École polytechnique de Louvain

# Grid voltage control strategies at the Coo pumped storage hydroelectric power plant

## Voltage stability and reactive power capability analysis

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# Abstract

Regarding the evolution of the power transmission network, the way in which voltage control has historically been carried out by power plants needs to be reviewed, and new means of voltage control have to be investigated in the near future. To this end, this thesis investigates the possibilities in terms of voltage control and reactive power management in large power plants and more specifically at the Coo pumped storage hydroelectric power plant. In general, step-up transformers, which can be equipped with on-load tap changers and synchronous machines are the main equipment for the control of reactive power and voltage in power station. This thesis investigates different control strategies to see which parameter influence the reactive power capacity of one generating unit. A voltage stability analysis is also performed. The results concluded that the controllers of these two different devices must not operate according to the same reference value.

# Acknowledgment

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# Abbreviations

| | |
|---|---|
| **AVR** | Automatic voltage regulator |
| **DSO** | Distribution system operator |
| **FACTS** | Flexible AC Transmission Systems |
| **HSVC** | High side voltage control |
| **HV** | High voltage |
| **LV** | Low voltage |
| **OLTC** | On load tap changer |
| **PSS** | Power system stabilizer |
| **RCC** | Reactive current compensation |
| **RES** | Renewable energy sources |
| **RT** | Recovery time |
| **STATCOM** | Static compensator |
| **SVC** | Static var compensator |
| **TODZ** | Time over the dead zone |
| **TSO** | Transmission system operator |

# Contents

# List of Figures

# List of Tables

# Introduction

Before the energy transition era, the electric power system was characterized by unidirectional power flows moving from the generation source linked to the interconnected transmission network to the loads primarily connected to the radially operated passive distribution network [1]. Today, the power system is undergoing a transformation as renewable energy sources (RES) take over from large conventional plants and this shift is causing changes in the flow of energy within the system due to the specific locations of these RES [2].

In the transmission system level, maintaining steady state and dynamic voltage control mainly depends on the contribution of synchronous generators, which prioritize the meeting of the power demands. Nevertheless, specialized equipment like dynamic compensators (such as synchronous condensers and FACTS devices) and static components (like capacitor banks, reactors, and transformer tap changers) also form integral parts of voltage control protocols [3]. At the distribution system which is distinguished by a higher resistance-to-impedance ratio ($R/X$) and mostly operates in a radial fashion, the strategy for voltage regulation capitalizes on the consistent decrease in voltage magnitude along the feeders [4].

RES, that are also connected to the distribution grid, pose new challenges due to their distinct characteristics than traditional plants. RES exhibit characteristics such as smaller installed capacities, a higher presence into medium and low voltage (LV) networks, their production is variable and intermittent linked to the availability of their primary resource, and their technology is based on power electronics rather than synchronous machines [5][6]. Furthermore, the decommissioning of thermal power plants, which primarily interface with the transmission grid, results in a reduction of connected synchronous generators, leading to a decrease of for voltage regulation support.

Additionally, the electrical characteristics of the network are undergoing shifts due to the introduction of numerous new underground cables, often replacing overhead cables, particularly within urban regions. These underground cables naturally function as capacitors, introducing reactive energy into the system, thus intensifying the imperative to further manage reactive energy flows [7].

In this framework, we can see that transmission system operators (TSOs) and distribution system operators (DSOs) face many challenges in ensuring the safety a reliability of the grid. Since without the transmission network voltage control, the distribution network encounters significant issues associated with voltage frequent variations [11], the conventional voltage control approaches executed by TSOs must undergo evolution to incorporate novel and pertinent enhancements.

Given these considerations there are various corrective measures that TSOs can implement to ensure voltage control and manage reactive power. Indeed for a too high or too low voltage case, the TSOs can for example use the tap changer of the power transformers, switching of capacitors and reactors, changing of reactive power output or voltage set-point of power plants, start-up of hydraulic power plants in condenser mode or even starting-up of additional power plants [8].

### Motivation and Objectives

As explained above, voltage control is one of the critical issues, which requires the system operators to develop new ways of managing voltage and reactive power flows. Today, for the TSOs, one of the key contributors to voltage control and reactive power management are the capacities of production or absorption of reactive power by generation unit [9].

Large power plants cooperate with the grid via HV substations with several voltage levels. An example of a power station diagram is illustrated on figure 1. In this example, the power plant has six generating unit[1] connected to busbars at three voltage levels: 400 kV, 220 kV and 110 kV. The power plant's busbars are connected by two auto transformers with on load tap changers and the transmission lines run from the substation busbars to each voltage level. The step-up transformers[2] can have a fixed ratio or a tap changing ratio. In general, in HV power plants, the following equipment can be used to control voltage and reactive power [28]:

- synchronous generator control
- tap changers of auto transformers connecting the station buses
- tap changers of step-up transformers

[1]In this work, the term generating unit is used to define the group formed by an generator and a transformer

[2]Also called the unit's transformer, it represents the main transformer of the generating unit

Hence, in a HV plant, the operation of these two or three equipment must be regulated according to predefined criteria in order to meet the future TSOs requirements.

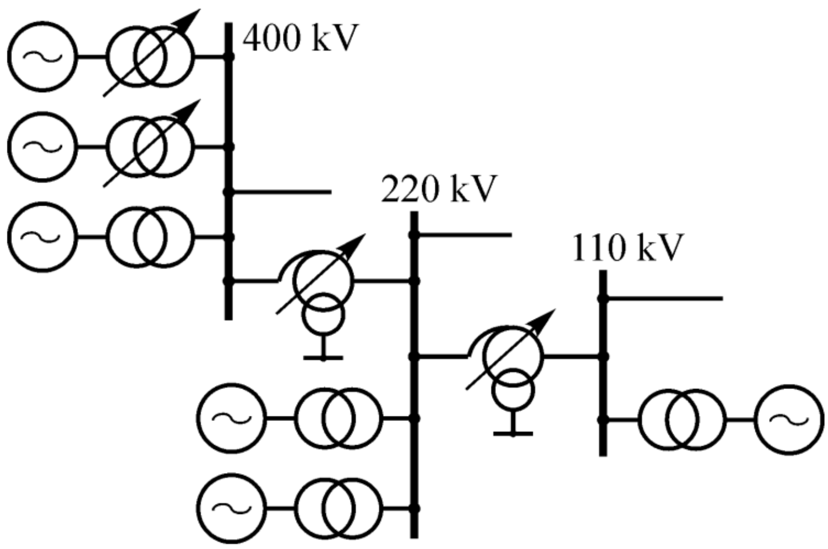


**Figure 1:** Power plant diagram [28]

From this perspective, the purpose of this thesis is to study the operation of the generator and transformer systems in order to maintain a stable voltage on the high-voltage busbar and maximize the generating unit's ability to generate or consume reactive power while maintaining all the limitations. This requires appropriate coordination and cooperation between the generator regulator and the step-up transformer controller. Indeed, the two systems differ in terms of speed and type of control. Generator control is continuous and fast. Transformer control is discrete, and the control process is much slower than the generator one [43]. To do so this thesis will expose the main equipment and methods for voltage and reactive power control especially the synchronous generator and the OLTC transformer. Then we will propose some possible control scenario. Finally, we will conduct a steady state and voltage stability analysis of these scenarios to see which of the proposed scenarios give potential solutions for the voltage control.

The system presented in this thesis is based on the data of a hydroelectric pumped storage plant located in Belgium: the Coo-Tois-Ponts plant with a total power of 1164MW [10]. The facility is used to adapt the constant energy supply of the Tihange nuclear power plant to the varying needs of the grid. Water is pumped when demand is low and stored during consumption peaks and operations are automated and controlled from Brussels.

### Research question

Based on the objectives outlined above, the subsequent research question is a means of addressing them:

*Which configuration should be adopted so that the coordination between the synchronous machine regulator and the OLTC transformer regulator fully exploits its reactive power capacity and ensures stable voltage regulation?*

### Thesis outline

The first chapter of this thesis begins by exposing the existing methods and equipment for voltage control and reactive power management mainly in the transmission system.

Chapter 2 sets out the description of the system studied by explaining its various components and specifying the parameters. In addition, this chapter introduces three proposed control scenarios.

Chapter 3 presents a steady-state analysis of the proposed scenarios. It first evaluates the reactive power capacity of the scenarios by presenting their UQ characteristic. Secondly, an evaluation of the machine and transformer losses will be conducted to see which scenario generate the least losses.

Chapter 4 shows a simulation analysis in Matlab Simulink of voltage stability according to two cases. The first one is a long-term voltage instability where the reactive power demand increase on the high voltage side and the second case is a short-term voltage instability where a three-phase fault occurs on the HV busbar.

Finally, this thesis concludes with a summary of the main results, the answer to the research question and a discussion of improvements and future work related to this topic

# Chapter 1

# Methods and equipment for the voltage and reactive power control

This chapter presents the main methods and equipment used to control voltage and reactive power in electrical transmission system.

The reactive power–voltage control holds crucial importance within power systems either under normal or in emergency conditions. In normal operation, its role is to guarantee the transmission of electrical energy with the desired voltage quality and under optimum conditions for suppliers and users. During emergency situations, voltage control plays a critical role in enhancing system security by expanding the buffer zone around the system's voltage instability limits. This action can help maintain uninterrupted system operation and create optimal operating conditions for the greatest number of consumers. [11]

To cope with these constraints and guarantee quality of service, certain players in the power system are called upon to provide a set of network services. They cover a number of priorities, such as [12]

- ensure balance at all times between active power generation and consumption through hierarchical frequency control;
- guarantee that voltage is maintained within contractual limits at all points in the power system;
- guarantee an operational reserve of additional energy that must be available to meet unforeseen needs;
- maintain power system performance through appropriate actions in the event of a disturbance, in particular to limit power transits to levels transmission equipment and to improve network stability;

- ensure the blackstart capability of the power system after a blackout by keeping certain dedicated generators ready for start-up, and by ensuring continuity of service with their auxiliaries only, i.e. by islanding certain generators to return voltage to the network;

### Link between reactive power and voltage

To establish the relationship between active and reactive power and voltage, we will take into account the one-line diagram represented in figure1.1 This diagram shows the

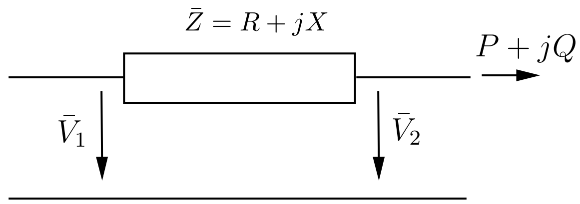


**Figure 1.1:** One-line diagram of the short line model

apparition of a complex voltage drop with two component

- one the longitudinal component, with the equation:

$$\Delta V = \frac{RP + XQ}{V_2}$$

- one transversal component, with the equation

$$\delta V = \frac{RP - XQ}{V_2}$$

Because generally $R << X$ for transmission lines, it results

$$\Delta V \approx \frac{XQ}{V_2}$$

Consequently, the voltage drop $\Delta V$ is mainly due to the reactive power flow on the line, so that the magnitude difference between $V_1$ and $V_2$ depends on the reactive power transit.

Based on the above considerations, the practical way to carry out voltage regulation in power systems essentially involves controlling the reactive power generated and consumed, and their flows at different levels in the power system. In the following section we will see how this can be done in practice.

## 1.1 Shunt Capacitors and Shunt Reactors devices

Shunt capacitors find application in the compensation of loads with lagging power factors, while reactors are implemented on circuits that produce VArs, as seen in lightly loaded cables. The function of these shunt components is to provide or absorb the necessary reactive power, to maintain the voltage magnitude stability. Capacitors can be linked either directly to a busbar or to the tertiary winding of a primary transformer.

Unfortunately, as the voltage drops, the VArs generated by a shunt capacitor or absorb by a reactor decrease as the square of the voltage. Consequently, when their utility is most required, their efficiency declines. Similarly, during periods of light network load when voltage is high, shunt capacitors produce a large output, potentially leading to voltage surges beyond acceptable levels. In such cases, local overvoltage relays might necessitate the disconnection of certain capacitors or cable circuits [13].

## 1.2 FACTS devices

### 1.2.1 Static Var Compensator

A Static Var Compensator (SVC) is a thyristor-controlled (since it is thyristor controlled, thus it is called static) generator of reactive power, either lagging or leading, or both. This equipment is alternatively referred to as a static reactive compensator. An SVC, operates at high voltages and effectively regulates the network voltage at its point of connection. Its primary role is to maintain the network voltage constantly at a given reference point. Additional control attributes of an SVC are the voltage control, reactive power regulation, attenuation of power oscillations, and control of imbalances. The SVC stands as one among the regulators that based on Power Electronics and other static components, identified as FACTS regulators. These regulators are employed to enhance the ability and flexibility of a transmission network [14].

### 1.2.2 STATCOM

The STATic COMpensator (STATCOM) is an alternative static VAR controller that shares similarities with the synchronous compensator. However, being an electronic device, it lacks inertia and offers numerous advantages, including enhanced dynamics, reduced initial investment, and decreased operational and maintenance expenses. It can be seen as a voltage source behind a reactance. The STATCOM achieves reactive power generation and absorption solely through electronic manipulation of voltage and current waveforms via a voltage source converter. Consequently, there is no requirement for capacitor banks or shunt reactors to generate or absorb reactive power, facilitating a compact design and size. The introduction of the STATCOM enables even more impressive performance gains, particularly in domains such as dynamic and steady-state voltage control within transmission and distribution systems, along with simultaneous management of both active and reactive powers [11].

## 1.3 Synchronous generator

The synchronous generators are the main equipment in the power system with the capability to either supply or consume a large amount of reactive power. The automatic voltage regulator (AVR) controls the excitation of the generator in order to maintain the voltage at the stator terminals at the reference value. To meet reactive power demand, generators can be regulated within their operating over- and underexcitation limits. Due to the presence of time constant values linked to the generator rotor and stator's thermal responses, a short time overload capability is allowed and can be usefully utilized to limit transient overvoltage and overexcitation circuits [11]. Consistently, a generator will function effectively while staying within its voltage thresholds, typically ranging from 5% below to 5% above the nominal value. Additionally, the generator will remain within its overexcitation and underexcitation limits, which establish the range for accessible reactive power. More precisely, when the generator voltage rises, the overexcitation limit decreases the amount of deliverable reactive power, whereas the underexcitation limit increases the capacity to absorb reactive powers.

Figure 1.2 shows the limiting curves illustrating the reactive power capacity at the generator in terms of the active load and terminal voltage at a given power factor. It can be seen that if the terminal voltage decreases the generator capacity in reactive power reserve increases. Hence, the generation or absorption of reactive power by an electric generator mainly relies on the active power it produces and the terminal voltage [15].
At constant generator voltage, a rise in grid voltage leads to a reduction in generator reactive power, while a decrease in grid voltage results in an increase in generator reactive power. This has a stabilizing effect on the grid voltage. This phenomenon contributes to stabilizing the grid voltage, as the reactive power output adjustments tend to mitigate the variations in grid voltage, either upward or downward.

### 1.3.1 Excitation system

The basic role of an excitation system is to supply a direct current to the field winding of a synchronous machine. Moreover, the excitation system carries out control and protective tasks that are essential for the effective operation of the power system. This involves regulating the field voltage, which in turn controls the field current.
The control functionalities include the voltage and reactive power flow management,

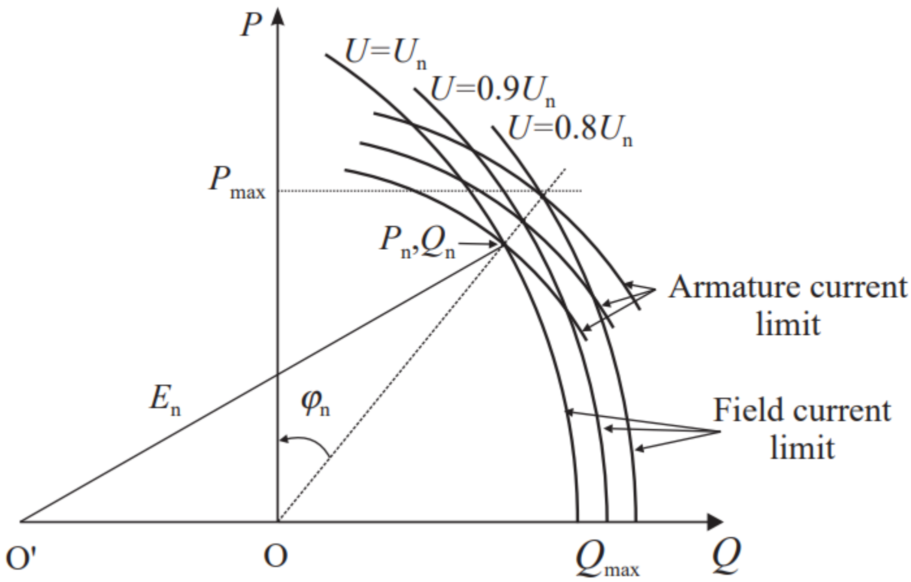


**Figure 1.2:** Variation of the armature current and the field current limits at a given power factor. [11]

as well as the enhancement of the system stability. The use of protective functions prevent that the capability limits of the synchronous machine, excitation system, and other equipment are not exceeded.

The performance requirements of the excitation system are determined by considerations of the synchronous generator as well as the power system [16].

From the generator point of view, the basic requirement is that the excitation system supply and autonomously regulate the field current of the synchronous generator. This ensures that the terminal voltage is maintained as the generator's output fluctuates within its continuous operational capacity. Additionally, the excitation system should be able to respond to transient disturbances with field forcing that align with the instantaneous and short-term capabilities of the generator [17].

From the perspective of the power system, the excitation system is expected to play a central role in efficiently managing and enhancing the system stability. It should possess the ability to rapidly react to disturbances in order to improve transient stability. Furthermore, the excitation system should have the capacity to adjust the generator field in a manner that enhances stability against small-signal fluctuations [17].

### Elements of an excitation system

The control block diagram of a typical excitation system for large synchronous generator is depicted figure 1.3

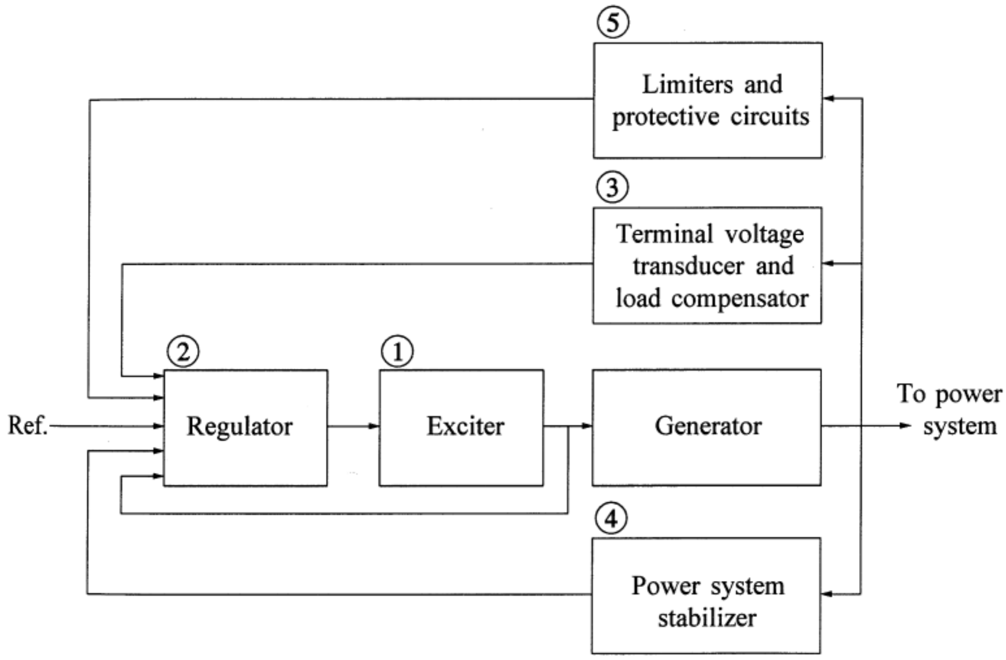


**Figure 1.3:** Functional block diagram of a synchronous generator excitation control system [17]

This system comprises several sub-systems described below:

1. the *exciter* which supply to the machine field winding a DC power and constitute the power stage of the excitation system

2. the *voltage regulator* which process the input control signals and amplifies them to a suitable level and form, for the exciter's control

3. *terminal voltage transducer and load compensator:* the voltage signal generated by the transducer stands as the main input within the excitation control system. In addition, load (or line-drop, or reactive) compensation is used if it is desired to control a voltage at some point internal or external from the generator terminal.

4. *the power system stabilizer (PSS):* is a compensation circuit use in order to provide additional damping torque through excitation control. Some of the frequent input signals are the rotor speed deviation, electrical power or the frequency deviation [36].

5. *the limiters and protective circuits*: these encompass a wide range of control and protection functions, designed to ensure that the operational limits of the exciter

and synchronous generator are not exceeded. Some of the commonly used limiters are the field-current limiter, terminal voltage limiter, volts-per-Hertz regulator and protection, and over and under excitation limiter.

### Types of excitation system

The excitation systems can be classified into three categories namely the DC, AC and Static excitation systems:

- The DC excitation systems provide current to the rotor of the synchronous machine through slip ring by using DC generators as source of excitation power. The exciter can be powered by a motor or by the generator shaft, and can operate in self-excitation or separate excitation. The use of a pilot exciter comprising a permanent magnet generator is required for the exciter field when the excitation is separate [11]. Figure 1.4 shows a typical DC excitation system with a rotating amplifier (amplidyne). The amplidyne has the capability to influence the exciter field according to the instructions from the voltage regulator, thereby ensuring the generator terminal voltage remains at the predetermined level. In cases where the amplidyne regulator is not accessible, a rheostat can be utilized to manually control the exciter field.

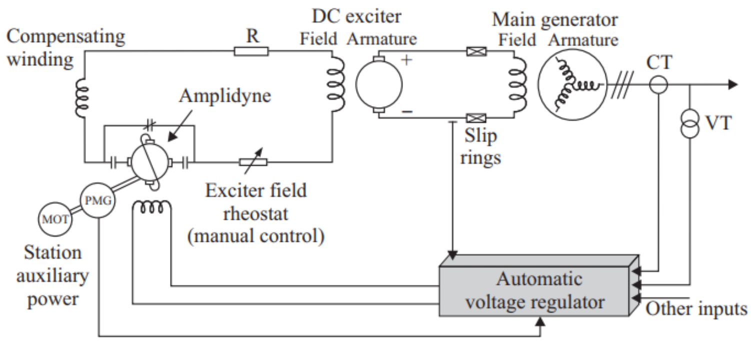


**Figure 1.4:** DC generator–commutator exciter with rotating amplifier [11]

- AC excitation systems employ alternators (AC machines) as the primary sources for generating the excitation power used in the main generator. Typically, the exciter is integrated onto the same shaft as the turbine generator. The AC output from the exciter is rectified through either controlled or non-controlled rectifiers to generate the necessary direct current for the generator field. The rectifier itself can be either stationary or rotating. Therefore, AC excitation systems can adopt various configurations based on the rectifier setup, method of controlling exciter output, and the origin of excitation for the exciter. We can have for example a stationary rectifier systems where the DC output uses slip rings to feed the field winding of the generator or rotating rectifier systems where the DC output is directly fed to the generator [17]

- Static excitation systems: All components in these systems are static or stationary. Static rectifiers, whether controlled or uncontrolled, directly provide the excitation current to the main synchronous generator's field via slip rings. The power needed by the rectifiers is sourced from the primary generator (or the station's auxiliary bus) through a transformer, which reduces the voltage to a suitable level. Alternatively, in certain instances, the power can come from an auxiliary winding in the generator itself.
  There is three forms of static excitation systems that have been widely used in practice [19]. We can first expose the potential source-rectifier exciter employing controlled rectifiers where the excitation power is obtained from the generator's terminals by utilizing a power potential transformer (also known as an exciter transformer) and a controlled rectifier (see figure 1.5).
  Then, we have the compound source-rectifier exciter employing non-controlled rectifiers where the power to the excitation system is generated by harnessing both the current and voltage of the main generator. This can be accomplished through the utilization of a power potential transformer and a saturable-current transformer, as illustrated figure 1.6.
  Additionally, there is the compound-controller rectifier exciter configuration which incorporates controlled rectifiers. In this system, controlled rectifiers are integrated into the exciter output circuits, and the combination of voltage and current sources derived from the generator stator is used to supply the excitation power.

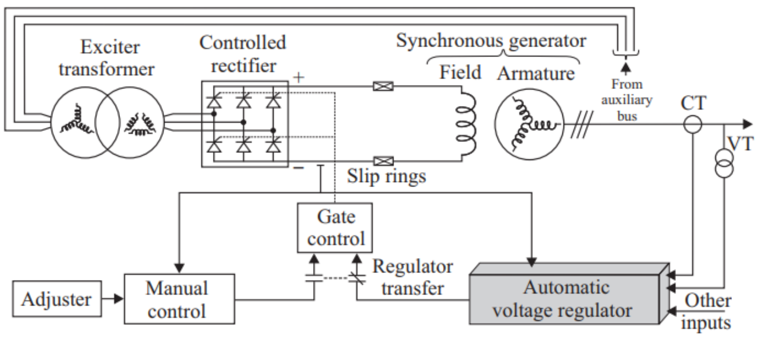


**Figure 1.5:** Potential source-rectifier exciter employing controlled rectifiers [11]

## 1.3.2 Synchronous compensator

A synchronous compensator, also referred to as a synchronous condenser, operates as a synchronous machine without any mechanical load. Depending on the level of excitation, it has the capacity to either absorb or produce reactive power, similar to how a synchronous generator works. Although its losses are relatively high in comparison to static capacitors, it maintains a power factor close to zero. This characteristic allows

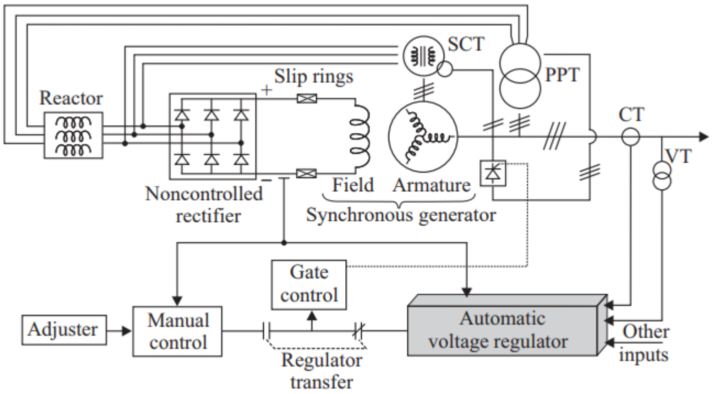


**Figure 1.6:** Compound source-rectifier exciter employing uncontrolled rectifiers [11]

it to function at its maximum capability for delivering or absorbing reactive power, according to the operating limits [11]. Synchronous condensers have been employed across distribution and transmission voltage levels to enhance stability and uphold voltages within predetermined boundaries under changing load circumstances and contingency events [20].

As shown in [21], we can have different type of synchronous condenser. The conventional synchronous condenser wher once synchronization is achieved, the field current is controlled to either generate or absorb reactive power in accordance with the requirements of the AC system. Its main advantage lies in the ease with which the correction level can be set [22].

An other type of synchronous condenser is the super synchronous condensers. It act as reactive power shock-absorbers of an electrical power system grid, generating or absorbing reactive power, and based on the voltage level of a transmission system. Super machines immediately respond to secure grids and electricity consumers in case of voltage dips and surges, commonly referred to as voltage transients in the power industry. These transients can originate from events like lightning storms, momentary line contacts due to tree branches, interactions between animals and transmission components, and various other sources [23].

## 1.4 On-Load Tap Changing transformers

Tap-changing transformers are effective devices for voltage regulation on one side, sustained by the voltage level on the opposite side. Typically, taps adjustments are applied to the high voltage side or lower current side in order to reduce current handling during transitions. Changing the turns ratio modifies the voltage in the secondary circuit, facilitating voltage control. This technique is the prevalent and widely adopted method for managing voltage across all voltage levels [11]. Figure 1.7 shows a schematic of a tap changer placed in the secondary side. In practice, the turns designated for disconnection or connection are not situated at the extremities of the windings. Due to structural considerations, they are positioned centrally within the windings or evenly spread between the two ends.

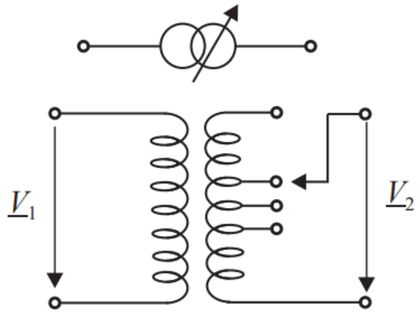


**Figure 1.7:** Single-phase representation of an OLTC wheret the tap changer is in the secondary [11]

## 1.4.1 Automatic OLTC control principles for single transformer

In a standard voltage reguator of an OLTC, the busbar voltage is typically measured at the low-voltage side of the power transformer. If no supplementary functionalities are activated (such as line drop compensatio), this voltage is employed to regulate the voltage. Subsequently, the voltage control algorithm compare the measured voltage with the predetermined target voltage and determines which action should be taken.

As this control method operates on a step-by-step principle, a deadband (i.e. degree of insensitivity) is introduced in order to prevent unnecessary switching around the target voltage. The deadband is typically symmetrical around the target value as shown in figure 1.8.

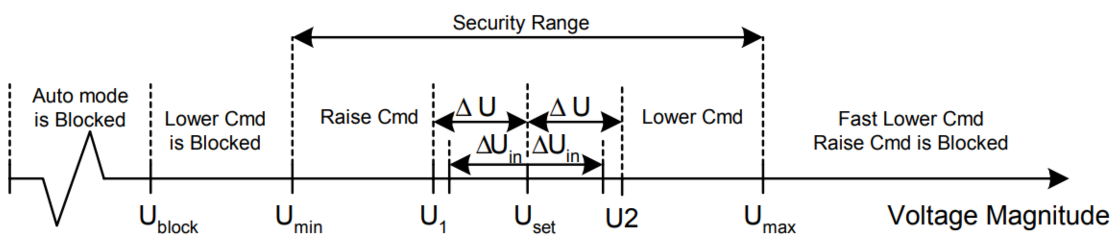


**Figure 1.8:** Voltage regulator principle of automatic OLTC [24]

Under standard operational circumstances, the busbar voltage remains within the deadband range, leading to no voltage regulator interventions. However, when the voltage decrease below $U_1$ or exceeds $U_2$ (as illustrated in figure 1.8), a corresponding countdown timer for reduction or elevation initiates. This timer remains active as long as the measured voltage remains outside the narrower inner deadband limits. If this state persist beyond a predetermined duration, the appropriate command to decrease or increase voltage is activated. When necessary, this sequence is reiterated until the busbar voltage once again resides within the confines of the inner deadband. The primary objective of the time delay mechanism is to avert unnecessary switching operations triggered by transient voltage fluctuations.

### 1.4.2 Applications of the OLTC Transformers for Voltage and Reactive Power Control

#### Combined use of tap-changing transformers and reactive-power injection

A widely common method for managing reactive power flow within transmission networks involve the use of the tertiary of three-winding transmission transformer for the reactive power injection via synchronous compensators, or capacitor reactor banks as shown on the figue 1.9

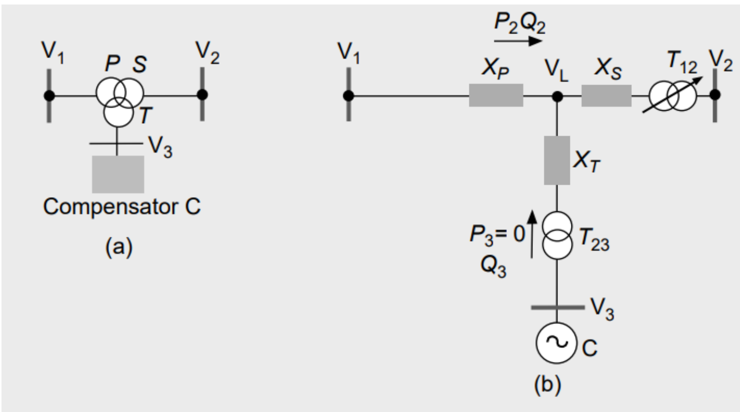


**Figure 1.9:** (a) Schematic diagram with combined tap-changing and synchronous compensation, (b) Equivalent network [13]

#### Use of tap-changing transformers to despatch vars in a transmission system

Interconnections between transmission networks with varying voltage levels are commonly established using On-Load Tap Changer transformers (see figure 1.10). When these networks take the form of infinite bus networks, the OLTC transformers serve as instruments for managing reactive power flow. Consequently, it can be shown that a suitable adjustment of the tap settings can regulate VARs dispatching.

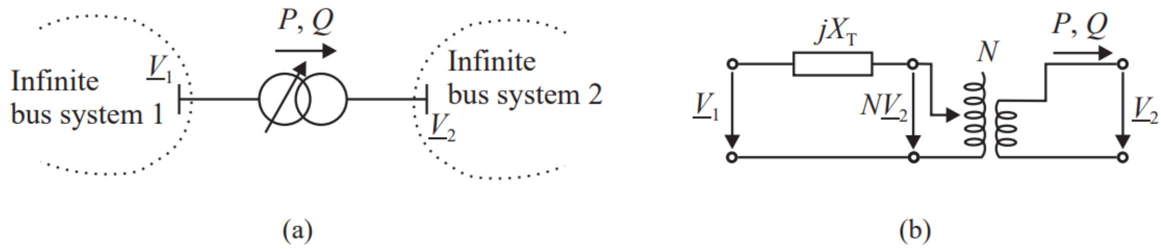


**Figure 1.10:** Interconnection of two strong networks through an OLTC: (a) one-line diagram, (b) equivalent impedance diagram. [11]

### ARNE/ARST systems

The ARNE/ARST[1] group control systems have the responsibility of automating the voltage regulation at the high voltage substation of power plants, controlling the flow of reactive power, and managing the flow of active power [25].

Within conventional setups, ARNE systems are implemented in the power plant, and control generators and step-up transformers. These ARNE systems collaborate with ARST systems situated in power substations, which oversee the functionality of coupling transformers, reactors, and capacitor banks. The role of ARNE systems encompasses

- voltage regulation across the buses of the high-voltage substation within power plants.
- control of the permissible zone of generator operations
- equitably distributing reactive power loads among generators that supply the same bus system

The ARST systems are them responsible for the substation operation i.e

- voltage regulation on the lower or upper side
- reactive power flow control

A description of classic ARNE/ARST control solutions can be found in [26], [27]

## 1.5 High side voltage control

An innovating power plant automatic voltage control of the local, HV side bus bar, is achieved through a unconventional control of the power plant able to coordinate the reactive powers of the operating generators in the plant (see figure 1.11). This closed-loop control mechanism effectively sustains the voltage ($V_s$) at the specified reference

[1]Polish designation for the electric power supply regulation system and automatic regulation of the transformer station

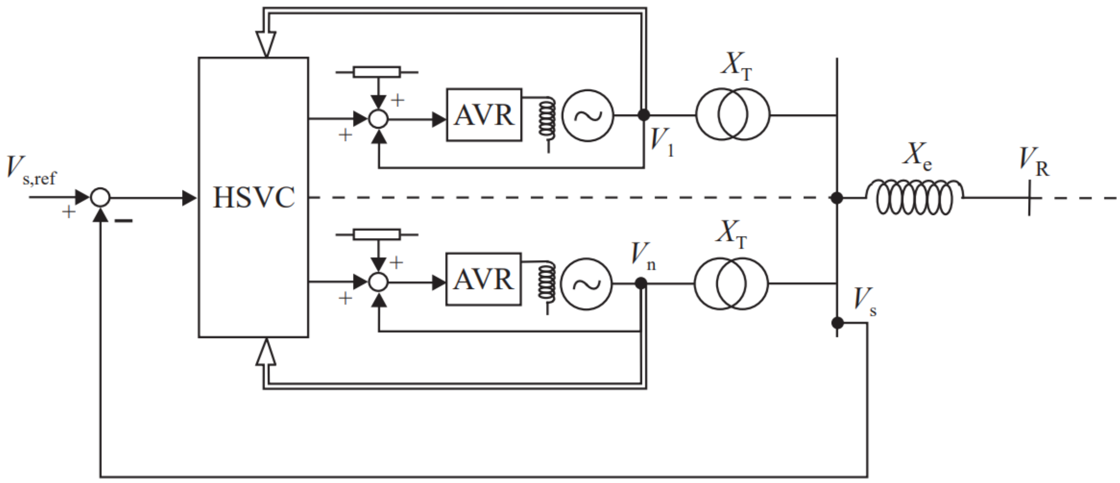


**Figure 1.11:** Principle scheme of the HSVC control [11]

value ($V_{s,ref}$) through synchronized management of the reactive power outputs from the plant's operating generators. The evaluation of this control strategy demands a suitable model representing the process.

Various studies on this topic can be found in the literature. For example, in [30], the authors traces development and usage of high side voltage control at Manitoba Hydro and shows that impedance compensation and direct high side control system offer a fast response, but is not as precise as a joint var control.

In [31], authors discuss some strategies of mitigating system voltage depressions that are available through excitation control of high side voltage conclude that the use of reactive current compensation (RCC) for line drop compensation can enhance system stability.

The study in [32] presents field verification results for the (HSVC), conducted at a hydro power plant. The results of these tests showed that the advanced HSVC had positive effects on voltage control and system stability compared with a conventional regulator.

The authors of [33] describes the principles, characteristics, and advantages of applying HSVC. It also underscores recent improvements in high side voltage estimation, achieved by integrating active current into the control algorithm. Simulation analysis confirmed that the accuracy of the estimated high side voltage and the resultant high side voltage control are improved and stable.

# Chapter 2

# System description

The Coo-Trois Ponts (Coo II) phase under study consists of three generating units, each with 230MW synchronous machine and 230 MVA 20/400 kV OLTC transformer. In this section we will only represent one generating unit and the major part of the data are related to this installation.

## 2.1 System description

The system diagram is given on the figure 2.1. The available equipment for the voltage control at the power plant are a 230 MVA, 20/400 kV step-up transformer with a tap changer and a 230 MVA synchronous machine located on the 20 kV side. On this side, there is also a unit and group auxiliary transformer modelled by a single load on the 20 kV side. The 400 kV side of the transformer is connected to a 380 kV line through an overhead lines of 2000m with an impedance of $Z_L = 0.658$ p.u. At the end of the 380 kV line we have a grid characterized by a short-circuit power of 15.13 GVA ($X/R = 12.4$).

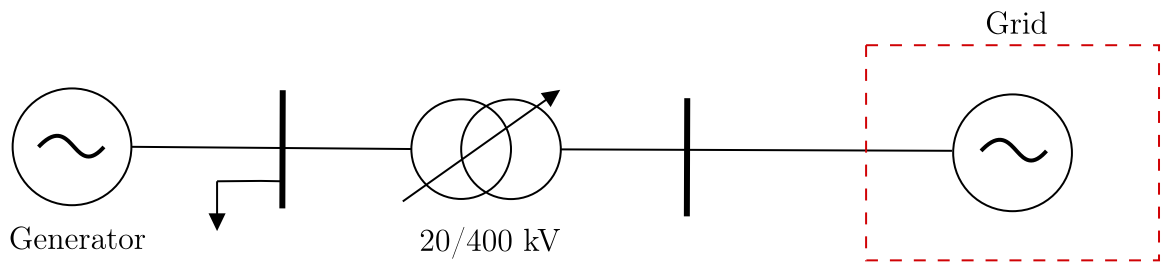


**Figure 2.1:** System model of the power plant generating unit

### Generator

The 230 MVA synchronous generator is a salient pole generator with 11 pole pairs. A salient pole machine has a larger air-gap in the region between the poles than in the region just above the poles. Consequently, the reluctance of the two regions in a salient-pole generator differ significantly and to account for this difference, the synchronous reactance is split into two reactances: the direct-axis synchronous reactance $X_d$ and the quadrature-axis synchronous reactance $X_q$ [35]. The armature current is also split into these two components[1]and we therefore have the following relationship between the no load voltage and the stator voltage:

$$\bar{E}_0 = \bar{V} + jX_q\bar{I} + j(X_d - X_q)\bar{I}_d$$

The magnetic saturation curve is shown on the figure 2.2. The curve can be obtain according to the following rule

$$\frac{i_f}{e_0} = 1 + m_d \cdot e_0^{n_d - 1}$$

where $m_d$ and $n_d$ are given parameters by the manufacturer. In our case $m_d = 0.115$ and $n_d = 6.14$. Beside, a value of $e_0 = 1$ p.u correspond to 20 kV which lead to a value of $i_f = 1.115$ p.u equal to the no load field current $I_{f,noload} = 669$ A.

The different parameters used for the generator are given in the table 2.1 and come from an external source.

**Table 2.1:** Synchronous machine parameters

| Symbol | Description | Value |
|---|---|---|
| $S_N$ | Apparent nominal power | 230 [MVA] |
| $U_N$ | Rated voltage | 20 [kV] |
| $\cos\varphi$ | Power factor | 0.9 |
| $p$ | pole pairs | 11 |
| $P_N$ | Nominal active power | 207 [MW] |
| $V_{lim}$ | Stator voltage limits | [0.95 - 1.05] [p.u.] |
| $I_{stat,max}$ | Maximal stator current | 6647 [A] |
| $I_{field,max}$ | Maximal field current | 2800 [A] |
| $R_s$ | Stator resistance | 3.4 [$m\Omega$] |
| $R_r$ | rotor resistance | 0.14 [$\Omega$] |
| $X_d$ | direct-axis synchronous reactance | 1.459 [p.u] |
| $X_q$ | quadrature-axis synchronous reactance | 0.817 [p.u] |

[1]where $I_d = -I\sin(\varphi + \delta)$ and $I_q = I\cos(\varphi + \delta)$, $\delta$ the internal angle (see A.1)

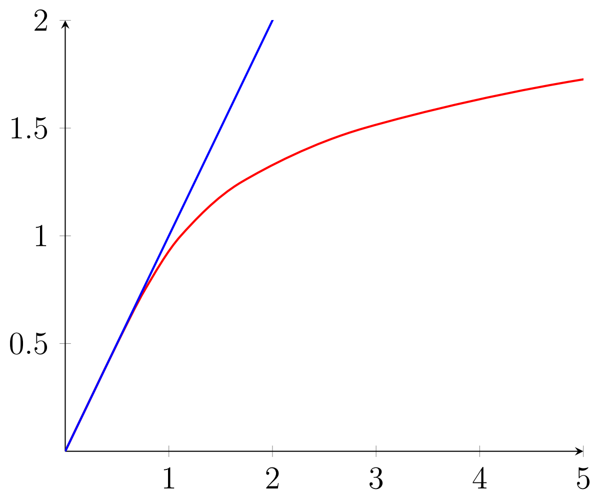


**Figure 2.2:** Saturation curve of the salient pole machine

#### Transformer

The tap changer is placed on the 400 kV winding and controls the voltage on the 20 kV in steps of 1.25 % with 25 tap positions ($\pm 12 \times 1.25\%$). The value of the short circuit voltage depends on the selected tap and is given for the middle tap and the two extreme tap. To determine its value for other taps, it is decided to interpolate linearly on each side of the median. The table B.1 show the short-circuit voltages for the different tap positions.

The parameters of our transformer are given in table 2.2

**Table 2.2:** Transformer parameters

| Symbol | Description | Value |
|---|---|---|
| $S_{TN}$ | Transformer rated power | 230 [MVA] |
| $U_0$ | No load voltage (middle tap) | 399.61 [kV] |
| $u_{cc}$ | Short-circuit voltage | see table B.1 |
| $\gamma$ | Voltage steps | 1.25 % |

### 2.1.1 Excitation system

The excitation system that is used in our system is a static excitation system. which comprises mainly a transformer, a thyristor converter, and a voltage regulator [11]. The name of this system comes from the fact that all the components are static or stationary and, in these systems, it is typical for the excitation power to be supplied either from the main terminals of the synchronous machine or from an auxiliary bus. Alternatively, this system can be characterized as a self-excited system [17].

In the system under consideration, the excitation system can be modelled by using the IEEE Type ST excitation models recommended by the IEEE standard 421.5 [36] In this study, the ST6B model (shown in figure 2.3) is implemented and simplifications are made through the adjustment of model parameter to suitable values.

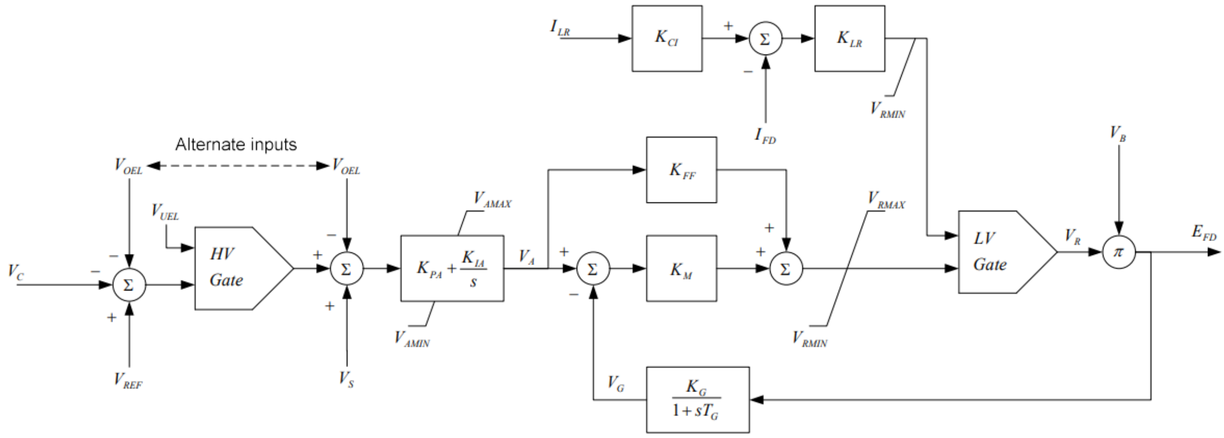


**Figure 2.3:** ST6B Excitation system block diagram showing major functional blocks [36]

According to [36], the model shown in figure 2.3 consists of a PI voltage regulator with an inner loop field voltage regulator and pre-control. The field voltage regulator implements a proportional control. The pre-control and the delay in the feedback circuit increase the dynamic response. The ceiling current ($I_{FD}$) limitation is included in this model. The power for the rectifier ($V_B$), may be supplied from the generator terminals or from an independent source. Inputs are provided for external models of the overexcitation limiter ($V_{OEL}$), underexcitation limiter ($V_{UEL}$), and PSS ($V_S$).

In order to simplify the ST6B excitation system (see figure 2.4), the inner loop field regulator pre-control gain constant ($K_{FF}$) and feedback gain constant ($K_G$) are set to 0 while the inner loop field regulator forward gain ($K_M$) and the exciter output current limit adjustment gain ($K_{CI}$) are set to 1.
The table 2.3 shows the parameters for the excitation system in this study :

**Table 2.3:** Excitation system parameter values

| Symbol | Description | Value |
|---|---|---|
| $K_{IA}$ | Voltage regulator integral gains | 74.25 |
| $K_{PA}$ | Voltage regulator proportional gains | 148.5 |
| $K_{LR}$ | Exciter output current limiter gain | 24.75 |

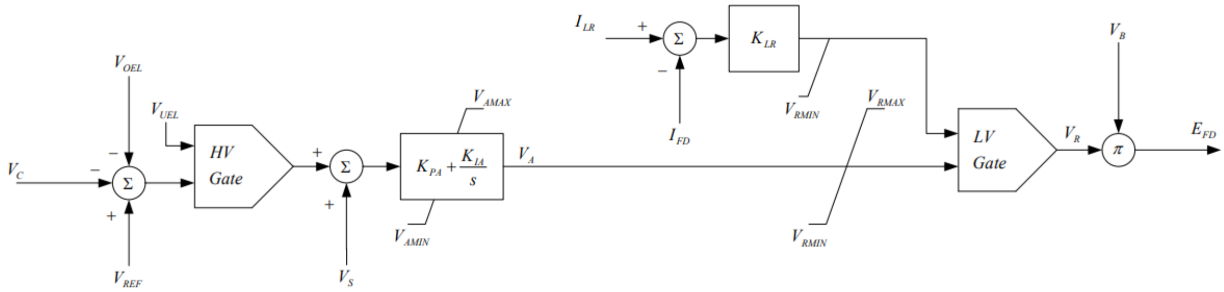


**Figure 2.4:** Simplified Excitation system model obtained by simplifying the IEEE ST6b excitation model

### Power system stabilizer

Power system stabilizers (PSS) serve to enhance the damping of oscillations within a power system by means of excitation control [37]. Typical input data often includes parameters such as shaft speed, terminal frequency and power [38].

In the system under study, the power system stabilizer model, shown in figure 2.5, is the IEEE type PSS2C. The design of this power system stabilizer aims to model a variety of dual-input stabilizers, typically employing combinations of power and speed (or frequency, or compensated frequency) as inputs to generate the stabilizing signal.

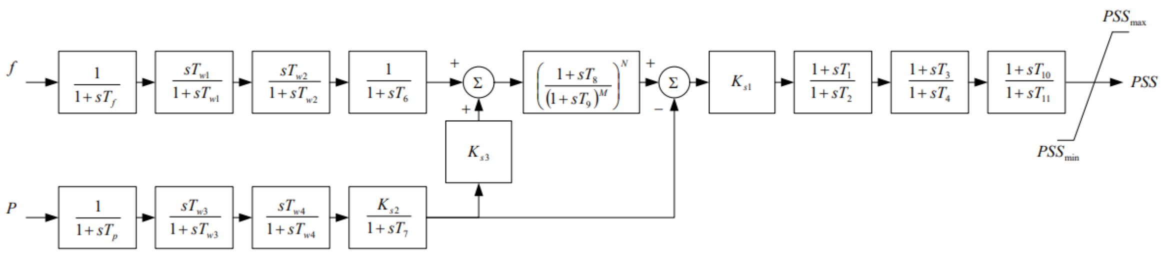


**Figure 2.5:** Power system stabilizer adapted from [36]

To address oscillation and instability issues, the power system stabilizer (PSS) can be introduced as a responsive (corrective) loop alongside the voltage regulator (AVR). This loop is constructed to generate a torque counteracting oscillatory modes manifesting in the generator shafts [11].

The parameters used for the PSS are shown in the appendix C.

## 2.1.2 OLTC transformer

In our system, the transformer is equipped with an automatic voltage on load tap changer which operates to maintain voltages within desired range, especially when the system is under disturbances. In other words, the OLTCs work to readjust transformer taps in order to rectify voltages. Consequently, this process leads to a gradual return of the voltage level to its state before the disturbance occurred.

The voltage regulation for the step-up transformer's on-load tap changing control needs to be implemented according to the following rule:

$$\begin{cases} V_m - V_{ref} > \frac{\Delta}{2} & \text{increase } k \\ V_m - V_{ref} < -\frac{\Delta}{2} & \text{decrease } k \end{cases}$$

where $V_m$ is the measured voltage, $V_{ref}$ is the reference voltage, $\Delta$ is the dead zone and $k$ is the tap position. The action of tap changing occurs only when the voltage error exceed the delay time $\tau$ which is the acceptable time value of disturbance.

### Dead zone design

The error voltage $\Delta_e$ is the difference between the actual value $V_m$ and the reference value $V_{ref}$. The sign of the voltage error can thus be positive or negative and to minimize the number of switching operations of the tap changer, the deviation of the voltage of interest from the reference value is tolerated within certain limits, that is, half the dead zone $\frac{\Delta}{2}$ [40].

The half of the dead zone is given as $\pm n$ % of the reference value and sets the limits for the maximum permissible relative fluctuation range of the measured voltage below and above $V_{ref}$. Furthermore, the half of the dead zone must be greater than the percentage tap increment of the transformer, because otherwise, after execution of a tap command, the changed output voltage of the transformer would again violate the opposite limit of the permissible voltage deviation. Once the specified time delay has passed, a tap adjustment command would be triggered to restore the transformer's tap to its previous position. This sequence would continually repeat, leading to frequent tap adjustments of the transformer and consequently causing undesired fluctuations in the main voltage. Hence, a too narrowly deviation results in a hunting process [40].

To avoid the hunting process, [40] recommend the following equation as a guideline for the mid dead zone value:

$$|\pm \Delta| \geq 1.2 \times \Delta V_{tap} \quad [\%]$$

where $\Delta V_{tap}$ is the voltage swing caused by a tap change.

### Time behaviour

In order to determine the delay i.e the reaction time $\tau$, the OLTC transformer comprise a time program parameter defining the relationship between the voltage deviation and the reaction time of the regulator. In our system, we have an integral time program which have an hyperbolic relationship between the voltage deviation and the reaction time as we can see figure 2.6. The time factor $t_f = 1$ here is used for adjusting the response time to the requirements of the installation or customer [40]. Another time quantity that we use is the dead time $\tau_{set}$ which is the minimum time required for the controller to complete its manoeuvre.

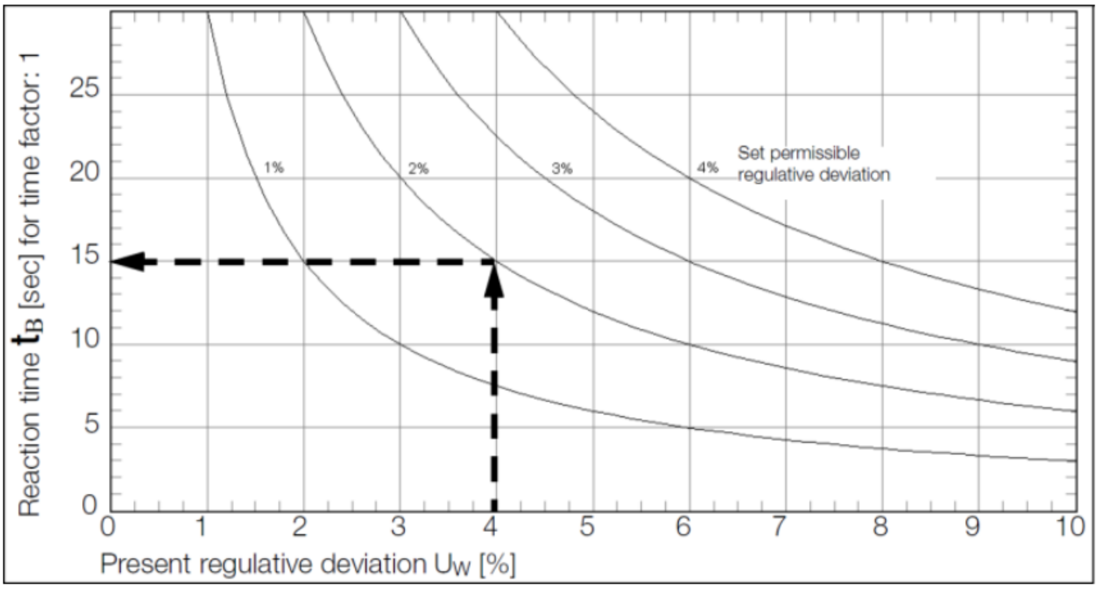


**Figure 2.6:** Hyperbolic relationship between the dead zone ($\Delta = U_w$) [%] and the reaction time ($\tau = t_B$) [s] for the integral time program [40]

Hence, the parameters for the OLTC transformer are given in the table 2.4

**Table 2.4:** Tap-Changer settings

| Symbol | Description | Value |
|---|---|---|
| #Tap | Number of tap positions | ±12 |
| $\gamma$ | Voltage steps | 1.25 % |
| $\Delta$ | Dead zone | 3 [%] |
| $\frac{\Delta}{2}$ | Half dead zone | ±1.5 % of $V_{ref}$ |
| $\tau$ | Reaction time | 15 [s] |
| $\tau_{set}$ | Dead time | 5 [s] |

## 2.2 Scenarios

In order to study the different ways of voltage control, we decide to expose four scenarios:

### 2.2.1 Scenario I

The first scenario is the more basic scenario only involving the generator for the regulation. The transformer will keep its rated transformation ratio and only the AVR is capable of controlling the voltage by measuring the stator current $I_g$ and voltage $V_g$. The system is shown on figure 2.7

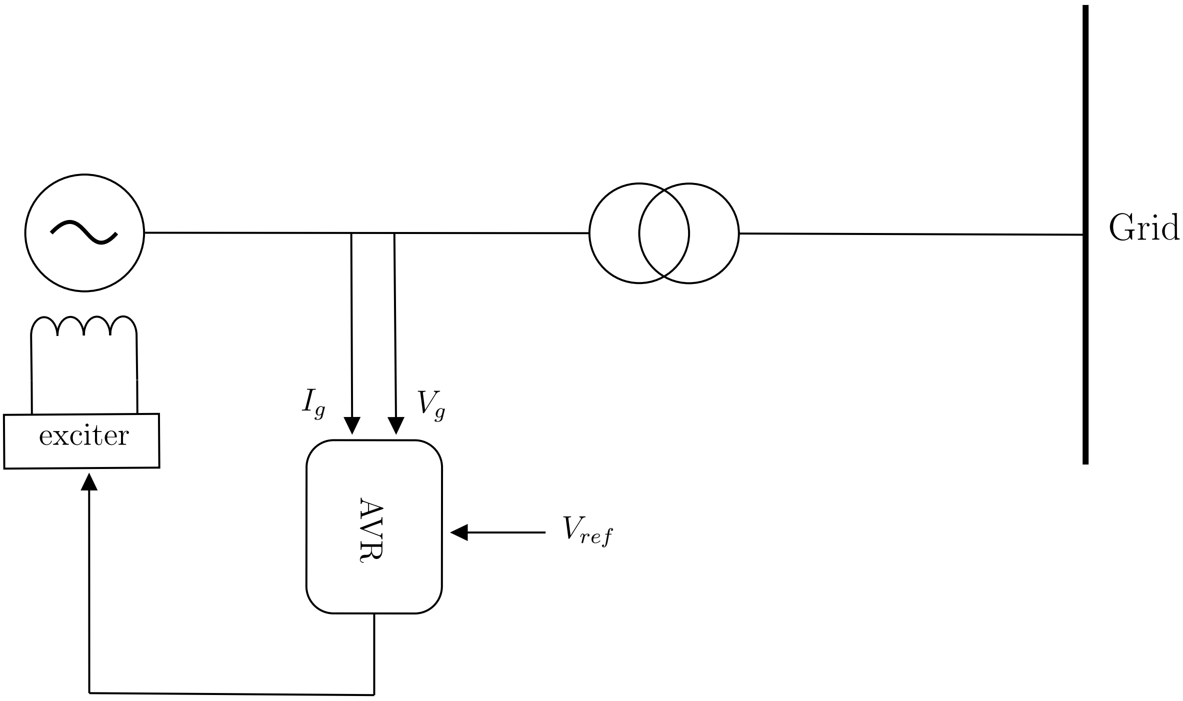


**Figure 2.7:** Scenario I control diagram

### 2.2.2 Scenario II

In the second scenario, we want that the generator works close to its rated voltage i.e within the 1 % around this value and that the transformer handles the voltage control by changing the taps. The diagram representing the system is shown on the figure 2.8.

### 2.2.3 Scenario III

In this scenario, we will use the potential of both of our voltage control equipment i.e the synchronous machine AVR and the OLTC transformer. We will divide this scenario

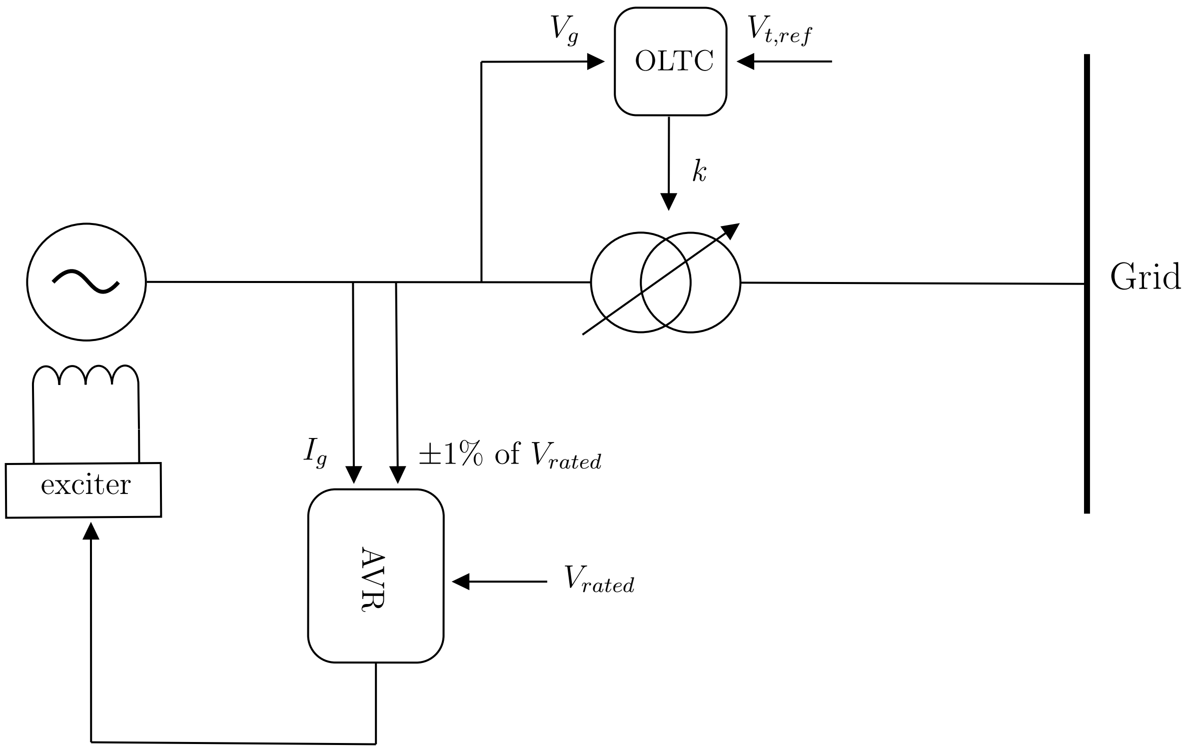


**Figure 2.8:** Scenario II control diagram

into two sub-scenarios depending on where the reference value is taken. For the reference value of the tap changing controller, we will assume that $V_{t,ref} = V_{ref}$ where $V_{ref}$ can vary such as $V_g$ stays within the stator generator limits $V_{lim}$.

The cooperation between the two controllers (AVR and OLTC) cooperate in the following way: when the grid voltage falls, the generator controller AVR increases the excitation current, which increases the stator terminal voltage and, according to rule described in 2.1.2, the OLTC increases the ratio $k$. Inversely, when the network voltage rises, the generator controller AVR decreases the excitation current, which decrease the stator terminal voltage and, according to rule described in 2.1.2, the OLTC lowers the ratio $k$. Obviously, as the OLTC is much slower than the response of the generator AVR, it is preferable for the tap adjustment control to be activated and executed only once the AVR's response has achieved a stable condition. In the simulation model presented in chapter 4, this is taken into account by introducing time delays in the tap changing control parameters.

### Scenario III.1

Here, the unit's transformer regulator and the generator regulator maintain the setpoint voltage at the generator terminals as we can see on the figure 2.9.

In this sub-scenario, the generator-transformer unit will be seen by the network

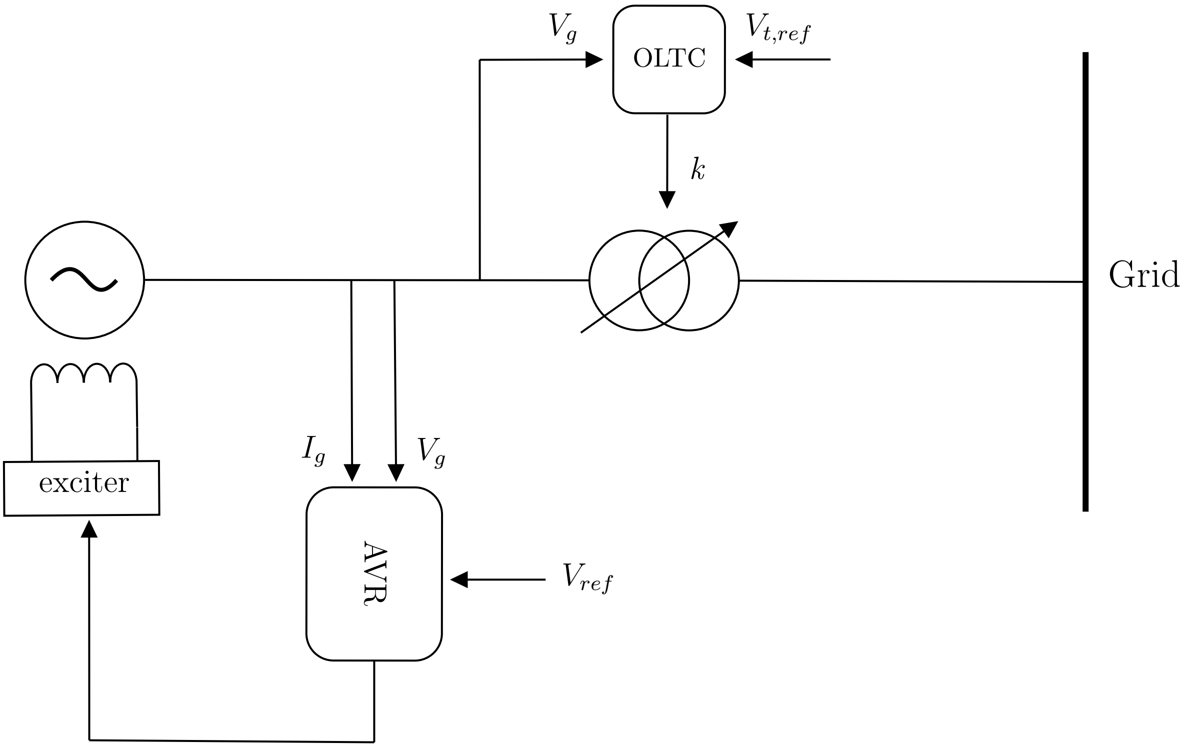


**Figure 2.9:** Scenario III.1 control diagram

as a voltage source with an internal impedance equal to the impedance of the main transformer [43] (see figure 2.12)

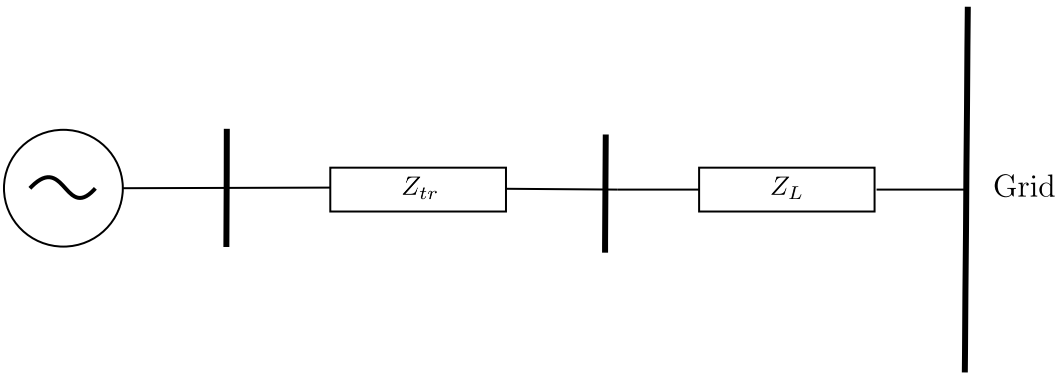


**Figure 2.10:** Simplified equivalent diagram of the generating unit in the scenario III.1

### Scenario III.2

The scenario III.2 is proposed by [28], and [41] [43] [42] are different related studies. In this sub-scenario, the unit's transformer regulator measures the voltage at the generator terminals, and the generator voltage regulator measures the voltage at the high-voltage side of the transformer. The system diagram of the considered control system is shown in figure 2.11. Here, from the side of the transmission network, the generating unit is seen as a source of voltage behind a small impedance introduced by the load compensation integrated within the automatic voltage regulator (see figure 2.11) [41].

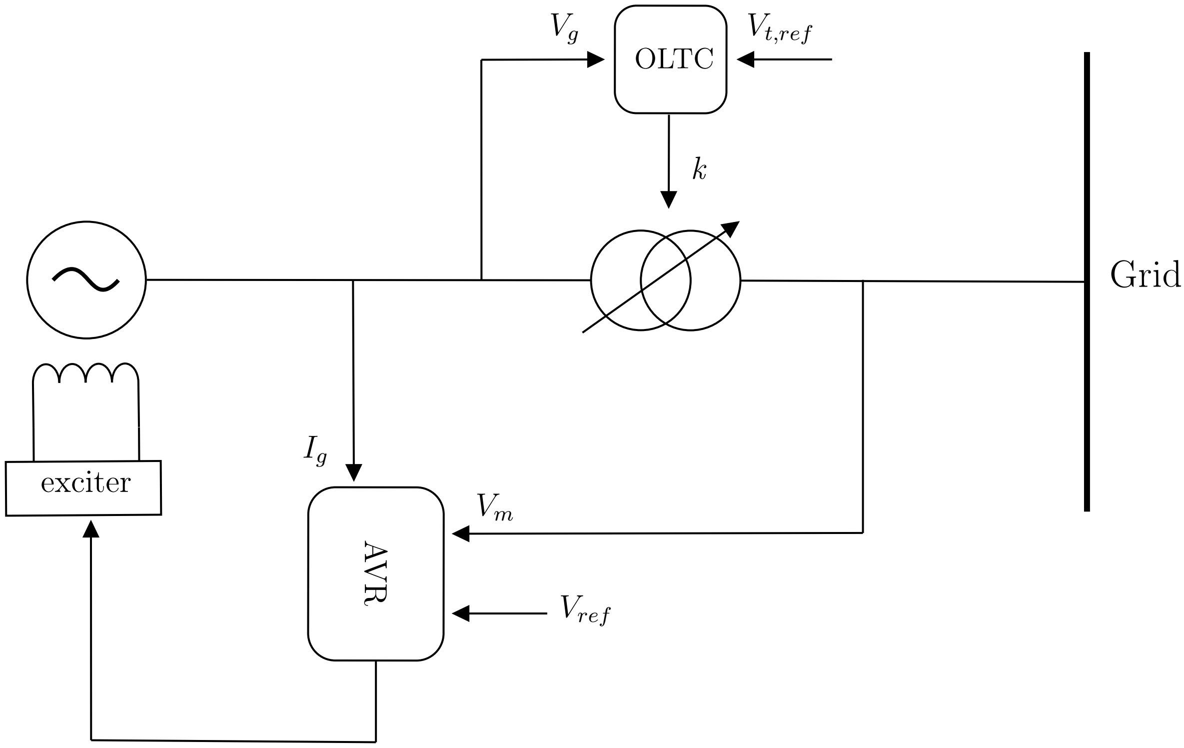


**Figure 2.11:** Scenario III.2 control diagram

Indeed, the point at which the voltage is measure is beyond the machine terminals so the use of a load compensation is required [29]. The voltage drop across the compensation impedance $Z_c = R_c + jX_c$ caused by the generator current $I_g$ is combined with the measured terminal voltage $V_m$ in order to generate the compensated voltage $V_{c1}$ according to the relation

$$V_{c1} = |\underline{V}_m + (R_c + jX_c)\ \underline{I}_g|$$

and according to [44], for large generators that supply the transmission grid, the resistance can be neglected, $R_c << X_c$. Figure 2.13 shows the block diagram of the terminal voltage measurement transducer and the load compensator.

For modeling purposes, the filtering associated with the voltage transducer may be simply reduced to a time constant $T_R$. For many excitation systems, this constant, which encompasses the entire process from sensing to load compensation, is very small and we will take a value of $T_R = 0.012$ as recommended in [36].

In the scenario III.1, the load compensation $Z_c = 0$ because we take the measurement at the stator voltage terminal and thus we have a simple sensing circuit and comparator

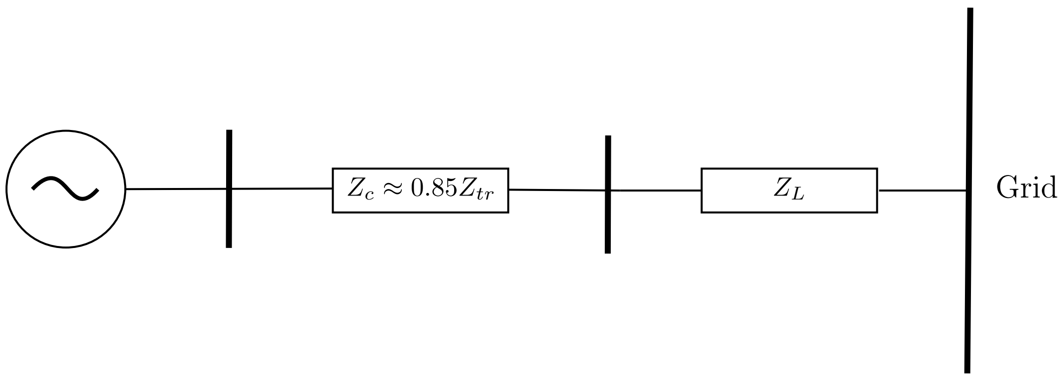


**Figure 2.12:** Simplified equivalent diagram of the generating unit in the scenario III.2

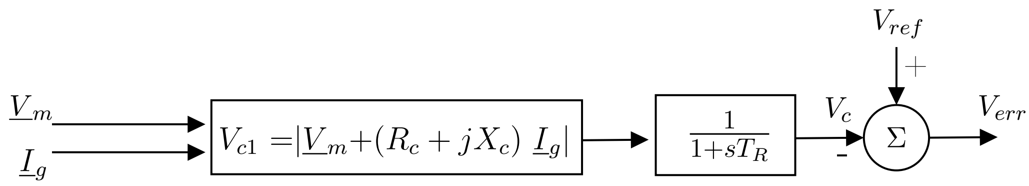


**Figure 2.13:** Load compensator circuit

[11]. In this sub-scenario, $Z_c \neq 0$ and usually, we take a value of $X_c \approx 0.85 X_T$ where $X_T$ is the reactance of the step-up transformer [29].

# Chapter 3

# Steady-state analysis of the voltage control scenarios

In this section we will carry out a steady-state analysis of the different scenario presented in the chapter 2. The steady-state analysis will be based first on the study of the capability area of the generating unit and then we will perform a losses evaluation of synchronous machine and the transformer for all our scenarios.

We will show that the scenario III can works under the whole region of operation bounded by the voltage limits of the network and the alternator, and the reactive power limits of the alternator. Beside this scenario generate the less transformer losses compare to the two other scenarios. Finally, we will conclude that the use of an OLTC transformer has a favorable impact on the capability area of the generating unit.

### Assumptions and constraints

- **Performance critera:** In order to evaluate our scenarios in steady state, we decide to chose two criteria. The first one evaluate the capability area of the generating unit i.e evaluate the limits of the generating unit and the second one is based on the minimization of the transformer and alternator losses.

- **System simplification:** In this chapter only the generator and motor mode are illustrated. For the generator mode, we will consider that the reactive power is supplied and is represented by a positive value. For the motor, the reactive power is absorbed and is represented by a negative value. Beside, we will fix the alternator active power at 207 MW for the generator mode, and 220 MW for the motor mode[1]. The corresponding HV active power are $P_r$ = 200.45 MW and $P_r$ = 226.55 MW (see calculations in 3.1)

- **Reactive power limits:** The reactive power supply and absorption limits are arbitrarily chosen and we decide to take a large range such that the reactive power

[1] The data come from an external source

supply limit of the alternator is 200 MVar and the absorption limit is -200 MVar.

- **Scenario II optimal tap criterion:** In the second scenario, the choice of the optimal tap is the one allowing the generator voltage to lies in a band of 1% around the rated voltage.

- **Scenarios III optimal tap criterion:** In the scenarios III.1 and III.2, the optimal selected tap is the one that minimize the transformer losses within the 3% around the generator rated value. We decide to minimize the transformer losses because they vary much more than the synchronous machine losses. Furthermore, in this steady state analysis, we will not differentiate the two sub-scenarios.

- **Per unit bases:** To do the calculations we decide to fix the base power to $S_B$ = 230 MVA and $U_B$ = 20/380 kV. The notation $U$ is for phase to phase voltage while the $V$ notation is for phase to ground voltage.

- **Transformer loading:** The loading state of the generator is defined by $S_L = \sqrt{P_r^2 + Q_r^2}$ and we do not want that $S_{TN} < S_L$. So, for $P_r = 200.44$ MW and $P_r = 226.55$ MW we have a maximum HV reactive power supply of $Q_r = 112.8$ MVar and a minimum HV reactive power absorption of $Q_r = -39.7$ MVar.

- **Base case:** In order to compare our different results, we will take a base case corresponding to a grid voltage of 380 kV and a supplied reactive power of $Q_r = 50$ MVar and an absorbed reactive power of $Q_r = -20$ MVar. Also, the adoption of a base case helps us to draw the U/Q diagrams as they are unique for a given tap and fixed active power.

## 3.1 Operating point calculations and U/Q diagram [45]

For the calculation of the different operating point, we have to choose a net guaranteed active power. Then, we set a value for the network voltage as well as for the reactive power exchanged with the grid. By calculating the voltage drop in the step-up transformer, we can deduce a value for the generator voltage and by using the power conservation, we can deduce reactive power exchanged by the generator. All these results will give us a linked operating point on the grid side and the generator side. The whole operating area can be determined by varying the entry parameter (network voltage and reactive power) within their respective limits.

To establish the relationship between the network voltage and the generator, we use a high voltage side Kapp diagram, the equivalent single-phase diagram represented by a

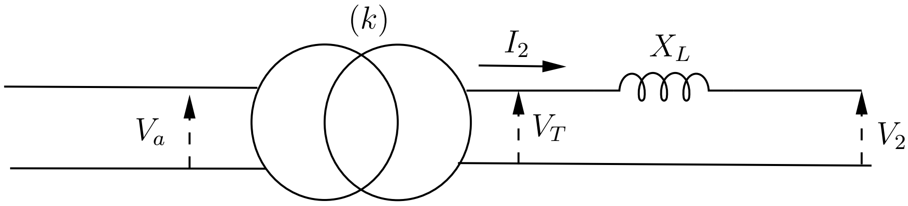


**Figure 3.1:** Equivalent single-phase diagram

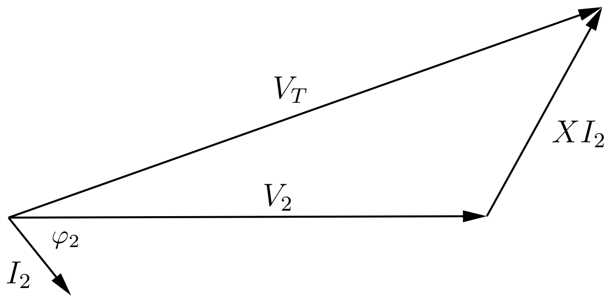


**Figure 3.2:** Kapp diagram

dipole in series with a perfect transformer with a ratio $k$ as illustrated on the figure 3.1.

When a transformer is equipped with a tap changer, the no load high voltage of the transformer depends on the selected tap according to the equation

$$U_{20}(k) = U_0 + k \cdot \frac{\gamma \cdot U_0}{100}$$

where $\gamma$ and $U_0$ are the voltage steps and the no load voltage on the middle tap respectively.

To calculate the operating point, the transformer load state must first be calculated by determining the apparent power corresponding to this load state and the HV current :

$$I_2 = \frac{S}{\sqrt{3} \cdot U_2} \quad \text{with} \quad S_L = \sqrt{P_r^2 + Q_r^2}$$

Then, we can deduce the impedance neglecting the resistive part (because of the negligible impact on the calculations)

$$X = u_{cc}\frac{U_{20}^2}{S_N} + X_L$$

Using the Kapp diagram figure 3.2, we can establish the following relationship

$$V_T = \sqrt{V_2^2 + X^2 I_2^2 + 2V_2 I_2 (X \sin \varphi_2)}$$

which allows us to obtain the corresponding low voltage side value taking into account the transformation ratio

$$U_a = \sqrt{3}\frac{V_c}{k}.$$

For a transformer with a Yd coupling we have that,

$$k = \frac{n_2}{n_3}\sqrt{3} = \frac{U_{20}}{U_{an}}$$

and therefore that the voltage at the generator terminal (corresponding to the load conditions) is

$$U_a = \sqrt{3} \cdot V_T \cdot \frac{U_{20}}{U_{an}} = \sqrt{V_2^2 + X^2 I_2^2 + 2V_2 I_2 (X \sin\varphi_2)} \tag{3.1}$$

Concerning the active and reactive power exchange between the machine and the grid, we can use the power conservation equations expressed by

$$P_{alt} = P_r \pm p_T + P_{aux} \tag{3.2}$$

where $p_{MT} + p_{AT}$ correspond to the sum of the losses of the main and auxiliaries transformers respectively and

$$Q_{alt} = Q_r \pm q_{MT} + q_{AT} + Q_{aux} \tag{3.3}$$

where $q_{MT}$ is the reactive power consumed by the main transformer and calculated by

$$q_{MT} = 3 \cdot X \cdot I_2^2$$

The auxilary transformer exchanges an apparent power of

$$S_{AT} = \sqrt{P_{AT}^2 + Q_{AT}^2}$$

and its reactive power is calculated using the short circuit impedance and the nominal values

$$q_{AT} = u_{cc,AT} \cdot \frac{S_{AT}^2}{S_{n,AT}}$$

The operating point is therefore characterized by two pairs of value: on one hand from the high voltage side by $[U_2, Q_2]$ and on the other hand from the generator side by $[U_a, Q_{alt}]$.

### 3.1.1 U/Q diagram

The study of the U/Q diagrams of a generating unit connected to the network is based on the relationships between the alternator voltage and the generator voltage, as

well as the relationships between the active and reactive power exchanged.
These diagrams provide the plant operator with a simple and immediate overview of the power exchange possibilities of the generating unit, as well as the limits of its permissible operating area.

They are presented in a $[Q_{alt}, U_{alt}]$ plan and they they present two types of straight lines: the lines corresponding to the network voltage $U_r$ and the lines corresponding to the network reactive power $Q_r$ and all these lines are parallel between them. Besides, the voltage limits of the network and the alternator, as well as the reactive power limits of the alternator, are also set and together, they form a polygon where all the points inside correspond to normal operation.

If we are interested in several active power values and/or our transformer contains a tap changer, we'll need to draw as many diagrams as we have taps and/or active power. Indeed, if $n_p$ represents the number of net active power values considered, and $n_k$ the number of transformer taps, we'll draw a number $n_d = n_a \times n_p$ distinct U/Q diagrams.

## 3.2 Losses calculations

### 3.2.1 Machine losses

The stator losses can be evaluated using the following relationship

$$P_{stator,gen} = 3 \cdot R_s \cdot I^2$$

. The current $I$ is calculated using the apparent power corresponding to the transformer load state :

$$\bar{I}_{pu} = \frac{\bar{S}^*_{pu}}{V_{380kV,pu}} \quad \text{with} \quad \bar{S}_{pu} = \frac{P_n + jQ_n}{S_B}$$

For the rotor losses, we have to evaluate the field current $i_f$ and the no load voltage $E_0$. We can obtain $E_0$ by using the equation

$$\bar{E}_0 = \bar{V} + jX_q\bar{I} + j(X_d - X_q)\bar{I}_d$$

and the field current is related to the no load voltage by the magnetic saturation curve of the machine. So by using the figure 2.2, we can find the field current.

To evaluate the rotor losses, we use the formula given by

$$P_{rotor,gen} = R_r \cdot i_f^2$$

### 3.2.2 Transformer losses

To evaluate the transformer losses, we will compute the Joule losses in the OLTC. To do so, we have to compute the apparent resistance of the transformer (HV side) [45]

$$R_t = p_{cc} \cdot \frac{U_{20}^2(k)}{S_n^2}$$

which take into consideration the current tap. The quantity $p_{cc}$ represent the short-circuit power of the transformer and we can compute it using the relation

$$p_{cc} = R_e \cdot I_N^2$$

where $R_e$ and $I_N$ are the series resistance of the equivalent diagram of the transformer and the nominal current in the high voltage side respectively.

The series resistance can be found using the short-circuit voltage $u_{cc}$ (for the considered tap), the nominal current $I_N$ and the assumption that the transformer resistance is very low compared to the inductance. To quantify this we will assume that $Z = 20 \times R$. We have then

$$Z_e = \frac{U_{cc}}{I_N} \quad \Rightarrow \quad R_e = \frac{Z_e}{20}$$

The Joule losses in generator mode are calculated by

$$P_{jt,gen} = R_t \cdot I^2$$

with $I$ the current corresponding to the loading state of the transformer.

## 3.3 Steady-state analysis

### 3.3.1 Scenario I

In this scenario, we have a transformer with a fix transformation ratio. Only the AVR is capable of controlling the voltage.

#### Capability area of the scenario I

The U/Q diagram of the first scenario is depicted figure 3.3 for $P_{alt} = 207$ MW and figure 3.4 for$P_{alt} = 226.55$ MW. In this diagram the maximum and minimum network voltage are represented by the 418 kV and 342 kV respectively. All the other voltages are parallel and their value are at ± 5 % of 380 kV. The reactive power drawn in this diagram are also parallel and represented with a space of 50 Mvar. The left values of the blue line representing the MVars are decreasing value and the right value are increasing value.

The goal of this diagram is to know until which point the power plant can operate. For example, if we want to exchange 100 MVar (right of 50 Mvar) instead of 50 MVar for a 380 kV voltage, we can see that it is still possible but for a higher reactive power exchanged by the generator.

We established the validity of the different operating point for the first scenario in the tables 3.6 and 3.7.

In general, we can see that we don't have a lot of flexibility with this scenario. Indeed, all the red cases are unreachable by the generating unit so only a small part of the generating unit capability can be covered from both of the modes. We only have at our disposal the synchronous machine to control the voltage so we are limited by its voltage limits without any flexibility as the transformer has a fixed ratio. Furthermore, the decisive limitation in reactive power generation/absorption is the limitation of the transformer loading. Therefore, we can see that we don't exploit all of the available capability because of the fixed transformation ratio. This will lead us to the second scenario where we will analyse the influence of the OLTC.

#### Losses evaluation

The losses evaluation for our base case is depicted in table 3.1:

**Table 3.1:** Base case alternator and transformer losses in the scenario I for $P_r = 200.44$ MW and $P_r = 226.55$ MW

| | Losses evaluation | |
|---|---|---|
| Type of losses | $P_r = 200.44$ MW | $P_r = 226.55$ MW |
| Stator losses [kW] | 362 | 431.9 |
| Rotor losses [kW] | 181.45 | 191.3 |
| Transformer losses [kW] | 281.58 | 341.28 |

### 3.3.2 Scenario II

Here, we want that the generator works close to its rated voltage and that the transformer handles the voltage control by changing the taps. The goal is to observe which tap gives us the generator voltage closest to the nominal voltage. To choose which is the closest voltage, we set a decision criterion which impose that the selected voltage has to lie in a band of 1% around the nominal voltage. Hence, we can compute the diverse operating point and see which is the tap respect our criterion.

#### Capability area of the scenario II

The U/Q diagrams for the optimal tap meeting the scenario II criterion considering our base case are depicted on the figure 3.5 and 3.6 with $P_r = 200.44$ MW ans $P_r = 226.55$ MW respectively.

#### Choice of the optimal tap

We established the validity of the different operating point for the first scenario in the tables 3.6 and 3.7.
We can see that we can reach a larger operating region than the first scenario with the tables 3.8 and 3.9. Some of the values in red in the top left corner of table 3.8 can be reach but do not respect the generator requirement. In fact, it doesn't matter, because it's a region corresponding to operation at very low network voltage, with a high level of reactive power absorption. This case is not very realistic because we would rather try to increase the voltage by injecting reactive power. For the case with $P_r = 226.55$ MW the whole operating area can be covered with the OLTC transformer.

#### Losses evaluation

The losses evaluation for our base case is depicted in the table 3.2 :

**Table 3.2:** Base case alternator and transformer losses in the scenario II for $P_r = 200.44$ MW ($k = +1$) and $P_r = 226.55$ MW ($k = -3$)

| | Losses evaluation | |
|---|---|---|
| Type of losses | $P_r = 200.44$ MW ($k = +1$) | $P_r = 226.55$ MW ($k = -3$) |
| Stator losses [kW] | 362 | 431.9 |
| Rotor losses [kW] | 181.45 | 191.3 |
| Transformer losses [kW] | 288 | 332.87 |

### 3.3.3 Scenario III

In this scenario, we will use the potential of both of our voltage control equipment i.e the synchronous machine AVR and the OLTC transformer. In steady state analysis, we will not differentiate the two sub-scenarios.

#### Capability area of the scenario III

We can draw the U/Q diagram for the tap respecting our optimal criterion i.e the tap that minimize the transformer losses within the 3 % around the generator rated voltage. We recall that the goal of this diagram is to assess the ability of our generating unit to respond at a specific demand in voltage and reactive power. For our base case i.e 380 kV/50 MVar and 380 kV/-20 MVar, the optimal tap according to our criterion is $k = -2$ for $P_r = 200.44$ MW and $k = -5$ for $P_r = 226.55$ MW, the diagram 3.7 and 3.8 shows all the different operating points that we can reach while staying on these tap for the fixed active power.

#### Choice of the optimal tap

The optimal taps for the other configurations are shown in the tables 3.10 and 3.11.

We can see that we can reach a larger operating region than the first scenario and the same area as scenario II but with much more flexibility. Similarly, as the second scenario, although some values in the top left corner can be reach it doesn't matter, because this region of very low network voltage and high level of reactive power absorption is not very realistic as we would rather try to increase the voltage by injecting reactive power.

Furthermore, for a same operating point, we will have different acceptable tap values for this scenario which means that we will have less tap operations to do compare to the second scenario. Indeed, as the dead band around the nominal value is larger, more different U/Q configuration could work. To do so we have to relax the constraint linked to the losses minimization.

For example, the range of possible tap values to stay within the 3 % around the nominal voltage for the 380 kV/50 MVar is $[-3; +2]$. So, if we set our OLTC transformer to $k = +1$ for this operating point, as in the second scenario, and we want to move to a 380 kV/100 Mvar operating point we do not have to do any tap changing. Indeed, the range of possible tap values for this configuration is $[-1; +5]$ so $k = +1$ is still acceptable for this new operating point unlike the second scenario where we have to move to $k = +3$ which may involve a longer time to reach a new operating point.

#### Losses evaluation

The losses evaluation for our base case is depicted in the table 3.3 :

## 3.4 Discussion of the results

The results of the operating area evaluation are shown in table 3.4. We can see that the third scenario is capable of working on the full operating region bounded by the voltage limits of the network and the alternator, as well as the reactive power limits of the alternator. Indeed, the action of the OLTC allows to have more flexibility on the

**Table 3.3:** Alternator and transformer losses in the scenario III for $P_r = 200.44$ MW ($k = -2$) and $P_r = 226.55$ MW ($k = -5$)

| | Losses evaluation | |
|---|---|---|
| Type of losses | $P_r = 200.44$ MW ($k = +1$) | $P_r = 226.55$ MW ($k = -3$) |
| Stator losses [kW] | 362 | 431.9 |
| Rotor losses [kW] | 181.45 | 191.3 |
| Transformer losses [kW] | 278.1 | 323.8 |

voltage and reactive power control. The second scenario offer a relatively good range of operation but may be limited by the too narrowly band around the rated voltage. The first scenario is the worst case. The simple use of the synchronous machine AVR for the voltage control do not offers enough flexibility and the region of operation is limited. Therefore, this scenario will be rejected for the voltage stability analysis in the chapter4.

**Table 3.4:** Capability area results for the 3 scenarios in the case where $P_r = 200.44$ MW and $P_r = 226.55$ MW

| | Capability area | | |
|---|---|---|---|
| Active power | Scenario I | Scenario II | Scenario III |
| $P_r$ =200.44 MW | **Half-full** | **Partially-full** | **Full** |
| $P_r$ =226.55 MW | **Half-full** | **Full** | **Full** |

The result concerning the losses are shown in the table 3.5. We can notice that the alternator losses are constant for the two active power cases. Indeed, these losses only depend on the value of the required power and as we are always working with the base case, these values are constant. However, we can see that these losses are almost twice as high as transformer losses. The transformer losses do not vary so much but we can see that the losses generated in the third scenario are the lowest.

Therefore, we can say that the main constraint on the capabilities of a power-generating unit, regarding the production or absorption of reactive power, is the narrow allowable range of voltage fluctuations within the generator (referred to as generator voltage limit), the generated active power and the transformer loading state.

By decreasing the active power generated by the machine, we can enlarge the reactive power reserve. With no active power generation, we can work under compensator mode and exploit the full reactive power capability of the machine. Furthermore, we

**Table 3.5:** Total alternator and transformer losses for the 3 scenarios in the case where $P_r = 200.44$ MW and $P_r = 226.55$ MW

| | Losses evaluation | | |
|---|---|---|---|
| Type of losses | Scenario I | Scenario II | Scenario III |
| Total alternator losses [kW] (200.44 MW) | 543.45 | 543.45 | 543.45 |
| Total transformer losses [kW] (200.44 MW) | 281.58 | 288 | 278.1 |
| Total alternator losses [kW] (226.55 MW) | 623.2 | 623.2.9 | 623.2 |
| Total transformer losses [kW] (226.55 MW) | 341.28 | 332.87 | 323.8 |

can say that the application of step-up transformers with an on-load tap changer and more specifically the control of its transformation ratio has a favorable impact on the capability area of the generating unit.

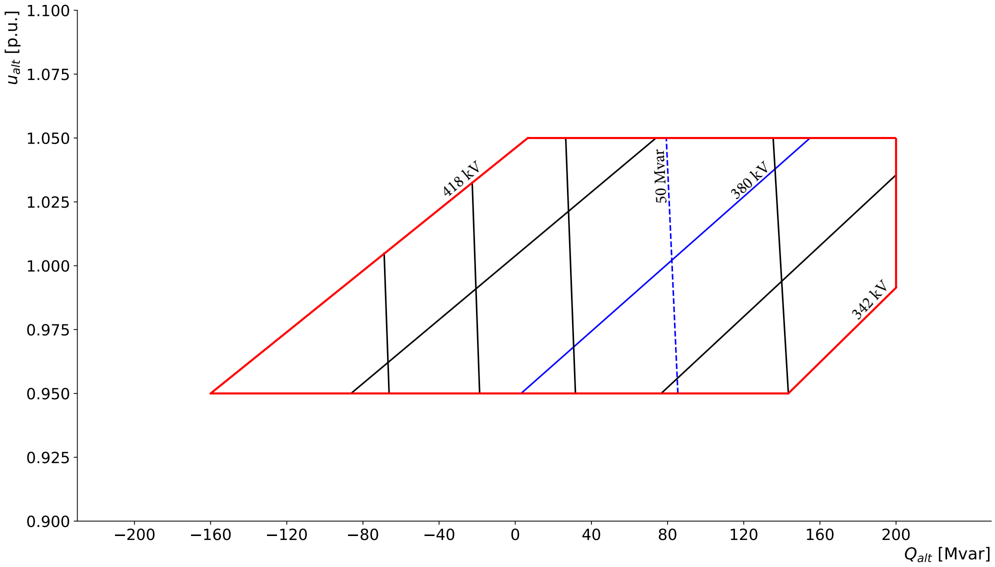


**Figure 3.3:** U/Q diagram of the scenario I for $P_r = 200.44$ MW

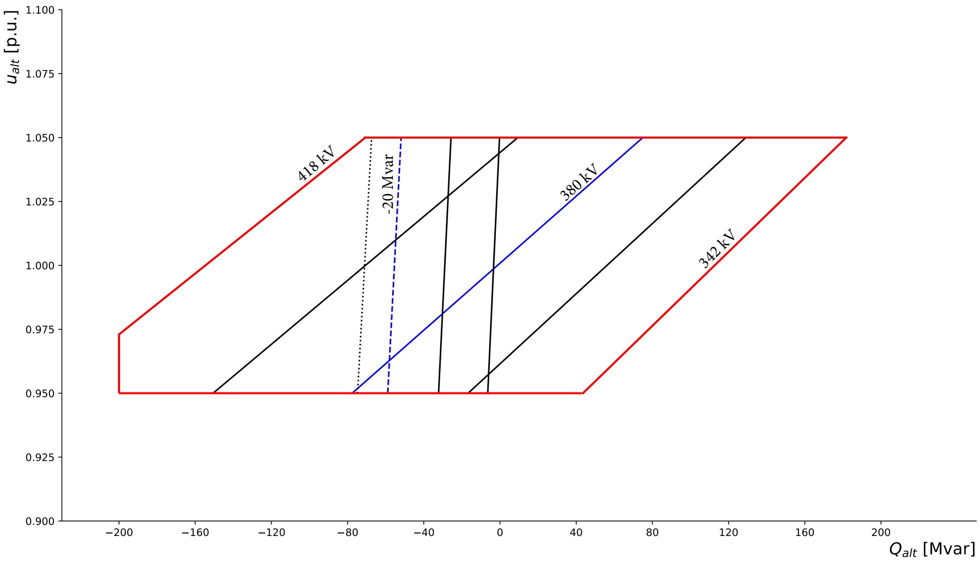


**Figure 3.4:** U/Q diagram of the scenario I for $P_r = 226.55$ MW

**Table 3.6:** Range of possible operating point for $P_r = 200.44$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| -112.8 Mvar | X | X | X | ✓ | ✓ |
| -100 Mvar | X | X | X | ✓ | ✓ |
| -50 Mvar | X | X | X | ✓ | ✓ |
| 0 Mvar | X | X | ✓ | ✓ | X |
| 50 Mvar | X | ✓ | ✓ | X | X |
| 100 Mvar | ✓ | ✓ | ✓ | X | X |
| 112.8 Mvar | ✓ | ✓ | X | X | X |

**Table 3.7:** Range of possible operating point for $P_r = 226.55$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| -39.68 Mvar | X | X | ✓ | ✓ | X |
| -20 Mvar | X | X | ✓ | ✓ | X |
| 0 Mvar | X | X | ✓ | ✓ | X |
| 20 Mvar | X | X | ✓ | ✓ | X |
| 39.68 Mvar | X | ✓ | ✓ | ✓ | X |

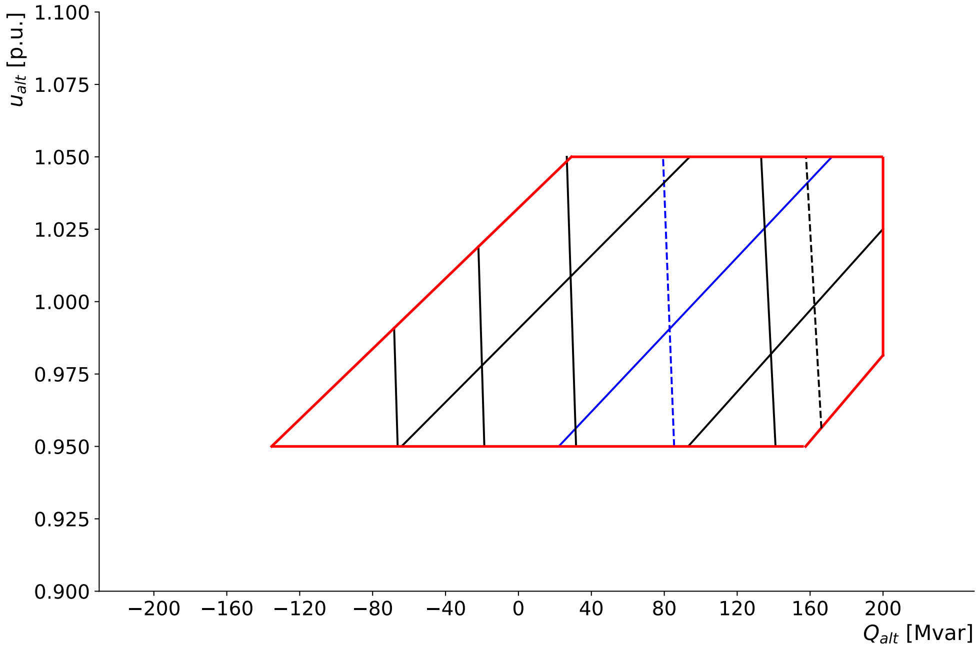


**Figure 3.5:** U/Q diagram of the scenario II for $k = +1$ and $P_r = 200.44$ MW

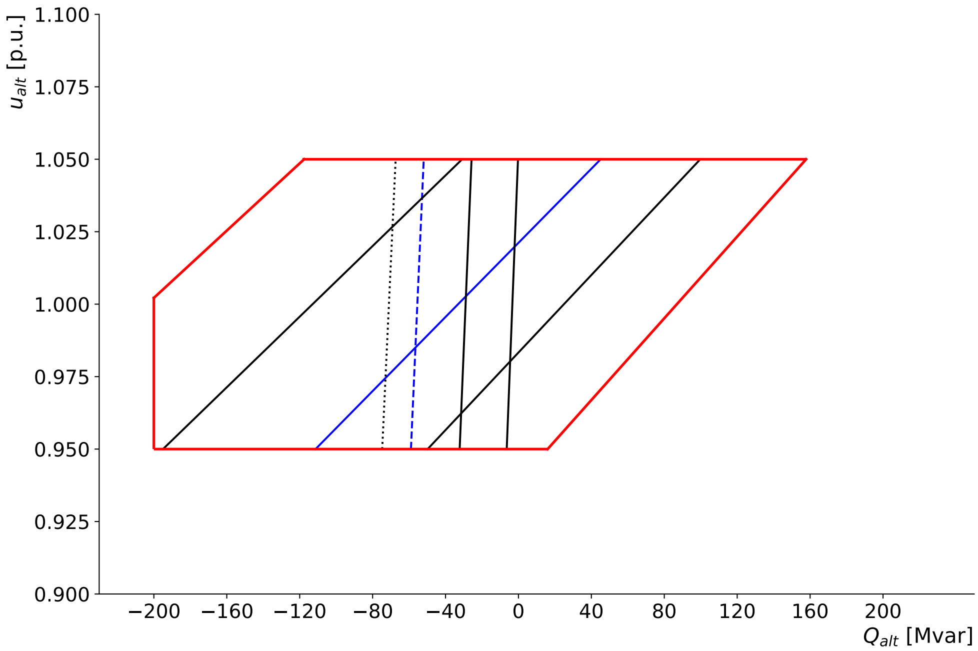


**Figure 3.6:** U/Q diagram of the scenario I for $k = -3$ and $P_r = 226.55$ MW

**Table 3.8:** Choice of the tap $k$ which meet the scenario II criterion for $P_r = 200.44$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| -112.8 Mvar | X | $-12$ | $-8$ | $-4$ | $-1$ |
| -100 Mvar | $-12$ | $-11$ | $-8$ | $-4$ | 0 |
| -50 Mvar | $-12$ | $-9$ | $-5$ | $-1$ | $+2$ |
| 0 Mvar | $-10$ | $-7$ | $-3$ | $+1$ | $+5$ |
| 50 Mvar | $-8$ | $-4$ | 1 | $+4$ | $+8$ |
| 100 Mvar | $-5$ | $-1$ | $+3$ | $+7$ | $+10$ |
| 112.8 Mvar | $-4$ | 0 | $+4$ | $+7$ | $+11$ |

**Table 3.9:** Choice of the tap $k$ which meet the scenario II criterion for $P_r = 226.55$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| -39.68 Mvar | $-12$ | $-8$ | $-4$ | $-1$ | $+3$ |
| -20 Mvar | $-11$ | $-7$ | $-3$ | 0 | $+4$ |
| 0 Mvar | $-10$ | $-6$ | $-2$ | $+1$ | $+5$ |
| 20 Mvar | $-9$ | $-5$ | $-1$ | $+2$ | $+6$ |
| 39.68 Mvar | $-8$ | $-4$ | 0 | $+3$ | $+7$ |

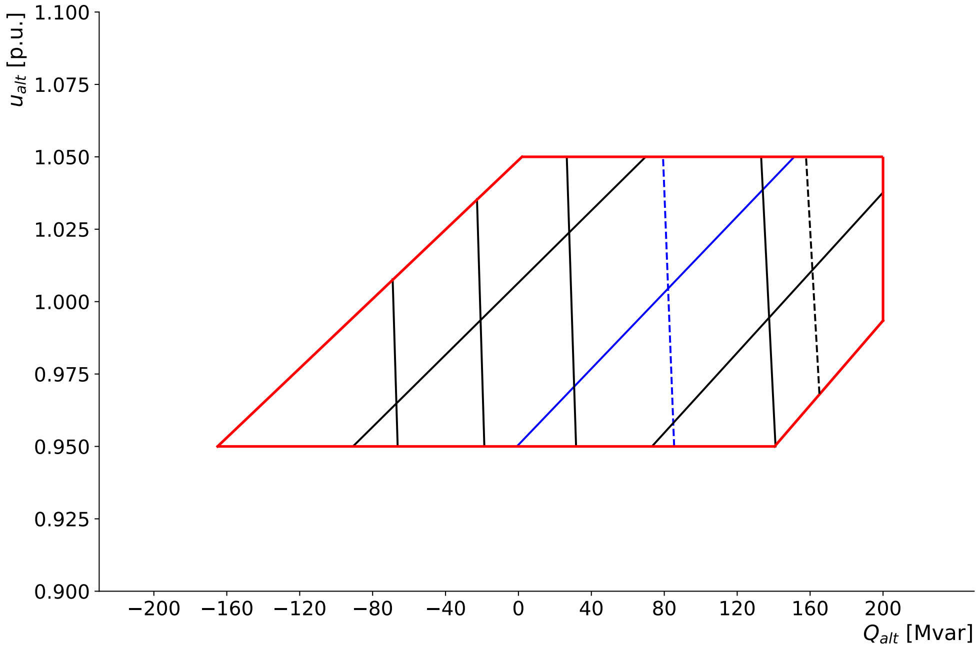


**Figure 3.7:** U/Q diagram of the scenario III for $k = -2$ and $P_r = 200.44$ MW

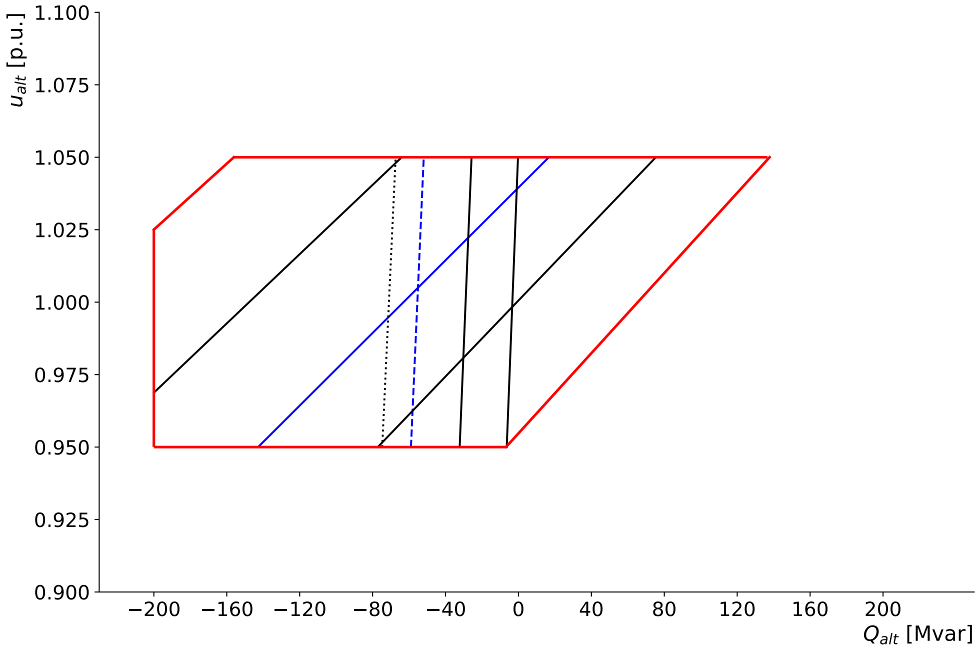


**Figure 3.8:** U/Q diagram of the scenario III for $k = -5$ and $P_r = 226.55$ MW

**Table 3.10:** Choice of the tap $k$ which meet the scenario III criterion for $P_r = 200.44$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| −112.8 Mvar | X | −10 | −9 | −5 | −2 |
| −100 Mvar | −12 | −10 | −8 | −5 | −1 |
| −50 Mvar | −10 | −10 | −6 | −3 | +1 |
| 0 Mvar | −10 | −8 | −4 | 0 | +3 |
| 50 Mvar | −9 | −5 | −2 | +2 | +6 |
| 100 Mvar | −6 | −3 | +1 | +5 | +8 |
| 112.8 Mvar | −6 | −2 | +2 | +5 | +9 |

**Table 3.11:** Choice of the tap $k$ which meet the scenario III criterion for $P_r = 226.55$ MW

| | 342 kV | 361 kV | 380 kV | 399 kV | 418 kV |
|---|---|---|---|---|---|
| −39.68 Mvar | −10 | −9 | −6 | −2 | +2 |
| −20 Mvar | −10 | −8 | −5 | −1 | +1 |
| 0 Mvar | −10 | −7 | −4 | 0 | +4 |
| 20 Mvar | −10 | −6 | −6 | +1 | +5 |
| 39.68 Mvar | −9 | −6 | −2 | +2 | +6 |

# Chapter 4

# Voltage stability analysis of the voltage control scenarios

The study of the possibilities of voltage regulation involving a generator and an OLTC transformer requires to takes into account the problems related to the coordination of these two regulators. Indeed, we are dealing here not only with the regulators of two different equipment, but also with two processes that differ in terms of speed and nature of control. In fact, control of the synchronous generator is a continuous and fast control while the regulation of the OLTC transformer is discrete and much slower than the generator regulation [41].

In this chapter, we will analyze the generator voltage behavior and the OLTC operation when the system is subject to different perturbations on the high voltage busbar. To do so, we will analyze the speed response of the systems and evaluate their voltage stability behavior. We will show that for the first case represented by a higher reactive power demand, the scenario III.1 better manage the issue. The second case involves a three-phase short circuit of 0.2 s, for which scenario III.2 gives the best response.

### Assumptions and constraints

- **Performance criteria:** In order to evaluate our scenarios, we decide to define two time criteria. The first one evaluates the time where the generator voltage lies outside the dead zone (TODZ) and therefore evaluate the ability of the system to restore a stable state under long term disturbance. The second criterion is the recovery time (RT), i.e. the time required for the system to return to equilibrium after the fault. This criterion, evaluate the ability of the system to restore equilibrium under short time disturbance.

- **System simplifications:** In the modelled system, the auxiliaries are modelled as constant active power load of 5 MW on the 20 kV and the lines resistance is neglected. We also decide to simulate an hydraulic turbine and governor with the default parameters given by the software (Matlab Simulink). Furthermore, only the generator mode is simulated here i.e we will only look at the behavior of the system when the reactive power demand increase (the HV busbar voltage decrease) and so when the generator injects reactive power in the system. The initial tap position is set on the neutral tap position ($k = 0$) and the saturation of the transformer is simulated using the default parameter of the software.

- **Time scale:** To limit the test duration, the OLTC reaction time and dead time were shortened to 3.75 s and 1.25 s respectively.
- **Scenarios:** Due to the limited capability range and so the limited flexibility given by the first scenario, the analysis are only conducted on the second and third scenarios. Furthermore, in order to meet the requirement of the second scenario 2.2.2, the OLTC dead zone is reduce to 1% instead of 3%.
- **Excitation system and PSS model:** In the simulation, the excitation system used is an ST6C model. Indeed, as mentioned in [36], any existing excitation system represented by the ST6B model could also be represented by the ST6C model. The PSS model used is the PSS2C block of the software. The parameters can be found in C.
- **Load compensator:** The ST6C excitation system model already implement a load compensator. The reactance $X_c$ was set to 85 % of the middle tap transformer reactance and the resistance $R_c$ was neglected.
- **Load model:** In order to simulate the reactive power variation, we will use three-phase parallel RLC load connected on the HV bus. The loads will be triggered at different times using the three-phase breakers. There is an initial load consumption on the HV bus of 10 MW in order to avoid simulation errors.
- **Limiters:** The limiters are not implemented here.

## 4.1 System simulation modelling

As shown in appendix D and table 4.1, a test model was established to verify the validity of the proposed scenarios.

**Table 4.1:** Simulation parameters

| **Component** | **Information** | **Parameter** |
|---|---|---|
| OLTC transformer | Rated voltage | 20/400 kV |
| | Rated Power | 230 MVA |
| | Total tap | 24 (±8) |
| | Dead zone | ±1.15% |
| | Voltage step | 1.25% of rated voltage |
| | Waiting time[2] | 5 s |
| Lines | Branch type | L |
| | Inductance | $2 \times 10^{-3}$ H |
| Three phase source | Phase to phase voltage | 380 kV |
| | Frequency | 50 Hz |
| | Short circuit level | 15.13 GVA |
| | $X/R$ ratio | 12.4 |
| Reactive power Loads | Phase to phase voltage | 380 kV |
| | Frequency | 50 Hz |
| | Load 1 reactive power | 100 MVar from $t = 30$ s to $t = 100$ s |
| | Load 2 reactive power | 200 MVar from $t = 40$ s to $t = 80$ s |
| | Load 3 reactive power | 500 MVar from $t = 55$ s to $t = 80$ s |
| | Load 4 reactive power | 300 MVar from $t = 85$ s to $t = 100$ s |
| Auxiliary Load | Phase to phase voltage | 20 kV |
| | Frequency | 50 Hz |
| | Active power | 5 MW |
| | Reactive power | 2 MVar |

[2]The waiting time is defined as the sum of the reaction time and the dead time.

## 4.2 Case studies

In this section, cases were conducted to analyze the behavior of the voltage at the generator and the OLTC operation when the system is subject to disturbances. The first case represents a higher reactive power consumption at the HV busbar leading to a decrease of the voltage in this side. The reactive power loads are switching on and off at different times as shown in table 4.1. The case 2, represent a short-term voltage instability on the HV busbar where a three-phase fault occurs at $t = 50$ s and is cleared at $t = 50.2$ s. The simulation runs for 100 s in the case 1 and up to 200 s in the case 2.

### 4.2.1 Case 1: Higher reactive power consumption at the HV busbar

#### Scenario II

Figure 4.1 and 4.2 show the tap position and the generator voltage respectively. The AVR of the machine restore the voltage within the dead zone when the reactive power demand increase at $t = 30$ s and $t = 40$ s. When the demand is too high ($t = 55$ s) the machine cannot restore the voltage within the dead zone and the OLTC starts to raise the voltage. When the voltage is close to the dead zone ($t = 70$ s), the OLTC start to oscillate leading to voltage fluctuations. This is a hunting process. The hunting is cleared when the load 2 and 3 demand stops; the AVR takes the control again and restore the voltage within the dead zone. The total time outside the dead zone is 30 s.

#### Scenario III.1

On figure 4.4, the machine's AVR restore the voltage within the dead zone until the reactive power demand rise too high. Figure 4.3 shows the action of the OLTC. We can see that to restore the generator voltage from the higher load variation, the tap has to be lowered three times. Then, the AVR will bring the voltage back within the dead zone at a lower generator voltage than initially. Finally, the AVR will manage the others load variations without the help of the OLTC and return to the initial state. The total time outside the dead zone is 14 s

#### Scenario III.2

Figure 4.5 and 4.6 show the simulation results for the scenario III.2. We can see that when the load 1 enter in action the AVR raise the field current, and therefore the stator voltage. It can stabilize the stator voltage but cannot restore it within the dead zone. The OLTC will raise the tap by one step to put the voltage under the dead zone. At $t = 55$ s, the demand in reactive power is the highest and the OLTC will restore the voltage. To do so, the tap has to change six times which is higher that the two other scenarios. During the time in which the load 2 and 3 demand stops and the load 4 demand starts, the tap has to increase three times to bring back the voltage into the dead zone. The system is therefore stable but not always within the safe limits. The total time outside the dead zone is 47 s.

### 4.2.2 Case 2: Three-phase fault of 0.2 s on the HV busbar

#### Scenario II

Figure 4.7 and 4.8 show the tap position and the generator voltage respectively. When the three-phase fault occur on the HV bus, the system cannot preserve the stability, and the generator voltage start to oscillate rapidly meanwhile the OLTC is trying to restore the voltage. At $t = 85$ s, the generator stops oscillating and the system is trying to find its equilibrium back. At $t = 90$ s, the OLTC starts to increase the tap until the voltage lies again in the dead zone. The voltage never stabilizes due to the hunting process occurring at $t = 150$ s. If the process does not stop, the recovery time tends towards infinity.

### Scenario III.1

On figure 4.10, the generator voltage also oscillates after the appearance of the three-phase fault. The OLTC will act in order to manage the generator voltage and bring it back into the dead zone (see figure 4.9). We can see that the recovery time lasts 90 s.

### Scenario III.2

Figure 4.11 and 4.12 show the simulation results for the scenario III.2. We can see that the system supports the fault without any voltage oscillation. The AVR will react and reach a stable state. This stable state lies outside the upper limit of the dead zone so the OLTC act by switching the tap three times in order to lower the voltage and reach an acceptable stable state. In this situation, the recovery time is 14 s.

## 4.3 Discussion of the results

The scenarios time and stability performances are summarized is the table 4.2. We can see that for a long-term disturbance (case 1) the scenario III.1 react faster than the other scenarios. Indeed, it lies most of the time within the dead zone while the scenario III.2 stays almost half of its time outside the dead zone which indicate that the system react more slowly. Nevertheless, these two systems are stable. For the scenario II, the time outside the dead zone is twice as long as scenario III.1 due to the hunting process and this will lead to instabilities in the system.

For the a short term disturbance (case 2), the time to restore a stable state is the fastest in the scenario III.2. Indeed, it takes only 14 s to bring the equilibrium back while the scenario III.1 is more than six times slower. So, this is a less stable scenario. For the scenario II, we can see that we have an unstable system: we never reach the equilibrium due to a hunting process of the OLTC.

We can see that the OLTC involve in the control ensure a safe system. Indeed, in the scenario III.2, the AVR will first stabilize the system but sometimes at a too high value exceeding the equipment's limit. Then, the action of the OLTC is to bring the

**Table 4.2:** Time outside the dead zone (TODZ) and recovery time (RT) for the scenarios II, III.1 and III.2 according to case studies

| | Time & stability performances | | |
|---|---|---|---|
| Criterion | Scenario II | Scenario III.1 | Scenario III.2 |
| **TODZ** (case 1) | 30 s | 14 s | 47 s |
| **RT** (case 2) | $\infty$ | 90 s | 14 s |
| **Stability** | unstable | partially stable | stable |

voltage into safe and stable operation. If the system is not stabilize by the AVR, it will lead to a high number of tap switching which may exceed the allowed number of taps as seen in the scenario II and III.1.

The hunting process that occurs in scenario II, is most likely due to the reduction of the dead zone value in order to meet the scenario requirement. Indeed, the condition stating that half of the dead zone must be greater than the percentage tap increment of the transformer is not respected (see section 2.1.2). Another possibility for the control of this scenario is the adoption of a transformer with a smaller voltage step but this solution require the installation of new equipment which can be too expensive.

The load compensation is probably reason why the scenario III.2 was able to resist to the three-phase fault. Indeed, according to [44], the compensation in the generator voltage controllers made the grid voltage more robust, and consequently improves the voltage control quality in terms of fast disturbances. As a result, the risk of generation unit shut down is reduced, which often averts voltage stability loss.
In our scenario, the voltage reference of the transformer and the generator is the same. One way to improve the voltage control in the scenario III.2, is to have an external control system providing the setpoint of the transformer controller. [41] propose that the reference value of the tap changing controller depend on HV reactive power demand according to the following formula:

$$V_{t,ref} = \left(1 + \kappa \frac{Q_s}{S_N}\right) \times V_N$$

where $V_N$, $S_N$ are respectively the nominal voltage and apparent power of the generator, and $\kappa$ is a positive gain defined by

$$\kappa = \frac{V_{lim} - V_N}{V_N} \times \frac{1}{\sin \varphi}$$

The upper limit of $V_{lim}$ is used for $Q_s > 0$ and the lower limit for $Q_s < 0$. After the calculations, the value of $V_{t,ref}$ must be passed through a limiter in order to determine the permitted generator voltage.

### Other works

The study conducted in [42] looks at the appropriate way of distributing control criteria between the generator and the transformer controller. The document draws attention to the aspect of voltage measurement location which has a significant impact on both the algorithm and the quality of the regulation. The article exposes the differences in regulation between the scenario III.1 and III.2. [42] comes to the conclusion that the scenario III.1 leads to a lot of control problems and recommend the introduction of additional dependencies between the generator and transformer control systems and/or considerably modify their operating algorithms. Therefore, the main advantage of such an easy-to-use solution loses its importance. On the other hand, the scenario III.2 does not suffers from the same problems and the authors recommend the solution presented in this scenario.

Another study presented in [43] analyzes the case where the transformer regulator maintains the reference voltage on the HV side and the generator voltage regulator maintains the voltage at the its terminals. The authors conclude that this option has to be rejected due to coordination problems.

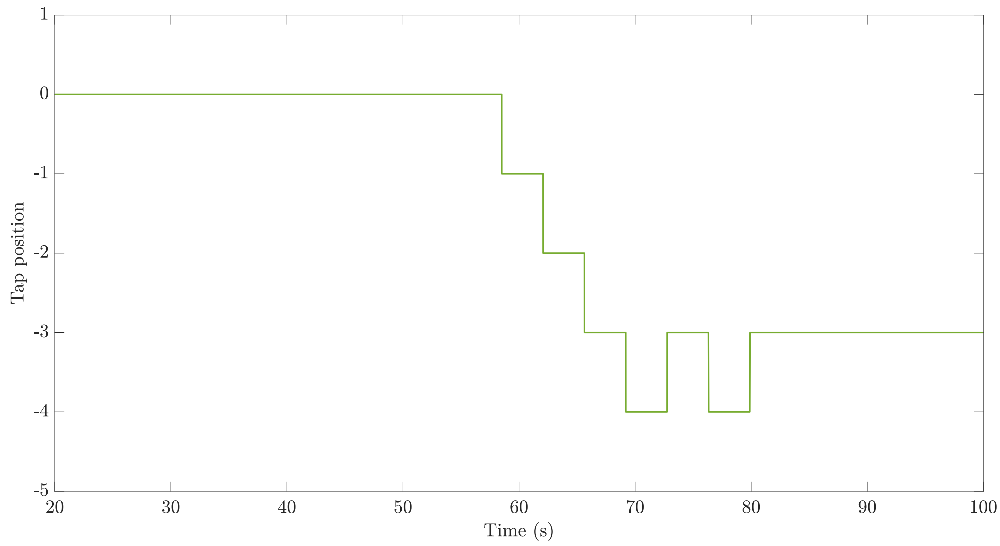


**Figure 4.1:** Scenario II tap position of the OLTC transformer during the case 1

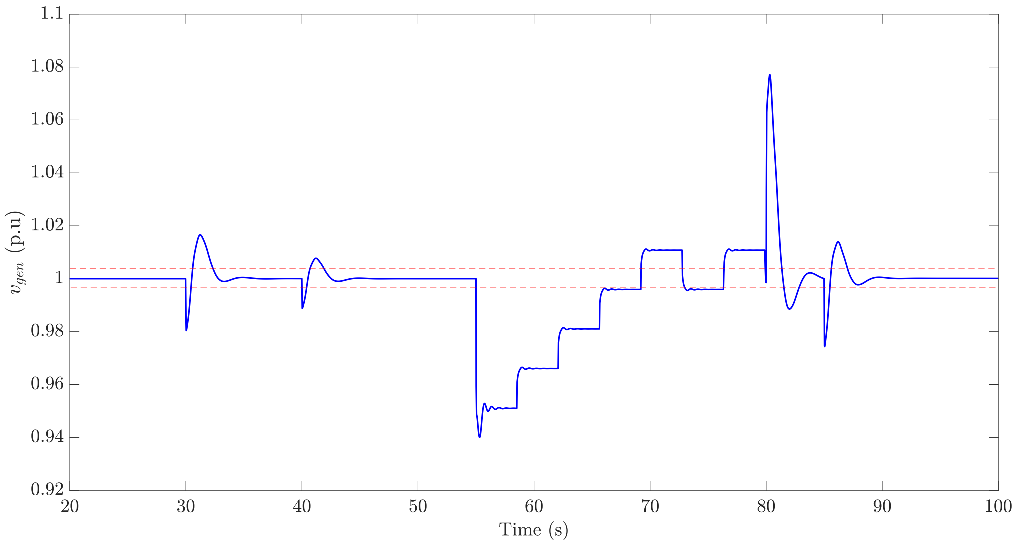


**Figure 4.2:** Scenario II generator voltage in p.u during the case 1

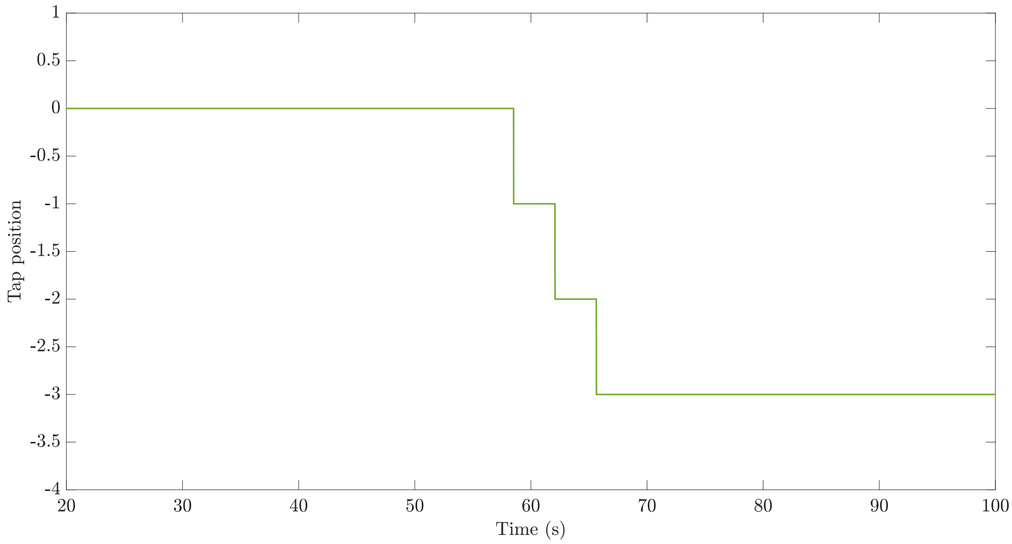


**Figure 4.3:** Scenario III.1 tap position of the OLTC transformer during the case 1

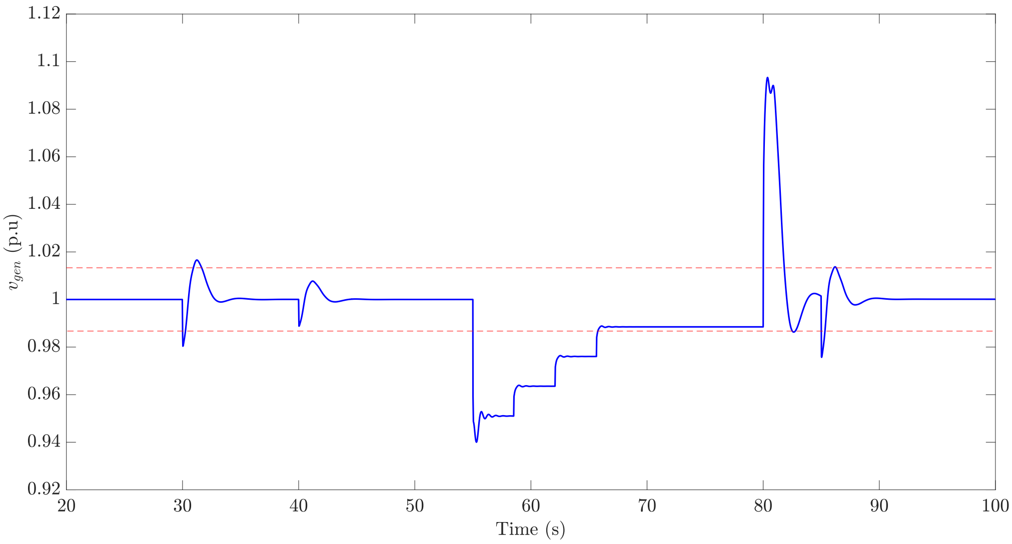


**Figure 4.4:** Scenario III.1 generator voltage in p.u during the case 1

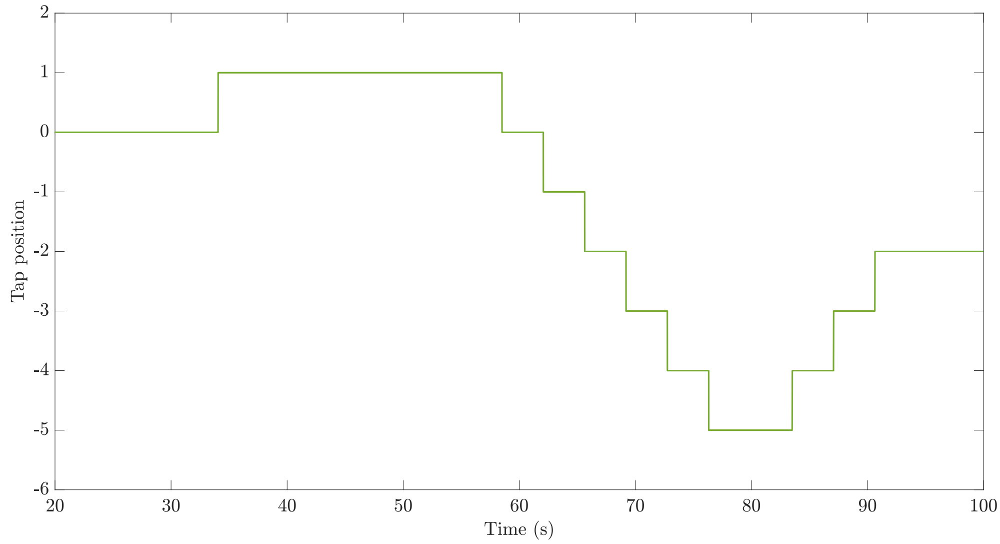


**Figure 4.5:** Scenario III.2 tap position of the OLTC transformer during the case 1

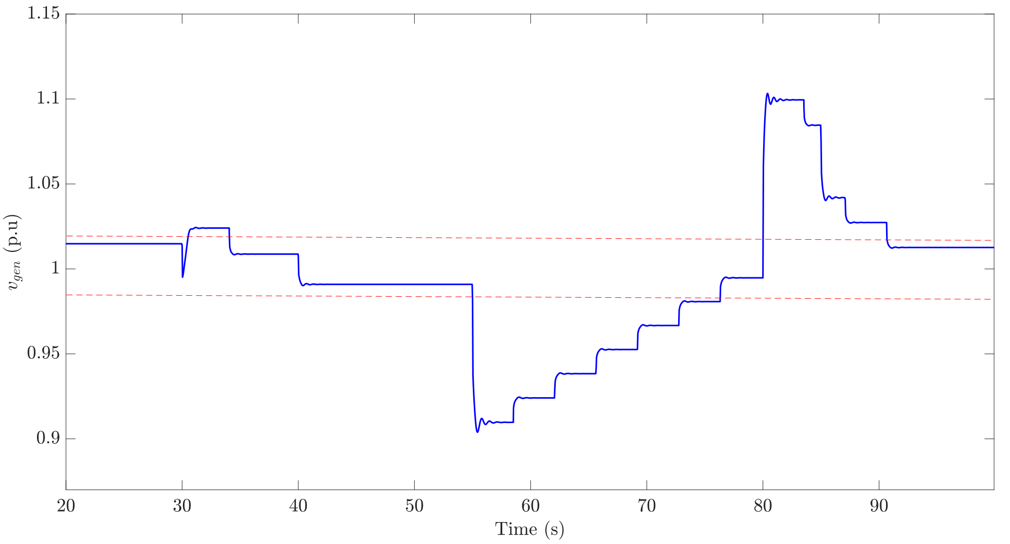


**Figure 4.6:** Scenario III.2 generator voltage in p.u during the case 1

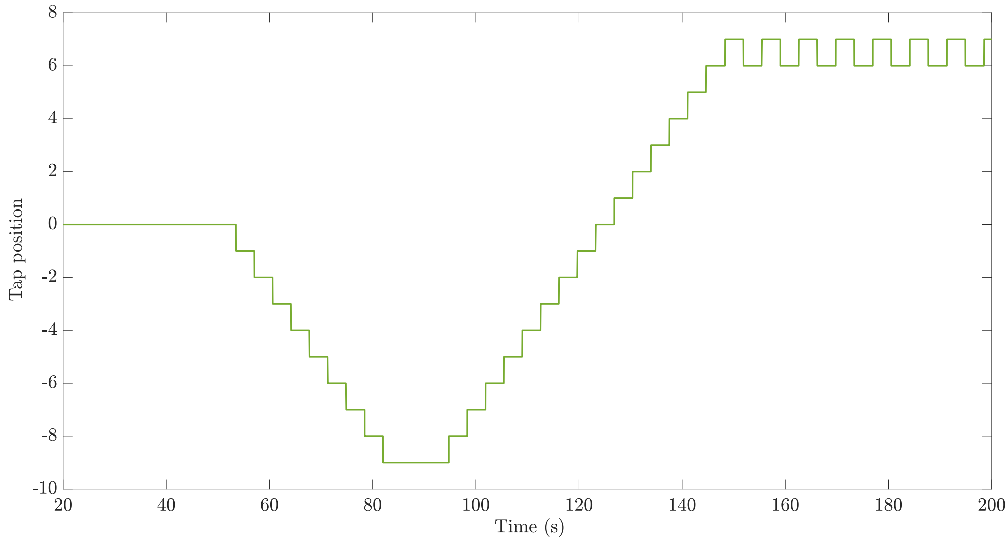


**Figure 4.7:** Scenario II tap position of the OLTC transformer during the case 2

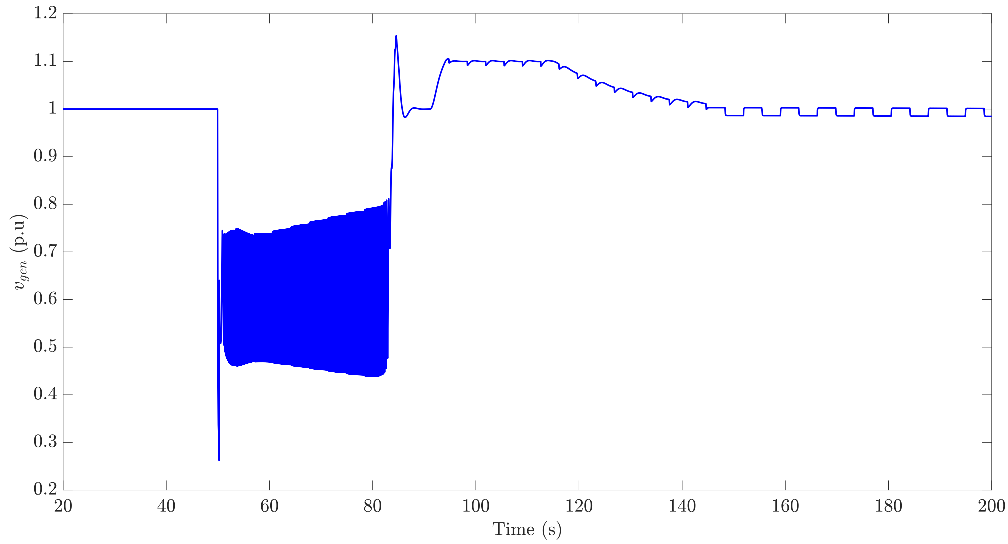


**Figure 4.8:** Scenario II generator voltage in p.u during the case 2

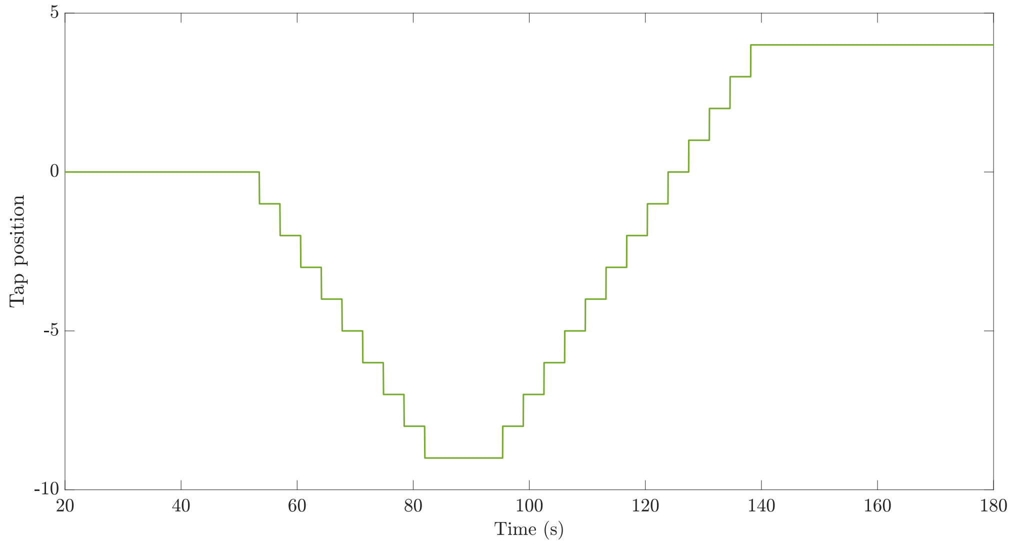


**Figure 4.9:** Scenario III.1 tap position of the OLTC transformer during the case 2

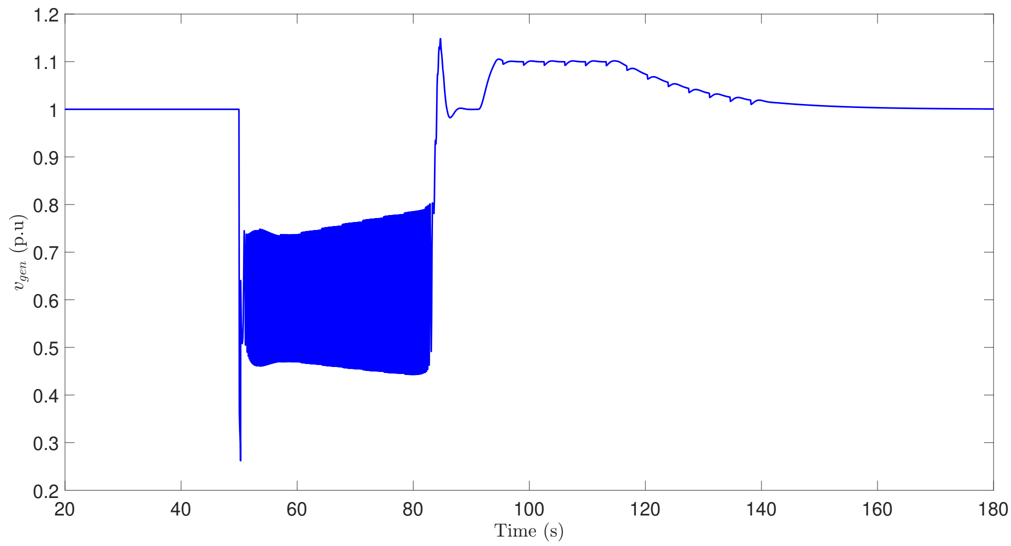


**Figure 4.10:** Scenario III.1 generator voltage in p.u during the case 2

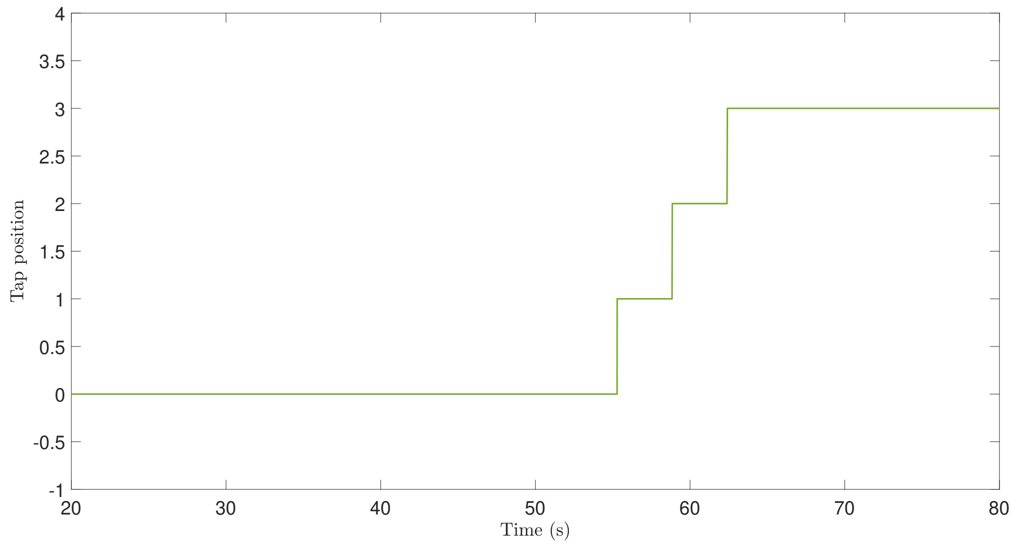


**Figure 4.11:** Scenario III.2 tap position of the OLTC transformer during the case 2

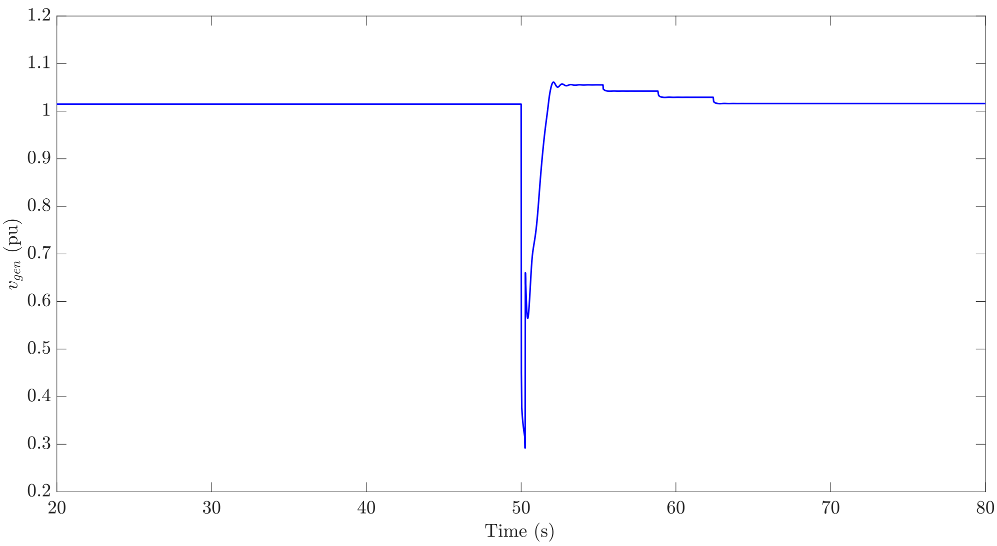


**Figure 4.12:** Scenario III.2 generator voltage in p.u during the case 2

# Conclusion

The main purpose of this thesis is to study the coordination between the generator automatic voltage control and the tap changer control of the step-up transformer in order to maintain a stable voltage on the high-voltage busbar and maximize the generating unit's ability to generate or consume reactive power. In order to achieve the desired objectives, we proposed different scenarios. Then, we conducted a steady state and voltage stability analysis.

The first scenario that we suggested only involve the generator regulator. The transformer is kept at its rated transformation ratio and only the AVR control the voltage. The second scenario relaxes the constraint on the transformer by allowing the tap changer to take part in voltage control. But in this case, the stator voltage limits, and so, the AVR are restricted and an operation within 1% around the rated value of the generator is imposed. The third scenario release the restriction of the two other scenarios and is divided into two sub-scenarios depending on where the voltage reference value is taken. The first one takes the generator terminal as the reference value for the AVR and OLTC controller. The difference in the second sub-scenario lies in the fact that the generator takes its reference value on the HV side and therefore implement a load compensation since the voltage reference is taken from a point external to the generator terminal.

From the reactive power capacity point on view, it can be shown that the simple use of the synchronous machine AVR for the voltage control do not offers enough flexibility and the region of operation is limited. When we have a restricted use of AVR but we dispose of the OLTC control, the reactive power capability can be limited depending on the grid configuration. For a joint use of both the generator AVR and OLTC controller, the results show that all the grid configuration can be reached while respecting the limits of the equipment. The losses generated by the three scenarios do not vary so much from one another for a given operating point. We should keep in mind that all the results presented here hold for a fixed value of active power. Therefore, we can say that the main limitations on the capabilities of a generating unit, regarding the production or absorption of reactive power, is the stator generator voltage limit, the generated active power and the transformer loading state. Besides, we can conclude that the use of an OLTC step-up transformers and its transformation ratio has a positive impact on the capability area of the generating unit.

Regarding voltage stability, when we face a long-term disturbance, the second scenario shows a hunting process and oscillation of the tap selector and therefore the stator voltage. The hunting can be cleared by a change in load demand but it is not immune to a restart. This process also appears for a short-term disturbance and in this case never disappear which imply that this configuration is unstable as we never recover the steady state. For the scenario III.1, we have a good and fast response of the system regarding the long-term disturbance but when a short-term fault appears the system takes quite a long time to reach the steady state meaning that we have a partially stable system. The scenario III.2 takes the longest time to reach a stable state within the dead zone however the system stays stable. For a short-term disturbance, this system is the fastest to restore the steady state. The use of the load compensation is probably the reason of this stability improvements.

To conclude, in order to answer the research question, this thesis recommend a solution in which the OLTC transformer regulator measure the voltage at the generator terminals, and the generator voltage regulator measures the voltage at the high-voltage side of the transformer as this configuration expose the largest reactive power capacity and the more stable behavior.

### Improvements and further works

Several improvements can be made in addition to this thesis:

- A more accurate excitation system model can be establish containing all the require parameters and external system as the limiters. In addition, a better design of the load compensation can also be conducted

- Working on a more complete algorithm for the transformer regulator with for example a more flexible voltage reference value.

- Establish a better model for the power plant by, for example the modelling of the auxiliaries system or the hydraulic turbine.

- Establish more accurate voltage-reactive power capability curves.

- Take a closer look to the motor mode and establish a study of the compensator mode.

- To go further, the work can be carried out taking into account the three generating units of COO II.

- Investigate special situation such as black-start and islanding mode operation.

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# Appendix A

# Phasor diagram of a two axis salient pole generator

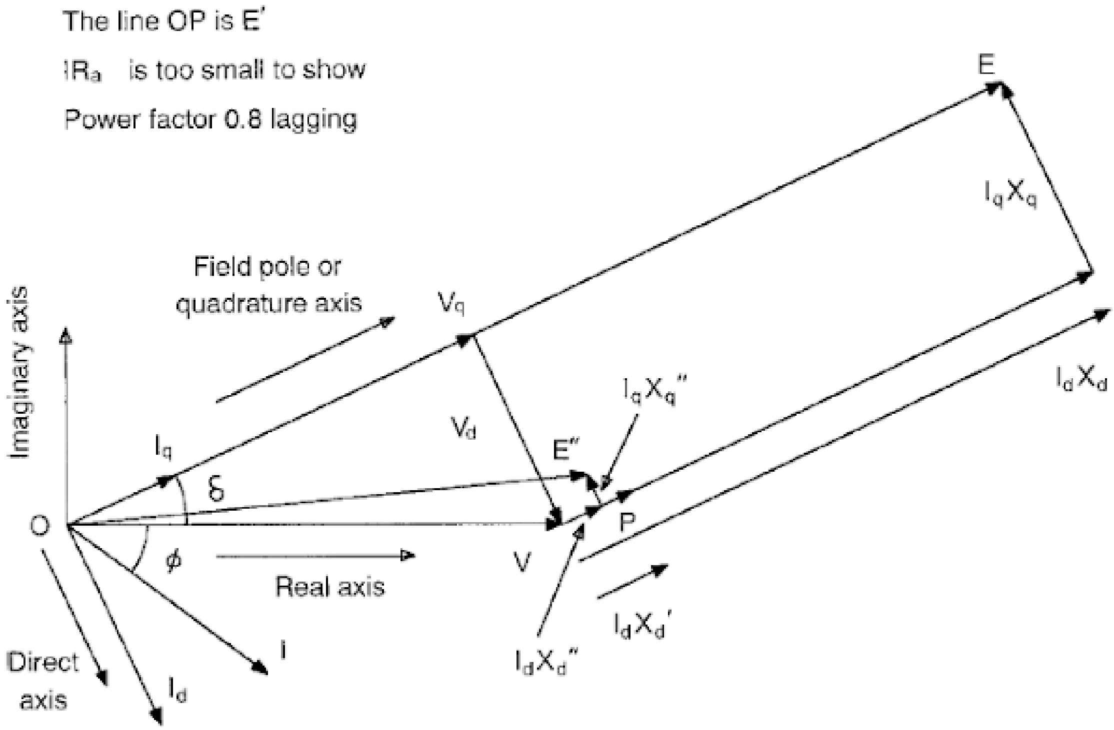


Figure 3.1 Phasor diagram of a two-axis salient pole generator.

**Figure A.1:** Phasor diagram of a two axis salient pole generator [34]

# Appendix B

# Short-circuit voltages for high (left) and low (right) tap positions

**Table B.1:** Short-circuit voltages for high (left) and low (right) tap positions

| High tap position | |
|---|---|
| Tap position | Short-circuit voltage $u_{cc}$ |
| +12 | 12.73 % |
| +11 | 12.87 % |
| +10 | 13.01% |
| +9 | 13.15% |
| +8 | 13.29 % |
| +7 | 13.43 % |
| +6 | 13.58 % |
| +5 | 13.72% |
| +4 | 13.86 % |
| +3 | 14% |
| +2 | 14.14% |
| +1 | 14.28% |
| 0 | 14.42 % |

| Low tap position | |
|---|---|
| Tap position | Short-circuit voltage $u_{cc}$ |
| 0 | 14.42 % |
| -1 | 14.61 % |
| -2 | 14.8 % |
| -3 | 15% |
| -4 | 15.2% |
| -5 | 15.38 % |
| -6 | 15.57 % |
| -7 | 15.76 % |
| -8 | 15.95% |
| -9 | 16.15% |
| -10 | 16.34% |
| -11 | 16.53% |
| -12 | 16.72% |

# Appendix C

# Power system stabilizer parameters

*Table 5-9: Parameters – PSS*

| Parameters | | Range | As Built Setting | Parameters | | Range | As Built Setting |
|---|---|---|---|---|---|---|---|
| $T_f$ | Transducer time constant | - | 20ms | M | Filter indice | 1,2…5 | 4 |
| $T_p$ | Transducer time constant | - | 20ms | N | Filter indice | 1 or 2 | 1 |
| $T_{w1}$ | Wash-out time constant | 0,1 ~ 20s | 3s | $K_{s1}$ | Proportional gain | 0 ~ 50 | 5 |
| $T_{w2}$ | Wash-out time constant | 0,1 ~ 20s | 3s | $T_1$ | Lead lag time constant | 0,001~20s | 0,12s |
| $T_{w3}$ | Wash-out time constant | 0,1 ~ 20s | 3s | $T_2$ | Lead lag time constant | 0,001~20s | 0,03s |
| $T_{w4}$ | Wash-out time constant | 0,1 ~ 20s | 3s | $T_3$ | Lead lag time constant | 0,001~20s | 0,12s |
| $T_6$ | Filter time constant | 0 ~ 20s | 0s | $T_4$ | Lead lag time constant | 0,001~20s | 0,03s |
| $T_7$ | Filter time constant | 0,1 ~ 20s | 3s | $T_{10}$ | Lead lag time constant | 0,001~20s | 1s |
| $K_{s2}$ | Proportional gain [4] | 0 ~ 50 | 0,284 | $T_{11}$ | Lead lag time constant | 0,001~20s | 1s |
| $K_{s3}$ | Proportional gain | -1 ~ 1 | 1 | $PSS_{max}$ | PSS maximum contribution | 0 ~ 0,2 | 0,05 |
| $T_8$ | Filter time constant [5] | 0,001 ~ 20s | 0,4 | $PSS_{min}$ | PSS minimum contribution | -0,2 ~ 0 | -0,05 |
| $T_9$ | Filter time constant | 0,001 ~ 20s | 0,1 | | | | |

**Figure C.1:** Power system stabilizer parameters [39]

# Appendix D

# Simulink test model

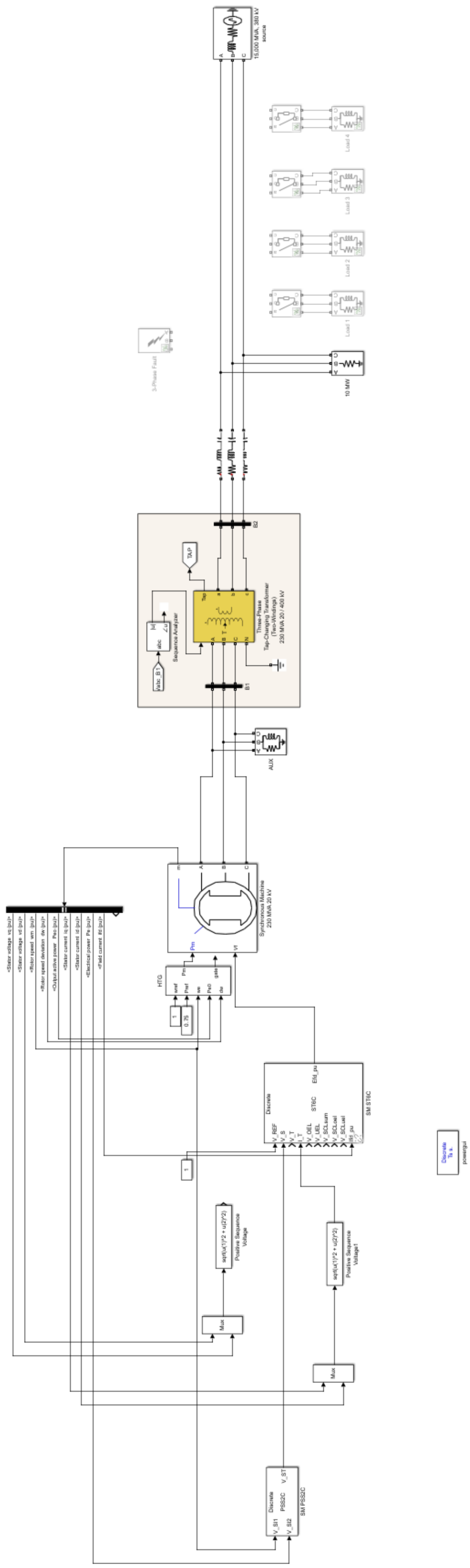

**Figure D.1:** Simulink test model

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