Parameter Identification of Dynamic Equivalents for Active Distribution Systems using Heuristic Optimisation Techniques

Master Thesis

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Parameter Identification of Dynamic Equivalents for Active Distribution Systems Using Heuristic Optimisation Techniques

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The used variables and symbols in this thesis are defined here.

- **speed**  
  Asynchronous machine speed
- **speed_ref**  
  Reference machine speed
- **i_x(ref)**  
  Reference x (= d,q) axis current
- **i_d**  
  d-axis component of output current
- **i_q**  
  q-axis component of output current
- **U_x**  
  d,q - axis component of voltage
- **i_rotor**  
  Rotor current from machines
- **θ**  
  Machine rotor angle
- **P_in**  
  Active power input
- **Q_in**  
  Reactive power input
- **Freq**  
  Frequency of the network
- **V_{dc,ref}**  
  DC Voltage reference
- **V_{ac}**  
  AC voltage
- **cosref, sinref**  
  Angles from PLL for PV model
- **V_t**  
  Terminal Voltage
- **V_{t0}**  
  Lower threshold below which all generation will trip.
- **V_{t1}**  
  Lower limit of disconnection free operation.
- **V_{t2, t3}**  
  Similar to V_{t0} and V_{t1}, but for over voltage disconnections.
- **V_{min}**  
  Tracks the lowest voltage through simulation but not below V_{t0}
- **V_{rflag}**  
  User settable flag which determines the percentage of reconnection or the percentage of active power recovered after a disturbance.
- **T_g**  
  Inverter Time lag constant. One of the control parameters for PVD1 model
- **D_{dqdv}**  
  One of the control parameters for PVD1 model
- **δ_{max}**  
  Maximum Relay angle for excessive angle relays
- **dline**  
  Length of aggregated line
- **p_{lini}**  
  Active Power of load
- **q_{lini}**  
  Reactive power of load
- **AVR**  
  Automatic Voltage Regulator
- **V_e**  
  Exciter voltage
- **K_a**  
  AVR Controller Gain
- **T_e**  
  AVR Exciter Time Constant
- **E_1**  
  AVR Saturation Factor 1
- **S_{E_1}**  
  AVR Saturation Factor 2
- **E_2**  
  AVR Saturation Factor 3
- **S_{E_2}**  
  AVR Saturation Factor 4
- **T_a**  
  Controller Time Constant
- **GOV**  
  Governor
- **p_t**  
  Turbine output power
- **phi**  
  Phase angle at the terminal
- **RMSE**  
  Root Mean Square Error
- **NRMSE**  
  Normalized Root Mean Squared Error
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INTRODUCTION

From developing the first electric power system of two line DC that powered street lamps to modern day behemoth of an extremely complex and connected super grid system, power grids have made an enormous impact on the development of 21st century world. It is nearly impossible for any task, from the most basic to the most critical and complex, to be carried out without electricity. A very high degree of reliability of power availability must therefore be maintained in this interconnected world.

1.1. BACKGROUND ISSUE

The great oil crisis of 1973 was one of the key factors that spurred an increased research in the field of wind energy and solar energy. Since then, the share of these new technologies in the electricity landscape has increased dramatically. The recently concluded climate conference in Paris was a historic moment as all the nations pledged to reduce carbon emissions and increase the share of green energy in their energy landscape. Modern day power systems face increasingly challenging tasks associated with increasing complexities on the planning, policing, technical and infrastructural fronts. The operational planning, load scheduling, minimising operating costs etc are putting massive pressure on the already ageing grid. On the other hand, wide participation of new energy sources like wind, photovoltaic with power electronic interfaces coupled with their intermittent behaviour and geographically distributed profile are significantly affecting the conventional power flow pattern and have led to progressive changes in the dynamic behaviour of power systems.

The adoption of renewable energy has generally seen a positive trend and many utilities and countries are making continued efforts to integrate more and more electricity from various renewable energy sources (RES). This resolve to integrate more RES is further pushed by increasing climate changes and some gruesome nuclear mishaps. Many countries such as China, Germany, United States, India etc. already have a massive infrastructure to support RES such as wind and solar and many more countries are following suit. European Union (EU) countries are perhaps more inclined towards integration of wind power into their grids. In order to reduce the green house gas emissions, the European Union has initiated a 10-year strategy called 20-20-20, as a part of it's Europe 2020 vision [3]. These targets, among others, state that by the year 2020, the EU as whole, will have; reduced green house gas emissions by 20% compared to the 1990 level; 20% of the energy to be obtained from the renewables; and 20% increase in energy efficiency. Germany has taken strict and determined steps to phase out nuclear energy by 2022 in the aftermath of the Fukushima Disaster in 2011 and integrate more renewable energy into their grid while shutting down it's nuclear plants.

The new RES are different from conventional power generating stations. They do not fit well into the traditional architecture of the electric power grid. These new generator systems are increasingly connected with power electronic interfaces with the grid which introduce difficulties with system studies. Some of them include, diminishing frequency reserves. Systems like PV, which are entirely power electronic based do not currently provide frequency containment reserves, like those provided by conventional rotating generators, for frequency maintenance in the network. Another challenge with these systems, as already highlighted, is their distributed geographical profile. This has effects on the voltage and reactive power in the network. Since these sources are generally of lower capacity than conventional generating stations, the number of such RES is distributed at various voltage levels (particularly in the medium voltage and low voltage networks) and over wide geographical area. Hence, these systems are also referred to as Distributed Generators (DG). Contrary to
popular beliefs, DG is not limited to renewable sources like PV and Wind systems but also include small scale Combined Heat and Power (CHP) systems, micro turbines, fuel cells etc. This is because the term DG refers to the generation connected at the Distribution Networks (DN). The three major technologies: PV, Wind and CHP, form majority of the DG installations today and their representation, thus, provides a good picture of the distribution network.

Due to the increasing number of DG in the LV and MV network in form of Wind Turbine Generators (WTGs), Photovoltaic Power Parks (PVPPs) and Wind Power Parks (WPPs), it is essential that network reliability be maintained. Development of models for system design and testing various contingency events to determine their effect on the network is therefore necessary. This system modelling and design has to be accurate enough to reflect the dynamic behaviour of the system (namely damping of power oscillations, frequency deviations etc.) so that adequate contingency measures can be taken in the event of a disturbance and system operation and reliability is maintained.

1.2. Literature Review

It is well known now that when the penetration level of DG increases, its impact is no longer limited to distribution network but begins to influence the whole system. Effect of increasing penetration of DG on power system dynamics and stability has been covered in some works particularly [3] and [6]. They highlight the impact of high DG presence in distribution grid, its impact on grid protection and consequences of fault ride through (FRT) behaviour. The transition from vertical to horizontal power system is inevitable with current trends in network planning. To accommodate newer RES and facilitate easy transition, it is necessary to conduct various studies by developing models predicting future scenarios and studying their effects on system. This enables us to plan adequately for any problems planners might run into while approving new projects in near future. The result of these studies is to propose recommendations to update grid code requirements (GCR) to accommodate future energy sources [6]. GCR are set by each utility that dictate how generators connected to the grid must behave at all times. They also specify the generator behaviour in case of faults and other contingencies. GCR is covered in more detail section 2.2.

An important part of such studies is modelling of network that have accurate representations of generator and load models. System analysis where detailed models of each generator connected to the grid are present is not feasible because this introduces a large computational overhead. This is illustrated in figure 2.2. Obviously, a larger, complex system will command more simulation time and computational resources. To reduce complexity of analysis, we use aggregated models. There is considerable literature available in the community on aggregation of synchronous machine based large generators while there has also been a good amount of literature available recently on aggregation of wind parks [7] and PV power parks [6]. [6] is particularly a good reference for modelling PV systems considering partial dropout techniques. This has been the driving methodology for deriving dynamic equivalents in this work. While individual aggregated generators are almost readily available for all different kinds of technologies, a unique aggregated model that can represent all the generators types along with their control structures is missing. This was one of the motivations of this work.

Apart from deriving a good dynamic equivalent, it is important that the developed model has good parameters. The problem of parameter identification of dynamic equivalents is not new. It has been covered in literature with various techniques like trajectory sensitivity [9], artificial neural networks (ANN) [10] etc. However, these come with their own set of problems and disadvantages. Trajectory sensitivity method requires user to create a parameter based optimisation objective function, which may not always be possible with non-linear complex power systems. ANN based identification techniques require a large set of training data to get results. More often than not, power system problems are very non-linear and convex. Trapping into local minima and hence, premature convergence is something that many optimisation algorithms suffer with, as has been mentioned in [11]. A unique heuristic optimisation technique, Mean Variance Mapping Optimisation (MVMO) [12] is therefore used. This is due to its unique characteristics and ability to find global minima effectively. It is also shown to have the least chances of trapping into local minima or the encountering the problems of premature convergence.

MVMO has been utilized to solve some of the power system problems like economic dispatch problem, but has not been applied to identification of DE parameters. Also, MVMO seems to be in the initial stages of development while the scope of this technique is huge. A general purpose open source script could open new possibilities for applying MVMO to other non-linear problems.
1.3. **Problem Definition**

Increasing penetration of DG in the power networks around Germany, and EU in general, calls for a change in the current grid code requirements (GCR) for DG systems. The Transmission System Operators (TSOs) and Distribution System Operators (DSOs) have traditionally considered distribution grid as a passive load. Taking DG connected to these networks as passive and static loads, simple disconnection schemes were adopted for them considering that they would result in an insignificant active power loss. These systems, according to previous GCRs, were required to disconnect from the network if the voltage at their terminals falls below 0.8 pu \[6\]. This technique worked fine when DG penetration was low. It was also essential to apply this method to avoid any malfunction of protection schemes installed to serve the conventional topology. However, with increased penetration of DG in the distribution network, the network’s participation in setting operation schemes has changed. Now LV/MV networks have to be more involved, and hence are referred as Active Distribution Networks (ADN). Due to prominence of ADNs, it is very important to make necessary changes in the GCR to account for their contribution to network dynamics and operations. Disconnection of a large amount of DG during a fault will cause a voltage dip not only on the LV network but can also affect the MV/HV network voltage. Simple disconnections can lead to sudden displacement of large amounts of active power from the network. This can cause imbalance and stability issue. As such, an update to GCR is required to maintain the reliability of the grid. Figure 1.1

![Diagram showing current and future scenarios](image)

Figure 1.1: Current and future scenarios

Various proposals to update GCRs have been recommended in the literature \[13, 14\]. Updating of GCR means that the generators have to comply with those regulations and as such, change their dynamic responses accordingly. As the control systems within power electronics becomes more advanced, DG are being required to provide the Dynamic Voltage Support (DVS) during faults in addition to providing other ancillary services like conventional power plants have been doing previously. Due to continuous update of GCR over time and corresponding GCR compliant DG installations, we have a network with high penetration of DG, with different control systems embedded. This means, set of DG responds differently to the faults.

Modeling of such network is a complex task. This forms our first problem definition, *developing aggregated models that accurately represent diverse DG in the present network*. Adding detailed models for each and every unit complicates the network and increases the computational stress and time to simulate contingencies. As stated in \[15\], vulnerability begins to develop in specific regions of the system exhibiting coherent dynamics; therefore, large, detailed models can be reduced to equivalent simple models that mimic the original detailed system response to contingencies as accurately as possible. A dynamic equivalent (DE) is a simple representation of the large system, modeled with enough detail and accuracy to obtain required system behaviour for stability studies. There are many methods listed in the literature for dynamic equivalencing techniques of such large power systems \[16, 17\]. Apart from DE structure definition, another major part of this this problem definition that we would be focussing on is the development of relevant control systems of such models. This is half the problem, developing the structure of DE.

The other half of the problem is to achieve an accurate DE by identification of it’s parameters so that it provides desired response. This gives us our second problem definition, *developing an automation tech-
1. Introduction

In this work, we devise a method to automate the determination the parameters of developed model to make the computation more efficient. Apart this, focus will also be on making this automation and identification procedure as general purpose as possible so that it can effectively be applied to various other power system problems.

1.4. Previous Work

Aggregated modeling of active distribution systems with increased penetration of PV, Wind et cetra has been done in the past. [16, 18] focus on modelling of wind turbine generators, but there is more literature available for other various generator types as well. Emanuel van Ruitenbeek’s [14] master thesis work at TU Delft is a key resource on impact of high penetration of PV in LV networks and it proposes certain recommendations to update the GCRs to accommodate this increased DG penetration and use it to provide support to the grid in the event of a fault. This involves development of aggregated models for active distribution systems to accurately model the detailed network. With the use of developed optimized aggregated models, we hope to significantly reduce the computational time to study fault simulations. Some work on development of aggregated models for loads and PVPPM is covered very well in [19]. It gives a detailed overview of the German grid network and it’s implementation in PowerFactory. The parameter identification part is often an iterative one. Authors have used trial and error methods based on the knowledge of system and making a close enough guess.

There has been some previous work in using optimisation techniques in identification of DE parameters; particularly [20] gives a good insight into using this technique for application to power systems, however, the work is limited to aggregation and identification of conventional synchronous machine generators. Power electronic interfaced systems have not been considered. Heuristic based optimisations techniques have also been applied to various other power system problems, however the work on using this technique for identification of power system dynamic equivalents is still in early stages. This work aims to make significant contribution to this area.

1.5. Objective and Research Questions

The objective of this work is to develop an online parameter identification approach for dynamic equivalents of active distribution networks. This is done using application of a novel heuristic based optimisation algorithm, Mean Variance mapping Optimisation (MVMO). We use a Python based script to link the models in DlgSILENT PowerFactory (DPF) with the MVMO optimisation algorithm to obtain these parameters. The interaction between the two softwares is shown in figure 1.2.

The following research questions are answered at the end of this work:

• How is the detailed network consisting of various DG at various voltage levels reduced to an equivalent model that can mimic the dynamic behaviour of such a complicated system?

• How well do the controllers modelled for these systems respond to various sensitivities? How efficient is the algorithm in determining these parameters?

• How much computationally efficient does this make the system studies? How much time is saved in simulation for stability studies?
1.6. RESEARCH APPROACH

Firstly, due to lack of electrical signals from Phasor Measurement Units (PMUs), we need a representative detailed network that can provide us with relevant measurements of required signals, which can be used as reference for validity of our aggregated models. The level of detail of the full scale model is determined by the amount of information needed from the model. These are full scale white box models developed by [14]. The aggregated model developed should be transparent enough that we can “see through” the control systems present in them like in case of white box models, while also retaining certain amount of black box characteristics. Hence, in this thesis, we try to model a grey-box model but with more of white box characteristics. Hence, suitable coherent systems will be identified and aggregated first. We also specify the set of disturbances that will be applied to the model.

Our objective is to minimize the error between the response of detailed model and the response of aggregated model to various contingencies by tuning of model parameters subject to some restraining conditions. The research approach used is thus shown in figure 1.3.

As can be seen from figure 1.3, on a defined DE structure, the MVMO algorithm will be used to perform fitness evaluation. This is done by comparing the results from aggregated model with available set of measurements from detailed model. This determines the objective function (OF). This value of OF is fed to Evolutionary mechanism which produces new parameters, in form of vector $x$, that are updated in the network model. If the stop criteria is satisfied, the MVMO stops working and sets the best obtained parameters into the model. We thus have our DE.

1.7. OUTLINE

Following this introductory chapter, chapter 2 talks about the detailed network representation. It briefs about the various control schemes modelled into the detailed network’s generator models while also delving into the various elements of the network themselves. It introduces our two test cases in detail.

Chapter 3 talks about the network aggregation, it’s need and procedure to derive aggregates. It introduces our DE model, the PVD1 model and details the procedure of network aggregation of our two test cases.

Chapter 4 talk about the identification algorithm used. It details the MVMO algorithm in detail and how it is applied to our test cases. It lists requirements for parameter selection for optimization for both the test cases and how individual test case requires it’s own algorithm settings.

Chapter 5 presents the results from the optimization task. Result curves from both the test cases are presented along with convergence graphs and RMSE values to validate results. Chapter 6 presents the concluding thoughts and recommendations for future work.
2.1. SYSTEM STABILITY

Maintaining system stability and reliability is of utmost importance in electric power systems. Thus, all studies done on electric power systems are, directly or indirectly, related to these two areas. The concept of power system stability is perhaps best defined in [21] which states that *Power system stability may be broadly defined as that property of system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subject to disturbance*. Power system stability studies remain one of the most important tasks for maintenance of reliability and stability of the network. System studies are often performed by modeling the system and analysing response of the simulated system to disturbances. Being an important issue, stability in power system is thus divided into 3 categories, as shown in figure 2.1.

![Figure 2.1: Categories of Power System Stability](image)

Short term stability focuses on transient stability of generators while focus is more towards inter-machine oscillations, automatic voltage regulators etc. In this work, we focus only on post fault transients for aggregated DG models.

With research and development focussing on making renewable energy technologies more affordable and efficient, a lot of generator types for different technologies have evolved. However, to install and integrate these machines into the electricity grid, utilities require manufacturers to provide with detailed behaviour report of these machines to plan for contingencies. This is done by modelling the machine and performing simulation studies. Manufacturers generally provide detailed models of their machines that reflect the total dynamic behaviour of the machine to various events in the grid. However, the manufacturer supplied
Detailed Network Representation

Models cannot be used for two reasons. Firstly, the use of detailed manufacturer specific models requires a substantial amount of input data to represent the individual types of generators and its unique control system. Secondly, the high level of detail of the single machine model multiplied by \( n \) number of machines in the system (like, in a wind power park) increases the computational overhead and thus, simulation time for models dramatically.

Considering, the vulnerability in the system begins to develop only in certain areas in the system, it is much more logical and computationally inexpensive to replace the fully detailed models with some simpler aggregated models that can represent the system dynamics decently. This is seen in figure 2.2. Figure 2.2a represents a detailed network while figure 2.2b represents a replica of the detailed model, only the MV/LV networks are now replaced by equivalent aggregated models. It is logical that replacing a full complex detailed model with a simpler equivalent structure would reduce the computational time significantly. This is validated by the results of this work. This reasoning gives us a motivation to develop a good representative aggregated model, also called the dynamic equivalent (DE).

![Detailed Network](image1)

![Aggregated Network](image2)

**Figure 2.2: Need for aggregation**

As remarked earlier in section 1.3, if a simple disconnection scheme is followed with DG, the system can see adverse effects and this will affect system stability as well. To reduce the impact of high DG penetration on power system, TSO specify fault ride through criteria for DG. Earlier, only central power stations, connected to HV and eHV networks needed to be compliant with GCRs. However, rising DG penetration requires new DG connections to adhere to these regulations as well. The DE developed should always be compliant with local grid code requirements (GCR) to enable safe and reliable operating conditions within the network. Hence, it is important to discuss the GCR in a bit detail and how they affect individual and aggregated models.

### 2.2. Grid Code Requirements

Grid code requirements are utility specific requirements which lay down the criteria that any generator must fulfill at all times while being connected to the grid network. These specify both the static continuous load flow conditions as well as transient dynamic conditions that have to be met at all times by the generating stations. These specifications are generally provided by the TSO and DSO in form of a voltage-time graph. Relevant to this work is the fault ride through capability of generators and hence, only transient conditions in GCR are covered in this section.

The FRT define for what voltage drops of specific durations, must the DG stay connected to the grid. These depend typically on the size of DG units, network topology, etc. Generators may also be required to provide additional grid support such as voltage and frequency support during the disturbance. This is important because many traditional generation facility do not have fault ride through capability. If the voltage at their terminal drops below threshold, they will disconnect from the grid. Generation facilities capable of providing voltage support to maintain voltage profile in the network are therefore important to help these generators
remain connected to the system. By having the ability to remain connected to the grid for a wider frequency and voltage range, wind farms support the system during abnormal operating conditions and allow for a fast system frequency restoration. The fault ride through requirement for Wind Turbine Generator is defined as follows:

A Wind Turbine Generator (WTG) shall remain connected to the grid during voltage dips for certain durations, and provide voltage and frequency support in event of fault to the network, and reduce the active power flow into the fault.

while the FRT for a PV power park is defined as follows:

PV inverters’ capability of remaining connected to the grid in event of grid failures, of not supplying and active power during grid fault, and of providing active power directly to the grid after clearing of fault, thus stabilizing the grid.

In this work, since a German MV case study is used, focus is more towards MV German Grid Codes specifications. German TSOs have specific requests for any inverter coupled DG due to high penetration of DG in their grid. These have already been put into place on April 1, 2011. The German MV FRT curves are shown in figure 2.3. The GCR curve in figure 2.3 gives much information about how the generating station must be-

![Figure2.3: Fault ride through capability of wind farm power stations according to German MV GCR.](image)

have during faults. The requirement specifies that voltage profile at the generator PCC, if lying in the “green region” (above red line) must not lead to instability of disconnection from the network. In the area between the two red lines (yellow area), generator must not disconnect from the network. The German TSO also specifies that if the voltage is in the white “STI” part, the generator may disconnect, but only if it can resynchronise itself to the grid within 2 seconds of disconnection. For the area under hard blue line, no FRT requirements apply and generators need to disconnect themselves from the grid. A conclusion from these points can be made.

- The dip of the voltage curve determines how low the voltage can fall at the PCC in the event of fault. It depends on the country and the utility to define this value. Generally, more deeper is the dip, the lesser is the time it can stay in that region without being disconnected implying a more stringent rule.

- The sloping part of the curve represents the fault recovery requirement. The flatter the slope, the more stringent the requirement.

Generally, it is expected from all power electronic interfaced generators that they provide active power in proportion to retained voltage and maximize the reactive current to the transmission system without exceeding converter limits while experiencing the voltage disturbances [13]. This is a part of ancillary services that conventional generators have been providing the grid traditionally, but now, DG are required to do same. Power
electronic converter in new DG can be used effectively to maximise energy yield, provide active and reactive power control and also for power quality improvement.

The models used in this thesis are compliant with latest German FRT requirements, which are considered to be the toughest in the world. It is of importance that the network topology is accurately represented. Since one of the test cases is an actual German Rural MV/LV network, consideration needs to be given to the fact that some generators will be non-LVRT equipped as well. Hence, we have a mix of FRT enabled and FRT disabled generation in our network. The nLVRT generation is "business-as-usual". Once the voltage at the point of connection goes below 0.80 pu, it disconnects from the grid. FRT enabled generators have 2 FRT schemes: Low Voltage Ride Through (LVRT) and additional Reactive Current Injection (aRCI). These are discussed in context with our 4 main generator technologies (DFIG WTG, FRC WTG, PV and CHP) brief next.

2.2.1. Low Voltage Ride Through

Power electronic interfaced generation generally has no problem in implementing a FRT scheme into their control system. This is because the entire generation is hidden behind this converter system and converter has complete control over the power provided to the grid. Therefore, generation facilities like Type IV generators, PV parks have no problem with LVRT implementation. Type II or fixed speed wind turbines have very limited LVRT capability. They require constant reactive power from the grid for their magnetization. We do not use any Type II generators in our analysis and hence, their FRT capabilities have not been discussed. Variable speed wind turbines (Type III) with 2 voltage source converters connected to the rotor circuit can provide grid support during faults. This is possible due to decoupling of active and reactive power from each other by the rotor side converter (RSC). However, this is not very effective in case of severe faults. Severe faults imply higher transient currents during faults. Since RSC are rated for a fraction of fully rated power of the turbine in DFIG, high inrush currents can damage these converters. To mitigate these effects, we can use a higher capacity converter with IGBTs. This is an expensive solution.

There is another method to have LVRT scheme enabled on DFIG machines without the need to upgrade the power electronics. This is achieved by having an active crowbar circuit between the rotor and the RSC as shown in figure 2.4. During normal operation the switch is open. The switch can be activated on detection of rotor over currents or DC-link overvoltage in order to redirect the rotor currents in the crowbar circuit, where the energy is dissipated in the resistor. Most of the current turbines employ this technique to save costs on power electronics. The models used in this thesis employ crowbar protection as well so that we have accurate representation of our network.

![Crowbar protection in DFIG. [1]](image)

2.2.2. Additional Reactive Current Injection (aRCI)

Another recently added requirement of TSO is that the DG must support grid by providing voltage and frequency support. This is already incorporated in German GCR and is called additional reactive current injection (aRCI). The idea is that in the event of a short-circuit, the converter can provide voltage support to the grid by injecting reactive current, and thus, resulting in a controlled short-circuit current. The main concept of this technique is that due to high X/R ratio of transmission and distribution networks, reactive current raises voltage levels of the network. All the PV and Type IV Fully Rated Converter Wind Turbines used in this thesis are capable of supporting grid through aRCI.
2.2.3. NEW Fault Ride Through Mode
Since we are considering a future scenario in our test case (Year 2022), apart from installing present generators with their FRT schemes, new generators are modelled into the system with their control schemes called NEW. The machines labelled NEW can be set to any of the 3 control modes:

- nLVRT: Generation disconnects 100ms after voltage drops below 0.80pu.
- LVRT: Also called Blocking Mode (BM) where $i_d$, $i_q$ are driven to 0 when voltage drops below 0.80 pu. After fault clearance, the system resynchronises immediately via a PLL.
- aRCI: Generator injects reactive current into the network to support grid voltage profile during voltage dips.

For our test case, it was agreed that the NEW technologies should be aRCI equipped. Therefore, henceforth, NEW would refer to aRCI fault control mode.

The introduction of various types of FRT schemes into the grid codes means that the generators in our network will have different FRT schemes in their control systems as well. This was already mentioned in 1.3 as one of our problems for our work. For a more detailed overview of various grid code requirements around Europe, the reader is referred to [23]. With the knowledge of fault support modes to be considered with the generators connected to the grid, it is now easy to define our models and then test cases.

2.3. Active Distribution Systems
Distributed Generation in the system is not limited to only renewable energy sources. With an increasing participation of DG in LV/MV networks, the distribution network is being transformed from a passive network to an active network. In this Active Distribution Network, consumers not only consume power, but are also providing power to the grid when their local generation exceeds their local demand. In an ADS, power flow is not limited to one direction, but is now bidirectional. Figure 2.5a shows the passive network structure while figure 2.5b shows the active network structure. Green dotted lines in (b) represent bidirectional power flow between utilities and consumer while the yellow dotted lines show power provided from concentrated DG plants in distribution network.

(a) Passive Network
(b) Active Network

Figure 2.5: Configurations of distribution networks.

2.4. Detailed Network
We now present the detailed network representation for both the test cases. The models making up this system are briefed in later sections.

2.4.1. The German Rural MV/LV Network
The entire data for the rural German network was taken from PhD thesis work performed by Jens Boemer at TU Delft [24]. The models were obtained from master thesis done by Emmanuel van Ruitenbeek [14]. The detailed model considered for validation of aggregation is shown in figure 2.6. The details of this network is specified in Appendix A. A summary of the network is as follows:
The network is one with a low generation scenario. The German network is globally viewed as a strong network with high integration of DG systems at distribution and sub-distribution levels. The detailed network contains four Type 3 and Type 4 wind turbine generators, eight photovoltaic systems (PV) with (low voltage ride through (LVRT), additional Reactive Current Injection (aRCI), and additional Reactive and Active Current Injection (aRACI) controls) represented by 3 machines and twelve Combined Heat and Power (CHP) machines represented by 4 synchronous generators on MV level. The LV network consists of aggregated 1710 non-LVRT PV systems represented by three separate converter interfaced models and 171 CHP systems represented by one synchronous generator. Each of the synchronous machines is equipped with an under-voltage and under/over-frequency protection relays. Two of the MV connected CHP are also equipped with excessive angle relays with cutoff angle set at 110°.

2.4.2. IEEE 34 BUS TEST FEEDER
The next test case is three PV modules connected to a IEEE 34-bus test feeder. This is shown in figure 2.7. The red arrows indicate the positions where PV plants are installed on the feeder. Model of PV plants is available in section 2.5.2. The network data for the feeder is available in Appendix A. A brief summary of the network follows:

The network is a modification of IEEE 34-bus feeder system that has 3 PV stations providing a combined generation of 1.5 MW. This is shown in figure 2.7. Each of the PV station is modeled as a current source with a shunt. This is connected to a transformer via a dc-ac converter module as shown in figure 2.13c. The PV station also has a voltage source connected via a reactor to the dc side of the converter. However, we disable the reactor-voltage source combination as it was noticed the voltage source dynamics do not contribute significantly to system dynamics, while also speeding up simulation process. One of the three generating
stations is equipped with LVRT or aRCI capability for each test case while the other two are not. This gives us six test cases. They disconnect from the network as the voltage drops below 0.8 pu at the PCC. This follows in line with our challenge highlighted previously about DG being equipped with different control schemes over a certain time period to adhere to continuously updating GCRs, ensuring topological diversity. The PV stations are also placed on different buses that are separated by quite some distance physically in the feeder. This is another aspect that helps achieve a geographical diverseness in the system. Such representation, thus, ensures we have an as-real-as-possible scenario for distribution feeder. The feeder has two types of loads: 6 Spot Loads (0.7 MW) and 19 Distributed Loads (0.8 MW). The total active power requirement is equal to 1.5 MW. Thus, in steady state, pre-disturbance period, there is no exchange of active or reactive power with the external grid. The connecting lines are all overhead lines carries defined as TypTow elements in PowerFactory. The feeder also consists of two voltage regulators and two two winding three phase transformers. It is tried that the detailed system represents an actual feeder as closely as possible.

Figure2.7: Test Case 2: IEEE 34 bus feeder system

2.5. GENERATOR MODELS

The manufacturer developed models are also not available to research community due to various issues like copyrights and confidentiality among others. The IEC along with several organisations, like Renewable Energy Modeling Task Force (REMTF) among others work to develop generic models of all kinds of generators and power system components. These components can be used by independent research organisations and can be modified easily to suit specific generation system. This work makes use of these generic models, modified to suit our test cases. More information on these generic models is available in appendix B. The following sections give an overview of individual generator systems used in this work. A generic framework is explained first and then the model in PowerFactory is illustrated. Modelling assumptions are listed in Appendix B. Variables used in figures are described in section List of Symbols.
2.5.1. **WIND TURBINE MODEL**

**DOUBLY FED INDUCTION GENERATOR MODEL**

The PowerFactory WTG model is based on synchronous machine model, configured as a Doubly Fed Induction Generator. It is supplied by a mechanical model made of turbine, shaft and pitch control and a power electronic model consisting of host of other controllers. The mechanical model is responsible for providing the machine with mechanical input turbine power calculated from mechanical control. This is calculated by measuring DFIG speed reference. The power electronic control consists of PQ Control and Ir Control, which provides the machine with a d,q voltages calculated from rotor current setpoints. These setpoints are calculated by measuring current and the angle from the DFIG. A block model depicting the DFIG used in our case is shown in figure 2.8. A more detailed PowerFactory frame is shown in Appendix C.

![Control structure for DFIG generator model used in simulations](image)

The Wind model controllers take grid voltages as inputs from the grid model and gives voltages from current setpoints as output for WT operation, basically acting as a current controlled voltage source. In PowerFactory, we use the DFIG templates available from DigSILENT [25]. The PowerFactory representation is shown in 2.13a. The total number of machines and generation from DFIG in the test case is listed in table 2.1.

**FULLY RATED CONVERTER GENERATOR MODEL**

The FRC generator model is almost similar to the DFIG model, apart from the fact that the generator being used is a static generator and has less control modules. A detailed FRC frame used in this work and the one used by PowerFactory along with the entire list of controls for this model is available in Appendix C. The figure 2.9 shows the simplified block definition of FRC turbine in PowerFactory. The model is essentially a current

![Control structure for FRC generator model used in simulations](image)
controlled voltage source whereby voltage signals for the generator are provided by the current controller module. The PQ control block is responsible for controlling the active and reactive power through rotor currents. The PQ control block is the most important block in this model since it is responsible for providing FRT capabilities to the machine, which are available to be configured according to user requirements via user settable flags. More data is available on this control structure in the Appendix C. The total number of machines and generation from FRC in the test case is listed in table 2.1

<table>
<thead>
<tr>
<th>Generator</th>
<th>Parallel Machines</th>
<th>Technology</th>
<th>Generation (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DFIG</td>
<td>2</td>
<td>LVRT</td>
<td>5</td>
</tr>
<tr>
<td>FRC</td>
<td>2</td>
<td>LVRT</td>
<td>5</td>
</tr>
</tbody>
</table>

Table 2.1: Wind generators used in Test Case 1

The PowerFactory representation is shown in 2.13b.

### 2.5.2. Photovoltaic Model

The photovoltaic model used in this work is simply a current source combined with a shunt capacitor on a common bus and interfaced to the grid via a dc-ac power electronic converter and a transformer. A central control scheme for this PV system is modelled and specified in the PowerFactory VSC converter model. A representation of the PV controller is shown in figure 2.10 while the PowerFactory representation is shown in figure 2.13c.

![Diagram](image)

Figure 2.10: Control structure for PV generator model used in simulations

Again, the controller forms the most important part of this system, dictating the response during faults through user settable flags. For example there are three control modes available for user to switch between so that model responds as desired. These are Zero Power Mode, LVRT and aRCI modes. More details on these modes is available in section 2.2.

The amount of different PV installations in our test cases is listed in table 2.2

<table>
<thead>
<tr>
<th>Test Case</th>
<th>Connection Level</th>
<th>PV technology</th>
<th>Generation (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>ZPM LVRT aRCI</td>
<td></td>
</tr>
<tr>
<td>Test Case 1</td>
<td>LV</td>
<td>1026 0 684</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>MV</td>
<td>1 1 6</td>
<td>1.4</td>
</tr>
<tr>
<td>Test Case 2</td>
<td>MV</td>
<td>50 50 50</td>
<td>1.5</td>
</tr>
</tbody>
</table>

Table 2.2: PV technologies in test cases
2.5.3. **Combined Heat and Power (CHP) Model**

The CHP plants used in this work are modelled as directly coupled synchronous generators. The dynamic modelled outline is taken from [5]. The automatic voltage regulator (AVR) and governor (GOV) models are taken directly from DigSILENT global library. Generator parameters used were taken from commercially available machine data of similar ratings. A generic description of such a plant is as shown in figure 2.11: The CHP plants are not interfaced to the grid via a power electronic interface and hence have protection systems installed in form of relays. Two FRT schemes are employed: LVRT and ZPM (nLVRT). We employ two different kinds of relays with the CHP models and details of these models are provided in section 2.7. The number of machines with different FRT schemes are listed in table 2.3. The PowerFactory representation is in 2.13d.

![Figure 2.11: Modules within the generic CHP plant model and interaction with grid.](image)

<table>
<thead>
<tr>
<th>Connection Level</th>
<th>CHP technology</th>
<th>Generation (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV</td>
<td>nLVRT LVRT</td>
<td>1.71</td>
</tr>
<tr>
<td>MV</td>
<td>6 6</td>
<td>4.8</td>
</tr>
</tbody>
</table>

Table 2.3: PV technologies in Test Case 1

2.6. **Load Model**

For both MV and LV networks, a balanced three phase load with a mix of static and dynamic loads is considered. Dynamic loads are motor loads connected primarily to the MV network. The mix of loads is such that the aggregated load represents a 20% industrial dynamic load and 80% static load. Load is modelled as an exponential load model given by equations 2.1 and 2.2.

\[
P_{\text{exp}} = P_0 \cdot \left[ a_P \left( \frac{V}{V_0} \right)^{e_{aP}} \right] 
\]

(2.1)

\[
Q_{\text{exp}} = Q_0 \cdot \left[ a_Q \left( \frac{V}{V_0} \right)^{e_{aQ}} \right] 
\]

(2.2)

where subscript '0' refers to the initial operating condition specified by the user. 'V' is the voltage on the connected bus in pu. The coefficients for the load are specified in table 2.4. The load values in the two cases is shown in table 2.5.

<table>
<thead>
<tr>
<th></th>
<th>(a_P)</th>
<th>(e_{aP})</th>
<th>(a_Q)</th>
<th>(e_{aQ})</th>
</tr>
</thead>
<tbody>
<tr>
<td>LV</td>
<td>1</td>
<td>1.7</td>
<td>1</td>
<td>4.7</td>
</tr>
<tr>
<td>MV</td>
<td>1</td>
<td>1.4</td>
<td>1</td>
<td>5.5</td>
</tr>
</tbody>
</table>

Table 2.4: Load coefficients values for Test Case 1

The load data for test case 2 is complex and thus has been described in detail in Appendix A when we define our test feeder for Case 2 in detail.
2.7. Protection Models

As already described in section 2.5.3, we have two different kinds of CHP connected to the network in case 1. These CHP generators are not interfaced to the grid via a PE based converter and hence the FRT capabilities are very basic. The LVRT equipped CHP machines are given the FRT capability by reducing the under voltage relay’s pickup voltage to 0.00pu. The nLVRT generators have their pickup settings set to existing DER regulation voltage of 0.80 pu. In addition to under voltage relays, two of the LVRT machines are also equipped with excessive angle relays. These relays are set to disconnect the generators from the grid in the event that the angle at their PCC to the MV network exceeds 120°. LVRT capability is added to CH machines by installing relays with pickup voltage set at 0.00 pu.

While under voltage relays are fairly basic, the excessive angle relay was modelled as a new DSL object with it’s own logic. The basic structure of this relay is seen in figure 2.12.

![Excessive Angle relay frame.](image)

The logic sends the breaker at the machine PCC an open signal if the angle at any of the generators exceeds 120°. This enables complete protection of the synchronous generators in the system.

<table>
<thead>
<tr>
<th>Test Case</th>
<th>Connection Level</th>
<th>Total loads</th>
<th>Load (MVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Case 1</td>
<td>LV</td>
<td>1</td>
<td>10.64</td>
</tr>
<tr>
<td></td>
<td>MV</td>
<td>2</td>
<td>2.5</td>
</tr>
<tr>
<td>Test Case 2</td>
<td>MV</td>
<td>25</td>
<td>1.65</td>
</tr>
</tbody>
</table>

Table 2.5: Load Values in test cases
Figure 2.13: Representation of generator models in PowerFactory

(a) DFIG model
(b) Fully Rated Converter WTG model
(c) Photovoltaic plant model
(d) Combined Heat and Power model
As already mentioned in previous sections, to keep the simulation time and computational overhead manageable, we need to perform aggregation of the network. The basic idea is to place representative generation and load behind an equivalent impedance. The detailed network dynamics are then matched to the aggregated network dynamics by tuning the model parameters.

![Image of Concept of Aggregation](image)

Figure 3.1: Concept of Aggregation

Generally, network aggregation is a complex task. There is a large amount of literature available that presents the validates the concept of network aggregation. However, the major drawback with the available literature is that these aggregated networks are representative of a particular generator type, i.e., solar, wind, fuel cells, micro CHP etc. aggregated individually. There have been little to no attempts to aggregated an entire network with a complex mix of all generating technologies. We make an attempt in this thesis to employ a rather unusual aggregation approach. We group the network generations into two categories:

- Generation hidden behind a power electronic interface
- Others (Mainly directly connected synchronous machine based generation)

Therefore, all the photovoltaic, and wind generation (both DFIG and FRC) are put into category 1. CHP is put into category 2. The aggregated load is the summation of all loads in the detailed network. We now go into details of how aggregation for our network was performed for both of our test cases. As described previously, we first take into account the PE interfaced generation and then we look into CHP aggregation.

### 3.1. Aggregated PE Interfaced Generation (WECC PVD1 Model)

All the power electronic interfaced generation is very flexible with implementation of FRT modes in their control algorithm. Remembering our first problem definition, we need to develop aggregated models that **accurately represent diverse DG in the present network**. To account for these diverse conditions, a WECC modelled distributed PV model (henceforth referred to as PVD1 model) is used. This has been developed by
the Renewable Energy Modelling Task Force (REMTF) and depicts with reasonable accuracy, an aggregated system of PV connected on the distribution level. This model’s usage was extended to capture the effect of not only distributed PV, but also power electronic interfaced wind generation.

The generic framework of PVD1 model is as shown in 3.2. The main components, as can be seen from the figure 3.2 are:

- **Active Power Controller Unit**
- **Reactive Power Controller Unit**
- **Protection Logic Unit**

These blocks are briefly explained as follows:

### 3.1.1. **ACTIVE POWER CONTROL**

This subsystem provides active current injection, which is subject to current limiting, to the network solution. It takes input reference active power (Pref) and terminal voltage (Vt) from load flow solution. The active power reference is taken as initial power flow value from load flow solution in this work. The output of this block is an active power current command (Ipcmd).

### 3.1.2. **REACTIVE POWER CONTROL**

Similarly to the active power controller, the reactive power controller issues a reactive current command to the network. Current limiting mechanism is applied to this block too. The block inputs a reference reactive power (Qref), load flow obtained solutions of terminal current (It) and terminal voltage (Vt). The reactive power reference command is the sum of initial reactive power from network load flow solution and droop signal derived from voltage deviation at the said bus. The model can switch between active or reactive current injection mode in the event of a disturbance by setting internal parameter (Pqflag). This flag parameter can be accessed via model definition and can be set to either 0 (active power injection) or 1 (reactive power injection). The setting of this parameter allows the model to set limits for current limiter model which determines the cap on the active (Ipmax) and reactive current (Iqmax, Iqmin) output of the model. The derivations are in the table 3.1 where Imax refers to maximum allowable current through the inverter (Between 1.0-1.3 pu on mbase, set to 1.2 as a default value).

### 3.1.3. **PROTECTION LOGIC**

This block performs the most important task of capturing diverse FRT criteria among all the installed DG in the system. This is based on modeling the converter considering partial dropout of generation according to [? ]. Since this block provides the most important function to working on our aggregated model, we will
describe it in more detail. The protection and partial dropout are implemented by this block by providing
two outputs in accordance with the terminal voltage and frequency obtained from network solution. The
internal parameter settings of the block determine if the generation recovery occurs when voltage and/or
frequency disturbances reverse, and if so, then in what proportion. In this work, we consider the effect of
voltage deviations on the generation and thus only the four internal parameters are considered. These are
Vt0, Vt1, Vt2, Vt3. These are the per unit voltage values that are constant for a given model definition and
determine the amount of generation that is disconnected and/or reconnected following a disturbance in the
network. The figure 3.3 gives a block diagram representation of this logic.

<table>
<thead>
<tr>
<th>Condition</th>
<th>Fvl value</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vt &lt; Vt0</td>
<td>0.0</td>
<td>Vt below minimum voltage</td>
</tr>
<tr>
<td>Vt0 &lt; Vt &lt; Vt1</td>
<td>(Vmin - Vt0) / (Vt1 - Vt0)</td>
<td>Decreasing terminal voltage</td>
</tr>
<tr>
<td>Vt0 &lt; Vt &lt; Vt1</td>
<td>((Vmin - Vt0) + Vrflag * (Vt - Vmin)) / (Vt1 - Vt0)</td>
<td>Recovering, partial reconnection</td>
</tr>
<tr>
<td>Vt &gt; Vt1</td>
<td>1.0</td>
<td>Normal disturbance free operation</td>
</tr>
<tr>
<td>Vt &lt; Vt1</td>
<td>((Vmin - Vt0) + Vrflag * (Vt1 - Vmin)) / (Vt1 - Vt0)</td>
<td>Vt was below Vt1, but has recovered now</td>
</tr>
</tbody>
</table>

Table 3.2: Derivation of Low Voltage Tripping Logic

In the table above, we use some terms that are described in list of symbols.

Table 3.1: Current limits according to Pqflag priority
3.2. Aggregated CHP Model

CHP are modelled as directly coupled generators in detailed system. Their aggregation in the reduced model is performed by classical generator coherency techniques. According to [26], coherency is a very intuitive concept that can be defined as:

*Two machines are called coherent if after a severe disturbance, they present similar dynamical behaviour; that is, their rotor angles or speed keep very similar among system state.*

This means that two generators are said to be *swinging together* if their rotor angles or frequencies similar trends with very little error between them. This definition is valid for large transmission level connected generator systems. We apply this definition vaguely on the DG level CHP plants. Hence, there are bound to be limitations to this method as well as errors. The detailed system in test case 1 has 171 LV connected and MV network has 4 CHP machines that represent a combined generation of 12 machines (number of parallel machines = 12). These 4 machines have 4 different FRT schemes: PF095, PF100, LVRT, NEW. As discussed previously, PF095 and PF100 represent machines working at constant power factor of 1.00. NEW represents the newly added machines for 2022 scenario and are aRCI equipped. Aggregation is done in the following way:

- The LV generator is kept as before, 1 synchronous machine model representing 171 LV connected CHP plants.
- Frequency and Speed curves of 4 machines is analysed and similarly behaving machines are grouped. The speed and frequency plots are shown in figure 3.4.

![Figure 3.4: Aggregation criteria for CHP generators in network](image)

We see that LVRT and NEW generators have similar characteristics while PF095 and PF100 have similar characteristics. Therefore, we aggregated our MV connected generators into two systems. FRT capable and FRT incapable generators. The aggregated generation for both PVD1 and CHP is summation of all power from each generators in the detailed system. Figure 3.5 and figure 3.6 shows the aggregated model made for detailed systems of 2.6 and figure 2.7 respectively.
Now that we have our detailed and aggregated model, we need to find the dynamic equivalent parameters. This is done by validating the aggregated network against the detailed network. According to [17], for validating ADN

3.3. **Network Validation Criteria**

As previously mentioned, the response of aggregated ADS model is compared with detailed ADS model for a number of specified external network faults. The voltage dips are seen with various retained voltages at the HV side of MV/HV transformer and the measurements of variables for validation are also made at this point. The validation method presented in [27] is used to measure the accuracy of our derived aggregated model. The two variables used as metrics for comparison of two models are:

- Active Power (P)
- Reactive Power (Q)
These metrics are studied for post fault period and analysis and fitness measurement is done based on these metrics. The transient simulation is divided into 3 regions: pre-fault, fault and post-fault. More focus is given to post fault period, as has already been discussed in the research approach (1.6) of this work. This emphasis to post fault period is given by dividing the error calculations between the three regions and assigning a weighing factor to these regions’ error. These weighing factor are listed in table 3.3.

<table>
<thead>
<tr>
<th>Fault Region</th>
<th>Weighing Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Fault</td>
<td>1</td>
</tr>
<tr>
<td>During-Fault</td>
<td>0</td>
</tr>
<tr>
<td>Post-Fault</td>
<td>1</td>
</tr>
</tbody>
</table>

Table3.3: Weighing factors given to various regions of fault curves

3.4. REFERENCE SIGNALS AND NETWORK DYNAMICS

The reference signals (active and reactive power flows) to be used for identification of DE are generated from the detailed test network, modeled in section 2.4, at the HV side of the interfacing transformer to the external grid. The faults are simulated at different locations inside the external grid by varying the fault impedance at the HV side of the transformer. The faults for test case 1 are specified in table 3.4.

<table>
<thead>
<tr>
<th>Retained Voltage (pu)</th>
<th>Fault Impedance (Ω)</th>
<th>Fault Time (s)</th>
<th>Clearing Time (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.55</td>
<td>3.70</td>
<td>0.25</td>
<td>0.5</td>
</tr>
<tr>
<td>0.60</td>
<td>4.54</td>
<td>0.25</td>
<td>0.5</td>
</tr>
<tr>
<td>0.65</td>
<td>5.62</td>
<td>0.25</td>
<td>0.5</td>
</tr>
<tr>
<td>0.70</td>
<td>7.06</td>
<td>0.25</td>
<td>0.5</td>
</tr>
<tr>
<td>0.75</td>
<td>9.08</td>
<td>0.25</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Table3.4: Contingencies in Test Case 1

The faults for test case 2 are specified in table 3.5.

The effect of applying these faults for such disturbance is different for different generator stations in both the test cases. As already highlighted in section 2.4, only few of the generating station are capable of riding
through the fault. The rest of the generators are disconnected from the grid when the voltage drops below 0.8 pu. Thus by using these fault conditions for identification, we automatically consider the case of network dynamics due to generation disconnection as well.

<table>
<thead>
<tr>
<th>Retained Voltage (pu)</th>
<th>Fault Impedance (Ω)</th>
<th>Fault Time (s)</th>
<th>Clearing Time (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.30</td>
<td>1.02</td>
<td>0.1</td>
<td>0.3</td>
</tr>
<tr>
<td>0.65</td>
<td>4.42</td>
<td>0.1</td>
<td>0.3</td>
</tr>
</tbody>
</table>

Table 3.5: Contingencies in Test Case 2
In power system stability analysis, more often than not, the problem is a non-linear one. It involves time domain simulation of systems governed by equations which are discontinuous, non-convex and multi-objective. These are difficult to solve in a reasonable time with current optimisation techniques. The advances in computing are giving rise to formulation of even powerful and faster optimisation techniques; not just for electrical power systems based problems, but also in other fields of engineering. It is only natural then to apply these optimisation techniques to solve selection of other non-linear problems presented by electric power systems.

Optimisation algorithms have long been used in modern day power systems. More commonly, it is used in solving the problem of economic load dispatch. Economic load dispatch (ELD) problem is a routine problem in the operational planning of a power system, where a pattern has to be defined to schedule the connected generating units of plant outputs so as to fulfill demands at minimum operating cost while, at the same time, satisfying all operational constraints. [28] describes use of various optimisation algorithms in ELD application. Recently, there has been an increase in techniques such as Artificial Neural Networks [29], Fuzzy logic based and other sophisticated techniques to solve a variety of power system problems. Although these techniques are excellent, they require a lot of time and historical data to train the network to be able to provide us reliable results. Recently, there has been an increase in the adoption of more heuristic based methods to solve such complex problems. Heuristic based methods don’t necessarily provide with the most accurate answers, but they save a lot on time and give us answers that are “almost accurate”.

This thesis will use the novel variant of heuristic optimisation technique called Mean Variance Mapping Optimisation (MVMO) for our problem. It is important to revisit our second problem statement which was to develop a robust identification tool for determination of parameters of developed dynamic equivalent. Naturally a question arises, parameter identification has already been done using many other optimisation techniques before like in [30], what makes MVMO special? The answer to this question is simple. Many of the present techniques get easily trapped into local optimum, since their searching performance depends on it’s appropriate parameter settings. Premature convergence and local stagnation is also a problem that these techniques face, especially for problems that are non-convex or multi-objective. MVMO, while not completely fool-proof to these pitfalls, it is much better than these techniques as it achieves a higher success rate of reaching a global optimum while avoiding premature convergence and also speeding up the search process.

4.1. The MVMO Algorithm

Like differential and evolutionary algorithms, MVMO is also a population-based stochastic optimisation algorithm. It borrows the ideas of selection, mutation and crossover from other evolutionary computational algorithms. The main feature of MVMO is it’s transformation or mapping of the mutated genes according to a unique mapping function that is derived from n-best stored solutions’ statistics. The approach used in our study case with MVMO is shown in figure 4.1. The various components of this flowchart are then discussed briefly.
4.1.1. **PROPOSED APPROACH**

A general purpose research approach was previously defined in section 1.6. The application of optimisation framework to the developed models for our test cases is shown in figure 4.1. It is important to discuss the approach in detail as it forms the core of this thesis.

After we have defined our dynamic equivalent models, a set of multiple disturbances for which our DE should be identified, are defined. These disturbances are listed in table 3.4 and table 3.5. Initially, the solution vector containing optimisation variables is randomly initialized. The search range for all optimization parameters is then normalized from [min,max] to [0,1]. This is one of the uniqueness of MVMO. Normalization of search space is required as a precondition for transformation in later stages. This also has the advantage that the generated offspring is never beyond the searching boundaries. The solution vector containing normalized solutions is de-normalized to obtain real valued parameters that are fed into models and used to perform time domain simulations. The desired signals from this model is then fed into the fitness evaluation test along with a set of reference signals. This fitness value forms the objective function. If the fitness violates a defined condition, a penalty is applied to the solution, and this solution is immediately rejected. All the acceptable solutions from the process are stored to an external csv file. The best solutions are stored and according to a mapping function, a new solution set is created that is again de-normalized and fed to models for simulations. This process is then continued. The process is stopped when termination criteria is satisfied.

Figure 4.1: Flowchart representing the approach used for identification of parameters if DE with MVMO.
As was mentioned before in the introductory chapter, the algorithm is coded in Python 3.4. The integration of the two softwares was already explained in figure 1.2. Python being one of the most used open-source language in the world, the development of the MVMO in Python was essential to increase it's wide adaptability for other power system problems.

4.1.2. Objective Function Formulation

Our objective is to minimize the error between the dynamic behaviours of detailed model and aggregated model for the defined disturbances. As discussed in section 3.3, the quantities compared from both detailed and equivalent models are active and reactive power at the point of common coupling (PCC). Thus, our objective function problem for optimisation can be formulated as follows:

\[
\text{Minimize: } \sum_{n=1}^{k} \alpha_n \int_0^t \left[ \left( P_n - P_{n,ref} \right)^2 + \left( Q_n - Q_{n,ref} \right)^2 \right] \tag{4.1}
\]

subject to

\[
x_{\text{min}} \leq x \leq x_{\text{max}} \tag{4.2}
\]

where \(x\) is the D-dimensional solution vector filled with the parameters of DE to be optimized while \(x_{\text{min}}\) and \(x_{\text{max}}\) are the minimum and maximum values of each element of \(x\). \(P_n\) and \(Q_n\) are the response of DE at any time \(t\), while \(P_{n,ref}, Q_{n,ref}\) are the corresponding response from detailed models at the same time. \(\alpha_n\) is the probability of the \(n^{th}\) disturbance. The values of \(\alpha_n\) are shown in table 4.1. \(k\) is the total number of disturbances for which the DE is to be defined.

<table>
<thead>
<tr>
<th>Test Case 1</th>
<th>(\alpha_1 = 0.7, \alpha_2 = \alpha_3, \alpha_4 = \alpha_5 = 1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Case 2</td>
<td>(\alpha_1 = \alpha_2 = 1)</td>
</tr>
</tbody>
</table>

Table 4.1: Probability factor \(\alpha\) used for objective function calculation

4.1.3. Fitness Evaluation

For a candidate solution generated in each function evaluation, fitness value is basically the objective function value. Thus, fitness value is the sum of squares of errors of \(P\) and \(Q\) curves between DE and detailed models for a set of disturbances simulated in PowerFactory over a period of time. The following strategy is defined for fitness evaluation:

\[
f' = \begin{cases} OF, & \text{if OF is within limits} \\ \rho, & \text{otherwise} \end{cases} \tag{4.3}
\]

The value of \(\rho\) is set to a high value (1e50) in our case.

4.1.4. Solution Archive

One of the strengths of MVMO lies in the fact that it has a knowledge archive that is used to derive constants that shape the transformation function, thus acting as a search guide. Moreover, this archive is dynamically updated as the algorithm finds better solutions. The archive stores \(n\) best solutions in a descending order of fitness. The archive size is fixed at the start of the procedure. An update to the archive is made only if a solution with a fitness value better than stored solutions is found. Figure 4.2 shows typical structure of the archive.

4.1.5. Offspring Generation

Offspring creation in MVMO is a 3 step process. This is the part, where uniqueness of MVMO from other evolutionary algorithms becomes evident. The steps are described in detail in the following sections:

The Parent of a New Solution

MVMO adopts a single parent offspring approach. As the name suggests, there is only a single parent involved in creation of child vector. Parent selection can be done in multiple ways:

- Best fit solution from archive
• A combination of best solution with another solution from archive

For this work, we chose to adopt the methodology to select the best fit solution as parent. Thus, the first entry from solution archive is taken as the parent to create offspring.

**Evolution of Parent based on Mapping Function**

This step forms the crux of MVMO’s working. The step is illustrated in figure 4.3. From the parent vector, $m$ ($m < D$) variables are randomly selected. These variables are then given to the transformation function. The new value of each selected dimension is computed using equation 4.4

$$x_i = h_x + (1 - h_1 + h_0) \cdot x'_i - h_0$$

where $x'_i$ is a uniform random number in $[0,1]$. $h$ is the transformation function. The transformation function is defined and changed dynamically as the algorithm proceeds further in its process to find optimal solutions. The function is a function of best fit solution’s statistics. The mutation function is given by equation 4.5.

$$h(x_i, s_1, s_2, u_i) = x_i \cdot (1 - \exp^{-u_i \cdot s_1}) + (1 - h_i) \cdot \exp^{(u_i - 1) \cdot s_2}$$

The subscript $i$ represents the $i^{th}$ selected dimension from parent vector. The variables $h_x$, $h_1$ and $h_0$ from equation 4.4 are outputs of transformation functions calculated as follows:

$$h_x = h(u_i = x'_i), h_0 = h(u_i = 0), h_1 = h(u_i = 1)$$

$x_i$ is the mean of the best solution in the archive. $s_1$ and $s_2$ are the shape factors. These shape factors determine the shape of the transformation function as is seen by the red line in figure 4.3 (ii). These shape factors are determined from the variance of the stored solutions. This relationship between shape factors and variance is a logarithmic one as is shown in equation 4.6.

$$s_i = -\ln(v_i) \cdot f_s$$

where $f_s$ is the user input scaling factor, generally set between $[0.9,10]$. The factors $s_1$ and $s_2$ are assigned with

![Figure 4.2: MVMO archive where solutions are stored.](image)
4.1. **The MVO Algorithm**

Solution statistics from stored archive

\[ \text{X}_{\text{child}} = \text{Mutated variable} \]

Parent variable

\( (i) \)

\( (ii) \)

\( (iii) \)

\[ \text{X}_{\text{parent}} = \text{parent vector} \]

\( (i) \)

\[ i \]

\[ i_1 \]

\[ i_2 \]

\[ x \]

\[ s \]

\[ s \]

\[ \_ \_ \_ \]

\[ \_ \_ \_ \]

\[ \_ \_ \_ \]

\[ * \]

\[ i \]

\[ = \]

\[ x \]

\[ \text{rand} \]

\[ \text{new} \]

\[ i \]

\[ x \]

\[ \text{new} \]

\[ \text{Procedure of mutation of selected genes from parent vector to create child vector.} \]

---

**Figure 4.3:** Procedure of mutation of selected genes from parent vector to create child vector.
the following scheme:

\[ s_1 = s_2 = s_i = -\ln(v_i) \cdot f_s \]

if \( s_j > 0 \) then
\[ \Delta d = (1 + \Delta d_0) + 2 \cdot (\text{rand} - 0.5) \]
if \( s_j > d_i \)
\[ d_i = d_i \cdot \Delta d \]
else
\[ d_i = d_i / \Delta d \]
end if
if \( \text{rand} > 0.5 \) then
\[ s_1 = s_i; s_2 = d_i \]
else
\[ s_1 = d_i; s_2 = s_i \]
end if
end if

Starting from the first function evaluation, the first value of \( x_i \) will be the first randomly initialized value. The variance is set to 1.0 therefore, \( s_i = 0 \). But with the continuation of optimisation process, these values are recalculated and updated to obtain a dynamically changing transformation function. The variable \( d_i \) is a parameter that determines the limits of variation of \( s_1 \) & \( s_2 \). Randomly varying \( s_1 \) & \( s_2 \) helps in fully exploiting transformation function's characteristics leading to good balance between exploitation and exploration. On a more general note, the algorithm's ability to focus either on exploitation or exploration can be set using the shape factor \(( f_s )\). Setting \( f_s \) to a large value \(( f_s \geq 1 \)), focuses the algorithm towards exploration, while a low value \(( f_s \leq 1 \)) means the focus is more on exploitation.

**CROSSOVER**

The newly mutated variables from the above process are now crossed with the parent vector to produce new solution vector \( x^{new} \) for the next function evaluation. The process is highlighted in figure 4.3. The \( D-m \) variables from parents are combined with the \( m \) mutated variables. This new vector has the parameters that are fed into the PowerFactory model.

### 4.2. PERFORMANCE TEST: ROSENBRUCK FUNCTION

To test the capability of our optimisation algorithm, it was tested on one of the benchmark test functions, the Rosenbrock function. It is a non-convex function, usually used to test performance of an optimisation algorithm. The function is as shown in figure 4.4a and derived in equation 4.7.

\[ f(x, y) = (a - x)^2 + b(y - x^2)^2 \]  

(4.7)

Generally, \((a, b) = (1, 100)\).

As is visible, the minimum is a parabolic valley. The algorithm was run on this function to determine the global minimum which is along the parabola. It was run for 100 times and every time, the algorithm was able to find one of the global minima lying in the parabolic valley. This demonstrates the effectiveness of the algorithm.

### 4.3. APPLICATION TO TEST CASES

The next step after developing the algorithm was to adapt the algorithm's working to each test case. This includes specifying the algorithm internal parameters, parameters from test case to be optimized etc. After several discussions, it was decided to keep the internal parameters of the optimisation constant. The scaling factor however was varied as the optimisation proceeded. Initially, it is important to have a greater focus on exploration, and hence, during the first 100 function evaluations, the scaling factor was set to 3. After 100 function evaluations though, the scaling factor was set to 0.9 to focus more on exploitation of already achieved solutions. The internal parameter settings of MVMO are described in table 4.2.
4.3. APPLICATION TO TEST CASES

(a) Rosenbrock function

(b) Solutions for 100 iterations

Figure 4.4: Benchmark function performance

In the table 4.2, MaxEval corresponds to maximum function evaluations. Nrandomly denotes the number of variables randomly chosen from the optimization vector \( x \). \( \rho \) is the penalty factor that is imposed on the objective function value if the solution does not obey the fitness criteria specified by the equation 4.3. It is also important to determine what parameters of the models we need to optimize. These need to be fed into the algorithm in Python. Parameters are identified using sensitivity analysis.

### Sensitivity Analysis

Sensitivity analysis is performed on a simulation model to determine which parameters influence the required output of the model significantly. In our case, the model is checked on the basis of its active and reactive power curves. Hence, we determine suitable parameters from the aggregated model derived in figure 3.5 and 3.6. These parameters are found to be \( V_{t0}, V_{t1} \) from the PVD1 model protection block, the PVD1 model inverter time constant \( T_g \), the dropout factor \( V_{rflag} \), the aggregated line length, and the load active and reactive power values. We consider only the under voltage \( V_t \) constants for optimization problem because we focus entirely on this part of system dynamics. It is assumed that there are no significant over-voltage dynamics in the system and so \( V_{t2}, V_{t3} \) are set to fixed values (1.1,1.2). The dropout factor is optimized in a very narrow range around the expected value of 0.33 since only one out of three generators will be able to ride through the fault. The line length (dline) is optimized to obtain equivalent R, X values that form the equivalent impedance in figure 3.1. Similarly, load active power (plini) and reactive power (qlini) are varied in a narrow \( \pm 5\% \) range around the aggregated sum of all loads in the detailed system. This is done to take into account the unknown system losses that occur.

Once the parameters to be optimized have been defined, we revisit our optimization objective function equation 4.1. The values of \( a_n \), which are the probability factor for the established faults are already given in table 4.1.

The parameters that were optimized for both test cases are shown in table 4.3.

<table>
<thead>
<tr>
<th>Case</th>
<th>Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Test Case 1</td>
<td>( V_{t0}, V_{t1}, T_g, V_{rflag}, Dqdv, dline, plini, qlini, K_n, T_e, E_1, SE_1, E_2, SE_2, \delta_{max} )</td>
</tr>
<tr>
<td>Test Case 2</td>
<td>( V_{t0}, V_{t1}, T_g, V_{rflag}, dline, plini, qlini )</td>
</tr>
</tbody>
</table>

Table 4.3: Parameters to be optimized
MVMO requires that each parameter being optimized be given a range of values between which the algorithm shall search for the optimal value. The results from MVMO are highly dependent on this search range input by the user. Following text gives the range of variation of optimization parameters that are fed into the algorithm.

The optimization parameter ranges are given as follows:

- \( V_{t0} \) [0.5, 0.65]
- \( V_{t1} \) [0.88, 0.92]
- \( T_g \) [0.01, 0.5]
- \( V_{rflag} \) [0.6, 0.65]
- \( Dqdv \) [5, 20]
- \( \delta_{max} \) [98, 115]
- \( dline \) [0.005, 0.2]
- \( plini \) [2.375, 2.625]
- \( K_a \) [360, 440], [160, 240]
- \( T_e \) [0.22, 0.32], [0.06, 0.14]
- \( E_1 \) [6.1, 6.35], [5.9, 6.1]
- \( SE_1 \) [0.5, 0.95], [0.26, 0.38]
- \( E_2 \) [5.5, 6], [4.7, 5.5]
- \( SE_2 \) [0.3, 0.5], [0.05, 0.25]
- \( T_a \) [0.02, 0.024], [0.014, 0.017]

The optimisation parameter ranges for Test Case 2 are shown below.

- \( V_{t0} \) [0.8, 0.88], [0.45, 0.5]
- \( V_{t1} \) [0.88, 0.92]
- \( T_g \) [0.01, 0.5]
- \( V_{rflag} \) [0.3, 0.35]
- \( dline \) [10, 100]
- \( plini \) [1.25, 1.50]
- \( qlini \) [0.8, 0.93]

The definitions of these variables is provided in chapter list of symbols.

---

1 Similar trends follow for rest of the parameters
2 For MV AVR
3 For LV AVR
4 For odd numbered sub-test cases
5 For even numbered sub-test cases
This chapter presents the results from the optimization. The results for the German MV/LV network are presented in section 5.1, while the results from the IEEE test feeder are presented in section 5.2. The simulations are performed on a Dell personal computer with Intel(R) Core(TM) i5-4670 CPU @ 3.4Ghz and 8 GB RAM. As already mentioned, the approach was implemented by using the algorithm coded in Python 3.4 and used to determine parameters of the dynamic equivalents modeled in DigSILENT PowerFactory 15.2. The fault is implemented at 0.25s and is cleared after 250 ms.

5.1. TEST CASE 1

The optimization problem in our test case contains 28 optimization variables which have been listed along with their search ranges in equation 4.1. The optimization problem and the objective function is recalled at this point from equation 4.1. We minimize the sum of squares of $\Delta P$ and $\Delta Q$ where $\Delta P$ (Q) is the point wise difference between the active (reactive) power curves of detailed and aggregated network. The analysis for this test case is done for 1000 function evaluations. The CPU time of MVMO execution for this optimization problem is approximately 183 minutes. The convergence graph is shown in figure 5.1.

The convergence graph is shown in figure 5.1. It can be seen from the convergence graph that the MVMO possesses a fast convergence characteristic. This demonstrates that MVMO is a fast and powerful heuristic optimization algorithm. MVMO reduces the error by 87.5% . This convergence is reflected in high resemblance of dynamic equivalent’s response to detailed network’s response as is visible in figure 5.2 and 5.3; the
faults for which DE was identified. Due to space restriction, only 2 faults for which the DE was identified are shown here. Results for other fault levels are shown in Appendix C.1. The following graphs follow a structure as: voltage, active power (P), reactive power (Q) and reactive current flow (iQ) at the HV side of transformer.

Figure 5.2: Plots for retained voltage level of 0.55pu.

Figure 5.3: Plots for retained voltage level of 0.65pu.

To validate our DE, we measure its response against fault scenarios which were not used for defining DE's parameters. A fault level of 0.50 pu and 0.79 pu were randomly selected and analyzed. The results are presented in figures 5.4. Since the DER cutoff limit was specified at 0.8 pu (shown with green dotted line), most erroneous results are expected to be around this value. It is, therefore, interesting to note the behavior of the network and DE at this level.

The optimized parameters obtained after process is over are listed in table 5.1.

It is seen that the DE is able to catch the behavior of the detailed network with reasonable accuracy even in such a zone, implying that the DE developed can be accepted as a good simplified representation of the detailed network. Additionally, it must be noted that the time to simulate the DE for similar disturbance
as defined for the detailed network is also reduced. An average of five iterations showed that to perform a 4-second simulation on the detailed network, the system required 2.73 seconds while a similar simulation required only 0.6 seconds, representing a 74% reduction in simulation time.

The NRMSE values give a good indication of the two curves relative similarity. Normalized RMSE is used in this case because the range of data set is high. NRMSE costs vary between $-\infty$ (bad fit) to 1 (perfect fit). If the absolute value of NRMSE is between (0,1), response can be considered accurate. It can be seen that the absolute NRMSE value is good not only for fault that was used for identification, but is also low for randomly chosen fault implying a good fit. From figures 5.2, 5.3 and 5.4, another observation made is that during the fault, curves for reactive power shows high deviations. This is attributed to the fact that PVD1 model isn't capable of providing a reactive power injection. The second iteration of PVD1 model developed by WECC will overcome this shortcoming. Nevertheless, the PVD1 model is developed to study the aggregated impact of distributed PV for a transmission system fault. That is, we are interested in the post fault dynamics of the system for bulk system studies. Consequently, we evaluate post fault curves with NRMSE values. These values are given in table 5.2

5.2. TEST CASE 2

This test case consists of six sub test cases. Each representing a different condition in the detailed network model. Due to space restrictions, only results for sub-test case 1 are shown. The remainder of the sub-test cases are shown and analysed in Appendix C.2. The optimization problem in our test case contains 7 optimization variables which have been listed along with their search ranges in section 4.3. The optimization problem and the objective function is recalled at this point from equation 4.1. We minimize the sum of squares of $\Delta P$ and $\Delta Q$ where $\Delta P$ (Q) is the point wise difference between the active (reactive) power curves of detailed and aggregated network. The analysis for this test case is done for 1000 function evaluations. The CPU time of MVMO execution for this optimization problem is approximately 28 minutes. The convergence graph is shown in figure 5.5.

Again, it can be seen from the convergence graph that the MVMO possesses a fast convergence characteristic. This demonstrates that MVMO is a fast and powerful heuristic optimization algorithm. MVMO reduces the error by 70%. This convergence is reflected in high resemblance of dynamic equivalent's response to detailed network's response as is visible in figure 5.6 and 5.7; the faults for which DE was identified. The following graphs follow a structure as: voltage, active power (P), reactive power (Q) and reactive current flow ($i_Q$) at the HV side of transformer.

To validate our DE, we measure its response against fault scenarios which were not used for defining DE's parameters. A fault level of 0.40 pu and 0.50 pu were randomly selected and analyzed. The results are
<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
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</thead>
<tbody>
<tr>
<td>PVD1 model</td>
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<tr>
<td>Vt0</td>
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</tr>
<tr>
<td>Vt1</td>
<td>0.9186</td>
</tr>
<tr>
<td>T_g</td>
<td>0.149</td>
</tr>
<tr>
<td>Dqdv</td>
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</tr>
<tr>
<td>Relay angle</td>
<td>δ</td>
</tr>
<tr>
<td>K_a</td>
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<tr>
<td>T_e</td>
<td>0.2204</td>
</tr>
<tr>
<td>E_1</td>
<td>6.1435</td>
</tr>
<tr>
<td>MV AVR 1</td>
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<tr>
<td>SE_2</td>
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<td>T_a</td>
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<tr>
<td>LV AVR</td>
<td></td>
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<tr>
<td>E_2</td>
<td>5.4892</td>
</tr>
<tr>
<td>SE_2</td>
<td>0.0515</td>
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<td>T_a</td>
<td>0.0138</td>
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<tr>
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<td>Active Power</td>
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<td></td>
<td>2.6244</td>
</tr>
<tr>
<td>Line length</td>
<td>0.1121</td>
</tr>
</tbody>
</table>

Table 5.1: Test Case 1: Optimized Parameters

<table>
<thead>
<tr>
<th>Uret (pu)</th>
<th>NRMSE(P)</th>
<th>NRMSE(Q)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.55</td>
<td>0.7024</td>
<td>-0.5231</td>
</tr>
<tr>
<td>0.6</td>
<td>0.6888</td>
<td>-0.6820</td>
</tr>
<tr>
<td>0.65</td>
<td>0.5782</td>
<td>-0.7610</td>
</tr>
<tr>
<td>0.7</td>
<td>0.7875</td>
<td>-0.5144</td>
</tr>
<tr>
<td>0.75</td>
<td>0.5678</td>
<td>-0.1042</td>
</tr>
<tr>
<td>0.77</td>
<td>0.4674</td>
<td>0.0261</td>
</tr>
</tbody>
</table>

Table 5.2: Validation of Test Case 1 by NRMSE values

It is seen that the DE is able to catch the behavior of the detailed network with reasonable accuracy even in such a zone, implying that the DE developed can be accepted as a good simplified representation of the detailed network. Additionally, it must be noted that the time to simulate the DE for similar disturbance as defined for the detailed network is also reduced. An average of five iterations showed that to perform a 2-second simulation on the detailed network, the system required 2.73 seconds while a similar simulation required only 0.26 seconds, representing a 90% reduction in simulation time. This is a tremendous improve-
5.2. Test Case 2

![Convergence of Optimisation](image)

Figure 5.5: Convergence of Optimisation

![Plots for retained voltage level of 0.30pu.](image)

Figure 5.6: Plots for retained voltage level of 0.30pu.

ment in computational speed and it can be safely assumed that this improvement in computational speed would be even significant for a much more detailed network than the one presented here. The table 5.3 lists the optimized parameters' values after performing the optimization.

It is important to bring to attention again that the analysis is based on producing equivalents that have satisfactory post-fault behavior. The performance of DE is measured by comparing the two curves. This is done by calculating the Root Mean Square Error (RMSE) of the two curves. The RMSE values are calculated in table 5.4.

Low RMSE values attest to the fact that the DE performs competently and can be used as a viable alternative for detailed networks in bulk system stability studies.
5.3. Result Analysis

The PVD1 model was developed to be a representative model for large distribution feeders with increased penetration of PV that could provide a reasonable post fault behavior for the grid. This is used for bulk system stability studies, where the equivalent model shown in figure 3.5 for test case 1 and figure 3.6 for test case 2, is plugged into the HV/eHV network for transmission system studies. Although a great DE, the PVD1 model has its own limitations. For cases where the detailed network model includes DG which are capable of not only riding through fault, but also support voltage in the grid by providing an additional reactive current injection (aRCI), the PVD1 model is not a very good DE. There is significant mismatch of P and Q curves during the fault part, which is attributed to the fact that in the current version of PVD1 model, reactive current injec-
Figure 5.9: Plots for retained voltage level of 0.50pu.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>PVD1 model</td>
<td></td>
</tr>
<tr>
<td>$V_{t0}$</td>
<td>0.8700</td>
</tr>
<tr>
<td>$V_{t1}$</td>
<td>0.89857</td>
</tr>
<tr>
<td>$T_g$</td>
<td>0.0410</td>
</tr>
<tr>
<td>$V_{rflag}$</td>
<td>0.3039</td>
</tr>
<tr>
<td>Load</td>
<td></td>
</tr>
<tr>
<td>Active Power</td>
<td>1.2693</td>
</tr>
<tr>
<td>Reactive Power</td>
<td>0.8425</td>
</tr>
<tr>
<td>Line length</td>
<td>95.9</td>
</tr>
</tbody>
</table>

Table 5.3: Test Case 2(1): Optimized Parameters

<table>
<thead>
<tr>
<th>$U_{ret}$</th>
<th>RMSE (P)</th>
<th>RMSE (Q)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.30</td>
<td>0.13</td>
<td>0.083</td>
</tr>
<tr>
<td>0.50</td>
<td>0.11</td>
<td>0.07</td>
</tr>
<tr>
<td>0.65</td>
<td>0.108</td>
<td>0.08</td>
</tr>
<tr>
<td>0.75</td>
<td>0.125</td>
<td>0.0645</td>
</tr>
</tbody>
</table>

Table 5.4: Root Mean Square Values for Active and Reactive Power curves.

In the absence of reactive current injection, the PVD1 model behaves in a perfect manner. Although the control parameter exists, it is de-activated because of the above reasoning. The next version of PVD1 model (called PVD2 model, developed by WECC) is expected to overcome this shortcoming and provide a better
representation of networks with aRCI equipped generator controls.

The PVD1 model has a great potential as an equivalent DE, specially for feeders with high penetration of distributed PV. This is possible if it’s parameters are accurately tuned. Tuning of the parameters requires data from the grid or from a detailed model simulation. Going into the future, DE can be tuned in real time for simulation studies if the data is directly available from the grid. The distribution system operator has to play a great role in providing this data by the installing phasor measurement units (PMUs). Providing data with PMUs ensures enough observability of phenomenon in real time, enabling the identified DE to be relevant to local operating conditions.
CONCLUSIONS AND CONTRIBUTIONS

The main conclusions of the research work are now presented. This involves discussion of few results. Afterwards the research questions that motivated this work are answered. Recommendations for future work are presented at the last.

6.1. CONCLUSIONS
Some important conclusions that can be drawn from the work are listed as follows:

1. Network reduction and simplification is an important aspect in the ever growing complex electricity infrastructure. Developing models that can represent the entire network topology very simply can greatly reduce computational time and resources.

2. A new dynamic equivalent in form of PVD1 model was introduced. The PVD1 model is able to accurately represent the PV and other forms of PE connected DG to the distribution grid.

3. The post fault dynamic response, which was our main focus, was analysed with root mean square errors. The RMSE representing the performance of DE are very low which implies that the identified parameters were determined with great accuracy.

4. A new method of determining parameters was developed. This method was developed using Python that can be utilized in other softwares as well. This makes this developed technique a very powerful and easy to use one. The user would just require to change the objective function as per his/her requirements.

5. The developed and identified DE is not developed for just one operating point or a particular technology as was the case with other research works. The developed method and DE is valid for the entire LV/MV distribution network consisting of various generation technologies and a range of operating conditions. This was validated by simulating the network models for faults other than those defined for parameter identification.

6. The developed technique can be used to apply on other power system non linear problems, one such application being optimal reactive power flow. This was used by another master student on her thesis project and the optimisation ran, giving very good results.

6.2. ANSWERS TO RESEARCH QUESTIONS
The research questions formulated at the beginning of this work are answered below:

1. How is the detailed network consisting of various DG at various voltage levels reduced to an equivalent model that can mimic the dynamic behaviour of such a complicated system? The PVD1 model developed by WECC consists of a protection logic that is able to simulate a percentage ride through of total generation. This model has its own limitations which were discussed in the results section. This PVD1 model has further scopes for development, but is seen as a viable option as a DE to replace for ADS in system stability studies. This is verified by the fitness values obtained in table.
2. How well do the controllers modelled for these systems respond to various sensitivities? How efficient is the algorithm in determining these parameters? The controllers were modelled and identified for a certain range of sensitivities. However, tests were also done to see how well these controllers and models respond to uncertainties and disturbances for which these models were not identified. Best fit values seem to suggest that the response was satisfactory and that the models behaved generally well for other disturbances.

3. How much computationally efficient does this make the system studies? How much time is saved in simulation for stability studies? The identified DE shows remarkable savings in time. The amount of time it now takes to simulate the test system 1 is reduced by 74%, while for test system 2, the reduction in simulation time is around 90%. This shows that our DE can be used effectively to reduce the computational overhead and fasten our analysis times for stability studies.

6.3. Contributions
1. Developed a deep understanding of Python and PowerFactory interaction that helped to create the optimisation code in Python to be applied to almost any PowerFactory optimisation problem.

2. Paper derived with the results obtained from the work accepted to workshop on Control of Transmission and Distribution Smart Grids CTDSG16.


4. Created a manual that detailed the integration of python with PowerFactory. This manual was used in the coursework for ET-4113 (Power System Dynamics) to help the students get acquainted with PowerFactory and Python.

6.4. Recommendations for Future Work
Despite the work carried out in this thesis, few assumptions and simplifications were used. Few aspects of this work were newly developed and thus still in rudimentary phase. Certain recommendations are thus to be made if further future work is carried out.

1. The optimization process makes use of 21 vectors and 2 matrices. These were created in PowerFactory via Python and accessed via Python. The optimisation process is expected to speed up significantly if all data processing is performed in python instead of PowerFactory. The use of Python’s NumPy and SciPy packages to create and use arrays and matrices would be useful in this regard.

2. The disturbances defined for each test case run for the time defined in the simulation dialog. These separate disturbances run in a sequential manner one after another. A way to speed up the process would be to introduce parallel processing. Parallel processing would enable runtime of more than one disturbance simulation of 4 seconds at a time by utilizing multi-core processing power of modern systems. Developing optimization code for multi-core parallel processing in python can be done to speed up the process of identification.
This appendix describes the network data of the two test cases in detail.

**A.1. Test Case 1: German Rural MV/LV Network**

The data for the test case was taken from the thesis work of Emanuel van Ruitenbeek. [14] provides in great detail the method of analysing the vast amount of data provided by German DSO. If specifics of topology derivation is needed, reader is referred to [14]. We concentrate on the network configuration. The peak load is approximately 12.6 MW. Ratings of various other elements in the network are as follows:

<table>
<thead>
<tr>
<th>Rated Capacity (MVA)</th>
<th>Short Circuit Voltage (%)</th>
<th>Losses (kW)</th>
<th>Parallel Transformers (#)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.4</td>
<td>4</td>
<td>3.85</td>
<td>171</td>
</tr>
</tbody>
</table>

Table A.1: MV/LV transformer specifications

<table>
<thead>
<tr>
<th>Rated Capacity (MVA)</th>
<th>Short Circuit Voltage (%)</th>
<th>Losses (kW)</th>
<th>Parallel Transformers (#)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>13.4</td>
<td>124.5</td>
<td>2</td>
</tr>
</tbody>
</table>

Table A.2: HV/MV transformer specifications

<table>
<thead>
<tr>
<th>R(Ω)</th>
<th>X (Ω)</th>
<th>Z (Ω)</th>
<th>B (µS)</th>
<th>R/X</th>
<th>Parallel Lines</th>
</tr>
</thead>
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<td>0.13</td>
<td>0.1885</td>
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<td>3</td>
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</tbody>
</table>

Table A.3: HV/MV line specifications

<table>
<thead>
<tr>
<th>Short Circuit Power (MVA)</th>
<th>Short Circuit Current (Ik&quot;max)</th>
<th>Bus Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>4000</td>
<td>21</td>
<td>Slack</td>
</tr>
</tbody>
</table>

Table A.4: External Grid Specification

The synchronous machines have been equipped with AVR models that are optimized, and GOV models that aren’t. The specifications for those are listed in tables A.5 and A.6. Here, A in ’Name’ is short for eHV-XX_-HV-XX_MV-02_SGCHP_ while B is short for eHV-XX_HV-XX_LV-02_SGCHP_.


### A. NETWORK DATA

#### A.5. AVR Data

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<thead>
<tr>
<th>Name</th>
<th>A_LVRT</th>
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<th>A_PF100</th>
<th>B_NEW</th>
<th>A_NEW</th>
</tr>
</thead>
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<td>0.025</td>
<td>0.025</td>
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<td>1</td>
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<tr>
<td>Tc</td>
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<td>2</td>
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#### A.6. GOV Data

<table>
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<th>A_LVRT</th>
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<th>A_PF100</th>
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<th>A_NEW</th>
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<td>T3</td>
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<td>1.1</td>
<td>1.1</td>
<td>1.1</td>
<td>1.1</td>
</tr>
</tbody>
</table>

### A.2. TEST CASE 2: IEEE 34-BUS STANDARD TEST FEEDER

The network data for the test feeder was taken from IEEE PES website [2]. The network is shown as in figure A.1. The details of the network are listed as in the following tables.
Figure A.1: IEEE 34 bus test feeder. Taken from [2]

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Phasing</th>
<th>Phase</th>
<th>Neutral</th>
<th>Spacing ID</th>
</tr>
</thead>
<tbody>
<tr>
<td>300</td>
<td>B A C N</td>
<td>1/0</td>
<td>1/0</td>
<td>500</td>
</tr>
<tr>
<td>301</td>
<td>B A C N</td>
<td>#2 6/1</td>
<td>#2 6/1</td>
<td>500</td>
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<tr>
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<td>B N</td>
<td>#4 6/1</td>
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<tr>
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<td>B N</td>
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Table A.7: Overhead line configurations
### Line Segment Data

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<th>Length(ft.)</th>
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<td>810</td>
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<td>812</td>
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<td>814</td>
<td>29730</td>
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<td>10</td>
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<td>888</td>
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<td>10560</td>
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Table A.8: Line Segment Data
## Table A.9: Regulator Data

| Regulator ID: | 1 |
| Line Segment: | 814 - 850 |
| Location: | 814 |
| Phases: | A - B - C |
| Connection: | 3-Ph, LG |
| Monitoring Phase: | A-B-C |
| Bandwidth: | 2.0 volts |
| PT Ratio: | 120 |
| Primary CT Rating: | 100 |
| Compensator Settings: | Ph-A Ph-B Ph-C |
| R - Setting: | 2.7 2.7 2.7 |
| X - Setting: | 1.6 1.6 1.6 |
| Voltage Level: | 122 122 122 |

| Regulator ID: | 2 |
| Line Segment: | 852 - 832 |
| Location: | 852 |
| Phases: | A - B - C |
| Connection: | 3-Ph, LG |
| Monitoring Phase: | A-B-C |
| Bandwidth: | 2.0 volts |
| PT Ratio: | 120 |
| Primary CT Rating: | 100 |
| Compensator Settings: | Ph-A Ph-B Ph-C |
| R - Setting: | 2.5 2.5 2.5 |
| X - Setting: | 1.5 1.5 1.5 |
| Voltage Level: | 124 124 124 |
### Distributed Loads

<table>
<thead>
<tr>
<th>Node A</th>
<th>Node B</th>
<th>Load Model</th>
<th>Ph-1 kW</th>
<th>Ph-1 kVar</th>
<th>Ph-2 kW</th>
<th>Ph-2 kVar</th>
<th>Ph-3 kW</th>
<th>Ph-3 kVar</th>
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<tbody>
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Table A.10: Distributed Loads Data

### Spot Loads

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<th>Load Model</th>
<th>Ph-1 kW</th>
<th>Ph-1 kVar</th>
<th>Ph-2 kW</th>
<th>Ph-2 kVar</th>
<th>Ph-3 kW</th>
<th>Ph-3 kVar</th>
<th>Ph-4 kW</th>
<th>Ph-4 kVar</th>
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<td>16</td>
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<td>16</td>
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<tr>
<td>840</td>
<td>Y-I</td>
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<td>7</td>
<td>9</td>
<td>7</td>
<td>9</td>
<td>7</td>
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</tr>
<tr>
<td>844</td>
<td>Y-Z</td>
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<td>105</td>
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<td>135</td>
<td>105</td>
<td></td>
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<tr>
<td>848</td>
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<td><strong>344</strong></td>
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Table A.11: Spot Loads Data
### Shunt Capacitors

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<th>Ph-C</th>
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<td>kVAR</td>
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<td>kVAR</td>
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<td>100</td>
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<td>Total</td>
<td>250</td>
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Table A.12: Capacitor Data

### Transformer Data

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<th>Substation</th>
<th>kVA</th>
<th>kV-high</th>
<th>kV-low</th>
<th>R - %</th>
<th>X - %</th>
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</thead>
<tbody>
<tr>
<td>XFM - 1</td>
<td>500</td>
<td>24.9 - Gr. W</td>
<td>4.16 - Gr. W</td>
<td>1.9</td>
<td>4.08</td>
</tr>
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</table>

Table A.13: Transformer Data
KEY MODELLING ASSUMPTIONS

While modelling, both the detailed and aggregated model, we take into account some key assumptions for modelling. These are listed for each model here.

B.1. PVD1 MODEL
The distributed PV model is in a way, simpler form of a Central PV station as mentioned in [31]. Key assumptions while implementing the PVD1 model are:

- The model operates in the cos(\(\phi\))-P characteristics control mode. It is a power factor controller where the power factor is determined by the specified limits.
- Closed loop voltage regulator dynamics are not considered. This is due to extremely small time constants involved with voltage regulators and do not affect the operation of our aggregated model.
- DC dynamics are not considered. These are ignored because of the same reason as above.
- Voltage and frequency tripping events following a disturbance are statistically uncorrelated.
- Certain modules like PV Temperature, Maximum Power Point Tracker, PV Irradiation, etc are marked out of service. This is done because it was seen that replacing them with constant values does not affect the analysis performed in this work. These were replaced by constants.
- The PVD1 model has been developed only for positive sequence networks. Therefore, fault conditions that include zero sequence components such as single line to ground faults, double line to ground faults etc are not valid for identification. It is for this reasons that none of the zero sequence components in the aggregated network are not optimized.

B.2. CHP MODEL
- All the CHPs are connected as directly coupled synchronous generators. While this may not be true for all the generators on the system, for simplicity, we make this key assumption. This assumption helps greatly to reduce the complexity of system modelling.
- CHPs use dynamic model by PowerFactory, with governor (DEGOV1) and exciter (EXAC1A). Type and exciter use data from manufacturers as much as possible.
- CHPs trip either due to undervoltage protection or for LVRT capable CHPs the angle relay is used to prevent transient instability. Disconnection angle set to 120 degrees since simulations without the angle relay showed that generators going beyond 120 degrees would eventually become unstable
- CHP PF095 are actually operated at PF100
B.3. **Wind Model**

- Wind DFIG model is standard DlgSILENT PowerFactory model.
- Wind FC model is standard DlgSILENT PowerFactory model modified by Jens C. Boemer.
- Dynamic models not relevant for the studied behaviour and time-frame are disabled. These are:
  - FC wind turbine model: OverFrequPowerReduction
  - DFIG wind turbine model: MPT, Pitch Control, Turbine, Shaft, Speed-Controller, OverFrequPwrReduction, Protection synch

B.4. **PV Model**

- PV model: Maximum Power Point Tracker, PV Module, PV Temperature, Active Power Frequency Reduction
- MV PV PF095 are actually operated at PF100
More Results

C.1. Results for Test Case 1: The German Rural Network
This section shows the remaining voltage levels that were not shown in the Results chapter. A similar conclusion can be drawn here as well. The curves show great accuracy in the post fault periods which underscores the effectiveness of MVMO as identification algorithm.

Figure C.1: Test Case 1: Retained voltage level of 0.60pu.
C.2. RESULTS FOR TEST CASE 2: IEEE 34- BUS TEST FEEDER

The results of the remaining 5 sub test cases of Test Case 2 are provided here. The Root Mean Square Errors (RMSEs) for these 5 test cases are shown next. First, a set of figures follow for various fault levels and then we produce the RMSE values for each fault point. The low values indicate a good fit. The effectiveness of MVMO is again highlighted by these results.
C.2. RESULTS FOR TEST CASE 2: IEEE 34-BUS TEST FEEDER

Figure C.4: Test Case 1: Retained voltage level of 0.77pu.

Figure C.5: Test Case 1: Retained voltage level of 0.80pu.

<table>
<thead>
<tr>
<th>Uret (pu)</th>
<th>RMSE (P)</th>
<th>RMSE (Q)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.3</td>
<td>0.145</td>
<td>0.098</td>
</tr>
<tr>
<td>0.4</td>
<td>0.122</td>
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</tr>
<tr>
<td>0.45</td>
<td>0.115</td>
<td>0.075</td>
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<td>0.5</td>
<td>0.102</td>
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<td>0.55</td>
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<tr>
<td>0.65</td>
<td>0.073</td>
<td>0.104</td>
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</table>

Table C.1: Test Case 2 (2): RMSE Values
Figure C.6: Test Case 1: Retained voltage level of 0.85pu.

Figure C.7: Test Case 2(2): Convergence Graph for optimization

<table>
<thead>
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<th>RMSE (P)</th>
<th>RMSE (Q)</th>
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</thead>
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<td>0.117</td>
<td>0.179</td>
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<td>0.4</td>
<td>0.107</td>
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<td>0.45</td>
<td>0.1</td>
<td>0.147</td>
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<td>0.5</td>
<td>0.092</td>
<td>0.139</td>
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<td>0.55</td>
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<td>0.65</td>
<td>0.346</td>
<td>0.172</td>
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</table>

Table C.2: Test Case 2 (3): RMSE Values
C.2. RESULTS FOR TEST CASE 2: IEEE 34- BUS TEST FEEDER

Figure C.8: Test Case 2(2): Retained voltage level of 0.35 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.9: Test Case 2(2): Retained voltage level of 0.4 pu. Red: Detailed Model. Blue: Aggregated Model

<table>
<thead>
<tr>
<th>Uret (pu)</th>
<th>RMSE (P)</th>
<th>RMSE (Q)</th>
</tr>
</thead>
<tbody>
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<td>0.127</td>
<td>0.096</td>
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<tr>
<td>0.4</td>
<td>0.116</td>
<td>0.093</td>
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<td>0.45</td>
<td>0.11</td>
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<td>0.5</td>
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<td>0.65</td>
<td>0.067</td>
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Table C.3: Test Case 2 (4): RMSE Values
Figure C.10: Test Case 2(2): Retained voltage level of 0.45 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.11: Test Case 2(2): Retained voltage level of 0.50 pu. Red: Detailed Model. Blue: Aggregated Model

<table>
<thead>
<tr>
<th>Uret (pu)</th>
<th>RMSE (P)</th>
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Table C.4: Test Case 2(2): RMSE values
C.2. Results for Test Case 2: IEEE 34-bus Test Feeder

Figure C.12: Test Case 2(2): Retained voltage level of 0.55 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.13: Test Case 2(2): Retained voltage level of 0.65 pu. Red: Detailed Model. Blue: Aggregated Model

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<th>Uret (pu)</th>
<th>RMSE (P)</th>
<th>RMSE (Q)</th>
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<td>0.073</td>
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<tr>
<td>0.65</td>
<td>0.068</td>
<td>0.098</td>
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</tbody>
</table>

Table C.5: Test Case 2(6): RMSE values
C. More Results

Figure C.14: Test Case 2(3): Convergence Graph for optimization

Figure C.15: Test Case 2(3): Retained voltage level of 0.35 pu. Red: Detailed Model. Blue: Aggregated Model
C.2. RESULTS FOR TEST CASE 2: IEEE 34-BUS TEST FEEDER

Figure C.16: Test Case 2(2): Retained voltage level of 0.4 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.17: Test Case 2(3): Retained voltage level of 0.50 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.18: Test Case 2(3): Retained voltage level of 0.65 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.19: Test Case 2(3): Retained voltage level of 0.75 pu. Red: Detailed Model. Blue: Aggregated Model
C.2. Results for Test Case 2: IEEE 34-Bus Test Feeder

Figure C.20: Test Case 2(3): Retained voltage level of 0.90 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.21: Test Case 2(4): Convergence Graph for optimization
Figure C.22: Test Case 2(4): Retained voltage level of 0.35 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.23: Test Case 2(4): Retained voltage level of 0.4 pu. Red: Detailed Model. Blue: Aggregated Model
C.2. RESULTS FOR TEST CASE 2: IEEE 34- BUS TEST FEEDER

Figure C.24: Test Case 2(4): Retained voltage level of 0.45 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.25: Test Case 2(4): Retained voltage level of 0.50 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.26: Test Case 2(4): Retained voltage level of 0.55 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.27: Test Case 2(4): Retained voltage level of 0.65 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.28: Test Case 2(5): Convergence Graph for optimization

Figure C.29: Test Case 2(5): Retained voltage level of 0.35 pu. Red: Detailed Model. Blue: Aggregated Model
C. More Results

Figure C.30: Test Case 2(5): Retained voltage level of 0.40 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.31: Test Case 2(5): Retained voltage level of 0.50 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.32: Test Case 2(5): Retained voltage level of 0.65 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.33: Test Case 2(5): Retained voltage level of 0.75 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.34: Test Case 2(5): Retained voltage level of 0.90 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.35: Test Case 2(6): Convergence Graph for optimization
Figure C.36: Test Case 2(6): Retained voltage level of 0.35 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.37: Test Case 2(6): Retained voltage level of 0.4 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.38: Test Case 2(6): Retained voltage level of 0.45 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.39: Test Case 2(6): Retained voltage level of 0.50 pu. Red: Detailed Model. Blue: Aggregated Model
Figure C.40: Test Case 2(6): Retained voltage level of 0.55 pu. Red: Detailed Model. Blue: Aggregated Model

Figure C.41: Test Case 2(6): Retained voltage level of 0.65 pu. Red: Detailed Model. Blue: Aggregated Model


