Lesson Learned

Single Phase Fault Precipitates Loss of Generation and Load

Primary Interest Groups
Transmission Operators (TOPs)
Generator Operators (GOPs)
Balancing Authorities (BAs)
Reliability Coordinators (RCs)

Problem Statement
A single phase to ground fault on a 400 kV transmission line in Southern England precipitated the loss of 1,878 MW of generation. This led to a frequency decline that resulted in a loss of 931 MW of load.[1] This European event has lessons applicable in North America.

Details
A lightning-initiated single phase-to-ground fault on a 400 kV transmission line north of London was detected and isolated within its design parameters (refer to **Figure 1**). The line was successfully reclosed 20 seconds later.

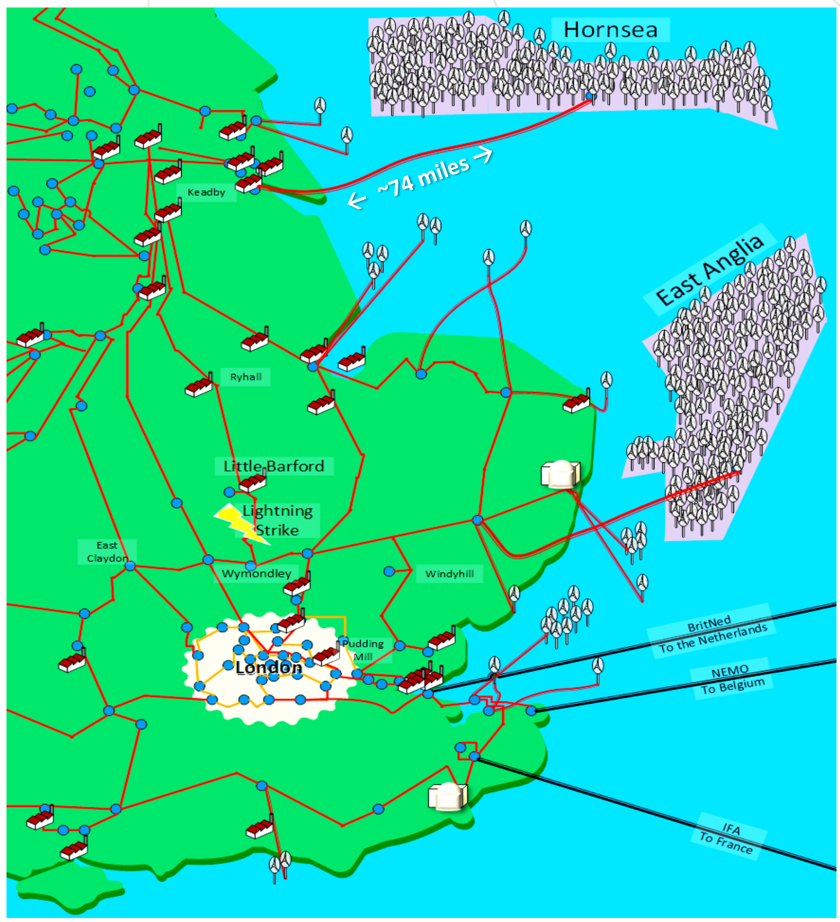

Figure 1: Simplified Transmission Map for SE Britain

Coincident with the fault, a steam turbine (part of a 2-on-1 combined-cycle configuration) at Little Barford tripped (244 MW). At the same time, Hornsea, a large offshore wind farm, unexpectedly reduced output from 799 MW to 62 MW (725 MW). Also, although a loss of 150 MW of distributed energy resources (DER) was expected for this type of fault, additional DER losses occurred approximately one second into the event. An estimated 350 MW of DER tripped due to rate of change of frequency (ROCOF) protection when additional generation reduced output. These events resulted in a cumulative power loss of close to 1,500 MW of

[1] See "Technical Report on the events of 9 August 2019" https://www.ofgem.gov.uk/system/files/docs/2019/09/eso_technical_report_-_final.pdf, "Appendices to the Technical Report on the events of 9 August 2019" https://www.ofgem.gov.uk/system/files/docs/2019/09/eso_technical_report_-_appendices_-_final.pdf, and "9 August 2019 power outage report" https://www.ofgem.gov.uk/system/files/docs/2020/01/9_august_2019_power_outage_report.pdf

generation within approximately one second of the fault. This resulted in a frequency decline from the European standard of 50.0 Hz to 49.1 Hz (see **Figure 2** and **Figure 3**).

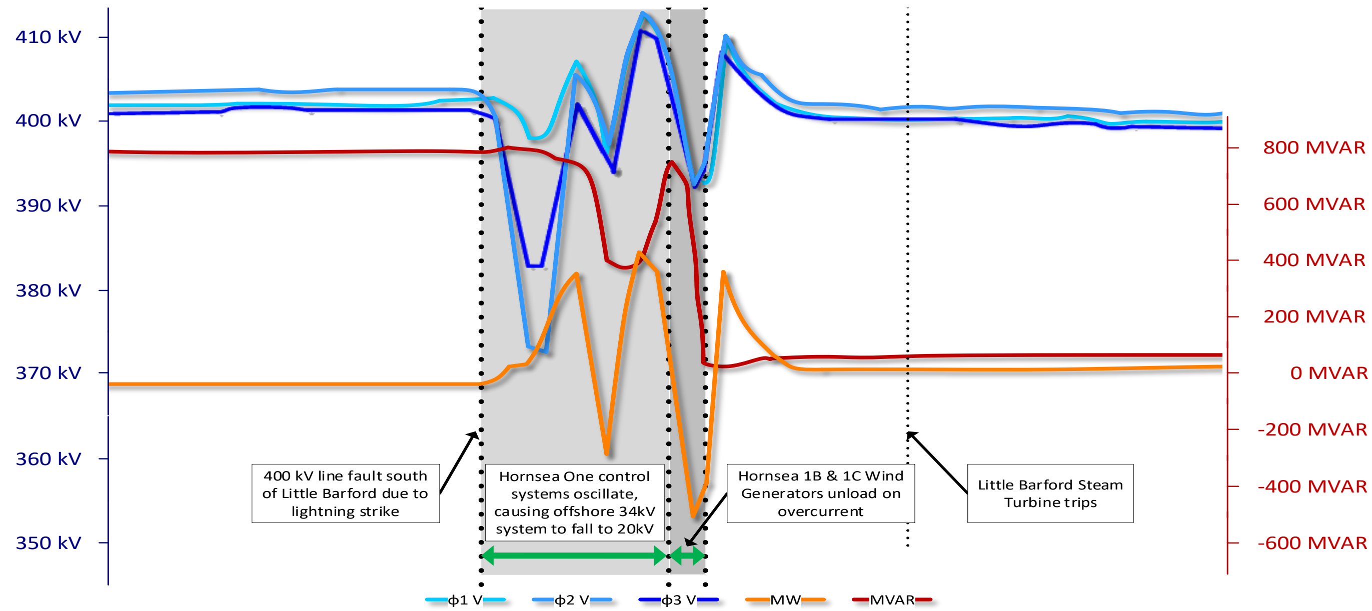

Figure 2: Parameters Measured at Hornsea Onshore Station – MW and MVAR

As frequency began to recover 58 seconds into the event, one combustion turbine of the Little Barford plant tripped (210 MW), resulting in further frequency decline. When frequency dropped below 49 Hz, more DERs tripped.

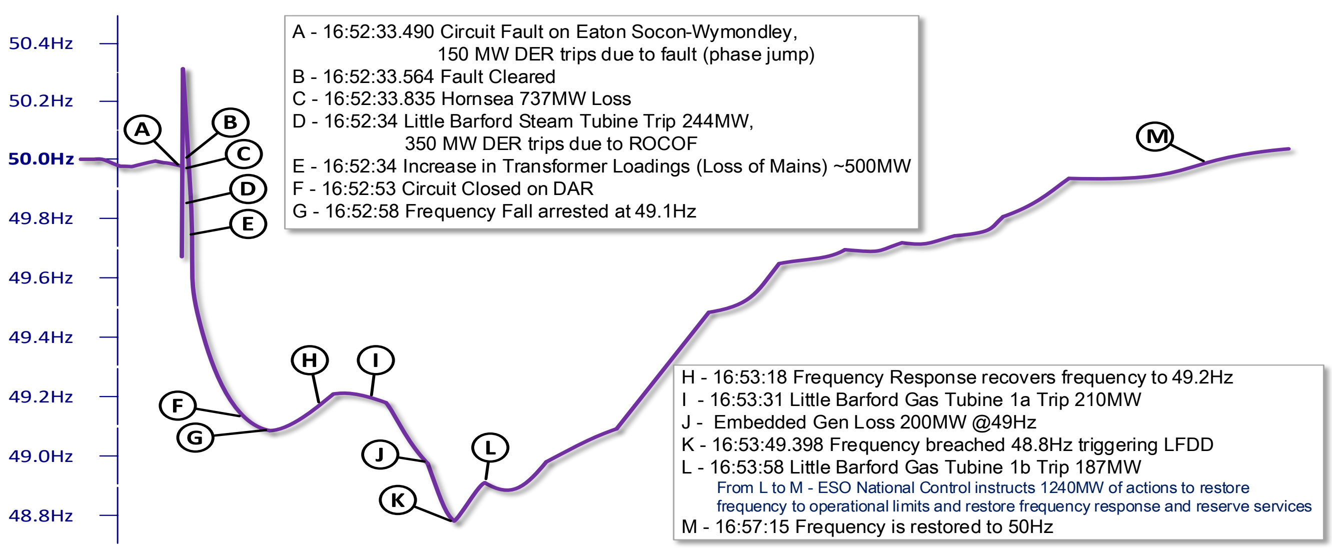

Figure 3: Frequency

Approximately 85 seconds into the event, a second combustion turbine was taken off-line at Little Barford by plant operators (187 MW), which made the cumulative generation loss of 1,878 MW, resulting in a frequency decline to 48.8 Hz. Underfrequency load shedding (UFLS) schemes operated at 48.8 Hz, disconnecting 931 MW of load. At this point, frequency stabilized at 48.9 Hz and began to recover as system operators dispatched resources.

For the operating day, the most severe single contingency was 1,000 MW. The entity had established 1,022 MW of primary frequency responsive reserve (10-30 seconds) and 1,314 MW of secondary frequency response (30 seconds to 30 minutes) to cover this loss. When the generation loss exceeded this level, frequency declined until UFLS operated, stabilizing frequency. The entity had previously determined that contingency planning and reserve levels met its reliability and economic goals and additional reserves would not be cost effective. Given the system performance for this event, these criteria are being evaluated.

During the fault, Hornsea 1's output dropped from 799 MW to 62 MW. This occurred due to an oscillation that began when the reactive output of the offshore wind farm increased to support voltage during the fault. The wind farm was operating in a "weak" system condition with an undersea cable out of service. This weak configuration resulted in an oscillation when the voltage control algorithm increased var output. High var and watt output resulted in overcurrent protection operating and reducing output of the wind farm. Analysis of the event resulted in the wind farm operator making control algorithm changes.

Control Difficulties in a Weak Grid Condition

There were limitations in the entity's knowledge of Hornsea 1's control system and the interaction between its onshore and offshore arrangements (See **Figure 4**). This impaired the understanding of Hornsea 1's performance during this event. The wind farm's onshore control system operated as expected when the system voltage dipped concurrently with the lightning strike. The offshore wind turbine controllers, however, reacted incorrectly to voltage fluctuations on the offshore network following the fault. This caused an instability between the onshore control system and the individual wind turbines. The instability triggered two modules to automatically shut down. In investigating the issues internally, the wind farm's developer identified that Hornsea 1's systems identified a "weak grid" condition at the time in question. The wind farm's developer identified the disturbance that resulted in the unloading was caused by an unexpected control system response due to an insufficiently damped electrical resonance in the sub-synchronous frequency range that was triggered by the event. The developer also identified that this stability issue with its voltage control system had occurred approximately 10 minutes prior to the incident on August 9 but did not cause unloading at that time. This may have been related to the trip of the Blyth – Eccles – Stella West 1 400 kV circuit trip at 16:43:25. At the time of the event, there were a number of transmission facility outages. Transmission facility outages (and less synchronous generator dispatch) reduces short circuit strength and contributes to creating a "weak grid" condition. The power electronics that inverter-based resources use require a minimum short circuit strength relative to their capability, often referred to as the "short circuit ratio," for stable operation. These outages contributed to the "weak grid" condition that Hornsea 1's systems identified and resultant unloading.

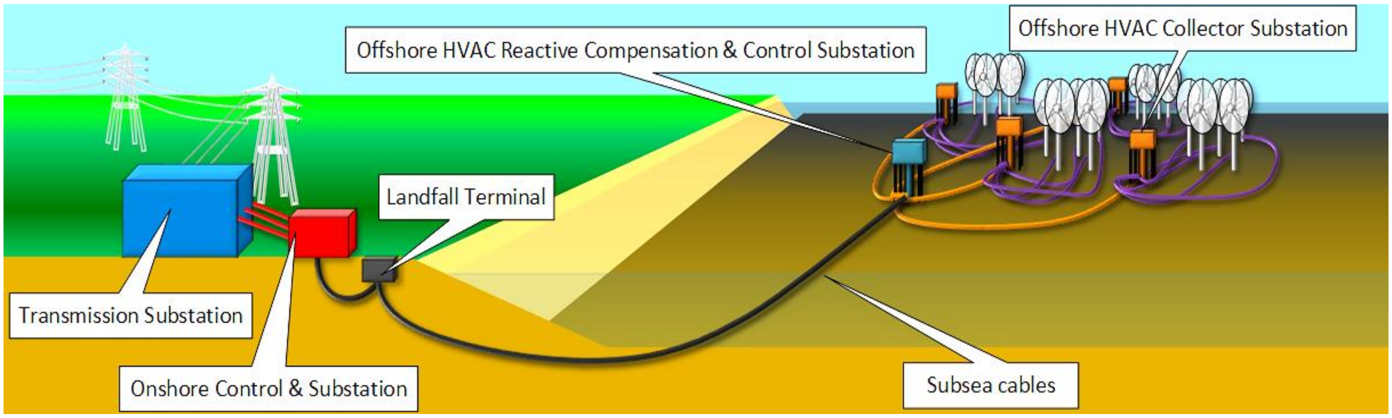

Figure 4: Typical Offshore Wind Farm Arrangement

System voltages did not exceed the ride-through requirement. **Figure 5** shows single phase voltage profiles at various locations.

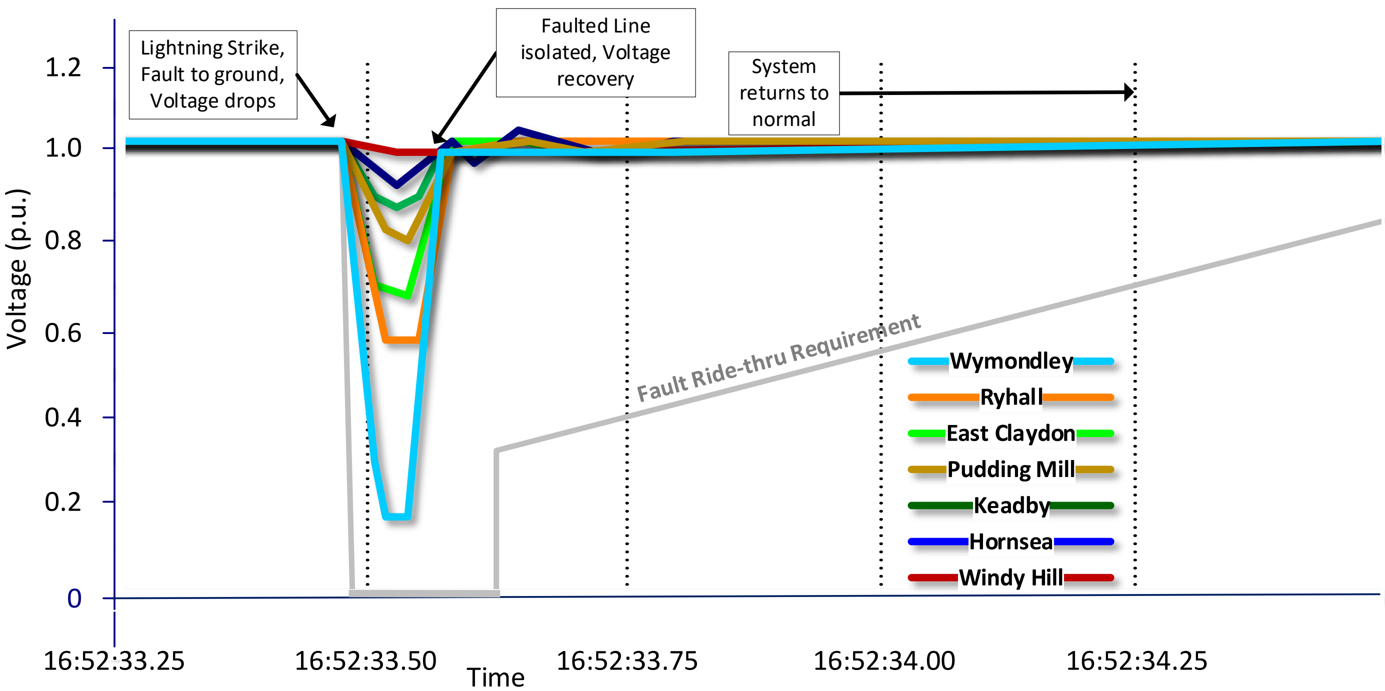

Figure 5: Voltage (p.u.) Profile at Various Locations During the Event

Three issues forced the two-on-one combined-cycle power plant off-line:

- The steam turbine came off-line due to a speed sensor input error during the initiating fault.
- Approximately 58 seconds into the event, one of the combustion turbines tripped off-line due to a problem with the steam bypass system.
- Steam pressure continued to increase, and local plant operators took the second combustion turbine off-line approximately 85 seconds into the event.

Further investigation did not reveal any issues with the speed sensor input. During the next maintenance cycle, the steam bypass system was maintained and tested.

DERs contributed approximately 500 MW to the loss of generation during the event. The entity models phase angle changes for any single contingency event and makes assumptions for loss of distributed generation based on post-contingency angles. The initial loss (150 MW) was due to phase shift protection, and this portion was an expected loss. Additional unexpected DER losses occurred, some due to incorrect ROCOF settings and some at 48.9 Hz instead of the proper underfrequency setting of 47 Hz.

Although some sensitive loads tripped during this event, they were due to internal settings, not related to the entity's UFLS scheme. The UFLS scheme operated as designed and was effective at arresting the frequency decline.

Corrective Actions

A thorough analysis of the event was performed by the entity. Their report recommended the following actions:

- Review the operational criteria to determine whether it would be appropriate to provide for higher levels of resilience in the electric system
- Review the timescales for anti-islanding protection to reduce the risk of inadvertent tripping and disconnection of embedded generation
- In addition to the changes in its first-hour communications processes that the entity initiated, conduct a wider industry review, including regulators and other stakeholders to establish new and enduring communication arrangements for similar events

Lesson Learned

Simple single contingency planning is inadequate to protect against UFLS events. The UK and the US have different approaches to UFLS requirements, described here:

- The UK entity's operational planning determined frequency responsive reserve requirements based on frequency deviation. Generation loss was calculated for a given frequency deviation, which was 49.5 Hz in this case. No single contingency (N-1) loss of generation can cause frequency to decline below 49.5 Hz. Frequency responsive reserve is procured to meet this requirement. An infrequent loss of generation event (exceeding N-1) must not allow frequency decline below 49.2 Hz. However, there is no requirement to carry frequency responsive reserve for generation losses exceeding 49.5 Hz. UFLS begins at 48.8 Hz.
- Under NERC Reliability Standard BAL-003-2, frequency responsive reserve requirements are determined by ensuring that the loss of the two largest resources in an Interconnection will not result in UFLS. Stated differently, NERC Reliability Standard BAL-003-2 set frequency responsive reserve requirements to prevent UFLS.
- The UK entity in this event determined its frequency responsive reserve requirements by a frequency deviation above UFLS frequency points. This allows the entity to carry less frequency

responsive reserve but creates a situation where UFLS becomes more likely if a generation loss exceeds the requirement for 49.5 Hz (N-1 event).

This event has also underlined the importance of understanding the reliability impacts associated with the rapidly changing portfolio of resources and their increasingly complex controls. The ability to predict resource responses to network faults are fundamental to the security and resilience of the power system. There are a number of lessons learned related to this, summarized as follows:

- There was significant reliance on self-certification of the models for the resources, including the interconnection of new resources, following modification to existing resources, and DERs. Enhanced compliance testing or verifications may have improved these models. Evaluate if more frequent review of the adequacy of modeling procedures is appropriate and identify any deficiencies.
- Interactions between onshore and offshore wind generation control systems need to be understood and coordinated to prevent adverse results. Limited understanding resulted in instability between Hornsea 1's onshore control system and the individual wind turbines and automatically control system shut down.
- Transmission facility outages (and less synchronous generator dispatch) reduces short circuit strength and contributes to creating a "weak grid" condition. The power electronics that inverter based resources use require a minimum short-circuit strength relative to their capability, often referred to as "short circuit ratio," for stable operation. These outages contributed to the "weak grid" condition that Hornsea 1's systems identified and resultant unexpected power reduction. These stability issues and their correlation to transmission system outages should be assessed.
- Evaluate if the coordination and communication between the TP, GO, TO, RC, and equipment manufacturers are sufficient to accurately model and understand the connected resources and their expected response under stressed or "weak grid" conditions.
- Evaluate if the tools, techniques and simulation approaches in the planning and operations horizons are adequate, especially in weak grid systems with higher penetration of inverter-based resources. Consider weak grid conditions that can dynamically occur due to changes in transmission topology, synchronous generator dispatch, and outages of inverter-based resources key components. This may include short circuit ratio screening technique development and the use of advanced electromagnetic transient applications. Reference the recommendations from the NERC *Integrating Inverter-Based Resources into Low Short Circuit Strength Systems Reliability Guideline*.[2]

Additionally, this event highlights the impact distributed generation (DG) outages can have on the bulk power system (BPS). Even though the loss of individual DG may have no impact on the BPS, the trip of multiple DGs may aggregate to a significant loss of generation which can impact the frequency of BPS. DG was a factor in this event as described below:

[2]Integrating Inverter-Based Resources into Low Short Circuit Strength Systems Reliability Guideline https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

- The UK system was operated under the assumption of certain amount of DG tripping for transmission faults; however, the amount of DG that was lost or could have been lost was more than anticipated, resulting in frequency decline.
- The majority of DG tripped due to ROCOF and vector shift protection settings. The ROCOF at which the DG tripped was well within the ride-through requirements for DERs specified in IEEE-1547-2018. The vector shift setting of 6 degrees was conservative compared to the recommended 20 degrees in IEEE-1547-2018. The DG trip was also initiated at a frequency (49 HZ for this 50 Hz system) that was well within the lower bounds of operability. It seems that the setting of some DGs were not modified per the distribution code requirements in the UK. It is recommended that distribution operators ensure that DG settings are compliant with IEEE-1547-2018 to avoid unnecessary DG loss during a transmission fault.[3]
- It appears that there were no robust processes to analyze the impact of the loss of DG in a transmission system as credible contingencies. Gathering data on distribution-connected generation and incorporating it in a real-time transmission system analysis is not a common practice in North America either, but some entities have mechanisms in place to forecast distributed resources with publicly available data and weather forecasts in real-time. The forecast values are then incorporated in real-time systems for operator awareness; however, analyzing for the loss of a significant amount of DG as a contingency is not prevalent. The amount of DG is growing rapidly and its loss can put significant strain on transmission.
- TOs and RCs should explore methods to incorporate the loss of DG in real-time analysis.

Example information provided by PJM regarding their methods for handling DERs

PJM uses two publicly available sources to collect DER information, and requests PJM TOs to provide additional information.

- Energy Information Agency EIA-860 report[4]
- PJM EIS Generator Attribute Tracking System[5]

Utilization in Real-time Operations

- A behind-the-meter (BTM) DER solar forecast is available for dispatch and is factored into PJM's load forecast
- Loads with known BTM DER generation are labeled as such in the energy management system (EMS), and those generators are listed in Post-Contingency Local Load Relief Warning (PCLLRW) reports
- BTM DER generators are also displayed on the Dispatch Interactive Mapping Tool

[3] Also see the NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper: "Fast Frequency Response Concepts and Bulk Power System Reliability Needs" at https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf
[4] https://www.eia.gov/electricity/data/eia860/
[5] https://www.pjm-eis.com/reports-and-events/public-reports.aspx

Example information provided by PJM regarding their methods for handling DERs
How does DER factor in during a capacity emergency or transmission emergency? • For a transmission emergency, any known BTM DER generator that could have an impact would be listed in the PCLLRW report, and PJM would communicate to the TO that the generator(s) may be able to help alleviate the constraint • There is no current protocol for involving BTM DER in a capacity emergency Can PJM lose DER because of a transmission event and has PJM had such events? • It is possible and our subject matter experts refer to the 2016 Blue Cut Fire[6] event in California. Given sensitive DER trip settings, we would lose and have lost DER because of transmission events, however this loss has not been directly measured.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the BPS. NERC is asking entities who have taken action on this lesson learned to respond to the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)

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Category: Transmission Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

[6] https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf