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LIST OF ABREVIATIONS

CABC	Chaotic Artificial Bee Colony
CHP	Combined Heat and Power.
CCGT	Combined-cycle Gas Turbines.
CAPSO	Coordinated Aggregation Power Swarm Optimization.
CDF	Cumulative Distribution Function
CVC	Coordinated Voltage Control.
CVD	Cumulative Voltage Deviation.
DG	Distributed Generation.
DER	Distribution Energy Resources.
ETS	École de Technologie Supérieure.
EPRI	Electric Power Research Institute.
GQ-GA	General Quantum Genetic Algorithm.
GA	Genetic Algorithm.
HSDO	Harmony Search Algorithm with Differential Operator.
HRSG	Heat Recovery Steam Generators.
IEEE	Institute of Electrical and Electronics Engineers.
IC	Internal Combustion.
IEA	International Energy Agency.
MT	Micro Turbine.

MINLP	Mixed Integer Non-linear Programming.
IMO	Multi-Objective Index.
MOPI	Multi-Objective Performance Index.
MO	Multi-Objective.
NREL	National Renewable Energy Laboratory.
NiCd	Nickel Cadmium.
NLP	Non-linear Programming.
OLTC	On-Load Tap Changer.
PV	Photovoltaic.
PEV	Plug-in Electric Vehicles.
PD	Population Diversity.
PSO	Power Swarm Optimization.
SC	Shunt Capacitor.
SGA	Single Genetic Algorithm.
SHP	Small Hydro Power.
VSF	Voltage Stability Factor.
WECS	Wind Energy Conversion System.

LISTE OF SYMBOLS AND UNITS OF MEASUREMENTS

P_{L_i} Active Power Losses at the i line [kW].

V_n Voltage at the n node [P.U].

V_n^{min} Minimum voltage limit [P.U.].

V_n^{max} Maximum voltage limit [P.U.].

V_{ref} Reference node voltage 1 [P.U].

P_{DG_i} Active power output at i DG unit [kW].

Q_{DG_i} Reactive power output at i DG unit [kVAR].

P_{Loss} Active power loss [kW].

Q_{Loss} Reactive power loss [kVAR].

PF_{DG_i} DG unit power factor.

P_{DG}^{min} Minimum limit for active power curtailment [kW].

P_{DG}^{max} Maximum limit for active power curtailment [kW].

Q_{DG}^{min} Minimum limit for reactive power injection [kVAR].

Q_{DG}^{max} Maximum limit for reactive power injection [kVAR].

PF_{DG}^{max} DGs Power factor maximum limit.

PF_{DG}^{min} DGs Power factor minimum limit.

Tap_h OLTC tap position at time h.

μ_{SR} Solar radiation mean.

σ_{SR} Solar radiation variance.

μ_L	Load demand mean.
σ_L	Load demand variance.
MW	Mega Watt
kW	Kilo Watt
m	Meter
km	Kilometer
^oC	Degree Celsius
s	Seconds
A	Amperes
kva	Kilo volt ampere
$kvar$	Kilo volt ampere reactive
F	Farad
Hz	Hertz
H	Hour
min	Minute
V	Volts
Ω	Ohm
CO_2	Carbon Dioxide
N_2O	Nitrous Oxide
SO_2	Sulfur Dioxide

INTRODUCTION

0.1. Background

The electric power system has been for many decades an efficient way to transmit power, from large and centralized production plants, to the homes and industries. The saturation of the network due the continuously growing demand, the concerns about the environmental impact of large electric power plants, changes in the consumer behavior, and the new technologies to harvest energy from renewable resources have change the traditional power production and transmission paradigm. Now, it is feasible to connect small generators to the feeders in a distribution system. In the literature, this connections are called Distributed generation (DG). In traditional power systems, the power flows unidirectional from the generation plants to the distribution system. DG generates power flows from feeders to substations, producing bidirectional power flow as stated by (Viawan, 2008).

The existing electric power system was not designed to operate with bidirectional power flow, or to accommodate generators into the distribution system, which is the most sensitive to losses and failures. DG has to be integrated after an extensive planning to avoid negative impacts in the network like voltage rise and interference with control elements. Generally, the most used method to avoid problems with DG, is to limit the amount of power the small generators can inject to the network, and to locate it near to the most congested load centers, although, these solutions do not exploit all the benefits that DG could bring to the network.

In the case of renewable sources like solar photovoltaic and wind, the intermittent nature of these sources presents an additional challenge to their interaction with the network control and stability. It is important to properly locate and determine the optimal amount of power that DG could inject to the grid, without negatively impact the network and maximizing the penetration of DG.

In distribution networks with DG presence, the distribution management system usually disconnects the distributed energy equipment in case of network failure as recommended in

(Basso and DeBlasio, 2004). Advanced control systems can take advantage of the distributed generators interfaces, and their fast time response for curtailment and reactive power output or absorption can be used as a new control element in the network. Nevertheless, the interaction of DG with traditional control devices as OLTCs could derive in interference and excessive control operations. Control actions of each element in the network have to be coordinated with the DG using centralized or coordinated voltage control methods.

The principal objective of this work is to address two principal factors that are present when DG is connected to the grid: Distributed generation units location, and proper control coordination with the system. Thus, a method to determine the optimal location and size of renewables DGs in an unbalanced network is presented. Additionally, this objective is complemented with a coordinated voltage control method to actively manage various renewables DGs units that will participate in the control process.

0.2. Methodology

The two principal objectives, allocation and voltage control, were addressed designing two multi-objective (MO) problems. These MO problems contain the individual objectives: active and reactive power losses, voltage stability, number of control operations, etc. Due the fact that the problems present a non linear behavior and are not concave, the solution method chosen was a genetic algorithm (GA) technique to find the global solution in an efficient way. The methods were tested using the IEEE-node test networks, wich are radial and unbalanced. Software OpenDSS (EPRI, 2015) was used to solve the power flow problem for the unbalanced networks.

0.3. Outline of the thesis

This thesis contains 5 chapters. Chapter 1 gives a literature review about the methods to the DGs allocation and the methods to perform coordinated voltage control with DG presence. Chapter 2 presents the software tools used in this thesis. An explanation of the principal features of OpenDSS software and a co-simulation example between OpenDSS (EPRI, 2014) and Matlab (MathWorks, 2014), are given. Chapter 3 gives an overview of the main distributed

generation energy resources. Chapter 4 proposes a method to optimally locate and size DG connections to an unbalanced distribution system. Chapter 5 proposes a method to determine the optimal settings of control elements, and outputs of DG plants in a coordinated voltage control scheme. Chapter 6 presents the conclusions of this work.

CHAPTER 1

LITERATURE REVIEW

1.1 Introduction

Distributed Generation (DG) is a new term that could refers, depending on the region of the world to: Decentralized Generation, Dispersed Generation, or Embedded Generation. The definition could be divided into different aspects as DG Location and Rating. The International Energy Agency (IEA, 2002) and (Ackermann *et al.*, 2001) agree that Distributed generation is an electric power generation unit that is located and connected to the distribution side of the network. While the Electric Power Research Institute (EPRI) adopts a definition for Distributed Energy Resources (DER), as smaller power sources that can be aggregated to provide power necessary to meet regular demand (EPRI, 2015). DG also can be defined or categorized based on their rating. As suggested by (Ackermann *et al.*, 2001):

Micro distributed generation: <5 kW;

Small distributed generation: 5 kW-MW;

Medium distributed generation: 5 MW-50MW;

Large distributed generation: >50MW;

According to (Koeppel, 2003), plants that exceed 300MW are not considered as DG.

Distributed generation includes a large group of energy sources and technologies. According to the type of resource can be classified into renewables and non-renewables. The most common source of renewable energy is photovoltaic and wind generators, which at the same time, are not dispatchable sources. The non-renewable energy sources more known small combustion engines powered with oil fuel.

Depending on the type of source, the technology of the generator and the interface with the grid can vary. For example, synchronous generators are used in combustion generators, or geothermal. While induction and permanent magnet generators are used with wind power, and hydropower. On the other hand, power electronic interfaces are of common use in photovoltaic and fuel cells. Nevertheless, generators and power electronics interfaces can be combined, as in the case of some wind power interfaces that use AC/DC/AC or AC/DC power converters.

1.2 Impacts of Distributed Generation on distribution networks

Distributed generators installations help to reduce some environmental impacts, that cause the traditional electric power system model expansion. DGs have generally fewer cost of installation. Transmission lines are no longer necessary, when DG units are located near the load demand. The environmental benefits are larger when renewable resources are used, generating economical benefits and ensuring the energy provisioning to the local region. Besides the economical and environmental benefits, DG can generate some impacts that should be considered.

Traditional distribution systems were conceived to manage an unidirectional power flow, were the energy flows from the substations to the consumers. The connection of various DG units along the radial system provokes bi-directional or multi-directional power flows. Therefore, the effectiveness of protection equipments as reclosers, breakers and fuses may be degraded, due the change of direction of power flow and the current fault levels (Balamurugan *et al.*, 2012).

The losses on a distribution network depend principally of two factors, resistance of the conductors and the current magnitude. To reduce the resistance in the conductors is necessary to invest in network upgrades (new equipment and modern conductors). The second factor has to do with current reduction. It has been demonstrated that the correct capacity planning and connection of DGs near the loads, can reduce the current level in the conductors, reducing the power losses. On the other hand, if the DG capacity is much higher than the load demand, the

power losses tend to increase (Méndez Quezada *et al.*, 2006). DG renewable sources are less effective in power loss reduction, due their intermittent behavior (Singhal and Ajjarapu, 2015).

The location and capacity of the DG also affect the voltage level in the distribution network. In a normal radial network, the voltage gradually decreases downstream to the loads. In contrast, DG presence cause a change in power flow direction. Reverse power causes voltage rise in the point of connection and near regions. If the DG capacity is high enough, a voltage limit violation could occur. In the same way, OLTCs and SVRs elements mechanism and sensors are not designed to bi-directional power flow. Thus, their operations can be interfered, causing unpredictable behavior in voltage level, deriving in voltage instability, (Abri, 2012).

1.3 Literature Review on Distributed Generation Allocation

Power losses in distribution and transmission networks occur when the current flow through electric lines, transformers and other electric equipments that present electric resistance. Consequently, there are two ways to reduce the power losses: Reduce the current through the power conductors or reducing the resistance of the conductors, the second requires increasing the quality of the conductor design, investing in conductors with better materials with minimum resistance. On the other hand, reducing the current requires to reduce the load in each feeders, by reducing the electric demand from the consumers.

Besides the traditional methods to reduce power losses, (Hoff and Shugar, 1995) demonstrate that power generators installed along the distribution feeders have the effect to reduce load losses. This is a result of supplying power to the load centers locally, reducing the current level in the distribution lines. Thus, DG location has a directly influence on power losses. In addition, the size of the DG has a direct relationship with the loss reduction or rise, depending of the specific network characteristics, load distribution, and the type of DG, (Ochoa and Harrison, 2011).

Optimum allocation refers to the study of the optimum location of DG connection and the optimum production level, without deteriorate the stability of the system.

Several studies have been addressed to find the optimum place and size of distributed generators in the network, either to reduce power losses or to improve voltage stability and regulation.

(Teng *et al.*, 2002) proposed a strategy to select the best DG type and the optimal place and size. The authors solve the problem using the value-based planning method, balancing the cost of DG installation and benefits, which include power loss and cost reduction, and improve of reliability. (Haesen *et al.*, 2005) describes a method to optimal placement and sizing of DG with the objective of power losses minimization. The method maintains the voltage profile within the nominal levels. The authors used the genetic algorithm (GA) to find the solution of the non-convex problem. (Kashem *et al.*, 2006) presents a technique to find the optimal operating point of DG and their location and size, using sensitivity analysis in function of power losses and voltage drop. (Ochoa *et al.*, 2006) presents a multi-objective performance index (IMO) to evaluate a distribution network with distribution generation presence. The IMO is used to analyze the impacts on power losses considering different power factor, location and DG size. (Celli *et al.*, 2006) proposed an evolutionary multi-objective method to find the optimal place and size of large amount of DG. The genetic algorithm is used to solve the MO problem. The objectives are the minimization of the capital, operational and energy losses costs, while maximizing the DG penetration. (Singh *et al.*, 2009) used the genetic algorithm optimization technique to find the best solutions for the multi-objective MO problem. The MO problem was based in performance indexes and used different load models. (El-Zonkoly, 2011) presented a multi-objective index based method to determine the size and DG location in a distribution network with no unity power factor and various types of load. The MO problem are composed, in order of importance, of the active power and reactive losses index, the current capacity index, voltage profile index and short circuit index.. The MO problem is solved using a particle swarm optimization (PSO) technique.

(Akorede *et al.*, 2011) stated that the improper DG allocation leads to power losses increment in distribution networks. Thus, the study proposed a single multi-objective. The problem is solved using genetic algorithm technique. A fuzzy control is used to manage the population diversity (PD). The study concludes that this technique is more robust than the single genetic

algorithm (SGA) methods. (Moradi and Abedini, 2012) presented an optimization method to locate and size DG using a combination of GA and PSO, with the objective to minimize power losses, and to improve voltage regulation and stability. (Al Abri *et al.*, 2013) proposed a voltage index method to place and size high penetration DG in a distribution network. The optimization problem is solved using mixed-integer nonlinear programming. The principal objective is to improve the voltage stability margin. This method is able to include the probabilistic nature of renewable DGs, like PV and wind generators. (Kayal and Chanda, 2013) used a new multi-objective PSO method to optimally locate arrays of wind turbine generation and photovoltaic units in a distribution system. A new index called voltage stability factor (VSF), is proposed as an efficient way to evaluate the impact of DG connection. The study concludes that DGs with lagging power factor offers more benefits to voltage profile in distribution lines. (Shaaban *et al.*, 2013) used a GA to find the optimal sizes and locations of DG. The objective functions considered in this work are the cost of system upgrade, energy loss, and costs of interruptions. Also, a variable load-generation model is taken into account to evaluate the method. (Kansal *et al.*, 2013) presents an optimal placement method for different types of DG. The authors use the PSO technique to solve the problem which includes the optimum size also. (Zhao *et al.*, 2014) solved the problem of the optimal location and capacity of DG in a distribution network, taking into account vulnerable nodes. Once the vulnerable nodes are identified, a genetic algorithm technique is used to solve the optimization problem. (Zeinalzadeh *et al.*, 2015) proposed a multi-objective problem to locate and size multiple DG and shunt capacitors in a distribution network. The MO problem is solved using PSO and Pareto optimal. The loads are modeled using fuzzy data theory. A method to find the optimum place and size for DG in a distribution network is proposed in (Kollu R., 2015). The method use harmony search algorithm with differential operator (HSDO) to solve the problem. The objective was to minimize active power losses and to improve the voltage profile. (Mohandas *et al.*, 2015) solved a multiobjective performance index (MOPI) problem for DG location and size using Chaotic Artificial Bee Colony (CABC) algorithm. The problem formulation includes active power loss, reactive power loss, voltage profile, and line flow limit index. (Gampa and Das, 2015) developed a multiobjective technique based on a genetic algorithm (GA) to optimal sizing of DG units. The sizing method

considers power loss reduction, line load reduction and voltage profile improvement. Also, investment costs included in the optimization problem. The location issue is solved separately using sensitivity analysis. The number of DG units to be allocated are not considered in the optimization problem. (Ganguly and Samajpati, 2015) presented a DG allocation technique that can work with uncertain variability of load and generation using triangular fuzzy number. The optimization problem is solved using the genetic algorithm. The objectives are to minimize the active power losses and the node voltage deviation.

1.4 Literature review on Coordinated Voltage control methods with Distributed Generation

Voltage regulation in a distribution system consists in keeping line voltages within the nominal limits. The traditional networks have regulations on the equipments that act locally to control the voltage levels. The most common equipments are on-load tap changer (OLTC) and shunt capacitors (SC). Their functioning is based on the premise that power flow is unidirectional, and can be regulated changing the turn ratio in transformers, or by the reactive power control that is directly related with voltage drop.

The connection of DG along the feeders in the distribution system changes the traditional model in which the power flows in one direction only, decreasing, from the substation transformer, to the feeders and the loads. This is due to the power generated in the DG units, that increases the voltage at the connection points. Thus, DG can interfere in the normal performance of voltage and reactive power regulation. Therefore, it is necessary to properly coordinate the DG units with the OLTC and shunt capacitors to avoid damaging the voltage profile and to not worsen the power losses.

In this section a literature review of various coordinated voltage control methods is presented.

(O'Gorman and Redfern, 2008) stated that the common practice is to avoid DG to act in the voltage control. Thus, authors proposed a method to control the voltage locally, at the point of common coupling (PCC) between the DG and the grid. Sansawatt *et al.* (2010) proposed a DG

decentralized control method for DGs. Using power factor and voltage control modes to keep the voltage levels at the connection bus between the limits. Also includes DG production curtailment capability in case of voltage rise. Local control methods allow to reduce the operation costs of DG and do not need communication channels to operate.

Another approach is to use the DG as an active control element in the distribution networks. DG as control element could offer many advantages due to their fast response to change their active and reactive power output. As proposed by (Dai *et al.*, 2004) and (Kim *et al.*, 2015). However, the control actions of the DGs, if are not coordinated, could interfere with the control actions of regulation equipment such as OLTCs, static var compensators, and SCs.

Borghetti *et al.* (2010) proposed the improvement of the Distribution Management Systems (DMS) from an active distribution network approach. When DG reaches important penetration levels, the network can take all the advantages of DGs: as an active and reactive power source and as a fast voltage control element. Additionally, the rest of the network resources could be coordinated with DG actions.

(Richardot and Viciu, 2006) proposed that distributed generation could act as an actively element in the coordinated voltage control (CVC) in a distribution network system. They proposed to apply the same control principles of transmission on the distribution network. The CVC aims to coordinate all the networks resources present at certain time, in order to optimize and to improve the power delivery and the quality of energy. Similar approaches have been proposed in various works. Tsikalakis *et al.* (2008) study the CVC approach to operate on line and off line microgrids with several types of DGs.

The optimization and coordination of several networks elements comprehends a combination of continuous (DG power output) and discrete variables (OLTCs and SCs control actions). Thus, the optimization problem becomes more and more complex. In this context, multi-objective solving techniques have been proposed.

(Viawan and Karlsson, 2008) presented an optimization method for CVC and reactive power control with and without DG. Authors conclude that the involvement of DG in the voltage control contributes in the reduction of losses and diminish the number of OLTC operations. Capitanescu *et al.* (2014) study a centralized optimization method to minimize the power curtailment of DG, taking into account traditional voltage control elements (OTLCs, SCs, and Remotely controlled switches) and DG operation modes. (Paaso, 2014), use a CVC approach in a multi-objective problem to minimize the power losses and maximize the power extracted from intermittent resources as PV.

Evolutionary algorithms are vastly used to solve this type of problems. The following works, use similar optimization problems using two of the most popular algorithms: Particle Swarm Optimization (PSO) and the genetic algorithm (GA). (Sarmin *et al.*, 2013) present a voltage and reactive power control strategy, using a mixed-integer nonlinear programming problem. The authors solve the problem using PSO. The optimization problem incorporates forecast data for the load and generation 24 hours ahead. (Vlachogiannis and Lee, 2006) uses a similar optimization problem approach. But, the problem is solved using a new particle swarm optimization algorithm called Coordinated Aggregation (CAPSO). (Kim *et al.*, 2015) presents a method to control the voltage in distribution networks, using DG as ancillary service to provide reactive power. The optimization method includes shunt capacitors and OLTCs in coordination with DG dispatch. The problem is solved using PSO. (Su *et al.*, 2011) use a binary PSO to solve the optimization problem. The method includes a coordinated network reconfiguration and volt/var control to limit the DG power injection at the connection point. Both, the load and generation are modeled as variable in time. (Senjyu *et al.*, 2008) proposed an optimal voltage control for distribution networks, using DG with OLTCs, shunt capacitors and voltage regulators to maintain an stable voltage level at feeders and to reduce the power losses. The genetic algorithm is used to solve the optimization problem. (Vlachogiannis and Østergaard, 2009) solved the optimization problem for a coordinated voltage control using the general quantum genetic algorithm GQ-GA. The method finds the optimal settings for various control elements in a distribution network including DG.

(Shivarudraswamy and Gaonkar, 2012) presents a method to determine the optimal set points of the control elements in a distribution network, including DG. The problem formulation use power losses reduction and voltage regulation. Additionally, the load and generation profile are considered time-varying. The problem is solved using the genetic algorithm technique. (Abapour *et al.*, 2014) proposed a multi-objective problem that minimize costs of active and reactive poser losses, by the coordination of control elements including DG. The proposed problem is solved using Non-dominated Sorting Genetic Algorithm. In (Azzouz and El-Saadany, 2014), authors developed a voltage regulation method that obtains the optimal settings for OLTCs and DG reactive power. Additionally, a new hysteresis controller for the OLTC is presented. The objective is to achieve proper voltage regulation and to reduce the number of tap operations.

CHAPTER 2

DISTRIBUTION NETWORK MODELING WITH OPENDSS

This chapter describes the software used to simulate the distribution networks used in this thesis. The methods described later in this work, needs to be tested on unbalanced radial distribution networks. Therefore, OpenDSS was used to obtain the power flow solutions, and MATLAB was used to run the optimization algorithms.

The traditional electric distribution network has resisted decades without mayor improvements or changes. Distribution networks were designed under the premise that customers, only could be passive consumers. Nevertheless, awareness about the environmental and economics benefits of energy efficiency and distribution generation, have been changing the way companies and consumers consider the distribution network. Modern distribution networks are including distribution generation, new control systems, active demand, etc.

The traditional modeling of distribution networks work with balanced networks, and unidirectional power flows. For traditional systems, simulations under this constraints, give a very good approximation of the steady state of the network. On the other hand, the modern distribution systems requires simulation tools that allows to work with bidirectional power flows, distribution generation models, unbalanced networks, time varying demand and generation profiles, etc.

OpenDSS is a distribution system simulator that fits with the new challenges of distribution systems.

2.1 OpenDSS

In this section, OpenDSS software is described, most of the content of this section is based on its reference guide by (Dugan, 2012).

OpenDSS is a distribution system simulator. DSS means Distribution System Simulator. It is an open source software supported by the Electric Power Research Institute (EPRI). The basic implementation is an executable program script-based, and numerical and graphical solutions. The second possible implementation is a COM server DLL which can be used from third platforms as Matlab, Excel VBA, Python, etc. This feature permits to increase the variety of uses and applications that OpenDSS could perform. The software supports rms steady-state analysis. Although the software was originally intended to simulate distributed generation. OpenDSS can simulate more complex features like harmonics analysis, energy efficiency and smart grids applications.

The principal applications are:

- Distribution Planning and Analysis.

- General Multi-phase AC Circuit Analysis.

- Analysis of Distributed Generation Interconnections.

- Annual Load and Generation Simulations.

- Risk-based Distribution Planning Studies.

- Probabilistic Planning Studies.

- Solar PV System Simulation.

- Wind Plant Simulations.

- EV Impacts Simulations.

- Development of IEEE Test feeder cases

Some of the solution modes implemented in OpenDSS are:

- Snapshot mode: Which is a direct power flow execution that reflects the actual steady state of the network.

- Daily mode: This mode performs power flow and control solutions for each time increment. 1 hour increment for 24 hours for default.

- Yearly mode: Performs solving actions for 8760 hours, the time period can be changed from 1 hour to any interval.

- Dutycycle mode: Small time increments in seconds.

- Harmonics.

- Dynamics transients.

- Fault study and Monte Carlo fault study.

The COM interface permits to increment the number solution types, which can be adapted according to the necessity of the researcher or user. OpenDSS can execute this solutions in radial distribution networks models and meshed distribution systems, where the circuit model can be multi-phase and unbalaced.

There are two posible power flow solutions: iterative and direct. By default, the iterative solution is performed each time. The Iterative solution considers loads and DG as injection sources. While the Direct solution take loads and generators as admittances, to be solved without iterations.

Fault studies also can be performed in OpenDSS. In three ways: A conventional fault study for all phases and circuit elements. The snapshot fault, where the user could place specific type of faults and locations. And Monte Carlo fault study, the user select specific elements and locations, and the program randomly chooses one fault at a time.

It is also possible to perform harmonic analysis, due the fact that OpenDSS is actually a frequency domain circuit solver. After doing a power flow solution, then, the harmonic solution is executed for each frequency the user sets. Loads, generators, voltage and current sources participate in the harmonic solution. Additionally, PV system model and Storage model could be considered for harmonic solution.

The Dynamic solution mode allows to simulate electromechanical transients of generators. The generator dynamic model is a single-mass model. To more sophisticated generators models, the user has to create a new DLL generator model, or to use a third party program to control the generator.

2.2 Simulation of a Medium Voltage Network with OpenDSS.

A brief introduction to the basic commands for the script interface of OpenDSS is presented. Then an example of an unbalanced 13-node distribution network with time varying load and a PV distributed generator is exposed in this section.

The stand-alone installation of OpenDSS permits to enter the functions and commands in text format, in any order. The compiler organizes the scripts of each circuit element and creates the components and the complete system.

2.2.1 New Circuit

To create a new circuit, it is necessary to determine the base frequency. the command: "Set defaultbasefrequency=60" should be used to do this action.

It is important to set the voltage source for the circuit, which should be considered the reference bus, necessary to initiate the power flow. It can be defined through a line or a transformer. The command that defines the voltage source should have this format:

New circuit.ExampleName basekv=115 pu=1.00 angle=0 Bus1=SourceBus R1 = Value X1 = Value R0=Value X0=Value phases=3.

Where "Bus" is the bus connected to the source. "basekv=" is the line to line voltage in KV. With "pu=" the voltage level at the source can be set in p.u. units. "Angle=" determines the phase base angle in degrees. Also, it is possible to set the positive and zero sequence of the resistance and reactance of the source with "R1=,R0=,X1=,X0=" respectively.

2.2.2 Transformer

The substation transformer can be defined using:

"New Transformer.ExampleTrans phases=3 windings=2 wdg=1 bus=SourceBus wdg2 = 2 bus = Bus.Name conns=(delta,wye) kvs=(115,4.6) kvas=(5000,5000) xhl=(8 1000 /) %loadloss=0"

The user specifies the number of phases, and the number of the windings. With "kvs=" and "kvas=", the base rated voltage and KVA of each winding is set. "xhl=" allows to set the high winding to low winding reactance. And the percent of losses in the transformer is represented with "%loadloss=".

A regulator transformer could be included following this format:

"new regcontrol.RegExample transformer=ExampleTrans winding=2 vreg=122 band=2 ptratio=20 ctprim=700 R=3 X=9".

"Ptratio=" specifies the ratio of the Potential Transformer that converts the controlled winding voltage to the regulator voltage, the default value is 60. "band=" is the bandwith of the controlled bus in volts. "CTprim=" defines the rating of the primary CT for the line current to control current, in Amperes. "R=" and "X=" set the value of the line drop compensator in Volts.

2.2.3 Lines

To define the lines of a distribution system, we should first set the "linecode", which specifies the line admittance matrix. Various lines can use the same "linecode". Nevertheless the admittance values can be written directly in the "line" command script.

"New linecode.codeExample nphases=3 R1=1.3292 X1=1.3475 units=km".

"New Line.lineExample Phases=3 Bus1=Bus1.name Bus2=Bus2.name LineCode = codeExample Length= 0.25 units= km"

To define the line, it is necessary to establish the two connection buses, the "length" of the line, the longitude unit and the number of phases.

The linecode with a larger admittance matrix could be written as follows:

"New linecode.lineExample nphases=3 rmatrix = (0.3465 | 0.1560 0.3375 | 0.1580 0.1535 0.3414) xmatrix = (1.0179 | 0.5017 1.0478 | 0.4236 0.3849 1.0348) units=km"

2.2.4   Loads

The load element is defined through its nominal active and reactive value "kW" and "kvar" respectively. Additionally, the load script accepts various properties as follows:

"new load.loadExamplebus1=B phases=3 Conn=Wye kV=33 kW=5000 kvar=1640 model=1 model=1"

When the reactive value of the load is not defined, the power factor should be set with "pf=". There are different load models available in the program:

- Model 1: constant P and Q.

- Model 2: Constant impedance load.

- Model 3: Constant P and quadratic Q.

- Model 4: Linear P and Quadratic Q.

- Model 5: Constant P and constant current.

- Model 6: Constant P; and Q fixed nominal value.

- Model 7: Constant P; and Q is fixed impedance at nominal value.

- Model 8: ZIP model.

Load variability can also be included in the command: "Daily=", "yearly=" or "Growth=" are used to call the load shapes that will determine the load behavior on daily, yearly or duty simulation modes.

2.2.5 Control Modes

The default control mode in OpenDSS is "Static". The sentence "set controlmode=OFF", turns off all control actions.

In mode static, time is not considered, and the control actions are executed for each power flow solution. This mode is the standard for snapshot, daily and yearly mode.

Modes Time and Event realize control actions driven by a time or a event, respectively.

2.2.6 Solution Modes

With the command "Mode=" the type of solution for the active circuit can be set. There are various solution modes. To solve the circuit for a specific configuration without time variation modes Snapshot and Direct could be used. The mode Snapshot is preferred when loads need to be modified.

Modes Daily, Yearly and Dutycycle, perform a series of solutions following a time load profile or an specific increment as in the case of Dutycycle.

2.2.7 Monitors and Meters

The Monitor object is a power monitor that is connected to any terminal of the circuit. Records the variables of voltage, current and power of all phases. The monitor exports the data in a CSV file.

The code has the following format:

"new monitor.MonExample element=transformer.Example terminal=1 mode=0"

With "Element=" as the circuit element where the monitor is connected. "Terminal=" is the terminal of the circuit element, could be defined as 1 or 2. Monitor can observe various variables depending of the configured "Mode=". "0" is the standard mode that records, Voltage, Current, and complex values. "1" records the power of each phase. "2" the Tap changes of a regulator. "3" records the state variables.

The EnergyMeter object is an energy meter which can be connected to any circuit element. Registers the exports and imports of energy, consequently, losses and overload values. Not only at its point of connection, but at a defined region in the circuit.

The command can be written as:

"new energymeter.ExampNetwrk element=transformer.TranExample terminal=1"

The Monitor and EnergyMeter can export data after the solution command "solve". The commands "monitor.MonExample.action=take" and "energymeter.ExampNetwrk.action=take" should be written in order to record all the values. After, the commands "export monitor MonExample" and "export meters" are used to export the data to the CSV files.

2.2.8   Simulation of a 13-node distribution network.

The Distribution Test Feeder Working Group, affiliated to the IEEE Power and Energy Society, published various test-feeder models. These test-feeders are used by researchers to evaluate and test unbalanced three-phase radial system new algorithms (PES, 2013). One of these test-feeder cases is the 13-bus Feeder, used in this thesis.

The IEEE 13-node test feeder is a small three phase unbalanced distribution system. It has short and high loaded, it has only one substation with three phase voltage regulator. Overhead and underground lines (Kersting, 1991). The one line diagram is shown in Fig. 5.3.

First the circuit is declared: "new circuit.IEEE13Nodeckt basekv=115 pu=1.0001 phases=3 bus1=SourceBus Angle=30 MVAsc3=20000 MVASC1=21000"

The substation transformer code is: New Transformer.Sub Phases=3 Windings=2 XHL=(8 1000 /) wdg=1 bus=SourceBus conn=delta kv=115 kva=5000 %r=(.5 1000 /) XHT=4 wdg=2 bus=650 conn=wye kv=4.16 kva=5000 %r=(.5 1000 /) XLT=4

Note that values can be written in polish notation.

Voltage regulators have the following code, for one phase:

New Transformer.Reg1 phases=1 XHL=0.01 kVAs= [1666 1666] Buses= [650.1 RG60.1] kVs= [2.4 2.4] %LoadLoss= 0.01 new regcontrol.Reg1 transformer= Reg1 winding= 2 vreg= 122 band= 2 ptratio= 20 ctprim= 700 R= 3 X= 9.

Lines and loads can be defined as follows.

"New Load.671 Bus1= 671.1.2.3 Phases= 3 Conn= Delta Model= 1 kV= 4.16 kW= 1155 kvar= 660". "New Load.634a Bus1=634.1 Phases=1 Conn=Wye Model=1 kV=0.277 kW=160 kvar=110".

"New Line.650632 Phases= 3 Bus1= RG60.1.2.3 Bus2= 632.1.2.3 LineCode=mtx601 Length= 2000 units=ft" "New Line.632670 Phases= 3 Bus1= 632.1.2.3 Bus2= 670.1.2.3 LineCode= mtx601 Length= 667 units= ft"

The 13-node test system have many more elements, the complete code and circuit definitions are in Appendix 1. The script interface looks like in Fig. 2.1

After solving the circuit it is possible to show some results, with the command "Show".

For example:

- "Show Voltages LN Nodes"

- "Show Losses"

- "Show Taps"

Figure 2.1   OpenDSS script interface

Which results in pop-up notepad windows, as shows the Fig: 2.2

Figure 2.2   Node voltage, circuit losses and taps movements
presented in text interface

The script interface also has the feature that allows to show graphics results. With the command
"plot profile phases=all", a graphic showing the voltage profile is obtained. Fig. 2.3

Figure 2.3   Voltage profile for the 13-node test system

2.3   Co-simulation OpenDSS with Matlab

In this section, a distributed generator is connected to the 13-node test system. Also, a load profile to vary the load level during the day, and a production profile to emulate the intermittent behavior of the PV panels is incorporated, using MATLAB as the programming interface.

Through MATLAB, scripts and commands can be entered to the main simulation engine of OpenDSS. In the same way, OpenDSS simulation engine can export results and scripts to MATLAB through the COM interface. In the Fig. 2.4 (Dugan, 2012) the OpenDSS structure can be appreciated.

Figure 2.4   OpenDSS structure

2.4   OpenDSS-MATLAB initiation

From a new MATLAB .m file, the commands used to initiate the COM interface are:

"[DSSStartOK, DSSObj, DSSText] = DSSStartup;"

In the example presented here, the main simulation engine will solve the power flow of the 13-bus system, as in the last section. The PV system, load profile, daily simulation, and control schemes, will be commanded from MATLAB interface and sent to the OpenDSS core. Both, .dss file and the .m file should be placed in the same file path.

On the editor window in MATLAB, the script which calls the file circuit from OpenDSS is:

```
1   if DSSStartOK
2       DSSText.command='Compile (C:IEEE13Nodeckt.dss)';
3       DSSCircuit=DSSObj.ActiveCircuit;
4       DSSSolution=DSSCircuit.Solution;
```

2.4.1 Load Shapes

The load shapes, for the load demand and the production curves, are important to perform the sequential power flow solutions. In this example, the interval between values is 1hr for 24hrs, 24 values in total.

The matrix of values can be entered in the line command, or be called from a .csv file. In the command line the number of points is defined with "Npts=". Those values are multiplied with the base kW values of loads or DG capacity.

Let the loadshape be called: daily. And the production curve: MyIrrad, which correspond to the irradiation values of the PV panels. These values are represented in chapter 5, Fig.5.2

```
1 DSSText.Command = 'New loadshape.daily npts=24 interval=1
2 mult=(0.3 0.3 0.3 0.35 0.36 0.39 0.41 0.48 0.52 0.59 0.62 0.74...
3 0.87 0.91 0.94 0.94 1.0 0.98 0.94 0.92 0.61 0.60 0.51 0.44)';
4 DSSText.Command = 'New Loadshape.MyIrrad npts=24 interval=1
5 mult=[0 0 0 0 0 0 .1 .2 .3 .5 .8 .9 1.0 1.0 .99 .9 .7 .4 .1...
6 0 0 0 0 0]';
```

In the same way the solution mode and the control mode should be written:

```
1 DSSText.Command = 'set mode=daily';
2 DSSText.Command = 'Set controlmode=static';
```

2.4.2 Photovoltaic system simulation

A very useful feature in OpenDSS is the PVsystem Element Model, developed by the (EPRI, 2011). The last version of the DLL model, implements a PV array model and the PV inverter. For its use, it is necessary to declare the "XYcurves". The points in the commands describe

how the active power max power point P_{mpp} varies with the rated temperature at kW/m^2. The other array represents the efficiency curve fro the inverter.

```
1  DSSText.Command ='New XYCurve.vv_curve npts=4 Yarray=
2  (1.0,1.0,-1.0,-1.0) XArray=(0.5,0.95,1.05,1.5)';
```

Then, the internal state variable has to be setup. The "irradiance=" sets the net irradiance after the load shape application. The "panelkW=" is the net power in kW, in function of the irradiance and the temperature. Alternatively, "kVA" and "pf=", apparent power and power factor. For more detailed description, PVSystem Object manual is available in the installation folder of OpenDSS.

```
1  DSSText.Command ='new PVSystem.plant4a phases=3 bus1=680
2  kV=4.157 kVA=1500 irradiance=1 Pmpp=1728 pf=1 daily=MyIrrad';
```

2.4.2.1 Inverter Control

The inverter control object in OpenDSS is named InvControl. Basically, this element, control the PVSystem Object, in three possible ways:

- Intelligent Volt-Var Function.

- Volt-Watt Function.

- Dinamic Reactive Current Function.

In this example, the Volt-Var function is used. In this function, the inverter controls the vars response based on the voltage at the point of connection, and the available KVA at determined time. The command permits to enter a vector of number that describes the volt-var curve, where the user can configure a dead-band or a hysteresis interval, (Smith, 2013).

The command to be entered in matlab is as follows:

```
1  DSSText.Command ='New InvControl.InvPVCtrlb mode=VOLTVAR
2  voltage_curvex_ref=rated vvc_curve1=vv_curve EventLog=yes';
```

Fig.2.5 shows the code in the matlab editor. For this example two PV plants, with a capacity of 1.5MW are connected to the nodes 680 and 671 respectively. The total capacity of the PV plants equals the total power of the 13-node test system. The complete code can be found in the Appendix 2 of this thesis.

Figure 2.5   OpenDSS code in MATLAB editor

2.4.3   Simulation and results

From Matlab, all data generated from OpenDSS can be used. Any type of graphics can also be performed.

For example, voltage from the three phases of node 680 can be graphic to see the impact of the PV plant, at the point of connection.

In Matlab, command "DSSCircuit.ActiveBus.puVoltages; " and "DSSCircuit.losses" are used to extract voltage values and losses from the circuit. These commands are written after the "DSSCircuit.SetActiveBus('680')" in order to consider only the bus 680.

By creating an iterative loop for 24 solutions, Fig. 2.6 is obtained. Where it can be observed a comparison for the voltage levels variation, within 24 hours, before and after the PV connection at bus 680.

Figure 2.6   24 hour voltage variation at point of connection bus 680

As an example, of the COM interface utility a 3D graphic showing the voltage profile of all 13 nodes variation during 24 hours was generated as shown in Fig. 2.7.

Figure 2.7   Voltage variation at all 13-nodes during 24 hours.

CHAPTER 3

DISTRIBUTED GENERATION TECHNOLOGIES

3.1 Introduction

This chapter presents a revision of various distributed generation technologies, and the principal challenges with their connection to the distribution network. The concept of distributed generation is scattered, but generally refers to small scale generation as stated in the introduction of this thesis. Units categorized as distributed generation consist in a compendium of several technologies including traditional generators (Combustion Engines) and non-traditional generators (Fuel cells, Storage devices, Renewables), (El-Khattam and Salama, 2004). In the same manner, traditional generators can be named as dispatchable and renewables sources as non-dispatchable due to their intermittent nature. The best examples are Photovoltaic and wind generators. Distributed generators, depending on the local regulation can be owned by consumers, private investors or by the utilities.

Every DG technology presents different challenges depending of the energy source, availability, capacity and connection to the grid. However, the proper addressing of these issues generates technical and economical benefits.

3.2 Combustion Engines

3.2.1 Internal Combustion Engines

Internal Combustion Engines are one of the most traditional and mature technologies used as distributed generation. Internal combustion engines (ICs) converts the explosion energy created by the combustion in mechanical energy, which drives the electric generator. The installed capacity of ICs could be from 1kW to 5MW, the capital cost are reduced compared with other technologies. Combustion engines are preferred as backup power systems and distributed generation. This is due to its fast start up and simple control. On the other hand, exist some

important challenges with ICs, like: Unpredictable fuel cost, high cost of maintenance, and high contaminant gas emissions CO_2, N_2O, SO_2. (Dean *et al.*, 2011) stated that the price for KW is around \$900 to \$3000, and the efficiency is 21.3 to 44 percent. Thus, the convenience of 24/7 use of ICs is at least debatable.

3.2.2 Gas Combustion Turbines

A gas turbine produces mechanical energy, expanding great amount of air from a compression and heated process. An electric generator converts the mechanical energy into electrical energy. The capacity of gas turbines are larger than ICs, from 30kW to 250MW, with an efficiency around 30 to 45 percent. Also, estimated cost per KW is about \$2000, (Dean *et al.*, 2011). Although, gas combustion turbines produce less pollutants than ICs, they still produce contaminants as nitrogen oxides and carbon monoxide. (EPA, 1995)

3.2.3 Micro-turbines

A Micro-Turbine (MT) is a small capacity combustion engine with a capacity limited between 25-500 kW. It can be driven by natural gas, hydrogen, propane or diesel. The efficiency is about 20-30 percent with the use of recuperation system, which recuperates the heat from the exhaust system and reincorporates in the air entrance, boosting the air temperature. Also, its characterized by low emission of nitrogen oxides (Capehart, 2014). MTs are a gaining adoption because its reduced size, light weight compared with ICs and reduced maintenance costs due the less number of moving parts, (El-Khattam and Salama, 2004).

3.2.4 Combined Heat and Power

Combined Heat and Power (CHP) is a compendium of system that seeks to use the residual heat from a combustion engine to generate electricity or to use it for heating. CHP increments the overall efficiency of power generation technologies based on gas and fossil fuels. For example, an internal combustion engine increment its efficiency from 44% to 80% using CHP. In the

same way, gas turbines with CHP increments their efficiency to 85% (Dean *et al.*, 2011). In theory, any combustion engine produce heat as secondary product that is dissipated into the air. CHP system consists in the same structure of combustion engines, but, includes heat recovery and transfer systems. CHP systems based in gas turbines, incorporates Heat Recovery Steam Generators (HRSG) to high pressure steam generation. The Combined-cycle Gas Turbines (CCGT) increments the efficiency of HRSG systems, which use a steam turbine with a back pressure system as stated by (Lako, 2010).

3.3 Fuel Cells

This distributed generation technology generates energy using chemical reactions. Unlike combustion engines, the fuel used in the fuel cell does not burn, thus avoiding the waste of excessive heat. Basically, fuel cells have the structure of a battery, with an anode and a cathode, separate by an electrolytic membrane. Oxygen and hydrogen are pushed through the membrane, the atomic reaction creates free electrons from the hydrogen atom, generating an electric current. The product is a molecule of water and some heat (El-Khattam and Salama, 2004). Fuel cells capacities varies from 1kW to 3MW (Dean *et al.*, 2011).

Fuel cells have the lowest emissions compared with engines technologies and efficiency between 40 and 60 percent. On the other hand, they has the highest capital and maintenance costs, (Dean *et al.*, 2011).

3.4 Storage Devices

These devices that store energy, traditionally used for backup purposes. In distribution generation are used to supply power during high demand periods. And, they can be used to smooth the production curve of intermittent sources as photovoltaic and wind generators. Batteries and flywheels are classified as storage devices (Srivastava *et al.*, 2012).

3.4.1 Flywheels

Flywheels are storage device that have a mechanical storage mechanism. The mechanism is a rotating mass that is connected to a motor and to a generator. They take the energy from the motor, store this energy as a kinetic energy. As the kinetic energy is drained, the flywheel rotation velocity decreases, and this energy is converted to electricity for the generator connected. The variable output frequency and power are driven for the power electronic interface. Many systems permit to combine the motor and the generator in a single device then reducing its complexity and its size. New materials and power electronics have increased the flywheels input and output capacity, and determine charge cycles as large as 90000 charge-discharge cycles, and have a capacity of about 400 kW (Hebner *et al.*, 2002).

3.4.2 Batteries

Batteries are the most know devices to store energy. This technology is in use for more than a century, it consists in an array of cells containing an anode and a cathode linked by an electrolyte compound to facilitate the flow of electrons. Their applications on distributed generation are in backup for PV and wind systems. They are also used to smooth the production curve of DG sources and to improve the energy quality parameters, (Srivastava *et al.*, 2012) and (Carrasco *et al.*, 2006). Future use of batteries at great scale, is the use of Plug-in Electric Vehicles (PEV) connected to the grid to sustain network parameters and supply energy during peak hours (Han *et al.*, 2012).

Batteries can be classified after their depth of discharge, cost, charge cycles, efficiency and maturity of the technology. The technology refers principally to the chemical used, the lead batteries are: Lead acid, Lithium Ion, Sodium Sulphur (Nas), Nickel Cadmium (NiCd) and Zinc Bromide. Lead acid and NiCd are the most mature technologies in batteries, and have an average efficiency between 72-78%, and a lifespan of over 3000 cycles. For DG applications lead acid batteries are preferred due its low cost (Coppez *et al.*, 2010).

3.5 Renewables

Power generation with zero emissions is possible using renewable resources as wind, sun, geothermal and hydro power to cite the most popular. Although, there exist multiple techniques to obtain energy from many other sources knowing as energy harvesting, In this section, they will not be taken into account due the reduced energy production and the immaturity state of the technology.

3.5.1 Photovoltaic generators

Photovoltaic (PV) generators are devices that generates electric current from a semiconductor material interacting with light energy. A photon impacts a semiconductor layer moving electrons to another cell, creating a current flow. Electricity produced for PV is DC, AC is obtained with the help of inverters connected to the PV arrays (FEMP, 2012).

Solar power is a wide available resource, but the efficiency of PV technology is highly dependable of clear sky. Clouds shadow reduces the power output of PV panels. Thus, proper geographic location is a restriction for the use of this technology (El-Khattam and Salama, 2004).

The principal components of PV technology are: PV array, inverters, and in some cases, battery banks. The PV modules is the principal part, it converts solar energy into electricity. Generally, a typical solar panel is manufactured to operate for 25 years. Is the most robust part of the system, and the maintenance cost is very low, compared with other technologies. The inverter converts DC power to AC, used in most applications. Further, modern inverters are capable to synchronize their frequency with the grid, for grid-connected applications. Some PV system includes battery banks to storage energy produced by the panels during sun light hours, and provide energy at night time, (FEMP, 2012).

The principal DG applications are: PV panels roof mounted, where, each home should be connected to the grid, inverters should be frequency synchronized and PV plants to sizes from

1 to 10MW. Special planning and operation have to take place in order to obtain the mayor benefits. PV plants could be connected in parallel to the grid, the power interface is responsible to disconnect the system when a fault is detected, (Basso and DeBlasio, 2004). PV plants also can be connected to distribution networks. Besides providing energy, they are being used to control voltage and power, and to reduce losses. (Thomson and Infield, 2007) and (Smith, 2013).

3.5.2 Wind Turbine generators

Wind turbines transform wind power into electric energy. In a complete wind energy conversion system (WECS), the turbine converts the wind power to mechanical power, then it is converted to electric energy by the electric generator integrated. The atmospheric and geographic factors determines the amount of output power (Zahedi, 2015). Traditionally, the mechanical rotor frequency has the same grid frequency, creating limitations in the amount of power delivered by the WECS, and quality issues. But, current technologies like variable-speed wind turbines, where rotation frequency is decoupled from the grid, increments the efficiency and expands the applications of wind generation systems on distributed generation.

Variable speed wind generators, includes modern AC-DC-AC converters. Allowing WECS to be connected on electric power distribution systems, and to be used on control applications, because the power electronics interface permits to vary the active and reactive power output faster than traditional control devices (Hunyár and Veszprémi, 2014). Also, the inertia of the rotor could be used in frequency stability support on fault cases (Zhang *et al.*, 2013). Additionally, the power electronic interface creates a DC link, between the AC converters, this DC link is used to connect the WECS to storage devices (Aktarujjaman *et al.*, 2006). Other power generators like PV can be connected to this DC link, which is named hybrid generation (Wang and Lin, 2007).

Wind turbines have in average 30 years of life expectancy. To large installed generation projects >1.5MW, the cost per kW is between $1,800 and $2,000. This cost increment as the project

power installed capacity diminish. The maintenance cost increments with the installed capacity, about \$50,000 per year (Dean *et al.*, 2011).

3.5.3 Geothermal generators

Power generation with geothermal energy is another renewable energy that relies in the heat and hydrothermal fluids emanated from the earth. It is possible to use high pressure vapor and high temperature water 100 to 200°C, and moderate temperature water. The pressure of the hot fluids is used to move a turbine generator, (Duffield and Sass, 2003).

The interest of this source of clean energy is increasing. By the year of 2015 is reported that a 12.8GW capacity is installed globally, and it is expected to reach a global 17.6GW by 2020, (Matek, 2015).

3.5.4 Small Hydropower

Hydropower is one of the oldest sources of energy, and one of the first sources to generate electricity at large scale. The kinetic energy of moving water bodies like rivers, and waterfalls, is used to move a turbine which is connected to an electric generator. Small hydropower (SHP), become of interest the last decades, because its less impact to the environment and the benefits to the local community in remotes areas, (Singh, 2009).

Hydropower plants which produce less than 10MW are named small hydropower plants. Plants that generates a maximum of 100 kW are categorized as microhydro systems (NREL, 2001).

OPTIMAL LOCATION AND SIZE FOR VARIOUS RENEWABLE GENERATORS UNITS IN DISTRIBUTION NETWORKS

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This chapter presents an efficient and robust methodology to optimally determine the best location and optimum size for Distributed Generators (DG), in a distribution network, while minimizing energy losses and improving voltage profile. The proposed methodology has been designed to consider variable demand and variable DG production scenarios, offering a set of optimum values for DG active power output and power factor. The optimization here presented uses the Genetic Algorithm (GA) and the OpenDSS power flow solver feature. The method has been tested on the IEEE 37-node test system, comparing voltage profile and energy losses in three scenarios. Additional tests on the IEEE 123-node, 34-node and 13-node have been performed to compare the method proposed with results found in the literature.

4.1 Introduction

The continuous growth in demand of electricity is saturating the capacity of distribution networks in many regions, (Asif and Muneer, 2007). This situation can be alleviated by connecting distributed generators (DGs) in the form of firm generation or intermittent renewable energy sources such as wind and solar farms. It is known that DGs in a distribution network can compensate for energy demand from transmission networks, improve the voltage profile in feeders, increase reliability, and reduce losses. However, an improper DG size and inappropriate allocation may cause high power losses and voltage profile limits violations, (Viawan and Karlsson, 2008). Knowing the optimum location and size is an important issue for both distribution network companies and private investors. Different techniques can be found in the literature to

properly address DG integration in the network. In (Ochoa *et al.*, 2006), the method presented analyzed various impact indices and technical issues facing DGs connected to distribution networks. However, it does not consider the optimal size of DG units with variable demand and variable DG generation. Analytical expressions allow the proper determination of the optimal size and location values. In (Acharya *et al.*, 2006) and (Hung *et al.*, 2010), analytical expressions derived from the "exact loss formula" (Reddy, 2014) are proposed to find the optimal DG location, size and optimal power factor; it should further be noted that real and reactive DG power are included in the formulas. Stakeholders involved in system planning and investment could be more interested in more efficient methods and tools that include realistic scenarios and larger networks, a fact that further complicates the problem. To solve this issue, techniques such as non-linear programing (NLP) and Mixed integer non-linear programming (MINLP) are used. In (Kumar and Gao, 2010), A MINLP is formulated, based on nodal price and line loss sensitivity to optimal location and DG size. In (Kaur *et al.*, 2014), the method is separated into two phases for DG siting and capacity planning, using combined loss sensitivity and sequential quadratic programming respectively for the problem. In (Atwa *et al.*, 2010), annual energy losses are reduced by the use of a probabilistic generation and load model in a MINLP problem. Some authors have used heuristic methods, including Genetic Algorithm (GA) and Particle Swarm Optimization (PSO), to solve a multi-objective problem. In (Anwar and Pota, 2012), PSO is used to solve an objective function to reduce total circuit active losses with two constraints, voltage stability limits, and DG active power limits. The same method is presented in (Kotb and Sheb, 2010), but the authors in that case solve the optimization problem using the GA, including cumulative voltage deviation (CVD) as an additional goal. In (Celli *et al.*, 2006), the authors propose a multi-objective function that includes the system upgrade and energy curtailment costs. In (Moradi and Abedini, 2012), a hybrid method using GA/PSO is studied; the method splits the problem into optimal sizing and optimal location using PSO and GA, respectively, to solve the problem of optimal location and DG size. These methods can work with unbalanced networks since evolutionary algorithms allow the inclusion of the separate Power Flow Solver tool from OpenDSS (Dugan, 2012). Although these methods solve the location problem satisfactorily, with the exception of the work presented in (Atwa *et al.*, 2010),

they only use fixed load demand and fixed or firm DG generation. A time-varying demand and generation approach was studied with the objective of reducing energy loss, rather than power loss. Thus, (Ochoa and Harrison, 2011) and (Paaso *et al.*, 2015) introduce Smart Grid control elements such as the dispachable DG power factor, to minimize energy loss and optimally accommodate DG units in the network. This method only considers balanced networks. (Al Abri *et al.*, 2013) uses a probabilistic approach to model the DG production and Load variability. In (Ugranl and Karatepe, 2012), a simpler method is presented based on weight assignment to find the optimal factors for buses and DG units. However, in order to reduce complexity, these methods modified the load curves, obtaining average values or discretizing them over very long time periods. Zou *et al.* (2012) proposed a planning strategy to accommodate various types of DGs, using statistical models to simulate the uncertainty of renewables. Authors solve the problem using two types of algorithms: TRIBE PSO and ordinal optimization. In the same way Arabali *et al.* (2013) proposed a new strategy to manage and hybrid-renewable generation and energy storage system using statistical data to scholastically model the photovoltaic, wind generation and load. The optimization problem is solved using a genetic algorithm technique.

As can be seen, this complex problem has been treated from different perspectives, particularly from a constant demand and production. In a real distribution system, the power demand is continuously changing, and renewable DGs vary significantly during the day. Those methods that use statistical models are relatively complicated, in this work a simplified method to meet intermittent production models and load with DG allocation is present. Therefore, this paper aims to develop a method that permits to allocate, and then to optimally plan the DG capacity (fixed or variable) in order to reduce energy losses.

This method uses the GA technique to minimize power loss. The IEEE 37-node feeder network is considered to test the validity of the proposed approach. As well, for comparisons with other methods, the method was applied on the IEEE 34-, and 123-node test feeders.

The principal objectives developed in this chapter are:

- A simple and robust method to minimize energy losses and improve feeder voltage profiles using renewable DGs, including variable demand and variable DG generation.

- An approach to control the DG power factor, to minimize power losses and reduce voltage variations at the feeders.

This chapter is organized as follows: section 2 presents the problem formulation and the method used. In section 3, the solution methodology is presented. The methodology and the algorithm are tested on the IEEE test feeder networks in section 4. Finally, conclusions are given in section 5.

4.2 Problem formulation

Most of the related works found in the literature have addressed the issue of DG connection from a maximum active power demand and nominal DG production perspective. However, the results obtained in those cases are only optimal in these conditions. When variable demand is considered, the results are no longer optimal.

Another consideration is that optimal DG capacity is greater during maximum demand. In a real scenario though, maximum demand only occurs during a short period of time. If DG capacity is planned as a function of maximum demand, unnecessary losses will occur in periods of lower demand. When the objective is to reduce losses, DG could result in oversized capacity.

In the light of the above, it was therefore necessary to propose a method that allows the determination of the optimal amount of power to be injected by distributed generators at specific times. Further, in this work, the benefits of reactive power control are added to optimize the power and energy losses even more without reconfigure the control equipment installed in the distribution network.

4.2.1 Proposed methodology

The main goal is to locate and determine the size of the DG units connected to the distribution system. The distribution system losses constitute one of the key parameters that determine distribution costs and technical problems in the network. DG units connected to the feeders should be able to minimize system power losses without causing voltage limits violations Vlachogiannis and Østergaard (2009). The first objective function to minimize is then (4.1):

$$f_1 = \sum_{i=1}^{N} P_{L_i} \tag{4.1}$$

where P_{L_i} represents the active power losses in the i line, and N is the total number of lines of the distribution network.

Distribution networks base their control on keeping the line voltages between permit limits. Substation regulators estimate the voltage drop down the feeder and determine the number of tap changes that the OLTC needs to perform to increase the voltage level. The minimization of the power losses in a distribution network with discrete control elements is a mixed-integer nonlinear programming problem (MINLP).

$$min f(x,u) \tag{4.2}$$

$$g(x,u) = 0 \tag{4.3}$$

$$h(x,u) \leq 0 \tag{4.4}$$

Where x is the vector of dependent variables and u is the vector of independent variables conformed by voltage and active and reactive power losses at each line. g and h are the equality and inequality constraints respectively.

$$x = [V_1, ..., Vn, P_L, Q_L]. \tag{4.5}$$

$$u = [P_{DG1}, ..., P_{DGn}, Q_{DG1}, ..., Q_{DGn}, DG_{Loc_1}, DG_{Loc_n}]. \tag{4.6}$$

P_{DG} and Q_{DG} are the active and reactive power output for each DG installed, and are continuous variables. DG_{Loc} represents the bus locations for the DG units, this variable can only assume integer values. The optimization problem became in an Mixed integer nonlinear programming (MINLP).

The following constraints are applied to the algorithm to improve the voltage profile and the maximum and minimum DG capacity available.

$$V^{min} \leq V_i \leq V^{max}, i = 1, ...n \tag{4.7}$$

$$P_{DG}^{min} \leq P_{DG_i} \leq P_{DG}^{max}, i = 1, ...DGunits. \tag{4.8}$$

$$Q_{DG}^{min} \leq Q_{DG_i} \leq Q_{DG}^{max}, i = 1, ...DGunits. \tag{4.9}$$

Where V^{min} and V^{max} are the minimum and maximum voltage range in every node i of the network. $P_{DG}^{min}, P_{DG}^{max}, Q_{DG}^{min}, Q_{DG}^{max}$ are the limits for Real Power and Reactive Power injection for each DG unit.

When the power losses are used as the only objective to minimize, excessive active power injected from the DG could cause voltage rise above the limits. It is necessary to add Reactive Losses as a second objective (4.10), Cumulative Voltage Deviation (4.11) as the third objective. To simplify the method and the algorithm as well, a constraint factor is included directly in the

equation, in form of a Quadratic Penalty Factor (QPF), equation (4.12), its minimization is then the fourth objective.

Equation (4.13) describe the complete objective function to minimize.

$$f_2 = \sum_{i=1}^{N} Q_{L_i} \tag{4.10}$$

$$f_3 = CVD = \sum_{i=1}^{N} |V_i - V_{rated}|/N \tag{4.11}$$

$$f_4 = QPF = \sum_{i=1}^{N} \begin{cases} (V_i - V_{min})^2; & V_i \leq V_{min} \\ 0; & V_{min} < V_i < V_{max} \\ (V_i - V_{max})^2; & V_i \geq V_{min} \end{cases} \tag{4.12}$$

Where:

- Q_{L_i}: is the reactive power loss at the i line and N is the total number of lines.

- V_i: is the Voltage in the ith node.

- N:is the number of nodes in the circuit.

- V_{rated} is the rated voltage for the distribution system, 1 pu, necessary to enhance the voltage profile and to maintain a good level of power quality Willis (2004).

- V_{lim} is the minimum or maximum voltage limit.

$$f = min \sum_{i=1}^{24} (\omega_1 f_{1_i} + \omega_2 f_{2_i} + \omega_3 f_{3_i} + \omega_4 f_{4_i}) \tag{4.13}$$

Each factor have a different weight represented by ω, and the total sum of all weights should be 1.

In this work, the time-varying load and DG generation behavior suggest that energy losses should be considered instead of power losses. Equation (4.14), is used to evaluate energy

losses before and after optimization during a time horizon of 24 hours. Where P_{losses_i} are the active circuit power losses for $i = 1$ to $i = 24$ hours.

$$F = \sum_{i=1}^{24} P_{losses_i} \qquad (4.14)$$

4.2.2 Genetic Algorithm

The minimization problem presented is solved with a Genetic Algorithm. The fitness equation (11) is applied to the unbalance distribution system with no linear components, creating a mixed-integer nonlinear programming problem, due the presence of discrete elements like the OLTC. The GA can address such problems effectively; it is a heuristic search algorithm based on the process of natural selection and evolution of individuals Paaso (2014). The algorithm generates a random group of individuals to be reproduced, and in each step, this group produces a new generation based on the crossover and mutation operations, evolving until the optimal solution is reached. The parameters of GA used for solving the problem in this paper are presented in Table 4.1.

Table 4.1　GA Parameters

Parameter	Specification
Population	60-100
Selection Method	Normalized
Crossover Function	Scattered
Number of Generations	1200
Population Type	Integer
Reproduction	Crossover 0.8
Mutation	Gaussian
Termination Criteria	Best Fitness Value

4.3 Probabilistic Simulation

To effectively capture the uncertainties of renewable sources output power and load variations, statistical models has to be defined. The following models are defined in form of probability

density functions (PDF). Those models allows to generate the random variables used to perform the Monte Carlo Simulations (MCS).

The probabilistic simulation based on MCS, performs the simulation process several times, using different random PV and Load shapes in each simulation. Those PV and Load shapes are generated from the PDF described below. The result from the probabilistic simulation is a great number of arrays containing: optimal locations, capacity and Power Factor for each DG. Those arrays may be treated as statistical data. Those results are discussed in Section 5, Case 4.

4.3.1 Probabilistic Photovoltaic generator Model

Solar radiation could be highly unpredictable due the weather variations, in this paper, a beta distribution function is used to describe the solar radiation behavior as suggested in Graham and Hollands (1990).

$$f(S_r) = \frac{\Gamma(\alpha + \beta)}{\Gamma(\alpha)\Gamma(\beta)} S_r^{\alpha - 1}(1 - S_r)^{\beta - 1} \tag{4.15}$$

The parameters α and β can be obtained with the following equations:

$$\alpha = \mu_{Sr}\left(\frac{\mu_{Sr}(1 - \mu_{Sr})}{\sigma_{Sr}^2} - 1\right) \tag{4.16}$$

$$\beta = (1 - \mu_{Sr})\left(\frac{\mu_{Sr}(1 - \mu_{Sr})}{\sigma_{Sr}^2} - 1\right) \tag{4.17}$$

4.3.2 Probabilistic Load Model

In the same way, load variability is modeled with a PDF using historical data with a resolution of one hour. The probability probability density function correspond to a normal distribution Conti and Raiti (2007).

$$f(P_L) = \frac{1}{\sigma_L\sqrt{2\pi}} \exp^{\frac{-(P_L-\mu_L)^2}{2\sigma_L^2}} \tag{4.18}$$

To generate the statistical data, it is necessary to compute a great amount of hourly solar radiation an load demand from historical data, preferable from several years Zou *et al.* (2012), Arabali *et al.* (2013). Then, it is possible to obtain the values for μ_{Sr}, σ_{Sr}, μ_L and σ_L for a representative hour of each day. The process from Zou *et al.* (2012) is followed to generate the statistical values. Where, a reduction of the number of samples for one year is presented also. By extracting one representative day for each month, we have 288 samples, that represent the PV and load variability for one year. By using 288 samples, the computation effort is reduced.

4.4 Solution Algorithm

The amount of power to be delivered by the DGs, as well as their optimal connection buses, are obtained by solving the objective function (4.13) for a determined period of time, subject to the corresponding constraints (4.7) to (4.9). The algorithm determines the location and DG size simultaneously, based on the GA.

The proposed algorithm receives as input data the Power demand profile and the DG production daily profile generated from the corresponding PDF models (4.15) and (4.18). The constraints provided to the algorithm considering (4.7) to (4.9): Voltage limits, set to vary $\pm 3\%$ from 1 pu. The maximum DG capacity, set to the maximum substation rating power 3MW. And, the power factor with a minimum of 0,8 to a maximum of 1.

The GA sets the initial population which includes the DG bus location, the DG active power, and the DG power factor. It then calculates the objective function with the help of the OpenDSS power flow solver feature, which includes the entire distribution system configuration. The Power Flow is executed considering time variation and load growth. Once the termination criteria for GA are met, the global solution gives the optimal bus locations, the optimum DG power capacity, and the power optimal factor, for each of the DG units. Fig.4.1 describes the algorithm developed to test this method.

The fitness function can be adapted to obtain better results, such as a better voltage profile, or to give a higher priority to loss reduction. In this work, various weights of each term of equation (4.13) were tested in order to obtain the best results through trial and error. The weights applied were: 0.5 to active losses P_L, 0.1 to reactive losses Q_L, 0.2 to the CVD factor, and 0.2 to the last term, voltage constraints.

4.5   Test Systems and Verification

The proposed methodology is implemented in Matlab in a co-simulation environment with OpenDSS through the COM interface. The results obtained from the tests are presented in this section. The first 3 cases studied used a deterministic curve for load demand and DG production. The DG production profile is a smooth normalized curve from a Photovoltaic (PV) plant extracted from the examples available in EPRI (2015). The forth case use statistical data to generate a year (1 hour resolution). The historical data used in the statistical models are extracted from Wilcox (2012). For this work, is assumed that all DG units have the same profile, except for the cases with firm generation, where is assumed that the DG have a constant level of power production. Also, the same load demand profile is considered for all system loads in all the cases. The case system used to test the proposed algorithm involves the unbalanced IEEE distribution test feeders with 37-node. Details of the distribution feeders can be found in Kersting (1991). The fitness function to minimize using GA is calculated in each power flow solution obtained with OpenDSS.

Figure 4.1   Algorithm Flow Chart

In order to demonstrate the behavior of the distribution when a DG is connected to one feeder, Fig.4.3 shows the IEEE 37-node test feeder with a 1400 kW DG unit connected to bus 740. The generator is assumed to have a unity power factor. Fig.4.4 presents the curve obtained

from power losses versus DG capacity with three different levels of demand. It can be seen from the graphic that the minimum power loss for each of the three demand levels occurs at three different DG power capacities.

Figure 4.2   Daily load and active power of PV panels profile for
the system.

4.5.1   Case studies:

Four case studies were considered to test the optimum DG location and size method:

a.   Maximum load and firm generation.

b.   Variable load and firm generation during a day.

c.   Variable load and PV variable generation during a day.

d.   Stochastic PV generation for a year planning.

Figure 4.3   DG unit connected to the IEEE 37 node test system.

The first case considers peak load demand and maximum DG production. Although this case does not reflect the normal behavior of a distribution system through time, it provides very important information, namely, the optimal DG location and maximum DG capacity that will minimize the system power losses. The cases 2 and 3 represent more realistic scenarios for firm and variable DG production. In these cases, DG can vary according to load demand to minimize energy losses for a 24-hour profile. Also, the algorithm is capable of obtaining the optimal DG

Figure 4.4   Power losses against peak, medium, and low demand.

Power Factor in order to further minimize the total energy losses. In case 4, statistical data for one year DG production and load demand is used to allocate 4 DGs. Also, cumulative voltage deviation before and after DG inclusion is shown, to demonstrate the correct perform of the algorithm.

4.5.2   Simulation Results:

4.5.2.1   Case1

The algorithm is improved to include a maximum of 4 distributed generators in the system. For this case, the IEEE 37-node test feeder is used.

The results for the optimal location and sizing using the 37 node test feeder are compared with those obtained using PSO in the Table 4.2. The table shows the location, DG size, active and reactive power loss. From the results it can be concluded that GA is more effective than PSO for DG location and sizing. The results in this chapter are obtained using GA.

Table 4.2   Results for optimal DG location and sizing using GA and
PSO algorithm

Method	Bus Number	DG Size (MW)	P Loss [kW]	Q Losses [kVAR]
GA	703, 734, 711, 714	0.35, 0.99, 0.43, 0.59	12.48	9.55
PSO	707, 701, 737, 728	0.25, 1.63, 0.59, 0.11	14.87	13.09

Results using 13, 34, and 123 test feeders are also included in order to compare the results with other methods from the literature. Tables 4.3 and 4.4 show the results for the location of 1, 2, 3 and 4 DG units in the 37-node and 123-node systems, respectively. The results shows how the total losses are reduced systematically by adding more DG units. The voltage profile for all the nodes in the system is improved by the DG connection. Fig.4.5 shows the comparison between the voltage profile before and after DG integration. In order to observe the impact in a more complex network, Fig.4.6 shows the voltage profile for the IEEE 123-node test feeder.

Table 4.3   Results of DG location and sizing for 4 DG units, case 1,
37-node test feeder

# DG	Bus Number	Size (MW)	Power factor	Losses (kW)	Losses (kVAR)
1	703	2.17	0.93	27.31	25.87
2	730,714	1.36,0.74	0.93;0.91	29.43	21.05
3	714,703,737	0.71,0.88,0.77	0.96;0.88;0.92	14.45	15.87
4	703,734,711,714	0.11,0.26,0.29,0.65	0.96;0.92;0.99;0.88	12.65	9.55

To validate the algorithm with similar works, Table 4.5 shows the results for location and size of one DG unit in the test systems 13, 34, and 123 EPRI (2015). These results are reported in Dahal (2014).

a) Without DG

b) with 4 DG units

Figure 4.5   Voltage profile of 37 node test feeder.

Table 4.4   Results of DG location and sizing for 4 DG units, case 2, 123-node test feeder

# DG	Bus Number	Size (MW)	Power factor	Losses (kW)	Losses (kVAR)
1	67	2.39	0.98	28.39	52.00
2	67; 47	2.03; 1.01	0.99;0.86	14.94	24.56
3	67; 47; 18	0.64; 1.88; 0.69	0.85; 0.99; 0.92	13.54	21.71
4	67; 76; 47; 13	1.07; 0.79; 0.82; 0.74	0.99; 1; 0.85; 0.89	12.75	19.9

Table 4.5   Results compared with RLF method

	RLF				Proposed method		
Test Feeder	DG Size (MW)	Bus No.	Power Loss (kW)	Base-Case (kW)	DG Size (MW)	Bus No.	Power Loss (KW)
13	1.28	675	58.13	112.41	1.93	671	44.5
34	1.15	844	68.13	273.32	1.54	834	54.43
123	1.32	76	43.44	95.77	2.41	67	31.45

4.5.2.2   Case 2

For case 2, the load profile from Fig. 4.2 is used in all the load spots in the system, while the DG unit is considered as a firm generator. Equation (4.14) is used to run the algorithm for 24 hours. In this case, generation curtailment is considered in the algorithm in order to reduce energy losses effectively during the time periods where demand is minimum. Also, the DG reactive power output is included as setting control variable, assuming that it can be varied by the power electronic interface. In Fig. 4.7, the "Firm DG" curve shows the voltage levels for case 2 in comparison with the base case curve.

4.5.2.3   Case 3

In this case, both demand and DG production are variables in time. Fig.4.2 shows the load profile for system demand and DG production. Equation (4.14) is used to run the algorithm for 24 hours as in the last case. For each hour, the proposed algorithm obtains the optimal DG power injection to minimize energy losses in the system for 24 hours. Fig.4.7 shows the

a) Without DG

b) With 4 DG units

Figure 4.6   Voltage profile of 123 node test feeder.

"PV DG GA" curve for this case in comparison with case 2 and the base case voltage levels. Additionally, the "PV DG PSO" curve shows the voltage profile result using PSO algorithm. Voltage profile results with GA and PSO shows a minimum advantage for the first algorithm.

Table 4.6   Energy losses comparison and DG
capacity for 24 hours period

	Energy Losses [kW] /24 Hours	DG injection [kW] /24 Hours
Base Case	1662.1	0.00
Invariable DG	1032.7	51960
Case 2	425.83	36443
Case 3	747.44	14742

Figure 4.7   Voltage Profile for base case, case 2 with firm DG,
and case 3 with variable DG

4.5.2.4 Case 4

In this case, for the optimization process a Monte Carlo simulation is performed. For each Monte Carlo iteration, a different PV and Load shape is randomly generated based on the probabilistic models (4.16)-(4.19). The parameters for the probabilistic PV model were obtained from historical solar data Wilcox (2012). The parameters for the probabilistic load model were obtained using data from the load shapes provided in EPRI (2015). The number of Monte Carlo iterations is set to 100. Table 4.7, shows the results for the optimal bus locations obtained from the stochastic optimization. The buses 703 and 737 are the most probable to be selected as DG connection points. Also, buses 709 and 707 shows a probability greater than 75% to be chosen as DG connection points along with the first ones. Other locations like buses 714, 734, 727 and 744 present probabilities less than 10%. With respect to the capacity results. The most probable DG connections buses can be observed in the Fig. 4.8 along with the zone where DGs also could be connected but with a much less probability according to the results.

Figs. 4.9 and 4.10 shows the dispersion of the capacity values for each DG, and the cumulative distribution function (CDF) of the power capacity for each DG respectively. Table 4.8 shows the maximum optimal capacity for each of the four DGs and their respective optimal PFs.

Table 4.7   DG allocation for 4 DG units,
case 4, 37-node test feeder, 1-year prediction.

DG unit	Bus Location	Location Probability
DG 1	703	95%
DG 2	737	94%
DG 3	709	76%
DG 4	707	77%

To show the reduction of voltage deviation, and according to relation (4.12), Fig. 4.11 shows the CVD results. The graphic was obtained by using one representative hour per month. With the inclusion of 4 DGs, the CVD factor is reduced from 3 pu to around 2 pu voltage variation.

Table 4.8   Maximum capacity and PF for 4 DG connections

DG unit	Bus Number	Max. Capacity [MW]$\geq 95\%$	PF
DG 1	703	1.384	0.92
DG 2	709	0.739	0.90
DG 3	737	0.712	0.92
DG 4	707	0.591	0.93

4.5.3   Energy losses

For cases 2 and 3, the objective is to minimize energy loss. In Fig. 4.12, energy losses for 24-hour periods are compared. Losses for peak hour slots are reduced considerably for case 2, with variable demand and firm DG. Here, the algorithm determines that DG production should be curtailed in order to reduce energy loss during minimum demand times. The zero production for night hours produces the curve for variable DG, where energy loss is minimized in the hours with high power demand, but only if those hours match the production hours of the PV curve considered for this work.

Table 6 shows the results in energy loss per day and DG production for 24 hours, where an extra case is included (Invariable DG (DG without curtailment)) for comparative purposes. It is noticeable that for cases 2 and 3, the method presented reduces the daily energy losses to a minimum, but at the cost of power curtailment for case 2. For case 3, losses will depend on the daily production and the technology used to generate energy.

4.6   Conclusion

The connection of multiple DG units permits the reduction of active and reactive losses in a distribution network. As well, the voltage profile is improved. The proposed algorithm offers an efficient way to optimally locate and size various DG units using an evolutionary algorithm, GA. The open source software, OpenDSS, allows a reduction of the computation time, and provides an accurate solution. It additionally allows the solution of the more complex problem that is the variability in demand and DG production. This algorithm presents another advan-

Figure 4.8   Optimal DG bus connections in the IEEE 37 node
test system.

tage, allowing the variation of the DG power factor to better match the load characteristics
and to optimally reduce energy losses. This work presented an optimal and simplified solu-
tion to overcome the problem of DG management, and could be used for existing distribution
networks, which are not capable of updating their entire control infrastructure.

Figure 4.9   Optimum capacity by DG bus location.

Figure 4.10   Cumulative distribution of the power capacity for
each DG unit.

Figure 4.11   Cumulative voltage deviation for one year

Figure 4.12   Energy losses for 24 hours, for base case, Case 2
with firm DG, and case 3 with variable DG

**COORDINATED VOLTAGE CONTROL FOR DISTRIBUTION NETWORKS WITH
DISTRIBUTED GENERATION PARTICIPATION**

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Distributed Generators connected to distribution networks offer multiple benefits for power networks and environments in the case of renewable sources. However, without proper planning and control, several problems, such as voltage rise issues and increased power losses, may occur. In this thesis, a coordinated voltage control method for distribution networks with multiple distributed generators is proposed. This method is based on a genetic algorithm approach to obtain the optimal setting points for each control element. This method considers time-varying demand and production, leading to an improvement in the voltage profile and to a minimization of active power loss.

5.1 Introduction

In the last decades, Distributed Generation (DG) has become an important alternative to compensate for growing energy demand. DGs are generally more environmentally friendly, as in the case of renewable sources, solar, wind, etc. Additionally, by installing DGs close to consumer centers, the need to build new traditional generation plants (hydroelectric, thermal, nuclear) and new transmission lines is reduced.

Renewable distributed generators (DG) connected to distribution networks offer multiple advantages, such as active power loss reduction and voltage profile improvement, as well as environmental benefits. To date, traditional voltage control methods and systems have been managing distributed generation in power networks, in a conservative fashion. Generally, by

limiting the amount of power injected into the grid, voltage rise and energy quality degradation which may cause a reverse power flow can be avoided (Heslop *et al.*, 2014).

In order to overcome the negative impacts of high active DG use, and to avoid power curtailment, various voltage control schemes involving DG have been proposed in the literature. Mostly, voltage regulation in the presence of distributed generation can be classified into two categories: Local control and Coordinated control, (Dragicevic *et al.*, 2015).

(O'Gorman and Redfern, 2008) proposed an autonomous distributed generation voltage control method. Local control does not require communication channels, but rather, relies only on local measurements to regulate voltage at its terminals. Distributed generators are also capable of intervening in the quality control process, as analyzed by (Illindala and Venkataramanan, 2013), where a control method to manage voltage sags and imbalances is proposed. (Dai *et al.*, 2004) and (Kim *et al.*, 2015) studies how DG phase inverter equipment is used to regulate active and reactive powers injected into the grid. DG can thus be used as a static Var element. In such methods, control elements, such as OLTCs, SVRs and SCs act individually and locally. These approaches usually interfere with control equipment producing excessive operations and capacitor switching, and although they solve most problems related to DG connection and management, the results in terms of power line losses and voltage levels could be improved by using coordinated voltage control methods.

With coordinated voltage control (CVC), DG control capabilities are coordinated between traditional control elements and DG power interfaces, in order to maintain an optimal voltage profile and to minimize power losses. CVC for distribution networks takes advantage of the control methods developed for transmission networks, (Richardot and Viciu, 2006). Several CVC approaches are presented in the literature. In (Muttaqi *et al.*, 2015) and (Pachanapan *et al.*, 2012), the control zone and priority concept are used, with the objective of ensuring that the control elements do not interfere with one another. These methods allow a successful reduction of the interference between control elements, in addition to maintaining low operating costs; further, they work without implementing communication infrastructure in the network.

Several studies have proposed the use of evolutionary algorithms and computation techniques to optimally set each element involved in the control of the distribution network, including DG units. Thus, fuzzy logic is used to control the power factor of multiple synchronous generators in (Gaonkar and Pillai, 2010) and is combined with CVC in (Ochoa *et al.*, 2010). An optimization method for CVC and reactive power control with and without DG is presented by (Viawan and Karlsson, 2008). A CVC method using intermittent PV generation is proposed by (Paaso, 2014). In (Daratha *et al.*, 2015) a centralized voltage control optimization problem is solved using Robust Optimization. Nevertheless, when dealing with more control elements and distribution networks, including distributed and unbalanced loads, it is preferred to address the network control through a multi-objective problem formulation. Evolutionary algorithms are widely used to solve such problems. Particle Swarm Optimization (PSO) in (Sarmin *et al.*, 2013), (Vlachogiannis and Lee, 2006), (Kim *et al.*, 2015), (Su *et al.*, 2011), and Genetic Algorithm (GA) proposed proposed by (Devaraj and Roselyn, 2010) are used. These works focus on various objectives, such as power loss reduction, voltage variation minimization, and OLTCs and Capacitor operation reduction. In (Devaraj and Roselyn, 2010), a genetic algorithm is improved to solve the reactive power dispatch problem in a distribution network. The method is based on the minimization of load bus indices, and uses the control elements as optimization variables. Another modification of the genetic algorithm is used in (Jeyadevi *et al.*, 2011) to solve a multi-objective problem and minimize the power losses in a distribution system, by optimizing the reactive power dispatch. Further, in (Khatua and Yadav, 2015) the genetic algorithm is combined with the Voltage Stability Constrained Optimal Power Flow technique to solve a multi-objective problem, where wind generation is used to improve the voltage stability of a power system. Other evolutionary algorithms, such as the Gravitational Search Algorithm (GSA) presented by (Mahboubi-Moghaddam *et al.*, 2016), are used to solve the optimization problem of control elements and distributed generation integration. Additionally, hybrid algorithms combining Fuzzy logic and Genetic Algorithm (FGA), (Nayanatara *et al.*, 2016), are being used to enhance optimization results, although this could add more complexity to the methods.

The objective function presented by (Viawan and Karlsson, 2008) only considers two factors: Total power losses at time i, and the status of the capacitors at time i. In (Daratha *et al.*, 2015), the objective function is also set to minimize the active power loss, with the OLTC position, status capacitor and DG reactive outputs as the control variables. In (Kulmala and Repo, 2014), the objective function is configured to minimize the active power losses and generation curtailment. Although, these works successfully address the CVC problem in unbalanced networks, they fall short when it comes to using more real scenarios, such as time-varying load demand and DG production. As well, they do not include objectives such as capacitor switching and OLTC operation reduction in the optimization problem, or when they do address these factors, they position the factors as a consequence of the optimization problem solution, and not as an objective. This thesis proposes an optimal coordinated voltage control method to optimize the power loss minimization and voltage profile in the presence of renewable distributed generation. The objective function proposed minimizes the active power losses, capacitor switching operations, and OLTC operations, and maximizes the distributed generator power outputs.

The results from the optimization process represent the optimal operation settings for DG units (active power and power factor), OLTCs and Shunt Capacitors (SC) operations for a 24-hour period. A GA conducts the optimization. It also includes a power factor control for the DG. The validity of the method is proven using a load curve and a DG production curve for the photovoltaic distributed power plant, over an unbalanced distribution test network.

The main contributions in this thesis chapter are:

- It provides a coordinated voltage control method to find all the optimal control settings for every control interface in the distribution network.

- It also provides an objective equation that simplifies the method and reduces the complexity of the algorithm, including the number of Tap operations and capacitor switching as penalties.

This chapter is organized as follows: The problem formulation is proposed in section II. In section III, simulations and results of the CVC application versus a local Volt/Var control method are presented. The study concludes in section IV.

5.2 Problem Formulation

Voltage and reactive power control in a distribution network essentially seeks to compensate for voltage drop along the feeders, and to reduce power losses. In a normal network with no DG connections at their feeders, feeder capacitors compensate for the reactive power consumption, boosting the voltage level when it drops under imposed limits ±3 p.u. The OLTCs change their taps to restore the voltage level to the proper limits , (Vlachogiannis and Østergaard, 2009), based on voltage drop estimation from local measurements. When power injected to the network by DGs is greater than the power needs in the connection bus loads, this power goes to the substation, interfering with the configuration of control elements, and provokes excessive operations, which degrades the life expectancy and increases maintenance costs (Kim *et al.*, 2015).

In this work, when a DG PV plant is connected to an end feeder, it can be assumed that the power interface is capable of controlling the reactive power Q_{DG} injection/absorption. In the case of voltage drop at the end of the feeder, DG can react faster than feeder capacitors in reactive power compensation, (Viawan and Karlsson, 2008). The DG interfaces cause DG units to act as a real and fast voltage and reactive control elements in the distribution networks.

5.2.1 Optimization problem formulation

The coordinated voltage control problem is formulated here as a nonlinear optimization problem with the following form:

$$MinF(x,u) \tag{5.1}$$

Subject to:

$$g(x,u) = 0 \tag{5.2}$$

$$h(x,u) \leq 0 \tag{5.3}$$

F represents the objective function for the problem, x and u are the dependent and independent variables respectively.

$$x = [V_1, ..., Vn, P_{Loss}^1, ..., P_{Loss}^L]. \tag{5.4}$$

$$u = [P_{DG1}, ..., P_{DGn}, Q_{DG1}, ..., Q_{DGn}, Tap_{step}^m, Cap_s^m]. \tag{5.5}$$

Where: P_{Loss}^L is the power loss at line L, Tap_{step}^m is the tap position of the OLTC regulator for the m units installed on the network, and Cap_s^n, is the capacitor state $S : on/off$ of the n units present in the circuit.

The objective function that defines the problem needs to have the following objectives: The first objective is to reduce the active power losses (5.6). In order to maintain the voltage between the maximum and minimum boundaries the Quadratic penalty Function (QPF) $(V_{Li} - V_{lim})^2$ is applied, considering all the line voltages and upper and lower voltage limits (0.97 & 1.03). Voltage has to be as close as possible to the rated voltage (1 p.u.), function $(V_{ref} - V_i)^2$ is used, this function is often called cumulative voltage deviation factor (CVD). The mixed integer non-linear problem in (Kim *et al.*, 2015), presents an objective equation to limit the excessive taps and capacitor switching operations. In this thesis similar factors was including with the following modifications: To reduce the number of tap operation, a penalty $|Tap_{h-1} - Tap_h|$, is imposed directly in the equation considering the last tap position $h - 1$ instead of the next $h + 1$ as stated in (Kim *et al.*, 2015). The same type of penalty is imposed to the shunt capacitor switching $|C_{h-1} - C_h|$. Also, the factor P_{DG} was included to increase the active power injection from the PV distributed generators.

$$f_1 = \sum_{k=1}^{N} P_{L_i} \tag{5.6}$$

$$f_2 = CVD = \sum_{n=1}^{k} (V_{ref} - V_i)^2 / k \tag{5.7}$$

$$f_3 = QPF = \sum_{i=1}^{N} \begin{cases} (V_i - V_{min})^2; & V_i \leq V_{min} \\ 0; & V_{min} < V_i < V_{max} \\ (V_i - V_{max})^2; & V_i \geq V_{min} \end{cases} \tag{5.8}$$

$$f_4 = |Tap_{h-1} - Tap_h| \tag{5.9}$$

$$f_5 = |C_{h-1} - C_h| \tag{5.10}$$

$$f_6 = P_{DG} \tag{5.11}$$

Then, the objective function is defined as follows:

$$F = min\{C_1 f_{1_t} + C_2 f_{2_t} + C_3 f_{3_t} + C_4 f_{4_t} + C_5 f_{5_t} - C_6 f_{6_t}\}; \forall t \in T \tag{5.12}$$

Subject to the following constraints:

$$V_n^{min} \leq V_n \leq V_n^{max}, i = 1, ...n \tag{5.13}$$

$$P_{DG}^{min} \leq P_{DG_i} \leq P_{DG}^{max}, i = 1, ...DGunits. \tag{5.14}$$

$$Q_{DG}^{min} \leq Q_{DG_i} \leq Q_{DG}^{max}, i = 1, ...DGunits. \tag{5.15}$$

$$Tap_{h-1} - c \leq Tap_h \leq Tap_{h-1} + c, h = 1, ...24 \text{ hours.} \tag{5.16}$$

where:

- P_{Loss} Circuit active power loss.

- V_{ref} Reference node voltage 1 p.u.

- V_n Voltage at node nth.

- V_n^{min} Minimum voltage limit.

- V_n^{max} Maximum voltage limit.

- P_{DG},Q_{DG} Active and Reactive power output of DG_i.

- PF_{DG_i} is the power factor of DG_i.

- P_{DG}^{min} Minimum limit for active power curtailment.

- P_{DG}^{max} Maximum limit for active power curtailment.

- Q_{DG}^{min} Minimum limit for reactive power injection.

- Q_{DG}^{max} Maximum limit for reactive power injection.

- PF_{DG}^{max} DGs Power factor maximum limit

- PF_{DG}^{min} DGs Power factor minimum limit

- Tap_h OLTC tap position at time h.

Additionally, $Tap_{h-1} - c$ and $Tap_{h-1} + c$ represent a constraint that limits the tap changes during each hour. This constraint is included in the algorithm. The number of tap movements is limited to $\pm C$ from the last set position. The objective of this restriction is to avoid having the OLTC assume the principal role in the control operations. The value of the constant c determines the amount of control priority that the OLTC will have. By restricting the OLTC, the DG equipment and other control devices are required to take part in the voltage control actions.

By modifying the weights of each factor in equation (5.12), an equilibrium between losses minimization, voltage profile, and OLTC operations is achieved.

The proposed problem is solved by minimizing the objective function equation (5.12), subject to the constraints (5.13) to (5.16), obtaining a set of optimal settings for the OLTC operation, active power and reactive power configurations for DGs, for a 24-hour planning horizon. These

optimal settings will reduce the active power losses in the network, while maintaining an optimal voltage profile in all the network nodes. Fig 5.1 shows the algorithm flow chart for the method.

Figure 5.1   Algorithm Flow Chart

5.3   Case Study

5.3.1   GA implementation

To solve the optimization problem presented here, a GA optimization has been used. The GA is capable of solving non-linear problems, obtaining the best global optimum solution. An initial population initializes the GA, and the objective function is evaluated for each solution (population). The algorithm continuously improves the population through reproduction, crossover, mutation, and evaluation processes. When the GA reaches the termination criteria, it presents the optimal solution. In the algorithm used in this work, the initial population is entered in integer format in order to reduce computation complexity. Due the large number of variables (tap steps, power factor, active power, power factor and capacitor state), the initial population size is set to 60 individuals in order to increase the possibility of finding the optimal solution, (Man *et al.*, 1996).

5.3.2   Simulation test system 1

The distribution system used to test the method presented here is the IEEE 13-Node Test Feeder. It is an unbalanced distribution system, and its specifications can be found in (Kersting, 1991). Solar PV was chosen as the renewable generator source for testing the proposed control method. Two PV-based distributed generators were connected to the buses (680 and 671). In this work, it was assumed that the power interface of the PV generators is capable of dynamically injecting or absorbing reactive power and of varying the active power injection level. In order to test the capabilities of the proposed method, a maximum power capacity of 1500 KW for each PV generator unit was chosen, which combined, represents the 88% of power penetration for the test network. Both DG units vary according to the generation pattern shown in Fig. 5.2. The demand profile for every load in the network is also shown.

An algorithm to test the proposed method was written in Matlab. This algorithm allows the execution of the GA, and interaction with the OpenDSS COM interface , (EPRI, 2015). For

Figure 5.2   Daily system load and DG power production profiles

each GA iteration, the OpenDSS software performs a power flow, calculating the total circuit losses, voltage levels in each node, and the value of the objective function (5.12). The value of the objective function is then sent back to Matlab to be processed with the GA. The solution presented for the GA is a vector containing the optimal settings for the OLTC taps position, the active and reactive power levels for the PV generators, and the on and off switching for the distribution capacitors.

The weights for the objective function (5.12) where established through trial and error. C_1 was set as 0.2, $C_2 = 0.2$, $C_3 = 0.1$, $C_4 = 0.2$, $C_5 = 0.2$, and $C_6 = 0.1$. Similarly, the constant c for the OLTC movement constraint is set to the value of ± 4.

5.4 Simulation Results

Simulation results were obtained with Matlab and OpenDSS in a co-simulation environment. The results from the presented CVC method were compared with two scenarios, and in each scenario, two PV generators were connected to the distribution network, injecting 3000 KW.

- The PV generators were connected to the distribution system without any control interface. The OLTC tap changing and capacitor switching were controlled locally.

- The electronic interface of each PV generator had a Volt/Var control capability. OLTC and capacitor switching was controlled locally. Volt/VAr control was implemented directly in the OpenDSS script interface, with control settings based on the work reported in, (Kim *et al.*, 2015).

5.4.1 Impact on the total circuit power losses by applying the CVC method

Connecting the two PV systems to bus 680 and bus 671 had a direct impact on the power losses. The total capacity of the generators was chosen to keep the same total power losses the network experienced before the DG connections. Nevertheless, the goal was to have the CVC method perform a minimization of active power losses, as compared to the two scenarios presented earlier.

Fig. 5.4 shows the network losses for the 13-node test system. The simulation uses the 24-hour load and DG patterns from Fig. 5.2. In Fig. 5.4 illustrates the total circuit Losses resulting: 1) from no control case, 2) from using local control and Volt/Var control, and 3) from the proposed CVC control. It can be seen that with the proposed CVC method, active power losses present the best results. This coordination permits the dynamic variation of the power injected from the PV generator according to the load variation. The OLTC planning is determined by the CVC, avoiding the use of the voltage estimator, which could be interfered for the reversed power from the distributed generators.

Figure 5.3   Diagram of the IEEE 13 Node test Feeders and the
two DG connections.

5.4.2   Impact of applying the CVC method on the voltage regulation

Distributed generators connected to a distribution system could cause voltage rises at the connected buses. This phenomenon is incremented when the load is much lower than the DG power production at those buses.

In Fig. 5.5, the voltage level at the bus 681 is shown. This voltage profile allows us to observe the impact of CVC on voltage variation. The voltage in all the network buses is maintained between the maximum and minimum limits (± 3 p.u.) by applying the optimal settings to the voltage control devices. Moreover, a comparison was made with no control and local control, respectively. To confirm the advantage of CVC over other techniques in voltage regulation, Table 5.1 shows the cumulative voltage deviation (CVD) at bus 681, equation (5.7), for each control technique, as well as the active power and reactive power losses for each scenario. This data is obtained for 24 hours, and the proposed method shows the best behavior in all the scenarios:

Figure 5.4   Daily network losses with CVC application and the
two comparison scenarios

Table 5.1   Cumulative voltage deviation (CVD) and Power Losses
for the different control scenarios

	Network without DG installed	DG with no control	DG Volt/VAr local control	DG CVC proposed control
Active Losses [MW]	1.21	0.692	0.743	0.619
Reactive Losses [MW]	3.51	1.83	1.98	1.63
CVD factor	1.3337	1.2267	1.1071	1.0663

The coordinated voltage control, includes an expression $|Tap_{h-1} - Tap_h|$ in the objective function, which limits the number of actions the OLTC performs at each control iteration. This expression is included in order to balance the control actions of each element. Fig. 5.6 shows the OLTC operations in each scenario. It can be seen that the tap changes seen with the CVC method do not increase significantly.

Figure 5.5   Daily voltage profile at bus 680, from phase A; with
the proposed method and the two scenarios

In this particular case study, capacitor switching does not present major state variations during the 24-hour planning period covered. The algorithm determines that both system capacitors are maintained in the ON position for each hour. As shown in Fig.5.7

5.5   Simulation test system 2

The second test system used was obtained from (Viawan, 2008). It is a 10kV distribution system connected to a 70kV transmission system. The system includes one tap regulator on the 18MVA substation transformer, two substation capacitors with 2Mvar and 4 shunt capacitors installed at the feeders with 1.4Mvar. Fig.5.8 shows the one line diagram of the test system used. Three DG plants with 3MVA are added to the second distribution feeder on the 10 node, and four 3MVA DG to the first feeder on the node number 3. The system is configured with local control for the tap regulator and the feeder capacitors. This case is presented with the

Figure 5.6   OLTC tap movements for 24 hours, with CVC, and
the two scenarios

Figure 5.7   Capacitors status for 24 hours with CVC, and the two
scenarios

objective of show a more explicit scenario for the minimization of OLTC and capacitor control

operations with the CVC method.

Figure 5.8 Transmission and distribution second test system
diagram

5.5.1 Results

5.5.1.1 Impact on the total circuit power losses by applying the CVC method

Fig.5.9 shows the total active power losses during a 24 hours scenario. For the first case: DG inclusion without control, the total looses are 10.87MW in a day. On the second case, where a Volt/Var local control has been added with each DG power interface, the losses are reduced to 9.63MW. And with the CVC method presented here, the total losses are 9.57MW. The loss reduction is minimum in comparison with the local control results.

Figure 5.9   Daily network losses with CVC application and the
two comparison scenarios

5.5.1.2   Impact of applying the CVC method on the voltage profile

Fig.5.10 shows the voltage profile comparison for the three scenarios. Here, the voltage profile in the bus 10 was effectively improved with the CVC method application. In numeric terms, the CVD function could be used to the comparison. With the only DG connection and no local control, the voltage profile presents a CVD of 0.58. With local control on each DG the CVD improves to 0.55. With the application of the method proposed, the CVD presents a factor of 0.2.

5.5.1.3   Impact on the OLTC and capacitor operations by applying the CVC method

Fig.5.11 shows the results for the OLTC actions during 24 hours. The DG connection without local control provoke 16 tap changes during a day. With local control for each DG, the number of tap movements are increased to 19. In the other hand, with the CVC method the control actions are reduced to just 8 changes during the day, representing approximately %50 of re-

Figure 5.10   Daily voltage profile at bus 10; with the proposed
method and the two scenarios

duction. Fig.5.12 represents the status for the feeder capacitors, where 0 means switched off
and 1 means switched on. The CVC method permits to achieve a significant reductions of the
capacitor operations.

5.6   Conclusion

In this chapter, a coordinated voltage control method for distribution networks with multiple
DG connections has been presented. The CVC method was designed to obtain the optimal
settings for the control devices from an optimization problem. The designed algorithm used a
GA in co-simulation with OpenDSS. The results show a satisfactory voltage control and loss
reduction, demonstrating the effectiveness of the method. The use of the time-varying load and
DG generation patterns shows that the algorithm can be used in real implementations, helping
to increase reliability and DG integration in distribution networks.

Figure 5.11 Tap operations for 24 hours, with CVC, and the two scenarios

Figure 5.12 Tap operations for 24 hours, with CVC, and the two scenarios

GENERAL CONCLUSION

In this thesis, two methods that deal with the principal steady state issues of distributed generation inclusion have been presented. The first method found the optimal location for at least 4 DG units connected to a radial and unbalanced distribution network and finds the optimal DG capacity considering time-varying generation and demand. The results show that the allocation method proposed, effectively permits to maximize the DG capacity not only without negatively impact the network but reducing the active power losses in the lines and improving the voltage profile.

The second method aims to coordinate the control actions of on-load tap changers and shunt capacitors with distributed generation with the assumption that DG units are capable of dynamically change their active and reactive power output. The method obtained the optimal settings for each control element,24 hour ahead. As in the allocation method. The CVC proposed method uses a time-varying load-generation model.

Both methods were modeled as multi-objective problems. Due to the fact that these problems are non-linear, genetic algorithm technique was used to find the global optimal values. Resulting in a reliable tool to find the best global optimal solution.

Using unbalanced radial distribution networks to test the methods, presented an important challenge. Especially when the power flow solution had to be performed several times to find the optimal solution for each method. The best solution to reduce the time for power flow, was using the software OpenDSS, in co-simulation with Matlab. The use of this software tools, resulted in an effective algorithm compared with similar techniques.

Recommendations for future work:

Although the methods presented in this thesis correctly meet the objectives proposed, some important issues involving DGs integration can be addressed in future research.

The reliability of a DG system based on renewable sources can be increased, due to the combination of various types of renewables and technologies. Consequently, this work will be extended to incorporate hybrid generation and storage devices, to ameliorate the stability and reliability of the distribution system.

The adoption of distributed generation not only requires technical impact studies, but also economic studies. The Initial investment and maintenance costs, are important factors that helps to measure the economic impacts of DG integration. Costs variables can be included in the problem formulation without change the principal structure of the algorithm presented in this thesis.

The impacts of DGs connection in frequency stability must be studied, especially on fault study and islanding scenarios. Dynamic and first level control methods should be incorporated along with those secondary and static methods presented here.

Similarly, the study of how the presence of DG impacts the protection equipments should be analyzed. In this thesis, protection equipments were considered indirectly. Nevertheless, new coordination approaches and reconfiguration can be studied.

OPENDSS CODE FOR THE IEEE 13 NODE TEST FEEDER

The following code was used to obtain the power flow solution for the IEEE 13-node test Feeder. The following code is provided with OpenDSS resources folder. Level modifications were maded and are specified with comments preceded with "//" symbol.

```
1
2  Clear
3
4  !
5  ! This script is based on a script developed by Tennessee Tech Univ ...
       students
6  ! Tyler Patton, Jon Wood, and David Woods, April 2009
7  !
8  new circuit.IEEE13Nodeckt
9  ¬ basekv=115 pu=1.0001 phases=3 bus1=SourceBus
10 ¬ Angle=30                                              ! ...
       advance angle 30 deg so result agree with published angle
11 ¬ MVAsc3=20000 MVASC1=21000    ! stiffen the source to approximate ...
       inf source
12 !SUB TRANSFORMER DEFINITION
13 ! Although this data was given, it does not appear to be used in the ...
       test case results
14 ! The published test case starts at 1.0 per unit at Bus 650. To make ...
       this happen, we will change the impedance
15 ! on the transformer to something tiny by dividing by 1000 using the ...
       DSS in—line RPN math
16 New Transformer.Sub Phases=3 Windings=2   XHL=(8 1000 /)
17 ¬ wdg=1 bus=SourceBus   conn=Δ  kv=115  kva=5000   %r=(.5 1000 /)  XHT=4
18 ¬ wdg=2 bus=650              conn=wye    kv=4.16  kva=5000   %r=(.5 ...
       1000 /)   XLT=4
19 !
```

```
20  ! FEEDER 1—PHASE VOLTAGE REGULATORS

21  ! Define low—impedance 2—wdg transformer

22

23  New Transformer.Reg1 phases=1 XHL=0.01 kVAs=[1666 1666]

24  ¬ Buses=[650.1 RG60.1] kVs=[2.4  2.4] %LoadLoss=0.01

25  new regcontrol.Reg1  transformer=Reg1 winding=2  vreg=122  band=2  ...
        ptratio=20 ctprim=700  R=3   X=9

26

27  New Transformer.Reg2 phases=1 XHL=0.01 kVAs=[1666 1666]

28  ¬ Buses=[650.2 RG60.2] kVs=[2.4  2.4] %LoadLoss=0.01

29  new regcontrol.Reg2  transformer=Reg2 winding=2  vreg=122  band=2  ...
        ptratio=20 ctprim=700  R=3   X=9

30

31  New Transformer.Reg3 phases=1 XHL=0.01 kVAs=[1666 1666]

32  ¬ Buses=[650.3 RG60.3] kVs=[2.4  2.4] %LoadLoss=0.01

33  new regcontrol.Reg3  transformer=Reg3 winding=2  vreg=122  band=2  ...
        ptratio=20 ctprim=700  R=3   X=9

34

35  !Set controlmode=off //Control mode is off, The control is driven ...
        from MATLAB interface

36

37  !TRANSFORMER DEFINITION

38  New Transformer.XFM1  Phases=3   Windings=2  XHL=2

39  ¬ wdg=1 bus=633        conn=Wye kv=4.16    kva=500    %r=.55     XHT=1

40  ¬ wdg=2 bus=634        conn=Wye kv=0.480   kva=500    %r=.55    XLT=1

41

42

43  !LINE CODES

44  redirect IEEELineCodes.dss

45

46  // these are local matrix line codes

47  // corrected 9—14—2011

48  New linecode.mtx601 nphases=3 BaseFreq=60

49  ¬ rmatrix = (0.3465 | 0.1560 0.3375 | 0.1580 0.1535 0.3414 )

50  ¬ xmatrix = (1.0179 | 0.5017 1.0478 | 0.4236 0.3849 1.0348 )
```

```
51 ¬ units=mi
52 New linecode.mtx602 nphases=3 BaseFreq=60
53 ¬ rmatrix = (0.7526 | 0.1580 0.7475 | 0.1560 0.1535 0.7436 )
54 ¬ xmatrix = (1.1814 | 0.4236 1.1983 | 0.5017 0.3849 1.2112 )
55 ¬ units=mi
56 New linecode.mtx603 nphases=2 BaseFreq=60
57 ¬ rmatrix = (1.3238 | 0.2066 1.3294 )
58 ¬ xmatrix = (1.3569 | 0.4591 1.3471 )
59 ¬ units=mi
60 New linecode.mtx604 nphases=2 BaseFreq=60
61 ¬ rmatrix = (1.3238 | 0.2066 1.3294 )
62 ¬ xmatrix = (1.3569 | 0.4591 1.3471 )
63 ¬ units=mi
64 New linecode.mtx605 nphases=1 BaseFreq=60
65 ¬ rmatrix = (1.3292 )
66 ¬ xmatrix = (1.3475 )
67 ¬ units=mi
68 New linecode.mtx606 nphases=3 BaseFreq=60
69 ¬ rmatrix = (0.7982 | 0.3192 0.7891 | 0.2849 0.3192 0.7982 )
70 ¬ xmatrix = (0.4463 | 0.0328 0.4041 | −0.0143 0.0328 0.4463 )
71 ¬ Cmatrix = [257 | 0 257 | 0 0 257]
72 ¬ units=mi
73 New linecode.mtx607 nphases=1 BaseFreq=60
74 ¬ rmatrix = (1.3425 )
75 ¬ xmatrix = (0.5124 )
76 ¬ cmatrix = [236]
77 ¬ units=mi
78
79
80 !LOAD DEFINITIONS \\Loads are anulled, this loads are declared in ...
        MATLAB.
81 !New Load.671 Bus1=671.1.2.3  Phases=3 Conn=Delta Model=1 kV=4.16    ...
        kW=1155 kvar=660
82 !New Load.634a Bus1=634.1      Phases=1 Conn=Wye  Model=1 kV=0.277  ...
        kW=160    kvar=110
```

```
83  !New Load.634b Bus1=634.2     Phases=1 Conn=Wye  Model=1 kV=0.277  ...
       kW=120    kvar=90
84  !New Load.634c Bus1=634.3     Phases=1 Conn=Wye  Model=1 kV=0.277  ...
       kW=120    kvar=90
85  !New Load.645 Bus1=645.2       Phases=1 Conn=Wye  Model=1 kV=2.4 ...
           kW=170    kvar=125
86  !New Load.646 Bus1=646.2.3    Phases=1 Conn=Delta Model=2 kV=4.16    ...
       kW=230    kvar=132
87  !New Load.692 Bus1=692.3.1    Phases=1 Conn=Delta Model=5 kV=4.16    ...
       kW=170    kvar=151
88  !New Load.675a Bus1=675.1    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=485    kvar=190
89  !New Load.675b Bus1=675.2    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=68    kvar=60
90  !New Load.675c Bus1=675.3    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=290    kvar=212
91  !New Load.611 Bus1=611.3     Phases=1 Conn=Wye  Model=5 kV=2.4  ...
       kW=170    kvar=80
92  !New Load.652 Bus1=652.1     Phases=1 Conn=Wye  Model=2 kV=2.4  ...
       kW=128    kvar=86
93  !New Load.670a Bus1=670.1    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=17     kvar=10
94  !New Load.670b Bus1=670.2    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=66     kvar=38
95  !New Load.670c Bus1=670.3    Phases=1 Conn=Wye  Model=1 kV=2.4  ...
       kW=117   kvar=68
96
97  !CAPACITOR DEFINITIONS
98  New Capacitor.Cap1 Bus1=675 phases=3 kVAR=600 kV=4.16
99  New Capacitor.Cap2 Bus1=611.3 phases=1 kVAR=100 kV=2.4
100
101 !Bus 670 is the concentrated point load of the distributed load on ...
       line 632 to 671 located at 1/3 the distance from node 632
102
103 !LINE DEFINITIONS
```

```
104 New Line.650632    Phases=3 Bus1=RG60.1.2.3   Bus2=632.1.2.3  ...
       LineCode=mtx601 Length=2000 units=ft
105 New Line.632670    Phases=3 Bus1=632.1.2.3    Bus2=670.1.2.3  ...
       LineCode=mtx601 Length=667  units=ft
106 New Line.670671    Phases=3 Bus1=670.1.2.3    Bus2=671.1.2.3  ...
       LineCode=mtx601 Length=1333 units=ft
107 New Line.671680    Phases=3 Bus1=671.1.2.3    Bus2=680.1.2.3  ...
       LineCode=mtx601 Length=1000 units=ft
108 New Line.632633    Phases=3 Bus1=632.1.2.3    Bus2=633.1.2.3  ...
       LineCode=mtx602 Length=500  units=ft
109 New Line.632645    Phases=2 Bus1=632.3.2      Bus2=645.3.2    ...
       LineCode=mtx603 Length=500  units=ft
110 New Line.645646    Phases=2 Bus1=645.3.2      Bus2=646.3.2    ...
       LineCode=mtx603 Length=300  units=ft
111 New Line.692675    Phases=3 Bus1=692.1.2.3    Bus2=675.1.2.3  ...
       LineCode=mtx606 Length=500  units=ft
112 New Line.671684    Phases=2 Bus1=671.1.3      Bus2=684.1.3    ...
       LineCode=mtx604 Length=300  units=ft
113 New Line.684611    Phases=1 Bus1=684.3        Bus2=611.3      ...
       LineCode=mtx605 Length=300  units=ft
114 New Line.684652    Phases=1 Bus1=684.1        Bus2=652.1      ...
       LineCode=mtx607 Length=800  units=ft
115 !SWITCH DEFINITIONS
116 New Line.671692    Phases=3 Bus1=671   Bus2=692  Switch=y  r1=1e-4 ...
       r0=1e-4 x1=0.000 x0=0.000 c1=0.000 c0=0.000
117 Set Voltagebases=[115, 4.16, .48]
118 calcv
119 Solve
120 BusCoords IEEE13Node_BusXY.csv
```

APPENDIX II

MATLAB CODE FOR PV INCLUSION AND VOLT/VAR CONTROL

The following code was used to obtain the results presented in chapter 2.

```matlab
[DSSStartOK, DSSObj, DSSText] = DSSStartup; %OpenDSS simulation

if DSSStartOK
    DSSText.command='Compile (\path_to_mfile\IEEE13Nodeckt.dss)';
    DSSCircuit=DSSObj.ActiveCircuit;
    DSSSolution=DSSCircuit.Solution; %start up the DSS
    %%%%%

    %Energymeters and monitors declarations

    DSSText.Command='New EnergyMeter.Main Line.670671 ';
    DSSText.Command='New Monitor.FeederEnd Line.670671 terminal=2';
    DSSText.Command='New Monitor.Tap1 element=Transformer.Reg1 ...
        terminal=2 mode=2';
    DSSText.Command='New Monitor.Tap2 element=Transformer.Reg2 ...
        terminal=2 mode=2';
    DSSText.Command='New Monitor.Tap3 element=Transformer.Reg3 ...
        terminal=2 mode=2';

    %Load Shape declarations
    DSSText.Command = 'New loadshape.daily npts=24 interval=1 ...
        mult=(0.3 0.3 0.3 0.35 0.36 0.39 0.41 0.48 0.52 0.59 0.62 ...
        0.74 0.87 0.91 0.94 0.94 1.0 0.98 0.94 0.92 0.61 0.60 0.51 ...
        0.44)';
    DSSText.Command = 'New Loadshape.MyIrrad npts=24 interval=1 ...
        mult=[0 0 0 0 0 0 .1 .2 .3 .5 .8 .9 1.0 1.0 .99 .9 .7 .4 .1 0 ...
        0 0 0 0]';
```

```
21
22     %Control mode and daily mode definition
23     DSSText.Command = 'set mode=daily';
24     DSSText.Command = 'Set controlmode=static';
25
26   %Declaration of PV system number 1
27     DSSText.Command ='new PVSystem.plant4a phases=3 bus1=680 ...
          kV=4.157 kVA=1500 irradiance=1 Pmpp=1728 pf=1 daily=MyIrrad';
28     DSSText.Command ='New XYCurve.vv_curve npts=4 ...
          Yarray=(1.0,1.0,−1.0,−1.0) XArray=(0.5,0.95,1.05,1.5)';
29     DSSText.Command ='New InvControl.InvPVCtrla mode=VOLTVAR ...
          voltage_curvex_ref=rated vvc_curve1=vv_curve EventLog=yes';
30   %Declaration of PV system number 2
31    DSSText.Command ='new PVSystem.plant4b phases=3 bus1=671 kV=4.157 ...
          kVA=1500 irradiance=1 Pmpp=1728 pf=1 daily=MyIrrad';
32     DSSText.Command ='New XYCurve.vv_curve npts=4 ...
          Yarray=(1.0,1.0,−1.0,−1.0) XArray=(0.5,0.95,1.05,1.5)';
33     DSSText.Command ='New InvControl.InvPVCtrlb mode=VOLTVAR ...
          voltage_curvex_ref=rated vvc_curve1=vv_curve EventLog=yes';
34    %setting of the maximum number of control iterations
35     DSSSolution.MaxControlIterations=100;
36
37    %Variable loads declarations commands.
38
39     DSSText.Command= 'New Load.671 Bus1=671.1.2.3  Phases=3 ...
          Conn=Delta Model=1 kV=4.16   kW=1155 kvar=660 daily=daily ...
          status=variable';
40     DSSText.Command= 'New Load.634a Bus1=634.1     Phases=1 Conn=Wye ...
           Model=1 kV=0.277  kW=160   kvar=110 daily=daily ...
          status=variable';
41     DSSText.Command= 'New Load.634b Bus1=634.2     Phases=1 Conn=Wye ...
           Model=1 kV=0.277  kW=120   kvar=90 daily=daily status=variable';
42     DSSText.Command= 'New Load.634c Bus1=634.3     Phases=1 Conn=Wye ...
           Model=1 kV=0.277  kW=120   kvar=90 daily=daily status=variable';
```

```
43    DSSText.Command= 'New Load.645 Bus1=645.2         Phases=1 ...
          Conn=Wye  Model=1 kV=2.4        kW=170   kvar=125 daily=daily ...
          status=variable';
44    DSSText.Command= 'New Load.646 Bus1=646.2.3    Phases=1 ...
          Conn=Delta Model=2 kV=4.16    kW=230   kvar=132 daily=daily ...
          status=variable';
45    DSSText.Command= 'New Load.692 Bus1=692.3.1    Phases=1 ...
          Conn=Delta Model=5 kV=4.16    kW=170   kvar=151 daily=daily ...
          status=variable';
46    DSSText.Command= 'New Load.675a Bus1=675.1    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=485   kvar=190 daily=daily status=variable';
47    DSSText.Command= 'New Load.675b Bus1=675.2    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=68   kvar=60 daily=daily status=variable';
48    DSSText.Command= 'New Load.675c Bus1=675.3    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=290   kvar=212 daily=daily status=variable';
49    DSSText.Command= 'New Load.611 Bus1=611.3      Phases=1 Conn=Wye ...
           Model=5 kV=2.4  kW=170   kvar=80 daily=daily status=variable';
50    DSSText.Command= 'New Load.652 Bus1=652.1       Phases=1 Conn=Wye ...
           Model=2 kV=2.4  kW=128   kvar=86 daily=daily status=variable';
51    DSSText.Command= 'New Load.670a Bus1=670.1    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=17    kvar=10 daily=daily status=variable';
52    DSSText.Command= 'New Load.670b Bus1=670.2    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=66    kvar=38 daily=daily status=variable';
53    DSSText.Command= 'New Load.670c Bus1=670.3    Phases=1 Conn=Wye  ...
          Model=1 kV=2.4  kW=117  kvar=68 daily=daily status=variable';
54
55 % Iterative solutions and Plots
56
57 DSSText.Command = 'Set number=1';
58 voltages=zeros(1, 13);
59    for i=1:24
60        DSSSolution.Solve;  % does one step in Daily mode
61        DSSCircuit.SetActiveBus('680');  % arbitrary bus
62        AllVoltages = DSSCircuit.ActiveBus.puVoltages;  % complex array
63        PLD(i) = DSSCircuit.losses(1);
```

```matlab
64          QLD(i) = DSSCircuit.losses(2);
65          Volts1D(i) = abs(complex(AllVoltages(1), AllVoltages(2)));
66          Volts2D(i) = abs(complex(AllVoltages(3), AllVoltages(4)));
67          Volts3D(i) = abs(complex(AllVoltages(5), AllVoltages(6)));
68          CVDD(i) = sum(abs(Volts1D(i)- 1))+ sum(abs(Volts2D(i)-1))+ ...
                sum(abs(Volts3D(i)- 1));
69          V1 = DSSCircuit.AllNodeVmagPUByPhase(1)
70          voltages=[voltages;V1]
71      end
72      Activelosses=sum(PLD)
73      Reactivelosses=sum(QLD)
74      CVD3=sum(CVDD)
75      % Make Plot voltage variation during 24 hours.
76
77       DSSText.Command = 'export mon FeederEnd';
78       Mon2FileName = DSSText.Result;
79       MyCSV2 = csvread(Mon2FileName, 1, 0);
80       Hour=MyCSV2(:,1);
81       VoltspuD = (Volts1D+Volts2D+Volts3D)/3;
82      figure
83  subplot(1,2,1)
84
85       plot(Hour, Volts1D,'-g+');  % black *
86       hold on
87       plot(Hour, Volts2D,'-r+');
88       plot(Hour, Volts3D,'-b+');
89  %     plot(Hour, VoltspuD,'-k');
90       plot(Hour, 1.03,'-g','LineWidth',2);
91       plot(Hour, 0.97,'-g');
92       title('Daily Simulation');
93       ylabel('Volts');
94       xlabel('Hour');
95       hold off
96  %     plot(Hour, Volts12,'-g+');
```

```matlab
97      legend('phase A','phase B','phase C','Location','SouthWest'); ...
            %put the legend
98      title('Daily Simulation With 3MW PV DG'); %plot title
99      ylim([0.94 1.06])
100     ylabel('Volts(pu)');
101     xlabel('Hours');
102     hold off
103 subplot(1,2,2)
104
105 plot(Hour, Volts1A,'-g+');   % black *
106     hold on
107     plot(Hour, Volts2A,'-r+');
108     plot(Hour, Volts3A,'-b+');
109 %     plot(Hour, VoltspuD,'-k');
110     plot(Hour, 1.03,'-g','LineWidth',2);
111     plot(Hour, 0.97,'-g');
112     title('Daily Simulation');
113     ylabel('Volts');
114     xlabel('Hour');
115     hold off
116 %     plot(Hour, Volts12,'-g+');
117     legend('phase A','phase B','phase C','Location','SouthWest'); ...
            %put the legend
118     title('Daily Simulation Without PV DG'); %plot title
119     ylim([0.94 1.06])
120     ylabel('Volts(pu)');
121     xlabel('Hours');
122     hold off
123
124 else
125     a='DSS Did Not Start';
126     disp(a);
127
128 end
```

APPENDIX III

OPTIMAL ALLOCATION ALGORITHM MATLAB CODE

The following code was used to obtain the results reported in chapter 4, to allocate 4 distributed energy units in IEEE 37-node test feeder.

1. Genetic algorithm optimization

```matlab
1  FitnessFunction = @opendss37;
2  nvars = 12;      % Number of variables
3  IntCon = [1 2 3 4 5 6 7 8 9 10 11 12];
4  LB = [1 1 10 1 1 10 1 1 10 1 1 10];   % Lower bound [Bus number, ...
       lower power factor, minimum DG capacity]
5  UB = [37 3000 100 37 3000 100 37 3000 100 37 3000 100];  % Upper ...
       bound [Bus number, maximum power factor, maximum DG capacity]
6  options = gaoptimset('PlotFcns',{@gaplotbestf},'PopulationSize',40);
7  rng(1,'twister')
8  [x] = ga(FitnessFunction,nvars,[],[],[],[],LB,UB,[],IntCon,options)
```

2. Fitness Function

```matlab
1  function y=opendss37(x)
2
3  %start up the DSS
4  [DSSStartOK, DSSObj, DSSText] = DSSStartup;
5  if DSSStartOK
6      DSSText.command='Compile (\path_to_mfile\ieee37.dss)';
7      DSSCircuit=DSSObj.ActiveCircuit;
8      DSSSolution=DSSCircuit.Solution;
9  %Energymeters and monitors
10     x(3)=x(3)/100;
```

```matlab
11      x(6)=x(6)/100;
12      x(9)=x(9)/100;
13      x(12)=x(12)/100;
14      DSSText.Command='New EnergyMeter.Main Line.L27 ';
15      DSSText.Command='New Monitor.FeederEnd Line.L20 terminal=1';
16      DSSText.Command =['New generator.plant1a bus1=' num2str(x(1)) ...
            '.1.2.3 phases=3 Conn=Delta kV=4.800 kW=' num2str(x(2)) ' ...
            pf=' num2str(x(3)) ' model=1'];
17      DSSText.Command =['New generator.plant2a bus1=' num2str(x(4)) ...
            '.1.2.3 phases=3 Conn=Delta kV=4.800 kW=' num2str(x(5)) ' ...
            pf=' num2str(x(6))  ' model=1'];
18      DSSText.Command =['New generator.plant3a bus1=' num2str(x(7)) ...
            '.1.2.3 phases=3 Conn=Delta kV=4.800 kW=' num2str(x(8)) ' ...
            pf=' num2str(x(9))  ' model=1'];
19      DSSText.Command =['New generator.plant4a bus1=' num2str(x(10)) ...
            '.1.2.3 phases=3 Conn=Delta kV=4.800 kW=' num2str(x(11)) ' ...
            pf=' num2str(x(12))  ' model=1'];
20      DSSSolution.Solve;
21
22      PQ=DSSCircuit.losses;
23      PL=PQ(1);
24      QL=PQ(2);
25      BusN=DSSCircuit.AllNodeNamesByPhase(1);
26      BusNb=DSSCircuit.AllNodeNamesByPhase(2);
27      BusNc=DSSCircuit.AllNodeNamesByPhase(3);
28      V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
29      V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
30      V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
31      CVD =sum(abs(V1-1))+sum(abs(V2-1))+sum(abs(V3-1));
32      Quad=QuadTerm(V1)+QuadTerm(V2)+QuadTerm(V3);
33  %%%%%%%%%%%%%%%solve OpenDSSS%%%%%%%%%%%%%%%%%%%%%%%%
34
35  %%%%%%%%%%%%%%%%%%%%
36  y = 0.5*PL+0.1*QL+0.2*CVD+0.2Quad;
37
```

```
38  else
39      a='DSS Did Not Start';
40      disp(a);
41  end
42  end
```

3. Quad term function

```
1  function  suma= QuadTerm(Vabc)
2  suma=0;
3  Vmin=0.97*10;
4  Vmax=1.03*10;
5  Vabc=Vabc*10;
6  for i=1:size(Vabc,2)
7      if Vabc(i)≤Vmin
8          suma=suma+((Vabc(i)−Vmin)^2);
9      elseif Vabc(i)≥Vmax
10         suma=suma+((Vabc(i)−Vmax)^2);
11     else
12         suma=suma+0;
13     end
14  end
15  result = suma;
```

APPENDIX IV

COORDINATED VOLTAGE CONTROL ALGORITHM MATLAB CODE

Genetic algorithm optimization used to obtain the results reported in chapter 5.

```matlab
1  loadshape=[0.3 0.3 0.3 0.35 0.36 0.39 0.41 0.48 0.52 0.59 0.62 0.94 ...
       0.87 0.91 0.94 0.94 1.0 0.98 0.94 0.92 0.61 0.60 0.51 0.44];
2  Prodshape=[0 0 0 0 0 0 0.1 0.2 0.3 0.5 0.8 0.9 1.0 1.0 0.99 0.9 0.7 ...
       0.4 0.1 0 0 0 0 0];
3  DGset=zeros(1, 24);PowerFactor=zeros(1, 24);tapsetA=zeros(1, ...
       24);tapsetB=zeros(1, 24);tapsetC=zeros(1, 24);
4
5  for i=1:1
6      load=loadshape(i)*100;
7      OptimumDG=2476;%%%%%%%%%
8      mDG=Prodshape(i)*OptimumDG;
9      P=mDG*0.2;
10     mDGUB=mDG+P;
11     mDGLB=mDG—P;
12     FitnessFunction = @opendss13CVCshapesinit;
13     nvars = 6;    % Number of variables
14     IntCon = [1 2 3 4 5 6];
15     LB = [mDGLB 1 0 0 0 load];   % Lower bound
16     UB = [mDGUB 10 32 32 32 load];  % Upper bound
17     options = gaoptimset('PlotFcns',{@gaplotbestf,@gaplotstopping},...
18     'PopulationSize',60);
19     rng(1,'twister');
20     [x] = ga(FitnessFunction,nvars,[],[],[],[],LB,UB,[],IntCon,options);
21
22     DGset(i)=x(1);PowerFactor(i)=x(2);tapsetA(i)=x(3);tapsetB(i)=x(4);...
23     tapsetC(i)=x(5);
24
25 end
```

```matlab
26
27 tap1=tapsetA(1);tap2=tapsetB(1);tap3=tapsetC(1);
28
29 for i=2:24
30     load=loadshape(i)*100;
31     OptimumDG=2476;%%%%%%%%
32     mDG=Prodshape(i)*OptimumDG;
33     P=mDG*0.2;
34     mDGUB=mDG+P;
35     mDGLB=mDG-P;
36     l_tapA=tap1-4;l_tapB=tap2-4;l_tapC=tap3-4;
37     u_tapA=tap1+4;u_tapB=tap2+4;u_tapC=tap3+4;
38
39     FitnessFunction = @opendss13CVCshapes;
40     nvars = 13;    % Number of variables
41     IntCon = [1 2 3 4 5 6 7 8 9 10 11 12 13];
42     LB = [mDGLB 1 l_tapA l_tapB l_tapC load tap1 tap2 tap3 l_capA ...
           l_capB cap1 cap2];   % Lower bound
43     UB = [mDGUB 10 u_tapA u_tapB u_tapC load tap1 tap2 tap3 u_capA ...
           u_capB cap1 cap3];  % Upper bound
44
45     options = gaoptimset('PopulationSize',60);
46     rng(1,'twister');
47     [x] = ga(FitnessFunction,nvars,[],[],[],[],LB,UB,[],IntCon,options);
48     tap1=x(3);tap2=x(4);tap3=x(5);
49     cap1=x(10);cap2=x(11);
50
51     DGset(i)=x(1);PowerFactor(i)=x(2);tapsetA(i)=x(3);tapsetB(i)=x(4);...
52     ...tapsetC(i)=x(5);
53
54 end
```

1.   Functions used in the main program

```matlab
1  function y=opendss13CVCshapesinit(x)
2  %%%OpenDSS simulation
3  %start up the DSS
4  [DSSStartOK, DSSObj, DSSText] = DSSStartup;
5
6  if DSSStartOK
7      DSSText.command='Compile ...
           (C:\Users\Tuesman\Dropbox\hiver2015\13Bus\IEEE13Nodeckt.dss)';
8      DSSCircuit=DSSObj.ActiveCircuit;
9      DSSSolution=DSSCircuit.Solution;
10     %%%%%
11
12     %Energymeters and monitors
13
14     DSSText.Command='New EnergyMeter.Main Line.670671 ';
15     DSSText.Command='New Monitor.FeederEnd Line.671680 terminal=1';
16
17     DG=x(1);
18     x(2)=x(2)/10;
19     x3=x(3);
20     x4=x(4);
21     x5=x(5);
22     x(3)=((16-x(3))*0.00625)+1;
23     x(4)=((16-x(4))*0.00625)+1;
24     x(5)=((16-x(5))*0.00625)+1;
25     x(6)=x(6)/100;
26     DSSText.Command='New Monitor.Tap1 element=Transformer.Reg1 ...
           terminal=2 mode=2';
27     DSSText.Command='New Monitor.Tap2 element=Transformer.Reg2 ...
           terminal=2 mode=2';
28     DSSText.Command='New Monitor.Tap3 element=Transformer.Reg3 ...
           terminal=2 mode=2';
29
```

```matlab
30    DSSText.Command =['new generator.plant1a bus1=671.1.2.3 phases=3 ...
         kV=4.16 kW=' num2str(x(1)) ' pf= ' num2str(x(2)) ' model=1'];
31
32    DSSText.Command= ['New Load.671 Bus1=671.1.2.3  Phases=3 ...
         Conn=Delta Model=1 kV=4.16    kW= ' num2str(x(6)*1155) ' ...
         kvar=' num2str(x(6)*660)];
33    DSSText.Command= ['New Load.634a Bus1=634.1     Phases=1 ...
         Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*160)    ' ...
         kvar=' num2str(x(6)*110)];
34    DSSText.Command= ['New Load.634b Bus1=634.2     Phases=1 ...
         Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*120)  ' kvar=' ...
         num2str(x(6)*90)];
35    DSSText.Command= ['New Load.634c Bus1=634.3     Phases=1 ...
         Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*120)  ' kvar=' ...
         num2str(x(6)*90)];
36    DSSText.Command= ['New Load.645 Bus1=645.2       Phases=1 ...
         Conn=Wye  Model=1 kV=2.4      kW= ' num2str(x(6)*170)  ' ...
         kvar=' num2str(x(6)*125)];
37    DSSText.Command= ['New Load.646 Bus1=646.2.3    Phases=1 ...
         Conn=Delta Model=2 kV=4.16     kW= ' num2str(x(6)*230)  ' ...
         kvar=' num2str(x(6)*132)];
38    DSSText.Command= ['New Load.692 Bus1=692.3.1    Phases=1 ...
         Conn=Delta Model=5 kV=4.16     kW= ' num2str(x(6)*170)  ' ...
         kvar=' num2str(x(6)*151)];
39    DSSText.Command= ['New Load.675a Bus1=675.1    Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*485)  ' kvar=' ...
         num2str(x(6)*190)];
40    DSSText.Command= ['New Load.675b Bus1=675.2    Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*68)  ' kvar=' ...
         num2str(x(6)*60)];
41    DSSText.Command= ['New Load.675c Bus1=675.3    Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*290)  ' kvar=' ...
         num2str(x(6)*212)];
```

```matlab
42    DSSText.Command= ['New Load.611 Bus1=611.3        Phases=1 ...
          Conn=Wye  Model=5 kV=2.4  kW= ' num2str(x(6)*170)  ' kvar=' ...
          num2str(x(6)*80)];
43    DSSText.Command= ['New Load.652 Bus1=652.1        Phases=1 ...
          Conn=Wye  Model=2 kV=2.4  kW= ' num2str(x(6)*28)  ' kvar=' ...
          num2str(x(6)*86)];
44    DSSText.Command= ['New Load.670a Bus1=670.1    Phases=1 Conn=Wye ...
           Model=1 kV=2.4  kW= ' num2str(x(6)*17)   ' kvar=' ...
          num2str(x(6)*10)];
45    DSSText.Command= ['New Load.670b Bus1=670.2    Phases=1 Conn=Wye ...
           Model=1 kV=2.4  kW= ' num2str(x(6)*66)   ' kvar=' ...
          num2str(x(6)*38)];
46    DSSText.Command= ['New Load.670c Bus1=670.3    Phases=1 Conn=Wye ...
           Model=1 kV=2.4  kW= ' num2str(x(6)*117) ' kvar=' ...
          num2str(x(6)*68)];
47
48    %%%OLTC%%%
49    DSSText.Command = ['Transformer.Reg1.Taps=[1.0 ' num2str(x(3))];
50    DSSText.Command = ['Transformer.Reg2.Taps=[1.0 ' num2str(x(4))];
51    DSSText.Command = ['Transformer.Reg3.Taps=[1.0 ' num2str(x(5))];
52
53    %%%%
54    DSSSolution.Solve;
55
56    PQ=DSSCircuit.losses;
57    PL=PQ(1)/100000;
58    QL=PQ(2)/100000;
59    BusN=DSSCircuit.AllNodeNamesByPhase(1);
60    BusNb=DSSCircuit.AllNodeNamesByPhase(2);
61    BusNc=DSSCircuit.AllNodeNamesByPhase(3);
62    V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
63    V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
64    V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
65    CVD =sum(abs(V1-1))+sum(abs(V2-1))+sum(abs(V3-1));
66
```

```
67  y = PL+CVD+(QuadTerm(V1)+QuadTerm(V2)+QuadTerm(V3))-0.1*DG;

68

69  else

70      a='DSS Did Not Start';

71      disp(a);

72

73  end

74  end
```

```
1   function y=opendss13CVCshapes(x)

2   %%%OpenDSS simulation

3   %start up the DSS

4   [DSSStartOK, DSSObj, DSSText] = DSSStartup;

5

6   if DSSStartOK

7       DSSText.command='Compile ...
            (C:\Users\Tuesman\Dropbox\hiver2015\13Bus\IEEE13Nodeckt.dss)';

8       DSSCircuit=DSSObj.ActiveCircuit;

9       DSSSolution=DSSCircuit.Solution;

10      %%%%%

11

12      %Energymeters and monitors

13

14      DSSText.Command='New EnergyMeter.Main Line.670671 ';

15      DSSText.Command='New Monitor.FeederEnd Line.671680 terminal=1';

16

17      DG=x(1);

18      x(2)=x(2)/10;

19      x3=x(3);

20      x4=x(4);

21      x5=x(5);

22      x(3)=((16-x(3))*0.00625)+1;

23      x(4)=((16-x(4))*0.00625)+1;

24      x(5)=((16-x(5))*0.00625)+1;
```

```matlab
25      x(6)=x(6)/100;
26      if x(10)==0
27          cap1=0;
28      else
29          cap1=600;
30      end
31
32       if x(11)==0
33          cap2=0;
34      else
35          cap2=100;
36      end
37
38
39      DSSText.Command='New Monitor.Tap1 element=Transformer.Reg1 ...
            terminal=2 mode=2';
40      DSSText.Command='New Monitor.Tap2 element=Transformer.Reg2 ...
            terminal=2 mode=2';
41      DSSText.Command='New Monitor.Tap3 element=Transformer.Reg3 ...
            terminal=2 mode=2';
42
43      DSSText.Command =['new generator.plant1a bus1=671.1.2.3 phases=3 ...
            kV=4.16 kW=' num2str(x(1)) ' pf= ' num2str(x(2)) ' model=1'];
44
45      DSSText.Command= ['New Load.671 Bus1=671.1.2.3  Phases=3 ...
            Conn=Delta Model=1 kV=4.16   kW= ' num2str(x(6)*1155) ' ...
            kvar=' num2str(x(6)*660)];
46      DSSText.Command= ['New Load.634a Bus1=634.1     Phases=1 ...
            Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*160)   ' ...
            kvar=' num2str(x(6)*110)];
47      DSSText.Command= ['New Load.634b Bus1=634.2     Phases=1 ...
            Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*120)  ' kvar=' ...
            num2str(x(6)*90)];
```

```
48    DSSText.Command= ['New Load.634c Bus1=634.3      Phases=1 ...
         Conn=Wye  Model=1 kV=0.277  kW= ' num2str(x(6)*120)  ' kvar=' ...
         num2str(x(6)*90)];
49    DSSText.Command= ['New Load.645 Bus1=645.2       Phases=1 ...
         Conn=Wye  Model=1 kV=2.4      kW= ' num2str(x(6)*170)  ' ...
         kvar=' num2str(x(6)*125)];
50    DSSText.Command= ['New Load.646 Bus1=646.2.3    Phases=1 ...
         Conn=Delta Model=2 kV=4.16    kW= ' num2str(x(6)*230)  ' ...
         kvar=' num2str(x(6)*132)];
51    DSSText.Command= ['New Load.692 Bus1=692.3.1    Phases=1 ...
         Conn=Delta Model=5 kV=4.16    kW= ' num2str(x(6)*170)  ' ...
         kvar=' num2str(x(6)*151)];
52    DSSText.Command= ['New Load.675a Bus1=675.1     Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*485)  ' kvar=' ...
         num2str(x(6)*190)];
53    DSSText.Command= ['New Load.675b Bus1=675.2     Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*68)  ' kvar=' ...
         num2str(x(6)*60)];
54    DSSText.Command= ['New Load.675c Bus1=675.3     Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*290)  ' kvar=' ...
         num2str(x(6)*212)];
55    DSSText.Command= ['New Load.611 Bus1=611.3      Phases=1 ...
         Conn=Wye  Model=5 kV=2.4  kW= ' num2str(x(6)*170)  ' kvar=' ...
         num2str(x(6)*80)];
56    DSSText.Command= ['New Load.652 Bus1=652.1      Phases=1 ...
         Conn=Wye  Model=2 kV=2.4  kW= ' num2str(x(6)*28)  ' kvar=' ...
         num2str(x(6)*86)];
57    DSSText.Command= ['New Load.670a Bus1=670.1     Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*17)   ' kvar=' ...
         num2str(x(6)*10)];
58    DSSText.Command= ['New Load.670b Bus1=670.2     Phases=1 Conn=Wye ...
          Model=1 kV=2.4  kW= ' num2str(x(6)*66)   ' kvar=' ...
         num2str(x(6)*38)];
```

```matlab
59      DSSText.Command= ['New Load.670c Bus1=670.3    Phases=1 Conn=Wye ...
            Model=1 kV=2.4  kW= ' num2str(x(6)*117) ' kvar=' ...
            num2str(x(6)*68)];

60

61      DSSText.Command =['New Capacitor.Cap1 Bus1=675 phases=3 kVAR= ' ...
            num2str(cap1) 'kV=4.16 '];

62      DSSText.Command =['New Capacitor.Cap2 Bus1=611.3 phases=1 kVAR= ...
            ' num2str(cap2) 'kV=2.4 '];

63

64      %%%OLTC%%%
65      DSSText.Command = ['Transformer.Reg1.Taps=[1.0 ' num2str(x(3))];
66      DSSText.Command = ['Transformer.Reg2.Taps=[1.0 ' num2str(x(4))];
67      DSSText.Command = ['Transformer.Reg3.Taps=[1.0 ' num2str(x(5))];
68      DSSSolution.Solve;

69

70      PQ=DSSCircuit.losses;
71      PL=PQ(1)/100000;
72      QL=PQ(2)/100000;
73      BusN=DSSCircuit.AllNodeNamesByPhase(1);
74      BusNb=DSSCircuit.AllNodeNamesByPhase(2);
75      BusNc=DSSCircuit.AllNodeNamesByPhase(3);
76      V1 = DSSCircuit.AllNodeVmagPUByPhase(1);
77      V2 = DSSCircuit.AllNodeVmagPUByPhase(2);
78      V3 = DSSCircuit.AllNodeVmagPUByPhase(3);
79      CVD =sum(abs(V1-1))+sum(abs(V2-1))+sum(abs(V3-1));
80      alltaps=tpa1+tpa2+tpa3;
81      OpOLTC= abs(x(3)-x(7))+abs(x(4)-x(8))+abs(x(5)-x(9));
82      OpCAP=abs(x(10)-x(12))+abs(x(11)-x(13));

83

84      y = 0.2*PL+0.2*CVD+0.1*Quad-0.2*DG+0.2*OpOLTC+0.1*OpCAP;
```

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