Case Study: Enhancing Grid Reliability in the Presence of Inverter-Based Resources Through Advanced Oscillation Detection and Mitigation

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***Abstract*—As the integration of inverter-based resources (IBRs) into power grids has increased, oscillations due to controller mistuning or malfunctioning have become increasingly prevalent. Controller issues vary widely, from problems with individual devices to complex interactions between device-level and plant-level controllers. These oscillations can serve as critical indicators of underlying issues that demand attention from generation owners. Unfortunately, these disturbances can be subtle, and traditional monitoring systems, at both the transmission- and generation-owner levels, often fail to detect them.**

In this paper, we present a wide-area monitoring system deployed at Dominion Energy (Virginia). The utility has installed a large number of digital fault recorders (DFRs) with synchrophasor streaming capability across Virginia and North Carolina. These devices monitor hundreds of solar farms, data centers, substations, and distribution centers. With such a large amount of streaming data, it is essential to have software capable of automatic data analysis, easy asset navigation, and user notifications when events occur.

This paper focuses on the oscillation detection application of the system. The primary function of this system is to automatically identify oscillations, promptly notify relevant stakeholders, and facilitate easy, thorough investigation of the events. The oscillation detection system analyzes synchrophasor data and produces results that are easy to understand for operators and engineers.

The paper then describes in detail several specific IBR oscillation cases, including the analysis of the underlying cause of oscillations. This event analysis and description of the utility's lessons learned provide insights for ensuring reliable power system operation in the presence of IBRs.

I. Introduction

The Virginia Clean Economy Act of 2020 [1] and the North Carolina House Bill 951 [2] established a schedule by which Dominion Energy transitions to 100 percent clean energy generation in Virginia by 2045 and in North Carolina by 2050. To comply, the utility is retiring traditional synchronous generation and incorporating more renewable resources into the generation mix. Most renewable resources are coupled to the grid via switching electronics and are thus categorized as inverter-based resources (IBRs). The use of other switching electronics, such as flexible alternating current (ac) transmission system devices (FACTS), which include static synchronous compensators and static volt-ampere reactive (VAR) compensators, is also expanding.

The transition to new sources of generation introduces challenges not previously seen on the power system. Among these challenges, a particularly important one is the dramatic increase in local oscillations, which consist of power system signals (typically voltage) changing magnitude in a periodic manner. Such oscillations have been observed on the utility's system due to IBRs as early as 2021 and have increased substantially in frequency as IBR penetration increases.

The first step in mitigating the undesirable effects of oscillations is detecting them. Oscillation detection using high-resolution power system signals has a long history [3–6]. A particularly successful custom solution based on synchrophasor data and implemented at the Bonneville Power Administration is described in [7].

While the system described in this study is a general-purpose oscillation detector, the fact that it operates on synchrophasor data limits its ability to detect certain oscillations, such as some subsynchronous oscillations (SSOs) [8] [9]. SSOs typically have frequencies in the range of 5 to 55 Hz. In this study, the synchrophasor data rate is 30 messages per second. Depending on the type and frequency of an oscillation, after processing by the phasor measurement unit (PMU), it will be filtered to the point that it cannot be effectively detected.

This paper describes a simple yet powerful detection methodology that is incorporated into a commercial, synchrophasor-based, wide-area monitoring software package. The critical features of this method are as follows:

- It is capable of analyzing many signals of different quantities (e.g., voltage magnitude and real and reactive power) simultaneously.
- It estimates oscillation magnitudes in real time and in units that are physically meaningful and easy for operators and engineers to understand.
- It has configurable frequency bands in which magnitudes are estimated.
- It can compare magnitude estimates for signals across the system.
- It creates alarms when oscillation magnitudes exceed configurable thresholds.
- Its output can easily be integrated into a geographic display for visualizing alarms over a large area.

This paper begins by describing the details of this automated detection tool. Then, we describe the utility's system monitoring capability in the context of oscillations. Their process for detecting, analyzing, and preventing future oscillation events is also described. Examples of actual system events are provided, including data captured during the oscillations and the underlying cause of the issue, as determined from analysis by Dominion Energy and the generation owners. Finally, we present the conclusion and our recommendations gleaned from the utility's experiences.

II. Detection Methodology

Oscillations are detected in PMU signals, such as voltage magnitude, real power, and reactive power, via a multistep signal processing chain designed around the Discrete Fourier Transform (DFT) algorithm. The estimated oscillation magnitudes are produced once per second.

A. Algorithm Description

The Fourier Transform is a signal processing technique that transforms a data series in the form of magnitude versus time into a data set of magnitude and phase versus frequency. An oscillation in time appears as the magnitude peaks at a specific frequency in the DFT output. The DFT output contains information on frequencies up to one-half of the sampling frequency. This limit on the maximum frequency resolvable from DFT data is known as the Nyquist rate.

The accuracy of the DFT in resolving low frequencies is related to the window length of the time series. For a steady-state oscillatory signal, a longer window provides finer frequency resolution from the DFT and thus a more accurate estimate of the oscillation frequency and magnitude. However, there is a natural tradeoff between steady-state accuracy and responsiveness of the result to changing signals conditions. A shorter window allows successive magnitude estimates to more quickly track changing oscillation behavior in a signal. The proposed algorithm manages this tradeoff by using either a 10-second or 40-second window length, depending on the frequency bands for which oscillation detection is desired. The following rule is used: if the lowest frequency in the configured band fits fewer than two full periods in the 10-second window, then the 40-second window is used; otherwise, the 10-second window is used. For example, if a frequency band's lower limit is 0.08 Hz, two periods have a duration of 25 seconds, so the 40-second window is used.

Before performing the DFT, both data windows are preprocessed by removing bad or missing samples, subtracting out the mean, applying a Hanning window function, and zero-padding the data to provide a minimum window length of 4,096 samples. The Hanning window smooths the results in the frequency domain, and the zero padding increases resolution. After this processing, the DFT is performed on each set of samples via the Fast Fourier Transform (FFT) algorithm.

The goal is to estimate the root-mean-square (rms) oscillation magnitude within a set of configurable frequency bands. The utility uses the following four bands: 0.01 to 0.15 Hz, 0.15 to 1 Hz, 1 to 5 Hz, and 5 to 14 Hz. Together, these bands cover the detection of very low-frequency oscillations up to nearly the Nyquist frequency of the most common PMU data rate (30 messages per second). PMUs demodulate the nominal 60 Hz power system data down to direct current (dc), so these oscillations typically manifest themselves as lower frequency oscillatory components in the PMU data.

To see how the rms magnitude is calculated from the DFT result, consider the definition of rms for a discrete-time signal, *x*, as shown in (1).

$$x_{rms} = \sqrt{\frac{1}{N}\sum_{k=1}^{N} x_k^2} \tag{1}$$

where N is the number of samples in the data window.

A version of Parseval's theorem [10] establishes the relationship between the energy in a signal in the time and frequency domains for discrete signals, as shown in (2).

$$\sum_{k=1}^{N} x_k^2 = \frac{1}{N}\sum_{j=1}^{N} |X(j)|^2 \tag{2}$$

where X(j) is the jth bin of the DFT of *x*. Combining (1) and (2) gives (3).

$$x_{rms} = \frac{1}{N}\sqrt{\sum_{j=1}^{N} |X(j)|^2} \tag{3}$$

Both the zero padding and Hanning window described previously artificially reduce the rms magnitude estimate. The zero padding reduces the rms magnitude by the factor in (4).

$$k_{zp} = \sqrt{\frac{N}{N_{FFT}}} \tag{4}$$

where N_{FFT} is the number of samples in the FFT after zero padding.

The average effect of the Hanning window on rms is shown in (5).

$$k_H = \sqrt{\frac{1}{N}\sum_{k=1}^{N} h_k^2} \tag{5}$$

where h_k are the samples of the Hanning window. After compensating for the effects of the zero padding and windowing, the final rms magnitude is estimated in (6).

$$x_{rms} = \frac{\sqrt{2}}{k_{zp}k_H N_{FFT}}\sqrt{\sum_{j \in F} |X(j)|^2} \tag{6}$$

where the set *F* contains all the bins of the DFT within the desired frequency band. The $\sqrt{2}$ compensates for the fact that *F* only contains bins in the positive-frequency half of the signal spectrum.

B. Example Algorithm Results

To demonstrate the accuracy of (6), consider the following test signal shown in (7).

$$x_k = 100 + 2\cos\left(\frac{2\pi f_1 k}{f_s}\right) + 3\cos\left(\frac{2\pi f_2 k}{f_s}\right) + 0.5\cos(2\pi f_3 k / f_s) \tag{7}$$

where:

$f_1 = 3$ Hz

$f_2 = 4$ Hz

$f_3 = 0.08$ Hz

$f_s = 30$ messages/second

The results from (6) for the default frequency bands described previously are shown in Fig. 1. The first two cosine functions in x_k fall in the 1 to 5 Hz band, and the third cosine function falls in the 0.01 to 0.15 Hz band. The rms estimates are quite close to the theoretical values in both bands. The expected results are $0.5/\sqrt{2}$, 0, $\sqrt{2^2+3^2}/\sqrt{2}$, and 0 for the four bands. There is a small amount of leakage into the 0.15 to 1 Hz and 5 to 14 Hz bands, but the magnitudes are negligible.

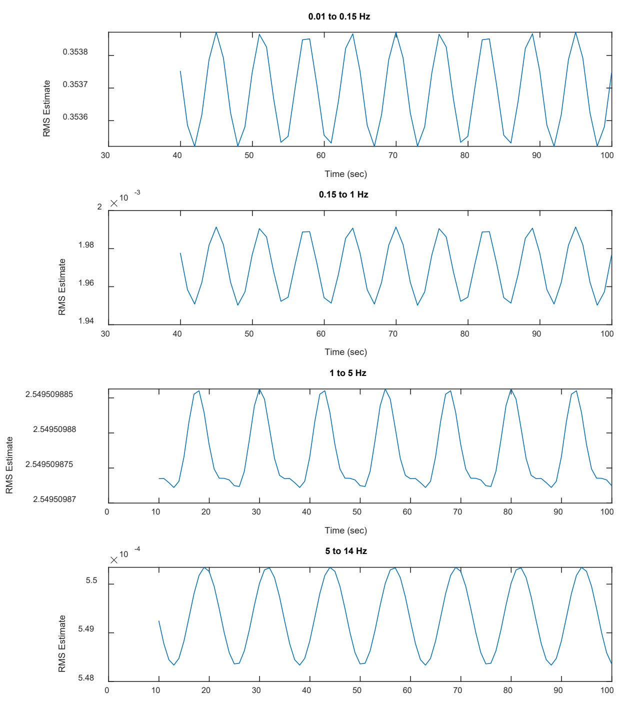

Fig. 1. Example rms magnitude estimates for test signal.

A second test signal, from actual PMU voltage magnitude data are shown in Fig. 2. From approximately 300 to 750 seconds, the signal contains a 0.25 Hz oscillation with a peak-to-peak magnitude around 550 volts.

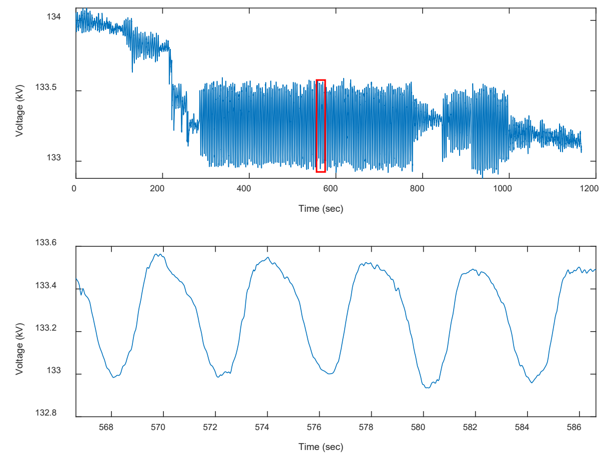

Fig. 2. PMU voltage magnitude—bottom chart expands the red rectangle of the top chart.

The results from (6) for the configured frequency bands described previously are shown in Fig. 3. The top right chart shows that the rms magnitude estimate is quite close to the observed oscillation size of approximately 560 volts peak-to-peak or 200 volts rms during the period when the oscillation is active. The spikes at around 220 seconds in the other three charts are due to the sharp drop in the voltage signal. Preventing alarms from this type of nonoscillatory behavior is discussed in the following section.

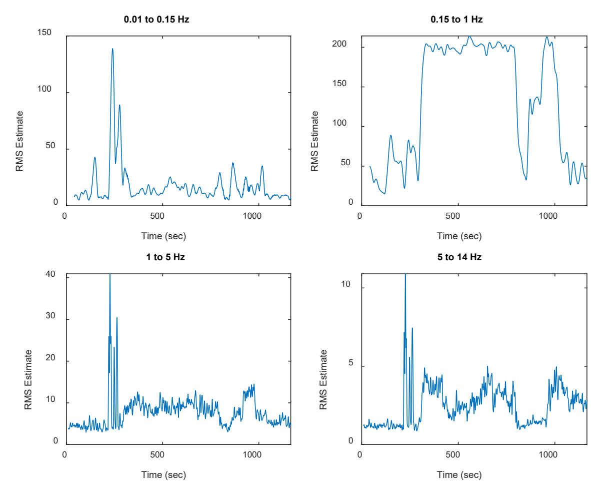

Fig. 3. Example rms magnitude estimates for actual PMU voltage signal.

C. Alarms Based on RMS Magnitude Estimates

A typical transmission operating entity wants to monitor many PMU signals for oscillations. It is not practical for an operator or engineer to directly observe, in real time, the rms magnitude estimates to detect an oscillation. To relieve this burden on operators, the estimates are automatically compared against alarm thresholds. When any estimate exceeds its threshold, an alarm should be created, and the affected signals automatically surface for an operator or engineer to investigate.

A practical method that has been successfully employed for setting alarm thresholds is to configure the software to compute rms estimates for the desired signals with the alarming disabled for approximately 1 to 2 weeks. After that period of time, the estimates are examined to establish the baseline level of the estimates when no oscillations are present. The thresholds are set near but above this level. Once the alarm is configured in this way, the engineer can adjust the thresholds based on the number of alarms that are being generated.

The algorithm described previously has been demonstrated to accurately estimate the magnitude of sustained oscillations. However, as seen in Fig. 3, it can also return large estimates for a short period of time, following a sharp change in the steady-state level of the input signal. Once the change moves out of the data window, the rms estimate returns to a normal state. To prevent false alarms in these situations, a pickup timer is applied to the alarm so that it does not assert until the rms estimate has exceeded the threshold for a period of time. The pickup timers should be slightly longer than the data window (40 seconds for lower frequency bands and 10 seconds for higher frequency bands) to ensure that any momentary disturbances have time to fully move through the window.

III. System Monitoring and Configuration at Dominion Energy

The utility monitors its transmission system for oscillations by measuring analog quantities located at substations that have multiple transmission lines, are IBR-connected, or are multiline and IBR-connected. The data are captured in various ways, including by the supervisory control and data acquisition (SCADA) system [11]. SCADA provides analog data values (voltage, current, watts, VARs, etc.) from primarily digital relays and transducers. While the SCADA system provides the largest number of data points, the low scan rates (~0.5 messages per second) and imprecise time alignment make it insufficient for observing many oscillations.

Other recording devices used include digital relays and digital fault recorders (DFRs) for post-event analysis [12]. Both devices include PMUs to provide synchrophasor data, which is streamed back to servers for storage and analysis. Voltage and current phasors are sent at a rate of 30 messages per second, and any other derived quantities are calculated on the server that receives the data. These phasors and the quantities derived from them are the inputs to the oscillation analysis algorithm described previously.

The utility has invested heavily in DFR technology, installing DFRs at almost all transmission facilities throughout its service territory. Most of these fault recorders have the ability to compute and stream synchrophasor voltage and current data, which allows their engineers to pinpoint the specific substation affected by an oscillation event, not just the general area, during event analysis. When an event is detected, higher-rate data (4,800 messages per second) can be pulled from the DFRs for in-depth analysis.

A. Transmission Configurations

A network configuration refers to the system configuration in which each end of a transmission system is connected to one or more sources (see Fig. 4a).

A radial configuration is created when one end of the line is connected to a source. A line can have both ends closed but still be radial (see Fig. 4b).

A transmission system is considered to be in a normal state when there are few or no outages across the service territory. In most cases, the normal state of the transmission system is networked.

During nonpeak loads in the spring and fall, various transmission lines and generators are removed from service for maintenance or construction. Switching operations are performed to remove the necessary equipment from service while maintaining a configuration that reliably supplies end users. These switching operations can result in radial configuration, and the utility has observed that these configurations commonly result in oscillatory behavior when the radial connects to an IBR facility.

Fig.4a

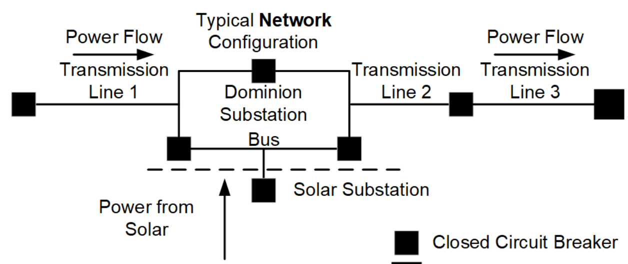

Fig. 4b

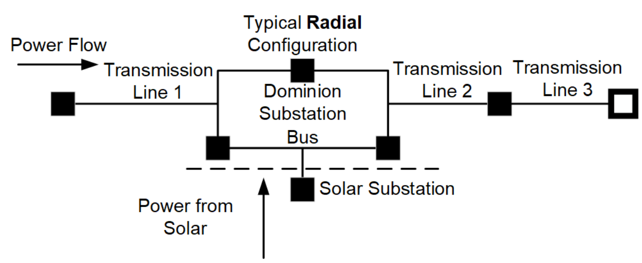

Fig. 4. Standard transmission system configurations.

B. Solar Generation Configuration

The typical solar power plant connects to the transmission system via two breakers at the substation. Fig. 5 shows a dedicated solar substation connected via a three-breaker ring substation.

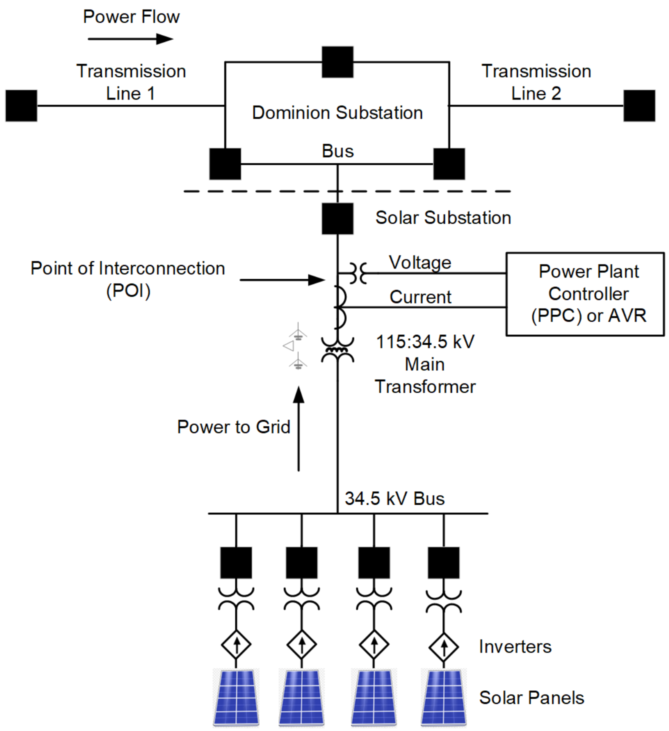

Fig. 5. Typical solar installation.

C. Oscillation Detection and Event Analysis Methodology

Traditionally, at the utility, transmission operators detect oscillations by receiving repeated over- and undervoltage alarms or repeated fault recorder triggers. Additionally, the transmission operators are notified by end users or generator owners who observe abnormal electrical behavior. These events are observed only once every few years. The events are complex and require expertise from technicians and engineers from both generation and transmission. Due to the large number of factors involved, understanding and resolving these events can take days.

Since 2021, reports of abnormal events across the utility's system have increased, due to the increase in IBR-connected generation. The process to analyze these events has been refined and improved to reduce analysis time, pinpoint the source of the oscillation, and resolve the issue in a timely manner. Synchrophasors at each IBR site feeding into the oscillation detection tool described previously has been proven to be the most efficient way to detect the issues in near real time.

After an oscillation is detected, the subsequent event investigation uses a mixture of SCADA, DFRs, and synchrophasors to determine the source. The steps for the engineer include the following:

1. Review changes in voltage magnitude at the suspected substation and connected substations.
2. Review changes in reactive power magnitude at the suspected substation and connected substations, with an emphasis on where generators or IBRs connect.
3. Review direction of reactive power at the suspected substation and connected substations, with an emphasis on where generators or IBRs connect.
4. Compute and analyze power spectrum density plots on signals to determine energy and mode signatures in the signals [13].

IV. Selected System Events

Table I shows 14 notable oscillation events detected on the utility's system from Winter 2021 to Spring 2024. The increasing density of detections after Fall 2022 corresponds to the implementation of the automatic detection scheme described in this paper as it is rolled out over the period of about a year. The lack of events in the summer is primarily due to the fact that radial configurations are rare in the summer because maintenance is confined to other times of the year when the system load is lower.

Selected events are described in detail in the following subsections. The two earliest events spurred the utility to evaluate the extent of the problems. This evaluation proceeded by deploying an additional monitoring capability to the most sensitive areas and implementing the automatic detection scheme.

A. Power Plant Controller (PPC) Oscillation, Winter 2021

A localized voltage and reactive power oscillation at a solar facility occurs after the site's connection to the transmission system switches from a network to a radial configuration.

A short oscillation immediately follows the switching but decays quickly. However, the PPC is not properly tuned for the weaker radial configuration, and it starts a cycle of overcorrection, alternating between increasing and decreasing reactive power, causing the voltage magnitude to oscillate. The oscillatory behavior decays over a period of 7 minutes and eventually returns to normal. Fig. 6 shows a portion of the overcorrection cycle.

TABLE I
OVERVIEW OF EVENTS

Oscillation Condition or Cause	Time	Duration	Frequency (Hz)	Maximum Change in Voltage Magnitude (%)
Controller Mistuning	Winter 2021	7 minutes	0.03	11
Load	Summer 2022	1 hour, 58 minutes	14.93	5
Multisite Controller Tuning	Fall 2022	43 minutes	0.03	8
Low Power Output	Fall 2022	19 minutes	0.07	3
Low Power Output	Fall 2023	21 minutes	0.07	5
Low Power Output	Fall 2023	4 hours, 20 minutes	0.01	4
Low Power Output	Fall 2023	1 hour, 7 minutes	0.02	5
Low Power Output	Fall 2023	1 hour, 18 minutes	0.02	5
Multisite Controller Mistuning	Winter 2024	8 hours, 5 minutes	0.03	2
Low Power Output	Winter 2024	15 minutes	0.06	1
Multisite Controller Mistuning	Winter 2024	1 hour, 10 minutes	0.04	10
Unknown	Spring 2024	4 hours, 45 minutes	0.03	2
Controller Mistuning	Spring 2024	23 minutes	0.36	1
Load	Spring 2024	45 minutes	1.00	2

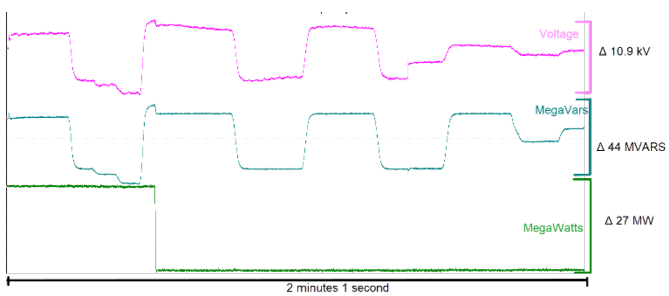

Fig. 6. Solar PPC overcorrection cycle.

Following this event, the PPC is retuned to reduce the gain of the voltage control loop. The new settings are tested by repeating the network-to-radial configuration change, and the site responds as desired. No further tuning is required.

B. Load Oscillation, Summer 2022

A localized voltage oscillation causes lights to flicker in the affected area. End users call the utility to alert them of the problem. The oscillation persists for a total of nearly 2 hours. Fig. 7 shows a representative sample of the voltage oscillations at several locations. The beating behavior in the voltages is due to the undersampling of the oscillation by the PMUs (the oscillation frequency is very close to the 30-sample-per-second PMU Nyquist rate of 15 Hz). The undersampling causes some loss of fidelity, but the oscillations are still clearly visible and can be detected by the automated scheme.

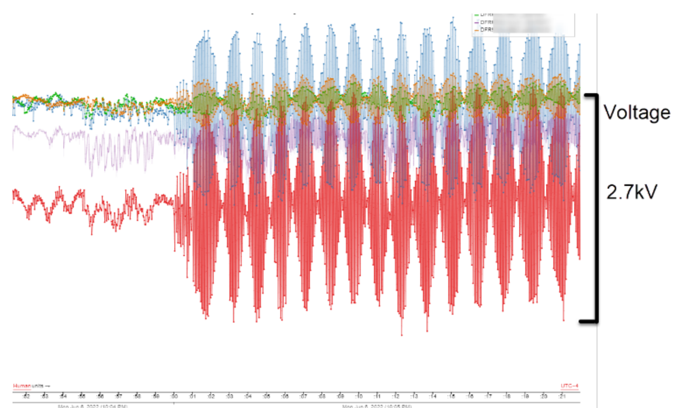

Fig. 7. Voltage oscillations caused lights to flicker, sampled at 30 messages per second.

Fig. 8 shows the voltage and power quantities at the POI of the offending site. The higher-rate data in the figure show the oscillations with the most fidelity. Fig. 9 shows the same signals and others nearby captured by the SCADA system. The low scan rates result in the magnitude of the oscillatory behavior being drastically underestimated. Because of this, SCADA data are unsuitable for capturing these oscillations, and PMU data are required.

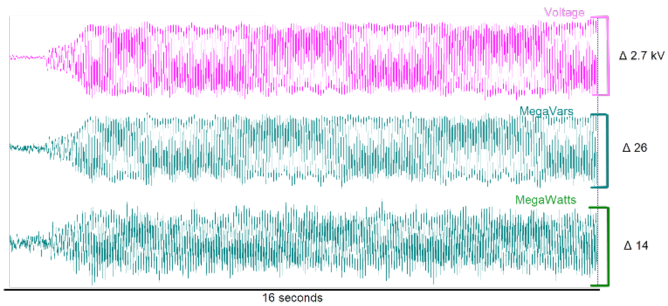

Fig. 8. Oscillations sampled at 960 messages per second.

Fig. 9. Oscillations sampled at SCADA scan rates.

Approximately 1 hour before the oscillations begin, a nearby synchronous generator is taken offline. The oscillations begin when a second synchronous generator is also taken offline. The oscillations persist until capacitor banks and FACTS devices are switched into service.

Further investigation reveals that the improper settings on the uninterruptible power supply at the industrial load site cause the problem and are modified. After the settings change, lower-level oscillations are still present.

C. *Solar Sunrise and Sunset Oscillations, Fall 2022*

A localized voltage oscillation at a solar facility begins at sunrise when the site power output begins ramping up. The oscillations are detected using the automated detection scheme described in Section II.A. A comprehensive review of the data from the site shows oscillations each day at sunrise and sunset, though the rms magnitude is below the configured threshold. Further, data from Fall 2020 show that similar oscillations have been occurring. Seven other solar sites show similar behavior.

Fig. 10 shows the voltage and reactive power oscillations at several sites, and Fig. 11 shows rms magnitude estimates for reactive power oscillations produced by the automatic detection scheme. The offending site crosses the alarm threshold, and the alarm alerts engineers to the problem. Fig. 10 and Fig. 11 are directly from the software system running the detection scheme. Voltage oscillation monitoring (results not shown) also detects the problem and creates an alarm.

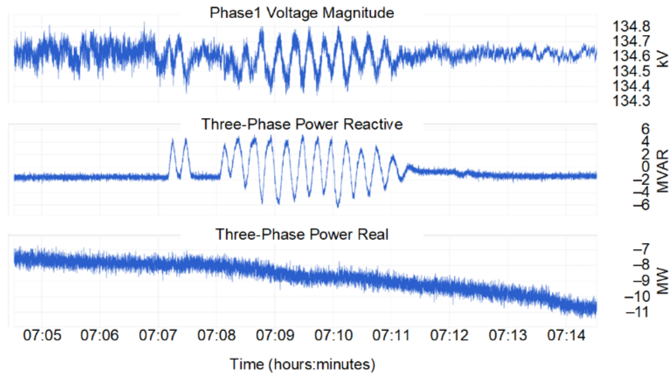

Fig. 10. Voltage oscillations and reactive power observed at sunrise.

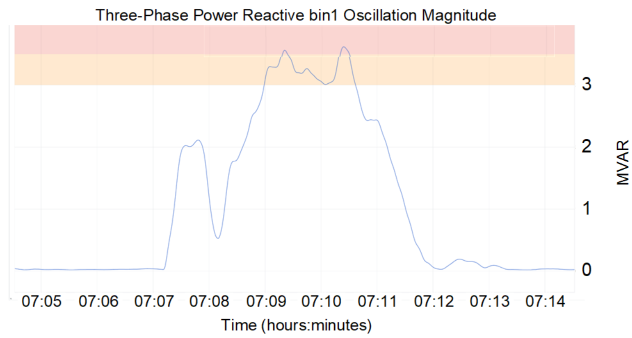

Fig. 11. RMS oscillation magnitude estimates for reactive power in the 0.01 to 0.15 Hz frequency band. The large blue estimate was at the offending site and crossed the alarm thresholds.

No switching events or suspicious system configuration are found to correlate with the events. The oscillations persist until solar irradiance is high enough for the sites to meet their requested real power output. Discussions with various inverter manufacturers indicate that they are familiar with the issue, and they suggest that settings changes resolve it.

D. *Low-Power Oscillations, Fall 2023*

A localized voltage oscillation occurs at a solar facility when an inverter's power requested from the PPC is curtailed to 0 MW at full irradiance. The oscillatory behavior is detected by the automated scheme. Fig. 12 and Fig. 13 show the observed voltage and power oscillations.

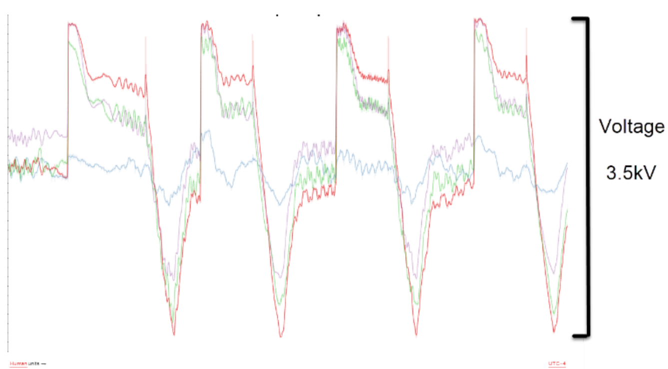

Fig. 12. Voltage oscillations at sunrise observed at several locations.

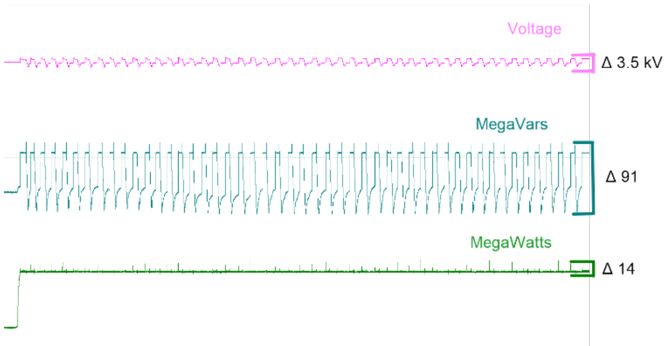

Fig. 13. Voltage and power at offending site.

An investigation by the site owner reveals that the oscillation is caused by the PPC entering a cycle of turning an inverter on and off. When the total power request for the plant necessitates turning one or more of the individual inverters off, these inverters consume a small amount of power, causing the aggregate plant power to drop below the requested aggregate power plus the deadband. This, in turn, causes the PPC to turn the inverters back on. The minimum achievable power from these inverters then causes the aggregate power to move above the set point, and the cycle repeats itself.

After reviewing and understanding the standby power consumption of the individual inverters, the PPCs' minimum power output is adjusted, and subsequent tests verify that the problem is resolved.

E. Multisite PPC Oscillations, Winter 2024

A voltage oscillation affects multiple facilities. The automated detection system creates alarms at several facilities, and end users call the utility and report flickering lights. It is caused by various system reconfigurations from network-to-radial and controller interactions between multiple generation sites. The configuration of the affected area is shown in Fig. 14.

No switching operations or system activities take place in the immediate time before the oscillations begin; however, a synchronous generator is just taken offline.

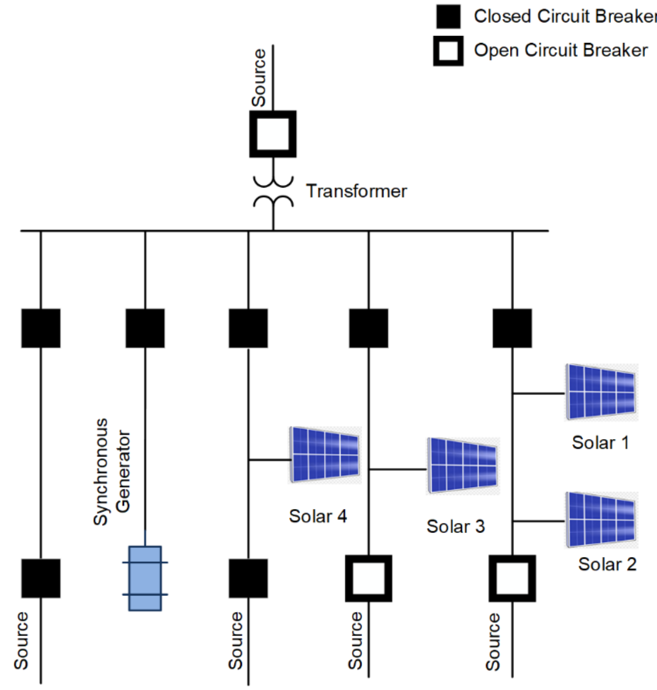

Fig. 14. System configuration immediately prior to multisite oscillations.

Synchrophasor data show that the voltage and reactive power changes are largest at Solar Facilities 1 and 2, with Solar Facility 3 showing large, intermittent voltage swings. From the previous day, Solar Facility 2 shows large voltage swings, but because Solar Facility 3 does not (it is in a network configuration), Solar Facility 2 is initially identified as the source of the problem. Changing the PPC at Solar Facility 2 from the voltage control mode to the power factor control mode eliminates the oscillations.

Fig. 15 shows voltage and power data from Solar Facility 2. Fig. 16 shows the rms magnitude estimates for many sites. The affected sites show clearly larger estimates and differ significantly from the ambient level making them easy to detect.

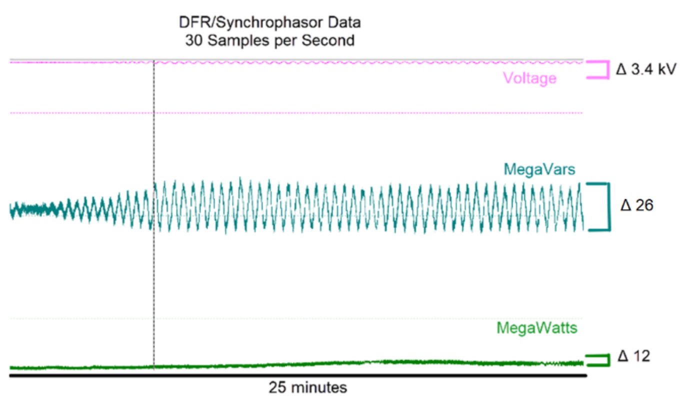

Fig. 15. Voltage and reactive power oscillations at Facility 2.

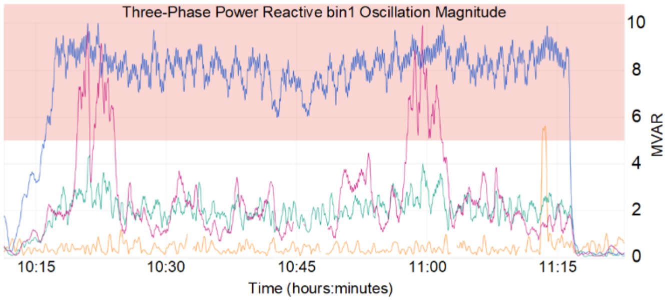

Fig. 16. Reactive power oscillation magnitude estimates at various sites.

Further investigation shows that the PPCs at Solar Facilities 1 and 2 simultaneously attempt to correct the voltage, which exaggerates the overall correction. A review of all solar facilities in the area shows that each PPC has been tuned independently when its associated transmission connection is in a network configuration. During the largest swings, six solar facilities' PPCs and one synchronous generator's voltage regulator actively respond to the changing voltage levels. Because of this, it is difficult to pinpoint a single source of the oscillation. Many facilities are affected, and each PPC behaves differently. Ultimately, the oscillation is caused by the interaction between all of the controllers because they are all tuned without the consideration of nearby controllers.

V. Conclusion

The first oscillation experienced on the utility's system immediately highlighted the need for high-resolution recording devices for correct engineering analysis. Without it, no conclusions could have been identified.

A. Sensing Equipment

Sensing equipment provides the key evidence necessary to detect and locate oscillation events. A high-density system of synchrophasor and continuous digital recording devices is critical to identify the source of these types of events, analyze their impact on other facilities, and work towards a resolution. At Dominion Energy, this is achieved using the DFRs as multifunction devices, high-resolution recorders, fault locators, and synchrophasor streaming devices. High-resolution evidence that pinpoints a particular facility is absolutely critical when approaching owners with requests to retroactively make changes. The DFR provides this direct evidence in various forms.

Synchrophasor systems, ranging from primary voltage- and current-sensing devices to the final storage and visualization media, should include devices with a wide-frequency response that allows oscillation detection at low levels. Sensing, detecting, and resolving issues at lower levels help avoid future problems.

SCADA data do not accurately represent the dynamic nature of voltage and reactive power due to its low scan rate. This makes it difficult to understand the source of the problem. DFRs and DFR synchrophasors are the only devices on the utility's system that can record with the high-resolution data needed for an accurate analysis.

B. Localized Voltage Oscillations

The typical transmission operations center is not equipped with tools to detect, pinpoint, and mitigate localized voltage oscillations. Without these tools, oscillations are not discovered until they are sufficiently severe enough that they affect the low-resolution SCADA data or end users complain.

However, localized voltage oscillations can be clearly identified by synchrophasors (streaming from the fault recorder), and they especially stand out in reactive power signals at each generator and IBR. Ideal system monitoring includes voltage oscillation detection at select sites throughout the system and reactive power oscillation detection at all IBR and synchronous generators.

As the number of IBR and synchronous generators increase, it gets more difficult to pinpoint the location of an oscillation.

FACTS devices help reduce the voltage impact of oscillations; however, their reactive power output should be monitored to ensure an oscillation is not simply masked by the support device.

IBR site monitoring should start during or at least immediately after site commissioning and be compared to background values to quickly identify and resolve any abnormalities emanating from the site. The longer an issue is outstanding, the more difficult it is to request that the site owner make changes to correct it.

PPCs are tuned during normal system configuration and are not changed unless requested. Such requests are infrequent or nonexistent. The controllers typically do not have gain scheduling or a similar capability to retune when the system configuration is changed (for example, if a line switches from network to radial) or if another plant is constructed in close electrical proximity. One PPC manufacturer explains their equipment does not have separate settings for different configurations, so it would have to be reprogrammed every time the line configuration changes. The manufacturer suggests that the utility turn down the voltage response gain to delay responsiveness but ensure stability. This is a stopgap solution, which does not work in the long term, because each time the system changes topology or another IBR is added in the area, the controller needs to be retuned. Retuning involves technicians and engineers being onsite and hooking up specialized test equipment.

PPC settings and configurations are the same for each solar IBR site, and dynamic modeling is not performed on a site-by-site basis.

Certain IBR solar sites have trouble controlling power output at low values (<2 MW).

PPC and inverter settings at sites near each other can conflict, leading to localized voltage issues under abnormal network conditions.

C. Synchrophasors

Storing all synchrophasor data indefinitely makes post-event analysis extremely efficient. This includes having an interface to quickly compare quantities across the system.

Monitoring each data stream allows for maximum coverage. Providing alarms when the current is interrupted improves system reliability and helps quickly resolve complicated issues.

Synchrophasor oscillation detection software provides the ability to monitor IBR and other transmission-connected devices continuously, as opposed to commission and spot checks. This allows each site owner the autonomy to complete upgrades and work as needed without negatively impacting local grid voltage.

Prior to synchrophasor oscillation detection software being deployed, the utility has required engineers to manually look at each part of the system for voltage issues. Issues are invisible until they became a large enough problem to be detected with SCADA or until sensing equipment is deployed. Manually reviewing just one point in time may prevent reviewing the time when the system is in its weakest state and most susceptible to oscillations. The oscillation detection tool presented in this paper makes engineers' work more efficient and aids in fast problem identification and resolution.

D. Recommendations for Future Work

Dominion Energy is evaluating the following to improve its monitoring of oscillation events:

- Update regulations by the Transmission Operators, Regional Transmission Operators, and Electric Transmission regulating bodies to include testing, commissioning, and performance requirements to avoid these events in the future.
- Accurately re-create events using the appropriate modeling software.
- Determine the accuracy of the solar facilities inverter and PPC models.
- Update the models as needed and improve the capability to predict oscillatory behavior in the future.
- Develop a process to allow the PPC performance to change based on system configuration. The PPC needs to quickly provide voltage control while not overresponding to voltage events.
- Identify worst-case system configurations for programing the PPC. Ideally, the PPC would be physically tested against these configurations, but this can be difficult due to transmission operating constraints.

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VII. Biographies

Thomas J. (TJ) Purcell IV received a BS degree in electrical engineering from Virginia Polytechnic Institute in 2010 and an MS degree in systems engineering from Old Dominion University in Norfolk, Virginia, in 2017. He has 13 years of utility experience in nuclear electrical design and test engineering, transmission system protection, and automated analysis. In his current role, he works in the System Protection Automation & Analysis division at Dominion Energy as a consulting engineer, reviewing abnormal system operations and working to implement automated detection of these events. He is a member of the Transient Recorders User Council and has been a licensed professional engineer in Virginia since 2015.

Josh Wold received BS degrees in electrical engineering and mathematics from Montana Technological University and a PhD in electrical engineering from Montana State University. He was a hardware engineer at Schweitzer Engineering Laboratories, Inc. (SEL) from 2009 to 2011, and then a professor of electrical engineering at Montana Tech from 2015 to 2021. Since 2021, he has simultaneously worked as a power engineer at SEL and adjunct professor at Montana Tech. He is a licensed professional engineer in Montana.

Md Arif Khan received a PhD and a Master of Science, both in electrical engineering, from the University of Wyoming. He is a senior engineer at Schweitzer Engineering Laboratories, Inc. (SEL) and is responsible for the research and development of new power system metering, monitoring, operations, and control technologies. Dr. Khan is a senior member of IEEE, and a member of the Tau Beta Pi honor society. He was the recipient of a University Gold Medal in 2010 from Khulna University of Engineering and Technology (KUET), Khulna, Bangladesh, and the President's Award in 2014 from the Rocky Mountain Bioengineering Symposium, Denver, Colorado.

Jared Bestebreur holds a Bachelor of Science in Electrical Engineering from Washington State University. He is currently a senior engineering manager at Schweitzer Engineering Laboratories, Inc. (SEL) and is responsible for synchrophasor and relay event analysis software products. He has supported the implementation of wide-area monitoring systems around the world. He is also an active member in the North American SynchroPhasor Initiative (NASPI) community.

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