Modelling, Evaluation and Demonstration of Novel Active Voltage Control Schemes to Accommodate Distributed Generation in Distribution Networks

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Abstract

Voltage control in distribution networks is becoming more challenging due to the growing amount of distributed generation that is being connected to the distribution networks in addition to increasing load. The output of the distributed generation can radically change power flows and voltage profiles in distribution networks, creating conditions that adversely affect the performance of automatic voltage control schemes and in addition cause unacceptable voltage rise. On the other hand, inherent limitations and current operational policies of AVC schemes very often restrict the output of DG or even prevent its connection.

This thesis investigates and analyses voltage control in terms of the shift from passive to active distribution networks. The thesis also reviews the performance of AVC schemes under varying load and generation output conditions, investigates effective utilisation of distribution network assets and methods to accommodate active voltage control schemes into existing infrastructure. A range of active voltage control and management schemes based on coordinated voltage control is presented and assessed. These schemes can be used to improve the voltage profile in distribution networks and increase their ability to accommodate distributed generation. The functionality of each scheme is assessed based on a number of factors such as the ability of the scheme to increase network capacity, reliability and accuracy.

Simulation software to accurately evaluate the performance of an active voltage control scheme in a particular distribution network scenario is essential before the scheme can be deployed. Formal assessment of advanced AVC models and SuperTAPP n+ functionality is performed using simulation software as developed and presented in this thesis. The accuracy of the software results and performance of the SuperTAPP n+ scheme is validated based on network trials carried out in EDF Energy Networks.

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Declaration

The work described in this thesis has not been previously submitted

for a degree in this or any other university,

and unless otherwise referenced it is the author's work

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List of Acronyms

AC	–	Alternating Current
ANM	–	Active Network Management
AVC	–	Automatic Voltage Control
CI	–	Customer Interruption
CML	–	Customer Minute Lost
CT	–	Current Transformer
DG	–	Distributed Generation
DMS	–	Distribution Management System
DNO	–	Distribution Network Operator
DSSE	–	Distribution System State Estimation
ETAPP	–	Enhanced TAPP
GIS	–	Geographical Information System
GSP	–	Grid Supply Point
HV	–	High Voltage
IFI	–	Innovative Founding Incentive
LDC	–	Load Drop Compensation
LEM	–	Load Exclusion Module
LV	–	Low Voltage
MD	–	Maximum Demand
M-F	–	Master – Follower
MV	–	Medium Voltage
NOP	–	Normal Open Point
NRC	–	Negative Reactance Compounding

OCEPS	–	Operational and Control Of Power System
Ofgem	–	Office of Gas and Electricity Markets
OLTC	–	On-Load Tap Changer
OLTS	–	Off-Load Tap Switch
PCC	–	Point of Common Coupling
PDF	–	Probability Density Function
RES	–	Renewable Energy Resources
RPZ	–	Registered Power Zone
RRTU	–	Reporting Remote Terminal Unit
RTU	–	Remote Terminal Unit
SCADA	–	Supervisory Control And Data Acquisition
SE	–	State Estimation
TAPP	–	Transformer Automatic Paralleling Package
TCC	–	True Circulating Current
X/R	–	Reactance to resistance ratio

List of Symbols

A	OLTC changing action
β	Angel representing substation power factor
BW	Bandwidth in the AVC
C_{DG}	Generation operation power factor in E_{DY} estimation technique
C_{LOAD}	Power factor of load in E_{DY} estimation technique
$DF_{C,I}$	Load diversified factor
ΔN	Transformer tap step
ΔV	Difference between measured and target voltage
ΔV max	Maximum voltage drop on a feeder
E	Voltage excursion outside permissible level
ε , ζ	Load model exponents
E_{DY}	Dynamic load ratio
E_{ST}	Load sharing ratio
F_{LC_MIN} and F_{LC_MAX}	minimum and maximum uncertainty coefficients
γ , δ	Load model coefficients
I_{CIRC}	Circulating current
I_E	Current feeder measurement
I_{FG}	Current on the feeder with DG
I_{FX}	Current on the feeder
I_G	Generator current
I_{GMAX}	Generator maximum current, rated current

LIST OF SYMBOLS

I_{LOAD}	True load on substation
$I_{M(FX)}$	Current measurement on the x^{th} feeder
$I_{\min,f}$, $I_{\max,f}$	Minimum and maximum load on the feeder f
I_{TL}	Total load at substation
I_{TX}	Transformer current
I_{TXMAX}	Maximum transformer current, rated current
k	Transformer tap position
K_{TX}	Rated transformer output (kVA)
L_F	Load on the feeder F
L_{PT}	Load on the power transformer
α_{TX}	Transformer power factor
N	Number of turns of transformer winding at the primary side
n	Number of turns of transformer winding at the secondary side
N_{MIN}, N_{MAX}	Minimum and maximum transformer tap position
P , Q	Real and reactive power
PF_F	Feeder power factor
PF_i	Load power factor
PF_{TAR}	Target power factor in TAPP scheme
P_G, Q_G	Real and reactive generator power
P_L, Q_L	Real and reactive load power
$R_{\%}$	Load drop compensation setting for voltage boost at substation busbars
R_L, X_L	Resistance and reactance of the line

LIST OF SYMBOLS

$R_{LDC}, -jX_{LDC}$	NRC scheme settings
S_F	Sensitivity factor in ETAPP scheme
S_i	Expected value of power demand at ith node
$S_{MD,i(FX)}$	Maximum power demand at ith node of feeder xth
$S_{M,(FX)}$	Power measurement on the xth feeder
$S_{MIN,i}, S_{MAX,i}$	Estimated minimum and maximum load demand at node
t	Transformer variable turns ratio
TC	AVC relay time counter
TD	AVC relay time delay setting
U_{TX}	Transformer voltage ratio
V	Voltage
V_{AVCMIN}, V_{AVCMAX}	Operational voltage limits
V_{COMP}	Compounding voltage bias
VDF_f	Voltage drop factor for feeder *f*
V_G	Generation voltage bias
$V_{GMAX}\%$	Maximum generation voltage bias
V_{LDC}	LDC voltage bias
VM_i	Voltage drop moment
V_{NET}	Network voltage bias
V_{TAR}	Voltage target for AVC relay
V_{TAR}'	Effective voltage target
$V_{TARADJUST}$	AVC voltage target adjustment

***L**IST OF **S**YMBOLS*

V_{VT}	Voltage measurement at substation busbars
Z_{TX}	Impedance of transformer, voltage drop at full-load
Y, G_E, B_E	Shunt admittance, conductance and susceptance in load flow model
Z_R, R_R, X_R	Impedance, resistance and reactance in load flow model

Chapter I - Introduction

1.1. Growth and Accommodation of Distributed Generation.

In recent years new approaches to the generation of electrical power have been adopted across the electricity industry. Such new approaches are specifically concerned with environmentally sustainable, reliable and affordable energy sources such that global energy policies support the generation of electrical power from wind, solar, marine, biomass, energy from waste, CHP as well as other sustainable means. In contrast to conventional fossil fuel generation plant these resources can be much smaller in capacity but greater in number and highly dispersed. As a consequence it must be cost-effective to connect these energy resources into distribution networks at both medium and low voltage levels [1].

In 1997 the total capacity of distributed generation (DG) installed in the UK was approximately 1.3 GW [2]. The impact of UK government policy since 1997 is evident by a steady increase in the amount of DG connected to distribution networks and an increase in the proportion of DG to the total installed generation capacity. At present, installed DG capacity is approximately 13 GW [2]. Future UK electrical power generation scenarios predict that by 2050 installed DG capacity may reach 40 GW, accounting for 50% of total installed capacity in the UK. Depending on future developments in electrical power generation and government policy, renewable generation may account for 30 % of total generation in a ‘business as usual’ scenario, 50 % in a ‘strong optimism’ scenario and up to 80% in a ‘green’ scenario [3],[4].

Therefore, it is reasonable to assume that a substantial amount of renewable generation will inevitably be connected to distribution networks in the future.

Technical and commercial challenges associated with the connection of DG into distribution networks have been recognised by both distribution network operators (DNOs) and the government regulator for the electricity networks, the Office of Gas and Electricity Markets (Ofgem).

To facilitate connection of DG in an efficient and cost effective way, Ofgem has introduced a number of incentive mechanisms such as the distributed generation incentive scheme, the innovation funding incentive (IFI) and the registered power zones (RPZ) [5]. The main objective of these schemes is to encourage DNOs to develop and implement technical innovations that provide a cost-effective connection of DG, improve the utilisation of existing distribution networks, promote flexible and efficient operation, increase security of supply and provide environmental and safety benefits [6].

1.2. Background and Objectives of the Thesis

With the growth of DG in distribution networks, DNOs are faced with many challenges in design, control and operation of their systems. Voltage control issues were identified as the main factor preventing the DG integration into distribution networks [7], [8]. An unacceptable voltage rise at the point of common coupling (PCC) and the performance of the automatic voltage control (AVC) schemes are often the limiting factors in the amount of generation that can be connected to the distribution network.

Standard practices for overcoming the voltage rise issue while accommodating DG into distribution networks are based on passive solutions such as network reinforcement and do not provide a cost effective solution for generators, DNOs or consumers [8]. Active voltage management can be the most cost effective solution in order to ease the constraints applied to the generator export capacity caused by static voltage regulation. A number of active network management (ANM) solutions for voltage control have been proposed [8], [9]. Many of these technologies are already available and have been implemented in trial installations across UK distribution networks [6].

However, due to a lack of expertise and confidence, such new technologies are not commonly used and on the UK distribution networks and where they are deployed, the functionality is not fully exploited. ANM schemes are often depicted as overcomplicated and as a consequences simpler established solutions are used instead [9]. Additionally, the presence of DG significantly changes the power flow in distribution networks and can compromise the operation of AVC schemes.

The main aim of this thesis is to propose strategies and techniques for DNOs in order to increase flexibility and efficiency of their networks while enabling the connection of DG.

Another aim of this thesis is to analyse the effect of DG on existing voltage control schemes. This may be achieved by the development of computational models for AVC schemes and associated simulation software that enables comprehensive analysis of performance of AVC schemes in distribution networks with DG. As both AVC and on-load tap-changer (OLTC) schemes are essential for active voltage control, accurate modelling of both is a necessity.

ANM schemes can offer robust control of the system voltage and can support an increased amount of generation, but such schemes necessitate more complex infrastructure, sophisticated algorithms and the requirements of continuous and reliable communication. Therefore simpler but similarly efficient solutions also need to be investigated. The objective of the thesis is to analyse voltage control schemes based on local measurements and investigate its performance in distribution networks. Additionally, consideration of the implementation of active voltage control techniques into an existing distribution networks infrastructure is considered.

Due to a lack of measurements, the observability of distribution networks is very low, particularly on the 11kV system. Therefore it is difficult to precisely evaluate the voltage profile on the network and estimate the available voltage headroom that can be utilised by an active voltage control scheme. The provision of simulation software that enables distribution planning engineers to correctly assess the voltage profile, and as a result fully exploit the functionality of the active methods, is another objective of this thesis.

1.3. Outline of Thesis

This introduction has outlined the background for this thesis. The remaining chapters are organised as follows:

Chapter II briefly describes the purpose of the electricity system, classification and attributes of various voltage levels in the UK. It also highlights the differences between the distribution and transmission electricity systems and discusses the effect these differences have on design, operation and control. Furthermore, the main characteristics of distribution networks are examined and the factors that affected development of these systems are discussed. Existing design and operation regimes as well as management and control schemes in distribution networks such as supervisory control and data acquisition (SCADA) and distribution management system (DMS) tool are described. This chapter concludes with an outline of the challenges for the DNOs regarding the control and management of their systems increasing amount of DG connections in their networks. The control of voltage is identified as one of the key problems while connecting DG into the distribution network.

Chapter III focuses on voltage control issues in the distribution network. Firstly, theoretical analysis of voltage management in the power system is discussed and resulting design and operating principles for a distribution network are given. Then the statutory voltage limits for various voltage levels of the UK power system are stated. Standard techniques and equipment employed by the DNOs in order to comply with the statutory limits under varying load conditions and network characteristics are discussed in detail. AVC scheme principles and functionality are presented.

Operational methods and common settings for the AVC scheme operated at a fixed voltage target as well as with load drop compensation (LDC) are specified. Additionally, conditions for parallel transformer operation and requirements for the AVC scheme to maintain the desired voltage level at the substation busbars while minimising circulating current between transformers are discussed. AVC control of paralleled transformers based on compounding voltage bias is also demonstrated.

In **chapter IV** the modelling and simulation of AVC schemes is presented. The general model of the AVC scheme is introduced and the principles of the most commonly used AVC schemes in UK distribution networks are analysed. Then computational models of these schemes and their implementation into load flow software are described. Performance of the AVC schemes under various load and generation output conditions in distribution networks are investigated by the use of the simulation software and corresponding results are presented. Factors affecting the operation of the schemes are examined and the errors are evaluated. Furthermore, the advantages and disadvantages of each scheme and any limitations in distribution networks with DG are discussed. Finally, a summary and comparison of AVC schemes and computational models that have been proposed and developed in this chapter are presented.

Chapter V presents a detailed investigation of voltage control issues in distribution networks with DG. It also reviews existing and newly proposed techniques to improve voltage management and support DG in distribution networks. Passive solutions, LDC utilisation, generator reactive power control and active schemes are examined and evaluated. Three main categories of coordinated voltage management for 33 kV and 11 kV networks are proposed. The challenges and benefits of active network management techniques in distribution networks are then presented. A novel technique to assess operational voltage limits for these schemes is proposed. Implementation of the active voltage control management within existing infrastructure is presented and limitations are identified.

Chapter VI presents a novel active voltage control solution based on the SuperTAPP n+ scheme. The principles of operation are discussed and characteristics and factors affecting the performance of the scheme are investigated. The SuperTAPP n+ scheme uses local feeder current measurements and the load share between the feeders to assess the generator export connected at the remote point on the network. Additionally, two new methods to estimate generator output using local measurements are proposed. The first method is based on a dynamic load ratio technique and the second is based on assumed constant power factors of load and generation. The consistency and accuracy of all three estimation algorithms is investigated using an offline simulation approach based on network measurements. Suitability, advantages and disadvantages of each algorithm are then discussed. Furthermore, the chapter describes the M-OCEPS simulation tool which has been developed for voltage analysis in distribution networks with DG and a corresponding assessment of the SuperTAPP n+ scheme functionality in a particular system. New algorithms for load distribution and voltage profile evaluation on the feeders are proposed and implemented into M-OCEPS. The precision and certainty of the voltage profiles obtained from the simulation are analysed using the probability density function (PDF) and Monte Carlo simulation. Finally, a novel voltage control scheme based on voltage drop factors is demonstrated.

Chapter VII details a SuperTAPP n+ field trial in EDF Energy Networks. The characteristics of the network, installation of the scheme and its performance are discussed. The results from the field trial are then used to validate the functionality of the assessment software M-OCEPS. Consequently, the voltage profile estimation results are compared with the real network measurements and hence the M-OCEPS algorithms and computational models are verified. Using the SuperTAPP n+ simulation tool, optimum settings for the scheme are obtained and the effectiveness analysed.

Chapter VIII presents a comparison of the coordinated voltage control schemes that are discussed in previous chapters. Firstly, another active voltage control trial in EDF Energy Networks based on a local voltage controller is presented. The GenAVC scheme, including installation and assessment tool are briefly described. Using simulation tools, two case studies based on the SuperTAPP n+ and GenAVC field trials are examined. The efficiency of the schemes based on the SuperTAPP n+ platform and the local voltage controller in various configurations with a number of remote terminal units (RTUs) is investigated and the results presented. The application, communication requirements, technical issues and installation of the schemes in existing distribution networks is discussed.

Chapter IX concludes the thesis. It summarises the main research and studies presented in this thesis and makes proposals for future research and development.

1.4. Summary of the Research Contribution

The summary of the original contribution to knowledge derived from the individual work by the author of this thesis is presented in this section.

1) Computational models of AVC schemes such as negative reactance compounding, true circulating current, transformer automation paralleling package (TAPP) and the Enhanced TAPP (ETAPP) scheme have been developed and implemented into OCEPS software. It has been demonstrated that a number of factors such as DG export, varying power factor and load can affect the performance of a voltage control scheme. The AVC models in the steady state analysis allow an evaluation of the functionality of these schemes under various load and generation conditions on the network. They also enable precise analysis of an effect of the changes in AVC settings such as voltage target, relay bandwidth, LDC and compounding on the voltage profile on the network, operation of OLTC, losses caused by circulating current, number of tap change operations, etc.

2) An efficient simulation software tool for analysis of active management of voltage in distribution network with DG has been developed. M-OCEPS software enables the user to combine historical SCADA data and a network model in order to investigate the voltage profile on a network and gives an evaluation of the available voltage headroom that can be created by use of an active voltage control scheme. A new load modelling method for pseudo-measurements in distribution networks has been developed and implemented in M-OCEPS. This method is based on feeder load scaling according to the feeder measurements and uncertainty factors for load at

distribution substations. The algorithm has been designed to optimise the use of available information from the DNO's databases and network data in order to provide accurate voltage profile estimation on a feeder.

3) A detailed computational model of the SuperTAPP n+ scheme has been developed and implemented within M-OCEPS. This provides simulation software that enables an assessment of an improved voltage profile and quantifies the benefits of the scheme when DG is to be connected. Additionally, it assists with optimal selection of the SuperTAPP n+ settings for a particular network application. The simulation software has been validated using data from real network trials and has been proved to provide accurate and consistent results. Two novel methods to estimate generator output based on local feeder current measurements have been proposed. These algorithm techniques offer an alternative estimation technique for the SuperTAPP n+ scheme. Depending on network characteristics, generator operation regimes, the power factor on the network and load distribution, one of the three estimation techniques can offer more accurate and consistent estimation of the generator export. As a result, improved performance of the SuperTAPP n+ scheme can be achieved and utilisation of the network increased.

4) Evaluation of operational voltage limits for active voltage control schemes in distribution networks with DG has been carried out and recommendations for DNOs' voltage control strategies have been presented. Existing distribution network infrastructure, AVC schemes and operational methods have been taken into consideration while determining the limits for the active voltage control.

5) Functionality of coordinated active voltage management schemes has been investigated in realistic network scenarios and comparison results are presented. The effectiveness of the advanced AVC scheme and local voltage controller in terms of the ability to support DG export has been assessed. Factors such as implementation into existing infrastructure, communication requirements and implementation costs have been discussed. Additionally, a novel active voltage control scheme based on feeder measurements and voltage drop factors has been proposed. The simplicity of the scheme does not require a powerful computation effort and can be implemented into the existing SuperTAPP n+ platform. It offers significant improvement on the network with irregular load distribution between the feeders and allows simple accommodation of RTU measurements. M-OCEPS software can be used to determine settings for the scheme and optimise its performance.

1.5. List of Publications

The following is the list of publications arising from this thesis:

[1] M. Fila, G.A Taylor, J. Hiscock, "Systematic modelling and analysis of TAPP voltage control schemes", UPEC 2007, Brighton, UK, 2007

[2] M. Fila, G.A Taylor, J. Hiscock, "Modelling and Analysis of Enhanced TAPP scheme for distribution networks," 16th Power Systems Computation Conference, PSCC 2008

[3] M. Fila, G.A Taylor, J. Hiscock, "Flexible Voltage Control to Support Distributed Generation in Distribution Network", UPEC 2008, Padua, Italy, 2008

[4] M. Fila, J. Hiscock, D. Reid, P. Lang, G. A. Taylor, "Flexible Voltage Control in Distribution Networks with Distributed Generation – Modelling Analysis and Field Trial Comparison", CIRED 2009 Proceedings, Prague 2009

[5] M. Fila, D. Reid, G. A. Taylor, P. Lang, M. R. Irving, "Coordinated Voltage Control for Active Network Management of Distributed Generation", IEEE PES General Meeting, Calgary, Canada, 2009

[6] M. Fila, G. A. Taylor, M. R. Irving, "Development and deployment of novel active voltage control schemes within MV networks to accommodate distributed generation", IET Proceedings, Generation, Transmission and Distribution (submitted 2010)

Chapter II – Distribution Networks

Electricity networks are generally divided into two categories, transmission and distribution systems. Until recently, research and engineering development was concentrated at the transmission system as it presented many challenges and prospects for improvement. A great deal of emphasis and resources have been dedicated in order to develop and improve theoretical understanding, underlying principles, control techniques, communication infrastructure and simulation analysis of the transmission system. In the meantime distribution systems have been considered as the more passive and uncomplicated system and much less effort has been given in order to improve its performance and increase efficiency. However, as the amount of distributed generation increases, DNOs are incentivised to improve efficiency of their systems as new operational and control techniques are required [10].

Due to the fact that transmission networks differ in many aspects from distribution networks many of the techniques developed for the former can not be applied into the latter or at least need to be modified in order to fit existing distribution system infrastructure.

The aim of this chapter is to present key differences between transmission and distribution networks and provide main characteristics of the latter. The existing control and operation principles, management systems as well as challenges and prospects for the distribution networks are presented in the following sections of this chapter.

2.1. Introduction – Transmission and Distribution Networks

The purpose of the electricity network is to connect all generators and provide electricity supply to all customers. It consists of overhead lines, underground cables, transformers, switchgear and many other apparatus which build a complex system to enable controlled, safe and efficient electric energy transfer [11].

The electricity system has developed over the years from the single generator supplying local load to the interconnected system covering entire countries. As the transport of large quantities of electric energy over long distances is more efficient at high voltage (HV), the network between large-scale generation and load demand centres are operated usually above 200 kV (275 and 400 kV in UK including (132kV in Scotland)). This network is the backbone of the electricity system. The transmission system provides power to grid supply points (GSP) and also large industrial customers. From GSPs the power is conveyed to medium and small customers through medium voltage (MV) and low voltage (LV) distribution networks [12].

The general purpose of transmission and distribution networks in principle is the same, however distribution networks differ from transmission networks not only by the means of the voltage level but also in many other aspects such as operation principles, physical characteristics, complexity, design, etc. [13]

Due to the fact that electrical energy is very difficult to store, power generation and load need to be continuously balanced. A number of generators are producing energy at various times of the day depending on the wholesale electricity market price, electricity fuel price, generator availability, network constrains and constantly changing load. These characteristics make the transmission network a dynamic system. A transmission system operator is responsible for maintaining power balance as well as keeping the system stable and within operational limits. To achieve these objectives active control of the whole system is essential. On the other hand, in distribution networks with little generation connected, load flow is typically unidirectional. Distribution networks take supply from GSPs and deliver electricity from higher to lower voltage networks, down to all customers. The network design is based on the worst case scenario derived from the forecasted maximum load. This simplifies the control of the distribution networks which are usually operated in a passive manner.

Another factor which differentiates transmission and distribution networks is the number of components; while the transmission network has a relatively small number of components, distribution networks consist of large number of various elements needed to supply a widely dispersed customer base. However, a failure of a single component in the transmission system may cause blackout spread over large area or even the collapse of the whole system. For this reason high redundancy in the network and sophisticated control and protection systems are used. Component failure in the distribution network affects a much smaller number of customers, in the worst case causing a local blackout, and it is rather unlikely to be a reason of system breakdown. Naturally, the distribution networks are designed and operated to minimise the effect of any component failure and DNOs need to comply with “Electricity supply quality and continuity regulations” [14] and “P2/6” directives [15] to reduce any supply disruption.

Due to the fact that a transmission network consists mainly of high voltage overhead lines, the system X/R ratio is high. This imposes a particular characteristic of the active and reactive power flow and determines control of the transmission system. On the other hand X/R ratio of the distribution networks is usually considerably lower and varies significantly with the voltage levels and proportion of cables and overhead lines. In the networks with much lower X/R ratio different control regimes need to be used in order to effectively operate the system. It should be noted here that compared to the impedance of lines/cables, transformer impedance contributes the most significant reactance to the system.

Finally, transmission networks are strongly interconnected systems. However, depending on the voltage level and complexity of the system distribution networks can be operated in radial or meshed manner. This factor also affects the operation and control method of the networks [16].

The characteristics of the distribution networks described above affect the design, operation and control of these networks. Depending on voltage level, complexity of the system, load demand and generation connected to the network an appropriate design principle, control method and operation regime need to be employed. The purpose, characteristic and design principles, as well as challenges for the distribution networks, are described in the following chapter with the particular focus on the matters affecting voltage control in the 33 kV and 11 kV networks.

2.2.Characteristics of Distribution Networks

A typical arrangement of the UK distribution system is shown in figure 2.2.1., however the system configuration and voltage levels can significantly vary from network to network.

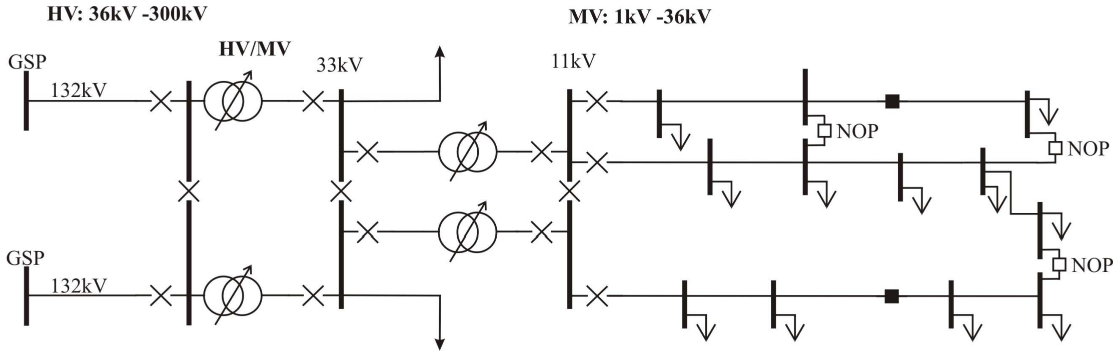


Figure 2.2.1 Distribution network arrangements

The grid substation is fed from the same or number of GSPs through 132 kV lines or similar voltage level. At the grid substation step down transformers reduce the voltage from the subtransmission level to the distribution level. Two or more transformers are usually installed depending on load demand in order to provide security and comply with engineering recommendation P2/6 [15]. MV level such as 33kV is commonly used to distribute electricity and supply the primary substations but direct change from 132 kV down to 11 kV is also common. 33 kV networks are operated in a pseudo radial manner but some parts of the network may be interconnected.

As with grid substations, the number of step-down transformers on primary substations depends on load demand and requirements for security and continuity of supply stated in [14] and [15].

A typical 11 kV network is commonly operated as radial system for economy and in order to simplify operation and protection procedures. A number of section switches is installed on the network in order to facilitate an alternative route of supply in case of fault or outage as presented in figure 2.2.2. Along the feeders a series of step-down transformers e.g. 11kV/433V are connected, from which customers are supplied at the statutory voltage.

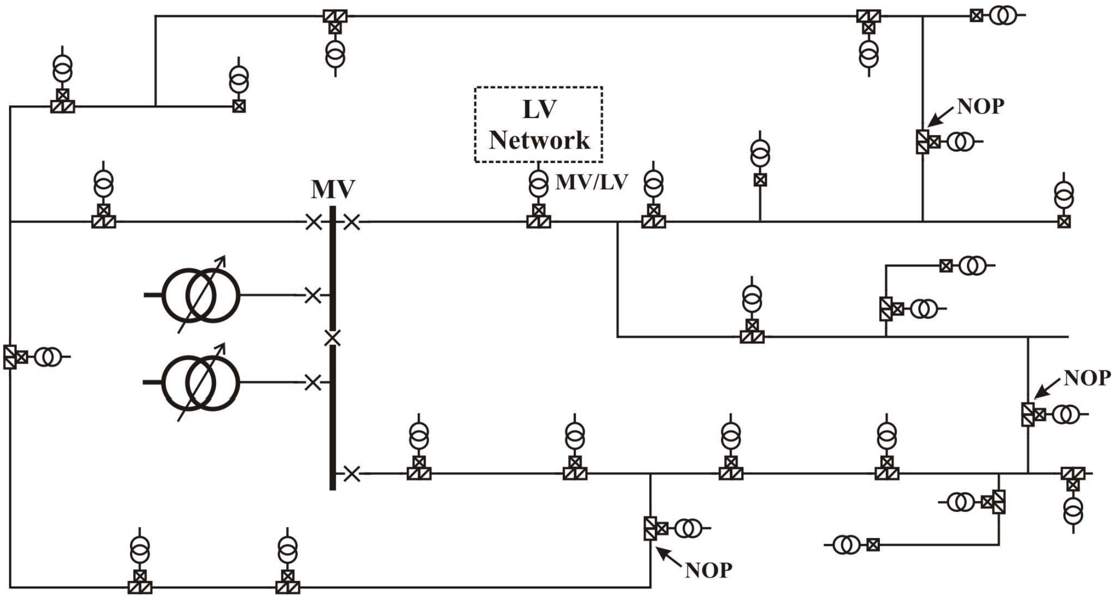


Figure 2.2.2 Typical 11kV network arrangement

Depending on location, load demand, load density, load character and load forecast, a number of types of distribution networks such as urban, rural or industrial systems can be identified [10]. Rural networks are characterised by long feeders, mainly overhead lines with the pole-mounted transformers in the range from 25 kVA to 200 kVA. Urban networks consist of much shorter, usually underground cables, feeders supplying distribution transformers located in ground-mounted substations or inside buildings. 500 kVA and 750 kVA distribution transformers are now standard in the UK. Frequently the primary substation feeds a mixture of rural and urban feeders, providing electricity to small or medium towns and surrounding areas. An arrangement of the industrial networks is determined by the character of the load, its density and sensitivity for disruptions.

The obligation of the distribution networks operators is to connect all customers and provide safe, efficient and uninterrupted supply within the statutory limits of voltage quality and security [17].

Historically, development, design and operation of distribution networks have been determined mainly by load demand. With little or no generation connected in medium and low voltage networks, load demand was predictable, power flow unidirectional and power factor consistent. The capacity of the distribution network based on this methodology was derived from a maximum demand forecast. The system was designed as a passive network to deliver electricity from the GSP to the end users within specified parameters under the worst load conditions with no or little automation. The capacity and redundancy of the system was proportional to the number of customers and security of supply requirements. As a result, in general the system was initially overdesigned [10].

Radial arrangement and unidirectional power flow significantly simplifies distribution network operation, protection and control. For example, most of the protection systems have been designed and set up to operate for unidirectional power flow and the voltage control scheme to operate at fixed power factor.

As the demand increases, DNOs develop the distribution network by reinforcing the system or adding new assets to increase the capacity. Additionally more advanced control schemes and management systems have been introduced in order to improve reliability and efficiency of the existing assets [18].

2.3. UK Distribution Networks Management and Control

The distribution network in the UK covers majority of the country, delivering electricity to millions of customers. In order to distribute electricity from GSPs to customers located in large cities, towns and rural areas, distribution networks consist of a vast amount of lines, cables, transformers, switches and ancillary equipment. This complex system needs to be controlled and managed in a safe and efficient manner. The SCADA system with the DMS is a tool which allows the operator to collect information about the state of the system, store and analyse data from thousands RTUs, identify problems and carry out any required action. The acknowledgement of the completed operation can be also transmitted.

A SCADA system provides the following types of signal:

- digital data: circuit breaker status, alarm indication, fault location
- analogue signals such as voltage, current, power factor
- control such as circuit breaker open/close , enable/disable AVC control

Depending on location, availability and bandwidth requirements the SCADA system uses mixture of communication channels such as pilot wires, copper circuit, fibre wires and radio.

DMS increases transparency of the system and enables control engineers to monitor the system and take required actions such as isolating a part of the network, clearing a fault, reconfiguring the network, restoring supply or optimizing the performance of the network. Data collected by SCADA and DMS can be used to analyse the system, pre-empt outages, allocate network constraints and plan network reinforcements.

The SCADA system in the UK distribution network was initially introduced at the higher voltage levels at 132/33 kV substations and it was later implemented by various degrees on the lower voltage levels down to 33/11 kV substations and 11 kV feeders [19]. All analogue and digital signals as well as the full circuit breakers telecontrol at the grid substations are provided for SCADA. Alarms and faults from majority of protection relays are sent to a control room. Most of the analogue signals are available and most circuit breakers can be remotely controlled at the existing primary substations.

However, full telecontrol is now a standard for all new or refurbished primary substations, due to a range of equipment involved and a lack of communication infrastructure there is little or no remote control over the embedded 11 kV network. Remote opening and closing of circuit breakers and information of their status have been introduced and is becoming commonly employed across the UK DNOs. Usually radio or mobile channels and recently satellite communication, is used for a transmission and receipt of single instructions. However, they are not suitable and cannot be used for continuous or a substantial quantity of data transfer. Therefore, no analogue signals are available beyond the primary substation feeder current measurements.

Apart from the centralised DMS and SCADA system there are number of local control schemes in distribution networks. One such example is a well established AVC scheme which is commonly used in UK distribution networks at grid and primary substations. Detailed description and analysis of such AVC schemes is presented in chapter III.

2.4. Challenges for UK Distribution Networks

UK DNOs are faced with a number of challenges regarding the control and management of their systems. DNOs are required to plan and develop the networks to a standard not less than stated in [15], provide connections for all new customers who require energy or intend to supply energy, as well as improve quality of supply and reduce losses in the system [18].

Firstly, DNOs are challenged by constantly increasing demand. As DNOs are obliged to connect new and supply growing energy needs of existing customers, the systems need to be constantly reinforced to meet the demand. Secondly, DNOs are incentivised to improve performance of the network. A number of incentive schemes have been introduced in the UK by energy regulator (Ofgem) to reduce energy losses in the system, minimise customer interruptions (CI) and customer minute losts (CML), as well as provide cost effective connections [17], [18].

The major development of the UK distribution networks took place in 1960s and 1970s. After 40-50 years of utilisation many of the components are approaching the end of their expected lifetime. Consequently, UK DNOs are faced with a substantial asset replacement programme. Additionally, in order to maintain high performance of the system, extend the lifetime of some assets and obtain advance warning about deteriorating component conditions, operators have introduced monitoring and supervisory systems. An example of such a scheme is a partial discharge monitoring system.

One of the biggest challenges for distribution networks is DG. In order to meet current and future government targets, growing amounts of generation from renewable energy sources (RES) are being connected to the power network. The majority of the RES is connected at medium and low voltages and classified as DG.

As previously discussed, distribution networks were originally designed to deliver electricity from GSP to numerous medium and small load customers in a reliable, efficient and statutory specified manner. Increasing penetration of the DG is changing the original character of the distribution networks from uni-directional to bi-directional power flow, increases in fault level and changing the voltage profile on the network.

It is recognized that connection of a generator can provide a number of benefits in a distribution network. Depending on location, network infrastructure and load conditions presence of DG can reduce losses in the system, alleviate heavily loaded feeders, improve voltage profiles and contribute to security of supply. However, due to the fact that distribution networks have not been designed to accommodate DG, a number of issues such as excessive fault level, thermal constraints and violation of voltage limits can arise. In order to be able to provide efficient and reliable connection for both DG and load customers without impairing the quality of supply, DNOs must develop and adopt new operational and control techniques.

2.5. Active Solutions for Distribution Networks

A number of innovative technologies has been recently developed and proposed with the purpose to help DNOs rise to the numerous challenges described in the previous section. These technologies broadly differ in complexity and application, however, they are generally regarded as active network management (ANM) solutions.

Number of definitions have been proposed in the literature to describe and categorize ANM [8],[9],[21],[51]. On the basis of these the common understanding of the ANM of distribution networks is that pre-emptive actions are taken to maintain networks within their normal operating parameters by the use of coordinated operation of network equipment, widespread monitoring and communication infrastructure and advanced algorithms embedded locally at the substation or centrally in a control room. The general objective of ANM is to transform passive networks into an active system which can be dynamically controlled and automatically configured.

ANM technologies have the potential to significantly improve network utilisation in an effective and cost-efficient manner. They can be used to increase security and reliability of supply, connect distribution generation or reduce operational cost and provide financial benefits for both load and generator customers.

The benefits of ANM are evident; however there is also a number of barriers for implementation of these technologies into distribution networks. Due to the fact that ANM strongly rely on communication, the reliable, widespread and continuous links are essential. Also new systems need to be integrated within existing infrastructure and coordinate with existing systems and network management routines. Moreover, safe and explicable operation of the system needs to be maintained while accommodating ANM technologies into the distribution networks.

Currently only single ANM trials are set up across the distribution networks, however, a growing number of active solutions is being introduced into distribution networks and innovative technologies have been identified as a promising platform for implementation. With the improved communication infrastructure, growing confidence, proved functionality and demonstrated benefits, distribution networks at all voltage levels are expected to become more active. The widespread automation and effective active control of distribution networks will not be easy due to the fact that UK distribution networks consist of more than 750 000 kilometres of overhead lines and underground cables and thousands of substations. Nevertheless a steady progress to move from current static approach for network management to active network control is expected.

2.6. Summary

Clearly, emerging active network control technologies can provide an efficient and cost effective solution for many issues associated with improving performance and the accommodation of DG into distribution networks [6], [19]. The necessity to move from the “fit and forget” approach of passive systems to an active solution is evident. However, a number of aspects need to be considered before new active network management technology can be implemented. Factors such as existing network infrastructure, amount of DG connected and future DG growth, the communication infrastructure, bandwidth requirements and costs need to be carefully analysed [6], [20].

One of the control techniques that can be significantly affected by the changes in distribution networks is voltage control. This technique needs to be revised in order to accommodate DG [21]. It has been recognised that excessive voltage rise on the network is a limiting factor for the accommodation of DG and presence of generation can severely affect automatic voltage control schemes currently used on UK distribution networks [7], [22].

ANM can provide an effective solution for voltage control problems in the distribution networks. However a number of issues such as AVC schemes operation, voltage profile and voltage limits on the distribution networks need to be considered before new active voltage control techniques can be utilised. Comprehensive analysis of existing voltage control schemes, options and risks of novel active voltage solution implementation into distribution networks are presented in following chapters.

Chapter III – Voltage Control in Distribution Networks

All appliances, electric machines and other electronic and electrical devices are designed to operate at a specific voltage supply level. However it is not economically practical to maintain a nominal voltage level at all customers connected to the distribution network and voltage variation needs to be allowed. The nominal voltage supply and permissible voltage deviation is now harmonized across Europe and is stated in [24]. As a result all equipment which is supplied from the mains must operate within these voltage limits and network operators are obliged to maintain the supply voltage at a satisfactory level.

Voltage regulation in distribution networks is required to offset the effect of voltage drop along conductors and other apparatus such as transformers in order to comply with statutory requirements. This is accomplished by means of selecting a suitable transformer ratio and appropriate conductor size. However, due to the fact that load demand varies considerably during the day, effective voltage control can be difficult to achieve using passive techniques. In order to automate, simplify, and optimise voltage regulation, AVC schemes are commonly used across the distribution networks [25].

In this chapter, theoretical analysis of the voltage control is discussed. Statutory voltage limits and the existing DNOs practices and techniques for voltage control to comply with this legislation are also presented. Detailed analysis of AVC schemes is described and their function in parallel control of transformers with OLTC discussed.

3.1. Theoretical Analysis of Voltage Control

When load is supplied from a remote source the voltage variation along the feeder can be described by the following equation:

$$\Delta \overline{V} = (R + jX)\bar{I} = (R + jX)\frac{P - jQ}{V} \qquad (1)$$

Where R and X are resistance and reactance of the line and P and Q real and reactive power flow respectively.

For the purpose of theoretical analysis the imaginary term of equation (1) can be neglected and the equation simplified to the form as presented in equation (2).

$$V_2 \approx V_1 + \frac{R \cdot P + X \cdot Q}{V_1} \qquad (2)$$

As the *X/R* ratio in a distribution network is low, neither the RP nor XQ term can be neglected. Considering active and reactive load: P_L and Q_L, as well as active and reactive power output of distributed generation: P_G and Q_G connected on the feeder, equation 2 takes form:

$$V_2 \approx V_1 + \frac{R \cdot (P_G - P_L) + X \cdot (\pm Q_G - Q_L)}{V_1} \qquad (3)$$

Equation 3 illustrates the factors, and their correlation, affecting the voltage profile on a distribution network. It might be seen that the voltage at a remote point on the feeder, V_2, is determined by the source voltage V_1, the impedance of the line $R + jX$ and the active and reactive power flow [26].

On the feeder where only load is supplied, the voltage drop will occur along the feeder as both terms $R \cdot (P_G - P_L)$ and $X \cdot (\pm Q_G - Q_L)$ are negative. On the other hand a voltage rise can occur when DG is connected on the feeder. Under these conditions the term $R \cdot (P_G - P_L)$ can become positive and the voltage level at the point of connection of DG and some parts of the feeder can then be higher than the voltage level of the busbar. The amount of voltage change depends on load, generator output and its power factor as well as parameters of the line.

Therefore voltage control of the distribution networks needs to be managed at the design stage by the correct selection of overhead lines and cable parameters. Additional correction of the voltage profile can be carried out in real time by certain operational techniques. It is achieved by source voltage adjustment under varying load conditions.

An example of the visual representation of the equation (3) is shown in figure 3.1.1. The active and reactive power flows on the feeders are represented by red and blue arrows respectively and the corresponding voltage profile is illustrated below. Feeder 1 is the feeder with DG connected at the remote point exporting electricity to the network while feeder 2 is the feeder with load only.

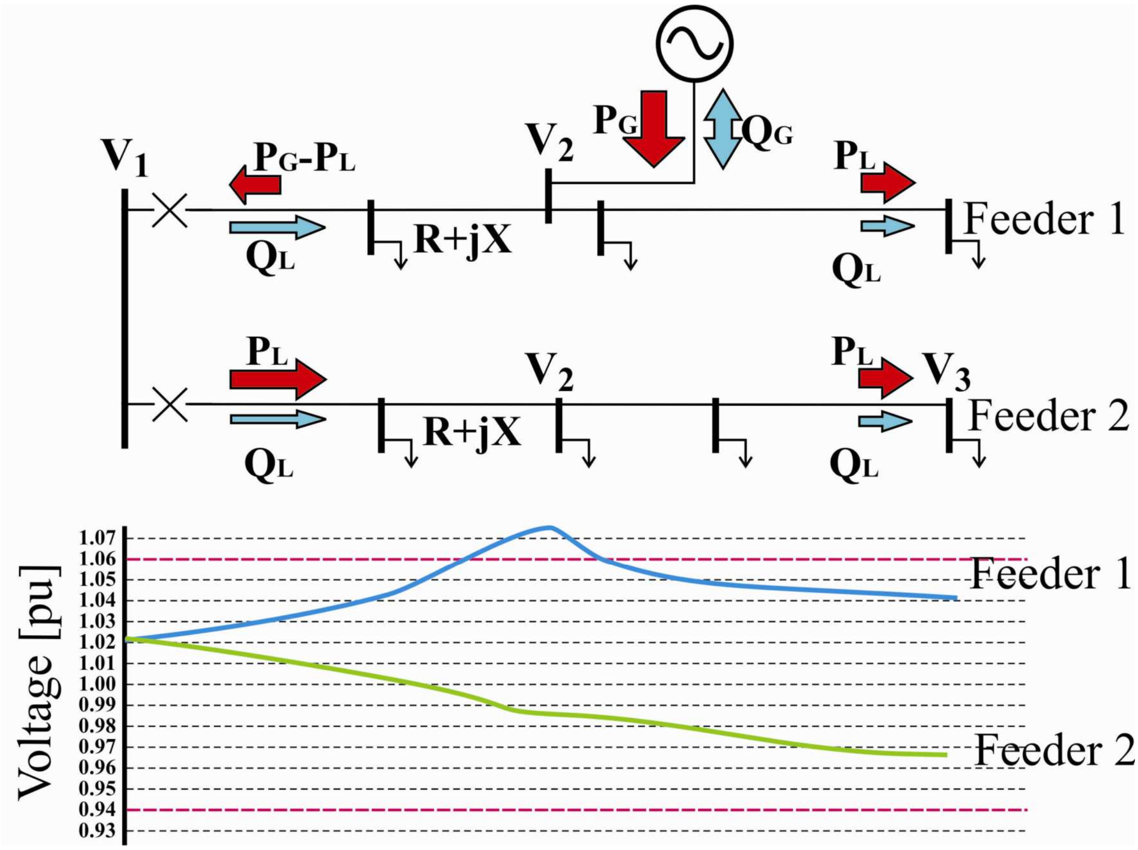


Figure 3.1.1 Voltage profile on a distribution network.

3.2. Statutory Voltage Limits

In the UK the DNOs' responsibility is to comply with regulatory requirements for the quality of supply and statutory voltage limits specified in [14] and [24]. The statutory voltage limits for all voltage levels are presented in Figure 3.2.1

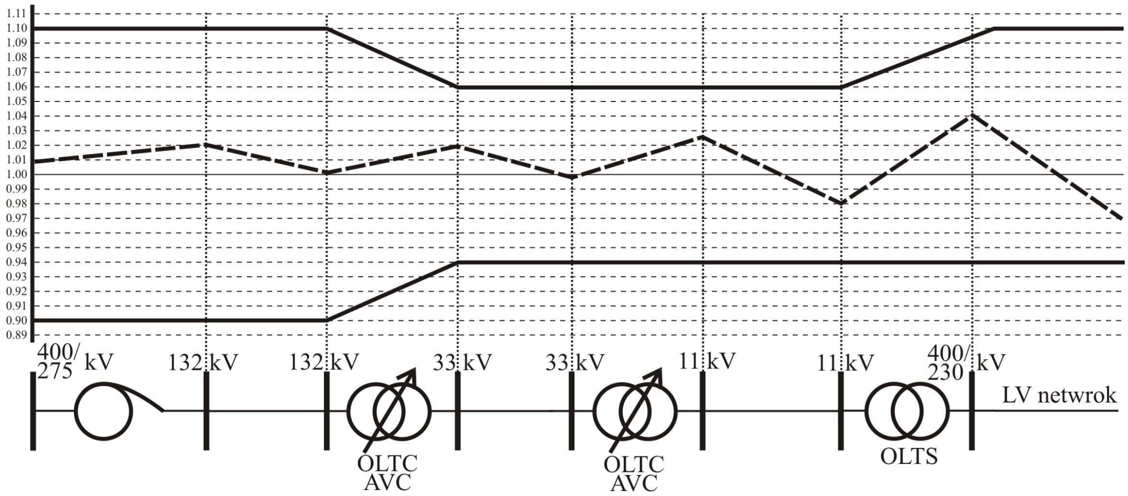


Figure 3.2.1 Statutory voltage limit in UK power system for various voltage levels and associate voltage control equipment.

For the transmission system and 132 kV distribution systems (often referred to as the sub-transmission system) the statutory limits are ± 10%. However, transmission network operator will normally maintain the voltage on the 400kV system within ±5% of the nominal value unless abnormal conditions prevail. Voltages on the 275kV and 132kV parts of the transmission system will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail [27].

For MV distribution networks, between 1 kV and 35 kV, the statutory limits are +/-6%. LV system limits within the declared range of 230 volts +10% and -6% are to be maintained under all network conditions. Any voltage deviation outside statutory limits, especially high voltage, can be hazardous for apparatus installed on the network and can cause damage to the customer’s equipment [2].

3.3. Standard Techniques of Voltage Management in Distribution Networks

In order to meet statutory voltage requirements, under dynamic load conditions and various network characteristics, purposely designed equipment and operational procedures are employed. An example of common voltage control arrangement at various voltage levels is presented in figure 3.2.1.

Distribution transformers fitted with off load tap switch (OLTS) provide a fixed voltage boost for the LV network. This boost is required in order to compensate for voltage drop on the feeders as well as across the transformer itself. A standard 11/0.433 kV distribution transformer has 5 tap positions in 2.5% steps, offering +/- 5% regulation range as presented in table 3.3.1

Position	**HV**	**LV**	**HV Boost**	**LV Boost @ 230/400 V**
	kV	*V*	*%*	*%*
1	11.55	433	5	3.1
2	11.275	433	2.5	5.6
3	11.00	433	0	8.2
4	10.725	433	-2.5	11.0
5	10.45	433	-5	13.9

Table 3.3.1 Standard off load tap changer of distribution transformer

Usually the tap ratio of the distribution transformer is determined at the design stage taking into account load demand, MV and LV network structure as well as voltage control technique used at the primary substation (such as AVC with or without LDC).

Although the tap position of the distribution transformer can be changed, for example seasonally, it is not common practice to adjust a distribution transformer ratio, unless it is required due to network change or adverse voltage level on the LV network.

A more effective method for controlling the voltage profile is used at primary and grid substations, where power transformers are equipped with OLTC and AVC schemes. The OLTC enables a transformer ratio to be changed and consequently the voltage output, without interrupting the load current. This is achieved by addition or subtraction of turns in the transformer winding, normally on the primary side of transformer. There are number of OLTC arrangements with a variety of selector and diverter types. An example of a tap selector and diverter switch type OLTC is presented in figure 3.3.1 [28]

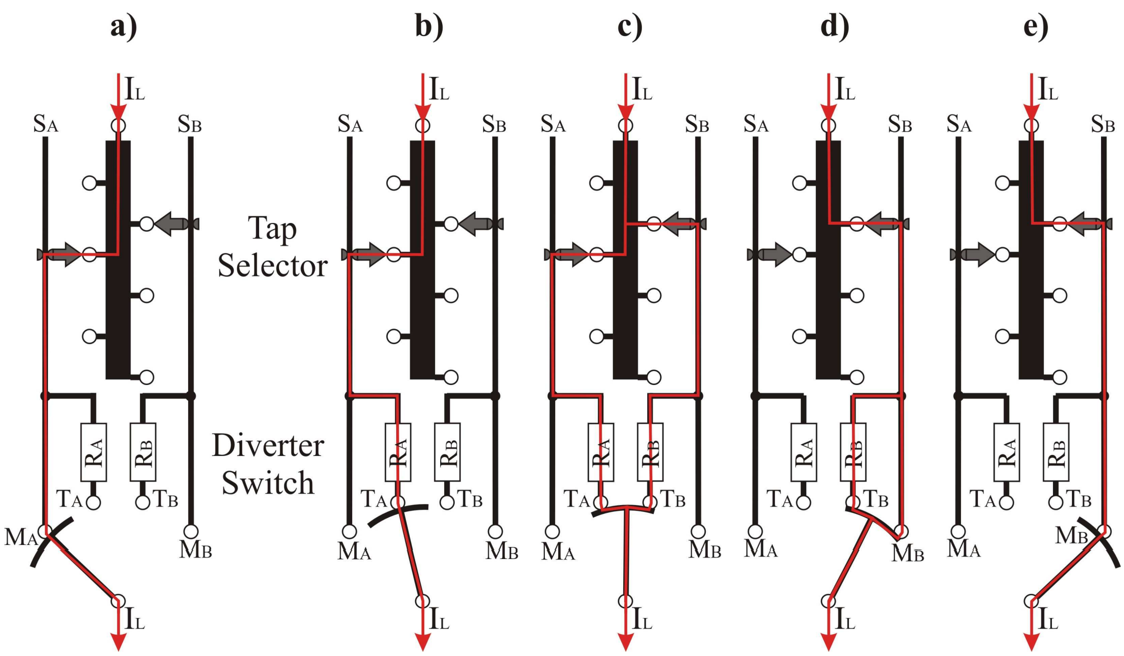


Figure 3.3.1 Principles scheme of a tap selector and diverter switch type OLTC [28]

A tap position change is carried out in a mechanically interlocked sequence. In figure 3.3.1 single tap position change is presented in five stages. In the first step load current is transferred through main contact on the left-hand side M_A. Tap selector S_B is load free and is used in order to pre-select subsequent tap position. When the tap selector reaches required tap position the diverter switch is actuated in order to transfer the load current from one position to another. To limit the circulating current and transfer the load current without interruption two resistors are used R_A and R_B with the transition switches T_A and T_B. The switching sequence is completed when diverter switch reaches main contact M_B on the right-hand side and the load current passes through selector S_B. At this point new tap position on OLTC is achieved reached [28].

Typically the OLTC used in distribution networks offers regulating ranges of 20 per cent in 17 or 19 tap steps, however this differs depending on the design and application of the tap changer.

In UK distribution networks, the OLTCs are installed at 132/33 kV and 33/11 kV substations in order to produce the appropriate voltage output at the substation busbars. AVC schemes are employed in order to automate and optimise operation of the OLTCs. At grid and primary substations the AVC scheme is typically linked to a SCADA system providing remote control functionality such as voltage reduction for emergency load shedding, remote tap operation or tap locking.

For more than half a century these AVC schemes have provided satisfactory and effective performance in distribution networks, helping to maintain a voltage profile within the statutory limits under varying load conditions. However, at a time of increasing use of DG, expansion of active network management and commitments to develop more efficient and flexible distribution networks, the traditional AVC schemes can become inefficient and their operation needs to be reviewed [29],[30].

The principle of operation and an in-depth assessment of the existing AVC schemes commonly used in distribution networks are presented in the following sections of this chapter. Computer representation and software simulation of various AVC schemes is presented in chapter IV.

Other voltage control equipment such as in-line voltage regulators and capacitor banks can be employed in distribution networks; these however, are not commonly used and are costly. A voltage regulator can be installed on an 11 kV feeder in order to provide an additional voltage control point on a line with excessive voltage drop. There are only a few of these devices installed in the UK at present [8], [19]. Raising the voltage by injecting reactive power in to the network using a capacitor bank is another method for voltage management, yet its implementation in the UK distribution networks is also very limited [51].

Distribution network operational techniques are designed to make efficient use of all available voltage control methods as well as the statutory voltage limits. Due to the fact that 11 kV networks are passive systems with very limited voltage control options, it is common practice to operate the primary substation 11 kV busbar at a relatively high voltage level. This ensures that, under heavy load conditions, customers at the distant point on the feeder receives voltage above the lower statutory limit and at the same time maintaining voltage level at customers close to the substation below the upper statutory limit.

One of the drawbacks of this practice is that customers connected at the remote point on the feeder can receive a voltage supply with a variation of 16.5% [25]. Another disadvantage of the high voltage target for 11 kV networks is that there is very limited voltage headroom in order to accommodate DG. Considerable voltage profile improvement in the networks can be achieved by modifying voltage target and using LDC. The principles and benefits of LDC are presented in section 3.4.5 and methods to improve the voltage profile and increase voltage headroom in distribution networks to connect DG are presented in the following chapters in this thesis.

3.4. Automatic Voltage Control Scheme Principle

The main purpose of the AVC scheme is to maintain the desired voltage level at the substation busbars under varying load conditions. When a voltage level outside the tolerable range is detected by the AVC relay, a raise or lower signal is sent to the OLTC in order to correct the voltage level.

A simple AVC scheme arrangement is shown in figure 3.4.1. In this arrangement only voltage measurement is used. The AVC relay compares the voltage measured at the secondary side of the transformer (V_{VT}) with the target voltage (V_{TAR}) in order to determine whether any actions are required.

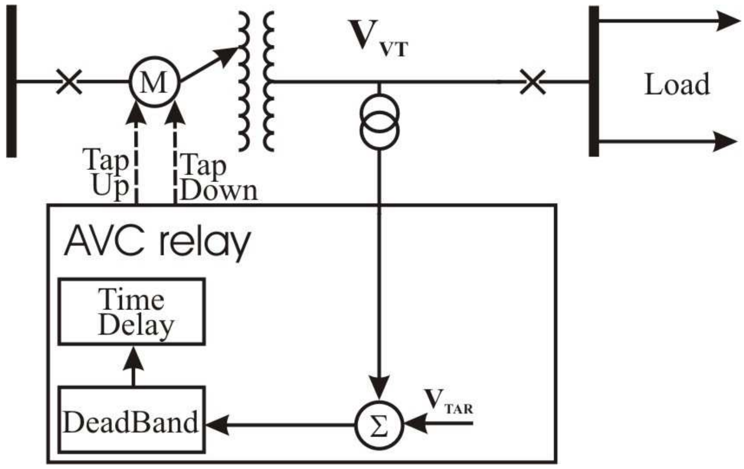


Figure 3.4.1 Simple AVC scheme arrangement

In order to ensure appropriate and efficient performance of the AVC scheme, basic settings such as voltage target, bandwidth, and time delay are essential, however, additional settings such as LDC, substation firm capacity, transformer impedance etc. can be also required.

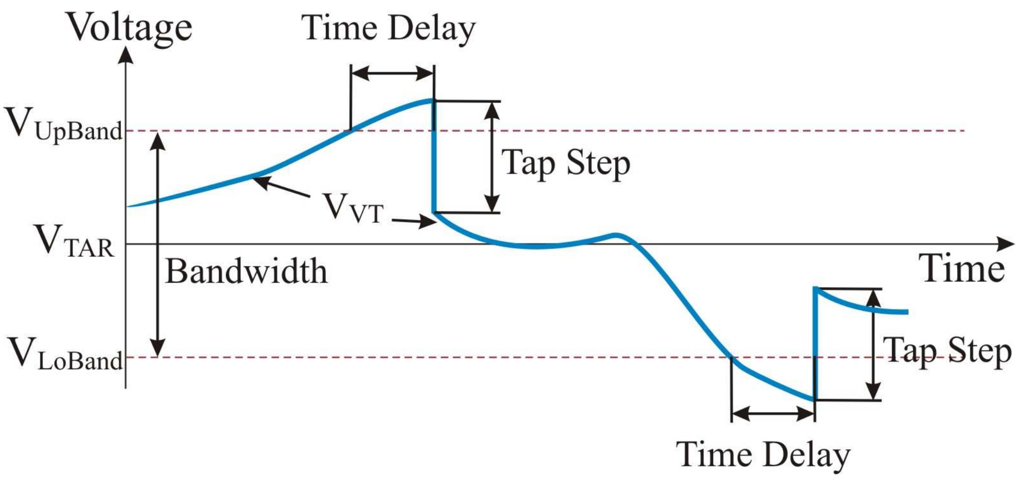
3.4.1. Voltage Target, Bandwidth and Time Delay Settings

The voltage target setting specifies the desired voltage level at the substation busbars which an AVC relay is intended to maintain. The voltage target varies from DNO to DNO and from network to network, but it is common for the 132/33 kV substations to run at a fixed voltage target at 101.5%. That gives the voltage level of 33.5 kV. For 11 kV networks the voltage target is typically set at 102.5% which gives the voltage level of 11.275 kV.

As a small deviation from the voltage target would cause the voltage control relay to operate, some tolerance range needs to be applied. The tolerance range in a voltage control relay is called the bandwidth setting, normally represented by a ± value from the voltage target. The bandwidth is defined as the voltage deviation from the voltage target below which no action is required by the voltage control relay. When the voltage deviation exceeds the bandwidth setting, the tap changer mechanism is activated in order to bring voltage back to a desirable level. The minimum bandwidth setting is determined by the voltage step of the tap changer. To prevent the AVC relay from hunting, the total bandwidth should be set greater than one step. The greater the bandwidth (BW) setting, the fewer the number of tap changer operations. On the other hand it should not to be set too high as the voltage precision will be compromised. Typically, the bandwidth is set between 1.5 and 2 tap steps [31].

Moreover, in order to avoid excessive tap changing due to short-term voltage fluctuations, a time delay must be introduced. The time delay setting is also used to coordinate operation of the AVCs between higher and lower voltage levels. It is desirable for a voltage change at 132 kV system to be corrected by the 132/33 kV transformer before correction is made by 33/11 kV transformers OLTC. Thus, time delay setting of the AVC scheme at the grid substations is usually between 30-60 seconds while at the primary substations is typically between 60-120 seconds.

The performance of the voltage control relay in time domain with the voltage target, V_{TAR}, measured voltage ,V_{VT}, bandwidth and time delay settings is illustrated in figure 3.4.2.



Firure 3.4.2 Performance of the AVC scheme

The voltage control relay monitors the voltage at the substation busbars and compares it with the voltage target and bandwidth settings. When the voltage exceeds the allowable voltage range, the relay starts timing. If the voltage level persists outside the range for longer then time delay setting, the relay takes actions to correct the voltage i.e. sends raise or lower signal to the OLTC.

3.4.2. Automatic Voltage Control with Load Drop Compensation

Another feature commonly implemented in the AVC relay is the LDC technique. In this method, in addition to voltage measurement, transformer current measurement is also used in order to determine the voltage level at a remote point on the network. An AVC relay with LDC therefore does not maintain the voltage at the substation, but at a remote point on the feeder under varying load conditions.

LDC voltage bias (V_{LDC}) is calculated and added to the voltage target (V_{TAR}). The AVC scheme arrangement with LDC functionality is illustrated in figure 3.4.3.

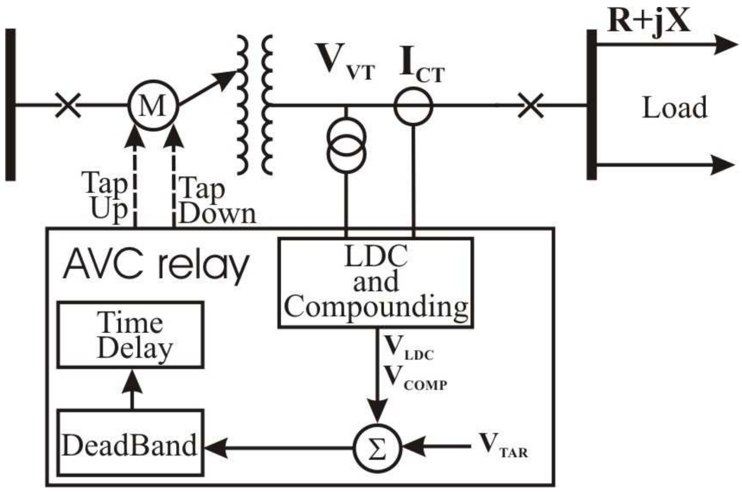


Figure 3.4.3 AVC scheme with LDC

There are two different approaches for the LDC scheme. They have similar purposes, but different implementation. The first approach is known as 'line drop compensation'. In this method feeder current, resistance and reactance of the line are used to estimate the voltage level at a remote point of the line. The line drop compensation bias is applied in proportion to measured current and *R* and *X* settings of the voltage control relay and calculated as follows:

$$\overline{V_{LDC}} = \overline{I_{CT}} \cdot (R_L + jX_L) \qquad (4)$$

The second method is called 'load drop compensation' and is intended for substations with multiple feeders. Voltage boost at the substation busbars, $R_{\%}$, is applied in proportion to the ratio of the actual current measurement to the current at full load. The LDC voltage bias is calculated as follows [32]:

$$V_{LDC} = R_{\%} \cdot \frac{I_{TX}}{I_{TXMAX}} \qquad (5)$$

This allows compensation for voltage drop along the feeders caused by load flow under various load conditions.

The main advantage of the load drop compensation technique over line drop compensation is that the former is much easier to set up as the maximum load of the substation is known, and transformer current is measured. On the contrary the latter technique requires knowledge of resistance and reactance of the feeder which are not clearly defined and feeder current which is not usually available. Additionally most substations have multiple feeders and R and X settings only apply to a single feeder with an end load. More details about the LDC schemes are presented in [25] and [33].

At substations where an LDC scheme is used the voltage target setting of the AVC scheme represents the voltage target at no load and the LDC setting represents the required voltage boost above the target voltage at maximum load conditions. Once again, various settings can be used for an AVC scheme with LDC, but typical settings for 33 kV busbar is 97% voltage target at no load plus 5% LDC boost at full load giving the voltage range from 32.01 kV up to 33.66 kV. The voltage target for 11 kV system is usually set up at 99% with 5% LDC voltage bias provide voltage range from 10.89 kV at no load and 11.44 kV at full load.

3.5. Parallel Operation

Grid and primary substations are commonly equipped with two or more transformers feeding a common busbar. In the case where a substation is equipped with only one transformer, the load can be also fed from substations located several miles apart with the network interconnected between transformers. In both cases the transformers are paralleled either on site or across the network. This practice improves security of the supply and simplifies the transformer outage procedures. Switching facilities are provided to separate transformers, however, these transformers are normally operated in parallel [29]

There are a number of conditions which need to be satisfied in order to parallel transformers. Any two or more transformers which are intended to be operated in parallel should posses following characteristics [34]:

1) the same polarity
2) the same phase sequence
3) the same inherent phase angle difference between primary and secondary terminals
4) the same percentage impedance
5) the same voltage ratio

Characteristics 1, 2 and 3 for all transformers operated in parallel must be the same, however, some degree of tolerance can be allowed in 4 and 5.

Identical transformers complying with all five characteristics and assuming the incoming voltages are equal will share the load equally and the transformer individual currents as well as total load current will be in phase with each other. The vector diagrams for two identical transformers, T_A and T_B operated in parallel is shown in figure 3.5.1

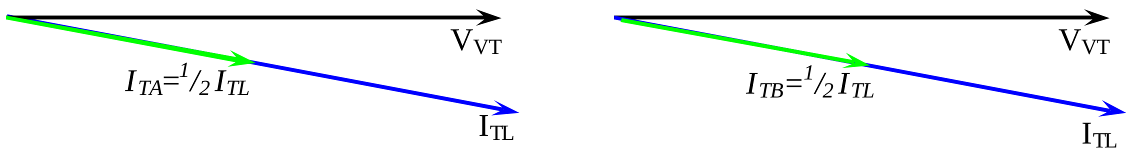


Figure 3.5.1 Identical transformers in parallel operation

Discrepancies in transformer impedance, to a lesser extent, affect parallel operation but influence load share between transformers. The distribution of the total load I_{TL} between two transformers T_A and T_B operated in parallel is given by:

$$I_{TA} = \frac{I_{TL} \cdot N_{TA}}{N_{TA} + N_{TB}} \qquad (6)$$

$$I_{TB} = \frac{I_{TL} \cdot N_{TB}}{N_{TA} + N_{TB}} \qquad (7)$$

Where for transformer T_A and T_B respectively:

I_{TA}, I_{TB} - represent full load transformer current

$N_{TA} = \frac{K_{TA}}{V_{ZTA}}$, $N_{TB} = \frac{K_{TB}}{V_{ZTB}}$

K_{TA}, K_{TB} - represents rated transformer output kVA

V_{ZTA}, V_{ZTB} - percentage impedance

Equations (6) and (7) both show that transformers at the substation share the load in proportion to their impedance when they have the same voltage ratios, the same resistance to reactance ratios and the same rating. The transformer with lower impedance is taking more of the total load and as a result the firm capacity of the substation may be reduced.

It is important to note that both transformer currents I_{TA} and I_{TB} are in phase with each other and even though the transformer currents are not equal, there is no circulating current flow between transformers.

The circulating current will flow between transformers operated in parallel when the voltage ratios are not exactly matched and/or incoming voltages are not equal. The magnitude of the circulating current depends on a difference in voltage ratios and impedances of the transformers as shown in figure 3.5.2 and is given by:

$$I_{CIRC} = \frac{U_{TA} - U_{TB}}{Z_{TA} + Z_{TB}} \tag{8}$$

Where for transformer T_A and T_B respectively:

U_{TA}, U_{TB} - transformer voltage ratio

Z_{TA}, Z_{TB} - impedance of the transformer

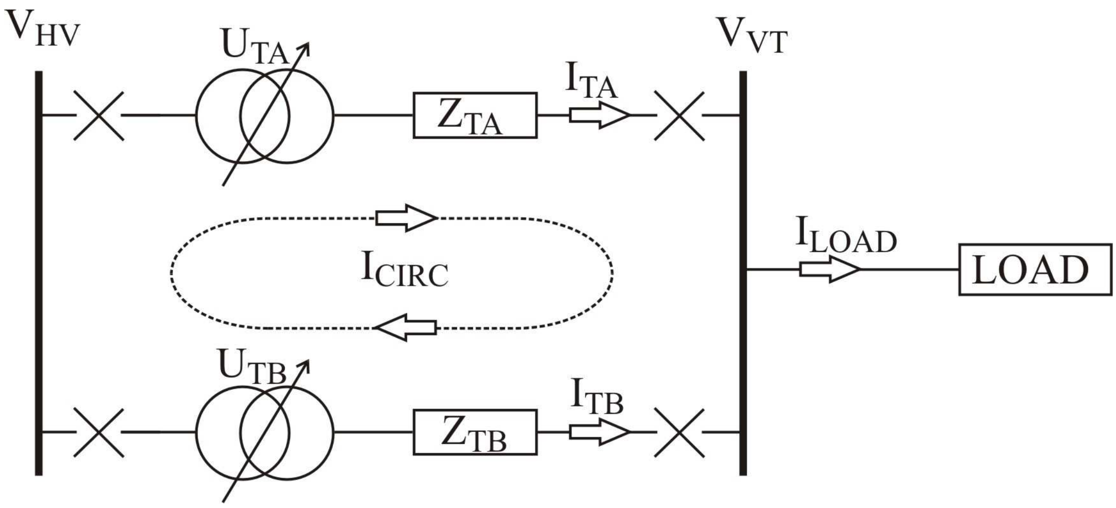


Figure 3.5.2 Circulating current in parallel operation

Due to a very high transformer *X/R* ratio, in the range of 30-50, equation (8) can be simplified and only transformer reactance can be used. This denotes that circulating current is dominantly reactive and determines the reactive power flow between transformers. Therefore, for the transformer with higher voltage ratio (in figure 3.5.2 transformer T_A) I_{CIRC} lags the busbar voltage, V_{VT}, by 90 degrees while for the transformer with lower voltage ratio (transformer TB) I_{CIRC} leads the busbar voltage, V_{VT}, by 90 degrees. The current flowing between transformers, shifts transformer current I_{TA} clockwise and current I_{TB} in the opposite direction as shown in figure 3.5.3.

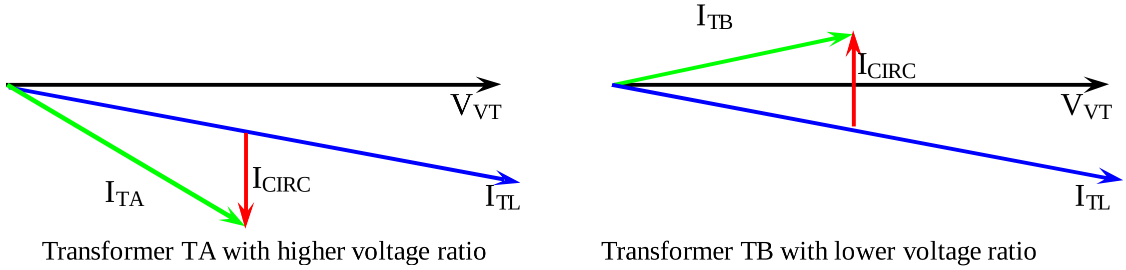


Figure 3.5.3 Paralleled transformers with different voltage ratio.

A small amount of circulating current in the transformer windings can be generally allowed. However, owing the fact that circulating current creates additional copper losses and causes overheating of the windings, thus reducing transformer capacity, it is required to minimise its flow between paralleled transformers as these losses increase exponentially as current increases.

In order to prevent excessive circulation current flow between paralleled transformers due to the difference in transformers' voltage ratio, an appropriate tap position for all transformers must be maintained. Referring to the voltage control scheme based on voltage measurement as described in section 3.4 consideration is given to the AVC scheme when two identical transformers with OLTC are paralleled. Initially, both transformers are at the same tap position (i.e. position 9) and no circulating current flows. Two voltage control relays are used to manage the voltage at the substation busbars under varying load conditions. Due to even very small discrepancies, for example, in voltage measurement or delay timing, one of the transformers will always operate before the other. For instance, as load at the substation decreases, voltage drop across the transformers reduces and voltage at the substation busbars rises. When the measured voltage exceeds the relay bandwidth $\Delta V > V_{TAR} - V_{VT}$, one of the transformers, in this case transformers T_A, operates after time delay in order to correct the voltage level as shown in figure 3.5.4 b).

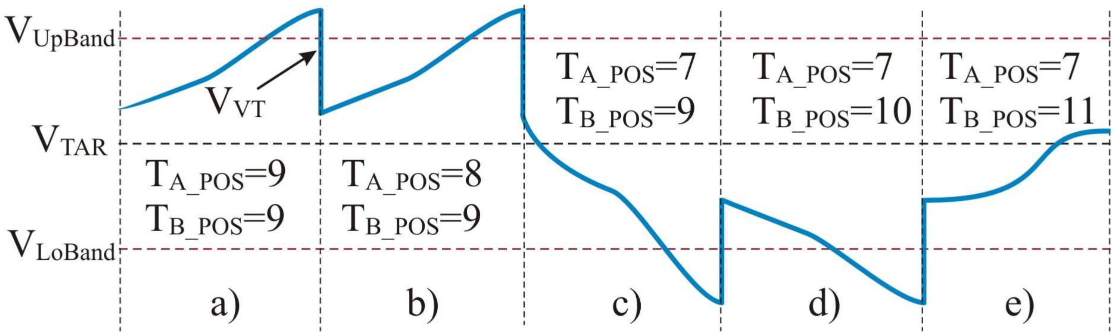


Figure 3.5.4 Paralleled transformers runaway

T_A taps down from position 9 to position 8 and the voltage level is brought back within the bandwidth. At this point the relay controlling transformer T_B is satisfied with the voltage level and does not take any action. The transformers are one step apart and some circulating current flows between transformers, however these conditions are acceptable as the magnitude of I_{CIRC} is relatively small.

When the load further decreases the process repeats itself and the OLTC of transformer T_A is operated again to correct the voltage. As a result the transformers are now two steps apart (figure 3.5.4 c)), the desired voltage target is maintained and more I_{CIRC} flows through the transformers windings.

The transformers will drift further apart when the load at the substation starts to increase; this time transformer T_B will operate first as the voltage at the substation busbars goes below the lower band. The OLTC of T_B is moved from tap 9 to tap 10 and with further load increase from 10 to 11.

At this point transformers are 4 steps apart as shown in figure 3.5.4 e) and, as the load at the substation varies throughout the day, the transformers would diverge to the opposite limits of the OLTC ranges. The resulting excessive circulating current causes hazardous conditions for the transformers and possibly transformer over-current or winding temperature protection to operate. If directional over-current protection is installed, the transformer on a lower tap position will trip leading to a high voltage at the substation busbars.

Thus, voltage control of the parallel transformers must be modified in order to prevent paralleled transformers from tapping apart. Therefore, another requirement of an AVC scheme, when two or more transformers operate in parallel, is to minimise circulating current between transformers and keep them on appropriate tap positions.

In the next chapter of this thesis various techniques in AVC schemes used to detect and reduce circulating current by adjustment of tap position are described.

A common feature of the schemes such as negative reactance compounding (NRC), transformer automatic parallel package (TAPP) or true circulating current (TCC) is that an additional voltage bias is used to modify the effective voltage target [30], [35][43]. A compounding voltage bias V_{COMP} is calculated for each transformer in the same manner. Its magnitude and direction depends upon the amount and direction of the circulating current. The effective voltage target is adjusted for all voltage control relays in the AVC scheme in order to enforce appropriate operation of the OLTCs. The principle of this method is presented in figure 3.5.5.

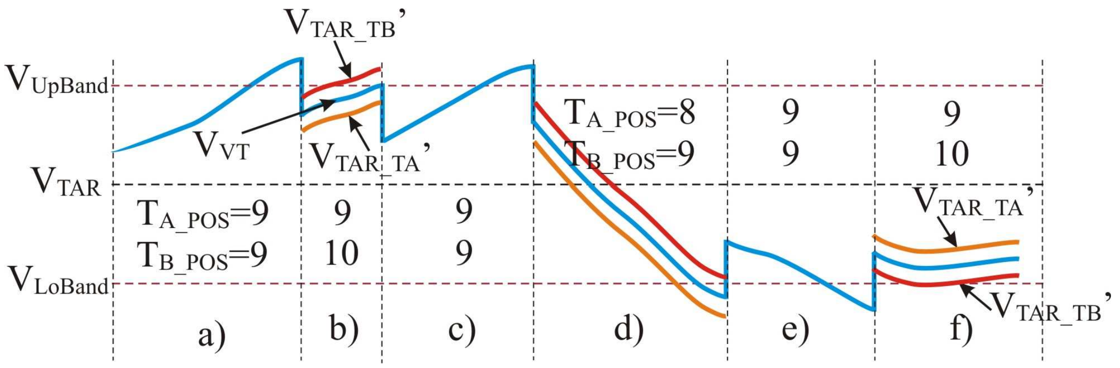


Figure 3.5.5 Operation of AVC with compounding voltage bias

As in the situation described in figure 3.5.4 transformer T_A operates first when the measured voltage exceeds the relay upper band and corrects the voltage level. As the transformer voltage ratios now differ due to one tap position divergence, a circulating current flows between the transformers. This current and its direction are detected and, depending on its magnitude and the voltage control relay setting, a compounding voltage bias is determined. The voltage target for each relay is modified and the effective voltage target V_{TAR}' is determined as follows:

$$V_{TAR}' = V_{TAR} \pm V_{COMP} \tag{9}$$

The effective voltage target for the transformer on the lower tap position V_{TAR_TA}' is reduced and for the transformer on the higher tap position is increased as represented by lines orange and red in figure 3.5.5 b) respectively. This process ensures that when load further reduces transformer T_B operates first and reduces the circulating current (figure 3.5.5 c) and in the case when load increases, transformer T_A increases its tap position and equalises the voltage ratio (figure 3.5.5 e), thus reducing any circulating current, ideally to zero.

Detection of the circulating current and calculation of the compounding voltage bias V_{COMP} varies from scheme to scheme. Some techniques rely on communication between transformers (i.e. TCC) others on transformer current power factor and reactive power flow (NRC and TAPP) or a mixture of both (Enhanced TAPP). An exception from the voltage compounding bias method is the approach used by a master-follower (M-F) scheme, where all parallel transformers are kept on the same tap position by an arrangement of mechanical and electrical signalling. However, this implies some limitations for the parallel operation of non-identical transformers.

3.6. Summary

Voltage control of the electricity system is an important aspect of network management. The statutory voltage limits are clearly defined and the network operators are obliged to design and control the system in order to keep all customers within this voltage range.

A number of techniques have been implemented into distribution networks to ensure that voltage profile is maintained within the voltage limits under various load conditions. An OLTC with AVC scheme is commonly used to automate and optimise the voltage profile on the 33kV and 11 kV distribution systems. However, due to the fact that the design and operation of distribution networks, including voltage control techniques, have been determined by load demand, connection of generation can affect performance of the AVC schemes and needs to be considered in the process of connection of DG into the distribution network.

In order to be able to assess the effect of DG on the performance of the AVC schemes, the principle of operation needs to be understood. Characteristics and limitations of the most common AVC schemes employed in distribution networks are discussed in the next chapter. Computer models and simulation analysis of the M-F, NRC, TAPP, TCC and Enhanced TAPP (ETAPP) schemes are also presented.

Chapter IV - Modelling and Simulation of AVC Schemes

Existing voltage control techniques and AVC schemes in distribution networks have been discussed in the previous chapter. It has been suggested that the connection of the distributed generation changes the character of the distribution networks and can affect voltage control techniques, in particular AVC schemes.

Using specifically developed simulation software the effect of DG on performance of various AVC schemes can be analysed. Firstly, this chapter briefly presents Operation and Control of Electrical Power Systems (OCEPS) load flow program, discusses the principles of the most common AVC schemes and presents associated computational models. Secondly, model implementation into load flow software is presented and simulation results of typical distribution network conditions are analysed. Finally, the performance of AVC schemes in distribution networks with distributed generation is examined and discussed.

4.1. Introduction

Load flow analysis software assists planning and control engineers with the evaluation of the steady state of a network under various configurations, load and generation conditions as well as operational routines.

With the increase of distributed generation being connected to the system as well as an increasing demand for electrical power, distribution networks have become more complex and operate closer to their design limits. In order to be able to maximise the utilisation of existing network infrastructure, increase efficiency and implement ANM techniques, more accurate, efficient and functional network design and operational tools are required [36].

One of the challenges for the DNOs is voltage control. Voltage regulating relays which control OLTCs are widely used to manage voltage levels on distribution networks. Even though these techniques are well established, traditional AVC schemes can be unreliable, particularly when a transformer arrangement is complex and conditions of the network variable. Network issues such as varying power factor, difference in incoming voltage, non-identical paralleled transformers, load pattern, distributed generation and changes in network configuration can undermine the performance of AVC schemes.

Simulation software can be used to investigate how a particular AVC scheme performs when subjected to the above network issues and consequently how the voltage profile, power flow, losses or security of the system is affected.

The basic tap changer control with automatic voltage controller is usually available in load flow packages, however, parallel control of the transformers is not included or it is based on master-follower scheme. In order to carry out the simulation study of the most common AVC schemes the computational models of these systems have been created and implemented into the OCEPS load flow program [37].

This chapter presents the principles, computational models and implementation into OCEPS of M-F, NRC, TCC, TAPP, and ETAPP.

In order to create the accurate computational representation of the AVC scheme, firstly a mathematical model of the scheme needs to be created. To achieve this objective the principles and functionality of the scheme need to be comprehended. The next step is the implementation of this model into the software with all required settings, interaction between the relays and response of the scheme to the network changes. The final stage of AVC model development is validation of the scheme operation, functionality and performance under various network configurations as well as generator and load conditions.

The operational characteristics, advantages and disadvantages of the above schemes are discussed and the performance under various distribution network load and generation conditions are investigated.

4.2. Load Flow Simulation and Transformer Model

An alternating current (AC) load flow provides a steady state solution for electrical power networks. With accurate models of all major components such as transmission lines, transformers, generators or loads the load flow algorithm calculates power flows, voltage levels, losses etc. throughout the network.

The OCEPS software is a commercial load flow package. It is based on the Newton-Raphson algorithm and uses a partitioned-matrix approach to the Jacobian equations. This algorithm has been tested on a variety of systems and proved to be a very robust tool for load flow studies in transmission and distribution networks [38]. This method is suitable for the analysis of distribution networks due to the fact that it efficiently handles networks with widely varying resistance and reactance parameters.

For its suitability to deal with a variety of transmission and distribution networks and widespread R/X network ratios, the OCEPS load flow package was considered as the suitable platform for the required network analysis. The OCEPS was created at Durham University and is being further developed at Brunel University and is commonly used at both the academia and the industry. For that reason it was chosen for implementation and analysis of AVC schemes in this project.

The OCEPS load flow application uses the plant models as presented in [37]. A brief description of the load, generator, transmission line and transformer models are presented in the following section.

A polynomial load modelling approach is employed in OCPES to represent the variation of load power with voltage. Active and reactive power loads P and Q are given by:

$$P' = \gamma_1 PV^{\varepsilon_1} + \gamma_2 PV^{\varepsilon_2} + \gamma_3 PV^{\varepsilon_3} \quad (10)$$

$$Q' = \delta_1 QV^{\zeta_1} + \delta_2 QV^{\zeta_2} + \delta_3 QV^{\zeta_3} \quad (11)$$

By selecting suitable values for coefficients γ and δ and exponents ε and ζ all standard types of load can be modelled.

Three modes of generation are accommodated within OCEPS: $V\theta$, PQ and PV. In distribution network simulation $V\theta$ mode is used to represent GSP, PQ mode is used for the distributed generation as it is very often required to operate at fixed power factor, usually close to unity, by the DNO. PV mode is used for larger generation connected at the 132 kV network level.

The medium line π-equivalent model with series impedance $Z_R = R_R + jX_R$ and shunt admittance $Y = G_E + jB_E$ is used to represent overhead lines and underground cables. This model enables an accurate representation of both short length line and medium length line but also can be used as the model for the transformer.

A transformer is represented as a network branch and ideal transformer model. The line impedance and resistance parameters are specified as in a transmission line model. However, when the branch in the network model is defined as a transformer, the transformer model as shown in figure 4.1.1 is used.

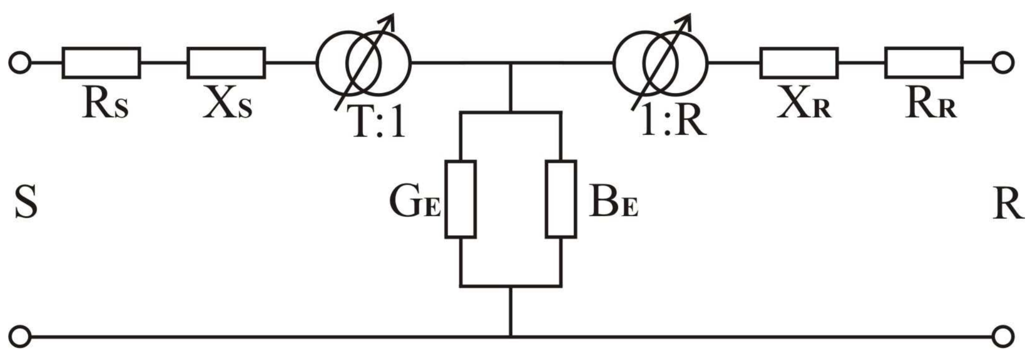


Figure 4.1.1 Transformer model in OCEPS

This model enables the allocation of the impedance of a transformer on both sides of the windings as well as the incorporation of transformer ratio on the primary or secondary side of the transformer by means of “*T*” or “*R*” parameters respectively.

In the load flow algorithm the steady state of the system needs to be executed for every change in transformer turns-ratio. The admittance matrix $[Y]$ must be recalculated to reflect the effect of this change on the primary and secondary voltages and currents in the system V_P, V_S, I_P and I_S respectively. This relationship is described as follows [40]:

$$\left[\frac{I_P}{I_S}\right] = \begin{bmatrix} Y & -tY \\ -tY & t^2 Y \end{bmatrix} \cdot \left[\frac{V_P}{V_S}\right] \tag{12}$$

It is important to note that network analysis of a transformer with variable tap ratio may significantly increase the number of calculations in the load flow software in order to achieve a steady state solution.

In the load flow studies, a transformer with OLTC is represented by discrete variable turns ratio “*t*” in the transformer model as follows:

$$\frac{V_{HV}}{V_{LV}} = t = \frac{N + k\Delta N}{n} = \frac{N}{n} + \frac{k\Delta N}{n} \tag{13}$$

Thus:

$$t = T + \frac{k\Delta N}{n} \tag{14}$$

Where "*N*" is the number of turns of winding at the primary side and "*n*" is the number of turns of winding at the secondary side. "*T*" represents nominal transformer ratio, "*k*" is the tap position and ΔN represents a tap step [35].

In order to simulate a realistic transformer with OLTC, a number of parameters for the transformer model have been added to the OCEPS software. Apart from resistance and reactance parameters which define a branch of the network, additional information such as number of taps, minimum and maximum turns ratio etc. are required to fully define the transformer with OLTC. The table below shows the OCEPS code of parameters describing a transformer and tap changer with a brief functional description and characteristic value.

OCEPS Code	Parameter description	Notes and typical Value
BRNCOD	Branch code:	-0 for a transmission line or cable, -N indicates that this branch represents transformer number N.
TAPLO	Lower limit of turns ratio	0.9 pu- minimum tap position gives -10% change of nominal transformer ratio
TAPHI	Upper limit of turns ratio	1.1 pu- maximum tap position gives +10% change of nominal transformer ratio
TAPSTP	Number of Tap Steps	The number of possible Tap Positions
TAPPOS	Current Tap Position	
TAPTYP	Transformer Tap, Changing Type	-0 - manually controlled tap position -1 - automatic control at 'sending end' -2 - automatic control at 'receiving end'
NODTSP	Node number of target node for transformer tap-changing controller	Usually substation busbars
VTSP	Voltage magnitude target	Required voltage target - default = 1 pu

Table 4.1.1 Transformer model parameters in OCEPS

4.3.General Model of AVC Scheme

A number of AVC schemes are currently used in distribution networks based on various techniques for voltage control and parallel operation of transformers. However, universal principles of operation can be recognized [38]. The following section presents a general model of the AVC scheme and its implementation into OCEPS.

As described in chapter III, the AVC relay operates to maintain the network voltage at the correct level. The function describing the action of the relay can be written as follows [41]:

$$N(t+1) = N(t) + A(E, TD, t) \tag{15}$$

$$E(\Delta V, BW) = \begin{cases} 1 & if \quad \Delta V > +BW \\ -1 & if \quad \Delta V < -BW \\ 0 & otherwise \end{cases} \tag{16}$$

$$A(E, TD, t) = \begin{cases} 1 & if \quad E = 1 \quad and \quad TC > TD \\ -1 & if \quad E = -1 \quad and \quad TC > TD \\ 0 & otherwise \end{cases} \tag{17}$$

Inequality constraints:

$$N_{MIN} \leq N(t+1) \leq N_{MAX} \tag{18}$$

$$V_{AVCMIN} \leq V_{VT} \leq V_{AVCMAX} \tag{19}$$

Where N is the tap position of the transformer, E indicates voltage excursion outside permissible level and that action is to be taken in order to correct the voltage, A

indicates tap changing action of the AVC relay. BW represents the AVC bandwidth setting, N_{MIN}, N_{MAX} define minimum and maximum tap position of the OLTC (that correspond to TAPLO and TAPHI in OCEPS transformer model), V_{AVCMIN} and V_{AVCMAX} specify operational voltage limits for AVC monitoring unit, TD represents the relay time delay setting and TC time counter.

In steady state load flow analysis the time domain in the AVC scheme model is not considered and the AVC model can be simplified by neglecting equation (17). As a result the equation (15) takes the form as follows:

$$N(t+1) = N(t) + E(\Delta V, BW) \qquad (20)$$

The tap position of the transformer will be changed when the voltage difference ΔV between the measured voltage V_{VT} and effective voltage target V_{TAR}' exceeds bandwidth setting.

$$V_{VT} - V_{TAR}' \geq BW \qquad (21)$$

To this point the AVC model is universal and can be applied to the most of the AVC schemes. However, different techniques to determine the effective voltage target V_{TAR}' are used in each AVC.

The relay voltage target can include LDC voltage bias, V_{LDC}, as well as compounding voltage bias, V_{COMP}. Additionally, in the more innovative active voltage control schemes, a voltage target adjustment $V_{TARADJUST}$ can be sent from the voltage controller or DMS, for example as presented in [42]. Considering the basic voltage target, V_{TAR}, and all voltage biases and adjustments, the calculation of the effective voltage target V_{TAR}' takes form as follows:

$$V_{TAR}' = V_{TAR} + V_{LDC} + V_{COMP} + V_{TARADJUST} \qquad (22)$$

The LDC voltage bias and compounding voltage bias calculation varies depending on an AVC scheme.

The next section presents various AVC techniques and how a voltage target is calculated depending on which method is used.

4.4. Master-Follower

In this method all paralleled transformers are kept on the same tap position. One of the parallel transformers (master) in the scheme monitors the voltage at the busbar and adjusts the tap position to maintain the required voltage level. When the master transformer finishes the action all other transformers (followers) in the scheme replicate it [29].

Due to the fact that all transformers are operated simultaneously, for each voltage correction the number of tap changes is equal to the number of transformers in a group.

This may unnecessarily increase number of operations of OLTC and as a result, maintenance costs. Additionally, for the single tap operation, the voltage change at the busbar is equal to the tap changer step and appropriately higher bandwidth settings may need to be used to optimise the number of tap changer operations. As a result voltage control precision is compromised.

The M-F scheme operates correctly under varying power factors and reverse power flow. The scheme might be used along with LDC. However, due to the fact that in most schemes LDC is based on transformer current not summed load, when one of the transformers in the group is switched out the LDC increases and the settings need to be adjusted in order to avoid over-voltage.

As a connection between relays is required, it is impractical to use this scheme to parallel transformers across a network. Additionally, circulating current will flow between paralleled transformers using this scheme unless the transformers are identical, such that they have the same impedance, number of taps and incoming voltage. This significantly complicates substation reinforcement, i.e. additional transformer installation. As a new transformer is usually different from the existing transformers at the substation and due to the fact that the M-F scheme is able to control only identical transformers, the AVC scheme at the substation will need to the replaced or modified.

The M-F scheme in OCEPS is modelled by the parameter PARTRAN(X) which describes each transformer. This parameter indicates which of the transformers operating in parallel is the master and which is the follower. When PARTRAN(X) = X then transformer X is a master. The voltage calculated at transformer controlled node is used to determine the required tap position in order to correct the voltage. All the Y transformers described by PARTRAN(Y) = X are paralleled with, and followers to, transformer X. Their tap position is replicated in the calculations for transformer X.

4.5. Negative Reactance Compounding

One of the most common AVC schemes in the distribution networks is NRC technique. In this technique LDC settings are used in order to produce a compounding voltage bias. It is achieved by changing the polarity of the imaginary part of the LDC settings jX_{LDC}. The relationship between LDC settings and NRC setting can be defined as follows [30]:

$$Z_{LDC} = R_{LDC} + jX_{LDC} \tag{23}$$

$$Z_{NRC} = R_{LDC} - jX_{LDC} \tag{24}$$

The principles of NRC scheme are presented in figure 4.5.1.

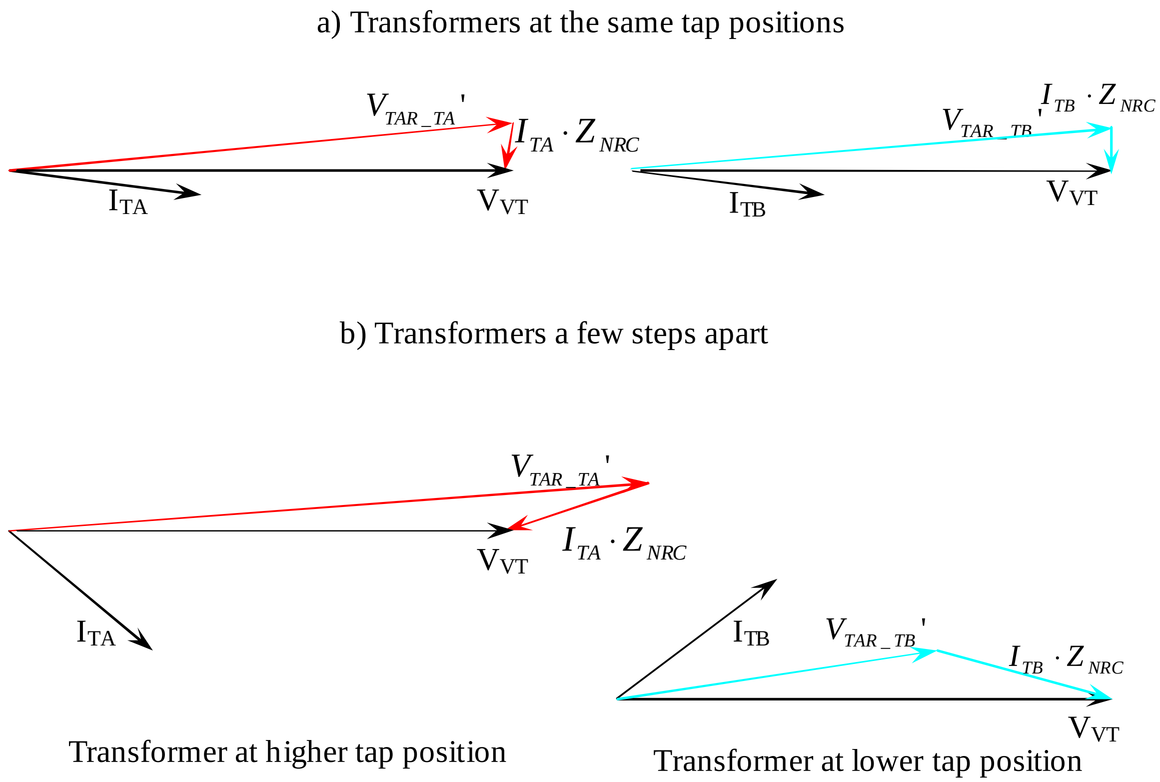


Figure 4.5.1 NRC scheme principles

Consider a substation where two paralleled transformers are on the same tap position and voltage boost from LDC is required and R_{LDC} is equal to zero. The $-jX_{LDC}$ setting is used to provide compounding voltage bias. With the assumption that the load power factor is close to unity, the voltage drop across $-jX_{LDC}$ caused by transformer current leads the measured voltage by 90 degrees. Under these circumstances the effective voltage target V_{TAR}' for both relays is approximately equal to the measured voltage magnitude V_{VT}, as shown in figure 4.5.1 a). It can be concluded that compounding voltage bias $I_{TX} \cdot (-jX_{LDC})$ has minimal effect and can be ignored.

The situation when the transformers are a few steps apart is presented in figure 4.5.1 b). The circulating current flows between transformers causing the transformer currents to rotate in opposite directions. Consequently the phasors of the voltage bias are shifted correspondingly. For the transformer on the higher tap position, the effective measured voltage V_{TAR_TA}' is increased over the measured voltage V_{VT} and the relay will be biased to tap down. For the transformer on the lower tap position, the effective measured voltage V_{TAR_TB}' is decreased over the measured voltage V_{VT} and the relay will be biased to tap up. As a result of the compounding voltage biases in the NRC AVC scheme the transformers are kept on the desired tap position, preventing transformers from runaway and any circulation current is reduced to an acceptable level.

In the NRC scheme a connection between transformers is not required as each AVC relay of the paralleled transformers acts independently. This feature makes NRC scheme suitable for paralleling transformers across the network and for paralleling non-identical transformers. However, this scheme has also disadvantages in that it is only accurate at unity power factor, and the error in voltage target increases with the load power factor deviation. To reduce this error a compromise between the benefit of the compounding and the susceptibility of the scheme to produce voltage errors for varying power factor must be found. Another disadvantage of NRC schemes is degradation of the LDC performance due to the change in the polarity of the X_{LDC} setting. To compensate for LDC boost the value of R_{LDC} must be increased. However, this complicates the correct settings selection for the NRC scheme to operate under various load conditions and the usual load power factor in the range of 0.95 – 0.98 lagging [43].

The NRC scheme in the OCEPS software is executed by setting negative values for the XLDC parameter. The XLDC parameter corresponds to LDC reactance setting jX_{LDC} as described above. The current that flows in the branch representing the transformer is used to calculate voltage biases across the LDC components. The voltage target parameter VTSP as shown in table 4.1.1 is modified to reflect the effective voltage target in the NRC scheme as follows:

$$V_{TAR}' = V_{VT} + V_{NRC} \qquad (25)$$

Where:

V_{TAR}' - Effective voltage target

V_{VT} - Measured voltage

V_{NRC} - Negative reactance compounding voltage bias calculated $\overline{I_{TX}} \cdot (R_{LDC} - jX_{LDC})$

4.6. Transformer Automatic Paralleling Package [44]

The TAPP scheme is widely used in the UK and selected as the standard AVC scheme by a number of UK DNOs. It is based on a modified negative reactance compounding principle [31], [44]. However, in this scheme, two separate circuits are used, one for the purpose of LDC and one for the purpose of compounding, in order to eliminate the need of trade-off between the benefit of the compounding and the susceptibility to produce voltage errors for varying power factors. The circulating current in the TAPP method is evaluated by comparing the measured transformer current I_{TX} power factor with the target power factor PF_{TAR} as is shown in figure 4.6.1. The value of the target power factor is 0.97 lagging and is chosen to match the usual load power factor.

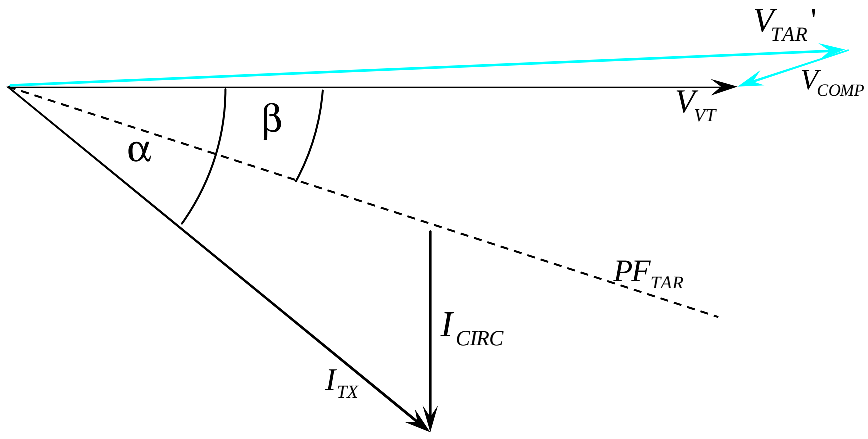


Figure 4.6.1 TAPP scheme principle

The TAPP scheme maintains the simplicity of the NRC scheme, in addition it also reduces the voltage error at and around normal network power factor conditions. The scheme is also much easier to implement as separate settings are used for LDC and compounding. Moreover, LDC in this scheme is redefined as load drop compensation. This technique is described in detail in section 3.4 and equation (5).

A weakness of the TAPP scheme is that the voltage error and degradation of the LDC performance occur when the network power factor moves away from the target power factor. This is because circulating current is considered as a part of the load current. Consequently the TAPP scheme is not easily applied to networks with distributed generation.

In order to model the TAPP scheme in the OCEPS software parameter TAPPSC has been introduced. This parameter identifies the transformers which are paralleled and in the same TAPP scheme. Using the transformer branch current I_{TX} , the power factor of the transformer current α_X is calculated and circulating current estimated using equation as follows:

$$I_{CIRC\_TX} = I_{TX} \cdot \left(\sin\alpha_X - \cos\alpha_X \cdot \tan\left(PF_{TAR}\right)\right) \qquad (26)$$

Target power factor PF_{TAR} has the fixed value of 0.97 lagging. When the TAPPSC of the transformer X is selected, RLDC and XRRC settings represent the load drop compensation setting and compounding setting respectively. Thus the LDC voltage bias is calculated using equation (27).

$$V_{LDC} = RLDC \cdot \left(\frac{\sum_{n}^{1} I_{TX}}{\sum_{n}^{1} I_{TXMAX}} \right) \qquad (27)$$

And the compounding voltage bias is calculated using equation (28).

$$V_{COMP} = \frac{I_{CIRC}}{\sum_{n}^{1} I_{TXMAX}} \cdot X_{RRC} \qquad (28)$$

Where:

n is the number of paralleled transformers in the TAPP scheme

I_{TX} - represents transformer load current

I_{TXMAX} - represents transformer rated current.

The effective voltage target VTSP' takes the form as follows:

$$V_{TAR}' = V_{TAR} + V_{LDC} + V_{COMP} \tag{29}$$

The effective voltage target V_{TAR}' is summation of the basic voltage target V_{TAR}, the LDC voltage bias V_{LDC} and the compounding voltage bias V_{COMP}

4.7. True Circulating Current

On networks with little or no generation changes in power factor are relatively small and the performance of conventional TAPP and NRC schemes are satisfactory. However, as the amount of distributed generation connected to distribution networks increases, significant deviations in power factor may be seen and techniques based on fixed target power factor become unsuitable. A scheme known as TCC provides an effective voltage control and circulating current detection for paralleled transformers on the network with distributed generation that operates at fixed close to unity power factor [45].

In this scheme a communication link between the AVC relays at the same site is used in order to exchange the information of each current of the paralleled transformers. This allows each relay to determine the total load at the substation and calculate the network power factor. Consequently the contribution of the circulating current to individual transformer current can be established and accurate compounding voltage bias applied to optimise the tap position of each transformer. The principles of the TCC scheme are presented in figure 4.7.1.

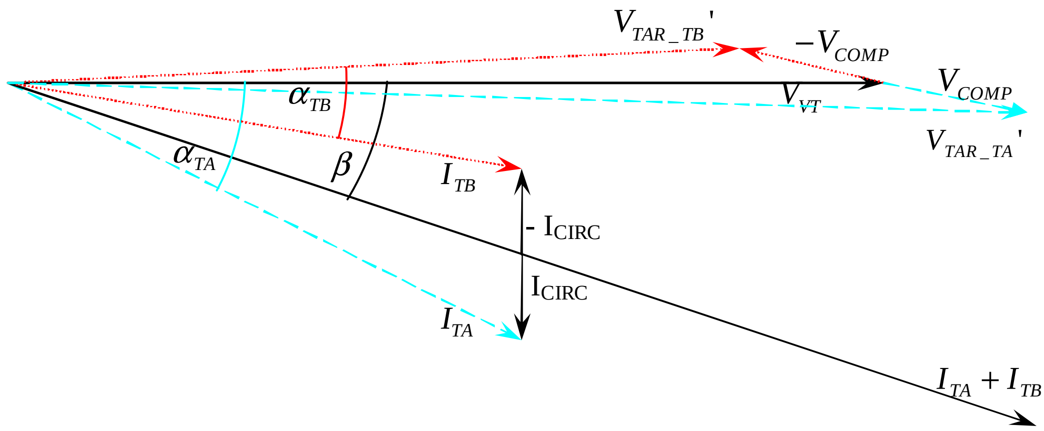


Figure 4.7.1 Principle of operation of the TCC

The circulating current is calculated by comparing individual transformer current I_{TA} or I_{TB} to the full load current equal to summed transformer currents $I_{TA}+I_{TB}$. The compounding voltage bias is used to increase the effective voltage target V_{TAR_TA}' of the transformer on the higher tap position T_A and decrease the effective voltage target V_{TAR_TB}' of the transformer on the lower tap position T_B. Such action is performed until the voltage level at the busbar is within the bandwidth of the target voltage and the circulating current is minimised. As the parameter β always represents the true network power factor, regardless of any circulating current between transformers, calculation of the circulation current I_{CIRC} is precise.

As with other AVC schemes TCC may be used with LDC. However, even though the scheme is not affected by a varying power factor, LDC performance is compromised as in all AVC schemes described in this section by the output from distributed generation. This is due to the fact that the substation total load current does not represent the true load on the network, as it is reduced by distributed generation export.

The arrangement of the TCC scheme is complicated by the necessity of an interconnection between transformers. As a result, the link must be rearranged when one of the transformers within the scheme is out of service. Additionally it is not feasible to parallel transformers across the network [46].

To execute the TCC scheme in OCEPS the AVCSC parameter needs to be set $AVCSC = 3$. $RLDC$ and $XLDC$ settings can be used for load drop compensation function and the $XRRC$ parameter is used for the compounding setting.

The circulating current is calculated as follows:

$$\beta = \arctan\left(\frac{\operatorname{Im}\sum I_{TX}}{\operatorname{Re}\sum I_{TX}}\right) \tag{30}$$

$$I_{CIRC\_TX} = I_{TX} \cdot (\sin\alpha_{TX} - \cos\alpha_{TX} \cdot \tan(\beta)) \tag{31}$$

Where β corresponds to actual power factor and $\sum I_{TX}$ is the summed transformer loads within the scheme.

The compounding voltage bias, V_{COMP}, LDC voltage bias, V_{LDC}, and the effective voltage target V_{TAR}' in TCC scheme are calculated as follows:

$$V_{COMP} = I_{CIRC\_TX} \cdot X_{RRC} \tag{32}$$

$$V_{LDC} = (I_{TX}\angle\alpha_{TX}) \cdot (R_{LDC} + jX_{LDC}) \tag{33}$$

$$V_{TAR}' = V_{TAR} + V_{LDC} + V_{COMP} \tag{34}$$

4.8. Enhanced TAPP

The ETAPP scheme is a combination of the TCC and TAPP methods [31]. In order to control voltage level and paralleled transformers on the same site, the TCC mode is used, while TAPP mode is used to parallel transformers across the network with a weak bias to offset errors due to power factor changes.

In order to execute the ETAPP scheme in the OCEPS software the AVCSC parameter needs to be set to $AVCSC = 2$. To model the ETAPP scheme the circulating current for paralleled transformer on the same site is calculated as for the TCC method described by equations (31) and the site compounding voltage bias V_{SITE} is calculated as follows:

$$V_{SITE} = \frac{I_{CIRC\_TX}}{\sum_{n}^{1} I_{TX\_MAX}} \cdot X_{RRC} \qquad (35)$$

The network circulating current and compounding voltage bias V_{COMP_TAPP} are calculated as for the TAPP method using equations (26) and (28) respectively. A sensitivity factor S_F is used to reflect the required strength for the compounding setting for transformers which are paralleled across the networks. The network compounding voltage bias is calculated as follows:

$$V_{NET} = S_F \cdot V_{COMP\_TAPP} \qquad (36)$$

The LDC voltage bias is calculated as for the TAPP scheme using equation (27) and the effective voltage target is give by:

$$V_{TAR}' = V_{TAR} + V_{LDC} + V_{SITE} + V_{NET} \qquad (37)$$

4.9. Simulation of the AVC Schemes Under Various Load and Generation Conditions

In the following section a simple network model is used in order to investigate the performance of the various AVC schemes under varying load and generation conditions in order to validate computational models for each of the schemes. The network model is implemented in the OCEPS load flow software with the AVC scheme models as described in the previous sections. Firstly, performance of the AVC schemes with realistic load profiles for a distribution substation is examined; voltage profile, AVC relays and effective voltage targets are investigated. Secondly, AVC scheme operation on a network with distributed generation is analysed and effectiveness of each scheme discussed.

4.9.1. Case Study

The simple distribution network, shown in figure 4.9.1, has been used to investigate the performance of various voltage control schemes. Figure 4.9.1 presents the primary substation with two 33/11 kV transformers operated in parallel. Both transformers are rated at 12 MVA, however, they differ slightly in percentage impedance. The impedance of the transformer T1 is 18 % and the impedance of transformer T2 is 17%. The transformers are equipped with OLTCs that offer voltage variation +/- 10% of the nominal voltage ratio in 17 steps.

The minimum substation load is 2 MVA and the maximum load is 9 MVA. The substation supplies a number of feeders with a mixture of load customers. A 6 MVA generator is being considered for connection to the network at some point on the feeder. The generator is required to operate at power factor close to unity. With the DG connected the power flows at the substation become bi-directional. For the period of low load 4 MW of active power can be exported to the network and for the period of high load and no generation, up to 9 MVA is supplied through the transformers.

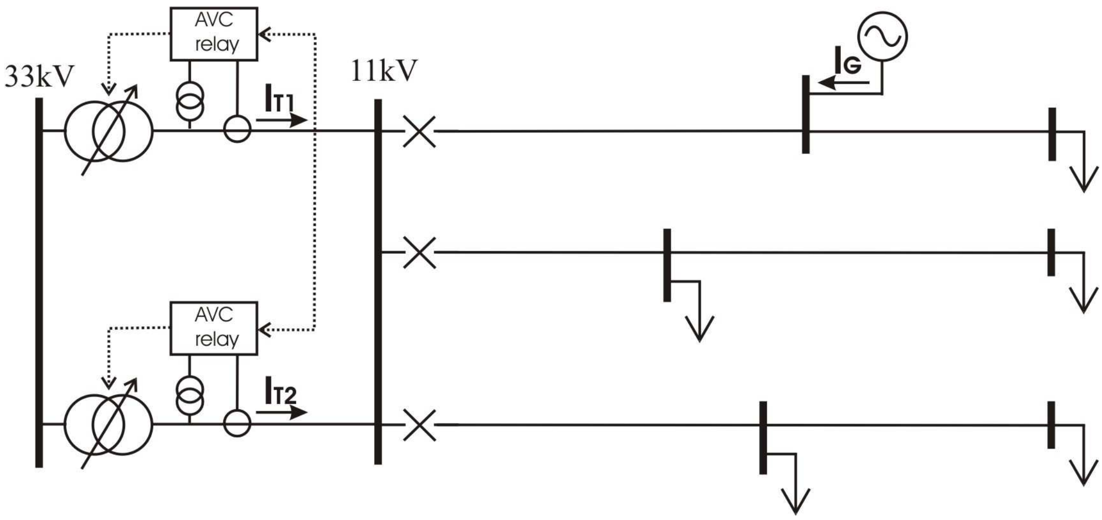


Figure 4.9.1 Simple distribution system

For all the AVC schemes the same voltage target and LDC settings were implemented to maintain voltage levels of 1 p.u. at the substation busbars or at the load centre respectively. For each scheme the bandwidth setting was set to be equal the tap step of

1.25% and the compounding settings were set up to maintain parallel transformers no more than one tap position apart under all network conditions wherever possible.

4.9.2. Standard Load Profile

Firstly, the performance of the AVC schemes is examined under standard load conditions on the distribution network. A typical load profile for a winter day is shown in figure 4.9.2. The load varies from 3.5 MVA in the early morning hours up to 9 MVA at peak load at around 5 p.m. The network power factor is lagging fairly consistently between unity and 0.98 lagging.

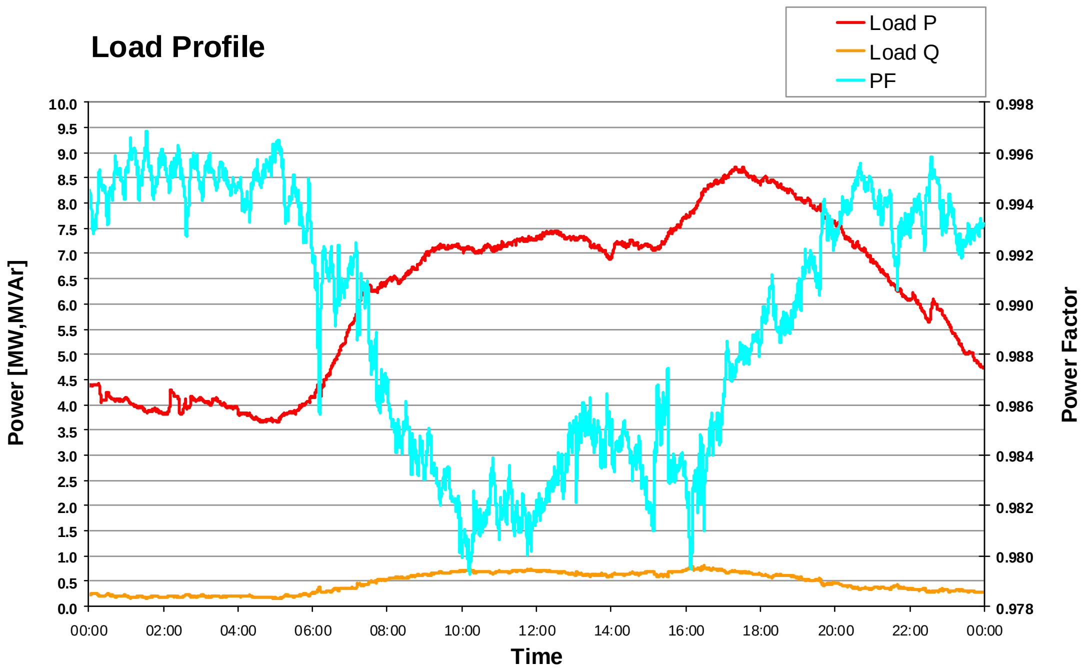


Figure 4.9.2 One-day load profile for distribution network

A series of consecutive load flow studies has been performed using the modified OCEPS software, which is presented in detail in chapter VI. The load flow studies have been performed on the network model shown in figure 4.9.1 with the changing load profile as presented in figure 4.9.2. The case study has been performed for each AVC scheme with a fixed voltage target and the simulation results are presented in figures 4.9.3 – 4.9.8.

In the fixed voltage target mode the AVC scheme is expected to maintain the required voltage level at the substation busbars despite the load conditions and also to minimise circulating current between transformers. With a bandwidth setting of 1.25% and the voltage target setting of 1 p.u. the voltage level at the substation should be continually maintained between 0.9875 and 1.0125 p.u.

Performance of the M-F, NRC, TAPP and TCC schemes under these conditions are presented in figures 4.9.3, 4.9.4, 4.9.5 and 4.9.6 respectively. The ETAPP scheme in this network configuration would perform exactly as the TCC and it is therefore not included in this analysis. All the results obtained for the TCC scheme are valid for the ETAPP scheme.

In the figures below the voltage at the substation busbars V_{VT} is represented by the blue line, the effective voltage target for the relay controlling transformer A V_{TAR_TA}' by the red line and effective voltage target for the relay controlling transformer B V_{TAR_TB}' by the orange line.

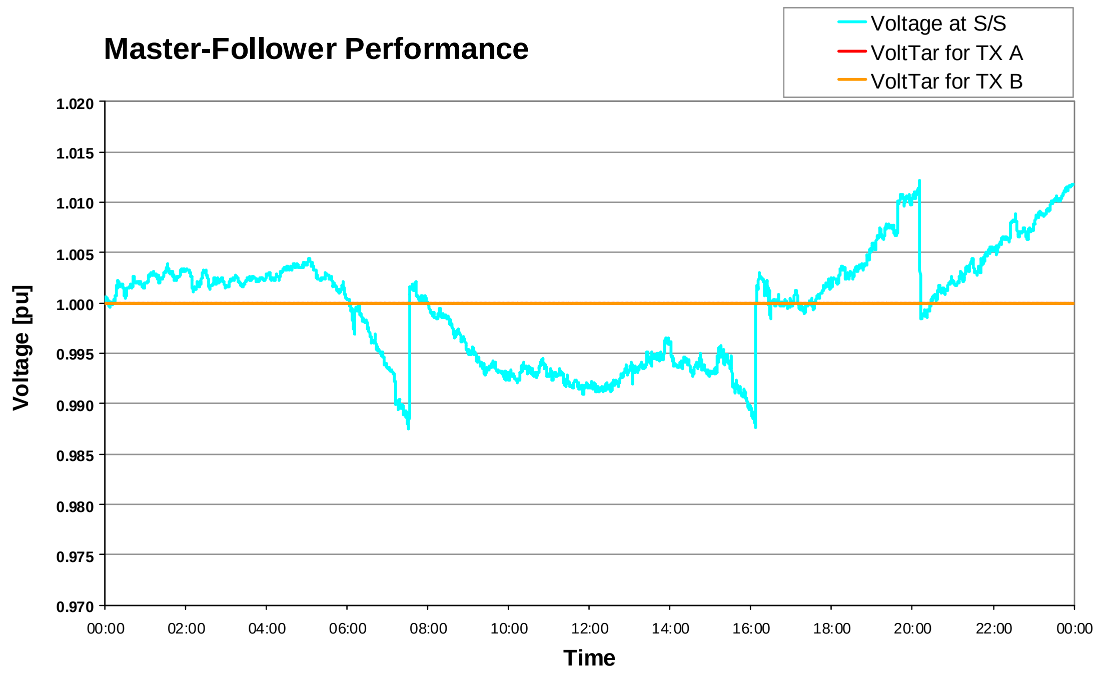


Figure 4.9.3 Performance of M-F scheme under typical load conditions

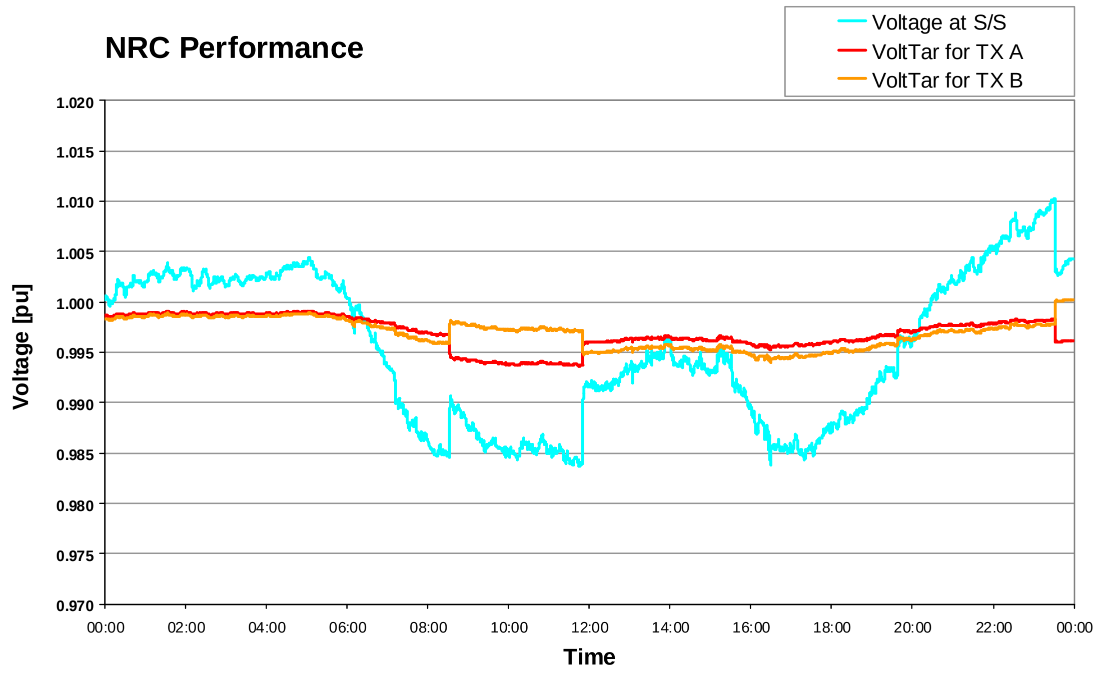


Figure 4.9.4 Performance of NRC scheme under typical load conditions

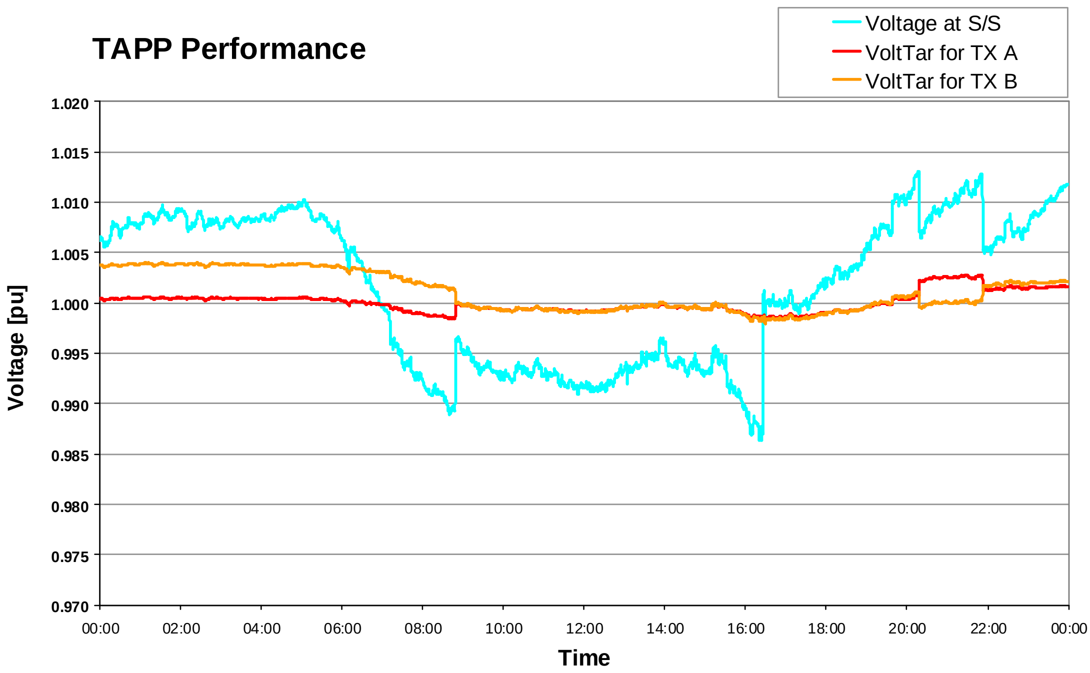


Figure 4.9.5 Performance of TAPP scheme under typical load conditions

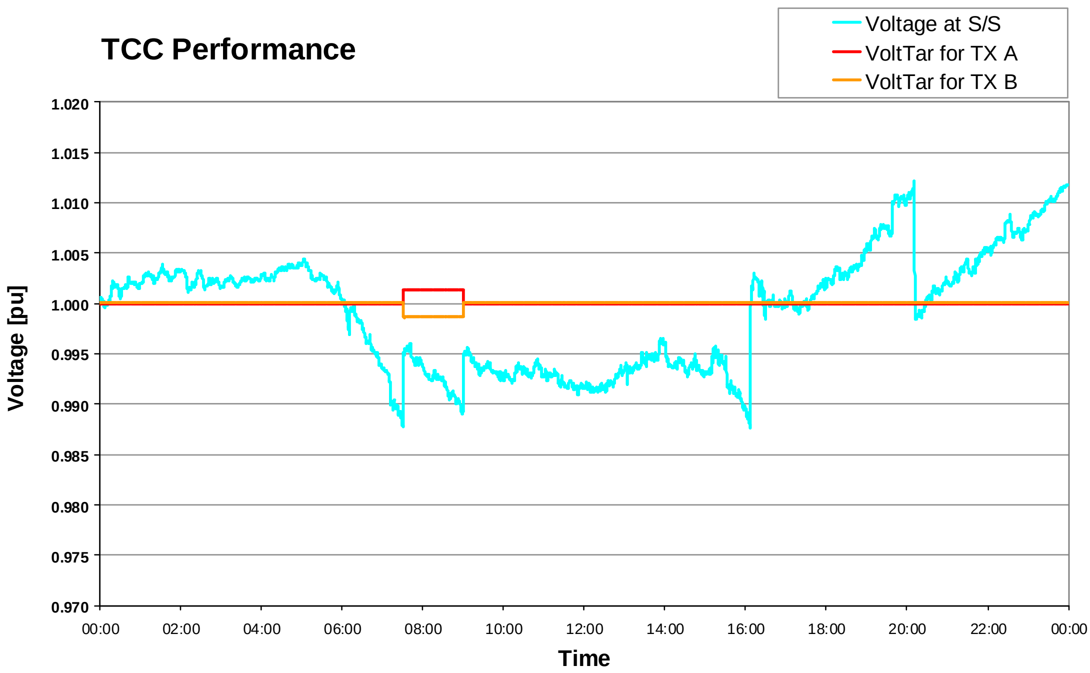


Figure 4.9.6 Performance of TCC scheme under typical load conditions

It can be observed that, under typical load conditions, all four AVC schemes perform accurately and maintain OLTCs on appropriate tap positions. The voltage precision is slightly compromised for NRC and TAPP schemes due to power factor deviations. The effective voltage targets for both relays in the NRC scheme decrease below 1 p.u. as the power factor becomes lower. To offset this voltage error on the network with a typical power factor it is common practice to use the resistance element of the LDC to provide voltage boost. The ratio of R_{LDC} to $-jX_{LDC}$ needs to be carefully selected in order to provide appropriate voltage correction. Selection of the R_{LDC} and $-jX_{LDC}$ settings for the NRC scheme are discussed in more detail in [29].

On the other hand the effective voltage targets for both relays in the TAPP scheme increase above 1 p.u. as the power factor gets closer to unity. However the voltage errors are quite small and in general do not affect the performance of the schemes. The effective voltage targets in the TCC scheme are at 1 p.u. except for the time when compounding voltage bias is applied when transformers are one step apart.

The M-F scheme is not affected by the load changes and the effective voltage targets are equal to 1 p.u. all the time. Both transformers are operated at the same time which can be observed by a full tap step voltage change compared to other schemes where only one transformer is operated at a time.

4.9.3. Connection of DG

The results presented in the previous section have already indicated that a voltage error will occur when the power factor deviates from unity, in the NRC case, and 0.97-0.96 lagging in the TAPP case. When a generator is connected in the network and operates at unity power factor, active power is exported to the network. As a result, the network power factor as seen at the substation busbars changes, and when the generator exceeds the load, the power factor becomes leading.

With the assumption that the load power factor is fairly constant and the distributed generation operates with unity power factor, it can be concluded that the network power factor is determined by the generation to load ratio.

In the distribution networks with DG for schemes such as NRC and TAPP, where performance is dependent on power factor, a significant error is introduced into the voltage target calculation. The voltage error is caused because voltage control relays in NRC or TAPP scheme are not able to distinguish the power factor deviation from the circulating current. As the power factor deviates from the target power factor due to the DG output, the effective voltage targets for all relays in the scheme are modified as the relays incorrectly detect and want to minimise circulating current. The erroneous compounding voltage bias is calculated and applied and this produces the voltage error.

Simulation analysis of the AVC schemes has been performed in order to estimate the magnitude of the voltage error which may be introduced by the scheme under various load to generation conditions. The network model presented in figure 4.9.1 was used, this time with DG connected and exporting real power to the network. The results of the simulation are presented and discussed below.

4.9.4. Results of the Simulation

In the NRC scheme the high $-jX_{LDC}$ keeps the transformers in close step, however, the scheme is more susceptible to changes in power factor as previously presented in [29]. By decreasing $-jX_{LDC}$ the compounding force between transformers is reduced and the voltage error caused by power factor deviation is also reduced.

In order to illustrate the effect of the R_{LDC} and $-jX_{LDC}$ settings on the voltage error in the NRC scheme, two sets of parameters "*A*" and "*B*" have been used. Set "A" has been chosen to ensure that paralleled transformers are quickly restored to the same tap position as for example in the study presented in previous section. Set "B" has been significantly relaxed allowing the transformer to remain one tap apart for a longer period. The graphs in figure 4.9.7 illustrate the voltage error of the NRC scheme with respect to generator to load ratio and power factor.

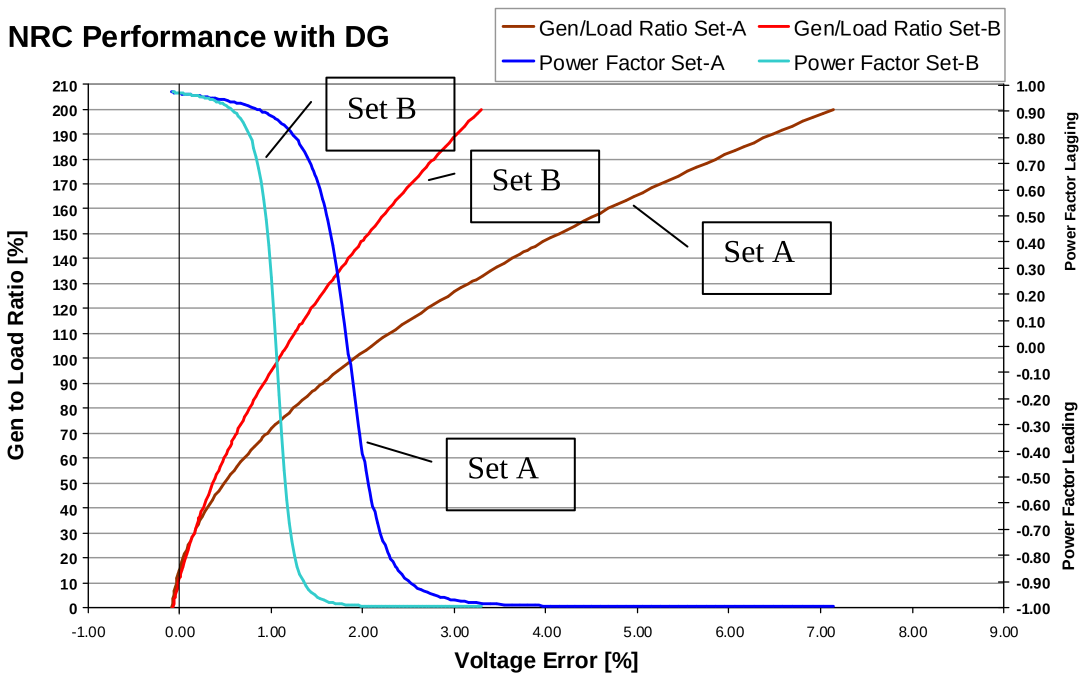
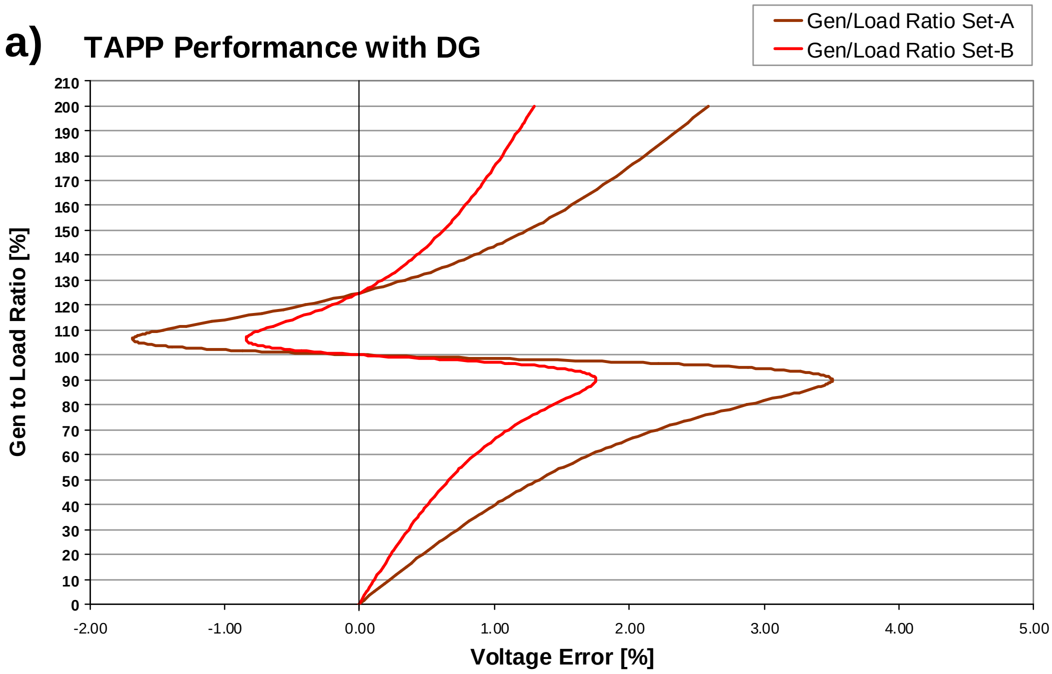


Figure 4.9.7 Performance of NRC scheme with DG

It can be observed that the voltage error in the NRC scheme increases with the generation to load ratio increase. The error is significantly greater for the set “A”, reaching about 2% when generation matches load (100%) and above 7% when the ratio is 200%. The voltage error caused by the generator output can be reduced by relaxing the compounding setting. The voltage error in NRC scheme for set “B” is represented by light red and light blue lines for generation to load ratio and power factor respectively.

The performance of the TAPP scheme in the network with distributed generation and varying power factor is also considerably affected. Similar to the NRC scheme the magnitude of the error depends on the compounding setting and two sets of parameters “A” and “B” have been used. As in the previous case, set “A” keeps transformers closely together, while set ”B” give a decreased compounding force.

The graphs in figures 4.9.7 a) and b) show the voltage error in TAPP scheme with respect to generator to load ratio and power factor respectively.



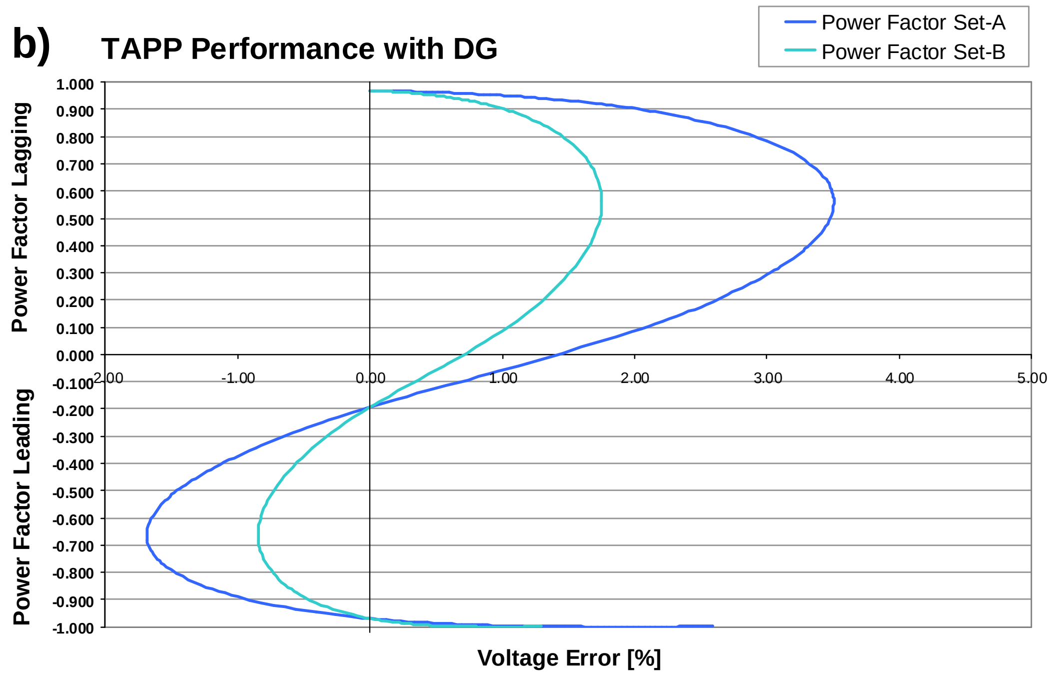


Figure 4.9.8 Performance of TAPP scheme with DG   a) Generation to Load ratio, b) Power factor

The correlation between voltage error and generator to load ratio in the TAPP scheme is more complex than for the NRC scheme. Depending on the network conditions it can be positive or negative. As the generator output increases, the voltage error in the TAPP scheme increases until the magnitude of transformer current becomes low. For the low value of transformer current the voltage error is relatively insignificant and becomes negative when power is being exported to the network. As reverse power flow increases, the voltage error becomes greater.

It is important to note that even though the TAPP scheme produces significant voltage error, especially at generation to load ratio of 90%, the maximum voltage error does not exceed 3.5% in case of parameter set A and 2% in case of set B.

Although, both NRC and TAPP schemes can generate significant voltage errors on the network with varying power factor, limited distributed generation can be accommodated. To facilitate DG in the network where NRC or TAPP scheme is used to control the voltage and OLTC, the compounding settings may need to be compromised. By reducing compounding settings the susceptibility of the scheme to changing power factor is reduced and as a result the voltage error lessened. However, energy losses caused by circulating current and the OLTC runaway risk need to be carefully analysed.

M-F, TCC and ETAPP schemes perform accurately in the fixed voltage target mode under various load and DG output conditions. However, the performance of these schemes is affected by the output of DG when the LDC function is used.

LDC is used to boost the voltage level at the substation busbars at heavy load conditions in order to offset voltage drop on the feeder. Due to the fact that the LDC bias is applied in proportion to the transformer measured current, its operation is compromised by the output of DG. The graphs in figure 4.9.8 show the voltage error in LDC performance on the network where, at full load a 5% voltage increase is required at the substation busbars.

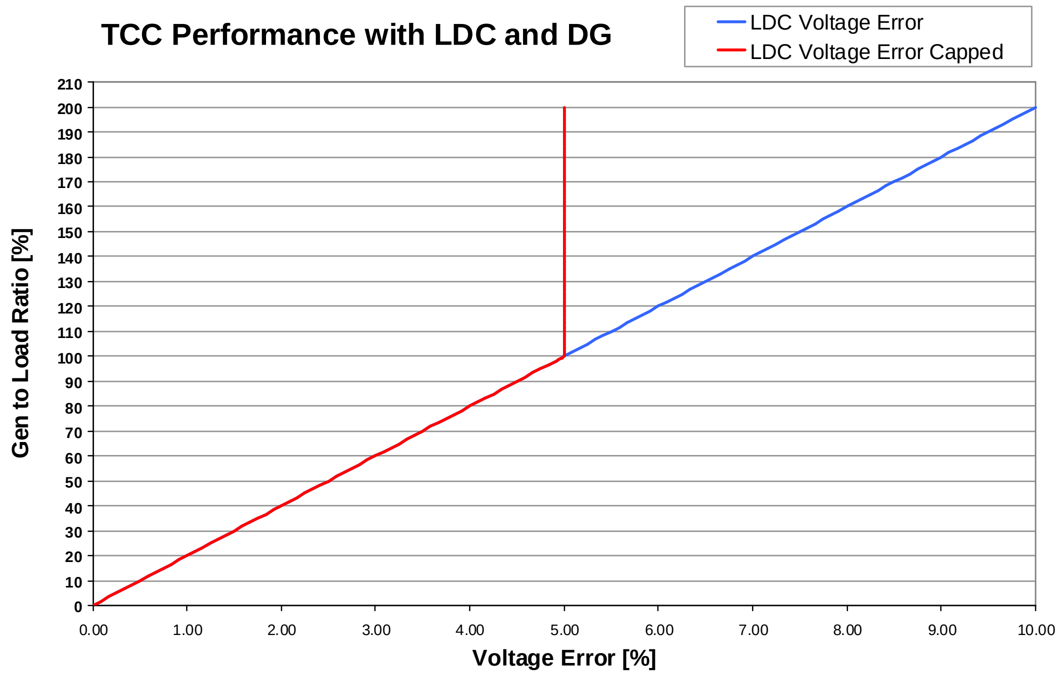


Figure 4.9.9 Performance of AVC scheme with LDC under varying generator output conditions

As the DG export increases the measured transformer current decreases and therefore so does the applied LDC. A result of this is an 'under-boost' in the AVC voltage target and lower than required voltage level at the remote point on the feeder. When the generator output is equal to the load at the substation no LDC bias is applied. At the reverse power flow, in the case where LDC is not capped, negative voltage bias may be added to the voltage target and further increase the voltage error.

Inadequate LDC performance may cause low voltages on the network, particularly at the end of the heavily loaded feeders

4.10. Summary

In order to analyse the effect of varying load, power factor and generator output conditions on the operation of AVC schemes, computational models of M-F, NRC, TCC, TAPP and ETAPP techniques have been developed and implemented within the OCEPS load flow analysis software. This enabled detailed investigation of the performance of the AVC schemes under various load and generation conditions on the network. The software can help with accurate settings selection, assessment of voltage accuracy and determination of alternative solutions.

From the simulation results of the performance of various AVC schemes it can be concluded that M-F, TCC and ETAPP schemes are suitable for operation in distribution networks with distributed generation. However, due to the fact that LDC performance degrades with the increasing amount of DG, LDC settings and safety margins need to be carefully assessed in networks with a significant amount of DG. Inadequate LDC performance may cause low voltages on the network, particularly at the end of heavily loaded feeders.

It has been shown that NRC and TAPP schemes do not provide consistent performance for networks with DG, as they are susceptible to changes in power factor. When the power factor deviates from the nominal value, i.e. 0.96 for TAPP and unity in the case of NRC, significant voltage error can occur on the substation busbars.

A summary of the results derived form the simulation and analyses of the AVC scheme implemented into the OCEPS software are presented in Table 4.10.

AVC Scheme: / Performance	Master/ Follower	NRC	True Circulating Current	TAPP	Enhanced TAPP
Resistance to varying power factor	***Yes***	***No***	***Yes***	***No***	***Yes***
Differing incoming voltages	***No***	***Yes***	***Yes***	***Yes***	***Yes***
Differing transformers	***No***	***Yes***	***No***	***Yes***	***Yes***
Paralleling across a network	***No***	***Yes***	***No***	***Yes***	***Yes***
Accurate LDC at target power factor	***Yes***	***No***	***Yes***	***Yes***	***Yes***
Accurate LDC at varying power factor	***Yes***	***No***	***Yes***	***No***	***Yes***
Accurate LDC at the presence of DG	***No***	***No***	***No***	***No***	***No***
Ability to control voltage profile on the network with DG	***No***	***No***	***No***	***No***	***No***

Table 4.10 Comparison of the AVC schemes

Above table along with the software simulation of AVC scheme performance can be used to help planning engineers select appropriate voltage control scheme and accurately evaluate how much DG can be securely connected to the network without the risk of violation of the voltage profile on the network.

Furthermore, the analysis of a network and AVC schemes can reveal that it is not possible to connect a required amount of DG to the network using existing voltage control schemes and maintain the voltage profile on the network within statutory voltage limits. In such a case alternative solutions to enable connection of DG need to be employed.

Methods to improve voltage control on distribution networks with DG and alleviate voltage constrains while connecting DG are presented in the next chapter.

Chapter V – Coordinated Voltage Control for Active Network Management of Distribution Networks

The simulation results presented in the previous chapter show that the presence of DG in a distribution network affects an AVC scheme, the operating principle of which is based on a fixed power factor. The effective voltage target and as a result, the voltage level at the substation, can have a significant error in schemes such as NRC and TAPP. Even though the voltage target in the schemes such as M-F, TCC and ETAPP is consistent on networks with DG, their performance is also compromised when LDC is used.

Furthermore, voltage rise at the point of connection of distributed generation can occur on distribution networks and can significantly change the system voltage profile. These factors can limit the amount of DG which can be connected to the network and in some cases even prevent connection of the generator.

This chapter discusses various issues with voltage control in distribution networks with DG. Methods to improve voltage management and increase voltage headroom for DG are examined. The challenges and benefits of ANM techniques in 11 kV distribution networks are then presented. Additionally, a range of voltage management schemes based on coordinated voltage control of the OLTC and the voltage profile on the network are demonstrated. Advantages and disadvantages of individual systems are analyzed with regard to functionality, the ability to increase network capacity for DG, accuracy, and reliability. Finally, the last section of this chapter discusses implementation of active voltage control methods into existing infrastructure and operational voltage limits are estimated.

5.1. Challenges for Voltage Control in Distribution Networks

With the growth of DG in distribution networks, DNOs are faced with many challenges in design, control and operation of their systems but it is also recognized that connection of a generator can provide a number of benefits in a distribution network. Subject to location, network infrastructure and load conditions, the presence of DG can reduce losses in the system, alleviate heavily loaded feeders, improve voltage profiles and possibly contribute to security of supply. However, due to the fact that conventional distribution networks have not been designed to accommodate DG, a number of issues such as excessive fault level, thermal constraints and violation of voltage limits can arise [26].

Operational experience has shown that unacceptable voltage rise is a common factor limiting and even preventing the connection of DG to MV distribution networks. The voltage rise effect occurs at the PCC of the network and DG. Due to the fact that the voltage level at this point can rise above the statutory upper voltage limit the output of the generator may need to be restricted [7].

Additionally, performance of the AVC schemes can be affected and LDC performance compromised, causing the voltage level drop below the lower statutory voltage limit.

Consequently, on distribution networks with DG, not only voltage drop but also voltage rise must be considered with regards to voltage control in order to make sure that the statutory limits are maintained.

There are several proposed solutions to improve the voltage profile in distribution networks with DG. Costly solutions of network reinforcement, such as line re-conducting or building a dedicated line are currently applicable and used in distribution networks. Active voltage control with remote voltage sensing units, line voltage regulation, scheduling of DG and several other active techniques have become available recently but are still at the development and trial stage. These schemes vary in complexity, efficiency, investment and communications requirements, as presented in [47]. These methods can be applied as the single solution or in combination to increase the capacity of the network to accommodate DG [9], [49].

Active voltage control may be achieved by the coordinated management of voltage levels at the substations, generator real and reactive outputs and voltage profiles of the network. This type of control method appears to be the most efficient solution to support both generation and demand in distribution networks without significant capital expenditure [1], [50], [51].

It is common practice in distribution network design that, in order to ensure that the network is maintained within statutory limits, two extreme load conditions are considered: minimum (no load) and maximum load. A similar practice has been adopted by DNOs when DG is connected to distribution networks. In such a situation four extreme network conditions are considered; minimum load and no generation, minimum load and maximum generation, maximum load and no generation, maximum load and maximum generation [10].

This passive approach guarantees operation of the system within statutory limits and compliance with contractual obligations. However, it can significantly limit the utilisation of a network even though any potential violation of the constraints can be very sporadic. As a result the amount of DG that can be cost-effectively connected to the network is considerably constrained.

Alternative approaches to operation of the distribution networks are based on ANM techniques. They comprise continuous monitoring and control of the system in order to take pre-emptive actions to maintain the system within normal operating parameters. These solutions can significantly increase the ability of the network to accommodate DG in a secure and efficient manner.

Under the minimum load condition a generator output might significantly exceed demand on a feeder to which it is connected, causing unacceptable voltage rise. Despite the fact that extreme conditions of minimum load and maximum generation occur occasionally and in specific operational time periods, they need to be considered before DG is connected to the network. Therefore it might be beneficial to connect a larger generator and restrict its output when voltage the level at the point of connection rises above an acceptable limit. However, it is important to note that this technique has negative economical and technical implications particularly for the generators and where an over-voltage is calculated if further generation is added.

The main challenge for the coordinated active voltage control schemes is an assessment of the state of the network. Due to a relatively small number of the real time measurements compare to the vast number of branches and nodes on distribution networks, the observability of the system is very low. Consequently, the estimation of the load flow and voltage profile of the network may suffer from substantial inaccuracy and thus the network capacity cannot be fully utilised [52]. In order to improve the estimation process and increase scheme efficiency adequate monitoring systems and associated communications infrastructure need to be developed.

A range of coordinated voltage control schemes have been proposed. Some schemes are designed for networks with high penetrations of DG or possible significant increases in the future and others for a single generator. Some might cover a wide area and others control a local system. Some provide a significant increase in network capacity, others improve the voltage profile and reduce the restrictions of the DG output. Distribution state estimation is often used but alternative solutions for evaluating the state of the network are also proposed. Their accuracy depends greatly on the number of available remote measurements [50], [51]. The solution choice will depend on cost, topology of the network and the amount of DG [19].

Even in a network where sophisticated active voltage control schemes are employed, it is important to note that the AVC relays still play a fundamental role. Even if an AVC relay may not control the voltage target directly in such a scheme its overall performance can be affected by the presence of DG. Due to the fact that standard AVC relays might become unreliable under varying load power factors and reverse power flows, appropriate AVC schemes need to be used, as described in the previous chapter.

In the active voltage control scheme the role of the AVC can be re-defined. It may no longer be responsible to calculate the voltage target, as it may be determined by the local voltage controller or applied remotely from the distribution management system (DMS) as presented in figure 5.1.2. However, it is still the role of AVC relay to execute an appropriate action in order to apply the required voltage target at the substation busbars, control paralleled transformers and provide basic and safe control if these systems fail.

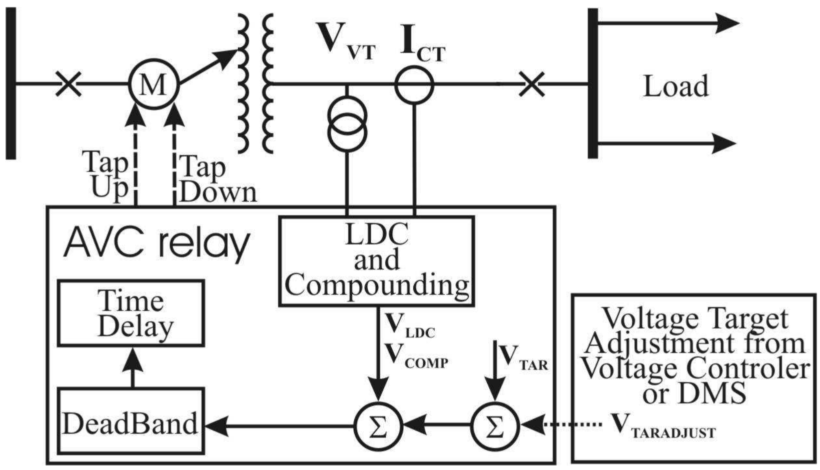


Figure 5.1.2 AVC scheme for active voltage management.

The following sections present and discuss a number of schemes to improve voltage profile, increase voltage headroom and ensure accurate operation of AVC on a network with DG. The schemes are assessed with respect to their functionality and ability to support DG in the distribution networks as well as their complexity and reliability. The suitability of each scheme and investment cost necessary for implementation within existing infrastructure is also investigated. Advantages, disadvantages and limitations of each scheme are examined

Firstly, passive solutions are described and generator reactive power control. Secondly, three main categories of coordinated voltage management for 33 kV and 11 kV networks are presented. Finally, implementation within existing MV distribution network infrastructure is analysed and the advantages and disadvantages of each scheme are discussed.

5.2. Passive Solutions

One of the passive solutions to reduce voltage rise is network reinforcement. By upgrading the conductor size of the feeder to accommodate DG, the resistance and reactance are reduced. That means that both terms in equation (3), $R \cdot (P_G - P_L)$ and $X \cdot (\pm Q_G - Q_L)$ are smaller under the same load and generation conditions and therefore the voltage rise is effectively reduced.

This method provides a satisfactory increase in the availability of the connection and also improves power quality, reduces losses and customer interruptions. However, implementation of this solution is associated with very significant costs [8].

The alternative solution for the connection of DG on the distribution network is the use of a dedicated feeder. Building a dedicated line may significantly increase voltage headroom for the DG and does not directly affect customers' voltage profile. However this solution imposes significant connection cost and can compromise LDC, if used, and AVC performance.

5.3. Generation Reactive Power Control

A common technique that is employed to manage voltage profile in a transmission network is generator reactive power control. In this technique, the voltage rise caused by a generator real power output P_G and consequently the increase of term $R(P_G - P_L)$ in equation 3, is compensated by absorbing reactive power $-Q_G$ and hence reducing term $X(\pm Q_G - Q_L)$. This technique maintains the desirable voltage level at the point of connection of the generator and its performance and effectiveness is described in [53]. However due to the fact that the X/R ratio in distribution network is typically much lower than in transmission network this technique is not as efficient for 33kV and 11kV cable feeders. It can provide reasonable effectiveness of voltage control when a generator is connected to overhead line, due to the fact that its reactance is approximately four times higher than a cable. However it can place a heavy demand on the generator to absorb reactive power. This may cause additional operational costs for the generator, lead to increase in losses in the network, and adversely affect AVC performance [26].

Managing the voltage rise in distribution networks by reactive compensation can be justified in some cases, nevertheless its application is limited and it is common practice for DNOs to instruct a distributed generator to operate at or close to unity power factor.

5.4. Use of LDC

As has been discussed in chapter III, an AVC scheme is often equipped with LDC functionality in order to provide additional voltage boost at the substation busbars. This functionality is not only used to improve customers' voltage profile but also to increase voltage headroom in order to accommodate DG [54].

When an AVC scheme is operated at a fixed voltage target, the critical (largest) voltage rise occurs under minimum load and maximum generator output conditions, but at the same time the voltage drop on the feeders without DG is relatively low as illustrated in figure 5.4.1. Under these conditions the voltage headroom which is available in the lower voltage range is lost and the generator output needs to be restricted as a voltage rise above the statutory upper voltage limit can occur.

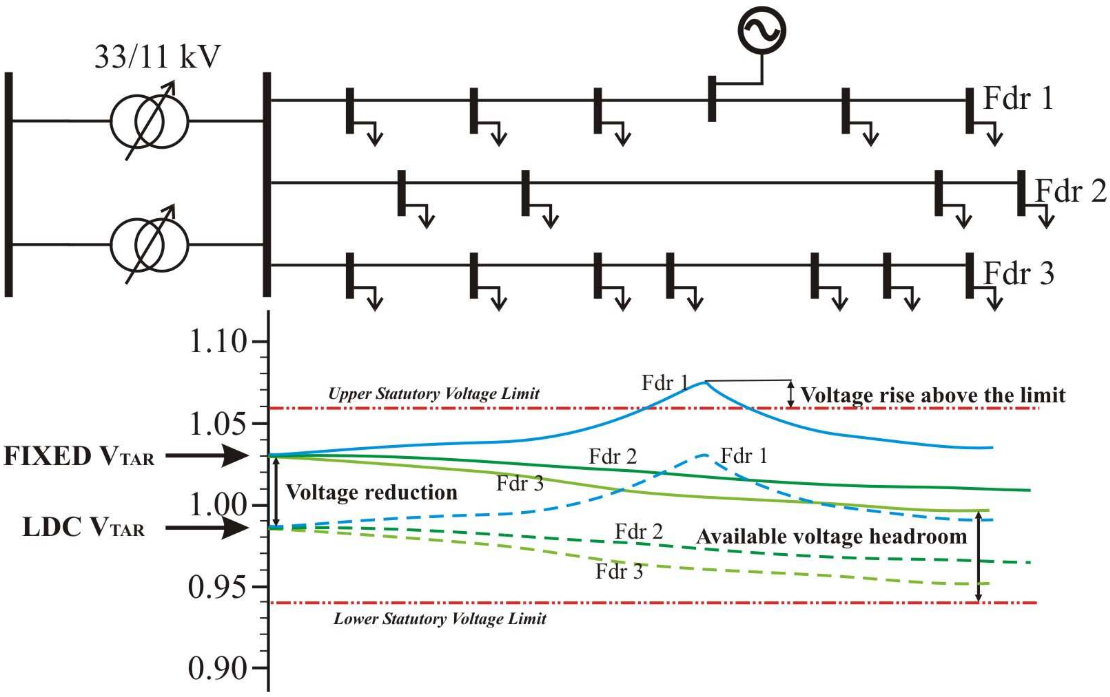


Figure 5.4.1 Voltage profile on the network with DG under low load conditions

By reducing the AVC voltage target V_{TAR} and using LDC voltage headroom for the generator can be released. Under low load demand conditions little or no LDC bias is applied and the voltage at the substation busbars is maintained at a low level. Consequently, the voltage at the point of connection of the generator is maintained within the limits but minimum voltage on the network is maintained above the lower statutory voltage limit. The voltage profiles on the feeders for AVC with LDC are shown by dashed lines in figure 5.4.1

When load demand increases the voltage target at the substation also increases. But under this condition the voltage rise at the point of connection of DG is counterbalanced by the voltage drop on the feeder and the fact that the generator is supplying local load as shown in figure 5.4.2.

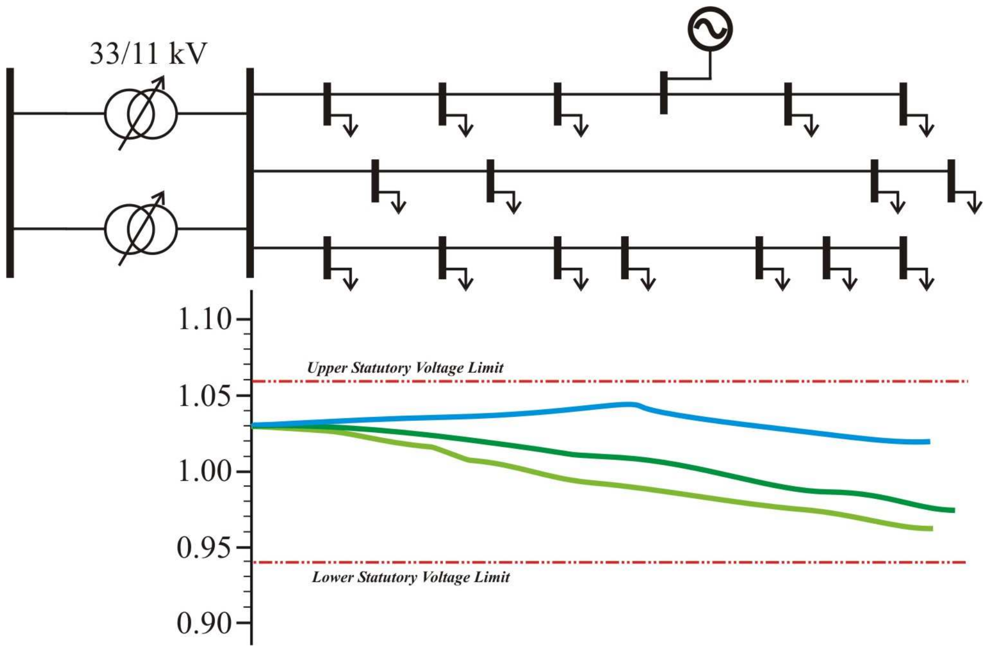


Figure 5.4.2 Voltage profile on the network with DG under high load conditions

The effective voltage target for the AVC with LDC under these conditions is the same as the AVC with a fixed voltage target.

Viawan et al. [33] further discuss voltage control on MV networks with DG using OLTC and LDC. Their paper demonstrates that revision of AVC voltage target setting and use of LDC can significantly increase the voltage headroom in systems, enabling the connection of DG with no additional equipment.

An AVC scheme with LDC is a simple example of a coordinated voltage control scheme that actively manages the AVC voltage set point, taking into account voltage drop on the network under various load conditions. However, the amount of DG and the voltage headroom that can be realised with the use of LDC is restricted due to the fact that the LDC voltage bias is lessened as the generator output increases, as presented in chapter IV. This creates a voltage error that may cause customers' voltage at the feeder end point to fall below the lower voltage limit. This issue can be considerably reduced using additional measurements at the substation level and estimation techniques, as it will be presented in the next section.

5.5. Advanced AVC Scheme Based on Local Measurements.

Using local measurements on the feeders, particularly on the feeders with DG, a significant improvement of the network voltage control can be achieved. The main advantage of this technique is that additional measurements are fairly easy to obtain and there is no need for a sophisticated and expensive communication channel for the transfer of these measurements. The existing substation infrastructure such as protection CTs mounted on the feeder circuit breakers and spare pilot wires can be used to feed AVC relays with load information on the individual feeders.

AVC schemes using a form of feeder current measurement have been used in distribution network for number of years. The commercial example of this technique is the load exclusion module (LEM) designed for the use with the SuperTAPP voltage control relay [44]. A typical application of this solution is on sites where capacitor banks, used for reduction of losses, are connected or where a heavy industrial load is supplied. The LEM enables removal of a ‘non-typical’ load from a transformer measured current and correction of the power factor as seen by a relay. As a result, the AVC scheme based on the TAPP principle can be effectively used where the power factor may vary as a result of the ‘difficult’ load.

Similarly, the LEM can be used on the feeder with DG. The effect of the generator on a transformer current, the power factor, and as a consequence on the TAPP scheme performance can be eliminated. As the generator current is removed from the transformer currents, also more accurate LDC is applied. This technique is very effective when a generator is connected on the dedicated line and the feeder measurement is simply the generator output. However, in the situation where the generator is connected on the feeder which also supplies other customers, the measurement does not correspond to the generator output. While removing the LEM current from the transformer currents, some portion of load is also removed and LDC performance is compromised to a degree.

The feeder exclusion approach is a simple and effective solution to accommodate DG on a network where an AVC scheme is dependent on power factor for circulating current control such as TAPP or NRC, and at the same time improve LDC accuracy.

However, the suitability of this technique depends on a network configuration, a number of feeders and generators as well as the load distribution between the feeders. It also has a number of limitations. One of them is that typically, only one feeder can be excluded. If the feeder, which provides connection for both generation and load, is excluded, a part of the load is also removed from the total load. For the substation with only few feeders, this can significantly disturb performance of the AVC scheme and LDC. Also, this technique is not able to provide any information about the network conditions, such as voltage level or output of the DG at the PCC.

It might appear that, on a feeder which provides connection for both, load and generation customers, the output and the voltage level at the point of connection of the generator can only be determined by a direct measurement. However, by using only measurements at the substation level and a resemblance of the load pattern on the feeders, the generator output as well as voltage rise at point of connection can be estimated [45].

With the provision of feeder and transformer current measurements the advanced AVC relay uses algorithms in order to calculate generator output. The generator output is then used to apply generator voltage bias V_G and LDC voltage bias V_{LDC}. An example of the scheme based on an advanced AVC relay is shown in figure 5.5.1.

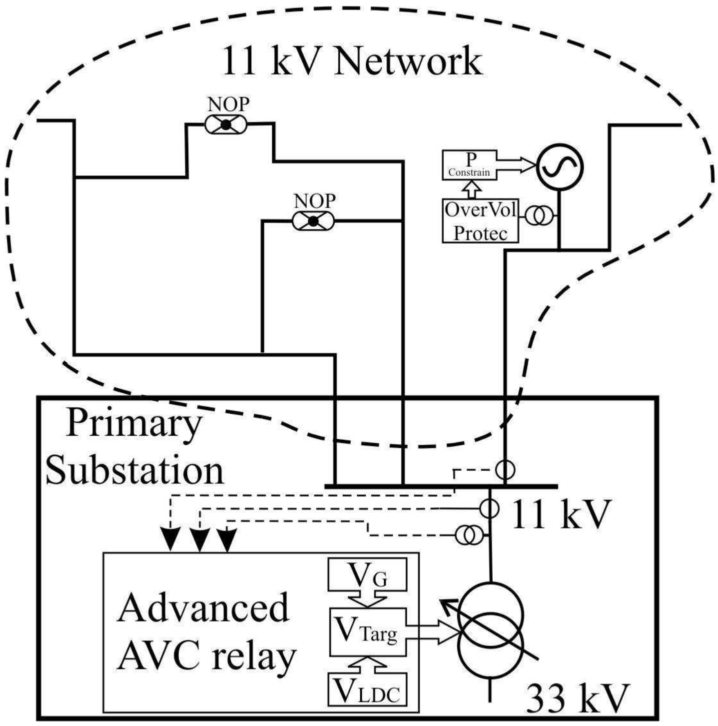


Figure 5.5.1 Active voltage control scheme based on local measurements

The generator voltage bias corresponds to the voltage reduction necessary at the substation level in order to counterbalance the voltage rise at the point of connection. Additionally, generator output current can be subtracted from the measured current at the substation and correct LDC voltage bias can be applied at the busbar. This technique improves performance of the LDC and allows increased utilization of the network and connection of the DG.

This coordinated voltage control concept is employed in the SuperTAPP n+ scheme. It offers firstly, very effective AVC performance based on the ETAPP algorithm as described in chapter IV and secondly, an innovative technique for voltage control in the distribution network with DG [22]. The key benefit of this scheme is that all measurements are taken or estimated locally and there is no need for remote communication with the generators. This, as well as simplicity of the scheme and the fact that an AVC relay is a fundamental piece of equipment required in every application, make it a cost effective and easy to install solution. A disadvantage of the scheme is that a considerable security margin needs to be maintained due to the possible inaccuracies of the estimation techniques.

The detailed description of operation and efficiency of the scheme will be presented in chapter VI along with assessment software for the scheme.

5.6. Advanced AVC Scheme with Voltage Reporting Units

The performance of the advanced AVC scheme is dependent on the precision of the estimation of generator output and the estimation of the voltage drop on the feeders. In order to ensure that the voltage profile is maintained within limits under all network conditions, strict AVC settings need to be applied. Relaxing AVC settings might cause occasional, yet uncontrollable violation of the voltage limits. To overcome this issue, voltage monitoring equipment in the form of an RTU can be installed at the points in the network where violation could occur. When the voltage level at this node is outside permissible range, the signal requesting a voltage target adjustment is sent from the RTU to the AVC.

The real-time operation of the advanced AVC scheme continues to be based on local measurements. However, single exception reporting instructions from the RTU are used to correct any unacceptable voltage deviation. A diagram of an advanced AVC scheme with reporting RTU (RRTU) is presented in figure 5.6.1.

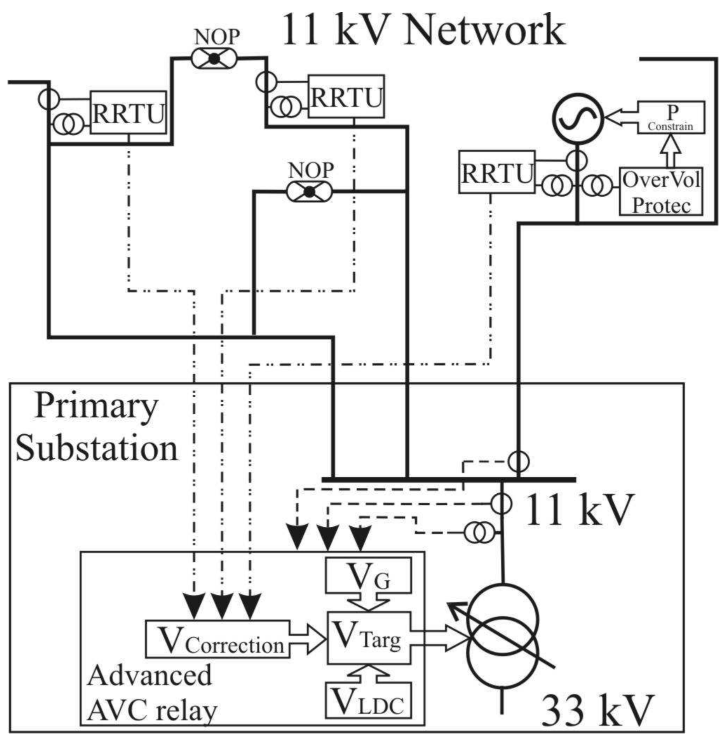


Figure 5.6.1 Diagram of advanced AVC scheme with RRTU

Relaxing AVC settings allows the scheme to improve the utilisation of the network and increase the amount of DG that can be connected. RRTUs monitor local voltages and communicate with the AVC only when the voltage threshold is about to crossed. As the communication between RRTUs and AVC is occasional, it can be provided, for example, by the GPS messaging service. This technique is based on the SuperTAPP n+ platform and is under development [23].

5.7. Local Active Voltage Management

For a particular network with voltage problems caused by distributed generation a more sophisticated approach based on a local voltage controller using the state estimation (SE) technique can be adopted [54]. An example configuration of a local active voltage controller is presented in figure 5.7.1.

In order to manage the voltage profile on a network with a single DG, the local voltage controller with SE needs at least one RTU installed at the PCC, usually located at the DG. For the other nodes SE evaluates a range of possible voltage values within which the actual voltage value resides.

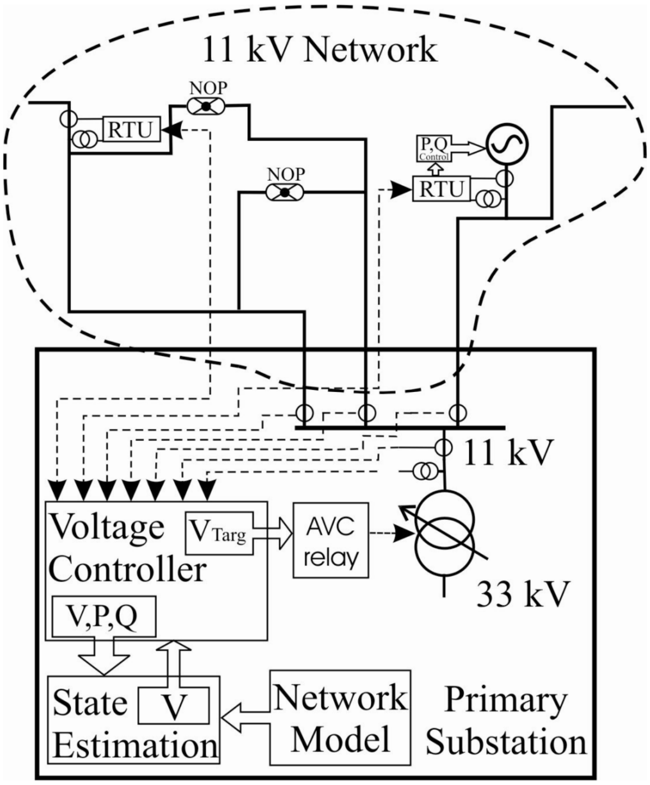


Figure 5.7.1 Local Voltage Controller.

The uncertainty of the estimation process increases with the distance from the measurement point as the uncertainty of the pseudo-measurements accumulates and the distance form the real time measurement increases. Due to the lack of RTUs on the feeders without DG, the last and only point of measurement on such feeders is at the primary substation. This results in significant voltage uncertainty at the most remote electrical node on the feeder. This particular node is important in voltage control schemes since it is expected that a customer connected at this node receives the lowest voltage in the system and must be kept above the statutory limit. This uncertainty must be taken into account and a correspondingly higher AVC voltage target needs to be applied [56], [57]. Accuracy of the SE can be enhanced by additional monitoring equipment on such networks. However, this requires further investment and increases the operational costs of the scheme.

Advanced techniques using a local voltage controller were presented by Liew and Strbac in [53] who demonstrate the benefits of three coordinated network management methods. Generation curtailment, reactive power control and coordinated OLTC control are analysed from the point of view of maximising the penetration of DG in distribution networks. The SE application in this active voltage control scheme has been discussed in [29], [32]. The examination of three algorithms for the purpose of distribution system state estimation (DSSE) is presented in [58]. Issues such as the consistency and quality of each algorithm are discussed. Implementation of the statistical distribution state estimator into an active voltage management scheme is presented by Hird, Leite et al. in [50]. Thornley, Jenkins and White analyse performance of an active voltage controller based on DSSE with a minimum number of physical measurements. Results from the real network application of this scheme are presented in [59].

A commercially available system using this technique is GenAVC [60]. The GenAVC system operates by taking voltages and power flow measurements at the substation as well as additional strategic locations across the network via communications links with RTUs. DSSE is used to evaluate voltages throughout the network and a desirable voltage target is determined for the primary transformer AVC [60].

The local voltage controller enables efficient utilization of the network. The scheme can support a significant amount of DG whilst maintaining network voltage profiles within specified operating limits. The standard operating limits can be applied across the whole network as well as deploying specific limits for individual nodes when necessary.

Some cost is associated with the implementation and operation of this scheme, however more importantly expensive reinforcement of the network can be avoided. Another disadvantage of the scheme is the static network model that is used for DSSE. Due to the fact that the network model is not coordinated with the current network state, the scheme will need to be disabled during abnormal configurations of the network and adjusted for any additional network connections. Consequently this may result in DG being temporarily constrained.

5.8. Centralised Active Voltage Management

The most comprehensive scheme, not only for active voltage control but also for ANM at the distribution level, is a scheme that can be embedded within the DMS.

A number of automation schemes already exist in DMS that improve reliability and enhance the performance of distribution networks. These schemes are used for switching operations and fault location purposes [47]. Communications from RTU's located at secondary substations is based on single instructions and limited reporting rather than continuous operation as required for ANM [48]. In Fig. 5.8.1 a functional diagram of a centralized voltage management scheme based within a DMS is presented.

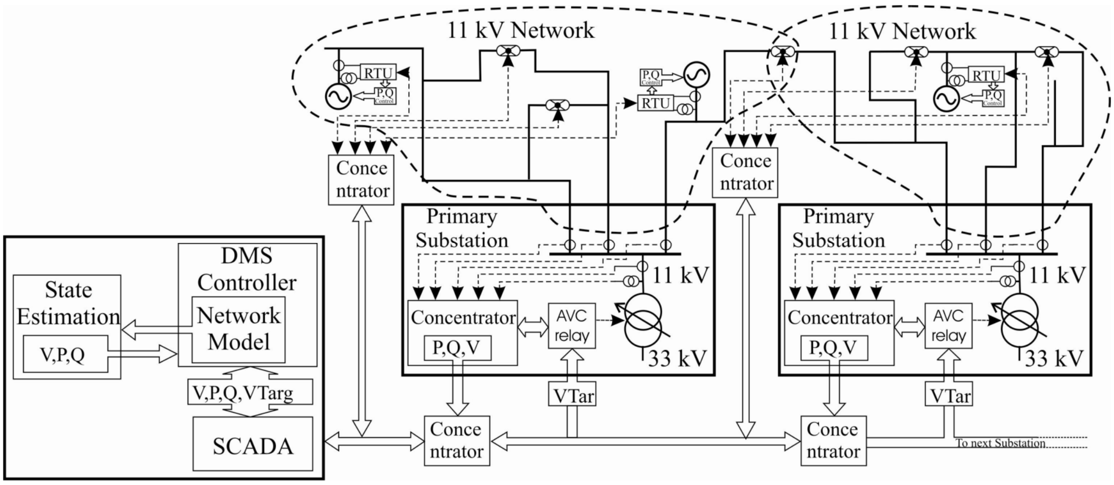


Figure 5.8.1 Centralised voltage controller.

The SCADA system collects measurements from RTUs located at strategic points in the network and sends this data to the DMS. The SE algorithm is used to evaluate voltage levels at all nodes. The DMS determines what action is required based on all collected and estimated information. Signals to adjust the voltage targets of AVC relays, modify generator outputs or change network configuration can be sent in order to maintain the optimum state of the network.

Even though the base infrastructure already exists, the transition from system automation to active control is challenging. In order to embed real-time voltage control within the control centre, significant amounts of voltage and power flow monitoring equipment needs to be installed across distribution networks and reliable communication channels for SCADA systems need to be provided. This will require substantial investment, which can be justified for networks with high penetrations or potential for DG. Nevertheless, the risk of a single point of failure needs to be taken into account.

The major advantage of such a scheme is its ability to coordinate various elements and voltage levels of the system. Centralized DMS control has the ability to provide SE with actual network models and data. All network reconfiguration can then be easily updated and accurate SE is constantly achieved. Core voltage control however, should remain at the OLTC, thus providing the default control in the event of a major communication failure.

5.9. Operational Voltage Limits for Active Network Management

In order to ensure that all customers are maintained within statutory voltage limits the distribution network may be operated at a fixed voltage target at the primary substation busbars regardless of the load. The voltage target is usually set at 1.025 pu in order to maintain all customers above lower statutory voltage limit under maximum load condition and below the upper limit under minimum load condition. This practice is simple and effective in the network without DG. However, due to the fact that voltage level in the network is constantly kept relatively high, it does not offer significant voltage headroom for the generator, especially under low load conditions.

The objective of the active voltage control is to maximise the available capacity of the existing network infrastructure in order to support the connection of DG by dynamically adjusting the voltage target level to within acceptable limits. Improved system utilisation can be achieved by coordination of the voltage target at the substation and voltage profile on the network. Under low load conditions, voltage drop along the feeders is less significant and a lower voltage target at a substation can be applied. As a result more voltage headroom is available for a generator connected to the network. The main concern is to accurately estimate the voltage profile in a network under all conditions. A miscalculation in the altered voltage target can result in a voltage level excursion outside statutory limits. Even very powerful and accurate tools for distribution network voltage control, equipped with an efficient scheme and robust DSSE are burdened with considerable uncertainty in terms of load flow and consequently the voltage profile. This is due to the high dimensionality of distribution networks, uncertainty in the network model, and most significantly, low observability of the network. In order to prevent this situation operational voltage limits and safety margins need to be established.

Furthermore, it is not viable to make all networks and all voltage levels “active”. It is rather expected that most LV networks will remain passive, as it is unfeasible to manually alter the tap position of a distribution transformer, and active network management will only cover MV distribution networks. Nevertheless, new technologies may emerge for the voltage control at LV levels, such as distribution transformers equipped with on-load tap changers or demand side management. Moreover, implementation of smart meters at customers' premises can provide valuable information about the voltage profile in the LV network. If voltage measurements from smart meters become available for network operation purposes, voltage control can be extended from the MV network to the LV network.

At present only MV networks are primarily being considered to become active networks. Active voltage control incorporates voltage management at the primary substation, point of the connection of DG and the HV side of distribution transformers. With the use of techniques such as AVC, LDC, local voltage controller, DSSE and generator active and reactive power control, the network voltage headroom can be significantly increased. However, due to measurement and estimation techniques uncertainty, and the fact that the LV network is likely to remain passive, distribution networks cannot be operated near the statutory voltage limits. In order to make sure that all customers are maintained within the statutory limits, operational voltage constraints as well as safety margins need to be assessed and applied in active network management schemes.

There cannot be a universal formula to calculate operational voltage limits due to the fact that each distribution network has been designed and operated under various standards. However, general patterns which can be applied are presented below.

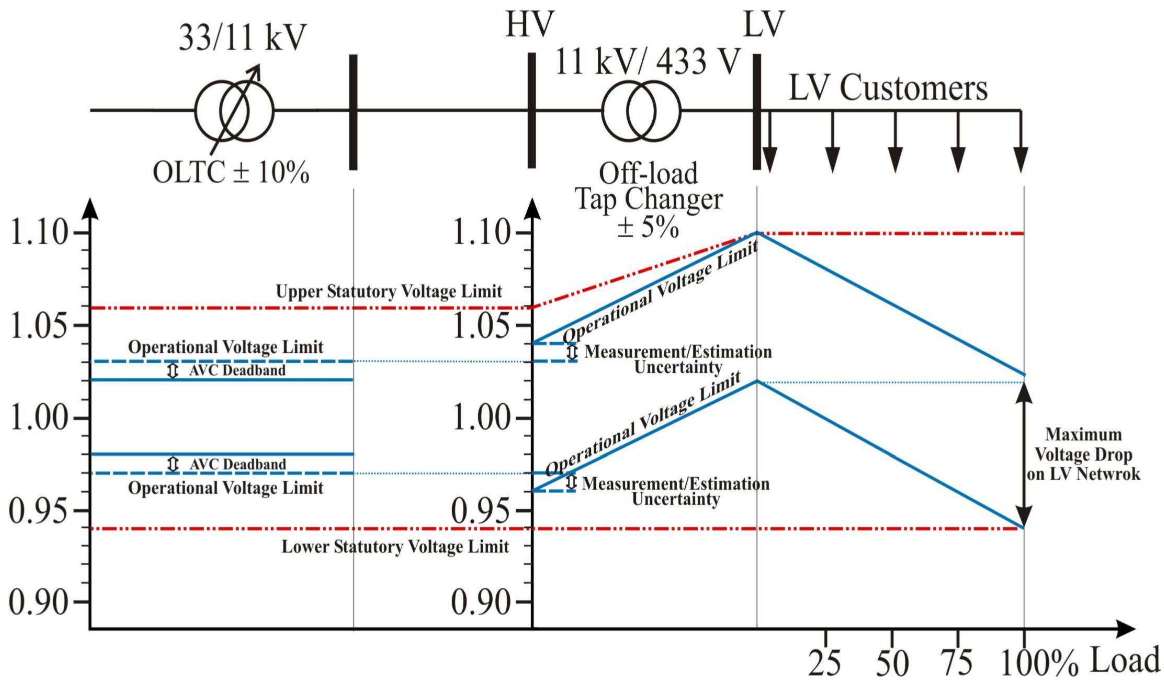


Figure 3.6.1. Operational voltage limit for MV network voltage control

Figure 3.6.1 indicates the fundamentals for the calculation of the operational voltage limits for the MV network and the settings of the AVC relay; voltage drop across distribution transformers has been neglected.

The operational voltage limits for the HV side of the distribution transformer are determined by LV network design. One of the criteria in the network design is a maximum allowed voltage drop on LV network and on the customers' service. This varies from system to system; however, 6% and 2% voltage drops respectively are commonly employed. That means that 8% voltage drop can occur, which indicates that the minimum voltage level to LV side of the transformer can not be maintained below 1.02 p.u. Applying a similar policy but considering the closest customer to the transformer and minimum voltage drop, the maximum operational voltage limit can be assessed. Generally MV/LV transformers have the higher than nominal ratio in order to provide a fixed voltage boost for the LV network and are fitted with an OLTS, typically in voltage regulation range of ± 5% in 2.5% steps. The OLTS position setting varies between utilities and LV networks, however, it is common to use tap position 2 which gives voltage level at LV side at 1.06 p.u. at 1 p.u. incoming voltage. Taking into account the ratio and the tap position of the distribution transformer, the maximum operational voltage limit at the HV side of the transformer can be evaluated as presented in Figure 3.6.1. This node becomes the last control point in the distribution network. Even though this is an inoperative node, which is the case for all load nodes, the voltage measurement or voltage estimation allows control of this node via the voltage level at the primary substation busbars.

For the common conditions and design rules as described above, the operational voltage range for a typical load node in the MV network is ± 4 % of the nominal voltage. Additionally, with the uncertainty in simulation results, DSSE performance and measurements need to be taken into account in order to ensure that these voltage limits are maintained.

It is important to note that some customers (for example a generator) might accept higher voltage levels of up to 1.06 p.u. and for some load nodes (for example an abnormal distribution transformer tap position) an individual operational voltage limit needs to be applied. Active voltage control schemes with DSSE provide a capability to apply individual operational voltage limits for each node and any exception can be easily defined in the scheme. Conversely, an advanced AVC scheme cannot comply with individual operational limits and this needs to be considered at the design and simulation stage of the scheme for appropriate settings to be applied. In the active voltage control scheme based on an RRTU, individual voltage limits can be achieved by installation of additional voltage measurement points on the network. The nodes which would require RTU installation need to be assessed at the design stage using a simulation tool.

The key voltage control point in an MV network for an active voltage control scheme is still the busbar at the primary substation. The voltage level is adjusted by an AVC relay, which changes the tap position of the OLTC with the aim of achieving the required voltage target at the busbar. Performance and settings of the AVC, such as relay bandwidth, need to be taken into account in the voltage target calculation.

Let us consider a random node without voltage measurement on the MV feeder, where the voltage level is to be maintained within ± 4 %. If uncertainty of the DSSE in voltage estimation at this node is 1% and the bandwidth setting of the AVC relay is ±1%, in order to ensure that the voltage is kept below the upper operational limit the voltage target must be less than 1.02 p.u.. Similarly, the voltage target must be above 0.98 p.u. to maintain the voltage at the node above 0.96 p.u. For simplicity in the above calculations the voltage drop along the feeder was neglected, however, the voltage control schemes must calculate this voltage drop and include it in the overall analysis.

5.10. Summary

Either conventional network reinforcement techniques or ANM schemes for voltage control can be used to overcome issues associated with the connection of DG. Smart grid technologies such as active voltage control can provide an efficient and cost effective solution for many issues associated with the accommodation of DG in distribution networks.

A number of aspects need to be considered before new ‘smart’ active network management technology can be implemented. Factors such as existing network infrastructure, load and voltage profiles, AVC schemes and their settings, the amount of DG connected with future DG growth, communication infrastructure, bandwidth requirements and capital cost. These need to be carefully analysed and therefore when considering active network management techniques, suitable and accurate assessment software is essential.

Chapter VI - SuperTAPP n+ Voltage Control Scheme and OCEPS n+ Assessment Software

A number of active voltage control schemes for distribution networks have been discussed in the previous chapter. One was the advanced AVC scheme that is implemented in the SuperTAPP n+ relay. In this chapter the principles of operation, functionality, accuracy and application of the SuperTAPP n+ scheme are presented. New estimation methods for generator output calculation are proposed and the effectiveness of these techniques is evaluated based on real network measurements. Moreover, and specific to this thesis, the simulation software designed for voltage analysis in distribution networks and assessment of SuperTAPP n+ scheme operation in particular network scenarios is presented.

6.1. Principles of the SuperTAPP n+ Scheme

SuperTAPP n+ is a voltage control relay designed to control the voltage of transformers connected to a distribution network in which there may be distributed generation and related voltage management issues [45], [46]. The relay offers very efficient control for parallel transformers based on the ETAPP scheme that was discussed in chapter IV. Additionally, an innovative technique employed in the relay provides the ability to estimate output of the generator which is connected at a remote point on a feeder.

The SuperTAPP n+ scheme relies on the system voltage measurement, V_{VT}, transformer current measurement, I_{TX}, feeder measurements, I_{FX}, as shown in figure 6.1.1, and embedded algorithms in order to modify the effective voltage target to compensate for load related voltage drop along feeders and generator related voltage rise at the point of connection.

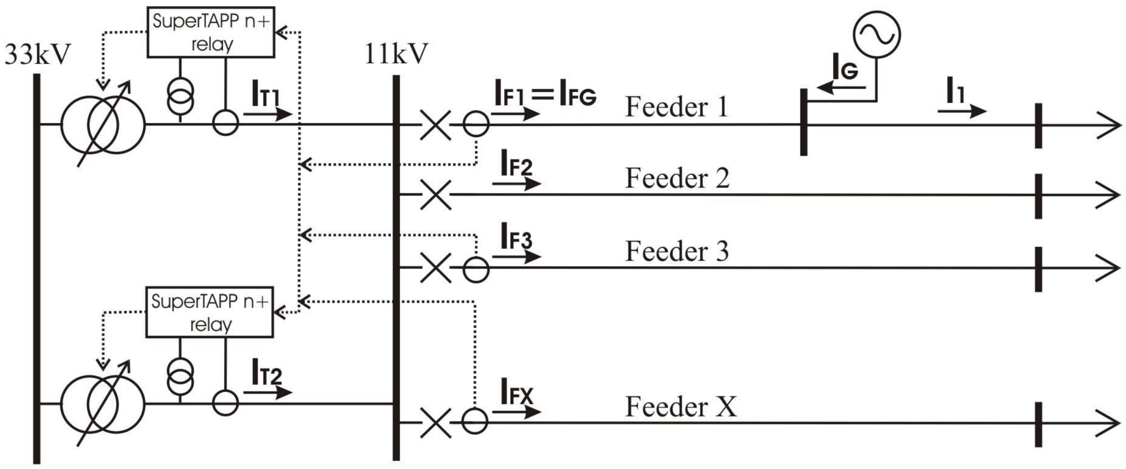


Figure 6.1.1 SuperTAPP n+ scheme arrangement

The control method employed by the device requires calculation of the summed load current at the node to which the device is connected and the injected current into the node from the distributed generator. The generator current estimation technique is derived from measured transformer currents, current measurement on the feeder with the generator and the load sharing ratio E_{ST} of the feeders with distributed generation to those that do not have generators connected.

$$E_{ST} = \frac{load\ on\ feeders with\ generators}{load\ on\ feeders without\ generators} = \frac{I_{FG}}{\sum I_{TL} - I_{FG}} \qquad (38)$$

Where:

E_{ST} - load ratio of the feeder with generators to the feeder without

$\sum I_{TL}$ - sum of transformers currents

I_{FG} - current on the feeder with generation

This ratio is calculated prior to the connection of the generator or when the output of the generator is zero i.e. when $I_G = 0$ and the measured current on the feeder is equal to the load current; $I_{FG} = I_{F1}$. Representing the sum transformer currents as follows:

$$I_{TL} = \sum I_{TL} = I_{T1} + I_{T2} \tag{39}$$

where the generator current I_G can be determined as follows:

$$I_G = \left(E_{ST} \cdot \left(I_{TL} - I_{FG}\right)\right) - I_{FG} \tag{40}$$

With the assumption that the load profile on the feeders is similar at all times, the E_{ST} ratio remains constant and a generator output can be determined.

Using the estimated value of the current output of the generator I_G, the voltage rise at the point of connection can be evaluated. Appropriate generator compensation bias, V_G, can be applied and the effective voltage of the AVC is modified. The generator compensation bias is calculated in reference to the voltage rise at the maximum generator current I_{GMAX} as shown in equation (41).

$$V_G = V_{GMAX}\% \cdot \frac{I_G}{I_{GMAX}} \tag{41}$$

The calculated generation voltage bias corresponds to the necessary voltage reduction at the substation in order to bring the voltage level at the point of connection of DG within statutory limits. However, the bias is offset by the acceptable voltage drop on the remaining feeders.

The additional advantage of this method is improved performance of LDC. In a network that supplies only load customers, the load current is equal to summed transformer currents, as in equation (39), and LDC is applied in proportion to this current. However, when a distributed generator is exporting power into the network, the summed transformers current does not represent total load at the network and is reduced by the generator injected current. As a consequence the LDC voltage bias is also incorrectly reduced.

In order to eliminate the error from the LDC performance caused by DG, the generator current is removed from the summative transformer current I_{TL} and true load current is calculated as follows:

$$I_{LOAD} = (I_{TL} - I_G) - (I_{TL} - I_{FG}) \cdot (1 + E_{ST}) \tag{42}$$

The LDC voltage bias calculation which is based on the true load current I_{LOAD} is not affected by the generator output and the LDC performance on the network with DG is significantly improved.

The SuperTAPP n+ scheme, with the provision of the LDC voltage bias and the generator voltage bias, is able to estimate the voltage drop along the feeder caused by the load current as well as voltage rise caused by the DG export at the point of connection in real time. These two voltage biases along with any circulating current voltage bias and basic target voltage are used to calculate the effective voltage target required to optimise the voltage profile on the network and minimise any circulating current. Thus, in the SuperTAPP n+ scheme equation (32) takes the following form:

$$V_{TAR}' = V_{TAR} + V_{LDC} + V_{SITE} + V_{NET} + V_G \qquad (44)$$

6.1.1. Advantages and Disadvantages of the Scheme

The main advantage of this scheme is that all measurements are taken locally and there is no need for remote measurements. This, as well as simplicity of the scheme and the fact that an AVC relay is a fundamental piece of equipment required in every application, make it a cost effective and easy to install solution.

However, as the scheme relies on local measurement and estimation techniques it is subject to some errors. Due to the fact that both generator compensation bias and the LDC voltage bias calculation are based on the E_{ST} ratio, any deviation of this factor from the set value introduces an error in the AVC target voltage. Figure 6.1.2 shows an example of the load profile on an 11 kV substation over a week [38]. The bottom line on the plot represents load current on the feeder prior to the connection of the DG. The line in the middle represents the total load on the substation. Under ideal circumstances the load on each feeder, and consequently the load on the substation, follow the same pattern and the ratio E_{ST} is constant. In real systems there are some discrepancies in the load current ratio on the feeders which are reflected in fluctuation of the factor E_{ST}. The magnitude of variation in E_{ST} is represented by the top line in figure 6.1.2 with the values on the right-hand axis.

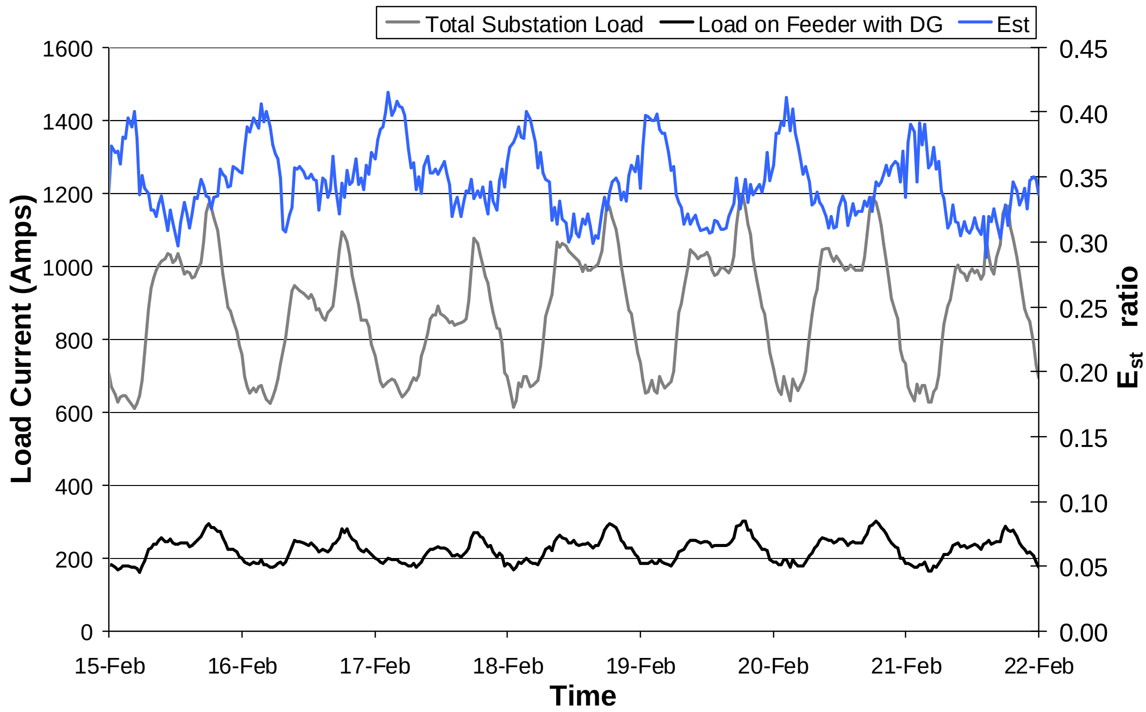


Figure 6.1.2 Load profile on the substation and E_{ST} ratio fluctuation.

In the example above the average E_{ST} ratio is 0.35 with the deviation approximately ±20 per cent. The range of variation in the E_{ST} ratio varies from network to network and it is influenced mainly by the character of the load on the feeders. For the feeders with the majority of the residential customers it tends to be less significant, whereas for the feeders with a considerable amount of commercial and industrial load, variation in E_{ST} has a tendency to increase. The data collected from SuperTAPP n+ trials and various distribution networks showed that under the latter condition it might rise to ±35% of the average value.

Another factor which affects generator voltage bias calculations and efficiency of the SuperTAPP n+ scheme is the amount of generation on the feeder. When the amount of DG is a small proportion of the feeder load, the change in E_{ST} , caused by DG, is also low. Any deviation in the load ratio from the set value introduces significant error. As the DG share in the feeder load increases, the error in the voltage bias calculation reduces. The curves in figure 6.1.3 correspond to various DG to load ratios and the generator voltage bias errors for a range of E_{ST} deviation.

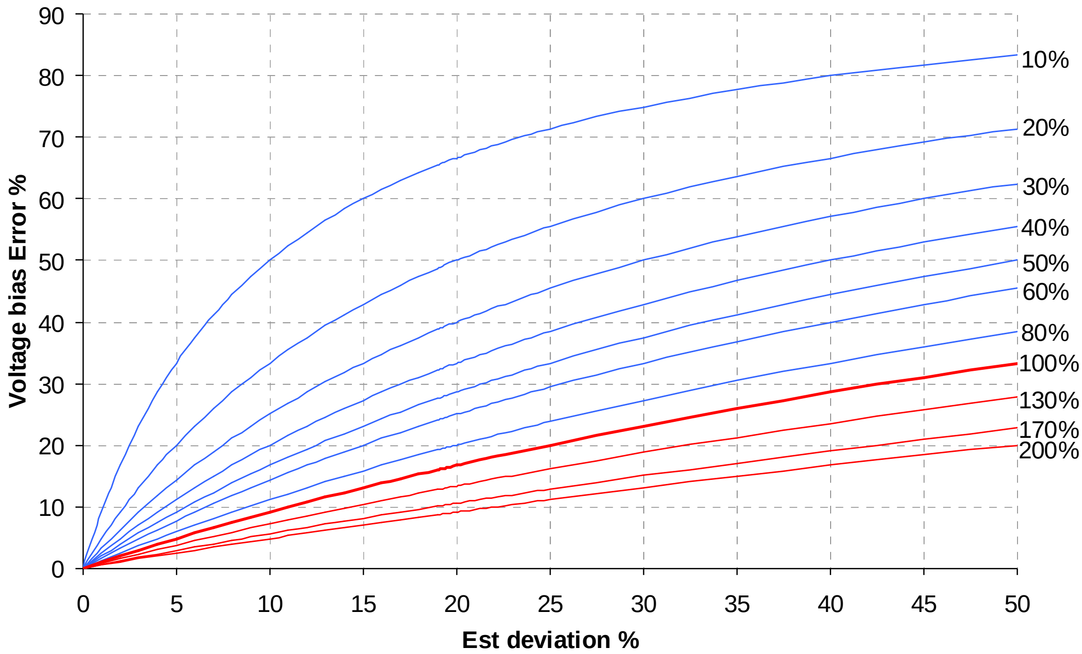


Figure 6.1.3 Voltage Bias Error in respect to generator to load ratio on the feeder and E_{ST} ***deviation***

It can be observed that the voltage bias error can become considerable, even at the E_{ST} deviation in the range of ±20% reaching 70%, when insignificant amount of DG is being connected on the feeder. However, in that case zero or minimum voltage rise occurs and generation voltage bias is not required. On the distribution network with a generator operating at unity power factor, the voltage rise effect becomes a problem when the generator output becomes a significant portion of the load on the feeder, possibly exceeding demand. Under these conditions the generator output to load ratio is more than 80%. Taking into consideration the E_{ST} with a variation in the range of 20%, the maximum error introduced in the SuperTAPP n+ performance does not exceed 20% [61].

Further improvement of the generator output estimation technique can be achieved with additional feeder measurements. In a network where significant changes in the load ratio E_{ST} are observed it can be beneficial to remove the dissimilar load, which affects the load ratio, from equation (38). The feeder measurement which supplies this load can then be excluded from the calculation and the error in the estimation technique can be reduced. Alternatively, a feeder or feeders with similar load profiles to the feeder with DG can be used to determine the E_{ST} factor. In that case equation (38) takes form as follows:

$$E_{ST} = \frac{I_{FG}}{I_{FX} - I_{FG}} \tag{45}$$

The SuperTAPP n+ scheme has an ability to accommodate numerous DGs on a network and estimate their output using local measurements. Generation can be connected on different feeders and current measurement is required on each of them. However, at the substation with multiple generators connected on various feeders, at least one feeder with no generation is essential. This is due to fact that the reference load is required for the estimation technique and only a feeder with no DG can be used. The accuracy of the SuperTAPP n+ estimation of the generators' output connected on multiple feeders is dependent on how closely the reference load represents the load profile on all the feeders with DG.

In order to maximise the utilisation of a distribution network with DG using SuperTAPP n+ scheme and prevent any voltage rise above the statutory limit, it might be required to install additional over-voltage protection system at the point of connection of the generation. At the time when the scheme is not able to maintain the required voltage, either due to a lack of voltage headroom on the network or generation estimation erroneousness, the over-voltage protection system sends a signal to curtail DG until the voltage is restored to an acceptable level.

6.2. New Generator Output Estimation Techniques

The load ratio E_{ST}, which is currently used in the SuperTAPP n+ scheme, is determined at the network analysis stage and applied into the relay when the AVC scheme is commissioned. The generator output estimation is based on transformer and feeder current measurements and a fixed E_{ST} value. The only factor affecting accuracy of the scheme is fluctuation in this parameter. As has been discussed above, the load ratio in distribution networks is not constant and can significantly diverge from the set value.

With the aim of improving the efficiency and accuracy of the estimation technique, two new methods to calculate generator current injection at the remote point on the feeder are presented in this section. Both methods are still based on local measurements. However, relationships between the active and reactive components of the measured currents are used.

6.2.1. Dynamic Load Ratio

This method is based on the dynamic load ratio, E_{DY}. Unlike the estimation method based on load share ratio E_{ST} between the feeders that needs to be evaluated when generator output is zero, the E_{DY} parameter is updated continuously. Calculation of the dynamic load ratio E_{DY} is based on the premise that load power factor on the substation and on individual feeders is similar and the fact that distributed generation operates at unity power factor.

The load share between the feeders with generation and those without can be calculated using reactive components of the summed transformer current I_{TL} and current on the feeder with DG I_{FG}. This calculation is as follows:

$$E_{DY} = \frac{\mathrm{Im}(I_{FG})}{\mathrm{Im}(I_{TL}) - \mathrm{Im}(I_{FG})} \qquad (46)$$

This parameter is then used to estimate generator output current as in equation (40), replacing the static load ratio E_{ST} with the dynamic ratio that gives:

$$I_G = (E_{DY} \cdot (I_{TL} - I_{FG})) - I_{FG} \qquad (47)$$

The advantage of this method is that the load ratio does not have to be changed in the relay if the load on the network changes, as it is a case for static load ratio algorithms. These changes are reflected in the local measurements and automatically used by the relay. However if additional 'new' load is added, the reactive current will also increase in proportion resulting in the change of the E_{DY}. As this is a predictable change suitable adjustment would be made to avoid any errors in the measurements. Additionally, the method using E_{DY} is susceptible to power factor deviations that affect the estimation accuracy.

6.2.2. Constant Power Factors

It has been described in previous chapters that the power factor on the distribution networks without generation is fairly constant [29], [36]. It is also common practice that DG is requested to operate at fixed power factor. The second method, called constant power factors, uses these two statements and the generator current output is calculated as follows:

$$I_G = \left[\mathrm{Im}(I_{FG}) \cdot \left(\underbrace{\frac{\mathrm{Re}(I_{TL})}{\mathrm{Im}(I_{TL})}}_{consant - C_{LOAD}} \right) - \mathrm{Re}(I_{FG}) \right] \cdot \underbrace{\left(\frac{\mathrm{Re}(I_{FG})}{\mathrm{Im}(I_{FG})} \right)}_{consant - C_{DG}} \qquad (48)$$

With the assumption that load power factor is constant the term $\frac{\mathrm{Re}(I_{TL})}{\mathrm{Im}(I_{TL})}$ has a fixed value and with the assumption that generator operates at fixed power factor, the term $\frac{\mathrm{Re}(I_{FG})}{\mathrm{Im}(I_{FG})}$ becomes a constant. Thus, the generator output can be calculated using the current measurement on the feeder with DG and two constants C_{LOAD} and C_{DG} as follows:

$$I_G = [\mathrm{Im}(I_{FG}) \cdot (C_{LOAD}) - \mathrm{Re}(I_{FG})] \cdot C_{DG} \qquad (49)$$

As the generator current output calculation relies on a constant power factor for both load and generation, any deviation from the set value of either will cause an error in the estimation.

6.2.3. Simulation Results of Dynamic and Constant Power Factor Ratio

The simulation results based on the SuperTAPP n+ and the real network data have been used to investigate consistency and accuracy of the proposed generation estimation methods and compare the results with the estimation technique based on static load ratio. A three day sample of the simulation results is shown in figure 6.2.1.

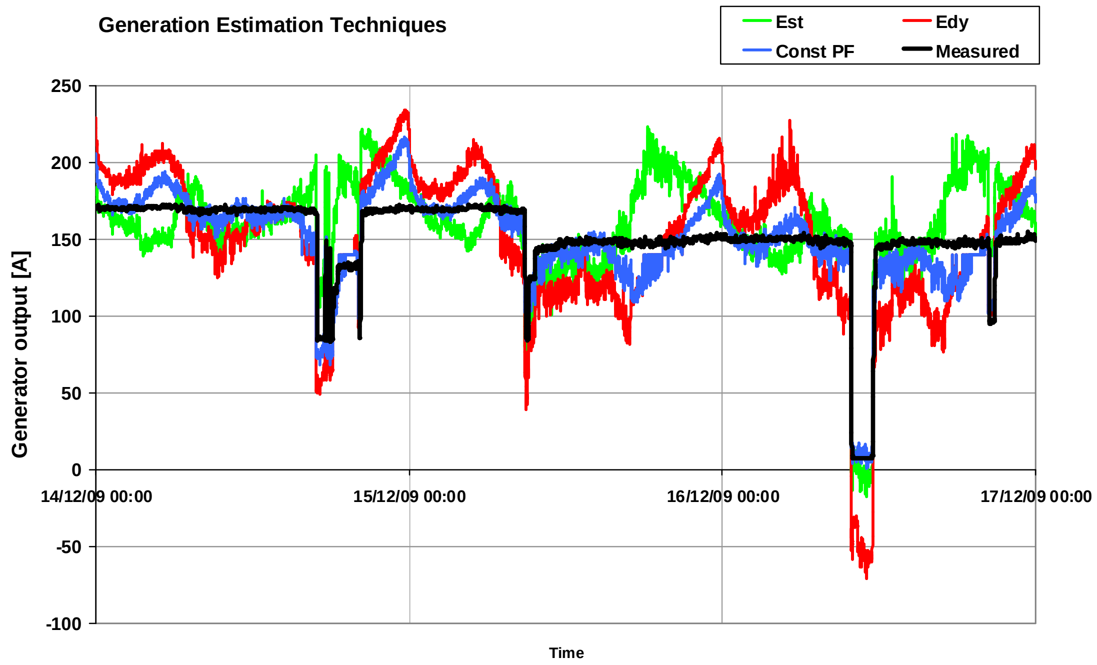


Figure 6.2.1 Generation estimation technique comparison.

Generation estimation techniques based on static, dynamic and constant power factors are represented by the green, red and blue lines respectively. The black line corresponds to the measured generator output at the point of connection. It can be observed that all three estimation methods have some errors. The least consistent is the technique based on E_{DY}. Estimation based on E_{ST} tends to overestimate generator current injection to the network between 15:00 and 01:00. The constant power factors method, in this case is the most accurate, the generator output closely following the black line in the figure 6.2.1.

It has been observed that, depending on the network conditions, load profile on the feeders, generator operation regime and load power factor, one of the three proposed estimation techniques can provide better accuracy than the others. For each network detailed analysis is necessary to select the most suitable technique in order to ensure the most accurate generation estimation based on local measurements.

The new methods offer alternative estimation techniques that can be used in the SuperTAPP n+ scheme to calculate generator current injection at the remote point on the feeder based on local measurements. The SuperTAPP n+ relay system has been design to facilitate multiple current measurements and each measurement can be programmed for a particular use. In this way it is a simple task to modify the program code for alternative estimation techniques. Both methods have been implemented in the SuperTAPP n+ relay and will be tested at SuperTAPP n+ trials to evaluate their functionality and accuracy in real networks.

6.3. SuperTAPP n+ Simulation Software

When the SuperTAPP n+ scheme is to be used to increase the ability of a network to accommodate DG, a detailed investigation of the network characteristics is performed. Several factors such as the load profile on the feeders, variation of E_{ST}, and required generator and LDC voltage biases are considered in order to guarantee effective and secure performance of the SuperTAPP n+ scheme.

Appropriate simulation software has been developed to provide an efficient tool for the SuperTAPP n+ scheme assessment and its potential performance on a particular distribution network. The SuperTAPP n+ assessment software is based on the OCEPS load flow software combined with the load and voltage drop estimation techniques, advanced AVC scheme and SuperTAPP n+ functionality. It uses a model of the network and historical SCADA data in order to estimate performance of the scheme in a particular network scenario over a period of time. The output of the software indicates the amount of DG that can be connected, the period of time when the scheme is able to accommodate the required amount of DG and when the DG export needs to be curtailed. It also indicates any possible violation of the voltage limits. Moreover, the software assists with the selection of appropriate SuperTAPP n+ settings and assessment of their effect on the performance of the scheme.

6.3.1. M-OCEPS Software

The design of distribution networks has conventionally been based on worst case scenarios. For the network with load customers only, maximum and minimum load conditions are studied. When a generator is to be connected on the network four extreme conditions must be considered such as maximum load-no generation, maximum load-maximum generation, minimum load-no generation and minimum load-maximum generation. To assist network planning engineers with the network analysis load flow software to evaluate steady the state of the system is commonly used.

Commercially used load flow packages, such as OCEPS, DINIS [62], GROND etc., are suitable tools to solve these four steady states of a particular network with the design of a passive distribution network. However, these simulation programmes become ineffective when an active approach to the operation of a distribution network is adopted. The active approach requires analysing many steady states of the network under various load and generation conditions. Additionally, these results need to be examined for any violation of a number of parameters. Using standard load flow programmes it would be very time consuming and in many cases unfeasible. Therefore, an appropriately designed simulation package is required for analysis and design of active distribution networks.

The M-OCEPS software has been developed to enable efficient analysis of distribution networks with distributed generation from the active voltage control point of view, particularly for 11 kV networks. The software has been designed to utilise the information available on distribution networks in conjunction with historical data. Additionally, the SuperTAPP n+ scheme model has been implemented into the software creating an efficient assessment tool for the scheme [63]. The simplified model of the M-OCEPS software with the SuperTAPP n+ model is shown in figure 6.3.1.

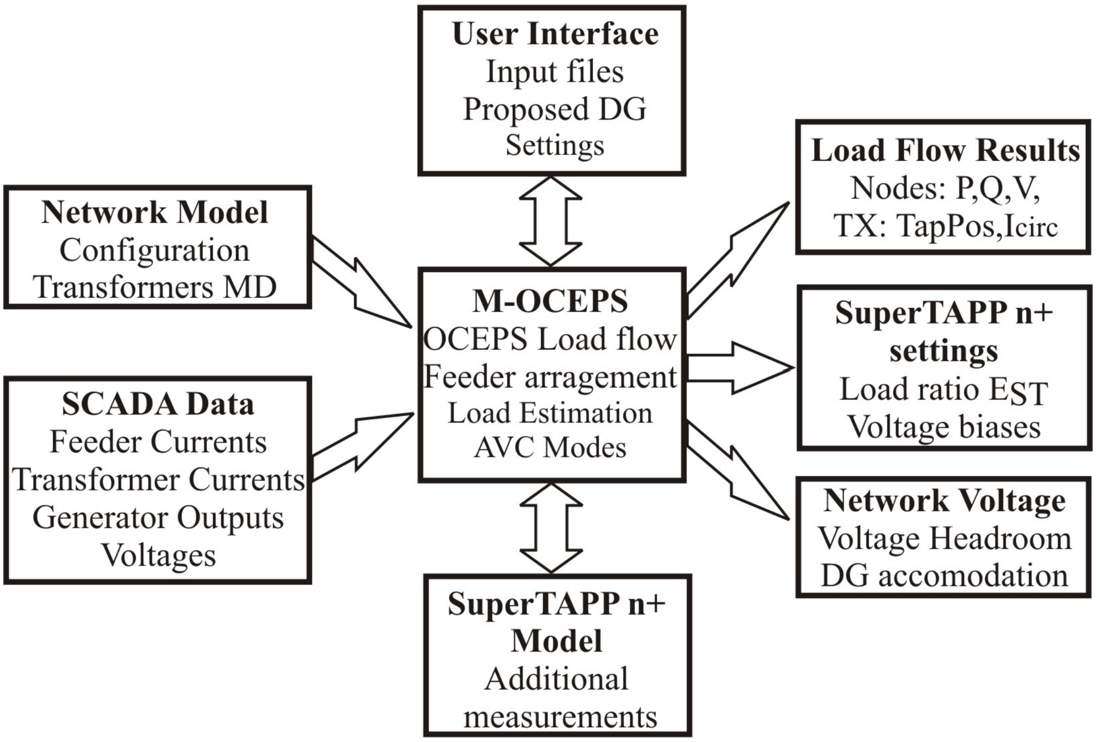


Figure 6.3.1 Overview of M-OCEPS software.

6.3.2. M-OCEPS Software Development and Functionality

The M-OCEPS software is based on the load flow algorithm described in Chapter IV. However, a number of functions have been added to make it suitable for active voltage control analysis. The software reads additional input files and creates three output files that include simulation results in an easy to analyse format. Feeder arrangements and feeder load estimation algorithms give practical information about load flow and voltage profile on individual feeders and a user interface allows various scenario related settings.

6.3.3. Input Files

Two input data files are used in M-OCEPS software: network model and SCADA measurements. Both files have been arranged to maximise information which is available from the DNO's database and SCADA system.

The network model input file consists of typical information about branches, nodes, transformers and the arrangement of a distribution network. This data may be extracted from the DNO's database or the load flow package. If the network model is not available, cable and overhead line parameters can be obtained from a GIS (geographical information system) database and transformer and load parameters from an asset management database. An example of this file is presented in appendix A. Each branch is described by impedance and shunt admittance and connection nodes. Additionally a rating of a line and BRANDCOD (see table 4.1.1) needs to be specified. Nodes are described by type as follows; 1 for Slack, 2 for *PV* and 3 for *PQ*. All load nodes are not characterised by the *P* and *Q* as it is common in the load flow software but by rated power of the distribution transformer, maximum demand (MD) recorded on the secondary substation and power factor. This is in order to maximise accuracy in load allocation on the feeder. If an MD reading is not available, maximum demand is assumed to be half of the rated power (according to the design standard stated in engineering recommendations). Transformers are characterised by the parameters presented in table 4.1.1.

In order to achieve simulation results as accurately as possible for a distribution system, any network measurement which is available via SCADA can be integrated into the software calculation. The SCADA data can be exported in a standard format and included into the input file. Typically, at the local substation level, voltage with transformer and feeder currents are available. Additionally, if any remote measurements are accessible they can be included in the SCADA input file. An example of the SCADA input data file is also presented in appendix B.

In the heading of the SCADA data file, information about the number of transformers, feeders and remote measurements that are used for simulation is presented. Branches for any current measurement and nodes for any power or voltage measurement are specified in the following section in order to link real measurements with the network model. The main body of the file contains all measurements, starting with the time and date of the measured sample. A list of the typical measurements in a SCADA input file, along with required unit and the most commonly available time intervals is shown in table 6.3.2.

SCADA data	Description and unit	Available time interval
Time Sample	Date and time of the measurement [dd/mm/yy hh:mm]	N/A
Side Demand	Apparent power recorded at the substation [MVA]	Average Half-hourly,1 minute
Transformer P	Transformer real power measurement [MW]	Average Half-hourly,1 minute
Transformer Q	Transformer reactive power measurement [MVAr]	Average Half-hourly,1 minute
Transformer S	Transformer apparent power measurement [MVA]	Average Half-hourly,1 minute
Transformer Current	Transformer Current measurement [A]	1 minute
Transformer Voltage	Transformer voltage measurement [kV]	Average Half-hourly,1 minute
Feeder measurements	Feeder current measurement in [A]	1 minute
Load P	Real power measurement (usually industrial customers are metered) [MW]	Average Half-hourly (1 minute with smart meter)
Load Q	Reactive power measurement (usually industrial customers are metered) [MVAr]	Average Half-hourly (1 minute with smart meter)
Generator P	Real power measurement (usually generators are metered) [MW]	Average Half-hourly (1 minute with smart meter)
Generator Q	Reactive power measurement (usually generators are metered) [MVAr]	Average Half-hourly (1 minute with smart meter)

Table 6.3.2 SCADA data input file measurements

To obtain satisfactory simulation results for a radial distribution network each feeder current measurement is required. Transformer P and Q measurements can be used to calculate load power factor and update the power factor from the network model. These with transformer voltage measurements and the historic performance of the existing AVC scheme, the current and voltage profile on the network can be analysed. Remote measurements can significantly improve accuracy of the simulation and should be used where available.

6.3.4. SuperTAPP n+ Model in M-OCEPS

The SuperTAPP n+ relay model, its functionality and algorithms as described in the above sections have been developed and implemented into the M-OCEPS load flow software. The enhanced TAPP model as presented in section 4.8 is used to calculate the effective voltage target with the modification as shown in equation (44).

In order to execute the SuperTAPP n+ scheme in OCEPS software the *AVCSC* parameter is set to $AVCSC = 2$ and one or more additional measurements need to be specified using parameter *FEEDERM* as presented in table 6.3.1. Additionally, if the *EST* parameter is specified, a generator estimation algorithm based on static load ratio is used. When the *EDY* parameter is set to 1, the estimation algorithm based on dynamic load ratio is activated and two constants *CLOAD* and *CDG* are set. The generator output is calculated using equation (49) when *EDY* parameter is set to 2.

FEEDERM value	Measurement Function
0	Measurement not in use
1	Transformer measurement
2	Feeder with DG measurement
3	Direct generator measurement
4	Excluded measurement

Table 6.3.1 Measurement in SuperTAPP n+ model

6.3.5. Load Flow in Radial Distribution Networks

As has been discussed in previous chapters, 11 kV distribution networks have relatively high X/R ratio compared to transmission networks and are operated in a radial manner. This poses a number of challenges for the load flow algorithms. A number of methods for radial distribution network load flow solutions have been proposed. A technique based on ladder-network theory was developed by Kresting et al. [64] and a modified fast decoupled method by Rajicic and Tamura [65]. Techniques based on receiving-end voltages are presented in [66] and [67] and an iterative method is presented in [68]. The proposed methods offer a range of effectiveness, computational requirements and differ in convergence rate.

The OCEPS software is based on a Newton-Raphson algorithm and partitioned-matrix approach to the Jacobian equation developed by Irving and Sterling [38]. Even though it may require more computational effort than the techniques mentioned above, it is proven to be a highly efficient algorithm for the solution of distribution networks, also for difficult or ill conditioned load-flow problems. This numerical method is also applicable for use in state estimation and dynamic simulation.

M-OCEPS has been developed to enable the incorporation of network measurements into OCEPS. Furthermore, functions for feeder arrangement detection, load scaling, load estimation and voltage headroom calculation etc. have been added and are described in the following section.

6.3.6. Feeder Arrangement and Load Scaling

The most significant challenge for the distribution network analysis is the small number of measurements that can be gained from the 11 kV and LV system. Generally customer loads are not measured and secondary substations are not equipped with any current or voltage monitoring equipment. In the absence of this data, in the simulation analysis, real and reactive power values for the load nodes are treated as pseudo-measurements. Therefore, before a steady state of the network can be obtained, this load data must be estimated.

A number of load modelling techniques have been recently proposed for power flow analysis to facilitate a distribution state estimator in active network management. To improve the accuracy of load estimation various data such as billing information, customer information, typical load characteristics, load survey and demographic information may be used as proposed in [69] and [70]. Modelling of pseudo measurements based on a probabilistic approach was presented by Ghosh, et al. [71] and based on load probability density functions as discussed in [73].

Currently, the most common technique of load estimation used by distribution planning engineers for 11 kV systems is feeder load scaling [16]. This feature allows the adjustment of individual load nodes to match a specified total feeder load. Commercial load flow packages offer this method with a function that allows selection of the loads that are to participate in the feeder scaling procedure [74], or the adding of load measurement data if available [75].

A modified load scaling functionality has been implemented in M-OCEPS software. It is based on primary substation feeder measurements and maximum demand recorded or the rating of the distribution transformers if a maximum demand reading is not available. For each node without power measurement the expected value is calculated. The load for each secondary substation is scaled in proportion to the feeder current measurement, summed maximum demands of all secondary substations fed by the feeder and the maximum demand at the substation in the formulation are as follows:

$$S_i = \frac{S_{MD,i}}{\sum_{i=1}^{N_{FX}} S_{MD,i(FX)}} \cdot S_{M,(FX)} \tag{50}$$

Where S_i and $S_{MD,i(FX)}$ are the expected value of power demand and maximum demand of the i^{th} node respectively. If the MD is not available, load is scaled in proportion to the 50% value of the transformer rating. Power measurement on the X^{th} feeder, $S_{M,(FX)}$, is determined from the feeder current ,$I_{M(FX)}$, and voltage ,V_{VT}, measurements at the primary substation as follows:

$$S_{M(FX)} = I_{M(FX)} \cdot V_{VT} \cdot \sqrt{3} \tag{51}$$

The real and reactive components of the load for the pseudo measurement is calculated as follows:

$$P_i = \frac{S_{MD,i} \cdot PF_i}{\sum_{i=1}^{N_f} S_{MD,i(FX)} \cdot PF_F} \cdot S_{M(FX)} \cdot PF_F \tag{52}$$

$$Q_i = \frac{S_{MD,i} \cdot \left(\sin\left(\cos^{-1}(PF_i)\right)\right)}{\sum_{i=1}^{N_f} S_{MD,i(FX)} \cdot \left(\sin\left(\cos^{-1}(PF_F)\right)\right)} \cdot S_{M(FX)} \cdot \left(\sin\left(\cos^{-1}(PF_F)\right)\right) \qquad (53)$$

Power factor, PF_F, can be specified for the substation or can be calculated from transformer P and Q measurements if available. The power factor for the individual nodes PF_i can be specified in the input file or it can be updated to match calculated value of PF_F.

This load estimation technique provides adequate results for a load flow analysis of the distribution network. Information such as feeder current measurements and transformers ratings or MD are available from the SCADA system. The accuracy of this technique can be affected by the industrial and commercial loads which do not follow typical load curve characteristics. However, as these customers are usually measured, the accuracy of load estimation on a feeder can be improved by replacing pseudo measurements with real measurement data for the nodes where these measurements exist.

An additional drawback of this technique is its inability to provide a measure of uncertainty regarding the estimates [69]. The load flow results based on load scaling can provide accurate results, however, it is not possible to assess their precision. In terms of active voltage control this implies that the security margins may not be fully evaluated. In the load estimation technique, which has been developed for voltage profile analysis for the active voltage management, this issue has been eliminated. This technique has been implemented into M-OCEPS software and is described in the following section.

6.3.7. Load Estimation in M-OCEPS

In order to investigate the relationship between load on the distribution transformer and load on the feeder supplying this secondary substation, monitoring equipment at several secondary substations have been installed recording real and reactive power and voltage. These measurements have been correlated with corresponding feeder current measurements.

To analyse the correlation of demand on the distribution transformers with respect to the feeder current measurement, load on the feeder L_F was represented by the measured value of the feeder current to the maximum demand on the feeder as follows:

$$L_F = \frac{S_{M,(FX)}}{\sum_{i=1}^{N_{FX}} S_{MD,i(FX)}} \tag{54}$$

Similarly the load on the transformer L_{PT} was represented as the recorded demand value on the transformer to the maximum demand on the feeder as follows:

$$L_{PT} = \frac{S_{i\_M}}{\sum_{i=1}^{N_{FX}} S_{MD,i(FX)}} \tag{55}$$

Under ideal circumstances where all distribution transformers equally share load on the feeder with proportion to the their MDs, load on the power transformers, factor L_{PT}, is equal to load on the feeder factor, L_F.

However, in the real network, load distribution on the feeder and between secondary substations varies depending on types of load, time, weather etc. To analyse this correlation a PDF of recorded distribution transformer measurements at particular loads on the feeder was employed. An example of a PDF for real network measurements is shown by the bar charts in figure 6.3.2 and figure 6.3.3 for the feeders supplying a majority of domestic and a mixture of domestic and commercial load respectively.

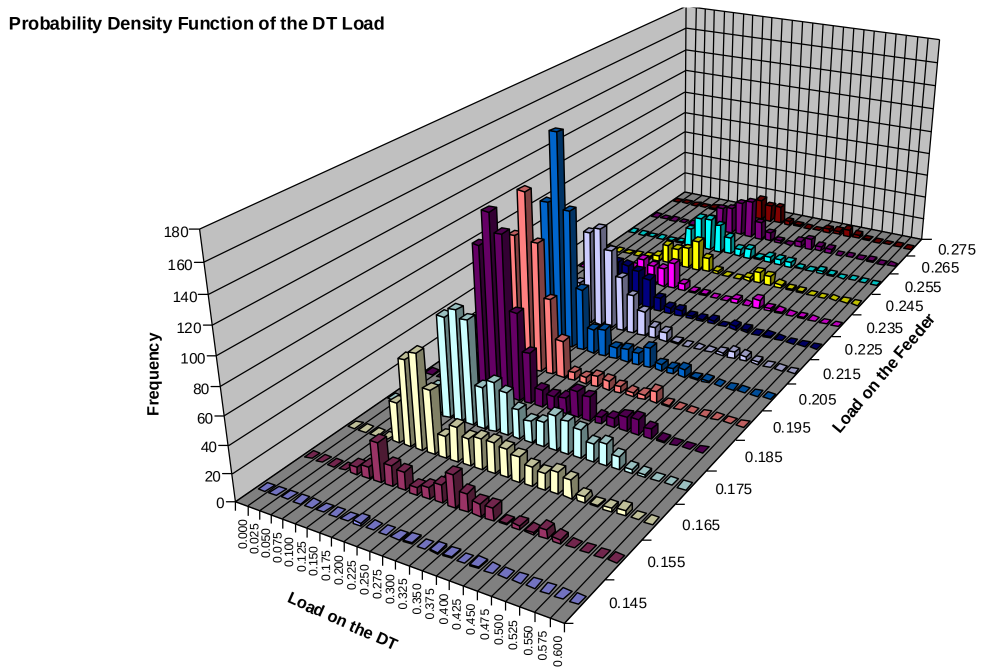


Figure 6.3.2 Probability density function of load demand on the distribution transformer supplying mixture of domestic and commercial load with respect to feeder measurement

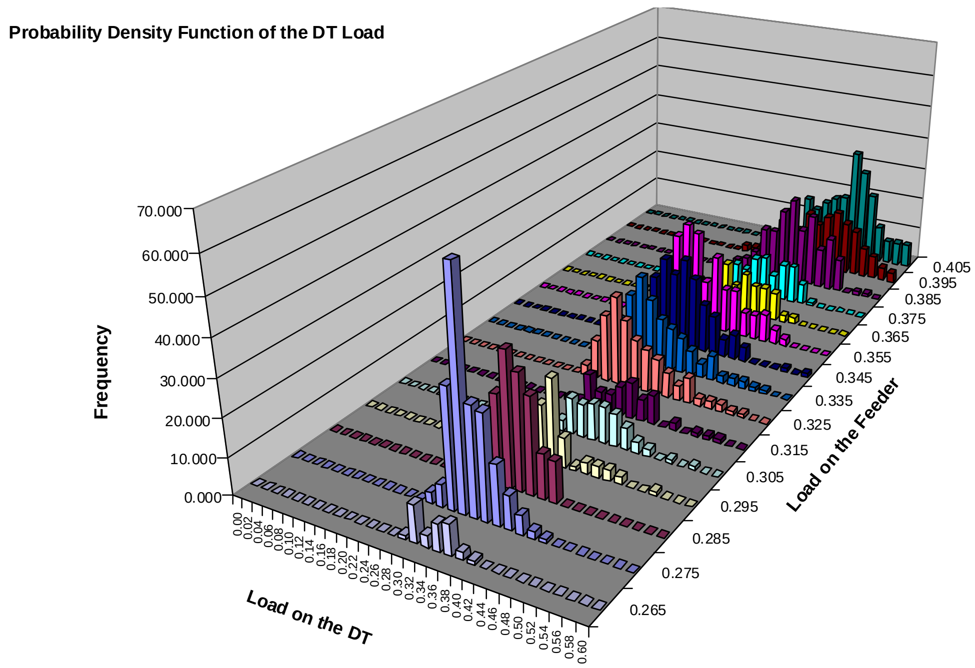


Figure 6.3.3 Probability density function of load demand on the distribution transformer supplying domestic load with respect to feeder measurement

It can be observed in the figures above that the peak value of the probability density function of the load on distribution transformer, L_{PT}, for each value of the load on the feeder, L_F, and its value match fairly closely in most of the cases. An increase in the latter is also reflected in an increase in the former. However, a significant variation from the mean value is also present.

The results obtained from the above analysis can be used to accomplish two objectives. Firstly, to represent the possible variation of the load on the distribution transformers at the particular value of the load on the feeder in order to assess maximum voltage change. Secondly, to quantify the level of uncertainty of this estimation technique.

The results presented in figures 6.3.2 and 6.3.3 indicate the variation of the load which can occur on the secondary substation from the expected value which is calculated using equation (50). Minimum and maximum power that can be absorbed at the specific feeder measurement is evaluated as shown in equations (56) and (57) respectively:

$$S_{MIN,i} = S_i - S_i \cdot \frac{F_{LC\_MIN}}{DF_{C,i}} \tag{56}$$

$$S_{MAX,i} = S_i + S_i \cdot \frac{F_{LC\_MAX}}{DF_{C,i}} \tag{57}$$

Inequality constraints:

$$0 \le S_{MIN,i} \le S_i \tag{58}$$

$$S_i \le S_{MAX,i} \le MD_i \tag{59}$$

Where F_{LC_MIN} and F_{LC_MAX} represent minimum and maximum uncertainty coefficients of the load class (LC) and $DF_{C,i}$ is the load density factor for i^{th} node. The F_{LC_MIN} and F_{LC_MAX} is specified for each node individually or for a load category. For example, for the node supplying mostly residential load F_{LC_MIN}n is equal to 0.5 and F_{LC_MAX} is equal to 1. This means that load at this substation may vary from 50% to 200% of the scaled value, S_i. An uncertainty range can be reduced by the $DF_{C,i}$ factor. For instance, the greater the number of customers connected to the node, the more closely the load profile at the node follows the load profile on the feeder, since the load is more diversified [10]. As a result, a diversity factor can be used to reduce uncertainty in the load estimation process. For the feeders supplying commercial load the minimum and maximum uncertainty coefficients should be increased to reflect the nature of the load and the fact that this type of load has a different characteristic. For the industrial loads, if measurement data is not available, F_{LC_MAX} coefficient should be equal to the maximum demand of the node and the F_{LC_MIN} coefficient should be equal to the minimum demand of the node. With these coefficients, the load is treated as on or off depending on the feeder measurement and the remaining load on the feeder.

6.3.8. Estimated Voltage Profiles on the Feeder

Due to uncertainty in pseudo measurements, accurate load distribution and precise voltage profile on a feeder is difficult to evaluate. A standard state estimation technique deals with this issue by calculating maximum and minimum possible voltage level for each node. The node with the lowest predicted voltage level is the node where maximum voltage drop is expected.

Analysing an 11 kV distribution network and taking into consideration radial arrangements of a feeder, it is not always necessary to estimate voltage variation at each node on the feeder, but to identify a range of possible voltage levels on the feeder under consideration for particular load conditions and the node where the maximum voltage level occurs.

The proposed method for voltage analysis in distribution network estimates the maximum voltage drop which can occur on the feeder as well as maximum voltage rise at the point of connection of the generator for particular feeder current measurements.

Additionally, the maximum voltage variation at the particular node specified by the user can be estimated. This method is based on the load estimation process described in the previous section. The estimated minimum and maximum load values for each node, $S_{MIN,i}$ and $S_{MAX,i}$, line and cable impedances as well as connections between the nodes are used to determined the maximum voltage change on the feeder.

The voltage drop along the feeder can be derived from equation (3) and given by:

$$\Delta\overline{V} = (R + jX)\bar{I} = (R + jX)\frac{P + jQ}{V} \tag{60}$$

Modifying equation (60) and assuming that the operational voltage is close to 1 p.u. it is seen that the voltage drop depends on the line impedance and power absorption as follows:

$$\Delta V = \overline{Z_i} \cdot \overline{S_i} \tag{61}$$

The 'voltage drop moment' VM_i can be defined as a product of power absorption at the i^{th} node, S_i, and sum of impedances of the lines from the primary substation to this node as follows:

$$VM_i = S_i \cdot \sum_{n=0}^{i} Z_i \tag{62}$$

It can be found that nodes with the highest voltage drop moment make the greatest contribution to the voltage drop on the feeder. For example nodes at the end of the feeder (high impedance seen from the substation) with a high load.

Using this assessment technique, two extreme load distribution conditions on the feeder from the voltage profile point of view can be seen; the maximum and the minimum voltage change on the feeder. The maximum possible voltage drop on the feeder is evaluated by applying the maximum estimated load value, $S_{MAX,i}$, at the nodes with the highest VM_i factor and the minimum estimated load value $S_{MIN,i}$ at the nodes with the lowest VM_i factor. The summed load of all nodes with losses on the feeder needs to match the measured feeder current. To evaluate the minimum voltage change on a feeder, at the same feeder current measurement, the load distribution on the feeder is arranged by applying the maximum estimated load value, $S_{MAX,i}$, at the nodes with the lowest VM_i factor and the minimum estimated load value $S_{MIN,i}$ at the nodes with the highest VM_i factor.

To illustrate this load and voltage profile estimation techniques in the M-OCEPS software the simple network with a single feeder as presented in figure 6.3.4 has been used. The feeder is supplying 10 secondary substations equipped with 800 kVA distribution transformers. The maximum demand on each transformer is assumed to be half of the transformer rating and all the loads to be the same category. 1 MW of generation is being considered, connected to node 11. Each connection between the nodes has the same impedance parameters. The feeder current measurement, represented by the power flow in the line between node 2 and 3, is used to estimate load on the individual distribution transformers. A simulation has been performed with four settings of the uncertainty factors as presented in table 6.3.2

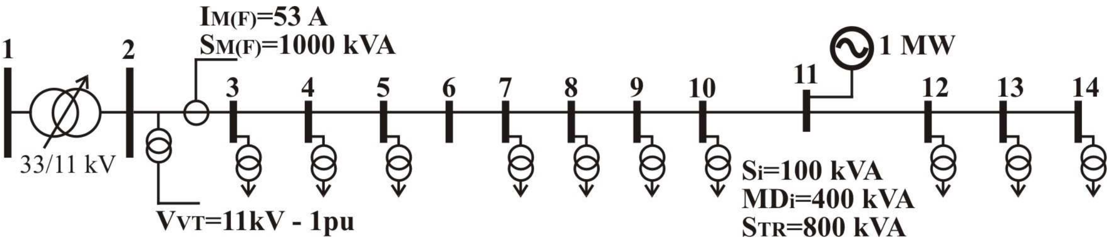


Figure 6.3.4 Single feeder system used for voltage profile analysis

The expected power demand on the nodes is calculated using equations (50-54) with the feeder current measurement equivalent to 1000 kVA. As all the transformers have the same MD, the expected power demand at each node has the same value and equals approximately 100kVA.

Firstly, the possible voltage profiles on the network without generation are analysed. Simulations are then performed with various load uncertainty factor settings for the load estimation algorithm and the obtained results are presented in figure 6.3.5.

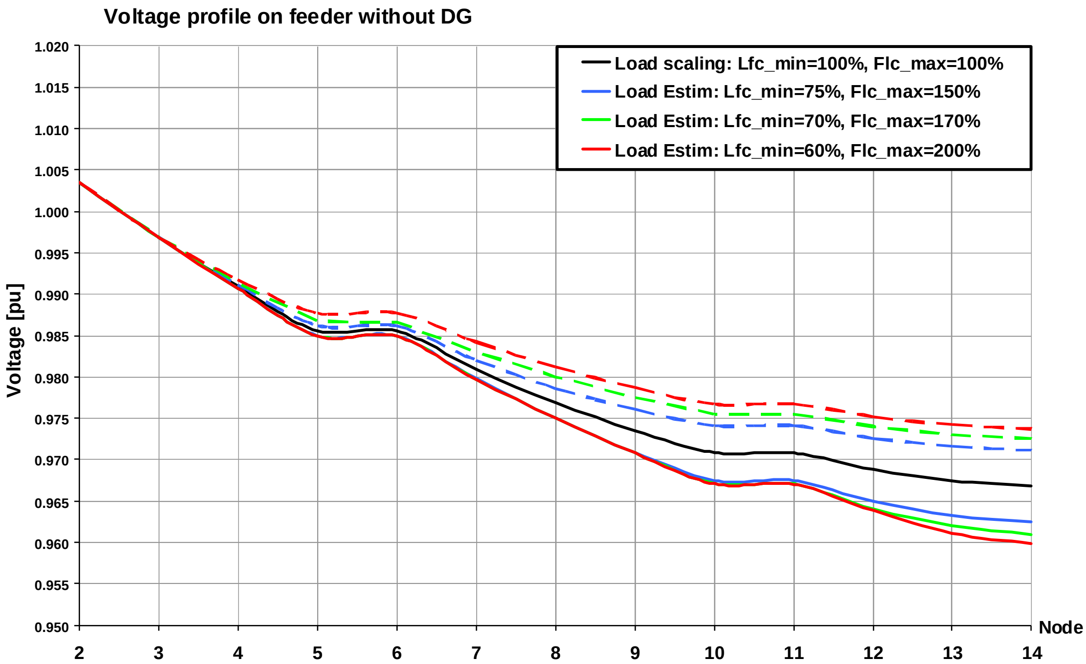


Figure 6.3.5 Estimated voltage profile on the feeder without DG with various F_{LC_MIN} and F_{LC_MAX} factors

The black line represents typical load scaling of the load on distribution transformers with respect to feeder measurement. Both load uncertainty factors are equal to 100% and do not affect the load distribution on the feeder.

The load estimation algorithm is enabled when load uncertainty factors F_{LC_MIN} and F_{LC_MAX} are set up. In the first case the load on the distribution transformers is set to change from 75% to 150% of the estimated value of S_i and the minimum and maximum load values for each node, $S_{MIN,i}$ and $S_{MAX,i}$ are calculated using equations (56) and (57). Two load distribution conditions on the feeder are arranged; one to evaluate the maximum voltage drop on the network and second to evaluate the minimum voltage drop on the feeder. In the first case, the maximum estimated load $S_{MAX,i}$ is allocated to nodes with the highest VM_i factor, that is, the three nodes at the end of the feeder. In the second case, the maximum estimated load $S_{MAX,i}$ is allocated to nodes with the lowest VM_i factor, i.e. the three nodes closest to the primary substation. The load allocation to the all nodes is shown in table 6.3.2.

The voltage profiles on the feeder obtained from these two load distribution conditions is shown by the blue lines in figure 6.3.5. It can be observed that the voltage drop on the feeder may vary between 0.962 and 0.971 p.u. and this occurs at node 14.

Settings	F_{LC_MIN}=100% F_{LC_MAX}=100%	F_{LC_MIN}=75% F_{LC_MAX}=150%		F_{LC_MIN}=70% F_{LC_MAX}=170%		F_{LC_MIN}=60% F_{LC_MAX}=200%	
Node	*Allocated* S_i *[kVA]*	*Allocated* S_i *[kVA]*		*Allocated* S_i *[kVA]*		*Allocated* S_i *[kVA]*	
		V_{MAX}	V_{MIN}	V_{MAX}	V_{MIN}	V_{MAX}	V_{MIN}
3	100	75	150	70	170	60	200
4	100	75	150	70	170	60	200
5	100	75	150	70	170	60	180
6	0	0	0	0	0	0	0
7	100	75	100	70	70	60	60
8	100	75	75	70	70	60	60
9	100	75	75	70	70	60	60
10	100	100	75	70	70	60	60
11	0	0	0	0	0	0	0
12	100	150	75	170	70	180	60
13	100	150	75	170	70	200	60
14	100	150	75	170	70	200	60

Table 6.3.2 Load allocation on the feeder under various load estimation settings

By increasing F_{LC_MIN} and F_{LC_MAX} factors to 70% and 170 % respectively, a larger imbalance of load distribution on the system can take place resulting in a greater voltage variation. With these load estimation settings, the voltage drop on the feeder may vary between 0.961 and 0.973. The possible voltage variation increases further as the load estimation setting increases. However, for a load variation of between 60% and 200% it can be observed that the change in the maximum voltage drop on the feeder in less significant. The minimum voltage level at node 14 is of 0.960 compared to 0.961 for the previous case.

A similar process can be carried out to investigate voltage profile on the feeder with DG. However, the point of connection of the generator is specified as the reference node for the load distribution on the feeder and this node in not included in the load distribution process. Instead, a fixed value for generator power injection, for example the maximum export capacity of the proposed connection, is used. For the simple network presented in figure 6.3.4 the same load distribution conditions for the load uncertainty coefficients are applied, but in a more complex feeder configuration it might not be the case. The voltage profiles on the feeder with DG exporting 1 MW for various F_{LC_MIN} and F_{LC_MAX} coefficients are shown in figure 6.3.5.

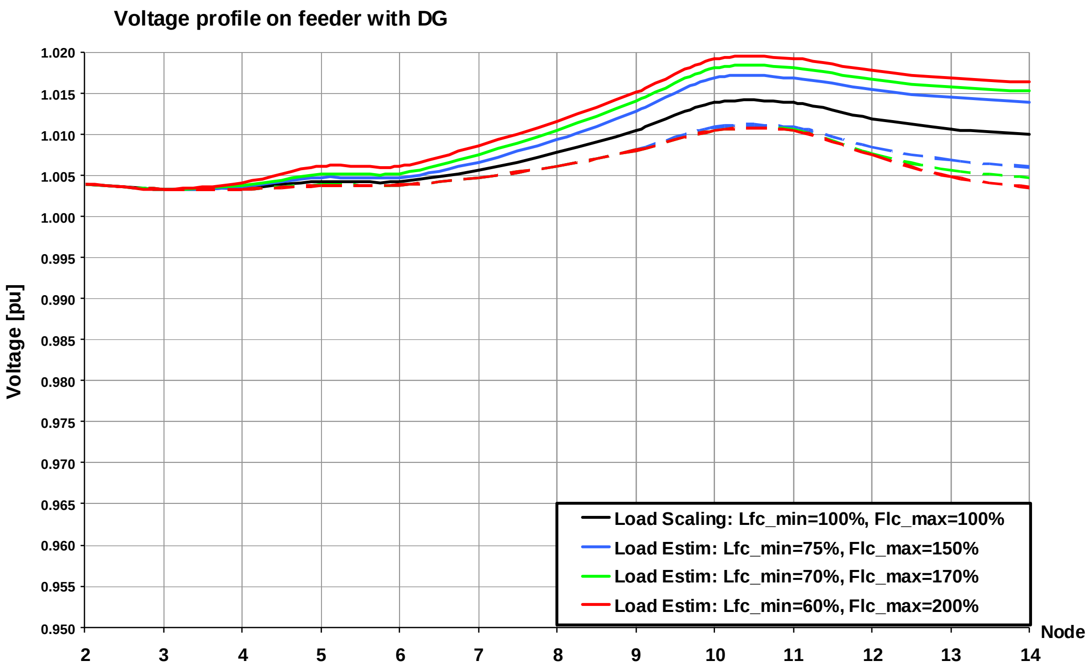


Figure 6.3.5 Estimated voltage profile on the feeder with DG with various load estimation settings

It can be assumed that highest voltage rise takes place for the load estimation settings between 60% and 200% and the maximum estimated load $S_{MAX,i}$ allocated to substations close to the source of the feeder. This voltage profile is represented by the red solid line. In can be concluded that the voltage at the point of connection for the feeder current measurement is above 1.011 but below 1.019 p.u.

The load estimation technique and voltage profile analysis discussed above provide practical information relating to predicted voltage levels on the distribution network. By increasing F_{LC_MIN} and F_{LC_MAX} coefficients the confidence that the voltage on the network will be within the predicted values increases. In order to estimate the probability of the occurrence of the voltage outside these values, probability density functions and Monte-Carlo simulation have been used.

The PDFs for the feeder supplying a high proportion of domestic load, presented in figure 6.3.3, have asymmetrical bell shaped curves. For a feeder supplying a mixture of domestic and commercial load, shown in figure 6.3.2, the asymmetry in the PDF shape is more significant. It is apparent that no standard distribution function can fit the curves in these two figures. However the gamma distribution with two-parameters; a scale parameter θ and a shape parameter k, as shown in figure 6.3.6, represents the curves satisfactorily and can be used for probability analysis [76].

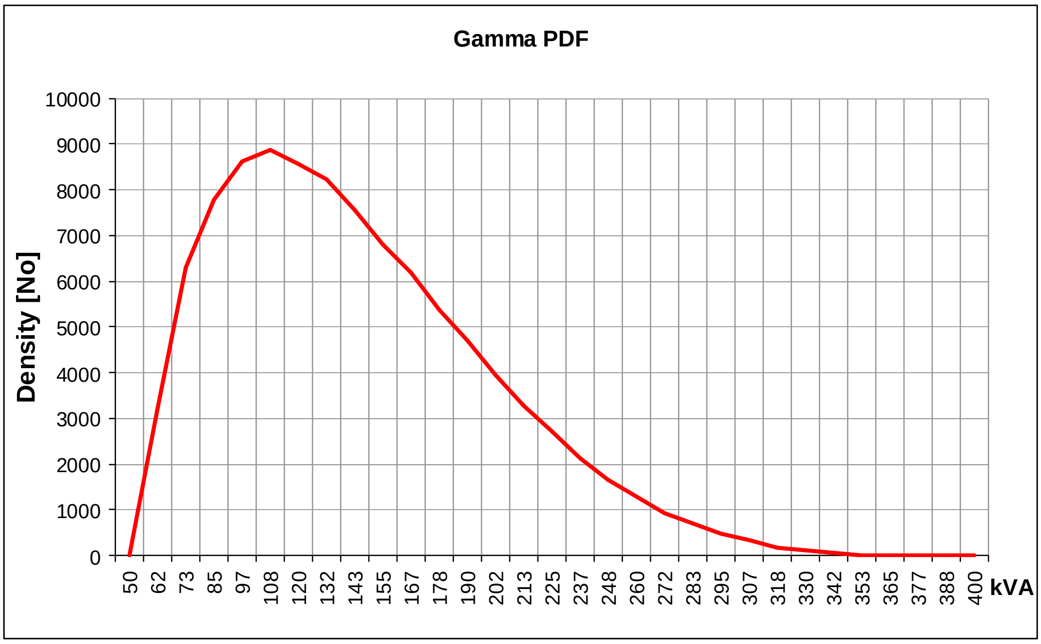


Figure 6.3.6 Example of Gamma PDF for load on secondary substation with the $L_{PT} = 100$ ***kVA***

The parameters of the gamma distribution have been selected to cover a load variation on the distribution transformers from 50% up to 400% of the L_{PT} at a given value of load on the feeder, L_F. For the system presented in figure 6.3.4 the PDF as presented in figure 6.3.6 was used.

As load distribution and thus voltage profile is dependent on a number of factors such as transformers rating, recorded values of maximum demand, number of load customers and impedance parameters of the lines etc., several realistic feeders have been analysed. The gamma distribution was used to represent the probability of the load demand on each secondary substation and the Monte-Carlo simulation was used to estimate the occurrence probability of the voltage outside the predicted voltage range under various load uncertainty factors [77]. The summary of the results is presented in table 6.3.3.

Gamma PDF	*Load Estimation uncertainty factors*		*Probability of voltage outside the range*
	F_{LC_MIN}	F_{LC_MAX}	
-50 % / +400%	100%	100%	**N/A**
-50 % / +400%	75%	150%	**1.62 - 2.9 %**
-50 % / +400%	70%	170%	**0.82 – 1.61 %**
-50 % / +400%	60%	200%	**0.148 – 0.23 %**
-50 % / +400%	50%	400%	**0 %**

Table 6.3.3 Summary of the results for voltage level probability analysis

The Monte Carlo simulation has been designed to calculate the probability of the lower and higher voltage levels on a feeder against those obtained from the M-OSEPS using load and voltage estimation algorithms. For short feeders with a relatively low number of secondary substations a small number of large transformers, this probability was higher than for the long feeders with large numbers of small transformers. However even for these feeders with uncertainty factors of 75% and 150%, the likelihood does not exceed 3%. As expected, with the increase of the F_{LC_MIN} and F_{LC_MAX} coefficients, the probability of the voltage outside the predicted range decreases and falls significantly below 0.5 % for the load variation between 60% and 200%.

The theoretical analysis presented above indicates that quality of the voltage profile on the feeder using algorithms implemented in the M-OCEPS is satisfactory. However to verify the simulation results the predicted voltage range is compared with real voltage measurements on the network in chapter VII.

6.3.9. Output Files

M-OCEPS produces three output files; load flow results, network characteristics with generation estimation and voltage headroom. The second and third output files can be customized by the user according to the requirements. The examples of these files are presented in appendices C-E.

The load flow results file provides conventional steady state results of the analysed network. Information such as the load flow in each line, voltage, real and reactive power at each node, losses in the system, tap position of the transformers etc. are included. Additionally, any errors or problems and the number of iteration are reported. This information may used directly to analysis the system; other parameter can be calculated if required. Examination of the data in this format can be time consuming and very inefficient when hundreds or thousands steady states of the network are considered. To simplify and automate this process, network voltage and network characteristics with generation estimation and SuperTAPP n+ settings output files have been created.

The network voltage output file contains all the information necessary to analyse the network from the voltage perspective in a comprehensible format. Data is presented in the table where each row corresponds to a time sample. The file contains information about the maximum and minimum voltage levels in the network and specify the nodes where these values occur. The voltage level at the substation busbars, effective voltage target for the AVC scheme as well as all the voltage biases are also listed. When the operational voltage limits are specified, any violation of the limits and the nodes are highlighted and the voltage headroom calculated. Also, the additional data such as the voltage level at nodes specified by the user or minimum and maximum voltage level of a particular feeder can be incorporated.

The information relating to the network characteristics, performance and operation of the SuperTAPP n+ scheme is presented in the third output file. Data in this file is used to estimate accuracy of the generation estimation technique as well as to select optimal settings for the scheme such as basic voltage target, LDC and generator voltage bias. The static load share ratio E_{ST} and dynamic load ration E_{DY} are calculated in order to assess the precision of various estimation techniques, estimate possible errors and select the optimal settings.

6.3.10. Limitations of the Software

The design and the nature of the algorithms implemented in the software impose a number of limitations to the network model and functionality. The first is associated with the load estimation and load distribution techniques used to estimate the possible voltage range on a feeder. This technique is suitable for the investigation of maximum and minimum voltage drops on the feeder for a specific feeder current measurement as well as at a selected node. However, it is not suitable for analysis of the voltage at number of nodes on the feeder and as a result it may not be used; for example in state estimation.

Another limitation of M-OCEPS is the fact that the load estimation technique can only be used for the radial operated networks. As the load estimation algorithms on the feeder rely on a single feeder current measurement and the scaling principle, it is not possible to use it for the feeders which are supplied from more than one source.

The last identified limitation is the inability of the software to deal with lines connected in parallel. When parallel lines are detected they are replaced by an equivalent circuit and marked as such.

6.4. Novel Voltage Control Scheme Based on Voltage Drop Factor

The load estimation algorithm and the assessment of the voltage profile on the feeder used in M-OCEPS initiated a development for an innovative voltage control scheme using an Advanced AVC relay (SuperTAPP n+ platform), local measurements to estimate voltage drop on the feeders without generation and a single remote measurement on the feeder with DG at the point of connection.

A network model of the system and historical data are used to determine the function representing the relationship between maximum possible voltage drop and current on the individual feeder which can be expressed as $\Delta V \max_f \left(I_E\right)$. From SCADA data, the maximum and minimum current values for each feeder in the network are identified. This data is then used to create input files such as the current value for each feeder and changes from the minimum $I_{\min,f}$ to the maximum $I_{\max,f}$ value in suitable steps.

The network model and input file with feeder measurements data are linked to M-OCEPS software and the simulation with relatively high load estimation uncertainty coefficients (for example $F_{LC\_MIN} = 60\%$ and $F_{LC\_MAX} = 175\%$) is performed. The process to calculate maximum voltage drop on the feeders using M-OCEPS software is presented in figure 6.4.1.

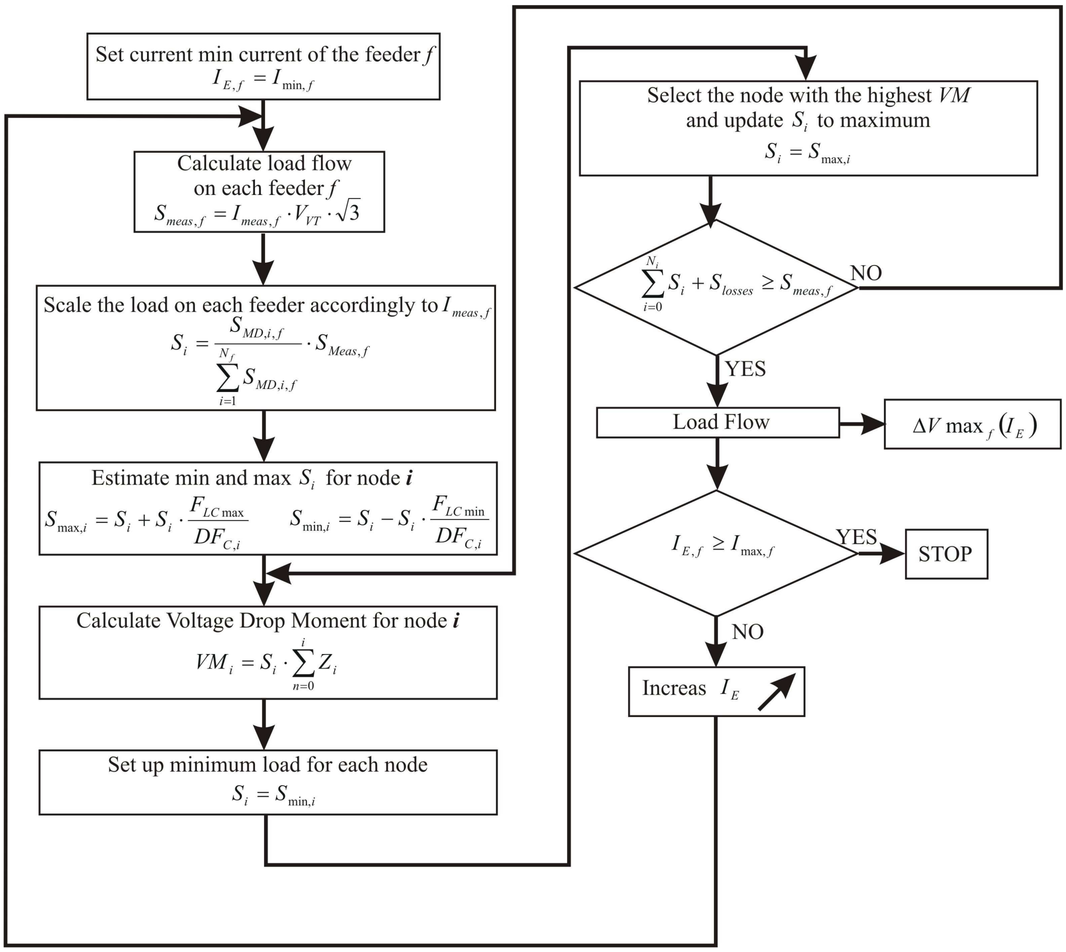


Figure 6.4.1 Flow chart of voltage drop factor calculation process

The results obtained for the simulation provide information about the maximum voltage drop on each feeder, $\Delta V\max$, with respect to feeder current measurement I_E. The graphs in the figure 6.4.2 show voltage drop characteristics for five feeders.

Figure 6.4.2 Relationship of the maximum voltage drop and the feeder current $\Delta V\max_f(I_E)$

The voltage drop factor is defined as the estimated maximum voltage drop on the feeder with respect to feeder current measurement and is calculated as follows:

$$VDF_f = \frac{I_{E,f}}{\Delta V\max} \qquad (63)$$

It can be noted that the relationship between the maximum voltage drop and feeder current is almost linear across the range of the feeder current values. As a consequence, the voltage drop factor for individual feeders is also linear. The VDF_f for the feeders presented in figure 6.4.2 is shown in the figure 6.4.3.

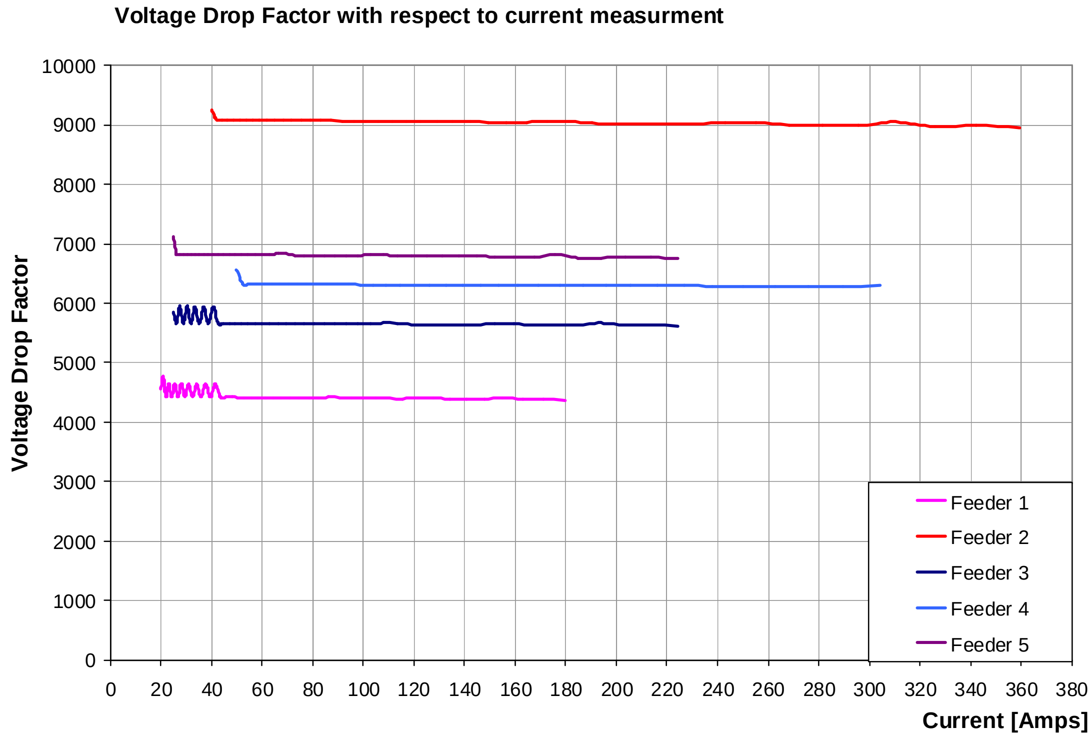


Figure 6.4.3 Voltage drop factor characteristics with respect to feeder current measurement for various feeders.

As the voltage drop factor values are constant (or can be approximated to the constant value) they can be simply implemented into the advanced AVC relay. Along with the individual feeder current measurements, the expected voltage drop on the each feeder without DG can be estimated, and the minimum voltage level on the network obtained. The maximum voltage level on the network can be either; obtained by the direct voltage measurement at the point of connection of the DG and sent to the relay or by using generation estimation techniques, voltage rise estimation on the feeder and generation voltage bias as described in this chapter.

As no complex calculation or estimation is involved, the analysis can be performed within a voltage control relay such as SuperTAPP n+. The flow chart for the advanced AVC scheme based on the local feeder measurements to estimate minimum voltage level on the network and single RTU unit with communication link to provide information about maximum voltage level is presented in figure 6.4.5.

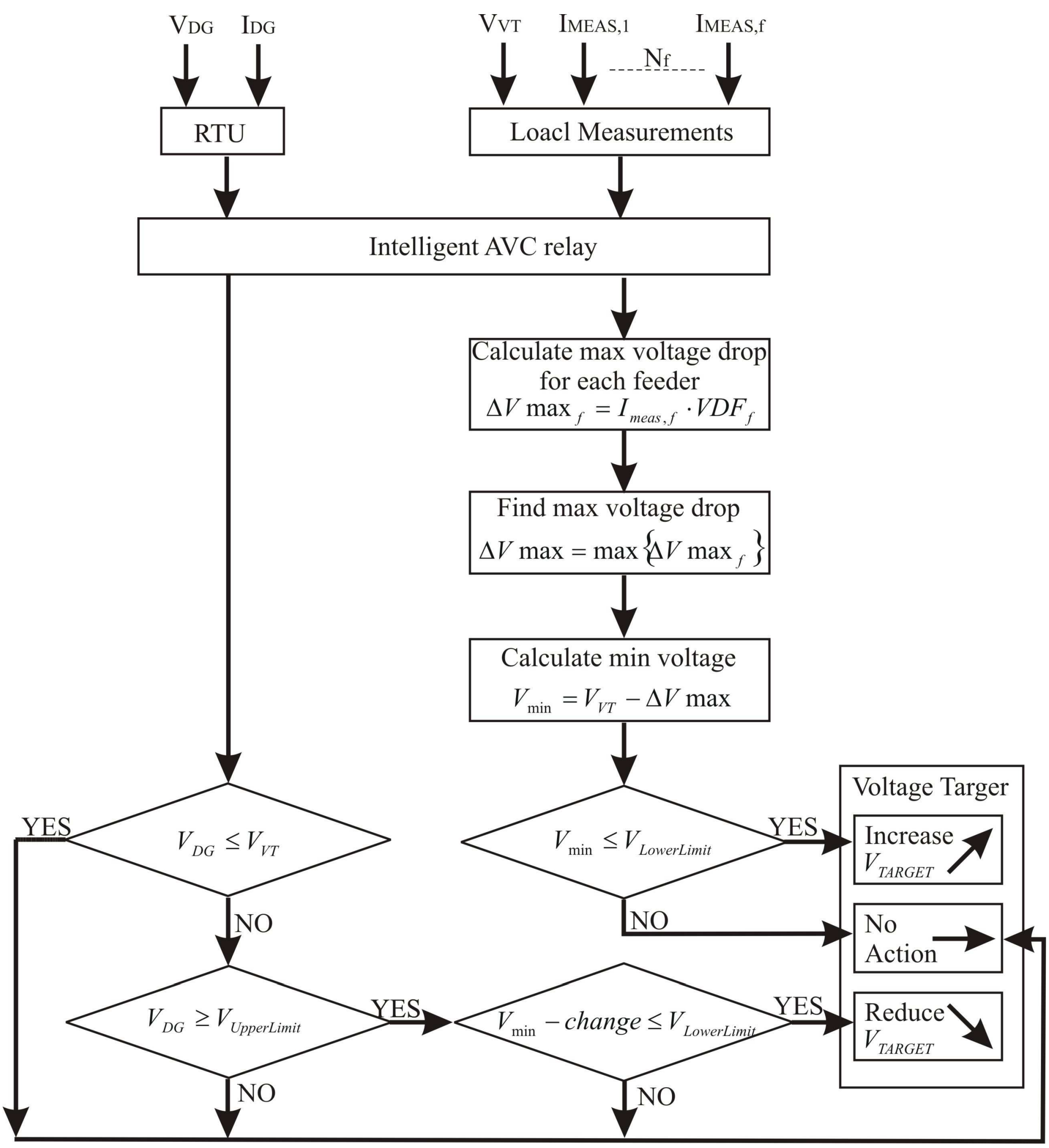


Figure 6.4.5 Flow chart of the operation of the Advanced AVC relay based on voltage drop factors.

The proposed voltage control scheme can be described as the LDC method based on individual feeders. The main advantage of the scheme is that it can provide improved voltage control compare to LDC based on transformer current, particularly on the network with unbalanced load diversity between the feeders or with the heavily loaded part of the system [78] with minimum investment cost. It can also increase voltage headroom and, with a single remote measurement, significantly improve the ability to accommodate DG into the network. The efficiency of the scheme can be evaluated and accurate settings for the scheme can be obtained by the use of M-OCEPS software. Due to its simplicity the existing SuperTAPP n+ platform can be used for real network implementation of this scheme.

The scheme can support multiple generation and future DG can be easily accommodated within the scheme. However, for each DG connected on a network, the dedicated RTU is required to provide voltage level information at the point of connection and generator output.

The main disadvantage of the proposed scheme is that the settings of the scheme such as voltage drop factor values need to be revised periodically or when the significant change on a network occurs. If there is no major modification on a network, the revision should be carried out every two-three years to examine and, if necessary, reflect load increase.

6.5. Summary

The principles of operation and characteristics of the active voltage management scheme SuperTAPP n+ have been presented in the first section of this chapter. The advantages and disadvantages of the scheme have been discussed and factors affecting the performance of the scheme illustrated. The generation estimation technique based on local measurements and static load ratio have been discussed and two new estimation techniques based on dynamic load ratio and constant power factors have been introduced. The accuracy, differences as well as network implementation of all three methods have been analysed.

Before any active voltage management technique is used to improve the voltage profile on the network or to increase voltage headroom in order to accommodate DG, a detailed analysis of the network must be carried out. Also, the proposed active voltage control schemes should be evaluated with respect to its ability to increase network capacity, efficiency and accuracy. With the purpose of providing an efficient tool for voltage network analysis and assessment tool for the SuperTAPP n+ scheme the M-OCEPS software has been developed.

The main functionality of the M-OCEPS simulation software is its capability to incorporate network measurements and exploit available information of the analysed network using innovative algorithms for load and voltage profiles on distribution networks. This significantly increases the accuracy of the network analysis and provides higher confidence in the achieved results.

The simulation results of the voltage profile indicate the possible voltage range on the feeder at the measured feeder current and specify uncertainty coefficients F_{LC_MIN} and F_{LC_MAX}. By applying higher values of the uncertainty coefficients, the probable voltage range is increased and, at the same time the confidence that the voltage profile on the feeder is within this voltage range. On networks supplying load customers only, the maximum voltage drop on each feeder can be assessed and the node where this condition occurs, identified. Additionally, minimum and maximum voltage levels at any node on the feeder can be determined if required. On networks with DG, this technique allows the evaluation of possible voltage rise at the point of connection, and maximum voltage drops on all feeders.

The network implementation of the SuperTAPP n+ scheme and preceding network analysis using M-OCEPS are presented in chapter VII.

Chapter VII SuperTAPP n+ Scheme Field Trial in EDF Energy Networks

EDF Energy Networks is one of the largest distribution companies in the UK servicing three licensed networks LPN, EPN and SPN covering Central London, the East of England and the South East of England, respectively. As a DNO, EDF Energy Networks is responsible for the operation, design, maintenance and development of its networks in an efficient and cost effective way in order to comply with UK legislation and conditions as specified in the distribution licence agreement [17]. EDF Energy Networks is also obliged to formally assess all requests for load and generation connection to its networks [83]. A significant increase in the number of connections of the latter has been seen as more and more energy in networks areas operated by EDF Energy Networks is becoming available from small and medium size energy sources such as landfill gas, wind turbine or CHP.

Reductions in network losses, greenhouse gas emissions, lower energy costs and deferment of network reinforcement are examples of the numerous potential benefits from the connection of distributed generation to the network. However, it is widely recognised that the connection of generation into the distribution network can be challenging. Typically, power factor, voltage regulation, fault level and network capacity are technical factors constraining the accommodation of DG in distribution networks [79].

In order to encourage DNOs such as EDF Energy Networks to develop and apply novel techniques with regard to the operation, design and future development of the distribution networks, Ofgem have introduced two incentive schemes; the IFI and RPZ. EDF Energy Networks actively participate in these schemes with a portfolio of projects to improve the efficiency of its networks, security and quality of supply as well as to reduce the cost of DG connections [80].

As a part of the IFI scheme a collaborative project between Brunel University and EDF Energy Networks has been established to investigate performance of the existing AVC schemes in networks with DG and to investigate existing active voltage regulation. M-OCEPS with a SuperTAPP n+ model has been developed to provide an assessment tool for voltage analysis of distribution networks. Additionally, a SuperTAPP n+ field trial has been set up on the EDF Energy Networks system in order to verify this simulation software and to analyse the performance and effectiveness of the scheme.

In the following chapter the network results from the SuperTAPP n+ trial are presented. These results along with additional network measurements are used to verify accuracy of the results as obtained from using the simulation software.

7.1. SuperTAPP n+ Field Trial

The SuperTAPP n+ trial has been set up in the EDF Energy Networks distribution network at a primary substation in the south of England in the Crawley area. This network is referred in this thesis as Network A.

7.1.1. Network A Characteristics

The substation consists of three 132/11 kV transformers, 30 MVA each. Two are operated in parallel and the third is used as the standby unit in the event of a transformer outage. The existing AVC scheme is a master-follower method operating at fix voltage target of 101%. The substation supplies a medium sized town and the surrounding area via thirteen 11kV feeders. At a remote point on the network, five units of DG are installed with the total capacity of 5 MW. Under normal network configuration the DG is fed from feeder 3, however an alternative connection can be provided through feeder 1 or 4. A simplified diagram of the network is presented in figure 7.1.1.

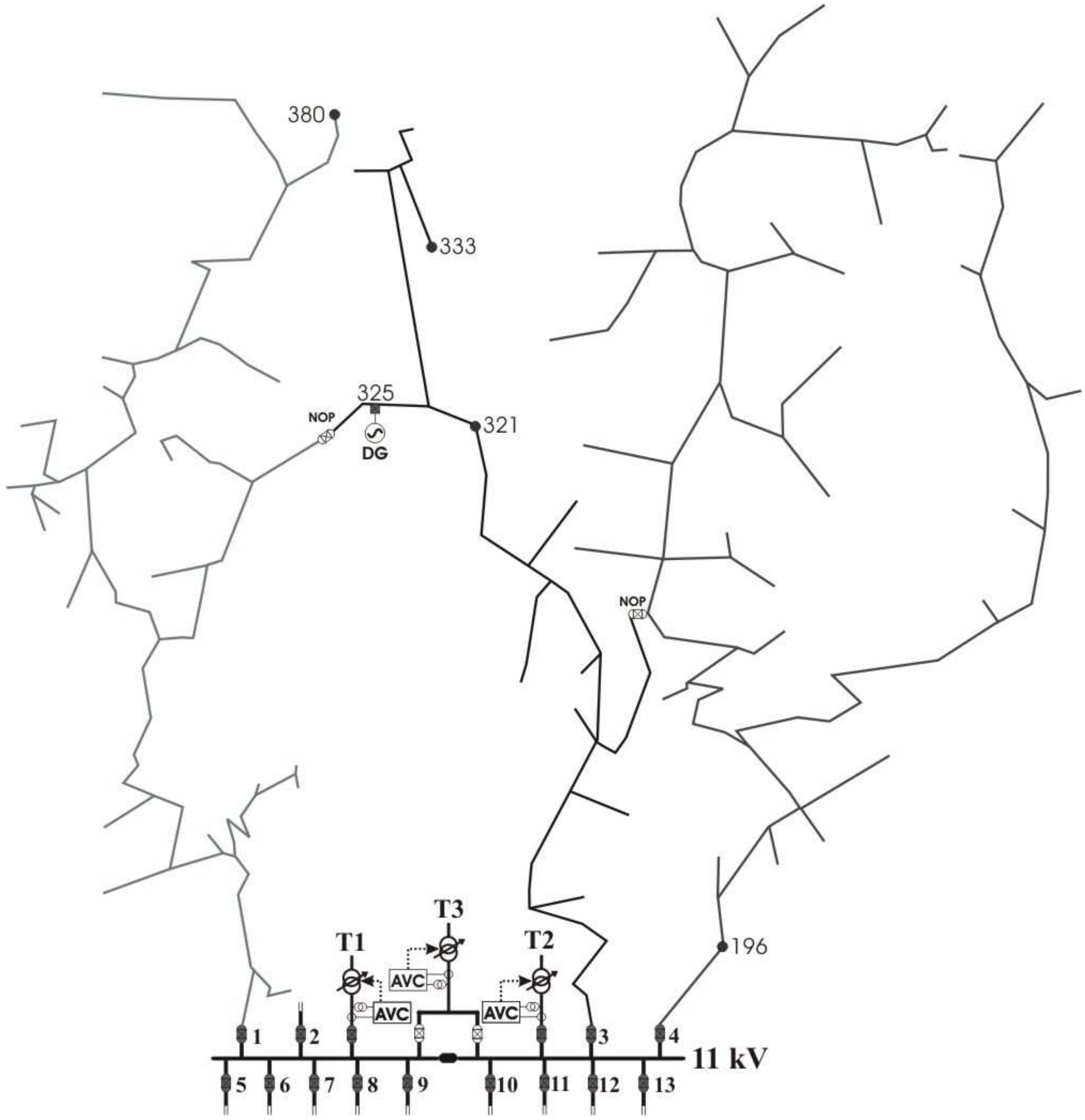


Figure 7.1.1 Simplified diagram of Network A

Taking into account the existing networks infrastructure and voltage control techniques used in EDF Energy Networks, it is recommended that the generation can be connected into the network if the connection of the generator does not result in a voltage rise along the HV feeder to the point of connection of the generator of more that 2% [81]. Preliminary analysis of Network A has shown that this limit can be significantly exceeded when the generator exports its maximum capacity of 5 MW.

As an alternative to network reinforcement in order to remove the voltage constraint, the innovative scheme has been installed local to the generator. The scheme was designed to measure the voltage at the point of connection and send signals to the generator to reduce its output if the operational voltage limit is reached and disconnect the generator if the statutory limit is reached [80].

Although, the scheme allowed connection of the generation and ensured that voltage level at the point of connection was maintained within the statutory limits, the generator suffered from intermittent export restrictions and experienced numerous over-voltage trips. Moreover, additional generation is being considered which would increase generator output from existing 5 MW up to 7 MW.

In order to improve the network capacity, accommodate existing generation and provide voltage headroom for the proposed increase in generation, a co-ordinated voltage control scheme at the primary substation with an over-voltage protection scheme at the point of connection of the generator has been proposed.

7.1.2. SuperTAPP n+ Scheme Implementation

The novel SuperTAPP n+ scheme was identified as a feasible and cost effective solution that could overcome voltage issues in the network and thus increase the network capacity to maximise the output of the DG. As the SuperTAPP n+ scheme is a novel technology, the trial has been designed to test the scheme as well as to obtain expertise and confidence with its performance and to provide evidence of the effectiveness of the scheme in distribution networks with DG and voltage issues.

In this instance the scheme consists of three SuperTAPP n+ relays, one for each transformer, which control the OLTC and the voltage target at the 11kV busbars. It also includes three additional feeder current measurements, on feeders 1, 2 and 3, in order to estimate the output of the DG and to provide information about the system load share between the feeders. The arrangement of the SuperTAPP n+ scheme at Network A is shown in figure7.1 2.

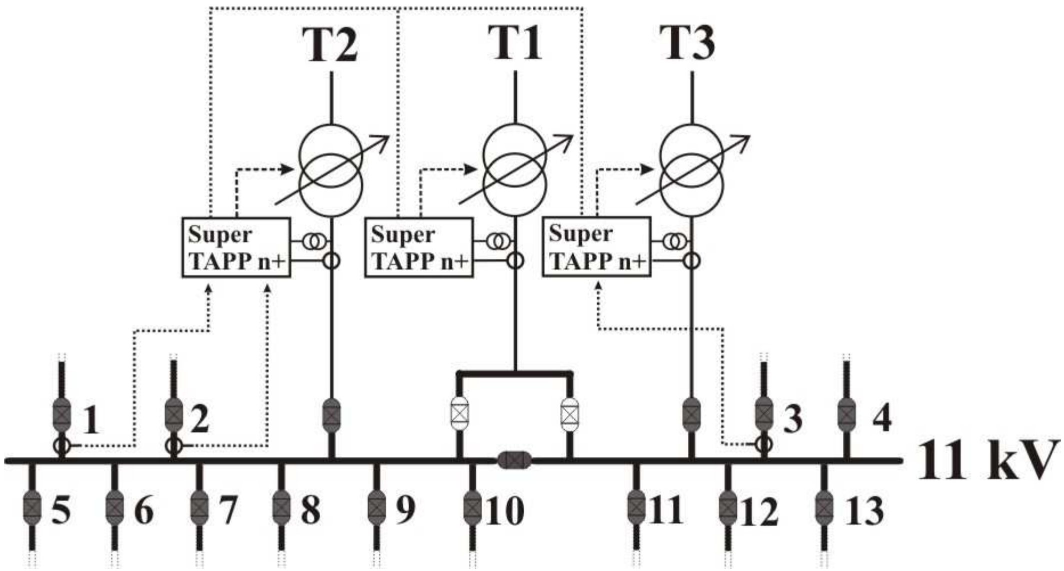


Figure 7.1.2 SuperTAPP n+ installation at Network A

The installation of the scheme has been designed to allow three modes of operation of the SuperTAPP n+. In the first mode SuperTAPP n+ is disconnected and the existing AVC scheme controls the voltage. The second is the off-line monitoring mode where the existing AVC scheme is still in control, however the SuperTAPP n+ relays are powered up and monitoring all voltage and currents measurements and indicate the action that would be performed if the devices were fully on-line. In the third mode the SuperTAPP n+ scheme is controlling the voltage at the substation busbars.

Three stages of the trial were planned. The first stage was to set SuperTAPP n+ in monitoring mode in order to collect and analyse the data. This stage was designed to confirm the reliability and consistency of the scheme as well as the accuracy of the generation estimation technique. During the second stage the SuperTAPP n+ scheme is switched into control mode, however, the same settings as the existing AVC scheme are applied. This will allow the new scheme to control voltage at the substation and compare the operation with the existing AVC scheme. The final stage is to set up SuperTAPP n+ scheme to utilise the generation estimation technique and optimise the voltage profile on the network.

As the system is based only on local measurements and estimation techniques, additional measurement equipment was temporarily installed to provide essential information about the state of the network. Smart meters were installed at the point of the DG to provide real and reactive power export/import and voltage. These readings in conjunction with measurements from the SuperTAPP n+ relays are then used to evaluate the accuracy and efficiency of the scheme and verify the simulation results obtained from M-OCEPS assessment software.

7.1.3. M-OCEPS Network Model and Initial Results

Data from the GIS system, DMS, Eclipse database and GROND load flow software have been used in combination to create an accurate network model of the Network A for M-OCEPS. The parameters of the lines and cables such as type, diameter, length etc. have been obtained from the GIS system to specify the resistance and reactance of the branches. The DMS has been used to determine the connections between nodes and the arrangement of the system. Ratings and maximum demand of the distribution transformers have been extracted from the Eclipse database and GROND.

The M-OCEPS model of the Network A consists of 510 nodes, including 302 PQ nodes and one generation node at which 5 MW of DG is connected (node 325 on feeder 3). The 132kV busbar is assumed to be infinite bus representing the rest of the network and is designated as the slack bus in load flow analysis.

Historical SCADA data and the network model have been used to examine the voltage profile in the network A and identify nodes where potential voltage violations can occur. A voltage level below the statutory limit can occur at the end of the most heavily loaded feeder (node 380) and at the end on the feeder with DG (node 333). Deviation of the voltage level above the upper voltage limit can occur at the PCC (node 325) and at the neighbouring load node (321).

The voltage monitoring equipment was installed at these points on the network and at node 196 close to primary substation as shown in figure 7.1.1. These voltage measurement units were placed at the critical points in the network in order to verify the voltage profile.

7.2. Network A – Field Trial Results

In the off-line field trial the SuperTAPP n+ scheme was operating in monitoring mode. Data such as feeder and transformer currents, generator current injection, voltage at the substation and at the strategic points on the system were collected. The data are used to estimate the load profile and load share between the feeders, calculate the E_{ST} factor and investigate the accuracy of the generation estimation. The result obtained from the simulation analysis is then compared with the network measurements. The assessment tool is also used to determine the optimal setting for the SuperTAPP n+ scheme at Network A.

7.2.1. Load Ratio E_{ST} Estimation

Due to the fact that the generator output estimation technique in SuperTAPP n+ is based on the E_{ST} factor it is necessary to investigate load profiles in the network with respect to errors under various load conditions. In a network with existing generation, calculation of the E_{ST} factor can be problematic as the feeder current measurement does not correspond to the load on the feeder.

To calculate the actual load ratio E_{ST} on the Network A, M-OCEPS assessment software together with the feeder current measurements and generator output data were used. The graphs in figure 7.2.1 show the E_{ST} factor over a one week period. The black line represents simulated load ratio while the red line illustrates the load ratio based on the trial measurements [63].

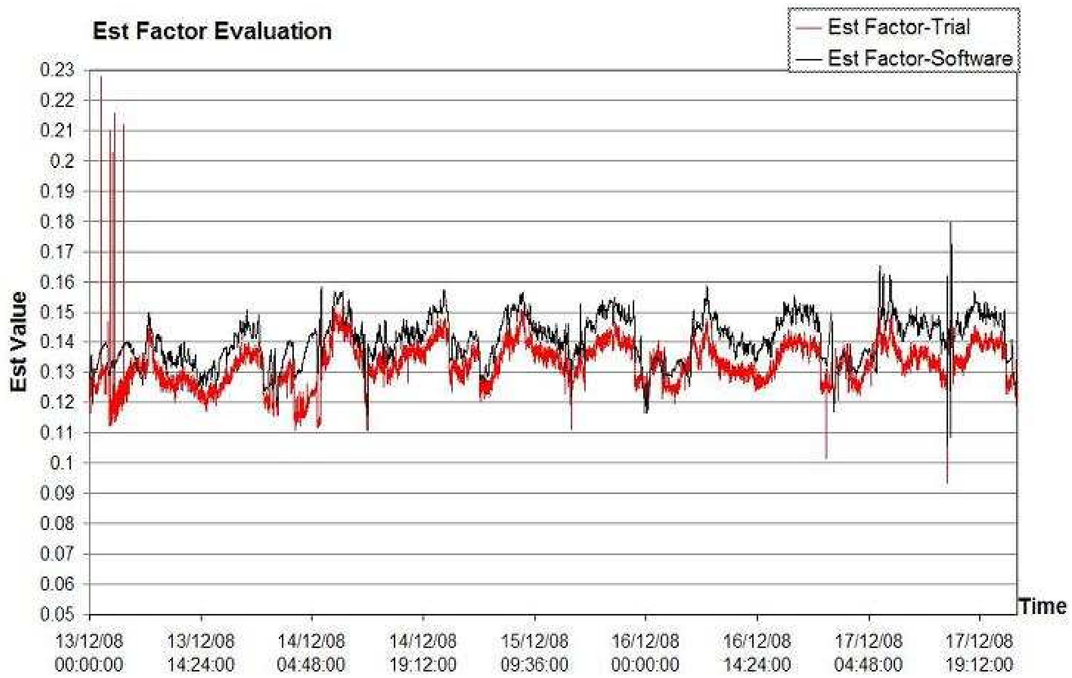


Figure 7.2.1 Comparison between simulated and measured E_{ST} factor.

It can be noted that the simulation results adequately represent the network conditions and that the graph can be used to determine the E_{ST} setting for the scheme. A discrepancy between simulated and network values is caused by the load power factor which in simulation was assumed to be 0.96 but the actual load power factor on the network was 0.98-0.99.

In the case presented in figure 7.2.1, the most suitable load ratio setting for the SuperTAPP n+ generation estimation is 0.14. It can be observed that the 0.14 load ratio value is in the middle of the E_{ST} factor variation range and provides the most accurate generation estimation under various load conditions throughout the year.

7.2.2. Generation Output Estimation

As is shown in the figure 7.2.1 E_{ST} factor is fluctuating caused by the load profile on the feeder with the DG not always following the exact pattern of the reference load profile. It was pointed out in chapter VI that any deviation of the E_{ST} factor from the setting value of 0.14, produces an error in the calculation of the generator output.

The active and reactive power measurements from the smart meter installed at the point of connection are used to estimate generator estimation accuracy of the SuperTAPP n+ trial and to evaluate precisely the simulation prediction of the scheme performance. A comparison between the estimated and measured generator output is represented by the graphs in figure 7.2.2.

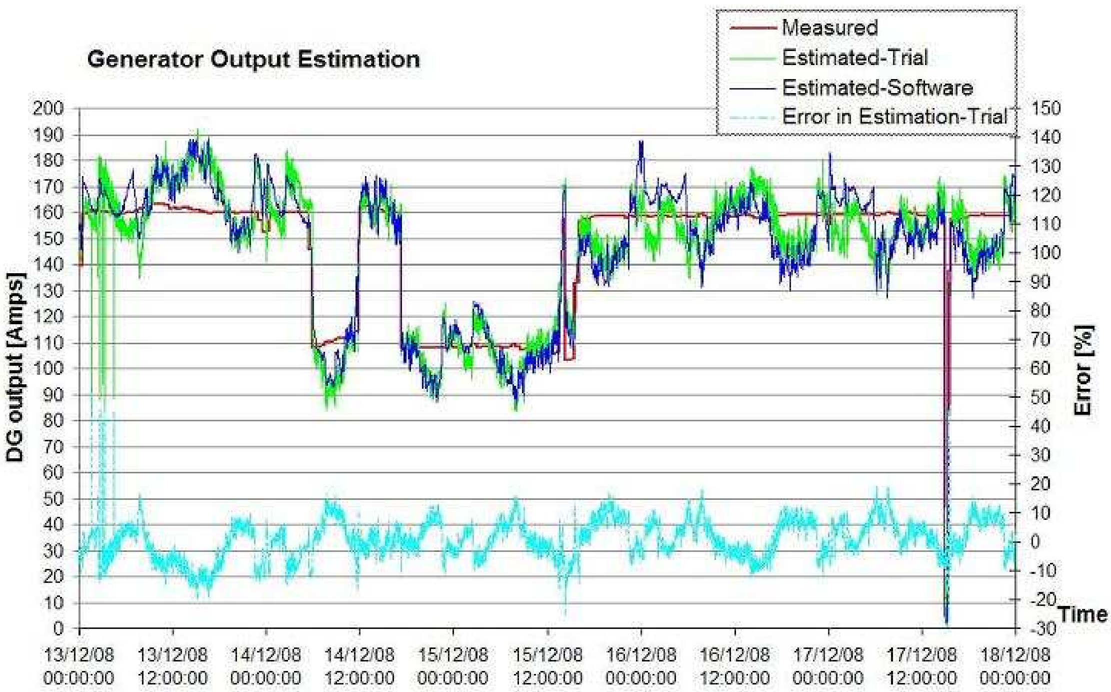


Figure 7.2.2 Comparison between estimated and measured generator output

The simulation results match the SuperTAPP n+ relay calculations of generator output which are shown by the green and blue lines respectively. The estimated value of the generator output is satisfactory as it always corresponds with the measured value (red line) within the tolerance of +/-20%. However, these discrepancies, caused by the fluctuation of the E_{ST} factor, results in an error of generation output estimation thus affecting of performance of the SuperTAPP n+ scheme. This error is represented by the light blue line in figure 7.2.2 and influences the generator voltage bias and LDC calculations. As a result the voltage target contains an error which needs to be taken into account in the setting selection of the scheme.

7.2.3. SuperTAPP n+ Optimum Settings Determination

It has been shown in previous sections that M-OCEPS with the SuperTAPP n+ model correctly represents the actual performance of the scheme. Thus, this assessment software can be used to select appropriate settings of voltage target, LDC, generator voltage bias etc. and so optimise the performance of the SuperTAPP n+ scheme for Network A. Historical SCADA data for the last two years has been used to investigate performance of the SuperTAPP n+ scheme under various load and generation output conditions on the network. The voltage drop on each feeder, the voltage rise at point of connection of the DG, accuracy of the generation estimation have been studied to ensure that the voltage profile on the network is maintained within the operational limits of ± 4% as required for active voltage control scheme. These operational voltage limits have been determined as described in chapter V section 3.6. An exception in the operation voltage limits is node 325 where 6% voltage rise is acceptable by the generator. In contrast, as discussed in section 7.1.1, only 2% voltage rise at the PCC was allowed if standard voltage control scheme is used.

Considering the above conditions and operational voltage limits, it has been estimated that the optimum performance of the SuperTAPP n+ scheme under existing network conditions is achieved with an E_{ST} factor of 0.14, an LDC voltage bias settings of 3 %, a generator voltage bias setting of 2 % and a voltage target of 99%. The aggregated value of generator voltage bias and LDC voltage bias corresponds to the required change in the voltage target as shown in figure 7.2.3.

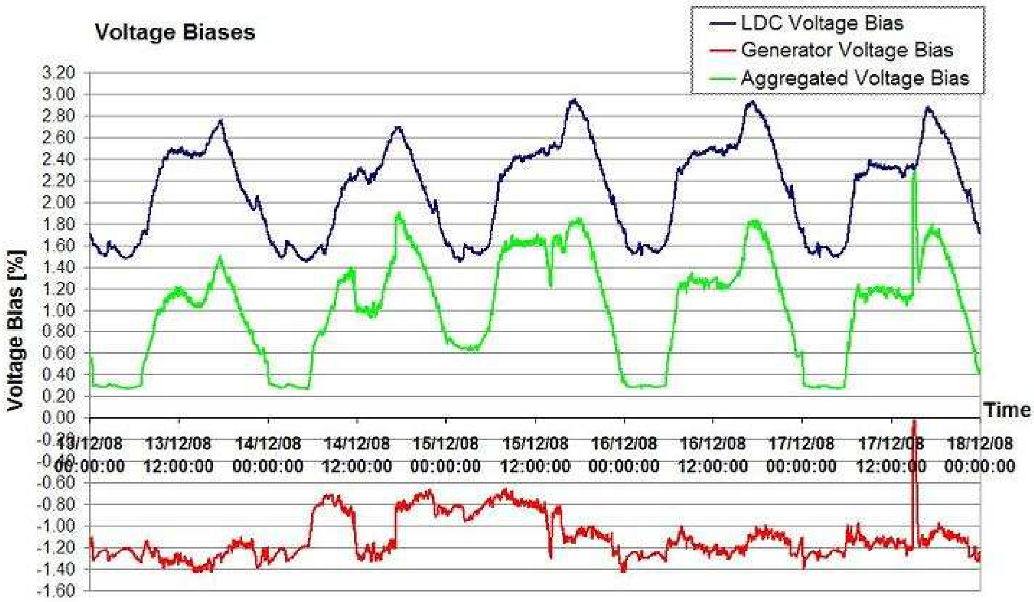


Figure 7.2.3 Generator voltage bias, LDC voltage bias and aggregated voltage bias in the scheme.

The generator voltage bias, shown by the red line in the figure 7.2.3, is applied in proportion to the estimated generator output, as indicated in figure 7.2.2. The 2% setting specifies the required voltage reduction when the generator is producing its maximum output. For the period presented in figures above, the time generator is usually exporting 3 MW and a voltage bias of approximately 1.2% is applied. When the generator output drops to 2 MW, the voltage bias is reduced to 0.8%.

In the SuperTAPP n+ scheme LDC is applied in proportion to the true load on the substation and is not affected by the varying generator output. This can be observed by analysis of LDC characteristic in figure 7.2.3. The peak load at the substation in December is close to the maximum demand and an LDC of 3% is applied despite the fact that the generator is exporting power into the network.

The aggregated value of the LDC and the generator voltage bias relate to the effective voltage change from the basic voltage target and is shown in figure 7.2.3 as the green line. With the provision of these biases the SuperTAPP n+ relay calculates the required voltage target to optimise the voltage profile in the Network A.

It can be observed from figure 7.2.3 that, when generator tripped on 17th December at 15:00 pm the aggregated voltage bias is equal to LDC, as the generator voltage bias was equal zero.

An example of the simulation results for five days in December is shown in figure 7.2.4 and indicates that with these settings the SuperTAPP n+ scheme will maintain the voltage on the network within the operational voltage limits. At these heavy load conditions the minimum voltage level is expected to remain above 0.96 pu. and below 1.04 at the point of connection and neighbouring nodes.

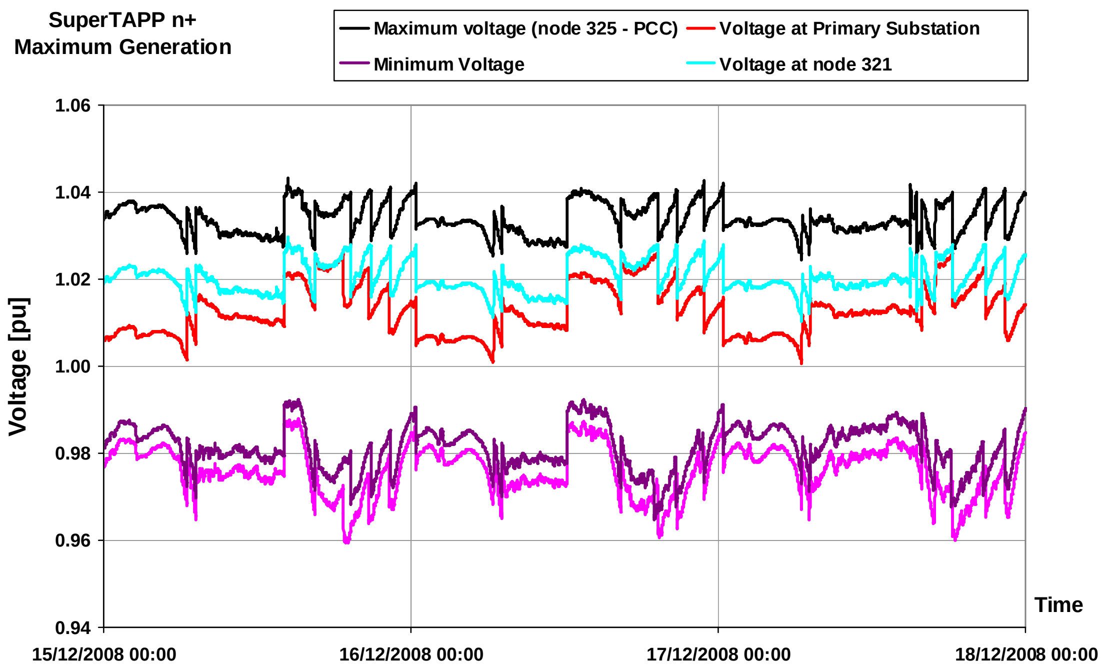


Figure 7.2.4 Maximum and minimum estimated voltage for SuperTAPP n+ operation in Winter.

7.3. M-OCEPS Voltage Estimation Accuracy

The simulation results presented in the previous section have been obtained from M-OCEPS using load estimation and voltage estimation algorithms. These algorithms, as has been described in chapter VI, enable an estimation of the maximum and minimum voltage on the network and the voltage range at the specific nodes. In order to validate the accuracy of these estimates, data collected during the first stage of the SuperTAPP n+ trial is used. The voltage measurements at a specific point on the network are compared with the corresponding voltage ranges obtained from the simulation.

The voltage target recorded by the SuperTAPP n+ relay is used in the simulation as the voltage target for the AVC to recreate the voltage profile on the substation busbars. The measured voltage and simulated voltage at the 11 kV busbar is indicated by the red and blue lines and shown in figure 7.3.1.

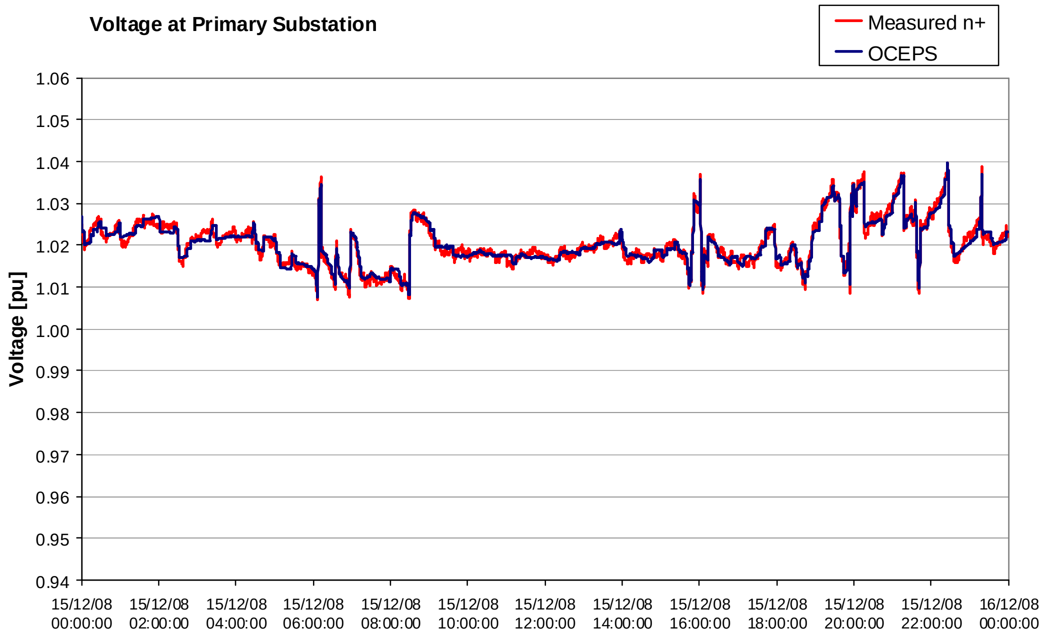


Figure 7.3.1 Measured and simulated voltage at the substation busbars

The load on each feeder is scaled according to the feeder current measurement using the load estimation algorithm with uncertainty factors of 50% and 150 % for F_{LC_MIN} and F_{LC_MAX} respectively. The minimum and maximum voltage levels at two nodes, 380 and 325 are determined and compared with measurements from the voltage recording units. The results are presented in figure 7.3.2 for node 380 and in figure 7.2.3 for node 325.

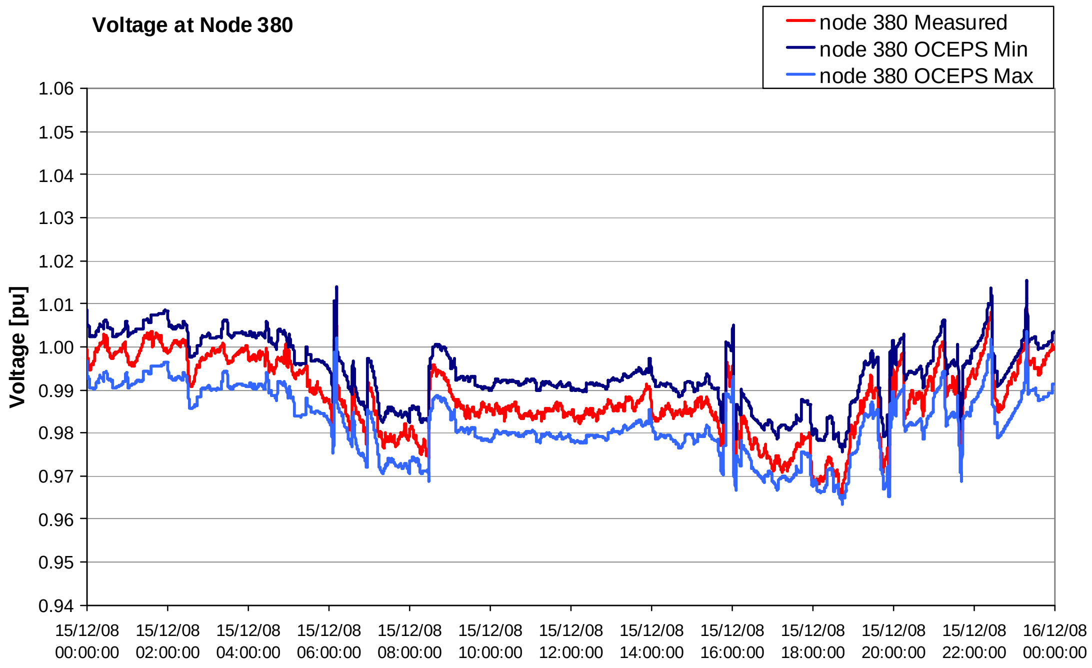


Figure 7.3.2 Estimated voltage range versus measured voltage at node 380

Node 380 corresponds to a distribution substation located at the end of feeder 1. This point on the network has been identified as the node where the lowest voltage level occurs most frequently and is monitored during the SuperTAPP n+ trial. The voltage profile recorded at this node is shown in figure 7.3.2 by the red line. The predicted voltage range obtained from M-OCEPS for the same period is indicated between two blue lines.

It can be observed that the recorded voltage at any time stays within the estimated voltage range. However, under heavy load conditions, the voltage at node 380 is close to the bottom of the range and during the night is closer to the top range. This indicates that the load distribution on the feeder does not follow the same pattern as estimated by the M-OCEPS algorithm, however, it shows that the uncertainty coefficients were selected correctly for the feeder load class.

A similar characteristic of the recorded voltage with respect to estimated voltage range can be observed at node 325 and is presented in figure 7.3.3. This node is the point of connection of the generator and in the normal network configuration is fed from feeder 3.

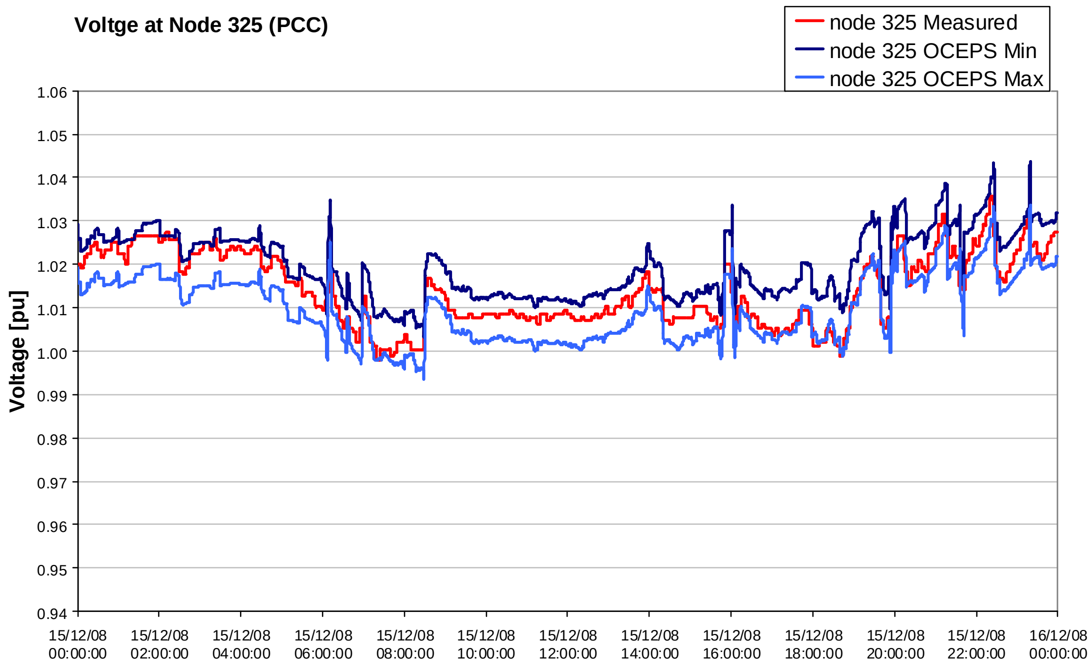


Figure 7.3.3 Estimated voltage range versus measured voltage at the point of connection of DG at node 325

The possible voltage range at this node is also estimated accurately. However, due to the fact that this feeder supplies a number of industrial and commercial loads, the voltage is closer to the acceptable limits, sporadically exceeding by a small percentage the lower and upper limits. In order to increase the confidence of the predicted voltage, the uncertainty factors can be increased as described in section 6.3. However, the increase in of the F_{LC_MIN} and F_{LC_MAX} factors in the load estimation algorithm reduces the utilisation of the available voltage headroom in the network.

An investigation into the voltage measurements on the network A and the estimated voltage ranges from M-OCEPS using the load estimation algorithm with the results presented above, provide evidence that the voltage profile obtained from the simulation is correctly evaluated and can be used for the network voltage profile analysis. Moderate settings of the uncertainty factors give adequate accuracy and do not compromise utilisation of the available voltage headroom in the network.

7.3.1. SuperTAPP n+ Effectiveness

When a request to connect the distributed generation to the network is being considered, M-OCEPS software can also assist with the estimation of the amount of the generation that can be accommodated when the existing AVC scheme is used and quantify the benefits and additional capacity on the network that can be achieved when a more active coordinated voltage control is used.

It has been stated that a maximum generation of 4 MW can be connected at node 325 in network A with the existing voltage control scheme. M-OCEPS has been used to evaluate the maximum amount of the DG which can be accommodated using SuperTAPP n+ scheme in the network. Taking into account that a voltage rise at the point of connection of the generation cannot exceed 6% and that the rest of the network needs to be maintained within operational voltage limits of ± 4%, the voltage profile on the network using historical data, the accuracy of the SuperTAPP n+ scheme with the settings as presented in the pervious section have been investigated.

The results indicate that the voltage headroom for an additional 3 MW of generation can be achieved in network A with the advance SuperTAPP n+ scheme based on local measurements. An example of the predicted voltage profile in the network while a SuperTAPP n+ scheme is controlling the primary substation busbars voltage is presented in figure 7.3.4.

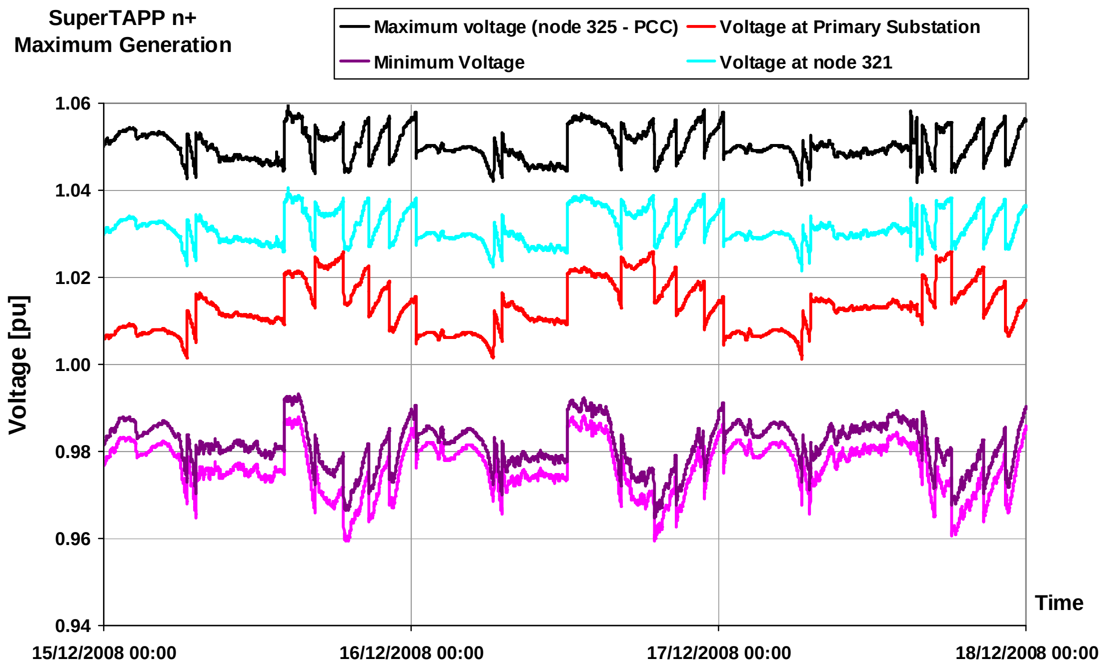


Figure 7.3.4. Voltage profile and voltage margins on the network A with 7 MW of DG.

The graphs show the estimated maximum and minimum voltage levels in network A when 7 MW of generation is connected at node 325. It can be noted that the SuperTAPP n+ scheme can maintain the voltage profile within the operating limits of -4 % and +6% at the PCC. However, it can be also observed that occasional restrictions of the generation, due to unacceptable voltage rise, may occur. Nevertheless, a significant improvement of the network utilisation is achievable and export capacity of DG can be increased by an additional 3 MW.

7.4. Summary of the SuperTAPP n+ Field Trial and Simulation Software

The SuperTAPP n+ trial in EDF Energy Networks has provided a number of benefits. Firstly, it enables a better understanding of distribution networks, feeder load distribution and voltage profiles, the AVC scheme performance and voltage headroom availability while accommodating distributed generation. Secondly, it a confirmed the operation of the new co-ordinated voltage control scheme SuperTAPP n+. On successful completion of the first off-line stage of the field trial, which proved the reliability and consistence of SuperTAPP n+ scheme functionality, the scheme was switched into on-line control and has been in operation since November 2008. Initially the scheme was controlling the voltage at the primary substation with the settings necessary to replicate performance of the existing AVC scheme. It has been observed that the new scheme is more accurate and that the basic voltage target can be reduced to optimise the voltage profile on the network. The results of operation of the SuperTAPP n+ scheme with the revised voltage target of 100% are shown in figure 7.4.1.

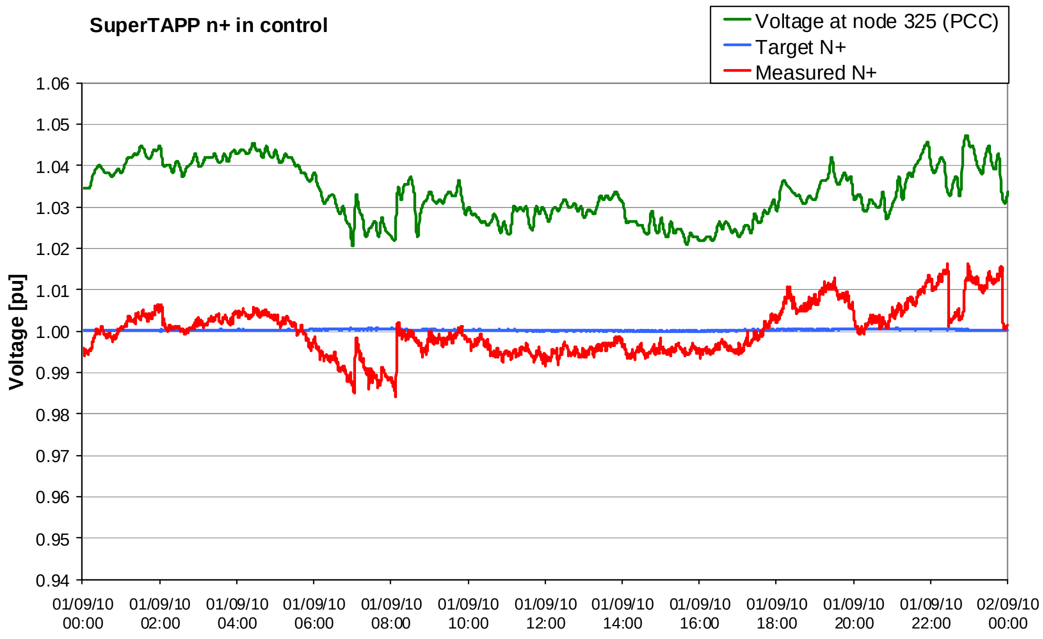


Figure 7.4.1 SuperTAPP n+ scheme controlling the voltage in Network A

As it can be observed in figure 7.4.1, the SuperTAPP n+ scheme has given more accurate voltage control at the primary substation and the reduced voltage target has improved the voltage profile at the PCC represented by green line on the graph. This allowed generator to export power into the network without interruption. For this reason and the fact that the generator is currently exporting up to 4 MW, the advanced functionality of the SuperTAPP n+ scheme has not yet been implemented. The voltage level at the point of connection is currently satisfactory, as shown in figure 7.4.1. However, it is continuously monitored by the smart meters that have been deployed at the site, and any voltage violation is reported. The advanced functionality of the SuperTAPP n+ scheme is expected to be applied when the generator increases its output and/or the voltage level becomes unacceptable.

Finally, the SuperTAPP n+ trial in Network A and the data collected during the trial has allowed the verification of functionality and accuracy of the M-OCEPS simulation software. It has been shown that the load and voltage estimation algorithms provide satisfactory results that are consistent with real network measurements. It has also been confirmed that the M-OCEPS simulation tool with the SuperTAPP n+ model can be used to evaluate the suitability of a scheme in a particular network and determine the most accurate settings. Additionally, the software can be used to analyse the voltage profile of a network, evaluate available voltage headroom and the maximum amount of generation that can be connected to the network using the SuperTAPP n+ scheme.

Chapter VIII Active Voltage Control Schemes Comparison

In the previous chapter the SuperTAPP n+ scheme field trial in EDF Energy Networks has been discussed. The results from Network A field trial and the simulation results based on network data were presented, demonstrating functionality of the advanced voltage control scheme based on local measurements and a simulation tool for voltage analysis in distribution networks with DG and SuperTAPP n+ scheme assessment.

Another innovative active voltage control scheme that has been deployed in EDF Energy Networks is GenAVC [59]. This scheme is based on a local voltage controller with state estimation as described in section 5.7 of this thesis. In addition, as a result of the collaborative project between EDF Energy Networks and Econnect Ventures, the GenAVC assessment software was developed to provide an indication of scheme efficiency in a particular network [80], [82].

In this chapter the GenAVC trial installation in Network B is firstly presented and the GenAVC assessment tool is also described. Moreover, the data from both the SuperTAPP n+ and GenAVC field trials together with the assessment tools are critically evaluated with regards to the various coordinated voltage control schemes as discussed in chapter V. The effectiveness of the schemes in terms of DG accommodation and utilisation of the available voltage headroom in the network is analysed and results are presented in this chapter. The advanced voltage control schemes based on SuperTAPP n+ platform and the local voltage controller schemes based on GenAVC with a various number of RTUs installed on the network with DG are critically evaluated and detailed results are presented.

8.1. Network B Characteristics and GenAVC Installation

The GenAVC scheme has been installed in the EDF Energy Networks in the south of England in the Brighton area. This network is referred to in this thesis as Network B. Network B is a rural network distributing electricity to a small town and the surrounding countryside. The load is supplied by a 33/11 kV primary substation. The substation consists of two 7.5/15 MVA transformers operating in parallel with three feeders from the common busbar, as illustrated in figure. 8.1.1. The landfill generation site, which is connected to feeder 1 at a significant distance from the primary substation at node 129, applied to increase output from 2 to 3 MW. Network analyses showed that, due to unacceptable voltage rise at the PCC, accommodation of an additional 1 MW export capacity required considerable network reinforcement.

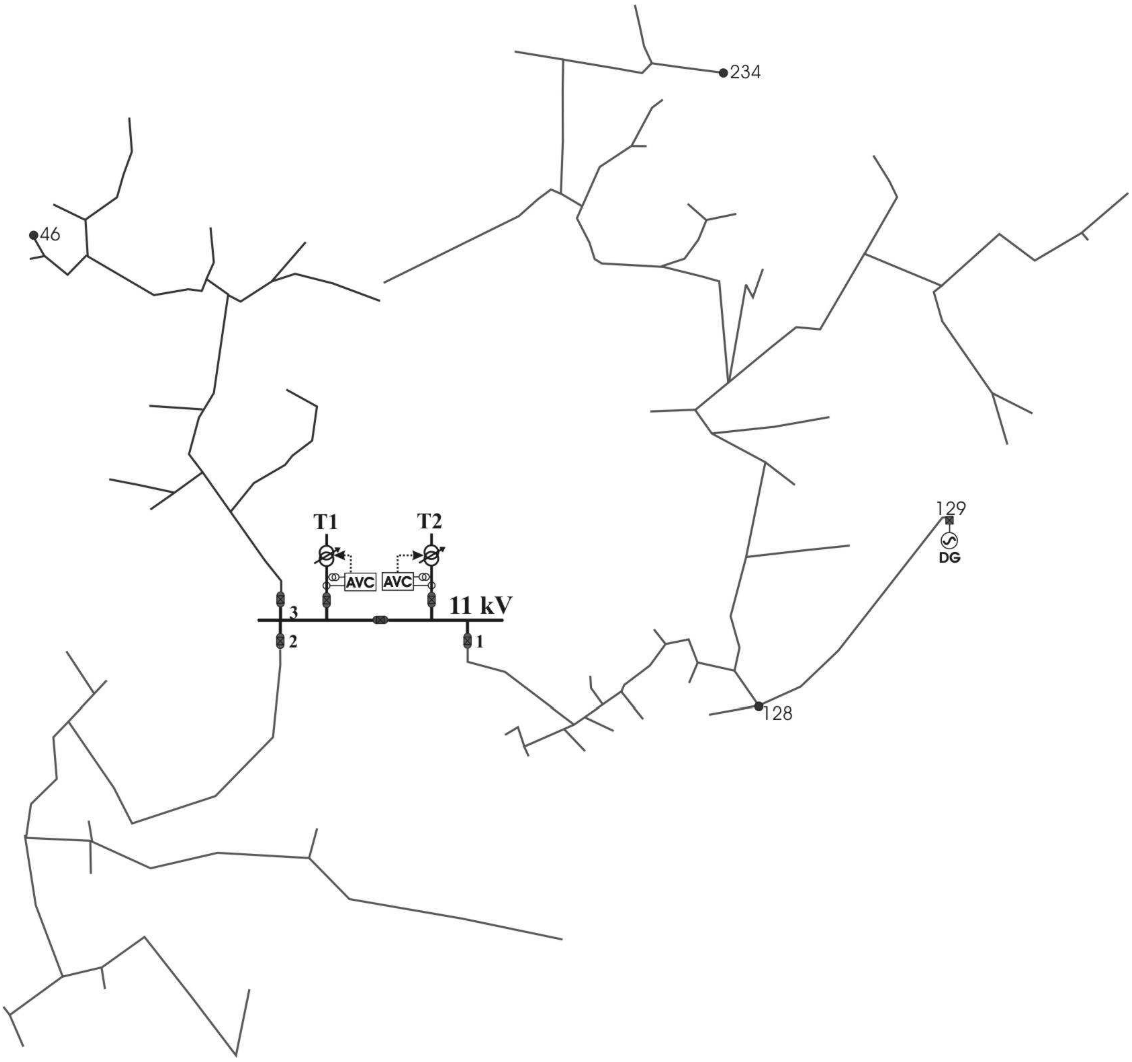


Figure 8.1.1. Simplified Network B diagram

As an alternative solution to the network reinforcement, the GenAVC scheme was installed in order to control the voltage profile on the network and to increase the network capability to accommodate 3 MW of DG. The scheme requires current measurements at each feeder within the substation and remote voltage and power output measurements at the generation site. The GenAVC installation at Network B is presented in figure 8.1.2.

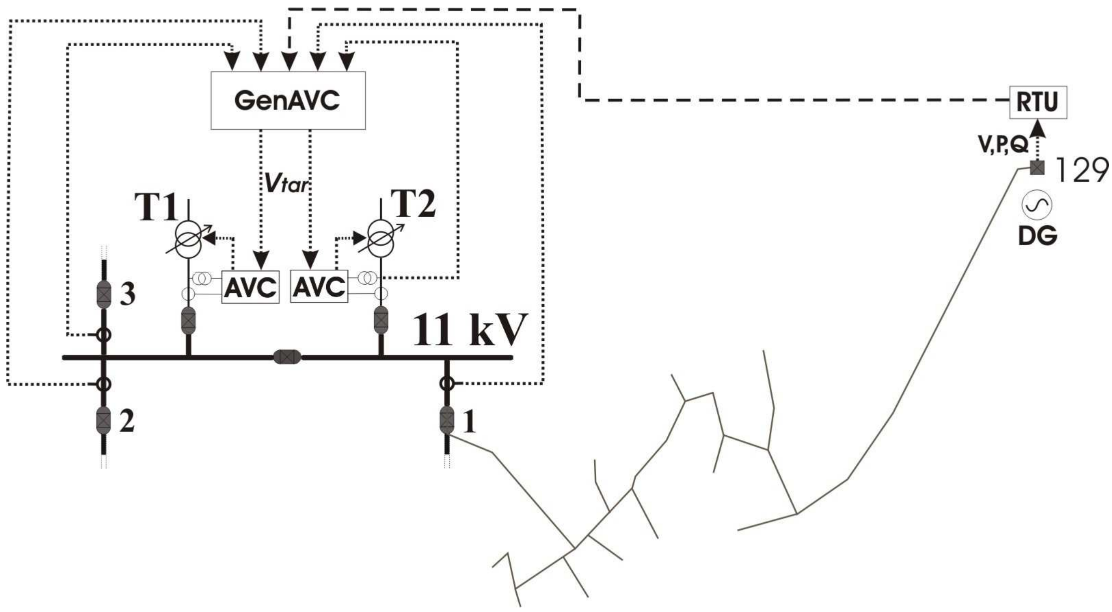


Figure 8.1.2 The GenAVC installation at Network B

With the provision of these measurements, the GenAVC scheme uses a state estimation technique in order to determine the voltage profile on the network and calculate required voltage target adjustment. This voltage target adjustment is then sent to the AVC relays in order to change the basic voltage target. In this manner GenAVC is able to maintain the voltage profile within operational limits.

Taking into account the existing infrastructure of the network and the voltage control regimes, the operational voltage limits for Network B have been determined. The voltage on the network must be maintained within ± 3% at all nodes apart from the PCC node where +5.5% voltage rise is acceptable.

Active network management of voltage in the form of GenAVC has proven to be an effective solution to maintain the voltage profile on the Network B within operational limits and allowing the DG to export 3 MW. The implementation of this solution was at a lower cost when compared with conventional network reinforcement; however, additional operational costs are associated with it as the continuous communication link and data transfer need to be provided for its correct operation. Also, this communication link imposes some risk for operation of the GenAVC scheme and the ability of the generator to export power to the network. A failure of the link between RTU at the PCC and GenAVC scheme at the substation disables the active voltage control and generator output may be constrained for duration of a fault.

8.2. GenAVC Assessment Tool

EDF Energy Networks and Econnect Venture collaborated to develop a web-based assessment tool for the GenAVC. The assessment tool provides an indication of the available generation export that can be accommodated by the use of the scheme based on the network model and historical network data that is input. The GenAVC assessment tool produces graphs of the voltage headroom in the network that can be created by the scheme and voltage profiles on the feeders. These graphs show the level of the generation which could be reasonably accommodated when GenAVC is used [82].

In order to analyse the network voltage profile and available voltage headroom in network B, a model of the system has been created using EDF Energy Networks data bases and DMS information. The network model contains 237 nodes including 120 PQ nodes and one generation node 129 at which 3 MW of DG is connected. The 33 kV busbar is assumed to be an infinite bus representing the rest of the network and is designated as the slack bus in the load flow analysis.

Simulation results from the assessment tool confirm that the GenAVC scheme is able to accommodate 3 MW of generation at node 129 as shown in more detail in section 8.3.1. In addition, it has been found that the node that violates the lower voltage limit most frequently is node 234 and the upper operational voltage limit is node of common coupling, node 129, and nearest to the PCC node 128.

8.3. Coordinated Active Voltage Control Schemes Assessment

The network trial results and field experience of the coordinated voltage control schemes in the EDF Energy Networks based upon SuperTAPP n+ as presented in chapter VII, and GenAVC as discussed above and presented in [82] are used to evaluate the efficiency of the proposed novel voltage management schemes in distribution networks with DG.

Two software tools, M-OCEPS with SuperTAPP n+ model and GenAVC assessment tool, have been used to investigate the performance of both schemes and their ability to enable network capacity to accommodate DG for the two network case studies. Case study 1 is based on the network B and case study 2 is based on the network A. Network models, historical load data for the substation, feeder currents and existing generation outputs are used to analyse the performance of both the GenAVC and SuperTAPP n+ schemes. Additionally, any improvement in the utilisation of the available voltage headroom by the use of the RTUs in the GenAVC and advanced voltage control scheme based on SuperTAPP n+ platform is investigated and quantitative results are presented.

In both case studies, in order to ensure that all LV customers are kept within the statutory voltage limits, the operating voltage limits for the 11 kV networks have been estimated and standardised. All MV nodes need to be maintained between 0.97 and 1.03 pu. The only exception is the generation point of connection where 6% voltage rise is permitted. Simulation analysis along with real voltage measurements from the network have been used in order to locate strategic points in both networks for the limits of voltage control. These points are nodes where violation of the voltage limits occurs most frequently, nodes with DG, or nodes close to the PCC. These nodes also indicate where additional measurement units or RTUs should be installed in order to increase the efficiency of the scheme.

8.3.1. Case Study 1 - Network B

The aim of this case study is to estimate the performance of both schemes and their ability to provide network capacity in the rural distribution network. The objective of the analysis is to maximize output from the existing generation site connected at node 129 under varying load conditions throughout the year.

An example of daily load profiles for this substation is presented in figure 8.3.1. It is important to note that even with DG capacity above 1 MW in summer and 2MW in winter, reverse power flow at the primary substation is possible.

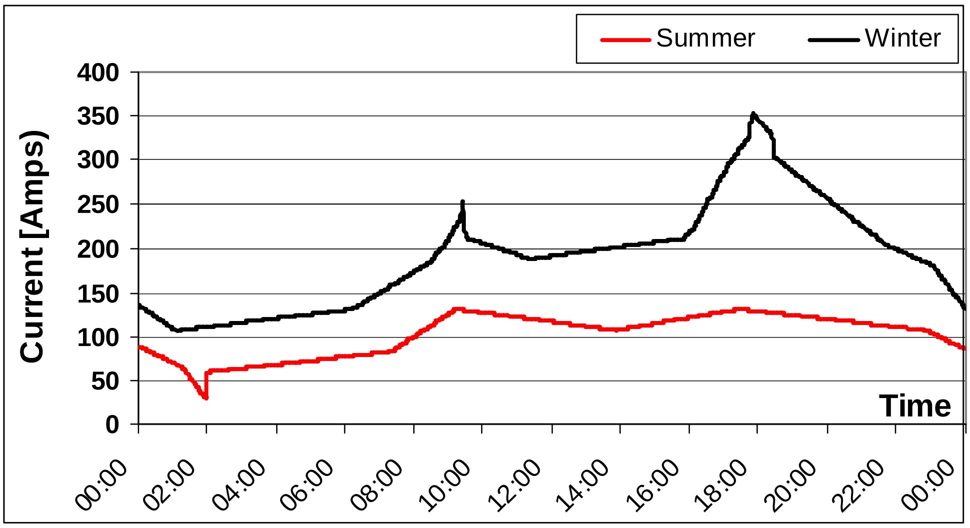


Figure 8.3.1 Daily load profile for case study 1

The network infrastructure and load conditions constrain DG to a maximum capacity of 2 MW when a standard AVC scheme is used, due to unacceptable voltage rise at the PCC. In order to support higher DG capacity, innovative voltage control techniques need to be applied.

Firstly, the GenAVC scheme is tested with a single RTU at the PCC and then with additional RTUs using the GenAVC assessment tool. Then, the SuperTAPP n+ simulation software results are used to investigate the performance of the scheme and how the network characteristics affect its operation.

8.3.1.1. GenAVC Performance

The graph in figure 8.3.2 shows the estimated voltage profile of the network as operated by GenAVC within +/– 3% voltage limits. The error bars around the mean value are an effect of the state estimation process and indicate the range of possible voltage values. Based on these results, the algorithm calculates the voltage headroom in the network that can be provided for the additional amount of DG.

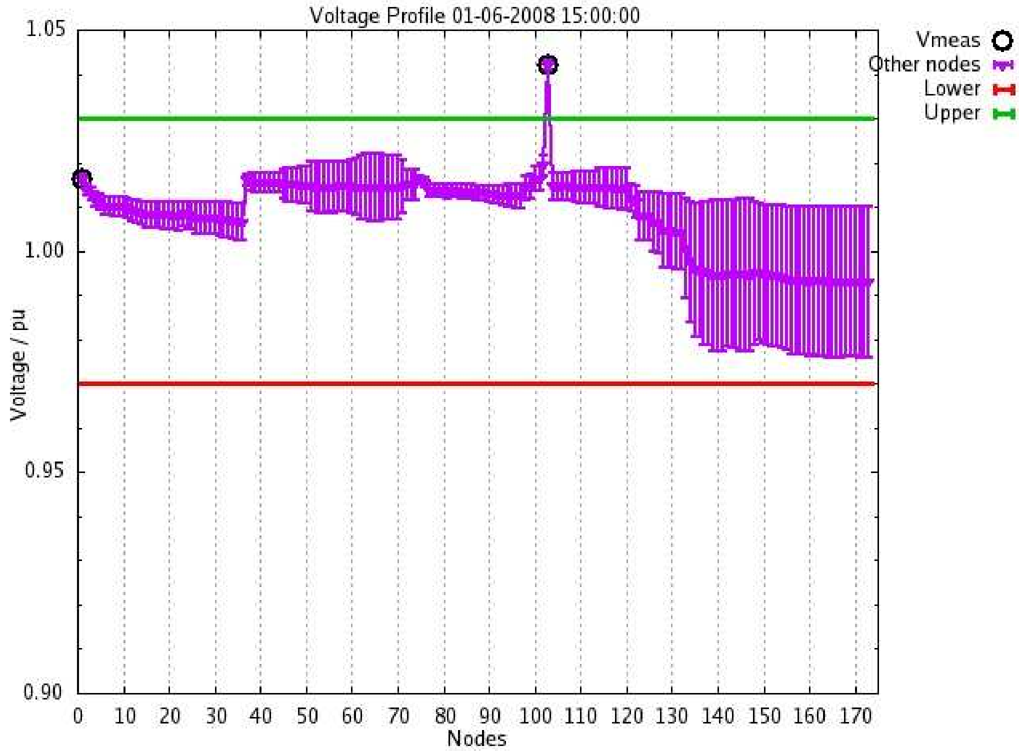


Figure 8.3.2. Network voltage profile of the study case 1 controlled by GenAVC

The graph in figure 8.3.3 shows the assessment results for one week in summer. The red line indicates the available voltage headroom in the network with the existing 3 MW of the DG and the area below the line suggests the available generation capacity. It can be noted that for the most of the time GenAVC is able to accommodate an additional 0.5 MW of DG as shown by the green line.

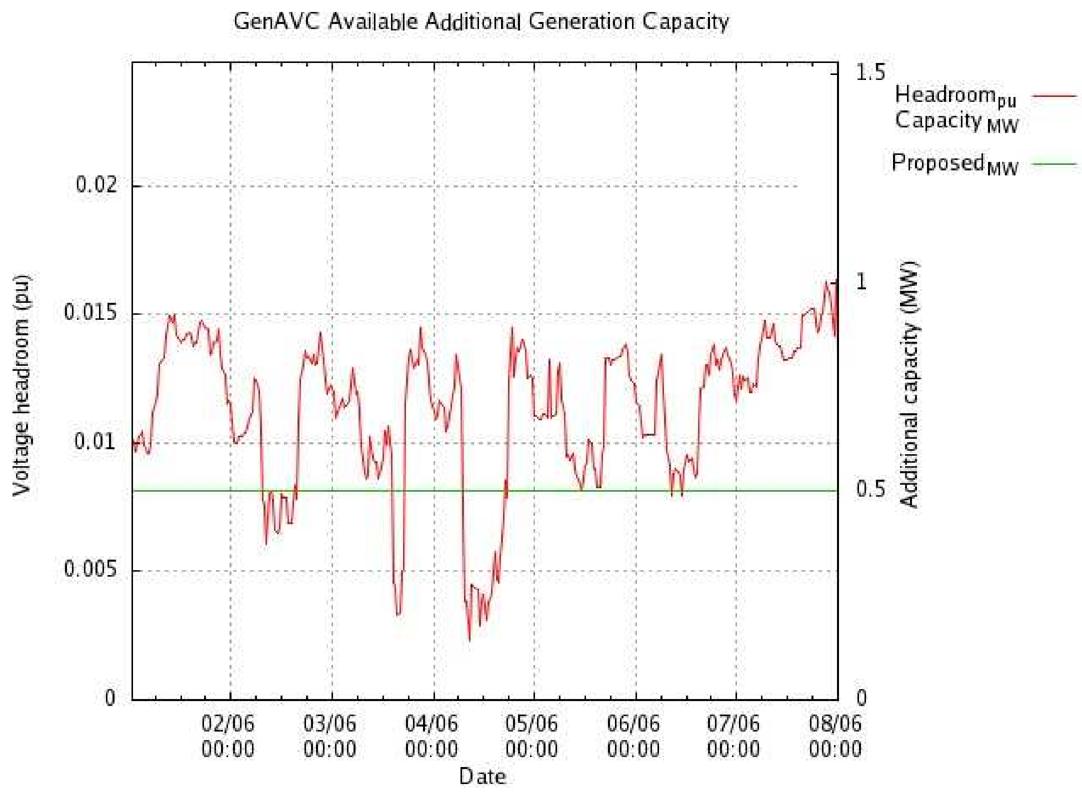


Figure 8.3.3 Voltage Headroom and available generation capacity with GenAVC

A corresponding simulation has been performed for a complete year in order to investigate GenAVC performance under various load conditions. The results show that GenAVC is able to increase network capacity to accommodate 3.5 MW of DG. However, for approximately 15 % of the time the generator needs to be restricted to 3 MW at a time when the system cannot create enough voltage headroom in the network. These periods can be observed on figure 8.3.3 when red line, related to the available voltage headroom is below green line indicating required voltage headroom for 3.5 MW of DG export.

The performance of the scheme can be significantly improved by an additional voltage measurement at node 234 which most frequently limits the available voltage headroom. A second RTU here improves the state estimation process and consequently enables the generator to increase its output from 3 up to a possible 5 MW as shown in figure 8.3.4.

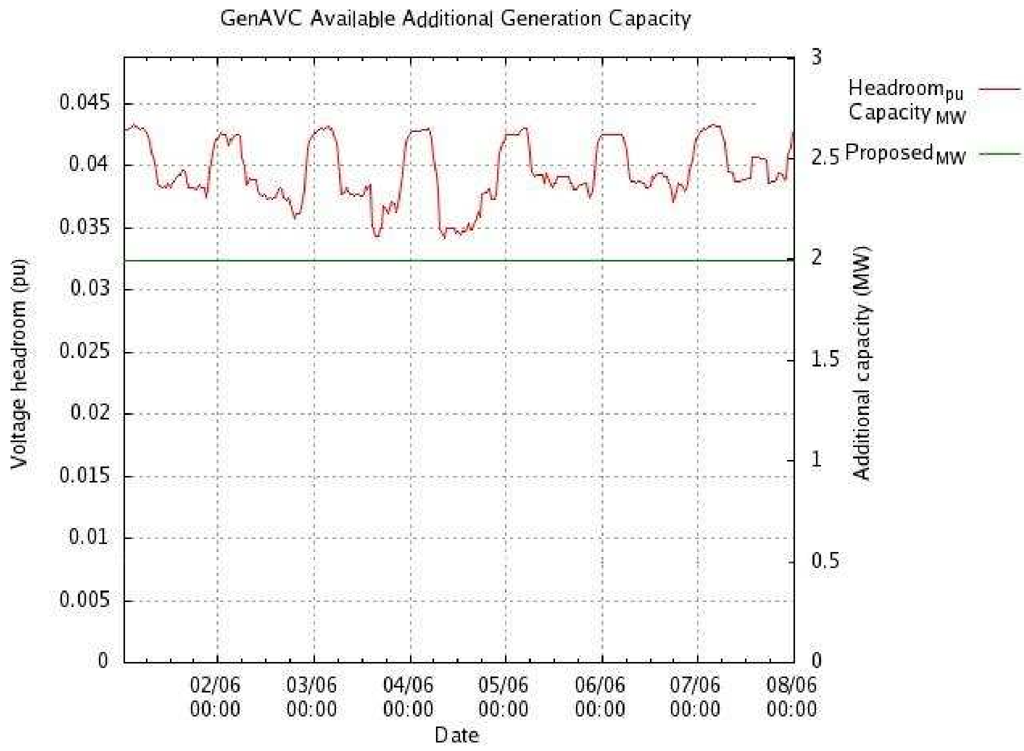


Figure 8.3.4 Voltage Headroom and available generation capacity for GenAVC with two RTUs.

Using the GenAVC assessment tool, a study has been performed for the active voltage controller with DSSE. With a single RTU at the PCC (node 129) the scheme is able to accommodate about 3.5 MW of generation. With three RTUs placed at strategic points in the network, the DG output can be increased by up to 5 MW.

8.3.1.2. SuperTAPP n+ Performance

SuperTAPP n+ simulation software has been used in order to investigate performance of the second active voltage control scheme on the same network. Firstly, appropriate settings for the relay have been calculated such as voltage target at the substation, E_{ST} ratio and generator and LDC voltage biases. Secondly, the maximum and minimum voltage levels in the network have been determined for the proposed export capacity of DG.

The plots in figure 8.3.5 show the assessment of the performance of the SuperTAPP n+ scheme in network B with DG export capacity of 3 MW.

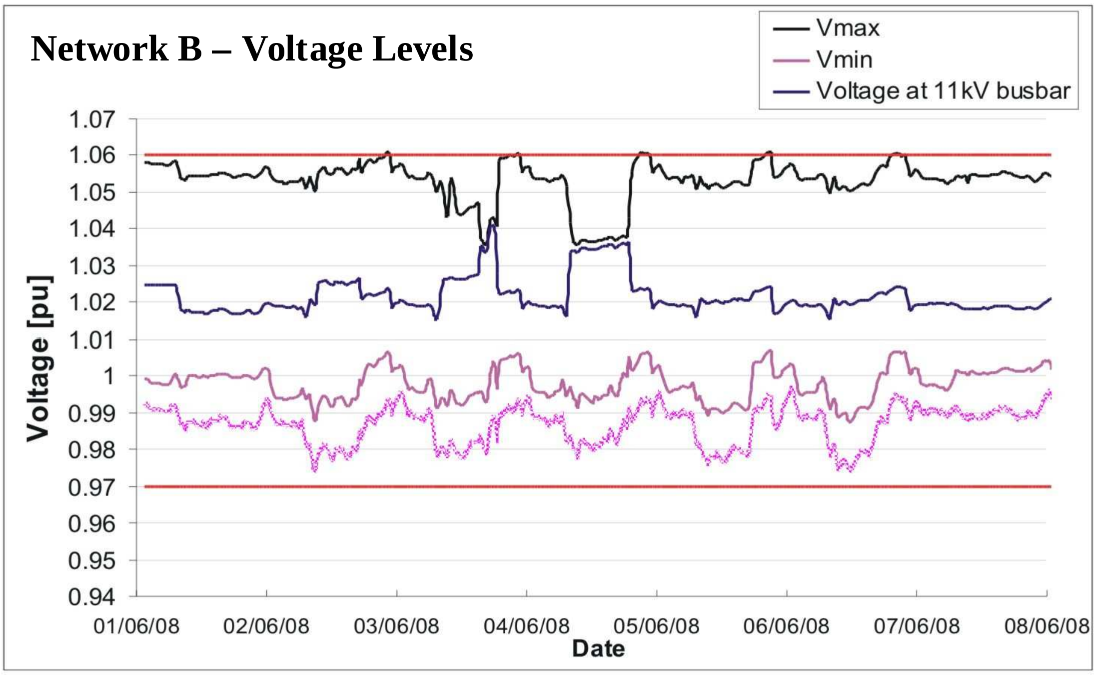


Figure 8.3.5 Performance of the SuperTAPP n+ scheme for Network B

The two lower plots correspond to the lowest predicted and the lowest possible voltage levels in the network respectively. The lowest possible voltage level is calculated using worst case load distribution scenario on the feeder. The topmost plot corresponds to the highest voltage level in the network. During the times when the latter is above upper voltage limit, the scheme is unable to provide sufficient voltage headroom and the generator must be constrained. Although the output of DG may be restricted occasionally during the one week that is presented in Fig. 8.3.5, the SuperTAPP n+ scheme provides enough network capacity to allow the generator to export 3 MW for a significant proportion of the time. Due to the fact that the operational voltage limits cannot be strictly applied in the scheme, as it has been described in chapter VI, both minimum and maximum voltage levels in the network need to be fully investigated in order to ensure that 3% voltage rise at the load customers connection points is not exceeded.

The plots in figure 8.3.6 show the generator voltage bias and LDC voltage bias, represented by pink and black lines respectively. These biases are used in order to calculate the required voltage adjustment as illustrated by the blue plot. This value is then used to alter the voltage target of the AVC relay in order to maintain the voltage profile within operating limits.

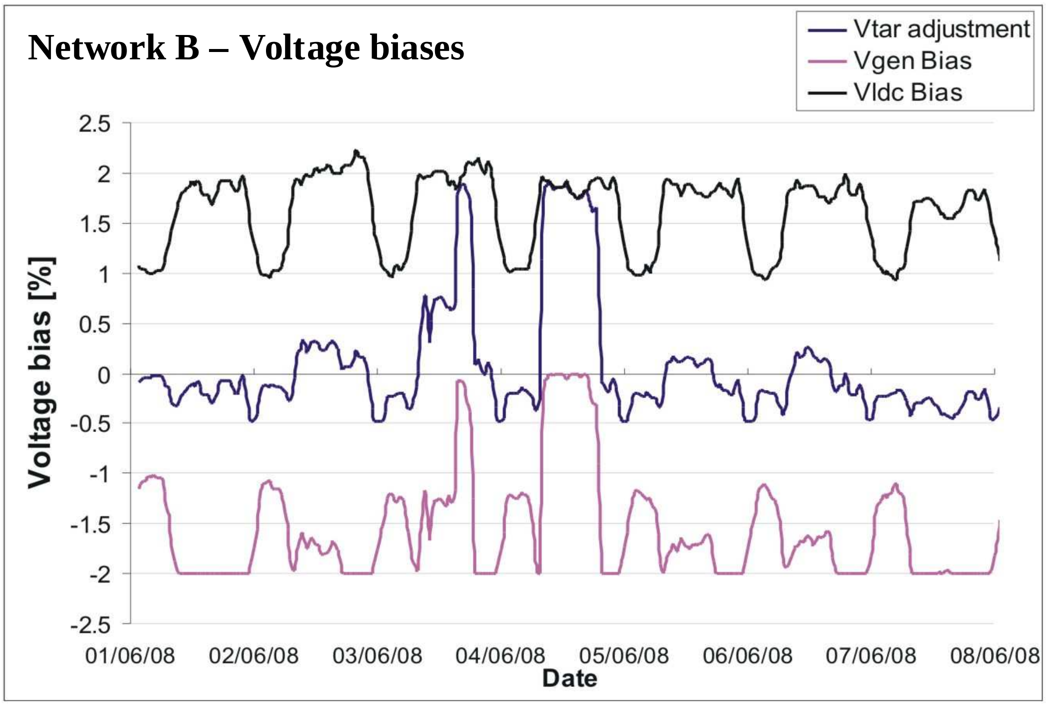


Figure 8.3.6 Voltage target adjustment in SuperTAPP n+ scheme

It has been discussed in chapter VI that the performance of the SuperTAPP n+ scheme is affected by the fluctuation of the E_{ST} factor, especially the calculation of the generation voltage bias. This is due to the fact that about 80% of the total load at the substation used for this study is supplied through the feeder with the generator, and it is difficult to verify the reference load profile for this feeder. Nevertheless, it is shown that the scheme accuracy is sufficient to support DG export of up to 3 MW as the voltage level on the network is maintained within the operational voltage limits and enough voltage headroom is provided for the output of DG.

The performance of the advanced voltage control scheme based on SuperTAPP n+ platform with voltage drop factor and RRTUs has been also investigated using M-OCEPS simulation tool. The simulation results showed that the scheme with one RTU unit at the PCC can accommodate 3.3 MW of export from the generator connected at node 129. The scheme with three RRTUs on the network can accommodate 4.8 MW export of DG. The reason that the advanced relay with one RTU scheme is less efficient than the scheme based on local voltage controller with the same number of RTUs is due to the fact that maximum voltage drop occurs on the same feeder where the generator is connected. This makes the estimation of voltage drop more difficult and can create higher voltage errors. In order to ensure that voltage is maintained within the limits an additional safety margin must be applied to comprise these errors. As a result the efficiency of the scheme is reduced.

8.3.2. Case study 2 - Network A

In this case study the same approach as in the previous case has been adopted to analyse the performance of GenAVC and SuperTAPP n+ schemes when installed in a much larger and more complex distribution network as shown in figure 7.1.1. The objective of the analysis is to determine the maximum output of DG connected at node 325 that can be accommodated by the active voltage control scheme.

An example of daily load profiles for this substation is presented in figure 8.3.7. It can be noted that the maximum load at this substation is 50 MVA and its profile varies significantly. Even with significant generation connected to the network at node 325, reverse power flow at the primary substation is not possible. However it should be noted that reverse power flow on feeder 3 is common.

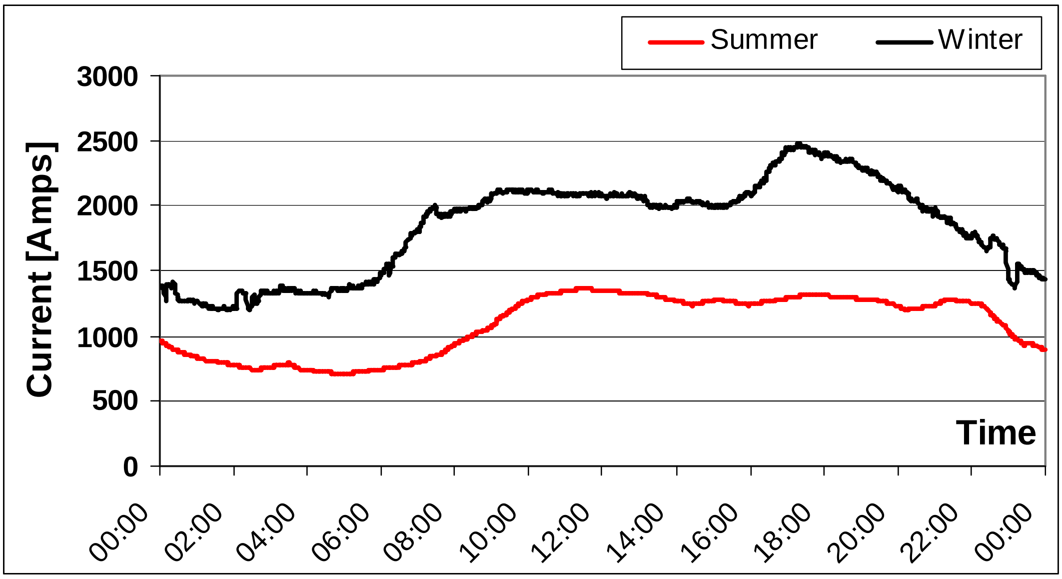


Figure 8.3.7 Daily load profile for case study 2

8.3.2.1. GenAVC Performance

Figure 8.3.8 presents the results of the assessment of the GenAVC performance with a single RTU at the point of connection of DG of 5 MW. The system is able to control the voltage profile in the network so making it possible to accommodate an additional 2 MW of export capacity from the existing generator without any predicted interruption of the generator operation. The additional generation that the scheme is able to support is marked by the straight green trace.

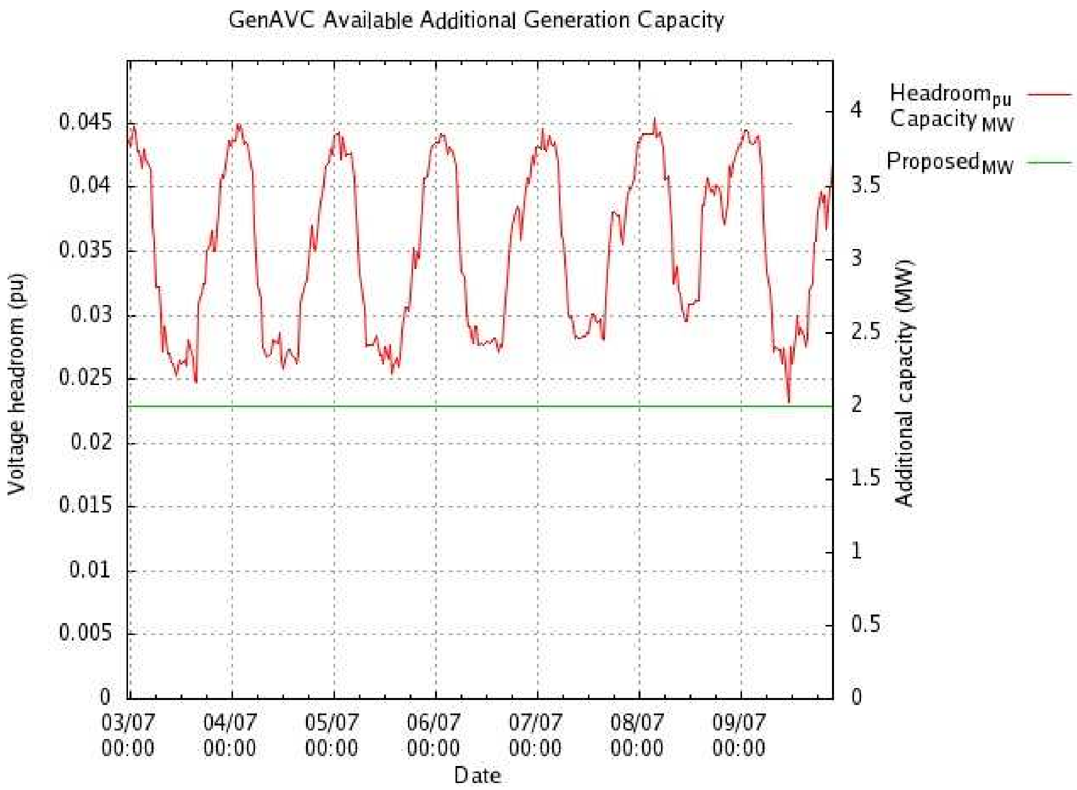


Figure 8.3.8 Voltage Headroom and available generation capacity with GenAVC

The plots in figure 8.3.9 show voltage profiles obtained by the state estimation for the number of feeders in the system.

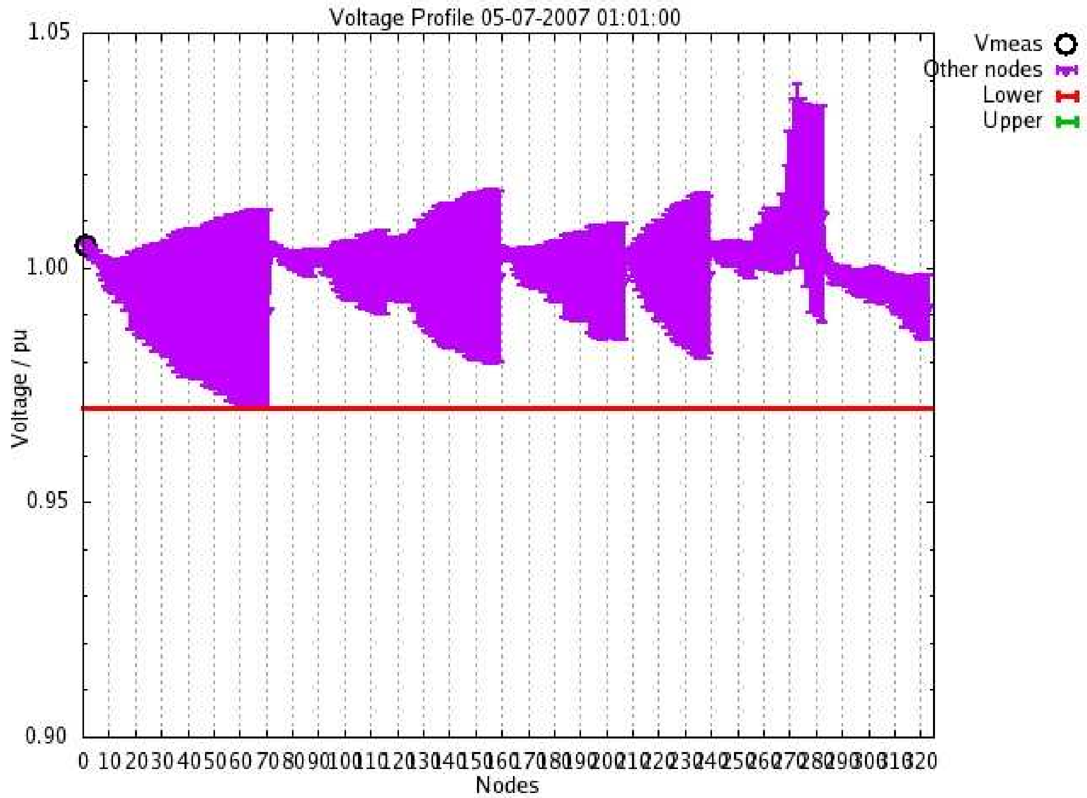


Figure 8.3.9 System voltage profile of the case study 2 controlled by GenAVC

It can be seen from figure 8.3.9 that each of the feeders has a significant voltage uncertainty that limits the performance of the GenAVC scheme. In order to further increase the efficiency of the scheme a large number of additional RTUs need to be installed on each feeder that has high voltage drop and voltage error. With six additional RTUs on the network with and communication links to the controlling unit, the GenAVC scheme can support 3 MW of additional export capacity.

8.3.2.2. SuperTAPP n+ Performance

As is shown by the simulation results in figure 8.3.10, the SuperTAPP n+ scheme is able to accommodate 6 MW of DG for a significant proportion of the time whilst simultaneously maintaining the voltage profiles within operating limits. However, there are times when the generator needs to be restricted due to an unacceptably high voltage levels at the PCC.

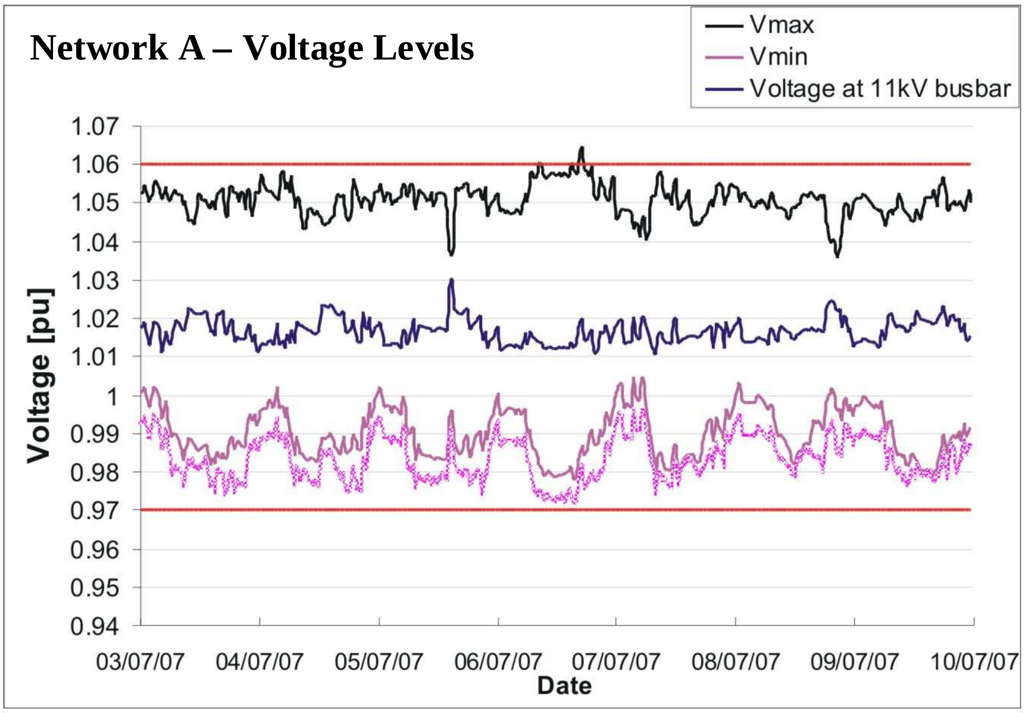


Figure 8.3.10 Performance of the SuperTAPP n+ scheme for case study 2 with 6 MW of DG

The undesirable voltage rise at the PCC typically occurs under low load conditions when the generator output exceeds load demand on the feeder. Under such circumstances the voltage generation bias surpasses the load drop compensation bias and the SuperTAPP n+ scheme reduces the AVC voltage target. Consequently the voltage headroom for the DG export is increased as shown in figure 8.3.11 for one week of the scheme operation during the summer.

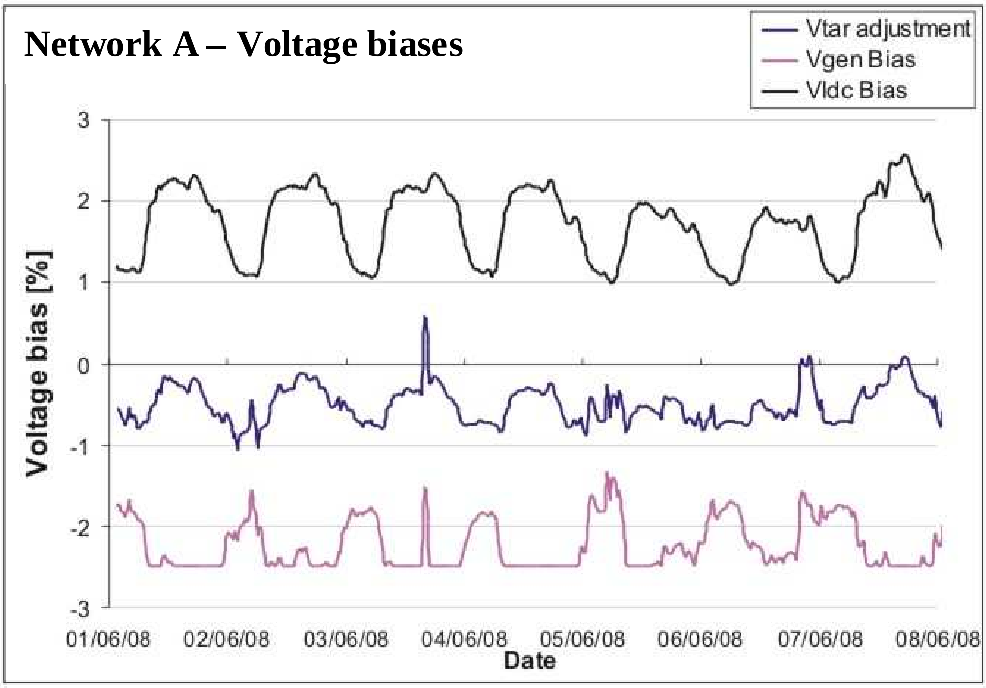


Figure 8.3.11 Voltage target adjustment in SuperTAPP n+ scheme – Case 2

In this case the SuperTAPP n+ scheme is able to support export capacity of the DG up to 6 MW with occasional limitations. However, most importantly, it can be observed that the scheme improves the voltage profile in the system with DG. The SuperTAPP n+ scheme maintains all customers within the operating limits and provides sufficient network capacity that allows existing generators to continue uninterrupted operation.

Load flow simulation results indicate that an advanced AVC scheme with single RTU at PCC is able to support above 8 MW of DG export without any restraint of the generator under all load conditions. A further increase of the scheme efficiency can be achieved when additional RRTUs are installed on the network. In the configuration, where one RTU at PCC and five RRTUs at nodes where operation voltage limits are most frequently exceeded are installed, the advanced AVC scheme is able to accommodate up 8.6 MW of DG at node 325.

8.4. Summary

Existing voltage control methods for MV networks do not provide sufficient support for DG and therefore novel schemes need to be employed in order to facilitate increasing amounts of DG. Fields trials and simulation results show that coordinated active voltage control schemes can be an efficient and cost effective solution.

In case study 1 the network infrastructure and load conditions constrain DG to a maximum capacity of 2 MW when a standard AVC scheme is used. In order to support higher DG capacity, innovative voltage control techniques can be applied. The evaluation of the abilities of the voltage control schemes to increase network voltage headroom in this network are presented in figure 8.4.1.

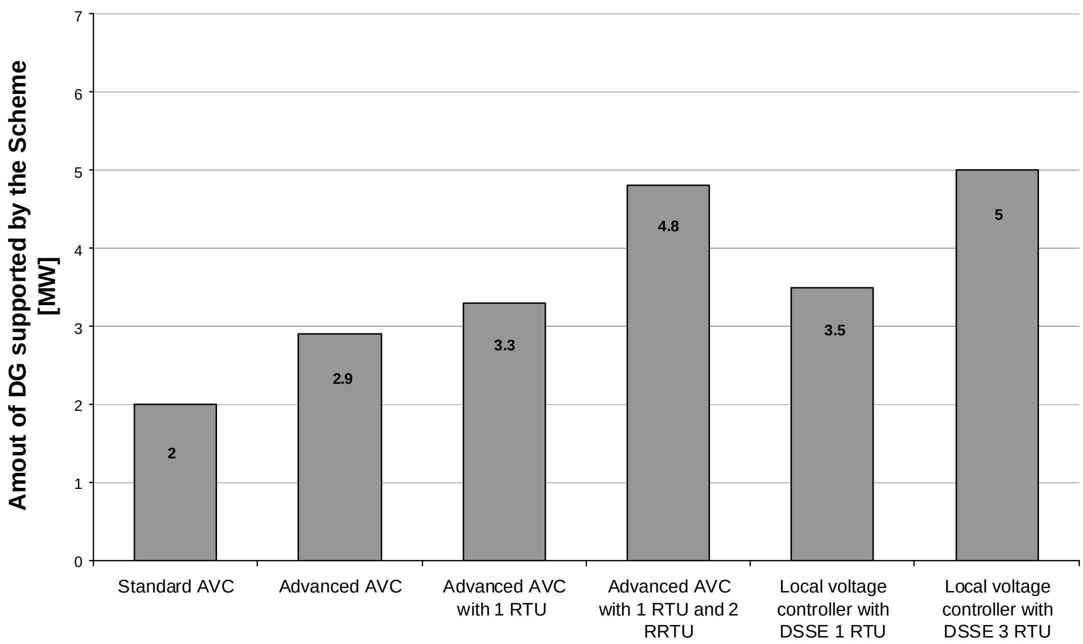


Figure 8.4.1 Coordinated voltage control schemes effectiveness in case study 1

Using the GenAVC assessment tool, a study has been performed for the active voltage controller with DSSE. With a single RTU at the PCC (node 129) the scheme is able to accommodate about 3.5 MW of generation. With three RTUs placed at strategic points in the network, the DG output can be increased to 5 MW.

The advanced AVC relay with local measurements only can support up to 2.9 MW of DG at node 129. With voltage drop factors functionality applied and a link to the RTU installed at PCC, the scheme effectiveness is increased to support 3.3 MW. When an RRTU is installed at the end of feeder 1 at node 234, the scheme can support a DG output of 4.8 MW.

Simulation results from case study 2 as shown in figure 8.4.2 indicate that the local voltage controller is able to create voltage headroom to allow DG of 7.1 MW in a configuration with one RTU. However, in order to significantly increase the efficiency of the scheme, six additional RTUs need to be installed. This is due to the relatively large number of feeders and the fact that DSSE uncertainty on a feeder without measurement is very considerable, with the consequence that a high safety margin in the calculation of voltage target for the AVC needs to be applied.

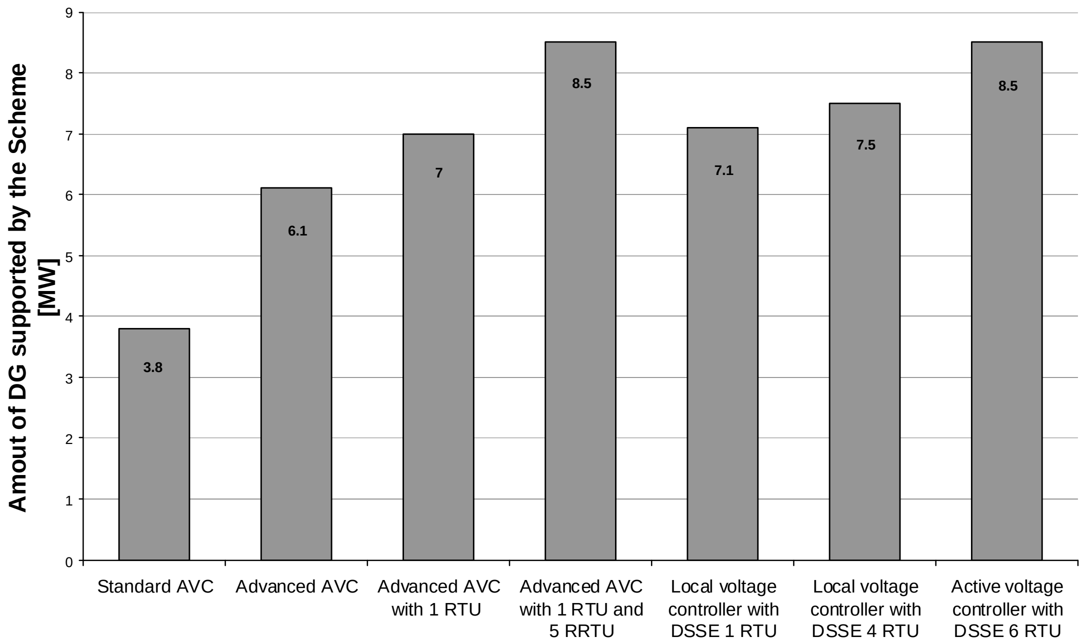


Figure 8.4.2 Coordinated voltage control schemes effectiveness in case study 2

The advanced AVC scheme based on local measurements is able to increase network voltage headroom and support DG capacity of 6.1 MW. Using the advanced relay with voltage drop factors applied and a single RTU at the PCC, the voltage headroom for 7 MW of the DG can be achieved. Installation of six RRTUs at the end of the most heavily loaded feeders and one RTU at the PCC allows an increased ability of the scheme to support DG of 8.6 MW.

The advanced voltage control scheme based on the SuperTAPP n+ platform can be easily implemented within an existing infrastructure as it does not require additional equipment. It provides essential AVC functionality and offers the potential to increase network capacity if required. The efficiency of the scheme can be further improved by estimation techniques and the installation of RRTUs. Due to the fact that RRTUs send information to a relay by exception, the operational cost is relatively low.

An active voltage control scheme with DSSE is a very efficient tool to control voltage profile in a network with DG, however additional monitoring equipment and reliable communication is essential. In any specific network, additional investment and operational costs may be necessary.

Computational models of AVC schemes and simulation analysis tools are critical to the performance and estimate errors of an AVC scheme in the distribution network under various load and generation output conditions. The load flow simulation software with the models of an advanced AVC scheme has been used to quantify the amount of DG which can be supported by the scheme.

It is seen that innovative voltage control schemes, in both case studies, can significantly increase network capacity to accommodate DG, depending on which scheme is used and the number of remote measurements units installed. The capacity of DG that can be connected to the network, based on voltage constraint considerations, can be increased by 2.5 times compared to standard voltage control strategies. To achieve this goal, observability of the network needs to be improved and monitoring equipment installed.

With the same number of RTUs, an active voltage controller with a DSSE scheme is able to support higher level of DG than an advanced AVC with RRTUs. However, installation costs and operational costs of the latter are much lower, typically some 20% of the former scheme. Reliability of operation of the scheme and its dependence on the remote measurements is another important issue which needs to be considered in the process of scheme selection and design. Availability and consistency of communication infrastructure also needs to be assessed.

For the selection of the most suitable active voltage control scheme, careful analysis of the voltage control of the network is required, including compatibility with existing practices, operational limit calculations, AVC scheme performance and availability of suitable communication infrastructures. This will ensure that the network is operated effectively and all customer supplies are maintained within the statutory limits.

Chapter IX Conclusions and Suggestions for Future Research

9.1. Rationale of the Thesis

In order for the UK to be able to achieve future targets of electrical power generation from the renewable sources and meet the associated future energy demands without unaffordable investment costs, distribution networks must be operated more efficiently in the future. Such challenges for existing distribution networks are significant with regard to requirements for current and future research. Innovative technologies, simulation tools, accurate system models and efficient utilization of network data are required to be developed and employed in the distribution networks in order to help network operators improve design, development, operation and management of their systems.

One of the main issues associated with the control of distribution networks is voltage management and parallel transformer operation. This is particularly problematic while DG is being connected on the network. A number of novel technologies have recently been proposed with the aim to improve voltage control in distribution network with DG and several network trials are currently at appraisal stage. However, in order to implement these techniques into the existing networks infrastructure and to efficiently utilise their capabilities a number of issues need to be analysed. Firstly, innovative voltage control techniques need to be assessed with regard to their suitability, reliability as well as installation and operation costs. Secondly, suitable and effective simulation software is required in order to be able to select and apply the most optimum solution for a particular network under various load and generation conditions. Finally, their performances need to be validated and proved in the real network trials.

The research project as presented in this thesis was initiated by the need to examine existing voltage control strategies in distribution networks and to investigate the potential of active voltage management techniques in order to make distribution networks more flexible and to be able to accommodate DG.

9.2. Summary of Main Research Contributions

The research presented in this thesis delivers a number of original contributions to knowledge. The contributions are summarised below.

9.2.1. AVC schemes evaluation and computational model development

A detailed review of the existing and potential AVC techniques for distribution networks revealed a lack of suitable mathematical models and available simulation software for analysis of commonly used voltage control schemes. This prompted the development of computational models and associated simulation tools to enable comprehensive analyses of the performance of AVC schemes in distribution networks with DG.

The computational models of AVC schemes such as NRC, true circulating current, TAPP and Enhanced TAPP have been developed and implemented into OCEPS load flow package. The simulation tool then has been used to evaluate their performance, limitations and suitability for networks with DG.

As a result of development of these AVC scheme models, the impact of DG on a network can be evaluated, and potential errors in an AVC scheme performance estimated. The benefits of these tools is that simulation analyses are now more accurate and precise effects of a connection of DG can be forecasted with improved level of confidence. In this way the potential for violation of the statutory limits can be established in a more quantifiable manner.

9.2.2. Development of simulation tool for effective analysis of distribution networks

Due to the sparseness of network measurements, a lack of accurate load and generator output information on the medium and low voltage networks analysis of the system can be very ambiguous and for this reason it is usually based on the worst case scenarios. This significantly reduces possible utilisation of the available voltage headroom in the network and may restrict the connection of DG.

This thesis enhances the existing tools currently used for the analysis of the voltage profiles on distribution networks with DG. Load modelling and voltage profile evaluation methods which have been developed and implemented into M-OCEPS software [37], [38], as discussed in chapter VI, enable a precise network voltage study to be carried out.

With the provision of historical SCADA data and available information from the DNOs' data bases, this tool can be used to evaluate and fully utilise the functionality of active voltage control methods. Additionally, to achieve confidence in the results obtained from the M-OCEPS, modelling and simulation tools have been validated using real network voltage measurements, smart meter readings and trial data.

The outcomes presented in this thesis demonstrate that the M-OCEPS simulation software produces realistic and accurate results and can be used as a tool for more precise voltage profile analysis in distribution networks with DG. As a result a network can be safely operated closer to their limits allowing more economical connection of DG and can accomplish more efficient design and utilisation of the system.

9.2.3. Assessment tool for SuperTAPP n+ scheme

One of the novel active voltage control schemes is SuperTAPP n+ and a number of trials have already been installed on the distribution networks in the UK. Thus, as the SuperTAPP n+ method is based on estimation techniques and assumptions of the load pattern, it is susceptible to certain errors and a detailed investigation of the network characteristics must be carried out to verify the acceptability of the scheme.

In this thesis the functionality of the SuperTAPP n+ scheme [22] has been investigated and its performance validated. Also, in order be able to perform analysis of the suitability of the scheme in a particular network, a comprehensive assessment tool for the SuperTAPP n+ has been developed [63]. Novel computational tools with advanced

AVC models and SuperTAPP n+ functionality have been proposed and developed to analyse the potential application of the SuperTAPP n+ scheme in a variety of the distribution network scenarios.

On the basis of the numerical results obtained for the specific systems that have been investigated in this thesis it is demonstrated that the M-OCEPS software can be used to determine scheme suitability and give accurate settings for the relay to accommodate DG in a voltage constrained system.

A number of limitations of the SuperTAPP n+ scheme such as inaccuracy of the generation estimation algorithm in certain networks and load conditions have been observed and discussed in this thesis. The developed assessment tool allows to quantify these errors and select appropriate settings and safety margins to prevent any voltage excursions outside the operational voltage limits.

9.2.4. Novel generation estimation algorithms and innovative voltage control scheme

In order to improve estimation technique and performance of the SuperTAPP n+ scheme new algorithms have been proposed. The final contributions of the thesis are the development of novel generation estimation algorithms and an innovative active voltage control scheme.

Due to the simplicity and operational functionality of these techniques they are suitable for implementation into an existing scheme such as the SuperTAPP n+. This enables the scheme to be implemented in networks with a wide variety of the network load and generation conditions and most importantly it can provide significant improvement in network utilisation with regards to the increase of the amount of DG connected.

9.3. Research Impact and Benefits to Industry

Resulting from this research and industry interest, off-line and on-line network field trial were set up in part of the EDF Energy Networks distribution network using the SuperTAPP n+ scheme. Analysis of the SuperTAPP n+ scheme performance and recorded voltage measurements on the network has provided evidence that the scheme is able to adequately estimate the generator output and calculate the required voltage target in order to maintain the voltage profile within the limits and support DG output. The experience obtained during the SuperTAPP n+ trial has demonstrated the performance of design and its capability for future installations.

Also, the analysis of the performance of GenAVC scheme and associated network voltage profile that was also performed as a part of this project has demonstrated that the scheme can accommodate additional generation without compromising the voltage profile on the network.

A key outcome of this project is a set of practical guidelines for active network management analysis and selection of the most appropriate solution for specific voltage issues in distribution networks with DG. The guidelines aim is to assist a distribution network planning engineer with the choice of the most appropriate active voltage control scheme taking into account the efficiency, complexity, communication requirement of the scheme and network infrastructure, estimated DG, operational voltage limits, investment and operational costs [48], [63].

The strategies and assessment tools for the active voltage control schemes developed in this thesis have enabled DNOs to use new technologies more confidently and therefore increase the utilisation of existing assets to provide a cost effective connection option for DG. Using these tools it will be possible to connect a greater amount of DG into the existing network infrastructure, thus contributing to the UK government's strategy for the development of renewable energy sources as a proportion of UK's total electrical power requirements [86].

9.4. Suggestions for Future Research

The research conducted in this project can be taken further in a number of ways.

When a study is carried out, the constantly changing nature of the power system requires significant computational effort to obtain simulation results for an active solution. Therefore, a future project should focus on the development of more efficient methods for load flows in radial networks to improve computation efficiency. This will reduce the time required to obtain results based on vast amounts of historical data. Also, in order to enhance the usability of the software, a more user friendly interface and visual result representation should be added to M-OCEPS. This will enable the use of M-OCEPS software in real time applications. In addition the adoption of emerging standards such as the common information model (CIM) for power system information and data exchange will enable improved interoperability of computational tools across both distribution network planning and operation. Furthermore, the extensive deployment of improvements in robust, secure and scalable ICT infrastructure across distribution networks will support more coordinated voltage management schemes [84]. Finally, further improvement in the accuracy of state and load estimation techniques is required in to improve the operational visibility and assessment of AVC scheme performance [23].

Two new generation estimation algorithms have been proposed in this thesis and their accuracy has been proven based on two network case studies. However, additional testing of the generation estimation methods will enable the development of a more generic set of rules. Such rules may be used for selection of an appropriate scheme for various network arrangements, load and generation conditions.

The AVC computational models and coordinated voltage control schemes proposed and developed in this thesis offer efficient tools for distribution networks analyses with regard to active voltage control. A future project could investigate implementation of these techniques into general active network management system for distribution networks [87]. This can benefit from improved voltage control and more accurate assessment of the ANM in distribution networks with DG. Additionally results from the case studies presented in this thesis can contribute to a novel voltage control systems such as approach based on case base reasoning [85].

As mentioned previously, one contribution is the development of the advanced AVC scheme that can be implemented into the SuperTAPP n+ platform. An expected action will be the practical application and testing of this potential solution. An advanced AVC scheme trial in a real network with a various combinations of RTUs and RRTUs should confirm the simulation results presented in this thesis.

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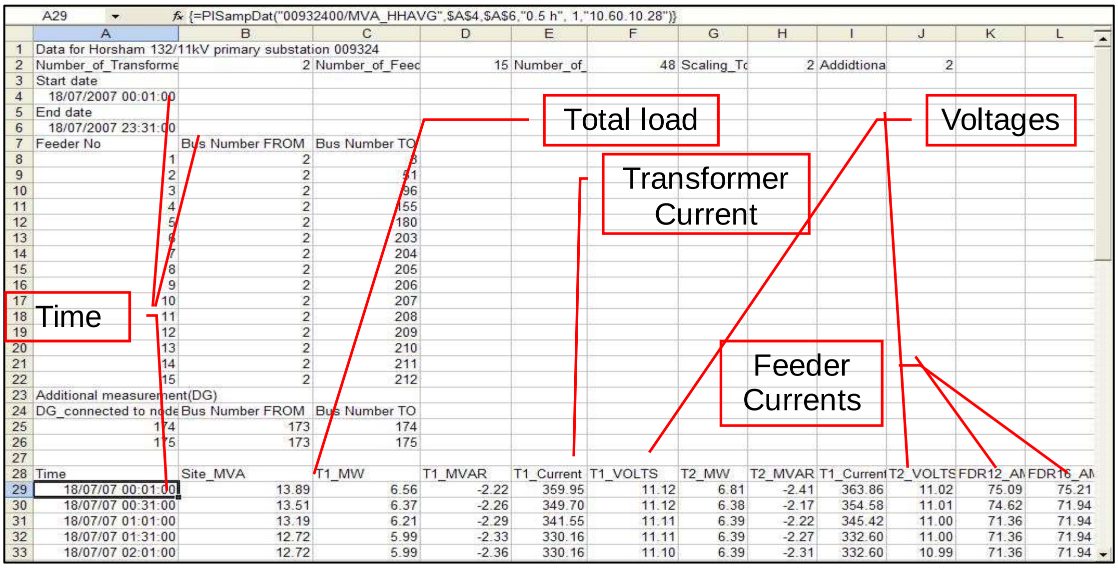
Appendices

Appendix A – M-OCEPS Network Model Input File

General		NB	NL	NT													
		8	8	5													
NODES	Nodes	V	SVA	SVAMAX	LPF	NDTYP											
132/11 bus-bars	1	34.65000	0.00000	0.00000	1.00000	1											
	2	11.00000	0.00000	0.00000	1.00000	3											
	3	11.00000	0.00000	0.00000	0.97000	3											
	4	11.00000	0.00000	0.00000	0.97000	3											
	5	11.00000	0.00000	0.00000	0.97000	3											
	6	0.43300	-300.00000	-300.00000	0.97000	3											
	7	0.43300	-500.00000	-500.00000	0.97000	3											
	8	0.43300	-1000.00000	-1000.00000	0.97000	3											
LINES	line	IS	IR	RL	XL	BRANCOD	IMAX	FEEDG	EST	KGEN							
Substation	1	1	2	0.03170	0.72670	1.00000	0.60000	0	0.00000	0.00000							
	2	1	2	0.02660	0.74270	2.00000	0.60000	0	0.00000	0.00000							
	3	2	3	0.32780	0.15948	0.00000	0.00000	0	0.00000	0.00000							
	4	3	4	0.49170	0.23922	0.00000	0.00000	0	0.00000	0.00000							
	5	4	5	0.57365	0.27909	0.00000	0.00000	0	0.00000	0.00000							
	6	3	6	5.04600	14.66800	3.00000	0.01000	0	0.00000	0.00000							
	7	4	7	2.71500	9.12100	4.00000	0.00500	0	0.00000	0.00000							
	8	5	8	1.16800	4.60300	5.00000	0.00300	0	0.00000	0.00000							
TRAFO	Trafo	TAPLO	TAPHI	PHSLO	PHSHI	TAPSTP	TAPPOS	TAPTYP	NODTSP	VTSP	LDC	RLDC	XLDC	RRRC	XRRC	TAPPSC	PARTRAN
	1	0.9	1.1	0	0	64	47	1	2	1.02	2	0.000	0.000	0.000	0.800	0	1
	2	0.9	1.1	0	0	64	47	1	2	1.02	2	0.000	0.000	0.000	0.800	0	1
	3	0.96998	0.8776	0	0	4	1	0	0	1.00	6	0.000	0.000	0.000	0.000	0	2
	4	0.96998	0.8776	0	0	4	1	0	0	1.00	7	0.000	0.000	0.000	0.000	0	3
	5	0.96998	0.8776	0	0	4	1	0	0	1.00	8	0.000	0.000	0.000	0.000	0	4

Appendix B – SCADA Data Input File



A29 fx {=PISampDat("00932400/MVA_HHAVG",A4,A6,"0.5 h", 1,"10.60.10.28")}

	A	B	C	D	E	F	G	H	I	J	K	L
1	Data for Horsham 132/11kV primary substation 009324											
2	Number_of_Transforme	2	Number_of_Feec	15	Number_of_	48	Scaling_Tc	2	Addidtiona	2		
3	Start date											
4	18/07/2007 00:01:00											
5	End date											
6	18/07/2007 23:31:00											
7	Feeder No	Bus Number FROM	Bus Number TO									
8	1	2	3									
9	2	2	51									
10	3	2	96									
11	4	2	155									
12	5	2	180									
13	6	2	203									
14	7	2	204									
15	8	2	205									
16	9	2	206									
17	10	2	207									
18	11	2	208									
19	12	2	209									
20	13	2	210									
21	14	2	211									
22	15	2	212									
23	Additional measurement(DG)											
24	DG_connected to node	Bus Number FROM	Bus Number TO									
25	174	173	174									
26	175	173	175									
27												
28	Time	Site_MVA	T1_MW	T1_MVAR	T1_Current	T1_VOLTS	T2_MW	T2_MVAR	T1_Current	T2_VOLTS	FDR12_AM	FDR16_AM
29	18/07/07 00:01:00	13.89	6.56	-2.22	359.95	11.12	6.81	-2.41	363.86	11.02	75.09	75.21
30	18/07/07 00:31:00	13.51	6.37	-2.26	349.70	11.12	6.38	-2.17	354.58	11.01	74.62	71.94
31	18/07/07 01:01:00	13.19	6.21	-2.29	341.55	11.11	6.39	-2.22	345.42	11.00	71.36	71.94
32	18/07/07 01:31:00	12.72	5.99	-2.33	330.16	11.11	6.39	-2.27	332.60	11.00	71.36	71.94
33	18/07/07 02:01:00	12.72	5.99	-2.36	330.16	11.10	6.39	-2.31	332.60	10.99	71.36	71.94

Appendix C – Load Flow Results Output File

```
   AFTER RETURN FROM NRLF

ITER=            1

NERR=            0  NERRMAX=        4000
   Date and Time  19/11/2009 00:00

Branch From To  P(MW)   Q(MVAr) P Loss(MW) Q Loss(MVAr) Tap(pu) P.Shift(r)

   1     1    2  1.9881   0.3191   0.0028   0.2015   7.0000   0.0000
   2     1    2  2.4818   0.3900   0.0043   0.2514   7.0000   0.0000
   3     2    3  4.4629   0.2561   0.0002   0.0002   1.0000   0.0000
   4     3    4  4.4627   0.2559   0.0327   0.0159   1.0000   0.0000
   5     2    5  0.0000   0.0000   0.0000   0.0000   1.0000   0.0000
   6     5    6  0.0000   0.0000   0.0000   0.0000   1.0000   0.0000

               P Total Loss(MW)  Q Total Loss(MVAr)
                     0.0400         0.4691

Branch     From      To        RIF(pu)       IIF(pu)     Current (Amp)

    1        1        2       -0.01963    -103.04548      0.00315     16.53944     104.36438
    2        1        2       -0.02451    -128.63499      0.00385     20.21167     130.21318
    3        2        3       -0.04414    -231.68047      0.00700     36.75111     234.57724
    4        3        4       -0.04414    -231.68047      0.00700     36.75111     234.57724
    5        2        5        0.00000       0.00000      0.00000      0.00000       0.00000
    6        5        6        0.00000       0.00000      0.00000      0.00000       0.00000

 Node    Name      Pinj(MW)     Qinj(MVAr)    V(pu)       Theta(rad)

   1               4.4700      0.7091      1.0000       0.0000
   2               0.0000      0.0000      1.0002      -0.1000
   3               0.0000      0.0000      1.0002      -0.1000
   4              -4.4300     -0.2400      0.9927      -0.1032
   5               0.0000      0.0000      1.0002      -0.1000
   6               0.0000      0.0000      1.0002      -0.1000

   END OF RESULTS
```

Appendix D – Network Characteristics and Generation Estimation

Time	Feeder Number 4	Est	Edy	LOAD_RI	LOAD_II	FDR_RI	FDR_II	FDR_MEA	GEN_RI	Gen RI Estimated
17/12/2008 00:00		0.165962	0.171596	0.001209	44.4	-1.47	29.2	211.58	206.54	168.24
17/12/2008 00:01		0.163608	0.169166	-0.00164	43.48	1.98	28.41	211.71	206.45	171.19
17/12/2008 00:02		0.163489	0.169042	-0.0019	43.38	2.29	28.34	211.57	206.43	171.36
17/12/2008 00:03		0.162603	0.168113	-0.00307	43	3.7	28.01	209.98	206.39	172.49
17/12/2008 00:04		0.161151	0.166629	-0.0043	42.66	5.19	27.68	208.38	206.36	174.21
17/12/2008 00:05		0.160206	0.16564	-0.00553	42.26	6.67	27.34	206.8	206.32	175.41
17/12/2008 00:06		0.158888	0.164281	-0.00676	41.9	8.15	27.01	205.21	206.28	177
17/12/2008 00:07		0.157734	0.163084	-0.00799	41.52	9.63	26.67	203.63	206.24	178.41
17/12/2008 00:08		0.153473	0.158733	-0.00914	41.5	11.23	26.32	202.05	206.32	183.29
17/12/2008 00:09		0.152364	0.157592	-0.01039	41.1	12.76	25.98	200.47	206.28	184.68
17/12/2008 00:10		0.151512	0.156703	-0.01162	40.69	14.24	25.64	198.88	206.23	185.76
17/12/2008 00:11		0.151068	0.156236	-0.01286	40.24	15.68	25.31	197.31	206.17	186.37
17/12/2008 00:12		0.150359	0.155494	-0.01408	39.83	17.12	24.99	195.72	206.11	187.28
17/12/2008 00:13		0.149619	0.154721	-0.01512	39.49	18.34	24.71	194.4	206.07	188.21
17/12/2008 00:14		0.149963	0.155086	-0.01527	39.41	18.47	24.69	194.34	206.06	187.81
17/12/2008 00:15		0.150195	0.155317	-0.01533	39.36	18.51	24.68	194.27	206.05	187.55
17/12/2008 00:16		0.151009	0.156141	-0.01544	39.25	18.54	24.67	194.21	206.01	186.63
17/12/2008 00:17		0.152014	0.157161	-0.01554	39.13	18.53	24.67	194.16	205.97	185.51
17/12/2008 00:18		0.152722	0.157898	-0.01563	39.05	18.55	24.67	194.09	205.95	184.71
17/12/2008 00:19		0.15364	0.158824	-0.01573	38.93	18.56	24.67	194.03	205.92	183.71
17/12/2008 00:20		0.154381	0.159574	-0.01582	38.84	18.57	24.67	193.96	205.89	182.91
17/12/2008 00:21		0.155109	0.160332	-0.01591	38.76	18.59	24.66	193.9	205.87	182.12
17/12/2008 00:22		0.156161	0.1614	-0.01602	38.64	18.58	24.66	193.85	205.83	181
17/12/2008 00:23		0.157513	0.162768	-0.01616	38.49	18.58	24.67	193.78	205.78	179.59
17/12/2008 00:24		0.158128	0.163401	-0.01622	38.42	18.58	24.67	193.72	205.76	178.96
17/12/2008 00:25		0.158834	0.164109	-0.01631	38.34	18.6	24.66	193.66	205.73	178.24
17/12/2008 00:26		0.158619	0.163901	-0.01634	38.34	18.65	24.65	193.59	205.74	178.46
17/12/2008 00:27		0.159354	0.164661	-0.01647	38.25	18.7	24.64	193.53	205.72	177.71
17/12/2008 00:28		0.159425	0.164716	-0.01648	38.24	18.71	24.64	193.48	205.71	177.65
17/12/2008 00:29		0.160029	0.165337	-0.01659	38.15	18.76	24.63	193.41	205.69	177.04
17/12/2008 00:30		0.163964	0.169392	-0.01334	38.99	15.02	25.45	197.67	205.76	172.66
17/12/2008 00:31		0.165329	0.170794	-0.01321	38.93	14.77	25.5	197.61	205.73	171.3
17/12/2008 00:32		0.166302	0.171786	-0.01327	38.83	14.75	25.5	197.54	205.7	170.37
17/12/2008 00:33		0.166297	0.171757	-0.0133	38.82	14.78	25.5	197.49	205.69	170.39
17/12/2008 00:34		0.166376	0.171848	-0.01337	38.79	14.85	25.48	197.42	205.69	170.32
17/12/2008 00:35		0.166489	0.171952	-0.01342	38.76	14.89	25.47	197.36	205.68	170.23
17/12/2008 00:36		0.165963	0.171427	-0.01344	38.8	14.96	25.46	197.3	205.7	170.73
17/12/2008 00:37		0.165748	0.171195	-0.0135	38.79	15.03	25.44	197.23	205.7	170.95
17/12/2008 00:38		0.165822	0.171282	-0.01357	38.77	15.1	25.43	197.17	205.69	170.89
17/12/2008 00:39		0.16535	0.170787	-0.01357	38.8	15.14	25.42	197.12	205.7	171.35
17/12/2008 00:40		0.165261	0.17072	-0.01365	38.78	15.23	25.4	197.05	205.71	171.43
17/12/2008 00:41		0.165697	0.171152	-0.01371	38.73	15.26	25.39	196.99	205.69	171.03
17/12/2008 00:42		0.16494	0.170374	-0.01373	38.77	15.34	25.37	196.93	205.71	171.77
17/12/2008 00:43		0.165197	0.170635	-0.01381	38.73	15.4	25.36	196.86	205.7	171.53
17/12/2008 00:44		0.164985	0.17043	-0.01385	38.73	15.45	25.35	196.81	205.7	171.73
17/12/2008 00:45		0.164781	0.17021	-0.01389	38.73	15.52	25.33	196.74	205.7	171.95
17/12/2008 00:46		0.165164	0.170612	-0.01399	38.67	15.58	25.32	196.68	205.69	171.58
17/12/2008 00:47		0.165131	0.170578	-0.01402	38.66	15.62	25.31	196.62	205.69	171.62
17/12/2008 00:48		0.165245	0.170682	-0.01408	38.63	15.67	25.3	196.55	205.68	171.53

Appendix E – Voltage Headroom Output File

Time	Voltage at SS	Vmin	Vmin Max	Vmin Min	Node Vmin	Vmax	Vmax Max	Vmax Min	Node Vmax	Lower Vol headroom	Upper Vol Headroom	Voltage Headroom	Vldc Bias	Vgen Bias	Volt at bus 325	Voltage at node 321	VoltTar for TX 1	TapPos TX 1	VoltTar for TX 2	TapPos TX 2
15/12/2008 00:00	1.005885	0.97923	0.97673	0.98173	509	1.030545	1.033545	1.027545	325	0.03923	0.012936	0.052166	0.016163	-0.016027	1.047064	1.018866	1.006648	11	1.005679	11
15/12/2008 00:01	1.005859	0.979203	0.976703	0.981703	509	1.030871	1.033871	1.027871	325	0.039203	0.01262	0.051823	0.016209	-0.016308	1.04738	1.019128	1.006694	11	1.005724	11
15/12/2008 00:02	1.006008	0.979356	0.976856	0.981856	509	1.031091	1.034091	1.028091	325	0.039356	0.012407	0.051763	0.016134	-0.016324	1.047593	1.019337	1.006616	11	1.005652	11
15/12/2008 00:03	1.006019	0.979862	0.977362	0.982362	509	1.031152	1.034152	1.028152	325	0.039862	0.012348	0.052209	0.016133	-0.016432	1.047652	1.019389	1.006615	11	1.005651	11
15/12/2008 00:04	1.005947	0.979788	0.977288	0.982288	509	1.031134	1.034134	1.028134	325	0.039788	0.012366	0.052154	0.016172	-0.016596	1.047634	1.01936	1.006655	11	1.005689	11
15/12/2008 00:05	1.006239	0.980088	0.977588	0.982588	509	1.031471	1.034471	1.028471	325	0.040088	0.012038	0.052127	0.016026	-0.01671	1.047962	1.019692	1.006504	11	1.005548	11
15/12/2008 00:06	1.006307	0.980158	0.977658	0.982658	509	1.031585	1.034585	1.028585	325	0.040158	0.011928	0.052085	0.015993	-0.016861	1.048072	1.019798	1.00647	11	1.005517	11
15/12/2008 00:07	1.006265	0.980115	0.977615	0.982615	509	1.031596	1.034596	1.028596	325	0.040115	0.011917	0.052032	0.016016	-0.016996	1.048083	1.019799	1.006493	11	1.005539	11
15/12/2008 00:08	1.006438	0.980293	0.977793	0.982793	509	1.031814	1.034814	1.028814	325	0.040293	0.011705	0.051998	0.01593	-0.017461	1.048295	1.020011	1.006404	11	1.005456	11
15/12/2008 00:09	1.006406	0.980259	0.977759	0.982759	509	1.031834	1.034834	1.028834	325	0.040259	0.011686	0.051945	0.015943	-0.017593	1.048314	1.020021	1.006418	11	1.005469	11
15/12/2008 00:10	1.006516	0.980373	0.977873	0.982873	509	1.031991	1.034991	1.028991	325	0.040373	0.011534	0.051907	0.015897	-0.017696	1.048466	1.02017	1.006369	11	1.005424	11
15/12/2008 00:11	1.006636	0.980995	0.978495	0.983495	509	1.03216	1.03516	1.02916	325	0.040995	0.01137	0.052365	0.01584	-0.017754	1.04863	1.020331	1.006311	11	1.005369	11
15/12/2008 00:12	1.006593	0.980951	0.978451	0.983451	509	1.032167	1.035167	1.029167	325	0.040951	0.011363	0.052314	0.015868	-0.017841	1.048637	1.020329	1.00634	11	1.005397	11
15/12/2008 00:13	1.006775	0.981138	0.978638	0.983638	509	1.032396	1.035396	1.029396	325	0.041138	0.011141	0.052279	0.015764	-0.01793	1.048859	1.020551	1.006232	11	1.005296	11
15/12/2008 00:14	1.006832	0.981196	0.978696	0.983696	509	1.032502	1.035502	1.029502	325	0.041196	0.011038	0.052234	0.015741	-0.017891	1.048962	1.020649	1.006208	11	1.005274	11
15/12/2008 00:15	1.006735	0.981097	0.978597	0.983597	509	1.032457	1.035457	1.029457	325	0.041097	0.011082	0.052179	0.015795	-0.017867	1.048918	1.020593	1.006263	11	1.005326	11
15/12/2008 00:16	1.006645	0.981004	0.978504	0.983504	509	1.032158	1.035158	1.029158	325	0.041004	0.011371	0.052376	0.015825	-0.017779	1.048628	1.020332	1.006296	11	1.005355	11
15/12/2008 00:17	1.006555	0.980912	0.978412	0.983412	509	1.031837	1.034837	1.028837	325	0.040912	0.011683	0.052595	0.015849	-0.017672	1.048317	1.020051	1.006321	11	1.005377	11
15/12/2008 00:18	1.006536	0.981345	0.978845	0.983845	509	1.031695	1.034695	1.028695	325	0.041345	0.01182	0.053165	0.015844	-0.017596	1.04818	1.019932	1.006317	11	1.005372	11
15/12/2008 00:19	1.006535	0.981345	0.978845	0.983845	509	1.03169	1.03469	1.02869	325	0.041345	0.011825	0.05317	0.015844	-0.017501	1.048175	1.019928	1.006316	11	1.005371	11
15/12/2008 00:20	1.006474	0.981282	0.978782	0.983782	509	1.031634	1.034634	1.028634	325	0.041282	0.011879	0.053161	0.015887	-0.017425	1.048121	1.01987	1.006361	11	1.005413	11
15/12/2008 00:21	1.006535	0.981344	0.978844	0.983844	509	1.031703	1.034703	1.028703	325	0.041344	0.011813	0.053157	0.01585	-0.017349	1.048187	1.019938	1.006322	11	1.005377	11
15/12/2008 00:22	1.006374	0.98118	0.97868	0.98368	509	1.031553	1.034553	1.028553	325	0.04118	0.011958	0.053138	0.015933	-0.017243	1.048041	1.019785	1.006409	11	1.005458	11
15/12/2008 00:23	1.006371	0.981176	0.978676	0.983676	509	1.031557	1.034557	1.028557	325	0.041176	0.011955	0.053131	0.01594	-0.017109	1.048045	1.019787	1.006416	11	1.005465	11
15/12/2008 00:24	1.006266	0.981069	0.978569	0.983569	509	1.031462	1.034462	1.028462	325	0.041069	0.012047	0.053116	0.015994	-0.017048	1.047953	1.019689	1.006471	11	1.005517	11
15/12/2008 00:25	1.005992	0.981251	0.978751	0.983751	509	1.031202	1.034202	1.028202	325	0.041251	0.0123	0.05355	0.016145	-0.01698	1.0477	1.019424	1.006627	11	1.005663	11
15/12/2008 00:26	1.006044	0.981304	0.978804	0.983804	509	1.03126	1.03426	1.02826	325	0.041304	0.012243	0.053547	0.016121	-0.017	1.047757	1.019482	1.006603	11	1.00564	11
15/12/2008 00:27	1.006096	0.981357	0.978857	0.983857	509	1.031317	1.034317	1.028317	325	0.041357	0.012188	0.053546	0.016098	-0.016929	1.047812	1.019538	1.006579	11	1.005618	11
15/12/2008 00:28	1.006207	0.981472	0.978972	0.983972	509	1.031433	1.034433	1.028433	325	0.041472	0.012076	0.053547	0.016038	-0.016923	1.047924	1.019654	1.006516	11	1.005559	11
15/12/2008 00:29	1.006367	0.982094	0.979594	0.984594	509	1.031596	1.034596	1.028596	325	0.042094	0.011917	0.054011	0.015955	-0.016866	1.048083	1.019818	1.006431	11	1.00548	11
15/12/2008 00:30	1.006436	0.982164	0.979664	0.984664	509	1.031668	1.034668	1.028668	325	0.042164	0.011847	0.054011	0.015905	-0.016448	1.048153	1.01989	1.006379	11	1.005431	11
15/12/2008 00:31	1.006593	0.982326	0.979826	0.984826	509	1.031829	1.034829	1.028829	325	0.042326	0.011691	0.054017	0.015828	-0.016319	1.048309	1.020052	1.0063	11	1.005356	11
15/12/2008 00:32	1.006731	0.983123	0.980623	0.985623	509	1.031972	1.034972	1.028972	325	0.043123	0.011552	0.054675	0.015744	-0.01623	1.048448	1.020195	1.006213	11	1.005275	11
15/12/2008 00:33	1.006567	0.982955	0.980455	0.985455	509	1.031817	1.034817	1.028817	325	0.042955	0.011702	0.054657	0.015834	-0.016232	1.048298	1.020038	1.006306	11	1.005363	11
15/12/2008 00:34	1.00663	0.983019	0.980519	0.985519	509	1.031886	1.034886	1.028886	325	0.043019	0.011636	0.054655	0.0158	-0.016225	1.048364	1.020106	1.006271	11	1.00533	11
15/12/2008 00:35	1.006618	0.983007	0.980507	0.985507	509	1.031879	1.034879	1.028879	325	0.043007	0.011642	0.054649	0.015821	-0.016216	1.048358	1.020097	1.006292	11	1.00535	11
15/12/2008 00:36	1.006623	0.983013	0.980513	0.985513	509	1.031892	1.034892	1.028892	325	0.043013	0.01163	0.054642	0.015814	-0.016264	1.04837	1.020109	1.006285	11	1.005343	11
15/12/2008 00:37	1.006629	0.983019	0.980519	0.985519	509	1.031905	1.034905	1.028905	325	0.043019	0.011617	0.054635	0.015807	-0.016286	1.048383	1.020122	1.006278	11	1.005336	11
15/12/2008 00:38	1.006725	0.983117	0.980617	0.985617	509	1.032006	1.035006	1.029006	325	0.043117	0.011518	0.054635	0.015768	-0.016279	1.048482	1.020222	1.006238	11	1.005299	11
15/12/2008 00:39	1.006786	0.983179	0.980679	0.985679	509	1.032072	1.035072	1.029072	325	0.043179	0.011454	0.054633	0.015731	-0.016323	1.048546	1.020288	1.006199	11	1.005263	11
15/12/2008 00:40	1.006796	0.983189	0.980689	0.985689	509	1.032088	1.035088	1.029088	325	0.043189	0.011439	0.054628	0.015717	-0.016331	1.048561	1.020303	1.006184	11	1.005249	11
15/12/2008 00:41	1.006736	0.982636	0.980136	0.985136	509	1.032036	1.035036	1.029036	325	0.042636	0.01149	0.054126	0.015755	-0.016293	1.04851	1.020249	1.006224	11	1.005286	11
15/12/2008 00:42	1.006729	0.982628	0.980128	0.985128	509	1.032036	1.035036	1.029036	325	0.042628	0.01149	0.054118	0.015769	-0.016363	1.04851	1.020247	1.006238	11	1.005299	11
15/12/2008 00:43	1.006692	0.982591	0.980091	0.985091	509	1.032008	1.035008	1.029008	325	0.042591	0.011517	0.054108	0.015771	-0.01634	1.048483	1.020218	1.00624	11	1.005302	11
15/12/2008 00:44	1.006745	0.982645	0.980145	0.985145	509	1.032067	1.035067	1.029067	325	0.042645	0.01146	0.054105	0.015747	-0.01636	1.04854	1.020276	1.006215	11	1.005278	11
15/12/2008 00:45	1.006694	0.982103	0.979603	0.984603	509	1.032024	1.035024	1.029024	325	0.042103	0.011502	0.053605	0.015771	-0.01638	1.048498	1.020231	1.00624	11	1.005301	11
15/12/2008 00:46	1.006733	0.982142	0.979642	0.984642	509	1.032069	1.035069	1.029069	325	0.042142	0.011458	0.0536	0.015768	-0.016345	1.048542	1.020275	1.006238	11	1.005299	11
15/12/2008 00:47	1.006739	0.982148	0.979648	0.984648	509	1.032081	1.035081	1.029081	325	0.042148	0.011446	0.053594	0.015761	-0.016349	1.048554	1.020286	1.00623	11	1.005293	11
15/12/2008 00:48	1.006802	0.982213	0.979713	0.984713	509	1.032151	1.035151	1.029151	325	0.042213	0.011378	0.053592	0.015718	-0.01634	1.048621	1.020355	1.006186	11	1.005251	11
15/12/2008 00:49	1.006863	0.982276	0.979776	0.984776	509	1.032217	1.035217	1.029217	325	0.042276	0.011314	0.05359	0.01568	-0.016324	1.048686	1.020422	1.006146	11	1.005214	11
15/12/2008 00:50	1.006911	0.982324	0.979824	0.984824	509	1.032269	1.035269	1.029269	325	0.042324	0.011264	0.053588	0.015664	-0.016413	1.048736	1.020473	1.006129	11	1.005198	11
15/12/2008 00:51	1.006967	0.982382	0.979882	0.984882	509	1.03233	1.03533	1.02933	325	0.042382	0.011204	0.053586	0.015634	-0.016413	1.048796	1.020534	1.006098	11	1.005169	11
15/12/2008 00:52	1.007132	0.982552	0.980052	0.985052	509	1.032498	1.035498	1.029498	325	0.042552	0.011041	0.053592	0.015543	-0.016375	1.048959	1.020703	1.006005	11	1.005081	11
15/12/2008 00:53	1.007252	0.982674	0.980174	0.985174	509	1.032622	1.035622	1.029622	325	0.042674	0.010921	0.053595	0.015469	-0.016309	1.049079	1.020827	1.005928	11	1.00501	11
15/12/2008 00:54	1.007405	0.983279	0.980779	0.985779	509	1.03278	1.03578	1.02978	325	0.043279	0.010767	0.054047	0.015394	-0.016237	1.049232	1.020985	1.005851	11	1.004937	11
15/12/2008 00:55	1.007508	0.983385	0.980885	0.985885	509	1.032886	1.035886	1.029886	325	0.043385	0.010664	0.054049	0.015342	-0.016196	1.049336	1.021092	1.005797	11	1.004887	11
15/12/2008 00:56	1.007513	0.98339	0.98089	0.98589	509	1.032896	1.035896	1.029896	325	0.04339	0.010655	0.054045	0.015335	-0.01613	1.049345	1.021101	1.00579	11	1.00488	11
15/12/2008 00:57	1.00756	0.983439	0.980939	0.985939	509	1.032949	1.035949	1.029949	325	0.043439	0.010603	0.054041	0.015319	-0.016078	1.049397	1.021154	1.005773	11	1.004864	11
15/12/2008 00:58	1.007624	0.983504	0.981004	0.986004	509	1.033019	1.036019	1.030019	325	0.043504	0.010535	0.054039	0.015275	-0.016046	1.049465	1.021223	1.005728	11	1.004822	11
15/12/2008 00:59	1.007671	0.983552	0.981052	0.986052	509	1.03307	1.03607	1.03007	325	0.043552	0.010485	0.054037	0.015259	-0.016038	1.049515	1.021274	1.005711	11	1.004806	11
15/12/2008 01:00	1.00768	0.983562	0.981062	0.986062	509	1.033086	1.036086	1.030086	325	0.043562	0.010469	0.054031	0.015245	-0.015991	1.049531	1.021289	1.005696	11	1.004793	11
15/12/2008 01:01	1.007746	0.984122	0.981622	0.986622	509	1.033159	1.036159	1.030159	325	0.044122	0.010399	0.05452	0.0152	-0.015985	1.049601	1.021361	1.00565	11	1.00475	11
15/12/2008 01:02	1.007793	0.98417	0.98167	0.98667	509	1.033211	1.036211	1.030211	325	0.04417	0.010349	0.054518	0.015184	-0.015957	1.049651	1.021412	1.005633	11	1.004734	11
15/12/2008 01:03	1.007802	0.984179	0.981679	0.986679	509	1.033227	1.036227	1.030227	325	0.044179	0.010333	0.054513	0.01517	-0.015954	1.049667	1.021427	1.005619	11	1.00472	11
15/12/2008 01:04	1.007901	0.98428	0.98178	0.98678	509	1.033329	1.036329	1.030329	325	0.04428	0.010234	0.054514	0.015125	-0.01596	1.049766	1.02153	1.005573	11	1.004677	11
15/12/2008 01:05	1.007906	0.984285	0.981785	0.986785	509	1.033341	1.036341	1.030341	325	0.044285	0.010222	0.054508	0.015118	-0.015958	1.049778	1.021541	1.005565	11	1.00467	11

Appendix F – Feeder Voltage profile

Time:	######													
FDR No: 1	Bus No	V [pu]	V [kV]	Distance [Z=R+jX]	FDR No: 2	Bus No	V [pu]	V [kV]	Distance [	FDR No: 3	Bus No	V [pu]	V [kV]	Distance [
	3	0.991624	10.90786	0.01095		84	0.99138	10.90518	0.01936		190	0.989877	10.88865	0.11226
	4	0.991239	10.90363	0.03748		85	0.991145	10.90259	0.03147		191	0.989612	10.88574	0.12815
	5	0.990073	10.89081	0.12086		86	0.990319	10.89351	0.07495		192	0.988455	10.87301	0.19762
	6	0.990073	10.8908	0.12162		87	0.990293	10.89323	0.12093		193	0.987282	10.86011	0.26805
	7	0.989317	10.88249	0.17934		88	0.988849	10.87734	0.15481		194	0.987203	10.85923	0.27298
	8	0.989303	10.88234	0.20732		89	0.988421	10.87263	0.17916		195	0.986906	10.85596	0.29144
	9	0.987552	10.86307	0.32129		90	0.988172	10.86989	0.1939		196	0.986545	10.85199	0.31384
	10	0.986939	10.85633	0.37443		91	0.987813	10.86595	0.25591		197	0.986129	10.84742	0.34011
	11	0.985973	10.8457	0.46098		92	0.987375	10.86113	0.33756		198	0.985522	10.84075	0.381
	12	0.985403	10.83944	0.51523		93	0.987127	10.8584	0.38625		199	0.985384	10.83922	0.39791
	13	0.985326	10.83858	0.64049		94	0.987093	10.85802	0.4331		200	0.985356	10.83891	0.45277
	14	0.984997	10.83497	0.56587		95	0.987032	10.85736	0.41206		201	0.984273	10.82701	0.54653
	15	0.984048	10.82453	0.69694		96	0.986648	10.85313	0.54419		202	0.983802	10.82183	0.61215
	16	0.983986	10.82385	0.7863		97	0.986625	10.85287	0.58862		203	0.983391	10.8173	0.67333
	17	0.984044	10.82449	0.69744		98	0.986386	10.85025	0.65443		204	0.982725	10.80998	0.77906
	18	0.983199	10.81519	0.86254		99	0.98633	10.84964	0.73424		205	0.982707	10.80977	0.83389
	19	0.983191	10.81511	0.88333		100	0.986284	10.84913	0.71323		206	0.982525	10.80777	0.81215
	20	0.983144	10.81458	0.87417		101	0.987979	10.86777	0.21232		207	0.982133	10.80346	0.88134
	21	0.981661	10.79828	1.18677		102	0.987945	10.8674	0.21584		208	0.982113	10.80325	0.88479
	22	0.981661	10.79827	1.18845		103	0.987917	10.86708	0.27894		209	0.982044	10.80249	0.99581
	23	0.981595	10.79755	1.20077		104	0.98751	10.86261	0.26444		210	0.982031	10.80235	1.07487
	24	0.981468	10.79615	1.22359		105	0.987506	10.86256	0.26488		211	0.982027	10.8023	1.0324
	25	0.981303	10.79434	1.25359		106	0.986452	10.85097	0.38946		212	0.982023	10.80225	0.90277
	26	0.980643	10.78708	1.37385		107	0.986121	10.84733	0.43779		213	0.98167	10.79837	0.97863
	27	0.980347	10.78382	1.42776		108	0.986109	10.8472	0.63204		214	0.981664	10.7983	1.06494
	28	0.979973	10.7797	1.4966		109	0.985419	10.83961	0.54503		215	0.98144	10.79584	1.02895
	29	0.979969	10.77966	1.54626		110	0.985273	10.838	0.56525		216	0.980948	10.79043	1.13217
	30	0.979964	10.77961	1.6069		111	0.984324	10.82756	0.69721		217	0.980132	10.78145	1.29374
	31	0.979488	10.77437	1.5888		112	0.983543	10.81898	0.81751		218	0.980111	10.78122	1.55923
	32	0.979481	10.77429	1.67578		113	0.983405	10.81746	0.83696		219	0.980083	10.78091	1.44865
	33	0.979005	10.76905	1.68237		114	0.982488	10.80737	1.02333		220	0.980071	10.78078	1.52805
	34	0.97887	10.76757	1.73918		115	0.981776	10.79953	1.1689		221	0.980063	10.7807	1.62586
	35	0.978786	10.76665	1.80294		116	0.981623	10.79786	1.20003		222	0.980058	10.78064	1.68989
	36	0.978835	10.76719	1.78846		117	0.981418	10.79559	1.24538		223	0.978555	10.76411	1.6339
	37	0.978786	10.76665	1.87313		118	0.981365	10.79502	1.27585		224	0.978374	10.76212	1.76384
	38	0.978939	10.76833	1.70913		119	0.981414	10.79555	1.24675		225	0.978333	10.76167	1.795
	39	0.978774	10.76651	1.77674		120	0.981353	10.79488	1.29373		226	0.978363	10.76199	1.93518
	40	0.978635	10.76499	1.83439		121	0.981331	10.79464	1.32191		227	0.978156	10.75972	1.76013
	41	0.97863	10.76493	1.95589		122	0.981337	10.79471	1.32409		228	0.977971	10.75769	1.81861
	42	0.978185	10.76004	2.02437		123	0.981153	10.79268	1.67576		229	0.977962	10.75758	1.91229
	43	0.978184	10.76002	2.10537		124	0.981111	10.79222	1.76956		230	0.977955	10.75751	1.98467
	44	0.977906	10.75696	2.14671		125	0.981097	10.79207	1.93214		231	0.97795	10.75745	2.09111