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Voltage regulation by means of storage device in LV feeder using OpenDSS interfacing with MATLAB

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Abstract

Abstract in italiano

Il presente lavoro di tesi ha riguardato l’analisi della regolazione della tensione nelle reti di distribuzione in bassa tensione e, in particolare, il caso in cui vi sia la presenza di generatori da fonte rinnovabile (generatori solari). Lo scopo della tesi è di studiare le cause dell’abbassamento /innalzamento della tensione e di introdurre una metodologia di controllo della tensione basata sull’utilizzo di sistemi di accumulo. La reti di distribuzione è stata modellizzata utilizzando il software OpenDSS mentre l’algoritmo di controllo è stato implementato in MATLAB. L’interfaccia tra i due software è stata realizzata tramite l’utilizzo di common object model (COM). I risultati ottenuti mostrano come, controllando opportunamente il sistema di accumulo, si possa raggiungere l’obiettivo della regolazione della tensione.

Abstract in inglese

This study presents an analysis of voltage regulation in low voltage distribution feeder and evaluates how the feeder’s voltage is affected when the feeder has PV connected. The aim of this thesis is to represent the reason of voltage rise/drop problem and introduce different solution options to regulate voltage, focusing on a storage control algorithm. The distribution feeder is built in OpenDSS software and the control algorithm is carried out by MATLAB. Indeed, the common object model (COM) interface capability of OpenDSS is used to interface with MATLAB to observe the effect of the proposed control in the power grid. Our results show that by applying energy storage control algorithm illustrated in the literature, the maximum and minimum of critical bus voltages can be controlled and network losses can be minimized.

1 A review of distributed PV generation and its integration into the grid

1.1 Growth of Renewable Energy in the Europe

Generation from renewable energy sources (RES) is increasing in response to economic, political and environmental reasons. According to the European Directive 2009/28/EC on the promotion of the use of energy from renewable sources, European Commission set mandatory targets “EU climate and energy package” (the so-called 20-20-20 package) as: (1) reducing EU greenhouse gas emissions by 20 %; (2) increasing the share of renewable energy to 20 % of consumption by 2020; (3) improving the EU's energy efficiency by 20 % by 2020 [1]. In 2014 the targets revised to 2030 Climate and Energy Policy as: (1) at least 40 % domestic reduction in greenhouse gas emissions by 2030 compared to 1990; (2) at least 27 % share of renewable energy consumed in the EU in 2030; (3) at least 27 % is set for improving energy efficiency in 2030 compared to projections of future energy [2].

In the year 2014, 25.4% of the produced energy in Europe came from renewable resources from different technologies including hydropower, wind, biomass, solar and etc. [3]. The installation of smaller and distributed power plants has been made possible due to changes in both the power system concept and the economy of scale. The distance between production and consumption has now become a vital factor compared to the past [4], so distributed generation (DG) technologies have advanced greatly in recent years.

The photovoltaic (PV) systems is growing due to falling PV system prices, increasing electricity prices and continues to increase in both market and investment share. From 2008 to the second quarter of 2014, generated electricity from residential PV systems prices decreased by over 70 % in the markets [2]. Local PV storage systems emerging in Germany as PV feed-in tariffs have dropped below electricity prices for households [5]. It means that nowadays, PV systems reached market parity.

Nowadays, self-consuming locally produced PV power is more beneficial than injecting it into the grid regarding grid concerns. Since, in self-consumption mode, only a small portion of generated power is injected to the grid and hence voltage rise compared to stand-alone PV systems without self-consumption is smaller.

Due to the difference of PV generation and load profile patterns, there is only a certain amount of time that these two profiles overlap and thus self-consumption is achievable. However, self-consumption can be increased using electricity storage systems [6].

According to the European Commission Joint Research Centre report [2], PV generation capacity in Europe reached 88.4 GW by the end of 2014 exceeding 2020, 84.4 GW target.

Support schemes for photovoltaics differ substantially from country to country. Fig. 1 shows power production in Italy from early 1963 and the nationalization of electricity sector to 2008, the year with booming increment in RES production. Italy and Germany connected 18 GW and 34.8 GW PV till the end of 2013 respectively [7], [8] (Fig. 2). According to the Italian national grid operator TERNA statistics, electricity generated from PV systems provided 21.6 TWh or 6.5 % of the total generated capacity in 2013 [9].

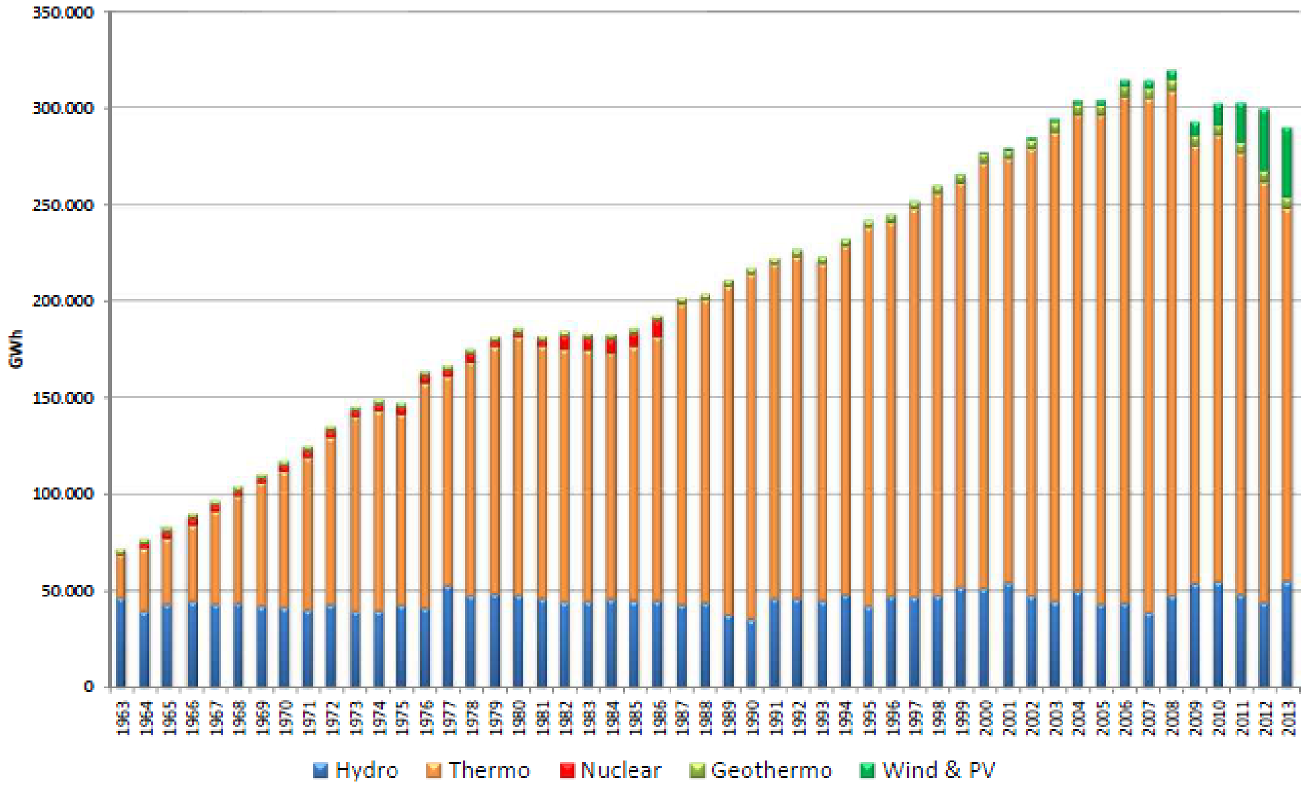


Figure 1 Production of power plants in Italy 1963 – 2013 [9]

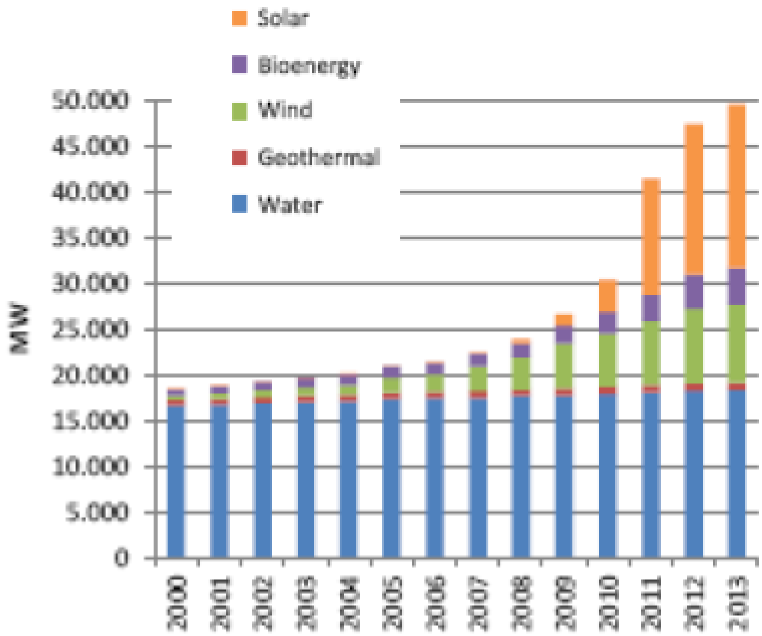


Figure 2 RES capacity trend in Italy [9]

1.2 Traditional Power Systems

Supply of electricity requires networks, where electricity is injected or retrieved. Power systems were traditionally planned and designed assuming unidirectional power flows from power plants to loads. It can be divided into subsystems as: generation; transmission; distribution system and load. (Fig. 3)

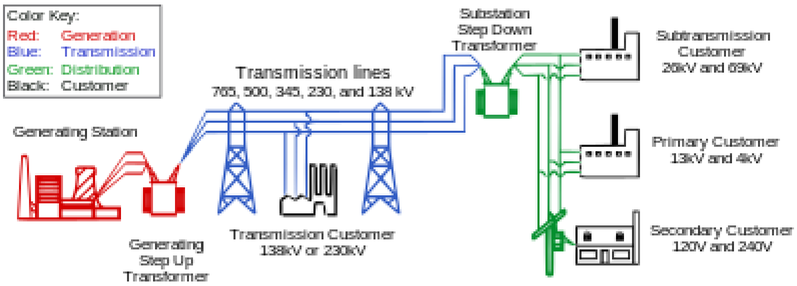


Figure 3 structure of power systems

The generated power is transmitted over long distances through the transmission system. Transmission network is designed in meshed to guarantee a high level of security.

In Italy, the transmission system transfers electricity at extra high voltage (EHV, 380-220 kV) and high voltage (HV, 150-132 kV) through 63.500 kilometers of lines. The transmission lines, centrally controlled by the Transmission System Operator (TSO) named TERNA [9]. In addition, distribution system make the delivery of electricity to users possible by: medium voltage (MV, 15 - 20 kV) network and low voltage (LV) network (400 V 3-phase supply; 230 V 1-phase supply). The distribution system is almost entirely passive with little communication and only limited local controls.

Finally, all the previous subsystems in a power system are called to meet the demand, which in 2014 the net electricity demand in Italy was 309 TWh with 51.6 GW peak power (installed: 120 GW) [9]

1.3 Smart Grid and Active Distribution Network

The smart grid could not be defined as a single clear definition [10]. EPRI (Electric power research institute) defines the Smart Grid as a grid that “incorporates information and communications technology into every aspect of electricity generation, delivery and consumption in order to minimize environmental impact, enhances markets, improves reliability and services, reduces costs and improves efficiency [11]. The European Technology Platform [12] defines the Smart Grid as “an electricity network that can intelligently integrate the actions of all users connected to it, in order to efficiently deliver sustainable, economic and secure electricity supplies.”

Figure 4 representation of a Smart Grid [13]

CIGRE C6.11 defines active distribution networks (ADNs) which deal more with distribution systems than transmission system as [14]: “Active distribution networks have systems in place to control a combination of distributed energy resources (DERs), defined as generators, loads and storage. Distribution system operators (DSOs) have the possibility of managing the electricity flows using a flexible network topology. DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement".

There are generally two approaches when facing with network failures such as violating voltage constraints. One is solving the problem using network reinforcement, capacitor banks and tap changing. The other is through coordinated control of storages and DGs which rely more on remote communications such as ICT infrastructure [14].

DSOs should guarantee network security and power quality. Active management enables the DSO to maximize the benefit of both consumers and utilities and optimize the operation of DER. In the future smart grid paradigm, the consumers play an important role and even could be considered as the heart of the grid. They can act as active prosumers who can have a peer-to-peer negotiation with other actors.

1.3.1 Centralized vs decentralized control

In centralized scheme, a central controller will find an optimal solution reducing the operational costs considering constraints. Centralized approaches require significant investment in communications to collect information from every single component in the system. Therefore, the centralized solution is costly and sensitive to any single failure. Also, participants may not be willing to reveal private information such as their generation costs, utility costs function, and power consumption patterns [15]. In addition, the centralized control must be coordinated with the local control systems of each DER.

Due to large amount of shared information which lead to a computational burden, decentralized control scheme could be applied. [16]

To see whether centralized controls are still appropriate for voltage control, a possible solution is to move from the centralized operation paradigm to the decentralized one by subdividing the distribution system grid into several zones according to voltage sensitivity coefficients criteria [17]. In the context of decentralized approach, each area is independently controlled by its own controller which could be distributed energy storage systems (DESSs). This would reduce the computational burden regarding centrally collective information.

1.3.2 Microgrid

One way to insert DG systems into an electrical network is through microgrids [18]. Microgrids are LV distribution networks comprising DG, storage devices and controllable loads that can operate either interconnected or isolated from the main distribution grid as a controlled entity (Fig. 5). “From the grid’s point of view, a microgrid can be regarded as a controlled entity in the power system that can be operated as a single aggregated load. From a customer point of view, Microgrids similar to traditional LV distribution networks, provide electricity and enhance reliability and improve power quality”. [19]

The operation of a microgrid offers distinct advantages to customers and utilities, i.e., improved energy efficiency, reduced environmental impact and greater reliability. One of the most important features of microgrids is the ability to independently operate in islanded mode without connection to the distribution system during power system faults or blackouts.

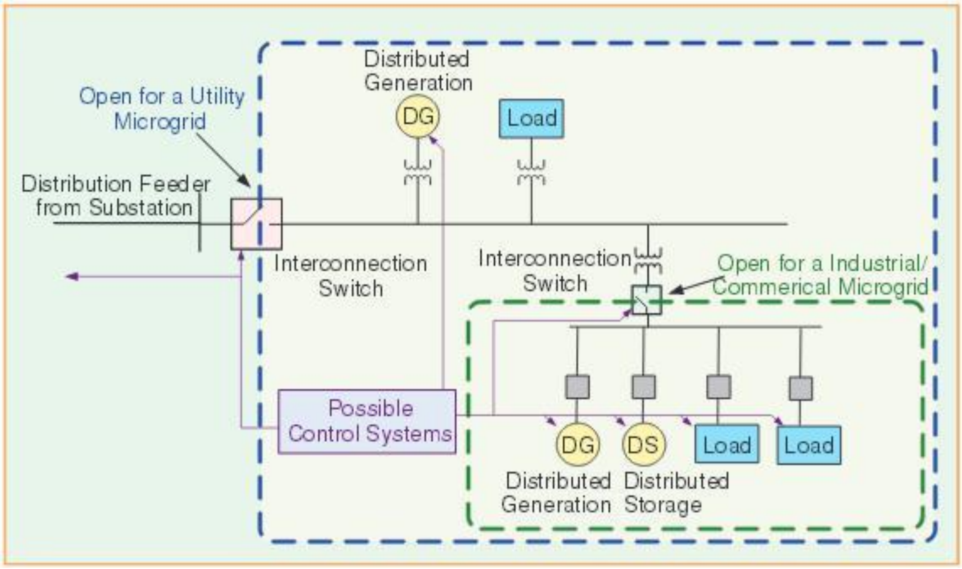


Figure 5 Microgrid Structure

1.4 Distributed PV Generation in Distribution Systems

The International Energy Agency (IEA) defines DG as an electric power generation within distribution networks or on the customer side of the network serving a customer on-site, or providing support to a distribution network [20]. CIGRE also give a definition with the following characteristic: not centrally planned and not centrally dispatched (this is the case of today but may change in future), usually connected to the distribution network and smaller than 50 or 100 MW [20]. Distributed generation technologies may be renewable or not. DG should not to be confused with renewable generation. Non-renewable DGs include internal combustion engine (ICE), combined heat and power (CHP), micro turbines and fuel cells.

1.4.1 benefits of distributed PV generation

Properly planned DG can provide both economic and technical benefits to the owner and system operator. Detailed analysis of benefits associated with photovoltaics (PVs) and generally distributed generations can be found in [21]. In summary:

- Enhancement in system reliability.
- Reduction in the power delivery costs (line losses).
- Provision of local voltage improvement and reactive power support.

1.4.2 Problems with distributed PV generation

High penetration of PV generation can cause also challenges on grid operation. some of the problems are as follow:

- Reverse power flow problem [22].
- Mis-operation of protection devices which leads to possible islanding.
- Increase in voltage unbalance due to uneven distribution of single phase PV units [23].
- Power quality deterioration: power electronic interfaces, can cause harmonic distortion, causing thermal and insulation stress and telephone interference.

1.5 Electric Vehicles (EVs)

In the long-term, EVs are important for countries seeking to decarbonize the transport sector. Following the electric vehicles initiative (EVI) which is a multi-government policy dedicated for accelerating the adoption of electric vehicles worldwide, in 2012 there were more than 180,000 stock of electric vehicles around the world. Europe and Italy have the share of 11 % and 0.9 % respectively (Fig. 6) [24].

EVs can be classified as follow: [24]

- Battery electric vehicle (BEV): An all-electric vehicle propelled by an electric motor powered by energy stored in an on-board battery.
- Hybrid electric vehicle (HEV): A vehicle that combines a conventional internal combustion engine (ICE) propulsion system with an electric one.
- Plug-in hybrid electric vehicle (PHEV): A hybrid electric vehicle with a high-capacity rechargeable battery that can use electricity as its primary propulsion source. The internal combustion engine typically assists in recharging phase of the battery or serves as a back-up.
- Fuel cell electric vehicle (FCEV): A vehicle that runs based on a fuel cell that generates an electrical current by converting the chemical energy of a fuel, such as hydrogen, into electrical energy.

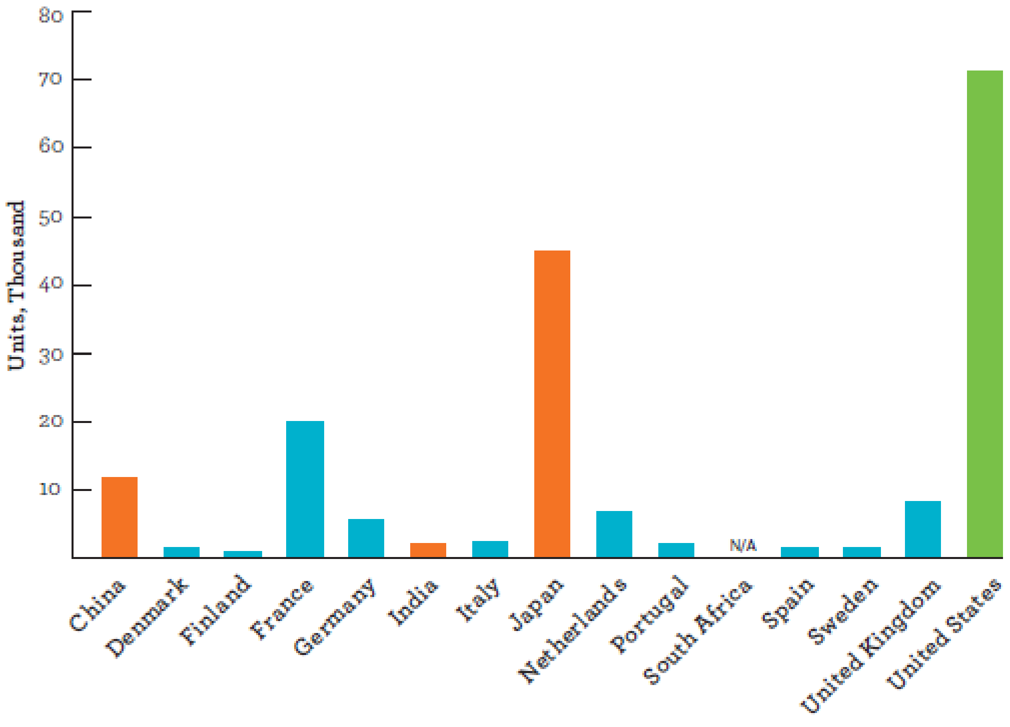


Figure 6 stock in EVI countries

1.5.1 Main challenges related to EVs

EVs will store energy, when plugged to the electric grid in a grid-to-vehicle mode (G2V). EV battery charging will increase the load demand, mostly in the peak hours. This behavior (called “dumb charging”), will cause thermal stress of distribution transformers and power line losses.

The stored energy could also deliver back to the grid during the parking hours in a vehicle-to-grid mode (V2G). Battery of EVs can charge during low demand times and discharge during peak times, when power is needed. [25]

EV’s impact on distribution system depend on vehicle, battery characteristics and battery charging and recharging frequency. Battery will degrade due to bidirectional applications and frequent charging and discharging. Coordinated smart charging and discharging minimizes EV impact on the grid [26]. EV with V2G-capablity can also provide reactive power support [27], active power control and peak load shaving [28].

Each vehicle can be treated individually or as part of an aggregation. Aggregators collect EVs into a group to create larger and more manageable loads [29].

2 Voltage rise problem

2.1 Background of the Problem

Times with high PV generation and low load demand, leads to the problem of reverse power flow in the LV residential feeder which then subsequently lead to over-voltage problem (Fig. 7). [30]

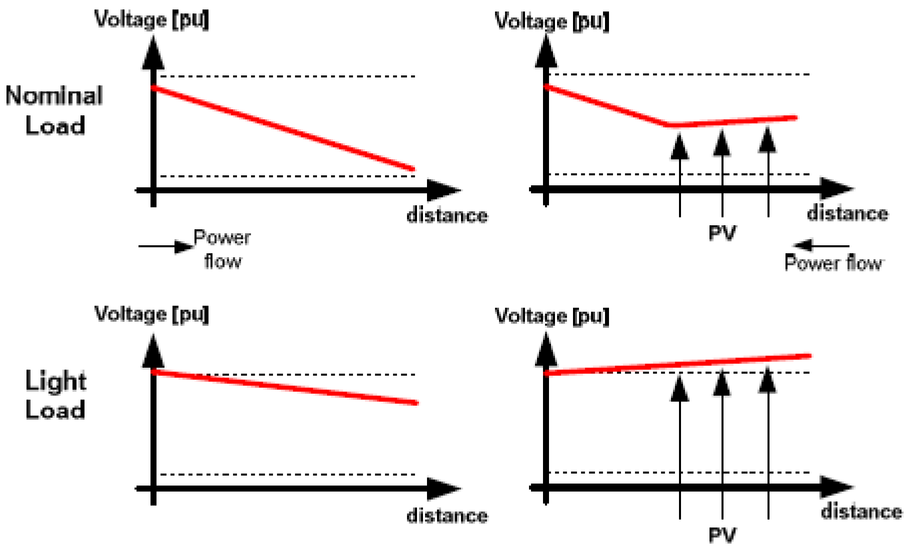


Figure 7 Typical voltage profile in a LV feeder. Second column shows the voltage profile with PV penetration [30]

Simple result is to put a limitation on the amount of PV that can be installed on LV feeders. For instance, German power system operator limits the permissible voltage increase on the LV level due to distributed generation to 0.02 p.u. [31].

In overvoltage study, the residential feeders are considered as a critical case regarding overvoltage problem due to their characteristics [32]. The load profile of residential feeders shows a peak value during evening in the absence of PV generation. However, the commercial and industrial feeders load profiles have a good correlation with the PV power profile, which tends to reduce the possibility of overvoltage. So, the focus should be on residential feeders to evaluate the potential risks of DG integration. (Fig. 8)

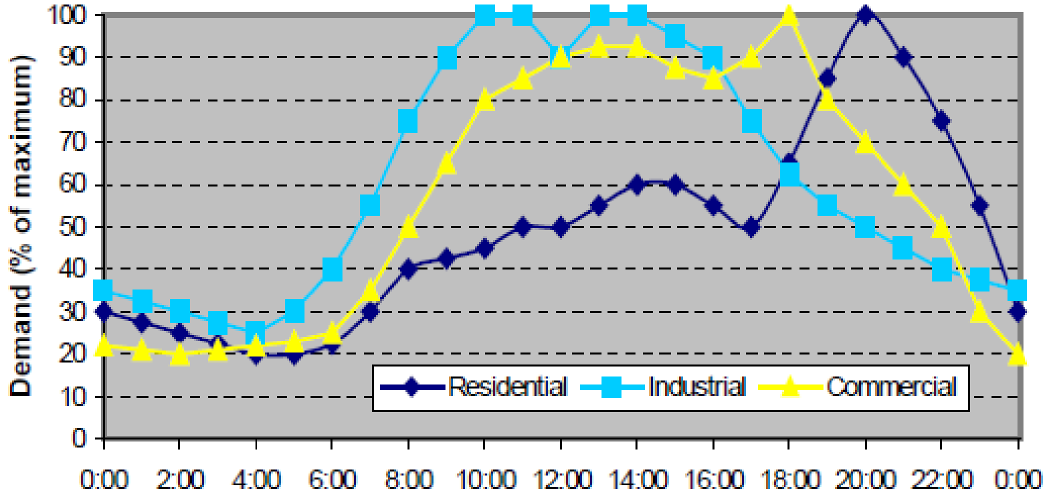


Figure 8 Residential, industrial and commercial load profiles [33]

In addition, there is more possibility for overvoltage problem in rural feeders, due to their length which increases the impedance value [32]. In analyzing the overvoltage issue, the effect of substation transformer's short circuit resistance and the feeder layout must also to be considered. [32] shows that the voltage rise rate is higher when the transformer has larger resistance. So, reducing the transformer short circuit resistance make system's efficiency higher and the possibility to incur a voltage rise problem lower.

2.1.1 Voltage rise and drop concept

2.1.1.1 Phasor interpretation

Fig. 9 shows a typical radial distribution feeder with N customers. Each customer comprises a PV source, an ESS and an AC load, which are connected to the corresponding bus. The buses will face voltage rise/drop based on the power flow [34].

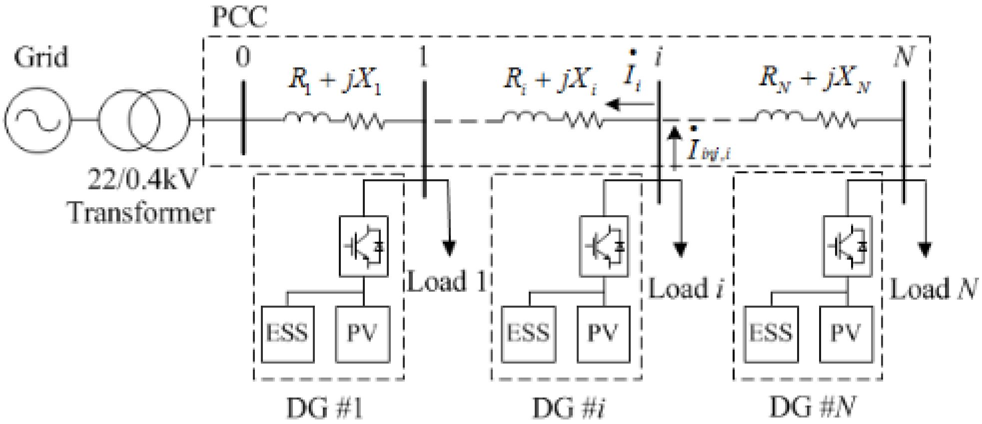


Figure 9 Radial distribution feeder [34]

- Convention: The power injection of DGs and absorption of the loads are defined as positive and negative values respectively.

The complex power injected/absorbed at the i th bus is:

$$S_i = (P_{DG,i} - P_{L,i}) + j(Q_{DG,i} - Q_{L,i}) \tag{1}$$

where $P_{DG,i} + jQ_{DG,i}$ and $P_{L,i} + jQ_{L,i}$ are the complex power of the DG unit and the load at the i th bus respectively. Using power flow analysis, the current flow $\dot{I}_i$ and voltage relationship between $(i-1)$th bus and i th bus can be expressed as:

$$S_i = \dot{V}_i \cdot \overset{*}{I}_{inj,i} \tag{2}$$

$$\overset{*}{I}_i = \sum_{k=i}^{N} \overset{*}{I}_{inj,n} = \sum_{k=i}^{N} \frac{S_n}{V_n} \tag{3}$$

$$\dot{V}_i = \dot{V}_{i-1} + \dot{I}_i (R_i + jX_i) \tag{4}$$

where $\dot{V}_i$ and $\overset{*}{V}_i$ are the voltage vector and its conjugate at the i th bus respectively, $(R_i + jX_i)$ is the impedance between $(i-1)$th bus and i th bus. The phasor diagram representation is shown in Fig. 10.

Fig. 10 (a) shows phasors of powers in distribution network in high PV generation. In Fig. 10 (b), the current flows from customers to the grid and causes voltage rise between two adjacent buses. The condition is opposite during the high demand period. Each customer absorbs power from the distribution network as shown in Fig. 10 (c). In Fig. 10 (d), the current flows from grid to the customers which lead to voltage drop between two adjacent buses. The dash line shows the possible operating ranges of DG units and loads. [34]

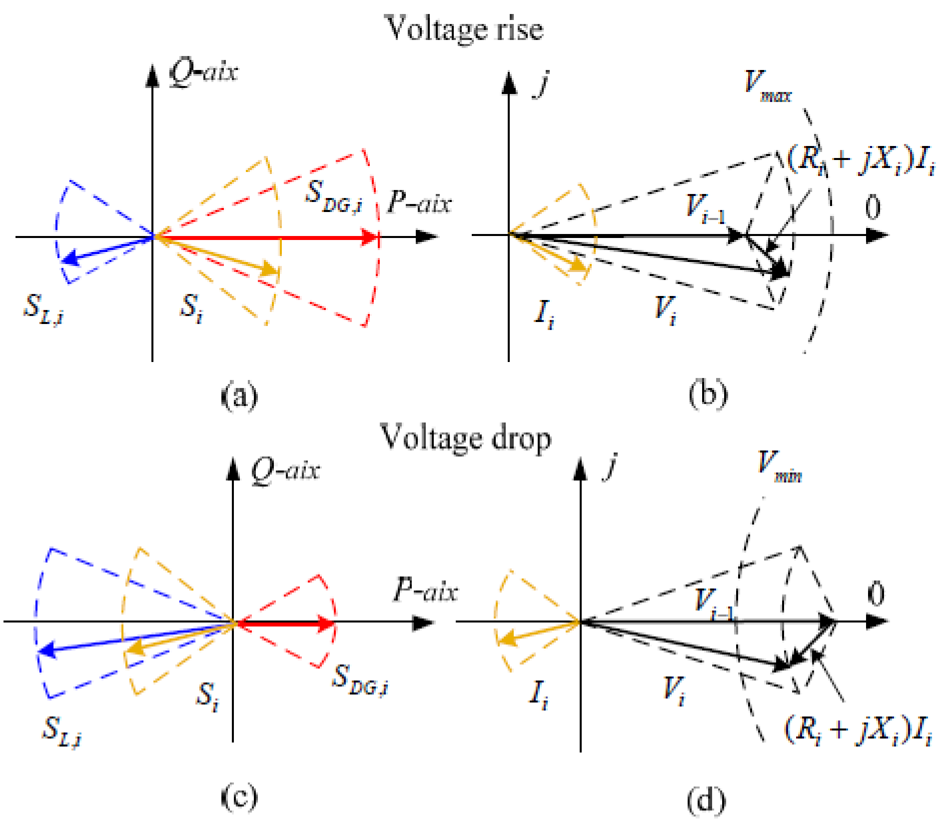


Figure 10 Voltage rise and drop issues. (a) Power injection at peak PV generation period. (b) Voltage rise issue. (c) Power absorption at peak load period. (d) Voltage drop issue. [34]

2.1.1.2 A comparison in addition to the interpretation

a) Voltage variation in conventional distribution network

In passive networks with radial configuration, the flow of power is always from the higher to lower voltage levels. The amount of voltage drop can be calculated from the analysis of two-bus distribution system as shown in Fig. 11. DS and OLTC stand for the distribution systems and on-load tap-changer respectively. V_S is the sending end voltage, V_R is the receiving end voltage, P and Q are the real and reactive power flowing through the distribution network to the customers. P_L and Q_L are the real and reactive power of the load. The voltage at the sending end can be written as

$$\dot{V}_S = \dot{V}_R + \dot{I}(R + jX) \tag{5}$$

Where $\dot{I}$ is the phasor representation of the current flowing through the line. The power supplied from the distribution system can be written as

$$P + jQ = \dot{V}_S \overset{*}{I} \tag{6}$$

Therefore, the current flowing through the line can be written as

$$\dot{I} = \frac{P - jQ}{\overset{*}{V}_S} \tag{7}$$

By using the value of $\dot{I}$, the sending end voltage can be expressed as

$$\dot{V}_S = \dot{V}_R + \frac{P - jQ}{\dot{V}_S}(R + jX) = \dot{V}_R + \frac{RP + XQ}{\dot{V}_S} + j\frac{XP - RQ}{\dot{V}_S} \tag{8}$$

Therefore, the voltage drop between the sending end and receiving end can be written as

$$\Delta V = \dot{V}_S - \dot{V}_R = \frac{RP + XQ}{\dot{V}_S} + j\frac{XP - RQ}{\dot{V}_S} \tag{9}$$

Since the angle between the sending end voltage and the receiving end voltage is very small, the voltage drop is approximately equal to the real part of the voltage drop [35] and if the sending end bus is considered as reference bus, the angle of this voltage is assumed to be 0. Therefore, the above equation can be approximated as

$$\Delta V \approx \frac{RP + XQ}{V_S} \tag{10}$$

If the sending end voltage of the system as shown in Fig. 11 is considered as the base voltage, then V_S can be assumed as unity. Therefore, equation (10) can be written as follows [36]

$$\Delta V = RP + XQ \tag{11}$$

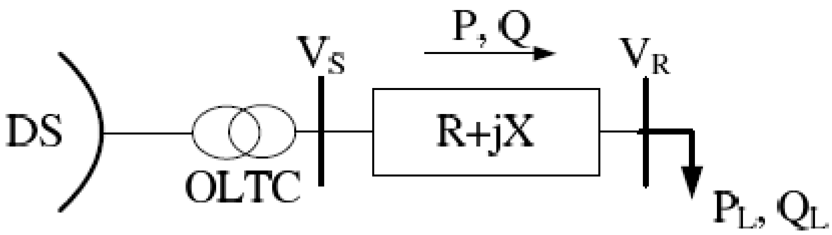


Figure 11 Conventional 2 bus distribution system [36]

b) Voltage variation in distribution networks with DG

When generators are connected to the distribution system, the power flow and the voltage profiles are affected as well as the system is no longer passive but active. In this case, the receiving end voltage V_R will be

$$V_R \approx V_S + RP + XQ \tag{12}$$

As the direction of the power flow is reversed. Thus, the voltage at the point of connection of the generator will rise above the sending end voltage which can be clarified through Fig. 12. P_G and Q_G are the generated active and reactive power, respectively, by the DG. P_L and Q_L are the active and reactive power of the load respectively and Q_C is reactive power of the shunt compensator. This DG with load and compensator is connected to the distribution system (DS) via overhead distribution line with impedance $R + jX$ through OLTC. The voltage rise along the distribution network as shown in Fig. 12 can be written as follows:

$$\Delta V = V_{GEN} - V_S \approx \frac{RP + XQ}{V_{GEN}} \tag{13}$$

where, $P = P_G - P_L$, $Q = (\pm Q_C - Q_L \pm Q_G)$. If V_{GEN} is expressed in terms of per unit, then equation (13) can be written as

$$\Delta V \approx R\ (P_G - P_L) + X\ (\pm Q_C - Q_L \pm Q_G) \tag{14}$$

The generators always export active power P_G and may export or import reactive power $\pm Q_G$, whereas the load consumes both active $-P_L$ and reactive $-Q_L$ power and the compensators may export or absorb only reactive power $\pm Q_C$. [36]

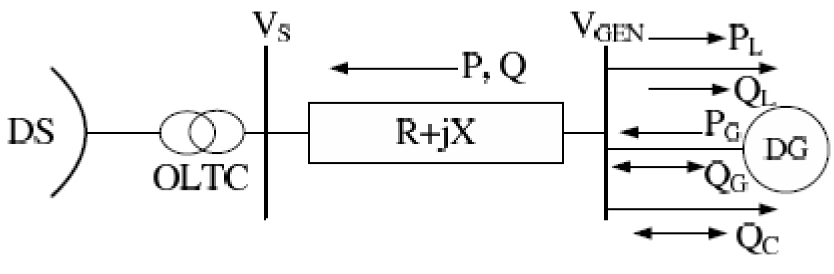


Figure 12 Two-bus distribution system with DG [36]

We assume the extreme conditions of minimum load ($P_L = Q_L = 0$), maximum generation ($P_G = P_{G,MAX}$) and unity power factor ($\pm Q_G \pm Q_C = 0$), the voltage at bus bar 2 (receiving end = bus bar 2, sending end= bus bar 1) which $V_{GEN} = V_2$ and $V_S = V_1$ becomes:

$$V_2 = V_1 + RP_G^{\max} \tag{15}$$

The size of generation that can be accommodated, without violating the network constraints, is thus limited by the maximum voltage at bus bar 2, as shown in the equation below:

$$P_G^{\max} \leq \frac{V_2^{\max} - V_1}{R} \tag{16}$$

It is important to observe that the real part of the network impedance (R) is critical for the DG capacity to be connected while the value of reactance (X) is not considered, as the generator operates with unity power factor. however, since the probability of this extreme situation (minimum load/maximum generation) is relatively low, it would be beneficial to accommodate a larger generation at bus bar 2, with the condition that generation is curtailed (P_G^{cur}) at the mentioned extreme conditions. The effect of curtailing generation under such circumstances is illustrated in eq. 17:

$$P_G^{\max} \approx P_G^{cur} + \frac{V_2^{\max} - V_1}{R} \tag{17}$$

As the generation curtailment typically occurs during off-peak periods, the price of this energy curtailed is relatively low.

Secondly, optimal management of reactive power can extend the amount of generation that can be connected. If reactive power, Q_{import} i.e. $-(\pm Q_G - Q_L \pm Q_C)$, is absorbed from the network, the maximum generation that can be connected can be increased as eq. 18:

$$P_G^{\max} \approx \frac{V_2^{\max} - V_1}{R} + \frac{Q_{import} X}{R} \tag{18}$$

It is important to observe that the effectiveness of reactive power import is greatly influenced by the value of the $\frac{X}{R}$ ratio. In this context, reactive compensation is considerably more effective on overhead networks (with typical reactance of $X_{OH} \approx 0.4\ [\Omega / km]$, than on cable networks (with typical reactance of $X_C \approx 0.1\ [\Omega / km]$. It should be noted that absorbing reactive power would lead to increase in losses.

Finally, control of voltage at bus bar 2 by regulating voltage V_1, at bus bar 1 using the OLTC can considerably increase the capacity of connected DGs. In this control option, the OLTC is used to lower voltage to the minimum value $V_1^{\min}$, enabling more injection of active power at bus bar 2:

$$P_G^{\max} \leq \frac{V_2^{\max} - V_1^{\min}}{R} \tag{19}$$

However, in a more complex network, the value of this voltage, and the corresponding tap position of the OLTC, would have to be optimized. These three methods of regulating voltage can be applied in combination. It should also be noted that reinforcing the system could also enhance the amount of generation that can be accommodated.

2.1.2 Traditional regulation approaches

DSOs usually focus on influencing impedance of the feeder Z by conducting grid reinforcements, such as new lines or replacing the substation's transformer. In distribution networks with unidirectional power flow, traditional approaches like incorporating on-load tap changing transformers (OLTC), switched capacitors (SC) and step voltage regulator (SVR) were put in place. OLTC is an autotransformer with automatically adjusting taps. At present, there are new solid state OLTC regulators which offer significant advantages of improved performance and reduced maintenance costs over traditional mechanical ones and they can provide more comprehensive control capability such as coordinated control with communication [37]. Like OLTC, SVR is also a tap changer based voltage regulator. Usually it is defined that the voltage regulator at the substation is an OLTC, and the one along the feeder is a SVR [38]. However, these devices do not provide fast enough voltage regulation in emergency conditions. Usually it takes about 10 seconds for the VR to move one tap [39].

In addition, for protection purposes, the DGs are usually fast (typically set to trip the DG within 2 seconds), if voltage level is more than 10% of nominal voltage. Hence, the VR cannot provide the quick voltage support needed to restore the voltages following a sudden disconnection of DG. For quick voltage support, a good alternative is to use DGs inherent capabilities [40].

The traditional control system of a tap changer based voltage regulator measures the voltage and load current, estimates the voltage at the remote point, and triggers the tap change when the estimated voltage is out of boundary [38]. Others have assumed the availability of voltage measurements from every node [41]. But this is rarely the case in existing rural distribution system. Acquiring the voltage measurements from electricity meters at the consumer side would be ideal, but very expensive. Even in the presence of smart meters which can provide load and voltage data from every customer nodes (as in, Italy [42]), these data are not available in the frequency that is required for voltage control. The highest data refresh rate currently available is 10 minutes in Italy [42], while for voltage control one need to have a data refresh rate in seconds.

State estimation (SE) based on real-time measurement along with pseudo-measurement is also proposed to determine the voltage level of the network [43]. Unlike the case of SE in transmission system, SE in distribution system, as in [44], lacks measurement redundancy which makes bad data detection impractical. However, to validate the results of the state estimation, the DSO can use an online voltage measurement data at one or more buses.

According to [45], most of the failures in the OLTC exist during the tap position switching since the load current is not interrupted at this moment. Therefore, the number of tap changing should be as minimum as possible. Increased number of operation of these components will reduce their lifetime. To solve this problem, many solutions have been proposed in recent years. For distribution networks with DG units and bidirectional power flow we get help from DG units for voltage regulation. [46] compared three control schemes including real power curtailment, reactive power compensation and area-based coordinated OLTC control. It concludes that by using the OLTC coordinated control, the highest revenue would be obtained. In order to relieve the tap changer operation stress and peak load shaving, [47] proposed a coordinated \control of distributed energy storage systems (ESSs) with tap changer transformers for voltage rise mitigation.

2.1.3 Voltage control strategies using PV inverters

2.1.3.1 Reactive power compensation

Reactive power compensation of distributed PV inverters has been developed for voltage regulation in many studies. The operation of PV inverters in non-unity power factor mode will reduce real power injection and allow reactive power absorption. Absorbing reactive power can be beneficial for controlling the voltage rise effect, especially in weak overhead networks. In this respect, the use of a reactive compensation facility, such as a STATCOM, at the connection point is discussed in [48].

[49] proposed a method which is not to control bus voltage but to guarantee that generator injection alone do not cause significant voltage rise. The advantage of [49] is that the voltage becomes independent of the generation and the DSOs can be kept to their traditional task of voltage regulation. However, this method requires information about the upstream feeder impedance resulting in a communicating need in case of feeder reconfiguration. In reference [50] there is also a method of reactive power control where inverters follow a continuously modification of their output active and reactive power by using the information which are exchanged between them.

However, the large R/X ratio in residential networks make this method less effective than in transmission networks since over-sized inverter is required to absorb reactive power. [30]

2.1.3.1.1 $\frac{R}{X}$ ratio effect

To estimate how much reactive power is needed for overvoltage prevention, we consider a simple two-bus system (Fig. 12) where the voltage rise at the end of the line with respect to that in the beginning of the feeder can be approximated by [51]:

$$\Delta V = \frac{PR + QX}{V} \tag{20}$$

Where P and Q are the active and reactive powers injected by a PV inverter. R and X are the resistance and reactance of the feeder. The PV inverter operates at unity power factor until the voltage reaches the maximum allowed value. From this point on, any increases in the injected power must be compensated with reactive power absorption. For the PV inverter operating with maximum power and unity power factor, maximum allowed voltage at the end of the feeder ($V_{\max}$) has:

$$\Delta V_1 = \frac{P_1 R}{V_{\max}} \tag{21}$$

To further increase the amount of injected active power to P_2 keeping constant the grid voltage ($\Delta V_1 = \Delta V_2$):

$$\frac{P_1 R}{V_{\max}} = \frac{P_2 R + Q_2 X}{V_{\max}} \tag{22}$$

Finally, the amount of reactive power required at the end of the feeder to keep the voltage constant at the maximum voltage allowed, for a certain increase in the injected active power ($\Delta P = P_2 - P_1$), as:

$$Q = -\Delta P \frac{R}{X} \tag{23}$$

From eq. 23, it is obvious that the higher the $\frac{R}{X}$ ratio, the higher the values of reactive power will be required to prevent overvoltage. So, requiring inverters with higher power capacity, will result in higher currents, and losses.

In order to analyze the impact of line characteristics on the effectiveness of reactive compensation for voltage improvement, [52] performed simulations to find the critical $\frac{R}{X}$ ratio of the distribution line for which reactive compensation can be effective for voltage improvement. Incremental line losses as well as line loading are calculated for different values of $\frac{R}{X}$ ratio using repeated load flow studies. Fig.13 shows the percentage of feeder loading level with the increase in $\frac{R}{X}$ ratio. With higher ratio ($> 4.5 - 5$), loading should be reduced to 70% of its peak value to keep the voltages in the acceptable range.

The incremental line losses, i.e. increase in the line losses when $\frac{R}{X}$ ratio increases from unity shows that losses are high for more resistive lines for same reactive injection. For $\frac{R}{X}$ ratio greater than 5, these losses are too high. Therefore, the effectiveness of PV inverters for voltage control is limited for higher $\frac{R}{X}$ ratio cases. For the urban case ($\frac{R}{X}$ ratio =1), the reactive capability of PV inverters is sufficient for the voltage improvement, whereas for the rural case ($\frac{R}{X}$ > 5), the reactive compensation alone is not sufficient and storage is required to achieve improved voltage profile.

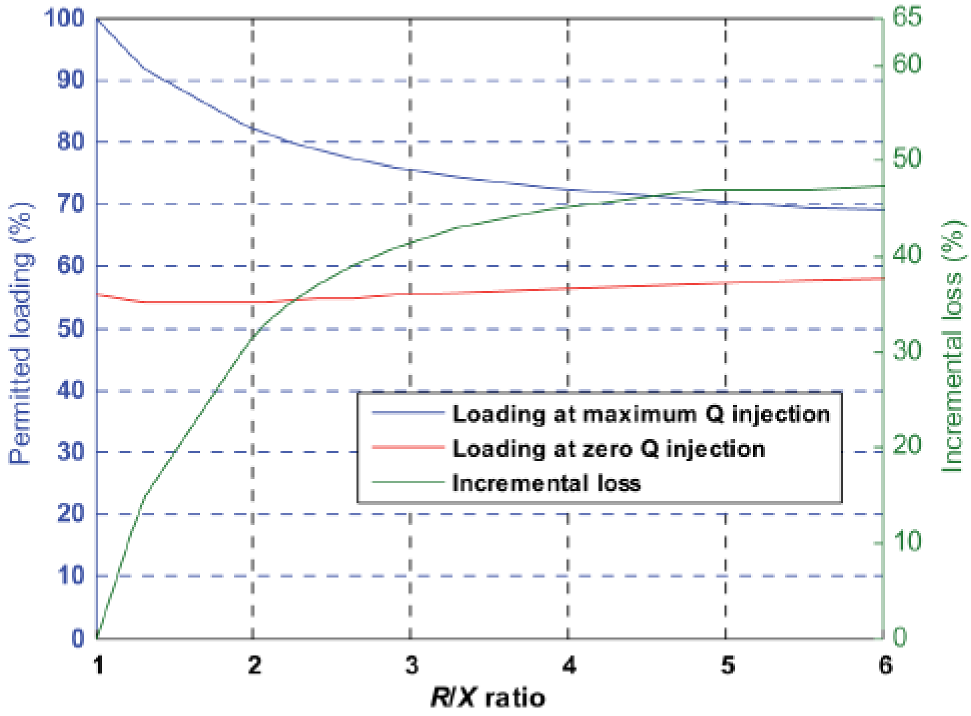


Figure 13 Permitted loading and incremental loss variation with $\frac{R}{X}$ ratio. [52]

2.1.3.2 curtailing real power (shedding)

Curtailing real power of PV at peak generation period seems very attractive since it just needs minor modifications in the inverter control logic [53]. The disadvantage is reduction in the efficiency of the PV and revenue for its owner. However, in small scale DG, the percentage reduction in revenue is less than that of the energy curtailed. This is due to the lower prices of electricity at the times of curtailment which usually occur at off-peak periods. For larger penetration (installed capacity more than 1 MW) the revenue lost and energy curtailed increases considerably.[46]

2.1.3.2.1 Droop-Based APC

Droop control is a well-known technique used for power sharing among generators connected in parallel, mostly relating active power with frequency. In LV systems, the relationship between voltage and active power is stronger than with reactive power given the highly resistive line characteristics [54]. It is proposed that the power injected by the inverter be a function of the bus voltage per:

$$P_{inv} = P_{MPPT} - m(V - V_{cri}) \tag{24}$$

P_{MPPT} is the maximum power available in the PV array for a given solar irradiance (kW), m is a slope factor (kW/V), and V_{cri} is the voltage (V) above which the power injected by the inverter is curtailed linearly with a droop factor. For, $V \leq V_{cri}$ the inverter injects P_{MPPT}, as most PV inverters do. [55], [56] and [57] tried different approaches to select the droop coefficients of inverters (m and V_{cri}).

2.1.4 Voltage control strategies using energy storage systems (ESSs)

Energy storage devices are being proposed as the solution to various reliability problems on power systems mainly due to large amounts of variable and uncertain power sources such as solar generation.

2.1.4.1 Application of storage on distribution system

Some of the applications proposed for storage installed at the distribution primary medium voltage (MV) or secondary (LV) level include the following: [58]

1. Compensating for, or smoothing solar PV power output.
2. Extending the power output from solar PV to meet the early evening peak demand. On many distribution systems, the peak load occurs after the sun has gone down.
3. Support of transmission grid: compensating for the loss of solar power at the end of the day to avoid the need for fast switching of conventional sources.
4. Extend the hosting capacity of an existing distribution feeder.
5. Controlling the frequency of a microgrid.
6. Arbitraging benefit: reducing the cost of electricity by charging off-peak when the energy is cheaper and discharging to supply load during peak demand periods.

There are undoubtedly many more potential applications for storage, but this list gives an idea of why there is much interest in storage on utility power distribution systems.

Until now, the main obstacle in applying the energy storage devices is the cost. However, in recent years, battery prices have been declined, which makes ES a promising solution.

2.1.4.2 Distribution planning issues by energy storage

Installing energy storage devices on the power distribution system also introduces several issues that should be considered by planners. These issues include the following: [58]

1. Over-voltages while discharging: The impact depends on the location and capacity of the storage devices. This could be a problem when storage is dispatched for purposes other than the benefits of the local feeder e.g. transmission grid benefits. The storage dispatch may occur at night or any other light loading time.
2. Extremely low voltages while charging: Excessive charging by storage can provide huge amount of capacity for charging which can aversely, affect the grid by lowering down the bus voltage.

Traditional way of operating a local ESS is based on charging the battery as soon as the PV generation exceeds the consumption. However, this strategy does not prevent overvoltage during maximum PV generation hours (12:00–14:00 PM), since the ESS battery gets fully charged during morning hours of sunny days, well before the maximum PV generation period [59].

So, [60] proposed a decentralized storage strategy, prioritizing the charge of ESS batteries around peak generation hours, as shown in Fig.14. Each ESS is activated at a certain power threshold P_{th}, which is different from P_{Load} and should be identified based on the voltage at the point of common coupling V_{PCC}.

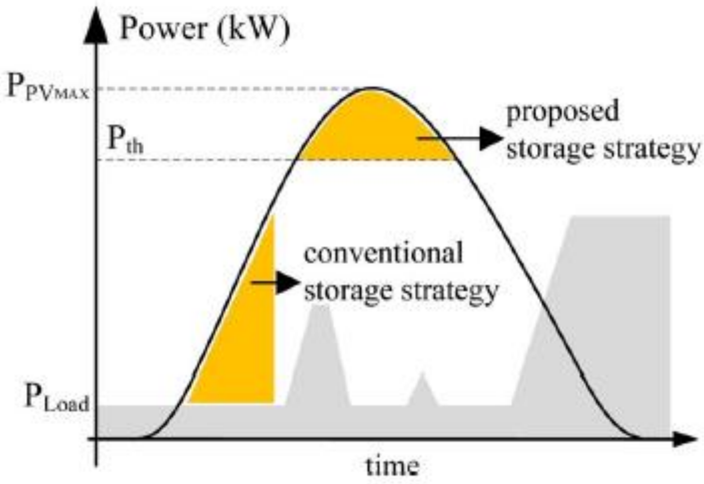


Figure 14 Conventional and proposed storage strategy [60]

As shown in Fig.15, if the residual load P_{res}, defined as the difference between P_{PV} and the absolute load demand P_{Load} (eq. 25) is positive, the battery $P_{Bat,ch}$ is charged with P_{res} until the SOC reaches 100 %. [5]

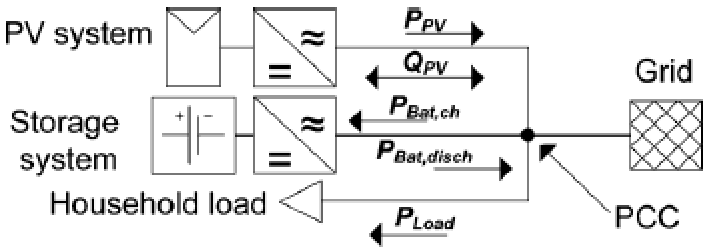


Figure 15 Grid connection of PV storage system [5]

Vice versa, the battery $P_{Bat,disch}$ is discharged with P_{res}, if P_{res} is negative and the SOC is above 0%, as shown in eq. 28 and 29. The SOC varies from $0-100\%$.

$$P_{res} = P_{PV} - |P_{Load}| \tag{25}$$

$$P_{Bat.ch} = -P_{res} \text{ if } SOC < 1 \text{ and } P_{res} > 0 \tag{26}$$

$$P_{Bat.disch} = |P_{res}| \text{ if } SOC > 0 \text{ and } P_{res} < 0 \tag{27}$$

Also, based on the voltage at the point of common coupling V_{PCC}, the voltage dependent control strategy is as follows:

$$P_{Bat.ch} = -P_{res} \text{ if } SOC < 1 \text{ and } \mathrm{V}_{PCC} > V_{thres} \tag{28}$$

$$P_{Bat.disch} = |P_{res}| \text{ if } SOC > 0 \text{ and } \mathrm{V}_{PCC} < V_{thres} \tag{29}$$

2.1.4.3 Energy storages, independent from or integrated to generators

There are different implementation approaches for energy storage devices. Some authors propose an energy storage independent from generators, as in [61]. Another option is to integrate storage and generation in a single system with a common dc bus as in [62]. This dc bus has a fixed voltage, so that power converters for both generation and battery management are necessary to adequate the voltage and perform the maximum power point tracking (MPPT) of the power sources. In [20], the proposed system is composed of a PV generator and a battery bank interconnected by means of a dc/dc converter. The inverter and the dc/dc converter share the same dc bus. The dc bus voltage is the same as the PV panel output voltage, which is imposed by an MPPT algorithm. This kind of systems usually have been designed for stand-alone applications.

2.1.4.4 Droop based ESS control

Control of power storage in batteries can be achieved using either constant droop-based or variable droop-based methods. The constant droop method utilizes same droop co-efficient (m_c) for all houses to store energy. m_c is a function of $P_{L,\max}$ and $P_{G.\max}$, and defined as eq. 30. Using m_c, the amount of reduced power $\Delta P_{n.reduced}$ from n th PV is calculated as eq. 31. With constant droop method, BES starts charging when the voltage of the house goes above V_{cri}, as defined in (23)

$$m_c = \frac{P_{G,\max} - P_{L,\max}}{V_{\max} - V_{\text{exp}ected}} \tag{30}$$

$$\Delta P_{n,reduced} = m_c (V_n - V_{\text{exp}ected}) \tag{31}$$

$$V_{cri} = V_{\max} - (m_c . \Delta P_{reduced}) \tag{32}$$

whereas the variable droop-based BES uses different droop co-efficient for different houses to ensure uniform energy storage.

3 Modeling of test system

3.1 Description of the Test Bed Feeder

TF C6.04.02 developed distinctive benchmark models [63]. The model consists of a set of benchmarks that together cover the spectrum of DG integration. Following this basis, a set of complementary references have been developed to facilitate the analysis of DG integration at low voltage level. Table 1 gives equivalent values of the European low, medium and high voltage levels

Table 1 European Grid Equivalent Data

Voltage level	DG power range	Grid voltage	Short circuit power
	[kVA]	[kV, r.m.s line-line]	[MVA]
Low voltage	1-500	0.4	3-10
Medium voltage	10-2000	20	500-1200
High voltage	1000-30000	220	1000-10000

The topology of the LV benchmark is shown in Fig. 16, illustrating the feeder which is an overhead line with twisted XLPE cable, serving a residential area. Typically, a European LV grid consists of a secondary step-down transformer to step down the voltage from the MV level to a 0.4 kV line-to-line voltage and of distribution. Lines or cables types are mentioned on the lines. feeder lengths can be determined from the number of poles, given the fixed pole-to-pole distance of 35-m. The pole and transformer groundings are assumed to be neglected for simplification [33].

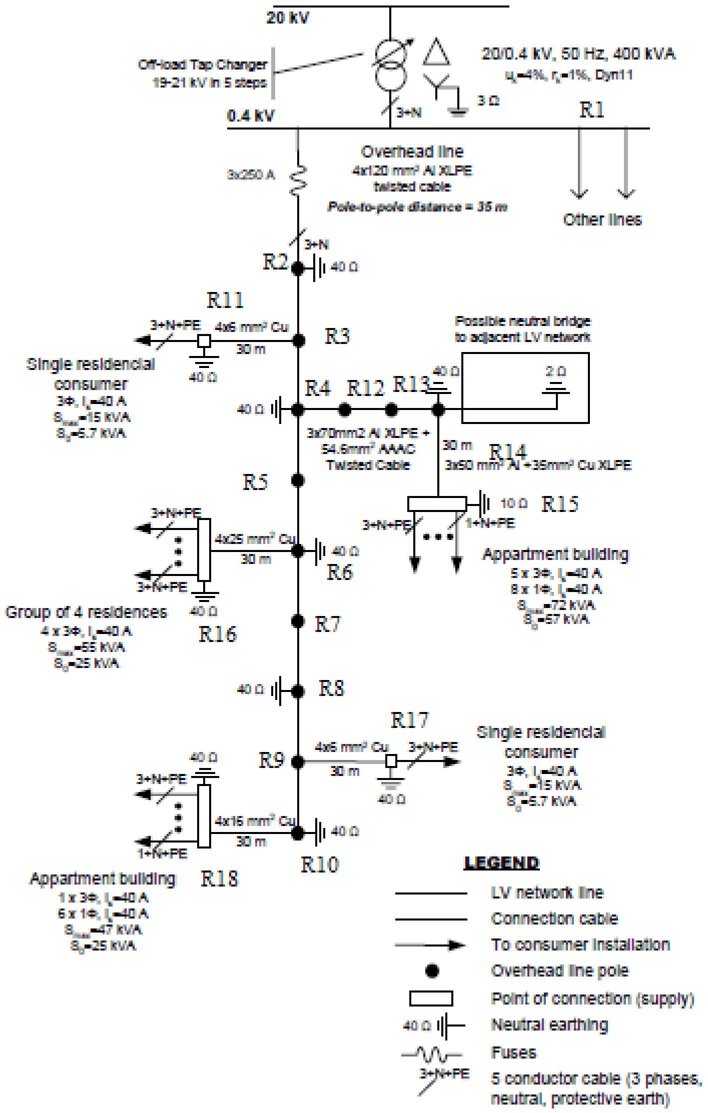


Figure 16 The benchmark LV feeder [33]

3.1.1 Substation transformer

The substation was modelled using a $20/0.4$ kV transformer as described in table.

Table 2 Transformer equivalent data

Transformer Parameter	Value
Primary Voltage	20kV
Secondary Voltage	400V
Rated Power	400kVA
Primary/secondary windings	Delta/wye
Load-losses	1 p.u.
Primary-to-secondary reactance	3.873 p.u.

3.1.2 Consumer Demand Characteristics

Three-phase wye connected loads are connected to buses 11, 15, 16, 17 and 18. I_s shown in Fig. 16, is maximum permissible current of each consumer, which corresponds to the rated current of the overcurrent protection. The maximum demand $S_{\max}$ and S_0 of each consumer group, also given in the Fig. 16. The total sum of maximum demand of all the consumers in the feeder is 204 kVA and the power factor of all, assumed to be equal 0.95 lagging. Daily load curves for the three load types of the benchmark networks are shown in Fig.17. However, in our study we use just the residential one and simulate with 1-m resolution by 1440 points. [33]

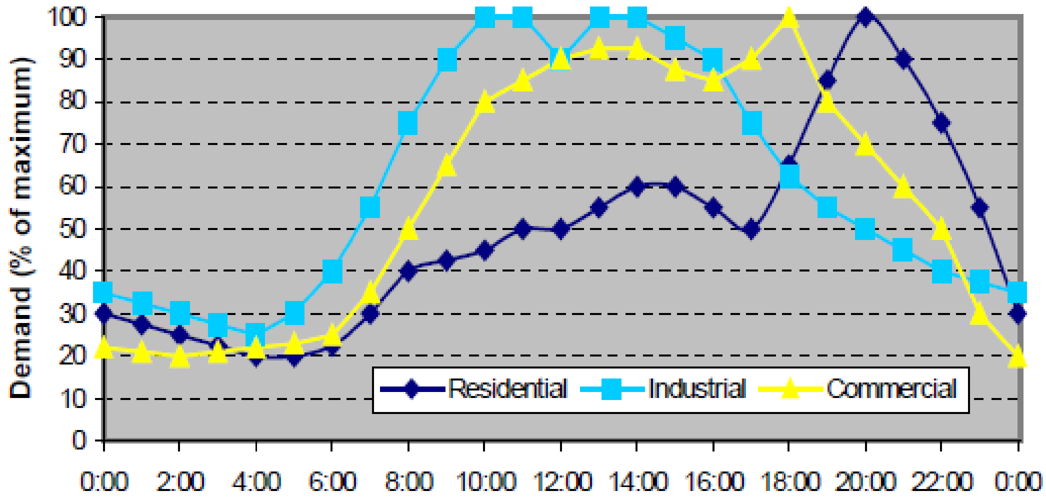


Figure 17 Load shapes [33]

Benchmark network data are organized in Table 3. Due to the short lengths of line, capacitance per unit length is neglected [33]. The feeder has 6 different types of lines, some of them are symmetric and some are not. In addition to positive sequence resistance and inductance, we also consider zero resistance and inductance sequence in LV networks unlike the case in MV. In LV networks, the neutral must be explicitly modelled. For model implementation in OpenDSS software, this means connections with 4 phases $(3ph+n)$

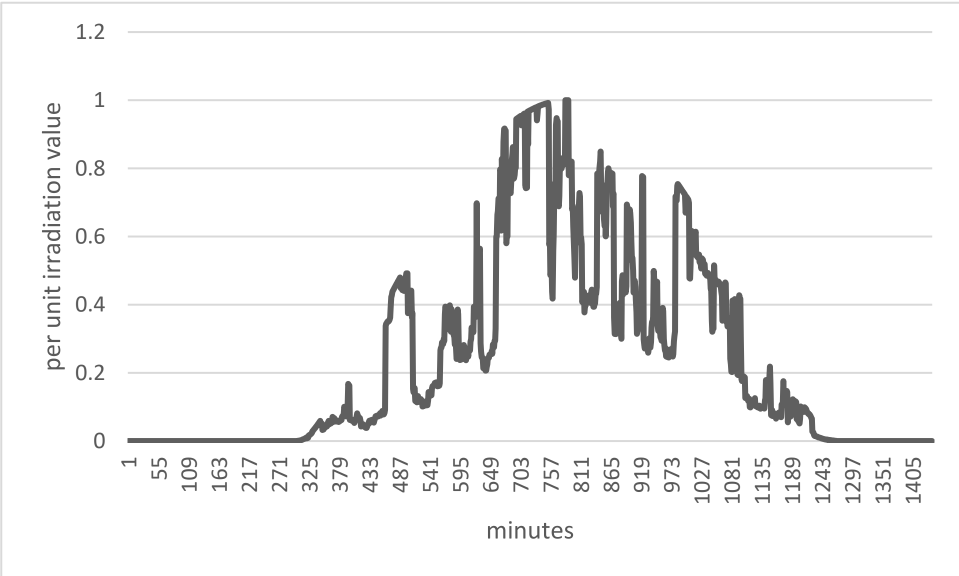
Table 3 Impedance data for the benchmark network lines [33]

	Line type	R_{ph} (Ω/km)	X_{ph} (Ω/km)	$R_{neutral}$ (Ω/km)	R_0 (Ω/km)	X_0 (Ω/km)
1	OL - Twisted cable 4x120 mm² Al	0.284 (1)	0.083		1.136	0.417
2	OL - Twisted cable 3x70 mm² Al + 54.6 mm² AAAC	0.497 (1)	0.086	0.630	2.387	0.447
3	OL - Al conductors 4x50 mm² equiv. Cu	0.397 (1)	0.279			
4	OL - Al conductors 4x35 mm² equiv. Cu	0.574 (1)	0.294			
5	OL - Al conductors 4x16 mm² equiv. Cu	1.218 (1)	0.318			
6	UL - 3x150 mm² Al + 50 mm² Cu	0.264 (2)	0.071	0.387 (2)		
7	SC - 4x6 mm² Cu	3.690 (3)	0.094		13.64	0.472
8	SC - 4x16 mm² Cu	1.380 (3)	0.082		5.52	0.418
9	SC - 4x25 mm² Cu	0.871 (3)	0.081		3.48	0.409
10	SC - 3x50 mm² Al + 35 mm² Cu	0.822 (2)	0.077	0.524 (2)	2.04	0.421
11	SC - 3x95 mm² Al + 35 mm² Cu	0.410 (2)	0.071	0.524 (2)		

3.1.3 PV system characteristic and model

3.1.3.1 PV system characteristic

Four 1-phase PV generators were connected to buses 15, 16, 17 and 18. The amount of installed PV power is 120 kW_p . The PV power profile shapes of all the 4 generators are assumed to be the same and as the Fig. 18. PVs were configured with unity power factor to inject only active power and reactive power is set to zero. Quasi static time simulation which would be described later is performed for a period of 24 hours taking 1440 different intervals at a step size of 1-m for analysis. (Fig .16)



3.1.3.2 PV system model

The PV System model in OpenDSS combines a solar PV array model with selected characteristics of the inverter such as efficiency curve, maximum power point tracking (MPPT) and also cut-in/cut-out as function of dc voltage. [64]

The model injects an active power, P_{out} , into the grid which is a function of irradiation, temperature, inverter efficiency and the rated power at the maximum power point, P_{mpp} defined for a selected temperature, usually $25^{\circ}C$ and base irradiation of 1 $^{kW}/_{m^2}$. [65]

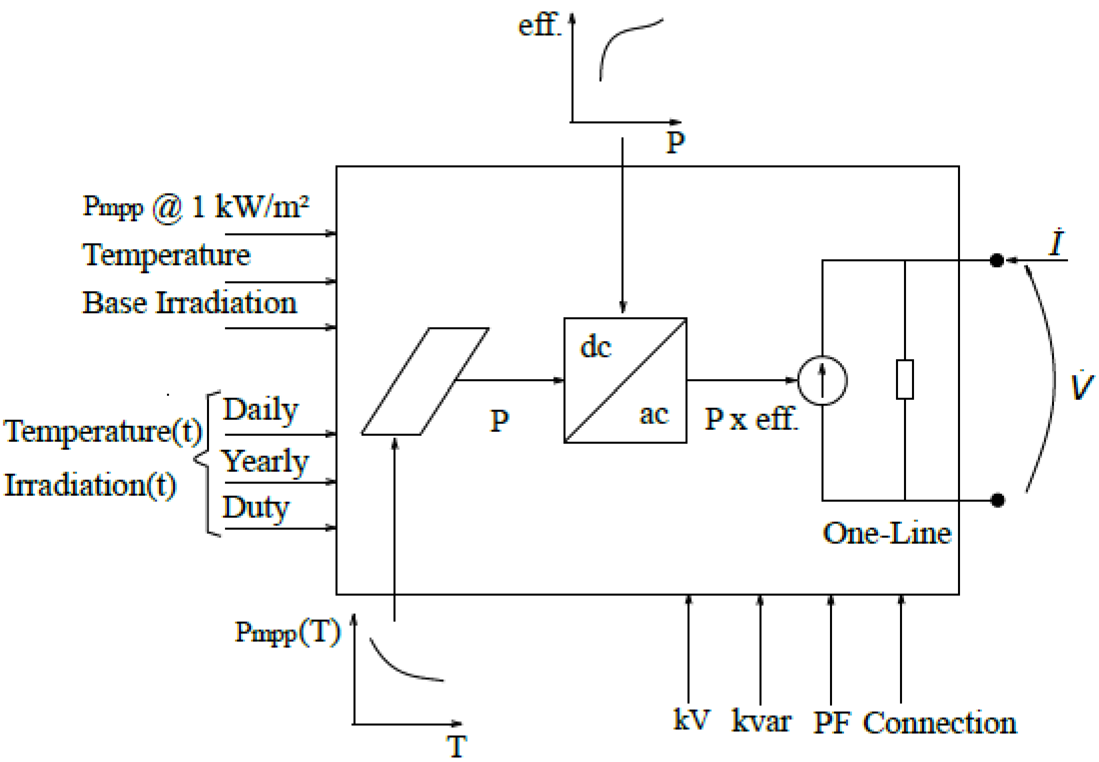


Figure 18 PV system model [65]

Fig .19 shows the block diagram and eq. 33 provides $P_{out}(t)$: [65]

$$P_{out}(t) = P(t)\ .\ eff\,(P(t)) \tag{33}$$

Where

$$P(t) = P_{mpp}(1\,{}^{kW}\!/_{m^2}).\ irrad(t).\ irradBase.\ P_{mpp}(T(t)) \tag{34}$$

And

- $P(t)$: Output power of PV array at a specific time, t.
- $P_{mpp}(1\,{}^{kW}\!/_{m^2})$: Rated power at the maximum power point and a selected temperature.
- $irrad(t)$: Per unit irradiation value at t.
- $irradBase$: Base irradiation value for shape multipliers.
- $P_{mpp}(T(t))$: P_{mpp} correction factor as function of the temperature
- $eff\,(P(t))$: Inverter efficiency for a given $P(t)$

Although, we use the PV system model inside OpenDSS software (which consider the solar radiation and the temperature of the PV panels), one can use a simplified model of generator with a fixed active power and unity power factor.

3.1.4 Energy storage system (ESS) model

The analysis is performed to study the feasibility of using a 3-phase distributed battery storage unit which is connected to the critical bus to regulate the daily voltages of a feeder energy stored in off-peak hours. It is done using 1-min substation feeder data.

The OpenDSS storage element model is a generic model intended to be suitable for planning studies (Fig. 20). It is not intended to be a specific model of any particular technology, but it should suffice for most planning studies involving one or more storage devices on a distribution system. [58]

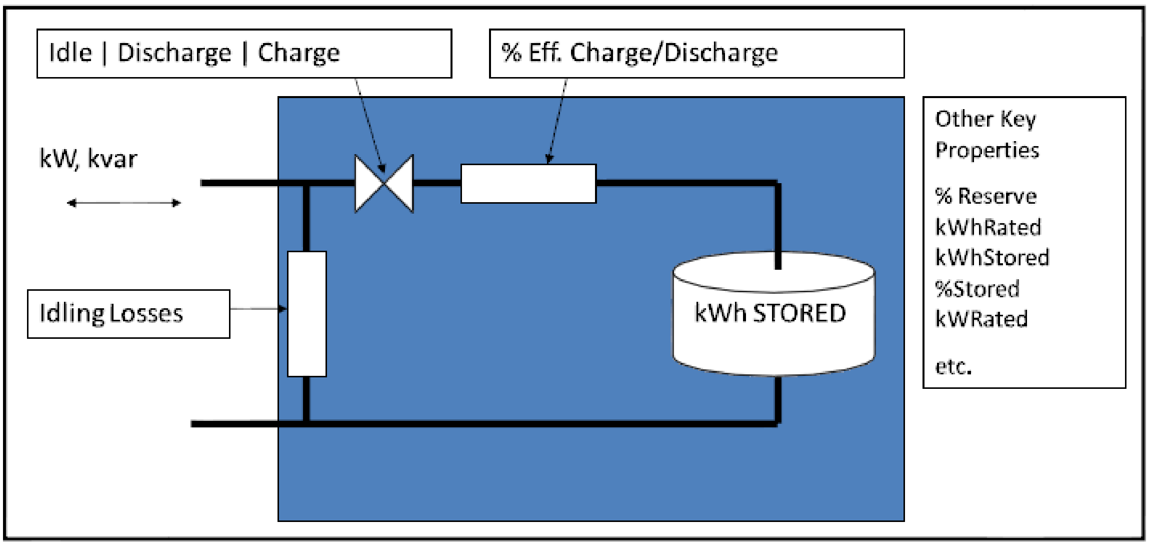


Figure 19 Basic concept of the EPRI OpenDSS storage model [58]

There are losses due to charging–discharging cycle of ESS which is accounted by round trip efficiency and idling losses during periods when a storage device is neither discharging nor charging. Idling losses include such things as keeping batteries cool or warm depending on the ambient temperature. As for simplicity, we consider 100% of round trip efficiency and 0% of idling losses.

In this work, the energy storage system (ESS) have been modeled as ideal energy reservoirs with the charge-discharge equations as expressed in eq. 35 and eq. 36, where P_d is the discharging power and P_c is the charging power of the ESS battery, respectively. $E(t)$ is the energy stored in the battery at time t ; Δt is the duration time of each interval [66]. The two coefficients η_d and η_c are the discharge and charge efficiencies respectively.

$$E(t+\Delta T) = E(t) - \Delta t.P_d / \eta_d \tag{35}$$

$$E(t+\Delta T) = E(t) + \Delta t.P_c.\eta_c \tag{36}$$

Considering energy constraints. The limits of state of energy (SOE) during charging/discharging can be described by eq. 37 and eq. 38 respectively:

$$E_{\min} \le E(t) \le E_{\max} \tag{37}$$

$$SOE_{\min} \le SOE(t) \le SOE_{\max} \tag{38}$$

Which $SOE(t) = \frac{E(t)}{E_{rated,stored}}.100$, is the state of energy and $E_{rated,stored}$ is the rated stored energy in the battery. $SOE_{\max}$ and $SOE_{\max}$ are considered 90% and 20% respectively.

3.1.4.1 Storage simulation modes

According to OpenDSS software documentation, five basic simulation modes were identified for modeling storage in the distribution system analysis, based on the application. [58]

1. Default mode: Storage element state is triggered to discharge or charge at the specified rate by the load-shape curve corresponding to the solution mode.
2. Follow mode: the kW and kVAr output of the storage element follows the active load-shape multipliers until storage is either exhausted or full. The element discharges for positive values and charges for negative values. The load-shapes are based on the kW and kVAr values in the most recent definition of kW and PF or kW and kVAr properties.
3. External mode: In this mode, storage element state is controlled by an external storage controller. This mode is automatically set if this storage element is included in the element list of a storage-controller element.

For the other two dispatch modes, the storage element state is controlled by either the global default Load-level value or the price level.

Since the approach of this study is to control the storage through MATLAB, we choose the external mode for controlling the storage device.

In distribution system, voltage regulation could be achieved by controlling both the real and reactive power output of the distributed ESS. The adopted control method involves the centralization of all the information in a single processing unit (Central Controller). The central controller gathers all the system data from monitors located in different buses and computes control variables set-points (i.e., active and reactive power) for the ESS.

As distributed control scheme is an effective control structure for multi-agent system, coordination between distributed ESSs would be a solution in larger networks than the case study here.

3.1.4.2 Battery selection

There are wide range of existing batteries systems available for storage including Lead-acid, Li-Ion, Alkaline, NiMH, and flow batteries (ZnBr, Vn redox). The following criteria are used for selecting the appropriate BES for residential purposes. [52]

1. *recharging ability:* Alkaline batteries are good for only 25–30 cycles. Therefore, these batteries are not considered due to lack of recharging ability.
2. *space and weight characteristics:* Too heavy and spacious battery equipment may require additional structural support and may not be an attractive option.
3. *round trip efficiency:* Affect battery size and cost. Therefore, high round trip efficiency is desirable.
4. *life cycle:* It is highly correlated with frequency of charging-discharging. Residential BES system needs at least one charging–discharging cycle every day.

Table 4 compares different battery technologies [67]. Low-energy density and deep discharging of non-battery-type energy storage systems, such as electrochemical capacitors, are ideal for high power and short duration applications. On the other hand, Battery-type storage are suitable for high energy, long duration applications such as residential distribution systems.

Table 4 Battery characteristics comparison [60]

Criteria	Lead acid	Li NMC/ graphite	Li $FePO_4$/ graphite	Ni MH	Vn redox	Zn Br
Energy density (Wh/kg)	40	160	110	75	45	40
Power density (W/kg)	350	1300	4000	600	120	110
Lifetime (cycles)	600	2500	5000	900	12 000	7000
Round trip efficiency (%)	85	93	94	75	80	80
Self discharge (%/month)	8	3	3	20	5	0
Energy storage system cost (USD/kWh)	330	900	900	900	600	400

Although this study performs the simulation for one day but the features selected for battery selection are upon a 1-year simulation.

Traditionally, lead-acid batteries were used for off-grid PV applications. However, they are one of the lowest energy-to-weight and energy-to-volume battery designs making it big and heavy for residential applications. Nevertheless, they are far cheaper than any other battery energy storage (BES) system available in the market.

Li-based batteries match the requirement of active distribution networks (ADNs) in terms of lifetime, energy density, self-discharge rate and round trip efficiency. this technology is adopted for the ES in this study [68] .

Although this study performs the simulation for one day but the features selected for battery selection are upon a 1-year simulation.

4 Simulation tools

4.1 Conventional simulation tools

Traditional modelling of distribution networks usually considers: [69]

1. Balanced networks which are not realistic but a good approximation for MV networks. However, it is inadequate when closer to end customers in low voltage (LV) grid.
2. snapshots or hourly profiles which simplify planning problems (e.g., reconfiguration for power loss minimization during peak), but on the other hand neglect the actual loadو (renewable) generation changes and the actual control of network elements (e.g., OLTCs act in 1 min).

   For many years, utilities have relied on commercial simulation tools to run steady state power flow and protection analyses on distribution feeders. The studies are limited to snapshots of critical time periods, such as peak and minimum load points which are selected to evaluate impacts on the distribution system. These simulations only provide a snapshot assessment of the power-flow on the distribution system and only give the magnitude of an impact at one instant in time. However, PV output is highly variable and the potential interaction with control systems may not be adequately analyzed with traditional snapshot tools and methods.

3. Deterministic approaches, so the uncertainties due to the variability, location, loads growth as well as renewable generation are neglected. This simplifies the problem but can over or underestimate problems/benefits.

4. Only a single voltage level which is adequate in smaller networks. But the impacts of new technologies on one voltage level (e.g., MV) can be over or underestimated if neglecting the interdependencies with other voltage levels (e.g., LV or HV)

Considering mentioned criteria, present electricity network and the new challenges persuade us to consider:

1. Unbalanced networks instead of balanced one
2. Realistic time-series profiles instead of snapshot
3. Probabilistic instead of deterministic
4. Integrated LV-MV-HV modelling instead of single voltage level

4.2 Quasi static time series simulation (QSTS)

Quasi static time series simulation (QSTS) is a useful method for analyzing the impact of distributed PV on the grid [70]. The PV power output is modelled as a time series and a power flow solution is performed for every time instant, assuming that the system reaches a quasi-steady state. The results can then be plotted as a function of time.

The main advantage of using QSTS simulation is its capability to properly assess the time-dependent aspects of the distribution system. QSTS produces sequential steady state power flow solutions where the converged state of each time-step is used as the beginning state of the next. Examples of the time-dependent aspects of power flow include the interaction between the daily changes in load and PV output and the effect on voltage regulation device controls [71].

Finding a software that can perform QSTS in all possible modes of operation is difficult. It can only be done, if the software offers a common object model (COM) interface capability to run it through an external program and utilize the capabilities of the external program [72].

It is unlikely to find QSTS capable software that offers the ability to simulate all existing control modes. However, if the QSTS software offers COM interface capability, it is possible to develop and implement control algorithms through an external program. [72]

4.2.1 QSTS Data

The QSTS requires more data to represent the time-varying PV output coincident with time-varying load. The time series data is often difficult to obtain as the measurement equipment will frequently not be available at the desired time resolution. In this thesis, feeder level load data is recorded at 1-minute resolution, where interpolation may be the best option for obtaining higher resolution data [71]. The necessary data set can become very large depending on the resolution and length of simulation desired, causing simulation processing times to increase and become burdensome. Data can be interpolated to run a QSTS simulation, but 1-minute average data does not capture enough variability with respect to load variations. Future research could add estimated PV output profiles and irradiances or proxy data from similar PV plants.

4.3 OpenDSS (Open Distribution System Simulator)

Currently available simulation tools are not generally well suited for sequential or dynamic simulations needed to fully characterize the effects of PV output variability on distribution feeders. OpenDSS provides a platform to model the feeder integrated with distributed generators and perform a quasi-static time series analysis.

OpenDSS program which is an open source software, was designed in 1997. The electric power research institute (EPRI) researchers had recognized that it is not possible to get the correct answer for distribution planning problems involving distributed energy resources (DER) unless a series of power flow solutions are performed over a large period. It is a script-driven, frequency-domain electrical circuit simulation tool with the flexibility to be driven from MATLAB. The most important feature of OpenDSS is that it can solve unbalanced radial feeders using Newton Raphson method to perform power flow analysis. [58], [73]

It would help distribution systems operators (DSOs) in analyzing unbalanced, multi-phase power distribution networks. It is usually used in DG interconnection studies, impacts of wind/solar PV (high penetration, variability, voltage rise, etc.), Harmonic distortion, Dynamics/islanding and many more applications. OpenDSS is commonly used to model PV impact on the grid because of its high-resolution time series analysis capability [74].

It should be noted that OpenDSS is a harmonics solver rather than power flow. However, it is simpler to solve power flow problem with a harmonics solver than vice-versa. In addition, it is not an electromagnetic transient solver (Time Domain) but can solve Electromechanical transients.

This software supports all r.m.s steady-state (i.e., frequency domain) analyses commonly performed for utility distribution network planning with the original purpose of distributed generation (DG) interconnection analysis.

OpenDSS offers a menu of solution modes such as:

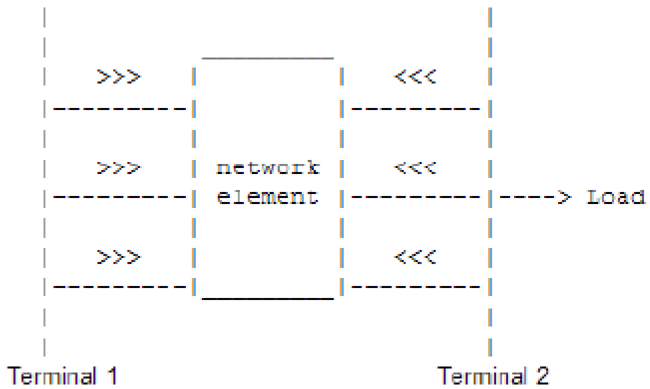
- Snapshot(static) power flow
- Direct (non-iterative)
- Daily-mode (default: 24 1-hr increments)
- Yearly-mode (default 8760 1-hr increments)
- Duty cycle (1 to 5s increments)
- Dynamics (electromechanical transients)
- Fault study
- Monte carlo fault study
- Harmonic
- Custom user-defined solutions

The main categories in OpenDSS elements can be classified as:

1. Power Delivery Elements (PDE)
   - Line (All types of lines, cables)
   - Transformer (multi-phase, multi-winding transformer models)
   - Capacitor, reactor (Series and shunt)
2. Power Conversion Elements (PCE)
   - Generator
   - Load
   - PV-system (Solar PV system with panel and inverter)
   - Storage (Generic storage element models)

3. Meters: Although we can always export CSV files with all voltages and currents, it is advisable to deploy monitoring devices (particularly when doing time–series analyses and using the COM server as is more manageable). It is sensible to have one at each loads and PVs, one at the storage device, on at the critical bus to monitor voltage variations and finally one at the source bus (or relevant substation) to meter net imports/exports (in the presence of DG) and total losses,
   - Energy-Meter (Captures energy quantities and losses)
   - Monitor (Captures selected quantities at a point in the circuit)
   - Sensor (Simple monitor used for state estimation)

- Convention: Energy Meter/Monitor at Terminal 1 will consider load-led current as positive, given that the model assumes currents flowing to the right. Energy Meter/Monitor at Terminal 2 will consider load-led current as negative, given that the model assumes currents flowing to the left.



4.4 COM interface capability

The COM interface capability can help control OpenDSS through an external program like MATLAB and make use of the functionalities of these external programs to perform studies at a higher level. Figure. 20 shows an example of using COM capabilities of OpenDSS to perform QSTS [75]. MATLAB command environment is used to invoke OpenDSS through COM. It can be seen in Figure. 20 that data can be transmitted to and from OpenDSS and MATLAB through the COM interface. MATLAB utilizes the data received from OpenDSS to vary the parameters to perform appropriate control.

In [75] there is a focus on simulation of dynamic VAr compensation using OpenDSS-MATLAB tool. Dynamic VAr compensation approach refers to providing compensation by injecting reactive power into the grid by customers or PV operators. It shows that voltage which drops under the limits, brought within the limits after applying VAr compensation. MATLAB plays an important role as it senses this drops using COM interface.

In [72] a control of a substation load tap changing (LTC) through interfacing process is reported. For each time step in the OpenDSS time-series power flow solution, MATLAB reads the transformer voltages by setting the OpenDSS active element to the monitored transformer by using the COM interface. Fig. 21

If the calculated control voltage is out of band, the control logic block is entered. When all conditions are met, MATLAB commands the appropriate winding in OpenDSS to move to the new tap position.

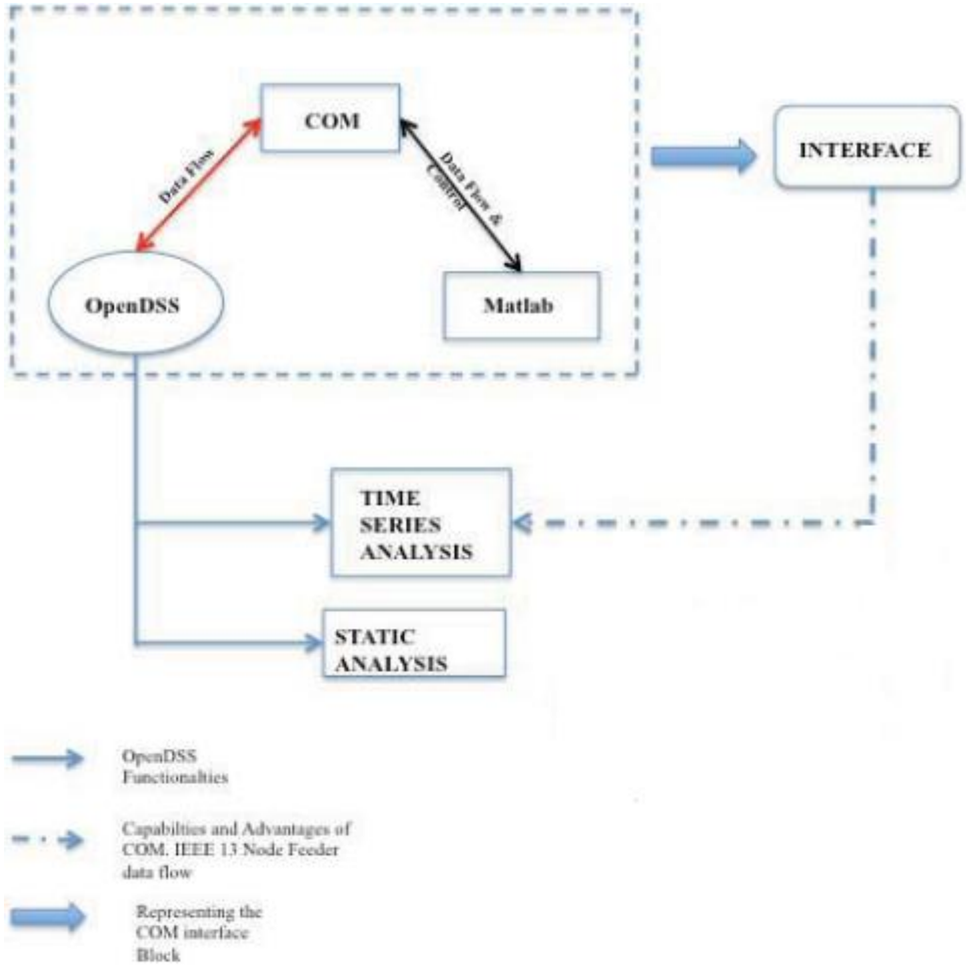


Figure 20 Proposed Model of OpenDSS and MATLAB interface [75]

4.4.1 Interfacing OpenDSS with MATLAB

By bringing control of OpenDSS to MATLAB, the functionality of OpenDSS is utilized while adding the looping, advanced analysis, and visualization abilities of MATLAB.

This will demonstrate how to initiate the COM interface within MATLAB and compile a circuit. The basic process for getting started with the interface is:

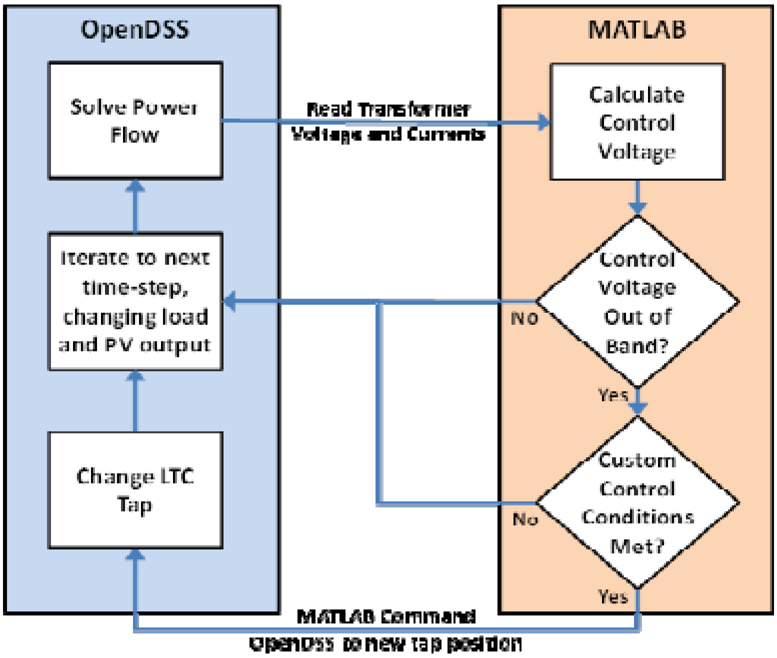


Figure 21 MATLAB/OpenDSS interfacing for custom LTC control. [72]

- Initiating the COM Interface

The first step is to initiate the COM interface. A MATLAB function does this for the user by calling DSSStartup:

```
[DSSCircObj, DSSText, DSSPath] = DSSStartup;
```

DSSStartup starts up OpenDSS in the background. DSSCircObj, which is the pointer to the COM interface, contains the active circuit (DSSObj.ActiveCircuit) and the text interface to OpenDSS (DSSCircObj.Text). DSSCicrObj will be empty until a circuit is compiled. DSSStartup will return an error if MATLAB was unable to create a link to OpenDSS.

- Compiling the Circuit

Using the text interface to pass the "compile" command into OpenDSS to open the circuit.

```
DSSText.Command = ...
      sprintf('Compile (%s%sall_in_one.dss)',DSSPath,'\');
```

To make changes to the circuit, we can use either the DSSText interface inside MATLAB or alternatively, manually by editing the ".dss" files and recompiling the circuit in MATLAB.

- Getting Data into MATLAB from OpenDSS

After solving the circuit, we can interact with the COM interface structure using MATLAB command window.

In the return for DSSCircObj.get, there are several pointers to OpenDSS interface COM objects. One such sub-pointer is the ActiveCircuit interface. The ActiveCircuit refers to the compiled circuit in OpenDSS and contains all parameters and power flow solutions.

```
DSSCircuit = DSSCircObj.ActiveCircuit;
```

- Active Elements

In interacting with the COM server, you can get data about a particular element in the circuit by calling "DSSCircuit.ActiveCktElement.get". In general, the class interfaces (lines, transformers, etc.) contain the information about the circuit element (ratings, connections, impedances, etc.) and the active element interface contains the power flow solution values for that element. Below is an example of how to set elements of the feeder such lines active to retrieve their data.

```
  %% Lines& Buses

% Get line names and set up structure
lineNames = DSSCircuit.Lines.AllNames;
Lines = struct('name',lineNames);
% Iterate and retrieve line buses
for ii=1:length(Lines)
     % Set the active element as current line
     DSSCircuit.SetActiveElement(['line.' Lines(ii).name]);
     % Get the bus names
     lineBusNames = DSSCircuit.ActiveElement.BusNames;
     Lines(ii).bus1 = lineBusNames{1};
     Lines(ii).bus2 = lineBusNames{2};
end
```

- Running Commands

The text interface allows string commands to be passed to OpenDSS and run directly in OpenDSS. Here, the text interface was used to solve the circuit after setting the particular control mode to time and a daily simulation with 1 minute time step. Time means that the solution is time driven. Control actions are executed when the time for the pending action is reached or surpassed.

The command string is compiled in OpenDSS, so the text interface can be used to do anything that can be done via scripting in OpenDSS.

```
DSSText.Command = 'Set ControlMode = time';
DSSText.Command = 'Set Mode=daily  number=1440 stepsize=1m';
DSSText.Command = 'solve';
```

- Adding/Editing Elements

One of the most common uses of the text interface is to add and edit circuit elements. Using the OpenDSS commands “new” and “edit”, different elements can be added, moved, and changed via MATLAB.

5 Simulation results

EN 50160 requires the average ten-minute r.m.s. of the voltage either not to exceed $\pm 10\ \%$ or to stay below $\pm 15\%$ of the nominal grid voltage for the entire time. [76]

a. Before connecting PVs

By inserting a monitor in substation transformer and tracking the 3-phases powers, one can see that they are symmetrical since all the elements along the feeder are symmetrical. (Fig. 22). Power injecting to the feeder is positive all the time like the traditional power systems. So, there is no reverse power flow phenomenon and hence no possibility of over-voltage.

The power pattern is also the same as the load shape pattern which is defined for the load. (Fig. 23)

Furthermore, monitored three phases voltages of the buses along the feeder are also symmetrical. Like the traditional grid, the maximum voltage occurred at the nearest bus to the substation transformer (bus 2) and by moving down to the feeder, as we face the voltage drops along the lines, the lowest voltage occurred at the end of the feeder (bus 18). The highest voltage in the feeder at bus 2 is equal to $230.4310V$ and the lowest voltage in the feeder at bus 18 during a day is $210.7660V$ which both maximum and minimum values are within the limits. (Fig. 24, 25).

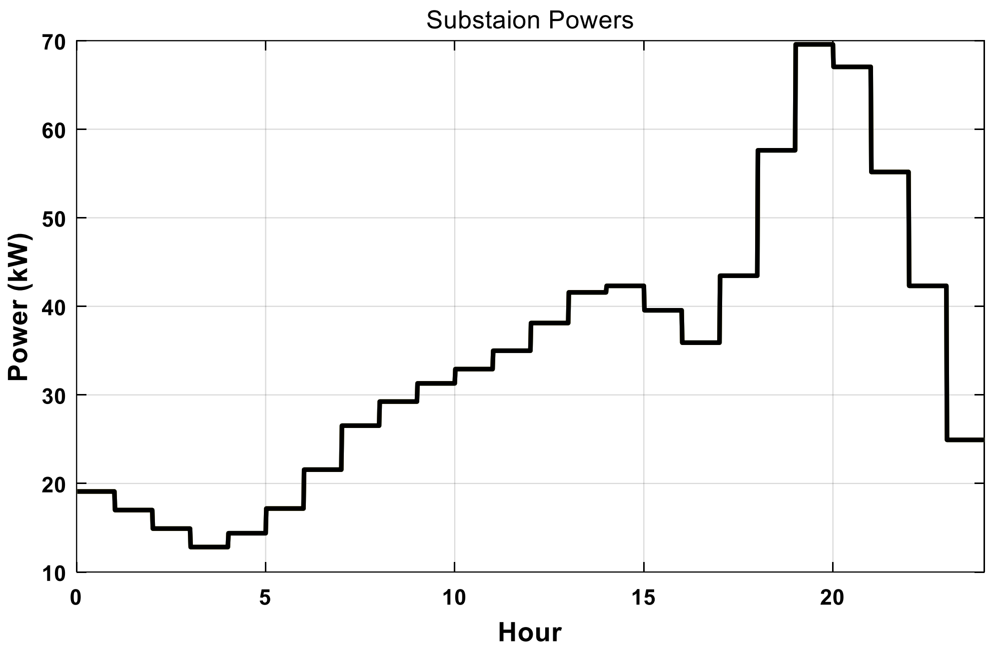


Figure 22 Three phases powers at substation transformer

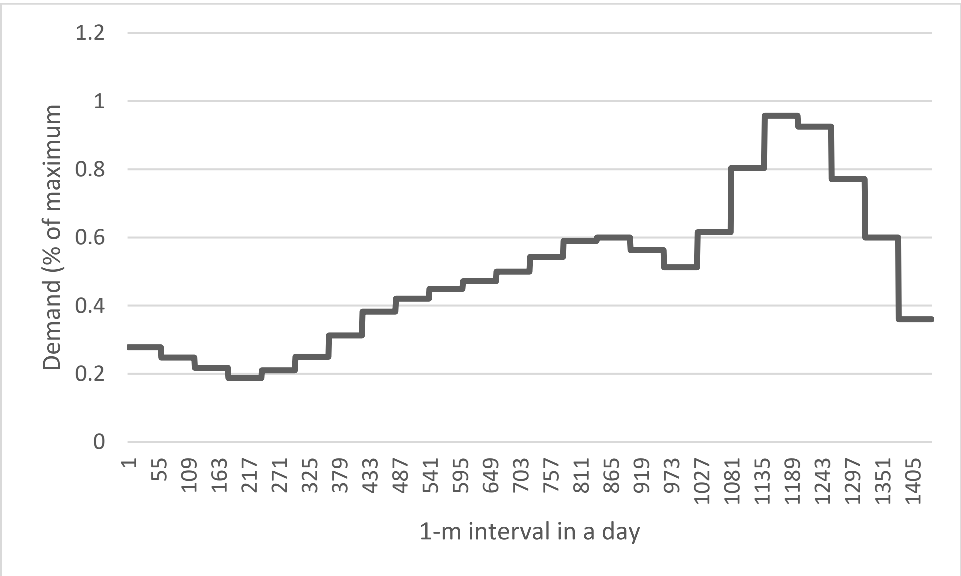


Figure 23 Daily load curve

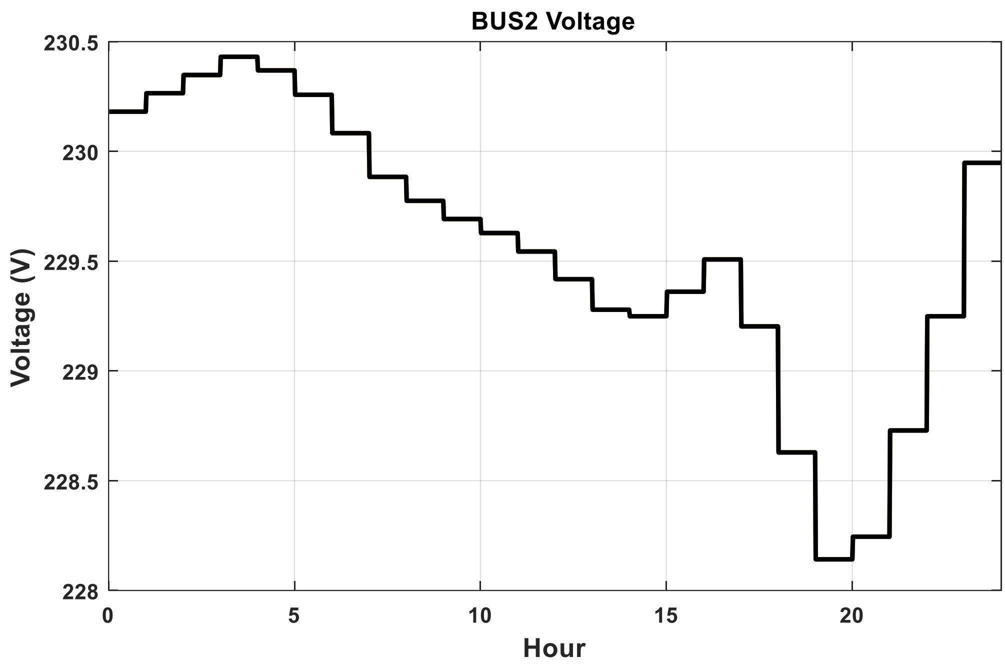


Figure 24 bus 2 3-phase voltages

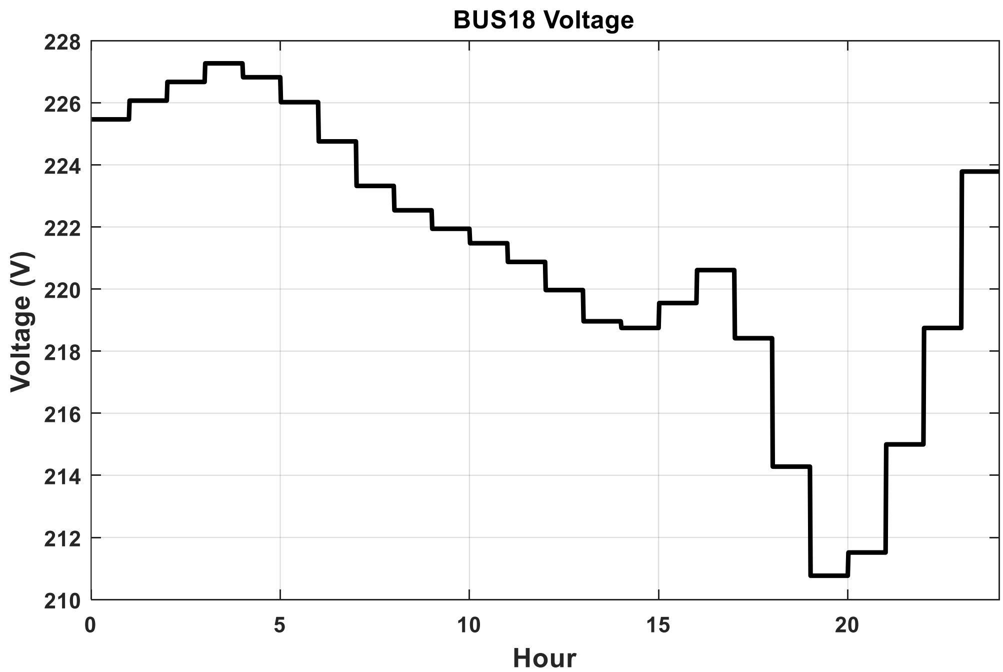


Figure 25 bus 18 3-phase voltages

b. After connecting PVs

Since both the maximum and minimum voltages along the feeder after connecting PV found in bus 18, we cinsider this bus as the critical bus and monitor just this bus.

According to the penetration level definition in [77]

$$PL = \frac{\sum P_{PV}}{\sum P_L}.100\% \tag{39}$$

The sum of loads in the feeder with the power factor of 0.95 is $\sum P_L = 234kVA$. $0.95 = 222.3kW$. Table 5 shows the maximum voltage of BUS18 for different penetration level. We connect each PV with $30kW$ output power, one after another. It is obvious from the table that until the 40.5% of PV penetration and the injection of $90kW$ of PV generators, the maximum voltage is still within limits. After connecting the fourth PV with $30kW$ power, the voltage at bus bus 18 exceeds the 10% deviation limits. So, a control strategy is needed to set back the bus voltage within limit.

Table 5 Different penetration levels and the corresponding maximum voltage

Number and capacity of PVs connected	Penetration level (%)	Bus 18 Maximum voltage per day (kV)	Bus 18 Maximum voltage per day(pu)
1 PV with $30kW$	13.5	230.4310	0.9978
2 PVs with $60kW$	27	233.6210	1.0116
3 PVs with $90kW$	40.5	243.4840	1.0543
4 PVs with $120kW$	54	256.6970	1.1115

From the substation power point of view, there are some hours with negative sign of power. This means that the power flows in a different direction in those hours from LV to MV side of the grid, the so called reverse power flow. (Fig. 26)

Since all the PV generators are connected to phase A of buses 15, 16, 17 and 18, the symmetcal voltages are not still valid and the highest voltage rise is also observed in phase A. (Fig. 27)

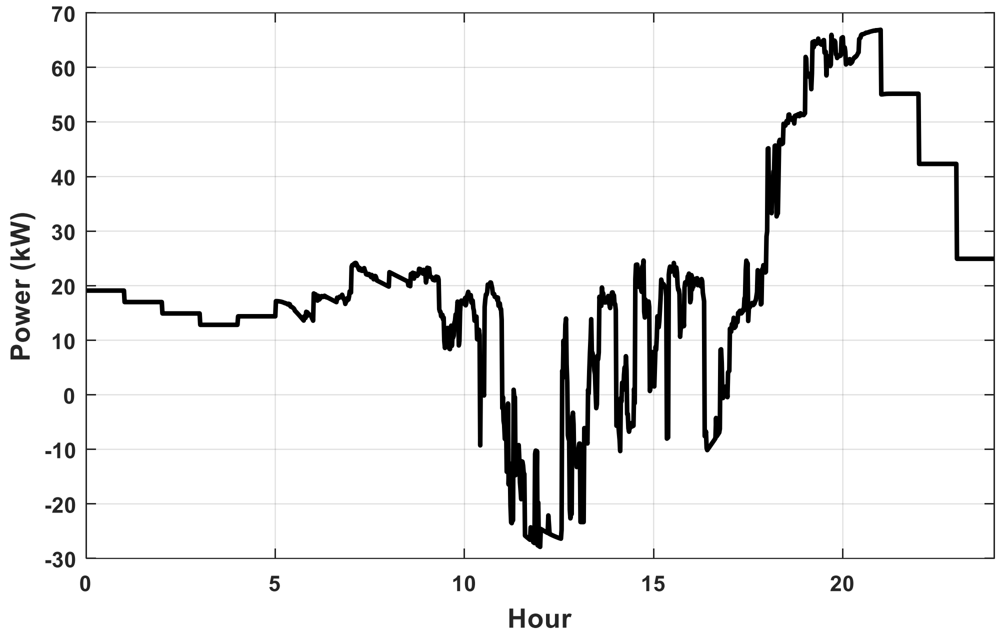


Figure 26 Phase A power of the substation transformer

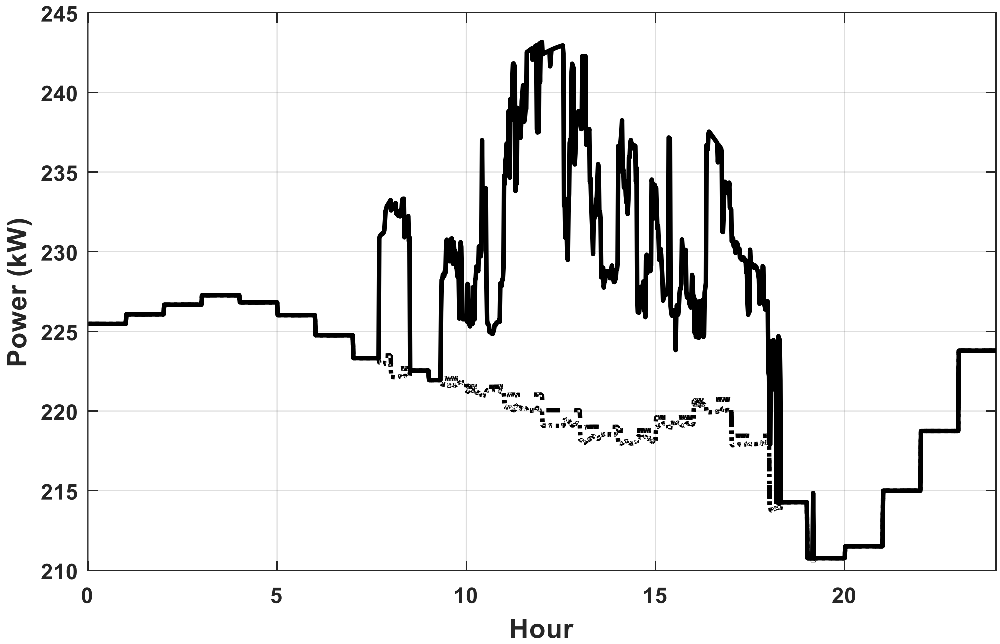


Figure 27 3-phases voltages of bus 18. Solid, dash and dots curves represent phase A, B and C respectively

5.1 Storage control interpretation and results

The flowchart of control algorithm is depicted in Fig. 29. It is a load flow followed by a voltage monitoring at the critical bus which here is bus 18. The storage device is going to discharge only if the critical voltage is below the limit and the SOE_t is greater than $SOE_{\min}$. On the other hand, the storage device is going to charge only if the critical voltage is beyond the limit and SOE_t is less than $SOE_{\max}$. Otherwise the storge device goes to idling mode. Table 6 shows the result of applying voltage device in the feeder. The maximum allowable limit is $254.0341kV$ and therefore a $44kW$ battery storage is sufficient to mitigate voltage rise. Since the peak hours and therefore the hours with reverse power flow is around 3 hours (Fig.26), we triple the rated power of battery to to reach the rated energy stored in the battery which is equal to $132kWh$.

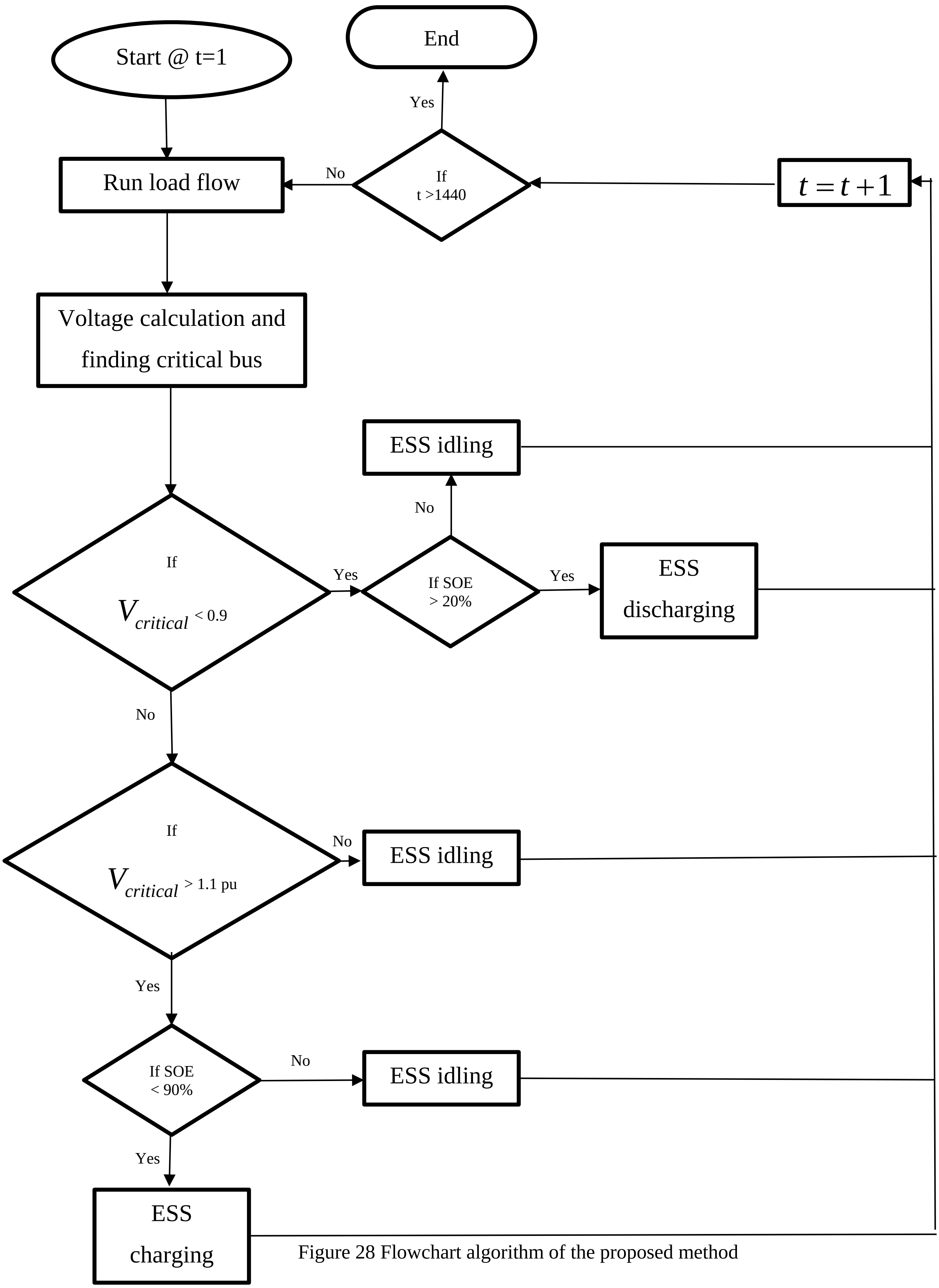


Figure 28 Flowchart algorithm of the proposed method

Table 6 Storage impact on voltage mitigation and power losses reduction

kW rated of storage	kWh rated of battery	Maximum voltage at bus 18 per day (kV)	Maximum voltage at bus 18 per day (p.u.)	Power losses per day (kWh)
43	129	254.0390	1.10002	169.72
44	132	253.9780	1.09976	169.68
60	180	253.0010	1.09553	169.36

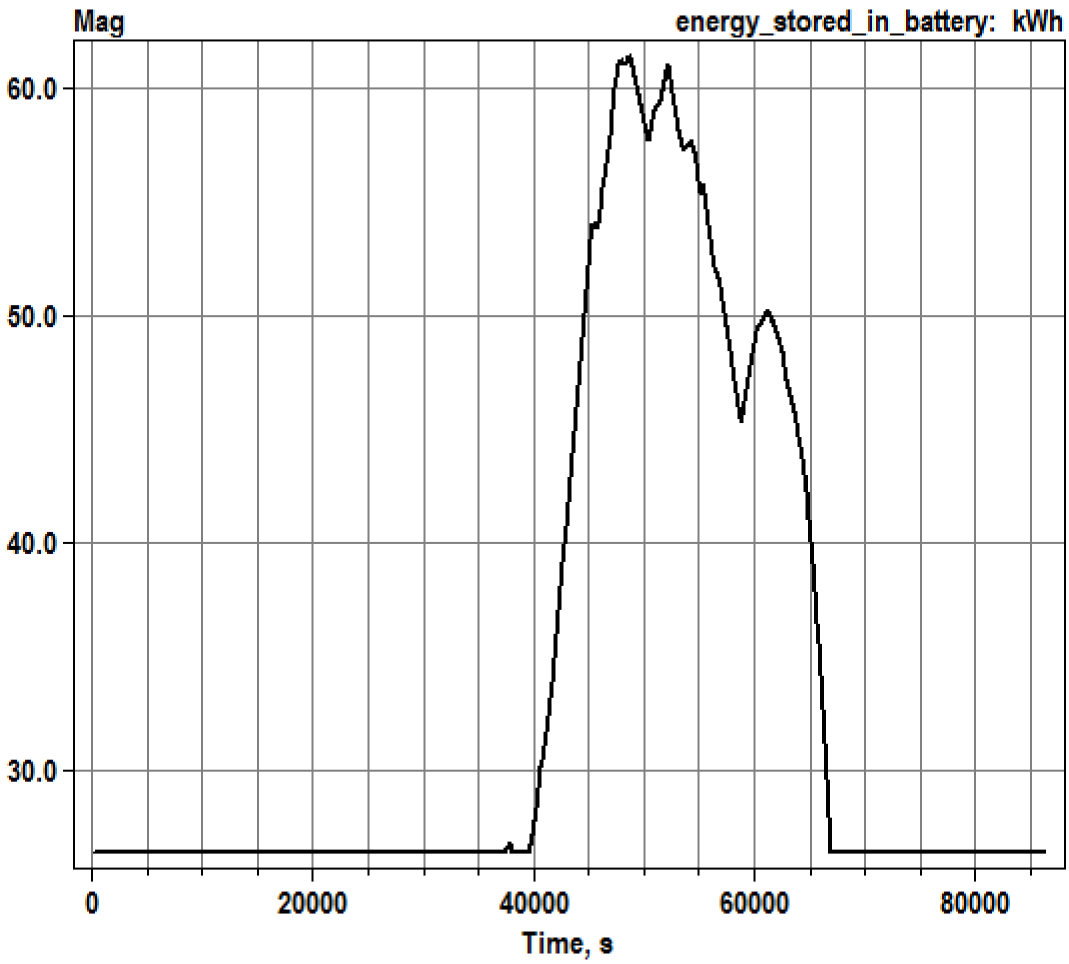


Figure 29 kWh stored in the battery over 1-day

Although over-sizing of the battery to $180kW$ helps us more in voltage regulation and power losses reduction, a 36.36% increse in kWh of the battery leads relatively low (0.189%) reduction in power losses.

Fig. 29 shows the energy stored in battery over a day. The storage device always starts with a 20% of SOE which is $20\%.132 = 26.4kW$. It continues in idling mode till around $10am$ which the PV generation would be greater than the demand and therefore the storage device starts to charge. Then at $17pm$, since now the demand is greater than PV generation the storage device starts to discharge till it reaches again 20% of SOE.

6 Future work

6.1 Unbalanced Distribution Network

The PV system considered is connected at a single-phase node, so the PV power injected is not equally divided between the three phases. Thus, the power increase is not the same in every phase. Voltage imbalance level should be analyzed. The voltage imbalance index was considered as the ratio between the negative-sequence voltage and the positive sequence voltage, as defined in [78] and calculated by (30).

$$D = \frac{V_-}{V_+}.100\% \qquad (40)$$

According to [78], it is desirable that this index remains below 2%, once a voltage imbalance greater than 2% could cause some damage in certain equipment.

Single phase PV voltage control is not a common practice nowadays but has the capacity [79]. The future studies can be dedicated to single-phase voltage control of unbalanced distribution system to regulate PCC voltage of each phase independently. It shows that reduction in the OLTC operation is more significant with each phase voltage control by both OLTC and PV. Each tap positions are changed independently to maintain the voltages in desired level.

Through time, consumers and the appliances they use get more attention, so one should analyze single, two and three phases loads, that cause the network to be unbalanced.

7 Conclusion

The thesis underlines the importance of the active management of the distribution network in the smart grid paradigm, to face the over/under voltage problems caused by emerging DGs and new loads as EVs. This work was largely motivated from the ongoing installations of 1-phase PV generators on the existing distribution feeders.

In this framework, traditional voltage control techniques of passive networks (e.g., OLTCs) should be revised to answer the uncertainties imposed. Here, different voltage control strategies for PV and PV storage systems were introduced and assessed and finally the voltage control by means of energy storage device is proposed to allow the DSO to manage the grid more efficiently.

It is essential to utilize software tools capable of modeling unbalanced networks and, furthermore, to perform the daily power flow calculation. In this study, the software OpenDSS with daily simulation mode was utilized to analyze the impact of high PV penetration on feeder's critical bus.

The proposed control method is validated using a radial residential feeder implemented in OpenDSS. The DERs are modeled using the ones inside OpenDSS with the corresponding load-shapes of each.

The distribution feeder is built in OpenDSS software and the control algorithm is carried out by MATLAB. Indeed, the common object model (COM) interface capability of OpenDSS is used to interface with MATLAB to observe the effect of the proposed control in the power grid. In other words, OpenDSS can be used to solve the power flow, and control logic can be implemented in MATLAB

The simulation results have demonstrated that the proposed control method ensures the securing of voltage quality per day according to standard EN 50160.

Battery charging/discharging is activated per voltage threshold. After identifying the critical bus, The storage device is going to discharge only if the critical bus's voltage is below the limit and the SOE_t is greater than $SOE_{\min}$. On the other hand, the storage device is going to charge only if the critical bus's voltage is beyond the limit and SOE_t is less than $SOE_{\max}$. Otherwise the storge device goes to idling mode. Testing the method on a simulated feeder with 54% PV penetration, it is found that a $45kW$ and $135kWh$ battery storage is sufficient to mitigate voltage rise.

Our results show that by applying energy storage control algorithm illustrated in the literature, the maximum and minimum of critical bus voltages can be controlled and network losses can be minimized. Furthermore, the deployment of such storage solutions would limit the practice of power curtailment, thus allowing an increased PV penetration.

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