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Reverse Power Mitigation System for Photovoltaic Energy Resources

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Reverse Power Mitigation System For Photovoltaic Energy Resources

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Abstract

The steady shift of the power grid from the radial system to one with renewable distributed generation (DG) is proving to have impacts on the grid's reliability. This project designs a reverse power mitigation system within Simulink that would detect the power output from a substation and send a signal to a DG inverter to control its output. In addition, the project studies possible impacts of reverse power flow on a National Grid substation and recommends ways of mitigation.

Acknowledgements

Without the help of the following, this project would not have been possible.

First, we would like to thank Professor Alexander Emanuel for advising the team on this project, encouraging us each week, and always giving the best advice---whether it be about the project or just life. We will forever carry your words with us.

We would also like to thank Jose Rubens Macedo Jr., Professor Emanuel's PhD student, for helping us with Simulink.

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Thank you to National Grid, our sponsor, for providing the tools and resources to study reverse power flow. Special thanks for Jeff Pond, the sponsor respondent, for making this project a reality and co-advising the project. At National Grid, we would also like to thank the Protection Engineering department, and especially Larry Nelson Jr., for helping us with any questions and being a great Protection Engineering resource. Thank you to Kristen Lemire and Elizabeth Spivak for being Truman and Julia's National Grid managers, respectively, and allowing us to work on the project during our time at National Grid. Finally, thank you to John G. Franklin, a National Grid lead outage coordinator, for helping the team with our feeder selection and to James M. McGrath for taking time out of his busy schedule to take the team on a site visit to the actual substation.

Executive Summary

This project addressed the problem of reverse power flow in the distribution network. The team outlined ways that reverse power can be mitigated and identified a mitigation system that could be implemented at a substation.

The Problem

The electric grid was designed to have power generated at a source, transmitted to different areas, stepped-down at substations, and distributed to load in a radial fashion. All throughout the grid, protection systems remain in place to protect system equipment and to maintain reliability of electrical service. In the distribution network, protection primarily consists of overcurrent relays and fuses. To protect the distribution system, the relays have to be programmed such that the relay can sense a fault in its primary zone, provide backup protection for secondary zones, and coordinate with surrounding relays.

However, as renewable distributed generation (DG) connects with the distribution network, the power demand from the electric grid is reduced. As DG becomes increasingly present, it can actually supply more power than the load demands and feed power back into substation and transmission grid. This would not only create instability of the system, but would result in overvoltage on the feeder as seen in Figure 1-1, protection miscoordination, increased fault currents, and incorrect operation of equipment.

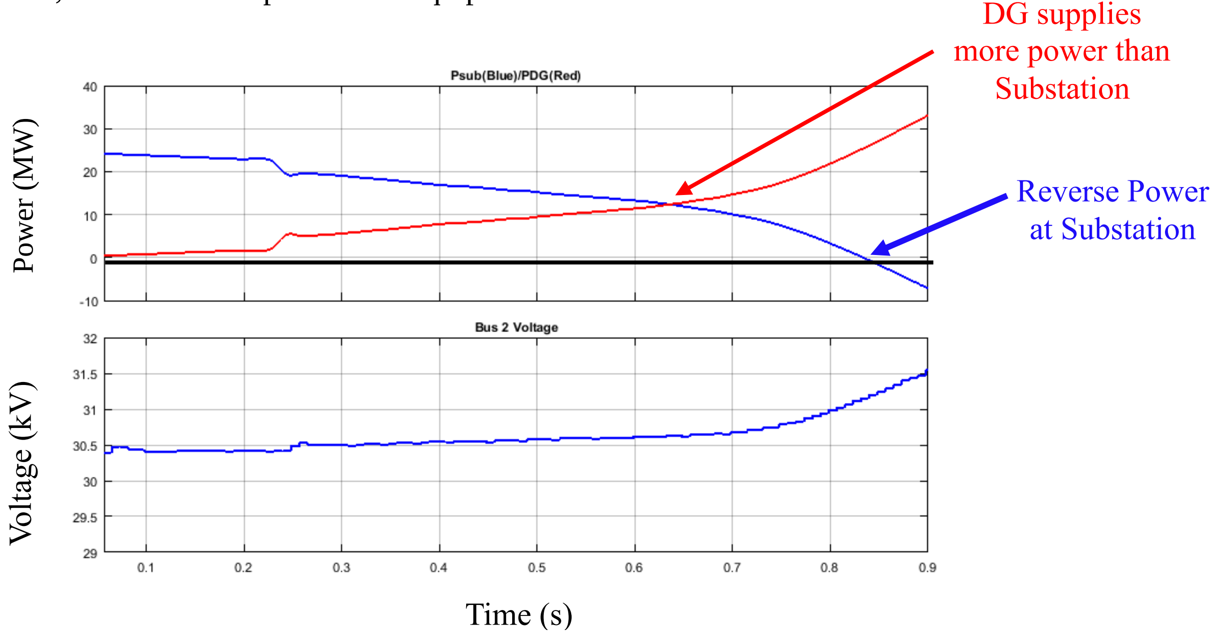

Figure 1-1. Reverse Power Effects on Overvoltage

The Solution

The team created a reverse power mitigation system that composes of a relay, a buck converter, and communication between the two devices. The one-line diagram of the system being implemented in a distribution network is seen in Figure 1-2.

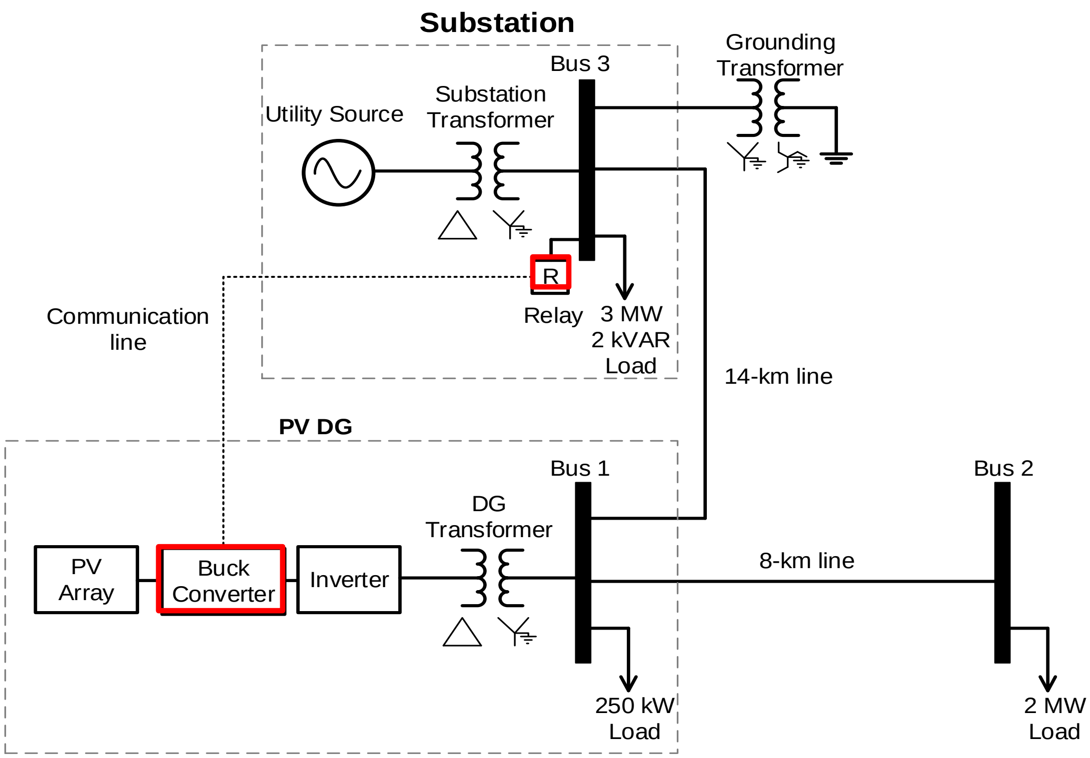

Figure 1-2. One-line Diagram of Reverse Power Mitigation System Integration

The relay contains two logic systems: (1) phase detection, and (2) under-current detection. The phase detector measures the phase difference between the voltage and current waveforms taken at the substation and triggers the relay when the phase difference is 180 degrees. However, because real distribution systems have inherent phase shifts due to non-unity power factors, the phase detector also compares the measured phase difference to a value calculated from a power factor tolerance input. To completely avoid a reverse power flow situation, the team reasoned that the current should never be allowed to flow back into the substation. This means that the current output from the substation should never be below a certain threshold. The under-current detector is responsible for just this. The under-current detector outputs a trip signal to the buck converter when the magnitude of the current drops below a set value.

Results

To verify the functionality of the mitigation system, the team ran three simulations on the distribution system in Simulink. The first simulation was a control case used to demonstrate that the system runs at nominal conditions. In the other two simulations, the team varied levels of irradiance on the PV array to control the PV's output and measured the effect with and without the mitigation system installed.

Figure 1-3 shows that with increasing irradiance, the power output from the PV inverter increased and became larger than the power output from the substation at about 0.83 seconds. Without the team's mitigation system implemented, overvoltage on distribution feeder occurred.

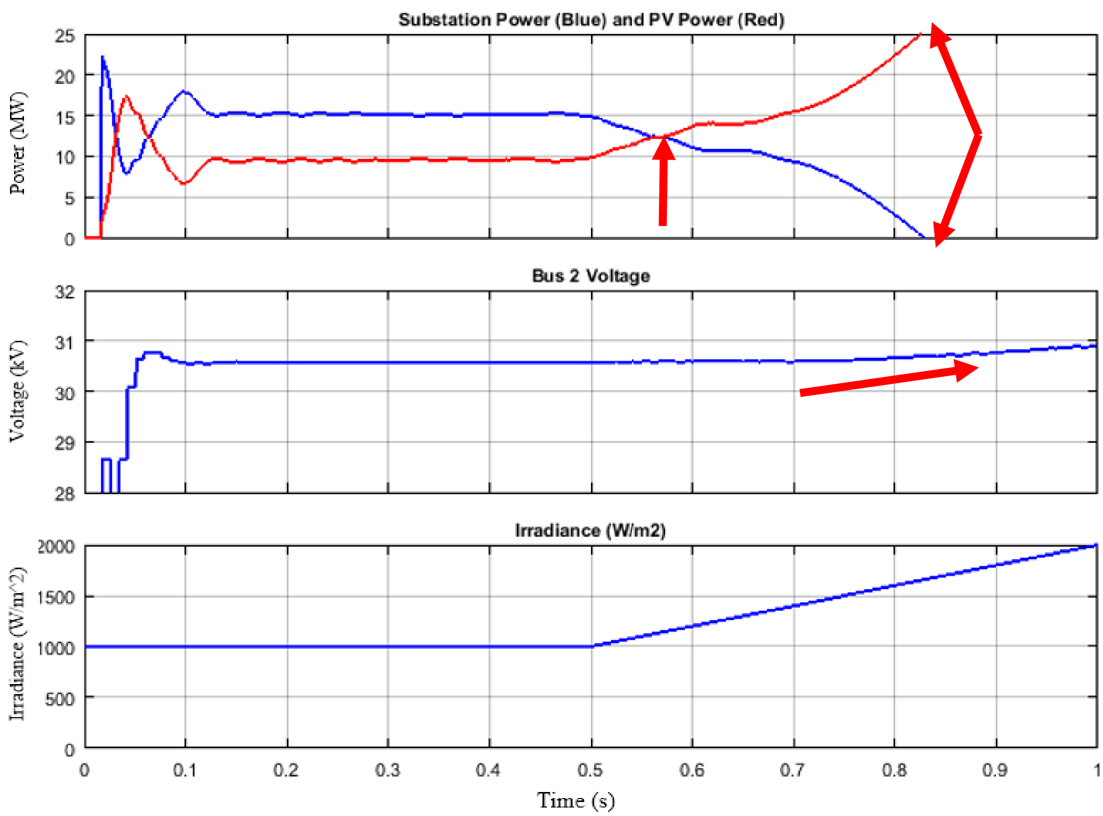

Figure 1-3. Voltage Measurement at Substation Bus with Increasing Irradiance and No Mitigation System

In the third simulation, the same irradiance input was applied to the PV array, but the team's mitigation system was implemented to the system. The mitigation system was set so that the substation output should not drop below 80% of the total load or 19MW. Figure 1-4 shows that although the irradiance input to the PV increased, the output from the substation, PV, and the substation bus voltage did not experience substantial effects.

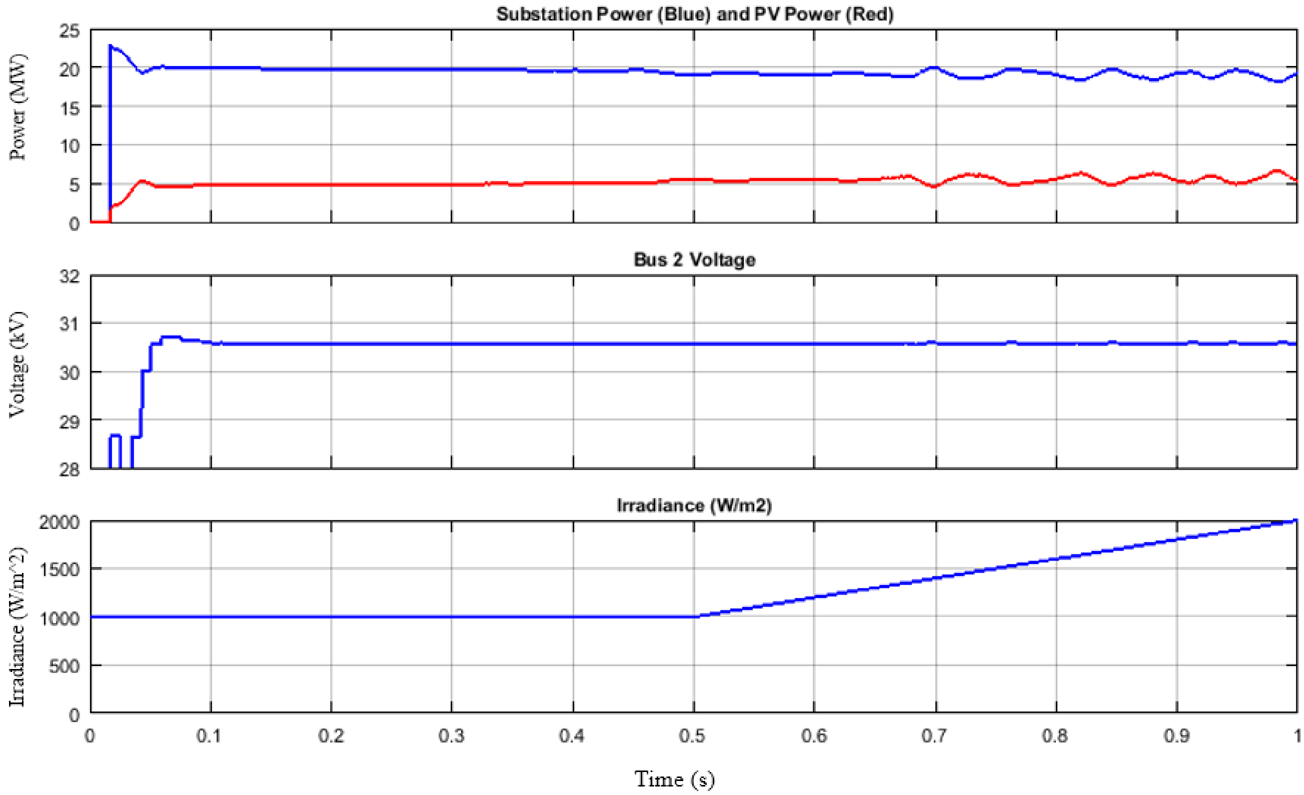

Figure 1-4. Voltage Measurement at Substation Bus with Increasing Irradiance and Mitigation System Implemented

Recommendations and Conclusions

The electric system, although has been able to withstand the PV DG interconnections to this date, may need additional mitigation systems to combat the negative effects of reverse power flow in the future. The team's reverse power mitigation system has proven to detect when the power output from the substation reached a minimum threshold, to communicate to the PV inverter to control its output, and to keep the effects of reverse power flow to a minimum.

Although the team was able to design a functioning mitigation system in Simulink, there are areas of the design that could be improved and real-world aspects that were not addressed. The team recommends that future MQP teams interested in this project could convert the relay model in this mitigation system to a physical device that could be tested.

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1. Introduction

The electric power network, as it stands today, was designed nearly 100 years ago with a radial nature in mind. Power is generated at large power plants scattered across the region and transmitted through transmissions lines at high voltages to the distribution networks that service towns, cities, and other loads that purchase the power. This structure of generation upstream supplying the transmission network, the distribution network, and, finally, load downstream makes up the radial network.

As technology advances, renewable distributed generation (DG), such as wind turbines or solar panels, have been able to reduce demand from utilities, a phenomenon called peak-shaving. In recent years, DG resources have become increasingly popular [1]. In one year alone, DG interconnection requests at National Grid, an electric utility operating in New England, quadrupled. As DG increases and provides more power than the load demands, power flows from the DG back to the substation and could feed power back into the grid, a problem called reverse power flow. Reverse power flow has been known to cause problems such as:

1. Overvoltage on the distribution feeder
2. Increased short-circuit currents
3. Protection desensitization and potential breach of protection coordination
4. Incorrect operation of control equipment [2]

In addition to the larger DG interconnection requests that utilities have received, there are many DG interconnections in the kilowatt range, such as roof-top solar arrays, that do not merit a protection review of the feeder. These individual kW photovoltaic (PV) systems can add up to a MW impact on a single feeder. This can have a serious impact on the feeder's protection without calling the attention of the utility's protection department.

The goal of this project was to develop a reverse power flow relay model that would detect the power output from the substation and communicate to the DG inverter to control its output. The relay would monitor the power output at the substation and would trip if it reached a set minimum threshold or was 180° out of phase. To achieve this goal, the team developed the relay and modeled a simplified power system in Simulink. As the power output from the DG increased and the power output from the substation decreased below a set threshold, the relay detected the change and sent a digital signal to the inverter in Simulink.

In addition to the development of the relay, the project sponsor requested for the team to study an existing National Grid feeder, determine whether reverse power flow would have an effect on the system protection, and recommend what could be done in the future for mitigation if problems were found. To accomplish this, the team began by selecting an existing National Grid feeder to study and testing impacts of the DG interconnection on the feeder coordination and overvoltage. There is little confidence from engineers in the inverter model ASPEN provides, so one of the team's objectives was to closely model an inverter-based generator in ASPEN. To study how an inverter typically behaves, the team studied the fault current behavior of a modeled inverter in Simulink and met with an inverter company to discuss current limits to formulate their inverter ASPEN model. With this model, the team then varied the type of DG transformer connection and size on the designed inverter model in ASPEN to test for general impacts of reverse power flow.

This project hopefully will help make an advancement in the study of reverse power flow relays and its application with the inverter. In addition, the team hopes that this project will aid Protection Engineers at National Grid with inverter-based generator modeling and concerns with future impact of reverse power flow.

2. Background

To be able to understand the system, the protection in place, and distributed generation, the team conducted research about such topics.

2.1. Protection Engineering

One of the important objectives of a utility company is to maintain reliability by continuously providing electrical service. However, due to natural causes such as a lightning storm or fallen tree branches, physical accidents, human error, unexpected equipment failure, and etcetera, reliability is compromised and dangerous situations can arise. In these situations, a fault condition can occur in which conductors touch ground or touch each other causing very high fault currents to flow in dangerous directions that can either harm equipment or human welfare. The implementation of a protection engineer's designs during these sudden consequential events can be the difference between a momentary disturbance in service and a major outage.

The disciple of the protection engineer is not about preventing conductors from touching the ground or each other, but rather minimizing the damage to the rest of the electrical grid when something does go wrong. When faults do occur, the objective is to detect that something has gone wrong and to electrically isolate the damaged area. Faults have certain electrical characteristics; the most common one is a sudden increase in current past normal levels of operation. It is up to the protection engineer to decide what a tolerable condition is and what actions to take.

Faults can occur anywhere on the electrical network from the large generators in a power plant to the power lines that lead up to consumers' residents. However, the scope of this project is limited to the section of the electrical grid nearest to the consumer or load. This area is called the distribution network, and it is the focus of this project because it is where renewable distributed generation is interconnected to the electrical grid. A distribution network begins at the substation where the voltage is stepped down from the high transmission levels and then continued through distribution lines of a lower voltage to customers. In this section, the team discusses the different types of protection devices used in the distribution grid.

2.1.1. Relays

According to the Institute of Electrical and Electronic Engineers (IEEE), a relay is defined as "an electronic device that is designed to respond to input conditions in a prescribed manner and, after conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits” [3]. Relays are ubiquitous in electrical applications and can be found in some of the most common places (i.e. refrigerator, air conditioner, stove top) and, of course, in electric utility protection. IEEE defines a protective relay as “a relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action” [4].

The first relays used to protect the electrical grid were electromechanical units. They operated on electromagnetic principles in which magnetic attraction or induction forces would move a component to physically break the circuit if the current was higher than the set amount. Since then, relays have advanced to use solid-state integrated circuits and digital microprocessors to take current measurements and decide when to operate. Today’s digital protective relays, like the ones that will be used in this project, are part of a two-man team. “Protective relays provide the ‘brains’ to sense trouble, but as low-energy devices, they are not able to open and isolate the problem area of the power system.” [5]. Circuit breakers and reclosers provide the ‘muscle’ in protection operation by breaking the circuit near the problem area. A key advantage of solid-state and digital microprocessor-based relays is their programmability. Instead of a device that is calibrated for a single current threshold, engineers now have relays that can process multiple sensor inputs and be set to operate under a variety of conditions. The focus is now on the relay settings and defining ‘setting philosophies’.

The scope of this project is restricted to studying distributed generation connected to utility feeders and thus restricts the span of relay study to feeder relays. Since there is little to no expected differences in setting impact between corresponding feeder overcurrent relays from different companies, we have narrowed down the background research by choosing to focus on Schweitzer relays. Schweitzer relays are the common brand of relays that Protection Engineers at National Grid install because of its trusted reliability from past experience. Narrowing down the brand of relays will also prevent confusion between different numbering conventions, acronyms, and etc.

2.1.2. The Directional Power Relay (ANSI Designation #32)

The idea of using a relay for reverse power purposes has been around for some time. Figure 2-1 shows one example: the BE1-32O/U Directional Power Relay [6]. These relays are marketed to protect machines against reverse power flow, under power, and over power conditions. Below is a picture of this type of relay.

Figure 2-1. Basler BE1-32O/U Directional Power Relay [6]

These relays do a good job at preventing reverse power flow, but these relays are more conventionally used on generator system. A directional power relay is typically used to monitor the power from a generator in parallel with another generator or utility. The relay is used to prevent power flowing from the bus bar into the generator [6]. These relays are used to prevent system failure when one generator fails.

What the team wants is a relay that detects reverse power at the substation. Also, the relay also will have to communicate to a mitigation system at the DG site. Just having a relay that trips the inverter would not work effectively. It would not work effectively because when the inverter trips, a lot of the load is supplied by the DG that is now turned off. This will cause the load flow to shift greatly and could be damaging to households and grid systems.

2.1.3. Example of a Protected Radial Feeder

The distribution network is divided into four different parts. First is the feeder that originates at the substation. The term feeder is used to describe the power line in the distribution network that delivers power from a primary distribution substation to one or more loads. The feeder's terminal protection at the substation is typically a circuit breaker controlled by a relay, as seen in Figure 2-2 downstream from the transformer. In this case, an S&D SM4 fuse is also protecting the transformer. Following the circuit breaker is a voltage regulator with ANSI devices 8 and 13, or control power disconnecting device and synchronous-speed device respectively. The switch connected in parallel to the circuit breaker and the voltage regulator is used to isolate the circuit breaker for operation and maintenance when needed. The power is then delivered from the substation to feeders that distribute power to customer's homes. The circuit breaker name is designated as 19W2, the same as the feeder, to denote that the circuit breaker is protection for the feeder.

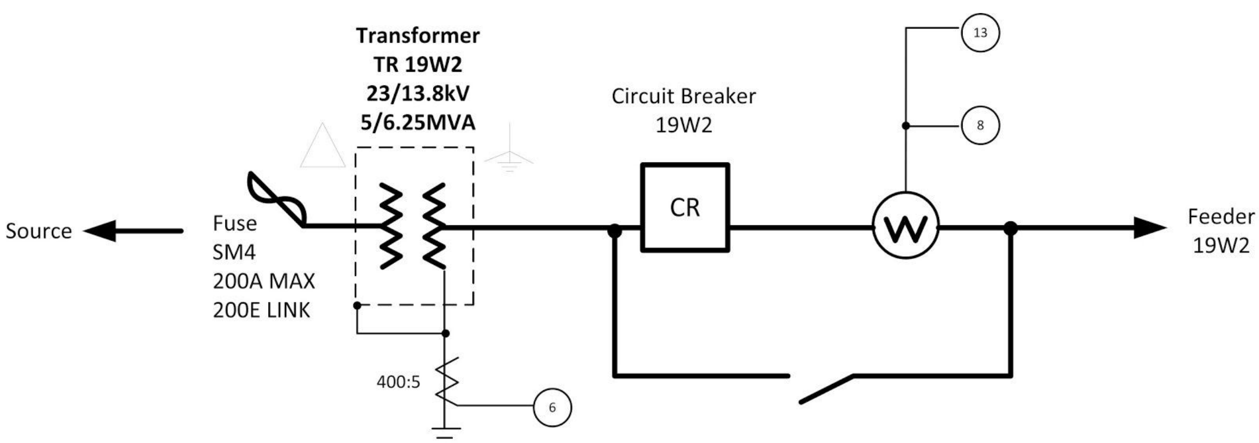


Figure 2-2. One-Line Diagram of Protection at an Example Distribution Substation

Feeder lines can be mounted overhead on wooden poles or underground and supplied by padmount transformers. Sections of the feeder in the system are protected by automatic reclosers. Taps off the feeder are also protected with automatic reclosers, as well as fuses. Finally, the pole-top distribution transformer is primarily protected by fuses. An example of where reclosers, fuses, and distribution transformers can be placed on feeder lines is shown in Figure 2-3.

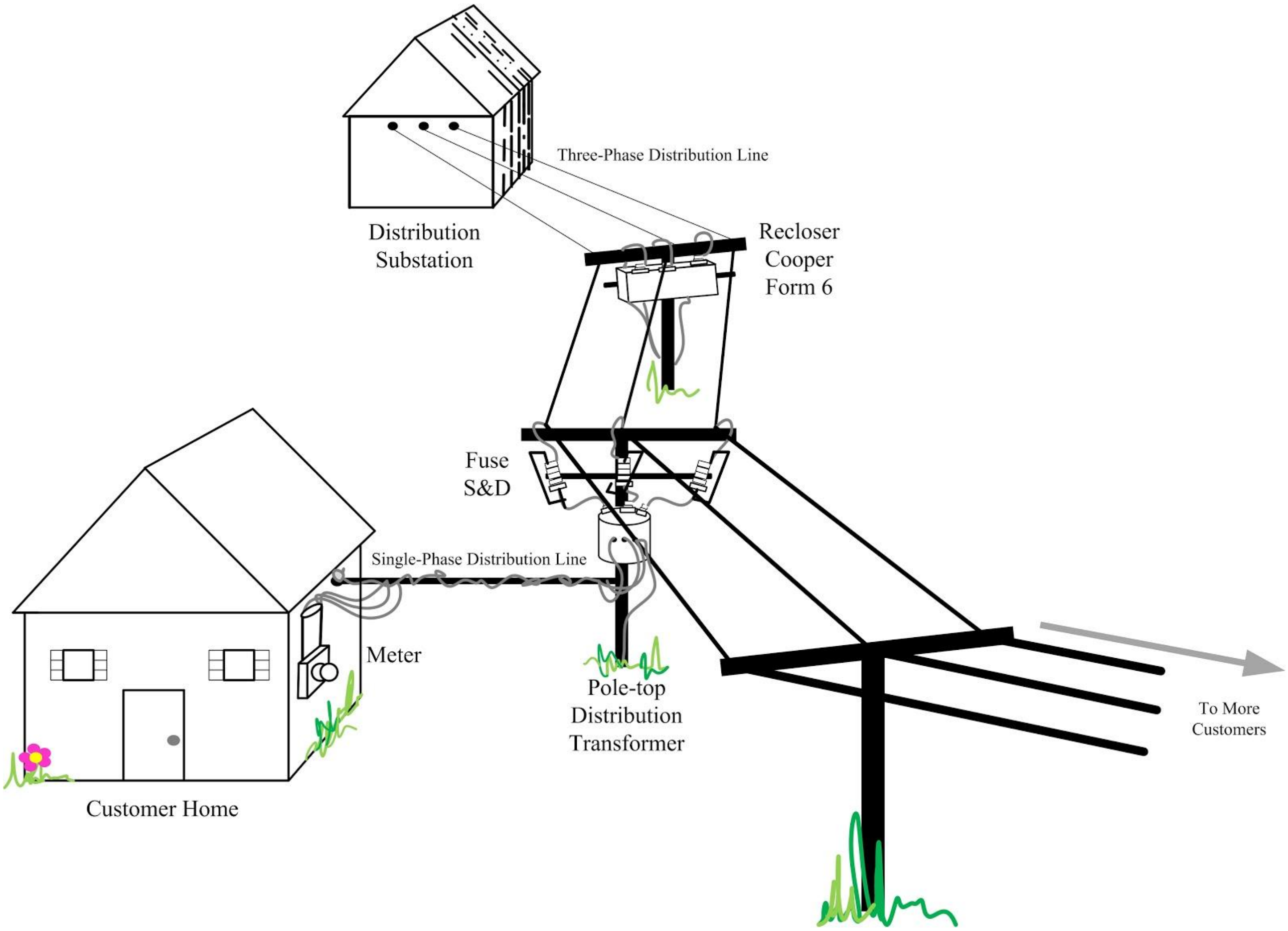


Figure 2-3. Protection for an Example Feeder Network

In Figure 2-3, the feeder lines originate from a distribution substation and are mounted on poles. At the pole, a Cooper Form 6 Recloser is mounted on the pole to protect the section of the feeder downstream from the device, or in this case to the next pole where the fuse and transformer are mounted. In the figure, S&D fuses protect the distribution transformer where a tap off the main line enters and converts the voltage for customers to use in their homes through a single phase distribution line. The single phase distribution line circuit is completed with a direct tap to the distribution circuit neutral wire. The line going directly to the customer's home is also tapped to a meter at the home where the utility tracks the usage and bills the customer accordingly.

Figure 2-3 models the placement of physical protection on a distribution system, but for the devices to respond to each together during faults, the devices need to be coordinated in performance.

2.2. Distributed Generation

Distributed Generation (DG) can be defined as “electric power generation within distributed networks or on the customer side of the network” [7]. Types of distributed generators are gas and oil reciprocating engines, combustion turbines, steam turbines, or geothermal. Renewable distributed generators, the more commonly connected, are wind, solar, or hydro. Power from DG is usually contracted to sell power solely to the local load but can be sold back to the utility when the DG system produces more power than the customer load. DG also reduces demand to the utility by peak-shaving, or reducing the amount of energy a utility needs to deliver during the hours of high energy demand.

One of the great advantages of the increasing connection of DG to the utility distribution system is the increasing implementation of renewable energy in an industry where the majority of the generating plants have harmful environmental consequences. Fifteen years ago, the number of customer DG connection was not expected to have increased to the amount that it is today. According to Figure 2-4, the amount of distributed generation has tripled since 2000 when only 47 GW of power was produced from DG. At National Grid alone, DG interconnection requests have doubled from 2012 to 2013 and have quadrupled from 2013 to 2014. Although Figure 2-4 shows global distributed power growth, the increasing rate of requests for DG interconnection at National Grid alone is sufficient evidence that there’s an increase of DG interconnection in the United States electric power system overall.

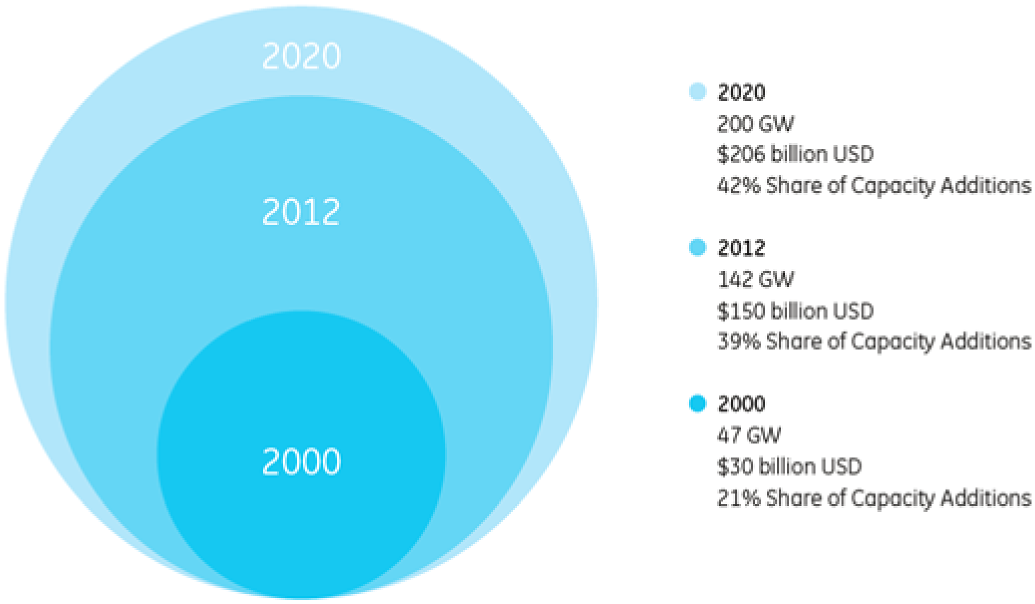


Figure 2-4. Global Distributed Power Growth [1]

Distributed Generation is increasingly becoming more and more common to the point that it is changing the structure of our electrical grid. The IEEE's response to this rise in DG connection was to publish the *IEEE 1547-2003 Standard for Interconnecting Distributed Resources with Electrical Power Systems,* which enacts guidelines for the interconnection of DG units 10 MVA or less [8]. But, this standard has its shortcomings. First, the standard does not take into account larger DG systems with ratings of 10 MVA or more. Second, the standard only addresses over/under voltage and frequency methods. The IEEE standard does not address the methods to reclose or reenergize DG generation after an outage, the recommended transformers that should be used in distributed generation, or the necessary protection [9]. These challenges produce a problem: how can we protect the utility and the customer from fault situations that also have distributed generation on the line as well. This leads the team to study the impact of distributed generation on protection systems and how protection procedures for DG can be improved.

2.2.1. How Distributed Generation Changed the Grid

The electrical grid that stands today is the product of about 100 years of development. Since its infancy, the grid has always followed and expanded upon the same centralized structure. Power is generated in large quantities (on the order of Megawatts or Gigawatts) in large power plants that are scattered across the region. The power is then transmitted through transmission lines at high voltages to the towns and cities that purchase the power. These are called load centers. At the load centers, the voltage would be stepped down in substations and then supplied to the end user through the distribution network; this network consists of the roadside power lines atop utility poles that most people are familiar with. This structure of generation, transmission, and distribution has been the static model for about a century for one major reason; it was always the most economically viable option. Large generation units benefited from the idea of ‘economies of scale’; the more power a plant generates means a bigger profit and the cheaper rate it could sell the power at. The most inefficient part of this centralized system is the transmission. Transmitting electric power up to hundreds of miles is costly. However, for the longest time, it made more economic sense to transmit large scale power than to try to construct small generators to fill individual power needs. Distributed generation is the counterpoint to the centralized grid structure. DG describes electrical generation units that are interconnected to an area of the electric power system and are close in proximity to the load that they serve. These units are usually small, on the order of 5 kW to 30 kW. Renewable DG in the form of solar panels are commonly mounted roof-top on households, as seen in Figure 2-5, and connected to the distribution network to supply the network if the unit is producing more power than the household is using. DG units can provide a host of advantages compared to conventional power including better power quality, lower emissions, and increased reliability. These advantages have caused the great popularity in distributed technologies.

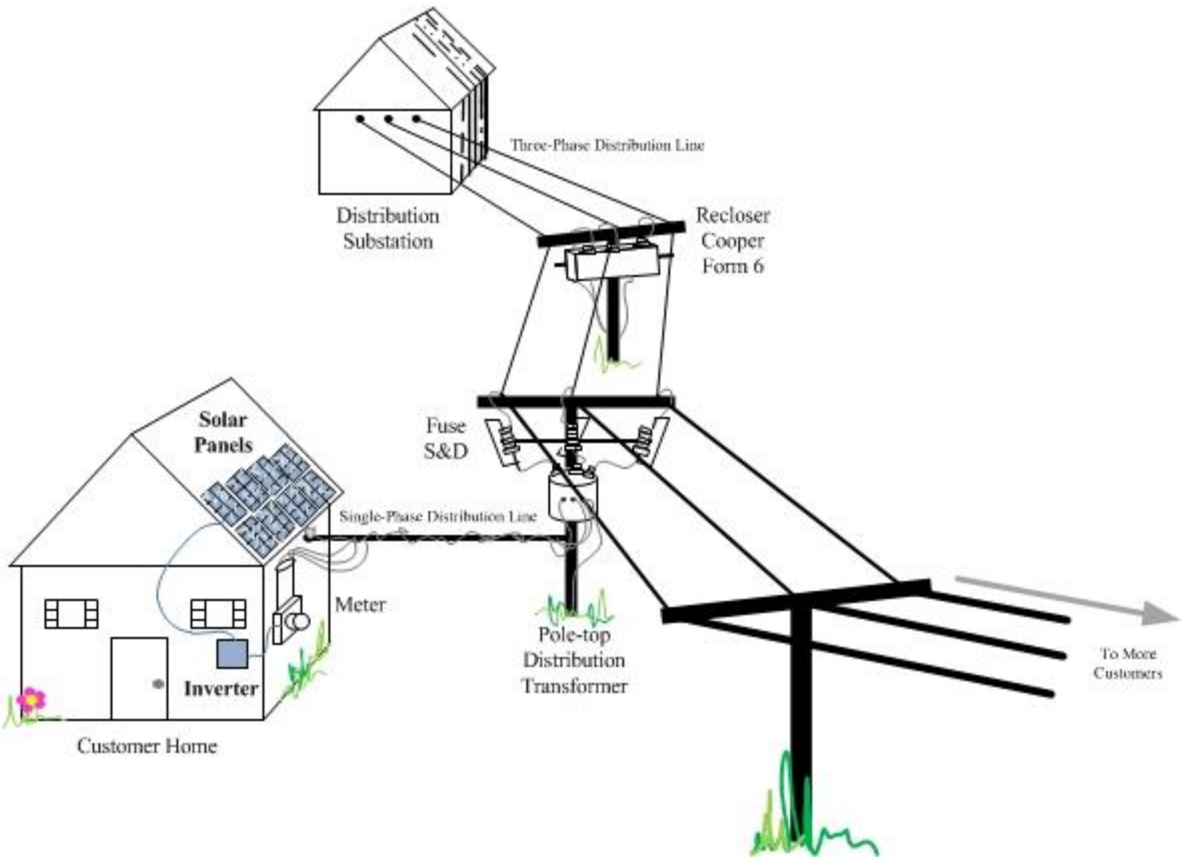


Figure 2-5. Example Solar Panel Connection to the Distribution Network

2.2.2. Types of Distributed Generators

There are a host of diverse technologies being employed on distribution networks and each generates or stores energy in a different way. But, they can be broken down into three simplified categories: induction, synchronous, and asynchronous generators. Induction and synchronous generators generate electric power from the rotation of their rotors within the magnetic field supplied by the enclosing stator, or the fixed portion of the machine. For an induction generator to operate, the rotor must be spinning slightly faster than the stator. This difference in speed between the two components is what generates the alternating current from the generator. Induction generators are typically small---producing less than 500kVA. They're restricted in size because of a needed excitation from an external source of VARs, which can be very expensive, to start the generation [10]. These systems can only provide a few cycles of faults during fault conditions. An example of an induction generator is a wind turbine.

Synchronous generators are more common. Unlike the induction generators, synchronous generators have a DC field winding to provide a source of excitation and therefore are less expensive than an induction generator. They convert the rotation of their rotors proportionally to the frequency of their AC output. They can provide both real power and reactive power to the system but can also provide sustained fault current during fault conditions [10]. An example of a synchronous generator is a combustion turbine or a reciprocating engine. These tools are used in DG to make cogeneration systems and combined heat and power systems [11].

Asynchronous generators are non-traditional, small dispersed generators. Examples of asynchronous generators typically include microturbines, fuel cells, and photovoltaic technologies [10]. These generators are generally connected "through a Static Power Converter (SPCs), a solid-state microprocessor controlled thyristor device that converts DC or AC voltage at one frequency to 60 Hz system voltages. Digital electronic control of the SPC regulates the device's power output and shuts down the machine when the utility system is unavailable. If the generator is islanded [a phenomena that occurs when DG is no longer connected to the electric power system but continues to supply power] from the utility system, the frequency will change and the control is programmed to trip the micro-turbine" [10]. These systems usually provide only a few cycles of fault current during system fault conditions.

2.2.3. Potential Protection Problems with DG Interconnection

Since there are many different types of generation, there are many different ways that things can go wrong in the system that could do damage to the home, transformer, or lines. These problems add greater complication to the grid.

According to Blackburn and Domin, the general problems with DG interconnection are the following [12]: "

A. Internal Faults
   a. Primary and backup phase or ground faults in the stator and associated areas
   b. Ground faults in the rotor and loss-of-field excitation
B. System Disturbances and Operational Hazards
   c. Loss of prime-mover; generator motoring
   d. Over-excitation: volts per hertz protection

e. Inadvertent energization: non-synchronized connection

f. Unbalanced currents: negative-sequence ; breaker pole flash-over

g. Thermal Overload

h. Off-frequency operation for large steam turbines

i. Uncleared system faults: backup distance ; voltage controlled time overcurrent

j. Overvoltage

k. Loss of synchronism: out of step

l. Subsynchronous oscillations

m. Loss of voltage transformer signal to relaying or voltage regulator

n. Generator breaker failure"

Before connection of DG, an unbalanced load current would have returned to ground through the main substation transformer neutral. But now with DG, unbalanced load current splits between the substation and the DG transformer neutral. This can reduce the load-carrying capabilities of the DG transformer and create problems when the feeder current is unbalanced due to operation of single-phase protection devices such as fuses and line-reclosers. DG also provides a source for redistributing the feeder load and fault currents, thus causing overvoltage problems.

These problems create the need for new special protection schemes that are catered to distributed generation interconnections.

"Interconnection protection serves essentially three functions [9]:

1. Disconnects the DG when it is no longer operating in parallel with the utility system
2. Protects the utility system from damage caused by connection of the DG, including the fault current supplied by the DG for utility system faults and transient overvoltage
3. Protects the generator from damage from the utility system, especially through automatic reclosing"

Generator protection generally provides detection of generator internal short circuits and abnormal operating conditions such as loss-of-field, reverse power, overexcitation, and unbalanced circuits. The typical synchronous generator protection includes the following [13]:

- 25 - Sync Check
- 27 - Undervoltage
- 32 - Reverse Power
- 46 - Negative-Sequence Overcurrent
- 47 - Voltage Phase Sequence
- 51V - Voltage Restrained Overcurrent
- 50/51N - Neutral Instantaneous and Time Overcurrent
- 50/51G - Ground Instantaneous and Time Overcurrent
- 59 - Overvoltage
- 59G - Ground Overvoltage Relay
- 81O - Over Frequency
- 81U - Under Frequency
- 87 - Differential

With induction-based DG, two to three fault cycles are supplied to external faults in regards to fault backfeed. Small synchronous generators have little contribution to fault backfeed when the substation breaker trips because of overloading conditions at the generator, however the larger the synchronous DG machine, the more likely it is to supply this fault backfeed. Typically, an AC directional overcurrent relay (67), a distance relay (21), or a voltage restrained overcurrent relay (51V) is used to provide phase fault backfeed detection [9]. According to Charles Mozina, protection systems consultant for Beckwith Electric Co. Inc., “when developing settings for the 67 and 21 relays, the relay pickup setting must be set above the level of generator current being supplied by the DG to the utility system. Ground fault backfeed removal depends on the primary winding connection of the interconnection transformer installations. For ungrounded interconnection transformers, neutral overvoltage relays (59N, 27N) provide the detection for supply ground faults” [9]. Voltage transformers (VTs) have their primary windings connected from line-to-ground and are rated for the full line-to-line voltages [9].

Loss of parallel operation occurs when the DG is islanded either due to a fault or an abnormal condition. To detect when the DG is no longer connected in parallel, an over/underfrequency (81P/U) and an over/undervoltage (27/59) relay is installed. In some cases, some states require additional protection such as a transfer trip (TT) scheme or a directional power relay (32). “A TT scheme can be a reliable means of communication for when voltage and frequency stay within the normal operating window and 81P/U and 27/59 relays trip if the load and generator are near a balance at the time of operation. When the loss of parallel operation is detected, the dispersed generator must be separated from the utility system quickly enough to allow the utility breaker at the substation to automatically reclose” [9].

Loss-of-synchronism is caused by a high level of negative sequence current supplied by open conductors, phase reversal, or operation of fuses and line reclosers. High levels of negative sequence current can result in rapid rotor heating, possible rotor damage, and voltage dips. When a voltage dip occurs, the less real electrical power the generator can supply and therefore more imbalance between electrical and mechanical output. To detect loss-of-synchronism conditions, or also called detection of damaging system conditions, a negative sequence overcurrent relay (46) is often used. To protect against the consequences of phase reversals “caused by inadvertent ‘phase swapping’ after power restoration”, a negative sequence voltage relay (47) is often used [9].

When the distributed generator supplies power into the utility system for more than a predetermined time interval instead of selling power directly to the local load like it’s initially contracted to do, the generator is in violation of its contract and is considered as operating in abnormal conditions. To prevent this and to protect against abnormal power flow into the utility, a directional power relay (32) is often installed.

To avoid unsynchronized closures during restoration, a synchrocheck relay (25) is often installed. “The synchrocheck relay is generally equipped with dead bus undervoltage logic to allow reclosure from the utility system for a dead bus condition at the DG facility” [9]. The relay is often multiplexed for multiple breakers.

“When the frequency decreases due to a major system disturbance, DG will trip off-line” [9]. To protect against this, a rate-of-change frequency relay (81R) is often used. The advantage of using this protection method is that it offers more rapid tripping for severe DG overloads while allowing the DG to remain connected to the system during the frequency fluctuation [9].

Loss of relay coordination can occur when unwanted ground fault current (from grounded primary transformer windings) supplies circuit faults and reduces the current from the nearby substation breaker. If the fault is near the end of the feeder, the reduction in substation ground fault current may result in substation ground fault relaying not responding to the fault. What has been done as practice in efforts to combat this problem has been to add pole-top line reclosure to detect ground faults near the end of the feeder circuit [13].

2.3. Silicon Controlled Rectifier (SCR)

The SCR (Silicon Controlled Rectifier) is a very common tool used in power electronics. It is used to control the output of AC voltage and current. The SCR accomplishes this through the activation of the SCR's gate. When current flows into the gate, the SCR becomes a diode through the Anode and Cathode until the current is discharged then the SCR deactivates. It then waits for another pulse from the gate to activate the SCR again [14]. By adjusting the firing angle of the pulse one can adjust the average power output of a system.

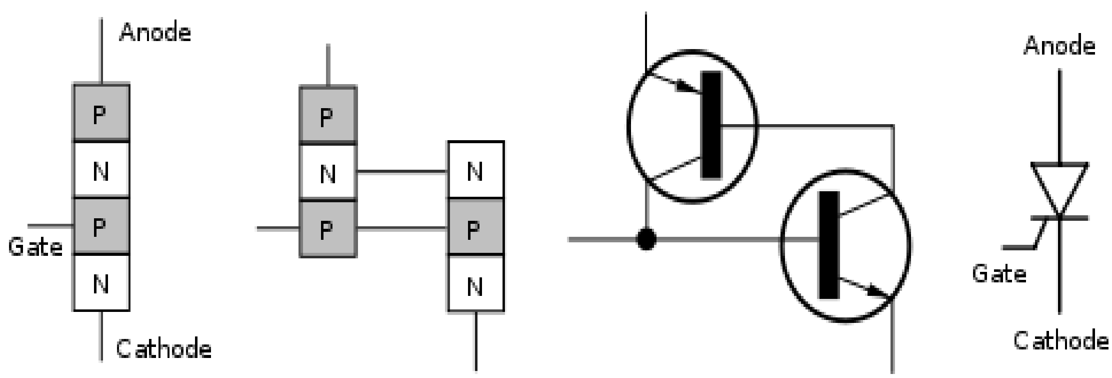


Figure 2-6. The Silicon Controlled Rectifier (SCR) [14]

Figure 2-6 depicts the internal component of a SCR. The SCR is made from a PNPN junction with a gate connected to the second P of the SCR [14]. The design can be further conceptualized as one PNP and one NPN BJT. The PNP's cathode is connected to the gate of the NPN and the gate of the PNP is connected to the anode of the NPN. The last picture shows the simplified diagram used for circuit analysis.

The firing angle of the SCR becomes a very important component for regulating power output. Figure 2-7 shows the basic idea behind firing angle and the discharging of the SCR:

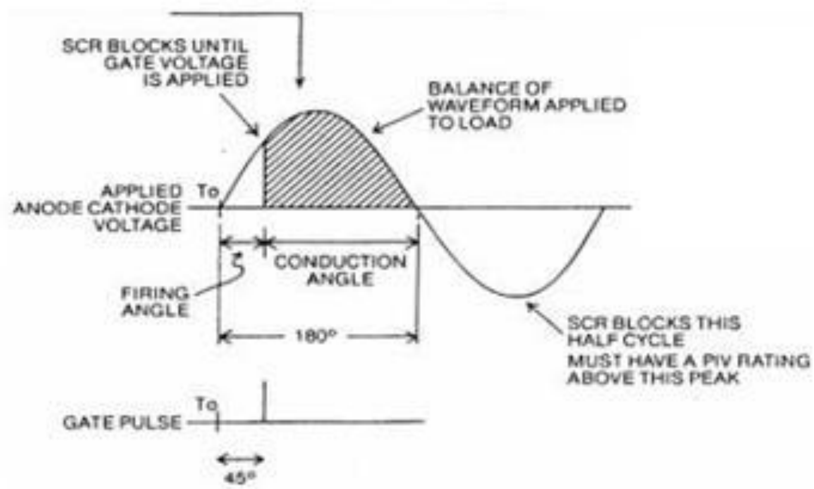


Figure 2-7. The Voltage Characteristic of an SCR [15]

The graph above shows the gate pulse (below), the output voltage (shaded), and the input voltage (the line). The output voltage is defined by the angle of which the gate voltage is fired at. The point at which the gate voltage pulses at is known as the firing angle. In the graph above firing angle is shown as the point in which the gate pulses.

This firing angle can be used to design an AC-to-AC conversion that could respond to a relay. It would work by first having a relay detect undercurrent at a specific threshold or a phase shift that is 180 degrees out of phase. When undercurrent occurs, the relay would command the SCR defining the firing that would activate the SCR. This would mitigate the average power until undercurrent was at normal conditions.

This could have been a good mitigation method but there are a few notable drawbacks. The relay would have a very complicated communication system to define a firing angle. The power output will also affect how large of a firing angle is required to mitigate the voltage. If the power from the DG increased the firing angle must increase as well. The response time is another complication of this system. The response time would have to match the speed of the changes in the sun’s irradiance. In conclusion, the SCR is a good method to regulate output power but would have a tough time keeping a constant value while the system constantly changes.

3. Reverse Power Flow Mitigation System

The team's goal was to design and simulate a system that mitigates reverse power flow in the presences of a PV DG resource on a distribution network. The team used the MatLab/Simulink software to develop and test this system.

3.1. Overview

The structure of this system is based on existing protection equipment that guards power systems against electrical faults. In existing two-part protection systems, a device called a relay measures the power system's voltage and current using potential transformers and current transformers. The relay takes these voltage and current waveforms as input and determines whether or not a power system is operating normally. If the relay detects unfavorable or dangerous voltage or current conditions it sends a signal to its partner protection device, the circuit breaker. The circuit breaker is the component that makes a change in the system, by opening like a switch and breaking the circuit.

The problem of reverse power flow mitigation could be handled by two similar components; a relay which detects the presence of reverse power flow and a buck converter that mitigates the DG's output.

The first objective for the team was to find a way to detect reverse power flow at the substation. The team began by running a few experiments on a simple distribution model in Simulink. This distribution network was based off of a pre-existing sample model that came with the Simulink power systems library. A one-line diagram of the distribution model is shown is Figure 3-1.

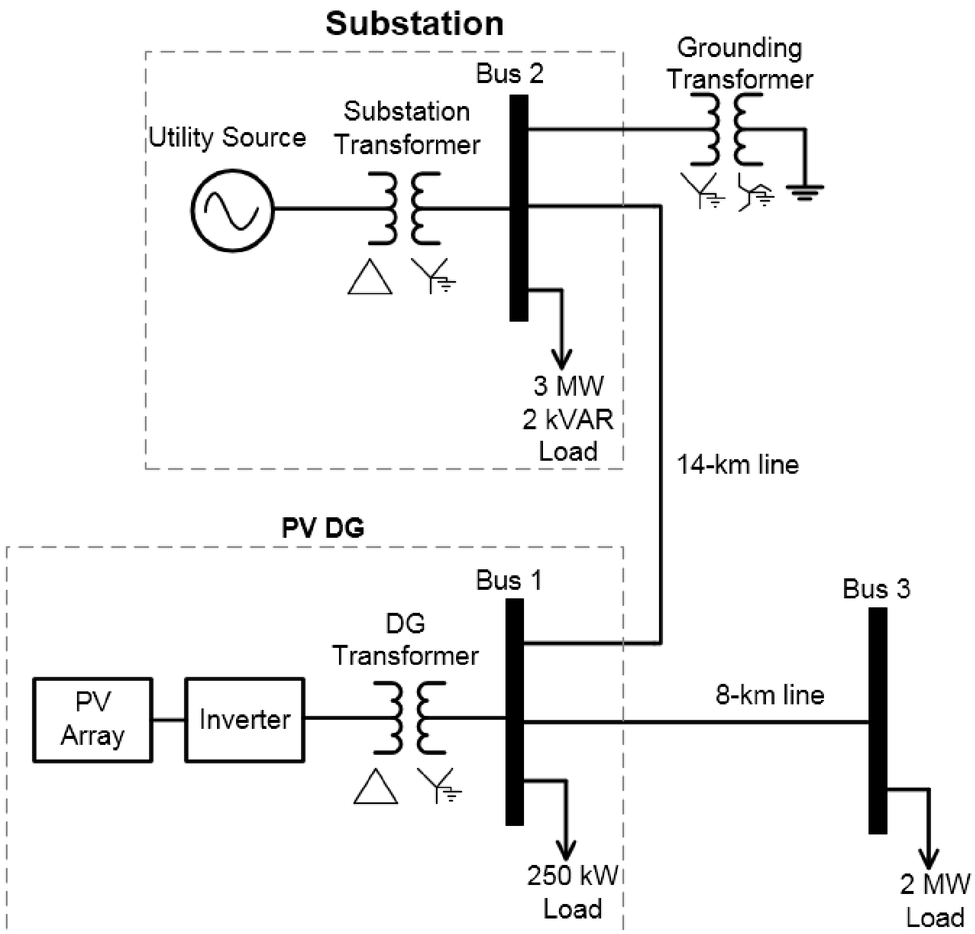


Figure 3-1. One-Line Diagram of a Simple Distribution System

The team knew that the most important aspect of the system was the direction of power flow at the substation, so the team measured the voltage and current at the substation bus. The team found that when measuring voltage and current at the substation, if power was flowing back into the substation, the voltage and current waveforms would be 180° out of phase as seen in Figure 3-2.

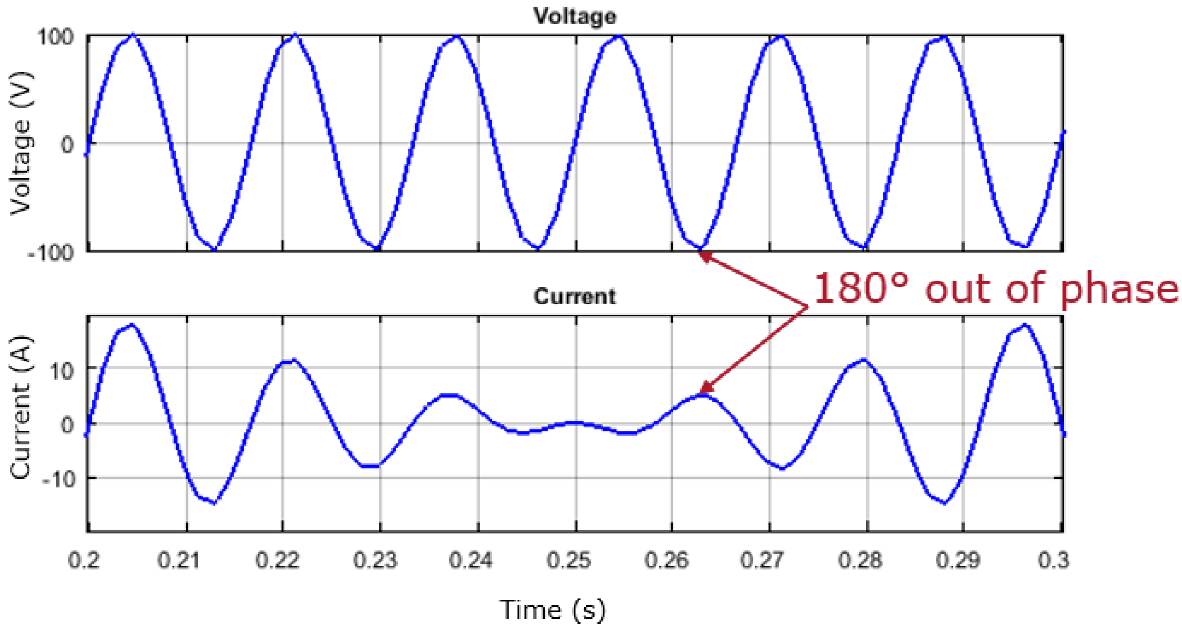


Figure 3-2. Voltage and Current at Substation Bus (Reverse Power Flow)

This led the team to conclude that the part of the mitigation system that detected reverse power flow, the relay, should be able to detect a 180° phase shift. However, this would not be sufficient to fully mitigate reverse power flow and the negative impacts it can cause. If the relay only acted when the voltage and current were already out of phase, then the relay would only start mitigating the DG after a reverse power flow situation already existed. To complement the phase shift detector, the team decided to add another logical block to the model that would detect when the current output from the substation reached a set minimum threshold. This under-current detector would ensure that the power output from the substation didn't fall below a minimum threshold, providing a healthy margin of safety, long before a reverse power flow situation could arise.

3.2. Relay

The relay model contains two logic systems that detect the unacceptable conditions of reverse power flow identified above. They are, the phase detector and the under current detector. The Simulink block diagram of the model can be seen in Figure 3-3.

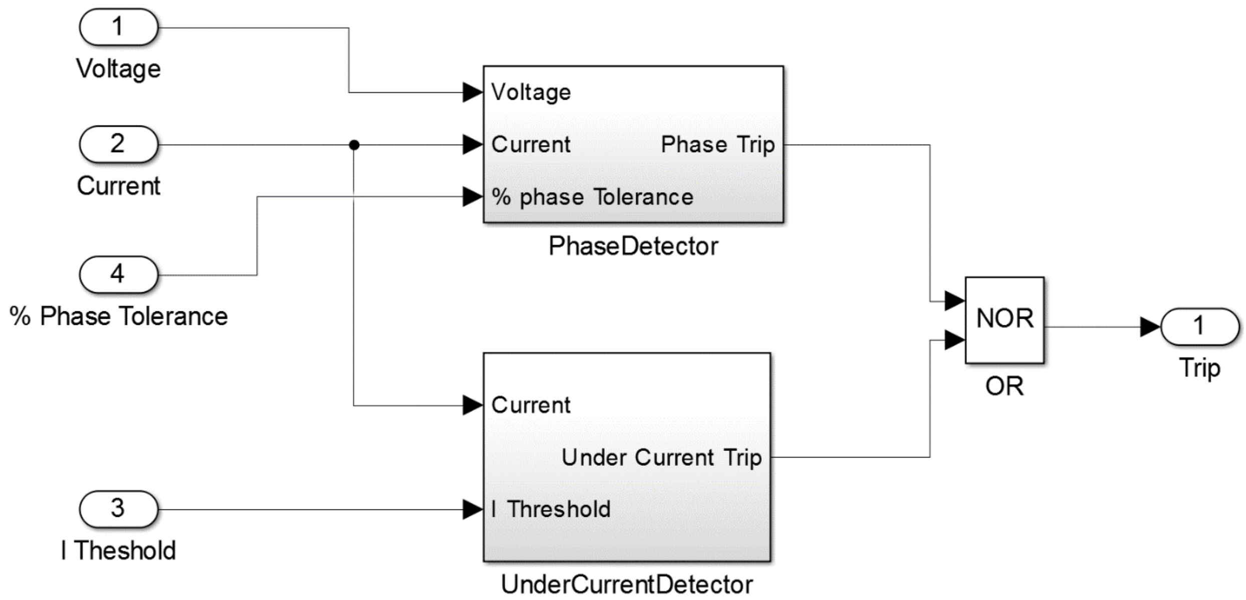


Figure 3-3. Relay Model

3.2.1. Phase Detector

The phase detector block of the relay model takes the voltage and current waveforms as input as well as a user-defined power factor tolerance. It measures the phase difference between the voltage and current waveforms as seen in Figure 3-4.

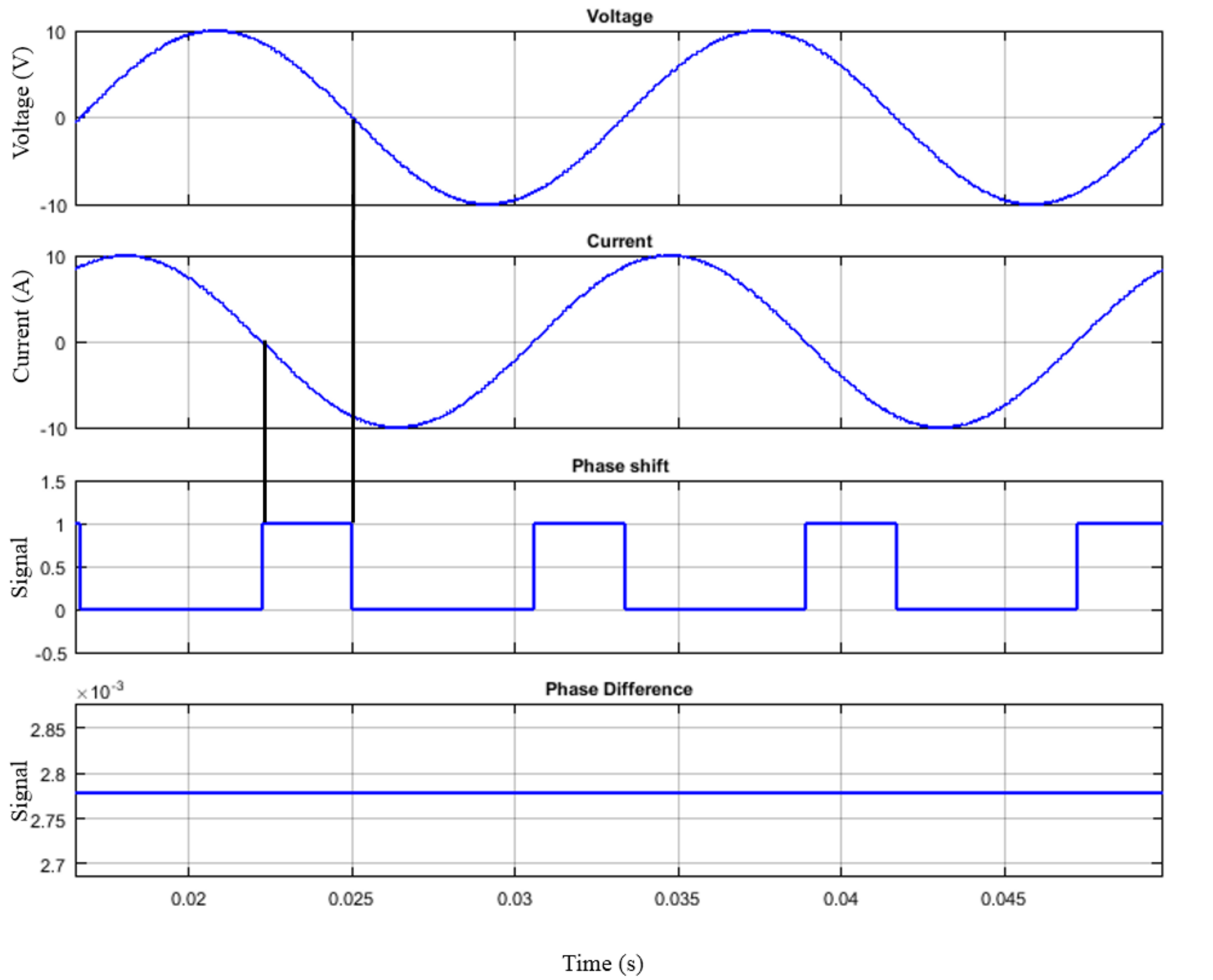


Figure 3-4. Phase Detector Operation

In Figure 3-4, the phase difference is $\frac{\pi}{3}$ or 60° which is $2.\overline{7} * 10^{-3}s$ with a 60Hz sine wave. The phase detector then checks if the measured phase difference is 180°. If the voltage and current were 180° the phase difference would be one half the period, or $8.\overline{3} * 10^{-3}s$ for a 60Hz sine wave. This system would not function in real life however because real distribution systems have inherent phase shifts due to non-unity power factors from reactive loads on the system. To account for this the phase detector compares the measured phase difference to a value calculated from the power factor tolerance input. The power factor tolerance is the normal power factor for the distribution system and defined by the user. The phase detector calculates the phase shift threshold from the following equation:

$$threshold = \left(\frac{\pi - \arccos(pf)}{\pi}\right) * \frac{T}{2}\ [s]$$

Where pf is the power factor tolerance and T is the period, or $1.\overline{6} * 10^{-2} s$ in the case of 60Hz. The block diagram for the phase shift detector can be seen in Figure 3-5 and its function can be seen in Figure 3-6.

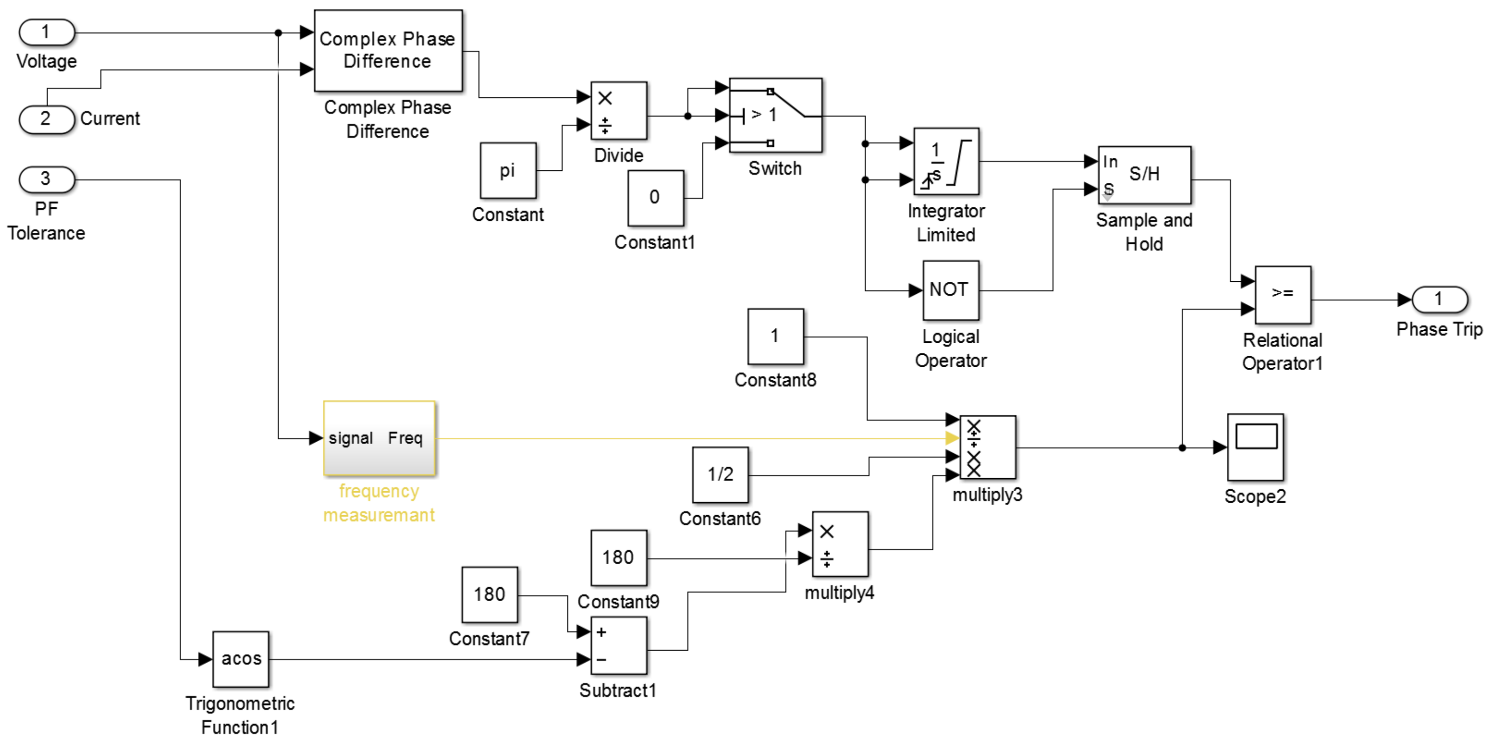


Figure 3-5. Phase Detector Model

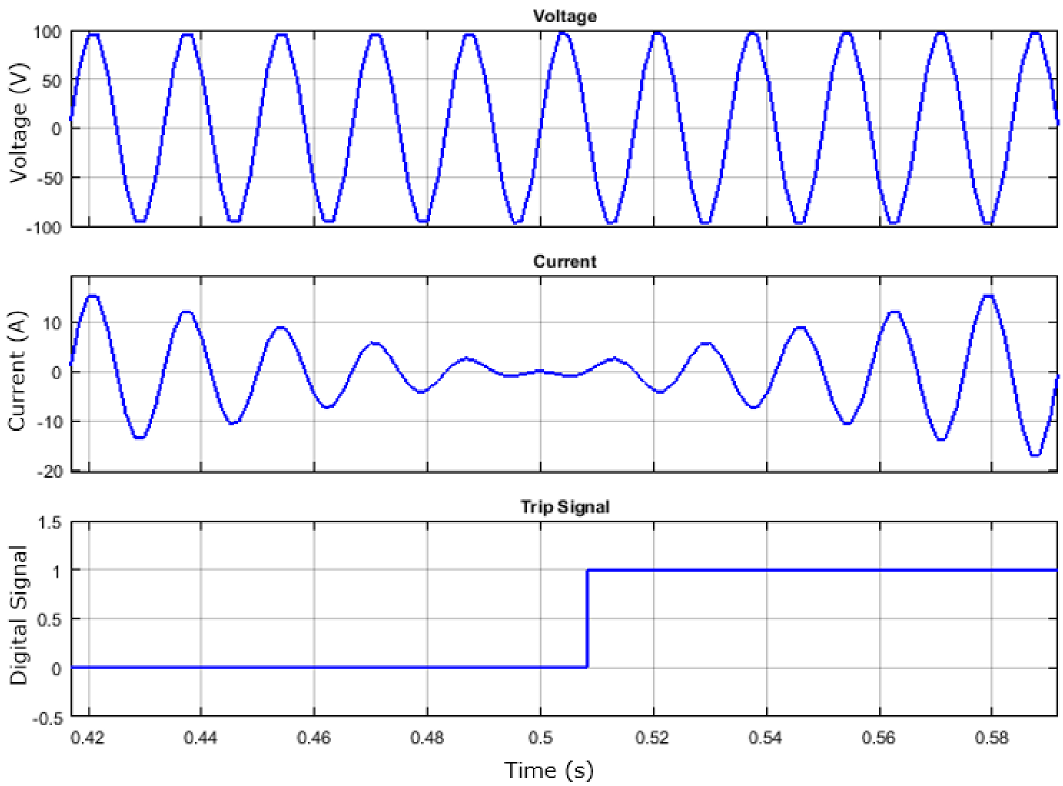


Figure 3-6. Phase Detector in Action

3.2.2. Under-Current Detector

If the relay only detected the voltage and current were to be 180° out of phase with each other than that would mean that a reverse power flow situation was already present by the time the relay tripped. The team reasoned that, in order to completely avoid a reverse power flow situation and all its negative effects, current should never be allowed to flow back into the substation and the relay should detect some condition before that. The team's solution was to have the relay trip if the current flowing out of the substation dropped below a set minimum value. To implement this, the team designed an under-current detector. The under-current detector outputs a trip signal to the buck converter when the magnitude of the current drops below a set value. The block diagram and function of the under current detector can be seen in Figures 3-7 and 3-8 respectively.

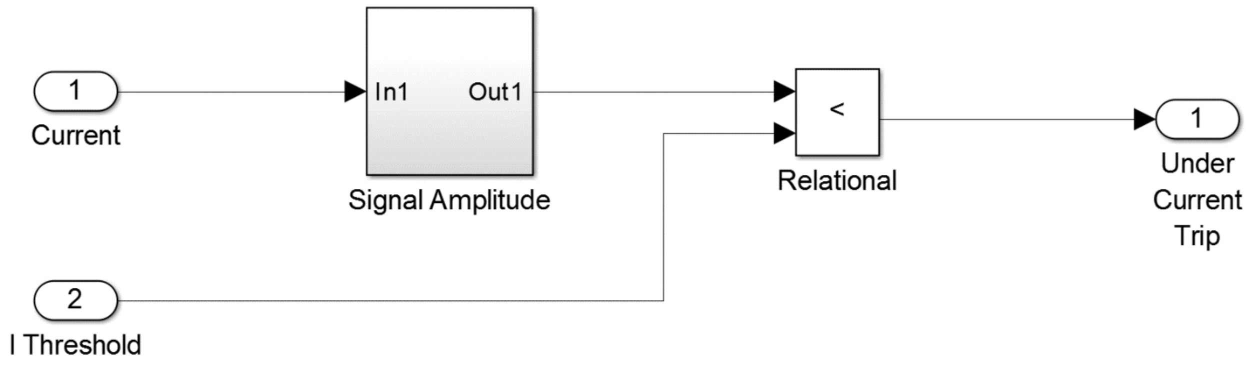


Figure 3-7. Under-Current Detector Model

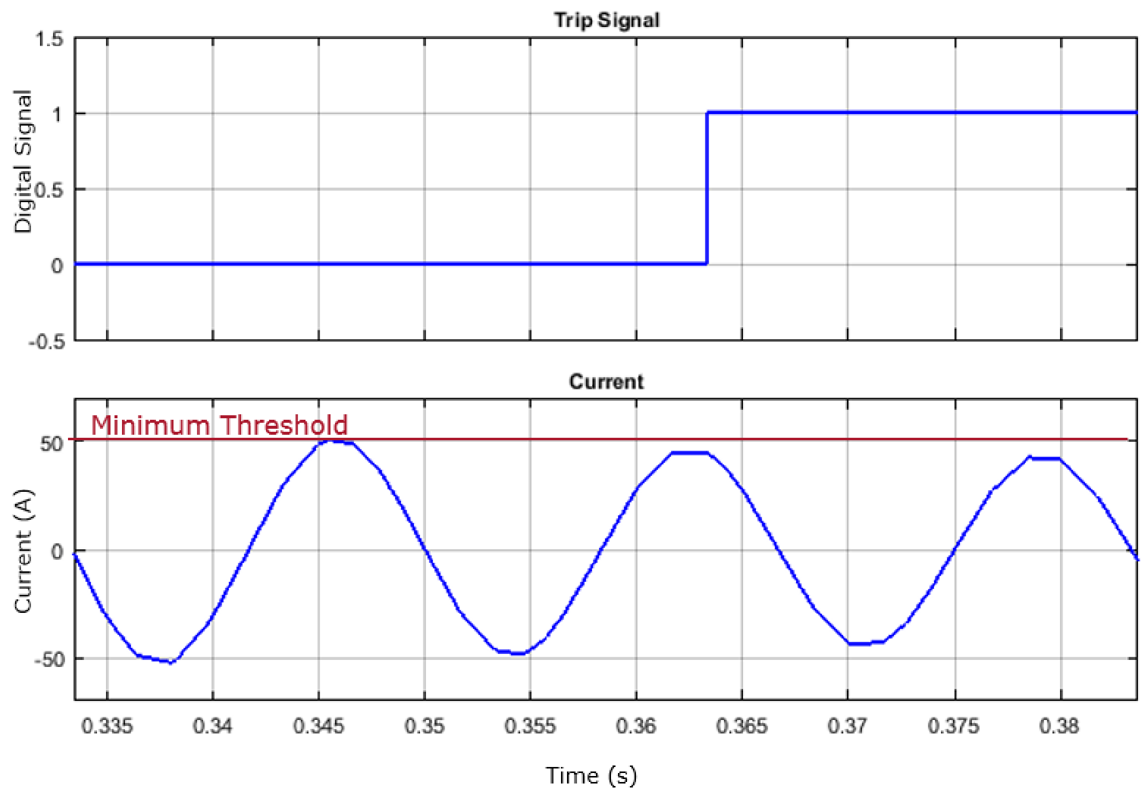


Figure 3-8. Under Current Detector in Action

3.3. Buck Converter

3.3.1. Introduction

One of the major components of the design of a reverse power flow relay was the buck converter. A buck converter is a power electronics circuit that steps down the voltage and by a factor between 1 and 0 as a function of its duty cycle D. A higher duty cycle equates to a voltage closer to the input voltage while a lower duty cycle equates to a voltage closer to 0. The formula that governs the output voltage is shown in equation 1.

$$V_o = DV_i \qquad \textit{Equation 1}$$

Where D = Duty Cycle,

V_o = Output Voltage,

V_i= Input Voltage

While voltage decreases due to a decrease of the duty cycle, the current will increase due to the decrease of the duty cycle. The formula that governs the output current is shown in equation 2.

$$I_o = \frac{1}{D} I_i \qquad \textit{Equation 2}$$

Where I_o= Output Current,

I_i= Input Current

As can be seen by the equations, when the voltage drops the current will increase proportionally. This is only in an ideal case. There are parasitic losses from many of the components in a buck converter. The buck converter has a switching loss that increases at higher frequencies. There is also a voltage drop across the diode and switchgear. In addition, there are losses from the non-ideal nature of inductor. The inductor will store and discharge current. But as the inductor discharges current, the current through the inductor will decrease. This non-ideal characteristic is what the team used to design the buck converter such that it properly works with the relay.

To achieve a steady output value, the team focused on the inductor. When the switch is closed, the inductor becomes charged with more current. Therefore, the current output increases. When the switch is open, the inductor discharges to the system. Therefore, the current output decreases. This idea of increasing and decreasing current is what the team uses to create the step down system. By using a negative feedback loop, the buck converter can react to the relay in real time. When too little current is flowing from the substation, the relay outputs logic ‘0’. The logic ‘0’ commands the buck converter to open the switch. This causes the inductor to discharge and the current to decrease. When the current flowing from the substation increases beyond the minimum threshold, the relay outputs logic ‘1’. The logic ‘1’ commands the buck converter to close the switch. This causes the inductor to charge and the current to increase. This cycle repeats to keep the current at the substation at a constant threshold. Figure 3-9 shows the concept of the buck converter’s operation.

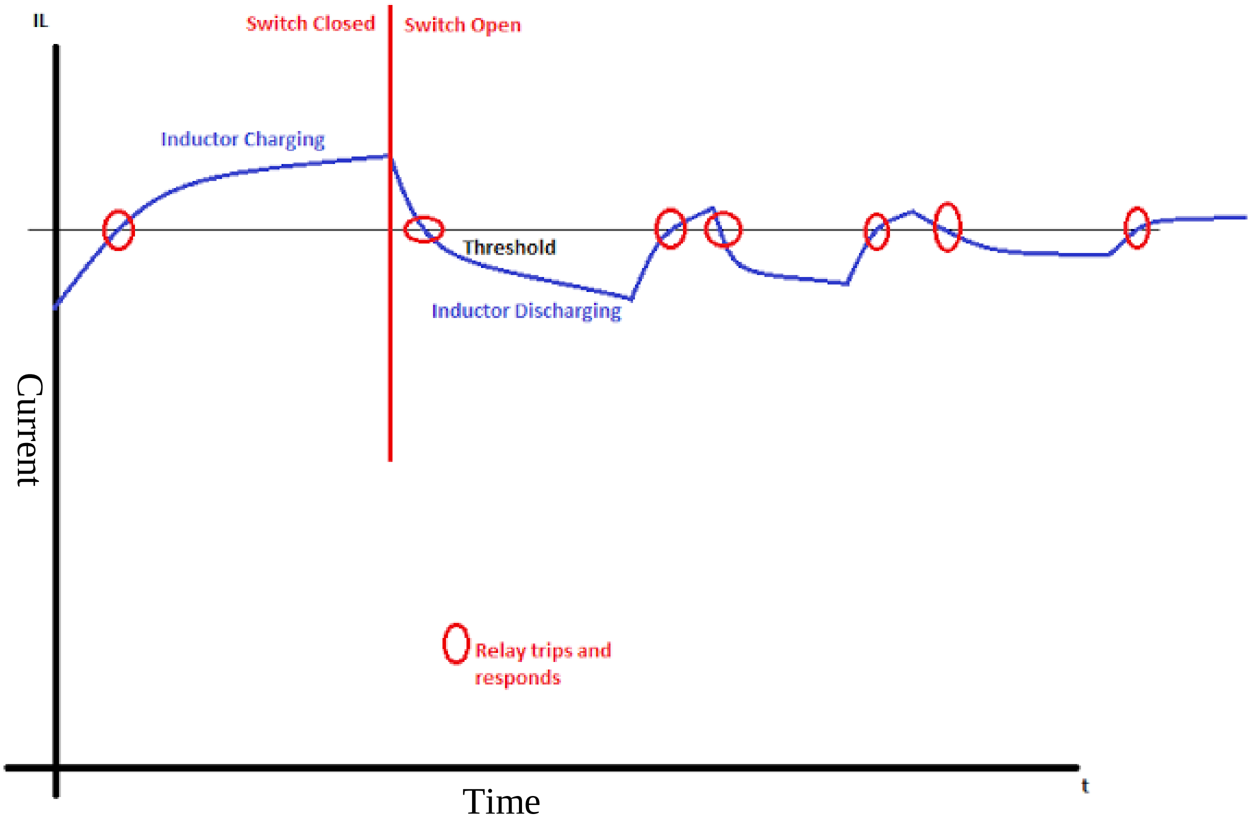


Figure 3-9. Buck Converter Controlling the Current

The DC-to-DC buck converter takes in three inputs: Duty cycle (Duty), positive input (+in), and negative input (-in). The duty pin takes in a digital logic value from the relay and will open the switch if the input value is logic “0” and will close the switch if the input is logic “1”. The +in acts as a wire and accepts a voltage and current value. The –in also acts as a wire and accepts a voltage and current value.

A filter capacitor (C1) was placed just before the switch and acts as a voltage storage location to the input. Without this capacitor the model will crash when the switch is open. Also two capacitors instead of one were used to make the buck converter. These capacitors were also given a 240V initial condition. This is to create a three-pin output to the next component.

The DC-to-DC buck converter then gives three outputs: positive output (+out), neutral (N), negative output (-out). The +out simulates a positive wire going to the next component. The N simulates a neutral (zero wire) to the next component. The –out simulates a negative wire that goes to the next component.

Initial conditions were placed on many of the components in the model to simulate a steady state scenario at time 0. This allowed the team to only have to run the model for 10 seconds instead of 60 seconds.

3.3.2. Results

The buck converter was placed the PV arrays and the inverter. It was used to step down the voltage of the PV array. Figure 3-10 shows the buck converter in the full model distributed generation system.

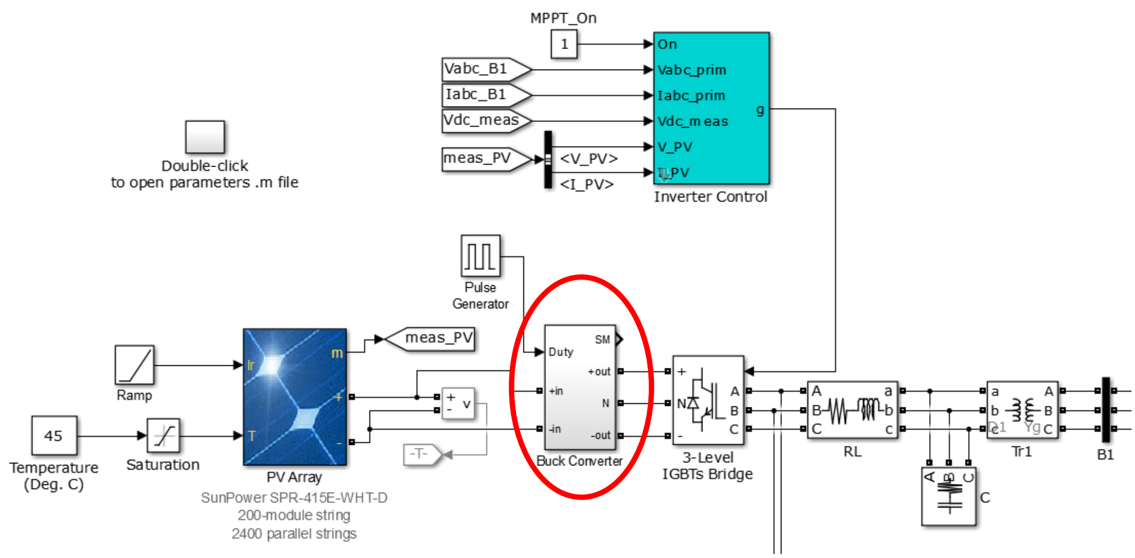


Figure 3-10. Simulink Distributed Generation Model

The buck converter then outputs to the inverter. Figure 3-11 shows the voltage and current measurements at the input of the buck converter. The switch modulation is shown in the bottom graph of Figure 3-11.

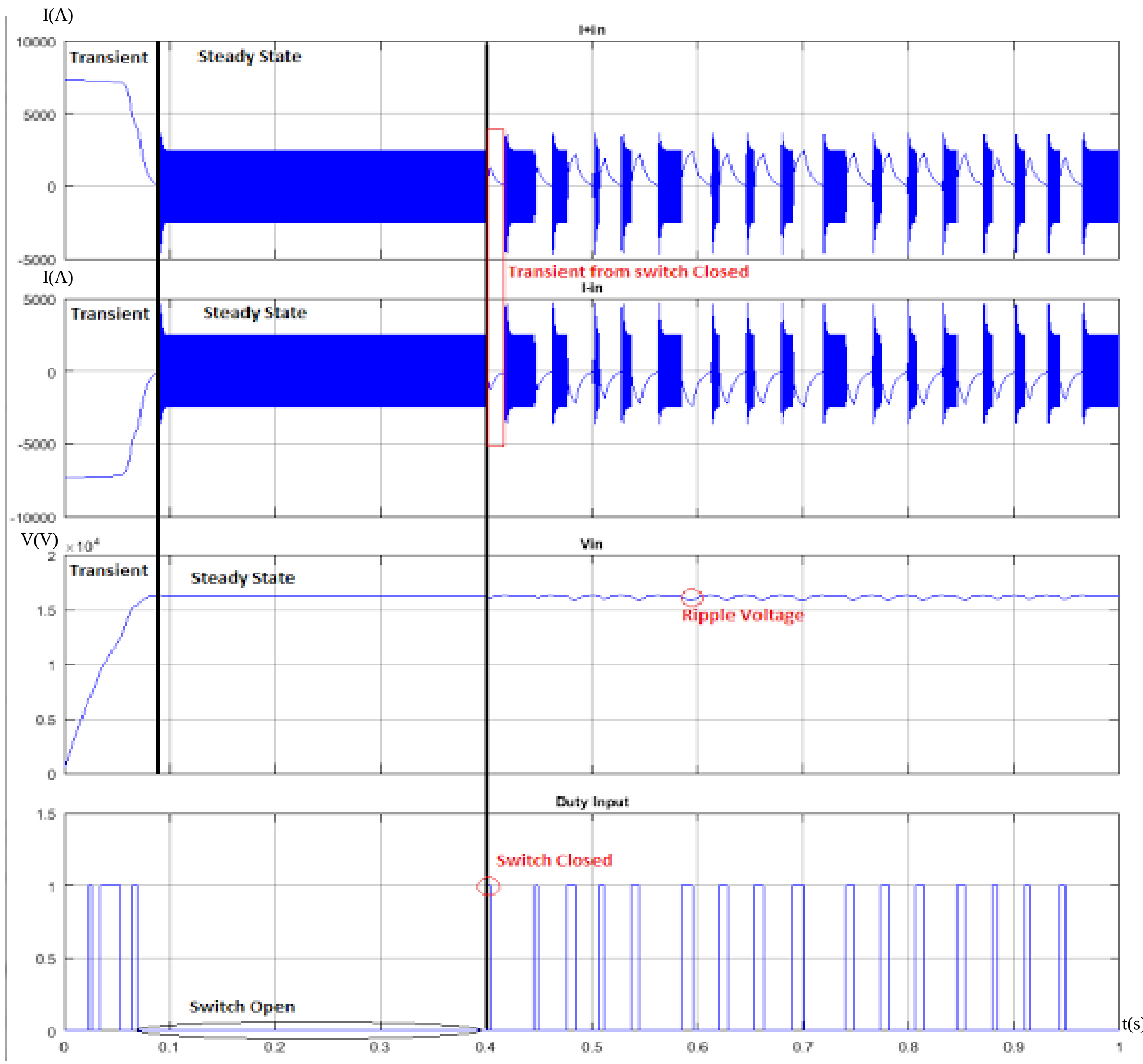


Figure 3-11. Voltage and Current Inputs to the Buck Converter

Notice that in Figure 3-11, the current is not an ideal DC waveform. Zooming into the steady state portion of the two current values shows two square waves 180 degrees out of phase with one another as seen in Figure 3-12.

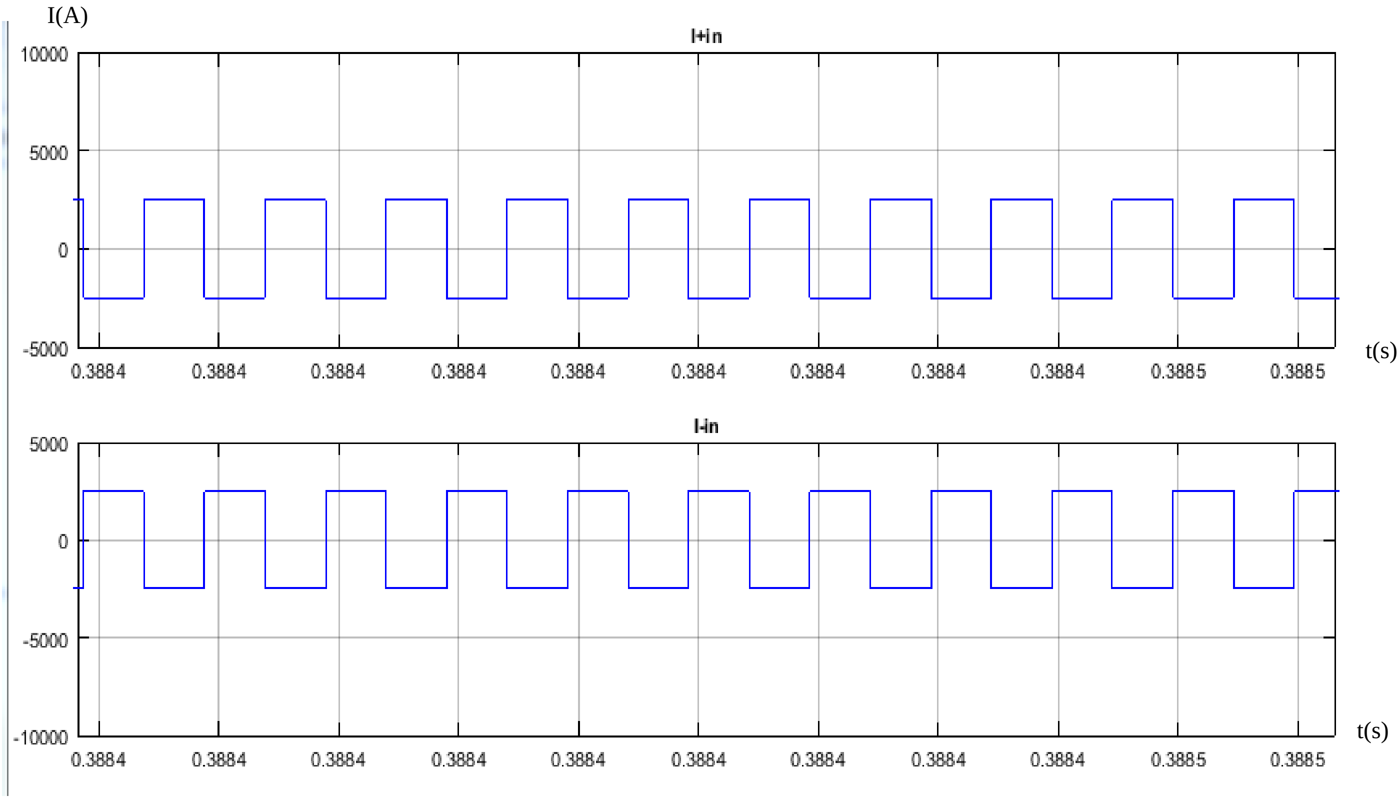


Figure 3-12. Input Current to the Buck at Steady-State

When the switch is open the current takes on a square wave property with opposite phases between the positive and negative inputs. This makes the current sum value 0 Amps but causes some problems to arise in the system. One problem is that though the current is 0A the PV array has to output current somewhere. An open circuit will cause a failure and in the team's model it will cause a crash. To prevent this, a capacitor was placed in parallel with the PV array to close the circuit. Another problem is that this sine wave pattern gets distorted due to transients from the inductor and capacitor. This distortion creates some interesting harmonics in the output of the buck converter. This problem is mitigated by the inverter and the inverters control systems.

The buck converter then takes the input and performs a DC-to-DC conversion. Figure 3-13 shows the current outputs of multiple components in the buck converter model.

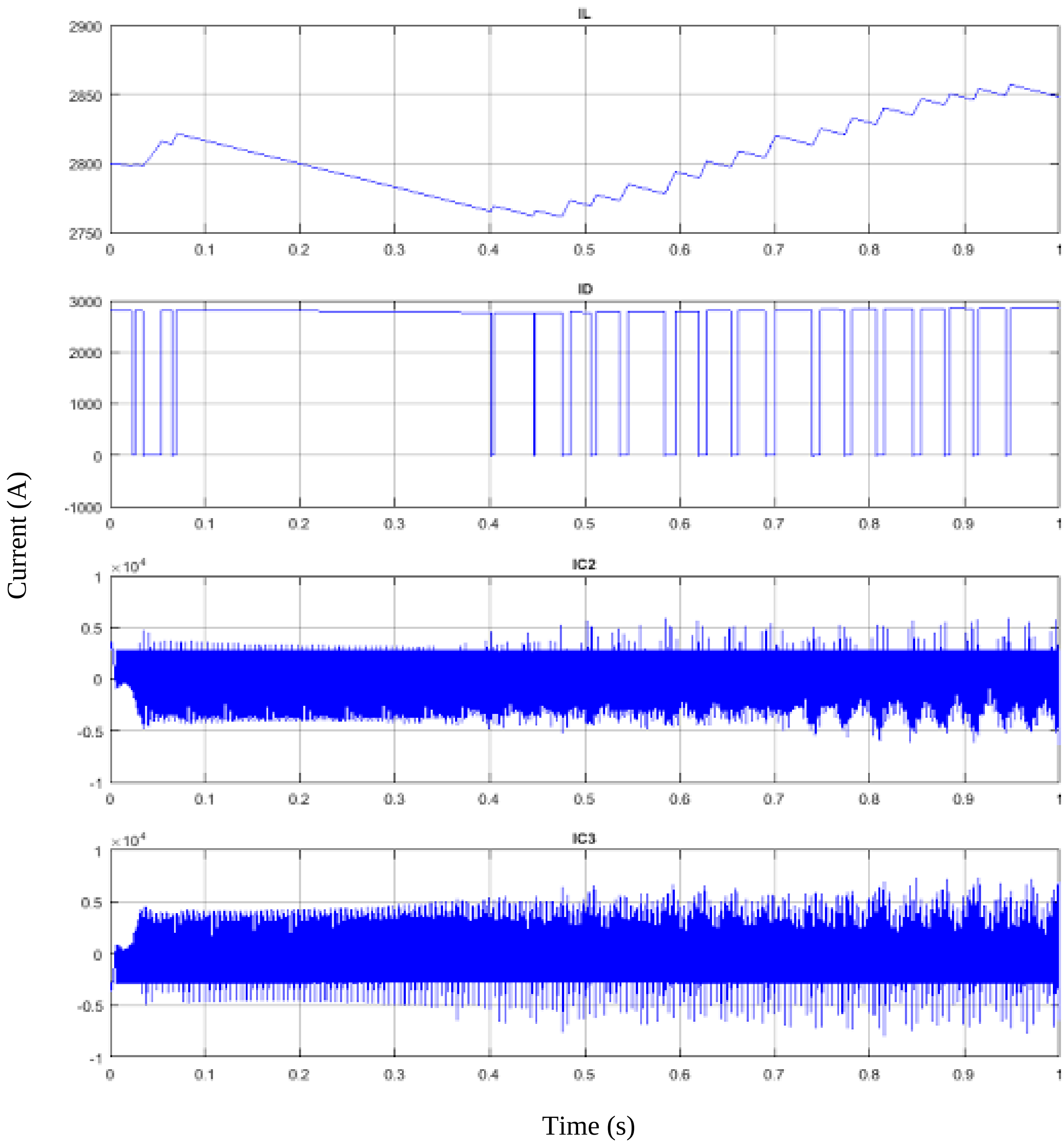


Figure 3-13. Buck Converter Components

The inductor and diode worked as expected. When the switch is open, the inductor discharges and the diode conducts. When the switch is closed, the inductor charges and the diode does not conduct. The capacitors react a bit differently. The capacitors have a lot of harmonics from the buck converter. These harmonics affect the current charge and discharge of the capacitors.

The output of the buck converter is not an ideal DC waveform. The voltage is accurate but the current has a very non-ideal waveform. This problem is mitigated by the inverter.

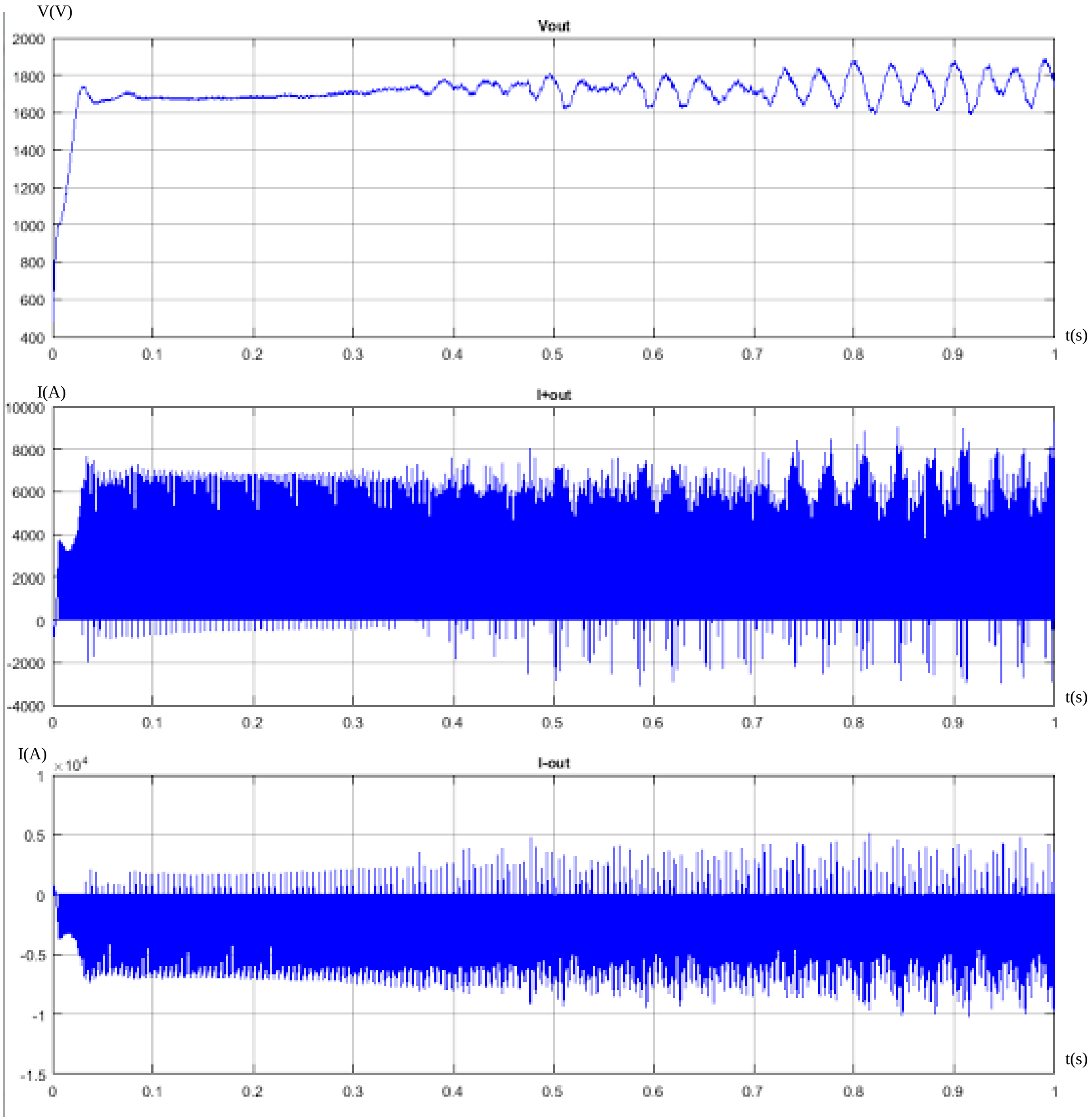


Figure 3-14. Current and Voltage Outputs of the Buck Converter

The output current is very non-ideal and Figure 3-15 shows a closer view of the waveform.

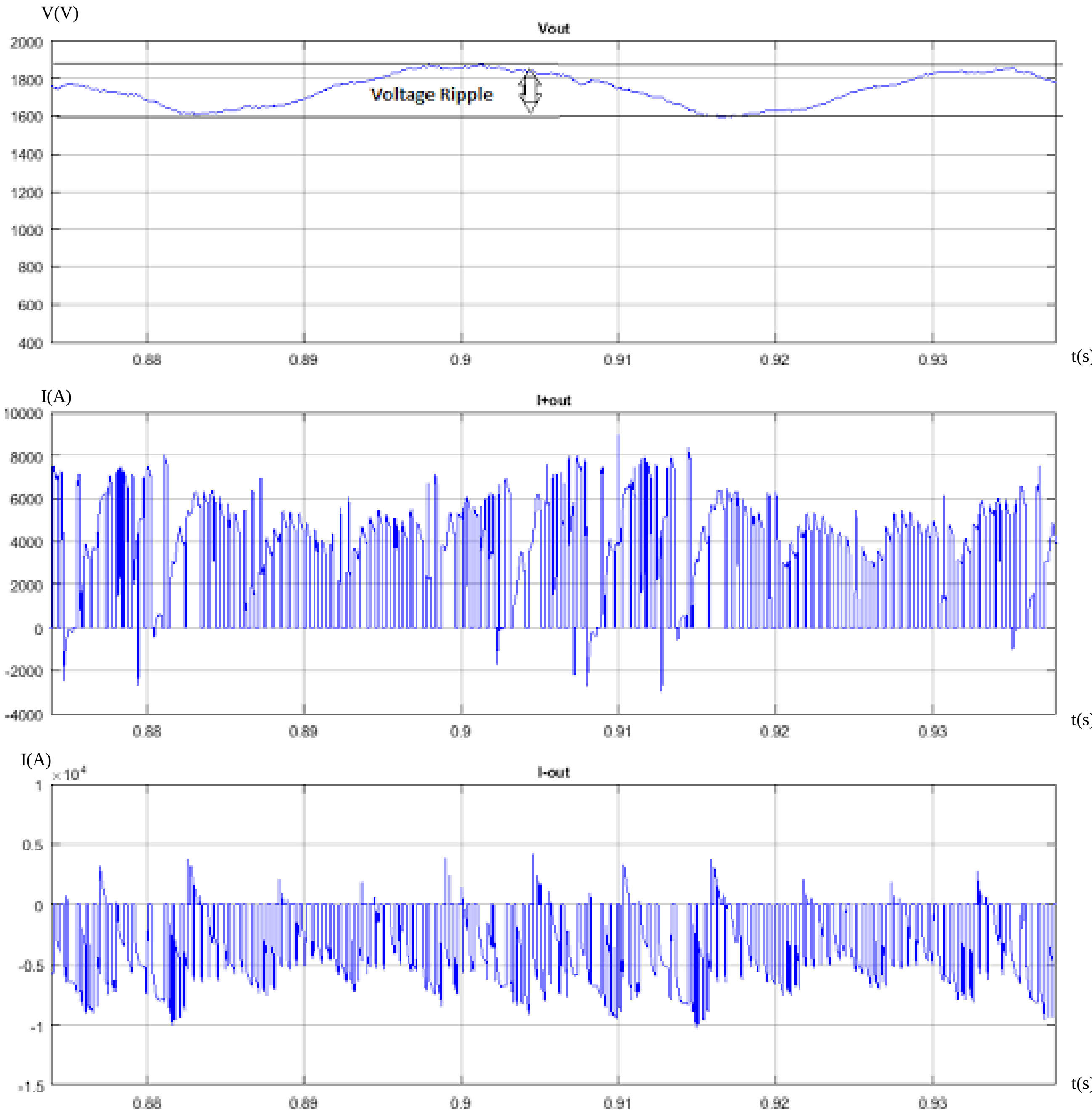


Figure 3-15. Output Zoomed of Buck Converter

As can be seen by the Figure 3-15 the current from the buck converter is very distorted from the square wave outputted from the PV array. This is due to the buck converters capacitors and inductors. Those component's transients cause the non-ideal output.

Also the buck converter outputs directly to 3-level IGBT Bridge. This is what causes the output of the current to have this shape. The IGBT is switching on and off from pulses causing the current pulse as well. Even with this rough current output the power output remains relatively stable. There are still some high-level spikes that could be damaging to the control components of a real life system. Therefore, further research on efficiency needs to be conducted. Figure 3-16 shows the power output of the buck converter.

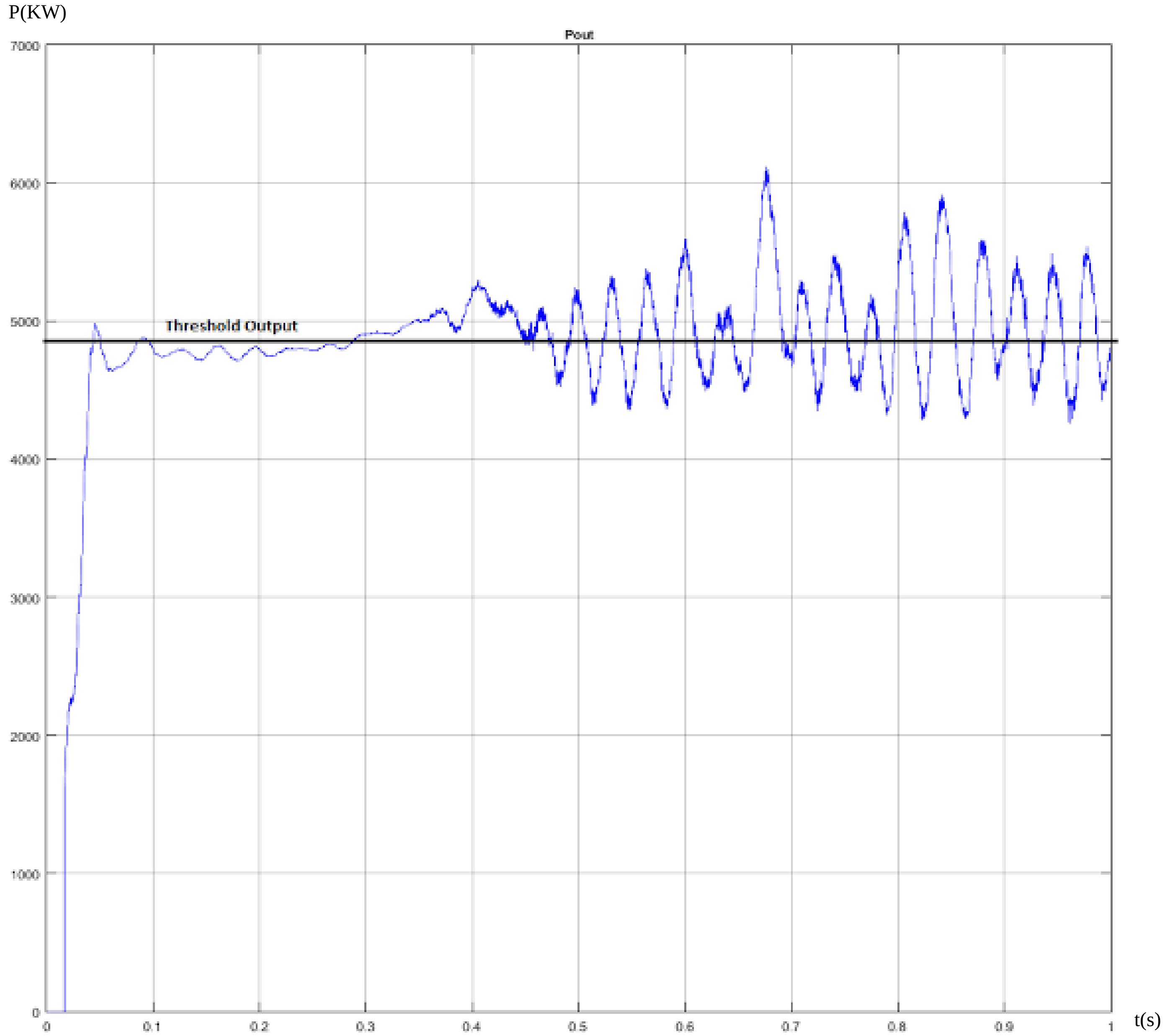


Figure 3-16. Total Instantaneous Power Output of Buck Converter

3.4. The DC-to-AC Inverter

3.4.1. Introduction

The DC-to-AC inverter is crucial component in photovoltaic DG systems. The inverter the team used for the model is a 6-pulse bridge inverter with unipolar pulse width modulation. IGBT's are used as the key switching component in the inverter. Figure 3-17 is the basic circuit design to a 6-pulse bridge inverter [16].

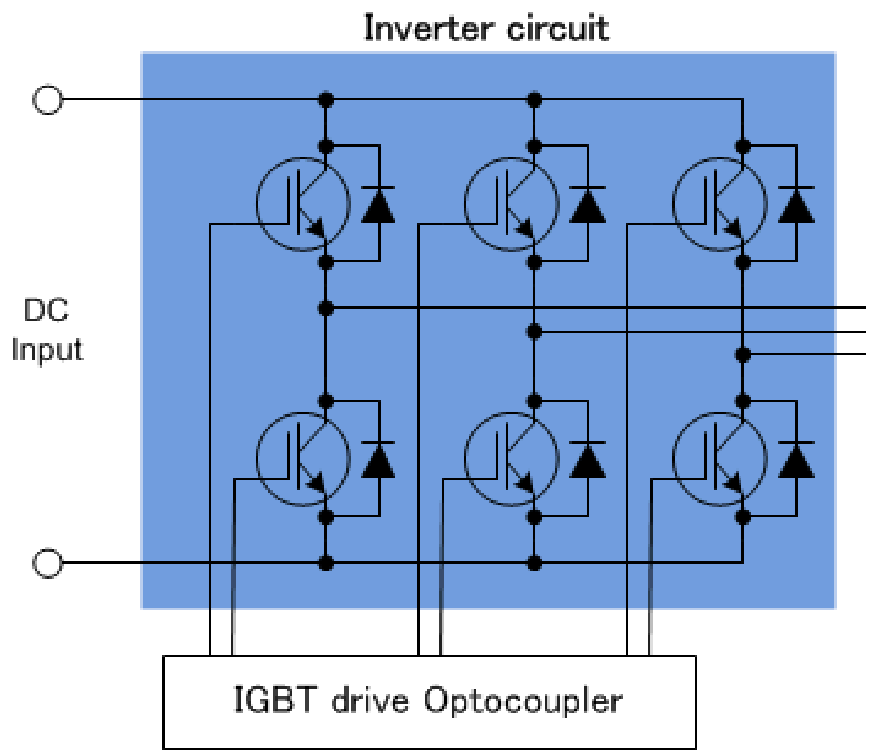


Figure 3-17. Six-Pulse Bridge Inverter Circuit [16]

The inverter takes in a DC voltage and current and outputs a three-phase AC voltage and current. It accomplishes AC output by turning the IGBT switches on and off to create a square wave that can be filtered into a sine wave. A duty cycle can be applied to the switching to make the wave easier to filter. One major method of creating the duty cycle is by comparing a sine wave to a square wave. The Figure 3-18 shows the method of generating the pulse to the IGBTs using unipolar switching.

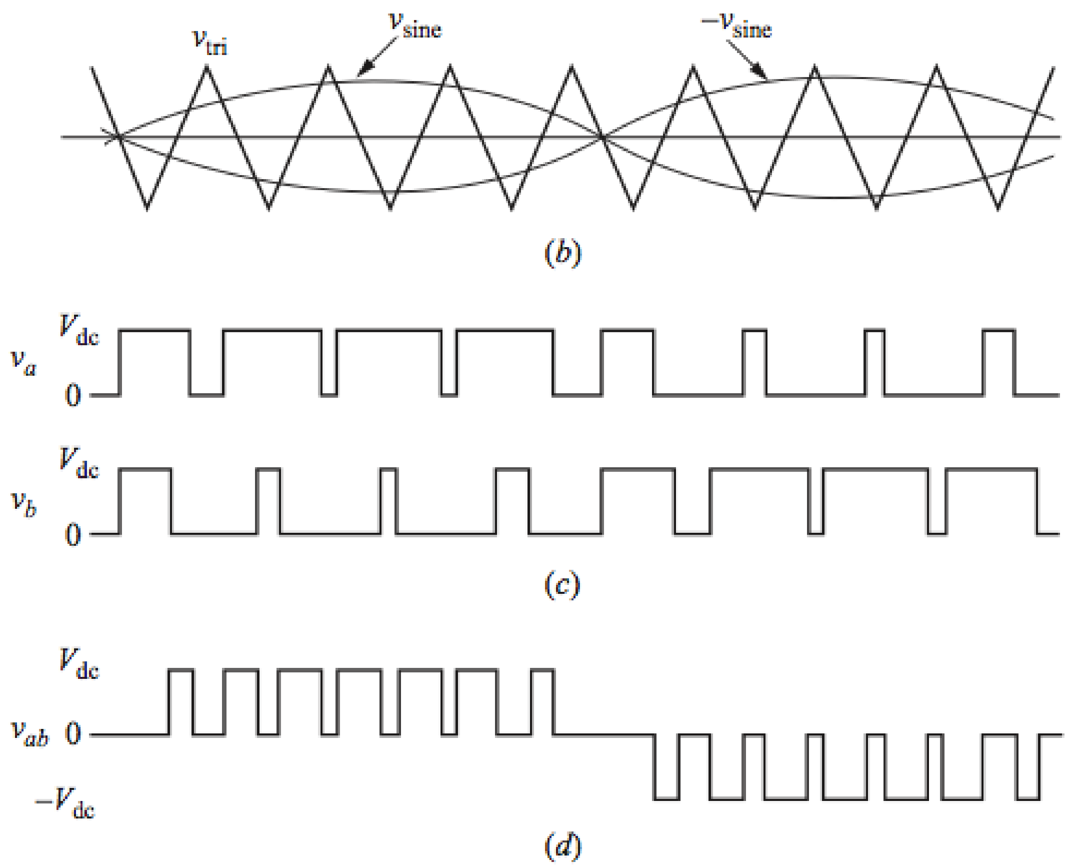


Figure 3-18. The Method of Processing Unipolar Modulation for Inverter Design [17]

The modulation V_a is generated from the V_{sine} wave. When V_{sine} is greater than V_{tri} the IGBT will close and the value of V_a will equal V_{dc}. When V_{sine} is less than V_{tri} the IGBT will open and the value of V_a will equal 0.

The modulation V_b is generated from the $-V_{sine}$ wave. When $-V_{sine}$ is greater than V_{tri} the IGBT will open and the value of V_a will equal 0. When V_{sine} is less than V_{tri} the IGBT will close and the value of V_a will equal V_{dc}.

The two modulation signals create an output signal V_{ab} shown in the figure above. This output signal can be filtered to create a sine wave. This is the method that was used by the team to model the inverters DC to AC conversion. The magnitude of V_{ab} can be seen in the equation below [17].

$$\widehat{V_1} = m_a V_{dc} \qquad \textit{Equation 3}$$

V_1=Peak voltage

V_{dc}= DC voltage source

m_a= Modulation Amplitude

This equation is derived from 2 major equations. The equations and derivation are shown below [17].

$$V_{A0} = m_a \frac{V_{dc}}{2} \sin(\Omega t) \qquad \textit{Equation 4}$$

$$V_{B0} = m_a \frac{V_{dc}}{2} \sin(\Omega t + 180°)$$

$$\Omega = \frac{w}{m_f}$$

w = The radial Frequency

m_f = Modulation Frequency

t=time

Derivation [17]:

$$V_{AB} = V_{A0} - V_{B0}$$
$$V_{AB} = m_a V_{dc} \sin(\Omega t)$$
$$m_a = \frac{\widehat{V_1}}{V_{dc}}$$

$$V_{AB} = \widetilde{V_1} \sin(\Omega t)$$

$$\widetilde{V_1} = m_a V_{dc}$$

3.4.2. Design

Below is the design of the inverter system and its components. It is noteworthy to credit this portion of the report to Simulink's power systems library. The team did not develop this inverter. Instead, the team used the inverter in the library to make a complete and accurate model.

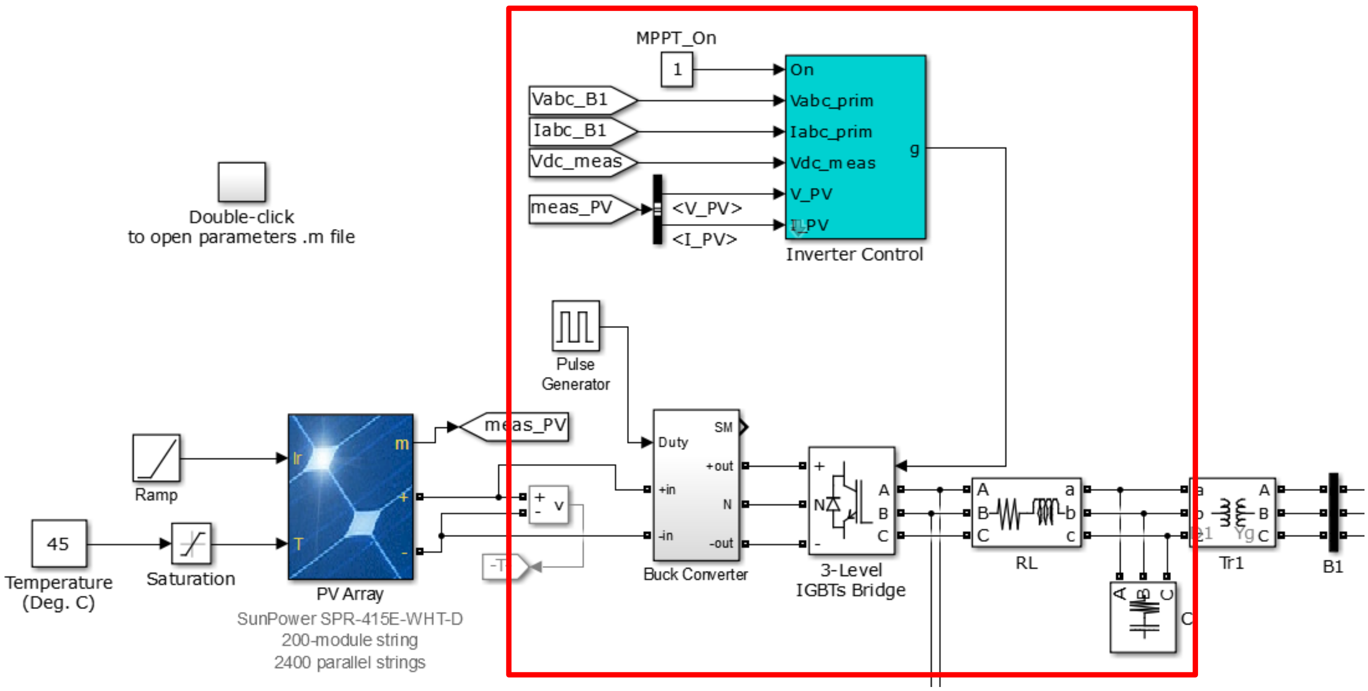


Figure 3-19. Simulink Model: Distributed generation portion of the model

The inverter takes in three inputs from the buck converter: positive DC input (+), neutral (N), and negative DC input (-). The inverter then outputs a rough three-phase AC waveform that is then filtered by the LC filter. The Filtered AC waveform then goes through the transformer completing the DG side transmission system of the model.

3.4.3. Inverter Controls

One major component that defines the output waveform of the inverter is the inverter control block. Figure 3-20 are the internal components of the inverter control block.

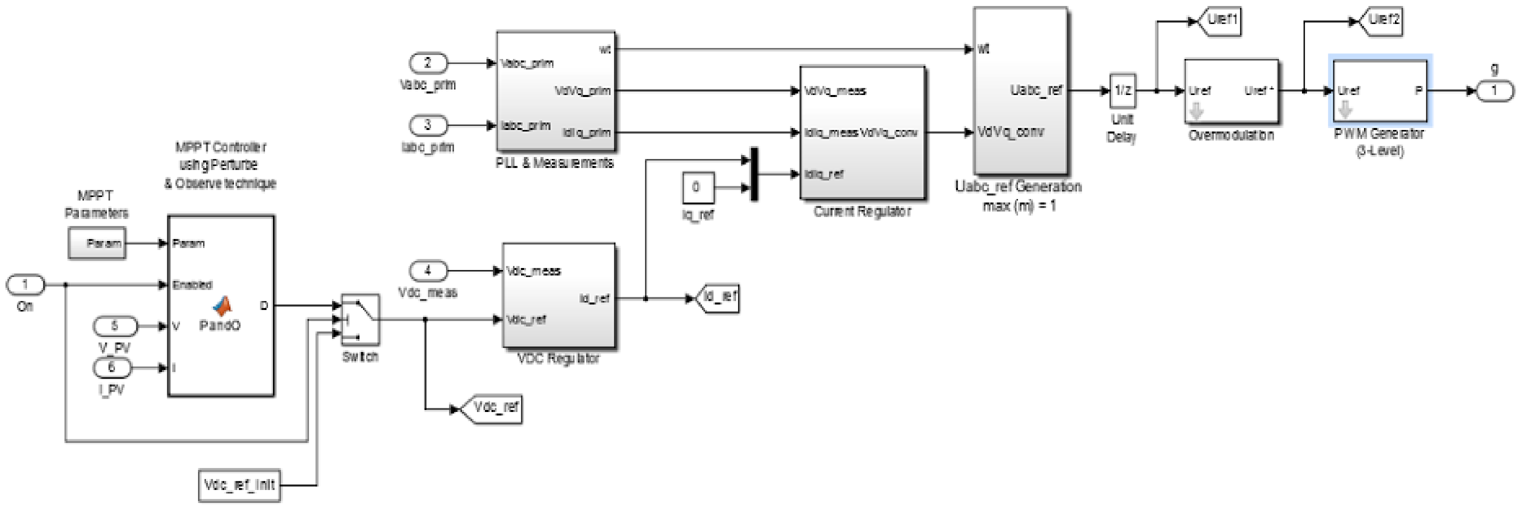


Figure 3-20. Inverter Control Block

The inverter control block has four major inputs: voltage and current at bus 1, voltage and current at solar array. The readings at bus 1 are AC readings while the readings at solar array are DC readings.

Beginning at the DC side the voltage and current is taken by the maximum power point tracker (MPPT) controller and is outputted to a DC voltage regulator. Figure 3-21 is a graph that shows the output D of the MPPT and the initial condition of VDC.

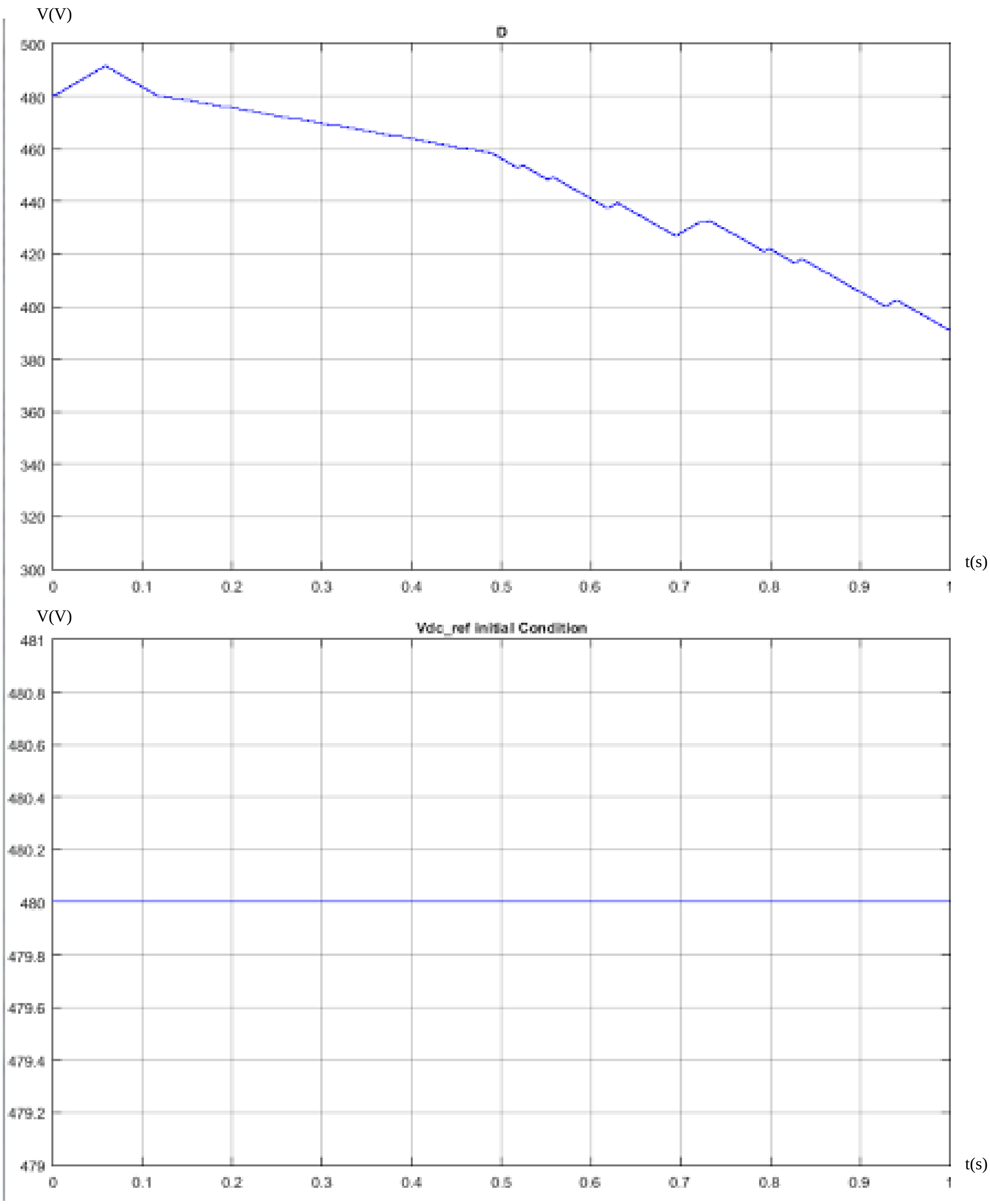


Figure 3-21. Inverter Controls: Output of the MPPT Controller Block

Now the MPPT output is an input to the VDC regulator along with the measured voltage value across the buck converter. Figure 3-22 shows the voltage measurements of the voltage from the buck converter and the voltage from MPPT.

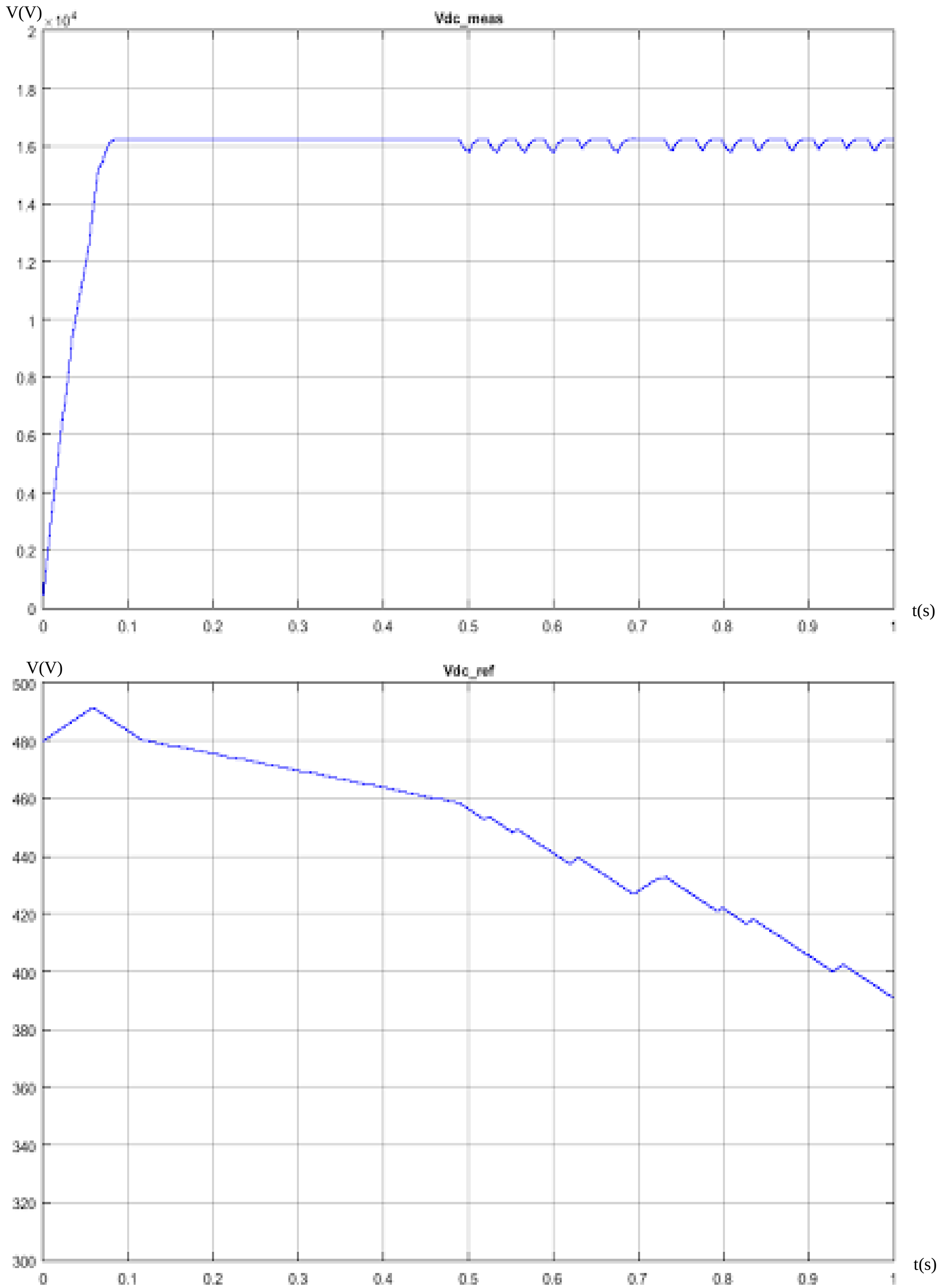


Figure 3-22. Inverter Controls: Input to the V_{dc} Regulator

Once the voltage is regulated the voltage regulator outputs a current value (Id_ref). This value then goes into the current regulator. Figure 3-23 is the current reference value that goes into the current regulator.

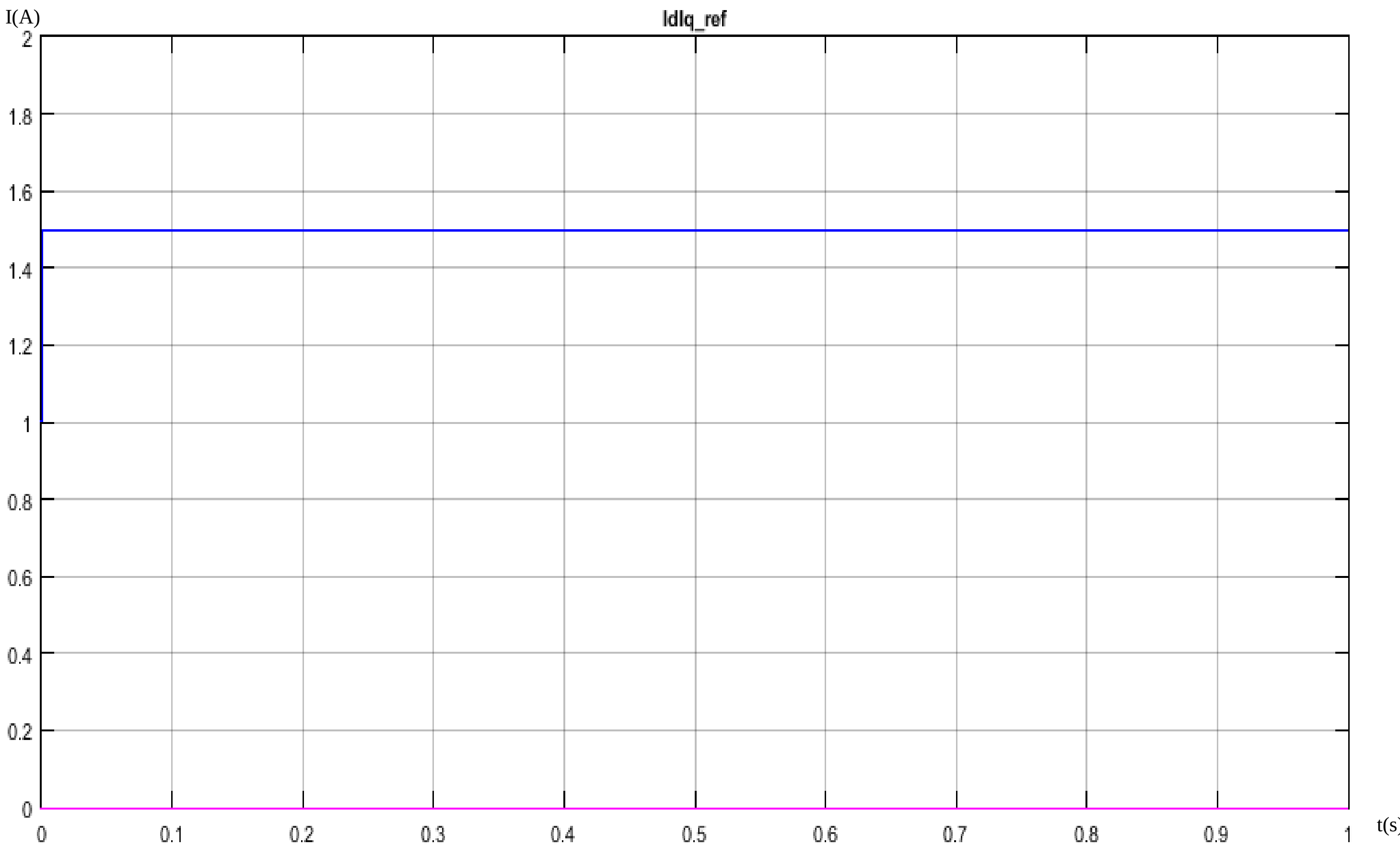


Figure 3-23. Inverter Controls: Output of V_{dc} Regulator

The current regulator takes a DC current as a reference and then takes two inputs from the PLL (phase-locked loop) and measurement block. The outputs voltage and current are then processed to create the pulse width modulation (PWM) for the 6-pulse full bridge inverter. Figure 3-24 shows the input voltage and current (VdVq_prim, IdIq_prim) and the output angle (wt).

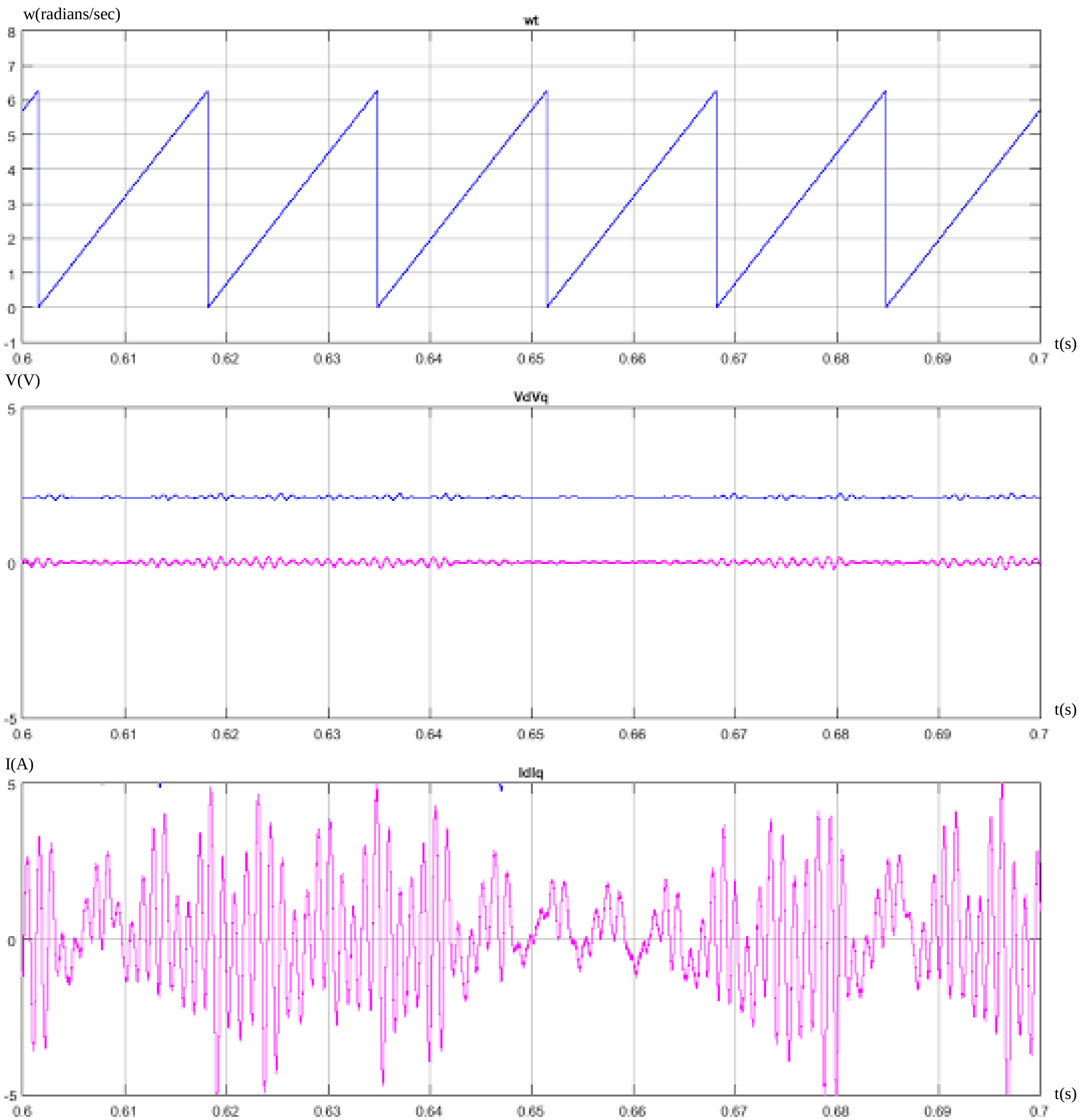


Figure 3-24. Inverter Controls: Output of the PLL and Measurement Block

Next this input is processed through multiple blocks and then a PWM (pulse width modulation) generator to create the output to the 6-pulse full bridge inverter. Figure 3-25 shows the signal at each process. The last signal is the drive to the inverter. That signal will be broken down to show all the components of the PWM driver.

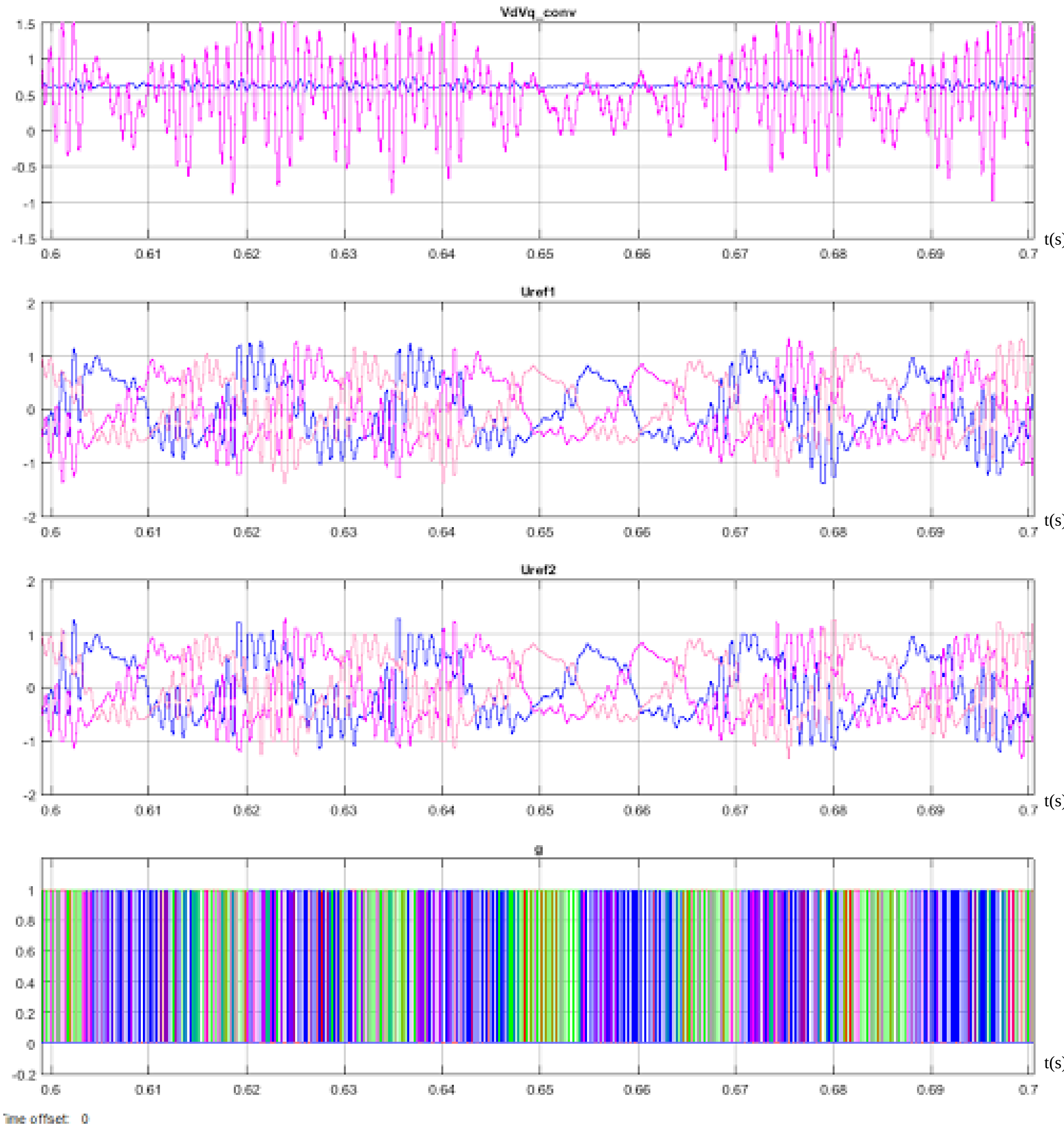


Figure 3-25. The Final Steps of Signal Processing the PWM

3.4.4. Pulse Width Modulation (PWM)

The inverter accepts a 6-pulse PWM wave from the inverter control to drive the IGBTs. The inverter uses the method of unipolar modulation by measuring the both the positive and negative components of the wave. This method can be seen above in the theory section of this report.

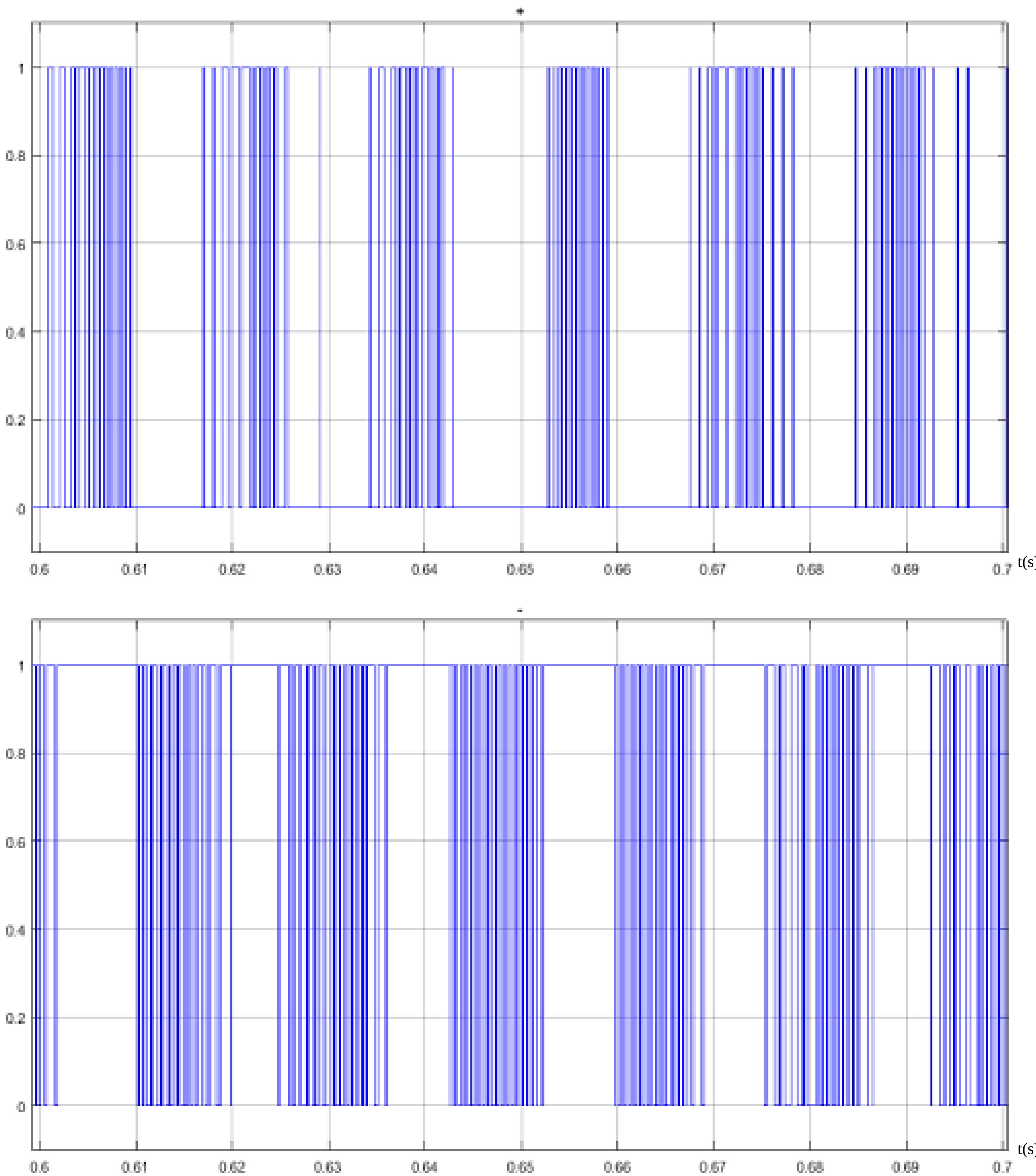


Figure 3-26. PWM Input to First IGBT of the A Phase Portion of the Bridge

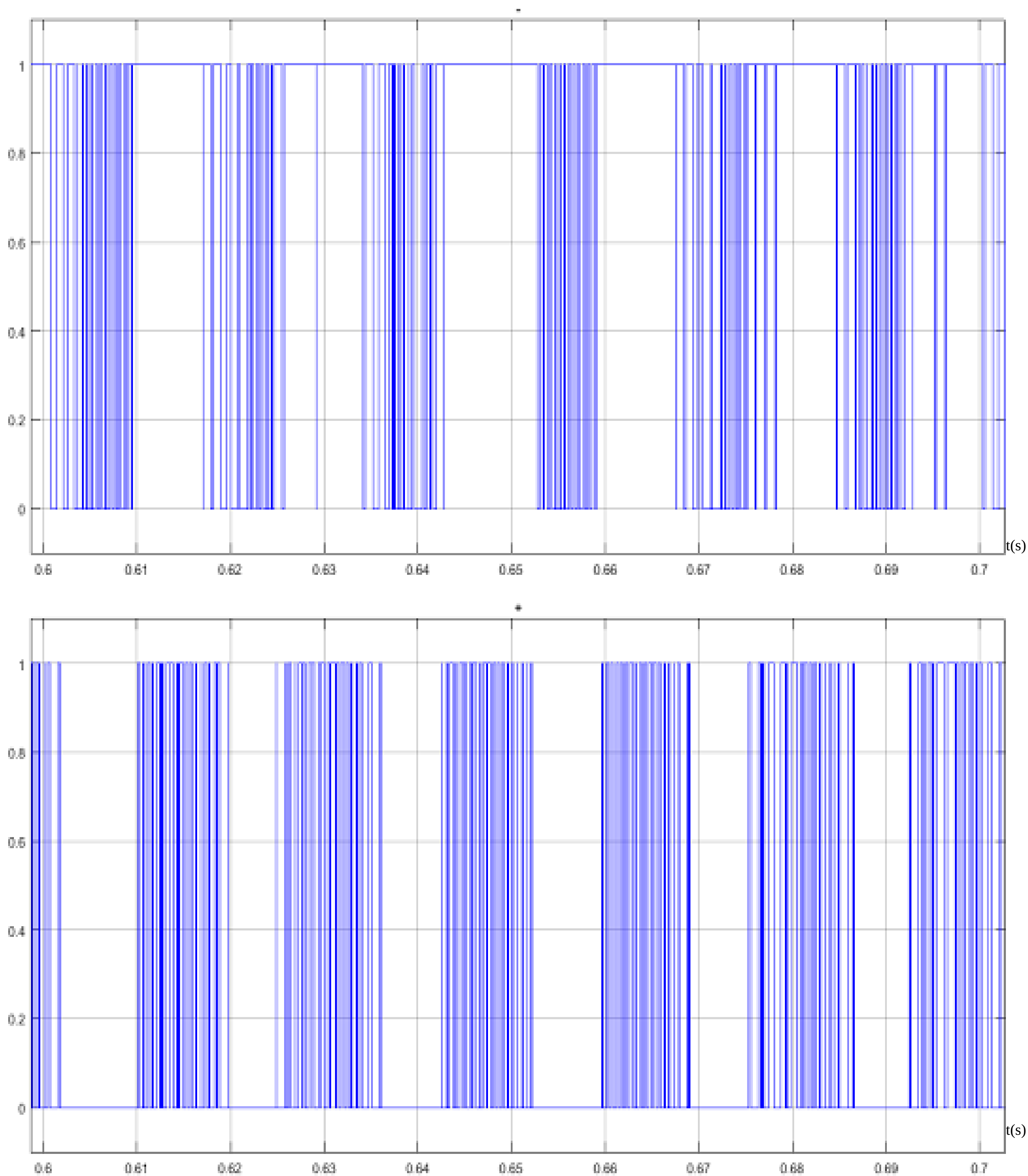


Figure 3-27. PWM Input to Second IGBT of the A Phase Portion of the Bridge

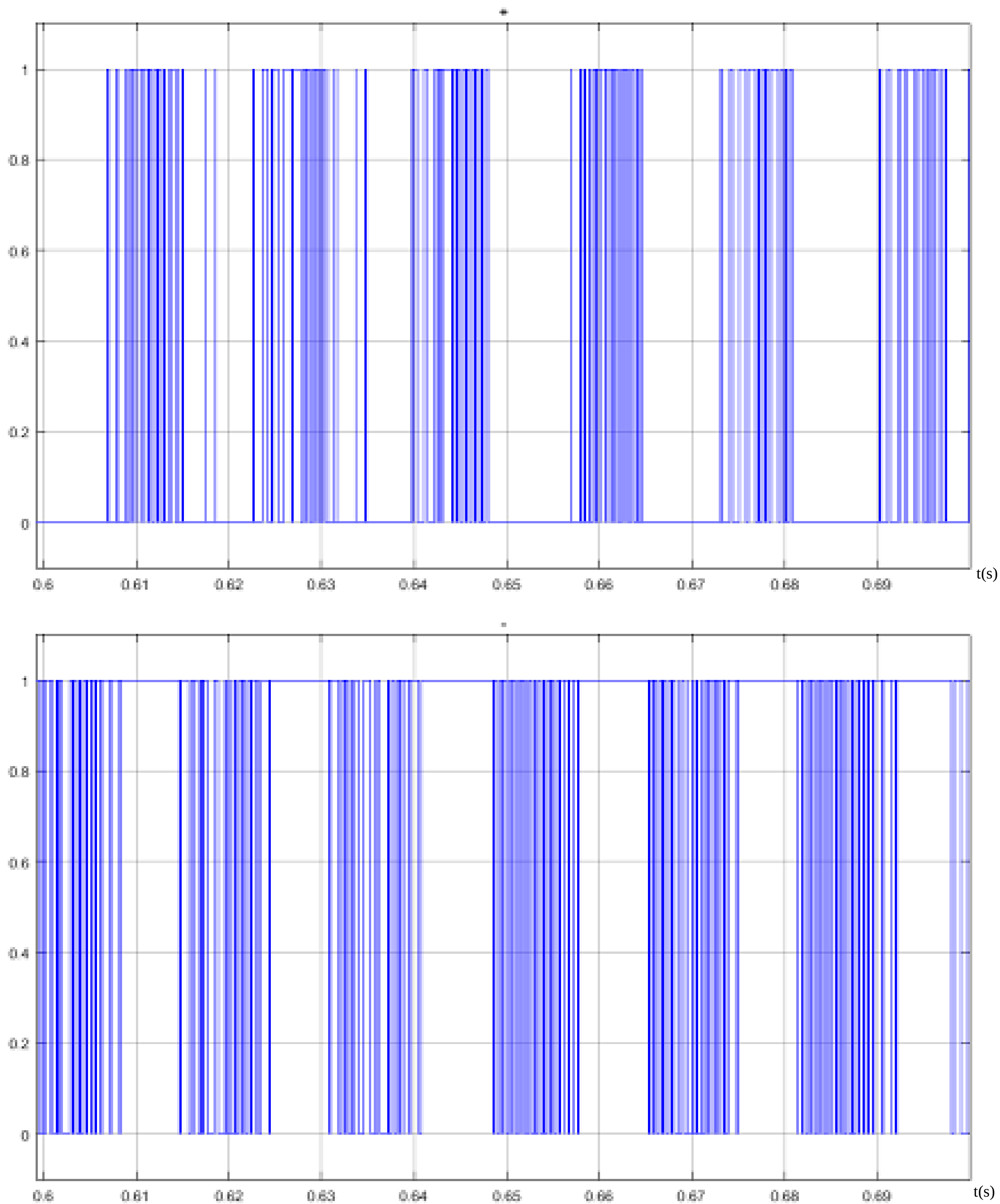


Figure 3-28. PWM Input to First IGBT of the B Phase Portion of the Bridge

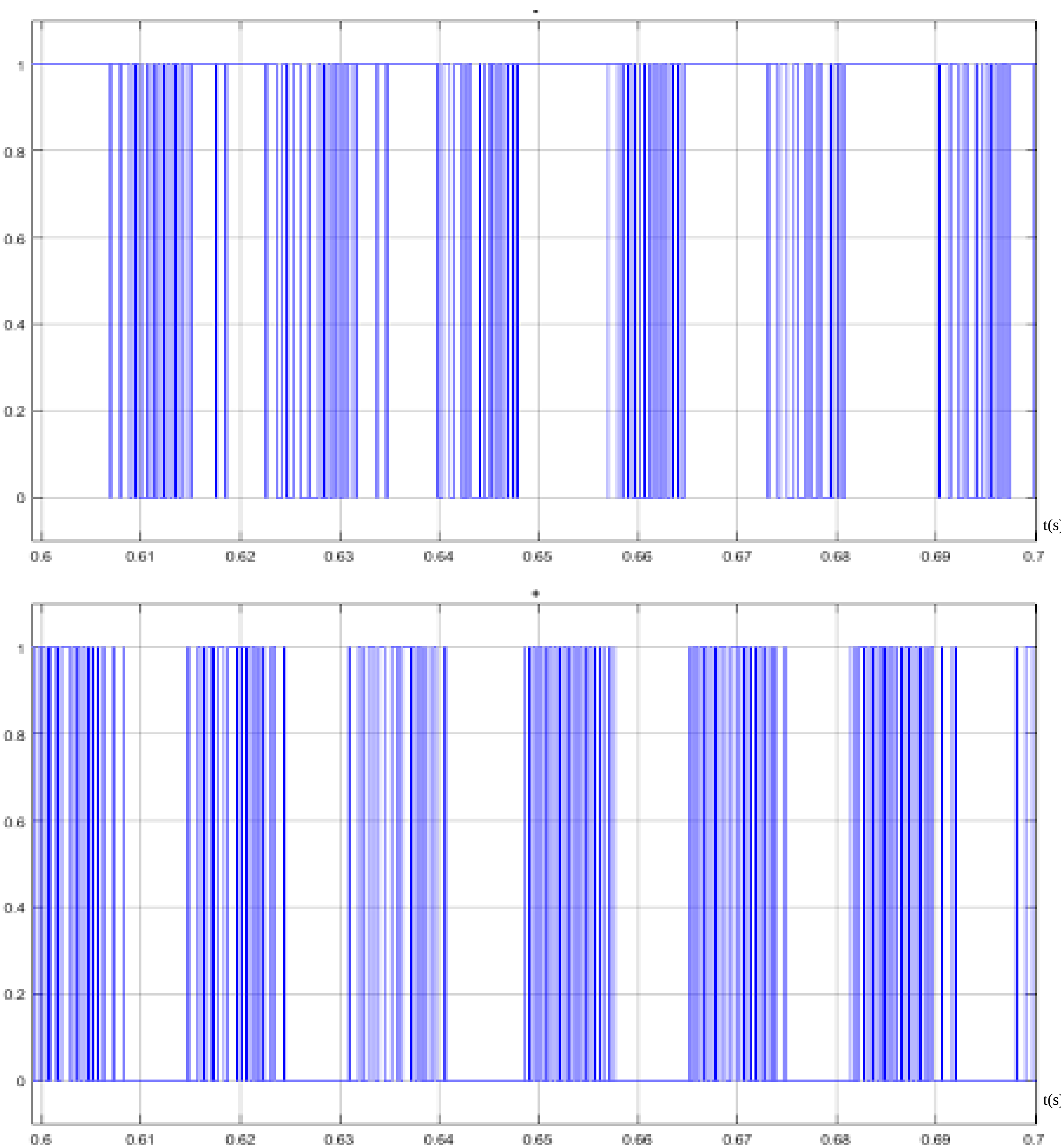


Figure 3-29. PWM Input to Second IGBT of the B Phase Portion of the Bridge

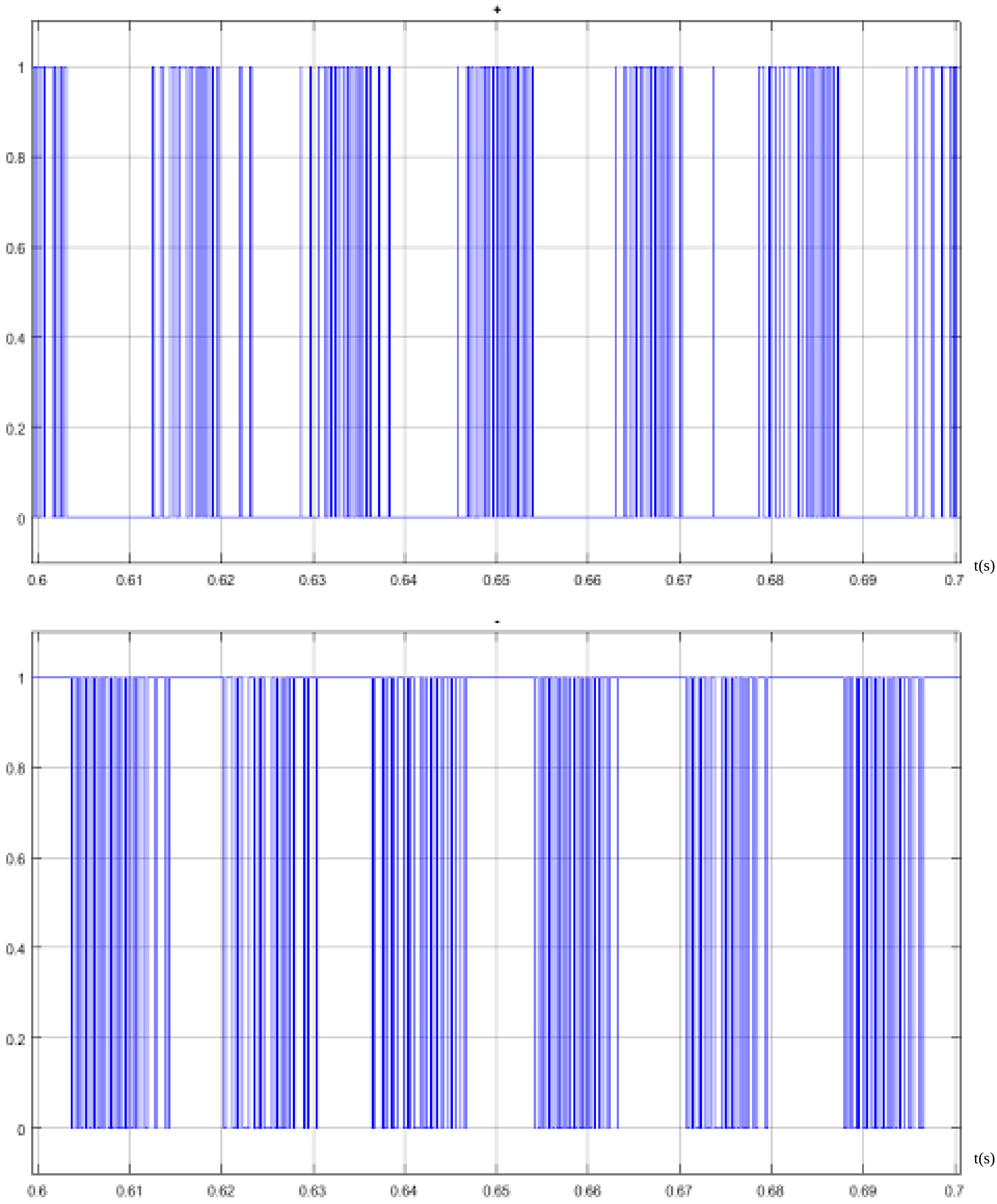
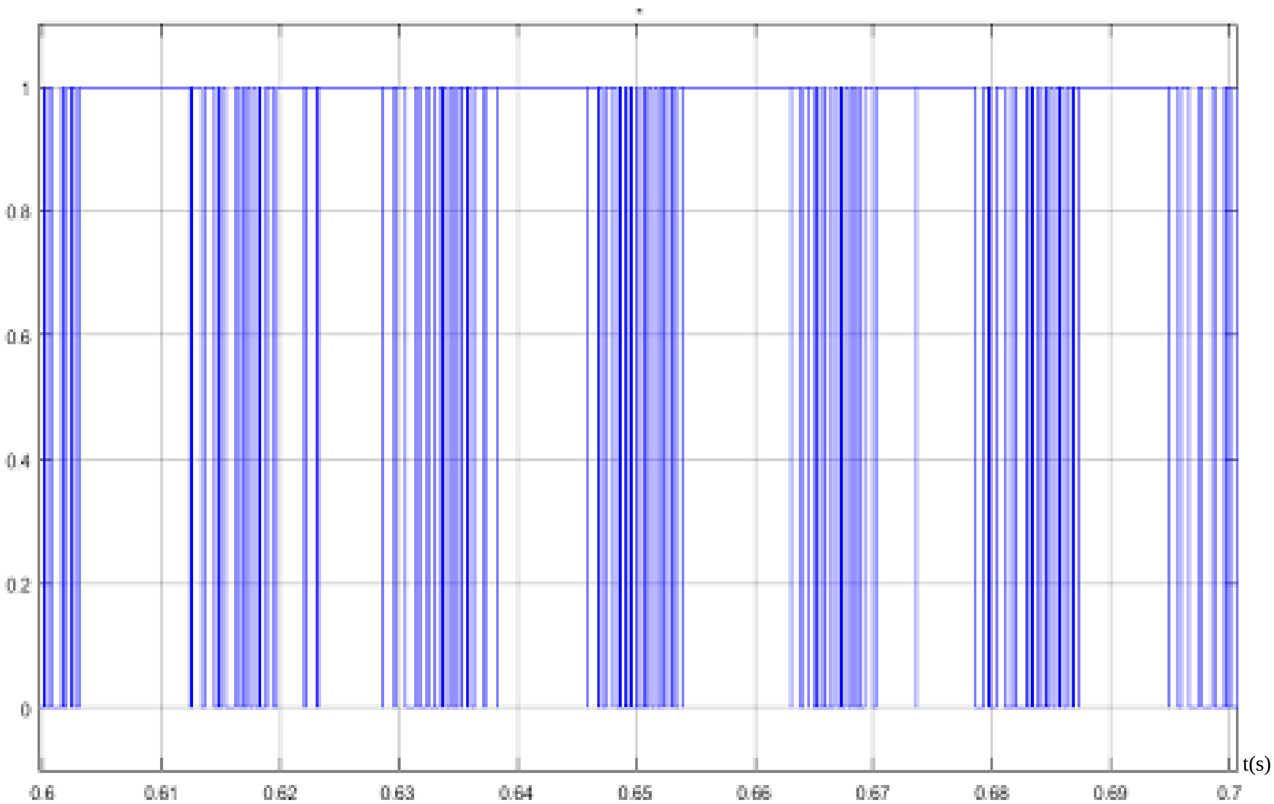


Figure 3-30. PWM Input to First IGBT of the C Phase Portion of the Bridge



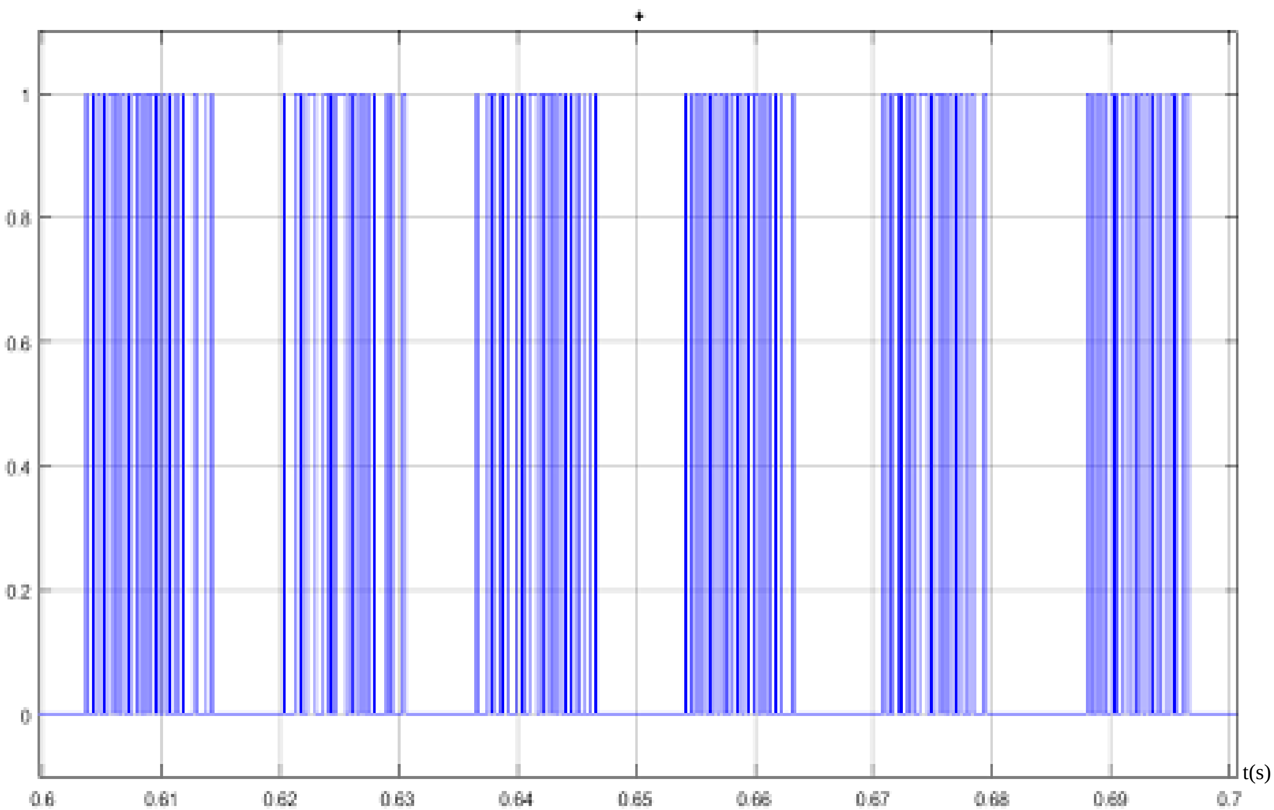


Figure 3-31. PWM Input to Second IGBT of the C Phase Portion of the Bridge

3.4.5. Results

The output of the Inverter is relatively stable with a bit of noise. When the buck converter is switching on and off, the amplitude varies. This causes some large high frequency harmonics to the voltage and currents of the inverter output. This can be seen in the graph Figure 3-32.

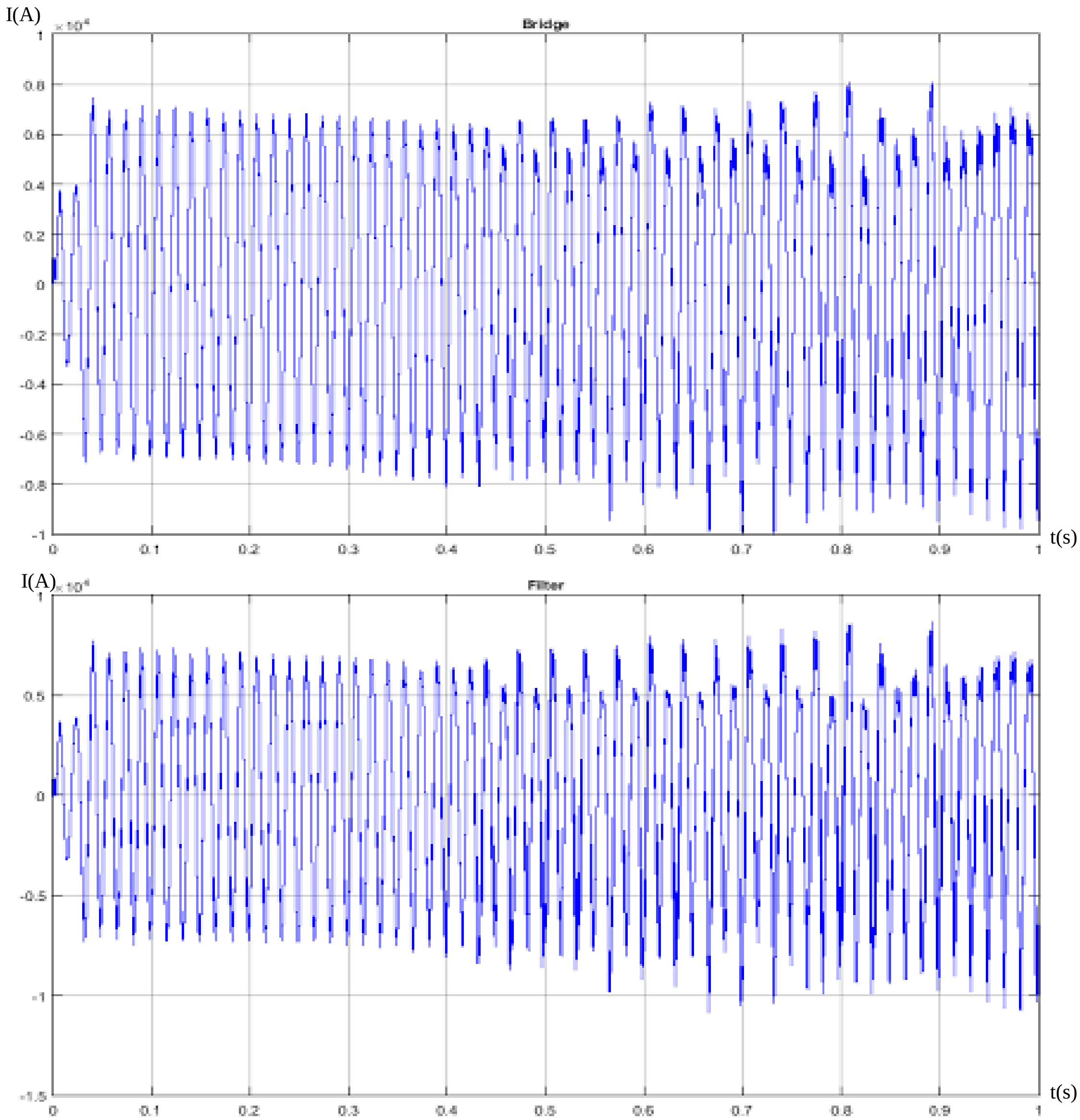


Figure 3-32. Output Current of the Inverter Before and After Filter

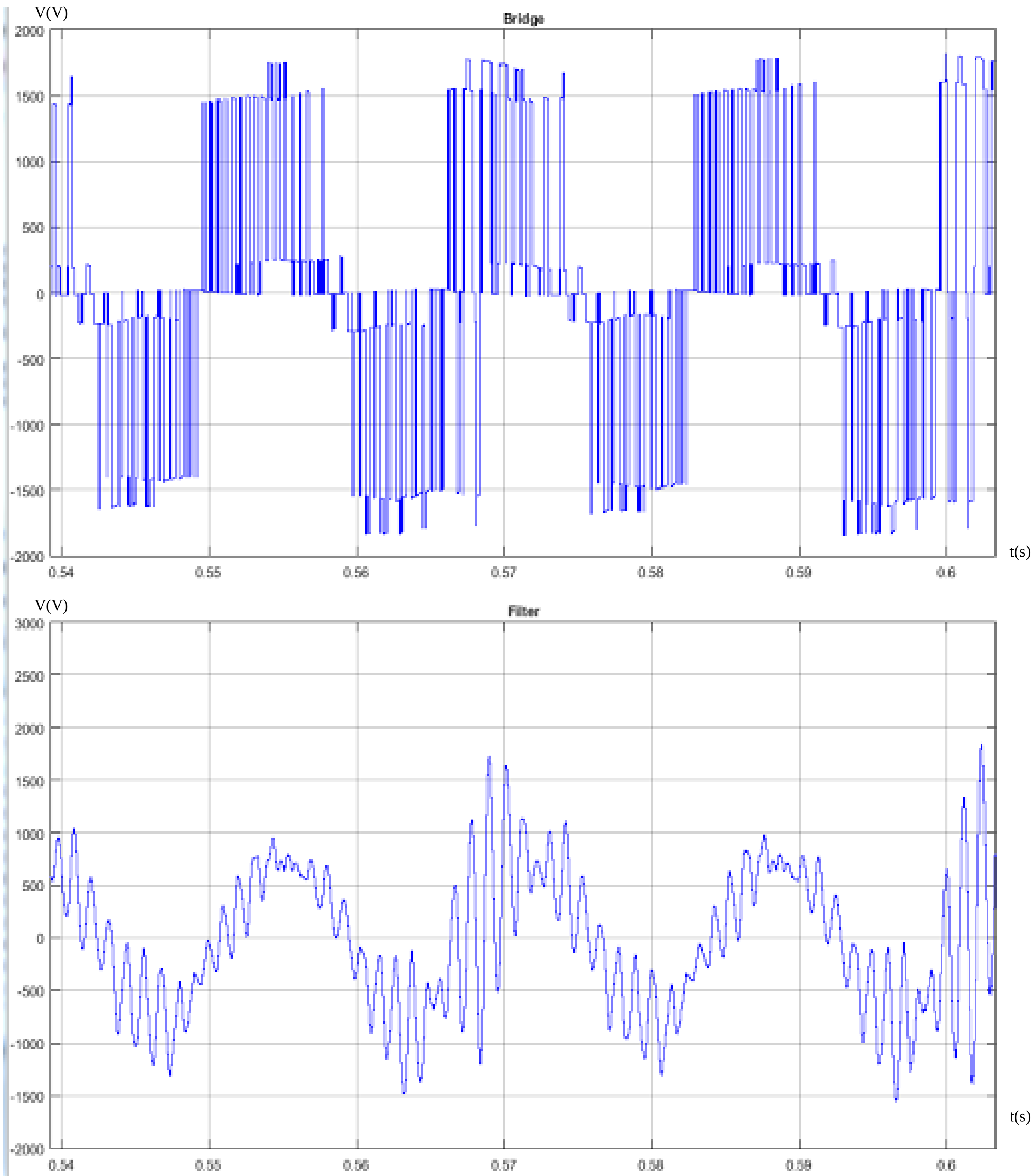


Figure 3-33. The Voltage Output of the Inverter Before and After the LC Filter

One way to mitigate these harmonics would be to add a low pass filter to the filter component of the inverter to decrease the high frequency harmonics. The team did not worry about this noise because when the transformer steps up the voltage, the high level harmonics are removed from the signal.

3.5. System Integration

Once both components of the mitigation system were designed, the mitigation system was integrated into the same simple distribution network as before. A one line diagram of the distribution network with the mitigation system can be seen in Figure 3-34.

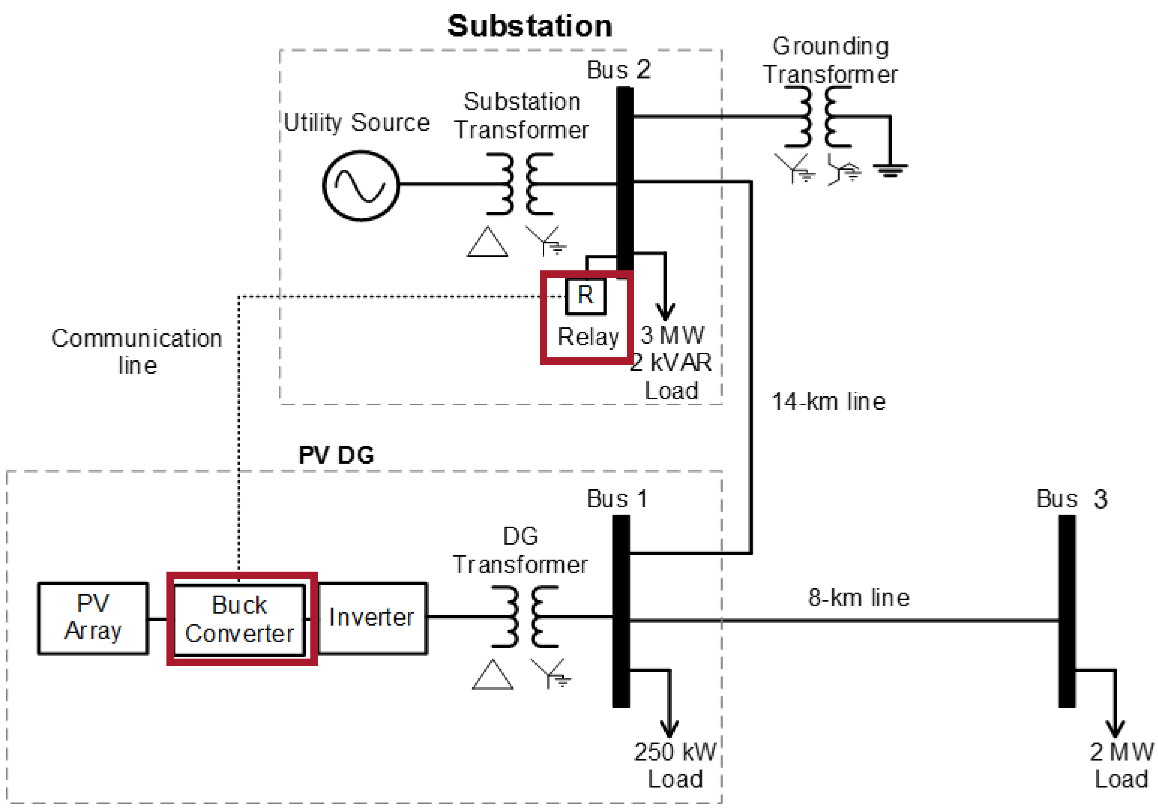


Figure 3-34. One-Line Diagram of Relay and Buck Converter System Integration

To verify the functionality of the mitigation system, the team ran three simulations on the distribution system. In each simulation the team varied levels of irradiance on the PV array to control the PV's output, and measured the effect with and without the mitigation system installed. The team measured power output at both the DG bus (Bus 1) and the substation bus (Bus 2) as well as the voltage level at Bus 2.

3.5.1. Simulation 1 - Normal Irradiance, No Mitigation

The first simulation was the control case. The irradiance was set at a nominal 1000 [W/m^2] and the mitigation system was not implemented. In Figure 3-35 the power output of the substation and the PV DG can be seen on the top plot with the Bus 2 voltage (the substation bus) on the middle plot and the irradiance on the bottom plot.

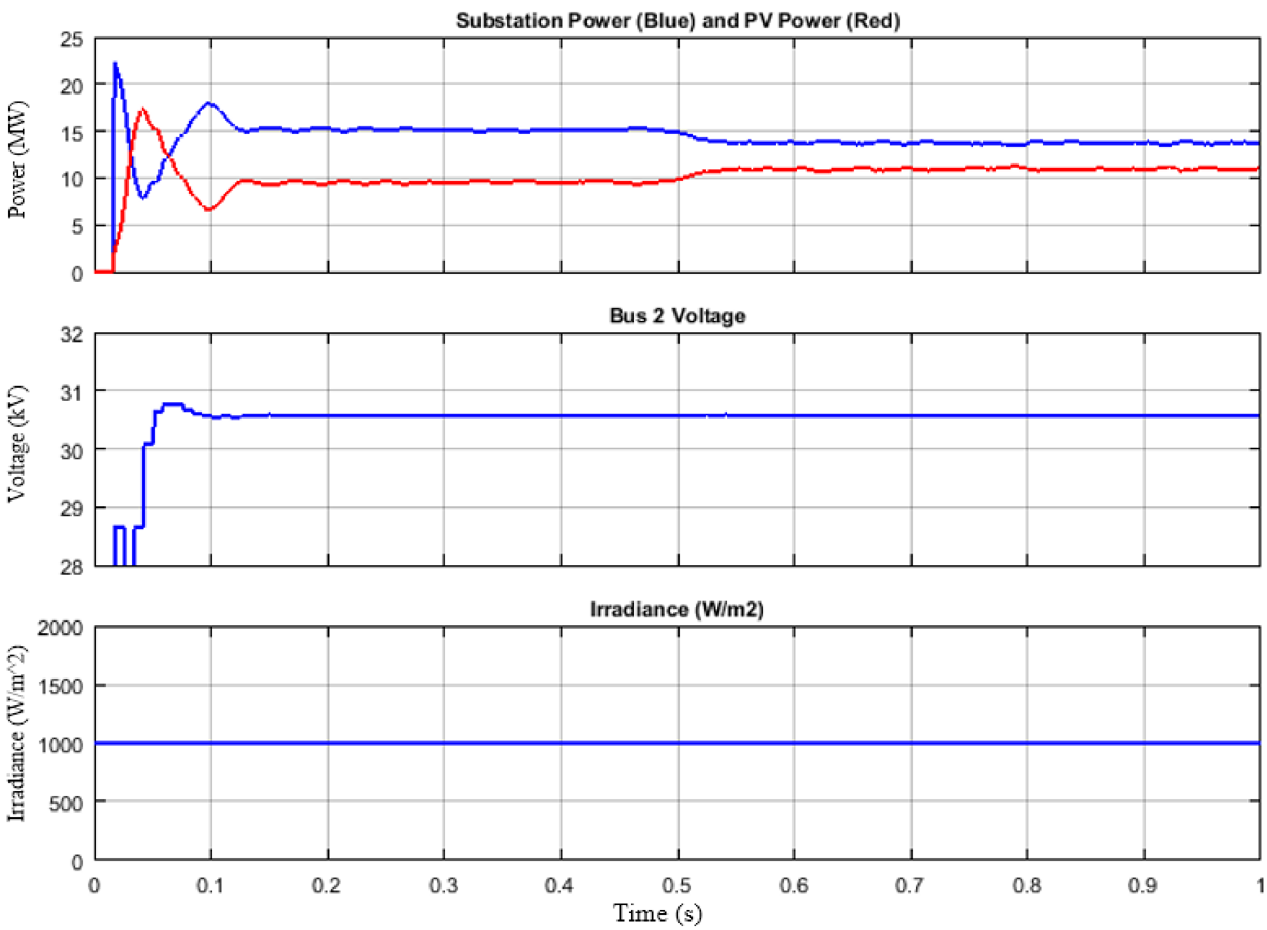


Figure 3-35. Power Output from Substation, PV and Substation Bus Voltage with Steady Irradiance

The Figure 3-35 shows the system reaching steady state between 0.5 and 0.6 seconds with the PV outputting about 11MW of the systems power and the substation outputting the other 14MW. The bus 2 voltage is also steady at a nominal 30.6kV.

3.5.2. Simulation 2 - Increasing Irradiance, No Mitigation

In the second simulation, the team set the irradiance to increase at a slope of 2000 [W/m^2] per second after 0.5s.

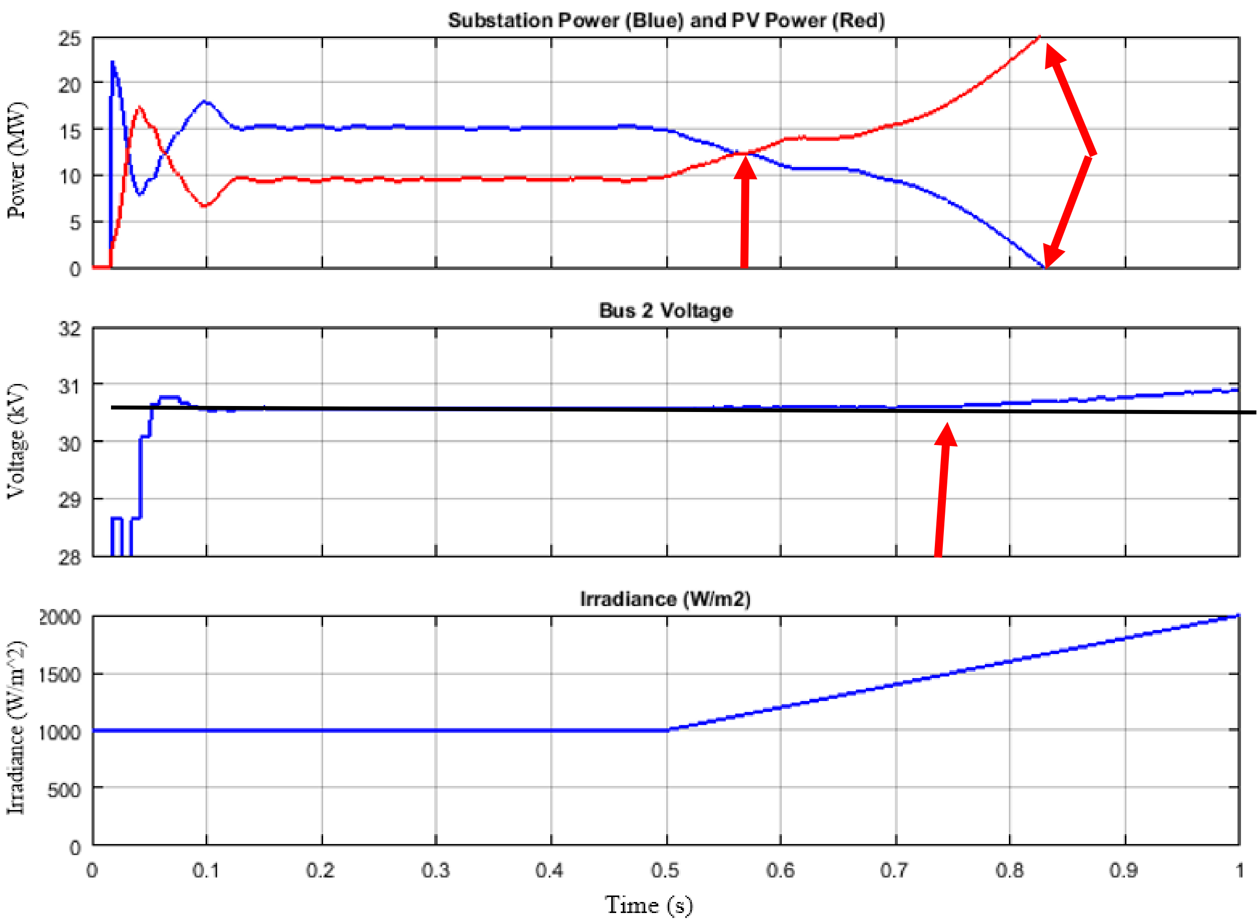


Figure 3-36. Power Output from Substation, PV and Substation Bus Voltage with Increasing Irradiance and No Mitigation System

This simulation clearly demonstrates the risks of reverse power flow. In the top plot it can be seen that the DG surpasses the substation's power output at about 0.57 seconds. The DG's power output keeps increasing until it supplies the entire 25MW system and keeps increasing in output unit at about 0.82s when it power begins to flow backwards into the substation. On the middle plot, it can be seen that after the DG's output surpasses the substation's the voltage at bus 2 begins rising to unsafe levels.

3.5.3. Simulation 3 - Increasing Irradiance, Mitigation System Present

In the third simulation, the same irradiance input was applied to the PV array, but this time the team's mitigation system was installed.

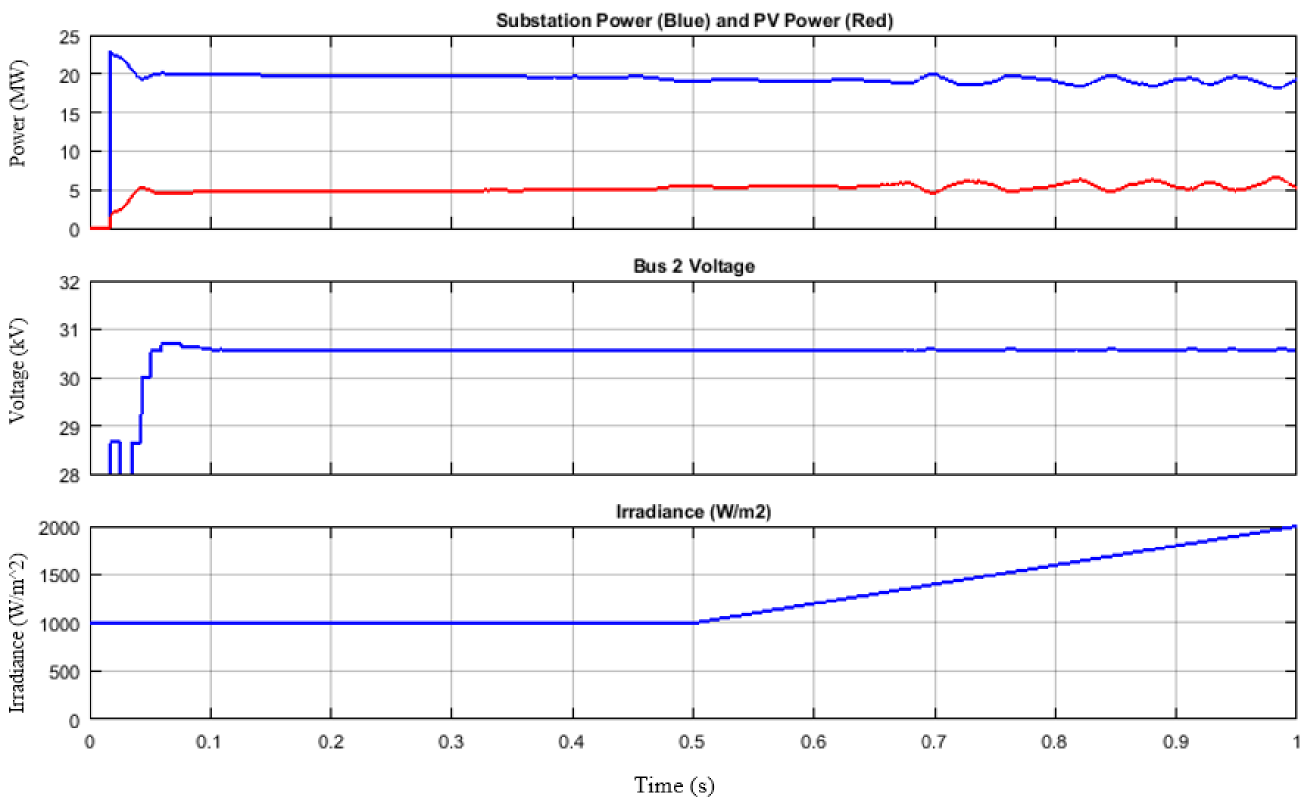


Figure 3-37. Power Output from Substation, PV and Substation Bus Voltage with Increasing Irradiance and Mitigation System Implemented

The mitigation system was set so that the substation output shouldn't drop below 19MW. It is clear from the top and middle plots that mitigation system was effective in controlling the output of the DG even under the increasing irradiance conditions without a substantial effect on bus voltage. It should be noted however that after 0.5s the power outputs of the DG and substation sway back and forth as the mitigation system tries to control the DG. Some of the mirroring ripples between 0.7s and 1.0s in power are up to 1MW in magnitude.

4. National Grid Case Study

4.1. Selection of a National Grid Study Feeder

Selecting a real existing feeder to model and simulate will enable the team to consider real world challenges like coordination and overvoltage that the protection engineers are up against. Because the information collected is confidential, the team is not allowed to share specific details such as the name of the substation, name of the feeder, location of the study area, and etc. The following criteria were used to determine a feeder to study:

- The interconnecting distributed generation (DG) is photovoltaic (PV). To narrow the scope of the project, the team chose to work with PV systems because of their acceptance by the industry.
- The substation has only one customer interconnection. The feeder having only one DG interconnection helped simplify the project and allowed the team to determine the impact of DG interconnection without other affecting variables. With this information, future projects can study the effects of multiple DG interconnections.

The team took a look at National Grid's network model and narrowed the network to all of the National Grid substations that supply DG. Upon further inspection, the team found one substation with exactly one PV interconnection. Figure 4-1 shows the one-line diagram of the substation.

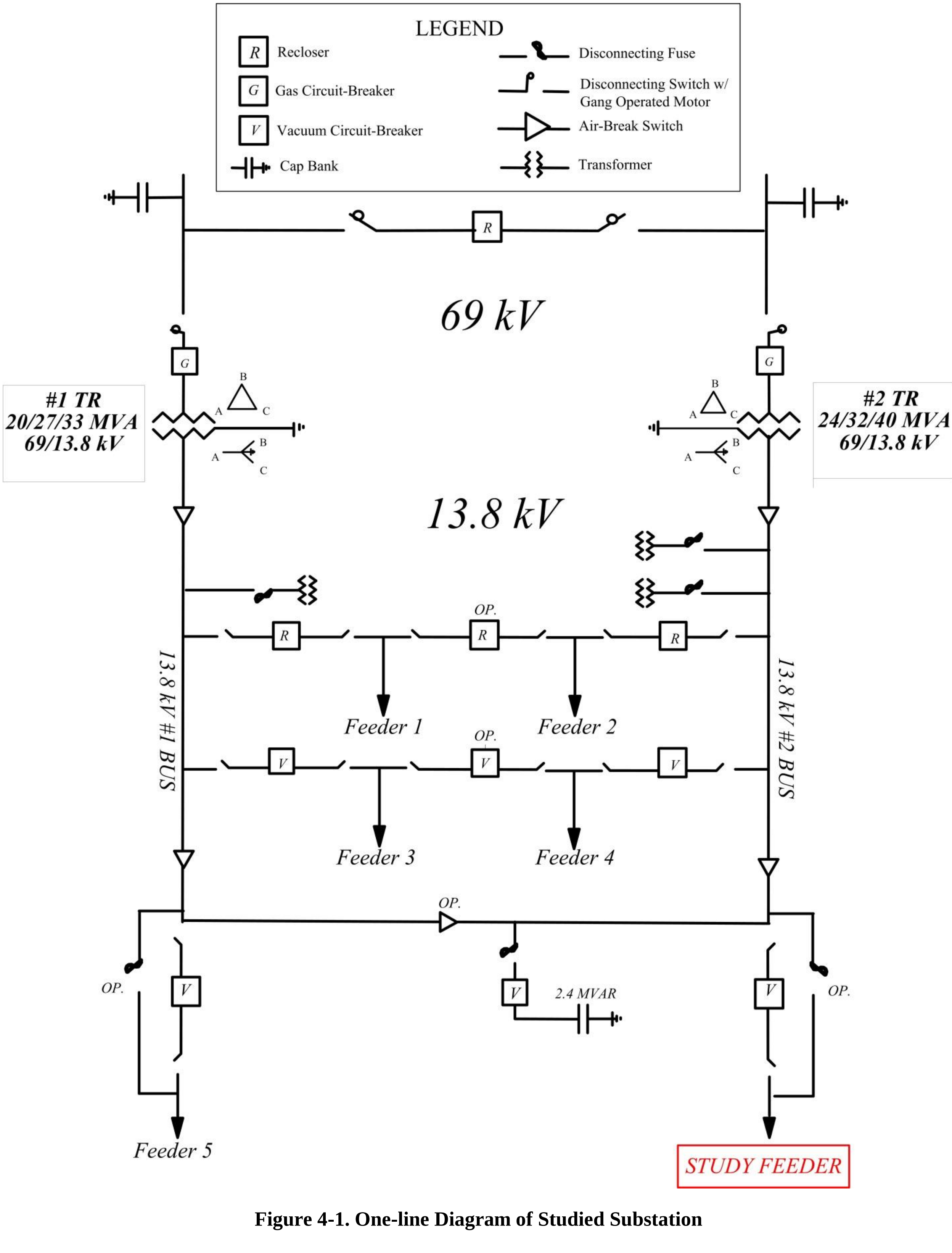


Figure 4-1. One-line Diagram of Studied Substation

The team was also able to take a site visit to the substation to scope out the equipment. Figure 4-2 shows the feeder recloser connected in the substation. As opposed to other feeders, the relays for this feeder were located outside the control house and within the breaker itself. The controls within the recloser are GE-2011E, which are bi-directional capable to accommodate the DG on the feeder.

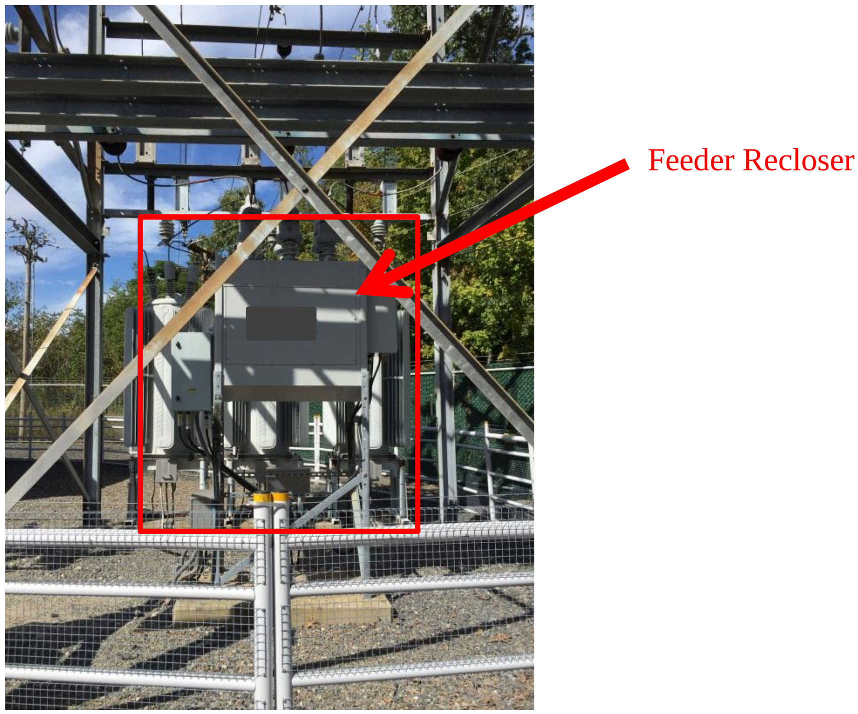


Figure 4-2. Feeder Recloser

The conductor is a combination of 336 AL, 4/0 AL, and 477 AL spacer cable. For the simplicity of the project, the team chose to model 336 AL conductor wire in all studies. The DG site resides 2.1 miles from the substation.

4.2. Coordination Check

In order for the team to check the protection for different potential DG cases discussed in the next section, the team needs to make sure the feeder is correctly modeled and coordinated. In a properly coordinated system, a fault is eliminated in the smallest possible amount of time and isolated from the rest of the system. Without proper protection coordination, a relay can misoperate and can either damage equipment or create additional outages. Distribution relays, fuses, and reclosers are currently not designed to respond to current flow direction and the potential fault contribution from DG units. To maintain reliability and safe operation of the electric power system, it is important to understand the impacts of DG interconnection on protection coordination.

Following the selection of a distribution feeder and its respective substation, the team began by reviewing the existing protection in the substation selected to check for how well coordinated the in-service protection with the DG is. Within ASPEN, National Grid owns a file that has the entire system modeled (i.e. lines, busses, transformers, and generators). Distributed generation may not always be modeled in the file and may not be modeled as an inverter-based generator correctly.

After reviewing the relay summary sheet, the team located the distribution substation selected in the National Grid ASPEN file and then modeled the in-service feeder protection by creating a new relay group on the feeder terminal closest to the substation. See Figure 4-3 for the modeled distribution substation and the feeder relay group and Figure 4-4 for the settings of the overcurrent phase and ground feeder relays.

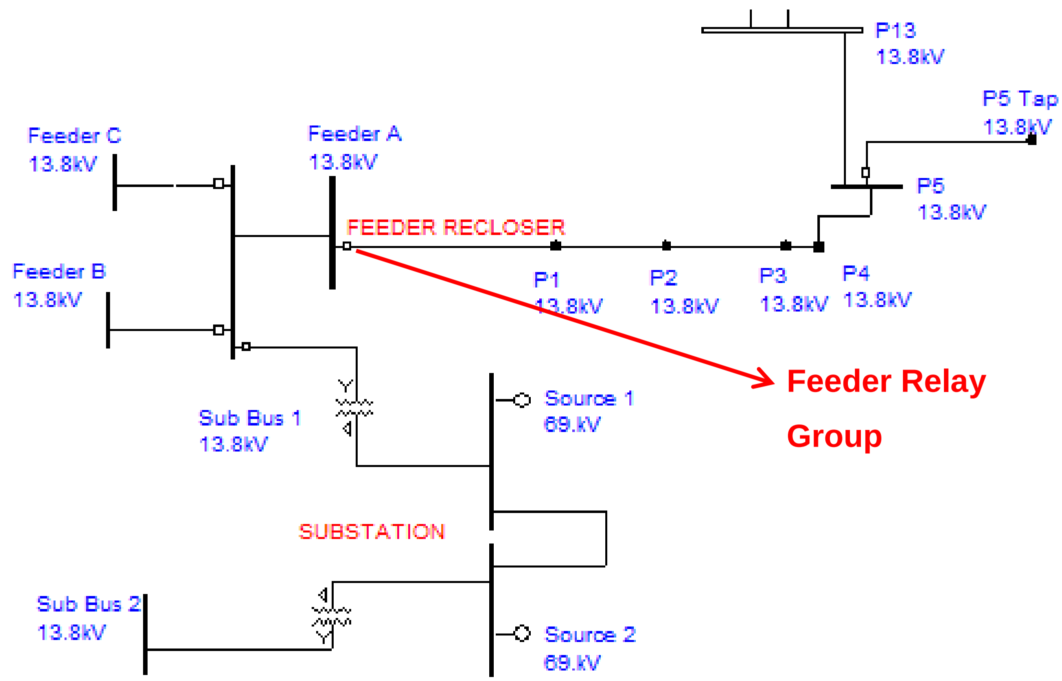


Figure 4-3. ASPEN Modeled Distribution Substation with Feeder Relay Group

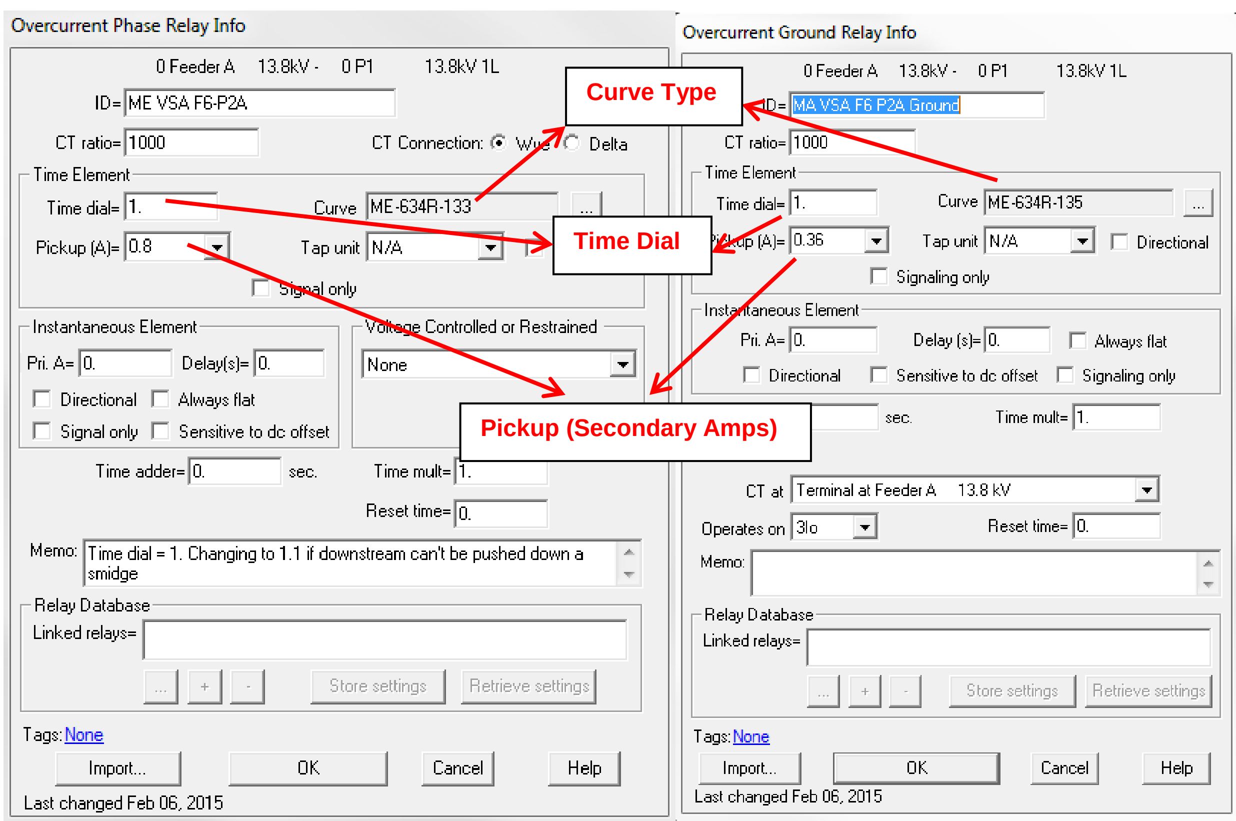


Figure 4-4. Overcurrent and Ground Feeder Relay Settings

Within the new relay group, the team input the time-dial, pickup, and curve settings indicated in the relay summary sheets. For confidential reasons, the relay summary sheet cannot be included in this report. In addition to the feeder protection, the team modeled the poles, pole fuses, and pole recloser. The DG station was mimicked from the existing ASPEN model where the customer protection was modeled and the inverters were modeled as current-limited generators. The entire ASPEN model can be seen in Figure 4-5.

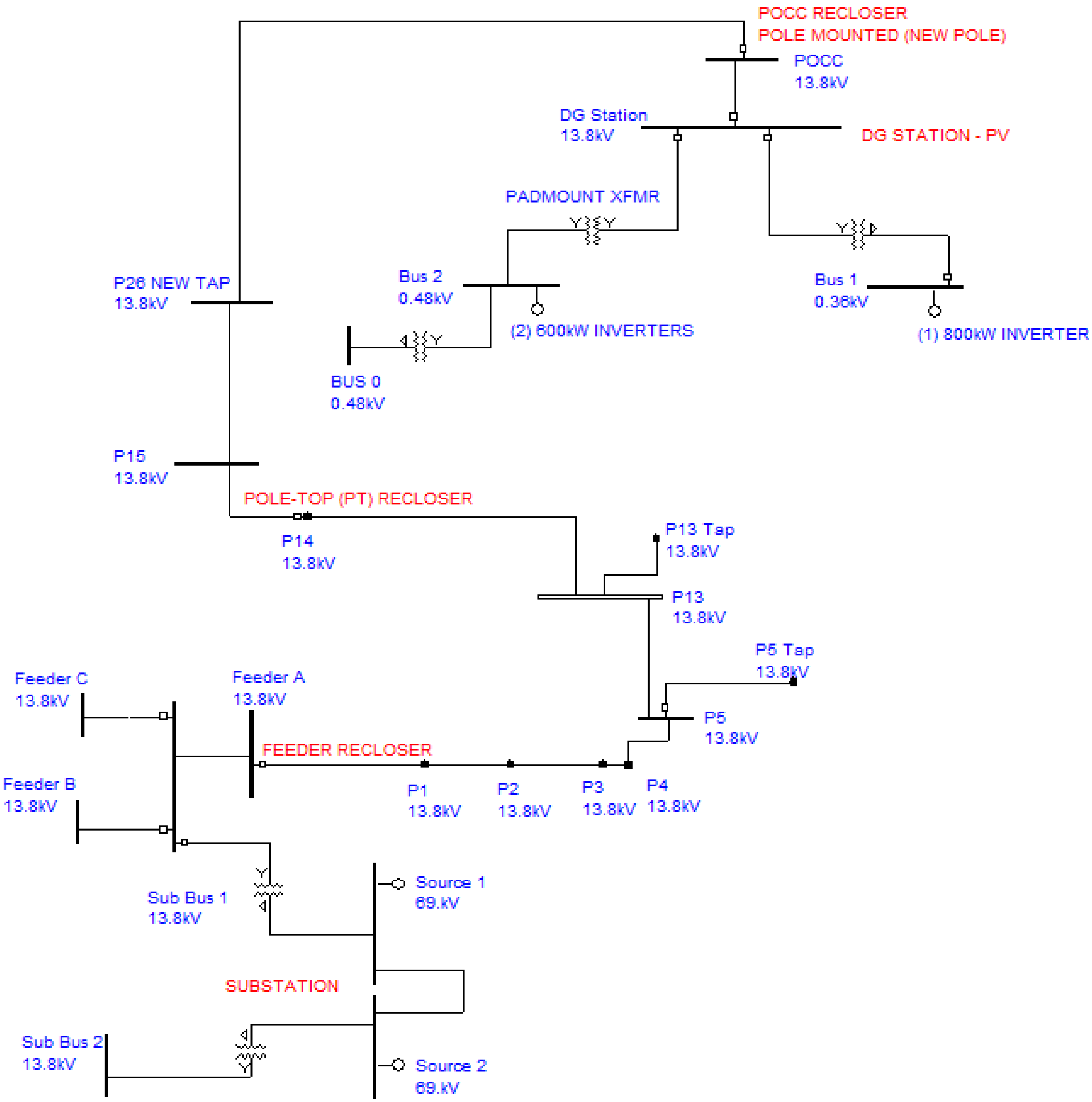


Figure 4-5. Entire ASPEN Model of Distribution Substation and DG Interconnection

A 3 line-to-ground (3LG), or 3-Φ fault, and 1 line-to-ground (1LG), or 1-Φ fault, were simulated for three situations.

1. Outside the DG Station and outside the Substation (at Bus P26 in Figure 4-6)
2. Inside the DG Station (at Bus "DG Station" in Figure 4-6)
3. Immediately after the feeder recloser (at Bus P5 in Figure 4-6)

For situation 1, a 3LG fault was simulated at Bus P26. The fault resulted in an 82A contribution from the DG Station and a 3002A contribution from the Substation.

The time-current characteristic curve indicated which overcurrent relays tripped in relation to time and the maximum fault current for a 3LG fault in that area. The maximum fault current resulted in 3079.1A. The reclosers that tripped, in order, are:

1. Pole-top Recloser at t = 0.34s
2. Feeder Recloser at t = 0.86s
3. DG Recloser at t = 1.74s

Detailed curves can be seen in Figure 4-6. The utility's point of common coupling (POCC) recloser was not set sensitive enough to trip for a 3LG fault at this location, but if the upstream protective devices trip as backup protection (as it does as seen in Figure 4-6), the POCC recloser not tripping is not of a concern. The pole-top recloser is the closest circuit breaking equipment to the fault, so the pole-top recloser correctly operated first. The feeder recloser is the next recloser down the line and properly tripped with at least a 0.3s margin. The DG recloser then correctly tripped to protect the customer equipment. Therefore, in this situation, the protection is properly coordinated.

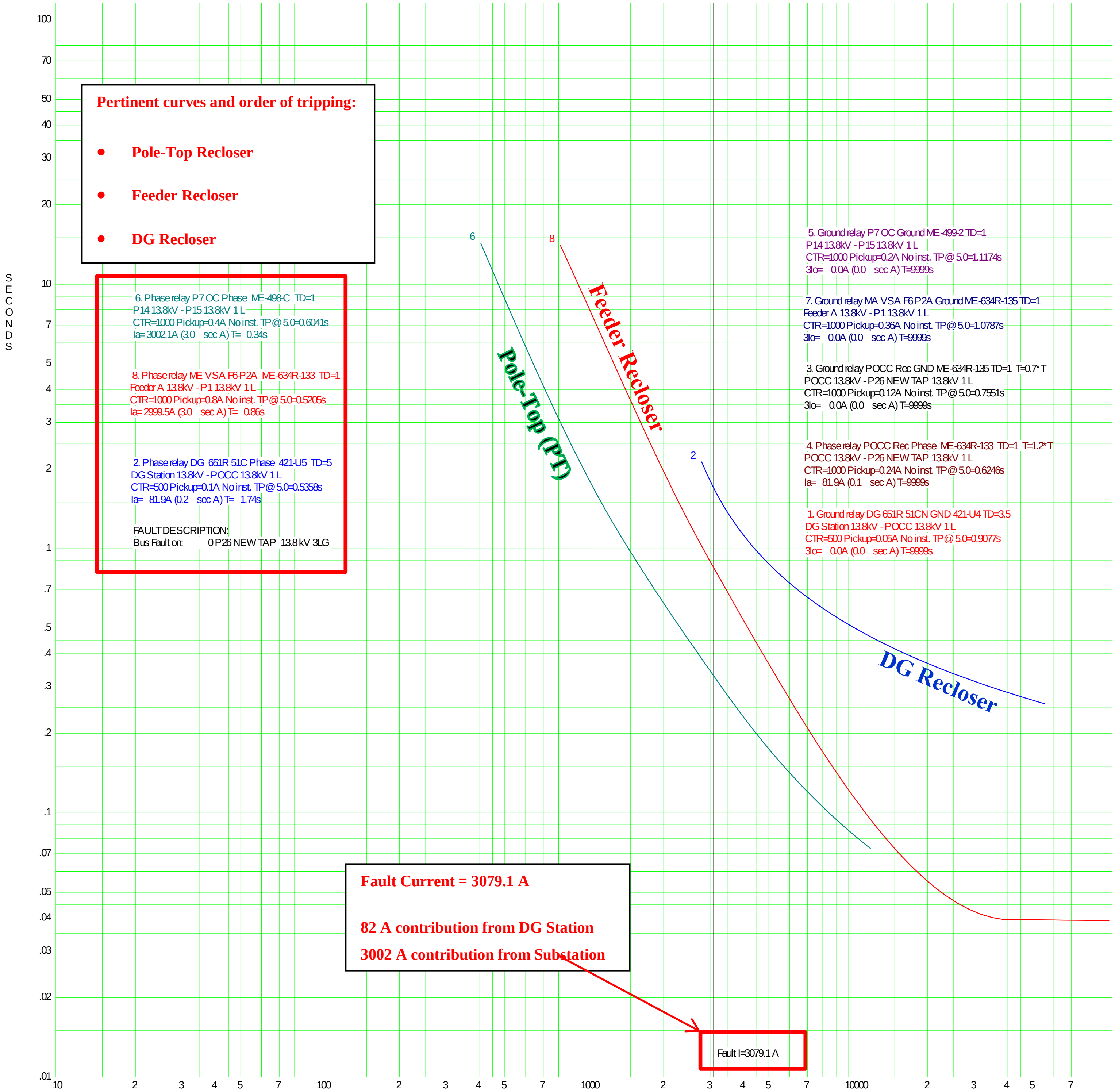


Figure 4-6. Time-Current Characteristic Curve for 3LG Fault at Bus P26

Again for situation 1, a 1LG fault was simulated at P26. The fault resulted in an 82A contribution from the DG Station and a 3002A contribution from the Substation. The maximum fault current was 2289.0A. The reclosers that tripped, as seen in Figure 4-7 in order, are:

1. DG Station Recloser at t = 0.26s
2. Pole-top Recloser at t = 0.53s
3. Feeder Recloser at t = 0.95s
4. POCC Recloser at t = 2.30s

The DG Station recloser tripped first because the ground overcurrent was set more sensitive than its phase overcurrent to protect against temporary overvoltage. The pole-top recloser is the next upstream protective device and therefore correctly tripped next. Following that, the feeder recloser tripped properly. The POCC recloser tripped for a 1LG for the same reason that the DG Station recloser tripped first---the ground overcurrent element was set more sensitive to protect against temporary overvoltage. The complete time-current characteristic graph can be seen in Figure 4-7.

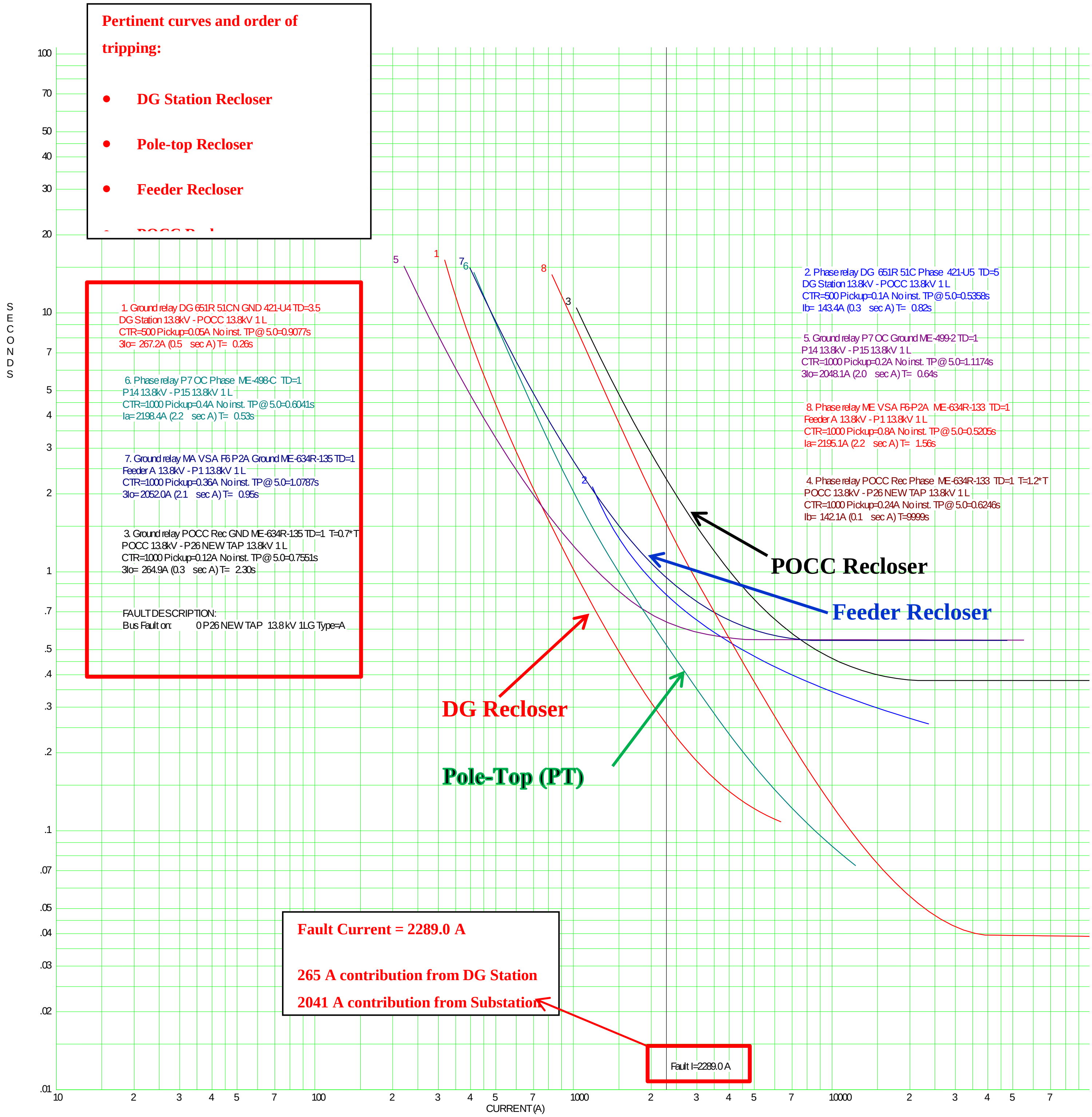


Figure 4-7. Time-Current Characteristic Curve for 1LG Fault at Bus P26

For situation 2, a 3LG fault was simulated inside the DG Station. At the fault location, the total fault current was 2901A with complete contribution from the feeder substation. The complete time-current characteristic graph as well as the order of tripping can be seen in Figure 4-8.

Figure 4-8 shows that the following relays tripped in this order:

1. POCC Recloser at t = 0.15s
2. DG Recloser at t = 0.26s
3. Pole-top Recloser at t = 0.35s
4. Feeder Recloser at t = 0.92s

For a fault inside the DG Station, it is expected that the DG recloser trip first and then, with safe delaying, that the POCC recloser trip after to protect the utility equipment from damage. However, the POCC recloser tripped very soon after the fault before the DG recloser had a chance to trip. From a Protection Engineering point of view, this would be considered miscoordination. However, from a Retail Connections Engineering point of view, as long as the POCC recloser coordinates with the protective devices upstream, then this situation is OK.

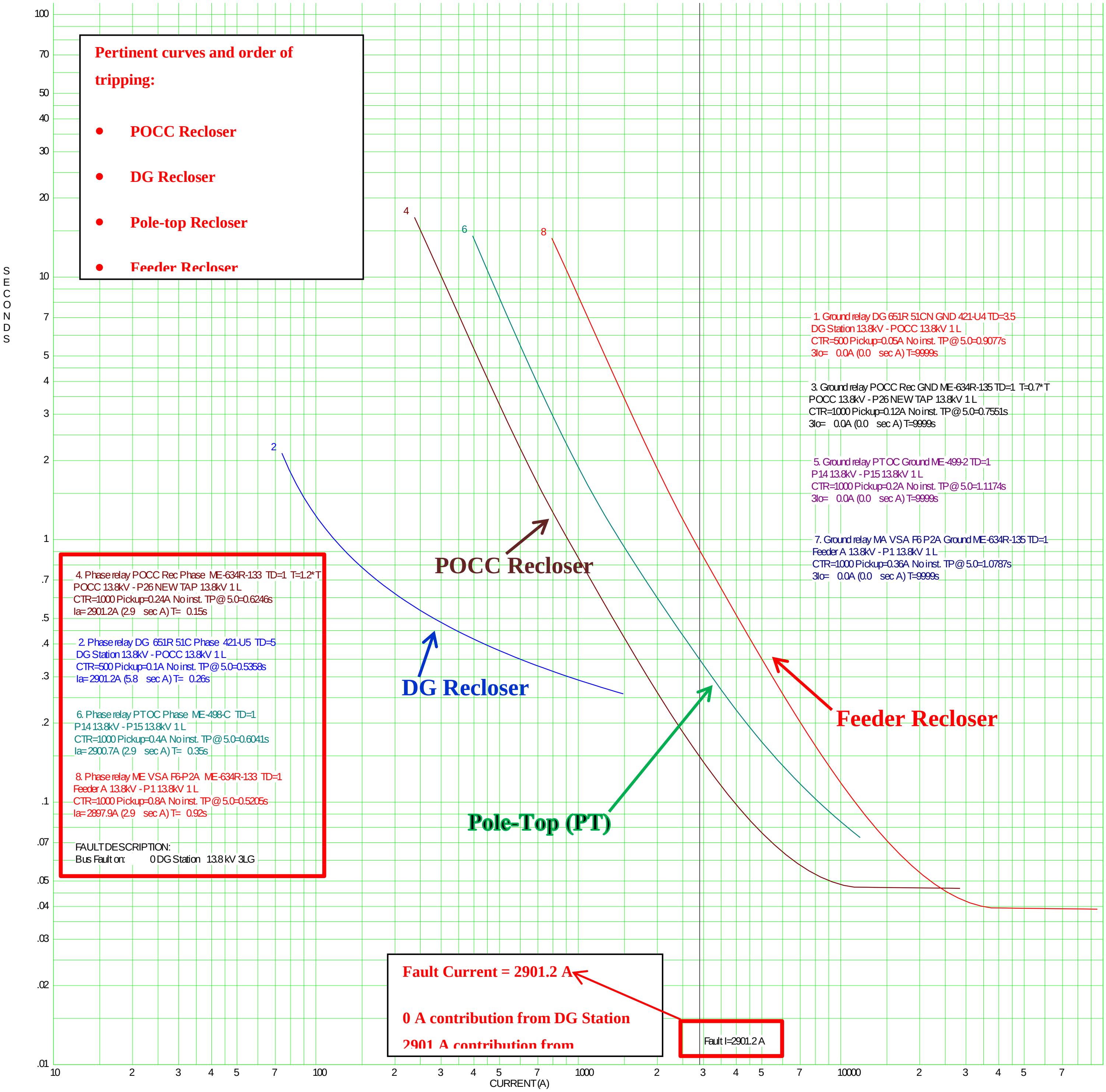


Figure 4-8. Time-Current Characteristic Curve for a 3LG Fault at Bus "DG Station"

For situation 2, a 1LG was simulated in the same location. The total fault current flowing to the faulted location was 2231.1A with 264A contribution from the DG Station and 1989A contribution from the Substation. The order of tripping was the following:

1. DG Recloser at t = 0.11s
2. POCC Recloser at t = 0.23s
3. Pole-top Recloser at t = 0.54s
4. Feeder Recloser at t = 0.97s

The complete time-current characteristic curves can be seen in Figure 4-9. The DG recloser tripped first as expected, but is less than 0.3 seconds within the next tripped device, the POCC recloser. Using the same rule of thumb in the previous fault, this situation is also acceptable because the POCC recloser coordinates well with the upstream devices.

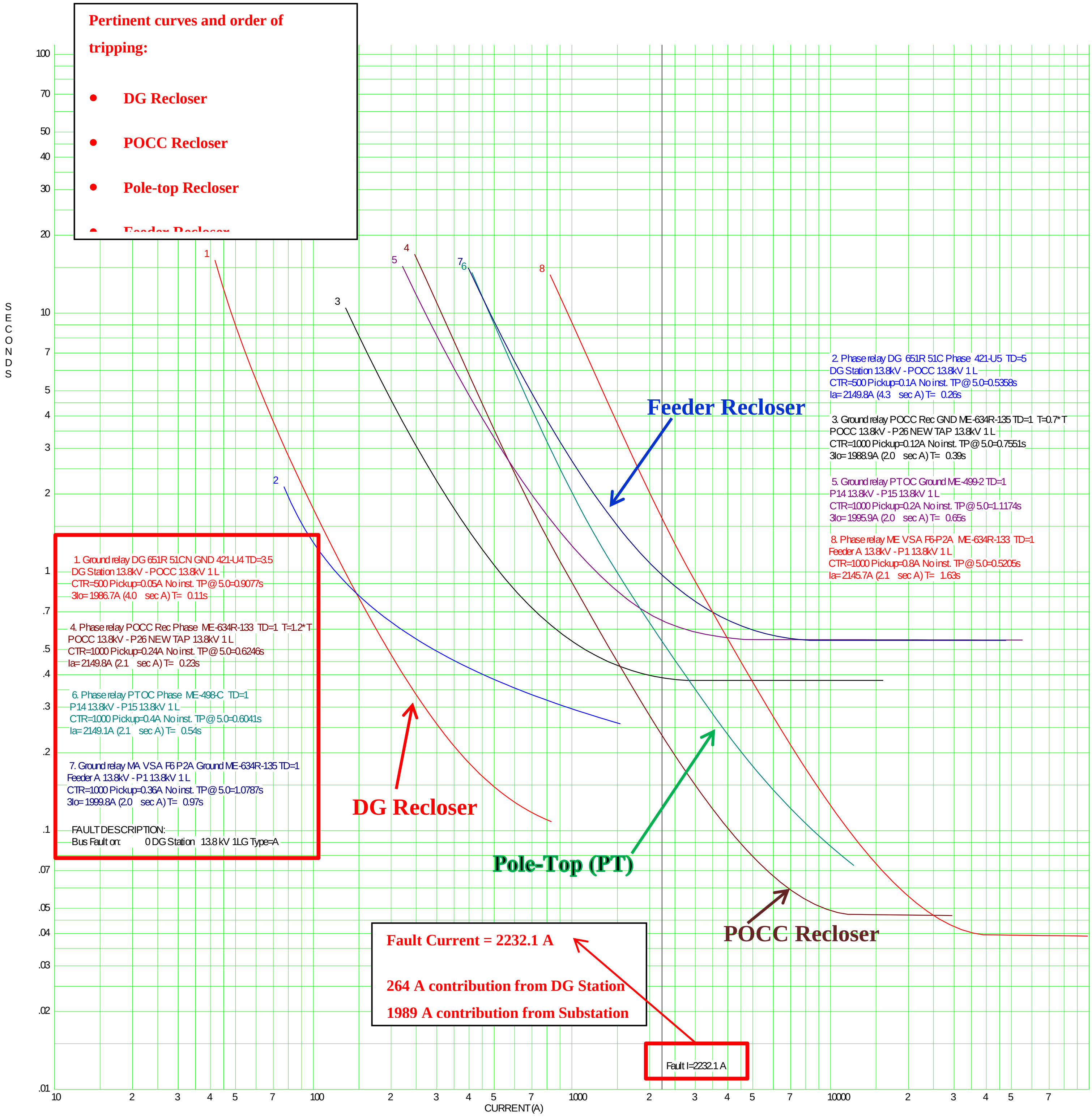


Figure 4-9. Time-Current Characteristic Curve for 1LG Fault at Bus "DG Station"

For situation 3, a 3LG and 1LG close-in fault was simulated immediately downstream the feeder recloser. For a 3LG fault, the total fault current was 6583.8A with full contribution from the Substation. The feeder recloser was the only device to trip. For a 1LG fault, the total fault current was 7156.5A with 126A contribution from the DG Station and 7033A contribution from the Substation. The order of tripping was as follows:

1. Feeder Recloser at t = 0.20s
2. DG Recloser at t = 0.78s
3. POCC Recloser at t = 8.15s

All devices tripped with more than sufficient delay time between each other. The DG recloser is set very sensitive and so tripped after the feeder recloser. The POCC recloser tripped as backup protection for the DG recloser. The complete time-current characteristic curves can be seen for both the 3LG and 1LG fault in Figures 4-10 and 4-11, respectively.

Having analyzed the complete coordination of the feeder between the new DG protection, ***the team confirms that the protection is fully coordinated. To accommodate the addition of the DG at this feeder, the utility did not have to change any existing protection at either the pole-top or the feeder***.

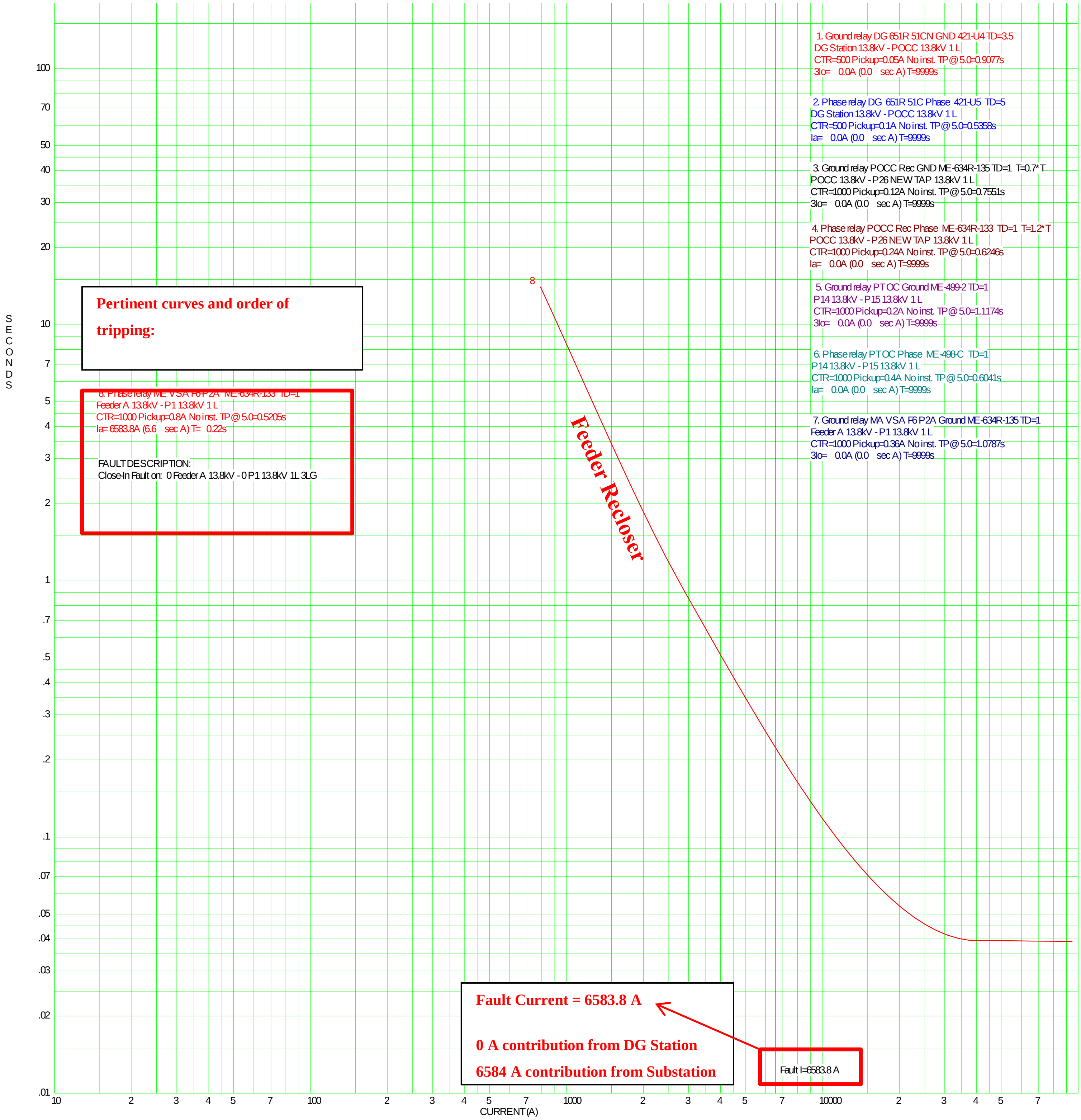


Figure 4-10. Time-Current Characteristic Curve for a 3LG Fault at Bus P5

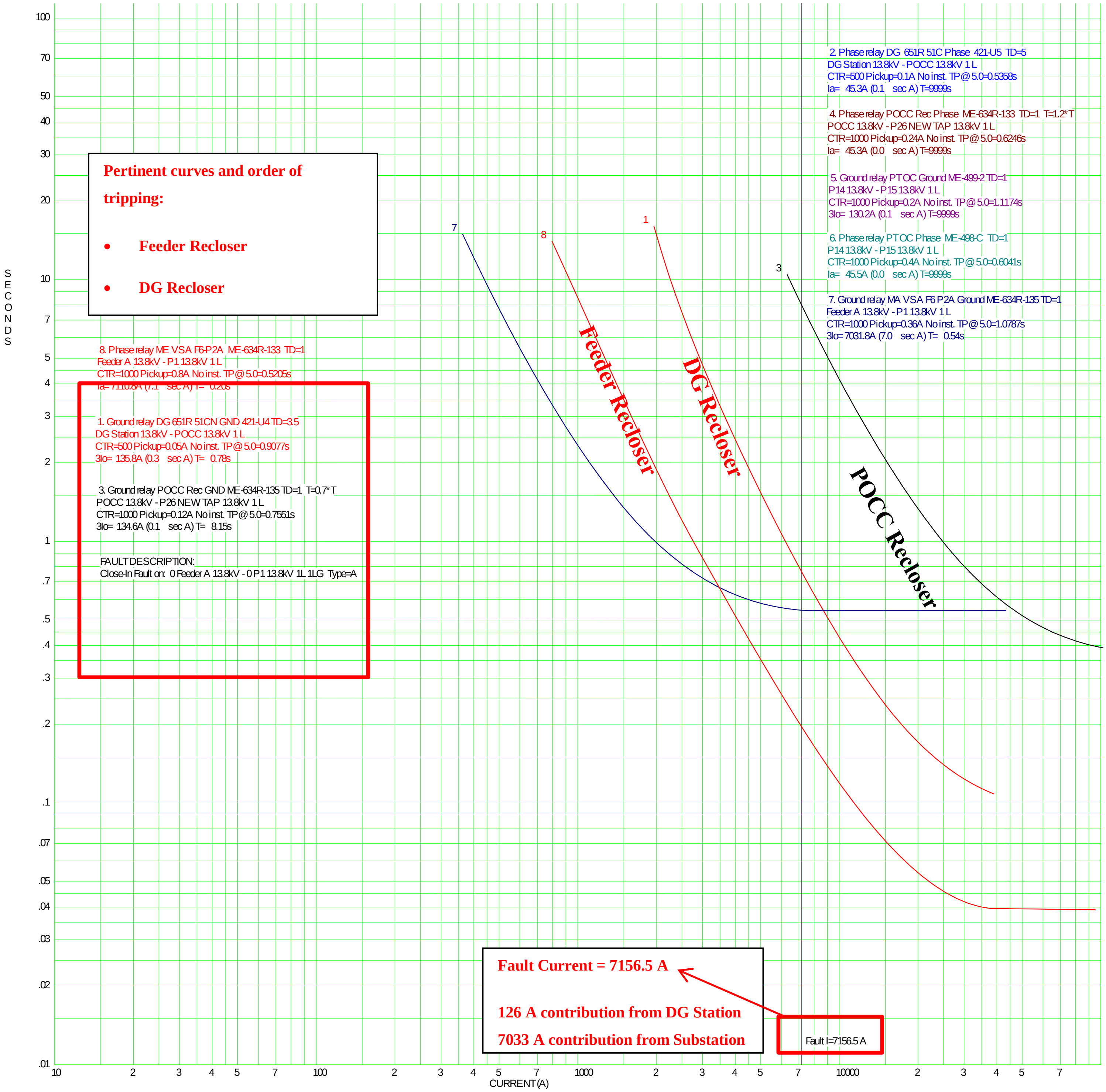


Figure 4-11. Time-Current Characteristic Curves for 1LG Fault at Bus P5

4.3. ASPEN Inverter Model Application

The inverter model affects the behavior of fault contribution so it's important to mimic the inverter as closely as possible. ASPEN OneLiner is a short circuit program used for fault analysis at National Grid. This particular DG site consists of (1) 800kVA inverter, (41) 20kVA string inverters, (13) 24kVA string inverters, and (1) 12kVA string inverter. The team met with the inverter company to discuss short circuit fault contribution. According to the company representatives, the subtransient and transient periods occur within the first two cycles of a fault, 300 microseconds and 16 milliseconds respectively. The protection devices do not trip until after at least 0.17 seconds, a moment well into the synchronous interval. Therefore, the settings in ASPEN were set to have the snapshot of the fault during the synchronous period. The synchronous current limit of the DG's specific inverter is equivalent to the maximum current output of the inverter unit and was modeled as such in ASPEN.

National Grid's general standard is to use a current limited generator and set the current limit to the following:

$$Current\ Limit = \ Full\ load\ current\ output * 1.2$$

or

$$Current\ Limit = \frac{Inverter\ rating}{Voltage\ output * (1.732)} * 1.2$$

To investigate how closely National Grid's general standard models the inverter company's inverter data, the team investigated the total fault current and more importantly, the tripping times of the protection devices.

The original National Grid model is shown in Figure 4-12. The (2) 600kW inverters were set to have a current limit of 1732A. This was derived from the following calculation:

$$\frac{1{,}200{,}000\ W}{(480\ V) * (1.732)} * 1.2 = 1732.11\ A$$

The (1) 800kW inverter was set to have a current limit of 923A. This was derived from the following calculation:

$$\frac{800{,}000\ W}{(600\ V) * (1.732)} * 1.2 = 923.79\ A$$

As seen in Figure 4-12, the POCC recloser trips 0.236 seconds after the fault and the PT recloser trips after 0.545 seconds for a 1LG fault at the DG Station. The total fault current is 2242A.

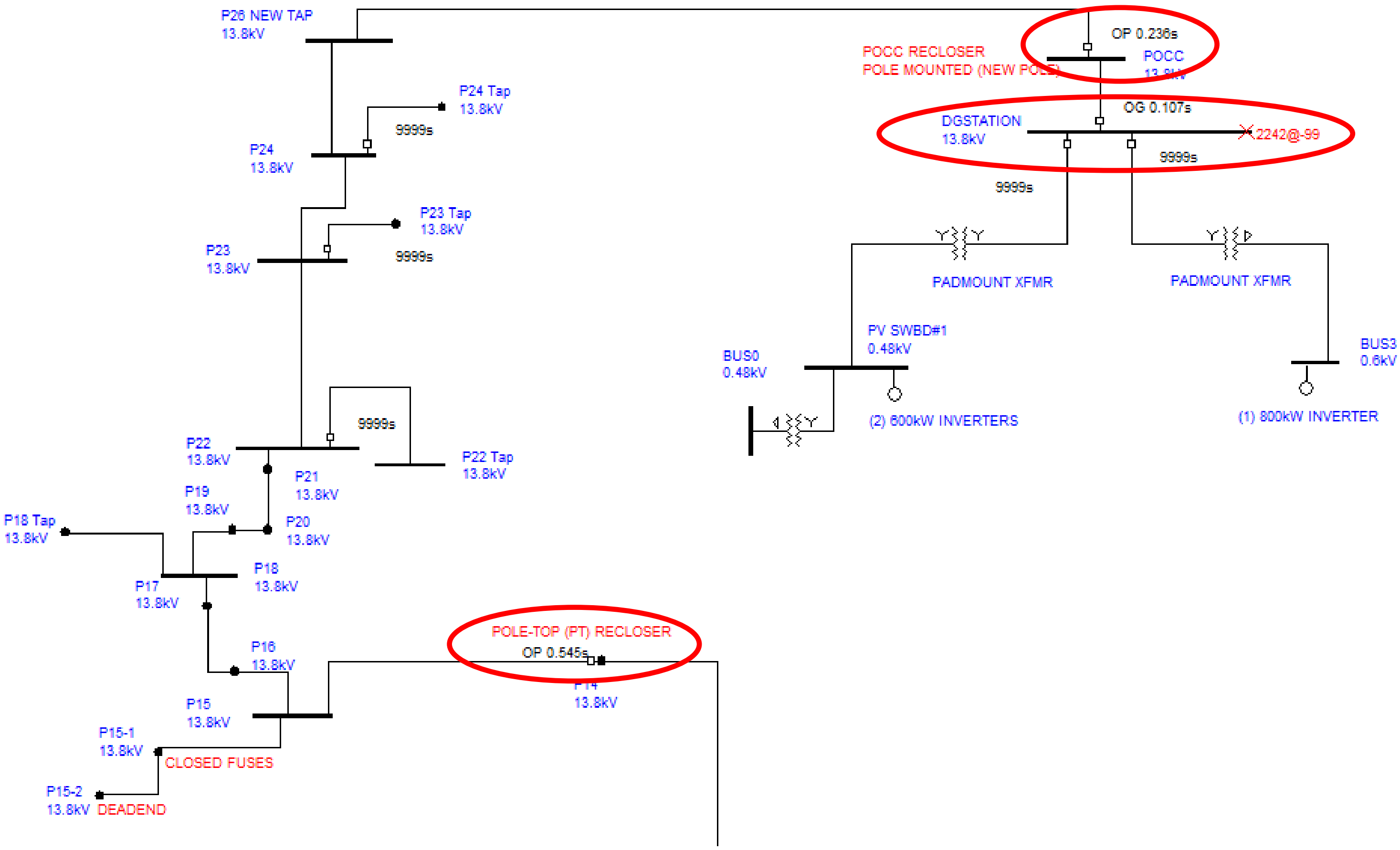


Figure 4-12. Original National Grid Model with 2MW DG

With the inverter company's data, the 800kW inverter current limit is 1411A in the synchronous time period. The (2) 600kW inverter is actually made up of several string inverters: (41) 20kVA string inverters, (13) 24kVA string inverters, and (1) 12kVA string inverter---totaling to 1.2MW. The current limit for each string inverter was also taken to be equivalent to the maximum current output in the synchronous time period. Taking the current limit for each string inverter, the total current limit totaled to 1375.4A for this unit.

As seen in Figure 4-13, the POCC recloser and PT recloser tripped at the exact same times as the original model. The total fault current varied by a few amps.

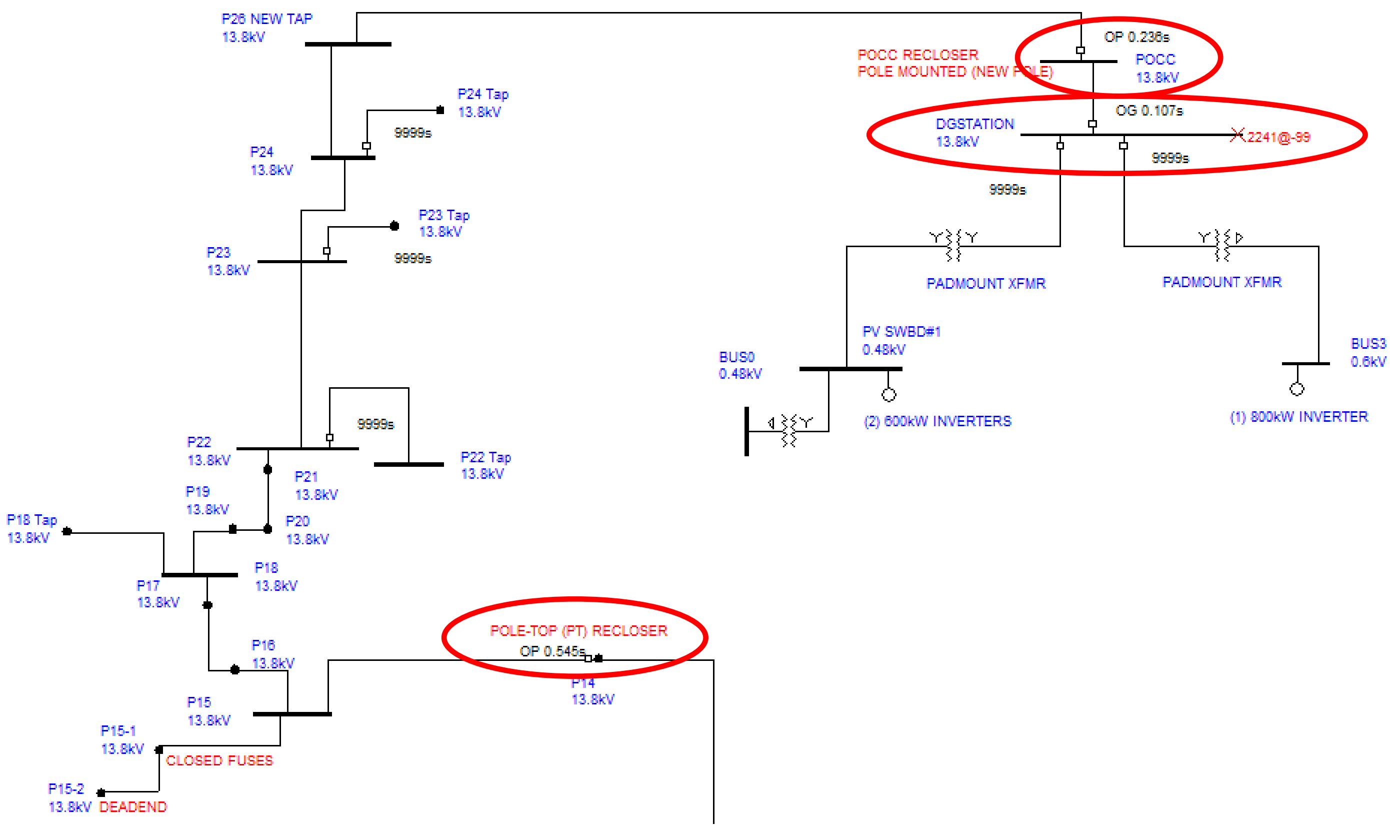


Figure 4-13. Model with Actual Inverter Data with 2MW DG

To see if a larger system had any effect, the team increased the total DG output to 6MW. Using the standard National Grid model, the following calculations were made for current limits:

$$\frac{3{,}600{,}000\ W}{(480\ V)*(1.732)}*1.2 = 5{,}196.3\ A$$

$$\frac{2{,}400{,}000\ W}{(480\ V)*(1.732)}*1.2 = 3{,}464.2\ A$$

As seen in the calculations, the limits were just multiplied by a factor of 3. Using the original National Grid model, the POCC recloser tripped after 0.242 seconds and the PT recloser tripped after 0.559 seconds, as seen in Figure 4-14. The total fault current increased to 2327 A.

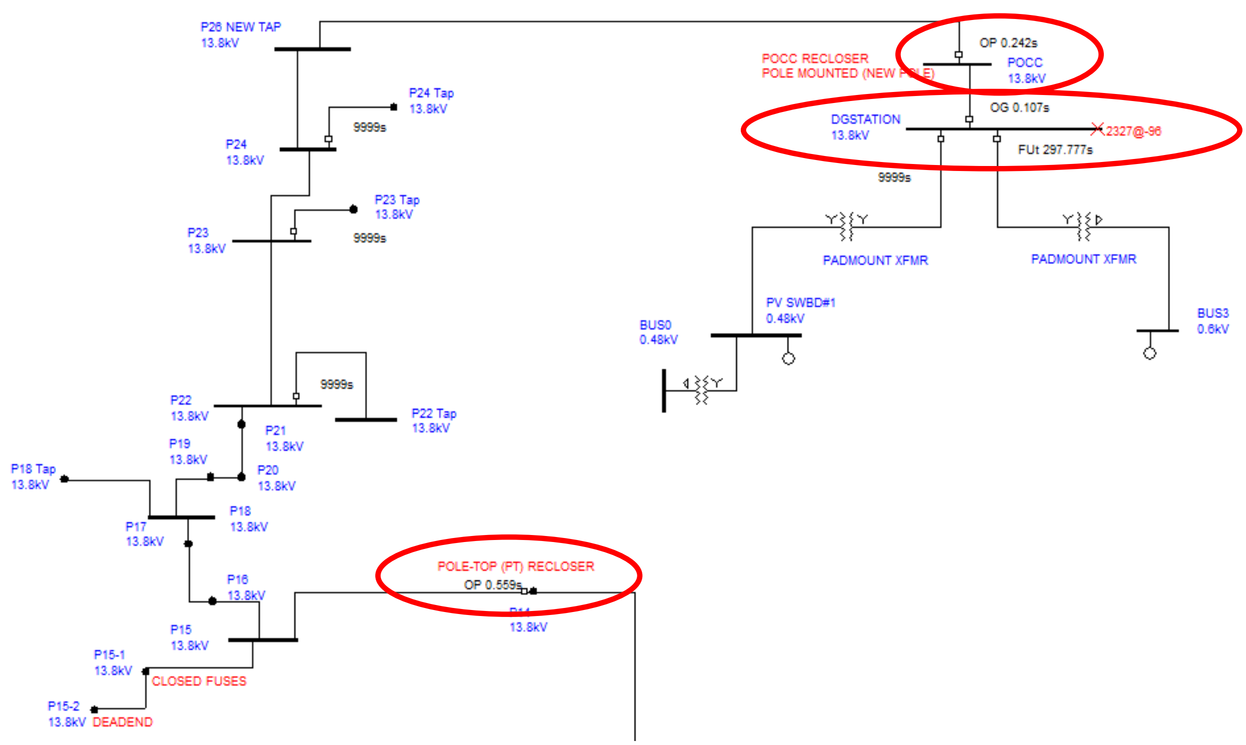


Figure 4-14. Original National Grid Model with 6MW DG

Similarly, with the inverter company's data, the current limits were multiplied by a factor of 3. The POCC recloser tripped after 0.242 seconds and the PT recloser tripped after 0.559 seconds. This is the same trip times as the original National Grid model, expect the total fault current increased slightly.

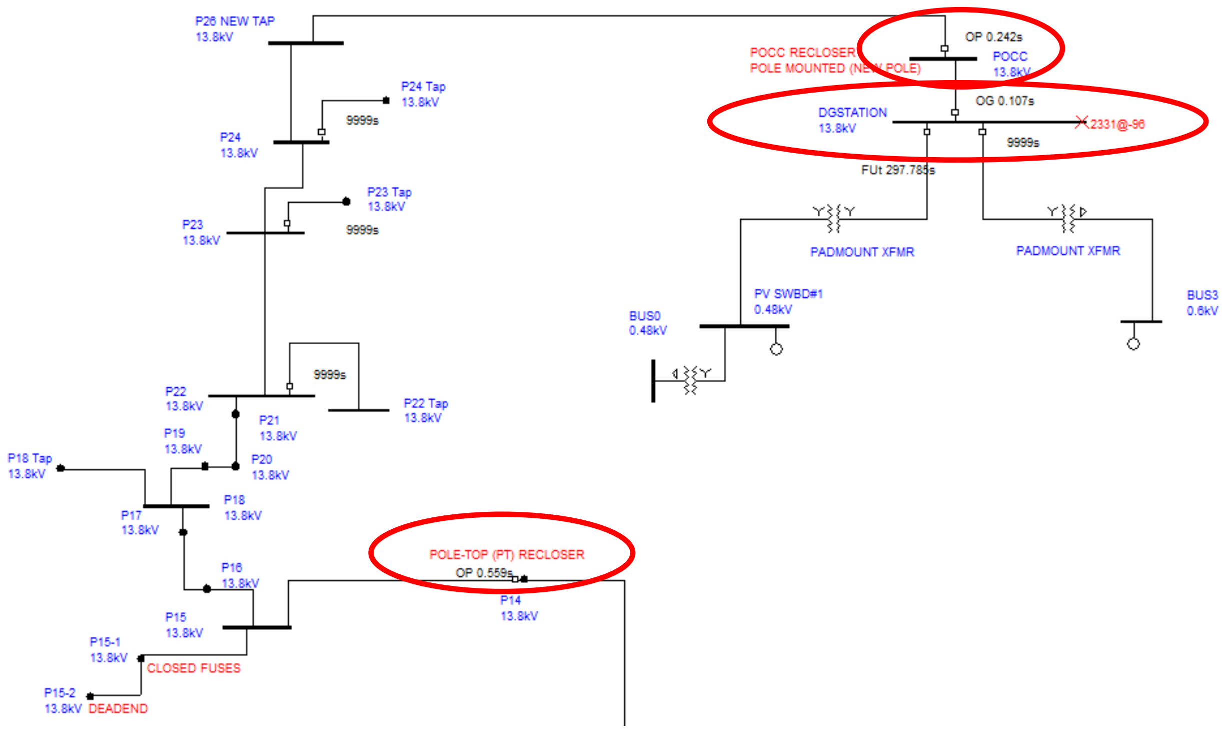


Figure 4-15. Model with Actual Inverter Data with 6MW DG

In conclusion, **the National Grid standard models very closely with the actual inverter despite initial current limit differences in the two generator units *in this specific case.***

Recommendations for future inverter modeling in ASPEN include contacting the inverter company during a DG installation project and obtaining the following information:

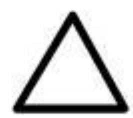
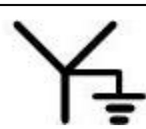
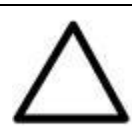
- Oscillographs for voltage and current behavior for 3 phase, SLG, and LL faults on the terminals of the inverter.
- Steady-state fault response of the inverter
- Short-circuit models

Oscillographs and test data for faults on the inverter terminals allow engineers to understand how the specific inverter reacts and therefore possibly understand how to best work it in with the ASPEN current-limited model. Knowing the steady-state fault response of the inverter could allow the engineer to replicate what was done in this section and determine a synchronous current limit. Lastly, if the inverter company already has possession of a short-circuit model, it would be beneficial to look at their settings to compare and possibly use.

4.4. Reverse Power Effects from Varied DG Size and XFMR Configuration

Because of problems known to be associated with transformer windings and size, the team simulated different types of DG transformer connections and varied the DG size in ASPEN OneLiner to test how reverse power flow affects coordination and overvoltage with changes to those two variables. Based off of the limitations of ASPEN with transformer connections, 6 total transformers connections were tested as seen in Table 4-1. For each of the 6 transformer connections, the team also varies the size of the DG from 500kW, to 1 MW, to 5 MW, and to 10 MW to see its additional impact. This totals to 24 different cases.

Table 4-1. Different Combinations of DG Size and DG Transformer Configuration Studied

Transformer Connection	**Primary**	**Secondary**	**DG Size**
Delta (primary)/Grounded Wye (secondary) *Abbreviated D-YG*			1. 500 kW 2. 1 MW 3. 5 MW 4. 10 MW
Delta (primary)/Delta (secondary) *Abbreviated D-D*			5. 500 kW 6. 1 MW 7. 5 MW 8. 10 MW
Grounded Wye (primary)/Delta (secondary) *Abbreviated YG-D*			9. 500 kW 10. 1 MW 11. 5 MW 12. 10 MW
Grounded Wye (primary)/Grounded Wye (secondary) *Abbreviated YG-YG*			13. 500 kW 14. 1 MW 15. 5 MW 16. 10 MW
Delta (primary)/Zigzag (secondary) *Abbreviated D-ZZ*			17. 500 kW 18. 1 MW 19. 5 MW 20. 10 MW

Grounded Wye (primary)/Zigzag (secondary) *Abbreviated YG-ZZ*			21. 500 kW 22. 1 MW 23. 5 MW 24. 10 MW

The team simplified the original model to one inverter-based generator source and one DG transformer to isolate the study. During this study, the resistive approach for the inverter model was used.

4.4.1. Coordination

To test for coordination, the team input the settings for each of the cases and simulated a 1LG and 3LG fault in the following three locations: (1) DG Facility, (2) right outside the point of common coupling, and (3) right outside the feeder. The purpose of the three locations is to have all reclosers pick up the fault and trip. This way, the team was able to see if all devices coordinated well with each other in all general situations. The devices that pertain to this study were:

- Transformer GND OC relay
- Substation feeder relay
- Pole-top recloser
- Point of common coupling recloser
- DG customer installed recloser

When looking at the time-current characteristic curves, the coordination times and tripped devices were compared to the original grounded wye (primary)/delta (secondary) 2MW case. Observations were made and can be seen in Appendix A. After analyzing the observations, the team found two particular situations that could create future problems:

1. With any DG transformer with a YG primary, academic resources say that "if the fault is near the end of the feeder, the reduction in substation ground fault current may result in substation ground fault relaying not responding to the fault" and therefore resulting in loss of relay coordination [4]. The team looked at all the cases with a YG

primary connection and saw that, for a 1LG fault outside the point of common coupling, a 10MW DG and a YG-ZZ transformer produced the worst coordination case in comparison to all other YG primary cases. In this situation, the coordination was still considered acceptable with a 0.31s time different between the feeder and pole-top recloser. However, **the team found that at a significantly large DG source (20MW and greater), there was a loss of coordination between the feeder and pole-top recloser as seen in Figure 4-16.** Although there is a loss of coordination, the protection may be re-coordinated with no problems. **This shows that the present protection on the feeder is sufficient for relatively large amounts of PV penetration.**

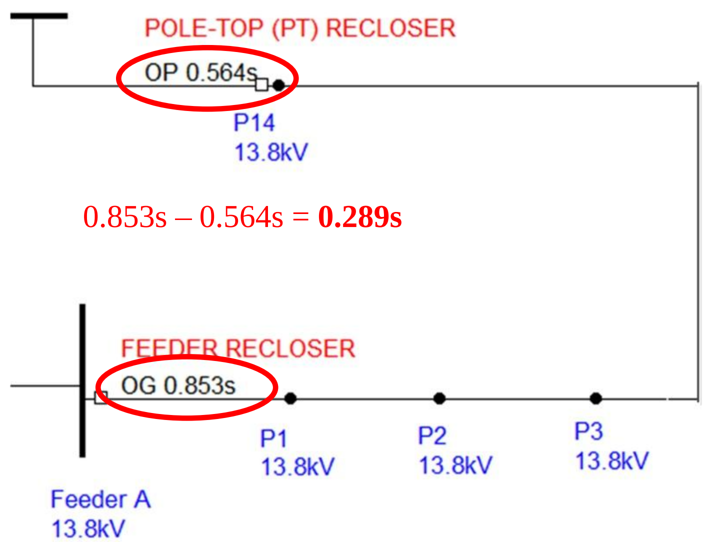


Figure 4-16. Loss of Coordination at 20MW for YG Primary DG XFMR

All other cases did not present a problem with coordination within the National Grid system.

4.4.2. Overvoltage

To test for overvoltage, the team studied cases when the DG was connected to the utility and when the DG was disconnected from the utility. All of the 6 DG transformer connections were studied, but the team picked 1 DG size after noticing not much voltage change between the sizes. When studying the DG connected to the utility, the voltages looked at are at the DG Facility and at the substation transformer primary. The voltages looked at were:

- Line-to-ground (L-G) voltage (kV)
- Line-to-line (L-L) voltage (kV)
- Sequential voltage (kV)

All voltages can be seen in Appendix B. Typically, engineers are concerned about the unfaulted phases rising to line-to-line voltage and damaging surge arrestors and transformer bushings. However, after analyzing the voltages produced, there were no strong concerns with overvoltage.

4.4.3. Operation of Protection Devices

Other concerns with protection include making sure that the correct devices trip under certain fault conditions. The team checked for the following:

1. When there's a L-G fault on the high side of the substation transformer, the DG will not pick-up the fault because zero amps are seen by the DG protection. This could create a dangerous situation in which the DG is continuing to feed an unbalanced circuit and should disconnect from the grid. **In all cases, the DG did not pick up for a fault on the high side of the substation transformer.** Another way to detect the fault and tell the DG to trip is through zero-sequence overvoltage. If there is a zero-sequence overvoltage relay for the primary line supplying the substation, then the relay should be able to detect ground faults on the primary line. If a backfeed condition persists from the interconnected DG, then the relay would also trip the relays responsible for the feeder with the interconnected DG. **For this particular**

study, the feeder schematics indicate a Basler 59N GV3 (Zero-Sequence Overvoltage) protection. Therefore, this particular feeder is protected from potential fault backfeed from the DG source.

2. **With a 10MW DG and a YG-D transformer, for a 1LG fault right outside the substation feeder relay, the pole-top recloser tripped for a fault upstream from its protection zone.** In all the other 24 cases (including the original 2MW case), the pole-top recloser never trips. This supports that **YG-D DG transformers contribute strongly to ground faults**. The pole-top recloser picked up the fault current contribution from the DG and tripped. Fortunately, the pole-top recloser retained its coordination with the other devices. *In future cases where it might be difficult to coordinate the additional recloser with the DG protection, a possible solution would be to enforce higher neutral grounding impedance on the YG primary DG transformer.*

5. Conclusion

The electric system, although has been able to withstand the PV DG interconnections to this date, may need additional mitigation systems to combat the negative effects of reverse power flow in the future. The team's reverse power mitigation system has proven to detect when the power output from the substation reached a minimum threshold, to communicate to the PV inverter to control its output, and to keep the effects of reverse power flow to a minimum.

Although the team was able to design a functioning mitigation system in Simulink, there are areas of future work.

5.1. The Mitigation System

The team was able to design a functioning mitigation system in Simulink, but the final product should not be considered perfect. There are areas of the design that could be improved, real-world aspects that were not addressed and the system as a whole was entirely simulation, lacking any physical circuitry.

The first part of the mitigation system worthy of a second look by a new team is the buck converter. The buck converter used in the final design was not fully optimized for the context. This was made apparent in section 3.3.3 of this report. The voltage ripple on the output was about 200V and the power output of the buck converter experienced power spikes 1MW in magnitude. Although the inverter compensated for this in the simulation any attempt to manufacture this buck converter in the real world would surely fail.

Another aspect of the mitigation system that could use additional attention is the real-world communication between the relay and the buck converter. The team was able to leave out this consideration because the project was solely simulation-base. If however, a future team was adapting this design to the real world, they would have to examine practical ways for the relay to send tripping signals to the buck converter. The team had some ideas about this including, using existing telecom lines, wireless communication and using GOOSE Protocol [18] [19].

The final recommendation the team can make for future MQP teams interested in our project is to try to convert the relay model in our mitigation system to a real-world circuit. Normal protection relays take in currents and voltages from measurement transformers that are at manageable levels (tens of volts and milliamps) for digital and analog circuit design. A small-scale version of the mitigation relay could be constructed and tested.

5.2. National Grid Case Study

After studying one of National Grid's feeder, it was determined that the feeder was equipped with the proper protection to accommodate large amounts of PV penetration (at least 20MW) and had additional protection to trip the feeder reclosers if the DG continually fed into a high side transformer fault.

In addition to studying the protection of the feeder, the team investigated the accurateness of the existing current-limited generator model used to model inverters in ASPEN used by National Grid with the fault current behavior of the inverter given by the inverter company. The National Grid model, although producing different current limits as the inverter company model, resulted in the same protection tripping times as the inverter company model. Therefore, the team concludes that the National Grid model closely depicts the behavior of the inverter for this particular feeder. Because the inverter studied belonged to only one company, this statement cannot be made accurate without the study of other inverters. With this, the team recommends that efforts be made by a future team interested in this project to contact other inverter companies and compare the fault current behavior with that of the National Grid model.

Because of time constraints, the team did not study how reverse power flow would affect relay operation of zero-sequence overvoltage relays on the high side of the substation transformer. Future work could involve this and would be beneficial to the protection engineering field.

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Appendices

Appendix A: ASPEN Coordination Observations for all Cases

Transformer Connection		DG Size	Comments/Observation	Big Takeaway
Primary	Secondary			
Delta	Grounded Wye	0.5 MW	For 1LG @ DG Facility, the PT took 0.2 sec longer to respond, but feeder and transformer GND responded a little quicker. No difference in 3LG @ DG Facility. For 1LG @ Outside POCC, the DG protection and utility POCC was not sensitive enough to trip…same for 3LG. For 1LG feeder fault, feeder protection took 0.22s MORE to respond and trip...however still coordinated with transformer protection. For 3LG feeder fault, the DG protection tripped for the original case, but was not sensitive enough in this case.	
		1 MW	For 1LG @ DG Facility, feeder recloser took 1.0s longer to respond. For 3LG @ DG Facility and outside POCC, no different than 0.5MW case. For 1LG @ feeder, the phase feeder recloser tripped instead of GND like in 0.5MW case, and much faster. No difference between 0.5MW 3LG fault @ feeder.	
		5 MW	For 1LG @ DG Facility, comparing to 2MW case, DG recloser tripped same, POCC tripping delayed and therefore was only 0.19sec between PT recloser, no longer in coordination…feeder and XFMR recloser tripped a little quicker. For 3LG @ DG Facility, no difference. For 1LG @ outside POCC, DG recloser took ~0.5sec longer to respond but feeder and XFMR reclosers were a little quicker...POCC recloser did not even respond. For 3LG @ outside POCC, DG recloser reacted 0.5 sec quicker and POCC recloser actually reacted, but took a really long time to (15 sec). No significant difference for 1LG @ feeder. For 3LG @ feeder, DG recloser responded ~0.5s quicker...POCC recloser also actually responded, but very late.	
		10 MW	For 1LG @ DG Facility, comparing to 2MW case, POCC and PT recloser tripped a little later, but feeder and XFMR recloser tripped a little quicker….still in coordination. 3LG @ DG facility, no difference. For 3LG @ outside POCC, DG recloser tripped >0.6 sec earlier, POCC recloser also actually tripped @ 5.57sec. For 1LG @ outside POCC, DG recloser tripped 0.10sec later, but feeder and XFMR recloser tripped ~>0.10 sec earlier. For 1LG @ feeder, DG recloser tripped 0.2sec earlier. For 3LG @ feeder, DG recloser tripped 0.6 sec quicker, POCC rec also tripped. For cases where DG recloser is the only device that changes, coordination is not much of a concern.	
Delta	Delta	0.5 MW	For 1LG @ DG Facility, feeder recloser reacted a little quicker…not a significant difference between 2MW case. No changes for 3LG @ DG. For 3LG @ outside POCC, DG recloser does not pick up at all. For 1LG @ outside POCC, DG recloser and POCC do not trip… PT and feeder recloser trip a little quicker. For 1LG @ feeder, DG does not trip and feeder rec trips much later ~0.2sec, XFMR backup trips the same. For 3LG @ feeder, DG rec does not trip, feeder rec trips the same.	DG tends not to trip
		1 MW	For 3LG @ DG Facility, no changes. For 1LG @ DG Facility, there was little variation, but POCC tripped 0.01s earlier, PT tripped 0.02s earlier, feeder tripped 0.05s earlier, and XFMR tripped 0.2s earlier. For 3LG @ outside POCC, although total fault current is more, DG rec did not trip...no other changes. For 1LG @ outside POCC, DG and POCC rec do not trip...PT rec trips 0.02s later and feeder rec trips 0.05s earlier...XFMR rec trips 0.18s earlier. Relays tripping earlier and some tripping later could result in miscoordination, but not of a concern here. For 1LG @ feeder, DG rec does not trip...feeder rec trips much later (~0.22s later). For 3LG @ feeder, DG rec does not trip again.	DG tends not to trip. PT and feeder trip times vary slightly, but no consistent changes.

		5 MW	For 3LG @ feeder, DG trips quicker than with 2MW and POCC also picks up, but very late. For 1LG @ feeder, the feeder rec trips the same, but the DG rec trips 0.11s earlier. For 1LG @ outside POCC, POCC does not trip like it does with 2MW… DG rec trips 0.15s later, feeder rec trips 0.05s earlier, and XFMR rec trips 0.17s earlier. For 3LG @ POCC, DG rec trips much sooner (~0.32s earlier), POCC rec also trips, but very slow. For 3LG @ DG Facility, no changes. For 1LG @ DG Facility, same problem in 1MW case up above.	For 1LG @ outside POCC, POCC does not trip like it did with 2MW case.
		10 MW	For 1LG @ DG Facility, same problem in 1MW case up above, coordination still good. For 3LG @ DG Facility, no changes. For 3LG @ outside POCC, similar as previous cases, DG rec trips much earlier (0.68s), POCC rec also trips at 5.57s. For 1LG @ outside POCC, no consistent changes... PT rec trips a little later while DG rec and feeder rec trip a little earlier, so DG and PT rec trip at basically the same time... XFMR rec trips earlier...coordination is OK if you ignore the DG rec... GND POCC never trips, but phase POCC comes in very late. For 1LG @ feeder, no significant changes... DG rec trips earlier, POCC phase rec actually trips but late. For 3LG @ feeder, DG rec trips even earlier@ 0.43s...POCC phase rec actually trips.	
Wye-Grounded	Delta	0.5 MW	For 3LG @ DG, no changes. For 1LG @ DG, all devices essentially react the same, but DG rec trips about 0.15s later… at about the same time the POCC trips. For 1LG @ outside POCC, small variation… PT trips 0.01s later, DG trips 0.02s earlier, feeder rec trips 0.02s earlier, XFMR rec trips 0.06 sec earlier, and POCC rec trips 0.25s earlier. For 3LG @ outside POCC, no difference except DG rec does not trip. For 3LG @ feeder, DG rec does not trip. For 1LG @ feeder, feeder and DG rec trip about 0.2s later...XFMR rec trips the same.	No significant changes, as expected, other than DG tended to not trip.
		1 MW	For 1LG @ feeder, no significant changes, but feeder and DG rec trip about 0.20s later. For 3LG @ feeder, no significant changes other than the DG rec does not trip. For 1LG @ outside POCC, no significant changes other than the DG rec tripping 0.5s earlier. For 3LG @ outside POCC, no changes other than DG rec not tripping. For 3LG @ DG Facility, no changes. For 1LG @ DG Facility, no significant changes other than XFMR rec responding a little slower.	
		5 MW	For 1LG @ DG, basically no changes, less variation than case above. For 3LG @ DG, no changes. For 1L @ outside of POCC, a lot of variation, nothing consistent…still ok coordination. For 3LG @ outside POCC, DG rec trips ~0.5s earlier and POCC phase rec actually trips, but late. For 1LG @ feeder, DG rec trips ~0.3 sec earlier and POCC phase rec actually trips, but late. For 3LG @ feeder, DG trips a lot earlier (~0.5s earlier) and POCC phase rec actually trips.	DG rec trips earlier and POCC rec trips when it doesn't in the 2MW case.
		10 MW	For 3LG @ feeder, DG trips about 0.6s earlier and POCC phase rec actually trips. For 1LG @ feeder, DG rec trips about 0.37s earlier, POCC phase rec actually trips, and PT rec trips (first case where PT trips for 1LG @ feeder). For 1LG @ outside POCC, instead of DG rec tripping second, DG rec trips before PT rec in this case. For 3LG @ outside POCC, DG trips about 0.6s earlier and POCC phase rec actually trips..feeder and PT trip the same. For 3LG @ DG, no changes. For 1LG @ DG, no significant changes.	PT rec trips for 1LG @ feeder due to significant PV power
Wye-Grounded	Wye-Grounded	0.5 MW	For 1LG @ DG, no significant differences except XFMR rec trips about 0.2s earlier. For 3LG @ DG, no changes. For 1LG @ outside POCC, DG rec took A LOT longer to respond (~10.5s). For 3LG @ outside POCC, no changes by DG rec not tripping. For 1LG and 3LG @ feeder, no changes except DG rec did not trip.	No changes, except DG does not trip
		1 MW	For 3LG @ feeder, no changes except DG rec did not trip. For 1LG @ feeder, DG rec tripped much later at 5s. For 1LG @ outside POCC, POCC did not trip and DG rec tripped ~0.5s later. For 3LG @ outside POCC, no changes except DG rec did not trip. For 3LG @ DG, no changes. For 1LG @ DG, no significant changes.	No changes
		5 MW	For 1LG @ DG, no significant changes. For 3LG @ DG, no changes. For 3LG @ outside POCC, DG rec trips ~0.5s earlier and POCC phase rec actually trips. For 1LG @ outside POCC, DG trips about 0.2s later, otherwise no significant changes. For 1LG @ feeder, DG rec trips about 0.1s earlier. For 3LG @ feeder, DG rec trips about 0.6s earlier, and POCC phase rec actually trips.	No changes

		10 MW	For 3LG @ feeder, DG rec trips about 0.7s earlier and POCC phase rec actually trips. For 1LG @ feeder, DG rec trips about 0.24s earlier and POCC phase rec actually trips, but late. For 1LG @ outside POCC, little variance but no significant changes. For 3LG @ outside POCC, DG trips much sooner (0.7s earlier) and POCC rec actually trips @ 5.57s. For 3LG @ DG, no changes. For 1LG @ DG, no significant changes.	No changes
Delta	Zig-Zag	0.5 MW	For 1LG @ DG, a little variance…POCC and PT rec trip a little slower, but feeder and XFMR rec trip a little faster. For 3LG @ DG, no changes. For 3LG @ outside POCC, DG rec does not trip. For 1LG @ outside POCC, PT rec trips 0.02s later, feeder GND red doesn't trip but its phase rec trips ~0.7s later... XFMR rec trips 0.2s earlier... DC and POCC rec do not trip at all. For 1LG @ feeder, no changes really except DG rec did not trip. For 3LG @ feeder, no changes except DG rec did not trip.	
		1 MW	For 1LG and 3LG @ feeder, no changes except DG rec did not trip. For 1LG @ outside POCC, DG and POCC rec do not trip… PT rec trips about 0.02s later and feeder and XFMR rec trip earlier. For 3LG @ outside POCC, no changes except DG rec does not trip. For 3LG @ DG, no changes. For 1LG @ DG, same situation as the above.	DG tended not to trip
		5 MW	For 1LG @ DG, no changes from the 1MW case except the XFMR rec trips 0.01s earlier. For 3LG @ DG, no changes. For 3LG @ outside POCC, DG trips about ~0.5s sooner and POCC phase rec actually trips, but very late. For 1LG @ outside POCC, GND DG does not trip but phase DG rec trips about 0.15s earlier... POCC rec does not trip. For 1LG @ feeder, the DG trips about 0.1s earlier...no other significant changes. For 3LG @ feeder, the phase DG rec trips about 0.5s earlier and POCC phase rec actually trips.	
		10 MW	For 3LG @ feeder, no significant changes except DG phase rec trips 0.6s earlier. For 1LG @ feeder, DG phase rec trips about 0.16s earlier and POCC phase rec actually trips, but later. For 1LG @ outside POCC, the DG phase rec trips earlier than the PT, the feeder and XFMR rec trip earlier, and the GND POCC did not trip, but the phase POCC did trip, but much later. For 3LG @ outside POCC, the DG phase rec trips about 0.7s earlier and the POCC phase rec trips at 5.57s. For 3LG @ DG, no changes. For 1LG @ DG, no significant changes but feeder rec trips about 0.1s earlier, and XFMR rec trips about 0.2s earlier.	
Wye-Grounded	Zig-Zag	0.5 MW	For 3LG @ feeder, phase feeder rec trips the same, but phase DG rec does not trip at all. For 1LG @ feeder, phase DG rec does not trip…phase feeder rec trips the same, GND XFMR rec trips 0.02s earlier. For 1LG @ outside POCC, phase PT rec trips 0.02s later, GND DG and POCC rec do not trip at all, GND feeder rec trips 0.06s earlier, and GND XFMR rec trips 0.2s earlier. For 3LG @ outside POCC, phase PT and feeder trip the same, but phase DG does not trip at all. For 3LG @ DG, no changes. For 1LG @ DG, phase POCC rec trips 0.01s later, phase PT rec trips 0.02s later, GND feeder rec trips 0.06s earlier, GND XFMR rec trips 0.22s earlier, and GND DG trips the same	Essentially same behavior as case below.
		1 MW	For 1LG @ DG, phase POCC rec trips 0.01s later, phase PT rec trips 0.02s later, GND feeder rec trips 0.06s earlier, GND XFMR rec trips 0.23s earlier, and GND DG trips the same. For 3LG @ DG, no changes. For 3LG @ outside POCC, phase PT and feeder trip the same, but phase DG does not trip at all. For 1LG @ outside POCC, phase PT rec trips 0.02s later, GND DG and POCC rec do not trip at all, GND feeder rec trips 0.06s earlier, and GND XFMR rec trips 0.2s earlier. For 3LG @ DG, no changes. For 1LG @ feeder, phase DG rec does not trip...phase feeder rec trips the same, GND XFMR rec trips 0.02s earlier. For 3LG @ feeder, phase feeder rec trips the same, but phase DG rec does not trip at all.	No significant changes other than DG tended to not trip.
		5 MW	For 3LG @ feeder, phase DG rec trips 0.57s earlier and phase POCC rec actually trips at 16.46s…phase feeder rec trips the same. For 1LG @ feeder, phase DG rec trips 0.03 later and GND XFMR rec trips 0.03s earlier… phase feeder rec trips the same. For 1LG @ outside POCC, phase PT rec trips 0.03 later, GND DG does not trip but phase DG rec does at 0.46s later, GND feeder rec trips 0.3s later, GND XFMR rec trips 0.27s earlier, and GND POCC rec does not trip at all. For 3LG @ outside POCC, phase DG rec trips 0.56s earlier and phase POCC rec actually trips at 15.46s...phase PT and feeder rec trip the same. For 3LG @ DG, no changes. For 1LG @ DG, phase POCC trips 0.02s later, phase PT rec trips 0.03s later, GND feeder rec trips 0.08s earlier, and GND XFMR rec trips 0.03s earlier...GND DG rec trips the same.	For 1LG @ outside POCC, GND DG does not trip, but phase DG does at a later time.

		10 MW	For 1LG @ DG, a little variance.. POCC phase rec trips about 0.02s later, PT phase rec trips 0.04s later, GND feeder rec trips 0.1s earlier and GND XFMR rec trips 0.37s earlier…GND DG rec trips the same. For 3LG @ DG, no changes. For 3LG @ outside POCC, phase DG rec trips about 0.7s earlier and POCC phase rec actually trips at 5.57s... phase PT and phase feeder rec trip the same. For 1LG @ outside POCC, phase PT rec trips 0.04s later, GND DG does not trip but phase DG trips about 0.1s later, GND feeder rec trips 0.09s earlier, GND XFMR rec trips 0.33s earlier, and GND POCC actually does not trip. For 1LG @ feeder, phase DG rec trips 0.2s earlier, GND XFMR trips 0.04s earlier, and phase feeder rec trips the same. For 3LG @ feeder, phase DG rec trips 0.69s earlier and POCC phase rec actually trips at 6.29s... phase feeder rec trips the same.	For 1LG @ outside POCC, GND DG does not trip, but phase DG does at a later time.

Appendix B: ASPEN Overvoltage Observations for all Cases

Transformer Connection		DG Size	With DG Disconnected from Utility (Secondary)			With DG Connected to Utility					
						DG Facility			XFMR Primary		
Primary	Secondary		L-G Voltage (kV)	L-L Voltage (kV)	Seq. Voltage (kV)	L-G Voltage (kV)	L-L Voltage (kV)	Seq. Voltage (kV)	L-G Voltage (kV)	L-L Voltage (kV)	Seq. Voltage (kV)
Delta	Wye-Grounded	1 MW	A: 4.582@-61.4 B: 4.663@-121.4 C: 8.006@88.3	AB: 4.624@-0.5 BC: 12.28@102.5 CA: 12.18@99.3	V+: 5.338@-31.4 V-: 2.669@-152.2 V0: 0.000@0.0	A: 7.999@-29.7 B: 7.792@-148.7 C: 8.016@92.1	AB: 13.61@0.4 BC: 13.64@-117.8 CA: 13.99@121.2	V+: 7.935@-28.7 V-: 0.143@-92.8 V0: 0.000@0.0	A: 39.84@2.0 B: 39.84@-117.8 C: 39.95@122.1	AB: 68.94@32.1 BC: 69.12@-87.8 CA: 69.12@152.0	V+: 39.88@2.1 V-: 0.072@-121.9 V0: 0.000@0.0
Delta	Delta	1 MW	A: 2.670@-0.5 B: 7.086@-102.5 C: 7.035@99.3	AB: 8.073@58.6 BC: 13.87@-91.7 CA: 7.939@118.6	V+: 5.338@-1.4 V-: 2.669@177.8 V0: 0.000@0.0	A: 7.787@-29.4 B: 7.804@-147.7 C: 7.996@91.3	AB: 13.38@1.5 BC: 13.75@-117.8 CA: 13.72@120.5	V+: 7.862@-28.6 V-: 0.135@-153.0 V0: 0.000@0.0	A: 39.77@2.1 B: 39.88@-117.8 C: 39.87@122.0	AB: 68.95@32.2 BC: 69.12@-87.9 CA: 68.94@152.0	V+: 39.84@2.1 V-: 0.068@177.9 V0: 0.000@0.0
Wye-Grounded	Delta	1 MW	A: 4.661@58.6 B: 8.006@-91.7 C: 4.584@118.6	AB: 12.27@77.5 BC: 12.19@-80.7 CA: 4.624@179.5	V+: 5.338@28.6 V-: 2.66@147.8 V0: 0.000@-0.5	A: 7.662@-28.7 B: 7.865@-148.0 C: 7.841@90.4	AB: 13.40@2.1 BC: 13.71@118.9 CA: 13.36@120.5	V+: 7.789@-28.8 V-: 0.128@144.9 V0: 0.000@-94.0	A: 39.78@2.2 B: 39.87@-117.9 C: 39.76@122.0	AB: 69.01@32.2 BC: 68.98@-88.0 CA: 68.83@152.1	V+: 39.80@2.1 V-: 0.064@115.8 V0: 0.000@0.0
Wye-Grounded	Wye-Grounded	1 MW	A: 2.830@-0.5 B: 7.056@-101.2 C: 7.008@98.0	AB: 8.077@58.6 BC: 13.87@-91.7 CA: 7.935@118.6	V+: 5.338@-1.4 V-: 2.669@177.8 V0: 0.169@-0.5	A: 7.786@-29.4 B: 7.804@-147.7 C: 7.997@91.3	AB: 13.38@1.5 BC: 13.75@-117.8 CA: 13.72@120.5	V+: 7.862@-28.6 V-: 0.135@-153.0 V0: 0.000@0.0	A: 39.77@2.1 B: 39.88@-117.8 C: 39.87@122.0	AB: 68.95@32.2 BC: 69.12@-87.9 CA: 68.94@152.0	V+: 39.84@2.1 V-: 0.068@177.9 V0: 0.000@0.0
Delta	Zig-Zag	1 MW	A: 2.670@-0.5 B: 7.087@-102.5 C: 7.034@99.3	AB: 8.077@58.6 BC: 13.87@-91.7 CA: 7.935@118.6	V+: 5.338@-1.4 V-: 2.669@177.8 V0: 0.000@0.0	A: 7.786@-29.4 B: 7.805@-147.7 C: 7.996@91.3	AB: 13.38@1.5 BC: 13.75@-117.8 CA: 13.72@120.5	V+: 7.862@-28.6 V-: 0.135@-153.0 V0: 0.000@0.0	A: 39.77@2.1 B: 39.88@-117.8 C: 39.87@122.0	AB: 68.95@32.2 BC: 69.12@-87.9 CA: 68.94@152.0	V+: 39.84@2.1 V-: 0068@177.9 V0: 0.000@0.0

Wye-Grounded	Zig-Zag	1 MW	A: 4.581@-61.4 B: 4.663@-121.4 C: 8.006@88.3	AB: 4.624@-0.5 BC: 12.28@-102.5 CA: 12.18@99.3	V+: 5.338@-31.4 V-: 2.669@-152.2 V0: 0.000@0.0	A: 7.999@-29.7 B: 7.792@-148.7 C: 8.016@92.1	AB: 13.61@0.4 BC: 13.64@-117.8 CA: 13.99@121.2	V+: 7.935@-28.7 V-: -.143@-92.8 V0: 0.000@0.0	A: 39.84@2.0 B: 39.84@-117.8 C: 39.95@122.1	AB: 68.94@32.1 BC: 69.14@-87.8 CA: 69.12@152.0	V+: 39.88@2.1 V-: 0.072@-121.9 V0: 0.000@0.0