EVALUATION OF PHOTOVOLTAIC DISTRIBUTED GENERATION ON THE VOLTAGE PROFILE OF DISTRIBUTION FEEDERS

by

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ABSTRACT

Distributed Generation (DG) is the term given to electric power generation systems of limited capacity operating in parallel with distribution circuits. Interest in DG has increased recently due to diverse factors. The interconnection of photovoltaic (PV) systems in particular has seen great advancements, and it is projected that the growth in PV DG capacity will continue. DG can provide benefits to customers and utilities, and their interconnection must be done carefully to maximize the benefits while not causing problems to the distribution circuits. Voltage rise, voltage fluctuations due to variations in the output of DGs and interruption of voltage regulation equipment are some of the issues that can surface with increasing penetration of DG in distribution networks. This project analyzes how variations in the point of interconnection and capacity of PV DG affect the voltage profile and losses in the feeder to which the system interconnects. Several feeder configurations, DG locations and penetration capacities are combined to establish which combination maximizes the voltage profile and minimizes the losses on the system. The interactions between a voltage regulator and DG are also analyzed.

RESUMEN

La interconexión de generadores con el sistema de distribución eléctrica se conoce como Generación Distribuida, o GD. Recientemente, el interés en GD ha aumentado debido a diversos factores. Los sistemas fotovoltaicos (PV) en particular han visto avances significativos, y se espera que el crecimiento en el número de éstos continúe creciendo. Los GD pueden proveer beneficios para los clientes y las compañías de electricidad, y su interconexión debe realizarse cuidadosamente para maximizar los beneficios sin causar problemas a los circuitos de distribución. Aumentos en voltaje, fluctuaciones de voltaje debido a cambios súbitos en la potencia de salida de los GD, y la interrupción de la operación de equipos de regulación de voltaje son algunos de los problemas que pueden surgir al aumentar la penetración de estos sistemas. Este proyecto analiza como variaciones en el punto de interconexión y capacidad de GD afecta el perfil del voltaje y las pérdidas en un alimentador. Varias configuraciones de alimentador y GD se evalúan para determinar cuáles maximizan el voltaje y minimizan las pérdidas. También se evalúan, en régimen permanente, las interacciones entre un regulador de voltaje y los sistemas de GD.

To my family . . .

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TABLE OF CONTENTS

Table List

Tables **Page**

Figure List

Figures **Page**

List of Abbreviations

DG	Distributed Generator, Distributed Generation
EPAct 05	Energy Policy Act of 2005
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
LTC	Load Tap Changer
LDC	Line Drop Compensation
MPPT	Maximum Power Point Tracking
PCC	Point of Common Coupling
PV	Photovoltaic
PV DG	Photovoltaic Distributed Generation
RPS	Renewable Portfolio Standard
REC	Renewable Energy Certificate

1 INTRODUCTION

1.1 Justification

Interest in Distributed Generation has increased due to factors such as improvements in technology, a desire for greater reliability in electricity supply, concerns on stability of fuel supplies and the negative environmental effects of burning fossil fuels. These issues, coupled with government sponsored programs that give incentives for the implementation of Distributed Generation technologies, particularly those that use renewable energy resources, have led to an increase in interconnection of these systems to utility distribution feeders. Distributed Generation can provide certain benefits to distribution feeders, such as loss reduction and voltage profile improvement. However, the radial nature of distribution feeders also leads to problems regarding voltage regulation when a large amount of DG capacity, relative to feeder capacity and loading, is installed on a feeder. The greatest hurdle to large scale integration of DG to distribution feeders is considered to be the negative effects these systems can have on voltage regulation and its associated equipment.

In present day Puerto Rico, increasing emphasis is being given to Distributed Generation as a way of offsetting the negative effects associated with the use of fossil fuels and as a tool to help diversify energy sources to curb our current reliance on oil for electricity generation and help lower energy costs. Both federal and local measures, such as rebate programs, tax incentives, interconnection standards, and net metering and wheeling rules have been enacted in recent years and serve as the main drivers to the growth of these systems on the island. To serve as an example, in just a couple of years the number and capacity of installed photovoltaic systems in the island has grown from tens of systems with capacities usually in the couple of kilowatts to hundreds of systems, some with capacities in the hundreds of kilowatts to several megawatts. Taking this into consideration, it is important to recognize that due to the physical issues associated with the integration of Distributed Generation into distribution feeders, proper understanding of the effects these that interconnections have on the local distribution system is critical in order to provide adequate interconnection guides more tailored to our reality and thus allow for proper growth of such technologies in the island.

This project seeks to examine several ways in which DG can affect voltage regulation on distribution feeders with configurations similar to those found in Puerto Rico. In particular, it will look at how DGs can interact with a voltage regulator, the effects of sudden disconnections and reconnections of DGs on the voltage profile of feeders with and without voltage regulators, and the effects DG size and position have on feeder losses and voltage profile.

1.2 Objectives

The main objective of this project is to evaluate the benefits of interconnecting Distributed Generation resources with varying or intermittent power output, particularly on the voltage profile and losses of feeders with characteristics similar to those found in the island of Puerto Rico. Specifically, the evaluation will focus on inverter-based photovoltaic systems, since a large proliferation of such systems has been seen in recent years and is expected to continue. The evaluation will include factors such as the voltage level and conductor types of the feeder and the presence or absence of voltage regulators. In all cases, the capacity and location of the DG system will be varied to observe the effects on the voltage profile and feeder losses. Also, the cases will be evaluated at heavy and light loading. The project will include the following specific objectives:

- Identify the combinations of DG location and penetration level that provide the most benefits in terms of improving the voltage profile of the feeder and reducing losses.
- Identify potential penetration levels where DGs can affect voltage profile for the selected feeder configurations under heavy and light load and peak PV system output.
- Evaluate how DGs can affect voltage profiles when voltage regulators are present on the feeder.
- Evaluate the effect of sudden DG power output changes, due to variation of energy source (solar irradiation) and disconnections and reconnections due to faults on the system, on voltage profile in the presence of voltage regulators.

1.3 Summary of Following Chapters

A basic introduction into the concept of Distributed Generation, including a discussion of the current interconnection standards and the impacts of DG in distribution systems is presented Chapter 2. A discussion of the concepts of feeder voltage regulation practices, general PV system characteristics and their interactions with voltage regulation is presented in Chapter 3. Chapter 4 describes the simulation software and circuit models used to evaluate the interactions between the DG and the voltage profile and losses in the distribution feeder. It includes a discussion of the seven simulation scenarios evaluated and the result of the simulations. Chapter 5 presents the conclusion, recommendations and future work.

2 DISTRIBUTED GENERATION

Distributed Generation, or DG, is the term given to electric power generation systems of limited capacity interconnected to and operating in parallel with the electric power distribution system [1]. Generally, it is recognized that the capacity of these systems does not exceed 10 MW [2].

The first major surge of interest in DG began in the late 1970's, brought about by the rapid increase in fuel prices caused by the oil crisis, the belief that oil supplies had reached their peak, maturing technologies and, in the United States, the enactment of the Public Utilities Regulatory Policies Act of 1978 (PURPA), which required utilities to allow the interconnection of DG to their systems and also provided tax incentives [3]. Interest in DG declined in the mid-1980s due in part to the expiration of the tax credits and reduction in the price of fuel. DG again gained momentum during the early 1990s due to an increase in the prices of electricity, and again subsided after the operating cost of DG rose, mainly due to increases in fuel prices. Finally, in the early 2000s, an increased awareness with global climate change, generally accepted as being caused by pollution from the use of fossil fuels, coupled with increases in the price of fuels such as oil and natural gas, and incentive programs such as net metering, tax credits, and rebates, revived interest in the use of DG, especially on those systems that use renewable energy sources [2]. Recently, the Energy Policy Act of 2005 (EPAct 05) required utilities to evaluate the implementation of five standards, among which were an interconnection standard and net metering standard, and to make their decision public by August of 2007 and August of 2008, respectively [4], [5].

Net Metering programs, incentive programs such as tax credits or rebates, and standardized interconnection procedures have had a strong influence in the recent growth of PV systems in the United States and Puerto Rico. Under Net Metering, the owner of the DG system is able to export power back to the grid during periods in which its DG system is producing more energy than needed by its loads. When the utility bills the customer, it uses the energy exported by the customer to offset its energy consumption. In this scheme, the customer does not need to install energy storage and receives full retail value for the energy it exports to the grid, improving the economics of the DG system. In other incentive programs, the government will give a tax credit or rebate to the customer based on the total cost of the installed system. In this way the cost of ownership of the system is effectively reduced. When coupled with Net Metering, these programs can considerably reduce the payback period of the investment needed to install and operate the system, raising the value of DG and making it more attractive to consumers. It is projected that the aggregate photovoltaic (PV) capacity installed in the US will reach 24 GW by 2015, due in great part to the incentive programs adopted by the states [6].

2.1 Incentives for Distributed Generation in Puerto Rico

In Puerto Rico, several measures have been implemented that have led to a rapid increase in the number of DG systems installed, particularly of grid interconnected PV systems (PV DG). In 2007, Act 114 established a Net Metering program, available from August 2008 onwards, for electricity customers that use on-site DG systems based on renewable energy sources [7]. The act established limits of 25 kW for residential customers and 1 MW for other customer classes including commercial, industrial and agricultural customers. It also established a cap on the daily energy exported to the grid that would qualify for Net Metering, setting the residential limit at 300 kWh per day and at 10 MWh for other customer classes. Besides the caps on capacity and daily energy export, the Act established that at the end of each fiscal year, any credits accrued by the customer from energy exported and not used to compensate for consumption would be paid by the utility at a rate of 10 cents per kWh, 75 per cent of which would go to the customer and the remaining 25 percent would be granted to the local Department of Education.

In 2008 several initiatives gave a big boost to the introduction of renewable DG in Puerto Rico, in particular to PV systems. The local utility published interconnection and Net Metering regulations in accordance with EPAct 05 and Act 114. Also, Act 248 was established, which granted tax credits for persons or corporations that installed PV systems on-site. The tax credits would stand at 75 per cent of total system cost for the first two years after its enactment, 50 per cent on years three and four, and 25 per cent afterwards [8].

In 2010, two important laws relating to renewable energy systems in Puerto Rico were signed. Act 82 of July 2010, also known as the Puerto Rico Energy Diversification through Sustainable and Alternative Renewable Energy Policy Act, established a Renewable Portfolio Standard (RPS) for Puerto Rico [9]. It sets a target of 12 per cent of energy production using renewable energy sources by 2015, which increases to 20 per cent by 2035. It also creates a Renewable Energy Commission which will be the entity that will oversee the implementation of the RPS. Also in July of 2010 Act 83, known as the "Green Energy Incentive Act", was enacted [10]. This act supersedes previous acts, including Act 248, and establishes a Green Energy Fund used to promote renewable energy projects in Puerto Rico. Qualifying projects are granted a rebate based on the technology used and the capacity of the system. For example, for small scale residential or commercial projects, those using PV or small wind turbines with a capacity less than 100 kW, the act provides a rebate of 50 per cent of total eligible project cost. The act also provides tax benefits to entities dedicated to the production of renewable energy on a commercial scale and introduces the concept of Renewable Energy Certificates, or RECs, to Puerto Rico. RECs are credits given for every megawatt hour of energy produced using renewable energy sources. These credits can be bought, sold or transferred between individuals and increase the value of the renewable energy system. It is expected that these measures will increase the local adoption of renewable energy systems, particularly of PV and wind turbine systems.

2.2 Distributed Generation Technologies

When contemplating the interconnection of generation to the distribution system, careful consideration must be given to the interactions between the generating systems and the grid. There are three main types of electrical power converters used in DG applications: synchronous generators, asynchronous (or induction) generators, and static inverters. The interactions between the DG and the grid are influenced by the type of converter used, due in part to different mechanical and electrical characteristics and time constants of controllers. Electronic inverters, often referred to as power conditioning systems, can be fed from rotating sources such as combustion or wind turbines, or from DC sources such as photovoltaic cells, fuel cells, batteries or capacitors. They convert the time-varying AC source or DC source power to synchronous AC power. This synchronous AC power can then be fed to AC loads or exported back to the grid [11]. Synchronous generators can either absorb or supply reactive power (VAR). Induction generators absorb reactive power. Inverter-based DGs may, depending on the model, absorb or supply reactive power to a limited extent [12].

The use of DG can provide advantages to both users and utilities. These systems can operate interconnected with the utility and some have the capability to serve as a backup power source upon loss of service. The efficiency of some DG systems, particularly of those that produce heat as well as electricity, can be increased if used in combined heating, cooling and power (CHP or CCHP) applications. DGs can also provide peak load shaving, where the DG serves part of the load of the customer and serves to reduce peak energy demand from the utility [13]. DGs can also benefit utilities. They can be located along a feeder to reduce peak load, or at a substation to provide relief to the substation transformer or transmission system during periods peak load. This can lead to transmission or distribution facility deferrals. DGs can reduce primary and secondary system losses by supplying power close to loads. They can improve the voltage profile by producing or absorbing VARS and reducing voltage drop on the distribution lines [14],[15]. Systems that use renewable energy sources can displace generation based on fossil fuels, greatly reducing or eliminating harmful emissions [16]. However, it is important to carefully consider the characteristics and behavior of the distribution system and DG resource to ensure reliability and power quality.

2.3 Interconnection Standards – IEEE 1547 Series of Standards

To understand how DGs interact with the utility grid, in particular with the steady state voltage regulation and losses on the distribution system, which is part of the scope of this project, it is necessary to understand how these systems operate in parallel with the grid. Manufacturers design PV inverters and other DG interface equipment to meet criteria that are contained in industry adopted standards. These specifications deal with the performance, mode of operation, and power quality of these systems.

The most relevant standard for the interconnection of DG to the grid in the United States, including Puerto Rico, is IEEE Std. 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems [17]. This standard is the first of a series of standards that deal with the interconnection of distributed resources. It is based on, and replaces, IEEE Std. 929-2000, IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems [18]. It also incorporates practices included in IEEE Std. 1001-1988, Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems. Since the adoption of this standard in 2003, three other standards in the series have been adopted:

- IEEE Std. 1547.1-2005 IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems
- IEEE Std. 1547.2-2008 IEEE Application Guide for IEEE Std. 1547, IEEE Standard for Interconnecting Distributed Resources with Electrical Power Systems
- IEEE Std. 1547.3-2007 IEEE Guide for Monitoring Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

The purpose of this series of standards is to provide a uniform set of rules on how DG technologies must interconnect with the grid, and thus provide the "minimum functional technical requirements that are universally needed to help assure a technically sound interconnection" [17]. IEEE Std. 1547-2003 does not focus on any technology in particular, and neither does it address impact studies, mitigation of the limitations of the area electrical power system, of tariff issues. Limited information on these was included in IEEE Std. 1547.2-2008. The requirements contained in the standard include performance, operation, testing safety and maintenance considerations, and the limits imposed by it must be met on the point of common coupling (PCC) [17]. The standard contains requirements that can affect the steady state voltage profile and voltage regulation on a feeder:

•Section 4.1.1 Voltage Regulation states that the DG cannot "actively regulate" the voltage at the PCC and cannot cause the voltages of the local distribution system to stray outside the limits established in ANSI C84.1-2006 Range A. A DG that attempts to regulate the voltage without proper coordination with utility voltage regulating equipment or other DGs could disrupt proper voltage operation. It is generally accepted that this requirement limits DG to operate mainly in a constant power factor mode, simply following the voltage at its interconnection point. However, IEEE 1547.2-2008 distinguishes between voltage regulation and absorption or delivery of reactive power by stating that IEEE 1547-2003 does not prohibit this [11].

•Section 4.1.2 Integration with Area EPS Grounding states that grounding of the DG shall not cause overvoltages that exceed the voltage ratings of any equipment connected to the local distribution system.

•Section 4.1.3 Synchronization states that the DG shall not cause a voltage fluctuation greater than $\pm$ 5 per cent at the PCC when paralleling with the utility.

•Section 4.2.1 Area EPS Faults indicates that when a fault occurs on the distribution system, the DG must disconnect to ensure safety and prevent damage to equipment.

•Sections 4.2.3 Voltage and 4.2.4 Frequency state that the DG must disconnect when the measured voltage or frequency meets a given criteria, reproduced here in Table 2.1 and Table 2.2. This is done to detect faults on the distribution system or possible island conditions. Note that the standard permits fixed set points for DG of 30 kW or less and field adjustable set points for DG greater than 30 kW. However, it does not specify how DGs composed of multiple smaller units but with aggregate capacity greater than 30 kW can meet these criteria.

Table 2.1 IEEE Std. 1547-2003 Voltage Trip Limits

Voltage range (% of base voltage)	Clearing time (s)
$V<50$	0.16
$50 \leq V < 88$	2.00
$110 < V < 120$	1.00
$V \geq 120$	0.16

Table 2.2 IEEE Std. 1547-2003 Frequency Trip Limits

Voltage range (% of base voltage)	Frequency range (Hz)	Clearing time (s)
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< {59.8 – 57.0} (adjustable set point)	Adjustable 0.16 to 300
	< 57.0	0.16

•Section 4.2.6 Reconnection to Area EPS establishes that the DGs can reconnect when normal voltage and frequency ranges have been restored and remain within limits for a predetermined time that can be up to five minutes.

All these requirements affect how the DGs interact with the utility grid and in some cases can affect the voltage at the PCC and along the feeder.

The interconnection standard to be considered by utilities under EPAct 05 stated that utilities had to incorporate IEEE Std. 1547-2003 into their interconnection practices. Since the interconnection standard adopted by the local utility in Puerto Rico was drafted in response to EPAct 05, it adopts the requirements established in IEEE Std. 1547-2003 and subsequent standards under this series.

2.4 DG Impacts in Distribution Circuits

Traditionally, distribution circuits are not designed to integrate large quantities of Distributed Generation. The interconnection of DG, if not properly evaluated, can potentially lead to problems in feeders. Four areas have been identified as being affected by DG: voltage regulation, overcurrent protection, grounding and service restoration [19]. A comprehensive 2008 study on DG sponsored by the United States Department of Energy (DOE), focusing primarily on PV systems, concludes that "grid integration issues are likely to emerge much more rapidly than many analysts expect" [6].

One of the first impacts of higher penetration of DG will be on voltage regulation. Voltage regulation can be affected because DGs can, under certain conditions, cause reverse power flows along the feeders they are connected to [20]. These reverse power flows affect the feeder voltage profile by changing the real and reactive power flows along its segments, and the effects are most noticeable when the DG exports both real and reactive power [21], [22]. Voltage regulating equipment, particularly voltage regulators, may not handle effectively these reverse power flows caused by DGs. Voltage regulation can also be affected by rapid fluctuations in the output of DGs or their disconnection and reconnection following system faults. The impact of DG on the feeder voltage profile depends on factors such as the size and location of the DGs, the presence of voltage regulating equipment and their operating mode, the impedance of the system and the operating mode of the DG [23], [24]. The penetration level at which such impacts will cause problems will vary depending on factors such as feeder layout, load profile and behavior, DG capacity and distribution [25]. DGs are often not allowed to regulate voltage because they usually do not have enough capacity to regulate the voltage, can compete with other DGs or voltage regulators, and can lead to islanding [26]. It is generally accepted that voltage problems can arise if the DG penetration is high with regards of the feeder capacity. Some researchers have concluded that probably the biggest technical hurdle to high levels of DG penetration in distribution systems is the issue of voltage regulation and control [27].

The installation of DGs, particularly those that use renewable energy sources such as the sun and wind, can cause voltage variations due to fluctuations on their power output, voltage rise due to the change in real and reactive power flows, and improper operation of voltage regulation equipment that can result in both overvoltages and undervoltages [28],[29]. To properly understand the interactions between PV DG and feeder voltage it is necessary to understand the basic concepts of voltage regulation and of PV system operation.

3 DISTRIBUTION SYSTEM VOLTAGE REGULATION AND PV DG SYSTEMS

In classical distribution systems, power is delivered from the substation, through distribution feeders, to the end users connected along a particular feeder. The flow of current through the distribution circuit will result in voltage drop and losses due to the impedance of the conductors. Distributed generation can help improve the voltage profile along a feeder and reduce losses. By feeding their local load and exporting power to the grid, DGs can reduce the flow of power from the substation, reducing voltage drop and losses through the feeder. Optimal placement of DGs is necessary to improve voltage regulation and maximize loss reduction [30].

3.1 Voltage Drop and Line Losses

From basic circuit theory we know that the cables used along a feeder are not perfect conductors – they resist the flow of current passing through them. The quantity that describes that opposition to current flow is aptly named resistance. We also learned, through Ohm's Law, that when a current flows through a resistance a voltage drop occurs between the input and output terminals of that resistance, and the relationship is given by Ohm's Law as:

$$\boldsymbol{V = I * R\ volts} \qquad \textbf{3.1}$$

Where *V* is the voltage across the element, *I* is the current flowing through it, and *R* is its resistance, measured in ohms (Ω) [31]. When referring to the voltage across a cable used to serve a load from a source, we refer to it as voltage drop, since the load now sees a voltage that is lower than the source voltage due to the current passing through the cable and its resistance. The importance of this is discussed below. In AC power systems the voltage and current are periodic functions of sinusoidal form, and can be represented by phasors:

$$\boldsymbol{V} = \boldsymbol{V} < \theta \ (V) \quad \textbf{3.2}$$

$$\boldsymbol{I} = \boldsymbol{I} < \phi \ (A) \quad \textbf{3.3}$$

where V and I are the voltage and current magnitude and θ and φ are their respective phase angles. The voltage and current can also be expressed as the sum of their real and imaginary components. The element's opposition to current flow is also a complex quantity known as impedance, given by its phasor:

$$\boldsymbol{Z} = \boldsymbol{R} + \boldsymbol{jX} \ (\Omega) \quad \textbf{3.4}$$

which is composed of a real part, the resistance (R) and an imaginary part, the reactance (X). From this, the voltage drop can be computed as:

$$\boldsymbol{V_{drop}} = (\boldsymbol{I_{real}} \cdot \boldsymbol{R}) + \boldsymbol{j}(\boldsymbol{I_{imag}} \cdot \boldsymbol{X}) \ \boldsymbol{volts} \quad \textbf{3.5}$$

The impedance of a given conductor depends on its material and geometry, its operating temperature, and its arrangement regarding other conductors and ground. The voltage drop depends on the conductor's impedance and the current flowing through it. These relationships show us that on circuits with high power factor, and thus a large component of active current, the voltage drop depends mainly on the resistance of the circuit. On circuits with low power factor and thus a large component of reactive current, the voltage drop depends mainly on the reactance of the circuit.

Electric and electronic devices are designed to work within a specific voltage range given by its voltage ratings. If equipment are subjected to voltages outside their designed operating voltage range, they can malfunction or get damaged, and even result in a safety hazard [30]. For this reason utilities try to maintain the voltage along a feeder within a specific range, to ensure that all customers are served with adequate voltage levels. These voltage levels are often specified by standards adopted by the industry. In the United States, many utilities and state regulatory bodies have adopted ANSI standard C84.1-2006 [11]. This standard defines the voltage limits at the point of delivery of power from the utility, known as service voltage, and at the equipment terminals, known as utilization voltage. Utilities are responsible to maintain the voltage within the specified service voltage range, and the customer is responsible to maintain utilization voltage within the given range. ANSI C84.1-2006 establishes three voltage classes: low voltage (up to 1 kV), medium voltage (greater than 1 kV up to 100 kV) and high voltage (greater than 100 kV). It also defines two voltage ranges. Range A is the voltage range that must be present under normal operation. Range B is the voltage range for operation under abnormal conditions, provided that these abnormal operating conditions are infrequent and that measures are taken to correct them. For low voltage systems, Range A limits service voltage to $\pm$ 5 per cent of nominal and utilization voltage to -8.3 to + 4.2 per cent of nominal voltage. Range B limits service voltage at -8.3 to +4.2 per cent and utilization voltage at -11.7 to +5.8 per cent. [30].

From the preceding we can see that a voltage drop will occur along a feeder, and that this voltage drop is proportional to the load current and increases as distance from the substation increases. Voltage drop and line losses are higher in circuits energized at lower voltages (since it takes a higher current to serve a given load), low power factor, unbalanced loads and single phase sections [1]. Utilities must maintain the voltage along a feeder above minimum voltage levels during peak loading, and below maximum voltage levels during light loading [32]. To maintain proper voltage regulation along a feeder, utilities employ equipment designed to regulate the voltage. These devices include the on load tap changer at the distribution substation transformer, voltage regulators at the feeders, and capacitor banks along the feeder. The extent of the use of these devices depends on the voltage drop on the circuits, which is influenced by factors such as voltage level, minimum and maximum load, power factor, conductor size, circuit length, and load unbalance.

Voltage unbalance is another important feature that can affect the voltage profile of a feeder. Single phase loads are a predominant part of the load connected to feeders. The unbalanced distribution of these loads can cause unbalanced voltage drops that will lead to unbalanced voltages along the feeder. Some three phase loads, such as motors, can malfunction or cease to operate with voltage unbalances of as little as 2.5 to 3 per cent [11].

Line losses are another consequence of the current flowing through impedances in the conductors [33]. Line losses can be computed as the product of the square of the current times the resistance of the component, and are frequently referred to as I^2R losses. Line losses are greatest in circuits with lower voltages, smaller conductors with high impedance, and unbalanced loads. These losses are undesirable because they lower system efficiencies and represent power that must be generated but does not accomplish any useful work. Thus, utilities try to minimize losses whenever possible.

Voltage drop and line losses can be reduced by several methods. The current through the feeder is proportional to the load (power) and inversely proportional to the voltage. Utilities can carry out voltage conversion to a higher voltage, which reduces the current and thus the voltage drop and losses along a feeder. However, this method is costly and very time consuming since it may require changing distribution transformers or clearances and isolation equipment along a feeder. Changing the mainline conductors to larger conductors with reduced the impedance can be used on circuits with heavily loaded conductors, but this is also costly and time consuming, and on some instances the circuits can already be using the highest rated conductors available. Typically, voltage regulation equipment and practices are used to maintain a proper voltage profile along the feeder [1]. Balancing loads and converting single and two phase sections to three phase sections can help reduce voltage unbalance.

3.2 Voltage Regulation Equipment

Utilities use voltage regulation equipment to maintain the voltage profile along feeders within the limits established in their respective jurisdictions [34]. It is important to understand the characteristics of these equipment and how they are employed in typical feeder configurations.

3.2.1 Transformer Load Tap Changer

Transformers equipped with an on load tap changer (OLTC or simply LTC) are able to change taps while loaded, enabling the transformer to vary its turn ratio and adjust the voltage at its secondary terminals [16]. The LTC control measures the substation distribution bus voltage and operates the tap changer to maintain proper regulation along the feeders. Since the voltage drops as distance from the substation increases, the LTC controls are set to maintain the bus voltage at the highest permitted range to allow proper voltage regulation even for the most distant customers while preventing overvoltage to those customers located close to the substation. LTCs usually have 32 taps and are able to regulate the voltage to ± 10 per cent of nominal.

3.2.2 Voltage Regulator

Voltage regulators, also referred to as step voltage regulators, are installed on feeders where the regulation provided by the LTC or reactive compensation is not enough to maintain proper voltage regulation along the feeder. They are typically used in distribution feeders with low primary voltage and/or lower capacity conductors, where the voltage drop is higher, or on long or heavily loaded feeders. They are also installed in substations to regulate the voltage when the substation transformer is not equipped with a LTC [22]. When installed on a feeder, they are typically placed at a location where the voltage falls to 0.95 p.u. during heavy loading. A voltage regulator is basically an autotransformer with adjustable taps that allow it to adjust its voltage within a specified range [35]. Typical voltage regulators are built with 32 taps that allow them to adjust the source voltage by ± 10 per cent. This gives a 5/8 per cent voltage step for each tap, which equals 0.75 V on a 120 V base. Regulators that are built with the taps on the load side are known as straight regulators, or ANSI Type A, while those built with their taps on the source side are known as inverted regulators, or ANSI Type B.

Voltage regulators can be single phase or three phase. Single phase regulators can be connected in several configurations including line to neutral, delta or open delta. Line to neutral connected regulators can regulate the voltage in each phase independently. Three-phase regulators can be connected wye or delta, but they regulate the voltage on all three phases simultaneously. The regulator control monitors one phase and adjusts all three phases based on the loading of that phase. The controls have three main settings that must be programmed. The set voltage, or band center, is the desired voltage that the regulator must try to maintain at its output. The second important value is the bandwidth. When the difference between the measured voltage and the set voltage exceeds half the bandwidth, a change of tap is initiated. The third important quantity is the time delay, which is the time that must pass between the moment when the measured voltage exceed the half-bandwidth criteria and the moment the regulator changes taps. Typical values of bandwidth and time delay are two times the step size (typically 1.5 V on a 120 V base) and 30 seconds to one minute, respectively [1].

Regulators can be programmed to maintain the voltage at their secondary side at a desired range. They may also incorporate what is known as line drop compensation, or LDC [36]. Under this mode, the controller measures the line current and regulator voltage, and takes into account the line impedance (R and X parameters) downstream to estimate the voltage drop and adjust the voltage appropriately. This provides greatest voltage increase during heavy load, when voltage drop is greatest and less voltage increase during light load, when voltage drop is less of a problem [35]. There are two main methods of LDC. One method is load center compensation, where the control operates to maintain the voltage on a predetermined load bus downstream, and the line R and X parameters are those between the regulator and the bus. The other method is voltage spread compensation, which uses the R and X parameters to maintain the voltage downstream of the regulator within a specified range. Since the configuration of the feeder changes over time, utilities do not always use LDC. When it is used, voltage spread compensation is the mode typically chosen.

3.2.3 Capacitor Bank

Capacitors banks are placed on distribution feeders to raise power factor and improve the voltage profile [37]. They reduce the reactive component of the current that is fed from the substation, lowering the current along the feeder and thus reducing voltage drop. They can be fixed or switched. When properly applied, capacitors reduce the magnitude of the current supplied from the substation, and they change the voltage profile upstream of the bank. If capacitors are not located properly, they can increase losses and create high voltages [38]. They do not interfere with voltage regulators when placed upstream of them. However, when placed downstream of a voltage regulator equipped with LDC, they may interfere with the control because it reduces the current the regulator sees.

3.2.4 Distribution Transformers

Although not typically listed as voltage regulation equipment, distribution transformers, used to change the voltage from primary distribution voltage to secondary distribution voltage, may provide a useful feature that can adjust the secondary voltage received by a customer. These transformers are usually not equipped with automatic tap changers. Instead, they may be provided with manual off-load tap changers to adjust the turns ratio and thus raise or lower the secondary voltage. They are used to maintain the customer's voltage within limits under light load and full load. Thus, if a customer is located on a part of a feeder that may be subjected to undervoltages, the tap ratio can be adjusted to increase the voltage and mitigate any undervoltage. However, in practice it is unusual for the tap changer to be changed from the position initially established when the transformer was installed [39].

3.3 Photovoltaic Systems

To properly understand how utility-interactive PV systems affect the voltage profile and voltage regulation on distribution feeders it is necessary to understand the composition and behavior of these systems. Photovoltaic systems convert energy from the sun into electrical energy that is used to power electrical loads. PV systems are basically composed of the PV module array, the inverter or inverters used to convert the DC power from the array to AC power to feed loads and export to the grid, and other electric equipment such as cables, junction boxes, fuses and circuit breakers, and monitoring equipment. Energy storage in the form of batteries and associated equipment is sometimes incorporated.

The fundamental component of a PV system is the PV module, which in turn is composed of PV cells. These are constructed using semiconductors that produce a characteristic voltage and current when exposed to light. The voltage and current produced by the cells depends on the material used in their elaboration. The most widely used semiconductor material is silicon (Si), which is doped with a variety of elements to create either a p-type semiconductor, which has electron voids, or a n-type semiconductor, which has free electrons [40]. The most common Si cells are crystalline silicon cells, typically referred to as c-Si cells. Depending on the fabrication method used, these can be made from either monocrystalline silicon or polycrystalline silicon. PV cells are constructed as thin wafers with an n-type layer covering a p-type layer, thereby creating a p-n junction. When the PV cell is exposed to light, photons will transfer their energy to electrons in the semiconductor materials, which then move around leaving holes. Due to an electrical field established at the p-n junction, electrons will migrate to the top of the n-type material while holes will collect at the bottom of the p-type material. When the top and bottom layers of the cells are connected electrically, the electrons will flow from the n-type material to combine with the holes in the p-type material, thus producing a current. The accumulation of electrons and holes in the top and bottom part of the cell will in turn produce a voltage. The open circuit voltage produced by crystalline Si cells is usually 0.6 V to 0.7 V, while the current depends on the cell area.

The PV cells are arranged into series parallel combinations inside the PV module which results a characteristic voltage and current. Cells will be connected in series to increase the voltage while combinations of cells in series will then be connected in parallel to increase the current. The electrical performance of a PV module is described by its current-voltage characteristic (I-V), which can be plotted as function of voltage and current, for a given cell temperature and irradiance. The curve intercepts the current axis when the voltage is zero, and the resulting current is known as the short-circuit current. When the curve intersects the voltage axis the resulting voltage is known as the open-circuit voltage. The point in the curve where the voltage and current produce the greatest power is known as the maximum power point, and can be seen as the knee in the curve. Changes in temperature or irradiance will change the voltage-current response of the module. Current increases linearly with irradiance while the voltage will increase rapidly with increasing irradiance up to about 200 w/m^2 at which point it will remain nearly constant [40]. Thus increases in irradiance will increase the power output of a PV module by the following relationship:

$$\frac{\boldsymbol{E_2}}{\boldsymbol{E_1}} = \frac{\boldsymbol{I_2}}{\boldsymbol{I_1}} = \frac{\boldsymbol{P_2}}{\boldsymbol{P_1}} \tag{3.6}$$

where E_2, E_1, I_2, I_1, P_2 and P_1 are the irradiance (in w/m^2), current (in A) and power (in W) at two different irradiance levels. Increases in temperature will reduce the voltage and slightly increase the current, resulting in a decrease in power. The behavior of the voltage and current of a PV module due to changes in temperature is given by its temperature coefficients. The changes in voltage and current from rated values can be computed using the following equations:

$$\boldsymbol{V = V_{Ref} + \left(T_{cell} - T_{ref}\right) \times C_V} \tag{3.7}$$

$$\boldsymbol{I = I_{Ref} + \left(T_{cell} - T_{ref}\right) \times C_I} \tag{3.8}$$

$$\boldsymbol{P = P_{Ref} + \left(T_{cell} - T_{ref}\right) \times C_P} \tag{3.9}$$

where V, P, and I are the voltage, current and power at a specified cell temperature T_{cell}, and V_{Ref}, I_{Ref}, and P_{Ref} are the module voltage, current and power at a reference temperature T_{Ref} and C_V, C_I, and C_P are the voltage, current and power coefficients of the module. The voltage and power temperature coefficients are negative numbers.

Since the output characteristics of PV modules depend on the irradiance incident on their surface and the cell temperature, manufacturers usually rate the module performance using a set of controlled conditions adopted through the PV industry. The most accepted set of conditions is the Standard Test Conditions (STC) under which the modules are rated at an irradiance of 1000

W/m^2, cell temperature of 25^{o}C and air mass of 1.5, which refers to the relative distance of atmosphere that sunlight must penetrate to reach the surface of the earth.

PV modules are combined in series to increase the voltage. Engineers use the temperature coefficients of the modules and historical climatological data of the site to determine the maximum and minimum open circuit module voltages expected for the site. The series combination of modules, known as a string, must provide a voltage range that is within the DC operating range of the inverter. The parallel combination of strings must provide a DC current that does not exceed the maximum DC current that can be handled by the inverter. Figure 3.1 shows how PV modules can be combined in strings. Strings are then combined in parallel to form what is known as an array.

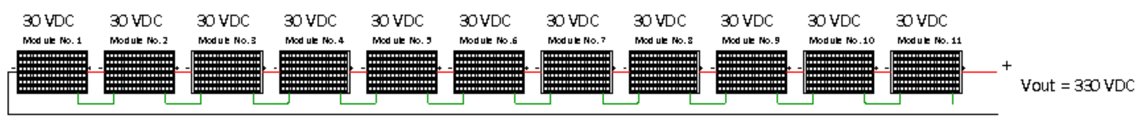

Figure 3.1 Combination of PV modules to form a string

The positive and negative terminals from the PV array are connected to the DC side of the PV inverter using cables, junction boxes and fuses. Inverters are power electronic devices that convert the DC source power into AC power that can be used by the loads or injected into the utility grid. Today PV inverters are typically pulse-width modulated (PWM) units that use insulated gate bipolar transistors (IGBTs). As discussed above, current interconnection standards and codes restrict non-utility inverters to operate on what is called a voltage following mode, where the inverters simply injects real power into the system and do not attempt to regulate the voltage at their AC terminals. Operation is usually carried out along the real power axis (producing almost no VAR), with a power factor of 1 [19]. Operation at a high power factor maximizes the economics of customer located inverters [29]. There are international efforts that would give DGs a broader participation in their contribution to local grids. For example, micro grids or intentional operation of electrical islands are an example in which DGs operate interconnected to the utility grid and are allowed to remain interconnected when the utility source is not present. Under this scheme the DGs would provide additional functions such as load management and voltage and reactive power control, actively participating in local voltage regulation [41]. Currently, IEEE has plans to include this concept in its 1547 series of standards with its IEEE P1547.4 Draft guide for Design, Operation and Integration of Distributed Resource Island Systems with Electric Power Systems under development. Nevertheless, the focus of this Masters project is on the more traditional operation of DGs as explained so far in this document.

Depending on their intended use, PV inverters can be single phase or three phase. Single phase inverters are used mainly in small residential and commercial PV systems and are usually rated between 2 and 10 kW. Their output can be combined to achieve the desired system rating. For larger commercial, industrial and utility systems, three phase inverters are typically used. These units can have ratings as low as 13 to 15 kW to as high as 250 to 500 kW. Again, multiple units can be combined together to achieve the desired power ratings. PV inverters are equipped with a function known as a Maximum Power Point Tracker (MPPT) [42]. This function allows the inverter to adjust the loading on the PV array so that it operates on its maximum power point at the present temperature and irradiance level. Most inverters perform the MPPT function for the whole array, while some newer inverters are able to perform this function for each string, which improves overall system performance. Typical inverter efficiencies are around 95 to 98 per cent.

On certain PV systems battery banks are used to store energy produced by the PV system. This stored energy can be used at a time when the PV modules are not producing power such as at nighttime or during overcast conditions. Battery banks are sized according to the available solar resource, the amount of PV power that can be installed, and the estimated energy consumption of the loads it will feed. The DC current from the PV array is used to charge the battery bank and any excess power is converted to AC to power customer loads or export to the grid. Some inverters that operate with battery banks include battery chargers and charge controllers. If the inverters are connected to the utility grid, they have separate output terminals to connect to the loads and to the grid. They can be programmed to export excess power to the grid or prevented to do so. PV systems with battery banks are more complex to design and install, and the added cost of the batteries and associated equipment raise the price per watt of the system. It is more common to find grid interactive systems without battery backup except in remote areas where access to the grid is difficult or non-existent

3.4 Impact of Photovoltaic Systems on the Voltage of Distribution Feeders

As discussed above, DG can affect the voltage profile and behavior of distribution feeders. In some cases the voltage profile improves in feeders with DGs. As will be seen in this document, a careful consideration of existing distribution systems as well as proper practices in the design of new or upgraded systems is necessary to deal with the voltage issues of DGs. How the feeder voltage profile is affected depends on issues such as the DG technologies used and their mode of operation, the topology of the feeder and the behavior of the loads. The three main voltage issues of high PV penetration are voltage rise, interference of voltage regulation equipment, and voltage variations due to cloud cover power variations and tripping of DG [25]. Each of these issues is presented below.

3.4.1 Voltage Rise

When DGs produce more power than what is consumed by the loads they serve, the excess power can be exported back to the grid. Depending on the amount of power exported, the location of the DG on the feeder, and the distribution of loads near the point of connection of the DG, reverse power can flow back along the feeder,, and at some points on the feeder, the power flow may become zero [43]. Upstream from the zero point power will flow from the substation, and downstream from the zero point power will flow from the DG. This reverse power will flow though circuit impedances and will result in a change in the voltage, raising the voltage on the PCC and along the feeder. When power flows is reversed and the direction of real power is from loads to the substation, the voltage drop, as seen from the substation, will be negative and the voltage at the PCC will be the substation voltage, or the voltage at the point where the power flow is zero, plus the voltage drop. This phenomenon is known as voltage rise. Voltage rise is given by the equation:

$$\Delta \boldsymbol{V} = \boldsymbol{I_{PV}}(\boldsymbol{X}\boldsymbol{sin}(\boldsymbol{\theta}) + \boldsymbol{R}\boldsymbol{cos}(\boldsymbol{\theta}))\ \boldsymbol{V} \qquad \textbf{3.10}$$

where *R* and *X* characterize the impedance of the feeder, from the point of PV current injection to the point where the power flow is zero, θ is the phase angle of the current with respect to the source voltage, and I_{PV} is the magnitude of the current injected by the DG [19]. From this we can see that depending on the magnitude of the current flowing back to the substation, the voltage along the feeder, and the line impedance, the voltage rise could force the local voltage at the PCC and surrounding areas outside ANSI C84.1-2006 limits. Depending on the magnitude, and if reactive power is absorbed or supplied, reverse power flow can also affect voltage regulation equipment and lead to voltage violations [28]. Recent studies show that voltage rise is a significant issue because it sets some of the lowest penetration limits [44].

High penetration of PV systems may raise the voltage above permissible levels under conditions of light load and high irradiation [45]. In residential feeders, the PV peak production will occur during periods of relatively light loading and the possibility of reverse power flows is high [29].

At high penetration levels, the reverse power flow during the period of maximum power production (typically at solar noon, when the sun is highest in the sky) might equal or exceed the load on the feeder. For example, if enough capacity is installed so that the total energy generated by the PV systems offsets all the energy consumption from residential loads, the peak PV power will likely be greater than the nighttime load since PV systems typically generate for about six hours while consumer loads run through the day, with noticeable peaks early in the morning and during the late evening and night. Voltage violations can occur if significant PV penetration is reached, especially under light load conditions and in the presence of shunt capacitor banks [25]. On feeders with capacitors, the placement of the DG must take into consideration voltage rise to avoid possible overvoltages.

DGs directly affect the voltage profile upstream of their location, and the best location for decreasing feeder loading is at the end of the feeder [46]. However, voltage rise it is more likely to occur when DGs are interconnected farther away from the substation and when feeder loading is light. Also, reverse power flows can actually increase system losses [47]. Utilities often reduce the sizes of the conductors as distances increase from the substation, since the load that the conductors serve decrease. If large amounts of DG are located near the end of a feeder, the power will flow through line segments with smaller conductors and higher impedances, leading to increased losses. As in capacitor placement, the 2/3, and the similar 2/(2n+1) rule can be used to determine the size and location of DG that can reduce losses and improve voltage profile. Instead of using reactive power as in the capacitor case, real power output is used in the equations [46].

Voltage rise can also occur on secondary distribution lines fed from a MV/LV distribution transformer, even with smaller sized PV systems, particularly if the transformers feed residential loads. Under minimum load, PV systems can raise the secondary voltage to unacceptable levels if the transformer's secondary voltage is already at maximum permissible levels. A study on the effects of interconnecting PV at the secondary voltage level looked at the issue of voltage rise on the secondary circuits [38]. It found that at maximum load, up to 158 per cent penetration, described as the ratio of DG connected to a single MV/LV transformer to the local load connected to the transformer, can be obtained without causing overvoltages if being fed from a single LV line. If DGs are connected to all LV lines of a transformer, up to 120 per cent penetration is possible under maximum load. The study concludes that higher limits are achieved if PV penetrates from a single LV line, and that the most severe limits occur during periods of minimum load, especially if the power system is already operating at its voltage limits.

Other studies regarding the issue of voltage rise have been carried out. On one study, simulations showed that when the load is distributed uniformly across a feeder, and the DG capacity is installed near its end, the end voltages can begin to exceed the substation voltage at around 15 per cent penetration. However, when the DG was distributed uniformly, the overvoltage became an issue with penetration levels around 50 per cent [13]. Another study concluded that PV penetration was limited to 33 per cent due to voltage rise issues, and that the overvoltages that occurred at that penetration level were minimal [25]. A study sponsored by the International Energy Agency concluded that the maximum PV penetration is equal to the minimum load on the feeder.

Several PV projects have been implemented in which voltage rise issues have been observed. Some of these studies have been carried out on feeders with residential loads. In Japan, the Gunma PV project consisted of 2.2 MWp of PV generation distributed among over 500 houses. In this project, a voltage rise of 1.5 to 2 per cent above maximum voltage limit was observed under conditions of light loading [45]. A PV project in Germany consisted of 300 kWp distributed among 50 condominium apartments. The complex was fed by two radial feeders from a 400 kVA substation. Overvoltages were observed during periods of light loading and high solar irradiation, which caused reverse power flows in the feeders. A study of a typical distribution feeder in Canada looked at changes in the voltage profile of a 10 MVA, 25 kV feeder. The scenarios analyzed included a uniform distribution of PV and load, and PV concentrated at the beginning or end of the feeder. Results included graphs of voltage profile at various levels of loading with and without DGs. It was found that under light load, when DG and load is distributed evenly, voltage increased as distance increased from the substation, with the maximum voltage occurring at the end of the feeder. Also, when the DG is connected at the end of the feeder, the voltage rise is greater than when it is located at or near the beginning of the feeder [45].

3.4.2 Disruption of Voltage Regulating Devices

Reverse power flows across voltage regulators can lead to improper operation. This can occur during periods of light loading, or if part of a feeder is lost due to a fault [25]. Several modes of failure can occur. How this reversed flow of power will affect the voltage regulator operation depends on the regulator type, its mode of operation, and on the programming of the regulator's controls [35].

Some voltage regulators are equipped with power flow sensing circuits that detect the direction of power flow and shift control logic when flows reverse [11]. Distribution feeders can have normally open ties to other feeders. These ties are used to transfer loads between feeders under normal operation and to transfer part of the load of a feeder when the feeder is affected by a permanent fault. When circuits are reconfigured, the source (substation) side can change to the secondary side of the voltage regulator. Shifting the regulating side and control logic allows the voltage regulator to operate properly when the source is shifted. When DGs cause reverse power flows through a regulator, its control might be confused into believing that the circuit has been reconfigured and that the source has changed to the secondary side of the regulator since it assumes that power will always flow from the substation to the loads. It can then move the tap changer to its highest or lowest position, causing high or low voltages on the DG side. If the voltage on the source side was high, the voltage regulator will attempt to regulate the voltage upstream, on the substation side, and since it will not be able to do so, it will tap to its limit, actually causing an overvoltage at the DG side. On the other hand, if the voltage on the source side was low, it will attempt to raise this voltage, and will tap to its limit to attempt to raise the voltage, creating an undervoltage at the DG side. This issue cannot be easily corrected with local settings and communications with distribution system control may become necessary. On some occasions, utilities have been forced to deactivate this function [48].

When voltage regulators are equipped with LDC, their operation can be disrupted even if no reverse power is flowing through the regulator. DGs downstream of a voltage regulator can interfere with the LDC algorithm and disrupt proper voltage regulator operation [49]. As explained above, when programmed with LDC, the regulator's control will measure the current through the regulator and based on the programmed line impedance values and mode of operation, it will either attempt to regulate the voltage at a remote load point downstream or maintain the voltage along the downstream feeder within a given range. DGs located downstream of a regulator will feed part of the load connected to the feeder, reducing the current the regulator sees. The regulator, sensing a reduced current, will set the regulating voltage lower, since its control will compute a lower load and thus less voltage drop. This can lead to undervoltages downstream of the regulator.

If the DGs are not exporting current to the grid or if they are exporting current and are located at or near the end of the feeder, the effects on the LDC will be reduced. Also, if the DG capacity is distributed over a larger area of the feeder, the likelihood of disrupting the LDC is reduced [19]. However, if the DGs are exporting considerable current and are located near the voltage regulator, the current through the regulator will be reduced but the current through the feeder will not, leading to under compensation. LDC disruption can occur with penetration levels of 20 per cent or more of the downstream load, and are usually worst when the DG capacity is located close to the regulator output.

When OLTC and voltage regulators are not operating with LDC a different issue arises. The regulating equipment will set the voltage at its output to a certain level, typically the highest voltage allowed for proper regulation, which may very well be 1.05 p.u. DGs connected downstream of the device can cause overvoltages near the PCC [46]. This phenomenon is more likely to occur with large DGs connected near the voltage regulating equipment.

3.4.3 Voltage Fluctuations

Fluctuations in the power output of DGs can also affect the voltage profile along the feeder. As mentioned above, PV systems convert the energy of the sun into electrical power. The output power of PV inverters depend on the DC input power from the array, which in turn depends on the instantaneous irradiation that hits the PV array, any shading present on the PV modules and the PV cell operating temperature. Even though the sun path across the sky and average irradiance per hour can be accurately predicted, changes in cloud cover can be hard to predict. Variations in irradiance due to passing clouds can be rapid, as much as 15 per cent per second, which results in fast ramping up or down of the PV inverter output [25]. An Electric Power Research Institute study on a PV project in Massachusetts found that the rate of change of irradiance from passing cloud cover was in the range of 60 to 150 $W/m^2/s$ [50]. Elsewhere, rates of up to 200 $W/m^2/s$ have been cited. At these rates it would take between 5.33s to 13.33s to go from 1000 $W/m^2/s$ to 200 $W/m^2/s$, with the corresponding drop in PV system output. These patterns provide a baseline for studies in Puerto Rico. However, the best approach would be to study local cloud patterns.

Since PV DGs feed part of the load on the feeder, considerable fluctuations in their output will cause noticeable changes in the loading condition in the feeder under high penetration of DGs, affecting voltage drop. These output variations of PV systems can lead to voltage fluctuations noticeable to customers. Since the rate of change of irradiance due to passing clouds can be high, rapid variations in the output of PV systems can lead to flicker and fast voltage fluctuations [6]. These rapid variations will not be mitigated by voltage regulation equipment, since their operating times are in the range of 30 s to one minute. Changes in irradiance can also be noticeable over a longer time. When this occurs, the loads can be subjected to voltages outside permissible limits until voltage regulating equipment operate. Frequent changes in the output of PV DG can lead to an increase in the rate of operation of voltage regulating equipment, leading to increased wear and reduced mean time between failures [25]. Power fluctuations can become significant at penetration levels above 20 per cent, particularly if the DG capacity is installed near the end of a weak distribution feeder.

When DG becomes a significant source of power, their immediate, uncoordinated removal can cause serious problems [13]. Current voltage and frequency trip settings, as those found in IEEE Std. 1547-2003, can cause problems when high penetration of DG is present. If a disturbance occurs on the power system, the DGs must disconnect to avoid the formation of unwanted electrical islands. The load supplied by the DGs will then be supplied by the utility grid, and the voltage profile across the feeder will be affected accordingly. A study performed by GE concluded that if a feeder depends on DG to feed a substantial amount of load, the sudden disconnection of DGs can result in undervoltages in the feeder [25].

The distribution of the DG capacity can play a big role in the effects of fluctuating output. DG capacity centrally installed is subjected to greater fluctuations since the system is affected all at once. DG capacity distributed over a wide area will not be affected as much since the PV systems will not be exposed to the same environmental or electrical conditions at the same time. The power fluctuations from changing DG output can have a localized impact on the feeder and substation, but system-wide impacts can result as well. This is particularly true of centralized PV systems. A study in Arizona focused on the effects of passing clouds on centralized PV generation. The study showed that approximately 5 per cent penetration was the upper limit before issues occurred. This study took into consideration the ramp rates of conventional power units used to compensate for the fluctuating PV output. Again, local studies are needed to get an accurate prediction of local cloud pattern impact on PV-based DG output.

Tens or hundreds of PV systems will tend to smooth out the effects of localized cloud cover, resulting in lower power variations [19]. A study conducted by the Public Service Company of Oklahoma examined the effects of distributing the installed PV capacity over a wide area. It found that a 15 per cent penetration caused marginal issues from cloud transients. A study by a utility in Kansas concluded that by raising the area over which the PV capacity is spread, the allowable penetration levels increase due to the "smoothing effects of geographical diversity". The study concluded that for the system evaluated the penetration levels could be raised from 1.3 per cent for the centrally located PV to 36 per cent for the distributed PV.

Essentially, by distributing the PV capacity over a greater geographical area, the PV systems will not be affected at the same time due to passing cloud cover.

3.5 Mitigation of Adverse Impacts of DG on Voltage Regulation

As can be seen from the above discussion, the interconnection of DG in distribution feeders can cause negative impacts on the voltage profile and voltage operation of the feeder. Under some circumstances even modest amounts of DG capacity can lead to problems with voltage rise, power fluctuations and disruption of the operation of voltage regulating devices. It is clear that at some point it will become necessary to implement different strategies that would mitigate the effects of DG and enable higher penetration of DG into the system. Some forms of mitigation can be implemented with very little change to current feeder layouts or to DG interconnection equipment. Other forms of mitigation, particularly those necessary to achieve high penetration levels, would need noticeable changes to distribution systems, DG interconnection equipment and current interconnection standards.

Several strategies can be employed using technology available today, perhaps with a few changes to control algorithms or to hardware. As was mentioned above, voltage rise is one of the main problems associated with DG, and particularly with PV systems located in residential areas. There are several ways to mitigate this. To limit voltage rise, utilities typically place a cap on the amount of DG capacity installed per feeder or limit the output power from the DGs [27]. One example of this is the 15 per cent rule established by national interconnection guidelines such as those published by the Federal Energy Regulatory Commission, FERC, or the National Association of Regulatory Utility Commissioners, NARUC [51],[52]. Under these guidelines, when utilities evaluate a proposed DG project, if the aggregate DG capacity connected to the feeder, including the proposed system, exceeds 15 per cent of the peak load of the feeder, system impact studies would be needed to confirm if the DG system can be interconnected safely. This can help lower the risk of problems in the feeders due to DG interconnection. Other strategies that involve the operation of the DG systems or of voltage regulating equipment can also be implemented. For example, another strategy is to revise the way distribution systems are designed, constructed and operated, a strategy that is easier to implement with new distribution feeders or feeders that are to be improved. That is not the focus of this project, as this requires changes in energy policy, however, it is important to point it out as future work. In this work the focus will be on the integration of DGs to existing and traditionally designed and operated distribution systems. Demand response strategies, suggested in the U.S. Energy Independence and Security Act of 2007 and adopted by FERC in its National Action Plan, could also address DG integration issues [53].

Reverse power flows are one of the causes of problems with voltage regulation. By limiting reverse power flows, some of the accompanying negative impacts can be reduced. For example, the export of power from customers with DG can be limited or curtailed during light feeder loading [25]. Power generated and not consumed by local loads can be diverted to power dump loads (also called diversion loads). For example, surplus active power can be used to power an electric power heater equipped with water storage or an air conditioning unit. Reduction of power export to the grid can also be achieved by diverting the real power generated by the PV system to some form of energy storage such as batteries. As a way to mitigate the voltage rise in the Gunma PV project and Ota City High Penetration PV Project, energy storage was implemented to redirect PV generation when the voltage limits are reached [45].

As a final measure, power output from the inverters can be reduced. This can be achieved by loading the PV array at a point outside the point of maximum production. A particular control strategy focuses in the use of the MPPT [29]. In this proposed scheme, the DG would be operated under MPPT, maximizing power output from the inverter, until the inverter output voltage reaches a certain limit, when the control would be switched to power curtailment mode. Here, the output of the DG would be varied to maintain the voltage within limits. Once the voltage drops down to acceptable limits, the inverter would switch back to MPPT mode. Curtailment of PV power production can reduce or prevent reverse power flows, but it is uneconomical to the PV owner or operator.

During normal operation, inverters can be used to control the load power factor. By doing this, the voltage profile along the feeder can be raised because inverters will feed both real and reactive power to the load. Also, this is a simple control strategy since it can be implemented locally and would not need to be coordinated with voltage regulation equipment or other DGs. Changes to the construction of the inverter would be necessary, as it would require a revision of the ratings of the power electronics equipment to maintain the real power ratings of the inverter.

Utilities can also make adjustments to their system that could reduce the possibility of voltage rise or other voltage regulation issues. Since the voltage rise depends on, among other things, the impedance of the conductors through which reverse power flows, the series impedance of the distribution system can be lowered by using larger conductors (with less impedance) and larger transformers to feed a given load. This is a technically attainable solution, but would require high capital costs from the utility, and customers requesting interconnection of DG could come to bear part of the economic burden. Lowering the impedance of the circuit can also affect the protection equipment and its coordination since it would result in increases in short circuit levels. Utilities can reduce the voltage on the feeder at times of light load and high DG output by adjusting the LTC at the substation or the settings of feeder voltage regulators [54]. However, this can lead to undervoltages on some feeder sections and can also cause problems when not all feeders on the same substation bus have high DG penetration or are under the same loading conditions [55]. It may also cause problems when the DG power output drops due to changes in the weather or when they disconnect due to disturbances in the system.

To mitigate secondary voltage rise, several steps can also be taken. A feasible solution would be to adjust the MV/LV tap changer to allow for greater PV penetration while maintaining proper voltage limits at the customers. For this, measurements of the primary or secondary voltages of the transformer under all loading conditions would be necessary to assess the voltage variation at the site. The results would be adjusted to account for worst expected conditions at the feeder such as minimum voltage and maximum voltage.

The general consensus seems to be that to address voltage regulation issues that will appear with high levels of PV DG, changes to the operating practices will be needed. In particular, DGs will need to regulate the voltage at their terminals and the operation of DGs and voltage regulation equipment will need to be coordinated. DGs can provide active voltage regulation by varying the active and reactive power they produce [56]. Since active power generation is important for economic reasons, most voltage regulation strategies focus on control of the reactive power output of the generator. DGs can regulate the voltage at the PCC by controlling their VAR output. If DGs regulate voltage by controlling their reactive power output, they can contribute more to the feeder. For example, DGs can absorb reactive power to control voltage rise on the feeders. In general, if a DG absorbs VAR, the voltage drop between the substation and the DG will increase [57]. This can be used to offset the voltage rise due to the export of real power, and can allow the DG to export more real power than it would be able to if operating in unity power factor. If the DG supplies VAR, the voltage drop from the substation to the PCC is decreased. This feature can be helpful under heavy loading, when DGs can help raise the voltage of the feeders. If equipped with energy storage, an inverter could even operate in the fourth quadrant, absorbing real power to feed loads or charge batteries if the need should arise. Operation in the fourth quadrant would be viable for DGs that supply local loads, and could be incorporated to the control logic of bi-modal inverters that use battery banks. The feature could then be enabled as necessary using a signal from the utility to curtail PV output or operate in the fourth quadrant until the voltage profile along the feeder is normalized.

Caution must be exercised when implementing VAR support from DG. Programming the inverters to provide VAR support will not always provide an adequate solution, since its VAR contribution can be restrained by the placement of the inverter on the feeder. For example, in situations under light load, the substation LTC or voltage regulator might tap down to a low setting. If DGs are distributed evenly along a feeder, the voltage profile along the feeder might increase with increasing distance, but as it does, the voltage places a limit on how much VAR the inverters can supply [29]. Also, just as capacitors, inverters placed near the substation would not provide the best benefits with VAR control. Also, in some cases, if inverters are allowed to vary reactive power to regulate voltage, they may absorb substantial amounts of VAR. This may lead to increased losses on the feeder and VAR loadings on subtransmission and transmission lines. High reactive currents also reduce the effective capacity of the circuits and increase losses. It must also be mentioned that inverters that regulate voltage will provide greater fault current, although less than DGs based on rotary machines [25]. This must be taken into account and the protection coordination along the feeder must be revised accordingly.

If inverters are to absorb or supply reactive power to help regulate the voltage, the ratings of the power electronics would need to be revised to maintain real power ratings. The energy storage capacitors would need to be sized as to prevent excessive ripple from reaching the PV array under high VAR production or absorption. It will be necessary to increase the capacity of an inverter for it to supply reactive power while maintaining peak power rating from the PV array. For example, if the inverter ratings are increased by 10 per cent, the power factor can be 0.91 leading to lagging, increasing VAR capacity from almost zero to 46 per cent of the peak ratings of the inverter [29].

Inverters that regulate the voltage must do so to regulate both slow and fast voltage variations. High speed voltage regulation, in the form of rapid VAR control from inverters, SVCs, and other power conditioning devices can be used to mitigate fast power fluctuations that can lead to voltage sags and flicker. To actively participate in voltage regulation, inverters must provide VAR control, to allow for slow voltage regulation, for voltage variations in the range of 30 seconds and over, and fast voltage regulation, for variations under 30 seconds, to mitigate against flicker and voltage sags caused by rapid variations in the output of the inverter. Fast voltage regulation can be performed autonomously by the inverter [58]. To prevent overcompensation, the control algorithm can use limited gain. Inverters could also vary real power output based on external commands from the utility, both slowly and fast, for frequency regulation and damping and stability enhancements, respectively.

Fast energy storage can be used to offset fast PV output changes due to passing clouds. More accurate forecasting and real time cloud information can help utility dispatch to rearrange generation dispatch ahead of expected cloud cover events. For example, the PV plant can ramp down with a shallower slope ahead of expected cloud cover events. This would give time for conventional generation to ramp up and cover the loss of DG [25].

If DGs are allowed to actively regulate voltage, new voltage regulation schemes that feature communications between utility voltage regulation equipment and customer PV systems may very well need to be adopted. To maintain proper voltage regulation under high penetration of PV, voltage regulating devices should communicate between themselves and also communicate with PV inverters [59]. In this way, all equipment will work cooperatively to maintain the voltage profile along the system. Also, in some situations, system control of the voltage regulation capabilities of inverters may be necessary for proper voltage regulation on the feeders.

It is desirable to allow DGs to ride through voltage sags or frequency events. This means readjusting practices and standards to allow more flexible trip settings [60]. The DG overvoltage protection will disconnect the DG once the voltage exceeds a given threshold for a given amount of time. This will cause the DG to go offline even if the service to the customer is not interrupted. In feeders where the DG provides voltage support, the disconnection of DG while the load is still in service can result in the degradation of the voltage profile outside allowed ranges.

Allowing DGs to regulate voltage and ride through system disturbances can interfere with current anti-islanding schemes. It may be required to modify current schemes or adopt new methods to ensure safety. For example, the loss of a continuous carrier signal embedded in the power lines can signal that the electrical connection between the DG and the substation has been compromised. Utility SCADA systems can also communicate with DGs to relay information about system status and send trip signals if faults are permanent and the feeder is disconnected.

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4 SIMULATIONS OF THE INTERACTION OF PV DG WITH THE VOLTAGE PROFILE OF A 4.16 kV DISTRIBUTION FEEDER

4.1 Introduction

From the literature review it is clear that the integration of PV DG in distribution feeders can provide benefits to utilities and customers. This must be done carefully to obtain the greatest benefits and avoid causing problems with the feeders. As mentioned previously, DG can help improve the voltage profile along the feeder and reduce losses. It is important to understand what configurations of DG will maximize these benefits to the distribution system while at the same time avoid the problems that can arise under certain circumstances. The main issues discussed in the literature and observed on actual PV projects are voltage rise, disruption of voltage regulating equipment and practices, and voltage fluctuations due to variations in the output of PV DG. Current public policy in Puerto Rico calls for aggressive integration of renewable energy systems to the grid, particularly of wind and PV systems. Undoubtedly, some of that capacity will be interconnected to the distribution system. It is evident, therefore, that to obtain the highest benefits from the integration of PV DG to the distribution grid while securing grid performance and power quality, it is necessary to understand how the abovementioned issues can manifest in distribution feeders typically found un Puerto Rico. The aim of this project is to determine how PV DG can be integrated to the grid and provide the greatest benefits in terms of voltage and loss performance. Once the interactions between PV DG and the distribution grid are understood, general guidelines can be developed that can be used to increase the benefits of DG in general and reduce the likelihood of problems.

To gain a better understanding of how PV DG will interact with distribution networks, simulations of generic 4.16 kV and 13.2 kV feeders were carried out. Different scenarios were developed and simulated to see how changes in load capacity and distribution, and DG capacity and distribution would interact. Particular attention was placed on load distribution, DG placement and penetration capacity in an effort to establish which combinations will provide a better voltage profile and the greatest reduction in losses.

4.2 Circuit Model

The simulation software used is the SynerGEE Electric software developed by Stoner. It is a distribution analysis tool used by engineers in electric utility companies. It allows engineers to perform studies on load flow, protection coordination, short circuit analysis, motor starting, capacitor placement and load balancing. It is representative of the type of software used by distribution planning engineers nationwide. The software includes models for equipment such as conductors, transformers, voltage regulators, capacitors, motors and loads. The user can work with the available models, can modify the existing ones or can prepare new models using equipment data provided by the manufacturer.

The software focuses on steady state evaluations of the circuit, and does not perform time varying analysis. This means that the interaction between DGs, loads and voltage regulating equipment as load and DG output vary cannot be modeled against time. Taking this into consideration, the simulations performed focused on steady state voltages along the feeder with varying DG penetration under conditions of light and heavy load. Also, the interactions between a voltage regulator and DGs were performed, focusing on the steady state voltages present when DGs downstream and upstream of the voltage regulator disconnect and reconnect after the predetermined time interval of five minutes established in IEEE Std.1547-2003.

The first step when performing the simulations is to develop the circuit model. For this, a generic 4.16 kV feeder model that can provide the flexibility to incorporate different load and DG combinations was developed. A length of 10 kilometers (6.21 miles) was chosen for several reasons. It allowed for the voltage drop representative of a 4.16 kV feeder with voltage regulators. One of the objectives of the simulations was to examine the interactions between the voltage regulators and DGs located along the feeder. A long, loaded 4.16 kV feeder will typically have a voltage drop along the mainline that will require the use of a voltage regulator. This feeder can also be configured with the load distributed evenly or lumped near the beginning or end of the feeder. This allows for the representation of several types of feeders commonly found, such as feeders that supply exclusively urban areas, or feeders that feed supply urban and rural areas.

The circuit model consisted of a substation transformer, which changes the transmission or subtransmission voltage to distribution voltage. The transformer type was chosen among the models provided in the library. A 38kV/4.16kV, delta-wye transformer with a capacity of 11.5 MVA was selected. It comes equipped with a load tap changer with 32 steps, which allows the transformer to raise or lower its output voltage by 10 per cent. The regulating voltage was set at 126 V on a 120 V base, and the bandwidth at 2 V, with the LTC set to regulate voltage automatically and to maintain the voltage at the beginning of the load, or first house voltage, between 126 V and 125 V. The primary side of the transformer was connected to a section designated as a transmission node. The voltage was set at 38 kV L-L, and the bus voltage specified at 1.05 p.u. The secondary side of the transformer was connected to the distribution feeder that incorporated the load, DG, and voltage regulating devices such as capacitors and voltage regulator.

The feeder consisted of a long mainline and three lateral branches. The mainline was divided into four sections of equal length. Each section was made up of ten segments, each measuring 250 meters (820 feet), for a total length of 2.5 km per section, and 10 km in total. The segments were assigned one of three different conductor types, based on their position in the circuits. The first third of the mainline from the substation, or 13 segments, was constructed using 556 ACSR conductor. The next third of the mainline was constructed using 266 ACSR. The rest of the mainline was constructed using 1/0 ACSR, with the final segment built with 4 CU HD. The generic feeder included three sections representing three phase lateral branches. In real world feeders, lateral braches will come out from the mainlines to supply loads at some distance from it. The laterals were connected at 2.5 km intervals along the mainline. They were divided into twelve segments measuring 100 meters each, for a total length of 1.2 km (0.5 mi) per lateral. The first six segments, or 600 m, of each lateral branch, were constructed using 1/0 ACSR, while the remaining six used 4 CU HD. The conductors chosen represent conductors commonly found in feeders around the island. Table 4.1 lists the conductors used and some of their electrical properties. Figure 4.1 illustrates the layout of the circuit.

Table 4.1 Conductor Properties

Conductor Type	Material	Capacity (A)	Resistance (Ω/m)
556 ACSR	Stranded Aluminum	700	0.1859 + 0.5615j
266 ACSR	Stranded Aluminum	450	0.3849 + 0.4646j
1/0 ACSR	Stranded Aluminum	240	1.1199 + 0.6558j
4 CU HD	Solid Copper	180	1.5006 + 0.5988j

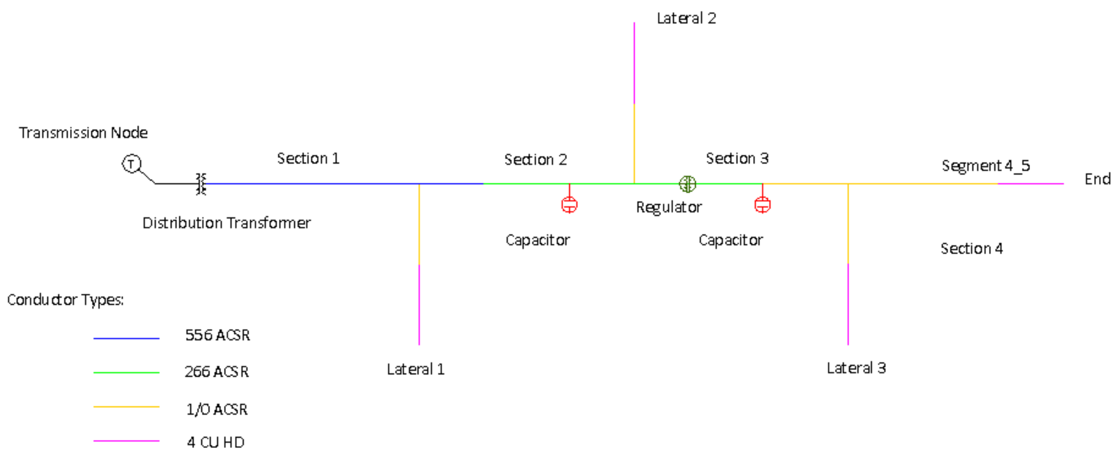

Figure 4.1 Layout of the circuit used for the simulations

After determining the layout of conductors in the feeder model, the next step was to establish loading and load distribution. As mentioned in the literature review, PV systems have their maximum output when the sun is highest in the sky, which is at solar noon. Feeder loads, on the other hand, behave according to the type of customers served. On feeders carrying predominantly commercial loads, the peak load will occur at noon or early afternoon, roughly coinciding with maximum PV output. On feeders with mainly residential loads, the peak loads will occur early at night, when residential activity is highest, and the diurnal minimum load will be around the time that PV systems will be at or near peak production, when people are away from their homes. To examine the effects of varying the type of circuit load, two loading scenarios were used. The first is a feeder load of approximately 50 percent of the feeder capacity. With the circuit energized at 4.16 kV, and the highest rated conductor being 556 ACSR with a capacity of 700 A, the feeder capacity is around 5.00 MVA. Thus 2.5 MVA represents approximately 50 per cent of feeder capacity. The other load scenario is that of light load, for which 60 percent of the peak load, or 1.5 MVA, was chosen. This can represent the light loading conditions of residential feeders at noon. It can also be used to represent light loading conditions of commercial feeders during the weekend or on holidays, when, for economic and practical purposes, the DGs will still operate.

Once the peak and minimum loads were determined, loading along the feeder would need to be established. Three load distribution scenarios were analyzed. The first was to distribute the load evenly through the feeder. The second and third scenarios represent cases were 2/3 of the load is distributed along either half of the feeder. To distribute the load along the feeder, the user must perform what is known as a load allocation. In this analysis, the software uses metering points along the feeder to determine the loading in that specific location. The metering locations and power flows through the meters are specified by the user. The user must also specify any spot loads present along the feeder. Spot loads are loads to which the user has knowledge of the actual demand for the scenario to be simulated. The program will fix the load at that point as that specified under the spot load setting. Finally, the user must also specify the capacity of distributed loads along the feeder segments. These represents transformers connected to the lines for which the user has no metering data. When the software carries out the load allocation, it will establish the load flow through the feeder using the metering and spot load data, and will distribute the load not assigned to spot loads among the distributed load through the feeder and corresponding losses through the segments.

The distributed loads through the feeder were assigned as follows. Twenty five percent of the distributed loads were divided between the four mainline sections. The distributed load at each line segment was set at 75 kVA. The load assigned to the lateral branches was 75 per cent of the distributed load capacity. The distributed load at each lateral segment was set at 225 kVA. In this scenario, the lateral branches represented load centers on the feeder. One meter was used at the beginning of the feeder when performing the load allocation for the case where the load is evenly distributed. Since no spot loads were specified, and the distributed load was set for the mainline and lateral segments, the program allocated the loads evenly through the feeder segments in proportion to the distributed load. To represent the loading of the feeder when two thirds of the load was located within the first half of the feeder, a second meter was added to the feeder near the second lateral line, at approximately half the distance from the substation to the end of the feeder. The loading of the meter was set at one third of the loading of the first meter to ensure that two thirds of the load was allocated in the first half of the feeder. For the case in which two thirds of the load was allocated in the second half of the feeder, the loading of the second meter was set at two thirds of the loading of the first meter.

Once the load allocation was carried out for each case, a load flow analysis was performed. The base case was taken as the case were the loads were distributed evenly along the feeder with no DG present. Since one of the objectives of the simulation was to represent both peak and light load conditions, the base case was selected as the circuit with peak loading. When the load flow was performed, it was quickly seen that the voltage along the feeder dropped as distance from the substation increased, and beyond a point in the feeder mainline it dropped to below 114 V on a 120 V base, or below 95 per cent of nominal. This resulted in an undervoltage below the lower limit of ANSI C84.1-2006 Range A. Two measures were carried out raise the voltage. First, two capacitors were added. A bank with a capacity of 75 kVAR per phase was located at segment 3_7, about two thirds of the way down the feeder. A load flow was performed again, which showed that the capacitor bank raised the voltage by about 3 volts on a 120 V base, but the feeder still had segments with undervoltages. Based on the results of this load flow, a second capacitor bank was installed at segment 2_7, or about 37.5 per cent of the way down the feeder. A load flow was performed and the voltage was raised about 2 volts, but some line segments still showed undervoltages. A three-phase voltage regulator, with a capacity of 250 A per phase was then added at segment 3_3, the last segment where the voltage remained above 0.95 p.u. The regulator chosen was a three phase unit, connected wye-grounded, with 32 taps able to adjust its output voltage by $\pm$ 10 per cent. It was set to regulate the voltage at its regulating side to 5 per cent above nominal, or 126 V on a 120 V base. It was also set in the locked forward mode, under which it would always attempt to regulate the secondary side. After adding the regulator, a load flow was performed and the results showed that the regulator and capacitor combination was able to maintain proper voltage regulation along the feeder. Figure 4.2 shows the circuit configuration and Figure 4.3 the voltage profile along the feeder. Table 4.2 lists a summary of feeder loading and losses.

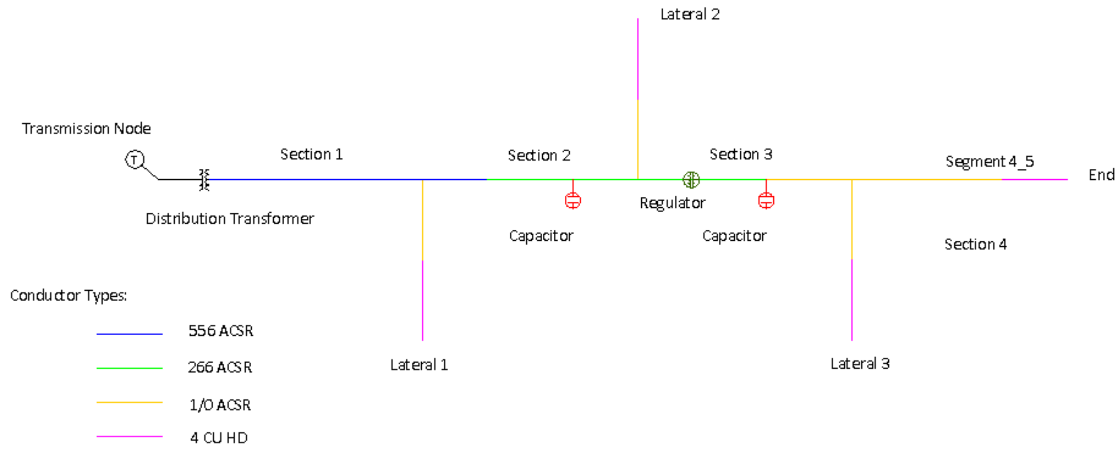

Figure 4.2 Base case feeder configuration

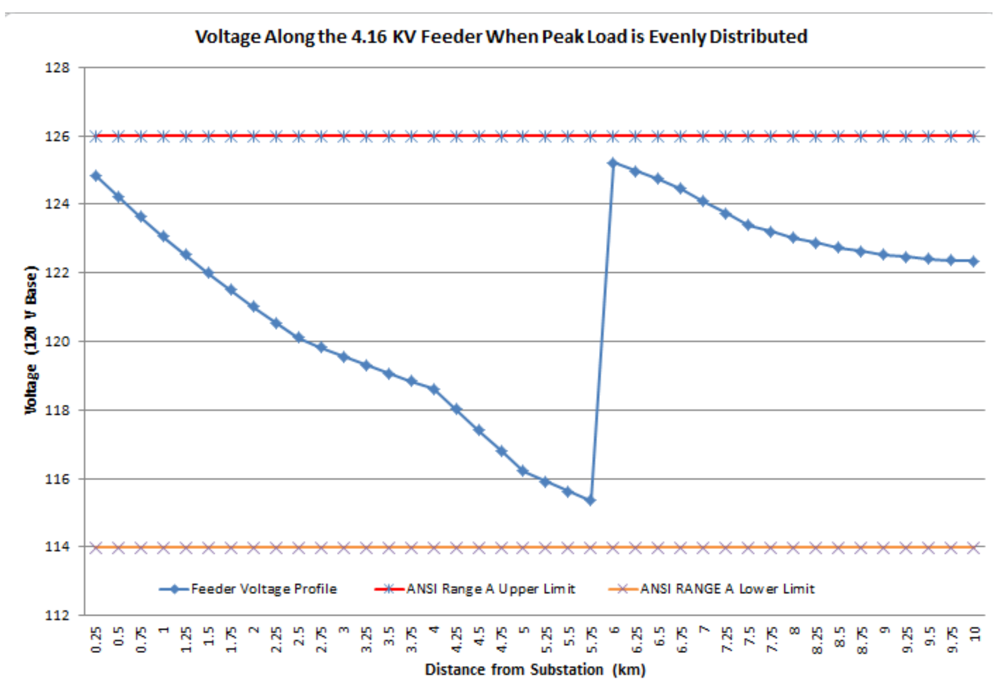

Figure 4.3 Voltage profile along the feeder

Table 4.2 Summary of Feeder Loading and Losses

Demand – kW	Demand - % p.f.	Demand - Amps	Load – kW	Load - kVAR	kW Loss - Total	kW Loss - %
2558	99	341	2354	147	204	7.96

Once the feeder was configured for proper operation under heavy load, the loading on the metering point was changed to represent the light loading scenario. A load allocation was the carried out, followed by a load flow. Under this scenario, the feeder continued to properly regulate the voltage along all line segments. Once the performance of the base case feeder model was verified, the same procedure was carried out for the other three loading scenarios. It was determined that the feeder configuration established for the first case was able to maintain proper voltage regulation in the case where 2/3 of the load was distributed on the first half of the feeder and with the feeder under light load.

When 2/3 of the load was distributed along the second half, the increased current through the mainline increased voltage drop, and the capacitor-voltage regulator combination was not able to maintain proper voltage regulation. It was necessary to change the location of the capacitor banks and the size and location of the voltage regulator. Capacitor banks of 225 kVAR and 150 kVAR were added on segments 4_1 and 2_5, and a three phase voltage regulator with a capacity of 334 A per phase was added at segment 2_6, closer to the substation than on the other loading scenarios since in this case the voltage drop to 0.95 p.u. occurred at less distance from the substation. The regulator capacity had to be raised because it would supply more load. The settings of the regulator were the same as the previous regulator. It was established that with this combination of capacitor banks and voltage regulator the feeder maintained proper voltage regulation. Figure 4.4 shows the layout of this circuit.

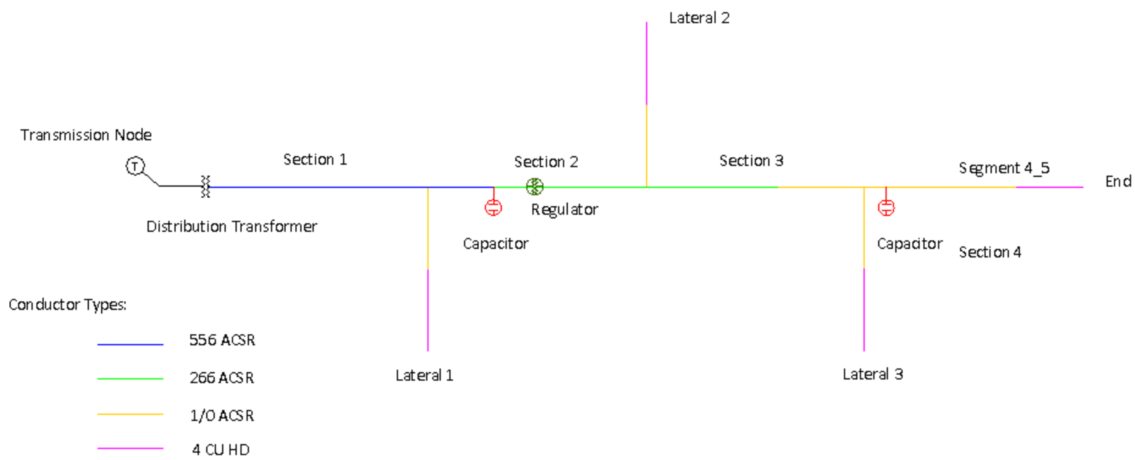

Figure 4.4 Layout of the feeder with 2/3 of the load at the second half of the feeder

At this point it is important to mention that the feeders were configured to maintain proper voltage regulation at all loading scenarios on purpose. This should be the normal operating characteristics of distribution feeders. When voltage regulation issues occur on a feeder, it is the utility's responsibility to correct these problems, and the burden of correcting this existing problem should not be placed on a customer wishing to interconnect a DG system. Thus, feeders with existing voltage regulation issues were not analyzed.

To evaluate the effect of interconnecting DG to a feeder energized at a higher voltage level, a 13.2 kV circuit model was developed. For this case, the same feeder layout was used. This allowed a direct comparison of the results for both voltage levels. The transformer model used was that of a 33.6 MVA, 115/13.2 kV transformer, connected delta in the transmission side and grounded wye in the distribution side. This transformer model is also provided with a LTC with 32 steps. The settings for the LTC were the same as in the 4.16 kV cases. The transmission node voltage was changed to 115 kV phase to phase.

Feeders energized at higher voltage levels are not affected as much by voltage drop as feeders energized at lower distribution voltages. Thus it is typical to see these feeders carry a larger load. With the circuit energized at 13.2 kV, and the highest rated conductor being 556 ACSR with a capacity of 700 A, the feeder capacity is roughly 16 MVA. A feeder loading of 11 MVA was chosen for the peak demand, which represents approximately 68 per cent of the capacity of the feeder. A loading of 6.6 MVA, or 60 per cent of peak loading, was chosen to represent light load. The same procedure described previously for the 4.16 kV circuits with the load distributed evenly was carried out. Two capacitor banks were added, one at segment 2_6 and another at segment 3_7, each with 150 kVAR per phase, to supply part of the reactive load of the feeder. Under this feeder configuration, the simulation results for both loading scenarios showed that the feeder was able to maintain the voltage profile within ANSI limits on all segments. The lowest voltages obtained were 117.56 V and 121.43 V for the peak and light loading scenarios respectively. Thus it was not necessary to install a voltage regulator along the feeder to maintain proper a proper voltage profile up to the last customers.

4.3 Simulation of Different DG and Load Configurations

The SynerGEE software models the DG with an equipment type called Large Customer. Several different types of such equipment are provided by the software, but for the purpose of this analysis, the Distributed Generator model was used. It allows the user to specify characteristics such as rated capacity, per cent of rated capacity operating and power factor. Since the purpose of the simulations is to examine the effect of PV DG on the feeder, the power factor was set at 1. A review of available commercial inverters ranging from small (4 kW) single phase units to large (500 kW) three phase units revealed that inverters are usually configured to operate at unity power factor. When one Distributed Generator was placed to represent a large centrally located DG or several smaller DGs lumped at one location, the rated capacity was set at the peak load of the feeder, and the actual power output from the DG was increased in steps of 10 per cent of rated capacity. When multiple DGs were used to represent the effects of distributing DG along the feeder, the capacity of each DG was set according to the total peak loading on the section to which it was connected, and their output was also varied in steps of 10 per cent of rated capacity. Figure 4.5 shows this configuration.

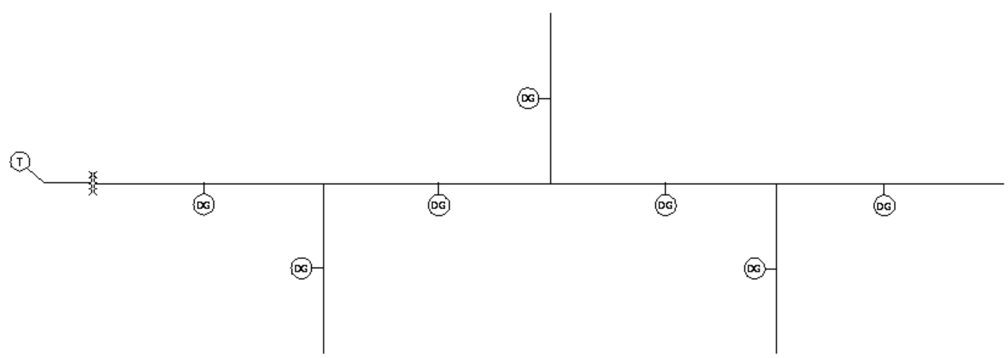

Figure 4.5 Circuit configuration with the DGs distributed evenly

Several scenarios with different combinations of DG capacity and location were analyzed for the different loading configurations discussed. The following is a discussion of the cases simulated and the results obtained. For simplicity, when discussing voltages, a 120 V base will be used. This represents a primary voltage of 2.4 kV per phase on the 4.16 kV feeder or a voltage of 7.62 kV per phase for the 13.2 kV feeder. If primary voltages are desired, the results can be multiplied by 20 or 63.5 for the 4.16 kV and 13.2 kV feeders respectively, to obtain the actual primary voltage. Appendix A contains graphs of the voltage profile of all scenarios evaluated.

4.3.1 Case 1 - Feeder with 2.5 MVA of Load Evenly Distributed

Under this scenario, the base case feeder was loaded at 2.5 MVA, or 833.3 kVA per phase at the beginning of the feeder, with the load distributed evenly as discussed above. This can represent a commercial feeder in an urban environment. The power factor with the capacitors installed was 99 lagging. A DG, with a capacity equal to the load on the feeder, was placed at different locations along the feeder, and the capacity was raised in steps of 10 per cent of DG rated capacity until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A. Thus, the limiting factor for DG capacity examined under this set of simulations is the voltage rise on the feeder.

In general, it was found that when the DG capacity was lumped in a single area of the feeder, voltage rise issues can establish the maximum capacity of DG that can be placed without creating steady state overvoltages above ANSI C84.1-2006 Range A. It was observed that when the DG capacity is lumped at the end of the feeder, adding just 10 per cent of the DG capacity caused a slight overvoltage exceeding 126 V at the point of interconnection of the DG. This occurs because the end of the feeder is lightly loaded, and all of the current exported from the DG that does not feed local loads will travel towards the substation to feed other loads. As it does, it will travel longer distances along conductors with higher impedances, causing a voltage rise. Since the voltage regulator is programmed to maintain the voltage to 10 per cent of its input voltage up to 126 V, the voltage downstream is in the higher range of allowable voltage, and the voltage rise from the current exported by the DG is enough to raise the voltage over 126 V. Figure 4.6 shows the voltage profile along the feeder when the DG is interconnected at the end (segment 4_10) of the feeder.

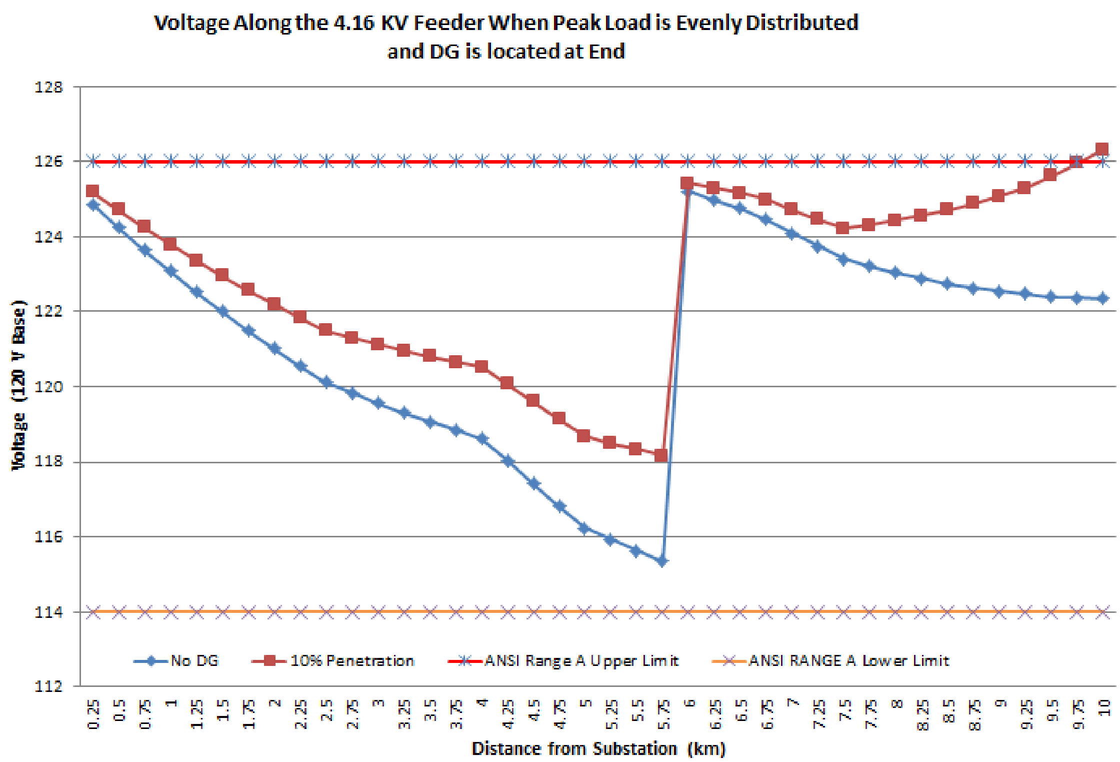

Figure 4.6 Case 1 voltage profile with DG at end

A similar issue occurs when the DG is placed in segment 4_5, which is near the end of the feeder, after the load centers represented by the three laterals. When the DG capacity is 10 per cent of feeder load, the voltage rise will push the voltage along all of the mainline downstream of the regulator between 124.9 V and 124.4 V. If DG capacity is raised to 20 per cent, the voltage along the mainline will increase to between 127.27 V and 125.2 V, with the highest voltage at the point of interconnection of the DG, forcing the voltage on some segments outside the permitted voltage range.

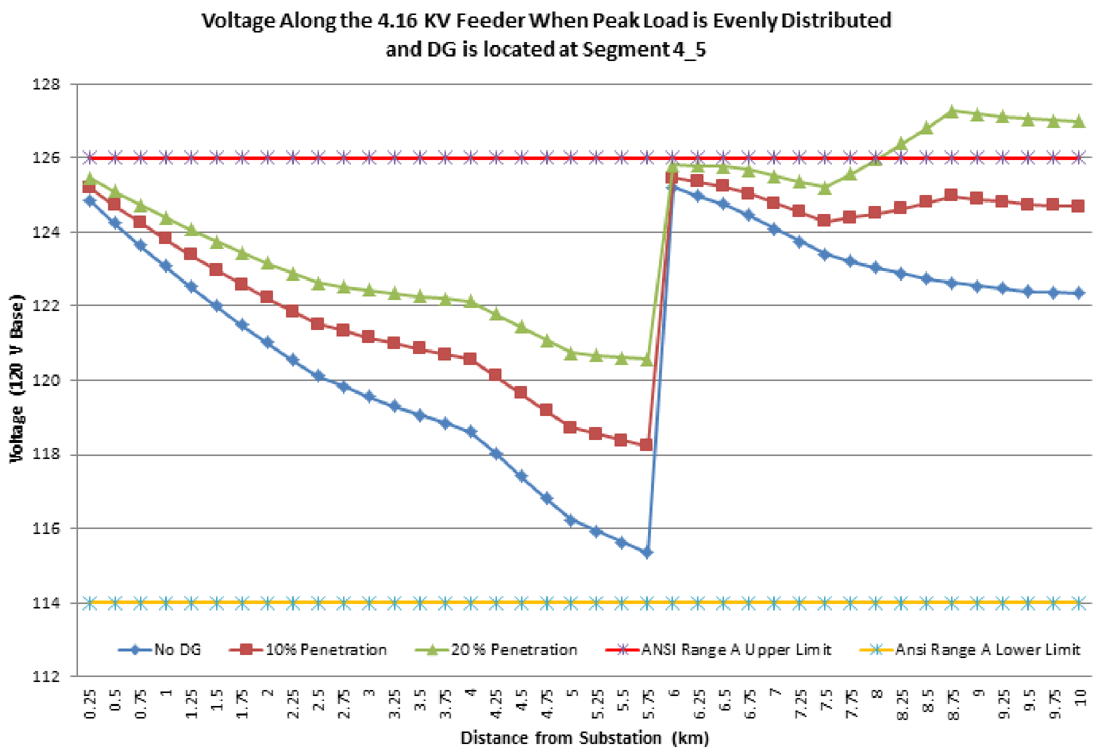

Figure 4.7 Case 1 voltage profile with DG at segment 4_5

When centralized DG is moved closer to the substation, in areas of higher load concentration, higher DG penetration is possible before voltage rise becomes a problem. When the DG is located near areas with higher loading, the power exported will travel less to reach the loads. Also, the current can flow over multiple paths to feed loads, something not possible when the DG is placed at the end of the feeder or lateral circuit, where all the current is essentially forced through the same conductors. These factors help to reduce the voltage rise on the circuit and maintain the voltages within range for higher DG penetration.

When the DG is located at the interconnection of Lateral 3, the DG capacity can be raised to 40 percent, at which point the voltage along the entire mainline will be between 123.5 V and 125.52 V. Since the DG is located after the voltage regulator, it affects the voltage upstream of the regulator as well as the voltage downstream since it reduces the amount of current flowing from the substation and thus the voltage drop, increasing the voltage level that reaches the regulator. Also, since it feeds part of the load downstream of the regulator, it reduces the current flowing downstream of the regulator and thus the voltage drop. If the DG penetration is increased to 50 per cent, overvoltages around the interconnection point of the DG will occur. With this DG penetration level, the voltage at the source side of the regulator is 125.34 V, and the regulator will not attempt to modify the voltage downstream, which would result in a sustained overvoltage near the DG.

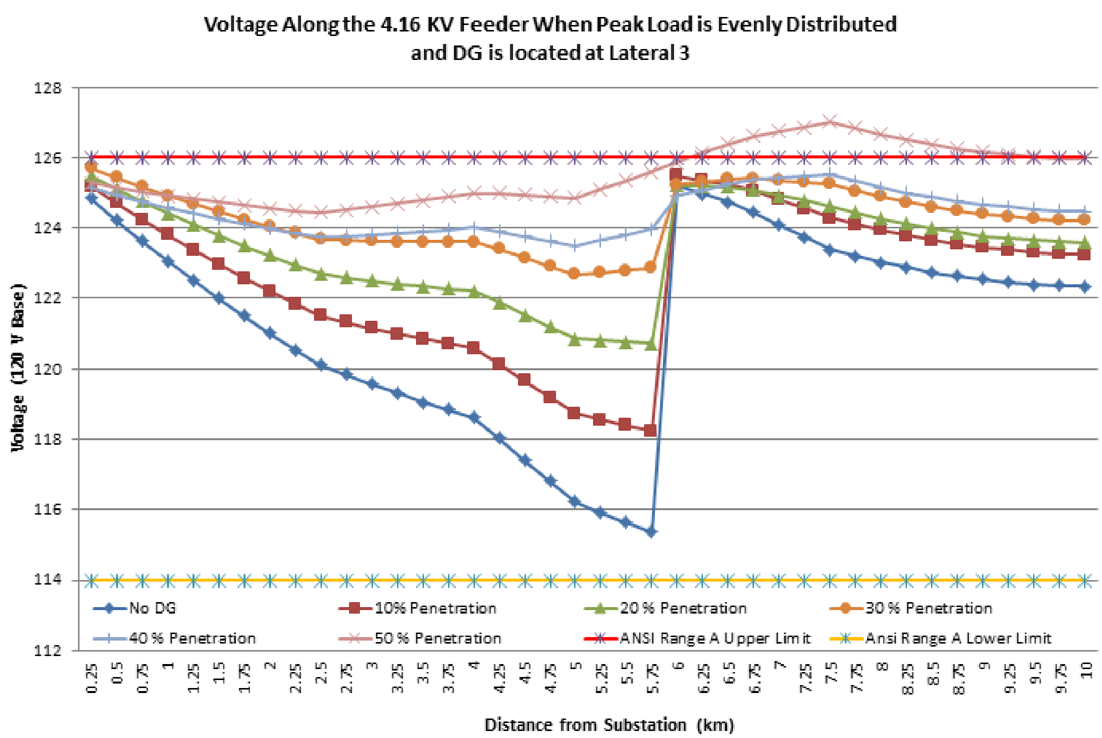

Figure 4.8 Case 1 voltage profile with DG at Lateral 3

When the DG is located at the interconnection of Lateral 2, 60 per cent of DG penetration is possible before overvoltages occur, with the voltages along the mainline between 125.74 V and 121.84 V. Since the DG is located before the voltage regulator, it will noticeably modify the voltage along the mainline up to the voltage regulator. As the voltage regulator is programmed to maintain its output close to 126 V, the voltage downstream of the regulator is not modified in the same manner as the voltage upstream of it. Also, when the DG penetration is 60 per cent, the voltage at the input to the regulator is 125.2 V, and the voltage regulator will not attempt to raise the voltage. In this case, the voltage downstream of the regulator is the lowest of all the voltages obtained with the different penetration levels evaluated with the DG at this location.

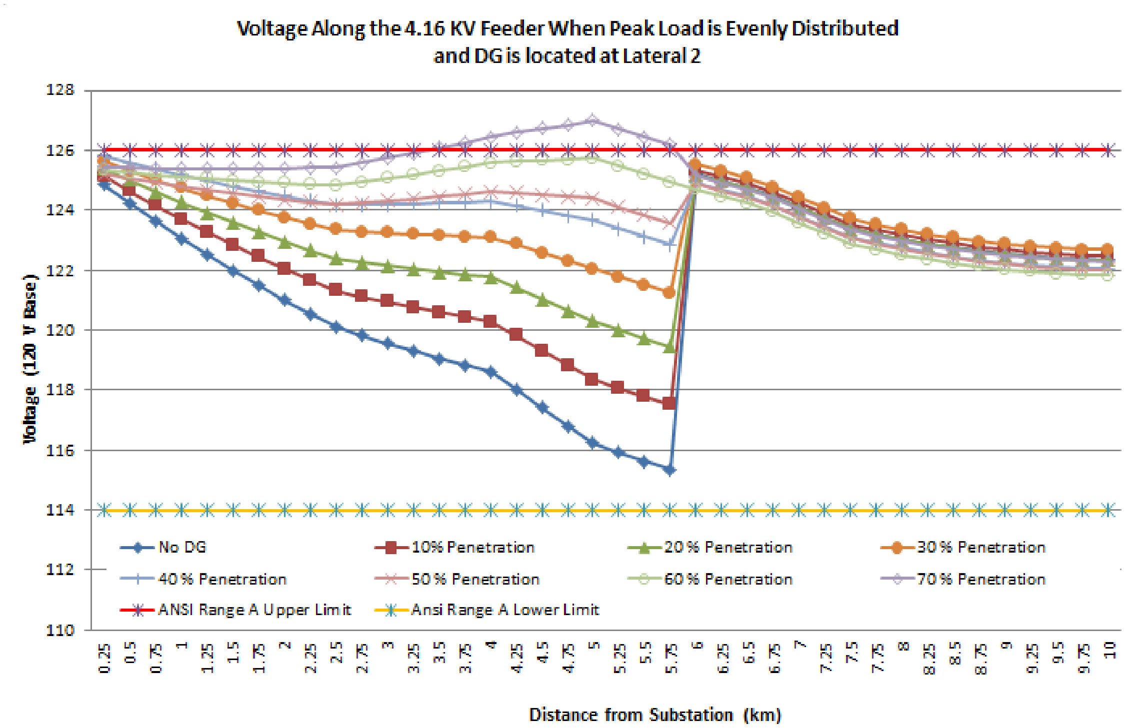

Figure 4.9 Case 1 voltage profile with DG at Lateral 2

If the DG is located at the interconnection of Lateral 1, 100 percent penetration can be achieved, with a voltage along the mainline between 125.86 V to 121.33 V. Since Lateral 1 is located close to the substation, most of the excess power supplied from the DG will flow downstream, and this will result in a voltage drop, just as it does when the power is supplied from the substation. This can be observed in Figure 4.10, which shows the voltage profile for this DG location. When 100 per cent penetration is applied at Lateral 1, the voltage profile has the same shape of the voltage profile for the case with no DG. The voltage however, is higher since the DG will reduce the current from the substation, reducing the voltage drop along the beginning of the feeder, which is evident from the slight voltage rise for the first 2.5 km of the feeder, to the point where the DG is located. The voltage profile downstream of the regulator is not modified significantly.

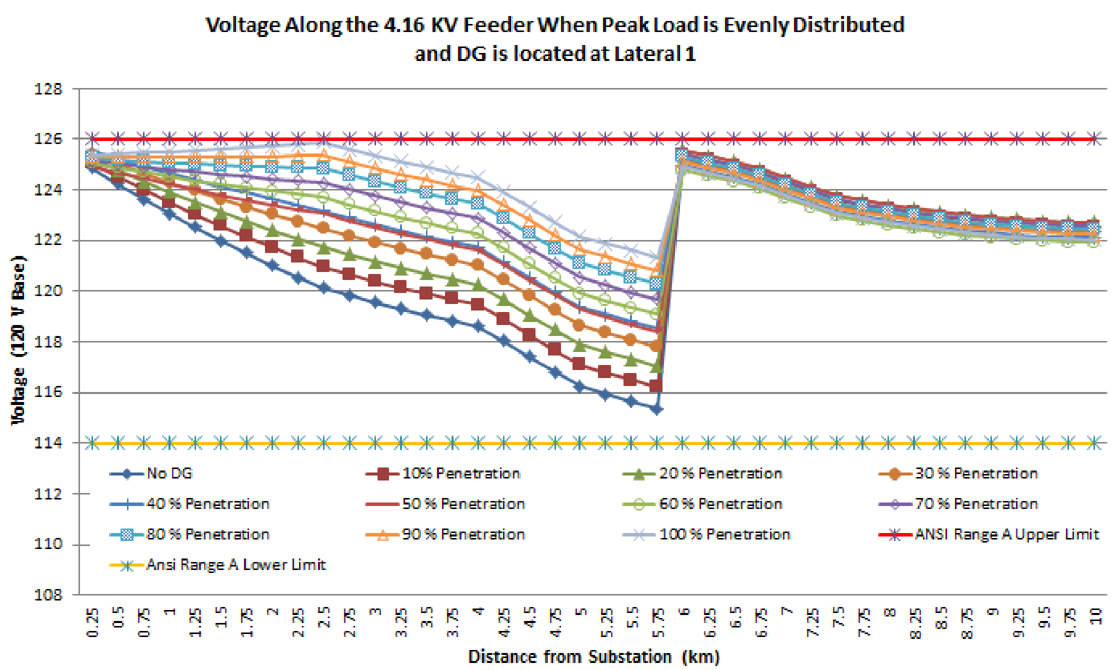

Figure 4.10 Case 1 voltage profile with DG at Lateral 1

When DG is evenly distributed, 70 per cent penetration can be achieved with just a slight overvoltage of 126.09 V at segment 2_6, which is the point of interconnection of the 150 kVAR capacitor bank. The voltage along the mainline up to the regulator is raised above 125.5 V, and the regulator taps down to maintain the voltage below 126 V. Under this scenario, increasing the DG penetration level will modify the upstream voltage noticeably, and will also modify the voltage profile downstream of the voltage regulator since part of the DG capacity is installed downstream of it. Figure 4.11 shows the voltage profile along the feeder when the DG was distributed evenly and the penetration capacity was varied. Figure 4.12 shows the best voltage profile obtained for each DG location.

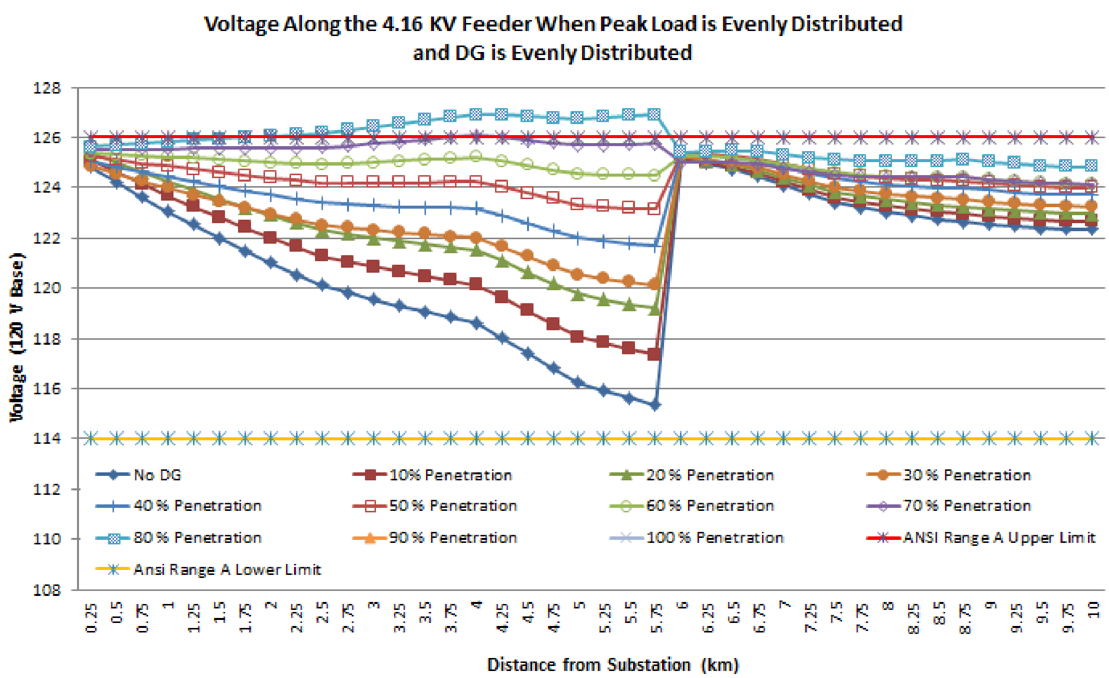

Figure 4.11 Case 1 voltage profile with DG evenly distributed

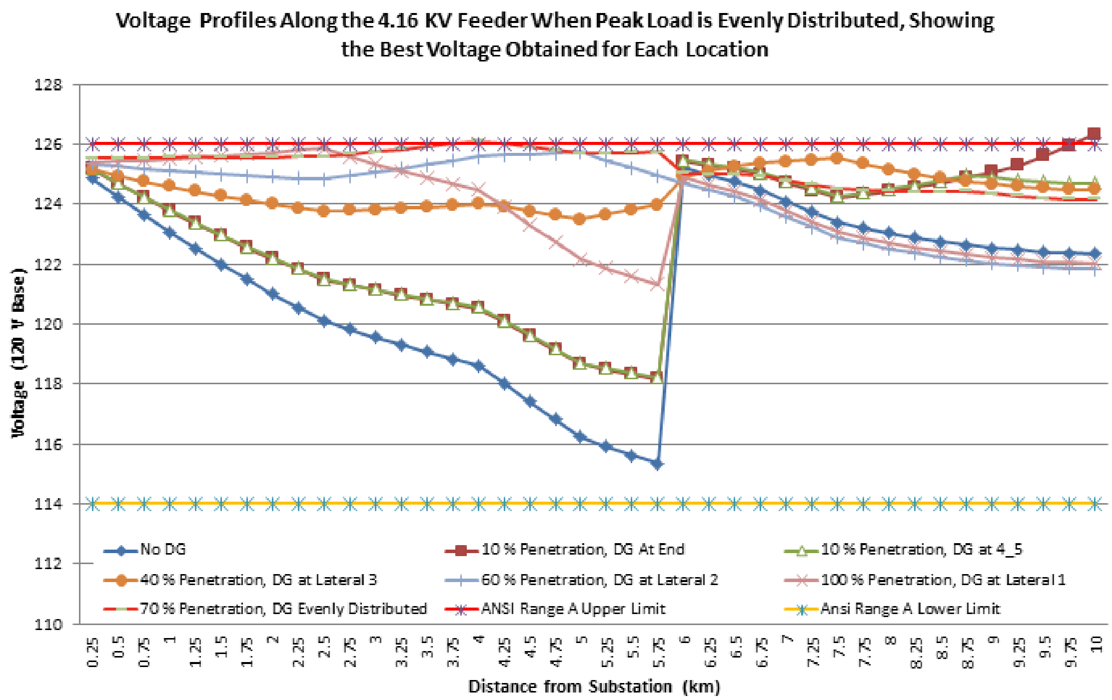

Figure 4.12 Best voltage profiles obtained for Case 1

From Figure 4.12 we can see that the best voltage profile along the mainline up to the voltage regulator was obtained when the DG was evenly distributed and the penetration was set at 70 per cent. Since approximately 63 per cent of the total load and DG capacity is located upstream of the voltage regulator, this distribution of DG affects mainly the voltage profile up to the regulator. Since DG capacity is also present downstream of the regulator, it will improve the voltage profile downstream of it. The best voltage profile after the regulator was obtained when the DG was located at lateral 3, which lies after the regulator, and represented 40 percent penetration. In this location the DG affects the voltage profile downstream of the regulator more than it affects the voltage profile upstream of it. It was observed that even though higher penetrations of DG were possible when the DG was moved closer to the substation, the voltage spread actually decreased as DG capacity got closer to the substation, and the voltages after the voltage regulator were lower than when the DG was placed at lateral 3. It is worthwhile to mention at this point that the changes in the slope of the voltage curves correspond to locations with large load concentrations, such as the three laterals, to the voltage regulator, capacitor banks, and the DGs.

Another result obtained in the simulations is the total losses in the circuit. The losses on the circuit without DGs were 204 kW, representing 7.96 per cent of feeder load as seen from the substation. By observing all cases evaluated, it can be seen that for high penetration levels the kW losses are minimized when the DG is evenly distributed, with the least amount of losses occurring with a penetration of 60 per cent of feeder loading, where losses were 23 kW. It is interesting to note that the lowest losses correspond to the best voltage profile along the whole feeder. Table 4.3 lists the results of the losses in the circuit for the cases simulated, with asterisks representing penetration levels not allowed since they resulted in overvoltages for the DG locations indicated.

Table 4.3 Losses in the 4.16 kV Feeder with Peak Load Distributed Evenly

Losses in the 4.16 kV Feeder with Peak Load Distributed Evenly						
No DG:	204					
DG Penetration	kW Losses Depending on DG Location					
	End	Section 4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	154	151	151	164	184	162
20%	*	117	110	131	166	126
30%	*	*	80	104	150	97
40%	*	*	61	83	137	72
50%	*	*	*	68	128	51
60%	*	*	*	57	118	35
70%	*	*	*	*	112	23
80%	*	*	*	*	107	*
90%	*	*	*	*	104	*
100%	*	*	*	*	103	*

The above results are important because they illustrate how changing the location of the DG affects the maximum DG penetration that can be allowed in the feeder and the resulting modifications to the voltage profile and losses along the feeder. One of the questions that is typically asked regarding DG is what is the maximum allowable capacity that can be installed in distribution feeders. The results of the simulations discussed above show that, when voltage rise is the restricting factor, DG penetration can vary from very low to very high based on the DG location on the feeder. In terms of maximum allowed DG penetration, the simulations show that if the DGs are located upstream of the load, close to the beginning of the feeder, the maximum amount of DG penetration, in this case 100 per cent of feeder peak load, can be reached without causing overvoltages.

It was discussed previously that DGs can benefit the feeders by improving the voltage profile and reducing losses. From the simulations we can see that the way in which the voltage profile and losses along the feeder are modified depends on the location and capacity of the DG. From the graphs of the voltage profile of the feeder we can see that the DG location that will provide the maximum DG penetration will not provide the best voltage profile along the feeder and thus is not able to maximize the benefits of improving feeder voltage. The configuration that provides the best feeder voltage is the case where the DG was evenly distributed along the feeder. Since the DG is located close to the loads it supplies, it reduces the current through all of the feeder segments, leading to a lower, and flatter, voltage drop. This is opposed to the case when DG capacity is placed near the substation, where it reduces the current for the first couple of segments, but still provides a current profile downstream of the DG similar to when the load is supplied from the substation. If we analyze the losses on the feeder we can see that the best performance is also obtained when the DG is evenly distributed and the DG penetration is high, and the worst performance, for all DG penetration levels, is achieved when the DG is located near the beginning of the feeder. When the DG penetration is low, losses were less when the DGs were located near the farthest load center, Lateral 3. These results are important because they show that the highest benefits obtained from the DG may not necessarily correspond to the highest penetration levels.

From the simulation results we can also establish some general observations on how DG affects the voltage profile of the circuit. When all of the DG capacity is placed upstream of the regulator, it will not noticeably modify the voltage profile after the regulator. The presence of a DG after the voltage regulator, will modify the voltage profile downstream of it, with the best improvement in the voltage profile after the voltage regulator. This result is important because it shows that DG can significantly affect the voltage profile downstream of the regulator even if the regulator continues to work properly.

4.3.2 Case 2 - Feeder with 1.5 MVA of Load Distributed Evenly

In this case, the feeder is loaded at 1.5 MVA, or 500 kVA per phase, which is approximately 60 per cent of peak load. The power factor with the capacitors installed was 99 per cent lagging. This can represent the mid-day loading of a feeder serving mostly residential load or commercial load under light loading situations that can occur during the weekends or on holidays. As in the previous case, a DG was placed at different locations along the feeder, with a capacity equal to 100 per cent of the load, which was raised in steps of 10 per cent of DG rated capacity until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A.

The simulation results were similar to the case where the feeder was loaded at peak load and the load distributed evenly. Adding just 10 per cent of DG penetration at the end of the feeder caused the voltage to rise over 126 V. Adding 10 per cent of DG penetration at segment 4_5 increased the voltage along all of the mainline downstream of the regulator to over 125 V. When the DG penetration was increased to 20 per cent, it raised the voltage over 126 V. The reasons for this are the same as previously discussed. In these two locations the loading is relatively light, and most of the power exported by the DG travels upstream along the feeder through conductors with higher impedances. Since the voltage regulator raises the voltage after segment 3_3, the voltage rise pushes the voltage over 126 V.

As the DG was moved towards the substation, into areas with more loading, the allowable capacity increased, since the power exported from the DG is divided among more paths and flows less distance to reach loads, lowering the voltage rise when compared to the case when the DG is located at or near the end of the feeder. If the DG is placed at the interconnection point of Lateral 3, where a greater amount of load is located, the allowed DG capacity increases to 40 percent penetration. It is also interesting to observe that at this amount of DG penetration at this location, the voltage regulator taps down and does not compensate for voltage drop. If the DG penetration at this location is increased to 50 per cent and over, the voltage on the source side of the voltage regulator will increase above 126 V, and the regulator will tap down in an attempt to maintain the output voltage at or below 126 V. However, a short distance after the regulator the voltage again rises over 126 V, around the interconnection point of the DG. Figure 4.13 shows the voltage profile along the mainline for different amounts of DG penetration.

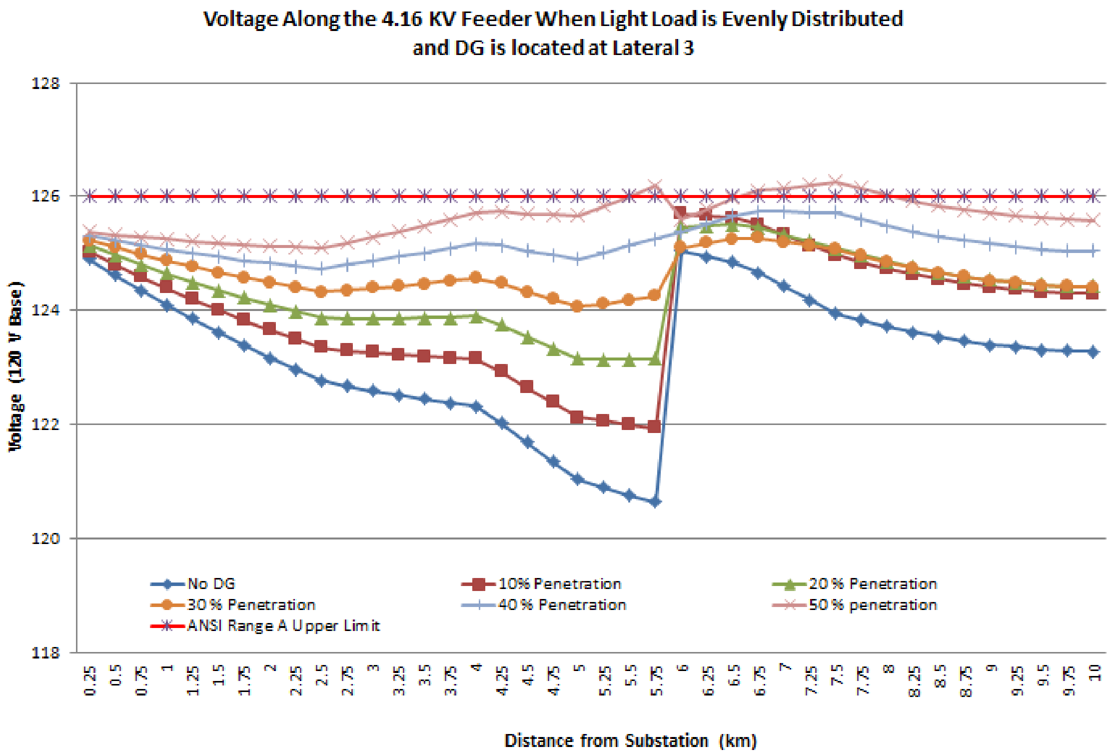

Figure 4.13 Case 2 voltage profile with DG at Lateral 3

When the DG is located at the interconnection point of Lateral 2, before the voltage regulator, the allowed DG penetration increases to 50 per cent. As before, it is interesting to notice that increases in DG penetration at this node have a big effect on the voltage before the voltage regulator, but the voltage after the voltage regulator is not affected as much. In fact, the voltage after the regulator is highest when the DG penetration is 30 per cent, and is lower than the base case without DG when capacity is increased to 40 or 50 per cent penetration. A possible explanation for this is that under these higher penetration levels, the voltage on the source side of the regulator is raised to 124.33 V and 125.13 V when penetration reaches 40 and 50 per cent respectively. In these scenarios, the voltage regulator will not raise the voltage at its load side since doing so could force the voltage above 126 V. When the DG was placed at the interconnection point of Lateral 1, the maximum penetration without causing overvoltages was 90 per cent. If DG capacity was increased to 100 per cent, a slight overvoltage would occur in the segments immediately before and after the DG point of interconnection. Again, increases in DG penetration have a noticeable change in the voltage profile before the regulator, and the voltage downstream of the regulator is not affected as much. In some cases where the DG penetration was increased the voltage downstream of the regulator actually decreased, but the difference between voltages was in the tenths of a volt. When the DG was evenly distributed along the feeder, the highest allowable penetration level was 60 per cent. If the penetration was increased to 70 per cent, overvoltages would occur in the mainline before the voltage regulator. In this case, the voltage along the mainline before and after the voltage regulator is more affected by changes in the penetration levels.

The best voltage profile before the voltage regulator was obtained when 60 per cent of DG penetration was evenly distributed. This also resulted in a very good voltage profile along the load side of the regulator, with the voltage remaining between 125.63 V and 124.86 V. The best voltage profile after the voltage regulator was obtained when the DG penetration was 40 percent lumped at the segment that fed Lateral 3, with the voltage remaining within the range of 125.74 V to 125.05 V. This location also provided very good voltage performance along the mainline before the regulator. Figure 4.14 shows the best voltage profile obtained for each DG location along with the DG capacity.

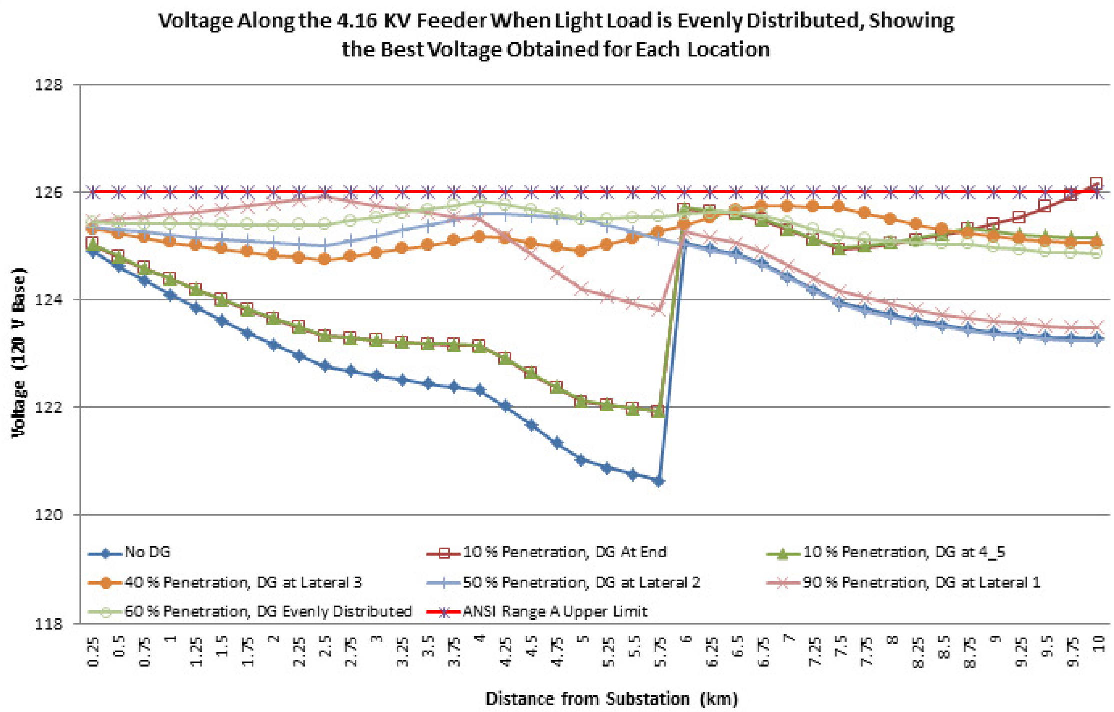

Figure 4.14 Best voltage profiles for Case 2

In this load scenario, the losses on the circuit without DG were 74 kW. The losses were reduced the most when 60 per cent penetration of DG was distributed evenly, with 12 kW of losses. This was followed by losses of 22 kW when 50 percent of DG penetration was also distributed evenly. In this case the lowest losses match the best voltage profile obtained in the simulations. Table 4.4 lists the results of the losses in the circuits for the cases simulated.

Table 4.4 Losses in the 4.16 kV Feeder with Light Load Distributed Evenly

kW Losses in the 4.16 kV Feeder with Light Load Distributed Evenly						
Losses with No DG:74						
DG Penetration	kW Losses Depending on DG Location					
	End	4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	58	57	57	62	68	61
20%	*	45	43	50	62	49
30%	*	*	33	41	57	39
40%	*	*	25	33	52	30
50%	*	*	*	28	49	22
60%	*	*	*		45	16
70%	*	*	*	*	43	*
80%	*	*	*	*	41	*
90%	*	*	*	*	40	*
100%	*	*	*	*	*	*

The simulation results in this case were very similar to the previous case, when the circuit was loaded at peak load. The same general relationship between DG location and capacity to the modification of circuit voltage profile and losses was observed. As before, the highest DG penetration was obtained when the DG was located at Lateral 1, close to the substation. This case also provided the highest losses for all DG penetration levels when compared to other DG locations. The best voltage profile along the entire feeder and lowest losses were also obtained when the DG was distributed evenly along the feeder and the penetration level was high. When the DG penetration is low, losses were also less when the DGs were located near the farthest load center, Lateral 3. Once again, when the DG capacity was installed before the voltage regulator, the results showed that the voltage profile after the regulator was not modified extensively. Also, when the DG capacity was installed after the generator, the voltage profile downstream of it was modified accordingly. The best voltage profile downstream of the regulator was also obtained when the DG is placed on Lateral 3. The reductions in the percent of the penetration levels of the DGs was due to the fact that under light load the voltage drop on the circuit is lower and the voltage profile higher when compared to full load. It requires less voltage rise to cause the voltage to exceed the maximum allowed voltage under ANSI Range A, resulting in the lower permissible penetration levels in terms of total DG capacity and in percent of DG capacity compared to feeder load.

In this case the maximum DG capacity was set at 1.5 MVA, equal to the load of the circuit. This was lower than the DG capacity established for the previous case, which was 2.5 MVA. This was done to maintain relationship in terms of penetration level, which for this study was defined as DG capacity divided by feeder loading for the case evaluated. A very important result can be obtained from these simulations. The results show that, in terms of voltage rise, the maximum allowed DG penetration level depends not only on the location of the DG and the distribution of the load, but on the loading of the circuit under peak DG production. This is very important because shows that if under certain situations, it is more useful to specify the penetration levels of DG based on the minimum load coincident with peak demand. This can establish the maximum amount of DG penetration on the feeder. For example, when evaluating the interconnection of DG, the analysis must evaluate the interconnection of the DG during light loading on the feeder.

4.3.3 Case 3 - Feeder with 1.5 MVA of Load, 1MVA Distributed Along First Half of Feeder

In this case the feeder is loaded at 1.5 MVA, with 1 MVA, representing 2/3 of the load, distributed evenly within the first half of the feeder. This can represent a feeder with a considerable amount of urban load but also supplying suburban or rural loads farther away from the substation. As in previous cases, a DG of rated capacity equal to the load on the feeder was placed at different locations along the feeder, and the DG output was raised in steps of 10 per cent until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A.

As in the previous two cases, when the DG was lumped at the end of the feeder, just 10 per cent penetration caused a slight overvoltage at the PCC with the DG. When the DG was moved to segment 4_5, 10 per cent penetration was allowed without raising the voltage above maximum limits. When the DG was located at the interconnection point of Lateral 3, just 30 per cent penetration was possible. The reduction in permissible DG penetration at this point when compared to previous cases is due to lighter loading of the circuit near the interconnection point. More current will flow upstream, resulting in a higher voltage rise. It is interesting to see that even though this is the highest DG penetration possible without causing overvoltages, when the DG penetration was 20 per cent the voltage after the regulator reached its highest value. This occurs because at 20 per cent penetration the voltage just before the voltage regulator is 124.68 V, and the regulator taps up to raise the voltage. However, when the penetration was 30 per cent, the voltage just before the regulator reached 125.63 V. In this case the regulator actually tapped down to maintain the voltage below 126 V.

When the DG was placed at the interconnection point of Lateral 2, the maximum allowed DG penetration was 40 per cent. While this penetration level raised the voltage along the mainline to the highest level compared to the other penetration levels at this point, this level actually pushed the voltage after the voltage regulator to the lowest level for this DG location. A similar situation occurred when the penetration level was 30 per cent. This occurred because at both penetration levels the voltage immediately before the voltage regulator was over 125 V. When the DG penetration was 30 per cent, the voltage regulator did not raise the voltage at its load side, since doing so would exceed 126 V. When the DG penetration was 40 per cent, the voltage regulator tapped down to lower the voltage.

When the DG was placed at the interconnection point of Lateral 1, the highest allowed penetration level was 80 per cent. Under this scenario, the voltage regulator did not regulate voltage downstream of it. As before, when the DG is located before the voltage regulator, the voltage profile upstream is clearly modified when DG penetration is varied, while the voltage on the load side of the regulator is not modified very much, as evidenced by the closely spaced voltage curves. When the DG was distributed evenly along the feeder, the maximum DG capacity that could be installed represented 60 per cent of feeder load. With this distribution the voltage along the mainline before and after the regulator was modified for different penetration levels. The voltage rise before the voltage regulator proved to be the limiting factor under this scenario.

The best voltage profile upstream of the voltage regulator was obtained when DG was evenly distributed and the penetration level reached 60 per cent. The best voltage profile downstream of the regulator was obtained when 20 per cent of DG penetration was placed at lateral 3. As before, this shows that a DG located after a voltage regulator has more influence on the steady state voltage downstream of the regulator than a DG located upstream of the voltage regulator, even when the capacity of the DG placed upstream is considerably greater. Figure 4.15 shows the best voltage profile obtained for each DG location along with the DG capacity.

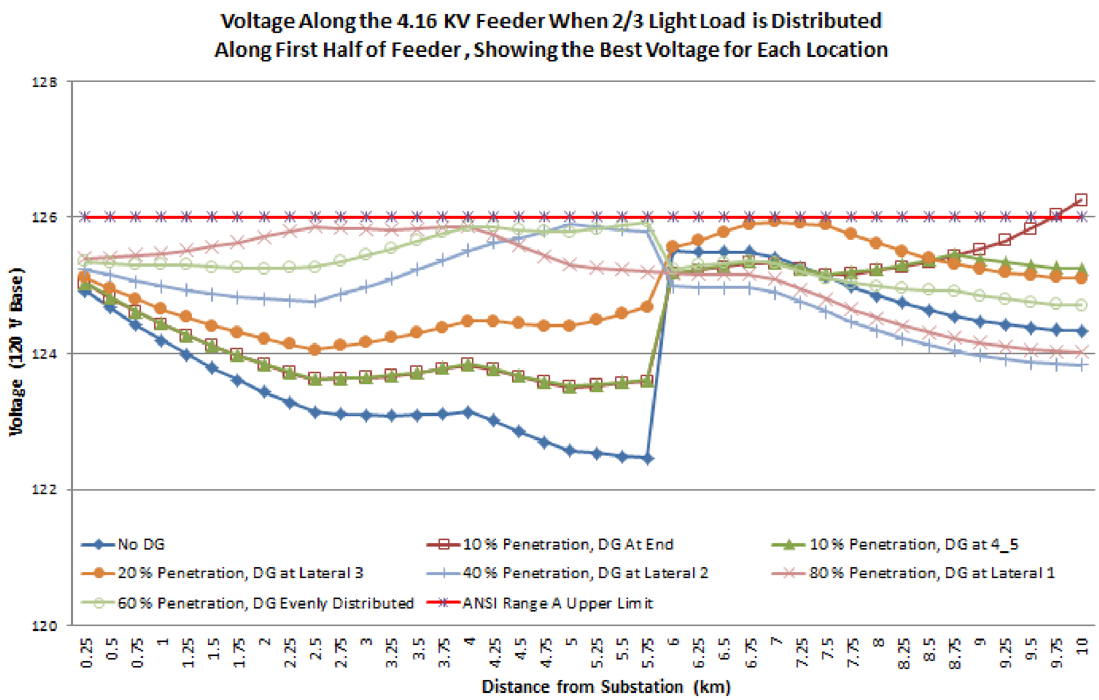

Figure 4.15 Best voltages obtained for Case 3

In this load scenario, the losses on the circuit without DG were 47 kW. The losses were reduced the most when 60 per cent penetration of DG was distributed evenly, with 11 kW of losses. This was followed by losses of 15 kW when 50 percent of DG penetration was also distributed evenly. In this case the lowest losses match the best voltage profile obtained in the simulations. Table 4.5 lists the results of the losses in the circuits for the cases simulated.

Table 4.5 kW Losses when 2/3 of Load is Distributed Along the First Half of Feeder

Losses in the 4.16 kV Feeder with 2/3 of Load Distributed along the First Half of the Feeder						
No DG:	47					
DG Penetration	kW Losses Depending on DG Location					
	End	4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	36	35	35	37	41	39
20%	*	28	27	29	36	31
30%	*	*	21	23	31	25
40%	*	*	*	19	27	19
50%	*	*	*	16	24	15
60%	*	*	*	*	22	11
70%	*	*	*	*	20	*
80%	*	*	*	*	19	*
90%	*	*	*	*	*	*
100%	*	*	*	*	*	*

The simulation results in this case were very similar to the previous two cases, when load was distributed evenly along the feeder. The same general relationship between DG location and capacity to the modification of circuit voltage profile and losses was observed. As before, the highest DG penetration was obtained when the DG was located at Lateral 1, close to the substation, with 80 per cent penetration. This case also provided the highest losses per DG penetration level when compared to other DG locations. The best voltage profile along the entire feeder and lowest losses were also obtained when the DG was distributed evenly along the feeder with 60 per cent penetration. Also, when the DG penetration is low, losses were less when the DGs were located near the farthest load center, Lateral 3.

Once again, when the DG capacity was installed before the voltage regulator, the results showed that the voltage profile after the regulator was not modified extensively. Also, when the

DG capacity was installed after the regulator, the voltage profile downstream of it was modified accordingly. The best voltage profile downstream of the regulator was also obtained when the DG is placed on Lateral 3.

The reductions in the percent of the penetration levels of the DGs was due to the fact that under light load the voltage drop on the circuit is lower and the voltage profile higher when compared to full load. Also, since a higher percentage of the load was distributed closer to the substation, the current along the mainline dropped faster than on the other two cases, helping to maintain a flatter voltage profile through the feeder, as evidenced in the graphs. It requires less voltage rise to cause the voltage to exceed the maximum allowed voltage under ANSI Range A, resulting in the lower permissible penetration levels in terms of total DG capacity and in percent of DG capacity compared to feeder load. These results seem to indicate that a circuit with more voltage drop is able to accommodate more localized DG capacity than a similar circuit with lower voltage drop. The results also showed that under certain scenarios, higher allowed capacity of DG does not necessarily result in a better voltage profile along certain parts of the feeder when compared to lower penetration levels.

4.3.4 Case 4 - Feeder with 1.5 MVA of Load, 1 MVA Distributed Along Second Half of Feeder

In this case the feeder is loaded at 1.5 MVA, with 1 MVA, representing 2/3 of the load, distributed evenly within the second half of the feeder. This can represent a feeder with a considerable amount of load located farther away from the substation. As in previous cases, a DG of rated capacity equal to the load on the feeder was placed at different locations along the feeder, and the DG output was raised in steps of 10 per cent until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A.

The results of this scenario differed somewhat to the other three scenarios discussed previously, due to the revised load distribution, ratings and location of voltage regulating equipment, and resulting voltage profile of the feeder. When the DG was located at the end of the feeder it was possible to interconnect 20 per cent penetration. Since a higher percentage of the load of the feeder is located closer to its end, the voltage drop along the mainline is greater, even after being adjusted by the voltage regulator. This allows for more voltage rise along the feeder before high voltage limits are met. The shape of the voltage profile is the same as for the other loading scenarios with the DG connected at the end, with the highest voltage occurring at the end of the feeder. When the DG was moved to segment 4_5, 30 per cent penetration was allowed without raising the voltage above maximum limits. This is due to the same reasons as before. The higher voltage drop along the feeder will allow more room for voltage rise. Also, the presence of more load near the DG helps to mitigate voltage rise.

When the DG was located at the interconnection point of Lateral 3, 40 per cent penetration was possible. The amount of DG penetration at this point is limited by the voltage rise in the mainline close to the point of interconnection. The voltage at the output of the voltage regulator will remain close to 125 volts for increasing penetration, but at penetration levels of 50 per cent or more the voltage around the interconnection point will exceed 126 V. This voltage exceeds the voltage level specified under ANSI Range A, but is below the voltage trip point specified under IEEE Std. 1547-2003. In this case the location of the DG is clearly marked by the peak in the voltage profile at a distance of 7.5 km from the substation.

When the DG was placed at the interconnection point of Lateral 2, the maximum allowed DG penetration was 70 per cent. This penetration level raised the voltage along the mainline to the highest level, both before and after the regulator, compared to the other penetration levels at this point. This occurred because a large portion of the load of the feeder lies downstream of the DG. Since the DG feeds a portion of this load, the current from the substation is reduced, as is the voltage drop along the feeder up to the point of interconnection of the DG. This is evident from the voltage rise along the feeder from the substation to the DG for this amount of penetration. At lower penetration levels the voltage between the substation and the DG would remain nearly the same or would drop with decreasing DG penetration, since more load is served from the substation and the voltage drop increases. It must also be mentioned that even if the DG was placed upstream of the voltage regulator, increasing penetration levels modified the voltage downstream of the regulator. Beginning at 60 percent penetration, the voltage regulator stops regulating the voltage at the load side, since the voltage at its load side increased over 125 V. This causes a wider spread of the voltage downstream of the regulator than on previous cases where DG was located at the same interconnection point.

When the DG was placed at the interconnection point of Lateral 1, the highest allowed penetration level was 100 per cent. As in cases before this, when the DG is located before the voltage regulator, the voltage profile upstream is clearly modified when DG penetration is varied, while the voltage on the load side of the regulator is not modified very much, as evidenced by the closely spaced voltage curves. When the DG was distributed evenly along the feeder, the maximum DG capacity that could be installed represented 70 per cent of feeder load. With this distribution the voltage along the mainline before and after the regulator was modified for different penetration levels. In fact, the voltage profile after the voltage regulator showed more distance between the voltage curves than on any other case. This is due to the fact that in this scenario greater DG capacity is distributed downstream of the regulator, and increasing DG penetration would feed the local load, noticeably lowering the voltage drop along the mainline. The voltage rise just before the voltage regulator proved to be the limiting factor under this scenario.

The best voltage profile overall, both upstream and downstream of the regulator, was obtained when DG was evenly distributed and the penetration level reached 70 per cent. Figure 4.16 shows the best voltage profile obtained for each DG location along with the DG capacity.

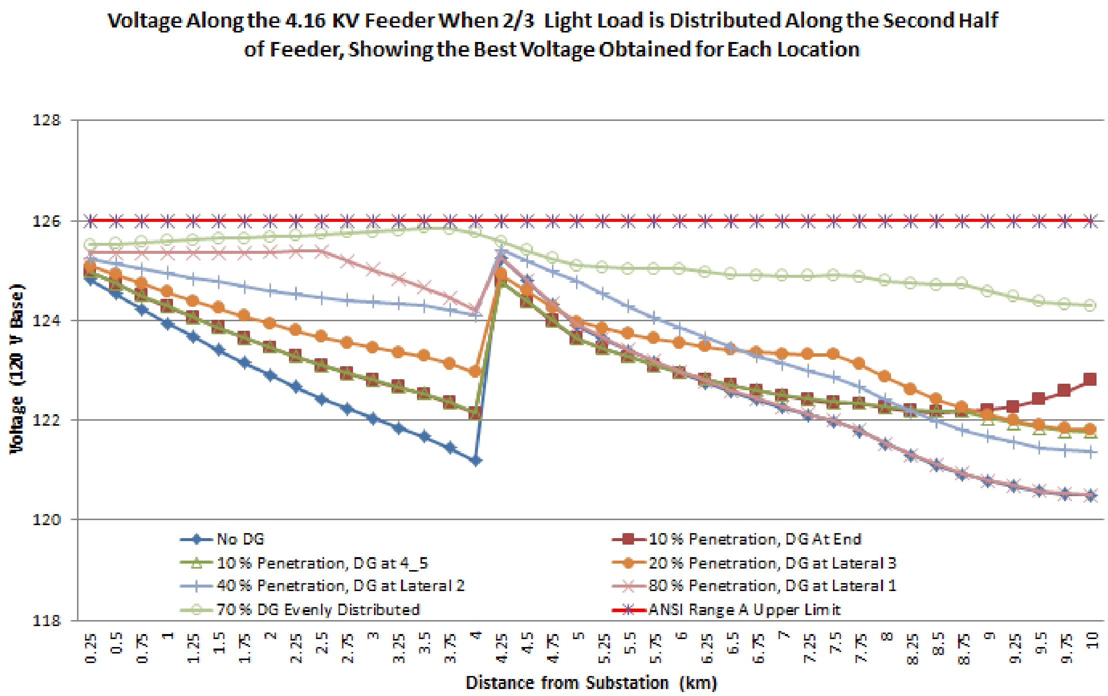

Figure 4.16 Best voltages for Case 4

In this load scenario, the losses on the circuit without DG were 83 kW. Lowest losses were obtained when 70 per cent penetration of DG was distributed evenly, with 11 kW of losses. This was followed by losses of 16 kW when 60 percent of DG penetration was also distributed evenly. The higher overall losses for this case, when compared to the previous cases under light load, is due to the load being distributed farther from the substation. This results in currents flowing through longer distances to reach loads. As in previous cases, the lowest losses match the best voltage profile obtained in the simulations, which occur when a DG penetration of 70 per cent is distributed evenly across the feeder. Table 4.6 lists the results of the losses in the circuits for the cases simulated.

Table 4.6 Losses When Load is Distributed Along Second Half of Feeder

kW Losses in the 4.16 kV Feeder with Light Load With 2/3 Distributed Along Second Half of Feeder						
No DG:	83					
DG Penetration	kW Losses Depending on DG Location					
	End	4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	62	62	63	69	76	67
20%	50	47	47	57	70	54
30%	*	37	35	46	64	42
40%	*	*	25	38	59	31
50%	*	*	*	31	56	23
60%	*	*	*	26	53	16
70%	*	*	*	22	50	11
80%	*	*	*	*	49	*
90%	*	*	*	*	47	*
100%	*	*	*	*	47	*

From the simulation results we can observe that higher penetration levels were obtained for the end of the feeder when compared to the previous three cases because the DGs are located in areas with more loading. This is important because when these results are compared to the previous cases we can see that in general, when the DG capacity is located near the loads it supplies, the allowed DG penetration is higher. Also, the increased voltage drop along the feeder allowed more voltage rise before voltage rise becomes an issue. Overall, the penetration levels along the different DG configurations equaled or exceeded the penetration levels for the other three cases studied. However, the losses in the circuit were the highest of the three cases with light load.

The results also show that when the DG is placed upstream of the load, higher DG penetration can be achieved since a large percentage of the current from the higher capacity DG will flow downstream to the load. This, however, results in a voltage drop, as opposed to voltage rise, and explains why DGs upstream of the load do not produce the best benefits in terms of improving voltage profile or reducing losses.

4.3.5 Case 5 - Interactions Between Voltage Regulator and DG

Another issue discussed in the literature review is that of voltage fluctuations and excessive tap changer operations with varying DG output. Since the simulation software does not provide time analysis, fluctuations of DG output from changes in irradiance cannot be properly evaluated. However, the software does provide a capability to analyze what occurs with the voltage profile when DGs vary their output for longer durations, such as more prolonged variations in irradiance or when they disconnect and reconnect after system disturbances. This phenomena can be used to understand how these interactions will manifest in the presence of voltage regulators. To examine this phenomena, the 4.16 kV circuit with 2/3 of the load distributed at the end was used.

IEEE Std. 1547-2003 establishes that a DG must disconnect from a circuit if certain voltage and frequency thresholds are crossed, as indicated previously in tables 2.1 and 2.2. Also, the standard requires that the DG remains disconnected for a given time after the voltage and frequency have stabilized. This can be as long as five minutes. When DG is located in a feeder with a voltage regulator, the disconnection and reconnection of the DG will affect the voltage profile and may lead to operations by the voltage regulator. A likely scenario would present a sequence of events as follows:

1. The feeder is operating under steady state, with a given DG output and voltage regulator setting.

2. A disturbance at some point in the system causes the voltage or frequency to exceed permissible levels and the DG inverter disconnects.

3. The voltage regulator, sensing the change in conditions, will initiate a change in taps to compensate for the increased load. This tap change will start after the predetermined time interval has lapsed , which can be 30 seconds or one minute.

4. The voltage regulator finishes adjusting its taps to properly regulate the voltage.

5. Once the predetermined time has passed, the inverter will reconnect to the circuit.

6. The voltage regulator will operate to adjust the voltage due to the change in circuit loading caused by the reconnection of the DG.

To simulate this scenario, the following steps were taken. A load flow was performed for the circuit before the disturbance occurs with the DG connected and the voltage regulator set to adjust its taps automatically. The voltage regulator was then put on manual control to fix the taps and the DG was turned off. The resulting load flow represents the conditions on the circuit after the DG disconnects and before the voltage regulator operates to adjust the voltage. The regulator is then set to operate automatically and a load flow is performed. This represents the time interval between the moment the voltage regulator has adjusted taps to compensate from the increased load and the moment the DG reconnects. With the regulator again set at manual control to fix the taps, the DG is turned ON, and the resulting load flow represents the time interval after the DG reconnects and the voltage regulator adjusts taps. Finally, the voltage regulator is set to automatically regulate the voltage and the DG is left ON.

Figures 4.17 and 4.18 show the steady state voltage profile of the circuit with the DG is interconnected at Lateral 3 and the penetration level set to 10 per cent and 40 per cent respectively.

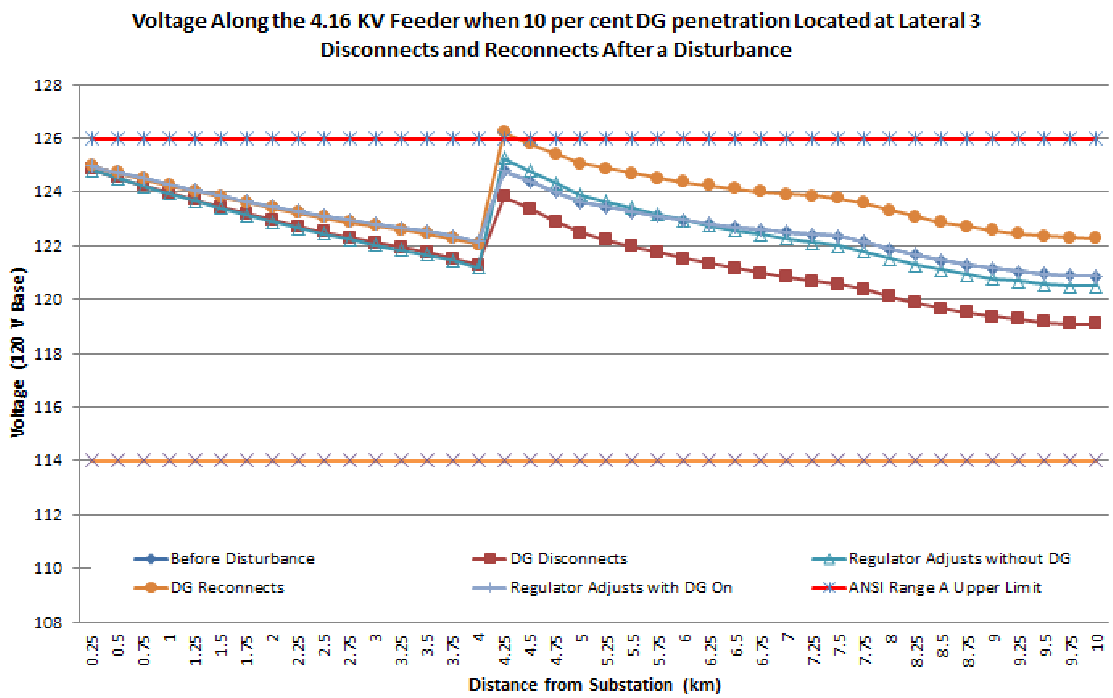

Figure 4.17 Case 5 voltage profile with 10 per cent DG at Lateral 3

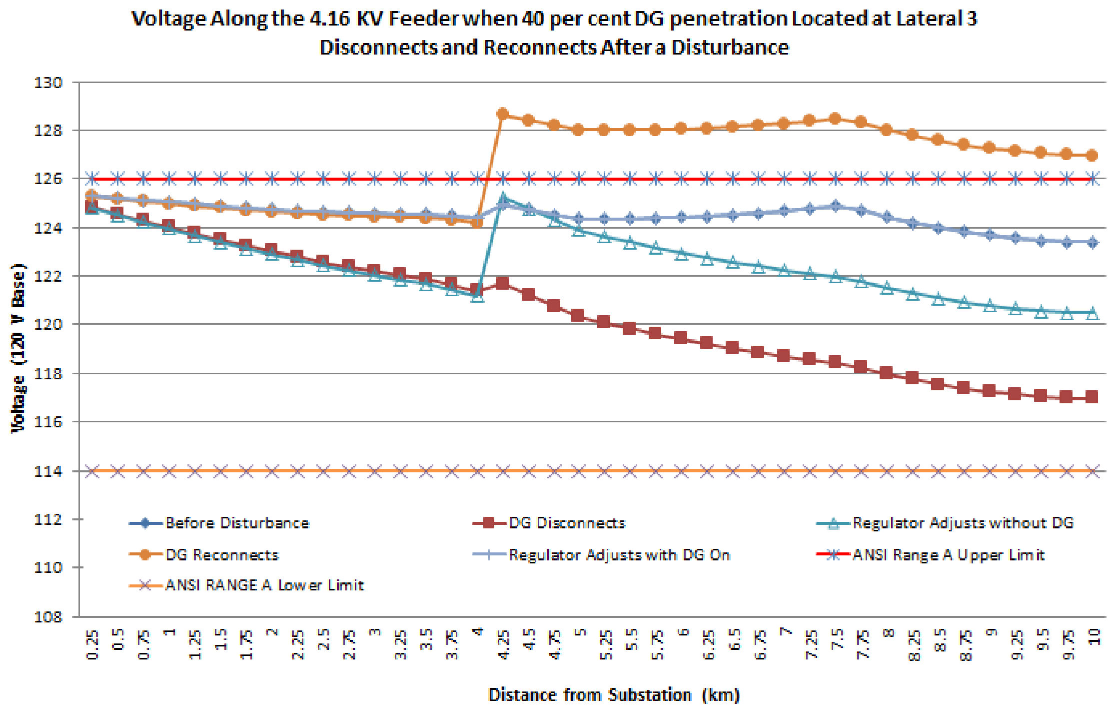

Figure 4.18 Case 5 voltage profile with 40 per cent DG at Lateral 3

From the previous figures we can see that for the DG penetration level at Lateral 3 previously determined to be permissible in the context of voltage rise, an overvoltage of up to 128.5 V would occur when 40 per cent of DG penetration, the maximum allowed penetration level before voltage rise occurs as determined in the previous simulations, reconnects after a disturbance. This overvoltage will last until the voltage regulator adjusts its taps after the DG reconnects, which can take up to one minute. From Figure 4.17 we can see that penetration levels as low as 10 per cent at Lateral 3 will cause slight overvoltages at the interconnection point.

The same behavior can be observed when this analysis is performed for the case in which the DG is located at Lateral 1. Figure 4.19 shows the results when the penetration at Lateral 2 is 70 per cent, the highest level of DG penetration possible for this location before voltage rise becomes an issue, as determined in the previous simulations.

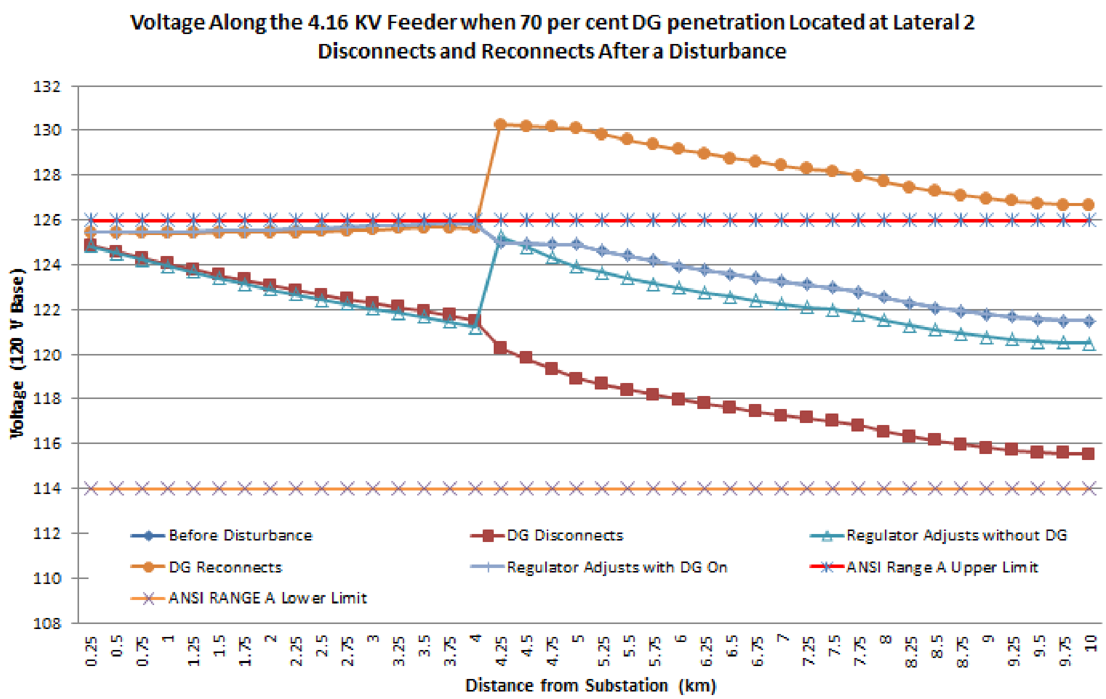

Figure 4.19 Case 5 voltage profile with 70 per cent DG at Lateral 2

We can observe that the disconnection and reconnection of the DG will cause an overvoltage of 130.26 V at the point of interconnection. Since the voltage does not exceed 110 per cent of nominal, the DG will not disconnect.

The results of these simulations are important. They show that under some circumstances the interactions of DGs and voltage regulators can lead to voltages outside the range established under ANSI Range A. This phenomenon can place further restrictions on the location and capacity of DGs when voltage regulators are present. It can be assumed that under certain circumstances the disconnection and reconnection of DGs in the presence of voltage regulators can even lead to undervoltages followed by overvoltages. This can further reduce the power quality of the circuit and lead to improper operation of equipment. The settings under IEEE Std. 1547-2003 do not adequately safeguard against this phenomenon.

4.3.6 Case 6 - 13.2 kV Feeder with 11 MVA of Load Distributed Evenly Along the Feeder

In this case the feeder is energized at 13.2 kV and loaded to 11 MVA, with the load distributed evenly along the feeder as described above. This can represent an urban feeder with a large amount of commercial load. As in previous cases, a DG of rated capacity equal to the load on the feeder was placed at different locations along the feeder, and the DG output was raised in steps of 10 per cent until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A.

Overall, higher penetrations of DG were possible at all DG locations except at Lateral 1 and in the case where the DG was evenly distributed, whereas before a penetration level of 100 per cent was possible without voltage rise issues. When the DG was located at the end of the feeder it was possible to interconnect 30 per cent penetration, compared to just 10 per cent penetration in the corresponding 4.16 kV case. The shape of the voltage profile is the same as for the other loading scenarios with the DG connected at the end, with the highest voltage occurring at the end of the feeder. When the DG was moved to segment 4_5, 40 per cent penetration was allowed without raising the voltage above maximum limits, and raising the penetration level to 50 per cent caused a slight overvoltage at the PCC and towards the end of the feeder. The presence of more load near the DG, and two possible paths for the current exported by the DG allow more DG penetration at section 4_5 than when the DG is located at the end.

When the DG was located at the interconnection point of Lateral 3, 70 per cent penetration was possible. The amount of DG penetration at this point is limited by the voltage rise in the mainline close to the PCC. When the DG was placed at the interconnection point of Lateral 2 or the interconnection point of Lateral 1, the maximum allowed DG penetration was 100 per cent. This penetration level is possible because about 62.5 per cent of the load lies downstream of the DG when it is located at Lateral 2, and 93.75 per cent of the load lies downstream of the DG when it is located at Lateral 1. In these cases most of the exported power would flow downstream of the DG and not contribute to voltage rise. The voltage profile before the DG is improved due to the reduced voltage drop caused by the reduced current from the substation and the current flowing from the DG to the loads upstream of it. As in previous cases, a given DG capacity placed at the interconnection point of Lateral 2 provides a better voltage profile than placing the same DG capacity at Lateral 1. It is interesting to observe that for this scenario, when the DG is located at Lateral 1, the voltage profile is least affected for different DG penetration levels, as evidenced by the closely spaced curves in Figure 4.20.

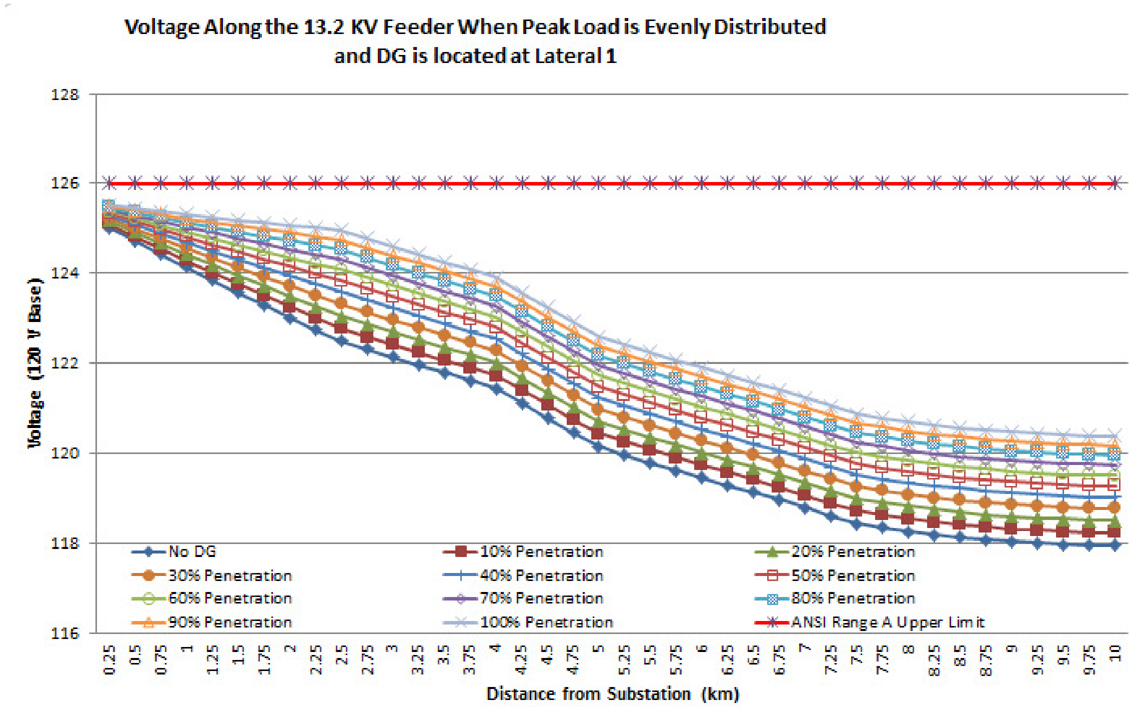

Figure 4.20 Case 6 voltage profile with DG located at Lateral 1

The difference between the voltage at the end of the feeder for the case with no DG (117.95 V) and when the DG penetration is 100 per cent (120.39 V) is 2.44 V. This is due to the fact the per unit voltage rise, or as in this case voltage drop, along the feeder is less than on the 4.16 kV feeder due to the higher voltage level of the circuit.

When the DG was distributed evenly along the feeder, the maximum DG capacity that could be installed also represented 100 per cent of feeder load. This scenario provided the flattest voltage profile along the feeder. Figure 4.21 shows the best voltage profile obtained for each DG location along with the DG capacity.

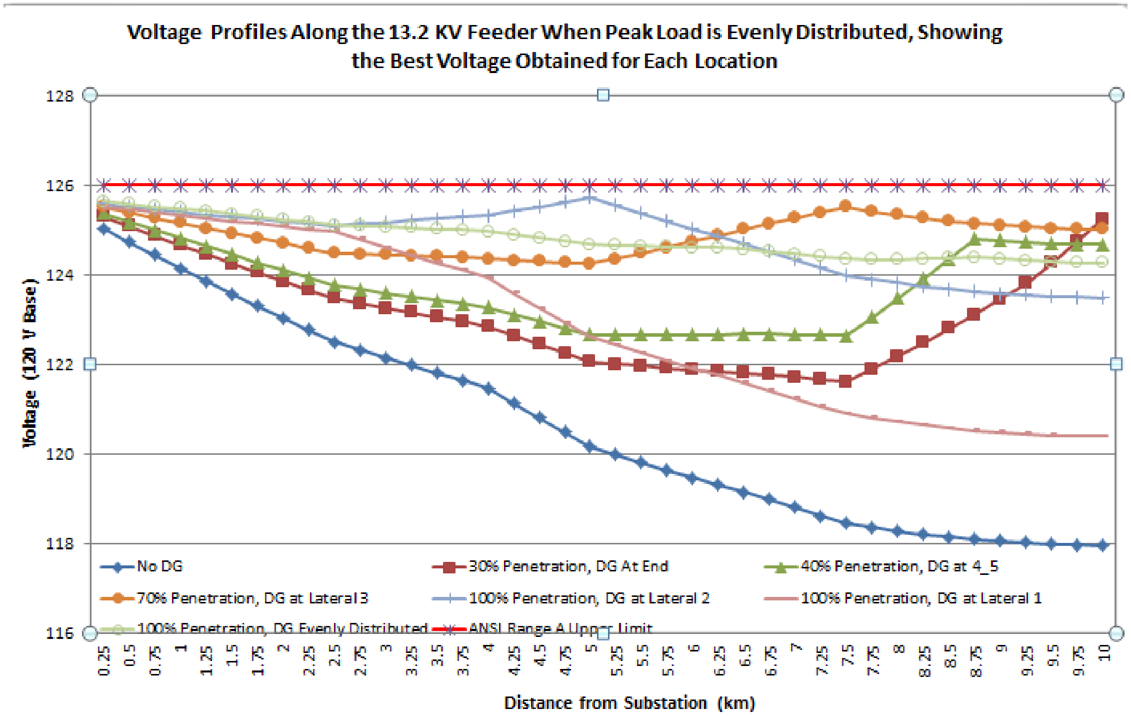

Figure 4.21 Best voltages for Case 6.

In this figure we can see that the best voltage profile overall was obtained when DG was evenly distributed and the penetration level reached 100 per cent. This scenario results in the flattest voltage profile along the feeder. When 70 per cent of DG penetration was placed at Lateral 3, the highest voltages along the final 2.25 km of the feeder were obtained. The highest voltage along the mainline was obtained around the point of interconnection of Lateral 2 when 100 per cent penetration was placed at this location.

In this scenario, the losses on the circuit without DG were 357 kW. The lowest losses were obtained with higher penetration levels of DG distributed evenly, with 13 kW of losses obtained when the DG penetration level was 100 per cent. This is just 11.2 per cent and 6.7 per cent of the losses obtained when 100 per cent of DG was located at Lateral 2 and Lateral 1 respectively. As in previous cases, the lowest losses match the best voltage profile obtained in the simulations, which occur when a DG penetration of 100 per cent is distributed evenly across the feeder. Also, as in previous cases, the highest losses with DG present were obtained when the DG was located at the interconnection point of Lateral 1. It should also be mentioned that as in previous cases, when DG penetration is low, the lowest losses were achieved when the DG was located at Lateral 3. Table 4.7 lists the results of the losses in the circuits for the cases simulated.

Table 4.7 Losses in the 13.2 kV Feeder with Peak Load Distributed Evenly

kW Losses in the 13.2 kV Feeder with Load Distributed Evenly - Peak Demand						
No DG:	357					
DG Penetration	kW Losses Depending on DG Location					
	End	4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	275	269	269	292	324	290
20%	237	213	199	237	294	231
30%	239	184	147	191	269	179
40%	*	181	112	154	247	135
50%	*	*	93	126	229	98
60%	*	*	89	108	214	68
70%	*	*	100	97	204	44
80%	*	*	*	95	197	28
90%	*	*	*	102	193	17
100%	*	*	*	116	194	13

From the simulation results we can observe that higher penetration levels were obtained in all cases except when the DG is located at Lateral 1 or when evenly distributed, when the maximum penetration level as in the 4.16 kV for both cases is 100 per cent. The higher penetration levels are due to the fact that the voltage rise on the 13.2 kV feeder is less when compared to the corresponding 4.16 kV cases. A voltage rise of 40 V on a 4.16 kV feeder represents 1.667 per cent of rated phase voltage. The same 40 V rise on a 13.2 kV feeder represents 0.53 per cent of rated phase voltage. This is 31 per cent of the voltage rise in p.u. of the 4.16 kV feeder. Also, the current contribution from a DG is lower on the higher voltage circuit. For example, the current at the primary side of the PCC of a DG exporting 100 kVA per phase is 41.67 A per phase. The same DG exporting 100 kVA per phase on a 13.2 kV circuit will produce a phase current of 13.12 A. This is important because it tells us that feeders energized at higher voltages will be able to interconnect more DG, both in terms of capacity and of penetration level before voltage rise becomes an issue.

In terms of the maximum DG penetration relative to the DG interconnection location, it can be seen, as in previous cases, that when the DG is located at or before the load, higher penetration levels can be achieved, at the expense of higher losses. The best scenario in terms of loss reduction and overall feeder voltage profile improvement was obtained when the DG was distributed evenly across the feeder.

4.3.7 Case 7 - 13.2 kV Feeder with 6.6 MVA of Load Distributed Evenly Along the Feeder

In this case the feeder is energized at 13.2 kV and loaded to 6.6 MVA, with the load distributed evenly along the feeder as described above. This can represent a predominantly residential feeder. As in previous cases, a DG of rated capacity equal to the load on the feeder was placed at different locations along the feeder, and the DG output was raised in steps of 10 per cent until the voltage at any part of the feeder exceeded the permissible range of + 5 per cent as established by ANSI C84.1-2006 Range A.

The results of this scenario were very similar to the case when the 13.2 kV feeder was loaded with peak load. Again, higher penetrations of DG were possible at all locations except at Lateral 1 and in the case where the DG was evenly distributed, whereas before a penetration level of 100 per cent was possible without voltage rise issues. As in the previous case, when the DG was located at the end of the feeder it was possible to interconnect 30 per cent penetration, compared to just 10 per cent penetration in the corresponding 4.16 kV case. The shape of the voltage profile is the same as for the other loading scenarios with the DG connected at the end, with the highest voltage occurring at the end of the feeder. When the DG was moved to segment 4_5, 40 per cent penetration was allowed without raising the voltage above maximum limits. This is due to the same reasons as before.

When the DG was located at the interconnection point of Lateral 3, 60 per cent penetration was possible without any overvoltage, and raising the penetration level to 70 per cent caused a very slight overvoltage of just 126.1 V at the PCC. Thus the amount of DG penetration at this point is limited by the voltage rise in the mainline close to the point of interconnection. When the DG was placed at the interconnection point of Lateral 2 the maximum penetration level without overvoltages was 90 per cent, and 100 per cent penetration would cause a slight overvoltage of 126.2 V. This is due to the fact that in this case the circuit loading is lower and the resulting voltage rise at the PCC was enough to push the voltage above ANSI C84.1-2006 limits.

When the DG was located at the interconnection point of Lateral 1, the maximum allowed DG penetration was 100 per cent. This penetration level is possible because about 93.75 per cent of the load lies downstream of the DG, and most of the exported power would flow downstream of the DG and not contribute to voltage rise. The voltage profile before the DG is improved slightly due to the reduced voltage drop caused by the reduced current from the substation and the current flowing from the DG to the loads upstream of it. Also, the voltage profile is least affected for different DG penetration levels, as was seen in the previous case. The difference between the voltage at the end of the feeder for the case with no DG (121.82 V) and when the DG penetration is 100 per cent (123.06 V) is 1.24 V. This is due to the fact the per unit voltage rise, or as in this case voltage drop, along the feeder is less than on the 4.16 kV feeder due to the higher voltage.

When the DG was distributed evenly along the feeder, the maximum DG capacity that could be installed also represented 100 per cent of feeder load. This scenario provided the flattest voltage profile along the feeder, as shown in Figure 4.22.

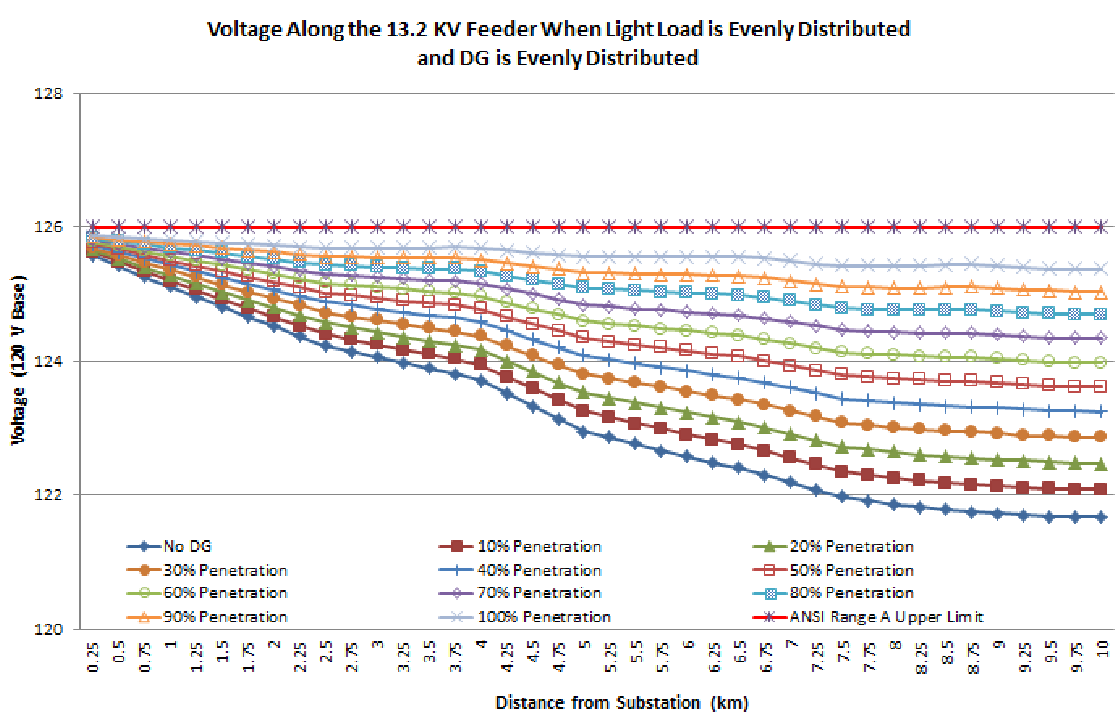

Figure 4.22 Case 7 voltage profile with DG evenly distributed

The best voltage profile overall was obtained when DG was evenly distributed and the penetration level reached 100 per cent. Figure 4.23 shows the best voltage profile obtained for each DG location along with the DG capacity.

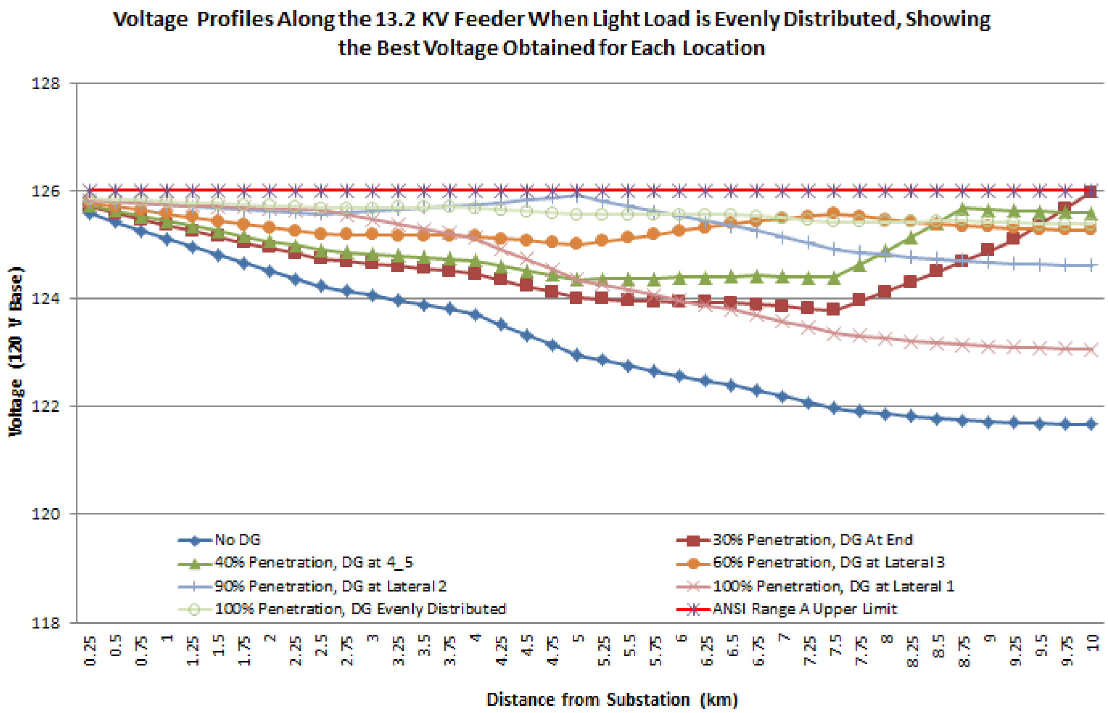

Figure 4.23 Best voltages for Case 7

As can be seen from the figure, when 100 per cent penetration is achieved with the DG evenly distributed along the feeder, the voltage profile through the feeder remains almost flat. As in the previous case, the highest voltage profile near the end of the feeder was obtained when the DG was located at the end or at section 4_5 near the end.

In this scenario, the losses on the circuit without DG were 129 kW. The lowest losses were obtained with higher penetration levels of DG distributed evenly, with 5 kW of losses obtained when the DG penetration level was 100 per cent. This is just 7.25 per cent of the losses obtained when 100 per cent of DG was located at Lateral 1. As in previous cases, the lowest losses match the best voltage profile obtained in the simulations, which occur when a DG penetration of 100 per cent is distributed evenly across the feeder. Also, as in previous cases, the highest losses with DG present were obtained when the DG was located at the interconnection point of Lateral 1, and the lowest losses when the penetration level was low were obtained when the DG was located at Lateral 3. Table 4.8 lists the results of the losses in the circuits for the cases simulated.

Table 4.8 Losses in the 13.2 kV Feeder with Light Load Distributed Evenly

kW Losses in the 13.2 kV Feeder with Load Distributed Evenly - Light Demand						
No DG:	129					
DG Penetration	kW Losses Depending on DG Location					
	End	4_5	Lateral 3	Lateral 2	Lateral 1	Evenly Distributed
10%	99	97	97	105	117	104
20%	85	77	72	85	106	83
30%	85	66	53	69	97	64
40%	*	64	40	56	89	48
50%	*	*	33	45	82	34
60%	*	*	31	38	77	23
70%	*	*	*	35	73	15
80%	*	*	*	34	70	9
90%	*	*	*	36	69	6
100%	*	*	*	*	69	5

The results of this scenario were very similar to the previous 13.2 kV scenario. In terms of the maximum DG penetration relative to the DG interconnection location, it can be seen, as in previous cases, that when the DG is located at or before the load, higher penetration levels can be achieved, at the expense of higher losses. The best scenario in terms of loss reduction and overall feeder voltage profile improvement was obtained when the DG was distributed evenly across the feeder.

5 CONCLUSIONS, RECOMMENDATIONS AND FUTURE WORK

5.1 Conclusions

As was seen from the literature review and the results of the simulations, Distributed Generation can bring benefits and provide challenges to utilities and users. Some of the benefits that can be obtained by installing DG systems are an improvement in feeder voltage profile and a reduction in losses. A proper understanding of how DGs interact with distribution feeders is necessary to maximize the use of DG to obtain the most benefits while properly addressing the possible challenges that might arise. The simulations performed provide valuable data that can help understand the effect of varying the location and penetration of DG on the voltage profile and losses on the feeder. They also provide an insight into the highest DG penetration levels before voltage regulation issues occur. The results obtained can help us determine how to better utilize PV DG to benefit the distribution system.

Based on the results obtained from the simulations we can arrive at some important conclusions. In general it was observed that increasing the amount of PV DG penetration can help improve the voltage level in the feeder and reduce losses. As was seen, some DG configurations can greatly improve the voltage profile along the feeders and reduce losses when compared to other configurations with similar capacities. It was observed that more DG capacity can be interconnected to a distribution feeder if the interconnection point is close to the load. Since the power exported by the DG flows over more paths and shortest distances to the load, the system is better able to accommodate the DG generation. The cases in which most PV DG could be interconnected where those when centrally located DG was placed near the substation or when DG was distributed evenly along the feeder in proportion to the load. Between these, the best voltage profile and lowest losses were obtained when DG capacity was distributed evenly with the load. For example, as seen in Figure 4.12 from Case 1, the highest levels of DG penetration obtained with DG evenly distributed on the 4.16 kV feeders was 70 percent. This case can represent an urban feeder with a lot of residential and small commercial loads connected along its length. A similar result was obtained in cases 6 and 7, where the feeder is energized at 13.2 kV and provides the same load distribution. In Table 4.8 we can see that by applying 100 per cent penetration of DG distributed along the feeder we can reduce the losses by 96 per cent, and Figure 4.23 shows that the voltage profile obtained with this configuration would be almost even along the feeder . These results support the idea that DG should be distributed along the feeder and sized to feed the local load.

It must be mentioned that lower penetration levels possible when DG was evenly distributed in the 4.16 kV cases were due to the fact that, to represent this distribution, the DGs were located at the middle of each section to which they supplied load. Since the rating of each DG equaled the load of each section, under high penetrations of DG, half of the exported power would flow downstream with the other half flowing upstream. This upstream flow of power caused the voltage rise that prevented higher penetration levels. If this is taken into consideration, it can be assumed that further distribution of DGs, to the point where each segment of the feeder has equal distribution of load and DG, would allow the greatest DG penetration level, improvement of feeder voltage profile, and reduction in losses. As mentioned above, this can be achieved by the implementation of many smaller systems sized to feed the local load.

Care must be taken to ensure that the interconnection of DG does not cause problems in the feeders. The literature review indicates that the problems most likely to be encountered with increasing DG penetration relate to the degradation of the voltage regulation in the feeder. Three main areas affecting voltage regulation were identified as voltage rise, disruption of the operation of voltage regulating equipment, and voltage fluctuations due to varying output of DG systems.

In all the cases evaluated for voltage rise, the highest centralized PV DG penetration before voltage rise becomes an issue was obtained when the DG located close to the beginning of the feeder. This is due to the fact that since most of the power exported to the grid will flow downstream of the DG, voltage rise will not be an issue. However, this location provided the highest losses when compared with similar penetration levels at other locations. This has important practical implications. When a high capacity, centrally located PV system must be interconnected to a distribution feeder, locations close to the substation would provide the best performance in terms of mitigating voltage rise. However, these locations do not provide the most benefits to the distribution feeder in terms of voltage profile and loss reduction. High PV penetration was also possible without voltage rise when DGs are distributed evenly along the feeder, as discussed above, in which case the most benefits on voltage profile and loss reduction were obtained.

When voltage regulators are present in the feeder, the way the voltage profile along the entire feeder is affected depends not only on DG penetration level but also on the location of the DG. If the DG capacity lies entirely upstream of the voltage regulator, the voltage downstream of the regulator is modified little under steady state conditions. If some of the DG capacity is placed after the regulator, the voltage profile downstream of it will be noticeably affected. The best voltage profile downstream of the regulator was obtained when DG was present at its load side. It was also found that under certain conditions, the interaction between the voltage regulator and the DGs could lead to unacceptable voltage levels when DGs disconnect and reconnect due to circuit disturbances. IEEE Std. 1547-2003 does not provide a safeguard against this since under that standard, the DG must disconnects for voltages of 110 per cent of nominal or greater. This can lead to the DG operating under voltages above ANSI Range A. Also, when DGs disconnect and reconnect, the voltage regulators can operate to compensate for the change in circuit load. This can lead to excessive tap changer operations and reduced equipment life. Voltage regulators could, under some conditions, be programmed to regulate with a lower voltage setting that still maintains proper voltage regulation on the feeder. By doing this, the possible voltage fluctuations when the DG disconnects and reconnects as well as tap changer operations, can be reduced. Voltage regulators will not be typically found in 13.2 kV feeders since these provide better voltage regulation due to less voltage drop. Thus, the issues relating to the interaction of DG with voltage regulators are not likely to occur on feeders energized at this voltage level.

It was found that distribution systems with higher primary voltages, such as 13.2 kV L-L, can better handle higher DG capacities and be more flexible to DG interconnections. Distribution systems with higher voltages exhibit better voltage profiles and seldom use voltage regulators. This can eliminate possible restrictions of DG capacities or interconnection location that can be imposed if voltage regulators are present. Also, since the circuit operates at a higher level, the current exported to the feeder primary for a given PV capacity is less at higher voltages. This results in lower voltage rise. A given voltage rise in 4.16 kV would also represent a higher percentage of nominal voltage when compared to the same voltage rise occurs in a 13.2 kV feeder. Thus, raising the voltage level of the feeder not only reduces losses and improves the voltage profile of the feeder, but also allows the maximization of the benefits provided by DG.

Based on the results of the simulations we can see that at lower penetration levels, DG provides more benefits when interconnected closer to the loads centers near the end of the feeder. After certain amount of DG capacity has been installed, more benefits are obtained when DG is distributed along the feeder in the same proportion as load. This suggests that to maximize the benefits of DG, it should first be located near the final loads in the feeder, and as penetration levels increase, DGs should be distributed along the feeder with the load.

In all, the simulations performed showed that the highest PV capacity is possible when DGs are placed closed to the beginning of the feeder, but this location will not provide the best benefits in terms of voltage profile and losses. To obtain the best voltage profile and loss reduction, the DGs must be distributed evenly across the feeder, in proportion to the load they serve. This could be achieved by installing many smaller scale PV systems, particularly those used in residential and small commercial applications, as opposed to larger PV plants. Larger PV systems can be connected at circuits energized at higher voltage level, while the interconnection of DG to circuits energized at lower voltage levels should focus on small systems sized to feed local load. We also saw that DGs affect the voltage after a voltage regulator when at least some DG capacity lies on the load side of the regulator, and sudden variations in the output of PV systems, such as those that occur when DG systems disconnect and reconnect after a fault in the system, can lead to voltages that exceed the allowed voltage levels under ANSI Range A. Circuits with higher primary distribution voltages can interconnect greater capacities of DG before voltage rise becomes an issue. Also, since the use of voltage regulators on these circuits is less frequent, the problematic interactions between these devices and DG can be reduced or eliminated. This provides additional reasons to support the conversion of circuits energized at low distribution voltages to higher voltage levels. The issues discussed in this project and the simulations carried out focus on PV DG systems that interconnect through inverters. However, some of these results can be applied to other DG systems that interconnect through power electronic devices.

5.2 Recommendations

Taking into consideration the information obtained through the literature review and the conclusions reached after evaluating the results of the simulations carried out, some general recommendations can be developed that can help better exploit the benefits of DG:

- To maximize the benefits of DG, the power profile of the DG should match the load it supplies. The highest capacities of DG can be interconnected when the peak PV production matches the load on the feeder. PV systems located on feeders supplying mostly commercial loads would benefit the most from the interconnection of PV systems. This also shows that when analyzing DG, emphasis should be placed on the load on the feeder, particularly at times of high PV generation, instead of just looking at peak feeder load.

- Whenever possible PV DG capacity should be distributed along the feeder and sized to supply the load it serves. This arrangement permitted high penetration levels of PV DG and provided the greatest benefits in the scenarios evaluated. In practice, this could be achieved by promoting the implementation of many smaller residential and small commercial PV systems as opposed to larger, centralized systems. From the simulation results we can see that by distributing DG along the feeder it would be possible to obtain penetration levels considerably higher than the 15% adopted by many utilities before voltage rise becomes an issue.
- Large capacity, centrally located PV DG systems should be incorporated into higher voltage circuits, since their impacts in these circuits, particularly that regarding voltage rise, will be less when compared to lower voltage circuits. Also, circuits energized at higher voltages, such as the 13.2 kV circuits found on the island, provide better voltage regulation, and seldom require the use of voltage regulators. This can eliminate the problematic interactions between DG and voltage regulators. As was seen in the simulation results for cases 6 and 7, feeders energized at 13.2 kV were better able to incorporate larger capacity centralized systems. Feeders energized at lower voltage levels can be used to interconnect smaller capacity DGs distributed with the load, particularly residential and small commercial systems.
- The simulations showed that circuits energized at higher voltage levels can allow more penetration of PV DG systems. To maximize the benefits that can be obtained from DG,

particularly those using renewable energy sources, circuits energized at lower voltage levels should be converted to higher voltages, particularly the 4.16 kV feeders. Converting to a higher voltage allows for greater participation of DG and improves the overall performance of the distribution system by lowering losses and improving voltage profile, raising the quality of service to customers.

- The challenges imposed by interconnecting smaller PV systems such as those found on residential or small commercial applications are different from those found when interconnecting large, centrally located PV systems. As such, the criteria used when evaluating PV systems should be appropriate to the type of system to be evaluated.
- Careful evaluations must be performed when DG systems are located in feeders where voltage regulators are used to maintain proper voltage along the feeders. Drastic reductions in DG output such as those that can occur when the irradiance levels fluctuate suddenly or when DGs disconnect due to disturbances in the grid can lead to increased operation of the voltage regulator, reducing its life expectancy. They can also expose customers to drastic voltage swings and voltages outside of allowed limits, reducing the power quality.

5.3 Future Work

The following future work on this topic is recommended:

- Further studies of the phenomena addressed here should be performed, to validate the results obtained in this study and to determine if other combinations of load, DG and circuit layout will produce similar or different results. Other simulation tools can be used to validate the results obtained using the specific software program.

- The simulations performed in this study focus on the steady state voltage regulation response of the system with PV DG. Studies focusing on transient or time varying voltage response under varying PV DG output should also be performed. These studies should model the dynamic behavior of the load, voltage regulating equipment and inverter. Particular attention must be placed on the inverter model used. Issues regarding the power fluctuations of DGs could also affect the DG penetration limits and how benefits of DG can be realized.
- Studies should be carried out to characterize the behavior of inverters subjected to variations in irradiance due to passing cloud cover in Puerto Rico. The data from these studies can be used to develop models that can be incorporated to the circuits analyzed using transient analysis software. This will allow a better understanding on how PV systems will behave in the particular climatic patterns found on the island.

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APPENDIX A

A.1 Voltage Plots For Case 1 – Feeder with 2.5 MVA of Load Distributed Evenly

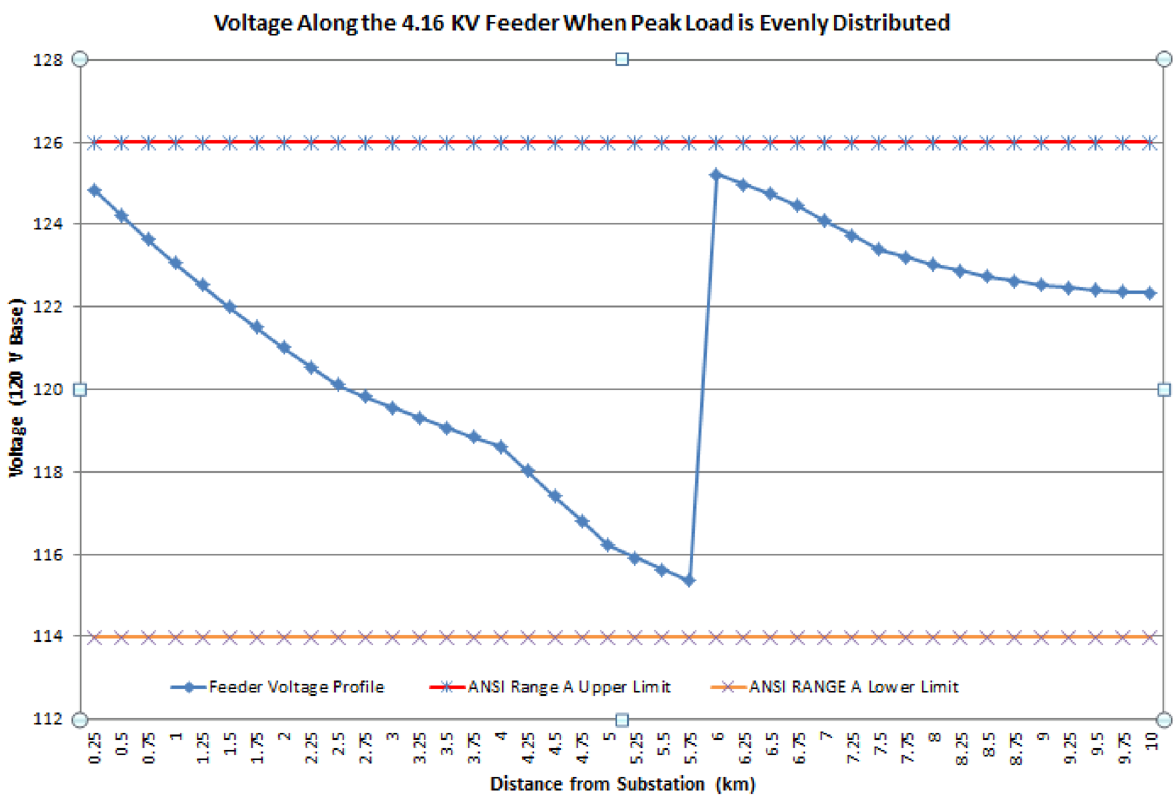

Figure A.1.1 Voltage along the feeder without DG

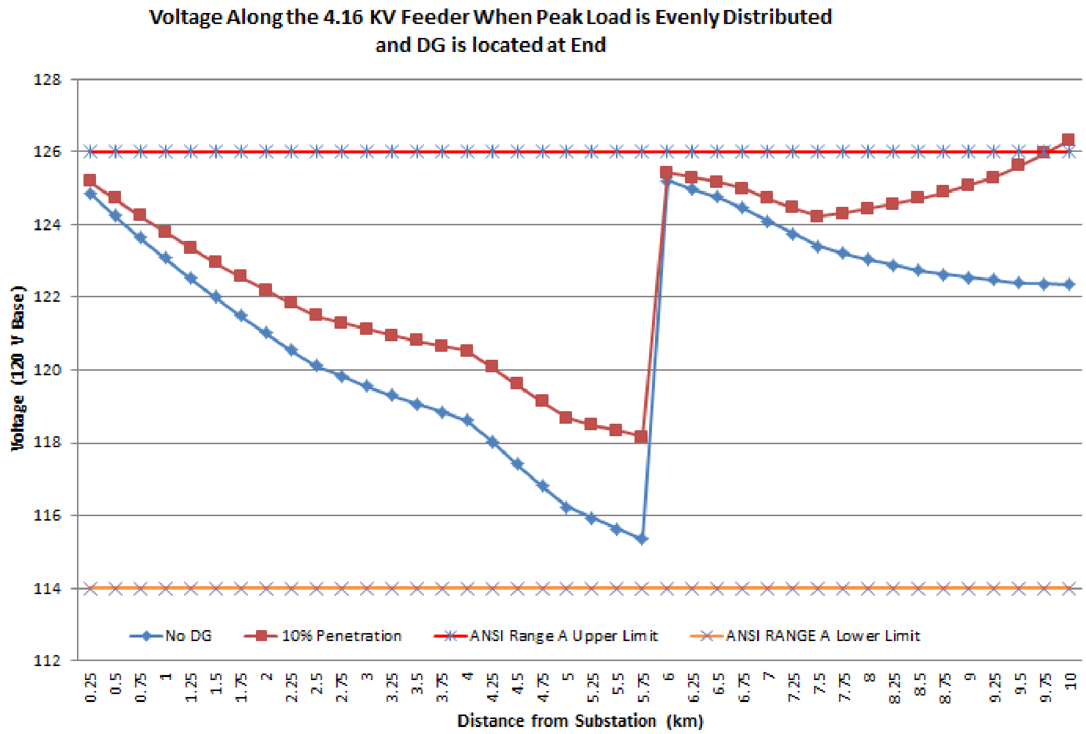

Figure A.1.2 Voltage along the Feeder with DG at end

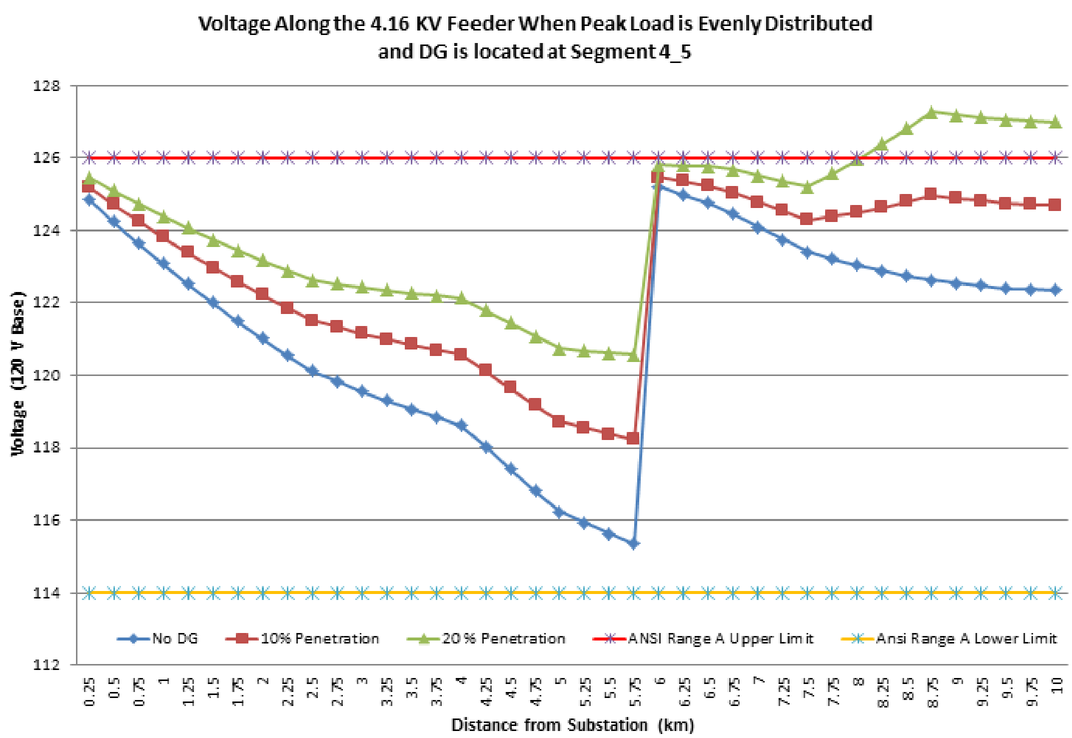

Figure A.1.3 Voltage Along the Feeder with DG at Segment 4_5

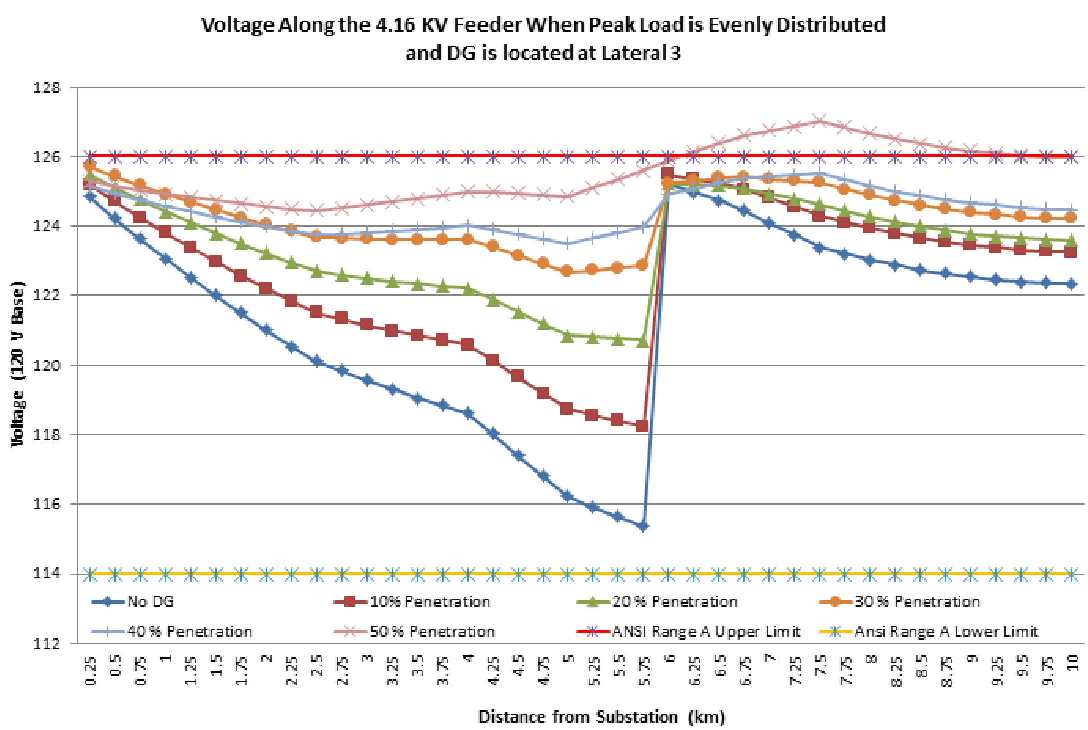

Figure A.1.4 Voltage along the feeder when DG is located at Lateral 3

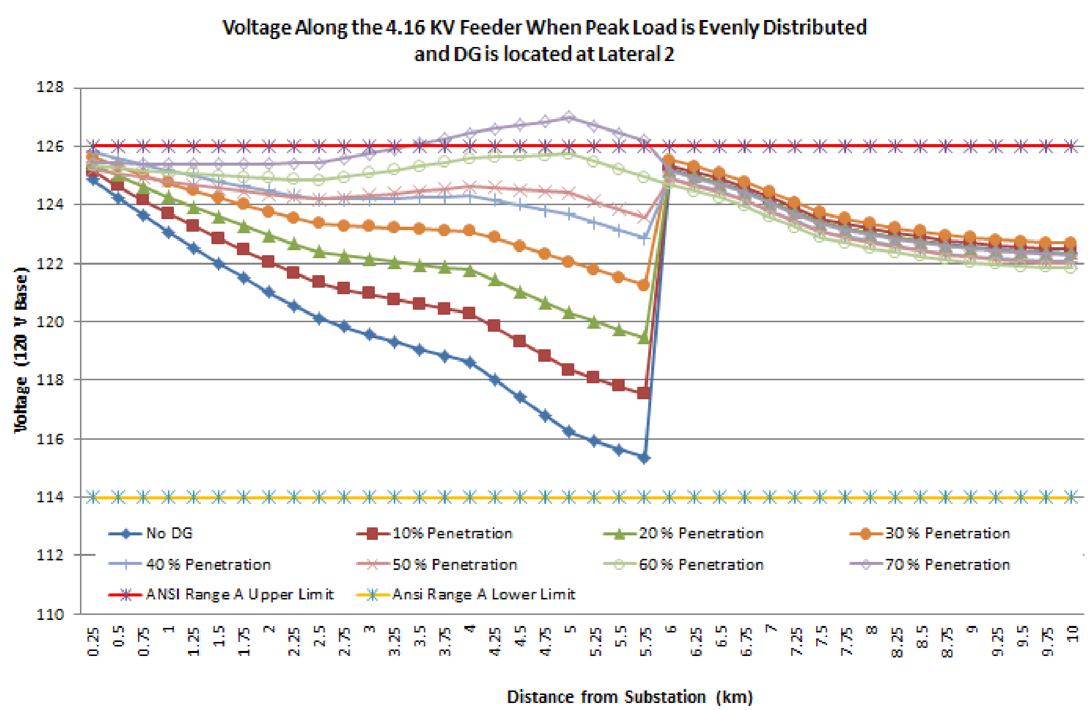

Figure A.1.5 Voltage along the feeder when DG is located at Lateral 2

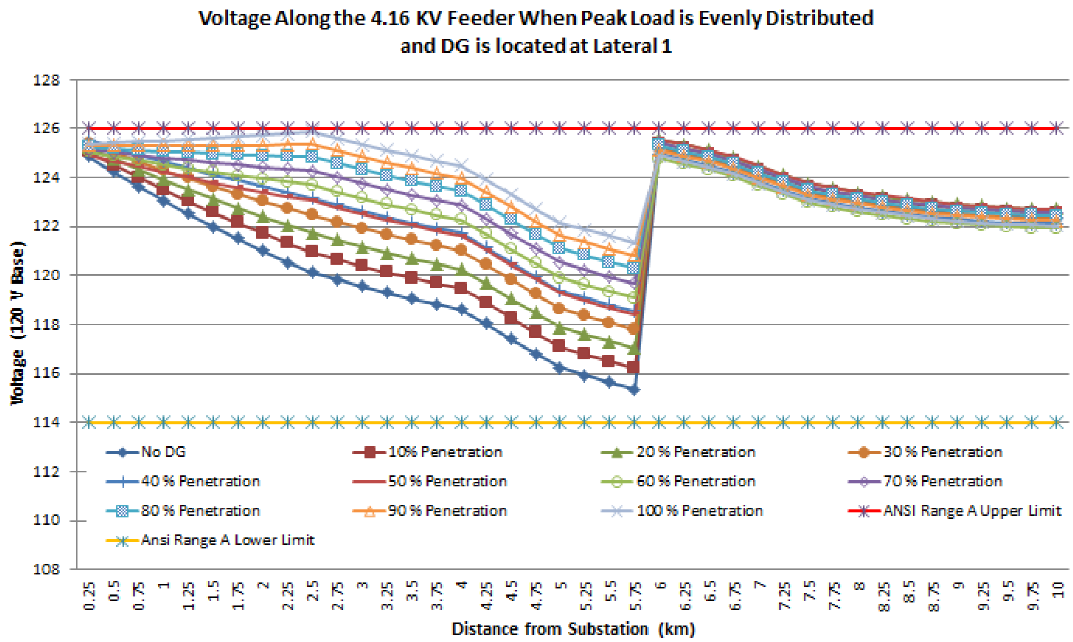

Figure A.1.6 Voltage along the feeder when the DG is located at Lateral 1

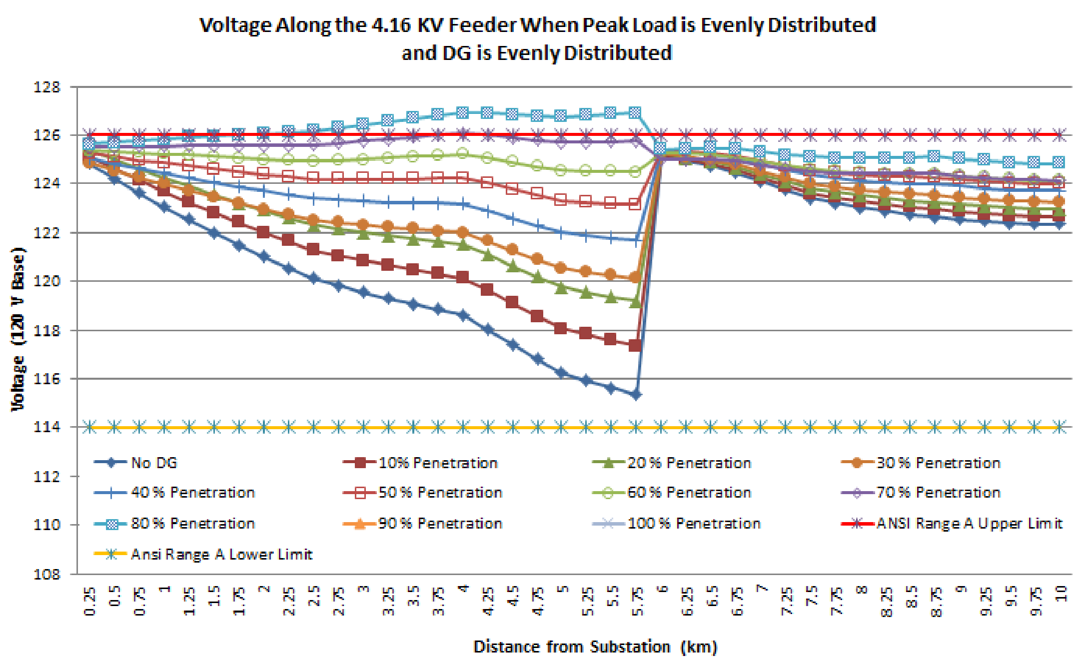

Figure A.1.7 Voltage along the feeder when the DG is Evenly Dsitributed.

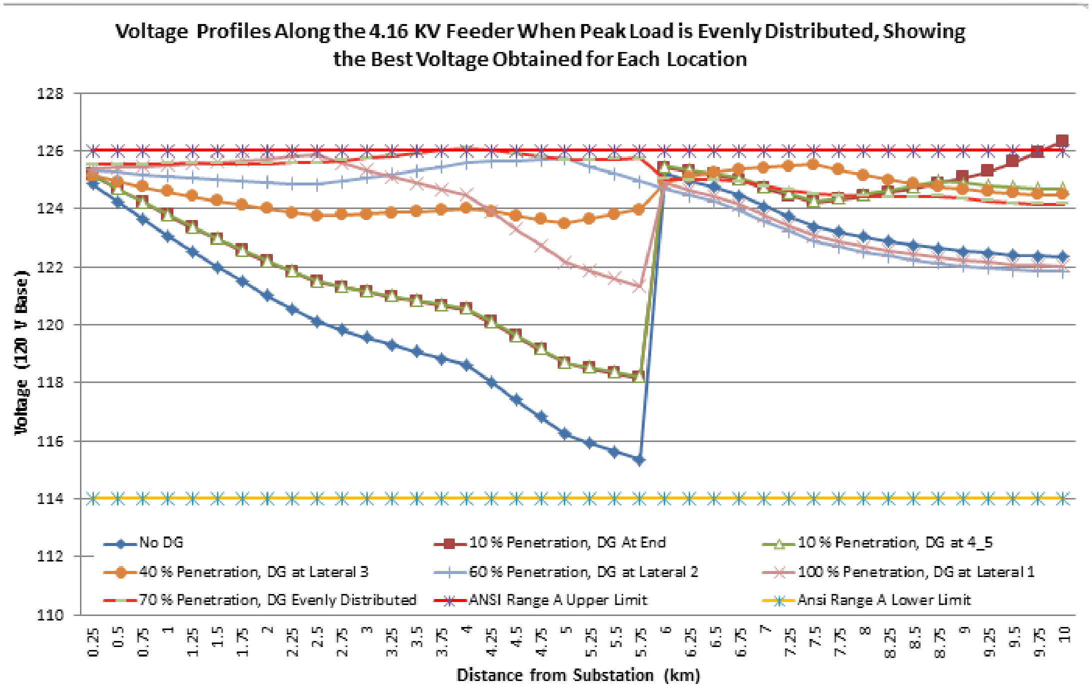

Figure A.1.8 Best voltage profiles obtained for the DG locations evaluated

A.2 Voltage Plots For Case 2 – Feeder with 1.5 MVA of Load Distributed Evenly

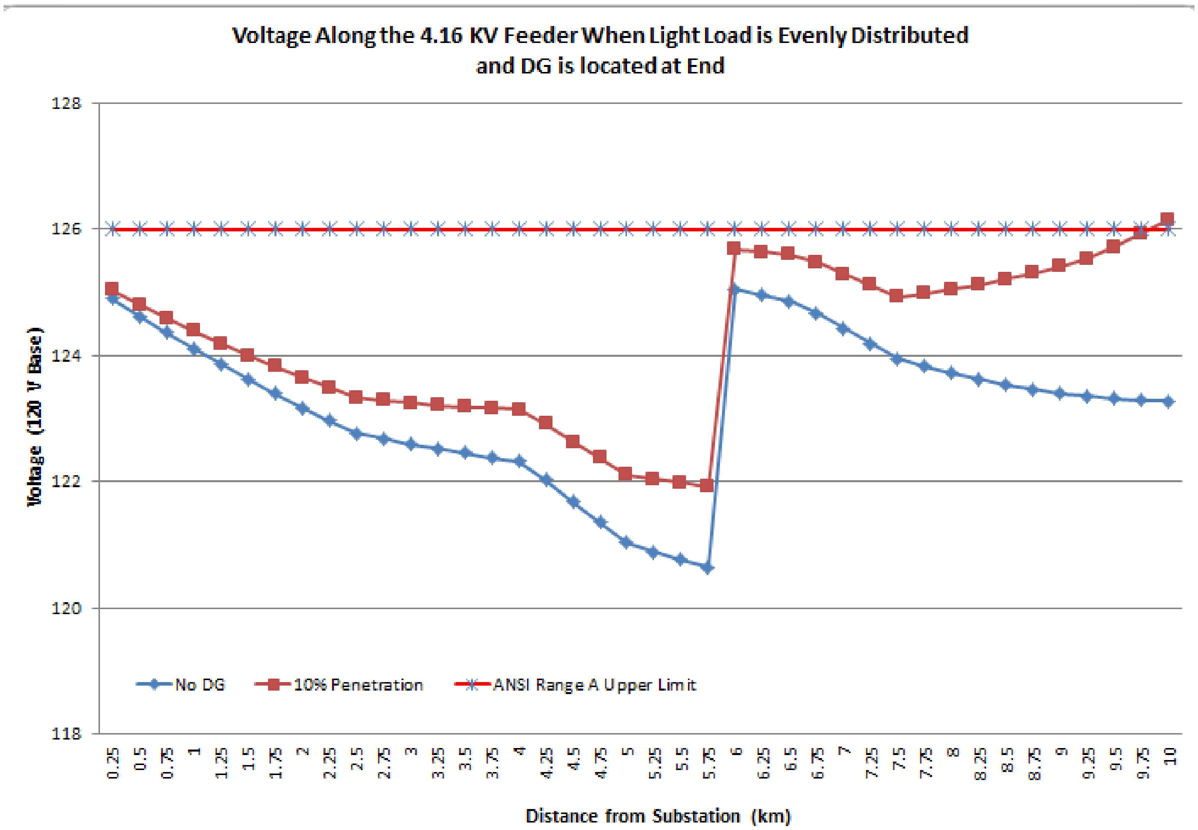

Figure A.2.1 Voltage along the feeder when the load is located at the end

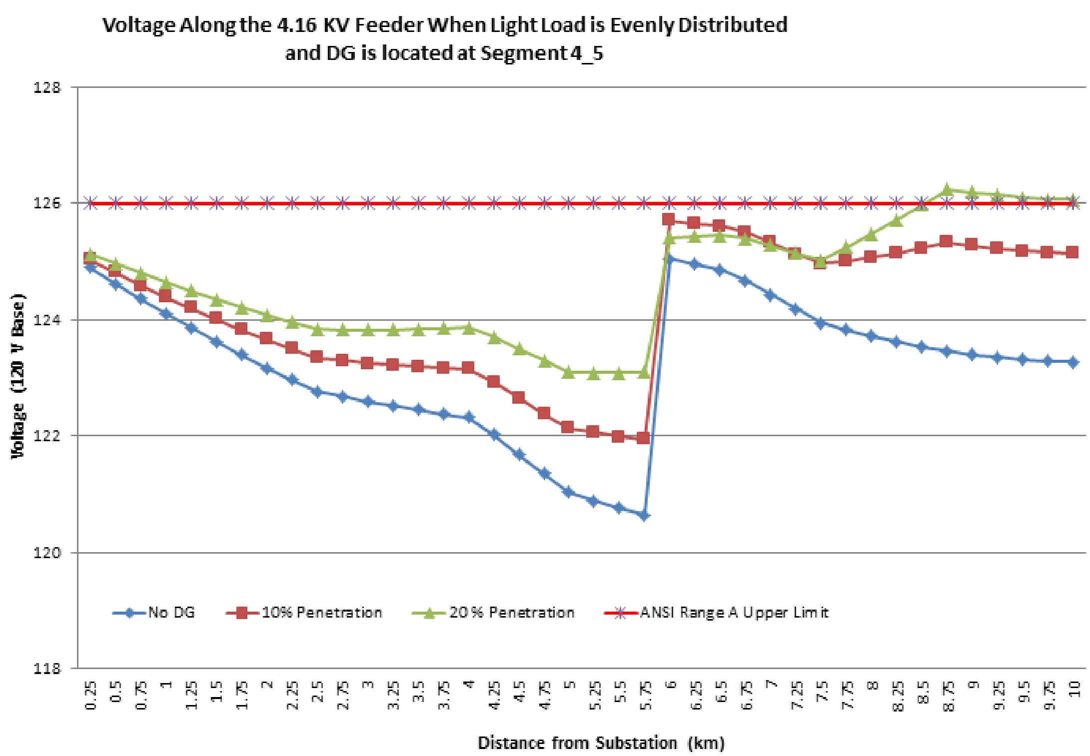

Figure A.2.2 Voltage along the feeder when the DG is located at segment 4_5

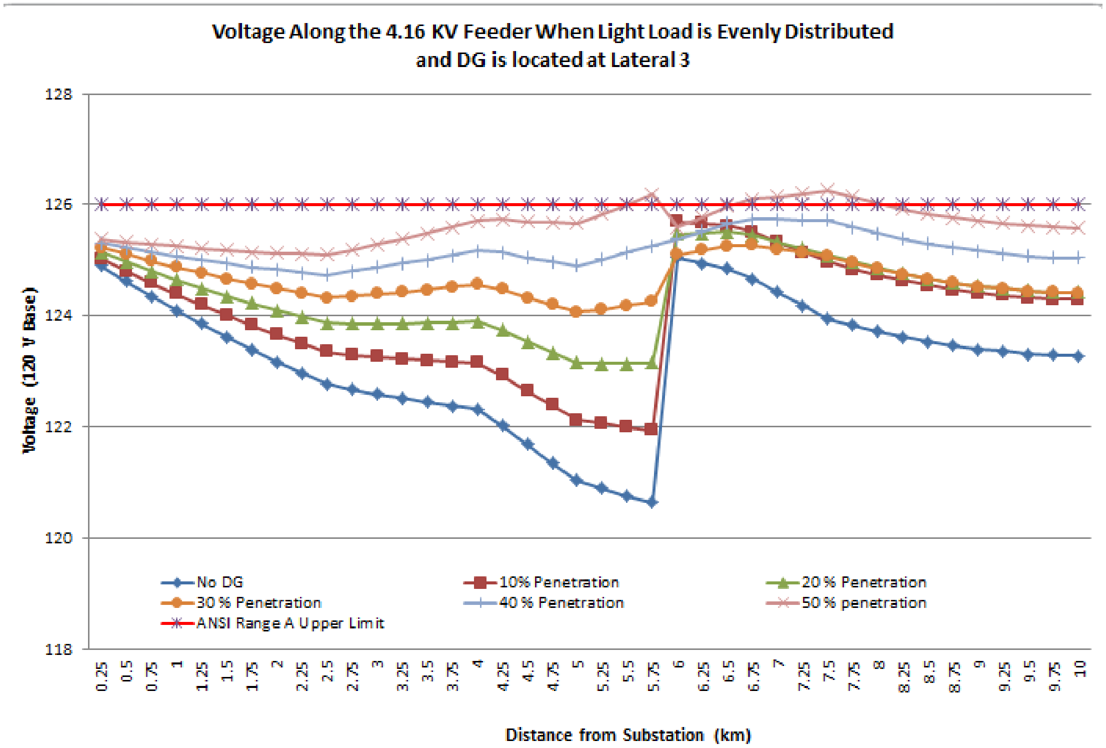

Figure A.2.3 Voltage along the feeder when the DG is located at Lateral 3

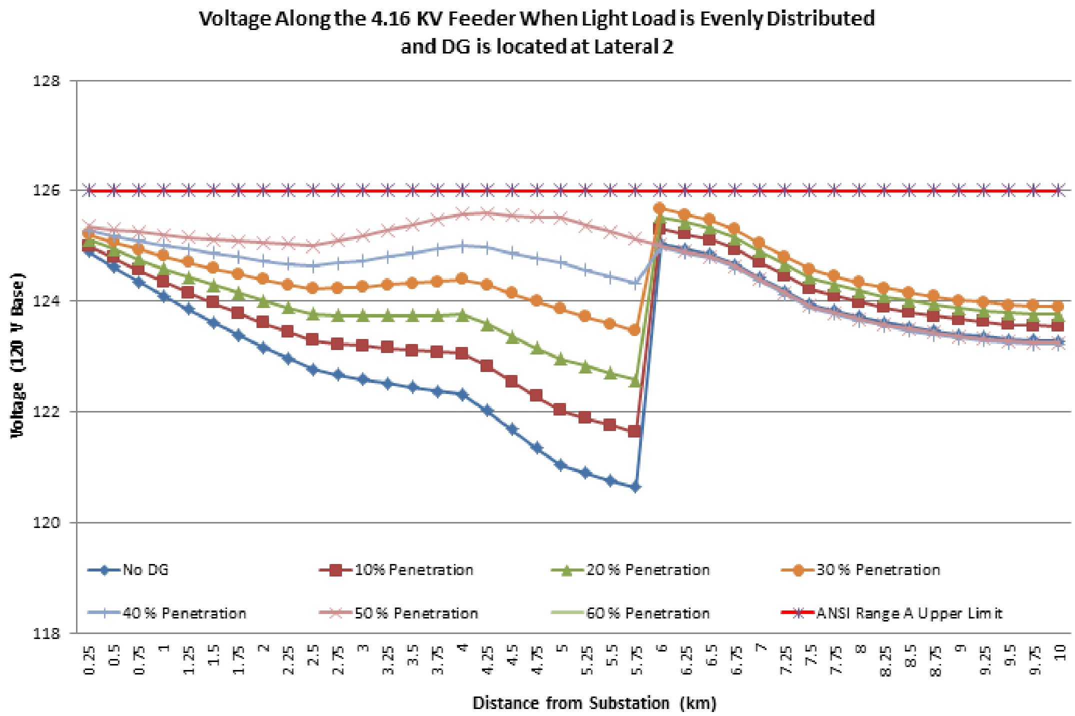

Figure A.2.4 Voltage along the feeder when the DG is located at Lateral 2

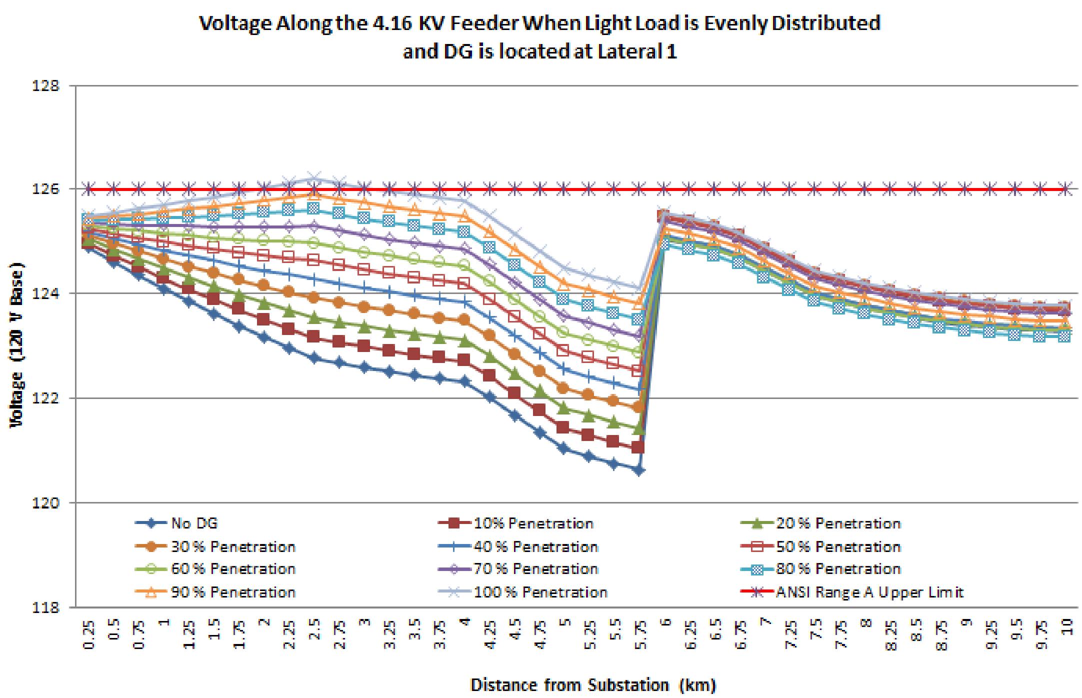

Figure A.2.5 Voltage along the feeder when DG is located at Lateral 1

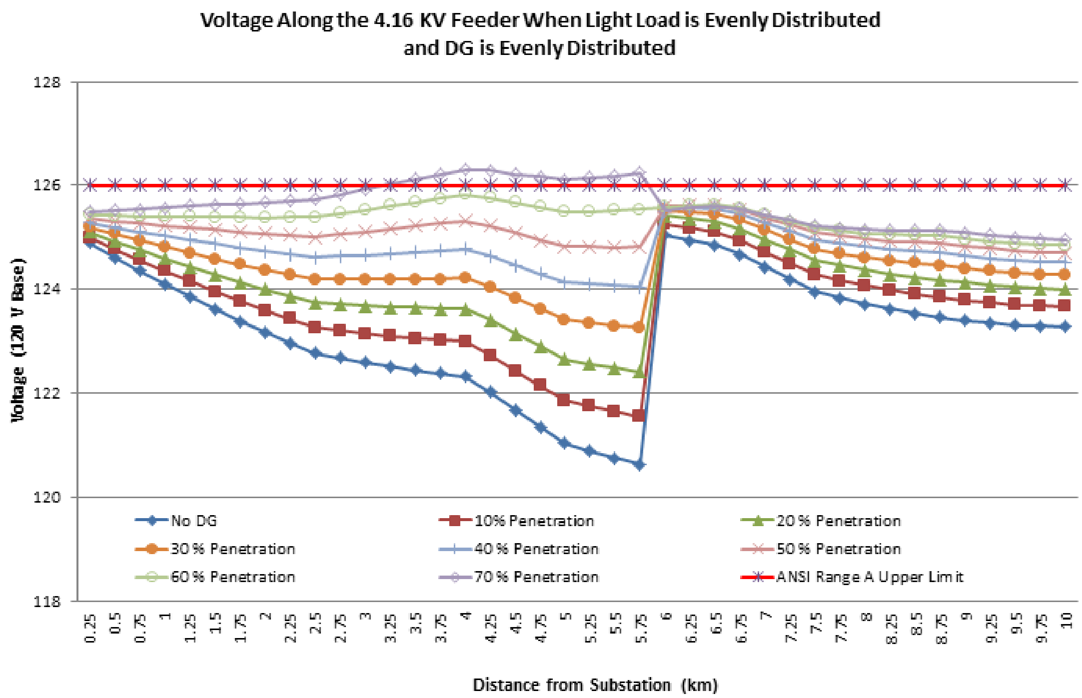

Figure A.2.6 Voltage along the feeder when DG is evenly distributed

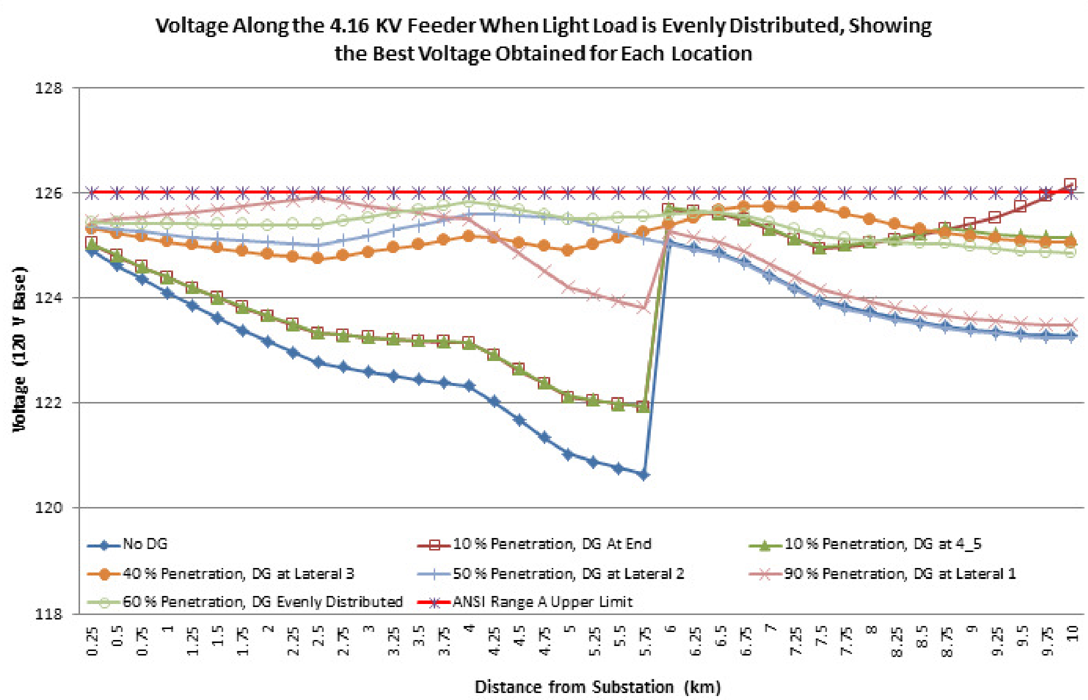

Figure A.2.7 Best voltage along the feeder for all DG locations evaluated

A.3 Voltage Plots For Case 3 – Feeder with 1.5 MVA; 1 MVA of Load Distributed Along First Half of Feeder

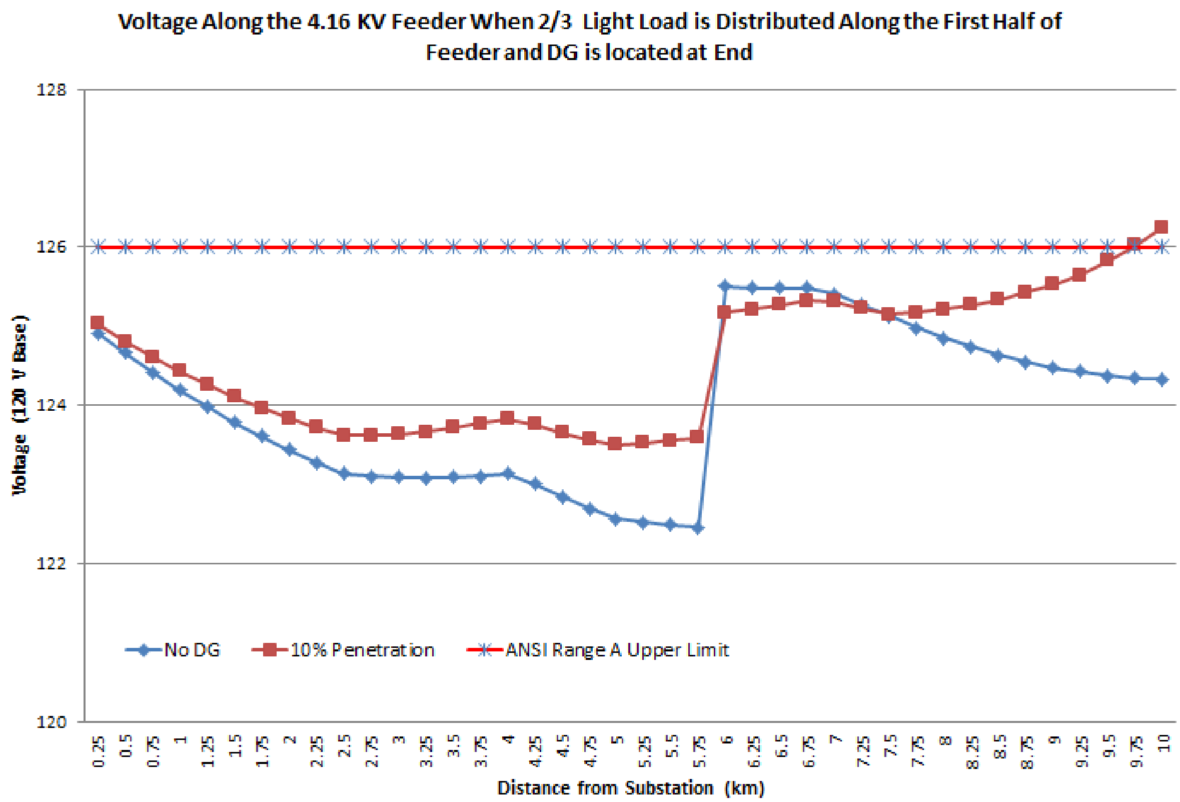

Figure A.3.1 Voltage along the feeder when the DG is located at the end

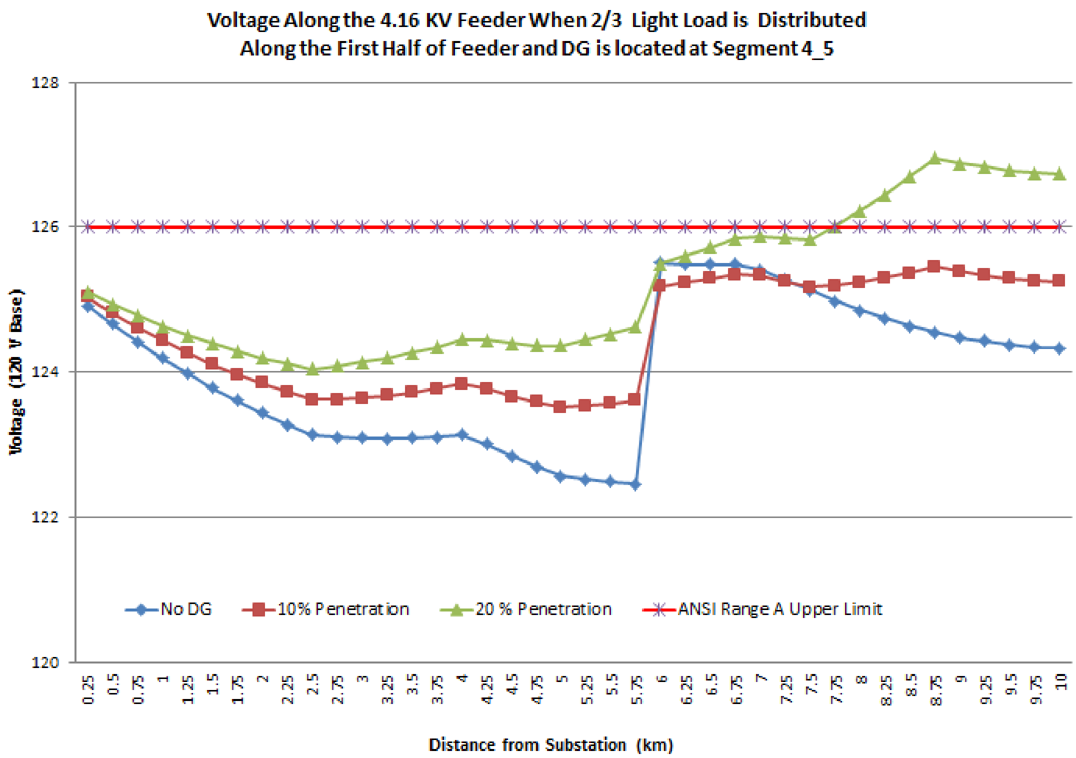

Figure A.3.2 Voltage along the feeder when DG is located at Segment 4_5

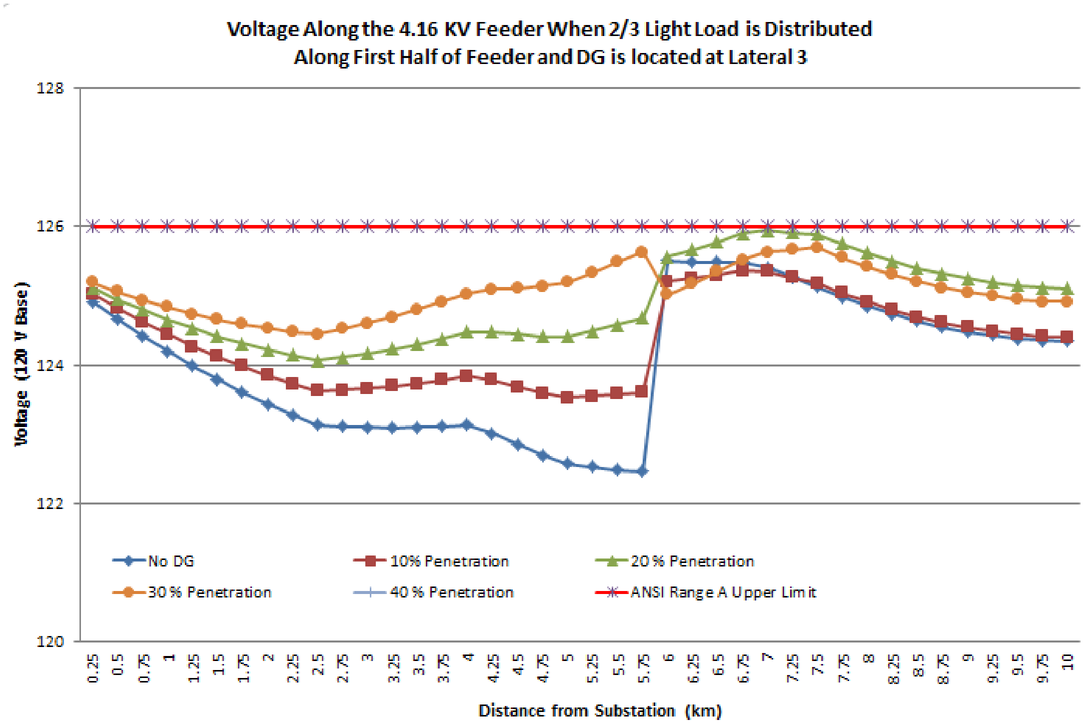

Figure A.3.3 Voltage along the feeder when DG is located at Lateral 3

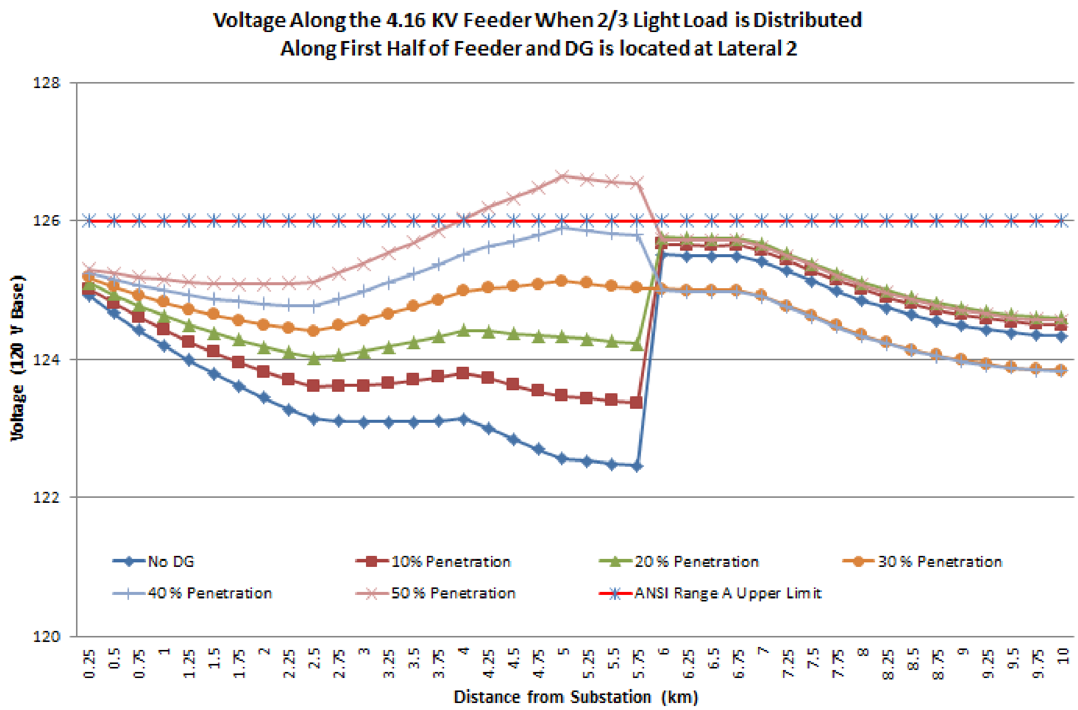

Figure A.3.4 Voltage along the feeder when DG is located at Lateral 2

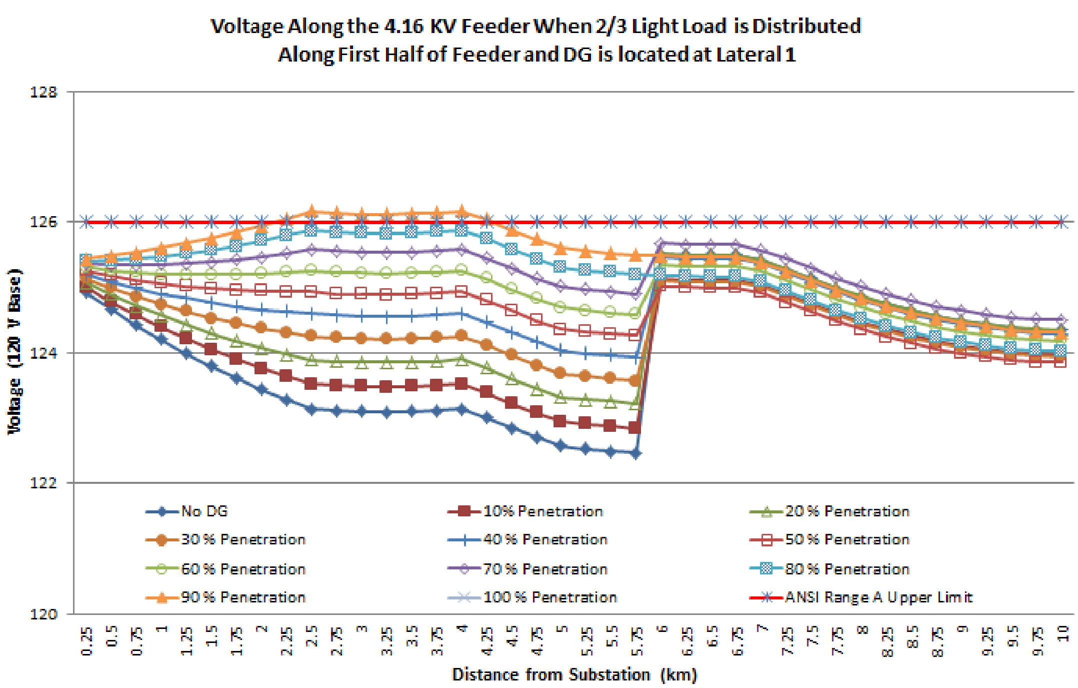

Figure A.3.5 Voltage along the feeder when the DG is located at Lateral 1

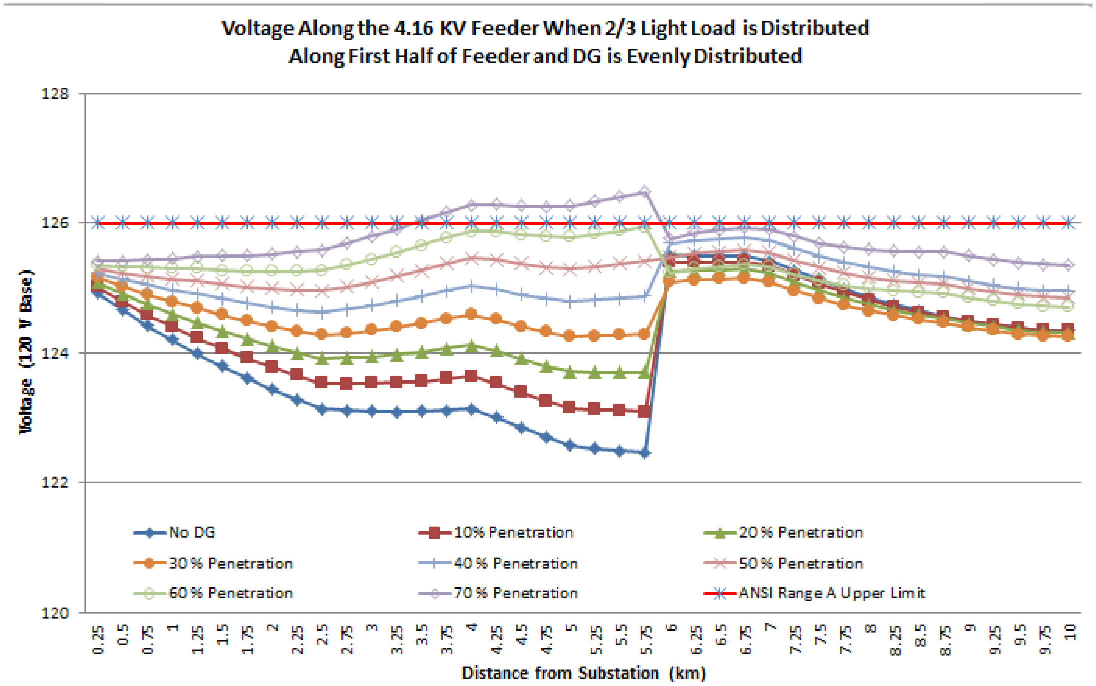

Figure A.3.6 Voltage along the feeder with the DG evenly distributed

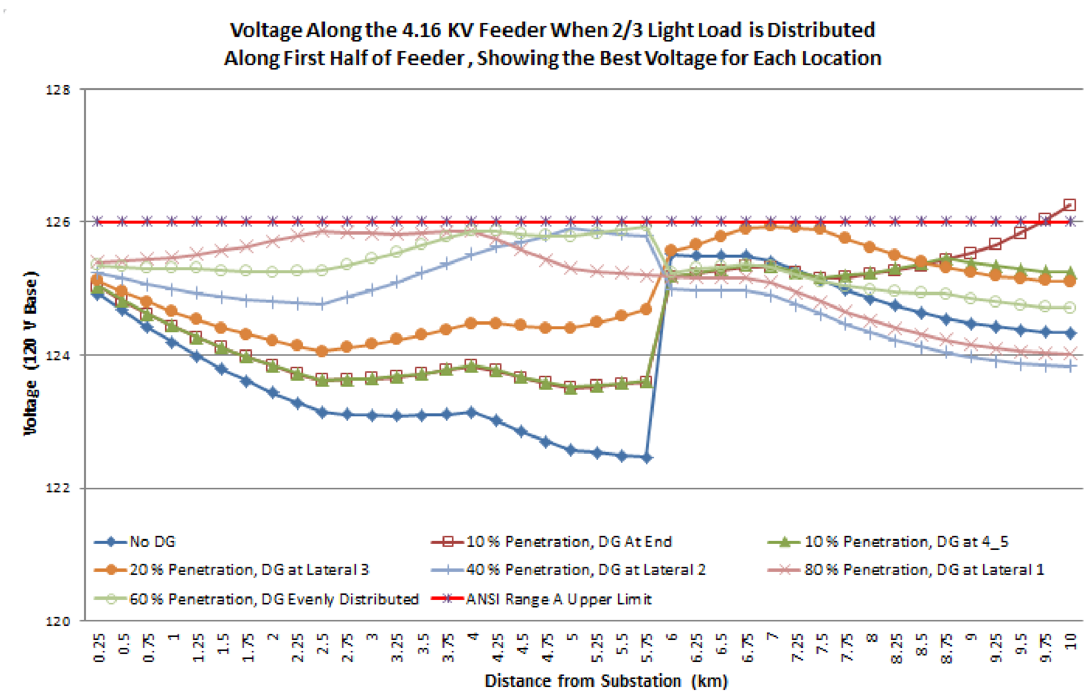

Figure A.3.7 Best voltage along the feeder for all DG locations evaluated

A.4 Voltage Plots For Case 4 – Feeder with 1.5 MVA; 1 MVA of Load Distributed Along Second Half of Feeder

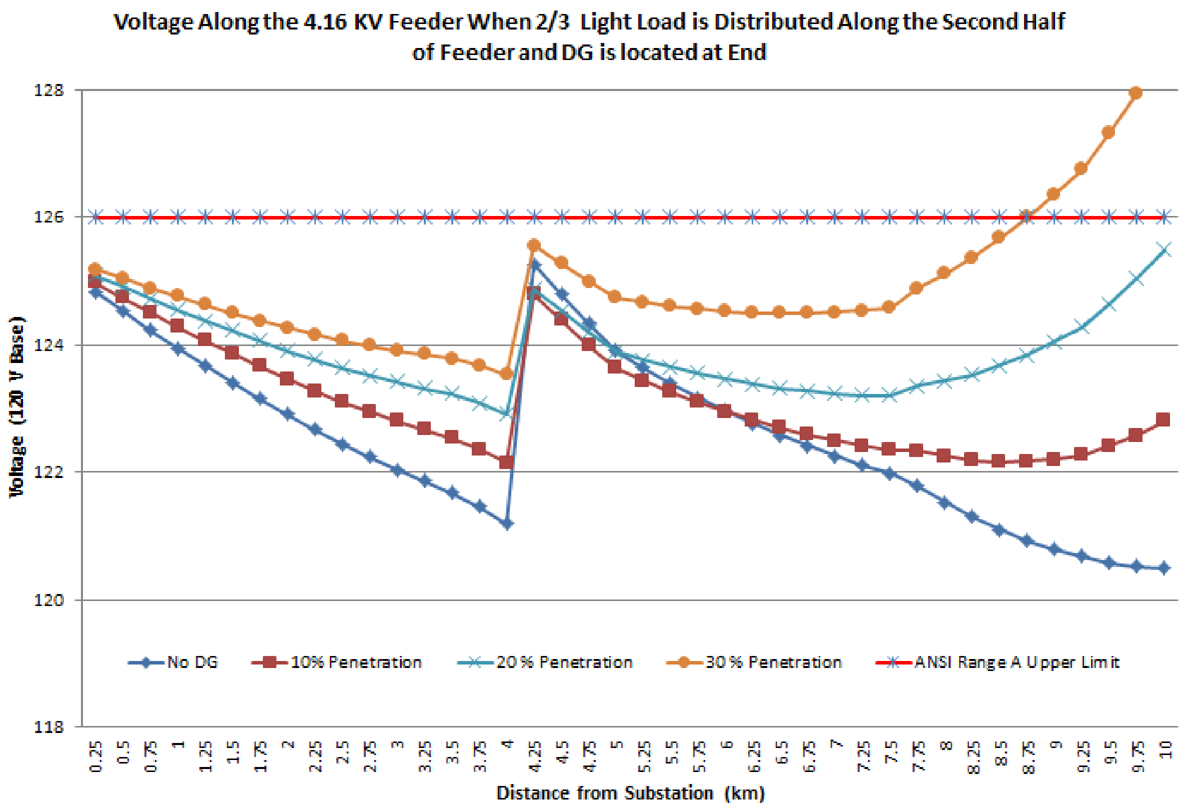

Figure A.4.1 Voltage along the feeder when DG is located at end

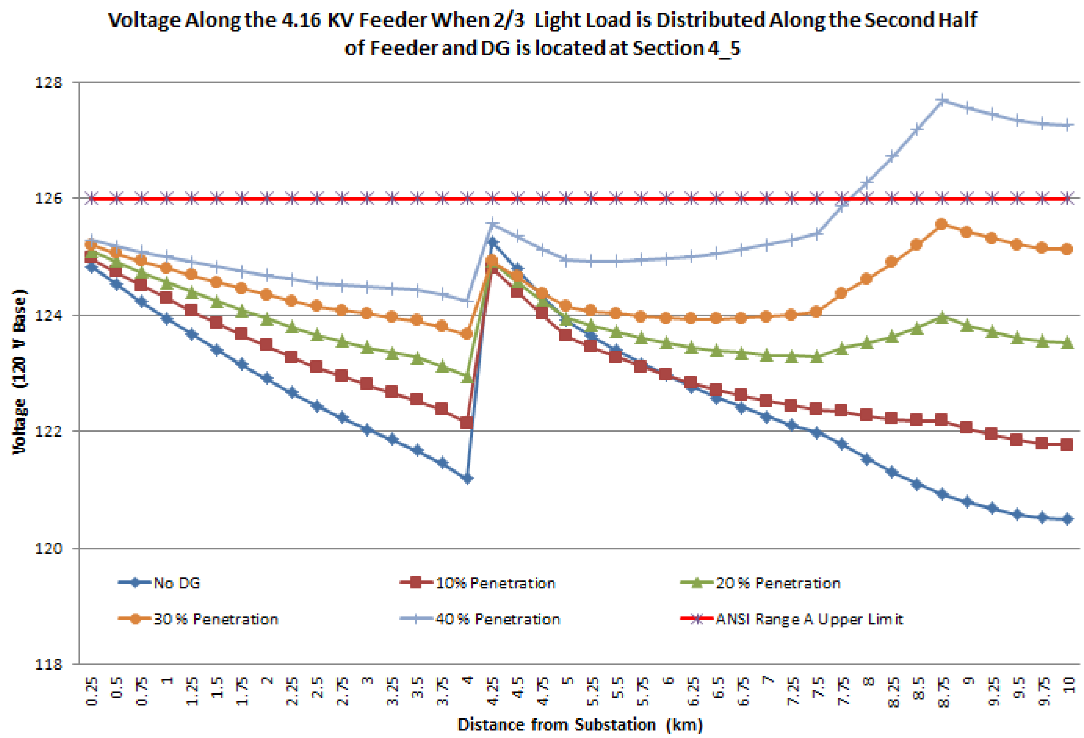

Figure A.4.2 Voltage along the feeder when DG is located at Segment 4_5

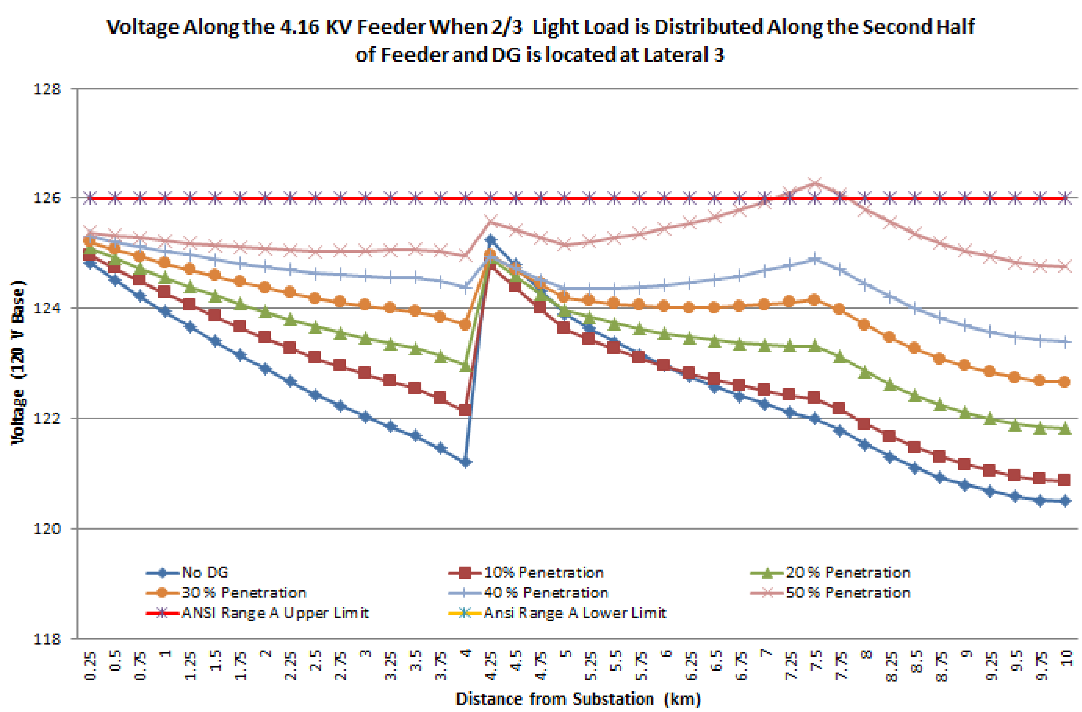

Figure A.4.3 Voltage along the feeder when DG is located at Lateral 3

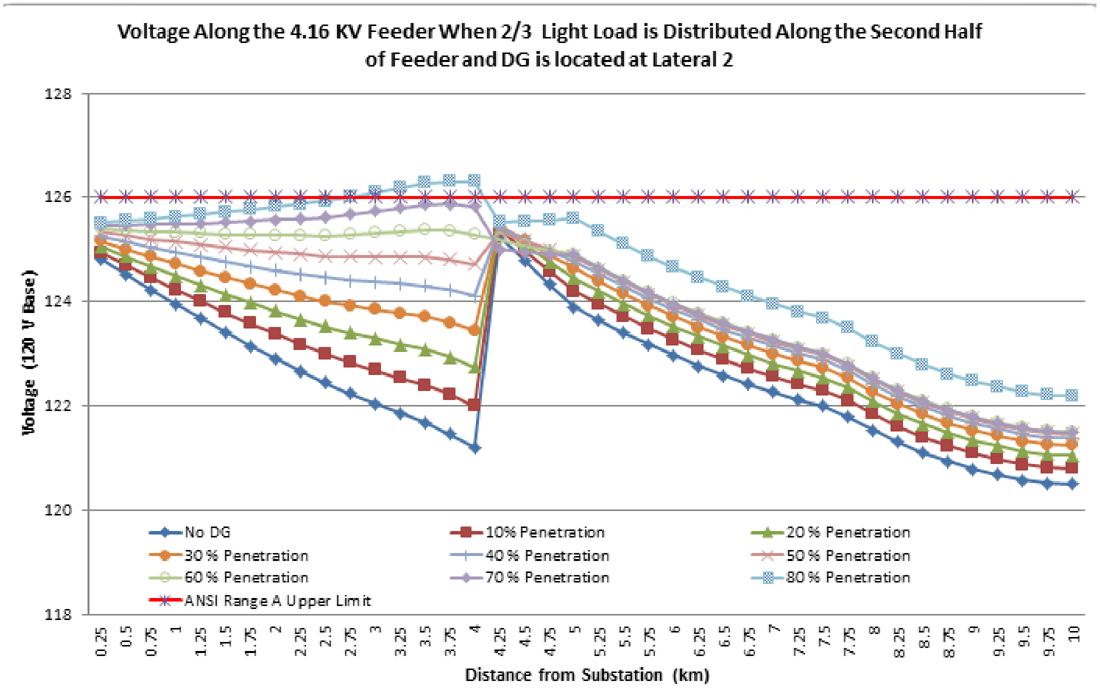

Figure A.4.4 Voltage along the feeder when the DG is located at Lateral 2

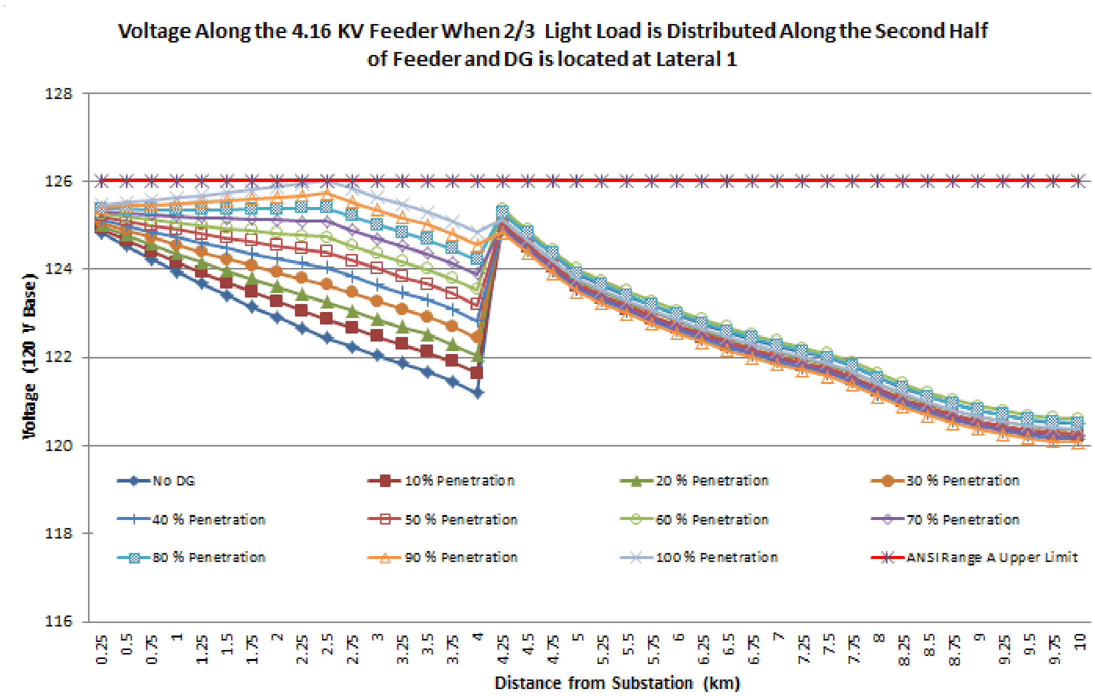

Figure A.4.5 Voltage along the feeder when DG is located at Lateral 1

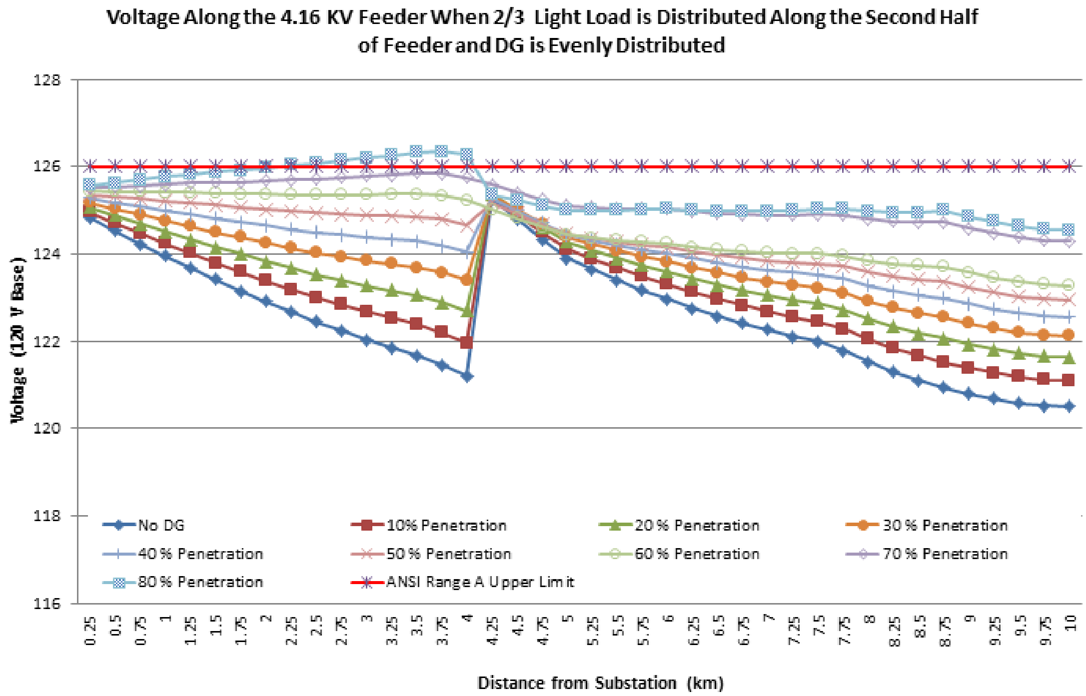

Figure A.4.6 Voltage along the feeder when the DG is evenly distributed

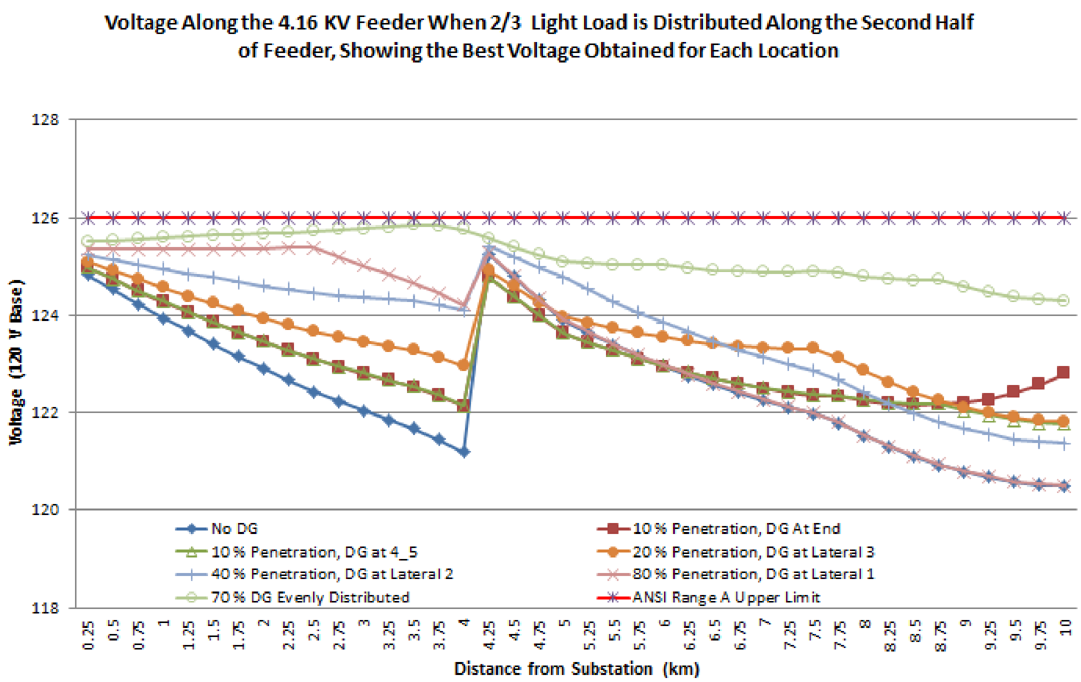

Figure A.4.7 Best voltage along the feeder for all DG locations evaluated

A.5 Voltage Plots For Case 5 – Interactions Between Voltage Regulator and DG

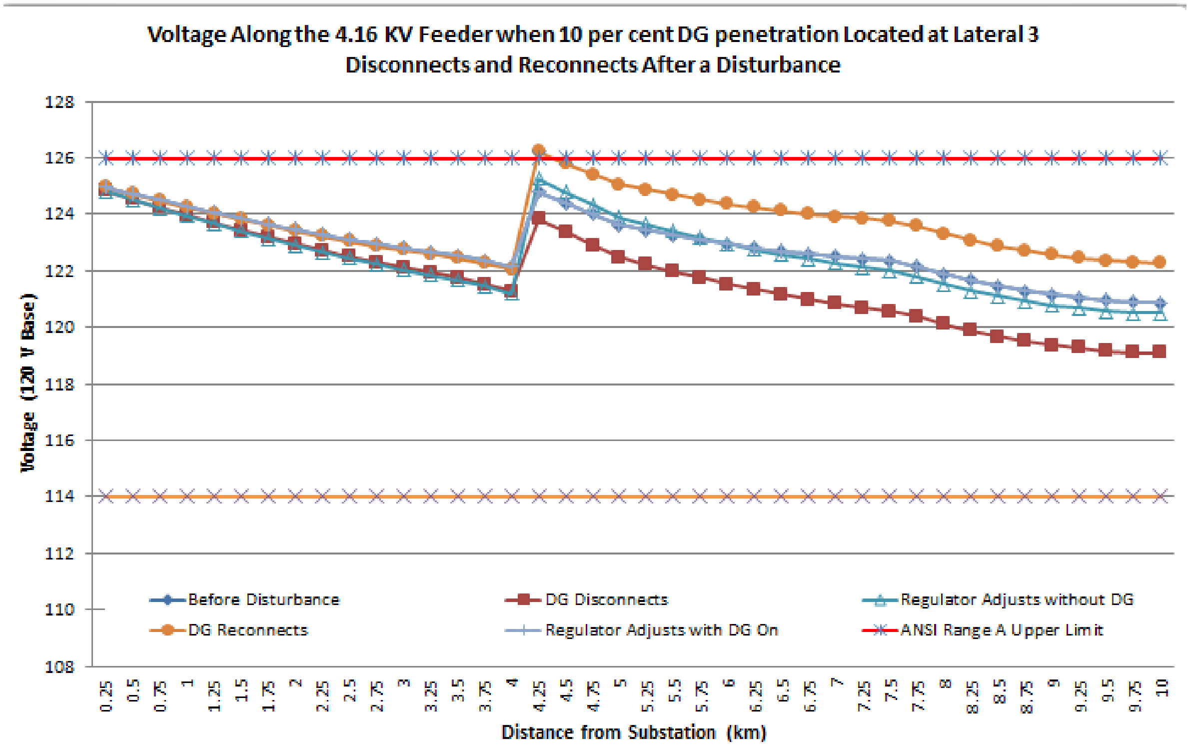

Figure A.5.1 Voltage along the feeder when 10 per cent DG disconnects and reconnects at Lateral 3

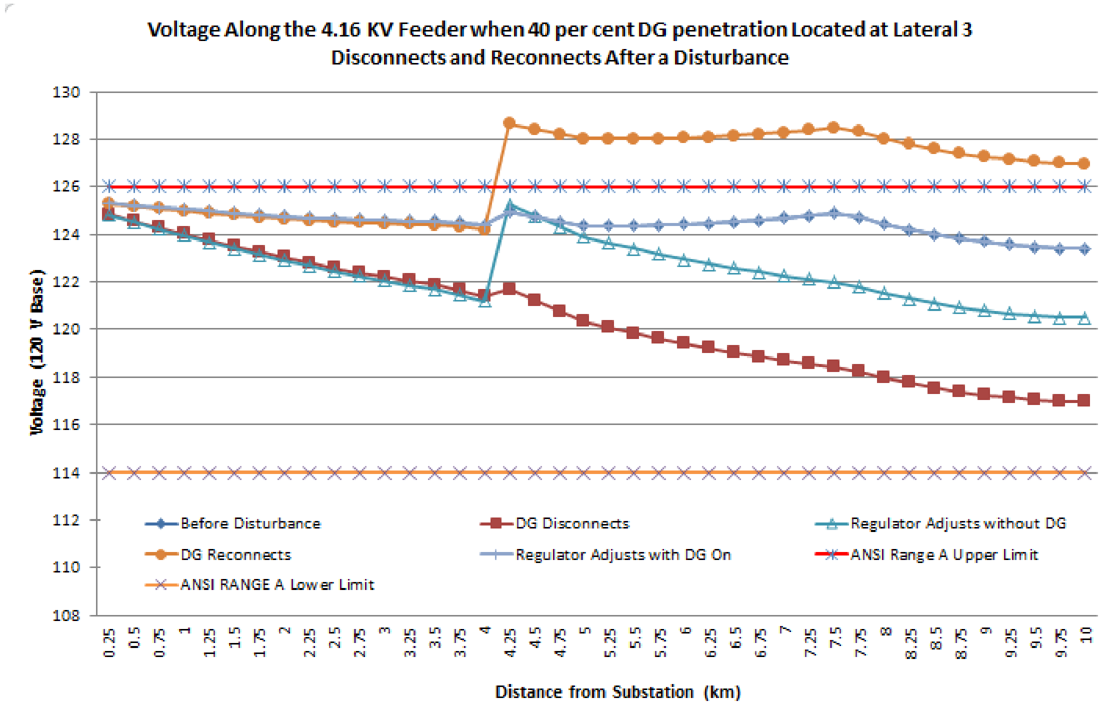

Figure A.5.2 Voltage along the feeder when 40 per cent DG disconnects and reconects at Lateral 3

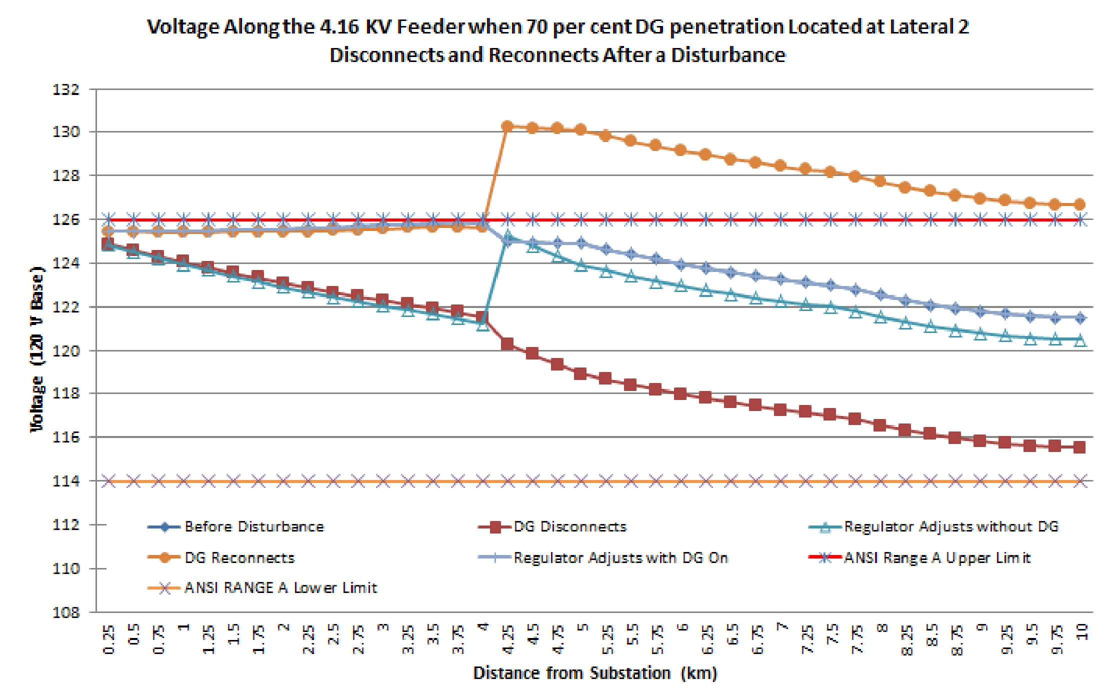

Figure A.5.3 Voltage along the feeder when 70 per cent DG disconnects and reconects at Lateral 2

A.6 Voltage Plots For Case 6 – 13.2 kV Feeder with 11 MVA Distributed Evenly Along the Feeder

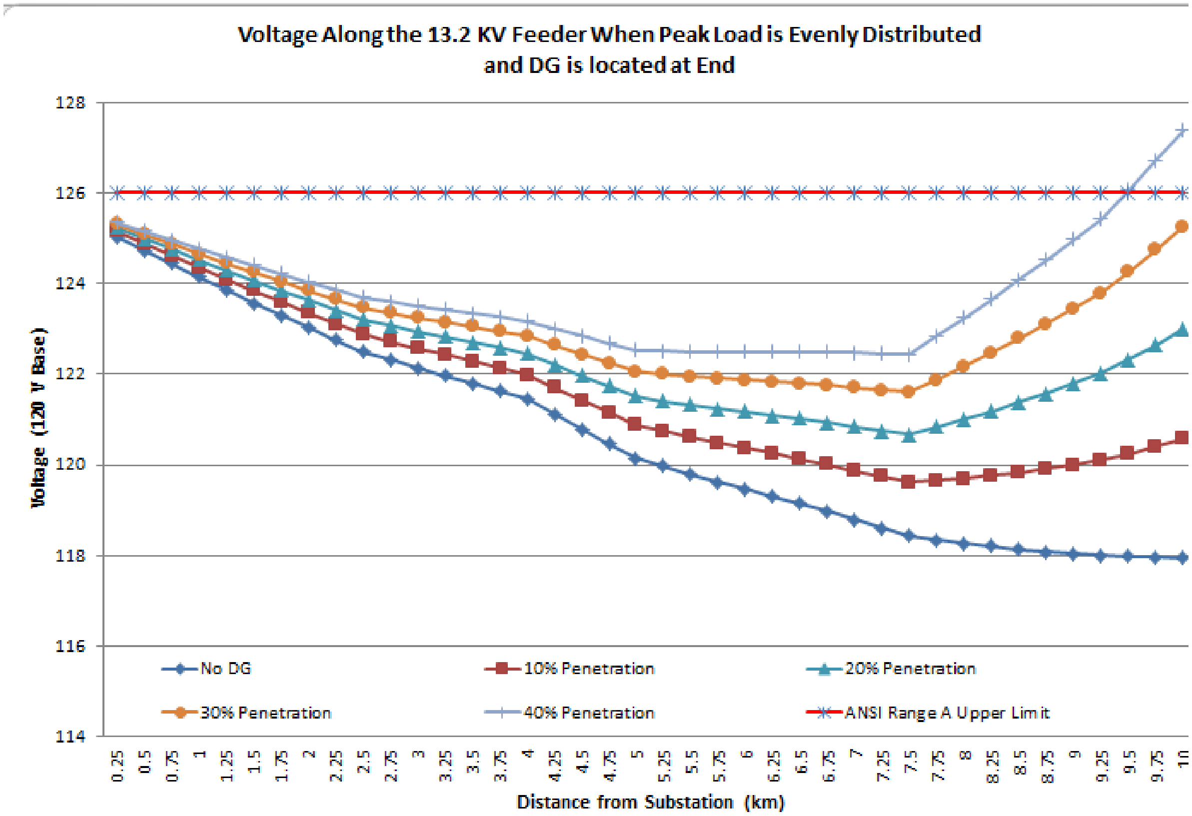

Figure A.6.1 Voltage along the feeder when DG is located at end

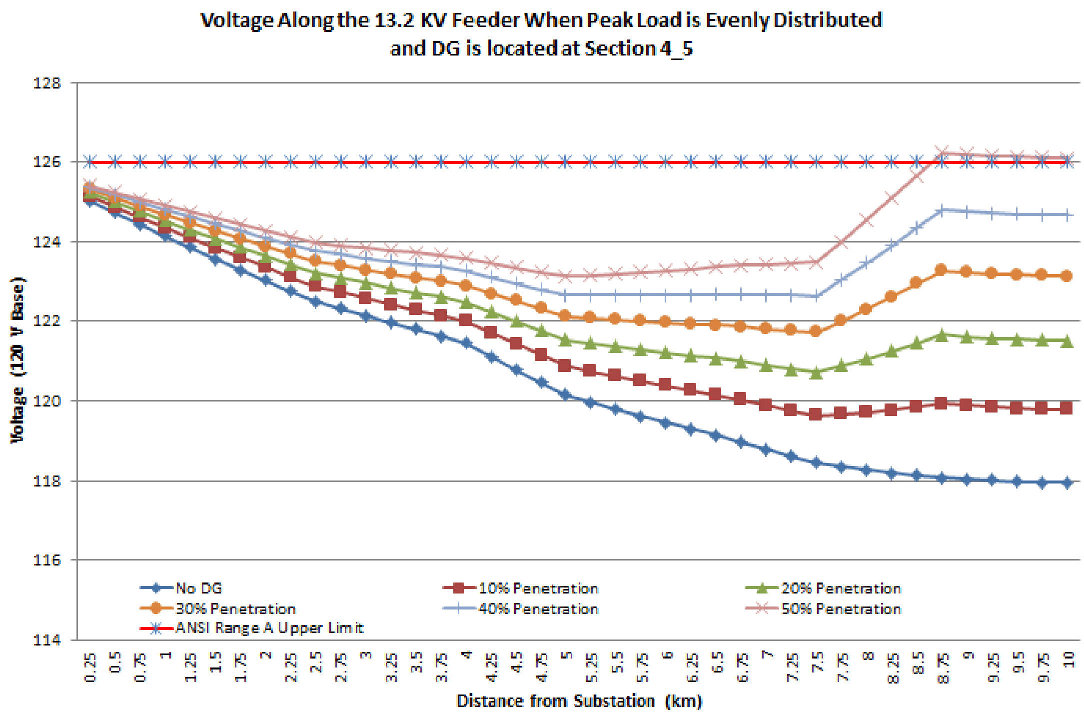

Figure A.6.2 Voltage along the feeder when DG is located at Segment 4_5

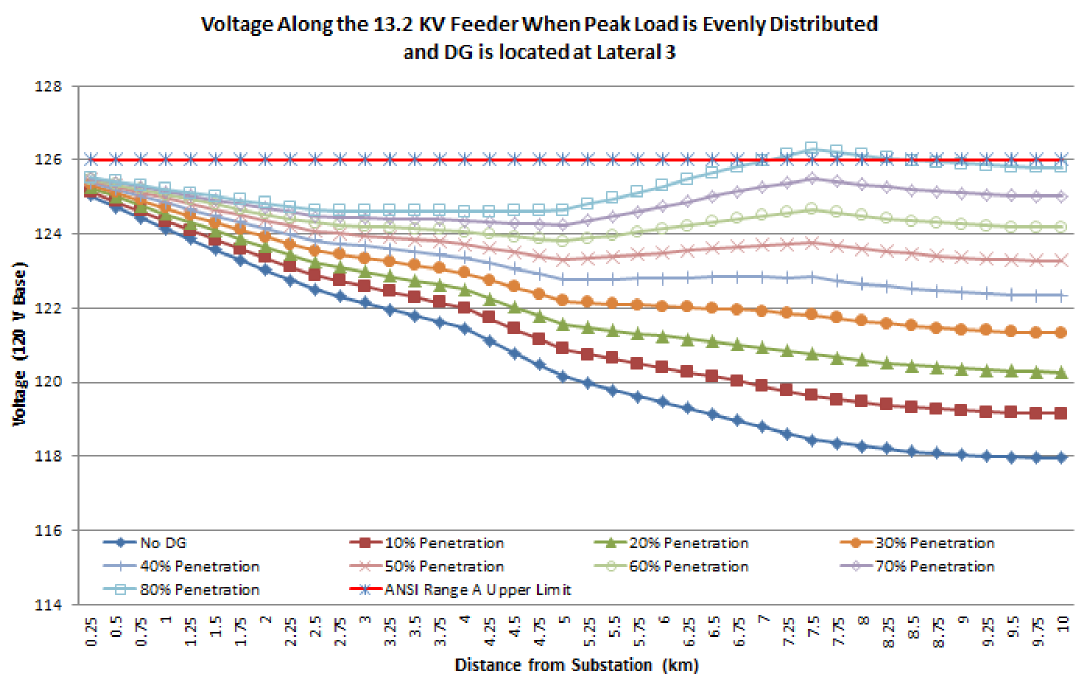

Figure A.6.3 Voltage along the feeder when DG is located at Lateral 3

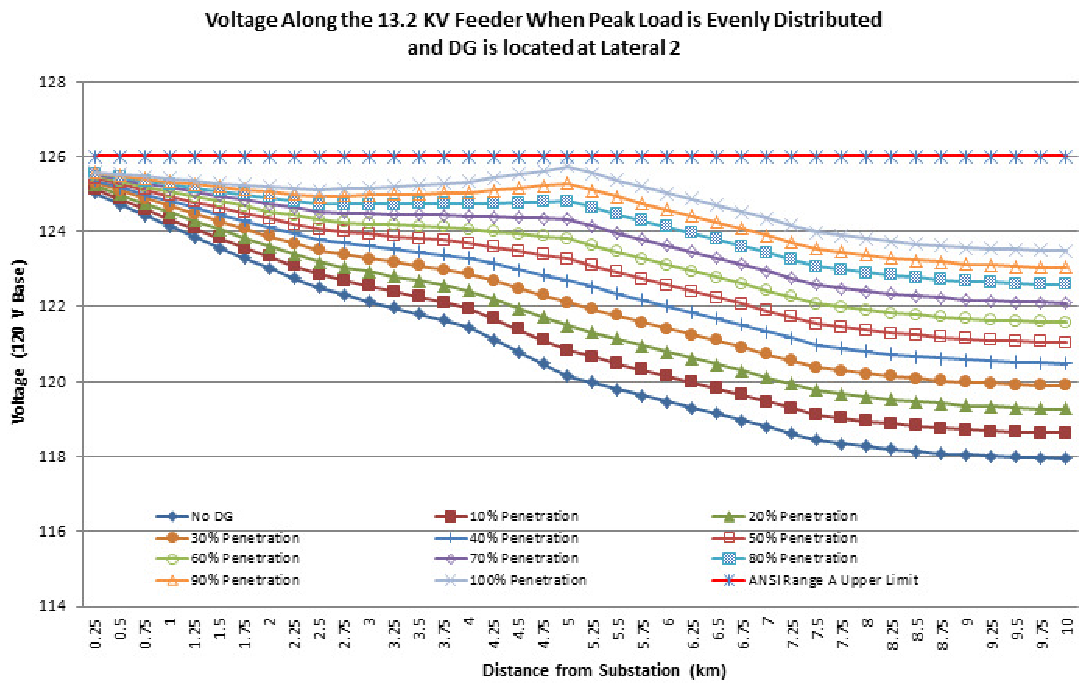

Figure A.6.4 Voltage along the feeder when the DG is located at Lateral 2

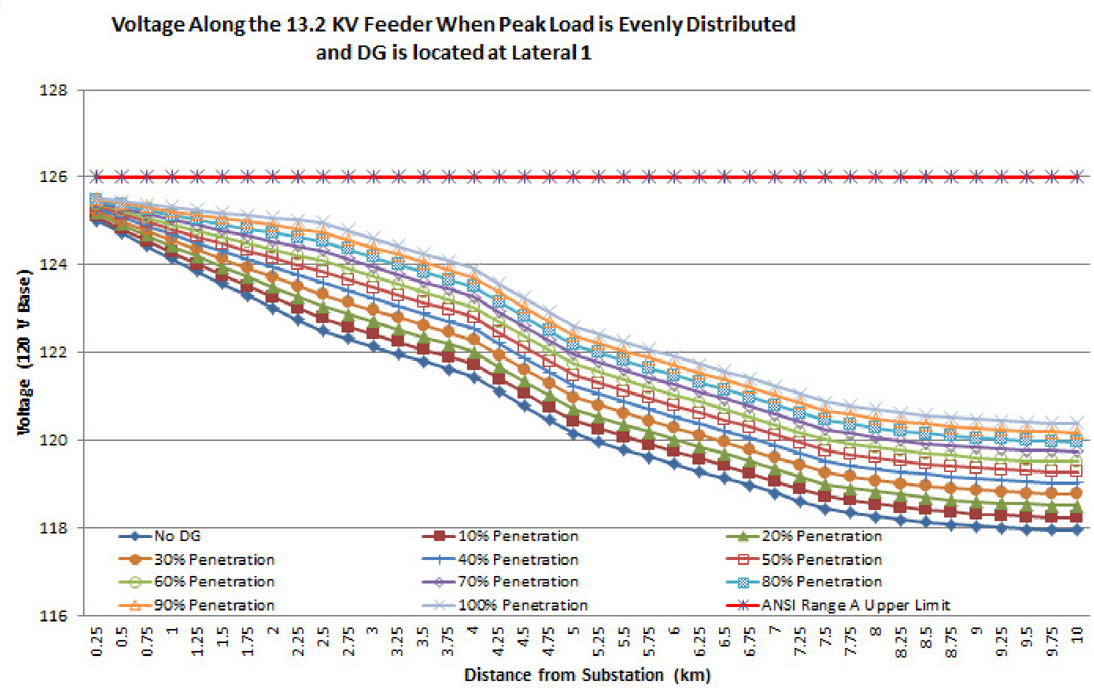

Figure A.6.5 Voltage along the feeder when DG is located at Lateral 1

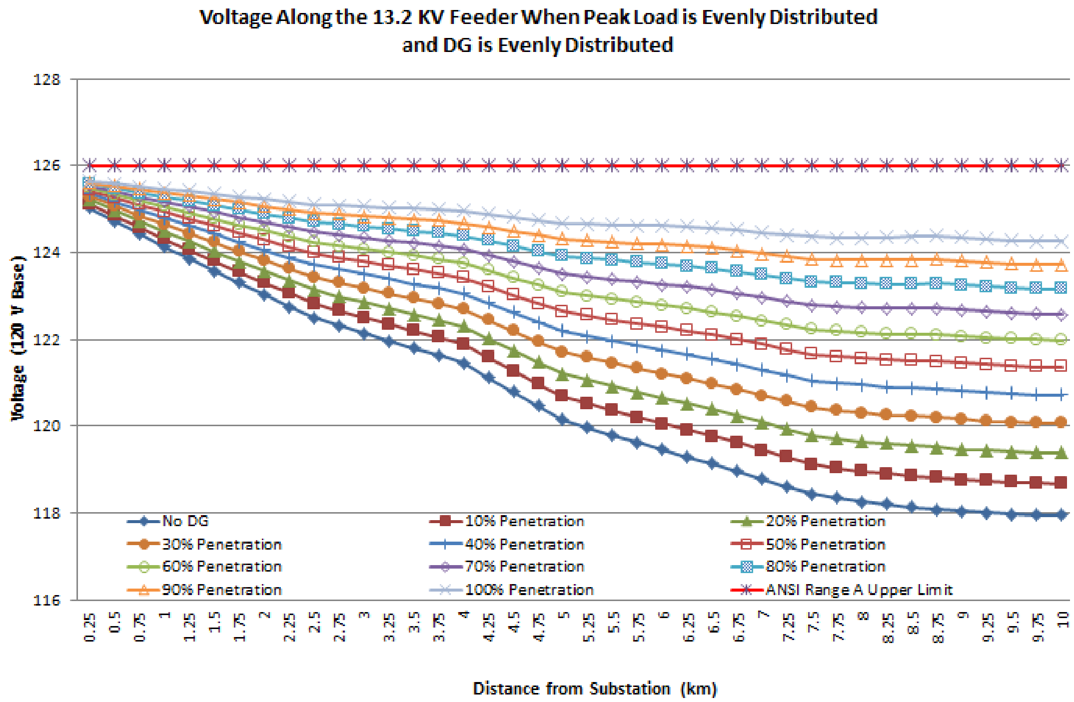

Figure A.6.6 Voltage along the feeder when the DG is evenly distributed

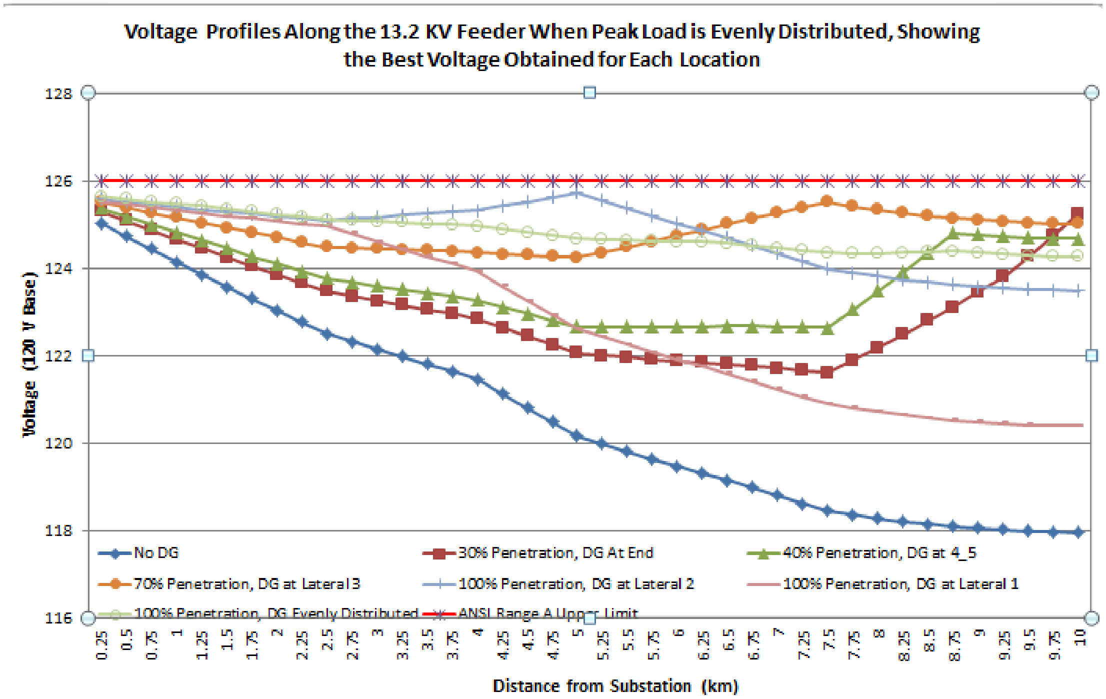

Figure A.6.7 Best voltage along the feeder for all DG locations evaluated

A.7 Voltage Plots For Case 7 – 13.2 kV Feeder with 6.6 MVA Distributed Evenly Along the Feeder

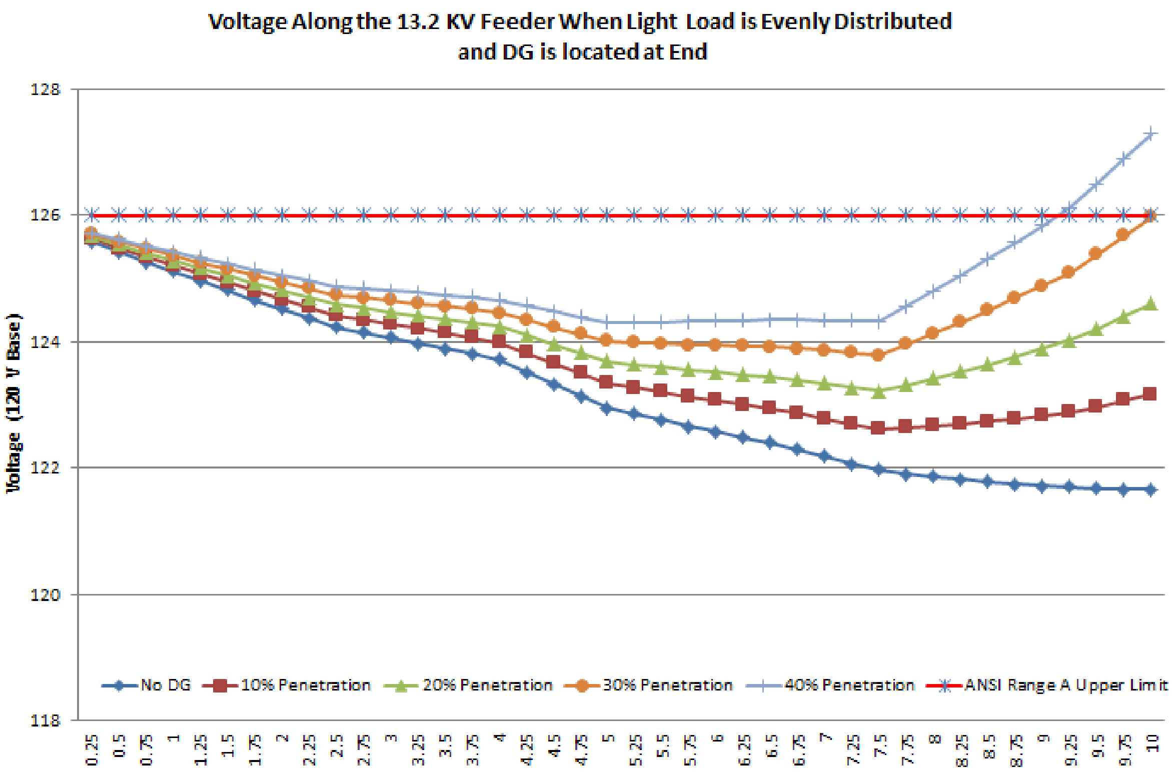

Figure A.7.1 Voltage along the feeder when DG is located at end

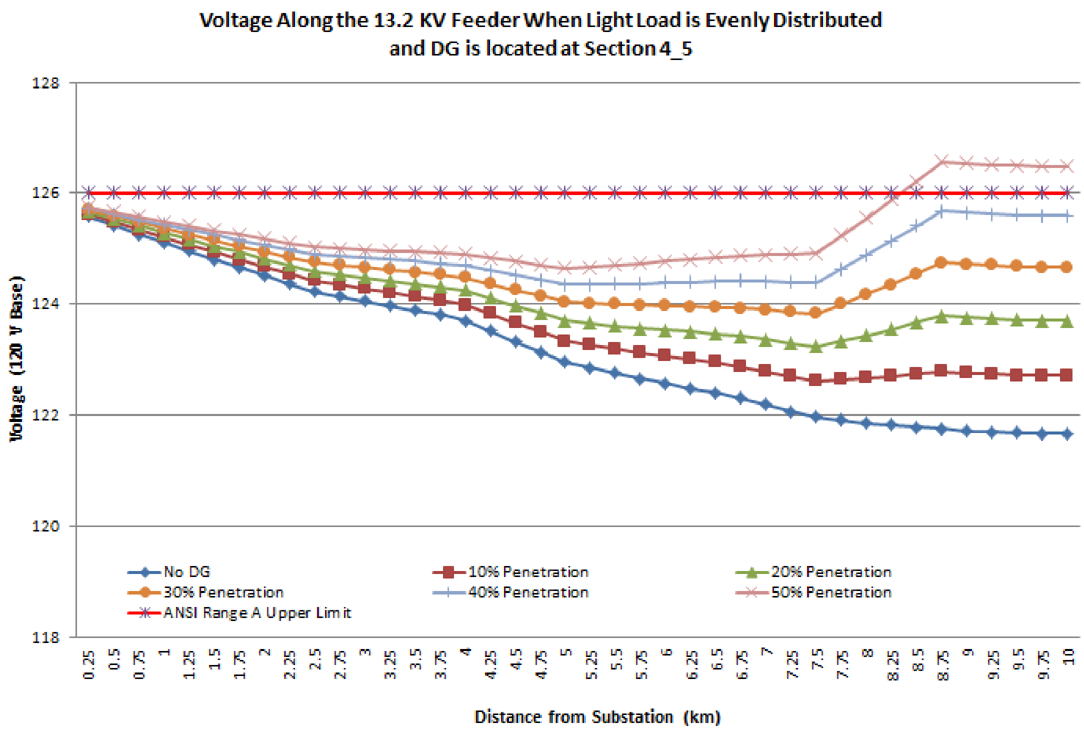

Figure A.7.2 Voltage along the feeder when DG is located at Segment 4_5

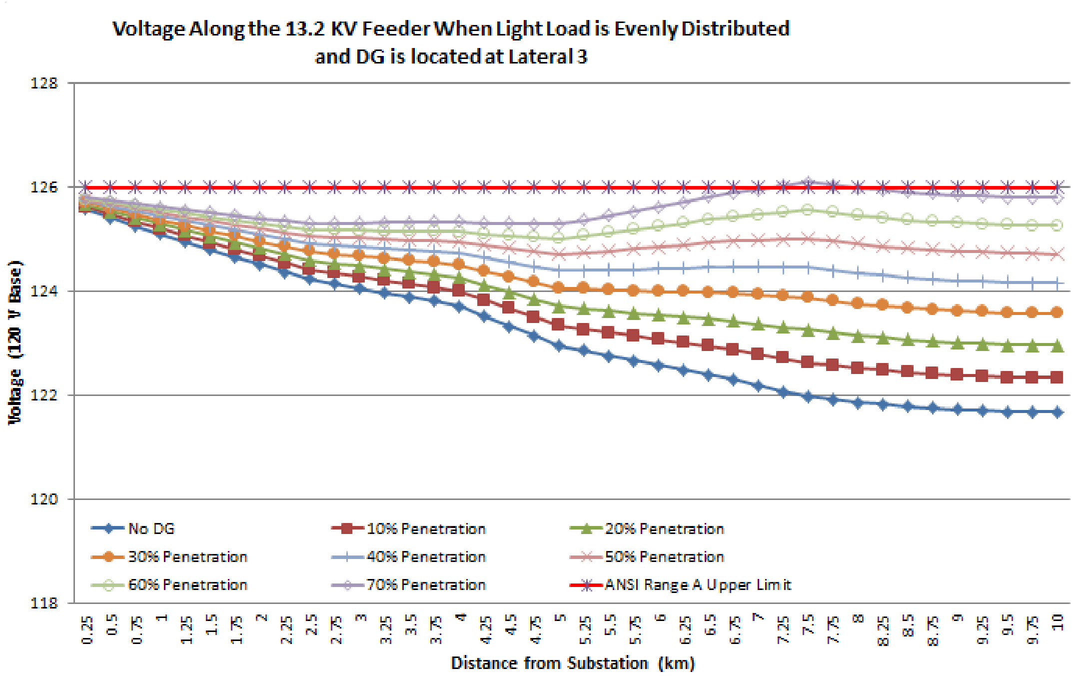

Figure A.7.3 Voltage along the feeder when DG is located at Lateral 3

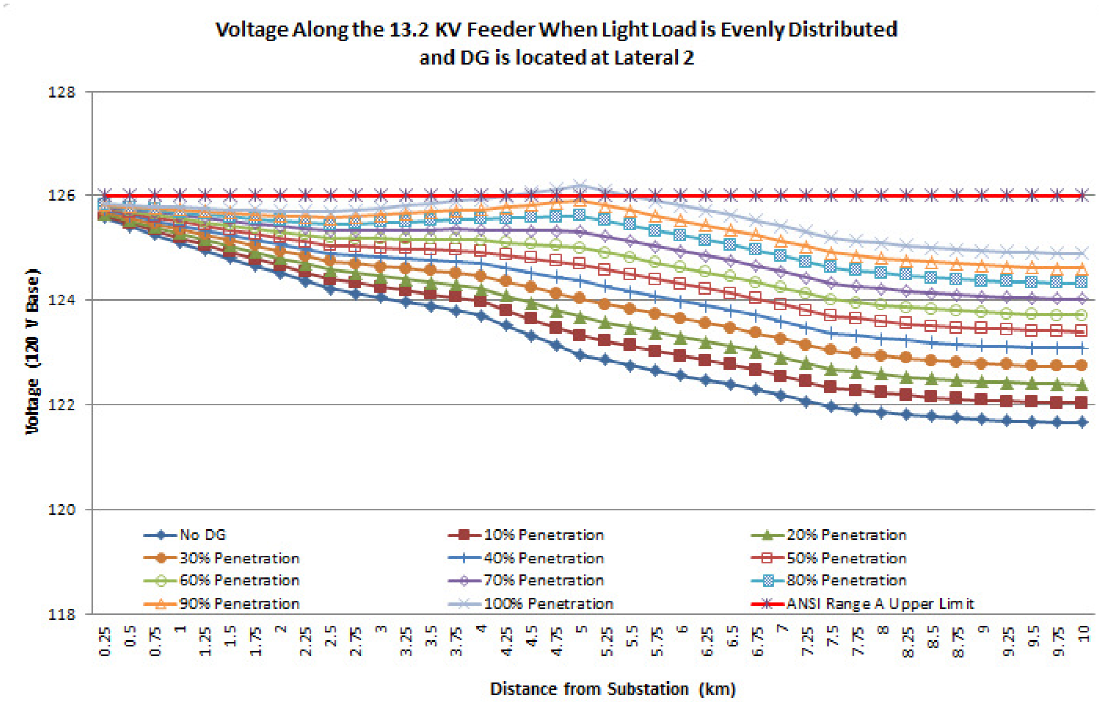

Figure A.7.4 Voltage along the feeder when the DG is located at Lateral 2

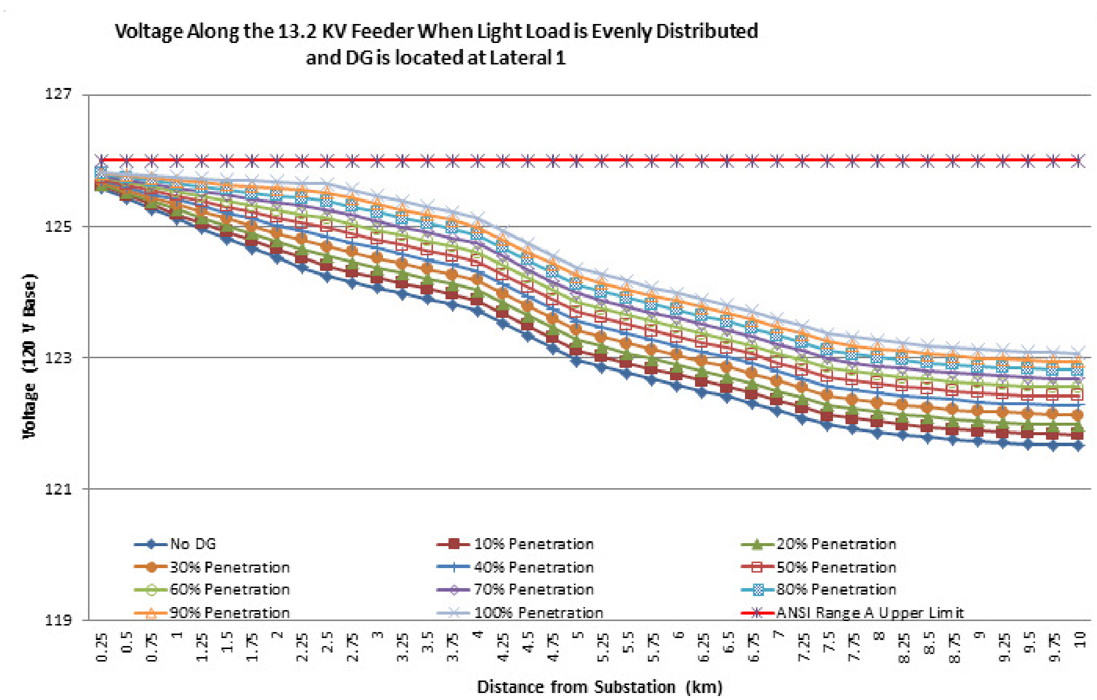

Figure A.7.5 Voltage along the feeder when DG is located at Lateral 1

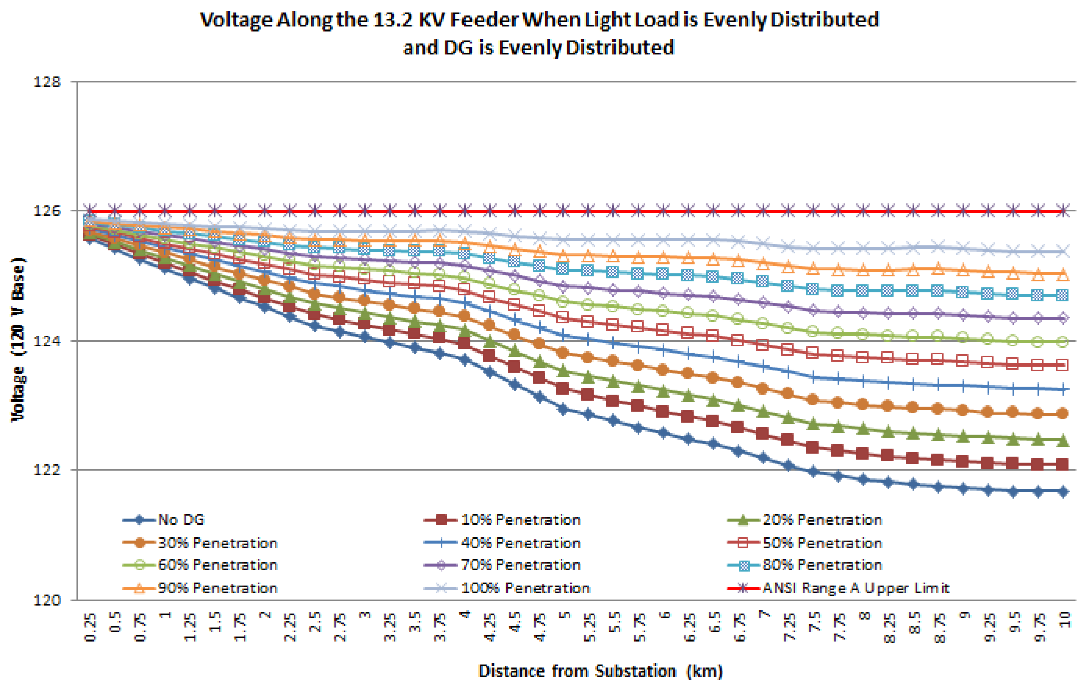

Figure A.7.6 Voltage along the feeder when the DG is evenly distributed

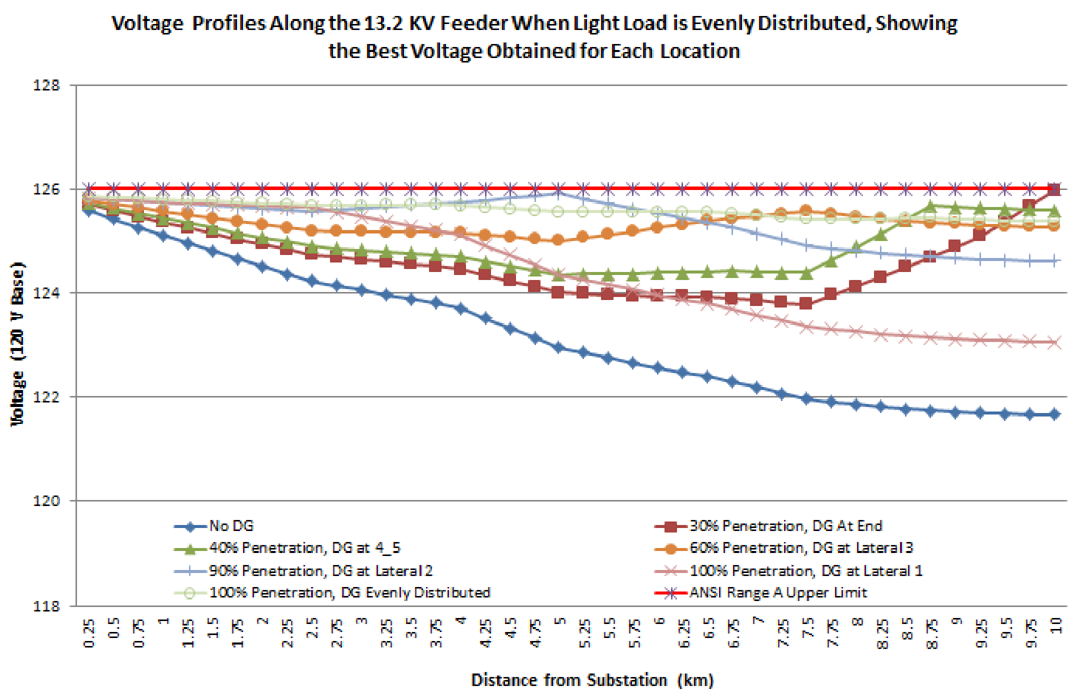

Figure A.7.7 Best voltage along the feeder for all DG locations evaluated