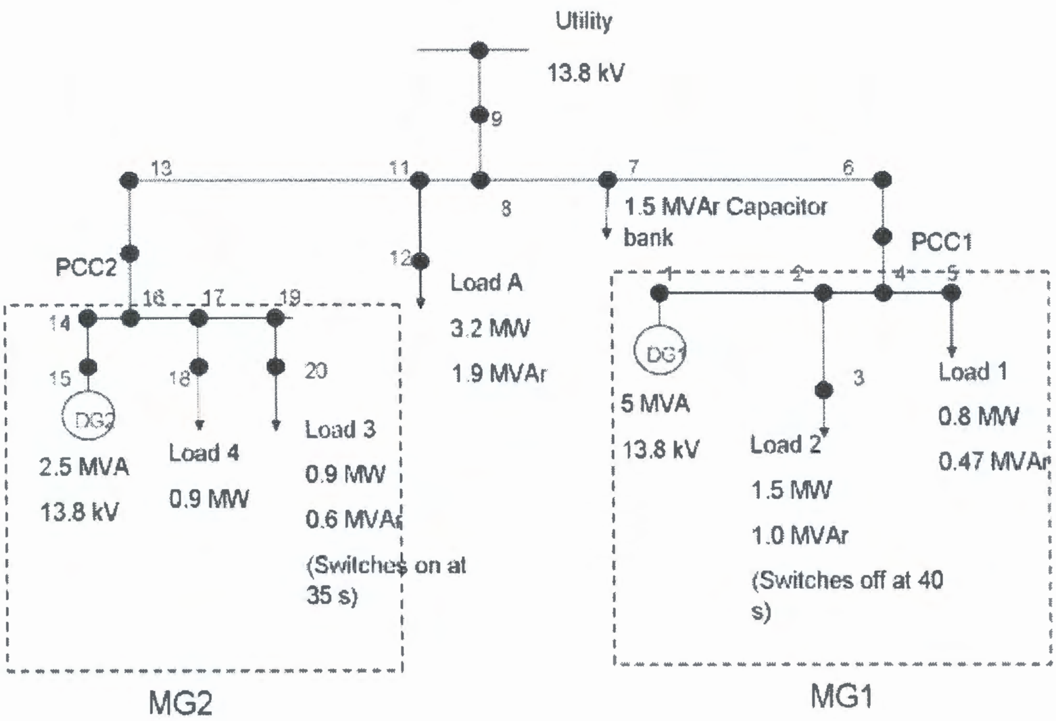


Figure 3.2 – Study system (I)

**3.3.1.1 Simulation of disturbances and results on test system (I)**



- At t = 35s load 3, connected to MG2, switches on and at t = 40s load 2 connected to MG1 switches off. Both of these load switching causes VU spikes at the corresponding DG terminals.
- At t = 45s an upstream CB at node 9 opens and the utility supply goes out, thus causing an unintentional islanding. Islanding causes a VU spike at the both DGs. The purpose of these tests is to show how the proposed technique discriminates between switching and islanding. The simulation results for the above system are given in figures 3.3 to 3.7. Initially the system is under normal operation with both MGs isolated from the utility at their respective PCCs. Both MGs run at 50.02 Hz before connecting to the utility. This is done to bring the MGs in phase with the utility grid before making connection to the grid. The synchronizing switches placed at PCC1 and PCC2 check the phase difference between the utility grid and each MG. In figure 3.3, a VU spike at DG1 terminal can be seen at t = 25.97s. This spike is due to closing of the CB

at PCC1. The VU spike detection algorithm for DG1, given in figure 3.1, activates immediately after MG1 connects to the utility. Hence this VU spike caused by connection to the utility is ignored. Another VU spike is observed at t = 26.86s which is due to closing of the CB at PCC2. This spike, being lower than the value given by (8), is also ignored.

- At t = 35s, load 3 in MG2 switches on. This switching does not cause a big change in the loading of DG1. As a result, the VU spike seen by DG1 is lower than the limit set by (8), and is again ignored.
- At t = 40s, load 2 in MG1 switches off. This load switching causes a large spike in the VU monitored at DG1 terminals, and is used to lower the frequency set point of DG1 from 50 to 49 Hz. It can be seen in figure 3.4 that the frequency set point for DG1 is lowered at t = 40s. Because the utility grid is energized, in spite of reducing frequency set point of DG1 for 1.5 seconds, the frequency of DG1 remains close to 50 Hz. Hence, islanding is ruled out and the frequency set point is restored to 50 Hz.
- At t = 45s, the CB at node 9 opens, causing islanding. As indicated in figure 3.3, at t = 45s, islanding causes a large spike in VU at DG1 terminals. Figure 3.4 shows that soon after reducing the frequency set point at t = 45s, the frequency drops very rapidly and falls below 49.2 Hz, resulting a trip signal is sent to PCC1 and the frequency set point is promptly restored to 50 Hz. It can therefore be concluded that islanding is efficiently detected within a short span of time (in about 0.21 seconds).
- Figure 3.5 shows the VU spike at DG2. At t = 26s a VU spike is observed due to closing of CB at PCC2. This spike is ignored since the islanding detection algorithm for DG2 was not activated. This algorithm activates promptly after closing of CB at PCC2.
- At t = 35s, load 3 has switched in and a VU spike could be seen at DG2 terminals. This spike is large enough to be acknowledged. Figure 3.6 shows that reduced frequency set point do not drop the frequency below the set point of 49.2 Hz at DG2 terminals. Thus islanding is ruled out at t = 36.5s
- Load 2 at MG1 switches off at t = 40s and causes a large spike at DG2 terminals. As seen in figure 3.6, this spike is again ruled out for islanding after lowering the frequency set point to 49.2 Hz for 1.5 seconds. It is noticed

lowering of frequency set point, does not lower the frequency at terminals of DG2.

- At t = 45s, due to islanding a large VU spike, is observed and therefore frequency set point of DG2 is lowered. This causes a quick fall of frequency at DG2 terminals as shown in figure 3.6. Soon after frequency reaches 49.2 Hz, a trip signal is generated and the CB at PCC2 opens. This frequency set point is restored back to 50 Hz, and MG2 continues autonomous operation.
- The effective speed of islanding detection for the whole system can be observed from figure 3.7. The CB at node 9 opens at t = 45s. Thus islanding occurs at this instant. In figure 3.7, it is indicated that power to the intermediate load A is cut off by t = 45.21s, that is 0.21 seconds after islanding. This means that, by t = 45.21s both PCC1 and PCC2 have opened, which means, islanding is detected in 0.21 seconds.
- It is also observed that all VU spikes detected in this proposed technique last longer than 0.05 seconds.

#### 3.3.1.2 Salient features



One of the important salient features of this proposed islanding detection system is to reduce the negative impact of the PF technique on the utility grid. In this technique only the DG that detects VU spikes larger than the set threshold value will change their frequency set point. The magnitude of the VU spike seen by DG depends on the size of the DG and distance from the disturbance. Comparing figures 3.4 and 3.6, it is noticed that when load 3 (in MG2) is switched on at t = 35s, only DG2, which is in the vicinity of disturbance, changes its frequency set point (figure 3.6), while the frequency set point of DG1, remains unchanged (figure 3.4). This is a great advantage over the PF technique, where all the DGs connected to the utility work together at all times to try to destabilize the utility frequency and voltage.

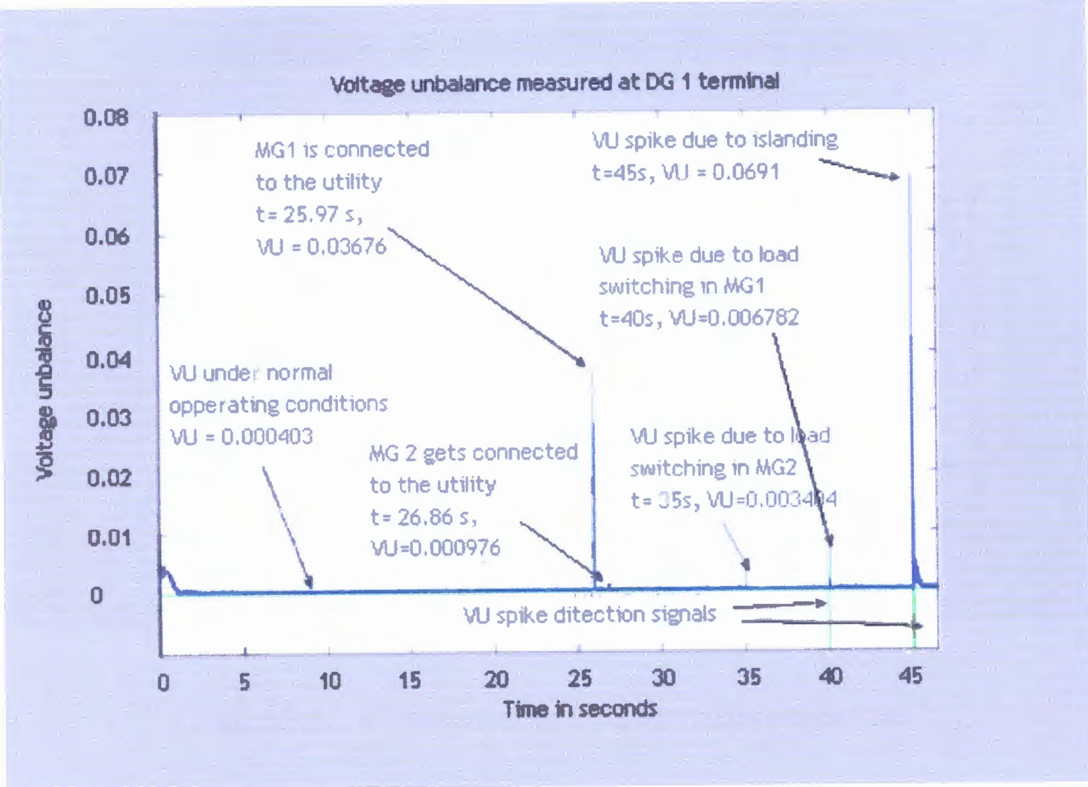


Figure 3.3 – VU at DG1 terminals verses time



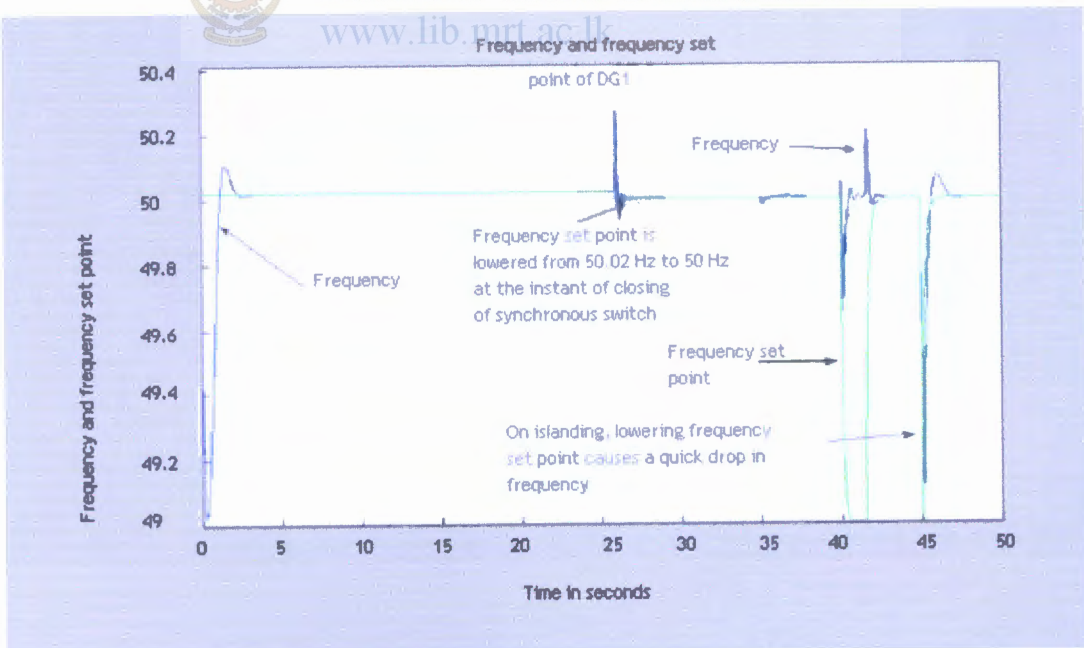


Figure 3.4 – Frequency and frequency set point of DG1 verses time

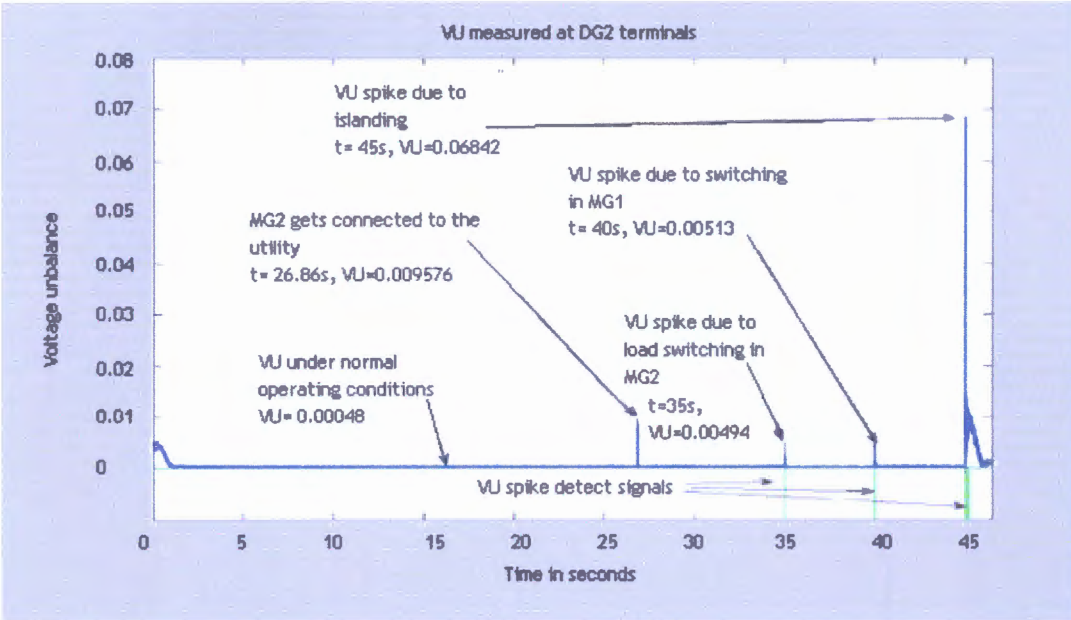


Figure 3.5 – VU measured at DG2 terminals verses time

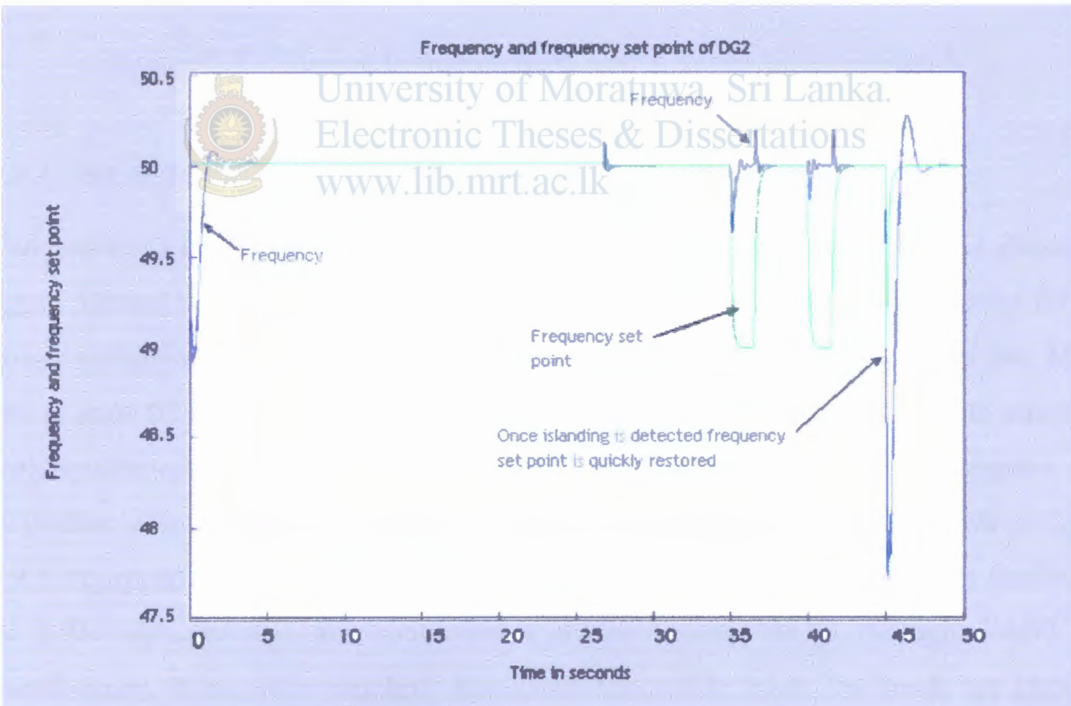




Figure 3.6 – Frequency and frequency set point of DG2 verses time

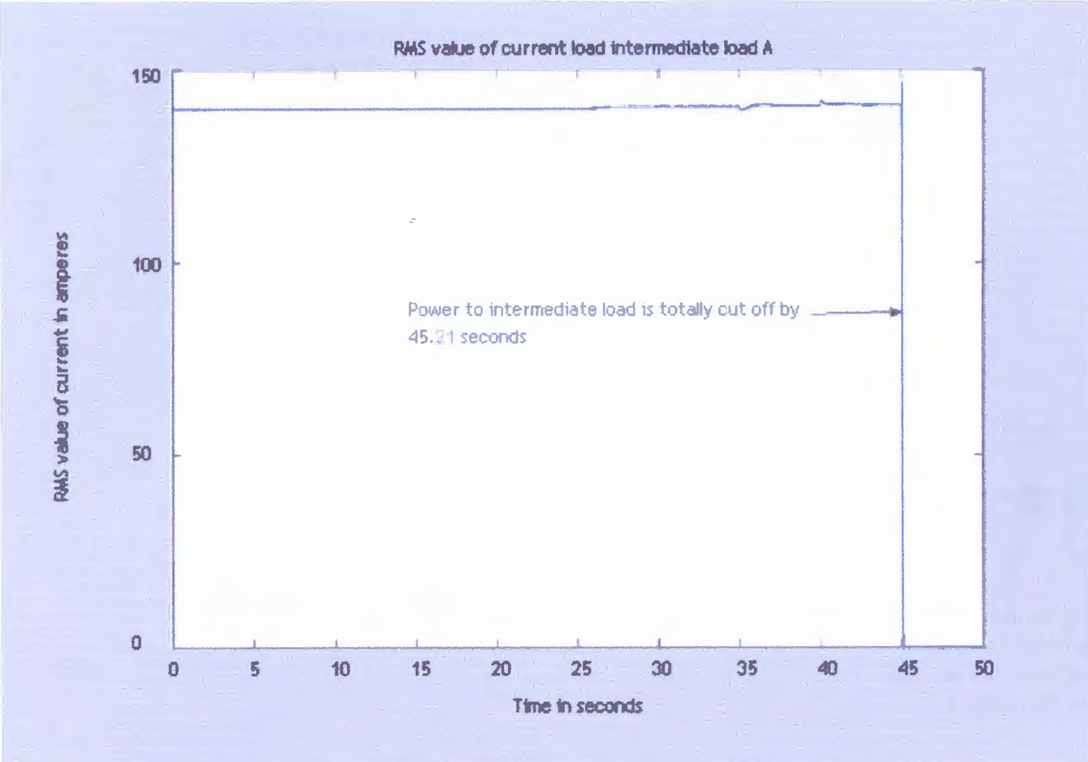


Figure 3.7 – Current to intermediate load A verses time in seconds



### 3.3.2 Test system (II)

The proposed islanding detection technique was tested on a test system as shown in figure 3.8 and was simulated using MAT LAB. The distribution line parameters for the power system are given in Appendix B. The system figure 3.8 composed of two MGs, one at node 03 (PCC 1) and the other one at node 04 (PCC 2). Both these are equipped with synchronous switches. Node 01 is connected to a 33 kV, 50 Hz Ratnapura grid substation where fault level is 6.9 kA. The MG1 connected to node 03, shown in figure 3.9 is equipped with 02 numbers of 02 MW, 400 V synchronous generators totaling to 04 MW capacity and are connected with the feeder No.08 through 0.4/33 kV transformers. It has two switching loads and one steady load. The loads are [1 + j1] MVA each with one switching on at t = 45s and other switching off at t = 50s. MG2, shown in figure 3.10, is equipped with 02 MW, 400 V synchronous generator and is connected with feeder no. 08 through 0.4/33 kV transformer. This has a steady load of 0.5 MW and a switching load of [1 + j1] MVA, switching off at t = 55s.

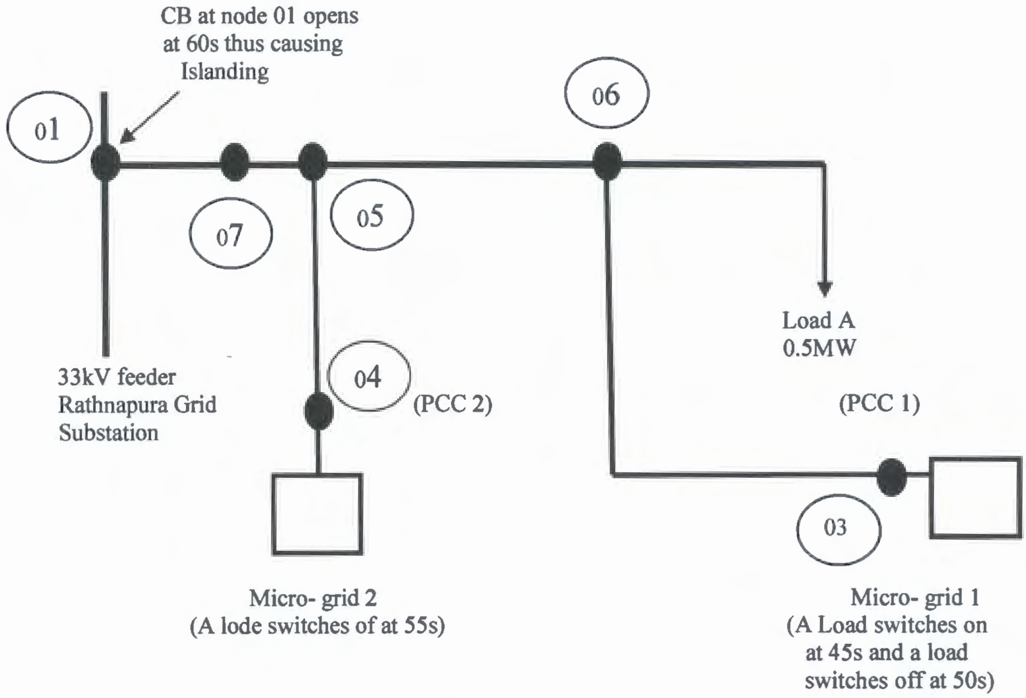


Figure 3.8 – study systems II



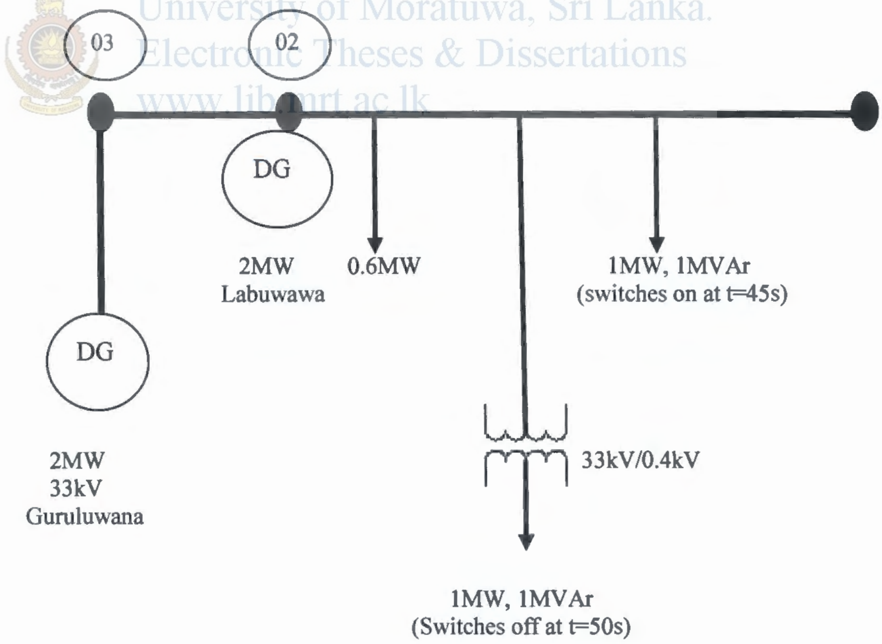


Figure 3.9 - MG 1

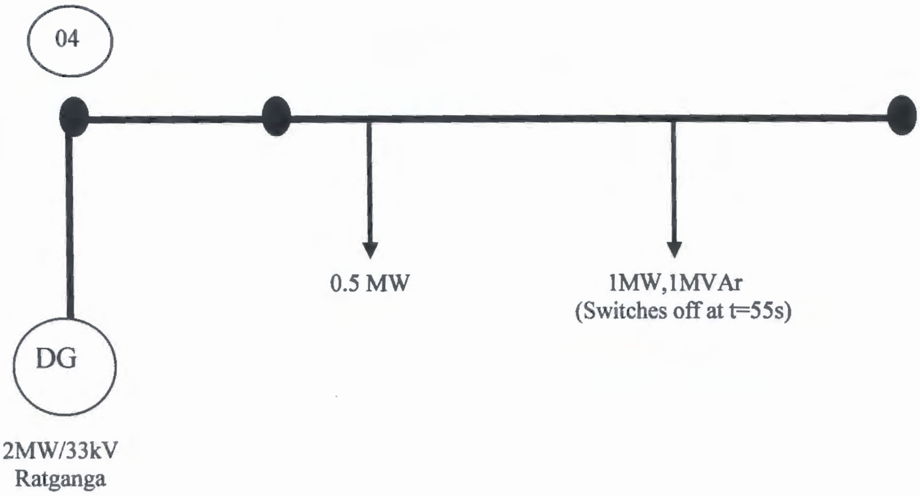


Figure 3.10 – MG 2

**3.3.2.1 Simulation of disturbances and results on test system (II)**

- An unintentional islanding occurs when CB at node 01 opens at t = 60s. Simulation results given in figures 3.11-3.15 show that the two MGs disconnects themselves from the feeder in 0.15s, which is well within 2s limit [1].
- Figure 3.11 shows the VU spikes at DG1 terminals. The CB at PCC1 closes at t = 11.74s and MG1 connects to the feeder. At this instant the VU spike detection algorithm for DG1 starts operating. A VU spike due to closing of CB at PCC2 occurs at t = 35s. Also, VU spikes due to MG load switching (in figures 3.9 & 3.10) occur at t = 45, 50 and 55s. These are all small enough to be neglected.
- At t = 60s the CB at node 01 opens and islanding occurs. As a result, a large VU spike is detected at the terminals of DG1 (Figure 3.11). This causes a drop in frequency set point from 50 Hz to 49 Hz, as shown in figure 3.12. As soon as the frequency of DG1 drops to 49.2 Hz, a trip signal is transmitted to the CB at PCC1, which isolates MG1 from the feeder and its frequency set point is restored to 50 Hz. Thus sanctioning autonomous operation of MG1.
- Figure 3.13 displays the VU spikes at DG2 terminals. VU spike detection algorithm for DG2 starts immediately after MG2 is connected to the feeder at t = 34.89s. The load switching at MG1 cause VU spikes at DG2, but they are small and are ignored. However, the VU spike due to a load switching in the

proximity of DG2, at t = 55s, is large and hence causes a change in the frequency set point of DG2. From figure 3.14 it can be seen that, in spite of lowering the frequency set point at t = 55s, the frequency still remains close to 50 Hz; islanding is therefore ruled out. Islanding occurs at t = 60s, and the VU spike at terminals of DG2, as seen in figure 3.13, is large enough to be detected. A reduction in the frequency set point causes a significant drop in the frequency. As soon as the frequency drops to 49.2 Hz, a trip signal is sent to the CB at PCC2 and MG2 disconnects from the feeder. The frequency set point of DG2 is now restored to 50 Hz, thus permitting an autonomous operation of MG2.

- In figure 3.13 it can be seen that the VU spike due to load switching at MG2 at t = 55s is much larger than the spike due to islanding at t = 60s. Hence, if VU/THD technique is used by itself, then a false tripping would result at t = 55s. It is therefore clear that hybrid islanding detection technique proposed is superior over the VU/THD technique.
- The islanding detection speed for the overall system of figure 3.8 is shown in figure 3.15. The CB at node 01 opens at t = 60s, thus causing islanding at that instant. It is seen in figure 3.15 that at t = 60.15s current through load A is cut off. This means that, by t = 60.15s both PCC1 and PCC2 have opened, which means islanding is detected within 0.15s. This is well within the 2 second set for islanding detection [1].

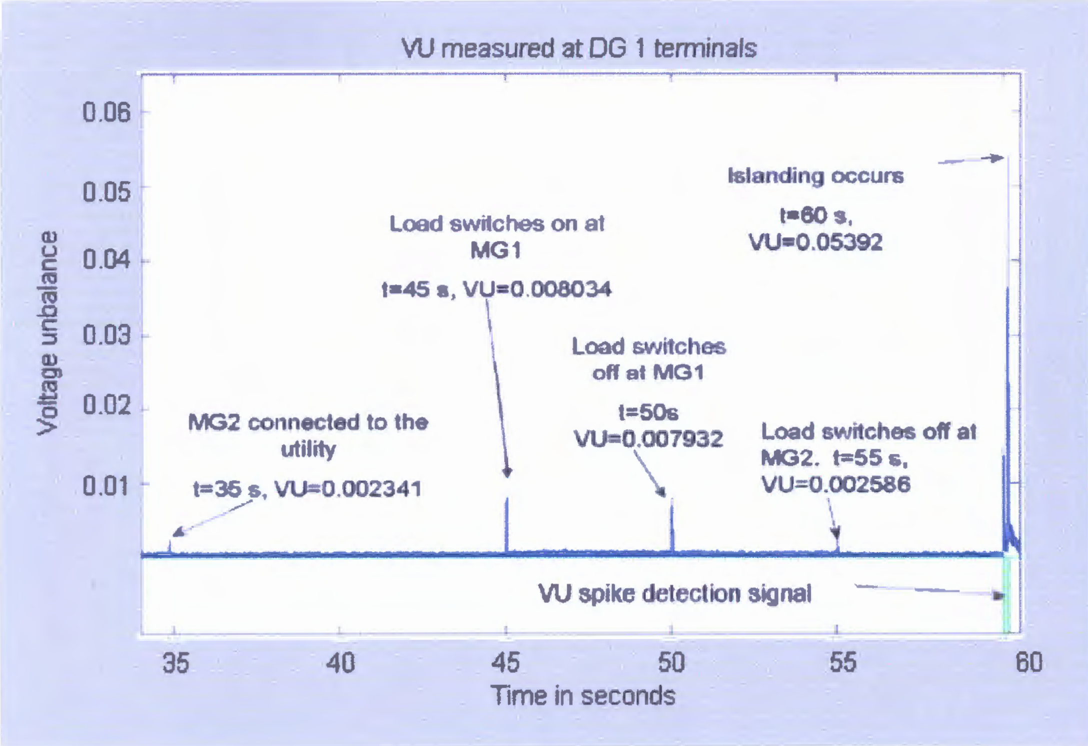


Figure 3.11 – VU measured at DG1 terminals



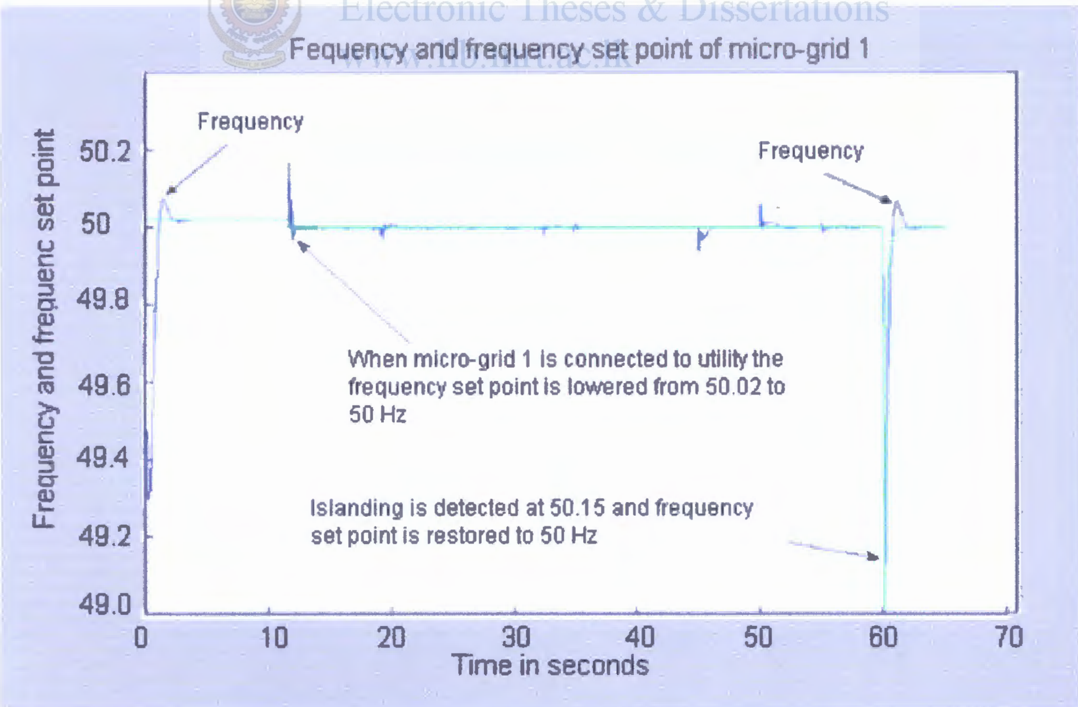


Figure 3.12 – Frequency and frequency set point of DG1

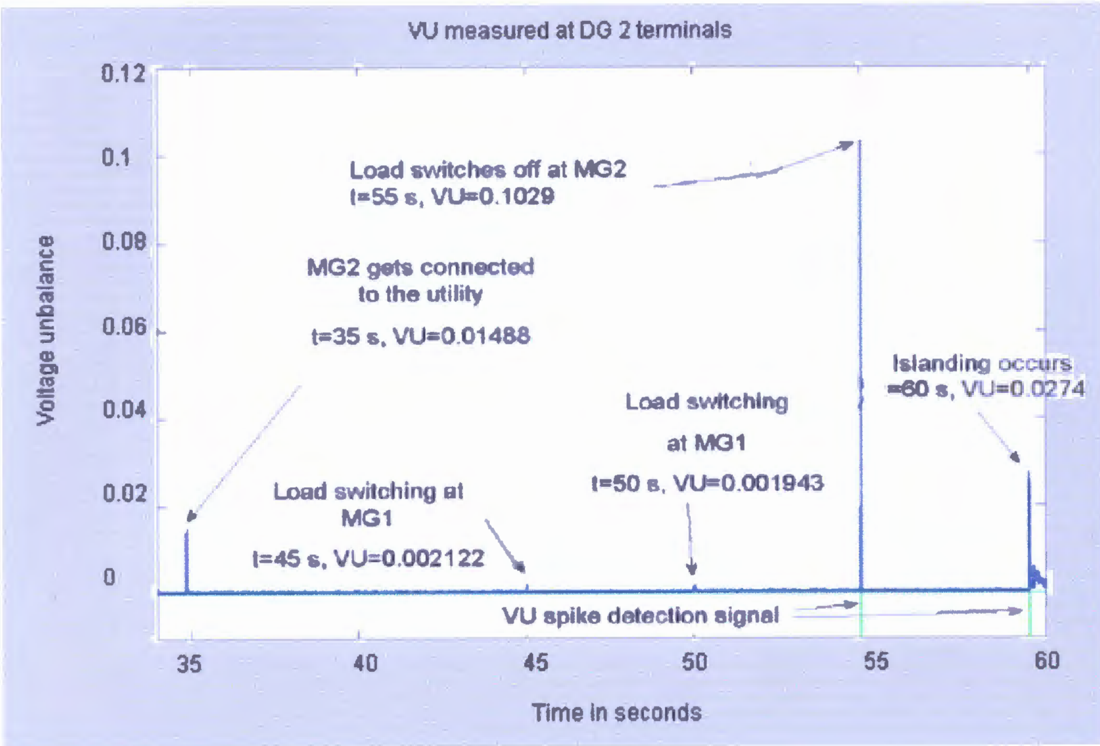


Figure 3.13 – VU measured at DG2 terminals



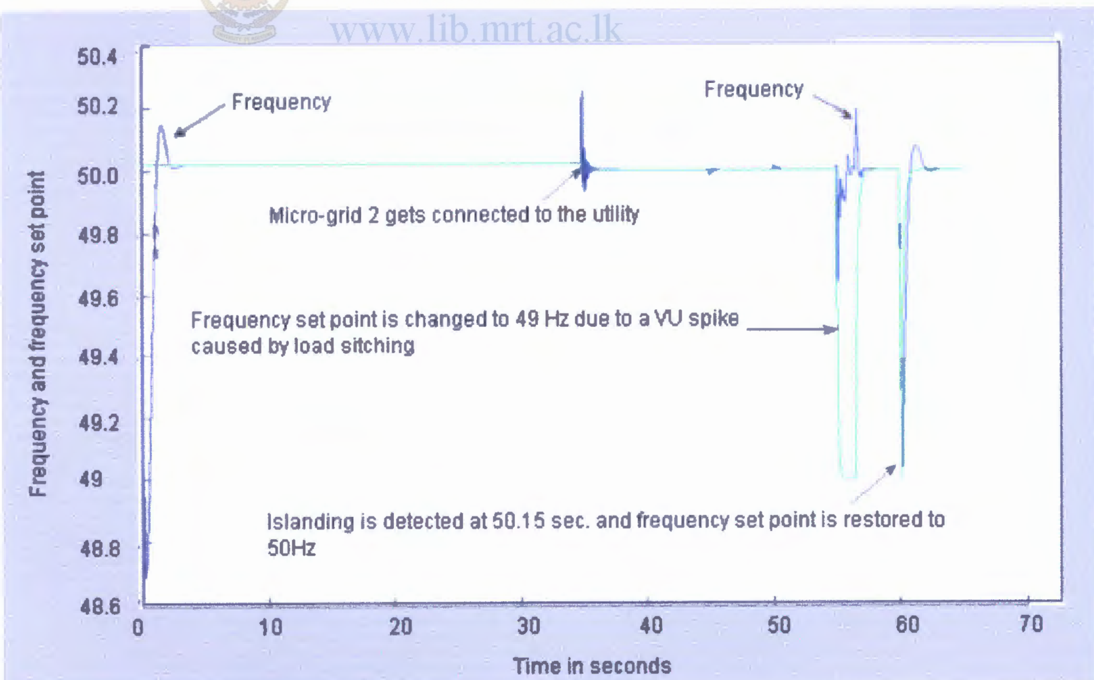


Figure 3.14 – Frequency and frequency set point of DG2

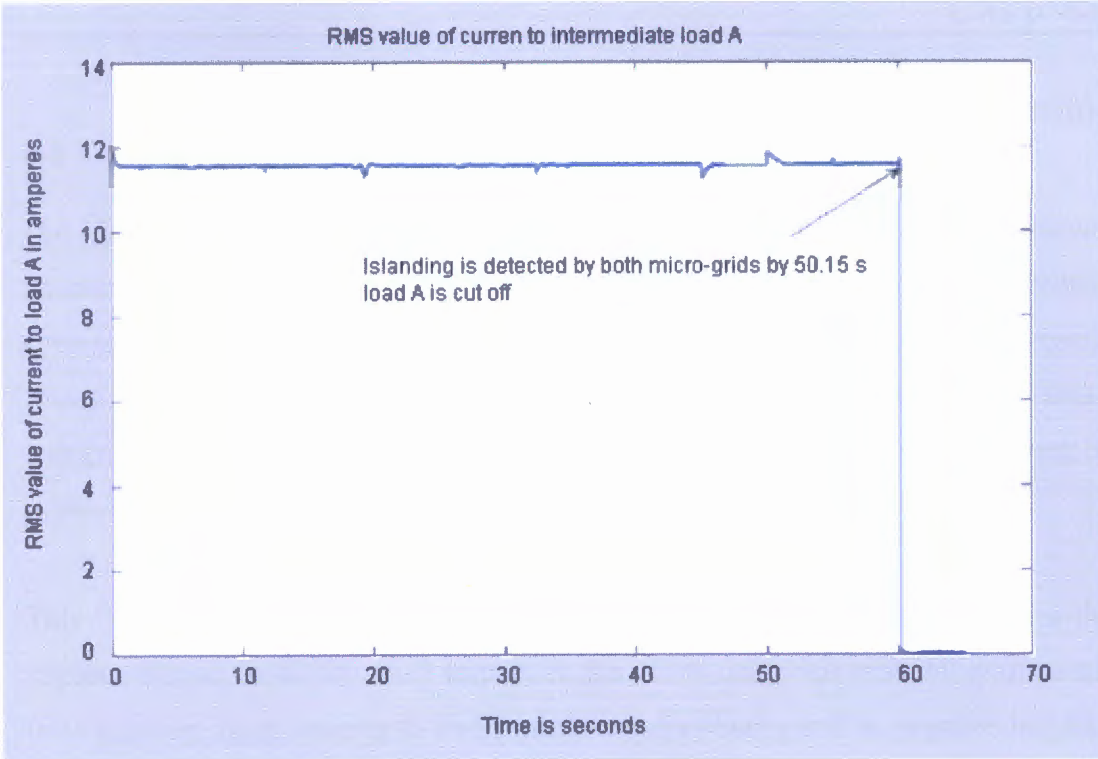


Figure 3.15 – Current to intermediate load A verses time in seconds.

# Chapter 4

## Conclusions

### 4.1 Conclusions, remarks and discussion

The increasing price of electricity and availability of a wide variety of distributed generators has brought about a new era of distributed generation. Distributed generation offers advantages such as reduced transmission losses, voltage and reactive power support to the grid, improved system reliability, and decreased cost of unit of energy. Although DGs have been getting a lot of attention in the recent past, the prospects of their widespread adoption is not certain.

This thesis reviews the prominent islanding detection techniques and looks at their implementation feasibility, their impact on the utility, and their probability of causing false tripping. In an attempt to overcome these drawbacks and to negative impact of the PF technique on the utility electric grid, a new hybrid technique involving both active and passive schemes is proposed and tested. In this technique only the DG that detect VU spike larger than the set threshold value will change their frequency set point. The magnitude of the VU spike seen by DG depends on the size of the DG and distance from the disturbance. This is a great advantage over PF technique, where all the DGs connected to the electric utility work together at all times to try to destabilize the electric utility frequency and voltage. Further it investigates how efficiently proposed islanding detection technique discriminates load switching and islanding.

It is therefore concluded that proposed hybrid islanding detection technique, which includes a combination of an active [30] and a passive [22] technique, has an ascendancy over the existing techniques.

### 4.2 Recommendation for future research

In this thesis only synchronously rotating DGs were considered. As a continuation of this work, it is proposed that DGs with electronic interface be included in the model to include both synchronous DGs and non-synchronous DGs such as fuel cells, photovoltaic power generation connected to utility grid.

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## APPENDIX – A : Details of Simulation Model (I)

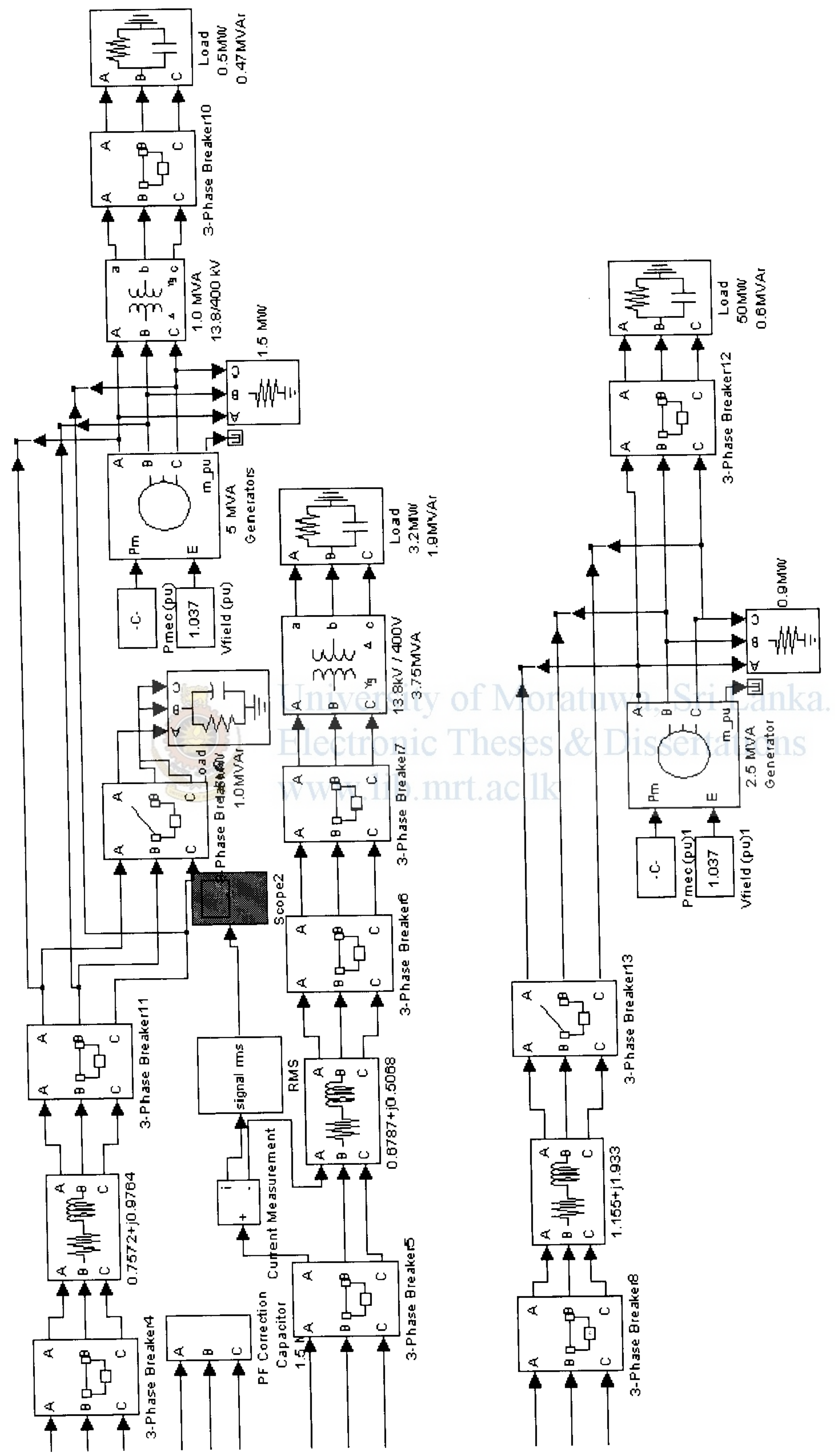




Figure A1 – Part A of simulation model (I)

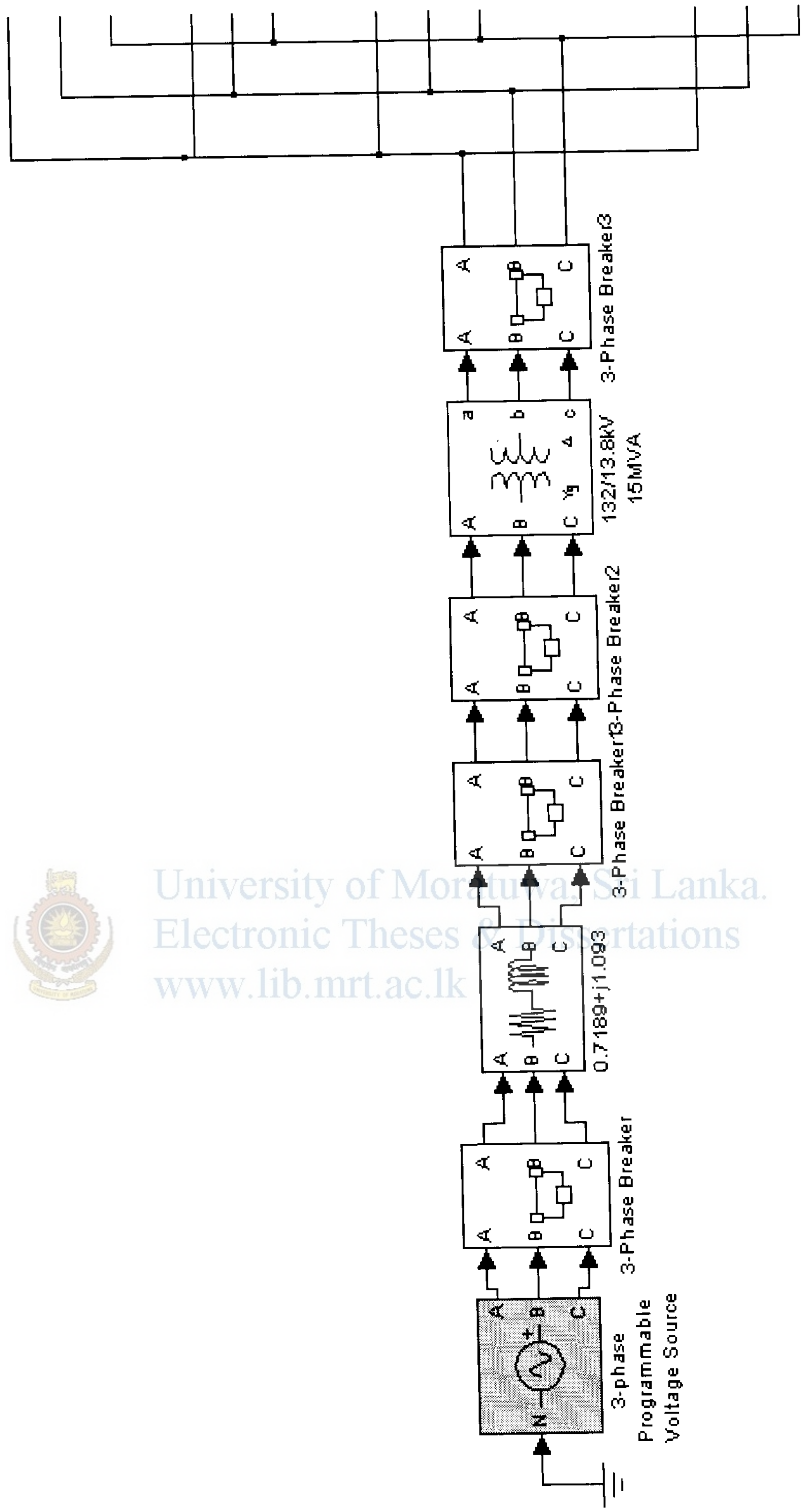


Figure A 2 – Part B of simulation model (I)

## APPENDIX – B: Details of Simulation Model (II)

### B.1 The line parameters and load flow details of feeder No.08 of Ratnapura Grid Substation (GS)

The 10 meter height concrete poles with horizontal cross arms and Raccoon conductors which have the size of 7/4.09 mm are used to construct the line. The dc resistance of Raccoon conductors is 0.3633 Ω/kM and inductance of the line is 1mH/kM for this configuration. Therefore the $X_L = 0.3142$ Ω/kM.

The fault level at 33 kV level at Ratnapura GS is 6.9 kA.
Therefore Impedance, Z = j 2.76 Ω.

The average peak load supplied by the GS is 3.3 MW and power supplied by generators are 6 MW and therefore total power consumed by the feeder is 9.3 MW. The total length of the feeder is 21.4 kM.
Therefore, 'per kilometer load distribution' = 9.3 MW/21.4kM = 0.44 MW/kM.



Decoupled load flow matrix:

$$\begin{bmatrix} Ig \\ 0 \end{bmatrix} = \begin{bmatrix} K & L \\ L^T & M \end{bmatrix} \begin{bmatrix} Vg \\ V \end{bmatrix}$$

$Ig = kVg + LV$ ..........(1)

$0 = L^T Vg + MV$ ..........(2)

$V = M^1 L^T Vg$

$Ig = KVg + LM^1 L^T Vg$

$Ig = [K + LM^1 L^T]\ \mathrm{Vg}$

$[Ig] = [Y_{new}]\ [\mathrm{Vg}]$

*Where,* $[Y_{new}] = [K + LM^1 L^T]$

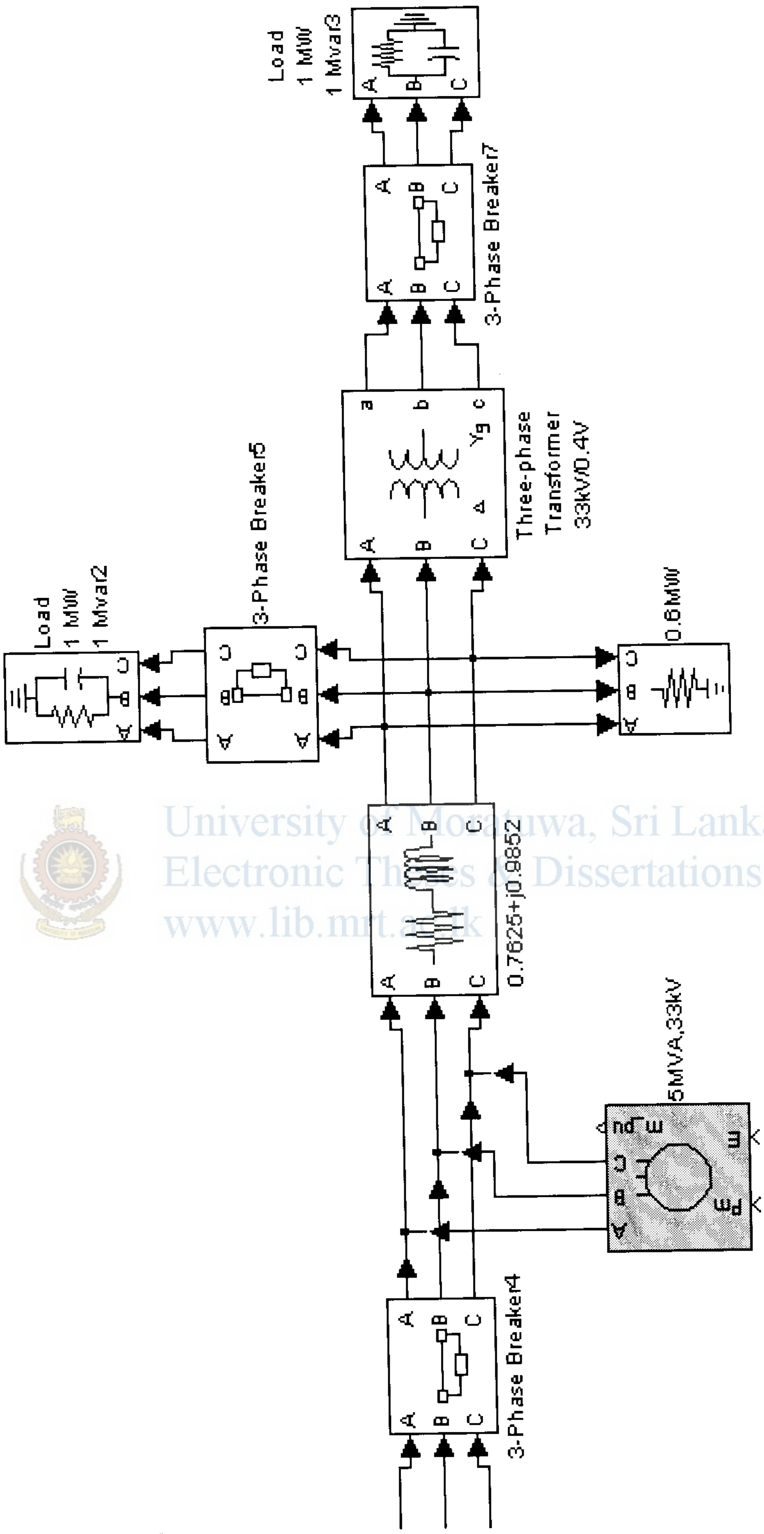




Figure B 1 – Part A of simulation model (II)

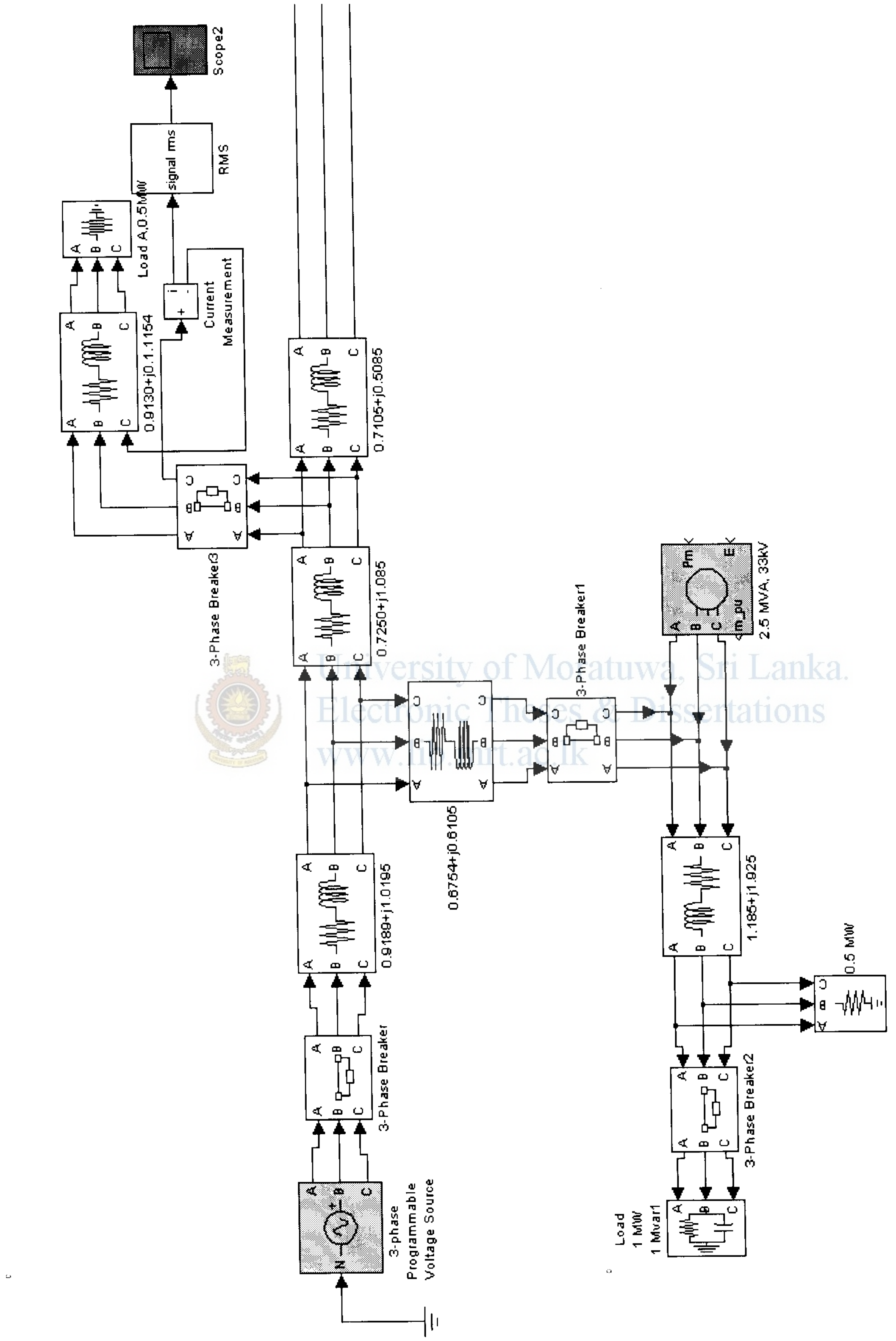




Figure B 2 – Part B of simulation model (II)

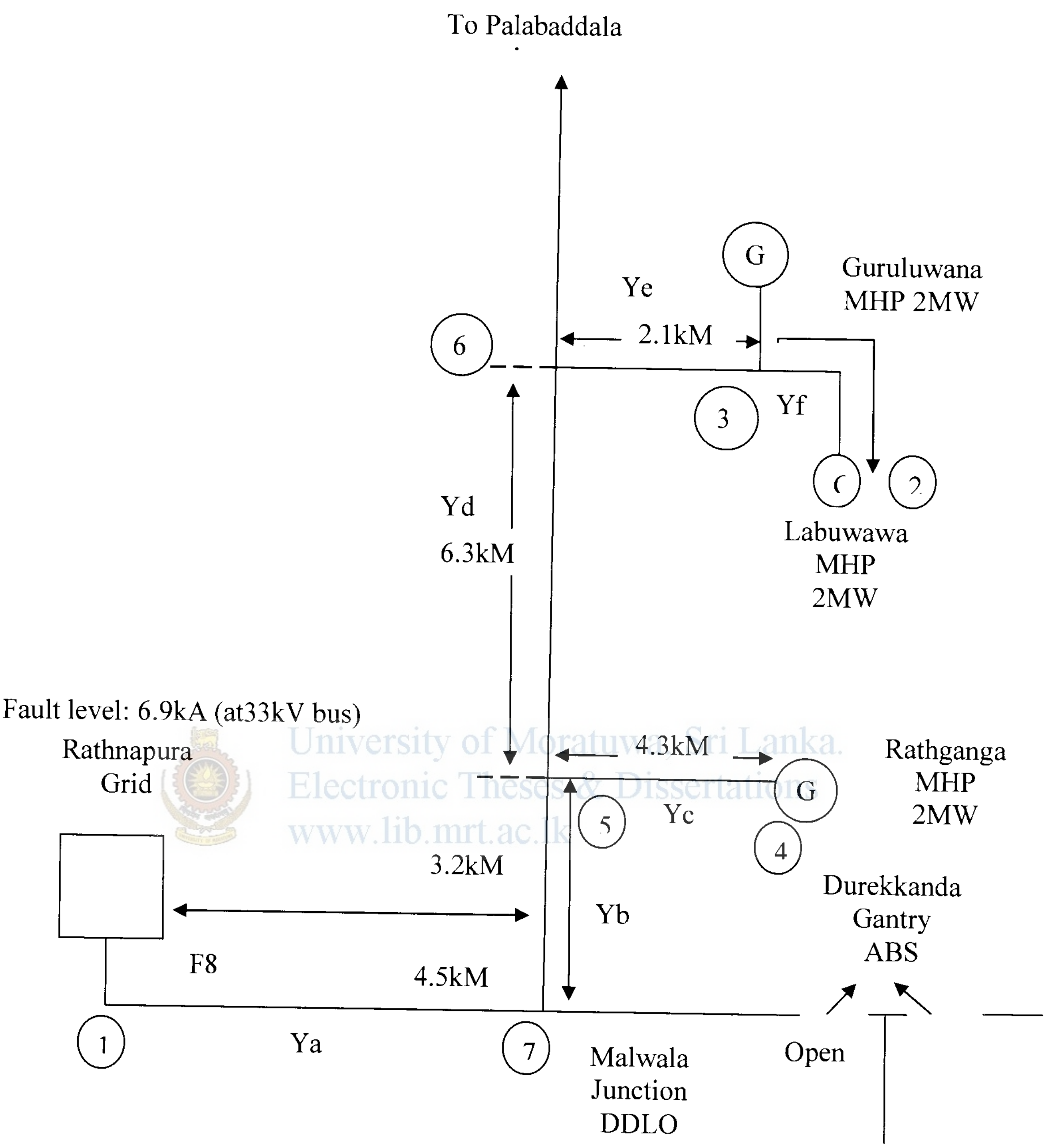


Figure B 3 – Feeder No.08 of Ratnapura GS

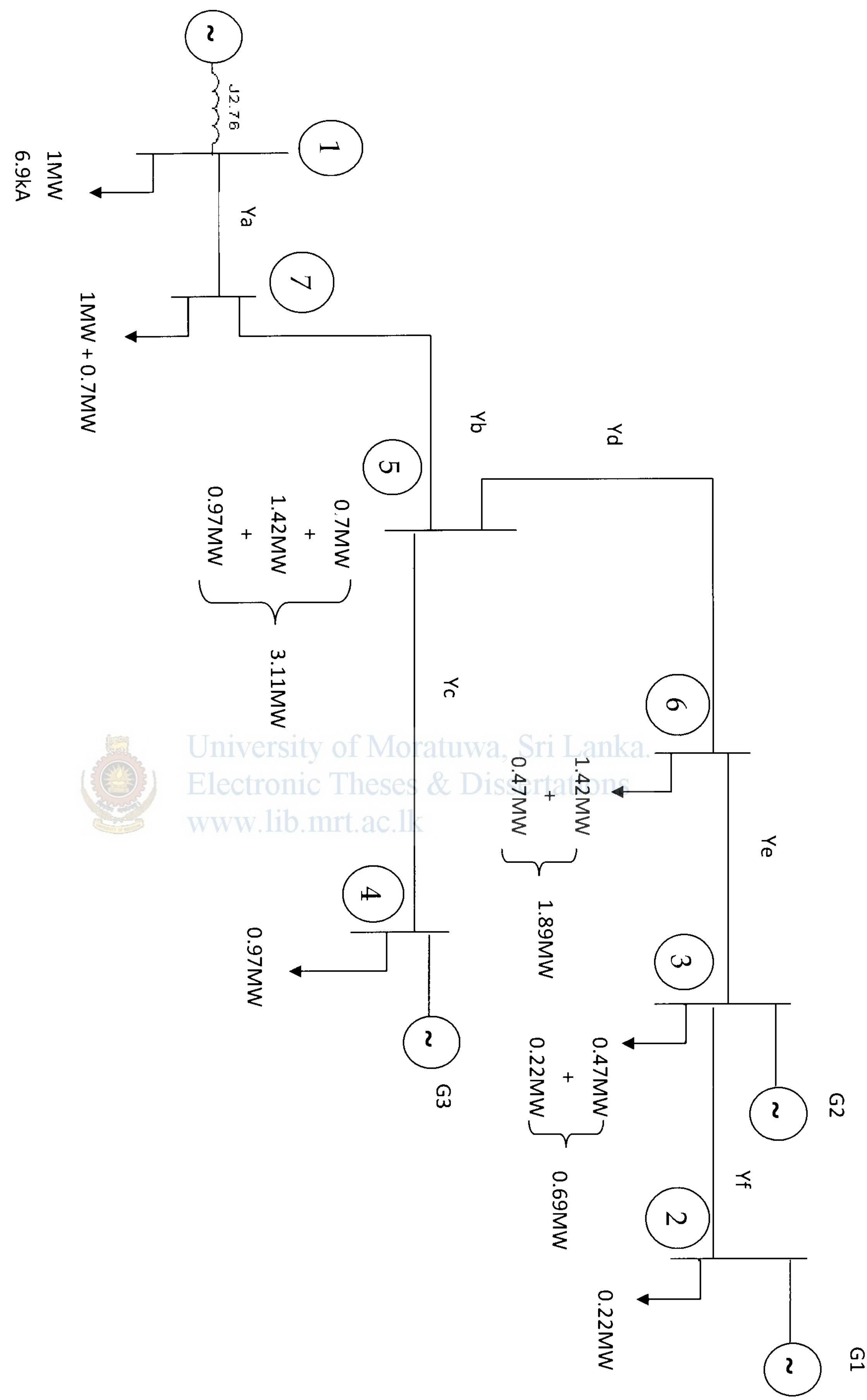


Figure B 4 – Load flow diagram of Feeder No.08 of Ratnapura GS

```
function o=ybus3(u)
delta=u/180*pi;
E=[1;1;1];
E=E.*cos(delta)+j*E.*sin(delta);
E=[E;1];
la=4.5;
lb=3.2;
lc=4.3;
ld=6.3;
le=2.1;
lf=1;
L1=1;
L2=.22;
L3=.69;
L4=.97;
L5=3.11;
L6=1.89;
L7=1.7;
LL=[L1 L2 L3 L4 L5 L6 L7];
RL=33^2*LL.^-1;
Z_perkm=0.3633+j*0.3142;
l=[la lb lc ld le lf];
Z=Z_perkm*l;
Zbase=33^2/1;
Z=Z/Zbase;
RL=RL/Zbase;
RL=RL.^-1;
Y=Z.^-1;
Ya=Y(1); Yb=Y(2);Yc=Y(3);Yd=Y(4);Ye=Y(5);Yf=Y(6);
Zrat=j*2.76/Zbase;
Yrat=1/Zrat;
ybus=[Ya+Yrat+RL(1)  0       0        0        0             0        -Ya
    0          Yf+RL(2)  -Yf       0        0             0        0
    0         -Yf       Ye+Yf+RL(3) 0        0            -Ye       0
    0          0        0         Yc+RL(4)  -Yc           0        0
    0          0        0        -Yc       Yc+Yd+Yb+RL(5)  -Yd      -Yb
    0          0       -Ye        0        -Yd            Ye+Yd+RL(6)  0
    -Ya        0        0         0        -Yb            0        Ya+Yb+RL(7)];
K=ybus(1:4,1:4);
L=ybus(1:4,5:7);
M=ybus(5:7,5:7);
ybusnew=K-L*inv(M)*L';
current=ybusnew*E
E_star=conj(E);
S=E_star.*current;
P=real(S);
o=P(2:4);
```

Figure B 5 - Y matrix of feeder No 08 of Ratnapura GS

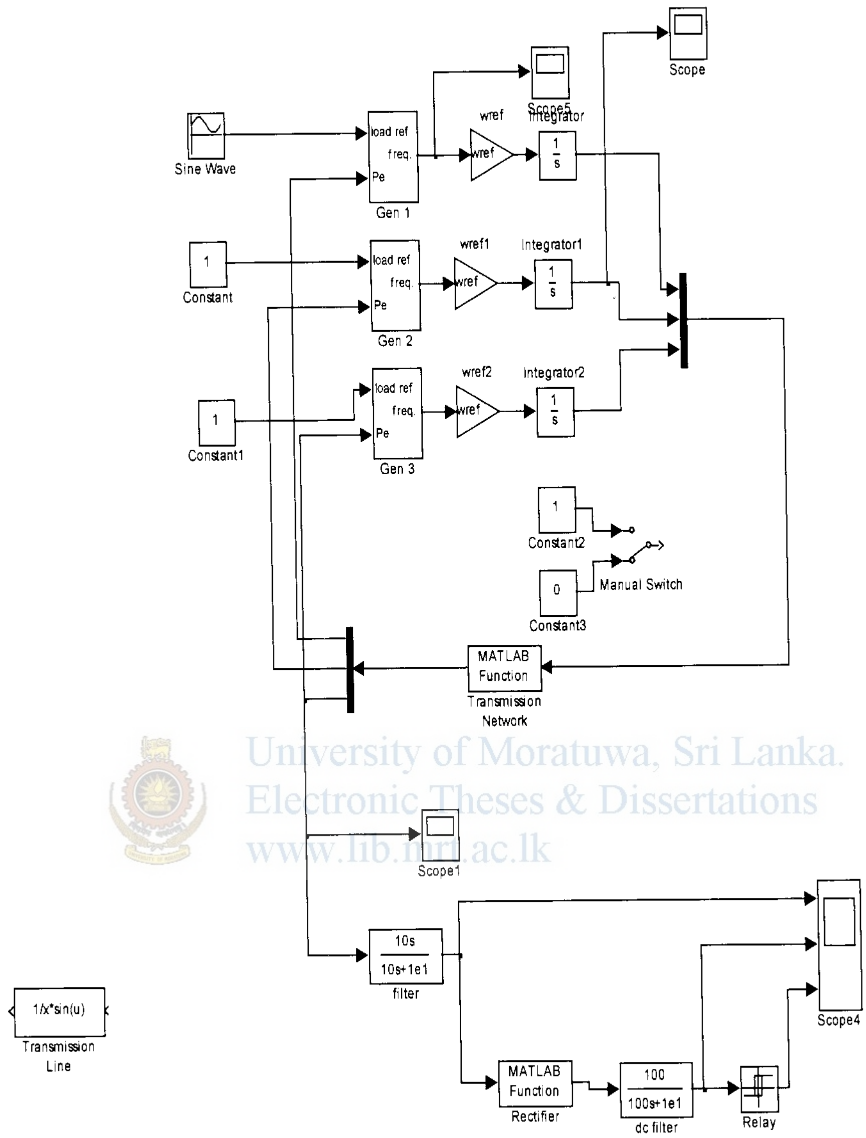



Figure B 6 – Complete MATLAB model of feeder No.08 of Ratnapura GS