Coordination of protection system and VSC-HVDC to mitigate cascading failures

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Abstract

The rapid development of the global economics has made power systems all over the world become large-scale interconnected grids. This increases the capability of power grids to transfer power over the long distance to serve the desired power demand with the minimum cost of operation. Unfortunately, it also enables the propagation of local failures into global networks. In other words, if a blackout happens in a power system, the size and the damage may significantly increase.

One of the main ways in which blackouts become widespread is cascading failures. This type of failure originates after a critical component of the system has been removed from the service by protective relaying. As a consequence, the load handled by the failed component needs to be redistributed which might cause an overloading on other components in the system.

On the other hand, the high power electronics controllable devices such as Voltage Source Converters-based High Voltage Direct Current (VSC-HVDC) transmission are recently developed. These electronics devices have the potential advantages such as the ability to independently control active and reactive power, and maintain voltage to be at acceptable level. Therefore, they are considered to be the promising devices that with an appropriately designed control strategy, they can substantially improve the performance and reliability of the power system.

This thesis presents the possibility to consider protection system status in the control of VSC-HVDC link. A great deal of this research is development of coordination between this power electronic device and protection system which normally are considered separately. The derivation of protection system has been selected to determine the operation of VSC-HVDC. The methodology is based on utilizing the signal created from a logical evaluation of relay and simplifications of certain parameters. By introducing information from the relays to the VSC-HVDC link via Central Control Unit (CCU), the modulation of transm-
ted power is devised in order to reduce the risk of system-wide failures. In turn, this means an avoided blackout.

Furthermore, this thesis also includes the preliminary suggestion to select the location of VSC-HVDC. The methodology is based on predicting voltage instability using voltage stability indices and related parameters which are derived by using Singular Value Decomposition method. The solutions indicate an effective location for applying corrective action such as load shedding. This optimal location is selected to reinforce the control strategy of VSC-HVDC in order to prevent cascading failures in the more encompassing systems.

**Keywords.** Cascading Failures, Protection Systems, VSC-HVDC, Voltage Stability, Singular Value Decomposition.
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Chapter 1

Introduction

1.1 Background

The long-term power system technology development resulted in the formation of large-scale interconnected grids worldwide during past decades. The integration of the national grids has been motivated mainly by the growth in electricity demand alongside the desire to minimize operational costs of the power system. In order to serve the increased demand of electricity consumption while minimizing the economic and the environmental impacts, existing power systems are expected to bear the burden. This increased burden has lead to that power systems sometimes have been operated closer to their stability margins. This leads to a chain of severe power system failures, consequently raising the number of customer disconnection events. Two examples of severe widespread power system failures are the blackout in Brazil in March 11, 1999 [1], and the blackout in USA and Canada in August 14, 2003 that affected approximately 50 million people [2]. In economic terms, estimates of total damage costs in the United States range between $4 billion and $10 billion. In Canada, the economic repercussions were the decrease of 0.7% in gross domestic product, a total loss of 18.9 million work hours, and a decrease in manufacturing shipments of $2.3 billion.

The usual case of several catastrophic power system failures is the unanticipated tripping of many other facilities due to the overloaded power system in conjunction with faults on critical facilities. As a result, this leads to that the infrastructure of the system becomes more vulnerable; eventually, the culmination of faults lead to system blackouts. Typically, most blackouts are triggered by
random events ranging from single to multiple equipment failures. More importantly, cascading phenomena are one of the principal contributors to the blackouts. In most cases of cascading phenomena, the protection systems, specifically relays, contribute to a substantial proportion of blackouts [3, 4] since they are capable of inducing domino-effect component disconnecting.

Taking into account the unfavorable impacts of power outages and the probable causes of cascading failures, power system stability and robustness, and blackout mitigation methods become actively sought topics. Certain control systems become viable in maintaining a power system stability under various disturbances. The advent of the power electronics devices, seen from the standpoint of the system operation such as the High Voltage Direct Current (HVDC), is beneficial to maintain a power system stability apart from serving their direct purposes [5, 6]. An appropriately designed control system can substantially improve the performance and reliability of the power system. Thus, these controllable devices become widely employed to reinforce the transmission network and to increase transmission power flow control capability.

Although blackout prevention should be based on training of dispatching personnel, wide-area system visibility, and comprehensive computer models for the analysis of the stability and security of power systems [7], automatic emergency control systems should be sufficiently applied to relieve overloading on system components. Automatic control systems could potentially react at a certain level of reliability in order to prevent instabilities caused by uncontrollable cascading failures. Hence, a compromise, between the prevention schemes given by approaches such as effective computer simulations, and the protection strategy represented by automatic control systems, should be achieved in order to enhance the resiliency of power systems to detrimental instabilities that could possibly lead to cascading failures. Ultimately, the accomplishments of the integration strategy would provide a seamless transition or mitigation from faults and fulfill the underlying intention of building a robust network to ensure the safety, continuity, and comfort of the benefiting parties.

1.2 Review

Blackout phenomena have been one of the major concerns in power systems and remain one of the active topics of interest. Extensive investigations have been done to describe some of the salient features of blackouts caused by cascading failure. One type of several models used to analyze blackouts is the prob-
1.2. REVIEW

Probabilistic model. The analytically tractable probabilistic models are comparatively conceptual due to the exhaustive complexities of large blackouts. Several of these models have been described in [8, 9, 10, 11]. Even though the models neglect the power system infrastructure and are too simple to practically and thoroughly represent aspects of cascading failures leading to blackouts, they address valuable global effects that have been elaborated in more detailed blackout models. Nonetheless, the study in [12] proposed improved simulation methods to create different cascading failure scenarios under some credible conditions.

Following from identification of cascading failures, the issue of power systems blackout mitigation needs to be addressed. One of the approaches to mitigate blackouts is the prevention principle. Similarly to the study of the blackout causes, the research surrounding blackout preventions has been discussed extensively, which culminated in several strategies being proposed. Among the multiple prevention methods, the application of controllable devices to reinforce the transmission network and to increase transmission power flow control capability has been proposed and widely implemented. The coordination of several controllable devices for stability enhancement as proposed either by FACTS [13, 14, 15] or through HVDC applications [16]. Most of the research on coordination of controllable devices emphasizes the optimal number of devices, the location for the devices, or the algorithm for coordination of the devices.

Concomitantly, while some of the efforts were focused on the mentioned approach which is prevention principle, some attention has also been given to another method which is protection principle. The concept of this principle is based on the minimization of unnecessary tripping that might lead to cascading failures. The adaptive logic proposed in [17, 18] is a method to postpone the relay tripping time, which requires communication channels between the relays in order to modify the setting parameters. In addition, some coordination methods between protective relays were proposed in [19, 20].

Although research involving prevention and protection principles often considers two of them separately, the coordination between the two principles presents a crucial extension to the previously studied cases. The behaviors of the coordinated components might be complementing or unpredictable. Hence, this presented study attempts to describe the composition of the prevention and protection principles by exploiting devices ascribed to each mitigation principle. Hence, the association of the two mitigation principles might prove to be more effective in averting blackouts from cascading failures.
1.3 Objectives

Within the framework of blending two cascading failure mitigation principles mentioned earlier, the main theme of the project is the development of power system topologies with controllable devices interfacing the various sub-systems with the interconnected power systems coordinating their protection and control in order to reduce the risk of system-wide failures. In addition, under this integration, all available assets of the power system, such as generators and lines, are sustained to their fullest operational extent by properly tuning controllers so that protective devices are activated at the latest possible moment in time. However, the first step of the project is this thesis. The idea of thesis is to address some fundamental studies in order to understand the nature of cascading failures. Therefore, an extensive literature related to cascading failure analysis is done. Also, a simple model explaining the basic mechanisms of a cascading failure is developed. Moreover, the fundamentals of protection system and HVDC technology are studied in order to design a simple coordination scheme between them for alleviating the instability mechanism caused by cascading failures.

The objectives of this thesis are:

1. Identification of causes of cascading failures in power systems.
2. Identification of needed communication for coordinated control.
3. Identification of input data for coordinated control.
4. Development of suitable methods for coordination between VSC-HVDC and protection system to ensure a reliable power system.
5. Design of control algorithms that would allow the mitigation of cascading failures in the power system.

1.4 Outline of the Thesis

The thesis are organized in six chapters:

Chapter 2 presents an overview of cascading failures and their definitions and a brief description of the several well-known techniques for cascading failure analysis is given.
1.5. MAIN CONTRIBUTIONS

Chapter 3 describes the fundamentals of protective relaying, addressing the operating principles of different relay applications and the vital associated definitions involving system protection.

Chapter 4 elaborates on the proposed control strategy to coordinate protection and control systems.

Chapter 5 introduces the test power system used in the numerical examples and presents the results of cascading failure modeling with comparisons between before and after applying coordinating control.

Chapter 6 presents the voltage instability prediction based VSC-HVDC location. The chapter begins with descriptions of the voltage stability indices and their products based on the Singular Value Decomposition method. Then, the application of voltage instability prediction is illustrated in order to present the power stability limit evaluation and indicate the suggested location to install VSC-HVDC.

Chapter 7 summarizes essential conclusions of the project and suggests extensions based on the current paradigm of combining protection and control systems.

1.5 Main contributions

The main contributions of the thesis are:

- **Historical overview of blackouts.** The coincidental series of unforeseen major blackouts affecting large metropolitan areas around the globe invite detailed analysis of widespread power outages. The probable causes and consequences of devastating blackouts during 2003 are identified in this thesis. This part can be found in Chapter 2.

- **Definitions of cascading failure and an overview of cascading failure analysis techniques.** A generic definition of a cascading failure is introduced and explained to facilitate the understanding of the underlying physical mechanisms governing cascading failure propagations in a power system. Building on the definitions and the overview, introductions to several well-known techniques related to cascading failure analysis are discussed based on their fundamental features. This part can be found in Chapter 2.
• **A proposed theoretical modeling basis prerequisite for cascading failure analysis.** Accurate modeling of integral power system components is essential for studying cascading failures. This thesis provides theoretical explanations in order to identify specific modeling needs for adequate representation of cascading failures in power system simulations. This part can be found in Chapter 2

• **Coordination of protection and control systems.** A method for coordinating protection system with controllable power in the DC link is determined by considering the protection system algorithm and control strategy simultaneously based on the calculation of the voltage stability index. This part can be found in Chapter 4

• **Controllable power transmission strategy.** Instead of a common AC line, a controllable power transmission in the DC link connected between different power systems has the ability to prevent the occurrence of cascading failure. From this, the modulated power control strategy is required. This part can be found in Chapter 5

• **A proposed method for voltage instability prediction.** The methodology is based on predicting voltage instability using a voltage stability index. The effective location of remedial action is determined by modal analysis techniques and the voltage stability index in order to mitigate voltage collapse. This part can be found in Chapter 6

• **Applications on test power systems.** Since the cascading failures are considered to be one of the prominent pathway for blackouts to affect sizable areas. This thesis aims to demonstrate the development mechanisms of cascading failures in power systems. Moreover, the proposed strategies are applied on test power systems where the results demonstrated that blackouts mitigation could be achieved. This part can be found in Chapter 5 and 6. The influence of the following factors on a power system stability are illustrated:

  – Voltage stability index to coordinate with selective load shedding.
  – Protection and control systems coordination.
1.6 List of Publications

The following articles were published during the project:


Chapter 2

Overview of Cascading Failures and methods

This chapter describes the mechanisms of cascading failure as the cause of severe blackouts. The severe blackouts that occurred in 2003 affecting large metropolitan areas around the globe are first reviewed. Then the probable root cause of each blackout event is identified in order to seek effective corrective preventive solutions. Several of the well-known techniques for cascading failure analysis and correction are discussed and characterized based on their fundamental features. Thereupon a new model power system component is proposed for simulating cascading failure in actual networks.

2.1 Historical overview of major blackouts in 2003

Power system security and vulnerability has been brought to political and public awareness from a series of significant system outages during 2003 in North America and Europe. These outages influence not only on power engineering but also in public communities. Some of the major cause and consequences of these significant blackout events in 2003 are summarized in the following sections.

2.1.1 North America Blackout - August 14

Based on the information available from the joint US-Canada task force final report [2], large portions in eight U.S. states and two Canadian provinces ex-
experienced an electric power blackout. The first major event started by loss of Eastlake unit 5 and several other generators in Northern Ohio which led to reactive power supply problems. Also, many 345 kV transmission lines were tripped due to tree contact in the area of Ohio and Michigan. Moreover, prior to the first event, the system software was inoperative, which gave operators inadequate situational awareness. This combination of events reversed power flow and, finally, heavily loaded the entire transmission system. The outage affected an area with estimated 50 million people and the 61,800 MW of interrupted electric load equated to approximately 11% of the total load served in the Eastern Interconnection of the North American system. During this event, over 400 transmission lines and 531 generating units at 261 power plants tripped. In the following morning, 16 hours later, 48,800 MW were restored, while the remainder of 16,000 MW experienced a longer recovery time than 16 hours. Power was not restored for 4 days in some parts of the United States, and parts of Ontario suffered rolling blackouts for more than a week before full power was restored [2], [21].

2.1.2 United Kingdom Blackout - August 28

The event commenced when alarm was raised from a power transformer or its associated shunt reactor that the first transformer had been taken out of service and the load was shifted to the second transformer. However, due to an incorrectly installed protection relay specified during the design process, the power shift tripped the second transformer. As a result, 724 MW of power amounting to around 20% of total London supplies was lost, which corresponded to approximately 476,000 customers including parts of underground and railway system. Birmingham experienced a similar blackout in just over a week later with 250 MW of lost load, which translates to 220,000 customers including international airport and national exhibition. Although both blackouts lasted only less than an hour, they dramatically affected the mass transportation system [22], [23].

2.1.3 Sweden and Denmark Blackout - September 23

A number of inter-connectors and power lines including four nuclear units were in scheduled maintenance before the first contingency happened. A 1250 MW nuclear power plant unit was removed from the grid. Although this was regarded as a manageable contingency, within 5 minutes, a double busbar fault occurred in a substation that disconnected four out of five 400 kV transmission lines. As a result, increasing flows on the other remaining lines in the system and low
voltage in Southern Sweden was interpreted by protection relays as a remote short circuit, and Southern Sweden and Eastern Denmark were completely disconnected from the Central grid after 90 seconds. The system is designed to have 15 minutes available to activate the standby reserve after the first critical component fails. The total load losses were approximately 4,700 MW in Sweden and 1,850 MW in Denmark. The restoration took about six hours to be completed [24].

2.1.4 Italy Blackout - September 28

The outages started between Italy and Switzerland with a flashover of a 380 kV transmission line onto a tree. An automatic and a subsequent manual reclosure were refused due to the large voltage phase angle across the breaker. Twenty minutes later, a second line tripped due to a contact with another tree. This initiated a cascade tripping of the remaining lines along the Italy-Switzerland border. Italy tried to import more power from France in order to compensate the loss of the Swiss power corridors, but lines became overloaded and tripped. A similar event happened to 220 kV and 380 kV line between Italy-Austria and Italy-Slovenia respectively. After the separation from the European system, Italy’s power deficit reached 6,400 MW, which initiated the synchronous disconnection. And as the frequency decayed to a certain level, generators tripped due to under-frequency instability. Thus, most of Italy suffered power loss as a result of the cumulative events beginning with a single transmission line. The restoration process lasted more than 18 hours before the supply with synchronization was completely effective [25], [26].

The causes and consequences of mentioned blackout events are summarized in Table 2.1.
Table 2.1: Major causes and consequences of blackout events in 2003

<table>
<thead>
<tr>
<th>When</th>
<th>Where</th>
<th>Causes</th>
<th>Consequences</th>
<th>Restoration Time</th>
<th>Effect&lt;sup&gt;a&lt;/sup&gt;</th>
<th>Instability Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aug 14th</td>
<td>North America</td>
<td>- Inadequate management and lack of situational awareness and Loss of several generators</td>
<td>Culmination of a blackout of several hundred lines and generation</td>
<td>16 hr</td>
<td>50 mil</td>
<td>Voltage</td>
</tr>
<tr>
<td>Aug 28th</td>
<td>UK</td>
<td>- Incorrect installation of a protective relay</td>
<td>Dramatic effect on local services and transportation system</td>
<td>&lt;1 hr</td>
<td>800,000</td>
<td>Hidden failure&lt;sup&gt;b&lt;/sup&gt;</td>
</tr>
<tr>
<td>Sep 23th</td>
<td>Sweden &amp; Denmark</td>
<td>- Loss of a generation unit - Busbar fault</td>
<td>Loss of power generation sources and lost of transmission paths</td>
<td>4 hr (swe)</td>
<td>1.6 mil (swe)</td>
<td>Voltage</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Flashover due to tree trips - Unsuccessful reclosure - Miscommunication between system operators</td>
<td>Separation from the UCTE grids</td>
<td>6 hr (den)</td>
<td>2.4 mil (den)</td>
<td></td>
</tr>
</tbody>
</table>

<sup>a</sup>The number of consumers affected

<sup>b</sup>With this type of failure, power system is operated to fulfill $N$ criterion instead of $N-1$ criterion.
2.2 Common causes of blackouts

The widespread power losses from the examples in 2003 addressed in the previous subsection reveal some similar patterns among such disturbances. Some common causes can be categorized and concluded from the system concept shown in Fig. 2.1. This concept is adopted for system handling in normal operation, this means that when there are multiple failures, for example several transmission lines trip at instantaneously, system will collapse eventually and some of possible problems in each unit are addressed as following:

![Figure 2.1: System handling concept](image)

**Measure Function:** Gathering information from power system.

**Possible problems**

- Insufficient monitoring system to alert operators of system component malfunctions.
- Malfunction of measuring and/or delivering information unit leads to faulty signal.

**Think Function:** Control room which analyze the obtained information from measuring unit and take decision.

**Possible problems**

- Inability of system operators to respond to impending disturbances or failure propagation.
- Lack of information for further analysis.

**Model Function:** Identification of the most appropriate response and the impact of potential measures.

**Possible problems**

- System identification model has not been adopted properly for analyze the system awareness.
- Inadequate measures during planning or operating period.
Control Function: Perform actions and/or send information to other grids.

Possible problems

- No automated countermeasures to prevent further overloading of the lines, arrest voltage decline or initiate automatic and pre-planned separation of the power system.
- Protection generates misoperation or unnecessary actions, resulting in heavy overloads on other lines, which may contribute to disturbance propagation.
- Insufficient voltage or reactive power support.

Even though blackouts could not be absolutely eliminated, blackout occurrences could be reduced by taking some reasonably cost-effective measures. The implementation of automated countermeasures with protection is proposed in Chapter 4. The aim is to prevent an imminent blackout or arrest its propagation that leads to undesired consequences.

2.3 Definition of Power system stability and Instability outcomes

After presenting an overview of some major blackout events in the previous section, it is worth noting the definition of power system stability and its outcomes. An attempt of this section is to clarify different types of stability in power system. An instability basis is also briefly explained for each type of stability problem.

2.3.1 Definition of stability

The definition of power system stability can be considered into three categories (i) Voltage, (ii) Rotor Angle and (iii) Frequency Stability. More details of each terms can be found as follow.

- Voltage stability is defined by the System Dynamic Performance Subcommittee of the IEEE [27] as being a system’s ability to maintain voltage under increased load admittance. The power would increase in conjunction with the increased load admittance; hence, both power and voltage are adjustable. Meanwhile in the CIGRÉ report 38.02.10 [28], the definition of voltage stability refers to the resiliency of a power system at a given operating state under disturbances for the voltage near loads to converge to the stable post-disturbance equilibrium values. In other words, the disturbed state is within the attraction region of the stable post-disturbance equilibrium.

- Rotor angle stability is defined in IEEE/ CIGRÉ joint task force on Stability Terms and Definition [29] refers to the ability of synchronous machines of an interconnected power system to remain in synchronism after being subjected to a disturbance. In other words, it is the ability to maintain
equilibrium torque and mechanical torque of each synchronous machine in the system.

- **Frequency stability** which is defined in the same report [29] as the ability of power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load.

### 2.3.2 Instability outcomes

- **Voltage instability** results in the form of dramatically rise or fall of voltage level of some busbars. The outcomes of the instability are, for instance loss of load in an area, tripping of transmission lines or other system components by their protection systems which may lead to cascading outages.

- **Rotor angle instability** results in the form of increasing angular swing of some generators which may lead to the loss of multi-machine synchronism due to lack of sufficient either damping torque in case of small disturbance or synchronizing torque in case of large disturbance.

- **Frequency instability** results in the form of sustained frequency swings which may lead to tripping of generators and/or loads. The possible outcome of the instability is the splitting of system into islands.

### 2.4 Definition of cascading failure

The removal of a critical system component initiates load redistribution to other components, which might become overloaded. Hence, the overall robustness of network is reduced, which leaves the system vulnerable or more susceptible to other failures. As a consequence, the system performance degradation due to critical system component removal might lead to a cascading failure. From this argument, cascading failures lead to blackouts due to theirs multiple processes and high number of possible interactions of undesirable events. However, cascading failures are not necessary precursors of blackouts due to a strong dependence on the scale of the lost loads. If the scale achieve an adequate size, then cascading failures would lead to blackouts.

### 2.5 Analysis techniques

A number of analysis techniques were developed to address and facilitate an understanding of the complexity of cascading failures relating to power systems blackouts. A plethora of deterministic approaches have been used to reproduce the features of the blackout. However, due to the stochastic nature of blackouts, exact location and timing predictions of blackouts must be handled through probabilistic modeling. The analysis reviewed in this thesis can be categorized into two groups: (i) an artificial system approach and (ii) a conventional reliability approach. Not all of these techniques are reviewed in depth in this thesis. Although there are several analysis techniques, some features of the common techniques are briefly described in the following subsections. The algorithms
and their proposes are summarized in Table 2.2 whereas the major deficiencies of each analysis techniques are briefly described in Table 2.3

2.5.1 Artificial system dynamics approach

OPA blackout model

One of the techniques to study complex dynamics of blackouts in power systems is ORNL-PSerc-Alaska (OPA) model [10]. In the OPA model, the cascading algorithm is modeled in terms of overload, and outages of the lines are determined by linear programing (LP) that enables the dispatch of a DC load flow [9]. The objective of LP is to minimize the amount of disconnected consumers. To start the cascade, the random line outages are triggered with the generation, and load is re-dispatched by using LP optimization while load shedding should be avoided by weighting the cost function. Lines are outaged with fixed probability according to the overload during the LP process. As the system self-organizes in response to the increased consumption, the OPA blackout model is capable of identifying this behavior and signaling for the network upgrade. There are two intrinsic time scales that characterize the responses in the OPA blackout model. Slow time scales, on the order of days to years, correspond to the incremental increase in maximum power flow due to transmission network upgrade triggered by the increasing demand. On the other hand, fast time scales, on the order of minutes to hours, relate to overloading of transmission lines, which might lead to cascades and blackouts. The model permits the study of blackout behaviors with a system at criticality, which is further elaborated in [30]. In simple terms, when the power demand is near the critical loading, the blackout risk increases significantly. In addition, the blackout mitigation efforts such as increasing the generator capacity margin or improving the transmission network, move the system away from criticality.

However, the blackout mitigation efforts do not guarantee a decrease in the number of blackouts compared to a similar scenario without any mitigation efforts. This ill-defined relationship between blackout mitigations and the number of blackouts stems from a strong non-linear coupling between the mitigation effects and the frequency of the occurrence as shown in [31]. Furthermore, this implies the difficulty of identifying effective mitigation measures that will guarantee improved performance of the power systems network.

CASCADE model

The CASCADE model [32] could be described by analogy to the domino effect; the failure of some components might, successively, trigger failures of a portion of remaining components. This process could propagate through the system; thus, the failures cascades through the system. The study of CASCADE model begins with a system consisting of a number of randomly loaded identical components. The parameters such as the initial load, load increase at each component as a result of a failure, and initial disturbance are represented in range of upper and lower bounds of component loading [11]. To start the cascade, each component is loaded by its initial load, and then an initial disturbance is ap-
plied as a model. This initial disturbance might cause some components to fail by exceeding their threshold limits. When the failed component is outaged, its load is redistributed and subsequent components are overloaded. With the system becoming overloaded the cascading process is likely to continue iteratively. The extent of the cascade depends on the initial component loadings [33]. The cascading process ends when none of the combination of initial load and transferred load of the remaining components is greater than the maximum stability limit.

Although the CASCADE model is too simple to reflect realistic aspects of power system, it provides an understanding of a cascading failure mechanism. The principal deficiencies are the disregard of the system structure, neglect of the time between adjacent failures, and generation adaptation during a failure. In other words, analysis of this model merely suggests general qualitative behaviors that may be present in power system cascading failures [34].

Hidden failure model

By definition, a hidden failure is defined to be a permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove circuit element(s) as a direct consequence of another switching event [35]. In other words, if one line trips, all the lines that share the same bus with that line are exposed to the incorrect tripping. To start the cascade, the transmission lines are randomly tripped and DC load flow computed. Then, the line flow constraints are checked for the violation. Next, the probability of incorrect tripping for all lines that connected to the last tripped line is evaluated. The LP load shedding is adopted to keep the system stable. However, the importance sampling method has been used to increase the frequency of rare events of hidden failure with altered probability.

Hidden failure models can be categorized into two types [36]: line protection hidden failure, and voltage-based hidden failure. Line protection hidden failure occurs if any line sharing a bus with a transmission line trips then hidden failures at that line are exposed. If one line trips correctly, then all the lines connected to its ends are exposed to the incorrect tripping [35]. On the other hand, the voltage-based hidden failure happens when the generator unnecessarily trips due to the misconduct of exciter by the incorrect response to the low voltage conditions. An addendum to the model includes the allowance of relays to malfunction with equal probabilities on all frequently exposed lines. Between the two types of hidden failure models, malfunctions tend to be categorized in the first type rather than the second.

The model has also been improved from its previous state when a line is exposed multiple times such that it allows relays to malfunction with equal probabilities on all the line exposures. Yet it would be more likely that malfunction occurs in the first exposure than the subsequent one [37]. The information obtained from the model can be used to determine the sensitive protection locations in the system. Thus, with information on sensitive locations, this model assists system upgrade plans.
2.5.2 Conventional reliability approach

FTA model

A fault tree analysis is a logic diagram that displays the interrelationships between a potential critical event (accident) in a system and its causes [38]. This model implements a logic tree approach by placing a potential critical event (accident) in a system as the highest (top) node or top event on the logic tree, and causes or basic events are placed as derived nodes. The fault tree analysis is a top-down method that aims to seek basic events or combinations of causes that would lead to the contingency. The problem and the boundary conditions include the physical state of the system, initial and external conditions (stresses) and the depth of resolution level of the potential failure causes. The causes are connected, level by level, via logic gates until all fault events converge to the top event. Therefore, the probability of the top event occurring is affected by the probability of the basic events.

The major advantage of the widely used FTA model is that non-specialists could easily grasp the logic provided that the system complexity can be decomposed into several parts. However, shortcomings include the absence of interaction between events, and the inadequate representation of repair models, such as the limited repair resources or logistic constraints [39].

Markov Analysis

Markov model describes a system using a set of mutually exclusive states and transitions between these states[40]. The system is represented by one state at a time, and the transition from one state to another state is made according to a certain probability distribution. The model implies the assumption of a system event process with no memory; the future states for the system are independent of all past states except the immediately preceding one [41]. The stochastic process of the system also needs to be stationary or time-homogeneous. Simply, the behavior of the system must be the same at all points of time. Hence, the basic characteristic of Markov modeling is that the probability of making a transition between two specific states is constant at all times in the model. Markov modeling can be applied to the random behavior of a system that varies discretely or continuously with respect to time. A Markov chain is usually used to denote discretized time while a Markovian process involves continuous time. The result of analysis can be evaluated by summing probabilities of all states that depicts the availability of the system. Very detailed analysis that entails the complete system description can be built in the Markov model, though the analysis is complex and laborious to be verified and constructed. In addition, the model size could become large, which increases the model's complexity as well as the possibility of neglecting certain components.

The aim of this project is to perform the simulation which take deterministic character of traditional dynamic simulation, for example the infrastructure of power system instead of considering it as artificial one, that the mentioned techniques have not included in their model. However, those methods provide
<table>
<thead>
<tr>
<th>Approach</th>
<th>Technique</th>
<th>Algorithm</th>
<th>Aim</th>
</tr>
</thead>
<tbody>
<tr>
<td>Artificial System</td>
<td>OPA</td>
<td>Using standard DC power flow with solving power dispatch using LP method</td>
<td>To determine the critical point of load demand [30] and to formu-</td>
</tr>
<tr>
<td></td>
<td></td>
<td>to satisfy restriction constrains.</td>
<td>lating the blackout mitigation effort [31].</td>
</tr>
<tr>
<td></td>
<td>CASCADE</td>
<td>Applying initial disturbance to identical components which randomly</td>
<td>To understand the propagation of failure [33].</td>
</tr>
<tr>
<td></td>
<td></td>
<td>loaded. The failed-component transfers fix amount of load to other</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>components by DC load flow checking an overloading to</td>
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</tr>
<tr>
<td>Hidden Failure</td>
<td></td>
<td>Line is randomly tripped with DC load flow checking an overloading to</td>
<td>To determine locations where protection is likely to be mal-</td>
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<td></td>
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<td>function.</td>
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<td></td>
<td>FTA</td>
<td>A top-down logic diagram displays that possible root causes and</td>
<td>To compute the probability of the interrelationships of potential</td>
</tr>
<tr>
<td></td>
<td></td>
<td>consequence of contingency</td>
<td>events that lead to the contingency.</td>
</tr>
<tr>
<td>Conventional Reliability</td>
<td>Markov Analysis</td>
<td>Stochastic process with the Markov properties which are memory less and</td>
<td>To determine probabilities for all system states represents the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>time-homogenous.</td>
<td>probability of dangerous failure.</td>
</tr>
</tbody>
</table>
Table 2.3: Major deficiencies of analysis techniques

<table>
<thead>
<tr>
<th>Techniques</th>
<th>Deficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPA</td>
<td>Small number of nodes in model compared with a real system and self-organization is not guaranteed in some cases.</td>
</tr>
<tr>
<td>CASCADE</td>
<td>Physical configuration of the network and the network internal interactions are neglected.</td>
</tr>
<tr>
<td>Hidden failure</td>
<td>Below the critical loading, the form of probability distribution of blackout size is not clear.</td>
</tr>
<tr>
<td>FTA</td>
<td>Requires different models to represent different events.</td>
</tr>
<tr>
<td>Markov Analysis</td>
<td>Analysis complexity increases as the size of the system increases.</td>
</tr>
</tbody>
</table>

valuable information for introducing stochastic model to some parameters, for example load modeling, hidden failure of protective relay, to make the simulation results compatible to the reality.

### 2.6 Modeling Needs for Cascading Failure Simulation

Widespread power system blackouts occur through a complicated sequence of cascading failures. They are generally triggered by random events ranging of multiple equipment tripping and protective relays that play a central role in the course of cascading events as shown in Fig. 2.2. For simplicity of the flow chart, frequency stability is omitted since this type of stability focus on the balance between generation and load as described in Section 2.3.1. This section provides a comprehensive practical treatment of the modeling that will identify the modeling needs for adequate representation of cascading failure in power system simulations.

The significant components required to be modeled before simulating cascading events are discussed as follows:

- **Generator control systems** must be modeled properly to portray the systems’ dynamical behavior accurately when subjected to disturbances. Typical generator control systems, such as the excitation system, consists of an exciter and voltage regulator of the type Automatic Voltage Regulator (AVR). Various types of additional components that can be modeled include prime mover, governor, power system stabilizer (PSS), rotor and stator current limiters, and under-excitation limiter. Furthermore, the control systems’ behavior must be considered in conjunction with other components in a system rather than separately due to possible non-linear feedbacks. The simulation results in [42] suggests that isolated operation
2.6. MODELING NEEDS FOR CASCADING FAILURE SIMULATION

![Diagram of components leading to cascading failure]

Figure 2.2: Flow chart of components leading to cascading failure

of generator control systems might be stable while they might exhibit mechanical oscillations when placed in a system. Moreover, generator can be modeled as stochastic system model by introducing inputs uncertainty. The generation uncertainty corresponds to both the output uncertainty due to the prime mover stochasticity and the loss of a generator due to a random failure as explained in [43].

- **Protective relays** are often classified according to the object that they protect. The requirements for protective relays must adhere to their functional purpose; hence, generalized modeling treatments for protective relays would not be appropriate, and must be addressed individually. For instance, distance relays are suitable for meshed systems due to their designed function being independent of their own reliabilities. Nonetheless, distance relays must react to proximal faults with defined time delays corresponding to defined zones. As an illustration, three zones are defined, with settings of 85%, 120%, and 150% in the impedance plane. When the apparent impedance, as seen from the line end towards the line, reaches the outer zone, the time delay starts. The time delay clock resets as soon as the impedance is outside that zone. For each of the zones, a certain time-limit is defined. If the impedance value is within a zone and the time expires, the line breaker will immediately open and the time limit normally includes the breaker time. In addition, to make stochastic model for protective relays, faulty coordination of relays and/or wrong operation zone setting can be introduced. Several ways to model relay stochastically
are explained in [44].

- **Load modeling** represents a mixture of various equipments. The load is affected by a number of factors such as voltage and frequency, dynamic properties, and spontaneous variations due to consumer actions. As a result of this multivariate dependence, the difficulty in constructing dynamic load models lies in contending with inadequate input data. Hence, the common load modeling is interpreted as an average load. In order to capture the effect of system loads on voltage stability, non-linear dynamic load model with the exponential power demand recovery is included. The non-linear load model has a voltage-dependent characteristic and behaves in the same manner as an automatic transformer tap changing functions that rectifies voltage levels. On occasions, this characteristic carries a negative impact due to its capability of developing the slow phase of voltage instability which could lead to a blackout. Details of this load type will be described in Chapter 4. Moreover, the universal behavior of load with high probability in generating cascading failure has been studied in [45]. The results indicate significant decrease in efficiency of system when buses with high number of connected links are tripped. This hypothesis has been confirmed by seeing that the cascading failures occur with the highest probability in heavy loaded regions with the smallest reserve margins[46].

- **Transformers** can be modeled by the impedance and the tap changer ratio. The transformer may be configured with a tap changer; a normal transformer is represented by a fixed step of the tap changer. For simplicity, the steps between the taps are assumed to be equal. The control unit operates in either manual mode or automatic voltage control mode. Regardless of the operation mode, the mechanical delay of the tap changer must be taken into account.

Some component models that can be added to make simulation results become more compatible to the real case

- **Sectioning of the busbars or Load shedding** can be modeled by considering frequency deviations. Load will be disconnected when the busbar frequency is below the threshold value for a certain time. Although only one frequency level can be defined for each load, a large load shedding scheme may be modeled. By defining several loads at each busbar, each busbar can have individual load shedding models. An example of automatic under-frequency load shedding of Sweden introduced by Nordic Grid Code [47] is addressed in Chapter 4. However, due to economic policy, load shedding has been considered as a last option.

- **Shunt capacitor and inductor** can be modeled as a separate object by connecting the shunt elements to separate busbars. Shunt elements are
modeled as shunt admittances where the control capability of elements could be toggled between either manual or automatic mode of operation.

- **Uncertainty in the systems** such as operator error, hidden failure (malfunction), or miscommunication can be curbed by setting a certain value of safety margin or applying noise in the signal detection as explained in [48].

- **Special Protection Schemes (SPS)** are designed to detect abnormal system conditions and take predetermined corrective action to preserve the system's integrity and provide acceptable system performance instead of isolating faulted elements [49]. This reinforces system protection and emergency control used to counteract power system instability. The schemes provide guidance on how protective measures can be used to avoid power system instability after unforeseen events. Such protective measures could be envisioned as activating relays to trip generators that increase power transfer limit between interconnected area when severe faults occur during stressed operational conditions.

An important caveat for modeling is that the $N-1$ criterion must be satisfied. The model will be unrealistic if tripping cascades occur when one of the critical components of the system is removed from service. In addition when setting up time-domain simulation, it is important to use the correct time steps for the simulation in order to observe the right phenomena in the results. For the RMS simulation the minimum time step should always be smaller than the time constants in the system. In controllers you have to consider not only the open-loop but also the closed-loop time constants. For electromagnetic transient e.g. when analyzing traveling waves, the smallest traveling time would set the upper limit for the minimum time step. For example, DIgSILENT PowerFactory simulation software [50] suggests the typical time steps 0.0001 sec and 0.01 sec for electromagnetic transients (EMT) and electromechanical transients (RMS), respectively.
Chapter 3

Overview of protective relaying

This chapter presents the fundamentals of protective relaying. The operating principle of any relay applications and some associated definitions that involve system protection are also introduced. This helps the readers to be familiar with technical terms which are shared in related subjects. Summaries of designs and principles of some common protective relays are given. The aim is to initiate background on the protection aspects and involvement of the various power system components.

3.1 Introduction

The IEEE defines protective relays as “relays whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action” [51]. Relays detect and locate faults by measuring electrical quantities of the system which are different during normal and intolerable conditions. Their task is to minimize the damage and expense caused by the insulation breakdowns which above overloads are called ‘faults’ by relay engineers. These faults could occur as a result from insulation deterioration or unforeseen events, for example, strokes of lightning or a trip due to a tree contact.

Relays are not required to operate during normal operation, but must be immediately activate to handle intolerable system conditions. This immediate availability criterion is necessary to avoid serious outages and damages to a partial or entire system network. Theoretically, a relay system should be capable of responding to an infinite number of abnormalities that may happen within the network. However, under actual operation, some compromise acceptances must be evaluated on the basis of comparative risks.

3.2 Definitions used in system protection

In this section, the conceptual terms and some associated practical definitions used in system protection engineering are defined. More specific descriptions of the following terms can be found in [52].
**Protective relaying** is the operation of protective devices, within a controlled strategy to maximize service continuity and minimize damage to property and personnel due to abnormal system behavior. The strategy's priority is not protecting the equipment from faults, since this is a design function, but rather to protect the normal system and environment from the effect of a system component which has failed.

**Reliability** of protective system is defined as the probability that the system will function correctly when required.

**Security** in protective systems is a term used to indicate the ability of a system or device to refrain from unnecessary operations.

**Selectivity** in protective systems describes the protective strategy's overall design wherein only those protective devices closest to a fault will operate to remove the faulted component.

**Sensitivity** in protective systems is the ability of the system to identify an abnormal condition that exceeds a nominal threshold value and initiates protective action when the sensed quantities exceed that threshold.

**Protection zones** are regions of primary sensitivity. Fig.3.1 shows an example of primary protection zones where the protected components are enclosed by dashed lines.

**Protection Zones**

![Protection Zones Diagram](image)

**Figure 3.1:** One line diagram showing primary protection zones

**Primary relays** are relays within a given protection zone that should operate under prescribed abnormalities within that zone.
3.3 OPERATING PRINCIPLE

Backup relays are relays that are situated outside their assigned primary protection zone, but are set to respond independently from primary relays to abnormalities within the primary protection zone.

Undesired tripping describes an unnecessary relay trip from a fault outside its defined protection zone or from an absence of fault. This usually occurs due to an overly defined protective system sensitivity.

Failure to trip is a protective system malfunction in which the protective system fails to take appropriate action when a condition exists for which action is required.

3.3 Operating principle

The objective of protection systems is to respond to faults and isolate faulted components. The five basic measurements of any relay applications are [53]:

- (i) Reliability: assurance of the protection performance
- (ii) Selectivity: minimum system disconnections
- (iii) Speed of operation: minimum fault duration and equipment damage
- (iv) Simplicity: minimum protective equipment and associated circuitry to achieve the protection objectives
- (v) Economics: maximizing protection for a given budget

Protection systems consist of several units used to evaluate the system condition by operating primarily on the comparisons between measured quantities and threshold quantities. A graphical demonstration of the protection systems’ operating function is depicted in Fig 3.2.

Figure 3.2: Functions of protection systems

According to Fig. 3.2, measured quantities are obtained through devices with current and/or voltage transformers. These instrument transformers provide insulation for the relays from the high power system voltages and reduce the magnitudes to practical secondary levels for the relays. The measured quantities, such as voltages and currents, are then compared to threshold quantities set within the comparison unit. If the comparison unit has indicated that certain thresholds are reached or exceeded, the decision unit is triggered to activate the action unit. The signal is released to a circuit breaker or another switching device to open and isolate a section of the system.
3.4 Types of Relay

In this section, the most common type of relays are grouped into three performance characteristic categories: overcurrent relays, differential relays, and distance relays.

3.4.1 Overcurrent relay

This type of relay is simple and cheap because the decision is made only by checking for the current magnitude \( I \). Most of the faults on power lines can be detected by applying overcurrent relays, since the fault current has a greater magnitude than the load current.

Radial circuits can be protected by nondirectional overcurrent relays, which can operate independently of the current’s direction. Since the circuit is radial, each section needs only one circuit breaker at the source end. Fig 3.3 shows a typical radial feeder. To clear faults at (1) and other faults to the right, only the breaker at Bus 3 needs to be activated. To clear faults in the area between (2) and (3), the breaker at Bus 2 must be activated.

![Figure 3.3: A typical radial feeder](image)

However, none of the relays at the breaker locations and in case of non-radial circuits can distinguish whether the remote fault is on the protected or adjacent line. In the relays’ frame of reference, a transmission line is a one-dimensional stack; hence, the distance to a fault along the line is indistinguishable to a relay. The relays’ selectivity can be improved by adding a delay mechanism or factor so that the operating time is inversely proportion to the current. This arrangement is designed to allow the relay to identify faulted location, disconnect, and clear the fault first before the others can trip. In other words, this means that close-in faults are tripped quickly but remote fault are tripped slowly.

3.4.2 Differential relay

The differential principle is to compare the inputs and outputs of current transformers (CTs) on the protected unit. In other words, the differential relay operates on the conservation of current through CTs. A non-zero divergence in the current flow will trigger a fault [51]. For example, one phase of a basic current-differential protection scheme is illustrated in Fig 3.4. Under normal conditions or external faults, the current entering the protected unit, \( I_{p1} \), would be equal to that leaving it, \( I_{p2} \), at every instant as shown in Fig 3.4a. The ideal current transformers would drive secondary currents \( (I_{p1} N_p/N_s \) and \( I_{p2} N_p/N_s \), pro-
portional to their primary currents. As a result, there is no current should flow in the relay under ideal conditions unless there is a fault in the protected unit.

![Diagram of basic principle of differential protection scheme](image)

(a) Normal conditions or an external fault

(b) Internal fault within protected zone

Figure 3.4: Basic principle of differential protection scheme

In the event of a fault on the protected unit, the input current would not be equal to the output current. Under such a condition, the input current would clearly be equal to the sum of the output and fault currents, \( I_f \), as shown in Fig 3.4b. The CTs would carry the difference current \( (I_f N_p / N_s) \) to activate the relay. A minimum threshold value for the difference current signaling circuit breaker operation is required to distinguish small imbalance in the CTs and communication fault in the zone [51].

Although differential protective schemes provide the possibilities of rapid fault clearance coupled with correct discrimination, they only protect the unit or zone between their current transformers, such as generators, transformers, and motor. In addition, this type of relays for line protection is impractical for transmission lines where the terminals and CTs are separated by a significant distance [53]. Moreover, differential relays are categorized as unit protective schemes since they do not provide a measure of back up to other parts of the network.
3.4.3 Distance relay

Due to the inappropriateness of differential relays for transmission lines, distance relays are used instead. These relays recognize faults occurring within the protected section of the line, from the fact that the distance from the relay to the fault is less than the setting of the relay [54].

Distance relays are designed to respond to current, voltage, and the phase angle between the current and voltage. The operation principle relies on the proportionality between the distance to the fault and the impedance seen by the relay. This is done by comparing a relay’s apparent impedance to its defined threshold value, $nZ_R$. Any line section in the power system can be represented as shown in Fig. 3.5, where relay current, $I_R$, and relay voltage, $V_R$ at an end of the lines determine the apparent relay impedance, $Z_R = V_R/I_R$. The apparent impedances are dependent on the location and nature of the fault. A number of distance relay characteristics plotted on the $R$-$X$ diagram are shown in Fig. 3.6a whereas Fig. 3.6b represents the mho relay which is inherently directional [52].

As an illustration in conjunction with the figure, suppose a fault arose, the voltage at relay will be lower or the current will be greater compared to the values for steady state load condition. The distance relays would be activated after $Z_R$ decreases to any value inside the parametric circle.

Like several engineering constructs, a backup is employed for redundancy. A minimum of two zones are necessary for primary protection of distance relays to address the faults at the far end of the protected line section near the adjacent bus. Such a criterion provides a safety factor to ensure that any operation against faults beyond the end of a line will not be triggered by measurement errors. Several protection zones can be built by using separate distance measuring units, which provided redundancy since both distance units will operate for faults occurring in Zone 1. The key difference between the two redundant units is in the time delay; the unit covering Zone 1 would operate instantaneously whereas the unit designated in Zone 2 would have an added time delay between fault signaling and operation. Also, by modifying either the restraint and/or operating...
3.4. TYPES OF RELAY

quantities, the relay operating circles can be shifted as shown in Fig. 3.6b.

In some applications, a further setting (Zone 3) is included, which is greater than Zone 2 setting. For a fault generated in Zone 1, Zone 3’s operation occurs after a longer time delay than that associated with the Zone 2. Therefore, the delay acts as a temporal tolerance for the protective schemes within the fault zone. The delayed operation will trigger if the tolerance is exceeded. Hence, this setting provides a form of back up protection.

Figure 3.6: Distance relay characteristics

Figure 3.7: Protection zones of distance relays

Figure 3.7 depicts protection zones of distance relays. Typically, Zone 1 is set in range of 85% to 95% of the positive-sequence of protected line impedance. Zone 2 is set to approximately 50% into the adjacent line, and 25% into the next two lines for Zone 3 [54]. The operation time for Zone 1 is instantaneous whereas Zone 2, and Zone 3 are labeled $T_2$ and $T_3$, respectively.
In this thesis, the mechanical and operational of overcurrent relay is explained in more details in Chapter 4. Moreover, this type of relay is used in the numerical studies in Chapter 5 to create cascading failure which can lead to system collapse, eventually.
Chapter 4

Control Strategy to coordinate Protection and Control Systems

This chapter consists of three main sections: blackout mitigation (Section 4.1), cascading failure modeling (Section 4.2), and coordination of protection and controllable systems (Section 4.3). The blackout mitigation section discusses some common countermeasures and devices for minimizing blackouts. The cascading failure modeling section addresses component modeling required in creating cascading failure in a power system. The coordination of protection and control systems section proposes a methodology to establish the communication between protection and controllable systems. The methodology is based on using the signal generated from a relay's logical evaluation with simplifications of certain parameters. From this derived signal, a corrective action is devised in order to reduce the risk of cascading failure.

4.1 Blackout mitigation

An ideal system devoid of blackouts remains highly desirable. The more reliable power systems are required to operate power system in the most economical manner due to the advent of deregulation and open access to the transmission grid. One way to solve this problem is to increase the capacity of the transmission network to improve the security of the system and reduce the probability of blackouts. Addition of the transmission network has the immediate effect to the reliability of the system, however in the long term, generating plants will be built in a way that makes full use of the transmission network. This means that power systems will again be operating near their security limits and the probability of a blackout will not have diminished. Certainly, a balance between an improved system security and the required increased capital investment must be fashioned through compromises. One way to tackle the argument between system security and economic interests is to utilize the improved controllers [55]. These emerging technologies would assist in significantly reducing the spread blackouts. Such technologies or schemes include the addition of controllable devices and load shedding.
CHAPTER 4. CONTROL STRATEGY TO COORDINATE PROTECTION AND CONTROL SYSTEMS

4.1.1 Controllable devices

Instead of installing new transmission lines to increase the capacity in order to address transmission congestions, controllable devices can directly control the power flow, which increases the overall power system utilization and alleviate the stress on the system. For this reason, the adoption of these devices have increased significantly. In this section, several controllable devices and theirs basic power control principles are briefly described.

HVDC family

Two basic converter technologies are used in High Voltage Direct Current (HVDC) transmission systems: conventional Line-Commutated Current Source Converter (LCC-HVDC) and Self-Commutated Voltage Source Converter (VSC-HVDC) [56]. The comparisons between the two HVDC converter technologies are presented in Table 4.1.

1. **LCC-HVDC**

   This conventional HVDC employs line-commutated with thyristor valves which is called Line Committed Converter (LCC) HVDC. Due to the thyristors, the current must discharge to zero in order to switch the valves off. The basic circuit is an AC transformer connected to a 6-pulse thyristor bridge. Typically, several thyristors are placed in series in order to reach the required high voltages. By using thyristors, a reverse power flow is achieved by changing the polarity of the voltage. Since thyristors require zero current to switch off, they require an external voltage source to modify current through a different value. Thus, it requires line commutated (50 Hz) to change the direction of power flow which is approximately 20 ms [56]. The converters at both the rectifier and the inverter consume high reactive power, typically 60% of the active power at full load [57]. As a result, reactive power is uncontrollable due to its relations with active power.

   At the rectifier side, the DC voltage can be expressed as [58]:

   \[
   U_{dc_r} = \frac{3\sqrt{2}}{\pi} U_{ac} \cos(\alpha) - \frac{3X_c}{\pi} I_{dc_r} 
   \]

   \[
   = U_{dc_0r} \cos(\alpha) - \frac{3X_c}{\pi} I_{dc_r} \tag{4.1}
   \]

   where \( U_{ac} \) is the AC bus voltage, \( U_{dc_r} \) is the DC bus voltage at the rectifier end, \( \alpha \) is rectifier firing angle, \( X_c \) is the commutation reactance, \( I_{dc} \) is current through HVDC link, and \( U_{dc_0r} \) is the rectifier voltage at zero firing angle. Likewise, a similar relation exists at the inverter side. In order to distinguish between rectifier and inverter side, the firing angle \( \beta \) is used for the advance angle at the inverter (\( \beta = \pi - \alpha \)), or the more common definition of the extinction angle at the inverter (\( \gamma = \beta - \mu \)). The angle, \( \mu \), describes the commutation or overlap angle [58]. Thus, the DC voltage at
4.1. BLACKOUT MITIGATION

**Figure 4.1:** LCC-HVDC Equivalent circuit [58]

The inverter side can be expressed as

\[
U_{dc_i} = \frac{3\sqrt{2}}{\pi} U_{ac} \cos(\gamma) - \frac{3X_{ci}}{\pi} I_{dc}
\]

\[
= U_{dco_i} \cos(\gamma) - \frac{3X_{ci}}{\pi} I_{dc}
\] (4.2)

The term \(3X_{ci} I_{dc}/\pi\) in Eq. 4.1 and \(3X_{ci} I_{dc}/\pi\) in Eq. 4.2, representing the commutation voltage drop across rectifier and inverter, can be omitted in order to emphasize the functional dependence on voltage amplitude and the phase angle. And according to the corresponding equivalent circuit of the LCC-HVDC link (Fig. 4.1), the DC current can be expressed as

\[
I_{dc} = \frac{U_{dco} \cos(\alpha) - U_{dco_i} \cos(\gamma)}{R_{cr} + R_L - R_{ci}}
\] (4.3)

where \(R_{cr}\) and \(R_{ci}\) represent the equivalent converter resistances for the rectifier and the inverter, \(R_L\) is the DC line resistance.

The power at the rectifier and inverter ends of the DC line could be expressed as

\[
P_{dc_r} = U_{dc_r} I_{dc}
\]

\[
P_{dc_i} = U_{dc_i} I_{dc} = P_{dc_r} - R_L I_{dc}^2
\] (4.4)

From equation 4.4, it can be concluded that \(P_{dc_r}\) can be controlled by controlling voltage amplitude at rectifier station, \(U_{dco}\), and phase angle, \(\alpha\). Meanwhile, the reactive power is the resulting of desired active power and can be determined by:

\[
Q_{dc_r} = -\sqrt{S_{dc_r}^2 - P_{dc_r}^2}
\] (4.5)

where \(S_{dc_r}\) is the complex power at rectifier and likewise to the inverter side.
CHAPTER 4. CONTROL STRATEGY TO COORDINATE PROTECTION AND CONTROL SYSTEMS

2. VSC-HVDC

The development of new self-commutated semiconductor switches for high power applications, especially the Insulated Gate Bipolar Transistor (IGBT), led to the emergence of voltage source converter based applications. Fig. 4.2 illustrates the basic VSC-HVDC interconnection. With high-frequency switching carried out by Pulse Width Modulation (PWM), Eq. 4.6 shows that both active and reactive power can be fully controlled by controlling voltage amplitude ($U_2$) and phase angle ($\delta$) of the VSC-HVDC terminal. Contrary to the LCC HVDC, the VSC HVDC DC voltage has a fixed polarity. The direction of the active power flow is determined by the direction of the DC current [59]. This implies that this type of HVDC is capable of controlling the direction of power can be changed instantaneously because IGBT forces commutation up to 2000 Hz (approximately 0.5ms) [56].

The active and reactive power can be controlled and expressed as

$$P = \frac{U_1 U_2}{X} \sin(\theta - \delta)$$
$$Q = \frac{U_2^2}{X} - \frac{U_1 U_2}{X} \cos(\theta - \delta)$$

(4.6)

where $\theta$ and $\delta$ are the phase angle at grid and VSC-HVDC terminal, respectively whereas $X$ is the reactance of the power transformer.

4.1.2 Load Shedding

Load shedding is an intentional electrical power outage executed to reduce the imbalance in regular operating conditions with the sole purpose of avoiding system collapse. Normal operating conditions are then restored prior to reinstituting the sacrificed load. This blackout mitigation method is normally considered to be the ultimate effort to avoid system collapse. Even though this mitigation technique is a low cost strategy of preventing widespread system collapse compared to several contingencies that might lead to voltage instabilities with possibilities of exacerbation, the uncertainty of a blackout and lack of foresight into a power outage pose more detrimental impacts on the power industry than the risk of some repercussions of voltage instabilities.

Typically, load shedding are categorized into two mains group, Automatic Load Shedding and Manual (Selective) Load Shedding. Typical load reduction amounts range on the order of 1000 MW to 2000 MW for automatic load.
4.1. BLACKOUT MITIGATION

Table 4.1: LCC-HVDC versus VSC-HVDC

<table>
<thead>
<tr>
<th>LCC-HVDC</th>
<th>VSC-HVDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Only P could be controlled, Q is derived</td>
<td>• Both P and Q can be controlled</td>
</tr>
<tr>
<td>• Require commutation channel</td>
<td>• No commutation channel</td>
</tr>
<tr>
<td>• High Harmonic contents, large filters</td>
<td>• Low Harmonic (high switching frequency)</td>
</tr>
<tr>
<td>required</td>
<td>• Direction of P can be changed instantaneously (≈0.5ms)</td>
</tr>
<tr>
<td>• Voltage polarity must be changed to</td>
<td>• Q can be produced or absorbed by</td>
</tr>
<tr>
<td>control direction of P (≈20ms)</td>
<td>converters</td>
</tr>
<tr>
<td>• High Q consumption for both rectifier and</td>
<td>• Low transmission capacity (50-1100 MW)</td>
</tr>
<tr>
<td>inverter converters</td>
<td></td>
</tr>
<tr>
<td>• High transmission capacity (6400 MW) [56]</td>
<td></td>
</tr>
</tbody>
</table>

Some approaches towards load shedding are documented; specifically, the various schemes of under-voltage load shedding (UVLS) are presented in [60], and under-frequency load shedding (UFLS) are addressed in [61]. An automatic scheme is deemed to be more effective to stabilize the interconnected systems and mitigate the effects of a system collapse than a manual intervention since system collapse can occur suddenly, and system operators might not have a sufficient amount of time to react. As examples of the automatic scheme, Puget Sound and Portland area [62] sets the automatic UVLS as shown in Table 4.2, and Nordic grid code [47] sets the automatic UFLS of Sweden as shown in Table 4.3.

Table 4.2: Automatic Under-voltage Load Shedding of Puget Sound and Portland area

<table>
<thead>
<tr>
<th>Bus volt. level of nominal load</th>
<th>Time delay [s]</th>
<th>Amount of load shedding</th>
</tr>
</thead>
<tbody>
<tr>
<td>≤ 90%</td>
<td>3.5</td>
<td>5% of load</td>
</tr>
<tr>
<td>≤ 92%</td>
<td>5.0</td>
<td>5% of additional load</td>
</tr>
<tr>
<td>≤ 92%</td>
<td>8.0</td>
<td>5% of additional load</td>
</tr>
</tbody>
</table>

The presented examples serve as a brief case study to illustrate the implementation of the load shedding principle; an absolute standard for automatic load shedding feasible for every system does not exist, and each system must be handled individually. The specific standards of each system depend on the system configurations, operational practices, the actual load responses, and control actions of other devices in the system.
### 4.2 System components modeling

In order to simulate a widespread cascading failure, several components modeling contributing to cascading propagation are explained here.

#### 4.2.1 Protection System modeling

In this thesis, the test power system is equipped with overcurrent relays, and the inverse-time characteristics of the overcurrent relays are defined as in the IEEE standard [63]. Hence, the pickup time of extremely inverse characteristic is expressed as

\[ t(I) = \frac{A}{M - B} + C \] (4.7)

where:

- \( t(I) \) is the trip time in seconds.
- \( M \) is the \( I/I_p \).
- \( I \) is the current in the relay.
- \( I_p \) is known as the pickup setting of relay.
- \( A, B, C \) are constants to provide selected time-current characteristic curve.

In order to introduce a logical evaluation for relay operation, Eq. (4.7) needs to be modified from the physics of the induction relay related to the various phenomena in an induction disk rotating towards the full travel position, which is expressed as

\[ K_i I^2 = m \frac{d^2\Theta}{dt^2} + K_d \frac{d\Theta}{dt} + \frac{\tau_f - \tau_s}{\Theta_{max}}\Theta + \tau_s \] (4.8)
where:

- $K_I$: A constant relating torque to current
- $K_d$: The drag magnet damping factor
- $I$: Input current
- $m$: The moment of inertia of the disk
- $\Theta$: The disk travel
- $\Theta_{\text{max}}$: The disk travel to contact closure
- $\tau_s$: The initial spring torque
- $\tau_F$: The spring torque at the maximum travel.

The resulting net disk torque can be expressed as

$$\tau_{\text{net}} = K_I I^2 - \tau_s$$ \hspace{1cm} (4.9)

where the current, $I$, can be represented in terms of $M$ multiplied by the pickup current $I_p$ ($I = MI_p$). Furthermore, the net torque on the disk is zero at $M = 1$, and the disk torque equation (Eq. 4.9) reduces to,

$$\tau_{\text{net}}(M=1) = K_I I_p^2 - \tau_s = 0$$ \hspace{1cm} (4.10)

Substituting Eq. (4.10) into Eq. (4.9), the net torque can then be expressed in terms of the spring torque,

$$(M^2 - 1)\tau_s$$ \hspace{1cm} (4.11)

By neglecting the moment of inertia of the disk and the extra spring torque due to $\Theta \neq 0$, Eq. (4.8) is then simplified and reformulated as

$$K_I I^2 - \tau_s = K_d \frac{d\Theta}{dt}$$ \hspace{1cm} (4.12)

Then, the integration of Eq. (4.12) yields

$$\Theta = \int_0^{T_0} \frac{\tau_s}{K_d}(M^2 - 1)dt$$ \hspace{1cm} (4.13)

The state variable of the relay, $x_r$, when then transmission line is tripped could be expressed as

$$x_r = \int_0^{T_0} \frac{\tau_s}{K_d\Theta}(M^2 - 1)dt = \int_0^{T_0} \frac{1}{t(I)}dt = 1$$ \hspace{1cm} (4.14)

where $K_d\Theta/\tau_s$ is replaced by constant $A$ in Eq. (4.7), $B = 1$, $p = 2$, $C$ is assumed to be very small, and $T_0$ represents the time required for the disk to complete one full rotation. Hence, the integration of Eq. (4.14) equals unity. This condition, $x_r = 1$, forces the relay logic orders circuit breaker to trip the transmission line.

According to the NERC transmission relay loadability standard [64], an overloading capacity must be included in the system in order to account for errors that might result in an over-tripping, such as voltage variation, transient overreach, or unspecified inaccuracies. In other words, transmission lines could be
overloaded within a certain range in order to prevent unnecessary relay operations. Thereby, from Eq. 4.14, the relay’s internal state variable can be determined with the conditions,

\[
x_r = \begin{cases} 
\int_0^{T_0} \frac{1}{t(I)} \, dt \quad ; |I| \geq 1.2I_p, \\
0 \quad ; |I| < 1.2I_p.
\end{cases}
\]  

(4.15)

### 4.2.2 Load modeling

Dynamic load models provide a more accurate description of the load behavior in realistic power systems than a static load. Hence, in order to describe the dynamic characteristic of the load, a non-linear dynamic load model with exponential recovery has been chosen. A differential equation which captures this behavior is expressed as [65]

\[
\frac{dx_p}{dt} = \frac{1}{T_{Lp}} \left( -x_p + P_s(V_L) - P_t(V_L) \right) 
\]  

(4.16a)

\[
P_L = x_p + P_t(V_L) 
\]  

(4.16b)

where \(x_p\) is an internal state modeling the active load recovery dynamics. The active load model is parameterized by the steady-state voltage dependency \(P_s(V) = P_0 V^{\alpha_{sp}}\), the transient voltage dependency \(P_t(V) = P_0 V^{\alpha_{tp}}\), and a recovery time constant \(T_{Lp}\). \(P_L\) represents the actual active power load while \(P_0\) is the sum of the rated power of the load connected.

The steady-state voltage dependence quantifies how much load has been restored after the recovery; a value equal to zero means a fully restored load, while a non-zero value indicates partly restored load. Furthermore, the parameter \(\alpha_{sp}\) of the steady state voltage dependency may attain negative values. Negative values force the power level in the load to overshoot the pre-disturbance value; the stationary level reached by the load after the recovery is greater than the prior value. Meanwhile, the transient load-voltage dependence denoted by \(\alpha_{tp}\) describes the load characteristic at the disturbance moment. The values of \(\alpha_{tp}\) denote certain characteristic of the load:

\[
\alpha_{tp} = \begin{cases} 
0, \quad \text{load = constant power,} \\
1, \quad \text{load = constant current,} \\
2, \quad \text{load = constant impedance.}
\end{cases}
\]

where the equation for reactive power load with parameter \(\alpha_{sq}\) and \(\alpha_{tq}\) follows the same form.
4.2.3 VSC-HVDC modeling

The VSC-HVDC modeling in this topic involves a similar principle to the injection model of VSC-HVDC described in [66], which states that the production or consumption of the active power is independent of the production or consumption of the reactive power. This means that VSC-HVDC link can be modeled as controllable AC voltage source as shown in Fig. 4.3. The injected active power can be calculated as follows,

\[ P_{si} = \frac{U_i E_i}{X_{eqi}} \sin(\theta_i - \delta_i) \] (4.17a)
\[ P_{sj} = \frac{U_j E_j}{X_{eqj}} \sin(\theta_j - \delta_j), \] (4.17b)

and the injected reactive power can be expressed as

\[ Q_{si} = \frac{U_i [U_i - E_i \cos(\theta_i - \delta_i)]}{X_{eqi}} \] (4.18a)
\[ Q_{sj} = \frac{U_j [U_j - E_j \cos(\theta_j - \delta_j)]}{X_{eqj}} \] (4.18b)

where \( P_{si} = -P_{sj} \). The voltage source can be controlled by manipulating the magnitude of \( E_i \) and the phase angle \( \delta_i \). This is done by explicitly expressing the dependences with

\[ \tilde{S}_{si} = P_{si} + jQ_{si} = \frac{U_i E_i}{X_{eqi}} \sin(\theta_i - \delta_i) + \frac{U_i [U_i - E_i \cos(\delta_i - \theta_i)]}{X_{eqi}}. \] (4.19)
Thus,
\[
P_{\text{si}}^2 + Q_{\text{si}}^2 = \frac{(U_i E_i)^2}{X_{eq_i}^2} \sin^2 (\theta_i - \delta_i) 
+ \frac{(U_i E_i)^2}{X_{eq_i}^2} \cos^2 (\theta_i - \delta_i) - \frac{2U_i^2 E_i}{X_{eq_i}^2} \cos (\theta_i - \delta_i) + \frac{U_i^4}{X_{eq_i}^2}
\]

\[= \frac{U_i^4 - 2U_i^2 E_i \cos (\theta_i - \delta_i) + (U_i E_i)^2}{X_{eq_i}^2}. \tag{4.20}\]

Rewrite Eq. 4.17a and 4.18a, the difference in the phase angles can be expressed as

\[
\sin (\theta_i - \delta_i) = \frac{P_{\text{si}} X_{eq_i}}{U_i E_i} \tag{4.21}
\]

\[
\cos (\theta_i - \delta_i) = \left( \frac{Q_{\text{si}}}{X_{eq_i}} \right) \frac{X_{eq_i}}{U_i E_i} \tag{4.22}
\]

Substitute Eq. 4.22 into 4.20, hence \(E_i\) can be computed as

\[
E_i = \frac{1}{U_i} \sqrt{\left( \frac{P_{\text{si}}^2 + Q_{\text{si}}^2}{X_{eq_i}^2} \right) X_{eq_i}^2 - U_i^4 + 2X_{eq_i} U_i^2 \left( \frac{Q_{\text{si}}}{X_{eq_i}} \right)} \tag{4.23}
\]

From Eq. 4.21, the phase angle \(\delta_i\) can be computed as

\[
\delta_i = \begin{cases} 
\theta_i - \arcsin \left( \frac{-P_{\text{si}} X_{eq_i}}{U_i E_i} \right) ; & \cos (\theta_i - \delta_i) > 0, \\
\theta_i - \left[ \pi - \arcsin \left( \frac{-P_{\text{si}} X_{eq_i}}{U_i E_i} \right) \right] ; & \cos (\theta_i - \delta_i) < 0.
\end{cases} \tag{4.24}
\]

where \(P_{\text{si}}\) and \(Q_{\text{si}}\) are determined as explained in Section 4.3

### 4.3 Coordination of protection and control systems

The goal of coordinated control of system protection and controllable devices is to avoid power systems approaching unstable state. Fig. 4.4 illustrates the transition between operational states of the system caused by a disturbance.

At point 1, the system operates under normal conditions. Following a disturbance, the system departs to state of emergency (point 2) outside the region defined by the satisfactory operating state. Operation of protection, control equipment or some actions from system operator moves the operating state within the satisfactory state (point 3). On the other hand without any mentioned responses, system goes toward the insecure state, eventually system collapse (point 5). The restoration of system reserves allows a return to a secure operating state (point 4). The duration of excursions outside the boundary defined by the satisfactory and secure operating states may vary from system to system. The coordinated control of this project focuses on the system that lie in the state of emergency.

As mentioned in Chapter 1, power systems are increasingly being operated close
4.3. COORDINATION OF PROTECTION AND CONTROL SYSTEMS

Secure Operation state
Satisfactory Operation state
State of Emergency
Unstable state

Figure 4.4: Transition of operation states in power system following a disturbance

to their limits, they are vulnerable when subjected to large disturbances. Consequently, they are approaching a potential catastrophic failure. Therefore, the automated devices which operate along with protection system are required to handle with small security margin of power system nowadays. Protection and controllable devices need to be coordinated to steer the system away from severity and to minimize the impact of disturbances. In order to have decent coordination, the concept of wide area disturbance protection is taken to the consideration. Wide area disturbance protection is a concept of using system-wide information and sending selected local information to a remote location to counteract propagation of the major disturbances in the power system [67].

Figure 4.5: Coordinated control algorithm for protection system and power flow controllers

Fig. 4.5 shows the utilization of monitoring and protection of wide area dis-
CHAPTER 4. CONTROL STRATEGY TO COORDINATE PROTECTION AND CONTROL SYSTEMS

44

This principle is adopted for coordinated control protection system and the controllable device during an emergency as follows: i) Monitoring Panel, ii) Decision-making unit, and iii) Correction unit. Generally speaking, every component in a power system is equipped with protective relays. The type of relays is differentiated upon its protected component, for example generator is equipped by out-of-step relay. This type of relay measures the current produced by generator and the bus voltage to determine its operational apparent resistance. If the instability develops, the rate of change of the measured resistance will be large. This provides an indication of impending angular instability. Hence, it implies that the state of power system is represented by several network parameters. These parameters, normally measured by relays, provide key information to detect an emergency. For instance, voltage magnitude, reactive power, and their rate-of-change are helpful for determining voltage instability. Angle between buses can provide valuable information for angular stability by comparing the difference in angles across the line. Frequency at each bus can be used to evaluate frequency stability since the frequency deviation from the nominal value is a result of power imbalance. Measuring current flows through transmission line can detect thermal instability which could lead to cascaded line tripping. Therefore, it can be concluded that the first step to determine the state of system is gathering power quantities measured by protective relays.

After obtaining the system parameters from monitoring panel, information of the entire system is analyzed at the Central Control Unit (CCU) to identify the state of power system whether it is in the emergency situation or not. The disturbance classification is determined and based on the constraints that are violated, severity and combination of violations, time scale of the phenomena, and utility control policy [49]. The identification of the place of a disturbance is also included at this stage. This means that the affected zone is detected. Moreover, a number of indicators such as low voltage level or high current flow are used as inputs to an algorithm for decision-making process and these indicators are used to derive the different criteria for each action. In general, there are several countermeasures, such as power re-dispatch or load-shedding, that are capable of employing corrective signal to deviate system from emergency to secure state; however this project utilizes corrective signal to control only the power flow controllers (PFC) which are FACTS and/or HVDC. Moreover, before sending out the signal to PFC, the best decision must be made in order to identify which PFC is suitable to be activated and which type of instability that system is confronting with. The selection of control action is based on power system conditions and recognized contingencies which are determined in the analysis stage. After control action has been applied, the system condition is improved but maybe only at satisfactory state. This is acceptable, since the initial implementation action stop further degradation of the system. Then, the more optimal action can be made when time allows. The choice of the actions is strongly related to the level of priority during emergency which the first priority is stopping the system degradation (stop the movement from point 2 to point 5 in Fig. 4.4) and return the system to a secure state (bring system state back to point 4, if possible). An intelligent coordination of the protection and power
flow controllers is a major challenge and a major requirement for any successful emergency procedure.

In this thesis, a coordinated control algorithm between the overcurrent relays and the injection model of VSC-HVSC is implemented in Chapter 5. This type of relay is normally used in distribution system which has less complexity in parameters setting compared to the one that equipped in transmission (meshed) system. The aim of this simple model implementation is to demonstrate the possibility of coordinating protection system with power flow controller in order to alleviate the voltage instability problem. Meanwhile, the coordination between more type of protective relays and multiple power flow controllers will be done in the continuation work.
Chapter 5

Numerical Examples

This chapter presents the quantitative analysis of cascading failures and shows the development of cascading failure in power system. Simulation results by coordinating the VSC-HVDC with protective systems demonstrate the prevention of cascading failure. Thus, blackout stemming from cascading failure can be avoided.

5.1 Coordinated control algorithm between overcurrent relays and VSC-HVSC

The coordinated control algorithm between overcurrent relays and the injection model of VSC-HVSC to improve voltage stability is shown in Fig. 5.1.

This algorithm provides the responding functions for the derived signal, $x_r$. The overcurrent relay installed on each transmission line generates the integrated value $x_r$ that is responsible for creating the activated signal to modulate injected power of voltage source. The current signal, $I$, is used in this control algorithm because operational logic of overcurrent relay is based on only the current variable. The derived value $x_r$ from each relay is sent to Central Control Unit (CCU) in order to determine the maximum value, $x_{max}$, among the connected transmission lines. Recalling that from Eq. 4.14, the relay triggers the breaker to trip the line if $x_r$ equals unity; hence, the value $x_{max}$ indicates the most susceptible line to be tripped which might initiate a cascading propagation as described in Section 2.4.
Once $x_{max}$ is determined at the CCU, it is then compared with the operating setpoint, $x_{ref}$. If $x_{max}$ is larger than $x_{ref}$, then the voltage source is activated. The modulation of active power ($P_{si}$) of the voltage source is determined by the PI-controller, which accepts $I_{p}$ and $I$ as inputs. The pickup current, $I_{p}$, has been set beforehand, and current magnitude, $I$, corresponds to the line which has the highest $x_{r}$. Meanwhile, the modulation of reactive power ($Q_{si}$) in this thesis is kept constant at zero. In next chapter, the case studies are shown that an adequate evaluation of the combined components should avert cascading failure.

5.2 Test Power System

The test power system used in these simulations is based on the Single-Load-Infinite-Bus (SLIB) system as shown in Fig. 5.2. The system is designed to fulfill the $N-1$ criterion in the Nordic Grid Code, which states that “$N-1$ criteria are a way of expressing a level of system security entailing that a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar, consumption etc.)” [47]. This system adequately represents the Swedish grid system with a generation area in the north and a consumption area in the south. The generation area is considered as a strong system represented by an infinite bus, and the load area is represented as an equivalent active and reactive model characterized by the non-linear dynamic load model with exponential full power demand recovery as explained in Section 4.2.2. The employed load model has voltage-dependent characteristics and operates similar to an automatic transformer tap changing functions that maintains voltage levels. Occasionally, the voltage-dependent characteristics have negative impacts on the power system due to the development of the slow voltage instability, which might lead to blackout events such as the Swedish system collapse in 1983 [68]. All simulations are performed with PowerFactory [50] and the results are plotted in MATLAB.

The impedance of each transmission line is tabulated in Table 5.1. The voltage level at the high-voltage side (Bus 1) and the low-voltage side (Bus 2) are equal to 400 kV and 220 kV respectively.

<table>
<thead>
<tr>
<th>Line</th>
<th>Length [km]</th>
<th>$R + jX$ [Ω]</th>
<th>$B$ [μS]</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>100</td>
<td>8.0+j80.00</td>
<td>14.0</td>
</tr>
<tr>
<td>L2</td>
<td>120</td>
<td>9.6+j96.00</td>
<td>16.8</td>
</tr>
<tr>
<td>L3</td>
<td>180</td>
<td>14.4+j144.00</td>
<td>25.2</td>
</tr>
<tr>
<td>L4</td>
<td>230</td>
<td>18.4+j184.00</td>
<td>32.2</td>
</tr>
<tr>
<td>L5</td>
<td>100</td>
<td>8.0+j80.00</td>
<td>14.0</td>
</tr>
</tbody>
</table>
The parameters of non-linear dynamic load described in Section 4.3 are defined in the following table.

<table>
<thead>
<tr>
<th>Active load parameters</th>
<th>Reactive load parameters</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_0$ = 160</td>
<td>$Q_0$ = 50</td>
<td>MW</td>
</tr>
<tr>
<td>$T_{Lp}$ = 20</td>
<td>$T_{Lq}$ = 20</td>
<td>sec</td>
</tr>
<tr>
<td>$\alpha_{sp}$ = 0</td>
<td>$\alpha_{tp}$ = 2</td>
<td>–</td>
</tr>
<tr>
<td>$\alpha_{sq}$ = 0</td>
<td>$\alpha_{tq}$ = 2</td>
<td>–</td>
</tr>
</tbody>
</table>

The PI-controller in coordination control as shown in Fig. 5.1 is defined as

$$PI = K_p + \frac{K_i}{sT_i}$$  \hspace{1cm} (5.1)

where the proportional gain is defined as $K_p = 4$, the integrator gain is taken to be $K_i = 3.5$, and the integrator time delay is $T_i = 1$ sec. The filter time constant in the figure is taken to be $T_p = 1$ sec.

The capacity of VSC-HVDC is based on restricted operation area explained in [69] without the dc cable and dc voltage limitation; $S^2 = P^2 + Q^2$ while all VSC-HVDC losses are also neglected. Meanwhile, predetermined parameters for relays represented in Eq. 4.7 are selected from the standard time-current characteristics in [63] as shown in the Table 5.3.
Table 5.3: Relay parameters

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>p</th>
</tr>
</thead>
<tbody>
<tr>
<td>Very inverse</td>
<td>19.61</td>
<td>1</td>
<td>0.491</td>
<td>2</td>
</tr>
</tbody>
</table>

5.3 Case Studies

The simulations are distinguished based on the number of tripped lines. Only the active power is controlled.

5.3.1 One line tripped

In this case, the transmission line L1 is tripped at time $t = 1$ s.

As shown in Fig. 5.3, the voltage at load bus drops from 0.9606 p.u. to 0.9566 p.u. However, with the non-linear dynamic load modeling, the active power load increases to its nominal value regardless of the voltage drop at the load bus.
5.3. CASE STUDIES

5.3.2 Two lines tripped - without coordination

This simulation case continues from the One line tripped case where L1 is tripped at \( t = 1 \) s, and the second line L5 is tripped at \( t = 4 \) s. Without the injected power from the VSC-HVDC injection model, the combined redistributed current increased through line L2 until it tripped at \( t = 13.881 \) s. Consequently, line L3 and L4 tripped at \( t = 19.026 \) s and \( t = 19.979 \) s. (see Fig. 5.6) respectively. The control algorithm used to trip the lines employs the internal state variable of each relay, namely \( x_r \). If any of the \( x_r = 1 \), then the relay sends the signal to the breaker in order to trip the line (see Fig. 5.7). The continuous current redistribution and tripping illustrates how cascading failure propagates through transmission lines. Although the simulation was done for 20 s, Fig. 5.5 shows the voltage at load bus and active power load at 0.01 ms before system collapse to emphasize the voltage reduction.

Meanwhile, Fig. 5.7 shows the maximum relay state variable, \( x_{max} \), that can be used to indicate which line is most likely to be tripped. The left-most peak (\( x_{max} \) reaches one) represents the time when line L4 is tripped, the middle peak represents the time when line L3 is tripped and finally, the right-most peak represents the time when line L4 is tripped. This variable is beneficial for coordinating protection system and VSC-HVDC as explained in section 4.3.
Figure 5.5: Load bus voltage (top) and Load response (bottom) - without control

Figure 5.6: Line current profile after L1 and L5 tripped - without control
5.3. CASE STUDIES

5.3.3 Two lines tripped - with coordination

In this section, the injection model of VSC-HVDC is operated at $x_{ref} = 0.5$ as explained in Section 4.3 with three different methods of power injection.

Case 1: Infinite Capacity In this case, the capacity of VSC-HVDC is infinite.

Case 2: Limited Capacity In this case, the capacity of VSC-HVDC is finite and approximately equal to one-third of the active power load which is equal to 45 MVA.

Case 3: Minimum Injected Power In this case, the VSC-HVDC is controlled to inject the required minimum power to prevent cascading mechanism.

Fig. 5.8 compares of $x_{max}$ between the systems with and without the control of HVDC. With the injection power, the current passing through each line decreases as shown in Fig. 5.9.

Fig. 5.10 shows the injected power of different cases, Fig. 5.11 shows the current in line 2 for all cases and Fig. 5.12 illustrates voltage and active power at load bus. All case are successful in preventing the cascading mechanism. For Case 1, the increased current is restored to the pickup current level of relay ($I_p$), by the use of PI-controller as explained in Section 4.3, without limitations on the injected power. This means that the active and reactive power are not limited based on the MVA-circle ($S^2 = P^2 + Q^2$). For Case 2, although the current would not be able to return to the pickup current level ($I_p$) due to exhaustion of the limited power, it would decrease below the overloading capacity; $|I| < 1.2I_p$ as in Eq. 4.15. This provides a range of power injection for current restoration. Meanwhile, for Case 3, the minimum power necessary to keep the derived maximum
value among the transmission lines ($x_{max}$) needs to be less than one at all time. In other words, a constant power is injected when $x_{max}$ returns to zero. The PI-controller which was used to evaluate the amount of injected power by using the difference between pickup current ($I_p$) and line current is neglected compared to the previous two cases. In other words, the injected power is optimized to prevent line tripping propagation.
Figure 5.10: Injected Active power of three cases

Figure 5.11: Current in Line L2 of three cases
5.3.4 Three lines tripped - effect of selected $x_{\text{ref}}$

This simulation case is an extension of the Two lines tripped Case 3 where the third-line L3 is tripped at three different scenarios, which are:

Case 1: After the completion of required injected power with $x_{\text{ref}} = 0.5$

In this case, L3 is tripped at $t = 16.5$ s which is 3 s after the injected power reaches its minimum required level for preventing cascading failure. That is, the line trips after $x_{\text{max}}$ returns to zero. Subsequently, $x_{\text{max}}$ would increase, which requires more power injection. Fig. 5.13 shows the minimum required power reaches, $P = 89$ MW. This means that in order to secure the system, the rating of VSC-HVDC has to be expanded at least to 89 MVA. The middle peak in $x_{\text{max}}$ plot start to rise when line L3 is tripped. At the meantime, more active power is injected to avoid tripping of further line. Fortunately, this middle peak stops increasing at $x_{\text{max}}$ equals to 0.99 before returning to zero. The right-most peak occurs because of the recovery active power load. By this load increment, the current in lines is increased until it is higher than the overload capacity, consequently this leads to the raising of $x_{\text{max}}$. When $x_{\text{max}}$ reaches 0.5, the injected power increases from 85 MW to 89 MW and the increase of power makes $x_{\text{max}}$ return to zero again. Fig. 5.14 shows the current in the remaining lines (L2 and L4).
Figure 5.13: $x_{max}$ (top), Injected power (middle) and Load response (bottom)

Figure 5.14: Case 1: Line current profile
Case 2: Before the completion of required injected power with $x_{ref} = 0.5$

Unlike the previous case, L3 is tripped at $t = 10.5$ s which is 3 s before the injected power reaches its minimum required level for preventing cascading failure. In other words, the third line is tripped while the variable $x_{\text{max}}$ is still increasing. Fig. 5.15 shows that at $t = 10.5$ s, the slope of $x_{\text{max}}$ becomes steeper. This means that the line will be tripped sooner compared to the previous case. On the other hand, the VSC-HVDC injects active power in accordance with the change of $x_{\text{max}}$. Unfortunately, the line L2 is tripped before the power reaches to the new minimum required value. Consequently, all the lines are tripped as shown in Fig. 5.16.

Figure 5.15: Case 2: $x_{\text{max}}$ (top), Injected power (middle) and Load response (bottom)
5.3. CASE STUDIES

Case 3: Before the completion of required injected power with $x_{ref} = 0.15$

In this case, the activated level for power injection is lowered from 0.5 to 0.15. With 2 lines tripped and the new level of $x_{ref}$, the injected power reaches the minimum required level at $t = 10.5$ s. Thus the line L3 is tripped at $t = 7.5$ s which is 3 s before the injection is completed. Fig. 5.17 shows that the VSC-HVDC is activated sooner compared to the previous case, which results in the high injected power of VSC-HVDC. The middle and the right-most peak of $x_{max}$ plot occur because of active power load recovery as explained in Case 1.

For this section, it can be concluded that in order to prevent cascading failure, it requires $i)$ the capacity of HVDC has to be large enough to compensate the disappearance of delivered power because of line tripping. $ii)$ the value of $x_{ref}$ has to be set low enough to allow time for VSC-HVDC to inject minimum required power.

Figure 5.16: Case 2: Line current profile
5.3.5 Three lines tripped - Models comparison

In this section, the injection model of VSC-HVDC is compared with the built-in model from PowerFactory. The simulation case is performed according to Case 3 in section 5.3.4. The active power set point in the built-in model uses the same control block diagram as in Fig. 5.1 where the No-load losses, the Copper losses, and the Short circuit impedance in the built-in model are neglected. Fig. 5.19 shows that both models are activated at the same time however, the built-in model injects power in the higher level. As shown in the plot of $x_{max}$, the left-most peak of the built-in model reaches 0.6 whereas the injection model reaches approximately 0.9. This implies that the built-in model can be activated later in order to prevent cascading failure, compared with the injection model. The active power load response and the current in line L2 are similar and voltage at load bus is coincide which is dropped approximately from 0.96 to 0.94 (see Fig. 5.18). Therefore it can be concluded that the injection model is applicable for preventing cascading failure.
Figure 5.18: L2 current (top) and Load bus voltage (bottom)

Figure 5.19: $x_{max}$ (top), Injected power (middle) and Load response (bottom)
5.3.6 Three lines tripped - PQ versus PV control

The simulation as in the previous section is performed only on the VSC-HVDC built-in model. However, the control mode of VSC-HVDC is changed from PQ control (where Q equals to zero) to PV control. This means that the voltage at the bus where VSC-HVDC is connected should be kept at the same level as pre-disturbance condition (see Fig. 5.21). Meanwhile, Fig. 5.20 shows that with PV mode, the injected active power reduce from 89 MW to 62 MW and the voltage level is compensated by the injected reactive power, Q, that is changed from zero to 48 MVAR. By this active and reactive quantities of PV mode, the rating of VSC-HVDC, that is required to avoid system collapse, decreases from 89 MVA to approximately 79 MVA.

![Figure 5.20: Injected Power - PQ mode versus PV mode](image)

In this case study, it can be concluded that both control mode can be used to prevent the system from cascading failure. The mode of selection depends on the rating of VSC-HVDC and also the voltage level at the load bus. If the voltage drop is lower than acceptable level of the system, PV mode is more likely to be chosen. In addition, the test power system in this thesis contains only a single load. In case of system with multiple load buses, the location of VSC-HVDC installation must be determined in advanced. Therefore, a methodology based on voltage instability prediction in Chapter 6 is suggested to ascertain the optimal placement of VSC-HVDC.
Figure 5.21: Voltage at Bus 1 - PQ mode versus PV mode
Chapter 6

Voltage instability prediction
based VSC-HVDC location

This chapter proposes a methodology to select the location of VSC-HVDC based on predicting voltage instability by using voltage stability indices. The aim of the analysis is to identify the vulnerable location for instability and apply proper corrective actions such as load shedding or optimal placement of controllable device.

6.1 Voltage stability indices

Voltage stability indices are invaluable tools for gauging the proximity of a given operating point to voltage instability. Each voltage stability index reveals specific information about how close a particular point is to the steady state voltage stability margin. Among the stability indices, the minimum singular value is of particular interest since it determines the system's stability. In order to derive the desired indices within this framework, online dynamic voltage stability assessment requires fast voltage stability indices, which can be synthesized by Singular Value Decomposition of the system's Jacobian as shown in publications such as in [70] and [71]. A brief description of their main properties will be given in this section.

The minimum singular value is calculated beginning with the Newton-Raphson root-finding method [58] to obtain the unknown nodal voltages and angles. In order to properly employ this technique, the known active and reactive power are linearized and expressed in a system of equations as

\[
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix} =
\begin{bmatrix}
P_\theta & P_U \\
Q_\theta & Q_U
\end{bmatrix}
\begin{bmatrix}
\Delta \theta \\
\Delta U
\end{bmatrix}
\] (6.1)

where \( P_\theta, P_U, Q_\theta \) and \( Q_U \) are matrices where their elements are partial derivatives of active power, \( P \), and reactive power, \( Q \), with respect to the nodal voltage angles, \( \theta \) and nodal voltages \( U \). Hence, the power flow Jacobian can be written as

\[
J(\theta, U) = \begin{bmatrix}
P_\theta & P_U \\
Q_\theta & Q_U
\end{bmatrix} = \begin{bmatrix}
\frac{\partial f_p(\theta, U)}{\partial \theta} & \frac{\partial f_p(\theta, U)}{\partial U} \\
\frac{\partial f_q(\theta, U)}{\partial \theta} & \frac{\partial f_q(\theta, U)}{\partial U}
\end{bmatrix}.
\] (6.2)
Furthermore, from Eq. (6.1), the Jacobian matrix can be modified by assuming $\Delta P$ equals to zero. Although the system voltage stability is affected by both active and reactive power, only the relation between the small-signal reactive power and voltage magnitude is desired, $\Delta P = 0$. This assumption is validated in [72]. Thus, the Reduced Jacobian, $J_R$, can be written as

$$
\Delta Q = [QU - Q_\theta P^{-1}_\theta P_U] \Delta U \overset{def}{=} J_R \Delta U.
$$

Following the method of singular value decomposition given in [70], the Jacobian or the Reduced Jacobian matrix can be decomposed into its singular value equivalents,

$$
J(\theta, U) = U \Sigma V^T
$$

where $U$ and $V$ designate unitary matrices of the eigenvectors of $JJ^T$ and $J^TJ$ respectively. Meanwhile, $\Sigma$ is a diagonal matrix given as

$$
\Sigma(\theta) = \text{diag}[\sigma_i(\theta)] \quad ; i = 1, 2, \ldots, n.
$$

where $\sigma_i \geq 0$ for all $i$. The diagonal elements of $\Sigma$ are ordered non-increasing whereas the non-diagonal entries are zero. In addition, singular values are the positive square roots of eigenvalues of $J^TJ$ (or $JJ^T$) that can be expressed as

$$
\sigma_i(\theta) = \sqrt{\lambda_i(J^T J)}.
$$

Thus, this shows that singular values have similar properties to eigenvalues, with the difference that the singular values are represented only by real numbers. According to the decomposition value, the effect on the $[\theta^T, U^T]^T$ vector for a small change in $P$ and $Q$ can be computed as

$$
\begin{bmatrix} \Delta \theta \\ \Delta U \end{bmatrix} = \Sigma^{-1} U \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}.
$$

Using Eq. (6.4), (6.5), and the similarity property to eigenvalues,

$$
\Sigma^{-1} U = \sum_{i=1}^n \sigma_i^{-1} v_i u_i^T
$$

where the column vectors of $V$, denoted by $v_i$, are called right or input singular vectors, and the column vectors of $U$, denoted by $u_i$, are called left or output singular vectors.

The inverse of the singular value of $\sigma_i$ can be interpreted as the incremental change in the state variables if $\sigma_i$ is considered to be adequately small. The smallest value of $\sigma_i$ that could be attained is called the minimum singular value ($\sigma_n$), which is used as an indicator of the proximity to the steady-state stability limit. In other words, if $\sigma_n$ becomes zero, the Jacobian matrix becomes singular, which implies a divergent power flow solution corresponding to an unstable system.
Even though the stability of the system could be determined by \( \sigma_n \), the location of the most vulnerable bus needs to be established through the participation vector. Denote that the maximum change in state variables occurs at \( \sigma_n \), the participation vector could be derived from the corresponding singular vectors. Moreover, from Eq. (6.7) and Eq. (6.8), the variables could be mapped as

\[
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix} = u_n
\]

(6.9)

where \( u_n \) represents the last column of matrix \( U \). Likewise,

\[
\begin{bmatrix}
\Delta \theta \\
\Delta U
\end{bmatrix} = \sigma_n^{-1} v_n
\]

(6.10)

where \( v_n \) represents the last column of \( V \).

In physical terms, the minimum singular value (\( \sigma_n \)) with its corresponding left (\( u_n \)) and right (\( v_n \)) singular vectors are interpreted as [73]:

- \( \sigma_n \): Indicator of the proximity to steady-state stability limit,
- \( v_n \): Sensitive voltages (and angles),
- \( u_n \): The most sensitive direction for changes of active and reactive power injections.

Furthermore, the technique of modal analysis found in [74] is adapted to find the participation factor. This factor is obtained from the multiplication of right and left corresponding eigenvectors that have been applied to the singular vectors. In this thesis, to avoid confusion, this bus participation factor is called participation vector and is defined as

\[
P_n = u_n \cdot v_n
\]

(6.11)

The physical interpretation of the participation vector is that the largest magnitude represents the highest sensitivity to voltage magnitude and direction for reactive power injection. This means that the load bus with elevated sensitivity contributes the most to voltage instability. Therefore, remedial measures would be most effectively implemented at the particular location of highest sensitivity. The application of the proposed indices have been validated through the Swedish system where the system’s physical structure will be briefly described in Section 6.2.

### 6.2 Application of voltage instability indices

Voltage instability indices have been applied on a test system called Nordic 32 system, which was proposed by CIGRÉ Task Force 38.02.08[75]. The single-line diagram of Nordic 32 system is depicted in Fig. 6.1.
The Nordic 32 test system consists of four major regions: North, Central, External, and Southwest. The voltage levels in the system are 400, 130 and 220 kV. There are 23 generators and 32 high voltage buses in the system; nineteen of them are 400 kV buses, eleven are 130 kV buses, and two are 220 kV. The generating units in the system are located throughout the area, but more concentrated in North. The generation and load in the system are distributed such that the power flows from North to Central while Southwest is weakly connected to the system.

The voltage stability indices introduced earlier have been applied to capture the slow voltage instability. In order to use the voltage stability indices, a scenario is created such that voltage magnitudes drop from their nominal values as reactive power consumption rises. This type of scenario is crucial for voltage stability problems as addressed in [71] so that voltage stability problems will dominate over angle stability problems under increased loading. Such a scenario can be simulated by modeling the load increment as typical constant reactive power
models and assumed to change according to

\[ Q_L = Q_{Lo} (1 + \alpha) \]  \hspace{1cm} (6.12)

where \( Q_{Lo} \) is the initial base reactive power levels of all nodal load whereas \( \alpha \) is the varying parameter representing the loading factor and step increment of \( \alpha \) is 0.005 p.u.

Once voltage instability has been established in the Nordic 32 test system, the calculation of Jacobian and Reduced Jacobian matrices are introduced as mentioned in Section 6.1. Fig. 6.2 shows minimum singular value of \( J \) and \( J_R \) against the reactive power consumption where \( \Delta Q \) is the reactive load increment. Noticeably in Fig. 6.2, the magnitude of the minimum singular value decreases for both \( \sigma_n(J) \) and \( \sigma_n(J_R) \) as loading increases. According to the figure, the \( \sigma_n(J_R) \) stability index depicts a more drastic change per load factor \( (\alpha) \) increment compared to \( \sigma_n(J) \). A larger change implies that \( J_R \) is capable of providing a distinguishable *early warning* before the system confronts voltage instability. Moreover, the determination of \( \sigma_n(J_R) \) is computationally efficient since a simple inverse iteration technique is readily applied to \( J_R \). As confirmed in [76], this value could be attained in a few iterations. Though the absolute values of \( \sigma_n(J) \) and \( \sigma_n(J_R) \) are not beneficial, the distinctive functional dependence of the minimum singular value on the load factor is the most significant.

If it is supposed that \( \sigma_n(J_R) \) measures the voltage stability limit according to Fig. 6.2, the system security margin, \( \epsilon \), must be set differently on different networks. The security margin acts as a precaution threshold demanding response before voltage instability. This ensures system operation at a reasonably high
level of reliability. The corrective action is applied to aid the system if the safety margin is violated. This margin is often determined through trial and error by running simulations of selected contingencies [77]. A more effective method for extracting voltage security can be found in [78]. More generally, the set value for the security margin is always questionable for system operators. Specifically, for this application study, $\epsilon$ is set to be equal to 10% of $\sigma_n(J_R)$ at the steady state condition.

During most voltage instabilities, several corrective actions are employed to prevent voltage reduction such as adding massive reactive compensation or shedding of a certain amount of load. And though load shedding offers a more favorable balance between cost and reliability [79], selecting the bus for load shedding requires more than the information provided by $\sigma_n$. Hence, the participation vector is also a necessary quantity to indicate the vulnerable bus. Therefore, some schemes are proposed in this section to elucidate the criteria for load shedding.

Table 6.1: Some bus data of Nordic 32 system

<table>
<thead>
<tr>
<th>Bus</th>
<th>$P_{\text{Load}}$ (MW)</th>
<th>$Q_{\text{Load}}$ (MVAR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>43</td>
<td>900</td>
<td>238.83</td>
</tr>
<tr>
<td>51</td>
<td>800</td>
<td>253.22</td>
</tr>
<tr>
<td>63</td>
<td>590</td>
<td>256.19</td>
</tr>
<tr>
<td>1044</td>
<td>800</td>
<td>300.00</td>
</tr>
<tr>
<td>1045</td>
<td>700</td>
<td>250.00</td>
</tr>
</tbody>
</table>

**Scheme 1: Shedding top 5 largest reactive load bus.**

This scheme begins with a specified cutoff iteration before load shedding. If nearly three hundred iterations of load increment, $\sigma_n(J_R)$ is less than the $\epsilon$ setting, then the load shedding scheme is applied to the system. Next, the five largest reactive loads are forfeited. The resulting minimum singular value of the system is shown in Fig 6.3 where $k$ represent the number of iteration.

According to Fig 6.3, shedding the five largest loads does not increase the time before $\Delta \sigma_n(J_R)$ declines to zero. The brief spike after this load shedding scheme has been implemented does not provide sufficient time for the system operator to provide proper corrective actions. In other words, the power flow still becomes divergent, and the system will become unstable near the minimum singular value as seen from the difference between the moment this load shedding scheme is applied and the point of voltage instability.

**Scheme 2: Shedding the largest magnitude of $P_n$ load.**

As described in Section 6.1, $v_n$ and $u_n$ corresponding to $\sigma_n(J_R)$ could be
6.2. APPLICATION OF VOLTAGE INSTABILITY INDICES

used to identify the most sensitive voltage node of the system and the most sensitive direction in reactive power injection. Fig 6.4 illustrates the plot of $\nu_n$ and $\mu_n$. The magnitude plots of the corresponding vectors are specific to the load increment case. In addition, both of the plots indicate that only one bus is the sensitive voltage bus within the system. The coincidence of $\nu_n$ and $\mu_n$ also suggests that the voltage stability indices are more responsive to change in reactive power of that node. Therefore, shedding the load on this node would have the most beneficial effect on system. The result of the load shedding has been confirmed by the magnitude of participation vector (see Table 6.2).
CHAPTER 6. VOLTAGE INSTABILITY PREDICTION BASED VSC-HVDC LOCATION

Table 6.2: Participation value of some load buses

<table>
<thead>
<tr>
<th>Bus</th>
<th>$p_n(J_R)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1041</td>
<td>0.9555</td>
</tr>
<tr>
<td>1045</td>
<td>0.0283</td>
</tr>
<tr>
<td>4045</td>
<td>0.0085</td>
</tr>
<tr>
<td>1044</td>
<td>0.0025</td>
</tr>
</tbody>
</table>

Fig 6.5 depicts the load shed from Bus 1041, which carries $P_{Load}$ and $Q_{Load}$ equal to 600 MW and 200 MVAR respectively. This plot illustrates that the system has a longer timescale serving as an early warning signal and permitting responses to solve voltage instability problem before a system collapse. The greater time scale also implies that load shedding on the consideration of $p_n$ is more appropriate than shedding several largest consumption load buses.

From the simulation results, the early warning signal obtained by using stability indices derived from Singular Value Decomposition is sufficient to determine the vulnerable location of which the remedial actions should be applied in order to decrease the voltage instability problem. In other words, it can be implied that the determined busbar is a good candidate to install VSC-HVDC in order to reduce the risk of cascading failure as shown in Chapter 5.
Chapter 7

Conclusions and Future Work

7.1 Conclusions

One of the aim of power engineering is to maintain the electrical networks under disturbances. One of the types detrimental disturbances leading to blackouts is the cascading failure. The propagating aspect and the widespread nature of this category of failures inflicted uncontrollable outages from seemingly minor causes. Thus, the non-linear characteristics of the cascades are often illusive to quantify. In order to properly tackle these failures, the roots of the cascades must be identified, which have been discussed in Section 2.2, such as heavy overloading due to unnecessary actions, and the lack of automated countermeasures to prevent further overloading.

In the search for methods to preserve a stability of network and prevent unnecessary outages through cascading failures, a model power system is concocted to replicate and characterize the failures. In this modeling stage, other components of the power system, such as relays and loads, must also be properly simulated in order to model the entire power system involved in this type of failure. From the results from the induced cascading failures within the model, a control algorithm is designed and tested to mitigate cascading failures resulting from voltage instabilities. The control algorithm is based on the identification of vulnerable buses, in order to respond with corrective actions. Hence, suitable coordination methods between HVDC and protection system are generated. The control algorithm proves to be a simple additional logic evaluation to reliably divert the power system from cascading failures for the tested scenarios. In other words, cascading failures were treated to avoid further damage on the remaining power system.

7.2 Future Work

Though the presented control algorithm is a viable option for preventing cascading failures, the model could be improved and extended to further characterize cascading failures. In terms of the implementation of the control algorithm, other effects that have not been addressed include the investigation of transient behaviors on the overall system stability. The power injection required to avert
cascading failure might produce adverse transient behaviors.

Arguably, the simulated power system might not be of adequate size compared to the interconnectedness of contemporary power networks. Hence, an expansive meshed system could be implemented to determine the impact of mitigating effects on a larger scale and with the augmented scale, distance relays would become pivotal factors in cascading failures. Furthermore, due to the non-linear characteristics of cascading failures, the system might behave differently from the presented responses. Hence, the control algorithm might require modification to take into account the added complexity, or might prove to be reliable even in larger networks.

Along with the inclusion of meshed networks, the interconnectivity between power systems across boundaries might pose intriguing responses. Extensions of the current model and analysis technique in conjunction with the added boundaries in terms of a larger network might include the investigation of the impacts of inter-area power trades on the stability. In order to efficiently communicate between different sub-systems, the optimal number and the most appropriate locations of HVDC links need to be determined. In addition, coordination between multiple HVDC links and protection needs to be fashioned to ensure reliable and economical operations of the whole interconnected power system.

Due to the non-linear character of cascading failures, a more expansive system might produce unpredictable behaviors. Hence, most of the noted extensions attempt to address expected issues that might arise due to the communications between networks. Although the control algorithm has been demonstrated to be efficient in obstructing cascading failures in the presented scenarios, the algorithm might foster unfavorable and/or unanticipated behaviors in a more substantial power network. Nevertheless, the investigation into cascading failures and the development of the arresting algorithm reveal beneficial evaluation for improving the robustness and resiliency of a power system.
Bibliography


