IMPACT OF INCREASING PENETRATION OF SMALL SCALE PHOTOVOLTAIC (PV) GENERATION ON VOLTAGE IN DISTRIBUTION NETWORKS

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Declaration

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Abstract

This dissertation proposes the implementation of a simple voltage management technique that uses active power curtailment to alleviate the impact of high PV penetration on network voltage. This stems from the results derived using power flow simulations to illustrate possible voltage impacts in two different networks, which is also documented. The need for such a study was derived from the global phenomenon of increasing embedded solar PV connections to the distribution grid. Despite there being a variety of economic and environmental advantages associated with the installation of these systems, their potential impact on the grid has yet to be fully understood. Findings show that a voltage control strategy based on active power curtailment was a successful technique to alleviate voltage rise, overvoltage and voltage change impacts brought about by increased PV penetration on a distribution network.

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Abbreviations

Abbreviation & Acronyms	**Description**
AC	Alternating current
All PV	Scenario where PV is evenly distributed throughout the network
Beg PV	Scenario where PV is only installed at the beginning of the network
CSP	Concentrating Solar Power
DC	Direct Current
DER	Distributed Energy resources
DG	Distributed Generation
DoE	Department of Energy
DS	Distribution System
End PV	Scenario where PV is only installed at the end of the network
HV	High Voltage
IPP	Independent Power Producer
kW	Kilowatt
kWp	Kilowatt Peak
LCOE	Levelised Cost of Energy
LV	Low Voltage
Mid PV	Scenario where PV is only installed in the middle of the network
MV	Medium Voltage
MVA	Megavolt amperes
MW	Megawatt
MWp	Megawatt Peak
NERSA	National Energy Regulator of South Africa
No PV	Scenario where no PV is installed on the network
NSP	Network Service Provider
OLTC	On-Load Tap Changer
PCC	Point of Common Coupling
POC	Point of Connection
PV	Photovoltaic
p.u.	Per unit measurement
REIPPPP	Renewable Energy Independent Power Procurement Programme
RPP	Renewable Power Plant
SANS	South African National Standards
SSEG	Small Scale Embedded Generation
TS	Transmission System

CHAPTER 1: INTRODUCTION

This dissertation focusses on voltage issues induced by increasing penetration of small-scale solar PV plants on the distribution network with a commendation of a simple voltage management technique that could be implemented to alleviate these issues. Extensive studies [1, 2, 3] have been conducted internationally to determine the impacts to voltage and technical losses on distribution networks and costs relating to these, however, there is a lack of analysis conducted for the South African networks. The need for such a study has been identified and development in this area is required.

The local conditions of networks, network loading and solar resources in South African make this research unique as no previous study with these components has been completed.

The local conditions, specific to South Africa, include conducting power flow simulations with the following:

- Long ageing networks with varying conductor sizes on one network, including Single Wire Earth Return (SWER) conductors. Network Service Providers (NSPs) in South Africa face many problems with these types of networks and these problematic networks are generally referred to as constrained networks,
- Using actual South African network loading data in terms of the customers' energy demand,
- Using actual South African generation or resource data. Note that South Africa has one of the highest solar resource in the world. The countries that have similar irradiation levels are Australia and other African countries,
- Implementation of a voltage control strategy that uses network voltage to dynamically induce active power curtailment of small-scale PV systems. This study has never been conducted using South African networks. Currently, the South African standard (NRS097-2-1) [4] for inverters does not include these smart inverter settings (referred to as Volt-Watt). This research will recommend that these settings be included in that standard based on its effectiveness on realistic networks with realistic loading conditions.

1.1. Background

Globally, there is an increasing trend of renewable energy deployment in various sectors. This is primarily due to the growing concerns over environmental and long-term sustainability impacts of conventional sources of electricity such as coal. The other reasons for the shift include government policy support and procurement programmes, tax incentives, increasing electricity tariffs and decreasing renewable technologies costs.

The renewable technologies that are seeing a significant rise in implementation in South Africa are solar photovoltaics (PV), wind energy and concentrated solar power (CSP).

These technologies are predominantly being installed on high voltage (HV) and medium voltage (MV) levels.

Distributed solar PV connections to the MV and Low Voltage (LV) grid are also seen to be a fast-growing phenomenon in many countries globally. According to a Navigant Research, global Distributed Energy Resource (DER) capacity is expected to grow from 132.4GW in 2017 to 528.4GW in 2026 [5]. At the end of 2017, it was estimated that a total capacity of 285MW (~140 000 installations) of small to medium scale solar PV was installed in South Africa. 95% of the installed capacity is considered to be grid-tied [6]. This is in all likelihood an underestimation as not all installations will be covered by the available sources; however, it gives an indicative value of the state of the market relative to the historic predictions. Although this was only 0.65% of the total installed capacity in South Africa at the time, this capacity has been increasing in an exponential manner. This is due to a variety of factors as mentioned above, as well as dependence being reduced on the utility networks in systems with high potential for overloading and outages (loadshedding), resulting in attractive business cases to some end-users. The South African Department of Energy (DoE) published a draft Licensing Exemption and Registration Notice on the 8th of June 2018 with the purpose of exempting various categories of generation facilities and electricity resellers from the requirement to hold a licence under the Electricity Regulation Act (ERA) 2006. However, facilities with an installed capacity of no more than 1MW require registration with the National Energy Regulator (NERSA). In 2021, the Minister announced that this cap will be increased to 100MW. Some municipalities have established registration processes permitting the connection of Small-Scale Embedded Generation (SSEG) to their distribution grid and in some cases, they have incentivised the process by introducing a net metering tariff. Once these processes become fully operational and consumers start to register their plants, the penetration of SSEG will be better understood. It has been reported that applications for ~**1000MW** of SSEG installations, with an installed capacity per installation ranging from 1MW-10MW, are waiting for approval from NERSA to connect to the grid [7]. This capacity is significantly larger than the estimated 285MWp in 2017; however, there is difficulty being reported on the matter of connection and regulatory approvals. The reluctance for approval also stems from the lack of ministerial allocation in a promulgated Integrated Resource Plan (IRP).

Despite the significant potential of renewable sources like wind and solar power, they are intermittent energy sources; that is, they cannot be dispatched (except by curtailing output) and their output varies depending on local weather conditions [8]. As there is an increase of renewable energy penetration on the grid, it must be noted that the original design of the grid did not envisage this intervention. The conventional power quality and other factors of the network were based on a centralised generation model with a small number of source nodes. The currents and voltages in this conventional three-phase network were designed to have perfect sinusoidal waveforms, a power factor of 1 and are balanced in phase and magnitude.

Increasing penetration of this technology adds to a risk of instability of the distribution network as the power injections from these generators change magnitude and direction of network power flows thus causing an impact on network operation and planning practices of distribution with both technical and economic implications [9]. The South African policies and standards which have been created/ amended to govern the installation requirements and penetration levels of SSEG are fairly new and most customers are unaware that they even exist. This along with South African customers' general disregard of governing principles can result in customers installing with systems resulting in undesirable penetration levels. The challenges that can be associated with high and undesirable SSEG penetration levels are power flow fluctuations, increased technical losses, overloading of equipment such as Medium Voltage (MV)/Low Voltage (LV) transformers and cables, grid protection malfunction and voltage variation, unbalance and overvoltage [10, 11, 12, 13, 14]. Overvoltage is seen as the predominant challenge in many LV grids with PV and is also considered one of the main limiting factors when increasing PV penetration in MV/LV grids [15].

To make matters worse, voltage management is considered to be an existing problem in the South African distribution environment. This is due to ageing networks and infrastructure coupled with poor to no maintenance on many of the networks; as well as long spans of varying sizes of poor current carrying capacity conductors. PV has proven to be a technology that is very intermittent in nature (meaning that the output generated can increase and decrease very quickly). This is predominantly due to PV production being affected by shading due to moving clouds, resulting in uncontrolled variability. The rate at which the output power of a generator changes is called the ramp rate and for PV systems this rate is between 10% and 20% per second [16, 17, 18]. This is very high even when compared to another renewable source like wind generation which has ramp rates of about 10% per minute [2]. This intermittency causes fluctuations in voltage that are not always predictable or being monitored and they could occur on time scales which are too fast for conventional voltage regulation devices that take long to react [2]. Furthermore, this occurrence takes place various times in a day and results in voltage regulation equipment being used in a way that it wasn't designed for and eventually leading to progressive failure [19]. In South Africa, generally the MV/LV transformers installed on the networks are not auto-transformers and cannot auto-react to these intermittencies. This can result in an increase of switching frequency, voltage issues and customers experiencing poor quality of supply.

This dissertation focusses on voltage issues induced by increasing penetration of small-scale solar PV plants on the distribution network with a commendation of a simple voltage management technique that could be adopted to alleviate these issues.

1.2. Objectives

The objective of this work is to determine the impact of installing small scale PV on voltage in Distribution networks. This analysis has been completed for different penetration levels of PV in MV distribution networks and in each penetration scenario, different location cases was also simulated. The voltage impact on the network was simulated using actual loading data with realistic generation data from the area. This provides the most realistic case for varying load and generation cases.

Furthermore, simulations with the implementation of a voltage control strategy using active power curtailment have been completed to determine if voltage impacts can be alleviated/ mitigated.

The key research questions this MSc aims to answer are:

1. What voltage impacts are experienced when installing increasing penetrations of PV on Distribution networks?
2. Can the voltage impacts in (1) due to increasing penetration levels of PV on Distribution networks be managed using active power curtailment of inverters? If so, what improvement can be observed?

1.3. Structure

The document is divided into various sections, each targeted at a specific characteristic of the dissertation. The structure is as follows:

Chapter 1: introduces the problem statement and previous work that was completed. It provides an overview of status of small-scale PV in South Africa and the challenges that are encountered on the network with the integration of this technology.

Chapter 2: provides a literature review on the technical impacts due to the addition of small-scale PV plants on distribution networks. Furthermore, the standards and procedures such as The Grid Code for Renewable Power Plants, NRS 097-2-1, NRS 048-2 and the Eskom network planning guideline for Distribution voltage and apportionment limits which are utilised in assessing compliance of a small-scale PV power plant in terms of voltage are evaluated.

Chapter 3: details the methodology along with the power flow simulation modelling that was required to accomplish the objectives highlighted in Section 1.2. of this document.

Chapter 4: comprises of the results and analysis from the Digsilent power flow simulations which were completed to achieve the objectives of this MSc. This chapter also provides theoretical results obtained from increasing penetration of PV installations.

Chapter 5: discusses the results and key findings from the theoretical simulations as well as whether or not the voltage control strategy using active power curtailment for PV generators is successful.

Chapter 6: comprises of the conclusions and recommendations made for the work in this document.

CHAPTER 2: LITERATURE REVIEW

2.1. Distributed Generation

Distributed generation (DG) is an electric power source connected directly to the distribution network or on the customer side of the meter [20]. This type of generation can also be referred to as small scale generation, embedded generation or decentralised generation [21]. There seems to be no consensus around the world on one specific definition due to the fact that the concept encompasses various technologies and applications. The concept of DG is not considered to be a new concept, in the past it was actually the rule and not the exception [21]. The IEEE defines DG as generation from systems that are significantly smaller than that of central plants so that interconnection to the grid at any point can occur [21]. In their effort to define DG, [22] refers to DG as any small generation source or storage facility not included in central generation but rather closer to the load with an installed capacity of <1kW – 10’s of MW’s. The CIGRE distribution generation working group defines it as any generation connected to the distribution network, neither dispatchable nor planned by utility with a maximum installed capacity of 50MW-100MW [23]. In [24], DG is seen as serving either purpose of supporting the network economically and/or meeting the customers direct energy requirements. These can have installed capacities of anything less than 30MW.

In South Africa, DG is most often than not classified as Small-Scale Embedded Generation (SSEG), which is defined as power generation with an installed capacity under 1MVA, such as PV systems or small wind turbines which are located on residential, commercial or industrial sites where electricity is consumed [25]. This type of generation forms part of that categorised in Category A of the South African Grid Code Requirements for Renewable Power Plants [26]. It can be concluded that all definitions and characterisations of DG suggest that it is decentralised generation which is generally located near the load on a distribution network and has a small installed capacity. This document refers to such generation with a typical installed capacity limited to 5MWp. In some instances, utilities can also use DG to provide support to the distribution grid. Various literatures show that the location and voltage level of installation is the most important characteristic in identifying DG rather than using its installed capacity.

DG is also considered to have flexibility in various facets such as installed capacity, modular expandability and operations. DG consists of 2 different types of generation i.e., conventional and non-conventional [27]. Figure 1 illustrates these types of DG. Figure 2 provides the classification of DG in terms of installed capacity and coupling interfaces.

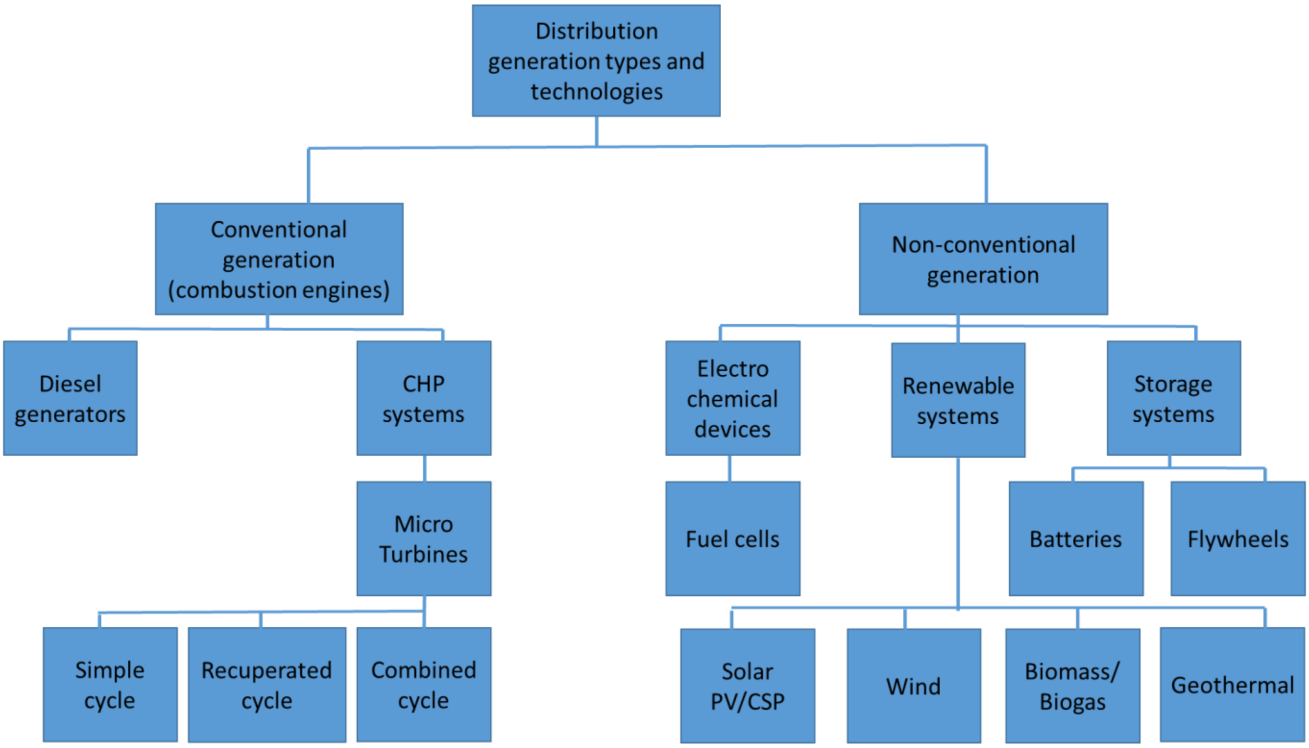


Figure 1: Different types of Distributed Generation (DG) [27]

DG Type	Power Rating
Micro	<5 kW
Small	5 kW - 5 MW
Medium	5 MW - 50 MW
Large	>50 MW

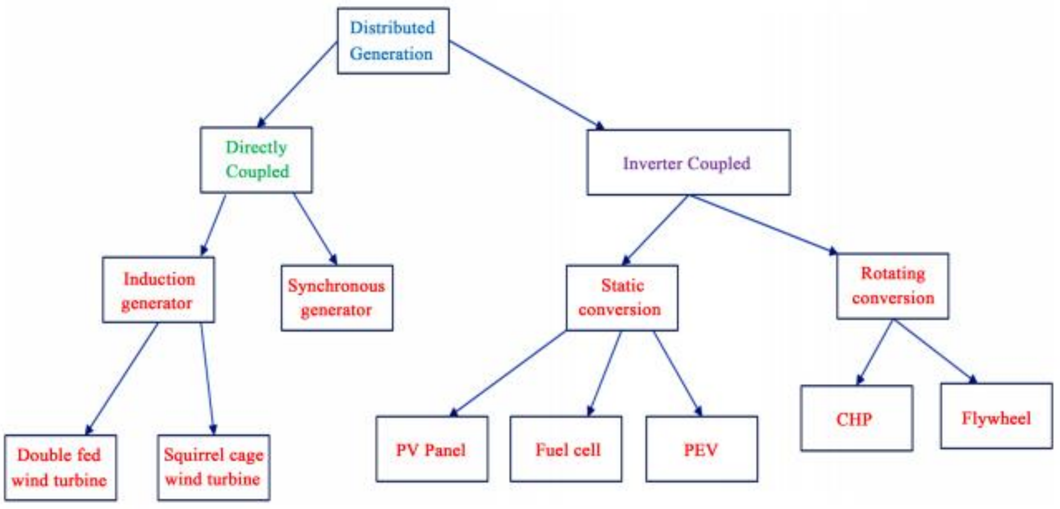


Figure 2: DG classification based on installed capacity and coupling [28]

Applications of DG (depending on technology) include, but are not limited to the following [27]:

- As "peaking plant" to decrease electricity costs in commercial and industrial consumers during their peak demand times,
- As standby systems installed at the load for use as a back-up system. This offers security of supply at all times including cases of outages from the grid,

- As stand-alone systems or “remote” systems replacing the need for a conventional centralised power supply. These systems are often referred to as mini-grids and are inclusive of battery storage. They are deployed in areas where access to the transmission or distribution grid is scarce,
- As micro-generation systems which are small-scale systems and are deployed mainly to serve residential consumers to reduce electricity costs,
- As combined heat and power systems.

The role of Distributed Generators, as given by [29] includes meeting future energy needs and the following (reasons applicable to South Africa extracted):

(a) Providing independence and flexibility to the customer in planning and developing the installation. This can assist customers who have sensitive and critical loads in environments which are subject to interruptions and curtailments of electricity.
(b) The generation cost of DG is decreasing to the point where it becomes competitive with grid energy. This allows power companies to add generation at critical points in the grid, particularly near loads.
(c) It allows for independent production of electric energy by a customer, possibly at a cheaper rate, thus saving on the utility bill. Excess energy can be exported into the grid and sold using net-metering schemes.
(d) The potential of providing some of the ancillary services exists.

The International Energy Agency states that DG is attracting increasing attention in policy-makers, economic state of and consumers and they propose that there are 5 main contributing factors as to why; these include increasing customer demand for reliable electricity and security of supply (specifically with the installation of back-up systems such as energy storage), liberalisation of electricity markets, utilities facing constraints in construction of new distribution and transmission lines (onsite DG can generate a cost saving of 30% from transmission and distribution deferrals), advances in technology of DG and growing concerns around climate change [30]. Other drivers include utility generation shortages, risk aversion for the future electricity prices, and improvement of power quality of the networks (this is more applicable to storage technologies) [31]. DG can serve as electrification of customers who are located in isolated areas as it will be cheaper to create an off-grid solution rather than build infrastructure to connect customer to the grid. One major limiting factor to the capacity that a customer could potentially install is the space availability on their property. Environmental concerns and the desire to become “green” also forms part of the reasons for customers installing DG [32].

In South Africa, the technology of DG that is most installed is PV. Within different economic sectors, the motivation for adopting renewable energy systems such as solar PV differs from case to case in different countries. These behaviours were studied within the residential, agricultural and commercial sectors to gain an understanding of which users are most likely to adopt solar PV and under what conditions. Table 1 summarises the outcomes of the international literature on the users most likely to adopt solar PV. It is evident that the main determining factor for installation of PV is directly related to cost and economics and essentially the payback period of the system.

Table 1: Users by sector most likely to adopt solar PV in South Africa based on behavioural studies [33]

Residential Sector	Agricultural Sector	Commercial Sector
• High income homeowners, • Freestanding homes, • Payback periods of 5 years.	• Non-seasonal electricity consumption, • Availability of funding • Payback periods < 6 years for systems sized under 50 kWp, • Payback period of <10 years was considered feasible for larger solar PV systems.	• Building owners, • Shopping centres, grocery stores, offices and distribution centres most likely to install, • Payback periods of 0-10 years, ideally 0-5 years.

An observation from an Organisation for Economic Co-operation and Development (OECD) survey on household investments in energy efficiency and renewable energy that is relevant to expectations of household PV growth in South Africa showed that the households most likely to adopt solar PV are "***high income earners, who own the freestanding homes that they live in, are unaware of their energy consumption and are active participants in environmental or energy conservation activities***" [34].

A decrease in installation costs of PV systems is envisaged, which is expected to lead to a more favourable uptake of the technology. The Levelised Cost of Electricity (LCOE) of PV systems in South Africa was evaluated and it further supports the above statement. Figure 3 below indirectly illustrates that the costs for distributed solar PV systems are decreasing [35].

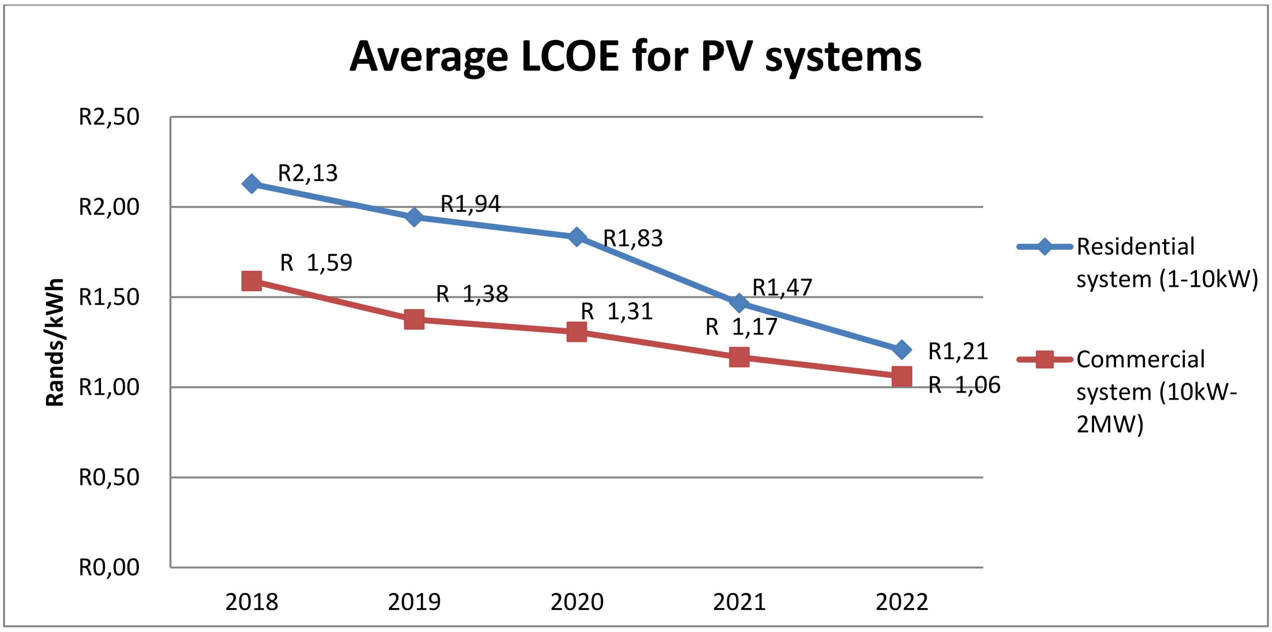


Figure 3: Average Levelised Cost of Electricity (LCOE) for distributed solar PV systems from 2018-2022 [35]

A useful set of information contained in the database collected for current installations relates to the installed capacities of the installations in each economic sector. Table 2 details the typical installation sizes for each sector in the market. Due to the large database of installation data, these numbers are vastly different from each other. Furthermore, it was apparent that the sector dominating the market is the commercial and industrial sector with 69.8% of the market share, followed by the agricultural sector with 22.5%.

Table 2: Typical installation size per sector [33]

Sector	Maximum Size	Average Size	Most Common Size
Overall	4 775kW	80.51kW	3kW
Commercial & Industrial	4 775kW	170.89kW	10kW
Agricultural	1 021kW	123.08kW	50kW
Residential	79kW	4.87kW	3kW

After evaluating the PV growth scenarios for South Africa in [33], it was estimated that by the end of 2020, ~839MWp of small-scale PV systems will be installed in SA. This increasing penetration displays an urgency for understanding how these installations impact our grid and how to better manage the integration of them. The conventional management of distribution networks is on a passive basis with a unidirectional flow of both real power (P) and reactive power (Q) from higher to lower voltage levels due to the design of the network being that of a radial or loop design, and not a meshed design as transmission networks [36]. However, with the inclusion of DG the power flows may become reversed [37]. With this occurring, a new approach to the organisation and operation of the network may be required and this must be based on active management techniques [38].

Note that DG in the context of solar PV only will be considered in the master's dissertation and is relatable to all aspects covered in this document.

2.1.1. Grid-tied solar PV systems

This dissertation considers the installation of a distributed generator which is of solar PV technology to the distribution network and is often referred to as a grid-tied solar PV system. This section will provide a detailed overview of such systems and its components.

A solar PV system generates electrical energy by harvesting the radiation or insolation from the sun using PV cells [39]. The main components of this system consists of the following [39] [40]:

- PV modules: Made up of various solar PV cells which generates DC power using the energy harvested from the sun. This is generally connected with other PV modules to form a PV array,
- Grid-tied inverter: This converts the DC power, which is generated by the PV array, to usable AC power. Existing inverters have the ability to track the maximum power point from the PV modules so that the maximum power is generated at the output.

A visual representation of a basic grid-tied solar PV system is illustrated in Figure 4.

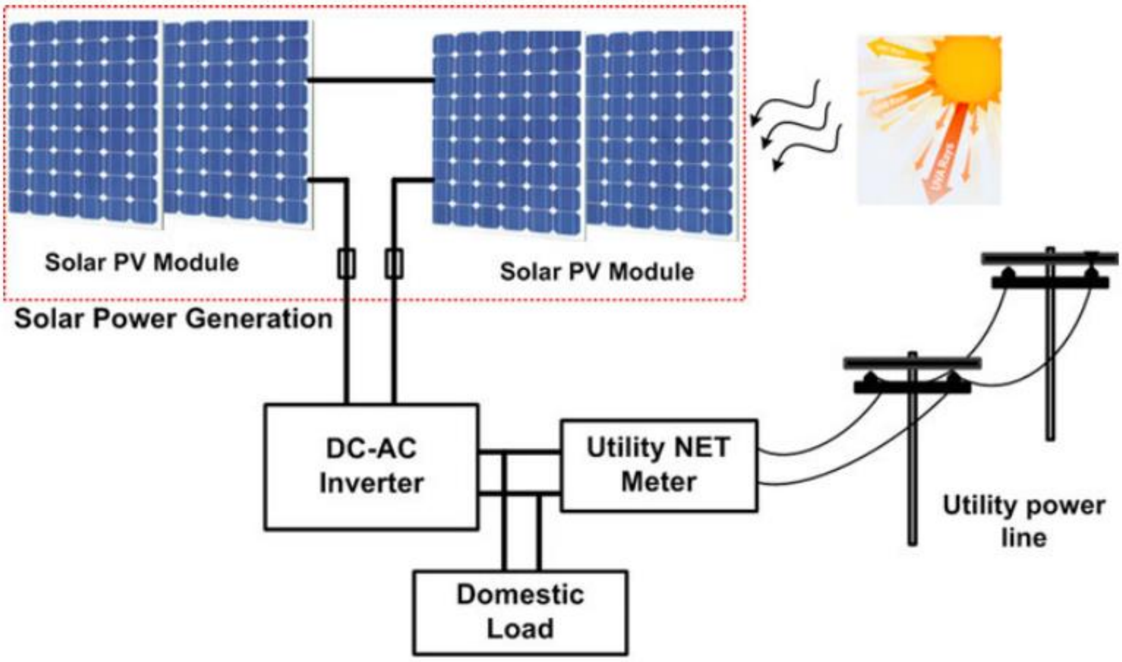


Figure 4: Grid-tied solar PV system components [40]

This type of system requires a bidirectional interface between the PV system AC output terminals and the grid utility network enabling the load to be fed by the PV system or grid. When the PV system generates more than the local load, the excess power will be fed into the grid. At this point is when reverse power flows within the distribution network and upstream of the customer's load point.

2.2. Technical impacts of installing Distributed Generation on the grid

Poor power quality of a network is as a result of the following [21]:

- Voltage dips, transients and interruptions led on by failures or switching operations,
- Disturbances brought about by loads or generators that cause voltage flicker or harmonics. Imbalances in a network can also tend to result in such faults.

The effect of DG on power quality with regards to several aspects of the network is expanded on below [21] [36] [22] [41]. Note that these aspects can result in increased grid maintenance costs incurred by the network service providers.

1. Power Quality:

   A brief introduction to power quality problems induced by DG is highlighted below.

   - Voltage Flicker:

     There is a potential for DG to induce noticeable flicker. Voltage flicker occurs when there is modulation of the voltage output at frequencies that are below 25Hz and is as a result of significant voltage fluctuations that develop during a short period of time. These occurrences are sometimes visible to the naked eye. DG can cause flicker during the starting of the generator or when there are sudden changes in the output.

- Harmonics (voltage and current):
  DG technologies that are inverter-based in order to supply AC to the grid are generally considered as high producers of harmonic injections. Older DG inverter technologies used Silicon Control Rectifier (SCR) thyristors that are known to inject a high level of harmonics to perform the switching operations required; however, newer technology makes use of Insulated-Gate Bipolar Transistors (IGBT's) which are considered to produce a cleaner output.

2. Voltage:
   - Voltage regulation:
     Voltage on a distribution network is regulated by the NRS specifications in South Africa. These conventional regulation practices are based on power flow in radial distribution systems from the source to the load; DG presents a different situation whereby the network becomes a "meshed" system where power flow direction changes and affects the voltage regulation of a system. The resultant effect of voltage swells/sags on a radial network can be significant when there exists increased penetration of DG on the network. This effect can be caused by the intermittent nature of some types of DG. Furthermore, if a voltage regulator is installed on a network to perform line drop compensation upstream from a DG, this regulator could receive mixed signals and in turn drop the setpoint for voltage to be regulated resulting in the opposite effect of voltage support to that network.
   - Voltage Notching:
     This phenomenon is caused by the switching occurrence in devices with Silicon Control Resistor's (SCR) which are connected to the grid. Voltage is distorted and creates "notches" in the resulting waveform. Some DG technologies utilise SCR's for switching and can induce such occurrences. These can result in the malfunction of equipment connected to the network, especially when the notches touch zero voltage.

3. Frequency:
   Increased penetration of DG can result in an imbalance between demand and supply thus resulting in a deviation from grid frequency.

4. Reactive power:
   Some DG technologies with switching capabilities are able to supply reactive power to the grid, if regulation allows it to be configured in this way. This can act as a way of performing power factor correction at points of the grid where it may be required. On the contrary, some DG sources inject reactive power during low loading conditions on the network and this can be seen as a challenge for NSP's.

5. Power flow:
   Reverse power flow caused by DG in networks can lead to different protection schemes required at distribution and transmission levels.

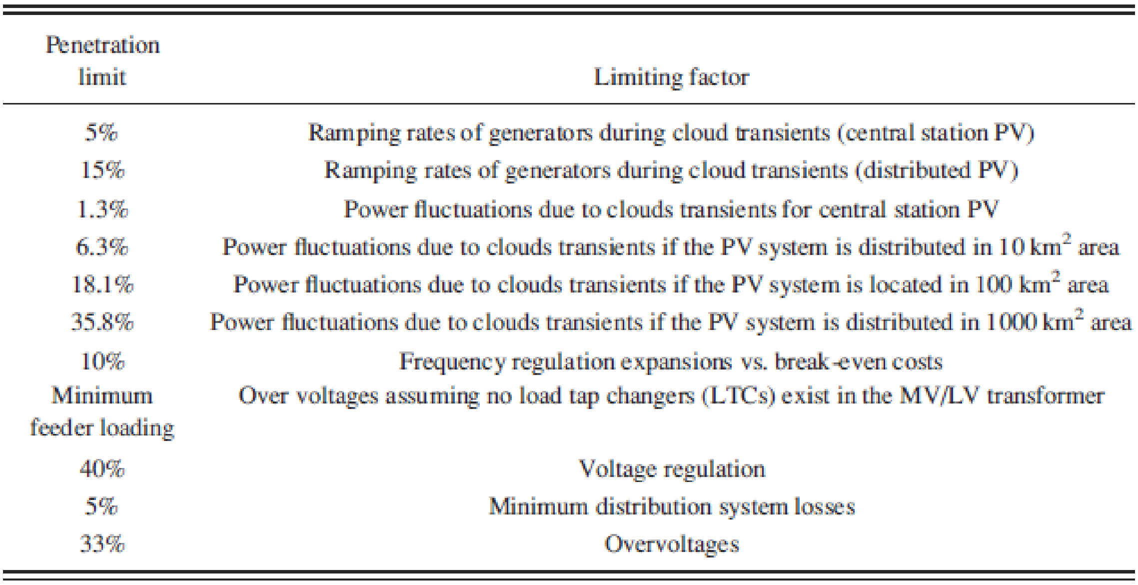
6. Protection and short circuit/fault current levels:
   The effectiveness of protection equipment available on the grid can be compromised due to the penetration of DG and their bi-directional flow. Safety of network operating personnel becomes compromised by the reverse power flow of DG when anti-islanding is not a feature on the installed systems. With regards to fault levels being impacted, one DG system on a network cannot contribute largely to the short circuit levels of other equipment on the network; however, the aggregation of many installations has a significant impact on it. Fault levels could in fact become increased. This can result in discoordination of fuse-breakers on the network. Voltage swells that could potentially result in damage to equipment connected on the same network as DG's can also be a significant issue. This occurs when DG sources are not effectively grounded. Installing DG systems on the network often involve an existing transformer interface. However, due to the diverse nature of DG, these existing interfaces may be problematic [33]. The transformer configurations play a significant role in determining whether the appropriate grounding measures are fulfilled. Overcurrent and impedance relays which are connected to a network with high DG penetration can malfunction due to the existence of DG. These are required to be re-programmed with the introduction of DG on the network.

7. Losses:
   Depending on where DG is positioned on a network, the contribution to losses can be seen as positive or negative. DG can cause a reduction in feeder losses if placed and sized optimally. The effect would be similar to that of a capacitor bank with the difference that DG impacts both real and reactive power. The penetration of generation on the feeder is also very important as in some cases DG may benefit the network only up to a certain percentage of penetration; thereafter, the losses might be negatively influenced. Unfortunately, utilities have no control of how DG is installed and where to position the systems on the network.

8. Demand:
   Some technologies of DG can contribute to reducing the demand at peak periods and this phenomenon is referred to as peak shaving. This is seen as a benefit to the system as more energy can be supplied to other customers during these periods. DG can also be used to supply high priority loads during outages and load shedding. This will depend on whether the technology used in the inverters is able to switch from grid-tied to off-grid operation.

In [42], a review of literature was conducted on recommendations for allowable penetration limits as seen in research. The summary of these limits as a percentage of peak load and the limiting factor associated is represented in Table 3. These limits vary from 1.3% going up as high as 40%. The limiting factors are predominantly as a result of ramp rates or power fluctuations due to intermittency caused by clouds. Other reasons include voltage issues, installed size, location and geographic distribution of the systems [42]. Note that these limits have not only been analysed for a whole feeder but individual and clustered plants as well.

Table 3: Recommended allowable penetration limits and the limiting factor associated with it (*ElNozahy and Salama, 2013*) [42]



Penetration limit	Limiting factor
5%	Ramping rates of generators during cloud transients (central station PV)
15%	Ramping rates of generators during cloud transients (distributed PV)
1.3%	Power fluctuations due to clouds transients for central station PV
6.3%	Power fluctuations due to clouds transients if the PV system is distributed in 10 km^2 area
18.1%	Power fluctuations due to clouds transients if the PV system is located in 100 km^2 area
35.8%	Power fluctuations due to clouds transients if the PV system is distributed in 1000 km^2 area
10%	Frequency regulation expansions vs. break-even costs
Minimum feeder loading	Over voltages assuming no load tap changers (LTCs) exist in the MV/LV transformer
40%	Voltage regulation
5%	Minimum distribution system losses
33%	Overvoltages

2.2.1. Voltage impacts from distributed generation

It is evident, from the cited research, that voltage regulation is one of the most critical technical parameters that can be affected by increasing penetration of DG on distribution networks. Conventionally, networks are designed for one directional flow of power with acceptable loss levels along the network due to loading. The highest voltage on a network is generally at the sending-end busbar and the voltage along the feeder gradually reduces due to the line impedance and the load [43]. However, as previously stated, PV introduces reverse power flow from the customers into the MV/LV transformers thus challenging the designed limits of the network and its' infrastructure. It is essential for the voltage in a distribution network to remain within a certain range as equipment, both customers and that of the grid, functions correctly if the voltage is maintained within this range. Details on this will be discussed further in 2.3.2.

Voltage variations occur when the load current flowing through the resistive and reactive impedances of the lines vary [36]. The effect is as a result of the fluctuating power flows generated by DG thus causing a change in the voltage drops across impedances at different points of the network [44]. This issue is especially prominent when there is voltage control equipment installed upstream to the DG sources on a network. These include Line Drop Compensators (LDC's) such as step-type or line voltage regulators, switched capacitor voltage regulators and Load Tap Changer (LTC) transformers. Furthermore, the capacity of DG installed, operational mode and control of the DG sources and relative location on the network has an impact in determining whether the effect on the voltage is seen as a benefit or not. Fluctuations are increased towards the end of the network for loads concentrated along this point as the distance from the source of the feeder is increased. DG can influence voltage variations in the following ways [36]:

1. In a positive way when DG is operated in coordination with local demand, meaning when the demand on the network increases so does the production from DG and vice versa,
2. In a negative way when DG is not operated in coordination with local demand. In this case, DG might increase the variation between the maximum and minimum voltage level as compared to a situation without DG.

In [31], the IEA also expresses concerns over voltage control when DG is connected to the distribution grid. Voltage rise is considered as the main concern when there is a high penetration of DG on a network [45]. Due to the fact that rural networks have a high transformer impedance ratio and a low X/R ratio, reverse power flows caused by DG can make voltage rise a significant issue specifically on these networks. With South Africa being a developing country, the state of networks is considered to be inferior to that of developed countries as funding to maintain them is not readily available.

With respect to relative installation of DG with voltage control devices installed on the network, the following was established:

- Voltage sags can be experienced when DG is installed downstream from LDC regulators such as step-type or line voltage regulators or LTC transformers. This effect is demonstrated in Figure 5.

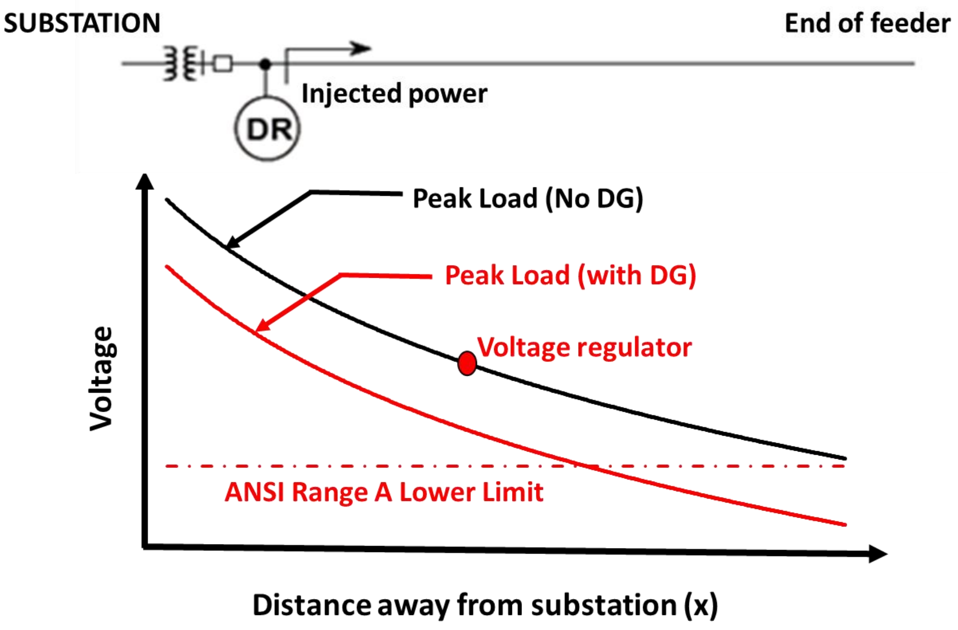


Figure 5: Effects on voltage relative to the lower limit for voltage regulation in US with DG connected upstream from voltage regulation equipment [44]

- Voltage rise can be experienced when DG is connected downstream from a voltage regulator or towards the end of the network. This phenomenon is illustrated in Figure 6.

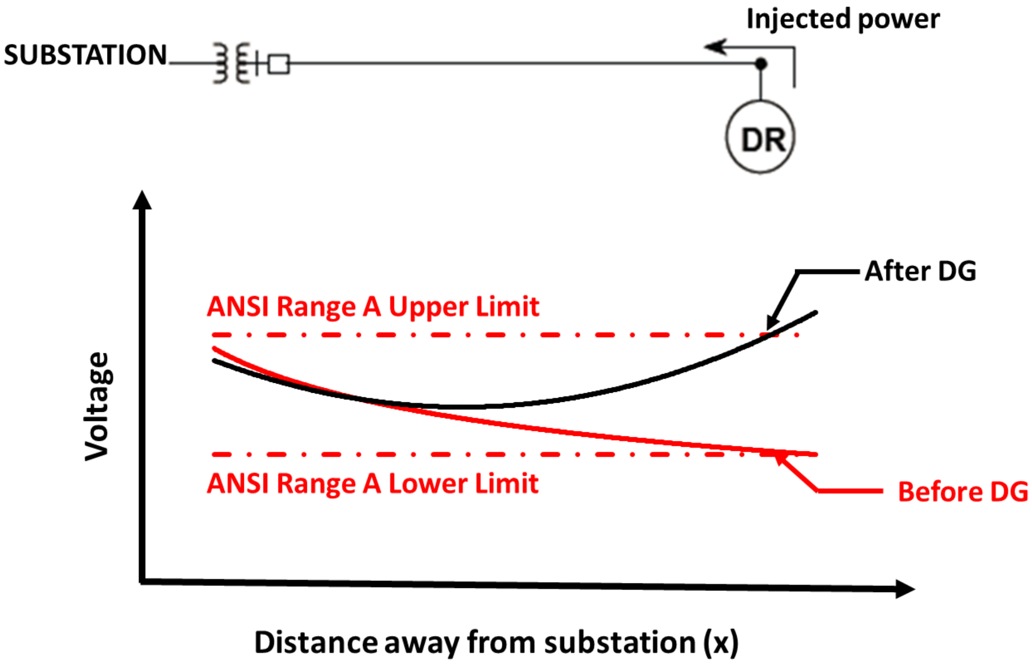


Figure 6: Effects on voltage relative to the limits for voltage regulation in US with DG connected downstream from voltage regulation equipment or towards the end of network [44]

The effects of scenarios with high and low DG output compared to high and low demand on the network with respect to voltage variation also needs to be analysed when there is high penetration of DG on a network. For example, if DG produces a low output during high load conditions, the voltage will drop and if DG produces a high output during low load conditions, the voltage will rise. Hence, the recommendation is that the following worst case scenarios must be considered when evaluating voltage variations with DG on a network as these will determine the limit of generation that can be installed on a network [47] [48]:

- High generation of DG with low load conditions,
- High generation of DG with high load conditions,
- Low/no generation with high load conditions and
- Low/no generation with low load conditions.

When using a limit of 3% of maximum voltage variation on an LV network, which is supported by NRS 097-2-3 [49], the following equation can be used to evaluate the steady state variation of voltage experienced at the Point of Common Coupling (PCC) [48]:

$$V_V = \frac{S_{DG}}{S_S}\cos\,(\varphi_S + \varphi_{DG}) = \frac{1}{R}\cos\,(\varphi_S + \varphi_{DG}) \leq 0.03 \tag{1}$$

The maximum allowable DG capacity on a network is then calculated using the following equation [49]:

$$S_{DG} = \frac{V_V \times S_S}{\cos\,(\varphi_S + \varphi_{DG})} \tag{2}$$

Where:

V_V is the voltage variation at PCC in V,
S_{DG} is the apparent power of the DG sources in MW,
S_S is the short circuit capacity at PCC in MW,
φ_S is the phase angle of impedance at PCC and φ_{DG} is the phase angle of the DG output power.

The above method is not considered as accurate due to the fact that many aspects not being taken into account in the calculation such as feeder parameters. A more detailed equation that can be used is given by equation 3 below [51]:

$$\boldsymbol{P_{DG}} = \left[\frac{\boldsymbol{V_{Upper}(V_{Upper} - V_{Setpoint})}}{\boldsymbol{r \times d}}\right] + \left[\boldsymbol{S_{min}}\left(\mathbf{1} - \frac{\boldsymbol{d}}{2 \times \boldsymbol{L}}\right)(\boldsymbol{cos\theta} + \boldsymbol{sin\theta})\right] - \left[\frac{\boldsymbol{x}}{\boldsymbol{r}}\boldsymbol{Q_{DG}}\right] \tag{3}$$

Where:

P_{DG} is the maximum power that can be exported by DG in MW,
V_{Upper} is the upper limit as per the voltage regulation standards in p.u.,
$V_{Setpoint}$ is the voltage setpoint on the On Load Tap Changer (OLTC) on the network in p.u.,
r represents the impedance in ohms/km of the network connecting the DG to the source busbar,
d is the distance between the DG and source substation in km,
S_{min} is the minimum apparent power of the feeder load in MVA,
L is the length of the backbone of the feeder in km,
$cos\theta$ is the power factor of the feeder at minimum load,
$sin\theta = \sqrt{1 - \cos^2\theta}$,
Q_{DG} is the reactive power exported into the grid in MVar. This is generally 0 as it is assumed that the DG will operate at unity power factor.

There have been many attempts to determine voltage rise from DG in distribution networks. In [52] the relative voltage rise that can be experienced when DG is added to a network is given by:

$$\frac{\Delta V}{V} = \frac{R \times P_{DG}}{V^2} \tag{4}$$

Where:

V is the nominal voltage,

P_{DG} is the active power that is exported into the grid in MW,
R is the source resistance at the generator in Ohms.

In [15] the voltage rise experienced in an LV distribution network is derived using the illustration in Figure 7 where a thevenin equivalent of the rest of the grid until the Point of Common Coupling (PCC) is used.

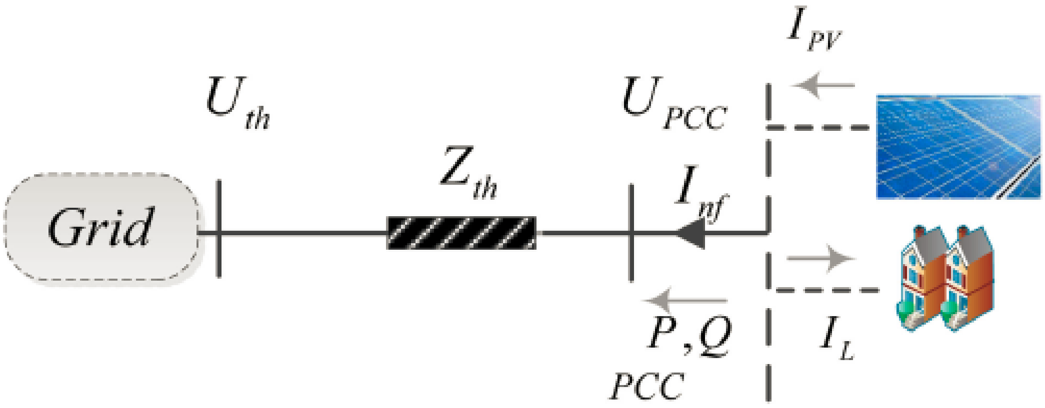


Figure 7: Thevenin equivalent of a PV system connected on an LV network [15]

The voltage rise at the PCC when net export occurs can be calculated using equation 5.

$$\Delta U \times U_{th} \cong P \times R_{th} + Q \times X_{th} \tag{5}$$

Where:
ΔU is the voltage variation at PCC in Volts,
$U_{th}$is the grid equivalent voltage,
P is the active power of the PV system in MW,
Q is the reactive power of the PV system in MVar and
R_{th}, X_{th} are the thevenin equivalent resistance and reactance of the network.

Static voltage impact studies conducted in [53] concluded that for reliability of a network to be sustained and of good standard for a developing country such as South Africa, the network will require upgrading due to voltage variations brought about by DG, however, quantification of this is not necessarily an easy task.

A study completed to determine the maximum penetration of PV on a number of LV networks in Cape Town, South Africa showed that a voltage rise of 3% can be sustained at a penetration of 45-60% with a probability of 5% voltage violation [54].

2.2.2. Voltage management techniques for networks with Distributed generation

This section provides details about the solutions that can be implemented to mitigate technical impacts of increasing penetration of PV on Distribution networks and to further increase hosting capacity on a network. Many measures have been mentioned in research; however, there is a lack of comprehensive analysis of advantages and disadvantages of them [15].

The traditional way of managing voltage on an MV feeder include operating the transformer by changing the tap settings, wide area control, reinforcement of networks by increasing the cross-section of the conductor (this will also reduce the impedance of the network) and the installation of voltage regulators and active transformers. However, this comes at a cost and if these equipment are not fast reacting to cater for the intermittent nature of PV, other equipment may be required. Other measures for new voltage management techniques could include reactive power injection from the PV inverters installed, curtailment of active power from PV installations, demand response from customers on the network, installation of energy storage systems and electric vehicles. These methods are tabulated in Table 4, where the placement or responsible party is also highlighted [15, 1, 54, 55]. The advantages and disadvantages of each measure is stipulated in the table and classified in terms of mitigating or managing voltage violations caused by increasing PV on distribution networks. These methods have been assessed on various types of networks theoretically using simulation tools.

The mitigation measures with associated locations are illustrated in Figure 8 below.

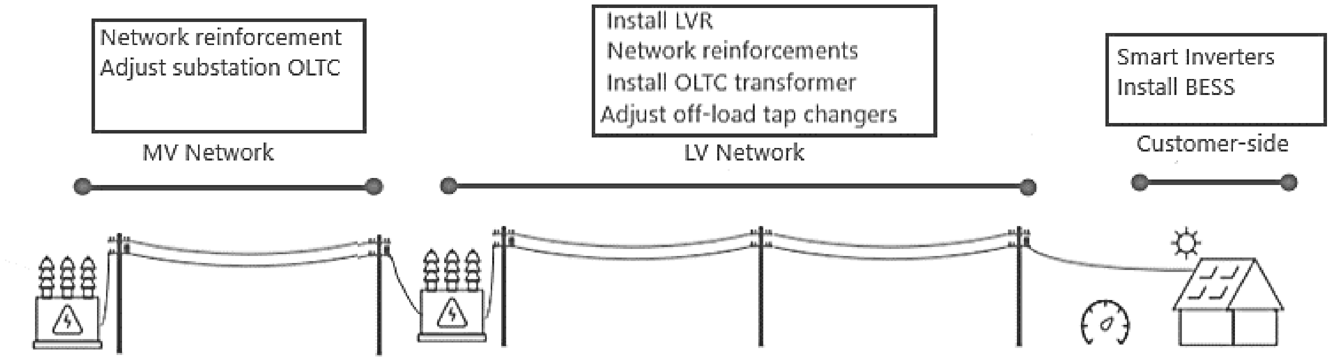


Figure 8: Mitigation measures with associated locations [15, 1, 54, 55]

Table 4: Summary of technical solutions and mitigation measures for increasing PV on Distribution networks [15, 1, 54, 55, 56]

Mitigation measure	Location	Summary description	Advantages	Disadvantages
Smart inverters	Customer side	Allow for PV system inverters with reactive power compensation (Volt-VAR) and active power curtailment (Volt-Watt) settings. These control measures allow adjustment of real and reactive power exported based on the measured grid voltage.	Prevents voltage rise and overvoltage violations. At no cost to the utility or NSP.	Unable to completely mitigate voltage changes caused by intermittency. Not included in SA standards yet. Consideration for unintended consequences of reactive power flow changes must be considered.
Installation of Behind the meter Battery Energy Storage System (BESS)	Customer side	The customer installs a battery system behind-the-meter alongside the PV system. The battery should be operated to maximise customer self-consumption i.e., charge from the surplus PV generation when generation exceeds demand, and the battery should discharge when there is no PV generation.	Minor improvements for voltage issues.	If BESS is set to operate to optimise customer self-consumption, then the battery can reach full State of Charge (SOC) during the day thus making it ineffective after this occurs. Ineffective at increasing hosting capacities.
Installation of Smart Battery Energy Storage System (BESS)	LV network	The customer or NSP installs battery systems that is controlled with a different operational mode as BTM BESS.	More effective than BTM BESS in managing voltage issues. Minor increases in PV hosting capacity.	Marginally increases the effectiveness of mitigating voltage and thermal issues.

Network Augmentation (LV) –Conductor reinforcement	LV Network	Replace LV conductors with those that have a larger ampacity.	Proven effective at managing thermal loading issues and increasing hosting capacity.	Only slightly effective at mitigating voltage issues.
Network Augmentation (MV) – Transformer upgrades and conductor reinforcement	MV network	Uprate transformers to a larger rating and replace MV conductors to that with a larger ampacity to alleviate or mitigate asset congestion issues. Upgrading the transformers to ones with additional buck taps can also be considered.	Proven effective at managing thermal loading issues.	Only slightly effective at mitigating voltage issues.
Installation of MV/LV On Load Tap Changer (OLTC) transformers	MV network	Replace existing MV/LV transformers with ones that have an OLTC mechanism. The OLTC automatically adjusts voltage based on the load in real-time and can include adaptive control logic. This solution can include uprating the transformer where possible.	Effectively manages voltage rise violations. Caters for voltage drops due to increase in future demand.	Not in commercial operation yet.
Installation of Low Voltage Regulator (LVR)	LV Network	Install LVR(s) at optimal locations on the LV network to manage the voltage on the LV network.	Highly effective at solving voltage issues. Reduces wear and tear on zone OLTC.	Voltage breaches greater than the tap range of the OLTC cannot be mitigated.
Adjustment of Zone Substation OLTC	MV Network	Reduce the voltage target/source voltage at the substation and by doing so unlock additional voltage headroom for the network.	Slight voltage headroom is created for overvoltage issues especially if coupled with adjustment of off-load tap changer in transformers.	Limited effectiveness at higher PV penetrations. Voltage drops due to excessive loading would remain an issue.
Adjustment of Off-load Tap Changers in existing transformers	LV Network	Reduce the off-load tap positions in existing MV/LV transformers to the lowest point possible.	Effective at mitigating overvoltage issues.	Cannot cater for high PV penetrations. Voltage drops due to excessive loading would remain an issue.

2.3. Review of guidelines and standards for connection of Distributed Generation

The power quality criteria and other measures, for renewable power plants, specifically DG, are assumed to be investigated when installing or accepting the installation of a new plant. These measures are assessed and accepted using the procedures and guidelines allocated by NERSA in the South African Grid Connection Code for Renewable Power Plants (RPPs) [57]. The basis for these requirements and technical specifications are based on other documents that govern power quality and safety for electricity grids nationally and internationally which include: NRS 048 series [59, 60], NRS 097-2-1 [4], NRS 097-2-3 [61], SANS 10142-1-2 [62], IEC 61000-4-30 [62], IEC 61000-3-6 [64], Cigré Technical report 468 [65], IEC 61000-4-7 [66] and IEEE 1547 [67]. However, due to majority of the current installed systems being considered as "illegal", the assessment or consideration of the power quality of these installations are assumed as not being completed in majority of the cases.

2.3.1. Grid Code of Renewable Power Plants in South Africa

The South African grid code for Renewable Power Plants (RPPs) [57] is the embodiment of legislation that is to be adhered to with regards to the connection of any type of renewable power plant. This document specifies the minimum technical and design requirements for the connection of renewable generators on a distribution or transmission network owned by a network service provider. The document shall be used in collaboration with other pertinent requirements of the Grid Code [68], the Distribution Code and the Scheduling and Dispatch Rules, as compliance criteria for the interconnection of renewable generators to the network.

Renewable power plants are categorised into 3 different categories with the first category further divided into 3 sub-categories. Table 5 provides a breakdown of these categories and their characteristics.

Table 5: Characteristics of the categorical requirements [57]

	Category				
	A1	**A2**	**A3**	**B**	**C**
Rated Power	0kVA-13.8kVA	13.8kVA-100kVA	100kVA-1MVA	1MVA-20MVA	>20MVA
Voltage Level	LV	LV	LV	MV	MV/HV

This document either explicitly stipulates or makes reference to relevant standards which stipulate the minimum grid connection and power quality requirements that are to be met by the renewable power producer. The noteworthy requirements stipulated for each category RPP are as follows:

- Tolerances allowed, in normal and abnormal operating conditions, for voltage and frequency deviations at the Point of Connection (POC),
- Voltage ride through capabilities required for the RPP,

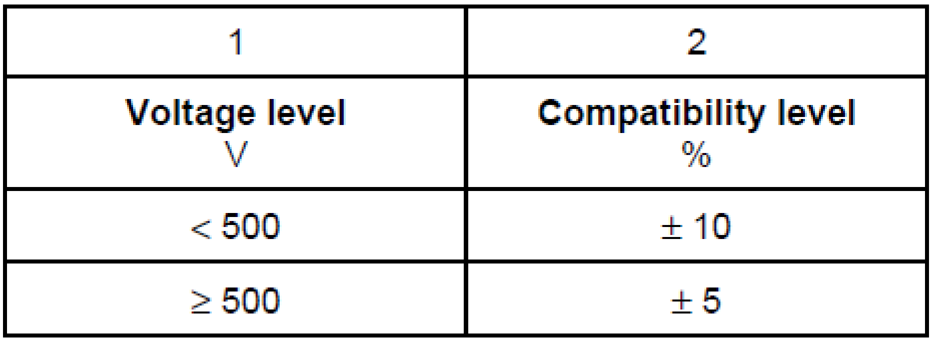
- Frequency response requirements for the RPP,
- Reactive power capability and power factor requirements,
- Power Quality requirements in terms of harmonic injections.

2.3.2. NRS Specifications

The specifications generally considered when assessing Quality of Supply (QoS) of a given network is NRS 048 suite of specifications. Part 2 (Voltage characteristics, compatibility levels, limits and assessment methods) and Part 4 (Application guidelines for utilities) are specifically important with regards to the work in this report. These specifications specify the voltage quality parameters. Furthermore, acceptable limits, compatibility levels and assessment methods for these parameters are specified.

In the NRS 048 specifications voltage regulation is defined as “the ability of the steady-state Root Mean Square (RMS) voltage to remain between the upper and lower limits”. The specified compatibility level for the supply voltages is as per Table 6 below. This shows that allowable levels for LV and MV voltage are ±10% and ±5%, respectively [69]. This resonates with the limits used by network planners in Eskom as specified in DST 34-542 (Distribution Voltage Regulation and Apportionment Limits) i.e., for MV networks is ±5% and for LV networks is ±10% of the nominal voltage of the network.

Table 6: Allowable deviation from standard or declared voltages [69]



1	2
Voltage level V	**Compatibility level** %
< 500	± 10
≥ 500	± 5

NRS 097-2-3 (Simplified utility connection criteria for low-voltage connected generators – SSEG) is the specification used as a guideline for approving applications by the NSP for the installation of SSEG on Distribution networks. It proposes when cases detailed network simulations are required and when not depending on the capacity being applied for as well as the network conditions. For cases where detailed simulations are not required, recommended size of generators with associated voltage levels and loading circumstances are given. It further stipulates that the maximum LV Rapid Voltage Change (RVC) is 3%. It is specifically mentioned that this is considered as best practice to account for transients induced by PV due to clouds. Furthermore, a maximum voltage rise of 1% is allowable. The accepted PV penetration given for simplified connection, based on acceptable voltage rise and voltage variations, is a maximum of 15% of the peak demand for a given MV distribution network is allowed to be installed as DG along that network.

NRS 097-2-1 (Utility interface for SSEG) is a specification used as a guideline for customers who wish to install DG to the distribution network. The interface requirements are specified in this specification with reference to other grid requirements. The requirements from the Grid code for RPP’s are expanded for SSEG connections and are predominantly related to the inverter specifications and installation requirements. This specification is most often used in conjunction with the draft SANS 10142-1-2 wiring code. Notable requirements applicable to the work in this dissertation are:

- Overvoltage and undervoltage requirements for normal and abnormal operating conditions,
- Power quality and voltage change requirements,
- Voltage and frequency control requirements and
- Power factor requirements.

2.4. Conclusion from literature

The review of literature has provided the following insights:

- There is an increasing penetration of distributed generation, specifically solar PV technologies, being installed on the distribution networks of South Africa due to various factors,
- The increase of this penetration has various technical impacts on the status of these networks. The main technical impact experienced on the network is related to the voltage stability of networks,
- Voltage management techniques are highlighted for the mitigation or alleviation of the impacts from increasing penetration of PV. It is noted that the smart inverter options are the only options that can be implemented at no cost to the utility or network service provider and the Volt-Watt setting was considered to be the easiest to implement with no unintended consequences for the network.
- The NRS specifications along with the Grid Code and other Eskom guidelines can be used to evaluate impacts when performing power flow simulations.

CHAPTER 3: METHODOLOGY

This chapter details the methodology that was utilised during the data collection and analysis of results in response to the research questions raised in this study. Hourly quasi-dynamic power flow modelling using Digsilent Powerfactory software was used to accomplish the following:

- The influence of adding multiple solar PV systems, which are geographically dispersed in various scenarios, on the voltage in two Medium Voltage (MV) conventional distribution networks. Simulations with and without PV was conducted for each hour of one year and
- Confirmation that an active power curtailment voltage control strategy, also referred to as Volt-Watt settings, will be effective as a voltage management technique that can be adopted by Network Service Providers (NSPs) to manage voltage in distribution systems with high penetration of PV systems. Simulations were conducted for a single day using a tailor-made strategy for each inverter. The day and scenario with the worst results on the most critical network was selected for this simulation.

The objectives of this research were met by completing the following tasks, in the given order:

1. The hourly loading characteristics were added to the case files to obtain realistic base conditions for the two networks. Thereafter, hourly power flow simulations were completed for each network to determine the baseline results for comparison. The hourly MV and LV voltages at the beginning, middle and end of the network were recorded at this stage,
2. PV systems, with hourly generation profiles correlating to the load profiles, were added to the two networks in the desired penetration and location scenarios (details of which are discussed below) and the same simulations were run recording the same results as in step 1,
3. Analysis of the baseline results in comparison to the results with PV involved evaluating for voltage violations such as:
    a. Voltage rise – when the voltage measured at the end of the feeder is higher than the voltage measured at the beginning,
    b. Overvoltage – when the voltage recorded at any point of the feeder exceeds the upper limit stipulated in the NRS 048 and
    c. Rapid voltage changes – the voltage change recorded as a result of intermittency from the PV system output.

    Note that specific days were analysed for voltage rise and rapid voltage changes,

4. After analysing the results, conclusions were made based on differences in the results for each type of network. A specific day with all voltage violations was then selected for the implementation of the voltage control strategy (Volt-Watt setting detailed in Section 3.5). This model was applied to the control mechanisms in the

PV systems for the selected scenario and the same voltage results were recorded as in Step 1,

5. Analysis of the results with control strategy vs without control strategy was completed and final conclusions were made.

3.1. Introduction

Theory in Chapter 2 showed that voltage issues arise when the active power produced by PV systems is injected into the grid and results in reverse power flow. This occurs during times when the PV production or generation surpasses the load or demand required by the consumer/s on that part of the network.

There can be a variation in the power produced by PV due to passing clouds and changes in the irradiation resource at the location of the plant. The rate at which the output power of a generator changes is called the ramp rate and for PV systems this rate is between 10% and 20% per second [16] [17] [18]. This is very high even when compared to another renewable source like wind generation which has ramp rates of about 10% per minute [2].

Due to the dynamic nature of PV power production and demand, dynamic power flow studies are required to understand the realistic impact of the PV systems on the network. Therefore, quasi-dynamic simulations with the lowest possible temporal resolution (in this case hourly) were used in this study. Two different networks were selected for the study to determine the differences in voltage impacts.

The voltage management capabilities at the MV substation (i.e., tapping of the on-load tap changer (OLTC) of the transformer) were not used in the simulations. Similarly, the voltage management technique of current approved NRS 097-2-1 inverters, whereby the inverter shuts down when the grid voltage is 1.05p.u., were not leveraged either. This results in conservative modelling results, specifically in terms of voltage rise and overvoltage.

Note that the validation and verification of the simulation results are not part of the scope of this MSc.

3.2. Network data

The South African NSP, Eskom, is known to have issues with long spans of poor current carrying conductors on ageing networks which experience poor to no maintenance. The networks were therefore selected with such characteristics in mind. Additionally, one network was classified as a thermal and voltage constrained network and the other was not. The selection was based on the access of data (both PV generation profiles and loading data).

The Digsilent Powerfactory case files used for the studies have pre-existing network equipment data and consumer peak load data based on the local conditions at the respective sites. The consumer peak loads at the Low Voltage (LV) level have been calculated and represented as lumped peak loads for each MV/LV transformer. This is due to the NSP’s lack of visibility of infrastructure and metered data for the LV network equipment. The study has imposed the hourly characteristic profile of the load data at MV level to the LV lumped loads.

Details for each network is documented in 3.2.1 and 3.2.2. Specific network names will not be disclosed in this dissertation.

3.2.1. Constrained network

This network falls within the Northern Cape Operating Unit (NCOU) of Eskom in South Africa and the geographical representation is depicted in Figure 9 below. The voltage measured at the end of line is less than 0.95p.u. and the thermal loading of network equipment is greater than 85% during most hours, which is in violation of the NRS 048 utility quality of supply standard and other internal Eskom standards. As a result, this network is classified as thermal and subsequently voltage constrained. The total length of the network is ~167km with a backbone length of ~30km. Almost half of the network length is made up of either Squirrel, Magpie and Fox Single Wire Earth Return (SWER) conductor installed. Other conductors installed include normal three phase Squirrel and Fox conductor. The network has a 22kV/19kV transformation when the change of three phase conductor to SWER occurs. There are 38 MV/LV transformers with a total capacity of 2.1MVA.

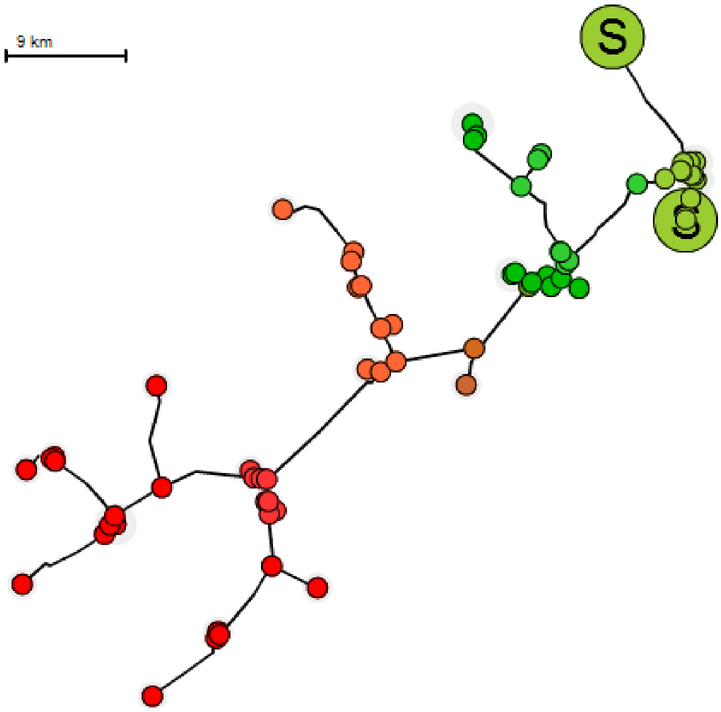


Figure 9: Geographic diagram for constrained feeder

The peak and average hourly demand recorded using metered 2019 hourly demand data is illustrated in Figure 10. The peak load was 2.74MVA with an average power factor of 0.96 leading. The hourly demand recorded for the whole year is illustrated in Figure 11.

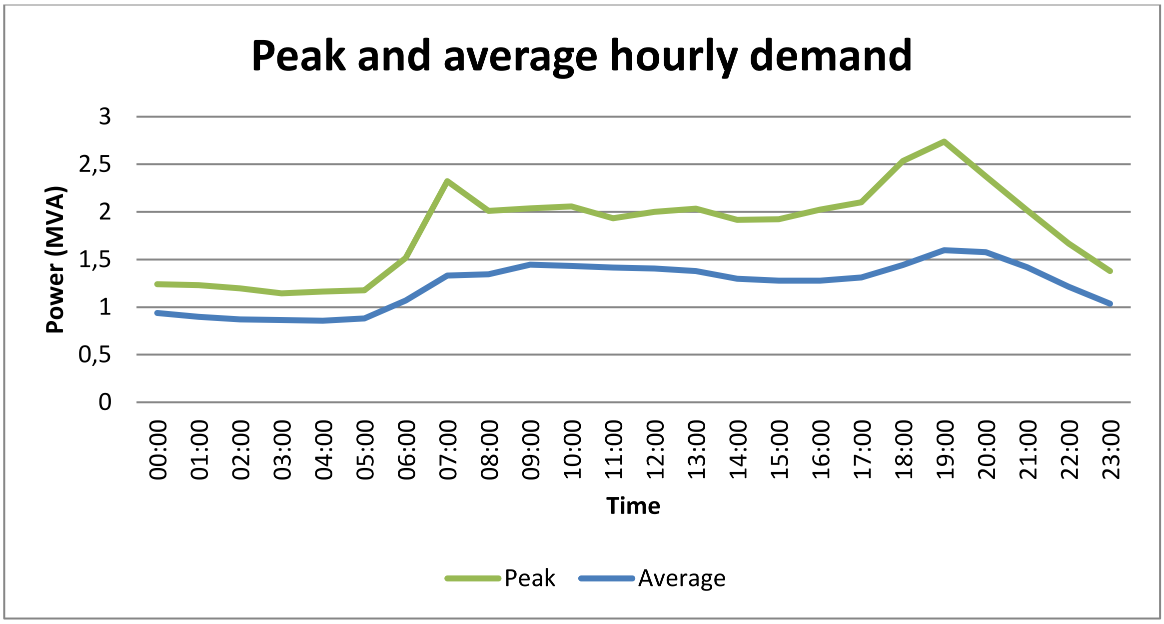


Figure 10: Peak and average day hourly demand using 2019 data for constrained feeder

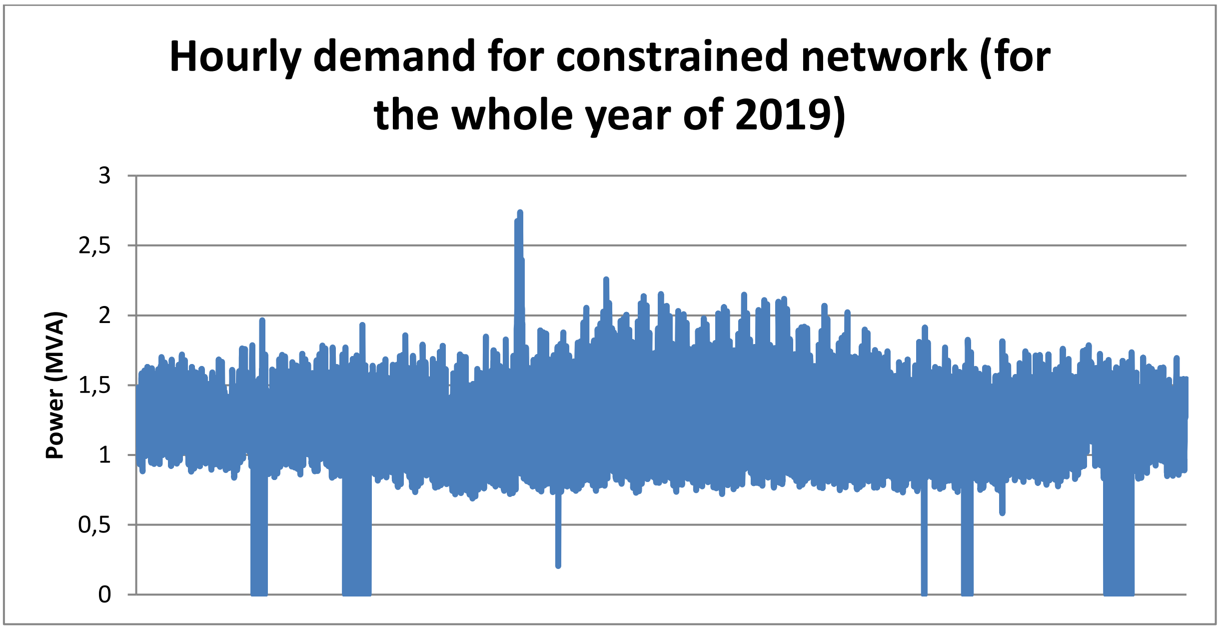


Figure 11: Demand for the constrained feeder for each hour for the whole year of 2019

3.2.2. Unconstrained network

This network also falls within the Northern Cape Operating Unit (NCOU) and the geographical representation is depicted in Figure 12 below. This network is not constrained in any way. The conductor types installed on the network include three phase Squirrel, Mink, Fox and Magpie. The total length is ~114km with a backbone length of ~52km. There are 36 MV/LV transformers with a total capacity of 1.61MVA.

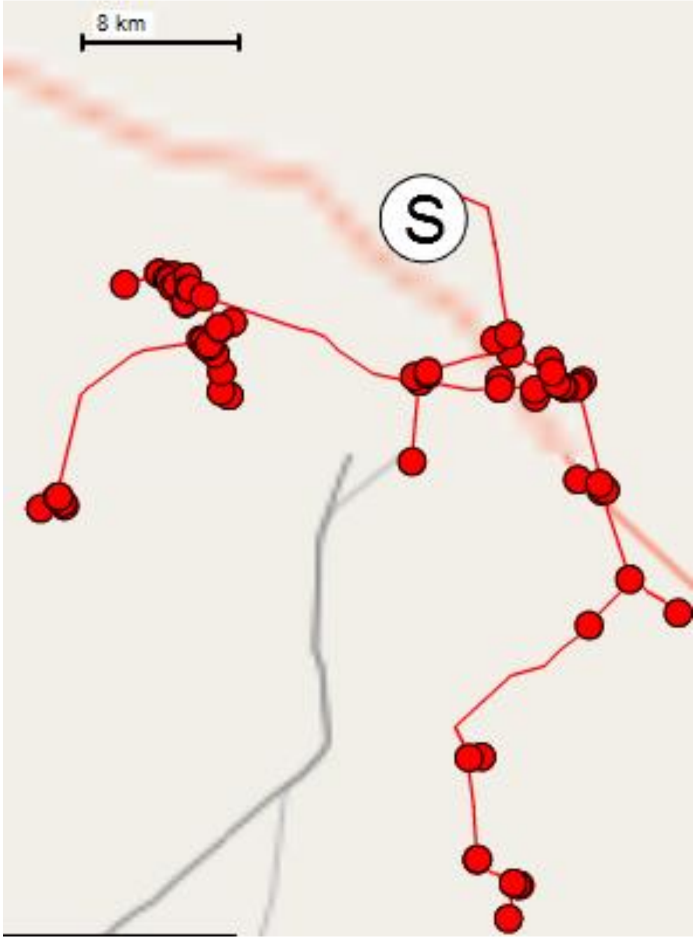


Figure 12: Geographic diagram for the unconstrained network

The peak and average demand using hourly metered data for 2019 is illustrated in Figure 13 and the hourly demand for 2019 is depicted in Figure 14. The peak load recorded was 1.35MVA with an average power factor of 0.9 leading.

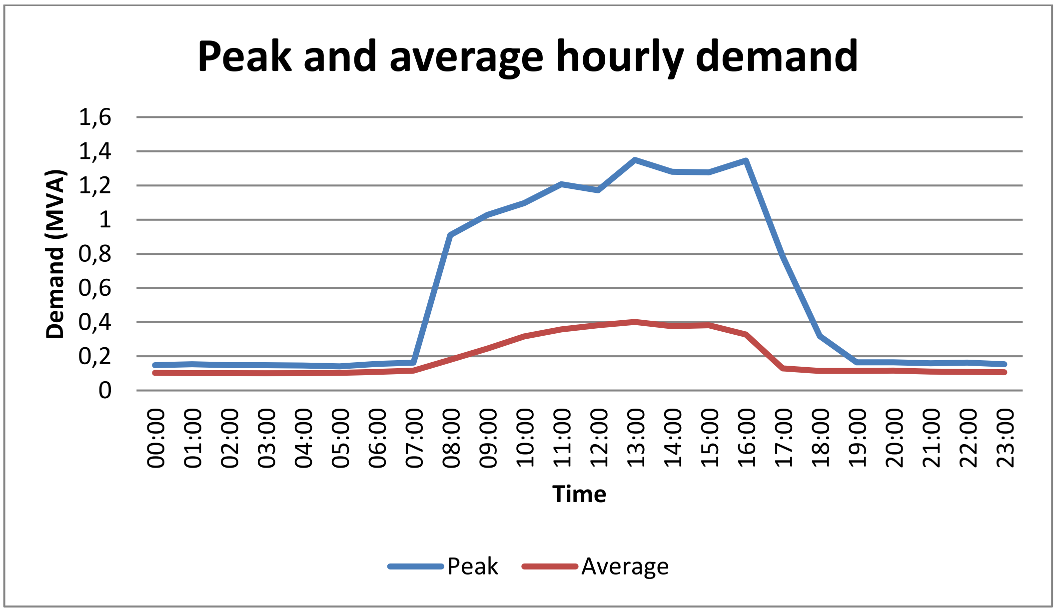


Figure 13: Peak and average day hourly demand using 2019 data for the unconstrained feeder

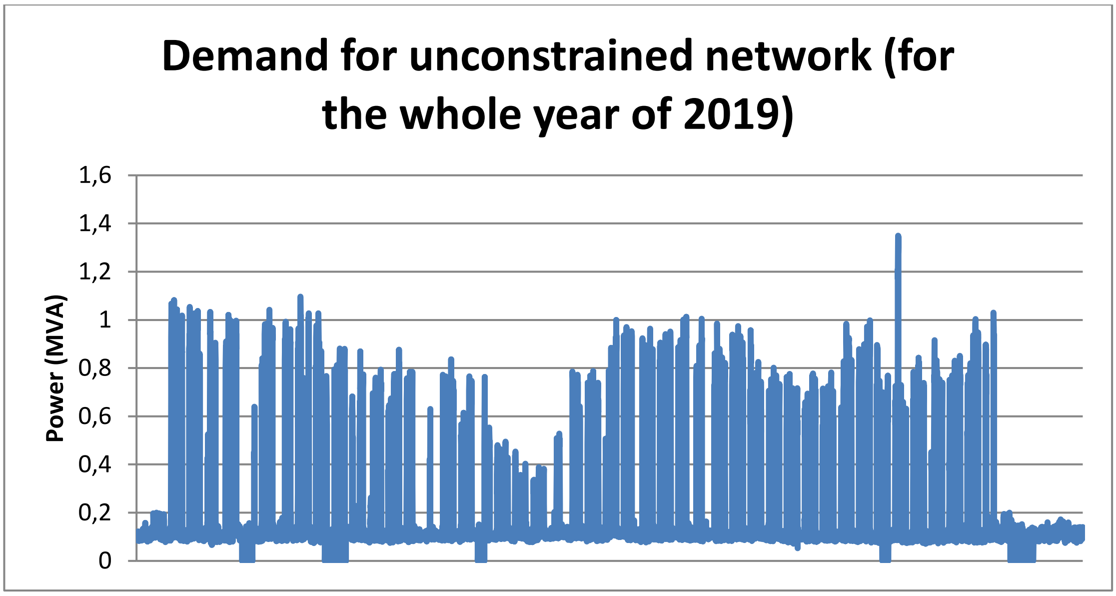


Figure 14: Demand for the unconstrained feeder for each hour for the whole year of 2019

3.3. PV systems generation modelling

The PV generators were modelled using the static generator in Digsilent PowerFactory. This PV system was initially modelled such that it meets the grid code requirements for category A renewable power plants. The PV power output for each case study adopted the hourly characteristic (for all of 2019) of installed fixed ground-mounted utility scale solar PV plants in the vicinity of each network. This enabled a realistic study using correlated load and generation profiles for the studies so that the dynamic impact of having a PV plant on the grid can be assessed. The plants are over 10km away from each other but span over a large distance. The normalised generation profile for one of the plants during a day with and without intermittency is illustrated in Figure 15 below.

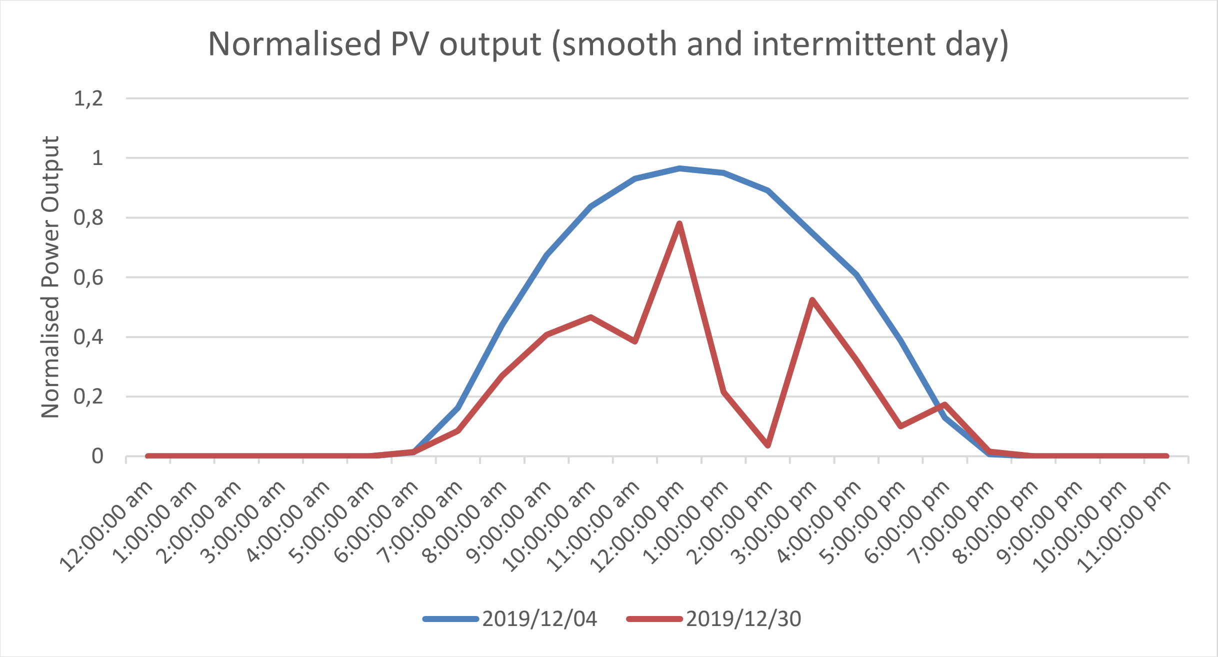


Figure 15: Normalised hourly PV generation profiles for a day with intermittency (30 December) and a day without intermittency (4 December)

3.4. Plant size and location of PV systems

The literature review has highlighted that the penetration of PV systems as well as the location can have varying impacts on the grid voltage. Consequently, the study was set up such that the influence on grid voltage from disparities in increasing PV penetration as well as location of PV systems can be analyzed. The following scenarios were thus simulated to determine the impact of increasing PV penetration on MV network voltage with PV systems being:

a. Evenly installed in proportion to the relevant MV/LV transformer capacity with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “All PV”,

b. Only installed at beginning of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “Beg PV”,

c. Only installed at the middle of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “Mid PV” and

d. Only installed at end of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “End PV”.

One PV plant was installed at the LV busbar to represent the lumped capacity of PV plants that could be installed on the respective LV feeder downstream from that point. The calculation for each PV plant capacity is represented in equation 6.

$$PV\ plant\ size_i = \frac{Transformer\ Capacity_i}{\sum_{i=0}^{n} Transformer\ Capacity}\ x\ PV\ peak\ penetration \qquad \textbf{(6)}$$

The associated plant capacities in each location for each case study is detailed in 3.4.1 and 3.4.2

3.4.1. Constrained network

The total PV peak capacity for each PV penetration scenario in the constrained network case study was 410.78kW (15%), 821.56kW (30%), 1369.26kW (50%) and 2053.89kW (75%). This capacity was then split up based on the location scenarios as mentioned above. The PV plant capacities for each busbar was determined using the transformer capacity relative to the total transformer capacity whilst maintaining the respective penetration level.

There was a total of 13 lumped PV systems for the end and middle PV case and 12 lumped PV systems for the beginning case. The PV system sizes for each case are tabulated in Table 7 below. Note that the system sizes differ based on transformer capacity as previously mentioned. The geographical location of the PV systems in the Beg PV, Mid PV and End PV case for this case study is illustrated in Figure 16.

Table 7: PV system sizes for All PV, Beg PV, Mid PV and End PV scenarios with 15%, 30%, 50% and 75% PV penetration (Constrained case study)

Transformer No.	Transformer Capacity (KVA)	All PV (PV System capacity kVA)				Beg PV (PV System capacity kVA)				Mid PV (PV System capacity kVA)				End PV (PV System capacity kVA)			
		15%	30%	50%	75%	15%	30%	50%	75%	15%	30%	50%	75%	15%	30%	50%	75%
T15-14	100	19.5	39.0	64.9	97.4	0	0	0	0	43.1	86.4	44.0	206.0	0	0	0	0
T31-1-3	100	19.5	39.0	64.9	97.4	60.6	20.1	201.0	302.9	0	0	0	0	0	0	0	0
T39-176-3	100	19.5	39.0	64.9	97.4	60.6	20.1	201.0	302.9	0	0	0	0	0	0	0	0
T39-178	100	19.5	39.0	64.9	97.4	0	0	0	0	43.1	86.4	44.0	206.0	0	0	0	0
T45-10	100	19.5	39.0	64.9	97.4	0	0	0	0	43.1	86.4	44.0	206.0	0	0	0	0
T39-1	16	3.1	6.2	10.4	15.6	0	0	0	0	0	0	0	0	3.7	27.4	45.6	68.5
T39-116-39-11-1	16	3.1	6.2	10.4	15.6	0	0	0	0	0	0	0	0	3.7	27.4	45.6	68.5
T39-159-108-11-4	16	3.1	6.2	10.4	15.6	0	0	0	0	6.9	3.8	23.0	34.6	0	0	0	0
T39-159-108-7-2	16	3.1	6.2	10.4	15.6	0	0	0	0	6.9	3.8	23.0	34.6	0	0	0	0
T39-159-3	16	3.1	6.2	10.4	15.6	9.7	9.4	32.3	48.5	0	0	0	0	0	0	0	0
T39-159-52-11-8	16	3.1	6.2	10.4	15.6	0	0	0	0	6.9	3.8	23.0	34.6	0	0	0	0
T39-159-52-24-2	16	3.1	6.2	10.4	15.6	9.7	9.4	32.3	48.5	0	0	0	0	0	0	0	0
T31-4	200	39.0	77.9	129.8	194.8	20.1	242.3	403.9	605.9	0	0	0	0	0	0	0	0
T39-116-39-13	25	4.9	9.7	16.2	24.3	5.0	30.3	50.5	75.7	0	0	0	0	0	0	0	0
T39-116-9-1	25	4.9	9.7	16.2	24.3	0	0	0	0	0.8	20.6	36.0	54.0	0	0	0	0
T39-143-3	25	4.9	9.7	16.2	24.3	5.0	30.3	50.5	75.7	0	0	0	0	0	0	0	0
T39-15-1	25	4.9	9.7	16.2	24.3	5.0	30.3	50.5	75.7	0	0	0	0	0	0	0	0
T39-38-1	25	4.9	9.7	16.2	24.3	5.0	30.3	50.5	75.7	0	0	0	0	0	0	0	0

T39-116-64	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-108-28-17	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-108-55-2	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-108-85	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-113-3	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-142-34	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-159-24-2	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-159-36	32	6.2	12.5	20.8	31.2	9.4	38.8	64.6	96.9	0	0	0	0	0	0	0	0
T39-159-198	32	6.2	12.5	20.8	31.2	0	0	0	0	0	0	0	0	27.4	54.8	90.3	36.9
T39-159-27-14	32	6.2	12.5	20.8	31.2	0	0	0	0	3.8	27.6	46.1	69.0	0	0	0	0
T39-159-52-32-1	32	6.2	12.5	20.8	31.2	0	0	0	0	3.8	27.6	46.1	69.0	0	0	0	0
T39-159-52-62	32	6.2	12.5	20.8	31.2	0	0	0	0	3.8	27.6	46.1	69.0	0	0	0	0
T39-159-59-6	32	6.2	12.5	20.8	31.2	0	0	0	0	3.8	27.6	46.1	69.0	0	0	0	0
T39-159-2	400	77.9	155.8	259.7	389.5	0	0	0	0	72.8	345.6	575.9	863.9	0	0	0	0
T39-133-12	50	9.7	19.5	32.5	48.7	30.3	60.6	1.0	50.5	0	0	0	0	0	0	0	0
T45-5-1	50	9.7	19.5	32.5	48.7	0	0	0	0	20.6	43.1	71.0	8.0	0	0	0	0
T39-116-62-9	64	12.5	24.9	41.6	62.3	38.8	77.6	29.3	93.9	0	0	0	0	0	0	0	0
T39-159-108-7T-2	64	12.5	24.9	41.6	62.3	0	0	0	0	0	0	0	0	54.8	9.5	82.6	273.9
T39-159-160-2	64	12.5	24.9	41.6	62.3	0	0	0	0	0	0	0	0	54.8	9.5	82.6	273.9
T39-159-163-5	64	12.5	24.9	41.6	62.3	0	0	0	0	0	0	0	0	54.8	9.5	82.6	273.9

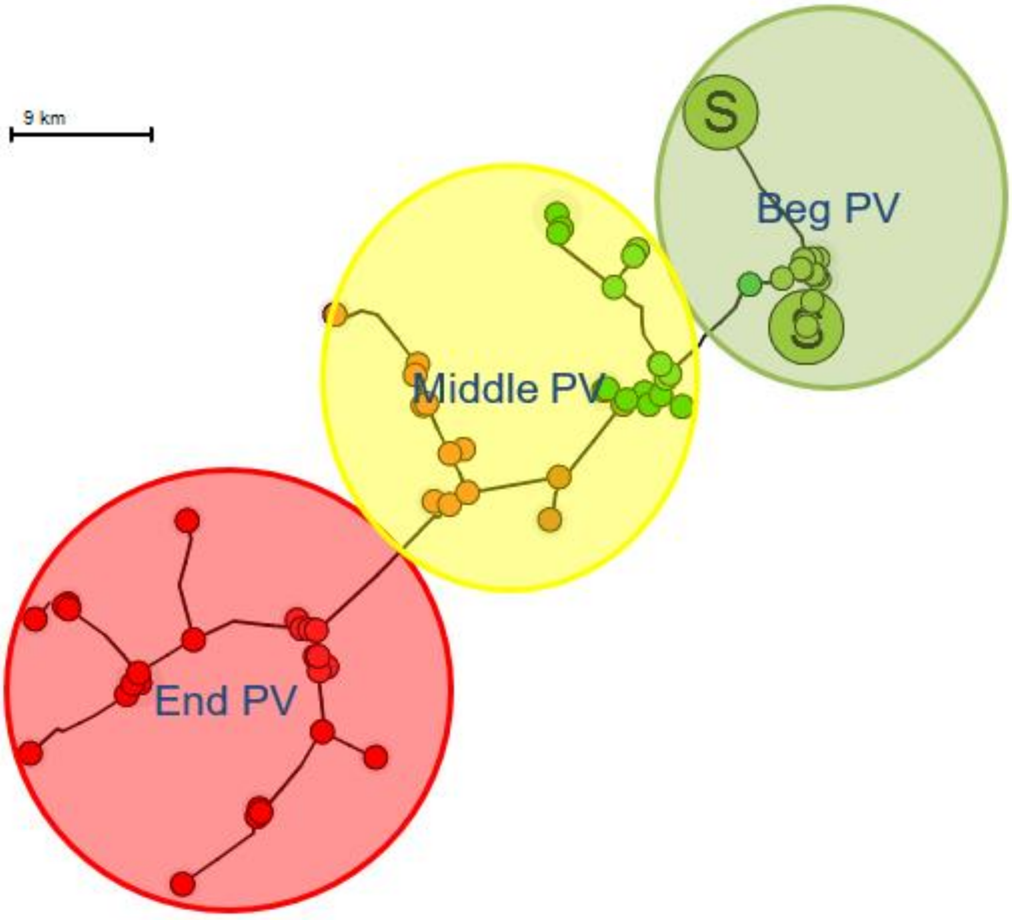


Figure 16: Geographic locations for Beg PV, Mid PV and End PV cases for constrained feeder

3.4.2. Unconstrained network

The total PV peak capacity for each PV penetration scenario in the unconstrained network case study was 202.40kW (15%), 404.81kW (30%), 674.68kW (50%) and 1012.02kW (75%). This capacity was then split up based on the location scenarios as mentioned above. The PV plant capacities were calculated as explained above.

There was a total of 12 lumped PV systems all location cases. The PV system sizes for each case are tabulated in Table 8 below. Note that the system sizes differ based on transformer capacity as previously mentioned. The geographical location of the PV systems in the Beg PV, Mid PV and End PV case for this case study is illustrated in Figure 17.

Table 8: PV system sizes for All PV, Beg PV, Mid PV and End PV scenarios with 15%, 30%, 50% and 75% PV penetration (Unconstrained case study)

Transformer No.	Transformer Capacity (KVA)	All PV (PV System capacity kVA)				Beg PV (PV System capacity kVA)				Mid PV (PV System capacity kVA)				End PV (PV System capacity kVA)			
		15%	30%	50%	75%	15%	30%	50%	75%	15%	30%	50%	75%	15%	30%	50%	75%
T179-184-13-6	100	14.3	28.6	47.7	71.6	0	0	0	0	41.6	83.1	138.5	207.8	0	0	0	0
T179-13-4	100	14.3	28.6	47.7	71.6	26.8	53.7	89.5	134.2	0	0	0	0	0	0	0	0
T179-221-1	15	2.1	4.3	7.2	10.7	0	0	0	0	0	0	0	0	8.2	16.3	27.2	40.8
T179-184-11-9	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-184-20-4	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-184-26-1	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-184-32	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-215-1	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-213-2	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-212-3-2	16	2.3	4.6	7.6	11.5	0	0	0	0	6.6	13.3	22.2	33.2	0	0	0	0
T179-184-30-9	16	2.3	4.6	7.6	11.5	0	0	0	0	0	0	0	0	8.7	17.4	29.0	43.5
T144-1	16	2.3	4.6	7.6	11.5	4.3	8.6	14.3	21.5	0	0	0	0	0	0	0	0
T179-1	16	2.3	4.6	7.6	11.5	4.3	8.6	14.3	21.5	0	0	0	0	0	0	0	0
T190-183	16	2.3	4.6	7.6	11.5	0	0	0	0	0	0	0	0	8.7	17.4	29.0	43.5
T179-202-8	200	28.6	57.3	95.5	143.2	0	0	0	0	83.1	166.2	277.1	415.6	0	0	0	0
T190-62-16	25	3.6	7.2	11.9	17.9	0	0	0	0	10.4	20.8	34.6	52.0	0	0	0	0
T179-184-11-8-1	25	3.6	7.2	11.9	17.9	0	0	0	0	10.4	20.8	34.6	52.0	0	0	0	0
T144-45-1	25	3.6	7.2	11.9	17.9	6.7	13.4	22.4	33.6	0	0	0	0	0	0	0	0

T179-184-24-2	25	3.6	7.2	11.9	17.9	0	0	0	0	10.4	20.8	34.6	52.0	0	0	0	0
T190-139-5	25	3.6	7.2	11.9	17.9	0	0	0	0	0.0	0.0	0.0	0.0	13.6	27.2	45.3	68.0
T190-159-2	25	3.6	7.2	11.9	17.9	0	0	0	0	0	0	0	0	13.6	27.2	45.3	68.0
T190-29-11	25	3.6	7.2	11.9	17.9	6.7	13.4	22.4	33.6	0	0	0	0	0	0	0	0
T190-172-2	25	3.6	7.2	11.9	17.9	0	0	0	0	0	0	0	0	13.6	27.2	45.3	68.0
T179-212-58	25	3.6	7.2	11.9	17.9	0	0	0	0	0	0	0	0	13.6	27.2	45.3	68.0
T179-212-64	25	3.6	7.2	11.9	17.9	0	0	0	0	0	0	0	0	13.6	27.2	45.3	68.0
T179-69-33	25	3.6	7.2	11.9	17.9	6.7	13.4	22.4	33.6	0	0	0	0	0	0	0	0
T179-30-5	315	45.1	90.2	150.4	225.6	84.6	169.1	281.9	422.8	0	0	0	0	0	0	0	0
T171-14	32	4.6	9.2	15.3	22.9	8.6	17.2	28.6	43.0	0	0	0	0	0	0	0	0
T179-230	50	7.2	14.3	23.9	35.8	0	0	0	0	0	0	0	0	27.2	54.4	90.7	136.0
T179-240-1	50	7.2	14.3	23.9	35.8	0	0	0	0	0	0	0	0	27.2	54.4	90.7	136.0
T179-244-2	50	7.2	14.3	23.9	35.8	0	0	0	0	0	0	0	0	27.2	54.4	90.7	136.0
T179-212-57-3	50	7.2	14.3	23.9	35.8	0	0	0	0	0	0	0	0	27.2	54.4	90.7	136.0
T133-9	50	7.2	14.3	23.9	35.8	13.4	26.8	44.7	67.1	0	0	0	0	0	0	0	0
T182-1	50	7.2	14.3	23.9	35.8	13.4	26.8	44.7	67.1	0	0	0	0	0	0	0	0
T189-2	50	7.2	14.3	23.9	35.8	13.4	26.8	44.7	67.1	0	0	0	0	0	0	0	0
T190-34-2	50	7.2	14.3	23.9	35.8	13.4	26.8	44.7	67.1	0	0	0	0	0	0	0	0

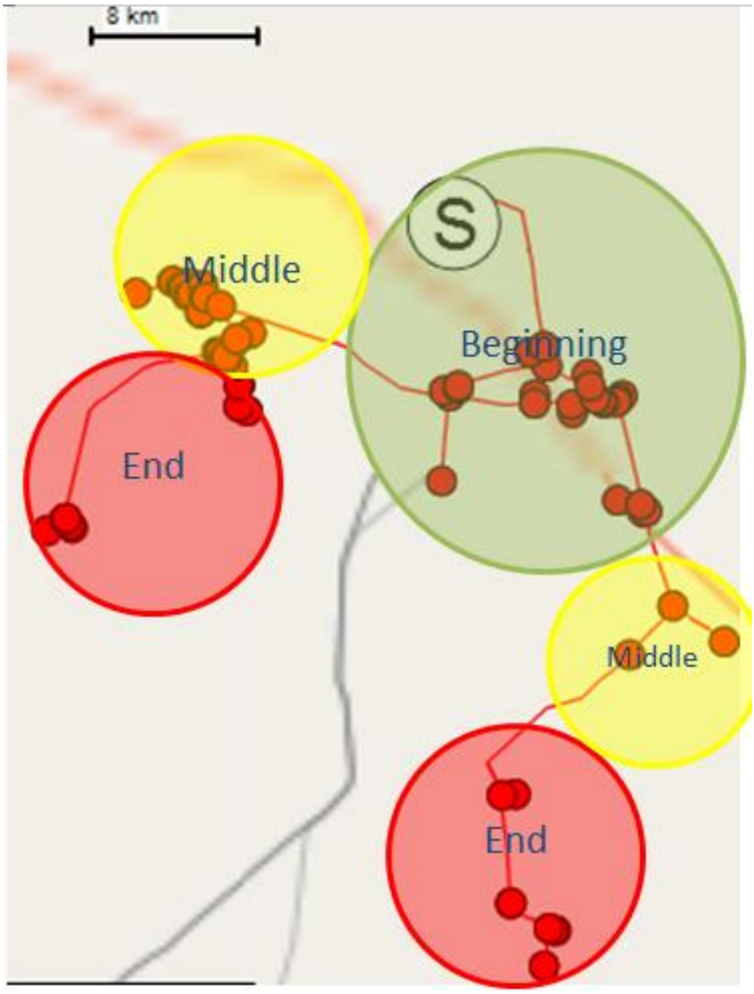


Figure 17: Geographic locations for Beg PV, Mid PV and End PV cases for unconstrained case study

3.5. Active power curtailment of PV generation

The final step for the study was to confirm that active power curtailment of PV generation based on measured grid voltage, also known as Volt-Watt control, can be an effective voltage management technique. This method was selected due to it being no cost to the utility or network service provider as well as since it is one of the easier methods to implement with no unintended consequences. This method was implemented by performing a quasi-dynamic simulation with the addition of a Volt-Watt setting for the inverters for a select day with significant intermittency and voltage violations. Furthermore, it was conducted for the worst-case feeder i.e., constrained feeder.

The control model for the inverter evaluates each power flow calculation and changes the output active power of each plant based on the measured grid voltage at the referenced grid point. If the grid voltage measured is greater than 1.05p.u., the active power of that PV plant is reduced to 0 and if the voltage is greater than 1.04p.u. but less than 1.05p.u. then the active power produced by the plant is as per calculation in equation 7:

$$P_{out} = \left(\frac{P_{act}}{U_{min} - U_{\max}} x\ V\right) - \left(\frac{P_{act}}{U_{min} - U_{\max}} x\ U_{max}\right) \tag{7}$$

Where:

P_{out} is the inverter output active power injected into the network,
P_{act} is the peak active power that could be injected at the given instance, without constrained, based on the PV plant generation profile,
U_{min} is the minimum grid voltage setpoint for the controller to start reducing inverter output active power,
$U_{\max}$ is the maximum grid voltage setpoint for the controller to reduce the inverter output active power to 0,
V is the measured grid voltage at the terminal/busbar selected by the user.

This control strategy is illustrated in Figure 18 with the respective voltages.

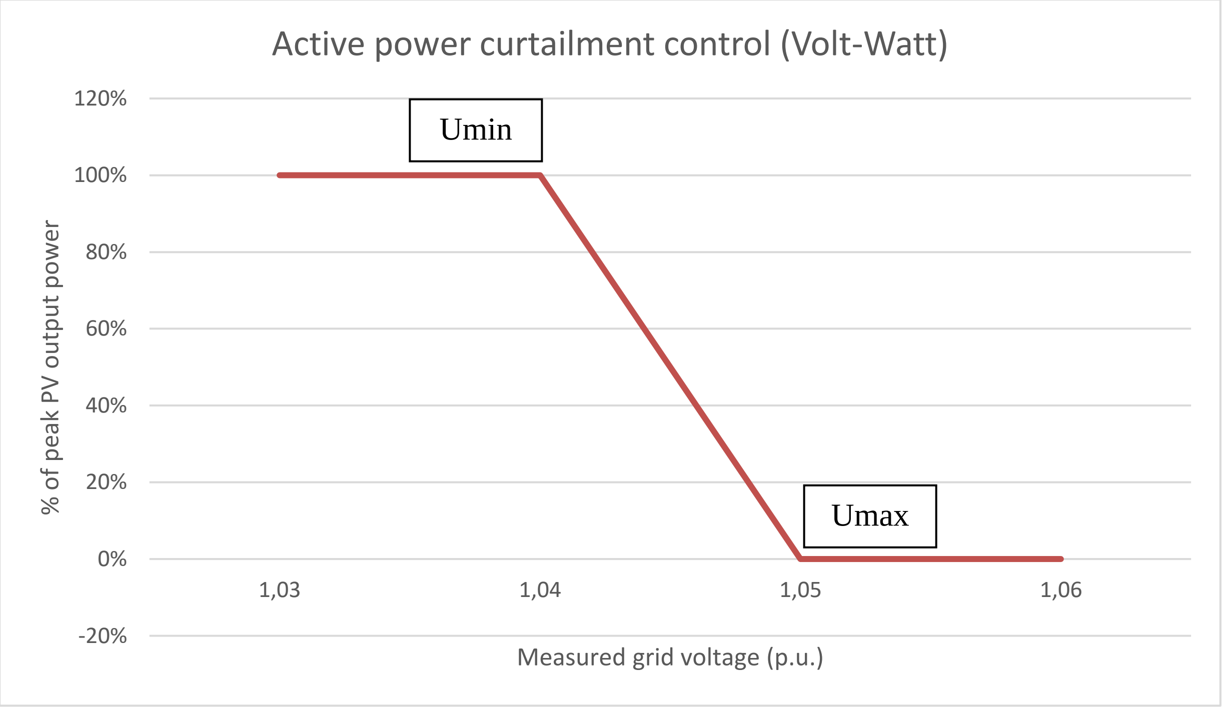


Figure 18: Active power curtailment (Volt-Watt) strategy implemented

CHAPTER 3: METHODOLOGY

CHAPTER 4: RESULTS

As discussed previously, voltage results were recorded from hourly power flow simulations for two networks i.e., constrained and unconstrained network with and without PV systems. These results will be unpacked in this section along with the comparison of results with and without the Volt-Watt control strategy.

The overall results for each network simulated in the following scenarios is presented in this section with PV systems being:

a. Evenly installed in proportion to the relevant MV/LV transformer capacity with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “All PV”,

b. Only installed at beginning of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “Beg PV”,

c. Only installed at the middle of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “Mid PV” and

d. Only installed at end of network in proportion to the relevant transformer with penetrations of 15%, 30%, 50% and 75% of peak load. Referred to as “End PV”.

Due to the large number of data points available for the whole year, only a few days (most of them with high PV ramp rates) have been selected to determine the impact of PV on voltage rise and rapid voltage changes. It has been observed that higher resolution of the PV and load data can provide more in-depth results; however, for these case studies only 1 hour resolution data was available.

4.1. Constrained network results

The MV and LV per unit (p.u.) voltages in the beginning, middle and end of the constrained network for the whole year of 2019 in the No PV scenario is depicted in Figure 19 and Figure 20, respectively. These results provide a base for comparison in order to conclude on what impacts are experienced with the addition of PV.

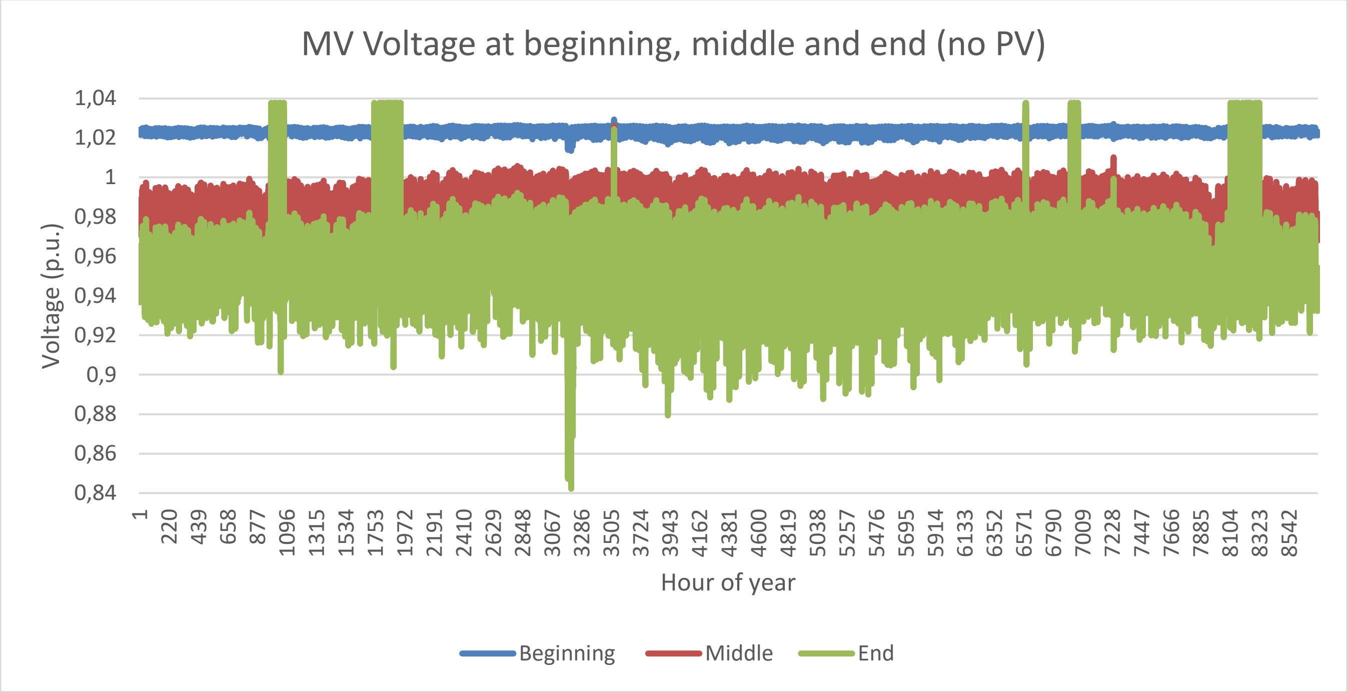


Figure 19: MV per unit voltage at the beginning, middle and end of the constrained feeder for the whole year of 2019 – No PV case

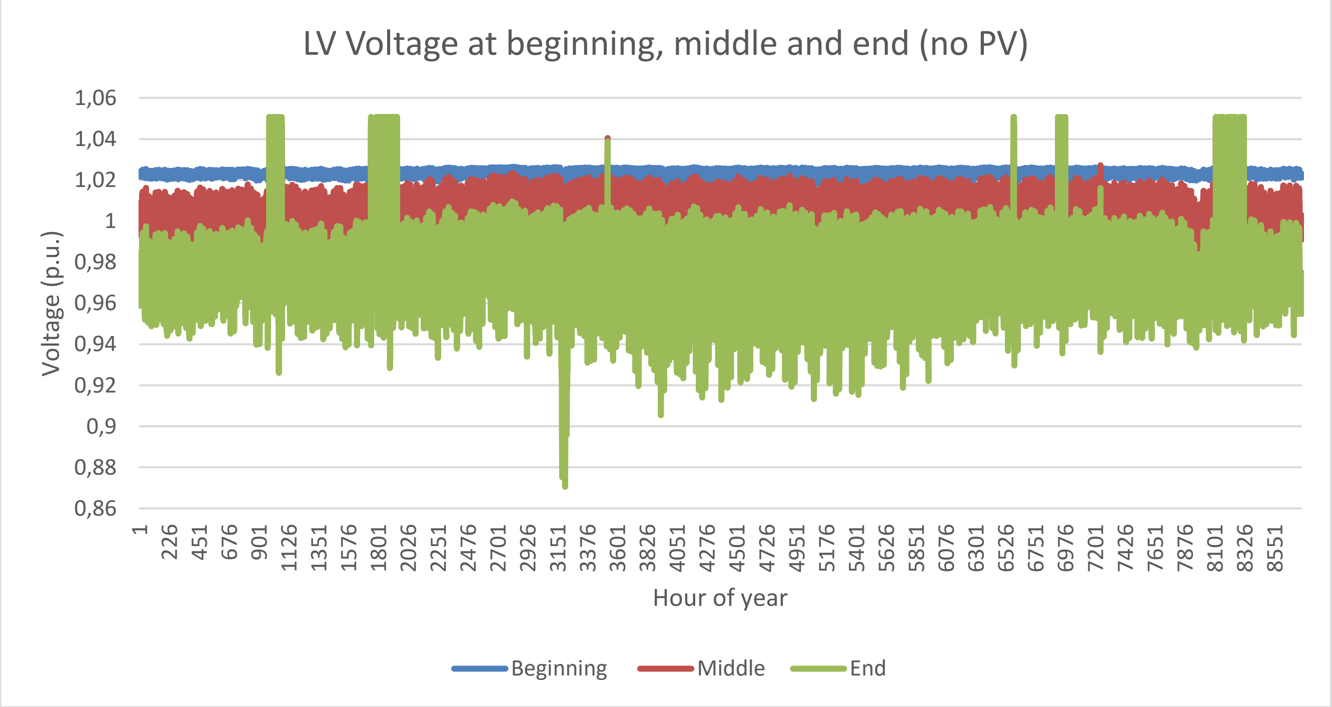
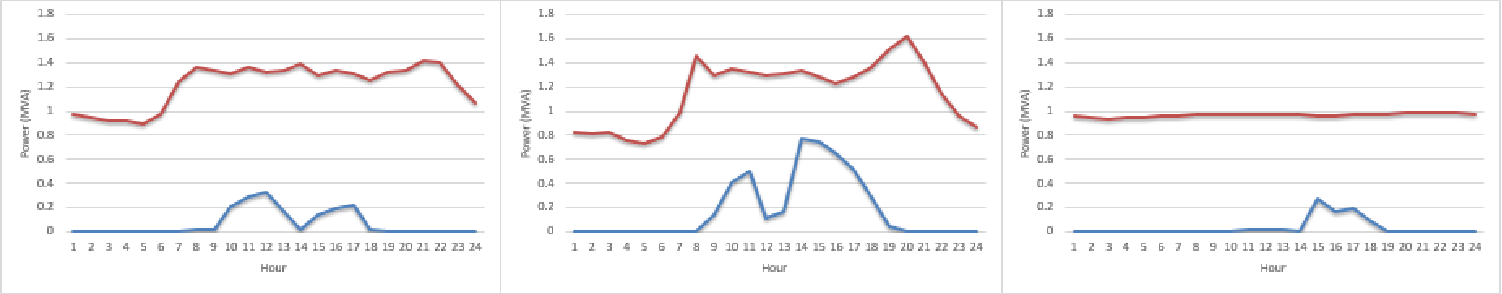


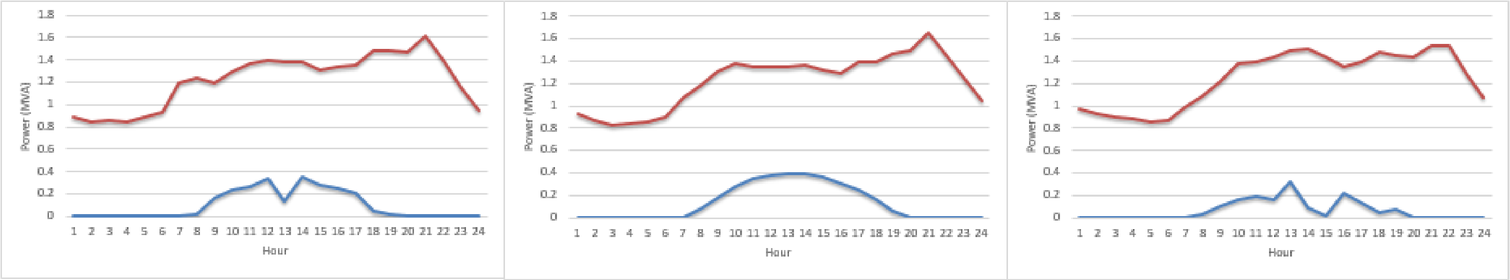
Figure 20: LV per unit voltage at the beginning, middle and end of the constrained feeder for the whole year of 2019 – No PV case

The limit, as specified in the network planning guidelines and NRS048 standard, for MV and LV voltage is ±5% and ±10%, respectively. Therefore, the number of times the MV p.u. voltage exceeds 1.05 and the number of times the LV p.u. voltage exceeds 1.10 will be used to determine if the status of the network is in violation of these parameters. It is evident from the results above that the network is constrained as the end of line MV voltage dips below 0.95 on several occasions and there are no instances where the voltages exceed the upper limit.

It was not practical to display and analyse the results for all the days in the year, hence, 6 days were specifically analysed for this case study (in all scenarios) to show the effect of PV on voltage variations. The PV generation (15% PV penetration case) and load profiles for the 6 days that was analysed is illustrated in Figure 21.



01 February 2019 **08 April 2019** **08 May 2019**



05 November 2019 **04 December 2019** **30 December 2019**

Figure 21: PV generation (in blue) and load (in red) profiles for 6 selected days to be analysed for constrained network case study

Due to the abundance of results available, the MV voltage and number of times voltage limits were violated in each scenario have been summarized in Appendix A – Section A1. Furthermore, the MV voltage recorded in each case for the days selected in Figure 21 are also available in the Appendix. The discussion and analysis of all significant findings for this case study is detailed in Section 5.1.

4.2. Unconstrained network results

The MV and LV per unit (p.u.) voltages in the beginning, middle and end of the unconstrained network for the whole year of 2019 in the No PV scenario is depicted in Figure 22 and Figure 23, respectively.

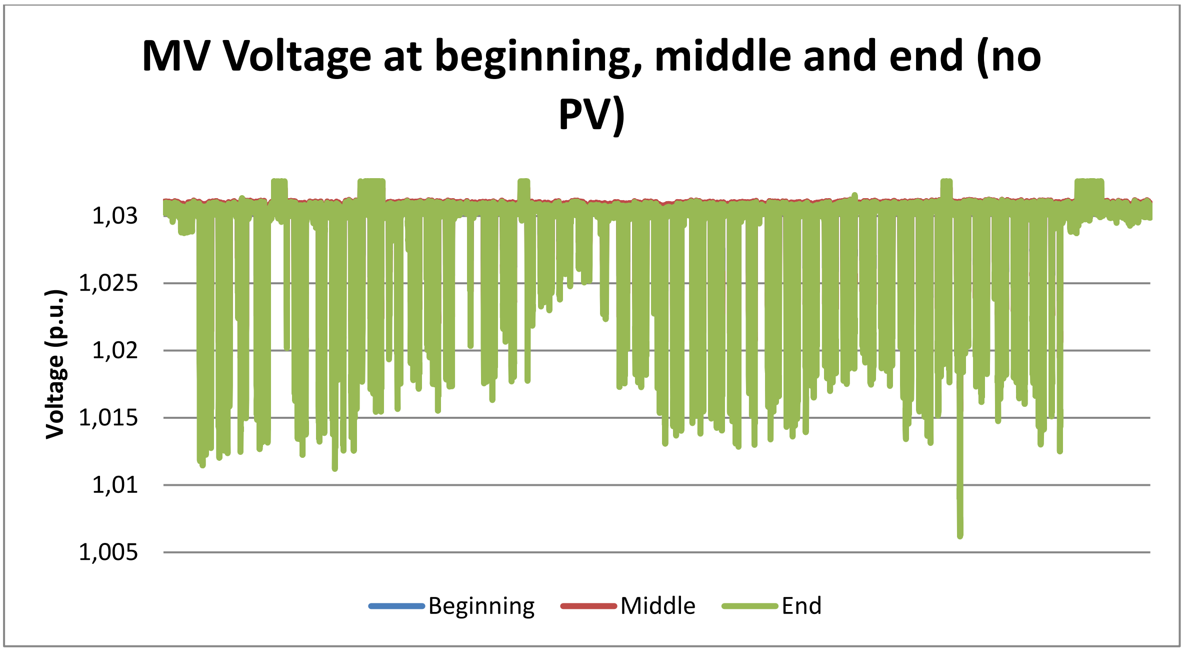


Figure 22: MV per unit voltage at the beginning, middle and end of the unconstrained feeder for the whole year of 2019 – No PV case

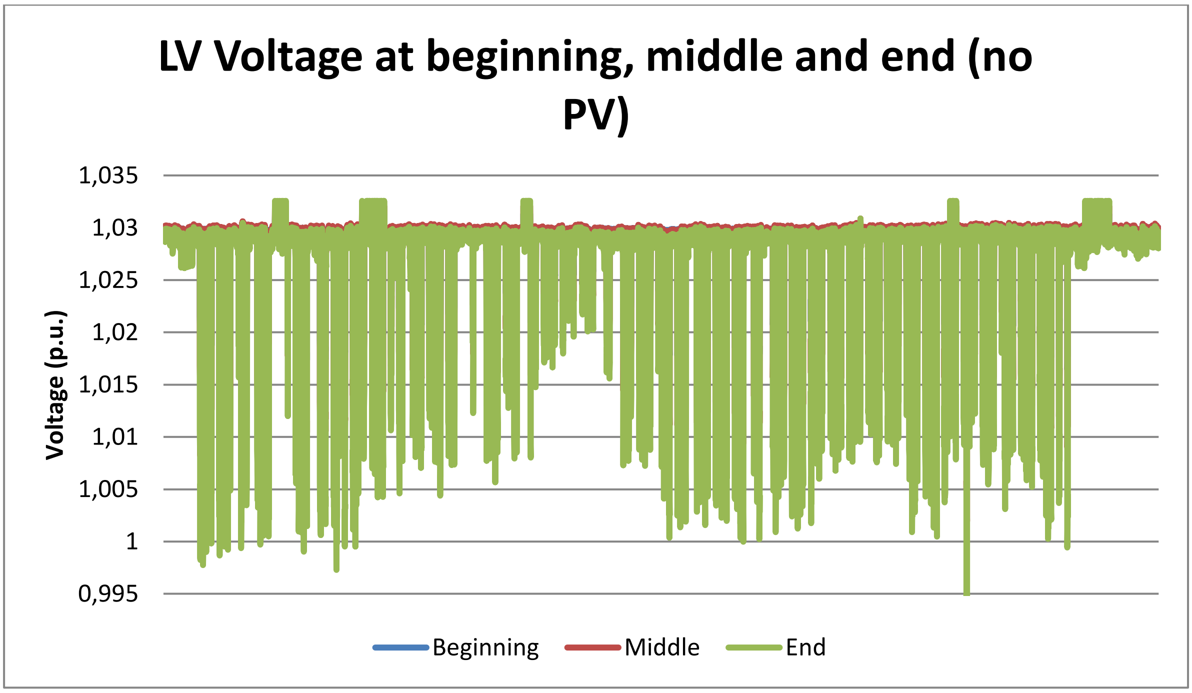
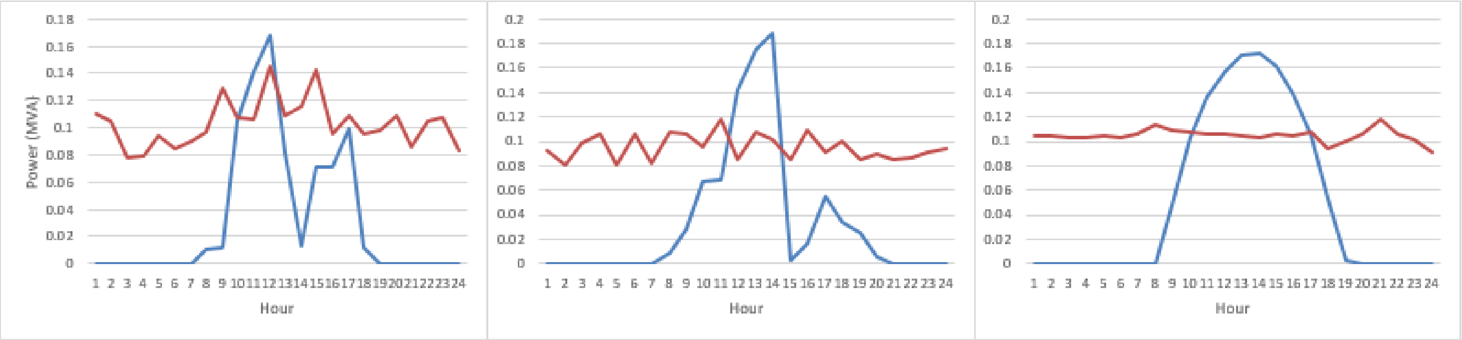


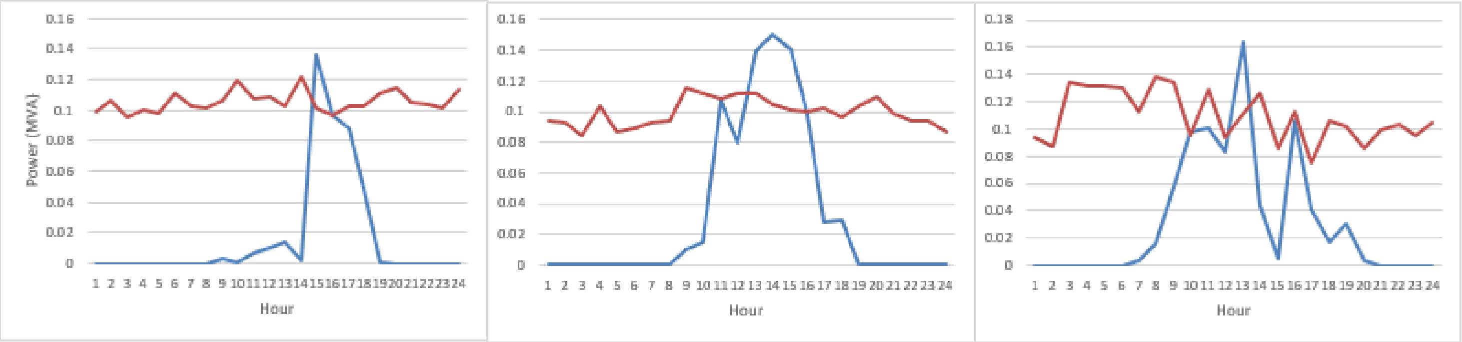
Figure 23: LV per unit voltage at the beginning, middle and end of the unconstrained feeder for the whole year of 2019 – No PV case

As previously mentioned, the number of times the MV p.u. voltage exceeds 1.05 and the number of times the LV p.u. voltage exceeds 1.10 will be used to determine if the status of the network is in violation of these parameters. It is evident from the results above that the network is not constrained at all, as the end of line MV voltage never dips below 0.95.

As with the constrained network results, only 6 days were specifically analysed for this case study (in all scenarios) to show the effect of PV on voltage variations. The PV generation (15% PV penetration case) and load profiles for the 6 days that will be analysed is illustrated in Figure 24.



01 February 2019 **02 February 2019** **27 April 2019**



08 May 2019 **26 May 2019** **30 December 2019**

Figure 24: PV generation (in blue) and load (in Red) profiles for 6 selected days to be analysed for the unconstrained network case study

Due to the abundance of results available, the MV voltage and number of times voltage limits were violated in each scenario have been summarized in Appendix A – Section A2. Furthermore, the MV voltage recorded in each case for the days selected in Figure 24 are also available in the Appendix. The discussion and analysis of all significant findings for this case study is detailed in Section 5.2.

4.3. Active Power Curtailment results

It was apparent from the results in Section 4.1 and 4.2 that the voltage rise and overvoltage impacts are more apparent in the constrained network case. Furthermore, the scenario where the PV systems are installed only at the end of the network induces more voltage violations compared to any other location scenario, even in the 15% PV penetration case in the constrained network. The details of this is available in Section 5.1 and 5.2. This suggested that selecting a specific day when these voltage violations occur for the constrained network would be most suitable for implementation of the voltage control strategy as detailed in Section 3.5.

The 8th of May with the scenario where 30% PV penetration and PV systems were only installed at the end of the constrained network was selected for this simulation analysis. The control strategy led to a total active power curtailment of 19% throughout the day compared to the active power reduction with no control. The difference in active power output with and without the control strategy is illustrated in Figure 25 below. Note that the significant change in output occurs between 14th and 16th hour.

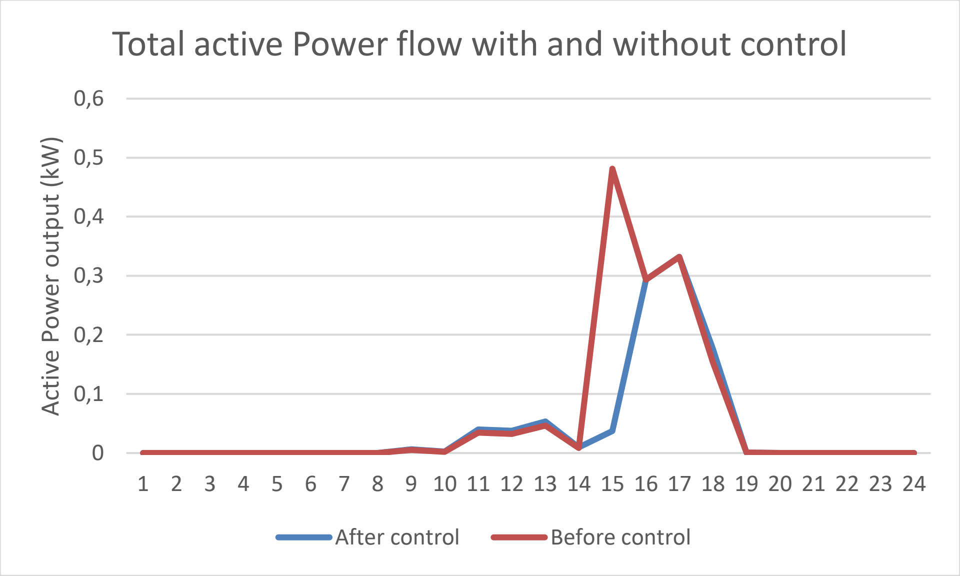


Figure 25: Total active power output with and without the Volt-Watt control

The end of line MV voltage with and without control is illustrated in Figure 26.

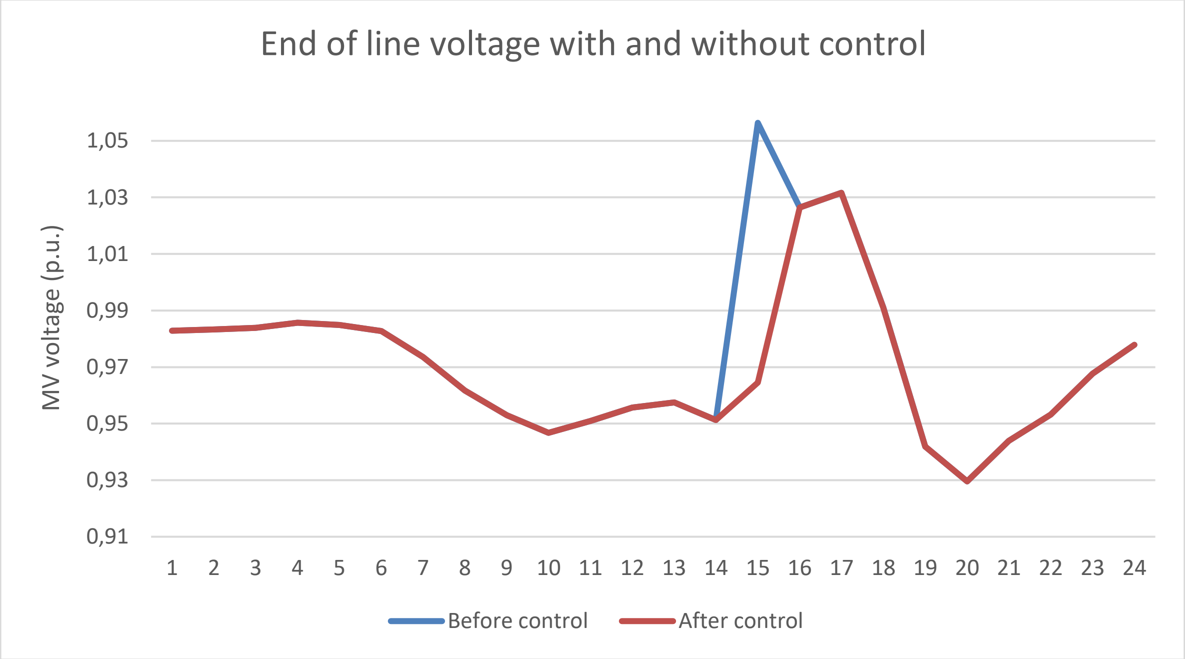


Figure 26: End of line MV voltage with and without Volt-Watt control

The voltage rise with and without the control strategy is illustrated in Figure 27.

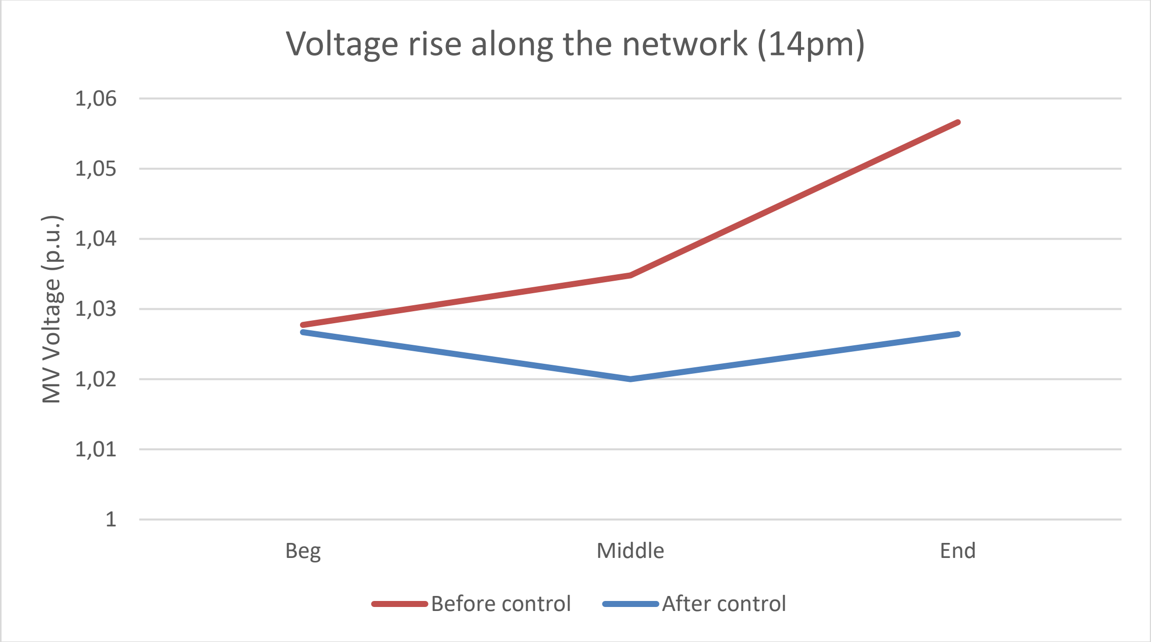


Figure 27: Voltage rise along the network at 14pm on 8 May with and without Volt-Watt control

CHAPTER 5: DISCUSSION OF RESULTS

This section highlights the key findings from the simulations completed for the addition of PV to the networks, in each location scenario, for all penetration cases. It was found that there are many factors to consider when analyzing the impact of PV on a network. These factors include, but not limited to, effect of ramps as a result of intermittency, effect of location within the network and the effect of size of generators vs local load. These will be elaborated on below.

Note that the results may not reflect real-world voltages, because the NRS specifications specify network safety mechanisms for the inverter that would switch off PV systems under high voltage conditions. However, in South Africa, customers are unaware and sometimes unfazed by such standards thus resulting in “illegal” connections and subsequently unexpected impacts on the network. Such impacts may not result in complete or instantaneous failure of the network equipment; however, long term impacts do result in failure which is earlier than expected.

5.1. Analysis of results for the constrained network

5.1.1. Effect of ramps or intermittency

As previously discussed, the ramp rate of a PV plant, generally caused by intermittency induced by moving clouds, is very high compared to other technologies. This ramp is said to impact the stability of the voltage on a network. Table 9 details the rapid voltage change results in each PV penetration case for 5 days in 2019 that had substantial ramp rates in the constrained network case study. It is evident that installing PV at the end of the network results in a higher voltage change and always surpasses the allowable limits for rapid voltage change as given in network planning standards. These ramps were averaged over either an hour or two and it is assumed that there will be significantly higher ramp rates that will occur in a higher resolution of time. The results also show that the higher the penetration level of PV the higher the voltage change will be. The voltage change is also proportional to the ramp rate that occurs. These effects are also evident in the detailed results available in the Appendix section A1 for this case study.

Table 9: Voltage changes that occurred due to ramping of PV in each PV scenario and penetration case for constrained network case

Date	Scenario	Highest ramp rate (% of installed capacity)	Time frame	Highest end of line voltage change (15%)	Highest end of line voltage change (30%)	Highest end of line voltage change (50%)	Highest end of line voltage change (75%)
01 February 2019	End PV	Dropped 75.6%	In 2 hours	6.30%	7.59%	15.11%	19.23%
	Mid PV			2.01%	2.36%	5.16%	7.13%
	All PV			1.78%	2.15%	4.81%	6.70%
	Beg PV			1.00%	1.08%	2.11%	2.87%
08 April 2019	End PV	Increased 60.6%	In 1 hour	4.71%	8.66%	12.92%	17.11%
	Mid PV			1.02%	2.21%	3.72%	5.44%
	All PV			1.68%	3.45%	5.65%	8.14%
	Beg PV			0.19%	0.59%	1.11%	1.74%
08 May 2019	End PV	Increased 66.6%	In 1 hour	6.26%	11.07%	16.71%	22.83%
	Mid PV			2.07%	3.40%	5.12%	7.13%
	All PV			2.79%	4.79%	7.34%	10.32%
	Beg PV			1.15%	1.59%	2.17%	2.88%
05 November 2019	End PV	Increased 52.3%	In 1 hour	4.14%	7.21%	10.38%	13.23%
	Mid PV			1.10%	2.10%	3.34%	4.77%
	All PV			1.66%	3.14%	4.92%	6.90%
	Beg PV			0.38%	0.72%	1.17%	1.70%
30 December 2019	End PV	Decreased 74.7%	In 2 hours	5.58%	10.14%	14.81%	19.21%
	Mid PV			1.09%	2.54%	4.34%	6.41%
	All PV			1.91%	4.06%	6.63%	9.47%
	Beg PV			0.05%	0.54%	1.19%	1.97%

5.1.2. Effect of size of generation

The impact of generator capacity is also significant when determining the impact of PV on the quality of network voltage. As seen from the results above, the increase in PV penetration can result in a higher impact on voltage change. It also impacts the instantaneous per unit voltage. Figure 28 shows the end of line MV voltage recorded on a day with a typical PV generation profile (4 December 2019) for each PV penetration case in the End PV scenario. This shows that as the penetration increases so does the instantaneous MV voltage. After detailed analysis it was evident that this is consistent in all scenarios for this case study.

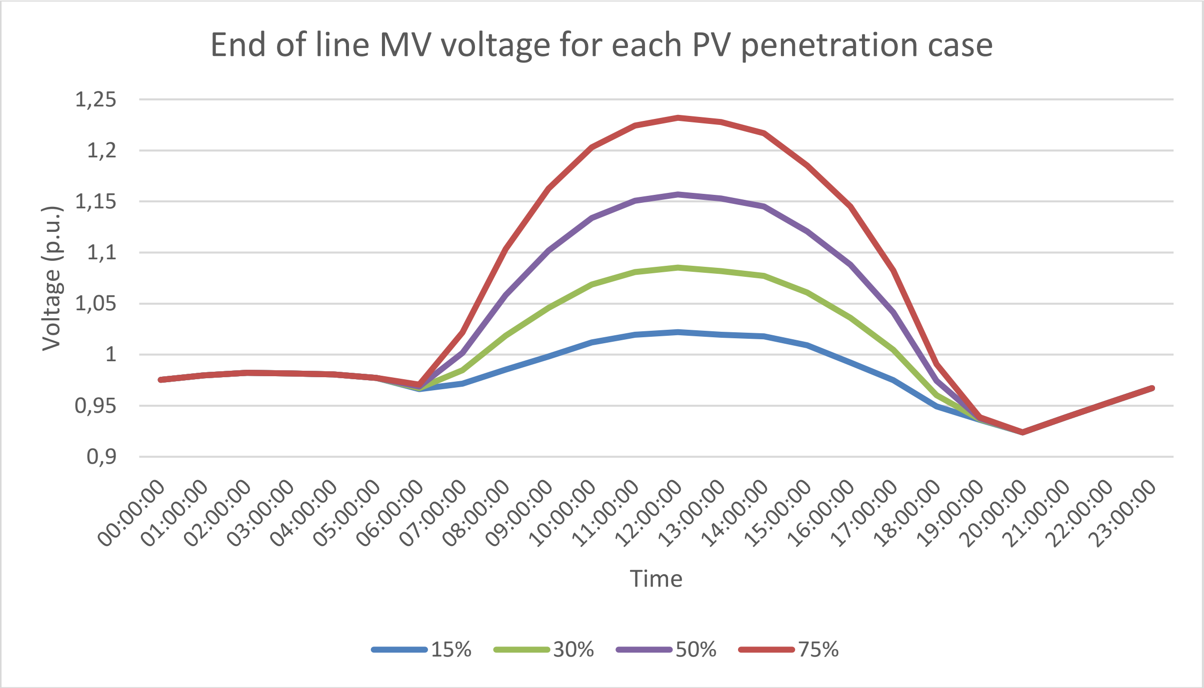
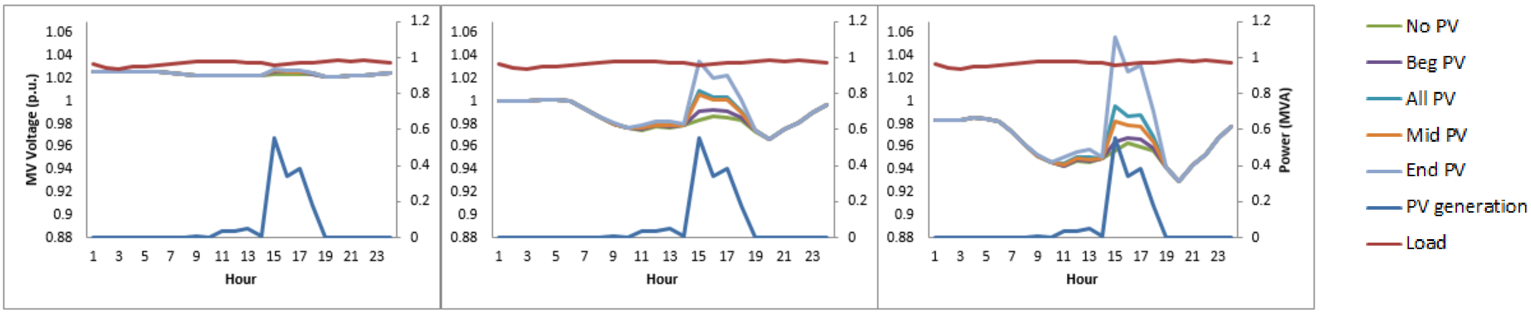


Figure 28: MV end of line voltage recorded for each PV penetration case in the End PV scenario for constrained network case

5.1.3. Effect of location of PV

With all results pertaining to grid voltages, it seems that the End PV scenario has the most impact on voltage rise as evident in Figure 29. This figure depicts the MV voltage at the beginning, middle and end of the network in all PV scenarios for the 30% PV penetration case on 8 May 2019; where it is visible that the voltage at the end of the feeder is higher than that at the beginning of the feeder. The impact of intermittency on the voltage is also more apparent in the End PV scenario. This voltage rise effect for each scenario is consistent in all PV penetration cases, where the End PV scenario results in the highest voltage change followed by All PV, Mid PV and Beg PV scenarios.



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 29: MV p.u. voltage at beginning, middle and end of the constrained network in all PV scenarios for 30% PV penetration case (8 May 2019)

5.2. Analysis of results for the unconstrained network

5.2.1. Effect of ramps or intermittency

As previously discussed, ramps caused by intermittency can have a significant impact on network voltage. Table 10 details the results for 4 days in 2019 that had substantial ramp rates in the unconstrained network case study. This table shows the MV voltage changes that occurred due to intermittency in each PV scenario for each PV penetration case. It is evident that installing PV at the end of the network results in a higher voltage change and starts to surpass the 3% allowable limit at 50% PV penetration limit. These ramps were averaged over either an hour or two and it is assumed that there will be significantly higher ramp rates that will occur in a higher resolution of time. The results also show as the PV penetration level increases so does the voltage change will be. Furthermore, the voltage change is proportional to the ramp rate that occurs. Interestingly, the voltage change is very low for each PV penetration level in comparison to the results seen for the constrained network.

Table 10: Voltage changes that occurred due to ramping of PV in each PV scenario and penetration case for the unconstrained network

Date	Scenario	Highest ramp rate (% of installed capacity)	Time	Highest end of line voltage change (15%)	Highest end of line voltage change (30%)	Highest end of line voltage change (50%)	Highest end of line voltage change (75%)
01 February 2019	End PV	Decreased 77.4%	In 2 hours	0.88%	1.79%	2.98%	4.42%
	Mid PV			0.65%	1.34%	2.24%	3.33%
	All PV			0.81%	1.65%	2.76%	4.10%
	Beg PV			0.21%	0.47%	0.81%	1.23%
02 February 2019	End PV	Decreased 93.4%	In 1 hour	1.08%	2.14%	3.49%	5.08%
	Mid PV			0.81%	1.62%	2.66%	3.89%
	All PV			1.00%	1.98%	3.24%	4.73%
	Beg PV			0.28%	0.59%	1.00%	1.49%
08 May 2019	End PV	Increased 66.7%	In 1 hour	0.84%	1.63%	2.67%	3.94%
	Mid PV			0.65%	1.25%	2.04%	2.99%
	All PV			0.78%	1.52%	2.48%	3.66%
	Beg PV			0.26%	0.49%	0.79%	1.15%
30 December 2019	End PV	Decreased 79.4%	In 2 hours	0.90%	1.81%	2.97%	4.36%
	Mid PV			0.67%	1.36%	2.26%	3.33%
	All PV			0.83%	1.67%	2.76%	4.06%
	Beg PV			0.22%	0.48%	0.83%	1.26%

5.2.2. Effect of size of generation

As previously mentioned, increasing PV penetration is said to also impact the instantaneous per unit voltage. Figure 30 shows the end of line MV voltage recorded for the unconstrained network case study during one day with a typical PV generation profile (27 April 2019) for each PV penetration case in the End PV scenario. This shows that as the penetration increases so does that MV voltage.

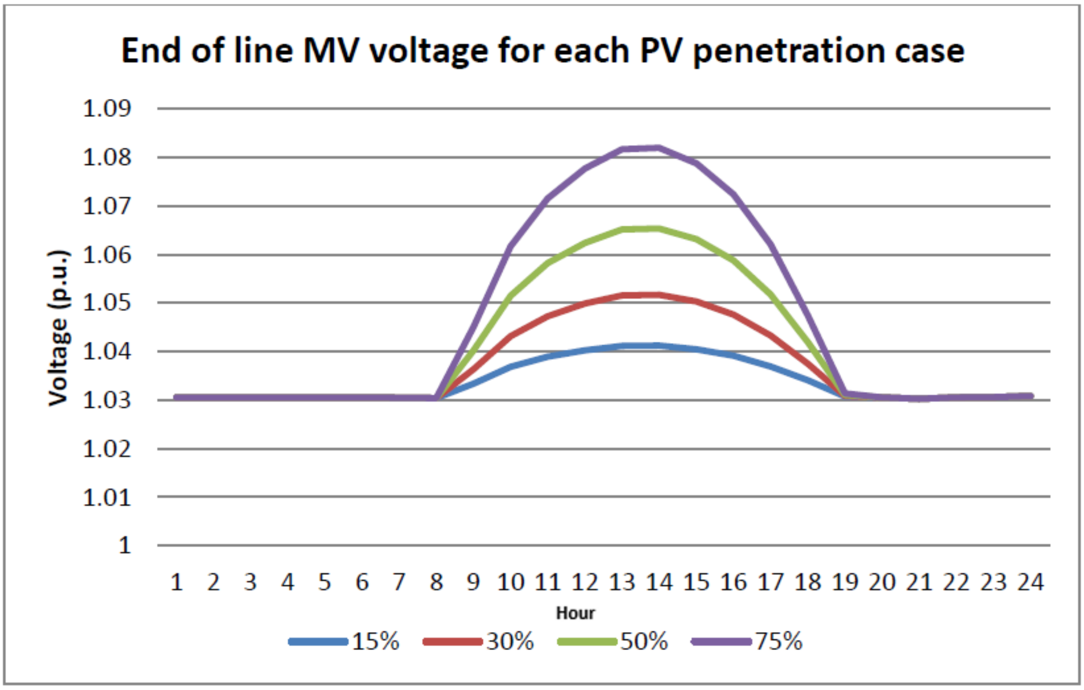
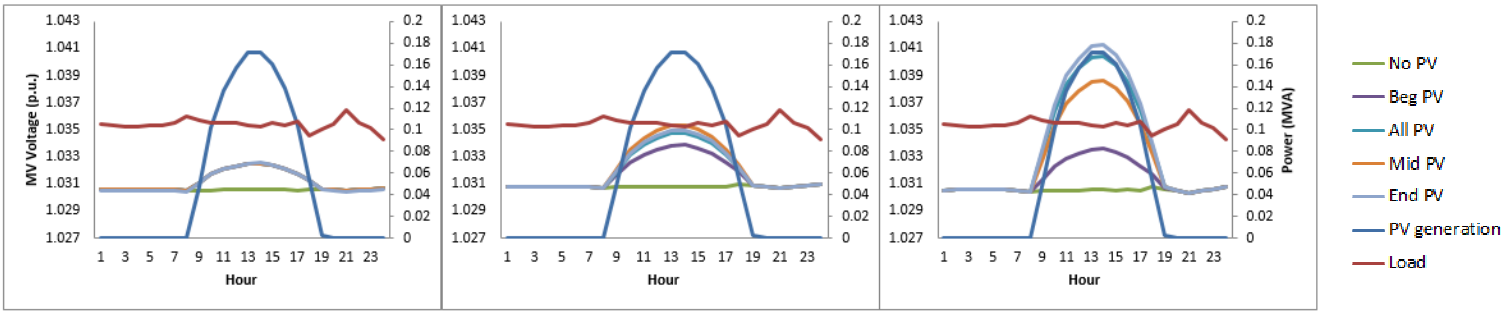


Figure 30: MV end of line voltage recorded for each PV penetration case in the End PV scenario for the unconstrained network

5.2.3. Effect of location of generation

In terms of the results for voltage impacts, it seems that for this case, the impact of the location of the PV systems have varying effects for the voltages at different points of the network. For instance, the End PV case results in the highest voltage at the end of the network but the Mid PV case results in the highest voltage at the middle of the network. The differences are considered to be minor; however, this is consistent for all PV penetration levels as depicted in the results section for this case study.

Figure **31** depicts the MV voltage at the beginning, middle and end of the network in all PV scenarios for the 15% PV penetration case on 27 April 2019. The End PV scenario results in the highest end of line voltage change as a result of PV.



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 31: MV p.u. voltage at beginning, middle and end of the unconstrained network in all PV scenarios for 15% PV penetration case (27 April 2019)

5.3. Active power curtailment as a useful voltage management technique

The control strategy results in no overvoltage violation, whereas the end of line MV voltage exceeded 1.05p.u. without control at the 14th hour which is indicated in Figure 26 in Section 4.3.

The voltage rise violation is totally mitigated with the Volt-Watt control strategy. This is evident in Figure 27 where an approximate 2.9% voltage rise is experienced without Volt-Watt control and an almost 0% voltage rise is experienced with control.

The rapid voltage change experienced without control was ~11% and this is reduced to ~6% with control as shown in Figure 26. Unfortunately, this is still above the allowed 3% even though the control does alleviate most of the impact from intermittency.

In conclusion, the implementation of the active power curtailment as a voltage control strategy has proven to be effective for voltage rise and overvoltage effects introduced by PV systems in a Distribution network. Even though the rapid voltage changes have not been entirely mitigated, it has been alleviated to a substantial degree.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

This dissertation focussed on voltage issues induced by increasing penetration of small-scale solar PV plants on distribution networks in South Africa with a hypothesis that a simple voltage management technique that uses active power curtailment can be adopted to alleviate these issues. All local conditions including type of networks, network loading, network equipment and solar resource that is specific to South Africa have been catered for in this research.

Numerous Powerfactory Digsilent power flow simulations were completed to research the following:

1. The impact of increasing PV penetration on the distribution grid voltage within two different South African distribution networks. The local conditions of these networks set them apart from each other where one network was thermal and capacity constrained one and the other was a lightly loaded one and
2. Testing the hypothesis that implementation of a simple voltage control strategy using active power curtailment can mitigate or at least alleviate the voltage impacts (from the results in point 1) brought about by high PV penetration.

The most significant conclusion that can be derived from this research work was that implementation of a simple voltage control strategy that makes use of active power curtailment in one or more PV systems can mitigate or at least alleviate the voltage rise, overvoltage and rapid voltage changes that are introduced by increasing penetration of PV systems connected to a distribution network in South Africa.

It was further noted that the major impacts that are to be considered when installing PV to a distribution network are:

- Ramping of PV generation due to intermittency caused by moving clouds,
- Size and overall penetration level of all systems and
- Location of the systems.

As the PV penetration on a distribution network increase so does the impact on voltage of the network. The impact on each network is dependent on the overall state of the network in terms of loading and consumption patterns, integrity of the equipment that is installed on the network as well as the location of the PV systems in relation to the source of the network i.e., substation. The study has also proved that installing PV systems at the end of a distribution network has the most substantial impact to the voltage violations that can be experienced, and the opposite is true for the case of installing PV systems only at the beginning of the network.

The results also showed that PV generators can experience extremely high ramp rates due to intermittency (as high as 93.4% of installed capacity in one hour). This results in an equally significant voltage change which South African networks, being old and poorly designed (conductor length, sizes and number of customers), are not well-equipped to handle these changes. It must be highlighted that temporal resolution of data will have a more significant impact on the results.

Despite the theoretical nature of these simulations, the results are striking and do spur into concerns about the current status of South African networks. Since the voltage control strategy using active power curtailment has proven to alleviate voltage impacts in distribution networks from increasing PV penetration, it is recommended that this strategy be added to the requirements for utility interface of inverters i.e., NRS 097-2-1 [4]. This can potentially allow for increased penetration (to a certain extent) on the networks without hampering on the voltage stability of the networks. However, the financial and technical implications need to be considered when applying this control strategy. Furthermore, the simulation results presented in this MSc can be validated and verified by installing inverters that have Volt-Watt settings and analysing the resulting measurements.

APPENDIX A

A1. Constrained network results

A1.1. 15% PV penetration

The total capacity of PV installed on the network for this case was 410.78kW. The most important results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2 over the entire year is tabulated in Table 11. The times at which the voltage is exceeded will be considered as overvoltage instances. Furthermore, the MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 32.

It is evident from Figure 32 that the phenomenon of voltage rise is already occurring in the End PV location case as the voltage at the end of the line is starting to supersede the voltage at the middle of the line in some instances. This can be compared to the No PV case results from Figure 19 in the report for further confirmation. The overvoltage phenomenon for the End PV case is also apparent in the number of instances the voltage exceeds the NRS limits.

APPENDIX A

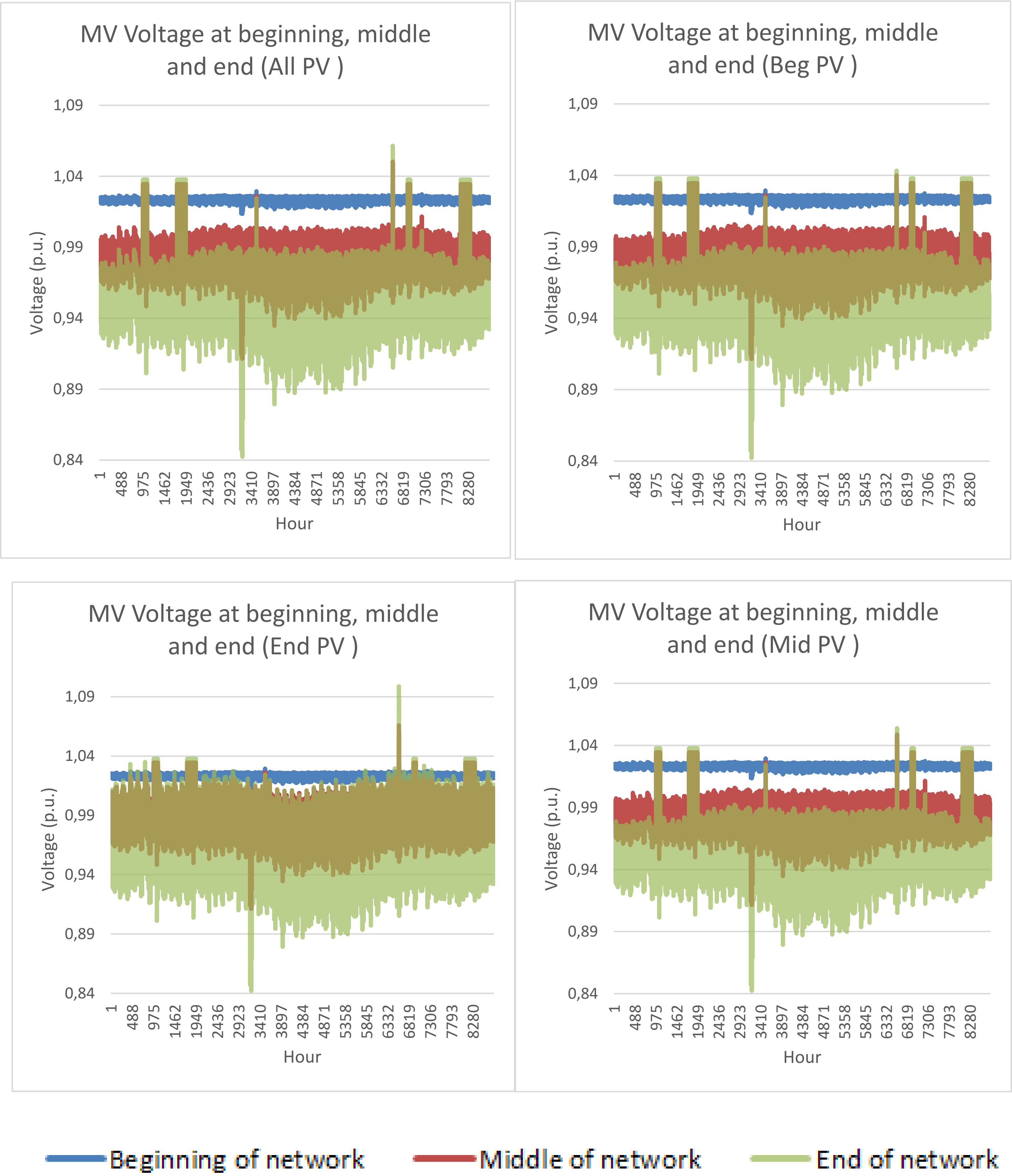


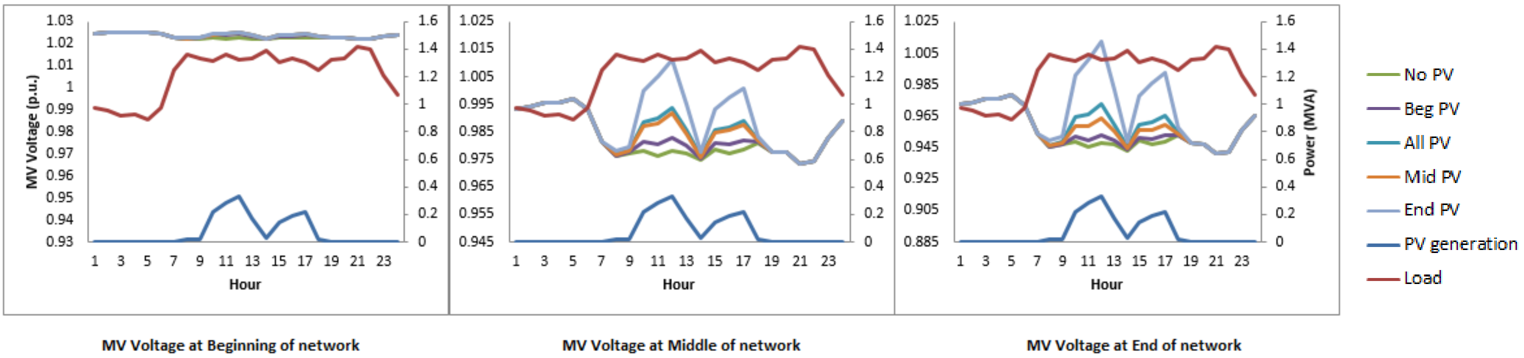
Figure 32: MV p.u. voltage for 15% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Table 11: Summary of results for 2019 in the PV penetration case of 15% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	8	0
Beg PV	0	0
Mid PV	5	0
End PV	14	6

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV scenario (End, Beg, Mid, All and No PV) in the 15% penetration case is illustrated in Figure 33 – 38 below. These figures highlight the rapid voltage change and voltage rise phenomena caused by intermittency in the PV plants.

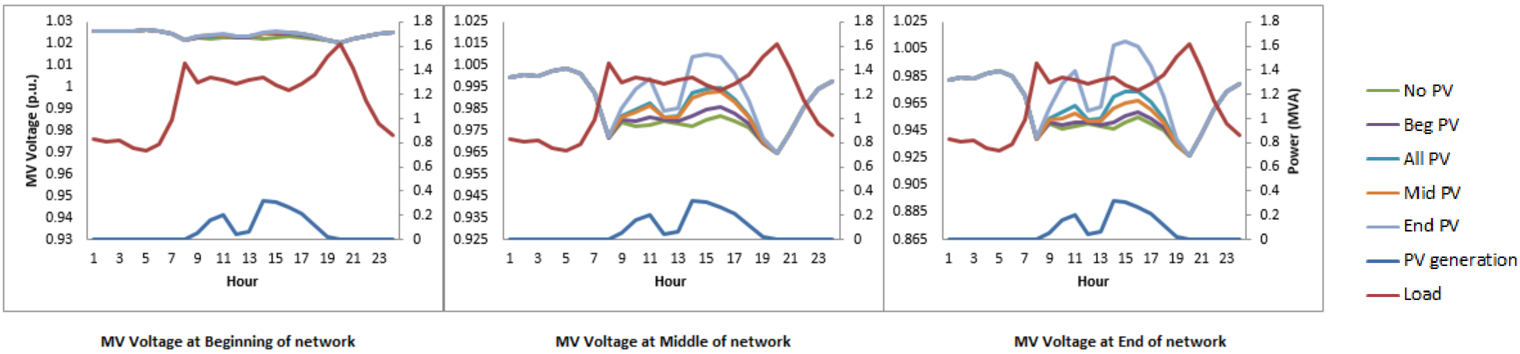


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 33: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network in each PV case



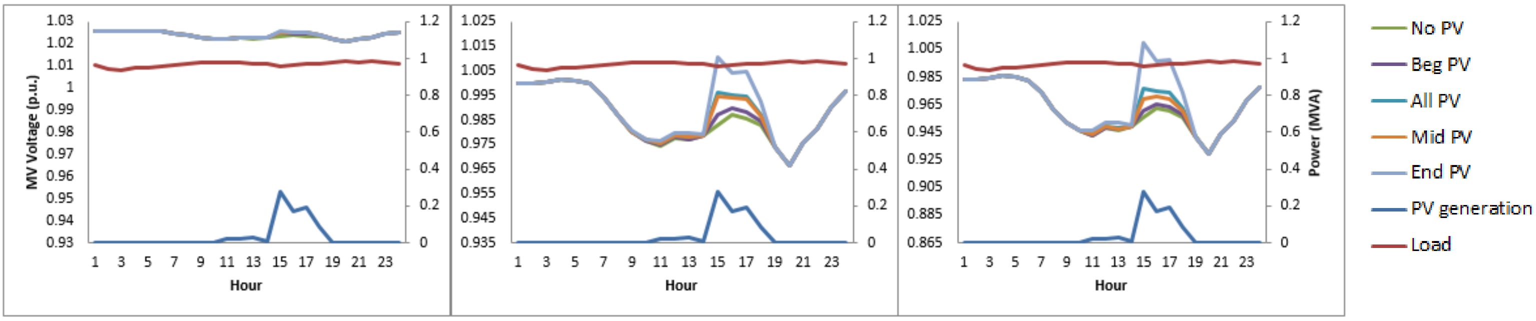
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 34: Detailed results for 8 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A

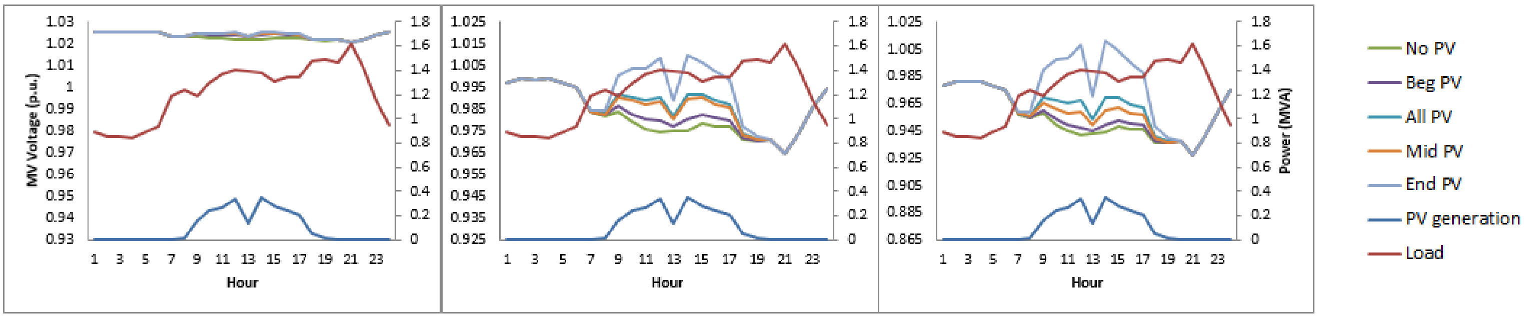


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 35: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

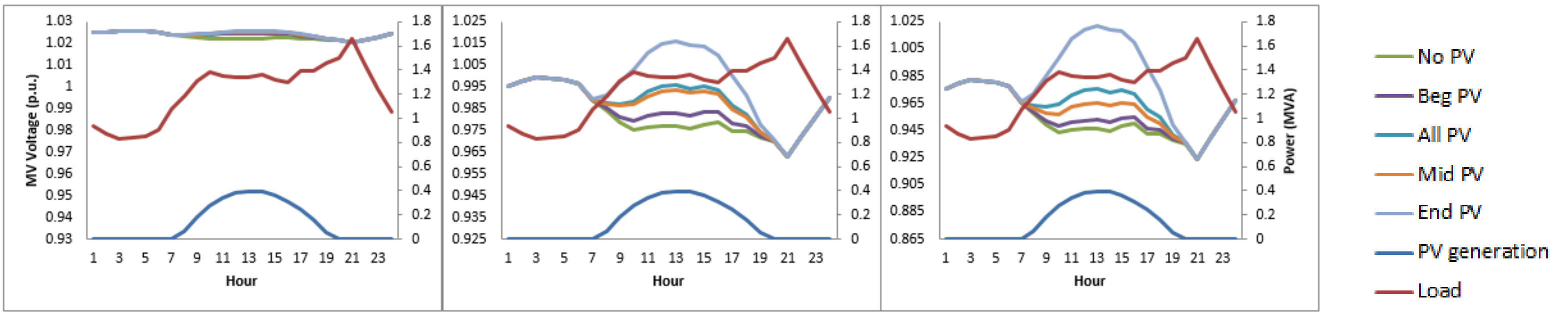


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 36: Detailed results for 5 Nov showing MV voltage (beginning, middle and end) on the network and losses in each PV case

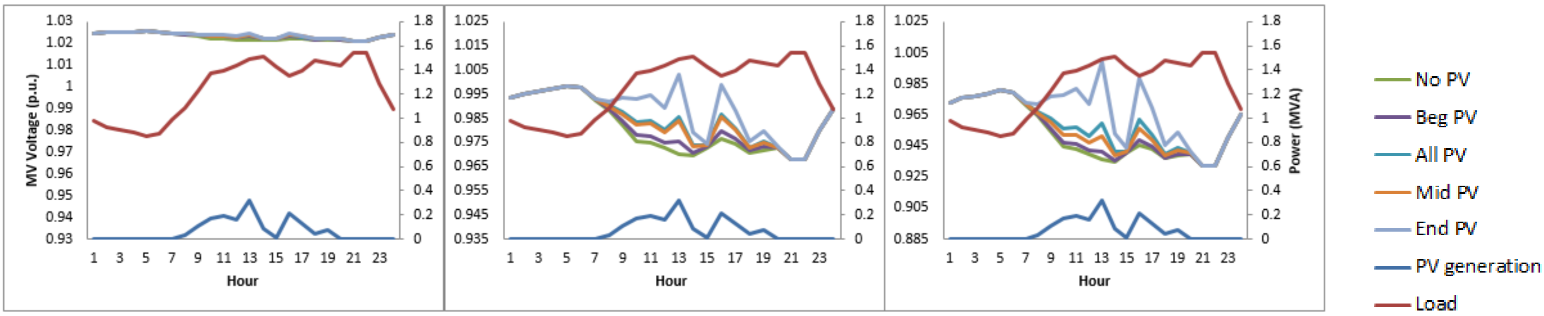


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 37: Detailed results for 4 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 38: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A1.2. 30% PV penetration

The total capacity of PV installed on the network for this case was 821.56kW. The most significant results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, over the entire year is tabulated in Table 12. Furthermore, the MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 39.

It is evident from Figure 39 that the phenomenon of voltage rise is already occurring in the End PV and All PV location cases as the voltage at the end of the line is starting to supersede the voltage at the middle of the line in some instances. This can be compared to the No PV case results from Figure 19 in the report. The overvoltage phenomenon for the End PV case is also apparent in the number of instances the voltage exceeds the NRS limits.

Table 12: Summary of results for 2019 in the PV penetration case of 30% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	14	0
Beg PV	0	0
Mid PV	14	0
End PV	1317	116

APPENDIX A

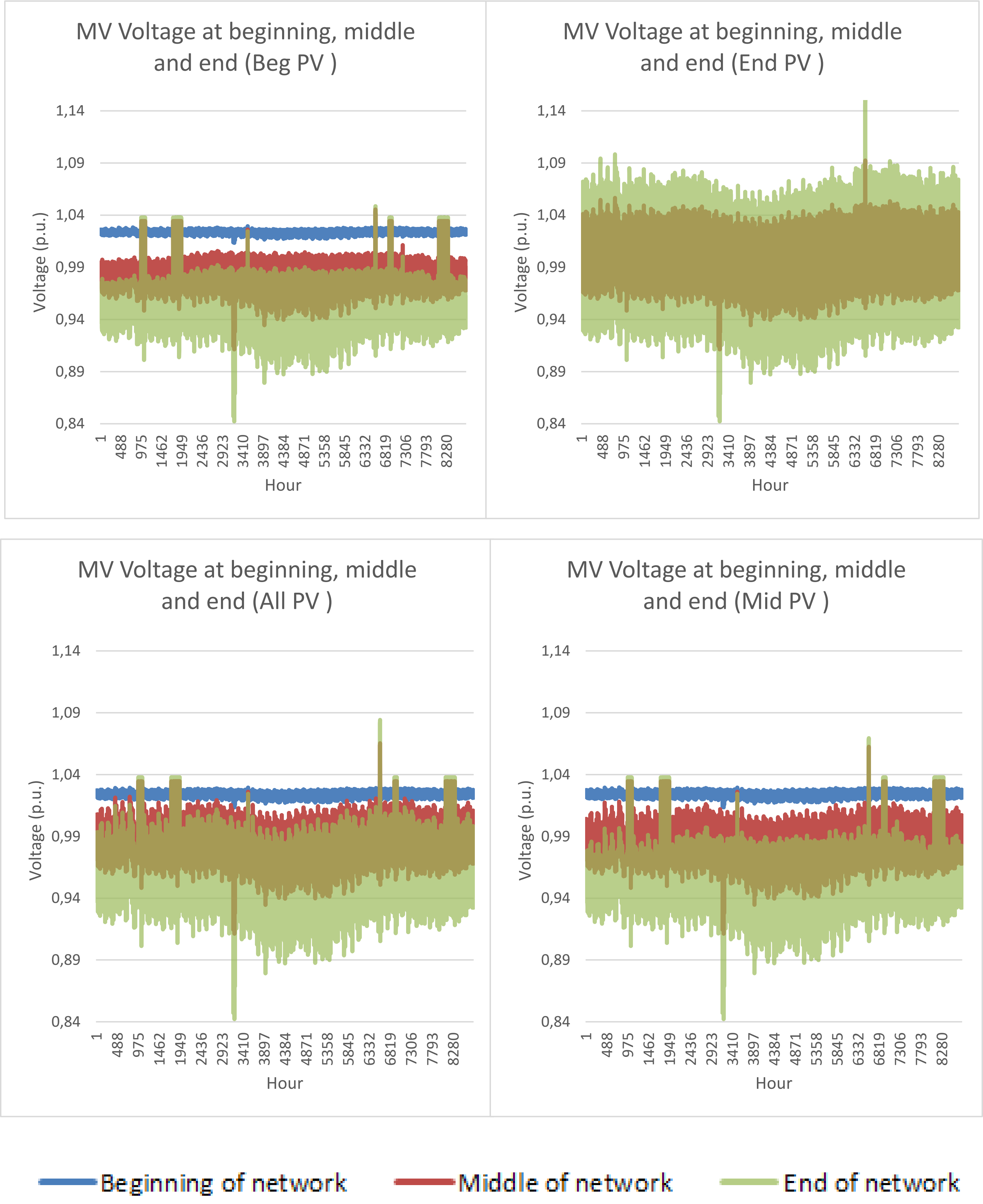
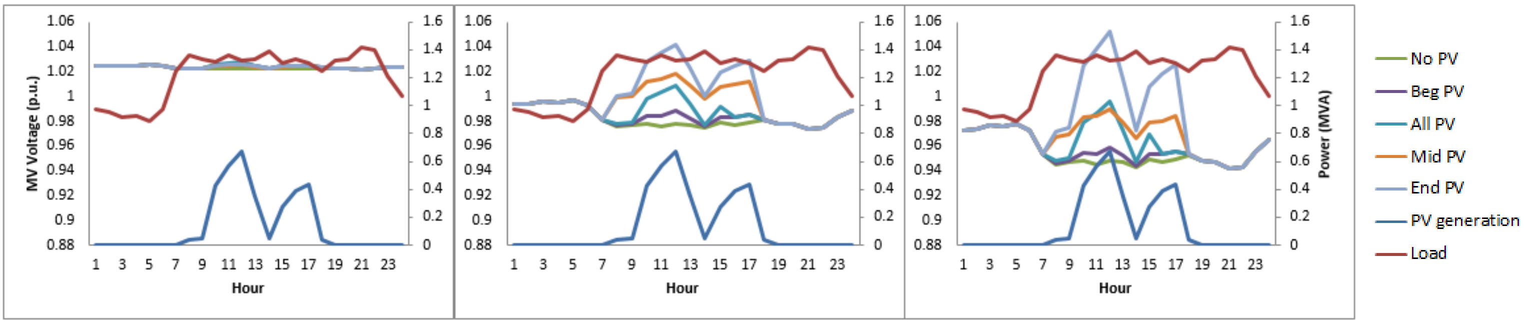


Figure 39: MV p.u. voltage for 30% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV scenario (End, Beg, Mid, All and No PV) in the 30% penetration case is illustrated in Figure 40 – 45 below. These figures highlight the rapid voltage change and voltage rise phenomena caused by intermittency in the PV plants.

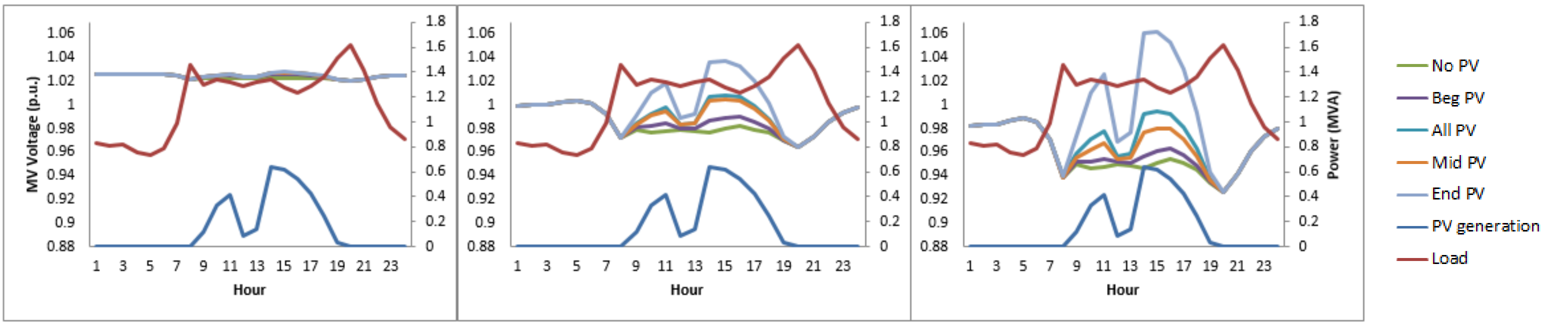


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 40: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

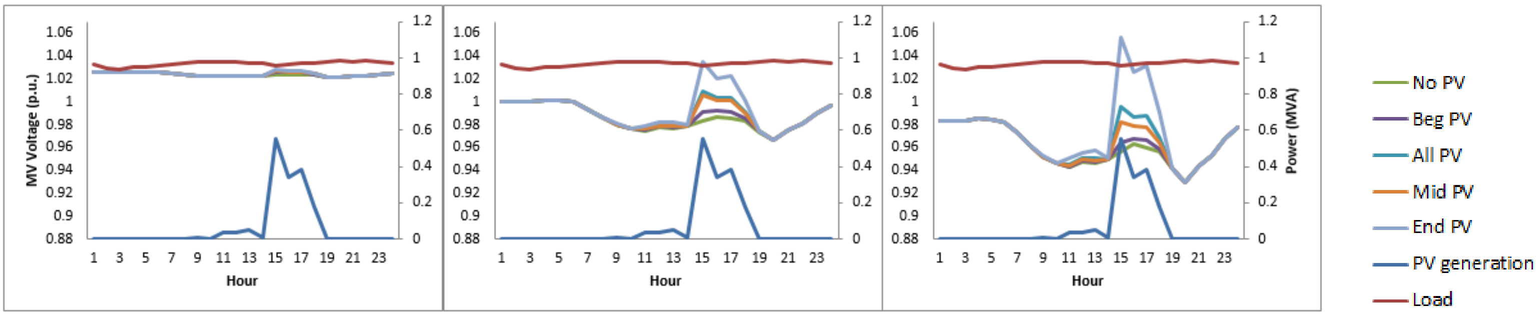


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 41: Detailed results for 8 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case



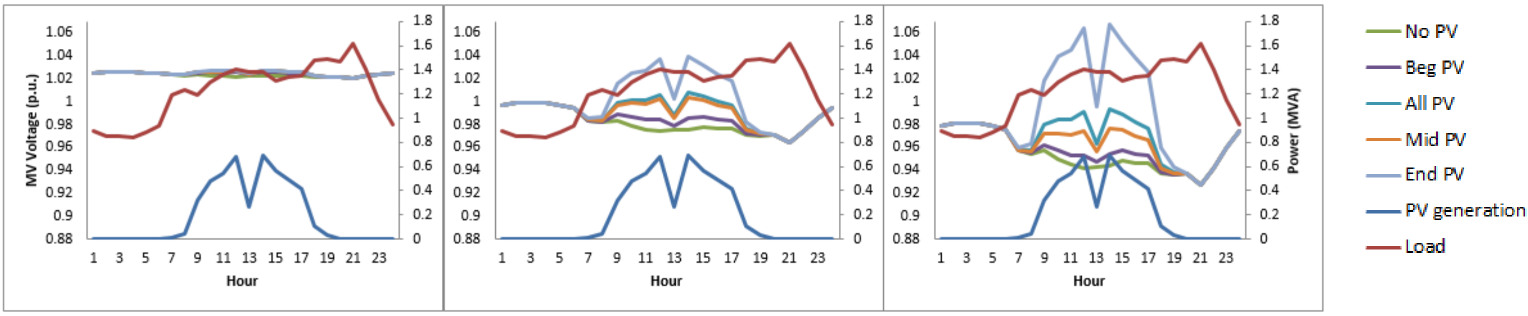
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

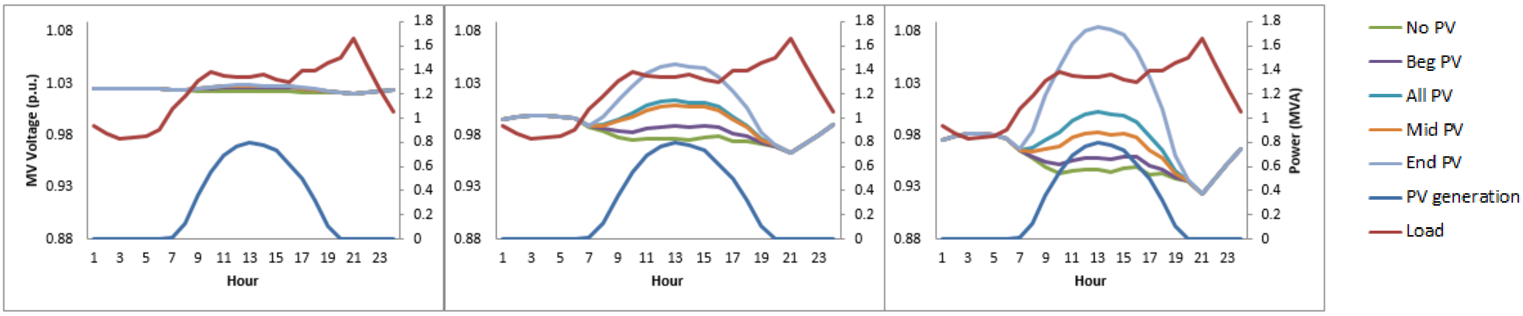
Figure 42: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A



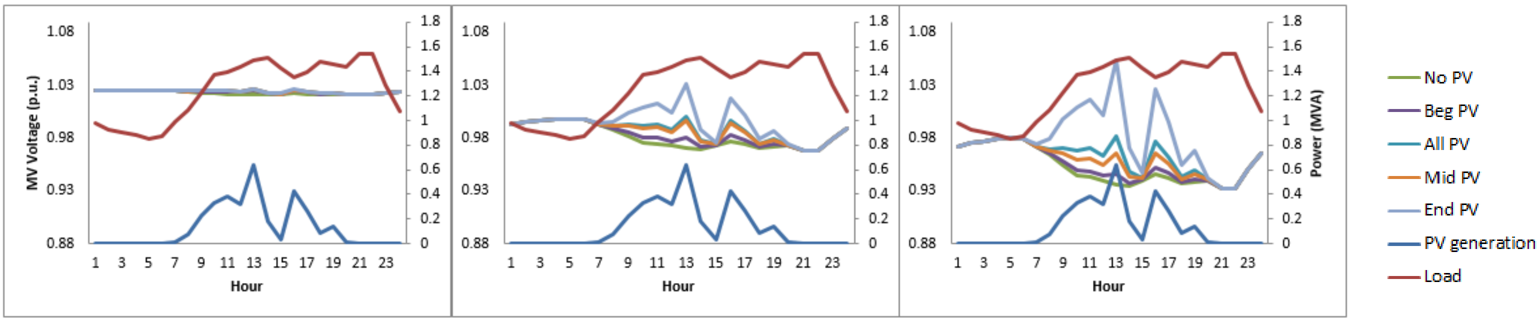
MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 43: Detailed results for 5 Nov showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 44: Detailed results for 4 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 45: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A1.3. 50% PV penetration

The total capacity of PV installed on the network for this case was 1369.26kW. The most important results for this scenario are detailed below. The MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 46. Furthermore, the number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage occurrences, over the entire year is tabulated in Table 13. The overvoltage and voltage rise violations is more apparent in the PV penetration scenario.

APPENDIX A

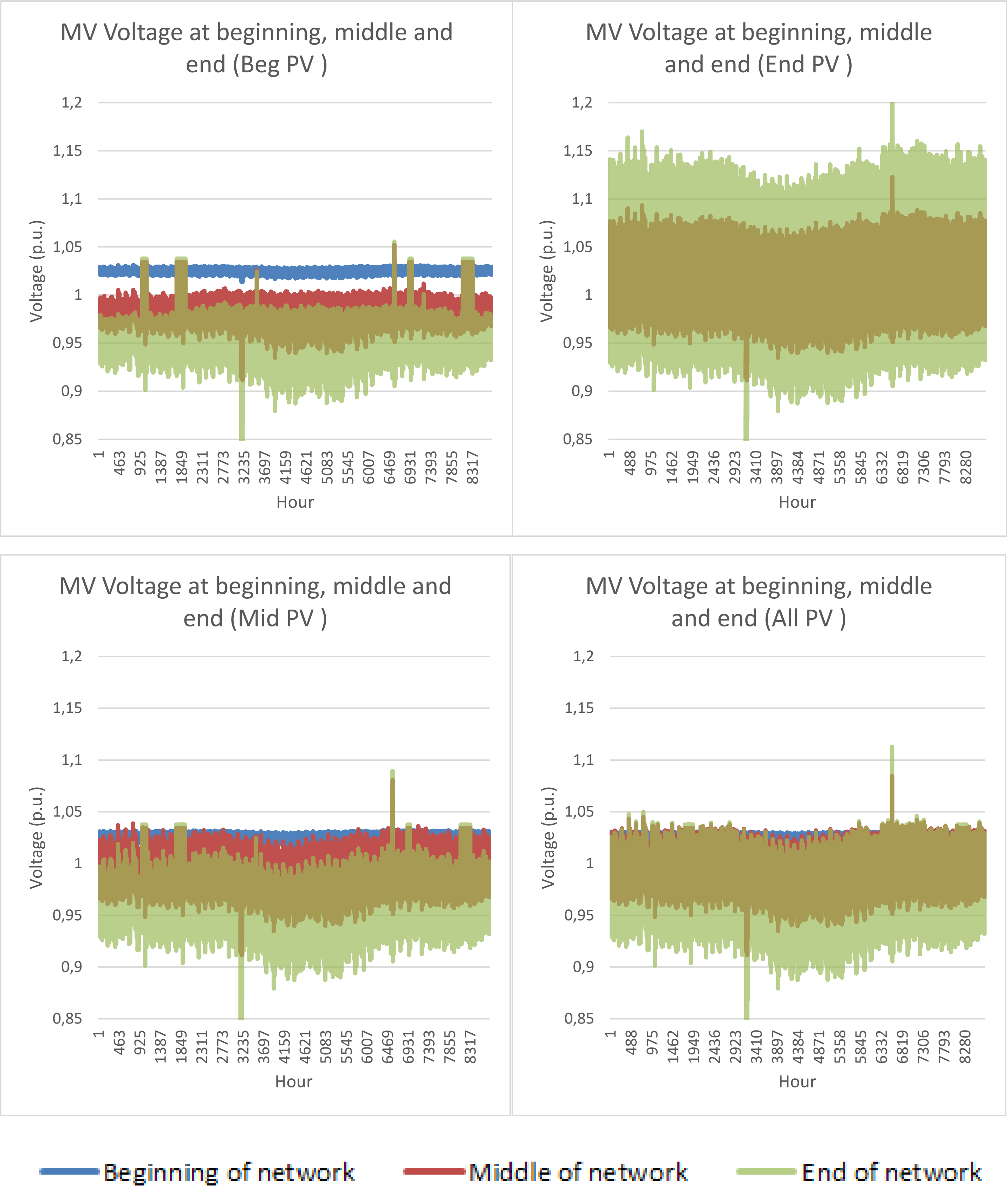


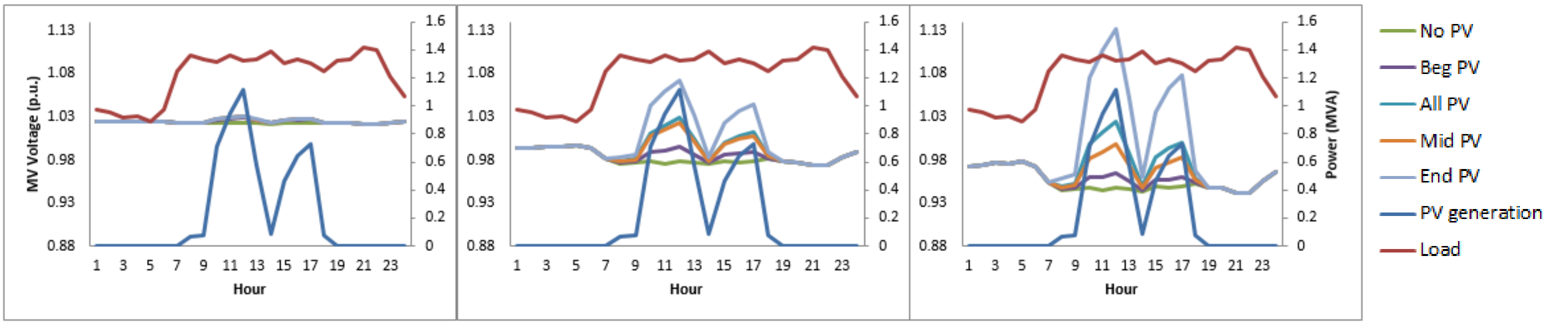
Figure 46: MV p.u. voltage for 50% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Table 13: Summary of results for 2019 in the PV penetration case of 50% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	15	6
Beg PV	10	0
Mid PV	14	3
End PV	4421	2267

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV case (End, Beg, Mid, All and No PV) in the 50% penetration case is illustrated in Figure 47 – 52 below. These figures highlight the rapid voltage change and voltage rise phenomena caused by intermittency in the PV plants.

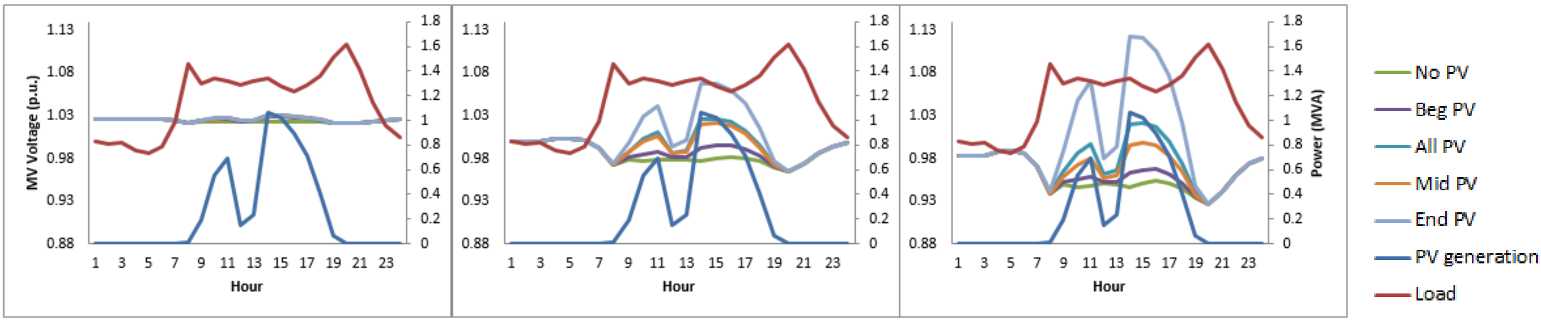


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 47: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

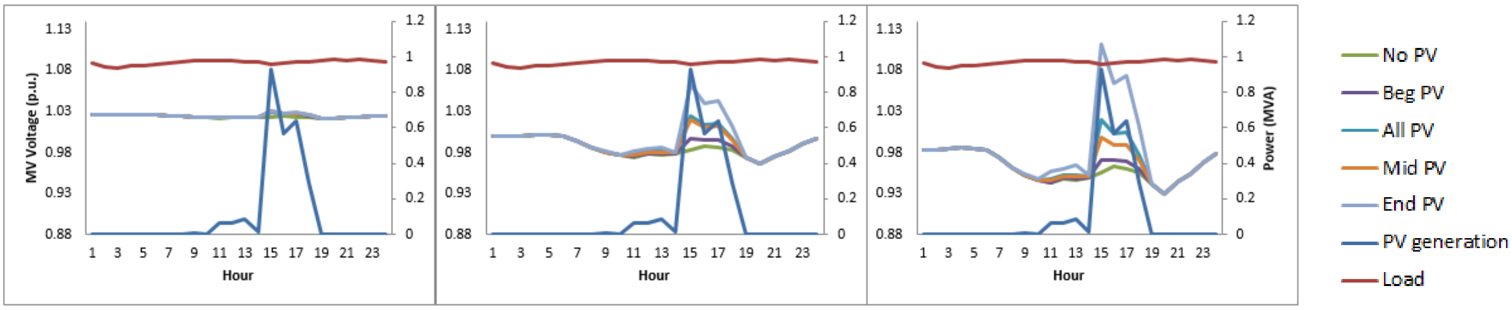


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 48: Detailed results for 8 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

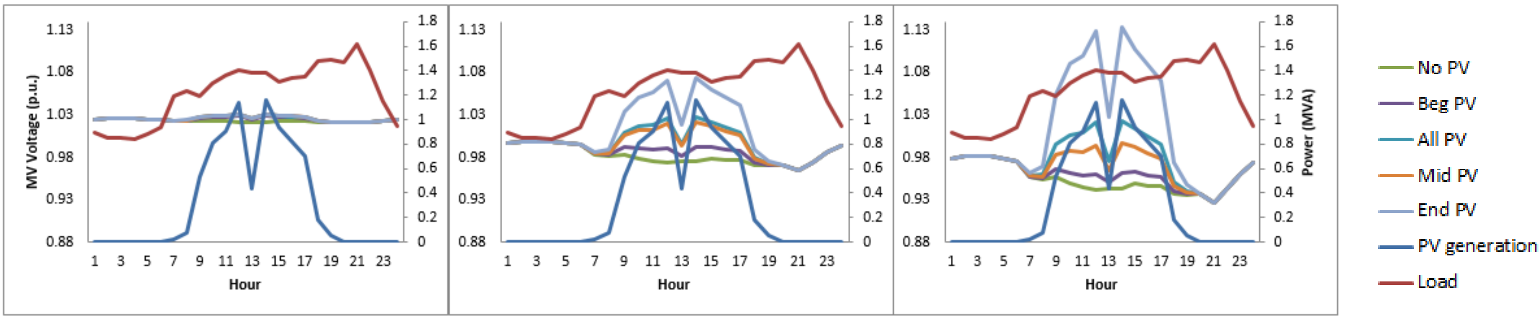


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 49: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

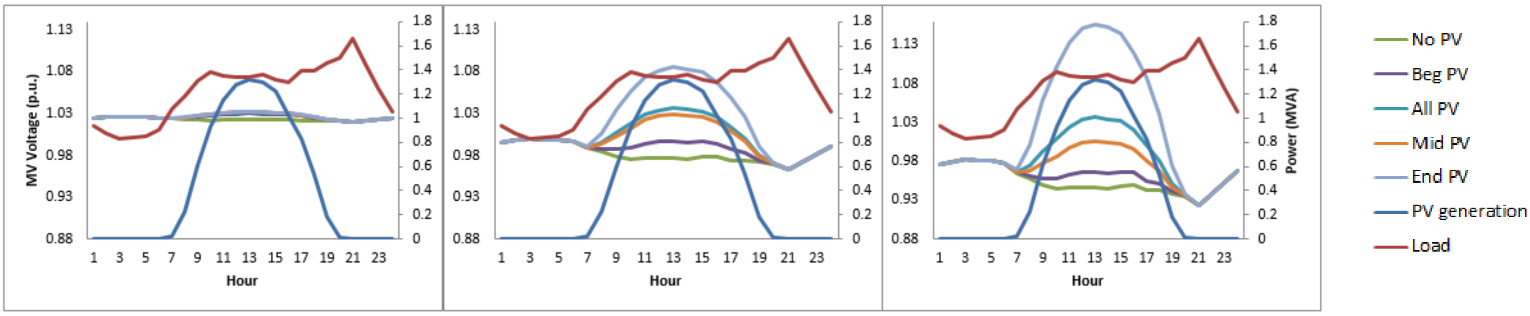


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 50: Detailed results for 5 Nov showing MV voltage (beginning, middle and end) on the network and losses in each PV case

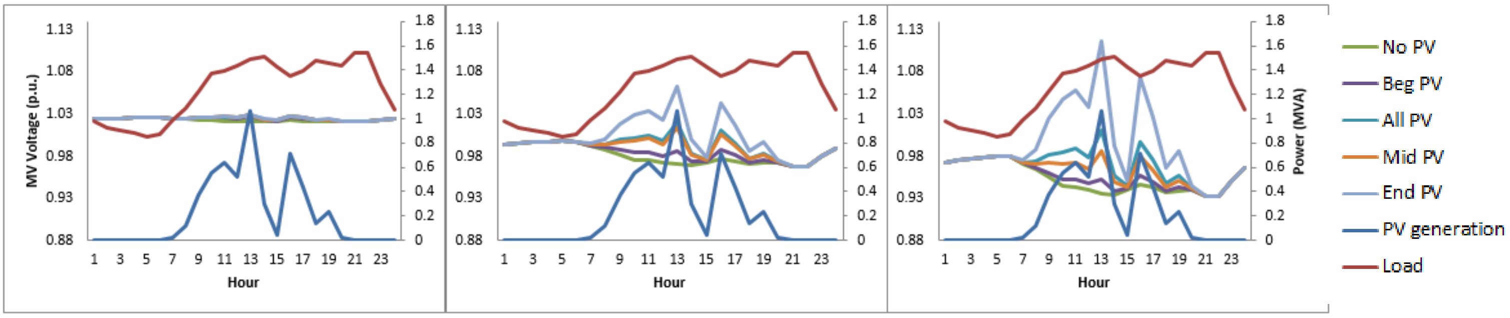


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 51: Detailed results for 4 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 52: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A1.4. 75% PV penetration

The total capacity of PV installed on the network for this case was 2053.89kW. The most significant results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, over the entire year is tabulated in Table 14. MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 53.

It is quite apparent that at this PV penetration the voltage violation instances are innumerous for all the PV location cases except the one where PV is installed only at the beginning of the network.

Table 14: Summary of results for 2019 in the PV penetration case of 75% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	1494	30
Beg PV	14	0
Mid PV	129	12
End PV	5678	4673

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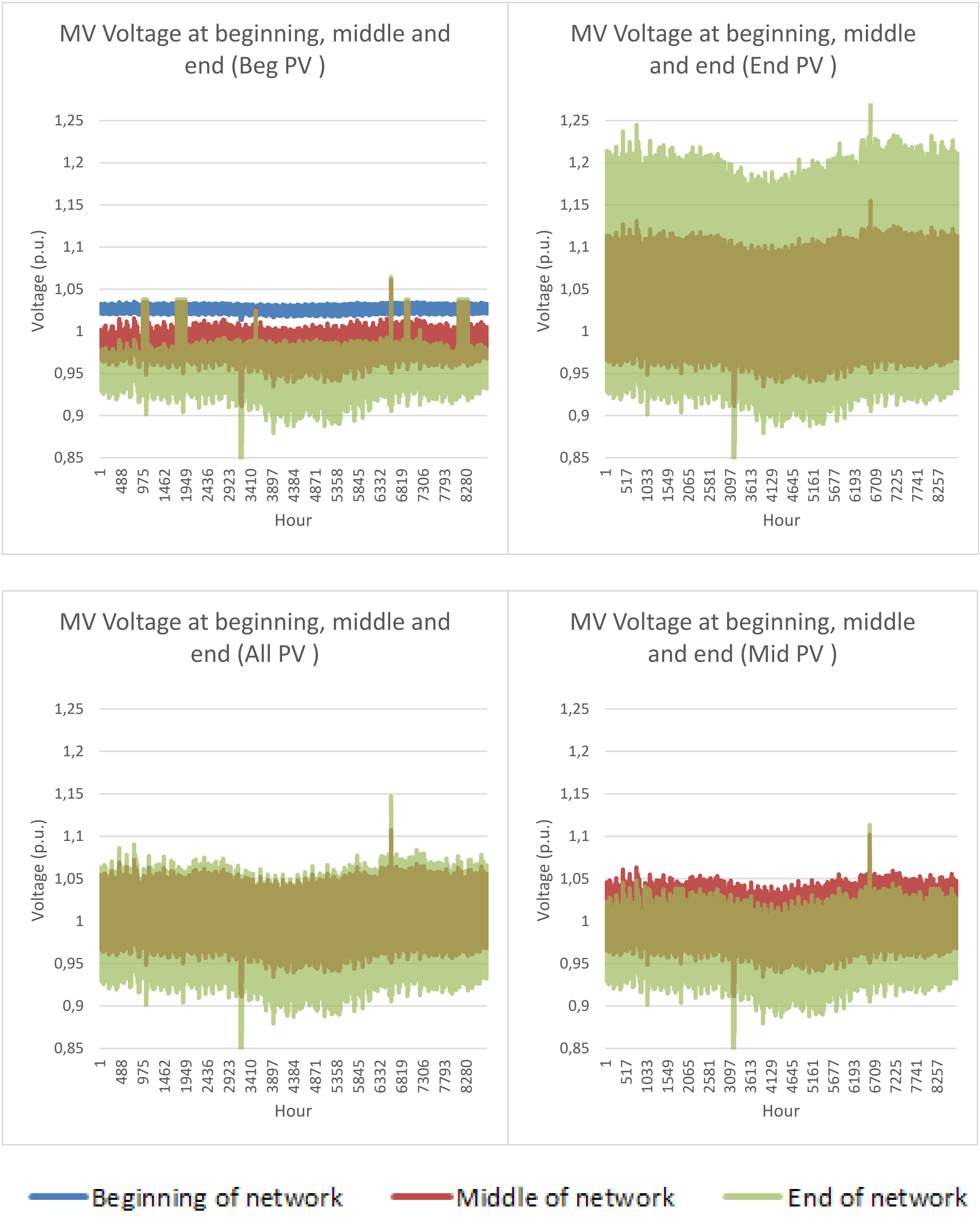
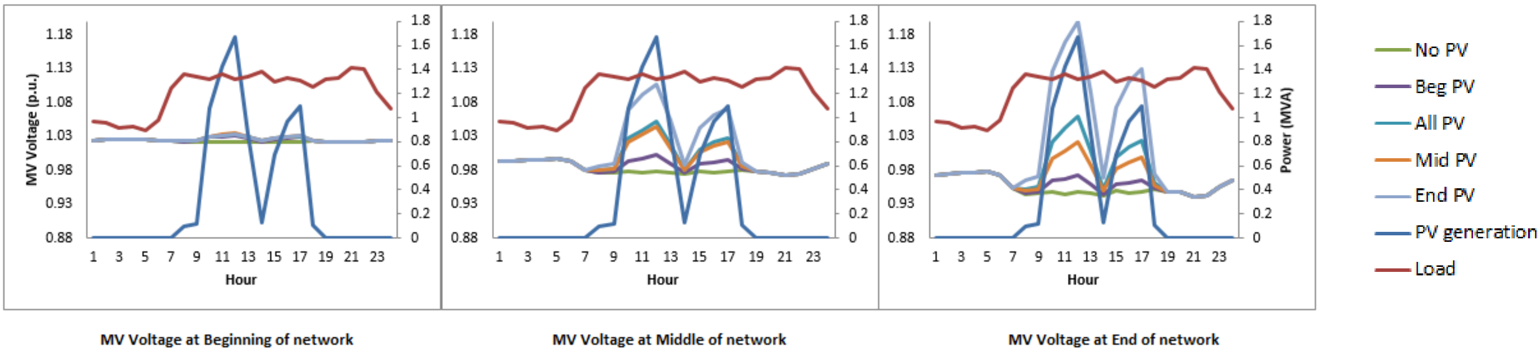


Figure 53: MV p.u. voltage for 75% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV case (End, Beg, Mid, All and No PV) in the 75% penetration case is illustrated in Figure 54 – 59 below. These figures highlight the impact of ramping phenomenon caused by intermittency in the PV plants.

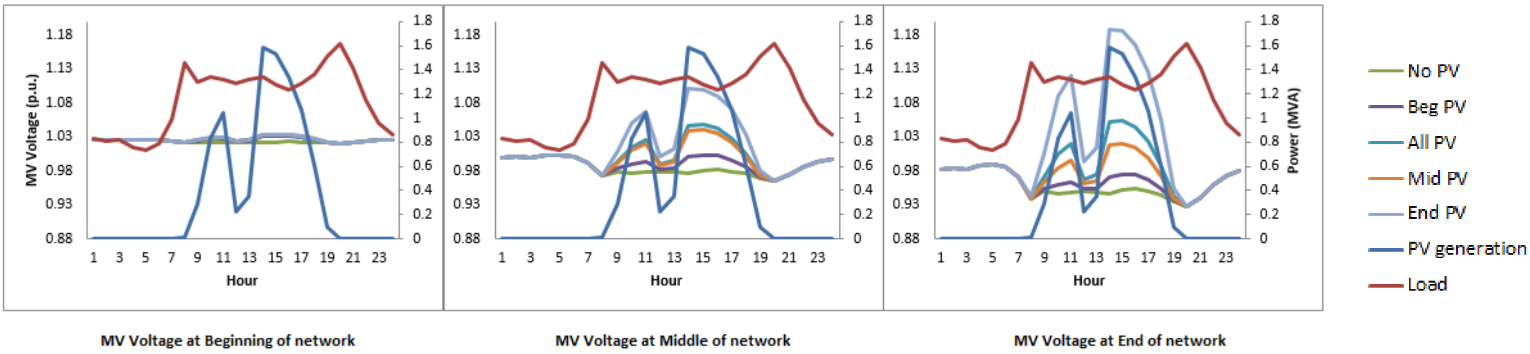


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 54: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

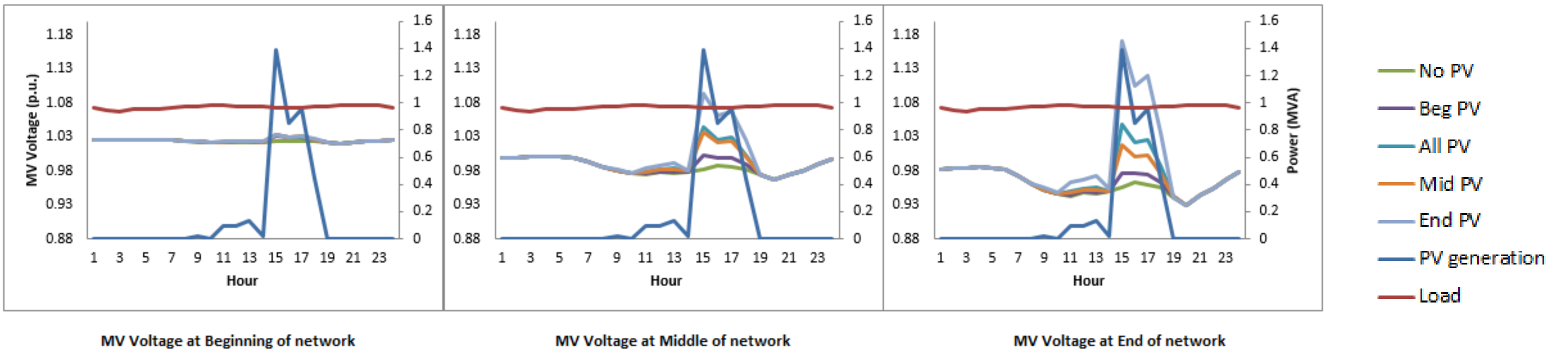


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 55: Detailed results for 8 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case



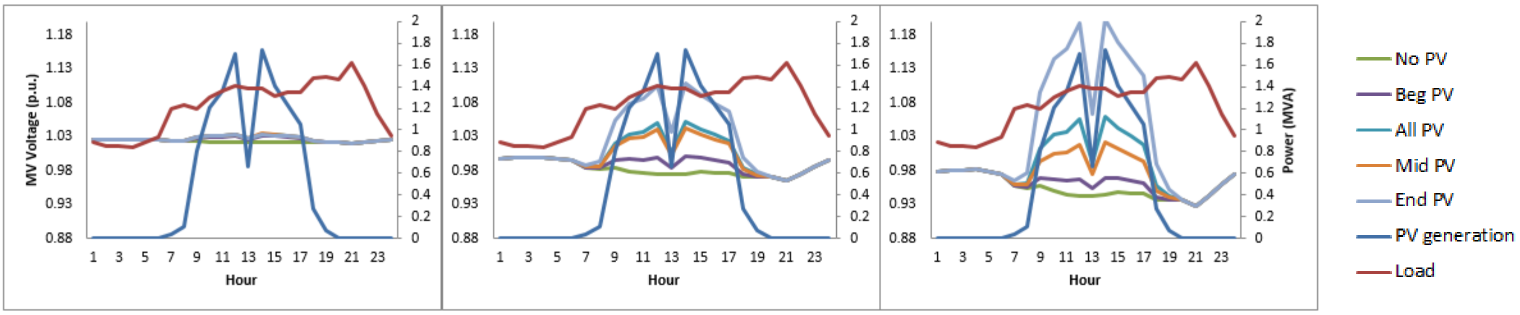
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 56: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A

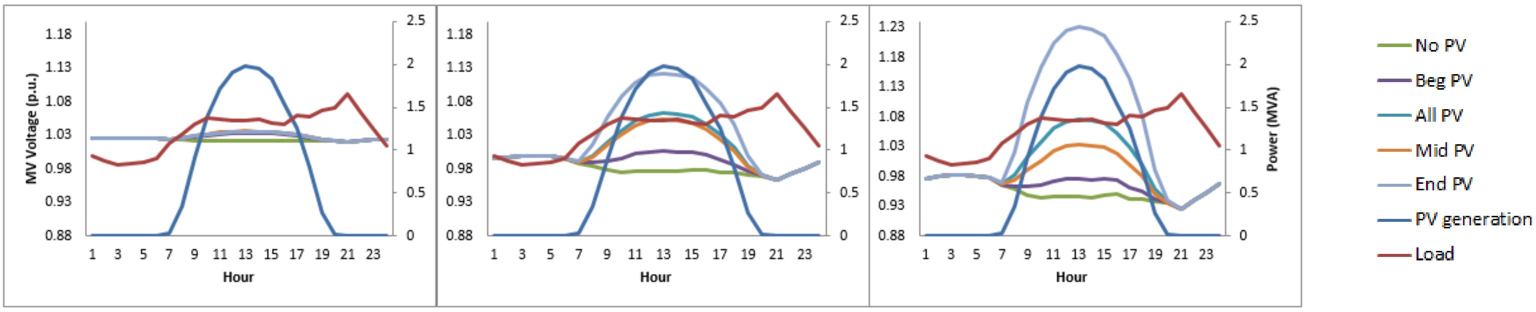


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 57: Detailed results for 5 Nov showing MV voltage (beginning, middle and end) on the network and losses in each PV case

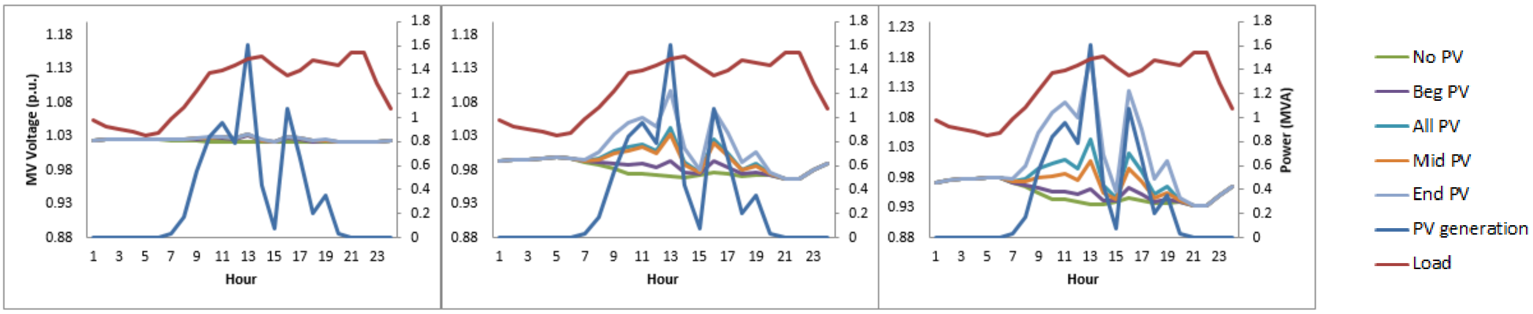


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 58: Detailed results for 4 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 59: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A2. Unconstrained network results

A2.1. 15% PV penetration

The total capacity of PV installed on the network for this case was 202.40kW. The most important results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, for the whole year is tabulated in Table 15. Furthermore, the MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 60.

There are no overvoltage recorded but voltage rise is apparent in Figure 60 for this PV penetration case.

Table 15: Summary of results for 2019 in the PV penetration case of 15% of peak load

Scenario	**No. of times MV voltage >1.05p.u.**	**No. of times LV voltage >1.10p.u.**
No PV	0	0
All PV	0	0
Beg PV	0	0
Mid PV	0	0
End PV	0	0

APPENDIX A

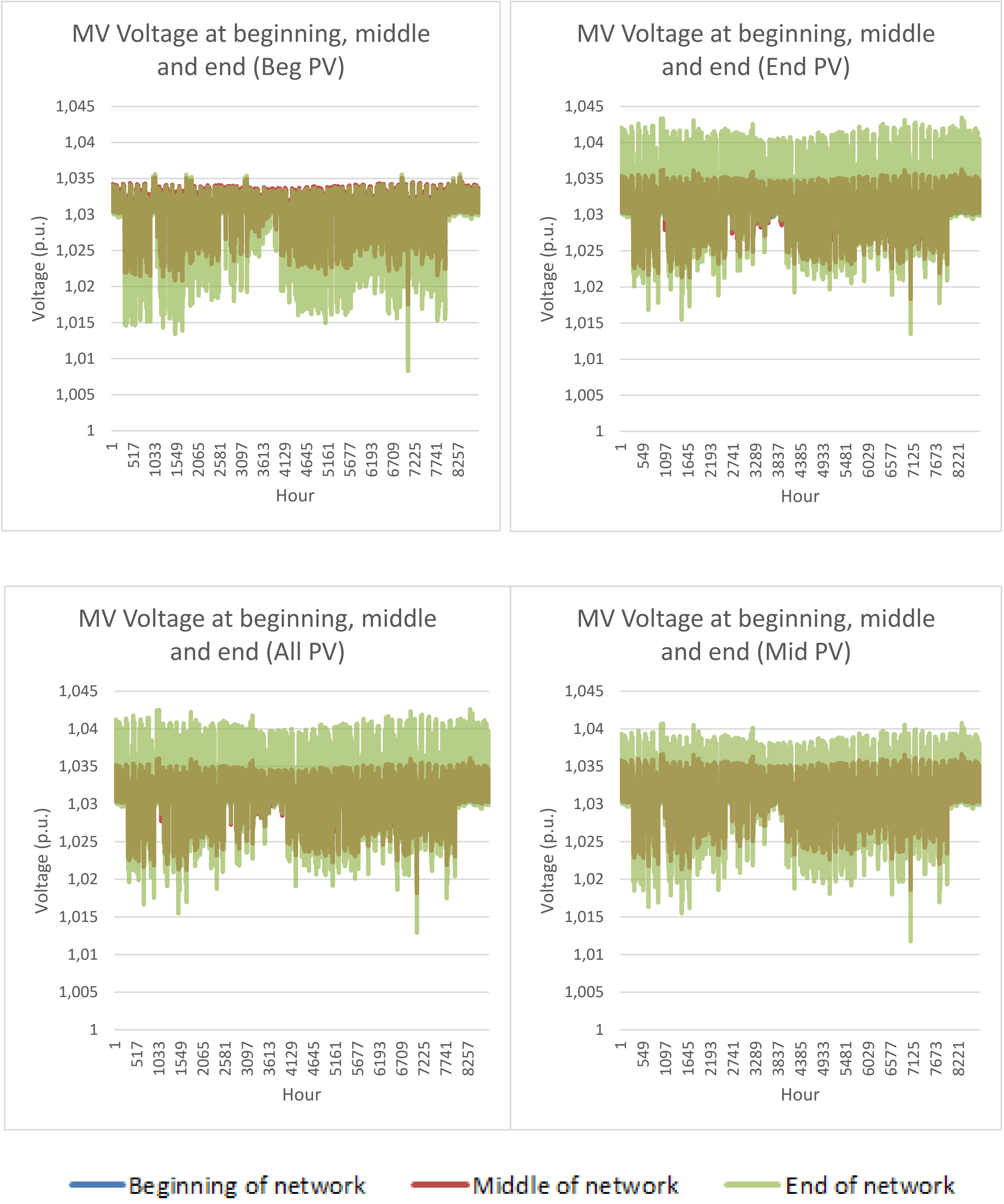
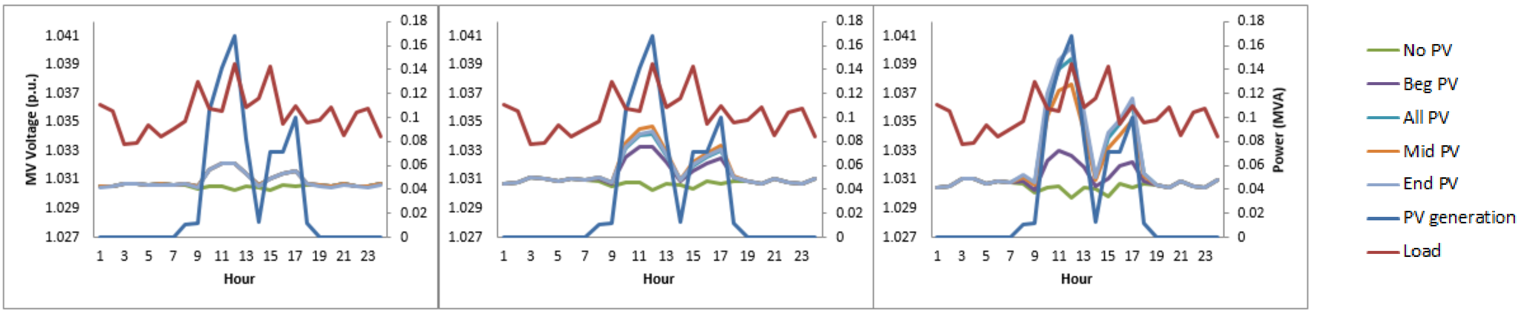


Figure 60: MV p.u. voltage for 15% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV scenario (End, Beg, Mid, All and No PV) in the 15% penetration case is illustrated in Figure 61 – 66 below. These figures highlight the impact of ramping phenomenon caused by intermittency in the PV plants.

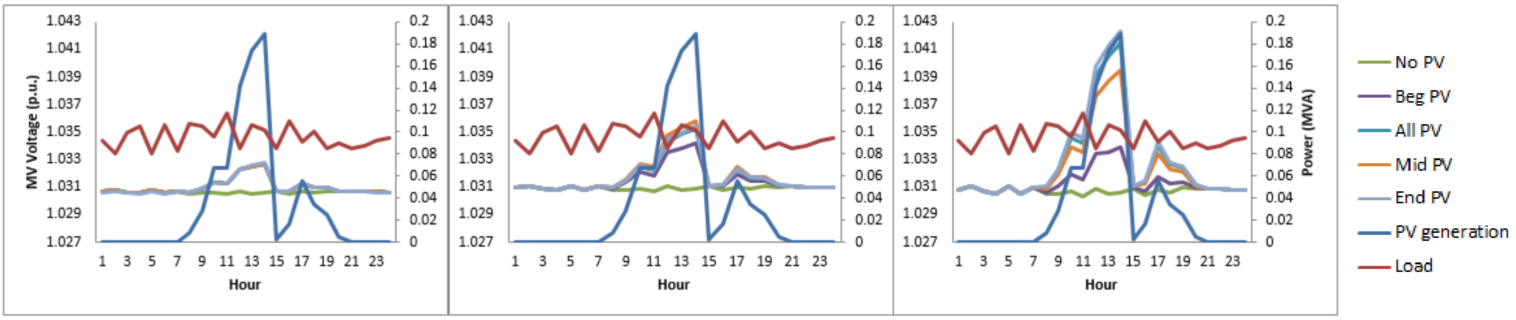


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 61: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

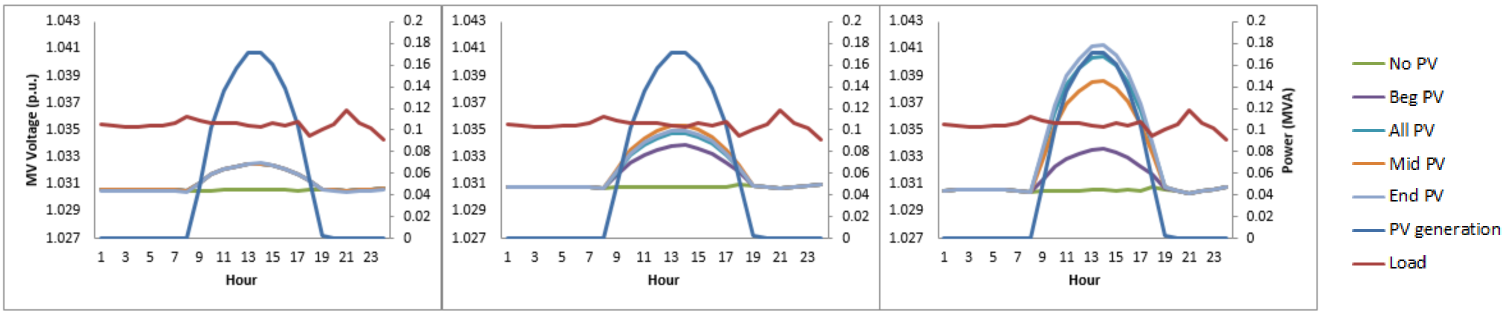


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 62: Detailed results for 2 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case



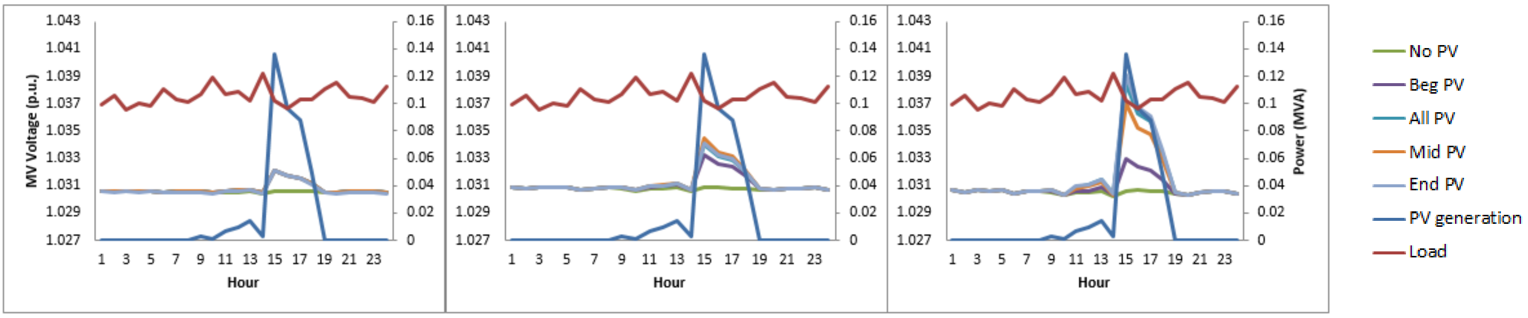
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 63: Detailed results for 27 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A

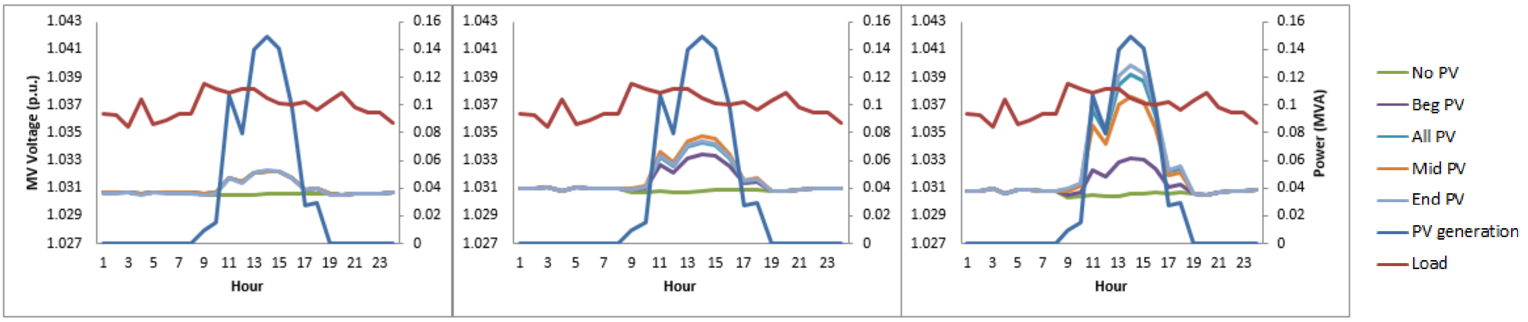


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 64: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

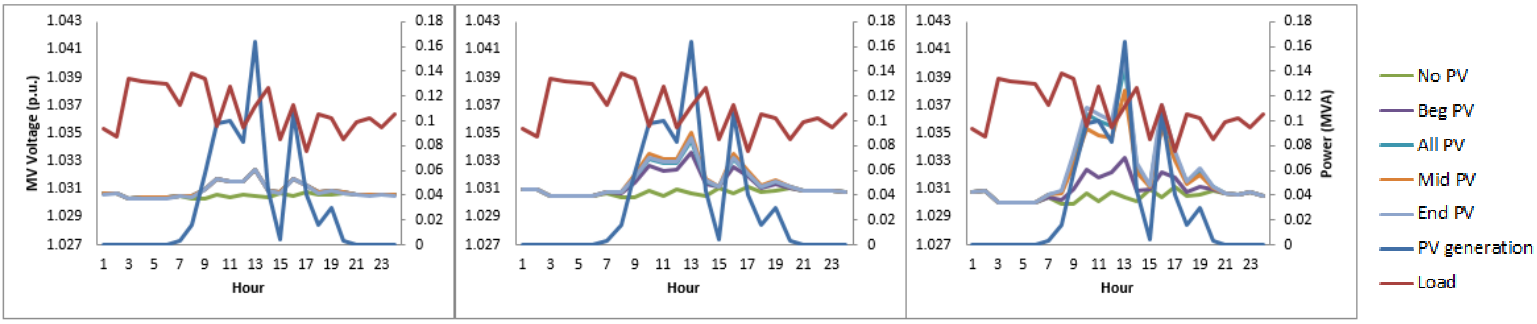


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 65: Detailed results for 26 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 66: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A2.2. 30% PV penetration

The total capacity of PV installed on the network for this case was 404.81kW. The most important results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, for the whole year is tabulated in Table 16. Furthermore, the MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 67.

The overvoltage and voltage rise occurrences are apparent for the All PV and End PV location scenarios.

Table 16: Summary of results for 2019 in the PV penetration case of 30% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	197	0
Beg PV	0	0
Mid PV	0	0
End PV	454	0

APPENDIX A

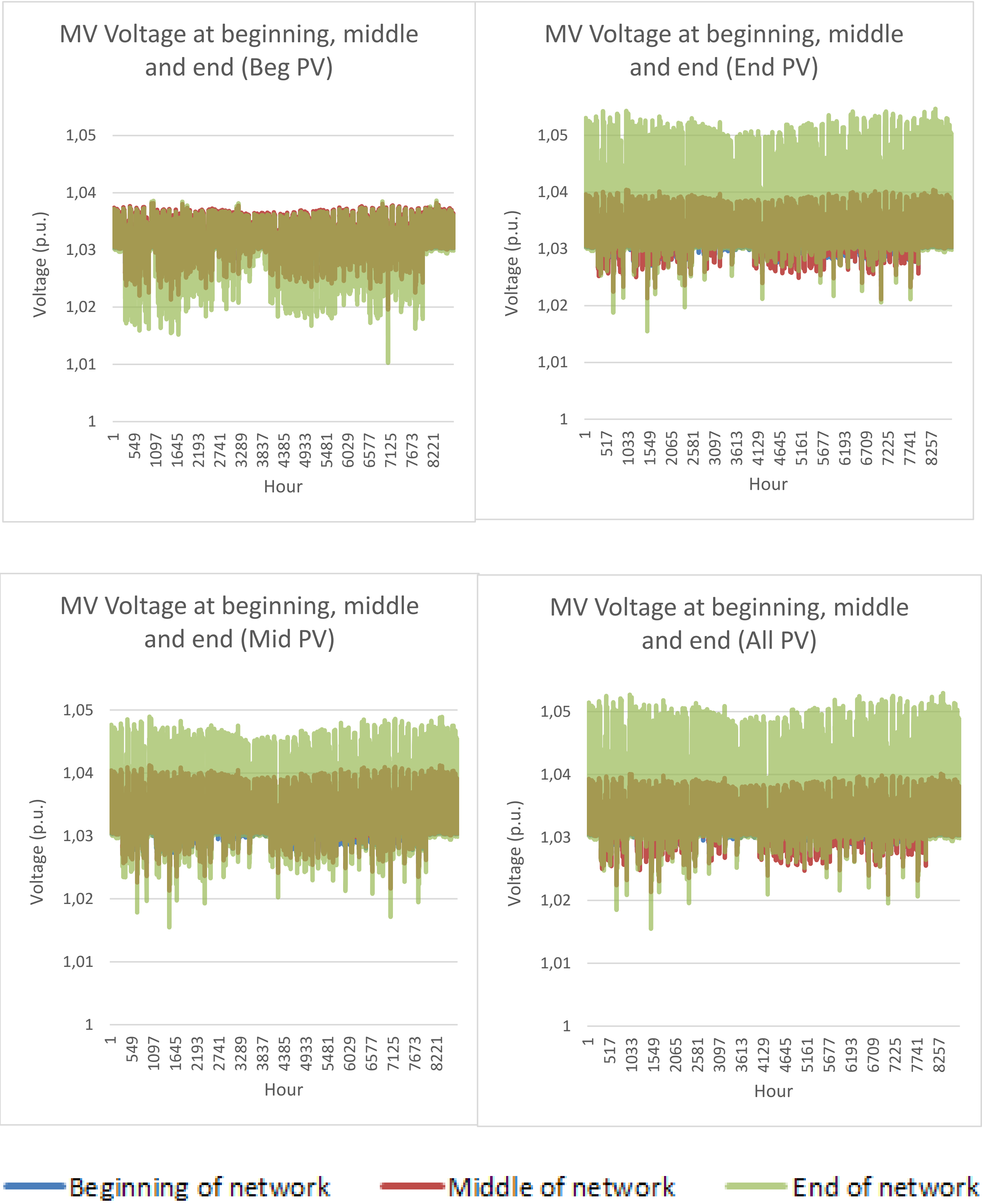
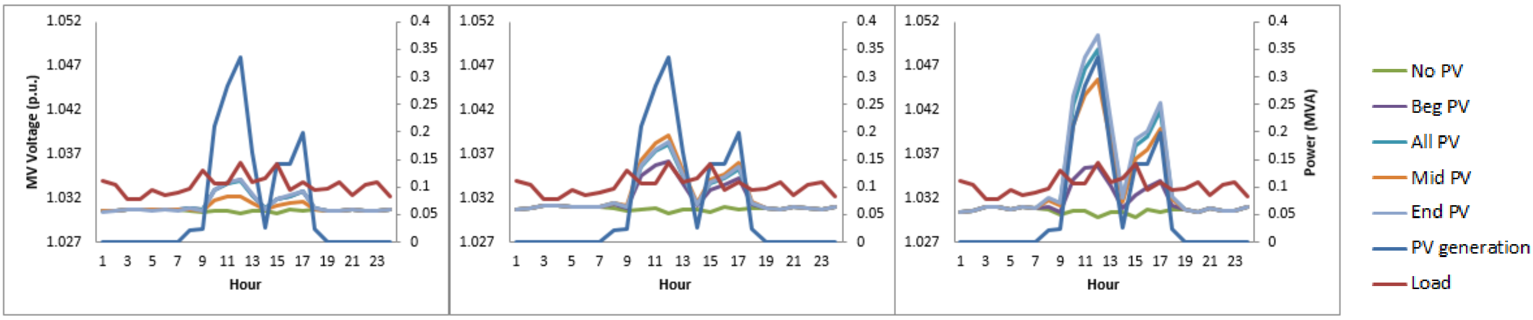


Figure 67: MV p.u. voltage for 30% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV case (End, Beg, Mid, All and No PV) in the 30% penetration case is illustrated in Figure 68 – 73 below. These figures highlight the impact of ramping phenomenon caused by intermittency in the PV plants.

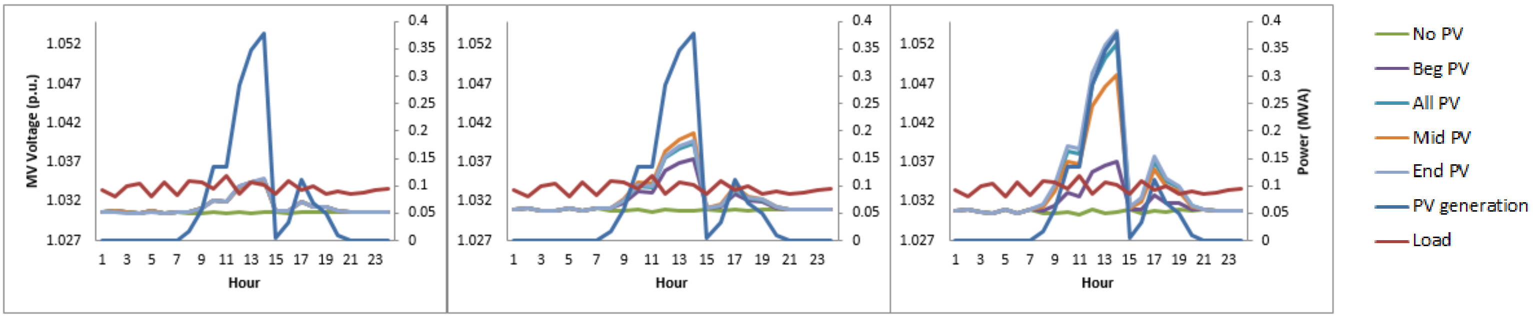


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 68: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

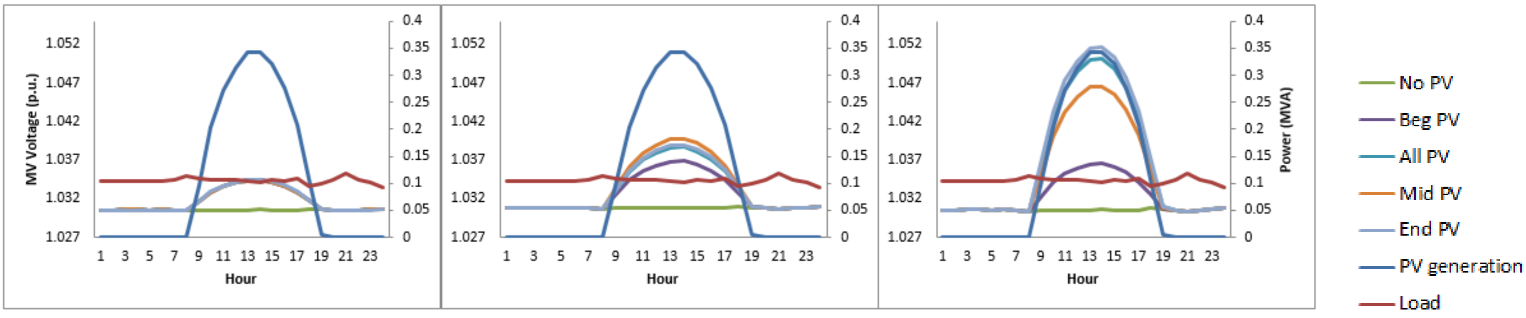


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 69: Detailed results for 2 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case



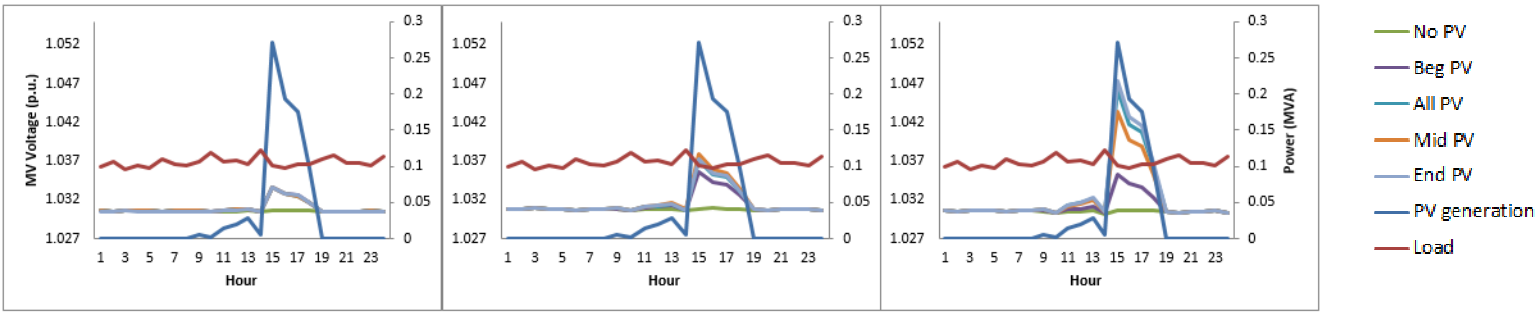
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 70: Detailed results for 27 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A

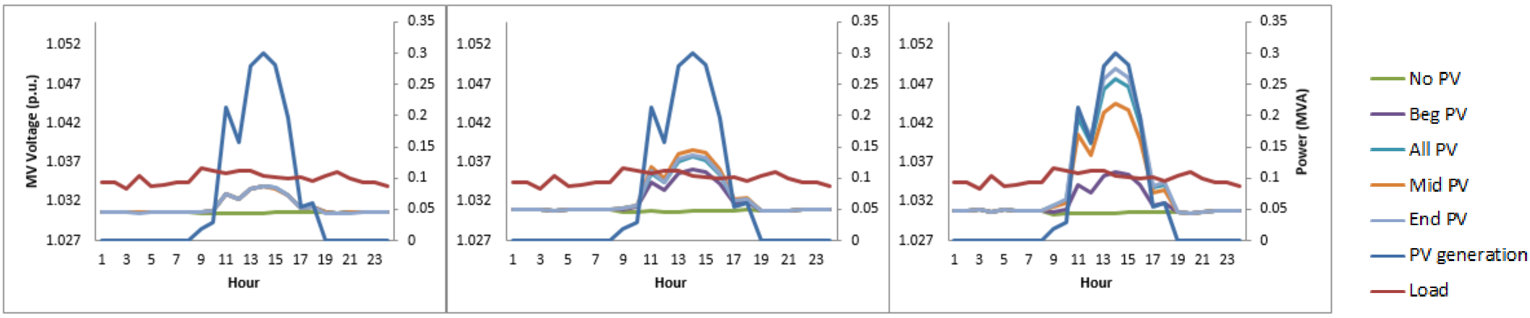


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 71: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

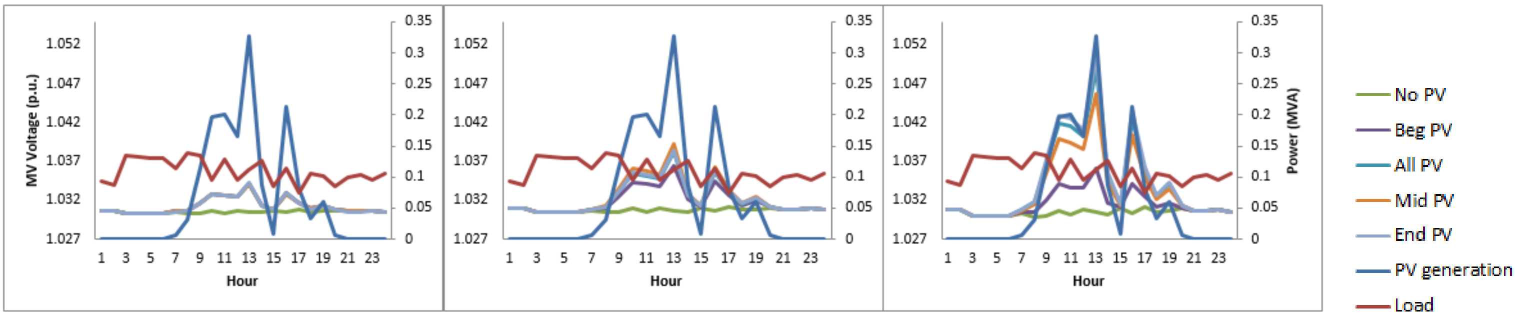


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 72: Detailed results for 26 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 73: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A2.3. 50% PV penetration

The total capacity of PV installed on the network for this case was 674.68kW. The most important results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, for the whole year is tabulated in Table 17 recorded for the year. Furthermore, the MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 74.

There are voltage violations being experienced in all cases except when PV is installed only at the beginning of the network.

Table 17: Summary of results for 2019 in the PV penetration case of 50% of peak load

Scenario	No. of times MV voltage >1.05p.u.	No. of times LV voltage >1.10p.u.
No PV	0	0
All PV	1682	0
Beg PV	0	0
Mid PV	1048	0
End PV	1964	0

APPENDIX A

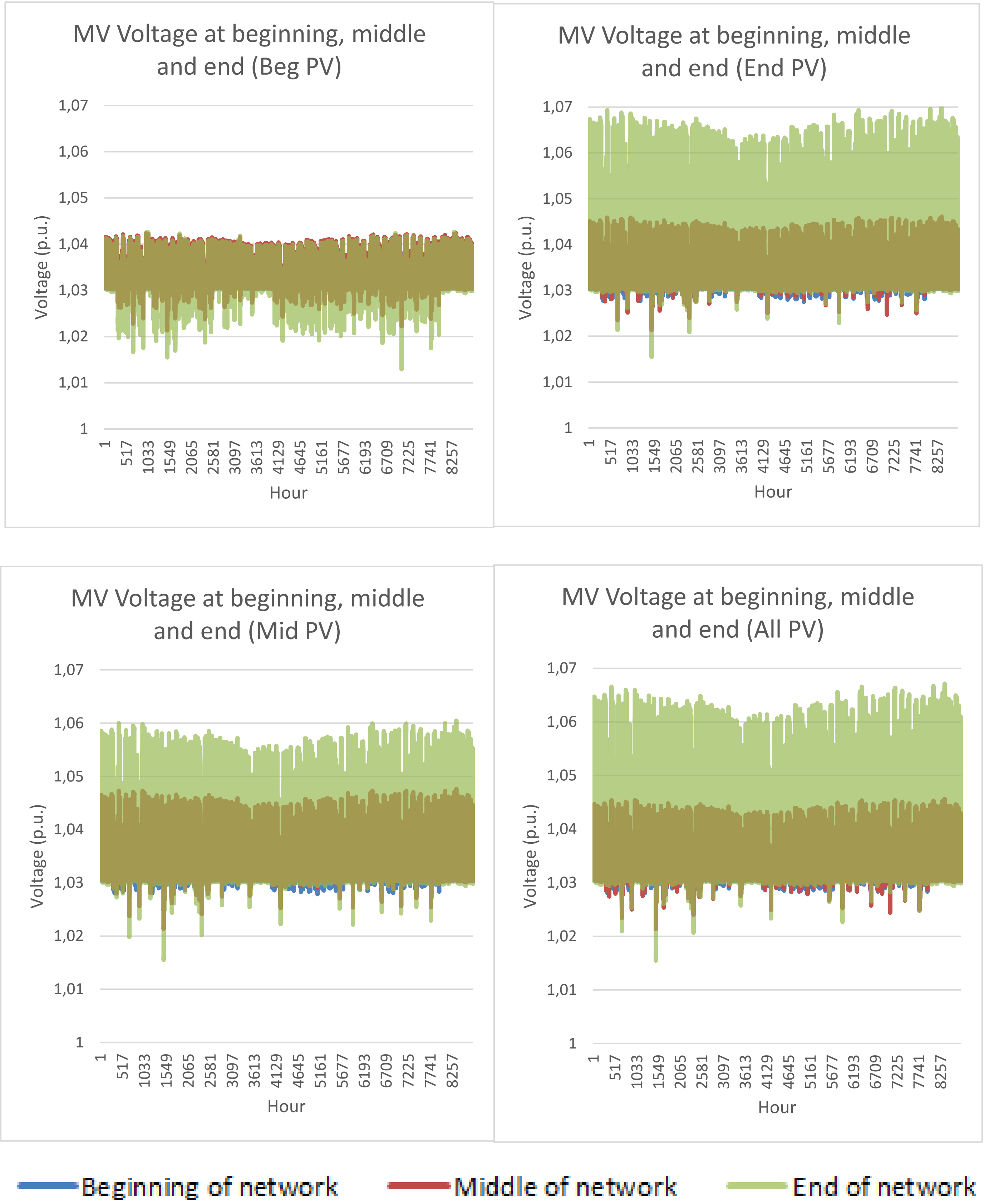
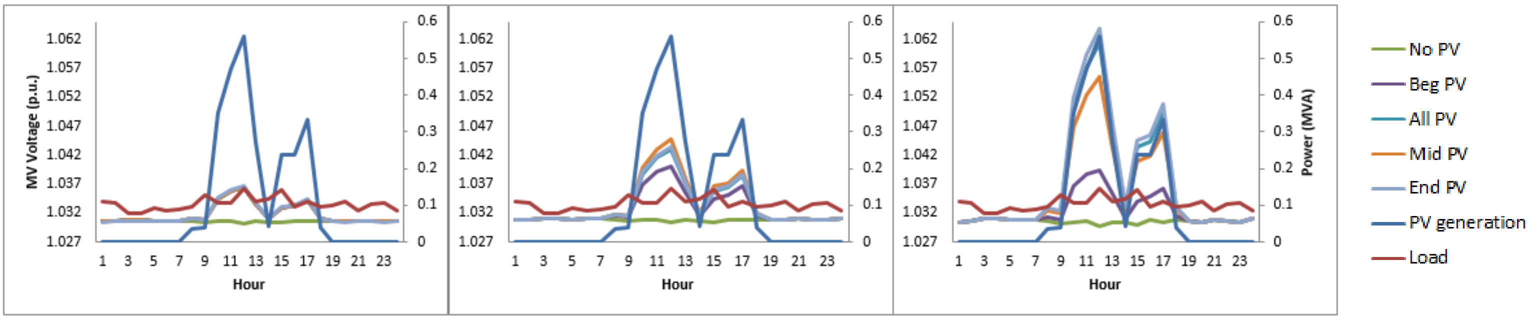


Figure 74: MV p.u. voltage for 50% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV case (End, Beg, Mid, All and No PV) in the 50% penetration case is illustrated in Figure 75 – 80 below. These figures highlight the impact of ramping phenomenon caused by intermittency in the PV plants.

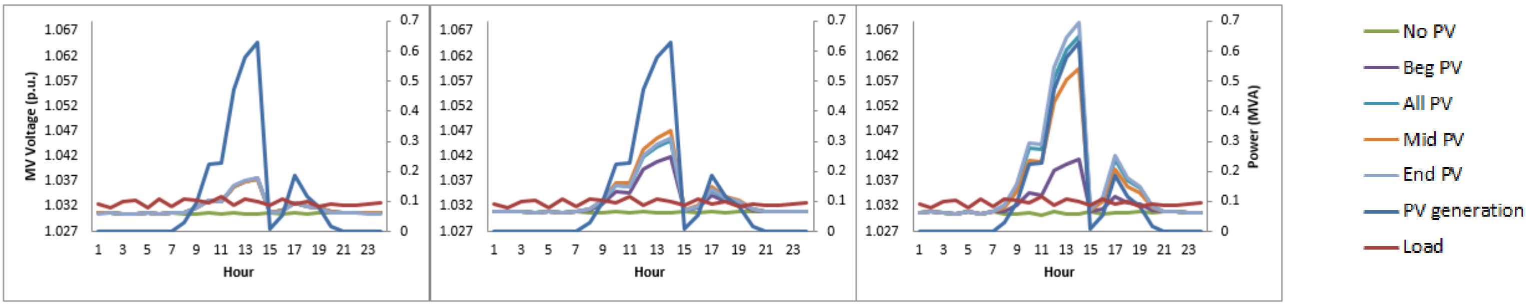


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 75: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

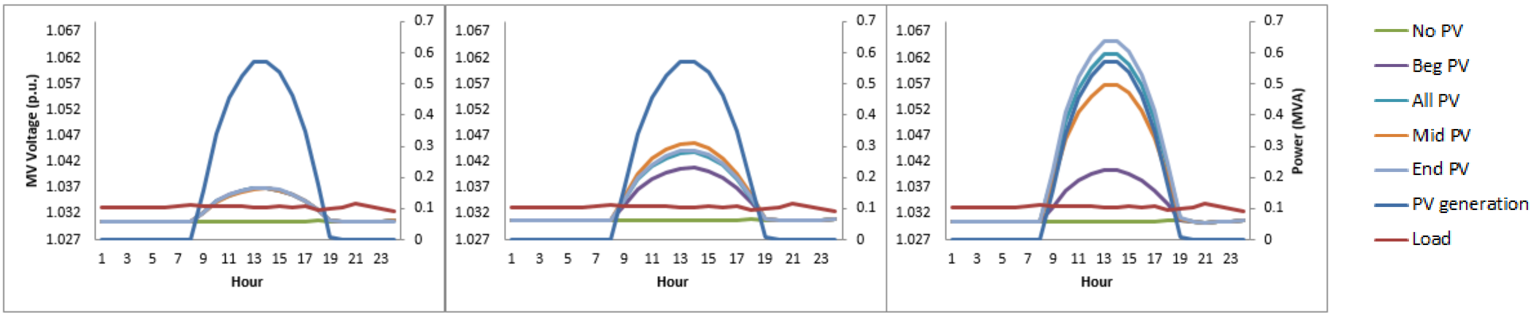


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 76: Detailed results for 2 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case



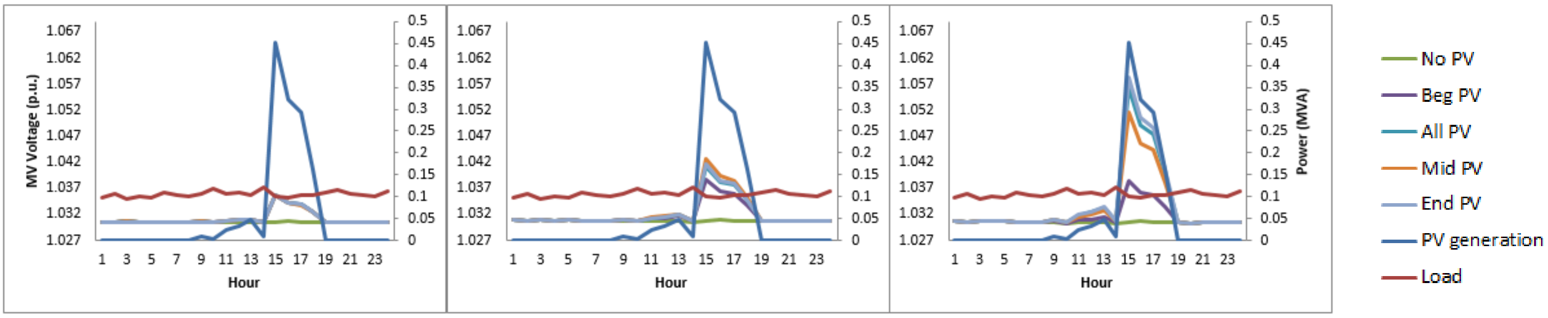
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 77: Detailed results for 27 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A

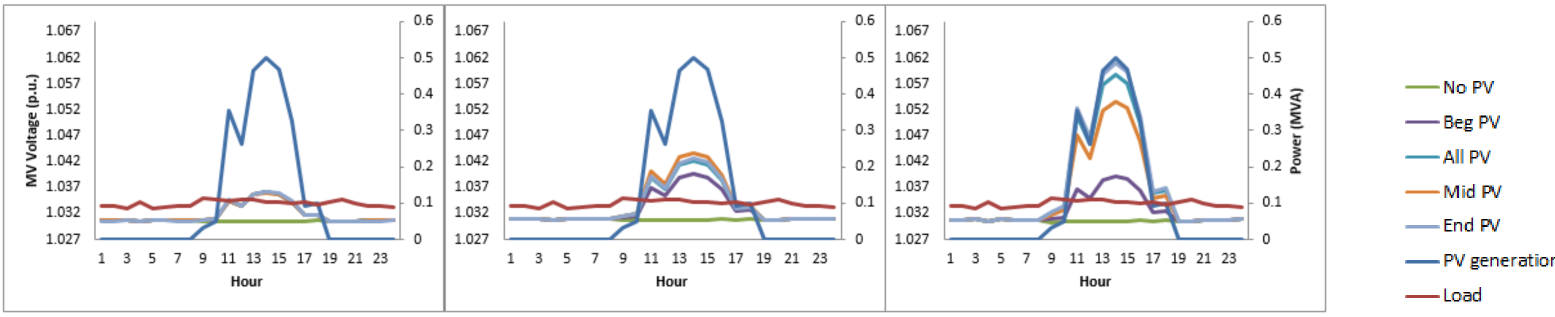


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 78: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case

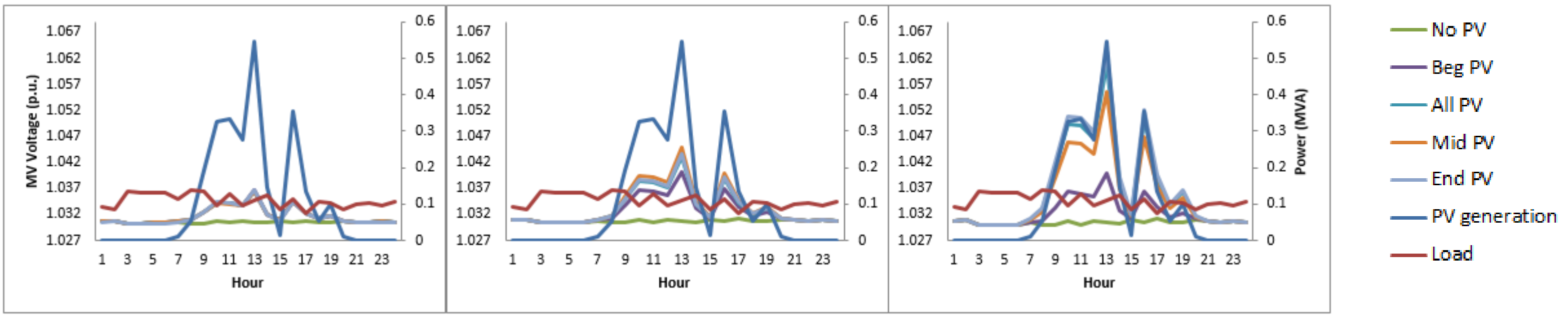


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 79: Detailed results for 26 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 80: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

A2.4. 75% PV penetration

The total capacity of PV installed on the network for this case was 1012.02kW. The most important results for this scenario are detailed below. The number of times the voltage exceeds limits as specified in NRS048-2, or overvoltage instances, for the whole year is tabulated in Table 18. The MV voltage recorded for the whole year in the All PV, Beg PV, Mid PV and End PV scenario's is illustrated in Figure 81.

This PV penetration results in voltage rise and overvoltage violations for all cases except when PV is installed only at the beginning of the network.

Table 18: Summary of results for 2019 in the PV penetration case of 75% of peak load

Scenario	**No. of times MV voltage >1.05p.u.**	**No. of times LV voltage >1.10p.u.**
No PV	0	0
All PV	2936	0
Beg PV	0	0
Mid PV	2933	0
End PV	3158	0

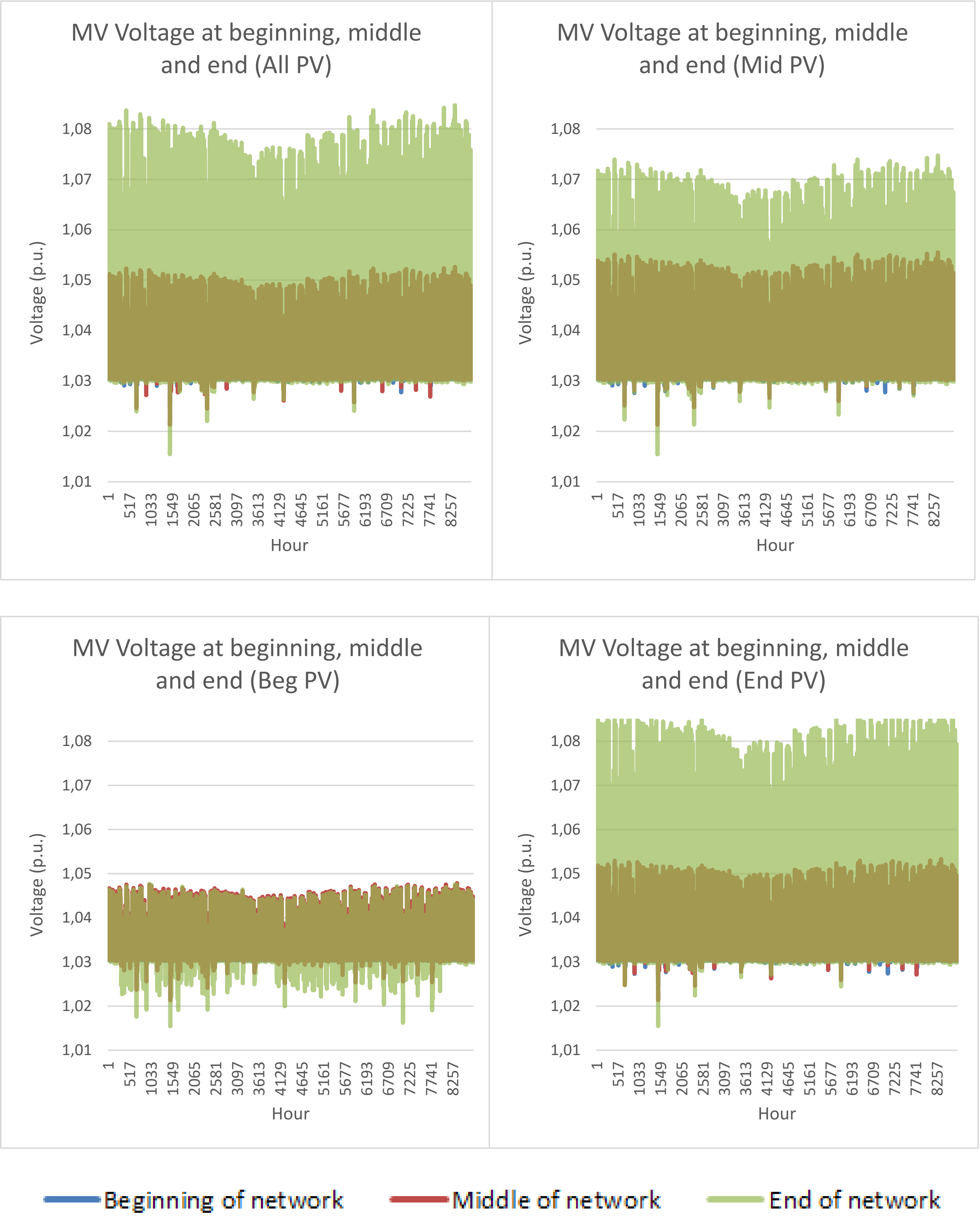
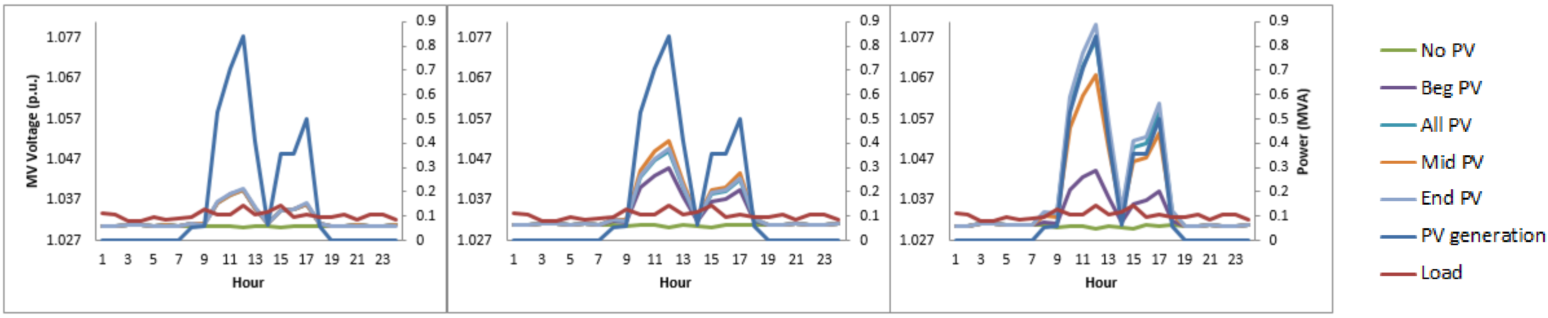


Figure 81: MV p.u. voltage for 75% penetration installed at beginning, even, middle and end of network PV cases

APPENDIX A

Detailed results for the 6 selected days in terms of MV voltage at beginning, middle and end of the network for each PV case (End, Beg, Mid, All and No PV) in the 75% penetration case is illustrated in Figure 82 – 87 below. These figures highlight the impact of ramping phenomenon caused by intermittency in the PV plants.

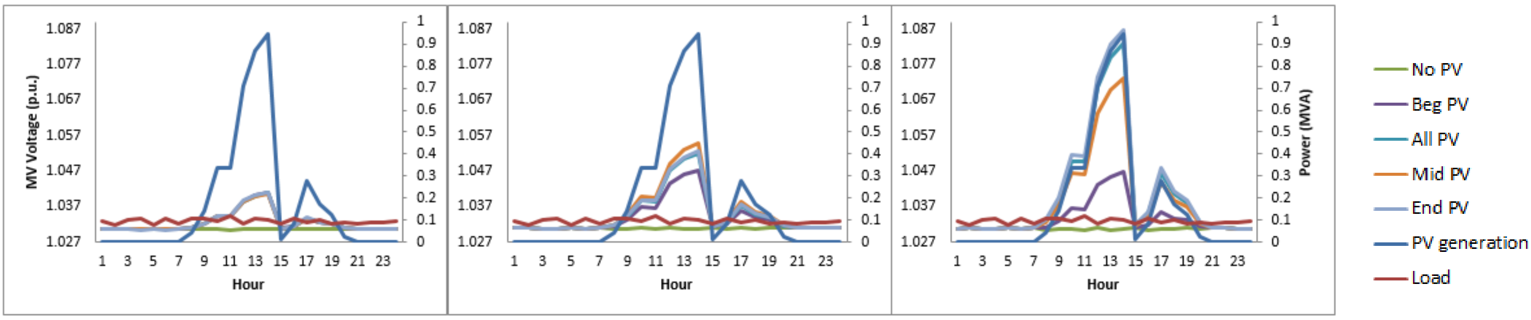


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 82: Detailed results for 1 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case

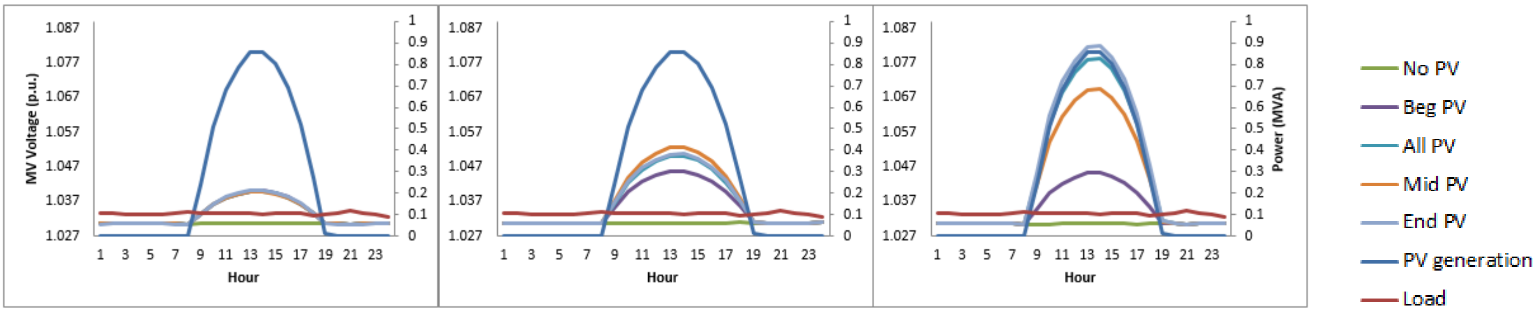


MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

Figure 83: Detailed results for 2 February showing MV voltage (beginning, middle and end) on the network and losses in each PV case



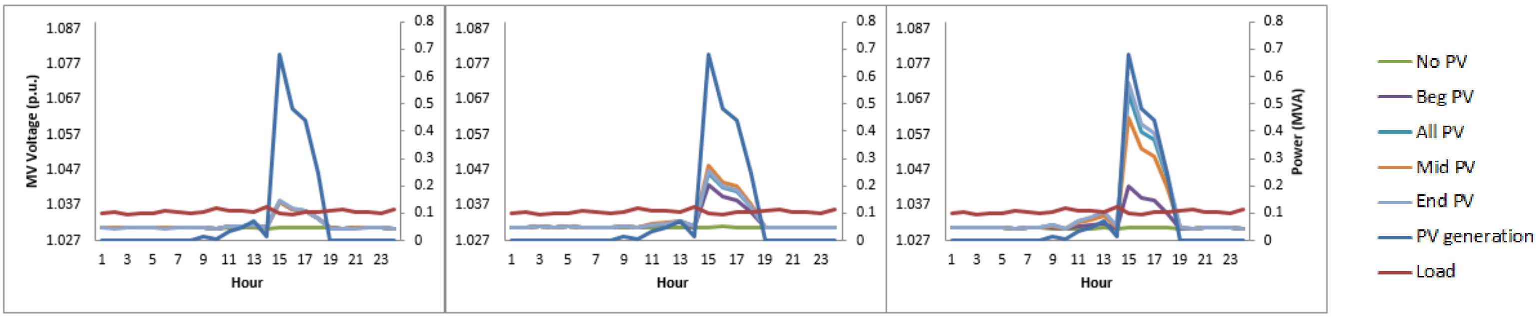
MV Voltage at Beginning of network

MV Voltage at Middle of network

MV Voltage at End of network

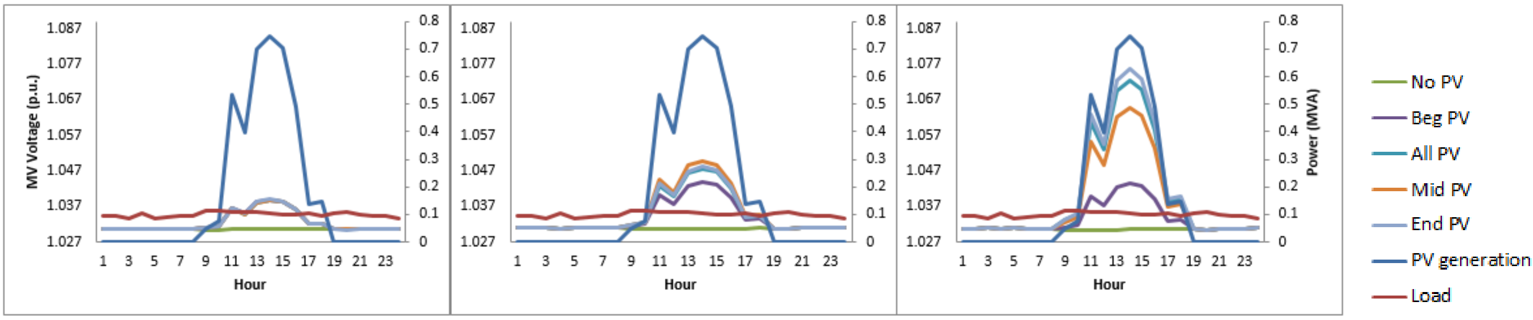
Figure 84: Detailed results for 27 April showing MV voltage (beginning, middle and end) on the network and losses in each PV case

APPENDIX A



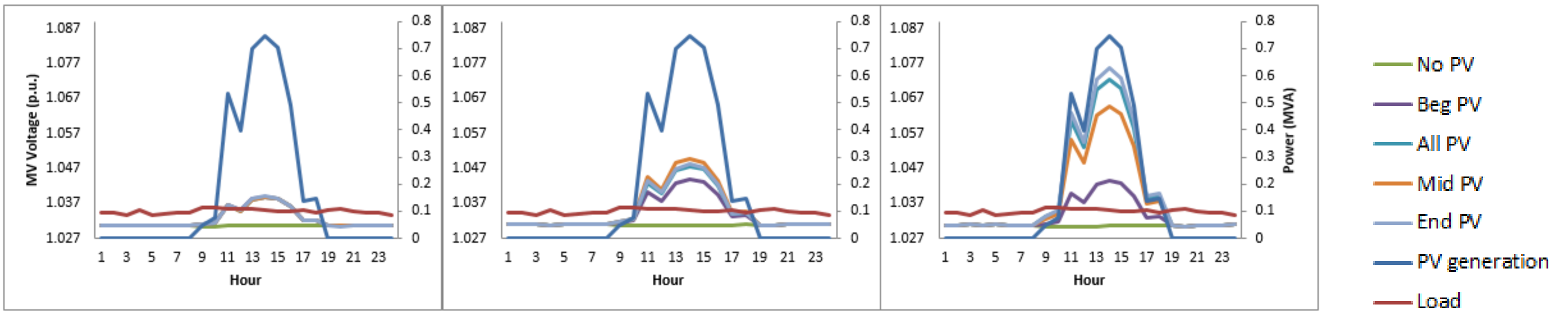
MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 85: Detailed results for 8 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 86: Detailed results for 26 May showing MV voltage (beginning, middle and end) on the network and losses in each PV case



MV Voltage at Beginning of network MV Voltage at Middle of network MV Voltage at End of network

Figure 87: Detailed results for 30 December showing MV voltage (beginning, middle and end) on the network and losses in each PV case

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