Voltage-based limitations on PV hosting capacity of distribution circuits

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October 21, 2016

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Acknowledgment and disclosure

Production of this paper was financially supported by Ameresco. NPPT gratefully acknowledges this support. The author also gratefully acknowledges the following reviewers, all of whom made helpful contributions to this paper. However, these reviewers' generosity should not be interpreted as an endorsement by any reviewer of the statements in this paper. The author accepts sole responsibility for the contents.

John Berdner, Enphase Energy
Paul Brucke, Brucke Engineering
Babak Enayati, National Grid
Milad Kahrobaee, Northern Plains Power Technologies
Michael McCarty, SolarCity
Chris Mouw, Northern Plains Power Technologies
Dustin Schutz, Northern Plains Power Technologies
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Reigh Walling, Walling Energy Systems Consulting

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Nomenclature

Area EPS	The EPS that serves the location at which a DER is to be installed. This would typically include the distribution circuit and substation, and possibly adjacent circuits.
Bulk EPS	The EPS that serves the Area EPS. This is normally taken to be the (sub)transmission system that serves the Area EPS.
DER	Distributed Energy Resource
EMVR	Electro-Mechanical Voltage Regulator (OLTC, line regulator, voltage-switched capacitor)
EPS	Electric Power System
IEEE	Institute for Electrical and Electronics Engineers; www.ieee.org
OLTC	On-Load Tap Changer (usually a substation transformer tap changer)
pf	Power Factor (here, the displacement power factor defined by the phase angle between the PV plant current and voltage at the POI)
POI	Point of Interconnection; the electrical interface point between a DER and the Area EPS
PV	Photovoltaic

Executive summary

This document addresses the problem of determining the size of photovoltaic (PV) plant that can be allowed to interconnect to a distribution circuit while minimizing the likelihood that the PV plant will lead to voltage constraint violations on the circuit. The key features of this report are:

1.) On page 9, in the blue box, a procedure is given by which the allowable PV plant size can be conservatively estimated, with certain assumptions, given a knowledge of
    a. The source R and X as seen from the PV POI;
    b. The expected base voltage normally observed at the PV POI;
    c. The number, location and types of EMVRs on the circuit;
    d. The control bandwidths of the EMVRs and the parameters of any line drop compensation used;
    e. The source R and X as seen from each EMVR.
2.) The use of nonunity power factor operation to mitigate PV voltage impacts is discussed. This method is effective, but it does increase the system operator's costs. Expressions are provided on page 11 for making first-order calculations of the required value of the nonunity power factor. Note that one can skip the procedure in the blue box on Page 9 altogether and go directly to the nonunity power factor equations on page 11, if the system operator allows nonunity power factor operation absorbing Vars.
3.) An argument is provided that suggests that flicker is not a limiting factor in allowable PV plant sizes on distribution circuits.

Introduction

In many service territories, electric power system operators are limiting the allowable sizes of some proposed photovoltaic (PV) plants due to concerns over the impact that the PV plant outputs will have on the voltage profiles of their host distribution circuits.

It is not in dispute that PV plants will impact circuit voltage profiles. The real power output of a PV plant will supply part of the load on the circuit, reducing current through the circuit and thus reducing voltage drop. If the PV plant output exceeds local load, power will flow back toward the utility source, and the voltage at the PV plant point of interconnection can actually rise. Other impedances associated with PV plants, such as the capacitance of underground collector systems in large PV plants, can also have an impact on circuit voltage profiles.

Ideally, the circuit, all associated electromechanical voltage regulators (EMVRs), and all interconnected loads and distributed energy resources (DERs) would be modeled using a detailed time-domain model. However, because of the time and expense associated with system studies, system operators and PV plant developers desire a simple screen that can be used to determine when a more detailed study might be needed. A simple screening tool used by many system operators is that a single PV plant shall produce a voltage deviation of no more than X% when the plant trips offline (i.e., its output goes from 100% to 0% in one time step). Different system operators use different values of X; 1.5%, 2% and 3% are all in use. Sometimes the basis for the selection of X value is not clear, but in some cases the basis is said to be flicker considerations. The purpose of this paper is to discuss a) the allowable voltage deflection requirement, and b) the resulting PV plant size constraints.

Approximation of the expected voltage modulation from a PV plant

Consider the highly simplified distribution circuit shown in Figure 1, with the sign conventions as noted.

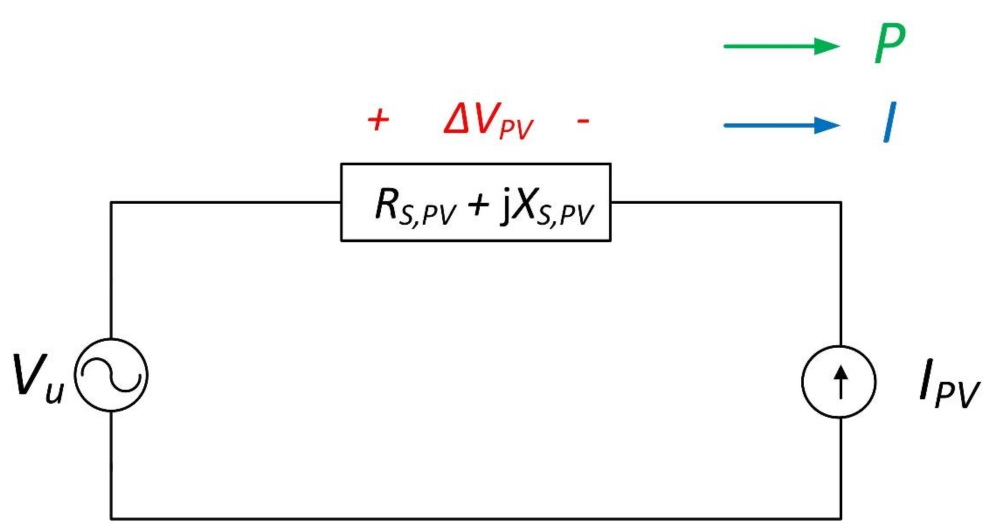

Figure 1. Simplified configuration for obtaining an estimate of ΔV_{PV}.

The PV power output flows through the source impedance, which creates a change in voltage ΔV_{PV}. The value of the PV-caused voltage change ΔV_{PV} is given by Equation (1)[a]:

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{(R_{S,PV} \times P_{PV}) + (X_{S,PV} \times Q_{PV})}{V_r^2} + j\,\frac{(X_{S,PV} \times P_{PV}) - (R_{S,PV} \times Q_{PV})}{V_r^2} \qquad \text{Eq. (1)}$$

where

- ΔV_{PV} is the fractional change in voltage at the PV POI caused by the change in PV output;
- $R_{S,PV}$ and $X_{S,PV}$ are the real and reactive source impedance as seen from the POI of the PV plant in question looking back up toward the utility source;
- P_{PV} and Q_{PV} are the change in injected real and reactive power per phase at the POI, using the load sign convention noted in Figure 1 (i.e., power injected by the PV plant is negative); and
- V_r is the nominal voltage at the PCC.

Equation (1) is written as an approximation to remind the reader that it assumes zero load on the circuit, and does not consider the impacts of any other DERs on the same circuit. This equation also neglects the real and reactive consumption of the source impedance itself, which can be accounted for by suitably adjusting P_{PV} and Q_{PV}.

If the PV plant is operating at unity power factor, then Q_{PV} is zero[b]. Thus, the magnitude of the voltage V_u, relative to V_r, is

$$\left|\frac{V_u}{V_r}\right| = \sqrt{\left(1 + \frac{R_{S,PV} P_{PV}}{V_r^2}\right)^2 + \left(\frac{X_{S,PV} P_{PV}}{V_r^2}\right)^2} \qquad \text{Eq. (2)}$$

If the X/R ratio is less than about 4.5, then the second term under the radical in Equation (2) adds less than 0.025 to the normalized magnitude of V_u, so under that condition, as a first-order approximation the quadrature or imaginary term in Equation (1) can be neglected. Then, Equation (1) can be simplified and rearranged as follows:

$$P_{PV,allowed} \approx \frac{\Delta V'_{allowed,PV} \times V_r^2}{R_{S,PV}} \qquad \text{Eq. (3)}$$

where $\Delta V'_{allowed,PV}$ is the *allowed* fractional voltage modulation (expressed as a unitless fraction) at the PV POI, and $P_{PV,allowed}$ is a per-phase value. When Equation (3) is used, sufficient margin should be built into the value of $\Delta V'_{allowed,PV}$ to account for the neglect of the quadrature term.

What should the allowable change in voltage be?

As noted above, the most accurate assessments of ΔV_{PV} and $P_{PV,allowed}$ are provided via detailed modeling of the circuit, EMVRs, and all DERs. However, system operators and PV plant developers desire some form of simplified planning-level screen that can be used to determine whether the expense and time of

[a] The derivation of Equation (1) is given in Appendix A.

[b] A reminder that setting Q_{PV} to zero neglects the Var consumption of the system inductances.

simulation are justified for a given plant. Usually this simplified screen takes the form of determining what value of $\Delta V_{allowed,PV}$ should be used in Equation (2). The next sections explore this question in detail.

Voltage limitations imposed by steady-state standards

The standard used by most utilities to determine the allowable voltage range on a distribution circuit is ANSI C84.1-2011 [1]. This standard specifies "service voltages", which for present purposes would be the steady-state voltage at the point of interconnection (POI) of a distributed energy resource (DER) to the distribution circuit; and "utilization voltages", which are the steady-state voltages seen at the terminals of customer equipment including the effects of secondary circuit elements. The voltage that is applicable to this discussion of allowable PV system impacts is the service voltage, because a PV plant cannot be responsible for the impacts on voltage of a customer's secondary circuit.

ANSI C84.1-2011 specifies two ranges: Voltage Range A and Voltage Range B. For 12.47 kV, 13.2 kV, and 13.8 kV distribution circuits, Voltage Range A is from 97.5% of nominal to 105% of nominal. Voltage Range B is from 95% of nominal to approximately 106% of nominal. These voltage ranges are shown graphically in Figure 2. The terminology associated with determining which range is applicable in this case is qualitative. The standard says that the distribution system shall be designed and operated such that "…most service voltages will be within the limits specified for Range A", but the term "most" is not quantified. The standard also says that it is permissible for service voltages to fall into Range B, as long as the excursions from Range A are "…limited in extent, frequency, and duration", and that whenever such excursions occur, corrective action is taken to bring the voltage back within Range A "within a reasonable time". Such corrective actions would include the operation of tap changers, line regulators, or switched capacitors, or actions taken by PV inverters. Again, the qualitative terms are not quantified and their definitions are left to the discretion of the system operator.

What is clear is that PV systems should be planned such that they are not expected to frequently drive their POI voltages outside of the A range. Ideally, one would meet this condition by modeling the PV plant and distribution circuit under a variety of loading and irradiance conditions, including the control actions of any affected EMVRs and the impacts of any other DERs on the circuit, and verifying that excursions into Range B are limited in extent, frequency and duration. However, such detailed modeling involves time and expense, and it is thus desirable to develop a simple recommended $\Delta V_{allowed}$ threshold and a simple means for assessing its value that can be used as a screen to assess when more detailed study might be needed.

The assessment means already in use by most utilities involves calculating or modeling the ΔV that results from tripping of the PV plant (100% output power to 0% output power in one time step)[c]. This 100% to 0% stepwise transition is a highly conservative approximation to a cloud passage, which in practice will not cause the PV power to drop all the way to zero output and which usually will not start from 100% output. Cloud shadows also do not cause stepwise changes in PV output, a topic that will be considered in detail later in this document.

[c] It is important to realize that the point of this exercise is NOT to model an actual trip condition, such as a fault. The tripping of the PV plant is used instead as a convenient way to assess the voltage rise (ΔV) caused by the PV output by suddenly eliminating that voltage rise.

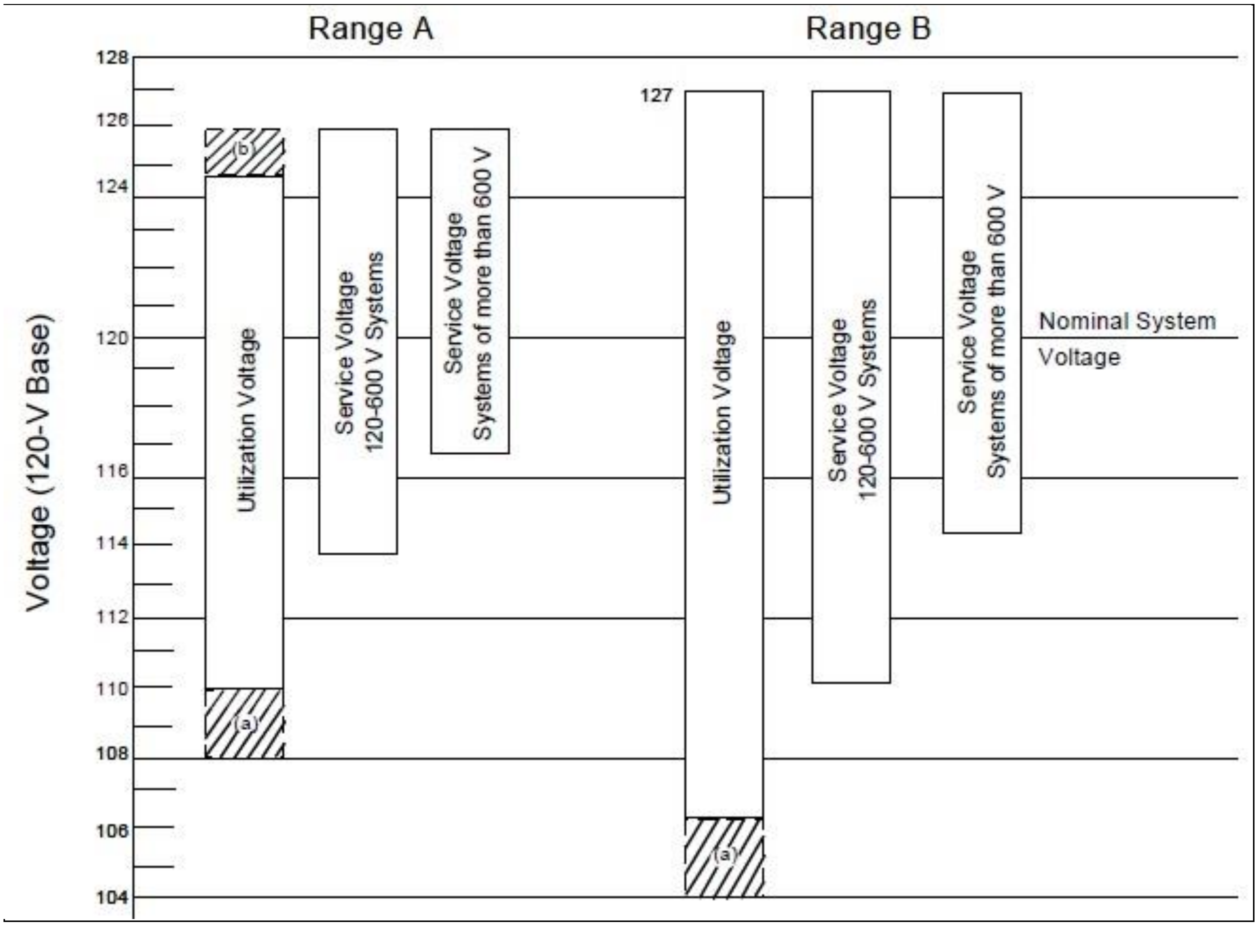

Figure 2. Voltage ranges specified by ANSI C84.1-2011, on a 120-V base (divide by 120 to get a per-unit value). From http://www.powerqualityworld.com/2011/04/ansi-c84-1-voltage-ratings-60-hertz.html.

Determination of the $\Delta V_{allowed}$ threshold value is more complicated. Under normal operating conditions, if the PV plant is operating at unity power factor and the X/R ratio of the circuit is below 4.5 or so[d], then the real power output of the PV plant will by itself cause the voltage at its POI to rise above its pre-PV value. Thus, it is obviously important to ensure that the upper limit of the ANSI A range (voltage of 105% of nominal) is not violated. However, the alteration of the distribution circuit voltage profile by the PV plant may lead to changes in the states of the EMVRs on the circuit. This changes the baseline voltage at the PV POI, which means that the steady-state voltage at the PV POI prior to the addition of the PV may be higher than the steady-state voltage one would see after the 100% to 0% trip test because the EMVRs, in particular any tap-changing transformers, may have adjusted their tap positions to reduce the elevated circuit voltage caused by the PV output. In this case, a cloud shadow could cause voltages on the circuit to drop below that lower threshold of 97.5% of nominal.

[d] The Var demand of the circuit inductances, caused by the real power flowing through those inductances, must come from the grid. If the X/R ratio is high, that Var demand can be large enough that the PV power actually can cause a voltage *drop* instead of a voltage rise. However, this is unlikely in distribution because the X/R ratio is rarely high enough.

Voltage limitations imposed by electromechanical voltage regulators

The foregoing discussion suggests that a simple means for minimizing the likelihood that PV plant outputs will cause ANSI A range voltage violations is to keep the voltage change caused by the PV plant at the EMVR measurement location, denoted ΔV_{EMVR}, within the control bandwidth of the EMVR, ***and*** that the voltage rise caused by the PV plant at its POI, ΔV_{PV}, does not cause the voltage to exceed the top of the ANSI A range. In this case, the states of the EMVRs will not change, and assuming the circuit was regulated to within the ANSI A range to start with, then the PV output will not lead to excursions from Range A.

It is not possible to completely eliminate EMVR state changes because the steady-state voltage may lie anywhere within the EMVR's measurement window, and if by chance the voltage is near one edge or the other than any ΔV will lead to a tap change. The most reasonable approach for minimizing EMVR state changes is to set ΔV_{EMVR} equal to one-half of the control bandwidth. A commonly-accepted minimum value for the control bandwidth of tap changing transformers is 1.25% of the nominal voltage (1.5 V on a 120 V base) [2], so ΔV_{EMVR} would be 1.25% ÷ 2 = 0.625%. However, many tap changing transformers have larger control bandwidths; values of 2%, 2.5%, and 3% are also common [2], and the ΔV_{EMVR} threshold should be increased accordingly if this is the case.

It is important to remember that the value of ΔV_{EMVR} applies at the EMVR measurement location, *not* at the PV POI. The value of ΔV_{EMVR} may need to be modified if the EMVR is using line drop compensation.

For EMVRs that are upstream of the PV plant (that is, between the PV plant and the utility source), one can roughly approximate the value of ΔV_{EMVR} using Equation (4):

$$\frac{\Delta V_{EMVR}}{V_r,_{EMVR}} \approx \frac{(R_{S,EMVR} \times \Delta P_{EMVR}) + (X_{S,EMVR} \times \Delta Q_{EMVR})}{V_r^2} + j\,\frac{(X_{S,EMVR} \times \Delta P_{EMVR}) - (R_{S,EMVR} \times \Delta Q_{EMVR})}{V_r^2} \quad \text{Eq. (4)}$$

Equation (4) is simply a restatement of Equation (1) evaluated at the EMVR location, so $R_{S,EMVR}$ and $X_{S,EMVR}$ are the complex components of the grid source impedance as seen from the EMVR location, and ΔP_{EMVR} and ΔQ_{EMVR} are the per-phase changes in P and Q through the EMVR relative to what they were prior to adding the PV output to the circuit. Assuming no load on the circuit, PV operating at unity power factor, and X/R ≤ 4.5, ΔP_{EMVR} would be the PV plant output and ΔQ_{EMVR} would be the reactive power consumption in the circuit inductances.

For EMVRs that are downstream from the PV POI, then using the no-load approximation the change in voltage at the POI and that at the EMVR would be the same, and Equation (1) would apply.

Setting the allowed value of ΔV_{EMVR} to half the control bandwidth of tap changing transformers has the advantage not only of minimizing the possibility that PV would cause voltage excursions outside of the ANSI A range, but also of largely mitigating the impact of PV plants on the lifetime of EMVRs. The addition of large PV plants to a distribution circuit can lead to a significant increase in the number of variations in voltage that require utility voltage regulation equipment to operate if ΔV is significantly larger than the EMVR control bandwidth [3,4]. This increase in the number of operations of EMVRs reduces equipment lifetimes, which in turn increases the system operator's costs.

Thus, to obtain the value of $P_{PV,allowed}$, assuming that the PV plant is operating at unity power factor and that the circuit's X/R ratio as seen from the PV POI is not greater than 4.5, a three-step process is recommended. The reader is reminded that this process is conservative and approximate.

1.) First, calculate the allowable PV plant size that keeps ΔV_{EMVR} within the control bandwidth of EMVRs *upstream from the PV plant* using Equation (5):

$$P_{PV,allowed} \approx \frac{\Delta V'_{allowed,EMVR} \times V_r^2}{R_{S,EMVR}} \qquad \text{Eq. (5)}$$

where $\Delta V'_{allowed,EMVR}$ is a unitless fraction and is set equal to one-half of the control bandwidth of the affected EMVR. The control bandwidth is usually taken to be 0.0125 but may be as large as 0.03 in some cases. As noted above, if the EMVR is using line drop compensation, that would have to be considered as well.

2.) Then, calculate the allowable PV plant size ensure that ΔV_{PV} does not lead to ANSI A violations using Equation (3) (repeated here for convenience):

$$P_{PV,allowed} \approx \frac{\Delta V'_{allowed,PV} \times V_r^2}{R_{S,PV}} \qquad \text{Eq. (3)}$$

with the value of $\Delta V'_{allowed,PV}$ as determined by Equation (6):

$$\Delta V'_{allowed,PV} = 1.05 - V_{quad} - V_{PVbase} \qquad \text{Eq. (6)}$$

where V_{PVbase} is the steady-state voltage at the PV POI after the PV reaches 0% power in the 100% to 0% power "trip test", and V_{quad} accounts for the neglect of the quadrature term in Equation (1). V_{quad} depends on the ratio of $X_{S,PV}$ to $R_{S,PV}$ as follows:

$X_{S,PV}/R_{S,PV}$	V_{quad}
2	0.005
2.5	0.01
3	0.01
3.5	0.015
4	0.02
4.5	0.025

Note that Equation (3) already covers the case of EMVRs downstream from the PV plant.

3.) The allowable PV plant size, assuming unity power factor operation, is the lesser of the values calculated in steps 1 and 2. Remember that the $P_{PV,allowed}$ will be per-phase.

To determine V_{PVbase}, the voltages at the proposed POI should be calculated for minimum loading conditions, with the operation of EMVRs taken into account, and the value that leads to the smallest

$\Delta V'_{allowed,PV}$ should be selected. For circuits with downstream line regulators, or for POI locations that have low values of V_{PVbase}, the resulting values of $P_{PV,allowed}$ may be very small. In these cases, nonunity power factor operation of the PV plant should be considered, as explained in the next section.

Mitigation of voltage issues via nonunity power factor operation

Equation (1) demonstrates that the voltage impact of the real power output of the PV plant can be mitigated at the PV POI if the PV plant is absorbing reactive power[e], which means that ΔQ has a nonzero negative value. In distribution circuits, normally (but definitely not always) the ratio of X_S to R_S is between 2 and 5, so a smaller Var flow can offset the voltage impact of a larger Watt flow.

The power factor of the PV plant is determined by the ratio of Q to P, so if the PV plant is operated in a constant power factor mode, absorbing Vars, then Equation (1) can be written thus:

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{(R_{S,PV}P_{PV})-(kX_{S,PV}P_{PV})}{V_r^2} \qquad \text{Eq. (7)}$$

where the quadrature term has been neglected,

$$Q_{PV} = k \times P_{PV} \qquad \text{Eq. (8)}$$

and pf is the power factor, so k is constant for a given pf, bearing in mind that Equation (7) is based on the same assumptions as Equation (1). Equation (7) indicates that if the PV plant is set to operate at a fixed output power factor pf_0 at the POI using Equation (9)[f],

$$\boxed{pf_0 = \cos\left(\tan^{-1}\left(\frac{1}{X_{S,PV}/R_{S,PV}}\right)\right) \qquad \text{Eq. (9)}}$$

then ΔV_{PV} could be made to be zero at the POI. As noted above, Equation (7) is an approximation that assumes that the load on the circuit is zero and that there are no other DERs on the circuit. Note also that Equation (9) gives the value of power factor at which ΔV_{PV} is zero at the POI, but it is not required to mitigate ΔV_{PV} all the way to zero, so the value given by Equation (9) will be lower than is actually needed. Equation (10) provides a more general version of Equation (9) that allows power factor correction to a given value of $\Delta V_{allowed,PV}$:

$$pf_0 = \cos(\tan^{-1}(k)) \qquad \text{Eq. (10)}$$

and

[e] For a generator, absorbing Vars means that the power factor is leading. In this report the terms "leading" and "lagging" are avoided because they tend to lead to confusion where generators are concerned.
[f] The derivation of Equation (9) is given in Appendix B.

$$k = \frac{R_{S,PV}P_{PV} - \Delta V\prime_{allowed,PV}V_r^2}{X_{S,PV}P_{PV}} \quad \text{Eq. (11)}$$

where $\Delta V'_{allowed,PV}$ is again the allowed fractional change in voltage (unitless). The best results will be obtained from detailed load-flow modeling that includes the impacts of the loads and load distribution and of other DERs on the circuit.

When a PV plant is operated at a nonunity power factor, the inverters should be in Var-priority mode, meaning that if the inverter approaches current or power capability limits, then the inverter should curtail its real power output to preserve sufficient headroom to be able to absorb the required reactive power.

The constant power factor approach is attractive because it is relatively simple, although it must be remembered that it is the power factor at the POI that must be controlled, not the power factor at the inverter terminals, so there may be a need for additional equipment and a plant-level controller. Also, the nonunity-power factor approach should usually reduce the required number of operations of EMVRs from the unity pf case, although it will not be a complete mitigation because the power factor is usually set to minimize ΔV_{PV} at the PV POI, not ΔV_{EMVR} at the EMVR measurement point. However, this method does have two important drawbacks.

1.) It creates an additional cost for the system operator because the system operator must expend resources to generate the needed Vars. The required Vars could be generated near or in the substation if the distribution circuit impedance dominates the total source impedance, especially the total source resistance. This is usually true in distribution, but not always.
2.) It will decrease the energy harvest from the PV plant, because for some fraction of the time the real power output of the inverter would be curtailed because of the Var-priority requirement. This decrease in energy harvest is usually fairly small, but the DC-AC ratios of today's PV plants are pushing 1.4 and higher, which makes this factor more significant.

An additional drawback to this approach is that the Var flows in the PV inverter lead to increased thermal losses and heating in the inverters, which if not properly accounted for at the design stage could lead to a reduction in inverter lifetime. However, the Var flows are generally not large, so this factor is probably secondary for most inverter designs.

Voltage limitations implied by flicker standards

Another document that describes allowable voltage modulation limits caused by a varying load or source on a power system is IEEE 1453-2015™ [5][g]. This Recommended Practice imposes a limit on the allowable amount of periodic voltage modulation that will prevent annoying changes in the brightness of incandescent lights, sometimes referred to as "voltage flicker". IEEE 1453-2015™ is intended to supersede all previous flicker standards, which are now considered obsolete by the IEEE. Note that IEEE 1453-2015™ is a Recommended Practice, whereas ANSI C84.1-2011 is a standard. As of this writing, the present draft of the new version of IEEE 1547™, which is a standard, contains flicker language that utilizes the methodology described in IEEE 1453-2015™.

[g] This Recommended Practice is not *strictly* applicable to PV plant output because it assumes a periodic variation. However, to facilitate application of simplified methods, a periodicity assumption is usually made anyway.

To use IEEE 1453-2015™, some assumptions must first be made. First, one must know the frequency of the modulation of the voltage, which for the case of a PV plant means knowing the frequency of cloud shadow passages over the PV array. Note that this assumption is also required to use the GE flicker curve. For this work, an assumption of two cloud passages per minute, or four changes per minute (two up and two down), which is 0.0667 Hz, will be used.

Second, the shape of the voltage modulation waveform must also be known. In most work, it is assumed that the voltage modulation is rectangular, which is appropriate for things like motor or other large-motor starts. This is also the assumption made in Table 4 of IEEE 1453-2015™, which is a commonly-cited source for values for the allowable voltage modulation, and this same assumption underlies the GE flicker curve. Figure 3 shows a representation of what a rectangular PV output modulation would look like, using the frequency assumption made above. The PV plant output is assumed to go from 100% to 30% in a stepwise fashion. When one estimates the voltage modulation from a PV plant by tripping the PV plant, one is essentially making this rectangular modulation assumption, and is further assuming that the output goes from 100% to 0%. A better approximation to the shape of a PV cloud transient is the "double ramp" function, which is shown in Figure 4.

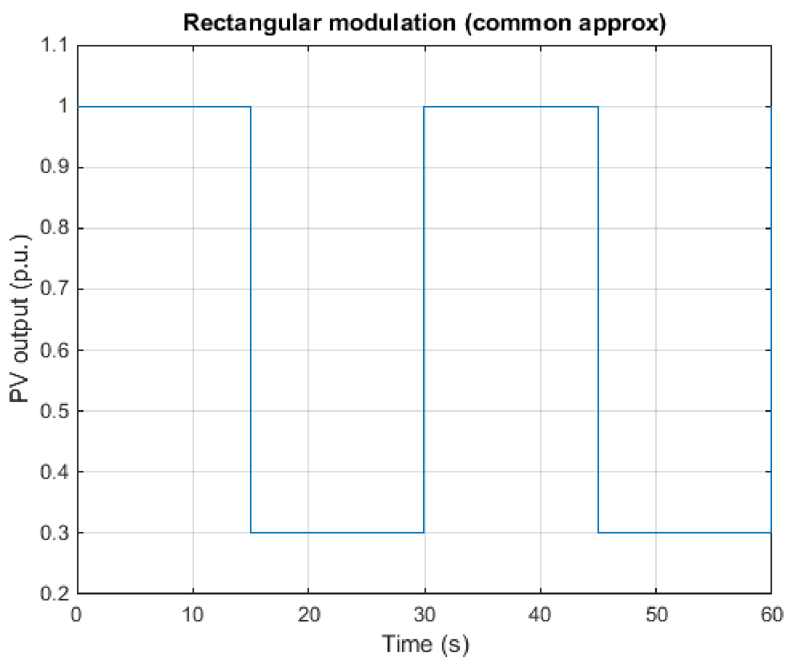

Figure 3. Rectangular modulation of PV output, a commonly-used approximation.

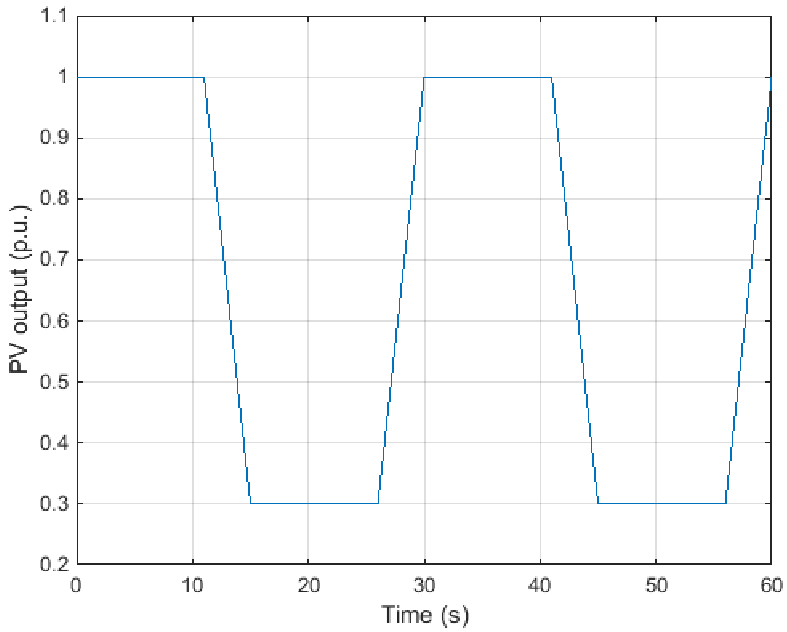

Figure 4. The double-ramp function, a better approximation to a PV cloud transient.

The allowable $\Delta V_{allowed,PV}$ value determined from Table 4 in IEEE 1453-2015™ can be modified to account for the shape of the modulation using a set of "shape factors" that are defined in Annex C of IEEE 1453-2015™. The allowable ΔV is determined from Table 4, and then the modification for shape factor F is calculated using Equation (12)[h]:

$$P_{ST} = \left(\frac{\Delta V_{PV}}{\Delta V_{PV,Pst=1}}\right) \times F \qquad \text{Eq. (12)}$$

where P_{ST} is the short-term flicker parameter defined in IEEE 1453-2015™. For P_{ST} = 1, Equation (12) can be rearranged:

$$\Delta V_{PV} = \frac{\Delta V_{PV,Pst=1}}{F} \qquad \text{Eq. (13)}$$

The shape factor F for the double ramp function is determined from Figure C.2 in Annex C[i]. Determination of F from Figure C.2 requires a third assumption: one needs to know the time length of the ramped portion of the wave shape in Figure 3. For this work, the shortest (fastest) ramp time will be assumed to be 4 s, which is a worst-case value explained in [6]. With these assumptions and for a rectangular modulation, Table 4 in IEEE 1453-2015™ suggests that the maximum allowable $\Delta V_{allowed,PV}$ is approximately 2%. Then, Figure C.2 from Annex C gives the values of F for a double-ramp function. The ramp length assumed here (4 s or 4000 ms) is actually off the graph to the right, but it is clear that F is decreasing as the time length of the ramp increases. Thus, it would be very conservative to take the value of F = 0.2 at the right edge of the graph. This would increase the allowable $\Delta V_{allowed,PV}$ by a factor of 5, to 10%. This $\Delta V_{allowed,PV}$ is considerably larger than that allowed by ANSI C84.1, suggesting that flicker will not be a limiting factor in allowable PV plant size.

[h] This is Equation (14) in IEEE 1453-2015™.

[i] Permission to include Figure C.2 here has been requested from the IEEE, but as of this writing it had not yet been granted.

The role of ramp rate

If the PV plant is operated at unity power factor, it may be possible to mitigate some voltage problems by requiring that the PV output power change at some maximum rate that would be selected to coordinate with the time delays of the EMVRs on the circuit. However, the effectiveness of this strategy is limited because PV is not able to moderate its downward ramp rate unless a) energy storage is available (see next section); or b) accurate irradiance forecasts are available. Also, it is important to note that adjusting the ramp rate would not be expected to reduce the *number* of EMVR operations[j]; it would merely assist in keeping the voltages within the ANSI A range.

Still, ramp rate control can be useful in some cases where the PV is close to the substation, the source impedance of the grid as seen from the substation is relatively high, and the substation normally operates at a slightly elevated secondary bus voltage. In some such cases, a fast uptick in PV power might lead to an overvoltage that persists until the substation OLTC is able to respond and reduce the voltage. The PV plant ramp rates can be coordinated with the OLTC response time in this case so that the voltage rise is sufficiently slow that the OLTC is able to "keep up".

Mitigation of voltage variation using energy storage

Voltage modulation caused by variable PV plant output can be effectively mitigated if the PV plant is coupled to an energy storage plant controlled to do PV plant output smoothing. In this application, the storage is used as an active power filter (APF). This approach has the advantage of actually eliminating one of the root causes of the problem: the total plant output (PV + storage) no longer has the short-term variability, and the concomitant voltage modulation problems disappear. This solution is effective for any value of source impedance and any X/R ratio. The primary issue with this solution tends to be its cost. Energy storage costs today are still too high for this to be a viable solution in most cases.

Mitigation of voltage variation by reconductoring

Reconductoring the circuit is usually an effective means of eliminating voltage modulation problems because it can reduce R_S and X_S and raise the X/R ratio, thereby addressing another of the root causes of voltage problems associated with PV power injection. Like energy storage, reconductoring is typically a high-cost option that often renders PV projects infeasible, and it also has the disadvantages of long lead times and the need to interrupt service to customers on the circuit during the line outage while the new conductors are installed.

[j] There could be some cases in which ramp rate limitation might reduce EMVR operations, for example if two cloud passages were closely spaced so that the PV did not re-acquire its full power output before the regulator had fully corrected for it. However, these cannot be relied upon.

References

[1] American National Standard ANSI C84.1-2011, “Electric Power Systems and Equipment—Voltage Ratings (60 Hertz)”.

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Appendix A. Derivation of Equation (1).

From Ohm's Law applied to Figure 1, we have

$$\Delta V_{PV} = Z\angle\theta_Z I\angle\theta_I$$

The apparent power is the voltage times the conjugate of the current, so making that substitution:

$$\Delta V_{PV} = Z\angle\theta_Z \left(\frac{S\angle\theta_S}{V_{PV}\angle\theta_V}\right)^*$$

Converting to rectangular coordinates:

$$\Delta V_{PV} = Z\angle\theta_Z \frac{P_{PV} - jQ_{PV}}{V_r}$$

Expressing Z in rectangular coordinates:

$$\Delta V_{PV} = \left(R_{S,PV} + jX_{S,PV}\right)\left(\frac{P_{PV} - jQ_{PV}}{V_r}\right)$$

Now perform the indicated multiplication, and divide the entire equation by V_r:

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{\left(R_{S,PV} \times P_{PV}\right) + \left(X_{S,PV} \times Q_{PV}\right)}{V_r^2} + j\,\frac{\left(X_{S,PV} \times P_{PV}\right) - \left(R_{S,PV} \times Q_{PV}\right)}{V_r^2}$$

That last equation is Equation (1).

Appendix B. Derivation of Equation (9).

We start with Equation (6):

$$\frac{\Delta V_{PV}}{V_r} \approx \frac{\left(R_{S,PV}P_{PV}\right) - \left(kX_{S,PV}P_{PV}\right)}{V_r^2}$$

Now set ΔV_{PV} = 0 and multiply both sides by V_r^2.

$$0 = \left(R_{S,PV}P_{PV}\right) - \left(kX_{S,PV}P_{PV}\right)$$

Add the second term to both sides:

$$\left(R_{S,PV}P_{PV}\right) = \left(kX_{S,PV}P_{PV}\right)$$

Divide by P_{PV}:

$$\left(R_{S,PV}\right) = \left(kX_{S,PV}\right)$$

Solve for k:

$$k = \frac{R_{S,PV}}{X_{S,PV}}$$

Because of the way k is defined, the arctangent of k is the power factor angle, so

$$pf_0 = \cos(\tan^{-1}(k)) = \cos\left(\tan^{-1}\left(\frac{R_{S,PV}}{X_{S,PV}}\right)\right)$$

The last equation is Equation (9). The derivation of Equation (11) is essentially the same except that instead of setting ΔV_{PV} to zero, one sets ΔV_{PV} to $\Delta V_{allowed,PV}$.