HIERARCHICAL TWO-LEVEL VOLTAGE CONTROLLER FOR
LARGE POWER SYSTEMS

By

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To the Faculty of Washington State University:

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Hierarchical Two-Level Voltage Controller for Large Power Systems

Abstract

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Keeping adequate voltage levels for each bus in a power system is a key factor for proper performance of power system equipment and reliability of the network when subject to disturbances. However, given the constant increase in loads and constraints in the operation of the grid, meeting this goal has become a challenge. Bulk power delivery substations play a key role in voltage control because they represent the primary connection points between high voltage transmission and distribution system. Proof of this is the impact of the growing renewable generation capacity in the modern power system, in which substations are expected to be a key unit in interfacing sophisticated power electronics on the distribution side to bulk transmission system of the power grid. Furthermore, Smart grid related
direct load controls present enhanced control capabilities at the substation level that need to be carefully coordinated from the control center.

The local character of the voltage control, the diversity of the control means and the interaction among them makes this task particularly difficult. In many European countries and in China, hierarchical voltage controllers have been proposed and implemented for automatically controlling the voltage profile of the transmission network by using different notions of primary, secondary and tertiary voltage controls. Pilot automatic voltage control projects have been implemented in the past at Bonneville Power Administration and PJM Interconnection.

This dissertation proposes a hierarchical two-level controller for large power systems that uses synchrophasor measurements for voltage control decisions. The first level, the Substation Local Voltage Controller (SLVC) supervises and controls voltages at substation level with discrete devices such as capacitor/reactor banks and transformer’s LTCs. Also, it monitors the reactive power output of the generators connected to the substation and keeps them in normal operation range.

The second level, the Supervisory Central Voltage Controller (SCVC) coordinates the operation of the SLVCs in the system to prevent hunting between substation controllers. It also provides the voltage schedules to each SLVC.
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Chapter 1

Introduction and Background

1.1 INTRODUCTION

Keeping adequate voltage levels for each bus in a power system is a key factor for proper performance of power system equipment and reliability of the network when subject to disturbances. However, given the constant increase in loads and constraints in the operation of the grid, meeting this goal has become a challenge. Bulk power delivery substations play a key role in voltage control because they represent the primary connection points between high voltage transmission and distribution systems. Proof of this is the impact of the growing renewable generation capacity in the modern power system, in which substations are expected to be a key unit in interfacing sophisticated power electronics on the distribution side to bulk transmission system of the power grid. Furthermore, Smart grid related
direct load controls present enhanced control capabilities at the substation level that need to be carefully coordinated from the control center.

A typical Bulk Power Substation is shown in Figure 1.1. These substations typically include a number of transformers with variable taps, as well as reactive support capability in the form of switched capacitor and reactor banks. Voltage and reactive power (VAR) control is exercised at these substations, for reliability and stability purposes. In North American power system, Load Tap Changers (LTCs) are traditionally used to control the secondary voltage of transformers, while the capacitor banks are switched on to correct power factor during peak

Figure 1.1: Typical Bulk Power Substations [8].
loads and are switched off during light loads to avoid overvoltages. In recent years, the control of voltage and reactive power in the high voltage network has become increasingly indispensable because of the need for more efficient use of transmission infrastructure, access of non-utility generators to the power network and the increase in power electronics devices. Furthermore, considering that substation voltage control devices are operated manually by operators in most of North American substations, the establishment of an automatic system that can prevent human errors becomes a necessity.

Besides devices such as LTCs, capacitor banks and reactor banks, the use of Static VAR Compensators (SVC) is becoming a trend in the operation of many utility substations for voltage control purposes. An important reason for the use of these power electronics devices is their fast response during dynamic conditions in the system, a property that none of the previous mentioned discrete devices have. However, the acquisition cost of SVCs is usually high. Therefore, it is important for utilities to use them optimally.

On the generation side, the Automatic Voltage Regulators (AVRs), associated with excitation field control, are the main tools for voltage control. Automatic wide area control systems based only on AVRs have been designed in the last 30 years with meaningful results in European and Asian countries. However, with the introduction of deregulation in the North American network, generation
companies, as independent business, try to deliver power at power factors closest to unity by injecting the minimum amount of reactive power allowed by the norm. This subsequently makes voltage control resources limited for utilities. Additionally, the fact that only the Interconnected System Operator (ISO) has access in real time to the setpoints of the AVRs makes the AVR-based voltage control infeasible from the utility perspective in many portions of the US. As a result, North American Utilities have installed capacitor banks throughout the network as a means of voltage control. Since reactive power does not travel long distances [32], the amount of capacitors at transmission level is considerable compared to non-deregulated networks. Consider for example the Southern California Area which has around 70 capacitors banks in the transmission network alone, not counting the amount of capacitors on the distribution side.

Last but not least, the increasing use of Phasor Measurement Units (PMUs) is a key factor to consider. In the last years, there is growing interest in developing control applications based on synchrophasors and voltage control is no exception. Having instantaneous measurements of the voltage magnitude and angle along with other variables opens the door for a number of versatile approaches in the voltage control problem.
1.2 MOTIVATION

This thesis work proposes a hierarchical voltage controller for large power networks in steady state conditions that will be explained in detail in the following chapters. The results of this work are being implemented by an important utility in the state of California [8]. This research work was supported by this utility with partial funding from Power System Engineering Research Center and US Department of Energy. The motivation behind this thesis is summarized in the following items:

- The need of substation operation automation close to “real” operation: most of the operation maneuvers aimed for voltage control at the substation level are performed manually by operators in the substations or control centers. Although operators have rich operational experience, this kind of operation is prone to errors in the decisions and lacks an exhaustive panorama of the available maneuvers that may solve a voltage alarm optimally, especially under unforeseen operating scenarios. This is evidenced in the existing response trend of the operators in front of a voltage alarm. Most of the time, the operator waits on the order of minutes to activate a device, with “the hope” that the voltage may come back to normal conditions, which happens in certain occasions. Although the installation of a fast closed loop controller would look like an appealing solution for instances such as this one, the fact
is that the operator’s reasoning is not totally wrong: Switching capacitors, reactors or LTCs frequently is not a desirable approach since this directly affects the effective life of the devices. This situation illustrates the need of a voltage control system that operates in a realistic way, that is, that takes into account real constraints and not just a mere theoretical approach.

- The need of a controller that gives priorities to local actions: Most of the current voltage controllers for large networks have a centralized approach. Inherently, this is not incorrect since control center maneuvers have wide area measurements that back the decisions behind them. Also, these decisions are holistic by nature. However, given that the voltage phenomenon is mostly local during steady state conditions, such reliance on centralized decisions is not imperative. Actually, an issue that some utilities try to avoid is the high dependence of operation on communication links to the control center. Furthermore, most of the steady state voltage control issues are handled at the substation level in the US. All these factors are a strong motivation for proposing a voltage controller that in its architecture gives priority to the substation instead of the control center. This does not mean a total decoupling from the control center per se, but an approach that minimizes the dependence on control center is ideal for the operating
conditions in the North American Grid, as will be highlighted in the next item.

- The need of a controller that is suitable for a deregulated environment: the North American grid is deregulated. This means that the generation, transmission and distribution of electrical energy are not operated by the state or a single firm. Furthermore, generation, transmission and distribution are independent businesses and any intent of a company to do more than one of these services will be considered a monopoly, which is forbidden by law. As a result, the utilities do not have a direct way of controlling variables in generation stations such as frequency of generation or voltage generation output. Therefore, AVR-based voltage control methods are not suitable from the utility perspective. As explained before, this has caused the utilities to rely on capacitor banks and utility owned SVCs to control voltage. This needs a different approach in voltage control, mostly based on discrete devices at substation level.

- The need for a voltage controller that uses local PMU measurements: Today, most approaches used in voltage control rely highly in State Estimation results. This brings a dependence on centralized results that are provided at a relatively slow rate. However, with the advance of synchrophasors, more and more applications have been developed for voltage security. The fast
rate and versatility of synchrophasor’s signals encourages the development of a controller that can use the local PMUs measurements as a major decision tool for voltage control instead of relying totally on state estimation.

- The need for a voltage control approach that can optimize the VAR resources in the system: a typical operation criterion in which there is no consensus among utilities is the switching of capacitors or LTCs for voltage control. Some utilities prefer to switch capacitors to avoid potential damage in the LTC mechanism and not taking out the transformer for maintenance. Others prefer the LTCs instead of the capacitor because with this the operating life of the capacitor will increase. This duality raises the need for a voltage control approach that can account for these particular restrictions in an optimal way, understanding optimality in this context as the best way to clear voltage alarms maximizing VAR resources.

1.3 STATE OF ART

During the 80s and early 90s, various automatic voltage control schemes were proposed for European countries with very common features that led to important definitions in the matter of voltage control. Some of them are the terms “primary”, “secondary” and “tertiary” voltage control. These are attempts to emulate hierarchical levels of frequency control. The primary voltage control level
corresponds to the fast actions performed by the AVRs of the machines in a local sense. Secondary voltage control is a slower level of control in which capacitor/reactor banks, LTCs and sometimes AVRs within a control area perform the control actions in a regional sense. Tertiary voltage control is the level at which the optimal voltage profile of the network is calculated in a multiregional sense. The tertiary level provides the set points for the controllers in the other two levels [3]. Figure 2 shows a schematic diagram of the hierarchical levels initially proposed in the 1980s. As illustrated in the figure, the primary level is associated with the voltage regulator of the machine which has two operating inputs: the terminal voltage of the machine $V_t$ and the setpoint $V_{ref}$ which is provided by the secondary level. The output of the primary level is a signal to control the field voltage $E_{fd}$ which will directly impact the terminal voltage. The secondary level provides the voltage reference $V_{ref}$ to the AVRs based on the voltage of the “pilot buses”, which will be defined later and the optimal voltage values of these buses $V_{opt}$ provided by the tertiary level.
Finally, the tertiary level provides the optimal voltage scheduling for the system mostly based on wide area measurements obtained by SCADA and optimal power flow calculations.

Most of the work done during the eighties was aimed at secondary voltage control. One of the problems faced was the amount of variables to be controlled (bus voltages) that unlike frequency, were far greater in quantity. Back then, handling so much information was an issue because of the nature of computer systems at the time [3]. As a result, the concept of “pilot points” or “pilot buses” was introduced. A pilot point is a bus that represents the voltage profile of an area that has several buses. It is claimed that the voltage profile of a pilot bus reflects the pattern of
performance of the other buses in the region. Usually the bus with the highest short circuit level in the region was chosen to be the pilot bus, though some other techniques to find pilot buses were later introduced. An example of this is the method proposed in [7] which selects pilot points based on the criterion of minimizing the voltage deviations throughout the load buses during steady state disturbances or load variations. Another example is the method used in [13]. In this approach the objective function is similar to the one proposed in [7] but the optimization method used is the Annealing algorithm which is a stochastic algorithm that has the property of avoiding local minima.

Once the pilot bus was selected, all the control actions from the secondary level were aimed at regulating the voltage in this bus. Thus, the AVRs set-points were changed as needed to meet the set-point voltage at the pilot buses.

This control scheme was implemented in countries such as France [3, 5], Spain [7], Italy [4] and Belgium. In France, the work was sponsored by Electricite de France (EDF) in collaboration with the Massachusetts Institute of Technology (MIT). An interesting fact that was a constant in this work was the analysis of the interactions among areas in the secondary voltage control. For secondary voltage control in France, fixed electrically-independent areas were defined. An important assumption was that the interaction among those areas was negligible. However, as the network grew and became more meshed, such assumption was not valid.
anymore and an improved approach that took into account the tie-line line reactive power flows had to be proposed [3]. In Spain, [7] describes a methodology that selects pilot buses with minimization of voltage deviation at load buses. In this study, the concept of objective function performance is used to shown that after a certain number of pilot buses have been selected, the performance of the objective function does not change significantly. As a result, only a discrete number of pilot buses associated with a particular number of control generators is needed to perform adequate voltage control. Particularly, for the Spanish transmission grid in 1996, only 7 to 9 pilot buses were needed for voltage control. The number of generators associated with the pilot buses ranged from 47 to 74. In Italy, most of the work described by [4] focuses in Tertiary Voltage Control. Normally, the tertiary level in Italy scheduled voltages at daily basis. However, given the fast change of the load, additional scheduling had to be introduced during a normal day. This led to the terms short-term reactive scheduling and very-short-term reactive scheduling. Short-term scheduling was performed on daily basis and very-short-term was executed when needed in the order of 15-30 minutes to few hours in advance. These two procedures were mostly based on load forecasting methods.
In the 90s some improvements in this methodology were introduced [3, 6]. Most of the improvements were in the pilot point selection theory and the decentralization of the controllers [6].

In the US, some ideas towards voltage control were developed in [1], a joint work between MIT and Northeast Utility Service Inc. In this work, voltage problems in the New England area were analyzed. Problems first arose when several nuclear plants were out of service for a prolonged period. It is important to note that [1] admits that the controller initially proposed was not in use due to the reluctance of the operators to switch capacitor banks frequently and the practice of changing the AVR set-points was not a common practice. This shows a difference in operation practices between the US and European countries where automatic closed loop voltage controllers are used to regulate the voltage in the grid. One of the conclusions of this study was the installation of several capacitor banks that are switched in in anticipation of possible contingencies. This became a more common practice as deregulation was introduced in the US.

In 2001, a slow, centralized voltage controller was proposed by Chen and Venkatasubramanian [11]. This controller took into account the American practices for operating the system: The controller was developed for a west Oregon subsystem of the WECC which has little generation support but many capacitor/reactor banks available. Given the discrete nature of these devices, this
work proposed an integer-programming method for implementing solutions to voltage alarms based on state estimation Model. It was not implemented because it assumed data from state estimator model that at the time was only available every half hour. Later in 2006, Su and Venkatasubramanian proposed an evolution of the previous controller that was not so dependent on state estimator mode and relied mostly in local measurements [12]. The most meaningful contribution of this work was the introduction of localized power flow calculations for control decision, which is partly the basis of the approach presented in this thesis.
Chapter 2

Controller Architecture

2.1 OVERVIEW

Because of the operation procedures for the North American grid explained in Chapter 1 and the deregulated context of the system, an AVR-based voltage control scheme is not suitable for utilities in the US. As a result, this research work presents a modified two-level hierarchical voltage control approach as a possible solution to solve steady state voltage issues in this given environment. The philosophy behind two control levels is to give priority and a certain degree of independence to substation maneuvers while properly supervising the overall system performance.

A schematic diagram of the proposed hierarchical design is shown in Figure 2.1. Both control levels are described as follows:
Figure 2.1 Hierarchical Controller Design [8].

a) Lower Level: This is a Substation Local Voltage Controller (SLVC) that uses mostly local measurements at the substation with supervisory guidance from a central coordinator (upper level) at control center level. The main task of the SLVC is to keep the voltages of the substation buses within a range determined by certain voltage reference values input to the controller. These voltage references for substation voltage controllers are determined by the central coordinator (SCVC) discussed next. Each substation in the system has an SLVC that is in
contact with the central coordinator through two channels: one for receiving the voltage reference values and the other for receiving enable or disable signals. The signals from central coordinator to local controllers are referred to as Supervisory control signals in Figure 2.1.

When a voltage alarm occurs (the voltage in at least one bus within the substation is deviating from the reference value), the SLVC will perform calculations to find a possible solution to the problem. However, the SLVC will perform the corrective action when the central coordinator enables it. The SLVC is normally disabled. The local controllers do all internal control calculations mostly based on local PMU measurements along with possibly a few SCADA like measurements from control center as shown in Figure 2.1. It is important to note that at typical North American substations, subtransmission lines connected to the 115 kV side are mostly radial in nature with sparse connections, if any, to neighboring 230 kV substations. Therefore, it is assumed that switching actions on the 115 kV side of SLVC will have little effect on other neighboring SLVC controlled 115 kV bus voltages. That is, every SLVC substation controller will always be enabled to control the local 115 kV bus side of the substation (or any subtransmission level bus). On the other hand, the 230 kV and 500 kV local voltage controls of all SLVC buses will be subject to central supervision through the enable/disable signals from the central coordinator.
It is important to note that the SLVC uses capacitor banks, reactor banks and transformers LTCs as means of solving voltage alarms. This is realistic in a deregulated environment and this has been the mean by which steady state voltage alarms have been cleared in the North American grid in the past. Some utilities have Static VAR Compensators that could be used for steady state voltage control purposes. However, most of them are aimed for fast dynamic response during transient conditions. As a result, because the controller proposed in this work is only meant for steady state conditions, the principal devices used for voltage control in this proposed scheme are the ones used currently.

Some secondary tasks performed by the SLVC could be monitoring reactive power flow in vital transmission lines that converge to the substation or monitoring reactive power generation if there is any in the substation (reactive power generation may proceed from synchronous machines or power electronic devices like Static VAR Compensators). In general, any sort of operational constraint could be part of the SLVC algorithm. For example, one substation may have a capacitor that is not meant to be used frequently and it is only deployed for certain scenarios. The SLVC algorithm has this restriction embedded. Although suboptimal by nature, the essence of the SLVC algorithm is to mimic the substation operator as closely as possible.
Furthermore, the SLVC executes the optimal corrective action from device switching perspective. Given a voltage alarm, there can be many possible switching actions that can clear the alarm. However, some of them may imply switching unnecessarily many devices. The SLVC must discriminate such candidate solutions to choose the most appropriate.

b) Upper Level: This is a Supervisory Central Voltage Coordinator (SCVC) at the control center level. The SCVC coordinates the overall voltage profile of the high voltage transmission network at all the 230 kV and 500 kV substations and some subtransmission buses (particularly the buses in the system edges). The SCVC has two main tasks: first, to provide voltage reference values to each SLVC. The central coordinator SCVC will carry out optimal power-flow based network calculations to determine optimal voltage schedules and controller operations to correct voltage problems and other VAR related issues in the 230 kV and 500 kV network. Second, to coordinate the harmonious operation of all SLVCs. SCVC decisions will be communicated to the substation controllers through the choice of voltage reference values for each of the substations and local controller enable/disable master signals. Coordination is needed to avoid undesired interaction among the controllers. For instance, if SCVC determines that substation A is the best candidate to handle voltage issues in the 230 kV network near substation A, SCVC will enable SLVC at substation A while disabling other
neighboring substation controllers in the vicinity of substation A. This is to prevent redundant switching or potential hunting between substation controllers.

Voltage scheduling performed by the SCVC is an optimal power flow problem aimed to maximize the network benefit in terms of voltage profile. SCVC will thus adjust the voltage profile to minimize transmission reactive power losses and to maximize VAR reserves. These tasks are performed while coordinating the control decisions of substation controllers to minimize the number of switching actions.

In some instances the SLVCs cannot find a possible solution to a voltage alarm or the coordination process does not seem to lead to a no-alarm state. In such cases, the SCVC takes over the control and clears the voltage alarm performing like a centralized controller by using the existing communication links with the capacitors and reactors of the network. This situation illustrates one of the limitations of this formulation: the SLVCs only have local information and only focus in the buses of the associated substation. As a result, it may happen that some voltage alarms may not be cleared by an action in an affected substation but by switching a device in a substation that does not have an alarm. In this extreme situation, major visibility of the system is needed and the SCVC is the one that has such perspective. However, the current steady-state operation of the North
American grid shows that these scenarios are rare and when they happen, control center actions are taken.

Figure 2.2: Controller Time Frames

Occurring once every 30 minutes, Optimization of the network voltage profile is the slowest of the control loops (see Figure 2.2). It is carried out using state estimator power-flow model. Coordination signals of SCVC that decide which substations to enable or disable are the next faster loop. This process occurs once every minute, and the computations use fast approximate local area based power-flow calculations (Local Voltage Estimator explained in Chapter 3). SLVC substation controllers are the innermost control loop with iteration times of approximately 10 seconds, and the calculations will also be done using Local Voltage Estimator restricted to only the substation buses. Finally, the generators AVRds belong to the fastest voltage control loop. Although generators are not
controlled directly in real time in this formulation, the reactive power output can be monitored for the SLVC perspective with the goal of keeping it closest to the minimum. This will allow the generators to have enough reactive power reserves to respond when fast dynamic events take place. In these conditions, discrete devices like capacitor banks are not fast enough to respond. As a result, during transient conditions, the generators and SVCs take care of the voltage control actions. SCVC functions and SLVC controller actions will be blocked during fault-on periods and other transient conditions to prevent the voltage controllers interfering with system dynamic events.

Having explained the substation controller, its benefits include[8]:

1) The automation of the switching operations that reduce the burden on substation operators. This is especially useful when a primary voltage control device such as an SVC is off-line for maintenance or otherwise. The substation controller also allows operators to focus on more important operation issues other than merely spending time monitoring the substation voltage state.

2) Efficient voltage regulation of different voltage levels at substations while minimizing the number of switching actions: Reducing the number of tap changer operations enhances the longevity of the banks while also reducing maintenance costs.
3) Monitoring and eliminating circular VAR flows among multiple parallel transformer banks at the substation: Circular VAR flows if left uncorrected lead to unnecessary flow of reactive power back and forth among parallel transformers leading to increased heating losses while also depleting valuable VAR resources.

4) Coordinating the switching of discrete devices to keep SVC VAR output to be near zero under normal operating conditions whenever so required at the substations.

5) Early detection of unusual operating conditions related to highly stressed system scenarios. These conditions are usually detected from significantly different system responses after routine switching events.
Chapter 3

Substation Local Voltage Controller (SLVC)

3.1 INTRODUCTION

As explained in Chapter 2, the SLVC is a voltage controller at substation level that takes care of the voltages at the substation based on local measurements, local topology (connections within the substation and connections to neighboring substations are the primary resource of topology on which the controller executes its decisions) and, of course, previous approval of the Supervisory Central Voltage Coordinator (SCVC) through enabling signals. The decisions of the controller are reflected in the status of the substation VAR control devices. In the case where no feasible solution can be reached in front of a voltage alarm, alarms are issued for
both local substation operators and control center. Figure 3.1 shows the general scheme of a typical SLVC.

Figure 3.1: SLVC Architecture [8].

3.2 FORMULATION

Given the fact that a typical substation may have a primary voltage control device such as a local generator or a Static VAR Compensator (SVC), special attention must be displayed in these circumstances concerning voltage control coordination. This is because the generators and SVCs operate faster than discrete switching devices. As a result, it is suitable to reserve primary controllers for fast dynamic events while using discrete devices for steady state conditions. Moreover, these primary voltage control devices are usually set to control the voltage of the bus to which they are connected. Since they respond faster, switching discrete devices to
control the voltage of the buses where primary controllers are connected would cause hunting within the same substation. In order to avoid destructive interference among primary controllers and discrete switching devices, the SLVCs work under two modes of operation: Slave Mode and Master Mode.

3.2.1 SLAVE MODE

When a SVC local generator is in voltage regulation mode, the substation SLVC controller operates in Slave mode. In this mode, SLVC monitors and controls all available discrete devices while primarily maintaining voltage schedules at other non-regulated voltage levels. It also keeps the SVC or local generator VAR output near zero (or any other pre-specified low value that allows this primary control devices to react in case of dynamic events) as a secondary control objective.

A typical complex substation in the North American grid has several switching devices, transformers, voltage levels and generators (or SVCs). For illustration, consider the three-voltage level substation in Figure 1.1. Assume that the substation 500 kV voltage is maintained by an SVC and, as a result, the SLVC is working in Slave Mode. In front of any voltage alarm, the SLVC shall choose an optimal switching action among all feasible control actions for that control iteration. In this mode of operation, SLVC assumes that SVC is in charge of
keeping the 500 kV voltage near the specified value range (determined by the Supervisory Central Voltage Coordinator through an optimization process that is explained in Chapter 4). Accordingly, SLVC will monitor and maintain only 115 kV and 230 kV voltages.

The controller objectives and priorities are:

1) Maintain 115 kV bus voltage within specified range.
2) Maintain 230 kV bus voltage within specified range.
3) Keep SVC VAR output within specified range (this range of operation is usually predefined by each utility through planning studies).

Controller priorities can be redefined by the power system engineers as needed. Other controller objectives such as VAR flow constraints on transmission lines can be easily accommodated in the SLVC formulation. The approach for the VAR flow constraint will be similar to the formulation of SVC VAR constraint previously discussed.

3.2.2 MASTER MODE

When SVC (or local generator) is not in service, SLVC will take over the voltage schedule maintaining of all voltage levels at the substation, by controlling all available discrete control devices at the substation. For example, if the SVC
connected to the 500 kV bus in the substation shown in Figure 1.1 is out of service due to maintenance, then the SLVC would work in Master Mode, monitoring and controlling all the voltage levels in the substation. Likewise, in Master Mode the priorities of the controller are:

1) Maintain 115 kV bus voltage within specified range.
2) Maintain 230 kV bus voltage within specified range.
3) Maintain 500 kV bus voltage within specified range.

3.3 SLVC STRUCTURE

Once the mode of operation is established, the SLVC monitors the variables corresponding to the mode of operation. If any of these variables is outside the specified range, then it is said that there is an alarm. Every time there is an alarm, the SLVC follows the scheme depicted in Figure 3.2.

![Figure 3.2: SLVC Stages.](image)

Each of the stages in Figure 3.2 involves a series of procedures that are explained as follows.
3.3.1 FORMULATION OF CONTROL ACTIONS

When an alarm occurs, the SLVC creates a customized list of candidate actions that may clear the alarm. The control actions mostly consist of single discrete actions such as switching in or out of a capacitor bank. Some of the actions can also be "multiple switching", such as simultaneous switching of parallel transformer bank LTCs, or changing of multiple taps, or switching of parallel capacitor banks as needed. Basically SLVC design allows pre-specifying the set of possible control actions as part of the design formulation. Specific time-constraints on switching can be also included in the formulation of potential control actions. This is particularly important in real life operation where the frequency of switching devices is an important factor for maintenance and the effective life of the device. This is the case in many utilities when dealing with the switching of capacitor banks. Usually, the utilities do not switch capacitor banks more than three times a day at most, to preserve the duty cycle of the devices. This feature is easy to include in the formulation of control actions by penalizing this particular procedure. Actually, many utilities already have a priority list of actions in front of different scenarios. This is the case at the company for which this research is aimed. As a result, this stage is flexible and adjustable to the requirements of each utility.
For illustration purposes, take the substation in Figure 1.1 as an example. Assume there is a voltage alarm at some point. Examples of candidate control actions are the following:

a) Switching of 500 kV capacitor and reactor banks.
b) Switching of 230 kV capacitor and reactor banks.
c) Switching of 115 kV capacitor banks.
d) Switching of 500 kV-230 kV transformer bank LTCs.
e) Switching of 230 kV-115 kV transformer banks LTC.

After formulating the candidate control actions, the SLVC must evaluate which of those actions brings the system to a satisfactory condition, namely, a condition with no alarms in the substation.

3.3.2 EVALUATION OF CONTROL ACTIONS (LOCAL VOLTAGE ESTIMATOR)

Once a list of candidate actions is available, the SLVC evaluates each action by means of predicting the future condition of the substation if such actions were implemented. The tool for predicting the state of the system is called Local Voltage Estimator (LVE). The LVE is a linearized power flow calculation that estimates the effect of a switching action in the substation’s voltages and reactive power flows. It uses PMU measurements and the topology of the substation and its
surroundings as input. For the LVE to work properly, the following assumptions must hold:

1) The topology of the substation is known.

2) The parameters of transmission lines that are connected to the substation are known.

3) The bus angle in the substation will not change after switching the voltage control devices.

4) The bus voltage phasors and current phasors of the transmission lines converging to the substation are available through PMU measurements.

![Figure 3.3: π-equivalent Model.](image)

To understand how the LVE works [13], consider the transmission line in Figure 3.3 represented by the π-equivalent model, with line admittance $Y_{ij} = G_{ij} + jB_{ij}$, shunt admittance $Y_{i0} = G_{i0} + jB_{i0}$ and $Y_{j0} = G_{j0} + B_{j0}$. If the terminal voltages
are $V_i = |V_i| \angle \delta_i$ and $V_j = |V_j| \angle \delta_j$, the reactive power flow between bus $i$ and bus $j$ is given by:

$$Q_{ij} = - \left\{ |V_i|^2 \left( \frac{B_{ij}'}{2} - B_{ij} \right) + |V_i V_j| \sin(\theta_{ij} + \delta_j - \delta_i) \right\}$$

(3.1)

Since the voltage angle is assumed to be constant, equation (3.1) can be formulated as

$$Q_{ij} = a_{ij}|V_i V_j| + c_{ij}|V_i^2|$$

(3.2)

where $a_{ij} = -Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i)$ and $c_{ij} = -\left( \frac{B_{ij}'}{2} - B_{ij} \right)$.

If some reactive power injection occurs nearby the line, the voltages in the line terminals will change by $\Delta V_i$ and $\Delta V_j$. The goal of the LVE is to find these changes. Given these changes, the new reactive power flow $Q_{ij}'$ in the transmission line is given by

$$Q_{ij}' = a_{ij}|(V_i + \Delta V_i) * (V_j + \Delta V_j)| + c_{ij}|V_i + \Delta V_i|^2$$

(3.3)

After expanding equation (3.3) and neglecting higher order terms $\Delta V_i \Delta V_j$ and $\Delta V_i^2$, equation (3.3) becomes

$$Q_{ij}' = (a_{ij}V_i V_j + c_{ij}V_i^2) + a_{ij}V_i \Delta V_j + a_{ij}V_j \Delta V_i + c_{ij}(2V_i \Delta V_i)$$

(3.4)

Subtracting equation (3.2) from equation (3.4) leads to
\[ Q_{ij} - Q_{ij} = a_{ij} V_i \Delta V_j + a_{ij} V_j \Delta V_i + c_{ij} (2V_i \Delta V_i) \]  \hspace{1cm} (3.5)

which can be rewritten as

\[ \Delta Q_{ij} = (a_{ij} V_j + 2c_{ij} V_i) \Delta V_i + (a_{ij} V_i) \Delta V_j \]  \hspace{1cm} (3.6)

with \( \Delta Q_{ij} = Q_{ij} - Q_{ij} \).

Since the present bus voltages \( V_i \) and \( V_j \) are provided by PMU measurements, equation (3.6) can be written as

\[ \Delta Q_{ij} = K_{ij} \Delta V_i + M_{ij} \Delta V_j \]  \hspace{1cm} (3.7)

where \( K_{ij} = a_{ij} V_j + 2c_{ij} V_i \) and \( M_{ij} = a_{ij} V_i \).

Now, define internal bus as any bus inside the substation and external bus as any bus in an immediate neighbor substation (see Figure 3.4).

![Figure 3.4: Internal and External Buses.](image.png)
From energy conservation, it is a fact that for any internal bus

\[ \Delta Q_i = \sum_{j=1}^{N_i+N_e} \Delta Q_{ij} \]  

(3.8)

where \( \Delta Q_i \) is an injection in bus \( i \), \( N_i \) is the number of internal buses and \( N_e \) is the number of external buses.

By substituting equation (3.7) in equation (3.8), the following relationship is obtained for every internal bus:

\[ \sum_{j=1}^{N_i+N_e} K_{ij} \Delta V_i + \sum_{j=1}^{N_i+N_e} M_{ij} \Delta V_j = \Delta Q_i \]  

(3.9)

This leads to a system of equations consisting of one equation similar to equation (3.9) for each internal bus. For the system to be consistent, it is necessary to have one equation for each external bus in terms of internal bus variables. One way to relate the voltages of internal and external buses is by calculating a set of constants \( \alpha_{ij} \) which is given by

\[ \alpha_{ij} = \frac{\frac{\partial V_i}{\partial Q_k}}{\frac{\partial V_j}{\partial Q_k}} \]  

(3.10)

where \( k \) is a bus in which a power injection \( \Delta Q_k \) occurs. As noticed in equation (3.10), \( \alpha_{ij} \) is the ratio of the sensitivities of the voltages of buses \( i \) and \( j \) to a
reactive power injection in bus $k$. As a result, if a set of $\alpha$-constants is calculated for each inbound transmission line, the internal buses could be related to the external buses by the relation

$$\Delta V_i - \alpha_{ij}\Delta V_j = 0 \quad (3.11)$$

Since there will be one equation per external bus that looks like equation (11), the equations (3.9) and (3.11) form a consistent system of equations of $(N_i + N_e)$ equations by $(N_i + N_e)$ unknowns. In matrix form, this system looks like

$$
\begin{bmatrix}
\Delta Q_1 \\
\Delta Q_2 \\
\vdots \\
\Delta Q_{N_t}
\end{bmatrix} =
\begin{bmatrix}
\Delta B_{11} & \Delta B_{12} & \cdots & \Delta B_{12} \\
\Delta B_{21} & \Delta B_{22} & \cdots & \Delta B_{22} \\
\vdots & \vdots & \ddots & \vdots \\
\Delta B_{N_t1} & \Delta B_{N_t2} & \cdots & \Delta B_{N_tN_t}
\end{bmatrix}
\begin{bmatrix}
\Delta V_1 \\
\Delta V_2 \\
\vdots \\
\Delta V_{N_t}
\end{bmatrix}
$$

where $N_t = N_t$ and

$$
B_{ii} = \sum_{j=1, i \neq j}^{N_t} K_{ij} \quad , \quad i = 1, 2 \ldots N_t
$$

$$
B_{ij} = M_{ij} \quad , \quad i = 1, 2 \ldots N_t \quad \& \quad j = 1, 2 \ldots N_t
$$

$$
B_{ii} = 1 \quad , \quad i = N_i + 1, N_i + 2, \ldots, N_t
$$

$$
B_{ij} = -\alpha_{ij} \quad , \quad i = N_i + 1, N_i + 2, \ldots, N_t
$$

In equation (3.16), $B_{ij} = -\alpha_{ij}$ is valid only if there is a connection between internal bus $i$ and external bus $j$. Otherwise, this matrix entry is equal to zero.
As a result, all voltages in the substation can be calculated when any reactive power injection occurs in the substation, by using

$$\Delta V = B^{-1} \cdot \Delta Q$$  \hspace{1cm} (3.17)

Note that matrix B is a function of local topology (the admittances inside the substation and the admittances of the transmission lines) and local measurements. Even though the voltages of the external buses are needed to compute the B matrix, these can be calculated from measurements of voltage and currents inside the substation, assuming that the impedance of the connecting transmission line is known.

Since the devices used for voltage control in the substation are capacitor/reactor banks and transformer LTCs, it is important to analyze how equation (3.17) applies to each of these cases.

- **ESTIMATION OF CAPACITOR/REACTOR BANK EFFECT**

When a capacitor/reactor bank is connected to bus \( k \) at the substation, an amount of reactive power \( \Delta Q_k \) is injected into the system. As a consequence, the vectors \( \Delta V \) and \( \Delta Q \) for this particular condition are given by

$$\Delta V = [\Delta V_1 \hspace{0.5cm} \Delta V_2 \hspace{0.5cm} \cdots \hspace{0.5cm} \Delta V_N]^T$$  \hspace{1cm} (3.18)

$$\Delta Q = [0 \hspace{1cm} 0 \hspace{1cm} \Delta Q_k \hspace{1cm} 0 \hspace{1cm} \cdots \hspace{1cm} 0]^T$$  \hspace{1cm} (3.19)
where $\Delta Q_k = -Q_c$ if a capacitor is connected and $Q_c$ is the capacitor bank capacity or $\Delta Q_k = Q_R$ if a reactor bank is connected and $Q_R$ is the reactor bank capacity.

- ESTIMATION OF TRANSFORMER TAP EFFECT

Consider the transformer $\pi$-equivalent in Figure 3.5.

Suppose the transformer is between buses $i$ and $j$, the transformer ratio is $t$ and the original transformer admittance $Y_T = G_T + jB_T$. From transformer theory, the transformer can be represented with a $\pi$-equivalent where the line admittance is $Y_{ij} = G_{ij} + jB_{ij}$ and shunt admittance is $Y_{i0} = G_{i0} + jB_{i0}$. The values of the equivalent impedances, in terms of the original impedance and turn ratio, are given by

![Figure 3.5: Transformer $\pi$-equivalent.](image-url)
Now, the reactive power flow in a line is equal to

\[ Q_{ij} = -V_i^2 (B_{ij} + B_{i0}) - V_i V_j (G_{ij} \sin \delta_{ij} - B_{ij} \cos \delta_{ij}) \] (3.23)

where \( \delta_{ij} = \delta_i - \delta_j \), in which \( \delta_i \) and \( \delta_j \) are the voltage angles. As result, the reactive flow in the transformer in terms of the turn ratio is given by

\[ Q_{ij} = -V_i^2 \frac{B_T}{t^2} - V_i V_j \left( \frac{G_T}{t} \sin \delta_{ij} - \frac{B_T}{t} \cos \delta_{ij} \right) \] (3.24)

\[ Q_{ji} = -V_j^2 B_T - V_j V_i \left( \frac{G_T}{t} \sin \delta_{ji} - \frac{B_T}{t} \cos \delta_{ji} \right) \] (3.25)

Notice that because the model is not symmetrical, flow \( Q_{ij} \) is different from flow \( Q_{ji} \) as illustrated by equations (3.24) and (3.25). If the variation of the reactive flow in the transformer is considered to be only a function of the transformer ratio variation \( \Delta t \), then two reactive power injections \( \Delta Q_{Ti} \) and \( \Delta Q_{Tj} \) can be defined as

\[ \Delta Q_{Ti} = - \frac{\partial Q_{ij}}{\partial t} * \Delta t \] (3.26)

\[ \Delta Q_{Tj} = - \frac{\partial Q_{ji}}{\partial t} * \Delta t \] (3.27)

in which,
Note that in (3.28) and (3.29), only transformer ratio, reactive power line flow and voltage magnitude measurements are needed to calculate these derivatives. As a consequence, it is possible to calculate the voltage change due to a transformer tap change by introducing a reactive injection $\Delta Q_{Ti}$ in bus $i$ and a reactive injection $\Delta Q_{Tj}$ in bus $j$, both injections given by equations (3.26) and (3.27) respectively. When using the LVE, the vector $\Delta Q$ has the form

$$\Delta Q = [0 \ldots 0 \ \Delta Q_{Ti} \ \ldots \ \Delta Q_{Tj} \ 0 \ 0]^T$$  \hspace{1cm} (3.30)\]

- **ESTIMATION OF GENERATOR OUTPUT BY USING LVE**

Given that some substations have generators or Static VAR Compensators, it is also important to predict the impact of a switching action in the VAR output of these devices. The LVE can be used to do so, but the formulation has a slight change. To understand this, assume a generator is connected to a bus $i$ of the substation. The voltage of this bus $V_i$ is supervised by the generator AVR and it is a good assumption to consider this voltage to be constant, that is $\Delta V_i = 0$. As a result, switching a reactor or capacitor will not affect the voltage $V_i$ but it will affect the generator output $Q_{gen \ i}$ by some amount $\Delta Q_{gen \ i}$. Since this $\Delta Q_{gen \ i}$ will be
distributed over all other buses of the substation (jth buses), equation (3.7) can be used as follows:

\[ \Delta Q_{\text{gen}i} = K_{ij} \Delta V_i + M_{ij} \Delta V_j \] (3.31)

But, since \( \Delta V_i = 0 \), equation (3.31) can be written as

\[ \Delta Q_{\text{gen}i} - M_{ij} \Delta V_j = 0 \] (3.32)

This results in a change in the set of equations that defines the LVE. However, all variables can still be calculated by using equations (3.9), (3.10) and (3.32), which leads to

\[
\begin{bmatrix}
\Delta V_1 \\
\Delta V_2 \\
\vdots \\
\Delta V_{i-1} \\
\Delta Q_{\text{gen}i}
\end{bmatrix} =
\begin{bmatrix}
\sum K_{1j} & \cdots & 0 \\
\cdots & \ddots & \cdots \\
0 & \cdots & 0 \\
M_{i1} & \cdots & -1
\end{bmatrix}^{-1}
\begin{bmatrix}
\Delta Q_1 \\
\Delta Q_2 \\
\vdots \\
0
\end{bmatrix}
\] (3.33)

Equation (3.33) shows that the number of variables and equations is still the same.

In this case, the new unknown is the reactive power output of the generator \( \Delta Q_{\text{gen}i} \), but the voltage variation in bus is now known, namely \( \Delta V_i = 0 \).

In order to see the accuracy of the Local Voltage Estimator, four test scenarios are presented next: capacitor switching and LTC switching in a substation in the IEEE 14 Bus system, a voltage alarm scenario, and a generator output violation in a substation in California.
a. **LVE Test Case: Capacitor Bank**

Consider the IEEE 14 bus system shown in Figure 3.6. Assume a capacitor bank of 10 MVAR is connected to bus 4. If the adjacent lines’ reactive power measurements and pre-switching voltages are assumed to be the ones from the full power flow solution, the LVE can predict the post-switching voltages just based on the topology of the substation and the \( \alpha \)-values taken from the Jacobian matrix of the system, as previously explained. Table 3.1 shows the LVE predictions and compares the post-switching voltages calculated by the LVE vs. the actual ones calculated through full power flow.

![Figure 3.6: IEEE 14 Bus System [33].](image)
Table 3.1 Voltage profiles before and after switching a 10MVAR capacitor bank in

\[ b. \textit{LVE Test Case: LTC change} \]

Consider again the IEEE 14 bus system shown in Figure 3.6. Assume there is a tap change \( \Delta t = 0.03 \) (approximately four taps) in the two winding transformer connected to buses 4 and 9. Given the initial conditions in Table 3.2, this change corresponds to the injections \( \Delta Q_{T4} = -6.21 \text{ MVAR} \) and \( \Delta Q_{T9} = 6.20 \text{ MVAR} \), calculated from equations (3.26), (3.27), (3.28) and (3.29). Table 3.2 compares the post-switching voltages calculated by the LVE vs. the actual ones calculated through full power flow.

### Table 3.2 Voltage and reactive power profiles before and after changing four taps

<table>
<thead>
<tr>
<th>Bus</th>
<th>Initial Voltages at the substation</th>
<th>Post-switching Voltages (actual)</th>
<th>Post-switching Voltages (LVE Predicted)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>1.0229</td>
<td>1.0269</td>
<td>1.0262</td>
</tr>
<tr>
<td>8</td>
<td>1.0900</td>
<td>1.0900</td>
<td>1.0900</td>
</tr>
<tr>
<td>9</td>
<td>1.0579</td>
<td>1.0596</td>
<td>1.0593</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Bus</th>
<th>Initial Voltages /Initial Reactive Flow</th>
<th>Post-switching Voltages (actual)/ Actual Reactive Flow</th>
<th>Post-switching Voltages/ Reactive Flow (LVE Predicted)</th>
</tr>
</thead>
<tbody>
<tr>
<td>V4</td>
<td>1.0229</td>
<td>1.0242</td>
<td>1.0243</td>
</tr>
<tr>
<td>V8</td>
<td>1.0900</td>
<td>1.0900</td>
<td>1.0900</td>
</tr>
<tr>
<td>V9</td>
<td>1.0579</td>
<td>1.0526</td>
<td>1.0523</td>
</tr>
<tr>
<td>Q49</td>
<td>-0.0022</td>
<td>0.0441</td>
<td>0.0434</td>
</tr>
<tr>
<td>Q94</td>
<td>-0.0108</td>
<td>-0.0581</td>
<td>-0.0571</td>
</tr>
</tbody>
</table>
These two examples show the accuracy of the LVE for discrete switching devices. The error in the calculations is negligible. The following example shows a more complex and operational situation in a real substation.

c. *LVE Test Case: Californian Substation*

Consider a substation with three voltage levels 500 kV, 230 kV and 115 kV. The substation has two transformers: one from 500 kV to 230 kV (AA bank) and one from 230 kV to 115 kV (A bank). Also, the substation has one capacitor bank at 115 kV level with a capacity of 46.8 MVAR and one SVC at the 500 kV level. Assume that the acceptable range of 115 kV bus voltage has been specified as 0.97 pu and 1.025 pu, while the ranges for 230 kV and 500 kV are assumed to be 0.978 and 1.022 pu, (225 kV to 235 kV) and 1.04 and 1.06 (520 kV to 530 kV) respectively. In the actual implementation, these voltage schedule ranges will be provided to SLVC by the supervisory central coordinator SCVC. Also, assume the SVC is not connected. Therefore, the SLVC is working in Master Mode and the SVC output is not a priority of the controller. For the operating scenario in this example, the substation 115 kV bus voltage being at 0.9574 pu is outside its acceptable range, as shown in Table 3.3. The immediate candidate control actions are listed next:

A1) Switch in 46.8 MVAR capacitor bank at 115 kV bus.
A2) One tap up at bank A.
A3) Two taps up at bank A.
A4) One tap up at bank AA.
A5) Two taps up at bank AA.
A6) Three taps up at bank AA.

For SLVC calculations, predicted voltages after each candidate control action can be calculated using the LVE. Results from LVE are shown in Table 3.3.

Table 3.3 shows two feasible control actions: A1 (switching in 46.8 MVAR cap banks at 115 kV bus) and A3 (two taps up changes at A banks). To verify the validity of approximate predicted values in Table 3.3, full power-flow solutions of these two control actions are carried out next. Table 3.4 shows that the predicted values (based on LVE) match well when compared with full nonlinear power-flow solutions. Given the existence of two feasible control actions A1 and A3, the controller may choose one based on the control priorities that will be specified by operations.
Predicted values

<table>
<thead>
<tr>
<th>Control action</th>
<th>115 kV voltage (0.97 to 1.025)</th>
<th>230 kV voltage (0.977 to 1.022)</th>
<th>500 kV voltage (1.04 to 1.06)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current condition</td>
<td>0.9574</td>
<td>0.9793</td>
<td>1.0460</td>
</tr>
<tr>
<td>A1: 46.8 MVAR IN @115kV</td>
<td>0.9788</td>
<td>0.9869</td>
<td>1.0518</td>
</tr>
<tr>
<td>A2: One tap up @ 1A-3A-4A</td>
<td>0.9664</td>
<td>0.98</td>
<td>1.0466</td>
</tr>
<tr>
<td>A3: Two taps up @1A-3A-4A</td>
<td>0.9751</td>
<td>0.9805</td>
<td>1.047</td>
</tr>
<tr>
<td>A4: One tap up @1AA-2AA</td>
<td>0.962</td>
<td>0.983</td>
<td>1.0438</td>
</tr>
<tr>
<td>A5: Two taps up @1AA-2AA</td>
<td>0.9661</td>
<td>0.9864</td>
<td>1.0414</td>
</tr>
<tr>
<td>A6: Three taps up @1AA-2AA</td>
<td>0.9703</td>
<td>0.9899</td>
<td>1.0389</td>
</tr>
</tbody>
</table>

Table 3.3. Predicted bus voltages after implementing each candidate control action[34]

Predicted/actual values

<table>
<thead>
<tr>
<th>Control action</th>
<th>115 kV voltage (0.97 to 1.025)</th>
<th>230 kV voltage (0.977 to 1.022)</th>
<th>500 kV voltage (1.04 to 1.06)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1: 46.8 MVAR IN @115kV (predicted)</td>
<td>0.9788</td>
<td>0.9869</td>
<td>1.0518</td>
</tr>
<tr>
<td>A1: 46.8 MVAR IN @115kV (actual)</td>
<td>0.9789</td>
<td>0.9865</td>
<td>1.0514</td>
</tr>
<tr>
<td>A3: Two taps up @1A-3A-4A (predicted)</td>
<td>0.9751</td>
<td>0.9805</td>
<td>1.047</td>
</tr>
<tr>
<td>A3: Two taps up @1A-3A-4A (actual)</td>
<td>0.9735</td>
<td>0.9799</td>
<td>1.0465</td>
</tr>
</tbody>
</table>

Table 3.4. Predicted versus actual bus voltages [34]

d. **LVE Test Case: Simultaneous Voltage Violations**
Consider the substation of the previous example. This time, let us assume that the controller is working in Slave Mode, that is, the SVC is connected to the 500 kV
bus of the substation. Let us assume that the SVC MVAR output is meant to be between -50 MVAR and +100 MVAR. For the operating scenario shown in this example, 230 kV bus voltage is 1.0226 p.u and 115 kV bus voltage is 1.0396 p.u. All voltages are outside their acceptable ranges. The candidate control actions are listed below:

A1) Switch out 46.8 MVAR at 115 kV level.

A2) Switch out 66 MVAR at 115 kV level.

A3) One tap down at AA banks.

A4) Two taps down at AA banks.

A5) Three taps down at AA banks.

Based on LVE formulation, the expected bus voltages after each of the control actions A1 to A5 are predicted to be as shown below in Table 3.5.

<table>
<thead>
<tr>
<th>Control action</th>
<th>115 kV voltage (0.97 to 1.025)</th>
<th>230 kV voltage (0.977 to 1.022)</th>
<th>500 kV voltage (1.04 to 1.06)</th>
<th>SVC MVAR (-50 to +100)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current condition</td>
<td>1.0396</td>
<td>1.0226</td>
<td>1.0468</td>
<td>82.11</td>
</tr>
<tr>
<td>A1: 46.8 MVAR OUT @115kV</td>
<td>1.0300</td>
<td>1.0203</td>
<td>1.0467</td>
<td>114.72</td>
</tr>
<tr>
<td>A2: 66 MVAR OUT @115kV</td>
<td>1.0263</td>
<td>1.0194</td>
<td>1.0467</td>
<td>128.09</td>
</tr>
<tr>
<td>A3: 500-230kV one tap down</td>
<td>1.0347</td>
<td>1.0175</td>
<td>1.0468</td>
<td>47.62</td>
</tr>
<tr>
<td>A4: 500-230kV two taps down</td>
<td>1.0299</td>
<td>1.0124</td>
<td>1.0469</td>
<td>12.66</td>
</tr>
<tr>
<td>A5: 500-230kV three taps down</td>
<td>1.0249</td>
<td>1.0072</td>
<td>1.0471</td>
<td>-21.89</td>
</tr>
</tbody>
</table>

Table 3.5 Predicted bus voltages after implementing each candidate control action [34].
Table 3.5 shows one feasible control action: A5 (three taps down at AA banks). To verify the validity of approximate predicted values in Table 3.5, full power-flow solution of this control action is carried out next. The comparison of predicted versus actual values in Table 3.6 shows that the predicted values (based on LVE formulation) work well when compared with full nonlinear power-flow solutions.

<table>
<thead>
<tr>
<th>Predicted/actual values</th>
<th>115 kV voltage (0.97 to 1.025)</th>
<th>230 kV voltage (0.977 to 1.022)</th>
<th>500 kV voltage (1.04 to 1.06)</th>
<th>SVC MVAR (-50 to +100)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control action</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A6: 500-230kV three taps down (predicted)</td>
<td>1.0249</td>
<td>1.0072</td>
<td>1.0471</td>
<td>-21.89</td>
</tr>
<tr>
<td>A6: 500-230kV three taps down (actual)</td>
<td>1.0219</td>
<td>1.0077</td>
<td>1.0469</td>
<td>28.91</td>
</tr>
</tbody>
</table>

Table 3.6 Predicted versus actual bus voltages [34].

3.3.3 DECISION

Once the LVE has purged the candidate actions, the SLVC will determine the best action that should be executed to clear the violations in the substation, by ranking each action that has been validated by the LVE. In selecting which action to execute, the optimization objective is mainly to keep the bus voltages as close as possible to the “optimal” profile specified by the upper hierarchical level. This is done by using the best control devices available while respecting some practical rules. Given the discrete nature of the actions, this optimization problem can be formulated as an integer programming algorithm with the following objective function [13]:
\[ \text{Min} \sum_{i=1}^{N_D} \left| k_i \right| \left[ C_i(k_i) + \lambda \sum_{j=1}^{N} P_{j}(\Delta V_j) + \mu \sum_{j=1}^{N} P_{Qj}(\Delta Q_j) \right] \]
\[ \text{s.t.:} \sum_{i=1}^{N_D} |k_i| \leq N_{sw} = 1; \quad k_i \in \{-1,0,1\} \]

where \( C_i(k_i) \) is the switching cost of the \( i \)-th bus; \( P_i(\Delta V_j) \) is the voltage penalty function of \( j \)-th bus; \( \lambda \) is the weighting factor of voltage penalty; \( \mu \) is the weighting factor of VAR output penalty; \( k_i \) is the action type of the \( i \)-th control device; \( N_D \) is the number of feasible control devices in problem area; and \( N_{sw} \) is the maximum number of control actions.

In the above formulation, \( k_i \) represents the switching type: -1 for switching out a capacitor/reactor at a bus, one tap decrease of LTC at a transformer, 0 for no switching and +1 for switching in a capacitor/reactor at the substation or one tap increase of LTC at the substation. To incorporate the practical rules used by operators, the switching cost \( C_i(k_i) \) is set as follows. First, the switching cost associated with switching in devices is set higher than switching out devices. Secondly, the switching cost for changing LTC tap settings may be set higher than for switching reactor/capacitor banks if, for example, the tap changes are to be discouraged. Thirdly, to prevent repeated enabling and disabling of the same substation, the switching cost increases substantially after one switching and the cost then decreases slowly for all type of devices. The voltage penalty function
$P(\Delta V)$ can be defined as in Figure 3.7 to evaluate how far a bus voltage is away from its optimal value.

\[
\begin{align*}
\beta \Delta V_{\text{max}} & \quad \Delta V_{\text{max}} \quad 0 \quad \Delta V_{\text{max}} \quad \alpha \Delta V_{\text{max}} \\
\Delta V & \quad \Delta V
\end{align*}
\]

Figure 3.7: Penalty Function [12].

$\Delta V$ in Figure 3.7 represents the difference between a bus voltage and its optimal value. The VAR output penalty function $PQ(\Delta Q)$ can also be defined similarly, where $\Delta Q$ represents the difference between the current VAR output and its nominal value. In equation (3.34), $N_{sw}$ defines the maximum number of devices that can be enabled simultaneously in the substation. Given that only one switching is executed per iteration, $N_{sw}$ is chosen to be 3, so that the controller is looking at maximum three iterations ahead to clear the voltage alarm optimally.
Chapter 4

Supervisory Central Voltage Coordinator (SCVC)

4.1 INTRODUCTION

As discussed in Chapter 2, SCVC is responsible for overseeing smooth operation of substation local voltage controllers (SLVCs), while also ensuring an optimal voltage profile in transmission network.

![Figure 4.1: Conceptual Design of the SCVC](image)

Figure 4.1: Conceptual Design of the SCVC [8].
A conceptual design of SCVC is shown in Figure 4.1. In this scheme, a hierarchical relationship between the SCVC and the SLVCs can be observed. This interaction is based on two main tasks executed by the SCVC:

a) Voltage Scheduling: the aim of this task is to determine the reference voltages of the network that will maximize the performance of the voltage controllers. Through this task, the SCVC will determine the optimal voltages that each SLVC needs to supervise. These voltage values are communicated to each SLVC every time the SLVC computes them based on the load profile of the network. This previous description leads to a constraint optimization problem in which the control variables are the injections of reactive power to the system (by synchronous machines and discrete devices) and the output will be the ideal voltage of each bus in the system. The constraints of the problem are the power flow equations of the network and the physical limits of the equipment involved. Since the idea of the formulation presented in this research work is aimed for voltage control purposes, the objective function of the optimization problem should be related to the benefit of some variable that is closely related to the controllability of the voltages in the system. For this reason in this thesis, the objective function proposed is minimization of MVAR losses of the grid. It is important to note that the focus of this work is not this optimization problem. This problem has been widely discussed in previous literature, such as in [6] and [7].
The selection of the objective function is a parameter that can be decided by the utilities considering their own needs. The goal of this task is to define some solid voltage references for the SLVCs to supervise. Specifically, the idea behind this objective function is to indirectly maximize the VAR reserves and at the same time take advantage of the uniformity of the losses distribution in the system. This fact takes care of the lack of reserves in some particular areas, which is the problem of other objective functions used for voltage control purposes like maximizing VAR reserves. In the same order of ideas, the optimization problem could be formulated as follows:

\[
\text{Min}_{\text{Bus } i: \text{ Gen Bus, SVC Bus, or SLVC Bus}} \sum_i \sum_j |Q_{ij} + Q_{ji}|
\]

\(V_i^\text{min} < V_i < V_i^\text{max}, \quad P_i^\text{min} < P_{Gi} < P_{Gi}^\text{max}, \quad Q_i^\text{min} < Q_{Gi} < Q_{Gi}^\text{max}\)

\[P_i = P_{Gi} - P_{Li} = \sum_j Y_{ij} V_i V_j \cos(\delta_i - \delta_j - \theta_{ij})\]

\[Q_i = Q_{Gi} - Q_{Li} = \sum_j Y_{ij} V_i V_j \sin(\delta_i - \delta_j - \theta_{ij})\]

Here \(V_i\) represents bus voltage magnitude at bus \(i\), while \(\delta_i\) denotes bus \(i\) voltage phase angle. \(Y_{ij}\) is the magnitude of the \((i,j)\)-th entry of the admittance \(Y_{\text{Bus}}\) matrix, while \(\theta_{ij}\) is the corresponding phase angle.

Optimization of voltage schedules are done possibly every 30 minutes or when there are significant changes in system conditions such as major contingencies. Once the optimal voltage profile is determined, the SCVC communicates these
values to each SLVC so that each of them can maintain its bus voltage within small pre-specified ranges around the reference values.

b) Central Coordination: SCVC needs to ensure that neighboring SLVCs do not interfere with each other when addressing their respective voltage alarms. Also, it needs to find solutions (in the rest of the system) to voltage alarms that cannot be cleared because of unavailability of discrete devices in a given substation. To meet these purposes, the SCVC has two modes of operation: Coordination Mode and Back-up Mode. These modes of operation will be developed in the following sections.

4.2 SCVC COORDINATION MODE.

When operating in Coordination Mode, the corrective actions are performed by the SLVCs with previous enabling from the SCVC. This mode of operation occurs when the SLVCs are able to clear any voltage alarm within their jurisdiction (the substation). This mode should be active most of the time. The algorithm that the SLVC uses to address voltage alarms is well described in Chapter 3. However, the SLVC cannot implement the solution without an enable signal from the SCVC. Since each SLVC makes decisions based only on information from the substation it is supervising, the duty of the SCVC is to coordinate the operation of the SLVCs for the benefit of the whole system. For instance, in the case of multiple alarms that
may be related to each other and, as a consequence, multiple SLVCs proposing to solve their alarms, the SCVC needs to decide which SLVC to enable that would lead the system, as a whole, to satisfactory condition. Actually, in many cases by enabling the correct SLVC, the SCVC may clear all the alarms issued in just one control iteration. It is important to note that the SCVC will enable only one SLVC at the time. This is to prevent any possible destructive interaction between SLVCs. As a result, leading the system to No-alarms condition may take more than one control iteration. In conclusion, when the SCVC is in Coordination Mode and a voltage alarm (or several) takes place, the SCVC decides if the SLVC is enabled or which SLVC to enable.

Figure 4.2: Coordination Mode Scheme

Figure 4.2 shows a general scheme of the Coordination Mode.
The SCVC Coordination Mode algorithm is based on supervisory control of discrete events systems theory [23][24][25]. A discrete event system is a system where events happen sequentially and in an asynchronous way. In this particular work, the events of interest are the enabling or disabling of any given SLVC in front of one or several voltage alarms. These events are sequential because only one SLVC can be enabled at the time. Also, the events are asynchronous because it does not matter how much time passes between enabling two consecutive SLVCs.

Among the many ways to model a discrete event system, Finite State Machines are one of the most popular. A finite state machine is a tuple $G = (\Sigma, Q, \delta, q_0, Q_f)$ where $\Sigma$ is a set of symbols, $Q$ is the set of the states of the system, $\delta$ is a transition function $\delta: Q \times \Sigma \rightarrow Q$, $q_0$ is the initial state of the system and $Q_f$ is the set of final states. For this particular work $\Sigma$ represents the enabling of any particular SLVC; $Q$ represents the combinations of alarm/no alarm state of the substations that initially presented a state of alarm in the system; $\delta$ is the function that allows transitions from state to state. In this case, the transitions occur when an SLVC is enabled. It is important to note that this is only allowed for substations with alarms. As a result, the transition not only depends on the transition function $\delta$, but also on a particular condition (the substation must have an alarm). In discrete event control theory, this condition is called guard; $q_0$ is the state where all the substations...
involved have a voltage alarm; \( Q_f \) is the state in which none of the substations involved has a voltage alarm.

The set of all possible sequence of events in a Finite State Machine is called the language \( L(G) \). The language \( L_m(G) \) is a subset of \( L(G) \) and it is defined as all the possible sequence of events that lead to a final state. Formally speaking,

\[
L_m(G) = \{ s \mid s \in \Sigma, \delta(q_0, s) \in Q_f \}
\]

In this work, \( L_m \) refers to any sequence of events that leads the system from an initial state to the state of no alarms.

Since the logic of each SLVC is embedded in the SCVC, the controller synthesis is essentially the construction of a forward looking tree \( T \) that represents all future behavior from the current state of the system. Once the tree has been constructed, the goal is finding the language \( L_m(G) \) of the system. However, in some conditions the tree can grow indefinitely or have several branches. The way to limit the number of branches is by stopping the tree growing after \( N \)-steps. This is called limited lookahead policy [26].

Take Figure 4.3 as an example: Suppose that the green circle represents the actual state of the system with voltage alarms at substations X and Y. Since there are SLVCs associated with substations X and Y, both SLVCs will try to find solutions for their particular alarms if enabled by the SCVC. Thus, the SCVC internally generates a forward looking tree to evaluate which SLVC enabling will lead to a
satisfactory condition. For instance, in Figure 4.3 enabling SLVC X is the best choice because after three transitions a No-alarm condition is reached (red circle).

In this work, N = 3 has been set for practical purposes. If a satisfactory state is not reached with this constraint, then the SCVC algorithm will switch to Back-up Mode, which will be explained in next section. On the other hand, if multiple No-alarms states are found, the SCVC will enable the one that takes fewer transitions to reach.

Figure 4.3: SCVC Coordination Mode Logic

It is important to note that the conditions of the grid vary from iteration to iteration due to external factors to the controller. For this reason, the procedure explained above is performed in every iteration (closed loop system) and the internal simulations performed by the SCVC (forward looking tree) are only predictions to make a decision (in Figure 4.3, enable SLVC X or SLVC Y).
4.3 SCVC BACK-UP MODE

This mode of operation is deployed when the SCVC Coordination mode cannot find a No-alarm state. This situation happens mostly due to the local nature of the SLVCs. Since each SLVC only supervises a substation, its decisions are only for the benefit of the substation. As a result, there will be conditions in which an SLVC may be able to clear a voltage alarm in its substation but not in the buses nearby. Moreover, the solution to voltage alarms in a region may be switching a device that is not in an affected substation. Under circumstances like this, the Coordination Mode will construct a forward looking tree that will not foresee a satisfactory state in N=3 steps. Hence, a controller that can visualize the system from a centralized perspective is necessary for these conditions. This is the task of the Back-up mode. Back-up mode is a centralized controller that backs the operation of the Coordination Mode. When operating in Back-up Mode, the controller does not have levels of hierarchy. The SCVC takes over all the control actions in the system and the SLVCs are all disabled. For this operation mode, the controller only uses capacitors and reactors to solve voltage alarms. This is because many utilities in America have the means of controlling these devices remotely from control center.

When the system is under these conditions and a voltage alarm (or several) is issued, the SCVC Back-up mode algorithm performs the following tasks:
• Control Area Formation.
• Candidate Corrective Action Listing, Filtering and Evaluation
• Optimal Action Selection

4.3.1 CONTROL AREA FORMATION

The SCVC identifies the buses with voltage violations and forms areas of control around them that gather buses with “electrical proximity”. In order to determine the control areas, it is important to measure the sensitivity at any bus i because of a change of reactive power at a bus k with an alarm. For this, sensitivity \( \lambda_i \) is defined and it is given by

\[
\lambda_i = \frac{\delta v_i}{\delta Q_k} \quad \frac{\delta v_j}{\delta Q_k}
\]

(4.1)

The derivatives in equation 4.1 are elements of the inverse of the Jacobian matrix of the system. Finally, the set of buses sensitive to a change in bus k are defined by the subset,

\[
A_k = \{ \forall i : \lambda_i > 0 \text{ for any } \Delta Q_k \}
\]

(4.2)

Figure 4.4 shows a schematic of this stage.
If more alarms are issued, the SCVC will need to form more than one area of control. Moreover, the elements of different areas may overlap. To address this issue, consider the following: Assume \( n \) buses are violating voltage constraints in the network. Then, with the procedure explained above, \( n \) clusters of coupled buses, \( A_1 \ldots A_n \), can be formed. If buses \( A_x \) and \( A_y \) are not electrically coupled, then

\[
A_x \cap A_y = 0
\]  

(4.3)

With this criterion, independent areas of control can be identified. On the other hand, the areas that have common buses will form new areas of control that will correspond to the union of their respective subsets. Take Figure 4.5 as an example: A1 is an independent area of control. A2 and A3 have some elements in common. As a result, the union of A2 and A3 constitutes an area of control.
This process enables the SCVC Back-up Mode to address the voltage alarms by dividing the system in areas of control that can be studied simultaneously without risk of overlapping actions.

4.3.2 CANDIDATE CORRECTIVE ACTION LISTING, FILTERING AND EVALUATION.

After forming the areas of control, the SCVC Back-up mode algorithm makes a list of possible control actions in each area of control. The candidate actions are listed
as follows: a binary variable $S_X$ is assigned to each control device with a logic zero meaning that the device status is not-connected and logic 1 means the device is connected. Then if there are $n$ discrete devices is the area of control, $S_1, S_2, \ldots, S_n$ will be variables representing the devices. As a result, the possible combinations of how the devices may be connected in the area are given by the possible combinations of the binary variables assigned to each device. This is shown in Table 4.1, where $z = 2^n - 1$ and $C_k$ is a particular combination.

<table>
<thead>
<tr>
<th></th>
<th>$S_1$</th>
<th>$S_2$</th>
<th>$\ldots$</th>
<th>$S_n$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_0$</td>
<td>0</td>
<td>0</td>
<td>$\ldots$</td>
<td>0</td>
</tr>
<tr>
<td>$C_1$</td>
<td>0</td>
<td>0</td>
<td>$\ldots$</td>
<td>1</td>
</tr>
<tr>
<td>$C_k$</td>
<td>0</td>
<td>0</td>
<td>$\ldots$</td>
<td>1</td>
</tr>
<tr>
<td>$C_z$</td>
<td>1</td>
<td>1</td>
<td>$\ldots$</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 4.1. Possible combinations of switching devices.

Then, the SCVC Back-up mode predicts the post-switching voltage levels associated to each $C_k$ at each bus of the area of control. This is done using a linearized power flow calculation using the Jacobian matrix of the system, just like the LVE introduced in Chapter 3. The final list is shown in Table 4.2, where $f$ is a function that represents the linear power flow calculation and its output is the voltage profile of the buses in the area of control after implementing a particular combination $C_k$. 
Table 4.2: Post-switching voltage profile associated to each combination.

<table>
<thead>
<tr>
<th>Combination</th>
<th>Voltage profile after introducing the combination to the system</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_0$</td>
<td>$f(C_0)$</td>
</tr>
<tr>
<td>$C_1$</td>
<td>$f(C_1)$</td>
</tr>
<tr>
<td>$C_2$</td>
<td>$f(C_2)$</td>
</tr>
<tr>
<td>.</td>
<td>.</td>
</tr>
<tr>
<td>.</td>
<td>.</td>
</tr>
<tr>
<td>.</td>
<td>.</td>
</tr>
<tr>
<td>$C_N$</td>
<td>$f(C_N)$</td>
</tr>
</tbody>
</table>

Figure 4.6 shows a schematic of this stage.

From Table 4.2, the SCVC Back-up mode can detect which combinations of actions would clear the alarms in the control area. Note in Figure 4.6 that, if none of the combinations found in Table 4.2 clears the alarms, an alarm is issued for the
operators at control center. On the other hand, the number of possible solutions can be high. In this case, the SCVC Back-up mode needs a method to pick the most appropriate in terms of system operation constraints. This is explained in the following task.

4.3.3 OPTIMAL ACTION SELECTION

By now, the possible combinations of actions that eliminate the voltage alarm have been identified. However, in real power system operation, the switchings of reactive power devices are not usually executed all at the same time. This means that the solution cannot be implemented immediately. There have to be transitions, usually one switching at the time. Indeed, both levels of hierarchy of the controller are supposed to only execute one action per iteration. For example: if the SLVC finds out that the best approach to clear a voltage alarm is to switch out a reactor and switch in a capacitor, in that iteration the controller only switches out the reactor. In the next iteration, all the process starts again. If the system does not change because of factors external to the controller (this is a very idealistic scenario), then it is logical that all the process will lead the controller to decide that switching the capacitor in is the solution. The reasons behind this approach are: first, to avoid excessive switching of devices. Sometimes, the load variation may help to solve the problem with no need of a second switching action; second, to
rely on the closed loop nature of the controller. Sometimes, it may occur that between iterations the problem becomes more severe. In this case, just executing the second switching of the previous iteration may not be enough. Then, it is better for the controller to decide again with the new conditions of the system.

Based on the previous constraints of operation, the decision problem can be formulated as a graph theory problem. Each combination of switching devices can be represented by a node in a graph. The edges of the graph represent the transitions from one combination to the other, that is, the switching of a device. Figure 4.7 shows how this graph would look like in general.

The transition from one node to another is given by particular constraints set by the designer. One example of this is the rule of one switching at the time mentioned before. Also, some transitions (or actions) may be penalized or rewarded by assigning a proper cost \( w_{ij} \) to each edge. An example of the use of the
transition cost is when operators prefer to switch out capacitors instead of switch in reactors. In this case, transitions associated with switching reactors in are penalized with higher costs than the actions associated with capacitor switch out.

The procedure to select the combination that will be implemented is as follows: first, the SCVC Back-up mode identifies the actual state of the system $C_i$ by finding the node that represents the actual status of the devices in the area of control. Second, the SCVC Back-up mode identifies combinations $C_m^f$ that will clear the voltage alarm ($i$ stands for initial and $f$ for final; $m$ represents the index of the combinations that will clear the alarm). Since there are several paths that will connect the actual state of the system $C_i$ to all the possible final states $C_m^f$, the SCVC Back-up mode needs a method to find the paths that will produce the least number of switchings and operation cost, that is, the shortest paths to these final solutions $C_m^f$. For this purpose, the Floyd-Warshall algorithm is used (See Section 4.3.4). This is graph theory method that finds the shortest path between two nodes and the total cost of this transition, considering the costs assigned to each edge. Consider Figure 4.8 as an example. If $C_1^f$, $C_2^f$ and $C_3^f$ are possible solutions to the voltage alarm, the SCVC has to decide which of them to implement. By applying Floyd-Warshall, it is found that the highlighted paths with their associated costs are the shortest transitions from $C_i$ to $C_1^f$, $C_2^f$ and $C_3^f$ respectively (for this example $m=1,2,3$).
The total transition to the each $C^f_m$ from the initial state $C^i$ will have a total cost $H_{im}$, which is the summation of the cost of each edge cost involved in the transition. Then, the optimal solution cost is given by

$$\text{Optimal Solution Cost} = \text{Min} (H_{i1}, H_{i2}, \ldots, H_{ip}) \quad (4.4)$$

where $p$ is the number of possible solutions. The node $C^f_m$ corresponding to this optimal cost is the combination of actions to which the SCVC will lead the system through the path previously found by Floyd-Warshall algorithm. In the example of Figure 4, $H_{i1}=9$, $H_{i2}=4$ and $H_{i3}=6$. Then, the solution that causes minimum cost is $C^f_2$.

Figure 4.8: Solution Paths.

Figure 4.9 shows an schematic diagram of this stage of the controller.
4.3.4 FLOYD-WARSHALL ALGORITHM

Floyd-Warshall is a graph theory algorithm that allows finding the shortest path between all pairs of nodes in a graph. Assume the graph is in the form $G = (V,E)$ where the vertices $V$ are numbered $1, 2, \ldots, n$ and the edges $E$ have a cost associated through a function $c: E \rightarrow \mathbb{R}$. Also define a cost matrix $C$, where $C(i,j)$ is the cost $c$ associated to the edge $(i,j)$. Floyd-Warshall calculates the cheapest cost matrix $A$, where $A(i,j)$ is the cheapest cost of any path from vertex $i$ to vertex $j$. Then, the algorithm is as follows[19]:

\[
\begin{align*}
&\text{FOR } i=1 \text{ to } n \text{ do} \\
&\quad \text{FOR } j=1 \text{ to } n \text{ do} \\
&\quad\quad A(i,j) = C(i,j); \\
&\quad \text{END} \\
&\text{END}
\end{align*}
\]
Floyd Warshall is $O(V^3)$ in time and $O(V^2)$ in space. Also, it does not work if negative costs are used.

4.4 TEST CASES

The following test cases illustrate how the SCVC algorithm works for both modes of operation. The test cases are organized as follows: the first two test cases show how the SCVC works in Coordination and Back-up mode respectively. The remaining cases show scenarios in California substations that are tested in both modes of operation. In each of this cases, a comparison between both modes of operation is shown.
4.4.1 TEST CASE 1: COORDINATION MODE OPERATION

This test is performed on the actual WECC system with more than 18000 buses. This scenario takes place in an important area of the WECC system and it features four adjacent substations with 500 kV buses experiencing overvoltages after injecting 400 MVAR at Substation 2 500 and 250 MVAR at Substation 1 500. The voltage magnitudes and tolerance ranges of the buses affected are shown in Table 4.3.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1 500</td>
<td>1.077</td>
<td>1.04 – 1.07</td>
</tr>
<tr>
<td>Substation 1 230</td>
<td>1.022</td>
<td>0.98 – 1.02</td>
</tr>
<tr>
<td>Substation 2 500</td>
<td>1.073</td>
<td>1.03 – 1.06</td>
</tr>
<tr>
<td>Substation 3 500</td>
<td>1.065</td>
<td>1.04 – 1.06</td>
</tr>
<tr>
<td>Substation 4 500</td>
<td>1.077</td>
<td>1.04 – 1.06</td>
</tr>
<tr>
<td>Substation 4 230</td>
<td>1.025</td>
<td>0.99 – 1.01</td>
</tr>
</tbody>
</table>

Table 4.3: Initial Voltages and Voltage Ranges

In this mode of operation, the SCVC needs to decide which SLVC has to be enabled to clear all the voltage alarms with the least number of switchings. For this decision, the SCVC constructs a forward looking tree and analyzes what would happen if each SLVC was enabled. Figure 4.10 shows the tree. In this case, there are four SLVCs involved: Substation 1, Substation 2, Substation 3 and Substation 4. Tables 4.4, 4.5, 4.6 and 4.7 show what would happen if each respective SLVC is enabled.
As seen in Tables 4.4, 4.5, 4.6, 4.7 and Figure 4.10, there are only two options that can lead to clear all the voltage alarms: enabling Substation 1 SLVC or Substation 3 SLVC. Both options will take two iterations to clear the alarms. On the other hand, if SLVC at Substation 2 is enabled, this will lead to a condition in which the only substation with alarms would be Substation 4. However, when Substation 4 SLVC is enabled subsequently, it cannot find a local action to clear its alarm. This would leave the system in an unsatisfactory condition. This is also the case if Substation 4 SLVC is enabled in first place.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Substation 1 500</td>
<td>Substation 4 500 0.017 p.u</td>
<td>Substation 1</td>
<td>Capacitor 1 and 2 @ 500 kV out</td>
<td>Substation 4 500 0.002 p.u</td>
<td>Substation 2 500</td>
</tr>
<tr>
<td></td>
<td>Substation 2 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Substation 3 500</td>
</tr>
<tr>
<td></td>
<td>Substation 3 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Substation 4 500</td>
</tr>
<tr>
<td></td>
<td>Substation 4 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Substation 4 230</td>
</tr>
<tr>
<td></td>
<td>Substation 4 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>No Alarms</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Substation 2 500</td>
<td>Substation 4 500 0.002</td>
<td>Vincent</td>
<td>Three taps up @ 230 kV</td>
<td>No Violations</td>
<td>No Alarms</td>
</tr>
<tr>
<td></td>
<td>Substation 3 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 4 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 4 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.4. Sequence of events if SLVC at Substation 1 is enabled.
<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Substation 1 500 230</td>
<td>Substation 4 500 0.017</td>
<td>Substation 2</td>
<td>Capacitor 1 &amp; 2 @ 500 kV out</td>
<td>Substation 4 500 0.003p.u</td>
<td>Substation 4 500 230</td>
</tr>
<tr>
<td></td>
<td>Substation 1 500 230</td>
<td>Substation 4 500 0.003</td>
<td>Substation 4</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.5. Sequence of events if SLVC at Substation 2 is enabled

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Substation 1 500 230</td>
<td>Substation 4 500 0.017</td>
<td>Substation 3</td>
<td>One Reactor Bank in</td>
<td>Substation 4 500 0.013p.u</td>
<td>Substation 1 500 230</td>
</tr>
<tr>
<td></td>
<td>Substation 1 500 230</td>
<td>Substation 4 500 0.013</td>
<td>Substation 2</td>
<td>Capacitor 1 &amp; 2 @ 500kV out</td>
<td>No Violations</td>
<td>No Alarms</td>
</tr>
</tbody>
</table>

Table 4.6. Sequence of events if SLVC at Substation 3 is enabled
Table 4.7: Sequence of events if SLVC at Substation 4 is enabled

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆V&lt;sub&gt;max&lt;/sub&gt; (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆V&lt;sub&gt;max&lt;/sub&gt; (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Substation 1 500</td>
<td>Substation 4 500 0.017 p.u</td>
<td>Substation 4</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>Substation 1 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 2 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 3 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 4 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Substation 4 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.4.2 TEST CASE 2: BACK UP MODE OPERATION.

The following situation takes place in the 2746 bus Polish power system (Winter case). After increasing the load to 100 MW and 100 MVAR in a specific area,
several voltage alarms are issued. The buses with alarms are shown in Table 4.8 with their tolerance ranges:

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage(p.u)</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>224</td>
<td>1.009</td>
<td>1.03-1.05</td>
</tr>
<tr>
<td>404</td>
<td>1.0029</td>
<td>1.03-1.05</td>
</tr>
<tr>
<td>412</td>
<td>1.0069</td>
<td>1.03-1.05</td>
</tr>
<tr>
<td>470</td>
<td>0.9949</td>
<td>1.03-1.05</td>
</tr>
</tbody>
</table>

Table 4.8. Initial voltages and voltage ranges

After identifying the alarms, the SCVC Back-up mode forms the area shown in Figure 4.11, based on the method explained in Section 4.3.1.

Notice that buses 24, 33 and 413 are considered in the area of control even when they are not displaying voltage alarms. This is because their electrical distance to the buses with alarms is meaningful and any corrective action may have an effect on them as well. The tolerance ranges of these buses are shown in Table 4.9.
<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>24</td>
<td>1.05-1.07</td>
</tr>
<tr>
<td>33</td>
<td>1.05-1.07</td>
</tr>
<tr>
<td>413</td>
<td>1.01-1.03</td>
</tr>
</tbody>
</table>

Table 4.9 Range of voltage operation.

Buses 224, 404, 412 and 470 have capacitor banks of 20 MVAR, 60 MVAR, 20 MVAR, 30 MVAR, respectively. There may be a possible solution to this voltage problem by switching a particular combination of these devices. As a result the possible combinations of switchings are shown in Table 4.10.

<table>
<thead>
<tr>
<th>Combination</th>
<th>Cap. bank in bus 224</th>
<th>Cap. bank in bus 470</th>
<th>Cap. bank in bus 404</th>
<th>Cap. bank in bus 412</th>
</tr>
</thead>
<tbody>
<tr>
<td>C0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>C1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>C2</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>C3</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>C4</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>C5</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>C6</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>C7</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>C8</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>C9</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>C10</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>C11</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>C12</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>C13</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>C14</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>C15</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 4.10. Possible combinations of switching devices.

By using linearized power flow calculations, the post-switching voltage levels are estimated for every combination and are shown in Table 4.11.

From Table 4.11, the SCVC Back-up Mode identifies C15 as the only possible solution to the problem. Suppose that the state represented by this combination can
be reached only by switching capacitors one at the time. Also, for illustration purposes, let us suppose that the capacitor associated with bus 404 could only be activated under extreme circumstances. In order to address these constraints, the graph theory approach explained in Section 4.3.4 (Floyd-Warshall) is used. The graph of the possible combinations is shown in Figure 4.12. Note that any operation associated with the capacitor in bus 404 is penalized with a higher value than any other operation (a value of 2 instead of 1 for normal operations).

Given that the initial state is associated with the combination C0, the minimum distance between this state and the candidate solution C15 has to be found.

<table>
<thead>
<tr>
<th>BUS</th>
<th>24</th>
<th>33</th>
<th>224</th>
<th>404</th>
<th>412</th>
<th>413</th>
<th>470</th>
</tr>
</thead>
<tbody>
<tr>
<td>C0</td>
<td>1.0612</td>
<td>1.0612</td>
<td>1.009</td>
<td>1.0029</td>
<td>1.0069</td>
<td>1.0289</td>
<td>0.9949</td>
</tr>
<tr>
<td>C1</td>
<td>1.0625</td>
<td>1.0625</td>
<td>1.0115</td>
<td>1.0096</td>
<td>1.0165</td>
<td>1.0290</td>
<td>0.9995</td>
</tr>
<tr>
<td>C2</td>
<td>1.0655</td>
<td>1.0655</td>
<td>1.0175</td>
<td>1.0254</td>
<td>1.0267</td>
<td>1.0291</td>
<td>1.0104</td>
</tr>
<tr>
<td>C3</td>
<td>1.0667</td>
<td>1.0667</td>
<td>1.0199</td>
<td>1.0318</td>
<td>1.0361</td>
<td>1.0292</td>
<td>1.0148</td>
</tr>
<tr>
<td>C4</td>
<td>1.0627</td>
<td>1.0627</td>
<td>1.0158</td>
<td>1.0106</td>
<td>1.0137</td>
<td>1.0289</td>
<td>1.0073</td>
</tr>
<tr>
<td>C5</td>
<td>1.064</td>
<td>1.064</td>
<td>1.0183</td>
<td>1.0173</td>
<td>1.0232</td>
<td>1.0291</td>
<td>1.0118</td>
</tr>
<tr>
<td>C6</td>
<td>1.0669</td>
<td>1.0669</td>
<td>1.0241</td>
<td>1.0328</td>
<td>1.0333</td>
<td>1.0293</td>
<td>1.0224</td>
</tr>
<tr>
<td>C7</td>
<td>1.0681</td>
<td>1.0681</td>
<td>1.0265</td>
<td>1.0392</td>
<td>1.0426</td>
<td>1.0294</td>
<td>1.0267</td>
</tr>
<tr>
<td>C8</td>
<td>1.0618</td>
<td>1.0618</td>
<td>1.0149</td>
<td>1.0057</td>
<td>1.0093</td>
<td>1.0290</td>
<td>0.9994</td>
</tr>
<tr>
<td>C9</td>
<td>1.063</td>
<td>1.0631</td>
<td>1.0174</td>
<td>1.0124</td>
<td>1.019</td>
<td>1.0290</td>
<td>1.004</td>
</tr>
<tr>
<td>C10</td>
<td>1.066</td>
<td>1.066</td>
<td>1.0234</td>
<td>1.0281</td>
<td>1.0291</td>
<td>1.0293</td>
<td>1.0147</td>
</tr>
<tr>
<td>C11</td>
<td>1.0672</td>
<td>1.0672</td>
<td>1.0258</td>
<td>1.0345</td>
<td>1.0384</td>
<td>1.0292</td>
<td>1.0191</td>
</tr>
<tr>
<td>C12</td>
<td>1.0632</td>
<td>1.0632</td>
<td>1.0217</td>
<td>1.0134</td>
<td>1.0161</td>
<td>1.0292</td>
<td>1.0117</td>
</tr>
<tr>
<td>C13</td>
<td>1.0645</td>
<td>1.0645</td>
<td>1.0241</td>
<td>1.02</td>
<td>1.0256</td>
<td>1.0292</td>
<td>1.0161</td>
</tr>
<tr>
<td>C14</td>
<td>1.0674</td>
<td>1.0674</td>
<td>1.0299</td>
<td>1.0355</td>
<td>1.0357</td>
<td>1.0293</td>
<td>1.0267</td>
</tr>
<tr>
<td>C15</td>
<td>1.0686</td>
<td>1.0686</td>
<td>1.0323</td>
<td>1.0418</td>
<td>1.0449</td>
<td>1.0294</td>
<td>1.031</td>
</tr>
</tbody>
</table>

Table 4.11. Power flow estimations for each combination.
Using Floyd-Warshall yields to the solution shown in Table 4.12.

<table>
<thead>
<tr>
<th>Candidate Combination</th>
<th>Distance to Initial State</th>
</tr>
</thead>
<tbody>
<tr>
<td>C15</td>
<td>5</td>
</tr>
</tbody>
</table>

Table 4.12. Distances to possible solutions.

The highlighted path in Figure 4.13 shows the sequence of operations that have to be performed by the controller.
Table 4.13 summarizes the actions executed by the controller and the condition of the system step by step.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>ΔVmax (before control)</th>
<th>Control Device</th>
<th>Control Action</th>
<th>ΔVmax (After control)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>-0.0351 Bus 470</td>
<td>Bus 412 Cap. Bank 20 MVAR</td>
<td>In</td>
<td>-0.0305 Bus 470</td>
</tr>
<tr>
<td>2</td>
<td>-0.0305 Bus 470</td>
<td>Bus 404 Cap. Bank 60 MVAR</td>
<td>In</td>
<td>-0.0152 Bus 470</td>
</tr>
<tr>
<td>3</td>
<td>-0.0152 Bus 470</td>
<td>Bus 470 Cap. Bank 30 MVAR</td>
<td>In</td>
<td>-0.0035 Bus 224</td>
</tr>
<tr>
<td>4</td>
<td>-0.0035 Bus 224</td>
<td>Bus 224 Cap. Bank 20 MVAR</td>
<td>In</td>
<td>No Violation</td>
</tr>
</tbody>
</table>

Table 4.13. Sequence of events during controller action.

4.4.3 TEST CASE 3

After injecting 500 MVAR at Substation 3 230 and -450 MVAR at Substation 1 230, two types of alarms occur at the same time in the same system, in two different areas. Substation 1 and Substation 2 experience undervoltage, while Substations 3, 4, 5 and 6 have overvoltages. Table 4.14 shows the current voltages of the substations and the range allowed for the voltages.
<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1 500</td>
<td>1.039</td>
<td>1.04-1.06</td>
</tr>
<tr>
<td>Substation 1 230</td>
<td>0.978</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 2</td>
<td>0.965</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 3 500</td>
<td>1.061</td>
<td>1.03 - 1.06</td>
</tr>
<tr>
<td>Substation 3 230</td>
<td>1.011</td>
<td>0.97-1.01</td>
</tr>
<tr>
<td>Substation 4</td>
<td>1.023</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 5</td>
<td>1.024</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 6 500</td>
<td>1.062</td>
<td>1.04 – 1.06</td>
</tr>
<tr>
<td>Substation 6 230</td>
<td>1.012</td>
<td>0.99 – 1.01</td>
</tr>
</tbody>
</table>

Table 4.14 Initial voltages and voltage ranges.

In Coordination Mode, the algorithm needs to decide which SLVC has to be enabled to clear the voltage alarms with the least number of switchings. For this decision, the algorithm analyzes what would happen if each SLVC is enabled by simulating the conditions of enabling each SLVC. In this case, there are six SLVCs involved: Substations 1, 2, 3, 4, 5 and 6. Tables 4.15, 4.16, 4.17, 4.18, 4.19 and 4.20 show what would happen if each respective SLVC is enabled. Figure 4.14 summarizes these results.
<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆Vmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆Vmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst.1 500 Subst.1 230 Subst.2 Subst.3 500 Substs.3 230 Subst.4 Subst.5 Subst.6 500 Subst.6 230</td>
<td>Subst.2 0.015</td>
<td>Subst. 1</td>
<td>SVD @ 230 kV in</td>
<td>Subst.6 500 0.006 p.u</td>
<td>Subst.3 500 Subst.3 230 Subst.6 500 Subst.6 230</td>
</tr>
<tr>
<td>2</td>
<td>Subst.3 500 Subst.3 230 Subst.6 500 Subst.6 230</td>
<td>Subst.6 500 0.006 p.u</td>
<td>Subst.3</td>
<td>Two reactors in</td>
<td>Subst.6 500 0.001 p.u</td>
<td>Subst.6 500 Subst.6 230</td>
</tr>
<tr>
<td>3</td>
<td>Subst.6 500 Subst.6 230</td>
<td>Subst.6 500 0.001 p.u</td>
<td>Subst.6</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.15: Sequence of events if SLVC at Substation 1 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆Vmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆Vmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst.1 500 Subst.1 230 Subst.2 Subst.3 500 Subst.3 230 Subst.4 Subst.5 Subst.6 500 Subst.6 230</td>
<td>Subst.2 0.015</td>
<td>Subst.2</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.16: Sequence of events if SLVC at Substation 2 is enabled.
<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆Vmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆Vmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 500 Subst. 1 230 Subst. 2 Subst. 3 500 Subst. 3 230 Subst. 5 Subst. 6 500 Subst. 6 230</td>
<td>Subst. 2 0.015p.u</td>
<td>Subst. 3</td>
<td>Two reactors in</td>
<td>Subst. 2 0.015p.u</td>
<td>Subst. 1 500 Subst. 1 230 Subst. 2 Subst. 3 500 Subst. 6 500 Subst. 6 230</td>
</tr>
<tr>
<td>2</td>
<td>Subst. 1 500 Subst. 1 230 Subst. 2 Subst. 6 500 Subst. 6 230</td>
<td>Subst. 2 0.015p.u</td>
<td>Subst. 1</td>
<td>SVD @ 230 kV in</td>
<td>Subst. 6 500 0.001p.u</td>
<td>Subst. 6 500 Subst. 6 230</td>
</tr>
<tr>
<td>3</td>
<td>Subst. 6 500 Subst. 6 230</td>
<td>Subst. 6 500 0.001 p.u</td>
<td>Subst. 6</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.17: Sequence of events if SLVC at Substation 3 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆Vmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆Vmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 500 Subst. 1 230 Subst. 2 Subst. 3 500 Subst. 3 230 Subst. 5 Subst. 6 500 Subst. 6 230</td>
<td>Subst. 2 0.015 p.u</td>
<td>Subst. 4</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.18: Sequence of events if SLVC at Substation 4 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>∆Vmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>∆Vmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 500 Subst. 1 230 Subst. 2 Subst. 3 500 Subst. 3 230 Subst. 4 Subst. 5 Subst. 6 500 Subst. 6 230</td>
<td>Subst. 2 0.015 p.u</td>
<td>Subst. 5</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.19: Sequence of events if SLVC at Substation 5 is enabled.
In this case, only two options get close to clearing the voltage alarms: enabling SLVC at Substation 1 or enabling SLVC at Substation 3. In both sequence of events, the SLVC at Substation 1 clears the alarms in Substation 1 Area. However, the local actions at Substation 3 solve the alarms at Substation 3 but not in the surrounding substations. This is the case of Substation 6. Furthermore, notice that...
the solution found by SLVC at Substation 3 is to switch two reactors in. While this is enough to clear the alarms at Substation 3, it is not enough to clear the alarms of other substations in spite of having more reactors available. This shows a limitation in the local approach of SLVC coordination. On the other hand, the Back-up Mode can “see” these wide area conditions and offer a solution that will benefit all substations in the Area. As a result, for this situation, Back-up Mode has to be activated to clear the alarms in Substation 3 Area.

**Back-up Mode:** After considering the electrical distances, the SCVC Back-up Mode algorithm forms two areas to attack these voltage alarms: one for Substation 1 area and another for Substation 3 area. Since the largest voltage deviation is in Substation 1 area, the algorithm works with this area first. The following voltage control devices are in this area:

1. Substation 1 230 SVD
2. Substation 1 reactors 1-6
3. Substation 2 SVD

A combination of these devices should be able to clear the voltage alarm in Substation 1 area. Since the number of devices is 8, the number of possible combinations is 256, which means that the algorithm will have to evaluate 256 possible actions with power flow calculations. This can be time consuming. As a result, the algorithm can reduce the number of possibilities by using the purging
process explained in Appendix A. The final number of actions is 50. After evaluating these through power flow calculations and optimization in terms of number of switchings (Floyd-Warshall), the recommendation of the controller is:

- Switch Substation 1 230 SVD in

After implementing this recommendation, the voltage profile of the buses in Substation 1 area is shown in Table 4.21.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1 500</td>
<td>1.055</td>
</tr>
<tr>
<td>Substation 1 230</td>
<td>1.003</td>
</tr>
<tr>
<td>Substation 2</td>
<td>0.986</td>
</tr>
</tbody>
</table>

Table 4.21 Voltages after implementing Back up Mode recommendation

As seen in Table 4.20, the alarms in Substation 1 area have been cleared. Then, to clear the voltage alarms in Substation 3 area, a second iteration is needed. The devices associated to this area are the following:

1. Substation 7 500 capacitor 1
2. Substation 7 500 capacitor 2
3. Substation 7 500 capacitor 3
4. Substation 3 500 capacitor 1
5. Substation 3 500 capacitor 2
6. Substation 3 reactors 1-6
7. Substation 3 230 SVD
Since the number of devices is 14, the number of possible combinations is 16384. However, the algorithm can reduce the number of possibilities to the 70 most possible. After evaluating these through power flow calculations and optimization in terms of number of switchings, the recommendations of the controller are (all of them need to be implemented):

- Switch Substation 7 500 capacitor 1 out.
- Switch 2 Susbtation 3 reactors in.

After implementing this recommendation, the voltage profile of the buses in Substation 3 area is shown in Table 4.21.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 3 500</td>
<td>1.057</td>
</tr>
<tr>
<td>Substation 3 230</td>
<td>1.006</td>
</tr>
<tr>
<td>Substation 4</td>
<td>1.018</td>
</tr>
<tr>
<td>Substation 5</td>
<td>1.018</td>
</tr>
<tr>
<td>Substation 6 500</td>
<td>1.058</td>
</tr>
<tr>
<td>Substation 6 230</td>
<td>1.008</td>
</tr>
</tbody>
</table>

Table 4.22 Voltages after implementing Back up Mode recommendation

As seen in Table 4.22, the alarms in Substation 3 area have been cleared. In conclusion this test case shows that the algorithm is able to attack simultaneous voltage alarms either in series or in parallel.
4.4.4 TEST CASE 4

This case shows a multi-undervoltage problem at 230 kV level namely, substations Substation 1, Substation 2 and Substation 3. Table 4.23 shows the actual voltages and the ranges allowed for these voltages.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1 230</td>
<td>0.956</td>
<td>0.96-0.99</td>
</tr>
<tr>
<td>Substation 2</td>
<td>0.957</td>
<td>0.96-0.99</td>
</tr>
<tr>
<td>Substation 3</td>
<td>0.959</td>
<td>0.96-0.99</td>
</tr>
</tbody>
</table>

Table 4.23 Initial voltages and voltage ranges.

In Coordination Mode, the algorithm needs to decide which SLVC has to be enabled to clear the voltage alarms with the least number of switchings. For this decision, the algorithm analyzes what would happen if each SLVC is enabled by simulating the conditions of enabling each SLVC. In this case, there are there SLVCs involved: Substation 1, 2 and 3. Tables 4.24, 4.25, and 4.26 show what would happen if each respective SLVC is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 230 Subst. 2 230 Subst. 3 230</td>
<td>Subst. 1 230 0.004 p.u</td>
<td>Subst. 1</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.24 Sequence of events if SLVC at Substation 1 is enabled.
### Table 4.25 Sequence of events if SLVC at Substation 2 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 230 Subst. 2 230 Subst 3 230</td>
<td>Subst. 1 230 0.004 p.u</td>
<td>Subst. 2</td>
<td>Subst. 2 SVD in</td>
<td>Subst. 1 230 0.001 p.u</td>
<td>Subst. 1 230</td>
</tr>
<tr>
<td>2</td>
<td>Subst. 1 230</td>
<td>Subst. 1 230 0.001 p.u</td>
<td>Subst. 1</td>
<td>Two taps up at three 500/230kV transformers</td>
<td>No Violations</td>
<td>No Alarms</td>
</tr>
</tbody>
</table>

### Table 4.26 Sequence of events if SLVC at Substation 3 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔVmax (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔVmax (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 230 Subst. 2 230 Subst 3 230</td>
<td>Subst. 1 230 0.004 p.u</td>
<td>Subst. 3</td>
<td>One capacitor @ 66 kV in</td>
<td>Subst. 1 230 0.003 p.u</td>
<td>Subst. 1 230 Subst. 2 230</td>
</tr>
<tr>
<td>2</td>
<td>Subst. 1 230 Subst. 2 230</td>
<td>Subst. 1 230 0.003 p.u</td>
<td>Subst. 2</td>
<td>Subst. 1 SVD in</td>
<td>No Violations</td>
<td>No Alarms</td>
</tr>
</tbody>
</table>

Figure 4.15: Test Case 4 Graph.
In this case, there are two possibilities for clearing the voltage alarms: enabling SLVC at Substation 2 or enabling SLVC at Substation 3 (see Figure 4.15). Both will take two time steps to solve the alarms. Therefore, it is up to the operator criterion to choose any of these two scenarios.

For illustration purposes, consider the response of the controller if this problem is solved with the Back-up Mode. After considering the electrical distances, the SCVC Back-up Mode algorithm forms an area with the buses that are electrically coupled to the affected buses. The following voltage control devices are in this area:

1. Substation 4 SVD
2. Substation 3 SVD
3. Substation 1 reactors 1-4

Since the number of devices is 4 (Substation 1 reactors have been grouped in groups of 2) the number of possible combinations is 16. After evaluating this through power flow calculations and optimization in terms of number of switchings, the recommendations of the controller are (all of them need to be implemented):

- Switch Substation 4 SVD in
- Switch Substation 2 SVD in
After implementing this recommendation, the voltage profile of the buses is shown in Table 4.27:

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1 230</td>
<td>0.962</td>
</tr>
<tr>
<td>Substation 2</td>
<td>0.964</td>
</tr>
<tr>
<td>Substation 3</td>
<td>0.965</td>
</tr>
</tbody>
</table>

Table 4.27 Voltages after implementing Back up Mode recommendation.

As shown in Table 4.27, the alarms have been cleared. Also, notice that the algorithm recommends switching a capacitor that is not in the affected substation. In this case the capacitor at one affected substation is not enough. Then, the controller has to find additional solutions elsewhere. On the other hand, notice that the solutions found by the SCVC in Coordination Mode algorithm involve devices in the substations with alarms whereas the Back-up Mode proposes switching devices in substations with no alarms (Substation 4 SVD). This is because some of devices used in Coordination Mode (66 kV capacitors and LTCs) are not control options for the Back-up Mode.

4.4.5 TEST CASE 5

This case presents a multi-undervoltage case affecting the following substations: Substations 1, 2, 3 and 4. Table 4.28 shows the actual voltages and the ranges allowed for these voltages.
<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
<th>Voltage Range (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1</td>
<td>0.968</td>
<td>0.97-1.01</td>
</tr>
<tr>
<td>Substation 2</td>
<td>1.036</td>
<td>1.04-1.06</td>
</tr>
<tr>
<td>Substation 2</td>
<td>0.975</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 3</td>
<td>0.963</td>
<td>0.98-1.02</td>
</tr>
<tr>
<td>Substation 4</td>
<td>1.049</td>
<td>1.05-1.07</td>
</tr>
</tbody>
</table>

Table 4.28 Initial voltages and voltage ranges.

In Coordination Mode, the algorithm needs to decide which SLVC has to be enabled to clear the voltage alarms with the least number of switchings. For this decision, the algorithm analyzes what would happen if each SLVC is enabled by simulating the conditions of enabling each SLVC. In this case, there are four SLVCs involved: Substation 1, 2, 3 and 4. Tables 4.29, 4.30, 4.31, and 4.32 show what would happen if each respective SLVC is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔV_{max} (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔV_{max} (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 2 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 2 230</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 4 500</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.29 Sequence of events if SLVC at Substation 1 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>ΔV_{max} (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>ΔV_{max} (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subst. 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.30 Sequence of events if SLVC at Substation 2 is enabled.
<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>$\Delta V_{\text{max}}$ (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>$\Delta V_{\text{max}}$ (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 Subst. 2 500 Subst. 2 230 Subst. 3 Subst. 4 500</td>
<td>Subst. 3 0.017 p.u</td>
<td>Subst. 3</td>
<td>No local solution found</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 4.31 Sequence of events if SLVC at Substation 3 is enabled.

<table>
<thead>
<tr>
<th>Time Step</th>
<th>Alarms before control</th>
<th>$\Delta V_{\text{max}}$ (before control)</th>
<th>SLVC enabled</th>
<th>Control Action</th>
<th>$\Delta V_{\text{max}}$ (after control)</th>
<th>Alarms after Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Subst. 1 Subst. 2 500 Subst. 2 230 Subst. 3 Subst. 4 500</td>
<td>Subst. 3 0.017 p.u</td>
<td>Subst. 4</td>
<td>SVD @115 kV in</td>
<td>Subst. 3 0.017 p.u</td>
<td>Subst. 3 Subst. 1 Subst. 2 500 Subst. 2 230</td>
</tr>
<tr>
<td>2</td>
<td>Subst. 3 Subst. 1 Subst. 2 500 Subst. 2 230</td>
<td>Subst. 3 0.017 p.u</td>
<td>Subst. 2</td>
<td>SVD @ 230 kV in</td>
<td>Subst. 3 0.002 p.u</td>
<td>Subst. 3</td>
</tr>
<tr>
<td>3</td>
<td>Subst. 3</td>
<td>Subst. 3 0.002</td>
<td>Subst. 3</td>
<td>Capacitor 1 &amp;2 @ 115kV in</td>
<td>No Violations</td>
<td>No Alarms</td>
</tr>
</tbody>
</table>

Table 4.32 Sequence of events if SLVC at Substation 4 is enabled.

![Figure 4.16: Test Case 5 Graph.](image)
In this scenario there are two potential options for clearing the alarms: Enabling SLVC at Substation 2 or SLVC at Substation 4. Given that the first option results in clearing the alarms with less iteration, SLVC at Substation 4 is enabled.

For illustration purposes, consider the response of the controller if this problem is solved with the Back-up Mode. After considering the electrical distances, the SCVC Back-up Mode algorithm forms an area with the buses that are electrically coupled to the affected buses. The following voltage control devices are available in this area:

1. Substation 2 230 SVD
2. Susbtation 2 reactors 1-6

Since the number of devices is 8, the number of possible combinations is 256. After evaluating these through power flow calculations and optimization in terms of number of switchings, the recommendations of the controller are (all of them need to be implemented):

- Switch Substation 2 230 SVD in

If these recommendations are implemented, the voltage profile of the bus is the displayed in Table 4.33.
As seen in Table 4.32, the alarms have been cleared. Also, this test case shows an important feature of the controller: coordination with local control devices like the SVDs. Notice the apparent contradiction between the results in Table 4.30 and the recommendation of the controller in Back-up Mode. Since the first action in Table 4.30 indicates that Substation 1 230 SVD is activated, this should have been enough to clear all the voltage alarms given the results in the Back-up mode, as shown in Table 4.33. The solution to this apparent error has to do with the fact that the SVDs have several capacitors available to clear voltage alarms. Therefore, in Coordination Mode the SVD is an autonomous device that will decide how many capacitors will be connected. Usually the SVDs are programmed to monitor the voltage of the bus where they are connected and choose the minimum number of capacitors necessary to clear the alarm at that specific bus. The Coordination Mode has into account this logic and is coordinated accordingly. In Back-up Mode the SVD logic is overridden. This means that the Back-up Mode is in control of all the capacitors that each SVD has. As a result, the Back-up Mode can connect as many capacitors as needed to clear voltage alarms, not only at the bus where the

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (p.u)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation 1</td>
<td>0.982</td>
</tr>
<tr>
<td>Substation 2 500</td>
<td>1.052</td>
</tr>
<tr>
<td>Substation 2 230</td>
<td>1.000</td>
</tr>
<tr>
<td>Substation 3</td>
<td>0.982</td>
</tr>
<tr>
<td>Substation 4 500</td>
<td>1.058</td>
</tr>
</tbody>
</table>

Table 4.33 Voltages after implementing Back up Mode recommendation.
capacitors are connected but also in other buses. Remember that the Back-up mode has absolute visibility of the system and, as a result, its decisions are aimed for the benefit of all the system.
Chapter 5

Conclusions and Future Work

5.1 CONCLUSIONS

This dissertation proposes and validates a hierarchical two-level voltage controller for large power networks. The formulation presented in this thesis focuses in using discrete control devices such as transformer LTCs, shunt capacitors and reactor banks to perform corrective actions. The controller is divided in two controllers related to each other by hierarchy: a Substation Local Voltage Controller (SLVC) for each substation and a Supervisory Central Voltage Coordinator (SCVC) at control center level. The SLVC controller is designed to carry out control decisions on switching local VAR devices mostly based on local PMU measurements. The SLVC has been tested in offline conditions and real time environment with the aid of RTDS. The on-going project is aimed at testing a
prototype version of the substation controller at a specific substation in California. On the other hand, the SCVC supervises and coordinates the operation of the SLVCs throughout the network. A novel approach using supervisory control for discrete event systems and graph theory is introduced to address voltage alarms from the SCVC perspective. The proposed approach for the SCVC has been tested successfully for voltage alarms in a large power networks like the WECC system.

5.2 FUTURE WORK
Both levels of hierarchy offer opportunities for improvement given that this is the first stage of formulation of this type of controller. For example, the SLVC performance depends strongly in the parameters $\alpha$ that are calculated for each transmission line converging to the substation. Although these values do not change significantly with different loading conditions, they can change if the topology of the system is changed. This is feasible situation in nowadays utilities that sometimes need to change the topology to meet operation demands. Given this situation, formulating a LVE that is not dependent on parameters $\alpha$ would allow more flexibility and versatility in the SLVC level.

Another factor that must be considered is the complexity of real time implementation in contrast to theoretical work. By the time this dissertation has
been written, the SLVC has been tested in real time environment with the help of RTDS. One of the lessons of these tests has been that formulations need to be adapted to what is available in the field (real network operation). This is part of the future work that needs to be done with the SCVC. Although the SCVC has been tested offline, the real time implementation and interaction with SLVCs will surely bring issues and modifications that are necessary because of the real operation of the system.
Appendix A

Consider bus $i$ is violating the constraint $V_{\text{min}} \leq V_i \leq V_{\text{max}}$. For illustration purposes, assume there is an undervoltage, that is $V_i \leq V_{\text{min}}$. Then, define the voltage deviation $\Delta V_{\text{dev}}$ as

$$\Delta V_{\text{dev}} = V_{\text{min}} - V_i \quad (A.1)$$

However, $\Delta V_{\text{dev}}$ can also be approximated as

$$\Delta V_{\text{dev}} = -B_{i1}'\Delta Q_1 - \ldots - B_{ii}'\Delta Q_i - \ldots - B_{in}'\Delta Q_n \quad (A.2)$$

Where $B_{ij}'$ is an element of the $i$-th row of the inverse of the imaginary part of the $Y_{\text{bus}}$ matrix, and $\Delta Q_j$ is a reactive power injection at bus $j$.

Since $|B_{ii}'| \geq |B_{ij}'|$ for $j = 1, \ldots, n$, it can be shown that

$$\Delta V_{\text{dev}} \leq -B_{ii}'Q_{\text{net}} \quad (A.3)$$

Where $Q_{\text{net}} = \sum_{j=1}^{n} \Delta Q_j$

Proof: Expanding equation (A.3) yields to

$$-B_{i1}'\Delta Q_1 - \ldots - B_{ii}'\Delta Q_i - \ldots - B_{in}'\Delta Q_n \leq \sum_{j=1}^{n} \Delta Q_j \quad (A.4)$$

Dividing both sides by $-B_{ii}'$ leads to
\[ \sum_{j=1}^{n} \frac{b_{ij}'}{b_{ii}'} \Delta Q_j \geq \sum_{j=1}^{n} \Delta Q_j \quad (A.5) \]

Since the ratio \( \frac{b_{ij}'}{b_{ii}'} \) is always less than one, the statement is proved.

The conclusion from this demonstration is important because it can help to purge the number of switching combinations that appear in Back up Mode operation of the SCVC. All the switching combinations that satisfy

\[ Q_{\text{net}} \geq \frac{\Delta V_{\text{dev}}}{-b_{ii}'} \quad (A.6) \]

will be able to clean the voltage violation.
Bibliography


