Whitepaper on Transient Voltage Response Criteria

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RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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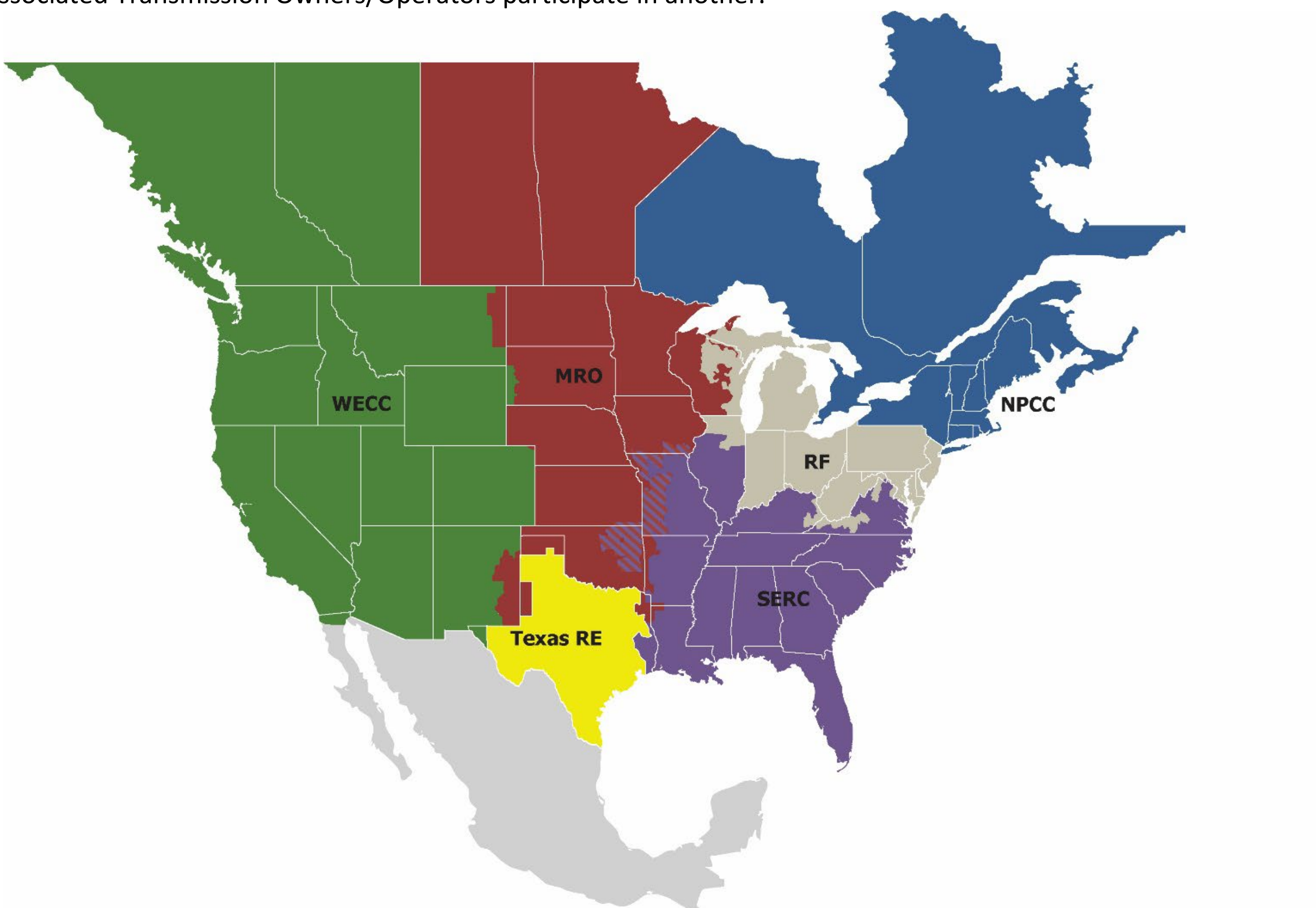
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The NERC standard TPL-001 requires the development and use of transient voltage response (TVR) criteria. The purpose served by the TVR criteria is to provide a simple and a direct means of identifying potential reliability issues when conducting positive sequence simulation studies of the disturbances that are directed by TPL-001 (P1 through P7). This white paper offers guidance on how to establish TVR criteria and—importantly—to identify reliability issues that planning entities may wish to consider when applying it. This paper does not direct adoption of specific numerical TVR criteria. Moreover, none of the recommendations in this paper should be interpreted as a directing, much less requiring, a particular action or response when applying TVR criteria.

Historically, TVR criteria have focused on confirming the rapid and sustained recovery of voltages subsequent to the first power swing during the initial transient period following a transmission system fault. In addition, TVR criteria have focused on confirming that load loss caused by a fault will be minimal.

The composite load model that is coming into widespread use can model fault-induced delayed voltage recovery. Inclusion of this model in system simulations can cause indicated voltages to recover much more slowly than they did when earlier, less sophisticated load models were used. In light of the availability of improved dynamic load models, it is appropriate to review and consider revisions to TVR criteria.

The review needs to examine whether existing criteria have become too stringent (albeit unintentionally) as the result of improvements in load modeling that have changed the character of voltage transients indicated by grid simulations. In many cases, where there are no indications of consequent events, an extended voltage recovery period may not pose any significant risk to the system. In addition to improved load modeling, many utilities today model system protection devices as part of their grid simulations. This addition can provide a more accurate picture of the risks of cascading, further indicating the need for revisions to TVR criteria.

TVR criteria assist in the task of distinguishing between simulations that indicate acceptable contingency response of the bulk electric system (BES) and those that do not. The contingencies of concern are described in general terms in NERC standard TPL-001. “Acceptable response is when the power system continues to operate stably within allowable bands of frequency and voltage.” The examination of a simulation run to determine if it indicates acceptable behavior requires consideration of large numbers of signals in relation to a range of aspects of system behavior. The following are examples of the signals that should be examined:

- Generator real and reactive power outputs and generator bus voltages
- Synchronous generator excitation voltages and currents
- Voltage at load serving buses
- Voltage at major substation buses
- Apparent impedances seen by distance relays
- Voltage at electronic elements including high-voltage direct current (HVDC) converters

Key aspects of BES behavior that must be recognized from examination of the simulation signals include the following:

- Maintenance or loss of synchronism of individual generators (transient stability)
- Loss of synchronism between sections of the BES (out-of-step, system separation)
- Maintenance of voltage at BES load-serving buses that ensures that end-use supply voltages are within statutory and locally determined acceptable limits

- Disconnection of load by undervoltage relays
- Tripping of generators as a consequence of low station bus or auxiliary bus voltages
- Stalling of customer's motor loads and associated delay in voltage recovery
- Operating mode transitions of electronic elements including HVDC converters, inverter-based generation, and electronically controlled loads
- Maintenance of minimum voltages at BES buses at the end of the transient time-frame such that system remains stable due to normal secondary control actions

A TVR criterion is a surrogate for the broad range of signals and aspects of system behavior that must be examined to draw a sound conclusion from a simulation run. It is not necessarily a firm performance criterion. Rather, BES voltages should be used as surrogates because long experience has shown that they are well correlated with key aspects of BES behavior: loss of synchronism is closely associated with short-term dips of voltage after clearance of transmission faults, delays of voltage recovery for several seconds after fault clearance are a "signature" consequence of the stalling of air conditioner motors, and prolonged oscillations are associated with instability of controls or unacceptable inter-area power swings.

TVR criteria aid in the recognition of the many and varied risks that arise from the approximations that are inevitable in simulations of large, complex, and constantly evolving systems. The voltage thresholds in a TVR criterion should reflect engineering judgements, regional practices, and regional experiences.

The guidance on the NERC standard TPL-001 provided in this white paper is general in nature, as TVR criteria are system specific and cannot be applied universally to all systems. This white paper has identified boundary conditions, based on voltage levels and timing, that should be considered in order to develop practical TVR criteria.

TVR criteria should be reviewed periodically in relation to the evolution of power system equipment, power system behavior, and the characteristics of simulation tools. It is anticipated that the evolution of the power system and of simulation tools results in behavior, both real and in simulation, will require on-going review of standing TVR criteria.

Figure ES.1 provides a visual summary of the phases of a simulated voltage recovery for which the considerations described in this white paper could be addressed by a TVR criterion.

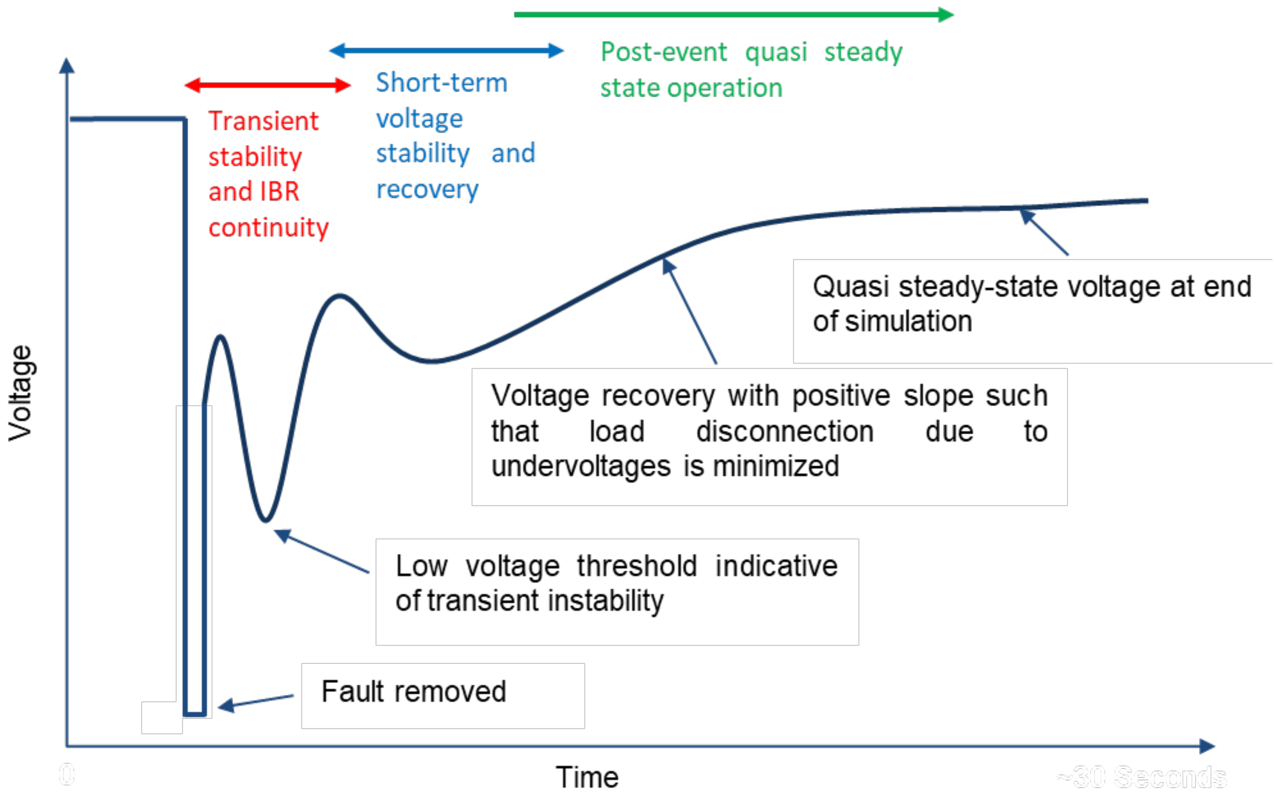


Figure ES.1: Establishing TVR criteria

Introduction

The NERC standard TPL-001 requires the development and use of the TVR criteria. The purpose served by the TVR criteria is to provide a simple and a direct means to identify potential reliability issues when conducting positive sequence simulation studies of the disturbances that are directed by TPL-001 (P1 through P7).

Historically, TVR criteria have focused on confirming the rapid and sustained recovery of voltages subsequent to the first power swing during the initial transient period following a disturbance. The obvious concern here is that the system may cascade if voltages do not recover. See **Figure I.1**.[1]

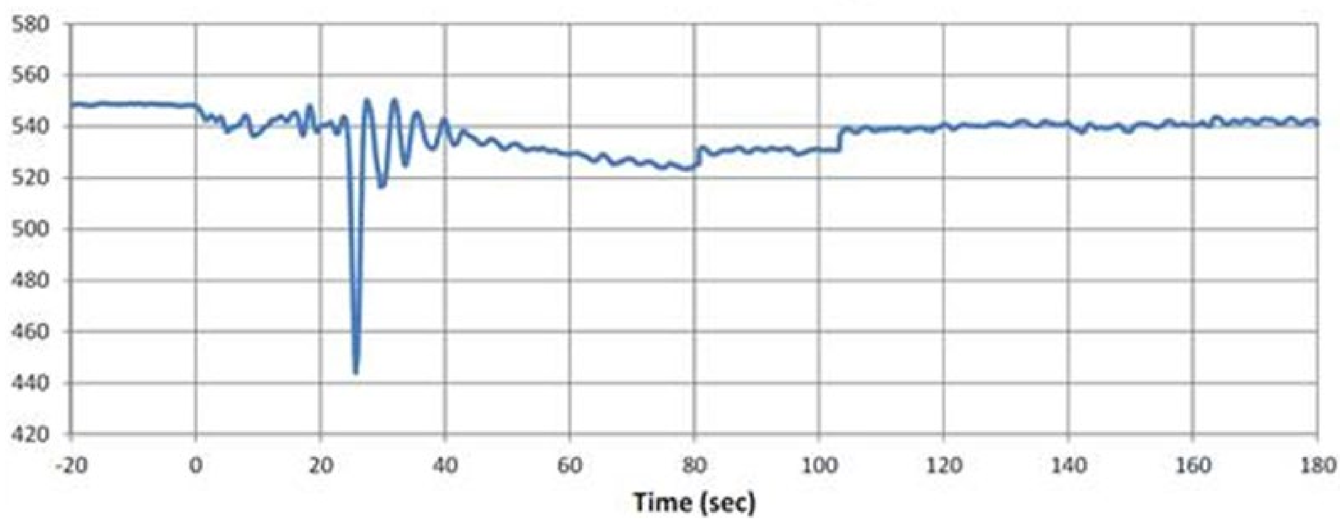


Figure I.1: Malin Voltage, June 14, 2004, West Wing Disturbance

In addition, TVR criteria also have focused on minimizing load loss caused by a disturbance. The composite load model that is coming into widespread use can model FIDVR. See **Figure I.2**. Including this model in system simulations can cause indicated voltages to recover much more slowly than they did when earlier, less sophisticated load models were used.

In light of the availability of improved dynamic load models, it is appropriate to review and consider revisions to TVR criteria. The review needs to examine whether existing criteria have now become too stringent (albeit unintentionally) due to improvements in load modeling that have changed the character of voltage transients indicated by grid simulations. In many cases, an extended voltage recovery period may not pose any significant risk to the system if there are no associated consequential events. In addition to improved load modeling, many utilities today include system protection device modeling in their grid simulations. This can provide a more accurate picture of the risks that provide further support for revisions to TVR criteria in turn.

This white paper has been prepared to support Transmission Planner (TP) and Planning Coordinator (PC) reviews of TVR criteria; it illustrates the importance of reviewing/revising the TVR criteria in the light of evolving power system equipment, improving modeling and simulation capabilities, and providing sound engineering judgement that is informed by past experiences.

[1] Agrawal, B. and D. Kosterev. 2007 Model Validation Studies for a Disturbance Event that Occurred on June 14, 2004, in the Western Interconnection. 2007 IEEE Power Engineering Society General Meeting. 24–28 June. Tampa, FL. **Available Online: https://ieeexplore.ieee.org/abstract/document/4275978**

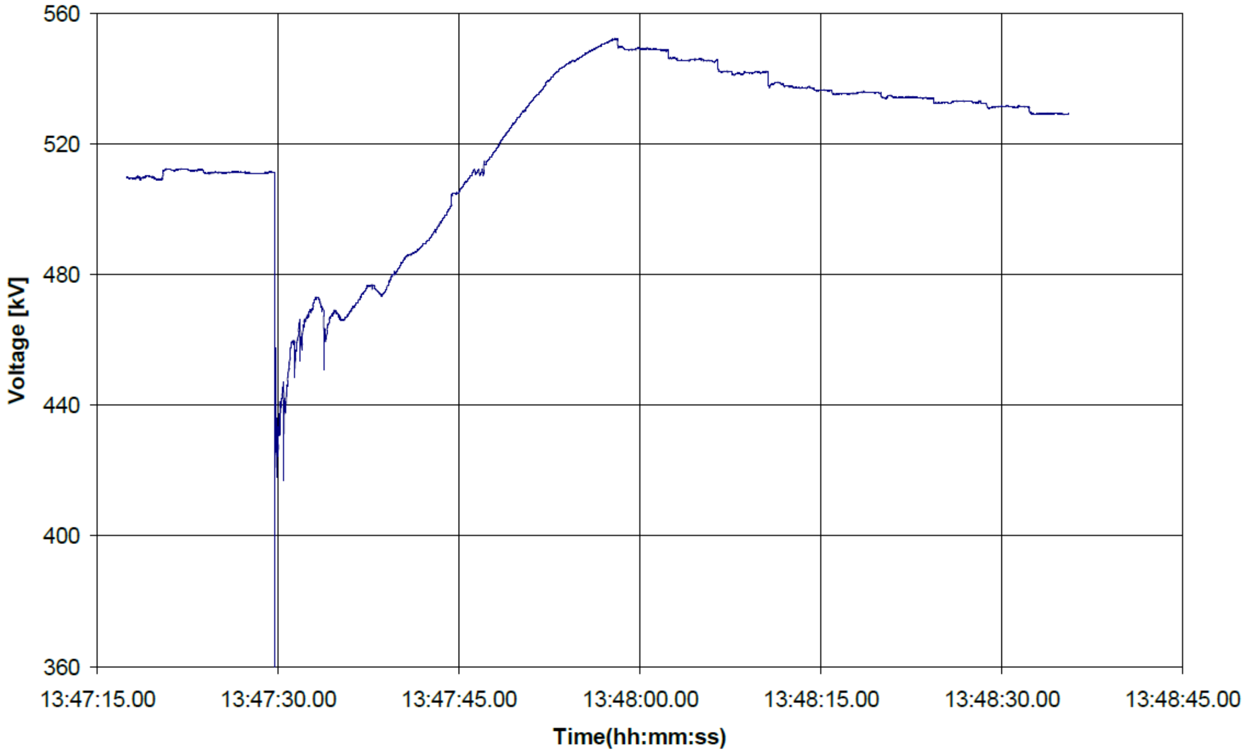


Figure I.2: 500 Kilovolt (kV) Bus Plot for a Three-phase Fault on August 5, 1997

Chapter 1 reviews the TPL-001 standard and requirement R5, which directs the development of TVR criteria. This chapter describes the original purposes served by TVR criteria that were necessitated by the then-current state of the modeling tools and computational methods available to study short-term voltage stability issues. This discussion highlights the importance of pacing and guiding review and revisions to TVR criteria in accordance with improvements in the understanding of the reliability risks posed by TVR and the capabilities of the tools and methods available to support assessments of them.

Chapter 2 describes the principal generation and transmission reliability risks that have been associated with transient voltage phenomena. There is now a wealth of experience with the reliability impacts they have caused. As noted, these experiences have led to the development of improved modeling and study approaches in order to assess them with greater confidence. These experiences also have emphasized the importance of understanding the system-specific circumstances in which they arise.

Chapter 3 describes modeling considerations for simulating actions of line protective relays as well as generator and generator auxiliary protection when dynamic load models are used to study FIDVR reliability impacts. To derive appropriate conclusions from FIDVR studies, it is important to pay special attention to the fidelity with which these actions are simulated.

Chapter 4 describes the TVR criteria that are used by the Western Electricity Coordinating Council (WECC) and ISO New England (ISO-NE). These examples illustrate how the development of TVR criteria have been driven by the need to study specific, identified reliability risks. The examples also illustrate how the actions triggered by simulation findings depend on engineering judgement based on experience and past studies and are informed by standards and local practices regarding acceptable reliability performance.

Chapter 5 concludes the paper by providing a high-level overview of the development and application of TVR criteria. The discussion is, of necessity, generic. As recognized by R5 (and as is emphasized throughout this white paper), sound engineering judgement must guide the development and application of TVR criteria. The generic process is organized around identification of specific time frames within which voltage deviations will be assessed by the criteria. The time frames and voltage thresholds associated with them vary according to the reliability risks that are under consideration, the known behavior of the system, and the capabilities of the tools that are used.

Appendix A provides background for this white paper by first locating the types of reliability issues that are studied with transient simulations with positive sequence dynamic simulation tools within the broader pantheon of power system stability issues in general and voltage stability issues in particular.

Appendix B documents some major system low voltage events.

Appendix C reproduces WECC's discussion of the considerations that may be relied on to establish TVR voltage thresholds that address load loss and Distributed Resources (DR) tripping on neighboring systems.

Appendix D discusses distribution reliability risks.

Chapter 1: The TPL-001 Standard and the Origins of R5

This chapter reviews the NERC TPL-001 Reliability Standard and Requirement R5, which direct the development of a TVR criteria. It also describes the original purposes served by transient voltage recovery criteria that were necessitated by the then-current state of the tools and computational methods available to study short-term voltage stability issues. This discussion reinforces the importance of pacing and guiding review and revisions to TVR criteria in accordance with improvements in the understanding of reliability risks that are associated with the TVR and the capabilities of the tools and methods available to support assessments of them.

NERC Standard TPL-001 and Requirement R5

The purpose of NERC Standard TPL-001 is to prevent adverse reliability impact[2] to the BES. The standard prescribes performance requirements in response to Planning Events (P1 through P7). Table 1 (Steady State and Stability Performance Planning Events) of the TPL-001 standard defines the fault type, either three-phase or single-line-to-ground, and whether or not non-consequential load loss is allowed for the different planning events. Non-consequential load loss is load loss other than the following: loads lost consequential to the outage, load loss due to response of voltage sensitive loads, and loads disconnected by end-user equipment.

Implicit in these expectations for system performance are trade-offs that must be made between the disturbance frequency and the severity of the consequences that might ensue when disturbances occur. Some events occur frequently, but because they are not severe in nature, they are ones that should be managed without loss of non-consequential customer loads. In contrast, other events are comparatively rare, but when they do occur, they represent severe threats to reliability. Disconnection of non-consequential customer load, while regrettable in these circumstances, can be a necessary action in order to preserve the integrity of the interconnection.

Requirement R5 in NERC Reliability Standard TPL-001 directs each TP and PC to have criteria for acceptable transient voltage response, including a low-voltage level and a maximum length of time that transient voltages may remain below that level.

The following is stated in R5:

> "Each Transmission Planning and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."

In practice, the TVR criteria are used to screen simulation studies to inform assessment of compliance with the TPL-001 standard. If the thresholds specified by the criteria are not crossed, then planners can conclude that the study demonstrates compliance with the standard.

The issues that must be considered when reviewing TVR criteria are the actions that are indicated by a simulation finding that a TVR threshold has been crossed. Review of the historic circumstances and practices that led to the original formulation of TVR criteria by TPs, which is discussed in the next subsection, helps to frame these issues for the present discussion.

[2] Defined in the NERC Glossary as "The impact of an event that results in Bulk Electric System instability or cascading"

History of Simulation Tools and Approaches for Studying Power System Reliability

In the era when computing power was limited, transmission planning studies were primarily conducted with the system representation terminating at intermediate voltage (usually 66–110 kV) buses depending upon the geographical location in the North American interconnection. The loads in these instances were represented at the lowest voltage bus represented. In some instances, as late as the mid-1990s, even large Interconnections like WECC had only very sparse representations of load buses below 230 kV. Given this limitation, it was critical to be sure that low voltages at the buses that were included in simulations would not result in load interruptions in lower voltage portions of the systems where the load is physically located. Early TVR criteria were used to identify buses where depressed voltage was likely to result in trouble in the unrepresented parts of the system.

As early as 1985,[3] there was serious concern in WECC about the low voltage phenomenon that affected irrigation pumps and motor load at customer locations as well as the loss of generation due to tripping of auxiliary station loads. The basis for the WECC regional performance criterion[4] was discussed in a white paper dealing with reliability criteria for planning purposes.[5] Among other things, the white paper suggests that WECC base cases have only sparse representation of load buses below 230 kV and, as such, simulations cannot adequately represent the impact of system contingencies on lower voltage buses because they are not represented in WECC cases for the most part. Furthermore, since the high voltage buses represented in WECC cases are so remote from load, the white paper argued that a voltage-limit criteria (0.8 per unit [pu], for example) would be inadequate; the paper suggested, as an alternative, use of a percent voltage dip criteria to better represent the performance impact at lower voltage buses. Regardless of the relative merit of a voltage dip versus a hard limit performance criterion, the representation of lower voltage buses in recent WECC base cases is far superior to the practice in 1994. For example, in a 2013 case, just over one-half the modeled buses were below 100 kV. To a large extent, the drawbacks with limited system representation are rendered moot by a more detailed representation of the system.

As an example, the low voltage criteria were typically aimed at addressing the issue of loss of coolant due to the stalling of cooling water induction motor driven pumps in nuclear plants. This issue is also addressed in NERC's reliability guideline, *Reactive Power Planning,* which states "WECC transient voltage dip criteria is based, in part, on a need to maintain a margin for nuclear unit auxiliary undervoltage protection and load transfer. A more general application is found in the setting guidelines of load transfer devices in IEEE Standard 446-1995(R2000)."

System studies have shown that short-term voltage stability is significantly affected by motor loads. The interaction between real and reactive power supply and motor load demand can manifest as a slow voltage recovery. In other cases, when power is transferred over long distances the interaction between real and reactive power supply and demand could manifest as voltage swings in the post-disturbance time frame. This indicates that load dynamics play an important role in the voltage performance of a system. Inability to meet the real and reactive power demands of the loads could lead to short-term voltage instability.

[3] NERC. 2016. Reliability guideline, *Reactive Power Planning*, December: **Available Online**

[4] WECC. 2015. Transmission System Planning Performance Proposed Transient Voltage Response Rationale for CRT Requirements R1.3 and R1.4. WECC-0100 Drafting Team. July 24: https://www.wecc.org/Reliability/WECC-0100%20Posting%203%20TPL-001-WECC-3%20White%20Paper%20on%20Requirement%20R1%203%20and%20R1%204%20-%20Not%20for%20Comment.doc

[5] WECC. 1994. Supporting Document for Reliability Criteria for Transmission Planning. August: https://www.wecc.org/Reliability/Reliability%20Criteria%20Supporting%20Document%20Aug%2094%20pdf%20-%20provided%20to%20WECC-100%201-24-2014.pdf

It has been recognized that system loads and distributed resources contribute significantly to the voltage performance of the BPS. In the past, loads were modeled as a combination of constant impedance, current, and power. This type of representation of loads is not realistic, as it is overly simplified and does not capture the dynamics of motor loads. Benchmarking of system events with simulation tools confirmed that the ZIP type of load modeling cannot replicate FIDVR type responses that have been observed, thus indicating the importance of modeling the motor loads in greater detail to understand their impact on the BPS. Findings such as these led directly to revisions to the TPL standards, which now require the use of dynamic load models.

Implications for the Review and Application of TVR Criteria

For transmission planning studies to be meaningful, it is imperative to consider the accuracy and level of detail that can be achieved in studying a given reliability risk as well what may be required. TVR criteria play a crucial role in this process because they embody judgements that establish when one set of studies alone may (or may not) be sufficient to assess a given reliability risk. In the previous subsection, the criteria were used to signal instances when limitations in the amount of information that could be saved from a positive sequence simulation run indicated that further study, possibly with different tools, was required to assess a given risk conclusively.

Simulation tools and the standards that rely on them are not static. They have co-evolved as both the understanding of the causes of past reliability events grows and computing technology improves. For example, the introduction of the CML was a direct result of forensic investigations of the Western blackouts in the summer of 1996 that, among other things, identified shortcomings in the representation and characterization of load behaviors in the then-current generation of power system modeling tools. In addition, the ability to conduct simulation studies with dynamic load models has been greatly facilitated by the dramatic advances in computing technology that have taken place over the past three decades.

It is a given that the tool capabilities will lag behind and follow the pace experiences in identifying new and previously unstudied causes of power system reliability events. The corollary is that standards (e.g., NERC's TPL standards, which depend on modeling studies to assess compliance) will be limited in what they can require because they can only refer explicitly to those events that have been experienced (and studied). Hence, even with these experiences and understandings, what can be studied practically will be limited by the sophistication and capabilities of present computing technologies to model and simulate the phenomena meaningfully.

Industry activities to address the issues that have emerged from the Blue Cut Fire event are only the latest example of a new found reliability risk that is necessitating enhancements to current modeling practices. Efforts to address the practical issues associated with conducting large-scale Electromagnetic Transients Program (EMTP) simulations are a principal focus.

Consequently, based on experiences (which have been repeated throughout the industry's history) and despite our best efforts to reduce management of transmission reliability risks to a series of prescribed simulation studies, the industry should expect to continue to be surprised by finding/experiencing new ways that the power system can fail.

The origins of R5 are reflective of this evolution and these understandings. It is a direct descendent of the practices that were used when computing limitations made it impossible to model all of the relevant detail in a simulation. Selected results were saved as proxies for related variables that for practical reasons could not be modeled. Industry should note that the behavior of proxy variables in relation to performance criteria indicates the need for further investigation in order to make a definitive finding.

Thus, the TVR criteria are best understood as embodying judgements that planners have made regarding design choices, which can (and cannot) be assessed prudently, based solely on the results of positive sequence simulation studies. These judgements necessarily strike a balance between what can be studied with the present generation of positive sequence load flow simulation tools and what must be studied either by enhancing the use of these tools or by using other tools.

Chapter 2: Reliability Risks

This chapter describes the principal generation and transmission reliability risks that have been associated with transient voltage phenomena. There is now a wealth of experience with the reliability impacts they have caused. As noted, these experiences have led to the development of improved modeling and study approaches that enable them to be assessed with greater confidence. These experiences have also emphasized the importance of understanding the system-specific circumstances in which they arise.

Voltage performance has a significant impact on the security and reliability of a power system. Depressed voltages in the transient stability time frame or steady state time frame may cause widespread collapse of a power system. Low voltages at BES buses may cause transmission lines to trip due to encroachment of the measured impedance into its zone of protection and lead to cascading. Generator station-service loads that are comprised mostly of induction motors are dependent on system voltages for proper operation of a generating station. Low system voltages could trip critical station service loads that lead to shutdown of a generating station. Inverter-based resources are also sensitive to voltage and could trip during a low voltage excursion. High-voltage, direct current (HVDC) links are also dependent on adequate voltage support for proper operation of the converters. Low voltages at HVDC buses could cause commutation failures and could lead to tripping of these links. Furthermore, interruption of electrical service to loads due to operation of end-user protection is also a concern.

Generation and Transmission Risks Associated with Fault Induced Delayed Voltage Recovery

FIDVR is a reliability concern that affects both transmission and distribution systems. It refers to the unexpected delay in the recovery of voltage to its nominal value following the fault clearing. Stalled residential air conditioning units (powered by single-phase induction motors) are the main cause of FIDVR. FIDVR events are common in utility distribution systems, and in some cases, they can impact the reliability of the bulk transmission system. The focus of this discussion is on transmission system impacts. There are numerous historical events that demonstrated a slow voltage recovery on the transmission system that led to a large amount of load loss. **Appendix B** provides a summary of recorded FIDVR events.

Figure 2.1 shows a 500 kV voltage plot for a three-phase fault on the 500 kV system in the Southern California Edison (SCE) control area on August 5, 1997; a total of 59 distribution circuits tripped, disconnecting approximately 3,500 megawatts (MW) of load. System voltages recovered slowly at first, but then they went too high as tripping brought the load below the pre-event level.

Figure 2.2 shows the 115 kV valley substation voltage for the above fault. Voltages close to 0.75 pu were recorded for this fault. The voltage recovered to 1.0 pu after 25 second(s).

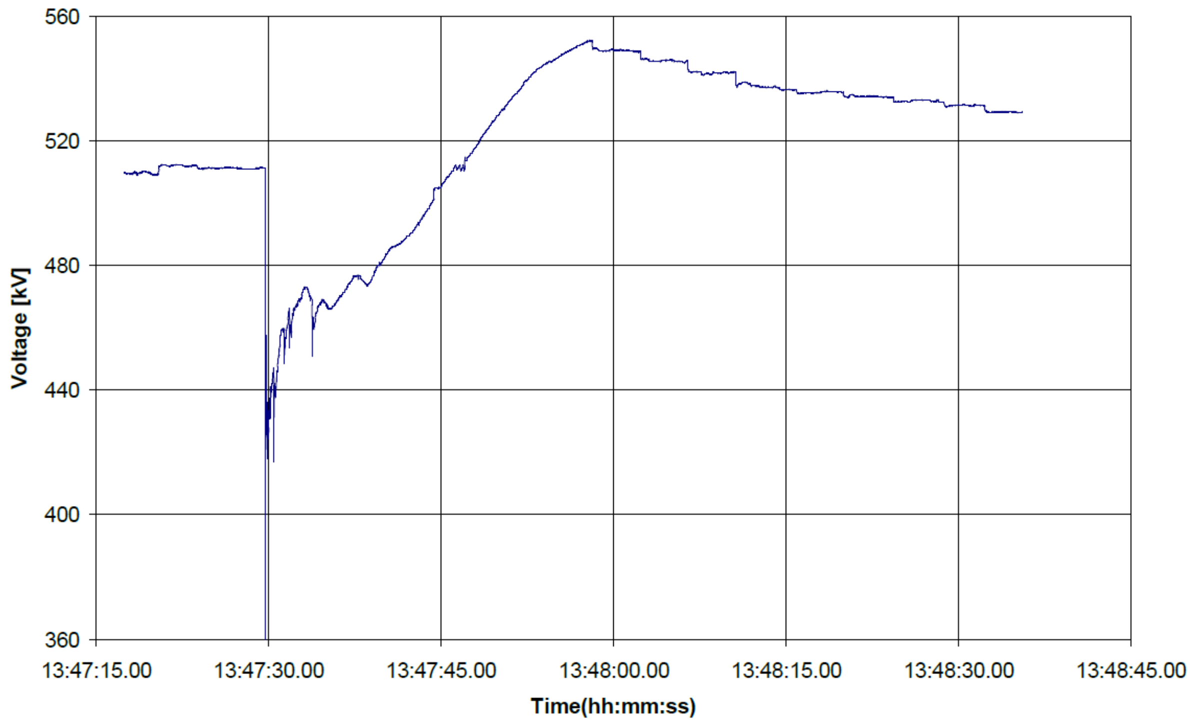


Figure 2.1: 500 kV Bus Voltage for a Three-Phase Fault Cleared in Two Cycles

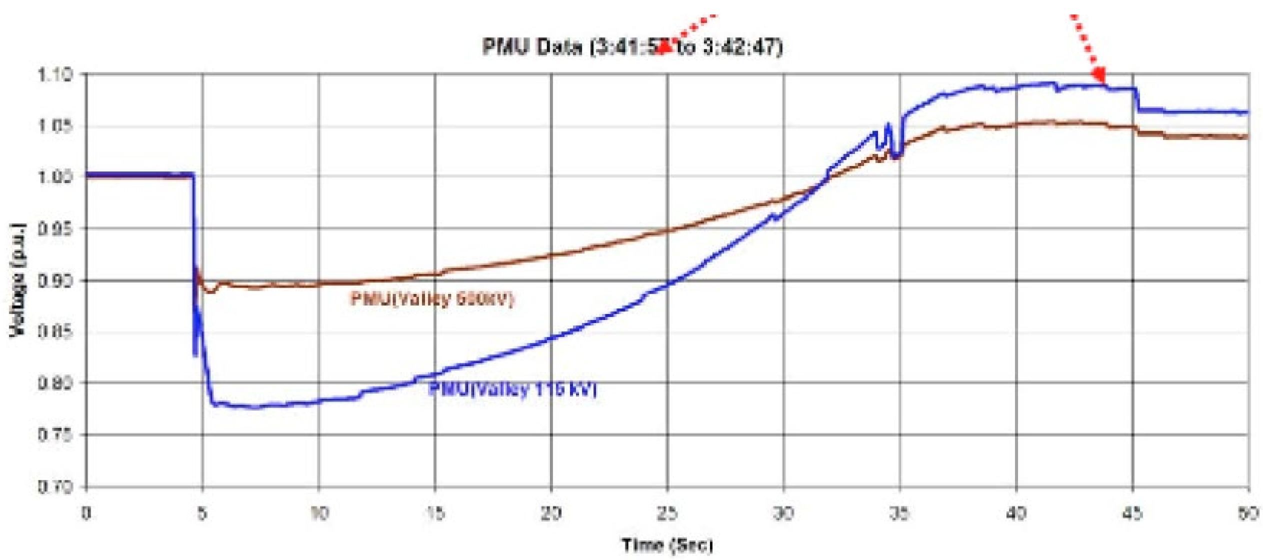


Figure 2.2: 500 and 115 kV Bus Voltage for a Three-Phase Fault Cleared in Two Cycles

In assessing the transmission reliability risks posed by FIDVR, there are two phases of FIDVR events. Phase 1 is depressed voltages that persist until residential air conditioners trip due to internal thermal protection. Phase 2 is high voltages that immediately follow the loss of residential air conditioning load. Each phase may create reliability risks for the transmission system.

Regarding Phase 1, it is now recognized that FIDVR events occur with some regularity. When they originate from faults on the transmission system, local transmission system voltages will be depressed. Low voltages may cause nearby generators to trip. Loss of generation and the local voltage support they provide are a cause for concern.

Regarding Phase 2, high voltages after residential air-conditioning units have disconnected are recognized as representing two distinct reliability threats. The first threat involves capacitor banks switching and locking out. When this occurs, voltage control following the eventual restart and resumption of loads from residential air conditioners represents a localized risk to the continuity of supply for the customers served on these feeders. The second threat involves nearby generators that are operating at close to their maximum excitation capability. Prolonged low voltages before residential air conditioners trip could cause generation auxiliaries to trip, and the system could start to collapse. In this instance, review of generation settings and operational procedures must be included in a review in order to fully understand the reliability risks that may be involved and solutions that may be warranted.

Low Voltage Transients have Caused Generators and Auxiliaries to Trip and Contributed to Cascading Failures

Tripping of generator auxiliaries on low voltages has been known to contribute to cascading power system events. The *Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations* stated that a number of critical generating units tripped on undervoltage protection.[6] Nuclear plants have a sizable amount of station-service loads and are mostly comprised of three-phase induction motors. These motors are sensitive to voltage fluctuations as they supply feed water pumps, coolant pumps, and other loads that are critical to the operation of a nuclear station. When voltage levels at auxiliary load buses that feed station service loads reach a certain low level, motors can stall and cause tripping. The function of the undervoltage protection is to transfer loads to the backup auxiliary power supply and protect the unit operation during low voltages.

IEEE Standard 741-2017 provides information on the protection of Class 1E power systems and equipment in nuclear power generating stations. Most nuclear station-service buses are equipped with voltage relays that operate upon detection of low voltages at their station-service auxiliary buses. The standard recommends two levels of undervoltage detection: One is the degraded voltage relay (DVR) settings, and the other is low voltage relay (LVR) settings. The degraded voltage settings are more of an alarm, and this indicate a possibility of reactor shutdown. These settings are specific to each nuclear units. Usually, the DVR time settings are in excess of 10s and have higher voltage set points than the LVR settings. The LVR voltage settings, on the other hand, are much lower than the DVR settings and have shorter trip times. The LVR setting is a voltage setting that prevents motors from stalling and subsequent tripping. Violation of the LVR trip settings could lead to disconnection of the station-service loads from the preferred power supply and transfer to on-site back-up supply. These trip settings are unique to every nuclear unit, and hence, effort should be made to obtain information on them from the unit owner. In the absence of detailed models for station-service loads, it is prudent to consider a reasonable TVR criterion for nuclear units in simulation studies, taking into consideration the potential for alarms and unit trip due to activation of these undervoltage settings.

The other issue that needs to be considered is tripping of nuclear units for main bus voltages between 0.9 and 0.95 pu.[7] These voltage set points are obtained through engineering studies that support the nuclear plant and safe

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[6] https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

[7] NERC. 2015. Considerations for Power Plant and Transmission System Coordination, Technical Reference Document – Revision 2. System Protection and Control Subcommittee. July: https://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

shutdown process, and these plants are required during licensing. Therefore, knowledge of these voltage set points are valuable in developing a TVR criterion for nuclear plants.

IEEE standard C37.102 section 4.5.7 describes the purpose of an ac generator under a voltage protection function (27).

Generators are usually designed to operate continuously at a minimum voltage of 95% of their rated voltage while delivering rated power at rated frequency. Operating a generator with terminal voltage lower than 95% of its rated voltage may result in undesirable effects, such as reduction in stability limit, import of excessive reactive power from the grid to which it is connected, and malfunctioning of voltage sensitive devices and equipment. The undervoltage is detected either by definite time or inverse time and is usually designed to alarm and not trip the unit.

As mentioned above, the undervoltage protection is usually set to alarm, rather than to trip the unit. Annex A of IEEE standard C37.102 provides sample calculations for setting a generator's undervoltage protection function. Also, sustained low terminal voltages below 0.87 pu could damage a generator.

Voltage Transients have Caused Inverter-Based Resources to Misoperate

Three major events that have caused inverter-based resources to trip are the Canyon 2 Fire event in 2017,[8] the Blue Cut Fire event in 2016,[9] and the San Fernando Disturbance in June of 2020.[10] Approximately 900 MW, 1,200 MW, and 205 MW, respectively, of inverter-based resources tripped due to these events. One of the key findings from the post-mortem analysis of the Canyon 2 Fire event was regarding the use of the PRC-024-2 curve for tripping inverter-based resources. The report recommends that the inverter trip settings be based on the actual physical limitations of the inverter rather than solely on the PRC-024-2 no-trip-zone boundaries. In the Blue Cut Fire event, a portion of the inverters went into momentary cessation due to voltages reaching low-voltage ride-through settings for these inverters. This caused a momentary loss of 450 MW. It is now widely recognized that voltage transients can cause large numbers of PV inverters to disconnect due to low voltages.

System Swings: Distance Relay Characteristics, Tripped Critical Lines, and Contributed to Cascading Failures

Following a disturbance, power swings do occur, causing the voltages at buses and currents flowing in transmission lines to vary. Detecting power swings and blocking distance relays from operating is critical for maintaining security and reliability of a power system. Inadvertent operation of distance relays due to power swings or due to overloading of transmission lines could have widespread impact. Depressed voltages could cause the impedance to encroach upon the relay characteristics and trip even if a fault is not present on the transmission line.[11] Such inadvertent operation could contribute to cascading failures. One of the findings of the 2003 Blackout study team was that many

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[8] NERC and WECC. 2018. *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*. February: https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf

[9] NERC. 2017. *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*. June: https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf

[10] NERC and WECC. 2020. *San Fernando Disturbance Report*. November: https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

[11] https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

critical lines tripped on Zone 3 protection that operated on overloads rather than on faults on transmission lines. The inadvertent tripping of distance relays on Zone 3 was one of the causes contributing to the 2003 Blackout.[12]

One of the requirements in the TPL-001 standard (4.3.1.3) is to include tripping of transmission lines based on actual or generic relay models in transient stability simulation studies. The purpose of this requirement is to detect power swings that could inadvertently operate distance relays and cause cascading failures. Typical protection operating times for Zone 2 operation is between 0.2–0.3 s; Zone 3 is about 1–1.5 s. Thus, the voltage performance of a power system has a direct impact on transmission line protection and system reliability.

System Swings: Commutation Failures and Loss of HVDC Converter Stations

Commutation failure in HVDC converter stations is a prime example of a transmission reliability risk that is situation dependent. At the end of extreme risk to an interconnection are HVDC converter stations responsible for major transfers of power across long distances (e.g., the Pacific dc intertie). At the other end of risk to an interconnection are the small back-to-back dc ties that connect interconnections to one another.

HVDC converter stations require adequate voltage support to be able to transfer power through the HVDC link. A low voltage excursion leading to reduction in voltage support can cause commutation failures and could lead to tripping of the HVDC link. The approximate voltage dip that can cause commutation failures is about 20%.[13] Voltages below 0.8 pu for a few seconds could lead to tripping of the HVDC link. Some HVDC links also can have trip settings as high as 0.9 pu for one second.[14] The lack of actual voltage trip setting information would necessitate the need for a reasonable TVR criterion for HVDC buses that could be used as a proxy for detecting possible commutation failures and loss of HVDC links.

Net Load may Increase Suddenly Due to DER tripping or Momentary Cessation

With higher penetration of distributed energy resources (DER), load performance characteristics may be significantly impacted by the DER voltage control strategies in aggregation. The DERs may affect the load response in many ways, such as active voltage control, megawatt reduction and ramping, momentary cessation, and tripping. Tripping and momentary cessation are of interest as both can have major impacts on the flows and voltage profile of both the distribution and transmission systems.

In a recent event (San Fernando disturbance) that occurred in Southern California on July 7, 2020, SCE observed an increase in net load at the time of the fault events in areas with a high DER penetrations. The net load increases were identified at two sub-transmission systems fed directly from 230 kV buses located relatively close to the fault location. **Figure 2.3** shows the load increases observed on the sub-transmission. Net load increased by about 60 MW and 20 MW at these two sub-transmission buses.

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[13] Thio, C. V., J. B. Davies, and K. L. Kent. 1996. "Commutation Failures in HVDC Transmission Systems." *IEEE Transactions on Power Delivery* 11(2), 946–957. April.

[14] NERC. 2020. *BPS-Connected Inverter-based Resource Modeling and Studies.* May: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_IBR_Modeling_and_Studies_Report.pdf.

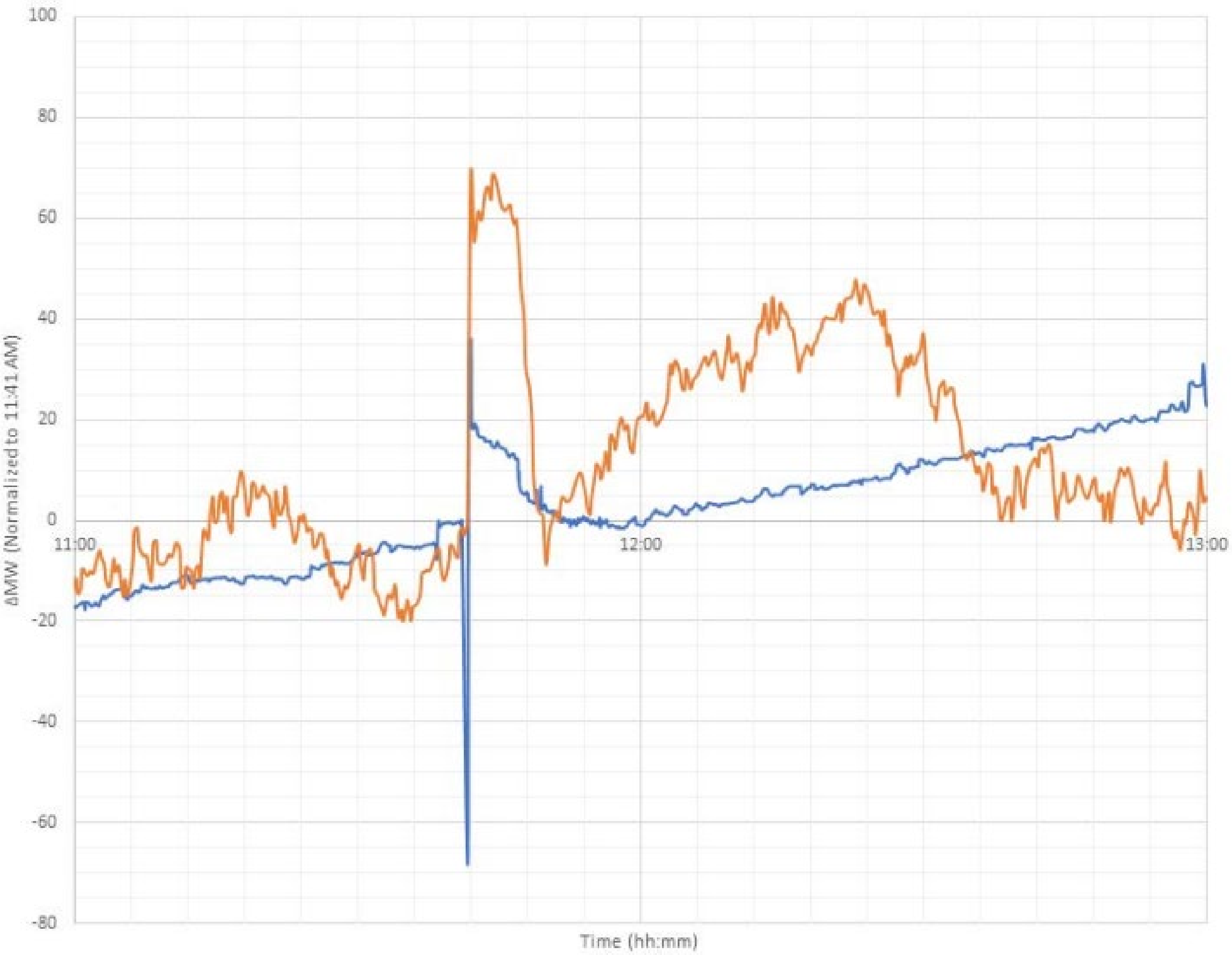

Figure 2.3: SCE Load Increase Due to DER Tripping

The net load increase persisted for about five to seven minutes, which is indicative of DER tripping and an automatic reconnection time specified in the legacy IEEE 1547 standards. The areas where net load increases were observed included high penetrations of residential rooftop solar installations, commercial installations, and utility-scale solar photovoltaic (PV) plants in the 1–10 MW range.[15] A sudden increase in loads leads to additional reactive power requirements and may lead to voltage collapse.

Concluding Thoughts on R5 and Reliability Risks

It is important to point out that this chapter has not been a discussion of BES reliability risks; it is a review of the known reasons why transmission voltage excursions have been linked to or associated with tripping or non-continuity of specific power system components. Viewed from this perspective, R5 can be understood as a means for signaling when a simulation result may exhibit such behavior.

The voltage thresholds contained in R5 reflect engineering judgements and regional practices that indicate initial simulation findings may warrant further investigation. They are, in this instance, best thought of as representing

[15] NERC and WECC. 2020. *San Fernando Disturbance Southern California Event: July 7, 2020.* November: https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

"margins" that, when crossed, call for increased scrutiny. However, past experiences may also support actions that target the voltage excursion directly. In these instances, the TVR criteria are now understood to represent performance criteria. Regional practices vary.

In summary, TVR criteria should reflect engineering judgement informed by past experiences and studies as well as regional practices and preferences. Typically, these practices will indicate the need for additional study with more specialized analysis tools in order to inform appropriate steps to address the risks that may be indicated.

Lastly, a simulation in which all voltages "meet" a TVR criterion must not be taken as confirmation that the power system is secure or that no dynamic performance issues need to be addressed. A TVR criterion must be an aide to the exercise of professional judgement and not a substitute.

Chapter 3: Modeling Considerations

This chapter describes modeling considerations for simulating the actions of line protective relays and generator auxiliary protection when dynamic load models are used to study the reliability impacts of FIDVR. To derive appropriate conclusions from studies of FIDVR, it is important to pay special attention to the fidelity with which these actions are simulated.

As discussed in **Chapter 2**, FIDVR events result from a high demand for reactive power, and the severity of the depressed voltage is contained within the transmission and the sub-transmission system more often. One of the major concerns about the transmission system is the advertent or inadvertent operation of protection devices that may be susceptible to sustained low voltages. Tripping of protection devices can cause cascaded impacts that may not be captured if protection systems are not modeled in simulation studies. However, modeling protection devices is not a standard practice among some utilities (due to the added complexity) so has been cited as a cause for concern while performing simulation studies. Another concern during FIDVR studies is if generators are located in areas experiencing sustained degraded voltages. During this condition, it is important to model the generator protection as well as any auxiliary system protection that may cause the generator to trip. The modeling of protection should incorporate limiters as well as tripping elements.

Line protective relay modeling considerations

An FIDVR condition is characterized by depressed system voltages with a significant amount of current being drawn by the stalled motors that is predominantly inductive in nature. Such conditions on transmission lines can result in an operation of phase distance relays that result in a possibility of a cascaded system event. These relays can operate in 0.2 to 0.3 seconds after the detection of a high current condition so need to be considered while performing dynamic studies. For the most part, it can be assumed that these relays are not at the risk of operation if the voltages recover within the utility set TVR criteria limits. As such, the TVR criteria implicitly screens the contingency conditions that can push the system in an area susceptible to further cascading due to relay operation. However, depending on the loading, some lines can be susceptible to trip during a FIDVR event even if the voltages recover within a time frame that is acceptable by the local TVR criteria. As such, a uniform TVR criteria may not be sufficient for all buses in the system, and modeling the protection device on such lines can provide a more realistic view of the progression of the FIDVR event in the system. The operation of phase distance relays in the context of transient voltage response is discussed in this section.

The depressed voltages and high reactive power flow during a FIDVR event might appear as a high impedance fault to phase distance relays on heavily loaded lines. Operation of these relays can lead to cascading outages. NERC standard PRC-024-3[16] specifies that the transmission line relays should be set such that they do not operate at 150% of their highest seasonal loading based on the four-hour emergency rating. To meet this requirement, the impedance setting Z_{relay} can be calculated with Equation 1:

Equation 1

$$Z_{relay\ 30} = \frac{0.85 * V_{l-l}}{1.5 * \sqrt{3} * I_{4\ HR}},$$

where $Z_{relay\ 30} = Z_{MTA} * Cos(MTA - 30)$, and MTA is the maximum torque angle.

[16] NERC. No date. PRC-023-4 Transmission Relay Loadability: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-023-4.pdf

Furthermore, the PRC-023-4 R1.2 standard requires that the relays should be set such that they do not operate below 115% of the 15-minute emergency rating. To meet this requirement, the impedence setting Z_{relay} can be calculated with Equation 2:

Equation 2

$$Z_{relay\ 30} = \frac{0.85 * V_{l-l}}{1.15 * \sqrt{3} * I_{15min}}.$$

These requirements are in place to ensure that the relays do not limit the loadability of the line by tripping inadvertently. However, the voltage levels can dip as low as 0.5 pu and remain below 0.85 pu for almost 20 seconds after the initial fault during FIDVR events. Assuming a power factor angle of 30 degrees, the loadability limits of the relay can be significantly reduced, as shown in **Table 3.1**.[17]

Table 3.1: Variation of Loadability of Phase Distance Relay with Reduced Terminal Voltage

Per Unit Voltage	Power Factor Angle	Loadability of the Relay in Terms of the 4-hr Emergency Limit (%)	Loadability of the Relay in Terms of the 15-min Emergency Limit (%)
0.85	30	150	115
0.8	30	141	108
0.75	30	132	101
0.7	30	124	95
0.65	30	115	88
0.6	30	106	81
0.55	30	97	74
0.5	30	88	68

Furthermore, due to the increased inductive current demand during FIDVR, the power factor angle may increase. This can cause the loadability of the lines to reduce further. Assuming a terminal voltage of 0.85 pu and maximum torque angle of 75 degrees, the loadability limits of the relay for different power factor angles is shown in **Table 3.2**.

Table 3.2: Variation of Loadability of Phase Distance Relay with Increased Power Factor Angle

Per Unit Voltage	Power Factor Angle	Loadability of the Relay in Terms of the 4-hr Emergency Limit (%)	Loadability of the Relay in Terms of the 15-min Emergency Limit (%)
0.85	30	150	115
0.85	35	138	106
0.85	40	129	99
0.85	45	122	94
0.85	50	117	90
0.85	55	113	87

Thus, a combination of reduced voltage and decreased power factor angle during an FIDVR event can cause the phase distance relay of a heavily loaded line to operate in Zone 2 or Zone 3 if the bus voltage takes more than a few seconds

[17] NERC. 2009. A *Technical Reference Paper: Fault-Induced Delayed Voltage Recovery*, Version 1.2. Transmission Issues Subcommittee and System Protection and Controls Subcommittee. June.

to recover above 0.85 pu. The typical protection operation time for Zone 2 is 0.2–0.3 s, and for Zone 3 is 1–1.5 s,[18] which is in the time frame of the FIDVR phenomenon, so the relays connected to the lines originating or terminating at this bus are at the risk of operating and, in this case, the TVR criteria will fail to screen this condition as critical even though the bus voltage recovery may be acceptable under a uniform TVR criteria. Therefore, transmission planners need to be cognizant of such impacts and appropriately model phase distance relays for heavily loaded lines in areas/zones susceptible to FIDVR for better characterization of the possible consequences. Note that, even though most relays also have blinders that increase their loadability, such relays can also be affected by FIDVR, but to a lesser extent.

Another point of concern is power swings. Most of these relays have a power swing block feature that prevents the relay from operating during a stable power swing. Therefore, in most cases, the relays will not operate during a transient power swing. However, with increased penetration of inverter-based resources (IBRs), the rate of power swing measured at certain lines close to the IBRs is high enough to mislead the relay into operation,[19] so relays on lines close to IBRs might also have to be considered. Most of the other relays do not raise any significant concern from a modeling perspective during FIDVR conditions.

Generator Modeling Considerations

If a conventional generator is located at a bus that is close to a load area experiencing FIDVR or has a significant amount of motor loads in electrical proximity, it is important that simulation models adequate represent various generator protections that might operate under degraded voltage conditions. Specifically, attention should be given to the following:

- Generator Protection
  - Stator over current protection
  - Field winding protection
  - Under and over voltage protection
- Generator Auxiliary System Protection
  - Lubrication pumps
  - Feedwater pumps
  - Forced draft/induced draft/primary air fans
  - Circulating water pumps

Implementing models to capture the effect of these protection devices is important since, in reality, these protection devices may operate under degraded voltage, tripping the generator and worsening the degrading event. If such devices are modeled appropriately, the evolution of a FIDVR event can be captured more accurately. NERC standard PRC-019-2 requires coordination of generator protection elements and excitation limiters.

The generator protection functions listed above can be implemented in the commonly used simulation programs. The auxiliary system protection functions listed above are equally important but can be tricky to implement in some cases. Presently, the PRC-024-3[20] standard does not require the plant auxiliary system protection to conform with

[18] Samaan, N. A., J. E. Dagle, Y. V. Makarov, R. Diao, et al. 2016. "Modeling of protection in dynamic simulation using generic relay models and settings." Proc. of 2016 IEEE PES GM. July. Boston, Massachusetts.

[19] https://www.cce.umn.edu/documents/CPE-Conferences

[20] PRC-024-2 *Generator Frequency and Voltage Protective Relay Settings*: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-024-2.pdf#search=prc%2D024%2D2

the “no-trip” zone as identified in the standard. However, the tripping of a plant auxiliary motor, such as a lubrication pump, can cause the entire plant to shut down that will result in further cascaded impacts. While the no-trip zone indicated in the PRC-024-3 can be modeled with the (LHVRT/VTGTPAT relay in GE PSLF™ and PSS®E, respectively), or based on a voltage level and time duration-based screening, it should be confirmed that vulnerable generators are indeed able to ride through without disruption within the limits set by PRC-024-3. If the plant auxiliaries are expected to trip in the “no-trip” area defined in PRC-024-3, the screening method used (either using LHVRT relay or voltage level-time duration-based screening) should be adjusted to account for this based on sound engineering judgement. Furthermore, these relay models can be set in *alarm* mode as well as in *trip* mode. Planners are advised to use judgement in employing these options so they can screen and study these problems appropriately.

In addition to the protection systems discussed above, it is important to recognize the effects of excitation limiters of generators that are in an area experiencing FIDVR or have a significant amount of motor loads in near proximity. When motors decelerate in response to a voltage disturbance, they consume an increased amount of reactive power. The capabilities of local voltage support resources, such as synchronous generators, can affect the voltage recovery of the system significantly. Excluding excitation limiter models can result in a generator supplying an unrealistic level of reactive power and overloading its field and stator circuits. **Figure 3.1**, shows the overload capability of the generator stator and field circuits as given in standard ANSI C50.13 [21] Modeling the excitation limiters will cause the field current to be restricted within allowable limits; they will restrict the reactive power output of the machine. Reduction in reactive power can result in loss of voltage support and made worse a voltage disturbance.[22]

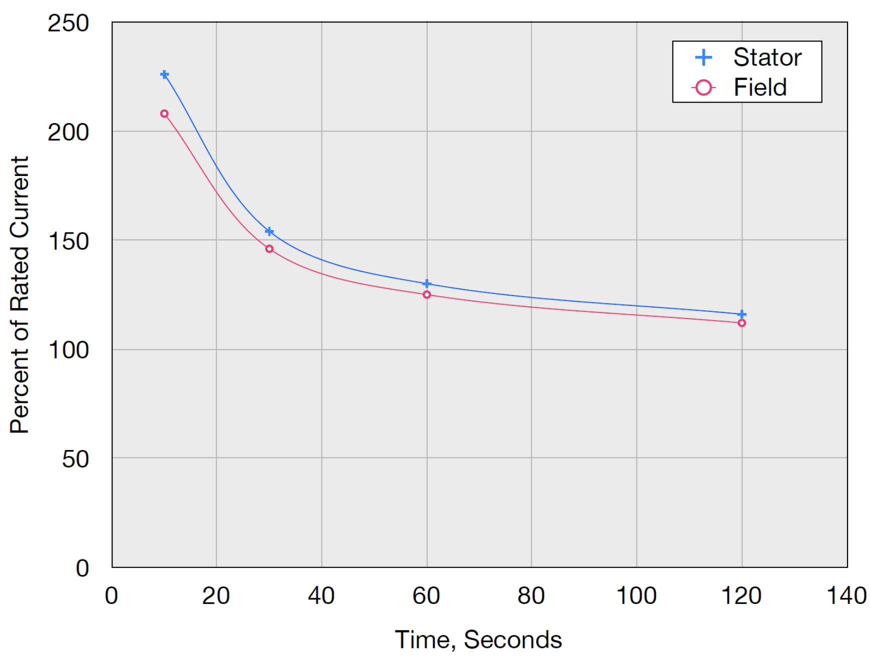

Figure 3.1: Generator Stator and Field Overload Capability

[21] IEEE C50.13-2014 - *IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above*: https://standards.ieee.org/standard/C50_13-2014.html

[22] Undrill, J. M. 2009. Generation Side of FIDVR. Presented at the 2009 NERC-DOE Fault Induced Delayed Voltage Recovery (FIDVR) Workshop. September.

Chapter 4: WECC and ISO-NE TVR Criteria

This chapter describes the TVR criteria used by WECC and ISO-NE. These examples illustrate how the development of TVR criteria have been driven by the need to study identified reliability risks. The examples also illustrate how the actions triggered by simulation findings depend on engineering judgement based on experience and past studies as well as being informed by standards and local practices regarding acceptable reliability performance.

WECC[23]

WECC revised its TVR criteria in 2015,[24] and the rationale for the revision was twofold. First, WECC acknowledged that its former TVR criteria[25] was based on a proxy for loss of voltage sensitive load in the absence of dynamic load modeling. WECC then observed that it was now using dynamic load models that more explicitly model the dynamic behavior of loads in simulations. WECC concluded that these more complex composite load models make the applicability of the present WECC regional performance criteria obsolete. Second, WECC also observed that, with approval of TPL-001, the general philosophy of the TPL criterion had changed from no loss of load due to voltage dips for planning contingencies to maintaining the integrity of the BES, recognizing that loss of voltage sensitive loads or loads tripped by end-user equipment cannot be prevented.

WECC's revised TVR criteria have two parts. The first part addresses faults that cause FIDVR; the second part addresses faults that do not cause FIDVR.

Referring to faults that cause FIDVR, the criteria require that "transient stability voltage response at applicable BES buses serving load (with no intermediate connection) shall recover to at least 80% of pre-contingency voltage within 20 seconds of the initiating event for all P1–P7 category events." The stated purpose is to specify a recovery voltage that allows enough time to recover during an FIDVR event. See **4.1**.

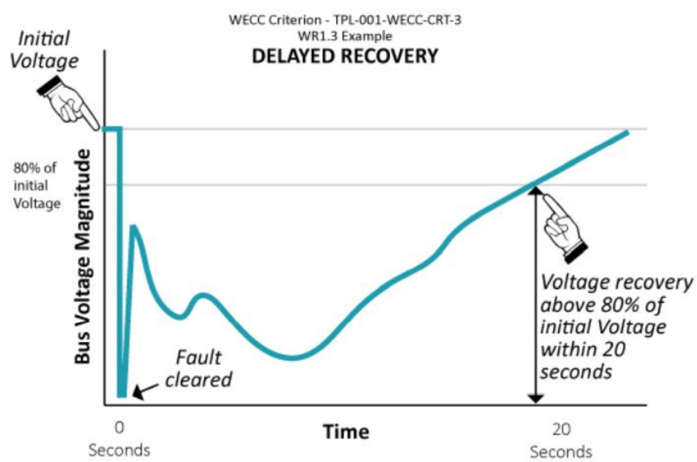

Figure 4.1: Delayed Response Voltage Parameters

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[23] WECC. 2016. *WECC Criterion. TPL-001-WECC-CRT-3.1*. September: https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.1.pdf

[24] WECC. 2015. WECC-0100 TPL-001-WECC-CRT-3 (CRT), *Transmission System Planning Performance,* proposed transient voltage response rationale for CRT requirements R1.3 and R1.4. July: https://www.wecc.org/Reliability/WECC-0100%20Posting%203%20TPL-001-WECC-3%20White%20Paper%20on%20Requirement%20R1%203%20and%20R1%204%20-%20Not%20for%20Comment.doc

[25] WECC. Table W-1 of the WECC Regional Criteria, TPL-001-WECC-CRT-3.2, System Performance (TPL). https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf

For faults that do not cause FIDVR, the criteria requires that "for voltage swings subsequent to fault clearing and the first voltage recovery above 80%, voltage dips at each applicable BES bus serving load (with no intermediate buses) shall not dip below 70% of pre-contingency voltage for more than 30 cycles or remain below 80% of pre-contingency voltage for more than 2 seconds for all P1-P7 category." The purpose is both to confirm that voltage has, in fact, recovered (i.e., the system will not cascade) and to provide "a reasonable expectation of minimal load loss." See **Figure 4.2**.

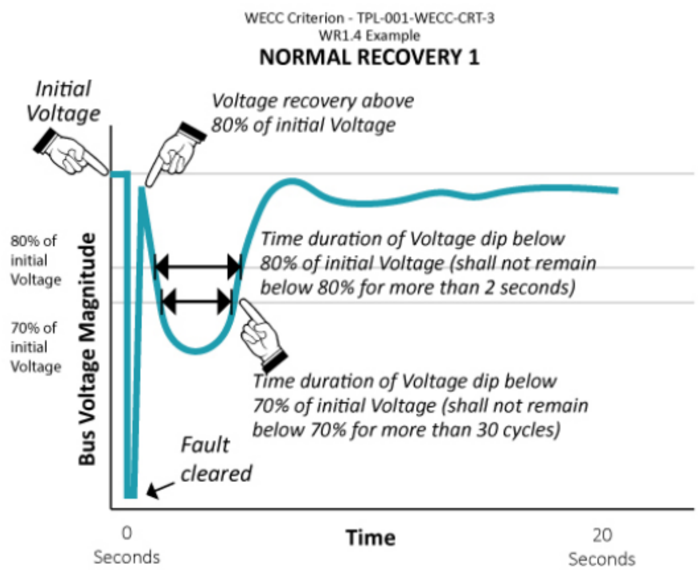

Figure 4.2: Normal Response Voltage Parameters

In describing the development of its revised TVR criteria, WECC is explicit in referencing the engineering judgement involved. The following is stated by WECC:

> "Even though there is no hard technical justification for 80%, it is widely understood that if the voltage did not recover to at least 80%, there could be unintended consequences such as protection system misoperation which could result in cascading. In addition, recovering in a maximum of 20seconds seems like a reasonable time to recover during a FIDVR event based on experience and engineering judgment. Since the TPL-001 is new, and there remains to be much research to be done regarding the FIDVR phenomena and related dynamic load modeling practices, these parameters should be revisited as better information becomes available."

WECC's criteria also recognizes that subsequent voltage dips due to power swings could cause load loss that may occur on neighboring systems. WECC's criteria seeks to minimize this potential impact on other loads by the limiting voltage dips subsequent to recovery of the first swing. **Appendix C** provides a discussion of loss of load considerations that may be relied on to establish these thresholds.

ISO-NE[26]

The intent of the ISO-NE *Transient Voltage Sag Guideline* is "to avoid uncontrolled islanding and significant load shedding that may lead to unintended system performance, such as widespread voltage collapse." ISO-NE has also used the guideline as a measure of system stability because it is concerned that a post fault voltage sag event could lead to either potential tripping of generators by low voltage based on tripping of auxiliary loads, or potential tripping of transmission lines during power swings due to relay actuation.

ISO-NE's *Transient Voltage Sag Guideline* is stated as follows (also see **Figure 4.3**):

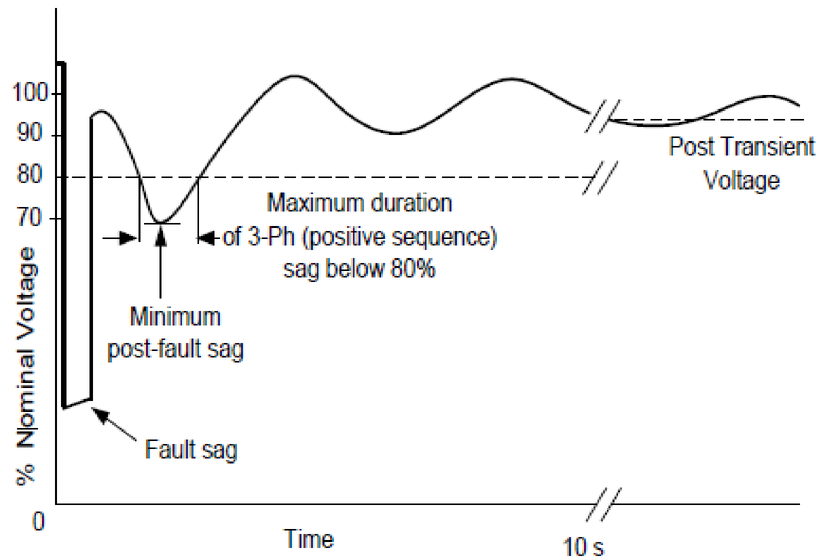

Figure 4.3: ISO-NE's Voltage Sag Guideline Parameters

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not exceed 250 ms below 80% of nominal voltage within 10 seconds of following a fault. ISO-NE further notes that these limits are supported by the typical sag tolerances shown in Figures C.5 to Figure C.10 in IEEE Standard 1346-1998. This is more of a screening criteria to prevent unintended system performance.

ISO-NE also notes that, while its *Voltage Sag Guideline* covers conditions that occur after the voltage reaches 80% post-fault clearing, it does not cover delayed voltage recovery (e.g., FIDVR), which is more of a concern during summer peak conditions. To address delayed voltage recovery, ISO-NE has developed the following criterion:[27]

> "At BES buses that are a part of the pool transmission facility (PTF) and that serve load or are connected to load-serving transformers, the voltage shall not stay below 0.8 p.u. for longer than 10 seconds for Planning Events under NERC TPL-001. At all other BES buses, no transient voltage recovery criteria are applied."

In developing this TVR criterion, ISO-NE acknowledges that there is no industry standard for a low voltage threshold at BES buses, such as 0.8 pu during a transient condition. Nevertheless, ISO-NE states that it is concerned that sustained voltages below 0.8 pu could lead to cascading outages based on protection system misoperation. ISO-NE is

[26] https://www.iso-ne.com/static-assets/documents/2022/04/transmission_planning_technical_guide_rev7_3.pdf

[27] pp3_r8.pdf (iso-ne.com)

explicit in recognizing that it is basing this criterion on its engineering judgement. Accordingly, ISO-NE also states that it is leaving open the possibility for revisiting the criteria as more experience is gained with the dynamic load models.

In addition to the above criterion, the voltages at the BES buses that are a part of the PTF must not violate the post-contingency, pre-switching low voltage limits at the end of the transient simulation. This is to ensure that the system can stably transition into a steady-state time frame without any voltage collapse.

With the use of dynamic load model in TPL studies, the transient voltage recovery phenomenon is sensitive to each load model type, including their protection settings. The composite load model includes models of three-phase motors, single-phase motors, and electronic and static loads, along with their associated voltage protection settings. Contingency simulations with the composite load model could lead to load being disconnected. Excessive disconnection of load could lead to significant changes in power flow within the New England system and across the tie lines to neighboring areas. To reduce the impact of load disconnection on system performance, ISO-NE restricts the net loss of load for planning events to 1,200 MW.

Chapter 5: Guidance for Setting up TVR Criteria

The purpose of a TVR criteria is to assist in the task of distinguishing between simulations that indicate acceptable response of the BES to contingencies and those that do not. The contingencies of concern are described in general terms in NERC standard TPL-001. Acceptable response is when the power system continues to operate stably within allowable bands of frequency and voltage. The examination of a simulation run to determine if it indicates acceptable behavior requires consideration of large numbers of signals in relation to a range of aspects of system behavior. Examples of the signals that should be examined are as follows:

- Generator real and reactive power outputs and generator bus voltages
- Sychronous generator excitation voltages and currents
- Voltage at load serving buses
- Voltage at major substation buses
- Apparent impedances seen by distance relays
- Voltage at electronic elements including HVDC converters

Key aspects of BES behavior that must be recognized from examination of the simulation signals include the following:

- Maintenance or loss of synchronism of individual generators (transient stability)
- Maintenance of voltage at BES load-serving buses that ensures that end-use supply voltages are within statutory and locally determined acceptable limits
- Loss of synchronism between sections of the BES (out-of-step, system separation)
- Disconnection of load by under-frequency or undervoltage relays
- Tripping of generators as a consequence of low auxiliary bus voltages
- Stalling of customer's motor loads and subsequent disconnection
- Operating mode transitions of electronic elements, including HVDC converters, inverter-based generation, and electronically controlled loads

A TVR criterion is a surrogate for the broad range of signals and aspects of system behavior that must be examined to draw a sound conclusion from a simulation run. BES voltages are used as surrogates because long experience has shown that they are well correlated with key aspects of BES behavior: loss of synchronism is closely associated with short-term dips of voltage after clearance of transmission faults, delays of voltage recovery for several seconds after fault clearance are a "signature" consequence of the stalling of air conditioner motors, and prolonged oscillations are associated with instability of controls. There are many more such associations.

When used in combination with sound engineering judgement, a TVR criterion aids in the recognition of risks that arise from the approximations that are inevitable in simulations of large, complex, and constantly evolving systems.

To be useful, a TVR criterion must recognize the physical facts of power system behavior and the practices by which the BES and distribution systems are built and operated. It must also recognize the capabilities and limitations of the simulation tools with which it will be used. Key aspects of BES behavior—discussed below—are associated with both the size of voltage variations and the time frames over which they occur. This is illustrated by **Figure 5.1** and **Figure 5.2**.

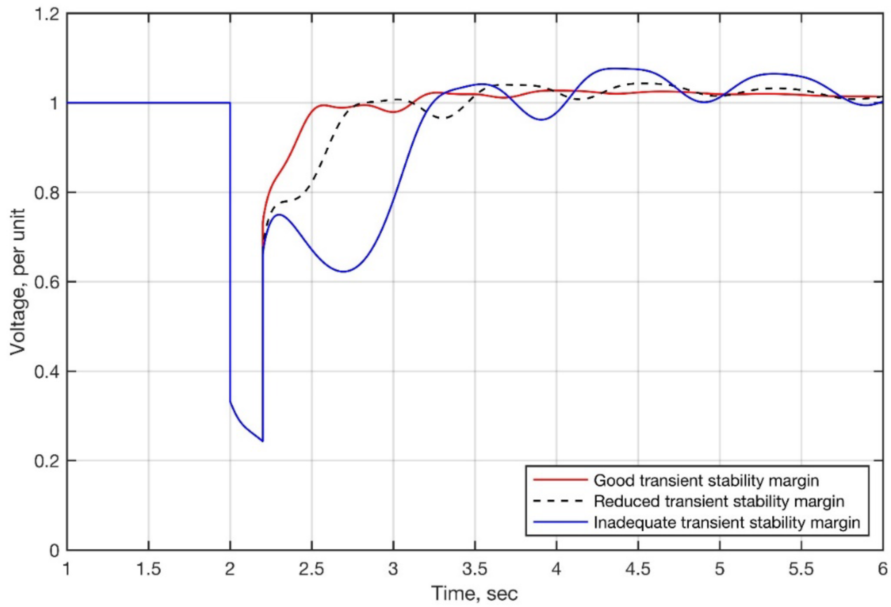

Figure 5.1: Simulated Response of Voltage for Fault Close to a Block of Generation

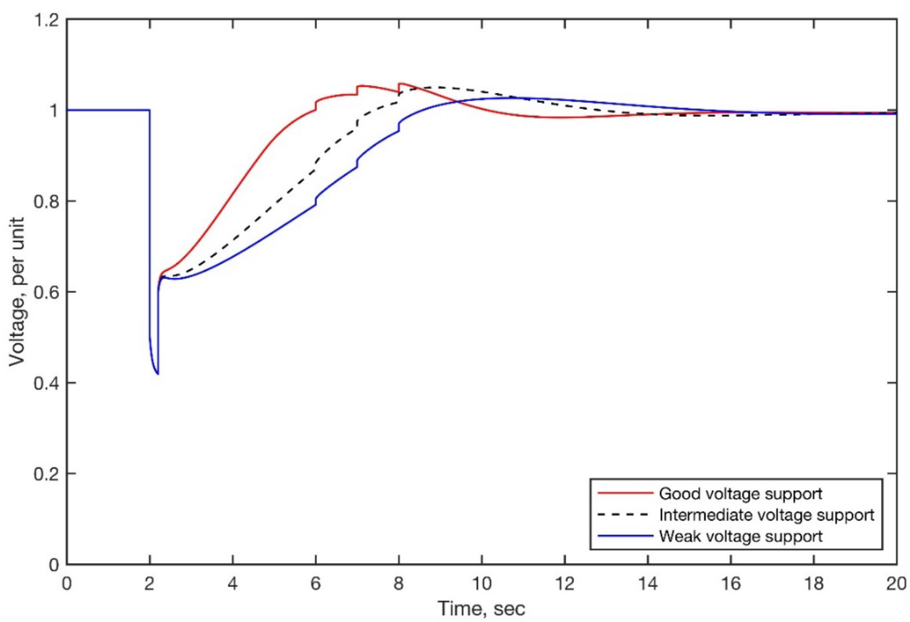

Figure 5.2: Simulated Response of Voltage in a Load Area

Rotor Angle Dynamics and Transient Stability*:* The timescale of behavior related to rotor angle stability and maintenance of synchronism is typically about zero to two seconds. **Figure 5.1** shows a bus voltage from three simulations of a transmission fault close to a synchronous generator. With strong transmission, after clearance of the fault, voltages recover quickly to 0.7 per unit (pu) and continue to reach their pre-event levels in less than 1.0 second (see both the red and dashed lines).

With weaker transmission, clearance of the fault allows voltage to recover to 0.7 pu but then, as generator rotors swing in relation to one another, voltage dips back down to 0.63 pu (see the blue line). Such a transient dip of voltage after an initial recovery is a good indicator that parts of the BES are close to going out of synchronism (out-of-step) with one another. This may be because a single synchronous generator pulls out of step or because large parts of the BES have separated. Details of the out-of-step behavior would be revealed by examination of signals, such as generator speed, generator power, or the apparent impedances seen by distance relays.

Consequently, a TVR criterion could be set up to detect this behavior by allowing post fault voltage to go and/or remain below 0.8 pu for as long as 0.5 second, but not longer. With such voltage and time thresholds, the two simulations with good ability to maintain synchronism (i.e., the red and dashed lines) would meet the TVR criterion, but the marginal case would not (i.e., the blue line).

However, in a situation such as this, it should be preferable to apply a MW or clearing time margin against the generation MW level or clearing time at which point the system loses synchronism rather than relying on a TVR criterion from which one cannot know precisely how near the loss of synchronism is in any given case.

Delayed Voltage Recovery*:* The timescale of delayed voltage recovery events can range up to 15 seconds. **Figure 5.2** shows voltages indicated by three simulations of a part of the system where load behavior is a concern. Real power transfers into the load region are moderate, and maintenance of synchronism is not an issue. In this case, the fault depresses voltage to a level at which a large amount of a single-phase motor load stalls. The stalled motors present the system with a significant increase in reactive power load above the pre-event level; this high reactive load causes the voltage to recover slowly, and complete recovery is achieved only when thermal cut-outs in the motors disconnect them from their supplies. The disconnection of load allows voltage to go above the pre-event level after the slow recovery.

A TVR criterion that addresses delayed voltage recovery behavior must recognize that the threshold voltage levels and time tolerances that are effective in regard to short-term synchronism transients can represent an impractical performance objective with regard to delayed voltage recovery. Accordingly, a TVR criterion that recognizes slow voltage recovery behavior such as that shown in **Figure 5.2** could, for example, simply require that the rate of change of voltage be positive.

Essential Service Loads*:* Regardless of consideration of system behavior at load buses, a TVR criterion should recognize the essential nature of power plant auxiliary loads. A TVR criterion may need to use special criteria (e.g., different voltage threshold and tolerance time) for buses serving generating plant auxiliary loads (such as lubricating oil and hydraulic control fluid pumps).

Post-event System Condition: At the end of a simulation run, the system should be operating stably in a quasi-steady state condition that can be maintained for an extended period. A TVR criterion does not need to require voltages to be completely restored to normal, or to be ideal for long-term operation, but it should require them to be in a range such that normal secondary control actions (such as regulator tap changes or capacitor switching) can restore normal conditions.

Figure 5.3 provides a visual summary of the phases of a simulated voltage recovery for which the considerations described in this section could be addressed by a TVR criterion.

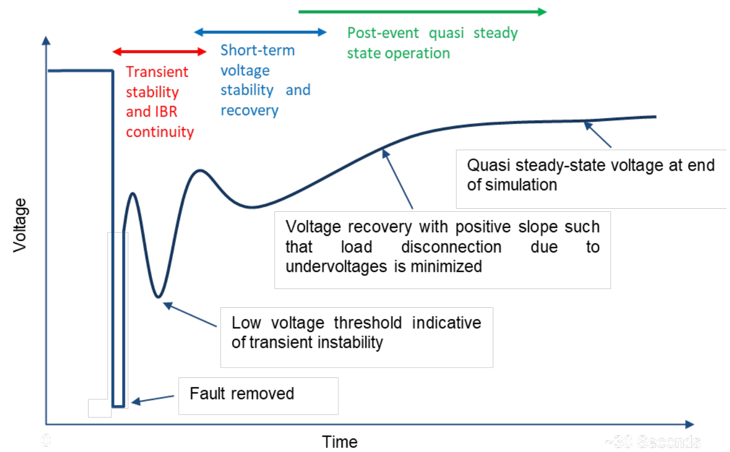

Figure 5.3: Considerations for Establishing TVR Criteria

TVR criteria should be reviewed periodically in relation to the evolution of power system equipment, power system behavior, and the characteristics of simulation tools. It is not unreasonable to anticipate that the evolution of the power system or of simulation tools results in behavior, both real and in simulation, that causes a standing TVR criterion to be excessively stringent in its requirements.

Transient voltage response criteria are primarily intended to indicate potential transmission reliability risks following a disturbance. The voltage thresholds contained in R5 reflect engineering judgements and regional practices that indicate when it is prudent to recognize that initial simulation findings may warrant further investigation. They are, in this instance, best thought of as representing “margins” that, when crossed, call for increased scrutiny. However, past experiences may also support actions that target the voltage excursion directly. In these instances, the TVR criteria are now understood to represent performance criteria.

The guidance on the NERC TPL-001 R5 requirement provided in this document is general in nature as these criteria are system specific and cannot be applied universally to all systems. It defines certain boundary conditions based on voltage levels that must be respected in order to develop a practical TVR criteria. It provides a means for determining the voltage levels corresponding to the boundary conditions that satisfies one of the requirements as stated in R5 of TPL-001 standard. The other requirement regarding the time duration below which the voltage levels can remain is system specific and is left to the planner to decide based on sound engineering judgement.

The Following are Contributors to the LMWG TVR White Paper:

- Bo Gong: Sr. Principal Engineer, Transmission Strategy, Salt River Project
- Dmitry Kosterev: BPA
- Joe Eto: Staff Scientist, Lawrence Berkeley National Laboratory
- John Undrill:John Undrill, LLC
- Kannan Sreenivasachar: Technical Manager, ISO-New England
- Olushola Lutalo: Lead Engineer, NERC
- Parag Mitra: Senior Technical Leader, EPRI
- Song Wang: Principal Transmission Planner, Portland General Electric.
- Vijay Vittal: Regents Professor, Arizona State University

Appendix A: Large-Disturbance, Short-Term Voltage Stability is the Focus of TPL-001 FIDVR

This appendix provides background for this white paper by first locating the types of reliability issues that are studied with transient simulations with positive sequence load flow tools within the broad pantheon of power system stability issues in general and voltage stability issues in particular.

An IEEE/CIGRE Joint Task Force on Stability presented a detailed classification and definition of stability problems in power systems.[28] Recently the document developed by the task force was revised[29] to include the impact of inverter interfaced resources. In this revised document, *power system stability* is classified as shown in the **Figure A.1** below.[30]

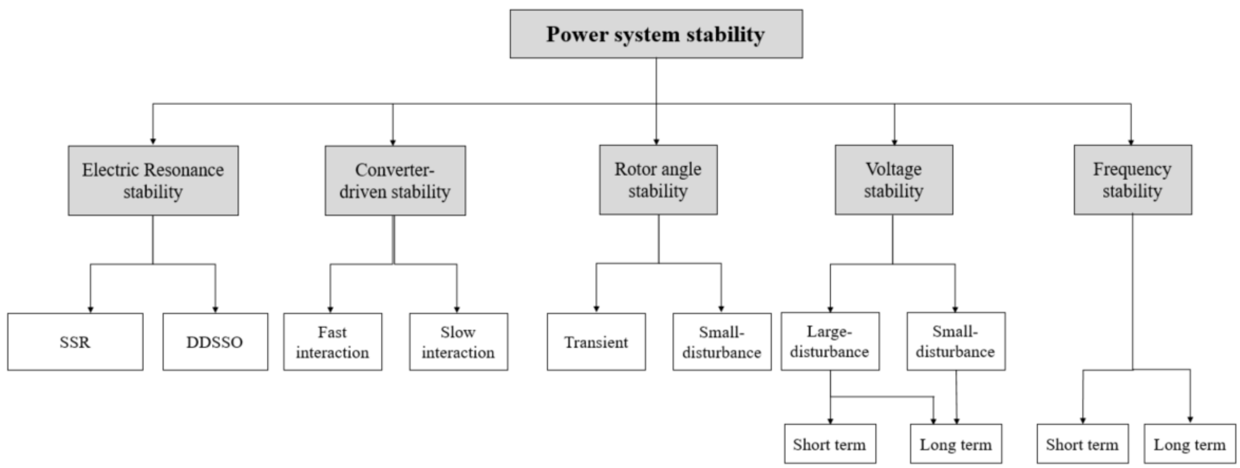

Figure A.1: Classification of Power System Stability

The classification of voltage stability pertains to the discussion in this white paper. The incidence of voltage stability can occur due to both large and small disturbances. The small-disturbance instability primarily manifests itself as a slow voltage collapse. This collapse is handled with steady state analysis techniques and is well documented in literature. The topic is addressed in this white paper is voltage instability due to large disturbances. Large-disturbance voltage stability can be further divided into short-term phenomena and long-term phenomena. Short-term voltage stability involves dynamics of fast acting load components, such as induction motors, electronically controlled loads, HVDC links as well as inverter interfaced generators and synchronous generators. The topic addressed in this white paper is short-term voltage stability.

The short-term voltage problem can be further subdivided into oscillatory voltage stability and non-oscillatory voltage stability. Oscillatory voltage stability primarily occurs in conjunction with power swings initiated by large disturbances, and synchronous generators swing against each other consequently. As a result, the voltages at locations in the transmission circuit connecting the synchronous generators oscillate. At the electrical center between the groups of oscillating generators, the voltage deviations can become zero.[31] This phenomenon is well described in examining the operation of out-of-step relays and results in tripping of transmission lines, HVDC pole tripping, or

[28] Kundur, P., J. Paserba, V. Ajjarapu, G. Andersson, A. Bose, C. Canizares, N. Hatziargyriou, D, Hill, A. Stankovic, C. Taylor, T. Van Cutsem, and V. Vittal. 2004. "Definition and Classification of Power System Stability, IEEE/CIGRE Joint Task Force on Stability Terms and Definitions Report." *IEEE Transactions on Power Systems* 19(3), 1387–1401. August.

[29] Pourbeik, P., J. Sanchez-Gasca, A. Stankovic, T. Van Cutsem, V. Vittal, C. Vournas. 2021. "Definition and Classification of Power System Stability – Revisited & Extended." *IEEE Transactions on Power Systems* 36(4), 3271–3281. July.

[30] Ibid.

[31] E. W. Kimbark. 1950. *Power System Stability Vol II,* (Chapter X). John Wiley and Sons, Inc. New York.

synchronous generator tripping. Non-oscillatory short-term voltage stability is primarily driven by the load (largely single-phase induction motors) and manifests as a slow voltage recovery following a large disturbance. Typically, this fault-induced delayed voltage recovery (FIDVR) phenomenon results in disconnection of customer load and power quality issues.

The time frame for assessing short-term voltage stability is about 10–20 seconds. In this time frame, the comparatively fast dynamics of generators and their control systems, HVDC, FACTS devices, inverter-based generators and loads, determine system stability. After this time frame, slower voltage control devices like under-load tap changers and automatically switched shunts start to operate to raise or lower system voltages within a set operating band. Accordingly, a study of short-term voltage stability is conducted using simulation models. NERC TPL-001 is formulated entirely around transient simulation studies conducted initially using positive sequence load flow tools.

Appendix B: Major System Events

This appendix reviews some actual system events characterized by depressed system voltages for varying periods following a system disturbance. Generation outages, inadvertent protection device operation, and human error exacerbated these depressed system voltages conditions. FIDVR events result in a high demand for reactive power within the transmission and the sub-transmission system. The following are some salient features of FIDVR events:

- Slow recovery of voltages on transmission and distribution load buses
- Significant disconnection of load due to delayed voltage recovery
  - Normally cleared faults and multiple faults lead to load disconnection
  - Tripping of several generating units
  - High voltage seen on transmission buses leading to automatic cap bank switching and locking out

The following sections detail some causes and impacts of significant events in various areas of the North American Interconnection.

August 22, 1987, Tennessee Valley Authority Event

The Tennessee Valley Authority event was one of the first FIDVR events to be identified. The initial cause of this event was a 115 kilovolt (kV) switch phase-to-phase flashover during operation.[32] Due to the protection scheme, the duration of the fault allowed motor loads to stall and draw large amounts of reactive power after clearing of the fault.[33] The long fault clearing duration resulted in a depressed voltage condition on both the 161 kV and 500 kV systems. These depressed voltages resulted in cascading that eventually tripped the 161 kV source for several substations, resulting in the loss of 700 MW of load.[34] Much of the load lost resulted from thermal and overload protection on individual pump and air conditioning loads. Tennessee Valley Authority lost an additional 565 MW of load after thirteen 161 kV substations were de-energized.

August 22, 1987, Tennessee Valley Authority Event

- Failure of a 115 kV switch leading to a delayed fault clearing
- Depressed 161 kV and 500 kV system voltages led to 700 MW of load disconnection
- Additional 565 MW of load was disconnected due to protective action

August 18, 1988, Florida Power & Light Event

Eight severe outage events occurred on the Florida Power & Light System during the 10-year period up to 1988, when normally cleared fault events in Southeast Florida caused a significant drop in customer load. In some of these events, distribution feeder breakers protection operated time overcurrent relays; however, most of the load was loss due to operation of customer device protection. The August 18, 1988, event caused the most concern because it took more than 10 seconds for the transmission voltage to recover to prefault levels.[35] There was concern that a surge in reactive load experienced following the fault isolation for this event could cause transient stability problems for fault in more

[32] Cascading Voltage Collapse in West Tennessee. August 22, 1987. Gary C. Bullock, Tennessee Valley Authority.

[33] Ibid

[34] Ibid

[35] John W. Shaffer. August 18, 1988. Florida Power & Light Event.

critical transmission circuits. Field tests have shown that normally cleared faults will cause residential air condition compressor motors to stall if the supply voltage is below 60% of normal during the fault.[36]

August 18, 1988, Florida Power & Light Event

- A three-phase fault on a 230 kV bus cleared in 3.5 cycles
- 825 MW of load disconnected

August 5, 1997, Southern California Edison Event

An airplane accident caused multi-phase-phase fault in two 500-kV lines in Southern California. Figure B.1 and Figure B.2 shows the 500 kV bus voltage at Adelanto and the bus frequency at the Palo Verde generating station. The fault resulted in FIDVR with delayed voltage recovery lasting about 15 seconds, and it caused intermittent disconnection of 3,525 MW of load by end-use controls and distribution protection.

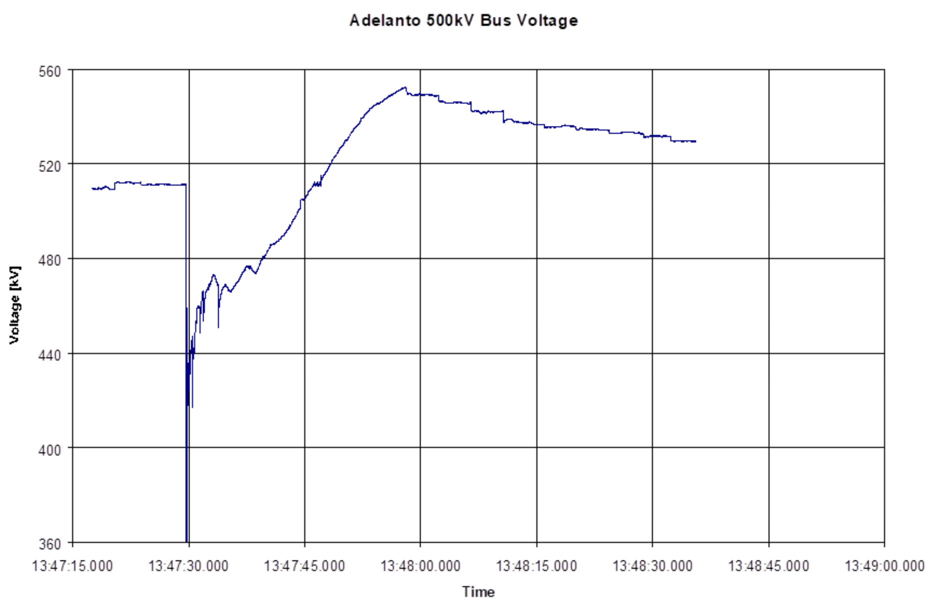

Figure B.1: Adelanto 500 kV Bus Voltage

[36] Ibid.

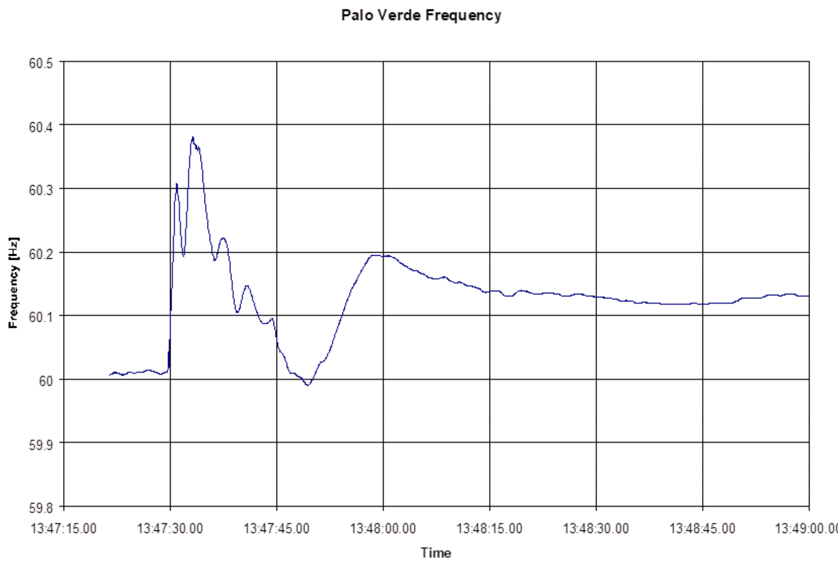

Figure B.2: Palo Verde Bus Frequency

July 30, 1999, Southern Company Union City Event

Southern Company's southern balancing area experienced a FIDVR due to multiple faults. Seven units with a total output of approximately 1,065 MW tripped during the event or minutes after it. As a result, approximately 1,900 MW of load was dropped. Less than 100 MW of the load lost was due to utility breaker operations. The vast majority of load lost was due to induction motor protection.

July 28, 2003, Hassayampa and Pinnacle Peak Event

Prior to the disturbance, there were two faults caused by contaminated insulators at Arlington Valley Substation on the Hassayampa 500 kV line. The Hassayampa to Arlington Valley 500-kV line was removed from service to clean the contaminated insulators. Figure B.3 is a fault diagram of the affected facilities. At about 6:54 p.m., local time, the 500 kV breaker was closed and the 500 kV grounding switch remained in the closed position. This action created a three-phase fault on the Hassayampa to Arlington Valley 500 kV line. The 500 kV breaker tripped in three cycles (50 milliseconds), clearing the fault from the system.[37]

[37] Bo Gong and Andreas Schmitt. "LMWG Presentation Hassayampa Event." July 2020 and November 2020.

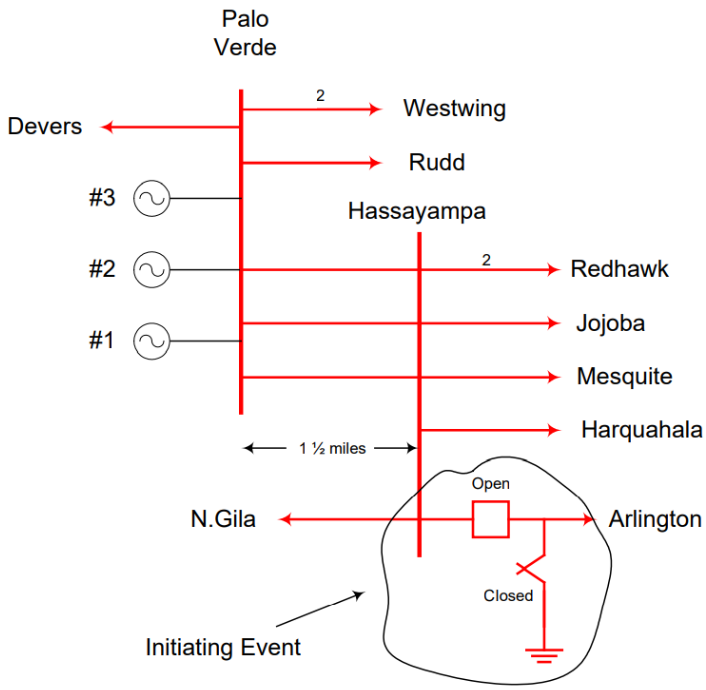

Figure B.3: Hassayampa Fault Diagram

Table B.1 shows the generation loss, and Figure B.4 illustrates the FIDVR effect on voltage.

Table B.1: 2003 Hassayampa Event Generation Loss[38]

Units Tripped	Generation Loss (MW)	Cause
Palo Verde Unit #3	1,252	SSO Relay
Redhawk CT#1 & CT#3	760	Over Frequency (incorrectly)
West Phoenix CT #5	490	Over Excitation Relay(incorrectly)
Harquahala CT #2	185	Loss of Auxiliary Power (incorrectly
Total Generation Loss	**2,687**	
APS	1,799	
SRP	219	
EPE	198	
SCE	198	
PNM	128	
SCPA	74	
LDWP	71	

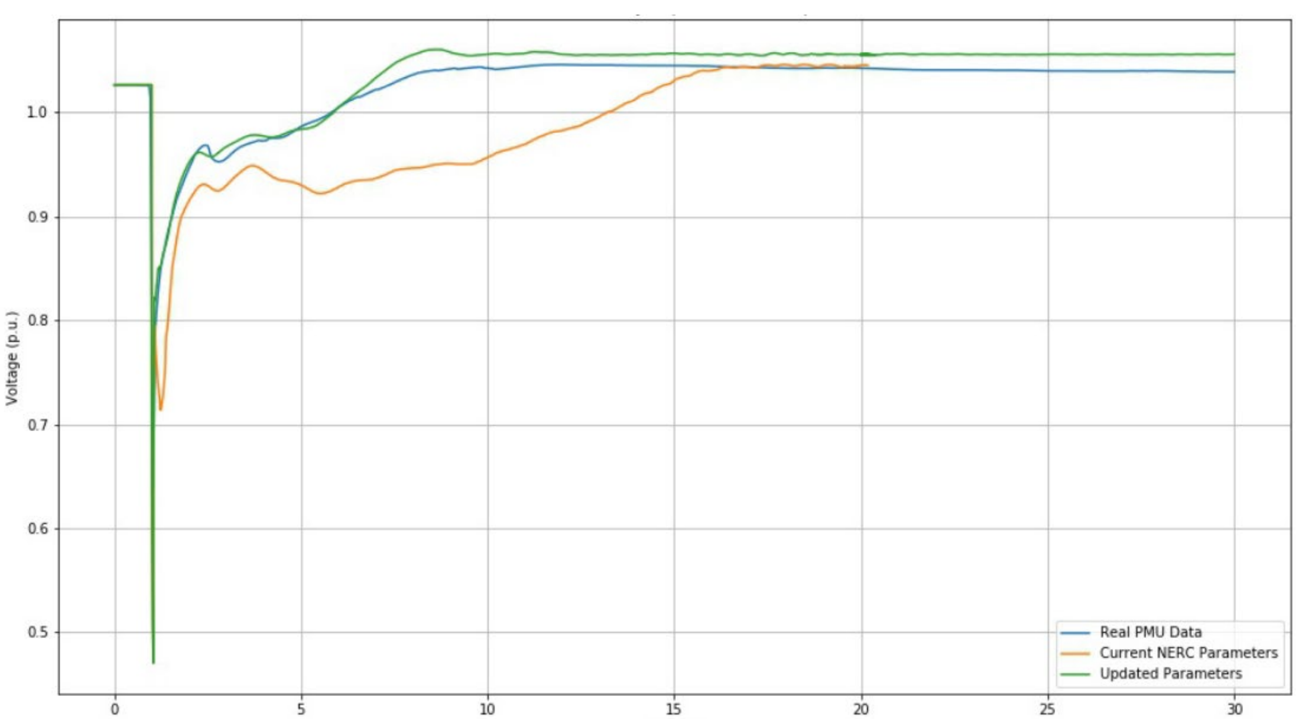

Figure B.4: 2003 Hassayampa Event Voltage Recovery[39]

[38] Ibid.

[39] Ibid.

July 28, 2003, Hassayampa and Pinnacle Peak Event

The Hassayampa Event is a three phase fault on the 500 kV system cleared in three cycles. The following are details that occurred with the event.

- FIDVR occurred, leading to 440 MW of load disconnection and 90,000 customers losing power
- 2,687 MW of generation tripped due to a protective relaying issue and not connected to FIDVR
- 1,000 MW of load disconnection due to FIDVR

September 8, 2011, Arizona Southern California Event

On the afternoon of September 8, 2011, an outage of the Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV line (H-NG) initiated an 11-minute system disturbance in the Pacific Southwest, leading to cascading outages that left approximately 2.7 million customers without power. These outages affected parts of Arizona, Southern California, and Baja California, Mexico. The entire San Diego area lost power with nearly one-and-a-half million customers losing power, some for up to 12 hours. Millions went without air conditioning on a hot day.

The loss of the 500 kV transmission line initiated the event, but it was not the sole cause of the widespread outages. The system is designed and should be operated to withstand the loss of a single line. The affected line—the APS H-NG)—is a segment of the Southwest Power Link (SWPL), a major transmission corridor that transports power in an east-west direction from generators in Arizona through the service territory of the Imperial Irrigation District and into the San Diego area. This transmission line had tripped on multiple occasions without causing cascading outages. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the system, increasing flows through lower voltage systems to the north of the SWPL, as power continued to flow into San Diego on a hot day during hours of peak demand. These increased flows on the lower voltage circuits caused extensive depressed voltages and delayed clearing.[40]

September 8, 2011, Arizona Southern California Event

- San Diego Gas & Electric lost 4,293 MW of firm load, affecting approximately 1.4 million customers.
- The Comisión Federal de Electricidad, in Mexico, lost 2,150 MW of net firm load, affecting approximately 1.1 million customers.
- Imperial Irrigation District lost 929 MW of firm load, affecting approximately 146,000 customers.
- Arizona Public Service (APS) lost 389 MW of firm load, affecting approximately 70,000 customers.
- The Western Area Power Administration, Lower Colorado Region lost 74 MW of firm load, 64 MW of which affected APS's customers. The remaining 10 MW affected 5 Western Area Power Administration customers.

Southern California Edison Summary of FIDVR Events

Southern California Edison has had a number of FIDVR events over the past few decades; they are summarized below:

- 1988 and 1989: First delayed voltage events observed at SCE (Devers and Antelope)
- 1990: Valley (June)—impacted a 1,000 square mile service area
- 1997: Lugo plane crash—lost 3,500 MW (August 5)

[40] FERC and NERC. 2012. Arizona-Southern California Outages Staff Report on September 8, 2011: Causes and Recommendations. April. https://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf.

- 2004: Four events at Valley/Devers
- 2005: Three events at Valley/Devers
- 2006: Thirty-seven events at Valley, Devers, Antelope, Rector, and Villa Park
- 2007: Six events at Rector, Antelope, and Valley

Appendix C: WECC Loss of Load and DR Tripping Considerations for TVR Criteria

WECC's TVR criteria account for the fact that subsequent voltage dips due to power swings can cause load loss and DR tripping on neighboring systems.[41] This appendix reproduces WECC's discussion of the considerations that may be relied on to establish TVR voltage thresholds that address these considerations.

The IEEE Standard 1668 (*IEEE Trial Use Recommended Practice for Voltage Sag and Short Interruption Ride-Through Testing for End-Use Electrical Equipment Rated Less than 1,000 V*)[42] defines a recommended practice for voltage-sag ride-through performance testing for electrical and electronic equipment connected to low-voltage power systems. This includes minimum voltage-sag immunity requirements based on actual voltage-sag data. The ride-through voltage and times specified in the IEEE standard give a reasonable expectation for voltage ride-through of loads connected to distribution systems. The IEEE standard classifies voltage-sag into three types: Type I and Type II cover single-phase and two-phase faults as well as Type III covers three-phase faults. For Type I and Type II tests, recommended parameters are as follows:

- 50% for 12 cycles
- 70% for 0.5 seconds
- 80% for 2 seconds

For Type III tests, recommended parameters are as follows:

- 50% for 3 cycles
- 70% for 6 cycles
- 80% for 2 seconds

Since the majority of faults that occur on the BES are single-phase faults, it is reasonable to assume that a voltage dip defined by the Type I and II parameters above is appropriate.

These parameters also seem unlikely to cause excessive tripping of DR. The IEEE Standard 1547 (IEEE Standard for Interconnecting Distributed Resources with Electrical Power Systems) provides technical specifications and requirements for interconnection of distributed resources within an area electric power system. In the IEEE standard there is a section that specifies the response of DR to abnormal conditions. Response to abnormal voltages specifies maximum clearing times for DR to cease energizing the area for reasons of safety and protection of equipment. The responses to abnormal low voltages listed in the IEEE standard are as follows:

- V < 50%, clearing time 0.16 seconds
- 50% < V < 88%, clearing time 2.00 seconds.

The 80% for 2.00 seconds parameter at BES busses serving load falls within the upper end of the voltage range for DR clearing time of 2.00 seconds.

[41] WECC. 2015. WECC-0100 TPL-001-WECC-CRT-3 (CRT) Transmission System Planning Performance Proposed Transient Voltage Response Rationale for CRT Requirements R1.3 and R1.4. July 23: https://www.wecc.org/Reliability/WECC-0100%20Posting%203%20TPL-001-WECC-3%20White%20Paper%20on%20Requirement%20R1%203%20and%20R1%204%20-%20Not%20for%20Comment.doc

[42] IEEE Standard 1668™-2014, IEEE Trial-Use Recommended Practice for Voltage Sag and Short Interruption Ride-Through Testing for End-Use Electrical Equipment Rated Less than 1000 V. [4] IEEE Standard 1557™-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

Appendix D: Distribution Reliability Risks

This appendix describes the general configuration of electricity distribution systems, strategies for maintaining their reliability, and factors that can threaten their reliable operation. A distribution system is formed by distribution feeders originating at distribution substations that are operated radially or in a network configuration. Distribution feeders typically range in operating voltage from 4 kV to 35 kV in either a single-phase or three-phase configurations. Distribution feeders provide power to service transformers as well as in either a single-phase or three-phase configurations, which step down the voltage to anywhere from 120 volts to 480 volts.

To serve customers in a radial system, distribution operators can frequently reconfigure the system by connecting or disconnecting feeders to each other. For this reason, the layout and topology of the distribution system can be changed more frequently as compared to the transmission system. The feeders are typically geographically distributed to serve each individual customer. It is common to have clustered distribution lines in high density commercial and residential areas but with longer distance radial lines to connect between them. Often, the distribution feeders are built along the roads or canals as well as buried underground. Depending on the geographic characteristic of a certain area, it can show a more visually complicated connection topology, such as curves and zigzags. **Figure C.1** shows a distribution system that is comprised of feeders (colored red, blue, green, and magenta). The underground section is shown as a dashed line, and the overhead lines are solid lines.

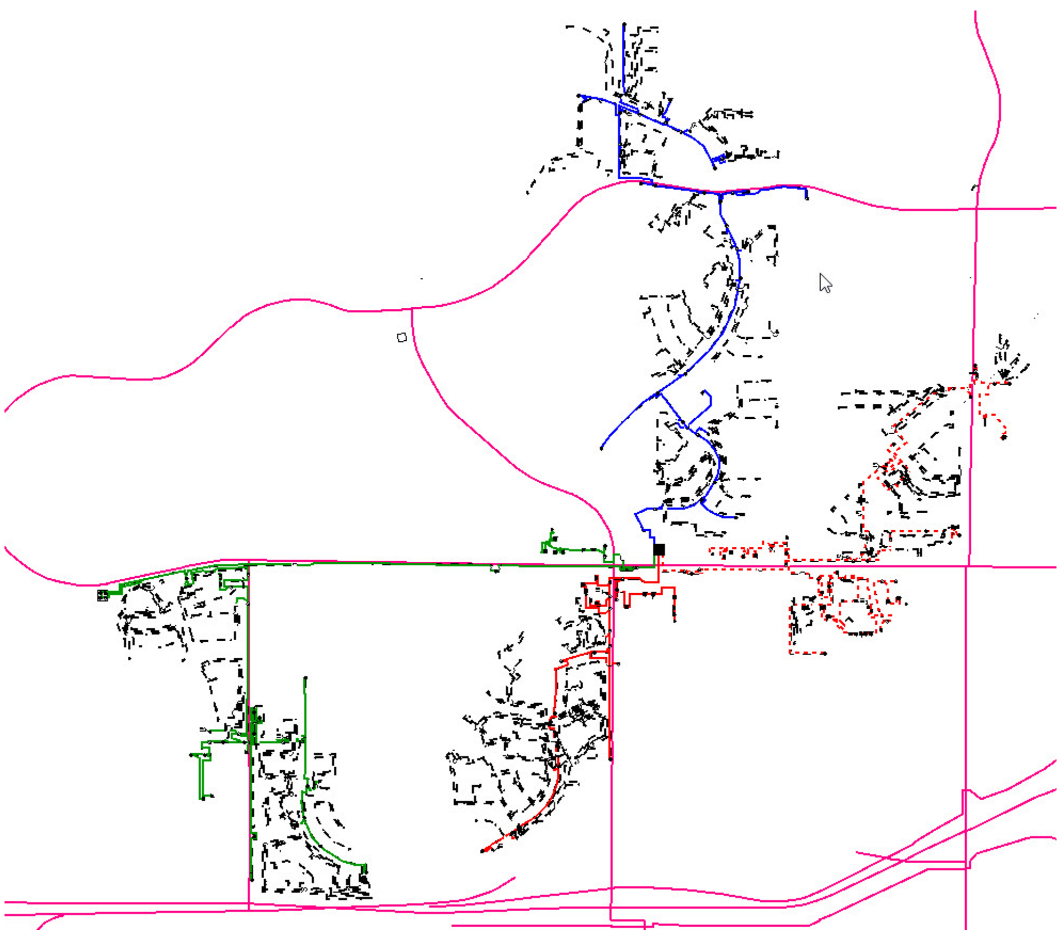

Figure C.1: Distribution Feeder

In contrast to the transmission system, where voltage is an important reliability issue, maintaining satisfactory distribution system voltage is more often a power quality concern for distribution planning and operation. Sustained low or high voltage and voltage flickers are among the primary concerns. In general, distribution voltage is highly dependent on the voltage of the transmission substation to which it is connected. For this reason, distribution planning and operation take a "passive" role in planning and maintaining its service voltage. "Passiveness" can be interpreted from the following two aspects:

- Distribution voltage planning focused on steady state voltage
- Distribution voltage planning assumes a constant transmission voltage

Two commonly used devices that help to regulate distribution voltages are load tap changers (LTC) and switching shunt capacitors. In general, LTCs are used to regulate distribution voltage, and switching shunt capacitors are used to correct power factors. Both devices operate with long delay times, ranging from five seconds to minutes, they often lead to a step change to the voltage magnitude and when triggered.

Figure D.1 shows a typical demand curve for a distribution feeder measured at the feeder head (12.47 kV side of the 12/69 kV transformer). The reactive power, shown by the red curve, was periodically regulated by switching shunt capacitors so the total demand was near unity power factor. Each switching action can cause a step change to the feeder reactive power demand. LTC taps were constantly adjusted, as shown by the green curve, to compensate for the variation of substation voltage, which followed a pattern similar to that of the real power demand (blue curve).

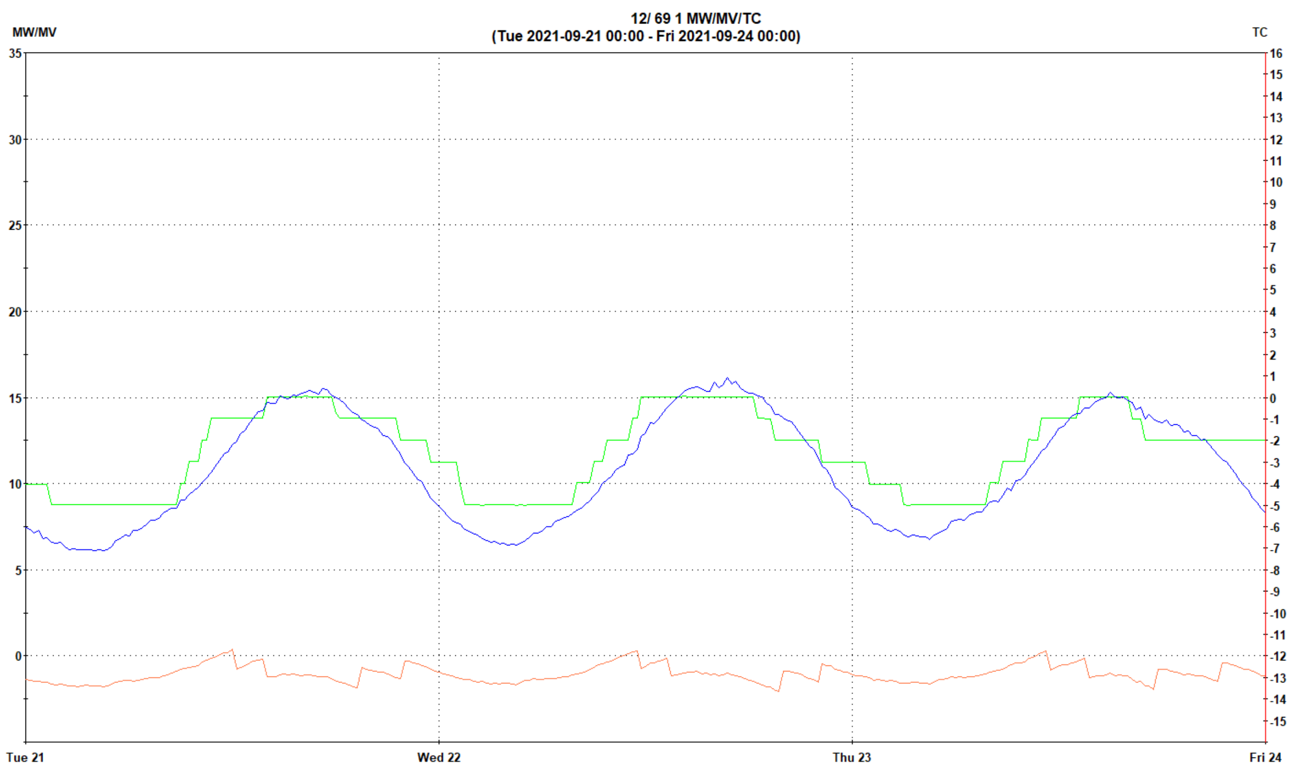

Figure D.1: Distribution Feeder MW, MVAR and LTC Tap Position

For distribution operation, both LTCs and switching shunt capacitors are operated in a slow switching mode (typically 45 seconds or longer for the initial switching) for consistency with steady state requirements. Operating in this manner helps to reduce wear and tear of the switching equipment and avoids competing with the primary voltage control from the transmission system. These steady state requirements include power factor requirements, voltage magnitude requirement, voltage harmonics requirement, and voltage flicker requirement. Detailed requirements can be varied from utility to utility, or from substation to substation.

For planning studies, it is uncommon for distribution planning to perform dynamic simulation for several reasons:

- Transient stability impacts from the transmission system are not taken into consideration and will not provide any accurate system response without modeling the transmission system.
- Distribution systems mainly serve loads that do not actively control voltage quickly.

Another notable assumption used in distribution voltage planning is that voltage on the transmission side is relatively constant. Under this assumption, distribution feeders are modeled as if they connect to a constant voltage source. Voltage control devices are planned to compensate for any voltage variation of +/- 10% at the transmission level or variation contributed by the peak/light power flow demand along the feeder. Fast voltage control devices commonly used with transmission systems, such as generators and static var compensators, are rarely adopted on the distribution system. Note that with the increasing penetration of DERs, the assumption of constant voltage at the transmission level may no longer hold

Even though the voltage impacts on the distribution system have been primarily viewed as power quality concerns, the reliability risk in the transient time frame should not be neglected. Distribution voltage problems can lead to numerous reliability and safety concerns, including service interruption, equipment failure fatigue or damage, unexpected protection action, fault induced delayed voltage recovery, large load increases due to DER tripping, and even voltage collapse. It can adversely impact transmission system reliability.

Industrial and commercial loads are mostly made up of three-phase induction motors. IEEE Standard C37-96-2000[43] states that a typical undervoltage trip setting time for three-phase induction motors is about two to three seconds. A typical sustained voltage level below which three-phase induction motors stall is about 0.7 pu. Residential loads like computers and televisions are more sensitive to voltage fluctuations and cannot withstand low voltages beyond a few cycles. **Figure D.2** and **Figure D.3** below show the ITIC and SEMI F47 voltage sag tolerance curve. The SEMI F47 standard shown in **Figure D.3** is the voltage sag immunity standard applicable to semiconductor processing equipment. Note that the voltage sag mentioned in **Figure D.2** applies only to single-phase-to-neutral or single-phase-to-phase disturbances.

[43] IEEE. Standard C37-96-2000, IEEE Guide for AC Motor Protection.

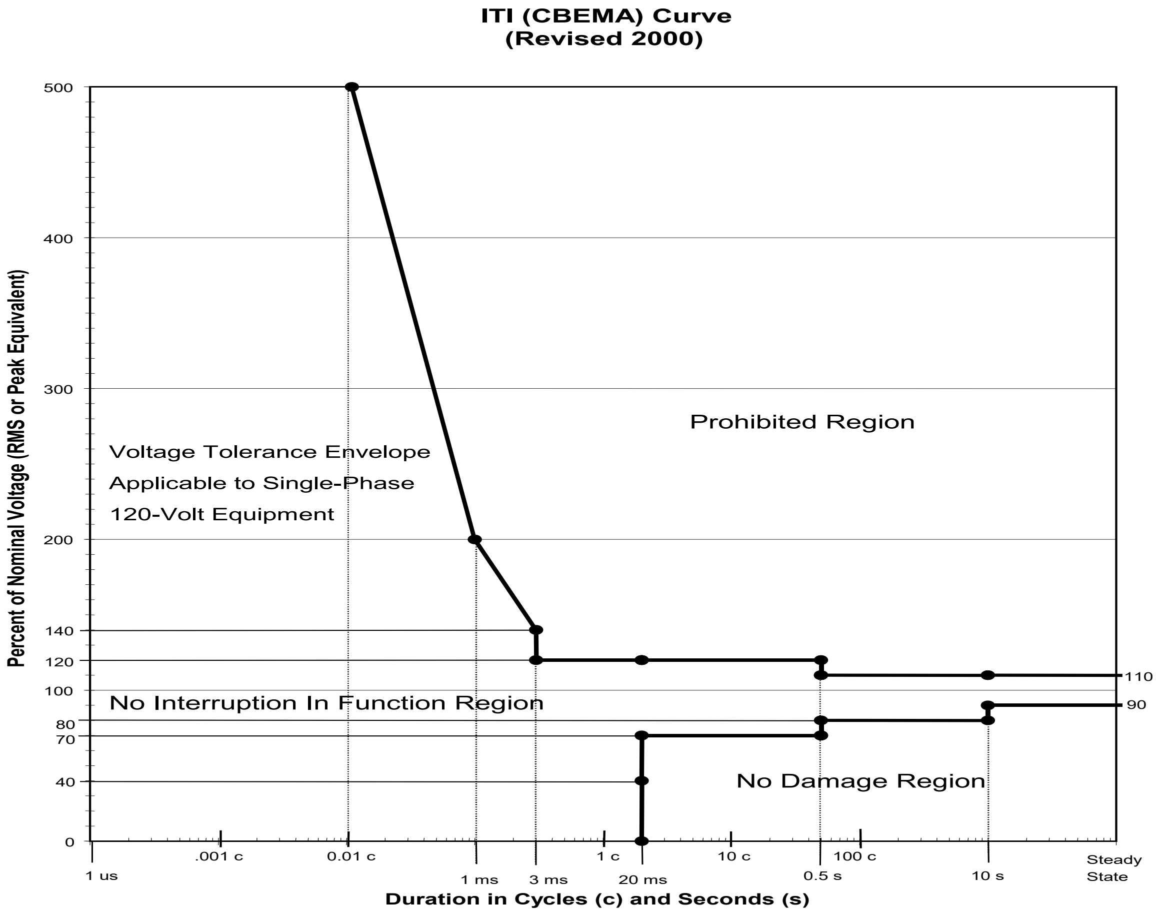

Figure D.2: ITIC Curve

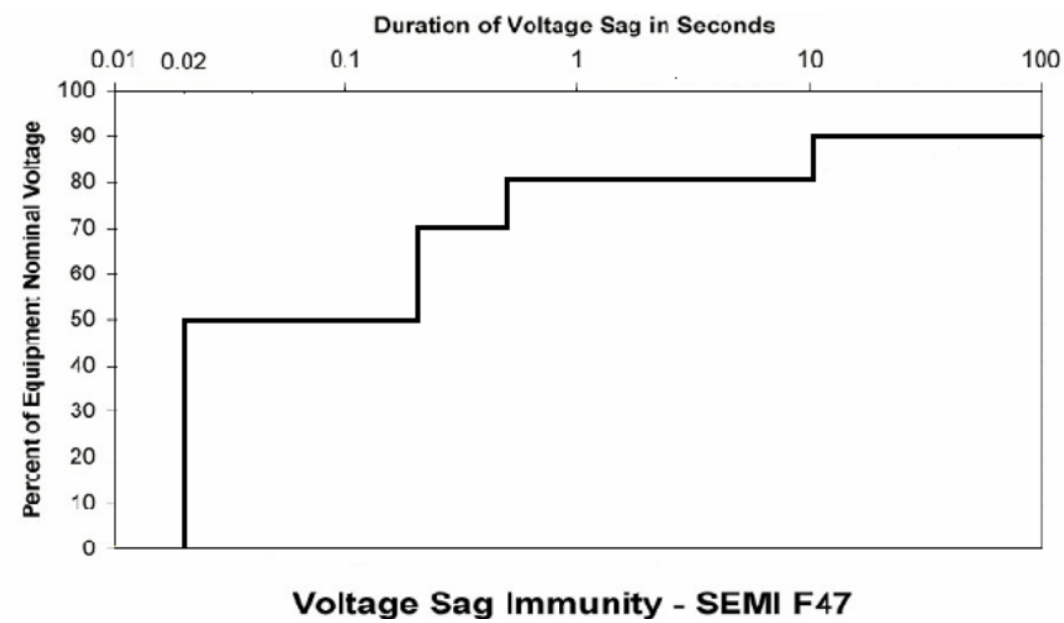

Figure D.3: SEMI F47 Curve for Voltage Sags

Appendix E: Examples of Transient Voltage Response Criteria

Some Examples of Transient Voltage Response Criteria

- For all P1 through P7 events, voltage shall recover to 80% of the pre-contingency voltage within 20 seconds. For voltage dip, when voltage recover above 80%, voltage at bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds.
- The voltage can be below 0.8 pu for 10 s at load buses.
- The voltage following fault clearing shall not dip below 0.7 p.u. for more than 2.5 seconds.
- For transmission buses, following the successful clearing of a fault (normal clearing = 6 cycles):
  - The voltage magnitudes should be no less than 70% of their nominal values.
  - Within 20 cycles following the clearing of a fault, the voltage magnitudes should be no less than 80% of their nominal values.
  - Within 0.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than 90% of their nominal values.
  - Within 1.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than the steady-state voltage minimum, typically 92–95% of nominal.
- Voltage must remain above 70% and must not remain below 80% of nominal voltage for more than 250 milliseconds within 10 seconds following a fault.
- Post-contingency voltage responses must be within 0.7 pu < Vtransient < 1.2 pu and recover to the steady state limits within 20 seconds.
- For buses 100 kV and above, the transient voltage response criterion is a recovery to 0.9 pu by five seconds after the fault has cleared.
- The transient voltage response criteria is a recovery to 0.9 pu by one second after the fault has cleared.
- Voltage recovery at transmission buses above 0.8 p.u in 2 s after fault clearing.
- Bus voltages on the BES shall recover above 0.70 per unit in 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared unless affected transmission system elements are designed to handle the rise above 1.2 per unit.
- For P1, voltage shall recover to 0.90 p.u within five seconds after clearing the fault. For P2 through P7, the voltage shall recover to 0.90 p.u within ten seconds after clearing the fault.
- Some entities have transient voltage criteria for generator buses only.
- Some entities have transient voltage criteria for generators and load bus.