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Active Voltage Control in Distribution Networks Including Distributed Energy Resources

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ABSTRACT

The structure and control methods of existing distribution networks are planned assuming unidirectional power flows. The amount of generation connected to distribution networks is, however, constantly increasing which changes the operational and planning principles of distribution networks radically. Distributed generation (DG) affects power flows and fault currents in the distribution network and its effect on network operation can be positive or negative depending on the size, type, location and time variation of the generator.

In weak distribution networks, voltage rise is usually the factor that limits the network's hosting capacity for DG. At present, voltage rise is usually mitigated either by increasing the conductor size or by connecting the generator to a dedicated feeder. These passive approaches maintain the current network operational principles but can lead to high DG connection costs. The voltage rise can be mitigated also using active voltage control methods that change the operational principles of the network radically but can, in many cases, lead to significantly smaller total costs of the distribution network than the passive approach. The active voltage control methods can utilize active resources such as DG in their control and also the control principles of existing voltage control equipment such as the main transformer tap changer can be altered.

Although active voltage control can often decrease the distribution network total costs and its effect on voltage quality can also be positive, the number of real distribution network implementations is still very low and the distribution network operators (DNOs) do not consider active voltage control as a real option in distribution network planning. Some work is, hence, still needed to enable widespread utilization of active voltage control. This thesis aims at overcoming some of the barriers that are, at present, preventing active voltage control from becoming business as usual for the DNOs.

In this thesis, active voltage control methods that can be easily implemented to real distribution networks are developed. The developed methods are, at first, tested using time domain simulations. Operation of one coordinated voltage control (CVC) method is tested also using real time simulations and finally a real distribution network demonstration is conducted. The conducted simulations and demonstrations verify that the developed voltage control methods can be implemented relatively easily and that they are able to keep all network voltages between acceptable limits as long as an adequate amount of controllable resources is available. The developed methods control the substation voltage based on voltages in the whole distribution network and also reactive and real powers of distributed energy resources (DERs) are utilized in some of the developed CVC methods. All types of DERs capable of reactive or real power control can be utilized in the control.

The distribution network planning tools and procedures used currently are not capable of taking active voltage control into account. DG interconnection planning is based only on two extreme loading conditions (maximum generation/minimum load and minimum generation/maximum load) and network effects and costs of alternative voltage control

methods cannot be compared. In this thesis, the distribution network planning procedure is developed to enable comparison of different voltage control strategies. The statistical distribution network planning method is introduced and its usage is demonstrated in example cases. In statistical distribution network planning, load flow is calculated for every hour of the year using statistical-based hourly load and production curves. When the outputs of hourly load flows (e.g. annual losses, transmission charges and curtailed generation) are combined with investment costs the total costs of alternative voltage control strategies can be compared and the most cost-effective approach can be selected. The example calculations show that the most suitable voltage control strategy varies depending on the network and DG characteristics.

The studies of this thesis aim at making the introduction of active voltage control as easy as possible to the DNOs. The developed CVC methods are such that they can be implemented as a part of the existing distribution management systems and they can utilize the already existing data transfer infrastructure of SCADA. The developed planning procedure can be implemented as a part of the existing network information systems. Hence, the currently used network planning and operational tools do not need to be replaced but only enhanced.

PREFACE

The work presented in this thesis has been carried out during the years 2006-2013 in the Department of Electrical Engineering of Tampere University of Technology. The supervisors of the thesis have been Professors Sami Repo and Pertti Järventausta to whom I would like to express my gratitude. Without their guidance and support this work could not have been done.

I would like to thank the personnel of the Department of Electrical Engineering for an inspiring working environment and good conversations on various topics. I especially want to thank Dr. Tech. Kari Mäki, M. Sc. Antti Mutanen, M. Sc. Antti Koto, M. Sc. Ontrei Raipala, M. Sc. Anssi Mäkinen and M. Sc. Juho Tuominen for all comments, discussions, encouragements and contributions to my work.

The research work has been carried out mainly in three projects: Active Distribution Network (ADINE), Influence of Distributed Generation and Other Active Resources on Distribution Network Management, and Smart Grids and Energy Markets (SGEM). I would like to thank all project partners for good collaboration. Special thanks go to Aimo Rinta-Opas, Juha Koivula and Jari Hakala of Koillis-Satakunnan Sähkö for making the real distribution network demonstration possible.

The financial support provided by Graduate School of Electrical Energy Engineering, Fortum Foundation, Emil Aaltonen Foundation, Finnish Foundation for Technology Promotion, Aimo Puromäki Fund of Finnish Foundation for Economic and Technology Sciences – KAUTE, Wärtsilä Fund of the Industrial Research Fund of Tampere University of Technology, Ulla Tuominen Foundation and Walter Ahlström Foundation is gratefully acknowledged.

I want to thank my parents Tiina and Jarmo and brothers Pekka and Olli for being there for me during my studies and throughout my whole life. I also want to thank my parents-in-law Sinikka and Kullervo for their encouragement and practical help with the children.

Above all, I want to thank my husband Ari for his love and support during this long process. You have pulled your weight in taking care of our family and made it possible for me to carry out the thesis work.

I dedicate this thesis to my children Jenna, 7 years, Tommi, 4 years, and Eetu, 1 year. You bring the greatest happiness to my life.

Tampere, March 2014

Anna Kulmala

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LIST OF PUBLICATIONS

This thesis is based on the following original publications which are referred to in the text as [P1]-[P8].

[P1] A. Kulmala, K. Mäki, S. Repo and P. Järventausta, "Active voltage level management of distribution networks with distributed generation using on load tap changing transformers, " in *Proc. Power Tech 2007*, Lausanne, Switzerland, July 2007.

[P2] A. Kulmala, S. Repo and P. Järventausta, "Increasing penetration of distributed generation in existing distribution networks using coordinated voltage control," *Int. Journal of Distributed Energy Resources*, vol. 5, pp. 227-255, July 2009.

[P3] A. Kulmala, A. Mutanen, A. Koto, S. Repo and P. Järventausta, "RTDS verification of a coordinated voltage control implementation for distribution networks with distributed generation, " in *Proc. Innovative Smart Grid Technologies Europe,* Gothenburg, Sweden, Oct. 2010.

[P4] A. Kulmala, A. Mutanen, A. Koto, S. Repo and P. Järventausta, "Demonstrating coordinated voltage control in a real distribution network, " in *Proc. Innovative Smart Grid Technologies Europe*, Berlin, Germany, Oct. 2012.

[P5] A. Kulmala, S. Repo and P. Järventausta, "Coordinated voltage control in distribution networks including several distributed energy resources, " accepted for *IEEE Trans. Smart Grid*.

[P6] A. Kulmala, K. Mäki, S. Repo and P. Järventausta, "Network interconnection studies of distributed generation, " in *Proc. IFAC Symposium on Power Plants and Power Systems Control*, Tampere, Finland, July 2009.

[P7] A. Kulmala, K. Mäki, S. Repo and P. Järventausta, "Including active voltage level management in planning of distribution networks with distributed generation, " in *Proc. Power Tech 2009*, Bucharest, Romania, July 2009.

[P8] A. Kulmala, S. Repo and P. Järventausta, "Using statistical distribution network planning for voltage control method selection," in *Proc. IET Conf. on Renewable Power Generation*, Edinburgh, UK, Sept. 2011.

LIST OF ABBREVIATIONS

AC	Alternating current
AMR	Automatic meter reading
ANM	Active network management
AVC relay	Automatic voltage control relay
AVR	Automatic voltage regulator
CHP	Combined heat and power
CIS	Customer information system
CVC	Coordinated voltage control
DB	Dead band
DC	Direct current
DG	Distributed generation
DER	Distributed energy resource
DMS	Distribution management system
DNO	Distribution network operator
HV	High voltage
IT	Information technology
LP	Linear programming
LV	Low voltage
MINLP	Mixed-integer nonlinear programming
MPPT	Maximum power point tracking
MV	Medium voltage
NIS	Network information system
NLP	Nonlinear programming
OLTC	On load tap changer
PFC	Power factor correction
pu	Per unit
PV	Photovoltaic
rms	Root mean square
RTDS	Real Time Digital Simulator
SCADA	Supervisory Control and Data Acquisition
STATCOM	Static synchronous compensator
SVC	Static VAr compensator
TSO	Transmission system operator

LIST OF SYMBOLS

C_{cur}	Lost income due to generation curtailment
C_{losses}	Cost of losses
I	Current
j	Imaginary unit
k_{p}	Coefficient related to excess probability p
m	Main transformer tap changer position
m_{max}	Maximum position of the main transformer tap changer
m_{min}	Minimum position of the main transformer tap changer
$marg$	Safety margin used in substation voltage control
n	Number of network nodes
P	Real power
P_{activei}	Real power of the ith active resource
$P_{\mathrm{activeimax}}$	Maximum real power of the ith active resource
$P_{\mathrm{activeimin}}$	Minimum real power of the ith active resource
P_{cur}	Curtailed generation
$P_{\mathrm{gen,i}}$	Generated real power at the ith node
P_{i}	Injected real power at the ith node
$P_{\mathrm{load,i}}$	Consumed real power at the ith node
P_{losses}	Real power losses
P_{m}	Mean real power
P_{p}	Real power having excess probability of p %
Q	Reactive power
Q_{activei}	Reactive power of the ith active resource
$Q_{\mathrm{activeimax}}$	Maximum reactive power of the ith active resource
$Q_{\mathrm{activeimin}}$	Minimum reactive power of the ith active resource
$Q_{\mathrm{gen,i}}$	Generated reactive power at the ith node
Q_{i}	Injected reactive power at the ith node
$Q_{\mathrm{load,i}}$	Consumed reactive power at the ith node
R	Resistance
S	Voltage sensitivity
S_{ij}	Apparent power flow in branch between nodes i and j
S_{ijmax}	Maximum allowed apparent power flow in branch between nodes i and j
tap	Main transformer tap step
$\mathbf{u_c}$	Vector of continuous control variables
$\mathbf{u_d}$	Vector of discrete control variables
V	Voltage
$\mathbf{V}$	Node voltage vector $[V_1 e^{j\delta 1},\ldots,V_n e^{j\delta n}]$
V_{lower}	Feeder voltage lower limit
V_{max}	Maximum network voltage
V_{min}	Minimum network voltage

V_{n}	Nominal voltage
V_{ref}	Reference voltage of substation AVC relay
V_{reflower}	Lower limit of the reference voltage of substation AVC relay
V_{refupper}	Upper limit of the reference voltage of substation AVC relay
V_{ss}	Substation voltage
V_{upper}	Feeder voltage upper limit
X	Reactance
$\mathbf{x}$	Vector of dependent variables
$\mathbf{Y_{bus}}$	Bus admittance matrix
Z	Impedance
δ	Voltage angle
σ	Standard deviation

1 INTRODUCTION

In the traditional power system, electricity is produced in large centralized power plants. The electricity is then transferred to the loads using the transmission and distribution networks. The distribution networks are planned and controlled using the assumption that power flow is unidirectional and that all components connected to distribution networks are passive i.e. their operation does not depend on the network state.

The European Union has set ambitious targets of 20 % share of energy from renewable sources by 2020 [1] to reduce greenhouse emissions and dependency on imported energy. To meet the overall renewable energy target the share of renewable energy sources in electricity production needs to be substantially increased. Renewable electricity is often produced in relatively small power plants whose location is determined by external factors such as wind and solar resources and that are, therefore, often connected to distribution networks. Moreover, deregulation of energy markets has made distribution network access available to all energy producers and the prices of small generating plants have reduced [2]. Many countries have also set feed-in tariffs for renewable electricity production. Hence, the amount of distributed generation (DG) is constantly increasing. Also other distributed energy resources (DER) such as controllable loads, electric vehicles and energy storages are likely to become more common in distribution networks in the future decades. Some controllable heating loads already exist but they are, at present, controlled based on the time of day and not on the state of the distribution network. When DERs are connected to the currently passive distribution networks, the assumption of unidirectional power flows is no longer valid and the operational and planning principles of the networks need to be revised.

1.1 Motivation and objectives

Distributed generation affects the power flows and fault currents in distribution networks and can, therefore, cause problems related to voltage quality, protection and increasing fault levels. In weak distribution networks, the capacity of connected DG is usually limited by the voltage rise effect. At present, the voltage rise is usually mitigated by reinforcing the network and the operational principles of the network are not altered. This can, however, lead to relatively high connection costs of DG.

The maximum voltage in the network can be lowered also by using active voltage control methods. When active voltage control is taken into use, the distribution network is no longer a passive system that is controlled only at the primary substation but also includes active components such as DGs whose operation varies depending on the network state. Using active voltage control can in many cases lower the total costs of a distribution network significantly compared to the passive approach [3], [4]. Active voltage control can also be used to enhance the power quality.

1.1.1 Barriers for active voltage control

Active voltage control has been studied extensively in the past decade and active voltage control methods of different complexity and data transfer needs have been proposed in publications. Although active voltage control methods for different kinds of situations already exist the number of real implementations is, however, still very low. This is due to at least the following reasons:

- Taking active voltage control into use changes the operational and planning principles of distribution networks substantially and, therefore, implementing active voltage control for the first time is quite laborious to the distribution network operator (DNO). Also, in the current passive distribution networks the DNO owns all network resources that are used in network management. In an active network, customer owned resources are also used in network management and the DNO has to trust the capability of the customer owned DERs to provide ancillary services like reactive power support to the distribution system in the correct place, time and manner. This is a new paradigm in DNOs' businesses which has been, however, successfully applied in transmission networks for decades.
- Active voltage control is still somewhat at its development phase. The majority of publications on active voltage control concentrate on determining the control principles of the control algorithm and do not address the time domain implementation of the algorithm and practical issues in taking the algorithm in real distribution network use. This is not, however, adequate to make active voltage control attractive for DNOs. Real distribution network demonstrations and commercial products are required before a large-scale deployment of active voltage control in distribution networks is possible.
- The network planning tools used currently are not capable of taking active voltage control into account. At present, DG is considered merely as negative load in distribution network planning and the networks are dimensioned based on two worst case conditions (maximum generation/minimum load and minimum generation/maximum load). This kind of planning determines only whether the network state is acceptable in all loading conditions and cannot be used to compare different control strategies. Hence, the planning procedures need to be developed to enable comparison of the total costs of alternative voltage control strategies. In some cases network reinforcement might still be the most cost-effective strategy whereas in some cases active voltage control can provide means to avoid or postpone large investments.
- The current regulative environment, at least in Finland, does not encourage DNOs to take active voltage control into use. The DNO is obligated to connect DG into its network but there is no incentive that promotes implementing the connection in the most cost-effective way. On the contrary, the current regulation incentivizes investments on physical devices and not on intelligence because the regulation allows capital expenditures but increasing operational expenditures is nearly impossible. Active voltage control usually decreases the investment costs but increases the

operational costs (e.g. costs of losses and communication). Moreover, in Finland the regulation emphasizes reliability and large penalties for long supply interruptions are set. This also affects the way in which the distribution networks are developed.

- Some active voltage control methods require information on the state of the whole distribution network which is not, at present, usually available. Traditionally, measurement data has been available only from the primary substation but installation of automatic meter reading (AMR) devices, secondary substation monitoring and feeder automation increases the number of available measurement data substantially. This enables accurate enough state estimation also at the distribution networks.

To enable widespread utilization of active voltage control all of these barriers have to be overcome.

1.1.2 Objectives of the thesis

This thesis aims at enabling DG interconnection in the most cost-effective way from the distribution network point of view. To achieve this, active voltage control methods and distribution network planning procedures are developed. The main objectives of this thesis can be summarized as follows:

- To develop active voltage control methods that can be implemented in real distribution networks without extensive work from the DNO.
- To demonstrate the operation of the developed voltage control methods using the Real Time Digital Simulator (RTDS) and also in a real distribution network.
- To develop the distribution network planning procedure to take active voltage control into account.
- To compare the functionality, complexity, costs and practical implementation issues of different voltage control strategies.

Hence, the thesis discusses issues related to the first three barriers introduced in 1.1.1. To enable large-scale deployment of active voltage control, the latter two barriers also need to be overcome. Development of the network business regulation model is needed and acquisition of adequate input data for active voltage control needs to be arranged.

In this thesis, the operation of the developed active voltage control methods is studied using time domain simulations in PSCAD simulation environment. Real time simulations are carried out in the RTDS simulation environment and also a real distribution network demonstration is conducted. The developed voltage control algorithms are implemented either as custom PSCAD models or as separate Matlab programs that interact with the simulations or the real distribution network. Matlab is utilized also to demonstrate the operation of the developed distribution network planning procedure. The results of these studies can be used to determine how and when active voltage control methods can be taken into real distribution network use and what kinds of actions are needed to overcome the barriers introduced in 1.1.1.

1.2 Publications

The thesis includes eight publications. Publications [P1]-[P5] discuss mainly issues related to the development of coordinated voltage control (CVC) methods. Publications [P6]-[P8] discuss network planning issues. The author of this thesis is the corresponding author of all eight publications. The author has conducted all the work reported in the publications if not otherwise stated in the list below.

- Publication [P1] proposes a CVC algorithm that aims to keep network voltages at an acceptable level by controlling the primary substation (from now on: substation) voltage. The operation of the algorithm is tested using time domain simulations.
- In publication [P2] the CVC algorithm determined in publication [P1] is further developed. The proposed algorithm controls substation voltage and reactive power of one DG to keep network voltages at an acceptable level. The algorithm is thoroughly introduced and time domain simulations are used to study its operation.
- Publication [P3] further develops the CVC algorithm presented in [P2] and verifies the operation of this algorithm in RTDS simulation environment. In this publication, the author of this thesis has been responsible for developing the CVC method, for implementing the method in Matlab simulation environment, for planning the RTDS testing and for writing the publication. M. Sc. Antti Mutanen was responsible for implementing the state estimator and M. Sc. Antti Koto implemented the data transfer between Matlab, SCADA and RSCAD.
- Publication [P4] discusses real distribution network demonstration of the CVC algorithm developed in [P1]-[P3]. The demonstration arrangement is introduced and possible problems that may arise when academic smart grid methods are implemented in real distribution networks are identified. The author of this thesis has been responsible for developing the CVC method, for implementing the method in Matlab simulation environment, for planning the demonstration arrangement and test sequences and for writing the publication. M. Sc. Antti Mutanen was responsible for implementing the state estimator and M. Sc. Antti Koto implemented the data transfer between Matlab and the control room computer.
- Publication [P5] proposes two CVC algorithms designed for distribution networks including several DERs. The first algorithm uses control rules to determine its control actions and is developed based on the algorithms proposed in [P1]-[P3]. The second algorithm uses optimization to determine its control actions. Both algorithms use substation voltage and reactive and real powers of DERs as control variables. The operation of the proposed algorithms is studied using time domain simulations and also the network effects and costs of the algorithms are compared. Moreover, practical implementation issues are covered.
- Publication [P6] discusses the overall planning procedure that is needed when a new distributed generator is connected to an existing distribution network. This publication was written in collaboration with Dr. Tech. Kari Mäki and the contribution of the author of this thesis is approximately 50% of the publication. Dr. Tech. Kari Mäki

wrote the parts that discuss issues related to protection and the author of this thesis the parts that discuss issues related to voltage control.

- Publication [P7] discusses in more detail the issues that need to be taken into account when active voltage control is included in the planning of distribution networks. Development needs for the network information system (NIS) are identified and a DG interconnection planning procedure regarding voltage issues is proposed.
- Publication [P8] demonstrates the use of the planning procedure proposed in [P7] in an example network. The planning procedure is implemented as a Matlab program and the costs and network effects of alternative voltage control strategies are compared. The Matlab program utilizes some parts coded by Dr. Tech. Hannu Laaksonen (e.g. formation of production curves) but is mainly implemented by the author of this thesis. Otherwise the work reported in the publication is conducted by the author of this thesis.

Prof. Sami Repo and Prof. Pertti Järventausta have been the supervisors of the dissertation work and have contributed to the publications through guidance during the research work and by commenting on the publications prior to publishing. Dr. Tech. Kari Mäki also commented on publications [P1] and [P7] prior to publishing.

Table 1.1 represents the relationship between the barriers for active voltage control (see 1.1.1) and the above listed publications.

1.3 Outlining of the thesis

The studies conducted in this thesis are performed in typical Nordic distribution networks. These networks are usually meshed medium voltage (MV) networks that are, however, radially operated. Symmetrical loading can be assumed because all customers have three-phase connections and significant unbalances do not usually occur in MV networks. Feeders can be quite long and overhead lines are commonly used especially in rural networks. Voltage is typically controlled only at the substation and feeder capacitors and step voltage regulators are only rarely used. The level of network automation is relatively high and, therefore, the network switching state can change quite often. Hence, the developed voltage control methods should manage also unusual switching states.

The developed algorithms and planning procedures operate on MV networks. It is assumed that the low voltage (LV) networks are dimensioned such that their voltages remain acceptable when the MV network voltages are between determined limits. The LV network can also include a central controller of its own that is responsible for voltage control at the LV side of the distribution transformer. In this case, also the resources connected to the LV networks can participate in the voltage control. The LV side voltage control is not developed in this thesis.

In this thesis, the only requirement for DERs is that their real or reactive power needs to be controllable. Hence, the developed algorithms are able to utilize all kinds of controllable resources such as DGs, controllable loads, energy storages, feeder capacitors and microgrids in their control.

In Finland, the distribution networks are managed using an advanced distribution management system (DMS). The DMS combines static network data obtained from the network information system and real time measurement data and control possibilities of SCADA (Supervisory Control and Data Acquisition). Calculation functions such as fault location and state estimation are also available in the DMS. [7] The active voltage control methods developed in this thesis are such that implementing them as part of the advanced DMS would be easy. They are, however, also applicable to distribution networks that do not use a DMS. In these cases the implementation of the methods would naturally be more laborious because the whole IT (information technology) architecture and data transfer infrastructure would need to be developed.

Table 1.1. Position of the publications in the research context. The bolded issues are covered in this thesis.

Barriers for active voltage control	Solutions
Active voltage control changes the operational and planning principles of distribution networks ⇒ Taking active voltage control into use for the first time requires lots of work from the DNO	• **Making introduction of active voltage control as easy as possible to the DNO** ○ **Developing active voltage control methods that can be easily understood and implemented [P1]-[P3], [P5]** ○ **Implementing active voltage control as a part of the currently used network management tools [P4]** ○ Established practices for making contracts with the owners of active resources
Active voltage control is still somewhat at its development phase	• **Real distribution network demonstrations [P3]-[P4]** • Commercial products
Current planning tools and procedures are not capable of taking active voltage control into account	• **Developing the planning tools to enable comparison of different voltage control strategies [P6]-[P8]** • Commercial products
The current regulative environment does not encourage DNOs to take active voltage control into use	• Developing the regulation model
Adequate data on the state of the distribution network is not available	• Utilization of AMR devices [5], secondary substation monitoring and feeder automation • Distribution network state estimation [6]

In [P6]-[P8] a deregulated energy market is assumed. In the deregulated energy market, the DNO is obligated to connect DG into its network and the location, size and type of the DG unit are determined by the DG owner. Therefore, the interconnection planning focuses on determining the most cost-effective way to connect the DG unit to a predetermined network node. This thesis does not consider for instance the optimization of the location of DG units. This thesis concentrates on short-term interconnection planning of DERs and long-term planning issues are not covered.

Although the studies of this thesis have been conducted in typical Nordic distribution networks, many of the results also apply in different types of networks. In the control algorithm developed and tested in [P2]-[P4] it is assumed that the network maximum voltage is always located either at the substation or at generator terminals and that there is no need to use DG reactive power control to increase network voltage. These assumptions are valid in most Nordic distribution networks but do not apply if for instance feeder capacitors are commonly used. In [P5] the control algorithm is further developed to remove the above mentioned limitations. Also the algorithms of [P5] might, however, need some modifications if the network structure is completely different from the Nordic network. In the rule based algorithm, the state estimator [5], [6] and the method used for voltage sensitivity calculation [8] are determined only for radial networks. Also, the selection of optimization method used in the optimizing algorithm might need reconsideration if the number of modelled network nodes and/or controllable resources is high. The planning procedure defined in this thesis is applicable in all kinds of distribution networks.

1.4 The structure of the thesis

Chapter 2 discusses the impacts of DG on distribution network voltage quality. Chapter 3 introduces the current voltage control principles used in distribution networks. Chapter 4 contains a review of active voltage control methods proposed in publications. The control methods developed in this thesis are also introduced and the development process of active voltage control methods discussed. Chapter 5 discusses interconnection planning of DG. The current planning principles are discussed and the planning procedure developed in this thesis is introduced. Chapter 6 concludes the contents of this thesis.

2 IMPACTS OF DISTRIBUTED GENERATION ON DISTRIBUTION NETWORK VOLTAGE QUALITY

Distributed generation affects the distribution network operation in many ways. Power flows and fault currents are altered and problems related to voltage quality, protection and increasing fault levels can occur. The effect of DG on network reliability and stability also needs to be analysed when DG interconnection studies are conducted. [2] This thesis focuses on issues related to voltage quality.

The distribution network voltages need to fulfil certain power quality requirements in order to avoid harmful effects to network components or customer devices. Deviations from the designated tolerances may result in malfunction of customer equipment or even breakage of network components or customer devices. Different limits for acceptable voltage quality are set in different countries. In Finland and several other European countries, European standard EN 50160 [9] is used to define the characteristics of the voltage at the network user's supply terminals. EN 50160 sets the minimum requirements for voltage quality and many countries and DNOs apply stricter limits for acceptable voltage quality. Moreover, the target voltage range used in distribution network planning is usually narrower than the acceptable voltage range.

Distribution network voltage quality consists of many features including e.g. frequency, voltage magnitude and voltage variations, rapid voltage changes, voltage dips, interruptions, voltage unbalance and harmonics [7], [9]. Distributed generation affects many of the voltage quality characteristics: DG alters the voltage level of the network, can induce rapid voltage changes and voltage dips and can increase or decrease the harmonic distortion and the unbalance of the network voltage. It also increases the distribution network fault level which also has an effect on voltage quality. [2] DG can also affect the number and duration of interruptions. Failures of DG equipment increase the number of interruptions. DG can also result in failed reclosing if the DG units are not disconnected from the network during the autoreclosure open time [10]. On the other hand, DG can decrease the number and duration of interruptions if island operation is allowed [11].

2.1 Voltage level

Distributed generation alters power flows in the distribution network. The changes in power flow affect network voltages directly but can also affect the operation of existing control equipment. Hence, DG can either increase or decrease network voltages. [2], [12]

The effect of DG on network voltages depends on its real and reactive power output. The voltage drop or rise caused by a load or generator can be examined using the two-bus system represented in Figure 2.1.

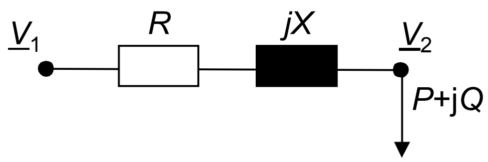

Figure 2.1. A simplified model of a line section. $\underline{V}_1$ is the voltage of bus 1 and $\underline{V}_2$ the voltage of bus 2. *R* is the resistance and *X* the reactance of the feeder. *P* is the real power and *Q* the reactive power absorbed to bus 2.

The voltage of bus 2 equals

$$\underline{V}_2 = \underline{V}_1 - (R + jX)\frac{(P-jQ)}{\underline{V}_2^*} \tag{2.1}$$

If $\underline{V}_2 = V_2\angle 0$ is set, the voltage difference ΔV between buses becomes

$$\Delta V = \underline{V}_1 - \underline{V}_2 = \frac{RP+XQ}{V_2} + j\frac{XP-RQ}{V_2} \tag{2.2}$$

Phasor diagrams representing the voltages in the two-bus system are represented in Figure 2.2.

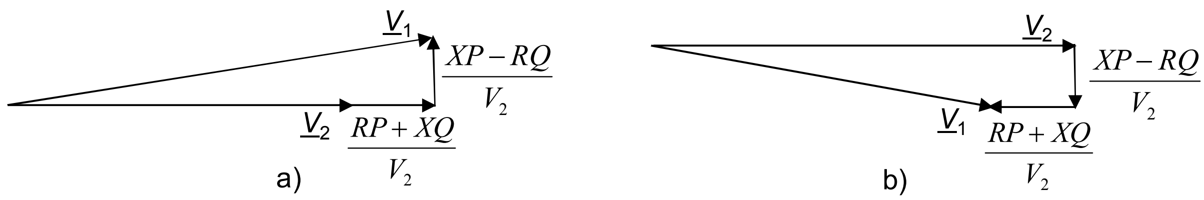

Figure 2.2. Phasor diagrams of voltages in the two-bus system. a) The real power is positive i.e. bus 2 is a load bus. b) The real power is negative i.e. bus 2 is a generation bus. In these phasor diagrams it is assumed that the real power is significantly larger than the reactive power and, hence, $|RP|>|XQ|$ and $|XP|>|RQ|$.

Often it can be assumed that the voltages are near their nominal value and that the angle between voltage phasors is small. With these assumptions equation (2.2) can be approximated

$$\Delta V = \frac{RP+XQ}{V} \tag{2.3}$$

In transmission networks the *X/R*-ratio is such that resistance can usually be omitted and network voltages depend mainly on reactive power transfer in the network. In MV networks the resistance and reactance are usually of the same magnitude and, therefore, both real and reactive power flows affect network voltages. Hence, the voltage at the generator or load node (bus 2 in Figure 2.1) depends on the real and reactive powers of the generator or load, feeder resistance and reactance and the voltage at the sending feeder end (bus 1 in Figure 2.1).

Figure 2.2 and equation (2.3) show that in practical cases DG almost always increases the voltage level in the network because the generated real power is usually significantly larger than the possibly consumed reactive power. Depending on the size, type, location and time variation of the DG unit this voltage rise can be beneficial or disadvantageous to the network. If the DG unit generates when the distribution network loading is high it supports the network voltages and, hence, improves the quality of customer voltages. On the other hand, large DG units generating at low load can raise the network voltages beyond acceptable limits. In weak distribution networks, the capacity of generation that can be connected to an existing distribution network i.e. hosting capacity is often limited by the voltage rise effect. [2], [13]

DG can also affect the operation of existing voltage regulation devices. If line-drop compensation (see chapter 3.1.1) is used at the substation automatic voltage control (AVC) relay, connecting generation to the network reduces the current flowing through the main transformer and, hence, the voltage at the substation is lowered and the customers in adjacent feeders experience lower voltage levels than without the generation. Also other voltage control devices such as step voltage regulators can utilize load current in their control and DG can, hence, also disturb their operation if not correctly taken into account when the controls are planned. [2], [12]

2.2 Transient voltage variations

EN 50160 determines limits for single rapid voltage changes and for flicker [9]. Distributed generation has an effect on both of these. Large transient voltage variations can occur when DG units are connected to or disconnected from the network. Flicker can be caused by changes in the primary energy source, by some forms of prime mover or adverse interactions between the DG units and other existing voltage control equipment in the network. Also frequent connections and disconnections of the DG units increase the flicker severity value. On the other hand, DG increases the fault level of the network and, therefore, reduces the effect of loading changes or faults on adjacent feeders on network voltages. [2], [12]

In case of a weak distribution network and a large single generator, the transient voltage variation at generator connection or disconnection can become the factor that limits the DG capacity that can be connected to the network instead of voltage rise [2]. The transient voltage variation at generator start-up depends on its network interface. For example, if an induction generator is directly connected to the network, its magnetising inrush current is much larger than the rated current. If a soft-start unit is used, the start-up current can be limited to the rated value. The voltage change at generator disconnection depends on the generator current before the disconnection and the maximum voltage transient occurs when the generator is operating at this time at its rated power. [2]

The voltage transient at generator connection can be diminished by careful design of the DG unit. Also network reinforcement diminishes the voltage transients at generator connection and disconnection. In some cases the voltage transient caused by DG connection or disconnection is large but still within the acceptable limits and the frequency of events can be the limiting factor. In these cases it is possible to set constraints on how often the units are allowed to start. A minimum delay between consecutive connections can be set and also the number of consecutive connections within a predetermined time period can be limited. Also, if the DG unit consists of multiple generators, the connection transient can be diminished if all generators are not connected to the network simultaneously but some delay between connections is used. [2], [12]

Distributed generation can also cause more frequent voltage changes. In case of intermittent sources (wind, solar) the changes in the input power can cause flicker but fortunately these changes are usually smoother than step changes and, hence, less likely to cause nuisance to other customers. Also some forms of prime mover can induce flicker. For instance a fixed-speed horizontal wind turbine can induce flicker to the network because tower shadow, wind shear and turbulence cause cyclic variations to the torque and these variations are passed directly to the output power of the generator. Flicker can also be caused by adverse interactions between DG units and other voltage control equipment in the network. Changes in the DG output power can result in for instance continuous operation (hunting) of the main transformer tap changer which could be experienced as flicker by network customers although the changes in DG output power alone would not cause noticeable voltage changes. [2], [12]

3 VOLTAGE CONTROL IN PASSIVE DISTRIBUTION NETWORKS

The objective of distribution network voltage control is to keep all network voltages at an acceptable level. The voltages need to remain within a relatively narrow range in order to avoid harmful effects to network components and customer devices. Customer equipment is designed for a particular voltage level and too large deviations from the nominal voltage can result in malfunction of the equipment. Moreover, excessive voltages can cause even breakage of network components or customer devices.

According to EN 50160 the standard nominal voltage V_n is 230 V in LV networks and can be agreed with the customer at MV networks. 95 % of 10 min mean rms (root mean square) values have to remain within the range of V_n±10 % and all 10 min mean rms values have to remain within the range of V_n+10 % / -15 %. In remote areas a wider range is allowed but the customer needs to be informed of the condition. [9]

3.1 Voltage control principles

The voltage profile of a radial distribution feeder that contains only load is depicted in Figure 3.1 in the situations where the highest and lowest voltages occur. In such networks voltage control is planned based on the assumption of unidirectional power flows. This planning is quite straightforward: maximum and minimum loading conditions are considered and maximum and minimum customer supply point voltages are examined. The network is dimensioned and the voltage control planned such that the minimum customer supply point voltage is near the lower limit of the permissible voltage range and the maximum customer supply point voltage near the upper limit of the permissible voltage range. [7]

Usually, only the substation voltage is automatically controlled and the network is dimensioned so that all network voltages remain in an acceptable level in all loading conditions. Also off-circuit taps of MV/LV transformers affect the customer supply point voltages. In some countries feeder capacitors and step voltage regulators are commonly used but in the Nordic countries these are rare. Capacitors are often connected at the substations but they are not used for voltage control purposes but rather to control the reactive power flow through the main transformer to avoid reactive power charges from the transmission system operator (TSO).

3.1.1 Substation voltage control

Substation main transformers are equipped with an on load tap changer (OLTC). The OLTC is a discrete device that mechanically alters the transformer winding ratio while the transformer is energized and is used to control the voltage of the substation MV busbar. The tap changer can be operated either manually or by an AVC relay. The latter is the normal operation mode in HV/MV transformers.

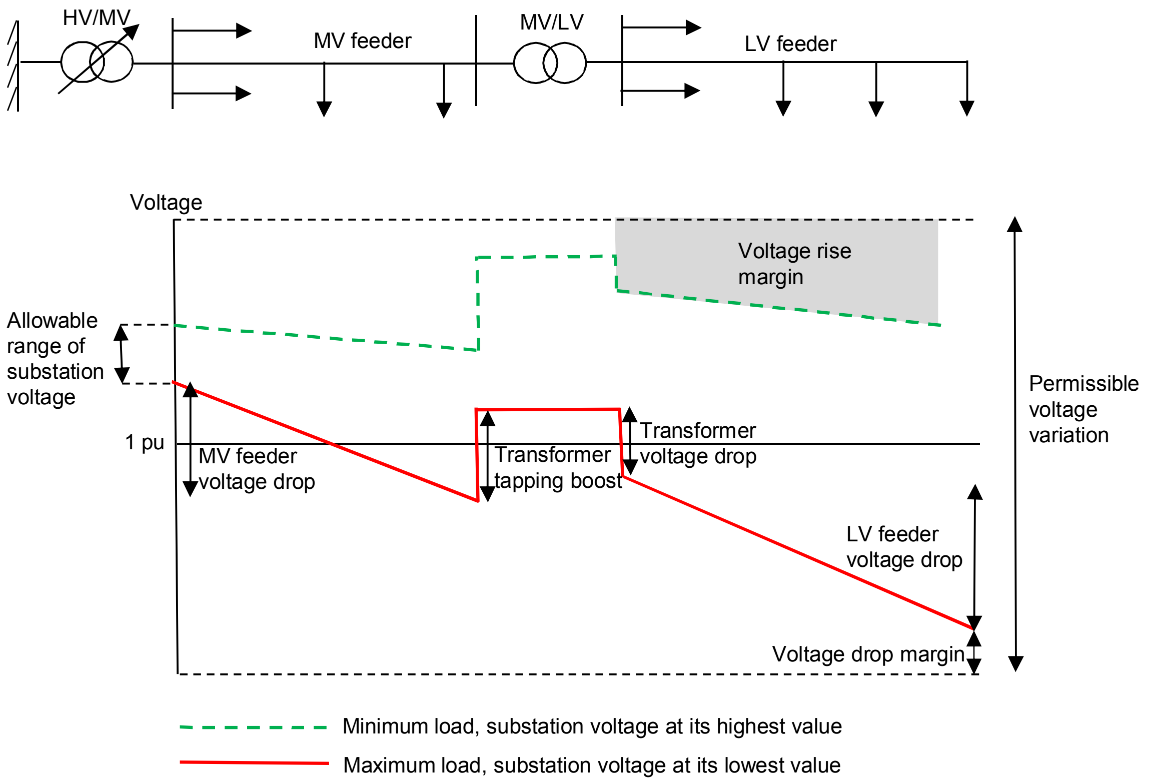

Figure 3.1. Voltage profile of a radial feeder with only load [2], [7]. The substation voltage varies inside the AVC relay dead band and is, in this figure, set at its maximum value when network minimum loading is considered because the maximum possible customer supply point voltage occurs in this case. When network maximum loading is considered the substation voltage is set to its minimum value because the minimum possible customer supply point voltage occurs in this case. Both the maximum and minimum customer supply point voltages need to remain between acceptable limits in all loading conditions.

At its simplest, the AVC relay aims to keep the substation voltage constant. Because the tap changer is a discrete component, a dead band (DB) is needed in order to avoid hunting of the tap changer. Also a delay element is usually included to avoid tap changer operation in case of short-time voltage variations. The AVC relay compares the measured substation voltage and the reference voltage and if the measured voltage differs from the reference voltage more than the AVC relay dead band, the delay counter is started. The delay counter remains active as long as the measured voltage remains outside the hysteresis limits of the AVC relay and a tap changer operation is initiated when the delay counter reaches its setting value. The delay can use definite or inverse time characteristic. When inverse time characteristic is used, the delay is inversely proportional to the difference between the measured voltage and the reference voltage. The time domain operation of the AVC relay is illustrated in Figure 3.2. [7], [14], [15]

Modern AVC relays include a possibility to use line-drop compensation as standard. In line-drop compensation the substation voltage is not kept constant but depends on the current flowing through the main transformer. The objective is to keep the voltage at some remote loading centre constant which is accomplished by replacing the measured substation voltage V_{ss} with $V_{ss}-(R+jX)*\underline{I}$ where R and X represent the resistance and reactance between the substation and the load centre and $\underline{I}$ is the main transformer current. In this way, the substation voltage is increased at high load and decreased at low load. [14], [16]

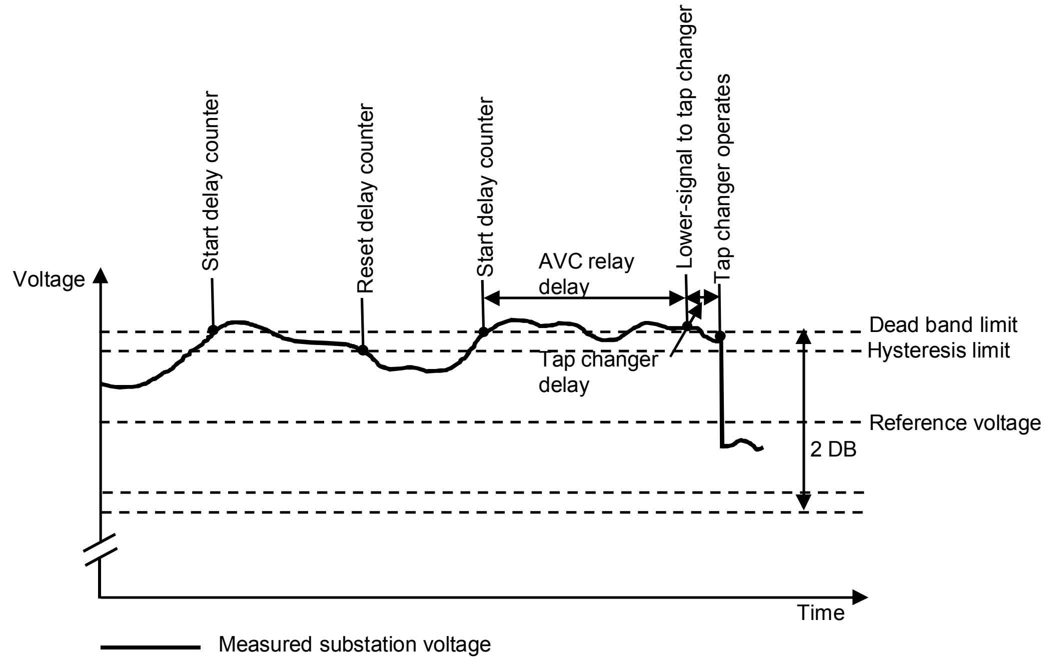

Figure 3.2. Time domain operation of an AVC relay [15]. Definite time characteristic is used.

If several transformers are connected in parallel, the basic AVC relay operation introduced above is not adequate because it will eventually lead to tap divergence because of component tolerances. This is not acceptable because circulating currents will start to flow if the transformers are not at the same tap and, hence, losses will increase. More importantly, the voltage control ability is completely lost if the tap changers of paralleled transformers run to their opposite limits. Hence, the AVC relay control algorithm should be modified to keep the tap changers a maximum of two steps apart. Three techniques are commonly used: master-follower, true-circulating-current and negative-reactance compounding. [16], [17]

3.1.2 MV/LV transformer tap settings

The MV/LV transformers often include off-circuit taps that can be used to change the winding ratio of the transformers. These taps cannot be changed when the transformer is energized but changing them requires an interruption of electricity supply. Therefore, their position is decided at the planning stage and kept constant throughout the year. [7]

The tapping selected depends on the voltage drop along the MV feeder, MV/LV transformer and the LV feeder and also on the selected control principles of the substation AVC relay. Usually, the distribution network can be divided into zones within which all distribution transformers operate on the same tapping. [7]

3.2 Distributed generation in a passive distribution network

Figure 3.1 represents the voltage profile of a radial distribution network that contains only loads. Unidirectional power flows have been assumed when the voltage control has been planned and, therefore, the margin to the feeder voltage upper limit (voltage rise margin in

Figure 3.1) is relatively small. When generation is connected to the network, the assumption of unidirectional power flows no longer necessarily applies and the voltage profile of the network can become quite different than without generation (see also chapter 2.1). Figure 3.3 represents the voltage profile of the same network of Figure 3.1 when generation is connected on the MV feeder. The profile is no longer descending throughout the whole feeder but can have descending and ascending sections. In maximum loading conditions, the DG unit increases the voltage level in the network and, hence, enhances the voltage quality. In minimum loading conditions, the maximum voltage, however, exceeds the feeder voltage upper limit and the voltage performance of the feeder is not acceptable.

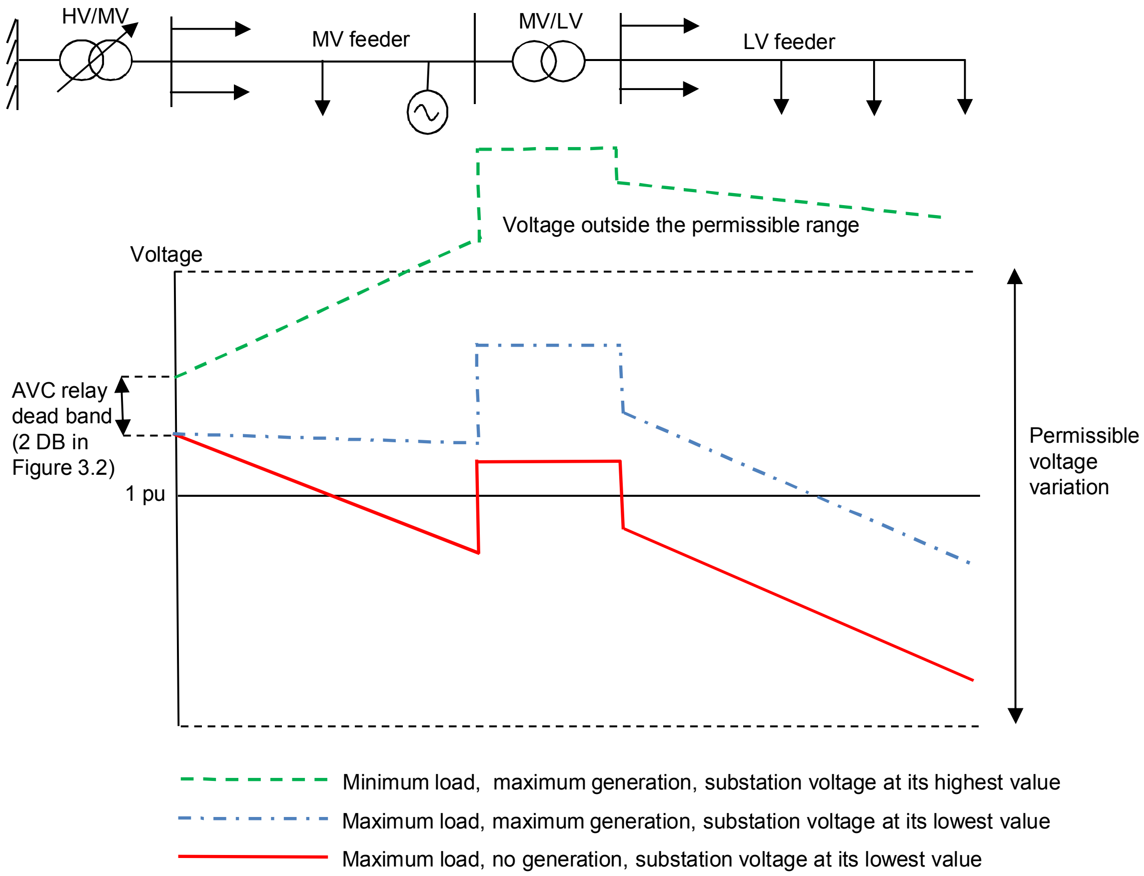

Figure 3.3. Voltage profile of a radial feeder when also generation is present.

In Figure 3.3 it is assumed that the substation AVC relay does not employ line-drop compensation or negative-reactance compounding. If either one is used, the effect of DG has to be taken into account when the control parameters are determined because otherwise DG can cause incorrect operation of these controls [16], [17]. Modifications to the AVC relay operation when DG is present have been proposed for instance in [18] and [19].

At present, DG is considered merely as negative load in distribution network planning and is not allowed to participate in network control in any way. The voltage control principles introduced in 3.1 are not altered and the planning focuses only on determining whether the DG unit can be connected to the planned network node. Two extreme loading conditions (maximum generation/minimum load and minimum generation/maximum load) are considered and if voltage rise becomes excessive in the latter case, passive methods are used to lower the distribution network maximum voltage to an acceptable level. Usually the network is reinforced by increasing the conductor size or the generation is connected on a dedicated feeder. The benefit of this kind of planning is that the network operational principles are not altered. The downside is that reinforcing the network or building a dedicated feeder can in many cases lead to high connection costs of DG.

4 ACTIVE VOLTAGE LEVEL MANAGEMENT

At present, distribution networks are considered to be passive systems whose voltage is controlled only at the substation. When the amount of active resources (e.g. DG) connected to distribution networks increases, this approach can, however, lead to high total costs of the distribution network. Utilizing the control possibilities of DERs in voltage control, i.e. taking active voltage level management into use, can in many cases decrease the distribution network total costs substantially.

4.1 Means to mitigate voltage rise caused by distributed generation

In weak distribution networks, voltage rise caused by DG is usually the factor that limits the hosting capacity for DG. The voltage rise can be mitigated by decreasing feeder impedance, by controlling the real and reactive power flows in the network or by adjusting the substation voltage or voltage at some point along the feeder (see chapter 2.1). One or a combination of the following methods can be used to decrease the maximum customer supply point voltage:

- Increasing the conductor size
- Connecting generation on a dedicated feeder
- Adjusting the off-circuit taps of the MV/LV transformers
- Installing step voltage regulators on feeders
- Reducing substation voltage
- Allowing the generator to absorb reactive power
- Allowing curtailment of generator real power
- Installing passive or active reactive power compensators on feeders
- Controlling the loads (demand response)
- Installing energy storages and charging them when voltage rise needs to be mitigated

At present, voltage rise problems are usually solved either by increasing the conductor size which decreases the feeder impedance or by connecting the generator to a dedicated feeder in which case a higher nominal voltage can be agreed with the generator owner. EN 50160 determines a precise voltage magnitude only at low voltage customer supply terminals. When these methods are used, the passive nature of distribution networks is maintained and no changes to network operational principles are needed.

The maximum customer supply point voltage can be lowered also by reducing voltage at the substation or at some point along the feeder. Adjusting substation voltage affects the voltages in the whole distribution network whereas the off-circuit taps of MV/LV transformers and the feeder step voltage regulators affect voltages only downstream from them. If the MV/LV transformer taps are used to lower the maximum customer supply point voltage when the voltage rise caused by DG becomes excessive, it should be noted that changing the tap position requires an interruption and, therefore, a suitable tap position for all loading conditions needs to be found. The main transformer OLTC and the step voltage regulators are able to operate also when energized.

The maximum voltage in the network can be lowered also by controlling the real or reactive power flows in the network. The power flows can be altered using any resource whose real or reactive power can be controlled such as generators, reactive power compensators, loads and energy storages. Some resources can be used to control both real and reactive power (e.g. generators) and some are able to control only one of them (e.g. reactive power compensators). The maximum customer supply point voltage can be reduced by increasing the real or reactive power transfer from the substation down the feeders. This can be achieved either by increasing consumption of real or reactive power (e.g. connecting additional loads to the network) or decreasing production of real or reactive power (e.g. curtailing DG real power or disconnecting feeder capacitors).

4.1.1 Real and reactive power control of distributed generation

The real power control capability of DG depends on its primary energy source and real power controller. Wind and solar generators are usually operated at the maximum available output power and, hence, the real power production cannot be increased. Production curtailment is, however, possible if the real power controller of the DG unit is capable of following dispatch commands to output a certain amount of real power. In wind generators, real power control is possible if pitch regulation is used [2]. In stall regulated units, real power control can be realized only by disconnecting the whole DG unit. Photovoltaic (PV) systems operate usually in maximum power point tracking (MPPT) mode but they could also be operated in constant real power control mode [20]. Small hydro power plants and combined heat and power (CHP) plants are at present usually dispatched by the plant owner and, hence, already include equipment that can be used to command the plants either to increase or to decrease their real power output.

The reactive power control capability of DG depends on the type of its network connection and naturally also on the reactive power/voltage controller of the unit. DG units can be connected to the network directly using synchronous or induction generators or through a power electronic converter.

The reactive power output of a synchronous generator is determined by the direct current (DC) flowing in its field winding on the rotor i.e. the excitation current. The excitation current is produced by an excitation system that consists of an exciter and an automatic voltage regulator (AVR). The exciter is used to generate and feed the desired excitation current to the field winding and the AVR determines the magnitude of the excitation current. The basic structure of the reactive power control system of a synchronous generator is represented in Figure 4.1. [21], [22] The real and reactive power of synchronous generators can be independently controlled as long as the operating point remains inside the area defined in the generator's operating chart [23].

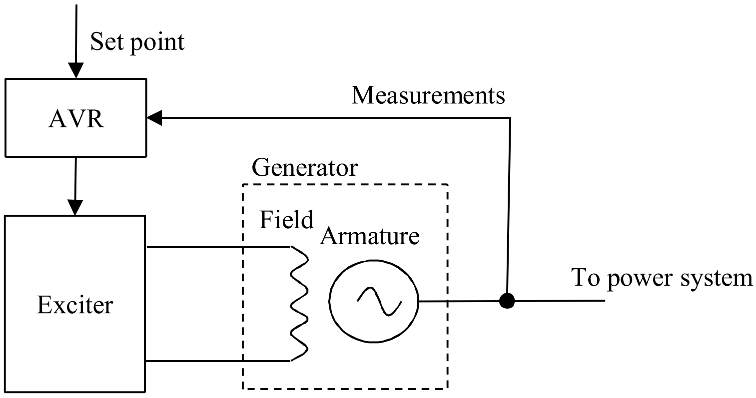

Figure 4.1. The reactive power control system of a synchronous generator.

The reactive power output of an induction generator is dependent on its real power output and the relationship between real and reactive power can be represented by a circle diagram shown in Figure 4.2. Induction generators always consume reactive power and independent control of the power factor is not possible. Reactive power control is possible only if some controllable reactive power compensation device is connected at the generator terminals. Power factor correction (PFC) capacitors are usually fitted at the generator terminals and also power electronic compensators such as static synchronous compensators (STATCOMs) can be utilized. [2]

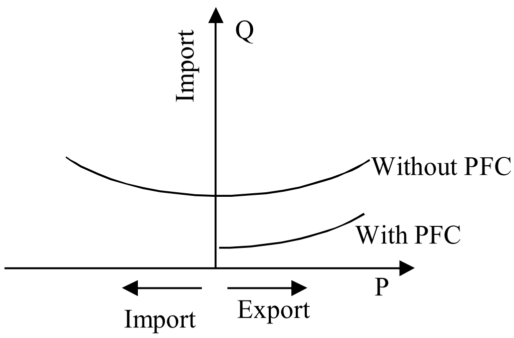

Figure 4.2. Induction generator circle diagram [2].

DG units can be connected to the network also through a power electronic converter. The converters can be used to invert the DC generated by for instance PV systems to alternating current (AC). They can also be used to decouple a rotating generator from the network to enable for instance variable speed operation of wind turbines. The real and reactive powers of DG units with power electronic interface can be independently controlled as long as the capacity limits of the converters are not exceeded. [2]

4.2 Survey of active voltage control methods

Active voltage control methods can be based only on local measurements or require information on the state of the whole distribution network. In this thesis the latter ones are referred to as coordinated methods. The different degrees of network voltage control activity and the requirements to implement these are illustrated in Figure 4.3.

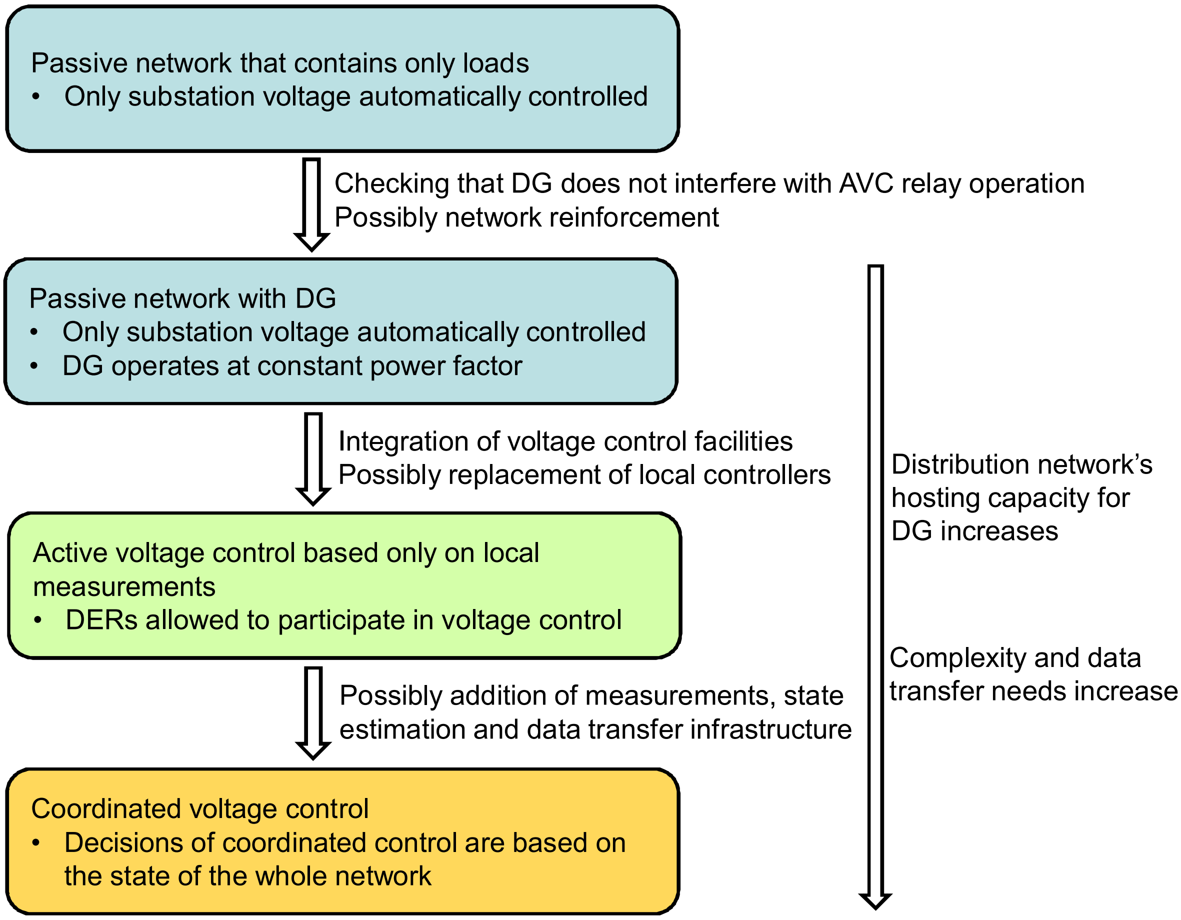

Figure 4.3. Activity degrees of distribution network voltage control.

4.2.1 Methods based on local measurements

The simplest active voltage control methods determine their control actions based only on local measurements. The reactive and real power of distributed generators can be controlled based on the terminal voltage. Also loads and reactive power compensators could be controlled based on local measurements. These methods do not require additional data transfer between network nodes and can in some cases be implemented using the already existing control equipment. They can, however, substantially increase the hosting capacity for DG in many networks [3].

4.2.1.1 Local reactive power control

The maximum distribution network voltage can be decreased by allowing some generator or reactive power compensator to absorb reactive power. The reactive power control capability of distributed generators depends on the type of their network connection (see 4.1.1).

At present, DG units capable of reactive power control are usually operated at constant power factor and, hence, their reactive power output does not depend on the network state. Power factor set points are usually the same for all generators but also methods that optimize the power factor set points have been proposed [24]. DG could, however, control its reactive power output also based on the terminal voltage i.e. operate in voltage control mode. This would lead to smaller variations in network voltage level between different loading conditions and enable connection of more DG into existing distribution networks. Also a combination of power factor control and voltage control is possible where the controller operates in power factor control mode as long as the terminal voltage remains within determined limits but switches to voltage control mode when the limits are overstepped [25], [26]. [27], [28]

Implementing local reactive power control can be quite straightforward. Modern generator AVRs often already include the capability to operate also in voltage control mode and, hence, replacement of existing control equipment is not necessarily needed. Modern AVRs can also include the possibility to switch between power factor and voltage control modes depending on whether the terminal voltage is at an acceptable level or not [29]. Hence, in some cases local reactive power control could be taken into use simply by changing the control mode of the generator AVR. Studies are, however, needed to confirm that no adverse interactions between controllers occur and that, for instance, the reactive power division between generators is proper. Droop control can be used to share the reactive power when multiple DG units operate in the same distribution network [30].

Methods that alter the local controllers have also been proposed. [31] proposes a reactive power control method for distributed generators that aims to keep the voltage profile of the distribution networks similar to the situation without generation. This method allows the DNOs to control the distribution networks as if there were no generation but can require high amounts of reactive power transfer.

When local reactive power control is taken into use its effect on network losses and main transformer tap changer control has to be taken into account. Moreover, the additional reactive power consumption can increase the need of reactive power compensation capacitors at the substation because the DNO aims to keep the reactive power transfer from the transmission system within the TSO determined reactive power window to avoid reactive power charges.

4.2.1.2 Local real power control

Distribution network voltages can be controlled also by altering the real power flow from the substation down the feeder. The maximum distribution network voltage can be decreased either by reducing the real power output of generators or by increasing the real power consumption of loads or energy storages.

At present, DG units usually have a firm connection i.e. are allowed to generate their nominal power regardless of the network state. This can lead to situations where the network is most of the time significantly overdimensioned because the voltage rise would otherwise become excessive in some rare loading/generation situations. In these cases, a non-firm connection can lower the total costs of the network significantly. In a non-firm connection the generator real power can be curtailed if the network state demands it. Production curtailment is a worthy alternative if curtailment is needed only rarely but other control methods should be considered if the percentage of curtailed generation becomes too high.

Production curtailment of DG can, at simplest, be implemented by disconnecting a required number of generating units when the DG terminal voltage exceeds its limit. If the real power of DG can be controlled for instance by pitch regulation of wind generators, disconnection is not required as the real power control of DG can be continuous. Droop control can be used to share the generation curtailment between connected DG units [32].

Local reactive and real power controls can also be combined. In [33] reactive power is primarily controlled and production curtailment is taken into use only if the reactive power capability of the DG unit is not adequate to keep the network voltages between acceptable limits.

4.2.2 Coordinated methods

Coordinated voltage control methods determine their control actions based on the state of the whole distribution network and, therefore, data transfer between network nodes is needed. CVC methods proposed in publications range from simple rule based algorithms with only one controlled resource to advanced optimizing algorithms that control all components capable of voltage control. Even the simplest CVC algorithms are often able to increase the distribution network's hosting capacity for DG significantly more than methods based only on local measurements [3].

This thesis concentrates on CVC methods that operate in real time. Also methods that predetermine a control schedule for the voltage controlling devices based on predicted loading and generation have been proposed [34]-[38]. Obtaining accurate enough load and generation forecasts can be a demanding task. Some of the predictive methods could also be suitable for online use as long as the real time requirements such as execution time of the algorithm are taken into account.

The CVC methods can determine their control actions based on control rules or use some kind of optimization algorithm. The input data can be directly measured or state estimation can be utilized.

Most CVC methods proposed in publications are centralized i.e. the CVC method is implemented at one point in the network where measurement data is gathered and control actions are determined based on the measurement data. Control commands are then sent to the controllable resources. The centralized methods usually change the set points of lower level controllers and, hence, the lower level controllers do not need to be replaced. Also methods that alter the lower level controllers or control the actuating devices directly have been proposed [39], [40]. Distributed methods based on multiagent systems have also been proposed (for instance [41], [42] and [43]) although many of these also include some coordinating component which makes the architecture somewhat centralized.

4.2.2.1 Methods based on control rules

CVC methods based on control rules are suitable for simple networks where only few control possibilities exist. Traditional radial distribution networks are such networks.

Distribution network maximum voltage can be decreased by lowering the substation voltage. The voltage drop margin in maximum loading condition is not, however, usually large enough to allow lowering the substation voltage permanently (see Figure 3.1). On the other hand, in minimum loading condition the substation voltage could often be lowered substantially which is also the situation when the voltage rise is at its maximum value. Hence, coordinated control of substation voltage can in many cases increase the DG hosting capacity of an existing distribution network substantially.

The simplest CVC method implements substation voltage control based on network maximum and minimum voltages [44]-[47]. The control principle is simple: substation voltage is lowered if network maximum voltage exceeds its limit and increased if network minimum voltage falls below its limit. If both voltages exceed feeder voltage limits, nothing is done because the voltages cannot be normalized by controlling only the substation voltage. Substation voltage control is realized by changing the set point of the already existing substation AVC relay. [P1] further develops this algorithm to prevent hunting of the tap changer and to restore the voltages to a normal level after for instance the disconnection of DG.

Coordinated control of substation voltage can be combined with local reactive and real power control (see chapter 4.2.1). In this case, the local control will usually operate faster than the coordinated substation voltage control because AVC relay and tap changer delays are much larger than delays of reactive and real power controllers of active resources. Hence, substation voltage is in these cases used as the last control resort. Control of real and/or reactive power can also be included in the CVC algorithm although determination of control rules becomes more difficult when the number of controllable components increases.

Several algorithms that use substation voltage and reactive power of DG units as control variables have been proposed. In [48] and [49] a continuous control algorithm that aims to keep network voltages near their nominal value is proposed. [50] further develops the algorithm to also minimize the reactive power flow from the substation. The control algorithm can also be such that control actions are taken only when either network minimum or maximum voltage is approaching its limit. In [51] main transformer OLTC position, voltage regulation mode of the substation AVC relay and the generators' reactive power output are controlled to keep the voltages between acceptable limits. In [52] and [53] main transformer OLTC is the primary control variable and DG reactive power is controlled only if the voltages cannot be restored between acceptable limits by substation voltage control. A ranking table is used in generator reactive power control. [P2] proposes a modular algorithm that controls substation AVC relay set point and DG AVR power factor set point. The algorithm aims to keep network voltages between acceptable limits and includes also a part that restores the controlled variables to their original state when control is no longer needed. The primary control variable can be selected to be either substation voltage or DG reactive power. In [P3] this algorithm is further developed to utilize state estimation in its control to speed up the operation of the algorithm.

Some methods control only reactive powers of DGs to keep the voltages at an acceptable level. The method in [42] is implemented using a multiagent system and voltage sensitivities are used to determine the order in which the DGs are controlled. In [54] voltage sensitivities are also used to select the controlled DG. In normal state the DGs are operated in unity power factor mode. When mitigation of voltage rise is needed, the generator with the highest capability to affect the exceeding voltage is switched to reactive power absorption mode where it operates at its minimum power factor. The reactive power control is not, hence, continuous.

In [55] only active power curtailment is used to manage voltage constraints. Voltage sensitivity factors are used to determine which generators are curtailed. In [56] loads are controlled to mitigate the voltage rise caused by wind turbines. Loads are switched based on the measured voltage at the wind generation point of connection. In [57] energy storages are controlled to decrease the number of substation tap changer operations and to mitigate the changes in feeder power flow due to changes in load and generation (i.e. charging at high generation and discharging at high load).

In [58] and [59] substation voltage and real and reactive power of DG are used as control variables and AMR measurements are utilized as inputs to the control algorithm. Terminal voltages of active resources are used to determine which resources are controlled. [P5] represents a modular rule based algorithm that controls substation voltage and real and reactive power of DERs to keep the network voltages at an acceptable level. Simplified voltage sensitivities are used to determine which resources are used at the real and reactive power control.

CVC methods that utilize some kind of rule database have also been proposed. In [60] and [61] case based reasoning is used to determine the control actions. Substation voltage and real and reactive powers of DGs are controlled and the case base is populated using simulations. In [43] substation OLTC, shunt capacitors and real and reactive powers of DGs are controlled using a multiagent system. Expert-based decision making is used and the control rules of the decision maker are obtained through simulations of the network.

The rule based CVC methods are relatively simple which is an advantage. Time domain implementation is straightforward and no convergence problems can occur. Also, understanding their operational principles is quite easy which might make them more attractive for DNOs. However, when the number of controllable components increases, the determination of control rules can become a complex task. Multitask control rules like combined voltage level management, network loss minimization and tap changer operation minimization also become very complex in practical applications. In these cases, methods using optimization algorithms can be more suitable.

4.2.2.2 Methods utilizing optimization

The optimization of distribution network voltage control is a mixed-integer nonlinear programming problem (MINLP)

$$\begin{aligned} &\text{minimize} && f(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) \\ &\text{subject to} && g(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) = 0 \\ & && h(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) \leq 0 \end{aligned} \tag{4.1}$$

where $\mathbf{x}$ is the vector of dependent variables, $\mathbf{u_d}$ is the vector of discrete control variables and $\mathbf{u_c}$ the vector of continuous control variables. The optimization aims to minimize the objective function $f(\mathbf{x},\mathbf{u_d},\mathbf{u_c})$ subject to equality constraints $g(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) = 0$ and inequality constraints $h(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) \leq 0$. MINLP problems are difficult to solve and several CVC methods using different optimization methods have been proposed in publications.

To simplify the optimization problem, linearization can be used. Linear programming (LP) is used in [3], [62]-[67]. In [3] the objective function is formulated to minimize the real power curtailment whereas in [62] the costs of transformer tap operation, reactive power absorption and real power curtailment are minimized. Both algorithms control the substation voltage and reactive and real powers of DG. In [63] a two-stage procedure is proposed: A day-ahead scheduler uses optimization to determine optimal real power set points for every dispatchable DG unit. An intra-day scheduler uses LP to minimize real power curtailment and losses and to keep network voltages near their nominal value. DG real and reactive powers are used as control variables. The intra-day scheduler is responsible for distribution network voltage control. In [64] and [65] DG real and reactive powers and controllable loads are used to minimize the costs of control actions and network losses. In [64] also network reconfiguration is considered. [66] proposes a voltage control method for large heavily-meshed distribution networks. It uses real and reactive powers of DGs as control variables and tries to minimize the amount of needed control. The large network is subdivided into smaller subnetworks by neglecting weak couplings between DG powers and node voltages and keeping the strong couplings. In [67] LP is used to minimize system losses. DG real and reactive powers are used as control variables.

Nonlinear programming (NLP) is used in several publications [68]-[81]. References [68] and [69] use a state machine approach to control substation OLTC and reactive and real powers of DGs. The substation voltage is controlled based on control rules as in [52] and the control of real and reactive powers is activated only if the substation voltage control is not able to keep all network voltages between acceptable limits. An optimization algorithm is used to minimize the amount of controlled real and reactive powers. In [70] the algorithm of [68] and [69] is further developed. Substation voltage control is used to keep the network voltage level in the middle of the allowable voltage range and reactive powers of DGs are used to keep the voltage range between network maximum and minimum voltages small enough. Optimization is used to minimize the reactive power of DGs. In [71] the substation voltage control is further developed to enable different operation modes in order to fulfil different control targets. Also a cooperative mode of substation voltage control and reactive power control is added to enable minimizing the number of tap changer operations. In [70] substation voltage control and reactive power control operate independently of each other. Control of DG real power is not implemented in [70] and [71] although planned in [68] and [69].

In [72] NLP is used to minimize the total energy cost that consists of production costs of DGs and price of power transferred from the transmission network. Substation OLTC, shunt capacitors and DG real and reactive powers are controlled. In [73] and [74] substation OLTC and reactive powers of controllable components are used as control variables. The objective function consists of the cost of losses, cost of reactive power control and cost of reactive power import from the transmission network. In [75] and [76] a learning algorithm is combined with NLP to reduce the computational time needed. The objective function takes into account real power losses, average voltage deviation, maximum voltage deviation and reactive energy costs.

In [77] only reactive powers of DERs are controlled. The optimization aims at keeping all network voltages at a set value. In [78]-[81] the optimization aims to keep voltages at the substation and some other specific nodes (pilot buses) at their set values. DG reactive and possibly also real powers are used as control variables.

In [P5] an optimizing algorithm utilizing NLP is implemented to enable comparison of the rule based and optimizing algorithms. Substation voltage and real and reactive powers of DERs are used as control variables and the objective function is formulated to minimize costs of production curtailment and losses.

Most publications on CVC utilizing LP or NLP omit the discrete nature of some control variables and treat all variables as continuous. In real applications of the algorithms this assumption is naturally not valid and, hence, some kind of procedure to assign the discrete variables is needed. In [73] an iterative heuristic approach to assign the discrete variables is proposed. At first, the optimization is executed assuming all variables are continuous. After that, the difference between the optimized continuous value and the nearest discrete admissible value is calculated. The discrete variable is assigned if the difference is smaller than a predetermined percentage of the step of the discrete control component. This procedure is repeated until all discrete variables are assigned with the exception that the allowed percentage error is increased in every step to ensure that all discrete variables are assigned. Also in [72] the optimization is, at first, executed assuming that all variables are continuous. After that, the discrete variables are simply assigned to the nearest discrete admissible value and the optimization is executed again with the discrete values fixed. In [P5] a three-stage procedure is used. In the first round, NLP is executed assuming that also the tap changer position is a continuous variable. After the first round, the two tap changer positions on both sides of the calculated value of the tap changer position are selected. The second and the third round execute NLP using the two previously selected tap changer positions. The alternative with the smallest value of the objective function is selected.

CVC algorithms utilizing metaheuristic optimization algorithms have also been proposed in publications. In [82]-[85] genetic algorithm is used to determine control actions. In [82] the algorithm controls the main transformer OLTC, step voltage regulators, static VAr compensators (SVCs) and shunt capacitors and reactors. The objective function is formulated to keep the network voltages near their nominal value and to reduce losses. In [83] and [84] the genetic algorithm is used to minimize the difference of network voltages to nominal. In addition to main transformer OLTC and DGs' reactive power, shunt capacitors are controlled in [83] and step voltage regulators in [84]. In [85] the objective function is formulated to minimize network losses. The algorithm controls substation OLTC, shunt capacitors, feeder voltage regulators and reactive power of DGs.

Particle swarm optimization is used in [86]-[88]. In [86] and [87] it is used to control the reactive powers of DGs, real and reactive powers of microgrids and main transformer OLTC. The operation of microgrids is emulated by an artificial neural network to reduce the computational time needed. The objective function aims at minimizing real power losses and production curtailment. In [88] the algorithm uses reactive powers of DERs to keep the network voltages within an acceptable range. The objective function tries to minimize the amount of reactive power control.

As a conclusion it can be said that a variety of CVC methods utilizing optimization have been proposed in publications. All methods manage well when their operation is studied using only steady state load flow studies. In practical implementations, however, some issues need to be taken into account: the computational time of optimization algorithms can become large when the size of the network and the number of controllable components increases. Hence, in real time applications it has to be ensured that the computational time does not exceed the requirements set. It is also possible that an optimization algorithm does not find a feasible solution at all i.e. it does not converge. Convergence problems cannot be tolerated if the optimization is used as the only voltage control method in a real distribution network. One alternative would be to use a rule based algorithm to make sure that the network voltages are restored within an acceptable range in a required time and to use optimization only to shift the network state from an acceptable one to another with more favourable characteristics. Selecting the most suitable optimization method for a particular case depends at least on the size and type of the network (radial/meshed), the number and type (continuous/discrete) of components participating in the voltage control and the selected objective function.

The benefit of using optimization is the methods' ability to find the optimal state for the network. Also, changing the operational principles is relatively easy because the output of an optimization algorithm is determined by its objective function and, hence, the operational principles can be changed simply by modifying the objective function.

4.2.2.3 Summary of coordinated voltage control methods

The CVC methods introduced above can be categorized based on different characteristics. One way to divide the methods into different categories is represented in Figure 4.4. In this figure the methods are divided into two categories: rule based methods and methods utilizing optimization.

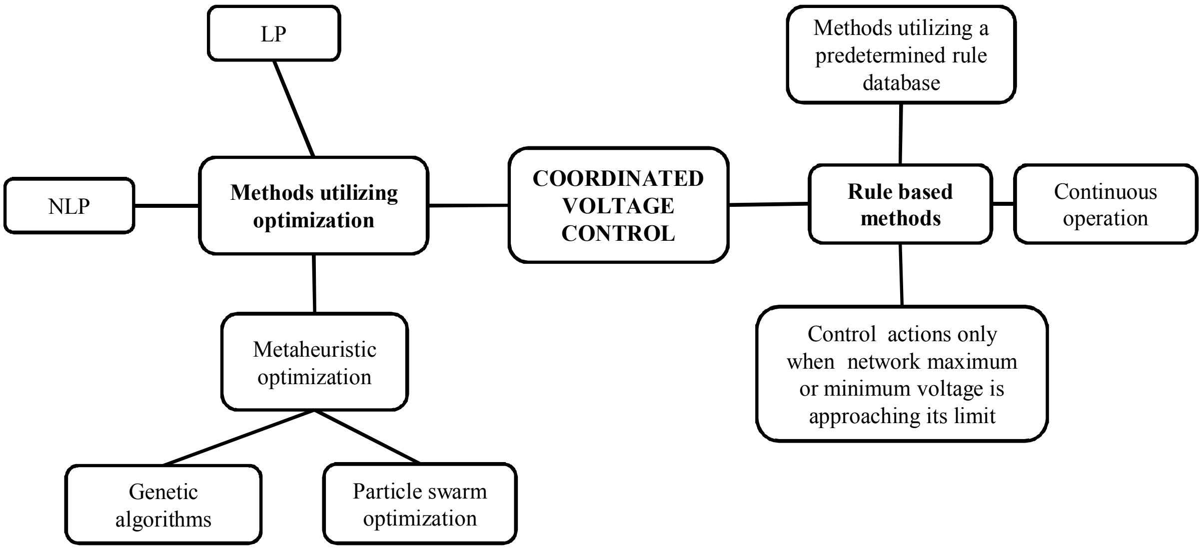

Figure 4.4. Coordinated voltage control methods divided into categories.

Coordinated voltage control methods could be categorized also based on the control variables they use in the control. Controllable components used in the methods introduced above include main transformer tap changer, DG units (real and reactive power control), shunt capacitors and reactors, SVCs, step voltage regulators, controllable loads, energy storages and switching devices (for feeder reconfiguration). The most common control variables used in control are substation voltage and real and reactive powers of DG units. It should be noted that there are significant differences in how easily different kinds of active resources can be taken into voltage control use. For instance production curtailment of DG units can be taken into use relatively easily if equipment needed for remote real power control already exists. Curtailment can simply be started when network voltages require it and cancelled when it is no longer needed. If, on the other hand, for instance loads are utilized, load control equipment needs to be installed because no such equipment usually, at present, exists. Also the behaviour of the controlled loads needs to be taken into account in the control algorithm. If the controlled load is for instance a heating load, the temperature of the house needs to be taken into account in the control and, hence, load control can continue only for some limited time. From the point of view of contractual issues, using DNO owned resources such as the main transformer tap changer is the simplest. Utilizing customer owned resources such as DG units requires making contracts with the resource owners.

The optimizing algorithms can be categorized based on the objective function. The possibilities for variables to be minimized include network losses, DG real power curtailment, costs of reactive power control, costs of reactive and real power import from the transmission system, number or costs of tap changer operations and quantities related to voltage quality such as average voltage deviation and maximum voltage deviation.

Some CVC methods proposed in publications are not easily applicable in the deregulated energy market. In the deregulated energy market, electricity distribution and production are unbundled and the DNO is not responsible for dispatching the DG units. Contracts can be made to allow the DNO to control the real power of DG units in cases where network voltage control requires such control, but the DNO does not have permission to make dispatch schedules for the units in normal operational state.

4.3 The developed voltage control methods

Two coordinated voltage control algorithms have been developed in this thesis. The first one is a rule based algorithm and the second one utilizes optimization. Both algorithms use substation voltage and real and reactive powers of DERs as control variables and are designed for typical Nordic MV networks. The only requirement for DERs is that their real or reactive power needs to be controllable and, hence, all kinds of active resources such as DGs, reactive power compensators, controllable loads, energy storages and microgrids/LV networks can be utilized in the voltage control. The algorithms just have to know the allowable range of the DERs real and/or reactive power and whether the resources are discrete or continuous. Taking the algorithms into use does not require replacement of the lower level controllers but the algorithms operate by changing the set points of the already existing control equipment. The substation voltage is controlled by changing the voltage set point of the substation AVC relay and the real and reactive powers of the DERs are controlled by changing the real and reactive power set points of the available resources.

The developed algorithms are centralized and designed so that implementing them as a part of the already existing advanced DMSs commonly used by Nordic DNOs would be easy. In the Nordic countries, the DMS is highly integrated with the network information system, customer information system (CIS) and SCADA and is, therefore, able to combine static information obtained from NIS and CIS and real time measurement data and control possibilities of SCADA [7]. Static network information consists of network parameters stored in NIS database and load information obtained from hourly load curves [89], [90] and CIS (annual energies and customer types). Real time measurement data and network switching state are obtained from SCADA and states of manual disconnecting switches are entered directly to the DMS by the network operator. Also state estimation is available in the DMS [7]. The state estimator can be utilized to generate input data for the CVC and the control commands given by the CVC algorithms can be sent to the DERs directly through SCADA.

The data transfer of SCADA can be directly utilized in the control if only a relatively low number of relatively large DERs is used in the control. If, however, the number of controllable DERs becomes large and the unit size small, some kind of aggregation (e.g. LV network controller in Figure 4.5) is needed to decrease the amount of data transferred to and from SCADA [91]. Cascaded control architecture can be implemented to enable the utilization of also the small-scale DERs connected to LV networks. In the cascaded control architecture, a central LV network controller installed for example at the MV/LV substation controls the voltages in the LV network and implements real and reactive power commands given by the MV network CVC algorithm. The proposed control architecture is represented in Figure 4.5. One possible implementation of such control system is represented in [92]. The LV network voltage control algorithms are not developed in this thesis.

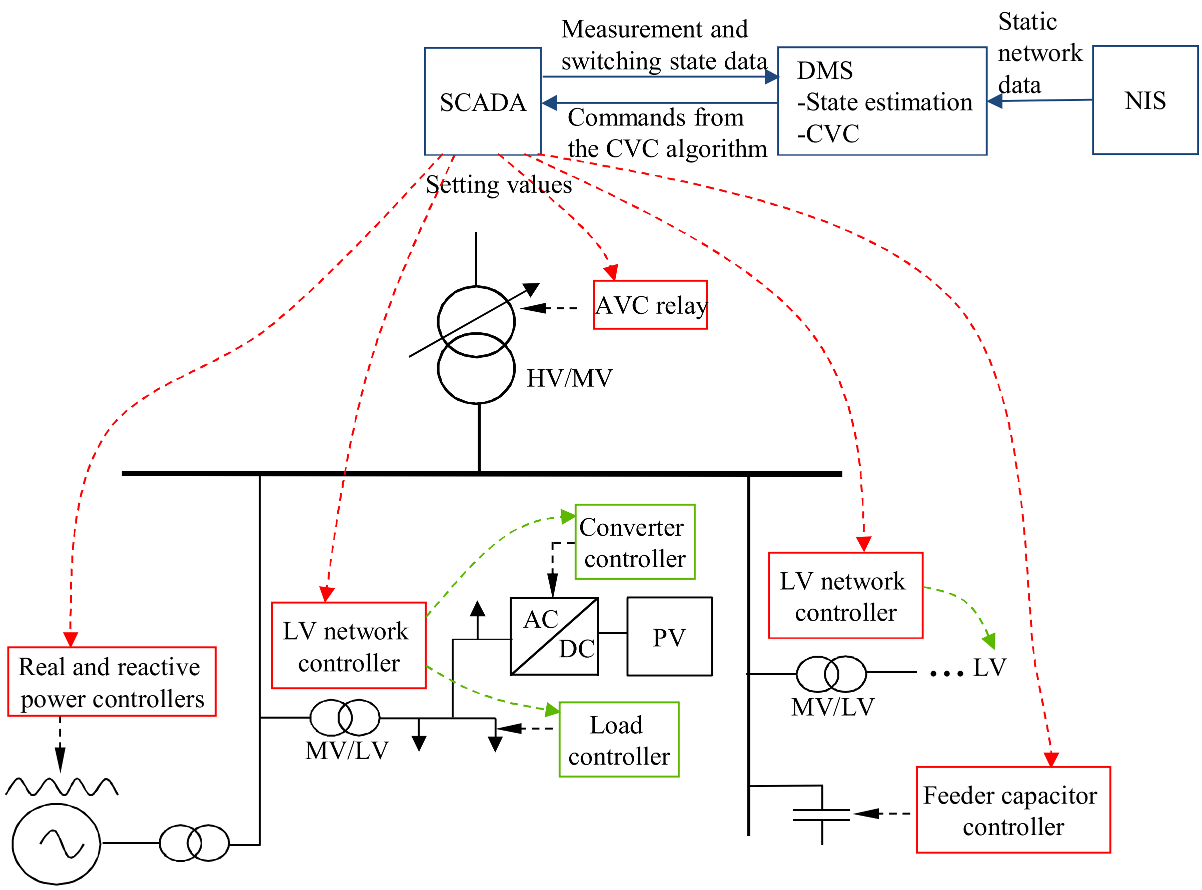

Figure 4.5. The cascaded control architecture.

4.3.1 The rule based algorithm

The rule based CVC algorithm of this thesis has been developed in [P1]-[P3] and [P5]. Coordinated substation voltage control is developed in [P1]. In [P2] the control of reactive power of one DG unit is added to the algorithm. The algorithm of [P2] does not assume that a state estimator is available, but the needed voltage input data can be either directly measured or estimated. The algorithm of [P3] utilizes a state estimator when determining the reactive power set point of the controlled DG unit and, hence, operates faster than the algorithm of [P2] which changes the reactive power set point in predefined steps. In [P5] the algorithm is further developed for use in networks that contain multiple controllable resources. Control of real power is also added to the algorithm. The algorithm of [P5] is the final version of the rule based CVC algorithm developed in this thesis.

The developed algorithm consists of basic and restoring parts. Basic control is used to restore network voltages to an acceptable level when either the network maximum or minimum voltage exceeds the feeder voltage limits. Restoring control aims to restore the real and reactive power of active resources closer to their original values when the network state allows it. It also restores the network voltages to a normal level if the voltages of the whole distribution network have remained in an unusually high or low level for some reason (for instance disconnection of a large DG unit). The operational principle of basic control is depicted in Figure 4.6 and the operational principle of restoring control in Figure 4.7. Both basic and restoring algorithms consist of substation voltage control, reactive power control and real power control.

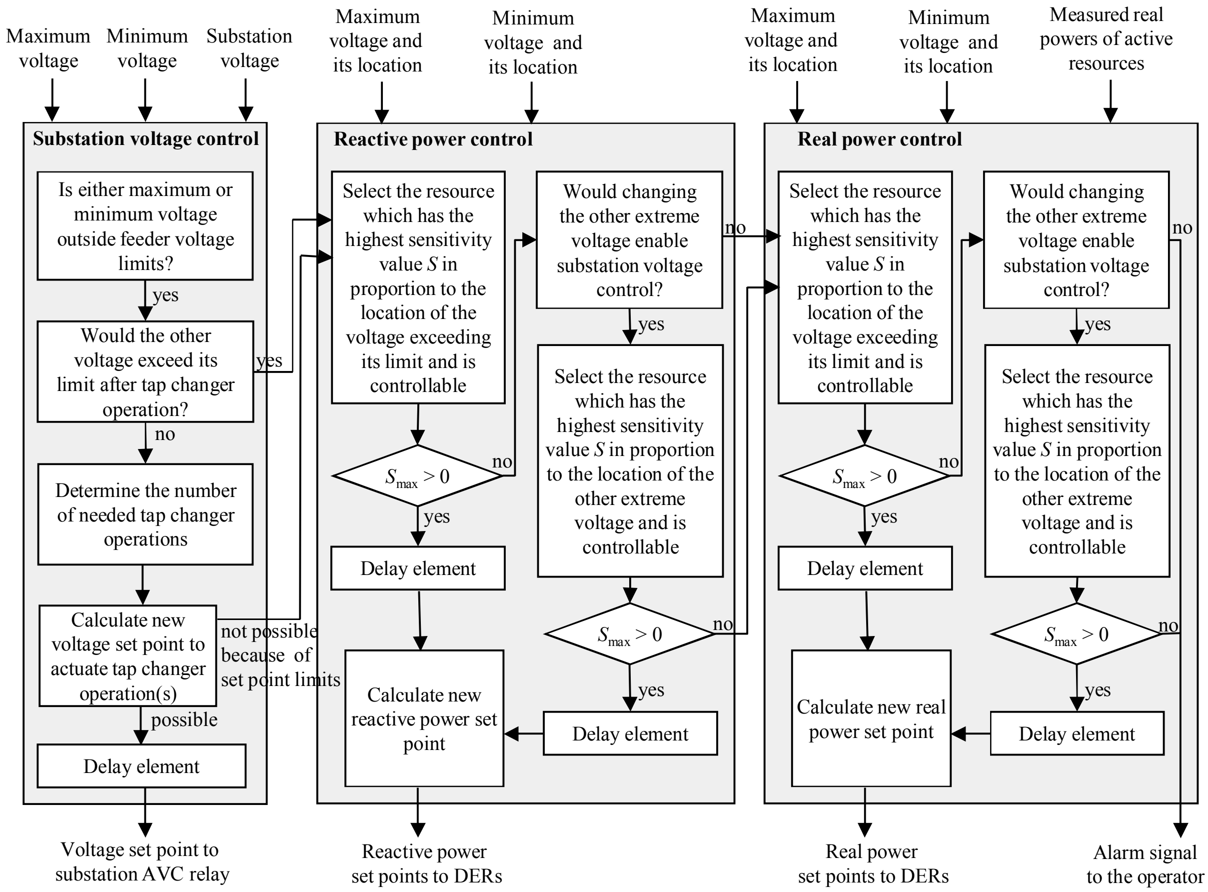

Figure 4.6. The operational principle of the developed basic control.

Basic control is activated when either network maximum or minimum voltage exceeds its limit. At first, it tries to restore network voltages between acceptable limits by controlling substation voltage. If substation voltage control is not able to restore network voltages to an acceptable level, reactive power control is activated. The final control variable, real power, is used only if network voltage violations still exist after substation voltage control and reactive power control.

In restoring control, the control blocks operate in reverse order compared to basic control. In restoring control, real power control is activated first. It tries to restore the real powers of all active resources as near to their original value as the network state allows. If restoring real power control is not needed (all real powers are at their original values) or cannot operate because the network state does not allow it, restoring reactive power is activated. Restoring reactive power control has similar objectives as restoring real power control, i.e. it tries to restore the reactive powers of all resources as near to their original values as the network state allows. If restoring reactive power control is not needed or cannot operate, restoring substation voltage control is activated. The restoring substation voltage control is similar to basic substation voltage control but has stricter voltage limits. It aims to restore network voltages to a normal level if the voltages in the whole distribution network have remained in an unusually high or low level. More detailed explanations on the operation of each control block can be found in [P2], [P3] and [P5].

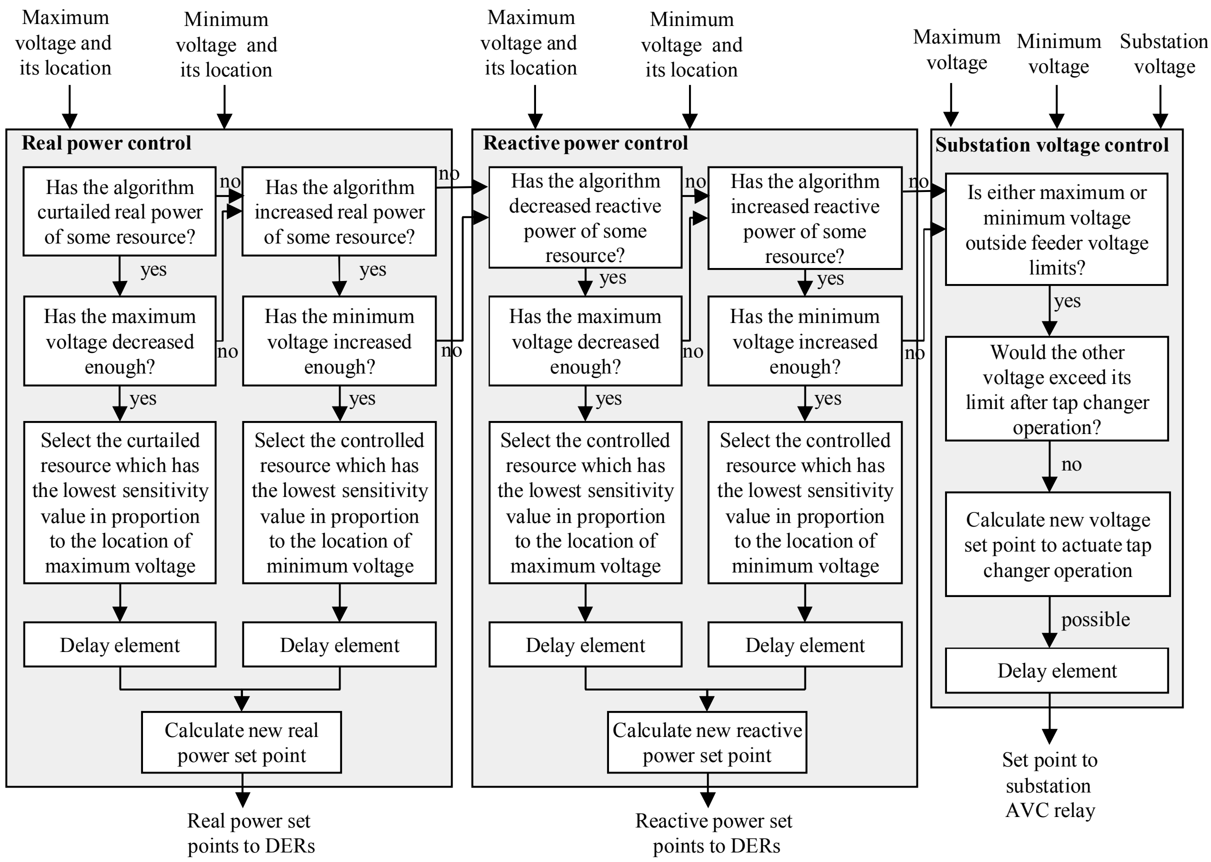

Figure 4.7. The operational principle of the developed restoring control.

It should be noted that basic and restoring controls have very different characteristics: when basic control is needed, the network is operating near or outside its operational limits and, therefore, relatively fast and preferably automatic control is needed. Restoring control, on the other hand, is used to change the network's operating point from an acceptable one to another with more favourable characteristics. Hence, restoring control can - and should - have larger delays than the basic control. Also, automating the controls is not as necessary as in basic control and the restoring control actions could be performed manually by the network operator. In this case, an algorithm that would recommend restoring control actions to the operator would be useful.

4.3.1.1 Determining voltage sensitivities

The real and reactive power control blocks use voltage sensitivities to determine which resource is controlled (see also chapter 4.3.3). The sensitivities are determined by an approximate method proposed in [8]. Some simplifying assumptions have been made in the method. Constant current models are used for loads and generators and the phase difference between voltages is assumed to be negligible. As a result of these assumptions, the voltage sensitivities can be represented by the following simple equation:

$$\begin{cases} \left[S_{I_p}\right] = -[R] \\ \left[S_{I_q}\right] = -[X] \end{cases} \tag{4.2}$$

where

$S_{I_p} = \begin{bmatrix} \frac{\partial V_1}{\partial I_{p1}} & \cdots & \frac{\partial V_1}{\partial I_{pn}} \\ \vdots & \ddots & \vdots \\ \frac{\partial V_n}{\partial I_{p1}} & \cdots & \frac{\partial V_n}{\partial I_{pn}} \end{bmatrix}$ is the voltage sensitivity matrix in proportion to real node currents I_p,

$S_{I_q} = \begin{bmatrix} \frac{\partial V_1}{\partial I_{q1}} & \cdots & \frac{\partial V_1}{\partial I_{qn}} \\ \vdots & \ddots & \vdots \\ \frac{\partial V_n}{\partial I_{q1}} & \cdots & \frac{\partial V_n}{\partial I_{qn}} \end{bmatrix}$ is the voltage sensitivity matrix in proportion to reactive node currents I_q and R is the real part and X the imaginary part of the impedance in the impedance matrix $[Z]$. The diagonal elements of $[Z]$ i.e. (Z_{ii}) are equal to the sum of the branch impedances forming the path from the origin i.e. the substation to the node i. The off-diagonal elements (Z_{ij}) are equal to the sum of the branch impedances forming the path from the origin to the common node of the paths from the origin to nodes i and j, respectively. Node i is the node whose voltage change is analyzed and node j the node whose reactive or real power is changed to control the voltage at node i. Hence, the controllable resource at node j can affect the voltage at node i more the longer (electrically) the common path from the origin to nodes i and j is.

In this method the voltage sensitivities are calculated based on only network impedances whereas in reality also other variables such as substation voltage, voltage at the node i and net real and reactive node currents affect the sensitivity value [8]. Hence, the method only gives approximate values of the sensitivities. However, these are adequate for the purpose of selecting the controllable resource. The benefit of the method is its simplicity and the fact that the sensitivity matrices need to be updated only when the network switching state changes. All data needed for determining the sensitivity values is already available at the DMS and composing the sensitivity matrices can be easily automated.

In this method, it is assumed that reactive and real power control affects voltages only on the feeder they are connected to because the origin is defined to be the substation. This is not, naturally, completely true because there is impedance also in the feeding HV network and the substation transformer. If also these impedances are wanted to be taken into account in the voltage sensitivity calculations, the origin should be defined to be the node representing the ideal voltage source behind the HV network impedance.

More accurate methods to determine the voltage sensitivities can be found for example in [93]-[96].

4.3.1.2 Discussion and development needs

The control algorithms of this thesis were designed for typical Nordic distribution networks but are, nevertheless, applicable also in different kinds of distribution networks. Algorithms of [P2]-[P4] utilize some characteristics of Nordic distribution networks but in [P5] the algorithm is further developed to operate also in distribution networks with different voltage control principles than the ones used in Finland. The only limitation for the algorithm proposed in [P5] is that the network needs to be radial. The algorithm parts controlling substation voltage are applicable even in meshed networks but the parts controlling real and reactive powers of DERs need to be modified before application in meshed networks because the method used for voltage sensitivity determination and the state estimation algorithm are applicable only in radial networks. The developed algorithm is modular and, hence, if modification of the algorithm is needed only the parts that are not applicable for a particular network need to be altered.

The developed algorithm is such that implementing it as a part of the Nordic DMS would be quite easy. All input information needed by the algorithm is directly available from the DMS and the control commands given by the CVC algorithm can be sent to the DERs directly through SCADA on condition that SCADA transfer capability is adequate (see also Figure 4.5). Hence, only the CVC algorithm itself needs to be added to the DMS.

The developed CVC algorithm can, however, also be applied as a separate controller. Its inputs and outputs (i.e. interface with other systems) are clearly defined and existence of a state estimator is not a necessity but the required input data can also be directly measured. If a state estimator is available, it is utilized in the real and reactive power control blocks when new set points are determined. However, if a state estimator is not available, the set points are changed in predefined steps and the algorithm still operates as desired. The drawback of this approach is that it will take a longer time to restore the network to an acceptable level compared to the approach utilizing state estimation. In the algorithm of [P5] the real and reactive control blocks control the DERs one at a time. To further speed up the algorithm operation, the algorithm could be developed to utilize state estimation also to determine how many resources are needed to restore the voltages to an acceptable level.

The developed control algorithm is able to operate also in unusual network switching states because the network switching state affects only the voltage sensitivity matrices. If the algorithm is implemented as a part of the DMS, all data needed to generate the matrices is directly available (i.e. feeder impedances and states of network switches). The new voltage sensitivity matrices can be automatically composed when the network switching state changes.

The parameters of the CVC algorithm can be used to change the objectives of the control. The voltage limits used in restoring substation voltage control can be selected depending on the objectives in the controlled distribution network. Conservation voltage reduction [97] can be achieved by setting the voltage limits in the lower part of the acceptable voltage range (for instance 0.95-1.0 pu if the acceptable voltage range is 0.95-1.05 pu). If, on the other hand, it is more profitable to keep the voltages near the feeder voltage upper limit, the voltage limits of restoring voltage control should be set in the upper part of the acceptable voltage range (for instance 1.0-1.05 pu if the acceptable voltage range is 0.95-1.05 pu). The latter applies in networks that contain mainly thermostatic and constant power loads because reducing the voltage of these types of loads does not lead to energy savings but rather to increased losses [98]. In Finland, the networks are usually operated in the upper part of the acceptable voltage range.

The objectives of distribution network CVC and control of reactive power flow through the main transformer can be contradictory. In CVC, reactive power consumption is used to mitigate the voltage rise on MV feeders and, hence, reactive power flow from the substation increases. On the other hand, the DNO aims to keep the reactive power transfer from the transmission system within the TSO determined reactive power window to avoid reactive power charges. This problem can be solved by producing the reactive power needed by the CVC at the substation but may require in some cases installation of new capacitors at the substations which affects the profitability of CVC.

4.3.2 The optimizing algorithm

The optimizing CVC algorithm of this thesis uses NLP to solve the MINLP problem of equation (4.1). The algorithm uses the same control variables as the rule based algorithm: substation voltage and real and reactive powers of DERs.

The vector of dependent variables contains the voltage magnitudes V and voltage angles δ of all n distribution network nodes.

$$\mathbf{x} = [V_1,\ldots,V_\mathrm{n},\delta_1,\ldots,\delta_\mathrm{n}] \tag{4.3}$$

The vector of discrete variables contains the switched control variables such as positions of tap changers, network switches and switched capacitors and reactors. In this case, the only discrete variable is the main transformer tap position m.

$$\mathbf{u_d} = [m] \tag{4.4}$$

The vector of continuous control variables contains variables such as set points of real and reactive powers or terminal voltages of DERs. In this case, the controllable variables are the real and reactive powers of DERs.

$$\mathbf{u_c} = [P_1,\ldots,P_\mathrm{j},Q_1,\ldots,Q_\mathrm{k}] \tag{4.5}$$

where P_j is the real power set point of the jth DER and Q_k the reactive power set point of the kth DER. The numbers k and j are not always equal because some resources might have the capability to control only either real or reactive power.

The objective function is defined so that it will minimize the total costs of network losses and generation curtailment

$$f(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) = C_\mathrm{losses}P_\mathrm{losses}+C_\mathrm{cur}\Sigma P_\mathrm{cur} \tag{4.6}$$

where C_losses is the price of losses, P_losses is the amount of losses, C_cur is the lost income due to generation curtailment and ΣP_cur is the amount of curtailed generation. The losses can be calculated as the sum of real power injections of all network nodes.

$$P_{\text{losses}} = \Sigma P_{\text{i}} \tag{4.7}$$

The bus power injections can be computed from the following equation:

$$\mathbf{P_i}+j\mathbf{Q_i} = \text{diag}(\mathbf{V})(\mathbf{Y_{bus}V})^* \tag{4.8}$$

where $\mathbf{V}$ is the node voltage vector $[V_1e^{j\delta 1},\ldots,V_ne^{j\delta n}]$ and $\mathbf{Y_{bus}}$ the bus admittance matrix [23].

In this optimization problem, the equality constraints model the power flow equations at each network node. In this case the substation (node 1) is defined to be the slack node and the following equality constraints have to be fulfilled there:

$$V_1 - \frac{V_{orig}}{m} = 0 \tag{4.9}$$

$$\delta_1 = 0 \tag{4.10}$$

where V_{orig} is the substation voltage with a tap ratio of 1.0.

All other network nodes are defined to be PQ nodes because all active resources operate in reactive power control mode instead of voltage control mode. At the PQ nodes the following equality constraints have to be fulfilled

$$P_{\text{i}} - P_{\text{gen,i}} + P_{\text{load,i}} = 0 \tag{4.11}$$

$$Q_{\text{i}} - Q_{\text{gen,i}} + Q_{\text{load,i}} = 0 \tag{4.12}$$

where injected powers P_{i} and Q_{i} can be calculated from equation (4.8), $P_{\text{gen,i}}$ is the generated real power at the ith node, $P_{\text{load,i}}$ the consumed real power at the ith node, $Q_{\text{gen,i}}$ the generated reactive power at the ith node and $Q_{\text{load,i}}$ the consumed reactive power at the ith node. The total number of equality constraints is $2*n$ where n is the total number of distribution network nodes.

The inequality constraints are used to model network technical constraints and the capability limits of the controllable resources. The following constraints are used in this case:

$$V_{\text{lower}} \leq V_{\text{i}} \leq V_{\text{upper}} \tag{4.13}$$

$$P_{\text{activeimin}} \leq P_{\text{activei}} \leq P_{\text{activeimax}} \tag{4.14}$$

$$Q_{\text{activeimin}} \leq Q_{\text{activei}} \leq Q_{\text{activeimax}} \tag{4.15}$$

$$m_{\text{min}} \leq m \leq m_{\text{max}} \tag{4.16}$$

$$S_{\text{ij}} \leq S_{\text{ijmax}} \tag{4.17}$$

The first inequality constraint (4.13) states that all network voltages have to remain between feeder voltage limits. The second constraint (4.14) sets the limits for real powers of controllable DERs and the third constraint (4.15) sets the limits for reactive power of controllable DERs. Constraint (4.16) limits the main transformer tap ratio. Constraint (4.17) limits the power flows in all network branches below the maximum allowed value.

4.3.2.1 Practical issues and development needs

In this thesis the optimizing algorithm is implemented using Matlab Optimization Toolbox. Function fmincon that realizes NLP is used and the only discrete variable main transformer tap position is assigned using a heuristic procedure introduced in chapter 4.2.2.2. This implementation is suitable for simulations and enables comparison of the optimizing and rule based algorithms. Some issues need to, however, be taken into account if the algorithm is taken into real distribution network use: the execution time of the algorithm has to remain reasonable and convergence problems cannot occur. The algorithm implemented in [P5] does not necessarily as such fulfil these requirements but some modifications might be needed.

Convergence problems are possible with the implemented optimizing algorithm. Network voltage limits are represented in the implementation as inequality constraints. If the algorithm is unable to find a solution in which all network voltages are within the acceptable range, it will not do anything. In many cases, however, the network state could be enhanced by control actions although a fully acceptable state could not be reached. Existence of a feasible solution can be guaranteed by replacing the hard voltage limits of (4.13) by soft limits and by modifying the objective function of (4.6) to include a penalty factor that is large when some network voltage is outside the feeder voltage limits.

Overvoltage is a more severe situation than undervoltage and, hence, if the situation is such that acceptable voltage levels cannot be guaranteed to all customers, the algorithm should lower the network voltage level to mitigate the network maximum voltage even though this would lead to undervoltage at some network nodes. This operation could be achieved by setting the penalty factor of overvoltage larger than the penalty factor of undervoltage in the objective function.

Also the execution time of the optimizing algorithm can become a problem in real distribution network implementations. The algorithm of [P5] operates in a reasonable time in the relatively small example network used in [P5]. However, when the number of network nodes and controllable components increases, the execution time can become excessive. Hence, the network data taken directly from the DMS might not be suitable for input to the optimizing algorithm but some network reduction might be necessary.

Previously it was stated that the rule based CVC algorithm can be quite easily implemented as a part of the DMS. Implementing the optimizing algorithm requires more work because optimization algorithms are not at present directly available in the DMS. Hence, the optimization algorithm either needs to be coded from scratch or a commercial optimization library needs to be integrated with the DMS.

The output of an optimization algorithm is determined by its objective function. In [P5] the objective function was formulated to minimize the combined costs of network losses and generation curtailment. Other components could also be added to the objective function. The objective function could include for instance the costs of reactive power generation and consumption, the amount of tap changer operations and quantities related to voltage quality such as average voltage deviation and maximum voltage deviation. Determining the costs of reactive power consumption and generation has been discussed for instance in [73] and adding these costs to the objective function would be quite straightforward although the costs for the DNO depend also on the interconnection agreements made with the DER owners i.e. is reactive power control defined as an ancillary service or a requirement for network connection. Determining the costs for tap changer operations or voltage quality issues is more complicated. Tap changer operations cause wear of the tap changer and can increase its maintenance need. The tap changer manufacturers give instructions that overhaul is needed after some number of tap changer operations (e.g. 100000) or after some number of years of service (e.g. five years) depending on which criterion is first fulfilled [99]. Hence, the additional tap changer operations caused by CVC start to increase the tap changer maintenance costs only after the interval between overhauls diminishes due to the CVC induced tap changer operations. Determining the cost of one tap changer operation is not, therefore, easy.

4.3.3 Discussion on commercial arrangements

The voltage control algorithms developed in this thesis aim at minimizing the amount of curtailed generation. In the rule based algorithm, the curtailed generator is selected based on voltage sensitivities and the resource with the highest sensitivity in proportion to the network node at which network voltage exceeds feeder voltage limits is curtailed first. In the optimizing algorithm, generation curtailment is embedded in the objective function and, hence, also in this algorithm the generators that can affect the exceeding voltage the most are curtailed first. With these algorithms, the amount of generated energy is the largest but also some problems can arise if the distribution network includes generators owned by different stakeholders because curtailment is not equally divided among generators. Also, the generators first connected to the network can have interconnection agreements guaranteeing a firm connection. Hence, also different kinds of criteria for selecting the curtailed generator can be used.

Instead of the technical approach taken in this thesis, the curtailed generator can also be selected based on the order of connection to the network (i.e. Last In First Out) or characteristics of the generators (e.g. generator size or carbon emissions). Curtailment can also be shared equally between generators or a market based approach can be taken. [100] In the rule based algorithm of this thesis, changing the selection criteria of the curtailed generator is easy: the voltage sensitivity matrix just needs to be replaced with a matrix representing the desired control order. In the optimizing algorithm, changing the selection criteria could be realized by modifying the objective function so that the desired operation realizes. For instance different curtailment costs for different generators could be introduced to determine the order in which the generators are curtailed.

4.4 From research to real distribution network use

Although a multitude of active voltage control methods have been proposed in publications, work is still needed to get the methods also in real distribution network use. The barriers for active voltage control have been discussed in chapter 1.1.1 and one of them is that many active voltage control methods are still somewhat at their development phase. The development process of active voltage control methods is represented in Figure 4.8. The development process is iterative i.e. results of each development step can lead to a need to revise the control principles determined at the first step.

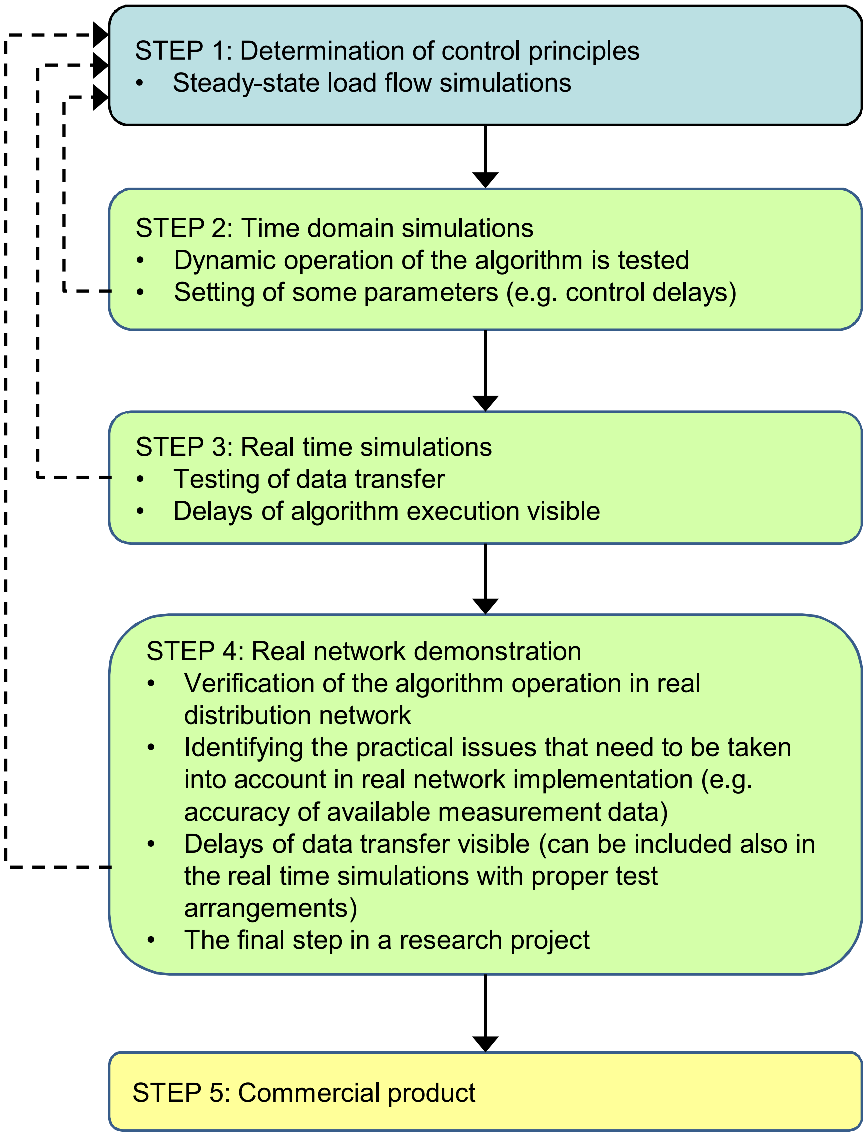

Figure 4.8. The development process of active voltage control methods.

Most publications on active voltage control concentrate only on determining the control principles of the control algorithm and the operation of the algorithm is tested using only load flow simulations. This is, however, only the first step of the development process. All five steps have to be gone through to make the developed method a real alternative in DNOs' network planning procedure. The phases of the development process are described in the following chapters.

4.4.1 Determination of control principles

At the first phase of the planning process, the control principles of the algorithm are determined. At this stage, time domain implementation is not studied and the operation of the algorithm is usually tested using steady-state load flow simulations. The control principles are usually determined only at the accuracy that is needed for steady state load flow calculations (see for example Figure 4.6 and Figure 4.7) and detailed determination on the real realization of the control rules is not necessarily presented. Most publications on active voltage control concentrate only on this phase.

4.4.2 Time domain simulations

At the second step of the development process, the algorithm is implemented in time domain format and time domain simulations are carried out. These simulations are conducted to test the dynamic operation of the algorithm and to make sure that no adverse interactions such as hunting appear. These interactions are not visible in the steady state load flow calculations because in load flow simulations it is assumed that all control actions are executed instantly.

When the algorithm is implemented to time domain format, a more thorough determination of its operation is needed. At the first step of the development process the control principles can be determined simply by stating what the desired operation of the controlled variables is (e.g. lower substation voltage if network maximum voltage is too high). At the second step, determination on how the control objectives will be reached is also needed (e.g. if substation voltage needs to be lowered by one tap step, set substation AVC relay set point to V_{ss}-*tap* [P2]). As an example, a detailed flow chart of the restoring substation voltage control of the rule based algorithm of [P5] is represented in Figure 4.9 (see also Figure 4.7). Part 1 in Figure 4.9 determines whether the substation voltage control should be used. The second part (Part 2) determines how many tap changer operations are needed to restore the voltages between acceptable limits. Part 3 calculates a new reference voltage for the substation AVC relay, checks that the calculated new reference voltage is between the set point limits and verifies that the new reference voltage will initiate a tap changer operation. Similar flow charts are needed for all control blocks of Figure 4.6 and Figure 4.7 to be able to conduct time domain simulations.

Time domain simulations can be used to determine values for some control parameters such as control delays. Also the order in which control actions are executed has to be decided and the control algorithm implementation needs to be such that this order is realized. Either delays or blocking signals can be used to determine the order.

Time domain simulations are conducted in some publications (for example [44], [47], [50], [101]). Many publications also include graphs that represent results of consecutive load flow calculations. They describe the steady state operation of the algorithm during the studied time period but do not give the same information as time domain simulations made with a time domain model of the studied voltage control algorithm.

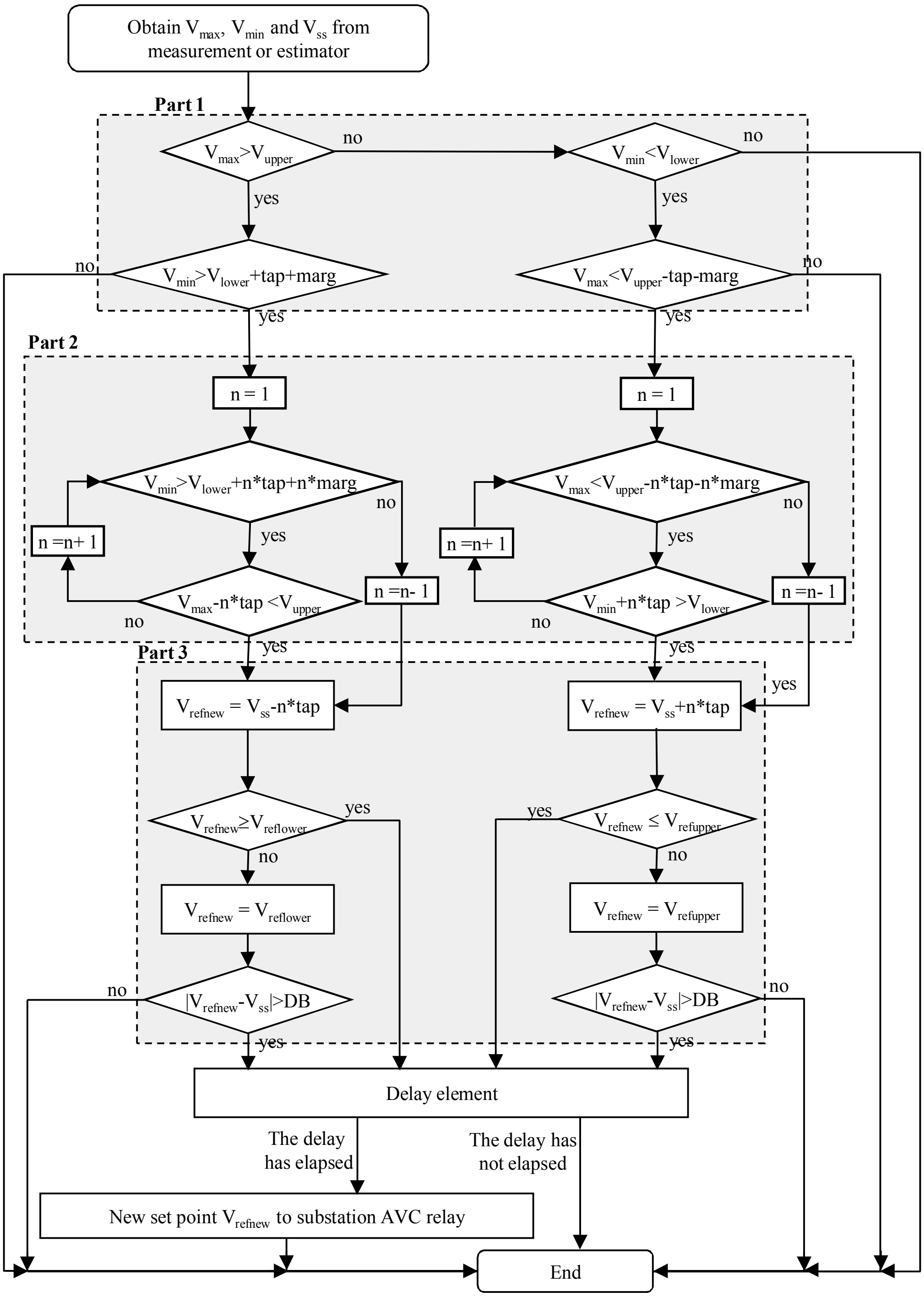

Figure 4.9. Detailed flow chart of restoring substation voltage control of the rule based algorithm of [P5]. Basic substation voltage control is similar to this but contains also parts that are used to determine whether or not basic reactive power control needs to be activated. *V_{max}*is maximum network voltage, *V_{min}* minimum network voltage, *V_{ss}* substation voltage, *V_{lower}* feeder voltage lower limit, *V_{upper}* feeder voltage upper limit, *tap* main transformer tap step, *marg* a safety margin to avoid hunting, *n* the number of needed tap changer operations, *V_{ref}* the reference voltage of the substation AVC relay, *$V_{reflower}$* lower limit of the reference voltage of substation AVC relay, *$V_{refupper}$* upper limit of the reference voltage of substation AVC relay and *DB* the AVC relay dead band.

In this thesis, time domain simulations are conducted in PSCAD simulation environment and CVC algorithms are implemented as custom PSCAD models using Fortran programming language [P1], [P2] or as separate Matlab programs that interact with the PSCAD simulation through a Matlab interface included in the PSCAD simulation environment [P5]. Time domain simulations are used to verify that the studied algorithm operates in time domain as designed and that no adverse interactions such as hunting occur. After the time domain simulations, a real implementation of the algorithm can be constructed. Time domain simulations cannot, however, be used to study all delays present in the real distribution network. In PSCAD, all calculations are conducted before proceeding to the next time step and, hence, the CVC algorithm's output is always based on the measured values at the same time step. In reality this is not naturally the case because the algorithm execution takes some time and also the measurement values are not updated continuously and simultaneously. Hence, time domain simulations are essential at the development phase of new CVC algorithms but also other studies are needed before the algorithm is ready for real distribution network use.

As an example, results of one time domain simulation are represented in Figure 4.10. In the example case, the rule based algorithm of [P5] is used to control substation voltage V_{ss} and real and reactive powers of three generators. The simulation network consists of two feeders and is constructed based on network data obtained from a real Finnish distribution network. More details on the simulation network and simulation sequence can be found in [P5].

Control system delays are visible in the time domain simulation results and the order in which control actions are conducted can be observed. Also the difference between set points and actual values of substation voltage and real and reactive powers of active resources can be studied.

4.4.3 Real time simulations

At the third step of the development process, real time simulations are used to test the operation of the real implementation of the developed voltage control algorithm (hardware-in-the loop or software-in-the-loop testing). Also data transfer between the algorithm and for instance SCADA can be realized and tested at this stage and the delays of algorithm execution are visible. Data transfer delays are not inherently present in real time simulations but can be included with proper test arrangements.

Conducting real time simulations before demonstration in a real distribution network decreases the amount of work required in the demonstration phase because the data transfer can be tested beforehand and also some deficiencies of the algorithm might be noticed at this stage. Real time simulations also enable the examination of cases that cannot be realized in the real distribution network demonstration. Moreover, a large number of simulations can be conducted which enables statistical evaluation of the results.

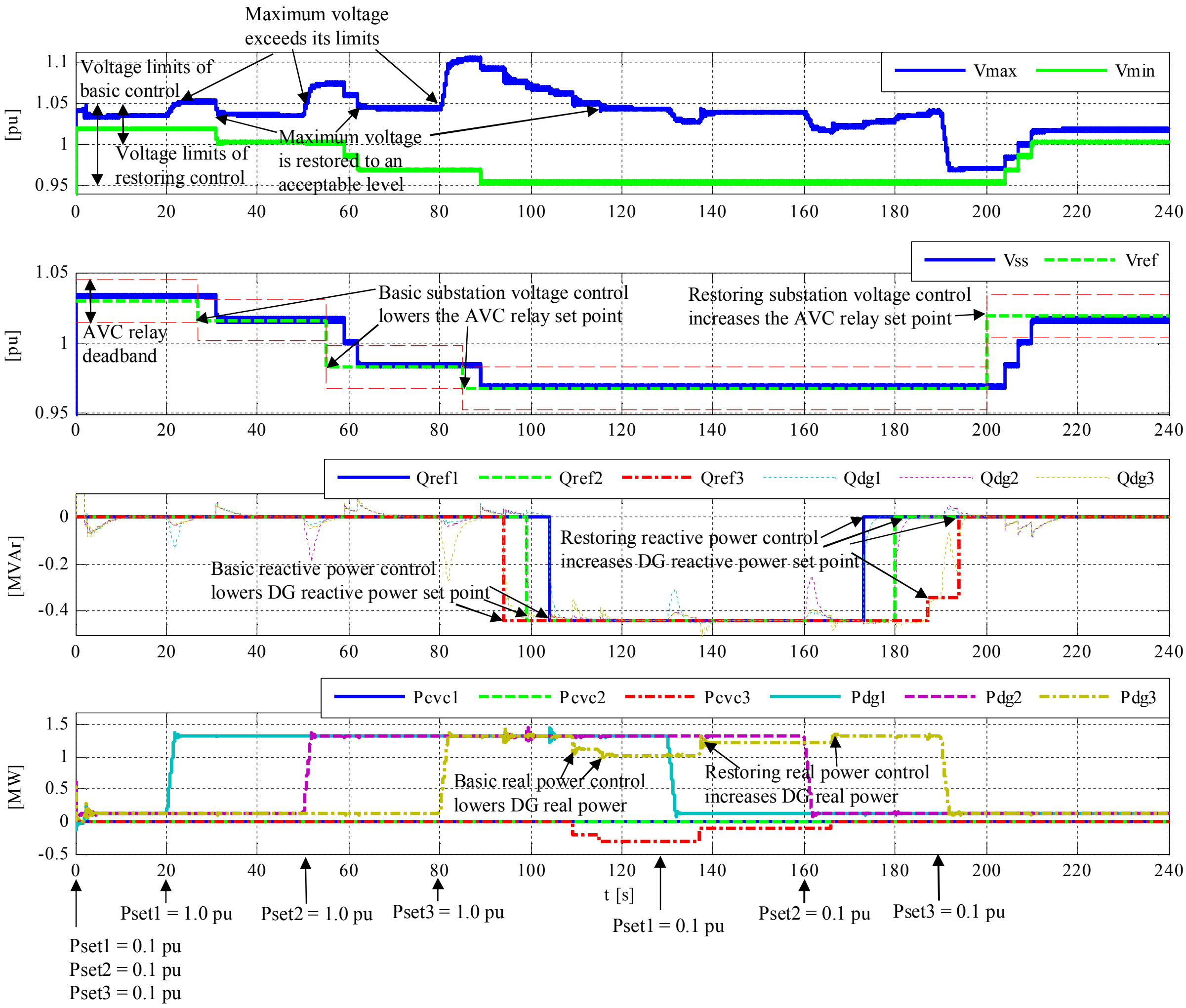

Figure 4.10. Time domain simulation results in one example case.

Real time simulations are carried out in a few publications. In [46] and [47] coordinated control of substation voltage is implemented on a separate distribution automation controller and the operation of the implemented prototype is tested using a closed-loop hardware testing facility. Network maximum and minimum voltages are directly measured and, hence, state estimation is not used.

[70] and [102] represent results of real time testing in an Austrian project DG DemoNet. Only coordinated substation voltage control is tested in these publications although also real and reactive power control is included in the previous publications of the same project (for instance [69]). In [70] and [102] the CVC algorithm is implemented as a standalone C++ application and the distribution network is simulated using DigSilent/PowerFactory. The data transfer between these systems is realized using an OPC interface and the voltages of critical nodes (i.e. nodes that can have maximum or minimum voltage) are measured.

[60] and [61] represent results of real time testing in a British project Aura-NMS. The developed CVC algorithm uses substation voltage and real and reactive powers of DGs as control variables and case based reasoning is used to determine the control actions. The proposed algorithm is embedded on a COM600 hardware platform and the real time

simulator is implemented in C++. OPC is used in data transfer between the COM600 and the real time simulator. The input voltages to the CVC algorithm are directly measured.

In [54] an algorithm that controls only reactive powers of generators is tested in RTDS simulation environment. The control algorithm is modelled in the RTDS environment and, hence, some implementation work is still needed before real distribution network tests are possible.

In [57] an algorithm utilizing energy storages is tested in the RTDS simulation environment. The control algorithm is implemented as two separate controllers and a real energy storage fed by a controllable voltage source is included in the simulation. A real smart meter provides measurement data to the coordination controller.

In this thesis, real time simulations are conducted in the RTDS simulation environment and the simulation arrangement is depicted in Figure 4.11. In the simulations, the RTDS emulates a real distribution network and the prototype software of the studied CVC algorithm is implemented as a Matlab program. Data exchange between the RTDS and the CVC algorithm is realized through a real SCADA (ABB MicroSCADA Pro SYS 600) and OPC is utilized in data exchange to and from the SCADA. [P3]

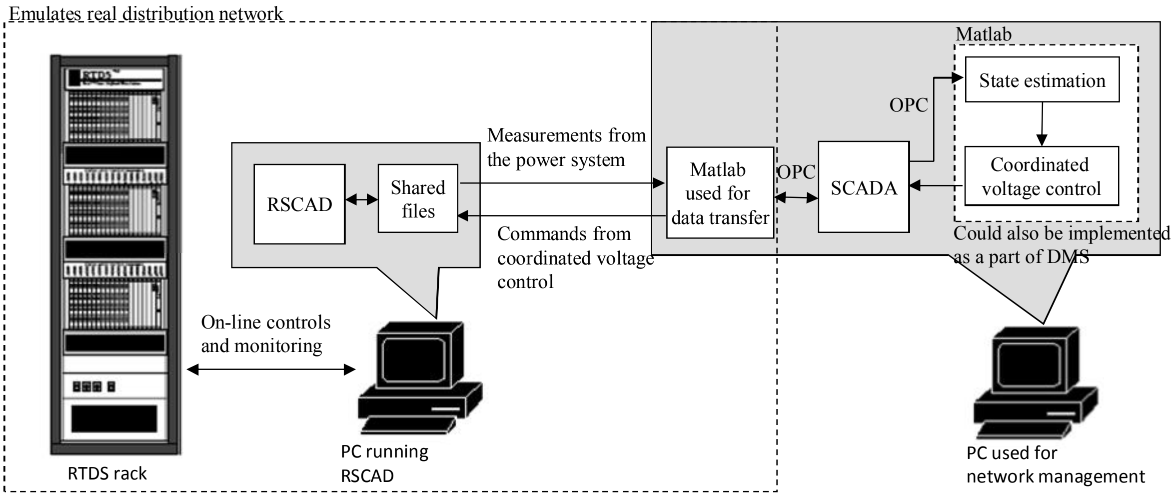

Figure 4.11. The connection used in RTDS simulations [P3].

The operation of the CVC prototype was studied extensively in the RTDS simulation environment. The simulations verified the correct operation of the implemented algorithm and the data transfer between the prototype and SCADA was tested. Also the delay of algorithm execution was visible. Based on the simulation results it was concluded that the prototype algorithm was ready for real distribution network tests. [P3]

4.4.4 Real network demonstrations

At the fourth step of the development process, real distribution network demonstrations are conducted. At this stage, problems that may arise in real network implementations are identified. Practical issues such as the need for additional measurements or the adequacy of measuring accuracy of existing equipment are discovered and the operation of the real implementation of the developed control algorithm is verified also in the real distribution network. The delays of data transfer are realistic and their effect on the operation of the algorithm can be evaluated.

The back-up procedures for situations where an important communication channel or some controllable component fails should also be tested at this development step. The voltage control algorithm should be able to detect these situations and to function reasonably also when the input data is inadequate or when some controllable component is unavailable for control. In these situations, one alternative is to use a set of predetermined control values that are such that all node voltages remain above the feeder voltage lower limit in all loading and generation situations. If the voltage rises excessively at some generator node, the unit is disconnected by its overvoltage relay.

At the beginning of real distribution network demonstrations, the algorithm is usually used in an open-loop configuration where the inputs of the algorithm are taken from the real distribution network but where the control algorithm does not yet directly control the network equipment. After successful open-loop operation is confirmed, closed-loop tests can begin.

Only a few real distribution network demonstrations have been reported in publications. [103]-[105] describe the real distribution network demonstrations of GenAVC system that implements coordinated control of substation voltage through control of AVC relay set point. The GenAVC is implemented as a separate controller and includes a state estimator and a CVC algorithm based on [44]. In [103] the open-loop operation of GenAVC is tested in two trial locations. In [104] and [105] the closed-loop tests are reported.

[71] reports the progress of field trials in project DG DemoNet. Field trials are conducted in two network locations and substation voltage and reactive powers of DGs are used as control variables in the demonstrations. The control of DG real power is not included although proposed in previous publications of the same project [69]. The CVC algorithm is implemented as a standalone C++ application and communicates with the distribution network through a real SCADA (Siemens SICAM 230). COM interface is used between the CVC algorithm and the SCADA. Critical distribution network nodes are determined by simulations and voltage measurements are installed to these critical nodes. State estimation is not used. In reactive power control, a contribution matrix is utilized. Hence, if the network switching state changes, the reactive power control algorithm might not operate correctly as the critical nodes change and the contribution matrix needs to be redetermined. The DG DemoNet voltage control strategy is planned to remain in real distribution network use also after the trial phase as [71] states that a number of DG projects have been approved for connection to one of the trial networks only on the condition that they participate in the DG DemoNet voltage control.

In [40] an algorithm utilizing optimization to determine tap positions of substation main transformer and step voltage regulators on feeders is tested in a real Japanese distribution network. The realization of the demonstration is not thoroughly documented.

Real distribution network demonstrations are planned also in Italy [54], in the UK [61] and in France [106], [107] but publications reporting the results of these demonstrations have not yet been published.

A real distribution network demonstration of one CVC algorithm is documented in [P4]. The Matlab implementation of [P3] is used to realize the CVC algorithm and data exchange with SCADA is realized using OPC. In the demonstration, the CVC algorithm operates only as an advisory tool. Measurement data is transferred automatically from SCADA to the CVC algorithm but the control commands given by the CVC algorithm are approved and executed by the network operator manually. Input data of the CVC algorithm is obtained using state estimation. The arrangement used in the demonstration is represented in Figure 4.12. [P4]

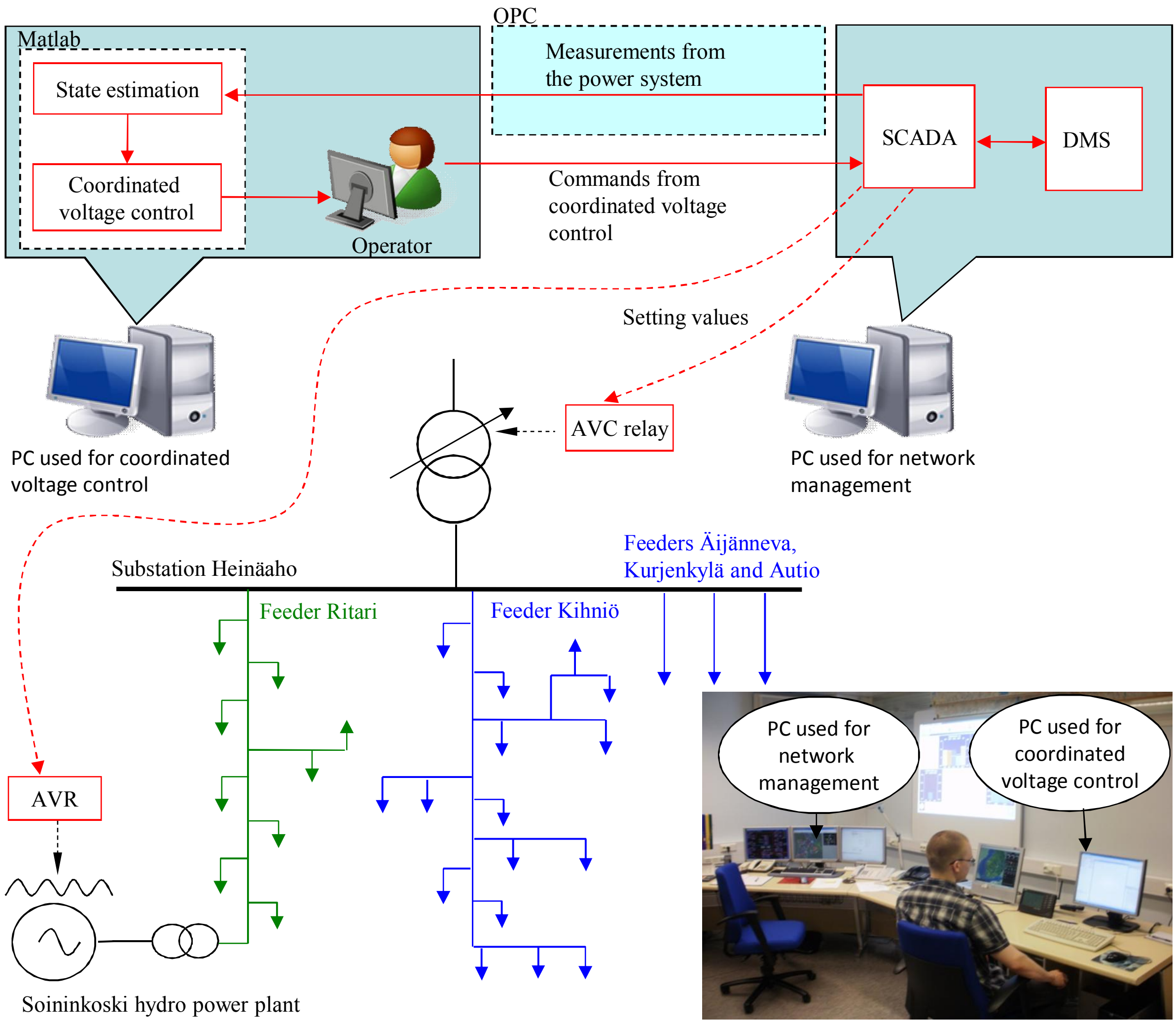

Figure 4.12. The arrangement in the real distribution network demonstration.

In the demonstration, the CVC algorithm and the state estimator were implemented as a Matlab program and run on an additional computer added to the control room. The CVC algorithm is, however, designed so that implementing it as a part of the already existing DMS would be quite easy. The DMS already includes a state estimator and, hence, only the CVC algorithm would need to be implemented. Moreover, the DMS network model is always at the same switching state as the real network and, hence, the algorithm implemented as a part of the DMS will be able to operate also in unusual network switching states. If the algorithm is implemented as a separate controller, the network model is static and the network data and switching state need to be maintained in two places (NIS database and the CVC controller) or some kind of automatic data exchange needs to be set up.

4.4.5 Commercial products

Real network demonstration is the final phase in a research project but development is needed also after this. If commercial products are available, the commissioning of active voltage control is easier to the DNO and, therefore, it is more probable that DNOs will start to consider active voltage control as a real option in network planning.

Local reactive power control can, in many cases, be realized using the existing DG voltage regulators and, hence, taking local reactive power control into use would require only revision of network planning methods. Commercial products realizing other active voltage control methods (e.g. local real power control and CVC methods) are not commonly available. At present, GenAVC [103]-[105] is to the author's knowledge the only commercial product implementing coordinated voltage control.

5 INTERCONNECTION PLANNING OF DISTRIBUTED GENERATION

In a deregulated energy market, the planning process for an interconnection of a new DG unit begins when a potential energy producer contacts the distribution network operator with a plan to connect a power plant to the DNO's network. The location, size and type of the DG unit are determined by the energy producer and the DNO has no influence in these characteristics as long as the DG unit fulfils the connection requirements set for DG units. Hence, the interconnection study is made based on the data obtained from the energy producer and concentrates on determining the possible actions needed to assure that the planned DG unit can be connected to the desired network node safely and without violating technical constraints. Also the connection costs are determined.

Publications that optimize the location and size of DG units have been published (for instance [108]-[110]). These kinds of studies cannot be directly used in distribution network planning in the liberalized energy market. They can, however, be used to inform potential energy producers on the available hosting capacity of the existing distribution networks. If all or a part of the possible network investment costs due to DG interconnection are charged from the energy producer, these kinds of studies can have a substantial effect on the locations where new DG units are planned. This thesis does not discuss these kinds of studies but concentrates on the interconnection planning of the DG units of predetermined locations and characteristics.

The aim in DG interconnection planning is to minimize the total distribution network costs including for instance investments required to connect the DG unit to the network (network reinforcement etc.) and the changes in losses and transmission charges due to the DG unit. The output of the planning procedure depends significantly on whether shallow or deep connection charges are used because the DNO aims at minimizing its own costs and does not usually try to minimize the connection fee or operational costs of the energy producer. When shallow connection charges are used, only the costs of connecting the DG unit to the nearest point in the network are charged from the energy producer whereas when deep connection charges are used, the energy producer pays all network investments required to connect the DG unit to the network [2]. Hence, deep connection charges incentivize DNOs just to reinforce the network whereas shallow connection costs can encourage the DNOs towards a more active distribution network management scheme. In Finnish MV networks, shallow connection charges are used when the connected DG unit is smaller than 2 MVA. When the connected DG unit is larger than 2 MVA the connection fee consists of the shallow connection charges and an additional fee determined based on the size of the generation unit and on the characteristics of the distribution network. This additional fee is meant to cover network reinforcement costs due to the DG unit connection. [111]

When DG interconnection is planned, the following technical constraints need to be considered:

- Distribution network voltage quality should remain acceptable also after DG interconnection.
- Thermal ratings of network components should not be exceeded.
- Fault currents in the network should not exceed the ratings of existing equipment such as the switchgear.
- DG should not adversely affect network protection and control.

The interconnection planning principles of DG vary depending on the country and also on the DNO. Some DNOs use simple design rules to decide whether a planned DG unit can be connected to the planned network node or not. The rules can give maximum generation capacities at different points of the distribution network (LV feeders, MV/LV busbars, MV feeders etc.) or determine that the fault level i.e. the three-phase short-circuit level of the connection point has to be at least some multiple of the generator rating. Also limitations determining the maximum proportion of generation to load can be used as planning rules. These kinds of rules are usually rather restrictive and, hence, often lead to a significantly lower penetration level of DG than the network would really enable. [2]

Most DNOs conduct more detailed calculations in interconnection planning as a default or if the simple design rules prohibit DG interconnection. With this approach every case is studied separately and the calculations are used to assure that all technical constraints mentioned above are taken into account. The required interconnection planning studies are discussed in [P6]. The remainder of this chapter focuses on planning issues regarding network voltage quality.

5.1 Present planning principles and tools regarding voltage quality

At present, DG is usually operated at constant power factor or constant reactive power and is not allowed to actively control the voltage at its connection point [112], [113], although reactive power control capability is already required from DG units in many countries (for example Germany [114] and Denmark [115]). In Finland, requiring reactive power control capability is recommended by Finnish Energy Industries [116]. In distribution network planning, DG is considered merely as negative load whose real and reactive power outputs are independent of the network state. The voltage control principles used currently are not altered due to DG interconnection and the planning focuses only on determining whether the DG unit can be connected to the planned network node. In weak distribution networks, voltage rise usually limits the network's hosting capacity for DG. Also the transient voltage variation at generator start-up or disconnection can become the limiting factor in some cases. In urban networks, the limiting factor is often the increase in network fault currents.

In present DG interconnection studies, two extreme loading conditions (maximum generation/minimum load and minimum generation/maximum load) are considered and a firm DG connection is assumed. If feeder voltage limits are exceeded in either case, passive methods are used to restore the voltages to an acceptable level. Usually the network is reinforced by increasing the conductor size or the generator is connected on a dedicated feeder. The benefit of this kind of planning is that the network operational principles are not altered. The downside is that reinforcing the network or building a dedicated feeder can in many cases lead to high connection costs of DG.

EN 50160 determines the acceptable voltage range and acceptable transient voltage variations. According to EN 50160, the voltages in the network have to remain within $V_n\pm10$ % (V_n is the nominal voltage). In LV networks, rapid voltage changes usually do not exceed 5 % V_n but single changes of up to 10 % V_n can occur some times per day. In MV networks, rapid voltage changes do not usually exceed 4 % V_n and the maximum allowed rapid voltage change is 6 % V_n. [9] Stricter limits for DG's effect on network voltage quality are set in many countries and by many DNOs. For instance in Germany the maximum allowable voltage change due to all generators connected to the network is limited to 2 % at all network nodes [114].

5.1.1 Network information system

Distribution network operators use a NIS in distribution network planning. Different kinds of NISs are available worldwide but also similarities between systems exist. Typical network information systems combine technical, economical and geographical data. Network data is stored in databases and calculation functions are also usually available. Steady state calculation methods and rms values are used [117]. [7], [118]

In the Nordic countries, the NIS is typically highly integrated with other systems such as the distribution management system and the customer information system. A graphical user interface is used and the network can be illustrated using a geographical map as a background. Calculation functions for power flow calculations, fault current calculations and reliability calculations are incorporated into the NIS and loads are modelled using hourly load curves [89]. Radial network structure is assumed but extensions to manage also meshed networks have been developed. [7]

The present network information systems are not adequate for DG interconnection planning even if the network voltage control method is not altered. When generation is added to the network, ring network calculation methods are needed which are not necessarily available. Also setting the calculation hour is not possible in all NISs but power flow calculations can be conducted only in the maximum loading condition of each feeder section. In DG interconnection planning the minimum loading case is, however, also needed. Hence, some development of the network information systems is needed even if active voltage control is not used. Development needs in the case where active voltage control is taken into use are discussed in chapter 5.2.2.1.

5.2 Development of planning methods to take active voltage control into account

The planning principles and tools used currently are not capable of taking active voltage control into account because a passive distribution network is assumed in the studies. Some publications (for instance [109] and [119]) propose extensions to the currently used planning procedures to model active voltage control methods but maintain the principle that planning is based only on few extreme loading/generation situations and, hence, only give information on whether the planned DG unit can be connected to the network or not. These kinds of changes to the planning procedure certainly improve the situation but do not allow comparison of network effects and costs of alternative voltage control methods.

Studies that consider the operation of the alternative voltage control methods throughout the year are needed to be able to select the most suitable method for a particular case. As a result, these kinds of studies produce information on for instance annual losses and annual generation curtailment which are more useful than the similar data calculated only for a single hour. Hourly load flow calculations using hourly load and production curves can be conducted to obtain this data [P7], [P8], [3], [120]-[123]. This statistical planning method is used in this thesis. Monte Carlo simulations can also be used to evaluate the network effects of alternative voltage control approaches [124]. In the Monte Carlo method, a large amount of simulations is conducted to obtain the probability density functions of interesting network characteristics such as node voltages. [125] combines hourly load flow calculations and Monte Carlo simulations. Load flow is calculated for every hour of the year and Monte Carlo simulations are conducted during hours where a risk of under- or overvoltage occurs to have a more accurate estimate on for instance the amount of needed generation curtailment.

5.2.1 Statistical distribution network planning method

In statistical distribution network planning, load flow is calculated for every hour of the year using statistical-based hourly load and production curves [120]-[122]. The calculations can be conducted using different voltage control strategies (i.e. passive network and different possibilities of active voltage control) and the outputs of the method can be used to compare the studied voltage control alternatives and to select the most cost-effective method for the particular case. The principle of statistical distribution network planning is depicted in Figure 5.1.

The inputs needed in statistical distribution network planning are represented on the left side of Figure 5.1. Static network data such as feeder impedances is naturally needed. Loads and generation are modelled using statistical-based hourly load and production curves. Also models for alternative voltage control methods are needed. Using this data, the hourly load flow calculations can be conducted and information on the network's operational characteristics using different network management methods is obtained. Interesting characteristics are for instance network voltage level, network losses, the number of main transformer tap changer operations, the amount of curtailed production, the amount of controlled reactive power and the amount of energy taken from the transmission network. When economical data (investment costs, cost of losses, transmission charges etc.) is combined with the outputs of hourly load flow calculations, total costs of each alternative voltage control method are obtained and the most cost-effective method can be selected.

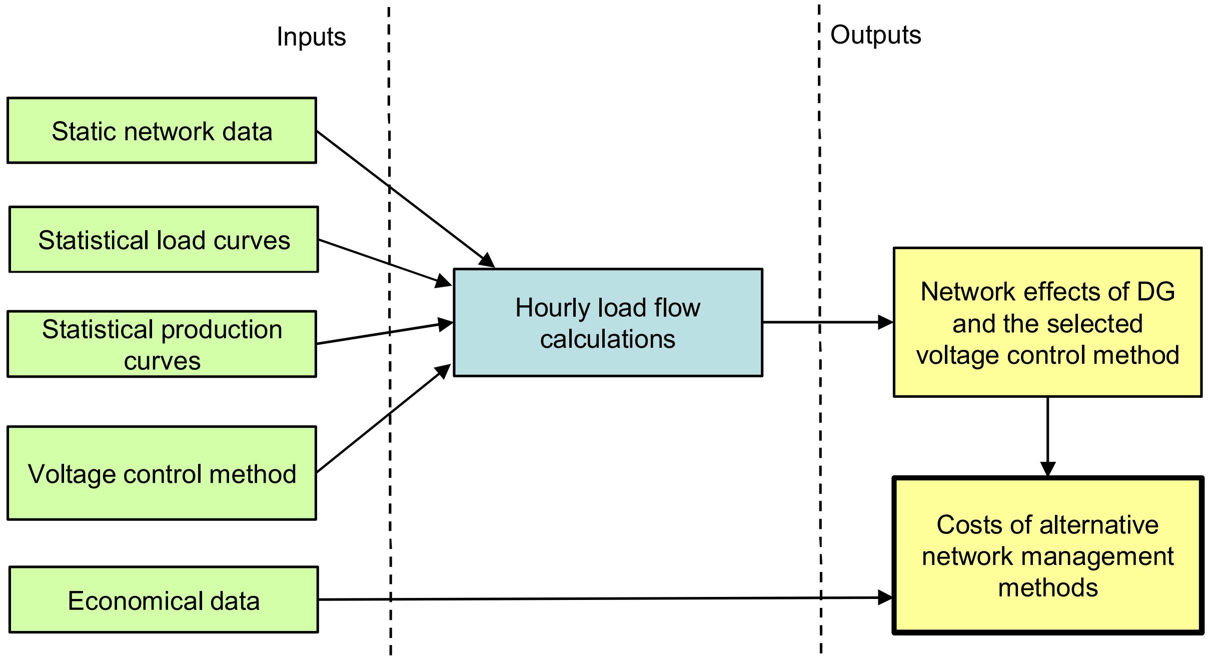

Figure 5.1. Principle of statistical distribution network planning.

It should be noted that certain technical constraints exist also in statistical planning (e.g. overvoltages should never occur). Taking these constraints into account is further discussed in chapter 5.2.2.

5.2.1.1 Load curves

In Finland, loads are modelled using hourly load curves that give the customers' average loads and standard deviations for every hour of the year. The load curves are customer group based and have been composed based on extensive measurement data obtained from Finnish distribution networks. The only variable in the model is the customer's annual energy consumption and, hence, each customer's mean powers and standard deviations for every hour of the year are obtained from the load curves just by knowing the customer group and the customer's annual energy consumption. This data is available from the customer information system. The model takes into account the different electricity use patterns of different kinds of days (working day, Saturday, Sunday, Christmas etc.) and also the temperature dependence of loads can be taken into account if desired. [89], [90]

The hourly load flow calculations of Figure 5.1 are used to compare the annual operation of alternative network management methods. In these calculations mean loads are used. For instance annual losses are calculated which requires using the mean powers [7].

When network dimensioning studies are conducted, mean powers cannot be used but powers that are not exceeded or gone below with some probability are needed. In voltage drop calculations, excess probabilities of around 10 % are often used. Even smaller probabilities are needed when equipment damage is possible (e.g. overloading studies). A Gaussian distribution is assumed for loads, which is valid when the number of customers belonging to the same customer group is adequate and, hence, is applicable in MV networks. The powers used in network dimensioning calculations can be determined as follows:

$$P_p = P_m + k_p \cdot \sigma \tag{5.1}$$

where P_p is the power having excess probability of p %, P_m is the mean power, k_p is a coefficient related to p and σ is the standard deviation. The statistical nature of the load curves needs to be taken into account also when multiple loads are summed. Arithmetic sum of powers P_p should not be used. Statistical rules need to be used instead. [7]

5.2.1.2 Production curves

Production curves are not readily available as is the case with load curves. They are, however, needed in statistical planning and, hence, need to be constructed. The production curves highly depend on the type of generating plant. Production curves modelling wind or solar power are quite fluctuating whereas production curves of small hydro power plants or CHP units are smoother. The production curves should be such that they model the statistical operation of the studied generating plant correctly.

In the studies of this thesis (publication [P8]) production curves for wind generation are composed using the method introduced in [121]. The Weibull distribution of wind speed is randomly sampled to create an hourly wind speed time series and the output power for every hour is calculated using the power curve of the studied wind turbine. The formation of the production curves is further discussed in [121].

The production curves are not accurate in the same way as load curves and cannot, therefore, be used to examine the network state during a certain hour. They, however, offer a good guess on the average operation of the network and can, therefore, be used to compare different network management options. They are, hence, suitable for statistical distribution network planning purposes. It is also possible to generate multiple production curves and to run the hourly load flow calculations using all the generated curves to take the inaccuracy of an individual production curve into account.

5.2.2 The developed planning procedure

A DG interconnection planning procedure regarding voltage issues (voltage level and fast voltage transients) is determined in [P7] and [P8]. In addition to statistical planning, also worst case studies are needed to make sure that technical constraints of the network are never overstepped. Network voltages need to remain at an acceptable level throughout the year and the fast voltage transient at generator connection or disconnection cannot exceed the set limits. The developed planning procedure is depicted in Figure 5.2.

At the first step of the planning procedure, input data is obtained. Network data and hourly load curves can be obtained from the NIS and generator data including for instance the reactive power operation and start-up current of the generator are obtained from the potential energy producer. Statistical production curves are created using the method of [121]. Also minimum and maximum production curves are needed for the worst case calculations. The minimum production curve is, at present, always a zero production throughout the year regardless of the type of the DG unit because it cannot be guaranteed that the DG unit produces at a specified hour. If, however, a large number of different types of DG units is connected to a network, the probability of zero production can become so small that the minimum production curve needs to be altered to larger values than zero production.

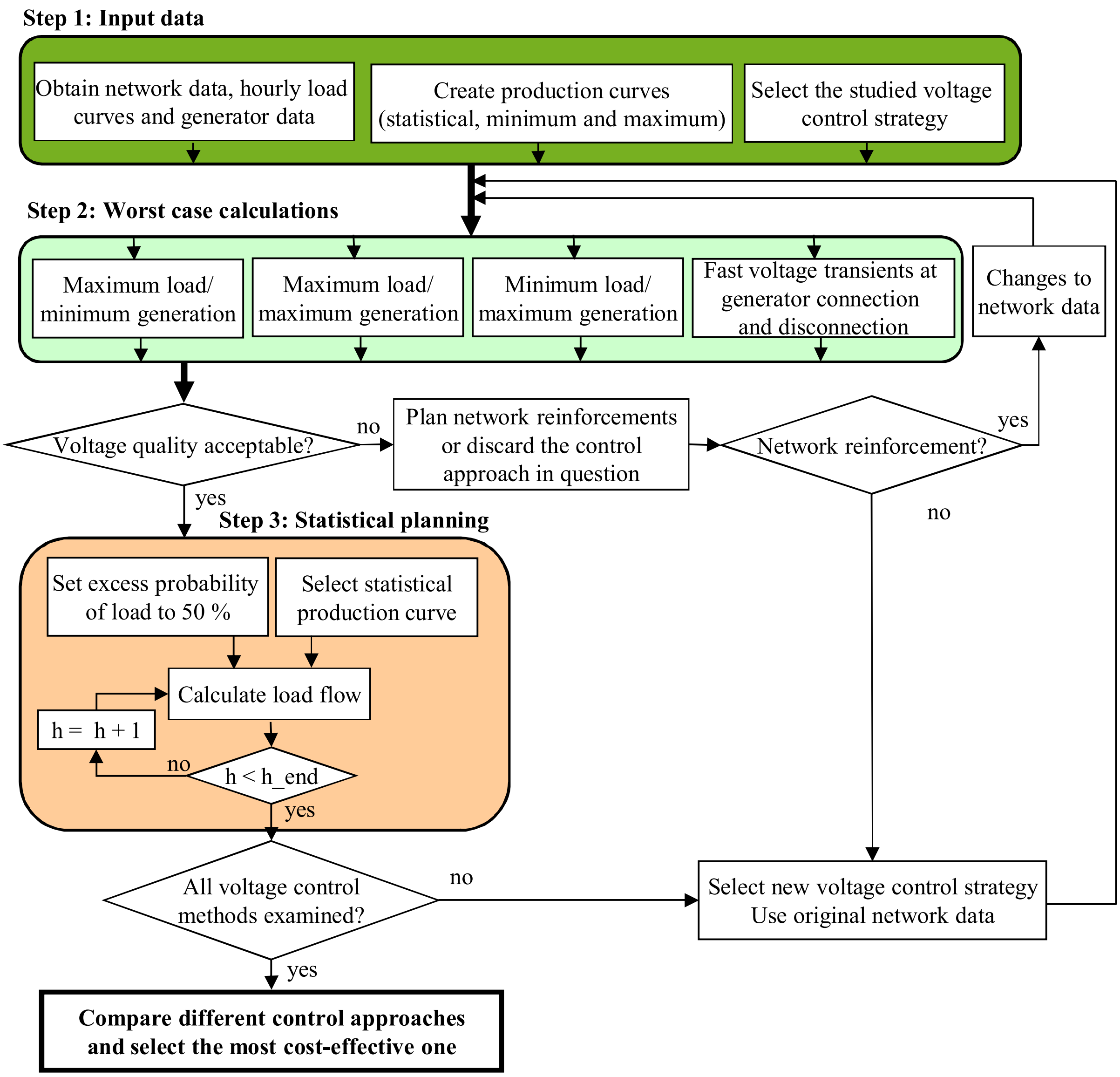

Figure 5.2. The planning procedure concerning voltage issues when a new DG unit is connected to an existing distribution network.

The maximum production curve varies depending on the type of the DG unit and on whether a firm or a non-firm connection is used. If production curtailment is allowed, the maximum production curve can also be set to zero throughout the year because if voltage rise becomes excessive at some hour, production curtailment can be used to restore network voltages to an acceptable level. If a firm connection is used, the maximum production curve is usually a flat curve representing nominal power production throughout the year. In case of, for instance, a CHP plant, the plant might not be used at summer time and, hence, the maximum production curve can be zero during summer months and at the nominal power at other times.

At the second step of the planning procedure, worst case calculations are conducted. These are needed to verify that the network operates acceptably throughout the year. The worst case calculations include calculating the fast voltage transients at generator connection and disconnection and calculating the voltage levels at three extreme loading conditions.

The transient voltage variation at generator connection and disconnection can be determined by calculating load flow with and without the generator. In these simulations, the voltage regulating devices such as main transformer tap changers should be disabled and the loading situation should be the one in which the DG unit causes the largest voltage variation in the network. This is usually the minimum loading condition. To be able to perform these studies, the start-up current of the generator needs to be known.

The voltage level of the network also needs to be studied during the worst case calculations. Three loading conditions are examined at this step: maximum load/minimum generation, maximum load/maximum generation and minimum load/maximum generation. These studies are used for network dimensioning purposes and, therefore, load powers that are not gone below (minimum loading) or exceeded (maximum loading) with some probability, are used. In voltage drop calculations, excess probabilities of around 10 % are often used [7]. This might be a suitable probability for these studies as well. Hence, the excess probability of loads can be set to 10 % when the maximum loading is determined and to 90 % when the minimum loading is determined.

The maximum load/minimum generation case is the case which is, at present, studied when distribution networks with no DG are planned. The dimensioning factor is voltage drop and, therefore, the substation voltage is set to its lowest possible value in these calculations. The minimum load/maximum generation case is the case which is, currently, used when interconnection planning of DG units is conducted (see chapter 5.1). In this case, voltage rise is the limiting factor and, therefore, the substation voltage is set to its highest possible value in these calculations. The maximum load/maximum generation case is needed because the difference between network maximum and minimum voltages can be largest in this case. Hence, if coordinated substation voltage control is used, it is possible that the control algorithm is able to keep all network voltages at an acceptable level in the minimum load/maximum generation case but at the maximum load/maximum generation case the network voltages cannot be normalized by using only the substation voltage control because of the large difference between network maximum and minimum voltages.

After the worst case calculations, it is checked whether the transient voltage variations at generator connection and disconnection are acceptable and whether the network voltage level remains acceptable during all hours of the year when the selected voltage control method is used. If the voltage quality remains acceptable, statistical distribution network planning is conducted. If any of the network's technical constraints is overstepped, network reinforcements are planned or a new voltage control strategy is selected and the worst case calculations are redone.

Worst case calculations and statistical calculations are conducted for different voltage control strategies and the outputs of these calculations are used to select the most suitable method for a particular case. The usage of the developed planning procedure is demonstrated in [P8].

The statistical planning procedure has been used in this thesis to study issues regarding network voltages, but a similar planning method could also be used when for instance thermal constraints are examined.

5.2.2.1 Development needs of network information systems

Some development of the current NISs is needed to be able to execute the statistical planning procedure introduced above. The Nordic NIS already includes network data (feeder impedances etc.) and loads are modelled using hourly load curves [89] and customer data obtained from CIS, but models for production curves and active voltage control methods are not available. These models need to be added to the NIS to enable the conducting of the hourly load flow calculations. Steady state calculation methods are used in the NIS and, hence, also models of DG units and active voltage control methods need to be simple enough.

At present, DG is modelled in NIS load flow calculations as a negative load with fixed real and reactive powers. This is adequate when the DG output is independent of the network state but when the DG unit is operated for instance in voltage control mode, its reactive power output depends on the terminal voltage and, hence, fixed reactive power output cannot be used. Therefore, the DG models need to be extended to enable modelling of different real and reactive power control strategies. Time domain modelling is not needed but a simple steady state model is adequate. For instance, if the DG unit operates in voltage control mode, only the droop curve describing the dependence of reactive power output on the terminal voltage needs to be added and the actual implementation of the control does not need to be considered.

Other active voltage control methods also need to be modelled using a simple enough description for NIS steady state calculations. Methods based only on local measurements can be quite easily modelled: only the dependencies between the measured variable and the controlled variable need to be described. Modelling of coordinated methods can require more work depending on the complexity of the control method. If active voltage control is implemented as a part of the DMS, and the NIS and the DMS are highly integrated, the DMS models can be directly utilized in NIS calculations.

The planning procedure of Figure 5.2 could be quite easily automated in the NIS. The different steps of the planning procedure could be implemented as separate functions. Load flow calculations for every hour of the year are needed in steps 2 (worst case calculations) and 3 (statistical planning). In step 2, hourly load flow calculations are needed when the calculations are conducted for the first time because the hours of maximum and minimum load are not known. In the following simulation rounds when different voltage control strategies are studied, the results of the first round can be utilized and simulations can be conducted only at the previously determined maximum and minimum load hours. In step 3, hourly load flow calculations are conducted at every simulation round. Conducting the load flow calculations by hand for every hour is not practically possible because there are 8760 hours in one year. Hence, the processes of steps 2 and 3 should be implemented as their own functions that would automatically conduct the required simulations for the whole year. Implementing these functions would be quite easy because the already existing NIS calculation functions could be utilized and only the loops implementing the calculations throughout the year need to be added.

A planning procedure for protection planning when DG is interconnected to a distribution network is presented in [10] and its implementation as a part of the NIS is discussed. If also the planning procedure regarding voltage issues proposed in this thesis was implemented as a part of the NIS, the DNOs would be able to conduct almost all DG interconnection studies using the NIS.

5.2.3 Future development needs

The statistical planning method used in this thesis calculates load flow only once every hour. In case of highly variable production such as wind or solar generation this might not, however, adequately describe the operation of the real system. The effect of generation on for instance losses and power flow between the distribution network and the transmission network can be adequately described using the average production value of each hour. The amount of control operations such as tap changer operations can, however, be substantially larger in reality than the hourly calculations predict. In future, the planning method should be developed to be able to also take the faster generation variations into account. This requires examining typical generation patterns of wind and solar generation and developing the planning method based on this examination.

This thesis concentrates only on interconnection planning of DG and does not discuss long-term planning of networks including DG. In future, also long-term planning should be developed. Long-term planning might, however, turn out to be rather complex in the current deregulated energy market because DG can appear at any point in the network and the DNO has no influence in the location, size, type or construction timing of the DG units. This makes the DG connection scenarios very uncertain. Moreover, political decisions such as feed-in tariffs can change the connection scenario substantially. Hence, if the network is dimensioned based on the maximum DG scenario, it will most likely be overdimensioned. On the other hand, if a smaller DG penetration level is assumed it is possible that the network will turn out to be insufficient and a second reinforcement is needed. In this operational environment, active voltage control can provide an attractive option in long-term planning of networks in areas where a significant amount of DG can possibly be connected in the future because it provides more flexibility because the investments are made on intelligence and not on physical devices such as conductors.

5.3 Selecting the most suitable voltage control method for a particular case

When the voltage control method for a particular case is selected, the network effects and costs of the alternative voltage control strategies need to be determined throughout the year. Also other issues such as the ease of implementation need to be taken into account.

5.3.1 Determining the total costs of alternative methods

The costs of alternative voltage control methods can be determined using statistical distribution network planning (see chapter 5.2.1). DG interconnection and the selection of the voltage control method affect at least the following cost factors:

- Investment costs (network reinforcement, added measurements, IT etc.)
- Costs of losses
- Transmission charges
- Distribution charges of DG
- Maintenance costs of the tap changer
- Costs of DER reactive power control
- Costs of curtailed generation

Some of these costs are paid by the DNO and some by the DG owner and this division depends on legislation and interconnection agreement made with the energy producer. Investment costs can be paid either by the DNO or by the energy producer depending on whether deep or shallow connection charges are used. Losses and transmission charges are paid by the DNO. Losses can increase or decrease due to DG and transmission charges decrease when DG is connected to the network. Distribution charges of DG are income to the DNO and costs to the DG owner with the exception of some rare DNOs that use negative DG distribution charges. In Finland, the maximum allowed distribution charge for production units is 0.7 €/MWh [126]. Maintenance costs of the main transformer tap changer are paid by the DNO. Reactive power control can bring about costs to the DNO if reactive power control is defined as an ancillary service in the interconnection agreement. It can also be set as a requirement for interconnection. Also generation curtailment can be seen as an ancillary service or as a requirement for connection and, hence, its costs can be paid by the DNO or it can just decrease the income of the DG owner. The aim in distribution network planning is to minimize the total costs of the DNO and, hence, the output of the planning procedure can vary significantly depending on legislation and contracts determining which costs are paid by the energy producer and which by the DNO.

When the total costs are calculated, the different natures of the cost factors need to be taken into account. The different timing of each cost factor can be taken into account using the present-worth concept [7].

5.3.2 Implementation issues

Taking active voltage control into use for the first time changes the operational and planning principles of distribution networks and, hence, requires lots of work from the DNO. To diminish this work and to relieve the reluctance of DNOs to change their operational principles, taking active voltage control into use should be made as easy as possible. The ease of implementation is affected at least by the following:

- Active voltage control can be implemented as a part of the already existing control systems (DMS) or as a completely new system. The first approach might encourage

DNOs to take active voltage control into use because DMS's data, calculation functions and control possibilities can be directly utilized. For instance, no additional network modelling is needed.

- The inputs of the active voltage control can be measured or estimated. Installing additional measurements and data transfer infrastructure incurs work and costs.

All methods that are selected as alternatives for voltage control should have the ability to work properly also in exceptional network states. The control system should manage for instance the loss of an important communication channel.

5.3.3 Effect of regulation

Regulation is the factor that eventually determines the way DNOs develop their networks. Practical implementation issues do certainly need to be dealt with before active network management (ANM) can become a part of business as usual for DNOs. Also planning methods need to be developed to enable comparison of network effects of alternative network management methods. The final selection of the network management method is, however, made based on which method gives the most profit. Hence, regulation has a significant role in determining whether widespread utilization of active voltage control will realize. If investments in physical devices (i.e. capital expenditures) rather than in intelligence (i.e. operational expenditures) are incentivized, the control principles of distribution networks will most probably remain intact. If the DNO is, however, rewarded for using ANM when it is cost-effective, ANM will eventually become common practice in distribution networks.

6 CONCLUSIONS

The structure and control methods of existing distribution networks are planned assuming unidirectional power flows. The amount of distributed generation is, however, constantly increasing which creates a need to revise the current operation and planning principles of distribution networks. Distributed generation affects the distribution network operation in many ways and can cause problems related to for instance voltage quality, protection and increasing fault current levels. In weak distribution networks, the amount of generation that can be connected to an existing distribution network is usually limited by the voltage rise effect. Also the transient voltage variation at generation connection or disconnection can become the limiting factor in some cases.

At present, the distribution networks are considered to be passive systems whose voltage is controlled only at the substation. DG is considered merely as negative load in distribution network planning and is not allowed to participate in distribution network control in any way. If DG interconnection would cause excessive voltage rise, passive methods such as increasing the conductor size or building a dedicated feeder are used to mitigate the maximum distribution network voltage. When this kind of planning is used, the operational principle of the network remains unchanged but, as a drawback, the connection costs of DG can become high. The voltage rise can be mitigated also using active voltage level management. This changes the operational principle of the network radically but can, in many cases, lead to significantly lower distribution network total costs than the passive method.

Distribution networks should be constructed in the most cost-effective way which would be, in many cases, achieved through using active voltage control instead of the passive approach. At present, active voltage level management is not, however, considered as a real option in distribution network planning. Distribution network operators are often reluctant to change their operational principles and the network business regulation does not, at least in Finland, incentivize usage of active voltage control. Moreover, commercial products realizing active voltage control are hardly available and the currently used planning tools are unable to take active voltage control into account. Hence, some development is still needed to enable large-scale utilization of active voltage control in real distribution networks. This thesis aims at overcoming some barriers that are, at present, preventing active voltage control from becoming a common tool in distribution network operators' planning procedure.

6.1 Main scientific contribution of the thesis

The work done in this thesis can be divided into two areas: development and testing of active voltage control methods and development of distribution network planning. The scientific contribution of the thesis can be concluded as follows:

- Various voltage control methods (rule based and optimizing) for different kinds of situations have been developed and tested using time domain simulations.
- Operation of one developed coordinated voltage control method has been verified using real time simulations and also a real distribution network demonstration is conducted.
- The development process of active voltage control methods has been defined.
- Statistical distribution network planning is developed to take active voltage control into account.
- Issues that affect selection of voltage control method for a particular case are discussed.

The developed voltage control methods are relatively simple and their operation can be quite easily understood. Moreover, the developed methods can be implemented as a part of the already existing distribution management system which could encourage DNOs to take the methods into use because active voltage control would only be a new feature of the DMS and not a completely new system. Hence, the developed methods are such that taking them into use would be relatively easy to the DNOs.

The complete development process of active voltage control methods is defined in the thesis and also gone through using one of the developed voltage control methods. Most publications on active voltage control concentrate only on determining the control principles of the control algorithm and time domain operation and practical implementation issues are omitted. This is not, however, adequate to make the proposed method a real alternative in DNOs' network planning procedure but the methods should be commercialized or, at least, their operation in real distribution networks needs to be demonstrated before the DNOs will consider taking the methods into real distribution network use.

Development and commercialization of active voltage control methods do not alone guarantee that the methods will be taken into real distribution network use. Also planning methods need to be developed in order to be able to show the possible benefits of utilizing active voltage control. In this thesis, a planning procedure that utilizes statistical distribution network planning is used to compare different voltage control strategies. Also other issues that affect the selection of the voltage control method for a particular case are discussed.

In conclusion, the studies of this thesis aim at making the introduction of active voltage control as easy as possible to the DNO. This is achieved by developing voltage control methods that are easily implementable in real distribution networks and by developing the distribution network planning procedure to enable comparison of alternative voltage control methods. First three of the barriers introduced in 1.1.1 are, hence, dealt with. In addition to these studies, also the network business regulation model needs to be modified and acquisition of adequate input data for active voltage control needs to be arranged to enable large-scale utilization of active voltage control.

The results of this thesis can be directly utilized by companies that produce network information systems and distribution management systems. Also distribution network operators can utilize the results of this thesis in distribution network planning and operation. At present, the network business regulation model does not encourage usage of active voltage control but this might change in the future if the regulators decide to change the model to incentivize towards minimizing the network's total costs instead of the current practice of favouring investment costs over operating costs. Also the regulators can exploit the results of this thesis when the regulation model is contemplated. Active voltage control can also indirectly affect the business of companies that manufacture small generation units because high connection costs can make otherwise profitable DG projects uneconomical.

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Publication 1

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Active Voltage Level Management of Distribution Networks with Distributed Generation using On Load Tap Changing Transformers

Anna Kulmala, Kari Mäki, Sami Repo and Pertti Järventausta

Abstract—**In this paper, time domain performance of active voltage level management based on co-ordinated control of substation voltage is studied. A control algorithm that controls the set point of the automatic voltage control (AVC) relay at the substation is proposed and its operation in an example network is tested using PSCAD simulations. The study network is a real distribution network located in south-west Finland which will experience voltage rise problems if a planned wind park is constructed.**

Index Terms— **Distributed generation, Active voltage level management, AVC relay, Time domain simulations**

I. INTRODUCTION

CONNECTIONS of distributed generation (DG) to weak distribution networks often experience voltage rise problems. The voltage rise caused by DG can be reduced with passive methods such as increasing the conductor size but this can be quite expensive and make the connection of DG uneconomical. Active management of distribution networks can allow connection of more DG into existing distribution networks and, consequently, reduce the connection costs of DG. Voltage rise can be actively mitigated for instance by controlling the active and reactive power of distributed generators or by reducing the substation voltage. [1], [2]

In this paper, co-ordinated control of the substation voltage is studied using time domain simulations. The studied voltage control algorithm controls the automatic voltage control (AVC) relay target voltage and is based on [3] and [4]. Some modifications to the algorithm have, however, been made to prevent adverse interactions that can cause continuous tapping (hunting) of the tap changer. Also, a control with stricter voltage limits is added to restore the network voltages to a normal level after for instance disconnection of the power plant. The time domain performance of the modified control algorithm is tested on an example distribution network using PSCAD simulations.

The paper will firstly introduce some active voltage level management methods for distribution networks. Thereafter, the proposed control algorithm is described in detail and selection of control parameters is discussed. The study system is introduced and simulation results are represented. Finally, the operation of the proposed control algorithm is assessed based on the simulation results.

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II. ACTIVE VOLTAGE LEVEL MANAGEMENT

The simplest active voltage level management methods are based only on local measurements and do not require additional data transfer between distribution network nodes. On the other hand, the voltage of distribution networks could be controlled using a sophisticated distribution network management system (DMS) which controls all components capable of voltage control and requires a lot of data transfer between network nodes. The DMS can control for instance tap changers at substations, voltage regulators, power plants, compensators and loads. [5]

Some active voltage control methods are introduced in the following chapters. The first two methods are based on local measurements. The third chapter discusses co-ordinated voltage control methods. In this paper, methods that require data transfer between network nodes are referred to as co-ordinated.

A. Local reactive power control

Voltage rise caused by DG can be decreased by allowing the generator to absorb reactive power. At present, DG is usually operated with unity power factor and is not allowed to participate in distribution network voltage control. However, if DG controlled its reactive power based on its terminal voltage (in other words operated in voltage control mode) the distribution network voltage level would vary less between different loading conditions and more DG could be allowed to connect to the network as the voltage rise would be decreased. If power factor control is preferred, the controller could operate in power factor control mode when the terminal voltage is within determined limits and switch to voltage control mode when the limits are overstepped. [6], [7]

The reactive power control capability of DG depends on its network interface. Power plants with synchronous generator or modern power electronic interface are capable of controlling their active and reactive power independently as long as their operational limits are not exceeded. When induction generators are used the reactive power is dependent on the active power and can not be controlled unless some kind of controllable reactive power compensation device is used. As these plants usually contain power factor correction (PFC) capacitors, the reactive power consumption could be at simplest controlled by disconnecting the capacitors when the terminal voltage rises excessively. If continuous control of reactive power is needed a reactive power compensator based on power electronics (e.g. STATCOM) could be connected at the machine terminals. [1]

If local reactive power control is used its effect on network losses has to be considered. Also, the adequacy of reactive power compensation capacitors at the substation has to be reviewed. [8]

B. Production curtailment

Voltage rise can be decreased also by reducing the active power output of DG. If the voltage limit is exceeded only rarely the DG owner might find it beneficial to curtail some of its generation at times of high voltage if allowed to connect a larger generator to the network. This kind of control would be particularly suitable for DG whose output depends on some external factor such as the wind speed. [2], [8]

The simplest method to implement production curtailment is to disconnect a required number of generating units when the voltage exceeds its limit. If active power of DG can be controlled for instance by blade angle control of wind generators, disconnection is not required as the active power of DG can be controlled continuously. [8]

C. Co-ordinated voltage level management

Co-ordinated voltage control methods determine their control actions based on information about the whole distribution network and therefore data transfer between network nodes is required. Typically, co-ordinated voltage control methods regulate the substation voltage and reactive power of DG but also other components capable of voltage control could be included in the control [5]. Control is usually based on network voltages that can be either measured or estimated. At present, measurements on distribution networks are usually restricted to the substation and precise information about the state of the network is not normally available. However, measurements in distribution networks are likely to increase in future which makes the use of co-ordinated voltage control methods more attractive. In Finland, some distribution network operators have already installed automatic meter reading (AMR) devices to all their customers.

Usually, co-ordinated voltage control methods alter the set points of lower level controllers such as AVC relays at the substations [3], [4] and power factor controllers of the DGs [9]. Also implementations that alter the lower level controllers or control the actuating devices directly have been suggested [10], [11]. The benefit of the first approach is that the lower level controllers do not need to be replaced and only the upper level controller and data transmission network have to be installed.

The simplest co-ordinated voltage control methods determine their control actions according to simple rules (e.g. reduce AVC relay set point when distribution network maximum voltage exceeds its limit). This type of control is most suitable for use in simple networks with only few measurements and control possibilities such as typical Finnish distribution networks. Co-ordinated control can also use an optimization algorithm to determine the control actions. Optimization algorithms should be used if determining simple control rules is difficult due to complexity of the network or multitude of controllable components. [12]

The simplest and most studied method of co-ordinated voltage level management controls the substation voltage based on maximum and minimum voltages in the distribution network. These maximum and minimum voltages can be measured [4] or estimated [3]. The control principle is simple: The substation voltage is decreased, when maximum voltage is too high, and increased, when minimum voltage is too low. If both maximum and minimum voltages are outside the feeder voltage limits it is not possible to normalize the voltages by controlling the substation voltage and, therefore, nothing is done. The substation voltage is controlled through changing the set point of the AVC relay which controls the tap changer of the main transformer. [3], [4]

When co-ordinated control of substation voltage is used, the number of tap-change operations is increased which increases the need for maintenance of the tap changer. However, the maintenance costs are likely to be smaller than network reinforcement costs.

III. THE PROPOSED CONTROL ALGORITHM

The proposed control algorithm controls the AVC relay target voltage and is based on the control algorithm presented in [3] and [4]. Some modifications to the algorithm have, however, been made to prevent unnecessary tapping of the tap changer and to restore the voltages to a normal level after for instance disconnection of DG. The functional diagram of the algorithm is shown in Fig. 1. The inputs to the algorithm are distribution network maximum and minimum voltages and the purpose of the algorithm is to keep both the voltages between the feeder limits. The voltages can be measured or estimated.

If both maximum and minimum voltages are within the feeder limits, the AVC relay set point is not changed as all distribution network voltages are at an acceptable level with the current setting. If maximum voltage exceeds the feeder voltage upper limit and minimum voltage falls below the feeder voltage lower limit, it is not possible to restore all voltages to an acceptable level by controlling the substation voltage and, therefore, the AVC relay set point is not changed in this case either. If only one of the input voltages is outside its limit, the set point is changed if certain other conditions are fulfilled.

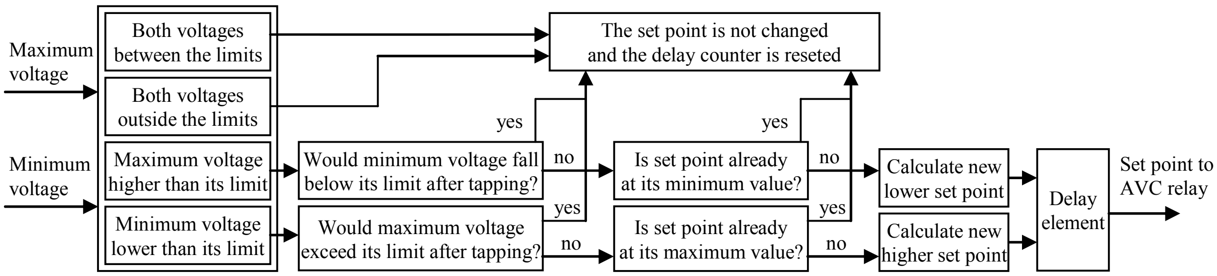

Fig. 1. The functional diagram of the proposed control algorithm.

When maximum voltage exceeds feeder voltage upper limit, the AVC target voltage is lowered. However, if the minimum voltage would fall below feeder voltage lower limit after tapping, the set point is not changed as this could lead to continuous set point changing and tapping of the tap changer. In [13] the target voltage is not changed if the minimum voltage is within the target voltage adjustment step of feeder voltage lower limit. In the algorithm proposed here, the minimum voltage has to be more than a tap step away from the lower limit to allow the set point change.

When minimum voltage falls below feeder voltage lower limit, the AVC relay target voltage is increased. Otherwise the operation of the algorithm is similar to that introduced in the preceding paragraph.

After determining whether the set point should be changed the algorithm checks if the set point is already at its limit. The set point limits are adjusted to keep the substation voltage within feeder voltage limits and, therefore, the AVC relay target voltage has to be between limits of $V_{upper}-DB \geq V_{ref} \geq V_{lower}+DB$, where V_{upper} and V_{lower} are the feeder voltage upper and lower limits, V_{ref} is the target voltage and DB is the AVC relay deadband setting. The AVC relay set point is changed in user-defined steps. However, if the calculated new set point would exceed the voltage reference limits the target voltage is set to its extreme value. This change might be so small that it will not initiate a tap-change operation but, on the other hand, the whole control range of the set point is used and tapping initiated always when possible. A delay element is also included in the algorithm as short-time voltage variations should not initiate a set point change.

If only the above described algorithm would be used the network voltages could remain at an unusually high or low level after a change in the operating conditions. Therefore, a control with stricter voltage limits (restoring control) is added to the algorithm. The operation of the control is similar to the basic control depicted in Fig. 1, only the control parameters are different. The purpose of the basic control is to restore the network voltages to an acceptable level when voltage rise or drop at some network node becomes excessive whereas the purpose of the restoring control is to restore the voltages to a normal level when the voltage level of the whole network remains unusually high or low after for instance disconnection of DG.

A. Selecting the parameters of the control algorithm

The control algorithm uses the parameters shown in Table I when determining the AVC relay set point. Some of the parameters are determined by the network's operating limits or parameters of other components in the network whereas some can be more freely selected. The parameters should be such that continuous tapping of the tap changer does not occur in any circumstances and that the set point is not changed if the AVC relay or the tap changer is operating. If target voltage adjustment step (the set point change at a time) and the delays are correctly selected these conditions can be fulfilled.

TABLE I
CONTROL ALGORITHM PARAMETERS

Parameter	Selection criteria
AVC relay deadband	Directly from AVC relay parameters
Main transformer tap step	Directly from main transformer characteristics
Feeder voltage upper limit	All customer voltages have to be kept in an acceptable level
Feeder voltage lower limit	
Target voltage adjustment step	One set point change should initiate only one tap-change operation
Delay in basic control	The set point should not be changed before the AVC relay has completed its operation
Delay in restoring control	
Voltage upper limit in restoring control	Network voltage level should not remain in an unusually high or low level
Voltage lower limit in restoring control	

The set point of the AVC relay is lowered (increased) only if minimum (maximum) voltage is more than a tap step away from the feeder voltage limit. Hence, one set point change should initiate one tap-change operation but never more. If multiple tap steps are initiated, oscillations between the AVC relay and the voltage control algorithm might occur. On the other hand, the target voltage adjustment step should be selected to be as large as possible to ensure that one tap-change operation is initiated as often as possible when the set point of the AVC relay is changed as the delay will naturally be longer if multiple set point changes are needed. If the target voltage adjustment step is selected to be a bit smaller than the tap step the preceding conditions are fulfilled.

If the delay of the control algorithm is too small the algorithm might change the AVC relay set point also in situations where no change is needed. For instance, a change in the supply system voltage might initiate a set point change even if the normal operation of the AVC relay would be sufficient in this situation. On the other hand, the control algorithm should be able to restore the voltages between feeder voltage limits before DG is disconnected from the network by its over/undervoltage protection and, hence, the delay should not be too long.

The delay can be selected using similar principles as with cascaded tap changers in radial networks: The number of tap operations needed to compensate for the worst case voltage disturbance at the supply system is computed. The delay of the proposed control algorithm is selected to be longer than the time needed to complete these tap operations. [14] This ensures that the set point is not changed when the AVC relay or the tap changer is still operating. After determining the delay it is checked that the voltage control operates faster than DG protection to prevent unnecessary disconnection of DG. In many cases the delay of the AVC relay has to be shortened from the delays used nowadays to be able to fulfill these requirements.

IV. Description of the Study System

The operation of the proposed control algorithm is studied in an example distribution network located in south-west Finland. The examined network consists of two medium voltage feeders which are fed from the same substation and its structure is depicted in Fig. 2. The network is relatively weak and contains a long sea cable and will therefore experience voltage rise problems when a planned wind park depicted in Fig. 2 is connected to the network. Voltage control in the example network has been previously studied in [8] using load-flow calculations but time domain simulations have not been carried out. In this paper, the operation of the proposed control algorithm is examined using PSCAD simulations. Simulations are conducted in maximum and minimum loading conditions of the example network. As the effect of DG on network voltage depends also on its ability to control its reactive power, simulations are performed with two kinds of network interfaces. When induction generators are used the reactive power is dependent on the active power and can not be controlled. When synchronous generators are used the reactive power can be controlled through excitation control. Network protection is not modeled.

The network model includes a representation of an AVC relay and tap changer mechanism [15]. The AVC relay measures the substation voltage and compares it with its target voltage V_{ref}. If the measured voltage differs more than the AVC relay deadband DB from the target voltage a delay counter is started. This counter remains active as long as the measured voltage is outside the hysteresis limits of the relay and a tap-change operation is initiated when the counter reaches its setting value T_{AVC}. In these simulations, the deadband DB is 1 %, the hysteresis limit 90 % of the operating value and the delay T_{AVC} 5 s. Line drop compensation is not used. The tap changer mechanism is modeled simply as a delay. The tap step is 1.67 % and the delay 1 s.

The target voltage of the AVC relay is determined by the control algorithm depicted in Fig. 1. The feeder voltage lower and upper limits used in the basic control are 0.95 and 1.05 pu whereas the restoring control tries to keep the network voltages between 0.98-1.03 pu. The target voltage adjustment step is 1.5 % which is a bit smaller than the tap step and the delay is 10 s in both the basic and the restoring controls. The minimum and maximum voltages are supposed to be measured.

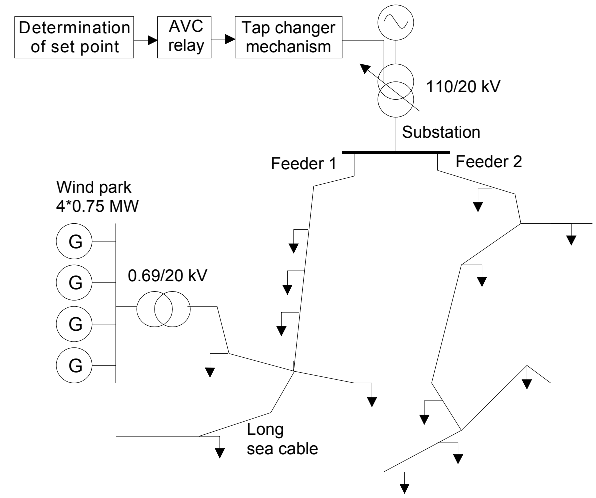

Fig. 2. The structure of the example network.

The wind park consists of four 0.75 MW induction or synchronous generators and a generator transformer. When induction generators are used a 200 kVAr PFC capacitor, which compensates for nearly all of the no-load reactive power demand of the generator, is connected to the terminals of each generator. Simulations are carried out with and without the capacitors.

When synchronous generators are used the reactive power of the wind park is controlled through excitation control of the generator. The automatic voltage regulators (AVR's) of synchronous generators can be operated either in voltage control or power factor control mode. The excitation system is of type IEEE AC8B and it contains also an underexcitation limiter of type IEEE UEL2 [16]. Power factor control is implemented as cascade control where the power factor controller determines the set point of the voltage controller. The power factor controller is of type IEEE Var Controller Type 2 [16]. Simulations are conducted in three different situations: voltage control with set point of 1.0 pu and power factor control with set points of 1.0 and 0.92_{ind}.

V. Simulation Results

The simulation sequence is similar in all the simulations: At the beginning of the simulation the wind power plant is not connected to the network. At time 10 s all the generators are connected to the network. The mechanical moment T_m of the generators is at this time 0.0 pu. At time 30 s T_m is raised to 0.5 pu which raises the active power output of the plant to approximately 1.5 MW. At time 90 s T_m is raised to 1.0 pu which raises the active power to approximately 3.0 MW. At time 150 s two of the four generators are disconnected from the network and at time 180 s also the remaining units are disconnected.

In the simulations the reactive power of the generators is controlled based on local voltage measurement whereas the substation voltage is controlled using the control algorithm illustrated in Fig. 1. The reactive power control is much faster than the co-ordinated control and the substation voltage will, therefore, be changed only if the reactive power control does not restore the voltages to an acceptable level.

A. Wind park with induction generators

When the 3 MW wind park depicted in Fig. 2 is connected to the network using induction generators the proposed control algorithm is able to restore the network voltages to an acceptable level in both maximum and minimum loading conditions irrespective of the state of the PFC capacitors. However, when the capacitors are in use and the network load at its minimum value the substation voltage is lowered to a value of approximately 0.96 pu and the minimum voltage in the network is almost at its limit. Hence, if the load of feeder 2 would in this situation increase even slightly the minimum voltage would fall below its limit. If the PFC capacitors are not used the voltage rise caused by the wind park is smaller and the substation voltage need not be lowered as much as with the capacitors connected.

If only the voltage level of the network is considered, no PFC capacitors should be installed to the wind park using induction generators as the voltage level of the network varies in this case less between different loading conditions and fewer control actions of the proposed control algorithm are needed to keep the network voltages within acceptable limits. However, the absorbtion of reactive power might increase the network losses significantly and, therefore, controlling the capacitors based on the terminal voltage might prove to be more profitable.

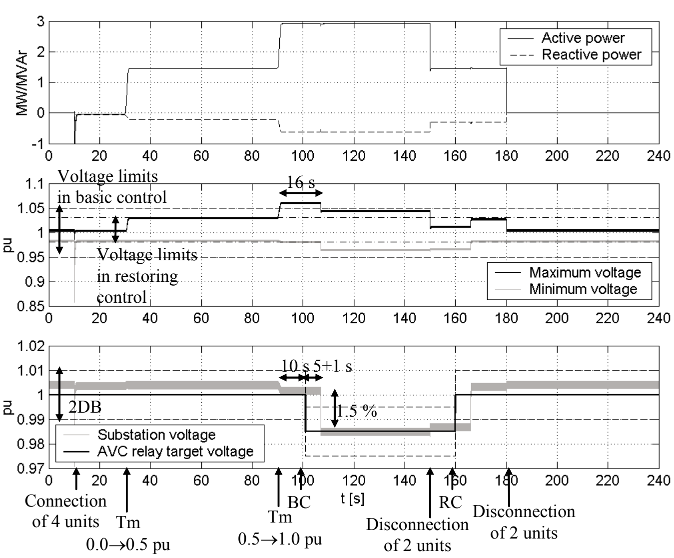

Fig. 3. The operation of the proposed control algorithm in maximum loading conditions with the PFC capacitors connected. The uppermost figure depicts the active and reactive power of the wind park measured at the 20 kV side of the generator transformer and the lower figures illustrate network maximum and minimum voltages, the substation voltage and the AVC relay target voltage. BC means basic control and RC restoring control.

The operation of the proposed control algorithm is illustrated in Fig. 3 in an example case. In this situation the network voltages remain in an acceptable level when the wind park generates 1.5 MW of active power but when the active power increases to 3.0 MW the voltage rise at the generator terminals becomes excessive and the proposed control algorithm lowers the AVC relay target voltage after a delay of 10 s. The tap changer operates after the AVC relay and tap changer delays (5+1 s) and the maximum voltage is restored below the feeder voltage upper limit. After disconnection of two generator units the network voltage level is below the restoring control limits and, therefore, the AVC relay target voltage is increased and the tap changer operates to increase the network voltages. The disconnection of the remaining generators does not initiate any control actions.

B. Wind park with synchronous generators

When the 3 MW wind park is connected to the network using synchronous generators the reactive power of the park is not dependent on the active power of the park but can be controlled through excitation control of the generators. Hence, the wind park can either absorb or generate reactive power whereas with induction generators the park absorbs reactive power in all situations. Traditionally these kinds of distributed power plants have been operated with unity power factor. In the example case studied, the unity power factor approach can not be used without network reinforcements because the proposed control algorithm is not able to restore the maximum voltage at an acceptable level when the wind park is producing 3 MW in network maximum loading conditions. In minimum loading conditions the substation voltage has to be lowered to approximately 0.96 pu and both the maximum and minimum voltages are almost at their limits. Hence, if a 3 MW wind park is connected to the example network, the network voltages can not be restored to an acceptable level only by controlling the substation voltage but also either the active or the reactive power of the plant has to be controlled. When synchronous generators are used the absorbtion of reactive power can be accomplished by using the AVR in voltage control mode or in power factor control mode with an inductive set point. Operation in voltage control mode is preferable as in this case the network voltages vary less between different loading and production conditions and also the losses are likely to be smaller because reactive power is absorbed only when necessary.

The operation of the proposed control algorithm with unity power factor control is depicted in Fig. 4 in network minimum loading conditions. The basic control (BC) operates three times: once when the active power is increased to 1.5 MW and twice when the active power is increased to 3 MW. When two tap-change operations are needed to restore the voltages to an acceptable level the second target voltage change takes place only 4 seconds after the first tap-change operation because the delay counter of the proposed control algorithm has been active since the preceding target voltage change. The latter change in AVC relay target voltage is only one per cent because lowering the target voltage by 1.5 per cent would have taken it below its lower limit. In this case also a target voltage change of one per cent initiates a tap-change operation and the voltages are restored to an acceptable level after a total delay of 26 seconds. The restoring control (RC) operates in this case twice: once after the disconnection of the first two generators and once after the disconnection of the remaining units. When voltage control is used in the same loading condition the network voltages vary less between different production conditions and only one operation of the proposed control algorithm is needed.

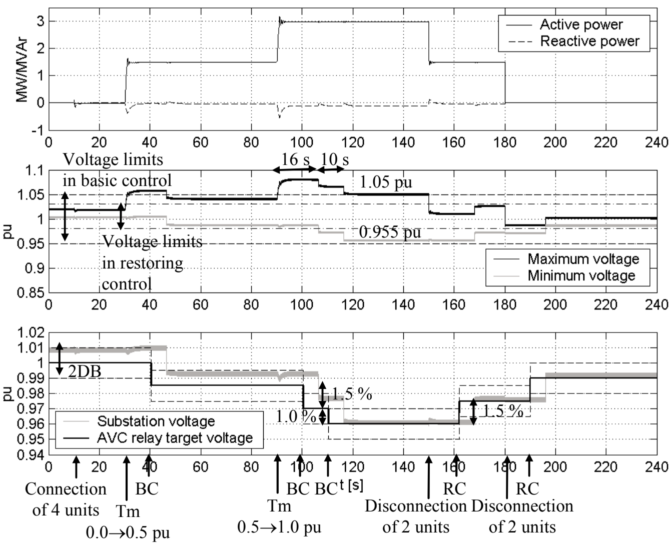

Fig. 4. The operation of the proposed control algorithm in minimum loading conditions when power factor control with set point of 1.0 is used. The notations are similar as in Fig. 3.

C. *Discussion of the simulation results*

The proposed control algorithm operated in the simulations as desired. The basic control restored the network voltages to an acceptable level if normalizing the network voltages by controlling the substation voltage was possible. No continuous tapping of the tap changer appeared and also the restoring control operated as desired, in other words, network voltages did not remain in an unusually high or low level after for instance disconnection of the wind park.

The proposed control algorithm regulates only the substation voltage and the reactive power of the power plant(s) is controlled based on local measurements. However, absorbing reactive power may increase the network losses and, therefore, controlling the substation voltage might be a better way to regulate the voltage. This could be accomplished by including the reactive power control as a part of the co-ordinated voltage control algorithm. In future, these kinds of studies will be conducted.

VI. Conclusions

In this paper, the operation of active voltage level management based on co-ordinated control of substation voltage was studied. A control algorithm that controls the substation voltage based on maximum and minimum voltages in the network was introduced and the operation of the proposed control algorithm was tested using time domain simulations. The simulations were carried out using an example network which is a real distribution network located in south-west Finland.

The proposed control algorithm operated in the simulations as desired. It restored the network voltages to an acceptable level always when possible and did not cause continuous tapping of the tap changer in any situation. Also, network voltages did not remain in an unusually high or low level after a change in network operating conditions.

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Publication 2

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INCREASING PENETRATION OF DISTRIBUTED GENERATION IN EXISTING DISTRIBUTION NETWORKS USING COORDINATED VOLTAGE CONTROL

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ABSTRACT

Connections of distributed generation (DG) to weak distribution networks often experience voltage rise problems. The voltage rise caused by DG can be reduced with passive methods such as increasing the conductor size but this can be quite expensive. Active management of distribution networks can allow connection of more DG into existing distribution networks and, consequently, reduce the connection costs of DG. Voltage rise can be mitigated for instance by reducing the substation voltage or by controlling the active and reactive power of DGs.

In this article, active voltage level management of distribution networks with DG is studied. A coordinated voltage control algorithm that controls the substation voltage and DG reactive power is proposed and its operation is tested using time domain simulations. The simulations are carried out in an example network that is a real distribution network located in central Finland and will experience voltage rise problems if a hydro power plant is connected to the network.

1 INTRODUCTION

The structure and control methods of existing distribution networks are designed based on the assumption of unidirectional power flows. However, the amount of generation connected to distribution networks is constantly increasing which changes the operation of distribution networks in many ways. Distributed generation (DG) can influence the distribution network in many positive ways, e.g. voltage support or loss reduction, but also some problems may arise. These include for instance voltage rise problems, protection problems and increase in network fault levels. [1]

In weak networks the capacity of connected generators is usually limited by the voltage rise effect. At present, DG is usually considered merely as negative load in distribution system design and the amount of DG is limited based on extreme conditions of minimum load/maximum generation and maximum load/minimum generation. It is assumed that DG can not participate in the control of distribution networks in any way. However, if the penetration level of DG is to be significantly increased, the current operating policy of distribution networks has to be revised. [1]

Voltage rise can be mitigated using passive methods such as increasing the conductor size or connecting the generator to a dedicated feeder or at a higher voltage level. This can, however, be quite expensive. Active management of distribution networks can allow connection of more DG into existing distribution networks and, consequently, reduce the connection costs of DG. Voltage rise can be mitigated for instance by controlling the active and reactive power of DGs or by reducing the substation voltage. Control can be based only on local measurements (e.g. production curtailment when the connection point voltage is above its limit) or be coordinated (e.g. control of substation voltage based on maximum and minimum voltages in the network). [2]

In this article, a coordinated voltage control algorithm is proposed and its operation is studied using time domain simulations. The algorithm controls the substation voltage and DG reactive power and determines its control actions based on the state of the whole network. The paper will firstly introduce some active voltage level management methods. Thereafter, the proposed control algorithm is described in detail and the study network is introduced. Finally, simulation results are represented and the operation of the algorithm is assessed based on the simulation results.

2 ACTIVE VOLTAGE LEVEL MANAGEMENT

At present, distribution network voltage is usually controlled only at the substation using on load tap changers (OLTC) of main transformers. Tap changers are controlled by automatic voltage control (AVC) relays and the voltage at the substation is maintained constant or, if line drop compensation is used, the substation voltage depends also on the load current through the transformer [3]. DG does not take part in voltage control in any way and is usually operated with unity power factor. Voltage rise problems are solved using passive methods and the operational principle of distribution networks is not changed.

Voltage rise can be mitigated also using active network management. The simplest active voltage level management methods are based only on local measurements and do not require additional data transfer between distribution network nodes. On the other hand, the voltage of distribution networks can be controlled using an advanced distribution network management system which controls all components capable of voltage control (e.g. tap changers at substations, voltage regulators, power plants, compensators and loads) and requires data transfer between network nodes [4]. When active voltage level management is taken in use the distribution network is no longer passive and the operational principle of the network is radically altered.

2.1 Methods based on local measurements

The simplest methods of active voltage level management are based only on local measurements and, hence, do not need any additional data communication to be installed. In many cases they can, however, increase the capacity of DG which can be connected to an existing distribution network considerably [2].

2.1.1 Local reactive power control

Voltage rise caused by DG can be decreased by allowing the generator to absorb reactive power. In most countries, DG is nowadays usually operated with unity power factor and is not allowed to participate in distribution network voltage control. However, if DG controlled its reactive power based on its terminal voltage (in other words operated in voltage control mode) the distribution network voltage level would vary less between different loading conditions and more DG could be allowed to connect to the network as the voltage rise would be decreased. If power factor control is preferred, the controller could operate in power factor control mode when the terminal voltage is within determined limits and switch to voltage control mode when the limits are overstepped [5]. [6, 7]

The reactive power control capability of DG depends on its network interface. Power plants with synchronous generator or power electronic interface are capable of controlling their active and reactive power independently as long as their operational limits are not exceeded. When induction generators are used the reactive power is dependent on the active power and can not be controlled unless some kind of controllable reactive power compensation device is used. At simplest the consumption of reactive power can be increased by disconnecting the power factor correction capacitors usually fitted at the generator terminals. If a power electronic compensator (STATCOM, SVC) is connected to the generator terminals the reactive power can be controlled continuously. [1]

If local reactive power control is used its effect on network losses has to be considered. The additional reactive power flow can also increase the need of reactive power compensation capacitors at the substation and increase the number of main transformer tap changer operations. However, if excessive voltage rise is expected to happen only occasionally the network's total costs can diminish significantly if large investments (network reinforcements) can be avoided. [8]

2.1.2 Production curtailment

Voltage rise can be decreased also by reducing the active power output of DG. If the voltage limit is exceeded only rarely the DG owner might find it beneficial to curtail some of its generation at times of high voltage if allowed to connect a larger generator to the network. The simplest method to implement production curtailment is to disconnect a required number of generating units when the voltage exceeds its limit. If the active power of DG can be controlled for instance by blade angle control of wind generators, disconnection is not required as the active power control of DG can be continuous. [2, 8]

2.2 Coordinated methods

Coordinated voltage control methods determine their control actions based on information about the whole distribution network and, therefore, data transfer between network nodes is required. Control is usually based on network voltages that can be either measured or estimated. At present, measurements on distribution networks are in many cases restricted to the substation and precise information about the state of the network is not available. However, measurements in distribution networks are likely to increase in future which makes the use of coordinated voltage control methods more attractive.

In Finland, distribution networks are typically managed using a distribution network management (DMS) system that combines the control possibilities of SCADA and the static information stored in network databases. The DMS calculates estimates for the distribution network states using substation measurements and hourly load curves that give the customers' average loads and standard deviations for every hour of the year. Also DG units can be taken into account if power measurements or production estimates are available. In Finland and worldwide, many distribution network operators have already installed automatic meter reading (AMR) devices to all their customers. The AMR measurements can be used to improve the accuracy of distribution network state estimate either by utilizing the measurements directly in the state estimation or by using the AMR measurements to improve the load curve accuracy. [9]

Usually, coordinated voltage control methods alter the set points of lower level controllers such as AVC relays at the substations [10, 11] and power factor controllers of the DGs [12]. Also implementations that alter the lower level controllers or control the actuating devices directly have been suggested [13, 14]. The benefit of the first approach is that the lower level controllers do not need to be replaced and only the upper level controller and data-communication network have to be installed.

The simplest coordinated voltage control methods determine their control actions according to simple rules (e.g. reduce AVC relay set point when distribution network maximum voltage exceeds its limit). This type of control is most suitable for use in simple networks with only few measurements and control possibilities such as traditional radial distribution networks. Coordinated control can also use an optimization algorithm to determine the control actions. Optimization algorithms should be used if determining simple control rules is difficult due to complexity of the network or multitude of controllable components. [15]

2.2.1 Methods based on control rules

The simplest and most studied method of coordinated voltage level management controls the substation voltage based on maximum and minimum voltages in the distribution network. The voltages can be measured [11] or estimated [10]. The control principle is simple: The substation voltage is decreased, when maximum voltage is too high, and increased, when minimum voltage is too low. If both maximum and minimum voltages are outside the feeder voltage limits it is not possible to normalize the voltages by controlling the substation voltage and, therefore, nothing is done. The substation voltage is controlled through changing the set point of the AVC relay which controls the tap changer of the main transformer. [10, 11] In [16] the algorithm is further developed to prevent unnecessary tapping of the tap changer and to restore the voltages to a normal level after for instance disconnection of DG.

The reactive power of DG can be controlled based on local measurements (see 2.1.1) in which case the reactive power control will always operate faster than the possible coordinated control of substation voltage. Therefore, the whole reactive power capacity of DG would be taken into operation before the substation voltage is controlled. Reactive power control of DG could also be included in the coordinated voltage control algorithm [17] which would determine both the substation voltage and the reactive power of DG.

When the number of controllable variables increases determining simple control rules becomes more difficult. In [12] and [18] a two-stage continuous control algorithm that aims to keep the network voltages near their nominal value is proposed. The control can also be such that actions are taken only when either the minimum or the maximum voltage is approaching its limit. Algorithm proposed in [19] tries to restore the network voltages between acceptable limits by controlling the OLTC position and voltage regulation mode of the main transformer and the generators' reactive power output. In [20] the OLTC of the main transformer is controlled first. If the voltages can not be restored to an acceptable level using the OLTC the reactive power of DGs is controlled according to a ranking table.

2.2.2 *Methods using optimization*

Coordinated voltage control algorithms can also use some kind of optimization algorithm to determine the control actions. Optimization algorithms are particularly useful in situations where several controllable components exist and where determining simple control rules is therefore difficult. The practical implementation of methods using optimization is more complex than those using simple rules. In some cases the optimization algorithm might not be able to find a solution (converge). In addition, since multiple control functions are used, the control algorithm should know the order in which the control actions need to be executed when multiple control actions are suggested. Also the computational time required for the optimization has to be taken into consideration as if the control method is designed for continuous use and not only for off-line studies its execution can not cause too much delay to the controls. Moreover, the control solution determined by the optimization algorithm should not radically deviate the network from the current operating point. [15]

Different optimization methods and objective functions have been proposed in publications. In [2] and [15] optimal power flow (OPF) is used to find the most favourable control options. In [2] OPF is used to minimise the active power curtailment and in [15] the OPF objective function was formulated to minimise the costs of transformer tap operation, reactive power absorption and the curtailed generation. The controllable variables are in both cases substation voltage (using main transformer OLTC) and reactive and active power of DG.

In [21], [22] and [23] a genetic algorithm is used to determine the control operations. In [21] the algorithm controls the main transformer OLTC, static VAr compensators (SVC), step voltage regulators (SVR) and shunt capacitors and reactors. Output of DG is not controlled. The objective function tries to keep the network voltages near their nominal value and, at the same time, reduce network losses. In [22] the main transformer OLTC, DG's reactive power and shunt capacitors are controlled using an algorithm that tries to minimise the difference of network voltages to nominal. In [23] the genetic algorithm is used to find a solution which minimises active power losses in the network. The execution time of genetic algorithms is typically quite long which should be taken into account if the objective is on-line control of the network and not only off-line studies.

In [24] a local-learning algorithm in conjunction with multiobjective optimization and a supervisory process is used to determine the set points to voltage controlling devices. The objective function consists of active power losses, average voltage deviation, maximum voltage deviation and the reactive energy costs. The benefit of this approach is that using a local-learning algorithm reduces the solution time substantially and, therefore, this algorithm would be particularly suitable for online operating modes. [24]

3 THE PROPOSED CONTROL ALGORITHM

The proposed control algorithm controls the substation voltage and reactive power of DG by changing the voltage set point of substation AVC relay and power factor set point of DG automatic voltage regulator (AVR). The AVR is operating in power factor control mode and, when network voltage control is not needed, unity power factor is used. Power factor control mode is selected instead of voltage control mode because the control variable in coordinated voltage control is DG reactive power. The algorithm is an extended and slightly modified version of the algorithm presented in [16]. The purpose of the algorithm is to keep the voltages at the medium voltage network between acceptable limits. If the low voltage network has been dimensioned correctly this should ensure that also customer voltages are acceptable. The acceptable level of customer voltages is defined in European Standard EN50160 [25].

The control algorithm comprises two functions: Basic control is used to restore the network voltages to an acceptable level when voltage rise or drop at some network node becomes excessive (in other words maximum or minimum voltage exceeds its limit). Restoring control restores the DG's power factor set point to unity when network state allows it and normalizes the voltages when the voltage level of the whole network has remained unusually high or low after, for instance, disconnection of DG. Both controls can still be divided in two: the first part controls the substation voltage and the second the reactive power of DG.

The algorithm used for substation voltage control is suitable for distribution networks in general and different number of DG because changing the substation voltage influences the whole network and, therefore, the location of maximum and minimum voltage does not affect the control algorithm operations.

The algorithm used for reactive power control of DG is suitable for use in traditional radial distribution networks where only few DGs exist. A typical example is the network introduced in chapter 4. The algorithm assumes that network maximum voltage is always located either at the substation or at generator terminals and that there is no need to use DG reactive power control to increase network minimum voltage (or that this is not possible). If the latter condition does not apply, the algorithm will still operate correctly but some control capacity will be left unused. In networks where DG reactive power control is needed also to increase network minimum voltage, the DG reactive power control algorithm needs to be extended and the inference used will become more complex.

Two versions of the algorithm are studied. In the first one, substation voltage is primarily controlled and DG power factor is changed only if substation voltage control is not able to restore the network to an acceptable state. In the second one, DG reactive power is the primary control variable. Both approaches have advantages and disadvantages: When substation voltage is primarily controlled, additional reactive power flow is needed more rarely and, therefore, also the losses are likely to increase less than in the second approach. On the other hand, the increased number of substation tap changer operations increases the maintenance need of the tap changer and causes transient voltage variations to the whole distribution network. Hence, depending on the network and planning principles either one could be more advantageous.

3.1 Operational principle

The inputs to the proposed control algorithm are maximum and minimum voltages in the network, substation voltage and the generator connection point voltage. In more complex networks also information about the location of maximum and minimum voltages etc. might be needed for power factor control. The voltages could be measured or estimated and the accuracy of the measurement or estimate has to also be taken into consideration [26] either in the input voltages given to the control algorithm or in the feeder voltage limits.

Figure 3.1 depicts the operational principle of the proposed basic control when substation voltage is primarily controlled. Substation voltage control block (on the left) is activated (started) every time the control algorithm is executed and DG

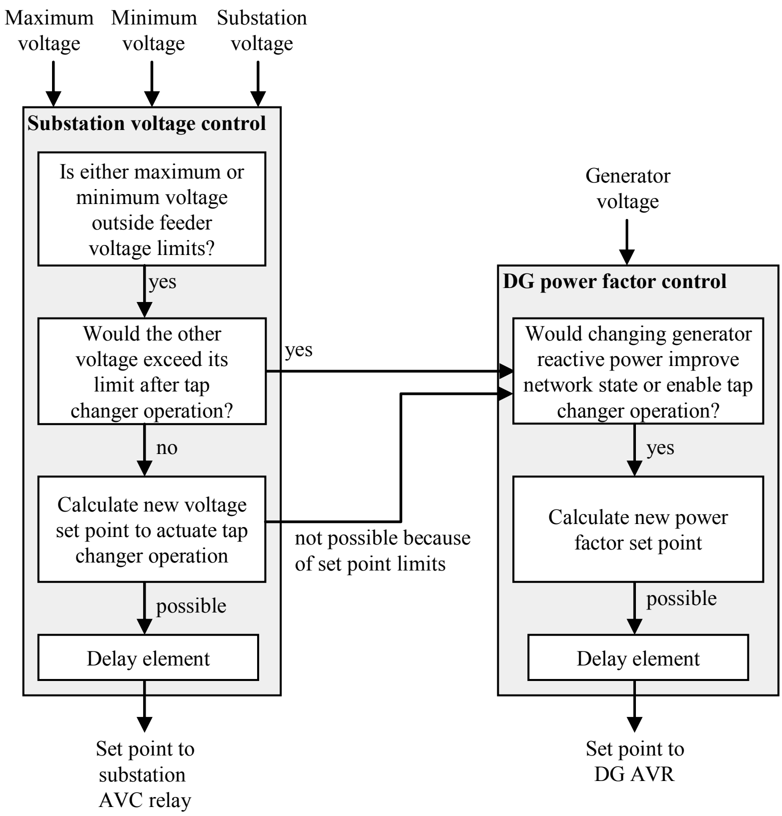

Figure 3.1: *The functional diagram of the proposed basic control when substation voltage is the primary control variable.*

power factor control (on the right) only when substation voltage control block activates it. When the sequence of controls is reversed i.e. DG reactive power is the primary control variable, the only change in the operational principle is that the two control blocks change places and substation voltage control is activated by power factor control.

The control principle in the basic control when substation voltage is controlled first is the following: Substation voltage is decreased when network maximum voltage exceeds feeder voltage upper limit and minimum voltage would not fall below feeder voltage lower limit after tap changer operation. Correspondingly, substation voltage is increased, when minimum voltage is lower than feeder voltage lower limit and maximum voltage has adequate margin to feeder voltage upper limit. If network voltages can not be normalized by controlling substation voltage, power factor control is activated and DG AVR power factor set point is changed if this would improve the network state or enable the operation of substation voltage control.

When DG reactive power is primarily controlled the control principle is following: DG power factor is decreased (and DG reactive power consumption increased) if this would either reduce network maximum voltage when it exceeds feeder voltage upper limit or enable the operation of substation voltage control when minimum voltage is lower than the feeder voltage lower limit. If DG power factor control is not needed or is not able to operate, substation voltage control is activated. In the proposed control algorithm it is assumed that the network is such that there is no need to use DG reactive power control to increase network minimum voltage and, therefore, no part that increases DG reactive power production is included.

The operational principle of restoring control is illustrated in Figure 3.2. It consists of two control blocks of which one is intended to restore the DG power factor to unity when network state allows it and the other to keep the voltage level of the whole network at a desired level. The control principle is following: DG power factor is increased if generator voltage has decreased enough. If the objective of the control algorithm is to keep DG power factor set point as near to unity as possible (substation voltage controlled first in basic control) also a part that reacts when minimum voltage has increased enough is included. This part activates basic substation voltage control that in turn lowers the voltage level of the whole distribution network. After tap changer operation also the generator voltage has decreased and the first part of the restoring DG power factor control is able to increase the power factor set point. If restoring power factor control is not needed, restoring substation voltage control is activated. Restoring substation voltage control is similar to basic substation voltage control but has stricter voltage limits.

The proposed control algorithm thus consists of four control blocks. Two of these control the substation voltage and two the reactive power of DG. A more precise description of the individual control blocks is given in the following chapters.

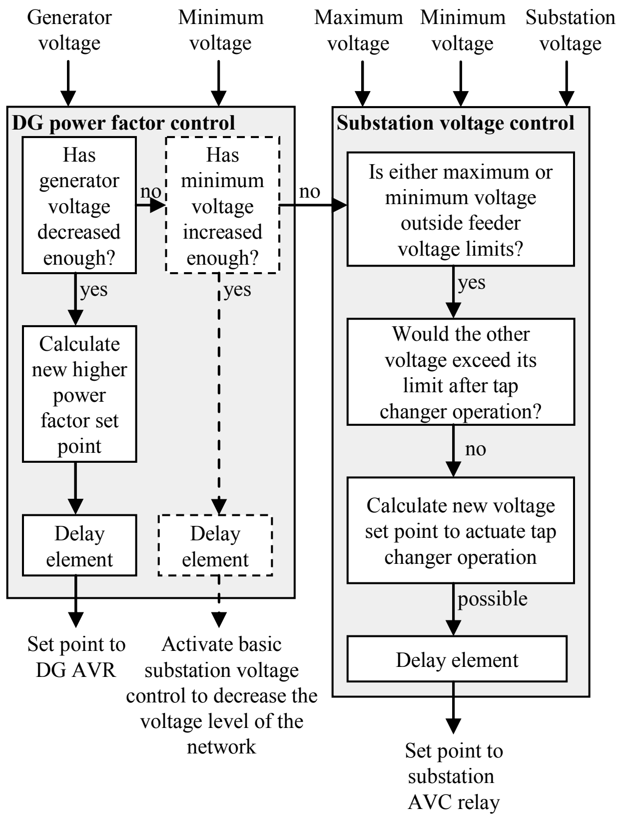

Figure 3.2: *The functional diagram of the proposed restoring control.*

3.2 Notation of variables

The following notations are used in the subsequent chapters:

V_{max}	network maximum voltage
V_{min}	network minimum voltage
V_{ss}	substation voltage
V_{gen}	generator voltage
V_{upper}	feeder voltage upper limit
V_{lower}	feeder voltage lower limit
V_{ref}	substation AVC relay voltage set point
V_{refupper}	AVC relay voltage set point upper limit
V_{reflower}	AVC relay voltage set point lower limit
DB	AVC relay deadband

tap	main transformer tap step
hyst	power factor control hysteresis bandwidth
$cos\varphi_{set}$	generator AVR power factor set point
$cos\varphi_{lim}$	minimum power factor set point
step	power factor set point adjustment step
$V_{diffupper}$	generator voltage operational limit in restoring power factor control
$V_{difflower}$	minimum voltage operational limit in restoring power factor control

3.3 Substation voltage control

The proposed control algorithm controls the substation voltage through changing the substation AVC relay set point. Substation voltage is controlled by two control functions: basic control (Figure 3.1) and restoring control (Figure 3.2). These controls are identical except for different parameter settings and the fact that restoring control never activates power factor control. A detailed flow chart of the operation of substation voltage control is depicted in Figure 3.3. Its operation is similar regardless of the sequence of controls. The inputs to the control are substation voltage V_{ss} and maximum V_{max} and minimum V_{min} voltages in the network. The algorithm uses maximum and minimum voltages to determine if the AVC relay voltage set point needs to be changed or the power factor control block activated. Substation voltage is used when the new AVC relay set point is calculated.

The first part (Part 1 in Figure 3.3) of the algorithm determines whether the substation AVC relay set point should be changed. When maximum voltage V_{max} exceeds feeder voltage upper limit V_{upper}, the AVC relay voltage set point V_{ref} is lowered to actuate a tap changer operation. However, if minimum voltage V_{min} would fall below feeder voltage lower limit V_{lower} after tapping, the set point is not changed as this could lead to continuous set point changing and operating of the tap changer (hunting). In the algorithm proposed here, it is assumed that a tap changer operation changes all network voltages by an amount equal to the tap step and, therefore, minimum voltage has to be more than a tap step away from the feeder voltage lower limit to allow a set point reduction. In reality, the change of minimum voltage is not exactly equal to the tap step (loads are voltage dependent etc.) but this is, nonetheless, a good approximation. In distribution networks negative dependencies between voltage and load do not typically occur [27] and, therefore, the change of the minimum voltage is in reality smaller than the tap step when substation voltage is lowered (the same applies for maximum voltage when the substation voltage is increased). Similarly, when minimum voltage falls below feeder voltage lower limit, the AVC relay voltage set point is increased if maximum voltage is more than a tap step below feeder voltage upper limit.

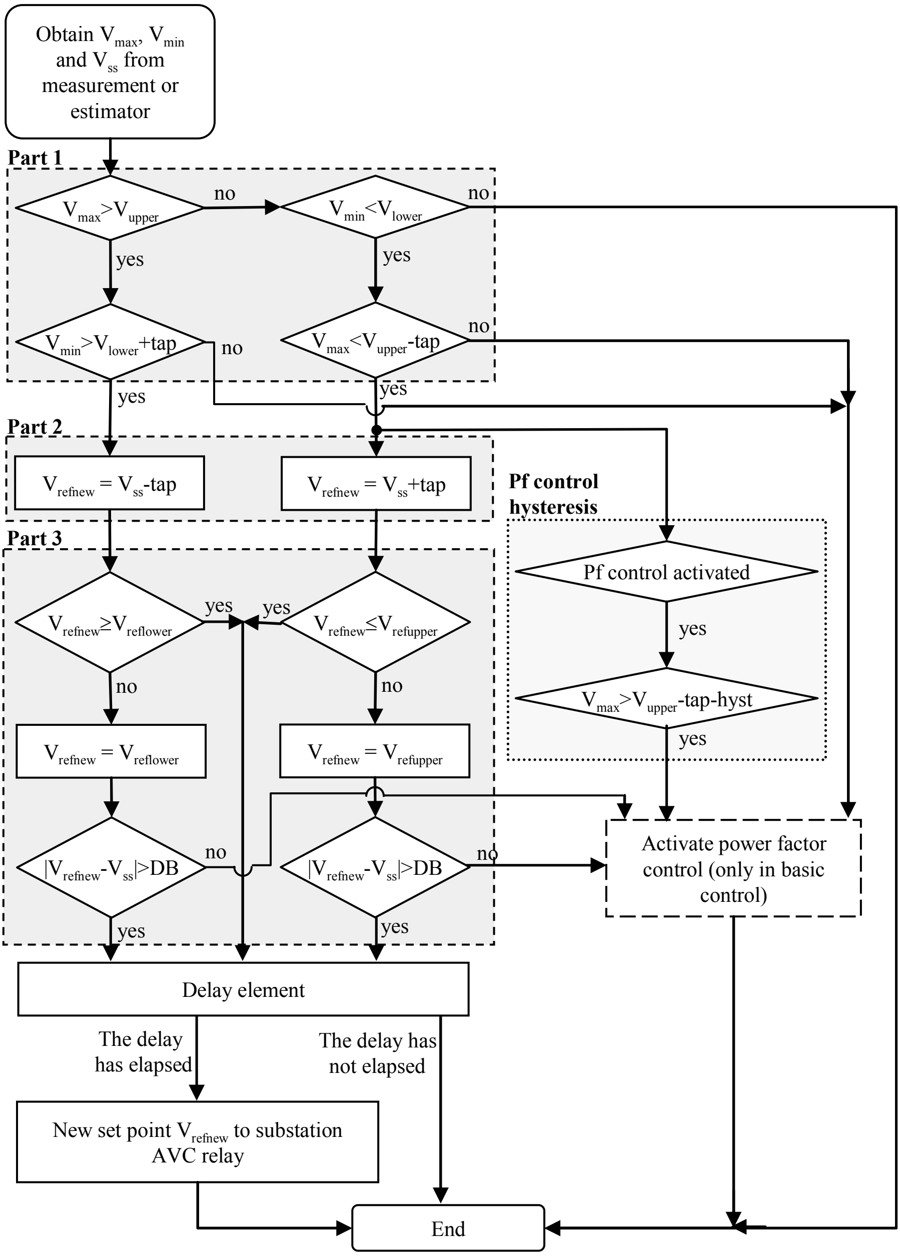

Figure 3.3: *The flow chart of substation voltage control.*

The voltage set point also has limits of its own (V_{reflower} and V_{refupper}). The set point limits can be selected such that the substation voltage is kept within feeder voltage limits regardless of any changes in the network, i.e. the AVC relay target voltage V_{ref} is between limits of V_{upper}-$DB \geq V_{\mathrm{ref}} \geq V_{\mathrm{lower}}$+$DB$. This kind of approach would, however, restrict the operation of the algorithm to cases where the substation voltage is more than 2*DB away from the feeder voltage limit. If the whole available control range is to be taken in use, the set point limits should be set equal to the feeder voltage limits i.e. $V_{\mathrm{upper}} \geq V_{\mathrm{ref}} \geq V_{\mathrm{lower}}$. In this case, the control algorithm should include a part which restores the voltage set point between the limits $V_{\mathrm{upper}}\text{-}DB \geq V_{\mathrm{ref}} \geq V_{\mathrm{lower}}+DB$ after the tap changer has operated.

The third part of the algorithm (Part 3 in Figure 3.3) checks that the new voltage set point is between its limits and verifies that the set point change initiates a tap changer operation. If the calculated new set point in Part 2 exceeds the voltage reference limits, the AVC relay target voltage is set to its extreme value (maximum or minimum). However, if this set point change would not initiate a tap changer operation, the set point is kept at its previous value and, in basic control, power factor control is activated. The new set point is given to the AVC relay only after a predefined delay because short-time voltage variations should not initiate a set point change. The conditions for set point change have to be fulfilled for the whole delay time and the delay counter is reseted when the control action is executed.

In basic control, power factor control is activated if one or both of the input voltages is outside the feeder voltage limits and normalizing the voltages using substation voltage control is not possible (i.e. tap changer operation would lead to the other voltage exceeding its limit or voltage set point can not be selected such that a tap changer operation would occur). Power factor control is activated also when minimum voltage is below its limit and maximum voltage has previously exceeded the limit $V_{\mathrm{upper}}\text{-}tap$ but has decreased slightly after this (Pf control hysteresis in Figure 3.3). This is done to enable control operations also in a situation where maximum voltage is very near to $V_{\mathrm{upper}}\text{-}tap$ and can, therefore, be at consecutive measurements just under and over this limit. If V_{max} varies in this way and hysteresis is not included, substation voltage control and power factor control are in turns activated but neither will operate and the network will remain at an unacceptable state. In different kinds of networks similar pf control hysteresis might be needed also when maximum voltage exceeds its limit and minimum voltage is very near to $V_{\mathrm{lower}}+tap$ (in this algorithm it is assumed that DG reactive power is not used to increase network minimum voltage).

The substation voltage control algorithm uses the parameters shown in Table 3.1. Some of the parameters are determined by the network's operating limits or parameters of other components in the network whereas some can be more freely selected. The parameters should be such that DG protection will not operate before coordinated voltage control but, on the other hand, short-time voltage variations are filtered out.

3.4 Power factor control

The power factor control algorithms (basic and restoring) are designed for traditional radial distribution networks. The algorithms assume that maximum voltage is always located at the substation or at generator terminals and that DG reactive power control is not used to increase network minimum voltage.

Table 3.1: The parameters of substation voltage control

Parameter	*Selection criteria*
AVC relay deadband	Directly from AVC relay parameters
Main transformer tap step	Directly from main transformer characteristics
Feeder voltage upper limit Feeder voltage lower limit	All customer voltages have to be kept in an acceptable level
Voltage upper limit in restoring control Voltage lower limit in restoring control	Network voltage level should not remain in an unusually high or low level
AVC relay voltage set point upper limit AVC relay voltage set point lower limit	Can be selected either to keep the substation voltage in any case between feeder voltage limits or to take in use the whole available control range
Delay in basic control Delay in restoring control	Short-time voltage variations should not initiate a set point change
Pf control hysteresis bandwidth	A relatively small value is usually adequate

DG reactive power is controlled by changing the power factor set point of generator AVR. In basic power factor control, the power factor set point is decreased (and DG reactive power consumption increased) if lowering generator voltage is beneficial to the network. Restoring power factor control is used to increase the power factor set point when network state allows it. Operation of both basic and restoring power factor controls is somewhat dependent on the sequence of controls.

Figure 3.4 illustrates a detailed flow chart of the operation of the basic power factor control algorithm. If substation voltage is assigned to operate first, basic power factor control is activated only when network voltages can not be restored to an acceptable level using basic substation voltage control. In this case the inputs to the control algorithm are generator voltage V_{gen} and the activation signal from substation voltage control. Also the state of basic substation voltage control (delay counter on/off) has to be known. If power factor control is assigned to operate before substation voltage control, no activation signal is needed and the inputs to the control are generator voltage and network minimum voltage V_{min}.

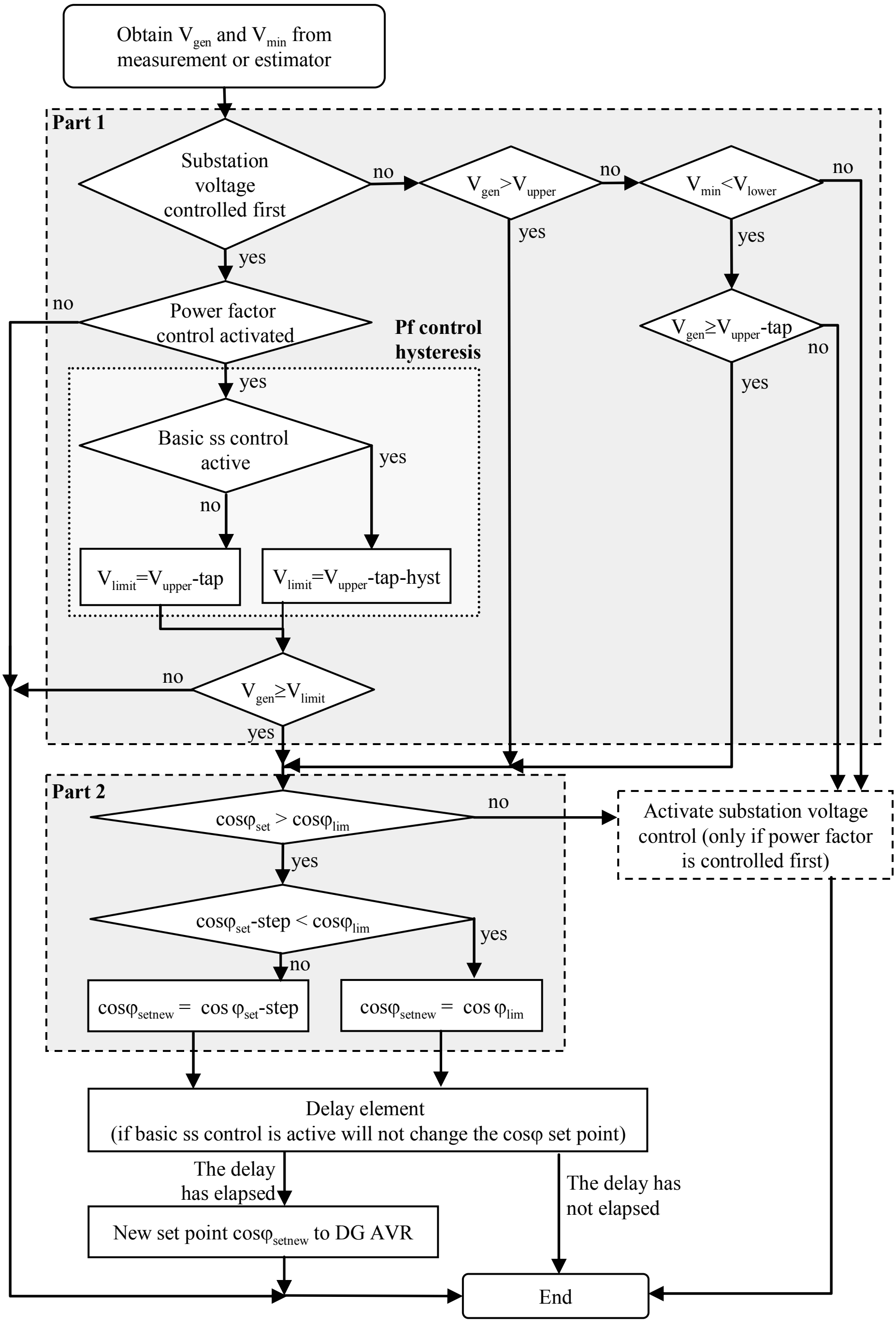

Figure 3.4: *The flow chart of basic power factor control.*

At first (Part 1 in Figure 3.4), the control algorithm determines whether the power factor set point $cos\varphi_{set}$ should be reduced. If substation voltage is controlled first, the power factor set point is reduced when power factor control is activated and generator voltage V_{gen} is less than main transformer tap step *tap* away (or *tap*+*hyst* if power factor control is activated by pf control hysteresis in Figure 3.3) from the feeder voltage upper limit V_{upper}. If the generator voltage is lower than V_{limit} lowering generator voltage would neither restore network maximum voltage $V_{\max}$ to an acceptable level nor enable tap changer operation by reducing $V_{\max}$ and, therefore, reducing $\cos\varphi_{\text{set}}$ would not improve the network state.

If power factor control is assigned to operate first, the power factor set point is lowered if the generator voltage exceeds feeder voltage upper limit. The power factor set point is lowered also when network minimum voltage $V_{\min}$ falls below feeder voltage lower limit V_{lower} and V_{gen} is less than a tap step away from V_{upper}. This is done to reduce network maximum voltage to a level where substation voltage control is possible. If power factor control is not needed, substation voltage control is activated.

After determining whether $\cos\varphi_{\text{set}}$ should be lowered the algorithm calculates its new value (Part 2 in Figure 3.4). The power factor set point is lowered in predefined steps *step* or set at its limit value $\cos\varphi_{\text{lim}}$. If the set point is already at its limit it can not be further reduced and substation voltage control is activated (when power factor control is assigned to operate first). The new power factor set point is given to the generator AVR after a predefined delay. The conditions for set point change have to be fulfilled for the whole delay time and the delay counter is reseted when the control action is taken. If basic substation voltage control is active (and hence power factor control has been activated by pf control hysteresis) the power factor set point is not changed because substation voltage is the primary control variable.

The parameters used by basic power factor control are represented in Table 3.2. Most of them are determined by parameters of other control components and only the delay and the set point adjustment step can be more freely selected. The delay can be set shorter than in substation voltage control because generator voltage control is usually much faster than tap changer control at the substation. It should, however, be long enough to allow the DG AVR to reach a new steady state before the set point is changed again.

Restoring power factor control is used to restore DG power factor set point closer to unity when network state allows it. Also the operation of restoring power factor control is dependent on the sequence of controls because the objectives of the restoring control are in the two alternatives different. If substation voltage is controlled first, power factor should be kept as near to unity as possible whereas in the second case power factor control is preferred to substation voltage control and, therefore, power factor set point is increased only if this does not require tap changer operations. A detailed flow chart of the algorithm is depicted in Figure 3.5.

Table 3.2: The parameters of basic power factor control

Parameter	*Selection criteria*
Main transformer tap step	Directly from main transformer characteristics
Feeder voltage upper limit Feeder voltage lower limit	Directly from basic substation voltage control parameters
Power factor set point adjustment step	Can be selected quite freely
Minimum power factor set point	Determined by generator characteristics
Delay	Depends on how fast the control is wanted to operate
Pf control hysteresis bandwidth	Directly from basic substation voltage control parameters

Restoring power factor control is needed only when the power factor set point is below unity. The purpose of the algorithm is to increase the set point if the network state is such that this is possible. The inputs to the algorithm are generator voltage V_{gen} and network minimum voltage V_{min}. If generator voltage has decreased enough the power factor set point is increased (Part 1 in Figure 3.5). Parameter $V_{diffupper}$ determines the difference between V_{gen} and feeder voltage upper limit V_{upper} that is considered to be large enough to enable power factor increasing. The power factor is increased in predefined steps *step*. The new power factor set point is given to the generator AVR only after a predefined delay and the operational conditions have to be fulfilled for the whole delay time. The delay counter is reseted when the control action is executed.

If substation voltage is controlled first in basic control, the restoring power factor control includes also a part which reacts in situations where minimum voltage V_{min} has increased enough i.e. differs more than $V_{difflower}$ from feeder voltage lower limit V_{lower} but the generator voltage has not decreased enough to allow a direct power factor set point increase (Part 2 in Figure 3.5). In this case, the control algorithm outputs a large V_{max} value that is given as an input to the basic substation control instead of the real network maximum voltage. This triggers a tap changer operation that decreases the voltages in the whole network and enables the operation of the first part of restoring power factor control. The large V_{max} is outputted after a predefined delay and it will stay at this value until the operational conditions of the control are not fulfilled anymore.

Restoring substation voltage control is activated if restoring power factor control is not needed (in other words $cos\varphi$ is 1.0) or if neither of the operational conditions of the restoring power factor control is fulfilled.

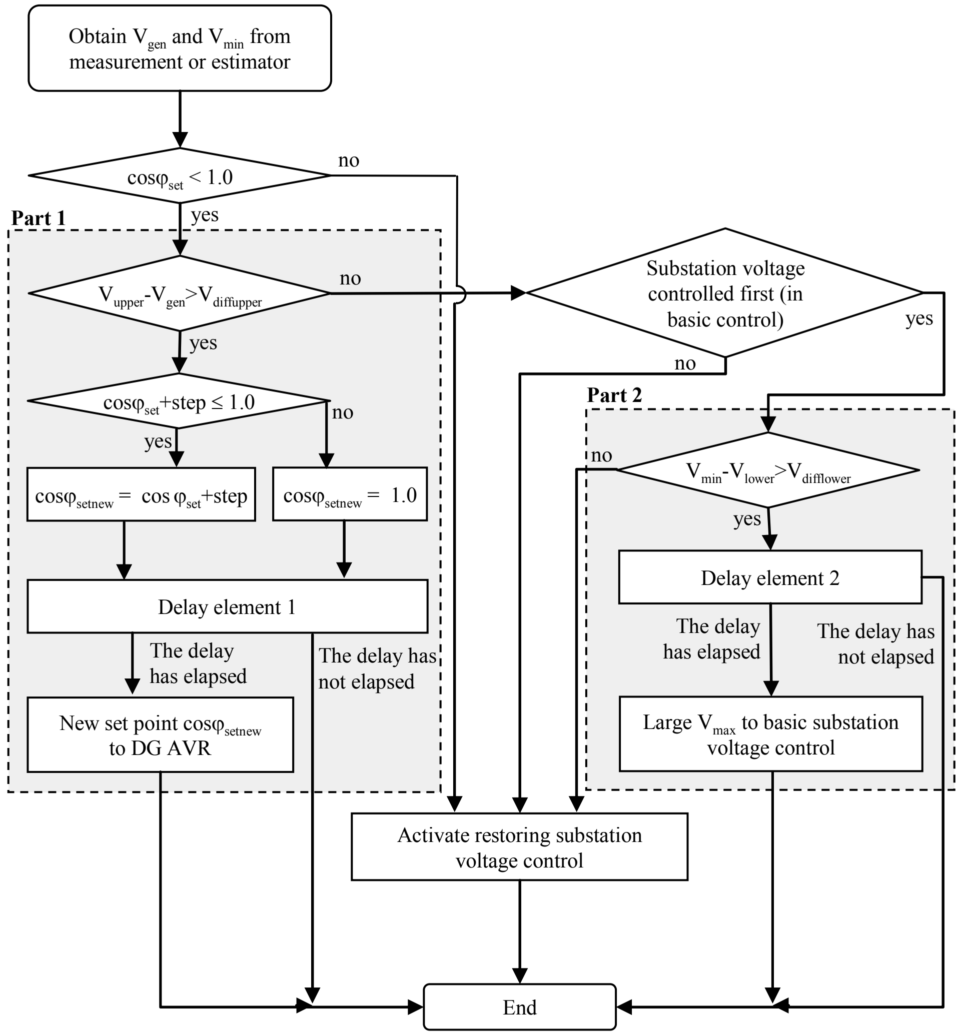

Figure 3.5: *The flow chart of restoring power factor control.*

The parameters used by the restoring power factor control are represented in Table 3.3. Some of them are determined by parameters of other control components and some can be more freely selected. The parameters should be such that adjustments made by restoring control do not activate basic control in any case. Increasing the power factor set point should not lead to generator voltage exceeding feeder voltage upper limit i.e. increasing power factor set point by power factor set point adjustment step should never raise the generator voltage more than generator voltage operational limit $V_{\mathrm{diffupper}}$. Minimum voltage operational limit $V_{\mathrm{difflower}}$ should be larger than main transformer tap step. The delays should be selected longer than in basic controls.

Table 3.3: The parameters of restoring power factor control

Parameter	*Selection criteria*
Feeder voltage upper limit Feeder voltage lower limit	Directly from basic substation voltage control parameters
Power factor set point adjustment step	Can be selected quite freely
Delay in *cosφ* control	Depends on how fast the control is wanted to operate
Delay in $V_{\max}$ control	Short-time voltage variations should not initiate a tap changer operation
Generator voltage operational limit $V_{\text{diffupper}}$	Power factor set point increase should not lead to basic power factor control operation
Minimum voltage operational limit $V_{\text{difflower}}$	Tap changer operation should not lead to basic substation voltage control operation

3.5 Interactions between control blocks

If the above described control blocks would be operating independently of each other, hunting or other adverse effects might occur. Hence, the control blocks must communicate with each other to obtain the desired functionality. Also, the parameters should be correctly selected. The inputs and outputs and the connections between individual control blocks are depicted in Figure 3.6 (substation voltage primary controlled) and Figure 3.7 (DG power factor primarily controlled). In addition to the inputs introduced in the preceding chapters, all control blocks have also a reset input. This input is used to reset the delay counter(s) of the control block and to block its operation.

The coordinated voltage control algorithm is blocked when either the AVC relay or the tap changer is operating. All control blocks are reseted also when either of the substation voltage control blocks changes the AVC relay set point.

When substation voltage is primarily controlled (Figure 3.6), basic power factor control is active only if basic substation voltage control has activated it. Restoring power factor control is blocked if basic substation voltage control is operating (i.e. its delay counter is on) or basic power factor control is activated. Restoring substation voltage control is active if restoring power factor control has activated it (see Figure 3.5). If restoring power factor control is blocked it activates restoring substation voltage control.

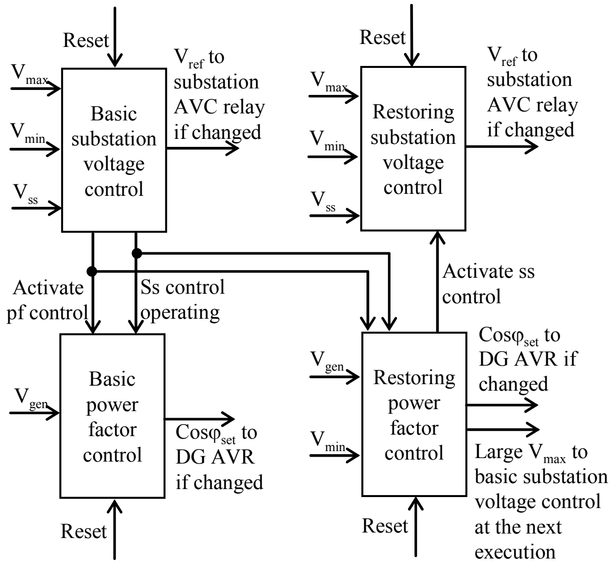

Figure 3.6: *The inputs and outputs and the connections between control blocks when substation voltage is primarily controlled.*

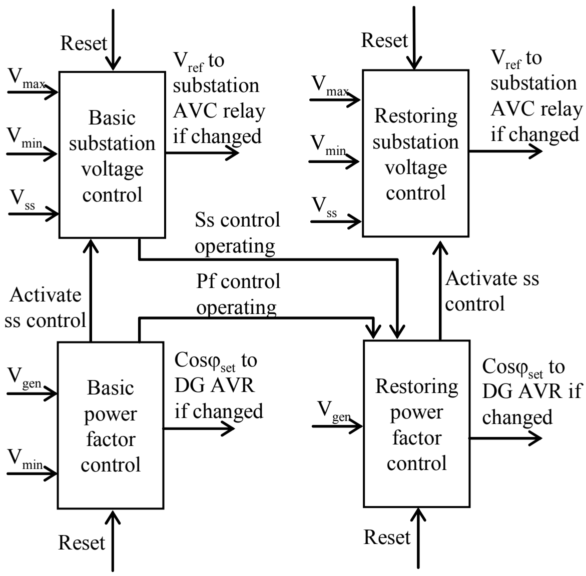

Figure 3.7: *The inputs and outputs and the connections between control blocks when DG reactive power is primarily controlled.*

When DG power factor is primarily controlled (Figure 3.7), basic substation voltage control is blocked if it has not been activated by basic power factor control. Restoring power factor control is blocked if basic substation voltage control or basic power factor control is operating. Restoring substation voltage control is activated by restoring power factor control similarly as in the case explained above. However, if basic power factor control is operating, restoring substation voltage control is not activated.

The order in which the control blocks should be executed depends on the preferred control sequence. If substation voltage is controlled first, the order is following: basic substation voltage control, basic power factor control, restoring power factor control and restoring substation voltage control. If DG power factor is controlled first, the first two exchange places i.e. basic power factor control is executed before basic substation voltage control.

4 DESCRIPTION OF THE STUDY SYSTEM

The operation of the proposed control algorithm is tested in a typical Finnish rural distribution network whose structure is depicted in Figure 4.1. The study network consists of two medium voltage feeders and contains one relatively large hydro power plant. In this paper, the operation of the proposed control algorithm is tested using PSCAD simulations. For the simulations, three loading conditions are selected: maximum and minimum loading and one loading condition between these (referred to as middle loading in the following). Both versions of the proposed control algorithm (substation voltage/DG reactive power primarily controlled) are examined. Network protection is not modelled in the simulations and, therefore, possible operation of protection has to be considered when simulation results are interpreted.

The distribution lines are modelled using a π-connection and the loads are modelled as static constant power loads because the voltage-dependence and dynamic performance of loads in the study network is unknown. In voltage control studies the worst situation occurs when constant power loads are used because in this situation the loads are not diminishing the voltage excursions at all (in distribution networks negative dependences between voltage and load do not typically occur [27]). The dynamic characteristics of loads can be omitted in the simulations because the dynamic behaviour of the loads can affect only the operation times of coordinated voltage control but not the actual operations determined by the algorithm. The distribution network voltages are obtained directly from the simulation and, therefore, state estimation is not included in the simulations.

The network model includes a representation of substation AVC relay and main transformer tap changer [28]. The AVC relay measures the substation voltage and compares it with its target voltage V_{ref}. If the measured voltage differs more than the AVC relay deadband DB from the target voltage a delay counter is started. This counter remains active as long as the measured voltage is outside the hysteresis limits of the relay and a tap changer operation is initiated when the counter reaches its setting value T_{AVC}. In these simulations, the deadband DB is 1.5 %, the hysteresis limit 90 % of the operating value and the delay T_{AVC} 3 s. Line drop compensation is not used. The tap changer mechanism is modelled simply as a delay. The tap step is 1.67 % and the delay 1 s. The delays used in the simulations are much shorter than delays in a real network. These shorter delays are used because the operation of the algorithm would be similar also with the realistic delays but the simulation time would increase considerably.

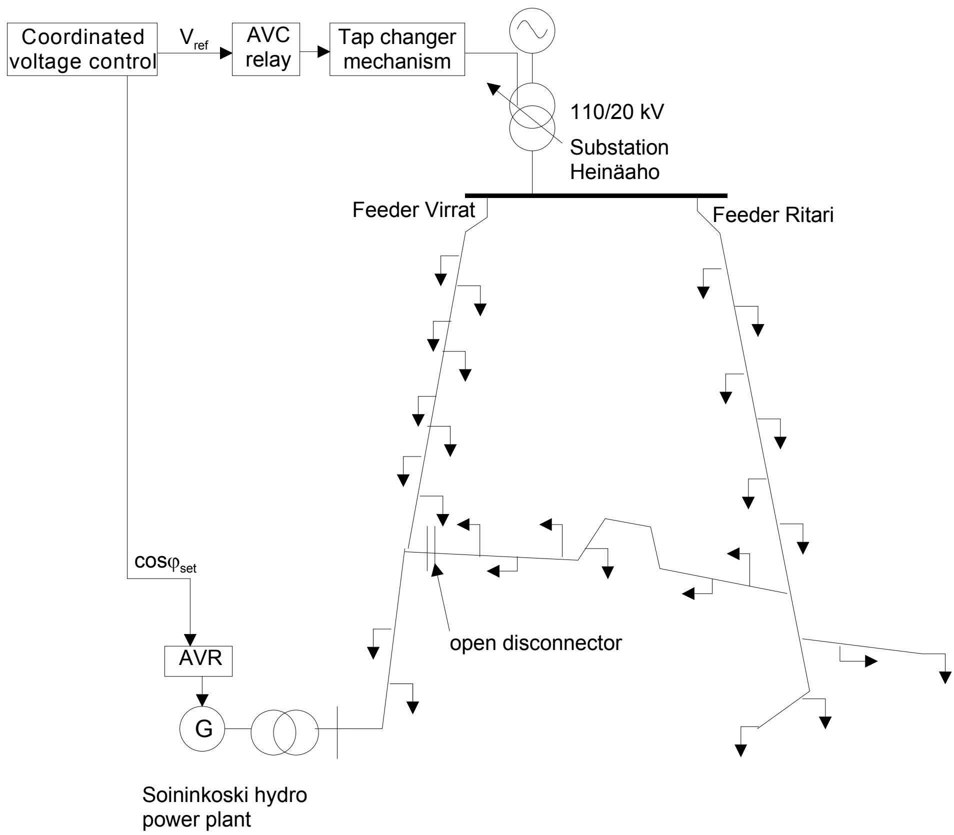

Figure 4.1: *The structure of the study network.*

The hydro power plant at Soininkoski is connected to the distribution network using a synchronous generator and its reactive power can be controlled through excitation control of the generator. The DG AVR is operating in power factor control mode and, when network voltage control is not needed, unity power factor is used. The excitation system is of type IEEE AC8B [29] and the power factor control is realised as cascade control where a power factor controller of type IEEE VAr controller Type 2 [29] determines the set point of the voltage controller.

The voltage set point V_{ref} of substation AVC relay and the power factor set point $cos\varphi_{set}$ of DG AVR are determined by the coordinated voltage control algorithm presented in chapter 3. The parameters of the control algorithm are selected such that as many features of the algorithm as possible are needed and are not, therefore, realistic.

The feeder voltage lower and upper limits used in basic substation voltage control are 0.98 and 1.045 pu whereas the restoring substation voltage control tries to keep the network voltages between 1.00-1.045 pu. The voltage reference limits are set equal to the feeder voltage limits and in basic substation voltage control the pf control hysteresis bandwidth is 0.005 pu. In basic substation voltage control the delay is 5 s and in restoring substation voltage control 10 s. The power factor set point adjustment step is 0.005 and time delay 3 s both in basic and restoring power factor controls. Minimum power factor set point is 0.98. In restoring power factor control, $V_{diffupper}$ is 0.01 pu with a delay of 3 s and $V_{difflower}$ 0.02 pu with a delay of 10 s.

5 SIMULATION RESULTS

PSCAD simulations are used to test the operation of the proposed control algorithm to ensure that it operates in a desired way. The algorithm should restore the network voltages to an acceptable level always when possible by controlling substation voltage and DG power factor. DG power factor should differ from unity only when network state demands it and network voltages should never remain in an unusually high or low level for a long period of time. Hunting should never occur.

Simulations are carried out in maximum, minimum and middle loading conditions with both versions of the proposed control algorithm. The simulation sequence used is the following: At the beginning of the simulation the power plant is not connected to the network. At time 5 s the generator is connected to the network with output power of 0 MW. At 10 s the DG output power is raised to 2.0 MW and at time 40 s lowered to 1.0 MW. At time 70 s the DG unit is disconnected. DG output power is not changed in steps but its maximum decrease and increase rates are set to 670 kW/s. However, a step change in the output power will naturally occur when the DG breaker is opened.

The proposed control algorithm operates in all the simulation cases as desired: It is able to restore the network voltages to an acceptable level when voltage rise becomes excessive and also the restoring parts of the control operate as expected. Simulation results in maximum loading conditions are represented as an example. Figure 5.1 depicts simulations results when substation voltage is primarily controlled and Figure 5.2 the corresponding simulation when DG reactive power is the primary control variable. Both versions of the algorithm operate in the simulations as intended.

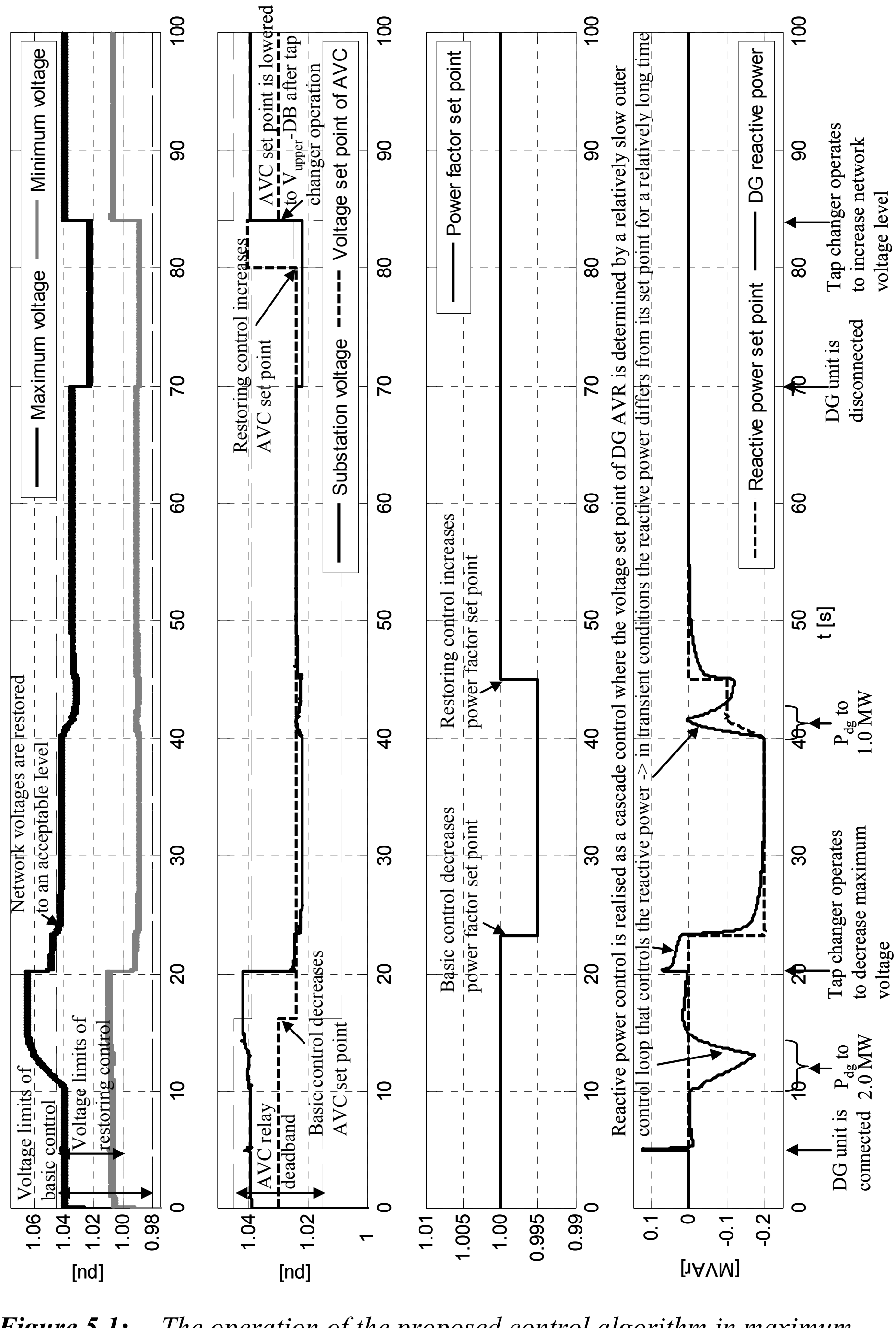

Figure 5.1: The operation of the proposed control algorithm in maximum loading conditions when substation voltage is primarily controlled.

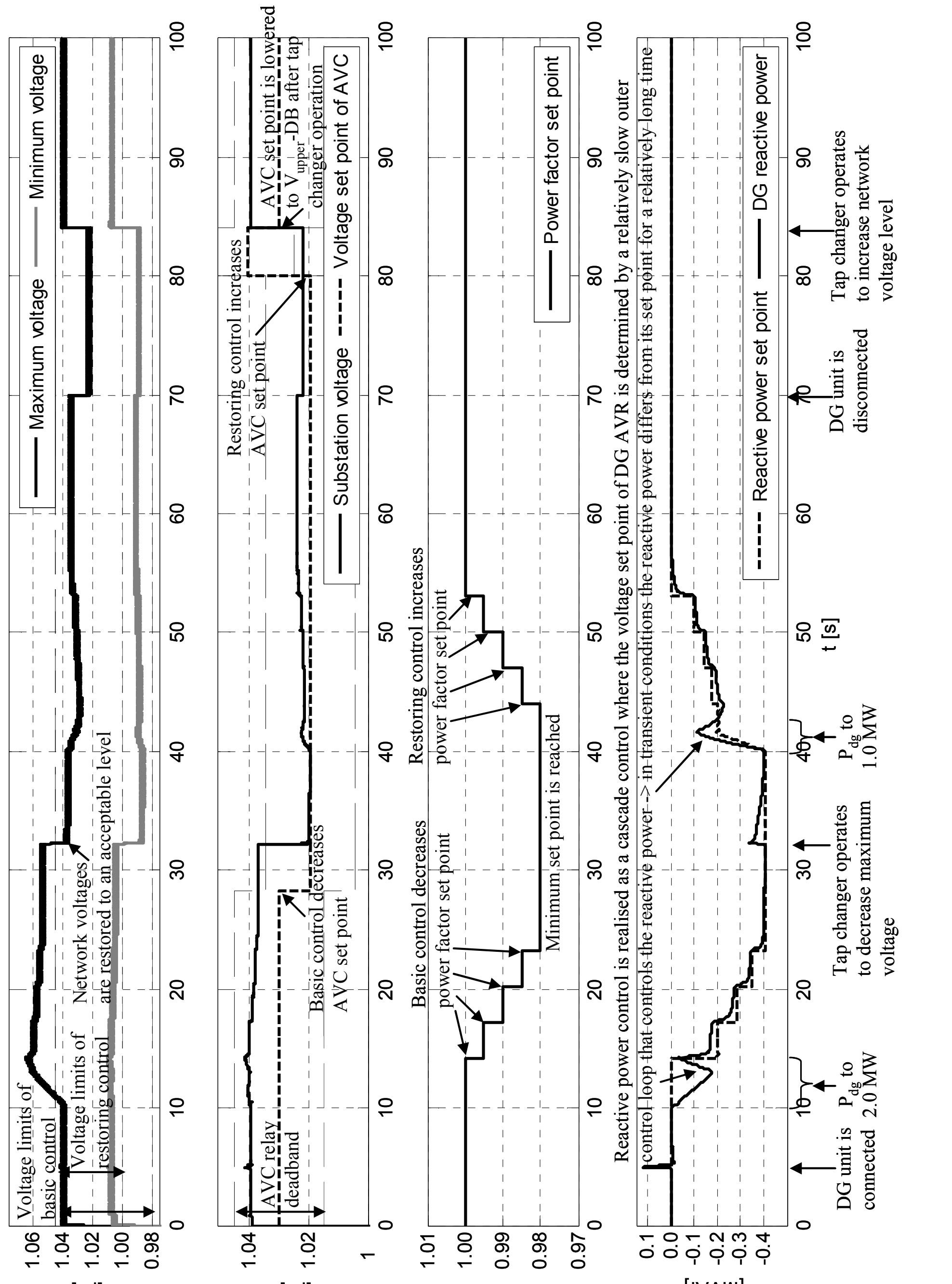

Figure 5.2: *The operation of the proposed control algorithm in maximum loading conditions when DG reactive power is primarily controlled.*

In Figure 5.1 network maximum voltage exceeds its limit when DG output power is raised to 2 MW. At approximately 16 s basic substation voltage control decreases the AVC relay set point and after the AVC relay and tap changer delays the tap changer operates at 20 s to decrease the network voltages. After tap changer operation, the maximum voltage is still above the feeder voltage upper limit but minimum voltage has decreased below the limit $V_{\text{lower}}+tap$. Therefore, basic substation voltage control is not able to operate and basic power factor control is activated. At 23 s basic power factor control decreases power factor set point and DG starts to consume reactive power which restores the maximum voltage to an acceptable level. When DG output power is lowered to 1.0 MW, network maximum voltage decreases and restoring power factor control increases the power factor set point to unity at 45 s. After DG disconnection at 70 s, the voltage level of the whole distribution network remains at an unusually low level. At 80 s restoring substation voltage control increases AVC relay set point and at 84 s the tap changer operates. After tap changer operation, the AVC relay set point is decreased to $V_{\text{upper}}-DB$. This is done to keep the substation voltage within feeder voltage limits regardless of changes in the network state.

In Figure 5.2 the control sequence is reversed i.e. DG reactive power is primarily controlled. When network maximum voltage exceeds its limit at 11 s, basic power factor control starts operating and DG power factor set point is decreased at 14 s, 17 s, 20 s and 23 s. After these four changes the maximum voltage is still above its limit but the power factor set point has reached its minimum value and, therefore, basic substation voltage control is activated. At 28 s basic substation voltage control decreases AVC relay set point and the network voltages are restored to an acceptable level at 32 s. When DG output power is reduced to 1.0 MW, network maximum voltage is lowered and restoring power factor control operates four times. After DG disconnection restoring substation voltage control restores the network voltages to a normal level.

When the simulation results are viewed it should be borne in mind that the parameters of the control algorithm are not very realistic but are selected to demonstrate as many features of the control algorithm as possible. In a real network, feeder voltage lower limit is usually lower than 0.98 pu which enables a second tap changer operation in the case of Figure 5.1 and, therefore, network voltages can be restored to an acceptable level even without DG power factor control. Also, DG minimum power factor is usually much lower than 0.98 and, therefore, it is likely that controlling only DG power factor would be sufficient in the case of Figure 5.2.

The delays used in the simulation are much shorter than delays in a real network and not in correct proportion to each other. In reality, the delay of substation AVC relay is much longer than 3 s and also the delay for AVC relay set point change in coordinated voltage control should be set quite long to avoid set point change during short-time voltage variations. The delay for DG AVR set point change can be set shorter than the delay of substation AVC relay set point change. Therefore, with realistic parameters the algorithm reacts to network state changes faster if DG reactive power is primarily controlled.

When the control sequence for a particular case is selected, network losses caused by additional reactive power flow, maintenance need for substation tap changer and transient voltage variations caused by tap changer operations have to be considered.

6 FURTHER STUDIES

6.1 Demonstration in a real network

The operation of the proposed control algorithm will be tested also in a real distribution network in the near future (project ADINE [30]). The control algorithm will be implemented as a part of ABB distribution management system MicroSCADA Pro DMS 600 and its operation will be tested in a real distribution network and also in Real Time Digital Simulator (RTDS) simulation environment. The study network is the same network that is studied in this article using PSCAD simulations.

In practical implementations it is always possible that an important communication channel fails and the inputs needed by the control algorithm are no longer available. The algorithm should be able to detect these situations and to function reasonably also in the absence or delay of essential input data. In these situations, the algorithm sets the substation voltage set point and the DG power factor set point to predetermined values and, if overvoltage occurs at the generator terminals, the plant is disconnected by its overvoltage relay.

6.2 Further development of the voltage control algorithm

When the control algorithm proposed in this article was designed, the objective was to make it as simple as possible. Simplicity has many advantages: The operation of the control algorithm can be easily understood which makes its introduction also for real use purposes more probable. Implementing the algorithm as a part of DMS does not require extensive work and can be performed within a reasonable time. Moreover, mistakes at the implementation stage are less likely to occur when the algorithm is kept simple and testing its operation is straightforward.

Also some disadvantages do, however, exist. The control algorithm is designed only to restore the network to an acceptable state and not to optimize the network's operation. For instance, the order in which the controlled variables (substation voltage, DG reactive power) are changed is determined beforehand. This can lead to, for example, lowering all network voltages in a situation where a minor change in DG reactive power would be sufficient. The operator is responsible for finding the optimal operating point.

Using a control algorithm that uses simple rules to determine the control actions is a suitable approach for simple networks where only few controllable components exist. However, if for instance multiple DG units are connected to the network, determining the rules can become difficult and, in some cases, even impossible. Additionally, if keeping the network at an acceptable state is not considered adequate but also some optimization features are desired, the algorithm has to be revised.

Coordinated voltage control will be, in the future, further studied. Its application also in more complex networks will be studied and methods using fuzzy logic and/or optimization algorithms will be developed and their operation will be examined.

7 CONCLUSIONS

In this article, active voltage level management in distribution networks with DG was studied. A coordinated voltage control algorithm that controls substation voltage and DG reactive power was proposed. The control algorithm was designed for a traditional rural distribution network with radial configuration and only few DGs and its operation was tested in an example network using time domain simulations.

Based on the simulation results it can be stated that, in the study network, the proposed control algorithm is able to keep the network voltages in an acceptable level regardless of loading and generation conditions. Hence, network reinforcement is not needed in order to connect the hydro power plant to the network. If only traditional voltage control methods (i.e. substation voltage control based on local measurements) were used, the voltage rise caused by DG would lead to excessive voltage levels in the network and, therefore, network reinforcement would be needed before interconnection of the power plant.

Also the restoring parts of the control algorithm operated in the simulations as desired. DG power factor differed from unity only when network state demanded it and after DG disconnection the network voltages were increased to the normal level. No continuous set point changes appeared. Thus, the proposed control algorithm as a whole operated in the simulations as desired and was able to increase the amount of DG that can be connected to the existing distribution network.

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Publication 3

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RTDS Verification of a Coordinated Voltage Control Implementation for Distribution Networks with Distributed Generation

Anna Kulmala, Antti Mutanen, Antti Koto, Sami Repo and Pertti Järventausta

Abstract--**In weak distribution networks the amount of distributed generation (DG) is usually limited by the voltage rise effect. The voltage rise can be mitigated using passive methods such as increasing the conductor size which can, however, be quite expensive. Also active voltage control methods can be used to reduce the maximum voltage in the network. In many cases active voltage control can increase the capacity of connectable DG substantially which can lead to significantly lower connection costs.**

In this paper, operation of an active voltage control algorithm is viewed. The algorithm controls the substation voltage and DG reactive power and determines its control actions based on the state of the whole network. The algorithm is implemented as a Matlab program and communication between Matlab and SCADA is realized using OPC Data Access. Correct operation of the algorithm is verified using Real Time Digital Simulator (RTDS). The same algorithm could also be implemented as a part of the distribution management system (DMS).

Index Terms--**Active voltage control, coordinated voltage control, distributed generation, real time simulations**

I. Introduction

THE amount of distributed generation (DG) is constantly increasing. The European Union has set ambitious targets of 20 % share of energy from renewable sources by 2020 [1] to reduce gaseous emissions, diversify the energy supply and reduce dependency on fossil fuel markets. To meet the overall renewable energy target a substantial increase in the share of renewable energy sources in electricity production is needed. Renewable electricity is often produced in relatively small power plants whose location is determined by external factors such as wind and solar resources. Hence, power plants using renewable energy sources are often connected to distribution networks. Also, deregulation of energy markets has made distribution network access available to all energy producers and the prices of small generating plants have reduced. [2]

The existing distribution networks are designed based on the assumption of unidirectional power flows. When the penetration level of DG increases, this assumption is no longer valid and the operation and planning principles of distribution networks need to be revised. [2]

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DG can have both positive and negative impacts on network operation. It changes the power flows and fault currents in the network and can, therefore, cause problems related to voltage quality, protection and increasing faults levels. In weak distribution networks, the maximum capacity of DG is usually limited by the voltage rise effect. Also the transient voltage variation at generator connection or disconnection can in some cases turn out to be the limiting factor. [2]

At present, voltage rise is usually mitigated by reinforcing the network (increasing the conductor size or connecting to a dedicated feeder) and the operational principle of the network is not changed. This can, however, be quite expensive. Also active voltage control methods can be used to reduce the maximum voltage in the network. Active voltage level management can in many cases increase the allowed penetration of DG substantially and, therefore, lower the connection costs. [3]

Several active voltage control methods of different complexity and data transfer needs have been proposed in publications. The simplest active voltage control methods are based only on local measurements and do not require additional data transfer between distribution network nodes. When only local measurements are used the voltage rise caused by DG can be mitigated by allowing the DG unit to absorb reactive power or by limiting the active power output of DG when the terminal voltage exceeds its limit (production curtailment). [3]

Coordinated voltage control methods use information about the whole distribution network when determining their control actions and, therefore, data transfer between network nodes is needed. The methods can determine their control operations based on simple rules [4]-[9] or use some kind of optimization algorithm [10]-[16]. The simplest control algorithms control the substation voltage based on network maximum and minimum voltages whereas network voltages can also be controlled using an advanced distribution network management system which controls all components capable of voltage control (e.g. tap changers at substations, power plants, compensators and loads). The most suitable control method is selected based on the structure of the network and the number of components participating in the control.

In this paper, correct operation of a coordinated voltage control implementation is verified using Real Time Digital

Simulator (RTDS) [17]. RTDS simulation environment enables testing real external devices in real time in an environment emulating real electricity network. The tested devices can be taken to real distribution network tests without any modifications. In this case, the combined operation of SCADA and the coordinated voltage control implementation is tested.

The paper will firstly introduce the coordinated voltage control method and discuss its implementation. Thereafter, the RTDS simulation arrangement is introduced and simulation results are represented. Finally, the operation of the implemented algorithm is assessed based on the simulation results.

II. The Coordinated Voltage Control Algorithm

The coordinated voltage control algorithm controls the substation voltage and DG reactive power by changing the set points of substation automatic voltage control (AVC) relay and DG automatic voltage regulator (AVR). The algorithm is a slightly modified version of the algorithm presented in [9] and its purpose is to keep all distribution network voltages between acceptable limits.

The algorithm comprises two functions: Basic control is used to restore the network voltages to an acceptable level when network maximum or minimum voltage exceeds its limit. Restoring control is used to restore DG power factor to unity when network state allows it and to normalize network voltages if the voltages in the whole distribution network have remained in an unusually high or low level. Both control functions consist of two parts: the first part controls the substation voltage and the second one DG reactive power.

Two versions of the algorithm have been implemented. In the first one, substation voltage is the primary control variable and DG power factor is changed only if substation voltage control is not able to restore the network voltages to an acceptable level. In the second version, DG reactive power is primarily controlled. Both approaches have advantages and disadvantages: When DG reactive power is the primary control variable, the additional reactive power flow often increases losses. On the other hand, when substation voltage is primarily controlled the number of tap changer operations is increased which increases the maintenance need of the tap changer and causes transient voltage variations to the whole distribution network. Hence, depending on the network and planning principles either one could be more advantageous.

A. Operational principle

The inputs to the algorithm are distribution network maximum and minimum voltages, substation voltage and generator connection point voltage. In the implementation discussed in this paper, substation and generator connection point voltages are measured. Maximum voltage is always located at either one of these and a state estimator is used to obtain network minimum voltage.

In [9] the origin of the coordinated voltage control algorithm input data was not defined and, therefore, existence of a state estimator was not assumed when the control algorithm was defined. In this implementation a state estimator described in [18] is available and some minor modifications that require state estimation are done. In [9] only one tap changer operation was initiated at a time and DG reactive power set point was changed in user-defined steps. In this paper, the calculation of new set points is modified in such a way that only one set point change is needed to restore the voltages to an acceptable level. In substation voltage control the algorithm determines the number of tap operations needed and uses this information to determine the new AVC relay set point. In power factor control state estimation is used to determine the new set point of DG power factor. In power factor control the algorithm uses state estimation also to determine whether DG's reactive power capability is adequate to lower network maximum voltage sufficiently.

The functional diagram of the basic control when substation voltage is primarily controlled is depicted in Fig. 1. Fig. 2 represents the operation of basic control when DG reactive power is the primary control variable. In the control algorithm it is assumed that network maximum voltage is always located either at the substation or at the generator connection point. It is also assumed that the network is such that there is no need to use DG reactive power control to increase network minimum voltage and, therefore, no part that increases DG reactive power production is included in basic control. The functional diagram of restoring control is depicted in Fig. 3. More detailed flow charts of each control block can be found in [9].

When substation voltage is primarily controlled (Fig. 1) the control operates as follows: If network maximum or minimum voltage exceeds feeder voltage limits, basic substation voltage control is activated. At first, the control determines the number of tap changer operations to be done based on two conditions: Firstly, the other voltage should not exceed its limit after the tap changer operation because this can lead to continuous set point changes and operations of the tap changer (hunting). Secondly, the voltage that exceeds its limit should be restored between acceptable limits if this is possible. The control algorithm assumes that a tap changer operation changes all network voltages by an amount equal to the tap step. So, the number of tap changer operations n is set such that 1) the other voltage (i.e. voltage not exceeding its limit) is more than n tap steps away from its limit and 2) the exceeding voltage is less than n tap steps away from its limit. If the latter condition can not be fulfilled, the largest n that fulfils the first condition is selected.

After the number of needed tap changer operations is determined, the new substation AVC relay target voltage is determined. The target voltage is set such that after the tap changer operations the substation voltage is near its setting value. Also the set point limits are taken into account at this point.

If basic substation voltage control is activated but is unable to improve network state (determined number of tap changer operations is zero or tap changer operation can not be initialized because of set point limits), basic power factor control is activated. Basic power factor control reduces the power factor set point of DG AVR (and increases DG reactive power consumption) if this would either lower network maximum voltage or enable basic substation voltage control. The new power factor set point is calculated using state estimation.

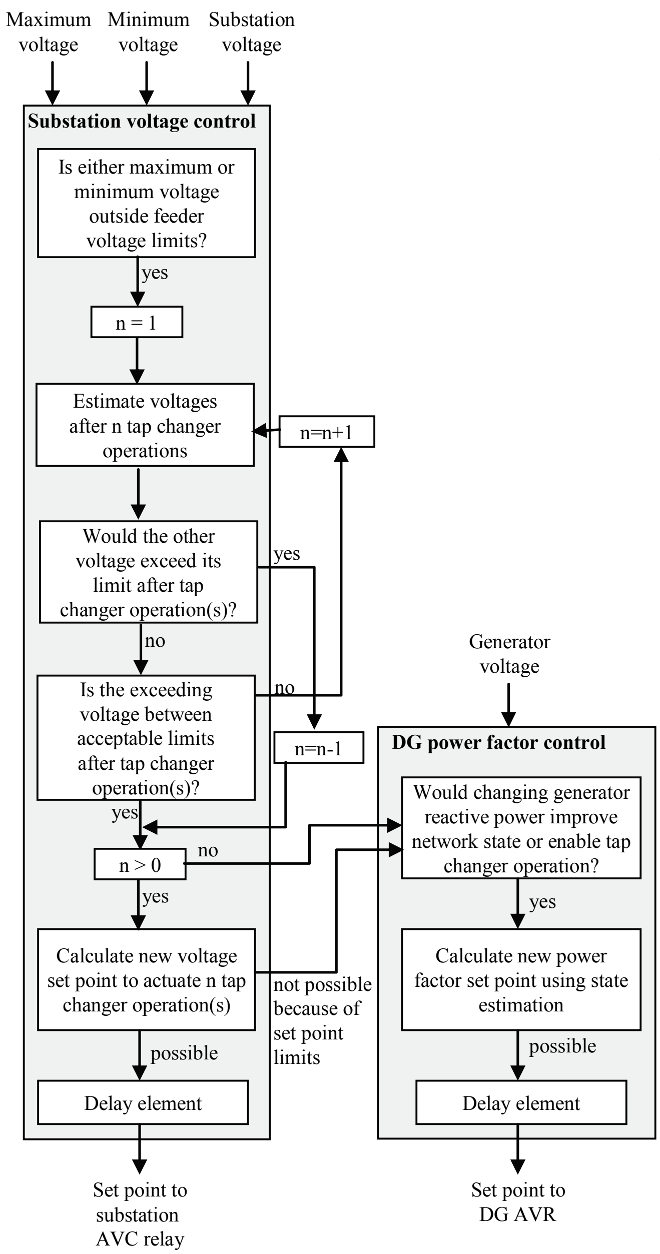

Fig. 1. The functional diagram of basic control when substation voltage is primarily controlled.

When DG reactive power is primarily controlled (Fig. 2) the two control blocks (substation voltage control and DG reactive power control) change places. DG power factor is decreased (and DG reactive power consumption increased) if this would either reduce network maximum voltage when it exceeds feeder voltage upper limit or enable the operation of substation voltage control when minimum voltage is lower than the feeder voltage lower limit.

DG power factor is not, however, reduced if DG's reactive power capability is insufficient to restore the voltages between acceptable limits. If the adequacy of DG's reactive power capability is not checked the following operation is possible: At first DG power factor is lowered to its minimum value but maximum voltage still remains above its limit. Basic substation voltage control is activated and the tap changer operates and the voltages are restored between acceptable limits. At this point, the generator voltage becomes lower than the limit of restoring power factor control and the power factor is increased. So, unnecessary controls of DG reactive power are made when controlling only the substation voltage would have restored the voltages to an acceptable level.

If DG power factor control is not needed or is not able to operate, substation voltage control is activated. Substation voltage control operates similarly as in Fig. 1 except for the fact that only one tap changer operation at a time is initialized. This is done to avoid the situation where the tap changer operates multiple times when one operation followed by DG reactive power control would have been sufficient.

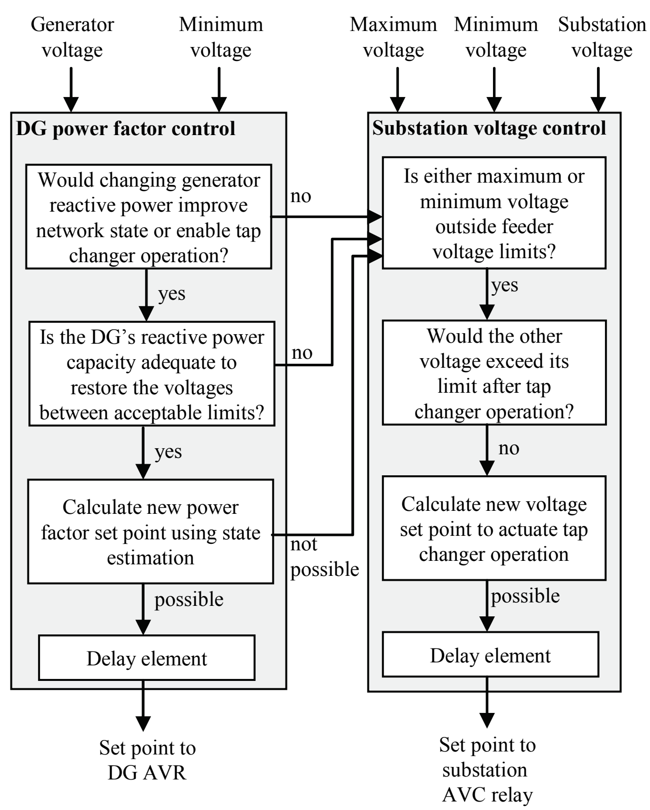

Fig. 2. The functional diagram of basic control when DG reactive power is primarily controlled.

Restoring control (Fig. 3) consists of two control blocks that are always executed in the same order. Restoring power factor control is intended to restore the DG power factor to unity when network state allows it. DG power factor can be increased if generator voltage has decreased enough. The new power factor set point is calculated using state estimation. If substation voltage is the primary control variable in basic control, also a part that reacts when minimum voltage has increased enough is included. This part activates basic substation voltage control that in turn lowers the voltage level of the whole distribution network. After tap changer operation also the generator voltage has decreased and the first part of the restoring DG power factor control is able to increase the power factor set point.

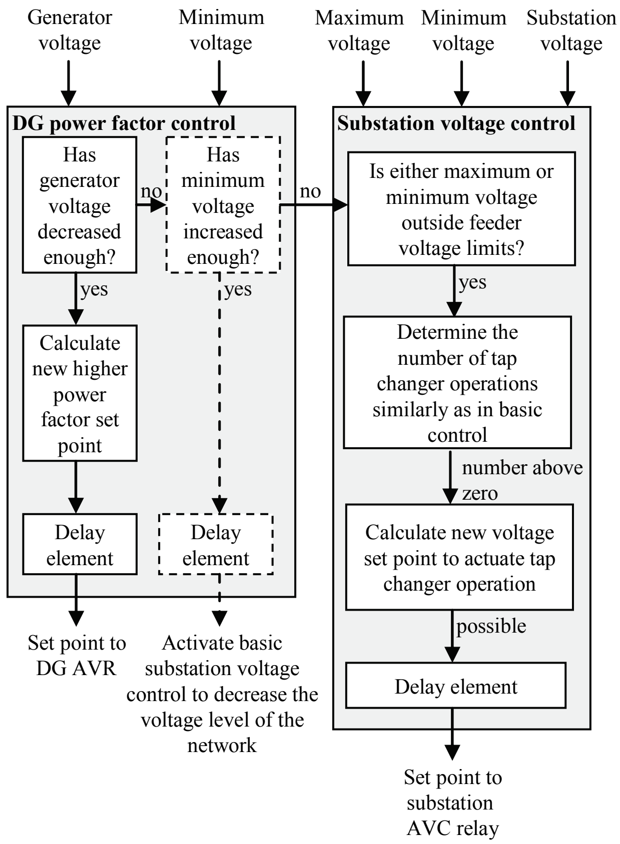

Fig. 3. The functional diagram of restoring control.

If restoring power factor control is not needed, restoring substation voltage control is activated. Restoring substation voltage control is similar to basic substation voltage control but has stricter voltage limits.

B. Coordinated voltage control prototype software

The coordinated voltage control prototype software is implemented using the Matlab programming language and it is run on a Matlab environment. It consists of a main program and several function subprograms and realizes state estimation, coordinated voltage control and data transmission between Matlab and SCADA.

The main function reads measurements from SCADA, executes state estimation and coordinated voltage control, sends possible commands to SCADA and saves data for later examination. The state estimation algorithm estimates network voltages using network information obtained from the network information system, load information obtained from the load curves and measurements obtained from the SCADA [18]. The coordinated voltage control algorithm uses the outputs of state estimation as inputs and determines the set points of substation AVC relay and DG AVR. Data transfer between Matlab and SCADA is realized via OPC Data Access.

The coordinated voltage control function realizes the functionality introduced in chapter II. A. If network voltages can not be restored to an acceptable level by controlling substation voltage and DG reactive power, a warning is outputted for the operator and the operator can take actions to improve the network state.

C. Discussion of the algorithm

The coordinated voltage control algorithm is designed such that it can be easily implemented as a part of distribution management system (DMS). In Finland, the DMS includes a state estimator and, therefore, only the voltage control algorithm needs to be implemented.

The voltage control algorithm is simple. Therefore, its operation can be easily understood and its implementation does not require extensive work. The algorithm requires only little computational time and the interval in which the algorithm can be executed in real DMS is mainly dependent on the execution time of state estimation. Although the algorithm is simple it is still able to utilize the whole control range of the controllable variables to restore the network voltages to an acceptable level.

The algorithm is also modular which has advantages both at the implementation phase and if changes to the algorithm are needed. The substation voltage control algorithm is suitable for distribution networks in general whereas the reactive power control algorithm is suitable only for traditional radial distribution networks where only few DGs exist [9]. If the reactive power control algorithm needs to be modified, the substation voltage control algorithm can still remain unchanged.

III. RTDS SIMULATION ARRANGEMENT

RTDS simulations are used to verify the correct operation of the coordinated voltage control prototype software. They are also used to test the algorithm in situations that can not be realized in real distribution network tests.

RTDS is a power system simulator for real time studies. The simulator environment consists of hardware and software. The hardware is used to solve electromagnetic transient simulations in real time and is installed in rack(s). The software RSCAD is run on an external computer and is used to construct the power system models and to control the simulations. Real external devices can be connected to the system. [17]

The connection used in the RTDS simulations of this paper is depicted in Fig. 4. In the simulations, RTDS emulates a real distribution network that is controlled using real SCADA (ABB MicroSCADA Pro SYS 600). Measurement signals are extracted from the simulated network similarly as from a real distribution network and control commands are transferred to the simulation through SCADA.

Data transfer between RSCAD and SCADA is realized using shared files. RSCAD writes the measurement signals

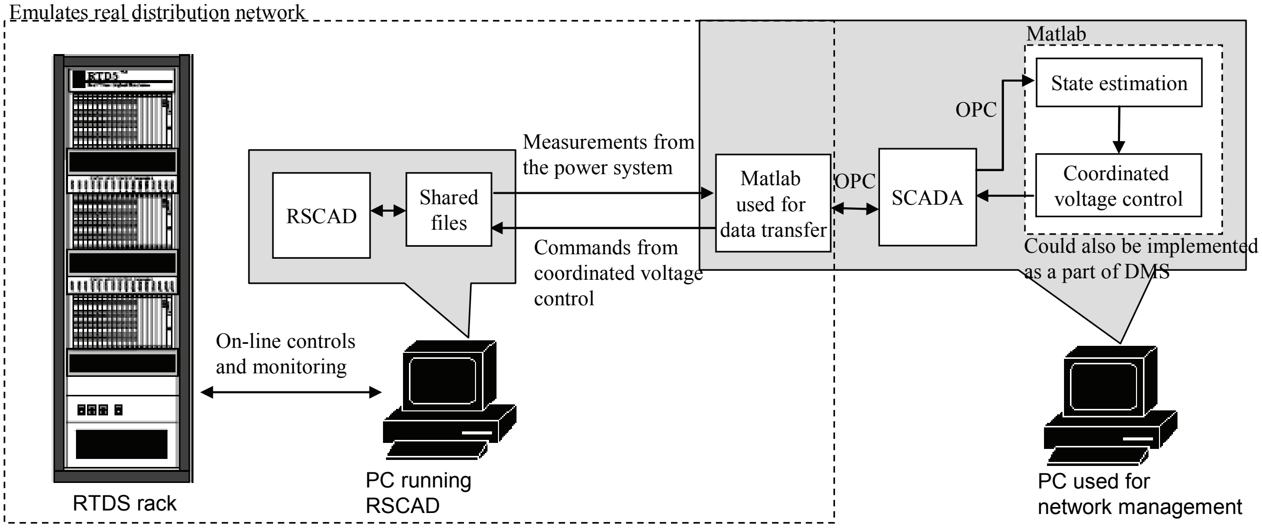

Fig. 4. The connection used in RTDS simulations.

from the power system to a file. Matlab located at another computer reads the file and transfers the data to SCADA using OPC standard. Similarly, the commands given by the coordinated voltage control algorithm are firstly transferred from SCADA to Matlab and, thereafter, Matlab writes the values to a file that is read by RSCAD.

The coordinated voltage control algorithm executed in another Matlab communicates with the SCADA via OPC. The coordinated voltage control algorithm is executed once every second.

A. The simulation network

The simulation network is a real Finnish distribution network. The network consists of two medium voltage feeders and contains one relatively large hydro power plant. The network will experience voltage rise problems if no actions are taken to diminish the effect of DG. The structure of the study network is represented in Fig. 5.

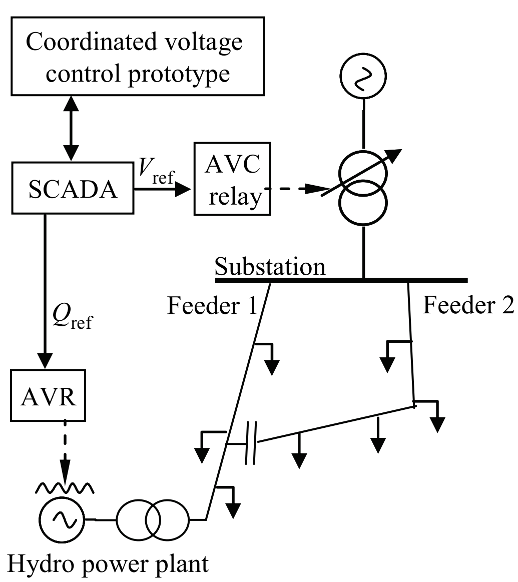

Fig. 5. The structure of the study network.

The distribution lines are modelled using a π-connection and the loads are modelled as static constant power loads. A representation of substation AVC relay and tap changer mechanism is also included [19]. The hydro power plant is connected to the network using a synchronous generator and its reactive power can be controlled through excitation control of the generator. The excitation system is of type IEEE AC8B [20] and the power factor control is realized as cascade control where a power factor controller of type IEEE VAr controller Type 2 [20] determines the set point of the voltage controller (PID control used instead of PI control). The coordinated voltage control algorithm outputs a power factor set point that is converted to reactive power set point before sending to the DG AVR.

B. Control parameters

The parameters used in the simulations are the following: AVC relay deadband *DB* is 1.5 %, hysteresis limit 90 % of the operating value and delay 10 s. Line drop compensation is not used. The main transformer tap step is 1.67 % and its delay is 2 s.

The feeder voltage lower and upper limits used in basic substation voltage control are 0.95 and 1.045 pu whereas the restoring substation voltage control tries to keep the network voltages between 1.00-1.045 pu. The voltage reference limits are set equal to the feeder voltage limits. In basic substation voltage control the delay is 20 s and in restoring substation voltage control 30 s.

Minimum power factor set point is 0.98 and the delay in basic power factor control 10 s. In restoring power factor control, the generator voltage has to be at least 0.01 pu below the feeder voltage upper limit to enable increase of the DG power factor. The delay in this control is 20 s. In the other part of restoring power factor control, the minimum voltage has to exceed the feeder voltage lower limit by at least 0.02 pu to activate basic substation voltage control. The delay in this control is 30 s.

IV. Simulation results

The operation of the coordinated voltage control prototype software is studied quite extensively in RTDS simulation environment. Simulations are conducted in three loading conditions (maximum, minimum and middle) and different kinds of simulation sequences are used. Changes in the real power of DG and loading changes are used to disturb the network state to make the coordinated voltage control algorithm active.

A. Example simulations

Results of two example simulations are represented here. Both simulations are conducted in minimum loading conditions and have similar simulation sequences. The simulation sequence is following: At 10 s the DG unit is connected to the network with output power of 0.0 MW. At time 50 s, the real power of DG is raised to 2.0 MW and at 150 s lowered to 1.0 MW. At 250 s the unit is disconnected from the network.

In the first simulation depicted in Fig. 6 substation voltage is primarily controlled and in the second one represented in Fig. 7 DG reactive power is the primary control variable.

In Fig. 6 network maximum voltage exceeds its limit when DG output power is raised to 2.0 MW. Basic substation voltage control is activated and AVC relay set point changed in such a way that two tap operations are initiated because maximum voltage would remain over its limit after one tap operation. After the tap operations, network voltages are restored between acceptable limits. When DG output power is lowered to 1.0 MW, all voltages still remain within feeder voltage limits both in basic and restoring controls and, hence, nothing is done. When the DG unit is disconnected at 250 s, network minimum voltage falls below feeder voltage lower limit in restoring substation voltage control and AVC relay set point is increased after the delay. In this simulation, DG power factor control is not needed at all.

In Fig. 7 network maximum voltage exceeds its limit when DG output power is raised to 2.0 MW. The primary control variable is DG power factor but the maximum voltage is so far from its limit that DG's reactive power capability is insufficient to lower the maximum voltage below its limit. Therefore, basic substation voltage control is activated and a tap changer operation initiated. After the tap changer operation maximum voltage is still above its limit and basic power factor control is activated. DG power factor set point is lowered to 0.985 and network maximum voltage restored below its limit. When DG real power is lowered to 1.0 MW, restoring power factor control operates for the first time and when DG is disconnected, DG power factor is restored to unity.

B. Discussion of the simulations results

Simulation results show that the coordinated voltage control prototype software implemented in Matlab operates as expected and that the modifications done to the algorithm improve the operation of the algorithm. New set points are

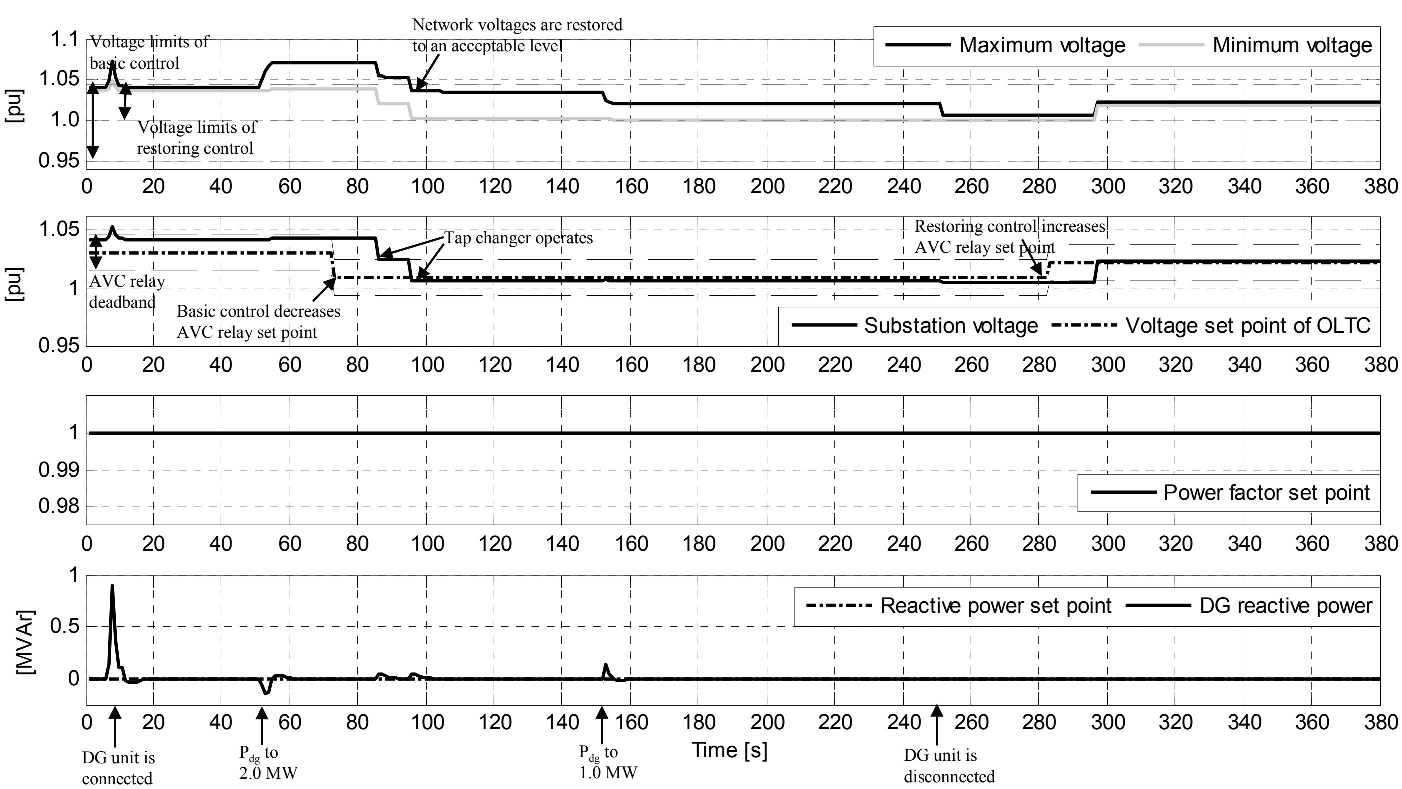

Fig. 6. The operation of the control algorithm in minimum loading conditions when DG reactive power is the primary control variable.

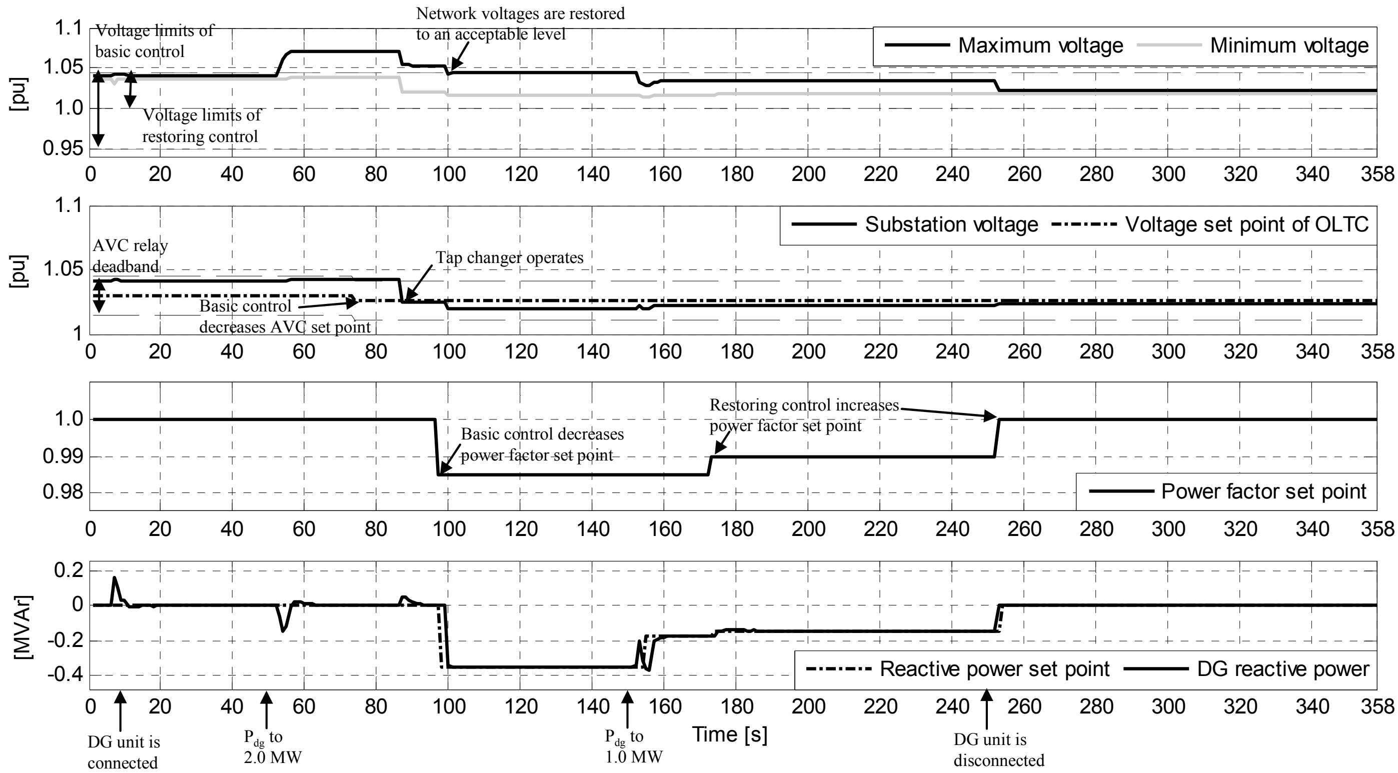

Fig. 7. The operation of the control algorithm in minimum loading conditions when DG reactive power is the primary control variable.

calculated such that only one set point change is needed to reach an acceptable network state whereas in the original algorithm [9] set point changes were performed in user-defined steps. Also, no unnecessary control actions are performed when the modified control algorithm is used. When DG reactive power capability is noticed to be inadequate, substation voltage control algorithm is activated and no control actions on DG reactive power are taken.

The implemented control algorithm restores the network voltages between acceptable limits in all the cases where restoration is possible by controlling substation voltage and DG reactive power. If restoration is not possible the algorithm outputs a warning for the operator. DG power factor differs from unity only when network state demands it and network voltages do not remain in an unusually high or low level for a long period of time. No continuous or unnecessary set point changes appear. Hence, the correct operation of the algorithm is verified and the prototype is ready for testing in a real distribution network.

V. Further Studies

The operation of the implemented coordinated voltage control algorithm will be next tested in a real distribution network. The real distribution network tests are currently in progress (project ADINE [21], [22]).

In future, coordinated voltage control methods will be further studied. Their application also in more complex networks that include a variety of components participating in voltage control will be studied. Also, methods using fuzzy logic and/or optimization algorithms will be developed and their operation will be examined.

VI. Conclusions

In this paper, the operation of a coordinated voltage control implementation was studied using RTDS simulations. In the simulations, RTDS was used to emulate a real distribution network whose voltage was controlled by the coordinated voltage control implementation. The control algorithm was implemented as a Matlab program that communicated with SCADA via OPC. The algorithm can also be implemented as a part of the distribution management system (DMS).

The RTDS simulations conducted verified the correct operation of the coordinated voltage control prototype software. The next step is to test the operation of the algorithm also in a real distribution network. The real network tests are currently in progress.

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VIII. Biographies

Anna Kulmala was born in Tampere, Finland, on March 13, 1982. She received her Master's Degree in electrical engineering from Tampere University of Technology in 2006.

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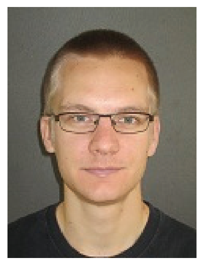

Antti Koto was born in Mustasaari, Finland, on March 4, 1984. He received his Master's Degree in electrical engineering from Tampere University of Technology in 2010.

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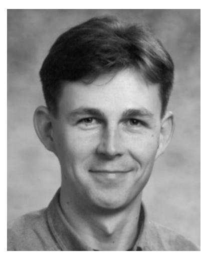

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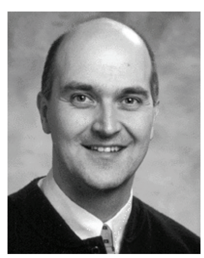

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Demonstrating Coordinated Voltage Control in a Real Distribution Network

Anna Kulmala, Antti Mutanen, Antti Koto, Sami Repo and Pertti Järventausta

***Abstract*—The connection of distributed generation (DG) to weak distribution networks is likely to cause voltage rise problems. At present, the voltage rise is usually mitigated by reinforcing the network but as the penetration level of DG increases also active voltage control methods need to be taken into use. Active voltage control has been a subject of extensive research in the past decade but the number of real implementations is still very low. One reason for this is that only few demonstrations have been conducted in real distribution networks.**

In this paper, the operation of one coordinated voltage control (CVC) algorithm is successfully demonstrated in a real Finnish distribution network. The main objective of the paper is to identify the problems that may arise when academic smart grid methods are implemented in real electricity networks. The second objective is to verify the operation of the studied CVC algorithm.

***Index Terms*—Distributed power generation, power distribution, power system management, reactive power control, voltage control**

I. Introduction

In weak distribution networks, the maximum capacity of connected generation is usually limited by the voltage rise effect. At present, voltage rise is usually mitigated using passive methods such as increasing the conductor size but this can be quite expensive. Also active voltage control methods can be used to decrease the maximum voltage in the network. Using active voltage level management can in many cases decrease the connection costs of distributed generation (DG) substantially. [1]

Active voltage control has been a subject of extensive research for years and several active voltage control methods of different complexity and data transfer needs have been proposed in publications. Although active voltage control methods for different situations have been developed, only few real network implementations have been realized. Several reasons for this exist: Active voltage control changes the operational and planning principles of distribution networks radically and, therefore, taking them into use might seem too laborious for distribution network operators (DNOs). Also, the current regulative environment does not encourage DNOs to take active voltage control into use even when it would be cost-effective. The currently used planning tools are not capable of taking active voltage control into account and adequate measurement data required by active voltage control methods might not be available from distribution networks. Moreover, active voltage control is still somewhat at its development phase and has not become an established way of action. In most publications on active voltage control only control principles are covered and time domain operation and practical implementation issues are omitted.

Hence, some development is still needed for widespread utilization of active voltage control in real networks. Real distribution network demonstrations are needed to identify and solve possible problems associated with active voltage control utilization in real distribution networks and also to convince DNOs that active voltage control is safe and can be taken into use relatively easily. Also, distribution network planning procedures and tools and the regulative environment need development.

This paper discusses real distribution network demonstration of a coordinated voltage control (CVC) algorithm. The algorithm was specified and its operation was tested using PSCAD simulations in [2]. In [3] Real Time Digital Simulator (RTDS) was used to verify the real time operation of the algorithm. This paper presents results of the final phase of the research project: demonstration in a real distribution network. This phase cannot be omitted in smart grid research projects if the objective is large-scale utilization of the developed smart grid methods.

The main objective of this paper is to identify the problems that may arise when CVC methods are implemented in real distribution networks. Although a specific algorithm is used in the demonstration, the findings are general and apply also when different kinds of CVC algorithms are used. The second objective of the paper is to verify the operation of the studied CVC algorithm in a real network.

II. Active Voltage Control

Active voltage control methods can be based only on local measurements or utilize information about the whole distribution network i.e. be coordinated. DG reactive power can be locally controlled to mitigate the voltage rise caused by DG. Also, production curtailment of DG can be based on local measurements. These local methods can, in many cases, increase the capacity of DG that can be connected to an existing distribution network significantly [1]. They do not,

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however, utilize all control possibilities of the network and, therefore, coordinated voltage control methods can increase the hosting capacity of an existing network significantly more than methods based only on local measurements [1].

A. Coordinated voltage control methods

The coordinated voltage control methods can determine their control actions based on control rules or use some kind of optimization algorithm. Methods based on control rules are suitable for simple networks where only few control possibilities exist. Traditional radial distribution networks are such networks. The simplest and most studied method controls substation voltage based on network maximum and minimum voltages [4]. Control of DG reactive power can also be included in the CVC algorithm [2], [5], [6]. Also DG active power can be used as a control variable in CVC [7]. The benefit of using control rules is the simplicity of the method. Time domain implementation is straightforward, no convergence problems can occur and network operators can easily understand the functioning of the system.

When the number of controllable components increases, determination of control rules can become a complex task. In these cases, methods using optimization algorithms can be more suitable. Several CVC methods using different optimization methods and objective functions have been proposed in publications. Some publications (e.g. [1], [8], [9]) use linear programming (LP). Nonlinear programming (NLP) is also used in several publications (e.g. [10], [11]). Some publications combine NLP with local-learning algorithms to reduce the computational time [12]. Genetic algorithm is used for instance in [13] and [14] applies evolutionary particle swarm optimization to solve the voltage control problem.

Some practical issues need to be taken into account when CVC methods based on optimization are used. The computational time required for the optimization cannot be too long if the method is intended for on-line use. The algorithm should also know how to operate if the optimization algorithm does not converge. Also, the algorithm should know the order in which control actions need to be executed if multiple control actions are suggested. Moreover, the control solution obtained from the algorithm should not radically deviate the network from the current operating point.

B. Real Implementations of CVC

Although several CVC methods have been proposed in publications only few real implementations yet exist. This is due to at least the following reasons:

Firstly, taking active voltage control into use requires substantial changes to the operational and planning principles of distribution networks and, therefore, implementing active voltage control for the first time is quite laborious to the DNO. Also, in the current passive distribution networks the DNO owns all network resources that are used in network management. In an active network, the DNO uses also customer owned resources (for instance controls the reactive power of DG) which is a completely new situation for the DNOs although common practice in transmission networks.

Secondly, the current regulative environment, at least in Finland, does not encourage DNOs to take active voltage control into use. The DNO is obligated to connect DG into its network but there is no incentive that promotes implementing the connection in a smart way. Moreover, the DNOs have to often answer the network interconnection enquiries of the DG planners in a relatively short time and, therefore, there is no time to consider alternative network management strategies.

Thirdly, the currently used planning tools are not capable of taking active voltage control into account. At present, distribution networks are dimensioned based on extreme loading/production conditions. This kind of planning determines only whether the network operates acceptably in all situations and cannot be used to compare different control strategies. Hence, the planning procedures need to be developed to enable comparison of total costs of alternative voltage control strategies. [15]

Fourthly, CVC requires information on the state of the whole distribution network which is not, at present, usually available. In Finland, an advanced distribution management system (DMS) is used to control the distribution networks. It combines static information obtained from network information system (NIS) and real time measurement data and control possibilities of SCADA. The loads are modelled using hourly load curves [16] and calculation functions such as state estimation are already available. However, measurement data has been previously often available only from the substation and, therefore, the accuracy of the state estimate has not been very good. The amount of available measurement data is, however, constantly increasing as automatic meter reading (AMR) devices are being installed. The AMR measurements can be used to improve the accuracy of distribution network state estimate either by using the real time measurements as additional inputs to the algorithm or they can be used to review the load curves [17].

Finally, most publications on CVC (especially those using optimization) concentrate on determining the control principles of the control algorithm and do not address the time domain implementation of the algorithm and practical issues in taking the algorithm in real distribution network use. Hence, demonstrations are still needed to make CVC feasible. The demonstrations can be used to identify and solve possible problems associated with real distribution network implementation of CVC. They can also be used to convince DNOs that taking active voltage control into use is worthwhile and relatively easy. Real distribution network demonstrations are inevitably needed before large-scale deployment of active voltage control is possible.

After the demonstration phase, the developed voltage control methods need to be further developed to commercial products to make introduction of active voltage control as easy as possible to the DNOs. At present, only one commercial product implementing CVC is to the authors' knowledge available. It realizes coordinated control of substation voltage [18]. No commercial products implementing more complex CVC methods are currently available.

III. The Coordinated Voltage Control Implementation

The implemented CVC algorithm is based on [2]. It controls substation voltage and DG reactive power by changing the voltage set point of substation automatic voltage control (AVC) relay and power factor set point of DG automatic voltage regulator (AVR). The purpose of the CVC algorithm is to keep the voltages in the whole distribution network between acceptable limits.

A. Operational principle

The CVC algorithm comprises two functions: Basic control is used to restore the network voltages between acceptable limits when either network maximum or minimum voltage exceeds its limit. Restoring control is used to restore DG power factor set point to unity when network state allows it and to normalize network voltages if the voltage in the whole distribution network has remained in an unusually high or low level. Both control functions consist of two parts: the first one controls the substation voltage and the second one DG reactive power.

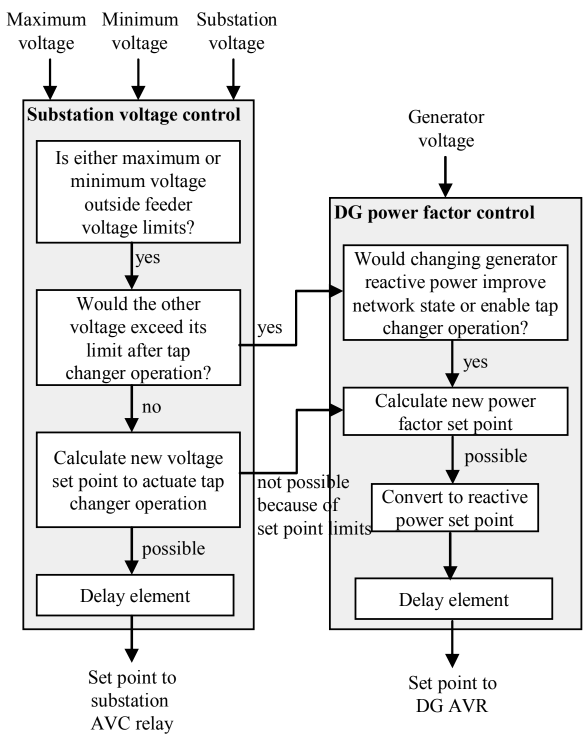

Fig. 1. The functional diagram of basic control.

The functional diagram of basic control is represented in Fig. 1 and the functional diagram of restoring control in Fig. 2. More detailed flow charts of each control block can be found in [2].

The basic control operates as follows: If network maximum voltage exceeds feeder voltage upper limit and minimum voltage is more than a tap step above its limit, the substation voltage is decreased. Correspondingly, the substation voltage is increased if network minimum voltage is lower than feeder voltage lower limit and maximum voltage is more than a tap step below feeder voltage upper limit. If basic substation voltage control is unable to improve network state (both maximum and minimum voltages exceed or are too close to feeder voltage limits or tap changer operation cannot be initialized because of set point limits), basic power factor control is activated. Basic power factor control reduces the power factor set point of DG AVR in predetermined steps (and increases DG reactive power consumption) if this would either lower network maximum voltage or enable substation voltage control. The power factor set point is further converted to reactive power set point because in the demonstration network the DG AVR is operating in reactive power control mode.

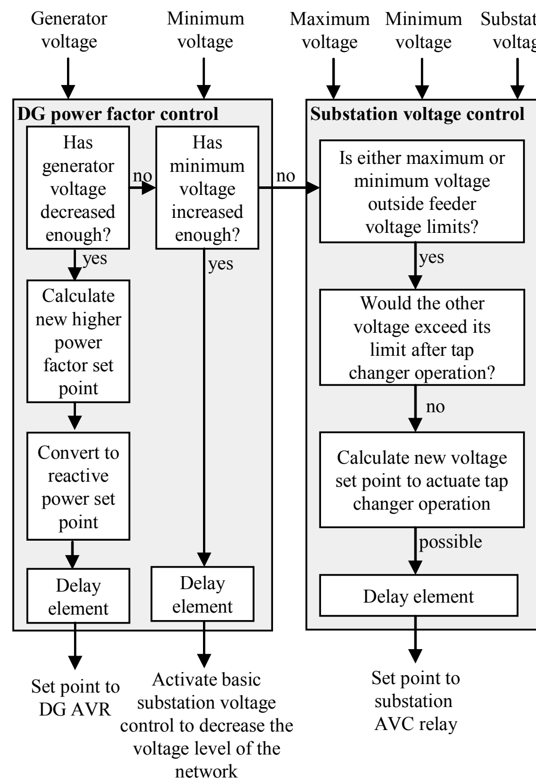

Fig. 2. The functional diagram of restoring control.

The restoring control operates as follows: DG power factor set point is increased if generator voltage has decreased enough. Restoring power factor control includes also a part that activates basic substation voltage control if minimum voltage has increased enough. Basic substation voltage control lowers the voltage level of the whole distribution network after which the first part of restoring power factor control can increase the power factor set point. If restoring power factor control is not needed, restoring substation voltage control is activated. It is similar to basic substation voltage control but has stricter voltage limits.

B. Limitations of the algorithm

The studied CVC algorithm is modular and consists of parts that control substation voltage and parts that control DG reactive power. Substation voltage control determines its control actions based on network maximum and minimum voltages. Although it does not take the location of these voltages into account, it is applicable to all kinds of networks regardless of the number or type of DG units because changing the substation voltage influences voltages in the whole distribution network similarly.

In the algorithm parts controlling DG power factor it is assumed that network maximum voltage is always located either at the substation or at generator terminals and that there is no need to increase network voltage by controlling DG reactive power. These assumptions are valid in most Finnish distribution networks because no capacitors are usually connected on feeders and the network is dimensioned such that undervoltage will not occur in any loading condition. If the assumptions are not valid, the reactive power control can be modified to suit the new situation.

The demonstration network contains only one DG unit and also the simulations in [2] and [3] are conducted in networks with a single generator. In real networks, it is naturally possible that multiple DG units are connected to the same network. The DG reactive power control determines its control actions based on generator terminal voltage and, therefore, will operate logically also when multiple generators are connected to the network. The reactive power division between generators might not, however, be optimal because all generators, whose terminal voltage exceeds the feeder voltage upper limit, decrease their power factor set point. Some control possibilities might also be left unused if the voltage at some network node exceeds the feeder voltage upper limit but voltages at terminals of controllable generators remain within acceptable limits. The algorithm will be further developed in future to remove the above mentioned limitations.

C. *Prototype software*

The CVC prototype software used in the real network demonstration was implemented using Matlab programming language and run in Matlab environment. The Matlab implementation consists of a main function and several function subprograms that realize state estimation, CVC and data exchange between Matlab and SCADA. The main function reads measurements from SCADA, executes state estimation and CVC and saves data for later examination.

The state estimation algorithm uses network parameters obtained from the network information system, load information obtained from the customer information system and measurements obtained from SCADA to determine network maximum and minimum voltages [17]. Measurements of substation voltage, power flows or current magnitudes at the beginning of the medium voltage feeders, generator real and reactive power and generator breaker status are needed.

The CVC algorithm uses the maximum and minimum voltages obtained from state estimation as inputs and determines the set points of substation AVC relay and DG AVR. It realizes the functionality described in chapter III. A. and in [2]. Data exchange between Matlab and SCADA is realized using OPC Data Access.

IV. The Demonstration Arrangement

The operation of the implemented CVC algorithm was demonstrated in a real Finnish distribution network. The arrangement used in the demonstration is depicted in Fig. 3.

In the demonstration an additional computer running Matlab was added to the normal control room set up. The Matlab communicated with SCADA through OPC Data Access. In the demonstration, only measurement values from SCADA were transferred automatically through OPC. The CVC algorithm was used as an advisory tool and the operator approved and executed the suggested control actions manually. In RTDS simulations also the new set points of substation AVC relay and DG AVR were transferred automatically through OPC [3].

Realizing the demonstration arrangement was relatively easy because in the demonstration case all necessary data was already available at the control room. The Finnish DMS is highly integrated with the NIS and the SCADA and, therefore, both static network data (feeder impedances etc.) and dynamic measurement and switching state data are available. Moreover, the existence of a standard OPC interface enabled easy data transfer from SCADA to Matlab. If no such architecture is present, implementing the CVC is naturally a more complex task including for instance planning of the ICT architecture and the communication infrastructure.

A. *The demonstration network*

The demonstration network comprises five medium voltage feeders ranging from one HV/MV substation and contains one relatively large hydro power plant (1600 kVA) at Soininkoski. In normal switching state the hydro power plant is fed by its own feeder from a nearby substation Killinkoski.

In the demonstration, network topology is changed and the hydro power plant is connected to the end of feeder Ritari some 40 km from the Heinäaho substation. The other feeders are pure load feeders. All feeders are radially operated although they construct rings. If no actions are taken, voltages of the DG feeder exceed feeder voltage upper limit. Minimum voltage is in the demonstration network always located at feeder Kihniö which extends itself about 38 km from the substation. A simplified diagram of the network is represented in Fig. 3.

In the demonstration network, all needed measurement data (substation voltage, feeder currents and DG real and reactive powers) is already available in SCADA. Also, the set points of substation AVC relay and DG AVR can be changed through SCADA. Additional measurements were added to the end of feeder Kihniö and to the Soininkoski generator terminals to ensure that network voltages indeed remain within acceptable range. These measurements were used purely for observation and were not given as inputs to the CVC algorithm.

B. *Control parameters*

The substation AVC relay set point is in normal state 1.03 pu, deadband 1.24 % and delay 30 s. The main transformer tap step is 1.67 % and its delay was estimated to be 10 s by the network operator. The AVR of Soininkoski hydro power plant is operating in reactive power control mode. In the original

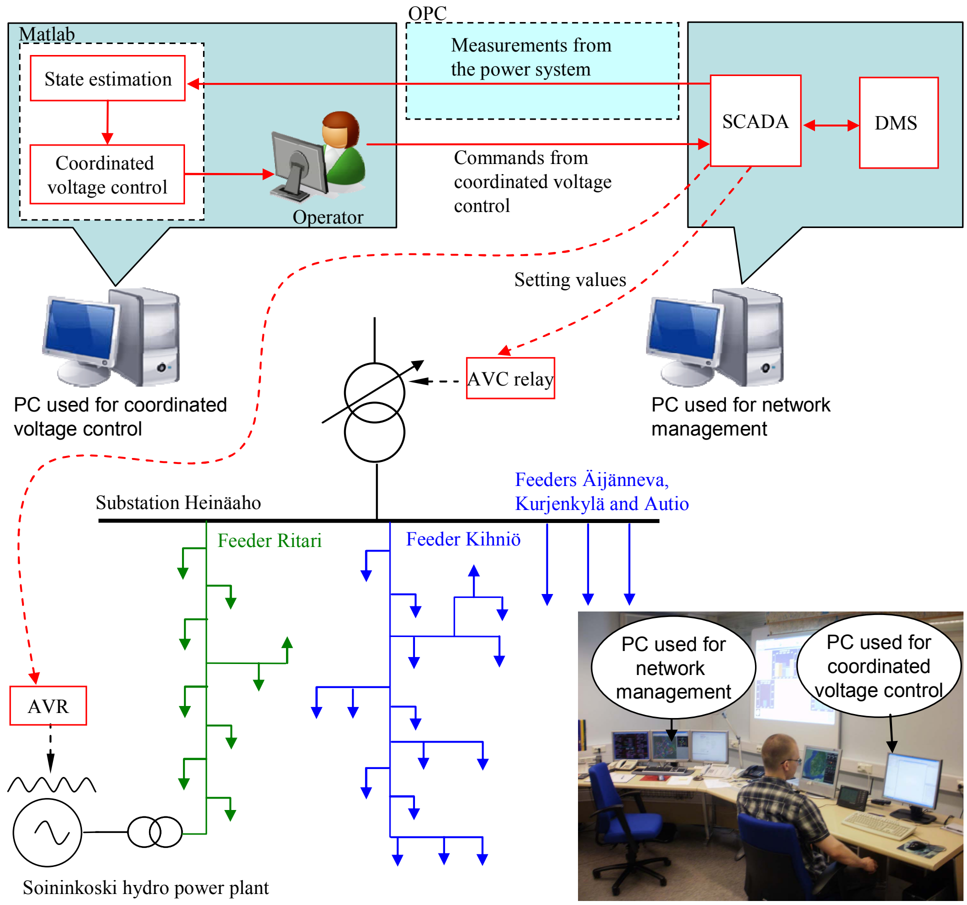

Fig. 3. The arrangement in the real network demonstration.

state it operates at unity power factor.

The feeder voltage lower and upper limits used in basic substation voltage control are 0.96 and 1.0424 pu whereas the restoring substation voltage control tries to keep the network voltages between 1.00-1.04 pu. The voltage reference limits are set equal to the feeder voltage limits. In basic substation voltage control the delay is 20 s and in restoring substation voltage control 120 s.

Minimum power factor set point is 0.98 and the delay in basic power factor control 20 s. In restoring power factor control, the generator voltage has to be at least 0.01 pu below the feeder voltage upper limit to enable increase of the DG power factor. The delay in this control is 60 s. In the other part of restoring power factor control, the minimum voltage has to exceed the feeder voltage lower limit by at least 0.02 pu to activate basic substation voltage control. The delay in this control is 240 s.

V. RESULTS

In the demonstration, DG real power changes were used as disturbances to make the CVC algorithm active. The DG real power was changed according to a predetermined sequence and the CVC algorithm did not participate in controlling the DG real power. Hence, the controllable hydro power plant appeared to the CVC algorithm similarly as non-controllable sources. Planned loading changes would have been difficult to realize in the real network. Some changes in the load were naturally constantly occurring but these were not controllable.

The test sequence used in the demonstration is following: At the beginning DG is operating at output power of 100 kW and with unity power factor. The substation AVC relay set point is 1.03 pu and substation voltage 1.04 pu. The real power of DG is increased in steps of 100 kW until the DG output power reaches 1300 kW. When maximum voltage exceeds its limit, the next increase in real power is done only after the coordinated voltage control has restored the voltages to an acceptable level. The DG operates with output power of 1300 kW for some time after which the real power of DG is decreased in steps of 300 kW until it reaches the output power of 100 kW. As a whole the duration of the test was about 2.5 hours. The operation of CVC in the test is represented in Figs. 4-6.

When the demonstration results are viewed some issues need to be taken into account. The CVC algorithm was used in the demonstration only as an advisory tool and, hence, there is some delay between the set point change suggested by the algorithm and the actual set point change. In some cases the need for set point change disappeared during consideration whether to execute the control action or not (for instance at times 14.02 and 14.13).

The resolutions of the CVC algorithm outputs and the real equipment set points were not equal in the demonstration and,

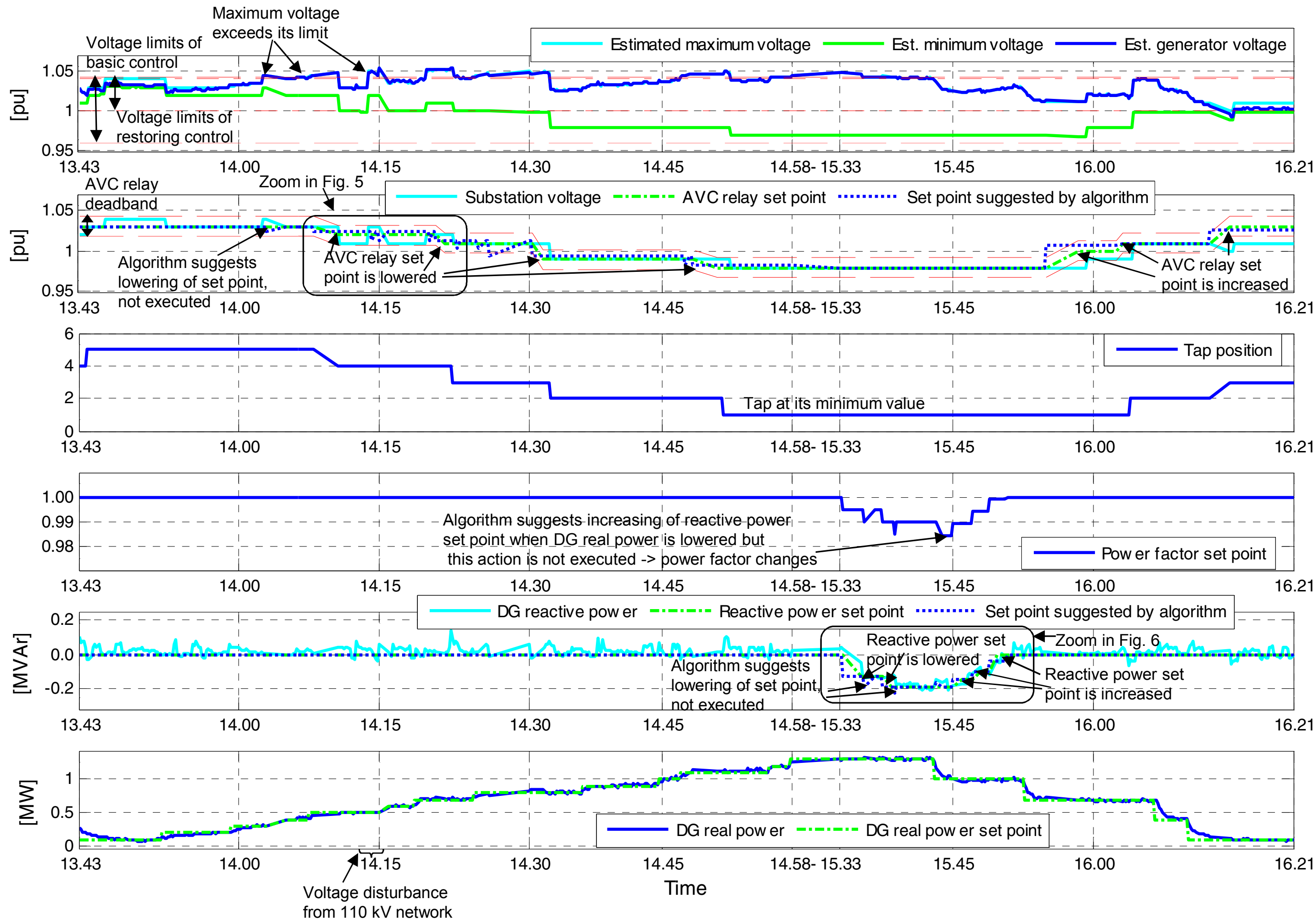

Fig. 4. The performance of the implemented CVC algorithm in real distribution network demonstration.

therefore, it was not possible to set the set points at exactly the values suggested by the CVC algorithm. This can be seen for instance in Fig. 5 where the algorithm suggests a set point of 1.0233 pu and the set point is set to 1.02 pu. This difference in resolutions led also to one mistake in the manual set point setting. At time 15.58 the AVC relay set point was incorrectly raised to 1.0 pu although the algorithm suggested a set point of 1.0067 pu. The tap changer operation was initiated only after the set point was further raised to 1.01 pu. For non-demonstrative implementations, the algorithm should be modified to output the set points with the same resolution that can be used in the real devices. In the equipment used in the demonstration, the AVC relay set point can be set at intervals of 1 % and the DG reactive power at intervals of 10 kVA.

The reactive power controller of the DG turned out to be substantially slower than expected and, therefore, the delay in basic power factor control was too small. This can be seen for instance in Fig. 6 where the algorithm suggests another set point change before a new steady state is reached.

A minor programming bug suspended the operation of the algorithm at time 14.58. The bug was searched for and found from the function that realizes DG reactive power control. This function had not been called for previously in the demonstration and, therefore, results prior to the bug fix are also valid.

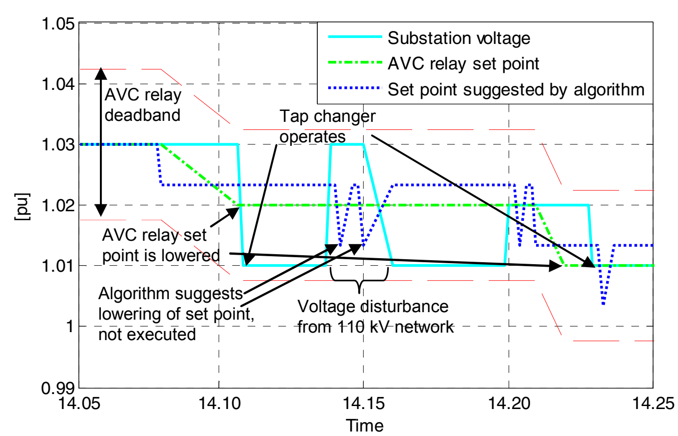

Fig. 5. Zoomed operation of basic substation voltage control.

In the demonstration, the state estimation accuracy was not as good as would be desired. The most important reason for this was that the substation voltage measurement could not be taken from the AVC relay as it outputted consistently too large values. This was discovered by extra measurements at the substation. The bus voltage measurement had to be used instead. In the demonstration case, the bus voltage measurement is quite inaccurate and outputs voltage values with resolution of 1 % (0.2 kV). New measured values are transmitted to the control room only when the voltage has changed more than 2 % but also inquiries of the current voltage value can be made. Since the CVC algorithm relies heavily on the state estimates, it is vital that in future implementations special attention is addressed to the accuracy of substation voltage measurement.

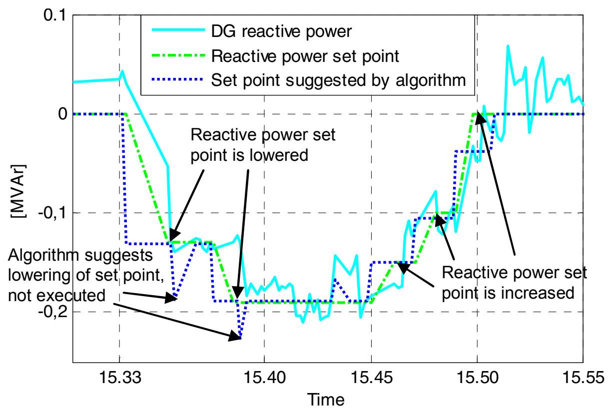

Fig. 6. Zoomed operation of DG power factor control.

A. *Discussion of the results*

The main objective of the study was to identify the problems associated with real network implementation. No major problems occurred but some minor difficulties were encountered. Some network measurements were more inaccurate than expected which reduced the accuracy of the state estimate. Hence, the accuracy of measurements needs to be determined before non-demonstrative implementations of the algorithm. Also, the reactive power controller of the Soininkoski hydro power plant was quite poorly tuned and, therefore, the new steady state after a reactive power set point change was reached quite slowly. Hence, the operation of the existing control equipment has to be examined and possibly also corrected before deciding the parameters of the CVC algorithm.

The second objective of the study was to verify the operation of the studied CVC algorithm also in the real network (simulation results can be found in [2] and [3]). Also this objective was fulfilled. The algorithm operated as expected throughout the whole demonstration and was able to restore the network voltages to an acceptable level in all situations. The only problem occurred at 14.58 when a minor programming bug suspended the operation of the algorithm. Also, the resolutions of the CVC outputs and the real controller inputs were not equal in the demonstration. In real implementations, the resolutions should naturally be the same.

In conclusion it can be said that the real network demonstration revealed some issues that were not visible in PSCAD or RTDS simulations but these were only minor difficulties and can be corrected quite easily.

B. *Practical issues regarding implementation*

In the demonstration, the CVC algorithm was implemented as a Matlab program and was run on an additional computer added to the normal control room set up. The algorithm could also be implemented as a part of distribution management system which would make implementation of CVC to real distribution networks quite easy. The DMS includes the network model and, therefore, no additional modelling is needed. Moreover, the network model is always at the same switching state as the real network. If CVC is implemented as a separate controller, the network model is static and the network data needs to be maintained in two places (network information system database and the CVC controller). The Finnish DMS includes also a state estimator and, therefore, only the CVC algorithm needs to be implemented.

In the demonstration, the inputs to the CVC algorithm are obtained from state estimation. The inputs could also be measured. In a radial network, the number of locations where maximum and minimum voltages can reside is limited and, therefore, only a limited number of measurements would be needed. In case of changes in the network switching state, the location of maximum and minimum voltage is, however, changed. It might not be profitable to install new measurements for voltage control purposes but if measurements already exist or are installed for some other reason, they should certainly be exploited. For instance AMR measurements could be utilized [17]. Also a combination of state estimation and measurements could be used where for instance the network minimum voltage is selected to be the smallest value of measured and estimated voltages in the network.

In practical implementations it is always possible that an important communication channel fails and the inputs needed by the control algorithm are no longer available. The algorithm should be able to detect these situations and to function reasonably also in the absence of communication channels. In these situations, the studied algorithm sets the substation voltage set point and the DG power factor set point to predetermined values and if overvoltage occurs at the generator terminals the plant is disconnected by its overvoltage relay. Communication failure between the central control room and some substation is, at present, very unlikely because two separate data links are usually utilized. Communication links to DGs or measurement devices are more likely to fail.

In the demonstration, the CVC algorithm was used only as an advisory tool. In real implementations, at least the operation of basic control should be automated because when basic control is needed the network is operating near or outside its operational limits and the corrective actions should be made fast. Automation of restoring control is not equally important because it is used to change the network's operating point from an acceptable one to another with more favourable characteristics.

VI. Conclusions

Active voltage control in distribution networks has been a subject of extensive research in the past years but the number of real implementations is still very low. One reason for this is that only few demonstrations have been conducted in real distribution networks.

In this paper, a real network demonstration of a coordinated voltage control algorithm was successfully conducted. The control algorithm operated as expected in the demonstration and was able to increase the maximum allowable penetration of DG in an existing distribution network.

The demonstration showed that CVC can be implemented in a real distribution network quite easily. In the demonstration network, no additional measurements or communication channels were needed, and, therefore, only the CVC implementation was added to the network which was quite straightforward. Some difficulties were encountered because some measurements had quite poor accuracy and one outputted consistently too large values. Because the CVC algorithm relies heavily on the state estimates, special attention should be addressed to accuracy of measurements in real CVC implementations. The problems in measurements can be solved using standard components and there is no need to use expensive special solutions.

In the demonstration, CVC was implemented as a Matlab program but it could also be implemented as a part of distribution management system. DMS is an everyday tool for distribution network operators and, hence, implementing CVC as a part of DMS might encourage DNOs to take it into use because CVC would only be a new feature of DMS and not a completely new system. Moreover, if CVC is implemented as a part of DMS, the network model and the state estimator already available in DMS can be utilized. There is no need to maintain parallel network data and the network model is always at the same switching state as the real network. Also, the control possibilities of SCADA are available through DMS and the CVC algorithm can give commands to network components directly from the DMS.

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VIII. Biographies

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Publication 5

A. Kulmala, S. Repo and P. Järventausta, "Coordinated voltage control in distribution networks including several distributed energy resources, " accepted for *IEEE Trans. Smart Grid*.

Coordinated Voltage Control in Distribution Networks Including Several Distributed Energy Resources

Anna Kulmala, *Student Member, IEEE*, Sami Repo, *Member, IEEE*, and Pertti Järventausta

***Abstract*—Connecting distributed generation (DG) to weak distribution networks can often cause voltage rise problems. Traditionally, these voltage rise problems have been mitigated by passive methods such as reinforcing the network. This can, however, lead to high connection costs of DG. The connection costs can in many cases be lowered if active voltage control methods are used instead of the passive approach.**

In this paper, two coordinated voltage control algorithms suitable for usage in distribution networks including several distributed energy resources are proposed and studied. The first algorithm uses control rules to determine its control actions and the second algorithm utilizes optimization. The operation of the implemented algorithms is, at first, studied using time domain simulations. Thereafter, the network effects and costs of both algorithms are compared using statistical distribution network planning and also practical implementation issues are discussed.

***Index Terms*—Distributed power generation, power distribution, power system management, reactive power control, voltage control**

I. Introduction

THE existing distribution networks have been designed assuming that the power flows are unidirectional and that the distribution networks do not contain any controllable resources. When distributed energy resources (DER) such as distributed generators (DG) are connected to distribution networks, these assumptions are no longer valid and the planning and operational principles of distribution networks need to be revised.

When generation is connected to weak distribution networks, voltage rise problems often occur. At present, voltage rise is usually mitigated using passive methods such as network reinforcement and the control possibilities of DERs are not utilized. This can, however, lead to relatively high connection costs of DG. The voltage rise can be mitigated also by using active voltage control methods. Active voltage control can, in many cases, decrease the total costs of the distribution network significantly [1].

The simplest active voltage control methods are based only on local measurements. DG reactive power can be locally controlled [2] and also production curtailment of DG can be based on local measurements. These local methods can, in many cases, increase the capacity of DG that can be connected to an existing distribution network substantially [1]. They do not, however, utilize all control possibilities of the system.

Active voltage control methods can also utilize information about the whole distribution network i.e. be coordinated. The coordinated voltage control (CVC) methods can determine their control actions based on control rules or use some kind of optimization algorithm. Most CVC algorithms proposed in publications are centralized but also distributed methods using multiagent systems have been proposed (for instance [3] and [4]).

CVC methods based on control rules are suitable for simple networks where only few control possibilities exist. Traditional radial distribution networks are such networks. The simplest and most studied CVC method controls substation voltage based on network maximum and minimum voltages [5]. Some methods control only reactive power of DERs to keep the network voltages at an acceptable level [3], [6] and some methods combine control of substation voltage and reactive power of DERs [7]-[10]. Also real power can be used as a control variable in CVC [11]-[12].

When the number of controllable components increases or when the control has several different objectives, determination of control rules can become a complex task. In these cases, methods using optimization algorithms can be more suitable. CVC methods using different optimization methods and objective functions have been proposed in publications. Linear programming is used e.g. in [1], [13]-[15] and nonlinear programming (NLP) e.g. in [16]-[19]. In [20] and [21] a local-learning algorithm is combined with NLP to reduce the computational time and [22]-[24] apply genetic algorithm to solve the voltage control problem. [25] utilizes evolutionary particle swarm optimization.

In this paper, two coordinated voltage control algorithms are proposed and studied. The first algorithm uses control rules to determine its control actions whereas the second algorithm utilizes optimization. Both algorithms are introduced in chapter II. and their time domain operation is studied using PSCAD simulations in chapter III. The network effects and costs of both algorithms are compared using statistical

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distribution network planning and also practical implementation issues are discussed in chapter IV.

II. The Proposed CVC Algorithms

Two coordinated voltage control algorithms are studied in this paper. The first algorithm is a relatively simple rule based algorithm and the second one utilizes optimization. Both algorithms use primary substation (from now on: substation) voltage and real and reactive powers of DERs as control variables. Substation voltage is controlled by changing the voltage set point of the substation automatic voltage control (AVC) relay that controls the main transformer tap changer. The real and reactive powers of DERs are controlled by changing the real and reactive power set points of the controllers of the resources. The only requirement for the DERs is that their real or reactive power needs to be controllable and, therefore, the algorithm is able to utilize all kinds of controllable resources (DGs, controllable loads, energy storages, feeder capacitors, microgrids etc.) in its control. If continuous control of real and/or reactive power is not available, also disconnecting or connecting a required number of DERs can be utilized in the control.

Both studied algorithms are centralized and have been designed such that implementing them as a part of an advanced distribution management system (DMS) would be quite easy. The advanced DMS combines static information obtained from network information system (NIS) and real-time measurement data and control possibilities of SCADA [26]. Therefore, the input information needed by the algorithms is directly available from the DMS and also control commands can be sent to the controllable resources directly through SCADA. In the Nordic countries, NIS and DMS are in everyday use and even low voltage (LV) network data is available in the DMS if needed.

When the proposed CVC algorithms are implemented in real distribution networks, the data transfer of SCADA can be used as such if only a relatively low number of relatively large

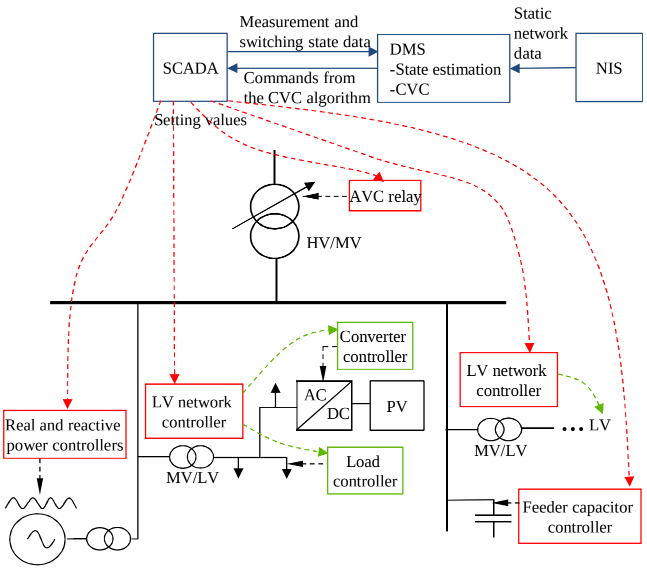

Fig. 1. The cascaded control architecture.

DERs is used in the control. If the number of controllable DERs becomes large and the unit size small, some kind of aggregation (e.g. LV network controller in Fig. 1) is needed to decrease the amount of data transferred to and from SCADA [27], [28]. Cascaded control architecture represented in Fig. 1 can be implemented to enable utilization of also the small DERs connected to LV networks.

A. *The rule based algorithm*

The rule based control algorithm is based on [7] and [29] and consists of basic and restoring parts. In [7] and [29] substation voltage and reactive power of one DER are used as control variables. In this paper, the algorithm is further developed to be suitable also for distribution networks that include several DERs. Moreover, real power of DERs has been added as a control variable. Both basic and restoring control algorithms consist of three parts: substation voltage control, reactive power control and real power control.

1) *Basic control*

The operational principle of the developed basic control is represented in Fig. 2. The objective of basic control is to keep the network voltages between feeder voltage limits. In basic control, substation voltage is the primary control variable. At first, basic substation voltage control determines whether substation voltage should be changed [7]. After that the number of needed tap changer operations is determined [29] and the new AVC relay set point calculated [7]. Finally, the new set point is given to the AVC relay after a predefined delay [7].

If basic substation voltage control is unable to restore all network voltages between acceptable limits, basic reactive power control is activated. At first, the algorithm uses an approximate method proposed in [30] to determine voltage sensitivity values between locations of maximum and minimum voltages and all controllable reactive power resources. After that, the resource that has the highest voltage sensitivity value in proportion to the location of the voltage exceeding its limit is selected. In this way the amount of controlled reactive power is minimized. If there is no resource that can affect the voltage exceeding its limit (i.e. all sensitivities are zero or all resources are already at their limit), the algorithm checks if changing the other extreme voltage would enable substation voltage control that could in turn restore the voltage exceeding its limit to an acceptable level. Also here the resource with the highest voltage sensitivity value is selected. When the resource to be controlled has been selected, a new reactive power set point is calculated utilizing state estimation [29], [31] and sent to the selected resource after a predefined delay.

If basic substation voltage control and basic reactive power control are not able to restore the network voltages between acceptable limits, basic real power control is activated. Basic real power control is very similar to basic reactive power control (see Fig. 2).

2) *Restoring control*

The operational principle of the developed restoring control

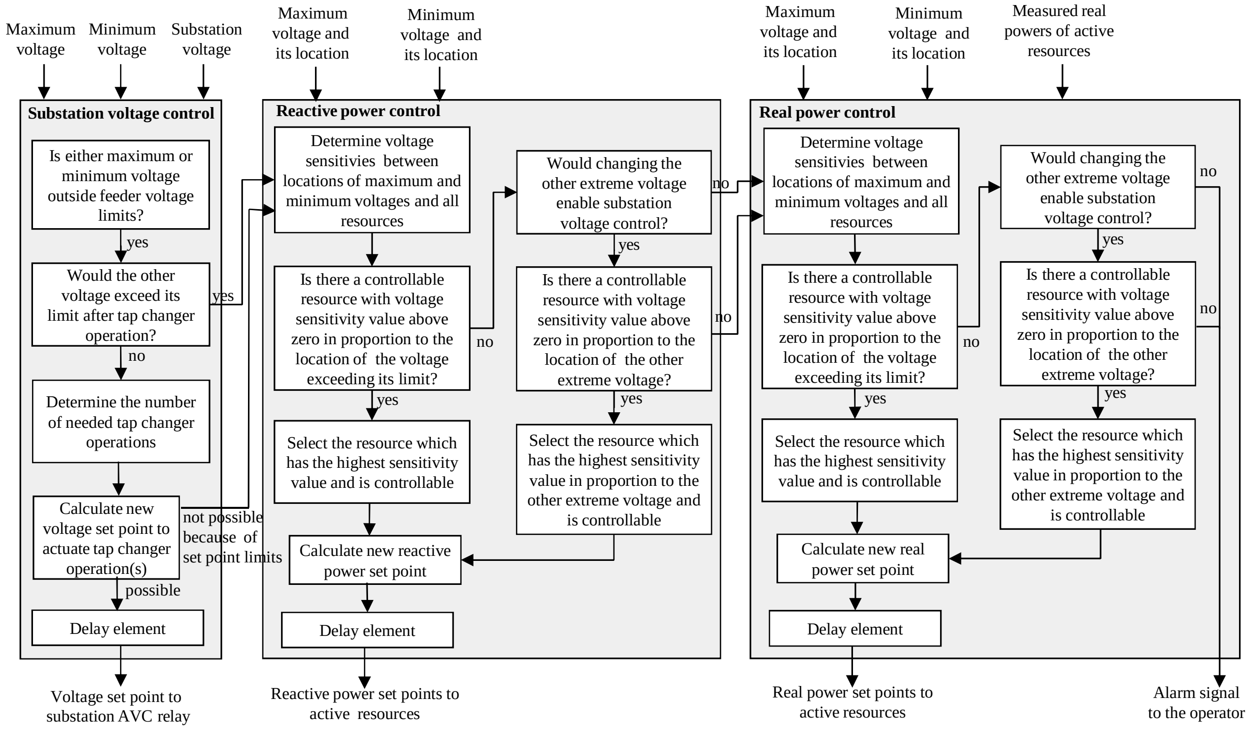

Fig. 2. The operational principle of basic control.

is represented in Fig. 3. Restoring control is used to restore the real and reactive powers of DERs as near to their original values as the network state allows. The original values are the values that would be used without the CVC algorithm. Restoring control also normalizes the network voltages if the voltages in the whole distribution network have remained in an unusually high or low level after for instance disconnection of a large DG unit.

In restoring control, real power control is activated first. It is determined that the real power of some resource can be increased if the maximum voltage has decreased enough i.e. is far enough from the feeder voltage upper limit. Correspondingly, the real power of some resource can be lowered if the minimum voltage has increased enough. The order in which the resources are controlled is also here determined using voltage sensitivities but in restoring control the resource with the lowest sensitivity value is controlled first. This way the amount of restored real power can be maximized. When the resource to be controlled has been selected, a new real power set point is calculated utilizing state estimation [29], [31] and sent to the selected resource after a predefined delay.

If restoring real power control is not needed or cannot operate, restoring reactive power control is activated. The algorithm is very similar to restoring real power control (see Fig. 3). Restoring substation voltage control is activated if restoring reactive power control is not needed or cannot operate. The restoring substation voltage control is similar to basic substation voltage control. The only difference is that stricter parameters are used.

B. *The optimizing algorithm*

The optimization of distribution network voltage control is a mixed-integer nonlinear programming problem (MINLP)

$$\min f(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) \tag{1}$$

$$g(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) = 0 \tag{2}$$

$$h(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) \leq 0 \tag{3}$$

where $\mathbf{x}$ is the vector of dependent (only indirectly controllable) variables, $\mathbf{u_d}$ is the vector of discrete control variables and $\mathbf{u_c}$ is the vector of continuous control variables.

The vector of dependent variables contains the voltage magnitudes V and voltage angles δ of all n distribution network nodes

$$\mathbf{x} = [V_1,\ldots,V_n,\delta_1,\ldots,\ \delta_n] \tag{4}$$

The vector of discrete control variables contains the switched control variables such as positions of tap changers and switched capacitors and reactors. In this case, the only discrete control variable is the main transformer tap ratio m.

$$\mathbf{u_d} = [m] \tag{5}$$

The vector of continuous control variables contains variables such as set points of real and reactive powers or terminal voltages of DERs. In this case, the controllable variables are the real and reactive powers of DERs.

$$\mathbf{u_c} = [P_1,\ldots,P_j,Q_1,\ldots,Q_k] \tag{6}$$

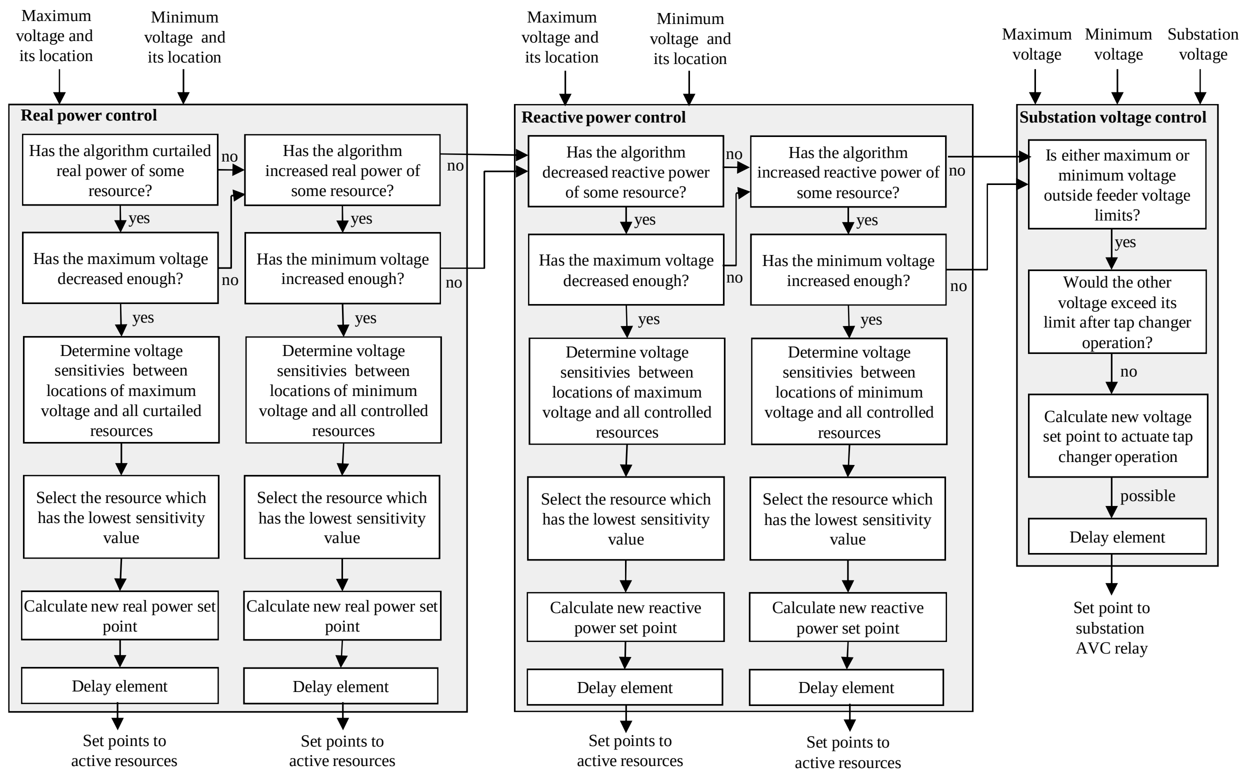

Fig. 3. The operational principle of restoring control. The direction of power transfer is defined to be positive outwards from the DER node i.e. for instance decreasing real power means that the injected real power of the node in question is decreased which can be realized either by curtailing the generation or by increasing the consumption.

where P_j is the real power set point of the jth DER and Q_k the reactive power set point of the kth DER.

The objective function is defined such that it will minimize the total costs of network losses and generation curtailment

$$f(\mathbf{x},\mathbf{u_d},\mathbf{u_c}) = C_{losses}P_{losses}+C_{cur}\Sigma P_{cur} \tag{7}$$

where C_{losses} is the price of losses, P_{losses} is the amount of losses, C_{cur} is the lost income due to generation curtailment and ΣP_{cur} is the amount of curtailed generation.

In this optimization problem, equality constraints model the power flow equations at each network node. In this case the substation (node 1) is defined to be the slack node and the following equality constraints have to be fulfilled there

$$V_1 - \frac{V_{orig}}{m} = 0 \tag{8}$$

$$\delta_1 = 0 \tag{9}$$

where V_{orig} is the substation voltage with a tap ratio of 1.0. All other network nodes are defined to be PQ nodes because all active resources operate in reactive power control mode instead of voltage control mode. At the PQ nodes the following equality constraints have to be fulfilled

$$P_i - P_{gen,i} + P_{load,i} = 0 \tag{10}$$

$$Q_i - Q_{gen,i} + Q_{load,i} = 0 \tag{11}$$

where P_i and Q_i are bus power injections, $P_{gen,i}$ and $Q_{gen,i}$ are the generated powers at the ith node and $P_{load,i}$ and $Q_{load,i}$ the consumed powers at the ith node. Bus power injections can be computed from the following equation

$$\mathbf{P_i}+j\mathbf{Q_i} = \text{diag}(\mathbf{V})(\mathbf{Y_{bus}}\mathbf{V})^* \tag{12}$$

where $\mathbf{V}$ is the node voltage vector $[V_1e^{j\delta 1},\ldots,V_ne^{j\delta n}]$ and $\mathbf{Y_{bus}}$ the bus admittance matrix [32].

The inequality constraints are used to model network technical constraints and the capability limits of the controllable resources. The following constraints are used:

$$V_{lower} \le V_i \le V_{upper} \tag{13}$$
$$P_{activeimin} \le P_{activei} \le P_{activeimax} \tag{14}$$
$$Q_{activeimin} \le Q_{activei} \le Q_{activeimax} \tag{15}$$
$$m_{min} \le m \le m_{max} \tag{16}$$
$$S_{ij} \le S_{ijmax} \tag{17}$$

The first inequality constraint (13) states that all network voltages have to remain between feeder voltage limits. The second (14) and the third (15) constraint set the limits for real and reactive powers of controllable active resources. Constraint (16) limits the main transformer tap ratio and constraint (17) the power flows in all networks branches.

In this paper, the optimization is realized using Matlab Optimization Toolbox. Function fmincon is used. This function realizes nonlinear programming and treats all variables as continuous. The voltage control problem includes, however, also discrete variables (in this case only the position of the main transformer tap changer). In publications on CVC, the discrete nature of some variables is not always taken into account at all or some heuristic method is used [17], [18]. In this paper, the tap changer position is assigned using a three-stage procedure. At the first round, fmincon is executed assuming that also the tap changer position is a continuous variable. After the first round, the two tap changer positions on both sides of the calculated value of the tap changer position are selected. The second and the third round execute fmincon using the two previously selected tap changer positions. The alternative with the smallest value of the objective function is selected.

C. *Limitations of the algorithms*

The algorithms are designed for typical Nordic distribution networks that are symmetrically loaded radial three-phase medium voltage networks. Voltage is typically controlled only at the substation and feeder capacitors and step voltage regulators are only rarely used. The proposed methods are applicable also in different types of networks (i.e. networks containing feeder capacitors) but if the network structure is completely different from the Nordic network some modifications are needed.

The algorithms assume symmetrical loading and the network is modelled in the algorithms using the single-phase equivalent. In Nordic distribution networks the assumption of symmetrical loading holds true because all customers have three-phase connections and significant unbalances on medium voltage networks do not usually occur. In case of significantly unbalanced networks, the algorithms need to be revised.

A radial network structure is assumed in the rule based algorithm. The parts controlling the substation voltage are applicable also in meshed networks but the parts controlling real and reactive power of DERs include components that operate only in radial networks. The method used for voltage sensitivity determination and the state estimation algorithm are applicable only in radial networks.

The data transfer capability of SCADA is the factor that limits the number of controllable components that can be used in the control. The control algorithms themselves are able to operate also in case of a large number of DERs. In the rule based algorithm, the number of controllable components affects only the size of the sensitivity matrices used to select the controlled resource and, hence, the algorithm is able to utilize a large number of DERs in its control. In the optimizing algorithm, the execution time can become too large if the number of controllable resources is high and also the method used for assigning the discrete variables needs to be modified if the number of discrete control variables is increased.

III. Time Domain Simulations

The operation of the CVC algorithms introduced in the previous chapter is tested in a typical Finnish distribution network. For time domain simulations, the example network is modelled in PSCAD simulation environment and the CVC algorithms in Matlab environment. PSCAD includes a Matlab interface which is used to combine the two simulation environments.

A. *The simulation network*

The simulation network consists of two 20 kV feeders that are fed from the same substation. The network model is constructed based on a real Finnish distribution network and its structure is depicted in Fig. 4. The distribution lines are modelled using a π-connection and the loads are modelled as static constant power loads. More detailed network data can be found in the appendix. The network model includes a representation of the substation AVC relay and the tap changer mechanism [33]. The AVC relay deadband is 1.5 % and the delay 3 s. Line drop compensation is not used. The main transformer tap step can be changed ±9*1.67 % and the delay of the tap changer is 1 s.

Four different loading conditions (maximum, minimum and two loading conditions between these) are modelled and a load multiplier is added to the model to be able to change the loading also during the simulation run. DG units can be connected to any node in the network. Synchronous generators operating in reactive power control mode are used to model the DG units. From the point of view of CVC algorithm testing, the simulation results, however, apply to all kinds of DERs whose real or reactive power can be controlled.

Simulations are conducted using both control algorithms introduced in the previous chapter (rule based and optimizing). In the rule based algorithm, the feeder voltage lower and upper limits used in basic substation voltage control are 0.95 and 1.05 pu whereas the restoring substation voltage control tries to keep the network voltages between 1.00-1.05 pu. The DG units are dimensioned such that the minimum power factor with rated real power P_{rated} is 0.95 i.e. the maximum and minimum reactive powers are approximately $0.33{*}P_{\mathrm{rated}}$. In restoring real and reactive power controls the maximum voltage has to be at least 0.01 pu below the feeder voltage upper limit to enable increase of the reactive or real power set

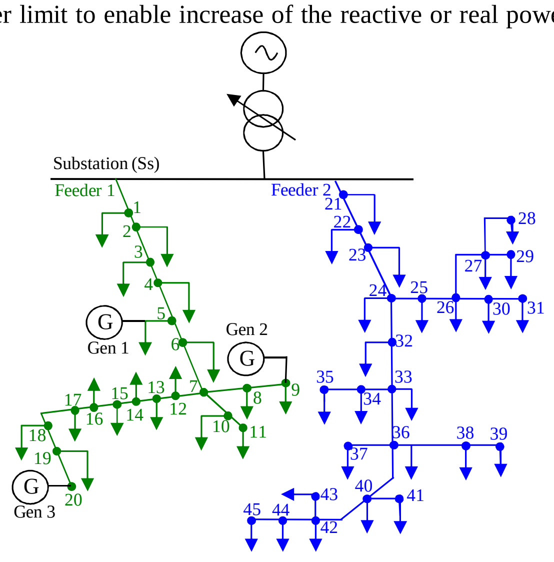

Fig. 4. The example network.

point. Similarly, the set point can be decreased if the minimum voltage is at least 0.01 pu above the feeder voltage lower limit. The delay in all basic control blocks is 4 s and the delay in all restoring control blocks 6 s. All delays used in the simulations are much shorter than delays in a real network. These shorter delays are used because the operation of the algorithm would be similar also with the realistic delays but the simulation time would increase considerably.

In the optimizing control, the feeder voltage limits and reactive and real power limits of DG units are similar to the limits used in the rule based algorithm. In the objective function calculation, the price of losses C_{losses} is assumed to be 44.6 €/MWh which is an average value of Nordpool Finland spot price in years 2006-2010. The price of curtailed energy is assumed to be 83.5 €/MWh which is the feed-in tariff for wind generators in Finland and the distribution charge is assumed to be 0.7 €/MWh which is the maximum allowed distribution charge for production units in Finland. The lost income due to curtailment C_{cur} is, hence, 82.8 (83.5-0.7) €/MWh. [34]

B. Simulation results

Simulations were conducted in different loading conditions and with different number of DG units connected to different nodes in the network. In the simulations, DG real power changes were used as disturbances to make the studied CVC algorithms active. The real power set points were changed regardless of the CVC operations and, therefore, the DG units appeared to the CVC algorithms as intermittent sources.

Both control algorithms operated in the time domain simulations as expected: Network voltages were restored between acceptable limits in all simulation cases and no adverse interactions such as hunting appeared.

Simulation results in one example case are represented in Figs. 5-8. In the example case, three generators are connected to feeder 1 in locations depicted in Fig. 4. One of the middle loading conditions is selected (weekday 12 p.m. in April). The simulation sequence of DG real power set points is represented in Table 1. Fig. 5 represents voltages of all network nodes when neither of the proposed CVC algorithms is used. From Fig. 5 it can be seen that network maximum voltage becomes excessive without active voltage control. Fig. 6 represents network operation when the rule based algorithm is used and in Fig. 7 the optimizing algorithm is used. Fig. 8 represents network losses using both control algorithms.

TABLE 1
THE SIMULATION SEQUENCE. THE RATED REAL POWER OF ALL GENERATORS IS 1.36 MW.

Time [s]	P_{set1} [pu]	P_{set2} [pu]	P_{set3} [pu]
0	0.1	0.1	0.1
20	**1.0**	0.1	0.1
50	1.0	**1.0**	0.1
80	1.0	1.0	**1.0**
130	**0.1**	1.0	1.0
160	0.1	**0.1**	1.0
190	0.1	0.1	**0.1**

The example simulation case was selected based on the fact that the most severe voltage situation occurs when significant amount of generation is connected on some feeders and some feeders contain only load. In this situation the voltage difference between network maximum and minimum voltages is the largest and, hence, for instance controlling only the substation voltage might not be adequate to restore all network voltages to an acceptable level but other control measures would be needed as well. Also simulations of cases where generators were connected on both feeders were conducted and the algorithms operated as designed also in these cases.

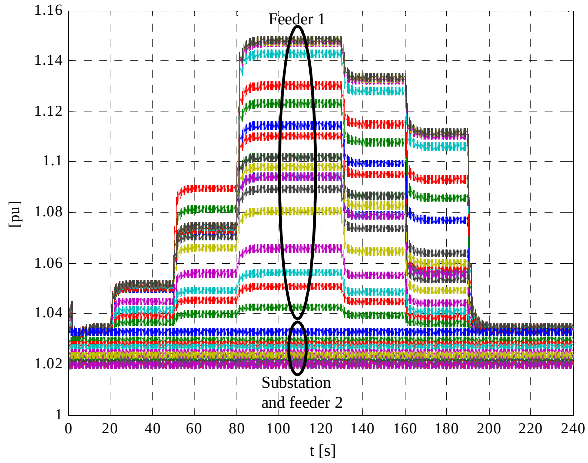

Fig. 5. Voltages of all network nodes without coordinated voltage control. The set point of the substation AVC relay is kept constant at 1.03 pu and the DG units operate at unity power factor.

Simulation results of Fig. 6 and Fig. 7 show that both algorithms operate in time domain as determined in chapter II. Network maximum voltage exceeds the feeder voltage upper limit for the first time when the real power set point of generator 1 is raised to 1.0 pu at time 20 s. The rule based algorithm decreases the substation AVC relay voltage set point after the CVC algorithm delay has elapsed and the tap changer operates after the delays of the AVC relay and the tap changer have elapsed. The optimizing algorithm uses reactive power control to decrease the network maximum voltage.

Network maximum voltage exceeds its limit again when the real power set point of generator 2 is raised to 1.0 pu at time 50 s. The rule based algorithm uses substation voltage control to decrease the network maximum voltage. At this time, one tap changer operation is not adequate but two tap steps are needed to decrease the network voltages sufficiently. The optimizing algorithm instructs three tap changer operations and also the reactive power set points of generators are changed to decrease the losses.

At time 80 s the real power set point of generator 3 is set to 1.0 pu and network maximum voltage rises again. At first, the rule based algorithm instructs one tap changer operation but this is not adequate to restore the network maximum voltage below the feeder voltage upper limit. Further tap changer operations cannot, however, be commanded because lowering the substation voltage further would reduce the network minimum voltage below the feeder voltage lower limit. Hence, basic reactive power control is activated and the whole reactive power control capability of all generators is taken into use one at a time in the order defined by the voltage sensitivity matrix. Network maximum voltage remains above its limit also after the reactive power control and, hence, basic real power control is activated and the real power of generator 3 curtailed. After the curtailment all network voltages are at an acceptable level. Also the optimizing algorithm utilizes substation voltage control, reactive power control and real power control to restore the network voltages to an acceptable level. The difference between the algorithms is that the optimizing algorithm determines all control actions at once whereas the rule based algorithm utilizes the controllable components one at a time. Hence, network voltages remain outside acceptable limits for a longer time when the rule based algorithm is used. Also, the steady state value of generation curtailment is a bit larger when the rule based algorithm is used than when the optimizing algorithm is used. This is due to the fact that in the rule based algorithm the real power set points are changed in steps of 0.1 MW whereas in the optimizing algorithm the real power set points are continuous variables. Hence, if the step used in the rule based algorithm is made smaller the amount of curtailment would be the same.

When the real power set point of generator 3 is lowered to 0.1 pu at time 130 s network maximum voltage decreases. The rule based algorithm reduces the amount of generation curtailment but some curtailment still remains. The optimizing algorithm removes all curtailment and also the reactive power set point of one generator is changed. The difference in generation curtailment is due to the fact that the restoring part of the rule based algorithm operates only when the maximum voltage differs from its limit more than 0.01 pu and, therefore, the generation is still curtailed after time 130 s although the network state would not necessarily require it. The margin in restoring control has been set to avoid constant set points changes in situations where the network state is such that curtailment is in turns needed and not needed. In the optimizing control such margin is not used and, therefore, hunting might occur in some network conditions.

At time 160 s the real power set point of generator 2 is lowered to 0.1 pu. Network maximum voltage decreases again and the restoring part of the rule based algorithm removes the remaining generation curtailment. Also the restoring reactive power control operates and the power factors of generators 1 and 2 are set to unity and the reactive power consumption of generator 3 is decreased. The optimizing algorithm changes the reactive power set points of all generators to decrease the losses.

Network maximum voltage decreases for the last time at time 190 s when the real power set point of generator 3 is set to 0.1 pu. At first, the rule based algorithm sets the power factor of generator 3 to unity and after that restoring substation voltage control changes the substation AVC relay voltage set point such that three tap changer operations are induced. After three tap changer operations all network voltages are between the voltage limits of restoring substation voltage control (1.0-1.05 pu) and, hence further control actions are not initiated. The optimizing algorithm instructs four tap changer operations and changes also the reactive power set points of the generators.

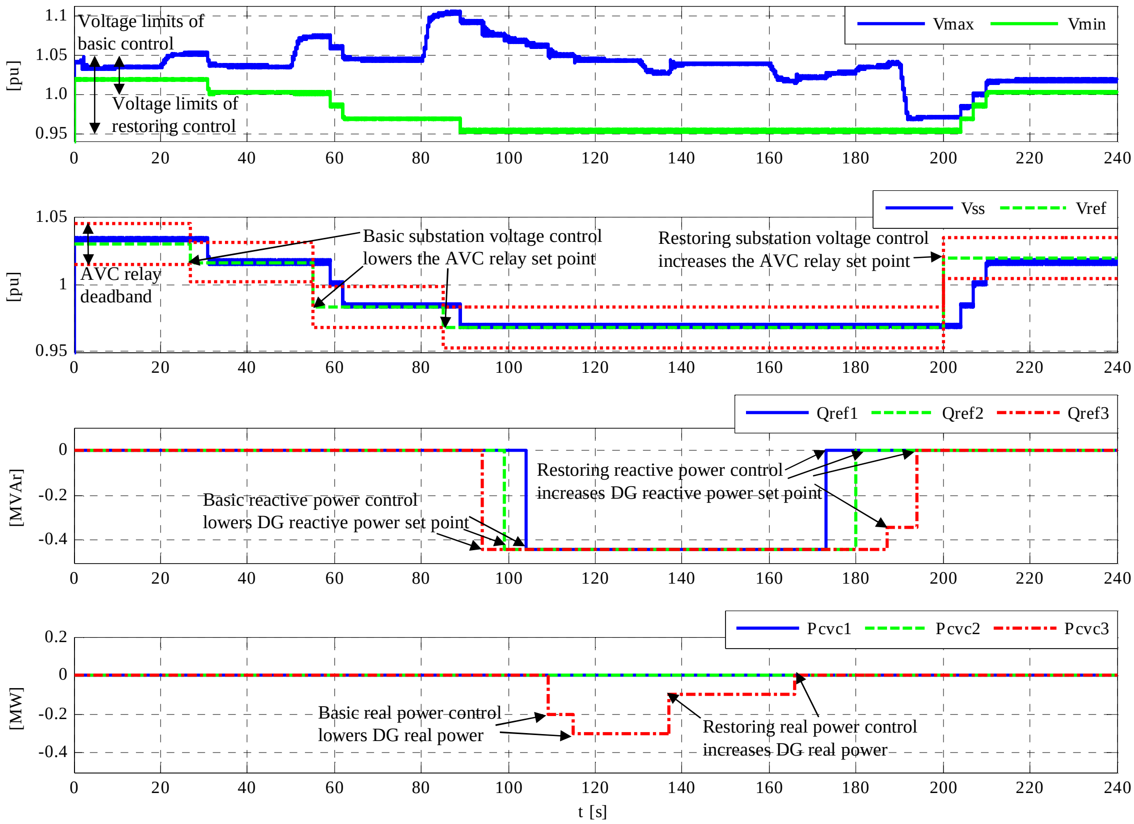

Fig. 6. Time domain operation of the rule based algorithm. The algorithm is executed once a second.

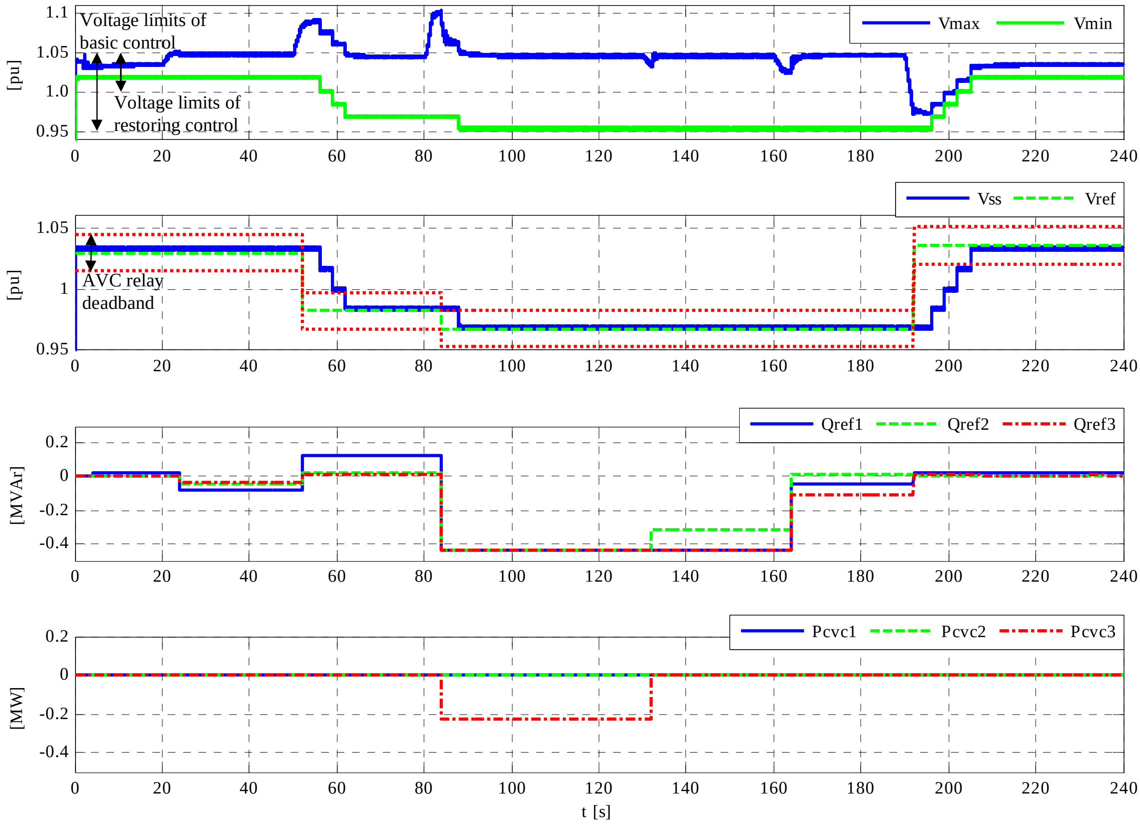

Fig. 7. Time domain operation of the optimizing algorithm. The algorithm is executed every fourth second. The execution interval is longer than with the rule based algorithm because this would be the case also in real applications due to the fact that the execution time of optimizing algorithm is much longer than the execution time of the rule based algorithm.

It should be noted that the delays of algorithm execution are not visible in the time domain simulation results because in PSCAD all calculations are conducted before proceeding to the next time step. Hence, the CVC algorithm's output is always based on the measured values at the same time step. Because of this deficiency in the simulations, it seems that the optimizing algorithm is able to restore the network voltages between acceptable limits always faster than the rule based algorithm. This might not, however, be the case in reality because the execution time of the optimizing algorithm is much longer and also varies more than the execution time of the rule based algorithm. Hence, these simulations cannot be used to compare which algorithm is able to restore the voltages between acceptable limits faster but real-time simulations (for instance using the Real Time Digital Simulator) would be needed for this comparison.

No significant differences in steady state losses can be seen in Fig. 8. Differences are mainly seen at times when generation curtailment is not equal between algorithms and are due to the fact that at these times the amount of transferred power is not equal. In the algorithm development it was assumed that it is beneficial to operate the DERs as near to unity power factor as possible which applies in this example network. In different kinds of networks (for instance networks containing long cables [34]) the assumption might not be valid and using optimization can lower the losses more.

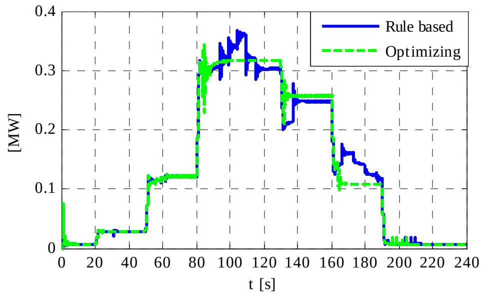

Fig. 8. Losses using both CVC algorithms.

IV. Comparison of the CVC Algorithms

The time domain operation of the introduced CVC algorithms was studied in the previous chapter in some loading and generation situations. These kinds of studies are essential in the development phase of new CVC algorithms but cannot, however, be used to select the most advantageous control strategy for a particular network. When the control strategy is selected, the network effects and costs of the alternative control strategies need to be determined throughout the year. Also other issues such as the ease of implementation need to be taken into account.

A. *Hourly load flow simulations*

Statistical distribution network planning can be used to compare different voltage control strategies. In statistical distribution network planning, load flow is calculated for every hour of the year using hourly load and production curves. The results of the load flow calculations can be used to compare for instance yearly losses of alternative voltage control strategies. [34]

In this paper, hourly load flow calculations are conducted for the same example case whose time domain operation is discussed in chapter III. The generators are assumed to be wind turbines with similar wind conditions i.e. they share the same production curves [35]. Hourly load curves are directly available from the Finnish NIS for each customer group [26]. Hourly load flow calculations are conducted using both CVC algorithms introduced in chapter II. Also a case with no coordinated voltage control is simulated for comparison. In this case, real power curtailment is the only control measure that is taken to restore the network voltages to an acceptable level. The main results of hourly load flow calculations are presented in Table 2.

TABLE 2
MAIN RESULTS OF HOURLY LOAD FLOW CALCULATIONS. CASE 1 USES ONLY REAL POWER CURTAILMENT, CASE 2 USES THE RULE BASED CVC ALGORITHM AND CASE 3 USES THE OPTIMIZING CVC ALGORITHM.

	Case 1	Case 2	Case 3
Net generation [MWh]	6828	12199	12376
Curtailed generation [MWh]	5810	440	263
Percentage of energy curtailed [%]	46.0	3.5	2.1
Lost income due to curtailment [€]	481068	36391	21749
Distribution losses [MWh]	112	669	684
Cost of losses [€]	4997	29825	30529
Absolute value of reactive power of DGs [MVArh]	0	2314	2417
Number of yearly tap changer operations due to control algorithm operation	0	2880	4850

Table 2 shows that using only real power curtailment is not an acceptable option in the example network as the amount of curtailed generation becomes very high. Using either of the proposed CVC algorithms decreases the amount of curtailed generation significantly.

In the example case, using the optimizing algorithm leads to a smaller amount of curtailed generation than using the rule based algorithm. On the other hand, optimization leads to slightly higher distribution losses which is due to the fact that, in the example network, increase in generated power increases also the power transfer and therefore also losses. Optimization also leads to a significantly higher number of tap changer operations and the amount of reactive power control demanded from DERs is higher than with the rule based algorithm. Hence, both algorithms have advantages and disadvantages and the final selection between the algorithms is not obvious.

When the results are viewed it should be noted that the outputs of the optimizing algorithm are determined by the objective function. In this case, the objective function consists of costs of losses and costs of generation curtailment and the price of curtailed generation is assumed to be higher than the cost of losses. If the objective function is altered, also the outputs of the optimizing algorithm will be completely different. The objective function could include also for instance the costs of reactive power generation and consumption, the amount of tap changer operations and quantities related to voltage quality such as average voltage deviation and maximum voltage deviation. Determining the costs of reactive power consumption and generation has been discussed for instance in [18] and adding these costs to the objective function would be quite straightforward although the costs for the distribution network operator depend also on the interconnection agreements made with the DER owners i.e. is reactive power control defined as an ancillary service or a requirement for network connection. Determining the costs for tap changer operations or voltage quality issues is more complicated. Tap changer operations cause wear of the tap changer and can increase its maintenance need. The tap changer manufacturers give instructions that overhaul is needed after some number of tap changer operations (e.g. 100000 operations) or after some number of years of service (e.g. five years) depending on which criterion is first fulfilled [36]. Hence, the additional tap changer operations caused by CVC start to increase the tap changer maintenance costs only after the interval between overhauls diminishes due to the CVC induced tap changer operations. Determining the cost of one tap changer operation is not, therefore, easy.

B. *Execution time and convergence of the algorithms*

The rule based algorithm proposed in this paper is quite simple. Its execution time is short and remains in the same range regardless of the network situation. The most time consuming part of the rule based algorithm is state estimation but also its execution time is in typical distribution networks quite small. Convergence problems cannot occur when the rule based algorithm is used.

The execution time of the optimization algorithm depends on the number of modelled network nodes and controllable resources. It can also vary significantly depending on the network situation. In the example network represented in Fig. 4 the execution time remains in all simulations reasonable. If the number of network nodes or controllable resources is, however, significantly increased the execution time can become too long for real-time control applications. Hence, network data taken directly from the DMS might not be suitable for input to the optimizing algorithm but some network reduction might be needed.

Convergence problems are possible when the optimizing algorithm is used. In real-time control applications non-convergence cannot be tolerated if the control algorithm is used to restore the network to an acceptable state. Hence, if the optimizing algorithm is used as the only voltage control algorithm in the network, there should be some mechanism that guarantees that the algorithm finds an acceptable network state within a reasonable time.

V. CONCLUSIONS

In this paper, two CVC algorithms (rule based and optimizing) suitable for distribution networks including several distributed energy resources are proposed and studied. The operation of the proposed algorithms is tested using time domain simulations and statistical distribution network planning is used to compare the network effects and costs of the control algorithms. Also, practical implementation issues are discussed.

The time domain simulations showed that both control algorithms are able to keep all network voltages between acceptable limits if adequate amount of controllable resources is available. Hence, both algorithms are suitable alternatives for usage in distribution networks that include several DERs on condition that the execution time of the optimizing algorithm remains reasonable and that it can be guaranteed that convergence problems will not occur. The most suitable voltage control method for a particular network can be selected using statistical distribution network planning.

VI. Appendix

Detailed feeder impedance data is represented in Table 3. Load data is represented in Table 4.

TABLE 3
FEEDER IMPEDANCES.

Nodes		Parameters in per unit (100 MVA, 20 kV base)		
From	To	R	X	B
Ss	1	0.31	0.29	8.36E-05
1	2	0.26	0.25	3.56E-05
2	3	0.17	0.18	2.55E-05
3	4	0.31	0.32	4.59E-05
4	5	0.45	0.34	4.66E-05
5	6	0.42	0.19	2.38E-05
6	7	0.24	0.11	1.34E-05
7	8	0.67	0.20	2.27E-05
8	9	0.69	0.20	2.34E-05
7	10	0.88	0.33	4.06E-05
10	11	0.49	0.21	2.53E-05
7	12	0.39	0.18	2.22E-05
12	13	0.37	0.14	1.74E-05
13	14	1.22	0.36	4.15E-05
14	15	0.80	0.23	2.73E-05
15	16	0.63	0.19	2.16E-05
16	17	1.13	0.48	5.92E-05
17	18	0.37	0.29	3.93E-05
18	19	0.08	0.09	1.22E-05
19	20	0.01	0.00	3.50E-05
Ss	21	0.53	0.43	1.03E-04
21	22	0.30	0.21	2.84E-05
22	23	0.21	0.15	2.01E-05
23	24	0.45	0.41	5.80E-05
24	25	0.72	0.49	6.98E-05
25	26	0.38	0.26	3.60E-05
26	27	0.49	0.15	1.77E-05
27	28	2.23	0.21	2.29E-05
27	29	0.55	0.18	2.15E-05
26	30	0.30	0.20	2.80E-05
30	31	0.25	0.17	2.32E-05
24	32	0.50	0.34	4.69E-05
32	33	1.05	0.72	9.89E-05
33	34	1.13	0.36	4.23E-05
34	35	1.30	0.52	6.34E-05
33	36	0.35	0.33	4.58E-05
36	37	0.85	0.26	3.07E-05
36	38	0.53	0.21	3.75E-05
38	39	1.79	0.17	1.84E-05
36	40	0.38	0.35	4.96E-05
40	41	0.91	0.17	1.96E-05
40	42	0.13	0.12	1.72E-05
42	43	1.51	0.21	2.33E-05
42	44	0.07	0.06	8.83E-06
44	45	0.60	0.25	3.12E-05

TABLE 4
LOADS IN FOUR DIFFERENT LOADING CONDITIONS. THE UNIT OF REAL POWER IS KW AND THE UNIT OF REACTIVE POWER KVAR.

	Maximum (Saturday 6 p.m. in January)		Minimum (Saturday 4 a.m. in July)		Middle 1 (weekday 12 p.m. in April)		Middle 2 (weekday 2 p.m. in November)	
Node	P	Q	P	Q	P	Q	P	Q
1	26.5	7.5	4.5	1.1	10.8	2.9	12.8	3.5
2	71.5	20.4	12.1	3.0	29.2	8.1	34.6	9.6
3	27.6	7.8	4.6	1.2	11.0	3.1	11.1	3.1
4	52.6	14.9	7.6	1.9	23.2	6.4	27.0	7.6
5	65.1	18.4	11.5	2.8	27.3	7.4	32.3	8.8
6	70.1	20.0	10.5	2.8	28.2	8.0	30.4	8.5
8	52.4	14.8	7.9	1.9	21.1	5.7	24.5	6.7
9	17.2	4.7	2.8	0.6	7.1	1.8	7.1	1.8
10	25.3	7.1	3.7	0.9	10.1	2.8	11.4	3.2
11	26.8	7.6	4.2	1.1	10.6	3.0	11.1	3.1
12	112.0	31.6	17.8	4.4	44.5	12.1	51.4	14.1
13	42.9	12.1	6.6	1.7	17.5	4.9	20.9	5.7
14	40.5	11.3	6.4	1.6	21.8	6.0	26.1	7.3
15	71.7	20.4	10.1	2.7	31.3	8.9	37.2	10.6
16	60.9	17.1	9.7	2.5	32.1	8.9	38.6	10.7
17	50.0	14.0	7.6	1.9	20.0	5.4	21.7	6.0
18	32.6	8.9	5.3	1.1	13.6	3.6	15.0	3.9
19	13.3	3.7	2.0	0.5	5.4	1.5	6.7	1.9
21	135.5	38.8	19.9	5.1	54.3	15.2	66.2	18.5
22	85.2	24.2	13.2	3.3	34.4	9.5	38.3	10.5
23	96.7	27.5	15.2	4.0	47.5	13.3	55.6	15.7
24	44.2	12.5	6.8	1.7	17.6	4.9	16.7	4.5
25	121.5	34.5	19.0	5.0	59.4	16.6	67.3	18.8
26	39.7	11.3	5.6	1.6	15.8	4.4	17.0	4.8
27	24.3	6.7	4.7	1.1	11.6	3.2	13.4	3.6
28	9.5	2.7	2.0	0.5	12.1	3.5	16.3	4.7
29	65.2	18.7	9.4	2.6	26.2	7.5	32.8	9.3
30	135.9	38.5	20.7	5.4	55.6	15.4	64.9	18.2
31	3.1	0.8	0.5	0.1	1.3	0.3	1.6	0.4
32	33.5	9.4	5.4	1.3	13.3	3.6	14.2	3.9
33	10.8	2.9	2.3	0.4	14.6	3.9	18.4	5.2
34	34.0	9.4	5.7	1.4	23.5	6.4	29.2	8.1
35	1.7	0.4	0.4	0.0	0.7	0.1	0.6	0.1
36	104.0	29.5	17.5	4.5	51.0	14.3	60.9	17.2
37	41.2	11.7	6.7	1.8	23.4	6.7	29.5	8.3
38	43.9	12.4	8.1	2.1	29.3	8.3	37.7	10.6
39	7.6	2.1	1.4	0.3	6.8	1.9	8.1	2.3
40	7.2	2.0	1.2	0.3	5.7	1.6	7.2	2.1
41	42.7	12.2	6.1	1.7	20.0	5.7	24.4	6.9
42	2.3	0.6	0.5	0.1	3.4	0.9	4.3	1.2
43	44.9	12.8	6.6	1.8	19.7	5.5	22.3	6.3
44	31.9	9.1	6.8	1.8	28.4	8.0	38.2	10.9
45	1.4	0.3	0.2	0.0	0.6	0.1	0.5	0.1

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VIII. BIOGRAPHIES

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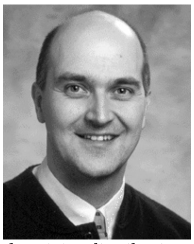

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Network Interconnection Studies of Distributed Generation

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Abstract: The structure and control methods of existing distribution networks are designed based on the assumption of unidirectional power flows. The amount of generating units connected to distribution networks is, however, constantly increasing which changes the operation of distribution networks in many ways. The directions of power flows and fault currents may be altered and the passive distribution networks become more active. This change in distribution network operation has to be taken into account also in network planning stage which, in turn, creates a need to develop the network planning tools and procedure.

In countries where the electricity market is deregulated the distribution network operator (DNO) is obligated to connect distributed generation (DG) into its network. The DNO has little power on the characteristics of the DG unit (location, size, network connection type) and conducts the interconnection studies based on the data obtained from the potential energy producer. This paper discusses the interconnection studies required when a new DG unit is to be connected to an existing distribution network. The effect of DG on distribution network planning is discussed and development needs for present network planning tools are proposed.

Keywords: Distributed generation, network planning, interconnection studies, planning tools

1. INTRODUCTION

The existing distribution networks are designed based on the assumption of unidirectional power flows. However, the amount of distributed generation (DG), i.e. generation located in the distribution network, is constantly increasing which changes the planning and operation of the networks in many ways. In a deregulated electricity market the distribution network operator (DNO) is obligated to connect DG into its network when it is possible with reasonable actions. The location and size of the DG unit are determined by the energy producer and the DNO has minor influence on these. The DNO conducts the interconnection studies based on the power plant data obtained from the potential energy producer.

This paper discusses the planning procedure needed when a new DG unit is to be connected to an existing distribution network. Firstly, DG impacts on distribution networks are discussed. Thereafter, the DG data and required interconnection studies are represented. Finally, the impact of DG on distribution network planning and planning tools is discussed.

2. GRID IMPACTS OF DISTRIBUTED GENERATION

Distributed generation influences the operation of distribution networks in many ways. The directions of power and fault currents may be altered. Also the operational principle of the networks is radically changed if active network management methods are taken in use.

2.1 Voltage quality

DG can have both positive and negative impacts on distribution network voltage quality. DG raises the voltage level in the network and supports the voltage at high load. It also increases the network's short circuit power and, therefore, reduces the effect of network disturbances at other parts of the network on customer voltage.

However, if the DG unit is large enough the voltage rise can become excessive. DG can also affect the operation of existing voltage regulating devices. For instance, if line drop compensation is used at the substation automatic voltage control (AVC) relay (Lakervi, Holmes 1995), connecting DG into the network will decrease the current through the transformer and, therefore, lower the voltages of customers at adjacent feeders.

Changes in the output power of the DG unit affect network voltages and can cause transient voltage variations and flicker. When the DG unit is connected or disconnected relatively large transient voltage variations can occur. More frequent voltage changes (flicker) can be caused by changes in the primary energy source (e.g. wind). Also some forms of prime-mover may cause flicker. (Jenkins et al. 2000)

DG can either increase or decrease the harmonic distortion of the network voltage. The effect on harmonics depends on the type of network connection (synchronous machine, asynchronous machine, power electronics) and the design of the DG unit. (Jenkins et al. 2000, Barker, De Mello 2000)

2.2 Protection

DG can result in certain problems with traditional feeder protection methods. These problems can be divided to four categories as follows (Mäki 2007):

- **Sensitivity problems.** The operation of feeder protection may become disturbed by the contribution of DG. This may result in undetected faults or delayed relay operations and further in safety hazards or damages.
- **Selectivity problems.** DG may result in unnecessary disconnections of the feeder it is connected to. The DG unit itself can also become disconnected unnecessarily for instance during voltage dips or faults elsewhere in the network. These are mainly power quality issues.
- **Reclosing problems.** The fast autoreclosing sequence may become disturbed if the DG units remain connected during the autoreclosure open time. This evidently results in longer interruptions but also in damages to the DG unit.
- **Islanding problems.** Islanding means a situation during which the DG unit remains feeding a part of the network without a connection to the main system. Presently, all unintended islandings must be prevented to assure safety and quality of supply. Detecting the formation of an island is challenging.

3. INITIAL DATA NEEDED

In countries where the electricity market is deregulated the planning process of a new DG unit starts when a potential energy producer becomes interested in constructing a power plant in certain location. The location, size and type of the planned unit are selected by the energy producer and depend on various factors. The DNO has no influence on these characteristics of the DG unit as long as the output power and the overall installation are reasonable. The interconnection study is made based on the data obtained from the energy producer. In this paper, it is assumed that shallow connection charges (Jenkins et al. 2000) are used i.e. only the costs of connecting the DG unit to the nearest point in network are charged from the energy producer. If deep connection charges (Jenkins et al. 2000) would be used the DNO would certainly have a significant effect on all the characteristics of the DG unit as all network reinforcement costs would be charged from the energy producer and the characteristics of the unit would thereby affect the connection costs directly.

Many factors affect the location of the DG unit. In many cases the location is determined by the primary energy source or for instance the location of a heating load. Also environmental and land use planning issues are important. It is not likely that permissions for the unit will be granted if for instance a hydro power plant is planned to be constructed to a conserved river or the location of the planned unit is zoned for some other purpose in the area development plan. Other factors affecting the location are land ownership issues and the accessibility of the place. The energy producer must possess or be able to buy the needed land area for the power plant and the land area has to be relatively easily accessible to make the maintenance visits possible.

The size and type of the DG unit depend also on many factors. In case of a combined heat and power (CHP) plant the size of the generator is mainly determined by the size of the heating load. When renewable energy (wind, hydro) is considered the available amount of the primary energy will affect the DG size. If the unit is intended to act also as reserve power its size is determined by the load it is designed to feed in disturbance situations. The type of the unit's network connection (synchronous machine, asynchronous machine, power electronics) is nowadays mainly determined by the primary energy source and the size of the unit. For instance new wind generators are usually connected to the network using power electronics whereas hydro power plants use mainly synchronous generators. At the DNO's point of view the type of the unit's network connection is significant. It affects the controllability of the unit's reactive power and the unit's operation at start-up and in fault situations.

The determination of the characteristics (location, size and type) of the planned DG unit is a complex task. At the end, the determining factor is, of course, profitability. Also the financing of the energy producer has a significant impact on the decisions as the investment costs can not exceed the energy producer's capital. Also the companies that deliver the power plants have a considerable impact on the characteristics as they usually offer certain kinds of units for certain kinds of situations e.g. power electronics interfaces for wind power generators.

When the potential energy producer has completed its planning process i.e. all the characteristics of the DG unit have been determined and permissions for the unit have been granted, the DNO performs a final interconnection study. Preliminary studies have usually been already conducted. To make the studies the DNO needs data about the planned unit. In addition to the data on the DG unit's location, size and type some other characteristics have to also be known. For voltage level studies the generator's reactive power operation has to be known. For studying the fast voltage variation when the unit is connected to the network the DG unit's behaviour at generator start-up has to be known. For protection studies the most essential issue is the DG's behaviour during faults.

4. REQUIRED STUDIES

When a new DG unit is to be connected to an existing distribution network its effect on voltage quality and network safety has to be studied. DG influences the voltage level in the distribution network and can cause fast voltage transients and flicker. It also increases the fault levels in the network and has an influence on protection. The required DG interconnection studies are discussed in the following chapters and an overview of these is depicted in Fig. 1.

4.1 Voltage level studies

The amount of connected generation is in weak networks usually limited by the voltage rise caused by the DG unit. At present, DG is usually considered merely as negative load in distribution network planning and the amount of DG is limited based on two extreme loading conditions (maximum load/minimum generation and minimum load/maximum generation). (Jenkins et al. 2000, Liew, Strbac 2002) These studies require calculating power flow in a meshed network and, therefore, some of the distribution network planning tools designed for radial networks can not be used to perform the studies. Some DNOs perform preliminary calculations by hand using approximate equations but also more precise calculations are needed before the unit can be interconnected.

The voltage rise effect can be mitigated using either passive or active methods. If passive methods such as increasing the conductor size or connecting the generator to a dedicated feeder or at a higher voltage level are used the operational principle of the network is not changed. The network remains a passive system whose voltage is controlled only at the substation. The substation voltage is controlled by an AVC relay that regulates the position of main transformer tap changer. The drawback of the passive methods is that they tend to be quite expensive and, therefore, can make the connection of DG uneconomical. (Jenkins et al. 2000)

Active management of distribution networks can also be used to mitigate the voltage rise caused by DG. The simplest active voltage level management methods are based only on local measurements and do not require additional data transfer between distribution network nodes. On the other hand, the voltage of distribution networks can be controlled using a complicated distribution network management system which controls all components capable of voltage control and requires a lot of data transfer between network nodes. The network management system can control for instance the tap changers at substations, voltage regulators, power plants, compensators and loads. (Strbac et al. 2002) When active voltage level management is used the distribution network is no longer passive and the operational principle of the network is radically altered. In the current network planning procedure active voltage level management is not taken into account in any way and the planning tools used are not capable of modelling the operation of these active methods.

When active voltage level management methods are taken in use the planning can not be anymore based only on the two worst case loading conditions. Instead, a statistical planning method that calculates the network state in every hour of the year should be used. (Mäki, Repo & Järventausta 2006, Repo, Laaksonen & Järventausta 2005) The planning aspects regarding active voltage level management are further discussed in (Kulmala et al. 2009, unpublished).

In addition to the voltage rise effect DG can also lower the voltages of some customers through interaction with existing voltage regulators (Barker, De Mello 2000). The possible interactions should be taken into account at the planning stage.

4.2 Fast voltage transients and flicker

Changes in the output current of a DG unit influence the voltages in the network. Large transient voltage variations occur especially during DG connection and disconnection. If a large single generator is connected to a weak network it is possible that the transient voltage variations at connection or disconnection become the limiting factor instead of voltage rise. The transient voltage variation at DG connection can be

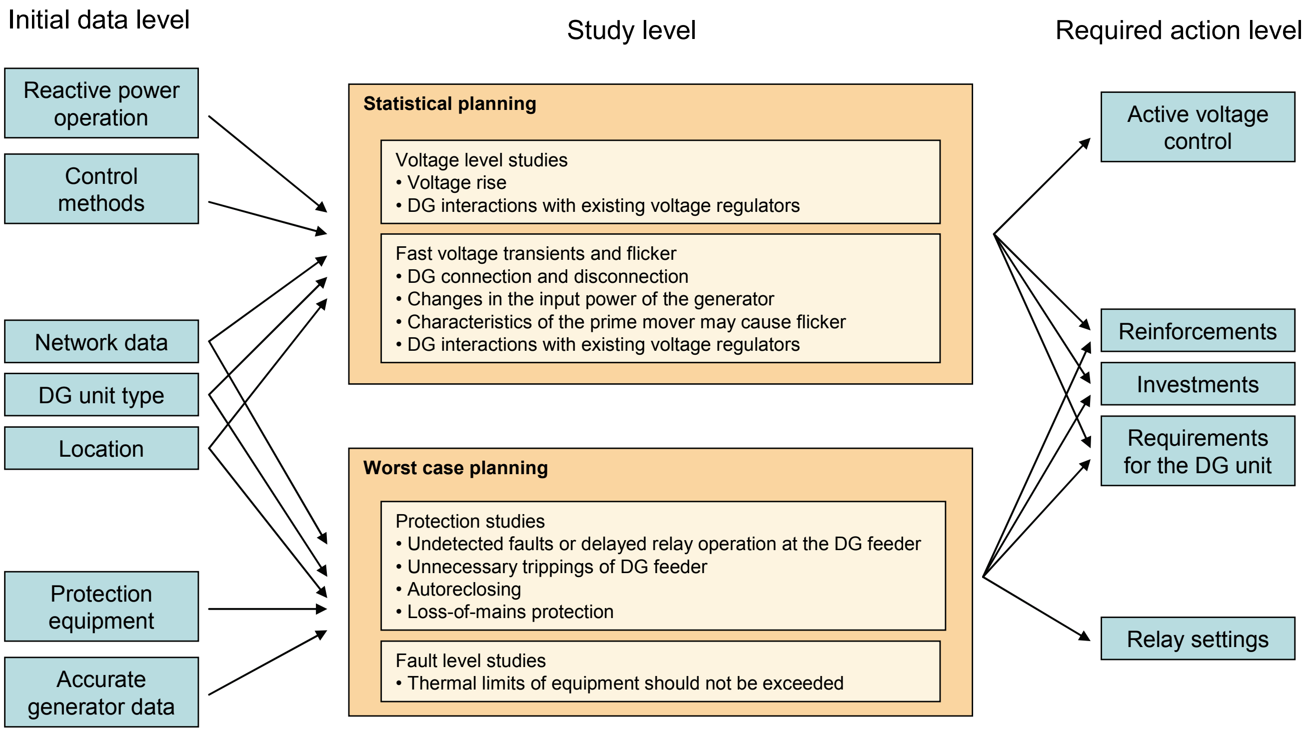

Fig. 1. The required interconnection studies when a new DG unit is to be connected to an existing distribution network. Initial data needed for the studies is represented at the left side, the different studies are depicted in the middle and required actions to overcome possible problems are illustrated at the right side.

diminished by careful design of the plant. Therefore, the more problematic one is usually the disconnection situation. Disconnection of the generators at full load may lead to significant voltage drops. Thus, unnecessary trippings of DG units should be avoided because they result in both nuisance to the energy producer and power quality problems in the distribution network. (Jenkins et al. 2000)

Rapid changes in generator current (and consequently transient voltage variations) at generator start-up can be mitigated by designing the DG unit properly as stated in the previous chapter. Network reinforcing will also mitigate the voltage transients caused by changes in DG current. If the voltage transient caused by DG connection or disconnection is relatively large but still at an acceptable level, the frequency of events may become the constraining factor. If the DG unit consists of multiple generators the connection voltage transients will be decreased if the generators are not all connected to the network exactly at the same time but some delay between connections is used. (Jenkins et al. 2000, Barker, De Mello 2000)

Studying the fast voltage transients at generator start-up or disconnection requires calculating power flow in a meshed network. In the studies the connection arrangement of the unit has to be taken into account. For instance, if an induction generator is connected directly to the network its magnetising inrush current can be even eight times the rated current whereas if a soft-start unit is used the start-up current can be limited to less than rated. When the transient voltage variations at start-up are studied the DG current to be used is the start-up current of the DG unit. At disconnection full-load situation is examined.

In case of wind turbines and photovoltaic generators also the possible flicker caused by the DG unit should be evaluated. The flicker can be caused by changes in the input power of the generator but fortunately these changes tend to be smoother than step changes and are, therefore, less likely to cause nuisance to other customers. Also some types of prime mover (e.g. fixed-speed wind turbines) can cause flicker. Flicker can also be caused by adverse interactions between the DG unit and, for instance, main transformer tap changer. Changes in DG output power may lead to continuous operation (hunting) of the tap changer which could be sensed as flicker while the DG fluctuations alone would not be noticed. The possible interactions with existing voltage regulators should be taken into account at the planning stage. (Jenkins et al. 2000, Barker, De Mello 2000)

4.3 Protection studies

The protection studies to be conducted include the operation of feeder protection and the operation of DG unit protection during faults. When considering the operation of protection, it is always required to study the most difficult cases to assure safety.

The studies can be started from faults occurring in the last points of feeder including the DG unit. If this unit is located along the feeder and thus between the fault and the feeding substation, it may disturb the operation of overcurrent protection as the fault current measured by the relay decreases. Depending on the generator type and the network, the impact may result in delayed tripping or even in totally undetected faults. It is important to calculate the decreased fault current value and to compare it with relay settings.

As a second study, faults occurring on adjacent feeders may be considered. Especially in the case of synchronous generators the upstream contribution of the DG unit may result in unnecessary feeder relay operations.

As a third point it will be necessary to evaluate the operation of autoreclosing where it is applied. The autoreclosure open time should always be longer than the expected disconnection time of the DG unit. A suitable margin must also be included. Practically the voltage, frequency and loss-of-mains protections at the DG connection point must operate clearly faster than the autoreclosure open time.

Fourth point to consider is probably the most complex one. The operation of loss-of-mains (LOM) protection should be assessed. From the DNO's point of view this is very difficult without extensive simulation studies. General requirements can be applied, but they are not evidently correct in all networks. The suitable LOM settings vary even depending on the location on feeder. Too sensitive settings will result in unnecessary trippings of DG unit and thus in dissatisfied producer. On the other hand, less sensitive settings will result in more probable islands. The theoretical worst-case islanding is still impossible to detect with present methods. Thereby defining the settings is more or less compromising.

Earth faults may also be problematic depending on the type of the network. In isolated or compensated networks the situation practically reverts to LOM protection as the generator does not disturb the actual feeder protection. System earth fault may be very difficult to detect from the DG unit's point of view. The resulting island can be detected instead with above mentioned constraints. In the case of directly earthed networks the problems are similar to two first studies mentioned above.

Some of the potential problems observed in the studies can be overcome by modifying relay settings:

- Delays or undetected faults by decreasing the tripping threshold if otherwise possible
- Tripping due to upstream fault currents by increasing tripping threshold or by coordinating the operation time of adjacent feeders
- Reclosings through autoreclosure open time and DG protection operation time
- LOM through DG protection settings

However, it may also be necessary to perform more radical actions, such as:

- Replacing overcurrent relays with directional ones
- Equipping DG connection point with separate zero sequence voltage relays for earth fault protection
- Equipping the DG unit with converter or otherwise limiting the fault current contribution

- Investing in communication between substation and DG unit
- Reinforcing the network

4.4 Fault levels

One important impact of DG is the increasing fault currents, also called fault levels. As the DG unit contributes to short-circuits, problematically high fault currents can be expected at the fault point but also near the DG unit. Heating or electromagnetic torques resulted may result in damages of equipment. Especially cable connections, transformers and switchgear can be problematic. As it was explained earlier, DG may result in delayed relay operations when feeding a fault together with substation. Combined with increased fault currents, this can easily result in exceeding the thermal limits of weakest conductors at the end of the feeder.

When considering network planning, it must be noted that the actions made for connecting DG often include reinforcements near the DG connection point and elsewhere between the DG unit and the substation. These reinforcements will evidently increase impact of DG on fault levels.

5. PLANNING ASPECTS

Presently DG interconnection planning is a relatively rare task for the DNO. It is quite common to use external consults for performing the needed studies as DNO does not have enough knowledge about network effects of DG. Additionally, the planning tools currently used are often not capable of taking DG adequately into account. In this arrangement some problems may exist. If the DNO does not have adequate knowledge to conduct the interconnection studies, it may be questioned whether it is able to assess the results obtained from consultants. In the authors' opinion, DNOs need more expertise on DG issues because relying only on calculations conducted by other parties might be even dangerous. Eventually DNO is responsible for the safety of the network. For instance completely wrong relay settings might result in dangerous situations.

Due to the incapabilities of planning tools, DNOs use different methods when evaluating the impacts of DG by themselves. They often use methods such as spreadsheet calculations, thumb rules, manual calculations, etc. It is also quite common to apply some recommendations given by other parties without weighing their suitability for own network. The most dangerous approach is to assume that small-scale generation has no system-wide impacts and it can thus be connected without technical analysis.

Planning principles used vary between countries and also DNOs. Also the national recommendations and practices vary depending on the country. In some countries simple design rules are used to determine if the planned DG unit can be connected to the desired network node (e.g. the fault level at that point has to be some multiple of the generator rating). (Jenkins et al. 2000) With this approach, this evaluation is considered adequate for interconnection. In other countries (for instance in Finland) more detailed calculations are conducted and every case is studied separately. Also the recommendations may include simple rules to be fulfilled, for instance a limitation of the maximum allowed voltage transient during DG connection or disconnection. (SENER, 2001)

DNO usually applies a network information system (NIS) or equivalent system for network planning. These planning tools are typically highly simplified with steady state calculation methods and root mean square (rms) values. One purpose of these planning tools is to combine technical analysis with economical matters. NIS typically integrates with other systems and offers thus an extensive tool for all planning purposes. For instance all network data, different analysis tools, geographical data and customer data are included. A connection to the real distribution process is linked through distribution management system (DMS). (Lakervi, Nurmi 1997)

The most essential problem at the moment is that NIS and DMS systems do not include adequate functionalities for DG studies. Connecting DG to the network automatically alters the former radial network to a meshed one. It is not self-evident that meshed networks can be studied in all systems. Modern systems manage meshed networks but this does not automatically solve all problems. Modelling the DG unit with steady state approach is very challenging. The dynamical behaviour can practically not be studied. For instance in fault studies the generator can presently be modelled relatively reliably in the case of synchronous generator as the constant fault current source model is somewhat suitable. However, more complex cases such as different induction generators or converter applications can practically not be modelled. If active voltage level management methods are taken in use they should be taken into account also at the planning stage and statistical planning method should be used instead of worst case studies. The present distribution network planning tools are not capable of modelling the active methods in any way.

Thus there is a need for developing the planning systems for DG studies. It is not relevant to perform planning studies in time domain; the simplified steady state approach needs to be maintained instead. Thereby the key issue will be building simplified models for NIS purposes. It would be possible to build predefined procedures in NIS which would perform required studies automatically. This would be beneficial as some studies require checking values point-by-point and can be laborious. (Mäki, 2007)

The significance of planning systems will be further highlighted when the amount of DG increases and there will be more units on same feeder or otherwise near each other. Managing the different combinations will be very challenging and planning system could be of help through iteration rounds.

6. FURTHER DEVELOPMENT

The topics covered in this paper are further studied in research project ADINE (Active Distribution Network). Development of simplified planning tools and methods for DG installations is an essential part of the project.

ADINE is a demonstration project co-funded by European Commission. The aim of the project is to develop, demonstrate and validate a new method for active management of a distribution network. (Repo et al. 2008) Fig. 2 illustrates the concept of active distribution network as it is understood in ADINE.

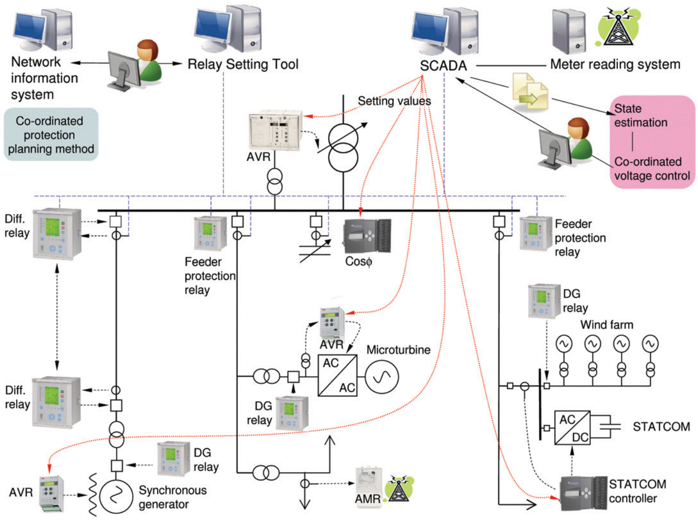

Fig. 2. Overview of the active distribution network in the ADINE project.

7. CONCLUSIONS

Generation on distribution level is a relatively unknown issue for DNOs at the moment. However, the penetration level of DG is definitely increasing and more knowledge will be required in the near future. At the moment, studies are often outsourced to consults. However, DNO should have at least the basic knowledge on the impacts of DG. In the future DG planning is likely to become a more common task and it may be necessary for the DNO to be able to perform the studies by itself.

The problems experienced can relate to voltage levels, voltage transients, fault levels and to operation of protection. Some of these impacts can be considered power quality issues whereas some may result in safety hazards. Similarly, some of the studies can be carried out with statistical approach whereas some of them must be made by using the theoretical worst case.

Regarding DG planning conducted by DNO, probably the most important problem at the moment relates to planning systems as they do not support DG planning adequately. Development of planning tools is thus needed; however their simplified calculation approach must be maintained. It does not seem relevant for the DNO to perform planning calculations with dynamic simulation tools. Instead, the great challenge can be seen in drawing suitable simplifications based on research results and implementing them in planning systems.

It should be noted that similar functionalities are needed in DMS systems as well. For instance modifications of network topology should be handled similarly to the interconnection planning process, e.g. by checking the protection settings. While the active network management methods are mainly distribution management tools, they can also be seen as an option to other investments in network planning.

For the DNO it is essential to be aware of the possible impacts of DG and to evaluate them when planning the interconnection of the unit.

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A. Kulmala, K. Mäki, S. Repo and P. Järventausta, "Including active voltage level management in planning of distribution networks with distributed generation, " in *Proc. Power Tech 2009*, Bucharest, Romania, July 2009.

Including Active Voltage Level Management in Planning of Distribution Networks with Distributed Generation

Anna Kulmala, Kari Mäki, Sami Repo and Pertti Järventausta

Abstract--**The existing distribution networks are designed based on the assumption of unidirectional power flows. The amount of distributed generation (DG) is, however, constantly increasing which creates a need to revise the current network operation and planning principles. This paper focuses on voltage level management issues related to DG. The effect of different kinds of voltage level management strategies on distribution network planning is discussed and a planning procedure regarding voltage issues when a new DG unit is interconnected to an existing distribution network is proposed.**

***Index Terms*--Active voltage level management, distributed generation, network information system (NIS), network planning**

I. Introduction

THE amount of distributed generation (DG) is constantly increasing. However, the distribution networks are still mainly operated and designed as passive systems and the control possibilities of DG are not utilized. In future, this approach should be revised because active network management methods can allow connection of more DG in existing distribution networks and, therefore, reduce the connection costs of DG. [1]

DG can have both positive and negative impacts on distribution network operation. It can support the voltage in the network or reduce losses. On the other hand, it can also cause problems related to e.g. voltage levels, protection or increasing fault levels. In weak distribution networks, the factor limiting the connected capacity of DG is usually voltage rise caused by DG. [2]

Voltage rise can be mitigated using either passive or active methods. If passive methods such as network reinforcement for instance by increasing the conductor size are used, the operational principle of the network is not altered and the planning methods currently used are still valid. If active voltage level management methods such as controlling the active or reactive power of DG are taken in use, the distribution network is no longer passive and the operational principle of the network is radically altered. The currently used distribution network planning tools and procedures are not capable of taking active voltage level management into account in any way and can not, therefore, be used to design networks in which active voltage level management methods are used.

In this paper, the influence of active voltage level management on distribution network planning is discussed. Firstly, DG impacts on distribution network voltage quality are discussed and some active voltage level management methods are introduced. Thereafter, distribution network planning tools and procedures currently used in distribution network companies are discussed and modifications to these are suggested. Finally, a planning procedure regarding voltage issues when a new DG unit is connected to an existing distribution network is proposed.

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II. DG Effects on Voltage Quality

Voltage quality consists of many features including e.g. voltage level and its variations, fast voltage transients, harmonics, voltage dips and interruptions. DG alters the voltage levels in the network, can cause transient voltage variations and might increase or decrease the harmonic distortion of the network voltage. It also increases the network's short circuit power and, therefore, reduces the effect of network disturbances at other parts of the network on customer voltage assuming that it stays connected during the disturbance. [2]

DG raises the voltage level in the network which can be either advantageous or disadvantageous to the network depending on the size, location and time variation of the DG unit. At high load DG supports the voltage and, consequently, improves the network's voltage quality. However, if the DG unit is large enough the voltage rise can become excessive. DG can also affect the operation of existing voltage regulating devices. For instance, if line drop compensation is used at the substation automatic voltage control (AVC) relay [3], connecting DG to the network decreases the current through the transformer and, therefore, lowers the voltages of customers at adjacent feeders.

Changes in the output current of the DG unit affect network voltages. Large transient voltage variations occur especially during DG connection and disconnection. More frequent voltage changes (flicker) can be caused by changes in the primary energy source (e.g. wind) but fortunately these changes tend to be smoother than step changes and are, therefore, less likely to cause nuisance to other customers. Flicker can be caused also by some forms of prime mover or adverse interactions between the DG unit and other existing voltage regulators such as the main transformer tap changer or reactive power compensation capacitors. [2], [4]

DG can either increase or decrease the harmonic distortion of network voltage. The effect on harmonics depends on the type of network connection (synchronous machine, asynchronous machine, power electronics) and the design of the DG unit. [2], [4]

The planning procedure proposed in this paper focuses on issues regarding voltage levels and fast voltage transients at generator start-up and disconnection. Also the possible flicker caused by the DG unit and the unit's effect on harmonics has to be taken into account when interconnection of a new DG unit is planned. These are typically managed using emission limits defined in standards such as [5].

III. Active voltage level management

Voltage rise problems caused by DG are at present usually solved using passive methods such as increasing the conductor size or connecting the generator to a dedicated feeder or at a higher voltage level. Also active voltage level management can be used to mitigate the voltage rise. Methods of different complexity and data transfer needs have been proposed and the selection between these is made based on the structure of the network and the number of components participating in the control.

A. Methods based on local measurements

The simplest active voltage level management methods determine their control actions based only on local measurements and, therefore, require no additional data transfer between network nodes. In many cases they can, however, increase the capacity of connected DG considerably [1]. At present, DG is usually operated at unity power factor and its network connection is firm i.e. the network is designed in such a way that the unit can produce its maximum power regardless of network conditions.

Voltage rise caused by DG can be diminished by allowing the DG unit to absorb reactive power. This can be accomplished by operating the DG unit in voltage control mode. If power factor control is preferred, the DG unit's voltage controller could operate in power factor control mode when the terminal voltage is between acceptable limits and switch to voltage control when the limits are overstepped. [6]

The reactive power capability of DG depends on its network interface. Synchronous machines and power electronics interfaces are capable of controlling their active and reactive power independently whereas the reactive power of induction generators can be controlled only if some external controllable reactive power compensation device is used. [2]

Local reactive power control alters the reactive power flows in the network and, therefore, affects network losses. The additional reactive power flow can also increase the need for reactive power compensation capacitors at the substation and increase the number of main transformer tap changer operations. These effects have to be taken into account at the planning stage. [7]

Voltage rise can be decreased also by limiting the active power output of DG when the terminal voltage exceeds its limit (production curtailment). This naturally reduces also the amount of power generated but if curtailment is needed only rarely the DG owner might still find it beneficial to curtail some of its generation if allowed to connect a larger generator to the network (non-firm network connection). [1]

B. Coordinated methods

Coordinated voltage control methods use information about the whole distribution network when determining their control actions. Hence, data transfer between network nodes is needed. At present, distribution networks contain only few measurements and, therefore, precise information about the state of the network is not normally available. However, measurements in distribution networks are likely to increase in the future which makes application of coordinated voltage control methods more attractive.

Coordinated voltage control methods can determine their control operations based on simple rules (e.g. decrease substation voltage when network maximum voltage exceeds its limit) or use some kind of optimization algorithm. The first approach is most suitable in simple networks where only few measurements and controllable components exist. The latter approach should be used in more complex networks where multiple controllable components exist and determining simple control rules is difficult. [8]

Even the simplest coordinated voltage control methods can improve the utilization of an existing distribution network in case of DG interconnection substantially. For instance, if the substation voltage is controlled based on network maximum and minimum voltages instead of only the local measurement, it was possible to increase the penetration of DG by a factor of 10 in one case study [1].

IV. Distribution network planning regarding DG

In countries where the electricity market is deregulated the planning process for interconnection of a new DG unit begins when a potential energy producer makes an inquiry on connecting a generation unit to the distribution network operator's (DNO's) network. The DNO has little power on the characteristics (location, size, network connection type) of the unit and, therefore, the interconnection planning procedure focuses on assuring that the DG unit can be connected to the network safely and without violating technical constraints such as voltage limits. The aim in planning is to minimize the total costs including for instance DG connection costs, costs of possible additional losses and the reduction in transmission charges. This paper focuses on planning issues regarding network voltages. A more extensive survey on required interconnection studies is represented in [9].

Distribution networks are in Finland planned using a network information system (NIS) that combines technical, economical and geographical data and includes also network calculation functions. Network data is stored in databases and steady-state rms-values are used in the calculations. [3] In modern NIS systems also DG can be included in the calculations. However, as the calculations are based on steady-state values, DG dynamics can not be modeled.

A. *Present planning principles*

In weak distribution networks, the capacity of connected generation is usually limited by the voltage rise effect. At present, DG is considered merely as negative load in distribution network planning and the capacity of connected generation is determined based on two worst case loading conditions (maximum generation/minimum load and minimum generation/maximum load). It is assumed that DG does not participate in distribution network voltage control in any way and that it can produce its maximum output power regardless of the network state (a firm connection).

The planning principles for DG interconnection vary depending on the country and also DNO. In some countries simple design rules are used to determine if a planned DG unit can be connected to the desired network node (e.g. the fault level at that point has to be some multiple of the generator rating). [2] In some countries (for instance in Finland) more detailed calculations are conducted and every case is studied separately.

The studies needed for DG interconnection can not be conducted using the currently used planning tools (NIS) but usage of more advanced simulation programs is needed. This requires a lot of extra work since the network already modeled in NIS has to be modeled in the other simulation program as well. The transfer of data could be quite easily automated but software interfaces for this are not at least for Nordic NIS systems currently available. Moreover, distribution network planners are not usually familiar with these more advanced simulation tools and do not possess enough knowledge on network effects of DG and are not, therefore, able to perform the needed studies. Hence, DG interconnection studies are presently often bought as an external service because conducting them requires both expertise on DG issues and usage of new simulation programs.

In the authors' opinion, the distribution network companies should be able to plan also the DG interconnections using the tools currently used and, hence, the NIS has to be developed. Also planning procedures for DG interconnection are needed. If DG interconnection studies remain a relatively rare task, using external consultants might be profitable also in future but the DNO should still possess enough knowledge on DG issues and adequate tools to be able to assess the results obtained from consultants.

B. *Statistical planning method*

The utilization of distribution networks in case of DG interconnection can be substantially improved if the presently used worst case planning principle is replaced with statistical planning. In statistical planning, load flow is calculated for every hour of the year instead of the two worst cases presently used. Different voltage control possibilities (DG active/reactive power control, substation voltage control etc.) can be included in the method. As an output the method gives information on the influence of the DG unit and the selected voltage control methods on the network's operational characteristics (e.g. network losses).

In Nordic NIS systems loads are modeled using hourly load curves that give the customers' average loads and standard deviations for every hour of the year [10]. For statistical planning similar curves are needed also for DG. These are called production curves. The production curves are not accurate in the same way as load curves and can not, therefore, be used for examining the network state on a certain hour. However, they give a good guess on the average operation of the network and can, therefore, be used to compare different planning approaches. [7], [11]

Naturally, also in statistical planning some technical constraints exist, e.g. overvoltages should never occur. Hence, solutions where the network state is unacceptable even for one hour of the year need to be discarded.

C. *Development needs for NIS*

At present, Nordic NIS systems do not include adequate functionalities for planning of DG interconnection. Connecting DG to a distribution network changes the former radial network to a meshed one. Modern NIS systems manage meshed networks and, therefore, the actual calculation functions do not need to be modified. However, there is a need to develop more accurate models for DG as using the steady-state approach might lead to misleading results. Also models for active voltage level management methods need to be included in the planning tools. The challenge lies in making simple enough models for NIS that still model the DG effects and operation of active voltage level management adequately.

DG is presently modeled in NIS load flow calculations as a negative load with fixed active and reactive powers. With the current DG operational principles this approach is adequate as DG operation is independent of the network state. However, if the unit is, for instance, operated in voltage control mode this approach can not be used because the reactive power output of the unit depends on its terminal voltage. Thus, for voltage level studies DG models should be extended to enable modeling of different reactive and active power control strategies. The models can still be quite simple, e.g. if the DG unit is used in voltage control mode, only the droop-curve describing the dependence of reactive power output on terminal voltage needs to be used instead of constant reactive power.

For studying the fast voltage transients at generator start-up and disconnection only relatively small changes to the DG model need to be made. The fast voltage transient can be simulated by simply running two load flows: with and without the generator. At generator connection, the current to be used is generator start-up current. At generator disconnection, full-load situation is examined.

Active voltage level management methods should be included in NIS as one way to overcome possible voltage problems caused by DG (other ways are passive methods such as increasing the conductor size). The models for different active voltage level management methods can be simplified and do not need to include information on the actual implementation of the algorithms or for instance their delays. A static description is adequate. Modeling the methods that are based on local measurements is quite straightforward: only the dependences between the measured variable and the controlled variable need to be described. Modeling of coordinated methods can require more work depending on the complexity of the voltage control method. The methods based on control rules can be included relatively easily because their modeling is practically similar to modeling of the methods based only on local measurements. Methods based on optimization algorithms require more work because also the optimization algorithm needs to be modeled.

V. THE PROPOSED PLANNING PROCEDURE

The proposed planning procedure considers voltage level issues and fast voltage transients at generator start-up and disconnection when interconnection of a new DG unit to an existing distribution network is planned (short-term planning). Its operational principle is depicted in Fig. 1. When a real DG interconnection is planned also other voltage quality issues (flicker, harmonics, adverse interactions between voltage regulating devices) and protection issues need to be considered. A planning procedure for protection planning is presented in [12].

The proposed planning procedure consists of three steps and is iterative. The first two steps consider network characteristics that are critical i.e. that need to always remain within determined limits. The third step uses the statistical planning method and is used to compare the effects of different planning approaches.

A. Step 0: Initial data

Before any calculations can be made adequate data on the network and DG unit needs to be available. The network data consists of network component (feeders etc.) data and load data (hourly load curves). Both are stored in NIS databases and are, therefore, always available for the DNO. The generator data is obtained from the potential energy producer. For voltage level studies the generator's reactive power operation needs to be known. For studying the fast voltage transients the generator's start-up current is needed. Naturally, also the generator's location, size and connection arrangement have to be known.

The limiting values for network voltage level and fast voltage transients can be found in [13]. DNOs can also have planning principles of their own and national recommendations can also give restrictions.

B. Step 1: Fast voltage transients

In the first step of the planning procedure, fast voltage transients at generator start-up and disconnection are studied. If a large single generator is connected to a weak distribution network the transient voltage variation at generator connection or disconnection can become the limiting factor instead of voltage rise [2]. Transient voltage variations at generator start-up can be diminished by planning the DG unit properly. Also network reinforcement mitigates the transient voltage variations but active voltage level management methods do not affect them at all. Thus, only passive correction methods (action 1: changes in the DG unit or in the network) are available if the transient voltage variation is too large.

The transient voltage variation is determined by calculating load flow with and without the generator. All the voltage regulating devices need to be in the same state in both calculations (e.g. the tap changer position of the main transformer). If the start-up current of the generator is larger than the rated current, the transient at generator connection is larger than at disconnection. However, if the DG unit consists of multiple generation units they can be connected to the network sequentially which, naturally, diminishes the start-up transient. Disconnection study is made in full-load situation.

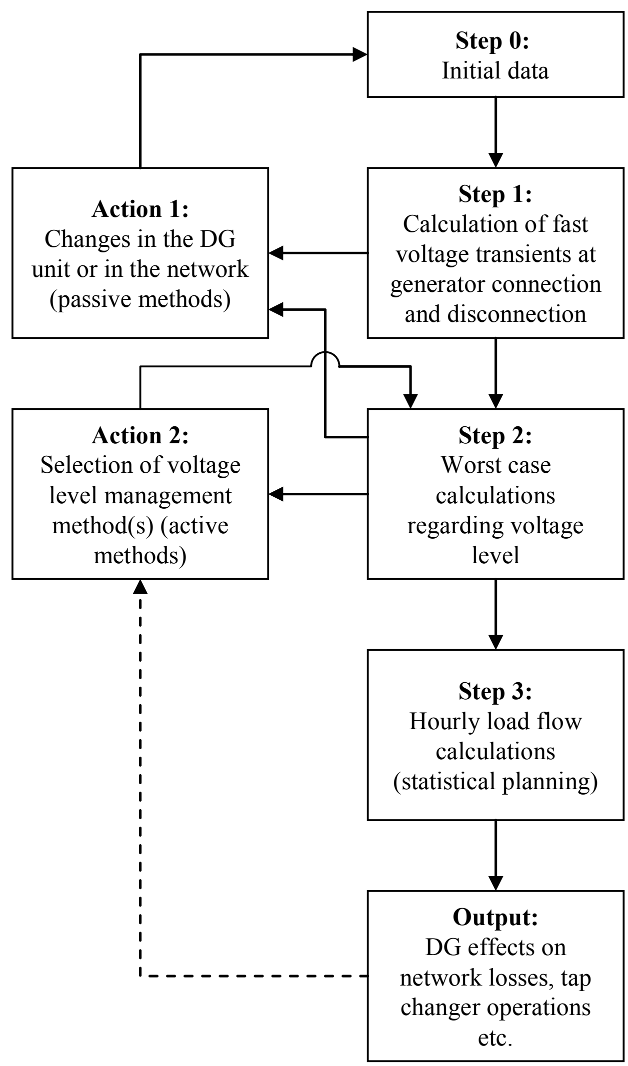

Fig. 1. The planning procedure considering voltage issues when a new DG unit is connected to an existing distribution network.

C. Step 2: Worst case voltage level calculations

If the transient voltage variations at generator connection and disconnection are acceptable, the next step is to consider voltage levels. In step 2 of the planning procedure, worst case calculations regarding distribution network voltage levels are conducted. This step is needed because using statistical planning is reasonable only after it has been verified that the network will operate in an acceptable way in every network state i.e. that overvoltages or undervoltages never occur.

At this step, load flow is calculated in two loading conditions that are maximum load/minimum generation and minimum load/maximum generation. Determining the maximum and minimum loading conditions requires load flow calculations for every hour of the year. Mean powers can not be used for network dimensioning purposes and, therefore, powers that are not exceeded or gone below with some probability are used [11]. The rated power of the DG unit is used as the active power in the maximum generation case and the reactive power is determined from the reactive power characteristics of the unit. With the currently used operational principles, unity power factor is usually used. In the minimum generation case the DG unit is disconnected from the network.

If the voltages remain in an acceptable level in both simulation cases, the DG unit can be interconnected and no actions are needed (in some cases they might, however, be advantageous in the long term). If the voltage limits are, however, exceeded, two alternatives for corrective actions exist. Passive methods (action 1 in Fig. 1) can be used solely in which case the planning procedure does not differ from the currently used planning principles in any way. Also active voltage level management methods (action 2 in Fig. 1) can be taken in use.

After the corrective actions are selected, the worst case calculations are redone and if network operation remains unacceptable, more actions need to be taken.

D. Action 2: Active voltage level management methods

Active voltage level management methods can control all components capable of voltage control. The most commonly used control variables are DG active and reactive power and main transformer tap position (i.e. substation voltage) but also for instance loads could be included in the control. For NIS modeling, the type (continuous, discrete) and control range of each control variable needs to be determined. Also the control algorithm used is needed.

NIS should include a possibility to choose the control variables used in active voltage level management and to define their characteristics. For instance DG active and reactive powers can be either continuous or discrete control variables depending on the characteristics of the DG unit whereas substation voltage is always a discrete variable.

Some commonly used active voltage control algorithms could be included in NIS. These should include at least control of DG active and reactive powers based on local measurements and coordinated control of substation voltage (see for instance [14]). Also a possibility to define own control algorithms would be useful. If active voltage level management is implemented as a part of the distribution management system (DMS), the DMS models can be directly utilized also in NIS because in Nordic countries NIS and DMS are highly integrated.

E. Step 3: Statistical planning

The third step of the control algorithm realizes the statistical planning method introduced in chapter IV.B in which load flow is calculated for every hour of the year using hourly load and production curves [7]. At this step, mean powers of loads are used because statistical planning is not used for network dimensioning but for comparing different alternatives to solve the possible voltage problems.

As an output step 3 gives information on the influence of the DG unit and the selected voltage control methods on the network's operational characteristics. Interesting characteristics are for instance network voltage level, network losses, the number of main transformer tap changer operations, the amount of curtailed production, the amount of controlled reactive power and the amount of energy taken from the transmission network. Also the investment costs are an important factor to be taken into account. The statistical planning can be conducted using different planning approaches and its outputs can be used to choose the best out of these.

F. Practical implementation aspects

The proposed planning procedure includes some features that could be easily automated. All the steps could be implemented as their own functions that would realize the functionality discussed in the preceding chapters.

In step 1, load flows with and without the generator are calculated. The function realizing step 1 should conduct the load flows using the correct generator characteristics i.e. start-up current in connection situation and full-load at disconnection.

In steps 2 and 3, load flow calculations for every hour of the year are conducted. In the current NIS systems these kinds of studies would have to be conducted by hand as only single load flows can be executed at once. As there are 8760 hours in one year, conducting the simulations one by one is not in practice possible. Moreover, even selection of the simulation hour is not possible in all planning systems but load flow can be calculated only for the peak power situation. The processes in steps 2 and 3 could be implemented as their own functions that would carry out the simulations for the whole year and store the needed data for later examination.

G. Further development

In future, the proposed planning procedure will be further developed and its operation in real NIS will be studied. If the planning procedures regarding voltage issues (proposed in this paper) and protection issues (defined in [12]) would be both implemented in NIS, almost all DG interconnection studies could be conducted by the DNO using the currently used planning tool (NIS). The procedure regarding protection issues will be implemented in NIS in project ADINE [15]. Also implementation of the voltage planning procedure would, thus, be interesting.

The proposed planning procedure covers only short-term planning issues regarding DG interconnection. In a real case also the long-term planning issues need to be considered. The DNO should try to predict the future development of the network and make planning decisions based also on the expected future developments and not only on the current situation. For instance, if it is expected that a lot of DG will be constructed near the site where the DG unit to be interconnected is located, building a dedicated feeder for the unit might be profitable even though the first unit could be connected also to an existing feeder with smaller costs. In future, the proposed planning procedure will be developed to take also the long-term planning aspects into account.

VI. Conclusions

The penetration level of distributed generation is constantly increasing which changes the operation of distribution networks in many ways. However, the distribution networks are still mainly operated and planned without consideration of the control possibilities of DG.

In this paper, the effect of DG on distribution network short-term planning regarding voltage issues was considered. The introduction of active voltage level management methods to distribution networks was discussed and their effect on network planning reviewed. Also development needs for the distribution network planning tools currently used were proposed. Finally a planning procedure regarding voltage issues when interconnection of a new DG unit to an existing distribution network is planned was proposed. The proposed planning procedure is such that it can be implemented in the currently used network planning tools relatively easily.

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VIII. Biographies

Anna Kulmala was born in Tampere, Finland, on March 13, 1982. She received her Master's Degree in electrical engineering from Tampere University of Technology in 2006.

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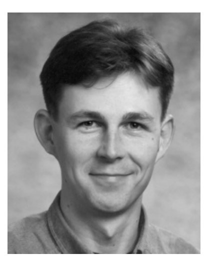

Sami Repo received his M.Sc. and Dr.Tech. degrees in Electrical Engineering from Tampere University of Technology in 1996 and 2001 respectively.

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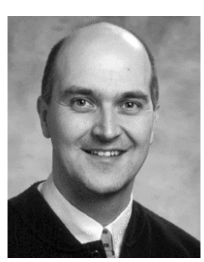

Pertti Järventausta received his M.Sc. and Licensiate of Technology degrees in Electrical Engineering from Tampere University of Technology in 1990 and 1992 respectively. He received the Dr.Tech. degree in Electrical Engineering from Lappeenranta University of Technology in 1995.

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Publication 8

A. Kulmala, S. Repo and P. Järventausta, "Using statistical distribution network planning for voltage control method selection," in *Proc. IET Conf. on Renewable Power Generation*, Edinburgh, UK, Sept. 2011.

USING STATISTICAL DISTRIBUTION NETWORK PLANNING FOR VOLTAGE CONTROL METHOD SELECTION

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Keywords: Active voltage control, coordinated voltage control, distributed generation, distribution network planning tools, statistical planning.

Abstract

The amount of distributed generation (DG) is constantly increasing which changes the operational principles of distribution networks substantially. Taking new operational principles into large-scale use requires also development of planning principles and tools. In this paper, usage of statistical planning for selection of distribution network's voltage control method is demonstrated.

1 Introduction

In weak distribution networks, the amount of connected generation is usually limited by the voltage rise effect. At present, distributed generation (DG) is usually considered merely as negative load in distribution network planning and is not allowed to participate in network control in any way. Possible voltage rise problems are mitigated using passive methods such as network reinforcement. This approach can, however, lead to relatively high connection costs of DG. Taking active voltage control methods into use can decrease the connection costs in many cases substantially. [1, 2]

The currently used distribution network planning tools and procedures are not capable of taking active voltage control into account. Only two extreme loading conditions (maximum loading/minimum generation and minimum loading/maximum generation) are considered when DG interconnection is studied. This kind of planning can not, however, be used to compare different voltage control strategies and their costs because it only determines whether the generator can be connected to the network or not. In statistical distribution network planning, load flow is calculated for every hour of the year using hourly load and production curves. Statistical planning outputs information on the influence of the DG unit and the selected voltage control method for instance on network losses.

In this paper, statistical distribution network planning is used to evaluate benefits and drawbacks of one coordinated voltage control (CVC) method. The studied CVC method controls substation voltage and DG reactive power to keep network voltages between acceptable limits. Its time domain performance has been previously studied [3] and its operation has been demonstrated also in a real distribution network [4]. The purpose of this paper is to view the CVC method from financial point of view and to describe a planning procedure that can be used to select the voltage control method when DG interconnection is planned.

The paper will firstly introduce the studied CVC method. Thereafter, statistical planning method is discussed and the Matlab implementation described. Finally, usage of statistical planning is demonstrated in a real distribution network.

2 Studied coordinated voltage control method

The studied coordinated voltage control algorithm controls the substation voltage and DG reactive power by changing the voltage set point of substation automatic voltage control (AVC) relay and power factor set point of DG automatic voltage regulator (AVR). Its purpose is to keep all network voltages between acceptable limits regardless of the loading and generating conditions.

The control algorithm consists of two parts: Basic control operates when network maximum or minimum voltage exceeds its limit and its purpose is to restore all network voltages to an acceptable level. Restoring control increases DG's power factor set point closer to unity when the network state allows it and operates also when the voltages in the whole network have remained unusually high or low for instance after disconnection of DG.

Two versions of the algorithm are studied: The first one uses substation voltage as the primary control variable and changes DG reactive power only if the voltages can not be restored between acceptable limits using only substation voltage control. The second one controls primarily DG reactive power.

The functional diagram of basic control is represented in Figure 1 when substation voltage is the primary control variable. If DG reactive power is the primary control variable, the two control blocks just change places. The operational principle is the following: If network maximum voltage is too high and minimum voltage is far enough from its limit, the substation voltage is lowered. Correspondingly, substation

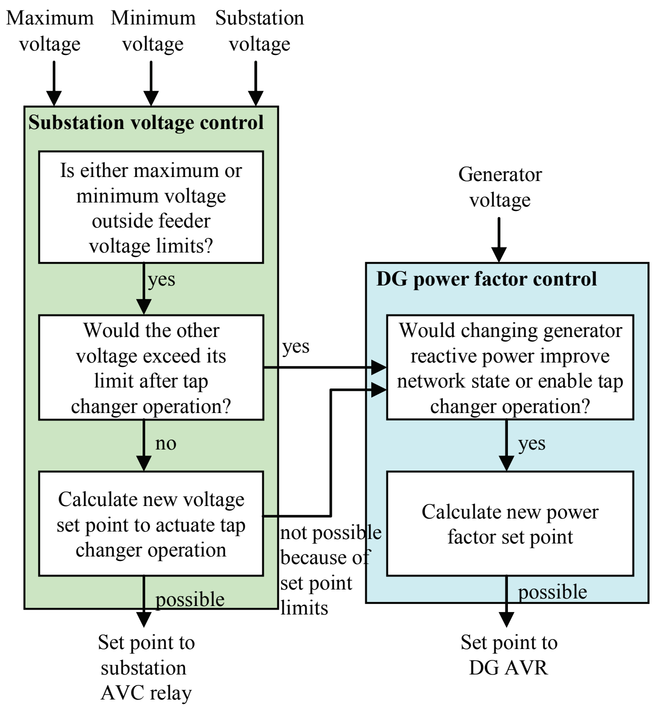

Figure 1: Operational principle of basic control when substation voltage is the primary control variable.

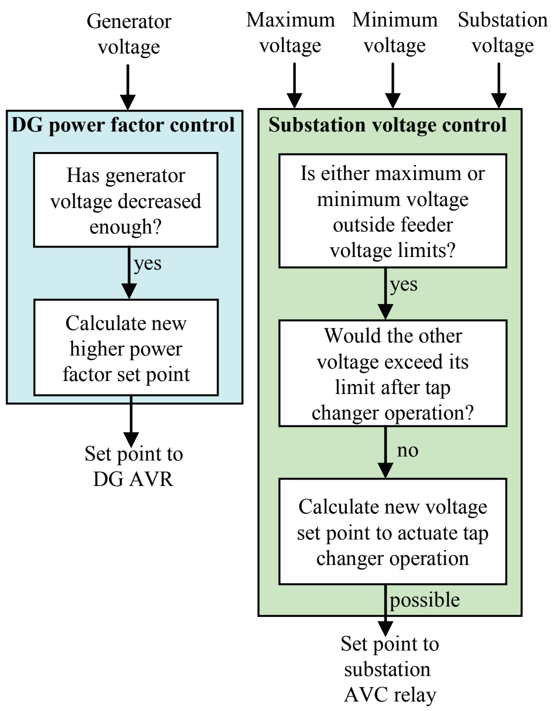

Figure 2: The operational principle of restoring control.

voltage is increased if the minimum voltage is too low and the maximum voltage would not exceed its limit after tap changer operation. DG power factor control is activated if network voltages can not be restored between acceptable limits by controlling only the substation voltage.

The functional diagram of restoring control is represented in Figure 2. The control consists of two parallel control blocks. Restoring power factor control increases DG's power factor set point if the generator voltage has decreased enough. Restoring substation voltage control is similar to basic substation voltage control but has stricter voltage limits.

Detailed flow charts of the control algorithm can be found in [3].

3 DG interconnection planning using statistical planning method

Current distribution networks are passive systems with control only at the substation. Loads and generators are firmly connected i.e. they can consume or generate their nominal power regardless of the network state. Planning these passive networks is quite simple: only few extreme loading conditions need to be considered to make sure that the network operation is satisfactory in all situations.

When active network management methods are taken into use, the operational principle of the network is radically altered. The distribution network becomes an active participant in the control and a wider examination is needed at the planning stage. In this paper, statistical planning method that calculates load flow for every hour of the year is used [5]. Similar studies are conducted in [1]. Also Monte Carlo method could be used to evaluate DG's effect on network voltages [6].

3.1. Operational principle of statistical planning method

In Finland, distribution networks are planned using a network information system (NIS) that combines technical, economical and geographical data and includes also network calculation functions [7]. Network data is stored in databases and loads are modelled using hourly customer group based load curves that give the customers' average loads and standard deviations for every hour of the year [8]. The statistical planning method has been developed such that implementing it as a part of the existing NIS is straightforward. The method has been used in this paper to study issues regarding network voltages but similar planning method could be used also when for instance thermal constraints are examined.

In statistical planning, load flow is calculated for every hour of the year using hourly load and production curves. The outputs of statistical planning can be used to compare different voltage control strategies and to choose the best out of these. Statistical planning gives information on for instance network voltage level, network losses, the number of main transformer tap changer operations, the amount of curtailed production and the amount of controlled reactive power. When investment costs and the results of hourly load flows are combined, the total costs of different control methods can be compared and the most cost-effective method can be selected.

The hourly load curves needed in statistical planning are already available in NIS. Similar curves are needed also for DG. Creation of these production curves is documented in [5] and [9]. The production curves are not as accurate as load curves and can not be used to forecast generation at a certain hour. However, they can be used to examine the average operation of the network.

In addition to statistical planning, also worst case studies are needed to make sure that technical constraints of the network are never exceeded. For instance network voltage level needs to be acceptable throughout the year. If DG is firmly connected, the network should be able to transfer the maximum real power of DG regardless of the loading condition. To assure this, studies should be made in the following situations: maximum loading/minimum generation, maximum loading/maximum generation and minimum loading/maximum generation. If DG production curtailment is allowed, only the maximum loading/minimum generation case needs to be studied. Only those voltage control strategies that manage to keep network voltages at an acceptable level in all these situations are further studied using the statistical planning approach. Reference [10] proposes a planning procedure for DG interconnection studies regarding voltage issues.

3.2 Matlab implementation of the planning procedure

In the studies conducted in this paper, statistical planning procedure is implemented as a Matlab program. The implemented planning procedure consists of three steps: input data, worst case calculations and statistical planning. The structure of the Matlab program is represented in Figure 3.

In step 1 input data for planning is determined. Network data and hourly load curves are obtained from a real network information system and represent a real distribution network. In this paper the data is gathered by hand but this could also be quite easily automated. Statistical production curves are calculated using the method introduced in [9]. If the DG connection is firm, production curves also for maximum and minimum production are needed. In practice the minimum production curve means zero production throughout the year regardless of the type of the DG unit because there is no guarantee that the DG unit will produce at a specified hour. The maximum production curve can, on the other hand, vary depending on the type of DG. In case of, for instance, wind power, the maximum production curve is a flat curve where maximum power is the value throughout the year. In case of, for instance, a combined heat and power (CHP) plant, the plant is not usually used at summer time and, therefore, also the maximum power curve is zero for summer months. At winter time, the curve is at its maximum value. In step 1, some initialization is also done: the voltage control method for the first round is selected and the starting hour of simulations is set.

Step 2 is needed to make sure that the network technical constraints are not overstepped in any situation. If the DG connection is firm, three simulations are conducted at this step: At maximum loading, simulations are conducted using DG maximum and minimum production curves. At minimum loading, simulations are conducted using the maximum production curve. Instead of mean consumption powers these studies utilize powers that are not gone below or exceeded with some probability (p1 and p2). In voltage drop calculations excess probabilities around 10 % are often used [7]. If the DG power can be curtailed, only the maximum loading/minimum production case needs to be considered in worst case calculations.

The case where the loading is at its maximum value and the production at its minimum value (zero production) corresponds to the network planning method currently applied when passive distribution networks with no DG are planned. In these simulations the dimensioning factor is voltage drop and, therefore, the substation voltage should be set to its lowest possible value. When the loading is at its minimum value and the production at its maximum value the voltage rise is at its maximum value and, therefore, in this case the substation voltage has to be set to its highest possible value. The third case where both the loading and the production are at their maximum values is needed because if, for instance, coordinated control of substation voltage is used it is possible that the control algorithm is able to keep the network voltages between acceptable limits in minimum loading/maximum production case but in maximum loading/maximum production case the voltage difference between network maximum and minimum voltage is so large that the network voltages can not be normalized by controlling only the substation voltage.

In step 2, hourly load flows are calculated for the whole year for all the three cases. This is necessary when the calculations are conducted for the first time because the time of the extreme hours is not known. In the following simulation rounds when different control strategies are tested, the results of the first round can, however, be exploited and load flows can be calculated only for the previously determined extreme hours.

Step 3 implements the statistical planning method introduced in chapter 3.1. It calculates load flow for every hour of the year using mean loading curves and statistical production curves. Mean loading is used because this step is not used for network dimensioning but for comparing the average operation of different control approaches. For instance loss calculations are conducted [7]. The outputs of this step are used to compare the different voltage control strategies.

Worst case calculations (step 2) and statistical calculations (step 3) are conducted for different voltage control strategies such as passive network with reinforcements, DG production curtailment, DG local voltage control and CVC. Based on these studies the voltage control method can be selected.

3.3 Integrating statistical planning to existing planning tools

The planning procedure presented above could be quite easily implemented as a part of the planning tools currently used in distribution network companies. The Nordic NIS already

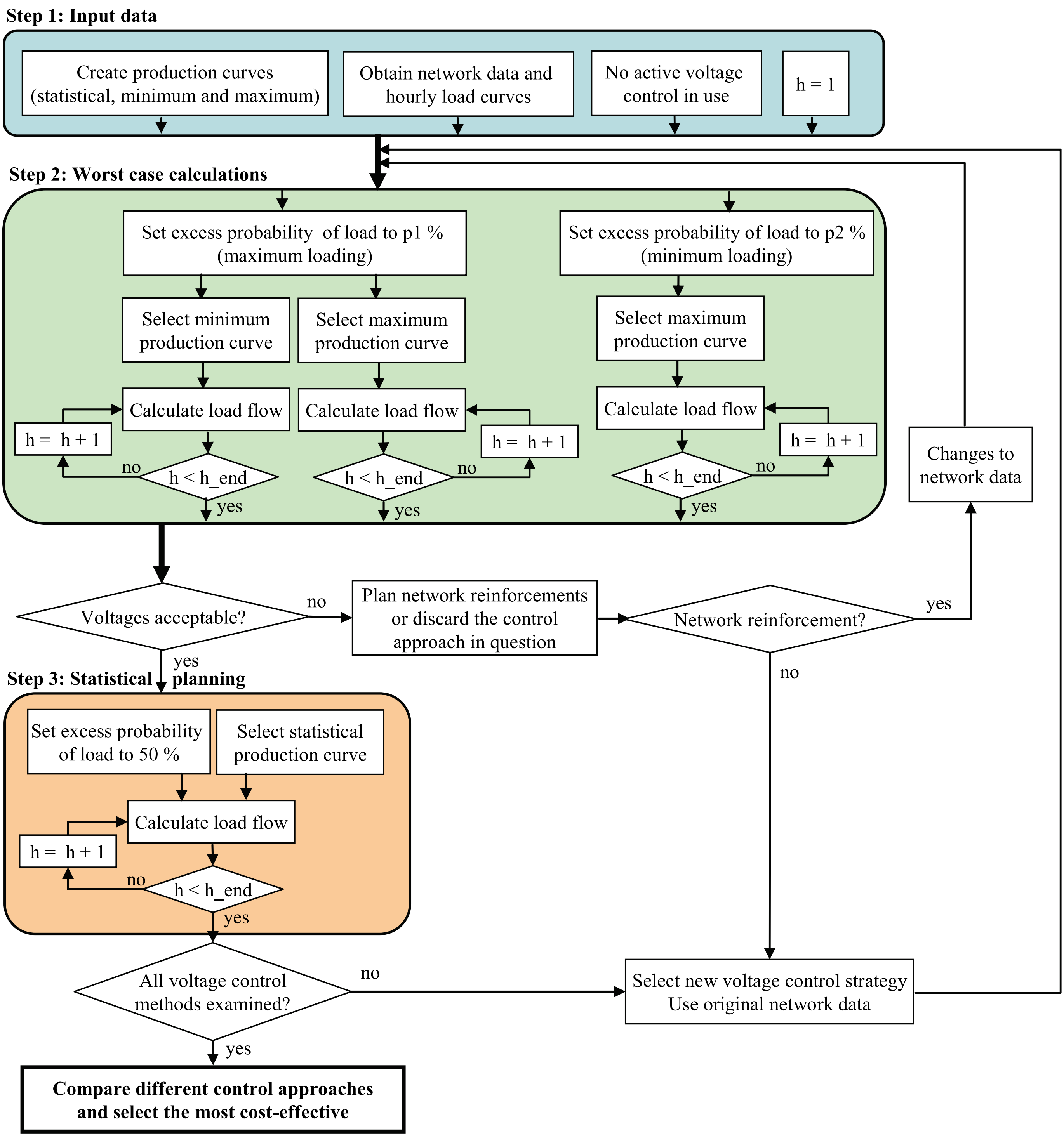

Figure 3: The structure of the implemented Matlab planning procedure.

includes network data and hourly load curves. Also load flow calculation functions are available (in some systems, however, only for radial networks). Therefore, only models for production curves and voltage control methods need to be added. The different steps of the planning procedure could be implemented as separate functions that use the already existing calculation functions in NIS [10].

If active voltage control is implemented as a part of the distribution management system (DMS), no additional control algorithm modelling is needed in NIS. The Nordic NIS and DMS are highly integrated and, therefore, DMS models can be used also in NIS. The Matlab implementation used in this paper models the CVC method using exactly the same Matlab function that was used also in the real distribution network demonstration in [4].

4 Example case

Usage of statistical planning is demonstrated in a real Finnish distribution network. The study network is located in south-west coast of Finland and consists of five medium voltage feeders ranging from the same substation. In the simulations, 3 MW of wind generation is connected 22 km away from the substation. Other feeders are pure load feeders.

Simulations are conducted with and without production. When the wind turbine is connected to the network, voltage rise problems exist and different control strategies are used to mitigate the voltage rise. Generator real power curtailment is used as the last resort in every case if the studied voltage control method is not able to keep network voltages between feeder voltage limits. Two implementations of generation curtailment are studied: disconnecting the whole plant or continuous control of DG real power. The former can be used if there is a possibility to control DG output power for instance by blade angle control of wind generators.

In Table 1 some main results of the simulations are represented. In all cases represented in Table 1, it is assumed that DG real power can be continuously controlled. In the cases where curtailment is realized by disconnecting the plant, the amount of curtailed generation is naturally larger. The acceptable range of voltages is set to 0.95-1.05 pu, the initial substation voltage set point is 1.02 pu and the substation AVC relay deadband is 1.5 %. The minimum power factor of DG is 0.92.

The studied cases in Table 1 are the following:

- Case 1: No production.
- Case 2: The DG is operated at unity power factor.
- Case 3: The DG consumes reactive power at power factor of 0.92.
- Case 4: The DG AVR is in voltage control mode with voltage set point of 1.02 pu. The reactive power can vary between -1.28 MVAr and 1.28 MVAr (calculated based on DG nominal power and minimum power factor).
- Case 5: Coordinated control of substation voltage is used but DG power factor is 1.0.
- Case 6: CVC when substation voltage is the primary control variable.
- Case 7: CVC when DG reactive power is the primary control variable.
- Case 8: Set point of substation voltage is permanently lowered from 1.02 pu to 1.0 pu. This can be done without voltage violations in maximum loading/no generation case calculated with load excess probability of 5 %.
- Case 9: Set point of substation voltage is 1.0 pu and the DG consumes reactive power at power factor of 0.92.

In Table 1, the price of losses is assumed to be 44.6 €/MWh which is an average value of Nordpool Finland spot price in years 2006-2010. The price of curtailed energy is assumed to be 83.5 €/MWh which is the feed-in tariff for wind generators in Finland and the distribution charge is assumed to be 0.7 €/MWh which is the maximum allowed distribution charge for production units in Finland. The lost income due to curtailment is calculated by multiplying the amount of curtailed energy by 82.8 (83.5-0.7) €/MWh. The transmission charge consists of a fixed fee, a consumption fee and a use of grid fee. The fixed fee and the consumption fee are the same for all cases and, therefore, only the use of grid fee is included in Table 1. The use of grid fees used are 0.72 €/MWh (from transmission grid) and 0.30 €/MWh (to transmission grid)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
Net generation [MWh]	-	5409	7109	8095	8973	9290	9293	7131	8801
Distribution charge of DG [€]	-	3786	4976	5667	6281	6503	6505	4992	6161
Curtailed generation [MWh]	-	3884	2184	1198	320	3	0.3	2162	492
Percentage of energy curtailed [%]	-	41.8	23.5	12.9	3.4	0.0	0.0	23.3	5.3
Lost income due to curtailment [€]	-	321595	180835	99194	26496	248	25	179014	40738
Distribution losses [MWh]	572	547	569	676	781	810	804	615	713
Cost of losses [€]	25511	24396	25377	30150	34833	36126	35858	27429	31800
Energy from transmission network [MWh]	26375	20940	19263	18385	17611	17324	17314	19287	17715
Use of grid fee [€]	18990	15077	13869	13250	12961	12829	12824	13887	12814
Energy from transmission network [MVArh]	-7443	-7949	-4883	-1333	-7589	-6810	-5331	-7439	-3539
Absolute value of reactive power of DG [MVArh]	-	0	3028	6721	0	757	2323	0	3749
Number of tap changer operations per year	1	1	1	55	3265	3235	2097	0	0
Cost of losses + use of grid fee - distribution charge [€]	44501	35687	34270	37733	41513	42452	42177	36324	38453
Costs including DG lost income [€]	44501	357282	215105	136928	68009	42700	42202	215338	79191

Table 1: The network effects of the wind generator with different voltage control strategies.

which are the 2011 charges defined by the Finnish transmission network operator Fingrid.

In addition to the above cost factors, Table 1 includes also information on the amount of DG's reactive power and on the number of main transformer tap changer operations. The costs of these factors are not easy to determine. DG reactive power control can be set as a requirement for the DG owner or it can be seen as an ancillary service. This depends on the interconnection agreement between distribution network operator (DNO) and DG owner. A cost is associated also with the tap changer operations because they cause wear of the tap changer and increase its maintenance need.

Table 1 shows that the CVC method introduced in chapter 2 (cases 5, 6 and 7) is the only strategy that is able to keep the amount of curtailed generation below 5 %. In case 9, the amount of curtailed generation is 5.3 % which might also be an acceptable value. In other cases, the amount of curtailed generation is too high and alternatively network reinforcement is needed or the size of the generator should be decreased.

Distribution losses are the highest in cases where the amount of curtailed generation is the lowest. This is reasonable because DG increases the amount of transferred energy. In the example case losses are lower in case 7 (reactive power primarily controlled in CVC) than in case 6 (substation voltage primarily controlled in CVC). This is due to the fact that the example network includes a long sea cable that produces a significant amount of reactive power and, hence, reactive power exceptionally flows towards the substation. When the DG starts to consume reactive power, the reactive power flows in the network decrease and, therefore, also losses decrease. Usually also reactive power flows downwards from the substation and, therefore, consumption of reactive power at DG usually increases losses.

The two lowest columns in Table 1 illustrate total costs. The first one sums up costs that are directly paid by the DNO. These include costs of losses and transmission charges. The distribution fee paid by the DG owner is subtracted from these. If only this column would be considered, cases with significant generation curtailment would seem the best. If, however, also the value of curtailed generation is taken into account, the cases which use CVC lead to lowest total costs. The drawback of CVC is that it increases the number of yearly tap changer operations significantly.

Table 1 does not include investment costs. These should also be taken into account. If the DG already includes an AVR that is able to operate in both power factor and voltage control modes, investments are needed only in cases where CVC is used. The investment costs of CVC are not necessarily high [4]. The benefit of case 9 is that it does not require any investments and that the network operational principle is not altered.

Some studies were made also regarding a firm DG interconnection. These studies showed that if the currently used planning principles are used (no active network management and unity power factor operation of DG), the only option is to build a dedicated feeder for the power plant. The cost of this dedicated feeder would be quite high because the distance between the wind generator and the substation is 22 km. If the cost of the feeder is assumed to be between 20000 €/km and 30000 €/km the total cost will be in the range from 440000 € to 660000 €.

5 Conclusions

Statistical distribution network planning can be used for comparison of different active network management methods. This paper presents a study where statistical planning is used to select the voltage control strategy for an example network. In the example network, coordinated control of substation voltage and DG reactive power turned out to be the least cost method if the investment costs of CVC remain moderate and if the tap changer can cope with the significantly increased number of operations.

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