Assessing the Impacts of Increasing Penetration of HVDC Lines on Power System Reliability

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Abstract

This thesis work evaluates the Nordic32 transmission test system reliability and the impacts of introducing HVDC lines. The main contributions from this thesis can be summarized as follow:

- A qualitative study has been carried out to assess the impacts of HVDC lines on the transmission system reliability and comparison between the AC and DC transmission alternatives was made.
- A modified version of the Nordic32 transmission test system has been used as an application study and the reliability data of each component has gathered from different sources. Thereafter, the test system has been implemented in the commercial power-system simulation tool NEPLAN. A number of system reliability indices for the AC conventional system have been obtained, and these values have been considered as the base case.
- A monopole two terminal HVDC line has been implemented in different locations in the test system. The modeled HVDC line is equipped with reactive controllers at both HVDC terminal stations in order to maintain the terminal voltage at its set level independent of the active power over the HVDC line. And finally, the resulting system indices for each HVDC case have been compared with the basic case so as to quantify the impact of HVDC lines on the Nordic system reliability.

Results from the study showed that the system reliability for the test system is increased with the introduction of HVDC by either adding HVDC lines to the system or by the replacement of some AC lines by HVDC. It is also shown that the impact depends on the location of the HVDC lines in the system. The improvement when adding HVDC lines is to a large extent due to the increase in transport capacity through the critical transmission corridors. HVDC links are in general better at maintaining voltage stability than AC lines. This is an important reason for the improvement observed when replacing AC lines with HVDC.

Furthermore, several assumptions and limitations have been made within this study, e.g. due to lack of input data and insufficient details of the transmission system model. Further studies are needed for a complete investigation of the impact of HVDC on the system reliability.

Keywords: HVDC, NEPLAN, Nordic32, Transmission system reliability

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Contents

1. Introduction

1.1 Background

The Electrical power system is a complicated system from the operational point of view. The main function of this system is to provide the end customer with a continuous and reliable power supply. The economic and social effects of losing the electric service are significant on both the electric supply utility and the end user.

The power systems have been subjected to many changes in order to enhance their performance. The interconnection between two or more power system is a common way to support the shortage regions with enough power to meet the demanded load. The electrical power system has evolved to include many technological components to enhance its operation and make it strong enough to stand against any unwanted disturbances. For example, power electronic components (FACTS), have been used to support and increase its capability. To reach a 100% level of system's reliability is impossible these days, due to the unexpected events that happen in the system during its operation, such as, control failures, protection or communication system failures, and disturbances that might happen in the system without any prior notice, such kind of disturbances could be a result of unfavorable weather, human operational errors, etc.

1.2 Problem description

Assume that at specified time instant, the electrical system in Figure 1.1 is in balance which means, the contracted load is fully supplied by the generation.

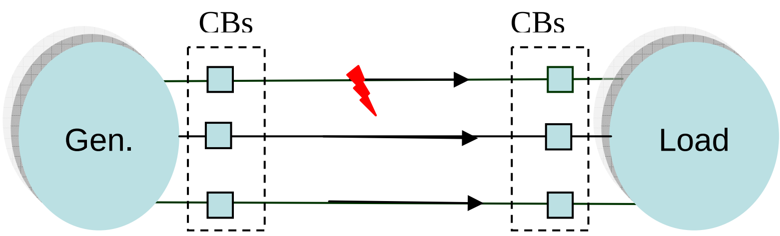


Figure 1.1: Simple power system model

During a stormy weather, a lightning strikes one of the main transmission lines which is handling one third of the total power to the load, the protection system observed the fault and isolated it from the system by disconnecting the faulted line, the other two transmission lines will handle the power for a while until the system operator re-close the circuit breakers, the system operator tried remotely to re-close the breakers but the breakers were jammed, until manually reconnect the line, the other lines will be overloaded and disconnected by the protection system, and the result is an interruption of the load. However, using an HVDC line in parallel with AC lines might contribute in reducing the amount of curtailed power by using the short-term overloading capabilities and its fast response to the AC and DC faults.

The impact of HVDC on transmission systems is a very broad subject, far beyond the reach of one M.Sc thesis. It includes technical, as well as economic issues. The technical issues cover normal operation, operation during alert or emergency states, and reaction to faults in the system, but also distortion and electromagnetic fields due to DC lines.

In this thesis we address the reliability of transmission systems and the way in which this is impacted by the introduction of HVDC. This issue will be addressed in two ways; first, a qualitative study will be performed by referring to some textbooks and other publications. Second, a test transmission system will be chosen to quantify the impact of introducing HVDC lines in different locations.

1.3 Objective and Approach

The objective of this thesis is to study the impacts of HVDC link on the transmission system reliability. The use of HVDC lines in the transmission system will affect the system reliability. The HVDC will have different impacts on the transmission system operational state. For instance, the location of the HVDC in the transmission system should be carefully chosen, the control system of the HVDC stations is one of the most important factor to obtain the HVDC efficiently working in the system.

In order to assess the impacts of HVDC lines on the transmission system reliability, a qualitative study will be carried out by referring to the relevant materials in the field. The qualitative study will evaluate the impacts of HVDC lines on the operational state of any transmission system. The Nordic32 transmissions test system will be used as an application to validate the qualitative aspects in the study. Noridc32 test system will be implemented and simulated using the commercial software NEPLAN. The Nordic32 test system represents a specific operational state of the Nordic system. Due to the complexity of the system, an analytical commercial solver/simulator called NEPLAN will be used to facilitate and ease the reliability calculation and to conduct the total system indices. Firstly, the given system will be implemented and simulated with NEPLAN, and secondly, different HVDC cases will be defined and implemented to check how the HVDC lines will impact the system reliability. The HVDC cases can be made by means of replacing some of the AC lines with HVDC lines and/or adding an HVDC line to the system. Different system indices for different HVDC locations in the system are possible.

1.4 Literature Review

Previously study has been carried out in [1], and the goal was to study the transmission system reliability. The NEPLAN software was used as a simulator and the RBTS was under the scope of the research. Another research has been done in [2]; where the Nordic32 test system was the approach and the goal of the thesis was to find the optimal and proper power regulation strategy of the HVDC after being allocated suitably in the network. That research was mainly concerning the operation and control strategies of the HVDC after being embedded in the system. The results showed that the HVDC will have a major influence on the stability of the transmission system under adverse disturbances.

In this study, the reliability of the transmission power system will be conducted. The HVDC link will be involved and the impacts of such transmission alternative on the overall system reliability will be conducted. Besides, this work will assess the suitability of NEPLAN as a tool to be used in the transmission system reliability calculations. Moreover, this thesis will thrash out the possibilities to extend the use of NEPLAN tool for more complicated networks and also will be considered as a continuation to the study that has been done in [1]. More about NEPLAN will be discussed in chapter four in this thesis.

1.5 Thesis Scope

Chapter two

A qualitative discussion of the impacts of HVDC transmission on the system reliability where the advantages and shortcomings of HVDC transmission are mentioned

Chapter three

In this chapter the Composite Generation/Transmission Reliability Evaluation technique and explanations of the reliability assessment algorithm are given.

Chapter four

In this chapter, an overview of the commercial reliability software NEPLAN is given. The way that NEPLAN does the failure contingency analysis is explained. The implementation process of the system in NEPLAN is explained as well.

Chapter five

In this chapter, the CIGRE 32 bus test system characteristics are mentioned. In addition, the system design requirements and two load flow scenarios are explained.

Chapter six

The simulation results including the failure contingency analysis based on both single failure and multiple failure analysis are conducted. Moreover, the system indices of the overall transmission system as well as the load point indices are presented. Analysis of some outages is given.

Chapter seven

Closure

2. HVDC Transmission

2.1 Background

It is known that the first commercially generated and transmitted electricity has been carried out by Thomas Alva Edison as DC power. However, the DC power transmission over long distances was impossible due to the low voltage characteristic of the DC system. The AC system was the best alternative at that time. After the massive evolution of the power electronic industry and mainly due to the development of high voltage valves, it became feasible to transfer DC power over long distances and the concept of HVDC technology became visible as a transmission alternative [2].

It is many years since the first Hewitt's mercury-vapor HVDC valve is presented in 1901 [2]. However, only after the successful commissioning of the first commercial application of mercury-arc based HVDC transmission link between the main land in Sweden and Gotland in 1954, the HVDC technology made its mark as an alternative transmission facility. The HVDC systems have been widely applied as bulk power transmission over long distances, power transmission through submarine cables, and interconnecting two asynchronous systems [4].

In 1972 and after the development of thyristor technology, the first thyristor based HVDC transmission facility was built in Canada as back-to-back asynchronous interconnection with a rating of 320 MW at +/- 80 KV. Since then, there has been a steady increase in the application of thyristor-based HVDC transmission.

The HVDC transmission technology growth has become clearly visible. This is noticeable from a listing of HVDC projects by the IEEE Transmission and Distribution committee in [11] where most of the ongoing and upcoming HVDC projects are listed. Table 2.1 gives the number of commissioned HVDC projects and also those which are planned to be commissioned.

Table 2.1: A summery of the HVDC projects [11]

	Commissioned	Planned	Under constructions
Number of projects	117	53	6

More details about the locations and transmission capacities of each different HVDC project can be found in [11].

2.2 Comparison of AC and DC transmission

To understand this exciting growth of the HVDC transmission system in the past fifty years, a comparison with the conventional AC transmission system is carried out. In the following subsections a comparison between the AC and Dc transmission systems taking into account different aspects such as transmission costs, technical considerations, reliability, and availability of each transmission technology.

2.2.1 Transmission Costs Comparison

The cost of any AC or DC transmission lines usually includes the cost of main components such as Right-of-Way (RoW) which is the amount of landscape that might be occupied during installations of towers, conductors, insulators, and terminal equipments in addition to the operational costs such as the losses in the transmission lines. However, for given operational constraint of both AC and DC lines, the DC lines has the ability to carry as much power with two conductors as the AC line with three conductors of the same size. Moreover, the DC lines require fewer infrastructures than the AC lines which will consequently reduce the cost of the DC lines installation. In Figure 2.1, a comparison of RoW for AC and DC transmission lines is presented [9]. In DC transmissions with two conductors, the losses will be reduced to about two-thirds of the comparable AC system. Both the corona and skin effects tend to be lower in case of DC transmission which will in turn reduce the transmission losses. Figure 2.2 expresses the total cost of the DC and AC lines with respect to the distance [9].

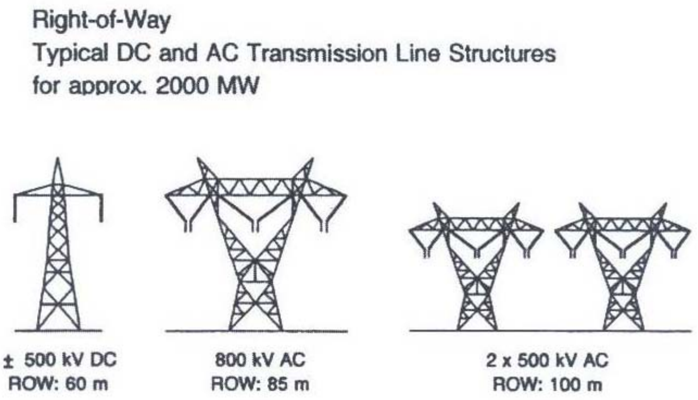


Figure 2.1: Comparison of RoW for AC and DC transmission systems [9]

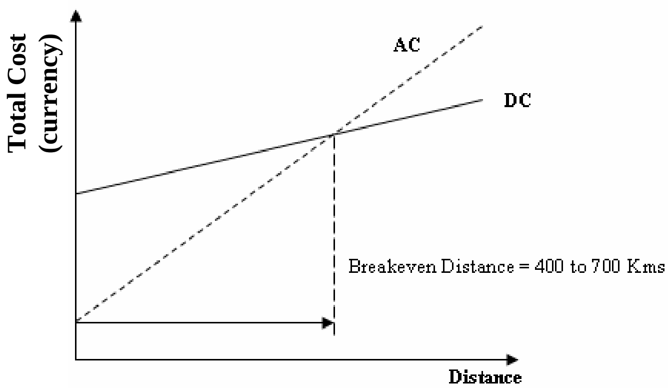


Figure 2.2: Feasibility of AC and DC lines with respect to the distance

2.2.2 Technical Comparison

The fast and full controllability of the HVDC transmission links make it possible to modulate the transmitted power in a quick and proper manner. Therefore, they have a significant impact on the stability of the associated AC power system. More importantly, a proper and rugged design of the HVDC controls is essential to ensure satisfactory performance of the overall

AC/DC systems [9] [13]. More about HVDC impacts on the system stability is explained in the next sections.

Stability limits

Consider the short AC line in Figure 2.3; the AC transmitted power over the line from the sending end to the receiving end depends on the angle difference between the bus voltages (load angle). The approximate power equation that represents the transmitted power from the sending end to the receiving end is given by (2.1).

$$P_{12} = \frac{U_1 U_2}{X_l} \sin(\delta_1 - \delta_2) \tag{2.1}$$

Where, U is the fundamental rms voltage, X_l is the series reactance of the line and $\delta_1 - \delta_2$ is the relative voltage phase shift (load angle). The suffix 1 and 2 indicate sending and receiving end respectively.

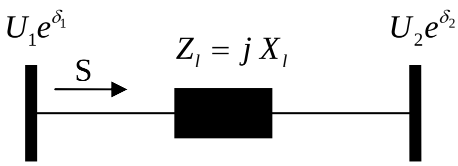


Figure 2.3: Power flow [short AC line model]

For a given power transfer level, this angle difference will increase with distance. And the total amount of power that can be transferred will be limited by the consideration of steady state and transient stability. Any disturbances in the power flow will result in load angle oscillations. For reasons of stability, the load angle has to be kept at relatively low values under normal operating conditions (about 30^o) [9]. As a result of stability limits, a parallel AC lines as well as some other switching stations such as series capacitors, synchronous condensers, and static compensators should be used to support the voltage profile and to avoid instability that might come after faults on the line [3].

Under light load conditions, the AC line transmits the charging current (reactive power), this effect could cause overvoltages in the lines and some buses in the system. Shunt reactors are connected to keep the bus voltage in the limits. It has to be noticed that the charging problem does not appear in the short lines compared to the long AC lines. However, the short line model has been used with its approximated power equation in order to simplify and illustrate the explanations.

Figure 2.4 shows the power carrying capability of an AC line which is inversely proportional to the transmission distance. In contrast, under steady state conditions the inductance and capacitance of the DC lines has no effects on the transmission distance. Thus, the above difficulties (i.e. distance and stability limits) will not come up in case of DC transmissions. Moreover, there will be no need for intermediate switching stations (compensating equipments) except for the converter stations to supply the substantial reactive power which is needed to maintain a proper operation of the terminal equipments [3].

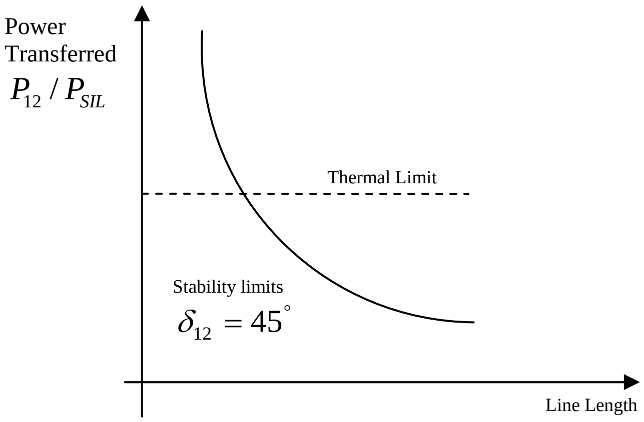


Figure 2.4: Illustration of thermal and stability limits in AC lines[1] [4]

Voltage Control

Due to the line charging and voltage drops, the voltage control of an AC line is complicated. The voltage profile of the AC lines is relatively flat, for different loading levels the voltage is continually fluctuating and for a good power quality it should be kept in an acceptable level [9]. To maintain the voltage constant at both ends, reactive power compensation is needed especially when the line loading is increased. High line loading level will reduce the bus voltage near the load points, if that bus voltage is left without reactive compensation; it will limit the amount of transferred power, see equation (2.1). Moreover, in case of AC transmission the reactive power compensation will increase as the line length increase.

On the other hand, the thyristor based HVDC station consumes reactive power which is estimated to be around fifty percent of the total active transmitted power and no line compensation is needed for the DC lines. In case of HVDC light there will be no reactive consumptions by the converter stations. As a result, the HVDC lines might be more suitable than the AC lines for high voltage long distance transmissions.

Reactive Compensation in AC systems

In AC transmission systems with long transmission distance the problem of line charging, stability limitation and voltage level variation will grow up. These problems are eliminated by series and shunt compensation equipments. For instance, line compensation is used to increase the transfer capability of the AC lines as shown in figure 2.5. For example, consider the approximated equivalent circuit of the AC transmission line in Figure 2.5; in order to increase the transfer capacity of the line, the overall reactance of the line is reduced by adding the series capacitance (Xc). Equation (2.2) describes the active power flow (P_{12}) between the line ends. The power flow is increase when the value of ($X_l - X_c$) is decreased. However, due to the stability limits, and especially the first swing problems in the system after large disturbances on the line, the added value of X_c will have a certain limit.

[1] P_{12} / P_{SIL} is the real power transmission between the AC line ends which is the ratio between the transmitted power in [MW] (P_{12}) and the surge impedance loading (P_{SIL}) where the line inductance and capacitance are balanced [4]

$$P_{12} = \frac{U_1 U_2}{(X_l - X_c)} \sin(\delta_1 - \delta_2) \tag{2.2}$$

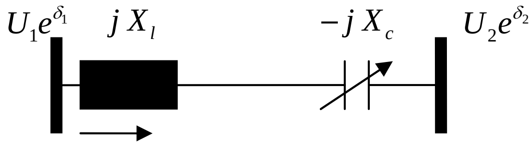


Figure 2.5: AC transmission line with SC (short AC line model)

Shunt compensation equipments are used to maintain the voltage level within certain limits in the system. Figure 2.6, it illustrates the voltage profile with respect to the transmission distance with and without shunt compensation along the line. As a result of the compensations, the cost of AC transmission will increase as the number of compensation equipments increase. In HVDC systems compensations through the lines is not needed. However, as previously mentioned, the converter stations consume reactive power and that would be compensated at both sending and receiving ends. Additionally, there is no reactive power flow on the DC line; therefore, there are less technical limits to the transmission distance compared to AC lines [24].

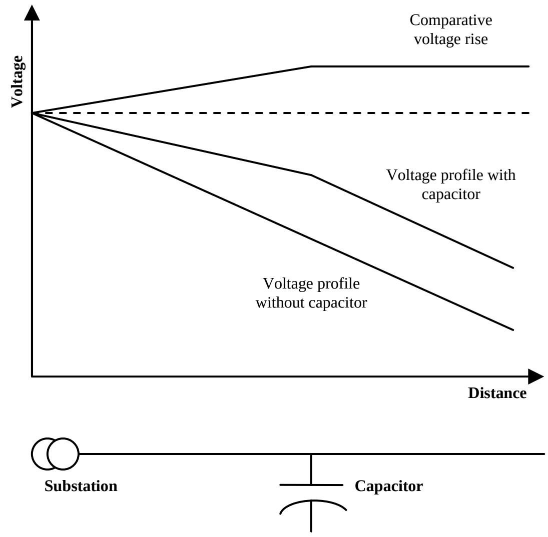


Figure 2.6: Effect of shunt capacitors on voltage profile [4]

2.3 Enhancement of AC system Performance using HVDC

Interconnecting two AC systems using AC tie lines will require the automatic generation controllers of both systems to be coordinated using the tie line power and frequency. However, the interconnected AC systems with control coordination are still subjected to some operational problems such as [9]:

- Large oscillations which may lead to equipments tripping.
- Faults level problem (High short circuit levels).
- Transmission of disturbances from one system to the other.

Using the DC line as a tie line would eliminate most of the mentioned problems. The DC line is insensitive to the frequency and it would connect two asynchronous systems and isolates the system disturbances [9] [13].

2.3.1 HVDC control

A strong control system for HVDC lines is particularly recommended and it will enhance the dynamic performance of the AC systems. There are many reasons that make the motivation for an extra control of HVDC lines, some them are:

- Damping the electromechanical AC system oscillations.
- To enhance the transient stability in the AC system.
- Control of frequency and reactive power oscillation.

Many high level controls are used in practice but the control objective of each depends on the associated AC system characteristics. Each control system that has been used tends to be a unique for that system. To date, no attempt has been made to develop a general and optimized control way that suites all systems [13]. More about HVDC control, the reader may refer to [13]. In the coming subsections a literature review is carried out based on some previous studies.

2.3.2 Stability Improvement

HVDC lines are highly controllable, and it is possible to take advantage of this characteristic to increase the transient stability of the AC system. After a specific disturbance in the power system, the HVDC link can be controlled in a manner such that the DC power can be ramped up and down quickly to restore the balance between generation and load in both sides of the AC system. In some situation ramping up the power is necessary to assist system stability and this can be done by means of the short term overloading capabilities of the HVDC link taking into account the thermal capacity of the rectifiers. However, in the modern HVDC industry, the rectifiers are overrated and designed to be overloaded for long time if necessary [13] [3]. Controlling the HVDC converters so as to provide reactive power and voltage support can be useful to augment transient stability. But it should be noticed that classical HVDC (thyristor based) can not provide reactive power, on the contrary, it consumes reactive power. New HVDC technologies such as HVDC light (IGBT based) can be utilized for that purpose.

2.3.3 AC System Strength and its Influence on the AC/DC interconnections

The AC/DC system interactions can be extremely impacted by the strength of the AC network relative to the HVDC link capacity. The weakness of AC system can be due to its high impedance or its low inertia. The strength of the AC/DC system can be measured by its short circuit ratio (SCR) which is the ratio between the short circuit MVA of the AC system (*Ssc*) compared to the DC converter MW rating (P_{dc}) as in equation 2.3 [13].

$$SCR = \frac{S_{sc}}{P_{dc}} \tag{2.3}$$

The Short circuit MVA of the AC system is given by:

$$Ssc = \frac{E^2_{ac}}{Z_{th}} \tag{2.4}$$

Where E_{ac} is the commutation bus voltage at rated DC power and Z_{th} is Thevenin equivalent impedance of the AC system.

The SCR presents inherently the strength of the AC system. An index called effective short circuit ratio (ESCR) has been introduced to measure the AC system strength taking into account the effects of the HVDC equipments which is connected to the AC side [13]. In addition, the HVDC control plays a vital role in the AC/DC interaction phenomena and it must be considered to achieve a very good level of AC system strength [13]. The SCR gives just the AC system strength taking into account the DC transmission (P_{dc}) while the ESCR takes into account the effects of the HVDC equipments.

The AC system strength can be classified of being high if the ESCR is greater that 3, or Low if ESCR is between 2 and 3 and very low if ESCR less that 2. Moreover, connecting the HVDC to the weak AC systems with low ESCR will negatively impact the AC system and cause the following problems.

- *High dynamic over-voltages* that come from the excessive reactive power at the HVDC terminals after the DC power being interrupted followed by zero absorption of reactive power. This reactive power comes from the shunt capacitors and filters which is connected to the converter terminals. These over-voltages might cause damage to some local customers.
- *Voltage instability* which is associated to the loading sensitivities of the HVDC link. For instance, an increase of the direct current will be followed by a fall of alternating voltage which will make the voltage control and recovery from disturbances difficult and the HVDC control might contribute to voltage instability by responding to the alternating voltage reduction leading to a progressive fall of voltage.
- *Harmonic resonance* due to the parallel resonance between AC capacitor filters and the AC system at lower harmonic. Additionally, eliminating the low-order harmonic resonance is important in order to reduce transient over-voltages [13].
- *Voltage flickers*, this is coming due to the continuous switching of shunt capacitors and reactors causing unacceptable transient voltage flickers.

All the previously mentioned problems associated to the weak AC networks can be alleviated by using synchronous condensers or SVCs additionally with a rugged HVDC controller that is able to modulate the reactive power in response to voltage variation [13].

Moreover, the over-voltage problems associated to the HVDC lines have been investigated in [31]. Different causes have been examined such as lightning on the DC cable at different positions (middle, first, and end); the results showed that the HVDC recovers quickly from such over-voltage problems. A standard lightning with 15kA that strikes the DC line 100Km from the rectifier station will cause over-voltage problems. Moreover, in [31] different kinds of over-voltages causes have been investigated such as HVDC line faults, ground faults, converter station DC side valve short circuits. However, the proposed control strategy in [31] made it easily for the HVDC link to recover from such over-voltage problems. In contrast, if such lightning occurred in case of AC lines the only way to alleviate such faults is to disconnect the line directly after the lightning which might have adverse impacts on the other AC lines and components in the system such as, transformers, and generators overloading which will consequently cause a cascaded tripping of the components.

2.3.4 Fast Response to System Faults

The HVDC Transmission system is affected by different types of faults during operation. For instance, faults on the DC cables, converters, and in the AC systems might take the HVDC station out of operation if no action is taken to clear them within an acceptable time. Nevertheless, most of the faults in the DC system are either self cleared or cleared through suitable actions from the converter controls, which is not the case in the AC system, where the faults are normally cleared by means of relays that trip out the AC lines. Though, the converter control system is very important and plays a vital role in the satisfactory response of HVDC lines to the faults on both DC and AC sides [13].

- **DC System Faults**

Most of the faults in the DC side are pole-to-ground faults. Bipolar faults are rare due to the need of high physical force to bring the two poles together. The DC line faults have a lower negative impact on the AC system than an the AC faults because losing one pole will just block the power transfer on that pole while the other pole is practically unaffected [13].

The HVDC controller can clear the faults on the DC line by either normal control action or using the fast acting line protection. Any short circuit on the DC line will cause momentarily the rectifier current to increase since it is feeding a very low impedance fault and the inverter current to decrease, in this case, the rectifier control will act to reduce the direct voltage and bring back the current to its reference value (set value). At the same time the inverter control will change its operational mode from constant extinction angle (CEA) to constant current mode (CC). However, the normal control action tends to restore the system state. In the *fast acting protection* control, additional control is used to reduce the fault current levels and recovery voltage, more about the control strategy the reader might go to [13], [3].

It has to be mentioned that, the total time for fault recovery lies between 200 to 300 ms if the fault is temporarily and the restart is successful. The recovery time is higher for DC lines connected to weak AC systems. The automatic restart of the HVDC cable system is not allowed due to the fact that, most of the HVDC’s cable faults are permanent faults [13].

Other kinds of faults worth discussing are converter faults, such kind of faults might require either the valve group or the whole pole to be shut down. The valve group fault will require the entire pole to cease transmission of power; following by current reduction to zero which normally takes less than 30 ms [13].

- **AC System Faults**

The DC system has a very fast response property to the transient disturbances that might happen in the AC system. The HVDC controller gets ride through any disturbances in the AC system by either reducing the active power temporarily or shutting down until the AC system recovers completely. Recovery from AC system faults is one of the main planned goals of HVDC controller.

Many kinds of AC system faults might happen at the AC side of both rectifier and inverter such as, *remote three phase faults, remote single-phase* and *remote phase-to-phase faults*.

Consider the HVDC schematic in Figure 2.9. The HVDC response to three phase fault occurred at a remote place in the AC network from the rectifier side can be summarized as follow:

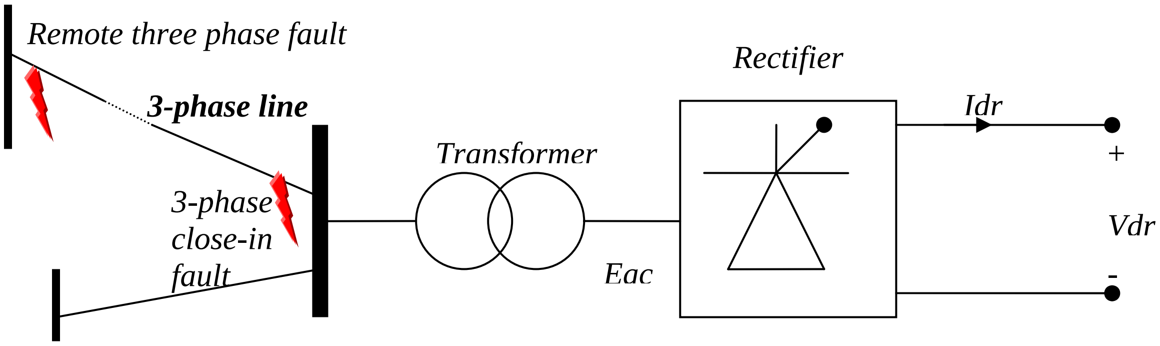


Figure 2.9: HVDC schematic from the rectifier side

- The rectifier commutation voltage *Eac* will drop slightly
- The rectifier DC voltage *Vdr* will drop and hence the current *Idr*
- The current regulator will try to reset the firing angle of the rectifier (reduce the firing angle) to restore the current (*Idr*) by increasing the voltage (*Vdr*)
- If the voltage *Eac* remains low, the tap changer of the transformer will operate to restore the direct voltage and current of the rectifier to normal.
- If the commutation voltage *Eac* remains low after tap changing, then the *voltage-dependent current-order limit* (VDCOL) controller will take over to regulate the current and power transfer under the low voltage. If the low commutation voltage persists, possible shut down of the HVDC station might be possible.

As previously mentioned, the duration of fault clearing (recovering duration) depends on the AC system strength (200 to 300 ms) and it might last longer if the DC link connected to a weak AC system.

On the other hand, if three phase fault happened close to the transformer from the AC side as shown in Figure 2.9, the commutation voltage drop will be significant which will shut down the HVDC station temporarily under the VDCOL until the fault is cleared.

For a remote single-phase and a remote phase-to-phase faults at the AC side of the rectifier, the HVDC will get ride through without any obvious effects, because the average commutation voltage E_{ac} will be higher than the case of remote three-phase faults (i.e. *Eac* will not drop too much). In case of significant drop in the commutation voltage, the HVDC control system's reaction will be similar to that for remote three-phase faults.

In case of inverter side faults, such as remote three-phase AC faults as shown in Figure 2.10, the result will be a small voltage dip at the inverter and simultaneously an increase in the direct current occurs. The rectifier and inverter controllers will respond to the changes to restore the system state. If the low alternating voltage continues, the tap changers will be activated to restore the converter firing angle hence the direct voltage. On the other hand, for a significant voltage dip, the commutating voltage will drop which may result to a temporary commutation failure at the inverter. Additionally, the resulting reactive power increase after the fault will force the HVDC control system to reduce the direct current in order to minimize the amount of absorbed reactive power during the fault clearing's process [13].

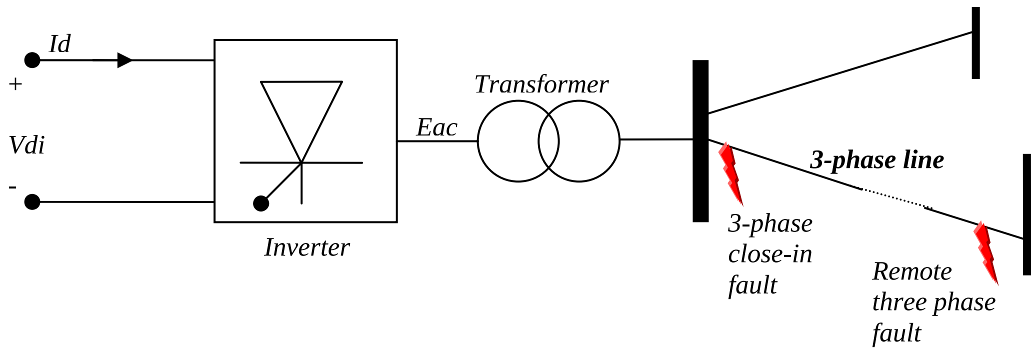


Figure 2.10: HVDC schematic from the inverter side

- **AC System Faults recovery**

The recovery process from AC system faults depends strongly on the strength of the AC system; after any disturbance in the system, the overall system performance will depend strongly on the AC/DC system interaction as mentioned before, as well as the converter control strategy and its associated response adjustments. However, it should be mentioned again that the recovery process after any AC system fault would be faster in case of strong AC system, while weak AC system may have difficulty in providing sufficient reactive power to the HVDC system which make the recovery process longer.

It will take the DC system about 100 ms to 500 ms to recover to 90% of its pre-fault power and that time will strongly depend on the DC and AC system characteristics as well as the control strategy of the HVDC system. Many factors influences the recovery rate, such as the inductance and capacitance of the DC cables, DC reactors, resonant harmonic frequency of lines as well as the converter transformer and filter characteristics [13].

Additionally, *the voltage-dependent current order limit* (VDCOL) plays a vital role in determining the recovery from faults. The VDCOL control module in the DC system is responsible for limiting the current mainly during the adverse faults on either the DC or AC side of the DC system and consequently limits the reactive power consumptions during the faults. For instance, during the disturbances on either the DC or the AC sides, the sudden voltage reduction will increase the amount of absorbed reactive power by the HVDC link which consequently make the recovery time of the system longer. Though, using the VDCOL control strategy will limit the current as a function of either the direct voltage or alternating voltage.

As a result, equipping the HVDC with a robust and advanced control strategy will assist the DC system recovery and make it faster. Extra control modules such as VDCOL might protect the system and prevent it from further voltage deterioration.

2.3.5 DC power modulation

The HVDC link that mainly interconnects two large power systems should have the ability to fully regulate and interchange the power between the two connected systems. The property of HVDC as a good power regulator system is used in some existing HVDC schemes to provide a perfect and full power modulation. The power modulation between the interconnected AC systems is crucial to the overall system reliability.

2.3.6 Frequency control

If two networks are connected through a DC tie line, this DC line should be able to modulate the power backward and forward so as to assist the frequency of the two interconnected AC systems. The HVDC link can share the frequency control by means of regulating its power when it is needed. All HVDC lines in operation has the ability to regulate the power by means of frequency feed back loop acting on the HVDC line control system. By doing so, the frequency of the interconnected AC networks can be controlled by utilizing the frequency control option of such a DC line. A typical case of frequency control is the Gotland link [3].

In most of the existing HVDC lines; a combination of control modes is used. Normally, the control signal that acts on the power controller of the DC link is a power order signal. That signal (i.e. the delivered power by the DC link) remains the same as long as the scheduled predetermined frequency remains within the limits. In case of violating the limits, the frequency control system of the DC link will take over to support the system frequency by modulating its power as needed. Nevertheless, if the maximum transmission capacity of the DC line is reached, then the frequency control system turns to be out of action. The frequency control curve is shown in Figure 2.12 [3].

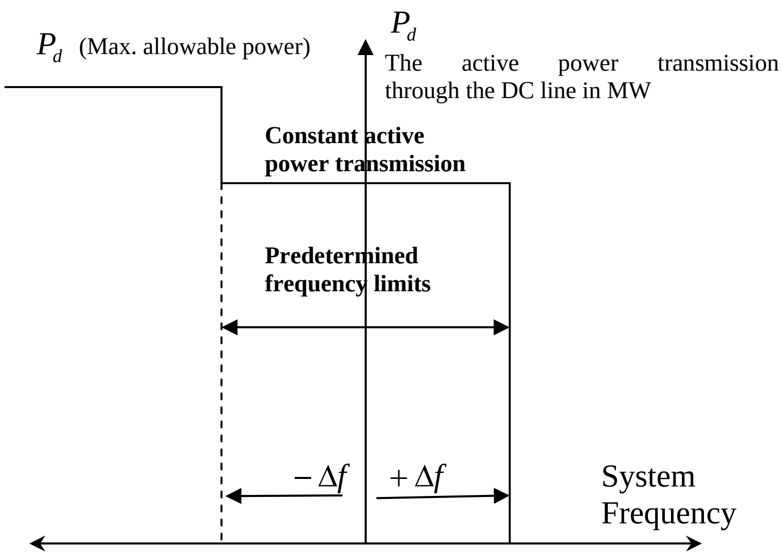


Figure 2.12: Power-frequency control characteristics

From Figure 2.12, it is obvious that if the frequency reduction is more than the minimum allowable limit ($-\Delta f$), then the DC link will reach its maximum transmission capacity and the frequency control system will be inoperative for further frequency reduction.

It should be noticed that, the HVDC lines are insensitive to frequency changes and it should be equipped with a reliable frequency sensors to detect any frequency variation and order the control system to assist the interconnected systems. If the DC line is left without such sensing elements, a constant power flow can accelerate a receiving end that has lost part of its load, and eventually a collapse in the sending end if the amount of the extracted active power by the DC line exceeded the maximum generated power at the sending end [3]. Moreover, the frequency deviation can be controlled through automatically imposed DC power modulation through the DC line [23].

2.3.7 Dynamic stabilization of AC systems

A power system is stable if and after any disturbance it returns to condition of equilibrium [3]. The HVDC lines that might be used to connect two AC systems should be equipped with a healthy control system so as to assist the dynamic instabilities. Connecting two AC systems by HVDC line will dynamically support the system by means of alleviating instability problems such as power swinging after the disturbances. The HVDC will contribute in damping process of the system during and after any disturbance by a small signal modulation of its transmitted active power. This DC power modulation is proportional to the frequency difference between the inter-tied systems. An example of dynamic instabilities is the northern and southern parts of the Western US power system which are connected by the parallel pacific AC and DC inter-ties. The development of DC power modulators made it possible to up-rate the AC pacific inter-ties from 2100MW to 2500MW [3].

HVDC stabilizers are usually designed so as to be able to modulate the power proportional to the speed difference between the rectifier and the inverter. The speed difference means the frequency difference in the interconnected AC systems. By doing so, the HVDC may assist the AC system to damp the power oscillation between interconnected systems. In the large scale AC/DC connected and weak-damped systems, both PSS and HVDC can coordinate to damp the oscillations by first utilizing the PSS control and then tuning on the HVDC stabilizers to suppress the oscillatory modes in the system [21].

An adaptive optimal control strategy have been proposed in [22] for a large scale AC/DC system. The proposed strategy aimed at damping the electromechanical oscillation in the AC system after being subjected to disturbances. The gained result was an excellent performance of the adapted optimal controller in damping the electromechanical oscillations [22].

2.3.8 Large signal modulation

The small signal DC power modulating control system that was explained in the previous section is not good enough to damp the large oscillations after any large disturbance. Losing a large generating unit in the system will be followed by large transient oscillations which also might lead to component’s tripping. Though, a large signal modulating DC system was developed to damp the oscillatory modes that come directly after large disturbances [3].

2.3.9 Active and reactive power modulation

The HVDC station consumes reactive power which is proportional to the transmitted active power over the DC line. The reactive power consumption of the HVDC station is expressed in terms of the transmitted reactive power as [3]

$$Q = P \tan \phi \tag{2.5}$$

Where, Φ is the angle between the fundamental AC commutated voltage and the AC current components.

During disturbances the consumption of reactive power will increase. Coordination between reactive and active power can be achieved by means of DC system voltage modulation to decrease the amount of consumed reactive power as a percentage of the transmitted active power.

2.3.10 Drawbacks of HVDC lines

Some factors still limit the application of the DC transmission; some of them are [3] [13]:

- Expensive cost of the equipment used for power conversion
- Harmonics that would result from the switching operation of the valves in the converter station
- Requirement of reactive power compensation for the converters.
- Control complexity.
- The DC lines might contribute to a voltage collapse during the swings that might come after a large disturbance followed by extreme reactive power consumption but using the active and reactive power modulation technique in the HVDC controller alleviates this problem.

The advanced technologies tried to overcome the mentioned disadvantages. Some of the advances that are used recently are [3] [2]:

- Increase the rated currents and voltages of the valves.
- Multi-pulse operation of converter (6-pulse,12-pulse,.etc)
- Use of forced commutation.
- The use of fast components like fiber optics, digital signal processing, digital computers in the converter control.

The resulted improvements after using the advanced technologies have minimized the cost of power conversion and improved the *reliability* of the HVDC line. Additionally, the advanced technologies opened the way for the modern HVDC technology. For example, the HVDC light is now in the operation and it reduced the cost of reactive power compensation at the HVDC terminals.

The challenge for proponents of HVDC is to ensure that the value of the technical characteristics of an HVDC system is fully recognised [24]

- Full and fast control of the power flow.

- Enhancement of AC networks (power oscillation damping capability, increased transmission capacity of parallel lines, etc).
- AC voltage control (smooth control with VSC Transmission)
- Reduction of short circuit current in strong AC systems [23]
- The HVDC lines embedded in the system is used in the optimal power flow process to reduce the total losses in the system.

2.4 Reliability Data of HVDC

Number of studies have been done and are still in progress to assess the availability of the HVDC lines in operation all over the world. For instance, CIGRE working group B4.04 collects data annually on the reliability performance of HVDC systems in operation all over the world.

This working group has developed definitions, terms, parameters and protocols to be used in collecting and compiling the data, it is clear from the collected data in [34] that the average energy availability in 2002 for all HVDC stations that have been reported their performance is around 94.48% and the forced energy unavailability in the same year for all stations is 1.6% while the scheduled energy unavailability in the same year and for the same stations is 4.1%. It has to be mentioned that the previous mentioned energy unavailability percentage was calculated as the sum of individual energy unavailability divided by the number of the stations regardless the location in the world and the same procedure has been made for the scheduled energy unavailability and the forced energy unavailability. More about the HVDC performance in operation can be found in [34].

Other studies have been performed by other researching groups worldwide to assess the availability of the HVDC lines in operation. For further knowledge, the reader might refer to [5], [17] and the annual reports of CIGRE group.

3. Transmission System Reliability

In this chapter, the transmission system reliability algorithm is presented and the way of calculating the system indices is explained.

3.1 Introduction

One of the basic objectives in the planning phase is to determine the sequence of equipment additions such as generating units, transmission lines...etc in the power system. However, that objective is also required to achieve an *economic* and *reliable* operation of the power system in order to meet the predicted load demand, but these objectives are conflicting since a higher reliability could lead to a high investment and then result in higher customer rates. Thus, the best possible *trade-off* between the *cost* and *reliability* should be achieved [7].

Additionally, the second and equally important element in the planning phase is the development of a trustable, robust and reliable *transmission network* to transfer the generated energy to the load points. The transmission network can be classified in two general areas which are the *bulk transmission* and *distribution* facilities. To assure the power transfer from the generation facility to the load points, a very good match between the bulk transmission and generation must be found [6]. In the next section the definition and subdivisions of the reliability assessment is presented.

3.2 System Reliability

The reliability of any system can be defined as the ability of an item to perform a required function under given environmental and operational conditions and for a stated period of time [15]. However, the item here can be either a component connected to a system, subsystem, or the whole system.

The reliability of any power system can be divided into two main parts, security and adequacy as shown in Figure 3.1 [18]. In reliability assessment technique associated to the power system, the goal is to assess whether that specific configuration of generators, transformers, circuits are able to satisfy the demanded load. Basically, this assessment should take into account steady state and dynamic aspects of system behavior [7].

The steady-state analysis/adequacy analysis is related to the existence of enough facilities within the system to satisfy the load demand or system operational constraints [7], [6]. Therefore, it is associated to static conditions and the suitable reliability assessment technique is the load flow.

The Dynamic/security analysis takes into account the system transient response after being subjected to disturbances such as sudden loss of generators or transmission lines that might lead to cascading outages and ultimately to a regional and/or system-wide blackouts [7]. Furthermore, it has to be noticed that the adequacy approach does not reflect the main concept of reliability. On contrast, the reliability of an operated power system has to be mainly assessed from the operational point of view to assure after any disturbance that the system is able to withstand it and recover dynamically without interrupting the demanded loads. Such study however would be too demanding.

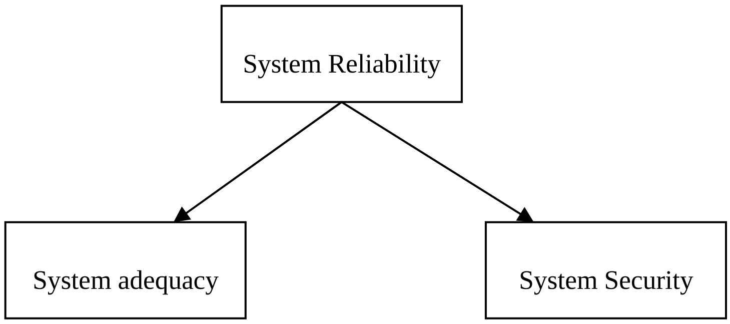


Figure 3.1: reliability's subdivisions [18]

3.2.1 Reliability Hierarchical Levels

The electrical power system can be divided into three functional zones; generation, transmission, and distribution. However, the three zones can be joined to develop three hierarchical levels for reliability assessment as illustrated in Figure 3.2.

- **Hierarchical level I (HLI)**

In this level, the reliability assessment can be done by assessing the capability of the generation system to meet the total predicted system load requirements. The ability of the transmission system to move the power from the generating units to the load points is neglected. The resulted probabilistic indices that would come out from this level might act as a reliability measure. For example, *loss of load probability* LOLP, *Expected power not supplied* EPNS, *failure frequency* FF, and *Failure Duration* FD have been extensively used in the planning phase. Due to the increased growth in power networks and the increased interconnection between the utilities, it has been realized that the transmission network plays a vital role in determining the overall system reliability [7]. An approach of combining the generation and transmission levels in reliability calculations was found and designated as hierarchical level II (HLII).

- **Hierarchical level II (HLII)**

The generation simple model is extended to comprise the *bulk transmission*. The reliability analysis of this level is usually termed *composite system reliability evaluation.* As a result of including the transmission system in the reliability calculations, the later became complex and more difficult to assess than when only the generation capacity is examined. For instance, an evaluation of system's steady state behavior for given *scenario* (i.e. when a load levels, generation availability, and circuit availability are predetermined), usually requires a load flow analysis instead of simple comparisons as in the case of generation reliability.

- **Hierarchical level III (HLIII)**

HL III is the result of joining the three functional zones. Though, due to the problem complexity and dimensions, the distribution system reliability evaluation is typically done separately from the generation and transmission systems. In this project, no considerations will be given to the distribution system.

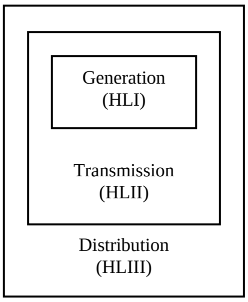


Figure 3.2: Hierarchical levels
For reliability assessment

3.3 Composite system Reliability Evaluation

For a given power system with *m* elements, such as generators, lines, transformers, etc. each element can be found in one out of a set of possible states while the load level can be represented by a discrete set of load values. The state vector of a power system can be represented by $x = (x_1, x_2, ..., x_m)$ where x_i is the state of component *i*, all possible states that come up from combination of component states, is denoted by the state space X [7].

However, a conceptual algorithm for reliability evaluation can be found in [7]. And it can be classified here in four composite steps.

- **a.** Select a system state/scenario $x \in X$, in terms of composite system reliability evaluation, the scenario may correspond to the load level, equipment availability, operating constraints, etc.
- **b.** Calculate the test function $F(x)$ for the selected state; here the assessment may include the effect of *remedial* actions such as generation rescheduling, load Shedding, etc
- **c.** Update the estimate of *E(F)* based on the results of (b) i.e. we calculate the reliability indices such as LOLP, EPNS, frequency and duration (FF,FD), etc
- **d.** Stop if the accuracy of the estimate is acceptable; otherwise go to the first step.

For each selected system state *x* (in step a) the load flow is needed. Assuming a power system with 20 transmission lines modeled with two states each, the number of possible states is 2^{20} which is more than one million states. In each state, load flow should be carried out taking into account the operational limits in the system such as voltage limits, loading limits of each component, generation rescheduling, etc. Anyhow, running load flow for each state is time consuming and it will increase the computational efforts which will need more expensive and powerful computers. Moreover, the number of states will increase even more if the generating units taken into account. For example, having another 20 generating units with two states each will result in more than one million states and the total number of system states is the result of one million multiplied with one million. Thus, an excessive number of states will come up which take a lot of computational efforts. For this purpose, a state selection is needed which will be a useful way to make the reliability calculation more efficient and quick.

3.3.1 State selection

Each component in state x can be modeled using either three states or two states Markov model as shown in Figure 3.3a and 3.3b respectively. Given the *failure frequency* and *failure duration* of each component, it is possible to calculate the *probability of occurrence* $P(x_i)$ of component x_i independently for $i=1,2,\ldots m$.

Additionally, knowing the *state* of each component in the state vector x, provided that the component failures are statistically independent, it is possible to calculate the *probability* of the *state vector* x, $P(x)$ and the transition rates among states.

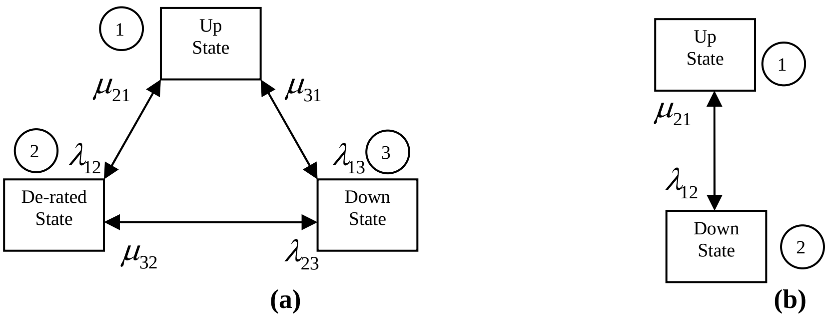


Figure 3.3: Three state Markov model (a), two states Markov model (b)

The probability of the *state vector* can be calculated using (3.1), as the product of the probability associated with the *state* of each component.

$$P(x) = \prod_{i=1}^{m} P(x_i) \tag{3.1}$$

For large systems, reducing the number of system states (i.e. state space) is very important and it will make the calculation process more efficient. The state enumeration technique has been used extensively for composite-system reliability evaluation. It is a way of reducing the system states and hence the computational time during reliability calculation [26] [7]. More about this method is coming in the next subsection.

State Enumeration

For a given transmission system the number of states increases exponentially as the number of components in the state vector x increases. For example, in the transmission system, if 30 lines needed to be enumerated, then the number of the resulted combinations is 2^{30} with two states model each i.e. over one billion states. So, evaluating all system states is practically impossible but may be possible for some small systems. For larger systems, the idea is to set an upper and lower bound limits for the number of states to reduce the computational efforts.

Limiting the contingency depth is one way among others to reduce the number of states; the contingency depth means the number of unavailable units in state *x* at the same time [26]. In order to simplify and reduce the calculation efforts it has been assumed that it is not necessary to go beyond two overlapping outages in the transmission system. In other word, at any system state *x* no more than two outages should be considered. Limiting the contingency depth to the second order will reduce the enumerating time. It has to be mentioned that, three overlapping outages will quickly increase the number of the system states excessively.

The constant failure rate that is used in most of the studies is the average failure rate of the component in a full working year. By assuming so, the probability of three components or two being unavailable at the same time is small. However, the impact of an adverse weather on the system reliability will be higher due to the fact that, in the adverse weather the failure rate of the components will increase. This will in turn make higher order contingencies much more likely to occur [26].

For farther reading about the state reduction techniques the reader recommended to read [26]

3.3.2 Performance Evaluation

The next step is to check the performance of each state which will depend on some predetermined constraints. The performance for each state *x* can be evaluated through *a test function* denoted as $F(x)$, this test function aims to evaluate the state from the success point of view (i.e. being healthy or not).

The test function can be used to assess whether the generation and transmission capabilities during a specific system state, are good enough to supply the specific load. For instance, $F(x)$ might represent the amount of shed load power that is required to prevent the system operating constraints from being violated. It can be said that *x* is a failed state, if $F(x)$>0, (i.e. there is a load shedding associated to system state *x*), and *x* is a success state, if there is no load shedding, $F(x)$=0. The expected value, $E(F)$ of different types of test functions over all possible states is given by:

$$E(F) = \sum_{x \in X} F(x)P(x) \tag{3.2}$$

3.3.3 Reliability Indices

The reliability indices are used to measure the degree of power system reliability, i.e. to measure the capability of the power system to supply the connected customers with power without interruption. In this section a demonstration of calculating the desired system indices will be given (step c in section 3.4)

In case of composite system reliability evaluation, the most important indices that can be used to assess the capability of the system are the frequency of interruption and its expected duration denoted as **FF** and **FD** respectively. However, other indices can be generated also to assess the degree of composite power system reliability, such as Expected Power not Served (EPNS), Loss of Load Probability (LOLP), etc

Reliability data

For each component in the system, the needed reliability data is the failure rate and repair time. The average failure rate and repair time of each component denoted as λ [1/yr] and μ [hr] respectively is needed. The probability of component x_i being unavailable can be calculated by (3.3)

$$P(x_i) = \frac{\lambda_i}{\lambda_i + \mu_i} \qquad (i = 1,2,.....m) \tag{3.3}$$

Where *m* is the number of component in the system state *x* and the index *i* denotes to component *i*. Consequently, the availability of each component is given by (3.4)

$$A(x_i) = 1 - P(x_i) \qquad (i = 1,2,.....m) \tag{3.4}$$

Expected Power Not Supplied (EPNS)

The **E**xpected **P**ower **N**ot **S**upplied (EPNS) in [MW/year] can be calculated using the test performance function as follow

$$\begin{aligned} EPNS &= \sum_{x \in X} F(x)P(x) \\ &= F(x_1)P(x_1) + F(x_2)P(x_2) + ... + F(x_n)P(x_n) \end{aligned} \tag{3.5}$$

Where, *n* is the number of system *states* and the test function, $F(x_i)$ denotes the amount of shed load power associated to state x_i for ($i = 1,2,...,n$). And $P(x_i)$ is the probability of being in that specific state.

Loss of Load Probability (LOLP)

The **L**oss of **L**oad **P**robability (**LOLP**) corresponds to the expected value of an indicator function $F(x)$ and it can be calculated as follow

$$\begin{aligned} LOLP &= \sum_{x \in X} F(x)P(x) \\ &= F(x_1)P(x_1) + F(x_2)P(x_2) + ... + F(x_n)P(x_n) \end{aligned} \tag{3.6}$$

Where;

$$F(x_i) = \begin{cases} 0 & ;\ if\ there\ is\ no\ load\ curtailment\ during\ state\ x_i \in X; i = 1.....n \\ 1 & ;\ otherwise \end{cases}$$

And, $P(x_i)$ is the probability of being in state x_i for (*i=1....n)*

Expected Energy not supplied (EENS)

The EENS index in [MWh/year] can be calculated using (3.7),

$$\begin{aligned} EENS &= \sum_{x\in X} F(x)P(x).8760 \\ &= [F(x_1)P(x_1)+F(x_2)P(x_2)+....+F(x_n)P(x_n)].8760 \end{aligned} \quad (3.7)$$

Given that, $P(x_i)$ and $F(x_i)$ are the system state probability and the amount of shed load power associated to each state respectively for $i=1,2,...,n$.

Failure Probability (FP)

It is defined to be the sum of all probabilities that might lead to load Shedding and it can be calculated by (3.8). For simplicity the load duration curve will be considered as in Figure 2.4.

$$\begin{aligned} FP &= \sum_{x\in X} F(x)P(x) \\ &= [F(x_1)P(x_1)+F(x_2)P(x_2)+....+F(x_n)P(x_n)] \end{aligned} \quad (3.8)$$

Where the performance function $F(x_i)$ represents the outage duration associated to the system state x_i and is defined as follow:

$$F(x_i) = \begin{cases} 0; \textit{if the outage in state } x_i \textit{ did not lead to load shedding} \quad i=1,2,...,n \\ 1; \begin{cases} \textit{if the outage in state } x_i \textit{ led to the whole contracted load shedding } i=1,2,...,n \\ (\textit{i.e the available power to be transfered is less than the } \min.\textit{load level}) \end{cases} \\ \dfrac{\textit{peak load} - \textit{availabel power after the outage } i}{\textit{peak load} - \min \textit{imum load level}}; \quad i=1,2,3,....,n \end{cases}$$

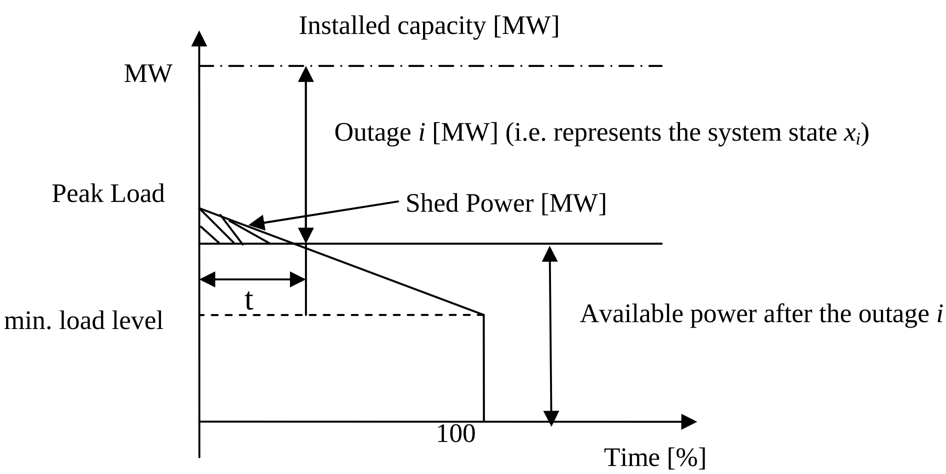


Figure 3.4: load duration curve

The available power after the outage *i* in [MW] is calculated as follow:

$\text{Available power after the outage } i = \text{installed capacity - outage } i$, For $i = 1,...,n$

And $P(x_i)$ is the probability of being in state x_i for $i = 1,...,n$

Failure Frequency (FF)

This index quantifies the number of failure occurrences per year [f/yr]. It can be calculated as the sum of all failure frequencies associated to state x_i for $i = 1,...,n$.

$$\begin{aligned} FF &= \sum_{x \in X} f(x) \\ &= f(x_1) + f(x_2) + ... + f(x_n) \end{aligned} \tag{3.9}$$

Where,

$f(x_i) = Dep(x_i).P(x_i)$, is the frequency of being in state x_i for i=1,2…n.
$Dep(x_i)$: The total rate of departure from state x_i, which is the sum of the individual rate of departure for each component in x.
$P(x_i)$: The probability of being in state x_i.
$i = 1,...,n$; $n \in X$, is the number of resulted states.

Failure Duration (FD)

The failure duration in [hour/failure] is given by (3.10),

$$FD = \frac{FP}{FF}.8760 \tag{3.10}$$

The previously mentioned system indices are the load point indices. In the transmission system level; NEPLAN can generate these indices. These indices will be used as an input to assess the distribution system reliability. The total system indices as well as the load point system indices will be conducted using NEPLAN in chapter six.

In the previous sections it has been shown that the reliability indices correspond to the expected value of test function $F(x)$ over the state space X can be defined based on the required system performance. However, the calculation of the estimation function $E(F)$ is straightforward by first enumerate each state, calculating $F(x)$, and finally accumulating the resulting value $E(F)$.

4. NEPLAN Overview

4.1 Introduction

NEPLAN is user-friendly and fully integrated power system analysis software; it was developed by BCP Inc. in cooperation with ABB Utilities GmbH and the Swiss Federal institute of Technology. NEPLAN can be used in different industrial fields such as electrical transmission and distribution as well as gas and water networks. NEPLAN includes optimal load flow, transient stability, reliability analysis and much more. This software has been used successfully by different utilities. In this project NEPLAN will be used as an analytical simulator for reliability analysis purposes to assess the suitability of such software. More details about NEPLAN will be given in this chapter.

4.2 NEPLAN Reliability

NEPLAN terminology in reliability calculation can be illustrated in the flowchart in Figure 4.1

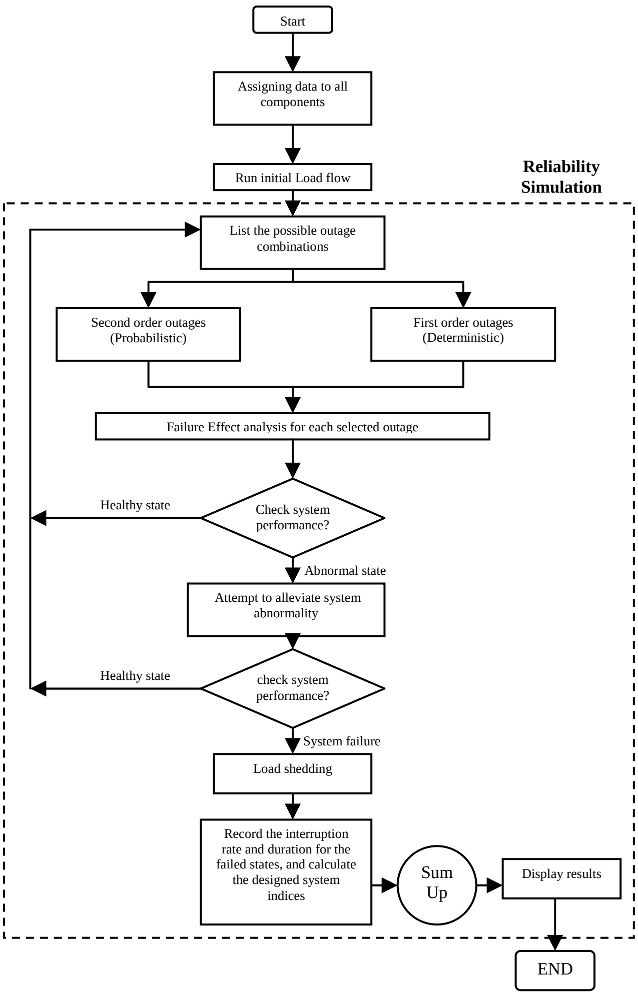


Figure 4.1: Possible flow chart to understand NEPLAN technique in reliability calculation

4.2.1 Outages listing and initialization in NEPLAN

NEPLAN will start by assigning the input data to each element. The initial load flow will be evaluated to determine the pre-state of the system. In this stage, NEPLAN will consider all the assigned operational constraints such as voltage levels, loading limits of all components. If there is any violation in the constraints NEPLAN will report that as a warning or error message. After the initial operating state is investigated, NEPLAN will go to the next step.

In the next step, a listing of all possible outage combination will be made. Normally, the number of possible second order outage combinations in NEPLAN is calculated as follow,

$$Number\,of\ combinations\ taken\ 2\ components\ at\,a\,time = \frac{n!}{2!(n-2)!} \tag{4.1}$$

Where n is the number of components in the system (i.e. generators, transmission lines, circuit breakers, reactors, etc).

As an example, if 108 components are considered in the simulation process, then the resulting number of second order outage combinations can be calculated using equation 4.1, which will give 5778 combinations. In NEPLAN the total number of outage combinations is considered to be the sum of both first and second order outage combinations. By doing so, the total resulting number of outage combination is 5778 plus 108.

However, the first order outages can be as a result of some failure modes such as *independent stochastic single outages*, *common mode outages*, *ground faults* and *unintended switch opening, etc.* The reliability input data for those failure modes are mainly the failure rate and repair time and the output data are failure rate and its associated duration. The second order outages (multiple failures with two overlapping outages) are considered to include two stochastic outages taken two outages at a time. Additionally, due to the sake of simplicity and to lessen the computational efforts and time, more than two overlapping outages is not considered in NEPLAN. The reason of not including the outages that are higher than two is due to the fact that in some applications they are not realistic. More about NEPLAN reliability modules the reader is recommended to read [29] [30].

NEPLAN Enumeration Technique

NEPLAN will be used as a tool to conduct the system indices of the transmission system. Nordic32 is a complex meshed transmission system, which makes the hand calculations impractical. Nordic32 transmission system has 52 transmission lines and 23 generating units as well as 8 power transformers. If each transmission line has to be modelled in two states then the resulted number of states is 2^{52}, which are more than four thousand trillion states. More than one million states will come up from the generating units, which will result in an extreme number of system states. NEPLAN generates the system states based on a smart way that reduces the number of simulated states and hence reducing the simulation time. For instance, NEPLAN considers one single stochastic independent outage (i.e. tripping one component at a time) and two stochastic independent outages (i.e. tripping two components together at zero time). The assumption behind this restriction in NEPLAN is mainly because more than two overlapping stochastic outages are unlikely to happen in the power system, whereas including three overlapping outages would result in a huge increase in calculation time. The earlier-mentioned 108-component system would require the study of 204 156 third-order outages, 35 times the number of first and second-order outages together.

In Nordic32, reliability simulation will be conducted taking into account both deterministic and probabilistic approach. In the deterministic approach (n-1) the number of simulated states is equal to the total number of components in the system, which is in this case 122 states (i.e. 122 components tripping one at a time). While in the probabilistic approach NEPLAN will enumerate the system states taking into account two overlapping outages in each state which will result in (122*121/2) or 7381 states and the total number of the resulted system states is the sum of both single (one component at a time) and double outages (two components at a time) which is 122 plus 7381.

For each state, the AC load flow has to be performed and many aspects have to be considered such as the voltage limits, the generation limits, etc. Moreover, NEPLAN will check the loading limits of the components and make load shedding to some load points in the system to alleviate the effects of some adverse outages. Though, it has to be noticed that reducing the number of system states is vital and it will speed up the calculation time. More about NEPLAN is coming later in this chapter.

4.2.2 Outages performance evaluation

In each state, NEPLAN checks the system performance. If the system performance is within the predetermined limits then another system state will be taken. In case of system abnormality for some states NEPLAN will take some actions to restore the system states such as automatic generation control, utilizing the short- and long-term loading limits of the AC lines and components, if the abnormality persists then a load shedding is the last action followed by an interruption record of the interrupted load point.

Failure Effect Analysis (FEA) and charts are two ways given by NEPLAN among some other evaluation ways in order to evaluate the results of system reliability. In FEA NEPLAN shows the outages list and the involved elements in each outage as well as all events taken by NEPLAN in each listed outage combination such as load shedding, generation rescheduling, etc.

4.3 HVDC module in NEPLAN

The two-terminal mono-polar HVDC module has been modelled in NEPLAN. Figure 4.1 shows the circuit topology of this model.

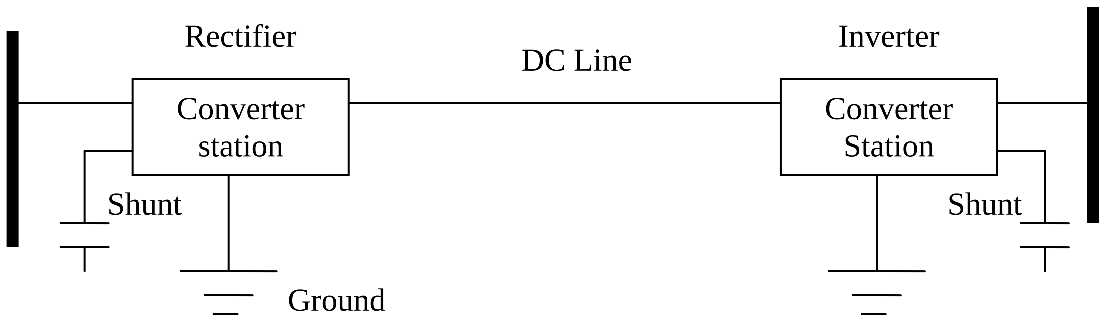


Figure 4.1: The HVDC two-terminal module in NEPLAN

The HVDC model in NEPLAN has been equipped with reactive power compensation at both ends. The continuous compensation at the station ends is responsible of keeping the AC side terminal voltages within the predetermined limit (in this case 98%).

4.3.1 Rectifier Station

The rectifier station in Figure 3.1 is handled by NEPLAN as an integrated converter transformer unit i.e. the transformer already integrated. Moreover, the control mode of this rectifier is assigned to be either power or current modulation to transmit the scheduled active power.

4.3.2 Inverter Station

The inverter station control mode is considered to be the voltage control mode i.e. to keep the voltage on the inverter DC side around unity.

4.3.3 DC line

The DC line is a line with a specific length and nominal voltage. The voltage drop over the line will depend on the line length and consequently the resistance per unit length. The length of the line will depend on its location in the system. The nominal transmission voltage of the HVDC line was assumed to be 600kV. The active power transmission in most of the cases assumed to be 1GW.

4.3.4 HVDC reliability

The reliability of each component that constitutes the HVDC line can be assigned in NEPLAN. The failure rate and repair time of the main HVDC components (i.e. converter stations and the DC line) will be considered and fetched from different resources.

Additionally, it has to be mentioned that the failure of DC line or converter station will directly lead to zero power transmission of the HVDC line (i.e. loss of the whole DC link). Consequently, if the idea is to consider the HVDC failure then it would be enough to consider the failure of the DC line only so as to reduce the number of outage combinations and consequently the simulation time.

It is worth to mention that the reliability assessment, which is carried out by NEPLAN is based on AC load flow for the evaluation of the contingencies. The AC load flow technique can check the existence of enough facilities in the system to meet the demanded load after each outage (single or multiple outages). It also assesses the voltage stability of the system after the contingency. If the system after the loss of the (one or two) components does not fulfil the voltage-stability requirement the ac load flow will not converge. Additionally, it is possible to set undervoltages and overvoltages limits for each node. No other stability aspects (like dynamic voltage stability of angular stability) are taken into account in the assessment process.

4.3.5 Shunt capacitors

The function of the connected shunt capacitors at both station ends is to continuously control the voltage on the AC side of the converter stations. In addition, they will be considered as reactive power compensators to meet the needed reactive power demand of the HVDC stations.

4.4 Reliability Calculation in NEPLAN

An investigation has been done to understand the strategy that NEPLAN uses in the reliability calculations. In [30] investigations have been made to assess NEPLAN calculation strategy. NEPLAN calculates the individual unavailability of each component in the system using the approximated equation as follow

$$P(x_i) = \frac{\lambda_i}{\mu_i} \qquad (i = 1,2,.....m) \tag{4.2}$$

Where the value of repair rate μ_i [r/failure/year] of each individual component is considered being much greater than the value of the failure rate λ_i [1/yr]

For m series connected components the general procedure to calculate the failure rate and equivalent unavailability is given by (4.3), (4.4) respectively

$$\lambda_s = \sum_i^m \lambda_i \qquad (i = 1,2,.....m) \tag{4.3}$$

$$P_s = \sum_i^m P(x_i) \qquad (i = 1,2,.....m) \tag{4.3}$$

Where x_i is the unavailability of component i and $P(x_i)$ can be calculated by using (4.2). After that, NEPLAN will calculate the probability of the state vector using (3.1).

If equation (4.2) is used to calculate the equivalent unavailability of each component, then this way is called the approximated analytical way. It has been shown in [30] that NEPLAN resulting indices are very similar to the approximated analytical way.

5. Nordic32 Test System

5.1 Background

The NORDIC32 test system is an internationally accepted test system. It has been proposed by CIGRE Task Force 38.02.08 [19]. Another version of the system called NORDIC32A is used by the Swedish system operator Svenska Kraftnät (SVK[2]) for training purposes. NORDIC32A system is a fictitious system with transient stability and long-term dynamic simulation properties suitable for training and as a reference, base case, for research studies especially where it concerns voltage stability [20].

In this thesis, a modified version of the NORDIC32A test system will be used for reliability assessment purposes. NEPLAN will be used as a tool for reliability evaluation. Introducing an HVDC line in the system is possible reforming of NORDIC32A, and it will impact the overall system reliability. In the next sections, more details about the test system are given and the two load flow scenarios are investigated.

5.2 System Structure and Design Requirements

The Nordic32A transmission test system consists of four major regions; North, Central, External, and Southwest. The voltage levels in the system are 400, 130 and 220 kV. The network structure of 400 kV voltage level is shown in Figure 5.1. There are 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 mainly in the North area. The generation and load in the system is distributed in a way that the power flows from North to Central. In addition, the Southwest region is loosely connected to the system [20].

To be suitable for transmission-system reliability studies, the test system should be at least (n-1)-secure; i.e. the loss of any single component should not lead to an interruption for any of the loads ("bulk supply points"). As a criterion for stable operation of the system after the loss of a component, convergence of the AC load flow in NEPLAN has been used. This is the same criterion as will be used in the reliability analysis in Chapter 6. Some of the states after loss of one component like after loosing line 4011-4021, were instable under this criterion. Therefore the following modifications were made to the system:

- Splitting some of the large generator units into two equal units. The loss of the large unit would have resulted in a system for which the ac load flow no longer converges.
- Adding a shunt capacitor bank to two of the substations.

[2] SVK stands for Svenska Kraftnät which is the transmission system operator in Sweden

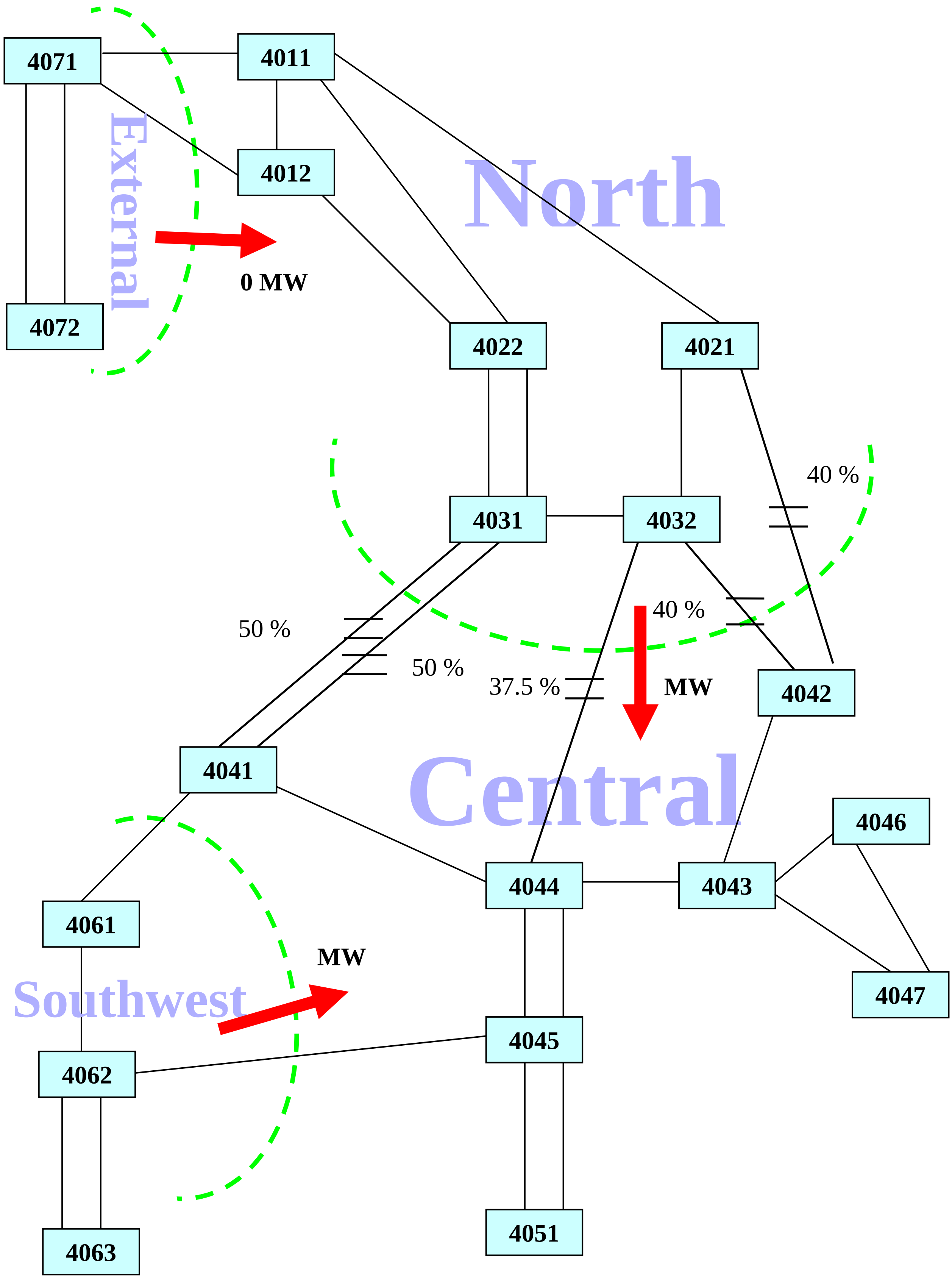


Figure 5.1: 400 kV network structure of NORDIC32 [20]

In Figure 5.1 the main five transmission lines that make up the power corridor between North and Central regions are series compensated [20]. The structure of the sub-networks with 220 kV and 130 kV are shown in Figure 5.2. Three of those networks located in the North and connected to the 400kV network through step up power transformers. The other 130kV sub-networks is located in the central area and it is heavily loaded. See Figure 5.3.

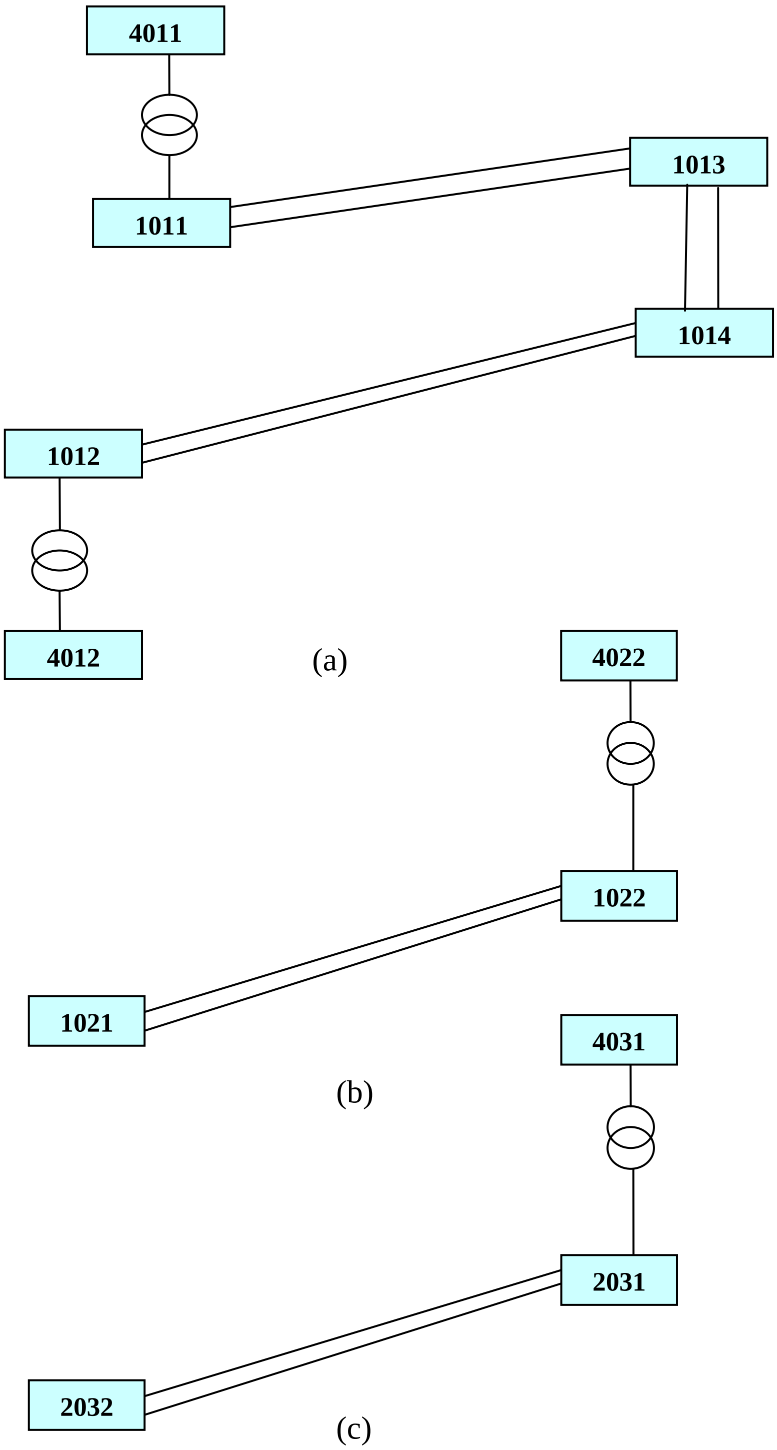


Figure 5.2: (a) and (b) are the 130 kV networks structure and (c) is a 220 kV network.
(a), (b), and (c) are all located in the North area

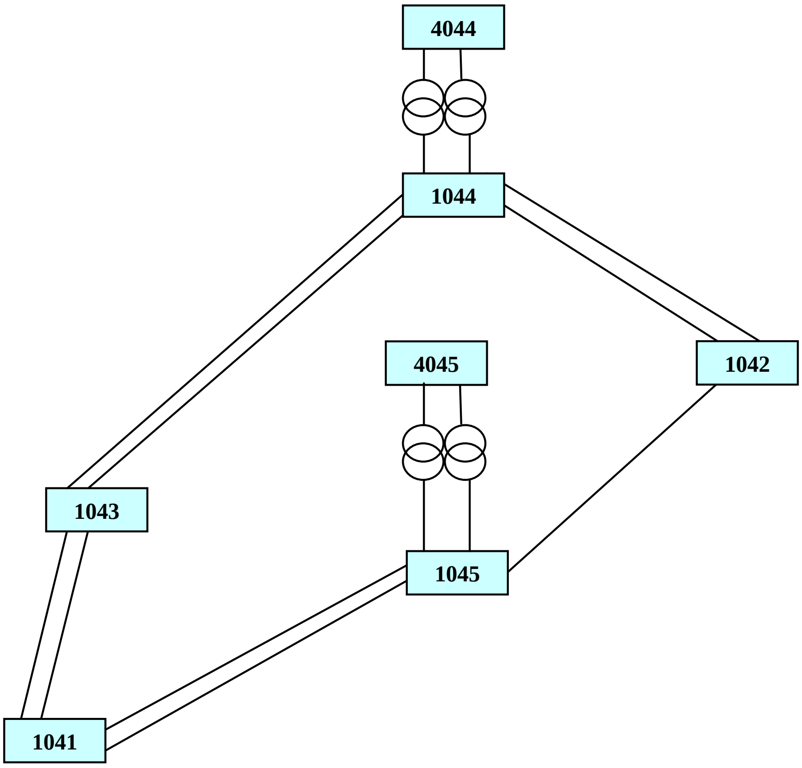


Figure 5.3: 130 kV network structure of the sub-area located in the central

5.3 Network Data and Load Flow Scenarios

The generation in the system is mainly in the North area while the load center is in the central area. Figure 5.4 shows the generation of each unit in the system. It is important to mention that the generated power in the system as it is shown below based on the moderate transfer load flow scenario from North to Central denoted as LF32-029.

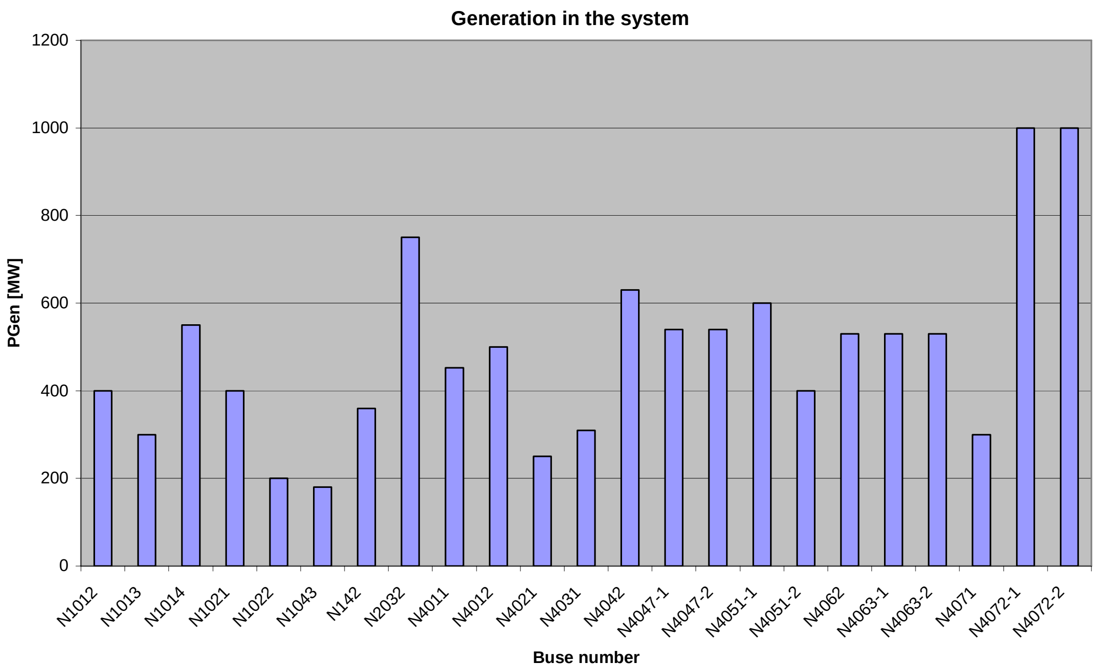


Figure 5.4: The generation of each unit

Where N in the x-axis denotes to bus number in the system

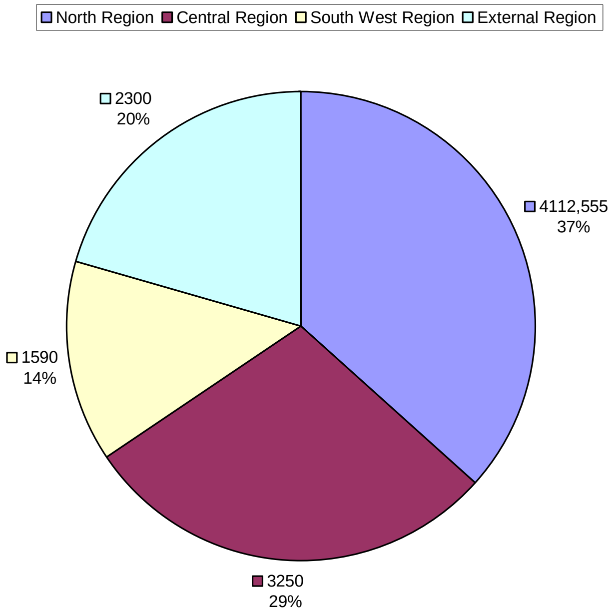


Figure 5.5: The generation percentages in the four regions (LF32-029) and using NEPLAN's load flow calculation

The load is distributed in the system is shown in Figure 5.5. The central region is considered to have the biggest amount of load where most of the loads are located in the central region. Figure 5.6 shows the load percentages in the regions.

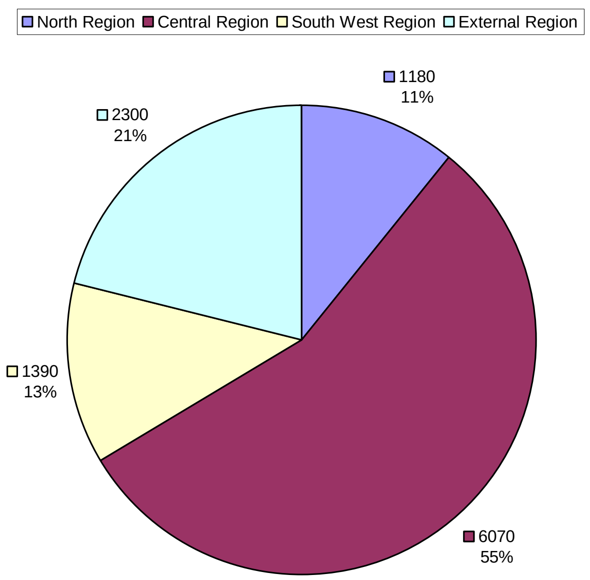


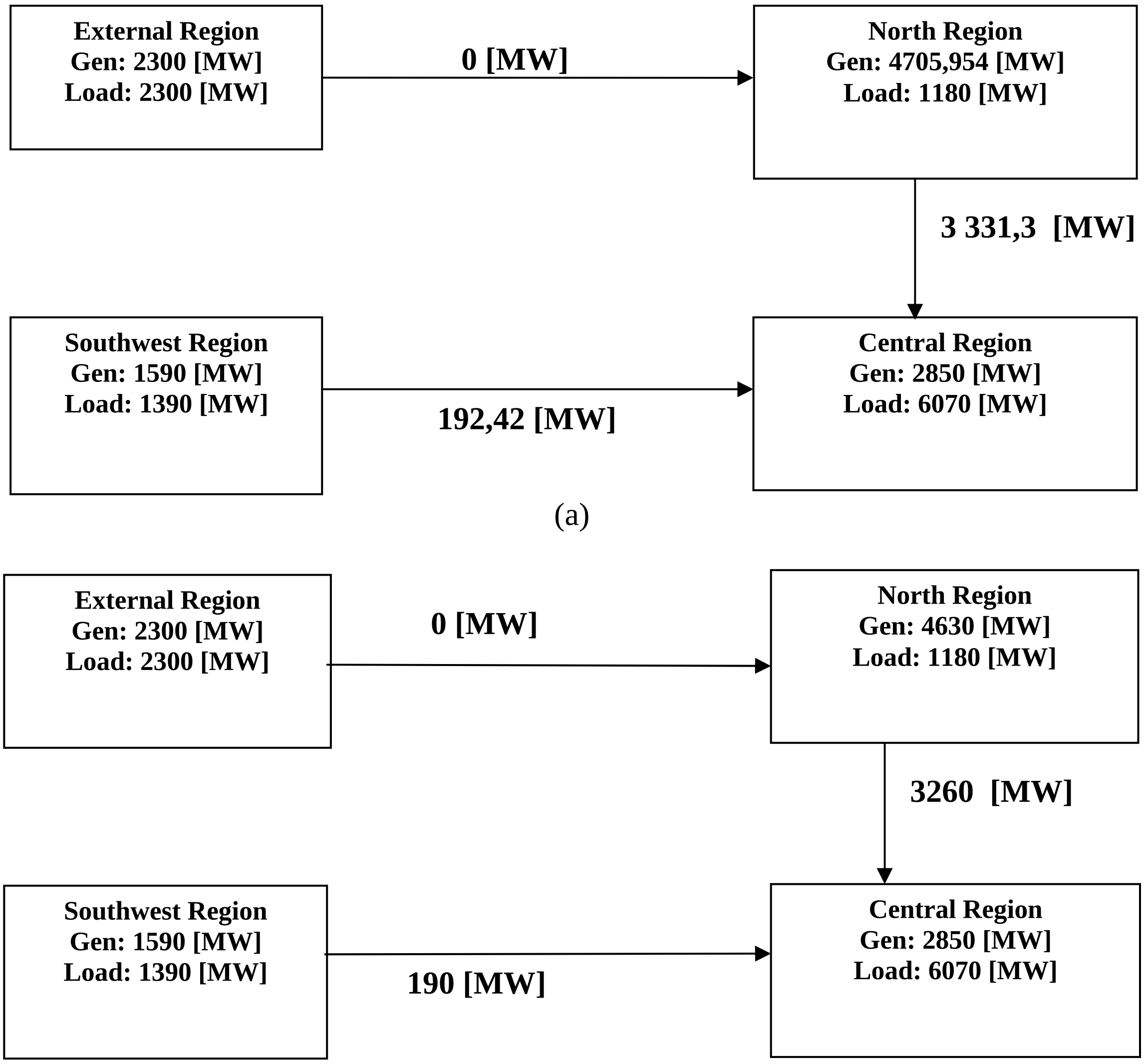
Figure 5.6: Load percentages in the regions

The total power generation in all areas is 11253 [MW] and the total load is 10940 [MW] while the resulting total active losses are 312.55 [MW].

Two load flow scenarios in the Nordic32 network are used for training purposes. LF32-028 is the load flow with high power transfer from North to Central area at the peak load. LF32-029 scenario is the load flow with moderate power transfer from north to central at the peak load. It has to be mentioned that LF32-028 is not (n-1) secure when using the convergence of the AC load flow in NEPLAN as a criterion.

LF32-029 is obtained from LF32-028 by extra generation of some units in the central area and decreasing the generation in the north area. The system can be modified to work in LF32-029 as follows (i.e. from LF32-028 to LF32-029).

- Generator 1 at bus 4011 From 668.5MW to 450.3MW (slack bus)
- Generator 1 at bus 4012 From 600.0MW to 500.0MW
- Generator 1 at bus 1012 From 600.0MW to 400.0MW
- Generator 2 at bus 4051 From 0 (not in operation) to 400.0MW



(b)

Figure 5.7: LF32-028 from SVK, (a) NEPLAN results, (b) Swedish system operator results

In Figure 5.7, the high transfer load flow scenario has been validated. NEPLAN's load flow results are very close to the results presented by Swedish system operator for the same load flow scenario.

Later on, in this thesis the moderate load flow scenario will be used in the reliability simulations. The moderate load flow scenario is shown in figure 5.8.

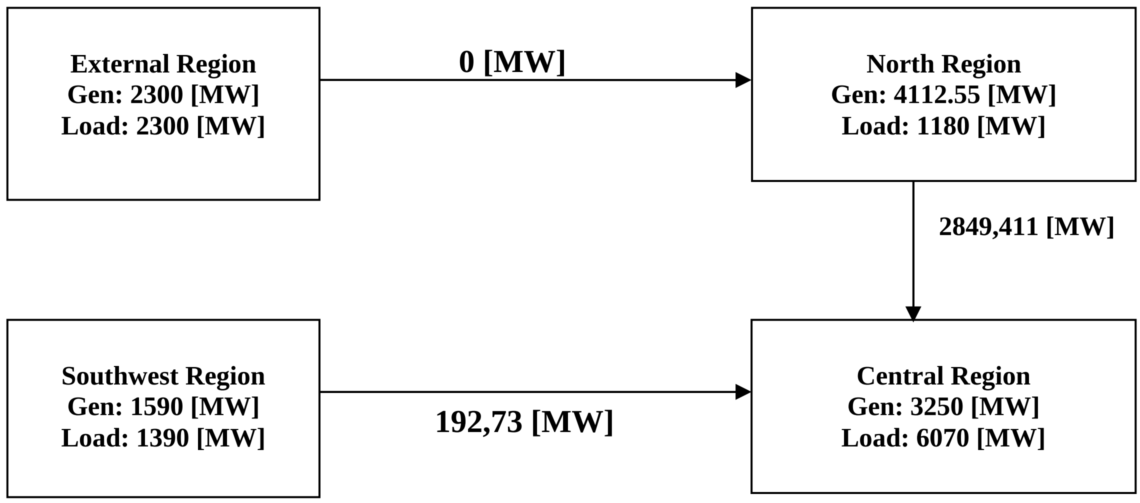


Figure 5.8: The resulting load flow scenario (LF32-029) based on NEPLAN load flow

The total resulting active losses in all regions for the moderate load flow scenario as it is shown in figure 5.8 are approximately 312 [MW]. The load flow results from NEPLAN do not exactly match the presented load flow results by the transmission system operator (SVK), which is mainly due to the line lengths approximations, as well as the line charging. Moreover, in each region, and for example in the North Region, Gen: 4112.55 [MW] stands for the actual generation based on NEPLAN terminology while Load stands for the actual installed load.

As mentioned before, in the reliability module of NEPLAN the stability of the system under a contingency (loss of one or two components) is assessed through the convergence of the AC load flow. If the load flow convergence it is assumed that the new operational state and the transition to this state are stable. If the load flow does not converge it is assumed that the new state or the transitions are not stable. It is further assumed that no three components are out at the same time.

6. Reliability Assessment of Nordic32 Test System

In this chapter the reliability simulation will be carried out in NEPLAN. The simulations consist of different cases. Firstly, the basic system (base case) will be simulated. The base case denotes to the modified Nordic32 AC conventional system without any HVDC involvements. Moreover, some HVDC cases will be proposed and added to the system in different locations to check how the system reliability will be impacted. It has to be noticed that all the simulated cases in this chapter are based on the moderate transfer load flow scenario (LF032-029). The used reliability data in this project has been fetched from [32] [33] [35].

6.1 Reliability input data

The failure rate and repair time of the 400 kV transmission lines are shown in Table 6.1

Table 6.1: The failure rate and repair time of the 400 kV transmission lines

Connected from Bus	Length [km]	Failure [1/yr]	Repair Time [hr]
4031 To bus 4041	770	3,92	38,89
4031 To bus 4041	770	3,92	38,89
4032 To bus 4044	810	4,13	40,91
4032 To bus 4042	580	2,95	29,29
4021 To bus 4042	1000	5,1	50,51
4042 To bus 4044	190	0,96	9,60
4042 To bus 4043	140	0,71	7,07
4022 To bus 4031	370	1,88	18,69
4022 To bus 4031	370	1,88	18,69
4021 To bus 4032	380	1,93	19,19
4012 To bus 4022	285	1,453	14,39
4011 To bus 4021	535	2,728	27,02
4011 To bus 4022	320	1,63	16,16
4011 To bus 4012	100	0,51	5,05
4071 To bus 4011	380	1,93	19,19
4071 To bus 4012	420	2,142	21,21
4071 To bus 4072	300	1,53	15,15
4071 To bus 4072	300	1,53	15,15
4044 To bus 4043	70	0,357	3,54
4043 To bus 4046	60	0,306	3,03
4046 To bus 4047	100	0,51	5,05
4043 To bus 4047	130	0,663	6,57
4044 To bus 4045	170	0,867	8,59
4044 To bus 4045	170	0,867	8,59
4045 To bus 4051	280	1,428	14,14
4045 To bus 4051	280	1,428	14,14
4062 To bus 4045	760	3,876	38,39
4041 To bus 4044	260	1,326	13,13
4041 To bus 4061	395	2,0145	19,95
4061 To bus 4062	130	0,663	6,57
4062 To bus 4063	230	1,173	11,62
4062 To bus 4063	269	1,173	11,62
4031 To bus 4032	93,7	0,408	4,04

In Table 6.1 the failure rate of the 400 kV overhead lines is assumed to be 0.51 [1/yr/100Km] as stated in the Nordel annul report, fault statistics 2005 [32].The average repairs time is assumed to be 5 [1/yr/100 km]. It has been assumed that both the failure rate and repair time will increase as the line lengths are increase.

In Table 6.2, the failure rate of both 110 and 220 kV overhead lines are assumed to be 2.11 [1/yr/100Km] and 0.91 [1/yr/100Km] respectively as stated in the Nordel annual report, fault statistics 2005 [32]. The average repair times of both 110 and 220 kV overhead lines are assumed to be 1, 69 [h/failure] respectively.

Table 6.2: Failure rate and repair time of the 110 kV and 220 kV transmission lines

Connected from Bus	Length [km]	Failure [1/yr]	Repair time [h]
1011 To bus 1013	43	0,9073	0,73
1011 To bus 1013	43	0,9073	0,73
1013 To bus 1014	31	0,6541	0,53
1013 To bus 1014	31	0,6541	0,53
1012 To bus 1014	56	1,1816	0,95
1012 To bus 1014	56	1,1816	0,95
1021 To bus 1022	94	1,9834	1,60
1021 To bus 1022	94	1,9834	1,60
1043 To bus 1044	49	1,0339	0,83
1043 To bus 1044	49	1,0339	0,83
1043 To bus 1041	38	0,8018	0,65
1043 To bus 1041	38	0,8018	0,65
1041 To bus 1045	77	1,6247	1,31
1041 To bus 1045	77	1,6247	1,31
1044 To bus 1042	187	3,9457	3,18
1044 To bus 1042	187	3,9457	3,18
1045 To bus 1042	187	3,9457	3,18
2031 To bus 2032	54	0,4914	0,92
2031 To bus 2032	54	0,4914	0,92

The reliability data for the circuit breakers on different voltage levels and for different components are given in Table 6.3(a, b); the data has been collected from [33]. The given data below were collected and averaged in the period between1997 to 2002.

Table 6.3: (a) and (b) presents the failure rate and repair time of the circuit breakers in the system for different voltage levels.

400 kV Circuit Breakers (CB)		
Connected to	**Failure [1/yr]**	**Repair time [hr/failure]**
lines	0,00214	12,48
Reactors	0,0242	10,0
Transformer	0,0215	6,55

(a)

220 kV Circuit Breakers (CB)		
Connected to	**Failure [1/yr]**	**Repair time [hr/failure]**
lines	**0,00285**	**1,138**

(b)

Table 6.4: Failure rate and repair time of power transformers

Connected from Bus	No. Of Transformers	Failure [1/yr]	Repair time [hr/failure]
4011 To bus 1011	**1**	**0,0147**	**9,766**
4012 To bus 1012	**1**	**0,0147**	**9,766**
4022 To bus 1022	**1**	**0,0147**	**9,766**
4044 To bus 1044	**1**	**0,0147**	**9,766**
4044 To bus 1044	**1**	**0,0147**	**9,766**
4045 To bus 1045	**1**	**0,0147**	**9,766**
4045 To bus 1045	**1**	**0,0147**	**9,766**
4031 To bus 2031	**1**	**0,0147**	**9,766**

In Table 6.4; the failure rate were fetched from [32] and the repair time has been assumed to be 9.766 [hour/failure].

The generating unit's failure rate and failure duration has been obtained from [35].

- The failure rate is 0.1691 [1/yr]
- The repair time is 32.7 [hr/failure]

The reactor's failure rate and failure duration (on 400kV level) has been fetched from [35].

- The failure rate is 0.354 [1/yr]
- The repair time is 39.5 [hr/failure]

The shunt capacitor failure rate has been obtained from [32] while the repair time has been assumed:

- The failure rate is 0.00512 [1/yr]
- The repair time is 10 [hr/failure]

The used reliability data in this project is not realistic for most of the components. It still can be used without affecting the final results. However, the resulting indices of the AC system is not either realistic, but still can be used for comparison[3] in this thesis work.

6.2 Assumptions and limitations

A number of assumptions had to be made during the study.

- Only single independent stochastic failures have been considered for each component and also for the HVDC line. This is due to the lack of data on dependent (common-mode) failures.

[3] The comparison is always made for the same AC system before and after introducing the HVDC lines to it. e.g. we compare the AC system indices without HVDC by the AC system indices after incorporating the HVDC line in the system.

- All bus bars in the system have been considered to be ideal (i.e. 100% available). The assumption has been made due to the lack of substation details, It was further as well as the proper reliability data.
- The voltage limits of all bus bars have been specified (i.e. 90% to 110%). The specified voltage limits has been assumed to be acceptable for a proper operation of the transmission system.
- The loadings of all lines, generators, and transformers have been approximated since no data was available for that.

In Figure 6.1 the numbers in the circles refers to the number of machines connected to that bus i.e. 1 for 1st machine and 2 for 2nd machine. The generation of each machine on different buses and its limits can be found in the appendices.

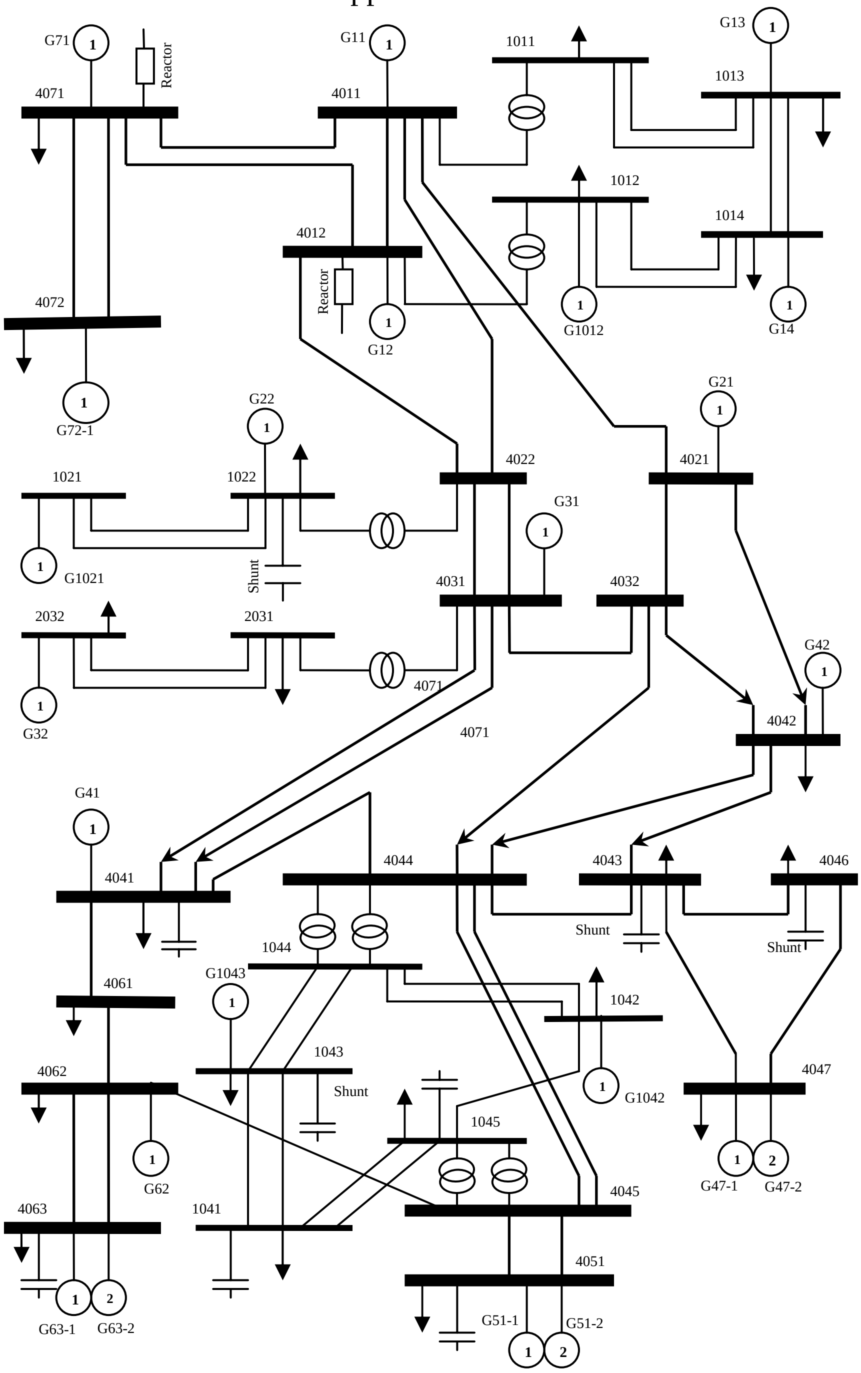


Figure 6.1: The single line diagram of Nordic32 test transmission system without modifications

6.3 System simulation

The simulations will consider the single and multiple failures where the first and second order outages are considered respectively. In each simulated *case*[4] the load point indices as well as the total system indices will be obtained and a comparison with the *base case*[5] will be carried out.

6.3.1 System modifications

The modifications that have been accomplished can be motivated as follow:

- It has been shown from the preliminary simulation of NEPLAN that losing the line between 4062 and 4061 as shown in Figure 6.2 has caused an under-voltage at bus 4061. Consequently, a load shedding has been taken place on that bus and the connected load point LP61 with 500 [MW] was completely shed.

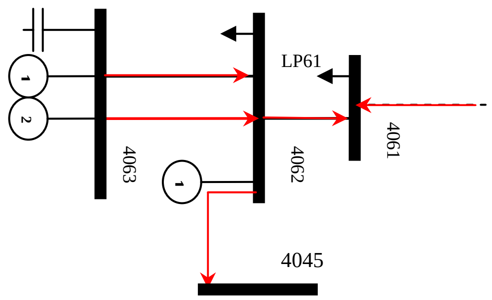


Figure 6.2: South West area subsystem

In order to reinforce the system to be (n-1) secure under the criteria used in the reliability analysis, particularly after losing this line, a capacitor bank of 100 MVar has been added to bus 4061. By doing so, the system has become more secure in case of losing this line. However, this line has been dynamically tripped and simulated by the Aristo simulator at Svenska Kraftnät and showed that the system is marginally stable but with poor damping[6]

- Losing the generating unit connected to bus 4072 with 2000MW will cause directly a load shedding on the same bus. The reason of load shedding is due to load flow un-convergence (not enough generating facilities). Losing the whole unit is not realistic. So, we have to assume that the unit is 100% available or splitting it into two machines sharing the 2000MW. By doing so, the system will be (n-1) secure and it will situate losing one unit at a time. Though, splitting up this large machine into two machines has been made.

- If the system loses the generator that is connected to bus 1042, the load flow will indicate an under-voltage on the same bus and hence a load shedding will take place due to the difficulties of alleviating the resulted under-voltage problem. The system has been modified to withstand this outage by connecting a capacitor bank of 50 MVar to bus 1042.

[4] *Case* here states for the modified Nordic32 system after adding the HVDC line in some particular location
[5] The *base case* denotes to the Nordic32 system after being modified and no HVDC lines added to it
[6] The simulation of this particular outage has been performed at SVK with Aristo during the last visit to Råcksta in Vällingby on 4th of April.

For the mentioned three single outages, the system had some difficulties in the restoration process. And the only unwanted way that had been adopted by NEPLAN to alleviate the abnormality is the load shedding. After the modifications; the system has become more secure and it has the ability to alleviate any single outages e.g. it is (n-1) secure.

The components that have been taken into account in the reliability simulation are listed below:

- Fifty-two transmission lines.
- Twenty-three generating units.
- Eight transformers (i.e. connecting different networks with different voltage levels)
- Twenty-three generator transformers (i.e. step up transformers)
- One synchronous condenser and its transformer
- Two reactors.
- Twelve shunt capacitors.

The total number of components is 122 components taking into account the new machine at bus 4072 (i.e. after modifications) and the two added shunt capacitors. The total number of outage combinations in NEPLAN is 122 plus 7381 (i.e. 7503 combinations). The number of served load points is 22, and all load points have the same priority of being interrupted.

In Figure 6.4, the single line diagram of the system has been redrawn again taking into account the proposed modifications. From now on, the simulation of the modified Nordic32 will be carried out based on the modified Nordic32 system and it will be denoted as the base case.

6.3.2 Base case simulation

The system as shown in Figure 6.4 has been simulated. The resulting load point indices are shown in Figure 6.3. The simulated system after the modifications contains 122 components, which will result in 7503 outage combinations (i.e. first and second order outage combinations).

The generated load point indices are defined as follow:

- ✓ F (1/yr) is the failure rate per year associated to each load point (interruption frequency).
- ✓ T (hour) is the average failure duration associated to each load point (Mean time of interruption)
- ✓ Pr (min/yr) is the expected probability of interruption in minutes per year
- ✓ P (MW/yr) is the power not supplied which is the product of interrupted power and its interruption frequency.

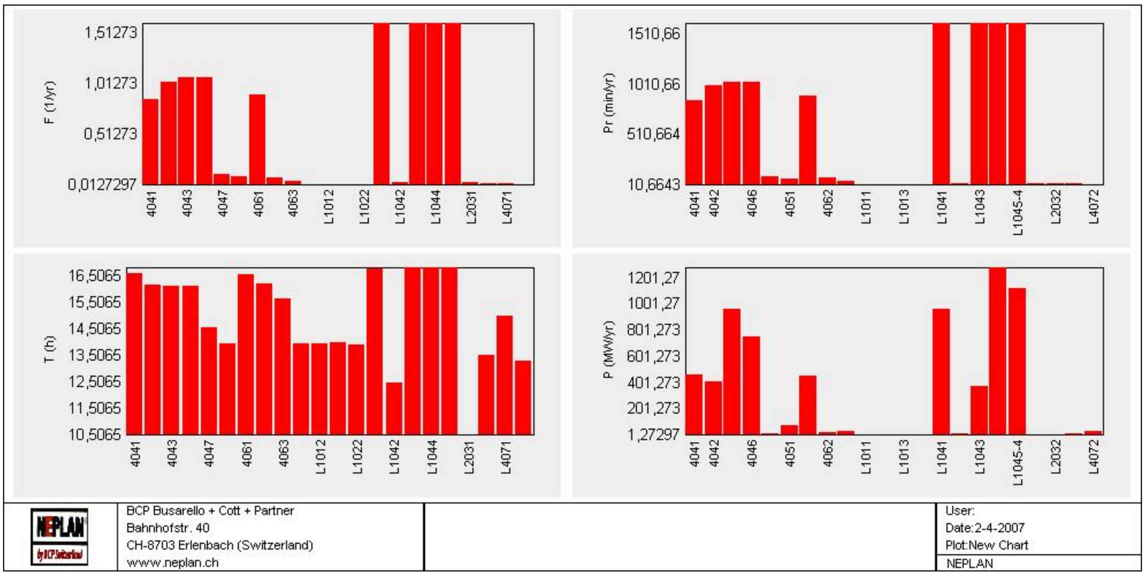


Figure 6.3: load point indices of the conventional modified AC system (base case)

Table 6.1: Total system indices of the conventional modified AC system (base case)

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,537	System average interruption duration index
SAIDI	min/yr	530,339	Customer average interruption duration index
CAIDI	h	16,475	Average service availability index
ASAI	%	99,899	System load interruption frequency
F	1/yr	1,609	System load interruption mean duration
T	h	16,718	System load interruption probability
Q	min/yr	1614,476	Total interrupted load power
P	MW/yr	6949,589	Total load energy not supplied
W	MWh/yr	114597,339	Total load energy not supplied

The total system indices are shown in Table 6.1 and they will act as reference indices to be compared with the different indices of the proposed cases, especially the cases where the HVDC lines are involved. It has to be mentioned that, the indices of any particular case should not be taken as a realistic indices, but the resulting indices e.g. the base case indices still can be compared to the resulting indices of the transmission system after adding the HVDC line. One more reason of not considering the indices as realistic is due to the uncertainty of the used reliability data and the fact that a non-existing system has been used as a test system.

Another system index is proposed to count for the number of adverse 2nd order outages. The new system index is called the system improvement index (SII) and is valid only for this study. SII is defined as the ratio of the number of adverse 2nd order outages that led to at least one load point interruption to the total number of examined outages. The idea behind this is to have another indicator that indicates the reduction of the adverse outages in each simulated case.

$$\text{System improvement index (SII)} = 1 - \frac{\text{Number of adverse 2nd order outages}}{\text{The total number of examinaed outages}}$$

However, in the simulated base case, the system improvement index (SII) is $1-\frac{405}{7503}=94.6\%$

This percentage represents how healthy is the system. For instance, 94.6% of the outages are healthy i.e. 405 outages out of 7503 outages considered of being dangerous and consequently led to load shedding. The more we increase this index the more reliable system we get. However, SII will increase if the resulted 2nd order adverse outages is reduced, and this can be done be reinforcing the system to get it more secure by introducing the HVDC lines.

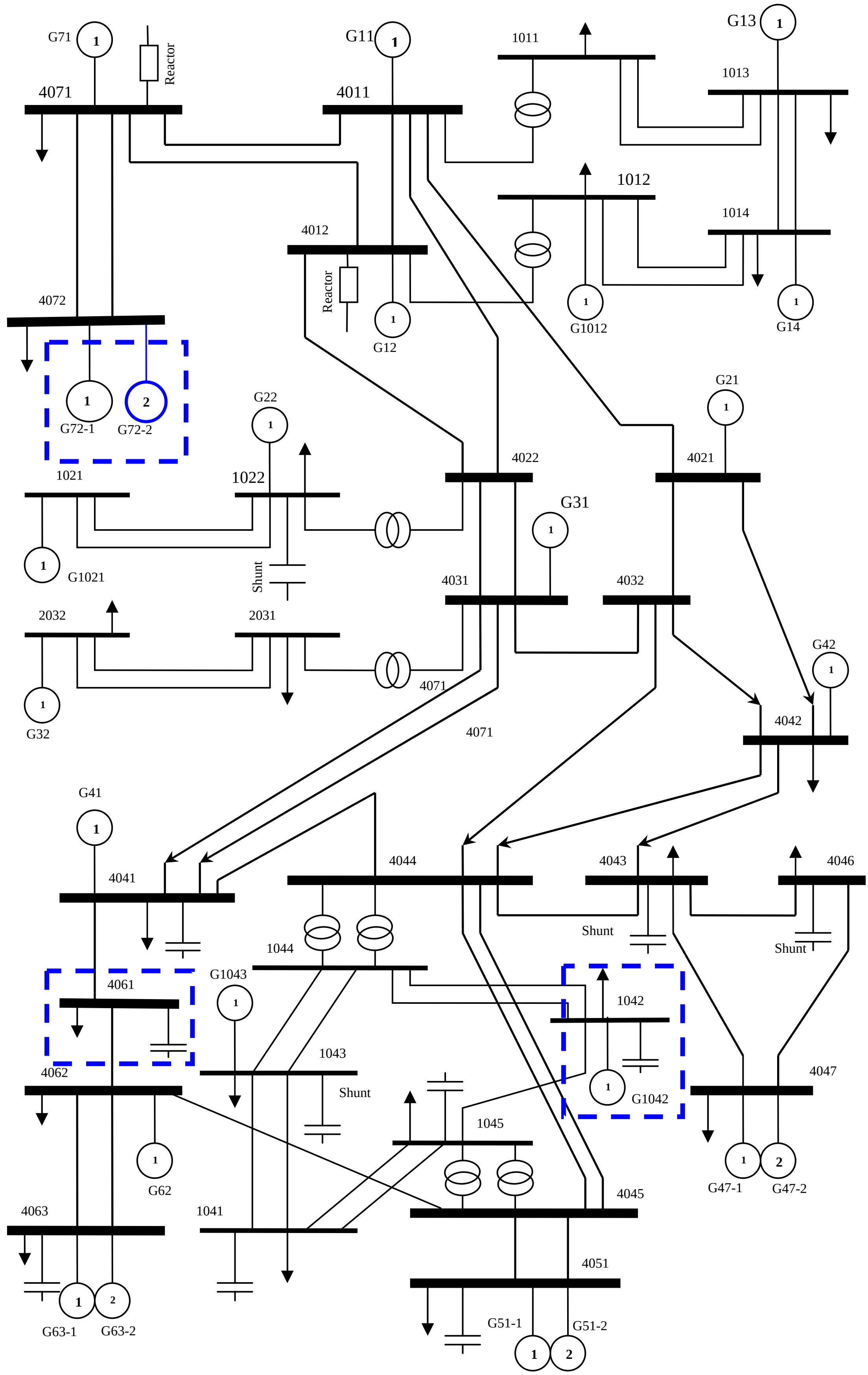


Figure 6.4: Nordic32 single line diagram after modifications (base case)

6.3.3 HVDC impacts on transmission system reliability

In this section we will introduce the HVDC link to the system. Before simulating the system, it is worth discussing how the reliability data is going to be assigned to the HVDC components. If we consider the HVDC link as shown in Figure 6.5. The availability of the HVDC line is associated to the availability of converter transformers at the terminal stations as well as the DC cable. In other word, the HVDC line will fail if one of the three components fails. For sake of simplicity and to reduce the number of simulated states, the failure rate and repair time of the HVDC line will be calculated as the equivalent failure rate and repair time of three series connected components.

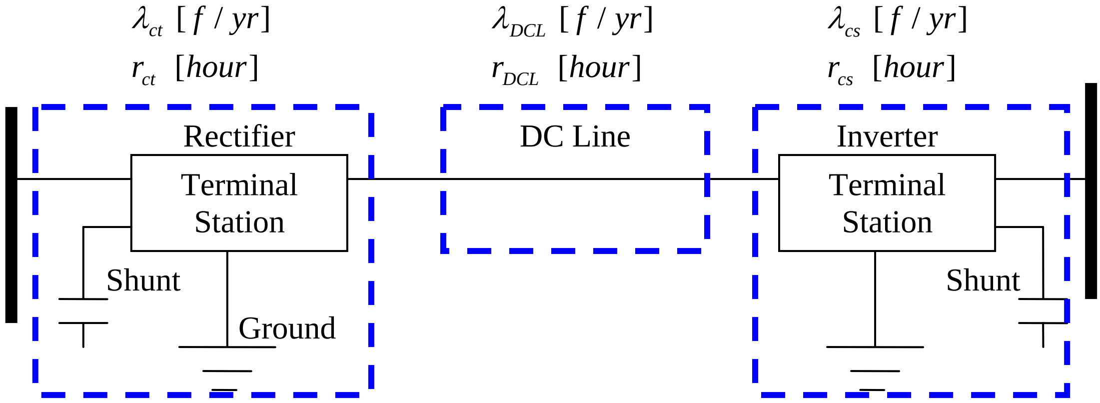


Figure 6.5: The reliability model of the HVDC link

The resulting failure rate and repair time will be assigned to the DC cable. NEPLAN will treat the HVDC link as any other component and it will be either in operation if the DC cable is connected or out of operation if the DC cable is out. The failure and repair rate of the converter transformer have been obtained from [35] as:

$$\lambda_{ct} = 0.0153\,[f/yr]$$
$$r_{ct} = 1664[hour/failure]$$

The failure rate and repair rate of the DC cable are fetched from [35]

$$\lambda_{DCL} = 0.000781\,[f/yr]$$
$$r_{DCL} = 68.8[hour/failure]$$

The equivalent failure rate and its duration time for the three series connected units can be calculated as follows [36]:

$$\lambda_s = \sum_{i=1}^{n} \lambda_i = \sum_{i=1}^{3} \lambda_i = \lambda_{ct} + \lambda_{DCL} + \lambda_{ct} = 0.0153 + 0.000781 + 0.0153 = 0.03138[f/yr]$$

$$R_s = \frac{\sum_{i=1}^{n} \lambda_i . r_i}{\lambda_s} = \frac{\sum_{i=1}^{3} \lambda_i . r_i}{\lambda_s} = \frac{0.0153 * 1664 + 0.000781 * 68.8 + 0.0153 * 1664}{0.03138} = 1624.35[hour/failure]$$

λ_s And R_s stand for the failure and repair rate of the whole HVDC link. In NEPLAN those values will be assigned to the DC cable. Table 6.2 presents the proposed HVDC cases. Moreover, the reliability model of the HVDC line is still simple and more detailed reliability model is needed in order to include the different failure mechanisms of the HVDC lines e.g. the maintenance outages, minor outages (de-rated states), etc.

Case 1: An HVDC link between bus 4032 and 4043 (Adding)

The connected HVDC link is a mono-polar link transmitting 1000MW from North to Central area. The HVDC model will be modeled in the load flow as a constant power link. Nevertheless, the HVDC link will be considered as a constant load on the North region and a constant power generation in the central region which will consequently reduce the line loadings of the AC transmission lines between the North and Central. If either a single failure or a multiple failure outages happened in the North or Central area the other AC transmission lines will regulate their power to restore the balance between the connected areas. In Figure 6.6, the layout of the conventional AC system that connects the two regions is shown.

Table 6.2: Proposed HVDC /cases

Cases	Description
1	An HVDC link between bus 4032 and 4043 (Adding)
2	An HVDC link between bus 4021 and 4042 (Adding)
3	An HVDC link between bus 4021 and 4042 (Replacing)
4	An HVDC link between bus 4031 and 4042 (Adding)
5	An HVDC link between bus 4032 and 4042 (Adding)
6	An HVDC link between bus 4032 and 4042 (Replacing)
7	An HVDC link between bus 4032 and 4044 (Replaced)
8	An HVDC link between bus 4032 and 4044 (Replaced)
9	An HVDC link between bus 4032 and 4044 (Replaced) and HVDC link between 4021 and 4042 (Replaced)

Before connecting the HVDC link between the two regions, The North region was exporting around 2849 [MW] to the Central throw the five AC transmission lines, see Figure 6.6. In Figure 6.7, the HVDC line has been embedded (Added) to the system between bus 4032 and bus 4043. The operational consequences of inserting this line can be summarized as follow:

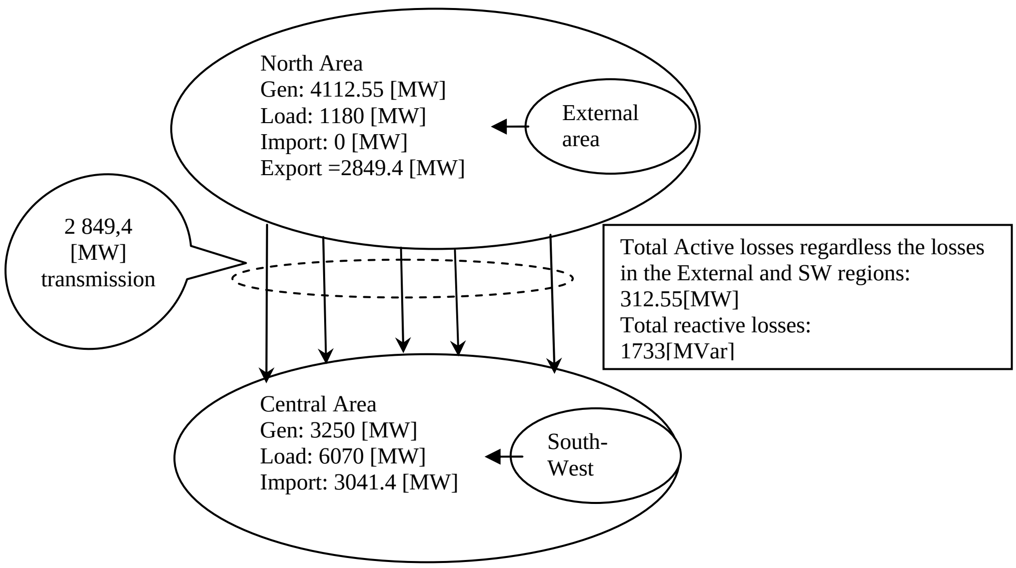


Figure 6.6: Area's layout without HVDC connected (base case)

- The AC lines loading have been reduced and thus increasing the power regulation margin. See Figure 6.7 where the amount of power transfer from North to Central is reduced. During any outage, those lines will regulate their power to assist the power deficit regions and consequently reducing the failure rate of load points.

- The total active and reactive power losses in the system reduced compared to the base case as shown Figure 6.7 and Figure 6.6. Moreover, the existence of HVDC link in any location will optimize the load flow operation and hence reducing the operational losses.
- An improvement in voltage stability of the Nordic32 test transmission system has been achieved.

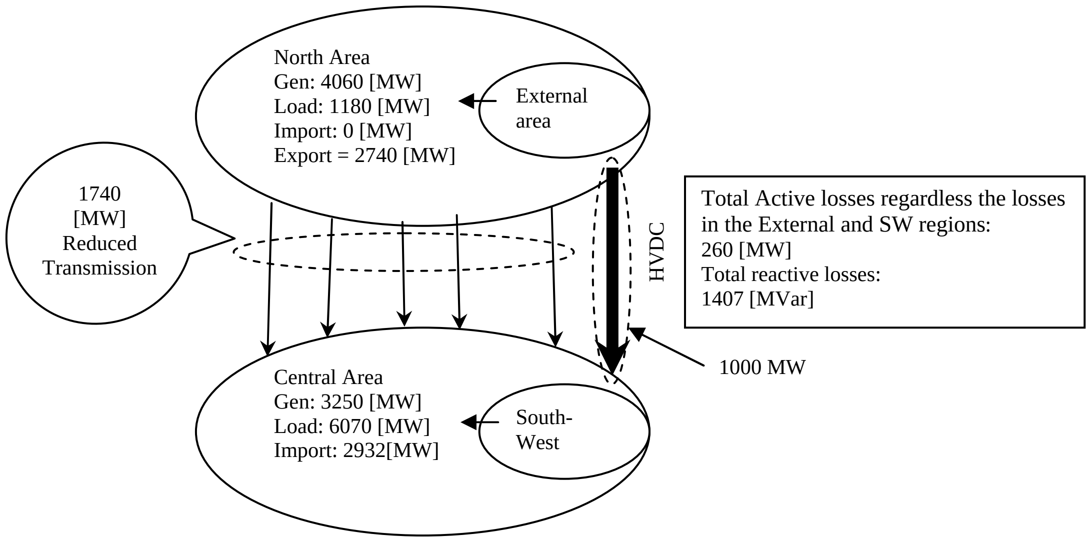


Figure 6.7: Area's layout with HVDC connected between 4032 and 4043 (case 1)

After losing the whole HVDC link, the system will come back again to its normal operation and the main five transmission lines will take over the 1000MW that was handled by the HVDC link. The load point indices of the system after adding the HVDC link between buses 4032 and 4043 are shown in Figure 6.8. And the total system indices are shown in Table 6.3.

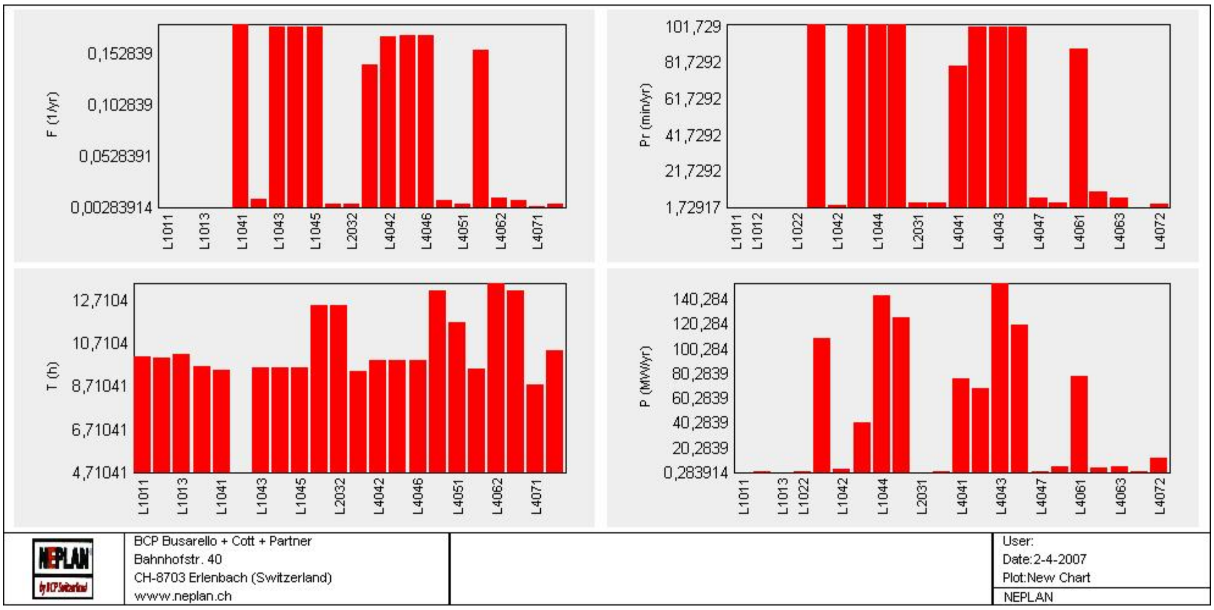


Figure 6.8: Load point indices of case 1.

The number of simulated components is 123. Therefore, the number of possible outage combinations is 7626. The system improvement index (SII) can be calculated as follow:

$$\text{System Improvement Index (SII)} = 1 - \frac{81}{7626} = 98.94\%$$

Where 81 represents the number of 2^{nd} order adverse outages that led to supply interruption. However, SII indicates the improvement of the system. It's obvious, after adding the HVDC link between 4032 and 4043 the system became more secure and it can stand 98.94% of the outages (i.e. multiple outages of second order). It is also worthy to mention that the single stochastic independent failures did not cause any load interruption since the system designed to be (n-1) secure. On contrast, the load interruption comes from the multiple independent outages of second order only.

Table 6.3: Total system indices of case 1

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,0732	System average interruption frequency index
SAIDI	min/yr	42,7169	System average interruption duration index
CAIDI	h	9,7314	Customer average interruption duration index
ASAI	%	99,9919	Average service availability index
F	1/yr	0,1888	System load interruption frequency
T	h	9,2892	System load interruption mean duration
Q	min/yr	105,2046	System load interruption probability
P	MW/yr	949,8795	Total interrupted load power
W	MWh/yr	9236,336	Total load energy not supplied

In Figure 6.8, the failure rate of all load points as well as the associated failure duration is reduced compared to the base case. It has to be noticed that introducing the HVDC line to the System in any location will improve the voltage stability and hence alleviating the load interruptions. The amount of curtailed load power after adding the HVDC link between 4032-4043 reduced from 6949MW/yr down to 949 [MW/yr] which is almost 13.6% of the curtailed load power compared to the base case.

Case 2: An HVDC link between bus 4021 and 4042 (Adding)

The added HVDC link in this case will act the same as in case one. It will reduce the loading of the AC transmission lines. It is obvious from Figure 6.9 that the failure rate and duration is lowered compared to the base case.

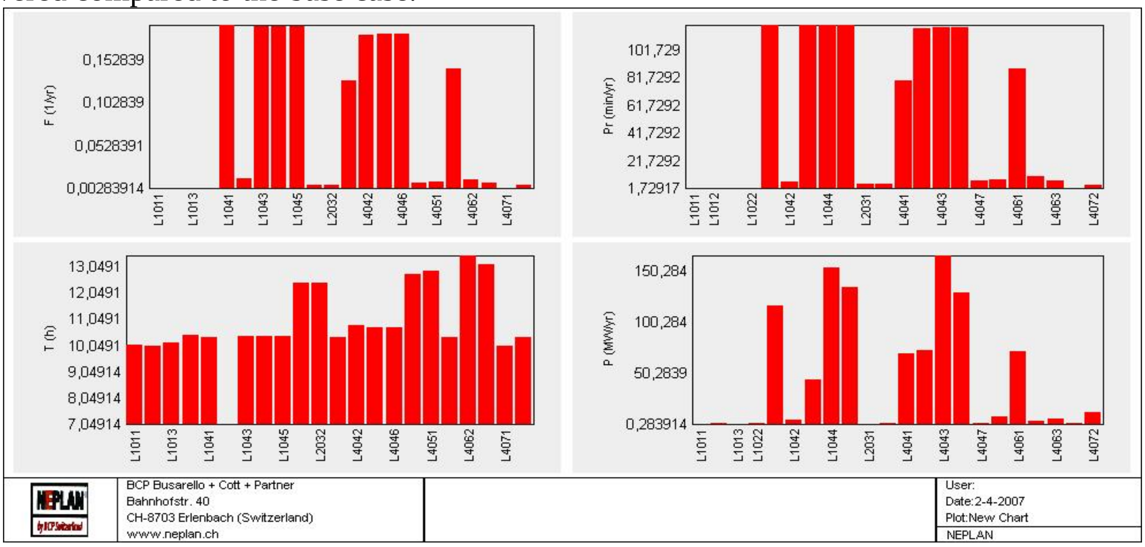


Figure 6.9: Load point indices of case 2

The number of interruptions reduced which are 79 out of 7626 outages; this will of course increase SII.

$$\text{System Improvement Index (SII)} = 1 - \frac{79}{7626} = 98.96\%$$

Where 79 of the resulted outages led to supply interruption; it should be mentioned that most of the supply interruption happened due to the un-convergence of load flow. The un-convergence might happen due to the lack of generation to cover the load after utilizing the whole power resources in the system or due to the network stress due to the extra load. The total system indices are shown in Table 6.4; it is obvious that the total curtailed load power is lower than the base case. It can be concluded that the location of the HVDC link can have different impacts on system reliability. Another conclusion is that the HVDC link and after being modelled as constant load and constant power could cause under-voltage and over-voltages problems to the buses where it is connected and also to the neighbouring buses, the occurrence of such problems would also be impacted by both the strength of the AC system and the amount of the extracted active power by the HVDC link. In all simulated HVDC cases the HVDC link has been equipped with a continuous reactive compensation to control the voltage at the AC sides of each converter station. The compensations are continuous and proportional to the bus voltages at both ends of the HVDC stations.

Table 6.4: Total system indices for case 2

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,0762	System average interruption frequency index
SAIDI	min/yr	48,3345	System average interruption duration index
CAIDI	h	10,5657	Customer average interruption duration index
ASAI	%	99,9908	Average service availability index
F	1/yr	0,2007	System load interruption frequency
T	h	10,1486	System load interruption mean duration
Q	min/yr	122,2353	System load interruption probability
P	MW/yr	994,2296	Total interrupted load power
W	MWh/yr	10505,23	Total load energy not supplied

Case 3: An HVDC link between bus 4021 and 4042 (replacing)

Replacing the line between 4021-4042 by HVDC link will reduce the total interrupted load power per year from 6949 [MW/yr] (i.e. in case of base case) down to 1446 [MW/yr]. See the load point indices in Figure 6.10 and the total system indices in Table 6.5.

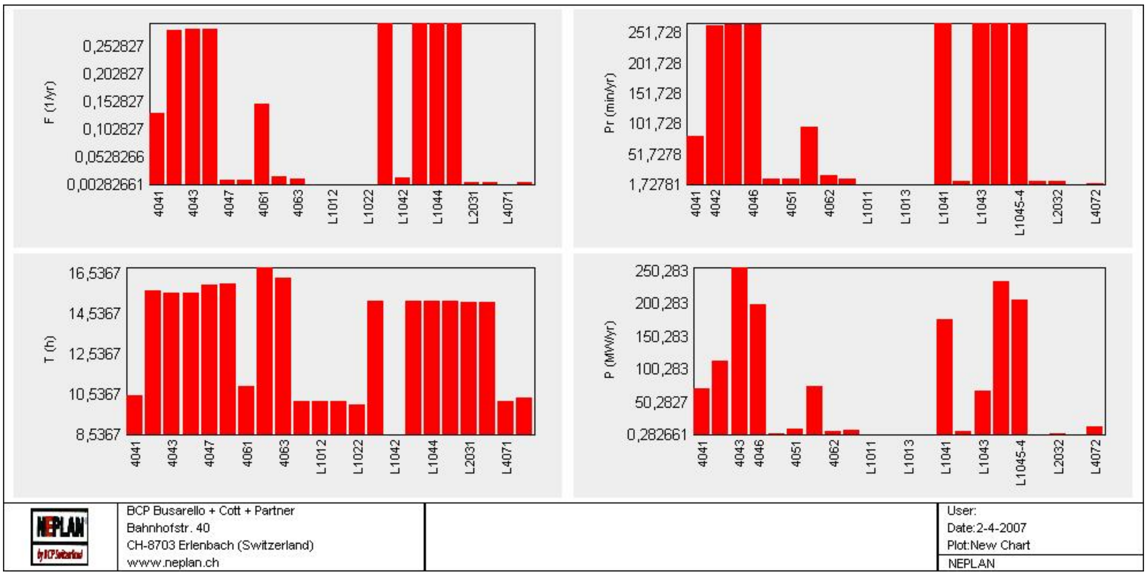


Figure 6.10: Load point indices of case 3

$$\text{System Improvement Index (SII)} = 1 - \frac{125}{7503} = 98.33\%$$

It is obvious from the total system indices that the system load interruption frequency [f/yr] has become lower than the base case which is an obvious improvement. However, compared to case two, the mentioned index has become inferior due to the replacement. It can be concluded that replacing the AC line with HVDC in this case is not as good as adding it but still better than the base case. Another system index that has become better than the base case is the system average interruption frequency index, *SAIFI [1/yr]*, replacing or adding the HVDC in this case will result in more adequate and secure system than the base case. Customer average interruption duration index, CAIDI [hour] has become better than the base case as well which is a good indicator to the overall system reliability improvement.

Table 6.5: Total system indices for case 3

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,1098	System average interruption frequency index
SAIDI	min/yr	96,8032	System average interruption duration index
CAIDI	h	14,6913	Customer average interruption duration index
ASAI	%	99,9816	Average service availability index
F	1/yr	0,3129	System load interruption frequency
T	h	14,4153	System load interruption mean duration
Q	min/yr	270,6226	System load interruption probability
P	MW/yr	1446,817	Total interrupted load power
W	MWh/yr	21378,66	Total load energy not supplied

For instance, in this case losing the HVDC with one of the main AC transmission lines will result to an overload of some lines as well as transformers which in contrast increase the failure frequency of the load points as well as the duration time.

Case 4: An HVDC link between bus 4031 and 4042 (adding)

The total load point indices are shown in Figure 6.11. It is clear that adding this link between the mentioned buses in the system will improve the reliability of the transmission system. The total system indices are also shown Table 6.6.

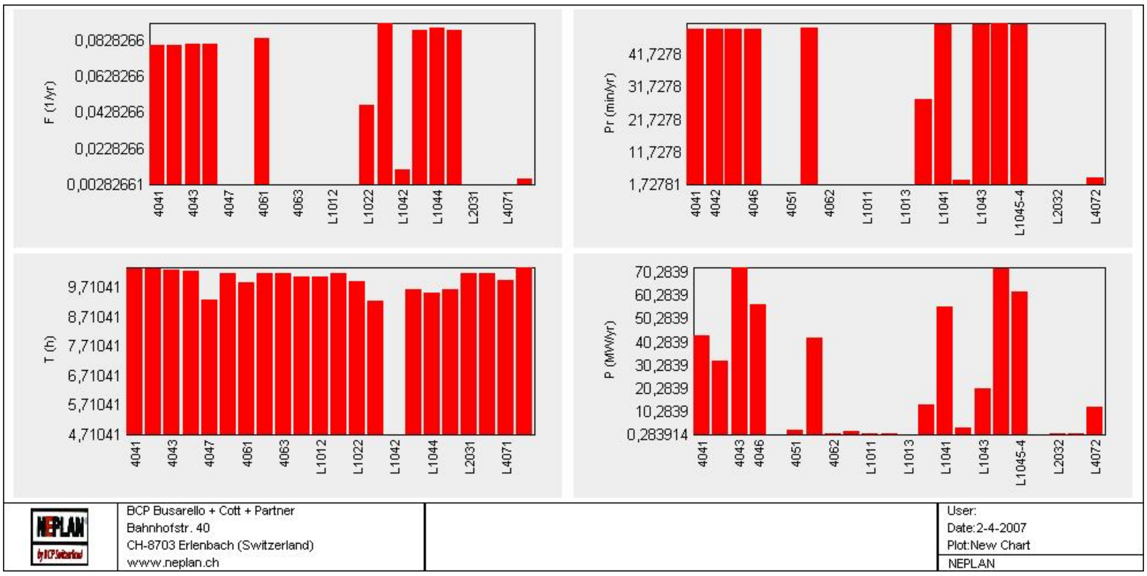


Figure 6.11: Load point indices of case 4

$$\text{System Improvement Index (RII)} = 1 - \frac{56}{7626} = 99{,}2\%$$

SII indicates that 56 outages out of 7626 are endangering the system health. This high improvement is very clear, because embedding the HVDC line in that location will obviously reduce the loading of the AC transmission lines and enhance the voltage stability. The total amount of interrupted load power is reduced to be 493[MW/yr] which is around 7% compared to the base case. Compared to case three, the total interrupted load power per year in addition to the system interruption frequency per year is lowered.

Table 6.6: total system indices for case 4

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,039	System average interruption frequency index
SAIDI	min/yr	22,979	System average interruption duration index
CAIDI	h	9,825	Customer average interruption duration index
ASAI	%	99,996	Average service availability index
F	1/yr	0,145	System load interruption frequency
T	h	9,175	System load interruption mean duration
Q	min/yr	79,963	System load interruption probability
P	MW/yr	492,866	Total interrupted load power
W	MWh/yr	4865,567	Total load energy not supplied

Case 5: An HVDC link between bus 4032 and 4042 (Adding)

In this case, the HVDC link has the same length as the adjacent AC line between the mentioned buses (4032-4042). Figure 6.12 and Table 6.7 present the load point indices and the total system indices respectively.

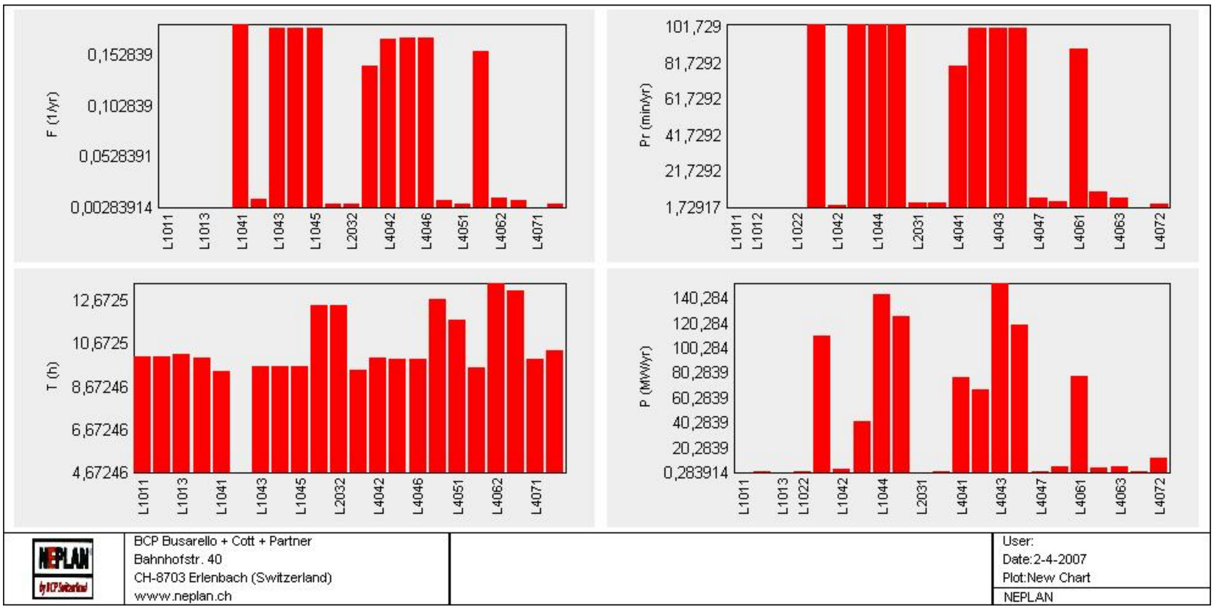


Figure 6.12: Load point indices of case 5

$$\text{System improvement index (SII)} = 1 - \frac{93}{7626} = 98.78\%$$

Table 6.7 shows that the total amount of interrupted load power is around 949 [MW/yr] which is reduced compared to the base case. It has to be noticed that tracking each load point in the resulted load point indices of the system for different cases is not preferable because they have the same priority of being interrupted.

Table 6.7: Total system indices for case 5

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,0731	System average interruption frequency index
SAIDI	min/yr	42,7516	System average interruption duration index
CAIDI	h	9,7436	Customer average interruption duration index
ASAI	%	99,9919	Average service availability index
F	1/yr	0,1905	System load interruption frequency
T	h	9,2285	System load interruption mean duration
Q	min/yr	105,4695	System load interruption probability
P	MW/yr	949,4004	Total interrupted load power
W	MWh/yr	9244,071	Total load energy not supplied

Case 6: An HVDC link between bus 4032 and 4042 (Replacing)

The impacts of replacing the AC line with HVDC in this case can be clearly realized by comparing it with the base case.

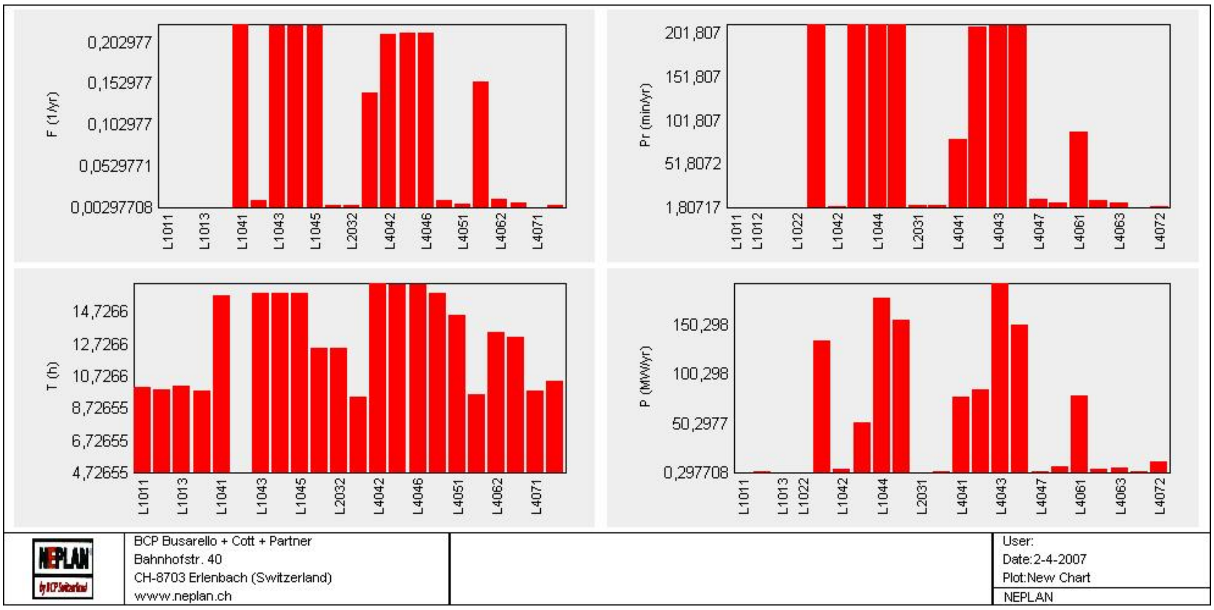


Figure 6.13: Load point indices of case 6

The resulted load point indices are shown in Figure 6.13. Whereas, the total system indices are shown in Table 6.6; total interrupted load power per year is around 1114[MW/yr].

$$\text{System Improvement Index (SII)} = 1 - \frac{285}{7503} = 96.2\% .$$

The improvement in this case also can be realized by comparing it with case five (adding the HVDC line between 4032 and 4042). The resulting system indices of both case five and six demonstrate the previous conclusion which is adding the HVDC line is always better that replacing. However, by comparing both case five and six with the base case, one can find it is still better than the base case.

Table 6.8: Total system indices for case 6

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,0871	System average interruption frequency index
SAIDI	min/yr	77,736	System average interruption duration index
CAIDI	h	14,8693	Customer average interruption duration index
ASAI	%	99,9852	Average service availability index
F	1/yr	0,2323	System load interruption frequency
T	h	15,3881	System load interruption mean duration
Q	min/yr	214,4735	System load interruption probability
P	MW/yr	1139,13	Total interrupted load power
W	MWh/yr	17148,64	Total load energy not supplied

Case 7: An HVDC link between bus 4032 and 4044 (adding)

The resulted load point indices are shown in Figure 6.14. Table 6.9 shows the resulted total load point indices. It is clear from the total system indices that the system turned to be more reliable than being working without HVDC.

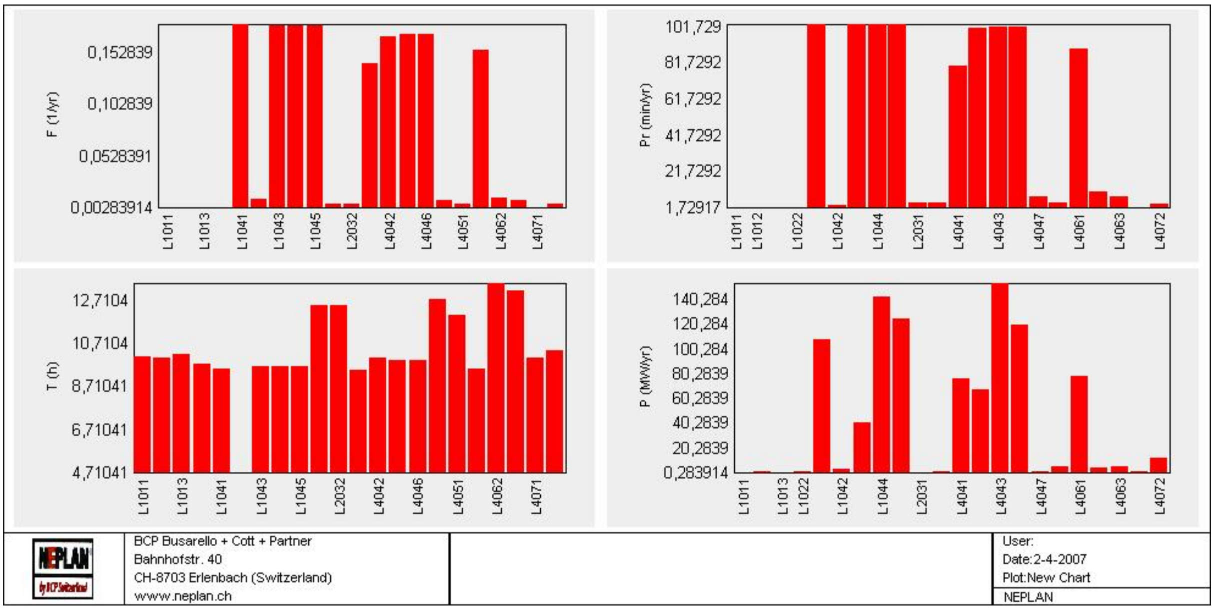


Figure 6.14: Load point indices of case 7

The improvement includes also the SII index which indicates that the system has become more adequate and secure. It can alleviate 98.9% of the resulted second order adverse outages.

$$\text{System Improvement Index (SII)} = 1 - \frac{84}{7626} = 98.89\%$$

The other system indices have become all better that than base case. The improvement in system reliability is still belongs to the same motivation as the previous cases. The system voltage stability has become more than the base case and hence the system bottleneck still far to happen due the reduced loading limits of the AC lines in the system. The resulting system operational state became more optimal by reducing the total losses in the system as well.

Table 6.9: Total system indices for case 7

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,0729	System average interruption frequency index
SAIDI	min/yr	42,6608	System average interruption duration index
CAIDI	h	9,7549	Customer average interruption duration index
ASAI	%	99,9919	Average service availability index
F	1/yr	0,1877	System load interruption frequency
T	h	9,3304	System load interruption mean duration
Q	min/yr	105,0803	System load interruption probability
P	MW/yr	946,7034	Total interrupted load power
W	MWh/yr	9225,668	Total load energy not supplied

Case 8: An HVDC link between bus 4032 and 4044 (Replaced)

The resulted system indices are shown in Figure 6.15. The total system indices are shown in Table 6.9. It is clear from the table that the system indices became better except the system index CAIDI [hour], this index is higher than the same index compared to the base case

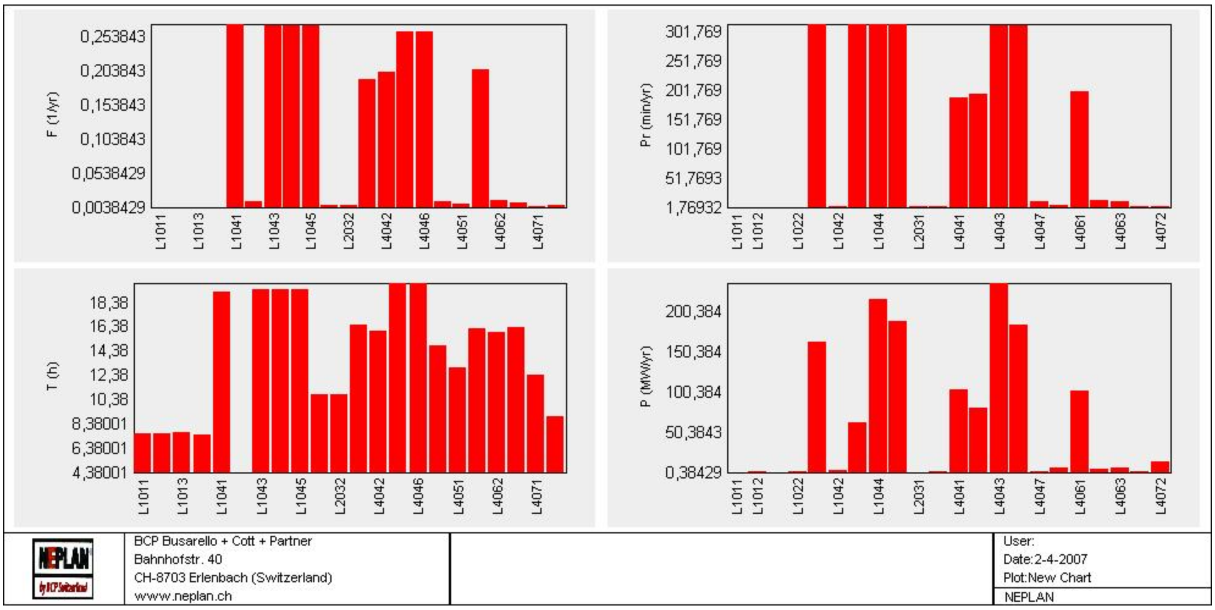


Figure 6.15: Load point indices of case 8

$$\text{System Improvement Index (SII)} = 1 - \frac{97}{7503} = 98{,}7\%$$

The reason of that is due to the long repair time of the HVDC link. However, the system load interruption frequency (F[1/yr]) is still lower that the base case due to the existence of HVDC, but it has to be noticed that CAIDI [h] depends much on the down time of the components which is high for the HVDC link (i.e. 1624 [hour/fail]). On the other hand, the other system indices have become better than the base case. For instance, comparing the two cases (case Eight and Seven), the reader will realize again that adding the HVDC in most of the cases improve the system reliability more than the case of replacing the AC line by HVDC.

Table 6.9: Total system indices for case 8

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,1045	System average interruption frequency index
SAIDI	min/yr	115,0563	System average interruption duration index
CAIDI	h	18,3534	Customer average interruption duration index
ASAI	%	99,9781	Average service availability index
F	1/yr	0,279	System load interruption frequency
T	h	18,9699	System load interruption mean duration
Q	min/yr	317,5735	System load interruption probability
P	MW/yr	1375,267	Total interrupted load power
W	MWh/yr	25647,52	Total load energy not supplied

Case 9: An HVDC link between bus 4032 and 4044 (replaced) and HVDC link between 4021 and 4042 (replaced)

The transmission capacity of each HVDC is 800 [MW] in this case. The total amount of transferred active power through the line is 1600 [MW]. However, an optimal power flow will be achieved in this case and consequently a reduction in the amount of active and reactive power losses in the system is achieved.

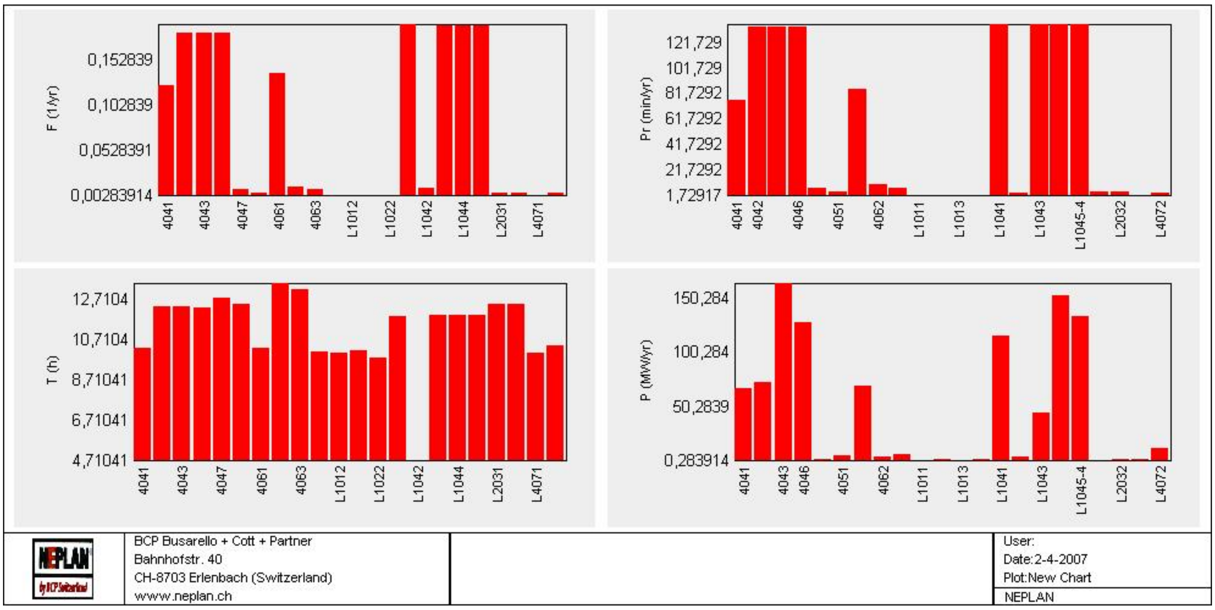


Figure 6.16: Load point indices of case 9

$$\text{System Improvement Index (SII)} = 1 - \frac{61}{7503} = 99.18\%$$

The resulted total system indices are shown in Table 6.10 and the load point indices are shown in Figure 6.16. It is clear that the system became more secure than being operated without the HVDC link. the system new operational state after embedding the two HVDC lines as an alternative to the two AC lines has become more adequate and the total losses reduced from 312 [MW] down to 249 and from 1733[MVar] down to 591 [MVar]. The sharp reduction of total reactive consumption in the system is due to the fact that the DC lines did not consume any active power and consequently a reduction in the reactive power generation has been achieved.

Table 6.10: Total system indices for case 9

Index	Unit	Value	Description
N	-	22	Total number of customers served
SAIFI	1/yr	0,075	System average interruption frequency index
SAIDI	min/yr	52,834	System average interruption duration index
CAIDI	h	11,725	Customer average interruption duration index
ASAI	%	99,99	Average service availability index
F	1/yr	0,199	System load interruption frequency
T	h	11,566	System load interruption mean duration
Q	min/yr	138,103	System load interruption probability
P	MW/yr	979,713	Total interrupted load power
W	MWh/yr	11544,15	Total load energy not supplied

6.4 Results

The simulated cases have been selected carefully taking into account the following limitations and aspects:

- The HVDC model in NEPLAN is a monopole two terminal link with 1000 MW transmission capacity @ 600 kV.
- NEPLAN during the load flow considers the HVDC link as constant power transmission link.
- No power regulation algorithms considered for the HVDC link in NEPLAN.
- No control has been adapted to the HVDC during the operation. And only the AC load flow has been used for reliability assessment. However, voltage control strategy has been equipped to the HVDC lines in order to keep the voltage at the AC sides of the HVDC stations around 99%.
- The length of the proposed HVDC lines has been considered the same as the approximated length of the AC line in case of adding/replacement of some existing AC lines. When the HVDC link proposed to be added in some locations, the length of the DC line is approximated based on the AC neighboring lines.
- More considerations have been given to the system network topology since some of the AC transmission lines in the given system were lumped together which is also the same for the other components such as generating units, transformers.
- No considerations have been given to the circuit breakers in the system (100% available). The reason of that is due to the lack of information about the substation topologies. For instance, in this study, if the circuit breaker of an AC line fails it will take the whole substation out of service which is not the case in reality and it will consequently increase the interruption frequency of the load points and their associated durations.
- The simulation time for the 7626 outages is around *one hour*. A laptop machine with 1.66 GHz Duo and 1GB random memory has been used. However, the number of simulated components was 123 components. On contrast, if the circuit breakers taken

into account the resulted number of components would be 321 and consequently the number of possible outages will be 51681 different possible outages and hence the simulated time will be around 7 hours on the same machine.

- New index has been proposed especially for this study to ease the analysis and to check how many interruptions led to fail to supply regardless the amount of the interrupted power and the interruption duration.

In all simulated cases, the system has been considered to be (n-1) secure with and without HVDC link. Which means that the system has the ability to withstand any single failure without endangering the system health; however, the main challenge in the simulation was to reduce the number of second order outages that would lead to supply interruption as well as to find an optimal location for the HVDC link in the system so as to achieve an adequate and secure state of the system. Table 6.10 presents some of the selected indices for all simulated cases. Those indices act as a measure to the transmission system reliability.

Table 6.10: System indices of all simulated

No.	HVDC cases	SII [%]	SAIFI	SAIDI	CAIDI	ASAI	P [MW/yr]	T [h]	F [1/yr]
0	Without HVDC (Base case)	94,60	0,537	530,339	16,475	99,899	6949,589	16,718	1,609
1	HVDC btn 4032-4043 (added)	98,94	0,0732	42,7169	9,7314	99,9919	949,8795	9,2892	0,1888
2	HVDC btn 4021-4042(added)	98,96	0,0874	50,1334	9,5619	99,9905	1146,6004	8,9944	0,2372
3	HVDC btn 4021-4042(replaced)	98,33	0,1098	96,8032	14,6913	99,9816	1446,8168	14,415	0,3129
4	HVDC btn 4031-4042(added)	99,27	0,039	22,979	9,825	99,996	492,866	9,175	0,145
5	HVDC btn 4032-042(added)	98,78	0,0731	42,7516	9,7436	99,9919	949,4004	9,2285	0,1905
6	HVDC btn 4032-4042(replaced)	96,20	0,0871	77,736	14,8693	99,9852	1139,1299	15,388	0,2323
7	HVDC btn 4032-4044(added)	98,90	0,0729	42,6608	9,7549	99,9919	946,7034	9,3304	0,1877
8	HVDC btn 4032-4044(replaced)	98,71	0,1045	115,0563	18,3534	99,9781	1375,2667	18,97	0,279
9	HVDC btn 4032-4044 (replaced), and HVDC btn 4021-4042 (replaced)	99,19	0,075	52,834	11,725	99,99	979,713	11,566	0,199

The selected indices have been plotted using Excel to see how the different /cases would impact the system reliability.

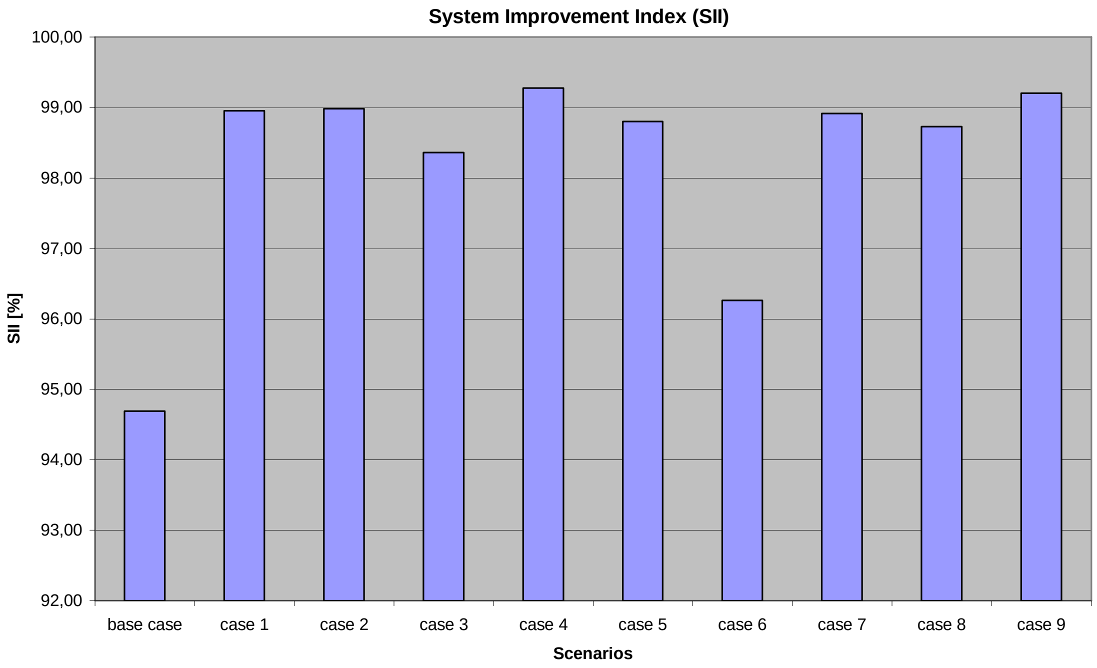


Figure 6.17: System Improvement Index (SII)

In Figure 6.17, the proposed index has been plotted for different system cases. By embedding the HVDC lines in the AC system it will increase its reliability by reducing the interruption frequency and the amount of shed load power per year. However, it is also obvious that different locations of the HVDC will give different degree of reliability. SII gives information about the number of adverse second order outages that the system can alleviate without interrupting the Load. However, it has been realized from the simulation that this proposed index is good enough to count that kind of outages regardless both the interruption duration at the load points and the amount of shed power on that point.

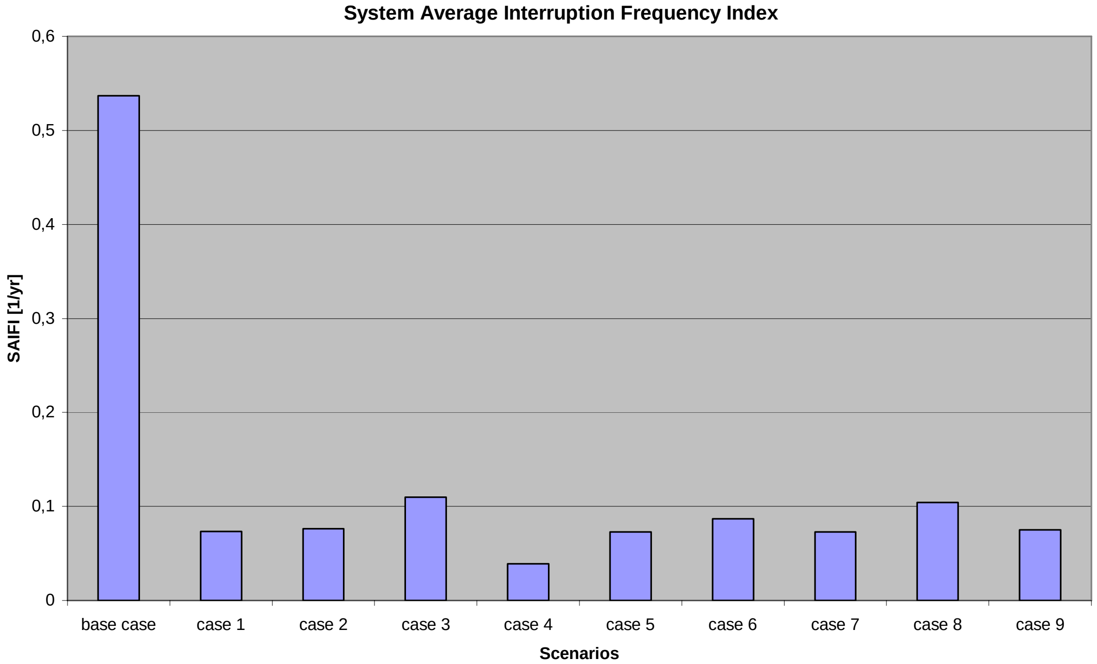


Figure 6.18: system average interruption frequency index

SAIFI is the system index that gives information about the average interruption frequency of the whole system. It is clear from Figure 6.18 that adding an HVDC link to a distinct place in the system will reduce the interruption frequency index of the whole system compared to the base case; different places for different HVDC will result in different system indices.

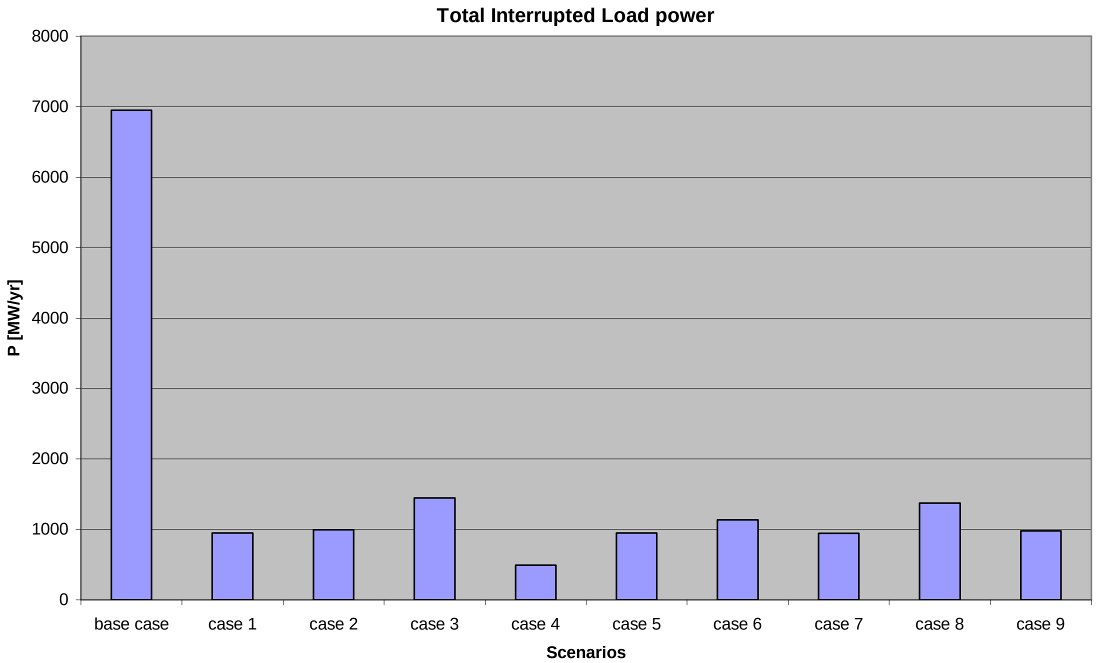


Figure 6.19: The interrupted load power index

In Figure 6.19, the total interrupted load power per year has been reduced after adding the HVDC link in different locations or replacing some AC lines by HVDC lines. The interrupted load power per year is also impacted by the location of the HVDC in the system. The best case among the simulated cases is *case four* where all system indices have become better than the base case.

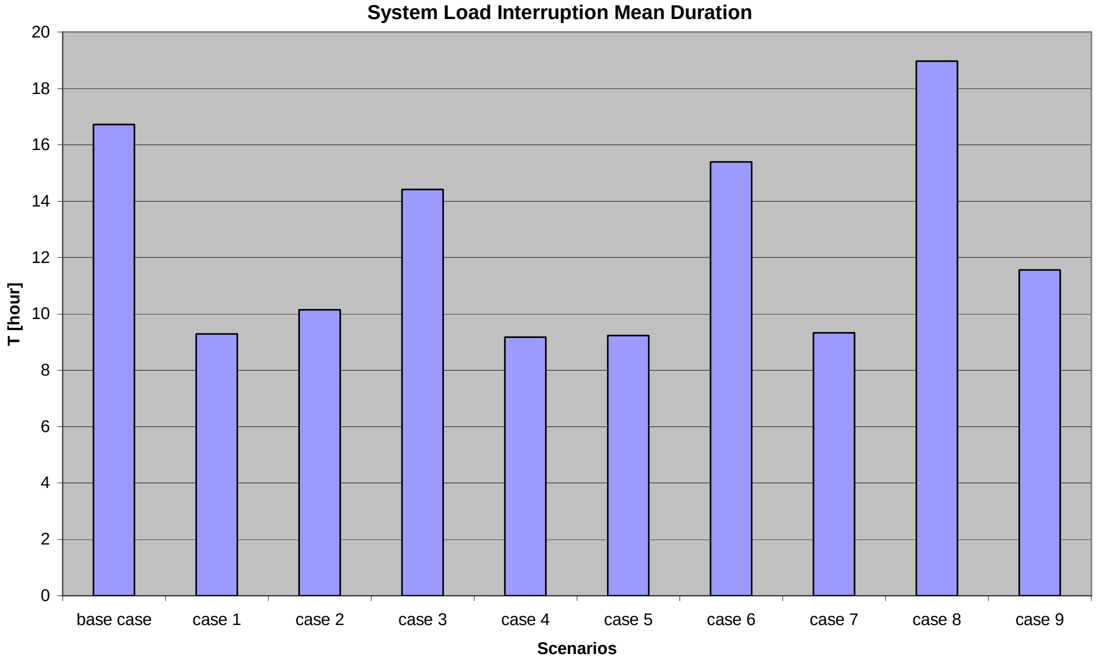


Figure 6.20: System load interruption mean duration

The mean time duration for the load interruption of the system is reduced for most of the simulated cases is shown in Figure 6.20. For instance, in case 8, the replacement of the AC line with HVDC link will increase the mean duration time of load points interruption in the system. The reason belongs to the long repair time of the DC link which will in turn increase the interruption time duration. It should be noticed that, the mean duration of load interruption is independent of the number of outages that caused that interruption.

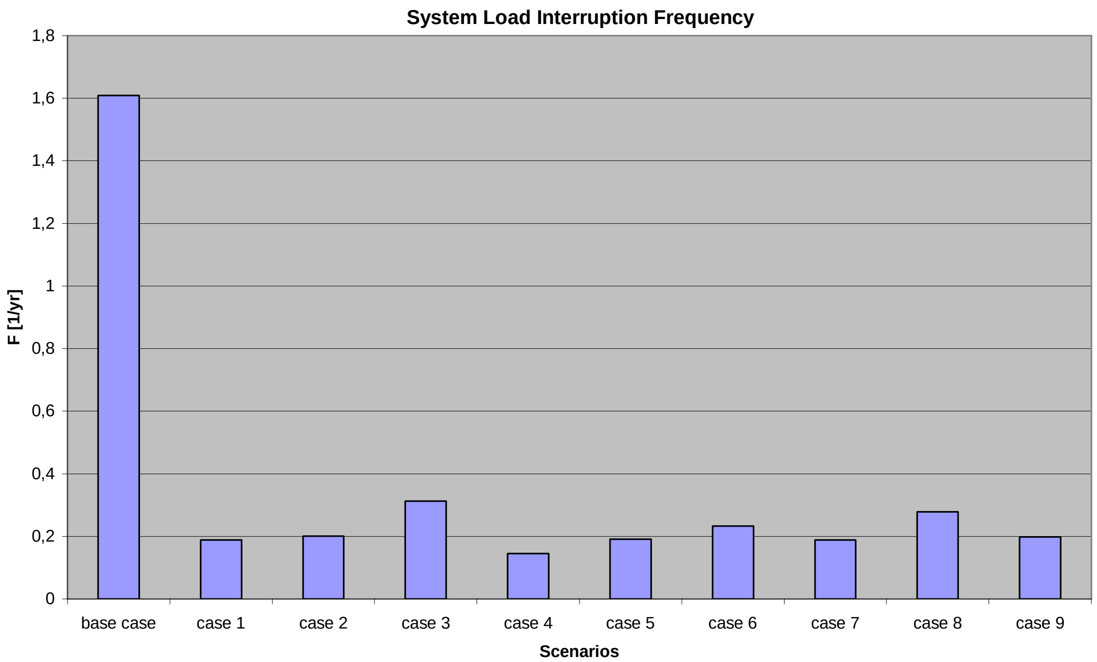


Figure 6.21: System load interruption frequency

From Figure 6.21, the system load interruption frequency is reduced. This is obvious because the number of interruptions in the system by adding the HVDC link is decreased. See the System improvement index (SII) in the simulated cases which gives information about the number of dangerous outages but it does not give information about the amount of interrupted power nor the interruption duration. SII will consider the outage as dangerous if it leads to at least one load point interruption regardless the amount of interrupted power at that point.

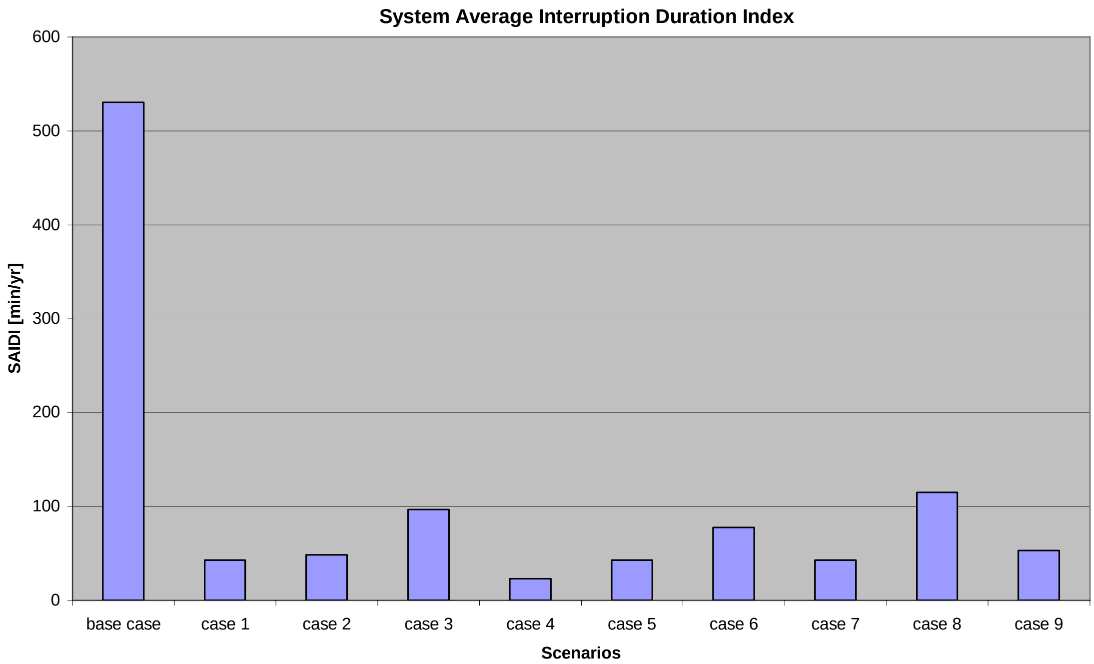


Figure 6.22: System average interruption duration index

In Figure 6.22 the system average interruption duration index (SAIDI) is also reduced for the proposed HVDC cases. The customer average interruption duration index CAIDI [hour] is shown in Figure 6.23. The resulted high index after replacing the AC line with HVDC in case 8 is due to the high repair time of the HVDC link.

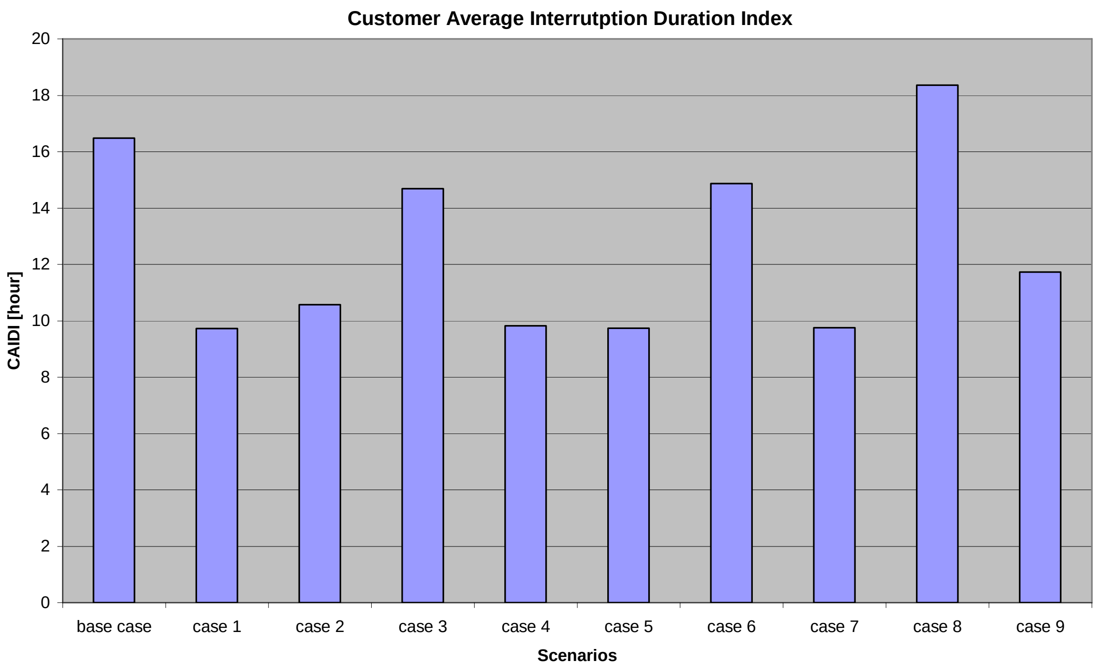


Figure 6.23: Customer average interruption duration index

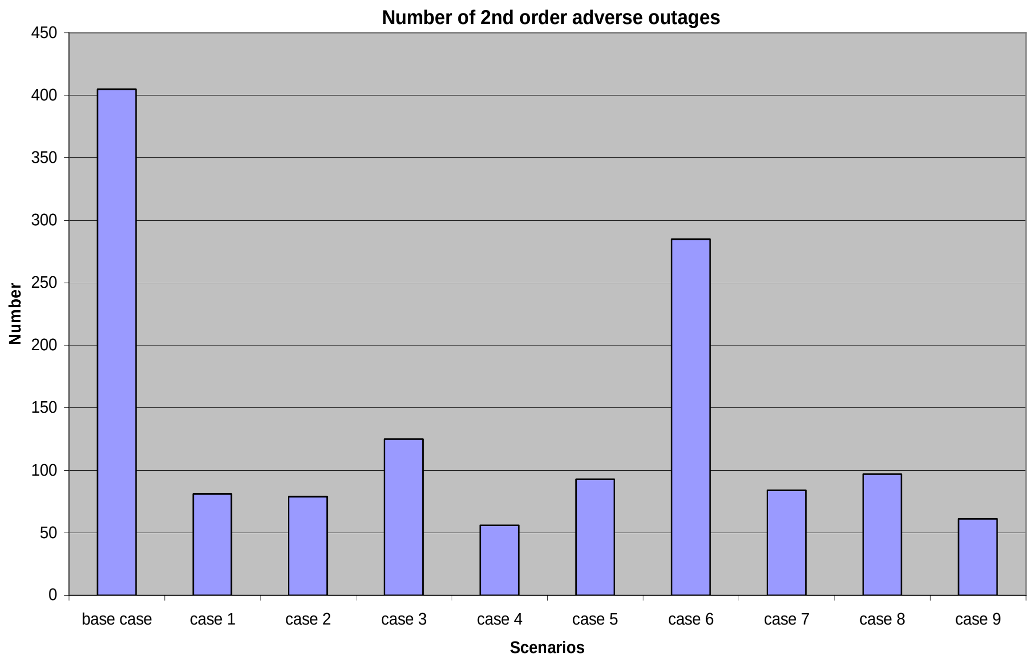


Figure 6.24: Number of adverse 2nd order outages for different

Figure 6.24, presents the resulted number of adverse 2nd order outages for each case. However, the adverse second order outages are those outages that led to at least one load point interruption regardless both the amount of interrupted power and the interruption duration of the specific interrupted load point.

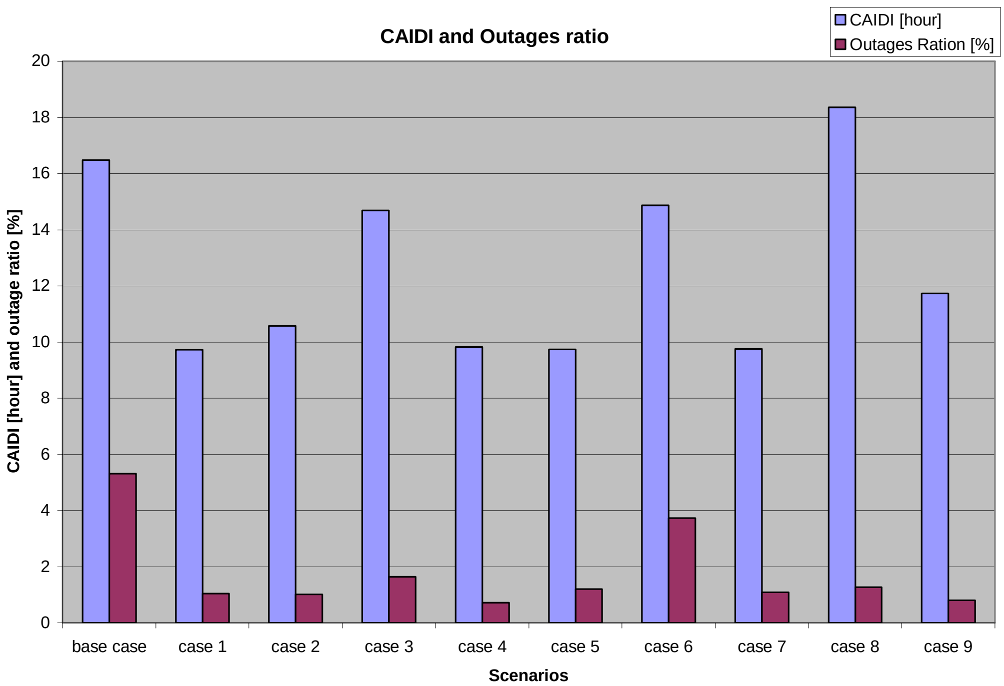


Figure 6.25: The relation between CAIDI [hour] and outages ratio [%]

In Figure 6.25, the outages ratio gives information about how healthy/secure is the system in different which is the ratio of the number of outages that led to at least one load point interruption to the total examined outages and it gives also information about CAIDI [hour]. For instance, the outages ratio in case 8 is 1.3% i.e. 1.3% of the total examined outages is not secured, which are in this case 97 outages. On contrast, 5.3% of the outages are not healthy in the base case. By comparing the customer average interruption duration index (CAIDI) of case 8 with the base case, one can say that CAIDI is lower in the base case than case 8 despite the high number of adverse 2nd order outages that led to load interruption in the base case. It can be concluded that the number of outages has different duration which in contrast made the 97 outages in case 8 to have long duration than the base case with 405 outages. Additionally, having the HVDC line in case 8 has clearly reduced the number of adverse 2nd order outages.

Comparing the results of case 8 with case 7 where the addition of the HVDC link has been made. Among 97 of the 2nd order outages that led to power interruption in case 8 there are 13 outages involved the HVDC line failure, while the HVDC line did not cause any power interruption in case 7.

The interruption frequency and duration for each load point can be compared with the base case to see the clear improvement of system reliability. Figure 6.26 shows the interruption frequency for each load point with and without HVDC.

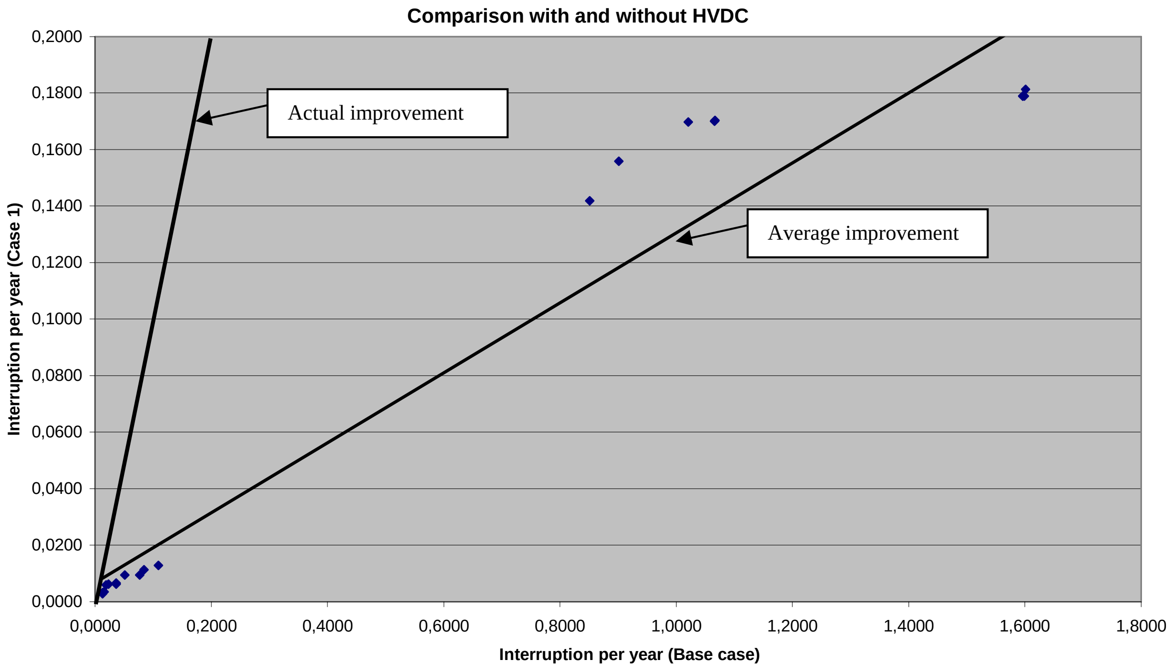


Figure 6.26: Base case vs. case 1

In Figure 6.26, it is clear that by introducing the HVDC the system has become more adequate and the number of load point failures is still located down to the trend line. This trend line gives the average improvement while the actual HVDC improvement is shown. The system reliability has improved by introducing the HVDC line in case 1. The idea behind this improvement belongs to the new optimal operating state and the voltage stability enhancement.

Figure 6.27, present the comparison between the base case and case 2. The interruption per year is still higher in the base case compared to case 2.

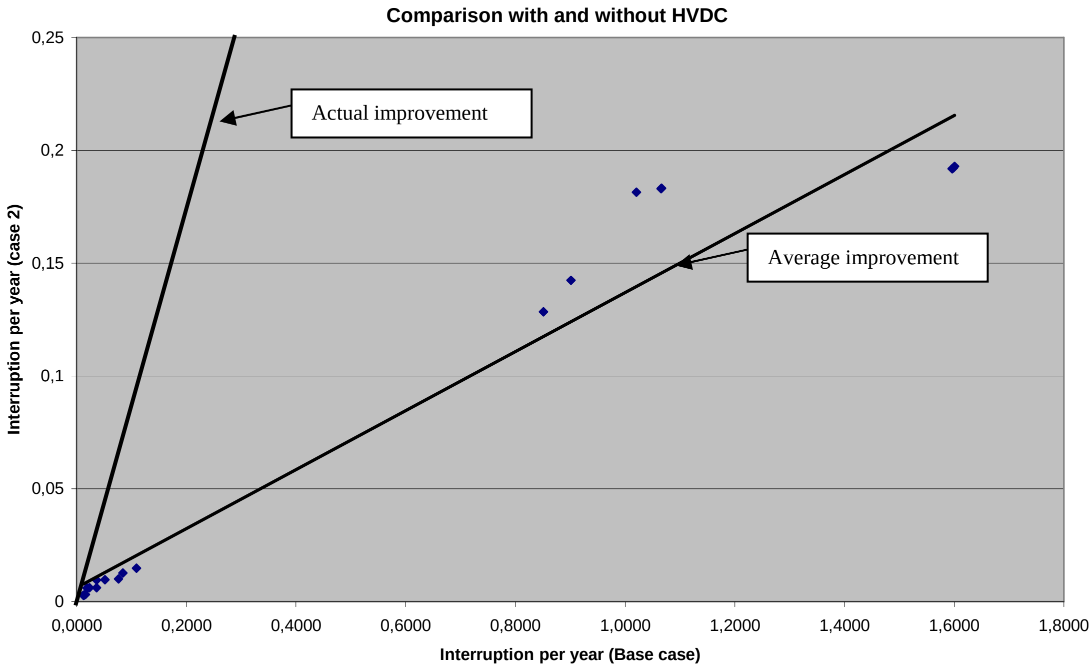


Figure 6.27: Base case vs. case 2

Figure 6.28 compare the base case with case 3. The compared value is the interruption per year for each load point. The improvement of the system reliability is clear. And the system has become more reliable in case 3 than case 1. The reliability improvement differs from one case to the other due to the different location of the embedded HVDC.

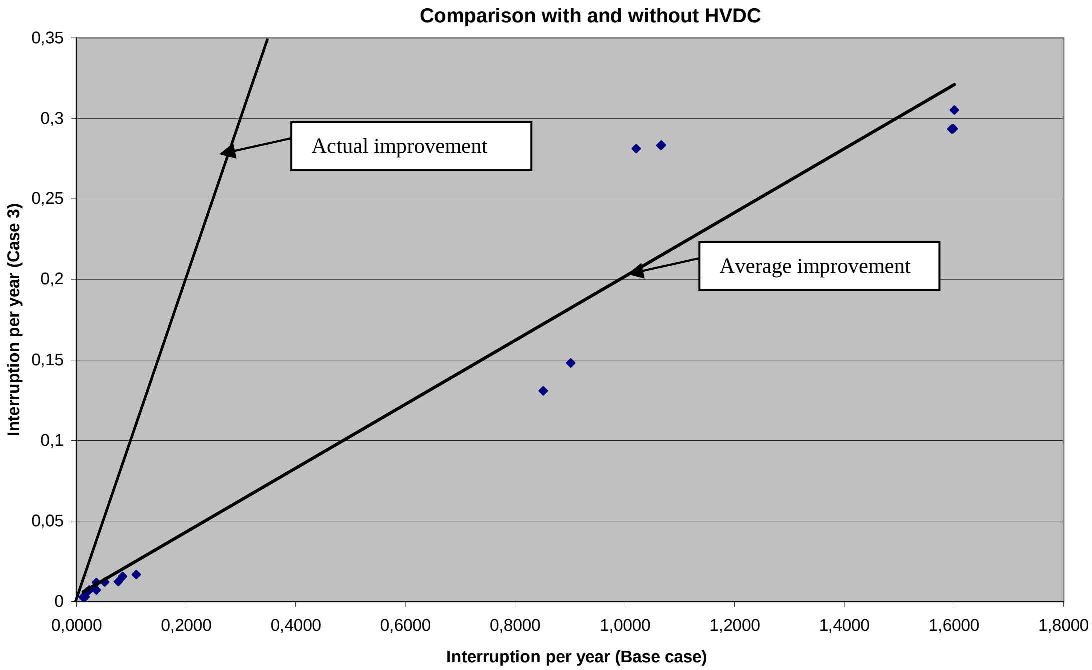


Figure 6.28: Base case vs. case 3

In Figure 6.29, the same comparison is made between the base case and case 4. However, if we compare all system indices of case 4 with all other cases, one can say that the system in this case became more adequate due to the system indices enhancement. It can be concluded that case 4 is the best case where the location of the HVDC link considered being the optimal location among the other simulated cases.

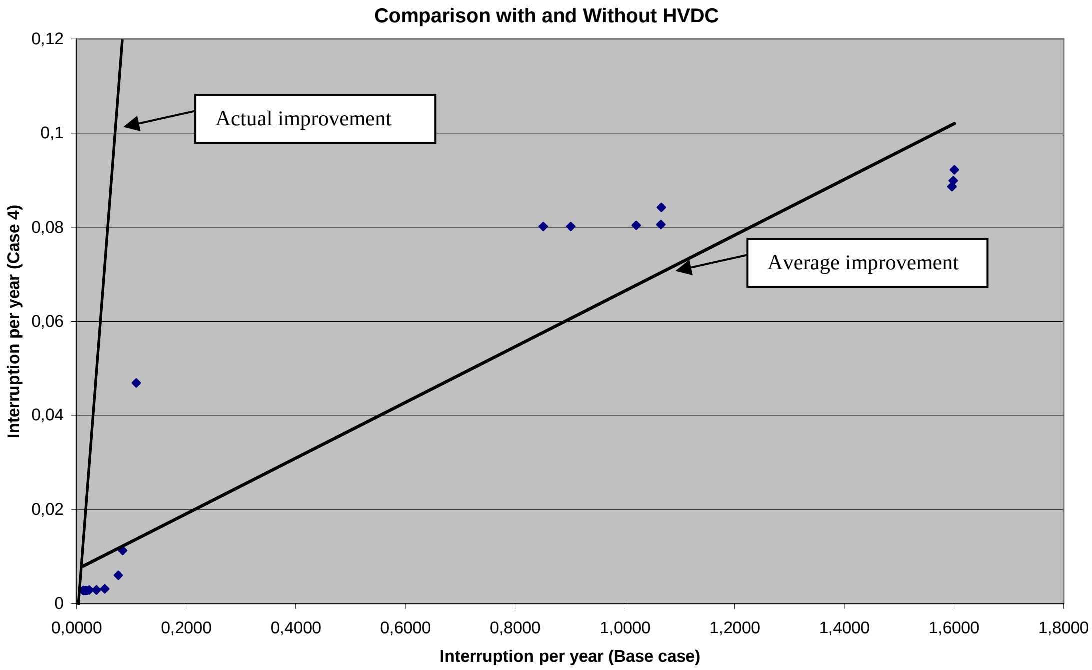


Figure 6.29: Base case vs. case 4

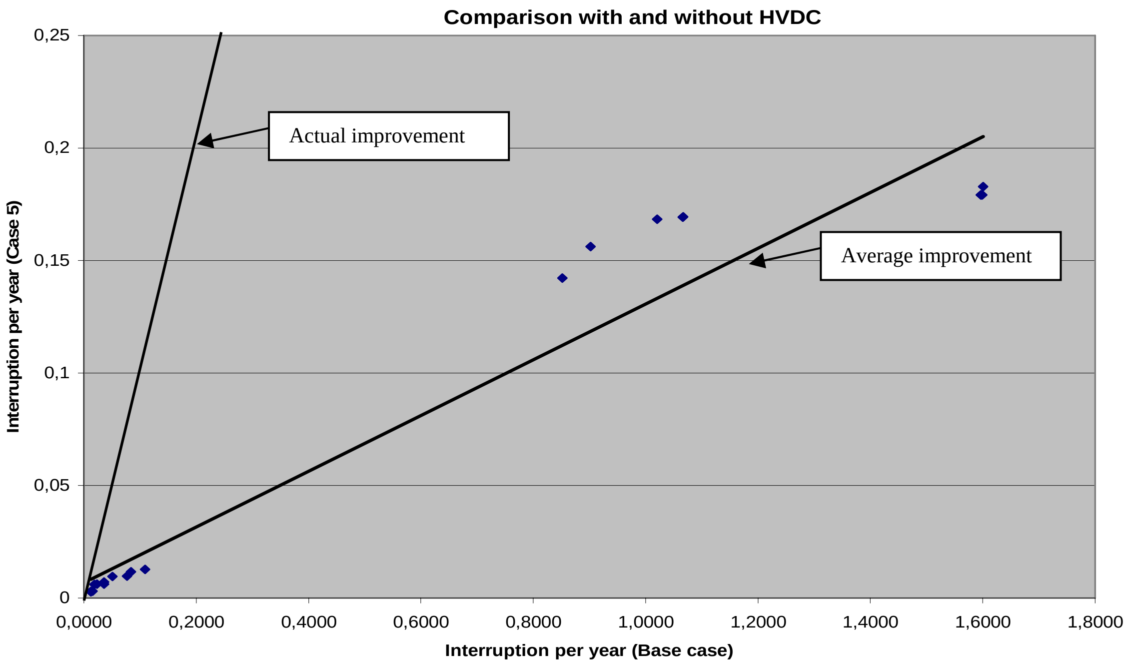


Figure 6.30: Base case vs. case 5

Figure 6.30 and Figure 6.31 both give an overview about the system average and actual improvement of the Interruptions per year of each load point in the system. The existence of HVDC lines boost up the system operational state and hence it has become more secure and adequate.

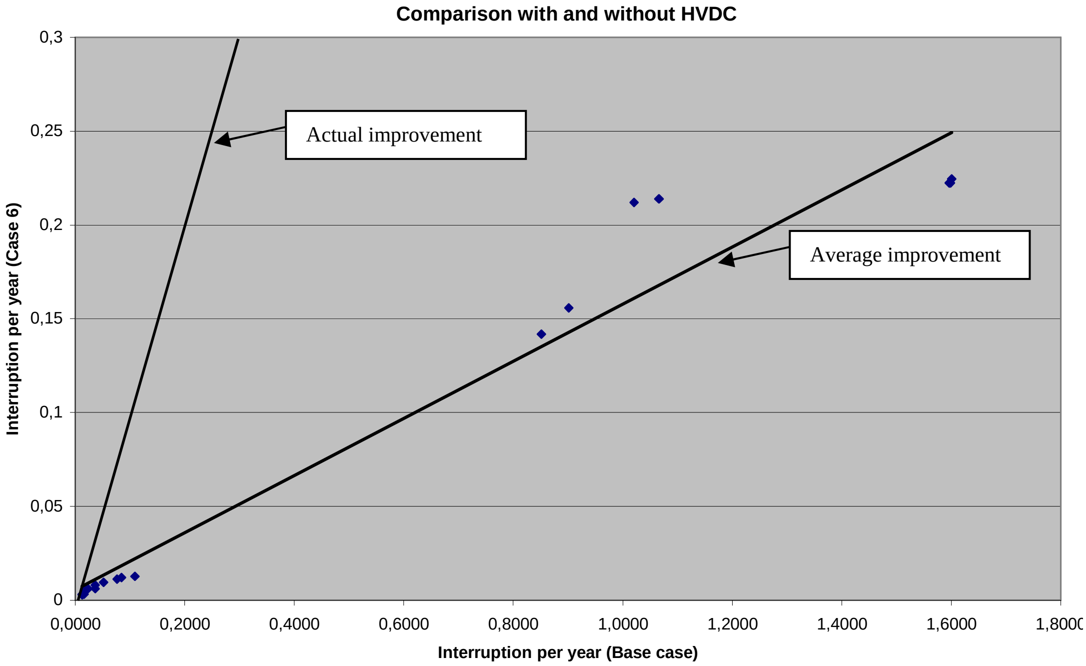


Figure 6.31: Base case vs. case 6

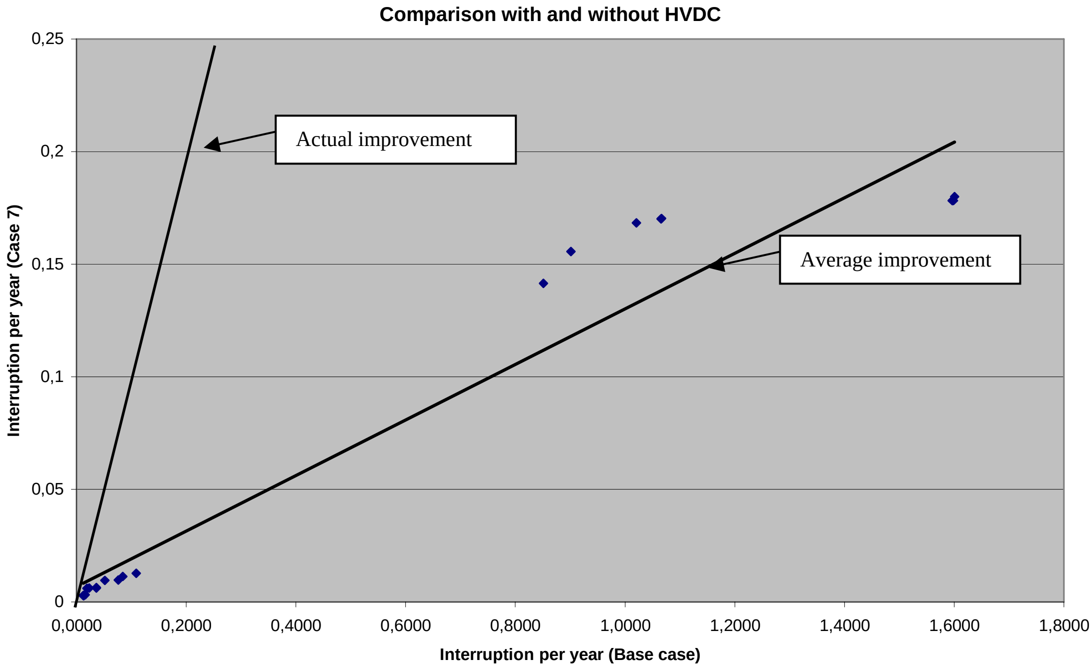


Figure 6.32: Base case vs. case 7

Figure 6.32 and Figure 6.33 both give a good overview about the system reliability improvement for different HVDC cases compared to the base case. It is obvious in the figures that the failure frequency of the load points is reduced compared to the base case. The actual improvement line give the maximum value of the failure frequency which is 0, 35 [1/yr] in case 8 while 1.6 [1/yr] in the base case, which is a clear improvement.

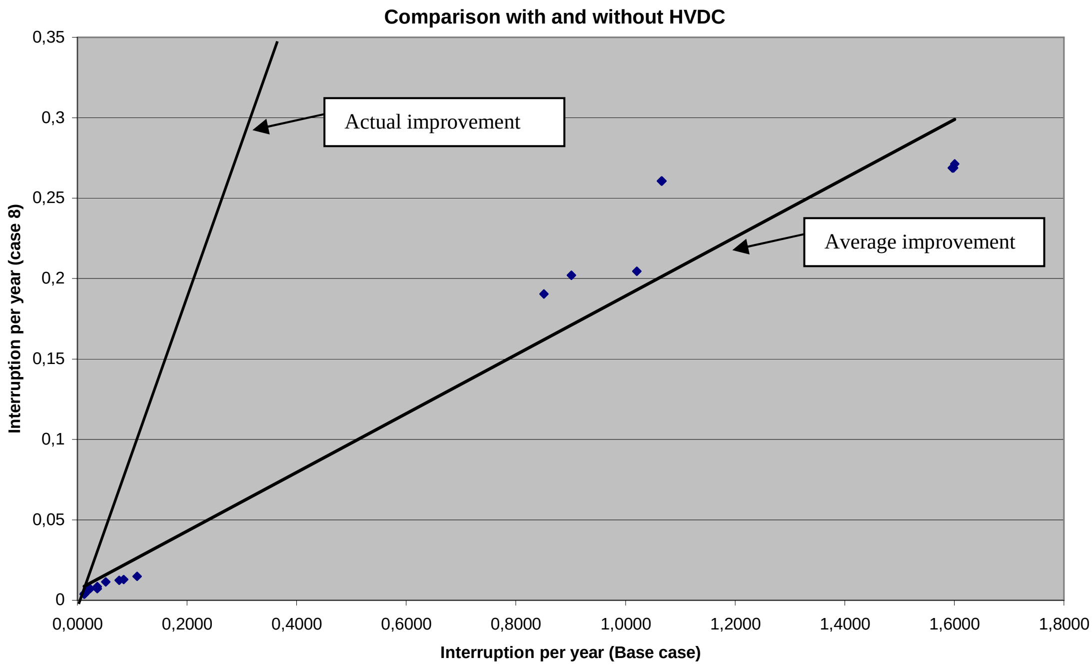


Figure 6.33: Base case vs. case 8

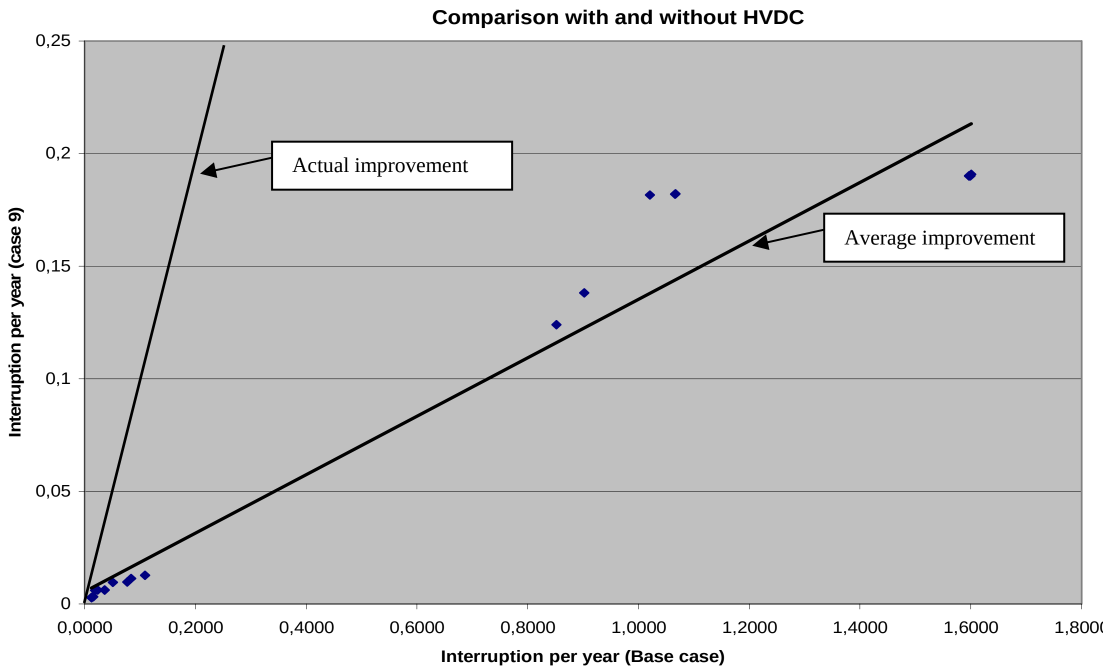


Figure 6.34: Base case vs. case 9

The same improvement is exemplified by replacing the two AC lines by HVDC lines in case 9. The actual and average improvement is shown in figure 6.34.

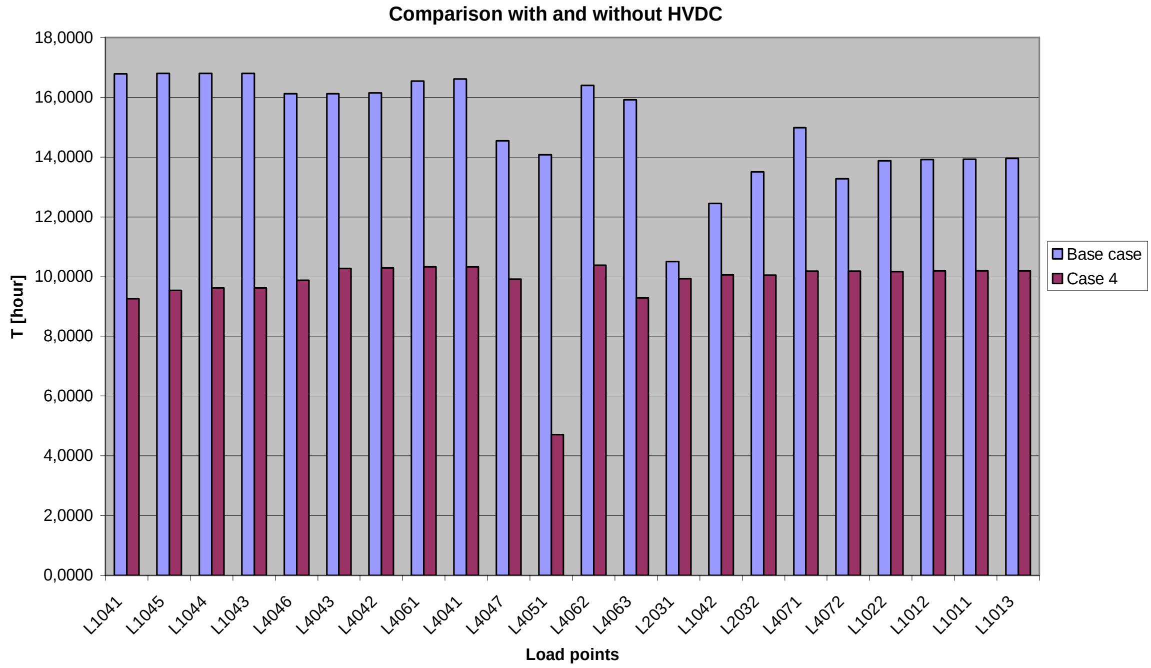


Figure 6.35: Base case vs. case 4 (failure duration comparison)

Figure 6.35 compare the failure duration of each load point with and without HVDC. Case 4 is compared with the base case; the reader can easily observe that introducing the HVDC link in case 4 will increase the system reliability by reducing the interruption duration for each load point.

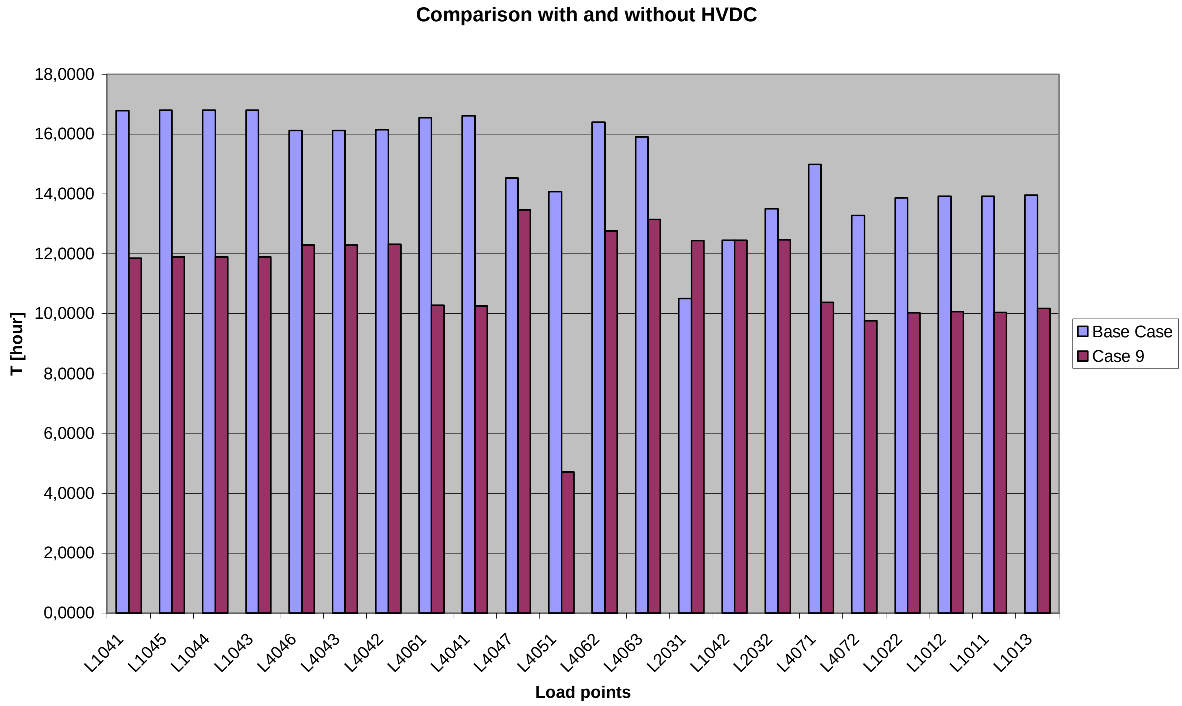


Figure 6.36: Base case vs. case 9 (failure duration comparison)

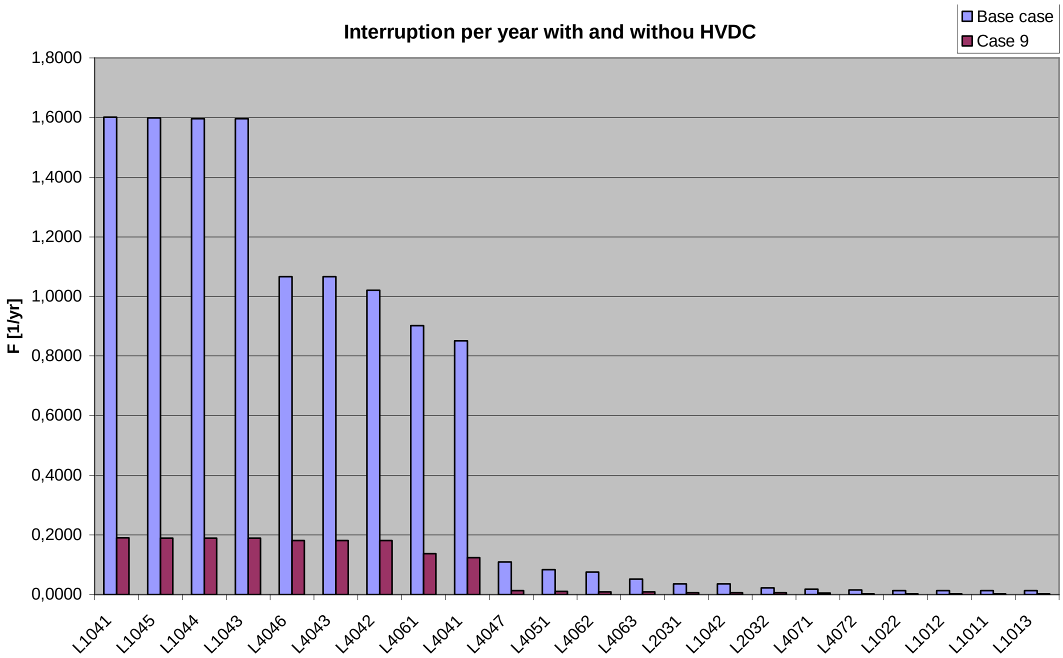


Figure 6.37: Base case vs. case 9

Figure 6.36 and Figure 6.37 show the failure duration and frequency for all load points in the system. It has to be mentioned again that the overall system indices of case 9 is better compared to the base case. The failure rate of the load point L2031 is lower than the failure of the same load point in the base case but the duration is longer compared to the base case.

However, for sake of comparison and the need of more results, the reader can find more interesting figures in appendix A

7. Closure

7.1 Conclusion

The simulations have been carried out for all system cases based on the assumption that a transition between two states (the loss of one or two components) is stable whenever both states are stable. This assumption is obviously not always correct as the fault resulting in the loss of a component does lead to oscillations in voltage, power and angle, which could lead to instability. Nevertheless, the AC load flow is the main technique that has been adopted by NEPLAN to check the system reliability. A detailed study of the dynamics for every possible fault would not have been possible for a large transmission system using the technology available at the time the reliability module of NEPLAN was developed. In the logic of using AC load flow, the HVDC link has been modeled as a constant power transmission corridor, which will consequently be impacted by its location in the system. For instance, embedding the HVDC in the system with 1000MW capacity is not useful in all cases and some times it might be preferable to transmit lower values through the HVDC Link depending on the location of the links.

In this study, nine HVDC cases were carefully selected in different locations. The resulting total system indices in all cases indicated an improvement of the overall system reliability. Replacement of some AC circuits with HVDC lines in some cases is not useful as much as adding the HVDC lines to the system. However, the resulting system indices after adding or replacing have shown an obvious and clear improvement of the Nordic32 transmission system reliability. Specifically, adding an HVDC line between 4031-4042 with 1000 [MW] capacity (case four) is the optimal location of the HVDC among the simulated cases, where all system indices have been improved compared to all cases. Losing any circuit breaker in the system will consequently cause unwanted tripping of some other circuit breakers and lines in the system which will increase the amount of load shedding in the system as well as the failure frequency of the load points. The HVDC line embedded in the system has improved the static part of the voltage stability and hence upgrades the operational system's state, which consequently reduced the number of load point failures.
NEPLAN is user friendly software that can facilitate and speed up the reliability calculations in case of large transmission systems. The load flow results from NEPLAN are very similar to the presented results by the transmission system operator (SVK), which is a good indicator to NEPLAN suitability in transmission system reliability calculations. Moreover, the integrated algorithms in NEPLAN during each system state are quite logical; such as generation scheduling, loading limits, voltage stability checking, etc which are enough for reliability assessment of transmission system.

The resulting system indices are fictitious since they are based on a hypothetical transmission system which has never been intended as a test system for evaluating transmission-system reliability. In that sense, those indices should not be used as realistic indices; the indices of the basic case are used mainly as a reference to be compared with the new indices of the simulated cases to be able to evaluate and assess the overall reliability improvement of the transmission system.

The transmission system is hypothetical system since it is representing a distinct operational state. Moreover, one type of the reliability data for each component has been used due to the insufficient reliability data.

7.2 Future work

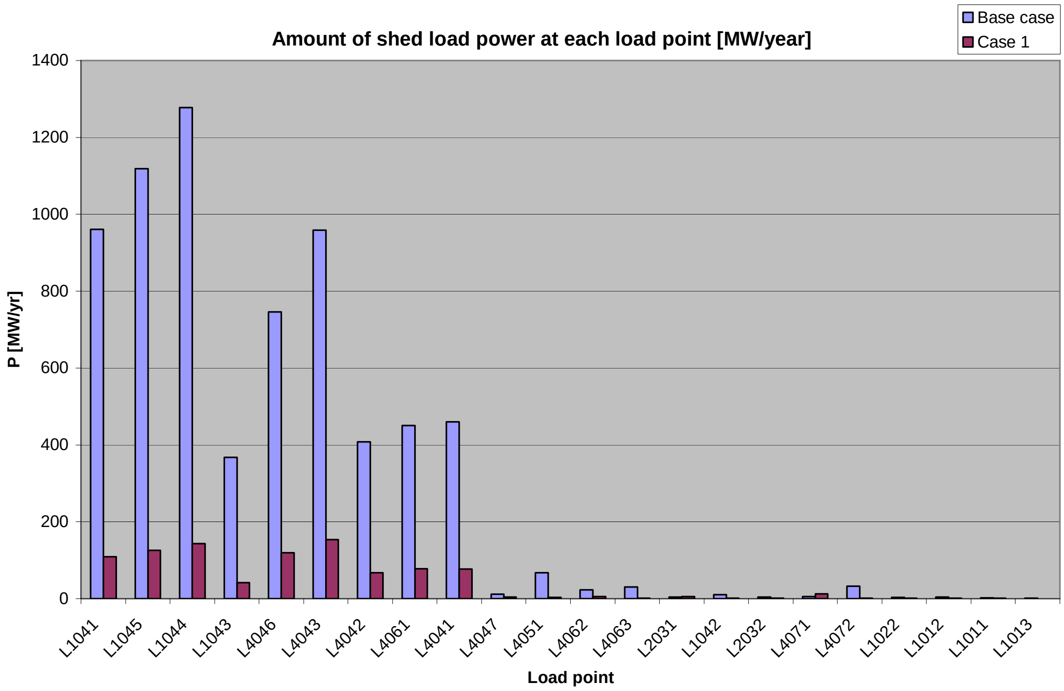
Further studies are needed for a complete investigation of the impact of HVDC lines on the transmission system reliability. For instance, including the circuit breakers in the simulations is possible if a detailed consideration is made for the substation’s topology which will on the other hand increase the simulation time. In NEPLAN; and during the load flow in each system state, a possible regulation of the power backward and forward of the HVDC lines should be taken into account for the implemented HVDC lines. The power regulation strategy is needed for the HVDC lines in order to assist the power deficit in two completely isolated AC systems and to act as AC lines in the power regulation sense. The HVDC is modeled in the load flow as a constant power link, but the power regulation technique in the HVDC can be integrated to the HVDC module in NEPLAN in order to facilitate the power regulation.

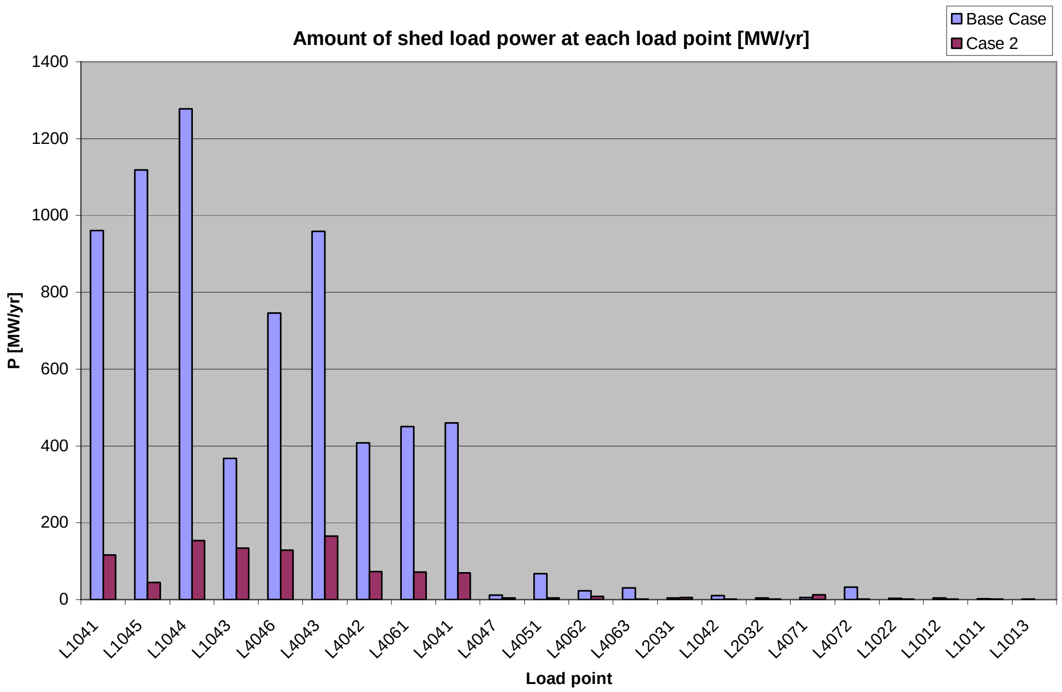
The reliability model of the HVDC line is rather simple and it should be modeled in more details to include the different operational states by including the different failure mechanisms into the model. This can be done by proposing a new HVDC model.

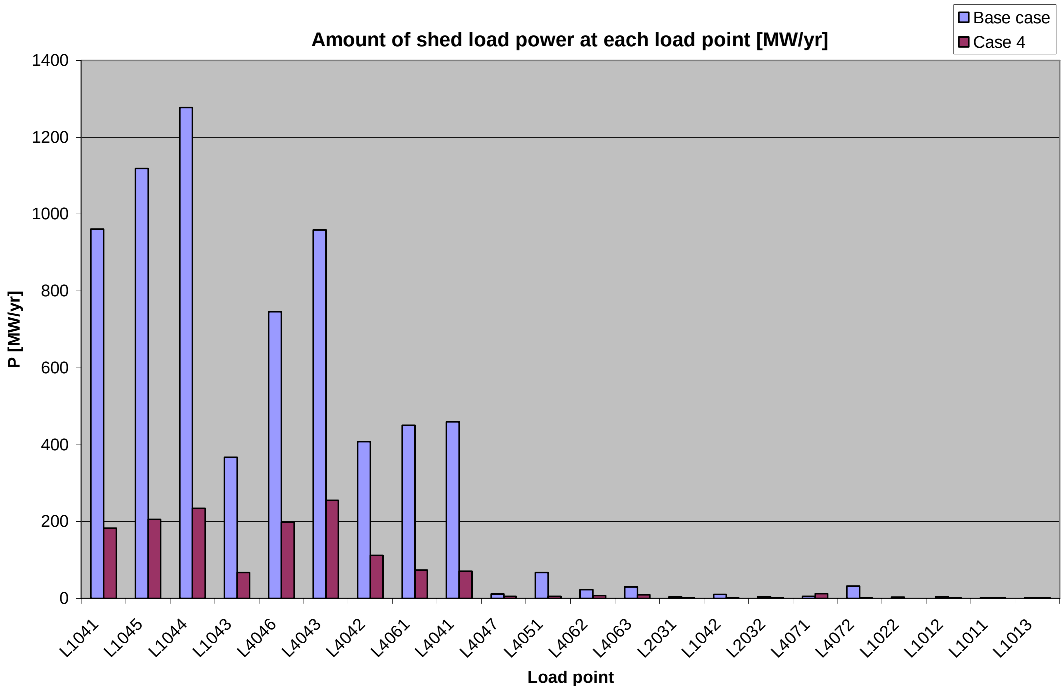
A validation of the 2nd order outages in real time simulation can be carried out to assure that the system is dynamically stable. This can be done by means of special tools that handle the dynamic aspects, which consequently take long simulation time, and up to now there are still no tools that can handle the transmission system reliability dynamically and statistically at the same time.

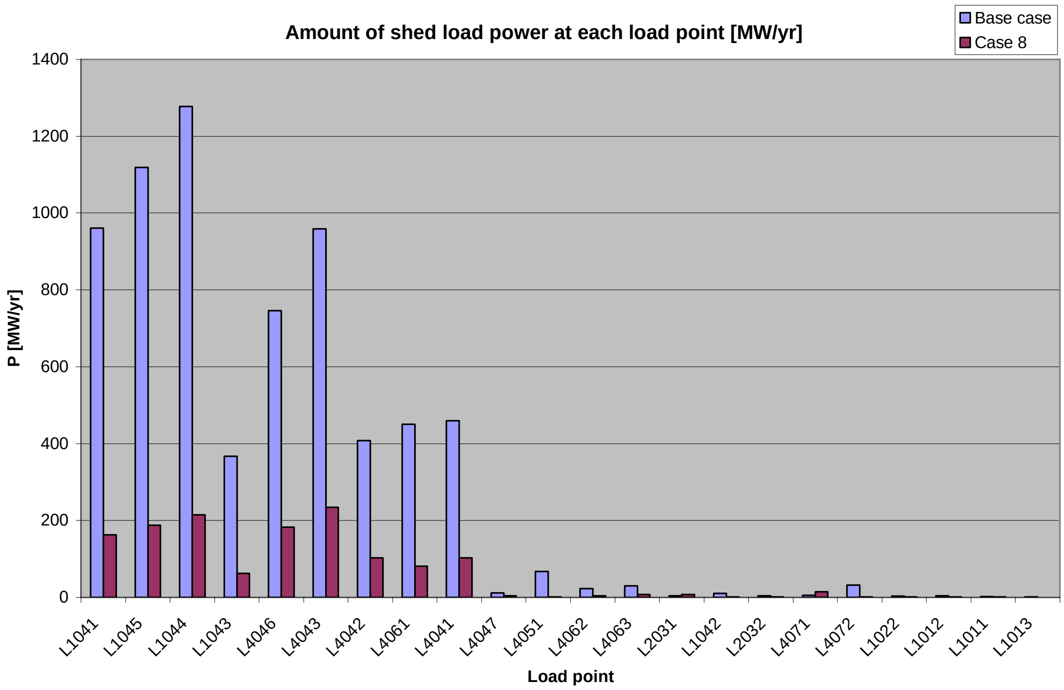
The Nordic32 Test transmission test system can be modified more in order to extend it and make it suitable for more detailed reliability studies. In other words, the substation layout as well as the suitable component’s dimensioning can be made in order to get this system suitable as a reliability transmission test system e.g. providing proper data about the lines loading limits, generators and transformers loading limits, installed generation and load, etc.

Appendix A-1


Amount of shed load power at each load point [MW/year]
Base case
Case 1
P [MW/year]
1400
1200
1000
800
600
400
200
0
L1041
L1045
L1044
L1043
L4046
L4043
L4042
L4061
L4041
L4047
L4051
L4062
L4063
L2031
L1042
L2032
L4071
L4072
L1022
L1012
L1011
L1013
Load point


Amount of shed load power at each load point [MW/yr]
Base Case
Case 2
P [MW/yr]
1400
1200
1000
800
600
400
200
0
L1041
L1045
L1044
L1043
L4046
L4043
L4042
L4061
L4041
L4047
L4051
L4062
L4063
L2031
L1042
L2032
L4071
L4072
L1022
L1012
L1011
L1013
Load point


Amount of shed load power at each load point [MW/yr]
Base case
Case 4
P [MW/yr]
1400
1200
1000
800
600
400
200
0
L1041
L1045
L1044
L1043
L4046
L4043
L4042
L4061
L4041
L4047
L4051
L4062
L4063
L2031
L1042
L2032
L4071
L4072
L1022
L1012
L1011
L1013
Load point


Amount of shed load power at each load point [MW/yr]
Base case
Case 8
P [MW/yr]
1400
1200
1000
800
600
400
200
0
L1041
L1045
L1044
L1043
L4046
L4043
L4042
L4061
L4041
L4047
L4051
L4062
L4063
L2031
L1042
L2032
L4071
L4072
L1022
L1012
L1011
L1013
Load point

Appendix B-1

Connected from Bus	Resistance	Reactance	charginf [uF]	Length [Km]
4031 To bus 4041	9,6	64	4,77	770
4031 To bus 4041	9,6	64	4,77	770
4032 To bus 4044	9,6	80	4,77	810
4032 To bus 4042	16	64	3,98	580
4021 To bus 4042	16	96	5,97	1000
4042 To bus 4044	3,2	32	1,19	190
4042 To bus 4043	3,2	24	0,99	140
4022 To bus 4031	6,4	64	2,39	370
4022 To bus 4031	6,4	64	2,39	370
4021 To bus 4032	6,4	64	2,39	380
4012 To bus 4022	6,4	56	2,09	285
4011 To bus 4021	9,6	96	3,58	535
4011 To bus 4022	6,4	64	2,39	320
4011 To bus 4012	1,6	12,8	0,4	100
4071 To bus 4011	8	72	2,79	380
4071 To bus 4012	8	80	2,98	420
4071 To bus 4072	4,8	48	5,97	300
4071 To bus 4072	4,8	48	5,97	300
4044 To bus 4043	1,6	16	0,6	70
4043 To bus 4046	1,6	16	0,6	60
4046 To bus 4047	1,6	24	0,99	100
4043 To bus 4047	3,2	32	1,19	130
4044 To bus 4045	3,2	32	1,19	170
4044 To bus 4045	3,2	32	1,19	170
4045 To bus 4051	6,4	64	2,39	280
4045 To bus 4051	6,4	64	2,39	280
4062 To bus 4045	17,6	128	4,77	760
4041 To bus 4044	4,8	48	1,79	260
4041 To bus 4061	9,6	72	2,59	395
4061 To bus 4062	3,2	32	1,19	130
4062 To bus 4063	4,8	48	1,79	230
4062 To bus 4063	4,8	48	1,79	269
4031 To bus 4032	1,6	16	0,6	93

Appendix B-2

Load points value:

Connected to Bus	Code	P[MW]	Q[MVar]
4071	2	300	100
4072	2	2000	500
4011	3	0	0
4012	2	0	0
4021	-2	0	0
4022	1	0	0
4031	2	0	0
4032	1	0	0
4042	1	400	125.7
4041	1	540	128.3
4043	1	900	238.8
4044	1	0	0
4046	1	700	193.7
4061	1	500	112.3
4062	1	300	80
4063	1	590	256.2
4045	1	0	0
4047	1	100	45.2
4051	1	800	253.2
1011	1	200	80
1012	2	300	100
1013	2	100	40
1014	2	0	0
1021	2	0	0
1022	-2	280	95
2032	2	200	50
2031	1	100	30
1043	-2	230	100
1044	1	800	300
1045	1	700	250
1041	1	600	200
1042	2	300	80

Code:

1: Load bus, i.e. varying load and angle
2: Generator bus, i.e. Varying Q generation
-2: Generator bus at Q limit
3: Slack bus, i.e. varying P and Q generation

Appendix B-3

Machines limits and shunts connected to the buses:

Connected to Bus	Number of machines	Shunt [Mvar]	PGen[MW]	QGen[MVar]
4071	1	400	300	194
4072	2	0	1000	140
4011	1	0	668.5	94,3
4012	1	100	600	-2,5
4021	1	0	250	-30
4022	0	0	-	-
4031	1	0	310	113
4032	0	0	-	-
4042	1	0	630	265
4041	S. condenser	-200	0	-9
4043	0	-200	-	-
4044	0	0	-	-
4046	0	-100	-	-
4061	0	0	-	-
4062	1	0	530	0
4063	2	0	530	88
4045	0	0	-	-
4047	2	0	540	152
4051	2	-100	600	217
1011	0	0	-	-
1012	1	0	600	84,9
1013	1	0	300	44
1014	1	0	550	82
1021	1	0	400	44
1022	1	0	200	125
2032	1	-50	750	145
2031	0	0	-	-
1043	1	-150	180	100
1044	0	-200	-	-
1045	0	-200	-	-
1041	0	-200	-	-
1042	1	0	360	79

Appendix B-4

Machines limits:

Connected to Bus	Pmax [MW]	Pmin [MW]
4071	450	0
4072	4050	0
4011	450	0
4012	720	0
4021	270	0
4022	NA	NA
4031	315	0
4032	NA	NA
4042	630	0
4041	270	0
4043	NA	NA
4044	NA	NA
4046	NA	NA
4061	NA	NA
4062	540	0
4063	540	0
4045	NA	NA
4047	540	0
4051	630	0
1011	NA	NA
1012	720	0
1013	540	0
1014	630	0
1021	540	0
1022	225	0
2032	765	0
2031	NA	NA
1043	180	0
1044	NA	NA
1045	NA	NA
1041	NA	NA
1042	360	0

Code:

NA: no machines connected

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