NTNU – Trondheim
Norwegian University of
Science and Technology

Voltage Control in Distribution Network with Local Generation

Anders Hagehaugen

Master of Science in Electric Power Engineering
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Supervisor: Kjetil Uhlen, ELKRAFT

Norwegian University of Science and Technology
Department of Electric Power Engineering

Summary

A growing trend is connection of new renewable energy resources to the power system. Small and medium-scale hydroelectric and wind power plants are examples of such new production with economic incentives being connected to the power system. The energy resources are often found in rural areas, and distribution networks are a feasible choice for connection. When connected, in general they are denoted distributed generation (DG). Connecting DG to distribution networks may imply challenges related to voltage rise, due to inherent network properties and the resulting power flow. Voltage control is necessary to obtain satisfactory voltage level at all operational situations. An effective voltage regulation may be achieved by use of an on-load-tap-changer (OLTC).

The main contribution of the thesis is moving away from a conventional transformer voltage control in which voltage are kept constant at the transformer secondary side to an approach in which power flow decides tap-changer position. Voltage level is a function of power flow through the transformer. Measured voltage and line current are used to determine tap-changer setting on an OLTC equipped transformer. Power loss and coordination with other voltage regulation mechanisms are focused. The input signal to the tap-changer control are manipulated by use of parameters multiplied with the measured line current and added together with the measured voltage. The principle is the same as used in the traditional transformer model with line drop compensation. It requires no communication. Compensation parameters are determined by a desired contribution at a given operational situation. A droop relation between active power flow and transformer secondary side voltage is obtained by use of these parameters.

Assessment and analysis of voltage control are carried out through power flow calculations and dynamic simulations. From simulations and calculations performed on simplified radial networks, the transformer voltage droop control is seen to be beneficial with respect to reducing network losses. In addition, it can be used to ease coordination with other voltage regulation mechanisms. Other voltage regulation mechanisms could be voltage regulators on synchronous generators. Results from a given network presented indicates that a loss reduction by some 15 % can be obtained when adapting tap-changer position to network operational situation. Furthermore, results indicates that traditional tap-changer control methods may cause erroneous tap-changer operation in networks with high share of DG production.

A challenge in networks with low reactance/resistance relation with high share of DG production at low load, may be export of active power and import of reactive power. The mentioned operational situation may be related to challenges with OLTC operation. Reactive power is seen to have a greater impact on tap-changer operation than active power. Export of active power may cause voltage rise along the network feeder, while import of reactive power may imply undesired tap-changer operation and increased losses. By use of the proposed transformer voltage droop control scheme, challenges related to opposite direction of active and reactive power causing challenges with OLTC operation are seen to be reduced.

Sammendrag

Grunnet økonomiske insentiver er det en økende trend å koble ny fornybar energiproduksjon til kraftsystemet. Små vannkraftverk og vindparker er eksempler på fornybar energiproduksjon som blir bygget ut og tilkoblet kraftsystemet. Energiressursene er ofte funnet i områder hvor distribusjonsnett muliggjør tilkobling. Ved tilkobling benyttes fellesbetegnelsen distribuerte generatorer (DG). Ved tilkobling av DG til distribusjonsnettet kan det være utfordringer tilknyttet spenningsnivå på grunn av nettets egenskaper og den resulterende kraftflyten. Spenningsregulering er nødvendig for å oppnå tilfredsstillende spenningsnivå for alle driftssituasjoner. En effektiv spenningsregulering kan oppnås ved bruk av trinnkobler på krafttransformator.

Oppgavens hovedbidrag er å bevege seg bort fra en metode hvor spenning holdes konstant på transformatorens sekundærside, til en metode hvor kraftflyten bestemmer trinnkoblerens innstilling. Spenning og strøm måles for bestemmelse av innstilling på trinnkobler. I hovedsak bestemmer kraftflyten trinnkoblerinnstillingen, hvor nettap og koordinering med andre mekanismer for spenningsregulering er i fokus. Kraftflyten er benyttet for trinnkoblerinnstilling ved å manipulere inngangssignalet til trinnkoblerens kontrollenhet ved bruk av parametere multiplisert med strømmen. Prinsippet er det samme som benyttet i tradisjonell kompensering for spenningsfall. Metoden er ikke avhengig av kommunikasjon. Det er oppnådd en droop funksjon for spenning på transformatorens sekundærside basert på aktiv kraftflyt ved parameterbestemmelse fra en gitt driftssituasjon.

Resultater fra simuleringer foretatt på forenklede radiale nett viser at en droop funksjon kan være hensiktsmessig med hensyn på reduksjon av nettap. Den muliggjør en enklere koordinering mot andre mekanismer for spenningsregulering. Andre mekanismer kan være spenningsregulator på synkrongenerator. Resultater presentert fra et gitt nett indikerer at nettap kan reduseres med opptil 15 % ved å tilpasse trinnkobleren til nettets driftssituasjon. I tillegg indikerer resultatene at tradisjonelle metoder for trinnkoblerregulering kan forårsake feilaktig trinnkoblerregulering i nett med høy andel produksjon fra DG.

En utfordring i nett med lavt forhold mellom reaktans og resistans kan være eksport av aktiv effekt og import av reaktiv effekt ved lavlastsituasjon. Nevnte driftssituasjon kan relateres til utfordringer med trinnkoblerregulering. Reaktiv effekt er påvist å ha større innvirkning på trinnkobleren, sammenlignet med aktiv effekt. Eksport av aktiv effekt kan innebære spenningsstigning i nettet, mens import av reaktiv effekt kan medføre uønsket trinnkoblerregulering i tillegg til økte nettap. Ved bruk av den foreslåtte metoden for etablering av en droop funksjon for transformatorens sekundærspenning basert på kraftflyten, indikerer resultatene at utfordringene reduseres.

Preface

This master thesis report is the final work of the two-year M.Sc Electric Power Engineering at the Department of Electric Power Engineering at the Norwegian University of Science and Technology.

I wish to thank my supervisor Professor Kjetil Uhlen for his guidance and assistance through the work of this thesis. I would also like to thank Trond Toftevaag for his assistance and help. I am grateful for the help from PhD candidate Traian Nicolae Preda with the simulation software DIgSILENT PowerFactory.

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Symbols and abbreviations

OLTC	=	On-load-tap-changer
DG	=	Distributed generation
HV	=	High voltage level. $V > 35$ kV
MV	=	Medium voltage level. $1kV < V < 35$ kV
LV	=	Low voltage level. $V < 1$ kV
TGC	=	Tradable green certificates
DSL	=	DIgSILENT Simulation Language
DMS	=	Distribution management system
AVC	=	Automatic voltage control
AVR	=	Automatic voltage regulator
LDC	=	Line drop compensation
PE	=	Power electronic
PF	=	Power factor
RMS	=	Root mean square
OPF	=	Optimal power flow
SCC	=	Short circuit capacity
V [V]	=	Voltage
I [A]	=	Current
R [Ω]	=	Resistance
X [Ω]	=	Reactance
Z [Ω]	=	Impedance
P [W]	=	Active power
Q [VAr]	=	Reactive power
S [VA]	=	Apparent power
E	=	Electromotive force (emf)
p.u.	=	Per unit
ϕ	=	Power factor angle
δ	=	Voltage angle, or voltage angle difference
T	=	Time-constant
K	=	Gain-constant

Chapter 1

Introduction

1.1 Background

A growing trend is connection of new renewable energy resources to the power system. Small and medium-scale hydroelectric and wind power plants are examples of such new production with economical incentives being connected to the power system. The energy resources are often found in rural areas, and distribution networks are a feasible choice for connection. In general, when generators are connected to distribution networks, they are denoted distributed generators (DG). Due to their inherent properties, power production is often uncorrelated with network load demand.

Distribution networks are traditionally planned, built and operated to supply electric power to customers. With integration of DG, distribution networks are facing a trend change towards a more dynamic and active network.

Voltage control are traditionally performed with a passive approach, or with an approach considering a unidirectional power flow. Integration of DG may imply bidirectional power flow. In distribution networks with considerable line resistance, challenges with over-voltage may be a reality. Hence, a well functioning voltage control is a necessity to obtain a voltage level inside the requirements.

Several voltage regulation mechanisms may be present in a network with DG. For instance on-load-tap-changer (OLTC) and regulators on synchronous machine based DG. It is necessary to obtain good coordination between the mechanism to maintain a stable voltage level.

1.2 Problem description

In chapter 2 a literature review is conducted, and concluded by the problem description listed below:

- How could the tap-changer control be designed for operation in a network with DG?

- How could tap-changer operation as function of power flow through the transformer be carried out to best coordinate OLTC operation with the network operational situation?
- How would a possible adaption of tap-changer operation to the operational situation interact on synchronous machine based DG?
- In what extend would an improved tap-changer operation influence network losses?

1.3 Thesis outline

The report is structured in 9 chapters. Chapter 1-4 are chapters used for information regarding background, literature to deduce and support the problem description, and basic theory. Chapter 5-7 are chapters for results and analysis, while chapter 8-9 are chapters for discussion and conclusion. Outline of the thesis is listed below:

- Chapter 2 holds a literature review, and is concluded by stating the problem description
- In Chapter 3 voltage control for on-load-tap-changer transformers is illustrated
- Chapter 4 gives a brief overview of different models used for distributed generation
- In Chapter 5 network studies on a simplified radial distribution network are carried out
- Chapter 6 contains considerations regarding power losses in the simplified distribution network with different generator and control modeling
- Chapter 7 holds studies in an extended model of the radial network studied in chapter 5
- Chapter 8 discusses the results and voltage control approaches
- Conclusions and suggestion for further work are found in Chapter 9

1.3.1 Analysis of voltage stability and control

Main scope for the work is voltage stability analysis in simplified radial networks. No considerations are made for transient stability, short circuit calculations or protection equipment. For assessment of voltage stability and control, power flow calculations and dynamic simulations are used. Simulations are conducted for test and validation of voltage control mechanisms in networks with changing operational conditions. DIgSILENT PowerFactory and Matpower are software used for analysis.

DIgSILENT PowerFactory

DIgSILENT PowerFactory is a commercial power system software for use in analysis of generation, transmission and distribution networks [1]. It is used for power flow calculations and dynamic simulations. The version used is 14.1.6.

Matpower

Matpower is an open-source power system simulator software for use in Matlab® [2]. Matpower is used for steady state power flow and optimal power flow (OPF) analysis.

Chapter 2

Literature review

2.1 Distributed generation in Norway

During 2011, 1393 hydroelectric power plants generated 122 TWh out of Norway's 128 TWh total electric power generation, while wind power generated 1.31 TWh. [3]. 1060 out of a total number of 1393 hydroelectric power plants have a capacity of 10 MW or less. These 1060 small and medium sized hydroelectric power plants, had by the entrance of 2012 a calculated average year production of about 6.3 % of Norway's 130 TWh total average hydroelectric power production [3]. A large extend of the small and medium sized power plants are placed in distribution networks, often in rural areas with long overhead lines.

242 wind turbines in 19 wind farms were installed in Norway by the entrance of 2012 [3].

2.1.1 Tradable green certificates

Norway and Sweden established January 1st 2012 a common marked for tradable green certificates (TGC) [4]. TGC is a purely financial marked based support scheme for renewable technology. A producer of renewable energy, also known as a green producer, deliver electricity to the grid and receive a number of green certificates corresponding to the amount of electricity delivered [5]. TGC have six main objectives [5]:

- Certify and support the use of renewable energy
- Encourage the development of new renewable energy technology in a cost effective way
- Stimulate technical development within some green technologies in a controlled direction
- Increase security of supply
- Allocate costs for support of renewable energy technologies from the authorities to the market

- Encourage and stimulate to research and development within renewable energy technologies

In the years from 2012 to 2020, Norway and Sweden are increasing the volume of renewable production by 26.4 TWh, based on TGC [4]. In the light of the introduction of TGC, the volume of distributed generation are likely to increase in the years towards 2020.

2.2 Regulations

Introduction of distributed generation (DG) may influence power quality in the network. Variations in the network voltage may be caused by DG integration. The Norwegian power quality regulation [6] has requirements regarding the magnitude of the voltage variations. Voltage variations should be within ±10 % of the nominal voltage measured at point of customer connection [6]. The Norwegian power quality regulation has no requirements regarding voltage variations at MV level.

Challenges related to power quality and operation will draw more attention in the future, as integration of DG likely will continue due to the introduction of TGC.

2.2.1 Supplementary literature to fulfill regulations

DG may imply challenges related to fulfill regulations in [6]. In order to plan networks with DG integration, [7] has a suggestion regarding planning procedure. In addition, suggestions regarding technical requirements for DG units with maximum active power production of 10 MW or less can be found in [8].

2.3 Connecting generation to distribution network

Traditionally were distribution networks planned, built and operated to supply electrical power to the customers. Figure 2.1 shows a simple model of a radial distribution network. A strong grid supplies a load in the network through transformers and a transmission line. The network has unidirectional power flow from the strong grid towards the load.

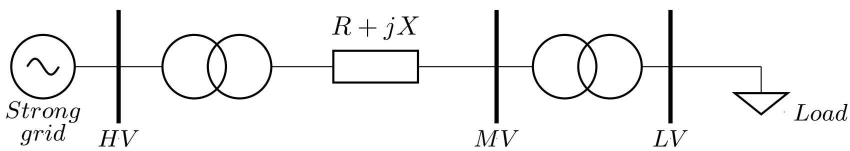

Figure 2.1: Simple radial distribution network

Figure 2.2 illustrates the principle network configuration when connecting generators to the distribution network. When connecting generators to the distribution network, the generators are denoted distributed generators (DG). [9] provides a definition of distributed generation. In the network model illustrated in figure 2.2, the power flow may not be unidirectional. According to the size and production of the DG unit, and network load demand, power flow in the network may be bidirectional.

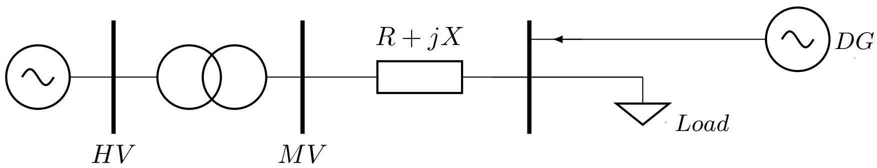

Figure 2.2: Simple radial distribution network with a DG unit

With a bidirectional power flow, challenges such as voltage rise may occur. Voltage rise due to the connection of DG in distribution networks can be an obstacle for connecting DG, especially in rural areas with long overhead lines [10].

2.3.1 Solutions to mitigate voltage rise

As voltage rise may be an obstacle for connection of DG, solutions to mitigate voltage rise is necessary. Network upgrades, reduced active power production, increase in reactive power consume, and tap-changing with OLTC are methods used to control voltage in distribution networks.

Capacity problems regarding integration of DG have in Norway normally been solved by network upgrades, while possibilities as improved tap-changer operation and local voltage control have not been utilized fully [11].

Synchronous generators with excitation system operated in voltage control mode is an advantageous strategy to increase the penetration level of DG units in a distribution network [12].

Maximum size of DG connected to a given feeder can be significantly increased by use of line drop compensation (LDC) in cooperation with OLTC [13].

2.4 Coordination and control in distribution networks

Different techniques for distribution system control are discussed in [14]. The discussion is based on the extent of the distribution system control intelligence, and what kind of architecture the control should have. In general, it is broadly distinguished between centralized and decentralized control architecture. In a centralized architecture all system intelligence is located in a central system, while a decentralized architecture have the intelligence spread across the system. With the two broadly distinguished architectures, four different categories related to distribution control are defined [14]:

- **Centralized.** Concentrated logic in one or more control centers, and staffed centers by individuals responsible for operating the distribution system.
- **Substation-centered.** For a set of distribution feeders, logic placed at the substation which serve the feeders. A decentralized architecture.
- **Fully distributed.** Control logic installed at the location of the controlled equipment. Defined as a decentralized architecture.
- **Coordinated hybrid.** An intermediate between the centralized and fully distributed control architectures. The central system should ensure security and control of operation under any circumstance, and offer a better integration with overlaying network.

Figure 2.3 provided in [15] is a suggestion to illustrate the difference between architectures with respect to voltage regulation.

Decentralized	*Coordinated*	*Centralized*
DG Voltage Control	OLTC/DG coordination	Distribution management system

Figure 2.3: Voltage control architectures [15]

In general, moving from left to right in figure 2.3 the complexity of the control increases. Figure 2.4 provide an indication regarding some of the main differences between centralized and decentralized voltage control.

Decentralized	**Centralized**
Local measurement	Wide measurement
No coordination	Full coordination
Limited optimization	Optimization
Local control	Extensive control

Figure 2.4: Centralized and decentralized control

2.4.1 Centralized voltage control

Voltage control in distribution network can be achieved with centralized control similar to the transmission system, through dispatch of active and reactive power, and control of other network elements [16]. A possible solution of central distribution control is integration of functions and applications necessary for operation, management, engineering and commercial management on a single platform, hence a Distribution Management System (DMS) [17].

2.4.2 Coordinated voltage control

Several contributors have performed research in the area of coordinated voltage control. Especially is the use of communication to coordinate voltage regulation mechanisms seen to have a positive effect on less curtailment of energy supplied from DG.

In [18] a coordinated control strategy on how voltage regulation mechanisms may be coordinated by use of control on OLTC and DG connected together with a coordination controller is proposed. With a coordinated voltage regulation, results indicate that the amount of curtailed DG energy is decreased, however network losses are increased.

In [19, 20, 21, 22] coordination between voltage regulation mechanisms are performed with a controller which ensure that voltage level is inside requirements at all network buses, while a second controller regulates the voltage band by optimization of the DG units reactive power capability.

Challenges related to coordinated voltage control

Both voltage control approaches mentioned above have the need for reliable and robust communication. Challenges are experienced in relation with older DG units, which do not have the reactive power capability at nominal power. For instance, newer requirements may demand the possibility of the generator to work with a power factor of 0.95 when consuming reactive power and 0.9 when producing reactive power [8]. Older units were not necessarily designed to have such reactive power capability.

2.4.3 Decentralized voltage control

A synchronous generator operated in voltage control mode is a simple form of decentralized control. The synchronous generator with its excitation system is a stand-alone DG unit, and it does not need any communication to other elements or devices.

Decentralized control may in addition be of other formats, as to control operating mode and active power curtailment. [15] illustrates a wind power case with decentralized voltage control, in which the control scheme varies between voltage control and power factor mode, in addition to use of active power curtailment.

A decentralized control scheme with control of an OLTC, substation-switched capacitors and synchronous machine based DG is shown to have good effect in reduction of losses and OLTC operations when they are proper coordinated [23]. DG operated with constant voltage are found to reduce OLTC operations. If the available capacitors have capability enough to compensate for reactive power demand, losses are not influenced significant by DG operation mode.

2.5 Challenges in networks with DG

By use of decentralized voltage control, voltage rise in distribution network may be mitigated. However, by finding a solution regarding voltage rise other problems may occur. Such challenges may be increased power losses or dynamic interactions inside the network due to uncoordinated operation of regulation mechanisms.

Another factor is the interaction of DG on tap-changer operation, and vice versa, the possible influence of tap-changer operation on DG.

2.5.1 Synchronous machines

Two main categories exist for synchronous machine operation [24]:

- *Voltage supporting machines.* Synchronous machines that would be expected to assist in regulation of system voltage.
- *Voltage following machines.* Synchronous machines that would not be expected to assist in regulation of system voltage, but instead are expected to follow the system voltage.

For voltage support and stability in a transmission system, as many machines as possible should operate to regulate voltage. However, a distribution system in which several synchronous generators on a single feeder are set to regulate voltage, coordination between they may be challenging. By use of voltage following synchronous machines, the coordination could be easier [24].

2.5.2 Power loss

Reactive power flow increases with increased DG production in a network with synchronous generators and decentralized voltage control, illustrated by measurement results given in [25]. The increased reactive power demand results in higher power loss due to the reactive power transport. A coordination for reactive power is suitable to keep voltage inside requirements, and the coordination can be used to reduce reactive power transmission, thereby reduce losses [25].

2.5.3 Voltage stability

Voltage stability is defined [26]:
"Voltage stability the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operation conditions and after being subjected to a disturbance."
Dynamic interactions inside a distribution network may, among other, be caused by [27]:

- Control action arising from transformer tap-changing
- Control action related to reactive power compensation or DG
- Operating of protective equipment

Dynamic interactions between voltage regulation mechanisms may cause problems related to generators protection and stability limits. Example of such problem is increase of voltage in a network due to DG production followed by undesired tap-changer operation, in which a synchronous generator tries to hold constant voltage, hence it consumes reactive power. The voltage regulation is seen as unsuccessful from the synchronous generator, and thereby the protection equipment disconnect the generator due to high reactive power import [28].

2.5.4 Tap-changer operation

Several factors influences tap-changer operation. Short circuit capacity (SCC), X/R ratio of external network and power flow are examples of factors influencing tap-changer operation.

Short circuit capacity and X/R ratio

Increased short circuit capacity and increased X/R ratio are both found decreasing the frequency of tap-changer operations [29].

Reactive power

Wind turbines operating at a lagging power factor, increases the tap-changer operation [29]. Reactive power loading has greater impact on tap-changer operation than active power loading [30].

2.6 Summary and argumentation for problem description

As literature describes, voltage control in distribution networks with DG is possible with several approaches. Voltage control can be carried out in a centralized manner with management systems with extensive communication and control. In a distribution network, it may not be appropriate to equip all units with extensive and real time control.

In [30] it is stated: *"It is important to realize that performance alone is not the only requirement of a control scheme. It should also be reasonably simple to implement."*

In a decentralized control, voltage control is performed without communication, and coordination between voltage regulation mechanisms may be challenging. However, a decentralized control scheme is reasonably simple to implement, compared to an extensive real time centralized control. Hence, possible coordination between mechanisms in a decentralized architecture should be given attention.

With changing network load demand and power production from DG units, operational situation of the network changes. In networks with high penetration level of DG, it is likely that there is a large difference in operational situation from low load with maximum production, to a high load situation without production. It is necessary to obtain satisfactory voltage level at all operational situations.

In networks with DG, power flow with export of active power and import reactive power may be a reality. Reactive power flow impacts tap-changer operation more, compared with active power flow. A conventional OLTC control only sees the voltage at a chosen point of measurement, often at the transformer secondary side.

From the challenges and arguments mentioned above, the following problem descriptions are developed:

- How could the tap-changer control be designed for operation in a network with DG?
- How could tap-changer operation as function of power flow through the transformer be carried out to best coordinate OLTC operation with the network operational situation?
- How would a possible adaption of tap-changer operation to the operational situation interact on synchronous machine based DG?
- In what extend would an improved tap-changer operation influence network losses?

Chapter 3

Voltage control of transformer

3.1 On-load-tap-changer

The on-load-tap-changer (OLTC) transformers are used between voltage levels to regulate and maintain the voltage, which is supplied to the customer within statutory limits [31]. HV/MV transformer equipped with on-load-tap-changer is used for voltage control in distribution networks. Voltage control with an OLTC is performed by regulating the turns ratio of the transformers primary and secondary windings. Voltage at the secondary winding is regulated. Regulating the turns ratio of the transformer is carried out by mechanical switches in steps. Thus, the voltage control is discontinuous. A typical voltage range of an OLTC can be 8 steps, each with step size 1.5 %. Hence, the resulting voltage control range is ±12 %. Figure 3.1 illustrates the basic utilization of an OLTC equipped transformer in a simple distribution network.

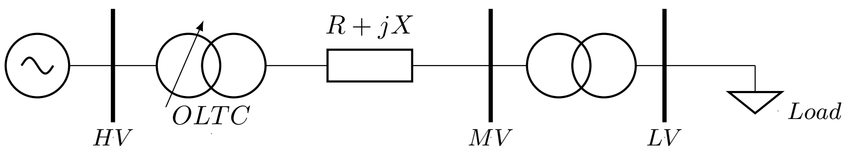

Figure 3.1: Simple radial distribution network with OLTC transformer

3.1.1 Representation of transformer with tap-changer

A transformer with nominal turns ratio is represented with a series admittance [32]. A tap-changing transformer has the ability of changing the turns ratio. With a changed ratio, the ratio becomes off-nominal, and the series admittance is different from both sides of the transformer. With an off-nominal ratio, it is necessary to modify the admittance to include the effect of changing turns ratio. Figure 3.2

illustrates a transformer with a series admittance and a turns ratio with off-nominal tap ratio $1 : n$. n is the off-nominal tap position, and if the transformer is a phase shifting transformer, n is a complex number.

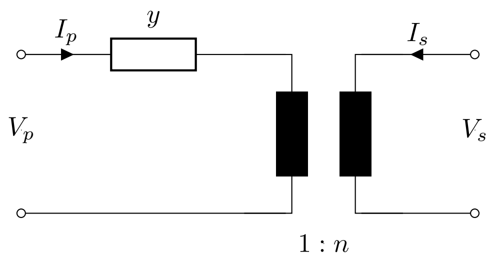

Figure 3.2: Transformer tap-changer with turns ratio 1:n

From figure 3.2 following relations can be set up:

$$I_p = y \cdot V_p - \frac{y}{n} \cdot V_s \tag{3.1}$$

$$I_s = -\frac{1}{n^*} \cdot I_p \tag{3.2}$$

Inserting 3.1 in 3.2:

$$I_s = -\frac{y}{n^*} \cdot V_p + \frac{y}{|n|^2} \cdot V_s \tag{3.3}$$

Rearranging equation 3.1 and 3.3, by writing them on matrix form give equation 3.4.

$$\begin{bmatrix} I_p \\ I_s \end{bmatrix} = \begin{bmatrix} y & -\frac{y}{n} \\ -\frac{y}{n^*} & \frac{y}{|n|^2} \end{bmatrix} \cdot \begin{bmatrix} V_p \\ V_s \end{bmatrix} \tag{3.4}$$

If the off nominal turns ratio n is real value, it is possible to use equation 3.4, and represent the equation with an equivalent circuit, illustrated in figure 3.3. Figure 3.3 is a π equivalent model representing a transformer with tap-changer.

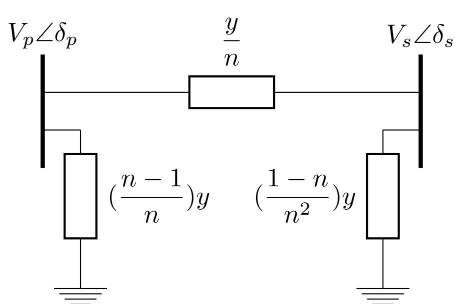

Figure 3.3: Equivalent circuit for tap-changing transformer [32]

Modeling the tap-changing transformer in the linearized power flow equations takes the general form given in equation 3.5, in which specified voltage is a control variable and n becomes a dependent variable [33].

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} & \frac{\partial P}{\partial n} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} & \frac{\partial Q}{\partial n} \end{bmatrix} \cdot \begin{bmatrix} \Delta \delta \\ \Delta V \\ \Delta n \end{bmatrix} \tag{3.5}$$

3.1.2 OLTC voltage control

Control of the OLTC transformer is performed by an automatic voltage control (AVC) relay, and adjust the OLTC in accordance with predetermined parameters [31]. A detailed analysis regarding modeling and analysis of OLTC equipped transformers including their control systems can be found in [26, 34]. A block diagram of a voltage control system for automatic tap-changing is illustrated in figure 3.4.

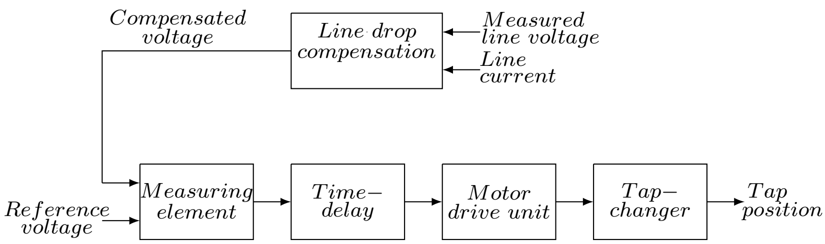

Figure 3.4: Block diagram of voltage control system for automatic tap-changing [26, 34]

The tap-changer control system consist of three basic elements [26, 34]:

- Tap-change mechanism. The mechanism is driven by a motor unit
- Voltage regulator, containing a measuring unit and a time-delay element
- Line drop compensator

Line drop compensation

The task of the line drop compensation unit is to provide a voltage to the voltage regulator. Voltage from the line drop compensation unit are the measured voltage at the transformer, and the line current multiplied by a line drop impedance, shown by equation 3.6.

$$V_C = |V_{meas} + (R_C + jX_C) \cdot I_{meas}| \tag{3.6}$$

Line drop compensation is used to control the voltage at a remote point, for instance at a selected point on a feeder or line, hence $R_C + jX_C \neq 0$. If the compensation impedance is zero, $R_C + jX_C = 0$, voltage is kept constant at the transformer secondary side.

If an assumption is made of power flow only in one direction, the current used for line drop compensation is $|I_{meas}|$ [35].

Voltage regulator

The voltage regulator consist of a measuring unit and a time-delay element. The measuring element is an adjustable deadband relay with hysteresis function [34]. Input to the measuring element is the voltage error between the voltage reference and compensated voltage, described by equation 3.7.

$$\Delta v = V_{ref} - V_C \tag{3.7}$$

Figure 3.5 illustrates the relationship between measurement unit input Δv, relay hysteresis band ϵ, and measurement output V_M.

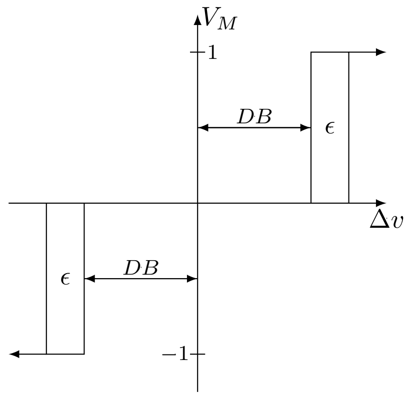

Figure 3.5: Measuring element in modeling of OLTC transformer [34]

Figure 3.5 shows how the measurement output is determining the sign of next tap-change operation, depending whether the voltage error Δv is positive or negative, and the hysteresis band ϵ.

From the measurement unit, the signal is fed to a time-delay unit. The time-delay unit is an adjustable relay, and is used to reduce unwanted effects like unnecessary tap-change operations caused by short-term voltage variations. The time-delay is a regulator operation delay given in seconds.

Two different time-delay are used. Some regulators utilize a constant time-delay $T_d = T_{d_0}$, while other regulators use a time-delay as function of initial time-delay setting T_{d_0}, voltage error Δv, and deadband DB. Regulators with varying time-delay characteristics usually utilize an inverse time-delay characteristic, given by equation 3.8 [34].

$$T_d = \frac{T_{d_0}}{|\Delta v / DB|} \tag{3.8}$$

Tap-changer mechanism

The tap-changer mechanism is a discrete step-by-step mechanism, and the operation could be represented by a time-delay element. Tap-changer position n_k after operation k is determined from the previous tap-changer position n_{k-1}, and the incremental change Δn_k, illustrated in equation 3.9 [34].

$$n_k = n_{k-1} + \Delta n_k \tag{3.9}$$

3.1.3 OLTC transformers operated in series

In power systems, OLTC transformers are used between voltage levels. Figure 3.6 illustrates a possible scenario of three different OLTC transformers operated in series in a simplified power system.

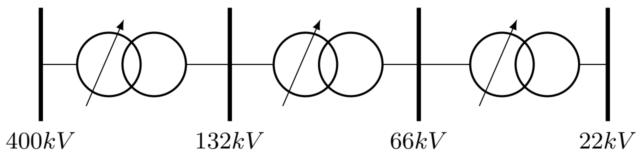

Figure 3.6: Example of OLTC transformers operated in series in a simplified power system

In a scenario as illustrated in figure 3.6, coordination between tap-changers is necessary to avoid unstable operation. Poor coordination of cascaded tap-changers can be dangerous from a voltage stability point of view [30]. For instance, trip of generation or lines in the transmission system may lead to a voltage drop and pushing the system towards its transfer limits. If uncoordinated OLTC in the distribution network downstream from the voltage drop temporarily increase the voltage, and thereby increase system loading, it may lead to instability. The increase in load with increased voltage level is due to voltage dependency of loads.

A tuning rule for setting time-delay for cascaded OLTC is proposed in [30]:

- *Set delay time T_1 for top level OLTC adequately long to filter out fast transients*
- *Compute number of tap operations N_1 needed to compensate for a worst case disturbance with the top level OLTC*
- *For downstream OLTC, make $T_{k+1} > N_k T_k$*
- *Make sure that time-delay of lowest level OLTC provides fast enough customer voltage restoration*

The proposed tuning rule in [30] is shown to have good effect on reducing the number of unnecessary tap-changer operations.

Chapter 4

Generators and power sources

4.1 Distributed generators

Chapter 4 provides a short model description of the different generators and power sources used as distributed generators. A brief overview for representation of generators in power flow calculations is provided.

4.2 Synchronous machine

Figure 4.1 illustrates a per-phase equivalent circuit of a round-rotor synchronous machine. The synchronous machine model, in all simplicity, contains a circuit for supplying the rotor field current, and a circuit with an internal voltage source in series with an impedance. The series reactance X_d is the sum of the armature reactance and self-inductance of the coil, while the series resistance R is the stator resistance [36]. From a power system point of view, the synchronous machine can be both a source and a sink of active and reactive power [27].

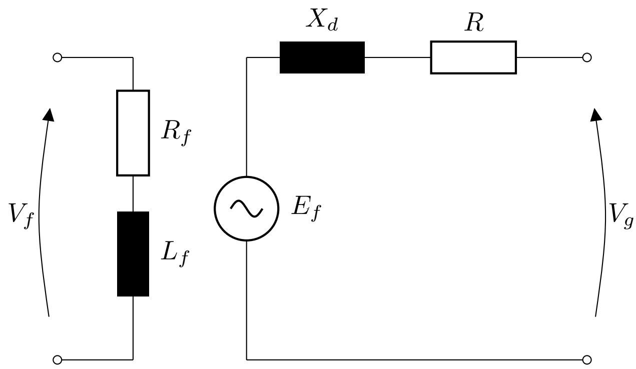

Figure 4.1: Per-phase equivalent circuit of a round-rotor synchronous machine with excitation circuit [36]

Two main types of synchronous machines exist; round-rotor and salient-pole machines. A round-rotor machine has few magnetic poles, and rotate with high-speed, for instance driven by gas or steam turbines. A salient-pole machine has many poles, and rotates slower. Slower rotation implies increasing rotor diameter. Salient-pole machines are driven by, for instance, large hydroelectric turbines.

In a round-rotor machine, the air gap is uniform, while in a salient-pole machine the air gap varies circumferentially around the machine. To represent the varying air gap flux of a salient-pole machine a transformation, which decomposes the mmf (magnetomotive force) acting along the d- and q-axis is performed [27]. By the decomposing into d- and q-axis, figure 4.2 illustrates an equivalent circuit diagram of a salient-pole machine.

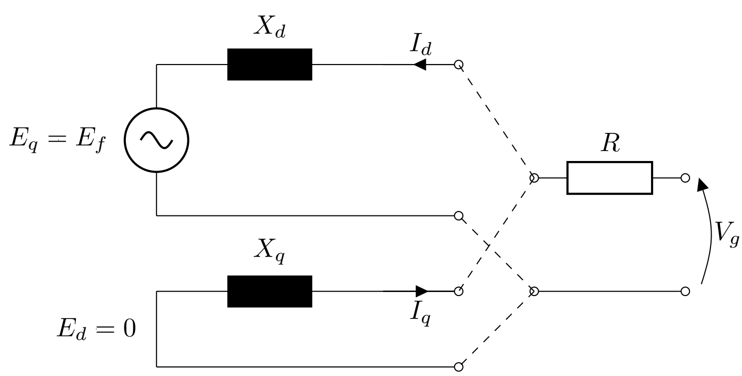

Figure 4.2: Per-phase equivalent circuit of a salient-pole synchronous machine [27]

4.2.1 Active and reactive power

Consider the equivalent diagram of the round-rotor machine in figure 4.1. By neglecting the series resistance, active and reactive power from the machine is given by equations 4.1 and 4.2, respectively.

$$P = \frac{E_f \cdot V_g}{X_d} \cdot \sin\delta \tag{4.1}$$

$$Q = \frac{E_f \cdot V_g}{X_d} \cdot \cos\delta - \frac{V_g^2}{X_d} \tag{4.2}$$

The angle δ is the angle between the voltages E_f and V_g.

4.2.2 Voltage control

Controlling the first term in equation 4.2, the machine may both supply and consume reactive power. If the machine is consuming reactive power, the machine is working in underexcited mode of operation. If the machine is supplying reactive power, the machine is working in overexcited mode of operation [27]. Therefore, by controlling the current supplied to the field winding, the machine terminal voltage is controlled. The field current regulation is the task of the automatic voltage regulator (AVR).

Demands regarding design and performance of AVR in Norway, are found in [37].

4.3 Induction machine

Induction machines are widespread used in the power system. The main use of induction machines are as motors, but they are for instance used as generators in some wind farms. In principal, the induction machine is a transformer with a rotating secondary winding. Figure 4.3 illustrates an approximated equivalent diagram of an induction machine [27].

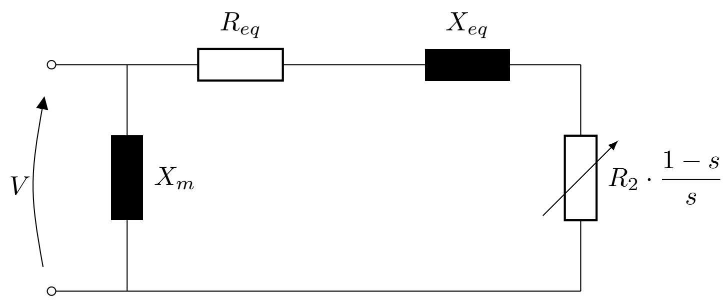

Figure 4.3: Per-phase equivalent circuit of an induction machine [27]

The angular electrical synchronous speed is $\omega_s = 2\pi \cdot f = \omega_{sm} \cdot p$, in which p is the number of pole pairs in the machine. The rotor electrical angular frequency is $\omega_r = \omega_{rm} \cdot p$. The relation between the rotor angular frequency and the angular synchronous speed is known as slip, and is given in equation 4.3.

$$s = \frac{\omega_s - \omega_r}{\omega_s} \tag{4.3}$$

Positive value of the slip corresponds to motoring mode of operation, while negative value of the slip corresponds to generator mode of operation. As seen from the figure, the induction machine always draw magnetizing current. From a power system view, the induction machine is always a sink of reactive power, and can be both a source and a sink of active power.

Due to the nature of the induction machine, it has no voltage control capability.

4.4 Power electronic interfaced DG

In contrast to rotating machinery connected directly to the grid, power electronic interfaced DG do not add inertia to the power system. No inertia is added because either the DG produces DC-power, or the mechanical rotor speed of the DG is decoupled from the frequency of the grid through power electronic interface [38]. Figure 4.4 and 4.5 illustrates the two above-mentioned ways of power electronic interfaced DG.

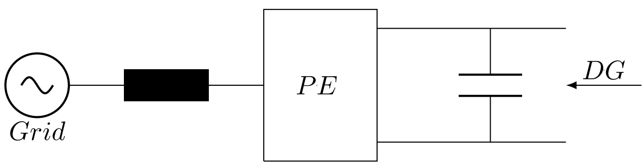

Figure 4.4: DG with DC power output connected to the grid through power electronic interface

Example of DG producing DC power is photovoltaic. In addition, the principal schematic in figure 4.4 can be used with a bidirectional power flow. As the power electronic interface may manage bidirectional power flow, for instance battery storage systems may be connected in a similar manner [39].

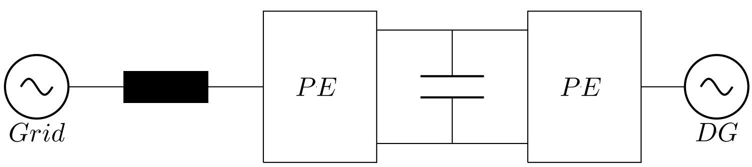

Figure 4.5: Rotating machinery connected to the grid through power electronic interface

Figure 4.5 illustrates a rotating machine decoupled from the grid through power electronic. The two power electronic converters are denoted as back-to-back coupled. An example regarding use of rotating machinery connected to the power system through power electronic interface, is wind power turbine systems with full rated power electronic converters. The back-to-back power electronic converters is used in order to achieve full control of active and reactive power. As the rotating machinery has the opportunity of operating at a wide operational range decoupled from the grid, independent control of active and reactive power is seen as advantageous, compared to directly connected rotating machinery [40].

4.5 Representation of generators in power flow calculations

Active and reactive power at bus i are given by equation 4.4 and 4.5, respectively. $|Y_{ij}| \angle\theta_{ij}$ is element of the bus admittance matrix.

$$P_i = \sum_{j=1}^{n} |V_i||V_j||Y_{ij}|cos(\theta_{ij} - \delta_i + \delta_j) \tag{4.4}$$

$$Q_i = -\sum_{j=1}^{n} |V_i||V_j||Y_{ij}|sin(\theta_{ij} - \delta_i + \delta_j) \tag{4.5}$$

Equation 4.4 and 4.5 are nonlinear algebraic equations, in which voltage magnitude and voltage angle are independent variables. Expanding the equations with Taylor's series and neglecting higher order terms give equation 4.6 [32]. The matrix containing partial derivatives is known as the Jacobian-matrix, and give the linearized relationship between small changes in voltage angle and voltage magnitude with the small changes in active and reactive power [32].

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} \end{bmatrix} \cdot \begin{bmatrix} \Delta \delta \\ \Delta V \end{bmatrix} \tag{4.6}$$

Four variables are present in the two equations 4.4 and 4.5. The four are active power P_i, reactive power Q_i, voltage magnitude $|V_i|$ and voltage angle δ_i. For solving the two equations 4.4 and 4.5, it is necessary to specify two out of the four variables. Buses are generally classified into three types [32]:

- **Swing bus.** The swing bus is the reference bus, in which voltage magnitude $|V_i|$ and voltage angle δ_i are specified
- **PV bus.** A PV bus is specified with the active power P_i and voltage magnitude $|V_i|$
- **PQ bus.** Active power P_i and reactive power Q_i are specified at a PQ bus

For representation of DG in power flow calculations, they are in this thesis assigned as both PQ and PV generators in different calculations.

Chapter 5

Network studies

5.1 Network model

A model of a simplified radial distribution network is established in DIgSILENT PowerFactory. The model contains an external network feeding two loads and two DG units through an OLTC transformer. Line segments separates the buses. Loads and DG units are connected to the buses. The distribution network model is illustrated in figure 5.1. The voltage level of the external network is 132 kV, while voltage level at the distribution network is 22 kV. The model is developed and chosen as it illustrates the typical challenges related to integration of DG in distribution network.

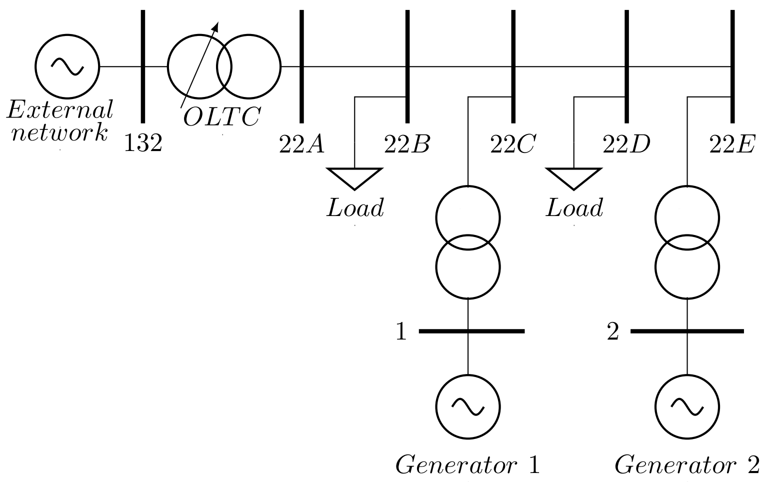

Figure 5.1: Simplified radial distribution network model used for study

5.1.1 Generator

The generators used in the model in figure 5.1 are synchronous generators. The generators are equal, and specific generator data can be found in Appendix A.4. The generators have a rated capacity of S = 16 MVA.

Voltage control of generator

Voltage control of the generators in dynamic simulation are performed with automatic voltage regulator (AVR) or power factor (PF) regulation. Details regarding the regulators are given in Appendix A.4.

5.1.2 Line

The network model has line segments between the buses. Each line segment in figure 5.1 is 5 km. Total line length from bus $22A$ to bus $22E$ is 20 km. The line has an X/R ratio of approximately 1. Data for the line can be found in Appendix A.3. Line model used in DIgSILENT PowerFactory is a PI-equivalent.

5.1.3 Transformer

The OLTC equipped transformer has rated capacity S = 50 MVA, and the step-up transformers have rated capacity S = 20 MVA. Transformer data and information regarding tap-changer modeling can be found in Appendix A.5. Tap step size for the OLTC transformer is 1.5 %. Transformers are represented with their short circuit impedance.

5.1.4 Load scenarios

The loads in the network are considered with voltage independent characteristic. For each load, values for high and low load are given in table 5.1. Low load is given as 20 % of high load.

Table 5.1: Values for each load at low and high load situation

	P [MW]	Q [MVAr]
High load	5	1.67
Low load	1	0.33

5.2 Challenges related to voltage level

Consider the network depicted in figure 5.1 and high load situation with no DG production in the network. To ensure proper voltage levels within the limits, it is necessary to compensate for the voltage drop along the line. Therefore, voltage is raised at the OLTC transformer secondary side. With a passive approach for voltage regulation, this operational situation decides the tap-changer setup. Hence, the tap-changer are set to maintain the voltage needed at a high load situation for compensating the voltage drop. This ensures that the voltage is within the required limits at the line end.

During low load situation the voltage drop is less, compared to high load. Consider the network in a low load operational situation and with the DG units producing active power. If the passive voltage control approach applies, voltage at the transformer secondary side is set to compensate for high load voltage drop. DG production may involve voltage rise. A voltage rise in addition to a high voltage at the main transformer secondary side may cause violation of the voltage level limits. Figure 5.2 illustrates the voltage level challenge.

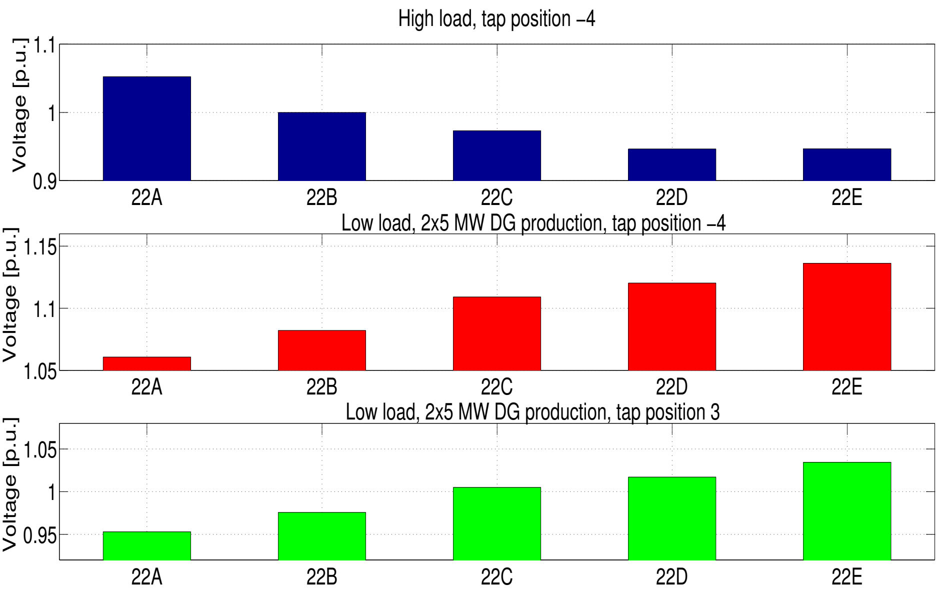

Figure 5.2: Voltages at network buses at different operational situations

Upper subfigure in figure 5.2 consider high load situation, with no DG production present in the network. Tap-changer position is -4. The voltage at the secondary side at the OLTC transformer has the relatively highest value. It is a distinct voltage drop along the line. Middle subfigure consider low load situation with the DG units producing 5 MW each ($cos\phi = 1$). The tap-changer position is the same as for high load situation in the upper subfigure (-4). Compared to the upper subfigure, it is a significant voltage rise along the line. The voltage level at three of the buses are outside the ± 10 % voltage band. In the lower subfigure of figure 5.2, voltage at the buses are within ± 5 %, facilitated by the tap-changer. Tap-changer position is adjusted to 3. The DG units produces 5 MW each ($cos\phi = 1$). Adapting to the operational situation in the network, effective voltage regulation with the OLTC transformer is possible, illustrated by figure 5.2.

Figure 5.3 illustrates tap-changer control, tap-changer position, and voltage at buses in the network for illustration when a conventional transformer voltage control is used. Voltage control measures voltage at transformer secondary side, and compares to a reference value. Voltage set-point is 1.0 p.u. and deadband is 0.02 p.u. These values are seen in the upper subfigure of figure 5.3. Production for the DG units at low load is 2x5 MW ($cos\phi = 1$). During the simulation, the generators are disconnected and loading is ramped from low to high demand. Voltage at bus $22E$ is high during low load, and low at times of high load demand. If a limit of maximum of ± 5 % of voltage variation are desired, figure 5.3 illustrates a network whose voltage control should be revised. ± 5 % is chosen as the maximum allowable voltage deviation due to a margin of safety for voltage deviation in a thought LV network. Table 5.2 holds the events used in the dynamic simulation.

Table 5.2: Dynamic simulation events

Event	Time[s]
Disconnection of generators	t = 200
Start load ramp (+400 %)	t = 400
End load ramp	t = 800

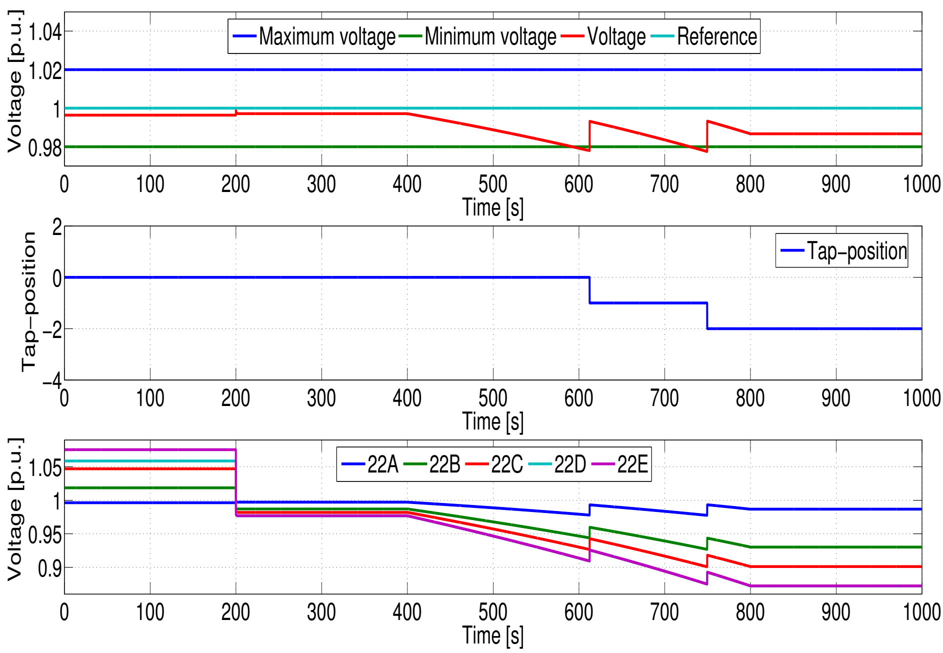

Figure 5.3: Conventional transformer voltage control. Upper: Tap-changer control. Middle: Tap-changer position. Lower: Network voltages

Due to their nature, synchronous generators may help regulate voltage control in the network. Figure 5.4 shows the voltages in the network when the synchronous generators have significant reactive power capability, and thereby help keep the voltage at a predefined value. The transformer tap-position is the same as for high load situation in the upper subfigure in figure 5.2 (-4). Seen from the figure, all voltages at the buses are within the stated ±5 % voltage maximum deviation. However, the reactive power consume at both generators are more than 3 MVAr, which is a high consume of reactive power for a generator producing 5 MW. Thereby, it is unreasonable to rely on such a voltage regulation. In addition, high reactive power consumptions imply increased losses due to transportation of reactive power.

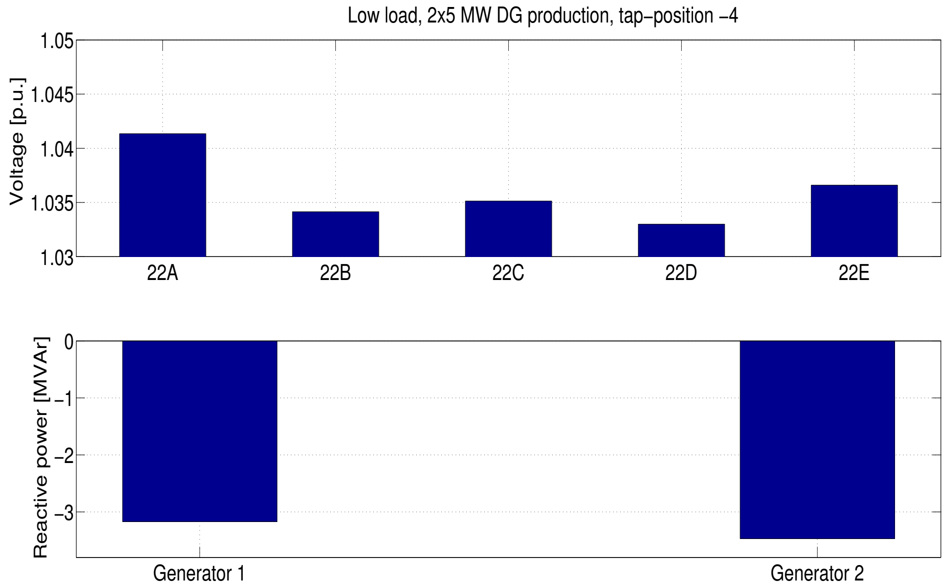

Figure 5.4: Low load. Upper: Voltage at buses. Lower: Synchronous generators capable of reactive power consume

5.2.1 Challenge with line drop compensation

Line drop compensation (LDC) is used to compensate for a voltage drop along a feeder. If an assumption regarding power flow in one direction is made, LDC may use absolute value of the line current. Voltage used for tap-changer control is given by equation 5.1.

$$V_C = |V_{meas} + (R_C + jX_C) \cdot |I_{meas}|| \tag{5.1}$$

Table 5.3 holds the R and X used for compensation of the voltage drop along the line. The values is used to compensate for a voltage drop approximately 7 km out on the line, hence they are negative. V_{meas} is measured voltage at the transformer secondary side.

Table 5.3: Parameters used for line drop compensation

R	X
-0.25	-0.25

Figure 5.5 illustrates the challenge related to use of absolute value of current with LDC, in a network with DG. Upper subfigure illustrates voltage at network buses with a load ramp from low to high load condition, without DG production. Middle subfigure illustrates voltage at the buses with increased DG production at low load condition. Lower subfigure contains tap-changer position for the two above-mentioned situations.

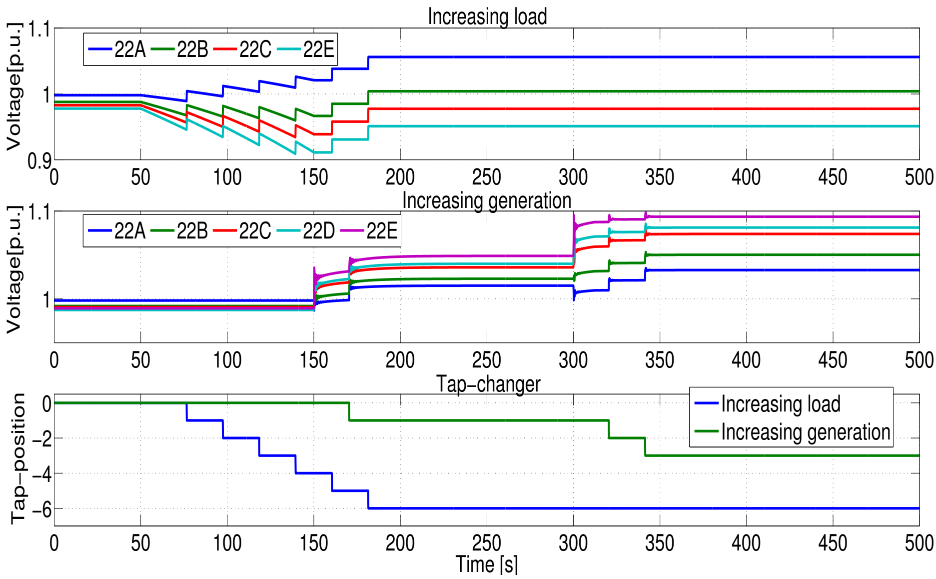

Figure 5.5: Voltage and tap-changer position with LDC using absolute value of line current

In upper subfigure in figure 5.5, voltage is increased to compensate for the simulated voltage drop. The voltage drop compensation is working as intended. In the middle subfigure DG production is increased in steps. Initial production at both generators is 0.5 MW, then at t = 150 it is increased to 2.5 MW, and finally at t = 300 production is increased to 5 MW. During low load and full DG production in the middle subfigure, active power flow is towards the overlaying network. With the reverse active power flow, voltage is increasing along the line. The LDC does not see the way of the power flow, as it only sees the absolute value of the current. As the current related to the reverse active power flow is of a substantial value, the tap-changer control sees this as an increase in load. Hence, LDC helps the tap-changer raise the voltage further in the network, when the load is low and DG production is present.

Clearly, use of absolute value of the line current for voltage compensation causes erroneous tap-changer operation at low load conditions and high share of DG production.

5.3 Transformer voltage droop control scheme

Figure 5.6 illustrates the characteristic for a possible voltage droop control scheme for a transformer. In figure 5.6, the droop control is a relation between the active power flow through the transformer, and voltage at the secondary side of the transformer. The figure is a simplification because it does not take into consideration the discontinuity of the tap-changer. Positive flow of active power is into the transformer secondary side. Thus, high load situation with no DG production gives the most negative value for the active power flow. Low load situation with maximum DG production gives the most positive active power value.

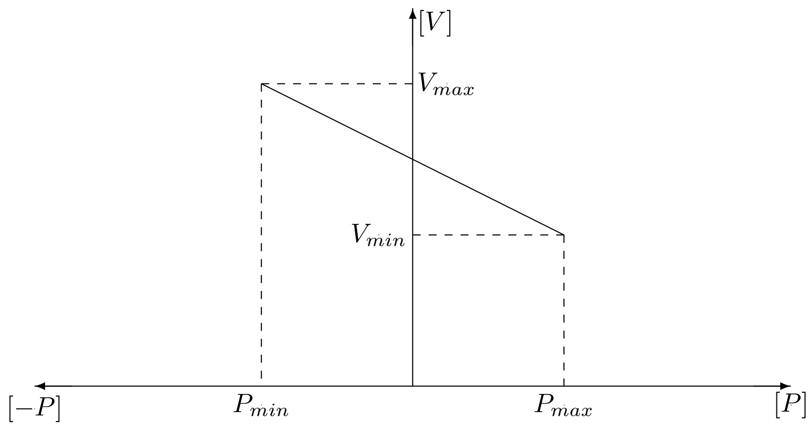

Figure 5.6: Thought characteristic of a transformer voltage droop control scheme

It is desirable to obtain an active power versus voltage relation of the transformer secondary side. Active power export is related to high voltage level in the network, and active power import is related to low voltage level at the end of the line. The relation between high active power import/export and low/high voltage level is illustrated in figure 5.2.

5.3.1 Control method

The voltage droop control of the transformer utilizes measurements of voltage and current at a chosen placement in the grid. In the radial distribution network illustrated in figure 5.1, the measurements are at the secondary side of the transformer.

To get the tap-changer to adjust its tap position according to the power flow through the transformer, it is necessary to manipulate the voltage used for controlling the tap-changer. Hence, the control voltage should be a function of the power flow through the transformer. It is desirable to increase the voltage at secondary side at times of active power import to the network, and decrease voltage at times of active power export. By manipulating the measured voltage with current multiplied with compensation parameters, the transformer can raise or lower its tap-position based on measured voltage and power flow.

A droop slot is inserted in the transformer control. Input values to the droop slot are measured values for real and imaginary voltage and current, in addition to compensation parameters R and X. Appendix A.5.2 contains detailed information regarding the tap-changer modeling in DIgSILENT PowerFactory.

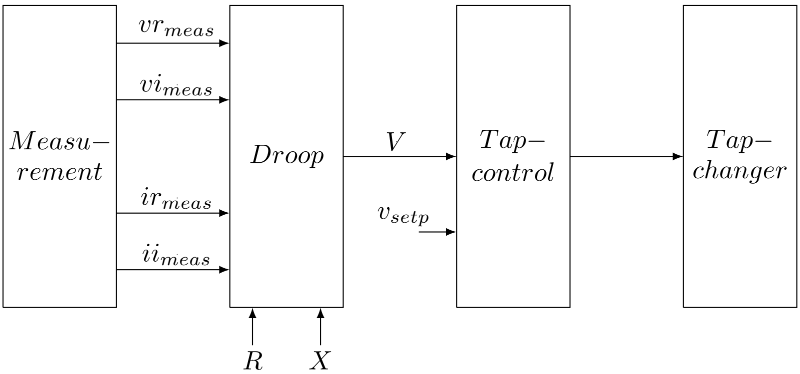

Figure 5.7: Block diagram of the transformer voltage droop control

5.3.2 Mathematical description

The voltage from the droop control, illustrated in figure 5.7, is given by equation 5.2.

$$V = \sqrt{(Vr)^2 + (Vi)^2} \tag{5.2}$$

Vr and Vi are given by equations 5.3 and 5.4.

$$Vr = vr_{meas} + ir_{meas} \cdot R - ii_{meas} \cdot X \tag{5.3}$$

$$Vi = vi_{meas} + ii_{meas} \cdot R + ir_{meas} \cdot X \tag{5.4}$$

vr_{meas} and vi_{meas} are measured real and imaginary voltage, respectively. ir_{meas} is the measured real current, and ii_{meas} is the measured imaginary current. Voltage over an impedance is illustrated in Appendix F.1.

The desired real and imaginary voltage subtracted the measured voltages give the wanted contributions from the droop control, and are illustrated in equations 5.5 to 5.8.

$$Vr - vr_{meas} = ir_{meas} \cdot R - ii_{meas} \cdot X \tag{5.5}$$
$$\Delta Vr = ir_{meas} \cdot R - ii_{meas} \cdot X \tag{5.6}$$

$$Vi - vi_{meas} = ii_{meas} \cdot R + ir_{meas} \cdot X \tag{5.7}$$
$$\Delta Vi = ii_{meas} \cdot R + ir_{meas} \cdot X \tag{5.8}$$

Equation 5.6 and 5.8 can be rearranged and written on matrix form, shown with equation 5.9.

$$\begin{bmatrix} \Delta Vr \\ \Delta Vi \end{bmatrix} = \begin{bmatrix} ir_{meas} & -ii_{meas} \\ ii_{meas} & ir_{meas} \end{bmatrix} \cdot \begin{bmatrix} R \\ X \end{bmatrix} \tag{5.9}$$

Equation 5.10 illustrates how the droop parameters R and X can be calculated when the currents are known, together with the desired voltage contribution of the droop control.

$$\begin{bmatrix} R \\ X \end{bmatrix} = \begin{bmatrix} ir_{meas} & -ii_{meas} \\ ii_{meas} & ir_{meas} \end{bmatrix}^{-1} \cdot \begin{bmatrix} \Delta Vr \\ \Delta Vi \end{bmatrix} \tag{5.10}$$

5.3.3 Approximation and test of droop parameters

It is necessary to decide in which operational situation the droop control should have the most impact on the transformer tap-position. This operational situation is either low load condition with maximum DG production, or high load situation with no DG production.

Some assumptions are made in order to approximate the droop parameters. An assumption is that the current through the transformer does not change with adjusted tap-positions. The currents used for calculations are the values obtained whit the transformer tap-changer in neutral position. Another assumption is all compensated voltage, is of purely real value. Thus, $\Delta V_i = 0$.

Consider the network in figure 5.1. With high load and no production in the network, and with the tap-changer in neutral position, the lowest voltage in the network is 0.87 p.u. If the desired voltage band is $Vn \pm 5$ %, the voltage should be raised 0.08 p.u. The current values with the transformer in initial position is $ir_{meas} = -0.22$ p.u. and $ii_{meas} = 0.09$ p.u. The positive direction is towards the external network, thus $\Delta Vr = -0.08$ and $\Delta Vi = 0$. The voltage and current values give:

$$\begin{bmatrix} R \\ X \end{bmatrix} = \begin{bmatrix} -0.22 & -0.09 \\ 0.09 & -0.22 \end{bmatrix}^{-1} \cdot \begin{bmatrix} -0.08 \\ 0 \end{bmatrix} = \begin{bmatrix} 0.3115 \\ 0.1274 \end{bmatrix} \tag{5.11}$$

The droop parameters calculated are $R = 0.3115$ and $X = 0.1274$.

Test of droop parameters

Testing of the transformer droop control with parameters $R = 0.3$ and $X = 0.1$ under different operation scenarios are performed. Tap-changer setup are found in Appendix A.5.1.

Figure 5.8 illustrates voltages at the buses in the network. Upper subfigure shows voltages at the buses under high load situation, with no DG production in the network. Seen from the figure, the voltage is raised at the secondary side of the OLTC equipped transformer. It is a significant voltage drop along the line, and lowest voltage are observed at the end of the line. The lower subfigure illustrates the voltages at the buses at low load situation, with 2x5 MW DG production ($cos\phi = 1$). The OLTC equipped transformer here lower the voltage level at the secondary side of the transformer. The highest voltage are observed at the bus at the end of the line.

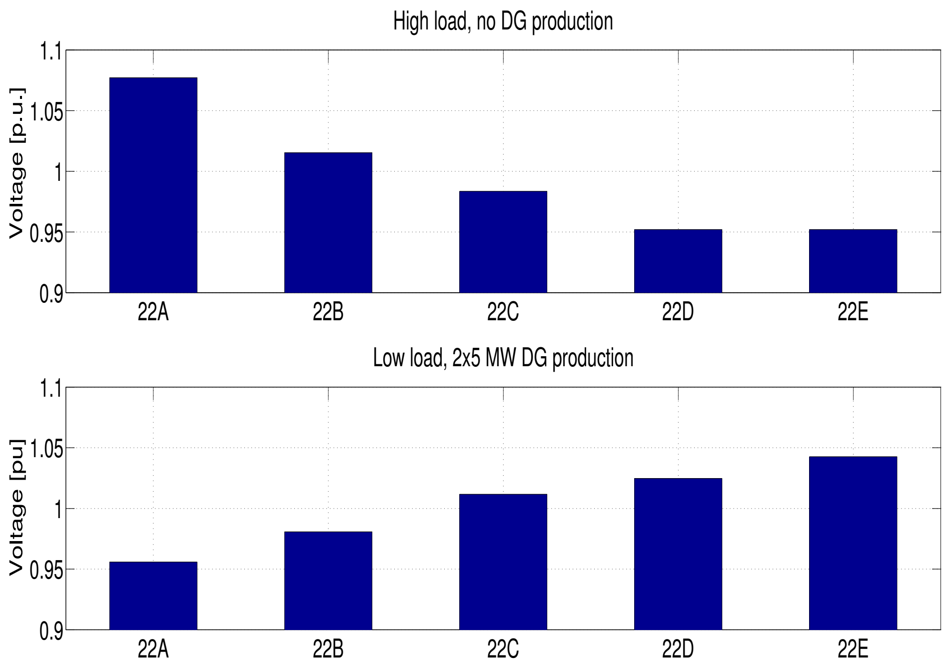

Figure 5.8: Voltage at buses in the network at high and low load situation under test of transformer droop parameters

The droop control helps to increase the voltage at transformer secondary side at high load, and decrease voltage at low load and high share of DG production, illustrated in figure 5.8. This test illustrates the principal behavior of the droop control, and it can be used in distribution networks with DG production.

Figure 5.9 shows the transformer tap-changer position under the two different operational situations tested. At the low load situation with DG production, the tap-changer position is 3. At high load situation without DG production, the tap-changer position is -6.

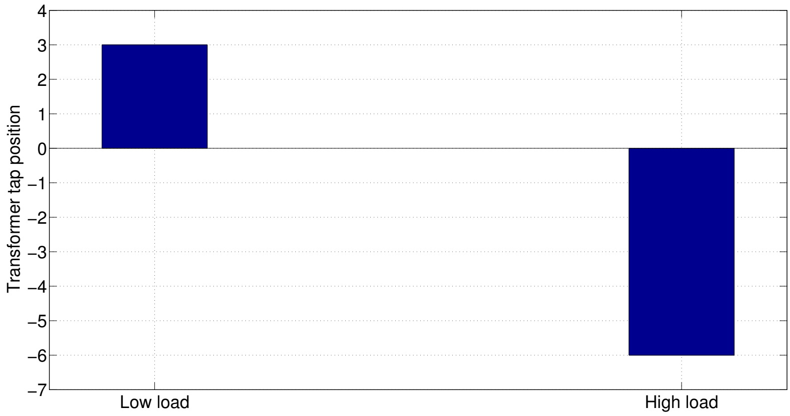

Figure 5.9: Transformer tap-position for test at low and high load

5.3.4 Transformer droop parameters based on optimal power flow

In section 5.3.3 the transformer droop parameters, R and X, were obtained by using equation 5.10, and stating a voltage rise at 0.08 p.u. from initial position at high load situation.

With respect to loss reduction, optimal power flow (OPF) for high load without DG production, and for low load situation with DG production are carried out. OPF calculates the optimal tap-changer position. The objective function of the OPF is to minimize losses. At low load situation the DG production is 2x5 MW ($cos\phi = 1$).

Table 5.4 is a summary of the OPF results. Complete OPF results can be found in Appendix B.1.1. The results from OPF shows equal tap-changer position to the one obtained in section 5.3.3 for high load situation, while at low load situation the tap-changer position has one tap-step difference.

To get the tap-position at tap-step 2, the maximum voltage on the tap-changer (v_{max}) is adjusted from 1.01 p.u. to 1.02 p.u., and the minimum voltage (v_{min}) is lowered from 0.99 p.u. to 0.98 p.u. All tap-changer settings are found in the table in Appendix A.5.1. The change in the voltage v_{max} results in a tap-changer position at step 2 at low load situation with 2x5 MW ($cos\phi = 1$) DG production. Figure 5.10 illustrates the behavior of the transformer voltage droop when testing the transformer voltage control droop scheme with dynamic simulation. Table 5.2 holds events used in the dynamic simulation.

Table 5.4: Summary of OPF results

	High load	Low load
Tap-position	-6	2
Voltage bus 22A	1.088	0.967
Voltage bus 22B	1.038	0.99
Voltage bus 22C	1.012	1.019
Voltage bus 22D	0.986	1.031
Voltage bus 22E	0.986	1.048
Gen 1 [MW]	-	5
Gen 1 [MVAr]	-	0
Gen 2 [MW]	-	5
Gen 2 [MVAr]	-	0

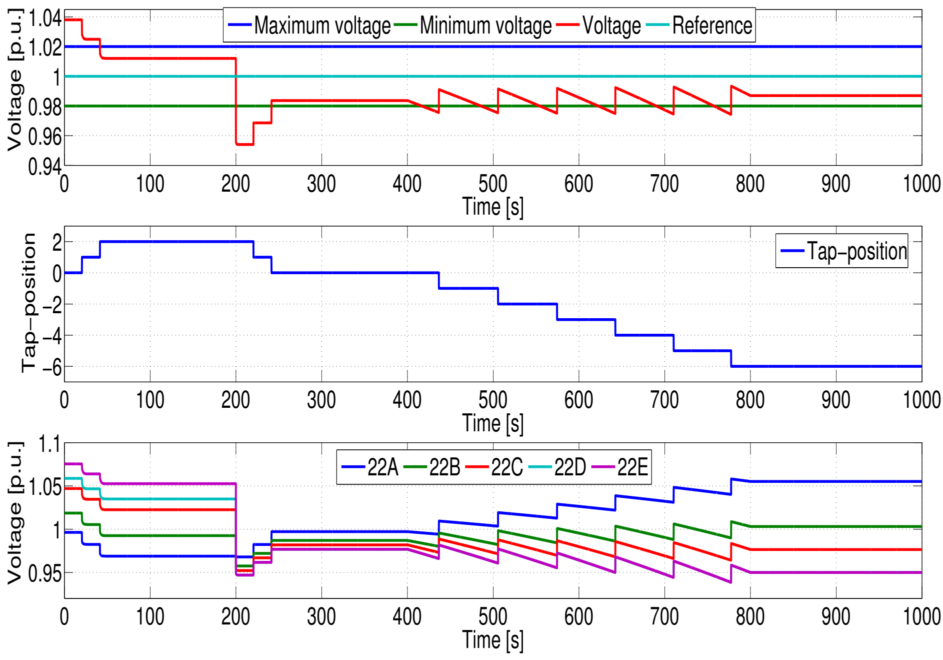

Figure 5.10: Dynamic simulation for test of transformer voltage droop. Upper: Tap-changer control. Middle: Tap-changer position. Lower: Network voltages

The upper subfigure shows all relevant voltages regarding the tap-changer as function of time. Middle subfigure illustrates tap-changer position as function of time, while the lower subfigure in figure 5.10 illustrates voltage at the network buses.

The initial load of the network is low load condition, and DG production is 2x5 MW ($cos\phi = 1$). Tap-position in initial state is neutral position. The droop control brings the tap-position to tap-step 2 ($40 < t < 220$). At t = 200 the generators are disconnected. The droop control brings the tap-position back to neutral tap-position. At t = 400 a load ramp from low load to high load situation is started. The load ramp has a ramping time of 400 seconds. The droop control are working as intended, and brings the tap-position at tap-step -6 after the load ramp is carried out. The voltage used for tap-changer decision is illustrated in the upper subfigure. In figure 5.3 the voltage is equal to voltage at bus $22A$. In upper subfigure of figure 5.10 the voltage used for tap-changer decision is not equal to voltage at bus $22A$, as it is compensated by the current and parameters.

5.4 Generator modeling

5.4.1 Generators in AVR or PF regulation mode

Dynamic simulations are performed to illustrate influence of DG on tap-changer operation. Synchronous generators are represented with AVR and PF regulator in different simulations. Separate simulations are carried with increase in load demand, and increase in power production. Table 5.5 and 5.6 hold the simulation events used for increase in load and power production, respectively.

Table 5.5: Dynamic simulation events with increased load

Event	Time[s]
Start load ramp (+400%)	t = 150
End load ramp	t = 250

Initial production of the generators is 0.5 MW at the simulations with increased production. At t = 150, active power production is stepped up to 2.5 MW by the torque input event. At t = 300 active power production is stepped by the torque input event to 5 MW.

Table 5.6: Dynamic simulation events with increased production

Event	Time[s]
Torque input = 0.2 p.u.	t = 150
Torque input = 0.4 p.u.	t = 300

Figure 5.11 illustrates voltage at buses $22B$ and $22D$, in addition to tap-changer position for the different simulations. Labels marked ”load” are simulations with increased load, while labels marked ”prod” are simulation with increased production.

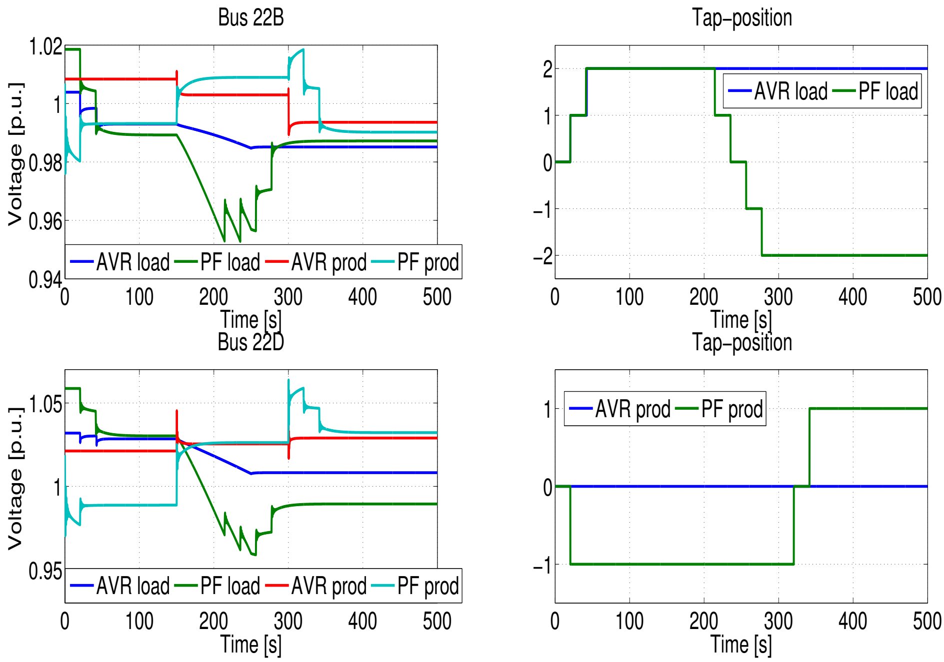

Figure 5.11: Voltage at bus 22B, 22D and tap-position with generators in AVR or PF mode

By use of PF regulation on the synchronous generators, the number of tap-changer operations is higher, compared when the generators are operated in AVR mode, seen from figure 5.11. It is a difference of four tap-changer operations when operated in PF regulation instead of AVR mode during the simulation in which the load is increased from low to high load. For the simulation in which the production is increased, PF regulation makes three tap-change operations, while in AVR mode no tap-change is observed. Both AVR mode and PF regulation in cooperation with transformer droop voltage control are feasible solutions for keeping the voltage inside the required limits.

5.4.2 Disconnection of generators

Figure 5.12 illustrates tap-changer position with different generator regulation during disconnection of the generators. Upper subfigure illustrates the tap-changer position when disconnecting generator 1 at t = 200. Lower subfigure illustrates tap-changer behavior when disconnecting generator 2 at t = 200.

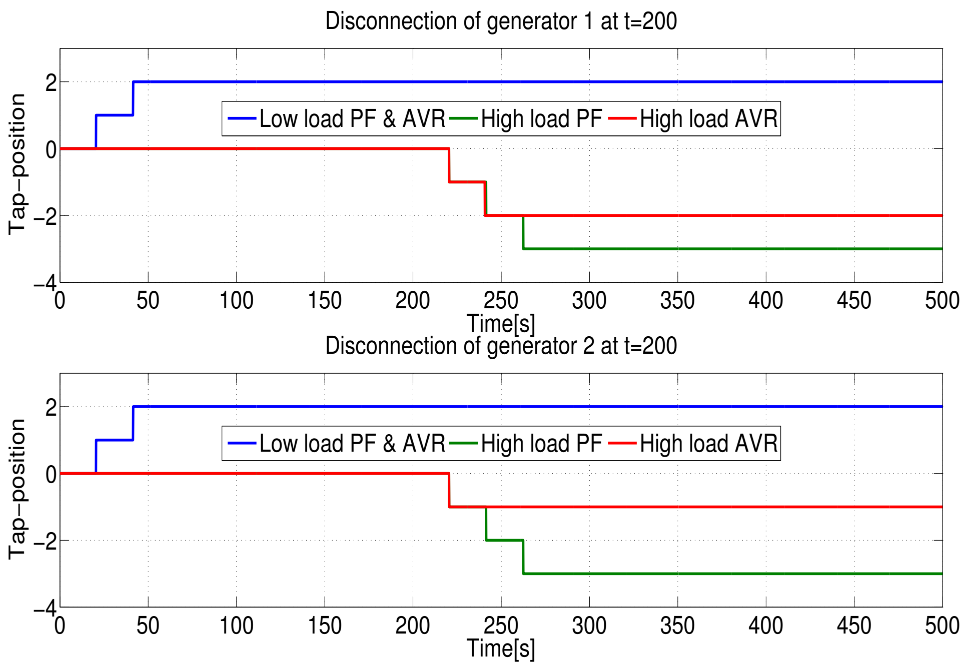

Figure 5.12: Tap-changer positions with different generator modeling

When the generators are operated in AVR mode, they provide voltage support and tap-changer operation are influenced the least. At all low load scenarios, tap-changer position is not influenced by disconnection of a single generator. The difference in tap-changer position when the units are regulated with PF-regulator, is due to the distance from the tap-changer to generator 1. Seen from lower subfigure, generator 1 helps keep the voltage higher when disconnecting generator 2, and thereby less tap-changer operations, compared to the upper subfigure when generator 1 is disconnected.

5.5 Difference between use of LDC and proposed droop control method

Line drop compensation (LDC) is used to simulate a measured voltage at some remote point in the network. For compensation, the line impedance between the actual measurement point and the virtual measurement point is used as the value for the compensation impedance. The proposed droop control scheme determines a desired contribution at a given operational situation, with some assumptions. In principal is LDC a droop control scheme, but to separate the two approaches they are denoted differently.

Line drop compensation

Consider the simplified distribution network in figure 5.1. Bus $22C$ is chosen for remote voltage control through line drop compensation. Line length is 10 km. The impedance between the transformer and bus $22C$ is given by equation 5.12.

$$
\begin{aligned}
Z_{LDC} &= (0.36 + j0.38) \cdot 10 = 3.6 + j3.8 \\
Z_{LDC_{p.u.}} &= \frac{3.6 + j3.8}{\frac{22^2}{50}} = 0.37 + j0.4
\end{aligned}
\tag{5.12}
$$

The per-unit impedance is used as parameters for the LDC.

Droop control

As seen earlier, high load condition is used for determination of R and X, with values of 0.3 and 0.1, respectively. Voltage contribution by the droop control at high load, is only real value.

Droop control with X = 0

Examining the tap-changer behavior with compensation parameters R = 0.3 and X = 0. As active power flow is closely related to real current value, the compensation reactance X is set equal to zero. It implies that it does not exist a relation between imaginary current and real voltage contribution from the droop control.

Comparison

To compare the three different parameter approaches, and thereby tap-changer operation, their contribution to tap-changer control is treated. Figure 5.13 illustrates real and imaginary voltage contribution from the control at high active power demand, as function of imaginary current. The imaginary current simulate increasing reactive power demand. Positive direction is into the secondary side of the transformer. Flow of reactive power is towards the loads. The real current is fixed at high load, and implies no DG production. Negative voltage contribution simulate voltage drop along the line. Current is given by equation 5.13, for simplicity V = 1.0 p.u. For the case of import of reactive power, imaginary current is positive

$$
\begin{aligned}
I &= \frac{S^*}{V} \\
I_r \mp j \cdot I_i &= P \pm j \cdot Q
\end{aligned}
\tag{5.13}
$$

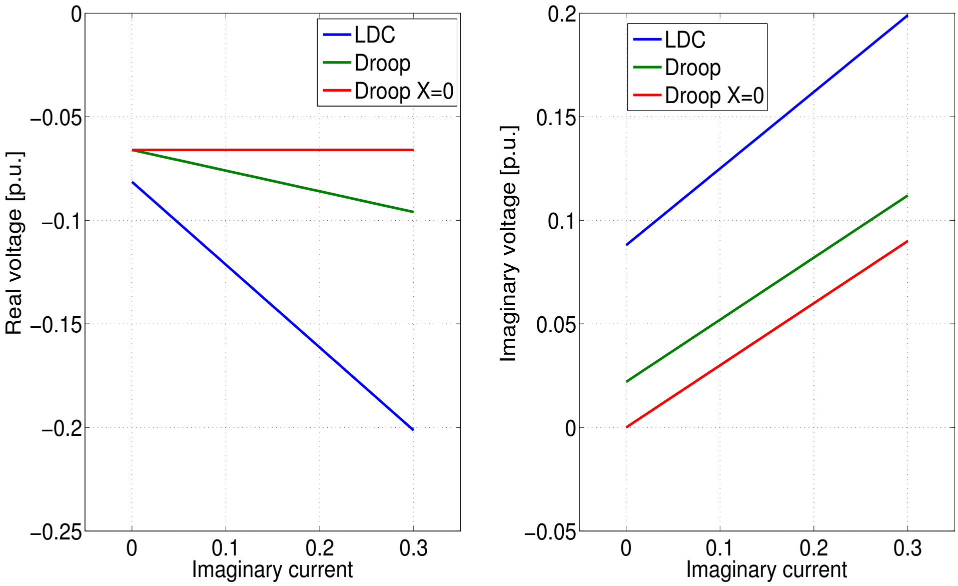

Figure 5.13: Real and imaginary voltage contribution of tap-changer control at high active load and increasing imaginary current

Figure 5.13 illustrates the difference in contribution by use of different parameters at high active power load. Real voltage contribution from the droop parameters determined by a linearization at high load, is more independent of reactive power flow than the use of line impedance value. Real voltage contribution is independent of the imaginary current with the droop parameters in which $X = 0$. The magnitude of imaginary voltage contribution is greater than the real voltage contribution. However, the real value is of greater importance since the real voltage value in the power system is normally of a much larger value than the imaginary.

To evaluate the three different parameter approaches further, low active power load with increasing reactive power demand is considered. Figure 5.14 illustrates real and imaginary voltage contribution at low load. At low load it is full DG production and thereby export of active power, which implies a positive real current value. The real voltage contribution with LDC has a much steeper decrease with increased reactive power demand. At about a reactive power flow of 0.15 p.u., the LDC simulates a voltage drop along the line, while the droop control simulates a voltage rise. Voltage rises along the line at times of low load and full DG production, seen in figure 5.2. If the tap-changer control utilizes the LDC control, it may lead to a further voltage increase in the network.

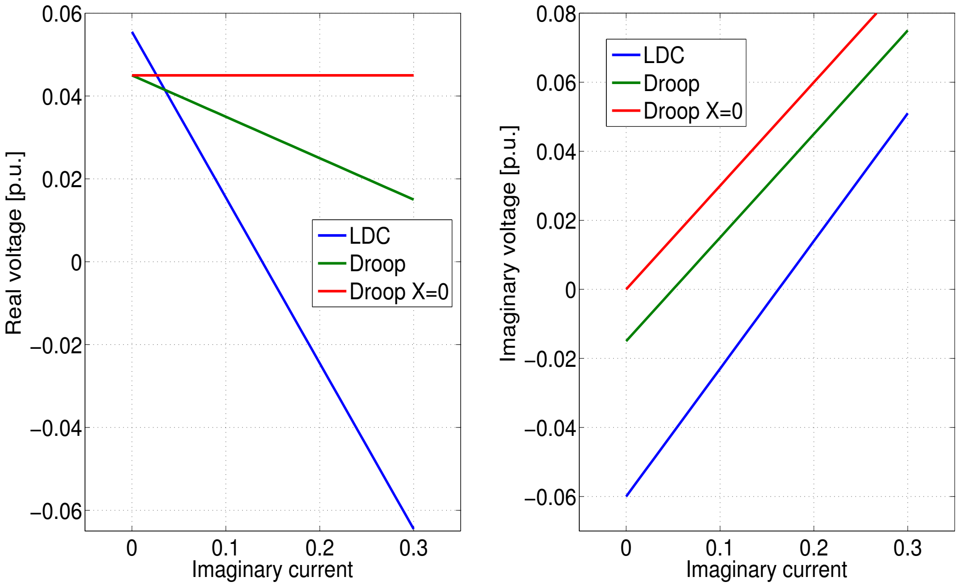

Figure 5.14: Real and imaginary voltage contribution of tap-changer control at low active load and increasing imaginary current

Dynamic simulations are carried out to illustrate the difference by use of line impedance, parameters determined by desired contribution, or parameters in which X = 0. Table 5.7 holds cases used for simulation. The simulation has a load ramp from low to high load. The load ramp is started at t = 100, and has a ramping time of 400 seconds. Results from the different cases simulated are illustrated in figure 5.15.

Table 5.7: Cases simulated to illustrate difference regarding LDC/droop control parameters

Case	Tap-changer parameters (R/X)	Generator 1	Generator 2
A	Droop, 0.3/0.1	5 MW, $cos\phi = 1$	5 MW, $cos\phi = 1$
B	LDC, 0.37/0.4	5 MW, $cos\phi = 1$	5 MW, $cos\phi = 1$
C	Droop, 0.3/0.1	5 MW, V=1.0 p.u.	5 MW, V=1.0 p.u.
D	LDC, 0.37/0.4	5 MW, V=1.0 p.u.	5 MW, V=1.0 p.u.
E	Droop, 0.3/0	5 MW, $cos\phi = 1$	5 MW, $cos\phi = 1$
F	Droop, 0.3/0	5 MW, V=1.0 p.u.	5 MW, V=1.0 p.u.

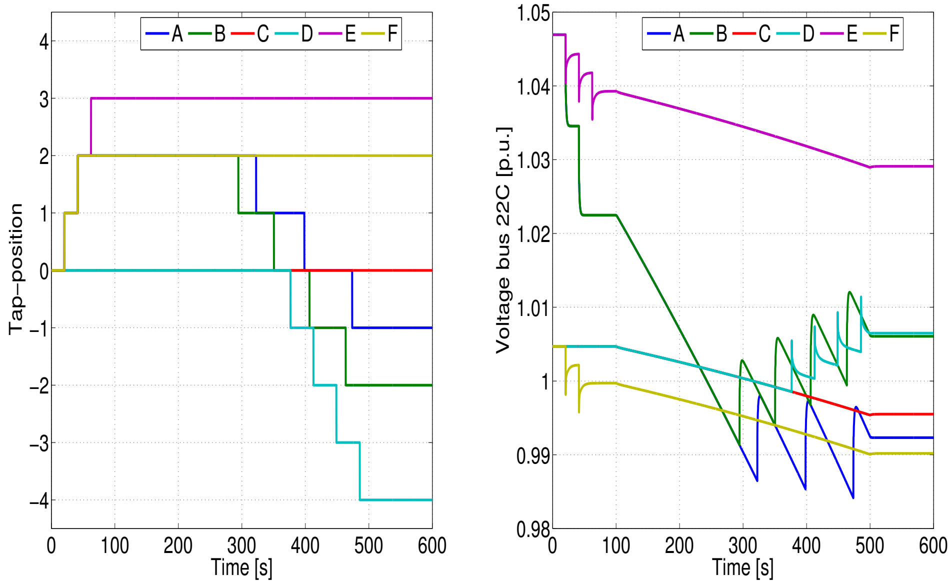

Figure 5.15: Tap-changer operation and voltage at bus 22C with LDC and droop control

Left subfigure illustrates tap-changer operation of the six cases, while right subfigure contains voltage at bus $22C$. Voltage level at bus $22C$ is visualized, as it is the remote bus controlled by the LDC. Tap-changer operations increase with use of LDC parameters, compared to the simulations with droop parameters, seen from the figure. The increase in tap-changer operations evident in case D. In case D, the generators are set to maintain voltage at 1.0 p.u. The voltage regulation at 1.0 p.u. implies reactive power compensation. Due to the chosen LDC parameters, voltage are kept at high at the transformer secondary side. This high voltage causes the generators to consume reactive power. Thus, reactive power must be provided by an overlaying network, and imaginary current increases. As seen in figure 5.13 and 5.14, reactive power flow causes a simulated voltage drop by the tap-changer control when X $\neq$ 0, and tap-changer operations to counteract the simulated voltage drop. The parameters calculated by determination of desired contribution make the tap-changer control less dependent on reactive power flow, seen by the flatter real voltage curve.

Wrong choice of parameters, seen in figure 5.15 with a high X value in case B and D, may aggravate coordination between tap-changer and synchronous generators. Case B has the highest total number of tap-changer operations. In principle, with LDC parameters and voltage regulation mode on generator 1, the two regulation mechanisms are both set to control voltage on bus $22C$. With use of parameters for tap-changer operation based on power flow, coordination can be easier, illustrated in figure 5.15 by the difference in case C and case D.

5.6 Time sweep study of different tap-changer control scheme

Using the internal DIgSILENT PowerFactory script *TimeSweep* to calculate bus voltages and tap-changer position as function of varying load during a 24 h period. Figure 5.16 illustrates the active and reactive load profile for each load, including the active power production for each generator. During the production time period, no reactive power are produced at the generators ($cos\phi = 1$).

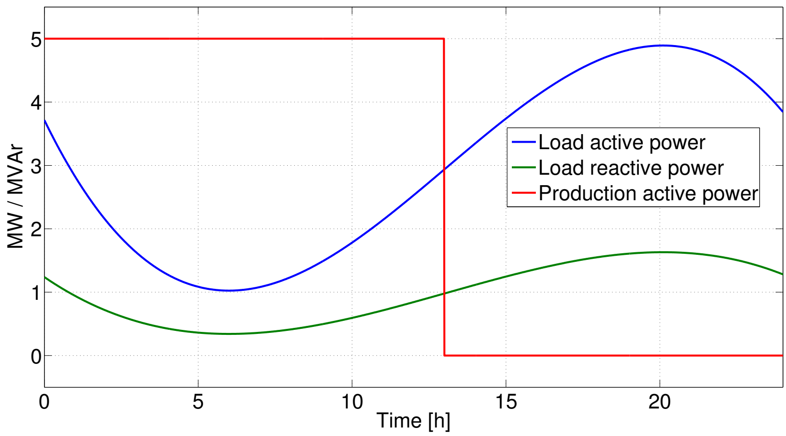

Figure 5.16: Load and active power production characteristic as function of time used in sweep analysis

DIgSILENT PowerFactory has the possibility for use of an internal tap-changer regulator. Determination of deadband and voltage set-point is necessary.

Using the internal tap-changer regulator together with the internal *TimeSweep* script to evaluate tap-changer behavior without voltage droop control. Table 5.8 holds the variables specified for the internal tap-changer.

Table 5.8: Specified variables for the internal tap-changer

Variable	Value [p.u.]
Voltage Set-point	1.0
Lower Voltage Bound	0.98
Upper Voltage Bound	1.02

Table 5.9 holds variables for the transformer voltage droop control, voltage boundaries and set-point for evaluation of the tap-position. To evaluate the droop control, the *TimeSweep* script is modified. Appendix C.2 provides the modified *TimeSweep* script.

Table 5.9: Specified variables for droop control and tap-changer

Variable	Value [p.u.]
Voltage Set-point	1.0
Lower Voltage Bound	0.98
Upper Voltage Bound	1.02
Droop parameter R	0.3
Droop parameter X	0.1

Figure 5.17 illustrates tap-changer position and voltage at some network buses for timesweep with and without transformer voltage droop control. Clearly, droop control scheme help keep the voltage within a more narrow voltage band. Compared with and without droop control, tap-changer operations increases with use of the droop control.

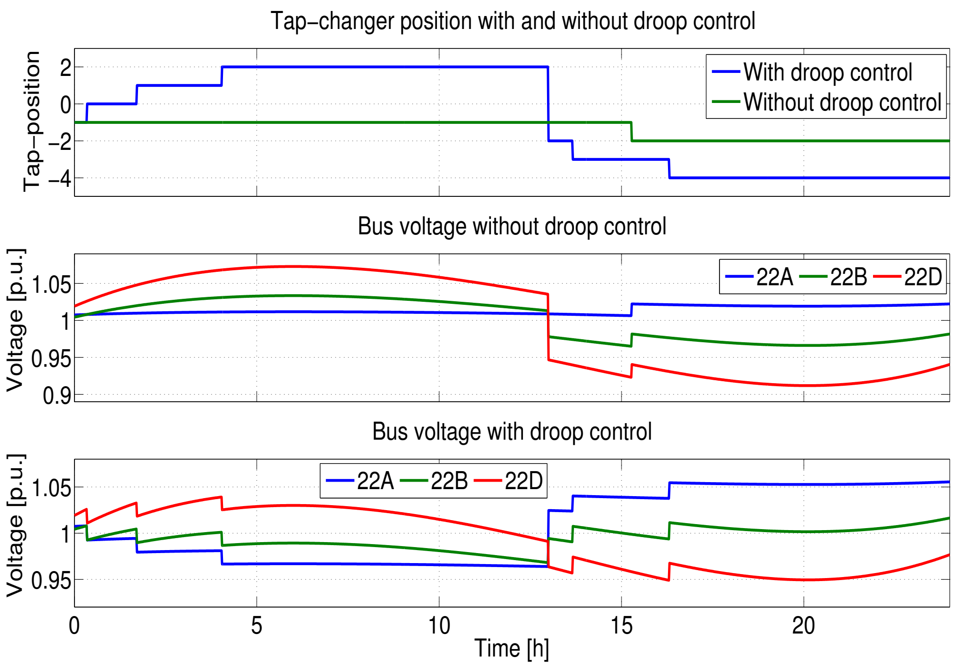

Figure 5.17: Comparison of tap-position and bus voltage with and without transformer voltage droop control during timesweep

Chapter 6

Loss considerations

6.1 Network power losses

Network losses are calculated by use of the integrated *TimeSweep* script in DIgSILENT PowerFactory. Information regarding the script can be found in Appendix C.1.1. Four different cases are evaluated. The cases are listed below.

- **Case A**: Synchronous generators modeled as PQ units with $cos\phi = 1$. Transformer droop voltage control is enabled
- **Case B**: Synchronous generators modeled as PV units. Tap-changer position is fixed in neutral position. Voltage set-point is 1.02 p.u. for both generators
- **Case C**: Synchronous generators modeled as PV units. Transformer droop voltage control is enabled. Voltage set-point is 1.02 p.u. for both generators
- **Case D**: Synchronous generators modeled as PV units. Transformer droop voltage control is enabled. Voltage set-point is 1.02 p.u. and 1.05 p.u. for generator 1 and generator 2, respectively

Low load situation is considered for all cases.

Network power loss results

Table 6.1: Network losses calculated with *Timesweep* for different modeling and control approaches

	Case A	Case B	Case C	Case D
Losses [MWh]	15.800	18.765	18.080	16.156

Table 6.1 is a summary of the timesweep results obtained, complete results are given in Appendix C.1.2. Lowest network losses are obtained in Case A, seen from

table 6.1. Based on the results provided in table 6.1, a loss reduction of 15.8 % at low load is possible to obtain when voltage is regulated only by the OLTC in Case A, to voltage regulation only by the generators in Case B.

Compared Case B and Case C, it is observed a loss reduction by some 3.6 % by use of transformer droop control. In Case D the losses are reduced by approximately 10.6 %, compared Case C.

Proper coordination between voltage control mechanisms is beneficial, seen by the loss reduction when adapting the tap-position to the operational situation. In addition, when adapting the generator voltage set-point such that a minimum of reactive power consume is necessary to maintain desired voltage, losses are further reduced.

6.2 Matpower

Appendix E includes the matrices used for modeling in Matpower. Swing bus is the secondary side of the OLTC transformer in figure 5.1, and modeled with constant voltage magnitude and angle. The step-up transformers in figure 5.1 are by simplifications omitted. Loads are defined with voltage independent characteristic, and modeled with defined values for active and reactive power consumptions at specified buses. The generators can be modeled as both PQ and PV units, and is complex power injection to chosen buses. The line model used is a short line model with a series impedance, in which the charging capacitance is omitted.

6.2.1 Difference between PQ and PV modeling of synchronous generators

Synchronous generators represented as PQ or PV units may lead to different results. By use of Matpower in Matlab studies on loss in the network of figure 5.1 is carried out, to illustrate the difference between PQ and PV modeling of synchronous generators in steady-state at low load.

Upper subfigure in figure 6.1 illustrates network losses as function of voltage at the secondary side of the HV/MV transformer. Lower subfigure illustrates generator voltage as function of voltage at the secondary side of the HV/MV transformer. Losses are reduced with higher voltage at the transformer secondary side, and generator voltage increases parallelly with increased transformer voltage. The voltage at the generators are considered a high value at all transformer secondary side voltages above 1.0 p.u.

Figure 6.2 illustrates network losses as function of HV/MV transformer secondary side voltage, with synchronous generators as ideal PV units. Ideal PV units are considered with infinite reactive power capability, and they are controlled to hold the voltage at 1.02 p.u. and 1.05 p.u. at generator 1 and generator 2, respectively. As seen from the figure, losses increase approximately exponential with increasing transformer voltage. The loss increase is due to reactive power transport to the generators for voltage regulation. It is obtained a certain minimum of network power loss with a transformer voltage around 0.96 p.u.

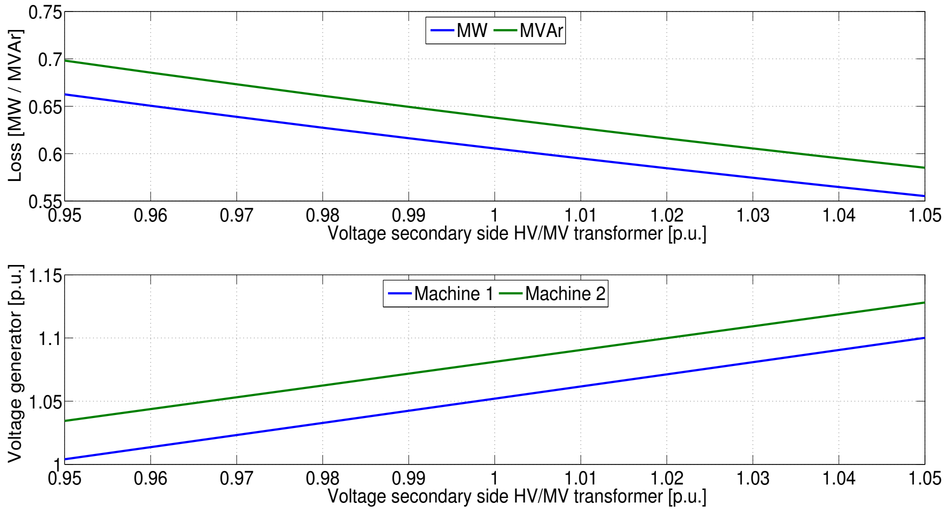

Figure 6.1: Network power loss as function of voltage at secondary side on HV/MV transformer with generators in the network modeled as PQ units

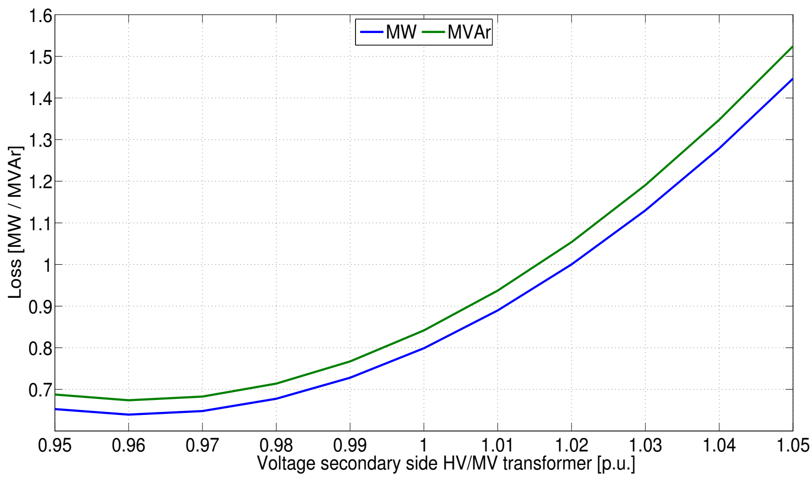

Figure 6.2: Network power loss as function of voltage at secondary side on HV/MV transformer with generators in the network modeled as PV units

6.2.2 Optimal power flow

The objective is minimization of cost through minimization of active power production, illustrated by equation 6.1. Total cost is C, f_p is the cost function for the generators, and P_G^n is the active power injection for generator n. Total number of generators is n_g. f_P is linear, and all generators have equal cost.

$$minC = min \sum_{n=1}^{n_g} f_P^n \cdot P_G^n \tag{6.1}$$

The two DG units are assigned with constant active power production. Loss minimum is obtained when the least amount of active power is produced at the swing bus. Voltage constraint at all buses are given by equation 6.2.

$$0.95 \leq V_{bus} \leq 1.05 \tag{6.2}$$

More information regarding OPF modeling and calculation in Matpower is found in [2].

Increase in load demand

OPF-calculation with increasing load demand is carried out. The calculation is performed with load demand increasing from low load condition to high load condition in steps of 0.25 MW and 0.0833 MVAr. Active power production is constant 5 MW at each generator. Results are illustrated in figure 6.3.

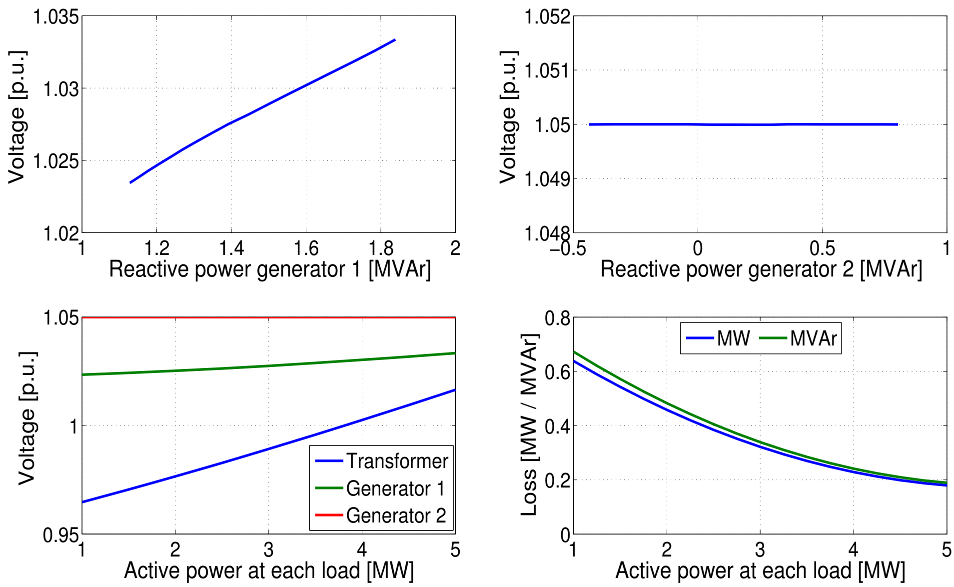

Figure 6.3: Generator voltages as function reactive power production, bus voltages and network power loss with increasing load demand

Upper left subfigure illustrates voltage on generator 1 as function of reactive power production. Based on the OPF results, voltage at generator 1 should therefore increase with increasing reactive power production. Upper right subfigure is voltage as function of reactive power production at generator 2. Voltage should be kept at 1.05 p.u. during all operational situation, illustrated by the OPF results. Lower left subfigure contains voltage at the secondary side of the HV/MV transformer and the two generators. Voltage at the transformer is increasing with increasing load demand. Lower right subfigure illustrates network losses. With increased load demand, losses are decreasing. The decrease in loss is due to reduced need for transportation of active and reactive power, as it is produced and consumed inside the network.

Varying active power production

OPF calculations with constant load at P = 2.5 MW and Q = 0.833 MVAr are performed. Power production at both generators are simultaneously increased from 0 to 5 MW in steps of 0.25 MW. Results from the OPF calculations are illustrated in figure 6.4.

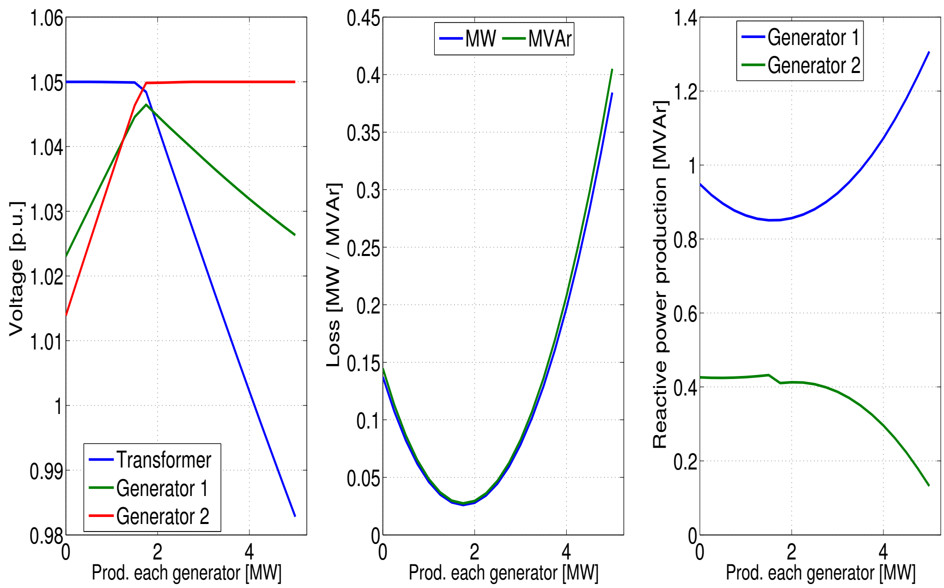

Figure 6.4: Voltage and network power loss as function of power production at each generator

Left subfigure shows voltage at secondary side of the HV/MV transformer, and voltages at the two generators as function of active power production at each generator. Seen from the figure, transformer voltage is constant and generator voltage are increased up till a generator production just below 2 MW. This is the same point, seen in the middle subfigure, in which a minimum of network losses are achieved. In this point, all voltages in the left subfigure are at their highest value within the voltage constraint given in 6.2. As the loads are constant power, lowest current are achieved at this point. Right subfigure illustrate reactive power production at the two generators with increasing active power production.

6.3 DIgSILENT PowerFactory

6.3.1 Network power loss

As seen in figure 6.3, voltage on generator 1 should increase with increasing reactive power output. By running dynamic simulations in DIgSILENT PowerFactory with different generator voltage set-points, network power loss can be obtained. Table 6.2 holds set-point voltage for the two generators at the different case A-C. Case D is the same as C, except that generator 1 is equipped with a droop reactance, with a value of X = -0.05 p.u. The droop reactance introduces an increasing voltage with increasing reactive power production.

Table 6.2: Generator set-point voltage for different cases

Case	Voltage gen. 1 [p.u.]	Voltage gen. 2 [p.u.]
A	1.0	1.0
B	1.0	1.02
C	1.02	1.05

During the simulation, loading in the network is ramped from low to high load. Ramping of the loads starts at t = 50, and has a ramp time of 400 seconds. Results are shown in figure 6.5.

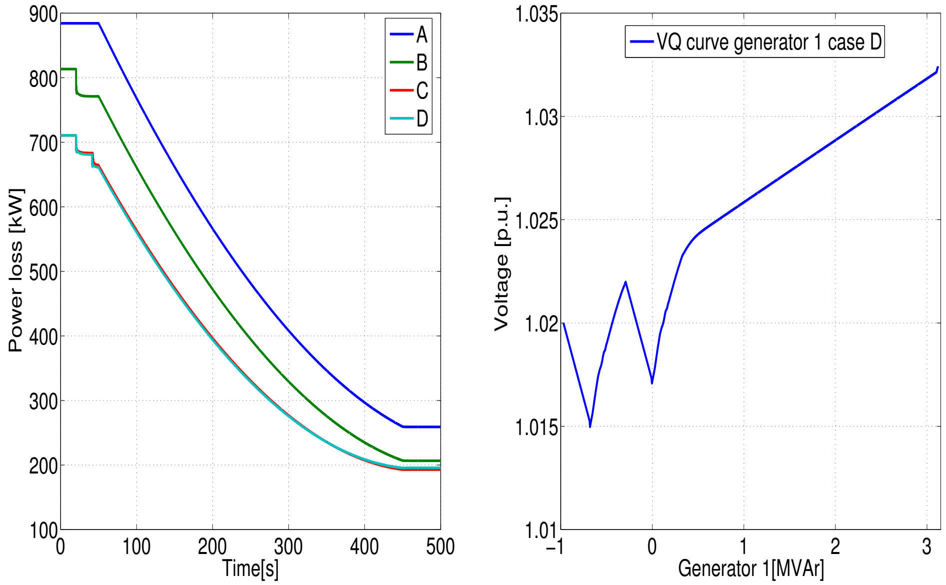

Figure 6.5: Network power loss and VQ-curve of generator 1 for cases with changing generator voltage set-point

Left subfigure illustrates total power loss for the lines in the network, while right subfigure shows VQ curve of generator 1. The sawtooth similar shape at the left in the VQ-curve is due to tap-changer operation.

OPF results illustrated a loss minimum in figure 6.3. The results indicated increased voltage at generator 1 with increased reactive power. However, use of reactive power voltage droop on generator 1 do not decrease power losses significant, illustrated in figure 6.5. More important, generator voltage set-point are influencing power loss more than droop setting of generator 1, illustrated in figure 6.5. This is the same as obtained in section 6.1.

Chapter 7

Extended network model

7.1 Extended network model

To evaluate the behavior of the droop control with an overlaying network, the model in figure 5.1 is extended. Figure 7.1 illustrates the extended network model. The network model are extended with an external network, a 132 kV overhead line and an OLTC equipped transformer between 132 kV and 300 kV level.

Extension of the network model makes it possible to evaluate the droop control with voltage fluctuations at the primary side of the 132/22 kV transformer.

The external network connected to the model at bus $132B$ have the ability of either import or export both active and reactive power. The external network may be seen as a reduction of a thought larger network. The thought external network have a high import of active power during high load, and a high export of active power during low load. A high export of active power during low load, could be due to some sort of unpredictable renewable power generation like wind power.

In DIgSILENT PowerFactory the thought external network is solved by use of a general load and a static generator connected to the bus $132B$.

The load connected to bus $132B$ are considered to be S = 20+j6 MVA at high load, and S = 4+j1.2 MVA at low load. Maximum generation at time of low load situation for the generator is considered to be P = 20 MW.

Appendix D.1 contains parameters for the added elements in the extended model.

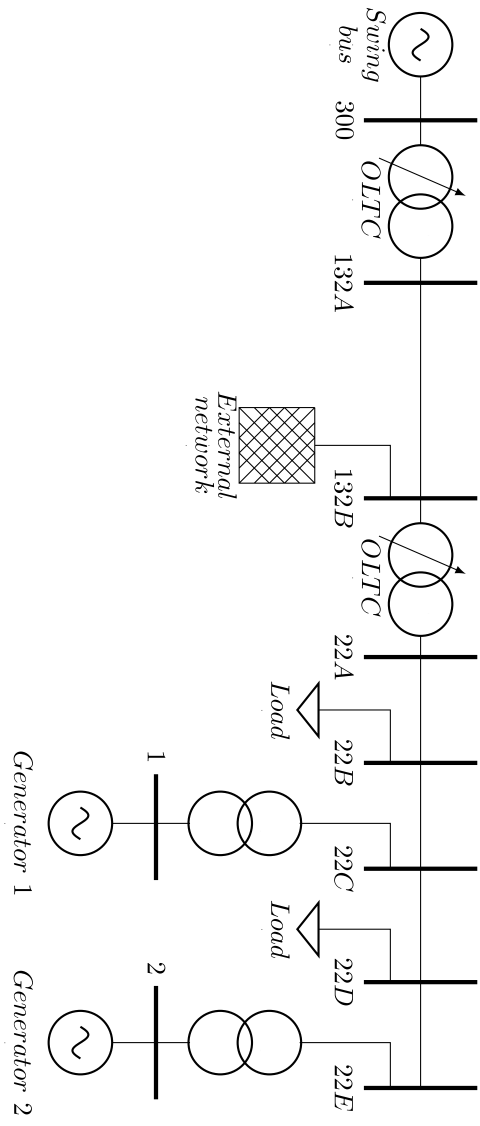

Figure 7.1: Extended network model used for study

7.2 Voltage conditions in extended network model

Figure 7.2 illustrates tap-changer control, tap-changer positions and voltage at network buses when none of the transformer droop controls are enabled. Hence, conventional transformer voltage control is used. It is observed with high load conditions that the voltages at the network at buses $22B$ and $22D$ are below the stated ± 5 % limit.

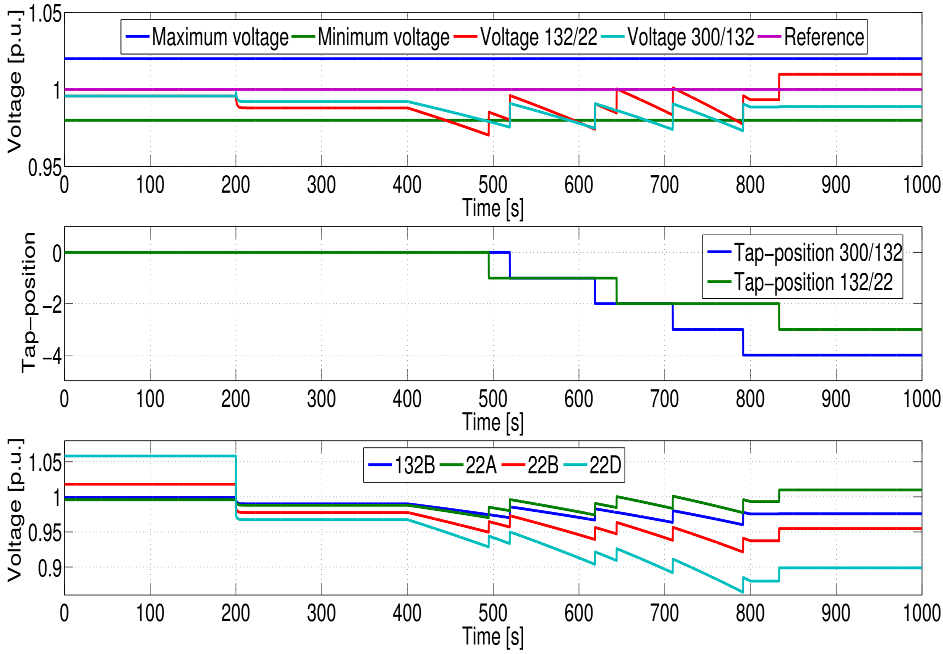

Figure 7.2: Dynamic simulation for test with conventional transformer voltage control. Upper: Tap-changer control. Middle: Tap-changer position. Lower: Network voltages

To achieve voltage inside the limits at buses $22B$ and $22D$, measures should be taken. As seen before, transformer voltage droop control is a possible solution.

7.3 Approximation of droop parameters for transformers

OPF calculation at high load to determine transformer tap-positions is carried out. Results are provided in Appendix D.1.2. Transformer tap-positions obtained from OPF, are given in table 7.1. OPF calculation results are used as indicators on how the voltage level should be.

Table 7.1: Tap positions obtained from OPF in extended network at high load condition

Transformer	Tap-position
300/132 kV	-3
132/22 kV	-4

Results from initial conditions at high load when transformer tap-positions are neutral, are provided in Appendix D.1.2. From the results provided it is possible to obtain the transformer currents. By using the transformer currents and the results from optimal power flow, it is by use of equation 5.10 possible to approximate the droop parameters.

Transformer 300/132 kV

From initial conditions, the power flow and voltage at the secondary side of the transformer are listed in table 7.2. Rating of the 300/132 kV transformer is 60 MVA.

Table 7.2: Power and voltage at secondary side of 300/132 kV transformer

Variable	Value	Value [p.u.]
Active power	-30.89 MW	$-\frac{30.89}{60} = -0.5148$
Reactive power	-10.65 MVAr	$-\frac{10.65}{60} = -0.1775$
Voltage	128.25kV $\angle -4.09$ kV	0.97 $\angle -4.09$

Current flowing in the transformer can be obtained by using the values in table 7.2, and the relation $S = U \cdot I^*$. Real and imaginary values of the current are given in table 7.3.

Table 7.3: Real and imaginary current on secondary side of 300/132 kV transformer at initial high load conditions

Variable	Value [p.u.]
Real current	-0.51
Imaginary current	0.22

From table 7.1, the voltage contribution from the droop should be 3 taps. Hence, 3 times the percentage voltage of a single tap-step, each 1.5 %, in total 4.5 %. By stating the droop contribution should be 0.045 p.u. and pure real value, equation 7.1 can be used for approximation of the droop parameters.

$$\begin{bmatrix} R \\ X \end{bmatrix} = \begin{bmatrix} -0.51 & -0.22 \\ 0.22 & -0.51 \end{bmatrix}^{-1} \cdot \begin{bmatrix} -0.045 \\ 0 \end{bmatrix} = \begin{bmatrix} 0.0744 \\ 0.0321 \end{bmatrix} \tag{7.1}$$

Transformer 132/22 kV

By using the same procedure as shown above for the 300/132 kV transformer, the droop parameters for the 132/22 kV transformer can be approximated.

Table 7.4: Power and voltage at secondary side of 132/22 kV transformer

Variable	Value	Value [p.u.]
Active power	-10.87 MW	$-\frac{10.87}{50} = -0.22$
Reactive power	-4.24 MVAr	$-\frac{4.24}{50} = -0.09$
Voltage	20,78 $\angle -6,91$ kV	0.94 $\angle -6.91$

Table 7.5: Real and imaginary current on secondary side of 132/22 kV transformer at initial high load conditions

Variable	Value [p.u.]
Real current	-0.22
Imaginary current	0.12

The voltage at 132/22 kV transformer are dependent of the 300/132 kV transformer. By using the same procedure for 132/22 kV transformer as seen in section 5.3.3, and using the currents in table 7.5, the droop parameters are approximated in equation 7.2.

$$\begin{bmatrix} R \\ X \end{bmatrix} = \begin{bmatrix} -0.22 & -0.12 \\ 0.12 & -0.22 \end{bmatrix}^{-1} \cdot \begin{bmatrix} -0.08 \\ 0 \end{bmatrix} = \begin{bmatrix} 0.2803 \\ 0.1529 \end{bmatrix} \tag{7.2}$$

7.3.1 Test of droop parameters

The approximated droop parameters are tested in the extended network model. The test are carried out with low load and DG production as the initial condition. During the simulation, the generators are disconnected, and the loads are ramped from low to high load during a time period of 400 seconds. Transformer droop parameters are as approximated above. The production in the network are run with $cos\phi = 1$.

Table 7.6: Dynamic simulation events

Event	Time[s]
Disconnection of generators	t = 200
Start load ramp (+400%)	t = 400
End load ramp	t = 800

Results from the dynamic simulation for test of droop parameters are illustrated in figure 7.3.

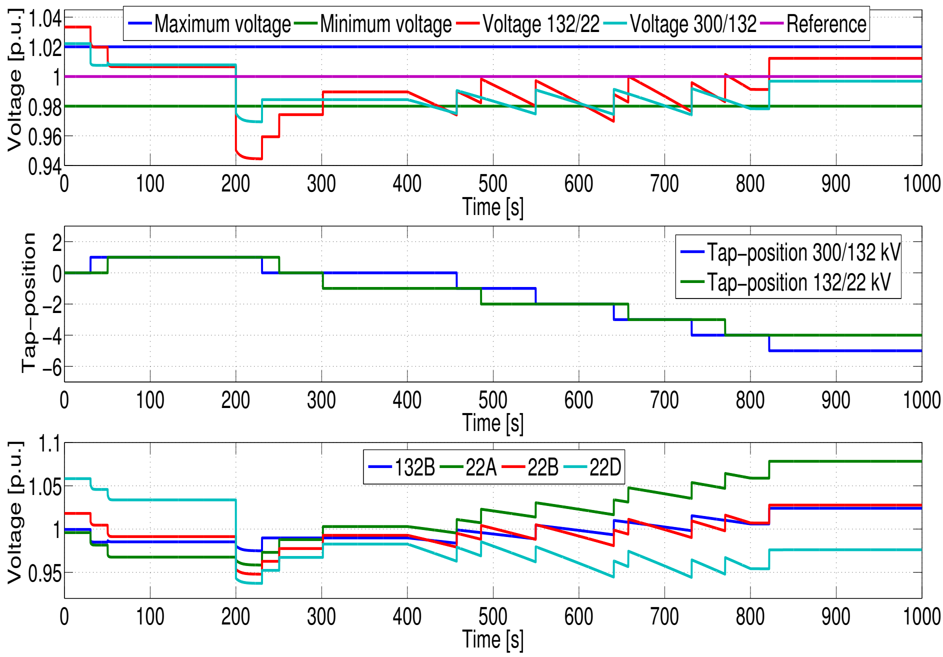

Figure 7.3: Dynamic simulation for test of transformer voltage droop in extended network model. Upper: Tap-changer control. Middle: Tap-changer position. Lower: Network voltages

Upper subfigure shows the tap-changer control as function of time, with the voltages from the droop control for both transformers. The tap-changer change position when the voltage from the droop control are outside the defined limits. Middle subfigure illustrates the tap-positions for the transformers as function of time, while the lower subfigure shows voltage at four buses as function of time. Highest voltage at low load and maximum DG production, and lowest voltage at high load conditions are at bus 22D, obtained from the lower subfigure. Droop control of the transformers help keep the voltage within limits.

7.3.2 Increased active power export from external network

Consider an increase in power production in the external network, maximum production is P = 50 MW. Initial export from external network is P = 10 MW, and is from t = 100 ramped up to P = 46 MW with a ramping time of 250 seconds.

Figure 7.4 illustrates the difference with conventional transformer control and a transformer voltage droop control scheme. The conventional control scheme on the 300/132 kV transformer have a voltage set-point of 1.0 p.u., and a deadband of 0.012 p.u.

The droop control scheme is described above in earlier section.

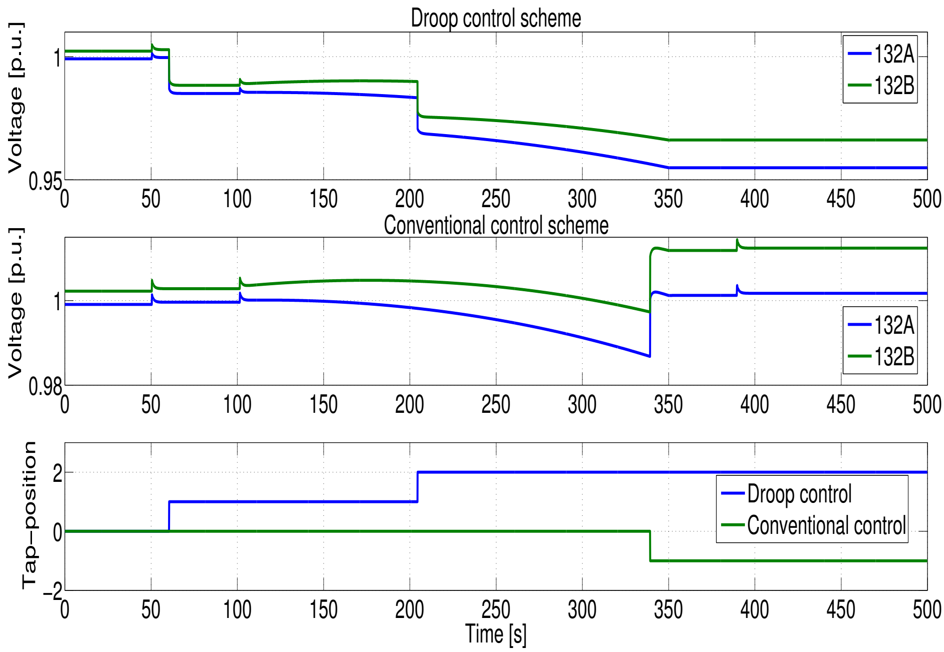

Figure 7.4: Simulation with increased active power export from external network

Upper subfigure in figure 7.4 illustrates voltage at bus $132A$ and $132B$ with droop control scheme. The middle subfigure holds voltage at bus $132A$ and $132B$ with conventional transformer voltage control, while the lower subfigure contains tap-changer position for 300/132 kV transformer for the two different control schemes. Conventional control scheme raises the voltage, because the voltage is below the lower deadband limit. The droop control consider the power flow, and decreases the voltage.

Increased line resistance and line length

The principal behavior of the two different control schemes illustrated in figure 7.4 is of interest. To illustrate the difference in their behavior even more, line resistance is raised from 0.153 Ω/km to 0.353 Ω/km, and the line length is increased to 100 km. Active power export from external network is initially P = 10 MW, and with an import of reactive power Q = 1.2 MVAr. During the simulation, active power export and reactive power import are ramped. The ramping starts at t = 100, and has a ramping time of 250 seconds. Active power export is ramped to P = 50 MW, and reactive power import to Q = 6 MVAr. Results from the simulation are illustrated in figure 7.5.

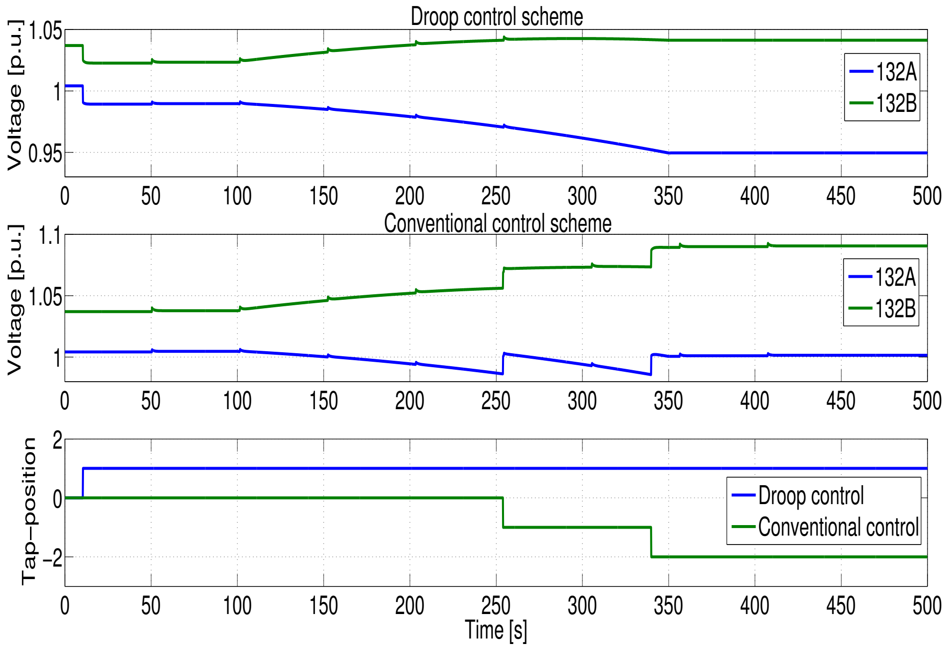

Figure 7.5: Simulation with increased active power export from external network, increased line resistance and line length

Upper subfigure in figure 7.5 shows voltage at bus 132A and 132B with droop control scheme. The subfigure in the middle illustrates voltage at bus 132A and 132B with conventional transformer voltage control, and lower subfigure holds tap-changer positions for the two different control schemes. Seen from the figure, the voltage increases along the line, due to high export of active power from the external network and a relatively high line resistance. The conventional transformer voltage control only see low voltage value at the secondary side of the 300/132 kV transformer. Thereby, an increase of the voltage to counteract the low voltage measured. It does not take into consideration that voltage rises along the line. The result is a further increase in voltage, and a high voltage level towards the line end. The droop control consider the power flow, and allow the voltage at secondary side of 300/132 kV transformer to decrease. As obtained from the figure, voltage at bus 132B is higher using conventional transformer voltage control, compared to the droop control scheme. In the particular case illustrated in figure 7.5, the droop voltage control has the least tap-changer operations compared the conventional voltage control.

7.4 Undesired operation of tap-changer

In networks with low reactance/resistance relation, a high amount of reverse active power flow implies that voltage rises along the line. In addition, if a reactive power flow is in reverse direction of the active power flow, simulations in section 7.3.2 shows conventional transformer voltage control rises the voltage level further.

7.4.1 Model for illustration of undesired tap-changer operation

Figure 7.6 is a simplified model of a network containing a swing bus, transformer represented by its short circuit impedance, transmission line represented by an impedance and an external network. The external network could represent a reduction of a network, or for instance large scale distributed generation. The external network has the ability of exporting active power and importing reactive power.

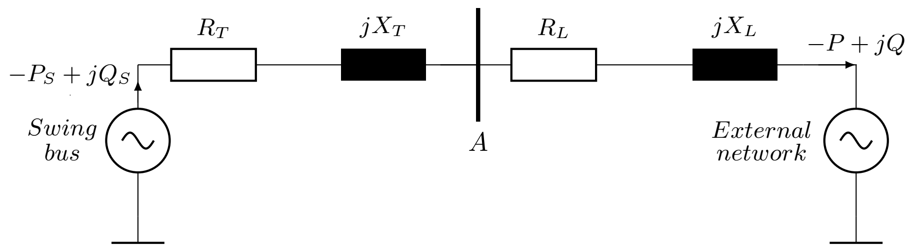

Figure 7.6: Simplified network model for illustration of undesired tap-changer operation

Current

Voltage at the swing bus is $1.0\angle 0°$ p.u., and the voltage is considered to be independent of the power flow, hence the swing bus is considered to be a strong grid. As the external network consumes reactive power, reactive power at the swing bus will be larger than the consumed reactive power at external network. The current in the network is given by equation 7.3.

$$I = \frac{S^*}{V} = -P_S - jQ_S \tag{7.3}$$

Voltage drop over transformer

Voltage drop over the transformer is given by equation 7.4.

$$\Delta V_T = (R_T + jX_T) \cdot (-P_S - jQ_S) \tag{7.4}$$

Decomposing transformer voltage drop into real and imaginary values in 7.5 and 7.6.

$$Re = X_T \cdot Q_S - R_T \cdot P_S \tag{7.5}$$

$$Im = -P_S \cdot X_T - R_T \cdot Q_S \tag{7.6}$$

Seen from 7.5 and 7.6 all terms with negative signs, provides a voltage rise over the transformer with the given power flow. The term with positive sign indicates a voltage drop over the transformer. If reactive power flow multiplied with the transformer reactance is of greater magnitude than active power flow multiplied with the transformer resistance, it will cause a real voltage drop over the transformer.

[7] gives typical values of power transformer reactance and resistance. For a 132/22 kV transformer, the reactance is approximately 32 times larger than the resistance. Due to the reactance/resistance relation, an approximation is to neglect the transformer resistance. 7.7 and 7.8 give voltage drop over the transformer.

$$Re = X_T \cdot Q_S \tag{7.7}$$

$$Im = -P_S \cdot X_T \tag{7.8}$$

From the equations above and with the given power flow, the real voltage drop in magnitude is considered to be less than the imaginary voltage rise. Consider a swing bus voltage of $V = 1.0 + j0$. Current through the transformer is $I = -0.8 - j0.25$. Transformer reactance is $X_T = 0.135$ p.u. With the given current and reactance, voltage over the transformer is shown in 7.9 and 7.10.

$$Re = X_T \cdot Q_S = 0.135 \cdot 0.25 = 0.03375 \tag{7.9}$$

$$Im = -P_S \cdot X_T = -0.8 \cdot 0.135 = -0.108 \tag{7.10}$$

7.11 gives voltage measured at the secondary side by the tap-changer control.

$$V_{SECONDARY} = V_{PRIMARY} - V_{DROP} = \tag{7.11}$$
$$1.0 - 0.03375 + j \cdot (0 - (-0.108)) = 0.96625 + j \cdot 0.108 = |0.972|$$

Even if the reactive power flow is considered to be significant lower than active power flow, and voltage drop due to reactive power in magnitude is less than the voltage rise due to active power, reactive power very much influences tap-changer operation.

Voltage drop along line

The line impedance is considered to have an $X/R \approx 1$. 7.12 and 7.13 give voltage drop along the line.

$$Re = X_L \cdot Q_S - R_L \cdot P_S \tag{7.12}$$

$$Im = -P_S \cdot X_L - R_L \cdot Q_S \tag{7.13}$$

As the line resistance is non-negligible, and active power flow considered higher than the reactive power, voltage drop along the line is negative, hence voltage rises along the line. With a substantial active power flow and large line resistance, voltage rise may cause problem related to over-voltage.

Tap-changer operation

Conventional transformer voltage control measures voltage at the secondary side bus, compares with a reference value, and verifies whether or not the voltage is inside or outside an allowed deadband. Voltage rise may be significant from the swing bus to the end of the line. Still, the voltage measured at the secondary side of the transformer may be below the deadband limit due to the reactive power flow. If the measured voltage is below the deadband limit, the tap-changer will alter the voltage at the secondary side inside the allowed deadband. This tap-change may further increase the voltage in the network, and seen as unfortunate.

Example

A power flow of the final values of the simulation described in section 7.3.2 is performed. The external network and the 22 kV distribution network are reduced in compliance with the model in figure 7.6. A summary of the power flow is given in table 7.7, and complete power flow results is provided in Appendix D.1.2. The power flow is calculated with transformer tap-changer in neutral position.

Table 7.7: Summary of power flow

Variable	Value
Voltage swing bus	1.0 p.u.
Active power swing bus	-51.3 MW
Reactive power swing bus	15.86 MVAr
Voltage bus A	0.97 p.u.
Voltage external network	1.06 p.u.
Active power external network	-57.4 MW
Reactive power external network	7.54 MVAr

Seen from table 7.7, voltage rises from the swing bus towards the end of the line. Nevertheless, voltage at bus A is 0.97 p.u. If a conventional transformer voltage control is used, with a set-point voltage of 1.0 p.u., and with a deadband of, for instance, 0.012 p.u., the tap-changer would increase voltage to comply with the parameters. Thus, voltage at the end of the line would be further increased.

In order to avoid the unnecessary tap-changer operation as described, some possible measures are possible. From equation 7.7 and 7.8, reactive power flow is significant for the voltage drop over the transformer. A possible measure is to reduce the reactive power flow. It would imply some sort of reactive power compensation in the network. With a reduced reactive power flow, unnecessary tap-changer operations due to voltage drop over the transformer could be reduced, in addition with reduced transmission loss.

Table 7.8 holds a summary of power flow calculation when reducing the reactive power consume by 6 MVAr. Complete power flow can be found in Appendix D.1.2.

Table 7.8: Summary of power flow with reduced reactive power consume

Variable	Value
Voltage swing bus	1.0 p.u.
Active power swing bus	-51.67 MW
Reactive power swing bus	8.89 MVAr
Voltage bus A	0.99 p.u.
Voltage external network	1.09 p.u.
Active power external network	-57.4 MW
Reactive power external network	1.49 MVAr

Compared the values in table 7.7 with table 7.8, voltage at bus A is increased by 0.02 p.u., active power import at swing bus are increased by some 0.3 MW, and reactive power loss is reduced with 1 MVAr in addition to the reduced 6 MVAr consume. Voltage at external network is increased by 0.03 p.u. due to the decreased reactive power consume. However, voltage is considered to be high, and other measures should be considered.

With the reduced reactive power consume, unnecessary tap-changer operation due to voltage drop over the transformer caused by reactive power flow should be eliminated.

Transformer voltage droop control scheme is a feasible solution to reduce and possible eliminate unnecessary and unfortunate tap-changer operations. The reduction in tap-changer operation is obtained by dynamic simulation in section 7.3.2, illustrated in figure 7.5

Chapter 8

Discussion

8.1 Main findings

8.1.1 Relation between tap-changer operation and reactive power

In [29] and [30] reactive power demand is seen to have close relation to tap-changer operation. Results found by testing conventional tap-changer control supports this theory.

8.1.2 Tap-changer control design

Tap-changer control design is based on OLTC modeling described in [26, 34]. Results indicates use of the traditional model with measurement of voltage and line current, in addition to use of compensation parameters is sufficient. It is necessary to measure voltage and current in all four quadrants. Only use of current magnitude is shown to lead to undesired tap-changer operation.

In a centralized control scheme in which data is gathered by communication and processed to obtain optimal settings, other representation of the tap-changer may be more appropriate. For instance, by use of optimization procedure for determination of tap-changer position. In such a case it may be advantageous to include a model to determine the total number of tap-changer operations. Thereby it can be developed an optimization objective to reduce the total number of tap-changer operations.

8.1.3 Adaption to the power flow

Transformer

Adaption to the power flow through a transformer is a well known technique. Line drop compensation (LDC) is used for representation of a virtual point at some distance from the transformer. The electric distance between transformer and the virtual point is an impedance value. Using the flow of current and the impedance, voltage drop between the transformer and the virtual point is compensated.

The main contribution of the thesis is moving away from a conventional transformer voltage control in which voltage are kept constant at the transformer secondary side to an approach in which power flow decides tap-changer position. Active and reactive power flow may have different directions. It is illustrated that use of the line impedance between the transformer and the virtual point may lead to erroneous tap-changer operation at certain operational situations. The situation in which active power flow is towards overlaying network, and a substantial reactive power flow in opposite direction is shown to have challenges. By a demonstrated approach for determination of compensation parameters, erroneous and undesired tap-changer operations can be eliminated. In networks with a low reactance/resistance relation, reverse active power flow together with a substantial line resistance, voltage rise may be a challenge. Nevertheless, reactive power flow may determine tap-changer operation. Transformer compensation parameters should be determined to compensate for the reactive power influence, whereas active power flow should be the main criteria for tap-changer operation.

Generator

Use of reactive droop capability on generators to obtain an voltage-reactive power relation is important when paralleling synchronous generators, to ensure a stable reactive power sharing [36]. Results from for instance OPF, indicate that a reactive power droop is beneficial to obtain a loss reduction. However, dynamic simulations show that a reactive power droop does not have a significant influence on power losses. The results are obtained with reactive power droop on a single generator. If several generators are equipped with reactive power droop to minimize total reactive power, results may be differently.

8.1.4 OLTC operation with LDC

It is illustrated that use of current magnitude in determination of voltage compensation may lead to erroneous tap-changer operation during low load and high share of DG production. This is as illustrated in [35].

As operational situation in distribution networks significant may vary between high load with no DG production to low load with maximal production, it may be challenging to find a point in the network with constant voltage at all operational situation. By use of traditional LDC, a point is chosen to hold constant voltage. Due to significant changes in power flow and thereby voltage level, it is illustrated that LDC may have unfortunate influence on voltage level. This is the main argument for moving away from keeping constant voltage at a point, to an approach in which voltage level is determined based on the power flow.

8.1.5 OLTC influence on power loss

OLTC operation influence network power loss. By moving away the conventional voltage control in which voltage are kept constant at transformer secondary side, to an adaption of tap-changer position to the power flow, losses can be reduced. The reduction in power losses is true when DG units are synchronous generators, or any other DG with voltage control capability, operated in voltage control mode. Holding voltage constant at a transformer secondary side, may imply a high voltage level in the network, depending on the power flow. When reducing transformer secondary side voltage at low load and high production, the need for reactive consumption to regulate voltage with the synchronous generators is reduced. By reducing the reactive power consumption, the total reactive demand is decreased, thereby losses are reduced.

Results presented in section 6.1 illustrates that a loss reduction of some 15 % can be obtained at low load in a given network when adapting tap-changer position to the power flow in the network. The loss reduction is dependent on generator modeling.

8.1.6 OLTC and synchronous generator coordination

Networks in which OLTC active regulate voltage, it may be possible to use PF/-VAr regulator on synchronous generators. When OLTC active regulates voltage, a synchronous generator with PF/VAr control follows the network voltage. An increase in tap-changer operations are observed when running synchronous generator in PF/VAr mode in cooperation with active OLTC regulation. A possible source of challenges related to coordination between the regulation mechanisms may be eliminated when only one mechanism is set to regulate voltage, as described in [24]. However, voltage regulation mode on synchronous generator is seen as a solution to integrate more DG without violating voltage level requirements [12]. Use of PF/-VAr regulation or voltage regulation mode must be determined in each separate case based on network influence by the generator.

With increasing load demand from low to high load, voltage control mode is seen as advantageous, because DG may produce both active and reactive power for local demand. A local production of both active and reactive power to meet local load demand, may reduce the number of tap-changer operations, and is seen as beneficial.

Illustrated in figure 5.15, is the increase in tap-changer operations when generators are set to hold constant voltage by use of reactive power, when a relative high X value is used for tap-change control compensation. The particular case illustrates that voltage control mode in cooperation with tap-changer need evaluation regarding choice of parameters to obtain a proper coordination. In addition, it is illustrated in figure 5.15 that by use of compensation parameters for the tap-changer based on power flow, in cooperation with voltage regulation mode on the generators, the total number of tap-changer operations may be reduced.

8.1.7 Undesired tap-changer operation

In networks with a low reactance/resistance relation, export of active power and import of reactive power may imply challenges. Voltage rises along the line due to active power export, while a non-negligible reactive power flow influences tap-changer operation. Tap-changer operation may be undesired, and thereby increase voltage level more. The results are obtained when the swing bus is modeled with a relative high short circuit capacity, $X >> R$ and constant voltage. The same undesired operation is not seen in the simulations when the swing bus is modeled with lower short circuit capacity or $X/R \approx 1$. When the swing bus is modeled with a higher internal resistance, the active power is seen to increase the swing bus voltage, and the effect of a voltage drop across the transformer due to reactive power import is not seen. It is difficult to find a generalization for the undesired tap-changer operation, because every network has different inherent properties.

Undesired tap-changer operation, independent of the reason for the tap-change, can be related to dynamic interactions inside the network, for instance as illustrated in [28].

8.1.8 Deadband adjustment

To obtain the tap-changer to adjust its tap-position to desired position at some operational situations, deadband is adjusted. In general, several recommendations are present for deadband settings. In [41] deadband is recommended to be 75 % of the tap-step. In [30] it is stated that dead zone should be chosen slightly smaller than two tap-steps. Based on these recommendations, adjustment of deadband to 0.02 p.u. when the tap-step is 0.015 p.u. may thereby have some adverse effects related to voltage stability.

8.2 Transformer voltage control droop scheme

The suggested approach for determining the transformer voltage control droop parameters is given a discussion in this section.

8.2.1 Operational situation used for linearization

The objective by the linearization is to determine a desired contribution from the droop control in a given operational situation. The desired contribution should be a voltage level and thereby a tap-position at a given operational situation in the network.

To approximate the droop parameters it is necessary to perform a linearization at an operational situation. The chosen operational situation is high load conditions with no DG production, with the tap-changer in neutral position. DG may be unpredictable, and voltage requirements applies at all operational situations. High load situation and thereby large voltage drop is seen as the most challenging operational situation.

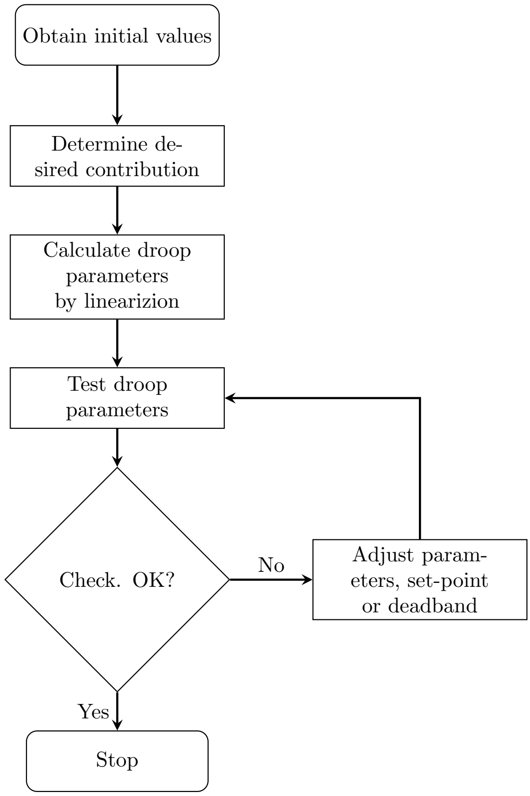

Figure 8.1: Flowchart transformer voltage droop control

A flowchart of the proposed scheme of determining the transformer voltage droop control parameters is provided in figure 8.1.

- **Obtain initial values**
  Determine in which operational situation the droop parameters should be approximated. Initial values could be obtained by power flow analysis. The tap-changer, which is subject for the droop control, should be kept in neutral position when obtaining the initial values.
- **Determine desired contribution**
  Determine tap-changer position in a given operational situation. In what extend should the droop control contribute to get to this operational situation, compared with the initial values obtained. Current in the network do not change when tap-changer position is changed, is an assumption.
- **Calculate droop parameters by linearizing, and test the parameters**
  By help of equation 5.10, calculate the droop parameters. Test transformer voltage control with the droop parameters for all operational situations. A test of voltage level could be performed with a dynamic simulation.

- **Check**
  For all operational situations, check voltage level in the network. The check must ensure voltage level at all relevant buses within requirements.

- **Adjust parameters, set-point or deadband**
  If the check reveals undesired voltage level, or results from for instance an optimal power flow are used as a reference, it may be necessary to adjust droop parameters, voltage set-point or deadband for the tap-changer.

8.2.2 Linearization

The linearization for approximation of the droop parameter is a subject of discussion for two reasons. Firstly, the line current values from the initial starting point is assumed not to change when voltage changes due to tap-changing. Secondly, tap-changer operation regulates the voltage discontinuously and uses a deadband function.

Current

Figure 8.2 illustrates the difference in real and imaginary current with different load modeling. The figure shows current, active and reactive power with voltage varying from 0.85 p.u. to 1.15 p.u. The load used for the plot is $S_{p.u.} = 1 + j1p.u.$ Seen from the figure, the current for all three different load modeling are equal at nominal voltage, and they change differently as function of the voltage. P, I, Z represent constant power, constant current and constant impedance, respectively.

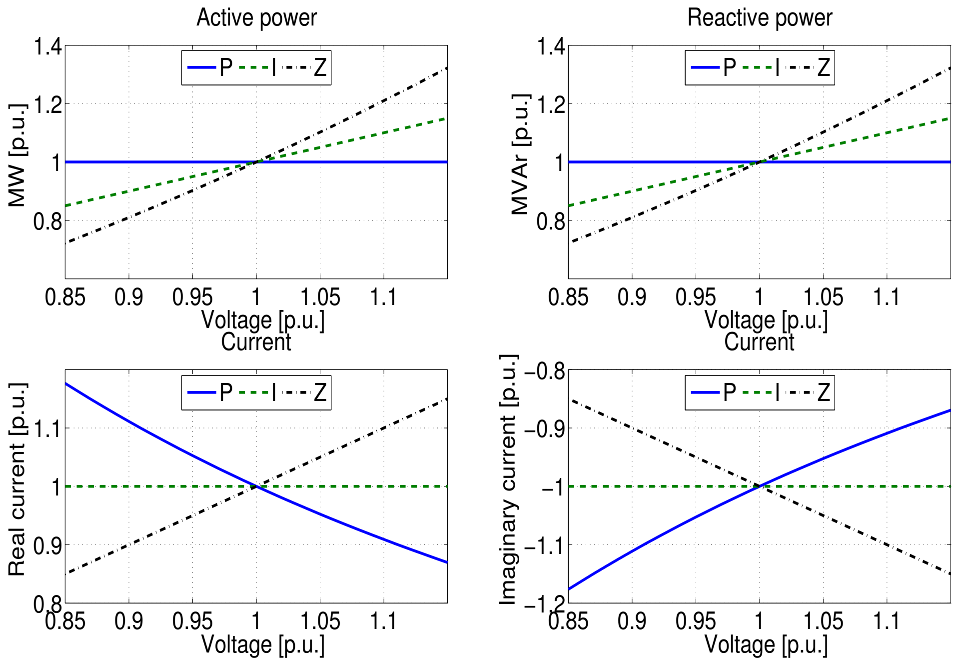

Figure 8.2: Power and current for different load modeling

Seen from figure 8.2 when the load is modeled with constant current, the non-changing current approximation is valid. Thereby, when the load in network is constant, or have a constant impedance characteristic, the assumption may lead to an error. Nevertheless, as the calculation of droop parameters only is intended as an approximation, it should be sufficient as a starting point.

Tap-changer

For power flow analysis can a transformer with changing transformation ratio be represented by a linear model [32]. When changing the turns-ratio, the linear model changes. Thereby, the approximation considers a non-changing model. How the model changes by changing of the turns-ratio is determined by transformer parameters and step size. The parameters may differ for different transformers, and the approximation could be seen as more valid for some transformers than others.

8.2.3 Possible disadvantages

Transformer voltage droop control may have some disadvantages. Possible scenarios regarding erroneous mode of operation is listed below:

- Improper setting of droop control parameters
- Failure of measurement equipment

- Network outages

Another factor to consider is if an OLTC equipped transformer, with droop control, is serving several feeders in which voltage profiles are different. Various voltage profiles on the different feeders may be challenging. For instance, DG is influencing a feeder with large voltage rise at low load, and at the same time a second feeder has a large voltage drop due to high load demand. In such a situation, it is necessary to take the operational situation into consideration when determining the droop parameters.

From the results it is obtained that the introduction of a droop relation for the transformer voltage based on the power flow may both increase and decrease the frequency of tap-changer operations. An increase in tap-changer operations in general is seen as a disadvantage. Higher frequency of tap-changer operations may lead to higher wear and increased aging of the tap-changer [30].

8.3 Time domain of tap-changer studies

Tap-changer behavior is studied with help from both power flow calculations and dynamic simulations.

8.3.1 Power flow calculation

In power flow calculations, loads and production are represented with their static characteristics, and real behavior can only be approximated for slow voltage variations [27]. An advantage, for instance with use of Matpower, is the ability to do studies to get an overview over the problem, or the possible actions to mitigate a problem without extensive network representation. However, tap-changer operation, synchronous generators, protection and control equipment and load dynamics are a close related dynamic process [27]. To study their behavior in detail, dynamic modeling are more suitable.

In power flow calculations, compared to dynamic analysis, simplifications and assumptions are more a necessity. It is necessary to be aware of the possible adverse effects of unfortunate simplifications and assumptions. An example of such is the difference between PQ and PV modeling of synchronous generators, and their influence on, for instance, tap-changer operation.

Quasi-static model

A model using static methods with simplified modeling of dynamic responses, are denoted a quasi-static model [42]. Tap-changer response are simplified and modeled, together with use of power flow calculations in section 5.6. The results indicates that such a model may be appropriate for evaluation of tap-changer behavior in distribution networks.

8.3.2 Dynamic simulation

Tap-changer influences the network, and by each change in tap-changer step, new dynamics are introduced. To evaluate control equipment and internal network behavior with respect to voltage level, dynamic modeling is a feasible solution. Typical range for time periods for dynamic simulations are defined [26]:

- Short term or transients: 0 to 10 seconds
- Mid-term: 10 seconds to a few minutes
- Long-term: a few minutes to 10s of minutes

Tap-changer operation are evaluated with mid-term and long-term studies, thereby it is necessary to represent their behavior with appropriate models. Model must represent the problem being studied [27]. Results provided indicates that dynamic simulations is an appropriate method for evaluation tap-changer operation in distribution networks.

Chapter 9

Conclusion and further work

9.1 Conclusion

Based on obtained results, tap-changer control design in network with DG could be based on the traditional transformer model, in addition to use of current measurement and compensation parameters. It is necessary to measure voltage and current in all four quadrants. Results indicates that traditional transformer voltage control may be insufficient in networks with DG. It is illustrated that a traditional transformer voltage control, with and without line drop compensation (LDC), may cause erroneous and undesired tap-changer operation when introducing DG.

The main contribution of the thesis is moving away from a conventional transformer voltage control in which voltage are kept constant at the transformer secondary side, to an approach in which power flow decides tap-changer position. Measured voltage and line current are used to determine tap-changer setting on an OLTC equipped transformer. It is the same principle used in the traditional transformer model for line drop compensation. It requires no communication. The compensation parameters are determined by a desired contribution at a given operational situation. Thereby, tap-changer position becomes a function of the power flow through the transformer, and a droop relation for the voltage based on the active power flow is obtained. Power flow through the transformer is a result of load demand, DG production and inherent network properties.

The droop relation between voltage level and power flow introduced with the transformer voltage control may ease coordination between voltage regulation mechanism in the network. Other voltage regulation mechanisms could be regulators for synchronous generators. Results presented illustrates that use of a transformer voltage droop control in cooperation with voltage regulation mode on synchronous generators may be an effective way of reducing the total number of tap-changer operations.

An effective voltage regulation is feasible by use of the possibilities offered by the OLTC. Synchronous generators may be run in PF/VAr regulation mode when using OLTC for active voltage regulation. This operational mode is by calculations seen to reduce network loss at times of low load demand, but increase in frequency of tap-changer operations is observed. A higher frequency of tap-changer operations may lead to higher wear and increased aging of the tap-changer. Results presented indicates that a loss reduction by some 15 % can be obtained when adapting tap-changer position to network operational situation.

A challenge in networks with low reactance/resistance relation with high share of DG, could be export of active power, and import of reactive power during low load. Export of active power may cause voltage rise along the network feeder, while import of reactive power may imply undesired tap-changer operation and increased losses. It is shown that undesired tap-changer operation can be reduced by determining compensation parameters based on a linearization and desired contribution from the tap-changer, whereas active power flow is the main criteria for tap-changer operation.

9.2 Further work

A suggestion for further work is field-testing of the proposed tap-changer control, in which the suggested approach for determination of compensation parameters is used. A possible field test would reveal if the proposed approach for determination of compensation parameters is a feasible practical solution. As coordination between voltage regulation mechanism could be easier with a transformer voltage droop control, a network in which synchronous generators are present could be an interesting field-test scenario.

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Appendices

Appendix A

Model in DIgSILENT PowerFactory

The appendix includes models, script and data used for modeling in DIgSILENT PowerFactory.

A.1 Network model

Figure A.1.1 illustrates the model developed in DIgSILENT PowerFactory. Model details are given in Appendix A.

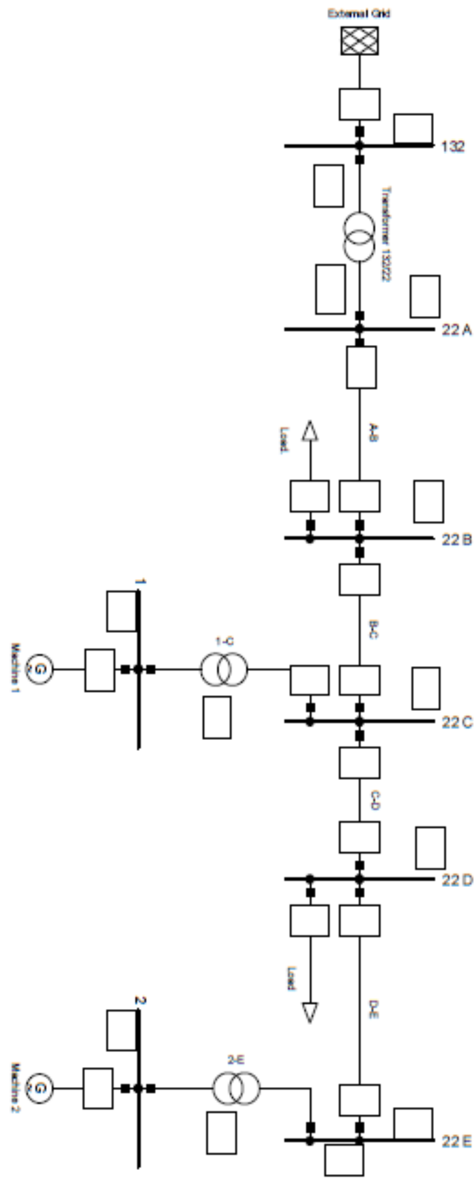


Figure A.1.1: Schematic of model developed in PowerFactory

A.2 External network

The external network is modeled as a swing bus. Parameters of the external network is provided in table A.1.

Table A.1: Initial values used for the external network

Variable	Value
Voltage	1.0 p.u.
Short circuit power	200 MVA
R/X ratio	0.1
Secondary frequency bias	100 MW/HZ
Acceleration time constant	99 s

A.3 22 kV line

The line model used is a π equivalent model. Table A.2 contains parameters 22 kV line. The parameters are obtained from *Tekniske data, Planleggingsbok for kraftnett*[7].

Table A.2: Parameters for 22 kV line

	Cu eqv	R $[\frac{\Omega}{km}]$	X $[\frac{\Omega}{km}]$	C_d $[\frac{nF}{km}]$	R_0 $[\frac{\Omega}{km}]$	X_0 $[\frac{\Omega}{km}]$	C_j $[\frac{nF}{km}]$	I_{th} [A]
79-AL1	50	0,36	0,38	9,663	0,707	1,216	5,241	407

A.4 Generator

Table A.3: Parameter for synchronous generator with salient poles

Parameter	Value	Description
Sn [MVA]	16	Generator rating
Un [kV]	6.6	Nominal voltage
Xd [p.u.]	2.04	d-axis synchronous reactance
Xd' [p.u.]	0.238	d-axis transient reactance
Xd" [p.u.]	0.143	d-axis subtransient reactance
Xq [p.u.]	1.16	q-axis sync. reactance
Xq" [p.u.]	0.137	q-axis subtr. reactance
ra [p.u.]	0.00219	Armature resistance
Xl [p.u.]	0.13	Leakage reactance
Td0' [s]	2.38	d-axis open-circuit tr. time constant
Td0" [s]	0.0117	d-axis open-circuit subtransient time constant
Tq0" [s]	0.11	q-axis open-circuit subtransent time constant
H [s]	0.836	Inertia constant
V1D [p.u.]	1.0	d-axis air-gap flux corresp. to SE1D
SE1D [p.u.]	0.1	Saturation factor corresp. to V1D
V2D [p.u.]	1.2	d-axis air-gap flux corresp. to SE2D
SE2D [p.u.]	0.3	Saturation factor corresp. to V2D

A.4.1 Automatic voltage regulator

Schematic for the automatic voltage regulator type ESAC8B is illustrated in figure A.4.2. The voltage regulator type is used for studies in which the generator excitation is a brushless static system.

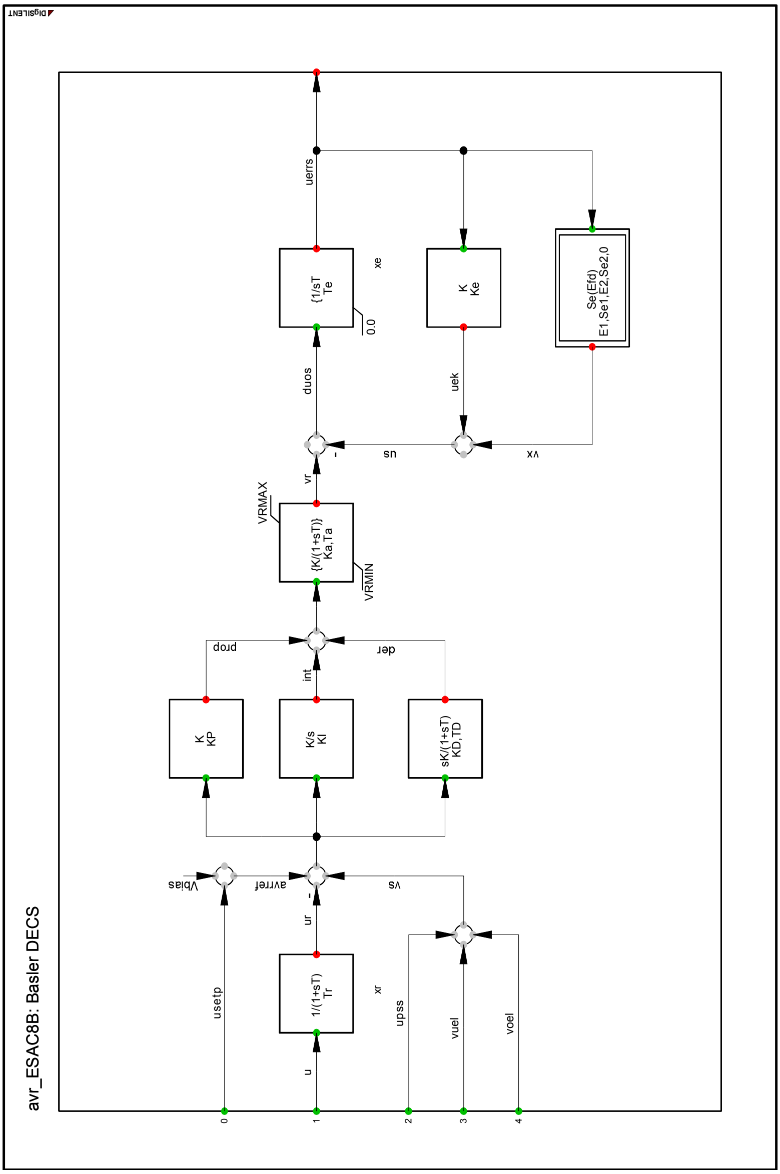


Figure A.4.2: Schematic for the automatic voltage regulator ESAC8B

A.4.2 Tuning of voltage regulator

Tuning of the voltage regulators for use in dynamic studies are tuned to comply with the suggestion found in FIKS [37]. The suggested ranges are:

- Settling time less than 2 seconds for a steady state voltage within ±2.5 %
- For a 5 % step response test with the generator disconnected from the grid, time to reach 90 % of steady state value is less than 1 second
- Maximum overshoot must be less than 15 % of the step

Table A.4 shows initial and tuned parameters for the voltage regulator. The parameters are determined by selection and observation of the response, shown in figure A.4.3.

Table A.4: AVR parameters

Parameter	Initial	Tuned	Description
Tr [s]	0.02	0.02	Measurement Time const
KP [p.u.]	0.2	0.2	Proportional Gain
Ka[p.u.]	100	40	Controller Gain
Ta [s]	0.02	0.02	Controller Time Constant
Ke [p.u.]	0.5	0.5	Exciter Constant
KI [p.u.]	0.05	0.05	Integral Gain
Te [s]	0.35	0.35	Exciter Time Constant
E1 [p.u.]	3.9	3.9	Saturation Factor 1
Se1 [p.u.]	0.1	0.1	Saturation Factor 2
E2 [p.u.]	5.2	5.2	Saturation Factor 3
Se2 [p.u.]	0.5	0.5	Saturation Factor 4
KD [p.u.]	0.05	0.1	Derivative Gain
TD [s]	0.03	0.03	Time Const. Derivative Action
VRMIN [p.u.]	-5.0	-5.0	Controller Minimum Output
VRMAX [p.u.]	5.0	5.0	Controller Maximum Output

The step respons test are performed with 0.05 p.u. step in the reference. The steps are +0.05 p.u. (1.0 to 1.05) at t = 0s, and -0.05 p.u. (1.05 to 1.0) at t = 15s. Maximum overshoot is 15 % of the step, i.e. maximum value is 1.0575 p.u. The results are shown in figure A.4.3.

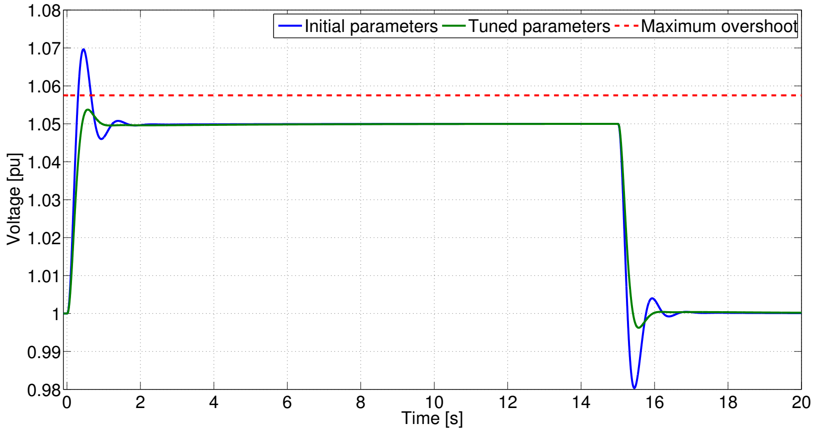


Figure A.4.3: Step respons test of voltage regulator

A.4.3 PF/VAr regulator

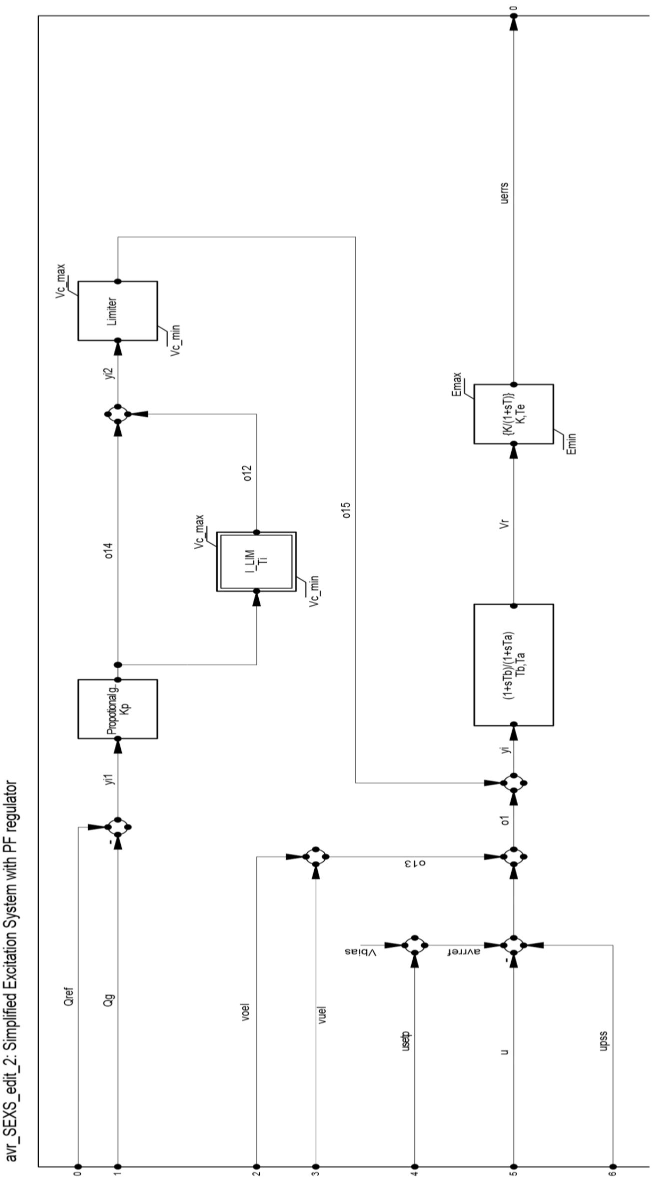


Figure A.4.4: Schematic for avr type SEXS with PF/VAr regulator

The PF/VAr regulator is a type II controller [24]. Figure A.4.4 illustrates a SEXS (Simplified Excitation System) equipped with a PF/VAr regulator. Table A.5 holds the parameters. Parameters above the vertical line is AVR parameters, while parameters below for PF/VAr regulator.

Table A.5: PF/var regulator parameters

Parameter	Value	Description
Ta [s]	2.0	Filter Derivative Time Constant
K [pu]	100.0	Controller Gain
Tb [s]	10.0	Filter Delay Time
Te [s]	0.5	Exciter Time Constant
Vc_{min} [pu]	-0.1	PF/var Controller Minimum Output
Vc_{max} [pu]	0.1	PF/var Controller Maximum Output
Ti [s]	10.0	Limited Integrator Time Constant
Kp [pu]	0.1	Proportional Gain
E_{min} [pu]	-3.0	Controller Minimum Output
E_{max}[pu]	3.0	Controller Maximum Output

A test for illustration of the PF/VAr regulator is provided. At t = 20 the reactive power reference is changed from 0 to -1.0 [MVAr]. Figure A.4.5 illustrates reactive power output and terminal voltage.

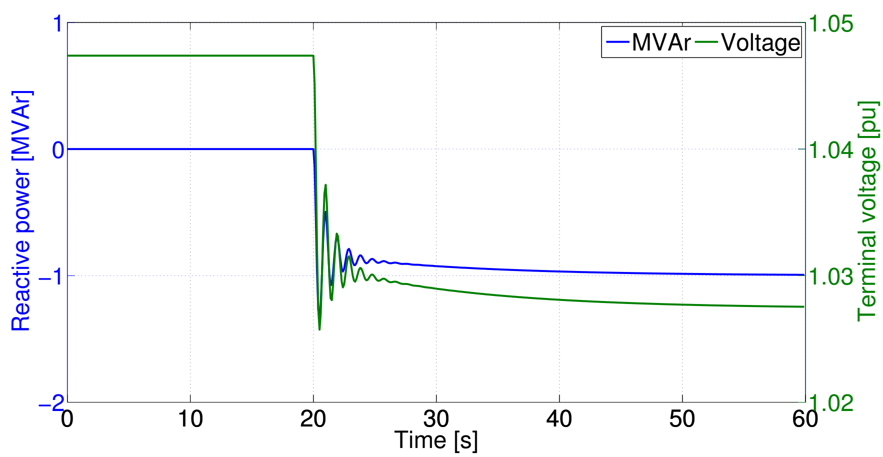


Figure A.4.5: Simulation of PF/VAr regulator

A.5 Transformer

Parameters for transformers in the network are given in table A.6.

Table A.6: Transformers

Parameter	Description	Transformer	Generator step-up
S_n	Capacity [MVA]	50	20
V_{HV}	Voltage primary side [kV]	132	22
V_{LV}	Voltage secondary side [kV]	22	6.6
X	Reactance [p.u.]	0.135	0.1
R	Resistance [p.u.]	0.0042	0.003

A.5.1 Tap-changer setup

Table A.7: Tap-changer setup

Parameter	Description	Initial	Based on OPF
v_{max}	Max Voltage [p.u.]	1.01	1.02
v_{min}	Min Voltage [p.u.]	0.99	0.98
v_{setp}	Voltage Set-point [p.u.]	1.0	1.0
Tdelay	Tap-changer Delay [s]	20	20
Tap min	Min Tap Position [p.u.]	-8	-8
Tap max	Max Tap Position [p.u.]	8	8

A.5.2 Modeling transformer tap-changer

Modeling of the automatic tap-changer with droop control in DIgSILENT PowerFactory is illustrated in this section.

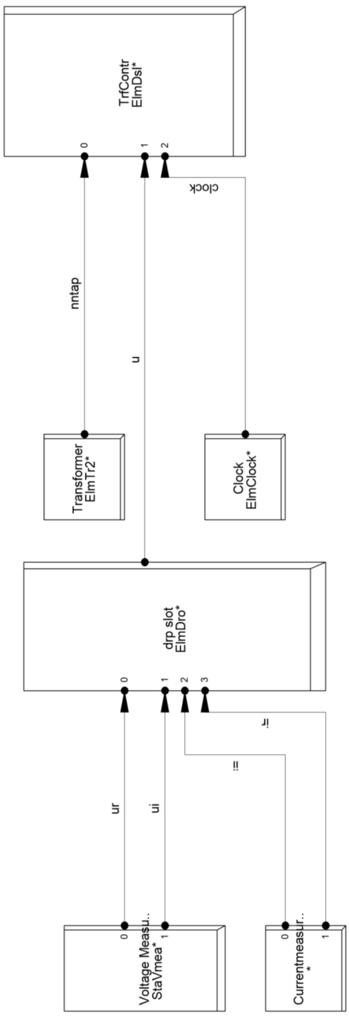


Figure A.5.6: Frame for transformer tap-changer

In figure A.5.6 frame for the transformer is illustrated. The frame contains several slots, which is assigned for different elements. The tap-changer frame consist of six slots.

Table A.8: Tap-changer frame description

Slot	Description
Voltage measurement	Voltage measurement for droop control
Current measurement	Current measurement for droop control
Droop(drpslot)	Calculation of voltage used for tap-changer control
Transformer	Obtain initial tap-placement used for tap-control
Clock	Used for tap-control
Transformer control(TrfContr)	Tap-changer control

Droop control

The code used to calculate the voltage used for the tap-control is given below.

```
inc(u)=0;
Iii=ii;
Iir=ir;

Ur= ur + (R*Iir) - (X*Iii);
Ui= ui + (Iii*R) + (X*Iir);

Ur2=sqr(Ur);
Ui2=sqr(Ui);
u2=Ur2+Ui2;

u=sqrt(u2)
```

Table A.9: Droop control description

Variable	Description
ir	Current measurement. Real transformer current in p.u.
ii	Current measurement. Imaginary transformer current in p.u.
vr	Voltage measurement. Real voltage in p.u.
vi	Voltage measurement. Imaginary voltage in p.u.
R	Droop parameter
X	Droop parameter

Tap-changer control

Figure A.5.7 illustrates the content of the transformer control slot in figure A.5.6.

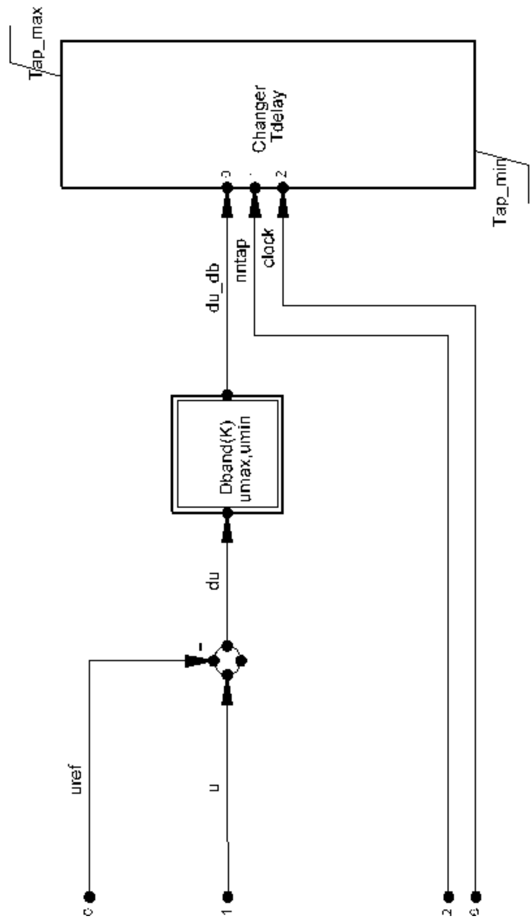


Figure A.5.7: Tap-changer control

The content of the Changer slot in figure A.5.7 is listed below.

```
inc(a) =0
a=(du_db/abs(du_db)) !Calculate sign of voltage error

!If negative voltage error; c is positive
c=select(0>a,1,-1)
!If positive voltage error; d is positive
d= select(a>0,1,-1)

!Define direction of next tap
up = lim((nntap + 1),Tap_min,Tap_max) !Define upward tap
down = lim((nntap - 1),Tap_min,Tap_max)! Define downward tap
```

```
!Tap initializes when sign changes from zero to positive.
!Clock signal used to force zero crossing
evtdown  = c + clock - 1.5
evtup  = d + clock - 1.5

!Event is used to change the tap-changer
!Tdelay is delay in seconds before tap-change
event(1,evtdown,'name=Change dtime=Tdelay value=down')
event(1,evtup,'name=Change dtime=Tdelay value=up')
```

Note regarding time-delay

The time-delay used is a delay from the decision for a tap-change is made, to the execution of the tap-change. It should be noted that in the tap-changer modeling presented in [26, 34], the time-delay is a time in which the voltage needs to be observed with an value beyond the limits. This implies that the model used will execute a tap-change even if the voltage deviation last only for a few seconds.

It was not successful to implement the correct use of time-delay in the model. The main purpose regarding testing of the tap-changer is the influence of the compensation parameters. It is considered not to have impact for the main results. The main issue of the tap-changer control time-delay reveals if simulation with transients from, for instance, short circuit is performed.

Appendix B

Optimal power flow

B.1 Optimal power flow results

This appendix contains results from optimal power flow (OPF) carried in DIgSILENT PowerFactory out for different purposes.

B.1.1 Determination of transformer droop parameters

Data from OPF for low load with DG production, and high load without DG production, is attached. The purpose of the OPF results is to determine optimal tap-changer position in different operational situations.

High load situation

DIgSILENT PowerFactory 14.1.6	Project:
	Date: 3/16/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
132										
	132,00	1,00	132,00	0,00						
Cub_1	/Xnet	External Grid			10,62	4,25	0,93	0,05		Sk": 200,00 MVA
Cub_2	/Tr2	Trafo 132/22			10,62	4,25	0,93	0,05	22,89	Tap: -6,00 Min: -8 Max: 8
2										
	6,60	0,99	6,51	-4,23						
Cub_2	/Sym	Machine 2								Typ: PQ
Cub_1	/Tr2	2-E			-0,00	-0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
1										
	6,60	1,01	6,68	-3,46						
Cub_2	/Sym	Machine 1								Typ: PQ
Cub_1	/Tr2	1-C			-0,00	-0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
22B										
	22,00	1,04	22,83	-2,72						
Cub_3	/Lod	Load.			5,00	1,67	0,95	0,13		Pl0: 5,00 MW Ql0: 1,67 Mvar
Cub_1	/Lne	A-B			-10,21	-3,54	-0,94	0,27	67,17	Pv: 403,43 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			5,21	1,87	0,94	0,14	34,43	Pv: 105,98 kW cLod: 0,01 Mvar L: 5,00 km
22C										
	22,00	1,01	22,26	-3,46						
Cub_1	/Lne	B-C			-5,11	-1,77	-0,94	0,14	34,43	Pv: 105,98 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			5,11	1,77	0,94	0,14	34,44	Pv: 106,08 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			0,00	0,00	1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data					
22D															
	22,00	0,99	21,70	-4,23											
Cub_3	/Lod	Load			5,00	1,67	0,95	0,14		Pl0:	5,00 MW	Ql0:	1,67 Mvar		
Cub_1	/Lne	C-D			-5,00	-1,66	-0,95	0,14	34,44	Pv:	106,08 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	D-E			0,00	-0,01	0,00	0,00	0,05	Pv:	0,00 kW	cLod:	0,01 Mvar	L:	5,00 km
22E															
	22,00	0,99	21,70	-4,23											
Cub_1	/Lne	D-E			-0,00	0,00	-1,00	0,00	0,05	Pv:	0,00 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Tr2	2-E			0,00	0,00	1,00	0,00	0,00	Tap:	0,00	Min:	0	Max:	0
22A															
	22,00	1,09	23,93	-1,36											
Cub_1	/Tr2	Trafo	132/22		-10,62	-3,96	-0,94	0,27	22,89	Tap:	-6,00	Min:	-8	Max:	8
Cub_2	/Lne	A-B			10,62	3,96	0,94	0,27	67,17	Pv:	403,43 kW	cLod:	0,01 Mvar	L:	5,00 km

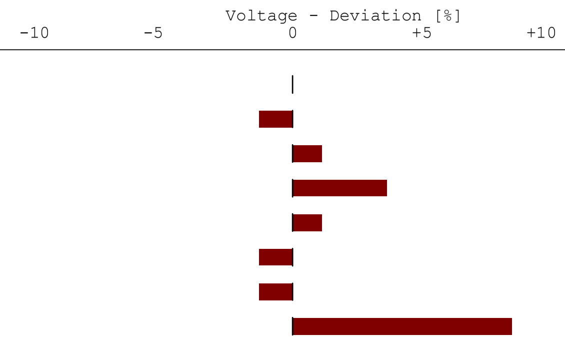
		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/16/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 3

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
132	132,00	1,000	132,00	0,00
2	6,60	0,986	6,51	-4,23
1	6,60	1,012	6,68	-3,46
22B	22,00	1,038	22,83	-2,72
22C	22,00	1,012	22,26	-3,46
22D	22,00	0,986	21,70	-4,23
22E	22,00	0,986	21,70	-4,23
22A	22,00	1,088	23,93	-1,36



		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/16/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 4

Volt. Level [kV]	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen-sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Interchange to	Power Interchange [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
6,60	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
22,00	0,00	0,00	10,00	0,00	0,00			0,62	0,62	-0,00
	0,00	0,00	3,34	0,00	0,00			0,62	0,65	-0,03
						132,00 kV	-10,62	0,01	0,01	0,00
							-3,96	0,29	0,29	0,00
132,00	0,00	0,00	0,00	0,00	10,62			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	4,25			0,00	0,00	0,00
						22,00 kV	10,62	0,01	0,01	0,00
							4,25	0,29	0,29	0,00
Total:	0,00	0,00	10,00	0,00	10,62		0,00	0,62	0,62	-0,00
	0,00	0,00	3,34	0,00	4,25		0,00	0,91	0,94	-0,03

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/16/2014

Optimal Power Flow

Max. Acceptable Error for Nodes	1,00	kVA
Max. Acceptable Error for Model Equations	0,10	%

Total System Summary | Study Case: Study Case | Annex: / 5

	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen-sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Inter Area Flow [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
\Anders\Master4\Network Model\Network Data\Grid	0,00	0,00	10,00	0,00	10,62	0,00	0,62	0,62	-0,00
	0,00	0,00	3,34	0,00	4,25	0,00	0,91	0,94	-0,03
Total:	0,00	0,00	10,00	0,00	10,62		0,62	0,62	-0,00
	0,00	0,00	3,34	0,00	4,25		0,91	0,94	-0,03

Low load situation

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/14/2014

Optimal Power Flow

Max. Acceptable Error for Nodes	1,00 kVA
Max. Acceptable Error for Model Equations	0,10 %

Grid: Grid System Stage: Grid Study Case: Study Case Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1	6,60	1,02	6,73	6,79						
Cub_2	/Sym	Machine 1			5,00	-0,00	1,00	0,43	31,25	Typ: PQ
Cub_1	/Tr2	1-C			5,00	0,00	1,00	0,43	24,53	Tap: 0,00 Min: 0 Max: 0
132	132,00	1,00	132,00	0,00						
Cub_1	/Xnet	External Grid			-7,34	1,71	-0,97	0,03		Sk": 200,00 MVA
Cub_2	/Tr2	Trafo 132/22			-7,34	1,71	-0,97	0,03	15,53	Tap: 2,00 Min: -8 Max: 8
2	6,60	1,05	6,92	8,72						
Cub_2	/Sym	Machine 2			5,00	0,00	1,00	0,42	31,25	Typ: PQ
Cub_1	/Tr2	2-E			5,00	-0,00	1,00	0,42	23,85	Tap: 0,00 Min: 0 Max: 0
22B	22,00	0,99	21,77	3,29						
Cub_3	/Lod	Load.			1,00	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	A-B			7,57	-1,32	0,99	0,20	50,07	Pv: 224,23 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			-8,57	0,99	-0,99	0,23	56,22	Pv: 282,71 kW cLod: 0,01 Mvar L: 5,00 km
22C	22,00	1,02	22,41	5,41						
Cub_1	/Lne	B-C			8,85	-0,70	1,00	0,23	56,22	Pv: 282,71 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			-3,86	0,58	-0,99	0,10	24,70	Pv: 54,54 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			-5,00	0,12	-1,00	0,13	24,53	Tap: 0,00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

		rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22D											
		22,00	1,03	22,67	6,36						
Cub_3	/Lod		Load			1,00	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne		C-D			3,91	-0,53	0,99	0,10	24,70	Pv: 54,54 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne		D-E			-4,91	0,20	-1,00	0,13	30,76	Pv: 84,63 kW cLod: 0,01 Mvar L: 5,00 km
22E											
		22,00	1,05	23,05	7,42						
Cub_1	/Lne		D-E			5,00	-0,11	1,00	0,13	30,76	Pv: 84,63 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2		2-E			-5,00	0,11	-1,00	0,13	23,85	Tap: 0,00 Min: 0 Max: 0
22A											
		22,00	0,97	21,27	1,22						
Cub_1	/Tr2		Trafo 132/22			7,35	-1,55	0,98	0,20	15,53	Tap: 2,00 Min: -8 Max: 8
Cub_2	/Lne		A-B			-7,35	1,55	-0,98	0,20	50,07	Pv: 224,23 kW cLod: 0,01 Mvar L: 5,00 km

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/14/2014

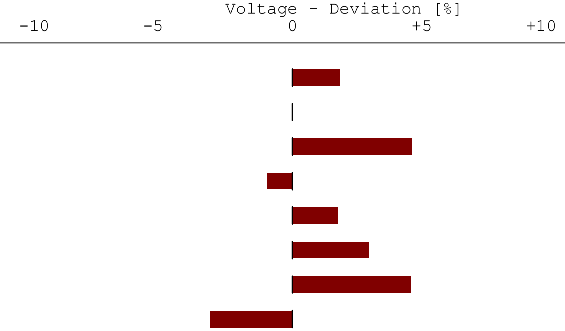
Optimal Power Flow

Max. Acceptable Error for Nodes	1,00 kVA
Max. Acceptable Error for Model Equations	0,10 %

Grid: Grid — System Stage: Grid — Study Case: Study Case — Annex: / 3

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
1	6,60	1,019	6,73	6,79
132	132,00	1,000	132,00	0,00
2	6,60	1,048	6,92	8,72
22B	22,00	0,990	21,77	3,29
22C	22,00	1,019	22,41	5,41
22D	22,00	1,031	22,67	6,36
22E	22,00	1,048	23,05	7,42
22A	22,00	0,967	21,27	1,22

Voltage - Deviation [%]



		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/14/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 4

Volt. Level [kV]	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen- sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Interchange to	Power Interchange [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
6,60	10,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
	-0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
						22,00 kV	10,00	0,01	0,01	0,00
							0,00	0,23	0,23	0,00
22,00	0,00	0,00	2,00	0,00	0,00			0,65	0,65	0,00
	0,00	0,00	0,66	0,00	0,00			0,65	0,68	-0,03
						6,60 kV	-9,99	0,01	0,01	0,00
							0,23	0,23	0,23	0,00
						132,00 kV	7,35	0,01	0,01	0,00
							-1,55	0,16	0,16	0,00
132,00	0,00	0,00	0,00	0,00	-7,34			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	1,71			0,00	0,00	0,00
						22,00 kV	-7,34	0,01	0,01	0,00
							1,71	0,16	0,16	0,00
Total:	10,00	0,00	2,00	0,00	-7,34		0,00	0,66	0,66	0,00
	-0,00	0,00	0,66	0,00	1,71		0,00	1,05	1,08	-0,03

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/14/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Total System Summary | Study Case: Study Case | Annex: / 5

	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen-sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Inter Area Flow [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
\Anders\Master4\Network Model\Network Data\Grid	10,00 -0,00	0,00 0,00	2,00 0,66	0,00 0,00	-7,34 1,71	0,00 0,00	0,66 1,05	0,66 1,08	0,00 -0,03
Total:	10,00 -0,00	0,00 0,00	2,00 0,66	0,00 0,00	-7,34 1,71		0,66 1,05	0,66 1,08	0,00 -0,03

Appendix C

Timesweep script

C.1 Time sweep

The time sweep studies are carried out using the DPL (DIgSILENT Programming Language) [1] script *TimeSweep*. The script are found under the menu *Execute DPL Script* on the toolbar.

C.1.1 Description

The *TimeSweep* script performs load flow calculations from a chosen start time, towards a final stop time with a chosen step size. The time used for calculation is 24h. By assigning load and generation changing characteristics, with the same time scale as the time sweep study, the time sweep script takes the changing load and generation into account when performing load flow calculations. With this change in load and/or generation time sweep studies can be a useful tool for calculating steady state values in the power system. If transformers are assigned with OLTC, the time sweep consider transformer tap-changer operation.

It is emphasized that the time sweep study is a series of load flow calculations, and not a dynamic simulation.

C.1.2 Time sweep study for calculating losses

Case A

The generators are modeled with $cos\phi = 1$. At low load situation, the droop control brings the tap position to tap-step 2. Running the Timesweep script with the generators modeled with $cos\phi = 1$, and tap-changer at step 2, the losses are calculated. Data for tap-changer and generators are shown in table C.1.

Table C.1: Generator output and tap-position for loss calculation

	Case A
Gen 1 [MVA]	5 + j0
Gen 2 [MVA]	5 +j0
Tap	2

Input to the Timesweep calculations are given in the section ”Results DG with unity PF”.

Results DG with unity PF

```
|                                                             | DIgSILENT     | Project:         |
|                                                             | PowerFactory  |------------------|
|                                                             |    14.1.6     | Date:  3/18/2014 |

| Calculation of Initial Conditions      Complete System Report: Substations, Voltage Profiles, Grid Interchange |
| Balanced, Positive Sequence        |                                                                     |
|                                    |        Maximum Error of Model Equations                    1,00 %    |

| Grid: Grid               System Stage: Grid | Study Case: Study Case          | Annex:               / 1 |

|          rated                    Active Reactive Power                |                                |
|         Voltage     Bus-voltage      Power   Power  Factor Current Loading|        Additional Data        |
|          [kV]  [p.u.]   [kV]   [deg]   [MW]   [Mvar]   [-]    [kA]    [%] |                                |
|1                                                                        |                                |
|         6,60    1,02    6,76    6,68                                     |                                |
|   Cub_2 /Sym     Machine 1               5,00     0,13   1,00    0,43   31,26 |Typ:    PQ                      |
|   Cub_1 /Tr2     1-C                     5,00     0,13   1,00    0,43   24,42 |Tap:     0,00     Min:      0      Max:     0 |
|132                                                                      |                                |
|       132,00    1,00  132,17    0,01                                     |                                |
|   Cub_1 /Xnet    External Grid          -7,43     1,42  -0,98    0,03   20,71 |Sk":   200,00 MVA               |
|   Cub_2 /Tr2     Trafo 132/22           -7,43     1,42  -0,98    0,03   15,57 |Tap:     2,00     Min:     -8      Max:     8 |
|2                                                                        |                                |
|         6,60    1,05    6,96    8,54                                     |                                |
|   Cub_2 /Sym     Machine 2               5,00     0,13   1,00    0,41   31,26 |Typ:    PQ                      |
|   Cub_1 /Tr2     2-E                     5,00     0,13   1,00    0,41   23,72 |Tap:     0,00     Min:      0      Max:     0 |
|22A                                                                      |                                |
|        22,00    0,97   21,32    1,24                                     |                                |
|   Cub_1 /Tr2     Trafo 132/22            7,44    -1,26   0,99    0,20   15,57 |Tap:     2,00     Min:     -8      Max:     8 |
|   Cub_2 /Lne     A-B                    -7,44     1,26  -0,99    0,20   50,21 |Pv:    225,51 kW  cLod: 0,01 Mvar L:    5,00 km |
|22B                                                                      |                                |
|        22,00    0,99   21,85    3,26                                     |                                |
|   Cub_3 /Lod     Load.                   0,95     0,31   0,95    0,03         |Pl0:     1,00 MW  Ql0:  0,33 Mvar           |
|   Cub_1 /Lne     A-B                     7,66    -1,03   0,99    0,20   50,21 |Pv:    225,51 kW  cLod: 0,01 Mvar L:    5,00 km |
|   Cub_2 /Lne     B-C                    -8,62     0,72  -1,00    0,23   56,13 |Pv:    281,85 kW  cLod: 0,01 Mvar L:    5,00 km |
|22C                                                                      |                                |
|        22,00    1,02   22,51    5,31                                     |                                |
|   Cub_1 /Lne     B-C                     8,90    -0,43   1,00    0,23   56,13 |Pv:    281,85 kW  cLod: 0,01 Mvar L:    5,00 km |
|   Cub_2 /Lne     C-D                    -3,90     0,43  -0,99    0,10   24,74 |Pv:     54,73 kW  cLod: 0,01 Mvar L:    5,00 km |
|   Cub_3 /Tr2     1-C                    -5,00    -0,01  -1,00    0,13   24,42 |Tap:     0,00     Min:      0      Max:     0 |
```

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 2

		rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data					
22D		22,00	1,04	22,79	6,23											
	Cub_3	/Lod	Load			0,96	0,32	0,95	0,03		Pl0:	1,00 MW	Ql0:	0,33 Mvar		
	Cub_1	/Lne	C-D			3,96	-0,38	1,00	0,10	24,74	Pv:	54,73 kW	cLod:	0,01 Mvar	L:	5,00 km
	Cub_2	/Lne	D-E			-4,91	0,07	-1,00	0,12	30,59	Pv:	83,68 kW	cLod:	0,01 Mvar	L:	5,00 km
22E		22,00	1,05	23,17	7,26											
	Cub_1	/Lne	D-E			5,00	0,01	1,00	0,12	30,59	Pv:	83,68 kW	cLod:	0,01 Mvar	L:	5,00 km
	Cub_2	/Tr2	2-E			-5,00	-0,01	-1,00	0,12	23,72	Tap:	0,00	Min:	0	Max:	0

Results from the Timesweep calculation is given in table C.2.

Table C.2: Load, generation and losses

	Case A
Total External Infeed	-176.239 MWh
Total Generation	240.048 MWh
Total Load	48.010 MWh
Total Losses	15.800 MWh

Case B and Case C

Case B with the transformer droop control disabled, hence tap-position kept at zero. Case C with the transformer droop control enabled. Input values to the loss calculation indicated in the table below, gathered from the sections "Results voltage control with only synch. generators" and "Results voltage control with synch. generators and transformer voltage droop", for Case B and Case C respectively.

Table C.3: Generator output and tap-position for Case B and Case C

	Case C	Case B
Gen 1 [MVA]	5 + j0.44	5 - j0.08
Gen 2 [MVA]	5 - j2.13	5 - j2.32
Tap	1	0

Table C.4: Load, generation and losses

	Case C	Case B
Total External Infeed	-173.959 MWh	-173.273 MWh
Total Generation	240.048 MWh	240.048 MWh
Total Load	48.010 MWh	48.010 MWh
Total Losses	18.080 MWh	18.765 MWh

$$\frac{18.080 - 18.765}{18.765} \cdot 100\% = -3.65\% \qquad \text{(C.1)}$$

Equation C.1 indicates that the losses are reduced by some 3.6%, compared Case B with Case C.

Results voltage control with only synch. generators

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/18/2014

Calculation of Initial Conditions — Complete System Report: Substations, Voltage Profiles, Grid Interchange

Balanced, Positive Sequence — Maximum Error of Model Equations 1,00 %

Grid: Grid — System Stage: Grid — Study Case: Study Case — Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1										
	6,60	1,02	6,73	7,65						
Cub_2	/Sym	Machine 1			5,00	-0,08	1,00	0,43	31,25	Typ: PV
Cub_1	/Tr2	1-C			5,00	-0,08	1,00	0,43	24,51	Tap: 0,00 Min: 0 Max: 0
132										
	132,00	1,00	132,00	-0,00						
Cub_1	/Xnet	External Grid			-7,22	4,29	-0,86	0,04	22,98	Sk": 200,00 MVA
Cub_2	/Tr2	Trafo 132/22			-7,22	4,29	-0,86	0,04	16,79	Tap: 0,00 Min: -8 Max: 8
2										
	6,60	1,02	6,73	10,65						
Cub_2	/Sym	Machine 2			5,00	-2,32	0,91	0,47	34,44	Typ: PV
Cub_1	/Tr2	2-E			5,00	-2,32	0,91	0,47	27,01	Tap: 0,00 Min: 0 Max: 0
22A										
	22,00	0,99	21,76	1,15						
Cub_1	/Tr2	Trafo 132/22			7,22	-4,10	0,87	0,22	16,79	Tap: 0,00 Min: -8 Max: 8
Cub_2	/Lne	A-B			-7,22	4,10	-0,87	0,22	54,16	Pv: 262,31 kW cLod: 0,01 Mvar L: 5,00 km
22B										
	22,00	1,00	22,02	3,67						
Cub_3	/Lod	Load.			1,00	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	A-B			7,49	-3,83	0,89	0,22	54,16	Pv: 262,31 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			-8,49	3,50	-0,92	0,24	59,14	Pv: 312,82 kW cLod: 0,01 Mvar L: 5,00 km

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22C										
	22,00	1,02	22,44	6,28						
Cub_1	/Lne	B-C			8,80	-3,18	0,94	0,24	59,14	Pv: 312,82 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			-3,80	2,98	-0,79	0,12	30,57	Pv: 83,54 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			-5,00	0,20	-1,00	0,13	24,51	Tap: 0,00 Min: 0 Max: 0
22D										
	22,00	1,02	22,50	7,71						
Cub_3	/Lod	Load			1,00	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	C-D			3,89	-2,90	0,80	0,12	30,57	Pv: 83,54 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	D-E			-4,89	2,57	-0,89	0,14	34,83	Pv: 108,47 kW cLod: 0,01 Mvar L: 5,00 km
22E										
	22,00	1,03	22,68	9,27						
Cub_1	/Lne	D-E			5,00	-2,46	0,90	0,14	34,83	Pv: 108,47 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			-5,00	2,46	-0,90	0,14	27,01	Tap: 0,00 Min: 0 Max: 0

Results voltage control with synch. generators and transformer voltage droop

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/18/2014

Calculation of Initial Conditions	Complete System Report: Substations, Voltage Profiles, Grid Interchange
Balanced, Positive Sequence	Maximum Error of Model Equations 1,00 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1										
	6,60	1,02	6,73	7,42						
Cub_2	/Sym	Machine 1			5,00	0,44	1,00	0,43	31,37	Typ: PV
Cub_1	/Tr2	1-C			5,00	0,44	1,00	0,43	24,60	Tap: 0,00 Min: 0 Max: 0
132										
	132,00	1,00	132,56	-0,02						
Cub_1	/Xnet	External Grid			-7,27	3,53	-0,90	0,04	22,11	Sk": 200,00 MVA
Cub_2	/Tr2	Trafo 132/22			-7,27	3,53	-0,90	0,04	16,33	Tap: 1,00 Min: -8 Max: 8
2										
	6,60	1,02	6,73	10,34						
Cub_2	/Sym	Machine 2			5,00	-2,13	0,92	0,47	33,96	Typ: PV
Cub_1	/Tr2	2-E			5,00	-2,13	0,92	0,47	26,63	Tap: 0,00 Min: 0 Max: 0
22A										
	22,00	0,98	21,57	1,16						
Cub_1	/Tr2	Trafo 132/22			7,27	-3,35	0,91	0,21	16,33	Tap: 1,00 Min: -8 Max: 8
Cub_2	/Lne	A-B			-7,27	3,35	-0,91	0,21	52,67	Pv: 248,09 kW cLod: 0,01 Mvar L: 5,00 km
22B										
	22,00	1,00	21,90	3,57						
Cub_3	/Lod	Load.			0,99	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	A-B			7,52	-3,10	0,92	0,21	52,67	Pv: 248,09 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			-8,51	2,77	-0,95	0,24	57,97	Pv: 300,55 kW cLod: 0,01 Mvar L: 5,00 km
22C										
	22,00	1,02	22,38	6,04						
Cub_1	/Lne	B-C			8,81	-2,46	0,96	0,24	57,97	Pv: 300,55 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			-3,81	2,78	-0,81	0,12	29,93	Pv: 80,03 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			-5,00	-0,32	-1,00	0,13	24,60	Tap: 0,00 Min: 0 Max: 0

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22D										
	22,00	1,02	22,46	7,44						
Cub_3	/Lod	Load			1,00	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	C-D			3,89	-2,70	0,82	0,12	29,93	Pv: 80,03 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	D-E			-4,89	2,37	-0,90	0,14	34,35	Pv: 105,46 kW cLod: 0,01 Mvar L: 5,00 km
22E										
	22,00	1,03	22,66	8,96						
Cub_1	/Lne	D-E			5,00	-2,27	0,91	0,14	34,35	Pv: 105,46 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			-5,00	2,27	-0,91	0,14	26,63	Tap: 0,00 Min: 0 Max: 0

Case D

Increasing the set-point voltage at machine 2 from 1.02 p.u. to 1.05p.u. Input values to the loss timesweep calculation are shown in section "Results voltage control with synch. generators and transformer voltage droop with increased voltage at machine 2".

The results from the timesweep calculation are given in table C.5.

Table C.5: Load, generation and losses with increased voltage machine 2

	Case D
Total External Infeed	-175.882 MWh
Total Generation	240.048 MWh
Total Load	48.010 MWh
Total Losses	16.156 MWh

The reduction in loss compared Case C and Case D are -10.64%, shown in equation C.2.

$$\frac{16.156 - 18.080}{18.080} \cdot 100\% = -10,64\% \tag{C.2}$$

Results voltage control with synch. generators and transformer voltage droop with increased voltage at machine 2

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/18/2014

Calculation of Initial Conditions	Complete System Report: Substations, Voltage Profiles, Grid Interchange
Balanced, Positive Sequence	Maximum Error of Model Equations 1,00 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 1

		rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1		6,60	1,02	6,73	6,90						
Cub_2	/Sym	Machine 1				5,00	-0,39	1,00	0,43	31,35	Typ: PV
Cub_1	/Tr2	1-C				5,00	-0,39	1,00	0,43	24,59	Tap: 0,00 Min: 0 Max: 0
132		132,00	1,01	133,10	-0,04						
Cub_1	/Xnet	External Grid				-7,36	2,19	-0,96	0,03	21,02	Sk": 200,00 MVA
Cub_2	/Tr2	Trafo 132/22				-7,36	2,19	-0,96	0,03	15,69	Tap: 2,00 Min: -8 Max: 8
2		6,60	1,05	6,93	8,86						
Cub_2	/Sym	Machine 2				5,00	-0,08	1,00	0,42	31,25	Typ: PV
Cub_1	/Tr2	2-E				5,00	-0,08	1,00	0,42	23,81	Tap: 0,00 Min: 0 Max: 0
22A		22,00	0,97	21,42	1,16						
Cub_1	/Tr2	Trafo 132/22				7,37	-2,02	0,96	0,21	15,69	Tap: 2,00 Min: -8 Max: 8
Cub_2	/Lne	A-B				-7,37	2,02	-0,96	0,21	50,60	Pv: 229,02 kW cLod: 0,01 Mvar L: 5,00 km
22B		22,00	0,99	21,88	3,32						
Cub_3	/Lod	Load.				0,98	0,32	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	A-B				7,60	-1,79	0,97	0,21	50,60	Pv: 229,02 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C				-8,58	1,46	-0,99	0,23	56,42	Pv: 284,68 kW cLod: 0,01 Mvar L: 5,00 km
22C		22,00	1,02	22,47	5,53						
Cub_1	/Lne	B-C				8,86	-1,17	0,99	0,23	56,42	Pv: 284,68 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D				-3,86	0,66	-0,99	0,10	24,75	Pv: 54,77 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C				-5,00	0,51	-0,99	0,13	24,59	Tap: 0,00 Min: 0 Max: 0

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22D										
	22,00	1,03	22,73	6,48						
Cub_3	/Lod	Load			0,99	0,33	0,95	0,03		Pl0: 1,00 MW Ql0: 0,33 Mvar
Cub_1	/Lne	C-D			3,92	-0,61	0,99	0,10	24,75	Pv: 54,77 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	D-E			-4,91	0,28	-1,00	0,12	30,71	Pv: 84,35 kW cLod: 0,01 Mvar L: 5,00 km
22E										
	22,00	1,05	23,10	7,56						
Cub_1	/Lne	D-E			5,00	-0,20	1,00	0,12	30,71	Pv: 84,35 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			-5,00	0,20	-1,00	0,12	23,81	Tap: 0,00 Min: 0 Max: 0

C.2 Modified *TimeSweep* script

The modified script are used in time sweep studies in the network model, and take the transformer voltage droop control scheme into consideration.

```
int    i, sweep, i_err;
int    Balanced, inotopo;
int    year, leap_year;
int    originalStudyTime, studyTime;
double max_hours, stop_hoy;
double TotLossLast, TotGenLast, TotInfeedLast, TotLoadLast;
string sStudyTime;
object com, tset;
object SumGrid;

        !Extra variables for the modified script
               int error,inc,ldf,lastflyt;
               double ii,ir,ur,ui,R,X,Ur,Ui,U;
               double u_min,u_max;
               R = 0.3;        !Droop parameter
               X = 0.1;        !Droop parameter
               u_max=1.02;     !Max voltage
               u_min=0.98;     !Min voltage


SumGrid = SummaryGrid();
if (SumGrid=NULL) {
  printf('No Summary Grid found.'); exit();
}
com = GetCaseCommand('ComLdf');
if (com=NULL) {
  printf('No loadflow command available'); exit();
}
inotopo = com:iopt_notopo;
if (com:iopt_net=0) Balanced = 1; else Balanced = 0;
tset = GetCaseObject('SetTime');  ! get time of study case
if (tset=NULL) {
  Error('No time settings available');
  exit();
}
! Save original values of Study Time:
originalStudyTime = tset:datetime;  ! time given as
 seconds since 01.01.1970 00:00:00
CreatePlotRes:ResObj  = Results;
CreatePlotRes:XvarObj = this;
CreatePlotRes:Xvar    = 'b:time';
i_err = CreatePlotRes.Execute(0, Balanced);
if (i_err) {
  printf('Cannot create result variable definitions.');
  exit();
}
i_err = CreatePlotRes.Execute(1, Balanced);
if (i_err) {
  printf('Cannot create graphs.');
  exit();
}
EchoOff();
if (start >= stop){
  Warn('Start time is later than stop time! Execution of
   time sweep not possible!');
  exit();
}
year = tset:year;   ! get year of study time (SetTime)
leap_year = tset:isleapyear;
if (leap_year) {
  max_hours = 8784;        ! leap year => 8784 hours
}
```

```
else {
  max_hours = 8760;        ! no leap year => 8784 hours
}
hour_of_year = start; ! "hour_of_year" is taken to change
SetTime stop_hoy = stop;
time = start;  ! "time" is taken for result diagrams, "time"
can continue over the end of a year
tset:min = 0.0;
tset:sec = 0.0;
i = 0;
sweep = 1;
while (sweep) {
  if (time > stop) {
    hour_of_year = stop_hoy;
    time = stop;
    sweep = 0;
  }
  ! Check if end of the year is reached:
  while (hour_of_year >= max_hours) {
    tset:year = year + 1;
    ! increase year of study case by 1
    hour_of_year = hour_of_year - (max_hours);
    ! subtract hours of a year
    stop_hoy = stop_hoy - (max_hours);
    ! subtract hours of a year
    tset.SetTime(hour_of_year);
    ! set hour of year to start of year
    leap_year = tset:isleapyear;
     ! Is current year a leap year?
    if (leap_year) {
     ! Set max. hours of current year
      max_hours = 8784;
      }
    else {
      max_hours = 8760;
    }
  }
  tset.SetTime(hour_of_year);
  if (i=0) {
 com:iopt_notopo = 0;
 studyTime = tset:datetime;
 sStudyTime = FormatDateLT('%Y-%m-%d, %H:%M:%S', studyTime);
 printf('Start Time Sweep at %s...', sStudyTime);
  }
  else {
    com:iopt_notopo = 1;
  }
  i_err = com.Execute(); ! execute loadflow

 !Evaluation of voltage from droop control, modified part
                        lastflyt = 1;
                        while (lastflyt){
                        error = Ldf.Execute();
                !Calculate voltage droop
                ii = Trafo132_22:m:ii:buslv;
                ir = Trafo132_22:m:ir:buslv;
                ui = Trafo132_22:m:ui:buslv;
                ur = Trafo132_22:m:ur:buslv;
                Ur = ur + ir*R - X*ii;
                Ui = ui + R*ii + X*ir;
                U = sqrt((sqr(Ur)+sqr(Ui)));
!Adjust tap-postion based on voltage from droop control
        if(U>u_max) {
        Trafo132_22:e:nntap = Trafo132_22:c:nntap +1; }
        else if(U<u_min){
        Trafo132_22:e:nntap = Trafo132_22:c:nntap -1;}
        else {
        Trafo132_22:e:nntap = Trafo132_22:c:nntap;
```

```
        lastflyt=0; }
                }
                !!End of modified part
  com:iopt_notopo = inotopo;
  if (i_err) { Error('Loadflow execution not successful');
   exit();}

  TotGen     = SumGrid:c:GenP;
  TotLoad    = SumGrid:c:LoadP + SumGrid:c:MotP;
  TotInfeed  = SumGrid:c:NetP;
  TotLoss    = SumGrid:c:LossP;
  if (i>0){
    ! numerical Integration
    TotEnLoss    += step/2*(TotLossLast   + TotLoss);
    TotEnGen     += step/2*(TotGenLast    + TotGen);
    TotEnInfeed  += step/2*(TotInfeedLast + TotInfeed);
    TotEnLoad    += step/2*(TotLoadLast   + TotLoad);
  }
  TotLossLast    = TotLoss;
  TotGenLast     = TotGen;
  TotInfeedLast  = TotInfeed;
  TotLoadLast    = TotLoad;

  Results.WriteDraw();

  ! set new time
  i += 1;
  time = start + i*step;   ! increase time based on start
  hour_of_year = hour_of_year + step;
  ! increase based on last hour of the year

}

studyTime = tset:datetime;
sStudyTime = FormatDateLT('%Y-%m-%d, %H:%M:%S', studyTime);
printf('Stop  Time Sweep at %s.', sStudyTime);

printf('');
printf('Summary:');
printf('Total External Infeed = %9.3f MWh', TotEnInfeed);
printf('Total Generation      = %9.3f MWh', TotEnGen);
printf('Total Load            = %9.3f MWh', TotEnLoad);
printf('Total Losses          = %9.3f MWh', TotEnLoss);

! Set Study Time to original values:
tset.SetTimeUTC(originalStudyTime);
! tset:year  = originalYear;
! tset:month = originalMonth;
! tset:day   = originalDay;
! tset:hour  = originalHour;
! tset:min   = originalMinute;
! tset:sec   = originalSec;

EchoOn();
```

Appendix D

Extended network model

D.1 Extended network model

D.1.1 300/132 kV transformer

Table D.1 holds parameters for 300/132 kV transformer used. Parameters for the other transformers are found in table A.6.

Table D.1: Parameter 300/132 kV transformer

Parameter	Description	Value
Sn	Capacity [MVA]	60
V_{HV}	Voltage primary side [kV]	300
V_{LV}	Voltage secondary side [kV]	132
X	Reactance [p.u.]	0.135
R	Resistance [p.u.]	0.0042

D.1.2 132 kV line

Line parameters obtained from *Tekniske data, Planleggingsbok for kraftnett*[7].

Table D.2: Parameters for 132 kV line

	Cu eqv	R $[\frac{\Omega}{km}]$	X $[\frac{\Omega}{km}]$	C_d $[\frac{nF}{km}]$	R_0 $[\frac{\Omega}{km}]$	X_0 $[\frac{\Omega}{km}]$	C_j $[\frac{nF}{km}]$	I_{th} [A]
31-ST1A	120	0.153	0.411	8.926	0.479	0.892	6.75	732

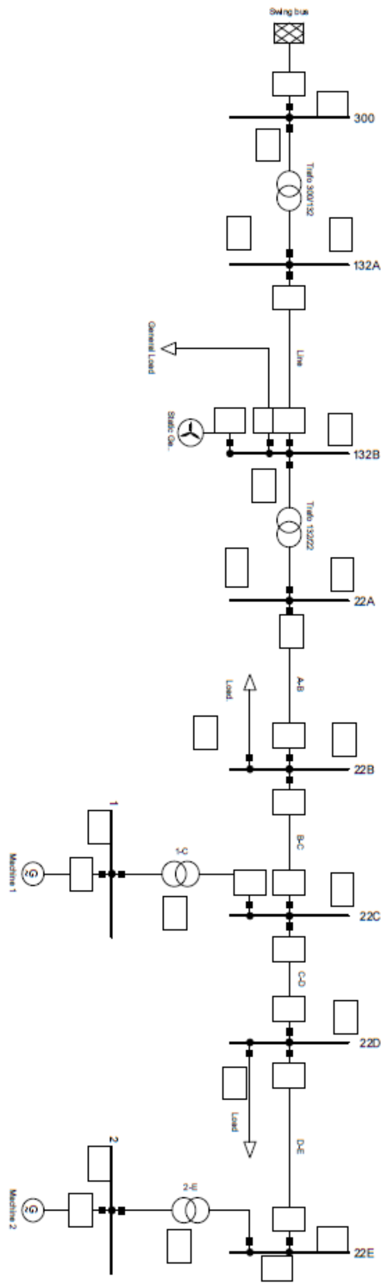


Figure D.1.1: Schematic of extended model developed in DIgSILENT PowerFactory

D.1.3 Optimal power flow at high load, extended network model

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Optimal Power Flow	
	Max. Acceptable Error for Nodes 1,00 kVA
	Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 1

		rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1											
		6,60	0,98	6,49	-8,22						
Cub_2	/Sym	Machine 1									Typ: PQ
Cub_1	/Tr2	1-C				-0,00	0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
132A											
		132,00	1,02	134,85	-3,69						
Cub_1	/Lne	Line				30,88	9,65	0,95	0,14	0,02	Pv: 222,89 kW cLod: 1,26 Mvar L: 25,00 km
Cub_2	/Tr2	Trafo 300/132				-30,88	-9,65	-0,95	0,14	55,28	Tap: -3,00 Min: -8 Max: 8
132B											
		132,00	1,01	133,21	-4,58						
Cub_4	/Genstat	Static Generator									
Cub_5	/Lod	General Load				20,00	6,00	0,96	0,09		Pl0: 20,00 MW Ql0: 6,00 Mvar
Cub_2	/Tr2	Trafo 132/22				10,66	4,31	0,93	0,05	22,79	Tap: -4,00 Min: -8 Max: 8
Cub_3	/Lne	Line				-30,66	-10,31	-0,95	0,14	0,02	Pv: 222,89 kW cLod: 1,26 Mvar L: 25,00 km
2											
		6,60	0,96	6,32	-9,04						
Cub_2	/Sym	Machine 2									Typ: PQ
Cub_1	/Tr2	2-E				-0,00	-0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
22A											
		22,00	1,06	23,37	-6,00						
Cub_1	/Tr2	Trafo 132/22				-10,65	-4,00	-0,94	0,28	22,79	Tap: -4,00 Min: -8 Max: 8
Cub_2	/Lne	A-B				10,65	4,00	0,94	0,28	69,08	Pv: 426,81 kW cLod: 0,01 Mvar L: 5,00 km

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

	rated Voltage [kV]	[p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22B										
	22,00	1,01	22,23	-7,44						
Cub_3	/Lod	Load.			5,00	1,67	0,95	0,14		Pl0: 5,00 MW Ql0: 1,67 Mvar
Cub_1	/Lne	A-B			-10,23	-3,56	-0,94	0,28	69,08	Pv: 426,81 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			5,23	1,89	0,94	0,14	35,47	Pv: 112,46 kW cLod: 0,01 Mvar L: 5,00 km
22C										
	22,00	0,98	21,65	-8,22						
Cub_1	/Lne	B-C			-5,11	-1,78	-0,94	0,14	35,47	Pv: 112,46 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			5,11	1,78	0,94	0,14	35,48	Pv: 112,56 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			0,00	-0,00	1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
22D										
	22,00	0,96	21,07	-9,04						
Cub_3	/Lod	Load			5,00	1,67	0,95	0,14		Pl0: 5,00 MW Ql0: 1,67 Mvar
Cub_1	/Lne	C-D			-5,00	-1,66	-0,95	0,14	35,48	Pv: 112,56 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	D-E			0,00	-0,01	0,00	0,00	0,05	Pv: 0,00 kW cLod: 0,01 Mvar L: 5,00 km
22E										
	22,00	0,96	21,07	-9,04						
Cub_1	/Lne	D-E			-0,00	-0,00	-1,00	0,00	0,05	Pv: 0,00 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			0,00	0,00	1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
300										
	300,00	1,00	300,00	0,00						
Cub_2	/Xnet	Swing bus			30,95	11,91	0,93	0,06		Sk": 2000,00 MVA
Cub_1	/Tr2	Trafo 300/132			30,95	11,91	0,93	0,06	55,28	Tap: -3,00 Min: -8 Max: 8

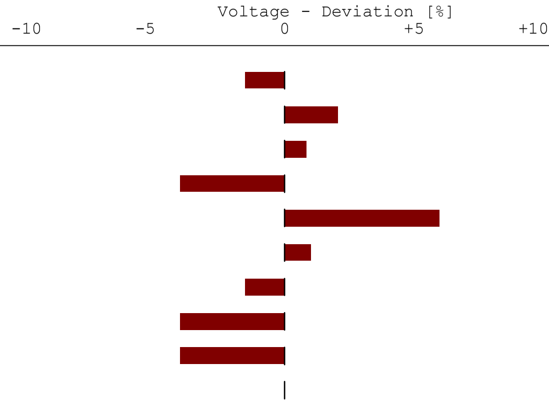
		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Optimal Power Flow

Max. Acceptable Error for Nodes	1,00 kVA
Max. Acceptable Error for Model Equations	0,10 %

Grid: Grid — System Stage: Grid — Study Case: Study Case — Annex: / 3

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
1	6,60	0,984	6,49	-8,22
132A	132,00	1,022	134,85	-3,69
132B	132,00	1,009	133,21	-4,58
2	6,60	0,958	6,32	-9,04
22A	22,00	1,062	23,37	-6,00
22B	22,00	1,010	22,23	-7,44
22C	22,00	0,984	21,65	-8,22
22D	22,00	0,958	21,07	-9,04
22E	22,00	0,958	21,07	-9,04
300	300,00	1,000	300,00	0,00



		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Grid: Grid System Stage: Grid | Study Case: Study Case | Annex: / 4

Volt. Level [kV]	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen-sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Interchange to	Power Interchange [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
6,60	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
22,00	0,00	0,00	10,00	0,00	0,00			0,65	0,65	0,00
	0,00	0,00	3,34	0,00	0,00			0,66	0,69	-0,03
						132,00 kV	-10,65	0,01	0,01	0,00
							-4,00	0,31	0,31	0,00
132,00	0,00	0,00	20,00	0,00	0,00			0,22	0,22	0,00
	0,00	0,00	6,00	0,00	0,00			-0,66	0,60	-1,26
						22,00 kV	10,66	0,01	0,01	0,00
							4,31	0,31	0,31	0,00
						300,00 kV	-30,88	0,07	0,07	0,00
							-9,65	2,26	2,26	0,00
300,00	0,00	0,00	0,00	0,00	30,95			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	11,91			0,00	0,00	0,00
						132,00 kV	30,95	0,07	0,07	0,00
							11,91	2,26	2,26	0,00
Total:	0,00	0,00	30,00	0,00	30,95		0,00	0,95	0,95	0,00
	0,00	0,00	9,34	0,00	11,91		0,00	2,57	3,85	-1,29

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Optimal Power Flow

Max. Acceptable Error for Nodes 1,00 kVA
Max. Acceptable Error for Model Equations 0,10 %

Total System Summary | Study Case: Study Case | Annex: / 5

	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen- sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Inter Area Flow [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
\Anders\Master4\Network Model\Network Data\Grid									
	0,00	0,00	30,00	0,00	30,95	0,00	0,95	0,95	0,00
	0,00	0,00	9,34	0,00	11,91	0,00	2,57	3,85	-1,29
Total:									
	0,00	0,00	30,00	0,00	30,95		0,95	0,95	0,00
	0,00	0,00	9,34	0,00	11,91		2,57	3,85	-1,29

D.1.4 Initial conditions at high load, extended network model

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Load Flow Calculation		Complete System Report: Substations, Voltage Profiles, Grid Interchange	
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1,00 kVA
		Model Equations	0,10 %

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	[kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
1										
	6,60	0,85	5,63	-9,78						
Cub_2	/Sym	Machine 1								Typ: PQ
Cub_1	/Tr2	1-C			-0,00	-0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
132A										
	132,00	0,97	128,25	-4,09						
Cub_1	/Lne	Line			31,14	10,19	0,95	0,15	0,02	Pv: 252,43 kW cLod: 1,14 Mvar L: 25,00 km
Cub_2	/Tr2	Trafo 300/132			-31,14	-10,19	-0,95	0,15	56,20	Tap: 0,00 Min: -8 Max: 8
132B										
	132,00	0,96	126,48	-5,08						
Cub_4	/Genstat	Static Generator								
Cub_5	/Lod	General Load			20,00	6,00	0,96	0,10		Pl0: 20,00 MW Ql0: 6,00 Mvar
Cub_2	/Tr2	Trafo 132/22			10,89	4,65	0,92	0,05	24,71	Tap: 0,00 Min: -8 Max: 8
Cub_3	/Lne	Line			-30,89	-10,65	-0,95	0,15	0,02	Pv: 252,43 kW cLod: 1,14 Mvar L: 25,00 km
2										
	6,60	0,82	5,43	-10,88						
Cub_2	/Sym	Machine 2								Typ: PQ
Cub_1	/Tr2	2-E			-0,00	0,00	-1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
22A										
	22,00	0,94	20,78	-6,91						
Cub_1	/Tr2	Trafo 132/22			-10,87	-4,24	-0,93	0,32	24,71	Tap: 0,00 Min: -8 Max: 8
Cub_2	/Lne	A-B			10,87	4,24	0,93	0,32	79,67	Pv: 567,73 kW cLod: 0,01 Mvar L: 5,00 km

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22B										
	22,00	0,88	19,46	-8,76						
Cub_3	/Lod	Load.			5,00	1,67	0,95	0,16		Pl0: 5,00 MW Ql0: 1,67 Mvar
Cub_1	/Lne	A-B			-10,30	-3,65	-0,94	0,32	79,67	Pv: 567,73 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	B-C			5,30	1,98	0,94	0,17	41,28	Pv: 152,35 kW cLod: 0,01 Mvar L: 5,00 km
22C										
	22,00	0,85	18,78	-9,78						
Cub_1	/Lne	B-C			-5,15	-1,82	-0,94	0,17	41,28	Pv: 152,35 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	C-D			5,15	1,82	0,94	0,17	41,29	Pv: 152,45 kW cLod: 0,01 Mvar L: 5,00 km
Cub_3	/Tr2	1-C			0,00	0,00	1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
22D										
	22,00	0,82	18,11	-10,88						
Cub_3	/Lod	Load			5,00	1,67	0,95	0,17		Pl0: 5,00 MW Ql0: 1,67 Mvar
Cub_1	/Lne	C-D			-5,00	-1,67	-0,95	0,17	41,29	Pv: 152,45 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Lne	D-E			0,00	-0,00	0,00	0,00	0,04	Pv: 0,00 kW cLod: 0,00 Mvar L: 5,00 km
22E										
	22,00	0,82	18,11	-10,88						
Cub_1	/Lne	D-E			-0,00	-0,00	-1,00	0,00	0,04	Pv: 0,00 kW cLod: 0,00 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			0,00	0,00	1,00	0,00	0,00	Tap: 0,00 Min: 0 Max: 0
300										
	300,00	1,00	300,00	0,00						
Cub_2	/Xnet	Swing bus			31,22	12,75	0,93	0,06		Sk": 2000,00 MVA
Cub_1	/Tr2	Trafo 300/132			31,22	12,75	0,93	0,06	56,20	Tap: 0,00 Min: -8 Max: 8

		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Load Flow Calculation — Complete System Report: Substations, Voltage Profiles, Grid Interchange

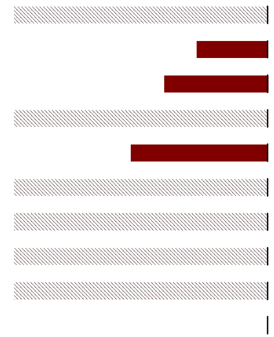
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1,00 kVA
		Model Equations	0,10 %

Grid: Grid — System Stage: Grid — Study Case: Study Case — Annex: / 3

Bus	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]
1	6,60	0,854	5,63	-9,78
132A	132,00	0,972	128,25	-4,09
132B	132,00	0,958	126,48	-5,08
2	6,60	0,823	5,43	-10,88
22A	22,00	0,945	20,78	-6,91
22B	22,00	0,885	19,46	-8,76
22C	22,00	0,854	18,78	-9,78
22D	22,00	0,823	18,11	-10,88
22E	22,00	0,823	18,11	-10,88
300	300,00	1,000	300,00	0,00

Voltage - Deviation [%]

-10 -5 0 +5 +10



		DIgSILENT PowerFactory 14.1.6	Project:
			Date: 3/21/2014

Load Flow Calculation — Complete System Report: Substations, Voltage Profiles, Grid Interchange

AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1,00 kVA
		Model Equations	0,10 %

Grid: Grid — System Stage: Grid — Study Case: Study Case — Annex: / 4

Volt. Level [kV]	Generation [MW]/ [Mvar]	Motor Load [MW]/ [Mvar]	Load [MW]/ [Mvar]	Compen-sation [MW]/ [Mvar]	External Infeed [MW]/ [Mvar]	Interchange to	Power Interchange [MW]/ [Mvar]	Total Losses [MW]/ [Mvar]	Load Losses [MW]/ [Mvar]	Noload Losses [MW]/ [Mvar]
6,60	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	0,00			0,00	0,00	0,00
22,00	0,00	0,00	10,00	0,00	0,00			0,87	0,87	0,00
	0,00	0,00	3,34	0,00	0,00			0,90	0,92	-0,02
						132,00 kV	-10,87	0,01	0,01	0,00
							-4,24	0,41	0,41	0,00
132,00	0,00	0,00	20,00	0,00	0,00			0,25	0,25	0,00
	0,00	0,00	6,00	0,00	0,00			-0,46	0,68	-1,14
						22,00 kV	10,89	0,01	0,01	0,00
							4,65	0,41	0,41	0,00
						300,00 kV	-31,14	0,08	0,08	0,00
							-10,19	2,56	2,56	0,00
300,00	0,00	0,00	0,00	0,00	31,22			0,00	0,00	0,00
	0,00	0,00	0,00	0,00	12,75			0,00	0,00	0,00
						132,00 kV	31,22	0,08	0,08	0,00
							12,75	2,56	2,56	0,00
Total:	0,00	0,00	30,00	0,00	31,22		0,00	1,22	1,22	0,00
	0,00	0,00	9,34	0,00	12,75		0,00	3,41	4,57	-1,16

D.1.5 Load flow - large active power import,reactive power export and 100km line length

		DIgSILENT PowerFactory 14.1.6	Project: Date: 4/4/2014

Load Flow Calculation			Busbars/Terminals
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1,00 kVA
		Model Equations	0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data					
2															
	6,60	1,14	7,50	22,23											
Cub_2	/Sym	Machine 2			5,00	0,00	1,00	0,38	31,25	Typ:	PQ				
Cub_1	/Tr2	2-E			5,00	0,00	1,00	0,38	21,99	Tap:	0,00	Min:	0	Max:	0
1															
	6,60	1,11	7,32	20,59											
Cub_2	/Sym	Machine 1			5,00	0,00	1,00	0,39	31,25	Typ:	PQ				
Cub_1	/Tr2	1-C			5,00	0,00	1,00	0,39	22,53	Tap:	0,00	Min:	0	Max:	0
22B															
	22,00	1,08	23,81	17,65											
Cub_3	/Lod	Load.			1,00	0,33	0,95	0,03		Pl0:	1,00 MW	Ql0:	0,33 Mvar		
Cub_1	/Lne	A-B			7,64	-1,21	0,99	0,19	46,06	Pv:	189,73 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	B-C			-8,64	0,88	-0,99	0,21	51,72	Pv:	239,27 kW	cLod:	0,01 Mvar	L:	5,00 km
22C															
	22,00	1,11	24,41	19,43											
Cub_1	/Lne	B-C			8,88	-0,63	1,00	0,21	51,72	Pv:	239,27 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	C-D			-3,88	0,53	-0,99	0,09	22,76	Pv:	46,34 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_3	/Tr2	1-C			-5,00	0,10	-1,00	0,12	22,53	Tap:	0,00	Min:	0	Max:	0
22D															
	22,00	1,12	24,65	20,22											
Cub_3	/Lod	Load			1,00	0,33	0,95	0,02		Pl0:	1,00 MW	Ql0:	0,33 Mvar		
Cub_1	/Lne	C-D			3,93	-0,49	0,99	0,09	22,76	Pv:	46,34 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	D-E			-4,93	0,16	-1,00	0,12	28,36	Pv:	71,93 kW	cLod:	0,01 Mvar	L:	5,00 km

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

		rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22E											
		22,00	1,14	25,00	21,12						
Cub_1	/Lne	D-E				5,00	-0,10	1,00	0,12	28,36	Pv: 71,93 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E				-5,00	0,10	-1,00	0,12	21,99	Tap: 0,00 Min: 0 Max: 0
132B											
		132,00	1,06	140,46	14,91						
Cub_5	/Lod	General Load				-50,00	6,00	-0,99	0,21		Pl0: -50,00 MW Ql0: 6,00 Mvar
Cub_2	/Tr2	Trafo 132/22				-7,44	1,54	-0,98	0,03	14,28	Tap: 0,00 Min: -8 Max: 8
Cub_3	/Lne	Line				57,44	-7,54	0,99	0,24	32,53	Pv: 5944,53 kW cLod: 5,09 Mvar L: 100,00 km
300											
		300,00	1,00	300,00	0,00						
Cub_2	/Xnet	Swing bus(1)				-51,30	15,86	-0,96	0,10		Sk": 1000,00 MVA
Cub_1	/Tr2	Trafo 300/132				-51,30	15,86	-0,96	0,10	89,49	Tap: 0,00 Min: -8 Max: 8
132A											
		132,00	0,97	128,69	6,86						
Cub_1	/Lne	Line				-51,50	9,37	-0,98	0,23	32,53	Pv: 5944,53 kW cLod: 5,09 Mvar L: 100,00 km
Cub_2	/Tr2	Trafo 300/132				51,50	-9,37	0,98	0,23	89,49	Tap: 0,00 Min: -8 Max: 8
22A											
		22,00	1,06	23,34	15,94						
Cub_1	/Tr2	Trafo 132/22				7,45	-1,40	0,98	0,19	14,28	Tap: 0,00 Min: -8 Max: 8
Cub_2	/Lne	A-B				-7,45	1,40	-0,98	0,19	46,06	Pv: 189,73 kW cLod: 0,01 Mvar L: 5,00 km

D.1.6 Load flow with large active power import and 100km line length

		DIgSILENT PowerFactory 14.1.6	Project: Date: 4/4/2014

Load Flow Calculation			Busbars/Terminals
AC Load Flow, balanced, positive sequence		Automatic Model Adaptation for Convergence	No
Automatic Tap Adjust of Transformers	No	Max. Acceptable Load Flow Error for	
Consider Reactive Power Limits	No	Nodes	1,00 kVA
		Model Equations	0,10 %

Grid: Grid | System Stage: Grid | Study Case: Study Case | Annex: / 1

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data					
2															
	6,60	1,16	7,68	20,78											
Cub_2	/Sym	Machine 2			5,00	0,00	1,00	0,38	31,25	Typ:	PQ				
Cub_1	/Tr2	2-E			5,00	0,00	1,00	0,38	21,47	Tap:	0,00	Min:	0	Max:	0
1															
	6,60	1,14	7,51	19,22											
Cub_2	/Sym	Machine 1			5,00	0,00	1,00	0,38	31,25	Typ:	PQ				
Cub_1	/Tr2	1-C			5,00	0,00	1,00	0,38	21,98	Tap:	0,00	Min:	0	Max:	0
22B															
	22,00	1,11	24,44	16,42											
Cub_3	/Lod	Load.			1,00	0,33	0,95	0,02		Pl0:	1,00 MW	Ql0:	0,33 Mvar		
Cub_1	/Lne	A-B			7,65	-1,18	0,99	0,18	44,95	Pv:	180,73 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	B-C			-8,65	0,85	-1,00	0,21	50,48	Pv:	227,93 kW	cLod:	0,01 Mvar	L:	5,00 km
22C															
	22,00	1,14	25,02	18,11											
Cub_1	/Lne	B-C			8,88	-0,62	1,00	0,21	50,48	Pv:	227,93 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	C-D			-3,88	0,52	-0,99	0,09	22,23	Pv:	44,19 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_3	/Tr2	1-C			-5,00	0,10	-1,00	0,12	21,98	Tap:	0,00	Min:	0	Max:	0
22D															
	22,00	1,15	25,26	18,86											
Cub_3	/Lod	Load			1,00	0,33	0,95	0,02		Pl0:	1,00 MW	Ql0:	0,33 Mvar		
Cub_1	/Lne	C-D			3,93	-0,48	0,99	0,09	22,23	Pv:	44,19 kW	cLod:	0,01 Mvar	L:	5,00 km
Cub_2	/Lne	D-E			-4,93	0,15	-1,00	0,11	27,69	Pv:	68,60 kW	cLod:	0,01 Mvar	L:	5,00 km

Grid: Grid	System Stage: Grid	Study Case: Study Case	Annex: / 2

	rated Voltage [kV]	Bus-voltage [p.u.]	Bus-voltage [kV]	[deg]	Active Power [MW]	Reactive Power [Mvar]	Power Factor [-]	Current [kA]	Loading [%]	Additional Data
22E										
	22,00	1,16	25,60	19,72						
Cub_1	/Lne	D-E			5,00	-0,09	1,00	0,11	27,69	Pv: 68,60 kW cLod: 0,01 Mvar L: 5,00 km
Cub_2	/Tr2	2-E			-5,00	0,09	-1,00	0,11	21,47	Tap: 0,00 Min: 0 Max: 0
132B										
	132,00	1,09	144,23	13,82						
Cub_5	/Lod	General Load			-50,00	0,00	-1,00	0,20		Pl0: -50,00 MW Ql0: 0,00 Mvar
Cub_2	/Tr2	Trafo 132/22			-7,47	1,49	-0,98	0,03	13,94	Tap: 0,00 Min: -8 Max: 8
Cub_3	/Lne	Line			57,47	-1,49	1,00	0,23	31,44	Pv: 5607,48 kW cLod: 5,31 Mvar L: 100,00 km
300										
	300,00	1,00	300,00	0,00						
Cub_2	/Xnet	Swing bus(1)			-51,67	8,89	-0,99	0,10		Sk": 1000,00 MVA
Cub_1	/Tr2	Trafo 300/132			-51,67	8,89	-0,99	0,10	87,38	Tap: 0,00 Min: -8 Max: 8
132A										
	132,00	0,99	130,75	6,78						
Cub_1	/Lne	Line			-51,86	2,71	-1,00	0,23	31,44	Pv: 5607,48 kW cLod: 5,31 Mvar L: 100,00 km
Cub_2	/Tr2	Trafo 300/132			51,86	-2,71	1,00	0,23	87,38	Tap: 0,00 Min: -8 Max: 8
22A										
	22,00	1,09	23,97	14,79						
Cub_1	/Tr2	Trafo 132/22			7,47	-1,36	0,98	0,18	13,94	Tap: 0,00 Min: -8 Max: 8
Cub_2	/Lne	A-B			-7,47	1,36	-0,98	0,18	44,95	Pv: 180,73 kW cLod: 0,01 Mvar L: 5,00 km

Appendix E

Matpower

E.1 Data matrices for network modeling

The following illustrates the data modeling used in Matpower. When ordinary load flow calculations are performed, the OPF Data matrices are not used.

```
{function mpc = master
%% MATPOWER Case Format : Version 2
mpc.version = '2';
%%-----  Power Flow Data  -----%%
%% system MVA base
mpc.baseMVA = 50;
%% bus data
%       bus_i   type    Pd      Qd      Gs      Bs      area    Vm      Va      baseKV  zone    Vmax    Vmin
mpc.bus = [
    1   3  0   0   0   0   1   1  0   22  1   1.05    0.95;
    2   1   1   0.33   0   0   1   1   0   22  1   1.05      0.95;
    3   2   0   0   0   0   1   1   0   22  1   1.05      0.95;
    4   1   1   0.33   0   0   1   1   0   22  1   1.05      0.95;
    5   2  0   0   0   0   1   1  0   22  1   1.05    0.95;
];
%% generator data
%       bus     Pg      Qg      Qmax    Qmin    Vg      mBase   status  Pmax    Pmin
        Pc1     Pc2     Qc1min  Qc1max  Qc2min  Qc2max  ramp_agc        ramp_10 ramp_30 ramp_q  apf
mpc.gen = [
1       0       0       100     -100    1       50      1       50      -50
        0       0       0       0       0       0       0       0       0       0       0;
3       5       0   50  -50     1       5       1       5       5       0
        5       -2      5       -2      2       0       0       0       0       0;
5       5       0       5  0    -50     1       5       1       5       5       0
        5       -2      5       -2      2       0       0       0       0       0;

];
%% branch data
%       fbus    tbus    r       x       b       rateA   rateB   rateC
        ratio   angle   status  angmin  angmax
mpc.branch = [
        1       2       0.186   0.196 0 150     150     150     0       0       1       -360    360;
        2       3       0.186   0.196 0 150     150     150     0       0       1       -360    360;
        3       4       0.186   0.196 0 150     150     150     0       0       1       -360    360;
        4       5       0.186   0.196 0 150     150     150     0       0       1       -360    360;
  ];
%%-----  OPF Data  -----%%
%% area data
%       area    refbus
mpc.areas = [
        1       1;
];
%% generator cost data
%       1       startup shutdown        n       x1      y1      ...     xn      yn
%       2       startup shutdown        n       c(n-1)  ...     c0
mpc.gencost = [
        2  0     0     3     0     100  0;
    2  0     0     3     0     100  0;
    2  0     0     3     0     100  0; ];}
```

Appendix F

Voltage drop impedance

F.1 Voltage drop impedance

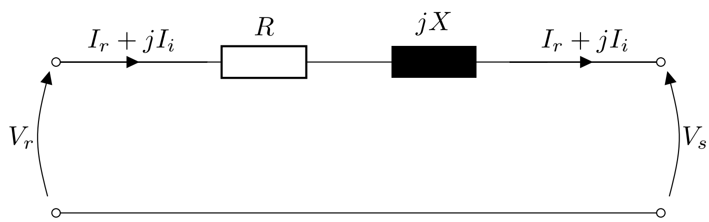


Figure F.1.1: Voltage drop over impedance

$$\begin{aligned} V_r - V_s &= \\ (R + jX) \cdot (I_r + jI_i) &= \\ R \cdot I_r + j(R \cdot I_i + X \cdot I_r) - X \cdot I_i & \end{aligned} \tag{F.1}$$

$$Re = R \cdot I_r - X \cdot I_i \tag{F.2}$$

$$Im = R \cdot I_i + X \cdot I_r \tag{F.3}$$