

Modeling  
solar plants'  
load levels  
and their  
effects on the  
distribution  
system



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# PHOTOVOLTAIC POWER GENERATION

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BY GREG J. SHIREK  
& BRIAN A. LASSITER

**B**OTH THE RENEWABLE PORTFOLIO STANDARD requirements and the potential to delay distribution upgrade expenditures has resulted in a vast increase of distributed energy resources (DERs) on utility systems. As a result, distribution engineers are confronted with the very challenging task of fulfilling the scope of a system impact study to determine whether there exists the potential for the DER to create any adverse operational or voltage issues, now or in the future, as system changes occur. Fortunately, there are industry standards and guides that describe how to fulfill the technical study

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requirements with some step-by-step guidance. The complexity of the system impact study also depends heavily upon the type and size of the DER and its operating modes. An all-encompassing study might cover a vast number of areas with just a few of these being voltage and stability analysis, harmonics, transients, distribution system protection, and DER relaying requirements. Predicting photovoltaic (PV) generation profiles for different seasons and hours of the day rests heavily on the plant design and layout.

In this article, ways to determine those load levels will be discussed. Distribution system and PV inverter modeling complexities will be presented, along with the reasons they are important for impact studies. An actual field installation of a large PV plant will be used to evaluate some distribution system impact issues, with a focus on loading scenarios and voltages. Various operating modes of inverters will be discussed, with a focus on how they may help or hinder the operation of the system. These operating modes and their effects on voltage-regulating (VR) device interactions will be presented to demonstrate how more commonly used regulator control settings without DERs may cause voltage violations with DERs.

### DER Assessment

Solar PV DER integration assessment has become increasingly challenging as larger PV plants with capacities exceeding local load levels are becoming quite common. The areas assessed in the impact study are much more vast and complicated than in the case of conventional induction or synchronous generators because of the capabilities of photovoltaic inverters' different operational modes, and each mode may affect the distribution system significantly differently. Therefore, each of these possibilities may need to be separately addressed to determine the system voltage consequences. Each mode may cause different power flows and both positively and negatively impact the system with tradeoffs between voltage improvement and loss increase.

Developing reasonable power generation profiles for intermittent DERs is another complication as it has a direct affect on voltage profiles and how regulating devices will operate. Investigating a variety of settings for this equipment in tandem with the DER control mode is necessary.

### Interconnection Standards and Guides

There are several standards that provide information and assistance regarding DER interconnections with the distribution system.

#### IEEE 1547 Series

Most noteworthy is the IEEE 1547 series of interconnection standards to assist in the planning, engineering, implementation, and maintenance of distributed generation (DG) resources [1]. The following four publications are most relevant for providing system impact study assistance.

The *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*, IEEE 1547, is a summary that lists the rules or interconnection policies such as voltage limits, voltage regulation, flicker levels, harmonics, frequency, disconnection rules, fault and protection

considerations, as well as rules on grounding. Overall, this standard provides the distribution system performance needs and DER technical specifications or criteria.

IEEE 1547.2, *Application Guide for IEEE 1547*, provides much more technical detail and includes the rationale behind each of the rules and how they were developed. Furthermore, some justification is provided on why and how the actual values in each rule were created. Different forms of DG, such as synchronous, induction, and inverter-based generation, are described to help educate the engineer on how each one may impact the distribution system differently. This application guide helps the engineer understand how to meet the IEEE 1547 rules through some informative tips, techniques, and rules of thumb.

IEEE 1547.7, *Draft Guide for Conducting Distribution System Impact Studies for distributed resource Interconnection*, provides engineering assistance and insight on what should be included in the scope and criteria prior to conducting a full study, along with the recommended steps to ensure all potential impacts are covered. Also provided are data requirements along with how the data are applied to the study. Overall, the standard provides a methodology with accompanying potential impacts the generation can have on the system [2].

IEEE 1547.8, *Recommended Practice for Establishing Methods and Procedures That Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Std. 1547*, was developed to provide guidance when the requirements of IEEE 1547 may limit the potential operational benefits. Rather than circumventing the rules set forth in IEEE 1547, these recommended practices provide unique methods and flexible designs to expand the usefulness of IEEE 1547. Much of the focus, content, and discussion areas of this document relate to the IEEE 1547 rule that the distributed resource shall not actively regulate the voltage at the point of common coupling (PCC) since industry has found this to be a significant barrier.

#### National Rural Electric Cooperative Association

The National Rural Electric Cooperative Association (NRECA) provides a technical application guide to the IEEE 1547 standard that is intended to be a supplement to IEEE 1547 [3]. The purpose of this guide is to clarify the requirements of IEEE 1547 and provide the necessary information as it applies to electric cooperatives. This guide is part of the DG Toolkit provided by the NRECA, which also includes other guides involving sample contracts and applications, business guides, rates manuals, and consumer guidelines.

### Distribution System Modeling

#### Circuit Model

Distribution systems are very complex to analyze because of the nature of the unbalanced impedances and loads. Most distribution analysis software packages use unbalanced phase impedance matrices and load flow solutions [4]. This is especially important not only for conventional unidirectional load flows but also when incorporating a DER since bidirectional kilowatt and kilovar power flows are now possible. The software needs to calculate the

voltage rise from reverse kilowatt flow and the voltage drop from forward kilowatt flow on different phases, as just one example. The voltage imbalance is also important as the interconnection standards list requirements pertaining to maximum or minimum voltage or flicker levels, and, therefore, violations may occur on only one phase rather than all three.

### Time Series Simulations

Traditional distribution planning makes use of a single point in time load flow analyses, which is adequate for peak power planning. However, adding a significant number of DERs or a significantly sized DER to the distribution system increases complexity since bidirectional power flows can occur based on the amount of generation as well as the location. Furthermore, the active and reactive power flow directions and levels can change every minute due to the intermittency of renewable generation such as PV DERs.

Overall, there is a need to use batch processes where both customer loads and DER outputs at various times of the day, or in certain steps, can be run in sequence to see the time-varying nature between them. Stepping these loads through a small enough time sequence with a completely and accurately defined VR device and DER controls with proper time delays and set points, to capture the operations of all active elements, will result in much more useful and informative conclusions about what is expected to occur on the distribution system.

### Step Voltage Regulators

When running time series load flow analysis, settings with regard to time are needed, and for step voltage regulators (SVRs), this is the time delay. If the voltage remains outside the bandwidth for longer than the time delay setting, the regulator will attempt to change taps to buck or boost the voltage. With intermittent generation, the voltage at the regulator may change so quickly that it may not take corrective actions with longer time delays.

Another important setting is line drop compensation (LDC). If the active power (P) and the reactive power (Q) flows change in small time increments, LDC will be affected as it is dependent not only on the active and reactive power flows but also upon whether the flow is in a forward or reverse direction.

There are many control modes on SVRs with bidirectional capabilities, such as cogeneration and reactive bidirectional modes, usually employed with DERs. Some of these modes will be demonstrated during the PV case study later in this article.

Regulators are motor-operated mechanical devices, thus tap changes will not be instantaneous. SVRs may take between 1–1.5 s to move one step, so with a 32-step regulator, almost a minute will elapse when moving from one extreme to the other.

Finally, SVRs have first house high- and first house low-voltage settings that, when reached, force the

INSOLATION  
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PANELS.

regulator to instantly start changing taps, thus bypassing the time delay setting.

### Capacitors

Capacitor banks may either be fixed or switched. Fixed capacitor banks typically cause fewer potential voltage problems than switched banks.

Switched banks have many control options, such as time of day, voltage, real amps, or reactive amps. The voltage and amp options have on and off settings so that when these set levels are reached, the capacitor switches on or off. Voltage-controlled capacitors usually will not interfere if the DER control is set to operate in unity power

factor (PF) mode.

Comparable with SVR LDC settings, capacitors that have been programmed to switch based on real or reactive amps may cause issues with DERs, regardless of whether the DER is in unity PF or VR mode. This is because intermittent DER generation profiles are constantly changing, and the current through the capacitor control will not reflect the downline load current profile initially used to establish the settings. The capacitor operated in reactive amp mode with a downline DER exporting only active power may switch on the basis of the reactive amp settings, which were properly set for no DER. But with the DER active power contribution raising the voltage, the capacitor kilovars will also raise the voltage, causing a high-voltage condition near the circuit extremities.

Similar to SVRs, capacitor controls also have time delay settings and bandwidths that need to be incorporated to see correct interactions with SVRs and DERs.

### PV Modeling

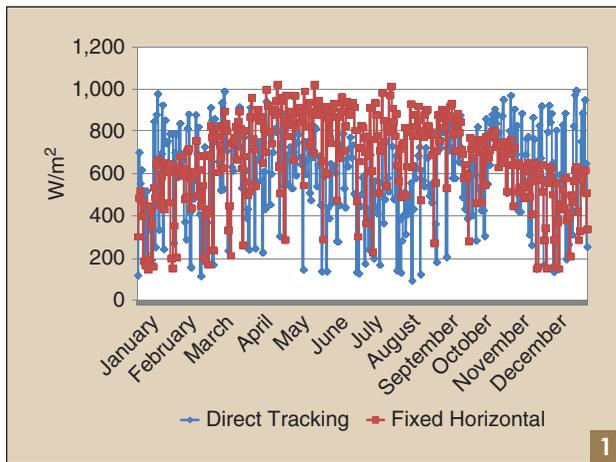
#### Intermittency

PV intermittency, or discontinuity of power output, is one of the most important traits used in evaluation, and it is often the largest barrier to introducing DERs on a utility system.

Irradiance is the amount of incident electromagnetic power received per unit area of a given surface, usually in units of  $W/m^2$ . Insolation is a measure of the irradiance within a given time period expressed in units such as  $W-h/m^2$ .

Panels are rated in peak watts, which is the power generated at a reference insolation level of  $1,000 W/m^2$ . A 1-kW nameplate rating on a panel will produce that much power if perpendicular to the sun rays at peak insolation periods. Insolation levels need to be gathered at the location where the PV will be installed to best approximate insolation profiles. Readings can be obtained from a variety of resources such as Typical Meteorological Year 2 (TMY2), National Renewable Energy Laboratory PVWatts, and the National Solar Radiation Database (NSRDB).

Insolation levels vary based on the angle and tracking method of the collector panels. This needs to be taken into account when analyzing the data since the collectors may have been oriented differently. Figure 1 reflects



Horizontal and direct insolation levels.

measured data taken from the TMY2 METSTAT database for direct axis tracking and fixed horizontal arrays, with the horizontal collector showing more insolation during the summer months and less during the winter months, as expected.

A review of the specifications, spacing, and orientation of the PV arrays is needed to most accurately represent the nature of its power output characteristics and intermittencies. The compass direction, or azimuth angle, is the angle from a true north direction. To obtain the most cumulative energy output, it is optimal for an array to be directly south facing or  $180^\circ$  (for the northern hemisphere), thus it can capture sunlight from sunrise to sunset.

Tracking arrays can either be one- or two-axis tracking. One-axis tracking systems rotate along the azimuth angle while having a fixed tilt angle. Two-axis tracking systems can adjust both tilt and azimuth to always be perpendicular to the sun's rays, maximizing generation.

### Ramp Rates

Cloud cover or shading levels are the main reasons for solar ramping and produce the fastest ramp rate output power fluctuation. As can be expected, assessing this dynamic can be incredibly difficult since weather patterns are constantly changing. In addition, one needs to know how many types of cloud patterns exist, the shading coverage area, the cloud height and optical transmission insolation rates, and the speed at which the clouds are moving [5].

Ramp rates need to be predicted or calculated for improving the accuracy in generation profiles. To calculate this rate of change, the cloud travel direction needs to be known in addition to the PV array length in parallel with the cloud direction. Dividing the speed of cloud travel into the PV array linear distance will result in the rate of change.

Studies have shown that squall line and cumulus clouds produce the worst problems for PV generation. The squall line type, described as a solid line of dark clouds, produces almost a complete loss of PV generation. Conversely, cumulus types, which are faster moving and more well defined, with clear skies between them, resulting in less

ground shading area, produce a smaller percentage loss of PV output but at a much more random rate of change. This may be the worst case, as voltage-regulation devices may not have time to operate. The intermittency caused by these cumulus clouds is much less predictable than the squall line clouds. There are many sources of information and programs available that will predict cloud coverage over a defined area [5], [6].

Many government agencies have been recording insolation rates in 1-s, up to 1-h, increments, with 1-h intervals being much more common. These data have been recorded with single collectors or arrays, so the intermittency for a single point can be obtained, but a second step is needed to apply these change rates to larger PV plants [7].

Determining reasonable ramp rates to include in the PV evaluation is not trivial. For example, cloud patterns, wind speeds, PV cell angle, azimuth tracking, plant land area, total surface area of PV arrays, and shading between arrays should be considered.

With lack of available data, an alternative is to use recordings from nearby similarly sized plants. However, this may be difficult given that these data are usually proprietary to the plant owner [8].

### Derating Factors

PV cells completely rely on a clear sky with no haze, rain, or humidity to generate their rated power. This, along with derating factors inherent to PV plant facilities, will cause a derating of the PV nameplate output. Items such as inverter efficiency, ac and dc wiring losses, snow or ice buildup, and transformer losses need to be applied to obtain a derating factor.

### PV Inverter Design

Typically, inverters used in PV installations are designed to accommodate unity PF operation. This limits the capabilities and design of inverter operation. Many inverters have the ability to provide reactive power to the utility system in addition to active power. Therefore, the inverters' capabilities for providing voltage stability, load curve leveling, loss reduction, and other ancillary services such as ride-through during system faults are very much underutilized.

IEEE 1547 states an important reason that DERs shall not regulate voltage: to avoid conflicts between the controls at the DER and the controls of traditional voltage-regulation devices such as voltage regulators, capacitor banks, and on-load tap changers. On the contrary, inverters that are allowed to actively regulate voltage may help hold system voltage levels and reduce the needed number of tap changes on regulators. Every situation is unique depending on the system impedances and X/R as well as the PFs of the loads [9].

Overall, only minor attempts have been made to fully take advantage of the unique capabilities of the reactive power output of inverter-based DERs due to IEEE 1547 [10]. If the voltage-regulation-controlled equipment is analyzed and coordinated properly to circumvent potentially harmful interactions, there can be substantial benefits to allowing DER voltage regulation [11]. In these cases, a mutual agreement between the DER owner and

the interconnect utility to allow voltage regulation may be beneficial [12].

Inverters have been designed to meet UL 1741 certification, which also incorporates IEEE 1547 and IEEE 519 compliance. UL 1741 requires the inverter shut down not only for abnormal voltages but also for loss of voltage at the PCC. This is again reasonable for small-scale DERs but vastly limits the potential for large-scale DERs. As a result of industry questioning some of the regulations, IEEE 1547.8 was opened to provide recommended practices for implementation strategies for expanded use of IEEE 1547 [13], [14]. In essence, IEEE 1547.8 takes into consideration applicable real-world experiences of those who have utility system DG design, installations, and operation backgrounds, know the limitations, and have contrary beliefs to a few of the technical areas of IEEE 1547. Many countries outside the United States are proactively changing their interconnection rules for large-scale PV generation so that inverters may beneficially regulate and support voltage during system faults and transients [10].

### **Inverter Capabilities and Operating Modes**

Inverter designs for both small- and large-scale applications typically size the inverter to match the dc rating of the PV cells, after applying derating factors as previously discussed. This is because the inverter does not need to be controlled to manage the reactive power export. For power flow analysis, this means that the inverters are to be modeled as current source inverters operating at unity PF, or simply negative active load.

However, inverters can export or import reactive power and then should be modeled as voltage source inverters [16]. If the inverter is oversized relative to the total derated output of the PV array(s), it will be able to provide some reactive power in addition to the entire PV array active power rating. The inverter can then exhibit dynamic inductive and capacitive behavior by design [17].

For example, if an inverter is simply increased by just 5%, from 100 to 105 kVA, this will enable the inverter to supply or absorb 32 kvar while still supplying 100 kW of active power, resulting in a PF range of  $\pm 95\%$ . This is a minimal increase in inverter size to gain significant reactive power capability.

### **Operating Modes**

As discussed, if inverters are designed and operated with reactive power capacity, much more versatility will exist and more operational modes can be deployed [18]. Operating modes are described as follows.

#### **Fixed PF with $Q = 0$**

The most commonly used operational mode is simply unity PF. The inverter will output active power based on the insolation levels captured by the PV arrays. This mode complies with IEEE 1547 and is most common.

#### **Fixed PF with $Q \neq 0$**

This mode simply allows the kVAR to follow the kilowatt output linearly. Based on the PF of the load and the X/R of the system, utilities have found that a leading PF, for instance, absorbing vars, can mitigate voltage rises due to

excessive active power export during periods of minimum local load on the circuit.

### **Variable PF**

The PFs can be adjusted based on the amount of kilowatt generated or also set up differently for various hours of the day. Note that this mode also complies with IEEE 1547 since the inverter is not actively regulating utility voltage.

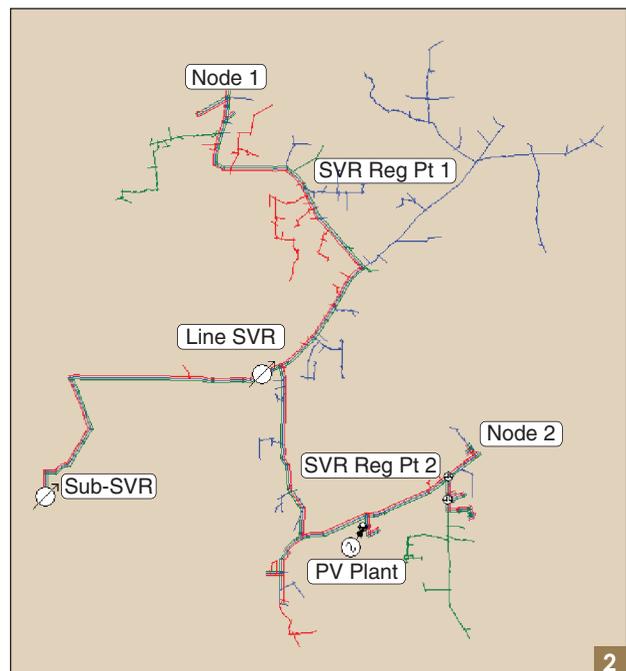
### **Voltage Control Mode with Reactive Power Capability**

Without argument, this dynamic control mode has the greatest potential for distribution load serving and voltage support benefits. This mode simply adjusts the reactive power import or export of the inverter to help regulate a set point voltage level at the PCC.

### **Distribution System Case Study for PV Voltage Impacts**

An example case study is now presented with various regulator settings and generator modes to address possible impacts a PV solar generation plant may have on the local distribution system. At the time of this writing, this PV project was still in the design stage. For the purposes of the examples that follow, the anticipated arrays, inverters, and panel orientations that will be included in the installation have been used to develop the generation curves and inverter operating modes. At this time, a full distribution system impact study has not been completed, and data are still being collected.

Commercially available software, Milsoft's WindMil, is used for the power flows for the study. The system model is fully detailed down to the customer meter, including distribution transformers and secondary services with 120-/240-V center-tapped transformers [19].



The circuit one-line diagram.

Energy, demand, and load class shapes for the various customer classes were used to allocate load throughout the circuit for the minimum and maximum summer and winter demands from the most recent year.

### System Characteristics

Figure 2 shows the one-line diagram of the distribution system.

The existing system has characteristics of a typical rural circuit, with some noteworthy items as follows:

- 12.47-/7.2-kV primary system voltage
- 16 mi of 3/0 aluminum conductor steel-reinforced cable to two three-phase extremities (Node 1 and Node 2 on the one line)
- 8-ft cross arms and conductor spacing
- 450 consumers
- SVRs at the low-side bus and also 5 mi out on the circuit (sub-SVR and line SVR).

### PV Plants Specifications

The PV plant specifications are listed as follows:

- 18,000 panels, each rated 132 W dc (standard test conditions rating), for a total rating of 2,376 kW dc
- ten panels per collector
- collector size of 5 ft × 48 ft
- 2,000-kVA transformer, 12,470–480 V 5.75%Z

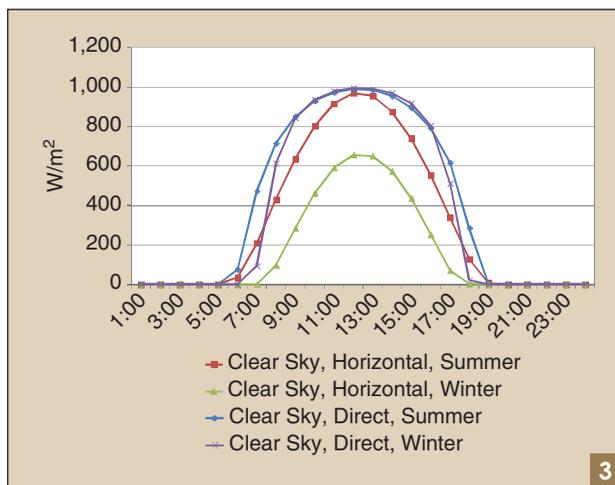
- eight 265-kVA inverters
- 20-acre site.

### Orientation of Panels

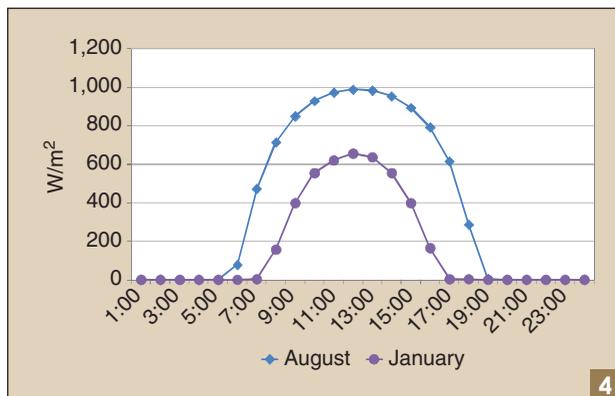
As previously discussed, knowing the orientation and tracking of the collectors is important for determining the potential power generated at various insolation levels. Each collector in this plant is horizontal but has the ability to rotate up to 55° both east and west to track the sun. With the panels tilted 0° at horizontal, they will be more efficient and generate more power during the summer months than the winter. Due to the ±55° azimuth tracking, additional power can be generated in the early morning and late afternoon hours more than with fixed panels. Figure 3 shows insolation levels on a clear-sky day for various panel orientations.

Since the PV arrays are horizontal, the panel rating output will only be possible during the summer months as the sun travels directly overhead at 12 p.m. During the winter months, since the sun is located more in the southern direction, the horizontal arrays will not capture as much irradiance, so the output will be less than the total panel rating.

Hourly insolation data for a full year were accessed to develop the potential maximum hourly output for the entire PV plant. For the case study, January and August data were used since these months represent the peak summer and winter periods. Since the PV arrays are fixed horizontal but track on the azimuth, interpolating insolation data points between the fixed horizontal and two-axis tracking systems from the database was accomplished. Figure 4 shows the final insolation curves for the PV plant.



The insolation curves based on array orientation.



The insolation curves for a PV plant.

### Derating Factors

Many loss factors will affect the total dc–ac derating and resultant power rating of the PV plant [20]. The case study used the derating factors with corresponding values shown in Table 1.

These produce a cumulative derating factor of 79%. Therefore, the total dc rating of 2,376 kW will have a peak ac potential at the PCC of 1,877 kW during maximum insolation.

### Load Levels

Figures 5 and 6 show the historical demands for minimum and maximum, summer and winter, in addition to the peak potential insolation profile for a clear-sky day. Also shown are the net minimum and maximum load profile curves, which is the circuit load minus the PV generation. These net load profiles help to determine what periods to analyze. The possible load on this circuit may lie anywhere between the summer or winter maximum curves and the net minimum curves.

### Case Study Examples

Cases are now presented by addressing voltage problems caused by load flow changes on the distribution from the DER contributions. For simplicity, the summer loading was used for the cases presented; however, for worst-case voltage flicker during periods of PV ramping or complete disconnection, both summer and winter loads were analyzed.

### PV Downstream from SVR with LDC

This circuit traditionally deployed LDC on the line SVR not only to help hold a more constant voltage at the load centers but to also provide conservation voltage reduction (CVR) benefits by attempting to hold voltages near the lower limits of the American National Standards Institute (ANSI) Range A levels. The line SVR base output voltage is set to 119 V. The X/R ratio from the SVR to the load center regulation point is 1.3, so SVR LDC settings of 7.1 and 5.7 V for X and R, respectively, were programmed for the 219-A SVR.

The following analysis was conducted assuming both the sub-SVR and the line SVR had the necessary length of time to ride through any ramping or intermittency of the PV. In other words, this is a steady-state load flow condition with 2,300 kW of local load and 1,600 kW of PV generation at 3 p.m.

As expected, during max PV generation, the active power export from the PV plant creates a situation that reduces the active current through the line SVR causing, in turn, the regulator to operate on a lower tap decreasing the delivered voltage. Figures 7 and 8 show the voltage profiles for Node 1 and Node 2 with and without the PV contribution. Voltages on all three phases at Node 1 are now lower than the ANSI Range A minimum of 118 V.

Essentially, the active power from the PV plant causes the regulated load centers to shift toward the substation since the SVR delivers lower voltage from the decreased active power through the R component of the LDC control. As expected, the voltage profile from the SVR to the end of the line near the PV plant is now seeing a voltage rise due to the reverse power flow.

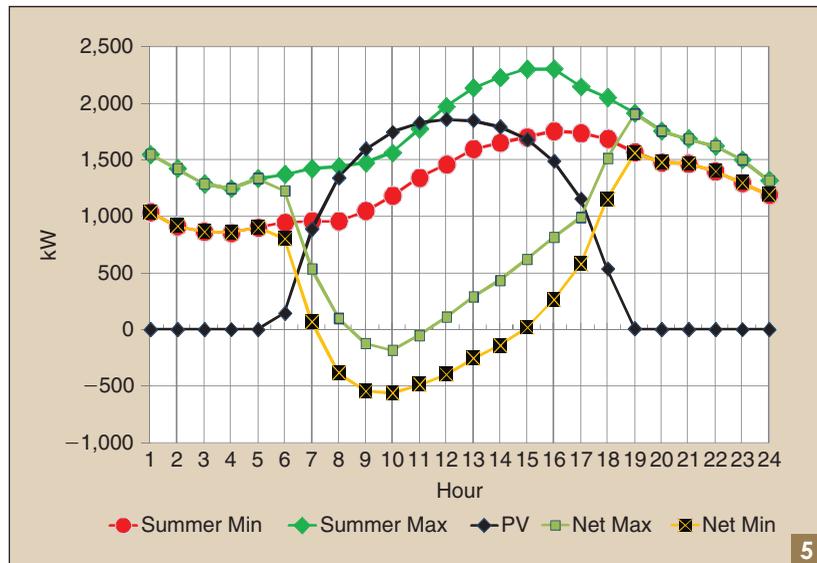
### Reverse Power Flow with Bidirectional Settings

A normally open gang-operated air break switch is located at Node 2 that connects this circuit to a nearby substation for contingency purposes. In addition to providing contingency service to this circuit, the adjacent substation has the capability to provide backup to other circuits on this substation during a transformer failure at off-peak hours. Therefore, to alleviate extreme voltage drops during this configuration, the bidirectional capabilities of the line SVR are used. Because of low voltage extremes that may occur, the bidirectional reverse power settings are set to the maximum ANSI Range A voltage level of 126 V.

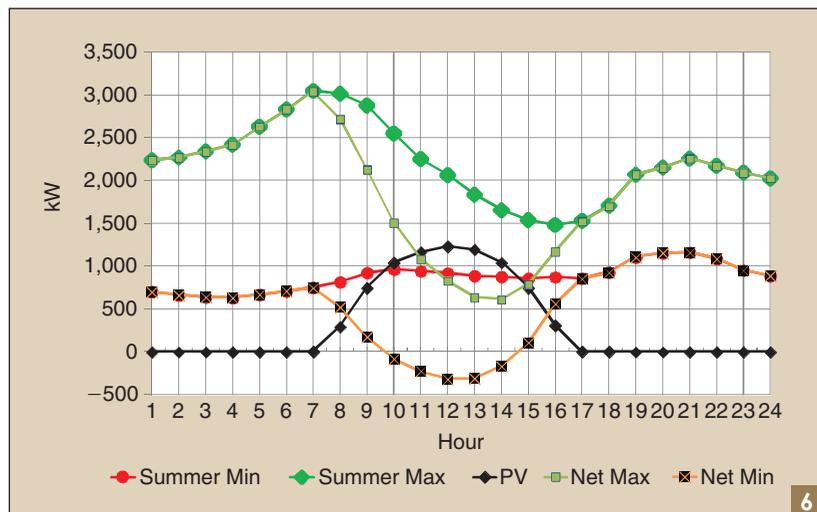
Historically, before the introduction of the PV, this SVR would only transition into reverse power mode during contingency periods when the power flow was still from only one direction or, more importantly, one

TABLE 1. DERATING FACTORS FOR A PLANT.

Item	Factor
Module nameplate dc rating	0.95
ac and dc wiring	0.97
Inverter mismatch	0.98
Inverter efficiency	0.965
Transformer losses	0.95
Dirt and debris	0.95
Total derating	0.79



The summer circuit load profile.



The winter circuit load profile.

stiff power source. Now, with the addition of the PV, during noncontingency periods, the main substation is still providing power, but now the PV creates potential

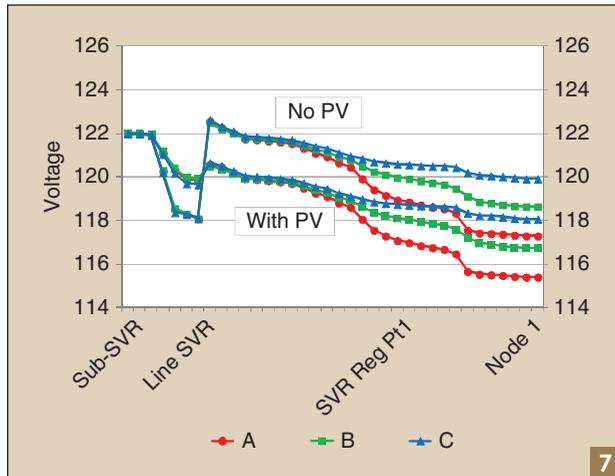
problems between the sub-SVR and line SVR during reverse power flow.

These issues may be expected during maximum insolation periods coincident with minimum circuit loads. As seen in Figures 5 and 6, historically, 9 a.m. to 3 p.m. in winter and 7 a.m. to 3 p.m. in summer show the potential for PV generation to exceed the local load.

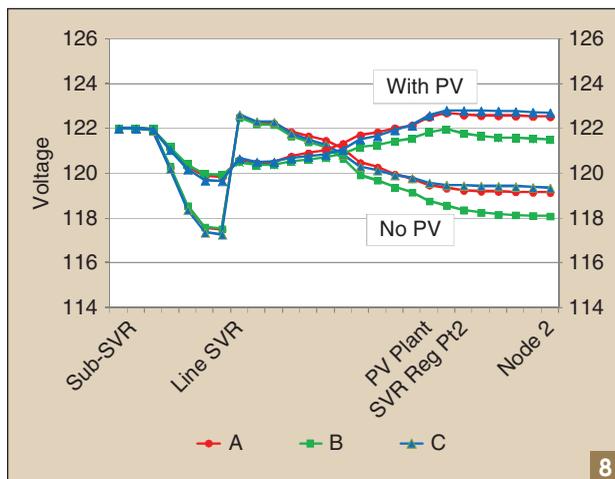
When the regulator shifts into reverse mode, it attempts to maintain voltage levels at the substation side of the regulator, rather than at the PV side during forward mode. This can be detrimental to the voltage profile on the circuit as the main substation is still the rigid source trying to maintain the sub-SVR 122-V setting at the low-side bus, whereas the line SVR is trying to sustain 126 V at the substation side of the regulator.

The line SVR substation-side voltage will then always be lower than its 126-V setting and will attempt to tap up or boost the voltage. Since the sub-SVR is holding the rigid voltage, basically, 126 V cannot be maintained at both regulators. As a result, the line SVR will then tap down the required number of steps trying to achieve 126 V. Initially, if the line SVR is sensing less than this, it will step to obtain that voltage but will actually be lowering the voltage on the PV side of the line SVR, just the opposite of what the control algorithm expects. This will continue until the regulator reaches its maximum step or, in this case, will cause a 10% voltage change across the regulator.

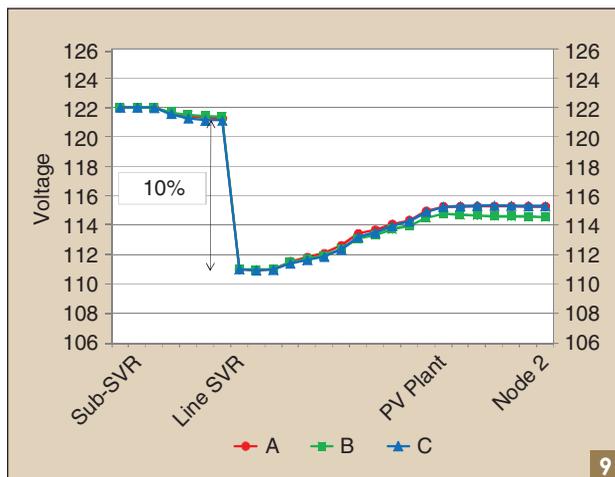
Figure 9 shows the profile for this case, assuming enough time constants have occurred for each regulator to step through the necessary tapping sequences.



The Node 1 peak summer voltage with and without PV.



The Node 2 peak summer voltage with and without PV.



The reverse power case with the line SVR reverse power mode.

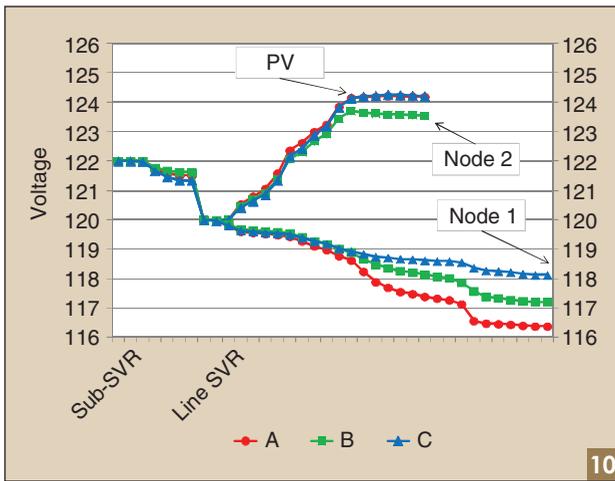
### Reverse Power Flow with Cogeneration Mode and Unity PF Inverter

In attempts to circumvent the previous problem, SVRs' cogeneration mode can be beneficial. This mode regulates the PV side of the regulator, not the substation side, during both forward and reverse power flow. A possible cogen mode set to 120 V is investigated.

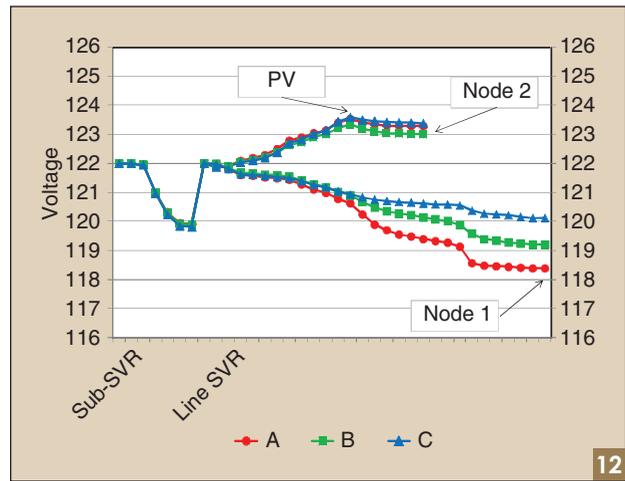
The PV is in fixed unity PF mode. During the summer peak load profile during daylight hours, the net forward reactive power flow will always exceed the level of net reverse active power flow through the substation. This is due to a rather consistent 95% PF on the circuit during daylight hours. Thus, a voltage drop will always be seen from the substation to the line SVR, as forward reactive power exceeds reverse active power.

There will always be a voltage rise from the line SVR to the PV plant during periods of reverse power when the PV inverter is in unity PF mode. This requires that the cogeneration mode voltage level be set to ensure that high voltages do not occur. Figure 10 shows the voltage profile for a cogen mode set to 120 V. In this case, there is less chance of negative interaction between the sub-SVR and line SVR.

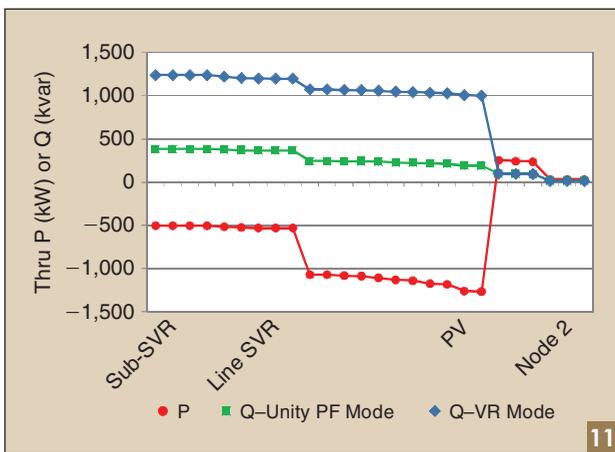
However, notice that there is a 4-V rise between the line SVR and the PV. This helps keep the voltage within limits at Node 2, but the voltage at Node 1 now encounters low-voltage violations, dropping below 118 V.



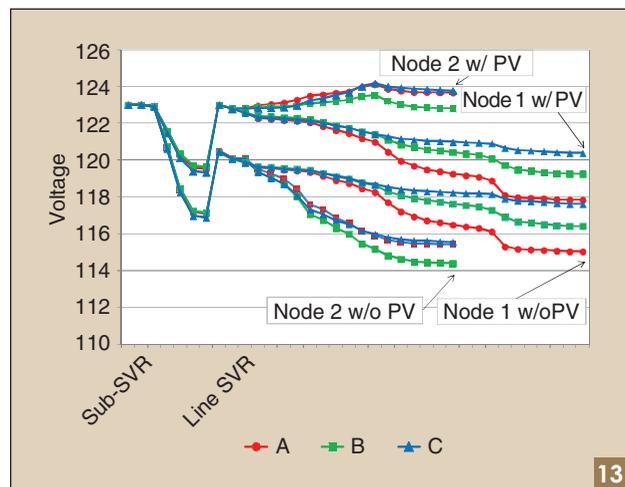
The line SVR cogen mode with the unity PF inverter.



The line SVR cogen mode with inverter VR mode.



The power flow with unity PF and VR mode.



The voltage change for PV ramping or disconnection.

### Inverter VR Mode

To reduce the 4-V rise encountered during maximum insolation, a study is conducted to see whether or not voltage improvements will occur if the inverter is operated in a mode that supports reactive power capabilities. For this case, an adjustable PF mode with VR capabilities is assumed.

This PV plant is equipped with eight 265-kVA inverters, for a total of 2,120 kVA. The expected peak negative net load on this circuit is approximately 600 kW, which is a result of a 1,180-kW customer load and 1,750 kW of PV generation. So at a generated 1,750 kW active power by the PV arrays, the inverter has the capacity to export or import 1,200 kvar.

Figure 11 shows the P and Q flows for both inverter operating modes, and Figure 12 shows the voltage improvement with VR mode. The SVR cogen mode voltage setting was increased to 122 V to help increase the low voltage levels at Node 1. The inverter simply needs to absorb more reactive power from the distribution system to help reduce the 4-V rise from the SVR to the PV as was the case with inverter unity PF mode. As the SVR is holding 122 V at the PV side

of the regulator, the inverter needs to absorb 1,000 kvar so that only a 2-V rise occurs between the SVR and the PV.

Running a variety of other load scenarios is warranted to assist with the development of the line SVR and PV inverter settings, especially when operating in a voltage-regulating mode. If this is not done, excessive reactive power exporting or importing may occur at the PV site causing excessive tapping or hunting of the SVR.

### Ramping or Tripping of PV

IEEE 1547 states that the DER must disconnect from the distribution system for any abnormal system conditions and remain disconnected for 5 min. Consequently, this anti-islanding requirement can create very large voltage changes with a significantly sized DER.

Also consider the ramping that occurs due to cloud shading. As discussed, a reasonable ramp rate for this installation is 30 s, and it was developed through discussions with the PV plant developer and also considered valid as calculated with [5]. With longer time delays set on regulators, the voltage change on the system would be

comparable to when the PV is completely disconnected because of abnormal voltage events.

Both summer and winter load and generation profiles were referenced to determine the worst-case periods for both months in which the PV could be either disconnected or fully ramped, producing excessive voltage flickers on the system. Load flows for the following scenarios were investigated:

- peak load with maximum coincidental PV kilowatts
- minimum load with maximum coincidental PV kilowatts
- peak PV at 12 p.m. with maximum coincidental circuit load.

The process for each of the above was to run a load flow to find the tap position of the regulators for the steady-state condition. Next, the regulators tap positions were locked, the PV generation dropped, followed by a new power flow to find the voltage change. In Figure 13, the worst-case voltage change of 9 V, or about 8%, occurs on Phase B at Node 2. Overall, voltages at Node 1 and Node 2 are significantly less than the required 118-V minimum.

## Conclusions

Distributed renewable energy resources such as PV plants have significantly changed the landscape from the traditional method of planning or operating the system for one-way power flows. As production costs decrease and renewable portfolio standards become more stringent, the size of these DER plant additions will only get bigger, surpassing the local load of the system. This will complicate the system impact review process, further justifying more robust time series capable power flow programs.

The IEEE 1547 series as well as the NRECA DG Toolkit provide invaluable insight into the possible operational or safety issues that may result when renewable generation is integrated with the distribution system. Actions to help remediate some of these potentially harmful situations are also provided. The NRECA DG Toolkit even takes it one step further and provides some interpretations of what each section or rule of IEEE 1547 is really aiming to accomplish or how and why the rule was developed.

Determining the potential power generation curves from PV at various times through the daylight hours and seasons is not a trivial task since they are dependent upon many factors such as solar irradiance, ambient temperatures, location of the sun, the arrays' tilt and azimuth, PV plant location, and site size. The inverters' ratings, design and operating modes also need to be considered since they can vary greatly. Coupling this with the local load profile to develop a wide variety of net circuit load levels with and without generation is needed with followup investigation to determine any issues with negative interactions between voltage-regulation devices, which in turn will assist with the development of new control settings to accommodate the DER-enhanced system.

Examples were presented with traditional voltage-regulator settings normally used for one-way, steady-state load flows, resulting in voltage problems when introducing intermittent generation, especially with

reverse power flow during periods of peak insolation. Also demonstrated were the effects of operating PV inverters in VR mode rather than the more commonly used unity PF mode.

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Greg J. Shirek, P.E. ([greg.shirek@milsoft.com](mailto:greg.shirek@milsoft.com)) and Brian A. Lassiter are with Milsoft Utility Solutions, Inc. in Abilene, Texas. Shirek is a Senior Member of the IEEE. This article first appeared as "Solar Photovoltaic Modeling Impacts on Distribution Systems—Case Study" at the 2011 IEEE IAS Rural Electric Power Conference.