# *Case Studies for Utility Scale Solar Facility Performance and Power Quality Issues*

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***Abstract -- The Tennessee Valley Authority (TVA) has evaluated over 10,000MW of solar generation interconnection requests since 2018 with only a fraction becoming approved, implemented projects. Commission testing was performed on completed utility scale solar generation facilities before commercial operation began. This paper will discuss power quality and reliability issues that were found through the interconnection study and commissioning processes. Case studies covered in this paper include harmonic distortion, flicker, rapid voltage change, response to transient overvoltage, response to system faults and voltage sags, and power oscillations.***

## I. INTRODUCTION

The Tennessee Valley Authority (TVA) is a generator and transmission owner/operator primarily serving local power companies and transmission-connected industries in the watershed of the Tennessee River Valley. This service area encompasses more than 10 million people, providing power through a network of 16,000 miles of high voltage transmission lines and 2,300 substation buses across a seven-state footprint.

Coal-fired generation plants have formed the backbone of the TVA power system since TVA first started using them in the 1950s. In keeping with a commitment to generate safer, cleaner energy, older and less efficient coal-fired plants are being retired and replaced with low- or zero-emission electricity sources such as solar. This has led to a sharp increase in prospective utility scale solar generation facilities sized over 50MW inside the TVA service territory that are primarily developed and operated by independent power producers (IPPs) and interconnected into the TVA transmission system (Fig.1). Since 2018, TVA has evaluated 87 solar projects totaling 14,100MWs of generation capacity. If all 87 of these prospective solar plants achieved commercial operation, they would represent 41% of the existing TVA generation capacity [1]. However, experience has shown that less than 20% of these projects are likely to achieve commercial operation. TVA currently has 2,076MW of signed purchase power agreements (PPA) with IPPs and approximately 600MW online as of May 2022 (Fig. 2).

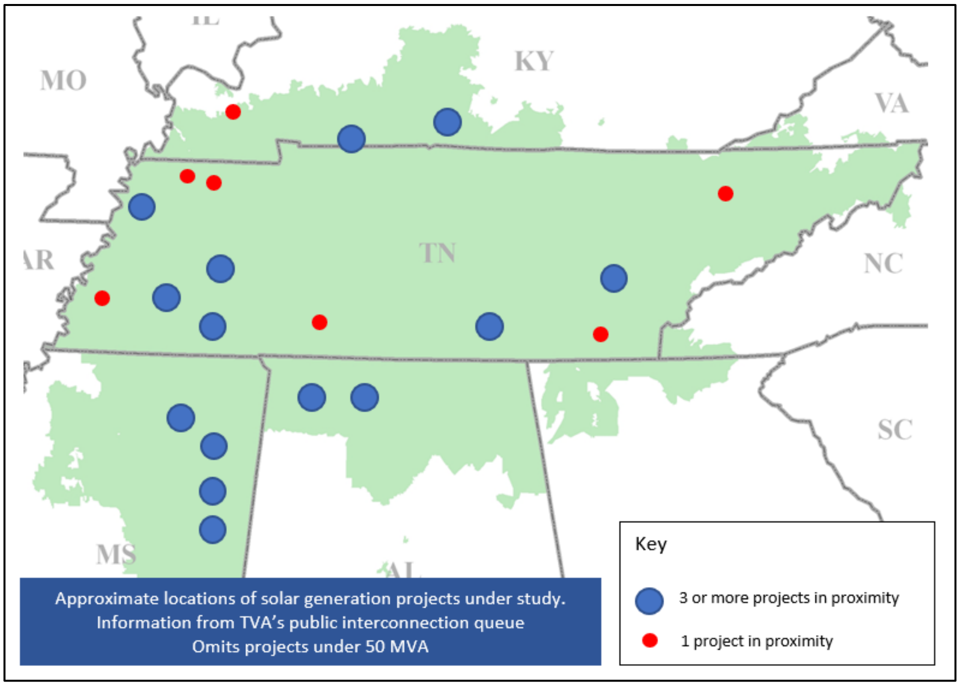


*Fig. 1. Proposed solar sites >50MW inside TVA service area (in green)*

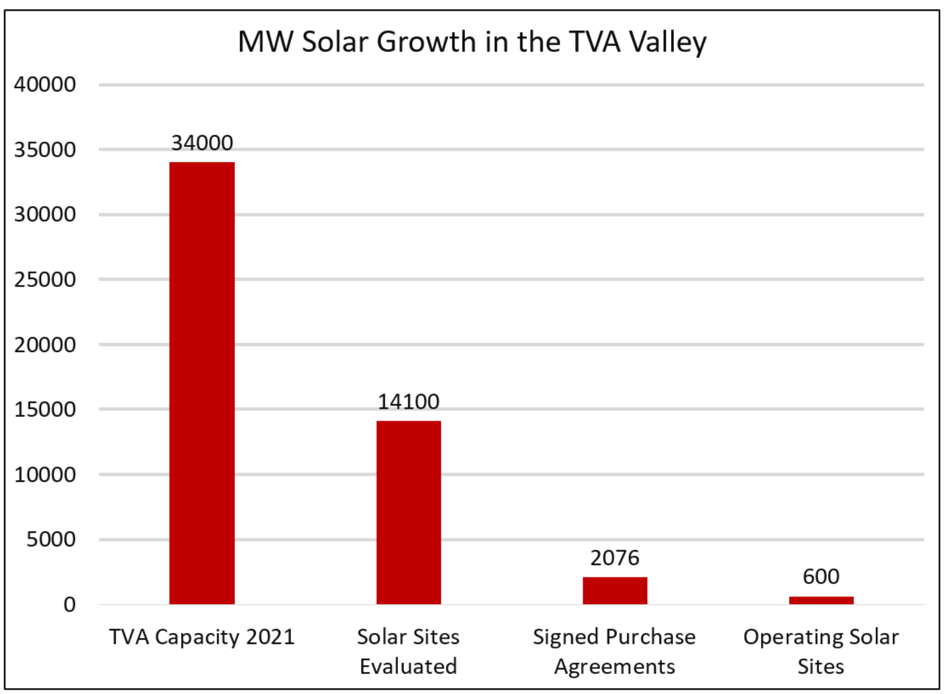


*Fig. 2. Solar growth (MW) inside TVA service area*

For the 87 solar projects evaluated to date, the typical solar generation proposal submitted to TVA has a capacity of 50-200MW (Fig. 3).

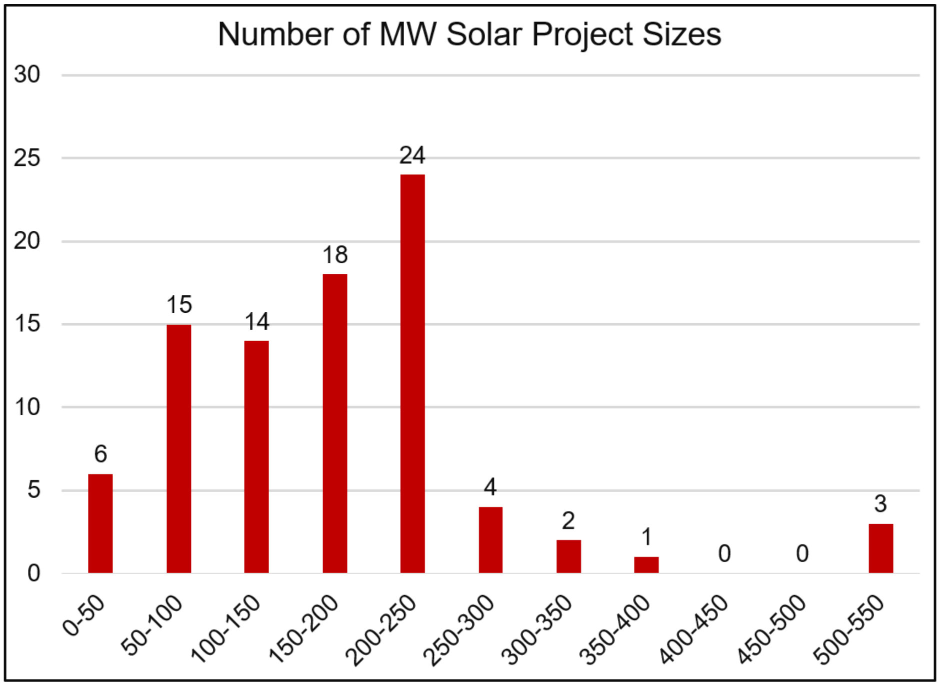


***Fig. 3. Histogram of MW capacity for proposed solar sites***

## II. PLANNING AND INTERCONNECTION PROCESS

TVA's interconnection study requirements mandate that the project must not create load-flow or system stability concerns. Some of the other aspects evaluated in the interconnection study process include short-circuit analysis, system protection evaluation, reactive power evaluation, and metering/visibility (SCADA) requirements.  TVA also requires evaluation of power quality issues like rapid voltage change (RVC) and voltage distortion that may impact customers at neighboring delivery points.

### *A. Modeling*

TVA requires positive-sequence and electromagnetic transient (EMT) models of the solar plant to be submitted in accordance with TVA's publicly posted modeling requirements, which include details for the plant controller, electrical controller, and converter controls.  Most interconnection dynamics studies are performed using only positive sequence models. However, a complete, accurate EMT model is imperative for post-event analysis of performance issues such as those described in the case studies that follow.    Once a solar facility was approved and the PPA was in place, considerable effort was spent refining the EMT model provided by the solar developer to ensure it included all details and settings of the inverters and power plant controllers, correct impedances for all busses and transmission lines and correct modeling parameters for the actual transformers, breakers and capacitor banks installed at the site.  Verification of model details for the full detailed inner control loops of the power electronics and the correct representation of all fast inner controls as implemented in the installed equipment was also performed. It is important that all model parameters provided reflect the actual installed settings in the field and not the manufacturer default settings. Unfortunately, the case studies examined here either pre-date TVA's EMT modeling requirements or involve aspects that were not adequately modeled in the model provided to TVA.

### *B. Interconnection Study*

If the interconnection study reveals load flow or stability criteria violations then TVA must specify line uprates, new transmission lines or other system components to allow the site to be interconnected to TVA's transmission system. Sometimes these TVA network upgrades are significant enough to affect the solar project's viability. The IPP must also evaluate the ability to purchase land and other key site issues not related to TVA requirements. Concerns related to power quality normally do not factor into the viability of a project, but there are typically some power quality concerns that must be addressed.

The most frequent power quality issue is the RVC associated with energizing a main, high voltage (HV) generator step-up (GSU) transformer (i.e. 161/34.5kV) and/or multiple medium voltage (MV) inverter skid (i.e. 34,500/645V) GSUs. Depending on the stiffness of the transmission system, the subsequent current inrush that accompanies these events can create RVC events that exceed the 5% limit given for HV systems in IEEE 1453 [2]. In these cases, mitigation techniques such as pre-insertion resistors or zero voltage closing controls must be specified for the main GSU high voltage circuit breaker. For MV issues, selective energization of inverter skids can be utilized. TVA discovered through the interconnection study process that 40% of the 87 sites evaluated needed mitigation measures to dampen GSU energization inrush related RVC.

A second power quality issue is harmonic distortion. In the normal all-ties closed transmission system configuration, harmonic issues are normally not an issue. However, in many cases the site being studied is served in the middle of a transmission line having a strong source on one end and a weaker source on the other end. It was determined that 55% of the 87 evaluated sites could potentially result in voltage distortion levels exceeding IEEE 519 [3] limits. In all cases, TVA monitors the site during commissioning for normal (N) and single contingency (N - 1) system configurations to determine if problematic voltage distortion is present. If issues are found, the primary mitigation approach will be to detune inverters away from problematic frequencies.

A third power quality issue that is routinely evaluated is the effect of switching transients from any nearby transmission capacitor banks. In such cases where a capacitor bank energization transient may impact the performance of a solar generation plant, capacitor switching technologies with transient mitigation have been included with the project.

## III. COMMISSIONING

In order to verify operational performance of the solar plant, TVA conducts a series of commissioning tests before commercial operation is allowed. An interconnection agreement (IA) outlines expected performance requirements of the solar plant. The current commissioning process consists of five tests, but additional tests may be added in the future as needed.

### *A) Commissioning Tests*

1) RVC – measure change in RMS voltage associated with the main GSU transformer and inverter feeder transformer current inrush to verify compliance with IEEE 1453 [2] and IEC TR 61000-3-7 [4]

2) voltage step – verify voltage control setpoint change response time and associated plant MVAR output comply with specified droop characteristic curve given in IA

3) reactive power capability – verify plant max reactive power production and absorption meet requirements of IA

4) frequency response – verify power plant controller/inverter response to frequency changes meet requirements of IA

5) distortion - measure current and voltage harmonics when solar production is near plant rated output and with varying combinations of TVA transmission capacitor banks and solar plant capacitor banks energized/deenergized to verify compliance with IEEE 519 [3].

Generally speaking, all five tests are performed in the all-ties closed configuration. However, some tests may be omitted from the radial from weak source and radial from strong source configurations if it is determined that transmission system strength in these abnormal N-1 conditions is not likely to produce significantly different results from the normal all-ties closed configuration. Also of consideration is that some commissioning tests are only demonstrating capability of the solar plant and not its interaction with the bulk electric system such that actual transmission system configuration may not be important.

*B. Instrumentation for Measurement*

It has been helpful to have a variety of instrumentation in place to measure solar plant performance parameters during commissioning tests. These include class "A' power quality monitors, phasor measurement units (PMU), and digital fault recorders (DFR).

Class "A" power quality monitors provide the ability to trend voltage and current harmonics and also view numerous real time power quality measurements and are especially helpful for the distortion commissioning test. PMUs provide real time and historical trend data for MW, MVAR and voltage/current and are especially helpful for the voltage step and frequency step tests. DFRs are easily configured to capture an event record for changes in bus voltage and have proven valuable for recording oscillography during the RVC tests.

## IV. CASE STUDIES

*A. Sudden Solar Plant MW Reduction Due to Switching Transient Overvoltage (Case 1)*

A 75MW, 161kV solar plant experienced a reduction in power coincident to a recorded transient overvoltage as shown in Fig. 4. The transient overvoltage was the result of a restrike on the C-phase pole of a circuit switcher when it was opened to remove an 81MVAR, 161kV TVA owned capacitor bank from service. The capacitor bank was located at a bus 12.5 miles away from the solar interconnection bus. The maximum transient overvoltage recorded at the solar interconnection bus was 151% of the nominal peak voltage and had a cumulative duration of less than 1ms exceeding 120% of nominal peak. The solar plant was producing 70MW of power at the time, dropped to 0MW when the transient overvoltage occurred and ramped back up to 50MW within 0.5 seconds. It is worth noting that solar plant output never recovered to the pre-event 70MW level at any point during the remainder of that day. This could be a matter of irradiance changes but could also be the result of protective relaying which operated inside the plant to disable a portion of the inverters.

While a restrike event is rare, switching transients due to transmission capacitor bank energizations are a routine daily occurrence. As such, TVA is requiring that all transmission capacitor banks in the vicinity of a solar interconnection be energized with a device equipped with transient overvoltage mitigation such as pre-insertion impedance.

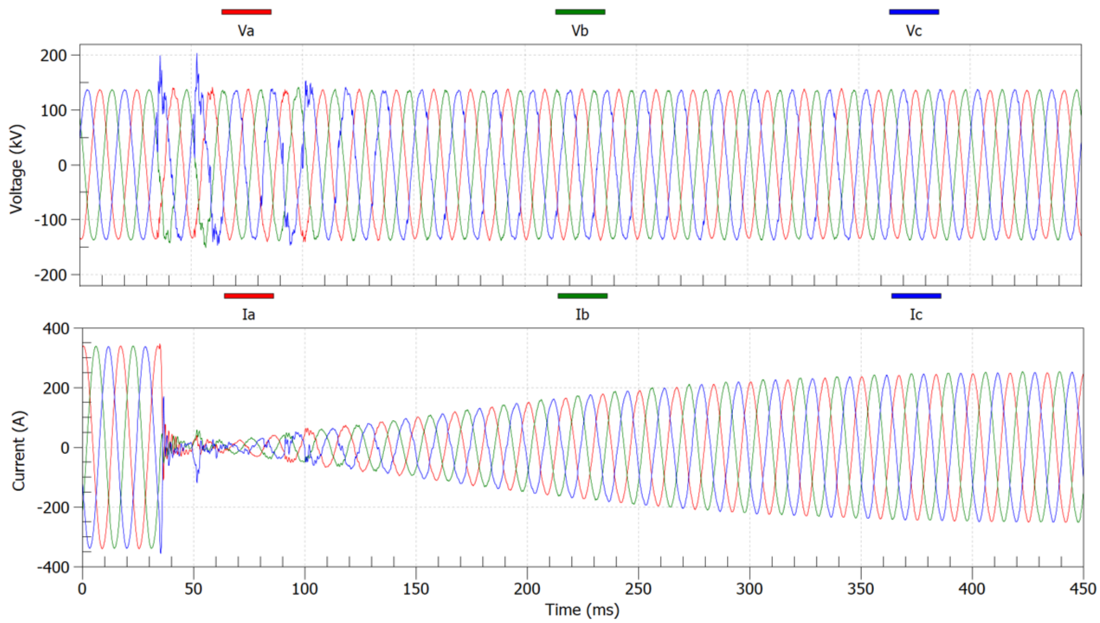


***Fig. 4. Solar plant MW reduction associated with switching transient***

*B. Sudden Solar Plant MW Reduction Due to Transmission System Fault Related Voltage Sag (Case 2)*

A 54MW, 161kV solar plant experienced repeated instances of reduction in power coincident to voltage sags from transmission system faults. Fig. 5 shows an example of the solar plant providing ~1000A peak (or 43MW) before a voltage sag to 85% of nominal for 2.5 cycles occurred. The voltage sag was the result of a C-phase to ground fault on the 161kV transmission system over five busses away from the solar interconnection bus. The power produced by the solar plant dropped from 43MW to 18MW and had recovered to 35MW after 12 seconds and to 40MW after 6.5 minutes. Each of the voltage sags were within the mandatory operation range specified in IEEE 1547 [5] and NERC PRC-024-2 [6].

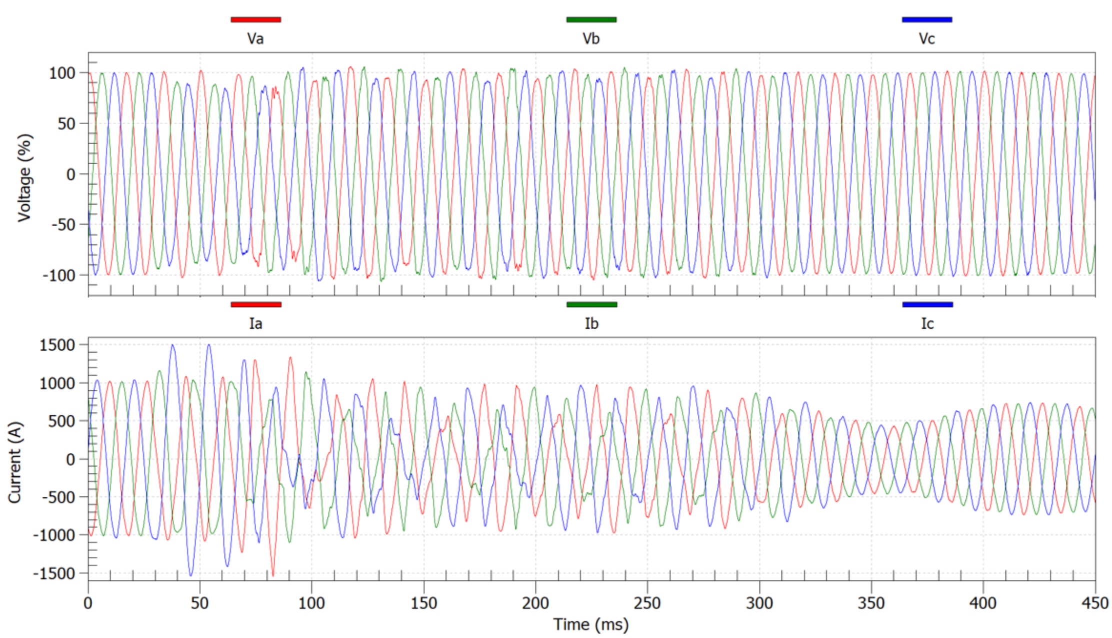


***Fig. 5. Solar plant MW reduction associated with transmission system fault related voltage sag***

*C. Excessive Voltage Distortion Related to Inverter Switching Frequency (Case 3)*

Inverter setting changes were made at the Case 2 solar plant in an attempt to remedy the incidents of loss of generation occurring during mild to moderate voltage sags. The initial "retuning" of the inverters resulted in an increase in the total harmonic voltage distortion (THD) primarily driven by an increase of the 49th harmonic which was exceeding IEEE 519 [3] limits. Fig. 6 shows an example voltage waveform after the initial "retuning" when solar generation was at 45MW output. This condition persisted for several weeks until additional inverter settings changes were applied finally resolving the issue. Fig. 7 shows an example voltage waveform after the final "retuning" when solar generation was at a similar power output.

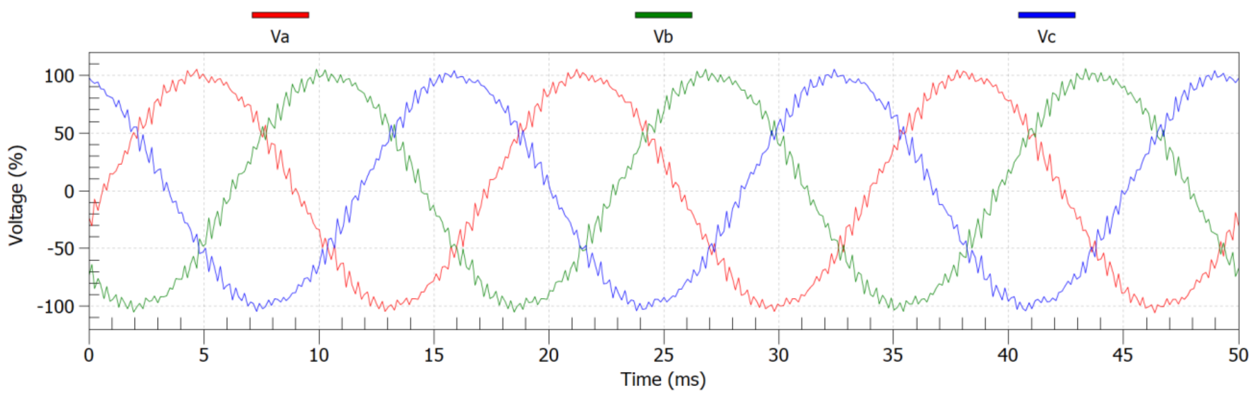


***Fig. 6. Voltage waveform at solar interconnection bus after initial retuning of inverters***

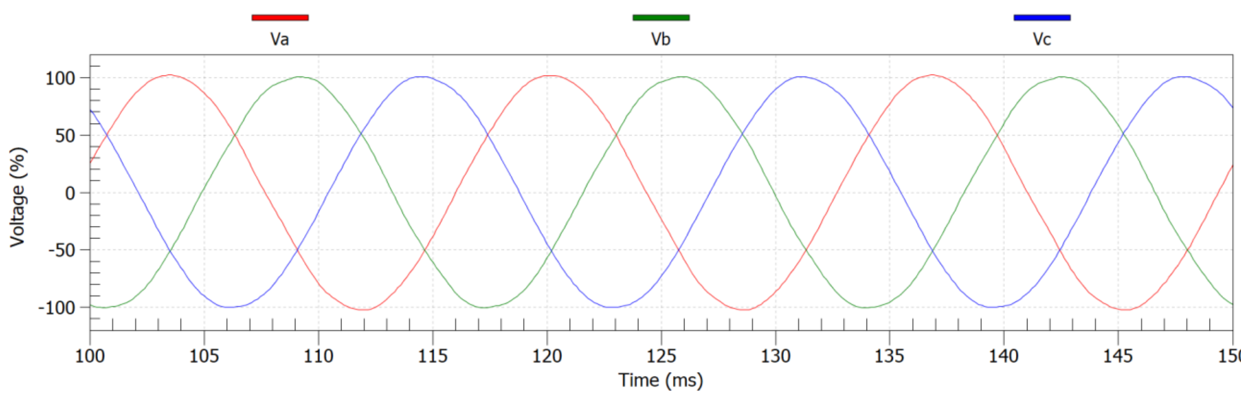


***Fig. 7. Voltage waveform at solar interconnection bus after final retuning of inverters***

The solar interconnection has a three winding 161/35/13kV main GSU. The elevated voltage distortion was only seen at the 35kV and 13kV buses; however, in this case other customer load was being served from the 13kV bus. This 13kV load had to be transferred to an alternate feed until the voltage distortion issues at the solar interconnection could be resolved. As a lesson learned from this and other similar cases, TVA now recommends dedicated main GSUs for future solar plants.

*D. Elevated Flicker Due to Frequent Energization of Solar GSU (Case 4)*

A 161/13kV distribution station has multiple general 13kV distribution feeders and a single dedicated 13kV feeder to an 8.25MW, 13kV solar interconnection from the common 13kV bus. The 13kV bus began to experience elevated flicker levels which were impacting customers served by the general distribution feeders. The flicker levels first elevated at 10 p.m., well after sunset, and continued throughout that night as shown in Fig. 8. Waveform recordings indicated what appeared to be classic transformer energization events originating on the dedicated solar feed. An example waveform is shown in Fig. 9. This was occurring about every 40 seconds throughout the night and early morning hours. The 13kV breaker to the solar plant feed was opened at the general distribution station at about 9 a.m. the following morning at which time the flicker levels returned to normal. It was later determined that a communication issue had been causing the solar plant main breaker to repeatedly operate.

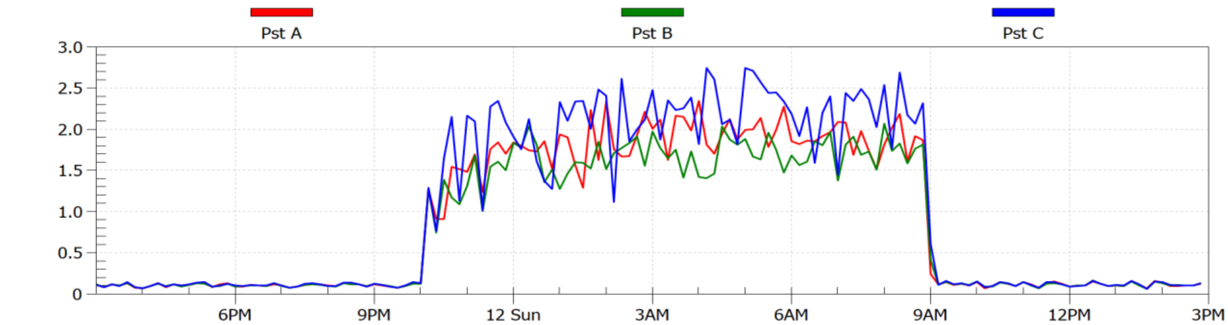


***Fig. 8. Elevated flicker due to repeated opening/closing of solar plant main GSU breaker***

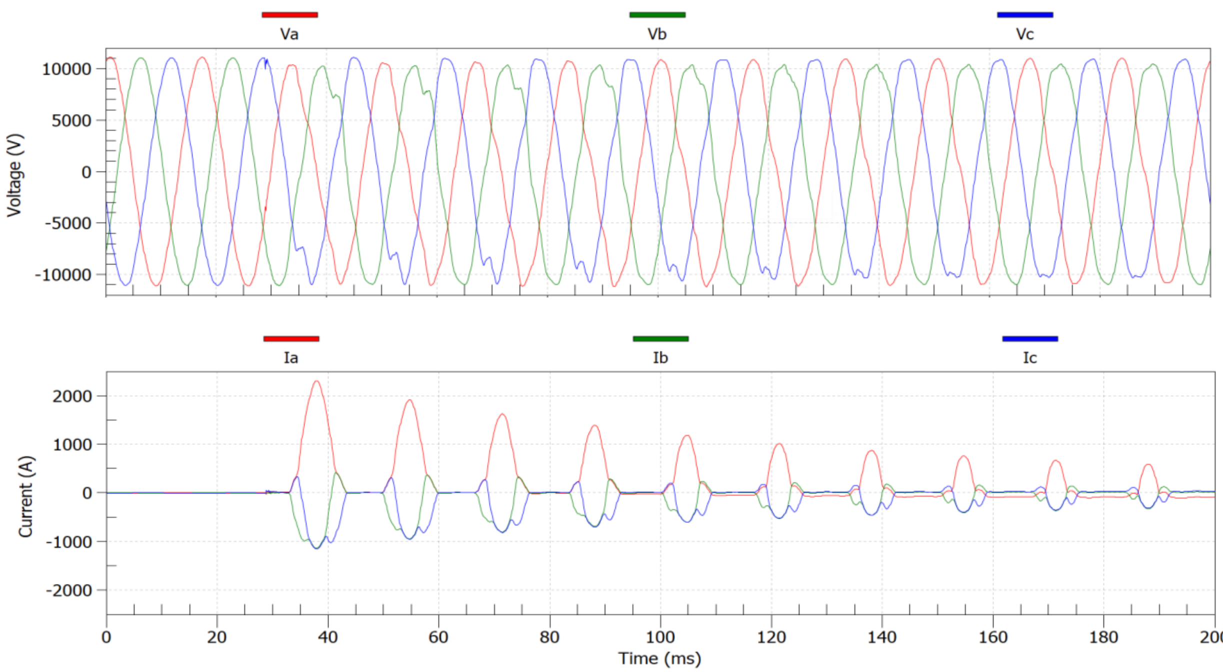


***Fig. 9. Example waveform (GSU inrush) from solar plant main GSU closing***

*E. RVC Violation Due to Energization of Solar Plant Inverter Feeders (Case 5)*

A 227MW, 161kV solar plant has two main 161Y/35Y/13ΔkV GSUs each rated at 75/100/125MVA. Each transformer has two 35kV feeders supplying 17 inverter transformer units each for a total of four 35kV feeders. The solar plant has two incoming 161kV transmission lines as sources. As part of commission testing, RVC tests were conducted by energizing each main GSU one at a time and then each 35kV feeder one at a time. The RVC test was repeated for all ties closed transmission system configuration as well as when radial from either of the two transmission lines.

TVA's requirement for RVC is to have no more than 5% change in voltage at the high voltage interconnection bus. During the study process, it was determined that mitigation would be needed to energize the main GSU to meet the 5% voltage change requirement. The solar developer elected to utilize breakers equipped with zero-volt closing control to energize the main GSUs. During commission testing this worked flawlessly. There was no detected step change in voltage when energizing either main GSU under any system configuration.

The RVC test was then continued by closing each of the 35kV feeder breakers. This resulted in step voltage changes of over 10% at the 161kV bus when in the radial configuration as shown in Fig. 10.

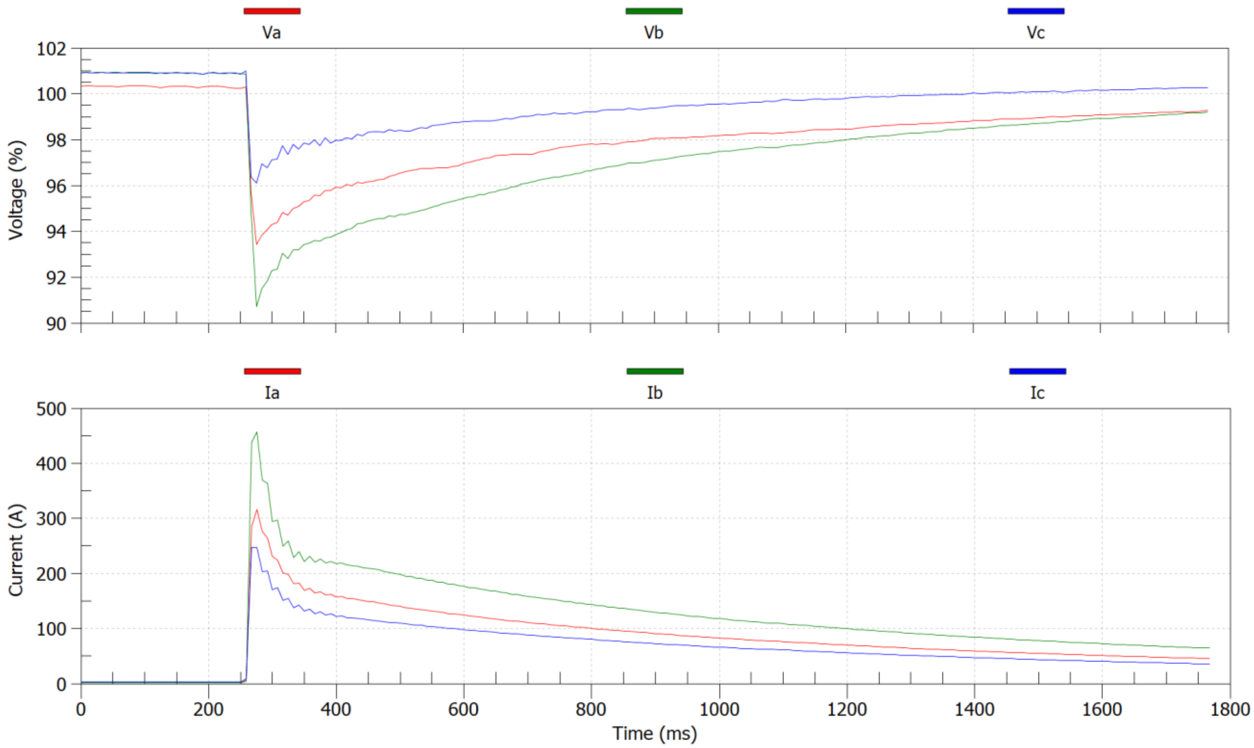


***Fig. 10. RVC associated with energizing 13 inverter skid GSUs via a single MV feeder breaker***

For future solar interconnections, TVA is now specifying a maximum amount (MVA) of inverter skid GSU units which may be energized on a single MV feeder to meet the 5% voltage change requirement at the HV bus.

*F. Solar Plant MW/MVAR Oscillations Due to Power Plant Controller Logic and Communication Issues (Case 6)*

After beginning commercial operation, the same 227MW, 161kV solar plant as in Case 5 had multiple instances where it experienced power oscillations. There were occasions where there were only oscillations in active power and other occasions where there were only oscillations in reactive power.

After the solar plant had been online for months without incident, TVA's oscillation monitoring system began seeing several real and reactive power oscillation events that had magnitudes and durations long enough to trigger oscillation alarms. The magnitudes of the more severe events were around 100MW for the real power oscillations and 80-100MVAR for the reactive power oscillations, all peak to peak. The durations of these events ranged from a few seconds to several minutes. Fig. 11 thru Fig. 14 show plots of these oscillation events.

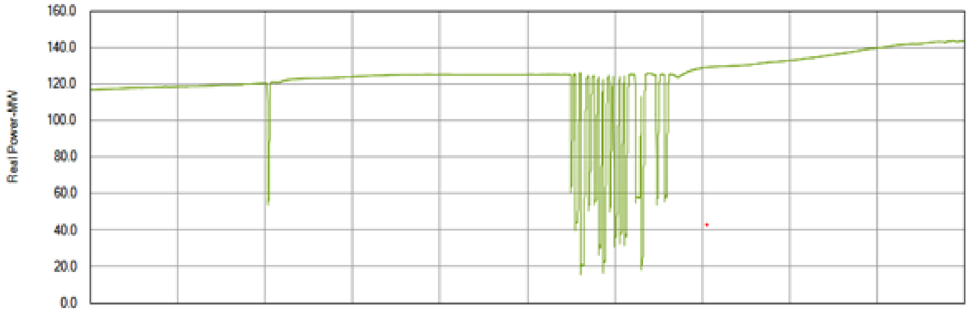


***Fig. 11. Example solar plant MW oscillation***

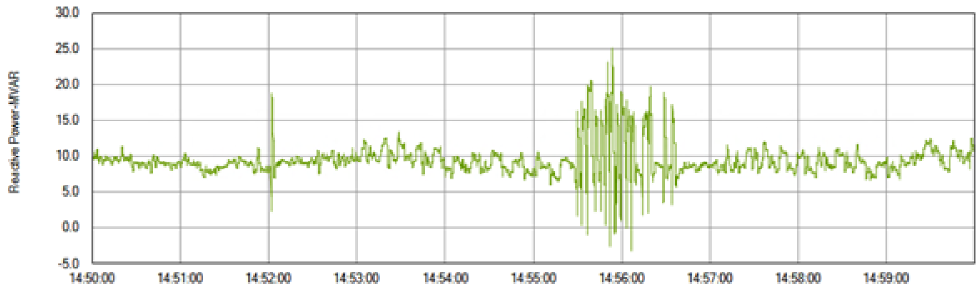


***Fig. 12. Example solar plant MVAR oscillation***

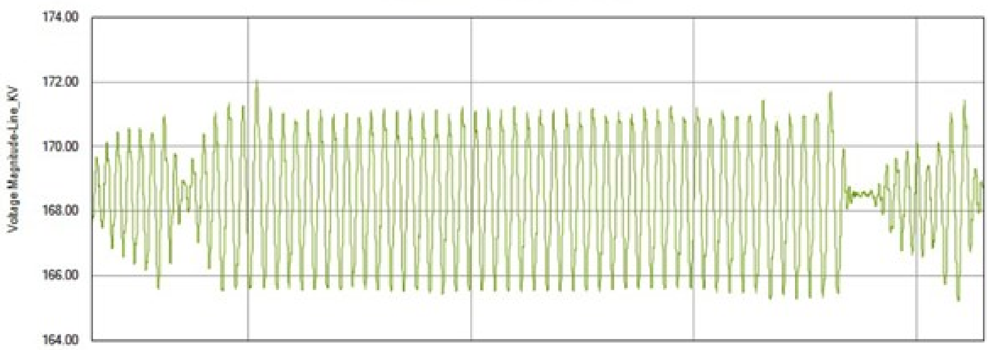


***Fig. 13. Example voltage oscillation resulting from MVAR swings***

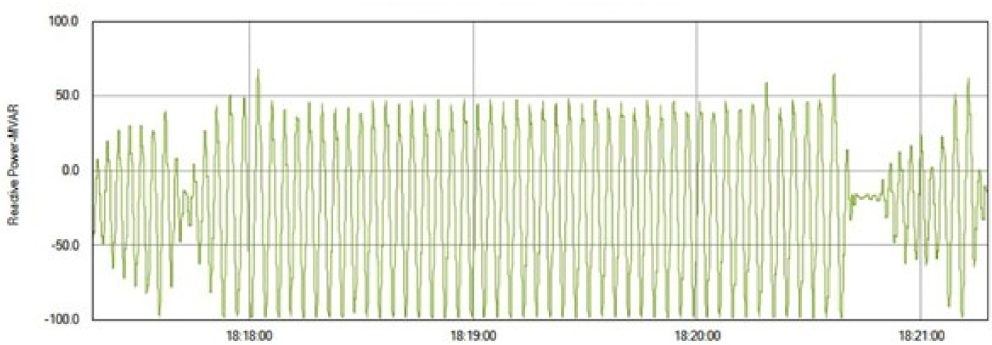


***Fig. 14. Additional example MVAR oscillation***

There were two primary causes for the solar plant oscillations. One cause was related to how the PPC handled the loss of communications to the inverters during over frequency events and the other cause was related to a short duration between exit of frequency curtailment and a subsequent curtailment causing cumulative reduction in plant output.

The PPC controller normally operates such that the freq/watt controller within the PPC detects system frequency outside of the deadband and modifies the point of interconnection (POI) limit based on the frequency error, plant capacity, frequency droop, and plant output power. Since most frequency errors are small, the freq/watt controller will generally set a POI limit value that is within a few hundred kW of the meter value at the onset of the frequency event. However, during situations where the inverters were not communicating with the PPC, the PPC would send new setpoints to the communicating inverters that were sufficiently low to ensure that if the non-communicating inverters were running at full power the POI limit would not be exceeded. When the non-communicating inverters were not producing full output power, the plant output was being driven significantly below the POI limit value. So, the plant would decrease the output too much such that the frequency would move back to the deadband limit. When this happened the PPC would tell the inverters to start producing power again and cause the plant output to jump back to where it originally was and put the frequency outside of the deadband, thus causing a repetitive cycle of rapidly changing the power output (oscillations).

This issue was addressed with modifications to the PPC and also settings changes in the inverters. The changes in the PPC modified the communication interface with each inverter to include a watchdog MODBUS register and add logic in the PPC to create the watchdog timer, remove non-communicating inverters from the power controller's setpoint calculation (effectively setting those inverters output to 0), add logic to disable the freq/watt control from the time that the communication with any inverter is lost and the inverter ramp down period ends, and add "on/off" status point to the TVA data map to reflect the status of primary frequency response/ frequency watt-control. Setting changes in the inverters were made to cause them to automatically ramp power to zero when they determined communication had been lost between the inverter and the PPC.

The problem with the short duration exit of frequency curtailment and subsequent curtailment was the power plant could not recover from the previous curtailment and would curtail again in quick succession. Thus, the next curtailment starts from a lower meter value than the first, and the plant drops to a lower power than the first curtailment. This ultimately resulted in a stair step down in the power plant output.

This issue was addressed by filtering the frequency signal to dampen the freq/watt control output such that the controller's response to a frequency excursion would be slower. In much the same way as damping the reactive power response increased system stability, damping the freq/watt response allowed time for the grid to absorb and respond to incremental changes in plant output. Additionally, the freq/watt controller now holds a meter reference for 30s following a frequency curtailment.

## V. CONCLUSIONS

Even though solar generation represents a small percentage of the overall generation across the TVA footprint as of May 2022, a number of cases have already been documented related to power quality, reliability and operational performance. Considering the rapidly increasing number of solar interconnections expected over the next 10 years, it is very prudent to continue effective evaluations through modeling, testing, and monitoring to prevent widespread issues in coming years.

## REFERENCES

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[3] IEEE 519 (2014), *Recommended Practice and Requirements for Harmonic Control in Electric Power Systems*

[4] IEC TR 61000-3-7 (2008), *Electromagnetic compatibility (EMC) – Part 3-7: Limits – Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems*

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[6] NERC PRC-024-2 (2015), *Generator Frequency and Voltage Protective Relay Settings*