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Communication Requirements for Hierarchical Control of Volt-VAr Function for Steady-State Voltage

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***Abstract*— A hierarchical control algorithm was developed to utilize photovoltaic system advanced inverter volt-VAr functions to provide distribution system voltage regulation and to mitigate 10-minute average voltages outside of ANSI Range A (0.95-1.05 pu). As with any hierarchical control strategy, the success of the control requires a sufficiently fast and reliable communication infrastructure. The communication requirements for voltage regulation were tested by varying the interval at which the controller monitors and dispatches commands and evaluating the effectiveness to mitigate distribution system over-voltages. The control strategy was demonstrated to perform well for communication intervals equal to the 10-minute ANSI metric definition or faster. The communication reliability impacted the controller performance at levels of 99% and below, depending on the communication interval, where an 8-minute communication interval could be unsuccessful with an 80% reliability. The communication delay, up to 20 seconds, was too small to have an impact on the effectiveness of the communication-based hierarchical voltage control.**

***Index Terms*-- automatic generation control; centralized control; communication networks; photovoltaic systems; reactive power control.**

I. INTRODUCTION

High penetrations of PV interconnected to the distribution system can cause over-voltages at the point-of-interconnection (POI) beyond ANSI Range A [1]. Over-voltages can cause damage to PV systems as well as any other loads connected close enough to be impacted. It is a high priority for electric utilities to maintain acceptable voltages within ANSI Range A, as well as PV inverter manufacturers, to protect equipment and customer assets. Given the increased deployment of renewable and distributed energy resources (DERs), innovative strategies for grid modernization and control are required.

With the emergence of smart grid and advanced inverter functions, such as fixed PF, constant reactive power (VAr), and volt-VAr (VV), there is an increasing interest in solutions for utilizing advanced inverter functions to mitigate PV impacts and increase PV hosting capacity [2]. Many of the advanced inverter functions, especially those that allow manipulation of the VAr generation/absorption, lend themselves to assisting with voltage issues [3]. The challenge lies in how to intelligently apply these grid edge devices in a practical and effective manner. For example, the appropriate VV settings can depend on many things such as feeder topology, POI distance to the substation, feeder load, etc. [4]. The result is that determining the appropriate advanced inverter settings can require extensive analysis [5], and settings will be far from optimal as the system changes. An alternative strategy is to dispatch the advanced inverter settings using a centralized controller to communicate with each PV system [6]. This hierarchical control strategy has the ability to recognize system issues and optimally dispatch new settings to real-time changing conditions.

For the purposes of this paper, a simple hierarchical control was developed to dispatch PV VV settings to provide distribution system voltage regulation. The effectiveness of the controller depends on a suitably fast and reliable communication infrastructure. The focus of the research was to evaluate the potential communication requirements when utilizing intelligent VV dispatch to mitigate over-voltages. The necessary communication infrastructure was tested by evaluating the effectiveness of the hierarchical control with varying communication intervals, reliability, and delays.

The outline of the paper is as follows. Section II introduces the distribution feeder and the test setup for the simulation. The hierarchical voltage control is described in Section III. The simulation results for voltage regulation during the minimum load week are shown in Section IV with the conclusions about the communication requirements in Section V.

II. TEST SETUP

A rural 12 kV distribution feeder serving a highly commercial load area was chosen as the test feeder. The feeder model consists of 215 buses and 39 service transformers. The feeder has a peak load of 3.98 MW. The feeder voltage is regulated via the substation transformer load tap changer (LTC); there are no line voltage regulators or switching capacitors.

The load data for the week ending on the date the minimum daytime load occurred, October 25th, was selected as the simulation week for all studies. The minimum daytime load was defined as the lowest load level that occurred between 10:00-14:00 when the solar power output is high. The minimum daytime load was found to be 1.51 MW (36% of peak). The measured substation supervisory control and data acquisition (SCADA) data at 15-minute resolution was used to model the load variation.

Quasi-static time series (QSTS) power flow analysis [7] was performed at 5-second resolution by linearly interpolating the load data. The analysis was performed in OpenDSS using the GridPV toolbox [8]. A map showing the layout of the feeder topology and the simulated PV locations is shown in Fig. 1.

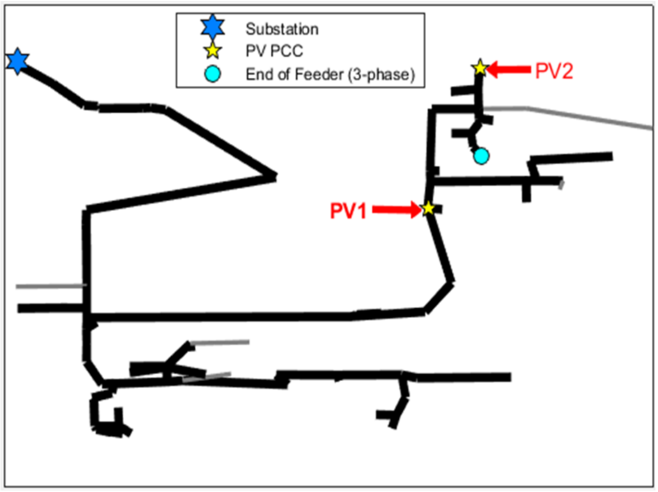

Figure 1. Map of the test feeder with the PV test scenario.

Two PV systems were simulated as shown by the yellow stars in Fig. 1. Each PV system is 750 kW, with an aggregate total of 1.5 MW of PV, just slightly less than the minimum daytime load level. To create the scenario of interest, the AC-to-DC ratio of PV1 was set to 1.12 and PV2 to 1.05. Under peak solar output, PV1 had a maximum VAr support capacity of ±378 kVAr, and PV2 had ±240 kVAr.

Similar to the motivation for selecting the minimum daytime load period for simulation, the maximum possible PV production was assumed in order to create the worst-case scenario for highest feeder voltages. The maximum possible solar production is modelled using a clear-sky global horizontal irradiance (GHI) profile generated using the Ineichen clear sky model via the GridPV toolbox [8]. The GHI was then converted to a plane-of-array (POA) irradiance, assuming a 30° surface tilt, using the PV_LIB toolbox [9].

III. Hierarchical Voltage Control

The objective of the hierarchical control is to regulate the voltage on the distribution system. Distribution system voltages are defined by ANSI C84.1 Range A to be within ±5% of nominal voltage with respect to 10-minute average voltages [1]. Because of the 10-minute average definition in the standard, feeder voltage regulation has an extended period to detect and correct voltage issues.

The hierarchical voltage control is composed of two layers. At the local layer, the PV systems monitor and attempt to regulate their local voltage using the VV function. The system control layer communicates with all PV systems to dispatch new VV settings for additional system benefits.

A. Local Control Layer

Each PV system is controlled locally using the VV advanced inverter function. This research focused on a scenario where PV inverters on a distribution feeder were all assigned a "default" VV curve [10], shown with the blue line in Fig. 2. The PV system is measuring the local voltage on the output of the inverter and reacting in real-time to change its reactive power output.

The VV curve is designed to adjust the PV inverter VAr level depending on the voltage, producing VArs as the voltage goes outside the deadband. Note that at high voltage, the PV system has negative reactive power (absorbing), which will work to bring the system voltages lower. The inverse is true when the voltage is low, with reactive power being injected into the distribution system. VV is able to provide local voltage regulation, but it does not have any additional information about the system conditions to regulate voltages throughout the feeder.

The y-axis on the VV curve in Fig. 2 is dependent on the size of the PV inverter relative to the DC rating of the PV system. It is common to set the maximum and minimum values of the curve to equal the reactive power headroom of the inverter during full PV real power output conditions. For example, for PV1 with an AC-to-DC ratio of 1.12, at full real power output, there is reactive power headroom of 0.504_{PU}, or 0.450_{PU} headroom with the inverter AC rating as the base.

B. Centralized Control Layer

Due to the limitations of local voltage control, a centralized system layer was added to the hierarchical control. It was assumed that the hierarchical controller received measurements from the PV systems and could send dispatch control signals back to the PV systems. Fig. 2 illustrates the VV curve and the logic behind the curve shifting strategy for voltage regulation.

Since the system controller has information about the voltages around the feeder, it can dispatch new VV curves to the PV systems to modify their reactive power output to help the system voltages even when their local voltages are fine. For a given voltage, by shifting the VV curve to the left, absorption of more VArs is induced, lowering the system voltage as a result. The inverse is true for a right shift in the curve.

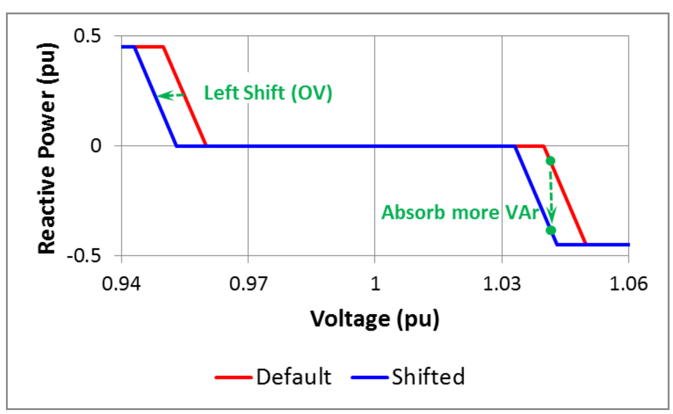

Figure 2. VV curve shifting logic.

An example motivating the need for the centralized system control layer is shown in Fig. 3. Fig. 3 shows the feeder voltage profiles at 11:00 AM on 10/25/09 for the default VV curves (red) and with controller shifted VV curves (blue). With the local default VV control during light load and high irradiance conditions, PV2 near the end of the feeder was unable to mitigate its local over-voltage after exhausting its VAr support capabilities (240 kVAr). PV1 was only absorbing a portion of its available reactive power (378 kVAr capacity), since it was below 126 V. The profile resulting from the centralized controller shifting the VV curve of PV1 left, to absorb more reactive power and keep the system voltages within ANSI Range A, is shown in blue.

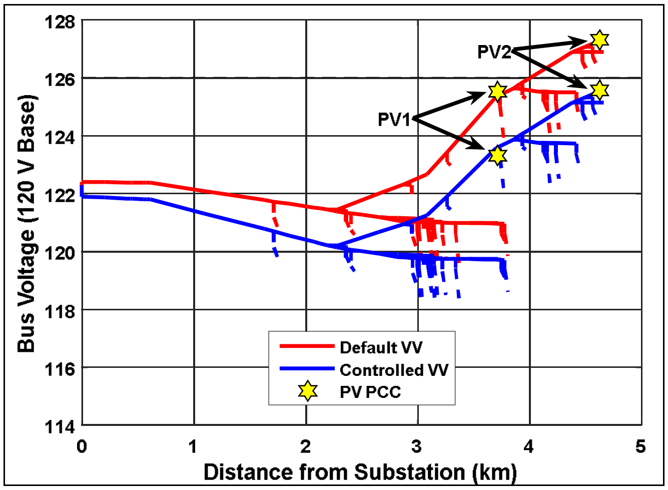

Figure 3. Feeder voltage profiles during daytime minimum with default VV curves (red) and with PV1's VV shifted left (blue).

In order to create the scenario, numerous parameters were adjusted: 1) number of PV systems, 2) location of PV systems, 3) size of PV systems, 4) phase(s) PV systems are connected to, 5) the feeder loading and PV penetration level, 6) the irradiance profile, and 7) the AC-to-DC assumptions for the PV systems. The latter assumption required some fine tuning to create an interesting case.

Fig. 4 illustrates the overall logic of the hierarchical voltage controller. The centralized control receives the voltage measurements at the PV inverters to modify the VV curves, i.e. the VAr levels, to mitigate any voltages outside ANSI Range A (0.95 to 1.05 pu, 114 and 126 on a 120 V base) [1]. The hierarchical controller dispatches new VV settings to the PV inverters only if the voltage was out of range.

The adjustable controller voltage deadband was set slightly tighter than the ANSI limits, 116.4 to 125.5 on a 120 V base, to prevent voltages outside of ANSI Range A. If a PV voltage was outside the controller deadband, all PV systems, except those reporting a voltage outside the deadband, were assigned a new VV curve shifted by an adjustable shift interval (set to 0.001_{PU} or 0.12 on a 120 V base) in the appropriate direction, depending on whether it was an over-voltage or under-voltage. The centralized controller deployed shifted VV curves to all inverters with additional VAr capabilities, per the communication interval, until all voltages are within ANSI Range A.

The logic provides voltage regulation for the feeder using existing measurements, and it also has the benefit of monitoring and regulating the voltage at the PV locations. At night when the PV inverters are off, the VV curves were reset to the default settings. During periods between the communication intervals, the local VV control reacts to regulate the local voltage based on its VV settings in a hierarchical control framework.

Due to VV modeling limitations, there were only two PV systems simulated in this example, but the control strategy described could be extrapolated to scenarios with more PV systems interconnected. In the case of many PV deployments on several phases, the centralized controller would dispatch the new VV curve settings based on the phase with voltage issues and the phases to which each PV system is interconnected. An intelligent, cascading proximity prioritization would also be prudent in a case with many PV systems, but was not applicable in this example.

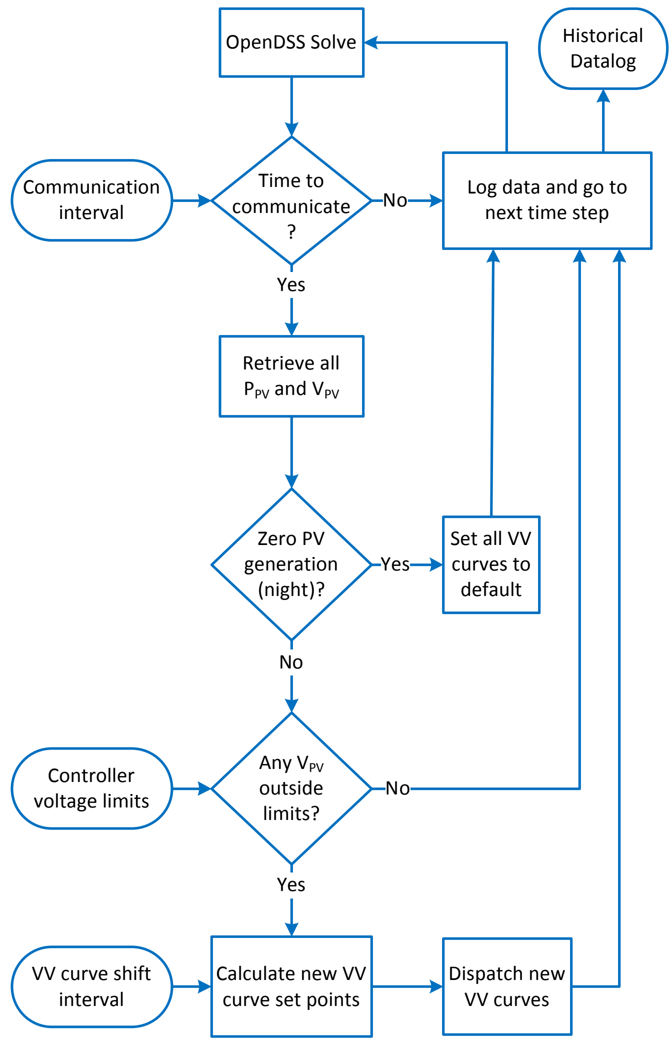

Figure 4. Controller diagram for voltage regulation using VV.

IV. Simulation and Communication Results

The hierarchical voltage control and communication network model were implemented in MATLAB, with OpenDSS running the distribution system model and power flow. All voltage issues are defined by the 10-minute moving-average voltage of any bus being outside the ANSI Range A. No under-voltage issues were observed in this case, so only the over-voltages and time above ANSI Range A (1.05 pu) were analyzed.

A. Voltage Regulation Results

Fig. 5 shows the 10-minute moving-average voltage results for the minimum daytime load week for the test PV scenario. When the PV is at unity power factor, there are 42.5 hours that the feeder is outside ANSI during the week. The total hours with ANSI violations is decreased to 24.9 hours when the default VV curves are added to the PV systems. Finally, Fig. 5 shows how the hierarchical voltage control removes all ANSI violations and keeps the maximum feeder voltage below 1.05 pu.

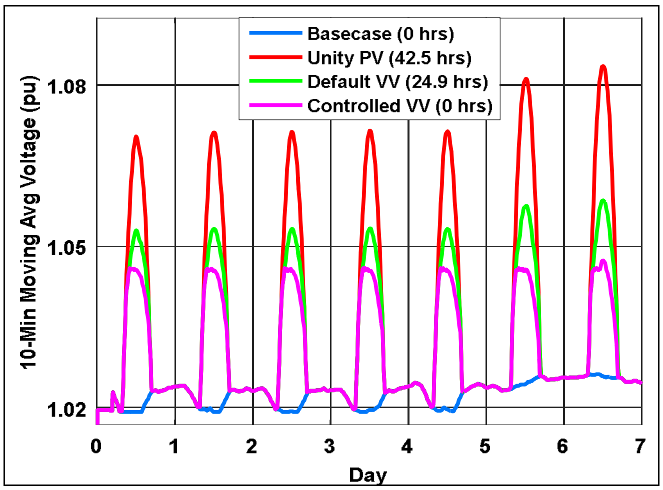

Figure 5. Maximum feeder voltage comparisons for simulation week.

The initial testing assumed that the controller requested and obtained parameters from all PV systems, processed calculation of dispatch values, dispatched values, and inverters implemented dispatched commands all within a 5-second simulation interval. The communication infrastructure requirements were tested by investigating three components of the communication network: communication interval, reliability, and delay. The sections below demonstrate how the effectiveness of the VV control was dependent on the communication network by quantifying the amount of time outside ANSI Range A observed.

B. Communication Interval Results

The communication interval, i.e. how frequently communication must occur, was studied by varying the communication between the inverters and controller from every 5 seconds to every 15 minutes. As the measured data and dispatched settings from the centralized controller were exchanged less often, the effectiveness of the hierarchical controller decreased. Fig. 6 shows the results for different communication intervals during the simulation week for the VV controller simulations with 100% reliable communication and no network delays.

For all intervals less than the ANSI metric of 10 minutes, the controller mitigated all over-voltages by modifying the PV VV curves to keep the voltage within the deadband. At communication intervals longer than 10 minutes, voltage deviations that persisted for more than 10 minutes between communication intervals resulted in voltage violations. In this case, any interval greater than 10 minutes would result in violations per ANSI Range A.

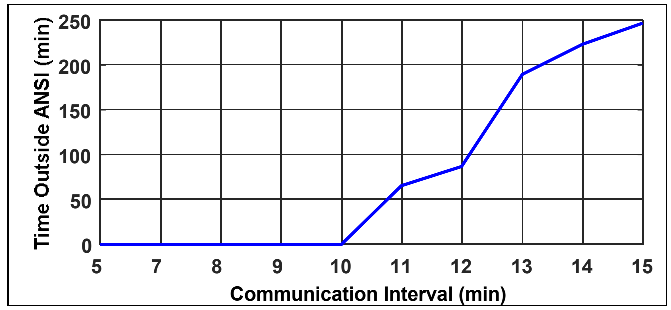

Figure 6. VV based controller results for the simulation week with different controller communication intervals.

C. Communication Reliability Results

The communication reliability was tested by implementing a random probability of successful communication. For example, when simulating a system with 99% reliability, each communication signal had a 99% probability of being received without errors. This stochastic model was applied to both the measurement signal coming into the centralized controller and the dispatch signal going to the inverters.

Due to the stochastic nature of the simulation, a given communication failure could occur while voltages are within ANSI Range A and not result in problems, or the communication failure could result in a voltage issue being missed resulting in a 10-minute average over-voltage. This was also very dependent on the communication interval, since it would likely be acceptable miscommunicating once for a 4-minute interval, resulting in the equivalent of an 8-minute interval.

The QSTS simulation was run three times for each test condition so that the stochastic results could be averaged. The results in Fig. 7 show an extreme sweep of different communication network reliabilities for a few communication intervals. The 7-minute interval was the longest one observed to not have any issues all the way down to 80% reliability, and the 11-minute interval was the shortest one observed to have issues even at 100% reliability, as was also observable in Fig. 6.

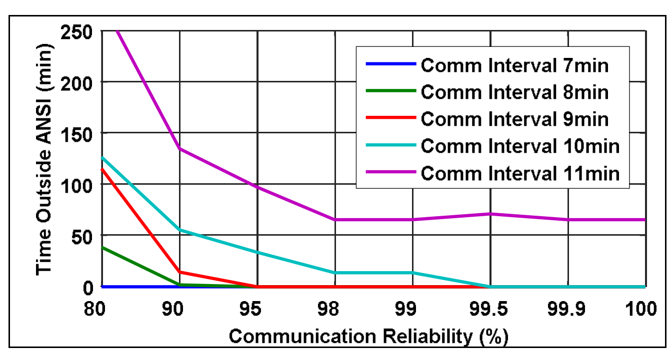

Figure 7. Controller results for different communication intervals and network reliability.

D. Communication Delay Results

In the previous simulations, it was assumed that there were no communication delays and the time from measurement to new setting implementation was performed within a 5-second simulation interval. In reality, there are many communication delays that may extend the process beyond one second [3]. While this would generally be achievable in a few seconds, the effect of the communication delays was tested by increasing the delay up to 20 seconds from the time of measurement to implementation of new settings.

Fig. 8 shows the time above ANSI during the simulation week for different communication intervals and communication delays. Note that even extremely large communication latencies of 20 seconds do not have an impact on the effectiveness of the hierarchical voltage controller.

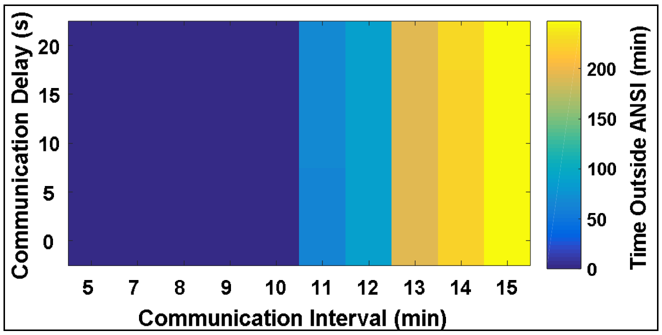

Figure 8. Time outside ANSI during the simulation week with different communication intervals and network delays.

V. CONCLUSIONS

A hierarchical control algorithm was developed to utilize photovoltaic system advanced inverter functions, specifically VV, to provide distribution system voltage regulation and to mitigate voltages outside ANSI Range A by using voltage measurements at the PV inverters. The controller was developed and demonstrated on a week-long analysis of a simple two-PV scenario on an actual 3-phase distribution system model. The necessary communication infrastructure for effective control was evaluated by testing three different communication aspects: 1) interval, 2) reliability, and 3) delay.

Based on this specific test system, the hierarchical VV controller mitigated any 10-minute average voltages above ANSI Range A up to a 10-minute communication interval assuming 100% communication reliability and no delay. These results were synonymous with other similar research focused on mitigating voltage regulator tap operations with a time delay setting of 30 seconds [3, 11], i.e. the communication timeframe required is directly correlated with the application time-urgency.

The reliability of the communication network did not have an impact on the controller for communication intervals of 7 minutes or less, even all the way down to 80%. At 9-minute communication intervals, the communication network must be at least 95% reliable, and at 10-minute communication intervals, the communication network must be at least 99.5% reliable for the hierarchical controller to be fully effective at mitigating all over-voltages.

A communication delay of up to 20 seconds, despite being a very high delay assumption in reality, had no impact on the effectiveness of the hierarchical voltage controller. From a distribution perspective, the ANSI requirement of 10-minute averages represents one of the least time-sensitive metrics where centralized control of advanced functions is applicable.

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