POLITECNICO DI MILANO

School of Industrial and Information Engineering

Master of Science in Electrical Engineering

Fault analyzes and protection strategies for MVDC systems

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Abstract

Medium Voltage Direct Current (MVDC) is a new concept gaining its popularity due to increase of the transfer capacity and improved power quality of the distribution networks.

The aim of this thesis is to investigate different short circuit faults in MVDC systems and proposing a protection strategy for each fault, furthermore, it is also to be analyze what happens when the fault occur on one side of the system. Whether it affect the whole system or that point.

Using the MATLAB simulation, this study analyzed the symmetrical and unsymmetrical faults in MVDC and proposing the protection strategy for these faults.

Line to Line to Line to ground and Line to Line to Line faults showed the same results and hence the same protection system was implemented. Pole to pole and double pole to ground has similar behavior and same technique was applied to control the faults and last but not the least Pole to ground has some unique results so different protection strategy was implemented.

Chapter 1

Introduction

Medium voltage direct current (MVDC) is gaining popularity by increasing the transfer capacity and providing improved power quality to the distribution networks. MVDC Transmission is a new concept which usually operates in the range of 15 to 50 kV and 30 to 150 MW capacity, and it is an alternative to AC interconnection to provide power to remote communities. The medium voltage dc (MVDC) is vital to realize the power transmission and distribution in the DC grids. There has always been a battle between AC and DC; we know them as "WAR OF CURRENTS." Edison introduced the first commercial distribution of electrical energy on the lower Manhattan, New York, a 24 kilometers long two-wire cable system of copper conductors that provided 110 V incandescent lighting. But due to the high length of the wire, it was outrated by AC in terms of efficiency. The AC system can use the transformer to step up the voltage for the high transmission line and reduce the losses, hence increasing efficiency. Moreover, as time passes, the technology improved, so as the usage of the AC system. The introduction of a three-phase AC system enhances efficiency, even more, thanks to the invention of Transformers.

When it comes to distribution networks, the DC system is more robust than the AC system due to well established, mature, and low-cost infrastructure. Therefore, the disadvantages of the DC system must be decreased as much as possible. This thesis is about how to increase the length of the transmission line without increasing the losses.

1.1 DC Advantages over AC

By converting a circuit to MVDC, it is in theory possible to increase the specific transfer capacity of that circuit compared to the nominal AC rating. As this is now fully controllable, additional network capacity increases (i.e., removing power-flow or voltage limitations). The MVDC capacity increase is based on the following factors [1]

- DC can use full peak voltage capability of AC circuits compared to the RMS rating (1,4 times)
- The current capability can be increased without taking care of sag because DC does not suffer from DC needs a metallic return so can only utilize 2 of 3 conductors on a single circuit (0,67 times)
- Existing AC circuits run with the single ground point at the bulk supply point, AC insulation rated for 1,7 times nominal voltage for single-phase voltage displacement at remote ends. DC does not have voltage displacement if grounded at both ends. Therefore, it can utilize the total insulation capacity (1,7 times).
- The Dc system has an advantage over the AC system in that it can provide higher efficiency of power transmission and distribution under the same voltage levels [2].
- Frequency synchronization and reactive power compensation are not required [3].

1.2 MVDC over HVDC

After the first installations in the fifties, HVDC has become a worldwide transmission technology that today can count on a long operational experience. Thanks to its speed and flexibility, the HVDC technology can provide the transmission system with different benefits such as transfer capacity enhancement, power flow control, transient stability improvement, power oscillation damping, voltage stability and control, rejection of cascading disturbances, absence of reactive power. Due to its features, over the years, HVDC technology has been preferred over HVAC transmission for selected applications, such as i) very long-distance lines, especially for bulk power transport, ii) longer submarine cable links, and iii) interconnections of asynchronous systems (in the full or back-to-back scheme) [4,5 ,6 ,7].

Although High voltage Direct current (HVDC) or High voltage alternating current (HVAC) is the desired way to transfer the power from generation to the substations, only MVDC grids are utilized for distribution grids. MVDC systems can unlock new sources of flexibility for the utilities that are not available using conventional technology using fully controlled converters. The benefits include and are not limited to; better utilization of existing network assets, reduced losses, better control options to avoid voltage and thermal limit violations, alleviate power quality problems by splitting, and increased headroom for embedded generation integration

HVDC has the following problems, which is the reason to prefer MVDC over HVDC.

HVDC has some problems while converting the voltages but MVDC, is not just best for voltage conversion at different levels, but the realization of MVDC grids can facilitate the use of a lower number of required energy conversion stages supply and load sides.

Apart from voltage conversion, HVDC has the following drawbacks.

- Switching
- Control
- Availability
- Maintenance

1.3 MVDC Network Configuration

Medium voltage direct current (MVDC) can be used together with the medium voltage alternating current (MVAC) to reinforce the distribution system, allowing power flows and decoupling of the meshed network in case of the fault. The MVDC configuration is shown in Figure 1.0 one of the biggest reasons for using the MVDC system instead of HVDC is that MVDC demonstrates the de-risk of the HVDC systems and components, testing at more minor scales the proposed level [8].
The primary considerations are the technical analysis of the component and the logic for managing the system's system.
There is an implementation of power converters and digital simulation models of medium voltage direct current (MVDC). The simulation allowed the evaluation of the system performances, for both active and passive distribution situations, In case of network voltage and frequency variation and voltage dips in the distribution grids or the direct current section. In

this configuration, the system behavior is evaluated during normal and faulty conditions during AC and DC networks. The results reveal that the fault current supplied from the converter DC must be limited. For this purpose, a current limiter based on power converter devices has been designed and modeled in a digital simulation environment.
The behavior of an MVDC network with different grounding methods and faults either in the AC and the DC sections has also been analyzed, highlighting the limits and opportunities offered by the considered solutions. In Particular, The DC system grounding solution using a resistance has put in evidence a better operation of the network during a fault in the DC section; a possible logic selectivity in the protection system has also been considered.

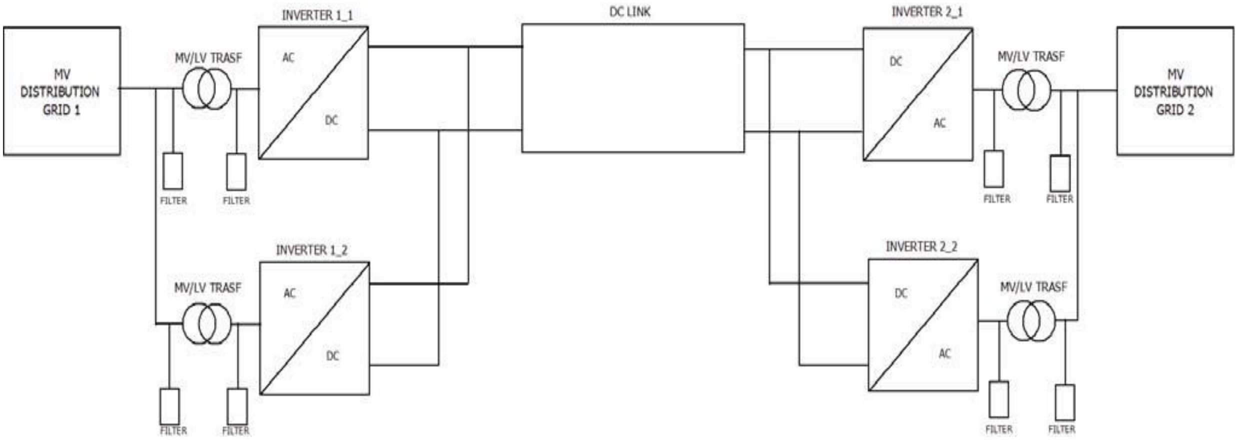


Figure 1.0. MVDC configuration.

Chapter 2

Electrical grids

Electrical power is transmitted using either high voltage alternating current (AC) or High voltage direct current (DC). However, the privilege goes to Medium voltage direct current (MVDC) when it comes to the distribution grids due to its easiness of voltage conversation in transmission and distribution at reduced voltage level stages [9]. As a result, the distribution is not only performed more efficiently but with higher control flexibility.

2.1 DC grid concepts

The grid concepts for DC grids are line concept and station concept. The possible line and station grids are presented in the following.

Line concepts of DC grids

The line concepts of DC grids deal with the design of lines regarding the required number of conductors. There are Four different line concepts presented, but only three are shown in Figure 2.1.

- Monopolar line concept with the ground as the return conductor
- Monopolar line concept with a metallic return conductor
- Bipolar line concept with the ground as a neutral conductor
- Bipolar line concept with a metallic neutral conductor

The monopolar line concept with the ground as a return conductor needs a single metallic conductor. The electrical loop can be closed using the ground as a conductor in the monopolar line concept with a metallic return conductor; the power is transmitted using two insulated metallic conductors. The bipolar line concept with the ground as a neutral conductor is a parallel conductor of two monopolar line concepts with the ground as the return conductor. As its name suggests, it requires two insulated metallic conductors because the return of both parallel monopolar systems takes place together by ground. The bipolar line concept with a metallic neutral conductor uses an additional metallic conductor that takes the ground as the neutral conductor. So, in conclusion, three metallic conductors are required. The monopolar line concept with the ground as return conductor and the bipolar line concept with the ground as a neutral conductor has no reason to be used due to the negative aspects of other underground infrastructure.

Station Concepts of DC Grids

The station concepts of DC Grids consider the design of AC/DC and DC/DC converter stations. Three different station concepts of DC Grids can be presented in Figure.2.1.

- Asymmetric monopolar station concept

- Symmetric monopolar station concept
- Bipolar station concept

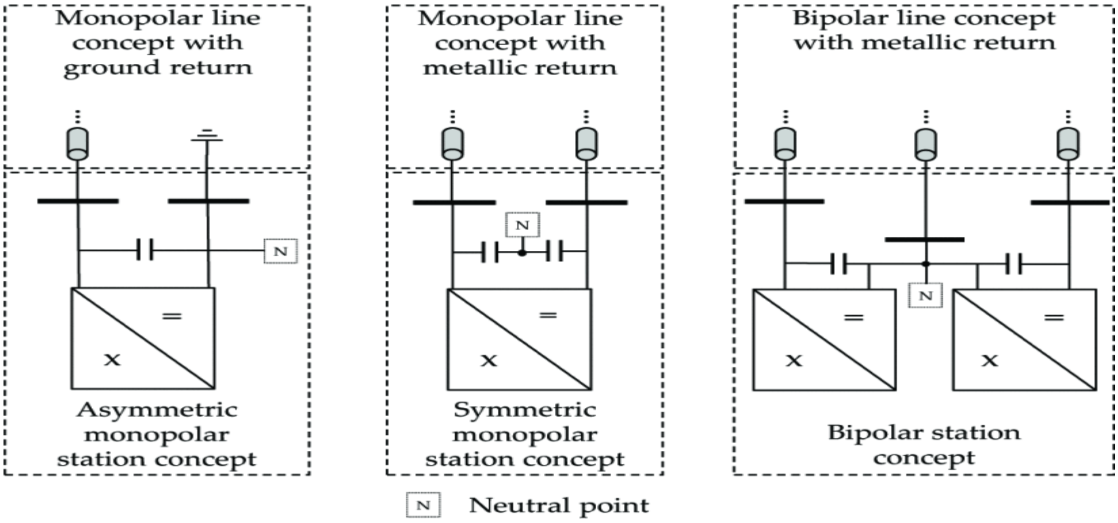


Figure 2.1 Different station and line concepts of DC grids

The Figure shows that the asymmetric and symmetric monopolar station concept uses two busbars and one power electronic converter. However, an additional power converter can be added in parallel to increase the reliability. The only difference between the two monopolar station concepts is the neutral point location and the poles' rated voltages. On the one hand, The location of a neutral point in the case of asymmetric monopolar station concept at one of the two poles of the converter system represents that this pole is a neutral pole, and on the other hand, in the case of symmetric monopolar station concept the neutral point is generated by two equally dimensioned capacitors. Due to this, the two poles experience two different voltage polarities: half of the converter's DC voltage. In the case of the bipolar station concept, it uses three busbars, and two parallel converters are installed. The location of the neutral point is generated by connecting the negative pole of one converter to the positive pole of the other converter system. Due to this reason bipolar station concept is considered two parallel asymmetric monopolar stations. Whereby the live electrical poles have opposite polarity.

Possible Grid Concepts of DC grids

Based on the different station and line concepts, different grid concepts regarding DC grids are possible.

- Asymmetric monopolar grid concept (AMGC)
- Symmetric monopolar grid concept (SMGC)
- Bipolar grid concept (BGC)

- Different hybrid grid concepts

In the asymmetric monopolar grid concept, the asymmetric monopolar station concept and the monopolar line concept with the metallic return conductor are used for all stations within the DC grid and all lines.

In the symmetric monopolar grid concept, the symmetric monopolar station concept is used for all stations within the grid, and the monopolar line concept with a metallic return conductor is used for all lines.

In the bipolar grid concept, the bipolar station concept is used for all stations within the grid, and the bipolar line concept with the metallic neutral conductor is used for all lines. This concept aims to improve the reliability of the system.

A hybrid grid concept does not use only a single station and line concept, but an exemplary hybrid grid concept for distribution grids is shown in Figure 2.2. from Figure, the hybrid DC grid concept uses the bipolar line concept with the metallic neutral conductor for all line within the grid. The bipolar station concept and the monopolar station concept prioritize the grids and low priority substations. If there is a fault in one of the live conductors of the line, the connected low priority substation can switches to the other electrical circuit Thereby, the reliability of supply regarding the low priority substations should be increased compared to the monopolar grid concepts with reduced costs compared to the bipolar grid concept.

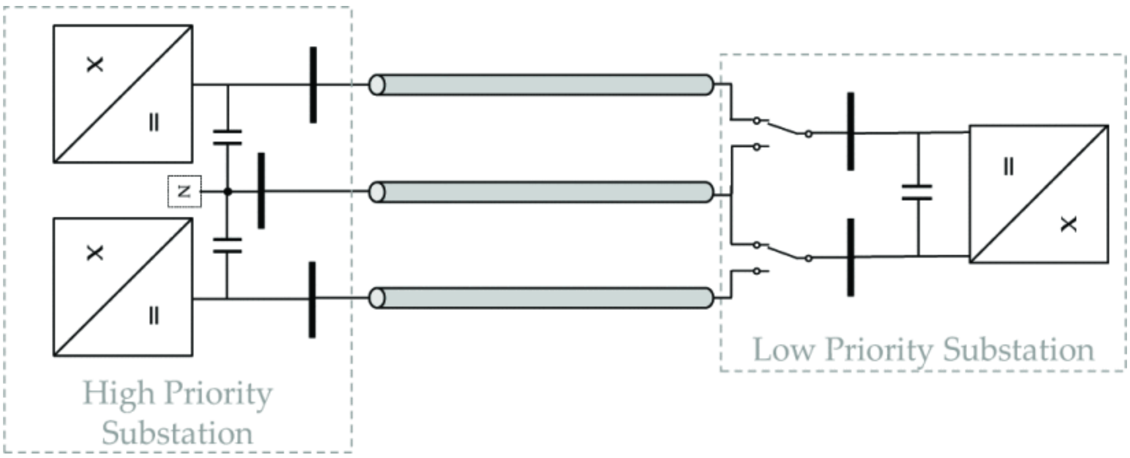


Figure 2.2 Exemplary hybrid DC grid concept

2.2 ABB MVDC and Grid interties

Medium voltage direct current (MVDC) applications in distribution grids are becoming a reality in the first pioneering demonstration projects [10]. The first installation of an MVDC converter in a distribution grid occurs in the Network equilibrium project in the UK. This application consists of connecting two adjacent distribution grids by a back-to-back (B2B) converter between southwest England and Wales [11]. The conversion cost (CAPEX and OPEX) can be significantly reduced when DC loads (fast-charging stations for electric vehicles, data centers, DC generation plants (wind and mainly solar) and battery energy systems utilizing

DC/DC converters are integrated. This would be one of the primary reasons for the introduction of MVDC. Conversion steps of AC voltage to DC voltage and vice versa are reduced if DC distribution systems are used, resulting in fewer losses in the overall system.

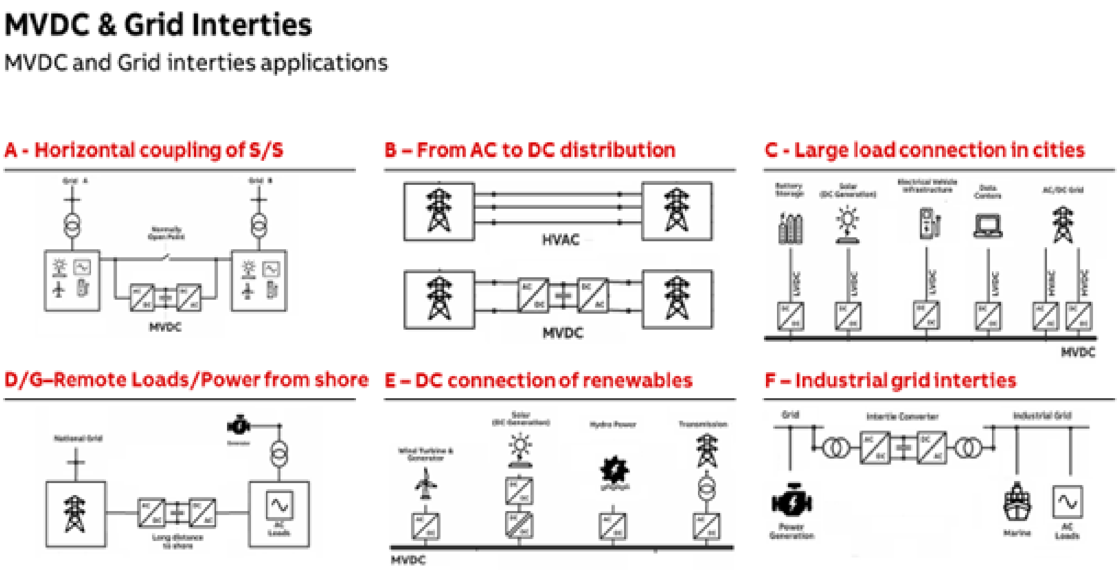


Figure 2.3 – MVDC and Grid Interties application

2.2.1 Application A - Horizontal coupling of substation

some grid sections cannot be interconnected on distribution and substation level due to the following reasons,

- Phase angle differences
- Frequency differences between two connection systems
- Excessive harmonics or flicker in one grid section
- Short-circuit current would otherwise be exceeded
- Redundant parallel supply from another utility/distribution grid to the same island grid
- A different concept of neutral earthing of each network

But there are some massive reasons to interconnect such grids.

- Overcome capacity limits in grid sections, due, e.g., growing distributed generation Provide capacity enhancement
- Power flow shall be controlled
- The voltage or reactive power shall be controlled dynamically on either connected AC grid
- De-coupling one AC grid from the other due to power quality or short circuit capacity reasons.

This application is also called soft open point (SOP).

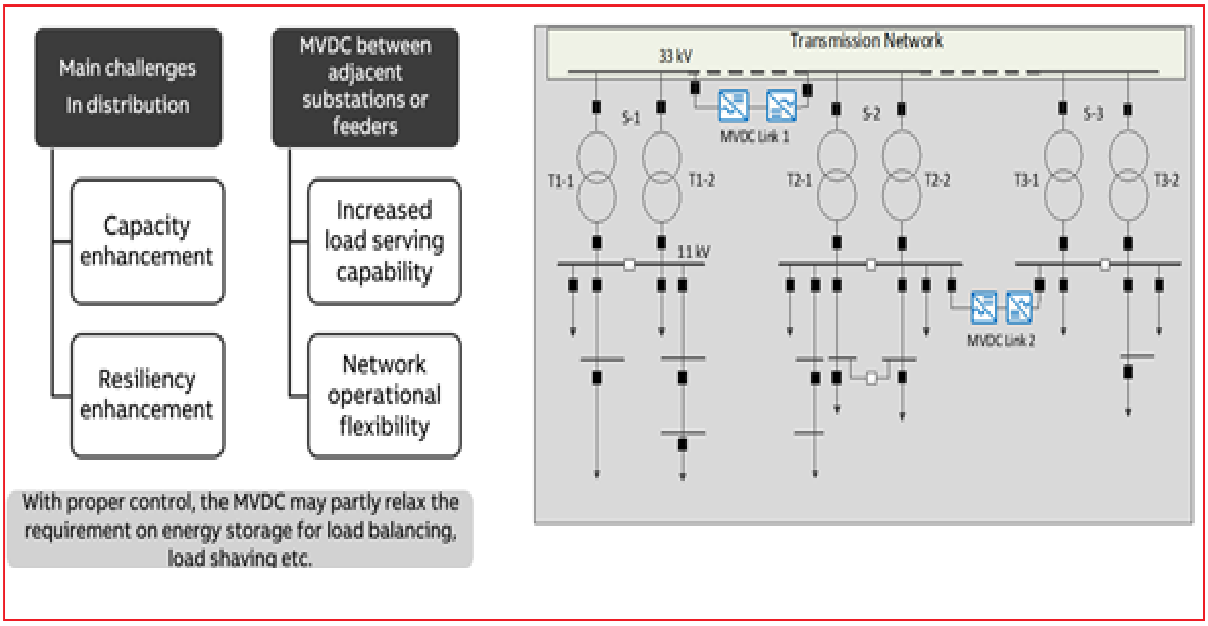


Figure 2.4 – Horizontal coupling of substations

2.2.2 Application B – Converting AC distribution to DC distribution

The power capacity of an existing grid can be increase by converting Alternating current to Direct current. For long, congested feeders in meshed distribution grids, line conversion can be a cost-efficient solution for increasing the power rating [12]. Apart from more significant power transfer, grid stability can be improved by providing embedded STATCOM functionalities on both sides of the grids.

Key customer benefits are:

- Avoid network expansions while re-using existing AC lines
- Limit the environmental impact with the installation of new DC cable instead of traditional AC overhead lines
- Increased asset utilization with 20-80 percent more transmitted power
- Grid stabilization

The limit of such application is determined by the length of the connection, as the cable losses can become significant.

2.2.3 Application C – Large load connections in cities

Extensive load connections require a new addition of connections. The ac lines are costly, and it's hard to get the permit for these AC lines in the city center; DC lines are preferable because of their cost and they carry less space than AC overhead lines; moreover, the underground connection is another reason for considering DC lines over AC: that also implies issues with capacitive currents which are not an issue using DC. There are two main approaches to be considered:

- We are using the MVDC grid as a backbone to integrate LVDC consumers/producers to reduce CAPEX and conversion losses for the connection of large DC loads within cities (e.g., EV charging stations).

- Support existing weak AC grids to avoid potential power quality problem and allowing power exchange between distribution line thanks to multi-terminal connections

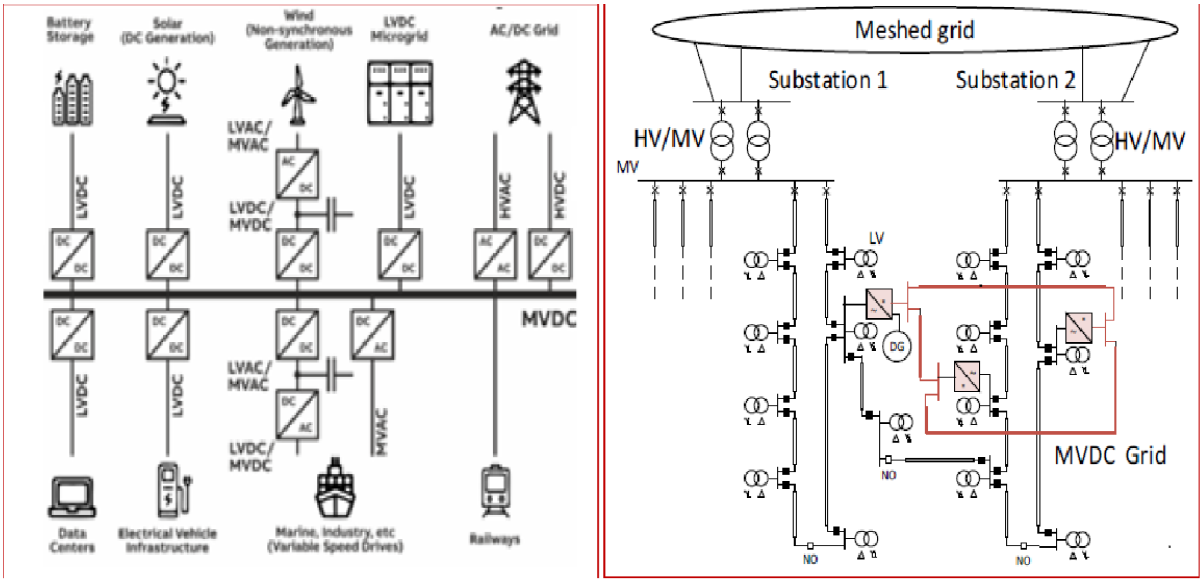


Figure 2.5 – Load connection in cities and multi-terminal MVDC connections

2.2.3 Application D – Remote load connections

Some communities are still available who are deprived of electricity and are not connected with the electrical grids, and the only source to get the electricity is from the local generations, which are very expensive.

These isolated communities can get electricity without paying much by installing an MVDC transmission line with low-cost extruded cables (island interconnection) or an overhead line. Cheap electricity from the main-land grid can be imported, and the local diesel generator can be shut down, thus reducing costs for fuel transport, storage, and diesel generators maintenance.

For overhead line application, the typical breakeven distance for choosing DC transmission over AC transmission is above 75-100 km, with also a reduced visual and environmental impact thanks to tight overhead lines.

2.2.4 Application E – DC connection of Renewables

Wind and solar above 10-20 MW generation plants can be connected to the sub-transmission level or HV/MV substation on the MV side. MVDC could avoid expanding the substation network by connecting new distributed generation plants to existing HV/MV substations located further away.

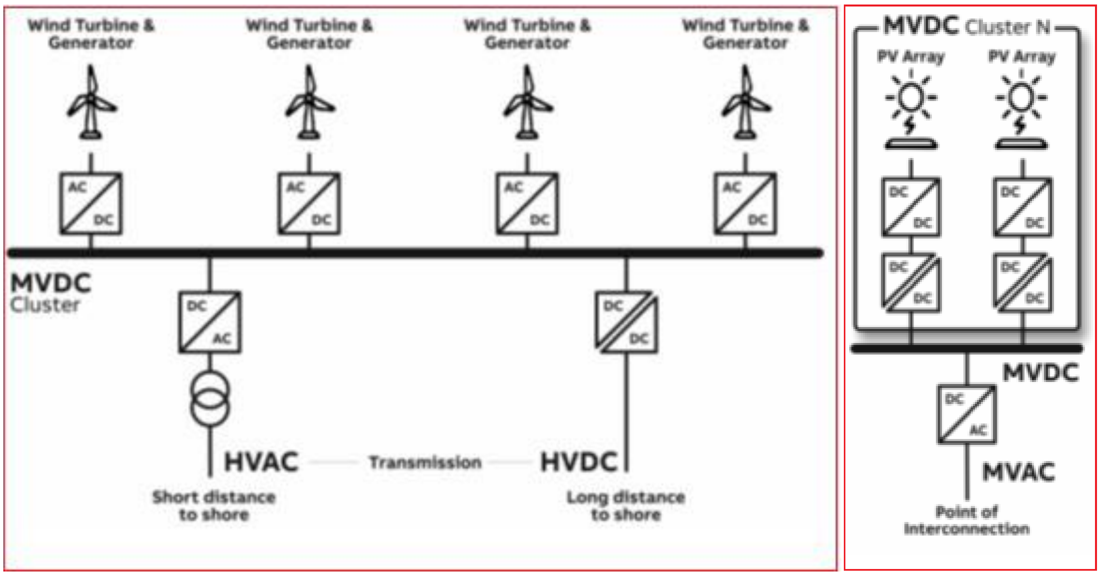


Figure 2.6 – Wind and solar MVDC collection

Prominent application cases would be

- **Offshore and onshore wind power:** the power collection efficiency and the overall cost would be improved with the help of the MVDC grid within a wind turbine cluster.

- **Solar:** 1.5 kV solar panels have been in use in large PV farms due to their low cost. It is likely possible that PV farms with higher voltages around 3.5 kV are expected due to double glass bifacial PV module technologies.

The main benefits would be:
- reduced space requirement inside a wind turbine since the only rectifier required.
- Direct connection of high voltage PV panels to MVDC inverters
- Reduced losses in the collection grid through DC currents and fewer conversion steps

2.2.5 Application F – Industrial grid interties

In this application, the utility grid faces the non-utility grid using a power conversation system. Several potential cases should be considered, including but not limited to the following:

Asynchronous links: there are some cases where there is a requirement for the power exchanges between an industrial and a public grid which can be identical or different frequencies, exactly when generation on one side and consumption on the other side is unbalanced. When this happens, a grid intertie system will provide smooth power transfer, block the harmonics to propagate into the public grid and provide sufficient reactive power to the industrial grid and balance the local loads.

Industrial Plant Relocation: when an existing industrial plant initially located in a 50 Hz (or a 60 Hz) country is moved to a 60 Hz (or a 50 Hz country) respectively; an industrial grid intertie is a viable option to the potential substitution of all the main industrial plant loads.

Microgrid connections: some microgrids might benefit from becoming grid-connected to allow selling back to a local utility the excess of generated power or to buy electricity when local generation is not sufficient. STATCOM functionality to stabilize the local microgrids or allow the connection into the utility grid in full compliance with local grid code might also be required and nested microgrid or microgrid clusters linked with controllable power flow.

Generations sets interface to grid: in emerging markets, power generation might be insufficient to serve the local industrial area needs. Therefore, the solution with re-locatable power plants or generation sets that might have been designed for a different frequency or grid code compliance shall be ensured by employing static frequency converters.

Grid simulators/test stands: some research or certification institutions need a laboratory to carry out specific tests on electrical grids or devices.

Rotating Frequency Converter replacement: replacing old RFCs to achieve better energy efficiency during operation

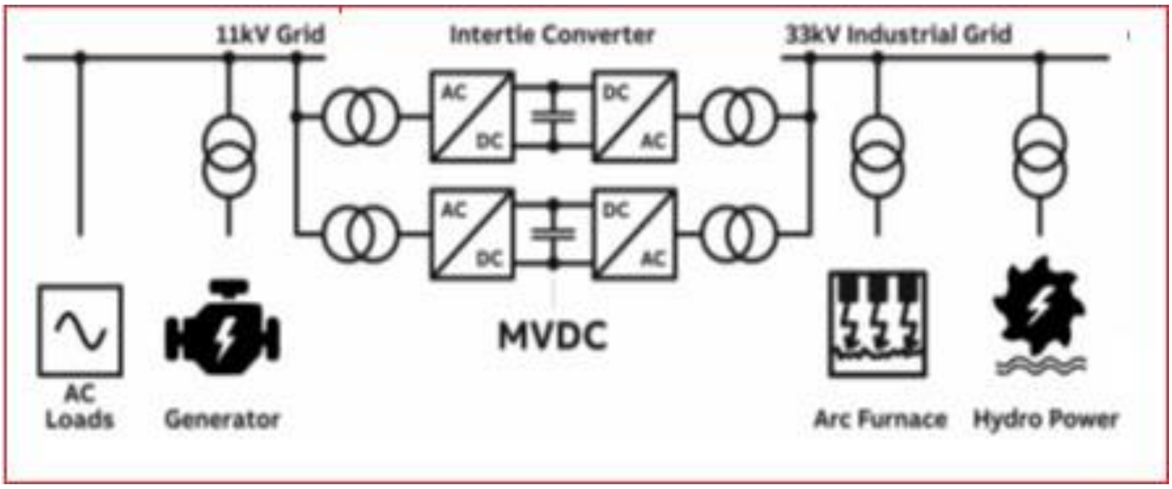


Figure 2.7 – Industrial Grid Interties

2.3 Applications of MVDC grids

There is much potential application, which was introduced, but they are categorized into two applications.

1) **Onshore**
2) **Offshore**

This shows in Figure (2.8.a) and Fig (2.8.b), respectively.

Whether onshore or offshore design, some electronic components are required for the design of MVDC Regardless of operating as the distribution system. Some of them are related to power electronics components like active and passive converters, DC/DC converters, DC/AC rectifiers. It also requires protection schemes and some control strategies that should be implied efficiently, reliable, and considered low cost [13].

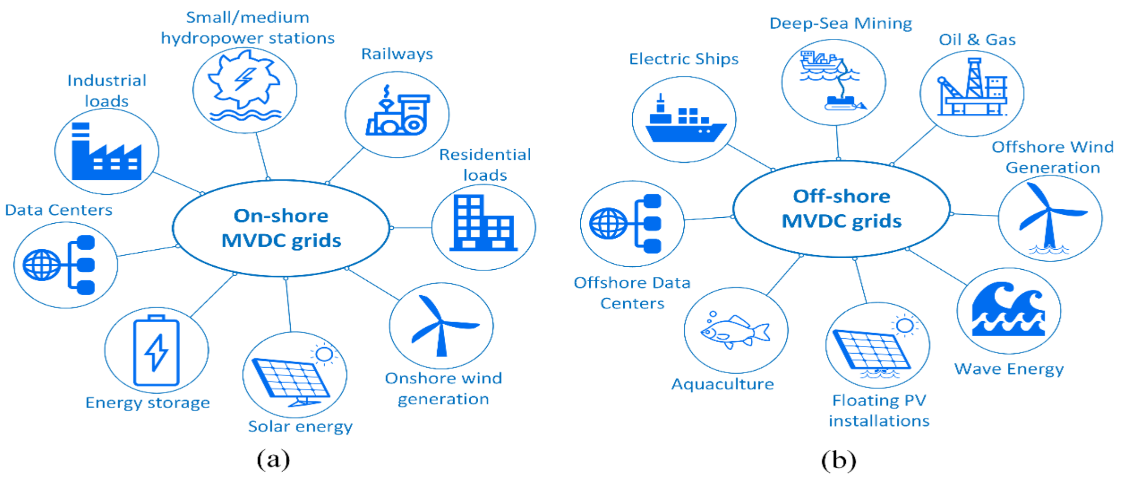


Figure 2.8: Potential (a) onshore and (b) offshore applications of MVDC grids.

It is also adopted for the application like data center, train/traction, marine, etc. [14,15]. renewable energy inflow is considered a suck as PV and wind energy at the MVDC network to reduce fossil fuel power consumption. [16]

Another significant area that MVDC grids that would show a beneficial performance are mi-crogrids with
integrated RES and battery energy storage systems (BESS). The main reason is the easier integration and more flexible power flow control enabled due to the common DC bus used.

The typical potential applications are

(i) offshore wind power, (ii) marine vessels, (iii) microgrids with renewable energy sources (RES) integration, (iv) transportation, (v) subsea electrification, (vi) electricity supply to data centers and buildings, (vii) electrification of oil and gas rigs and (viii) others (i.e., DC homes, electrification of a university campus, mine site).

One observation on this Figure is that there is a tendency for the voltage level to reach 40 kV, while the power ratings can be at least 100 kW [17].

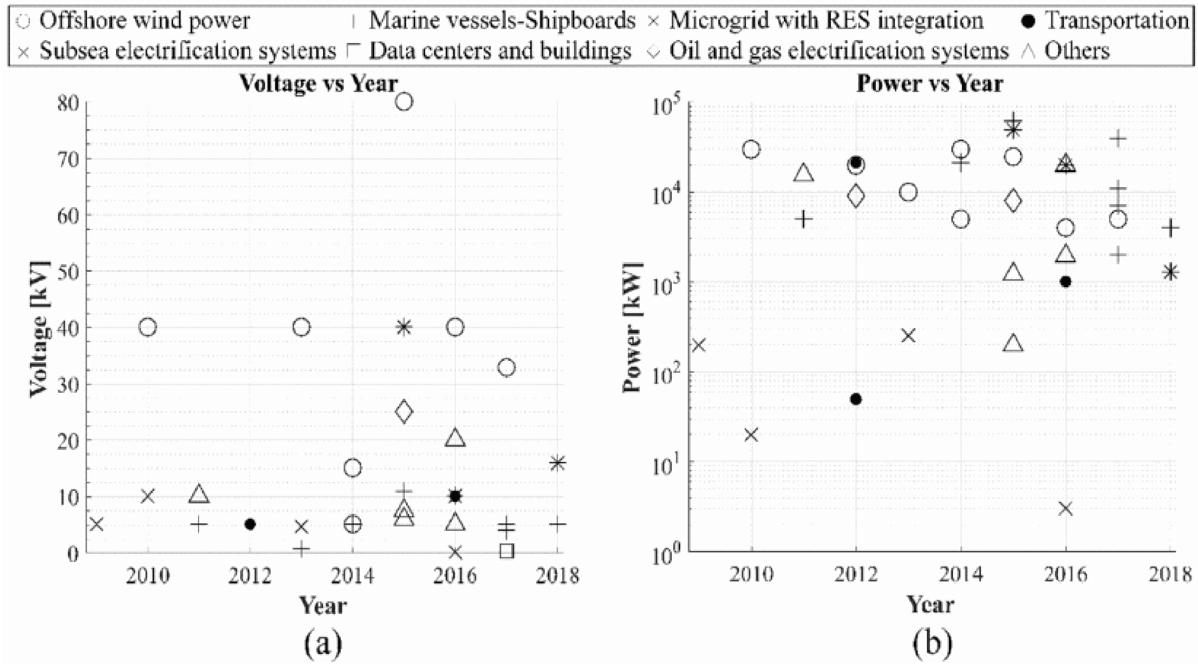


Figure 2.9 Scatter diagram of reported MVDC applications, listed concerning a) voltage (kV) as a function of year and b) power as a function of the year on a logarithmic scale

There are few other potential applications where MVDC grids would be ideally suited. These could be a "DC home" [18] (at 5 kV with 1.95 MW load), the electrification of an entire university campus [19] (at 10 kV with 15.5 MW load), and the power distribution on an onshore mine site [20] (at 6 kV with 1.2 MW load).

2.4 Protection for MVDC Grids

Protection for MVDC grids is facing different challenges [21]. A protection concept must fulfill the criteria of appropriate selectivity, fastness, security, and economic efficiency and can be divided into fault detection, fault localization, clearing, and re-supply. A protection concept for MVDC grids needs to consider future grid structures, mainly because meshed grids are possible. The following types of common short circuit faults usually occur in the DC network indicated by previous researchers [22,23].

- Short-circuit in a positive pole
- Short-circuit in a negative pole
- Short-circuit between +ve/-ve to neutral pole
- Positive pole to earth fault
- Negative pole to earth fault
- Neutral pole to earth fault.

The question arises of how to protect our system from these faults, and the previous researchers presented research; circuit breaker and fuses are the standard protection devices used for this new technology protection on the DC grids. Here the circuit breaker can have more problems disconnecting the circuit from the lines as the current being used is DC instead of AC. AC breakers rely on the natural zero crossings of the AC; hence, these breakers cannot be applied in dc systems due to the lack of zero-crossing in the DC. Maybe it needs more energy to open the breaker isolation mechanism. The alternative would be fact-acting DC solid-state fault isolation electronic devices because they can perform faster and softer than conventional circuit breakers.

2.5 Fault protection methods for MVDC systems

2.5.1 Using AC circuit breakers

There are AC Circuit breakers in AC distribution networks. When there is an AC fault, the fault is detected, located, and ACCBs open to isolate from the fault. The duration of this process can be ten to hundreds of milliseconds in the distribution networks. And finally, the system can be restored and re-powered the load beyond the faulty zone.

The ACCBs are already installed at the convertor side and can protect the DC systems. As shown in the Figure 2.10, this is the so-called handshaking method, which employs the AC-CBS and the fast DC switches. When there is a fault in the system, the first activity is to block the converters after the located fault current, and then ACCBs are tripped. Further-more, the fast dc switches located at both ends of each line isolate the faulty line under zero current. The healthy circuits can be restored once the faulted line is isolated.
The use of ACCBs is economical and straightforward, but the long fault isolation time associ-ated with this strategy can lead to the de-energization of the entire DC grid. This may nega-tively affect the system's secure operation.

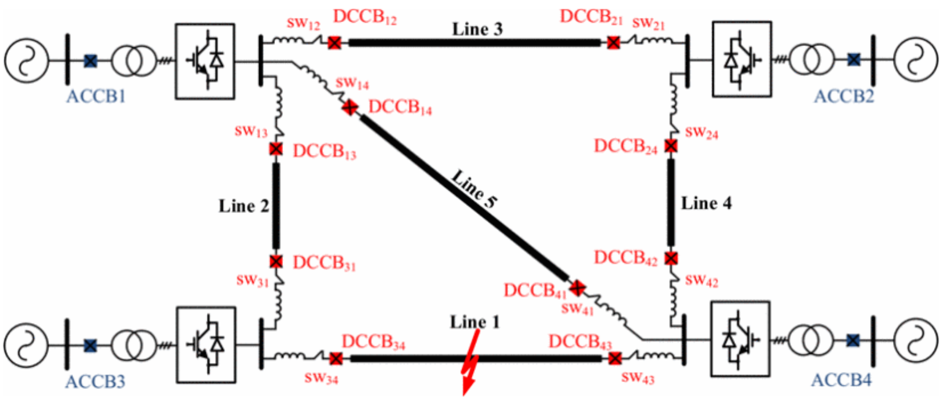


Figure 2.10 Schematic diagram of a 4-terminal DC grid equipped with ACCBs, DCCBs, and fast DC switches.

2.5.2 Using DC Circuit Breakers

it is more difficult for the DC circuit breakers to interrupt the fault current than AC circuit breakers as they do not have zero-crossing phenomena which make thing a bit complicated. However, some manufacturers proposed many DCCBs, but their high-cost limits them to large-scale DC systems. Therefore, fast and economical DC protection is one of the main obstacles to deploying large-scale DC networks.
Figure 2.10 shows applications of DCCBs in the DC grids. Typically, DCCBs are installed at the two ends of a DC line. Sometimes, a single DCCB is needed to protect a DC bus.
In a DC grid using DCCBs to provide fast clearance of a DC fault, two leading solutions ap-pear: one is to apply the same protection philosophy and principles used as AC systems called the "Fully Selective Approach," other is the "Open Grid" concept.

2.5.3 Using fault blocking converter

The converters can block the AC in feeding current by blocking the converter such as full-bridge modular multi-level converter (FB-MMC), clamp-double MMC (CD MMC), and alternate arm converter (AAC) are the typical examples of these kinds of converters. Once all the converters are blocked, the DC fault current starts to decay to zero naturally so that fast DC switches can operate and isolate the faulted circuits. The converters can be de-blocked once the faulted line is isolated, and the DC grid can start to restore to a new steady state.
The main drawback of using this technique is higher capital cost and power losses, and even this may become worse in medium and low voltage systems.

2.6 Future Protection Challenges in MVDC grids

The short circuit fault is very challenging to overcome from the above analysis, and high-performance CBs are in demand than ever before. These high-performance CBS require some specifications, most likely with its design and operating characteristics. There are as follows.

- First and foremost, the CB should clear the fault as fast as possible not to damage power electronic components. In austere worlds, fast fault clearance.
- There should be low conduction losses which can result in higher energy efficiencies in the grid.
- Fast residual energy dissipation to completely de-energize the fault line and set the CB ready for reclosing operation.
- Development of specific standards that governs the design and operation of CB for MVDC applications
- Reliability of the CBS is the primary aspect that repeatable breaker performance under different fault conditions and expected conditions in MVDC grids.

2.7 Power flow control in MVDC grids

Rapidly increasing progress in technology and decreasing cost in power electronics components in the last years enables us to prefer DC grids instead of AC grids. It's possible to control the power flow in the MVDC grids with the help of converters; the controllability of power flow has advantages, like decreasing the losses and a technically permissible grid operation in a regular operation due to component failure can be ensured.

However, the MVAC cannot control the power flow due to its infrastructure; in such a grid, structures were appropriate because the power flow direction was from power plants to the customers in a lower level voltage. Because Low voltage (LV) grids often exhibit just simple radial grid structures due to their supply task.

2.7.1 Controllable converters

Power flow control is possible with the converters if certain conditions are fulfilled. On the one hand, converters require the possibility to actively adjust the power flow, which is impossible with the fixed power of grid users behind the converters. In the following, these converters are called controllable. On the other hand, controllability of power flows is only possible if lines connect at least two controllable converters within one grid [24]. The convertors at the PSs, which are shown in Figure 2.11, are controllable.

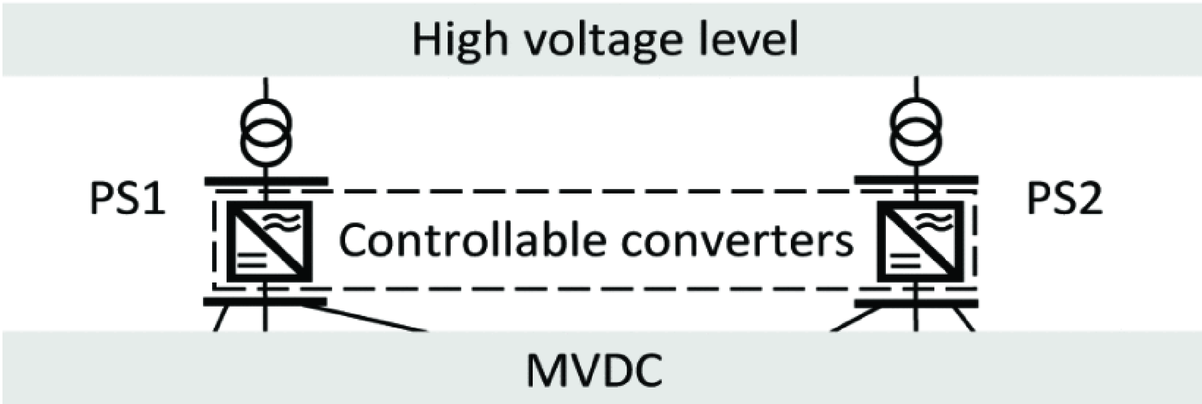


Figure 2.11 Controllable converters at primary stations

The main task of these controllable converters is to provide a link between the two voltage levels of overlaying high voltage and medium voltage, which gives an adjustment by these converters in and out of the MVDC grids. The additional converters can provide a more robust power flow control on the grids, but some drawbacks like increasing the losses, risk of failure, and cost.

2.7.2 MVDC grids operations and technical limits

The currents and voltages should not be violated. It also applies to the converters in any condition, whether it's normal or faulty. The power limit of the converter is the consequence of the upper semiconductor current limit, and the voltage limit depends upon the converter control and converter topology [25]. AC voltages and phase shifting between the ac grids and converter ac voltage can easily be controlled within this limit of the converters, but the efficiency depends on the converters' loading. It mainly caused by the switching and conduction losses but also loading independent part exists [26].

2.7.3 Redundancy and consideration of high voltage levels

Grid structure can give a redundancy; there is a different kind of redundancy depending upon their concrete structure. After switching or an immediate redundancy is appropriate for the MV level. A long non-availability is acceptable In a radial structure; therefore, no redundancy and repair work for the resupply after switching. Meshed grids have the advantage of resupplying lines immediately after the redundancy even if a line fails due to the condition of each node is connected to at least two different electrical paths.

Applied to the MV level, two or more PSs can be connected in one grid depending on the grid structure. If the connection of PSs is only by a single electrical way, a line outage could also cause the forming of temporary sub-grids with single PSs in the grids. If the grid is divided into several sub-grids, setpoints of controllable converters at PSs could have to change significantly. This can cause high additional power flows over and thus loadings of the HV grid. But the power flow over PS converters is technically limited by the size of the converters and the HV level. The overlaying HV grids could allow only a maximum power exchange. Moreover, a restriction of setpoint changes because of the HV grid's limited dimensioning could result. Therefore, the overlaying grid structure restrictions need to be considered while designing grid structure [27].

2.8 Planning and design of MVDC grids

The design and planning of MVDC grids required different aspects which interact with each other.

As shown in the Figure 2.12, the medium voltage level is surrounded by high and low voltage levels. The low voltage level has a radial structure to work with AC and DC, so the MVDC grid works with either technology. When it comes to AC technology on the low voltage grids, DC-AC converters are used at the coupling points to establish an interaction between the voltage levels. Moreover, if underlaying LV grids are based on DC technology, DC-DC converters are required instead. A typical example would be dual active bridges because they allow bidirectional low flow, and they can be easily used for the required power flow and voltage classes of medium voltage levels.

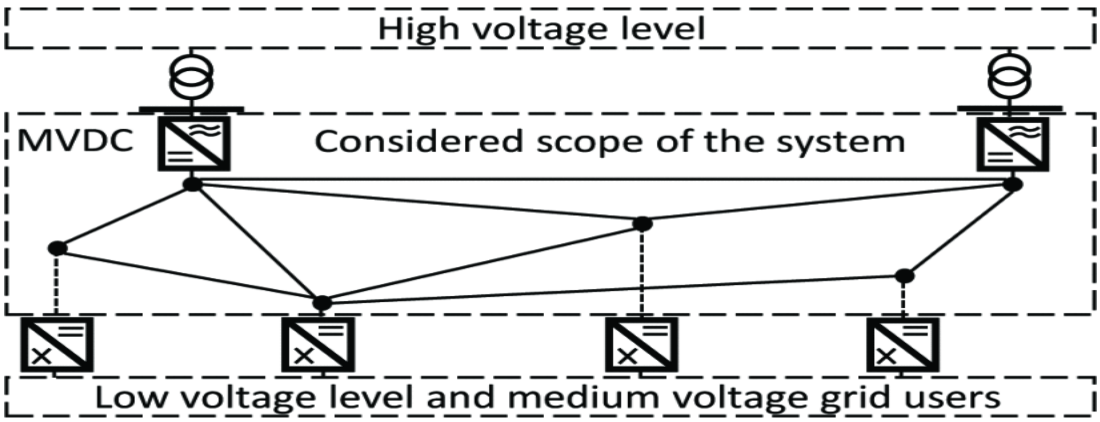


Figure 2.12 Medium voltage level as the scope of investigations

The design options and technical restrictions are discussed below.

2.8.1 Grid structure

The grid structure is not decided before, and it depends upon the reliability of the supply. The most common structures are radial, ring, and meshed. After switching, the deterministic (n-1) criterion operated as ring structure is used in Germany AC MV grids leading to open and closed after the switching. The ring structure provides the reliability of the supply and requires less protection compared to other grid structures as the radial structure does not satisfy these conditions and not suitable for medium voltage grids. However, meshed and ring can be used, and sometimes they are considered appropriate to be used. The meshed structure even increases the reliability of the supply, but it comes with enhancing the cost and a more complex operation.

2.8.2 Technical restrictions for grid operation

In MVDC grids, the customers and other voltage levels are connected with the help of converters. This can enable to limit the voltage levels. The temperature limits current flow; however, overloading for a short amount of time is possible in the AC grids through the transformers. But when it comes to converters, the overloading should be strictly avoided as they have sensitive semiconductor devices. Moreover, the short circuit currents should be within the technical restrictions as the technical specification of the grid components have to be dimensioned according to the fault current.

The DC short circuit current is not only divided into the discharge of the converters and line capacities, but it also involves feed-in converters itself [28]. The discharge of the line capacities impacts increasing the fault current and feed in converters causes a stationary fault current. The peak current is the consequence of the capacities and converter's contribution.

2.8.3 Operating voltage

Operating voltage is an important aspect when it comes to the design of the grids. The higher voltage allows more power to be transported over a line with the same conductor's cross-section and lower current and, as a result, more minor losses. However, choosing a nominal voltage is the suitable dimensioning of the grid components, but the customers' safety must also be considered.

2.8.4 Voltage control

voltage control is required to maintain the power balance in the DC grids because, in DC systems, the capacities work as energy storage; if there is less feeding than demand, then the capacity discharge causes a voltage decrease and vice versa. Due to this relation, the voltage is an indicator for the power balance in the grid. In MVDC grids, the converters at the primary substations can enable a bidirectional power flow to exchange power in or out of the grid to control the voltage. Since grid users are connected to MV grids and their feed-in and load is changing volatilely, power cannot be controlled arbitrarily at user nodes to support voltage control concepts compared to HVDC terminals [29].

2.8.5 Converter technology and topology

There are two kinds of converter technologies—current sourced converters and voltage control switches. The current sourced converter is based on the thyristor, and voltage control converters (VSC) uses semiconductor devices that can be quickly turn on and off. VSC technology allows an AC grid-independent switching and operation. Furthermore, a reversal of power flow direction within the DC grid can be enabled by changing the current direction due to technological and systemic advantages. VSC technology is suitable for the MVDC grids with a high number of connected substations. It also offers different converter technologies [30].

The voltage source converter (VSC) technology is becoming an attractive alternative to conventional line commutated converters (LCCs) for its features. These include

1. compact and flexible station layouts, with low space requirements, and a scalable system design
2. High dynamic performance and stable operation with AC networks
3. the capability of supplying power to passive networks and black star
4. Independent control of active and reactive power
5. No voltage polarity reversal during power flow reversal.

Therefore, VSC-based DC systems are more suitable for distributed renewable energy integration than their LCC counterpart.

On the one hand, two or three-level converters, as comparison with Modular multilevel converters (MMC), has a simple design and control and are less expensive, but on the other hand, MMCs operate with more minor switching losses, cause fewer harmonics, and have a significant systemic advantage in the field of short circuit currents.

2.8.6 Line configuration and customer connection

Three configurations can be applied to the MVDC grids

- Asymmetric monopole
- Symmetric monopole
- Bipolar configuration

They differ with each other upon the cost and transmitted power [31]; in contrast to HVDC grids, especially the customer's connection concept is considered.

If the customers are connected to both the poles in bipolar configuration and the customer's converter is correctly dimensioned. There is a fault in one of the poles, and they can be supplied; this is a matter of the reliability of the supply; on the other hand, a higher dimensioning of both poles and converters is necessary. Additionally, an unsymmetrical connection leads to an unsymmetrical operation, permanent current flow over the neutral conductor, and requires a concept to deciding to which pole to connect new grid users. Furthermore, a suitable grid structure that fulfills the (n-1) criterion leads to the high reliability of supply and avoids the required over dimensioning [32].

2.9 Power electronic converters for MVDC grids

2.9.1 DC/DC Converters:

Rapid technology improvement of the power electronic components leads us to shift the paradigm from AC distribution grid and precisely due to the development of high-power DC/DC converters having high voltage gains which was the critical factor for replacing the low frequency, bulky AC transformers. The only problem with these power converters is that low efficiency when a high voltage ratio is required. The dual active bridge (DAB) topology seems to be a promising concept that provides high efficiency and galvanic isolation when a high voltage ratio is required. Apart from this, multi resonant converters in series or/in parallel configuration can achieve high current and high voltage with high efficiency due to soft switching.

2.9.2 DC/AC Converters:

Apart from DC/DC converters, there is also a need for performing AC/DC electric energy conversions. These AC/DC converters must operate in a bidirectional power flow mode, thus interfacing variable frequency energy sources and loads with the MVDC grid.
The most important AC/DC topologies are categorized as

I. two-level VSCs,
II. three-level Neutral Point Clamped (NPC) VSCs and
III. Modular Multilevel Converters (MMCs)

they can be operated either using a high bridge or full bridge submodules. thyristor-based line-commutated converters (LCCs) seems reliable and attractive solution in HVDC transmission grids but due to the limiting controllability of the thyristor, the VSCs (mostly based on Insulated Gate Bipolar Transistors,
IGBTs) seem to gain more attention towards the development of MVDC grids.

2.10 Multiterminal DC Grids

Multiterminal Direct current (MTDC) systems are operating in a few numbers around the world today. As Direct current is more prominent than Alternating current, it might be a possible reality in the real world. The large-scale integration of remote renewable energy resources into existing alternative current (AC) grids and the promotion and development of the international energy markets are the main drivers for constructing direct current grids.

The famous AC vs. DC battle known as "Wars of currents," which was discussed above, presents some results that in the late 19th century, AC dominated DC with its power transmission design as AC transformers were more efficient and transferred power on a large scale. DC systems are rebooting in 1954, when ABB linked the island of Gotland to the Swedish mainland by a High-voltage Direct current (HVDC) link, delivering the world's first commercial HVDC system. The Gotland HVDC system (Gotland 1) used mercury-arc valves to convert and transfer 20 MW of power over 98 km, with a 100 kV submarine cable—connecting Västervik on the mainland with Ygne on the island of Gotland. In 1970, the conversion stations were supplemented with thyristor valves connected in series with the mercury-arc valves, raising the voltage to 150 kV and the transmission capacity to 30 MW [33].

The question here is not a choice between AC and DC but how to best integrate both current formats. This is due to the advancement of technology.

On the generation side, electricity production is increasing due to renewable resources, either in hydropower plants far from the urban centers, offshore winds, or photovoltaic generation. Changes in consumption patterns call for innovative technical and social solutions, such as intelligent consumers and intelligent grids on the demand side. Power electronics, control, and information and communications are the key enabling technologies in this paradigm change. Particularly, high-power electronics devices and conversion systems are being developed at a rapid pace, incorporating an ever-growing list of technical capabilities while their price continues to drop [34,35]

With the introduction of voltage source converters (VSC), Multi terminal DC grids become possible.

2.11 Advantages of Using VSC based multiterminal MVDC networks

The multi-terminal voltage sourced converter medium-voltage DC (VSC-MVDC) distribution network is the new, unproven conceptual interconnection platform proposed to bring many advantages. The MVDC distribution network is not simply a scaling of voltage levels from the HVDC to LVDC systems but an innovative platform with specific power system applications [36]
VSC based MVDC technology can provide services like

- Reactive power compensation

- Frequency support
- Voltage stability
- In solar PV integration, this technology can provide AC network stability which is not a general case.

2.12 Voltage control strategies for VSC-MTDC grids

DC Voltage control is essential in the operation and stability of VSC-MTDC grids. The converter outage results in a shortfall of the current in and out of a DC network. The results are in DC voltage at different terminal changes due to discharging or charging of the capacitor and cable capacitance. There are two consequences due to the converter outage, and there will be a current surplus which leads to overvoltage if the converter is exporting current to the AC system, on the other hand, if the converter is importing power to the DC grid, the outrage causes a current shortfall leading to DC under voltage. Thus, the DC voltage is directly related to the power balance, and the power flow is similar to the AC frequency in the AC system. DC voltage has some drawbacks which make it difficult to control. Likely, DC voltage varies greatly at different terminals in the DC network, unlike frequency, increasing the control of DC voltage and power flow. It is even more burdensome as little standardization exists for DC networks. Despite these drawbacks, DC voltage appears the best indicator for stable DC grid operation control [37,38 ,39]
Coordinated DC voltage control strategies rely on the fact that the deviation in the controlled DC voltage (local measurement at each DC bus) is determined and corrected by a control action that restores the current or power balance [40]
The most basic DC voltage coordinated control strategies for the MTDC network are the master-slave and droop control.

2.13 Principles of VSC-MTDC network coordinated control

In the VSC-MTDC grids, in VSC terminal can operate in the following modes.

2.13.1 Constant power (PQ)

In this mode, as the name suggests, the steady-state power flowing through the VSC terminal is constant regarding DC bus voltage and equal to the reference value. The active and reactive power is an exchange between the VSC terminal, and the grid regulates to a given value by adjusting the amplitude and phase of the output voltage for the VSC at the AC side.

2.13.2 Constant DC voltage (*V*dc)

In this mode, the DC voltage and active power balance are maintained by the VSC terminal. Thus, it controls operation and efficiency, which is the reason behind the reliability and security of the entire MTDC network.

2.13.3 Droop

The Droop controller is derived from the combination of constant DC power mode and constant DC voltage mode. The droop controller is the opposite of the DC voltage controller as it varies the DC bus voltage linearly with changes in the power flow. In this way, the droop controller regulates power to its reference value simultaneously with DC voltage.

The slope of the droop control characteristics is the droop constant or DC voltage response, R_{droop} analogous to the frequency response in AC systems. The inverse of the droop constant is the droop gain, K_{droop}. The VSC terminal with a smaller droop constant is more sensitive to DC fluctuations, hence plays a more crucial role in voltage control. Depending on the magnitude of the droop constant/gain, each of the first three control modes can be represented with a droop controller. Thus, in constant power mode, the R_{droop} is zero (or $K_{droop} = \infty$), while in the constant DC voltage mode, K_{droop} is zero (or $R_{droop} = \infty$).

2.13.4 Constant AC Voltage frequency

The constant AC voltage frequency mode applies to a VSC connected to a passive or active load. The amplitude, phase, and frequency of the AC output voltage of the VSC are controlled to a set value for it to present voltage source characteristics.

2.14 Centralized DC voltage control

2.14.1 Master-slave control method

This control is the most mature of all the VSC-MTDC grid control strategies. In this method, only one converter known as the master terminal operates in constant DC voltage mode, while the slave terminals are configured in constant power or constant current modes. Figure 2.13 shows the master-slave control scheme of an MTDC grid with three converters.

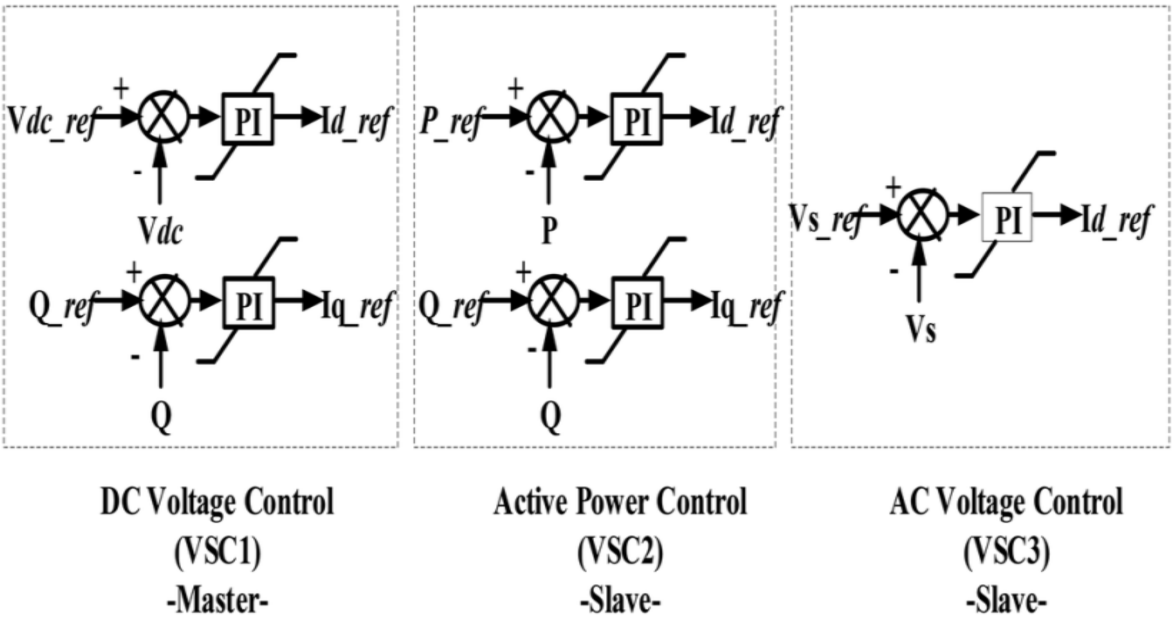


Figure 2.13 The master-slave control structure of an MTDC grid

Advantages of Master-Slave Control Scheme

- ✓ simplicity in control design and implementation
- ✓ high system response,
- ✓ and little risk of undesirable interaction between various voltage regulators

Considerations

Since its a centralized DC voltage control, an outage of the master terminal results in over-voltage or
under-voltage and, subsequently, total collapse of the entire MTDC network. So, the following consideration should be considered

- ✓ the control scheme needs accurate and high speed and communication requirements between DC terminals to coordinate the voltage control.
- ✓ The master terminal should have an enormous power rating, and the connected AC system should be strong enough to accommodate all amounts of power imbalance of the slave terminals in the MTDC grid.

It should also be noted that the feasibility of the master-slave control decreases as the network size increases. Thus, the strategy lacks the $N-1$ security for DC voltage regulation, hence not recommended for operation control of MTDC grids [41,42 ,43].

2.14.2 Voltage margin control

This scheme is the modification of the master and slave scheme in which constant power/current and constant voltage modes have been combined in each controller terminal. The voltage margin set is essentially the difference in the DC voltage reference between the terminals in an MTDC network.
There are two conditions.

1) When within average operating voltage margin, then the terminal operates in constant power/current mode.

2) When the operation is not regular, like the voltage changes from the set margin, the terminal operates in constant DC voltage mode to prevent further deviation.

One-stage or two-stage voltage margin controllers can be used for the implementation of voltage deviation.

The two-stage controller is more robust and versatile than one stage, so it's preferred for the MTDC control as the requirements for the communication for the terminals are more reduced. The two-stage voltage margin is shown in Figure 2.14 with its characteristic curve.

The V_{dc}_r$_{efL}$ and V_{dc}_refH are the lowest and highest DC voltage values for the set voltage margin. The minimum, reference, and maximum active power values are P_{min}, P_{ref}, and P_{max}, respectively. When the DC voltage (V_{dc}) is within the margin, the controller works in the constant power mode (*PQ*), in which the active power (*P*) has been controlled to P_{ref}. if a fault occurs such that the active power in the MTDC is above zero, the *V*dc rises to V_{dc}_refH and stabilizes due to the action of the DC voltage controller (V_{dc}_refH). If the *V*dc falls below zero, the DC voltage reduces to V_{dc}_refL and stabilizes due to the DC voltage controller (V_{dc}_refL) [44].

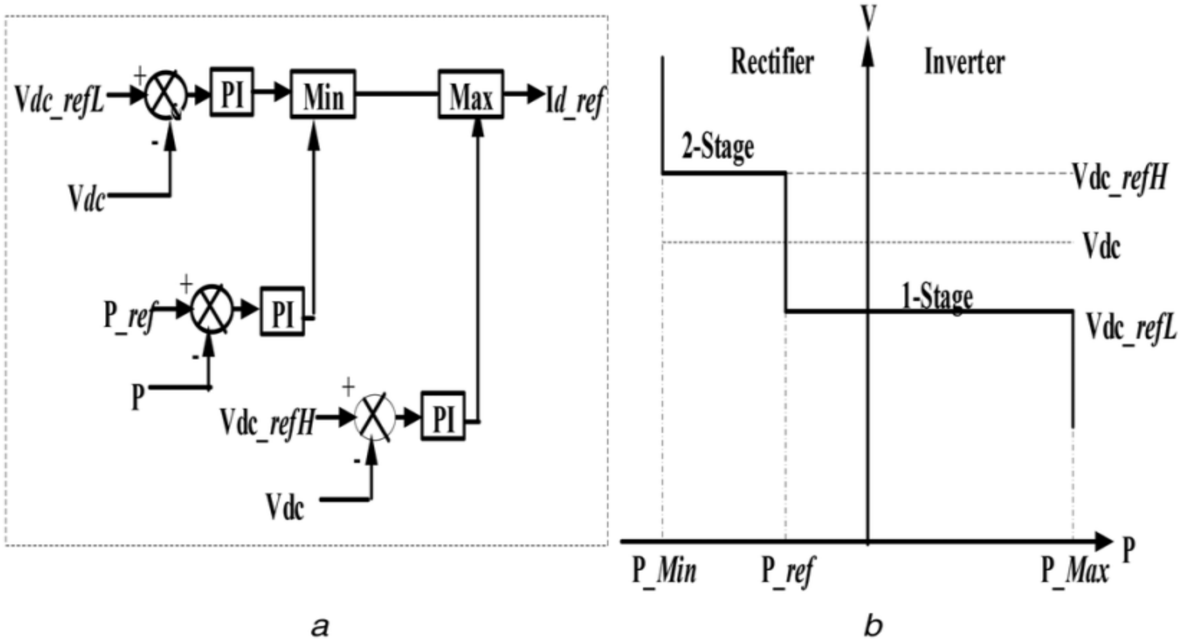


Figure 2.14 Voltage margin control

(a) Two-stage controller, (b) Characteristic curve

2.15 Distributed DC voltage control

2.15.1 DC voltage droop control

This converter proposes due to the drawbacks of the centralized DC voltage control strategies. In this method, each converter terminal is equipped with the droop converter, regulating the DC voltage by adjusting the current. Thus, the active power balance is guaranteed in the network. The basic droop control principle is shown in Figure 2.15 also shows the droop controller and its characteristic curve.

$V_{dc}=V_{dcref}+(1/K)(P-Pref)$

V_{dc}, V_{dc_ref}, P, P_{ref}, and K are the measured and reference DC voltages and power at the converter station and droop gain (the inverse of droop constant, R), respectively.

Advantages of DC voltage droop control

- The multiple converter terminals in the MTDC can share DC voltage regulation to attain a distributed sharing of the unbalanced active power.
- The MTDC grid does not collapse like the case with the master-slave control when one DC voltage regulating terminal fail after encountering a severe contingency as the remaining terminals share the voltage control responsibility
- It is easy to configure the droop control without modifying the control systems of other converters, hence preferable when several converters are to be interconnected in phases to attain a larger MTDC network

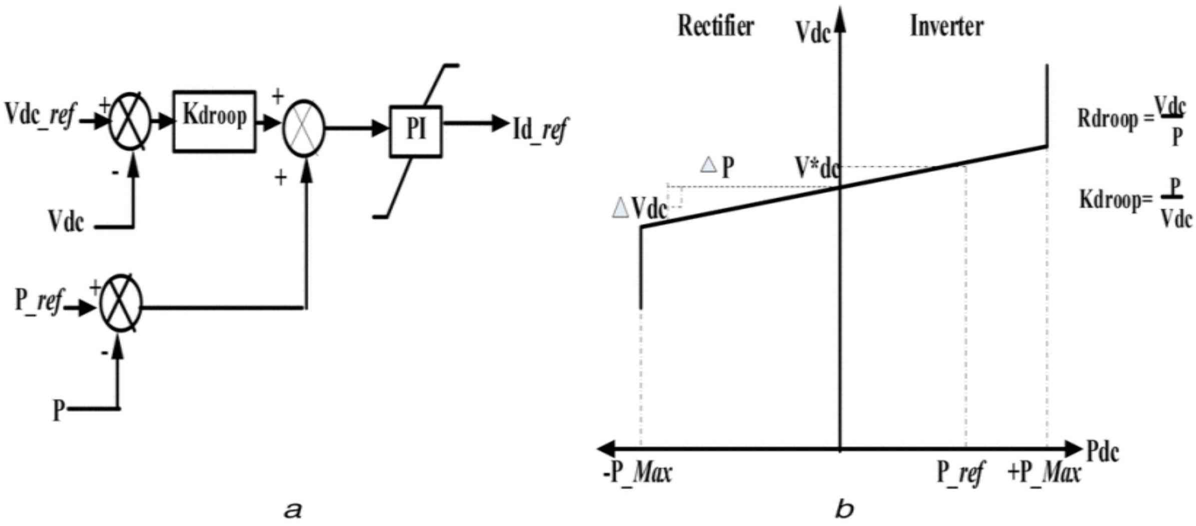


Figure 2.15 Droop control strategy, (a) Controller structure, (b) Characteristic curve

2.15.2 Master-slave with droop control

One converter terminal in the MTDC network is configured with a constant DC voltage control, while slave terminals are assigned with droop control. When in standard network operating conditions, the power balance is regulated entirely by the master terminal. However, when an outage occurs on the master and the network communication fails, the other terminals take over the DC voltage control; hence, the power balance achieves high stability and reliability in MTDC grid operation [45].
The master-slave with droop control reduces pressure on the master terminal in DC voltage control and power balance. Unlike in the master-slave strategy, the droop control incorporated here assist the slack bus in managing the DC over-voltage and under-voltage transients that enhances its feasibility for secure MTDC grid application

2.15.3 Dead band droop control

This method combines voltage margin and DC voltage droop in each converter terminal to increase its dynamic response and flexibility in the MTDC network. In the voltage margin, the control scheme operates in the constant power/current mode when in typical operation margin/dead band, and on the other hand, it works under droop when out of the dead band.

Figure 2.16 shows a dead-band droop controller and its characteristic curve. The set-point for the DC voltage reference for each converter is defined by the network master control considering the DC voltage profile of the MTDC grid. The converter assigned for DC voltage control mode regulates its voltage to the fixed reference within the defined power dead-band for normal operation. On the other hand, those for active power mode regulate their AC-side power to the set value if the DC voltage is within the
defined DC voltage dead-band for normal operation. Outside the outlined voltage/power (V–P) dead-band for normal steady-state operation, the converter has a DC V–P droop characteristic. For instance, K_{droop} 1 and 2 in Figure 2.16 allow all the converters to assist in stabilizing the MTDC grid during disturbances [46].

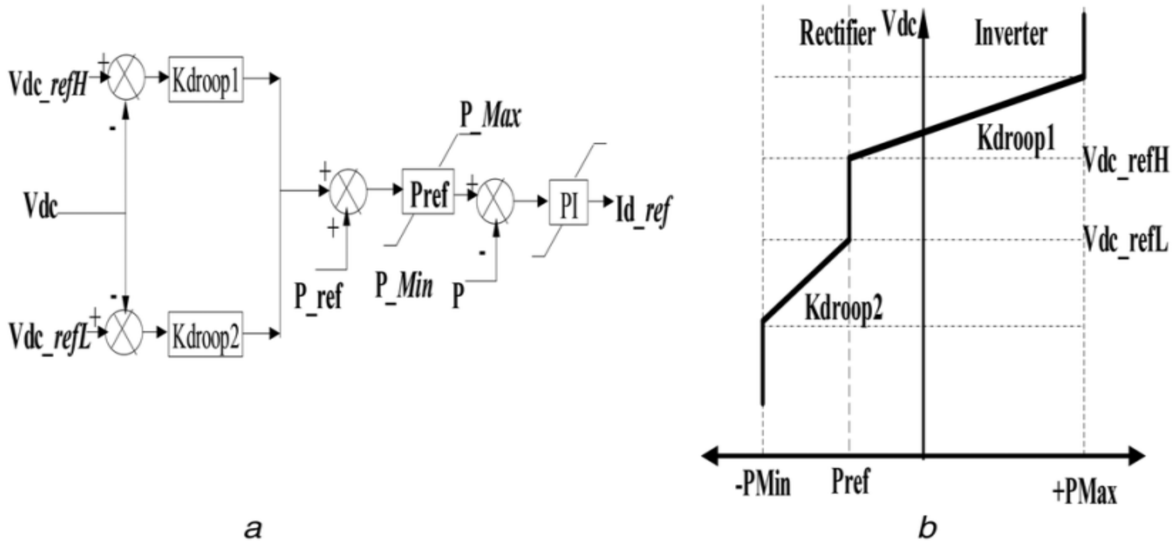


Figure 2.16 dead-band droop strategy (a) V–P droop with dead-band, *(b)* Characteristic curve

Chapter 3

MVDC Substations

It's more realistic and advantageous to use DC systems in transmission and distribution systems than traditional AC systems. With the advancement of the power electronics components

Currently, electrical equipment or devices requiring DC power to function, whether loads or resources, necessitate AC/DC conversion technologies. Having an accessible and direct supply of DC power to serve such loads and resources creates the potential to mitigate losses experienced in the AC/DC conversion process, reduce overall electrical system infrastructure, and lessen the amount of power generated from power plants, as well as other advantages.

High voltage direct current has proven its merit over high voltage alternating current (HVAC) in many different cases. Its advantageous includes

- Power factor correction
- Decreased right-of-way clearance
- Improved control over power flows
- Less infrastructure
- Reduced losses

HVDC also provides an asynchronous link for robust but instability-prone AC power systems, and advanced HVDC systems can even provide the black-start capability. The cost of AC/DC conversion and DC/AC inversion terminals has decreased steadily due to the reduction of voltage ratings, current efficiency, and cost of the solid-state electronics in these converters over the years. Most importantly, the design and construction of HVDC have improved a lot.

With the help of large-scale wind and solar forms, fuel cells, battery storage, and distribution generation, the need for MVDC technology has been developed a lot. MVDC is feasible and technically advantageous, and certainly economically attractive in many cases.

A general setup for a proposed MVDC layout with representative energy supply, distributed resources, and loads is displayed in fig; below [47].

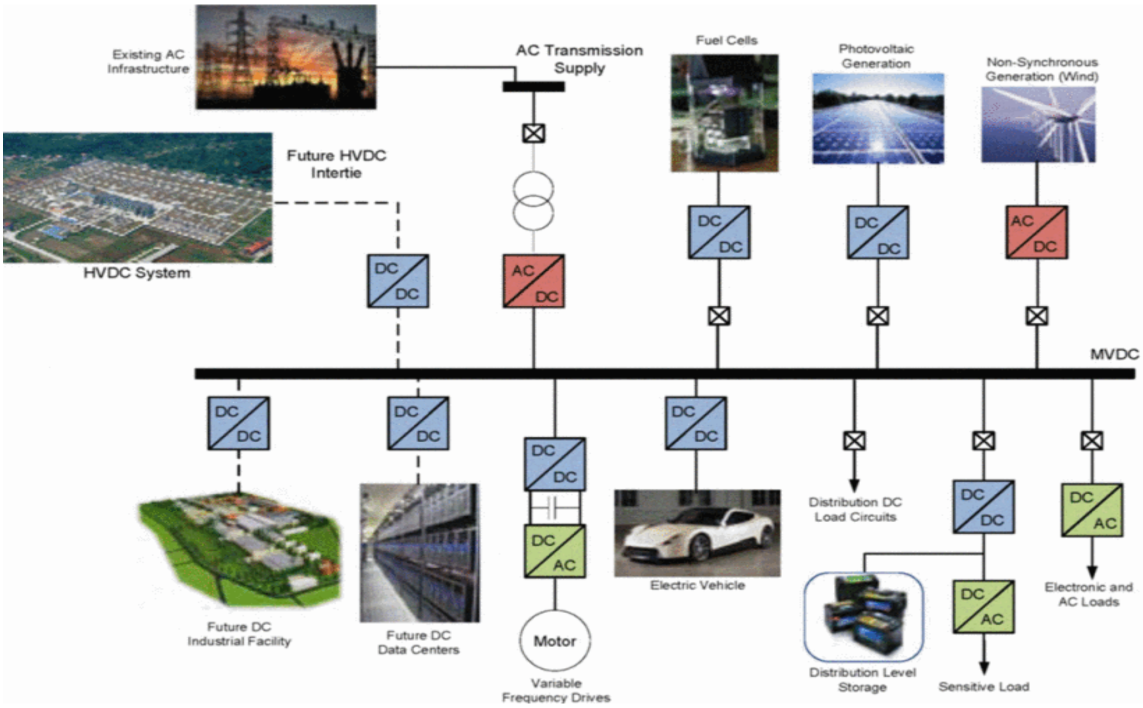


Figure 3.0 MVDC Substation

The model consists of renewable energy resources including wind and solar, energy storage, a general form of a battery, and other applications (electric vehicle integration) at a direct medium voltage connection. Generic blocks are also presented, representing various converter technologies for interfacing the medium voltage bus with the associated generation resources and loads. Finally, an overall control system that builds intelligence into the network has been designed to regulate the output power of the various generation resources and deliver power to the loads within the framework and design of the MVDC substation concept. This scheme control initially employs energy balancing methodologies.

3.1 MVDC network model Development

There is no complete model or simulations of MVDC systems up to date as this technology is new, but certain individual aspects and components are discussed below. The most crucial component is DC to DC converters due to their growing popularity for interfacing renewable energy resources to the electric grid.

Figure 3.0 contains many components that require advanced modeling, so only a few are discussed here. These devices include two multilevel DC-to-AC inverters, a six pulse AC-to-DC rectifier, two induction machines, a bidirectional DC-to-DC converter, and the intermittent renewable generation resource being wind.
An overview of the system model in PSCAD is found in Figure 3.1 [48].

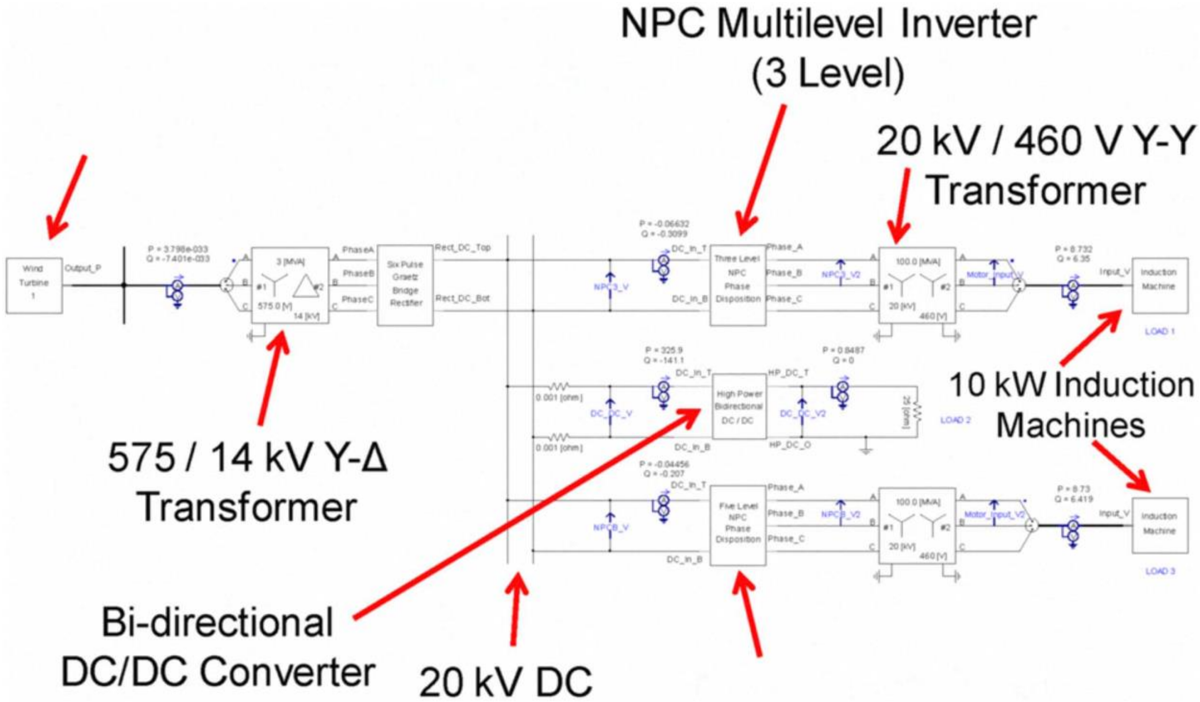


Figure 3.1. PSCAD MVDC Network

3.1.1 Neutral point clamped Multilevel inverter

The configuration of neutral point clamped (NPC) can generally be three, four, or five-level topologies. However, only three-level inverters have found wide application in high power medium voltage drives [49].

Figure 3.2 shows a five-level NPC inverter consisting of four capacitors labeled C1, C2, C3, and C4. Table (3.0) provides five different switching states of the five-level NPC Inverter with associated voltage outputs.
If a DC voltage is applied across the inverter terminals, as the number of capacitors is 4, the voltage across the capacitor will be $V_{dc}/4$; furthermore, the stress of each device will be limited to $V_{dc}/4$ thanks to the clamping diodes.

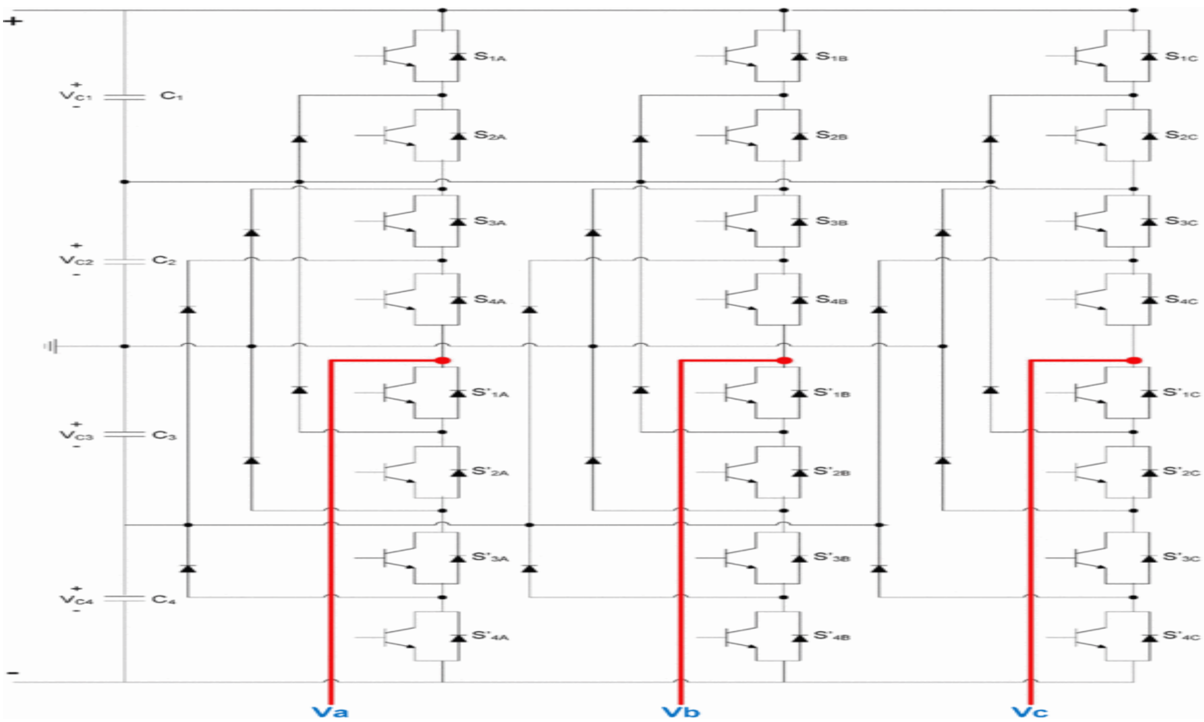


Figure 3.2 Five-Level NPC Multilevel Inverter Topology

In general, each active switching device is required to block a voltage level of V DC / (n-l), where n is the number of levels in the line-to-neutral output voltage waveform, and the number of diodes required for each phase will be (n-l) x (n-2). When n becomes sufficiently high, the number of diodes required can make the system impractical to implement. If the control strategy for the switches is based on PWM, the diode reverse recovery of the clamping diodes becomes the primary design challenge in high-power applications.

The major problem with NPC Topology is that it changes the neutral point voltage, resulting in an imbalance in capacitor voltage as the output voltage level increases. Unbalanced DC capacitors due to manufacturing tolerances, inconsistency in switching device characteristics, or unbalanced three-phase operation are the reasons for deviation in neutral point voltage.

Table 3.0.
Binary Switching States for the five-level NPC Inverter

	S1	**S2**	**S3**	S4	**s′1**	**S′2**	**s′3**	**s′4**	**Voltage**
I	1	1	1	1	0	0	0	0	$V_{dc}/2$
II	0	1	1	1	1	0	0	0	$V_{dc}/4$
III	0	0	1	1	1	1	0	0	0
IV	0	0	0	1	1	1	1	0	−Vdc/4
V	0	0	0	0	1	1	1	1	−Vdc/2

3.1.2 Induction Machine Modeling in MVDC Network

The machines serving as loads have the following configurations

- Wye connected
- 20hp
- 460 V (line to line RMS)
- Three-phase
- 4 pole induction motor

Figure 3.3 provides the PSCAD schematic for simulating the induction motor.
This model has two external inputs. First is the steady-state rated mechanical speed and the load. The traditional way to start is to initiate a machine using the speed control, and when the simulation hovers switch into torque control, load torques are typically proportional to the square of the mechanical speed.

Figure 3.3 PSCAD Simulation Model of induction Motor

Analytically determined with a MATLAB script, the load torque and electromagnetic torque reach a steady-state value of 0.6680 Pu. This is equivalent to the output power per-unit basis since the system operates at a rated frequency (60 Hz). The machine's expected output power and torque, using physical variables, are 9.96 kW and 52.85 Nm. The max torque of the machine was determined to be 164.65 Nm [50].

3.1.3 Wind Turbine Model in MVDC Network

The diagram of the single wind turbine schematic is shown in Figure 3.4.
the model consists of a wind source that can be adjusted at the two-point of the simulation, a block that represents the mechanical component of the wind source which can be found on MOD-2 (three-blade rotor), a wind turbine controller that controls the pitch angle, 13, of the blades and another induction machine model.

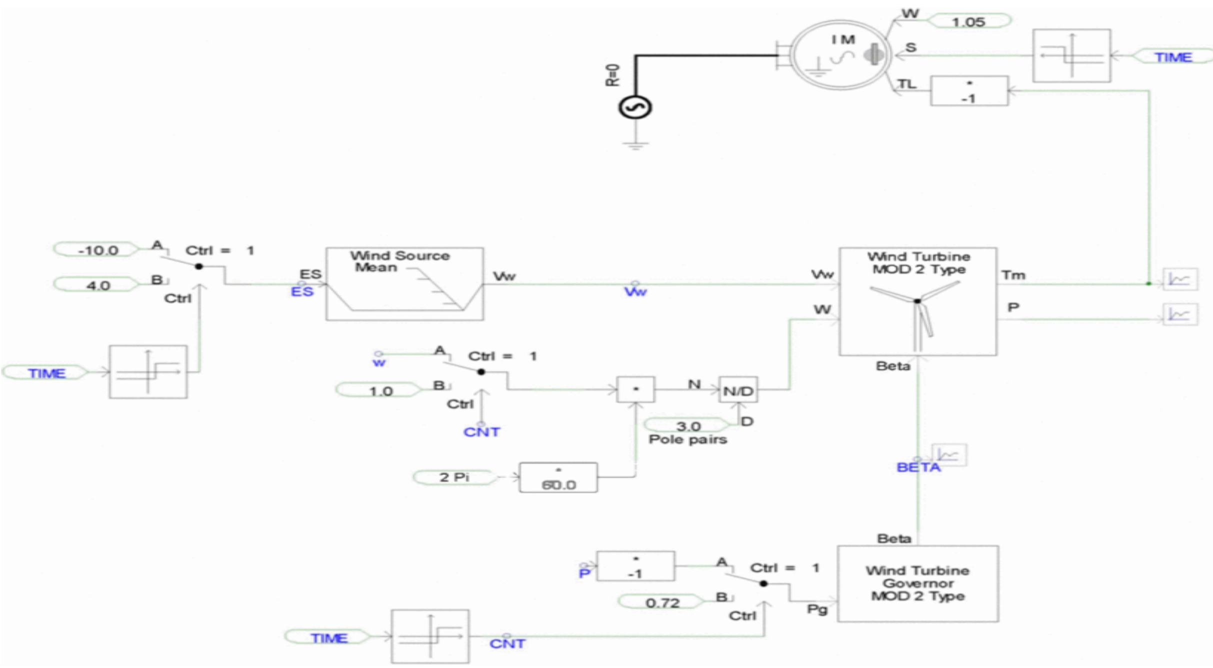


Figure 3.4 Single Wind Turbine Model used in PSCAD Simulation

MOD-2 structure of the wind turbine considers the consideration of the mechanical aspects of the wind turbine. The parameters found in Table 3.1 can also be used in the wind turbine MOD-2 block.

Table 3.1. Wind Turbine Mechanical Components

Parameters	Numerical Quantities
Generator Rated MVA	1.667 MVA
Machine Rated Mechanical Speed, ω_r	125.667 rad/s
Rotor Radius	35.25 m
Rotor Area	3904 m^2
Air Density	1.225 kg/m3
Gear Box Efficiency	0.97 pu
Gear Ratio	77

The blade dynamics can determine the output power of the wind turbine from equation 1 through equation 2.

$$\omega_h(\omega) = \frac{\omega}{G_R} \tag{1}$$

$$P(\omega, \beta) = \frac{1}{2}\rho A \omega_v^3 C_p(\omega, \beta) G_\eta \tag{2}$$

Equation (1) shows a linear relationship for determining the hub speed of the wind turbine where G_R is the gear ratio.

$$\gamma\omega = \frac{2.237V}{W_{\omega h(\omega)}} \tag{3}$$

equation (3) is the ratio between the wind velocity and hub speed of the wind turbine, which computes the tip speed ratio of the turbine blade.

$$C_p(\omega,\beta) = \frac{1}{2}[\gamma(\omega) - 0.022\beta - 5.6)e^{-0.17\gamma(\omega)} \quad (4)$$

The power coefficient of the MOD-2 wind turbine is shown in equation (4). it is highly nonlinear and a function of blade pitch angle, 13, and tip speed ratio, V.

$$P(\omega,\beta) = \frac{1}{2}\rho A\omega_v^3 C_p(\omega,\beta)G_\eta \quad (5)$$

Last but not least, equation (5) shows the output power of the wind turbine. A is the swept area of the blades, p is the air density, and Gq is the gear efficiency.
Based on the above nonlinear equations that determine the wind turbine dynamics, the desire output power can be determined with the aid of Figure 3.5.

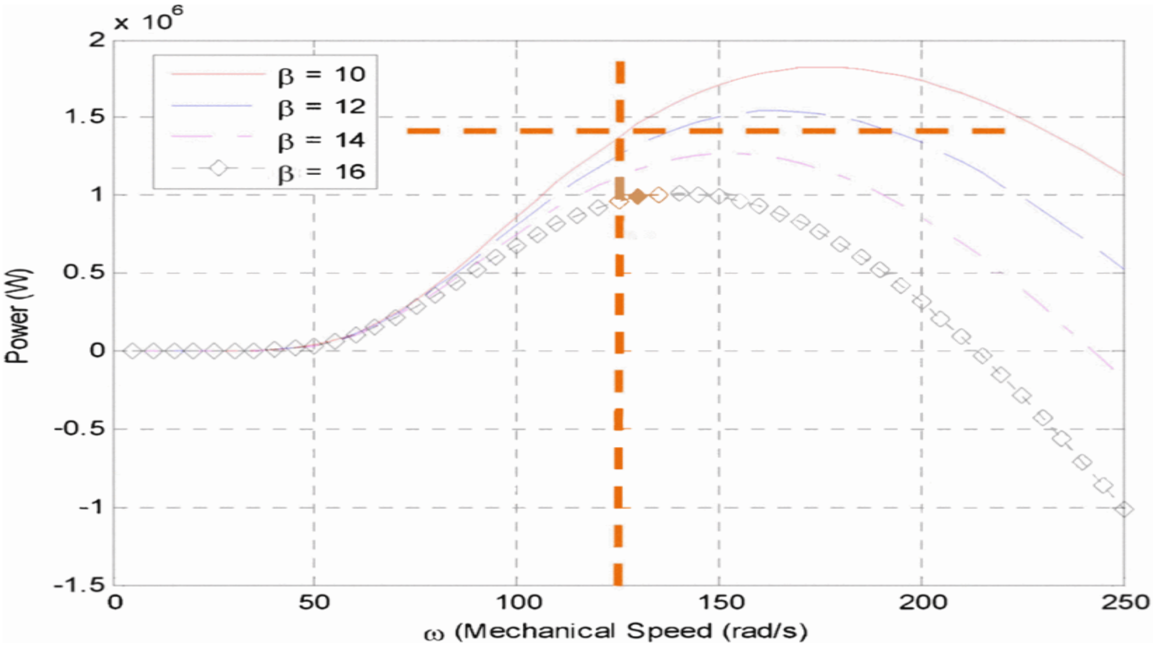


Figure 3.5 Single Wind Turbine Model used in PSCAD Simulation

The initial pitch of the blade, β, is pre-programmed into the controller with a value equal to 10. The rated mechanical speed of the system is 125.67 rad/s. Just knowing these two coordinates, the expected steady-state operating point of the turbine can be seen in Figure 3.6.

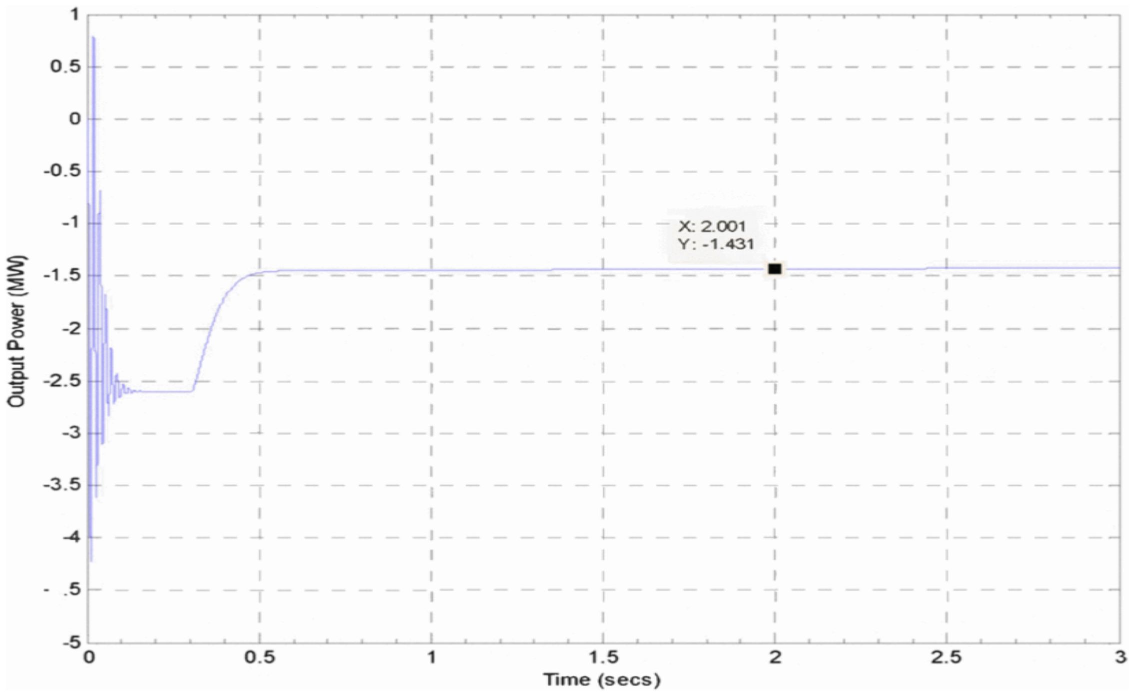


Figure 3.6 Simulated Output Power of the Wind Turbine System under Steady-State Conditions

3.1.4 Six Pulse AC/DC Rectifier Modeling in MVDC Network

The most crucial aspect of a rectifier is that it transforms the AC signal into a DC signal. The typical example of the six-pulse rectifier is modeled in Figure 3.7.

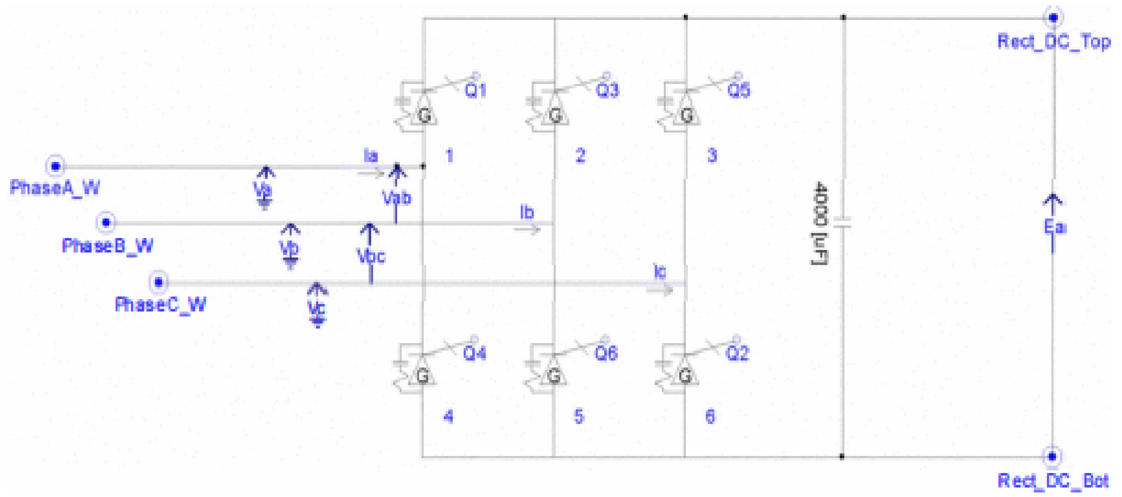


Figure 3.7 PSCAD Model of Controllable Six Pulse Rectifier

The semiconductor devices which are being used are GTOs with a snubber circuit in parallel with the device. The size of the capacitor is 4000 μ which is very large, but this is just for the high-power applications.

The line-to-line output voltage of the converter is shown in Figure 3.8.

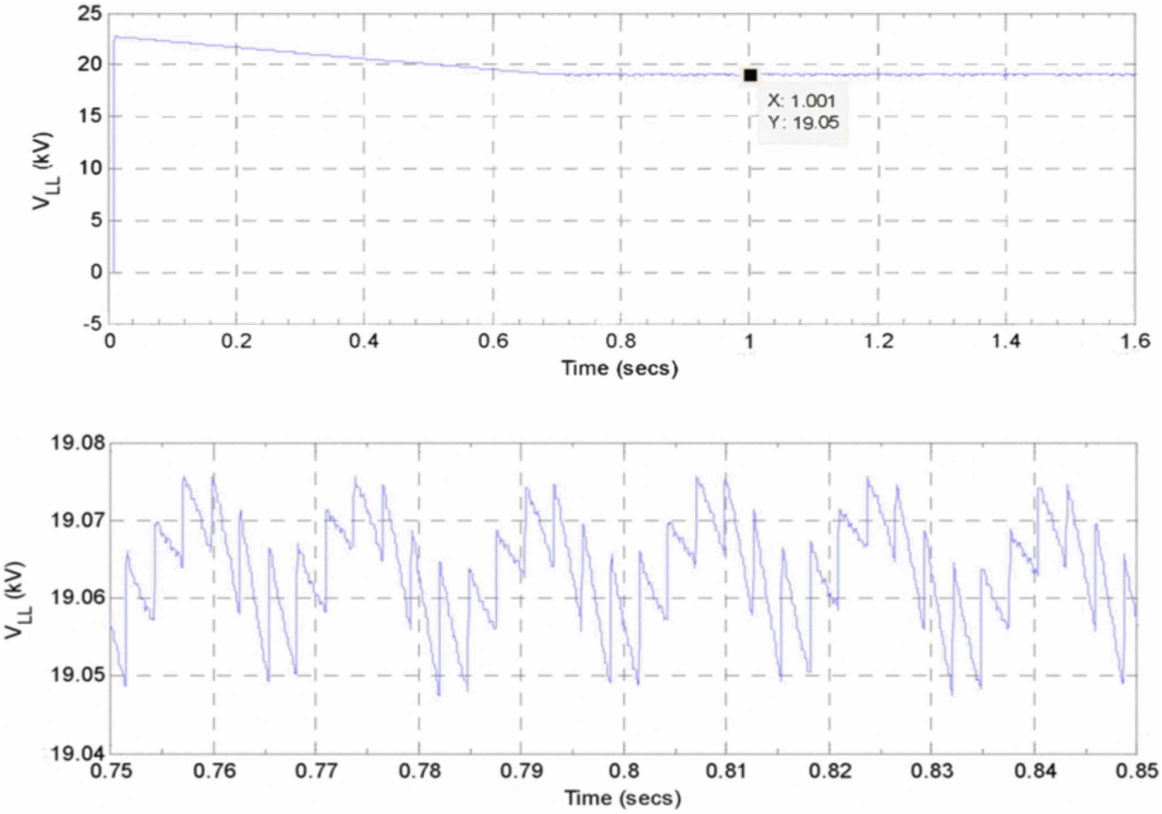


Figure 3.8 Output Line-to-Line Voltage of Six Pulse Rectifier

The steady-state output voltage that approaches 19 is based upon the following equation.

$$V = 3\sqrt{\frac{2}{\pi}}\,(V_{LL}.RMS.\cos\alpha = 3\sqrt{\frac{2}{\pi}}\quad(14kV).\cos(0) = 18.91kV \tag{6}$$

However, the steady-state dc voltage looks very clear and harmonic free, but the closure look shows a different story. There is a high ripple on the top of the output voltage due to the line inductance of the transformer.

3.1.5 Bidirectional DC-DC Converter Modeling

The PSCAD model of the DC-DC converter is shown in Figure 3.9, And the table related to its parameters is shown in Table 3.2.

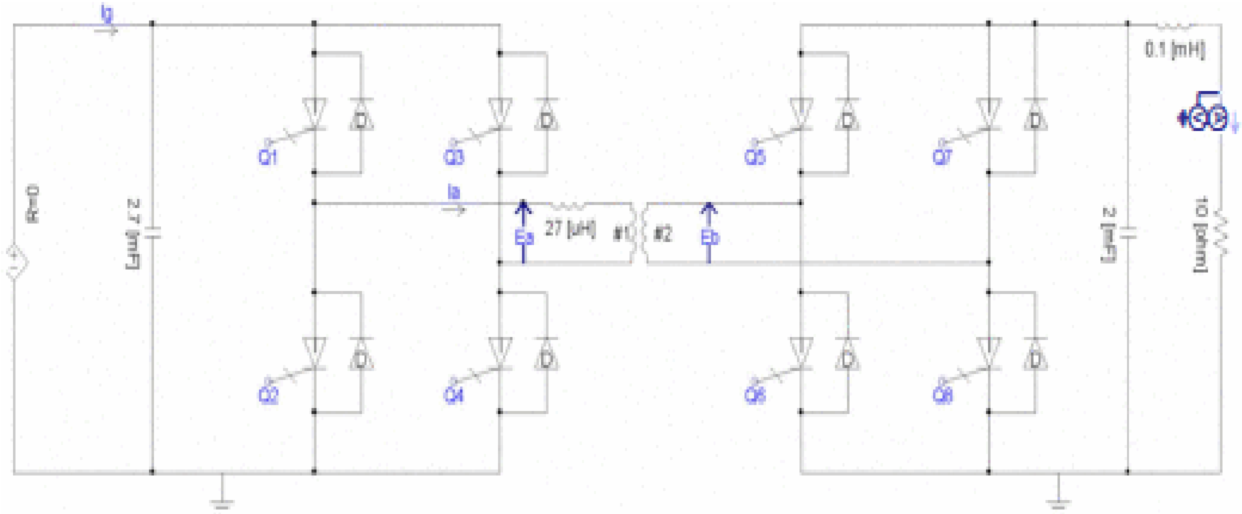


Figure 3.9 PSCAD Model of bidirectional DC-to-DC converter

Table 3.2. Bidirectional dc-to-dc converter parameters

Parameter	Numerical Quantity
Transformer Rated MVA	25 MVA
Switching Frequency, f_s	2000 Hz
Input Filtering Capacitor	2.7 mF
Output Filtering Capacitor	2 mF
Leakage Inductance, L1	27 µ H
Choke Inductance	1 mH
$n=n_2/n_1$	5

The diagram in Figure 3.9 contains an ideal voltage source at its input. The input to the DC-to-DC converter in the overall model uses the output DC voltage of the rectifier. If an ideal voltage source were not used to perform the initial validation of this component of the overall model, the output waveforms would be questionable. An input voltage of 4 kV can be used for the initial validation.

3.2 Scope of MVDC

Recent surveys show that most of the loads are DC instead of AC, and according to some estimates, approximately 80% of loads in commercials and residual structures are DC. The Dc distribution network market is a single market but encompasses several opportunities; utility networks, offshore networks, and data centers are the typical example of such opportunities.

3.2.1 MVDC for Utility Distribution Networks

Medium voltage direct current (MVDC) is gaining popularity by increasing the transfer capacity and providing increased power quality to the distribution networks. Due to fully converted controlled converters, it provides valuable opportunities which are not available in traditional technologies. Some challenges need to be overcome to get better operational efficiencies, legacy systems, aging equipment, and rapid growth in the embedded systems.

The following are some of the examples which provide a better understanding of how MVDC can provide a beneficial business case for the development:

- Long overhead line circuits
- Urban cable circuits
- Circuits through highly constrained or sensitive areas
- Fault-level constrained, but capacity increase required
- Phase-angles across transmission in-feeds
- Neighboring feeders with different load factors or power
- Quality that links releases additional capacity
- MV groups with voltage and power-flow challenges

The use of MVDC can provide the following benefits.

- MVDC utilizes better existing network assets.
- They are deferred/avoided investments in network reinforcement.
- Reduced losses in other equipment.
- The protection arrangement unchanged as power electronics do not contribute any fault current.
- Short circuit levels, voltage differences, loop flows, or limitations due to phase-angle differences are unaffected.

MVDC has some complicated factors that need to be considered.

- Short lifetime equipment has higher replacement costs; this needs to be considered in any business plan.
- Substation space still required for DC converters even if provided as containerized solutions.
- The most important aspect is that MVDC losses are higher than transformers or circuit breakers, so losses need to be considered at an overall network level.

3.2.2 Substation Reinforcement Opportunities

MVDC can be used at the substation level to increase transfer capacity where the transformers and up rating cables are expensive. Some of these options are

- Splitting would be an option to alleviate the power quality problems.
- Dynamically rebalancing voltage and flows to avoid limit on individual phase
- It increases the control option in the network, which limits the voltage impinging before thermal limits.
- Balancing the loads between the transformers and creating new routes power between substations.

These can be achieved with the help of MVDC of different arrangements by the so-called "soft open point" (SOP) application.

It is arranged by two converters connected back-to-back across a conventional Open-point or busbar section. MVDC in this configuration can improve power balancing at the heavily loaded substation and improve reliability while maintaining the short circuit level within circuit breaker ratings.

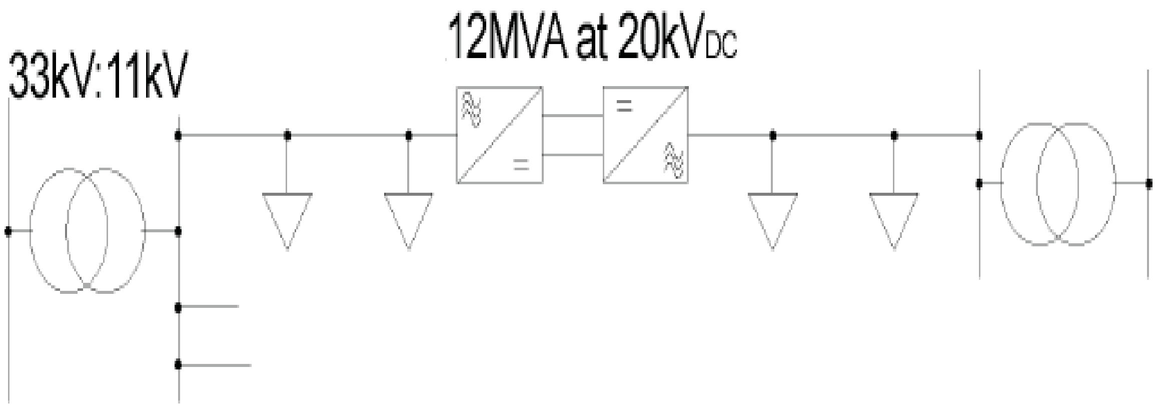


Figure 3.10 MVA / 11kV Soft Open Point formed with back-to-back converters.

3.2.3 Corridor Reinforcement Opportunities

It is always advisable to convert the existing AC right of way to DC at the HV transmission level because there can be a considerable increase in the power supply. It is also essential when there are highly restricted non-electrical reasons as environmental restrictions or restricted corridor width.

MVDC can increase MV circuits' capability by combining increased current and voltage operation, avoidance of voltage drops and phase angle, and power factor limitation.

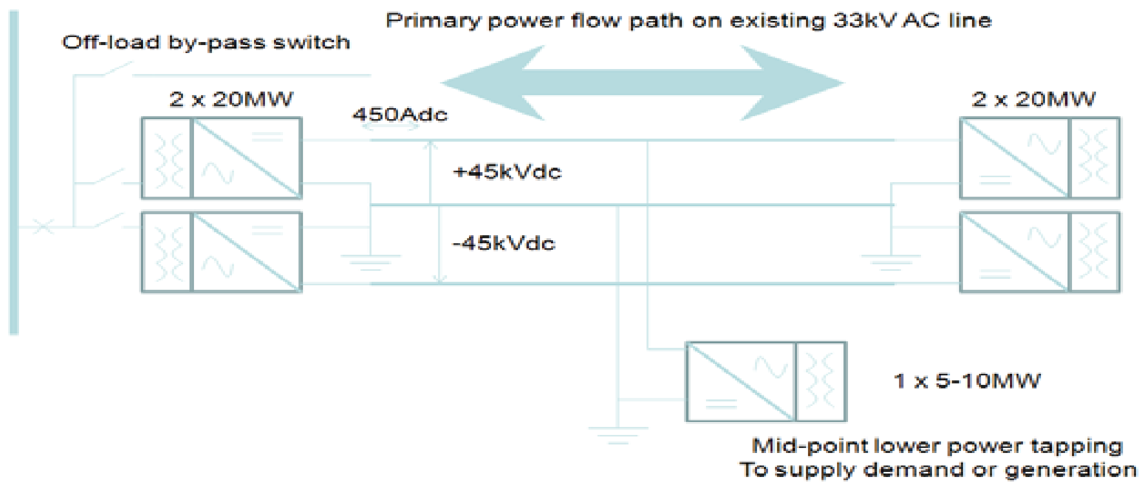


Figure 3.11 MVDC corridor capacity enhancement

MV networks have a maximum of four terminals within a specific protection group, limiting the maximum number of converter stations within a specific multi-terminal group. Within each protection group, the circuit breakers are only at each end. Therefore, MVDC does not require DC circuit breakers.

3.3 MVDC challenges related to the building of long overhead lines

The HVDC concept is well established in the electrical industry. Compared with AC systems overhead lines, the DC system does not have reactive power to be compensated, with no skin effect and, most importantly, no proximity effect. HVDC line commuted converters have been used for massive transmission of electrical supply over a long-distance line. VSC (voltage source converters) introduction resulted in a reduced footprint, load flow control, and the absence of polarity reversal on the DC lines, making them suitable for offshore grid access, grid interconnection, and power transmission over a moderate distance. Their reactive power supply also improves the grid voltage stability [51].
LVDC (low voltage direct current) is available for the low power range for industrial applications and renewable generators.
MVDC (medium voltage direct current), as compared to conventional AC lines for distribution network reinforcement, can transmit more power over a longer distance from the same voltage source.
Potential applications of MVDC are

- ✓ Grid reinforcement
- ✓ Grid access of remote power plants
- ✓ Grid access of remote users
- ✓ Need for load flow control preventing from re-dispatch and congestion in the grid

When it comes to building a new line, MVDC overhead lines can transfer more power than AC overhead lines. Figure 3.12 illustrates the difference between a power tower of type "Donaumast" for the nominal voltage of 30 kV and 110 kV [52].

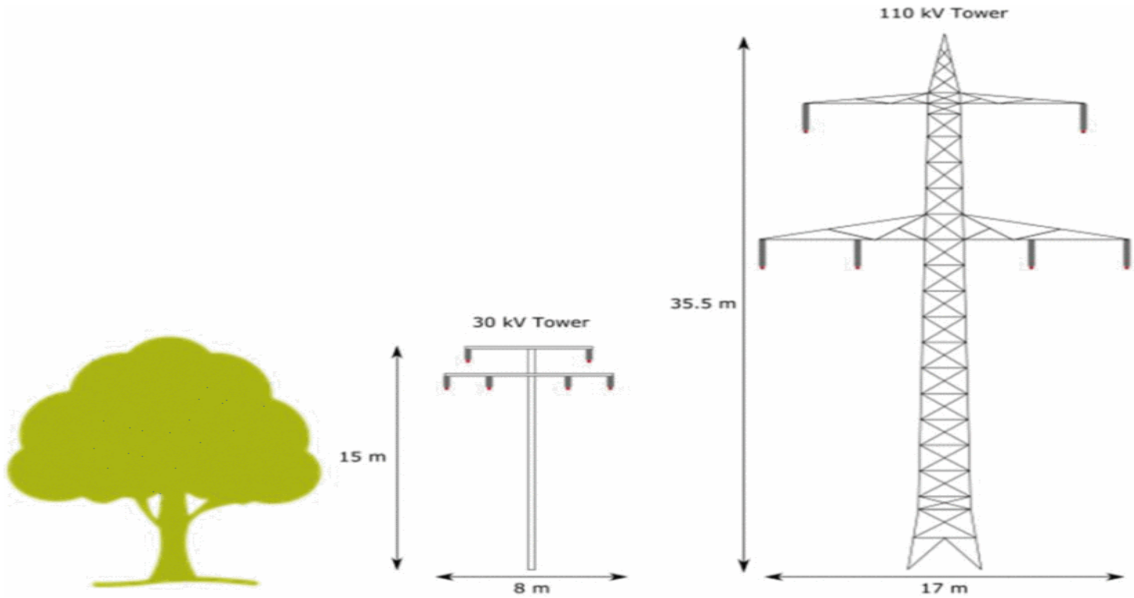


Figure 3.12 Power towers for a 30 and 110 kV AC line

3.4 MVDC Plus

MVDC Plus uses a siemens approach which consists of downscaling HVDC voltage source modular multilevel converter (VSC MMC)., the following strategies are implemented to determine the cost of MVDC plus

- ✓ simplification of the installation compared to HVDC
- ✓ discrete design with predefined type rating
- ✓ use of MVAC components post-qualified for DC voltage.

We can see from Figure 3.13 that the nominal active power is used as a reference for the scaling of the active power diagram and the nominal reactive power for the reactive power diagram. It is simply a way to compare HVDC; no tap changers are installed on the converter transformer; instead, the operating area is adjusted in function of AC voltage at the converter connection.

Capacitive reactive power and inductive reactive power are limited during overvoltage and Undervoltage events, respectively. For the grid to work efficiently without overloading the converter, the reactive power supply Is prioritized overactive power supply during AC under voltage.

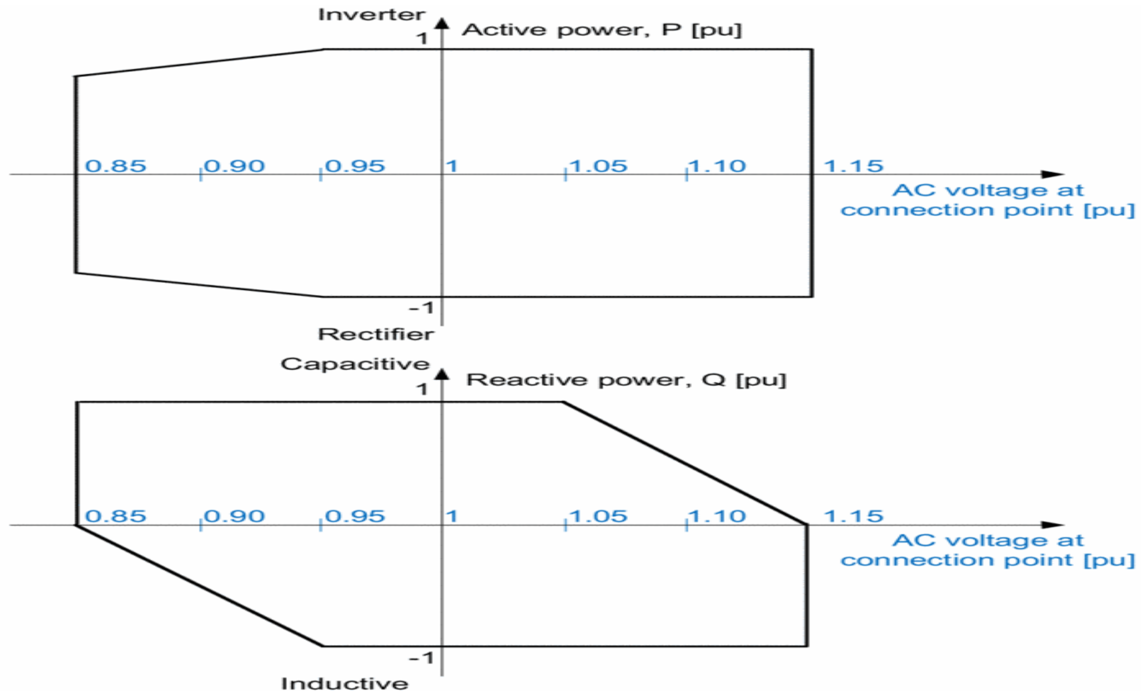


Figure 3.13 Operating area depending on the AC voltage at the connection point

The components of HVDC converters are produced in smaller numbers; while MVDC Plus already has available medium voltage AC components, it saves type tests and specific development costs. Moreover, it also decreases the storage cost as spare parts are quickly deliverable. DC offset should be avoided in the converters as they are not designed to withstand DC voltage. Therefore, a symmetrical monopole converter configuration is used (see Figure 3.14).

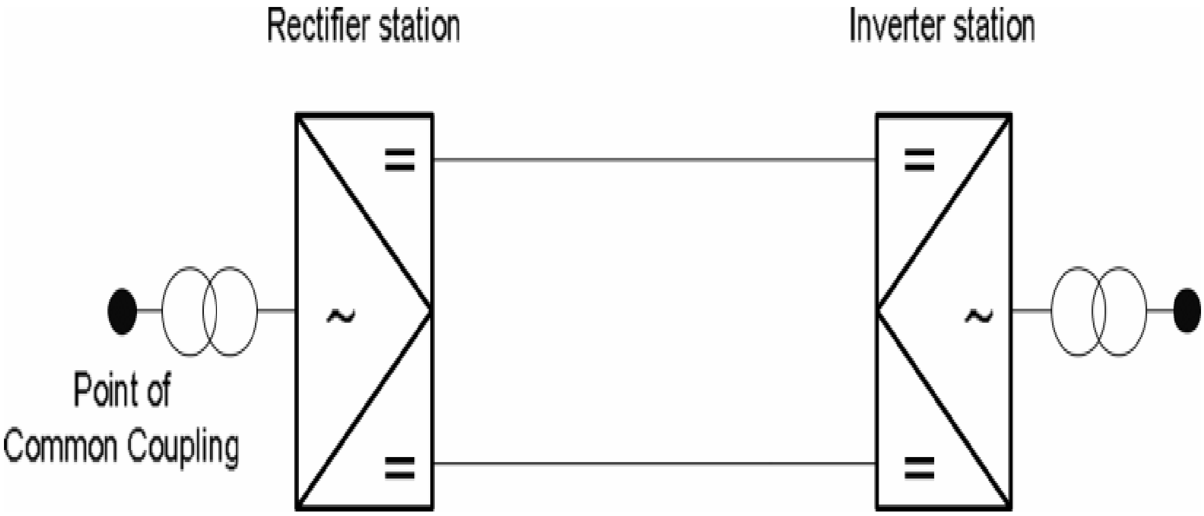


Figure 3.14 Symmetrical monopole configuration used from MVDC PLUS

MVDC Plus uses discrete designs. Three different variants are developed to cover a broad spectrum.

From Table 3.3, we can see that the three designs are different in terms of their maximum active power and DC voltages.

Table 3.3. MVDC PLUS design variants

	Variant 1	Variant 2	Variant 3
DC voltage at rectifier station	±24 kV	±30 kV	±50 kV
Maximum active power at point of common coupling at rectifier station	70 MW	90 MW	150 MW
Power factor	0.9	0.9	0.9

3.5 Power converters

One of the essential elements in substations of MVDC is power converters Which converts the alternating current into direct current or vice versa. DC-DC converters have an enhanced efficiency due to the reduction of the conversion steps, power qualities independence from the utility, and simplified control design due to the absence of reactive and harmonic power flows, which is the most suitable option for renewable source and loads as they have a power electronics interface with a DC link. The attraction towards moving to DC has increased in previous years in distribution systems, even utility scales.

There has been an increase in recent previous years in a concept based on conversion of 5 kV dc distribution system from 13/22 KV AC system to feed loads in the range of 100 to 5 MW.

Requirements for this concept include the availability of reliable, compact, and cost-effective conversion modules. The essential requirement is to convert the 5 kV dc to 480V AC with high-frequency isolation, high efficiency, power factor on the load side, and robust and reliable operation.

The fantastic features of Dual Active Bridge (DAB) converters are used for converting 5 kV DC to HVDC or LVDC. DAB is always considered when it comes to the conversion of DC to DC as it has some advanced features like soft switching, bidirectional power flow capabilities, and high-frequency isolation, which is an advantage in DC-to-DC applications, but when we deal with DC to AC conversion in DAB converters, it's required to have an extra DC-AC converter. The addition of different converter results in a high level of complexity and losses.

3.6 Universal MVDC Converter

the Universal MVDC converter can interface either 3 phase LVAC or LVDC while providing bidirectional power flow and high-frequency isolation. This converter can be the reason for providing higher voltage higher power systems. One of the features of this converter is soft switching solid-state transformer known as (S4T), which can provide high efficiency over an entire operating load range, integrated high-frequency isolation, and low EMI through dv/dt.

The schematic of the universal MVDC converter for LVDC and LVAC applications is shown in Figure (3.15.a) and in Figure (3.15.b), Respectively.

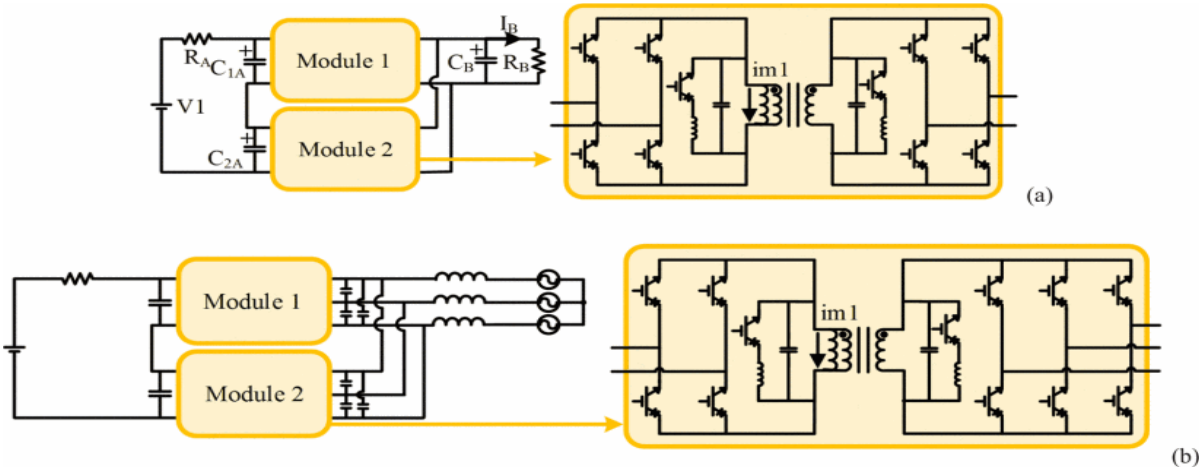


Figure 3.15 (a) Schematic of M-S4T for MVDC to LVDC application. (b) Schematic of M-S4T for MVDC to 3-phase LVAC application.

The Figure shows that the modular universal converter consists of soft switching solid-state transformer (S4T), and for producing galvanic isolation and energy storage over a short duration, a high-frequency transformer can be used. Two current source inverters (CSI) and auxiliary resonant circuits provide zero voltage switching [53].

The high voltage bridge consists of two legs to interface MVDC for both LVDC and LVAC, but Low voltage bridge consists of two legs for the LVDC and 3 legs for LVAC application. A modular converter is necessary for high voltage applications where voltage levels can be significantly higher than commercial semiconductor devices. Whichever the modular converter should be, there is always a rule that the modules are connected in series on the HV side and connected in parallel on LV Side.

This converter can be proposed as the universal MVDC converter because it can provide bidirectional power flow and easily interface with LVDC and LVAC without changing the configuration. It can also achieve higher voltage and power.

This converter module can provide the following features

- single stage architecture with the minimal device and component count
- low dv/dt
- high efficiency over the entire load range
- very benign failure modes
- The elimination of dc bulk capacitors results in a reduction in the converter's size, enhances the operating temperature range, and eliminates a significant failure.

3.7 Operating principle and control of the proposed MVDC Converter

3.7.1 Operating principle

The essential operation of S4T convert has two cycles: a forward and a regen cycle.

In the forward cycle, the energy can be transferred from the sending terminal to the magnetizing inductance of the transformer, and the regen cycle transferred the energy from inductance to the receiving terminal. The two active states can be interposed with the ZVS transition state and the resonant state, which aid in achieving ZVS.

3.7.2 Control Scheme:

It is compulsory for any modular series stacked converter to have a fast and robust stacked side capacitor voltage balancing under any condition. In the M S4T converter case, the voltage balancing is more complicated than the other converter topologies due to low inertia. The primary requirement of the proposed stacked converter is as follows.

- Maintain magnetizing current at the desired value
- Dynamically balance the stacked side capacitor voltage
- Deliver high-quality power to the low voltage grid.

Input bridge duty cycle and output bridge duty cycle are the two independent control freedoms to achieve the objectives mentioned above at any arbitrary transients. Therefore, there should be a tradeoff between the 3 objectives to be achieved in terms of control. A prediction-based priority switching control can be proposed, shown in Figure 3.16.

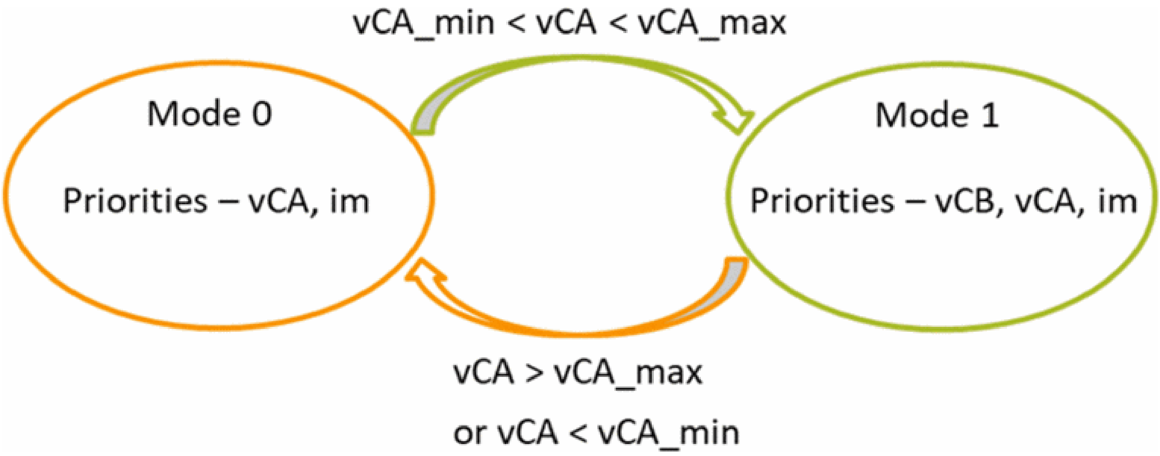


Figure 3.16 Proposed model prediction-based priority switching control.

The operation of this system considers two modes

Mode 0: When the stacked capacitor is out of the range, the system is considering in mode 0, and the highest priority goes to the stacked capacitor voltage and magnetizing current.

Mode 1: When the stacked capacitor is within the desired range, the system must be considered in mode 1. In this case, each of these objectives has an equal priority.

3.8 Design of the modular S4T Converter

The objective is to design a 50 kVA 5 kV DC to 480 V AC/600 V DC converter based on two 25 kVA S4T modules [54].
The following points are discussed below.

3.8.1 Devices

A custom HV module based on 3.3 kV SiC MOSFETs and 3.3 kV SiC diodes was developed to minimize the parasite inductance. The mentioned devices and the schematic image which CREE™ developed can be shown in Figure 3.17.

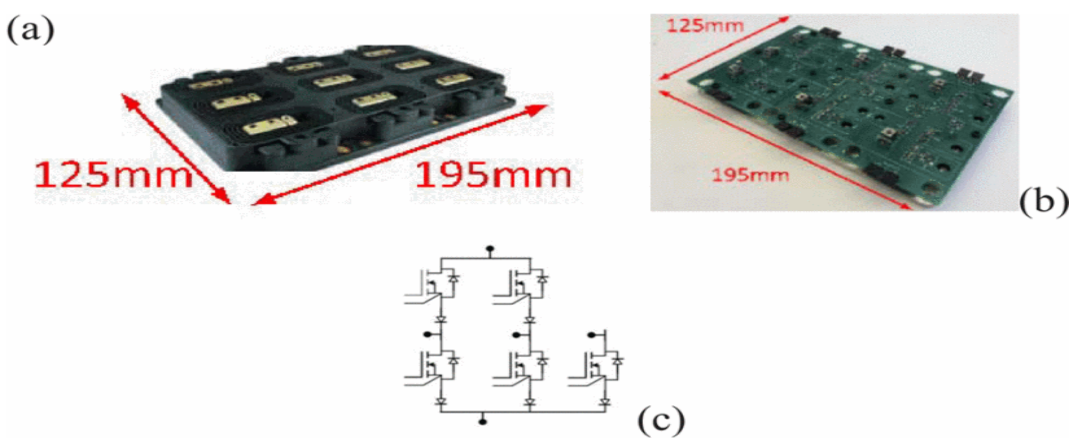


Figure 3.17 (a) Custom-built HV module based on 3.3 kV SiC MOSFETs and 3.3 kV diodes. (b) Custom-built the module with discrete 1.7 kV MOSFETs and diodes. (C) Schematic of the module

The devices can be characterized by the double pulse tests, which showed that the soft switching losses were reduced by 98%. The parasitic inductance with 3.3 kV modules is 50 nH compared to 120 nH with a 1.7 kV module, built using discrete devices. The LV module can be built using discrete 1200 V 100 A Si IGBTs and 1200 V 100 A SiC diodes [55].

3.8.2 Transformer design

The specification of the transformer can be designed as shown in table (3.4).

The function of transformer magnetizing inductance and average magnetizing current is called peak transformer current, as it showed in Table 3.4. that the value of the average magnetizing current is 2.5 Pu of the nominal load. The additional 0.5 Pu current is lost in ZVS transition stages and resonant periods. High magnetizing current leads us to lower current ripple but large transformer but low magnetizing current results in high current ripple but increase losses and associated control issues. Therefore, the value of magnetizing current is a free variable to be determined through optimization.

Table 3.4. Specification of HF Transformer

Parameter	Value
Transformer operating freq	16 kHz
Im_avg (A)	25 A (HV)/100 A(LV)
Loss	< 1.0 %
Magnetizing inductance (Lm)	200- 400 uH (HV side)
Inter winding capacitance	< 1 nF
Leakage inductance	< 1 % of Lm
Isolation	15 kV

In this design, a custom-built coaxial winding can be used to achieve both low leakage and high isolation. The coaxial winding consists of an inner Litz wire and an outer tinned copper braid separated by HV insulation to achieve 15 kV isolation, as shown in Figure 3.18.

Figure 3.18 Structure of coaxial cable.

3.8.3 Resonant Circuit Design

Resonant circuit design gives us insurance to provide zero switching voltage for all the primary devices during the whole load range. The leakage reactance is unavoidable; therefore, there are two resonant branches. Each across one side of the transformer and each resonant branch consists of a resonant capacitor, a resonant inductor, and a resonant switch.

During a switching cycle, the resonant capacitor voltage can be controlled to traverse from the space vectors corresponding to the most positive voltage level corresponding to the most negative voltage level. At the end of the switching cycle, the resonant capacitor voltage can be reset to a value positive enough using the resonant inductor and switch.

3.8.4 Control power supply for HV bridge

Isolation plays a vital role in the HV bridge. The HV bridge devices and their associated devices should be isolated from each other and the ground. The control signal and the power supply should also be isolated galvanically. The power supply isolation is shown in Figure 3.19.

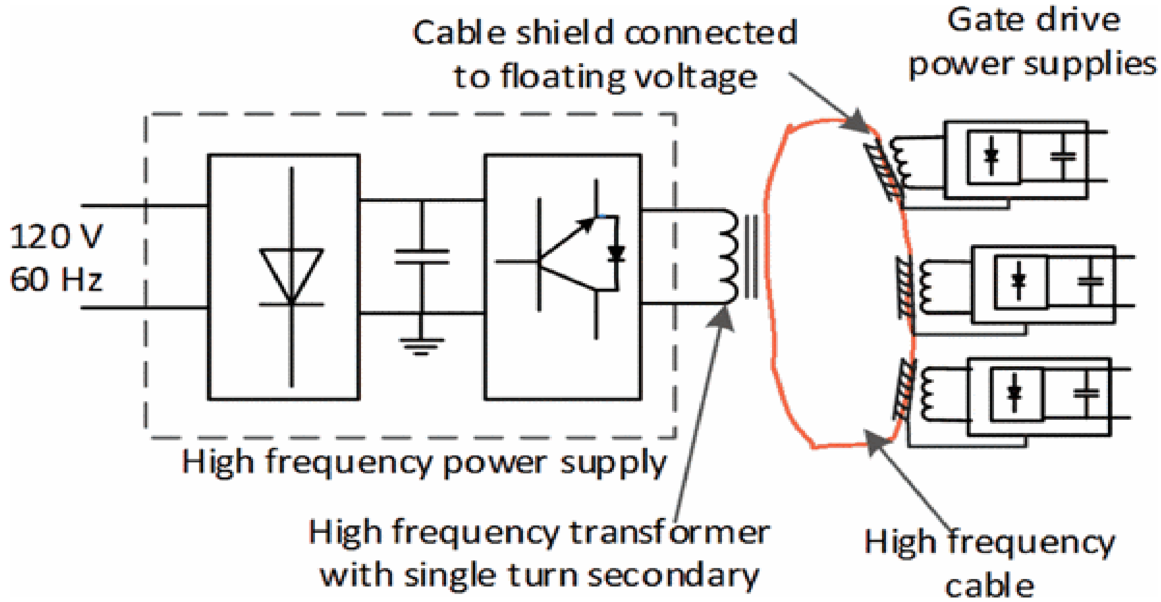


Figure 3.19 Structure of control power for HV bridge.

The control signal can be supplied to the gate drivers via fiber optics. The power can be transferred to the individual gate drivers through a high frequency then this high-frequency power is rectified on the gate driver side to generated DC voltage for driving IGBTs.

3.8.5 25 kVA 2.5 KV DC/ 600 V DC converter module

The components used in this converter module can be shown in Table 3.5.

An FPGA/DSP-based controller has been used to implement the control algorithm. The image of this module converter can be shown in Figure 3.20.

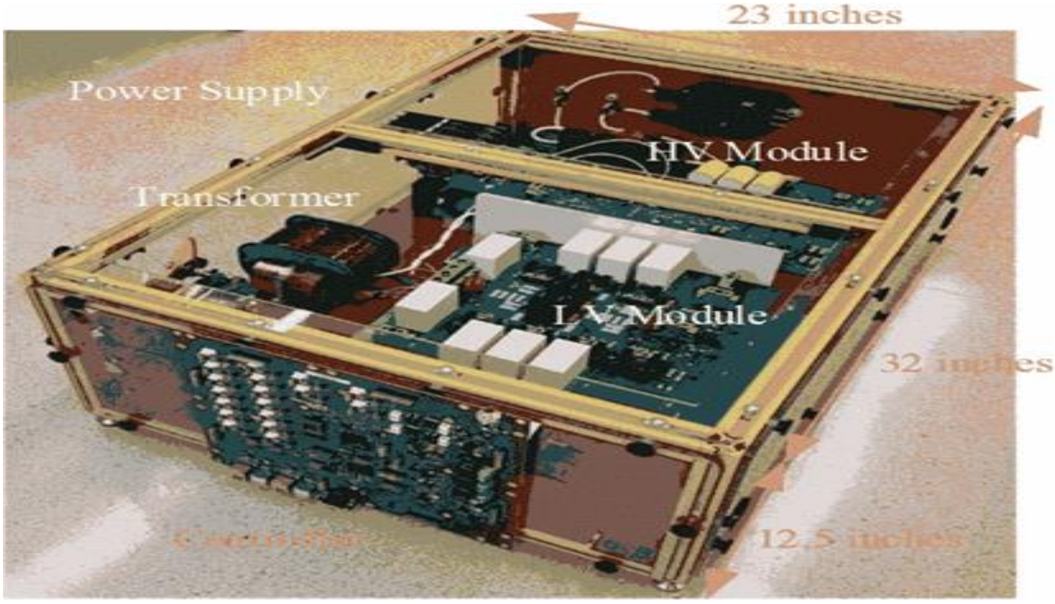


Figure 3.20 Image of the 25 kVA 2.5 kV DC/ 600 V DC converter module.

Table 3.5.
Significant components of 25 kVA 2.5 kV DC/ 600 V DC converter module based on S4T

HV devices	3.3kV CREE Custom module, 1 3.3 kV CREE diode, 3
LV devices	Infineon IGW60T120, 13 GlobalPower GP2D050A120B, 16
HV gate drivers	CREE 3.3 kV Gate Driver, 5
LV gate drivers	CREE CRD-001, 5
Transformer	Nano-crystalline core transformer, 1
LV caps	KEMET C4ASPBW4250A3MJ, 8
HV caps	Cornell Dubilier, UNL15W4P7K-F, 4
HV resonant cap	KEMET CKC33C223KJGACTU, 5
Controller	FPGA/DSP based Controller, 1
HV voltage sensor	LEM DVM 4200, 1
LV voltage sensor	LEM CV 3-1000, 3
HV/ LV grid current sensor	LEM LF 210-S, 4
HV/LV Im sensor	LEM LF 510-S, 2

Two such modules can achieve a 50 kVA 5 kV DC to 600 V DC converter.

3.9 DC Transformers

Renewable energy source RES such as wind and photovoltaic energy has been developing recently, so dc grid technology has many advantages to connect and utilize this energy source. The rapid development of High voltage DC (HVDC) transmission lines and low voltage DC (LVDC) has lots of practical systems worldwide. Based on this background Medium voltage DC (MVDC) has been more into consideration [56,57,58].

Apart from the connection of various RES and production of high-power quality, MVDC can be used as an intermediate link to connect the HVDC transmission bus and LVDC microgrid bus. In this application, a dc transformer (DCT) is necessary to achieve voltage conversion, flexible power management, and electrical isolation between the MVDC distribution bus and LVDC microgrid bus [59].

The typical solution for the Direct current transformer for dc distribution application is the dual active bridge (DAB) based on input series output parallel system as shown in Figure 3.21. (a) from the input side, several (DAB) are connected in series to access the MVDC bus and parallel to access LVDC from the output side. One of the most crucial advantages of this scheme is that the system efficiency can be increased (DAB) with excellent soft switching performance.

From the figure, we can see that from the MVDC side; there is a concentrated capacitor which means that there can be a large current when the MVDC bus is short-circuited, so a DC circuit breaker is needed for the MVDC short-circuited side because the fault cannot be limited by turning off the switching of DCT. The cost and volume of the system can be significantly increased also. Moreover, it is impossible to cut out fault DAB unit or cut in redundant unit online for this kind of scheme with the concentrated capacitor in the DC terminal, and the system should stop running when any unit fails. Because many units should be connected in series for the MVDC application to get high reliability, it cannot be accepted without a redundant unit [60].

Figure 3.21 The topology evolution process of MHDCT. (a) DAB-DCT. (b) MDCT (c) MHDCT

The solution for this problem is modular multilevel converter (MMC) employment, which is widely used in HVDC transmission to a DCT application. DCT based on MMC (MDCT) for

MVDC application can be proposed, shown in Figure 3.21 (b). The MMC can be used as an MVDC interface converter, the full-bridge converter can be used as an LVDC interface converter, and the ac terminals of MMC and FB are connected in the primary and secondary sides of the isolated transformer, respectively. Unlike the operation of MMC in the ac system, the MMC in DCT should work in high-frequency operation to decrease the volume of the transformer. Because there is no concentrated capacitor for MMC on the MVDC side, this scheme has good reliability. DCT can cut off the short-circuit fault current on the MVDC side, so the dc breaker is not needed, which decreases the cost and volume of the system. However, the modularity of the scheme is low; MMC in DCT should be debugged and operated as a whole system. Predominantly because the MMC operates with a high switching frequency, it is hard to achieve voltage matching regulation and balance control. Moreover, the trapezoidal modulation should be employed to decrease dv/dt of high-frequency-link (HFL), increasing control complexity [61].

Over the past few years, many DC transformers have been introduced, which has advantages and disadvantages but here, only the practical scenarios can be discussed. The implemented situations of DC transformers can be divided into three scenarios shown in Figure 3.22.

Scenario 1: in this scenario, the Medium-voltage Direct current (MVDC) collector grid or distribution grid can be connected to the High voltage direct current (HVDC) transmission. Following requirements needs to be fulfilled

- High voltage ratio
- Medium voltage level
- Reliability and security, especially in distribution grids, are the most important as they prevent the system from collapsing when there is a severe DC network fault in the local connection out of the regular operation.

Scenario 2: this type of connection can connect high voltage direct current (HVDC) to Ultra-high voltage direct current (UHVDC) in series. Load centers are directly connected to the onshore connection points with higher voltage, and high-speed DC circuit breakers can be ignored as the fault is handled quite well. The requirements for this scenario are

- Medium voltage ratio
- High voltage levels
- DC fault protection
- High efficiency

Scenario 3: Finally, this type can connect the different DC grids that foam a dc network. Two dc grids can be independently developed, so the DC transformer needs to exchange power between the networks. Then the requirements ae

- Low voltage ratio
- High voltage levels
- Bidirectional power flow

Each of the above categories has specific requirements. Therefore, there is not a single DC transformer topology that is implemented for every situation.

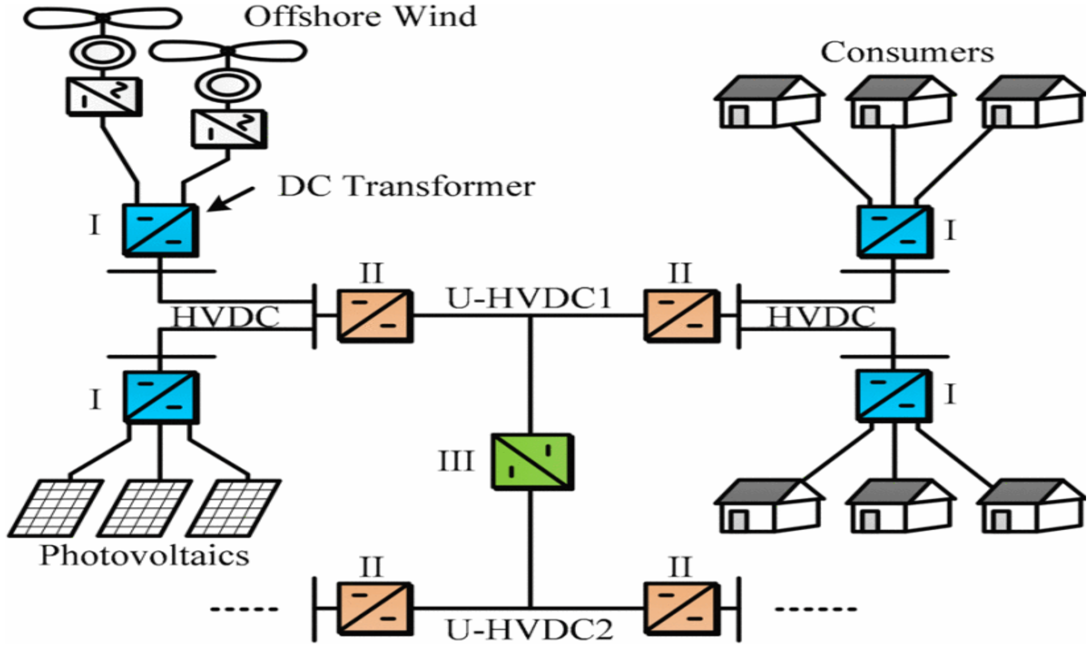


Figure 3.22 three implemented scenarios for DC transformers

3.10 Review of Established and emerging DC Transformer Topologies

DC Transformer topologies in terms of the classification and features have been shown in Figure 3.23. These topologies can be divided into two categories.

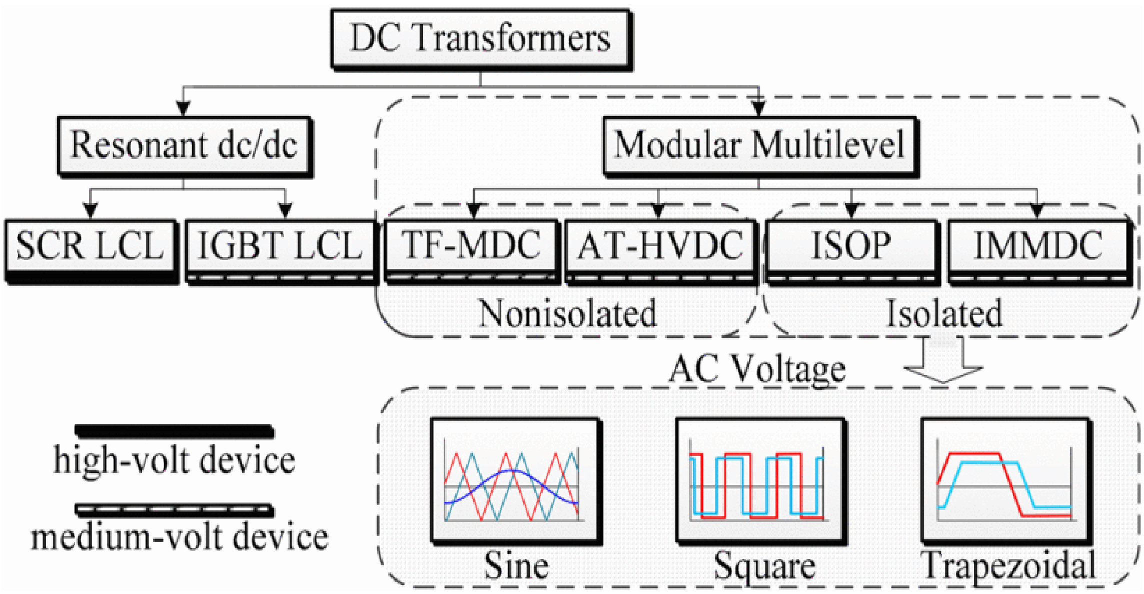


Figure 3.23 The Classification of DC Transformers.

3.10.1 Topologies based on LCL Resonant.

There are two different resonant Dc transformers based on different components.

- Thyristors
- IGBTs

These topologies are more straightforward than the DC transformers based on modular multilevel techniques, but their voltage levels are limited.

a) Thyristor-Based DC-DC converter (SCR-LCL)

A typical SCR-LCL can be seen in Figure 3.24; it consists of two resonant LC circuits [62,63], front to front connected, sharing a typical capacitor in the middle. It uses two thyristors that are symmetrical with each other in each valve and achieves fast power reversal. Series-connected thyristors have pros and cons.

Pros

- Low losses
- Good overcurrent capability
- And megawatt power transfer

Cons

- Requires a sizeable DC side inductance which is costly and increase the volume of the weight of the converter
- The SCR-LCL is a frequency-controlled element, so the design of the passive elements is not easy.

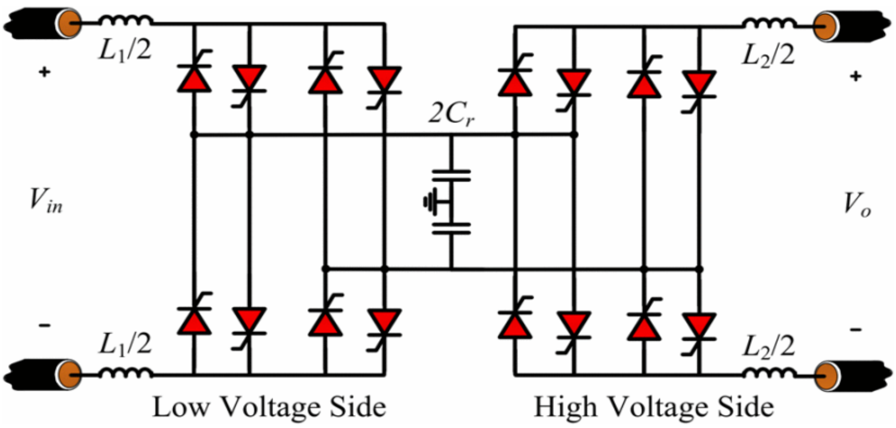


Figure 3.24 An LCL thyristor bidirectional DC/DC converter.

b) Resonant DC transformer Based on IGBT (IGBT-LCL)

IGBT-LCL can be shown in Figure 3.25; it consists of active switches (S_t, S_b), output capacitors

(C_{toi}, C_{boi}, i=1,2…), resonant inductors (L_{rti},L_{rbi},i=1,2…) and resonant capacitors (C_{rti}, C_{rbi}, i=1,2…). This topology has soft switching, and output voltage ripple can be reduced without extra components by inherent interleaving property. Due to the resonant voltages that are i-fold, the input voltage does not feature the real modularity, and its voltage level can be limited by the maximum voltage of the last two resonant capacitors. Hence, it may be limited to apply in high voltage scenarios.

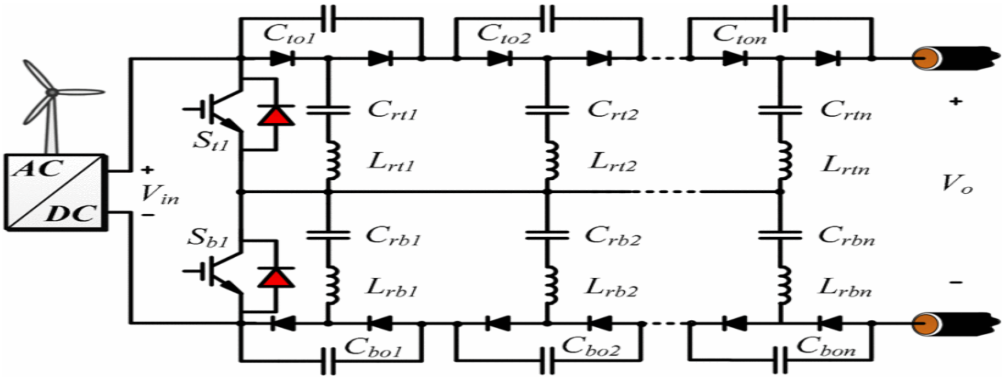


Figure 3.25 An LCL resonant dc transformer topology based on IGBTs.

3.10.2 Topologies Based on Modular Multilevel Technique

These topologies have similar features as other multilevel topologies, such as high voltage level, high efficiency, modularity, and scalability, which is easy to fulfill high voltage requirements in HVDC but needs many semiconductor components.

(a) Tuned Filter Modular Multilevel DC Converter (TF-MDC)

This Converter is shown in Figure 3.26 (a). the secondary power loop maintains the power balance between the upper arm and the lower arm, which uses a few kilohertz frequencies to transport the energy. But secondary power loop has a side effect of inducing a high conduction loss when it has a high current. This converter may not be suitable for medium and high voltage applications because the converters require significant filtering at both the input and output dc points.

(b) HVDC-DC Auto Transformer (AT-HVDC)

This topology is like the AC autotransformer, which is shown in Figure 3.26 (b). AT-HVDC converter allows the direct interconnection of HVDC lines with different DC voltage levels. From the figure, it can be seen that both the upper sub-converter and lower sub-converter are connected through an AC link. It does not need a secondary power loop, resulting in lower conduction losses and high efficiency but at the cost of an autotransformer. The extended topology can be presented in Figure 3.26 (c), which implements an ac transformer and can be used in multiple connections.

(c) Input-Serial-and-Output-Parallel Dual Active Bridge system (ISOP-DAB)

Dual Active Bridge converter uses the smallest unit of ISOP-DAB shown in Figure 3.26 (d). DAB consists of two full-bridge converters and a medium frequency transformer. Higher frequency fundamentals (> 1 kHz) in the ac link reduces the overall size and weight of the dc/dc converter without sacrificing the efficiency. The structure of ISOP is easy to achieve a higher voltage with low voltage rating components. The main drawback of the ISOP-DAB is the high number of low-power transformers, which have to be isolated for the full high-level DC voltage; thus, the volume and cost can be consumed mainly in isolation and insulate designs.

(d) Isolate Modular DC-DC Converter (IMDCC)

Figure 3.26 (e) shows that IMDCC uses two ac/dc converters (typically as MMC) coupled through a transformer. Galvanic isolation can be provided by the transformer between voltage steps as well as two dc connections. Galvanic isolation can be used first and foremost in abnormal operating conditions and for separating grounding arrangements for different parts of a dc network.

It is more reasonable for manufacturing to design one high-voltage and high-power medium frequency transformer than to assemble large numbers of full-high-voltage but low-voltage transformers in HVDC transmission. However, the installed converter power is at least twice the nominal DC-DC power since there are two power conversion stages, and all power is inverted into ac then rectified into another dc side. Finally, thus the initial investment of this topology may be higher.

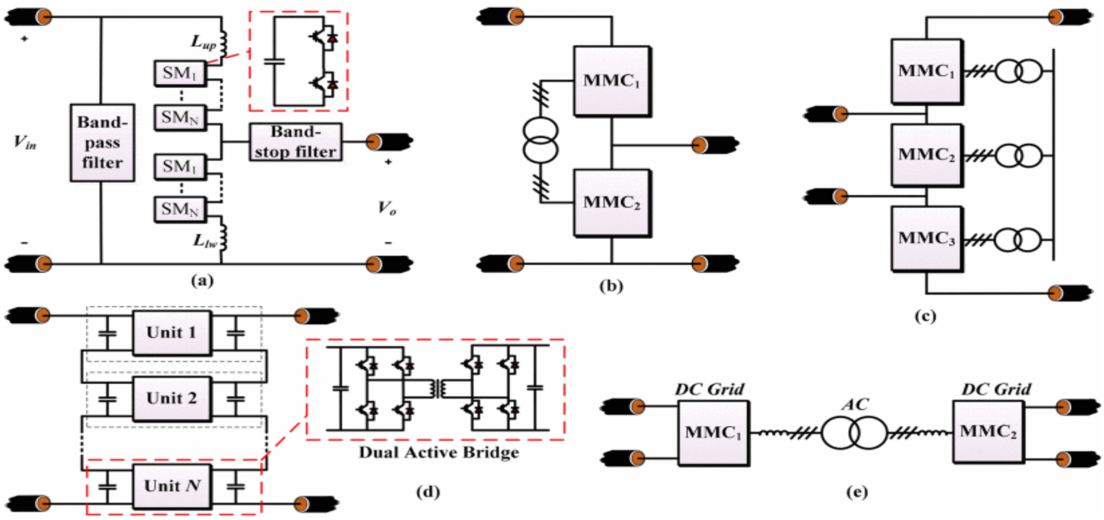


Figure 3.26 Several typical modular multilevel DC transformer topologies.

3.11 Faults and Effects in Electrical Power Systems.

The electrical power system is increasing day by day in every sector like generation transmission and distributions—the growth results in complexity of the system and ordinary occurrence of the faults. Short circuit faults result in severe economic losses and reduce the reliability of the system. An electrical fault is an abnormal condition caused by equipment failures such as transformers and rotating machines, human errors, and environmental conditions. These faults cause interruption to electric flow, equipment damages, and even cause the death of humans, birds, and animals. [64]

Some faults are prevalent and quickly cleared, but some are complicated to deal with. There are two categories of faults named symmetrical and unsymmetrical faults. Let's discuss each of them in detail.

3.11.1 Symmetrical faults

Symmetrical faults rarely happen, But when they do, the results are very destructive. These faults are also called balanced faults because the impedance values are the same in each phase. Only 2-5 percent of system faults are of these kinds.

There are two types of symmetrical faults known as Three-phase faults or line-line-line faults and three-phase to the ground or line-line-line-ground faults shown in Figure 3.27.

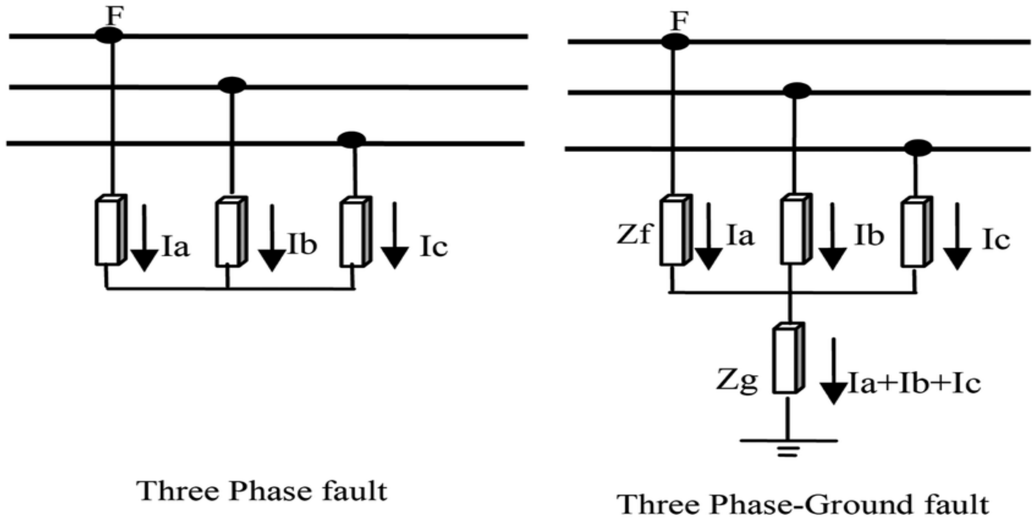


Figure 3.27 symmetrical faults.

The above figure shows the types of symmetrical faults. It's easy to analyze these faults and customarily carried out based on a phase.

Three-phase fault or L-L-L fault

The system remains balance when this kind of fault occurs; that's why these faults are also called balanced faults. This fault doesn't occur so often, although it is a harsh kind of fault that holds the most significant current. This fault can determine the rating of the Circuit breaker.

Three phase-Ground faults or L-L-L-G faults

This fault occurs among the three-phase and the ground terminal of the system, so the probability of this fault is around 2-3%. In this type of fault, fault currents in all phases are symmetrical, i.e., their magnitudes are equal, and they are equally displaced by angle 120°. Because of the balanced nature of the fault, only one phase needs to be considered in calculations since the other two phases will also be similar.

3.11.2 Asymmetrical faults

These faults are prevalent and less severe than symmetrical faults. These faults only involve one or two phases. Those faults on the power system which give rise to unsymmetrical fault currents (i.e., unequal line current with unequal phase displacement) are called Unsymmetrical fault. These are also called unbalanced faults since their occurrence causes unbalance in the system. The impedance values are different in each phase, causing unbalance current to flow in the phases. These are more difficult to analyze and are carried by per phase basis similar to three-phase balanced faults.

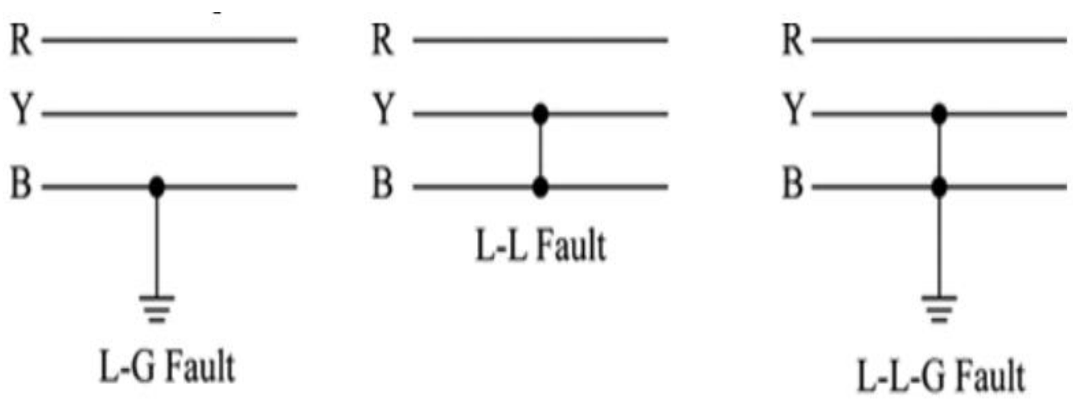


Figure 3.28 Types of asymmetrical faults.

The asymmetrical faults are classified into three types.

- Single line to ground or L-G fault
- The line to line or L-L fault
- Double line to ground or L-L-G fault

Single line to ground fault

This kind of fault occurs when a single conductor faults towards the ground terminal. 70-80% of the faults are of this nature. Such types of failure may occur in power systems due to many reasons like high-speed wind, falling off a tree, lightning, etc.

The Pole to Pole fault

These faults occur when two conductors are short-circuited due to the heavy wind or whatever reason. 15-20% of the faults are of this nature.

Double Pole to ground fault

Two lines get in touch with each other and with the ground. There is a 10% probability of this kind of fault.

3.12 Causes of Electrical faults

Weather conditions: it included heavy rains, heavy winds, lightning strikes, snow and ice accumulation on transmission lines, salt deposition on overhead lines and conductors, etc. these conditions interrupt not only the power supply but also damages the electrical installations.

Equipment failures: different electrical equipment like motors, transformers, generators, switching devices, reactors, etc., causes short circuit faults. The consequence of these failures is that high current flows through the device and further damages it.

Human errors: Human errors are also one of the main reasons for this kind of fault, such as selecting offensive rating of equipment or devices, forgetting electrical conducting parts after servicing, switching the circuit while it is under servicing.

Smoke or fire: ionization or air, due to smoke particles surrounding the overhead line, sparks between the lines or between conductors to the insulator.

3.13 Effects of Electrical faults:

Loss of personal equipment: short circuit faults result in heavy current, which can burn the equipment's components of the equipment entirely and lead to improper working of the device. Many times the whole equipment gets burnt.

Overcurrent flow: when the short circuit faults occur, low impedance and high current cause tripping of relays, damaging insulation and components of the equipment.

The danger of operating personnel: fault occurrence can also cause shocks to individuals. The severity of shock depends on the current and voltage at fault location and even may lead to death.

3.14 Fault limiting devices:

It is possible to minimize causes like human error, but environmental changes cannot be lessened or controlled. If we manage to disrupt or break the circuit when a fault arises, it reduces the considerable damage to the equipment and the property.

Some of the limiting devices are as follows.

Fuse: it is a protecting device that melts when excessive current flows in the circuit. Manual replacement of the wire is essential once it a blowout.

Circuit breaker: it makes the circuit at normal and breaks at abnormal conditions. It causes automatic tripping of the circuit when a fault occurs.

Relay: The condition-based operating switch consists of a magnetic coil and normally open and closed contacts. Fault’s occurrence raises the current, which energizes the relay coil, resulting in the contacts operating, so the circuit is interrupted from the flowing of current. Protective relays are different types such as impedance relay, mho relays. [65]

Lighting power protection devices include lighting arrestors and grounding devices to protect the system against lightning and surge voltages.

Chapter 4

Matlab Simulations.

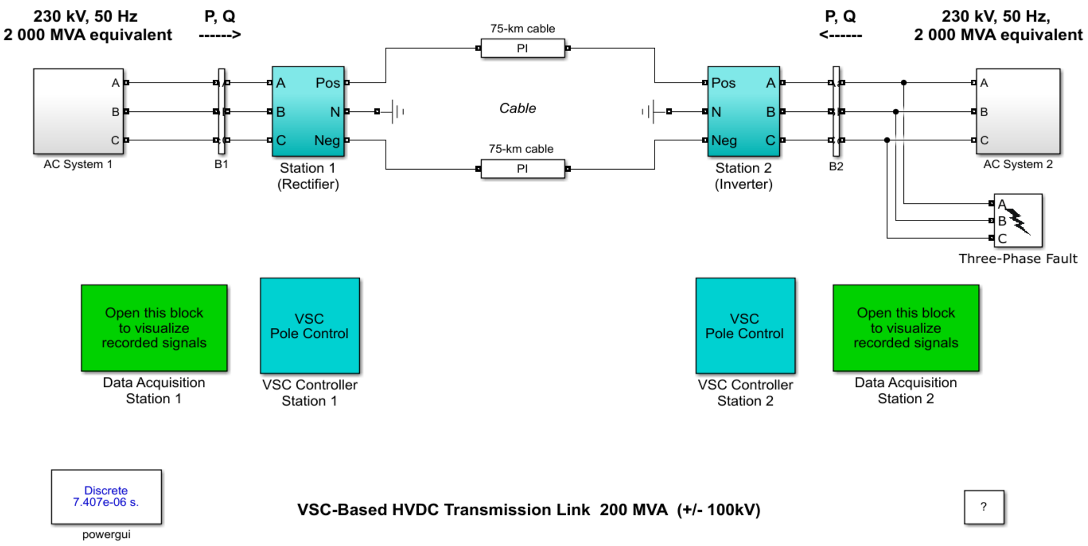


Figure 4.0 (VSC-Based HVDC)

Figure 4.0 is a VSC-based HVDC (High voltage direct current) transmission system. A 200 MVA (+/- 100 kV DC) forced commutated VSC (voltage sourced converter) is used to transmit power from a 2000 MVA, 230 kV, 50 Hz system to another AC system. Inside AC system 1, three-phase programmable source, three-phase series RLC Branch and three-phase parallel RLC are connected. AC system 1 is connected by B1, which is a three-phase VI measurement (mask). B1 measures the three-phase voltages and currents inside the circuit. Real and reactive power flows from AC system 1 towards station 1 (rectifier). Station 1 converts three-phase AC to DC, and then this DC is transmitted through the 75km cables known as transmission lines.

If station 1 is analyzed, we know how three-phase AC is converted to DC for transmission purposes. Figure 4.1 represents station 1 (Rectifier). The components used for the AC system are a Yg-D transformer, AC filters, phase reactor, and three Level Bridge IGBT/Diodes. This AC is converted during an arduous but straightforward process. During this process, DC capacitor, DC filters 3rd harmonic reactor, and some current measurement blocks and gains are used. The output current is delivered to IdcPN1. It is the vector that contains the measurement positive and negative current. VdcPN1 supplies the output voltage.

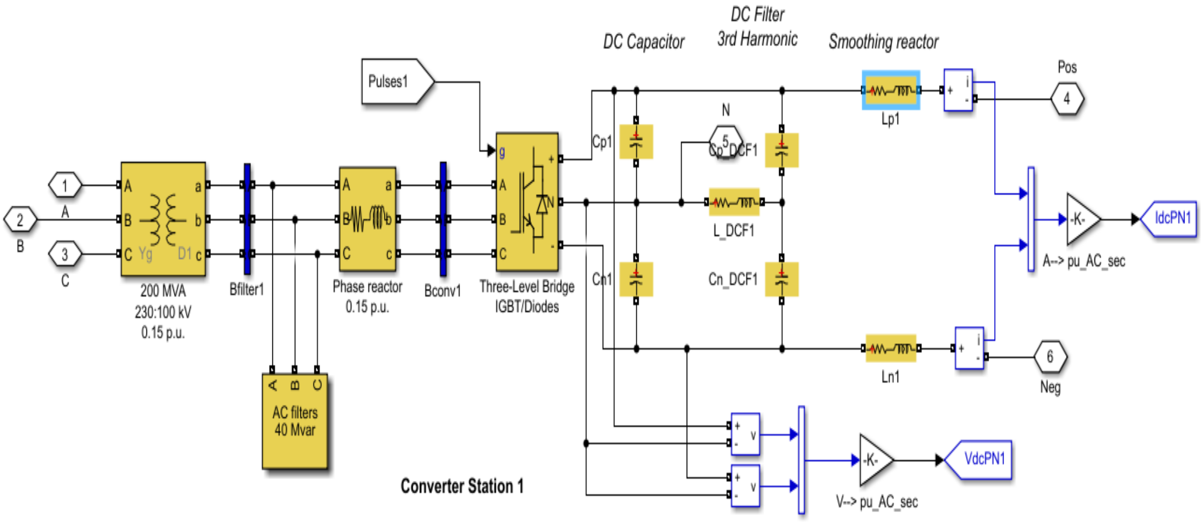


Figure 4.1 Station1 (Rectifier)

Station 1 and 2 have the same components and values for HVDC.
Three-phase transformers in Figure 3.1 have the following values.
Nominal power = 200 MW

Winding 1 parameters

Phase to phase RMS voltage 1 = = $230e^3$ * 0.915
Resistance 1 [R1(Pu)] = 0.0025
Inductance 1 [L1(Pu)] = 0.075

Winding 2 parameters

Phase to phase RMS voltage 2 = $100e^3$
Resistance 2 [R2(Pu)] = 0.0025
Inductance 2 [L2(Pu)] = 0.075
Magnetizing inductance and resistance have the same value of 500.
There are two crucial blocks in the diagram that need to be discussed in detail, but for now, there is an overview of these two blocks, namely Data acquisition and VSC controller.
Data acquisition is simply a block to show the recorded signals of the system. Due to this block, we can analyze the behavior of the currents with and without a short circuit and can propose a suitable protection strategy for our system.

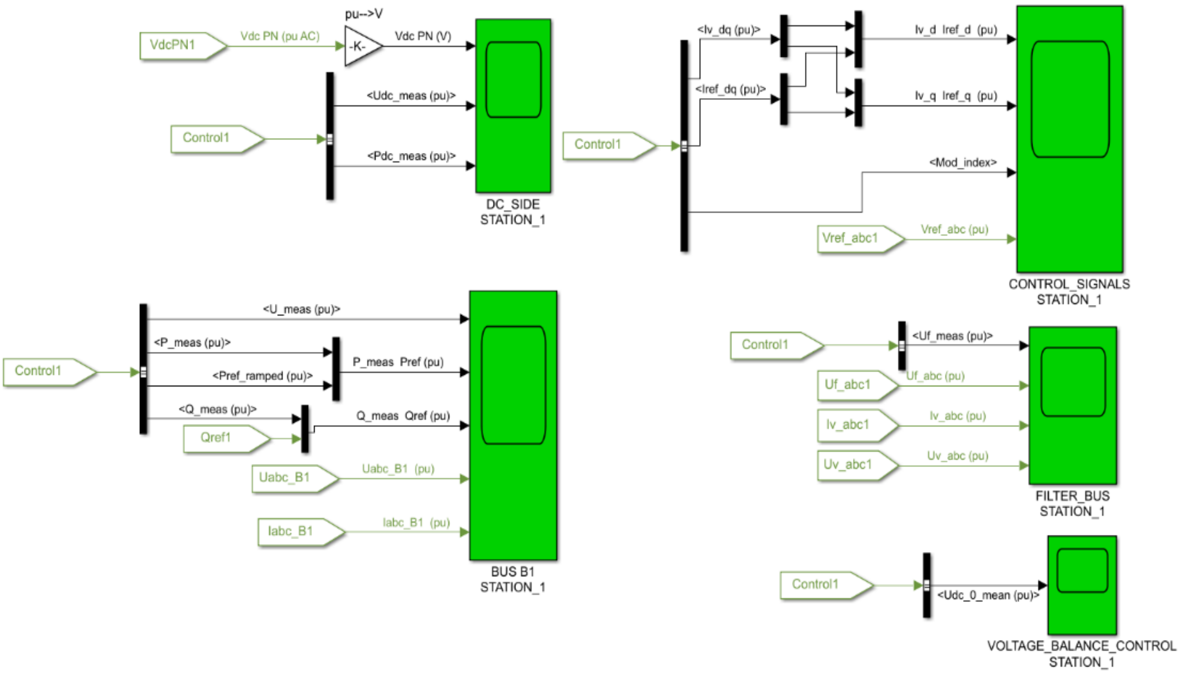


Figure 4.2 (Data acquisition station 1)

Figure 4.2, it is to be seen that Data acquisition station 1 can analyze the recorded signals on Bus station 1, DC side station 1, control signals station 1, filter bus station 1, and voltage balance control station. VSC controller is an essential block from which all the crucial controls are performed here. Inside VSC controller looks like in Figure 4.3.

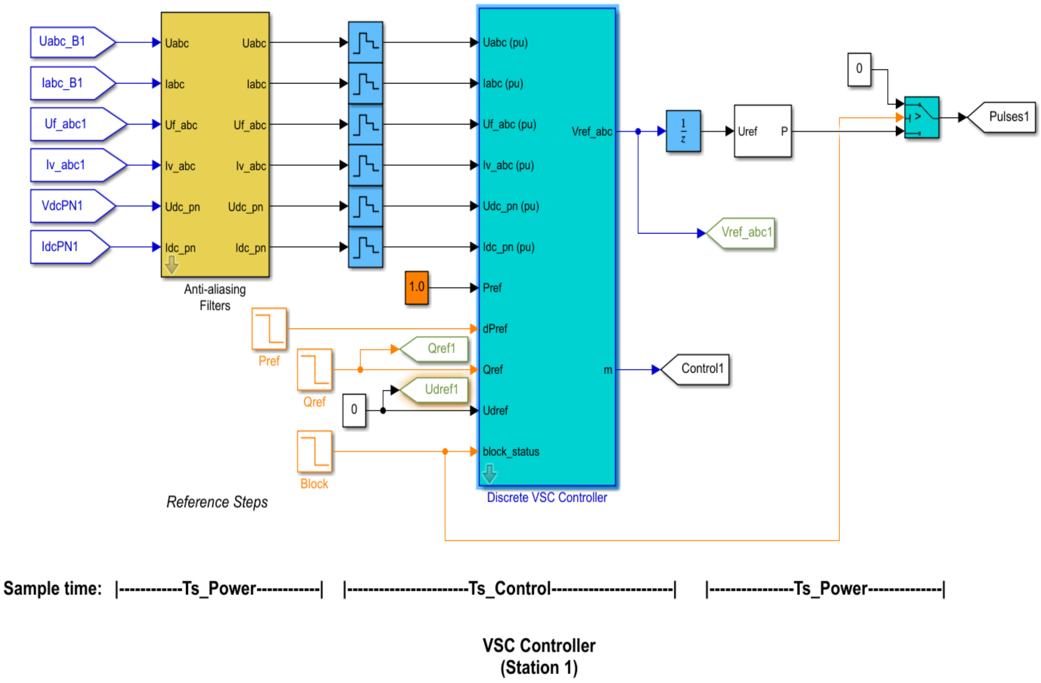
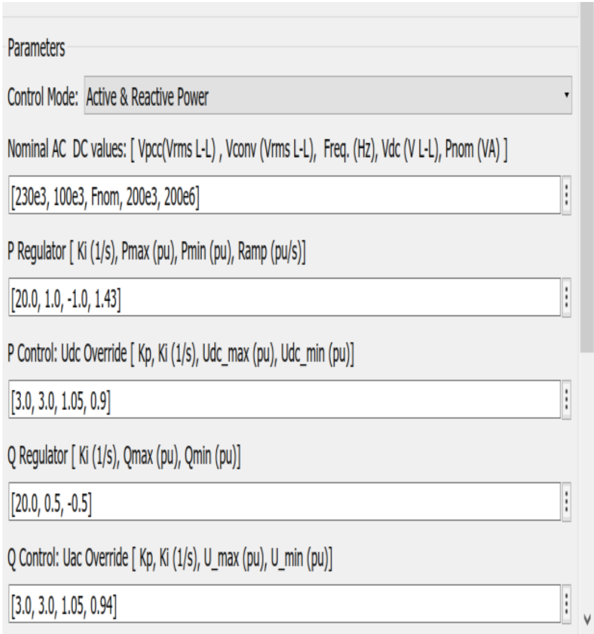


Figure 4.3. VSC Controller (station 1)

The values for HVDC discrete VSC controller are as follows.



The most important values are the nominal AC DC values.

There need to be some modification of the HVDC values to convert the system to MVDC. Now we discuss what values need to change to make the system MVDC and then analyze the results and design a protection system for short circuit faults.

First, change the phase-to-phase voltage, which is very high in the case of HVDC. MVDC Transmission is a new concept that usually operates in the range of 15 to 50 kV and 30 to 150 MW capacity. It is an alternative to AC interconnection to provide power to remote communities, as shown in Figure 4.4.

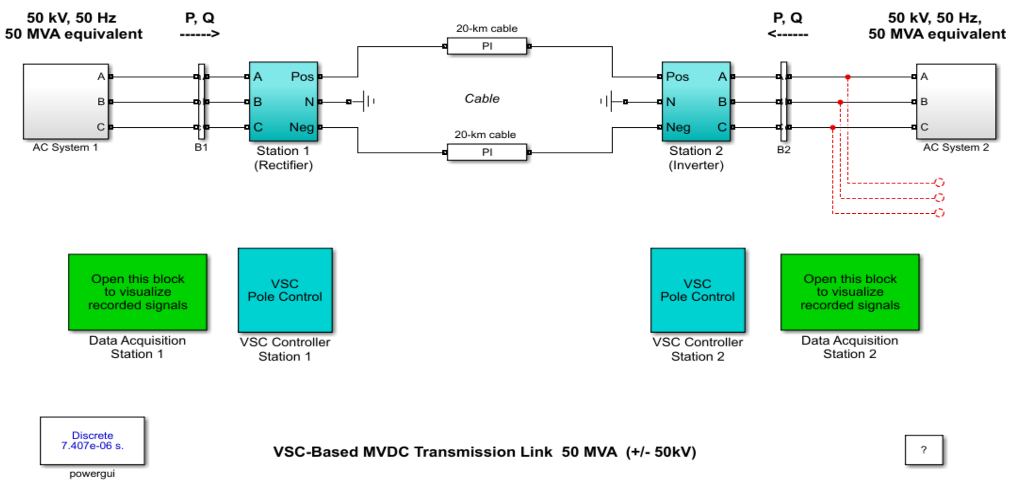


Figure 4.4 VSC-Based MVDC Transmission link 50 MVA

Three-phase transformer values must also be changed. Nominal power has changed from 230 to 50 MVA. The phase-to-phase voltage 1 parameter and phase to phase Voltage 2 parameters are 50 and 25, respectively. The rectifier and inverter three-phase transformer should have the same values. The transmission length is very high, which is not suitable for MVDC, so it is better to reduce it from 75km to 20km. The step time is set to 0.3. The inside of a converter station is shown in Figure 4.5.

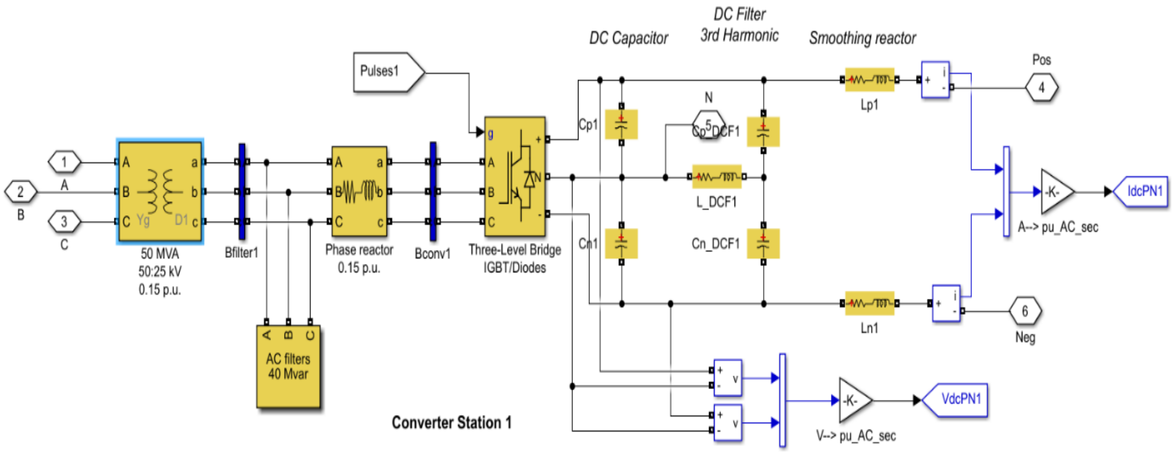


Figure 4.5 inside of a converter station 1.

Three-phase transformer values are also changed to be compatible with MVDC. Nominal power has been changed from 200 MVA to 50 MVA, phase to phase voltage for winding 1 from $230e^3$ to $50e^3$And phase to phase voltage for winding 2 from $100e^3$ to $25e^3$. Switching times of the short circuit fault is also changed from [(0 0.12) + 2.1] *100 to [1 1.5].

Now, all the values from HVDC are changed to MVDC. It is time to run the program, but before that, let's add some more blocks to design a protection system. 6 ideal switches are added, 3 in AC system 1 and 3 in AC system 2. Ideal switches have a gate port, so the command must be given to it from the protection system. There are 2 conditions which are as follows

- 1 if the breaker closed
- 0 if the breaker is open

But for now, adding the constant 1 to the signal of all the 6 switches. After analyzing the system's behavior with different faults, we can add a relay instead of the constant 1.

A current measurement device needs to be connected in series to measure the current in each phase; as we need the RMS current, so RMS block is also attached. Scopes and digital displays are connected to the output of RMS to get the results in a more detailed way for analyzing them deeply. The same is also done on the AC system 2. The overall system would look like this (Figure 4.6).

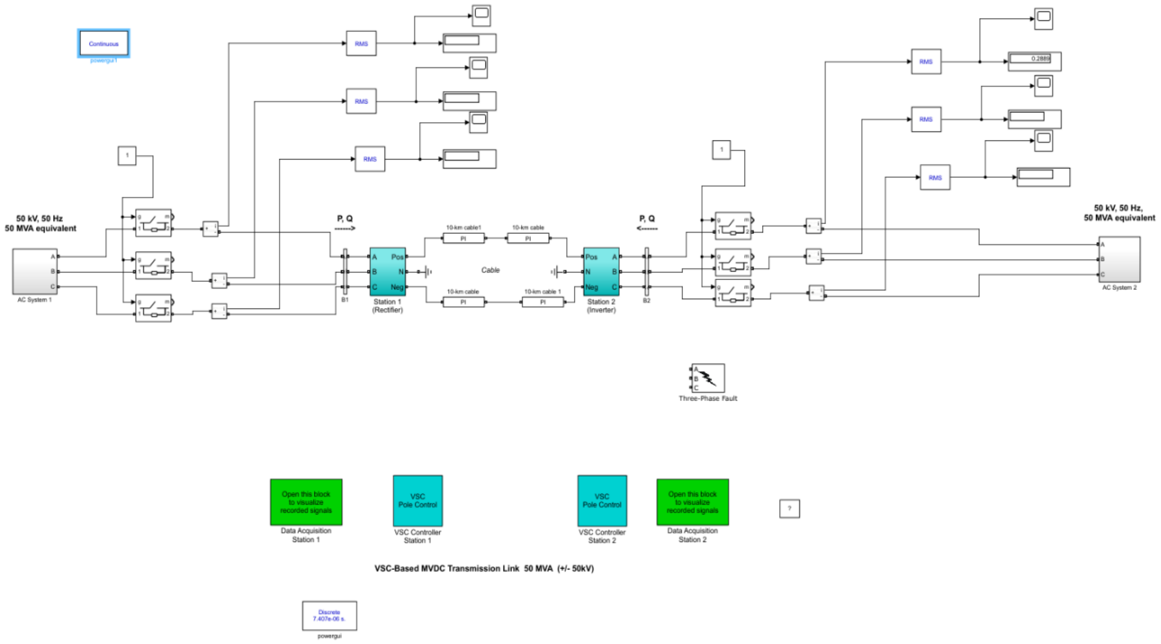


Figure 4.6 VSC Based MVDC system

There is one more important block that needs to be explained which is, The powergui. It solves the equations involves in the system blocks. There are different modes in powergui, but we are going to use continuous mode.

Now It is time to run the model and analyze the system without short circuit faults.

4.1 Without short circuit fault

4.1.1 Bus station 1:

The result shows 5 parameters: measured voltage (pu), measured power (pu), reactive power (pu), voltage measurement (pu), and current measurement (pu).

Umeas (pu): Measured Voltage is in per unit that should come as close to 1 as possible. And it is very close to 1, which is what we want. We can also see a change on 0.3, which is step time in the block diagram. And the output values took some time to become stable.

Pref (pu): The constant value for measured power or reference power has been set to 0.3. The step time for Pref has been developed to 1.5*1 as we can see that the second change occurs on 1.5. the initial and final values are 0 and -0.5, respectively, inside the Pref block.

Qref (pu): the block parameters of the Qref have two-step times. One is the Pref that we set to 1.5*1, and the second one selected is 2.0*1. The initial and final values are 0 and -0.1, respectively.

Voltage (pu) is per unit voltage, and Current (pu) is per unit current. Voltage shows a continuation throughout except a slight change during the step-change time. Current is low before the step change, but it goes high instantly and manages to be in normal condition afterward.

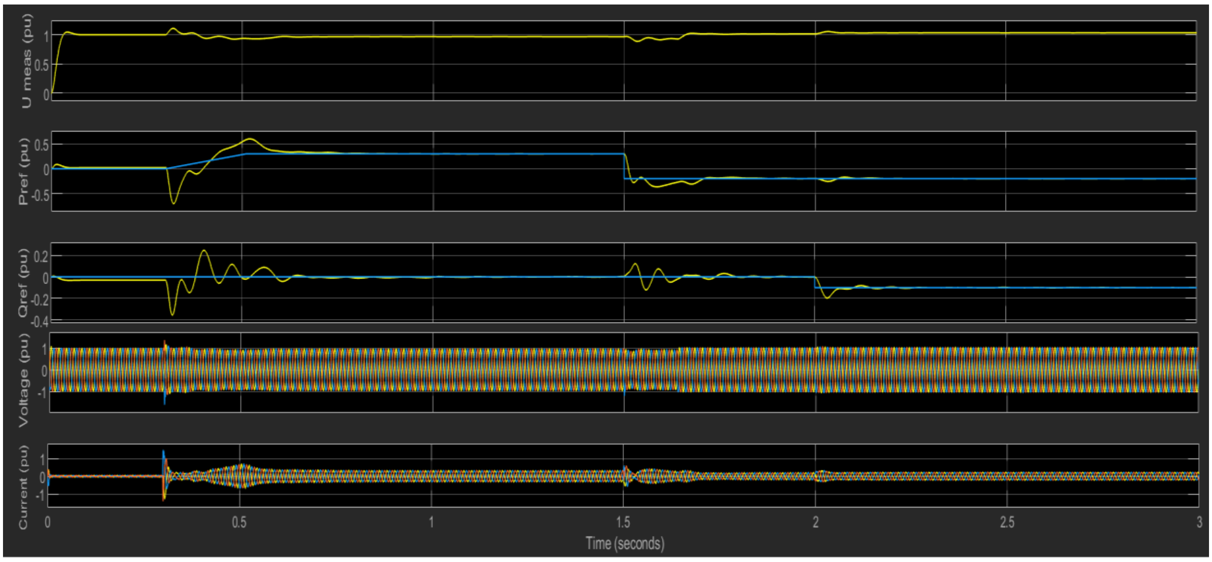


Figure 4.7 (a) Recorded signals in Bus station 1.

4.1.2 Bus station 2:

Bus station 2 should show similar results as bus station 1, but , some minor differences need to be discussed.

Let's analyze Figure 4.7 (b) in detail.

Umeas (pu): The per-unit measured voltage in sub-station 2 shows almost the same behavior as sub-station 1 with minor differences. There is a slight instability at approximately 0.2 seconds to about 0.4 seconds which wasn't happening in sub-station 1. But this change is so tiny; it can be ignored.

The measured voltage is stable after 0.5 seconds and almost equal to 1 per unit volt throughout the simulations. This behavior is almost the same as bus station 1. The duration of the simulation is chosen manually. It's possible to change it when the results need a more extended period of implementation.

Pref (pu): The per-unit reference power is different in sub-station 2 compared to sub-station 1. The reference power is the combination of per unit measured power and per unit ramped reference power in sub-station 1, but the input of sub-station 2 has only measured power. The inputs of bus stations 1 and 2 can be found in Figure 4.7 (b.1) and Figure 4.7 (b.2), respectively.

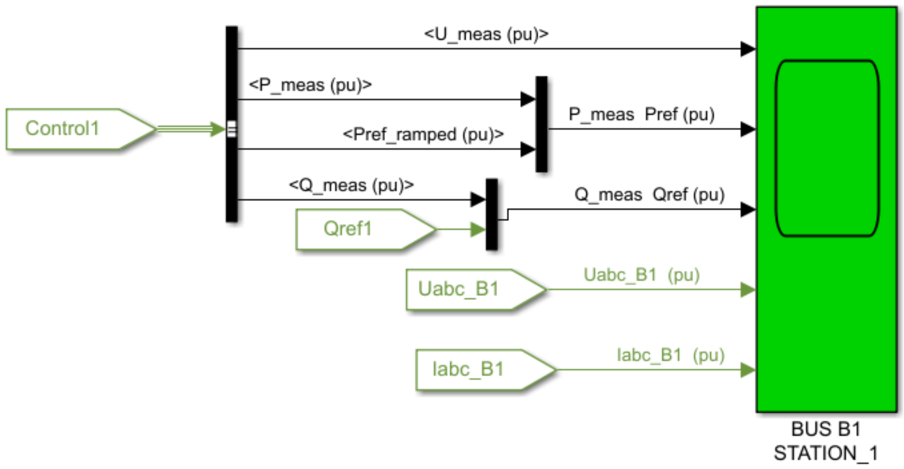


Figure 4.7 (b.1) Bus station 1

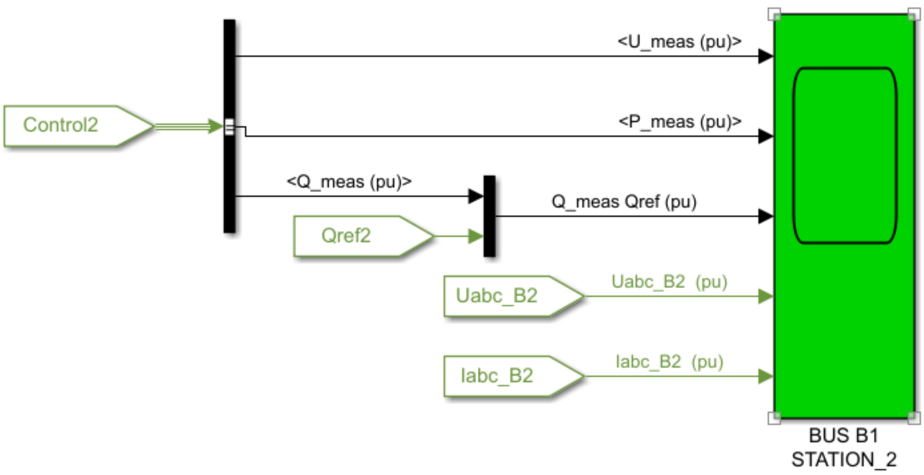


Figure 4.7 (b.2) Bus station 2

Figure 4.7 (b) shows that the reference power starts at 0, and when it reaches approximately 0.2 seconds, it starts fluctuating until it reaches approximately 0.4 seconds. After this point, the reference power goes below zero-till reaches 1.5 seconds; moreover, when it crossed this point, it becomes positive and shows stability.

Qref (pu): Per unit reactive reference power in bus station 2 shows almost the same behavior as bus station 1. The only difference is that Qref (pu) becomes unstable at approximately 0.1 seconds in bus station 2, and bus station 1 shows fluctuation at the step time.

Voltage (pu): it shows the same behavior as bus station 1.

Current (pu): The bus station 1 and 2 is almost identical except, the fluctuation of the current starts before the step time in bus station 2, not after step time as in case of bus station 1.

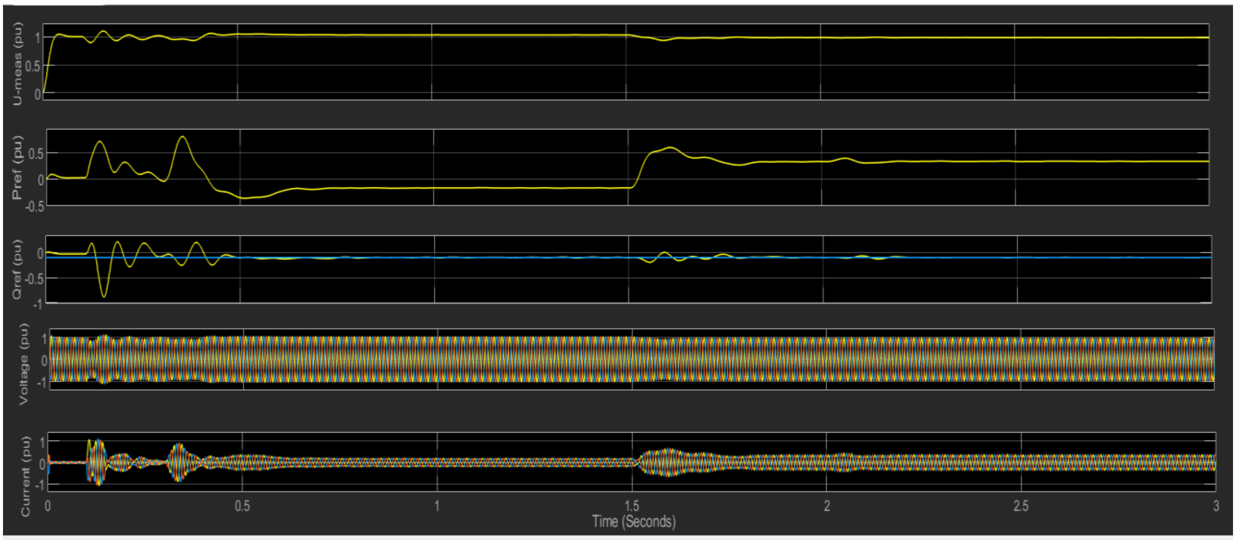


Figure 4.7 (b) Recorded signals in Bus station 2.

4.1.3 Direct current (pu):

Station 1:

Now let us analyze what happened on the DC side. The DC output can be taken from IdcPN1, which is inside the station 1 rectifier. The scope must be connected in series with IdcPN1 to get the output result.

The measurement part is IdcPN1 which contains the positive and negative measured currents. The currents are in per unit. The maximum per-unit positive current is approximately 0.45 amperes, and the per-unit negative current is approximately -0.58 amperes that can be seen in Figure 4.8 (a). These values are beneficial for determining the protection system. We can also see that there is a coherency between DC and AC currents. When DC increases on 0.3, AC also increases.

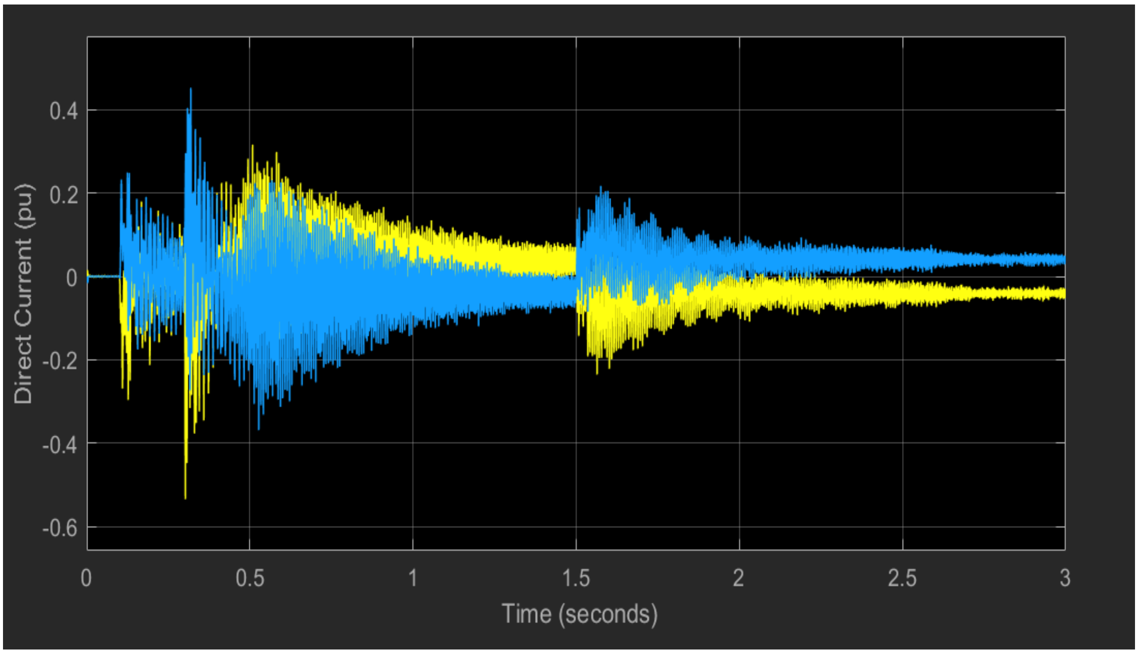


Figure 4.8 (a) positive and negative Direct Currents (Station 1)

Station 2:

The currents have been reversed, but overall results in both bus stations are the same. It can be seen in Figure 4.8 (b).

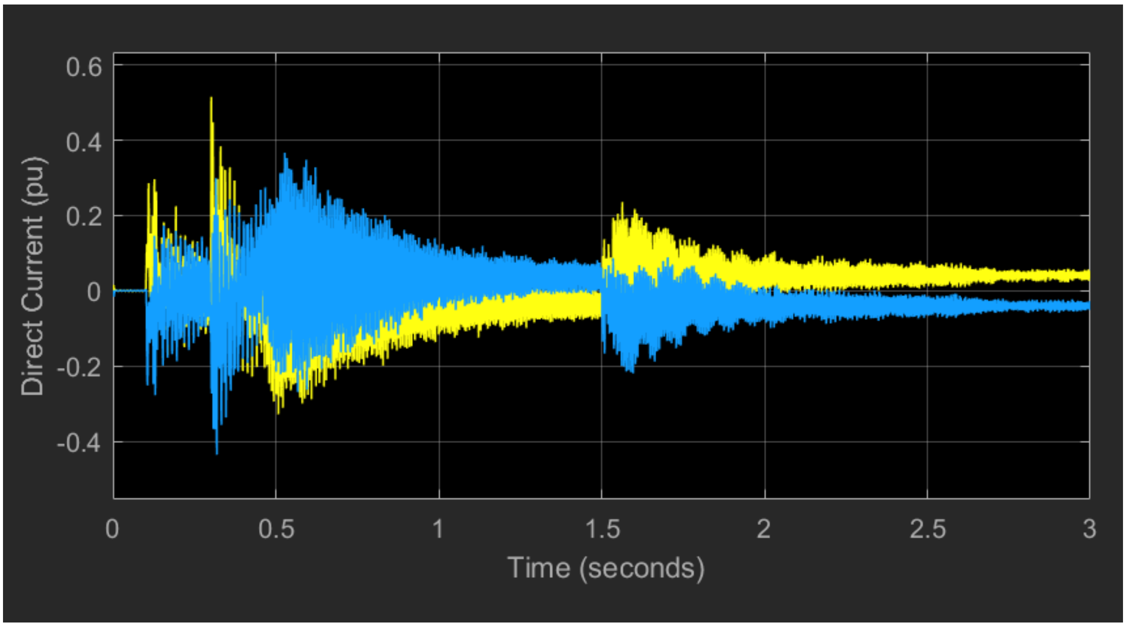


Figure 4.8 (b) positive and negative Direct currents (Station 2)

4.1.4 DC Voltage:

DC Voltage starts from zero and reaches to 1 for positive voltage and -1 for negative voltage after a short duration and it becomes constant after step change. Dc measured voltage (pu) is the same as the positive voltage obviously. Last but not the least also starts from zero but drops below zero and fluctuates till step change. After this point and increases and becomes constant from approximately 0.5 to 1.5. then it drops again and maintains it behavior throughout.

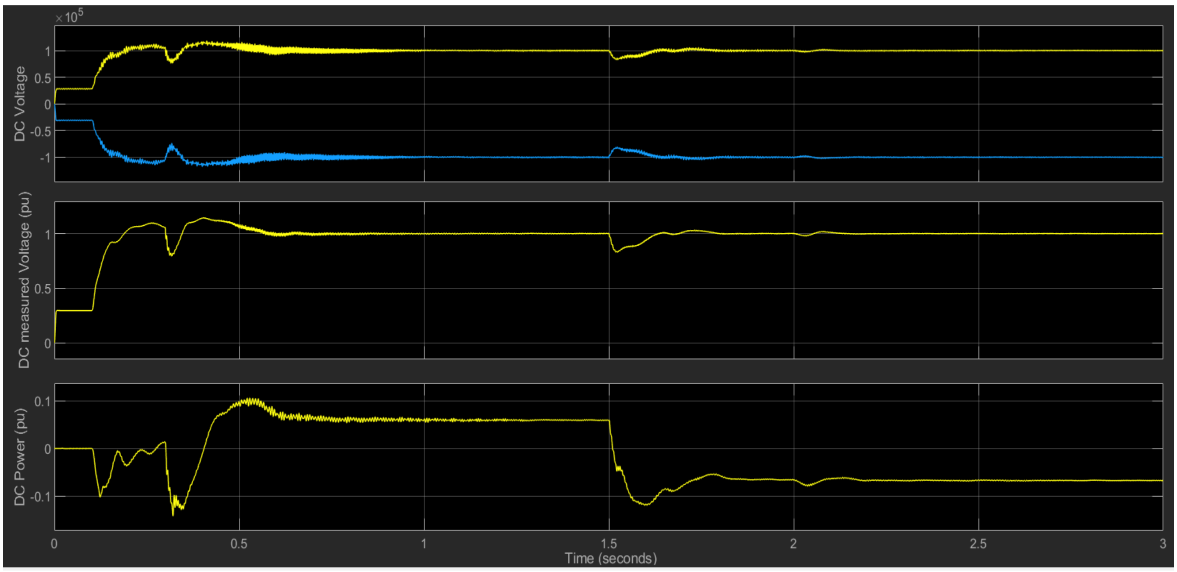


Figure 4.9 (a) DC Voltage (station 1)

DC voltages for station 1 and 2 shows the exact same behavior. DC Power (pu) in station 2 is exactly opposite to station 1.

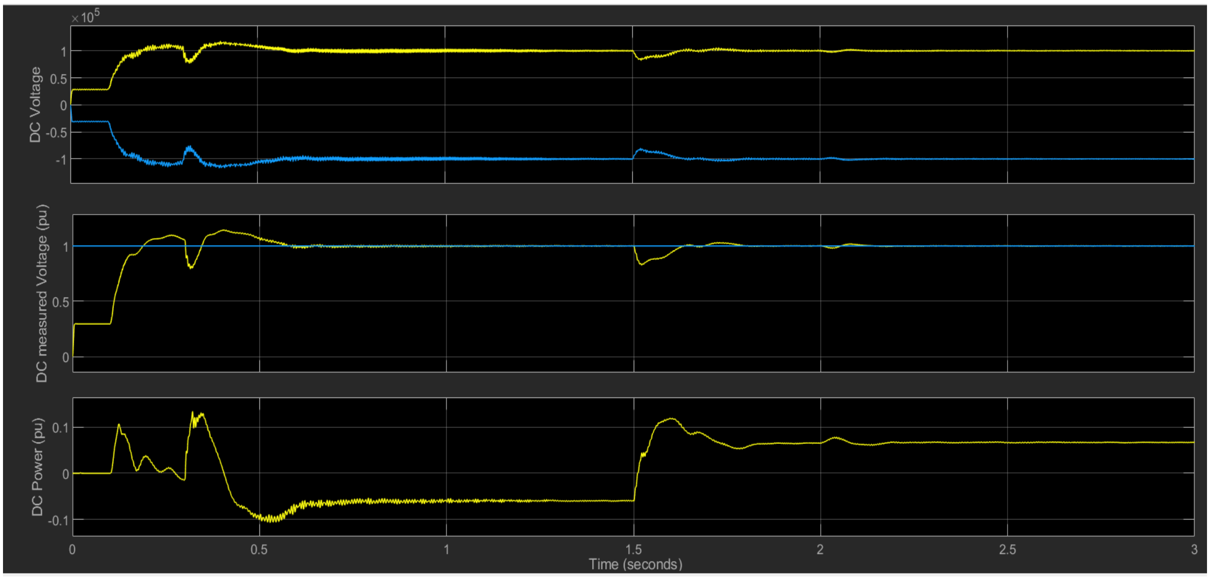
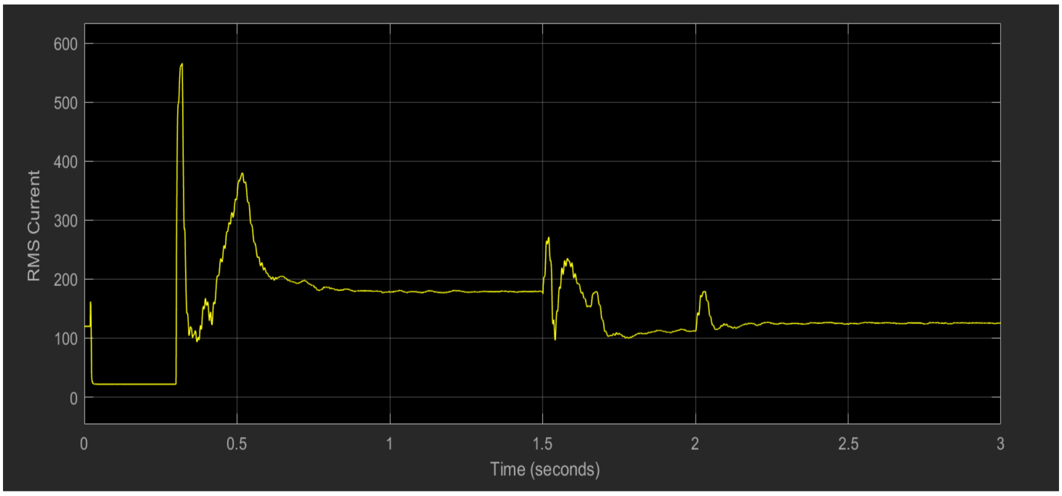


Figure 4.9 (b) DC Voltage (station 2)

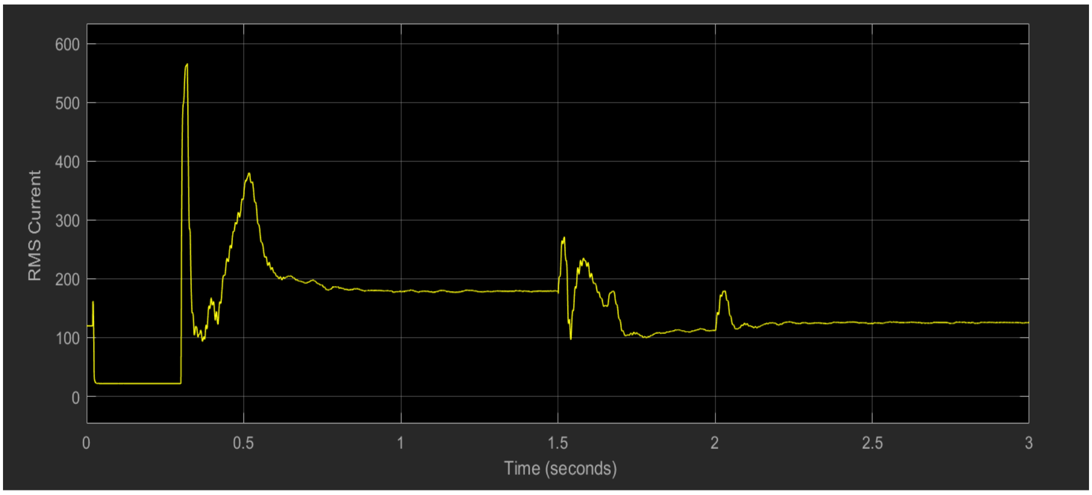
4.1.5 The RMS currents in each phase:

There are two ways to measure the RMS current. The first is to use a digital display to show the current digitally while simulating the system, but the problem is that the current keeps changing, so the high value of the current is so hard to catch. The second way is to use a scope block which shows the current in a graph. It's easier to find the exact point of the current. We are going to use both.

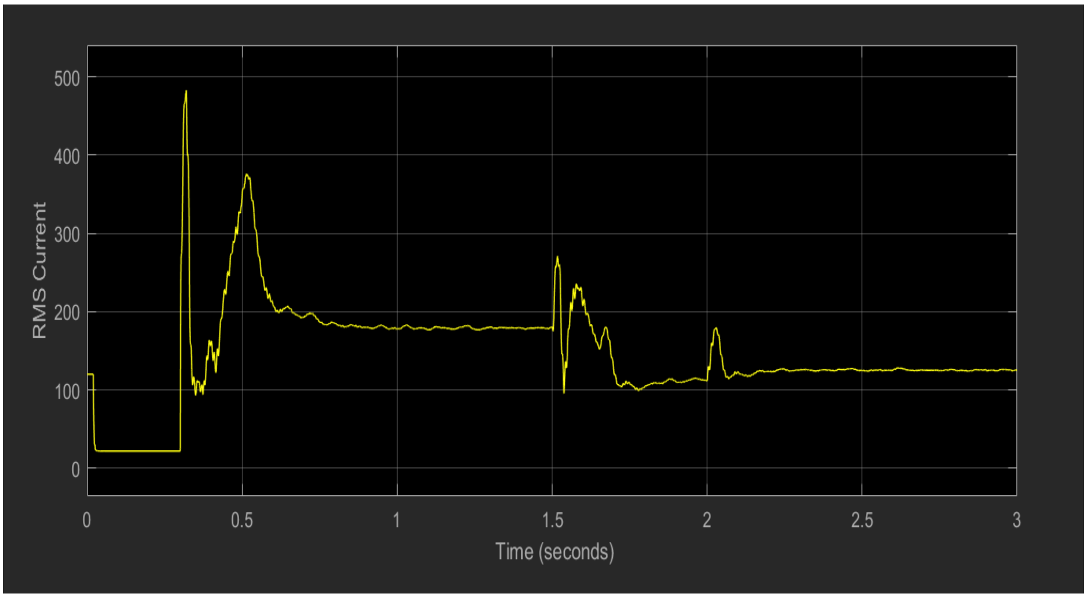
From switches 1,2, and 3, we can analyze that the RMS current without a short circuit can go as high as 566, and almost all the phases show identical behavior. The behavior of each switch can be found below.



RMS current (Switch 1)

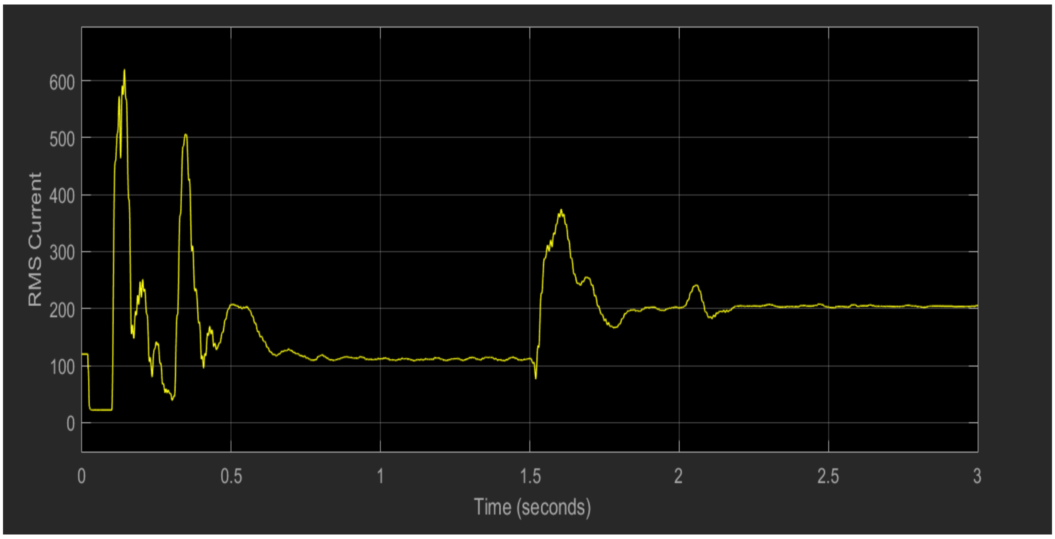


RMS current (Switch 2)

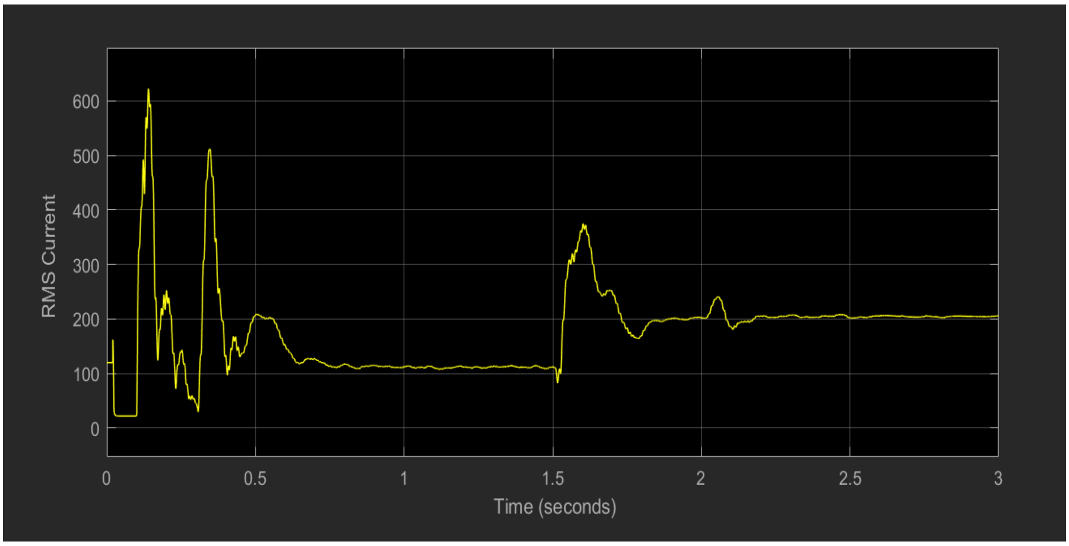


RMS current (Switch 3)

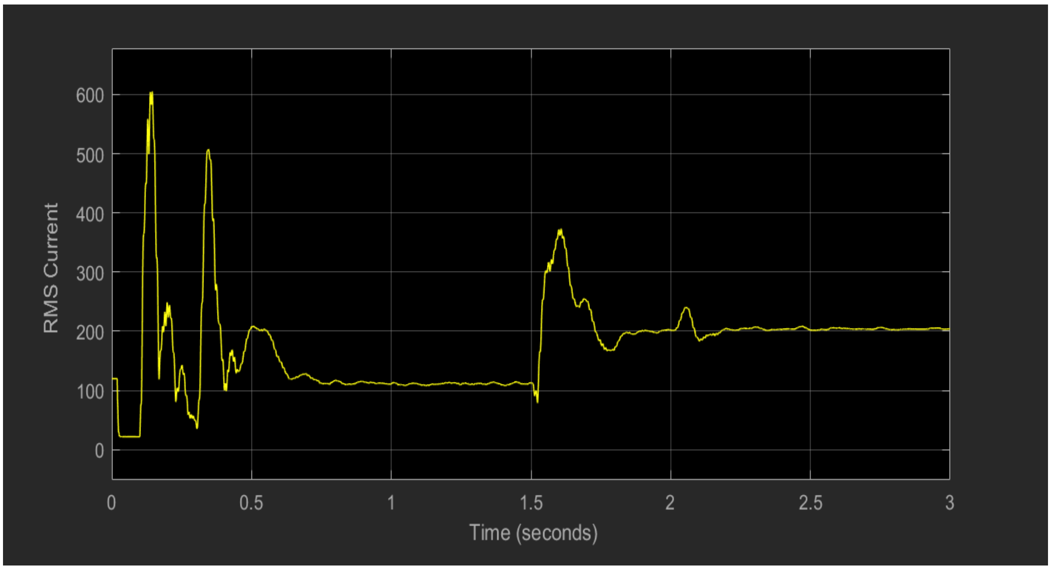
From switches 4,5 and 6, we can conclude that the highest point that a current reaches without a short circuit would be approximately 622, which is slightly higher than the switches on the AC system 1. These values can give a hint of choosing a reference value for the protection system.



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (Switch 6)

Table 4.0 shows the highest RMS current of each switch. RMS currents on the AC side 2 are higher than AC side 1.

Table 4.0

Ideal switches	RMS current
Ideal switch 1	527
Ideal switch 2	566
Ideal switch 3	482
Ideal switch 4	620
Ideal switch 5	622
Ideal switch 6	605

4.2 With short circuit faults

Under ordinary conditions, the current and voltage flow typically without affecting or damaging the equipment, resulting in safer operation of the system, but when the fault occurs, the current and voltage show an excessive amount of flow, which causes damage to equipment and devices. The fault detection and analysis of the system are vital to design the circuit breakers, relay, or other protection devices.

There are mainly two types of faults in the electrical power system: symmetrical and unsymmetrical faults.

4.2.1 Symmetrical Faults.

Symmetrical fault rarely occurs in practice as most faults are unsymmetrical. The symmetrical fault is the most severe and imposes more heavy duty on the circuit breaker. It comprises three short-circuited lines with an earth connection at the fault (L—L—L—G) or all three short-circuited lines (L—L—L).

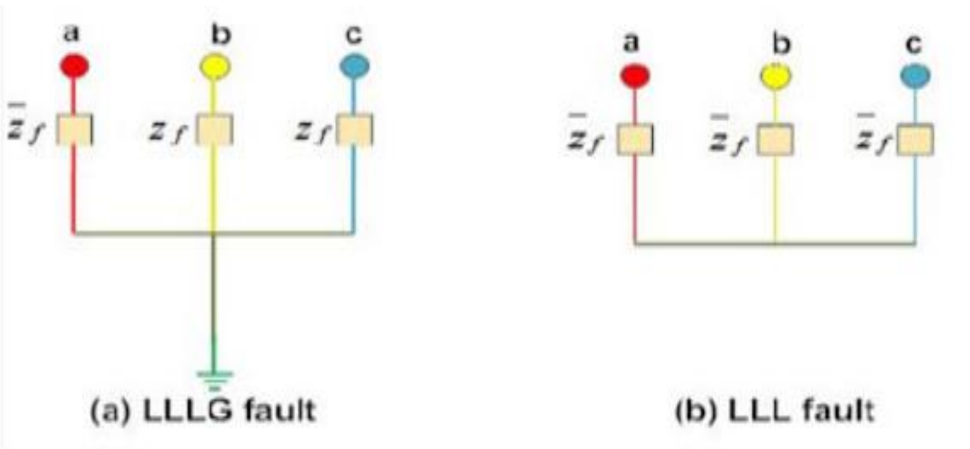


Figure 4.10 Types of symmetrical faults

i. Three-phase short-circuited with an earth connection fault or L-L-L-G fault

When this fault occurs, the overall system looks like this, shown in Figure 4.11.

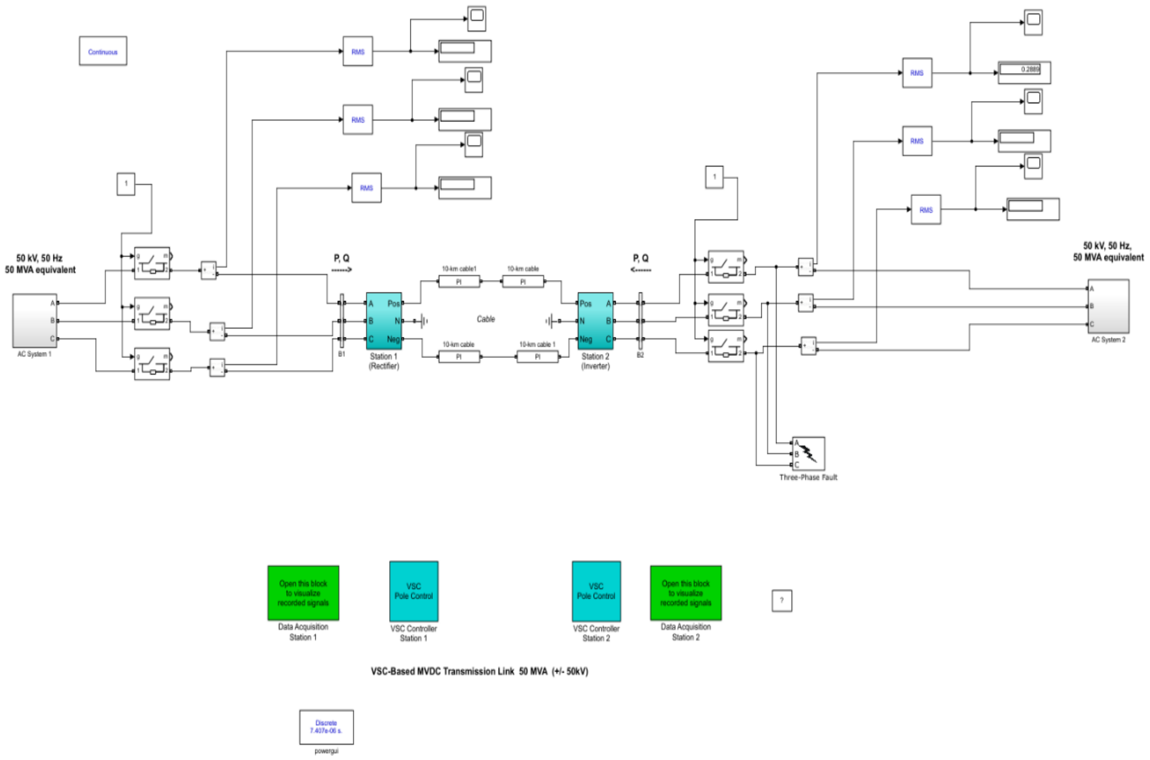


Figure 4.11 three-phase short-circuited with an earth connection

The block parameters of the three-phase fault can be changed according to the requirements, so we need to have a line-to-line-to-line-to-ground fault, so we have selected phase A, phase B, phase C and the ground as shown in Figure 4.12.

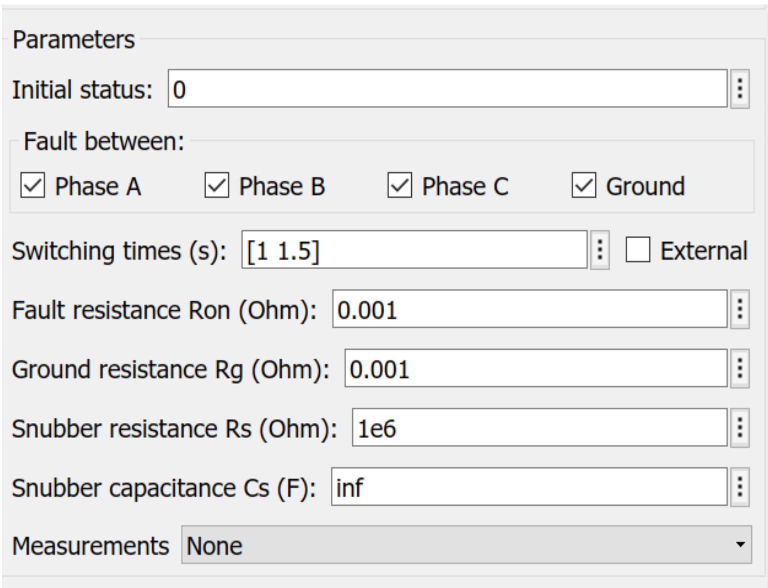


Figure 4.12 Three-phase fault block parameters.

Switching times are critical. So, the switching times are [1 1.5]. It means after 1 and 1.5; we are simulating the fault. So initially, there is no fault in the system, but when you reach point 1 or 1.5 seconds, the fault occurs. We can see that there is a fault resistance. We also know that there is no resistance and high current flow when there is a short circuit, but a regular wire has some resistance; that is why 0.001 is significantly less resistant.

Bus Station 1:

The result shows some significant differences, as shown in Figure 4.13 (a).

Umeas (pu): We can see almost no change with or without short circuit events. It follows the same pattern as without a short circuit fault event. It starts from 0, reaches 1, and is constant throughout, but there is a fluctuation in 0.3 due to step time. The change in 1.5 is due to the three-phase short circuit fault.

Pref (pu): the reference power changes due to the short circuit fault after 1 and 1.5 seconds.

Qref (pu): between 1 to 2 seconds, there is an increase in the reactive power. It increases both positive and negative sides.

Voltage (pu) and Current (pu) also show some changes, but they need to be zoomed in to see the differences. Due to the L-L-L-G fault, the current values have been increased, which can be a concern for our devices.

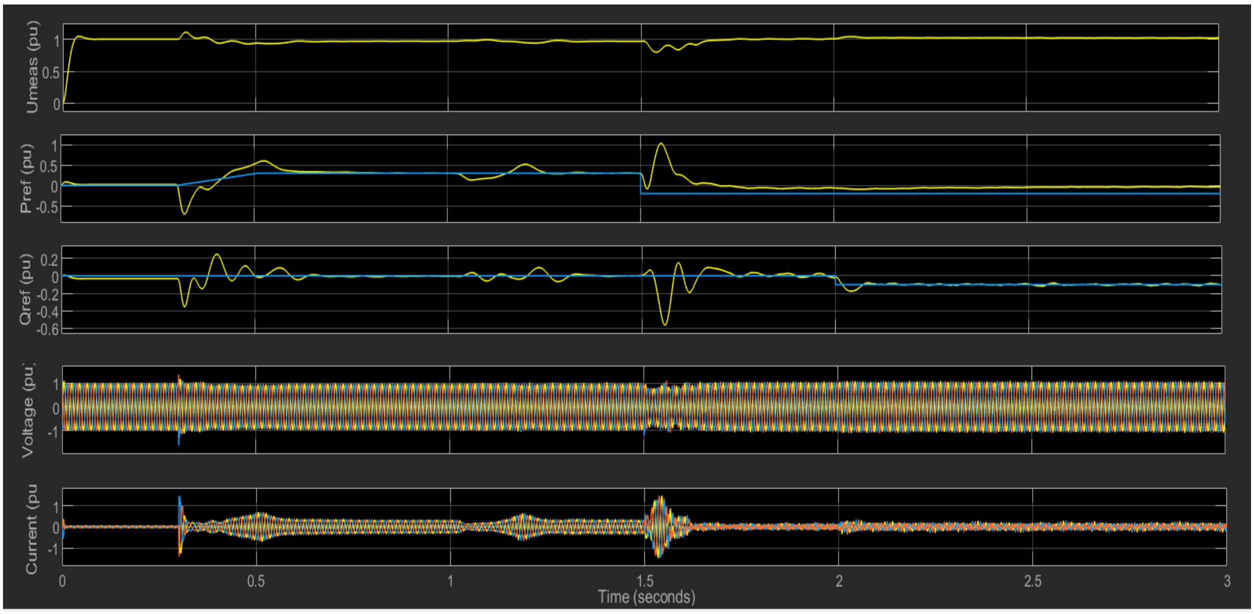


Figure 4.13 (a) L-L-L-G fault (Bus Station 1)

Bus station 2:

The only point is to be discussed here is the time between 1 and 1.5 seconds which is the time when the fault is commanded to occur. When there is a short circuit fault, the voltage goes to zero, and the current goes very high. The fault is on AC side 2, so the quantities in station 2 are highly affected. The voltages are zero while the current goes very high, as shown in figure 4.13 (b).

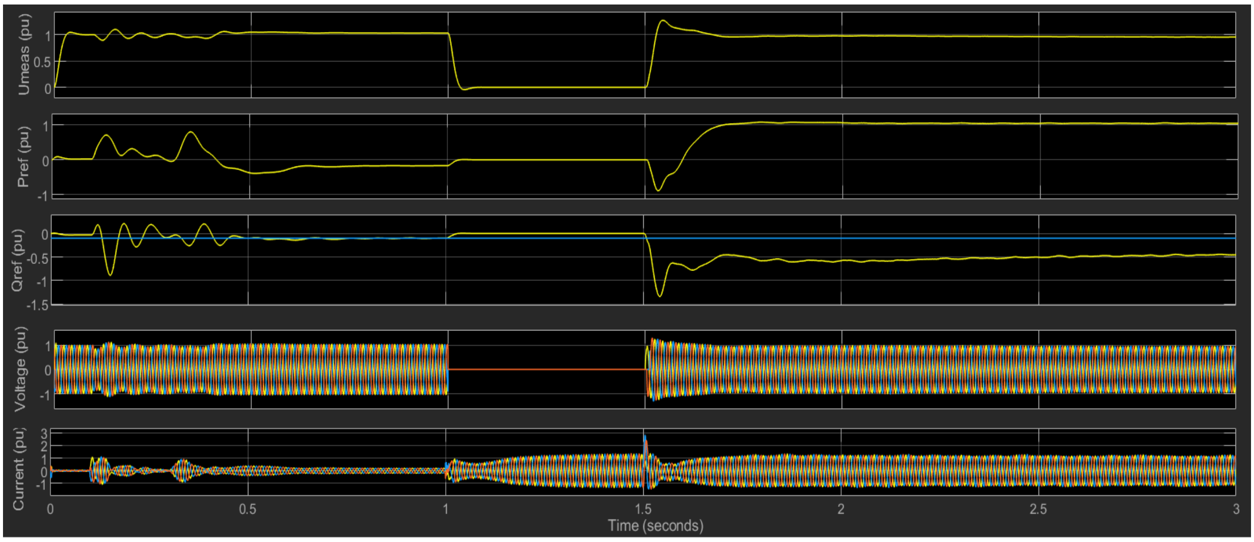


Figure 4.13 (b) L-L-L-G fault (Bus Station 2)

DC Voltage:

Station 1

DC voltages are affected when there is a fault as it can be seen from the figure 4.14 (a). The fault starts from 1 second. There is a significant change after that in the DC voltages which is completely unstable.

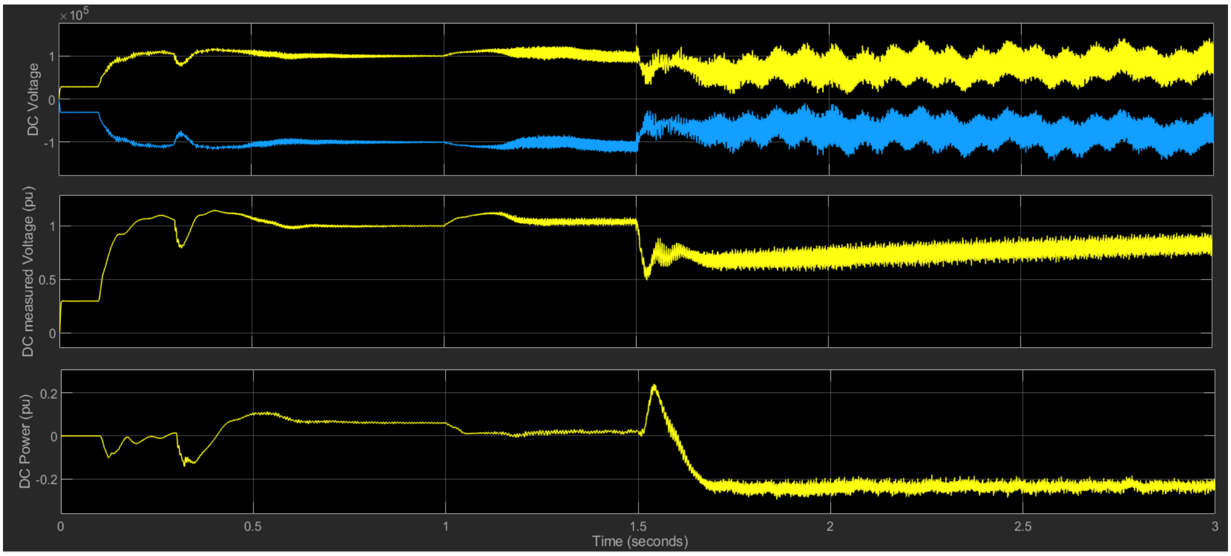


Figure 4.14 (a) DC Voltage (station 1)

Station 2

DC voltages on station 2 shows almost the same results as station 1 but the latter case has more intensity in the voltages. The DC power is as expected is totally opposite as compared to station 1.

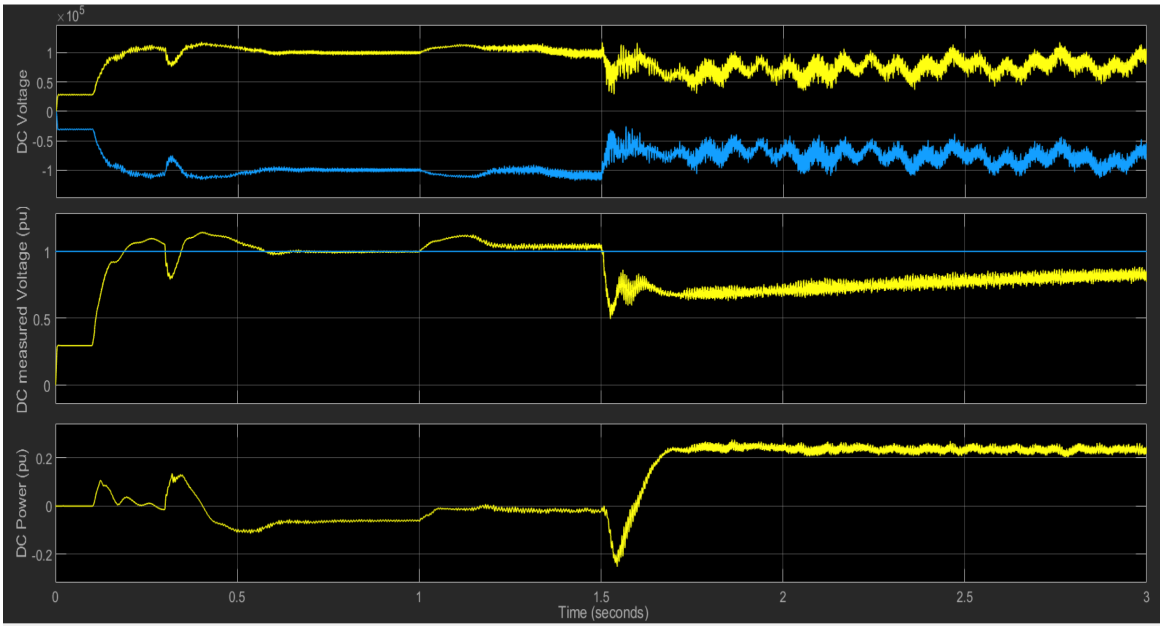


Figure 4.14 (b) DC Voltage (station 2)

Direct Current (pu):

Station 1

The positive current is approximately 1.5 amperes, which is almost four times the current without a short circuit fault. The negative current also spikes to approximately -1.5, which is also very high compared to DC without a short circuit current. The results of DC also show the coherency here.

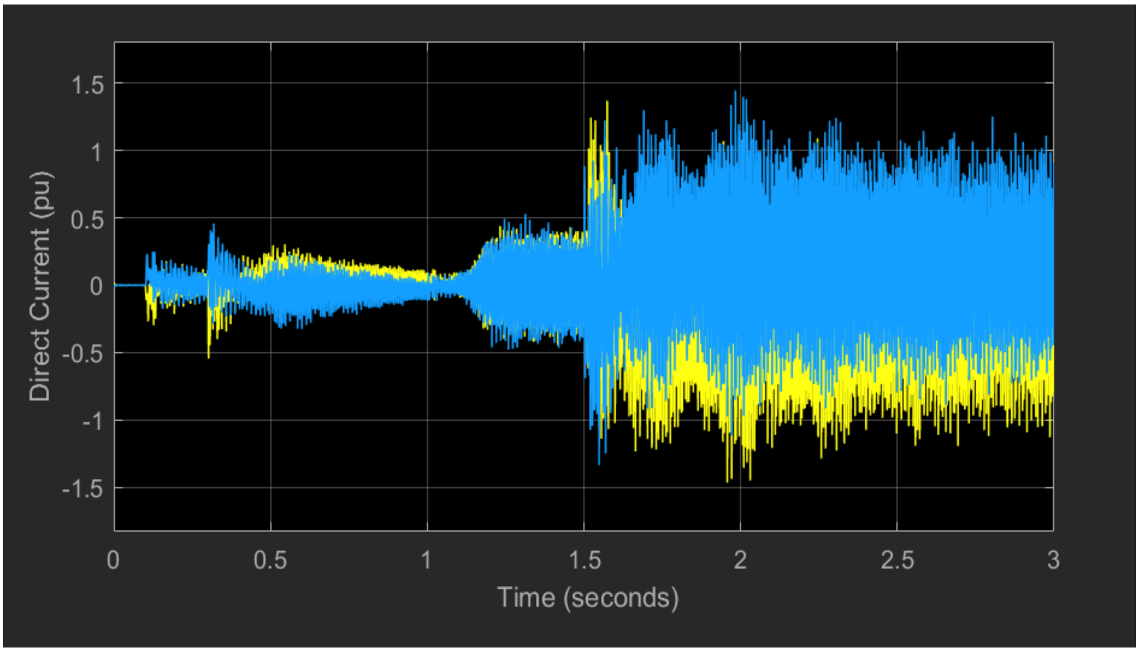


Figure 4.15 (a) Positive and negative Direct current of L-L-L-G fault (station 1)

Station 2:

Station 1 and 2 show the same behavior, but the current in station 2 is a bit higher and reversed currents.

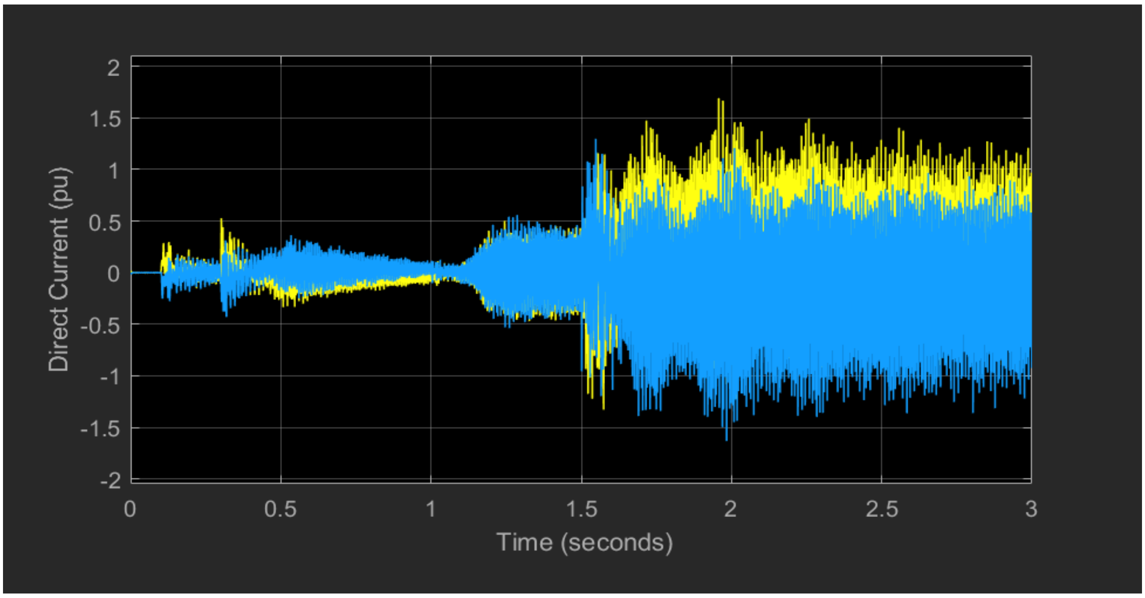
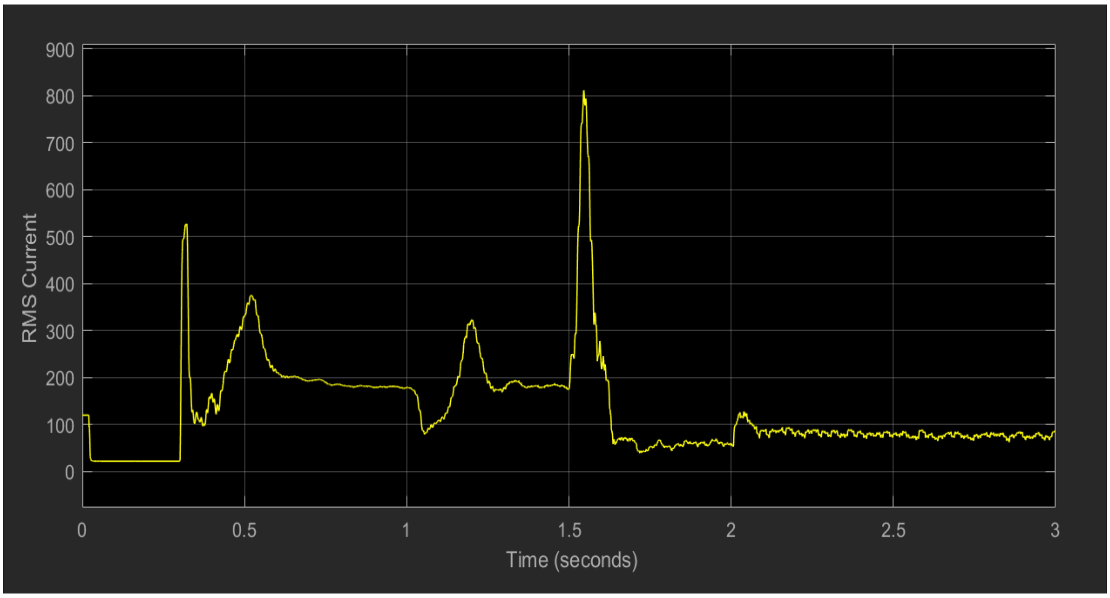


Figure 4.15 (b) Positive and negative Direct current of L-L-L-G fault (station 1)

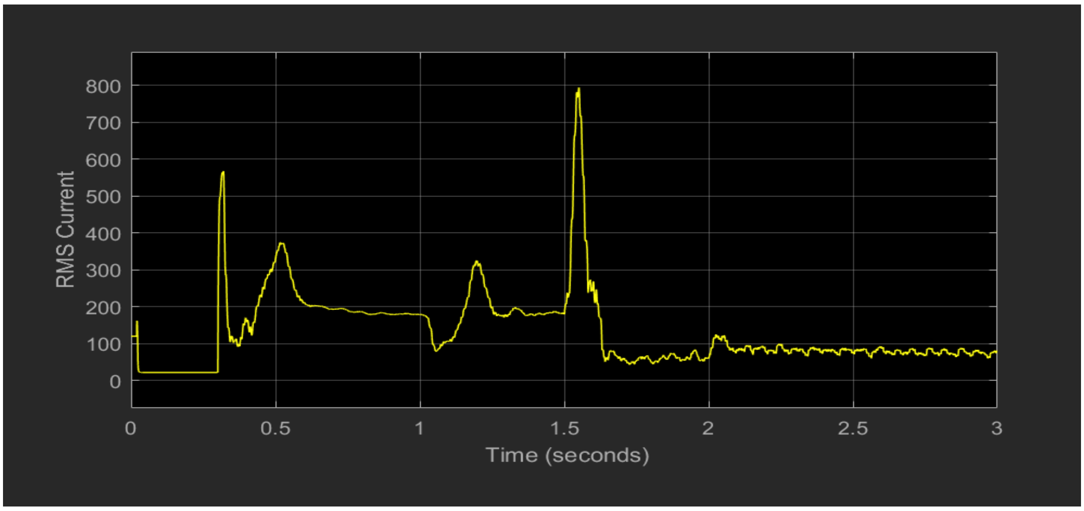
The RMS current in each phase due to the L-L-L-G fault is as follows.

Switches 1, 2, and 3 are shown below, respectively.

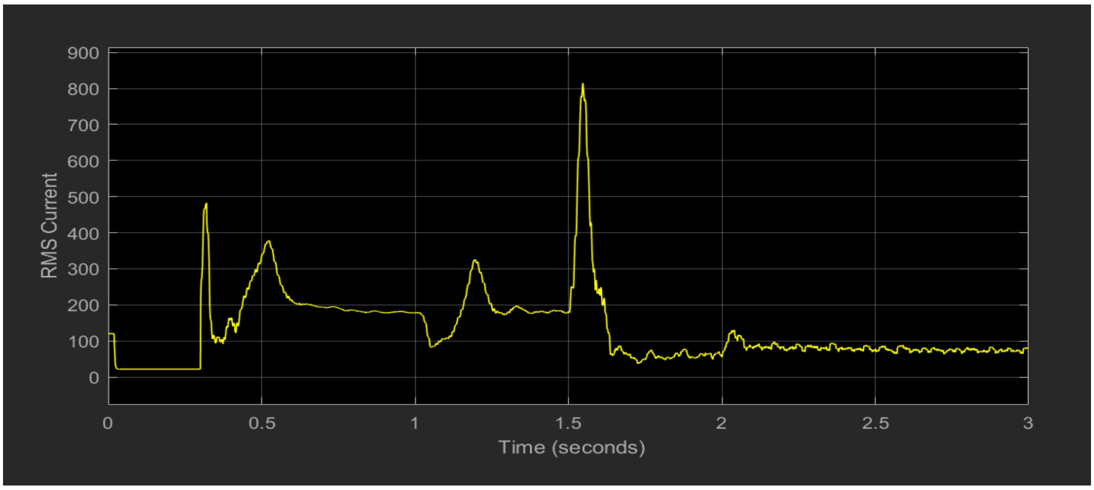
The maximum current that occurs due to the three-phase fault is approximately 815, which happens in switch 3 and appears on the second switch time (1.5).



RMS Current (Switch 1)

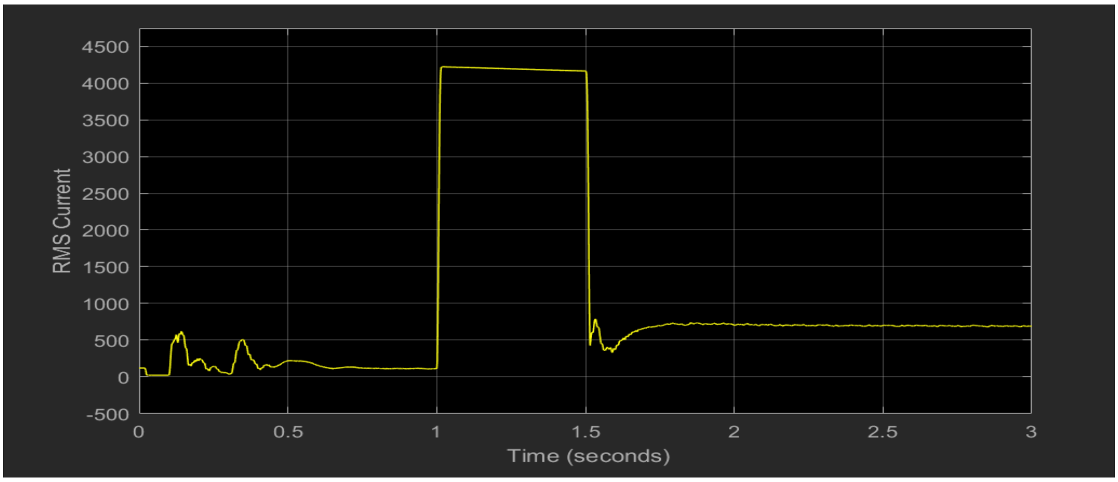


RMS Current (Switch 2)

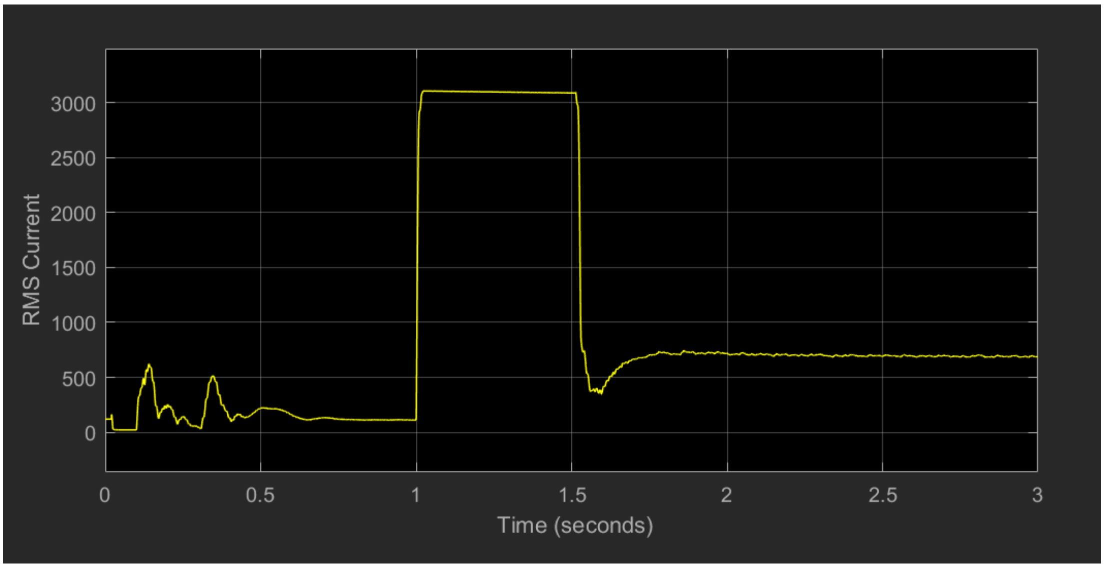


RMS Current (Switch 3)

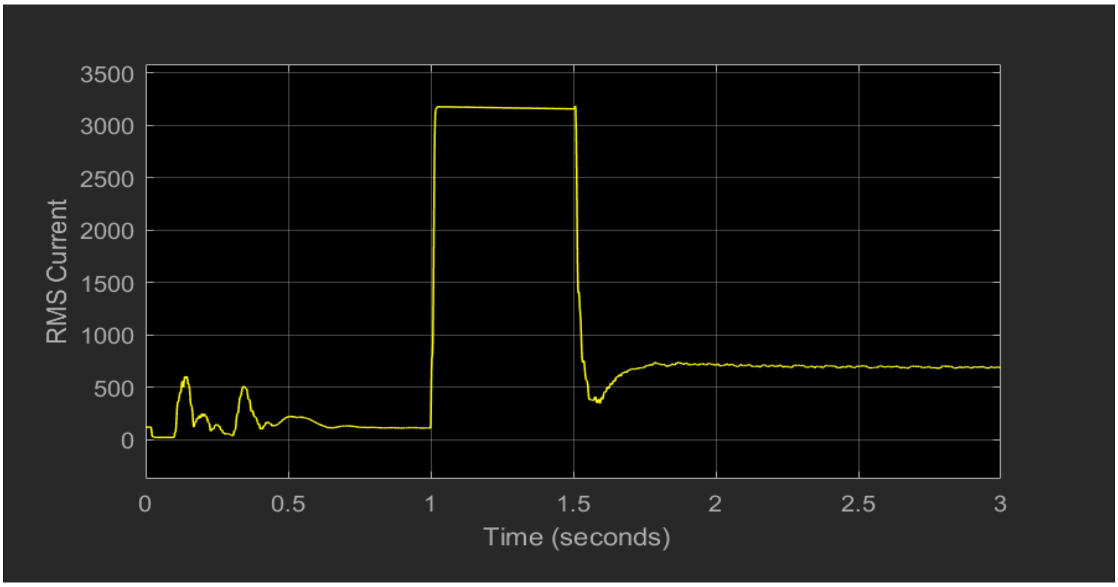
The graphs of Switches 4, 5, and 6 are as follows.



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (switch 6)

The current shoots up in the AC system 2. It goes as high as 4420, which is more than three times the current on the AC system side 1. This high current maintains its behavior from 1 to 1.5. For clearing, let's write the highest current due to the three-phase fault in Table 4.1.

Table 4.1

Ideal switches	RMS current
Ideal switch 1	810
Ideal switch 2	793
Ideal switch 3	815
Ideal switch 4	4420
Ideal switch 5	3100
Ideal switch 6	3177

We can say that the three-phase short circuit has massively impacted the current. It has increased from 620 (in normal condition) to 4420 (in faulty condition) in ideal switch 4.

The reason for this instability is obviously due to the fault but also because of the converter. In the case of a short circuit, the circuit behaves as a diode bridge; in fact, you can see the typical ripple of a diode bridge because if the DC voltage collapse, is not able to perform the switching. It becomes a diode bridge through the freewheeling diodes. A diode bridge is a reason that we can find the six-order ripple.

We come to the results of the L-L-L-G fault that when it occurs, the AC side 2 shows very high value because the fault is on that side, and it is not affecting that much on the AC Side 1. The RMS current is within 1000 amperes in AC side 1, and it goes above 4000 on AC side 2.

ii. Line to line to line (L-L-L) fault.

In this fault, all three lines are short-circuited with each other, so three-phase must be marked in block parameter of three-phase fault in the simulation. This kind of fault rarely occurs, but the result of this fault is very distractive so let's analyze them also.

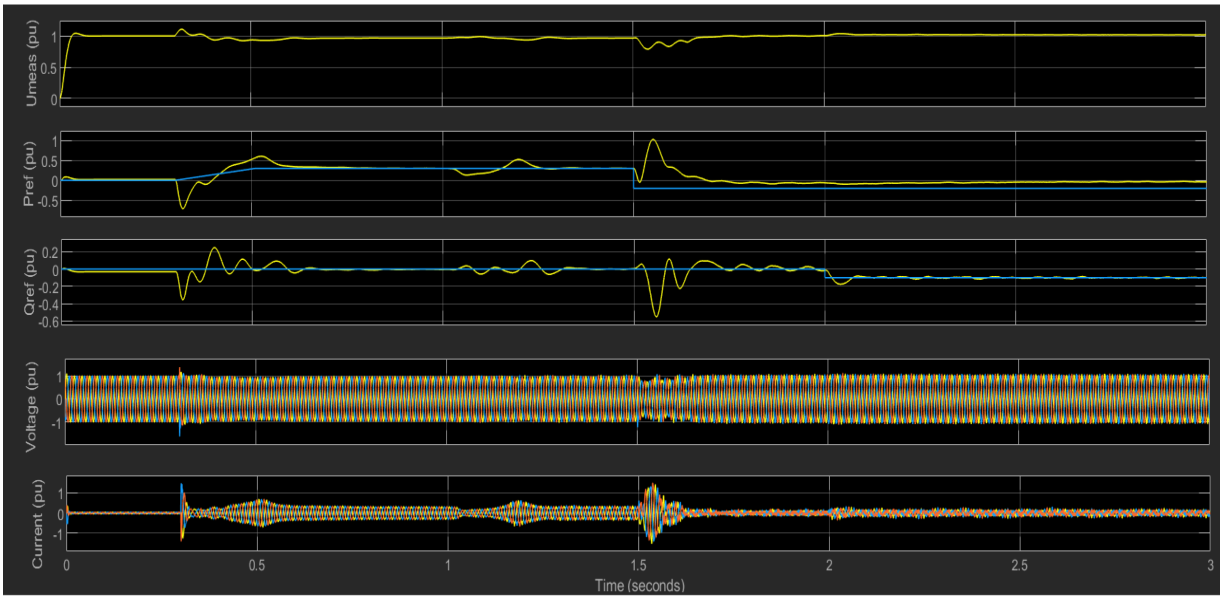


Figure 4.16 (a) line-to-line-to-line short circuit fault in Bus Station 1.

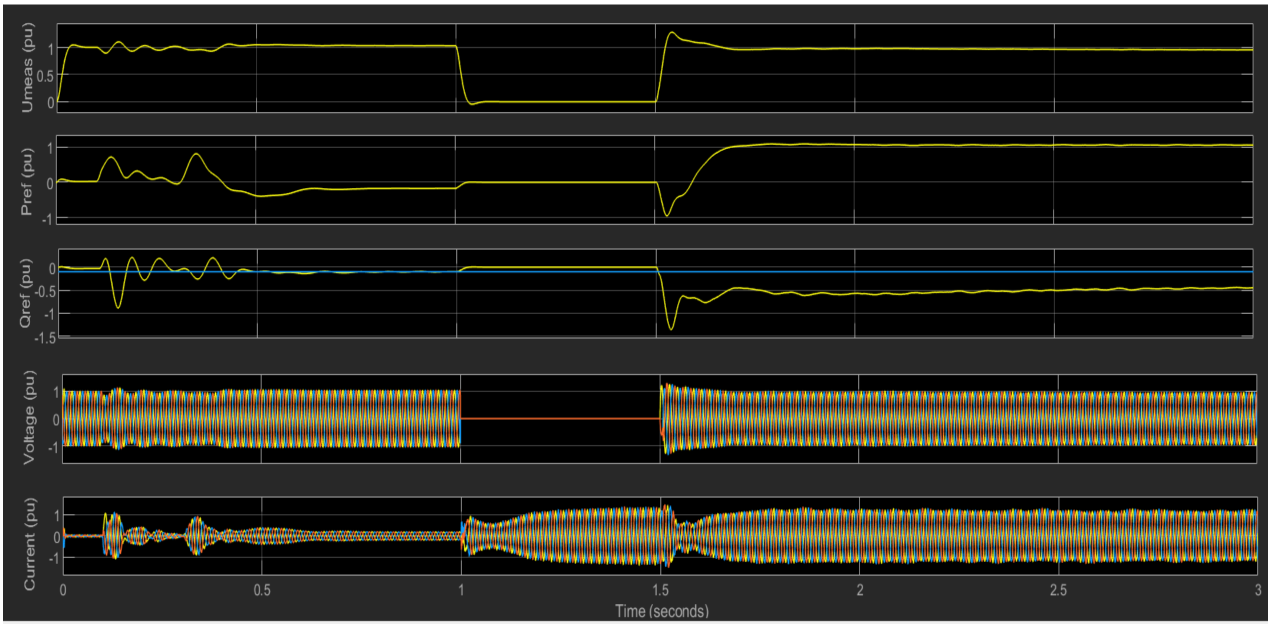


Figure 4.16 (b) line-to-line-to-line short circuit fault in Bus Station 2.

The results are precisely the same as three-phase short circuit faults because the magnitude of the load current is the same in all three phases with 120 deg phase displacement.

Now let's see if the DC side results are also the same as the three-phase short circuit fault.

Direct currents (pu):

The positive and negative DC results are almost the same as three-phase short circuit faults.

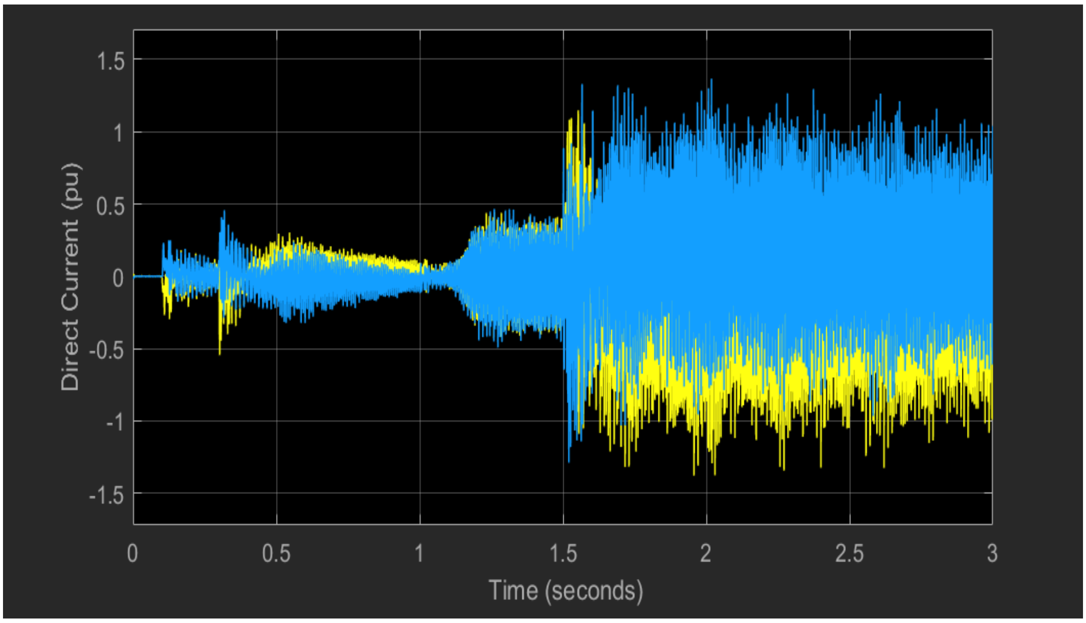


Figure 4.17 (a) Positive and negative DC of line to line to line fault. (station 1)

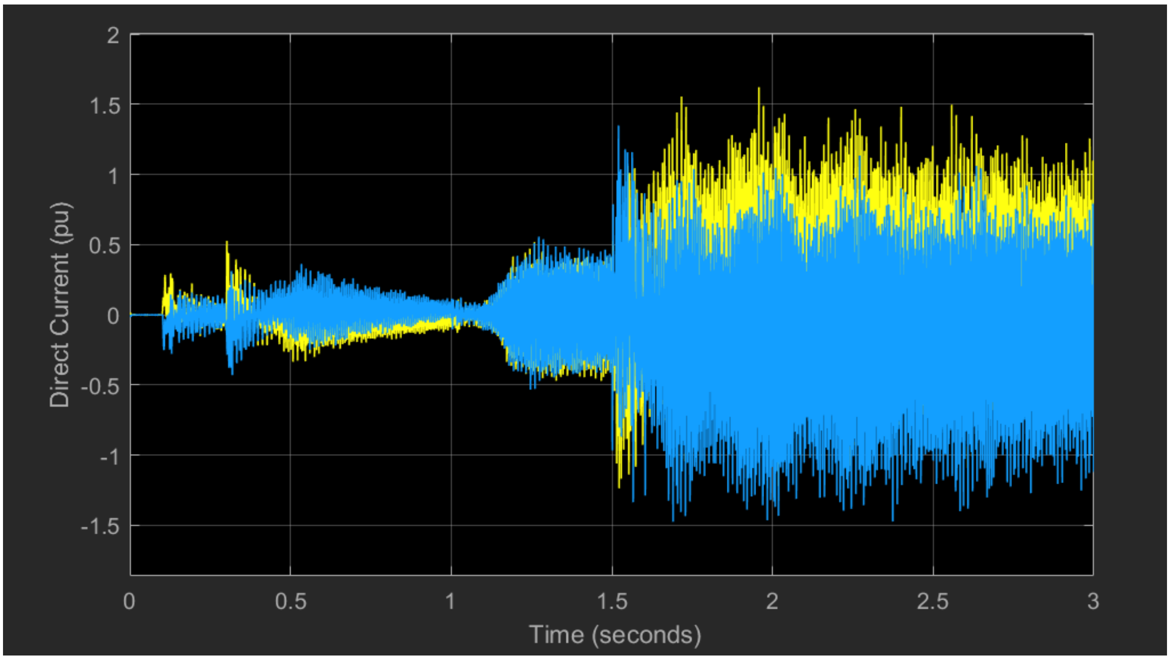


Figure 4.17 (b) Positive and negative DC of a line-to-line-to-line fault. (station 2)

DC Voltage:

Station 1 and 2 shows the same behaviour as L-L-L-G fault.

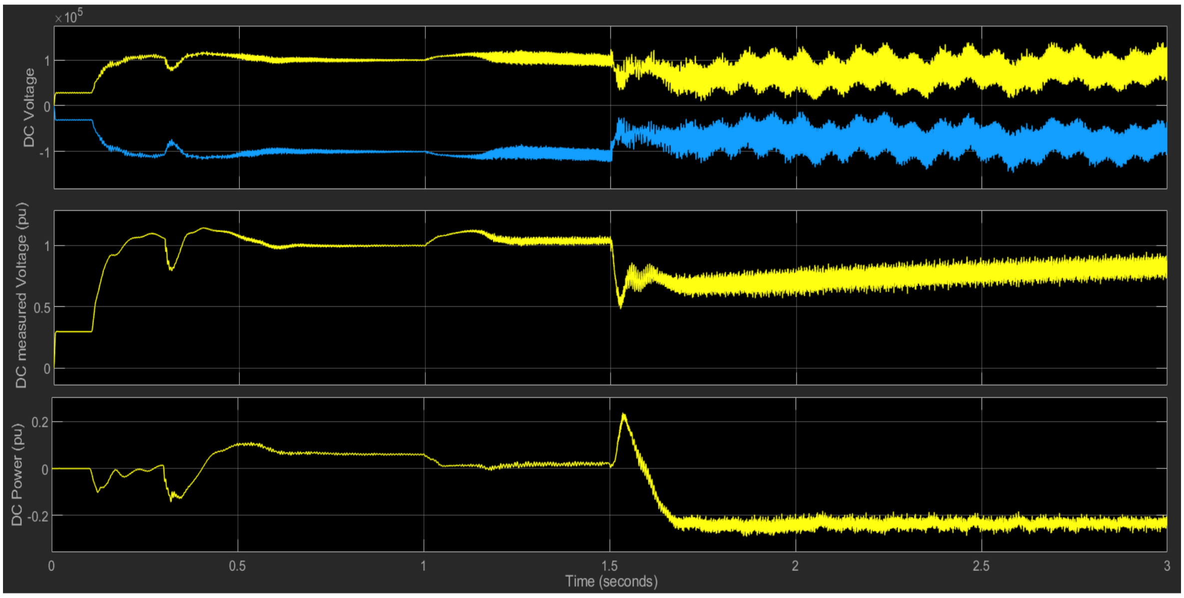


Figure 4.18 (a) DC Voltage (station 1)

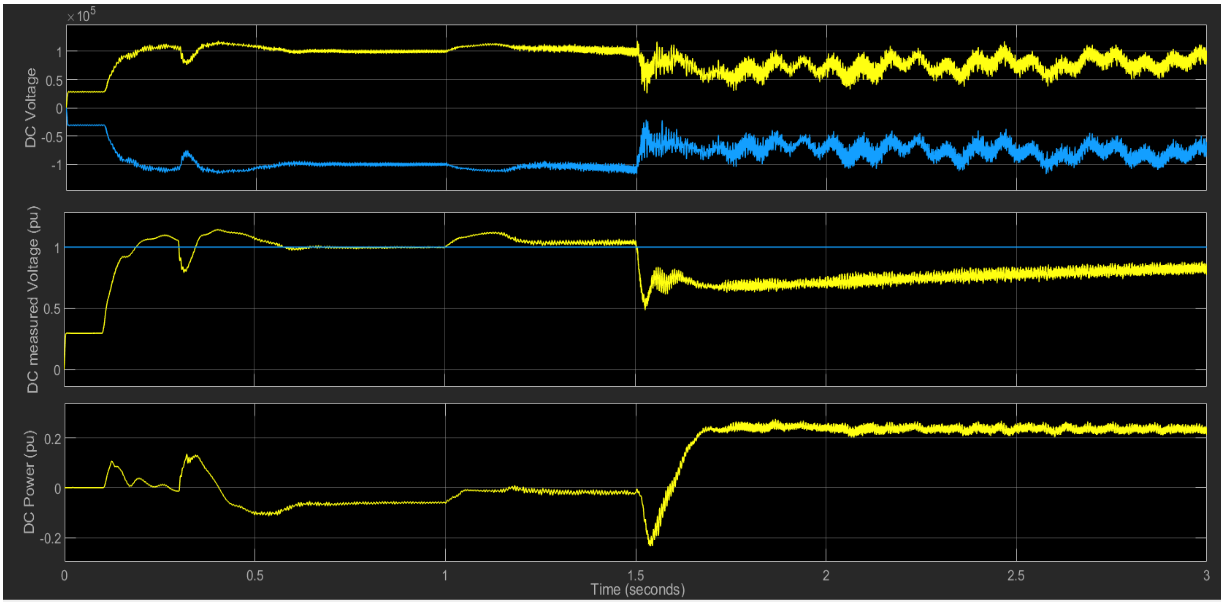
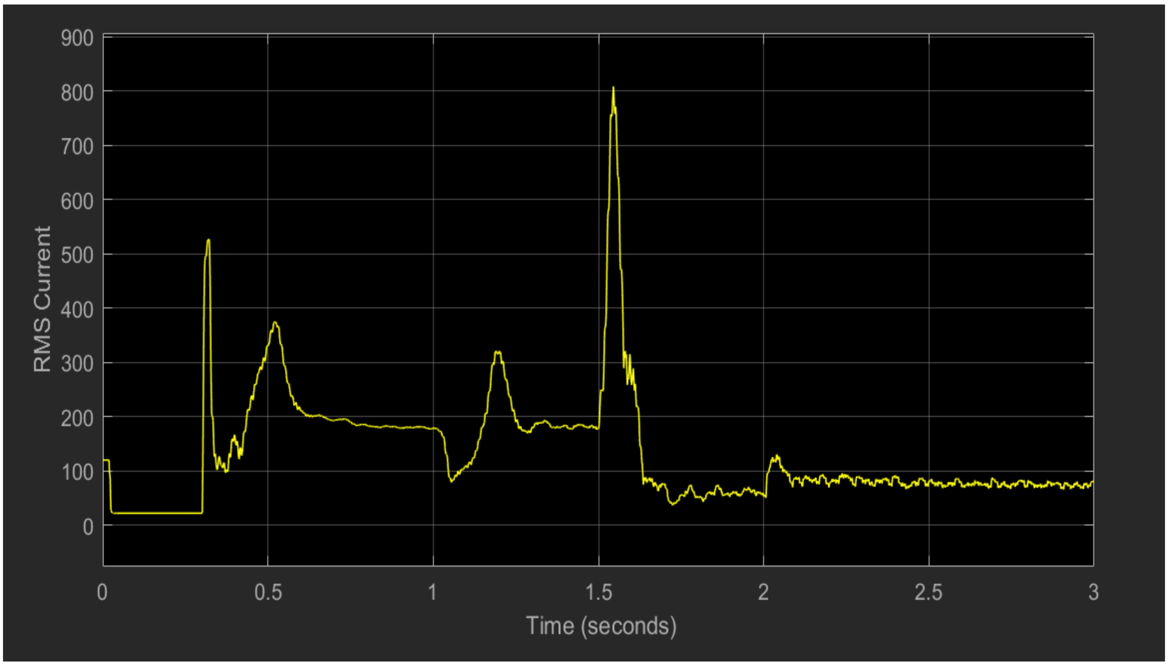


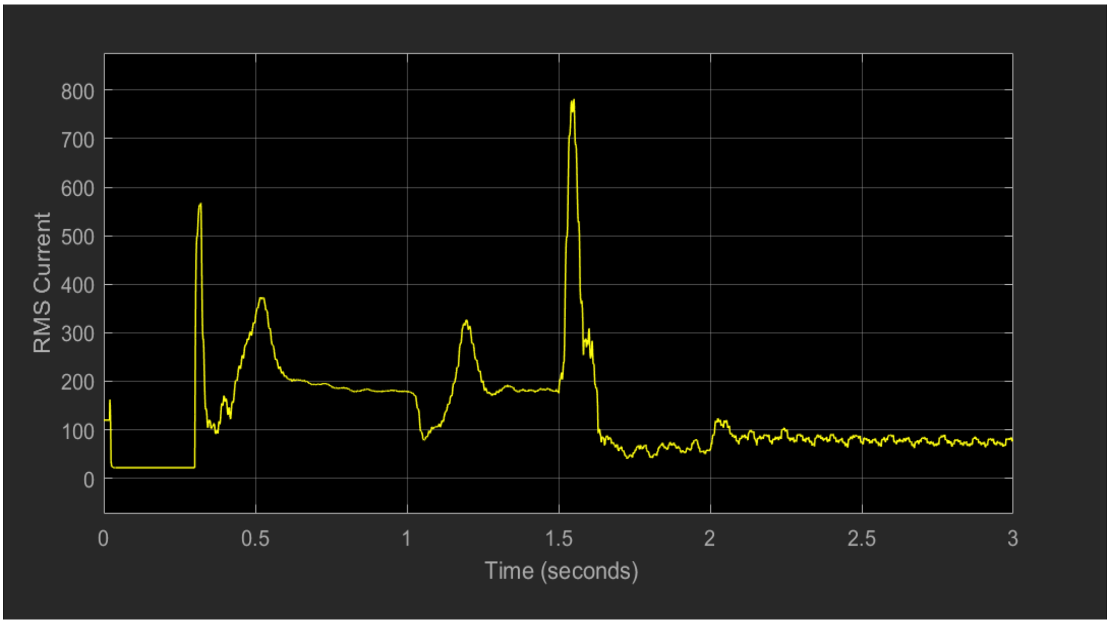
Figure 4.18 (a) DC Voltage (station 1)

The RMS currents in each phase can be analyzed, and the highest value of the current can quickly determine which helps design the protection system.

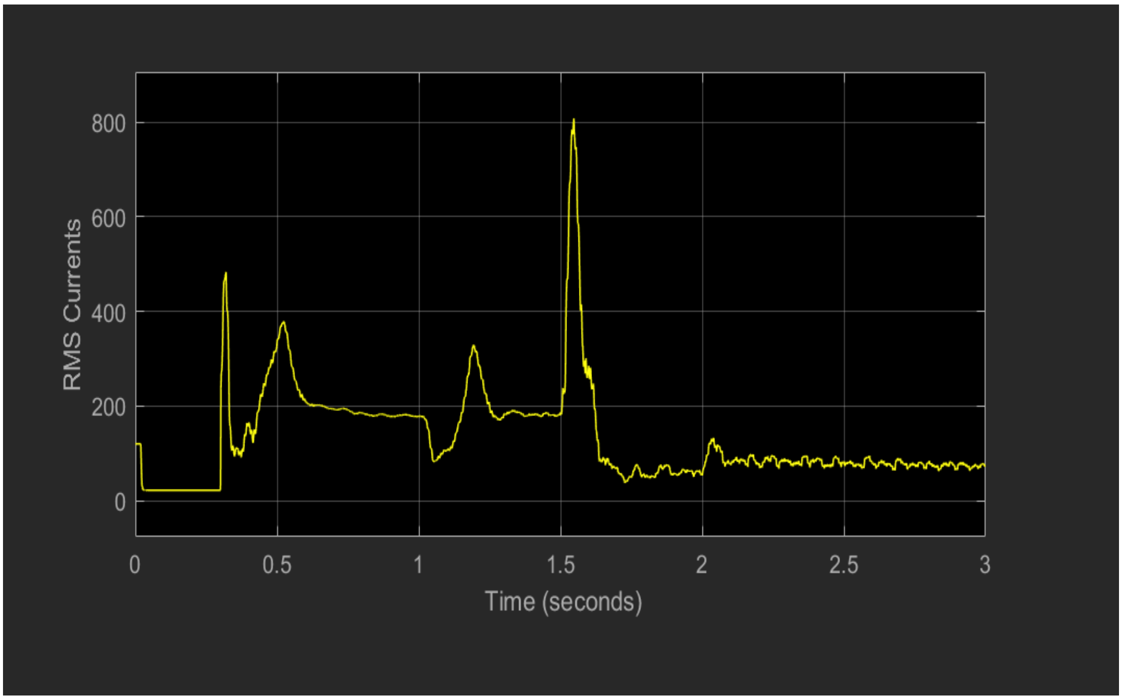
The results of switches 1,2, and 3 are as follows, respectively.



RMS Current (Switch 1)



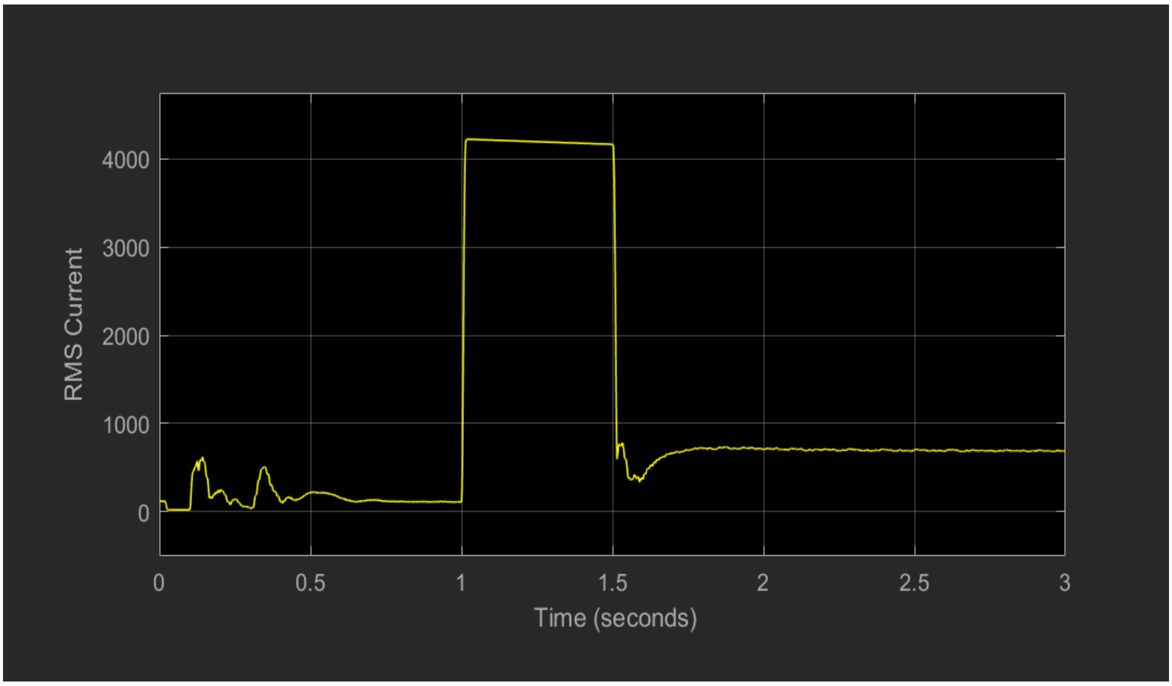
RMS Current (Switch 2)



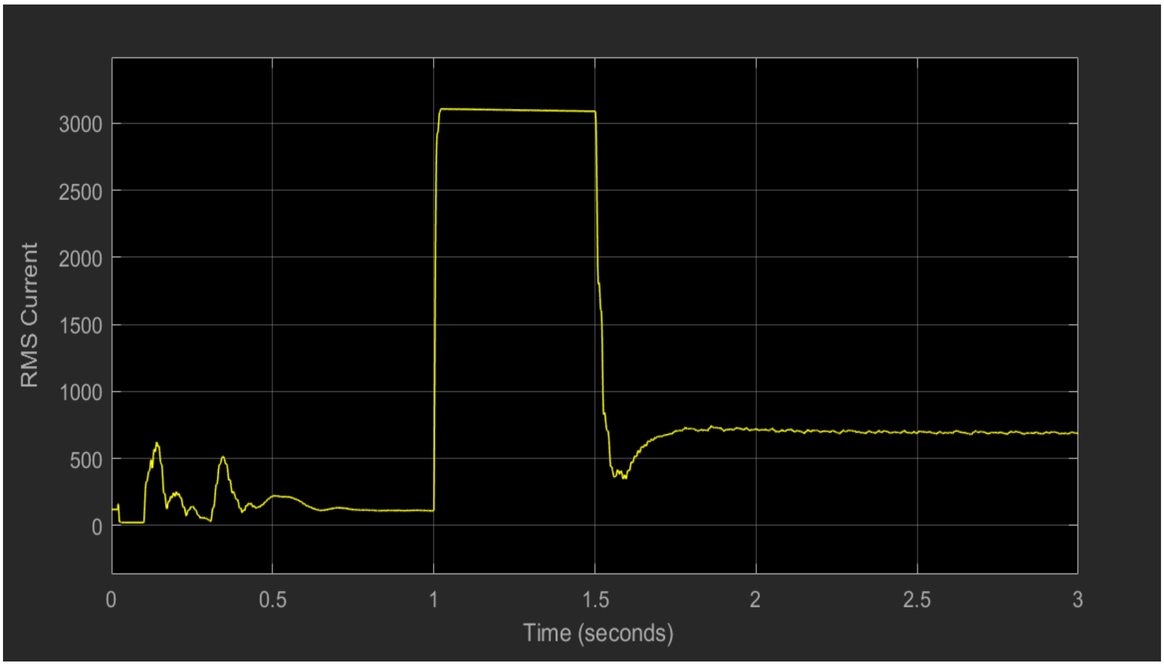
RMS Current (Switch 3)

As expected, the results of all the switches are almost the same as the previous case of symmetrical fault.

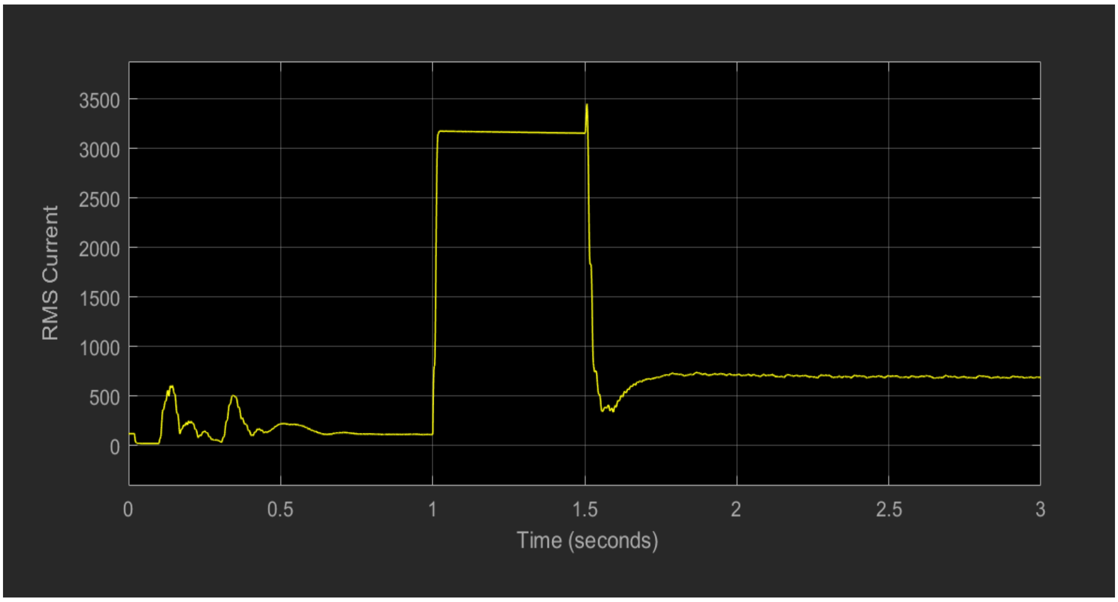
Now let's see the switches on the AC system 2. Will they be the same as the previous one, or will they somehow show a change?



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (Switch 6)

The currents in switches 4 and 5 are the same as the previous case, but for switch 6, there is a slight change when the second switching time comes; apart from this change, it's almost the same. So, in conclusion, the results of (L-L-L) faults show the same behavior as the (L-L-L-G) fault. Small changes can be ignored.

The highest values of the switches would be in Table 4.2.

Table 4.2

Ideal switches	RMS current
Ideal switch 1	809
Ideal switch 2	784
Ideal switch 3	802
Ideal switch 4	4224
Ideal switch 5	3107
Ideal switch 6	3463

From the above table, we can see that there is not much difference in the high values of the current in both symmetrical faults. Just in ideal switch 6, the current goes from 3177 to 3463; other than everything is the photocopy of the previous case.

4.2.2 Unsymmetrical Faults

Unsymmetrical faults are more common faults than symmetrical faults. In these kinds of faults, three-phase lines become unbalance (unequal currents with unequal phase shifts in a three-phase system), and they do not have equal phase displacement with each other. There are mainly three types, namely pole to ground (L-G), pole to pole (L-L), and double pole to ground (L-L-G).

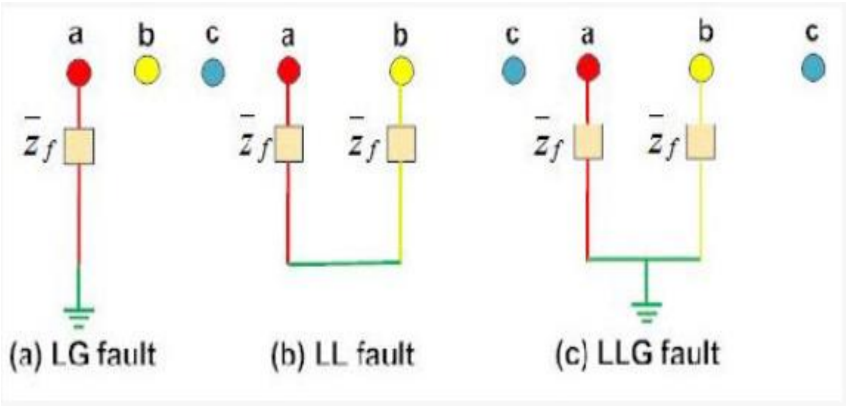


Figure 4.19 Types of unsymmetrical faults

I. Pole to ground fault.

This fault is the most common in unsymmetrical faults. 65-75 percent of faults are of this type. It causes the conductor to come in contact with the earth or the ground.

As we need to get the result of line to ground fault, we need to change the selections inside the three-phase short circuit fault block parameters.

For example, to program a fault between phases A and B, you need to select the Phase A and Phase B block parameters only. To program a fault between phase A and the ground, you need to choose the Phase A and Ground parameters and specify a small value for the ground resistance. The ground resistance Rg is automatically set to 10^6 ohms when the ground fault option is not programmed.

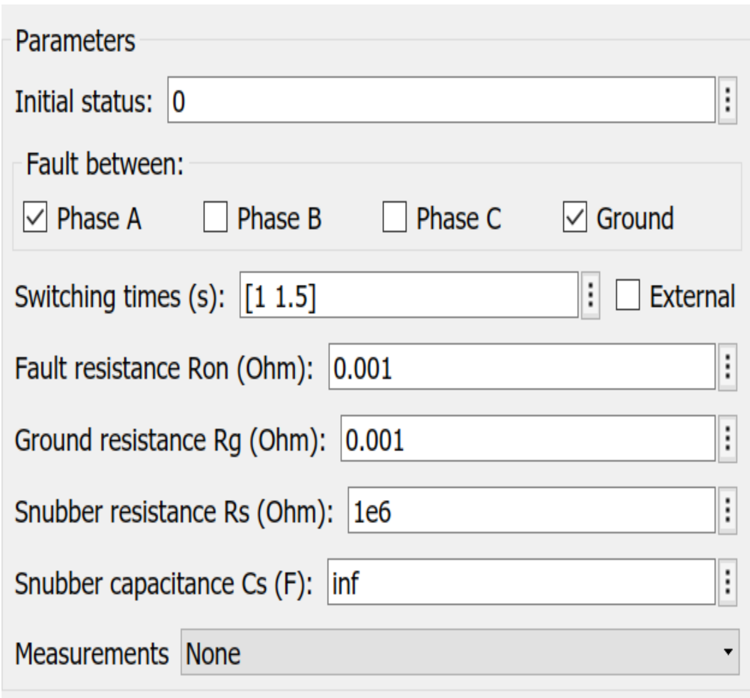


Figure 4.20 Block parameters. (pole to ground fault selection strategy)

The connections inside the system would look like this, shown in Figure 4.21

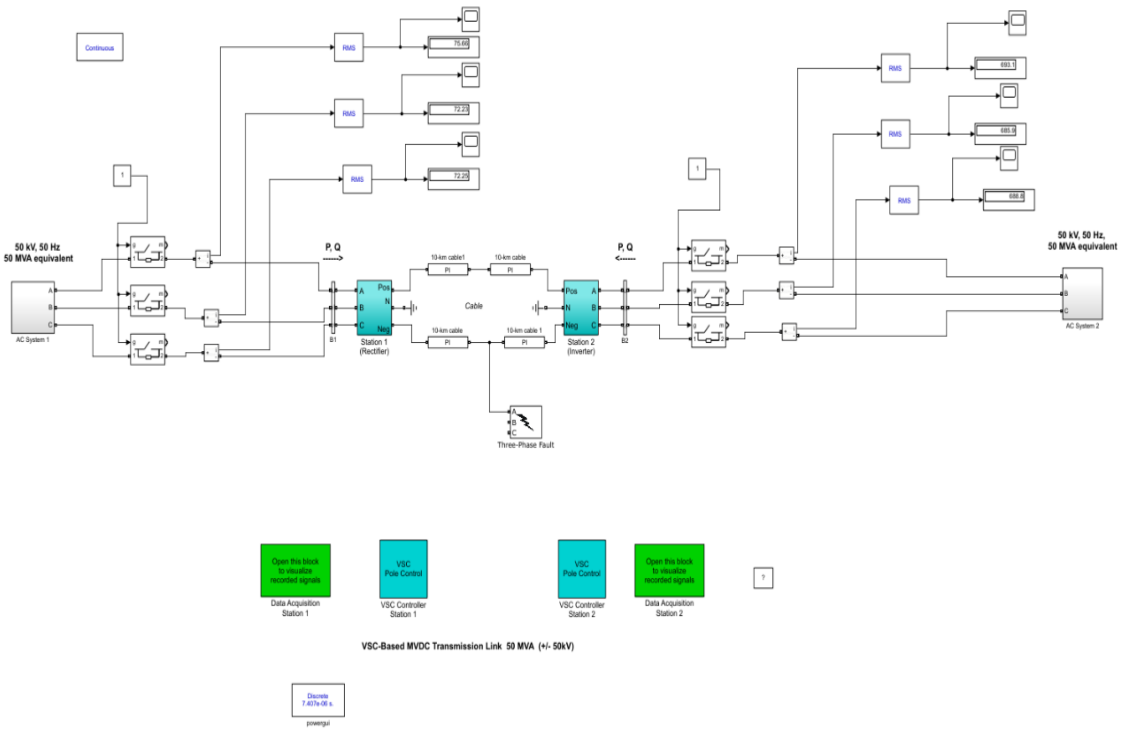


Figure 4.21 Pole-to-ground fault.

The fault is connected between the 20 km cables. Now let us analyze the results.

Bus Station 1:

The result is different than without short circuit fault and with three-phase short circuit fault events.

Umeas (pu): measure voltage has some significant changes due to the short circuit fault. It is known that the switching times are 1 and 1.5. the measured voltage starts fluctuating from 1 onwards. The fault is between the transmission lines, so the protection system must be designed so that only transmission line fault can be cleared without turning off the supply on both AC systems, and it must trip as soon as possible.

Pref (pu): Reference power or measured power also shows an irregular pattern after 1 second. The fluctuations are different and dangerous compared to with or without three-phase short circuit faults. These results can be very harmful if not cleared in time.

Qref (pu): Measure reactive power or reference reactive power also shows some remarkable results, as shown in Figure 4.22 (a). The positive and negative peaks are very high as compared to three-phase short circuit faults. There is no stability in the system after the switching time is initiated. The protection system should be designed to work fast and accurately; otherwise, the transmission line would get damaged.

Voltage (pu) and Current (pu) show some prominent high peaks due to pole to ground fault. After 1 second, both currents and voltages go high but unexpectedly, the voltage value is higher than the current in pole to ground faults almost all the time except during the switching times.

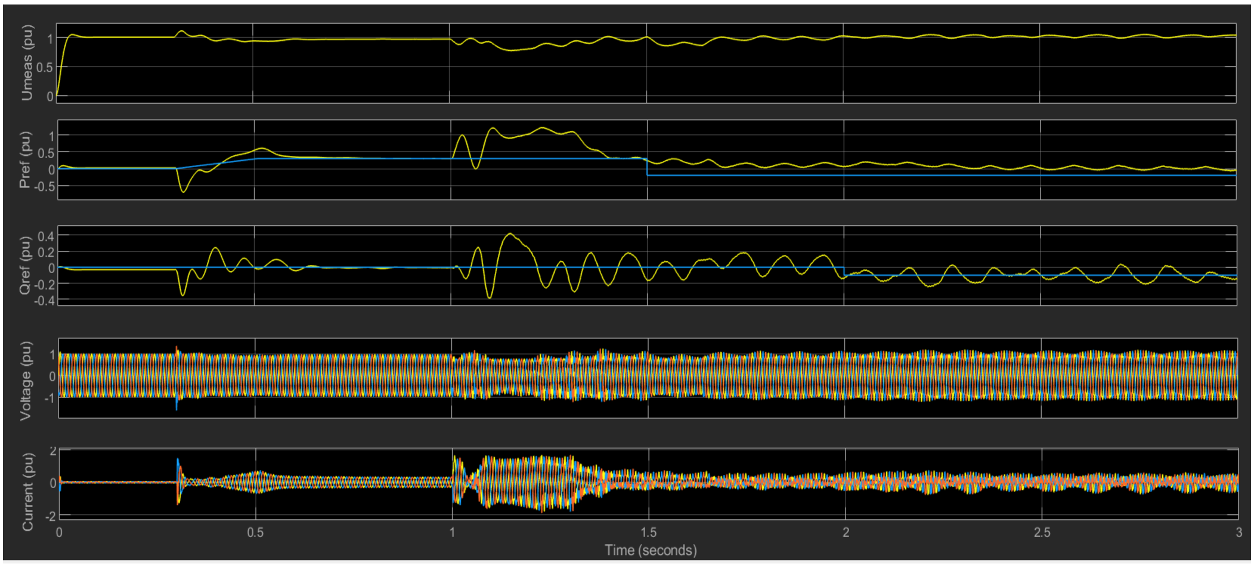


Figure 4.22 (a) Pole to ground short circuit fault. (Bus station 1)

Bus station 2:

Bus station 2 looks the same as bus station 1, but Pref (pu) and current (pu) show slightly different behavior when there is a pole to ground fault.

Umeas (pu): the results in both bus stations are almost the same.

Pref (pu): it shows some noticing behavior compared to the bus station 1. We can see from Figure 4.23 (b) that at approximately 0.2 seconds, the Pref (pu) starts fluctuating, and when it reaches the step-change, it goes below zero till the switching times are finished. Then it goes to 1 and shows instability to the end.

Qref (pu): it is only changed between 0 1o 0.5 seconds. The fluctuation times in bus stations 1 and 2 are different during this period and other than, both show the same behavior.

Voltage (pu): the results are almost the same in both stations.

Current (pu): the per unit current in bus station 1 starts fluctuating before and at the step time. During the switching times [1 1.5] both the station shows almost the same behavior. After 1.5 seconds, the current (pu) goes high to the end of the simulation.

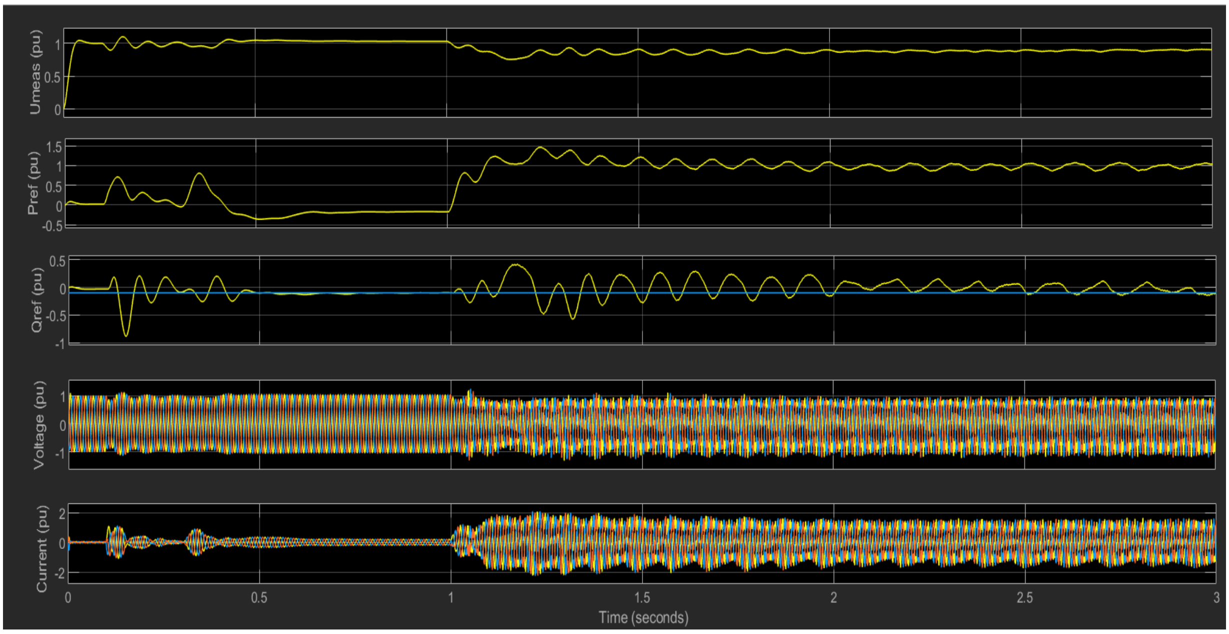


Figure 4.23 (b) Pole to ground fault. (Bus station 2)

Dc side results:

The fault is between the transmission line, so the DC voltage is very high. The positive current went as high as approximately 4.5 compared to L-L-L-G faults, which was just 1.5 and the negative current reaches approximately -5.8 compared to L-L-L-G faults, which is -1.5.

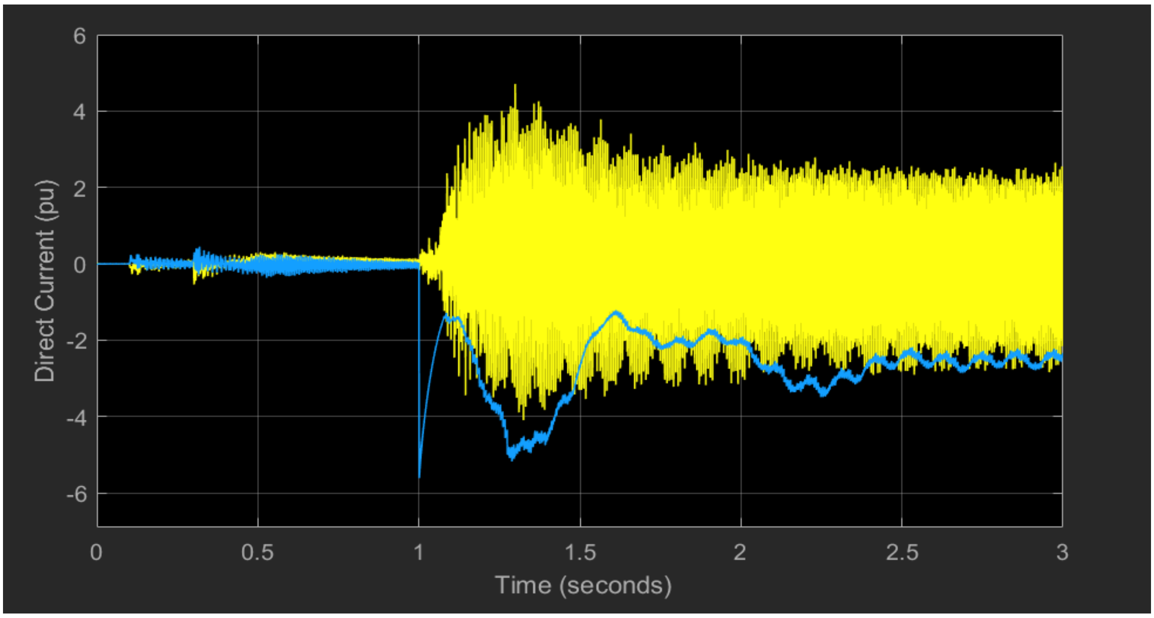


Figure 4.24 (a) Positive and negative DC of pole to ground fault. (station 1)

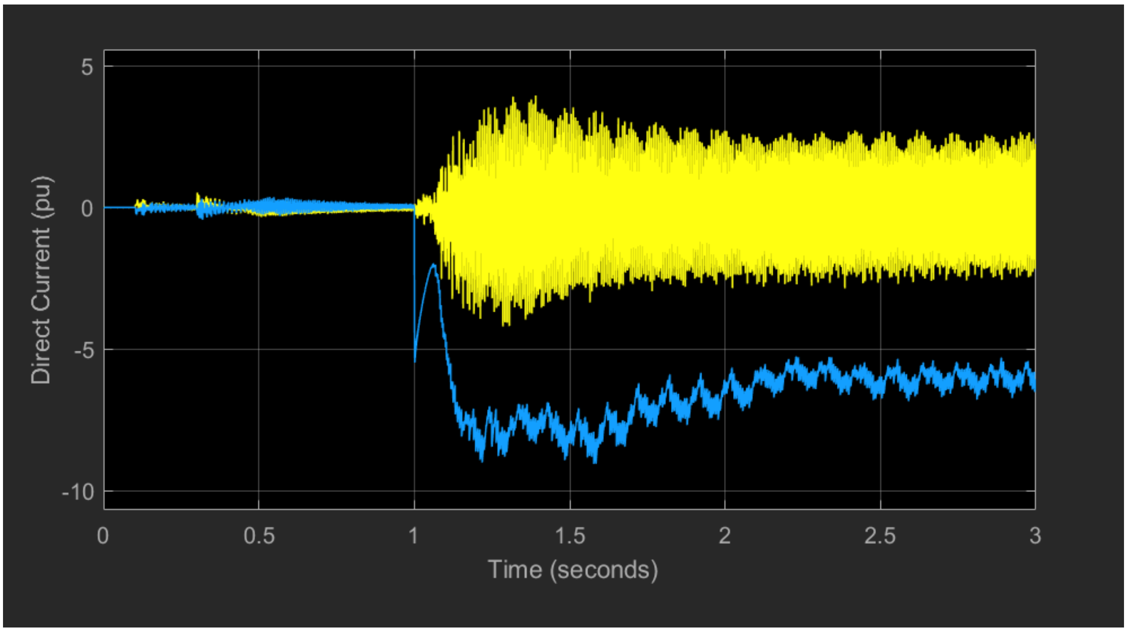


Figure 4.24 (b) Positive and negative DC of pole to ground fault. (station 2)

DC Voltage:

Station 1:

Positive DC Voltage provide a very high value due to the pole to ground fault. The DC voltage can go as high as 2 and as low as 0, furthermore it fluctuates after the switching times. The negative DC voltage goes to zero after the fault and remains till the end of simulation. DC power (pu) shows also a massive change after the fault. The power goes really high and shows irregularity throughout this period.

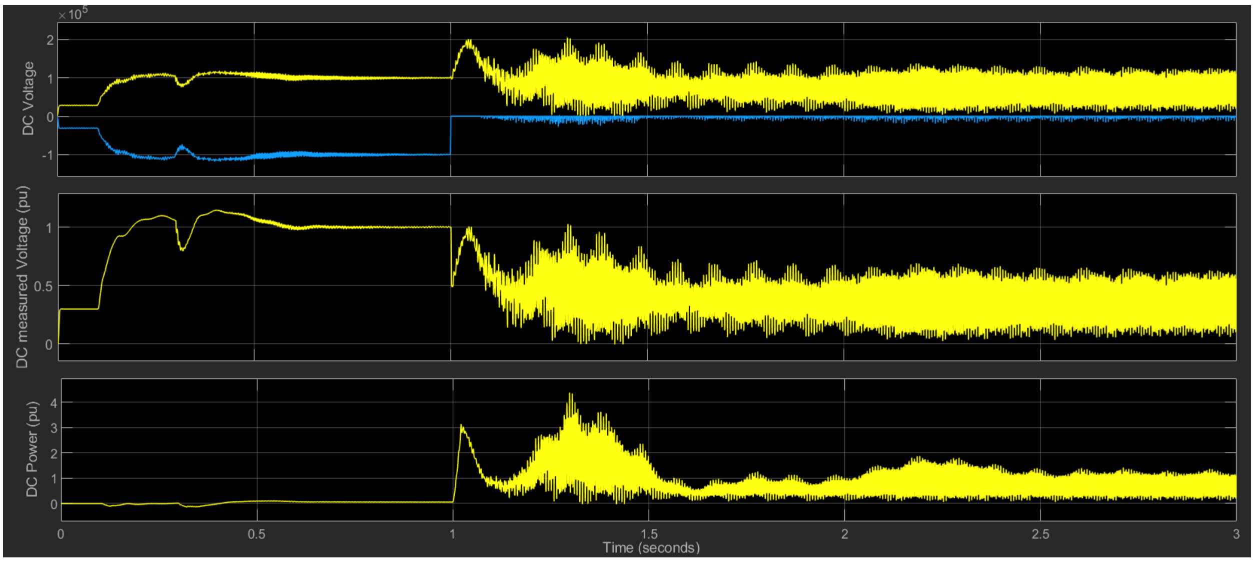


Figure 4.25 (a) DC Voltage (station 1)

DC Voltages shows the same behavior as station 1 but it goes to zero more likely. DC Power in station 2 is higher than in station 1.

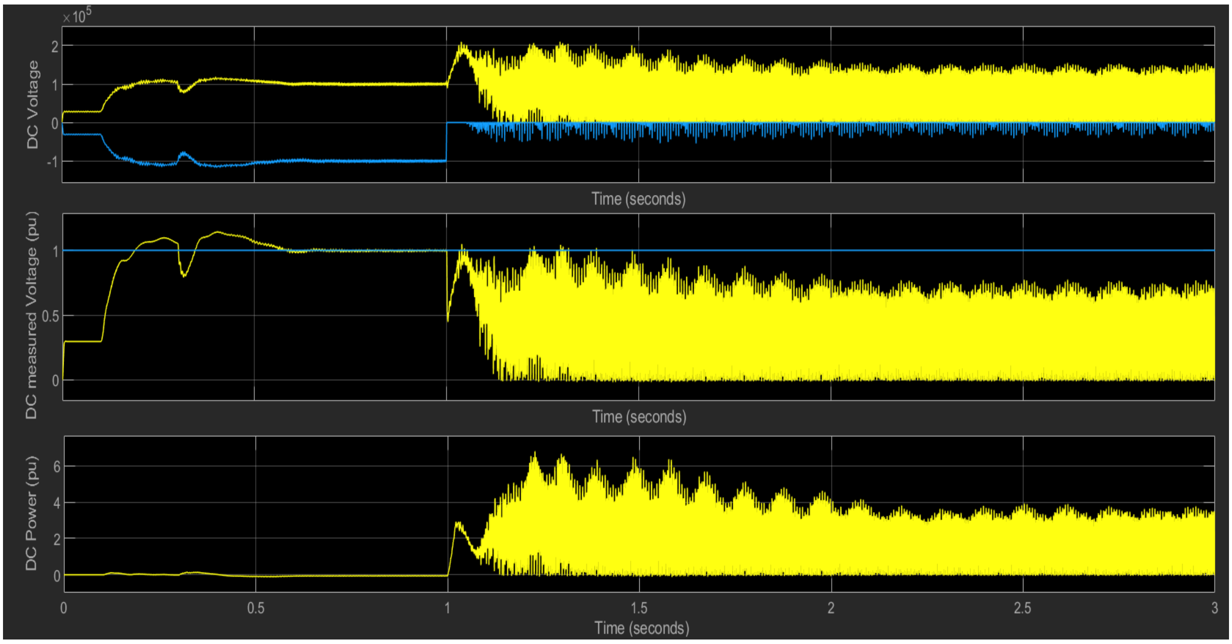
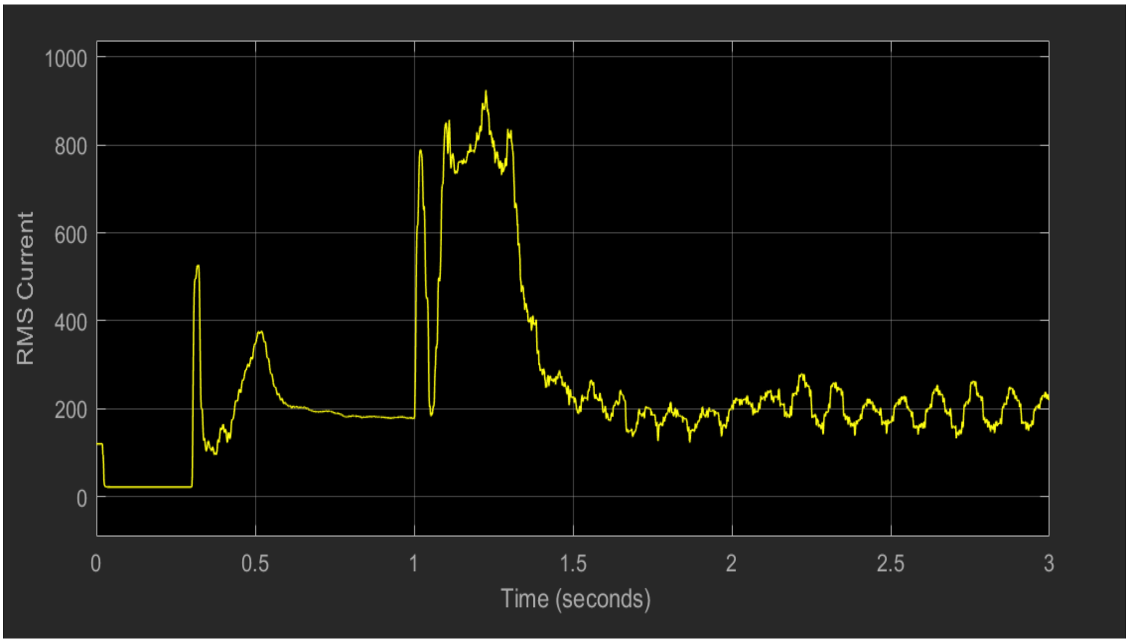


Figure 4.25 (b) DC Voltage (station 2)

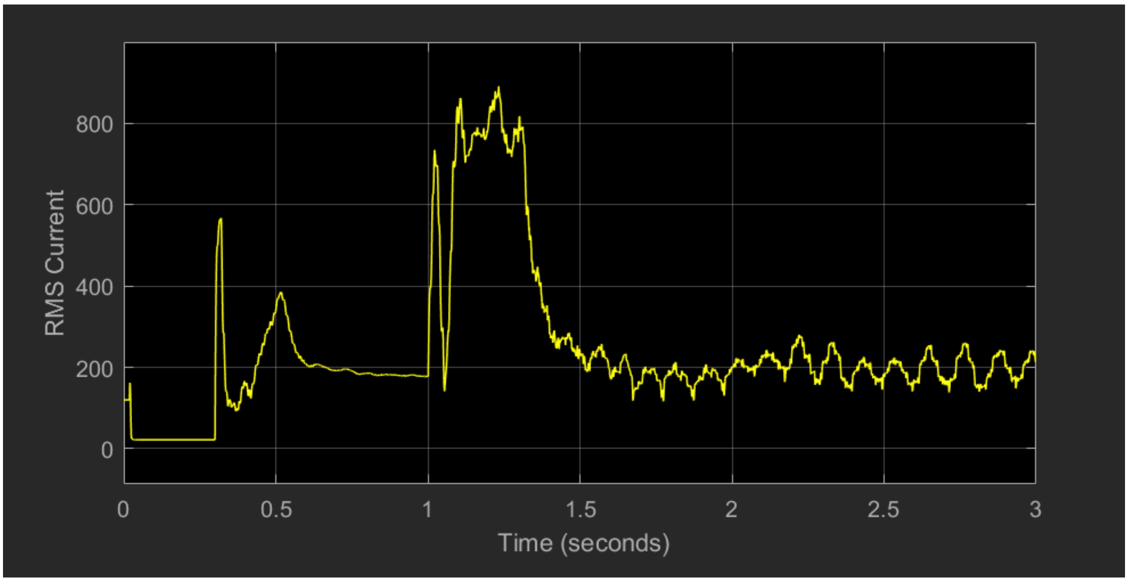
The RMS current in each phase due to the pole-to-ground short circuit is as follows.

First, let us analyze switches 1,2 and 3.

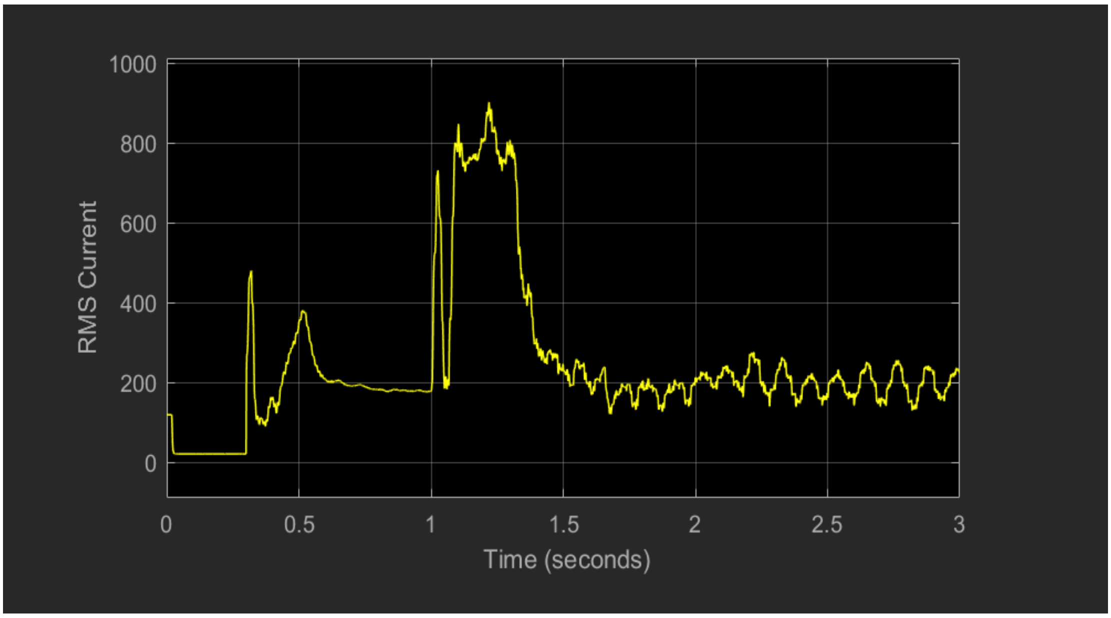
The highest current recorded between the three switches 1,2, and 3 is approximately 918, which doesn't show much difference compared to the three-phase short circuit fault.



RMS Current (Switch 1)



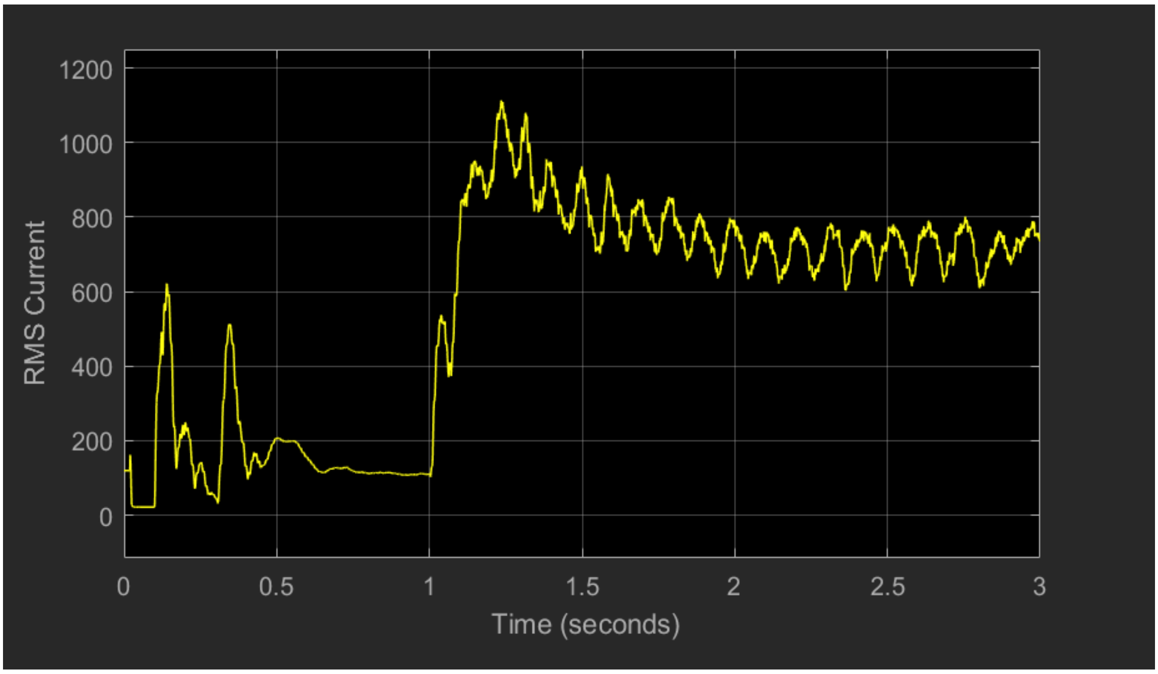
RMS Current (Switch 2)



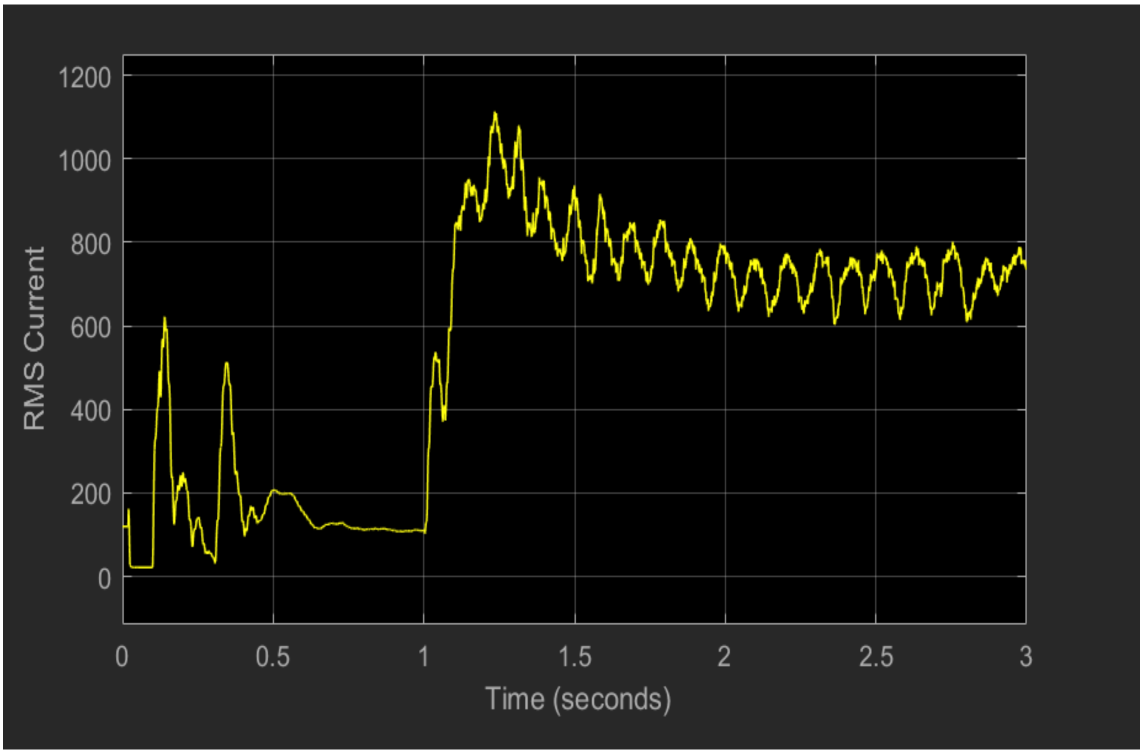
RMS Current (Switch 3)

Now let's see how switches 4,5, and 6 have to offer.

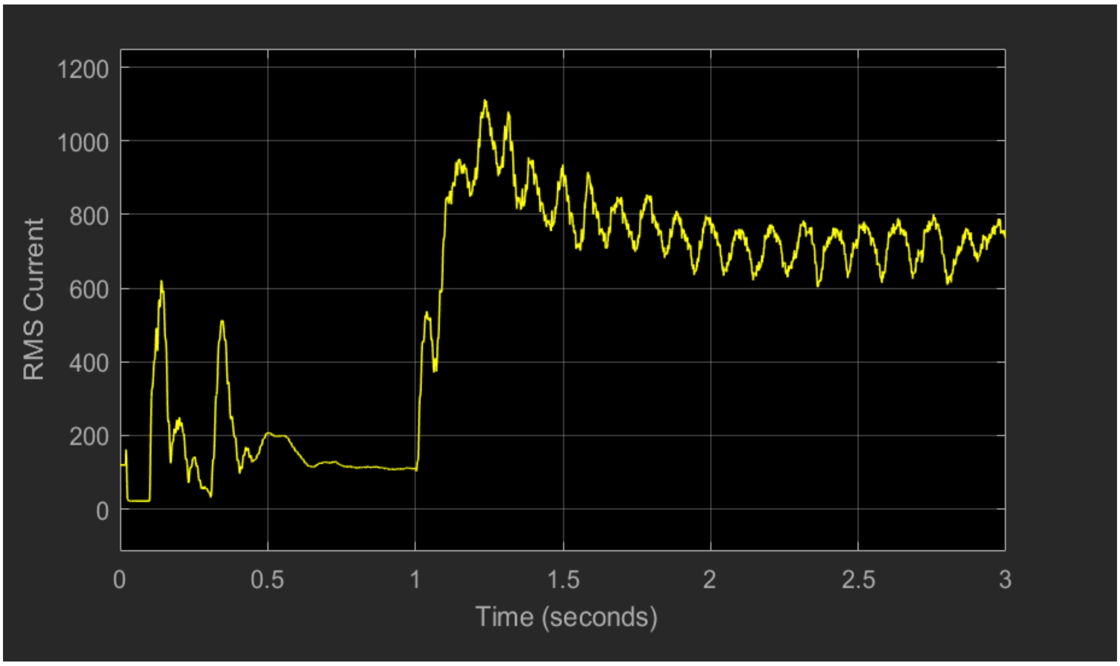
From the below graphs, approximately 1116 is the highest point on the graph of switch 4. The behavior of RMS current in both stations is different, especially after the start of the fault. The RMS current goes near 200 amperes after the switching times reached in bus station 1 and fluctuates, but The RMS Current goes between 600 and 800 amps in bus station 2, which is quite a lot when It comes to comparison. Both the stations show the fluctuation behavior after the switching times.



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (Switch 6)

The recorded highest values of RMS Currents can be found in Table 4.3.

Table 4.3

Ideal switches	**RMS currents**
Ideal switch 1	918
Ideal switch 2	880
Ideal switch 3	913
Ideal switch 4	1116
Ideal switch 5	1105
Ideal switch 6	1106

Ideal switch 1, 2 and 3 has been massively increased due to pole to ground fault. We need to overcome this problem and design a protection system that would trip the circuit breakers when the current exceeded the reference value. The reference value can be known or can be selected by the above values on the tables.

II. Double pole or pole to pole fault (L-L)

This kind of fault occurs when two conductors contact each other while swinging lines due to the winds. The line-to-line faults are only 5-10 percent of the faults. The connection of the pole-to-pole fault can be shown in Figure 4.26.

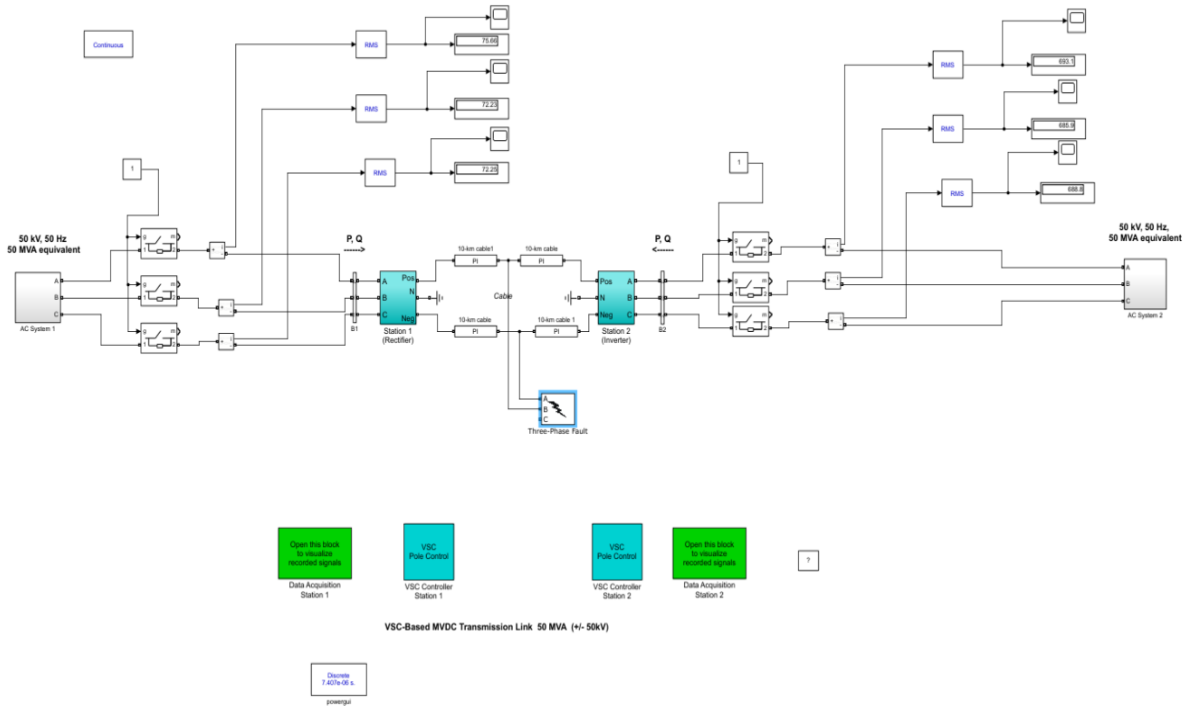


Figure 4.26 Pole to Pole faults

Let's analyze Bus station 1 when there are pole-to-pole faults. Indeed, some significant changes need to be discussed.

Umeas (pu):

Before 1 second, there is no difference in voltages when compared to the pole to ground fault as the switching time is 1 and 1.5 seconds. After 1 second, the measured voltage decreases from 1 to approximately 0.3, and then it keeps the value of 0.3 almost throughout. The results of the pole to ground showed the fluctuation after 1, but the pole to pole fault shows stability.

Pref (pu):

It starts from 0, at 0.3; it steadily increases to approximately 0.3 when it reaches 0.5 seconds. After that, it holds on to this until 1.5 seconds and then drops to -0.3. After that, it's in the same negative value till the simulation finishes.

Qref (pu):

The measured reactive power (Qref) increases from 0 to approximately 1 when the switching time reaches. Then there is a slight fluctuation from 1 to 1.5, and it drops then came back to the original position and became stable afterward. The blue line shows the expected behavior, just like the pole to ground fault.

Voltage (pu) and Current (pu):

Voltage measurement is the same as the previous case, but the current measurement, in this case, shows more stability than in pole to ground faults.

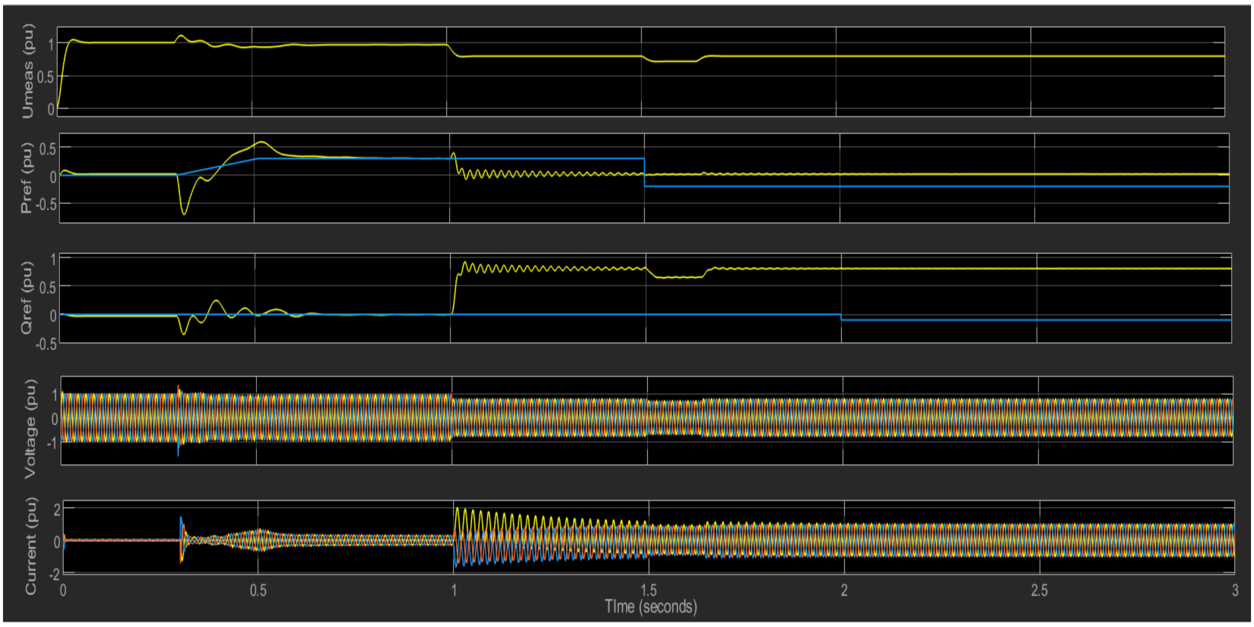


Figure 4.27 (a) Bus Station 1 for pole-to-pole fault.

Bus stations 1 and 2 show almost the same behavior with some minor changes. Umeas (pu), Qref (pu), Voltage (pu) are almost the exact behavior. Pref (pu) behaves like the pole to a ground fault until the switching times. Then it's fluctuating, which is the same as in bus station 1. Current (pu) shows the two ripples before 0.5 in bus station 2, but bus station 1 shows just one.

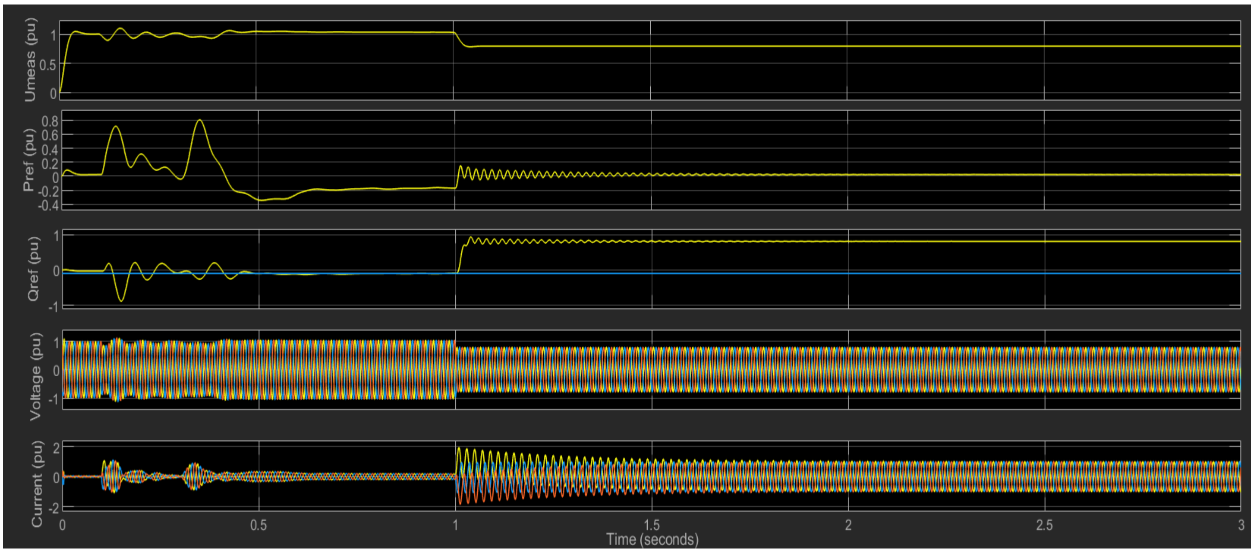


Figure 4.27 (b) Bus Station 2 for pole-to-pole fault.

DC side results:

The positive and negative currents are exactly the replica of each other. For example, the positive yellow current goes as high as 5.8, and the negative blue current goes the same height but in the opposite direction. So, in conclusion, the positive and negative current is almost the same value, but one is positive, and the other is negative. Both Station 1 and 2 show almost the same result. The graph of stations 1 and 2 are to be found in Figure 4.28 (a) and Figure 4.28 (b), respectively.

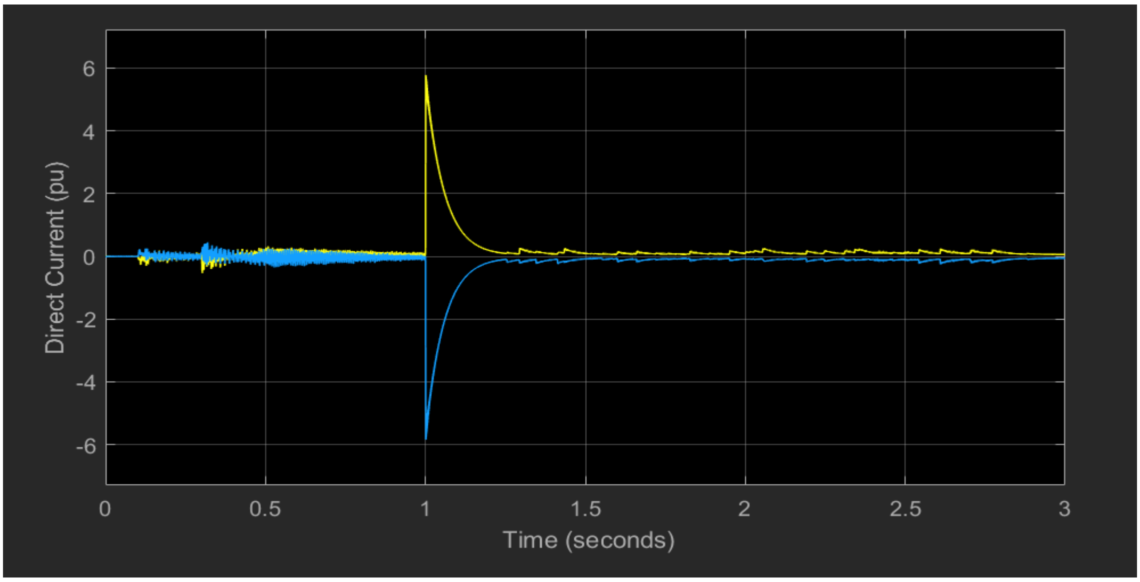


Figure 4.28 (a) Positive and negative currents of pole-to-pole faults. (station 1)

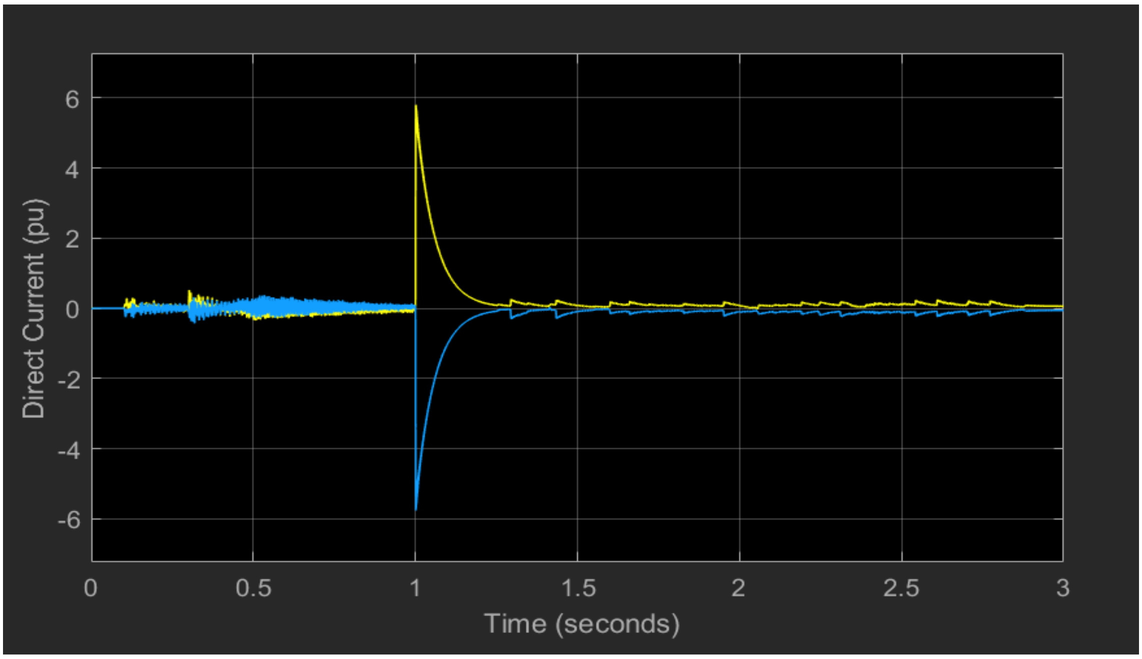


Figure 4.28 (b) Positive and negative currents of pole-to-pole faults. (station 2)

DC Voltage:

DC voltages for station 1 and 2 shows the same behvaiour. The values of the voltages goes to zero after 1 second in both cases. Just to keep in mind that the values of DC Power (pu) are reversed as before.

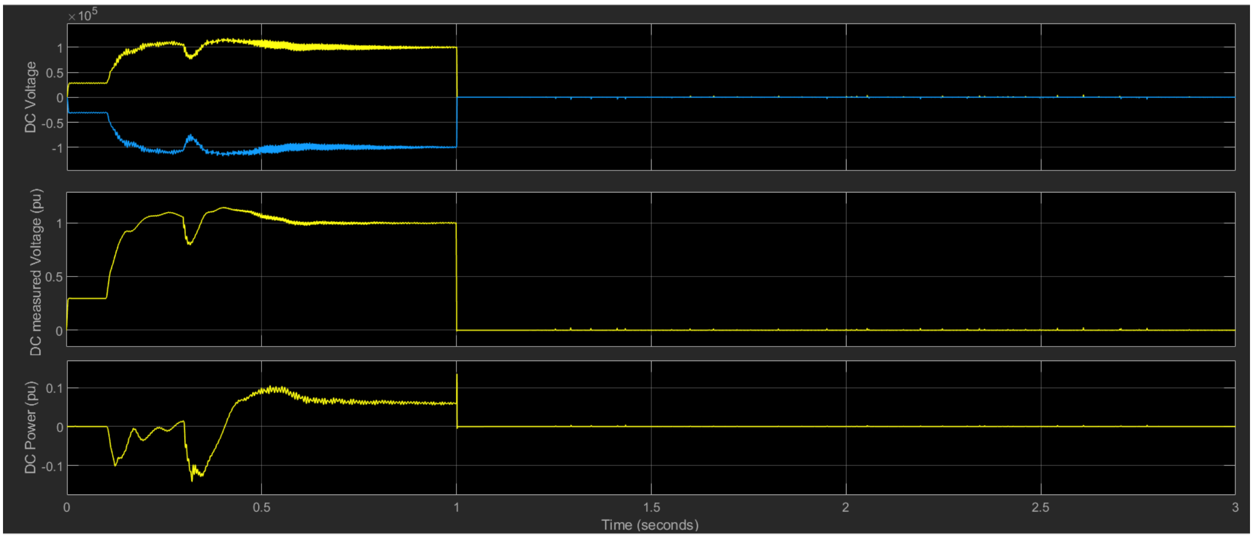


Figure 4.29 (a) DC Voltage (station 1)

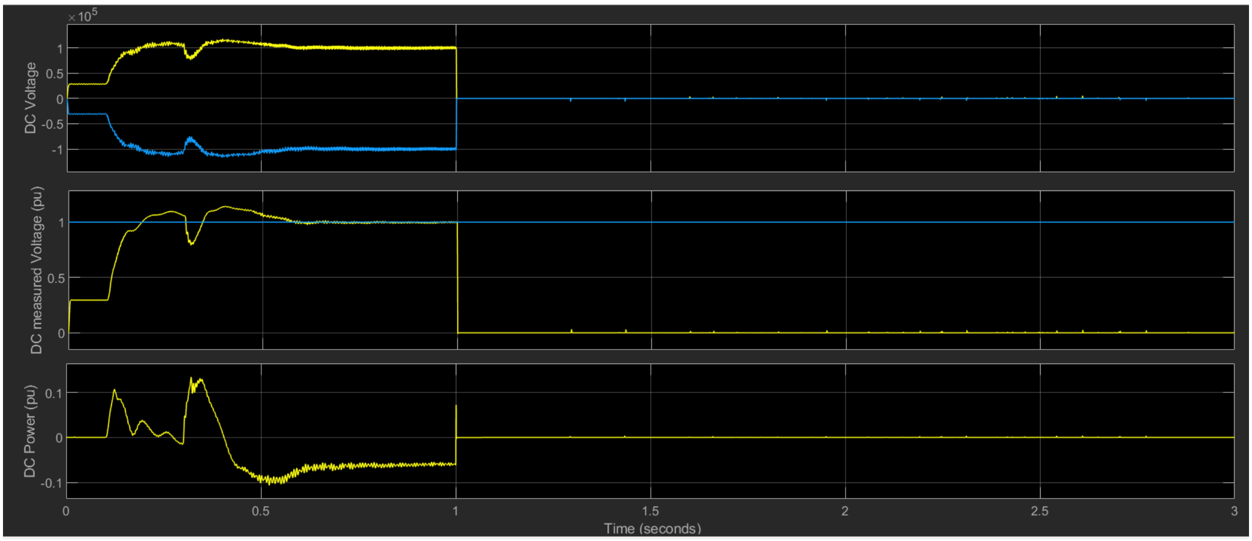
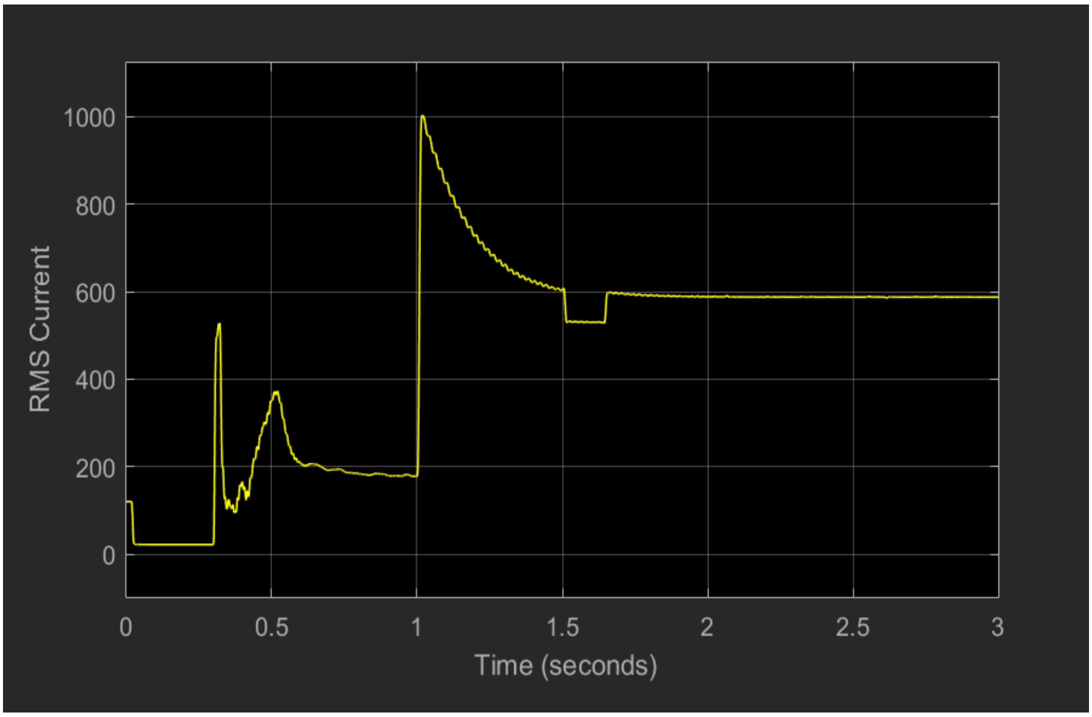


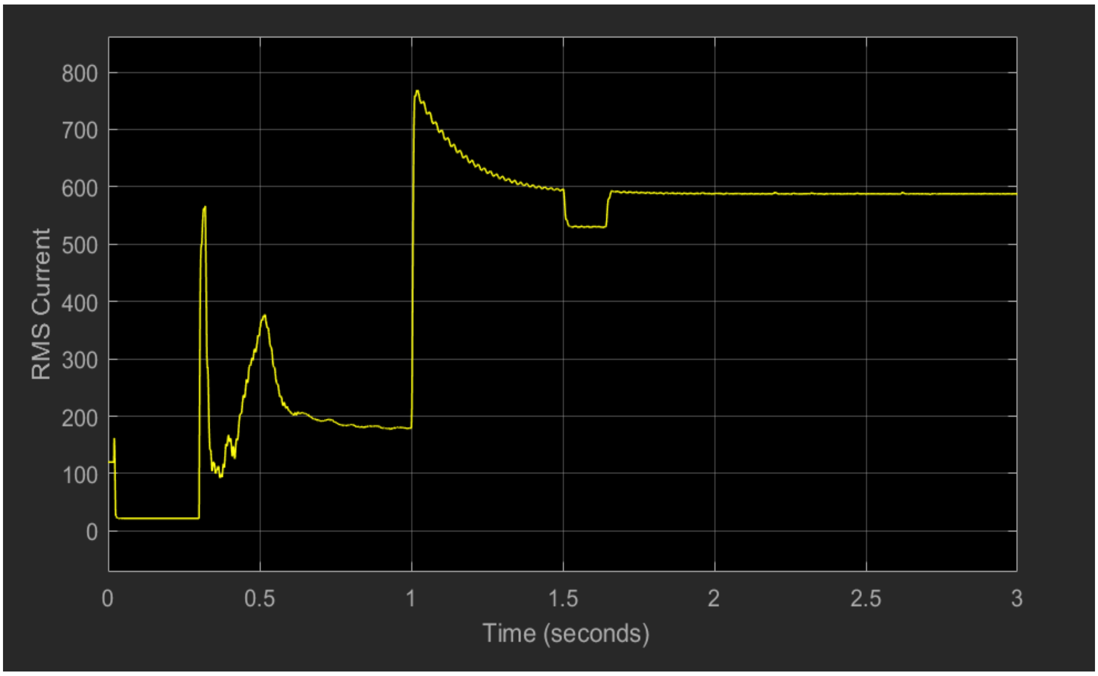
Figure 4.29 (b) DC Voltage (station 2)

The RMS current of switches 1,2, and 3 are as follows, respectively.

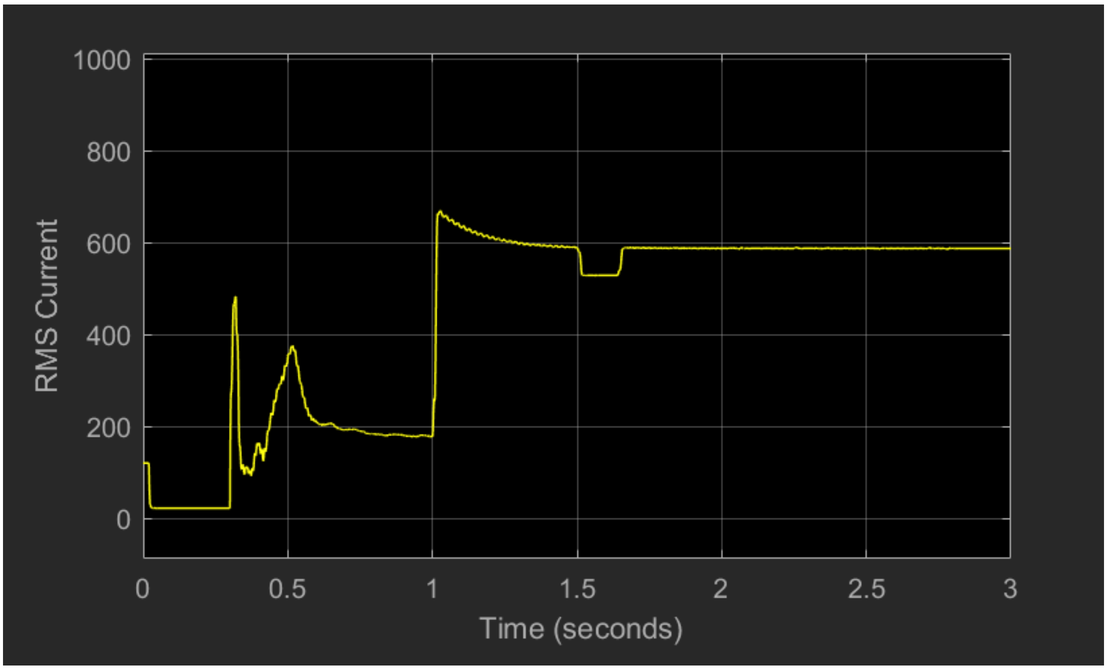
The RMS current can go as high as approximately 1000 amperes for switch 1. The other two switches show a smaller current. The behavior of the three switches is almost the same but different amplitudes of the currents.



RMS Current (Switch 1)



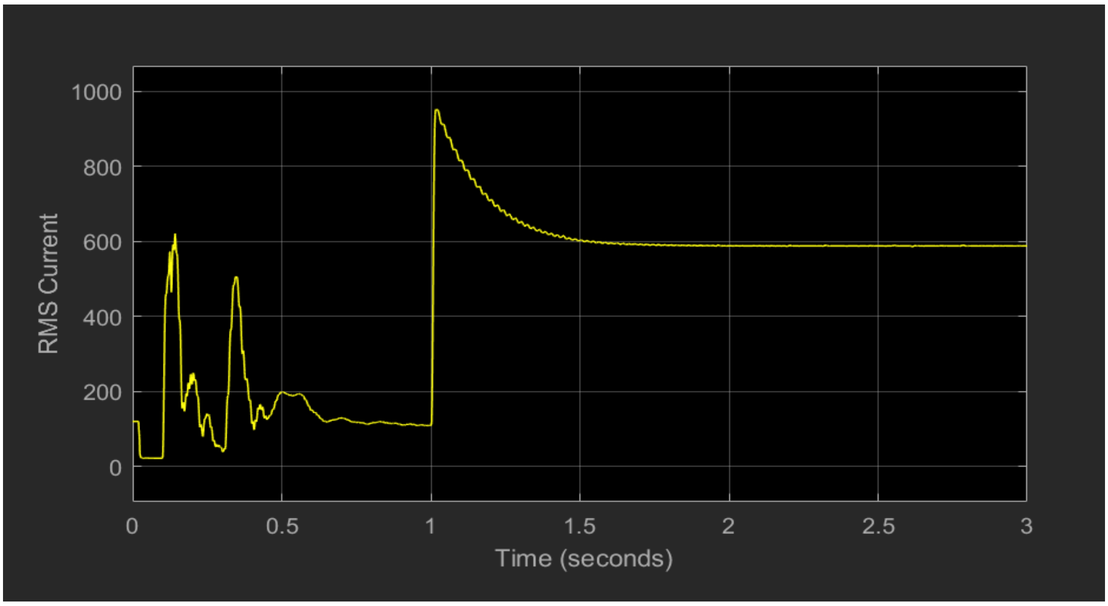
RMS Current (Switch 2)



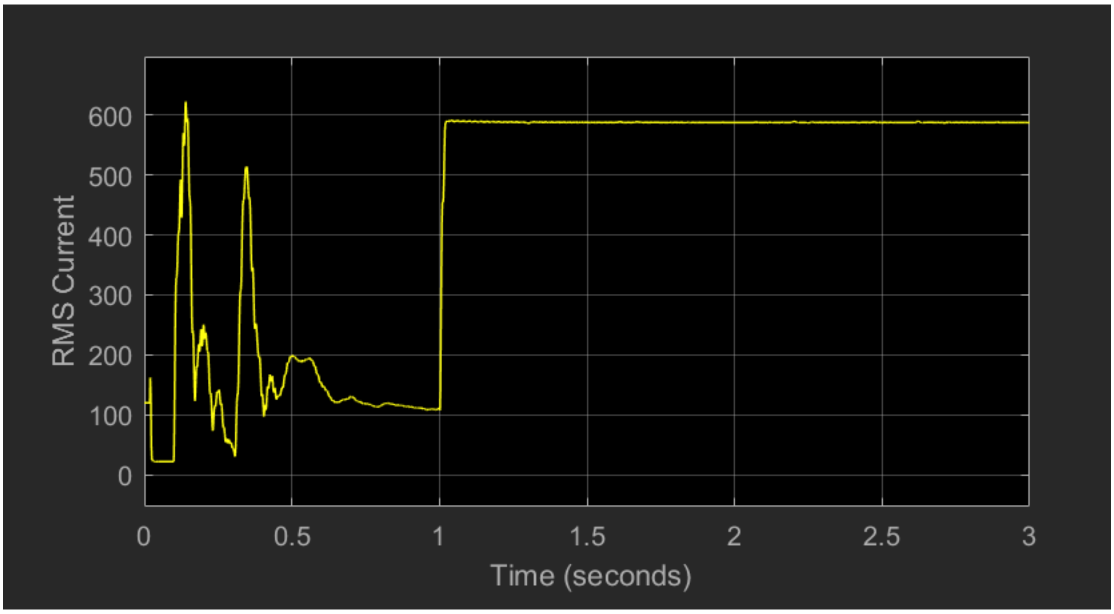
RMS Current (Switch 3)

Now let's analyze the RMS currents of switches 3,4, and 5, respectively.

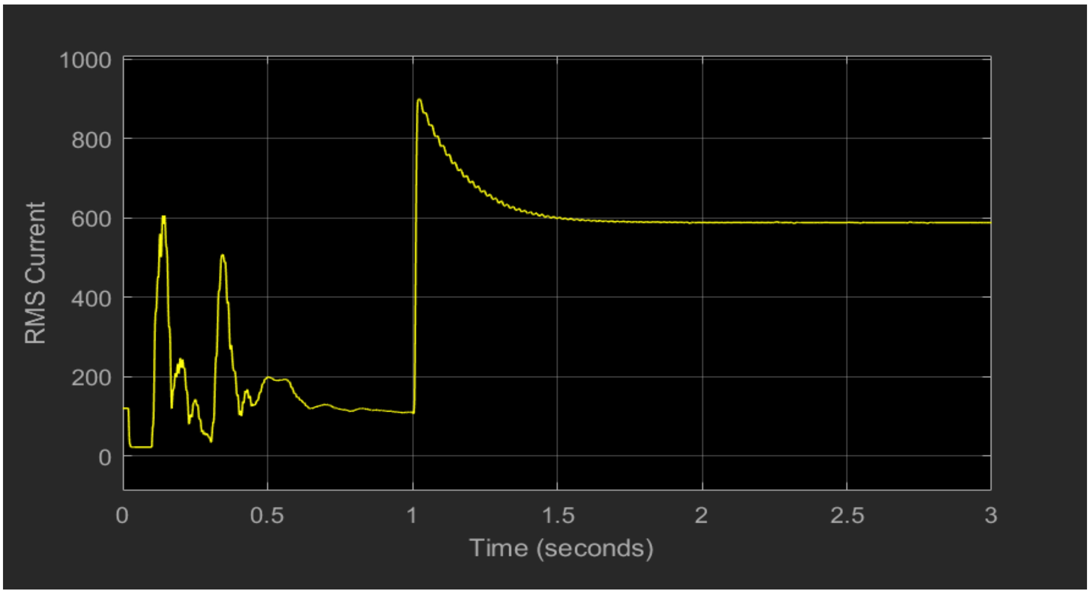
Switch 4 and switch 6 show the same current flow, and the current values are almost the same. The maximum current that reaches is approximately 950 in switch 4. Switch 5 shows a unique flow after 1 second. Switches 4 and 6 become stable after the value of the current drops, but for switch 5, the story is different. In switch 5, the current goes stable after it reaches its peak value at 1 second.



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (Switch 6)

The highest currents in each switch can be shown in Table 4.4.

The highest currents among these switches can be found in switch one, which is 1003.

Table 4.4

Ideal switches	**RMS currents**
Ideal switch 1	1003
Ideal switch 2	768
Ideal switch 3	670
Ideal switch 4	952
Ideal switch 5	623
Ideal switch 6	899

III. Double pole to ground (L-L-G) faults

15 to 20 percent of faults are double pole to ground faults and cause the two conductors to contact the ground. The connections of the components or blocks are the same as the pole-to-pole faults. The only difference is the allowance of ground fault by selecting the ground option inside the block parameters.

Bus Station 1:

The results of bus stations 1 and 2 are the same as a pole-to-pole faults. Till now, pole to pole and double pole faults are showing the same behavior.

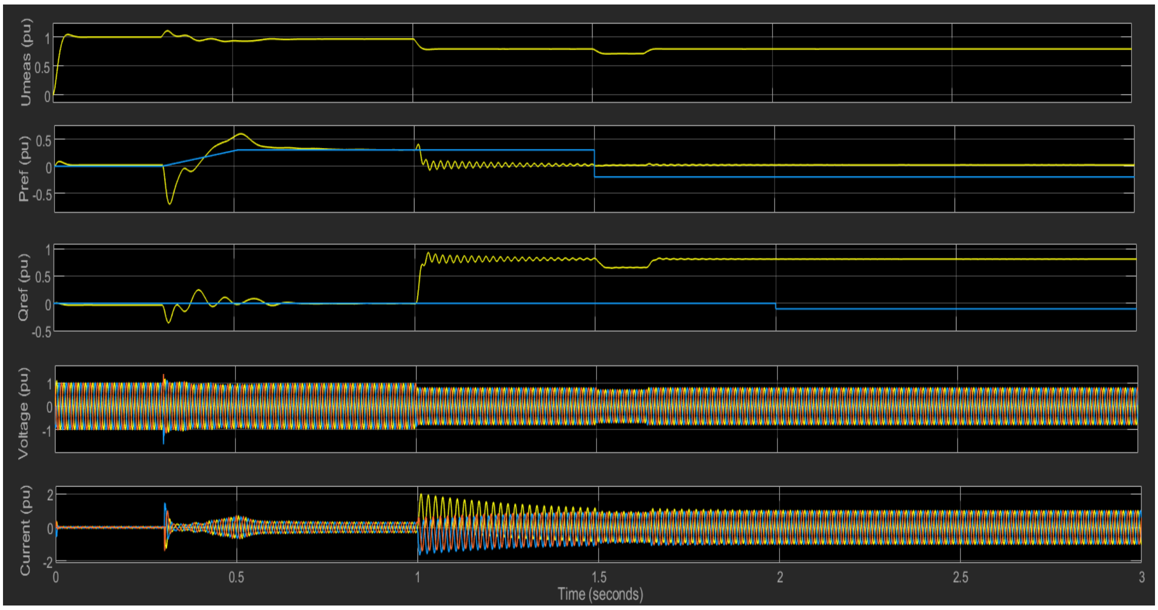


Figure 4.30 (a) Bus Station 1 for the double pole to ground fault.

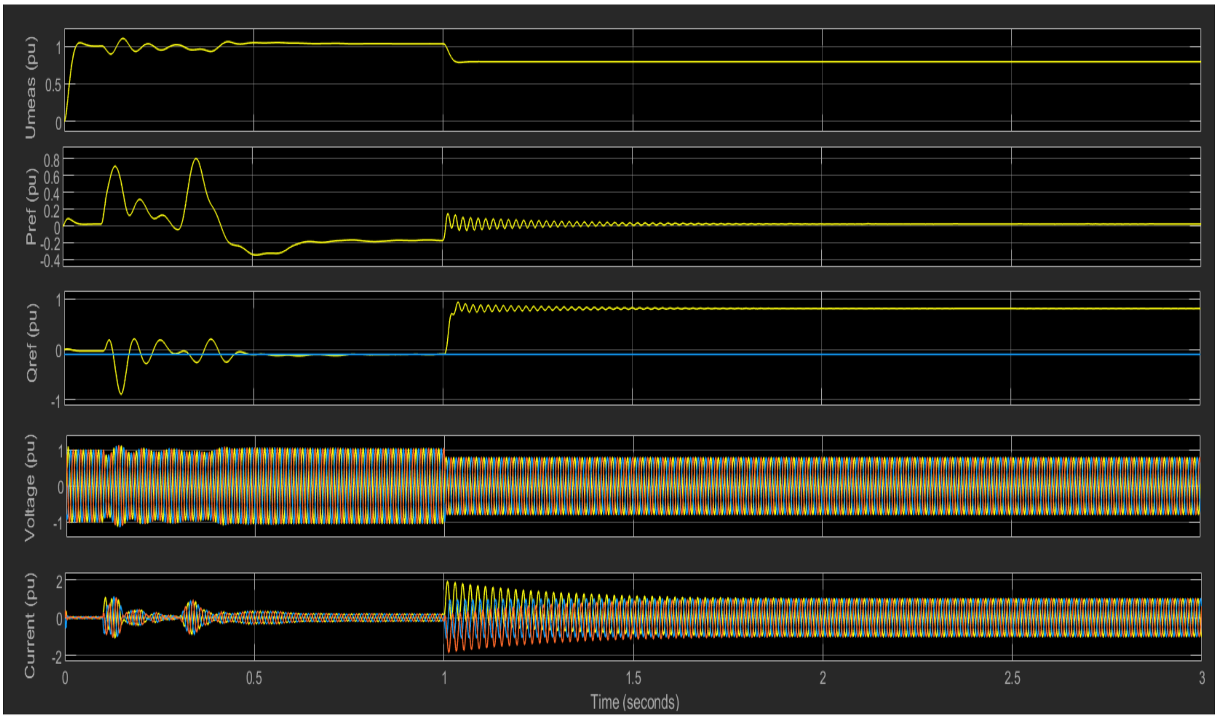


Figure 4.30 (b) Bus Station 2 for the double pole to ground fault.

Direct Current results:

Direct currents are also almost the same as the pole-to-pole faults

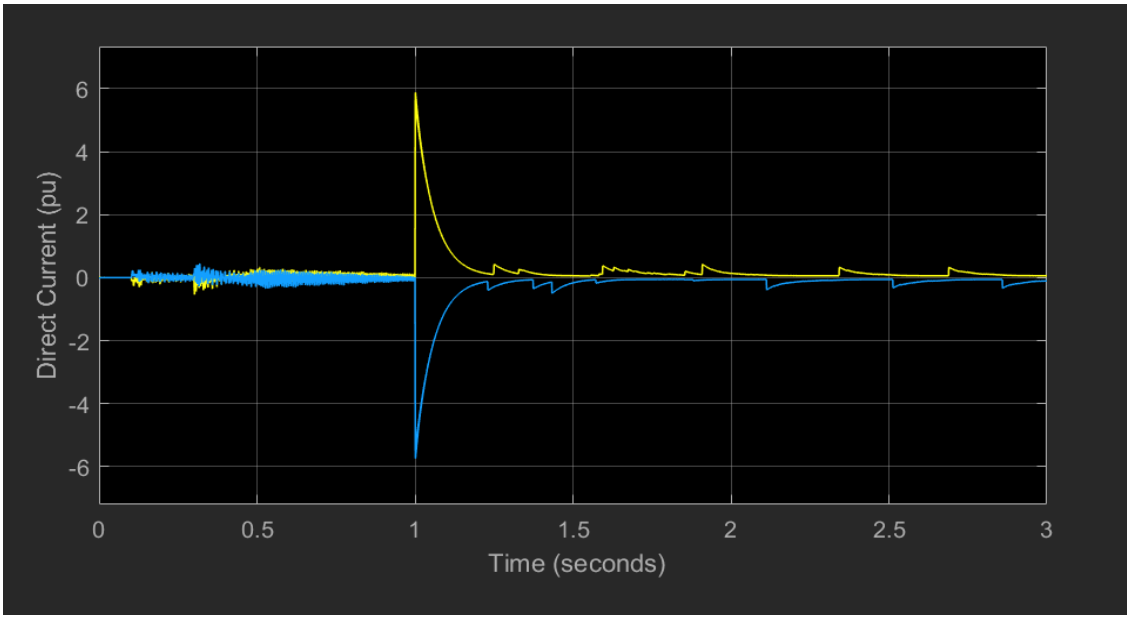


Figure 4.31 (a) Positive and negative current of double pole to ground faults. (station 1)

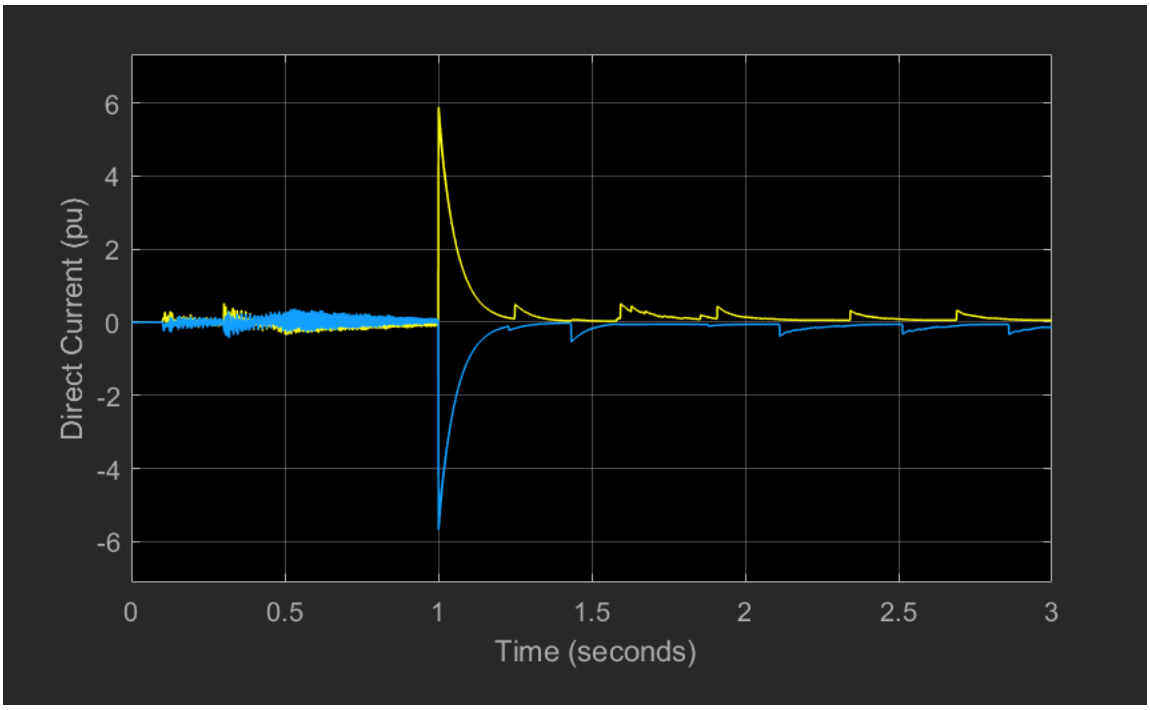


Figure 4.31 (b) Positive and negative current of double pole to ground faults. (station 2)

DC Voltage:

Pole to pole and double pole to ground shows the same behavior.

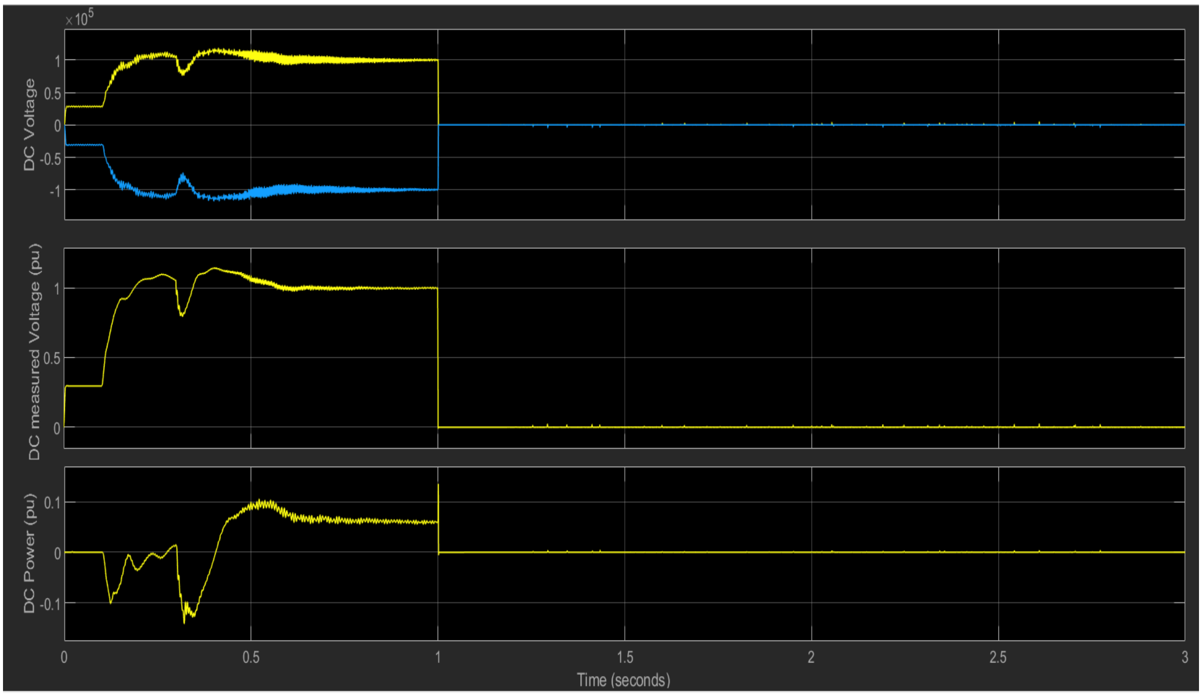


Figure 4.32 (a) DC Voltage (station 1)

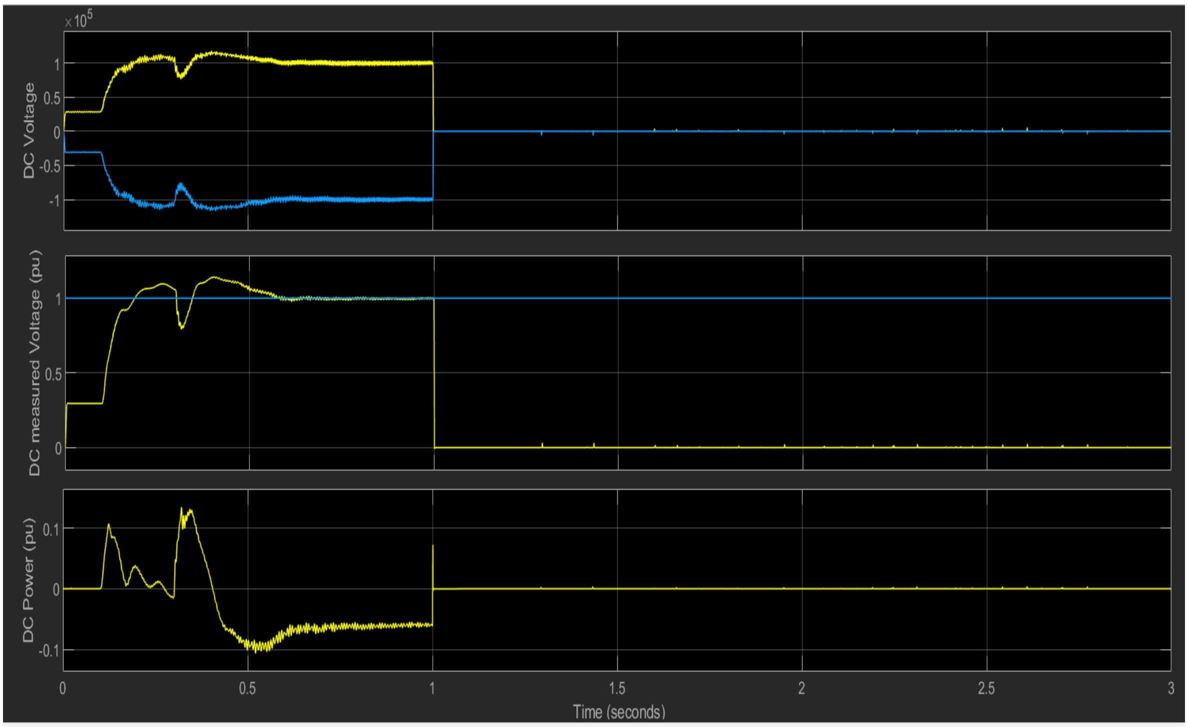
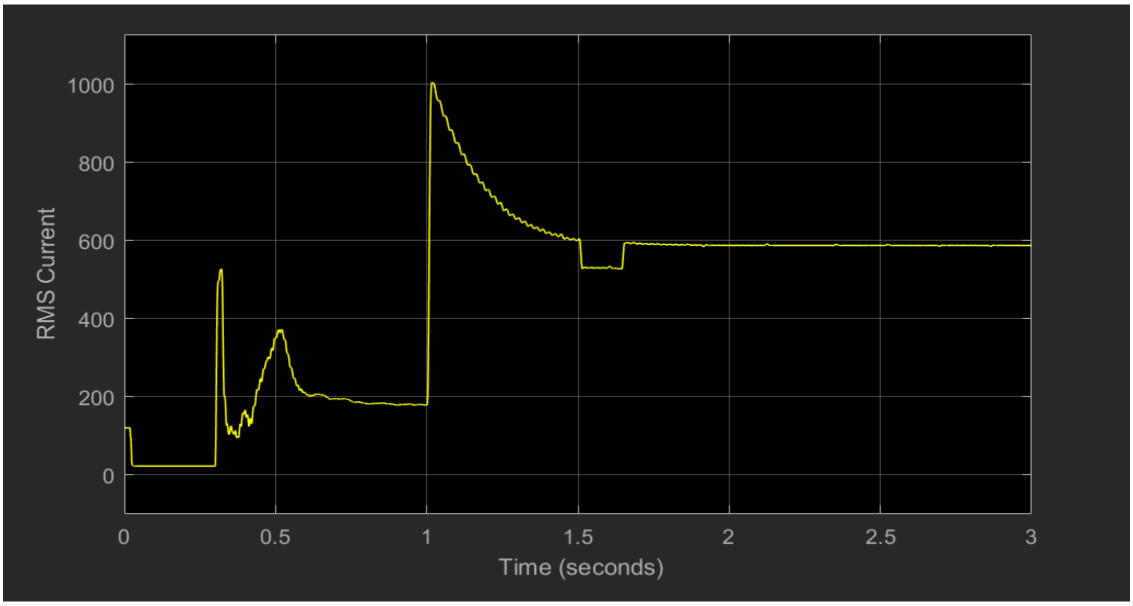
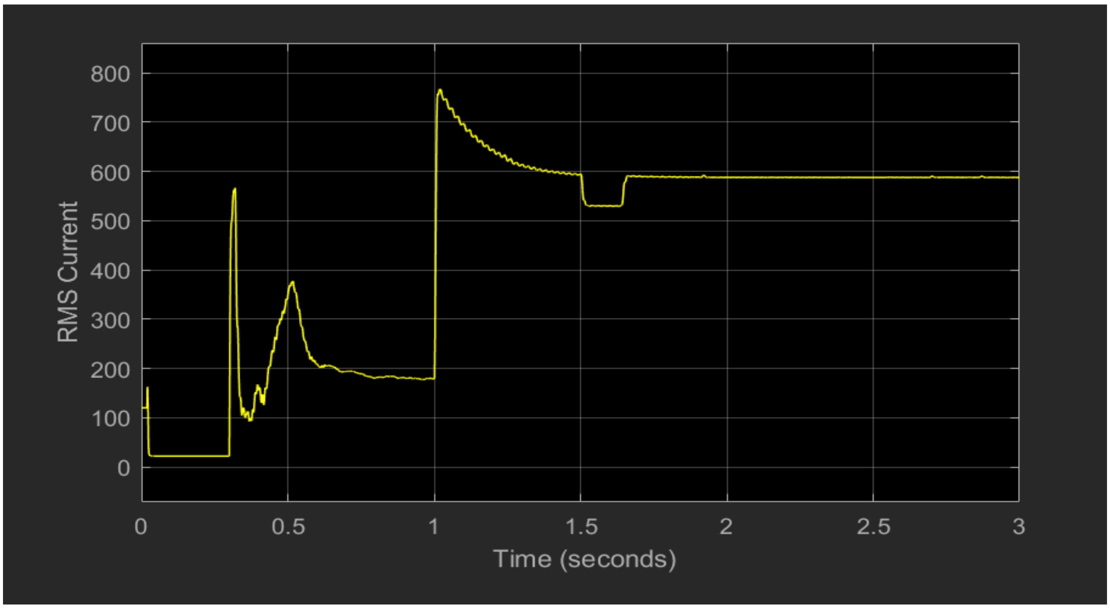


Figure 4.32 (b) DC Voltage (station 2)

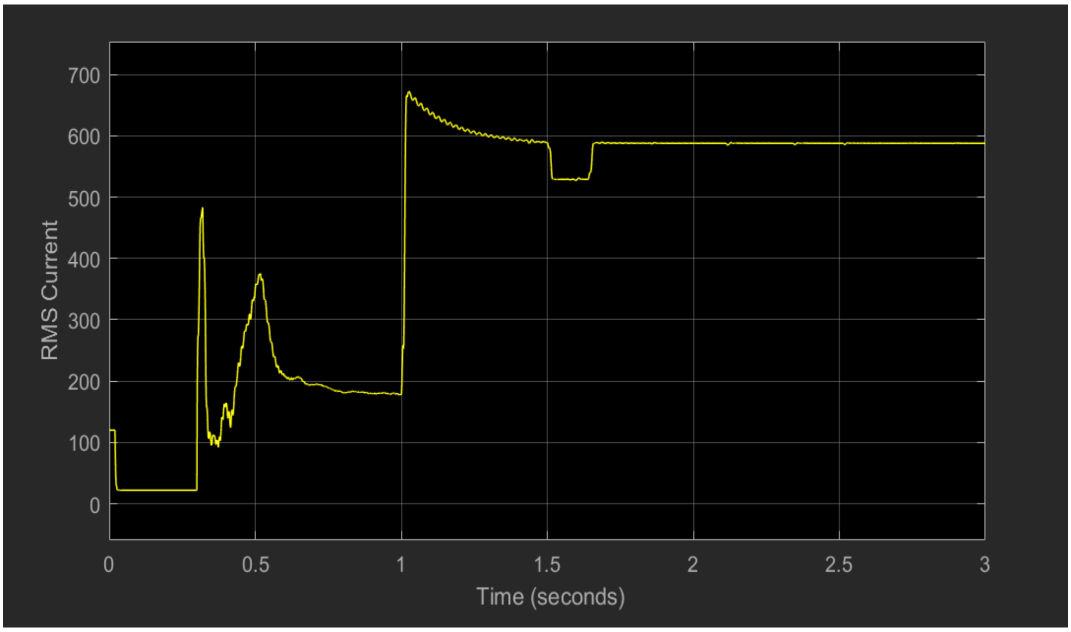
The RMS current of switches 1,2 and 3 are the same as the pole-to-pole faults.



RMS Current (Switch 1)



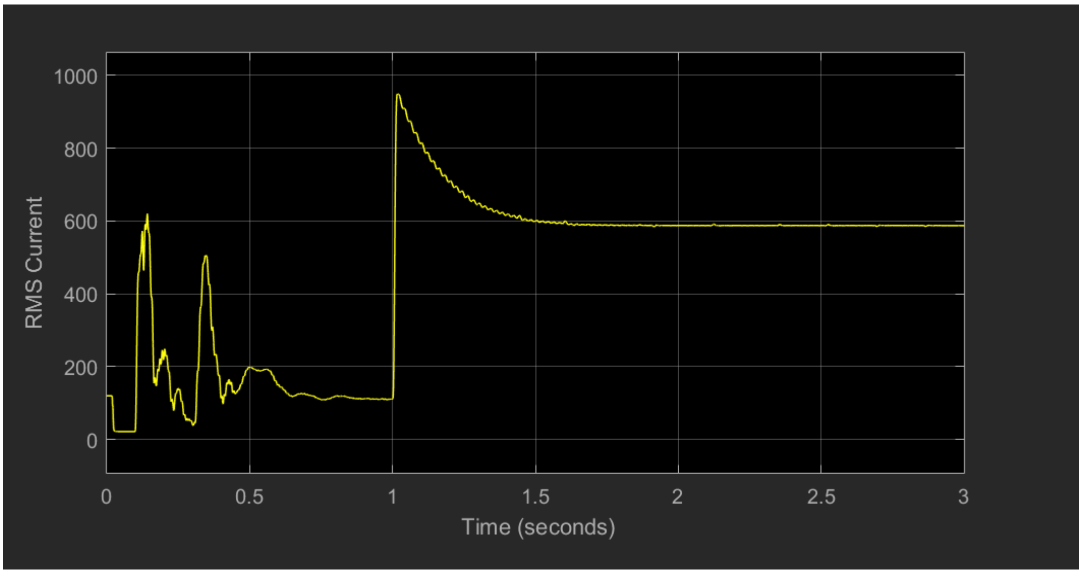
RMS Current (Switch 2)



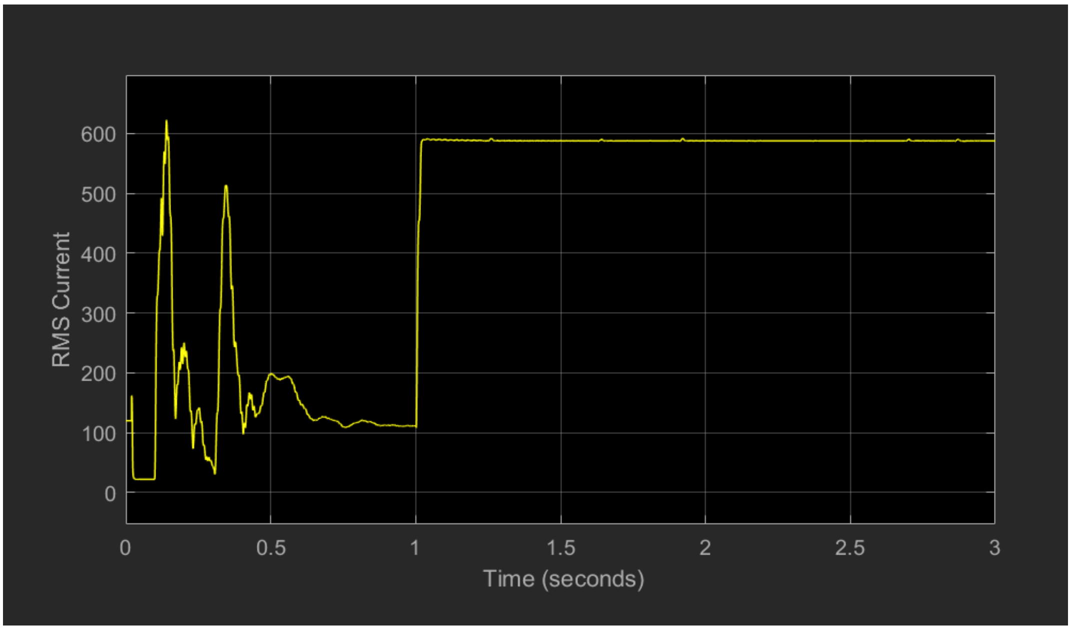
RMS Current (Switch 3)

The RMS Current value of switches 4, 5, and 6 are shown below.

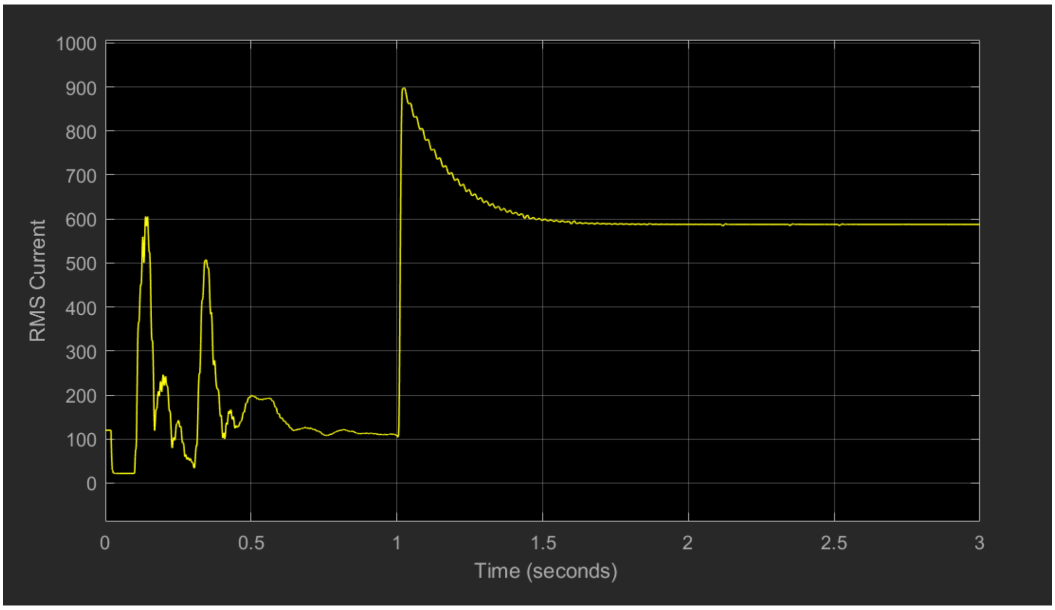
From the graphs, we can conclude that whatever is valid for the pole-to-pole faults is also true for the double pole to ground grounds. The switches from AC system 2 of the double pole to ground faults also show identical behavior with the pole to pole faults.



RMS Current (Switch 4)



RMS Current (Switch 5)



RMS Current (Switch 6)

The highest current in each switch can be found in the following Table 4.5.

Table 4.5

Ideal switches	**RMS currents**
Ideal switch 1	1006
Ideal switch 2	768
Ideal switch 3	672
Ideal switch 4	948
Ideal switch 5	622
Ideal switch 6	898

4.3 Protection Strategy for symmetrical Faults.

Before simulating the protection strategy, let's see what blocks are needed for the protection systems and how they can be connected. The modified circuited has been shown in Figure 4.33; the output of three RMS blocks is entered through max for giving a single output. The most important block is the relay. The constant 1 has been removed, and the relay has been added. This relay stores the reference value that is assigned. When the current exceeded this reference value, the circuit must trip and stop the fault current inside the circuit. Another two-input scope is also added for clarifying the exact duration of trips.

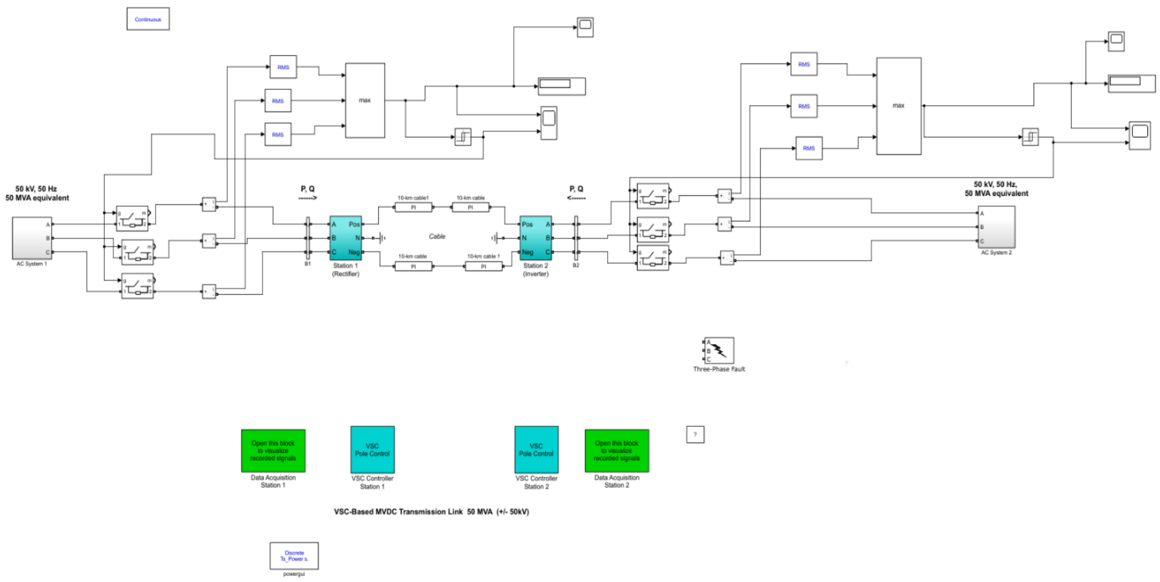


Figure 4.33 Modified circuit for Protection strategy

4.3.1 Three-phase with ground connection fault. (L-L-L-G)

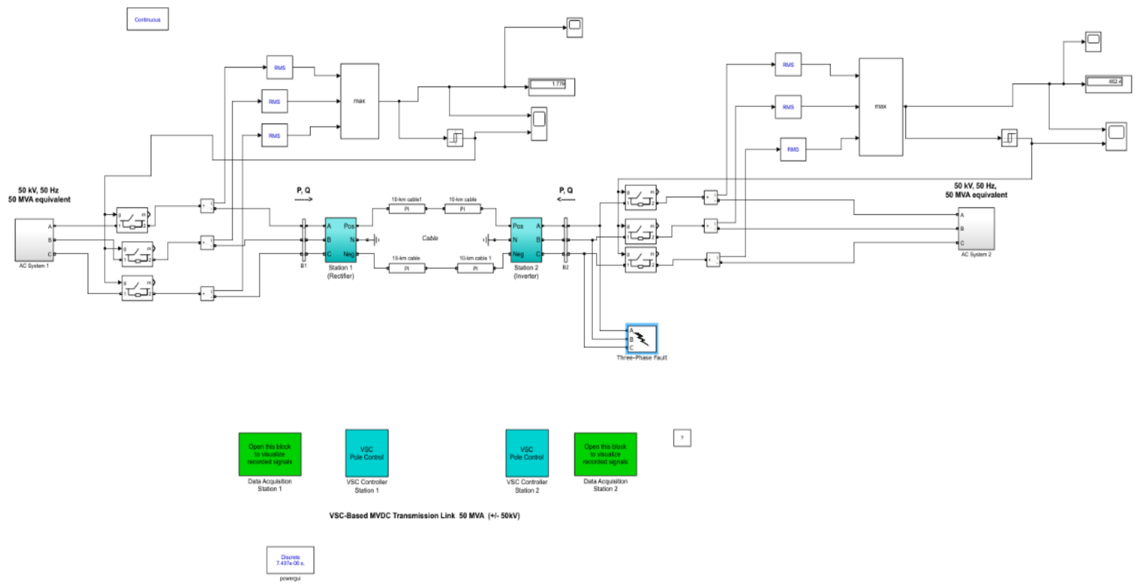


Figure 4.34 protection strategy of three-phase with ground connection fault

The highest standard current on AC system 1 switches is 566, so we can choose the reference value of 600 amperes on the AC system 1 side. On the AC system 2 side, the highest current from the table is 622, so we can choose the reference value as 700 amperes. Due to the short circuit fault, the current exceeded a lot on both the AC sides, so we need to trip the system when the current goes above the expected value.

These reference values must be commanded in the relay. For example, from Figure 4.35, the block parameters of the relay are shown. The current reaches 700; the output current we get should be zero; otherwise, 1 when the current is below 700. We assign Switch-on points.

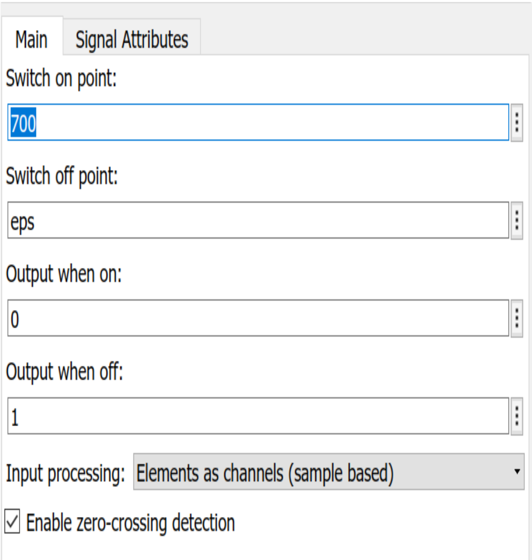


Figure 4.35 Block Parameters of Relay.

Let's apply this strategy when we have a three-phase with ground connection fault.

Figure 4.36 (a) shows that the values are the same until 1.5 seconds because the reference value of the current is not exceeded but after this time, the circuit trips. Pref, Qref, current, and voltage measurements show the same behavior with or without applying a protection system before the circuit trips. After it trips, every value comes to zero. Measure voltage has to offer something more. Approximately at 1.6 seconds, the voltage goes as high as approximately 3, then it drops to zero. The system shutdowns for a while unless the short circuit fault is cleared and re-energized. The auto reclosure is not applied here. It can help us by not damaging the system and protecting the expensive components.

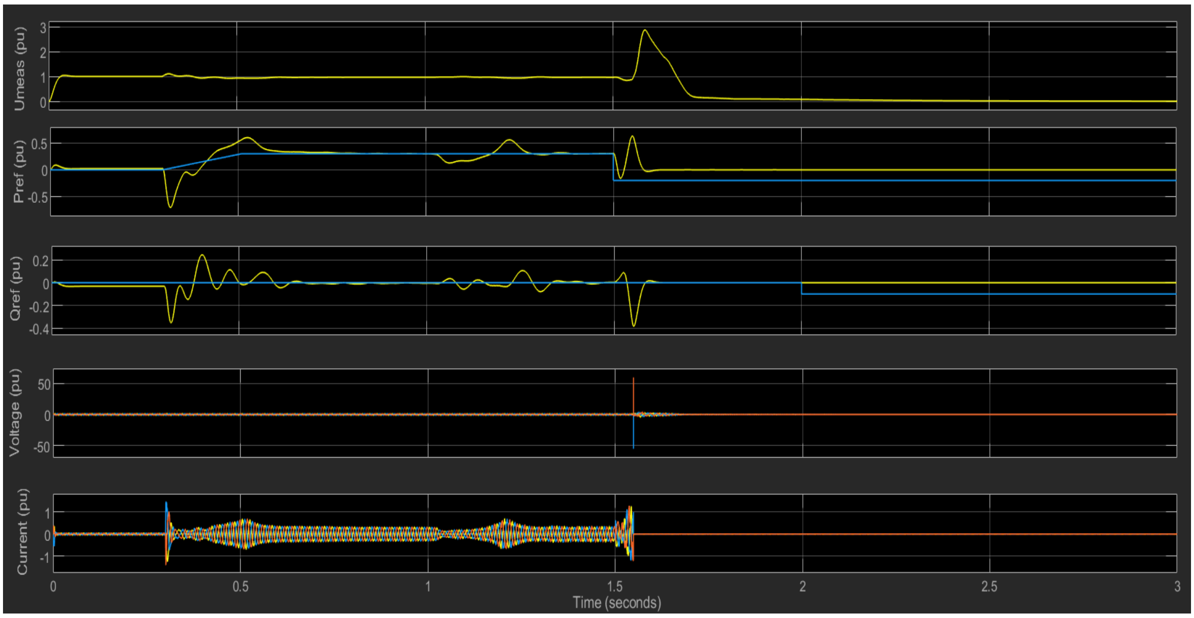


Figure 4.36 (a) Bus station 1 after applying protection strategy.

Figure 4.36 (b) shows that when the reference value is exceeded, every quantity comes to zero. This reference value is considered a nominal value if the value of a quantity is less than the value; it is considered normal, but when it goes above this, it is abnormal, so the relay trip the circuit.

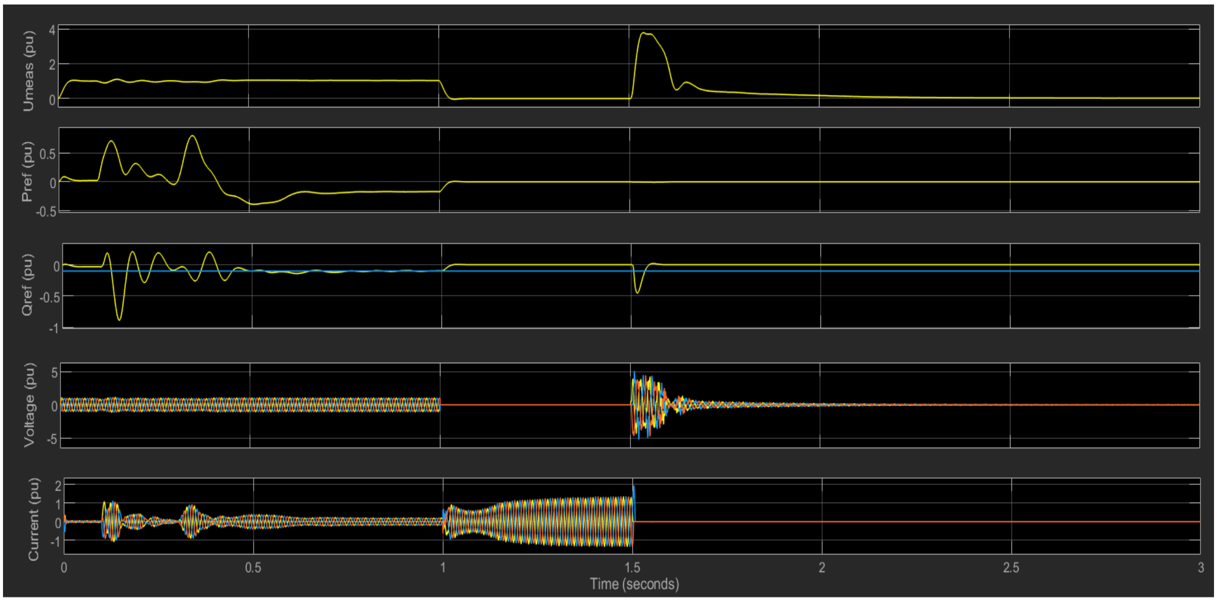


Figure 4.36 (b) Bus station 2 after applying protection strategy.

Direct Current result:

The Direct Current shows some changes after 1.5 switching times. The system has been shut down due to the fault. The switches are open and show no signs of current flowing after the current exceeded the reference value.

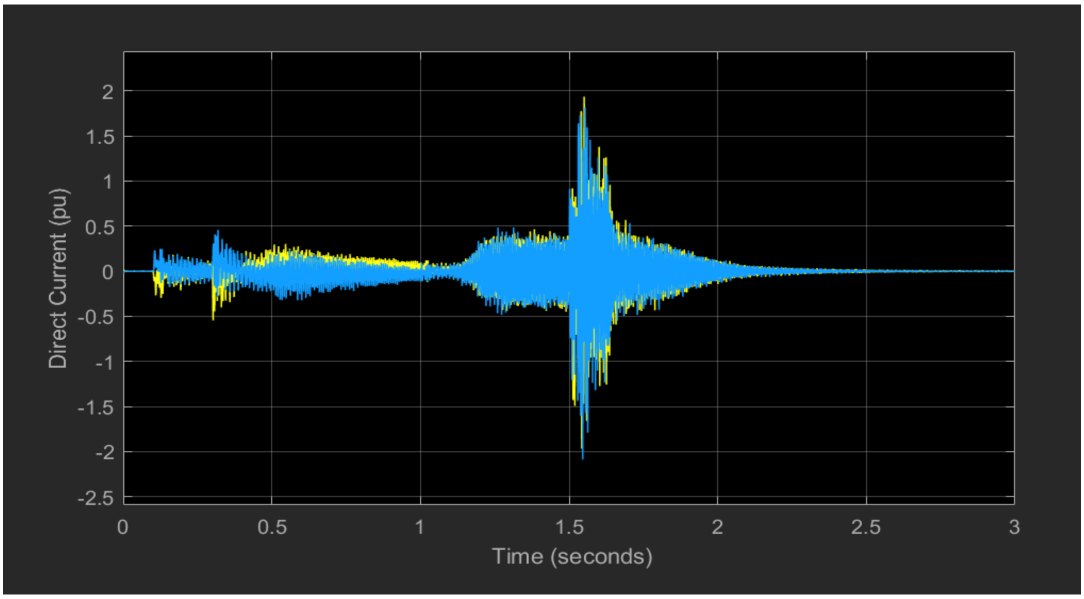


Figure 4.37 (a) DC after applying protection strategy. (station 1)

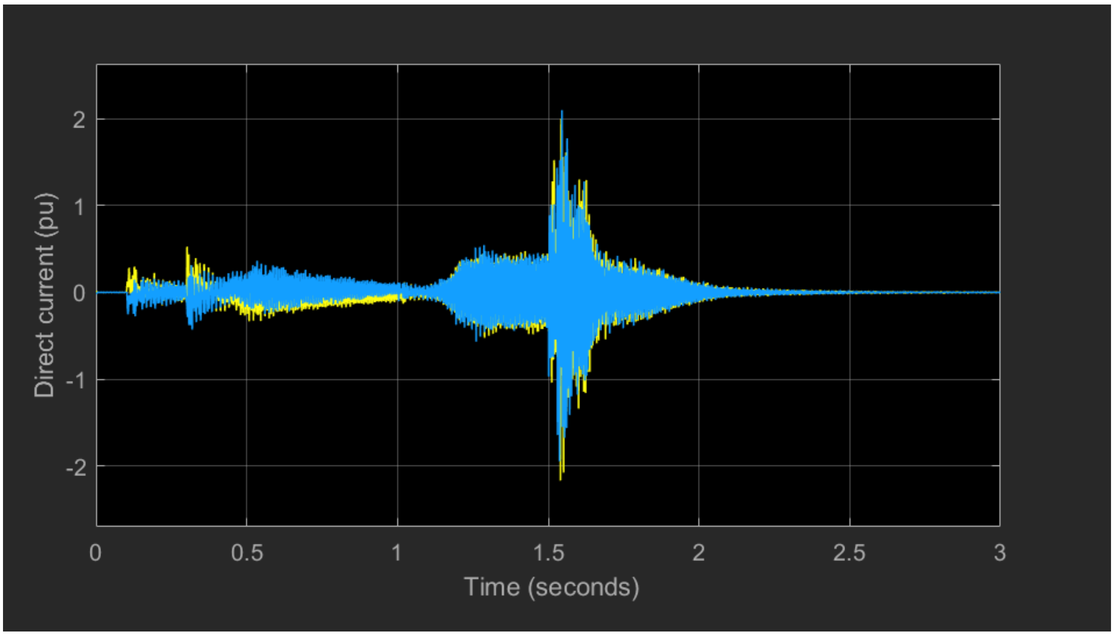


Figure 4.37 (b) DC after applying protection strategy. (station 2)

DC Voltage:

The circuit has been tripped when the fault has occurred. It is shown in the Figure 4.38 (a) and Figure 4.38 (b), when the reference value has been exceeded, the relay sends the command to the circuit breaker to trip the circuit. And we can see it has been tripped after 1.5 seconds. It took some time to come to zero.

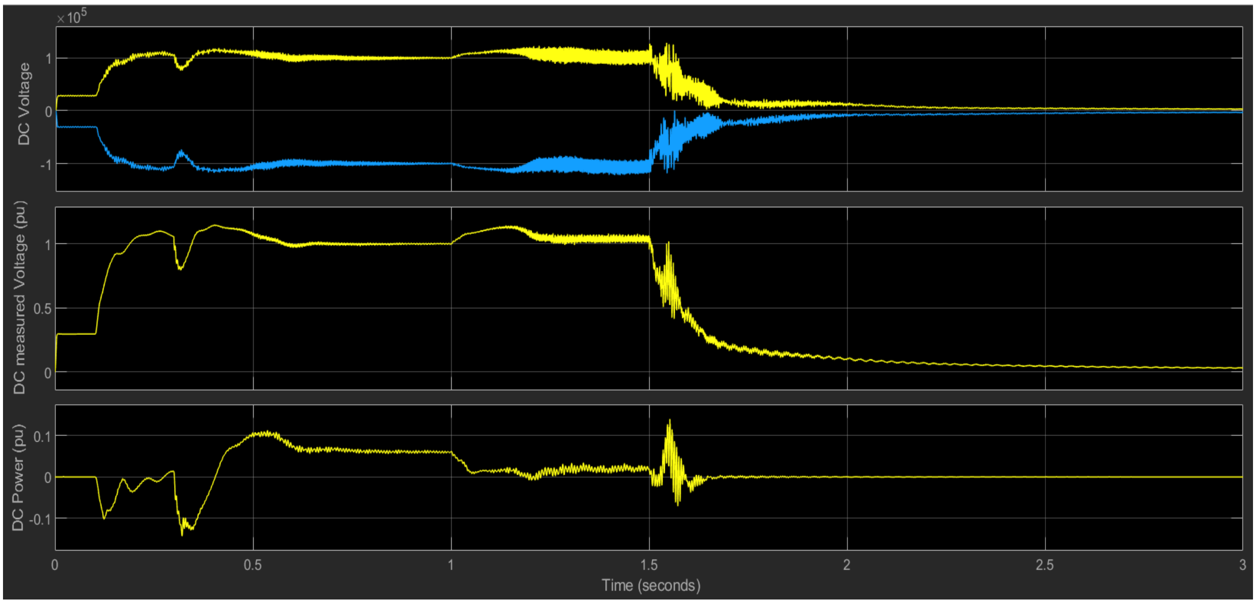


Figure 4.38 (a) DC Voltage (station 1)

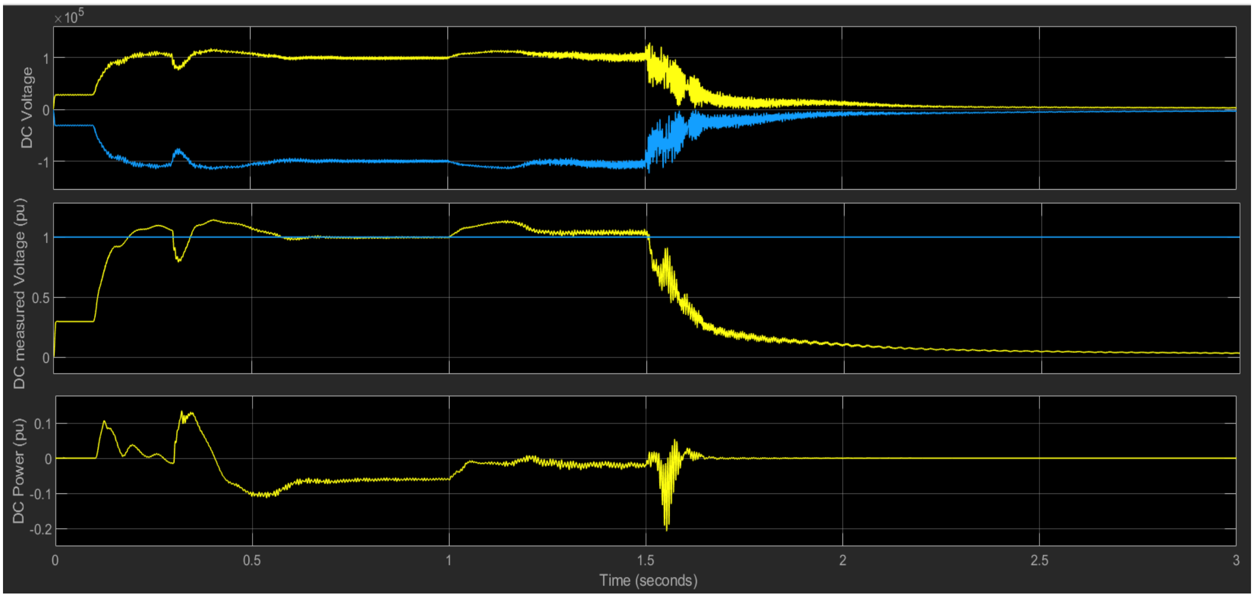


Figure 4.38 (b) DC Voltage (station 2)

The RMS current after applying the protection strategy:

It is cleared that when there is no fault in the system, the system works fine and shows the same behavior as without a short circuit, but after the switching time is reached, the current is exceeded rapidly. Moreover, it is not happening here because the relay sends the signal to the switches to trip when the current exceeded the reference value.

Figure 4.39 shows 2 graphs. The upper one shows when the circuit has been tripped, and the current becomes zero, and the lower one shows the relay commands. When the current is less than the reference value, the output of the relay is 1, and when the current exceeds the reference value, the output of the relay drops to 0. The system is switched off unless the fault is cleared.

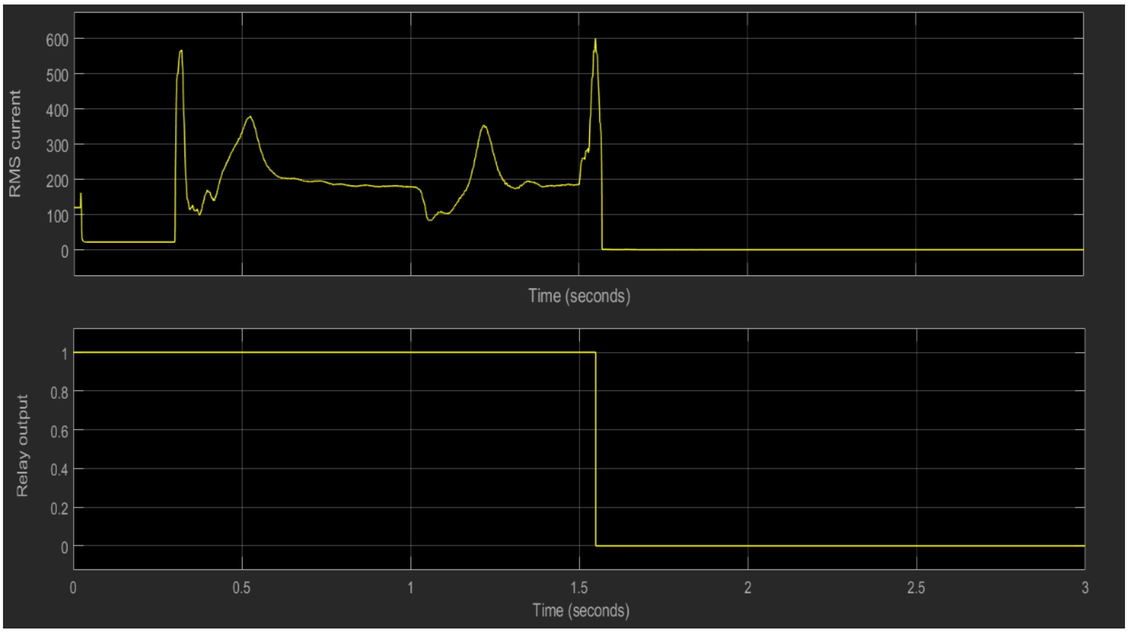


Figure 4.39 result of AC System 1 after applying the protection strategy.

Now let's jump on the other side of the system and see how the currents on AC system 2 change.

From Figure 4.40, it is shown that when the current increases the reference value, the relay sends the command to the switch to switch off. And there won't be any current flow unless the fault is apparent and bring back the normal condition of the current. Till point 1 second, the system is working fine, but then the current increases due to the fault, and the protection system enables and trips the circuit.

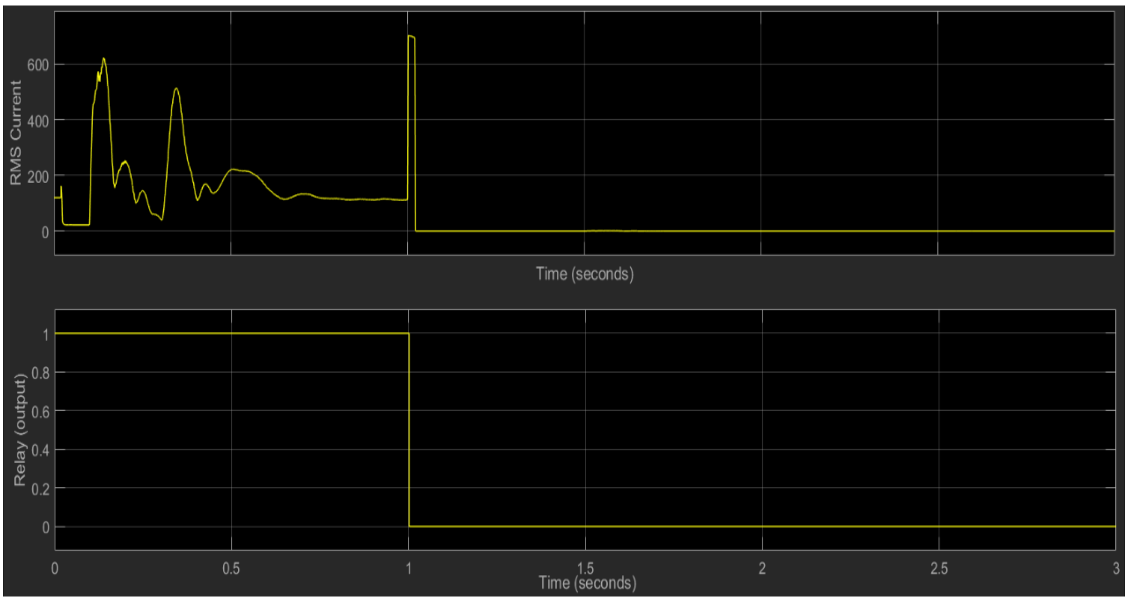


Figure 4.40 Results for AC System 2 after applying the protection strategy.

4.3.2 Line to line to line (L-L-L) fault

As previously discussed, the results of line-to-line-to-line faults are almost the same as the line-to-line-to-line-to-ground faults, so that the protection strategy would be the same in both cases. On the ac side 1, 600 amperes reference is chosen, and on the ac side 2, 700 amperes is chosen. When the current goes higher than these values, then the circuit must trip.

From Figure 4.41 (a) and Figure 4.41 (b), it to be seen that the outcome of (L-L-L) faults are the same as (L-L-L-G) faults, obviously because the short circuit current was showing the same behavior in both cases.

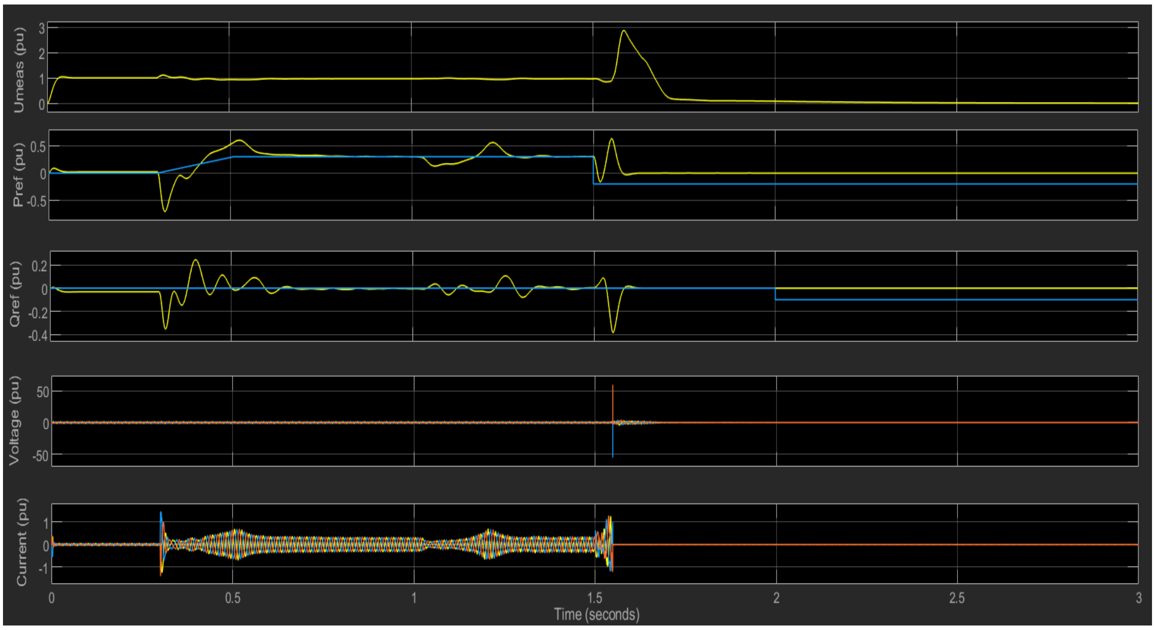


Figure 4.41 (a) Bus station 1 after applying protection strategy.

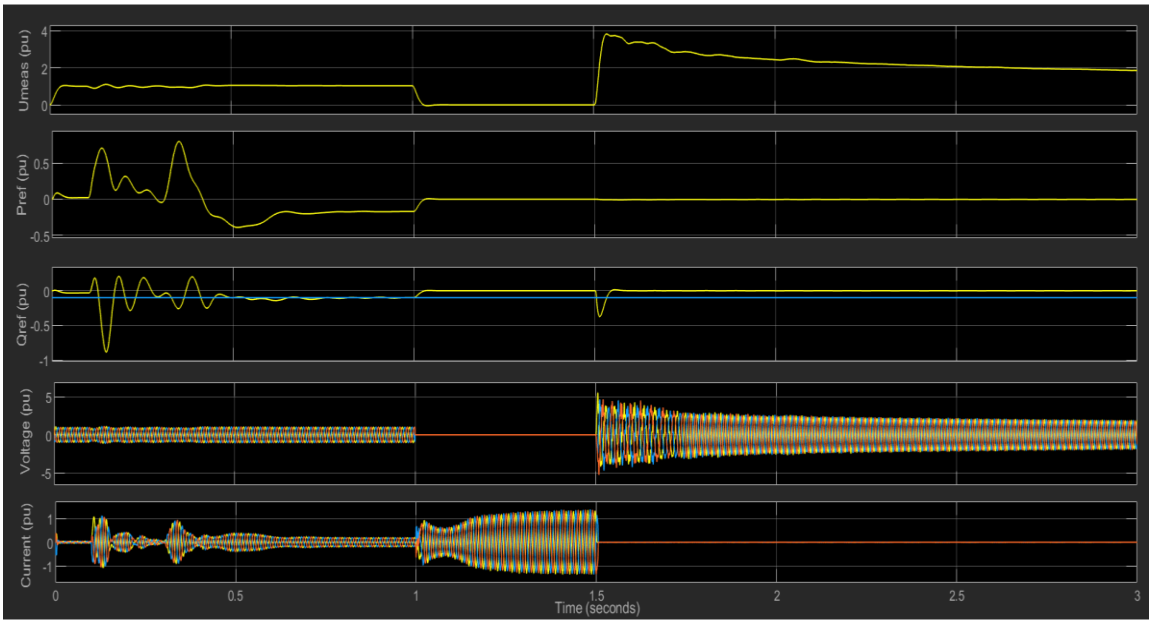


Figure 4.41 (b) Bus station 2 after applying protection strategy.

Direct Current results:

Positive and negative currents also show the same results as expected. The currents usually act when there is no fault current, but the circuit trips thanks to the command of relays to the switches when the fault occurs. The relay helps us save our unique equipment and give us time to clear the fault as soon as possible.

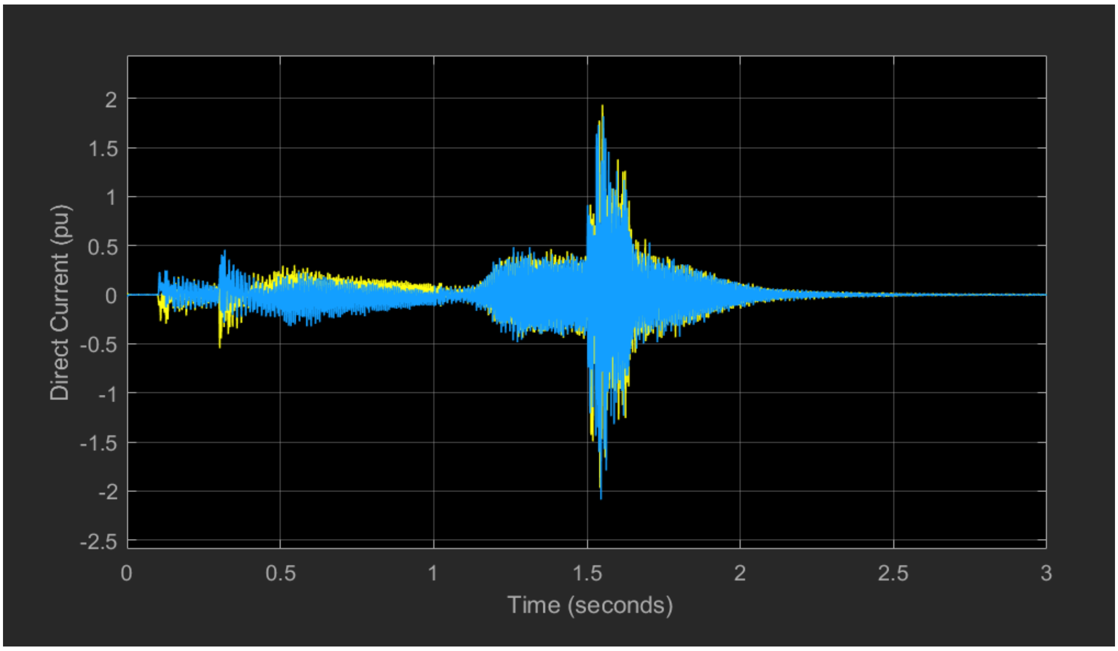


Figure 4.42 (a) DC after applying protection strategy. (station 1)

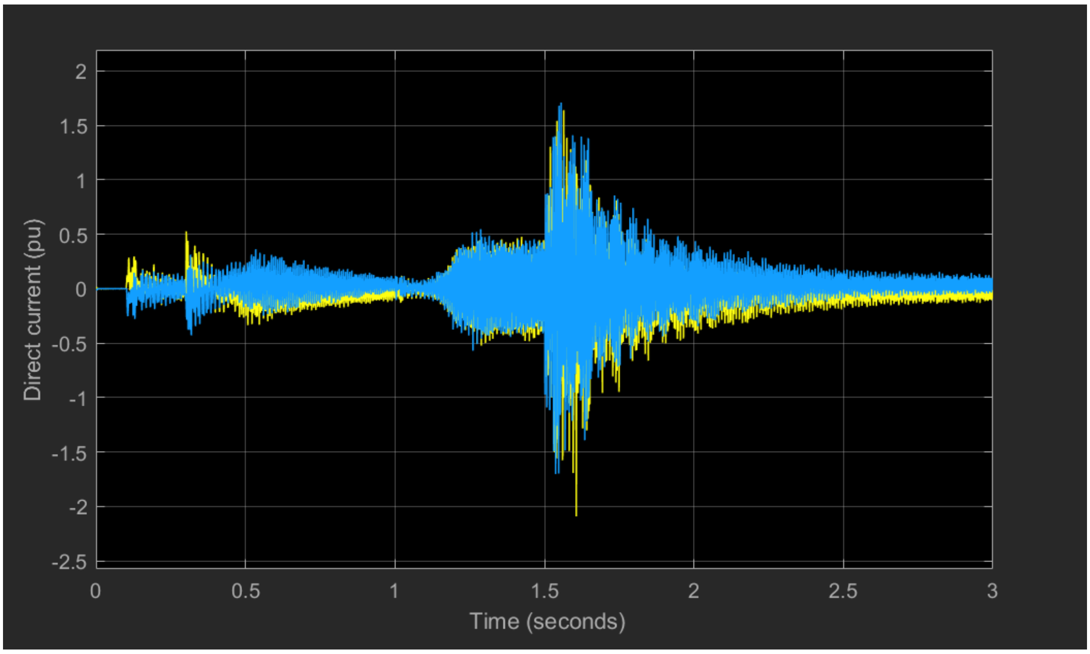


Figure 4.42 (b) DC after applying protection strategy. (station 2)

DC Voltage:

The results of station 1 and station 2 reveals that even though due to the relay, the circuit has been tripped but still the value of voltages and power doesn't reach to zero. It close to zero.

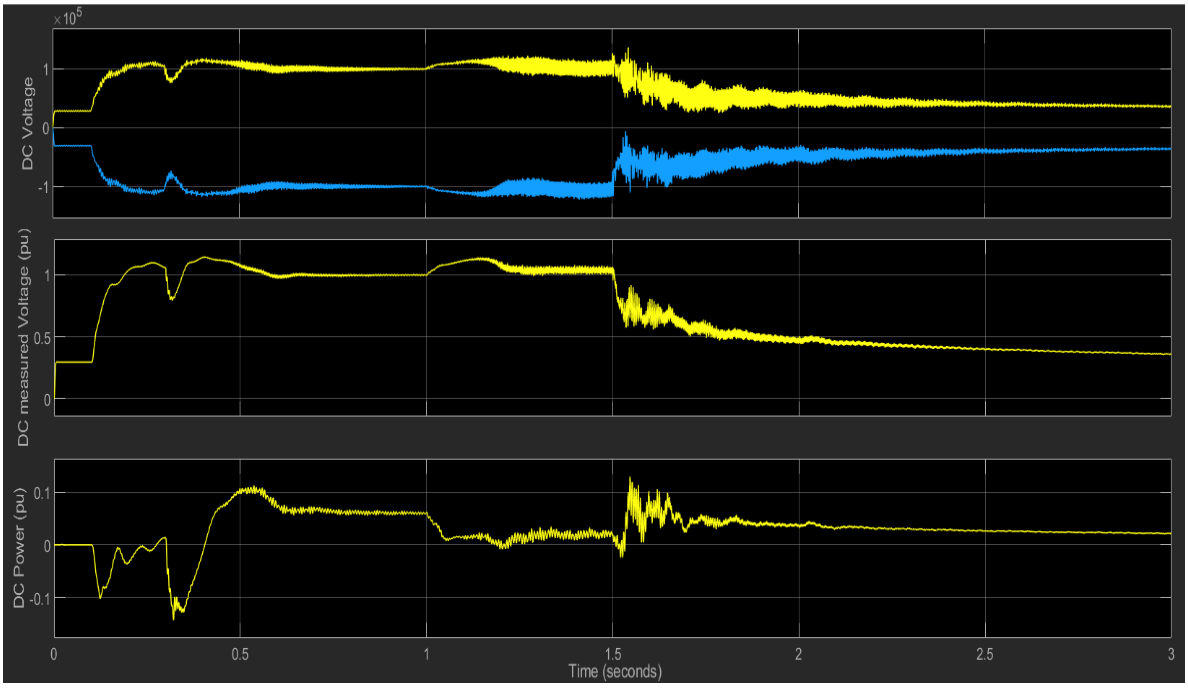


Figure 4.43 (a) DC Voltage (station 1)

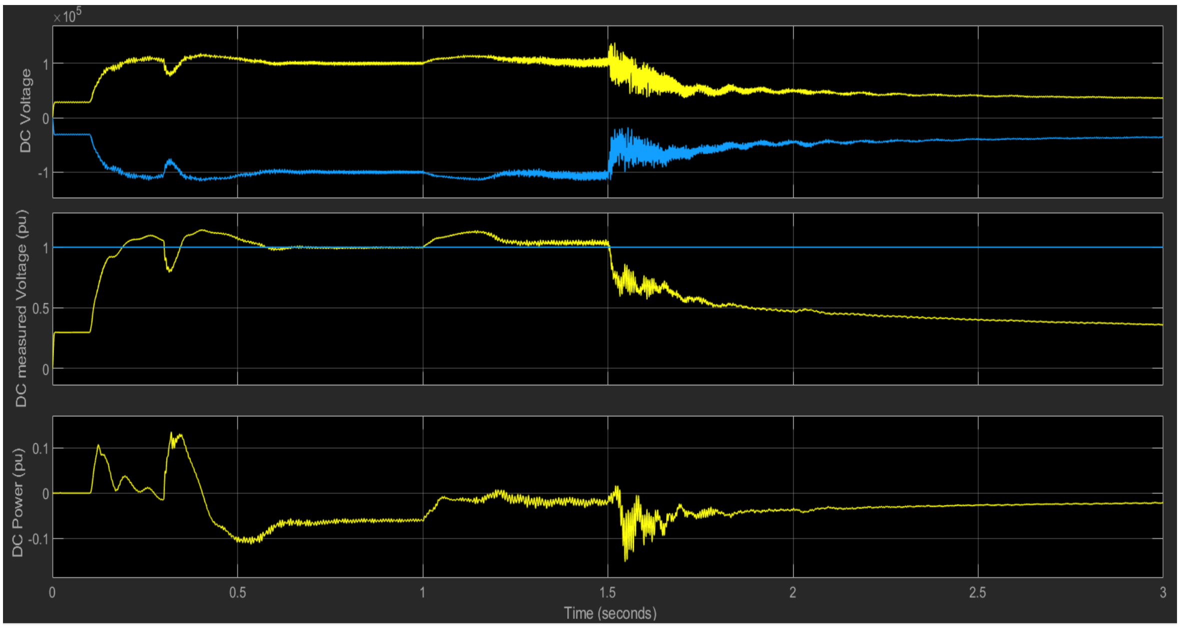


Figure 4.43 (b) DC Voltage (station 2)

The RMS current after applying the protection strategy:

We can see from Figure 4.44 (a) and Figure 4.44 (b) that when the current follows the normal flow, the circuit usually behaves, but the current exceeded the typical values when there is a symmetrical fault. If these High currents are not cleared in time, then there would be massive destruction, but with the help of relays and switches, we can control this High current.

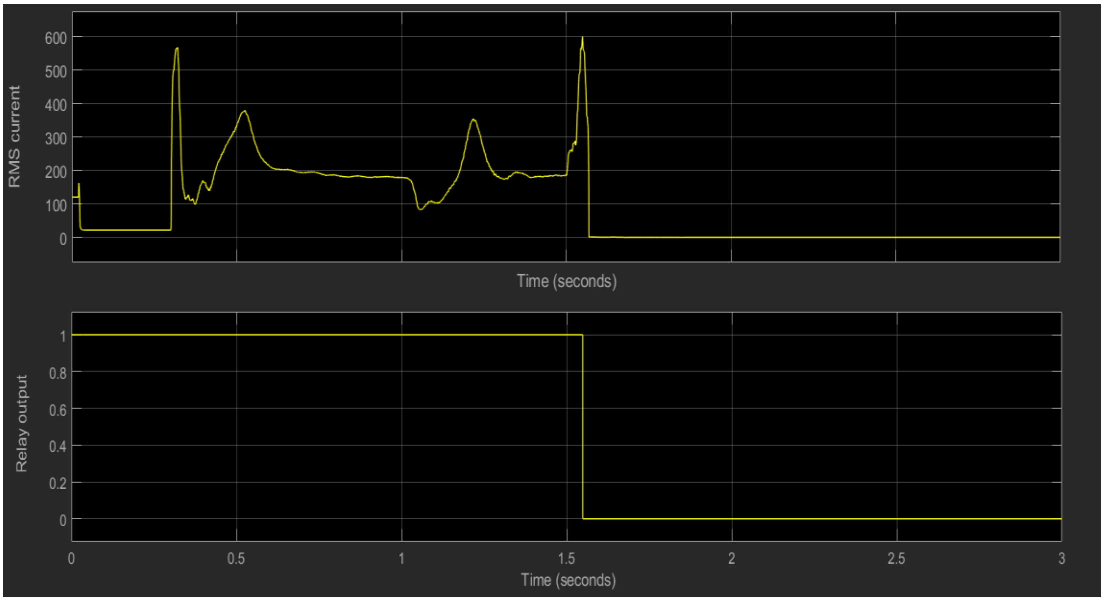


Figure 4.44 (a) Result of AC System 1 after applying the protection strategy.

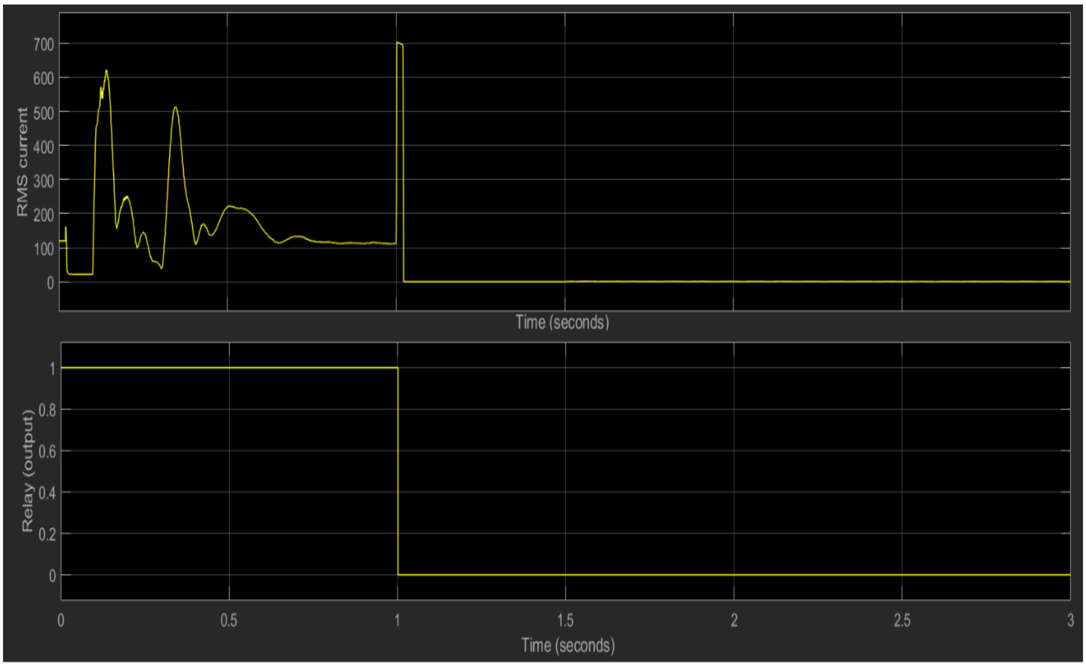


Figure 4.44 (b) Results for System 2 after applying the protection strategy.

4.4 Protection strategy for unsymmetrical faults.

4.4.1 The pole to ground fault

From the analysis, we conclude that the highest current that would flow when there is a pole to ground is approximately 918, which is the highest among the three switches in AC side 1. So, for the AC side 1, we can take the reference of 700 because the normal flow of current is approximately 566, and the fault takes the current to 918.

For the AC side 2, the reference value suitable to choose is 750

The circuit would look like the following (Figure 4.45)

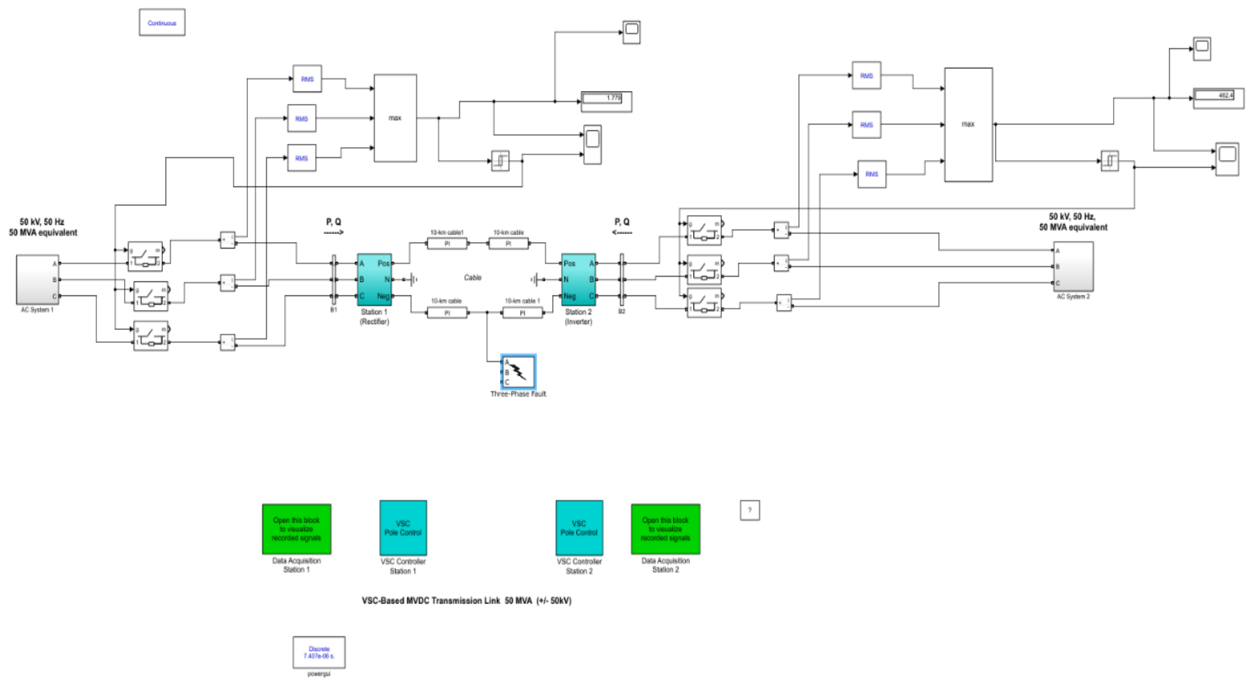


Figure 4.46 Modified circuit for Protection strategy of phase to ground fault.

Bus station 1.

Bus station 1 shut down after 1 second as the current goes over the reference value that we assigned inside the relay to protect our system.

The bus station 1 blocks would show the following behavior shown in Figure 4.47 (a).

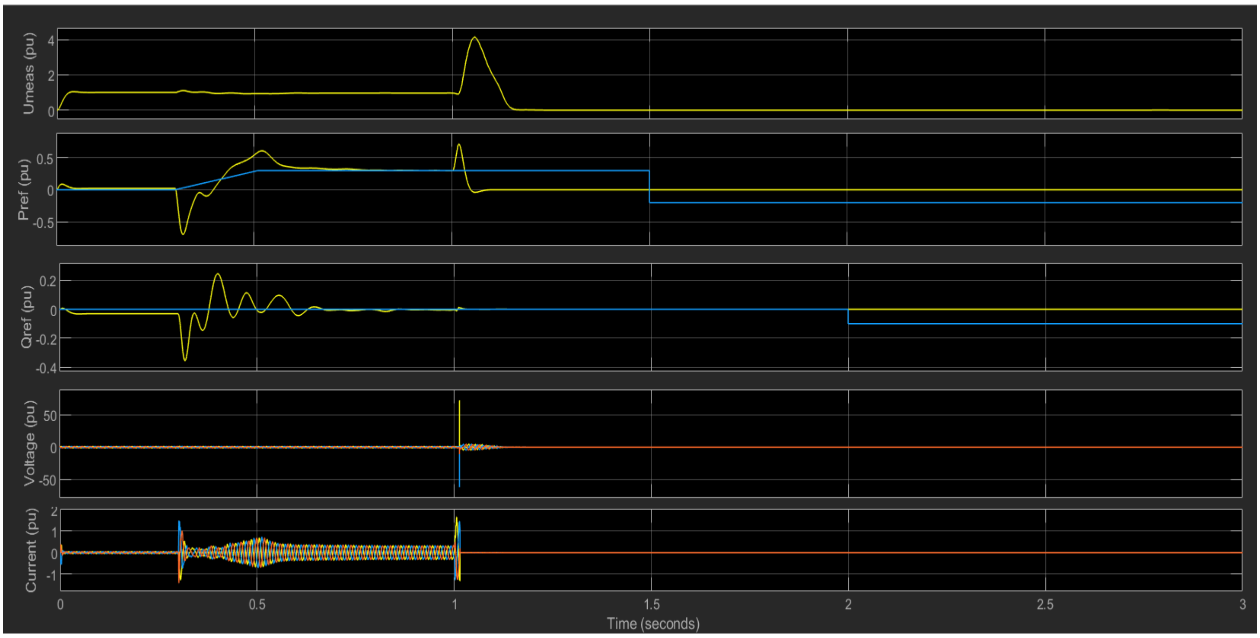


Figure 4.47 (a) Bus station 1 of the pole to ground fault after applying the protection strategy.

Bus station 2:

It can be seen from figure 4.48 (b) shows that when the quantities in bus station 2 go to zero, the quantities value exceeded the reference value.

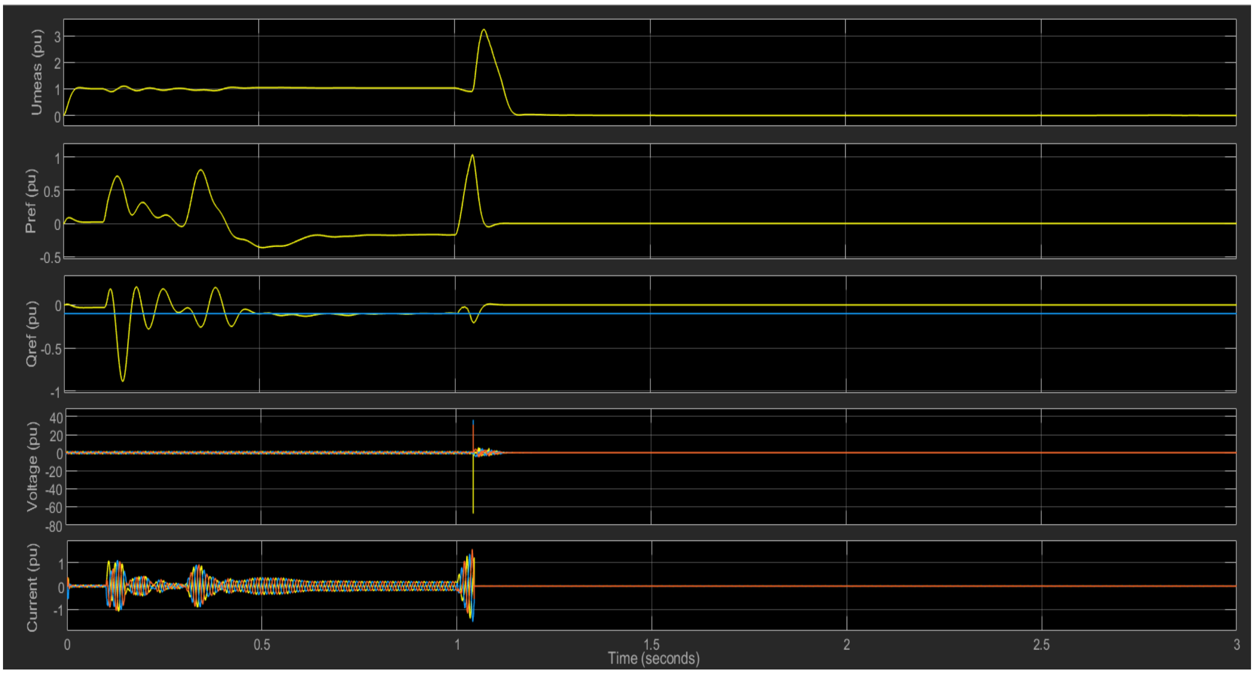


Figure 4.48 (b) Bus station 2 of the pole to ground fault after applying the protection strategy

From Figure 4.48 (b). it's cleared that the fault is no longer going to affect our system. The switch goes off, and the system shutdowns after 1 second. It is like this until the fault is cleared.

DC Current Result:

When there is no short circuit fault, the system usually behaves obviously, but the current hits the peak value after the fault occurs. With the help of the relay and the switch, the fault is cleared after switching time, as shown below.

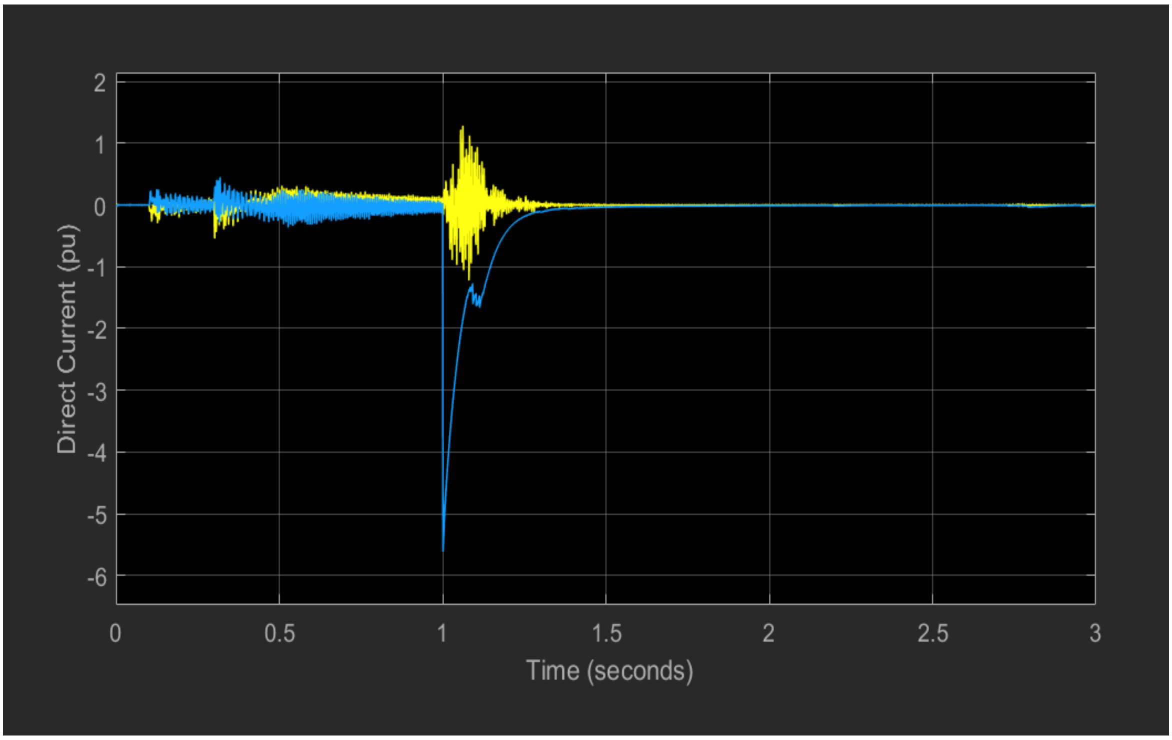


Figure 4.49 (a) DC behavior of pole to ground fault after applying the protection strategy. (station 1)

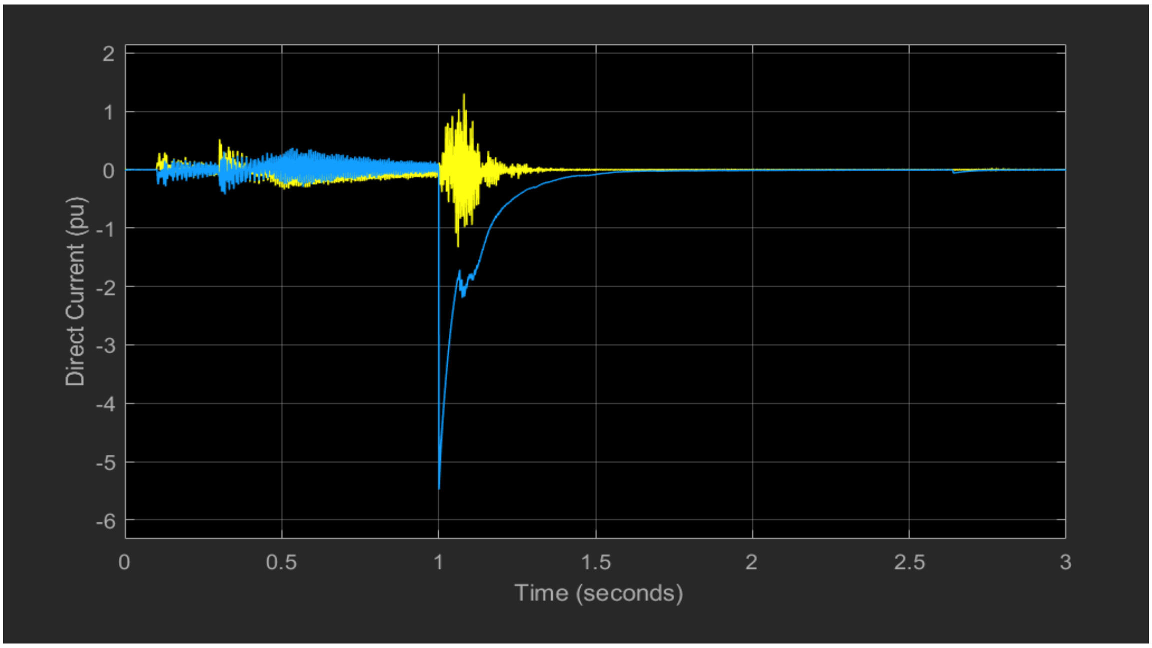


Figure 4.49 (b) DC behavior of pole to ground fault after applying the protection strategy. (station 2)

DC Voltage:

The circuit has been tripped immediately after the pole to ground fault occurs but It took a little time for the positive voltage to come to zero.

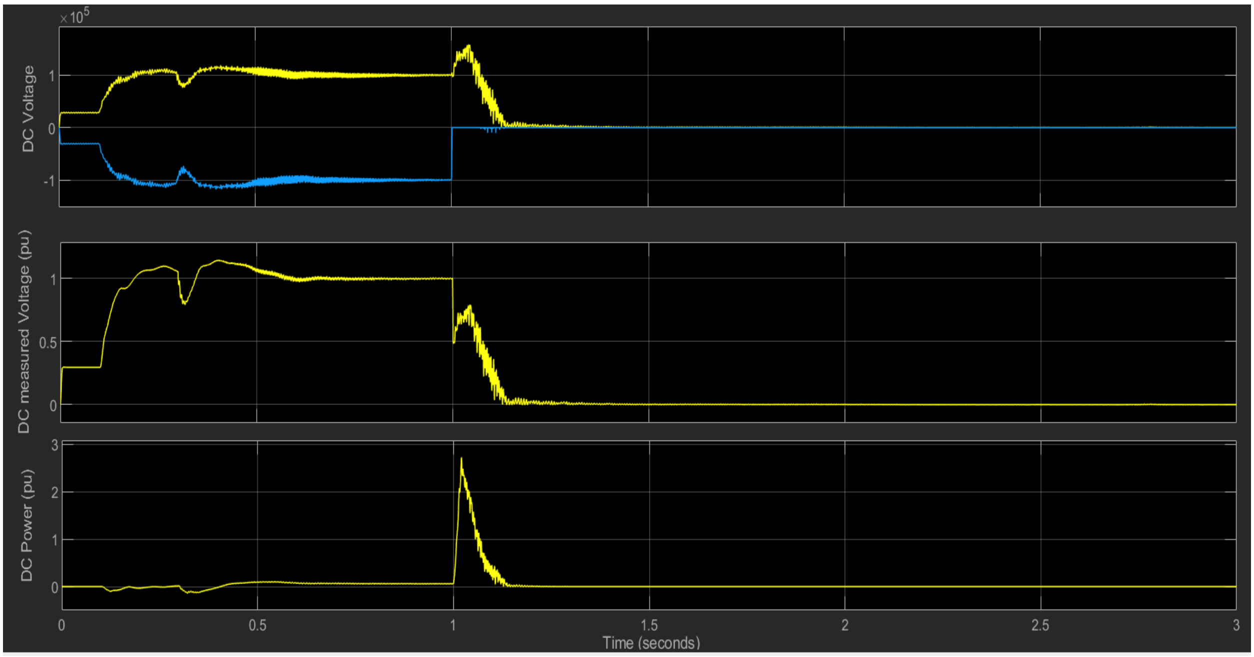


Figure 4.50 (a) DC Voltage (station 1)

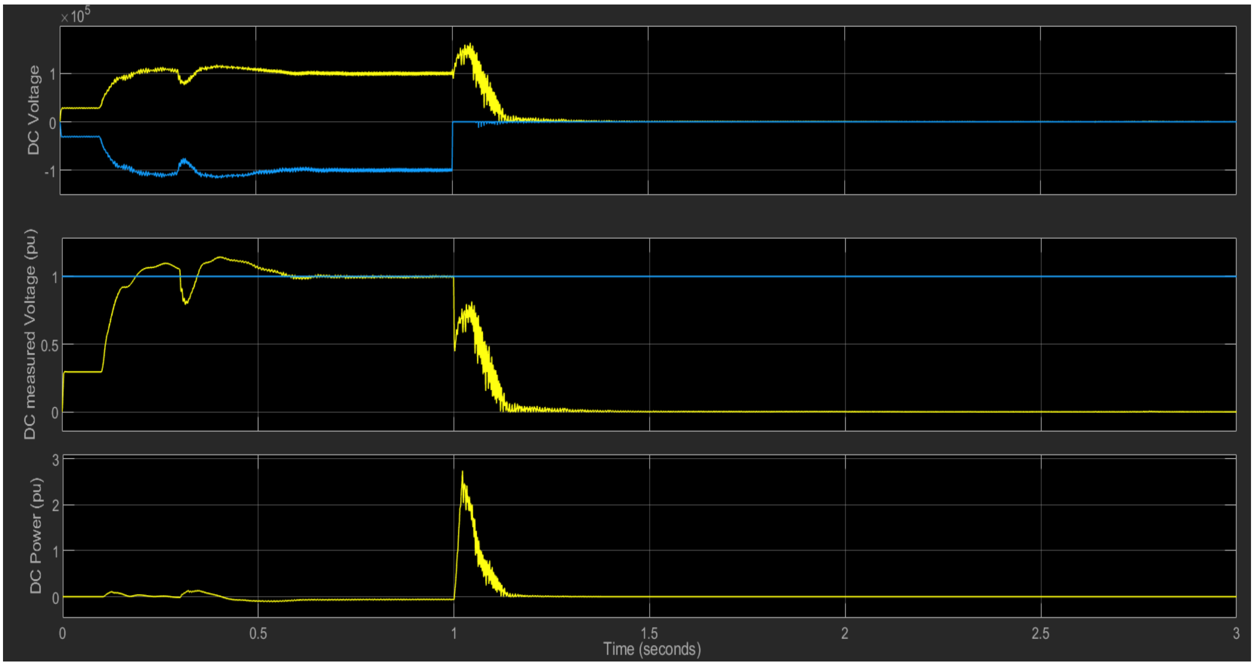


Figure 4.50 (b) DC Voltage (station 2)

RMS current of the pole to ground fault:

It's easily understood now that why these graphs look like this. It's just because of the relay signal which makes the switch to trip. After the reference value, the current goes to a hazardous point where the electrical component can be destroyed easily. So, the protection system prevents them and keeps the whole system safe by tripping the switch. That is what is happening in Figure 4.51 (a) and Figure 4.51 (b)

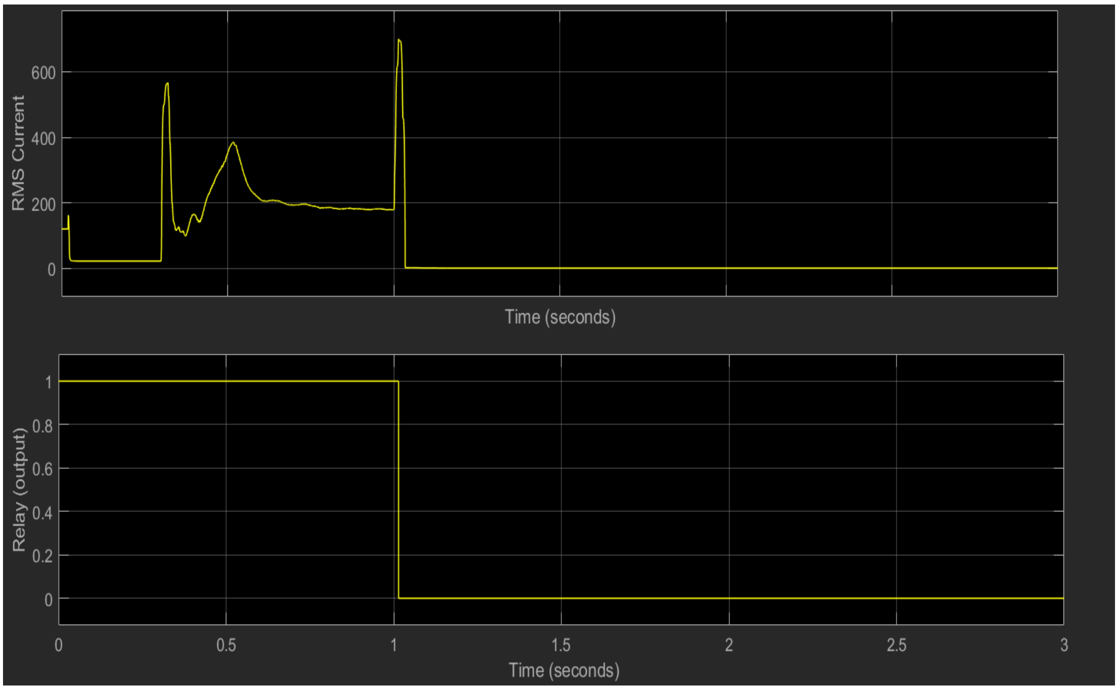


Figure 4.51 (a) RMS current on AC Side 1

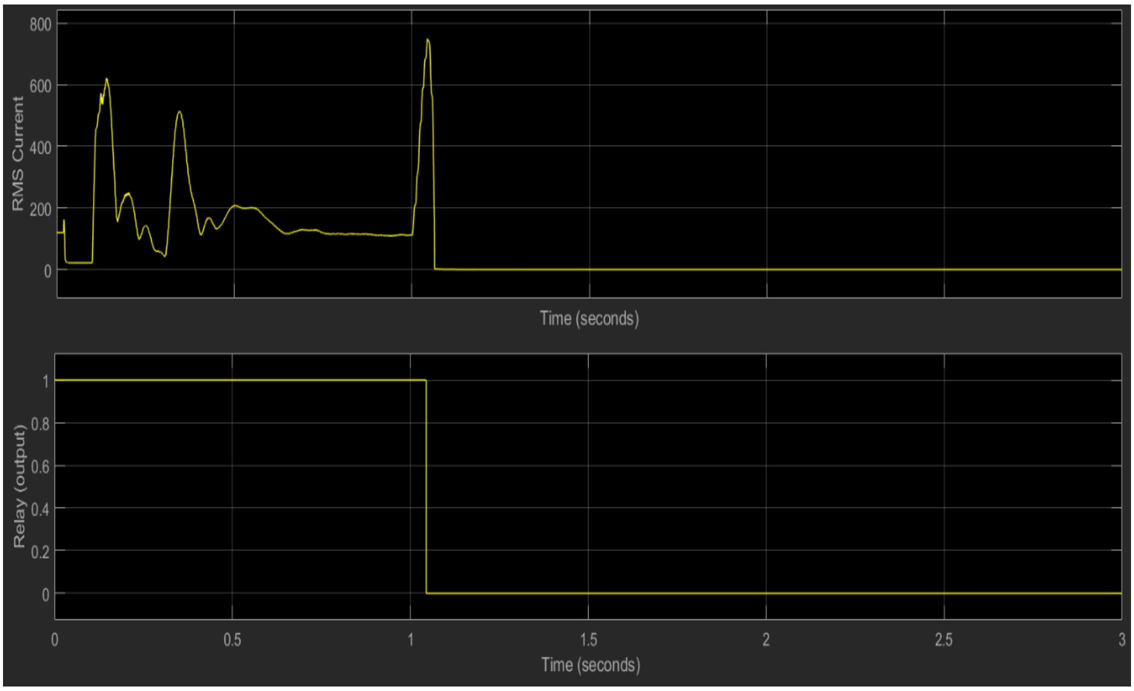


Figure 4.51 (b) RMS currents on AC side 2

4.4.2 Double pole or pole to pole faults

The circuit with the protection strategy would look like the following. (Figure 4.52)

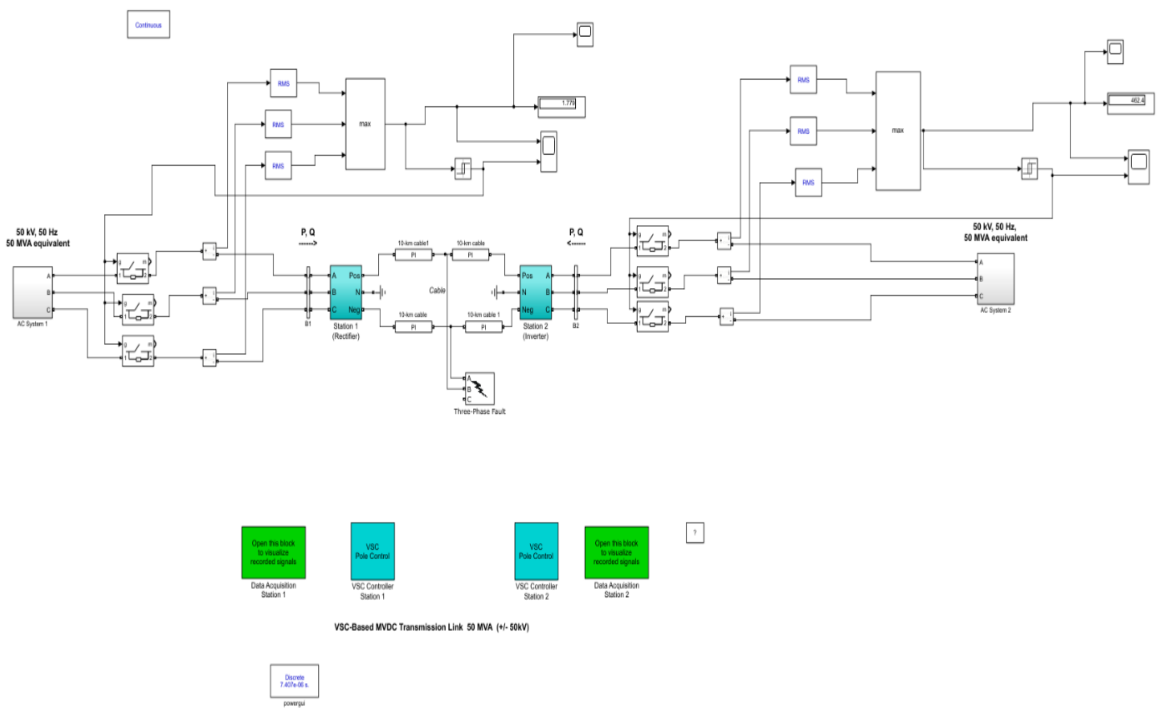


Figure 4.52 Protection strategy of Double pole faults

In this kind of fault, the fault current is slightly higher in AC side 1 and lower in AC side 2 than symmetrical faults, which was reversed. So the appropriate reference value would be 660 amperes in AC side 1 relay and 800 amperes in AC side 2 relay.

Let's simulate and analyze the results.

The values of bus station 1 and bus station 2 show that when time 1 second is reached, there is a double line short circuit fault, and the quantities in each station shoot up. It can be very harmful, but the values drop to zero due to the protection system as the value of the quantities exceeded the reference value. Approximately from 1.51 seconds onwards, every quantity becomes zero in all value which is helpful for not damaging our system.

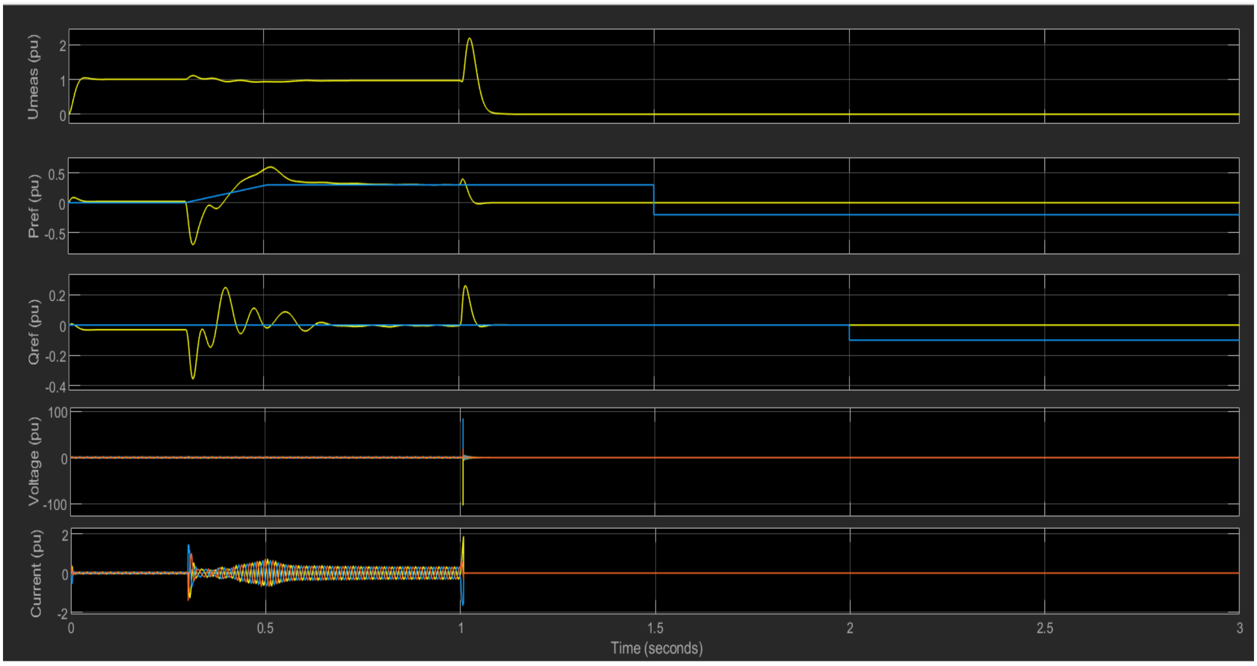


Figure 4.53 (a) Bus station 1 after applying protection strategy.

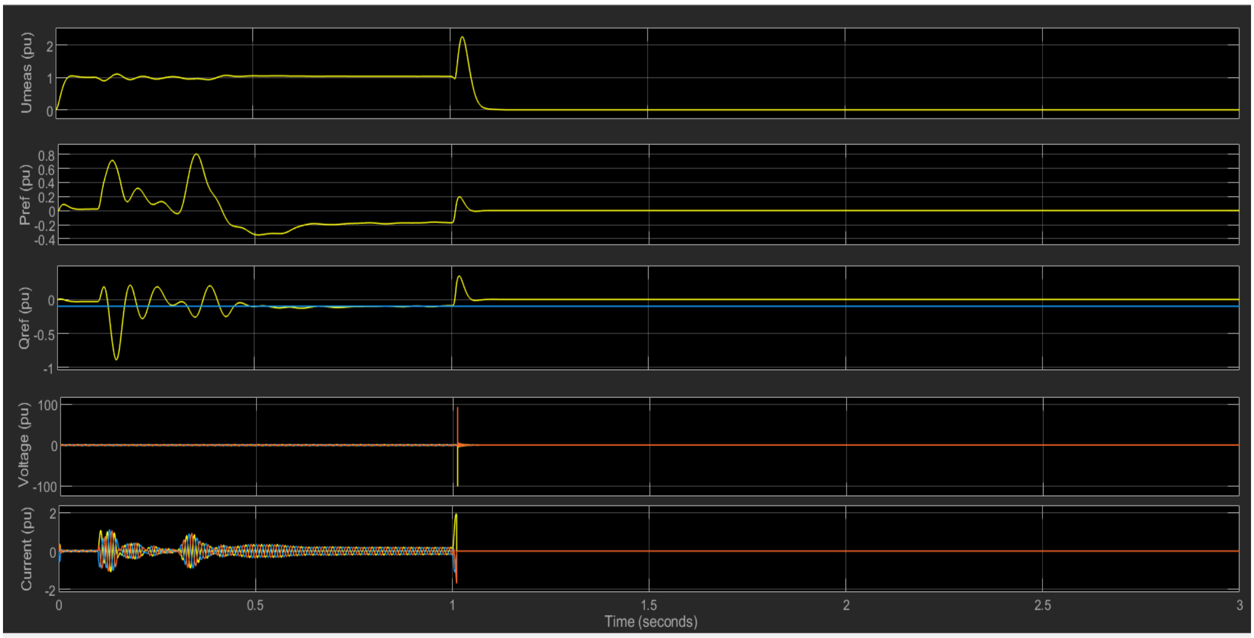


Figure 4.53 (b) Bus station 2 after applying protection strategy.

DC Currents results:

The positive and negative currents are precisely equal and opposite to each other. The currents reach their peak value when the relay sends the command to the switches to turn off the system because the currents have exceeded the reference value and can be hazardous for the system. So, the circuit trips, the current goes to zero, seen in Figure 4.54 (a) and Figure 4.54 (b).

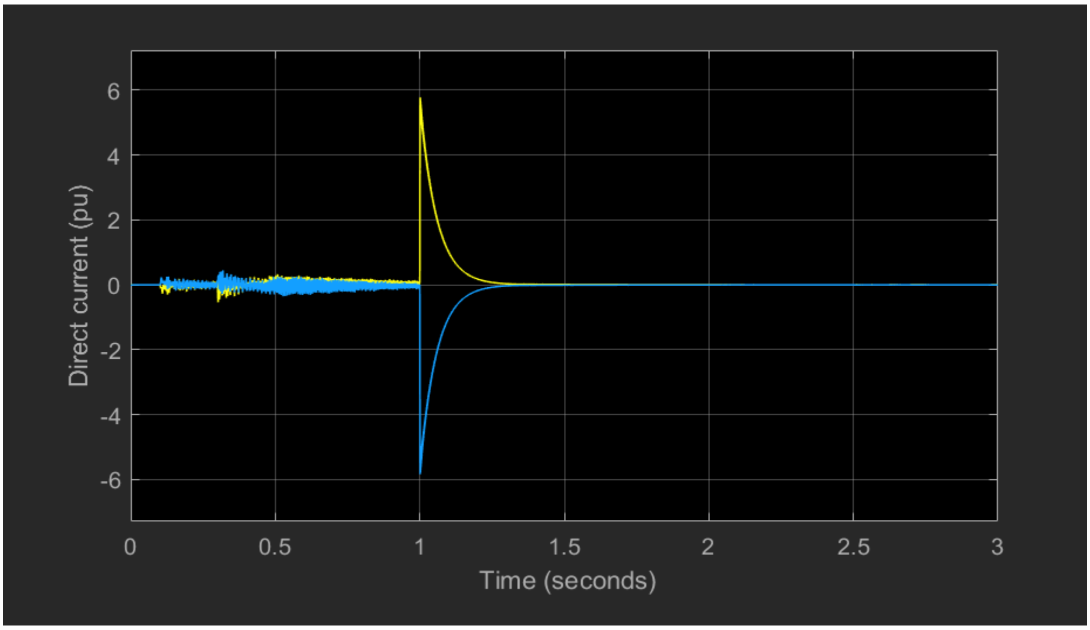


Figure 4.54 (a) DC currents of pole-to-pole faults after applying protection strategy. (station 1)

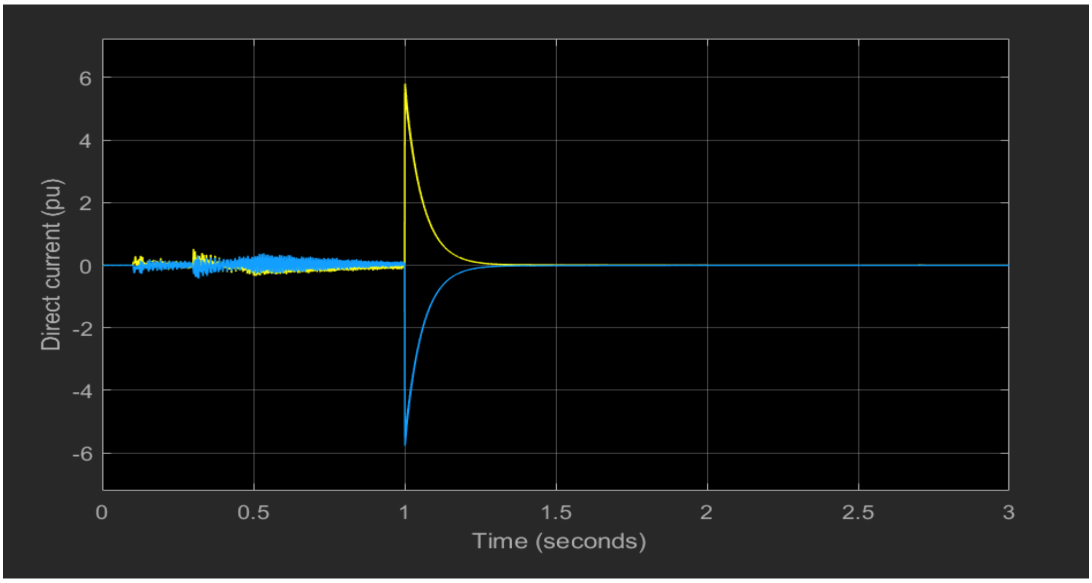


Figure 4.54 (b) DC currents of pole-to-pole faults after applying protection strategy. (station 2)

DC Voltage:

The voltages and Powers goes to zero immediately after the reference value has been exceeded. It can be shown from Figure 4.55 (a) and Figure 4.55 (b).

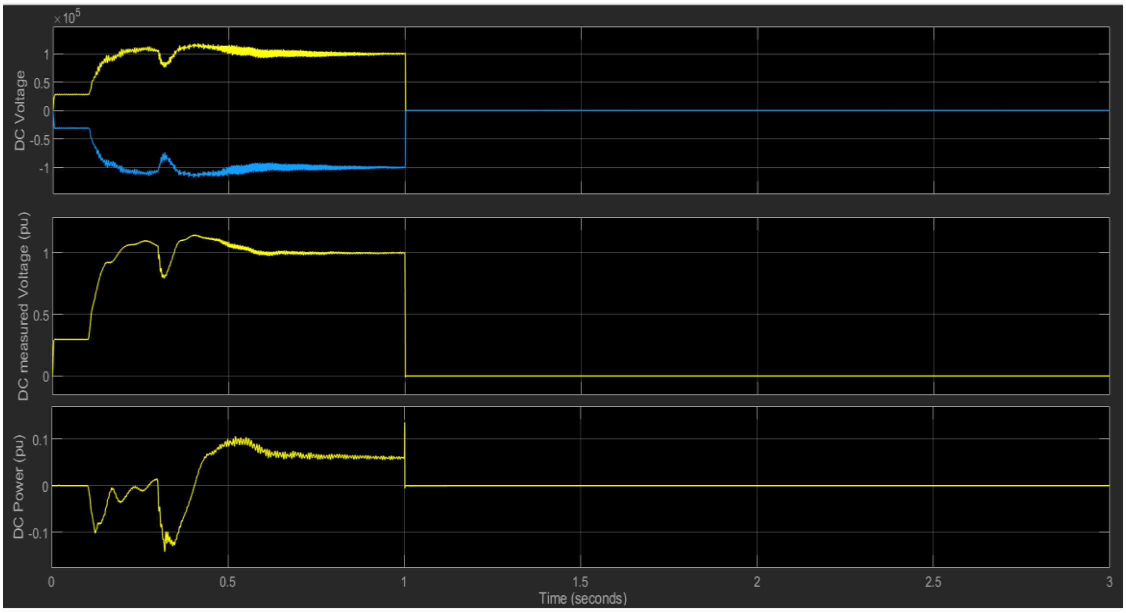


Figure 4.56 (a) DC Voltage (station 1)

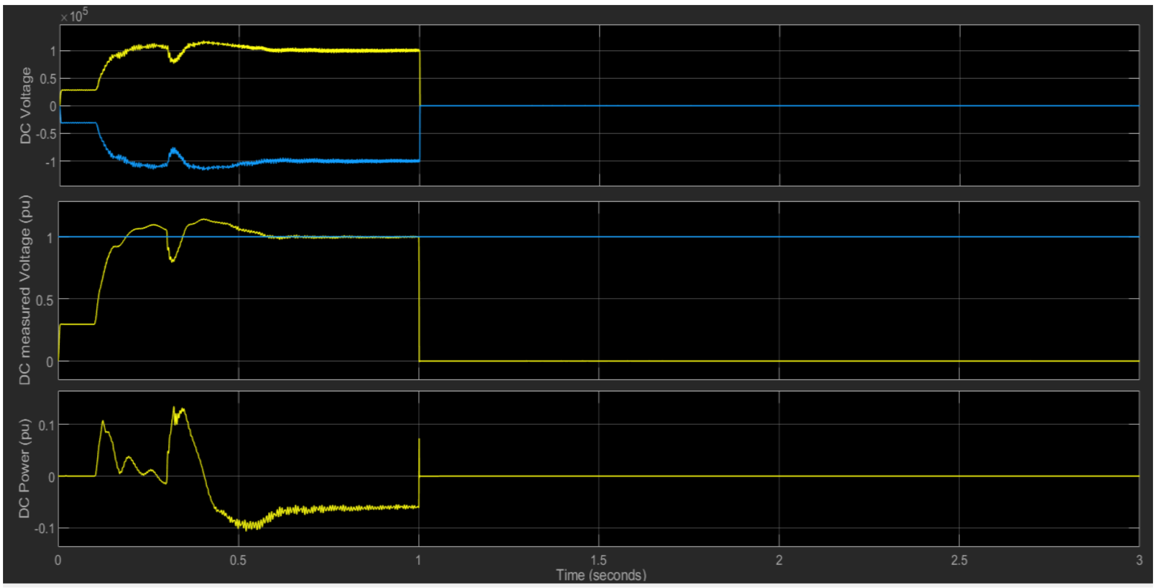


Figure 4.56 (b) DC Voltage (station 2)

RMS values for pole-to-pole fault after applying protection strategy:

The behavior is the same as the previous case, just the time of trips has changed because the short circuit currents and reference values are different.

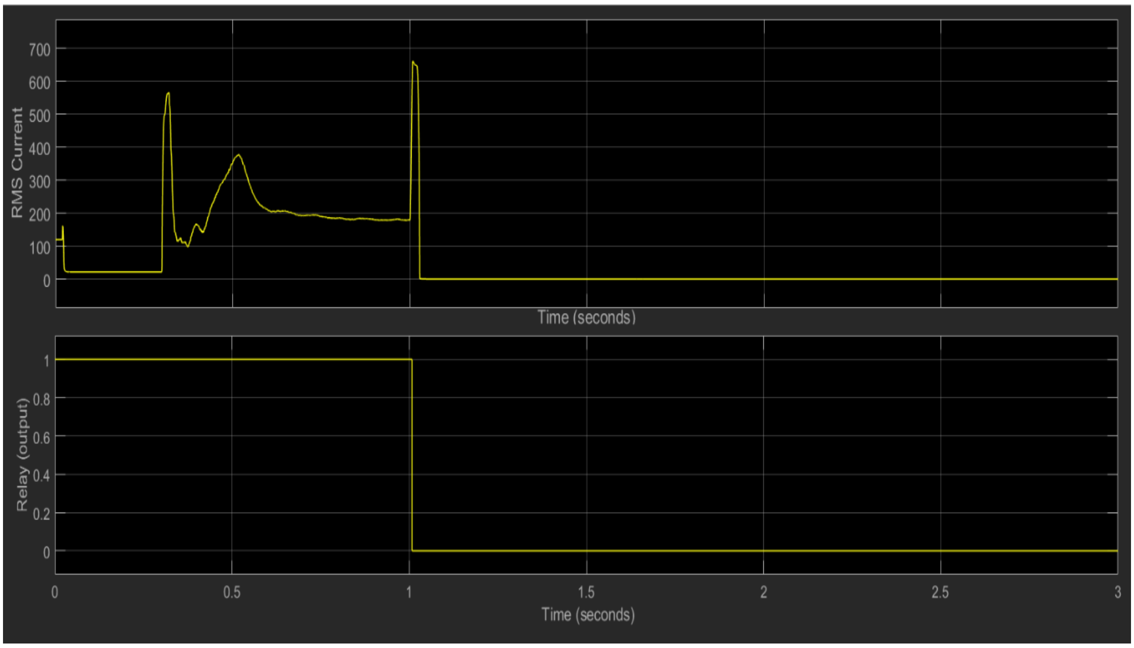


Figure 4.57 (a) RMS currents on AC Side 1

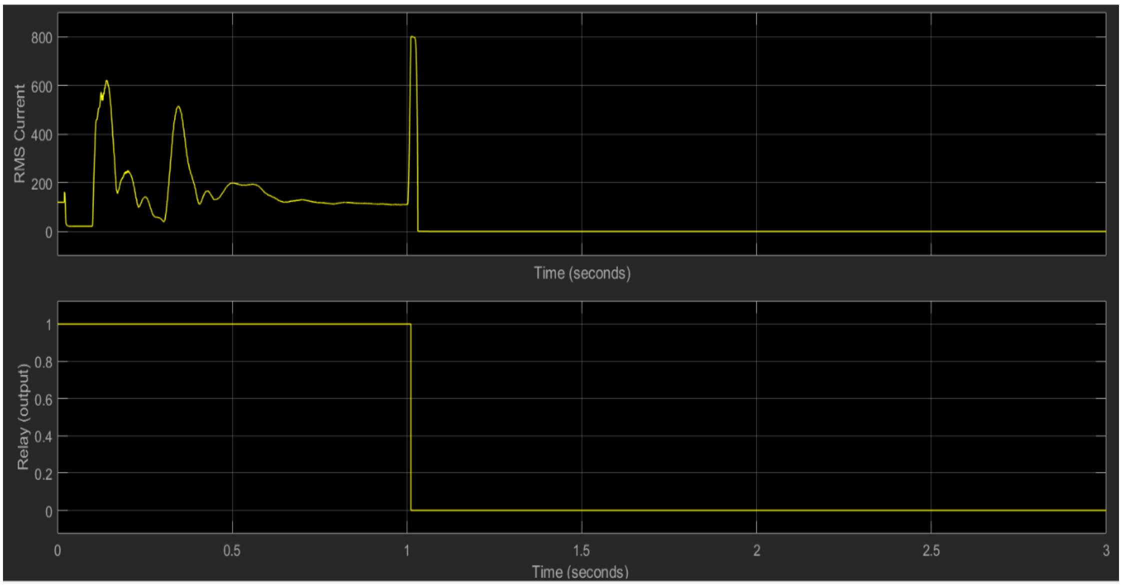


Figure 4.57 (b) RMS Currents on AC Side 2

4.4.3 Double pole to ground fault

The suitable reference values for the double pole to ground fault would be 660 amperes on the ac side 1 relay and 800 on the ac side 2 relay. These values are chosen according to the analyzes we made previously. The switches must open when the current exceeded these values to prevent any damages.

When 1 second is reached, the three-phase fault occurs, and the current goes to a very high point as analyzed. The relay stops this high current and turns the system off by enabling the switch to open. We can see from Figure 4.58 (a), Figure 4.58 (b). that after 1 second, the system goes to zero, all the quantities inside the bus station 1 go to zero, or simply the system trips unless the short circuit fault is cleared and re-energized or implementing auto reclosure.

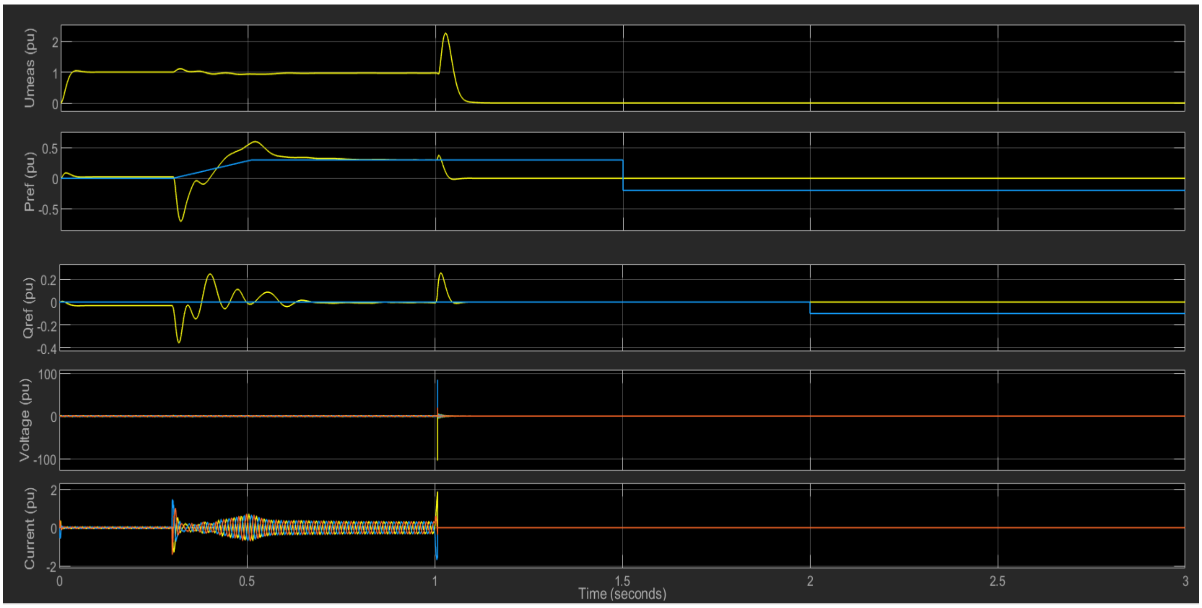


Figure 4.58 (a) Bus Station 1 of double line to ground fault after applying protection strategy.

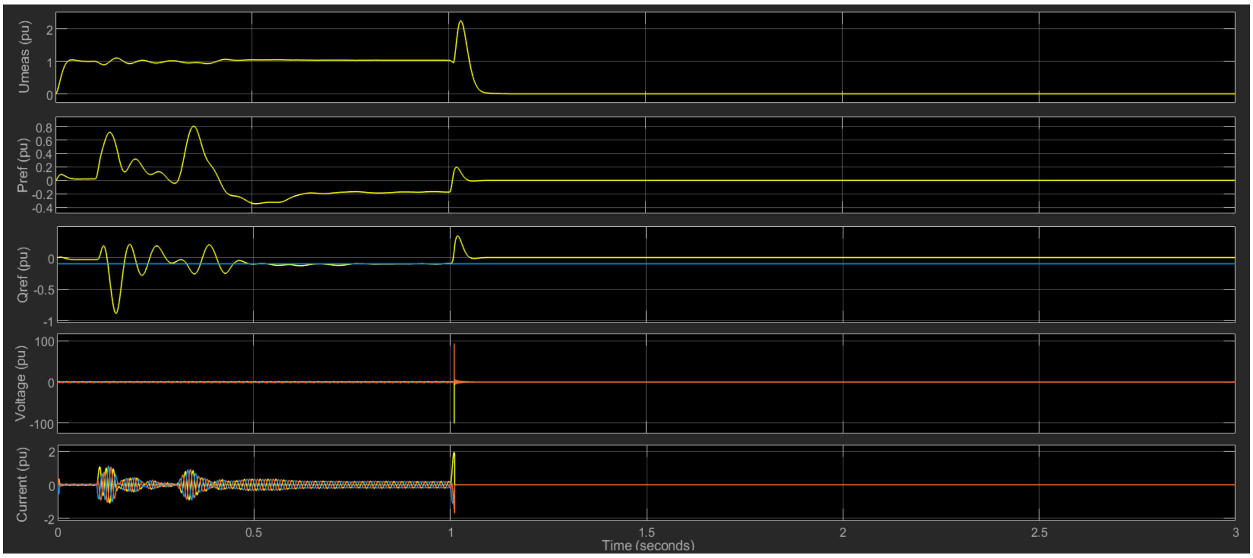


Figure 4.58 (b) Bus Station 2 of double line to ground fault after applying protection strategy.

DC Results:

The positive and negative currents show the same behavior as in the previous case explained above. The currents go up when the three-phase faults occur and then come to zero due to the system's protection system. In this way, the overall system is protected, and other parts of the system are still working without shutting them.

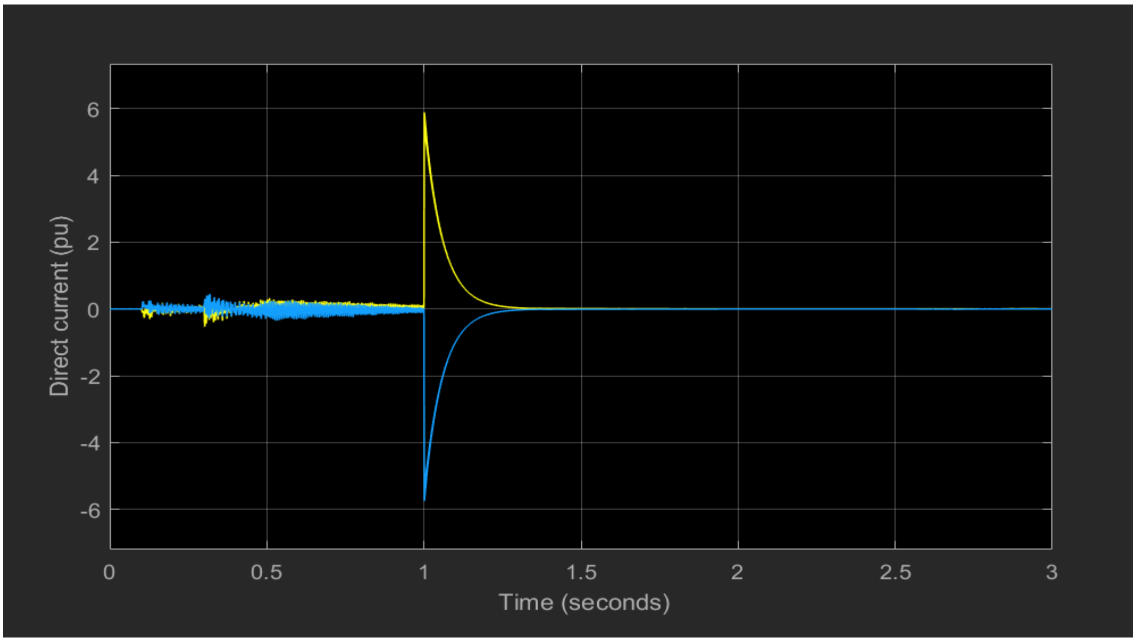


Figure 4.59 (a) DC Currents of double line to ground faults. (station 1)

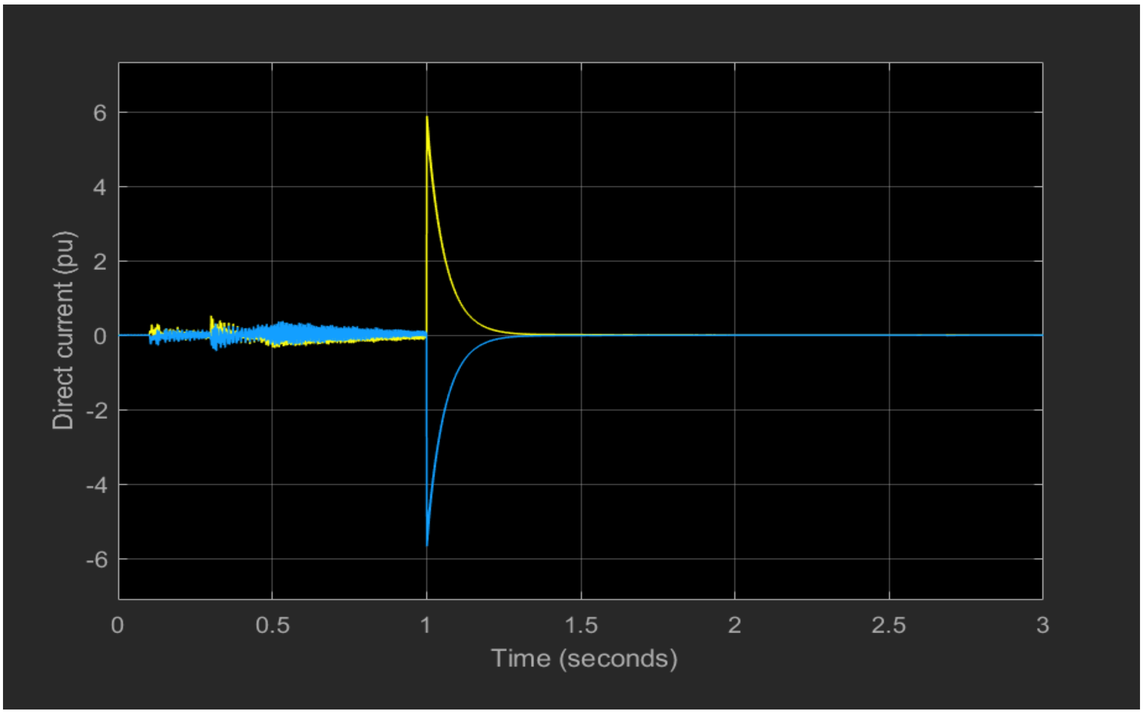


Figure 4.59 (b) DC Currents of double pole to ground faults. (station 2)

DC Voltage:

Pole to pole and double pole to ground show the same behavior. The results of double pole to ground DC Voltages are shown in Figure 4.60 (a) and Figure 4.60 (b)

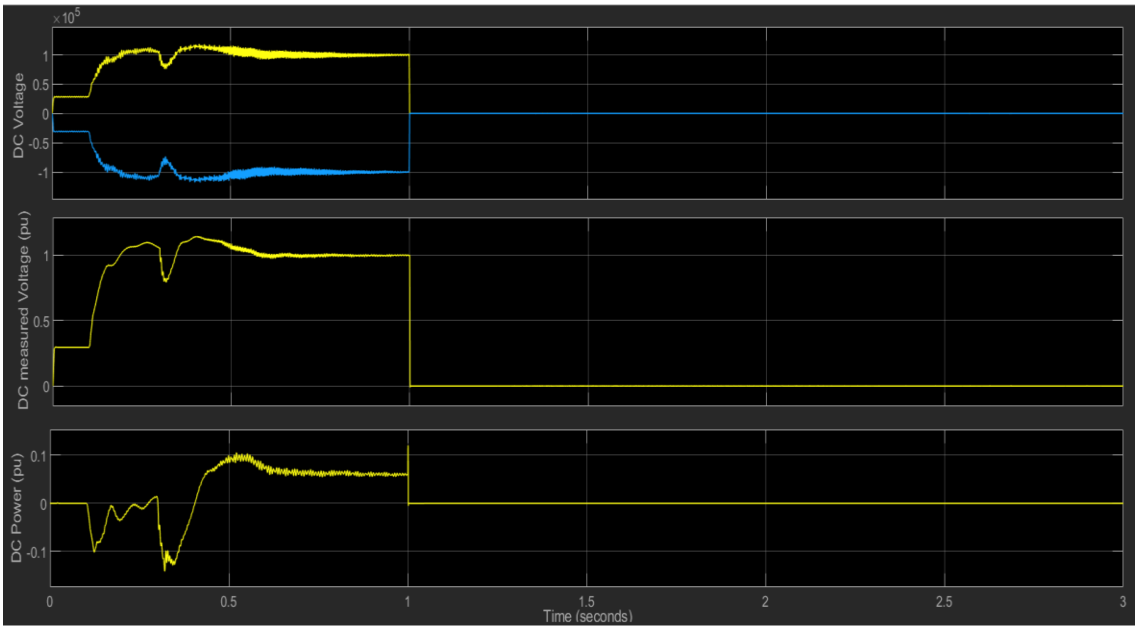


Figure 4.60 (a) DC Voltage (station 1)

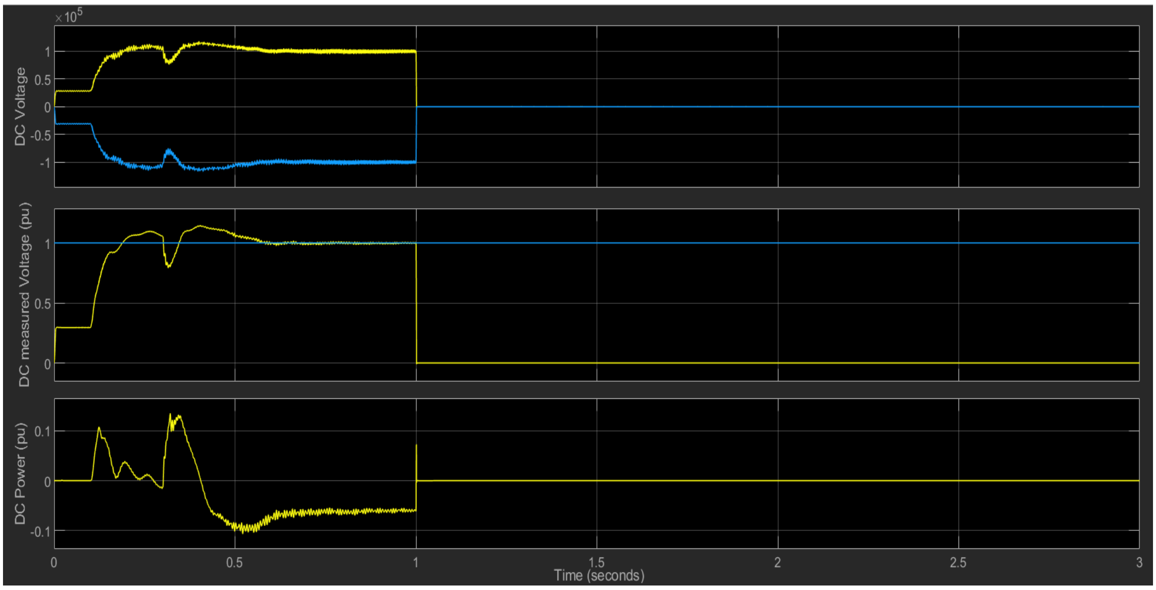


Figure 4.60 (b) DC Voltage (station 2)

RMS values for the double pole to ground fault after applying protection strategy:

RMS values of pole to pole and double pole to ground show the same behavior. The peak of the currents in double pole to grounds are a bit higher, but overall, they look the same. Both types of faults trip around 1. It can be seen in Figure 4.61 (a) and Figure 4.61 (b) of line to line and double line to ground faults, respectively.

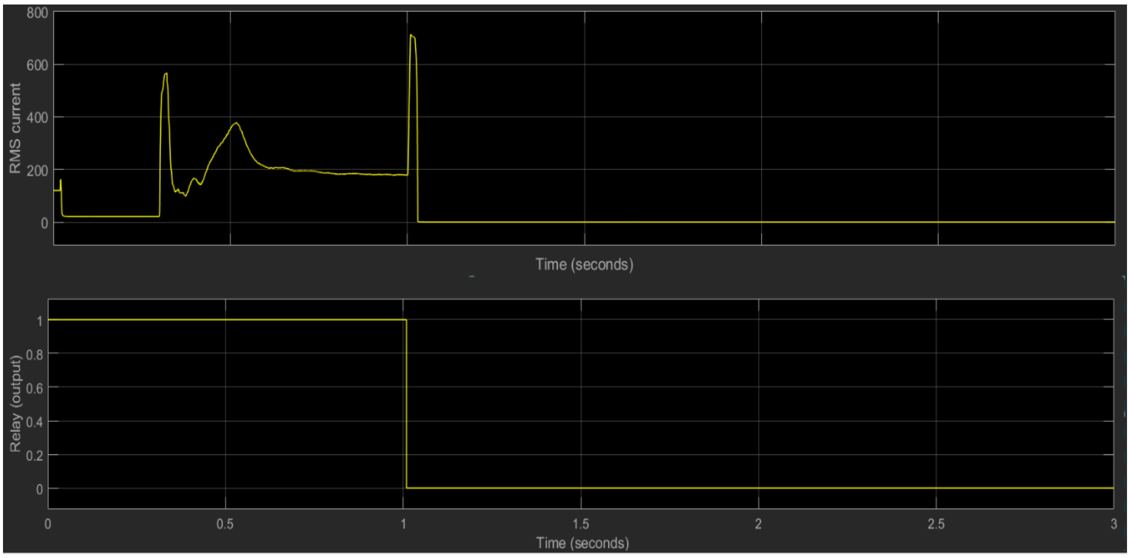


Figure 4.61 (a) RMS Current on AC Side 1

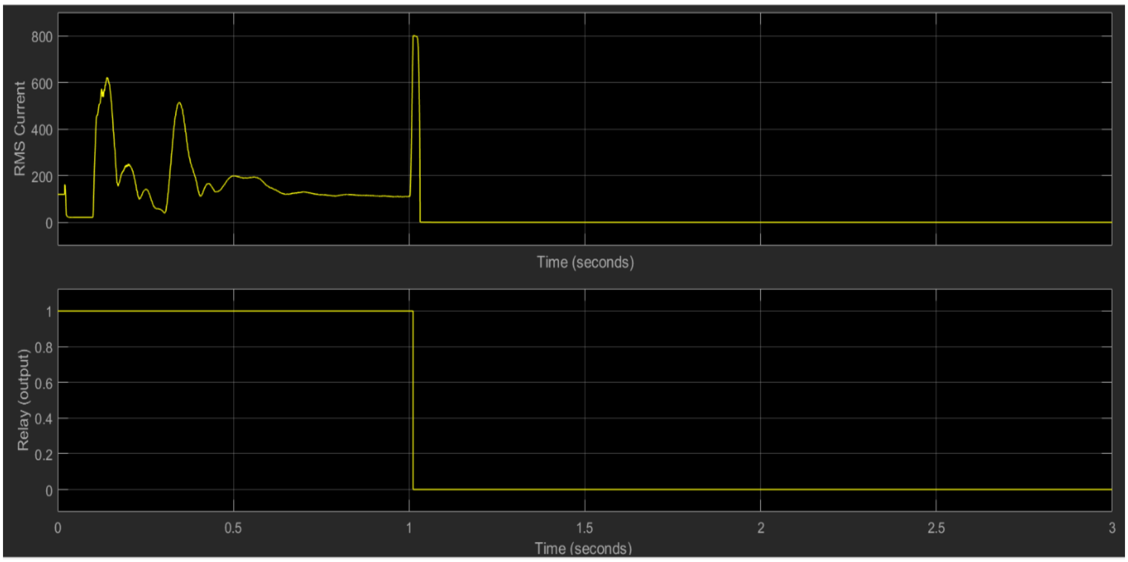


Figure 4.61 (b) RMS currents on AC side 2

We can see that the middle point is grounded on station 1 and station 2 on the Figure 4.62. lets measure the current on both stations when there is a pole to ground fault on the DC Side and Line to ground fault on the AC Side.

4.5 Ground Current

4.5.1 Pole to ground fault without protection strategy

We add current measurement, RMS block and a scope to measure the current at the grounded point on both stations. The overall system would look like this, shown in Figure 4.62.

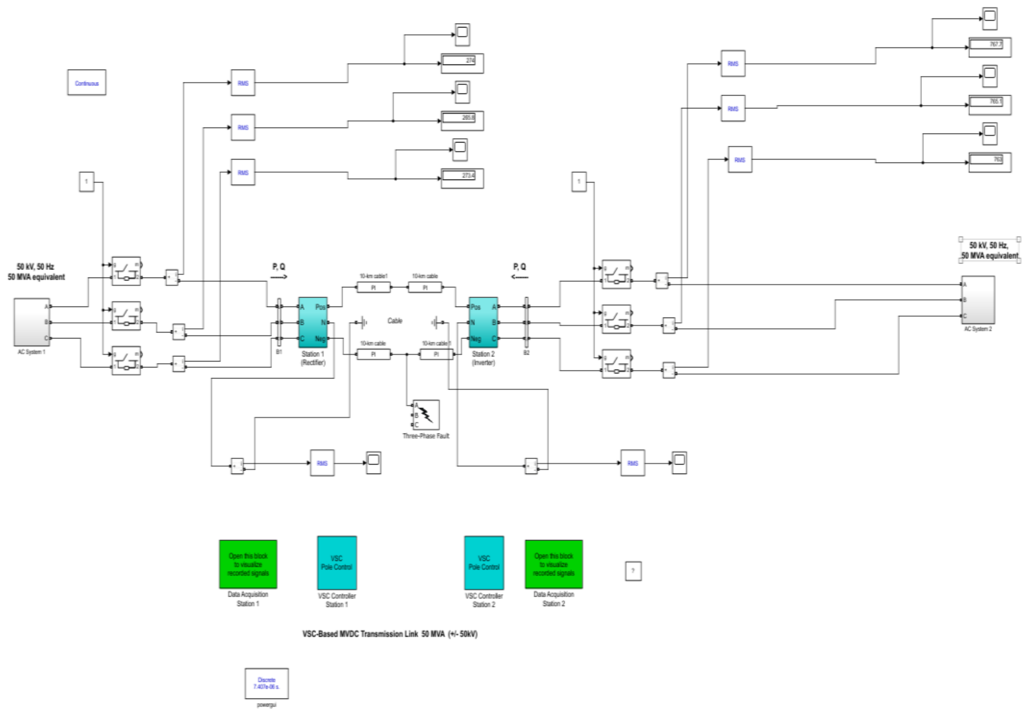


Figure 4.62 Pole to ground fault without protection strategy

Figure 4.63 (a) shows very interesting behavior. Normally when there is a pole to ground fault the ideal switch shows maximum of 918 RMS Current among the three switches on station 1 but the RMS Current on the grounded point is very high. The Highest RMS current on station 1 grounded point is more than 25000 as can be seen in Figure 4.63 (a).

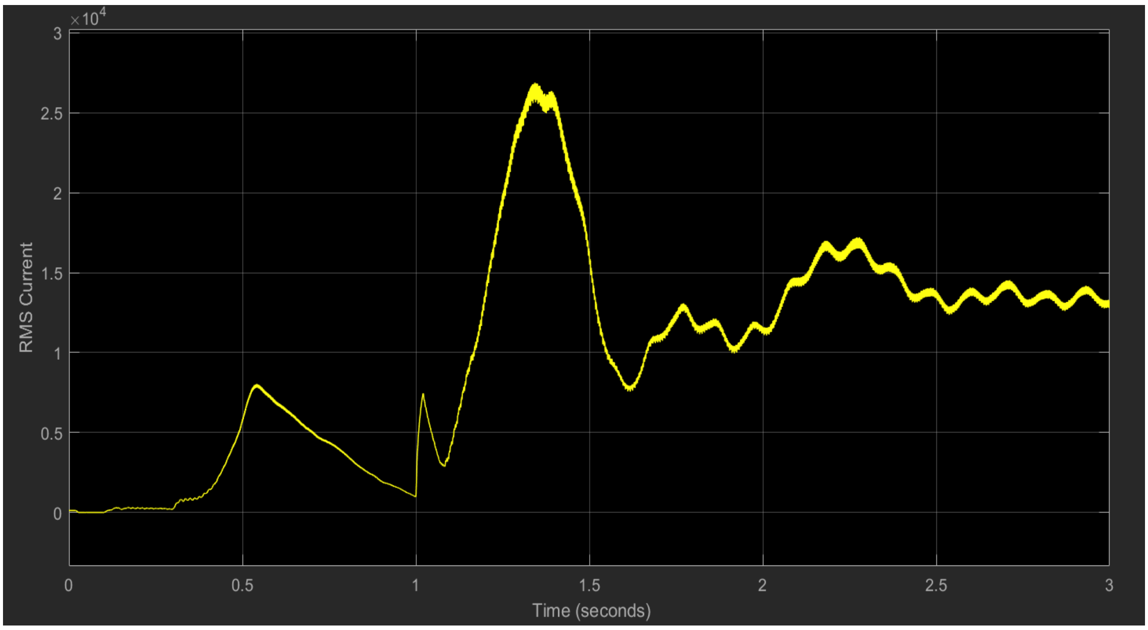


Figure 4.63 (a) RMS Current at grounded point of Pole to ground fault (station 1)

The station 2 also shows some high RMS Currents and this current is higher than station 1 after the pole to ground fault occurs. It's possible to see the visual representation on Figure 4.63 (b).

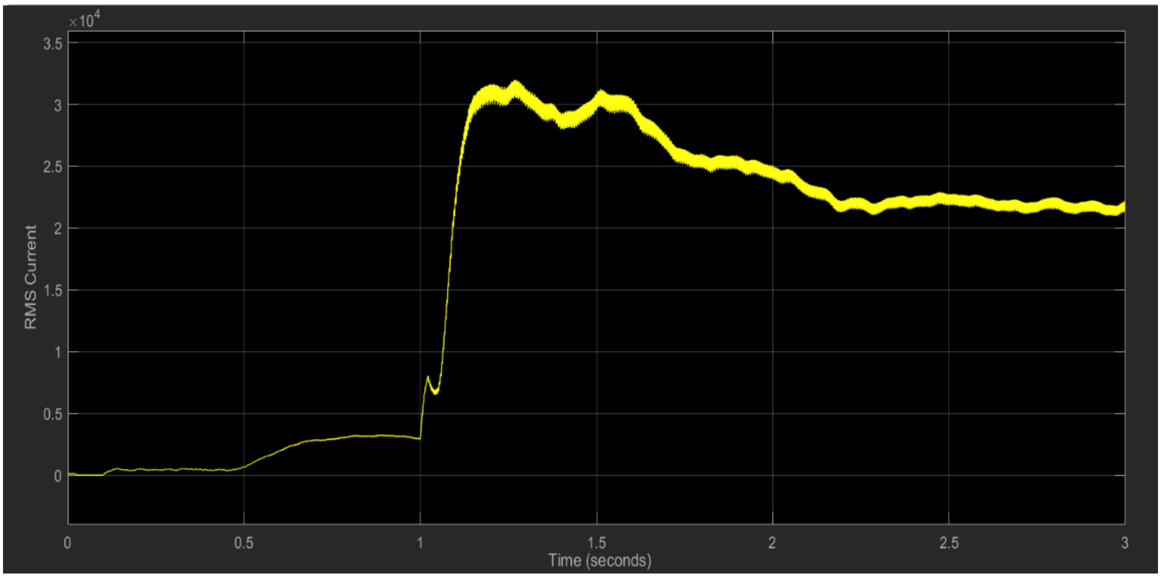


Figure 4.63 (b) RMS Current at grounded point of pole to ground fault (station 2)

4.5.2 Line to ground fault without protection strategy

Now let's see how the Line to ground fault behaves on the AC side. Configuration is shown in Figure 4.64.

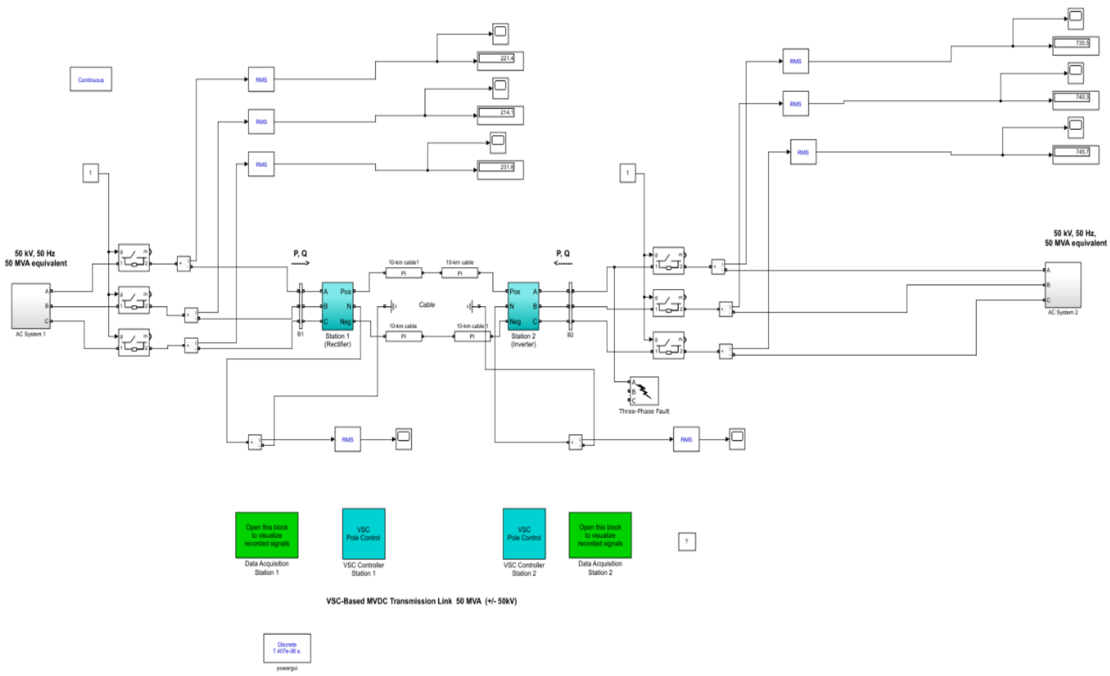


Figure 4.64 Line to ground fault without Protection strategy

Line to ground fault also shows some unique behaviors. If we analyze the switches on AC Side 1, the RMS current can go as high as approximately 568 amperes among the three switches when there is a Line to ground fault. The grounded point of the system shows higher RMS Currents then the switches (Figure 4.65). Even though the RMS Current on grounded point can provide us with approximately 6500 amps but compare to pole to ground fault is very low. The behavior of station 1 and station 2 can be seen in figure 4.65 (a) and figure 4.65 (b) respectively.

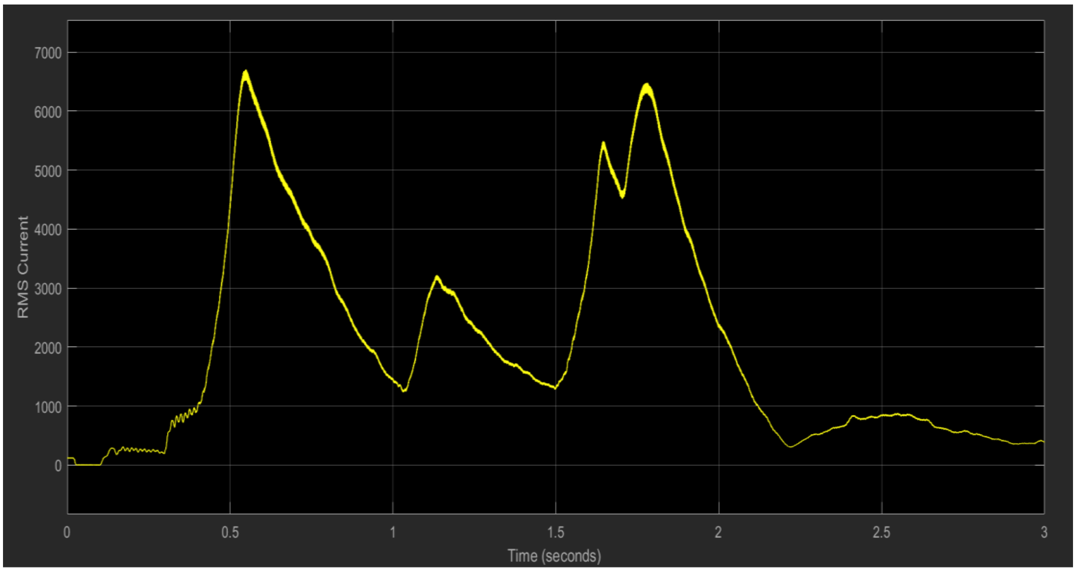


Figure 4.65 (a) RMS Current at the grounded point of Line to ground fault (station 1)

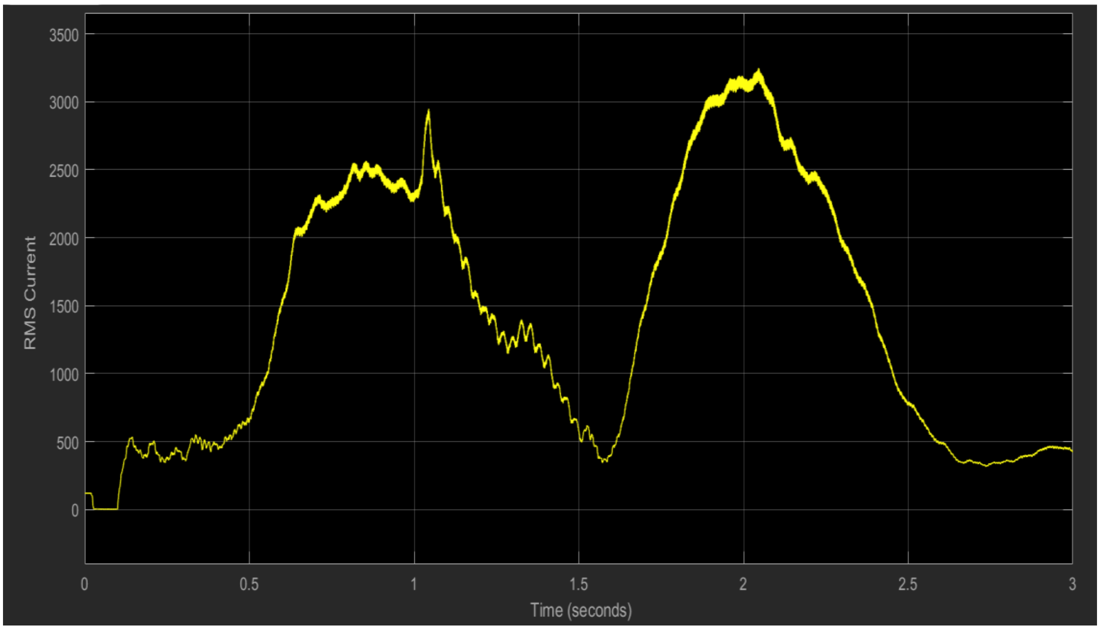


Figure 4.65 (b) RMS Current at the grounded point of Line to ground fault (station 2)

4.5.3 pole to ground fault with protection strategy

The same protection strategy is implemented as the previous cases of pole to ground fault. The motive of this is to analyze the RMS Current at the middle point of the system which is grounded.

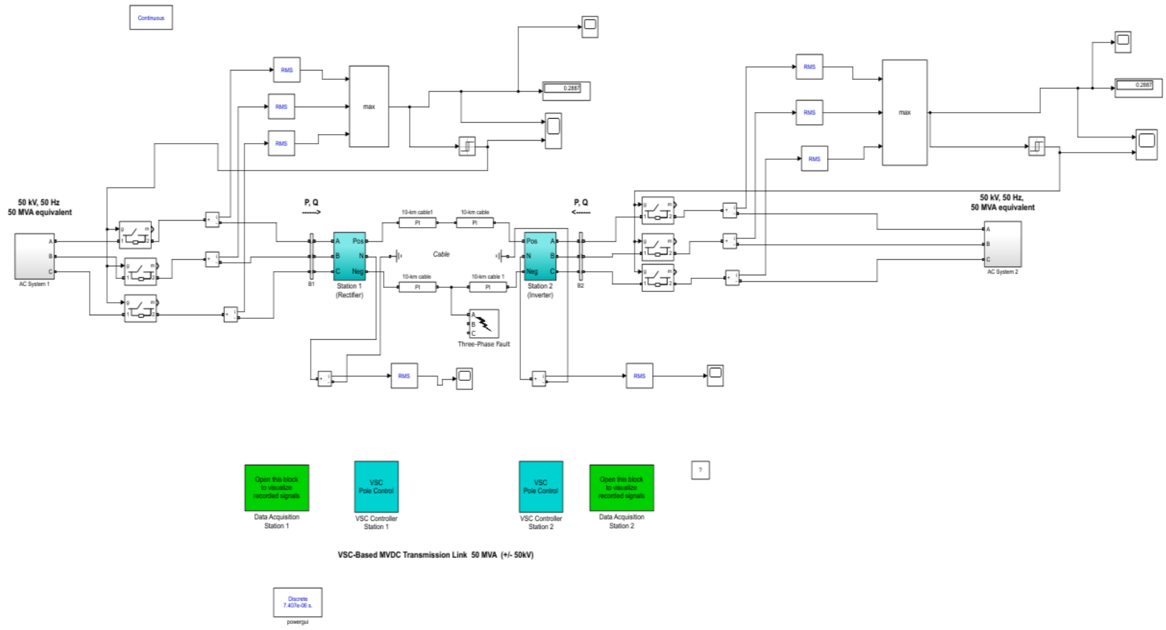


Figure 4.66 Pole to ground fault with protection strategy

The RMS Current is so high, although the system has been tripped but The RMS Current goes as high as 8000 amps before the short circuit is initiated. It can be seen from Figure 4.67 (a). Figure 4.67 (b) shows the similar behavior.

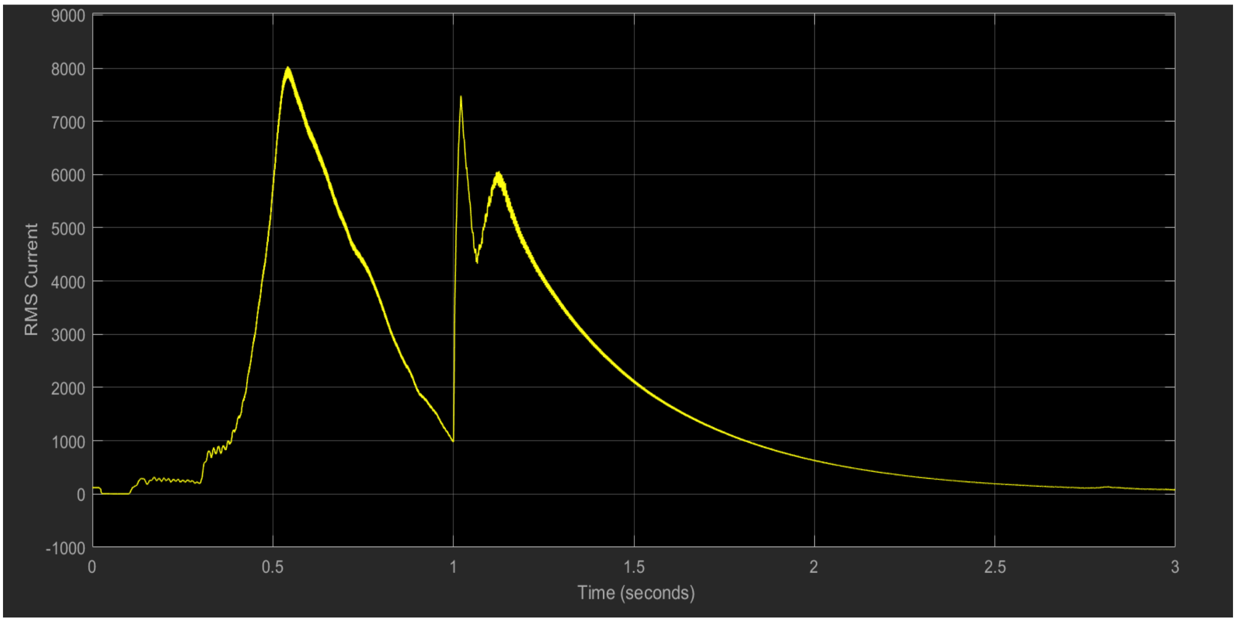


Figure 4.67 (a) RMS Current at the grounded point of pole to ground fault after implementing the protection strategy (station 1)

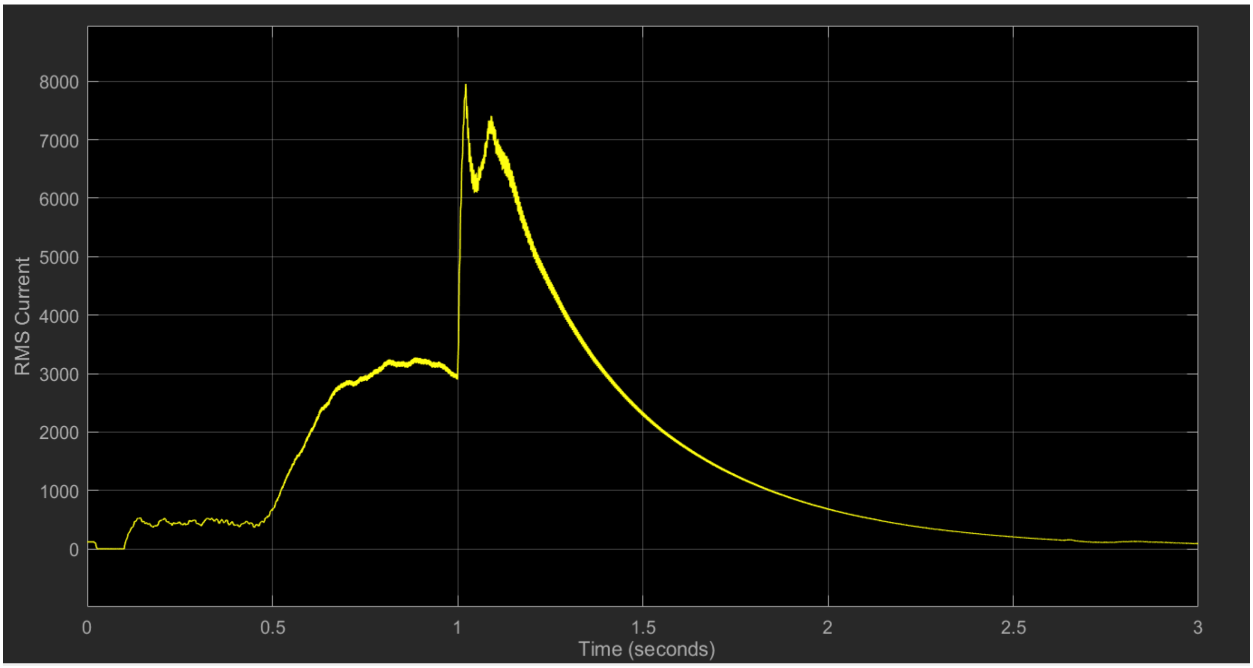


Figure 4.67 (b) RMS Current at the grounded point of pole to ground fault after implementing the protection strategy (station 2)

4.5.4 Line to ground fault with protection strategy

The system will trip when the current exceeded 600 amps on the AC Side 1 and 700 amps on the AC Side 2. The overall system would look like as follows. This configuration is applied just to find the RMS Current at the grounded point of the system on both stations.

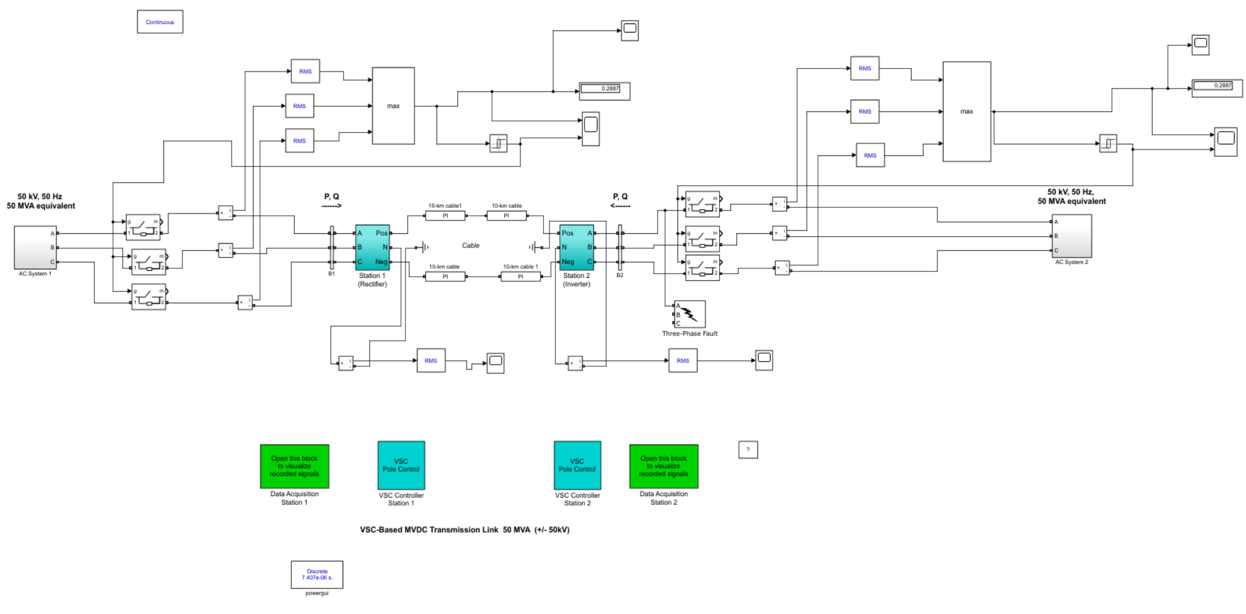


Figure 4.68 Line to ground fault with Protection strategy

It can be seen from the Figure 4.69 (a) and Figure 4.69 (b) that when the reference value have been overcome, the system tripped. The RMS Current comes to zero. Because of the high RMS Current at grounded point of the system, it looks like, the RMS Current before the fault is higher than after the fault but it is not as we have analyzed before.

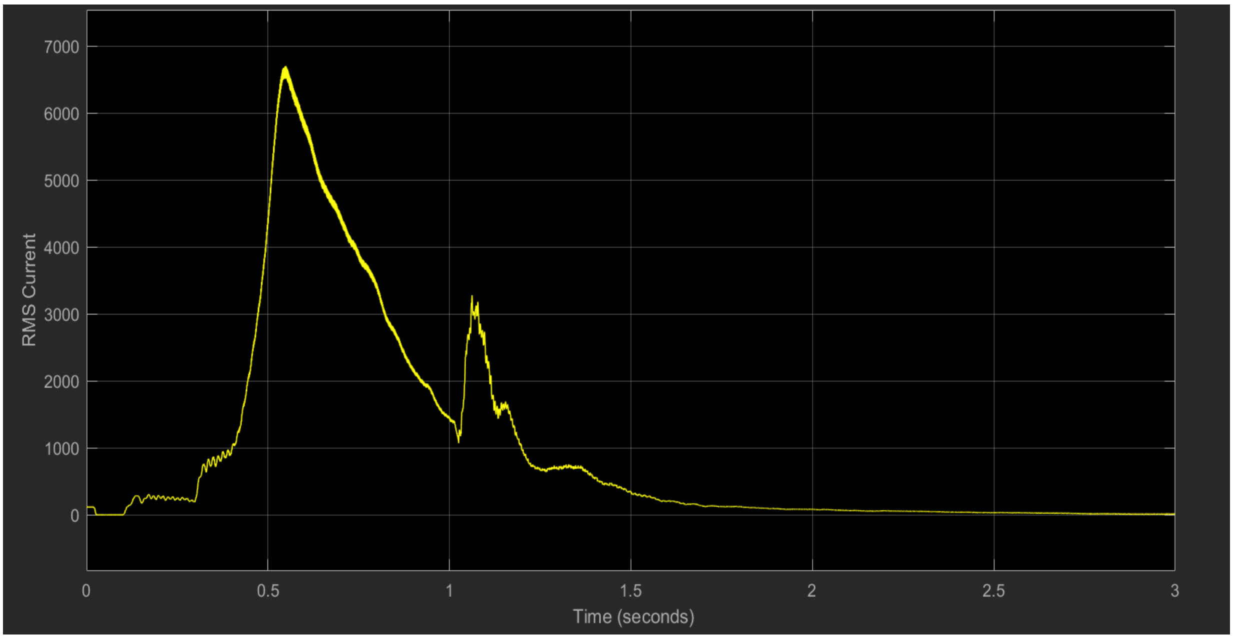


Figure 4.69 (a) RMS Current at the grounded point of Line to ground fault after implementing the protection strategy (station 1)

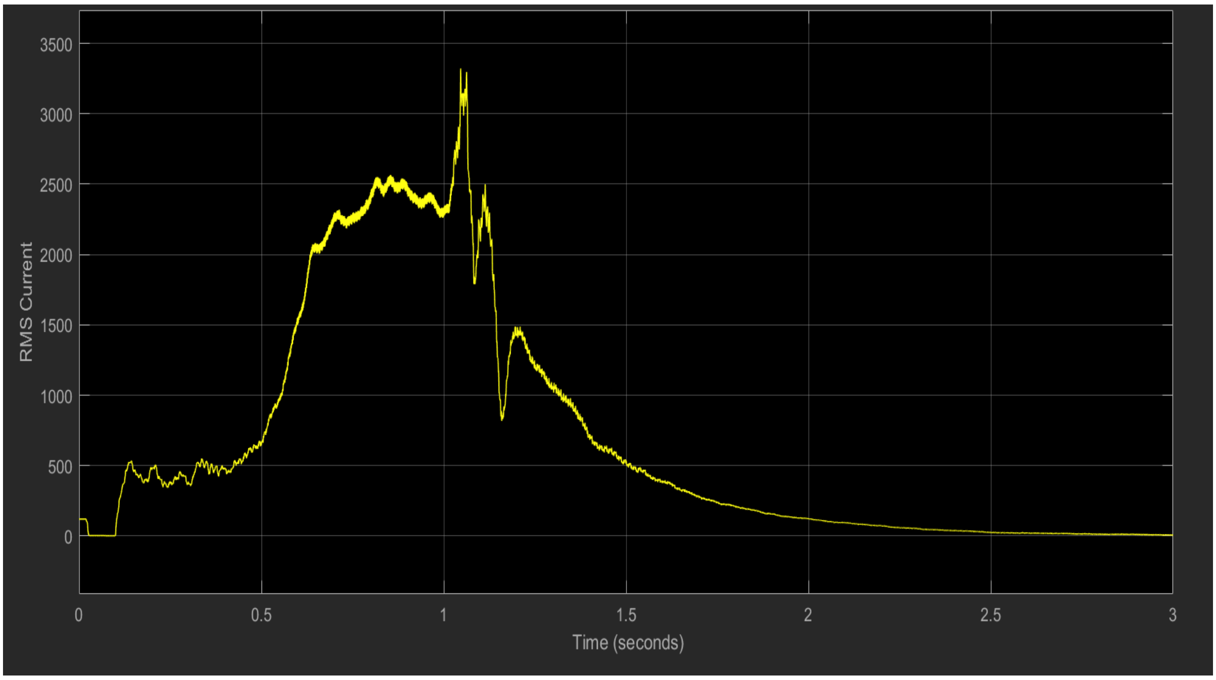


Figure 4.69 (b) RMS Current at the grounded point of Line to ground fault after implementing the protection strategy (station 2)

Conclusion:

In this thesis I have analyzed MVDC Systems with and without short circuit faults and compare the results of station 1 and station 2. After analyzation, I have proposed and later applied the protection strategies for all the faults using MATLAB simulation. Short circuit faults are critical to be analyzed and cleared as soon as possible. The short circuit is an electrical circuit that allows the current to flow in an unintended path with no or zero impedance. It results in an excessive current flow through the circuit, which is extremely dangerous. There are two types of short circuit faults named Symmetrical and asymmetrical or unsymmetrical faults. Symmetrical faults rarely happen; only 2-5 percent of faults are of this nature. If these faults occur, the system remains balanced but results in severe damage to the electrical power system equipment.

On the other hand, asymmetrical faults are more often to happen but less severe than symmetrical faults. These are also called unbalanced faults since their occurrence causes unbalance to the system. These kinds of faults are challenging to analyze.

Symmetrical faults are categorized into two types: three-phase to ground fault or line-to-line-to-line-to-ground fault and three-phase short circuit fault or line-to-line-to-line fault. When a three-phase to ground fault occurs, the current goes very high and puts the system at the urge of collapse if not cleared instantly. Unsymmetrical faults have three types which can be named as the pole to ground fault, the pole-to-pole fault, and the double pole to ground fault. The pole to ground fault is the most common fault and 65-70 percent of faults of this nature. 15-20 percent faults are of double pole-to-ground faults, and 5-10 percent faults are pole-to-pole faults.

A protection system has been designed for symmetrical and unsymmetrical faults. This strategy allows the relay to command the circuit breaker to trip when the current exceeded the reference value. The reference value has been chosen differently for each type of fault. In the normal condition, the current goes as high as 566 amperes in the AC side 1 and 622 amperes in the AC side 2, so it is a hint for the protection system how to choose the reference value. The most severe types of faults need to be analyzed first. After analyzation we conclude that L-L-L-G faults shows almost the same behavior as L-L-L faults. The fault is not transferred when this kind of faults occurs. For example, if the fault occurs on the station 2, the fault affects the components of only station 2 and the station 1 remain normal. The protection strategy should be chosen for one fault and can be implemented for the other.

L-L and L-L-G fault show the same behavior. If the fault happens in any of these faults, the consequences of station 1 and station 2 are the same. It is very easy to design a protection system for these kinds of faults, on the other hand, L-G fault has something more to offer. L-G fault is not only totally different from other faults it also shows some unique results. Station 1 and station 2 shows totally different behaviors. The protection strategy should be chosen carefully for station 1 and 2. Moreover, the Ground RMS Current of pole to ground fault is higher than the RMS Current at the grounded point of Line to ground fault. The RMS Current at the middle point which is grounded can go as high as 20000 amps on DC Section when there is a pole to ground fault and it goes approximately 3000 amps for the Line to ground fault.

To conclude, the protection strategy helps us analyze and trip the system when there is a fault. It indeed protects our expensive equipment and abstains us from unwanted events happening. The beauty of the protection system is that it does not shut all the system but the short circuit area, thanks to the relays and switches.

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