Analysis of Real-World Sub-Synchronous Oscillation Events in a Power System with High Penetration of Inverter-Based Resources

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Abstract—**Over the past several years, Dominion Energy Virginia has experienced multiple subsynchronous oscillation (SSO) events because of increased penetration of transmission-connected (>69kV), inverter-based resources (IBRs). Events like these present all utilities with novel technical and organizational challenges, one of which is to understand the mechanisms that caused these events. SSOs are traditionally difficult for system operators to identify since their magnitude and frequency can exceed traditional Supervisory Control And Data Acquisition (SCADA) systems. This paper focuses on how Dominion identified events on its transmission system using the high density and high resolution of strategically located continuous recording devices. The paper reviews system topology and establishes real-world system strength (or stiffness) during these events. Using case studies, we identify the causes of the SSOs and the remediating actions taken to prevent them in the future. Finally, this paper presents a methodology to identify SSO events using existing substation equipment, including digital fault recorders (DFRs) and synchrophasor technology (IEEE C37.118.1).**

Keywords— Inverter-based resource (IBR), subsynchronous oscillation (SSO), digital fault recorder (DFR), SCADA, sampling rate, phasor measurement unit (PMU), synchrophasor

I. INTRODUCTION

The Virginia Clean Economy Act of 2020 and North Carolina House Bill 951 established a schedule by which Dominion Energy Virginia will transition to 100% clean energy generation in Virginia by 2045 and in North Carolina by 2050. To comply, Dominion is retiring synchronous generation and incorporating more inverter-based renewable resources (IBRs) into the generation mix. The use of flexible AC transmission system devices (FACTs) is also expanding, specifically static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

The transition to new sources of generation introduces challenges not previously seen on the power system. One of them is subsynchronous oscillations (SSOs). A Subsynchronous oscillation is when a signal (typically voltage) begins to periodically change in magnitude and/or phase angle. The SSOs caused by IBRs were seen on the power system as early as 2021 and have increased substantially as IBR penetration increases. The focus of this paper is to provide methods to detect and analyze SSOs and prevent future occurrences.

II. SYSTEM OVERIVEW

A. Monitoring

System-wide SSO is monitored by measuring analog voltage and current quantities located at substations that have multiple transmission lines, are IBR-connected, or are multi-line and IBR-connected. Other values can be used, but all necessary values can be derived from analog voltage and current. The data is captured in various ways, including by the Supervisory Control And Data Acquisition (SCADA) system.[1] SCADA provides analog data values (voltage, current, watts, vars, etc.) from primarily digital relays and transducers. Other recording devices used include digital relays and digital fault recorders (DFRs) for post-event analysis. [2] Both devices include phasor measurement units (PMUs) to provide synchrophasor data, which is streamed back to servers for storage and analysis. The sampling rate and recording ability of each method and device are summarized in Table I below:

Table I
Recording Capability of Monitoring Devices

Device	Samples per second	Continuous recording
Digital Fault Recorder	4800	Y
Digital relay	240	N
SCADA*	0.5	Y
Synchrophasor**	30	Y
*Not a standalone device, integrated into digital relays and transducers		
**Not a standalone device; integrated into digital relays and DFRs		

It should be noted that Dominion Energy has invested heavily in DFR technology, installing DFRs at almost all transmission facilities throughout its service territory. Almost all our fault recorders have the ability to collect synchrophasor voltage and current data, which allows us to pinpoint the specific substation, not just the general area, during event analysis.

B. Transmission Configuration

A "*network*" configuration refers to the system configuration where each end of a transmission line is connected to one or more sources (see Fig. 1).

A "*radial*" condition is created when one end of the line is connected to a source. It is important to note that a line can have both ends closed but still be radial (see Fig. 1).

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

During non-peak loads in the spring and fall, various transmission lines and generators will be removed from service for maintenance or construction. Switching is performed to remove the necessary equipment from service while maintaining a configuration that will reliably supply customers.

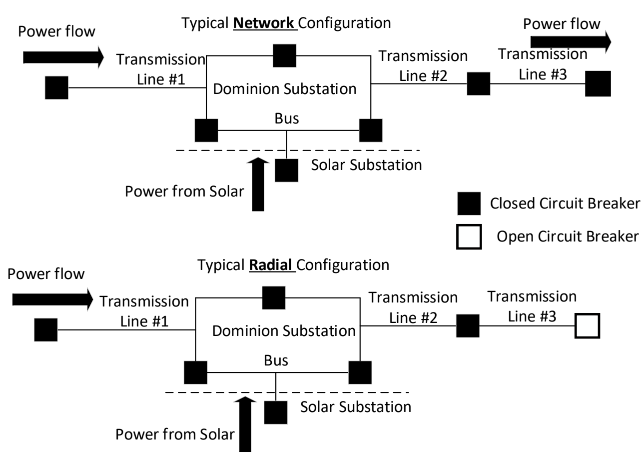

Fig. 1. Standard transmission system configurations.

C. Solar Configuration

The typical solar power plant connects to the transmission system via two breakers at the substation. Fig. 2 shows a dedicated solar substation connected via a three-breaker ring substation.

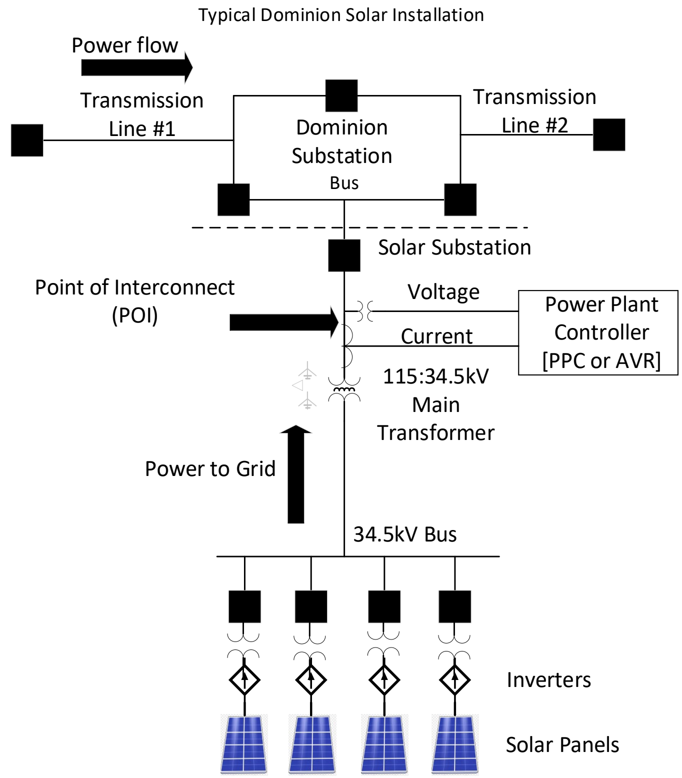

Fig.2. Typical solar installation.

III. DETECTION

A. Overview

Traditionally, transmission operators detected SSOs by receiving repeated over/under voltage alarms, or repeated fault recorder triggers. The transmission operators also were notified by customers or generator owners who observed abnormal electrical behavior. These events were observed only once every few years. The events are complex and require expertise from technicians and engineers from generation and transmission, and can take days to understand and resolve due to the number of factors involved.

Since 2021, reports of abnormal events across the Dominion system have increased, due to the increase in IBRs. The process to analyze these events has been refined and improved to reduce analysis time, pinpoint the source of the SSO, and resolve the issue in a timely manner. Synchrophasors at each IBR site feeding into a software program with set alarm thresholds has proved to be the most efficient way to detect the issues real time.

Each event investigation uses a mixture of SCADA, digital fault recorders and synchrophasors to determine the source. The steps 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 in reactive power** at the suspected substation and connected substations, with an emphasis on where generators or IBRs connect.
4. **Perform power spectrum density plots on signals** to determine energy and mode signatures in the signals [3].

B. Events

Numerous SSOs events have occurred at IBR connected substations, each of these events is shown in the attached Table 2 and 3. Each of these events were reviewed and then grouped by type based on the oscillation behavior. The following includes an example of each type of event observed.

PPC Oscillation, Winter 2021. *A localized voltage oscillation at a solar facility was caused by a transmission line switching from a network to radial configuration.*

After switching, the oscillations decayed, and the voltage returned to steady state. However, the switching weakened the system configuration and the Power Plant Controller (PPC) over-responded, lowering the voltage and bringing it out of band. It then attempted to correct by adding reactive power and raising the voltage. The over- response cycle took 7 minutes to dampen out.

The controller was adjusted by turning the PPC response gain down. The new gain settings were tested by taking the line from network to radial. This time the solar facility responded as expected, and no additional tuning was required.

The location of the oscillation was identified because the voltage and reactive power changes were largest at solar facility #1.

Load Oscillation, Summer 2022*. Customers contacted the utility about lights blinking in the area, which was due to a localized voltage oscillation.*

A little more than an hour before the event, a nearby synchronous generator was taken offline. The blinking began when a second synchronous generator was taken offline. The oscillations continued until capacitor banks and FACTs devices were placed in service.

The Uninterruptible Power Supply (UPS) settings were identified as the problem and were modified, but low-level oscillations were still present. The voltage and reactive power changes were largest at an industrial customer's location and it was concluded that this was the source of the oscillation.

These two events provided the evidence we needed to move forward on evaluating how widespread the problem was and to deploy additional monitoring in sensitive areas.

Sunrise/Sunset Oscillation, Fall 2022. *At sunrise, a solar facility began localized voltage oscillation.*

At the time, a review of switching and system operations was unable to identify any corresponding events. The oscillations stopped when enough irradiance was present for the inverters to meet the requested power output.

A review of data back to fall of 2020 showed that the same oscillations in voltages and current occurred at sunrise and sunset each day, but to a lesser degree. A more in-depth review showed similar behavior at seven other sites during sunrise and sunset.

Discussion with various inverter manufactures indicated they were familiar with the problem, and they suggested that changing settings would resolve the issue.

We discovered the location using synchrophasor oscillation detection software; the voltage and reactive power changes were largest at a solar facility.

Low Power Oscillation, Fall 2023*. A localized voltage oscillation occurred in a solar facility when its output was curtailed to 0 MW at full irradiance.*

The site owner discovered that although the inverters shut off when 0 MW was requested from the PPC, they still consumed power in this state. So the inverters' aggregate power consumption exceeded the 0 MW PPC dead band setpoint.

In an attempt to get back to 0MW, the PPC would then request that the inverters turn back on. Yet the minimum inverter output also exceeded the setpoint, which caused the PPC to shut down the inverters again, this cycle continued until the 0 MW curtailment was removed.

After reviewing the standby power consumption of the inverters, the PPCs minimum power output was raised and subsequently tested successfully.

We discovered the location by using synchrophasor oscillation detection software, and the voltage and reactive power changes proved to be largest at the solar facility.

Multi-site PPC Oscillation, Winter 2024. *Customers contacted the utility about lights blinking in the area during sunlight hours.*

A localized voltage oscillation that affected a number of facilities was caused by various transmission lines switching from network to radial configuration, (see Fig. 3).

No switching or system activities were taking place in the area when the oscillation began, however, a couple of hours earlier a synchronous generator had come offline. At the time of the oscillation, the system was in a normal configuration with each breaker closed.

Synchrophasors showed that the voltage and reactive power changes were largest at solar facilities #1 and #2, with solar facility #3 intermittently showing large voltage swings. The previous day, #2 had shown large voltage swings, but because #3 did not (it was in a network configuration), #2 was identified as the source. Changing the PPC from voltage control to power factor mode at #2 eliminated the oscillations.

Further investigation showed that the PPCs at #1 and #2 simultaneously attempted to correct the voltage, which exaggerated the voltage correction. This resulted in another exaggerated correction as both PPCs attempted to bring the voltage back into the operating band.

A review of all facilities in the area found that each PPC had been tuned separately when the transmission line was in a network configuration. During the largest voltage swings, six solar facilities' PPCs and one synchronous generator's AVR actively responded to the voltage and synchrophasor alarms.

It was difficult to pinpoint the source of the oscillation just by reviewing voltage and reactive power magnitude changes. A large number of facilities were impacted and each controller behaved differently. Also, as each PPC was tuned independently, the time delays and tuning parameters of other sites were not considered.

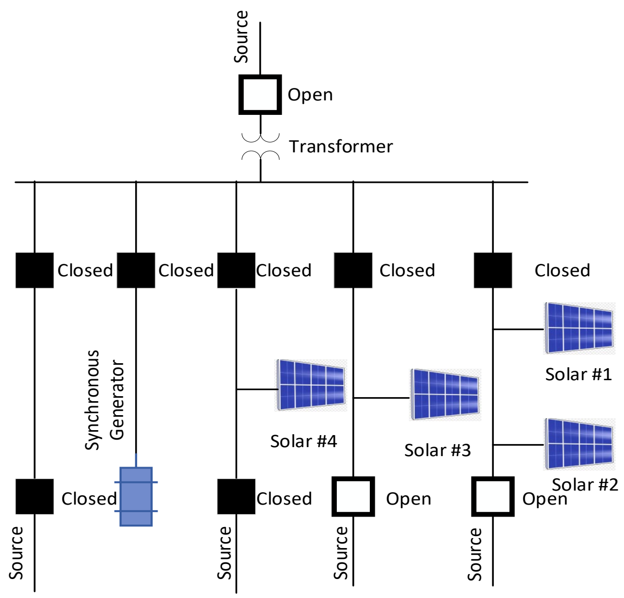

Fig 3. System configuration just prior to multi-site oscillations.

IV. LEARNINGS FROM EVENTS

The first oscillation experienced on the Dominion system immediately highlighted the need for high resolution recording devices for correct engineering analysis, without it no conclusions or learnings could be identified. This section provides details on the specific learnings to efficiently resolve SSOs.

A. Sensing Equipment

Sensing equipment provides the key evidence necessary to detect and locate these events.

A high density of synchrophasor and continuous digital recording devices is critical to identify the source of these types of events and analyze their impact on other facilities. This is done using the digital fault recorders as multi-function devices, high resolution recorders, fault locators and synchrophasor streaming devices. It is difficult to ask facility owners to retroactively makes changes without direct evidence that pinpoints the location of the oscillations. The digital fault recorder provides this direct evidence in various forms.

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

SCADA data does not accurately represent voltage and reactive power due to its low sampling rate (reference table 1). This makes it difficult to understand the source of the problem, since the data is too low resolution. Digital Fault Recorders and DFR synchrophasors are the only devices on our system which could record the level of detail we needed for accurate analysis.

B. Localized Voltage Oscillations

The typical Transmission Operations Center is not equipped to detect, pinpoint, and mitigate localized voltage oscillations. In that situation, oscillations are not revealed until changes affect the low-resolution SCADA data or customers complain.

However, localized voltage oscillations can be clearly seen by synchrophasors (streaming from the fault recorder) when looking for reactive power oscillations 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 unknown oscillation does not go undetected.

IBR site monitoring should start immediately after the site is commissioned and be compared to background values to quickly identify and resolve any abnormalities within the site. The longer an issue is outstanding, the more difficult it will be to request that the site owner make changes to their system.

PPCs are tuned during normal system configuration and not changed unless requested. Such requests are infrequent to non-existent. They are not retuned if the system configuration is changed (for example, if a line switches from network to radial) or if another plant is added in proximity. One PPC vendor explained their equipment doesn't have separate settings for different configurations, so it would have to be reprogrammed every time the line configuration was changed. The vendor suggested that we turn down the voltage response gain to delay responsiveness but ensure stability. However, this can work in the short term but does not appear to be a long-term solution, as each time the system changes topology configuration or another IBR is added within the area the controller would need to be re-tuned. 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, dynamic modeling is not done on a site-by-site basis.

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

PPC and inverter settings can conflict with each other, 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, which 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, yet not negatively impact local grid voltage.

Until synchrophasor oscillation detection software was deployed, the utility required engineers to manually look at each part of the system for voltage issues. Issues were invisible until they became a large enough problem to detect or sensing equipment was deployed. Manually reviewing just one point in time can result in omitting reviewing the time when the system is in its weakest state and most susceptible to oscillations. Oscillation detection software makes engineers' work more efficient and aids in fast problem identification and resolution.

V. Recommendations For Future Work

Dominion is evaluating the following to improve its monitoring of SSO 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 recreate events using the appropriate modeling software.
- Determine the accuracy of the solar facilities inverter and PPC models.
- Update the models as needed and use the learnings to model if future events will occur.
- Develop a process to allow the PPC performance to change based on system configuration. The PPC needs to quickly provide voltage control while not over-responding to voltage events.
- Develop "worst case" system configurations for programing the PPC. Under the best of circumstances, the PPC should be tested against these configurations; but this can be difficult due to transmission operating constraints.

VI. References

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VII. Acknowledgements

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[1] Trent Derr, Baywa Solar
[2] Josh Wold. Sweitzer Engineering Labs
[3] Andrew Bilitski, Strata Solar

VIII. Biographies

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Richard E. Tuck is a Supervisor of Electric Transmission Engineering Standards. He received a BS degree in electrical engineering from Virginia Commonwealth University, Richmond, in 2012. He has 12 years of utility experience including nuclear electrical design engineering, transmission system operations, distribution system protection, transmission system protection and System Operations Center relay protection. He is an active member of the North American Transmission Forum and IEEE.

Chetan Mishra, PhD is a Consulting Engineer with the Engineering Analytics & Modeling group at Dominion Energy, where he leads synchrophasor analytics research. He has more than eight years of industry experience, with a focus on analyzing renewables' impact on the transmission system. His research interests include nonlinear dynamics and synchrophasor analytics. He received the B-Tech degree in electrical engineering from Indian Institute of Technology (Banaras Hindu University), Varanasi, India, in 2012, and M.S.

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Micah J. Till, PhD is a Manager of Electrical Transmission System Protection and Data Communications at Dominion Energy. His work history includes time in Dominion Energy's Special Studies, Reliability Engineering, System Protection Engineering, Electric Transmission Planning, Operations Engineering and System Protection Automation and Analysis groups. He has also worked at Tennessee Valley Authority in Chattanooga and ABB Group in Baden, Switzerland. He received his PhD from the University of Tennessee, Knoxville in 2017.

Table II
Event Overview

Event Number	Oscillation Type	Sunlight	Time3	Customers Called	Duration	Frequency (Hz)	Max Change in Voltage Magnitude	Max Change in Reactive Power
1	Controller Tuning	Y	2021 Winter	No	7 minutes	0.03	11%	74 MVAR
2	Load	N	2022 Summer	Yes	1 hour 58 minutes	14.93	5%	19.5 MVAR
3	Multi-site Controller Tuning	Y	2022 Fall	No	43 minutes	0.03	8%	57 MVAR
4	Low Power Output	Y	2022 Fall	No	19 minutes	0.07	3%	17 MVAR
5	Low Power Output	Y	2023 Fall	No	21 minutes	0.07	5%	15 MVAR
6	Low Power Output	Y	2023 Fall	No	4 hours 20 minutes	0.01	4%	69 MVAR
7	Low Power Output	Y	2023 Fall	No	1 hour 7 minutes	0.02	5%	73 MVAR
8	Low Power Output	Y	2023 Fall	No	1 hour 18 minutes	0.02	5%	66 MVAR
9	Multi-site Controller Tuning	Y	2024 Winter	No	8 hours 5 minutes	0.03	2%	8 MVAR
10	Low Power Output	Y	2024 Winter	No	15 minutes	0.06	1%	10 MVAR
11	Multi-site Controller Tuning	Y	2024 Winter	Yes	1 hour 10 minutes	0.04	10%	27 MVAR
12	Unknown	Y	2024 Spring	No	4 hours 45 minutes	0.03	2%	72 MVAR
13	Controller Tuning	Y	2024 Spring	No	23 minutes	0.36	1%	0.5 MVAR
14	Load	Y	2024 Spring	No	45 minutes	1.00	2%	5 MVAR

Table III

Event Timeline