Updating Technical Screens for PV Interconnection

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Updating Technical Screens for PV Interconnection

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***Abstract* — Solar photovoltaics (PV) is the dominant type of distributed generation (DG) technology interconnected to electric distribution systems in the United States, and deployment of PV systems continues to increase rapidly. Considering the rapid growth and widespread deployment of PV systems in United States electric distribution grids, it is important that interconnection procedures be as streamlined as possible to avoid unnecessary interconnection studies, costs, and delays. Because many PV interconnection applications involve high penetration scenarios, the process needs to allow for a sufficiently rigorous technical evaluation to identify and address possible system impacts. Existing interconnection procedures are designed to balance the need for efficiency and technical rigor for all DG. However, there is an implicit expectation that those procedures will be updated over time in order to remain relevant with respect to evolving standards, technology, and practical experience. Modifications to interconnection screens and procedures must focus on maintaining or improving safety and reliability, as well as accurately allocating costs and improving expediency of the interconnection process. This paper evaluates the origins and usefulness of the capacity penetration screen, offers potential short-term solutions which could effectively allow fast-track interconnection to many PV system applications, and considers longer-term solutions for increasing PV deployment levels in a safe and reliable manner while reducing or eliminating the emphasis on the penetration screen.**

***Index Terms* — screens, interconnection, utility, electric utilities, public utility commissions, penetration, high penetration.**

I. Overview and Purpose

Solar photovoltaics (PV) is the dominant form of distributed generation (DG) technology interconnected to electric distribution systems in the United States, and deployment of PV systems continues to increase rapidly. Considering the rapid growth and widespread deployment of PV systems in the United States today, it is important that interconnection procedures be as efficient as possible to avoid unnecessary interconnection costs and delays.

Interconnection procedures vary depending on state or federal jurisdiction, and implementation practices vary by utility system. Most procedures allow for expedited interconnection without additional technical studies if the proposed interconnection passes a series of technical screens. If a proposed interconnection fails one or more of the screens, supplemental interconnection studies may be required before it can proceed to interconnection.

Because many PV interconnection applications involve installations on distribution feeders with greater than 15% capacity penetration, the process needs to allow for a sufficiently rigorous technical evaluation to identify and address possible system impacts. There is an implicit expectation that those procedures will be updated over time in order to remain relevant with respect to evolving standards, technology, and practical experience. Modifications to interconnection screens and procedures must focus on maintaining or improving safety and reliability, as well as accurately allocating costs and improving expediency of the interconnection process.

The purpose of this paper is to evaluate the origins and usefulness of the capacity penetration screen, offer short-term solutions that could effectively allow fast-track interconnection to many PV system applications, and consider longer-term solutions for increasing PV deployment levels in a safe and reliable manner while reducing or eliminating the emphasis on the penetration screen.

II. The 15% Penetration Threshold

In 1999, before the FERC SGIP was established, the California Public Utilities Commission (CPUC) issued an order instituting a rulemaking to address interconnection standards for devices to the electric grid in California. The order resulted in the reform of CPUC Rule 21, which identified screens that allowed low-impact generators to be interconnected relatively quickly and made the review process more efficient for small, low-impact generation at low penetration levels. During the reformation of CPUC Rule 21, a 15% threshold was established to identify situations in which the amount of DG capacity on a line section exceeds 15% of the line section annual peak load. The 15% threshold was then adopted in the FERC SGIP and is used by most states as a model for developing their interconnection procedures. Under most applicable interconnection screening

procedures, penetration levels higher than 15% of peak load trigger the need for supplemental studies.

The 15% threshold is based on a rationale that unintentional islanding, voltage deviations, and other potentially negative impacts are negligible if the combined DG generation on a line section is always less than the minimum load.

Capacity penetration, or simply "penetration," is defined as the nameplate capacity of the combined DG on a circuit divided by the annual peak load on that circuit. The penetration threshold is expressed in terms of peak load because utilities track peak load information.

Figure 1 summarizes the FERC SGIP initial review process, from which many states have adopted the same or a similar set of screens. The first screen examines total penetration by capacity and determines whether penetration level is less than 15% of the line-section peak load. For typical distribution circuits in the United States, minimum load is approximately 30% of peak load. Based on this generalization, the 15% penetration level (one half of the 30%) was selected as a conservative penetration level for general screening purposes.

Originally, the purpose of the 15% screen was intended as a "catch all" rule to eliminate potential problems related to voltage rise and system protection. The following sections discuss these PV characteristics and how the current 15% screen does not always take them into account.

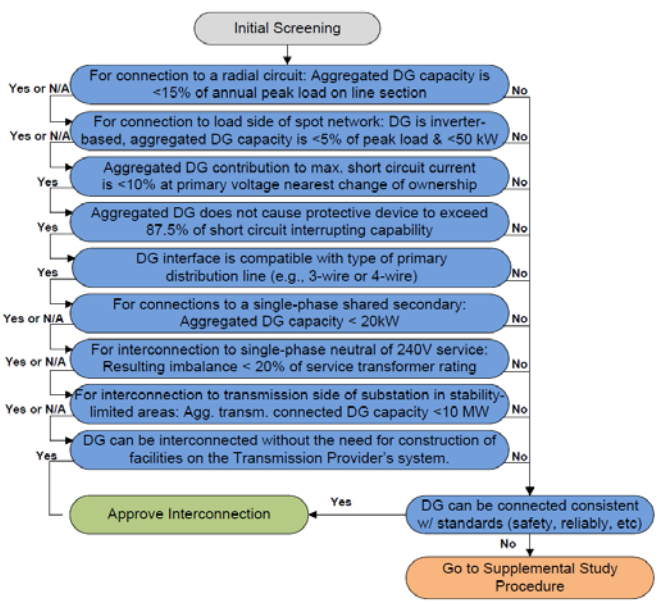

Fig. 1. FERC SGIP initial review screens summarized.

A. Unintentional Islanding

Risks from unintentional islanding conditions include unacceptable voltage and frequency levels, transient over-voltage conditions, equipment damage, and operational safety concerns. Grid-connected PV inverters have unintentional-islanding features built into the controls and are required to be "certified" for the intended use, meaning that they must have UL 1741 certification and meet IEEE 1547 requirements.

B. Voltage Control

A major concern with high penetration of PV on distribution feeders is high steady-state voltage. When power is injected into the electric power system that normally serves load, the voltage at that location may increase. The impact of PV on steady-state voltage is generally lessened as the distance to the substation is decreased.

Figure 2 illustrates the possible impact of PV on steady-state voltage. If PV power injected into the circuit is high enough, the voltage will increase, potentially pushing voltage above normal operational conditions.

Similar to steady-state voltage issues, if the PV system is located further from the distribution substation, PV output variability can result in significant voltage variability. Possible consequences are poor voltage regulation and increased cycling and stress on voltage control equipment.

C. Protection Coordination

A PV inverter's contribution to fault current is limited by design and is not as likely to cause protection problems[1] as rotating machines. However, coordination and grounding compatibility impacts may still arise, and there are screens to check for those possibilities. In some PV inverter installations, an effectively grounded neutral is required to reduce the potential for transient overvoltage during unbalanced system faults. Multiple ground sources can increase ground current contribution and affect the sensitivity of ground current protection functions at the substation.

III. Upgrading the 15% Screen

During review of PV interconnection requests in locations with a high level of PV deployment, the 15% interconnection screen often triggers the need for supplemental studies. In many cases, even when PV penetration is substantially above 15%, the supplemental review does not identify any necessary system upgrades. There are many circuits across the United States and Europe with PV penetration levels well above 15% where system performance, safety, and reliability have not been materially affected.[2]

[1] Keller, J., Kroposki, B. (2010). Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources. NREL Report No. TP-550-46698. http://www.nrel.gov/docs/fy10osti/46698.pdf.

[2] M. Braun et al. "Is the Grid Ready to Accept Large Scale PV Deployment? - State of the Art, Progress and Future Prospects," Submitted to *Progress in PV*, to be published in 2012.

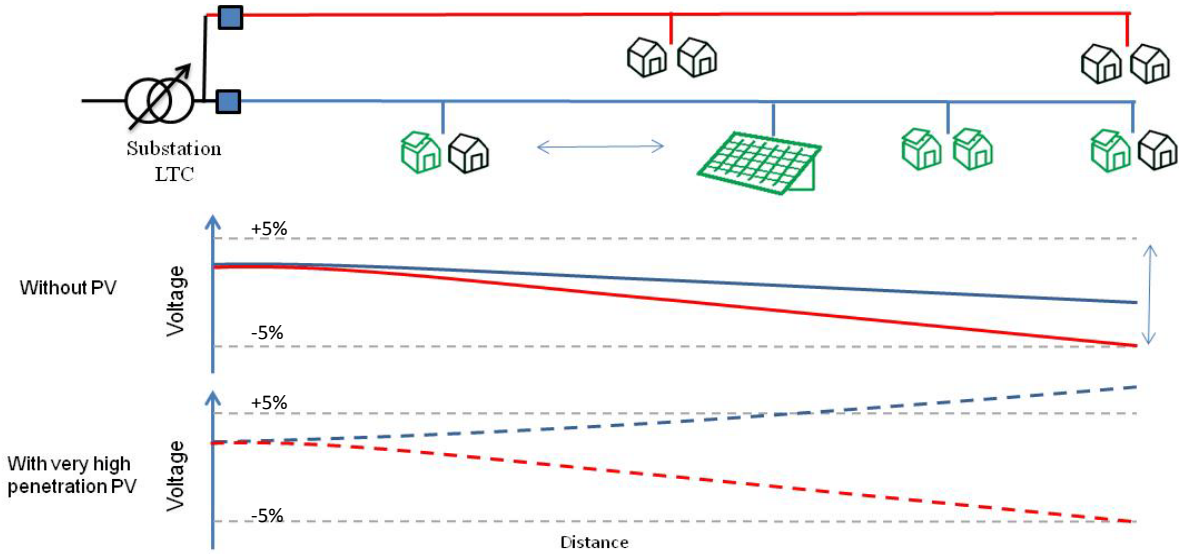

Fig. 2. Example of voltage rise problem for a high penetration scenario.

These observations offer some indication that the existing 15% screen is conservative and is not an accurate method of determining the hosting capability of a particular feeder. The following short-term, mid-term, and long-term approaches may be considered as possible steps to improve interconnection procedures for distribution-connected PV systems.

IV. Short-Term Solutions

Inverter-based PV has unique technical characteristics that reduce the impacts on grid operations. Unlike other DG resources, the output pattern of PV is strictly diurnal (active in daytime). The grid-PV interface is an electronic inverter with adjustable settings and short-circuit current much lower than synchronous generators of the same output rating. PV inverters are designed to comply with IEEE 1547 standards and UL-1741 certification without the need for external protection or controls. By taking into account these technical characteristics, it is possible to refine screening procedures to be more efficient and effective, substantially reducing interconnection process time and effort for PV deployment without compromising the safety and reliability of the interconnected distribution system. Several possible approaches could be undertaken in the short term to improve screening procedures for distribution-connected PV systems.

There are three conceptual examples discussed in this section. The first approach is to include a PV-specific screening criterion that utilizes the minimum daytime load. The second approach is to apply additional screens to identify possible technical issues, regardless of penetration level. The third approach is to increase the penetration levels by identifying zones of higher penetration based on the utility distribution feeder configuration and location of substations.

A. Base Screen on Minimum Daytime Load

The fact that PV generation has a strictly daytime pattern is significant considering that voltage impacts tend to be greater during periods of highest instantaneous penetration. By the time PV systems are producing a substantial amount of power, loads are well above their nightly lows on most feeders. A new screen may set a threshold at minimum daytime load, during the period between 10:00 a.m. and 2:00 p.m. A simple modification of the SGIP screening criteria to implement this PV-specific screening criterion is depicted in Fig. 3. If actual historical data is available, load data in areas of interest could be analyzed to establish factors that relate minimum daytime load levels to peak load levels. Some utilities already use minimum daytime load as a screening criterion and have determined these load levels for their service territory. Figure 4 illustrates an example circuit where the annual minimum daytime load is significantly higher than the minimum 24-hour load. Figure 5 shows the comparative ratios of minimum load to peak load, and minimum daytime load to peak load, for 500 residential and commercial feeders in a southwest U.S. city. The figure shows the percentage of the feeders that have a minimum to peak load ratio between zero and 20%, 20% and 30%, 30% and 40%, and 40% and 50% based on minimum daytime load (10 a.m. to 2 p.m.) and minimum 24-hour load.

Many utilities have access to feeder minimum and peak load data via Supervisory Control and Data Acquisition (SCADA) systems. Minimum daytime load can also be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis.[3] Load variability and circuit segment switching must be

[3] See http://www.sce.com/AboutSCE/Regulatory/loadprofiles/2011loadprofiles.htm.

considered by utility planning engineers when determining minimum daytime load of sections of feeders.

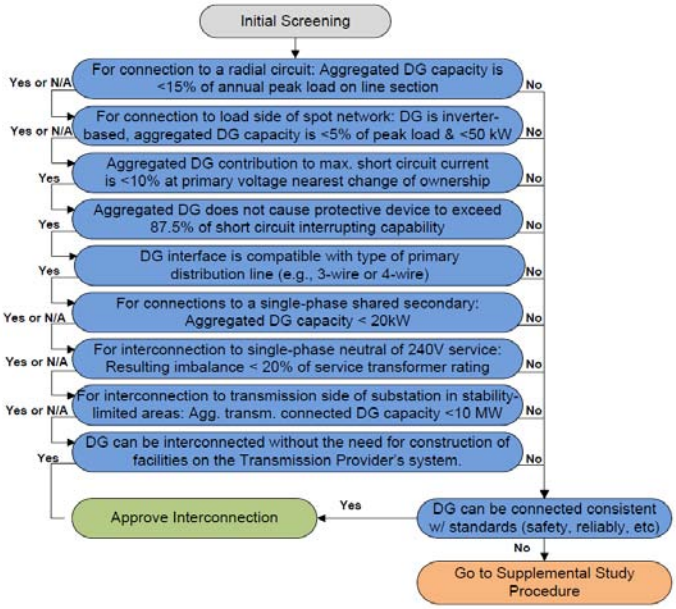

Fig. 3. Modified SGIP screens to address PV interconnection based on minimum daytime load.

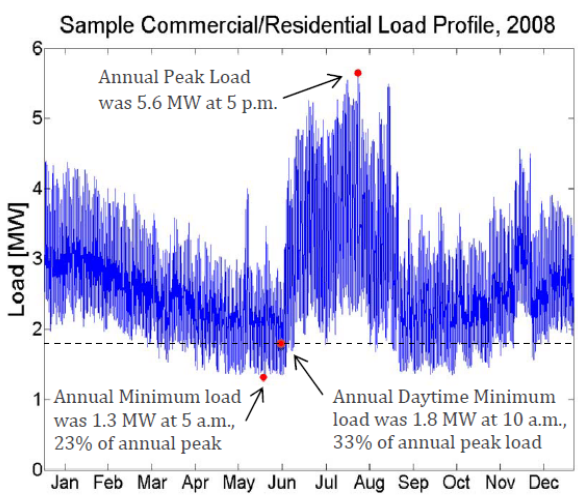

Fig. 4. This load profile indicates that minimum daytime load is significantly higher than absolute minimum load.

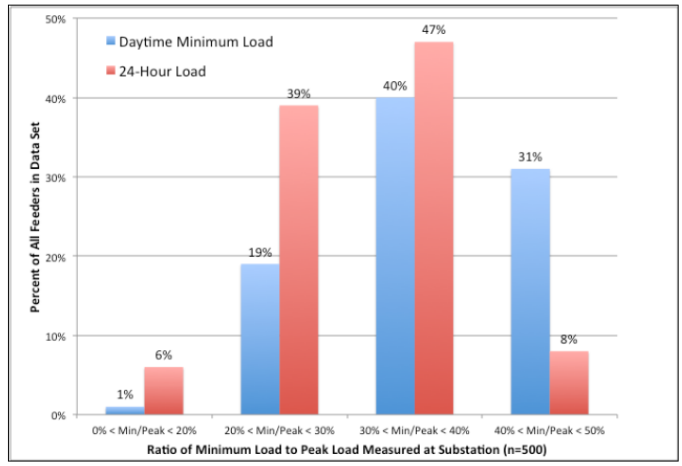

Fig. 5. Ratio of minimum load to peak load for daytime minimum load (10 a.m. to 2 p.m.) and 24-hour minimum load.

B. Apply Supplementary Screens

Applying supplementary screens to identify possible technical issues, regardless of penetration level, focuses on utilizing more comprehensive analyses as part of the initial review in order to eliminate the possibility of voltage regulation issues and the creation of unintentional islands. An example of this concept is shown in Fig. 6.

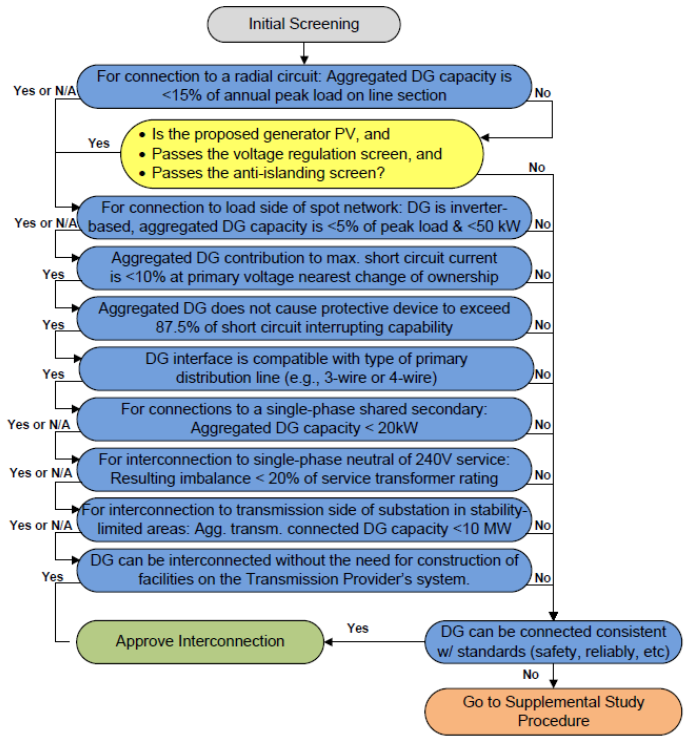

Fig. 6. Modified SGIP screens to address PV interconnections regardless of penetration level.

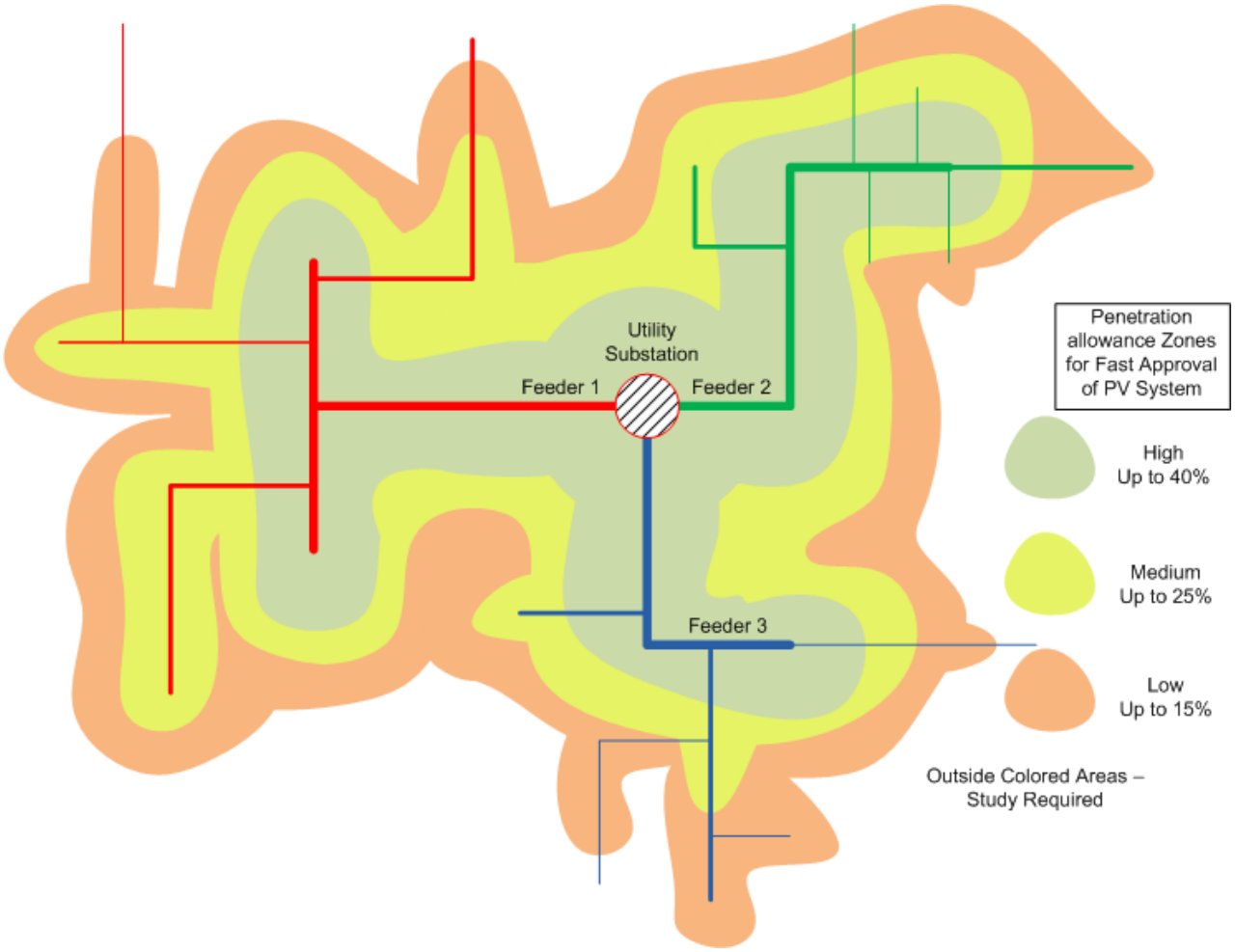

Fig. 7. An example area with zoned penetration limits.

California Rule 21 Supplemental Review Guideline contains several simple procedures that can be incorporated into the review screen for PV systems.[4] Similarly for anti-islanding, Rule 21 Supplemental Review Guide contains a simple screen that can be applied as part of the initial review.

C. Utility Identified Zones of Penetration Levels

Another concept for increasing penetration criteria is to identify zones where higher penetration is acceptable. These zones would likely be located in areas closer to substations or with low-impedance conductors, thus having a lower potential for voltage abnormalities or protective system miscoordination. Figure 7 is an example area displaying zones that allow for greater penetration and those that require further study.

V. Mid-Term and Long-Term Solutions

While short-term solutions might be applied in 12 to 18 months, there are more promising solutions to be considered that will take longer to develop and implement. Mid-term solutions, for this paper, might be those that happen in the one-to-five-year range, while long-term solutions are likely those beyond the five-year horizon.

A. Develop Higher Accuracy Screening Metrics and Formulas

PV penetration metrics alone are insufficient indicators of the expected distribution system level impacts from PV interconnection. One potential solution is to develop more accurate screening metrics that can be used in a revised screening process. An interconnection impact metric for each PV interconnection concern, e.g., voltage effects, unintentional islanding, and protection coordination, could be developed. These metrics would be functions of multiple distribution and PV system characteristics.

B. Upgrade Distribution Circuit Design for PV-Hosting Applications

Upgrading existing distribution feeders with larger-sized (and thus lower-impedance) conductors, installing voltage

[4] http://www.energy.ca.gov/distgen/interconnection/model_rule.html.

regulation devices, and increasing operating voltages (e.g., voltage levels and increase the PV hosting capacity of a feeder. Larger conductors and higher operating voltages allow greater levels of power delivery to loads while maintaining voltage levels, but there are significant costs associated with these approaches.

C. Deploy Inverters with Advanced Functions

Future investments and application of new technologies are expected to significantly increase PV hosting capability. Although it will take time to widely implement, a new generation of inverters is available with advanced functions designed to interact with and support the grid. Advanced communication and control will enable the future distribution systems to better coordinate settings and limits of switch, protection, and voltage control devices as conditions change.

Relative to many other devices connected to utility distribution systems, PV inverters are highly capable in terms of responsiveness, controllability, processing capability, and memory. Advanced inverters and controllers will provide real-time reactive power compensation, real power curtailment, watt-voltage, and watt-frequency management, etc. Configurable autonomous actions can support the grid during abnormal voltage or frequency conditions.

VI. Conclusion and Next Steps

There is an implicit expectation that existing interconnection procedures will evolve over time to reflect from 4 kV to 13.2 kV), are ways to maintain acceptable changes in standards, technology, and practical experience. Modifications to interconnection screens and procedures must have a focus on maintaining or improving safety and reliability, as well as reducing costs and improving expediency of the interconnection process.

Three short-term approaches have been presented for consideration. The first approach uses PV-specific screening criteria that would utilize minimum daytime load for a circuit rather than absolute minimum load or a percentage of peak load. The second approach uses additional screens to evaluate potential voltage or unintentional island problems, regardless of penetration levels. The third approach would increase penetration levels in specific areas or zones based on substation location, circuit design, and existing DG. These three conceptual approaches may be considered as solution frameworks for increasing levels of PV deployment.

Mid-term and long-term solutions require close cooperation between all PV stakeholders. These solutions will ultimately produce straightforward approaches to understand how much PV can be deployed on a circuit, and at what locations, while maintaining a focus on safety, reliability, and cost.

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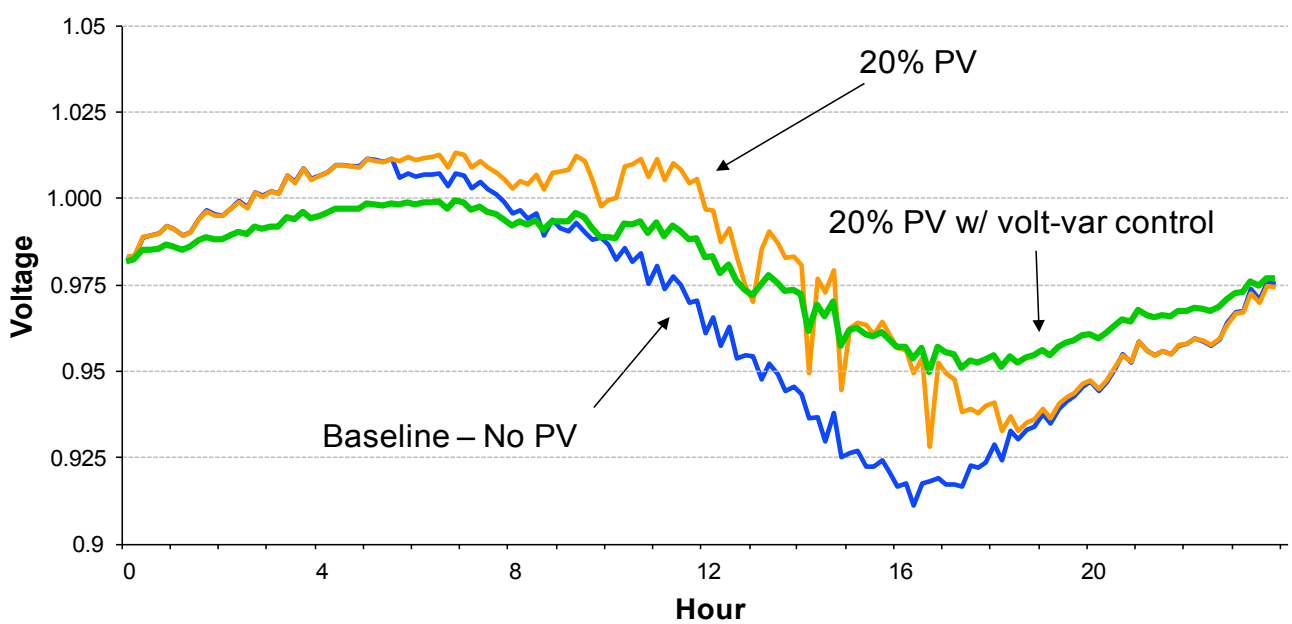

Fig. 8. Feeder voltage response with advanced VAr control[5].

[5] Smith, J., Sunderman, W. Dugan, R., Seal, B., "Smart Inverter Volt/VAr Control Functions for High Penetration of PV on Distribution Systems," 2011 Power Systems Conference and Exposition, Phoenix, Arizona, March 2011.