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Determination of Smart Inverter Power Factor Control Settings for Distributed Energy Resources

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SUMMARY

This paper presents three methods to determine appropriate smart inverter power factor settings that reduce voltage impact of inverter-based distributed energy resources (DER) on the distribution system. The power factor setting formula can be easily derived when there is only a single DER system connected to a distribution feeder. However the further analysis shows that the power factor settings in the single DER scenarios are not appropriate when multiple DER systems are connected. The aggregate impact on voltage from all DER systems must be taken into account. The three methods presented vary in computational complexity, data requirements, and effectiveness. The simulation results performed on a 4 kV utility feeder show that although the three methods vary in effectiveness, they all help reduce the voltage rise and hence the potential overvoltage.

KEYWORDS

Distributed Energy Resources, PV, Power Factor, Smart Inverter, Voltage Deviation

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Introduction

With the onset in the past few years of tax incentives, subsidies, and renewable portfolio standards for distributed energy resources (DER), utilities are experiencing increasing numbers of interconnection requests. With the arising issues caused by DER integration, more and more utilities have recognized the need for inverter technologies to provide grid-support function. Voltage-related issues are often the most limiting issues regarding integrating DER. In many cases, use of inverter controls (advanced inverter grid support functions) can be the least cost solution for mitigating DER-induced voltage issues. Moreover, previous studies [1] [2] have shown that advanced inverter functions can significantly increase a feeder hosting capacity which is the ability to accommodate DER systems without causing adverse impacts.

A common set of the inverter grid support functions have been developed [3] by the industry. Power factor control, volt-var control, and volt-watt control are several common grid support functions targeting voltage issues at the distribution level. Among them, the power factor control is probably the most common function since it is most easily understood and used. Nearly all large three-phase DER system interconnecting to the grid have power factor control capability, and vendors for smaller single phase units are adopting this capability as well. In addition, the IEEE 1547 Working Group has recently voted to allow DER to provide reactive power control if the local utility allows for it.

While the industry is moving towards adopting advanced inverter functions, determining appropriate settings for these functions is critical to ensure DER provide the response that is anticipated. DER having power factor setting close to unity may not be effective at mitigating DER-induced voltage issues while low power factor settings could exacerbate the voltage issues, increase the need for reactive resources, and increase power losses. Additionally, power factor settings that work for one DER site may not work for another location. A systematic approach is needed to address these issues. Exhaustive simulations of the potential settings could identify the appropriate power factor settings [4] [5]. However, this method requires intensive simulations especially when multiple DER systems are on the feeder and the number of possible power factor settings combinations is significantly large.

This paper presents the analytical solutions to determine the appropriate power factor settings for single DER systems as well as multiple DER systems on a single feeder. The proposed methods can be easily applied to any radial distribution feeder with a model.

Importance of Reactive Power Capability

Historically, the inverters of photovoltaic (PV) systems have been sized 10-20% larger than the PV array. With falling PV module prices, project financials have changed in favor of higher array-to-inverter ratios. However, any reactive power (var) related inverter function used to mitigate adverse voltage impacts from DER requires sufficient inverters capacities. If the inverter is undersized and the active power (watts) has precedence, the DER system cannot provide reactive power at full output when the reactive power capability is needed most; as a result, unacceptable voltage rise can occur.

Equation (1) is the reactive power output of a PV system which has a watts precedence setting, where P and Q are the PV active power and reactive power; pf and $Rating$ are the PV inverter power factor and the rating respectively. In a watts- precedence mode, the inverter gives precedence to active power and curtails reactive power when the total current in the inverter reaches its rating. It is obvious that with a watts- precedence setting the reactive power has to decrease to allow for the active power when the active power increases beyond the rating times the power factor. On the other hand, if the inverter has a var- precedence setting, the active power are limited to the rating times the power factor and the inverter works under the designated power factor in its full range.

Fig. 1 shows the voltages under three different scenarios: 1) unity power factor, 2) power factor control with a watts- precedence setting, and 3) power factor control with a var- precedence setting. The voltage with the PV at unity power factor, denoted by the blue curve, goes beyond the ANSI limit (1.05pu) at high PV generations. The power factor control with a watts- precedence setting (orange curve) helps reduce the voltage. However, as the active power increases to near full output, the inverter's capability to provide reactive compensation decreases, thus also decreasing the ability to provide overvoltage mitigation. The worst case condition occurs when the active power reaches full output and the reactive power drops to zero, resulting in the voltage suddenly "snapping" to the high voltage condition that occurs when the PV is operating at unity power factor. As a comparison, the power factor control with a var-precedence setting (gray curve) successfully mitigates the overvoltage. This example demonstrates that the reactive power capability is very important especially when the active power is close to the full output where the overvoltages are more likely to occur.

$$Q = \begin{cases} \frac{P\sqrt{1-pf^2}}{pf}, & P \le Rating * pf \\ \sqrt{Rating^2 - P^2}, & Rating * pf < P \le Rating \end{cases} \quad (1)$$

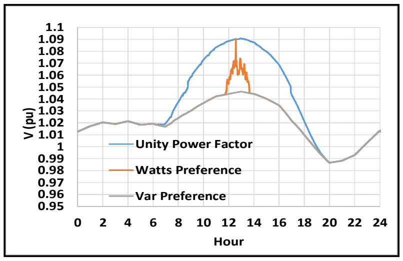


Figure 1. Voltages

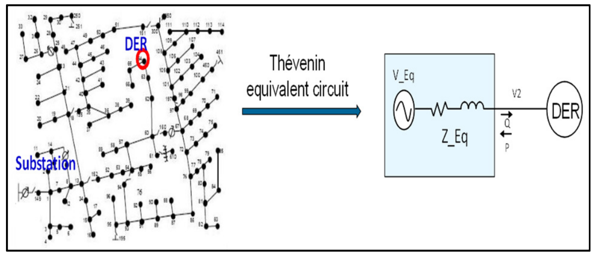


Figure 2. Equivalent circuit of a feeder with single DER

Var precedence ensures the var capability over the full inverters range. Although the var precedence causes potential energy curtailment, the curtailment is usually only a small fraction of the total PV energy. In the example in Fig. 1 the energy curtailment due to the var precedence is only 0.45% of the total energy at 0.96 power factor. Alternatively, oversizing inverters can also provide the necessary var capability. A 10% increase in inverter size can provide +/- 0.90 power factor at full output.

In the following discussions the inverters are assumed to have the full-range var capability and to be able to provide up to +/- 0.90 power factor.

Determination of Power Factor Settings to Mitigate Voltage Rise

The inverter-based DERs can use off-unity power factor and absorb reactive power to reduce voltage rise. If appropriate inverter settings are chosen, one DER is able to mitigate the voltage rise caused by the active power injection without causing any adverse impacts, such as creating unacceptable voltage change or low voltages elsewhere on the system. In this section, methods are presented that demonstrate how to determine appropriate power factor settings for both single DER system and multiple DER systems on a single feeder [6].

A. Power Factor Settings for Single DER System

A feeder with a single DER site is shown Fig. 2. Looking from the terminal of the DER system the feeder can be simplified as an equivalent voltage source connected with an equivalent impedance as shown in Fig. 2. The voltage deviation caused by the DER active power and reactive power generation can be determined from the equivalent circuit as Equation (2).

$$\Delta V_{pv} \cong \frac{R \times P + X \times Q}{V} \quad (2)$$

$$\frac{P}{Q} \cong -\frac{X}{R} \quad (3)$$

Where ΔV_{pv} is the DER-induced voltage change; V is the base voltage; X, R are the equivalent reactance and resistance; P, Q are the DER active power and reactive power. Let $\Delta V_{pv} = 0$, the relation between P and Q can be derived as Equation (3).

The negative sign indicates the opposite directions of the active power and reactive power. The power factor can be derived as Equation (4).

$$pf \cong \frac{\frac{X}{R}}{\sqrt{\left(\frac{X}{R}\right)^2 + 1}} \quad (4)$$

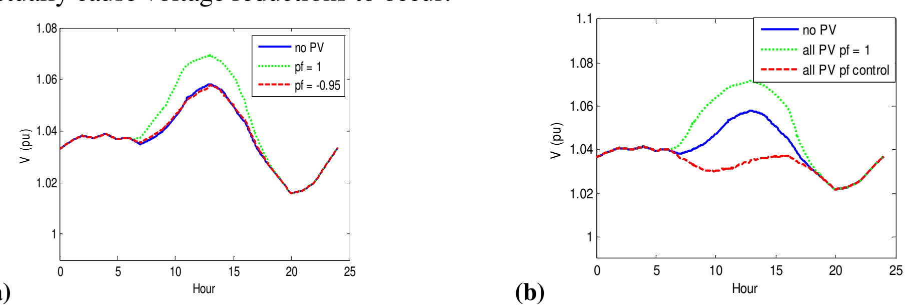
The X/R ratio at the DER interconnection primary node (medium-voltage side of DER step-up transformer) determines the power factor. Given the DER location on the feeder, the X/R ratio can be calculated by a short circuit study and then the power factor can be simply calculated with Equation (4).

B. Power Factor Settings for Multiple DER Systems

1) Aggregate Impacts of Multiple DER Systems

As shown previously, the calculation of the power factor for single DER system is straightforward and simple. When it comes to the scenarios of multiple DER systems connected at different locations on a feeder, an instinctive question would be *can we still use the power factor settings calculated for each single DER to mitigate the voltage rise without causing adverse impacts?*

The voltage response on a feeder with a single DER system operating at unity power factor (green curve) and the calculated power factor using Equation (4) (red curve) are shown in Fig.3 (a). As can be seen, the calculated power factor setting successfully mitigates the voltage rise and keeps the voltage very close to the no-DER condition (blue curve). A separate simulation is performed wherein two additional DERs are interconnected at other locations while the voltage at the first DER location is again shown Fig. 3(b). In this case, the red curve refers to the voltage with all the DER systems having the power factor settings calculated using Equation (4) and based on each of their short-circuit X/R ratios. It is clear that when multiple DER system are connected to the same feeder and power factor settings are calculated using only (4), the DER systems can overcompensate for voltage rise and actually cause voltage reductions to occur.



(a) **(b)**

Figure 3. Voltage compariosns (a) single DER (b) multiple DERs

In multiple DER systems scenario, the voltage deviation from the no-DER case at a DER primary node is actually the result of all the DERs' active power and reactive power productions. The calculation formula in Equation (4) essentially considers the impacts of the DER at this location alone and does not take into account the impacts of the other DER systems' power productions. As a result, the voltage could be reduced unnecessarily low by the aggregate impacts from the other DERs. Therefore, to properly calculate the power factor settings for multiple DER systems, the aggregate impacts on the voltages from all the DER systems connected on a feeder must be considered.

2) Methods to Calculate Power factor Settings

As discussed in the previous subsection, all the DER systems connected on a feeder have to be taken into account when determining the power factors for multiple DER systems on a feeder. Three methods varying in complexity to calculate power factor settings for multiple DER systems will be discussed in the following.

The first methods is a simple estimation that applies the median X/R ratio of a feeder using Equation (4) to calculate a single power factor setting for the whole feeder. Although that single setting may not be very effective, the median X/R ratio based method provides a quick and simple estimation with limited DER system information (e.g., location).

If the DER systems sizes and the locations are known, an alternative method is to use the size weighted average X/R ratio of all the DER systems to calculate a single power factor setting. This method is certainly effective for a single DER system. However, similar to the median X/R ratio based method, this weighted average X/R based method is not always effective in multiple DER systems scenarios.

The most complex but the most effective method is the sensitivity based method that approximates the aggregate impacts on the voltage deviations through sensitivity analysis. This method requires the feeder circuit model and the DER systems sizes and locations information to perform the calculation. As shown in Fig. 4, the sensitivity-based method approximates the aggregate impacts from all the DER systems on the voltage deviation of a particular bus by linearization [7]. The sensitivity factors SP_{ij} and SQ_{ij} are defined in Equation (5) where ΔP_j is the active power change of the DER at but j and ΔV_{ip} is the resulting voltage change at bus i due to ΔP_j. SQ_{ij} is defined in the similar way. SP_{ij} and SQ_{ij} are the sensitivities of voltage at bus i with respect to the active power and reactive power of the DER at bus j. The voltage change at bus i caused by the DER at bus j can be expressed as the sum of SP_{ij} multiplies the DER active power and SQ_{ij} multiplies the DER reactive power. Accordingly the total voltage change at but i caused by multiple DER systems on the feeder can be expressed as Equation (6) where N is the number of the DER systems connected on the feeder. The voltage change at each DER primary bus can be formulated as Equation (7).

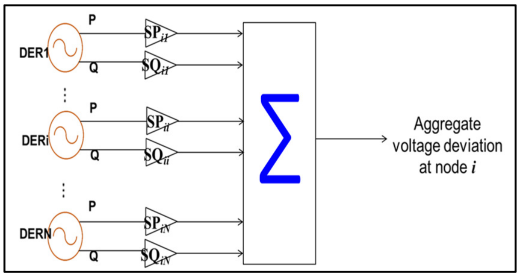


Figure 4. Aggreate impacts on voltage deviation

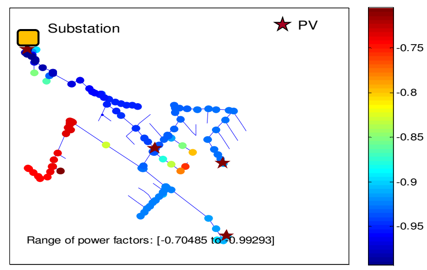


Figure 5. Required power factor at different locations

$$SP_{ij} = \frac{\Delta V_{ip}}{\Delta P_j}, SQ_{ij} = \frac{\Delta V_{iQ}}{\Delta Q_j} \quad (5)$$

$$\Delta V_i = SP_{i1}\Delta P_1 + SQ_{i1}\Delta Q_1 + \cdots SP_{iN}\Delta P_N + SQ_{iN}\Delta Q_N \quad (6)$$

$$\Delta V = SP * P + SQ * Q \quad (7)$$

Where $\Delta V = [\Delta V_1, \Delta V_2, \ldots, \Delta V_N]^T$; $P = [P_1, P_2, \ldots, P_N]^T$; $Q = [Q_1, Q_2, \ldots, Q_N]^T$; SP and SQ are the sensitivities matrices composed of SP_{ij} and SQ_{ij} respectively.

The objective is to mitigate the voltage deviations given in Equation (8). If the power factor of the DER is limited, the constraint can be expresses as Equation (9), where a can be derived from the power factor limit. Combining Equation (5) to (9), the power factor setting for each DER system can be solved as the solution to this optimization problem.

$$min \sum_{i=1}^{N} \Delta V_i^2 \quad (8)$$

$$\left|\frac{Q_i}{P_i}\right| \le a \quad (9)$$

Simulation Results

TABLE I. **PV SYSTEMS LOCATIONS CHARACTERISTICS**

PV	X/R	Short-circuit impedance	Power factor for single PV	PCC voltage rise due to single PV @unity pf
PV1	6.149	0.2	-0.992	0.0014
PV2	2.385	0.61	-0.943	0.0123
PV3	1.965	1.18	-0.921	0.0274
PV4	1.905	0.82	-0.913	0.0202

In this section the proposed power factor calculation methods are applied on a distribution feeder to test their effectiveness. The simulated distribution feeder has 4 kV primary voltage and 2 MW peak load. Four 1MW PV systems on the feeder are marked in Fig. 5. The characteristics of the PV sites, the calculated power factor setting for each single PV, and the simulated PCC voltage rise due to each single PV are listed in Table I.

A. DER Location Matters

The short-circuit impedance increases while X/R ratio decreases toward the feeder end. As a result the voltage rise induced by the same sized DER is minimal near the substation and increases toward the feeder end as indicated in Table I. On the other hand, the required power factor setting for a single DER system is close to unity power factor near the substation and drops toward the feeder end as shown in Fig. 5. Therefore, the location of DER on a feeder does impact the power factor setting as well as the DER impact on that feeder. For instance, PV1 located near the substation induces only 0.0014 pu voltage rise while PV4 closer to the feeder end induces 0.0202 pu voltage rise at unity power factor. In order to mitigate the voltage rise, PV1 only requires a near unity power factor while PV4 requires a much lower power factor.

The results in Table I and Fig. 5 indicate that locations with high short-circuit strength, like PV1 location, may not require any reactive power control even though inverter functions that utilize var control are most effective at high X/R ratio locations. More reactive power absorption is needed in order to mitigate the voltage rise caused by the same sized DER toward the feeder end. Therefore, inverter functions utilizing reactive power as mitigation become less effective at low X/R ratio locations further toward the feeder end.

B. Voltage Deviation Mitigation with Power Factor Control

The combinations of the four 1 MW PV systems locations make fifteen PV deployments. The primary side voltage rise of each PV deployment case at unity power factor is plotted against the total PV penetration in Fig. 6. The voltage rise increases with the increase of PV penetrations. The highest voltage rise is approximately 5% when all the four PV systems are connected.

The median X/R ratio of the simulated feeder is 2.36 and the power factor calculated by Method 1 is 0.92. This power factor is applied to all PV systems, other than PV1 which does not require power factor control due to minimal PV-induced voltage rise at that location. The voltage deviations under this single feeder-wide power factor setting are shown in Fig.7. In some higher penetration levels this power factor setting over-mitigates the voltage rises and causes a 2% voltage drop.

The voltage deviations under the power factor settings calculated by Method 2 that uses the weighted average X/R ratio are shown in Fig.8. In single PV scenarios (1 MW penetration), Method 2 yields similar results to Method 1. However in the multiple PV systems scenarios, the effectiveness of Method 2 is somewhat random. In some lower penetration such as 2 MW it is found that near 2% voltage deviation can be seen, while in higher penetrations such as 4 MW it holds voltages within 1% band. Although the power factor settings calculated by Method 2 vary based upon the PV deployments, a single power factor setting is used through the whole feeder for each PV deployment.

Fig. 9 shows the voltage deviations of the simulated PV deployments under the power factor settings calculated by Method 3. The voltage deviations are well within 1% band for all penetration levels. In this method the power factor settings vary with the PV deployments as well as the PV locations.

The simulation results from the three calculation methods show that the sensitivity based method is most effective and is able to reduce voltage deviations to a small band. The other two simple estimation method are not as effective as the model based analysis method but compared with the unity power factor case they still help reduce the voltage rise and reduce the risk of overvoltage.

This similar approach for analyzing various PV deployments using the three methods proposed here was applied to a number of additional distribution feeders with widely varying characteristics [6] and similar responses were observed. Method 1 and Method 2 were somewhat effective, while Method 3 generally resulted in improved voltage response.

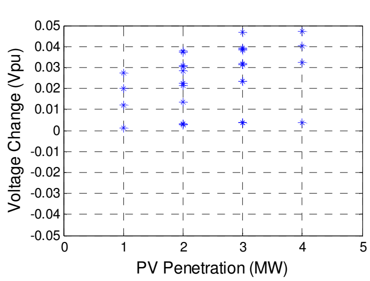


Figure 6. Voltage rise@ unity PF

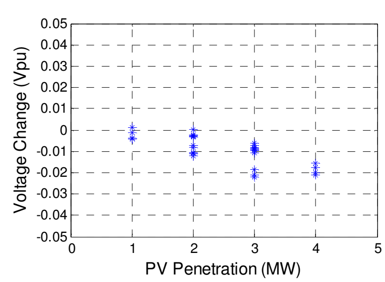


Figure 7. Voltage deviation@ PF by Method 1

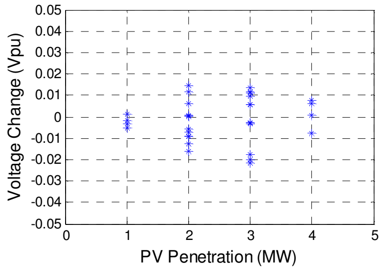


Figure 8. Voltage deviation@ PF by Method 2

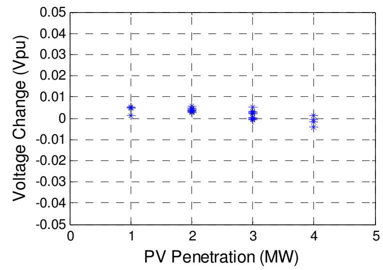


Figure 9. Voltage deviation@PF by Method 3

Conclusions

Power factor control is a common method of reactive power control to mitigate voltage rise issues caused by DER interconnection. This paper discusses various methods for determining appropriate power factor settings and simulation results comparing each method are also presented. From the analysis and the simulation results we can conclude that the simple method for considering a single DER is rather effective. This method determines a site-specific power factor based upon the DER point of interconnection X/R ratio.

However this same method is not effective when multiple DER systems are located on the same distribution feeder. Other methods are necessary. Simple techniques such as using the feeder median X/R ratio or weighted average X/R ratio are found to be somewhat effective, however the sensitivity based approach proposed is found to be the most effective.
The location of DER on a feeder does impact the power factor setting. Locations with high short-circuit strength may not require any reactive power control even though inverter functions that utilize var control are most effective at high X/R ratio locations. At low X/R ratio locations, other inverter functions can be used and may be more effective. These functions include volt-var, volt-watt, etc. Methods to determine settings for these functions are currently being developed. While the analysis examples shown here are based upon distributed PV, similar results are expected with other forms of DER as well.

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