NERC

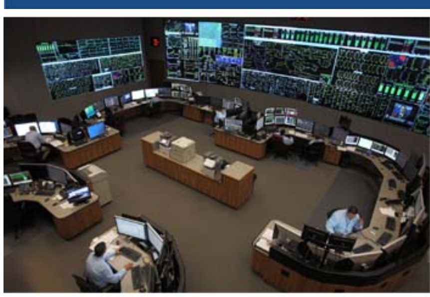
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Distributed Energy Resources

Connection, Modeling and Reliability Considerations

November 2016

RELIABILITY | ACCOUNTABILITY

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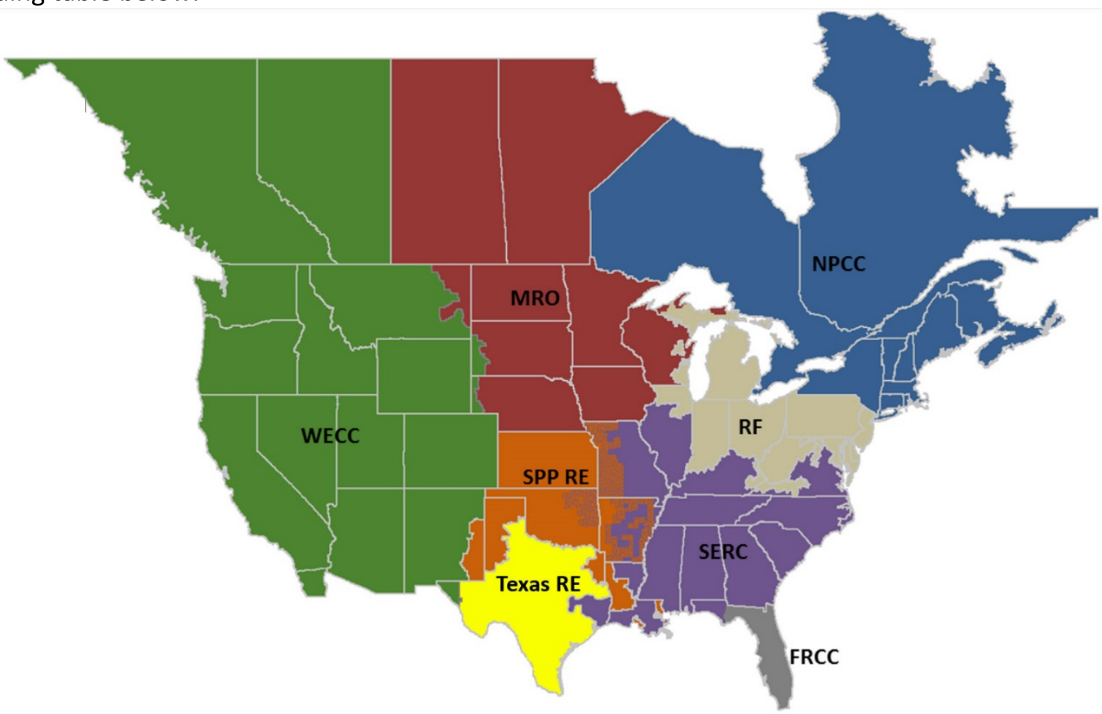
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

*(**DELETE RED TEXT PRIOR TO PUBLISHING**) The Executive Summary should be the last part of the report written. The tone is that of a high-level narrator; the Exec Sum should not be as detailed as the body of the report. **DO NOT COPY AND PASTE** anything from the report into the Exec Sum, including graphs, charts, figures, or tables. Write new content that briefs the executive on the main point of the report. Allow the rest of the report to go into the details. Those visuals should be used in the body of the report—and only once—to support data findings.*

The Executive Summary should include:

1. *The purpose statement*
2. *Summary of conclusions and findings*
3. *Summary of recommendations*

Introduction

*(**DELETE RED TEXT PRIOR TO PUBLISHING**) Think of the Introduction and the Conclusion as the bookends that hold the report together. The purpose of the Introduction is to brief the reader on what the report will cover. It is not a summary of the report, and it should not include conclusions or recommendations.*

The Introduction should include:

4. *The purpose statement*
5. *The objectives*
6. *Background information on subject matter (Note: Background is not its own chapter; it is part of the Introduction and can be a subheading listed here)*
7. *Limitations in research performance*
8. *Significance of research*

Background

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There is an important section break that starts on the next page. The front matter, which includes the Preface, Executive Summary, and Introduction, ends after this page (as do the roman numerals for page numbers). If you want to include more pages in the front matter, make sure that you add them before this break. To view the break, click the Paragraph symbol from the Home tab on the Word ribbon. If you are finished adding pages to the front matter, begin the body of the report with text beneath the Chapter 1 heading.

Chapter 1 - What are Distributed Energy Resources?

What are Distributed Energy Resources? – *Brian Evans-Mongeon, Layne Brown, Sylvester Toe, Tony Jankowski, Gary Keenan*

a. Definitions
    i. Functional Model - NERC
b. Behind the Meter Generation (BTMG)
    i. Size/scale
    ii. Net metering arrangements
    iii. Customer owned
c. Distributed Generation (DG)
    i. Directly connected to utility distribution facilities
    ii. Interconnected generator resource
d. Demand Response
e. Typical resources? Solar, small hydro, wind, what?

Distributed Energy Resource (DER): Any non-BES real or reactive resource (generating unit, multiple generating units at a single location, distributive generator etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including:

- Distribution Generation (DG): Any non-BES generating unit or multiple generating units at a single location owned and or operated by the distribution utility.
- Distribution Independent Power resource (DIP): Any non-BES IPP generating unit or multiple generating units at a single location owned and or operated by a merchant entity.
- Behind The Meter Generation (BTMG): A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail Load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind‐the‐meter. This definition includes any generation identified under E2 of the NERC BES Definition.
- Demand-Side Management (DSM) (see NERC definition: All activities or programs undertaken by any applicable entity to achieve a reduction in Demand)
- Cogeneration (see NERC definition: Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process)
- Emergency, Stand-by, or Back up generation (BUG): A generating unit, regardless of size, that serves in times of emergency at locations providing basis or elemental needs of the customer or distribution system. This definition only applies to resources on the utility side of the customer retail meter.
- Load Management Resource (LMR): Any load reduction effort (non-generation) that reduces Demand up to the Demand of feeder or individual End-user.

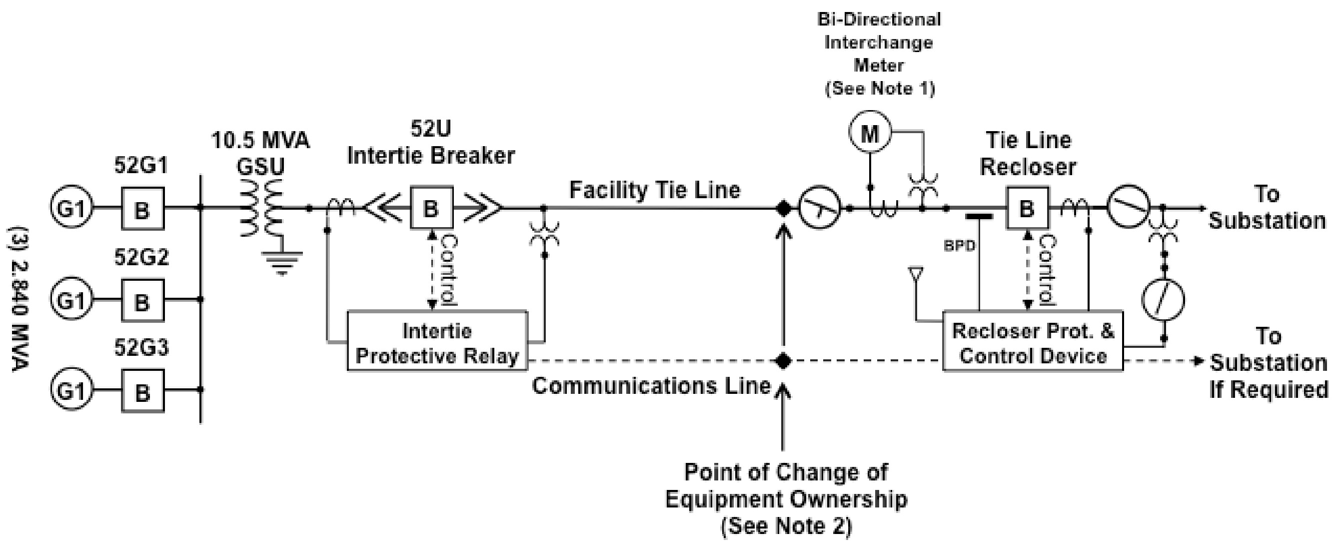
Chapter 2 - How are Distributed Energy Resources Connected?

How are Distributed Energy Resources connected? – *Sylvester Toe*

a. Low voltage BTMG – NEC code and utility requirements
b. Distributed Generation – NESC and utility requirements
c. Metering – what data goes back to BA or utility? Real-time, hourly, monthly read?

Typical DER Interconnections Distribution Feeders

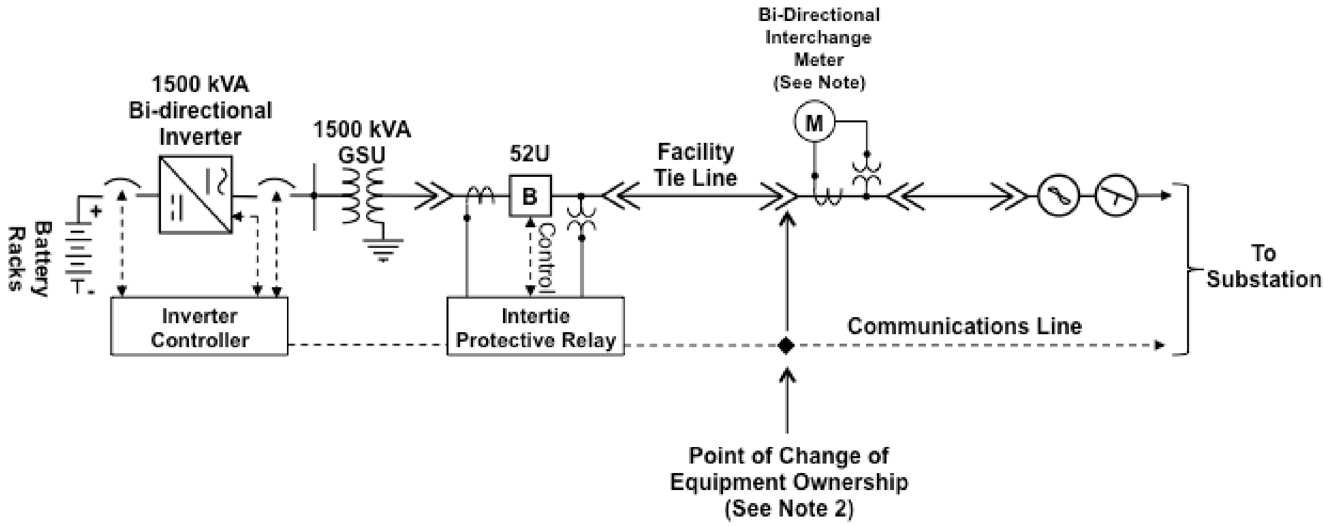
Landfill Gas QF Interconnection



Note:

1. The bi-directional interchange meter has two registers. One register captures energy flow from utility to the Facility (i.e. delivered). The other register measures energy flow from the Facility to the utility (i.e. received). If the power purchase agreement for the Facility stipulates the Facility will be compensated at an hourly avoided energy rate for the received energy, then an advanced meter with capability of capturing 30-minute interval kW, kVAr, kWh data is installed. The 30-minute interval readings recorded by the meter for the previous day are captured by the utility Meter Data Management System (MDMS) daily. The MDMS validates the data and transmits the validated data to the Billing Group and other users of the data including the Balancing Authority at the Power Coordination Center. For Facilities whose PPA only requires that they be compensated for their received energy at a fixed rate, a simple kWh meter is installed. kWh readings recorded by the meter are transmitted over the AMI network to the Billing Group only.
2. The Customer is responsible for designing and installing equipment of the Customer side of the point of change of equipment ownership in accordance with the National Electrical Code, the National Electrical Safety Code, other national codes, and any local code pertaining to electrical facility design, construction, or safety. The Utility will energize the tie line after the Customer has provided proof (typically in the form of an electrical inspection certificate) that its interconnection facilities have been inspected either by the Authority Having Jurisdiction or by a licensed electrician or registered professional engineer, if there is no inspecting authority, and after the Utility verifies adherence of the Facility installation to the Interconnection Agreement and verifies proper configuration of the Facility interconnection protection and control devices and schemes.

Large Battery Energy Storage Interconnection



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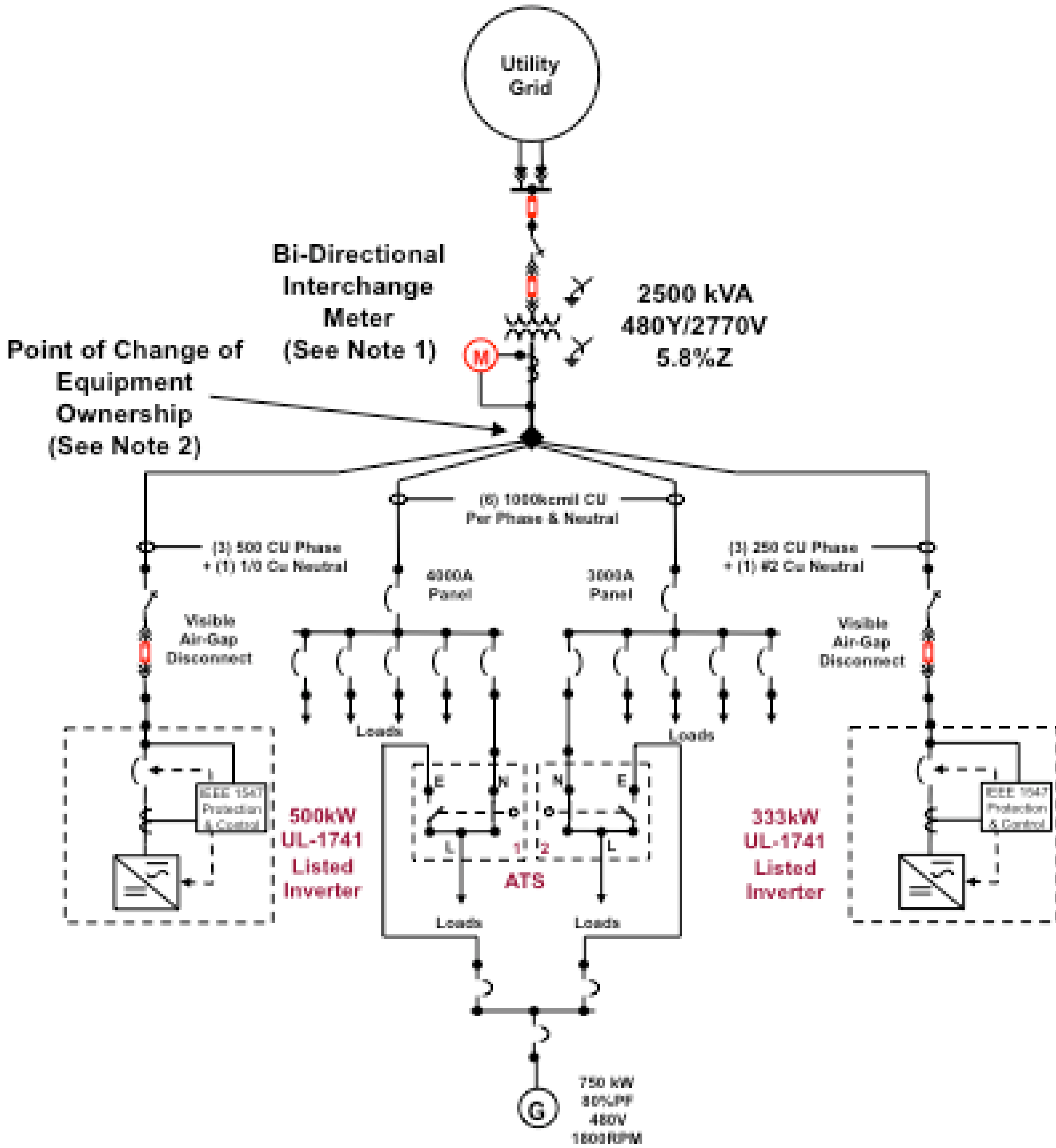
Commercial Behind-the-Meter Solar PV Interconnection



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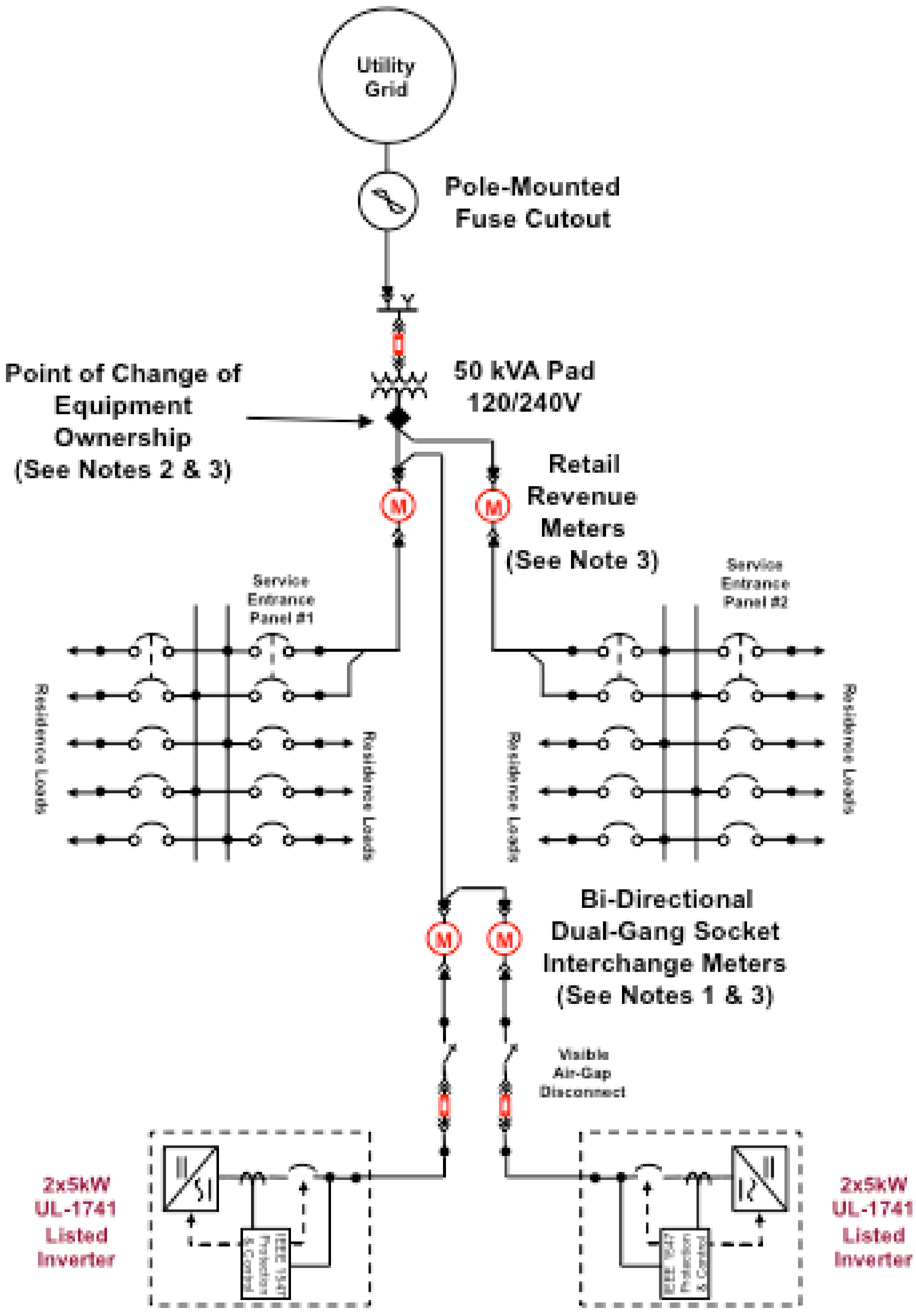
Residential Solar PV QF Interconnection



Note:

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received). If the power purchase agreement for the Facility stipulates the Facility will be compensated at an hourly avoided energy rate for the received energy, then an advanced meter with capability of capturing 30-minute interval kW, kVAr, kWh data is installed. The 30-minute interval readings recorded by the meter for the previous day are captured by the utility Meter Data Management System (MDMS) daily. The MDMS validates the data and transmits the validated data to the Billing Group and other users of the data including the Balancing Authority at the Power Coordination Center. For Facilities whose PPA only requires that they be compensated for their received energy at a fixed rate, a simple kWh meter is installed. kWh readings recorded by the meter are transmitted over the AMI network to the Billing Group only.

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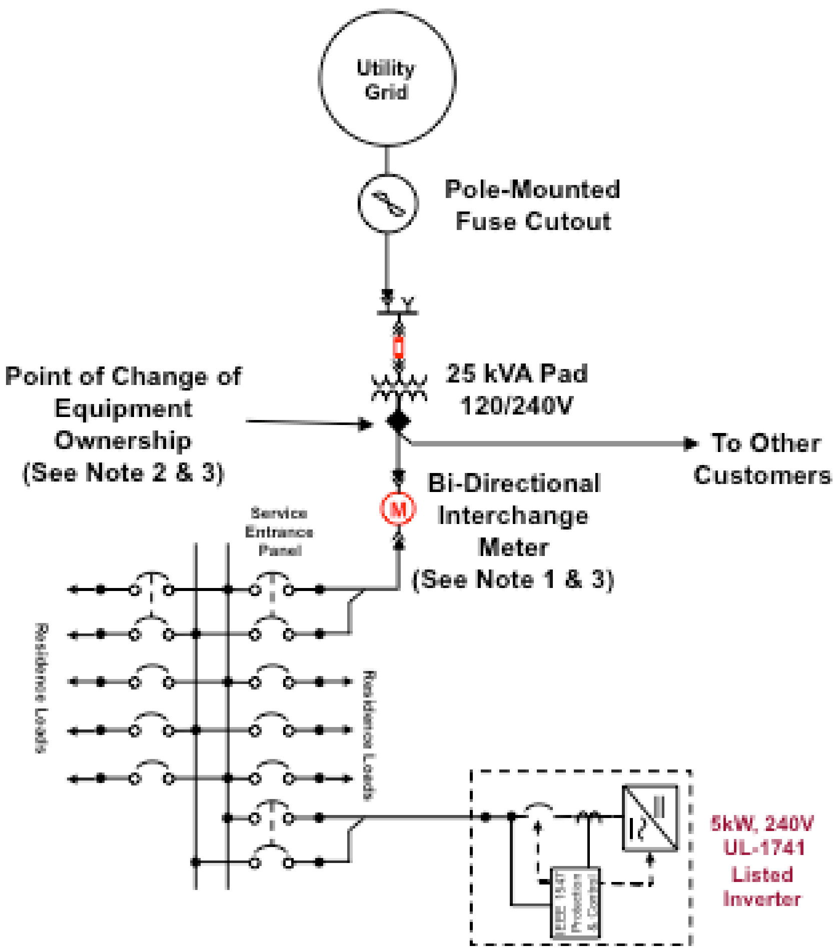
3. The Customer owns the meter socket and the conductors between the meter socket(s) and the service transformers. The Utility owns the meter.

Residential BTM Solar PV QF Interconnection



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3. The Customer owns the meter socket and the conductors between the meter socket(s) and the service transformers. The Utility owns the meter.

IEEE P1547 Pending Changes

Additional information copied & pasted from IEEE P1547/Draft 3 with changes approved by the P1547 Working Group members at a meeting on March 8-9, 2016, in Juno Beach, FL [1]:

4.2.3.1 Applicable Voltages

The voltages applicable to the requirements of this clause shall be the voltages at the Point of Common Coupling (PCC) for all Local EPS

a) having an aggregate DER rating of 500 kW or greater, and

b) having an average load demand of equal or less than 10% of the DER rating.

In all other situations, the applicable point for meeting performance requirements shall be the Point of DER connection.

For DER with a PCC located at the medium-voltage level, the Applicable Voltages shall be determined by the nature of the Area EPS at the PCC. For DER with a PCC located at the low-voltage level, the Applicable Voltages shall be determined by the nature of the low-voltage winding configuration of the Area EPS transformer(s) between the medium-voltage system and the low-voltage system. The

Applicable Voltages which shall be detected are shown in Tables 1.1 and 1.2. For multi-phase systems, all phases shall be included.

Table 1.1 – Applicable Voltages when PCC is located at medium voltage.

Area EPS at PCC	*Applicable Voltages*
Three-Phase, Four-Wire	*Phase to phase and phase to neutral*
Three-Phase, Three-Wire, Grounded	*Phase to phase and phase to ground*
Three-Phase, Three-Wire, Ungrounded	*Phase to phase*
Single-Phase, Two-Wire	*Phase to 2nd wire (the 2nd wire may be either a neutral or a 2nd phase)*

Table 1.2 – Applicable Voltages when PCC is located at low voltage.

Low-Voltage Winding Configuration of Area EPS Transformer(s) [1]	*Applicable Voltages*
Grounded Wye, Tee or Zig-Zag	*Phase to phase and phase to neutral*
Ungrounded Wye, Tee or Zig-Zag	*Phase to phase or phase to neutral*
Delta[2]	*Phase to phase*
Single-Phase 120/240 V (split-phase or Edison connection)	*Line to neutral – for 120 V DER units* *Line to line – for 240 V DER units*
[1] *A three-phase transformer or a bank of single-phase transformers may be used for three-phase systems.* [2] *Including delta with mid tap connection (grounded or ungrounded).*	

[…]

References

[1] *Draft Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems*, IEEE P1547/D3. IEEE Standards Coordinating Committee 21, 2016.

Chapter 3 - How are Distributed Energy Resources Modeled?

How are Distributed Energy Resources modeled? – *Jens Boemer, Gary Keenan, Barry Mather, Quoc Le, Dariush Shirmohammadi*

a. Distribution load is netted at source bus on present models
b. Is it being modeled discretely anywhere?
c. When does it become significant?
d. NERC Load Modeling Task Force
e. EPRI and WECC Guideline (PVD1 model)
f. Recommendations for minimum data requirements of DER

DER modeling

The increasing amount of Distributed Energy Resources (DER) connected to the distribution system requires consideration of these resources in bulk power system planning studies. The scope of this chapter on DER modeling covers (a) steady-state power flow and short-circuit studies and (b) dynamic disturbance ride-through and transient stability studies for bulk system planning. Distribution system aspects, bulk system small-signal stability, and bulk system operational aspects such as flexibility and ramping are out of the scope.

While it may be desirable to model DER in all planning studies and in full detail, the additional effort of doing so may only be justified if DER are expected to have significant impact on the modeling results. An assessment of the expected impact will have to be scenario-based and the time horizon of interest may vary between study types. For long-term planning studies, expected DER deployment levels looking 5-10 years ahead may reasonably be considered. Whether DER is modeled in bulk system studies or not, it is strongly recommended that minimum data collection of DER interconnections be established in order to adequately assess future DER deployments.

Modeling modern bulk systems with a detailed representation of a large number of DERs and distribution feeders can increase the complexity, dimension and handling of the system models beyond practical limits in terms of computational time, operability, and data availability. Therefore, a certain degree of simplification may be needed, either by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. Netting of DERs with loads at substation level is not recommended for high DER penetration scenarios because it can misrepresent the models needed to determine potential aggregate impacts of DER on bulk system power flows and dynamic performance.

A *modular approach* to represent DERs in bulk system studies as illustrated in Figure 1 is recommended to ensure accurate representation of the resources for the specific bulk system study type. The hierarchy of the clustering of DER for model aggregation could consider:

- Differentiation of DERs per resource type in order to derive meaningful dispatch scenarios rather than worst-case dispatches for bulk system planning studies.
- Differentiation of DERs per interconnection requirements performance in order to represent the fundamentally different steady-state and dynamic behavior among the legacy DERs.
- Differentiation of DERs per technology-type, e.g., inverter-coupled versus directly-coupled synchronous generator DER, in order to accurately represent the technology-specific dynamic behavior.

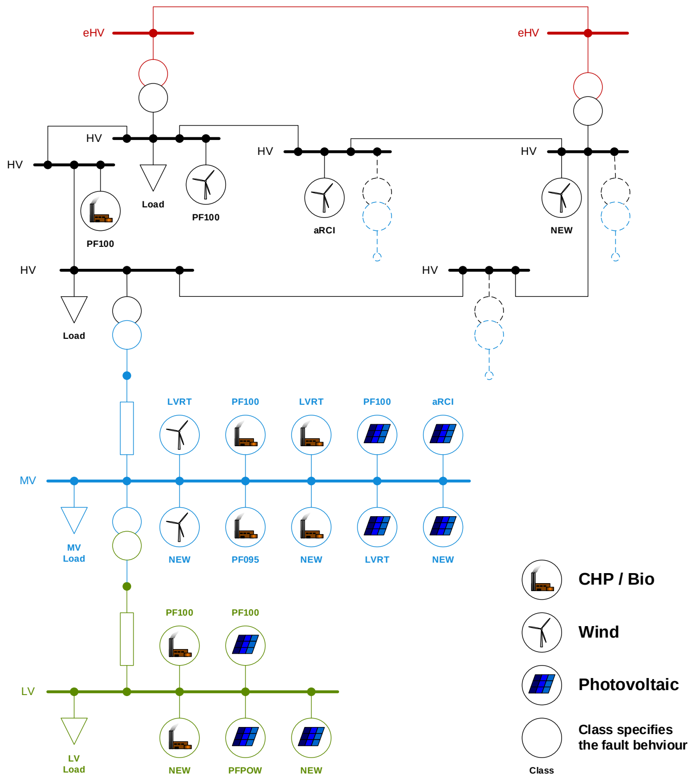

Figure 1: Modular representation of Distributed Energy Resources in bulk system steady-state and dynamic studies. [1; 2]

Defining the appropriate balance between model accuracy and simplicity of steady-state and dynamic equivalent models for DER is a major objective of ongoing research efforts.

Certain guidelines for DER modeling have been published. The following includes a synopsis of the industry guidelines issued by the Western Electricity Coordinating Council (WECC). Aggregated and/or equivalent modeling of DER is discussed for four types of bulk power system planning studies:

1. Steady-state power flow studies
2. Steady-state short-circuit studies
3. Dynamic disturbance ride-through studies
4. Dynamic transient stability studies

Data requirements that result from the modeling approaches and recommendations on sharing of information across the Transmission & Distribution (T&D) interface are summarized at the end of the chapter.

The limited existing knowledge and experience on modeling DERs in bulk system planning studies require future collaborative research, knowledge exchange, and learning.

Steady-state studies

Steady-state studies aim at:

a. power flow calculation to determine bulk system real and reactive power flows for network expansion planning, voltage stability studies and coordination of voltage controls at the Transmission & Distribution (T&D) interface, and

b. short-circuit calculation to determine short-circuit power levels for equipment rating and voltage sag propagation analysis.

Modeling of DERs in these studies would consider the real power injection at distribution system level and the reactive power that may be supported or required by DERs. A power flow case is also needed to initialize the state variables of a dynamic bulk system model for a dynamic stability study.

Steady-state DER models

Appropriate DER models are required and may differ between the steady-state study types. Steady-state power flow calculations may only require a standard generator or simplistic Norton or Thevenin equivalent with voltage control loops appropriate for steady-state analysis under normal conditions of voltage and frequency.

Steady-state short-circuit studies require appropriate DER models that would adequately represent the short-circuit contribution from DERs. Inverter-based DERs are current and power limited sources. A current-limited Norton equivalent with control loops that adequately model the response under abnormal conditions of voltage is required. The short-circuit contribution of DERs depends significantly on the performance specified by interconnection requirements, such as trip and ride-through requirements. Traditional steady-state short-circuit analysis algorithms are not suitable for inverter-based DERs. New algorithms that iteratively calculate the current-limited short-circuit contributions from inverter-based DERs may be needed.

Aggregated Modeling and Netting of DERs with Load

In bulk system planning studies the distribution system load is typically aggregated at the transmission buses and netted with load (load is reduced by DER generation at a specific substation). In those study cases and grid regions where DER levels are expected to significantly impact power flows between the bulk and distribution system that they may conflict with NERC system performance criteria, e.g., NERC TPL-001-4 [3], DER should not be netted with load but modeled in an aggregated and/or equivalent way. Exceptions for permissive netting of DER (not explicitly modeling DER but reducing load by DER generation based on explicitly available DER data) may be acceptable in steady-state studies for those DER that inject real power at unity power factor.

Depending on the study region, the aggregate DER penetration at substation level, regional level, or interconnection-wide level may give indication towards the expected impact of DER on the system performance; the decision to aggregate DERs, however, must always be system-dependent. This assessment should be irrespective of whether it is behind-the-meter DER or before-the-meter (utility-scale) DER.

While netting of DERs with loads at substation level should be discontinued in future, existing guidelines do not require modeling of all DERs in order to limit the complexity of the system model and data requirements. For example, the WECC manual and data [4; 5] only require

a. modeling of any single DER with a capacity of greater than or equal to 10 MVA explicitly, and
b. modeling of multiple DERs at any load bus where their aggregated capacity at the 66/69 kV substation level is greater than or equal to 20 MVA with a single-unit behind a single equivalent (distribution) impedance model as shown in Figure 2 based on WECC's "PV Power Plant Dynamic Modeling Guide" [6].

The threshold above which DERs are not netted with loads is system-specific and may depend on the study type, DER penetration level, and load composition. In the regional case of WECC, a maximum amount of 5 % netted generation of area total generation is recommended [4]. In the future, netting of DERs with loads should be avoided.

Minimum data collection for DER modeling should be established to enable adequate assessment of future DER deployments. Related data requirements are outlined in WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5].

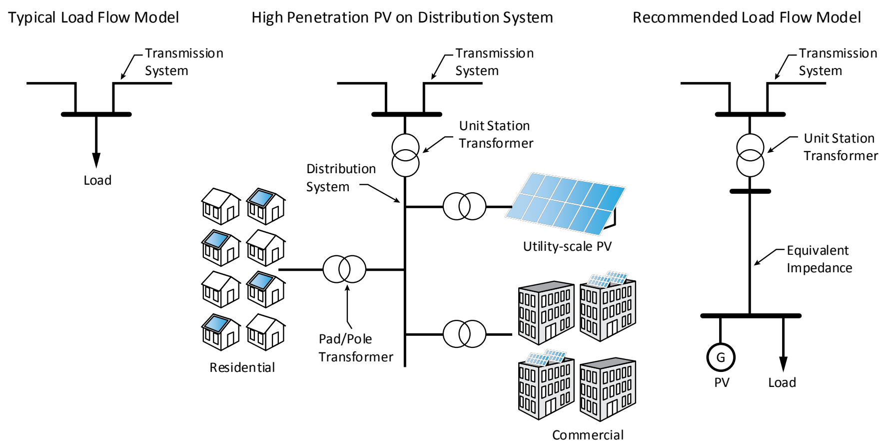

Figure 2
WECC recommended power flow representation for study of high-penetration PV scenarios. Source: EPRI figure based on [6].

More Detailed Representation in Special Cases

As stated earlier, the objective of modeling of DERs for power flow studies is to capture the effect of reactive power support as well as the voltage tolerance characteristics of DERs in steady-state and dynamic simulations, particularly voltage stability. Aggregation of various DERs behind a *single* equivalent distribution impedance may be insufficient for steady-state studies in special cases. The following special conditions may require detailed representation of the distribution system, either through considering the *multiple* equivalent impedances of High Voltage to sub-transmission lines as well as Medium Voltage to primary and Low Voltage to secondary feeders separately [2] or through equivalent voltage control blocks in the equivalent DER generator model:

1. High penetrations of modern DER that inject real power at power factors substantially different from unity.
2. High DER penetration levels (e.g. above approximately 50%) of instantaneous interconnection-wide load, i.e. kW or MW or GW loads).
3. A significant amount of reverse power flows from distribution to bulk system level.
4. Substantial amounts of DER connected at different voltage levels in a region.

Depending on the particular characteristics of the distribution systems and their level of uniformity in the study case, regionally-specific equivalent impedances and equivalent voltage control blocks in the equivalent DER generator model may be used (e.g., for urban, sub-urban and rural feeders) to accurately model the voltage at the equivalent DER model terminals.

In grid regions where DER performance requirements are *changing*, i.e., have been changed or are expected to change substantially in the future, *multiple* equivalent generators may be used for each DER generation in order to appropriately reflect the DER performance. Existing DER units (i.e. legacy DERs) are typically not upgraded to meet the latest performance requirements.

Dynamic studies

Dynamic simulation studies aim at:

a. disturbance ride-through analysis to determine bulk system frequency and voltage stability following normally-cleared or delayed-cleared transmission faults with considering the amount of DER power that may be tripped off-line during the disturbance due to under-voltage, over-voltage, under-frequency, and/or over-frequency protection, and

b. transient stability analysis to determine bulk system transient stability during and following normally-cleared or delayed-cleared transmission faults with considering a fast reactive support from DER that may improve transient stability of directly-connected synchronous generation.

Modeling of DERs in dynamic bulk system studies requires a solid understanding of DER performance mandated in interconnection requirements (see chapter 4) as well as technology-specific DER performance and control systems.

Interconnection Requirements

Interconnection requirements (also known as performance requirements) are differentiated by individual DER's rated capacity in North America and by DER's connection voltage level in Europe. Interconnection requirements are evolving with increasing DERs penetration and as a consequence of this, a number of DER classes with very different dynamic behavior exist in the power system. For power system stability studies, interconnection requirements determine a *performance framework* for the network fault response of individual DERs depending on their commissioning period, connection level or size, and sometimes technology type.

With regard to disturbance ride-through requirements, the 'get-out-of-the-way' principle as it has been mandated in IEEE Std. 1547-2003 [7], FERC's SGIP/SGIA [8; 9], and the former CA Rule 21 [10] for North America and California in particular, have been or are currently being revised for voltage and frequency ride-through [11–13]. Additional dynamic performance requirements for DER, such as 'dynamic voltage support' during and/or following network faults, may evolve in the future similar to the requirements for an additional reactive current injection during faults as in [14] for Germany.

Dynamic DER models

With respect to bulk system connected wind and PV generation (i.e. wind and PV power plants of typically 10 MW or larger) the following state-of-the-art generic dynamic models exist:

- Wind: The WECC generic wind turbine generator model (primarily for use with bulk power system connected WTG, and could be used for DER where detailed distribution models are developed) are documented in [15]. The IEC models are documented in IEC Standard 61400-27-1 [16]. It is noteworthy that differences do to exist between the generic wind turbine generator models specified in the IEC standard and the modeling WECC guidelines. The IEC models include a more detailed representation of the dynamic performance of wind turbine generators during the fault period than the WECC models [17–19] and, therefore, seem to be more suitable for transient stability studies.
- Photovoltaic (PV): The first generation of generic models for PV plants, developed by the WECC Renewable Energy Modeling Task Force (REMTF), has been approved under the WECC Modeling and Validation Working Group [6; 20; 21]. These models can potentially be used for modeling DERs, where explicit detailed modeling of DER is warranted. For the purposes of bulk system studies, much of the distribution system and the DERs are represented as aggregated models. WECC has initiated and

developed some aggregated, and simplified, DER models for representing devices such as distributed PV [6]; however, discussions continue within the WECC REMTF to improve these models. Currently, there is no IEC standard on PV modeling.

- Synchronous generator DER: Modeling of large-scale directly-coupled synchronous generator (SG) and their excitation systems in power system stability studies is well established and widely accepted recommendations exist [22; 23]. Modeling of medium to small-scale, low-inertia, distributed combined heat and power (CHP) plants is a less investigated field, although some older publications exist [24–26]. A relevant publication from recent years, [27], models the network fault response of a medium-scale diesel-driven synchronous generator.

Aggregated Modeling and Dynamic Equivalencing

Modeling of Distributed Energy Resources in dynamic bulk system planning studies may require a certain degree of simplification in order to limit the data and computational requirements as well as the general handling of the bulk system model. Model reduction could either be achieved by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. However, equivalent models for DERs should have sufficient fidelity to accurately consider the two main challenges of

a. spreading model parameters of the controllers of the various DERs in a distribution feeder, and
b. variance of the terminal voltages of DERs connected at different locations of a distribution feeder.

With regard to consideration of spreading model parameters, it is recommended that modeling distinguishes at least the DER performance mandated by interconnection requirements. This could either be achieved by using separate classes of DER models with each representing the amount of DERs that went into operation when a certain requirements were in place, or by equivalent modeling of a mixed population of 'legacy' and 'modern' DERs with a 'partial tripping' design parameter as it has been considered in WECC's distributed PV (*PVD1)* model [6]. Consideration should also be given to regional underfrequency load-shedding (UFLS) and undervoltage load shedding (UVLS) programs that may trip distribution feeders at substation level and thereby supersede DER ride-through or trip settings.

Consideration for the variance of the terminal voltages of DERs connected at different locations of a distribution feeder will be important to accurately model the dynamic response of DER in the periphery region (annulus) of a voltage sag as illustrated in **Error! Reference source not found.**3 [28]. This is the area where the modeling accuracy of DERs may have a large impact on the modeling results in very high DER penetration studies, because [28]:

- The annulus of the voltage sag can have a very large geographic extension.
- The number of DER units in this part of the system can become a significant part of the total number of DER units that will obviously trip because they may be located near the fault.
- Depending on the real and reactive power injection of DERs during fault ride-through operation based on the interconnection requirements, DERs can significantly influence the distribution system voltage and therefore the tripping behavior of 'legacy' DERs.

As illustrated in **Error! Reference source not found.**3, the post-fault real power imbalance due to undervoltage tripping of DERs will be larger in the case shown in diagram (a) than in the case shown in diagram (b). Hence, the accurate modelling of the voltage contour that delineates all system nodes in the annulus of a voltage sag at

transmission system level where the retained voltage is smaller than the DER's undervoltage protection threshold is important to accurately determine how much DER generation may trip during a disturbance.

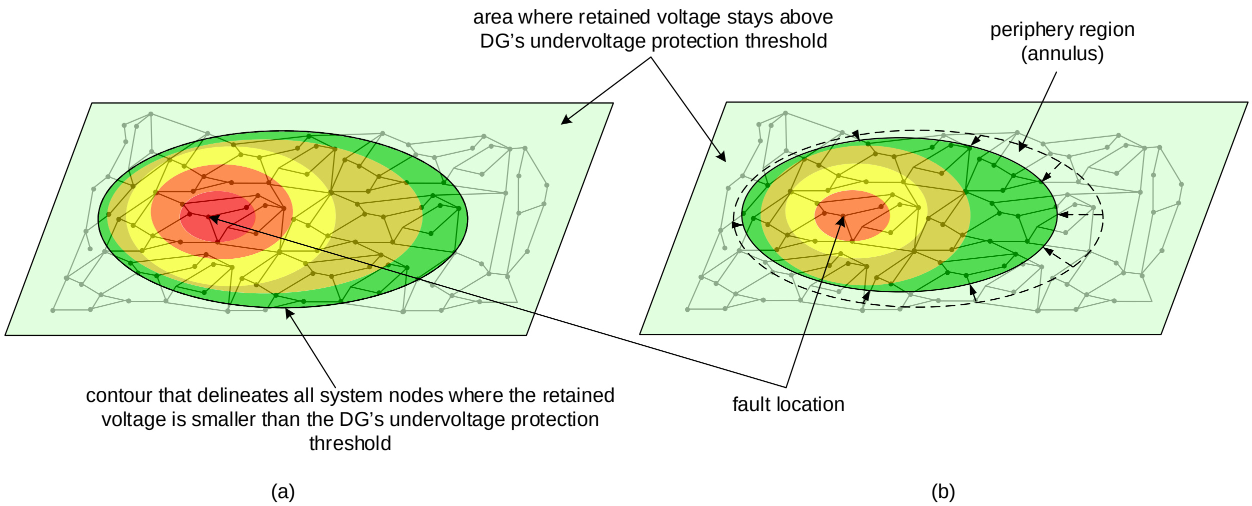

Figure 3: Illustration of the area where modeling accuracy of Distributed Energy Resources is critical. [2]

Additional model complexity that is unlikely to increase system-wide modeling accuracy should be avoided.

Until a few years ago, very little research has been published on dynamic equivalencing of stability models of active distribution systems (ADSs) that comprise significant amounts of DERs [29]. Publication [30] summarizes the state of the art for the application of dynamic equivalencing methods to derive aggregated models of ADSs. Recently, a consensus is evolving that *grey box modeling* is recommended for equivalent modeling of ADSs when sufficient physical knowledge is available. The computational challenges are reduced and these composite models can be easily integrated in dynamic simulation tools.

Notable former publications include NREL's *analytical method* of equivalencing the collector system of large wind power plants for steady-state studies [31], a generic dynamic model of an active distribution system for bulk system stability studies [32; 33], and WECC's dynamic *reduced-order stability model* of DERs in distribution systems considering partial loss of DER in-feed described below [6; 34].

NREL's analytical method for steady-state studies, however, does not seem to be able to accurately consider influence of distribution grid loads, the general voltage diversity present on a distribution grid and the active dynamic behavior of modern DERs with low-voltage ride-through (LVRT) and fast dynamic reactive support (DRS). WECC's simplified distributed PV model (*PVD1* [6; 35]) is currently not widely applied and may require further refinement. That said, WECC's proposed simplified equivalent model for distributed PV systems (*PVD1*) behind a single equivalent distribution feeder impedance (Figure 24) can currently be regarded as the "best-in-class" reduced-order modeling approach for *practical* power system studies. This model is described in WECC's "PV Power Plant Dynamic Modeling Guide" [6] and is similar to the model described in [34] for the first time.

WECC's Simplified Equivalent Model for Distributed PV (PVD1)

WECC's simplified equivalent model for distributed PV systems (*PVD1*) is a highly reduced, almost algebraic model to represent distributed PV systems in bulk system stability studies. It includes active power control, reactive power control, and protective functions [35] and can account for partial tripping of distribution connected PV systems without the need to represent the distribution feeders explicitly; it can also consider the evolving mix of distributed energy resources with and without ride-through capabilities, hence beyond default settings in IEEE Std. 1547-2003 [7]. The model structure of *PVD1* is shown in the Figure 24.

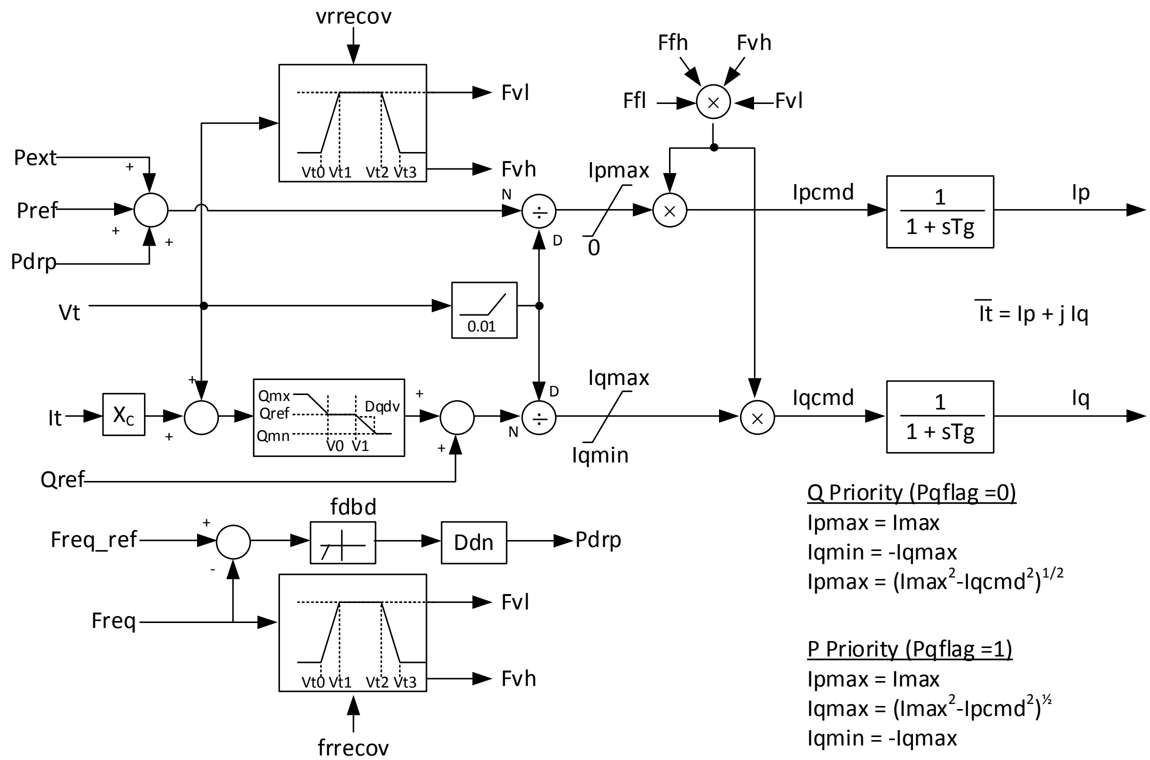

Figure 2
WECC Distributed PV Model Block Diagram. Source: EPRI figure based on [36].

An indicative verification and analysis of the accuracy of the *PVD1* model has been conducted by EPRI in [37], including a comparison of modeling results with a more detailed DER aggregation technique as proposed in [2]. It was shown that the *PVD1* model accurately represents the amount of tripped DER power in the post-fault period as long as 'dynamic voltage support' from new-to-be connected DER is neglected. The *PVD1* model simplifies the DER dynamics that occur *during* the fault period significantly by assuming 'momentary cessation' of DER that ride through faults; this could potentially overestimate the amount of partial DER tripping. Neither does the *PVD1* model represent the delay of the protection functions. Overall, the *PVD1* model tends to produce conservative results because it tends to suggest a greater loss of DER generation than it would likely be seen in the real system being simulated.

With the current limitations of WECC's *PVD1* model to represent dynamics during the fault period, the *PVD1* model may not be suitable for this type of study. The use of detailed generic DER models used for utility-scale DER (larger than 10 MVA) is recommended.

WECC's Composite Load Model with Distributed PV (CMPLDWG)

Besides modeling of DER, proper representation of load, especially in terms of voltage dependency is important [38]. Figure 3 illustrates WECC's Composite Load Model [39] with distributed PV (*CMPLDWG*). The *PVD1* model is currently integrated into this model in a fixed way which limits the flexible use of the model. That said, it is expected that a modular approach will become available in the near future.

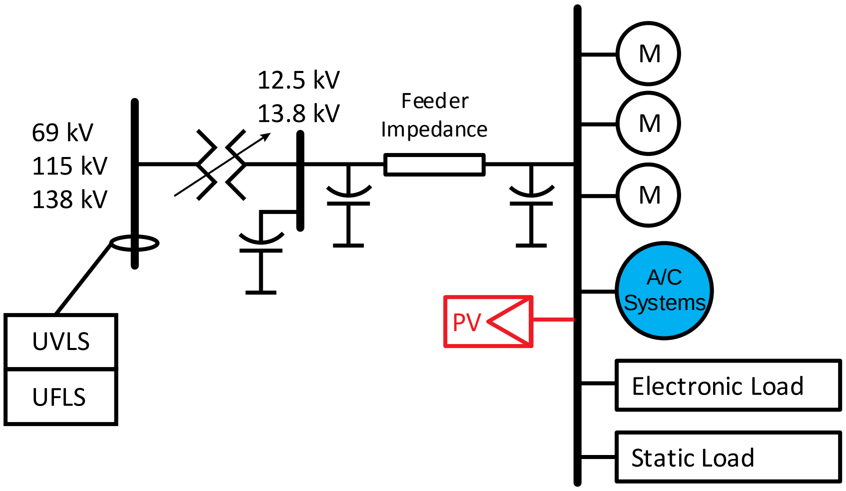

Figure 3
Distributed PV Model Block Diagram. Source: EPRI figure based on [39].

Data requirements and information sharing across the T&D interface

With Distributed Energy Resources being connected at the distribution level but having potential impact at the bulk system level, the following recommendations can be given with regard to data requirements and the sharing of information across the Transmission & Distribution (T&D) interface in order to allow for adequate assessment of future DER deployments:

- DER data in an aggregated way for each substation, including data to represent a mix of DERs that trip and have ride-through ("legacy").
    - DER type.
    - DER rated MVA.
    - DER rated power factor.
    - DER PCC voltage.
    - DER location: behind-the-meter / in-front-of-the-meter.
    - Date that DER went into operation.
- High-level clustering of distribution grids / a set of default equivalent impedances for various distribution grid types that can be used to choose adequate parameters for, e.g., WECC's PVD1 model for distributed PV systems.
- Relevant interconnection performance requirements based on national or regional standards.
- Distributed energy resources stability models and their parameters. In particular the regionally-specific parameters Vt0, Vt1, Vt2, and Vt3 of WECC's distributed PV model (*PVD1*).

The recommended data requirements should be considered by the Regional Committees and specified in Regional Criterion such as WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5] and others.

Additional data requirements may include real-time generation profiles of DERs in order to derive meaningful dispatch scenarios rather than worst-case dispatches for bulk system planning studies. Although such data may be desirable, it is deemed outside NERC's mandate to require the collection of such data from DERs.

Conclusions and Recommendations

The increasing amount of Distributed Energy Resources (DERs) connected to the distribution system requires consideration of these resources in bulk power system planning studies. DERs should not be netted with load in

the future but be explicitly modeled in (a) steady-state power flow and short-circuit studies and (b) dynamic disturbance ride-through studies and transient stability studies for bulk system planning with a level of detail that is appropriate to represent the aggregate impact of DERs on the modeling results over a 5-10 year planning horizon.

Dynamic models for different DERs technologies are available and can presently be used to model the evolving interconnection requirements related performance requirements. WECC's simplified distributed PV model (*PVD1*) [6] currently seems to be the most promising concept to reach a reasonable balance between modeling accuracy, computational requirements, and handling of the system model, but some further improvement may be needed.

Minimum data requirements and the sharing of information across the Transmission & Distribution (T&D) interface will be required in order to allow for adequate assessment of future DER deployments.

Further research is needed to enhance grey box model structures and parameter identification techniques recently proposed and validated in [6] by explicitly considering the active distribution system's composition with regard to the interconnection requirements-related performance framework and either the explicit modeling of the low-voltage (LV) and medium-voltage (MV) equivalent impedances. Alternately, the aggregate DER response due to these impedances could be modeled by the use of equivalent voltage-dependent control blocks in the equivalent DER generator model. The consideration may not need to be extremely system-specific but rather based on generalized system characteristics that may account for regional differences of distribution system topologies and feeder impedances (e.g., for urban, sub-urban and rural feeders).

A *modular approach* to represent DERs in bulk system studies as illustrated in Figure 1 is recommended to ensure accurate representation of the resources for the specific bulk system study type.

Finally, the limited existing knowledge and experience of modeling DERs in bulk system planning studies require future collaborative research, knowledge exchange, and learning. The industry should collaborate with vendors of simulation software in order to continuously enhance equivalent models for DER representation in bulk system planning studies.

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Chapter 4 - DER Operating Characteristics

What are Distributed Energy Resources' operating characteristics? *Jason MacDowell, Rich Hydzik, Dariush Shirmohammadi*

a. IEEE 1547 Requirements
    i. Now
    ii. Future
b. Frequency and voltage ride through (pending NERC PRC-024-2)
c. Active fault source?
d. Can it run independently of utility connection?
e. "Smart" or passive?
f. Governor action
g. FERC Notice of Inquiry on Primary Frequency Response
h. FERC Notice of Proposed Rulemaking – Voltage Support and Control

Chapter 5 - Effects of DER on the Bulk Electric System

What effects to Distributed Energy Resources have on the Bulk Electric System (BES)? – *Tony Jankowski, Gary Keenan, Charlie Smith, Dariush Shirmohammadi*

   a. Planning – What is the net load? What is the peak load to serve?
   b. Operations – MSSC how big is it?
   c. Negative distribution load? Flow up the transformer? Fault source?
   d. Balancing Authority Load
      a. DER nets with load from BA perspective
      b. Steady or variable?
      c. Predictable in BA load forecast?
      d. How does it affect operating reserve requirements?
   e. X

Background: NERC has taken a detailed look at the potential impacts of DER on the BES in the form of distribution connected PV. This work has been reviewed and documented in the Task 1-7 report of the IVGTF, **Performance of Distributed Energy Resources During and After System Disturbance: *Voltage and Frequency Ride-Through Requirements,*** issued in December of 2013. This section is based on the findings of the Task 1-7 report. [Rich, this is a lightly edited summary of that work with original figure references. It can be further edited and summarized depending on level of detail desired.]

A large amount of distribution-connected generation may have significant effect on the reliability of the bulk power system. Existing interconnection requirements for DERs do not specifically take into account potential effects on bulk system reliability. Of particular concern to BPS reliability is the lack of disturbance tolerance, which entails voltage ride through (VRT) and frequency ride through (FRT) capability. Under high penetration scenarios, it is possible for a large amount of DERs to trip on voltage or frequency due to a transmission contingency, which could potentially affect bulk power system stability. These resources are required to comply with IEEE Standard 1547, which at present does not contain any VRT or FRT stipulations. Instead, IEEE Standard 1547 requires DERs to disconnect from the grid within a short period of time after voltage or frequency fall outside a certain range. The results of the IEEE Standard P1547a ballot were announced in September of 2013, and the outcome was that VRT and FRT are now permitted, but not required. The current revision underway is intended to address both of these issues.

The IVGTF made the following general recommendations in its report:

1. *In the short-term, NERC should engage in current efforts to revise DER interconnection standards by providing information, raising awareness and encouraging the adoption of VRT and FRT for DERs. The initial focus should be on identifying the need for adopting minimum tolerance thresholds for VRT and FRT in the IEEE Standard 1547 and, then, establishing those minimums.*

2. *In the longer-term, NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into future DER interconnection standards revision efforts. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. As a result, VRT and FRT concepts receive limited consideration and may have been outweighed by distribution system protection concerns. This liaison process would be too late for the P1547a amendment, but it would be timely for the full revision to begin in December 2013.*

Introduction: Distribution-connected PV generation is expected to grow very fast in some regions over the next decade. A large amount of distribution-connected generation or distributed energy resources (DERs) can have significant effect on the reliability of the bulk power system. However, present interconnection standards applicable to DER do not address or take into account this potential impact. Of particular concern to bulk system reliability in North America is the lack of disturbance tolerance requirements for DERs, specifically voltage ride-through (VRT) and frequency ride-through (FRT).

In North America, VRT and FRT standards for both BPS-connected and distribution-connected generators are in a state of evolution. NERC Reliability Standard PRC-024-1 was recently approved as a relay setting requirement. The standard requires that generator voltage and frequency relays not be set to trip within the specified frequency and voltage performance envelopes, unless it is necessary to do so to protect equipment or meet one of several other exceptions. With respect to disturbance tolerance, DER interconnection standards are inconsistent with the direction in which bulk system standards are evolving.

IEEE Standard 1547 is the *de-facto* interconnection standard applicable to DERs in North America. Interconnection requirements applicable in Canada are harmonized to a large extent with IEEE Standard 1547. IEEE standards are, by definition, voluntary; however, they may be made mandatory by regulatory authorities or by utilities to which interconnection is made. So, in practice, IEEE Standard 1547 is a requirement in most places but not universally in the NERC interconnections. Rather than VRT and FRT provisions, the existing IEEE Standard 1547 contains “must-trip” provisions for off-nominal voltage and frequency that raise the possibility of compounding transmission contingencies with sympathetic loss of significant amounts of distributed generation. These requirements were originally driven by safety and protection/control coordination of distribution systems, and did not consider the possibility of high penetration of DERs in the system. As DER capacity continues to increase, sympathetic DER tripping due to a BPS contingency could become significant enough to negatively impact bulk system reliability.

Need for Disturbance Tolerance: In order to ensure a high degree of reliability of the interconnected power system, it is imperative that bulk generation and transmission elements have a degree of disturbance tolerance. A principle of system protection is that elements should not be intentionally tripped unless it is necessary to clear a fault, to prevent equipment damage, or to preserve system stability. All other elements should remain connected to the grid and contribute to frequency and voltage recovery following the disturbance. Disturbance tolerance is a required element to prevent cascading outages following voltage or frequency excursions that happen during normal system operation. This philosophy is reflected explicitly or indirectly in bulk-level grid codes or interconnection standards, including the recently approved NERC Reliability Standard PRC-024-1.

In contrast, with the expectation of disturbance tolerance for BPS-connected generators, IEEE Standard 1547 contains only must-trip requirements whereby DERs must disconnect within a short period of time when voltage or frequency fall outside a certain range. For example, a DER that experiences a voltage drop to 0.5 p.u. or lower would be required to trip within 10 cycles. This kind of voltage sag could occur over a fairly large area of the system during transmission system faults. While distribution facilities often have voltage regulation capability to offset voltage drops on the system, if the voltage drop is not countered this could exacerbate transmission contingencies and, in worst cases, contribute to a cascading outage if these contingencies are not studied and the effects properly mitigated per the TPL standards. Thus, under high penetration of DERs the existing provisions of the IEEE Standard 1547 could adversely affect bulk electric system reliability.

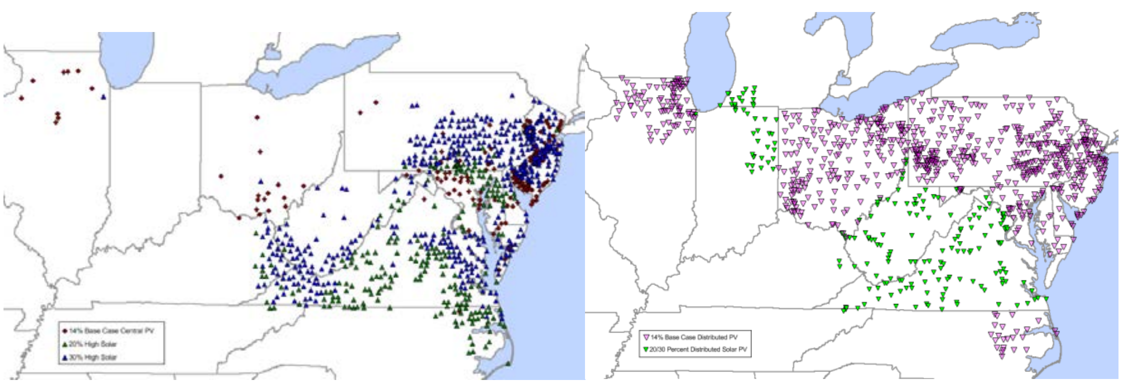
IEEE Standard 1547 must-trip requirements were in response to safety and protection/control coordination at the distribution systems level. When IEEE Standard 1547 was first developed, there were not large penetrations of DERs and BPS reliability was not a factor. It was not anticipated that distributed generation would be playing a significant role in power supply. In the near future, DER (especially PV) is expected to grow to the point that the

must-trip requirements contained in IEEE Standard 1547 may play an important role in the transient behavior of the bulk power system following system disturbances.

Potential System Reliability Impacts: When DER levels in a given region can be significantly high, the concern is that BPS disturbances that would otherwise have negligible impact may challenge the IEEE Standard 1547 trip thresholds and, thus, become compounded by sympathetic tripping of a significant amount of DERs. In worst cases, this could lead to an increased exposure to system instability, under-frequency load shedding or cascading outages over large areas of the interconnected system. As noted in IEEE Standard 1547, the frequency and voltage trip settings were designed to protect distribution circuits and potential BPS system impacts were not the primary consideration. In most North American power systems, and especially in the Eastern Interconnection, DER penetration is low in most jurisdictions. However, DER penetration on some systems is increasing and has the potential to grow rapidly in the future. With this in mind, potential reliability issues need to be addressed proactively by updating and enhancing standards when gaps are identified. Revising standards and other interconnection requirements on the front-end is generally preferable to implementing costly retrofits to legacy equipment in the future. Certain entities in Europe--particularly Germany where penetration levels on the distribution system are very high compared to the North American systems--have recognized this reliability exposure and have taken steps in the form of revised interconnection standards for DERs.

Voltage Tolerance: As of January 2012, approximately 4,800 MW of wind and 205 MW of solar generation were interconnected on the PJM transmission (primarily) system. PJM has approximately 22,680 MW of wind projects and 1,650 MW of solar projects in the interconnection queue. A PJM Renewable Integration Study15 illustrates that for the 2026 time frame, various scenarios estimate distributed solar PV to be about 4,100 MW in the base case and 34,710 MW in a high-solar penetration scenario case. The range in the scenarios is dependent on a number of factors, but is primarily attributed to the range of uncertainty in the timing and aggressiveness of respective state renewable portfolio standards. Figure 5 below shows expected locations of central and distributed solar resources in a high penetration scenario.

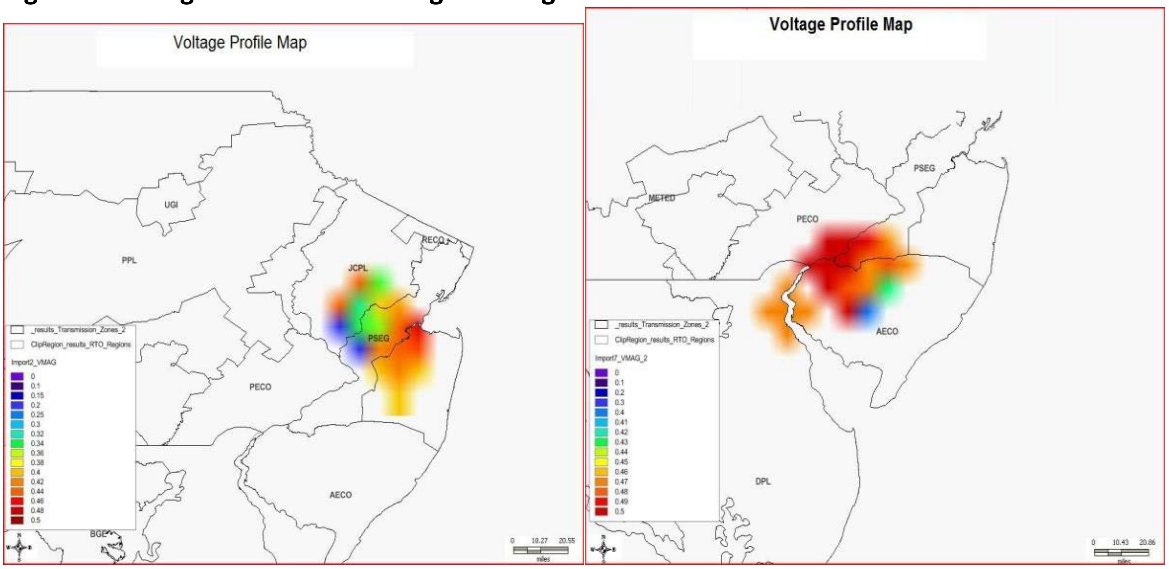
Figure 5: High Solar Generation Scenarios used in PJM Renewable Integration Study



According to the existing IEEE Standard 1547, DERs that experience voltage drop to 0.5 pu or lower at their interconnection point are required to trip within ten cycles (0.16 seconds). This kind of voltage sag would not be uncommon over a fairly large area of the system during transmission system faults. In addition, since the DER trip requirement in IEEE Standard 1547 is a maximum trip and clear time, trip must be initiated before the clearing time. Figure 6 below shows the extent of voltage depression below 50% of nominal for BPS faults at various EHV locations. In the shaded areas, DERs connected to distribution circuits served from that portion of the transmission system are likely to trip on under voltage within ten cycles. It should be noted that, in this case, the fault is not on the distribution system, the distribution protective system is not required to clear the fault, and the possibility of a localized islanding situation does not exist. Yet, if the penetration of DERs in this region is

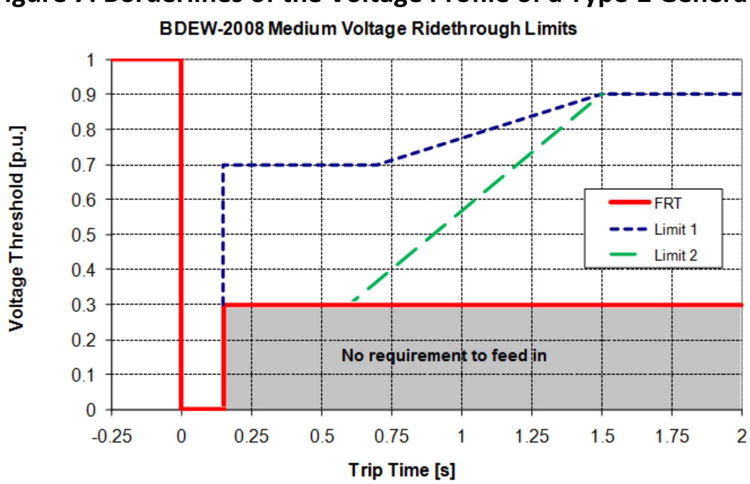
high enough, a transmission contingency would be compounded which can potentially increase the probability of a cascading disturbance if not studied and properly mitigated. The Hawaiian Electric companies (Hawaiian Electric, Maui Electric, and Hawaii Electric Light) all have DER penetration levels that already affect the local bulk power system reliability. For this reason the DER frequency trip settings have been adjusted to the maximum duration/lowest frequency settings available. Voltage setting requirements are under evaluation.

Figure 6: Voltage Contours of Voltages during Faults on Two Different Transmission Buses



The bulk system reliability issue described above has been recognized and is being addressed by reliability organizations in Europe. A German association of energy industries (BDEW) issued a recommendation for generator interconnection at medium voltage (i.e., distribution-level voltages) that is more in line with grid codes for interconnection with the BPS. Figure 7, taken from Technical Guideline of BDEW for Generating Plants Connected to Medium-Voltage Network (published June 2008), shows the existing requirement for DER connected at Medium Voltage (10 kV to 60 kV) to remain connected without instability for voltage drops to zero at the interconnection point for 150 milliseconds.

Figure 7: Borderlines of the Voltage Profile of a Type-2 Generating Plant at the Network Connection Point



Adoption of this guideline was justified by reliability exposure similar to the scenario described above. Since the standard was adopted in April 2011, PV capacity in Germany has increased by more than 50% to 35 GW. Other jurisdictions have followed suit.

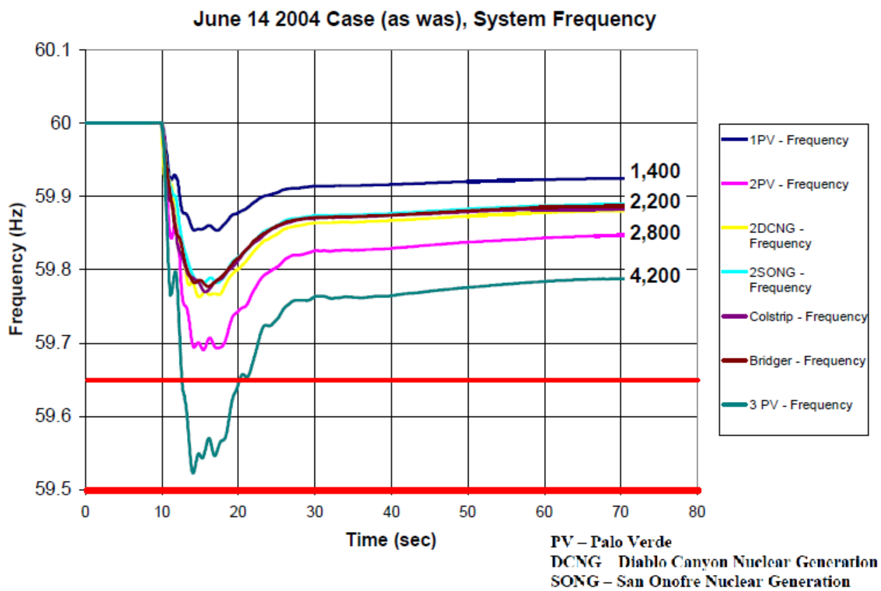
Fault induced voltage recovery (FIDVR) could also be exacerbated by under-voltage DER tripping. By definition, a FIDVR event lasts beyond fault clearing, possibly 10 to 20 seconds, and can be followed by high voltage due to switching of shunt devices as well as load tripping. With high penetration of DER in a load area, shunt capacitors and reactors configuration may be such that FIDVR could happen more frequently or more severely. DER tripping during the fault as well as during the FIDVR event would cause net load in the load area to increase, which can further delay voltage recovery and cause additional loss of load. For this reason, it would be advisable to consider longer voltage ride-through tolerance at a higher voltage (e.g., 70%).

Frequency Tolerance: Sudden changes in generation or load (such as that resulting from a large generating unit trip) result in system frequencies deviating from their normal ranges. Over a short control period, system frequency regulation controls like generator governors and Automatic Generation Control (AGC) would restore system frequency to within its normal range. However, if additional generation or load trips due to this frequency disturbance, it has a potential to amplify the disturbance and adversely affect system reliability. Therefore, to preserve system reliability, it is desirable for generators connected to the electric system to ride through such frequency disturbances, remain interconnected and stable, and continue operating close to their pre-disturbance levels. Overly sensitive frequency DER sensitivity could result in a frequency disturbance becoming compounded due to DER tripping, which delays frequency recovery and possibly leads to further under-frequency load shedding.

IEEE Standard 1547 requires DER to disconnect within 160 ms when frequency is above 60.5 Hz, or below 59.8 Hz (upper range of adjustability for DER >30 kW). In the Western Interconnection, a generation contingency of 2,000 MW could cause frequency to decrease to near or below 59.8 Hz for several seconds (Figure 9). A survey of the Western Interconnection generation contingencies for the time period of 1994 to 2004 shows that this level of generation loss happens roughly once a year. For the same generation loss, the frequency dip would be greater in a smaller interconnection and during light load periods. In a high penetration DER scenario, the possibility of significant DER tripping on under-frequency would impact the level of reserves required to ensure adequate frequency recovery.

As DER grows, tripping at frequencies not coordinated with system protection, and which are reached by contingencies, essentially increases the size of potential contingencies. To further complicate matters, the actual amount of MW from variable DER is difficult to determine in real time as it is not generally monitored, and therefore challenging to include as a consideration in operating reserves. Loss of DER during low-voltage transmission events will result in a net load increase, which will exacerbate low-voltage conditions and potentially result in collapse.

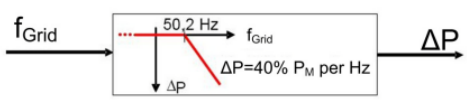
Figure 9: Western Interconnection Frequency for Various levels of Generation Loss21



Under certain conditions, high frequency could also pose a reliability risk, and this has been recognized in Europe. In Germany, the applicable standard DIN V VDE V 0126-1-1:2006-02 requires that DER disconnect within 0.2 seconds when frequency reaches 50.2 Hz. Several other European countries use this standard as well. During the 2006 UCTE event, frequency in the Eastern portion of the system rose above 50.2 Hz. With the amount of DERs in the system today, the generation loss could have threatened the stability of the grid.

Recent efforts to address this reliability exposure, known as the 50.2 Hz problem, led to the adoption of requirements such as the BDEW high frequency droop, depicted in Figure 11. The concept is that DER output power will, in aggregate, be reduced in proportion to frequency and then return as frequency is restored rather than drop to zero. Concurrent with adoption of this requirement, a DER retrofitting campaign was undertaken to address the reliability exposure of the existing DER capacity. A similar retrofitting program was required in Spain to address wind generation low voltage ride-through.

Figure 11: Germany's (BDEW) Solution to Address Challenges—NERC is Proposing the Same



$$\Delta P = 20\, P_M \frac{50{,}2\ Hz - f_{Grid}}{50\ Hz} \quad \text{at } 50.2 \text{ Hz} <= f_{Grid} <= 51.5 \text{ Hz}$$

P_M = Generated Power

ΔP = Power Reduction

f_{Grid} = System Frequency

at 47.5 Hz <= f_{Grid} <= 50.2 Hz → No restrictions

at f_{Grid} <= 47.5 Hz or f_{Grid} >= 51.5 Hz → Disconnection

The need to address high frequency DER tripping was raised as part of FERC's Small Generator Interconnection Procedure (SGIP) Notice of Proposed Rulemaking Docket No. RM13-2-000. This issue was also discussed in the

context of IEEE Standard P1547a proceedings. A high frequency droop characteristic similar to the BDEW requirement described above has been proposed as an option, but not yet mandated.

Summary of VRT and FRT Requirements Applicable to BES-Connected Generators: The reliability of the bulk power system depends on most generators remaining connected in the event of a system fault. At the bulk system level, the expectation is that generators will remain connected during a disturbance and contribute to restoration of voltage and frequency as soon as possible. If even a few large generators fail to ride through a disturbance, the power system risks a cascading failure and blackout. Historically, this disturbance tolerance capability for conventional generators was considered inherent, rather than required by standards.

During the initial phase of large-scale VER deployment, there were no specific requirements for any generators to ride through faults. VERs were significantly smaller than conventional generators and could be distribution-connected. DER also added a complication to distribution circuit protection schemes. The dynamic response of inverter-based VERs was poorly understood or, in the case of induction-based wind generators, was known to be detrimental to voltage recovery. For these and other reasons, VERs were designed to quickly disconnect from the grid after a voltage or frequency disturbance. As the potential for large-scale integration of VERs became apparent, VER (wind) specific VRT/FRT requirements were incorporated into grid codes. Today, disturbance tolerance standards are still evolving. There are efforts to harmonize requirements so that they can be applied to all generators, not just VERs. In North America, there are several regional standards that address disturbance tolerance of transmission-connected generators. These are discussed below.

FERC Order 661A contains a low voltage ride-through (LVRT) requirement that applies only to FERC-jurisdictional (US only) wind generators larger than 20 MVA. FERC Order 661-A states:

> *"Wind generating plants are required to remain in service during three-phase faults with normal clearing (which is a time period of approximately 4–9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU."*

ERCOT, WECC, the Quebec Interconnection, and other Canadian provinces have also established disturbance tolerance standards that apply within their own jurisdiction. In the case of WECC, the disturbance tolerance standard only addresses low voltage ride-through. In regions where there are no explicit FRT requirements (Eastern Interconnection and WECC, for example), new generators are expected to remain connected within the envelope defined by the off-nominal frequency programs applicable within the interconnection. BPS Reliability Standards apply to transmission-connected plants and generating units above a certain size.

NERC initiated a project to include FRT and VRT as part of NERC Reliability Standard PRC-024. The final version of the Standard approved by the NERC Board of Trustees in March 2013 addresses frequency and voltage relay settings, but does not establish an explicit disturbance tolerance requirement for generators. According to the standard, generators are allowed to trip for reasons other than voltage or frequency relay action, including impending or actual loss of stability, as needed for fault clearing or as part of a special protection scheme, and

documented regulatory or equipment limitations. While the standard is a relay setting standard, generator performance enhancements are expected as a result.

Figures 12 and 13 describe the "no-trip zone" for voltage and frequency contained in the NERC Reliability Standard PRC-024-1. The no-trip zone described in the NERC Reliability Standard PRC-024 applies to generator voltage and frequency protection relays. The time dimension is the cumulative time that the value (voltage or frequency) is more severe than that given value (e.g., voltage less than value for LVRT, greater value for HVRT). That is, the requirement does not establish continuous generator must-run ranges. For example, if voltage dips no lower than 0.8 pu, the corresponding relay must have an intentional delay no shorter than three seconds. Note that the frequency no-trip zone is defined differently among NERC interconnections, but the voltage no-trip zone is the same across the NERC footprint.

Figure 12: NERC Standard PRC-024-1 Generator Voltage Relay Setting Requirement

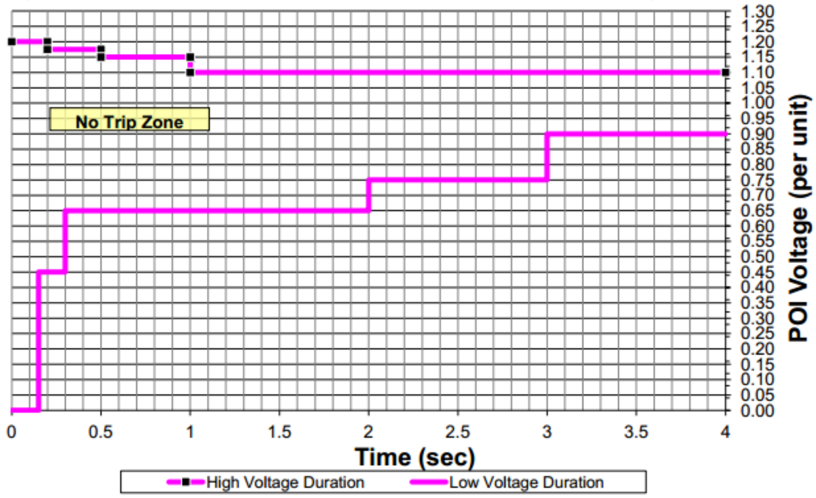
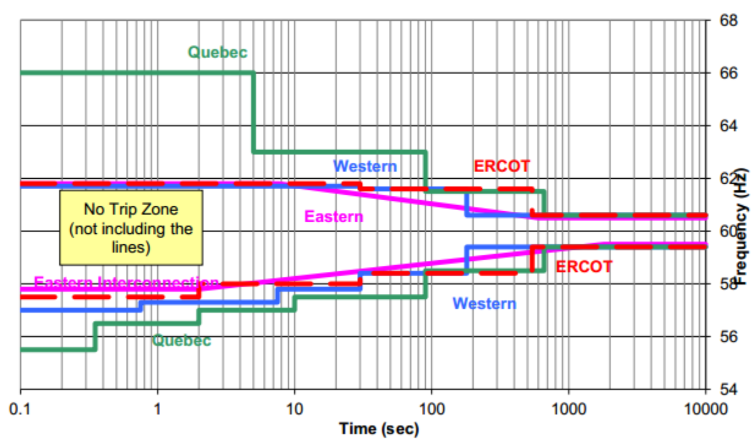


Figure 13: NERC Standard PRC-024 – Generator Frequency Relay Setting Requirement

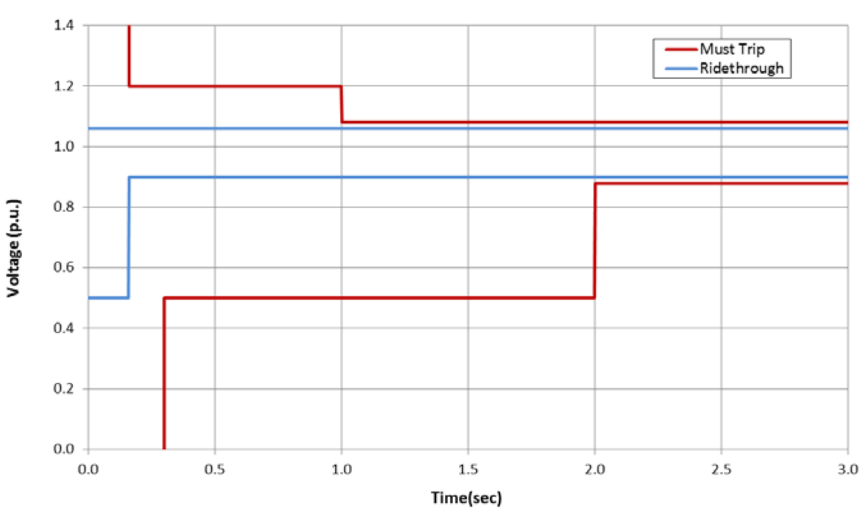


NERC Reliability Standard PRC-024-1 contains several clarifications that are useful to properly interpret the standard. It states, "Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve." It clarifies that the curves apply to voltage excursions regardless of the type of initiating event, and lists several baseline assumptions to be used when evaluating protective relay settings. NERC Standard PRC-024 voltage relay standard applies at the point of interconnection.

Guidelines and Recommendations: The task force offered the following general guidelines on VRT and FRT specifications for distributed VERs and other DERs, for consideration in the IEEE Standard 1547 revision. It is assumed that VRT and FRT requirements would have to co-exist with revised "must trip" provisions needed to address safety and protection/coordination issues in distribution systems.

1. The revised IEEE Standard 1547 should allow for different methods of meeting the functional requirements of fault detection (clause 4.2.1), reclosing coordination (clause 4.2.2) and unintended islanding detection (clause 4.4.1). At present, DERs meeting those functional requirements would still have to trip on voltage (clause 4.2.3) and frequency (clause 4.2.4) excursions. Removing those linkages would help pave the way for VRT and FRT requirements. The IVGTF recognizes that these alternative methods are more expensive, require more engineering effort, and in some cases require further technical development. However, the increasing level of DER and the potential impact on the BPS justifies the effort.
2. The revised IEEE Standard 1547 should include explicit low and high VRT requirements. Likewise, the revised IEEE Standard 1547 should include explicit low and high FRT requirements. These requirements should be expressed as voltage versus cumulative time and frequency versus cumulative time requirements.
3. Must-trip voltage thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective VRT envelope without overlap (Figure 16).
    a. As an example, Figure 16 shows a possible approach to implement low voltage ride-through down to 50 percent voltage for 10 cycles (160 ms), within the existing IEEE Standard 1547 framework.
    b. Zero voltage ride-through is not required for BPS reliability. A ride-through level down to approximately 50 percent voltage would provide adequate tolerance during transmission faults.
    c. A ride through period longer than shown in Figure 16--possibly greater than 10 seconds--at higher voltage level (e.g., down to 70% voltage) may be needed to avoid compounding fault-induced delayed voltage recovery (FIDVR).

Figure 16: IVGTF 1-7 Recommended Ride-Through and Must-Trip Requirements for DER



Must-trip frequency thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective FRT envelope without overlap.

The time dimension of the VRT/FRT curves discussed previously is meant to represent cumulative time elapsed since the onset of a disturbance event that result in temporary excursions of voltage and/or frequency. The VRT/FRT envelopes should not establish must-run ranges for generators (i.e., they should not prevent intentional shutdown of a DER for reasons other than grid voltage and frequency disturbances, such as normal shutdown of PV at night or by operator action.)

The prospective disturbance tolerance standard should provide a default VRT and FRT envelope, but should allow for the time and frequency/voltage magnitudes to be adjustable, within certain limits, for coordination with local protection, in coordination with the distribution system operator.

FRT and VRT requirements should cover all DERs that are normally grid connected, regardless of size or technology. However, a range of thresholds could be considered based on technology differences (e.g., inverter versus rotating machines), as some European grid codes do. In general, focusing requirements on the truly functional needs of the grid tends to eliminate the need to have technology-specific requirements.

The restarting of DERs during system restoration should be considered during the development of DER interconnection requirements. While the restoration situation in North America is somewhat mitigated at present by the sequential nature in which distribution feeders will likely be reenergized after a major blackout, reliability impacts of DERs should consider the automatic restarting of DERs. Failure to consider and mitigate these impacts could lead to further instability during a disturbance.

Chapter 6 - Applicable NERC Reliability Standards

Applicable NERC Reliability Standards – *Jason MacDowell, Gary Keenan*

a. MOD-010-0 Steady State Data for Modeling and Simulation of Interconnected Transmission System
b. MOD-012-0 Dynamics Data for Modeling and Simulation of the Interconnected Transmission System
c. MOD-016-1.1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management
d. MOD-017-0.1 Aggregated Actual and Forecast Demands and Net Energy for Load
e. MOD-019-0.1 Reporting of Interruptible Demands and Direct Control Load Management
f. MOD-020-0 Providing Interruptible Demands and Direct Load Control Management Data to System Operators and Reliability Coordinators
g. MOD-021-1 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts
h. MOD-031 is pending
i. MOD-032 replaces MOD-010
j. MOD-033 replaces MOD-012
k. PRC-006 UFLS
l. PRC-0?? UVLS schemes
m. PRC-019
n. PRC-024-2 (pending) Generator Voltage and Frequency Coordination

Chapter 7 - Recommendations

Recommendations

a. Connection requirements
b. Modeling
c. Performance requirements?
d. Accounting Load/Gen?
e. Modifications to any NERC Standards?

Task Force Membership

Miscellaneous (Appendices?)

a. IVGTF Task 1-7
b. DERSG
c. NERC Load Modeling TF

TEMP: Examples of Tables, Figures and Highlight Boxes

TEMPORARY – TO BE DELETED LATER

*(**DELETE RED TEXT PRIOR TO PUBLISHING**) The Results section is where the author points out and explains significant data in text, tables, charts, and figures. It should include key trends or relationships and highlight unexpected as well as expected findings. This section should not include an analysis of the data—just the facts.*

Table Example

All tables must be numbered and named. Note the table title is part of the actual table. Report text should introduce the table by number ("Table 1") before it appears. Do not use the terms "above" or "below" when describing the table's location in case during formatting the table moves.

It may be prudent to do a page break (ctrl+enter) before a page with a table or figure on it. This will prevent the table from moving if text is changed on prior pages. If possible, try to keep the text that describes the table on the same page as the table.

Table 1: Report Template Formatting

	Font	Size	Typeface	Space Before	Space After	Color
Cover Page						
Title	Tahoma	48	Bold	0	0	white
Subtitle	Tahoma	24	Roman	0	0	white
Internal Pages						
Chapter Title	Tahoma	16	Bold	0	0	dark blue
Section Heading	Tahoma	14	Bold	0	0	black
Sub-Heading 1	Tahoma	11	Bold	0	0	black
Sub-Heading 2	Tahoma	11	Bold, Italic	0	0	black
Body Text	Calibri	11	Roman, Justified	0	0	black
Header/Footer	Calibri	9	Bold, Centered	0	0	dark blue
Footnotes	Calibri	9	Roman	0	0	black

Figure Example

All figures must be numbered and named. Note that the figure title goes below the figure and is centered. Report text should introduce the figure by number ("Figure 1") before it appears. Do not use the terms "above" or "below" when describing the figure's location in case during formatting the figure moves. Figures will be different sizes; their placement depends on author and proofer discretion. Do not stretch or shrink a figure, and do not use figures that are blurry or have illegible text. If a figure is blurry, it is the wrong size.

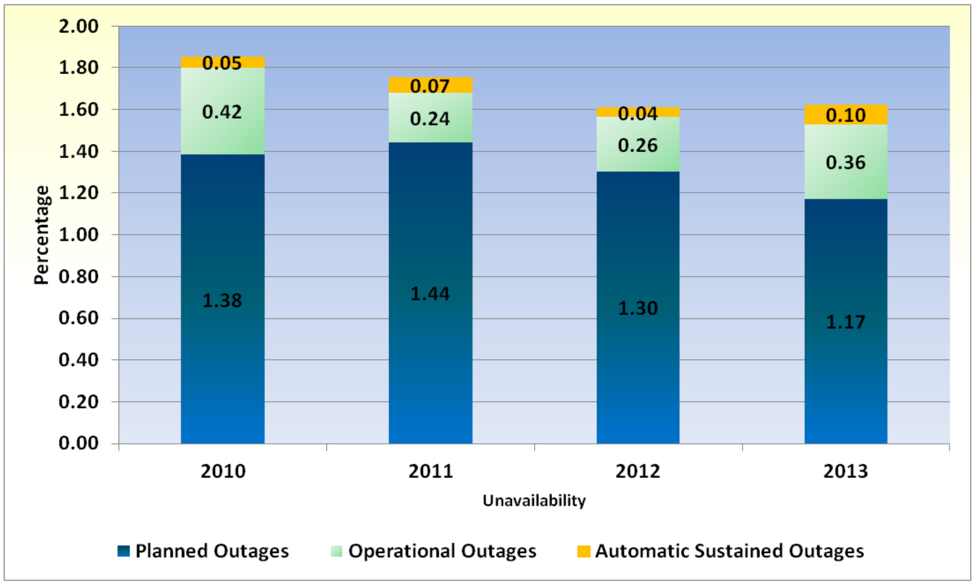


Figure 1: Unavailability of NERC Transmission Transformers by Outage Type (2010–2013)

Highlight Box Example

A highlight box is used to emphasize key terms, facts, figures, etc. Always use NERC Light Blue as the fill color. Refer to the NERC Style Guide (Chapter 6 – Formatting) for guidance on other NERC corporate colors.

<u>Voltage and Reactive Subarea Concept Paper</u>

ERSTF Voltage and Reactive Subgroup

Voltage regulation and reactive resource management is a critical part of planning and operating the BES. Maintaining adequate voltage profiles across the BES both pre and post contingency is a function of the reactive resources available and their utilization. The ability to control the production and absorption of reactive power often becomes the driving force behind studying and operating the BES over a wide range of conditions, especially in those areas where weak transmission systems supply load and generation or the transmission network can be subjected to heavy power transfers.

So while engineers must consider voltage and reactive performance over a wide range of system conditions there is a significant justification for focusing the analysis on much smaller subsets of the BES. Due to the lack of transportability of reactive resources on the BES, planners and operators need to consider defining subsets of the BES within their footprint that have their own unique set of voltage / reactive performance issues which only lend themselves to local resources and remedial actions. The BES varies widely from area to area based on the specific topology and electrical characteristics. There has been a long held belief in many industry sectors that reactive resource reserves are the key to maintaining a robust system. While at a high level this is true, the reality is if those abundant reactive reserves are not electrically close to where they are needed, they will be totally ineffective in managing voltages on the system.

Consider the inherent difference between a typical large urban area and that of a typical large rural area in such variables as load level and load power factor (LPF), various overhead and underground transmission network configurations, dynamic and static reactive resources and, the appropriate minimum and maximum voltage limits to adhere to. While these two areas may be within the same RC/BA/PC footprint the voltage and reactive performance of each can vary significantly. That difference will drive both the criteria and the type of planning studies required to meet the objective of developing a robust reliable system. Similarly those same differences may impact the way the real-time operations are managed. The determination of appropriate subsets within the larger footprint becomes the primary and most critical first step in planning and operating the BES. Considerations in defining subsets of the system are:

- Reactive performance within the footprint both pre and post contingency
    - Insufficient reactive compensation in a single area can impact or cascade to neighboring areas and affect overall BES operation
    - The system can reach a state where even though voltages appear adequate, most available reactive resources are exhausted and the next contingency can degrade voltages and reactive performance pushing the BES quickly into unacceptable performance

  - The loss of high voltage BES facilities can load remaining facilities more heavily and resulting in significantly increased losses which will negatively impact the voltage profile and reactive resources
  - Outages of major reactive resources not only removes the reactive capability but can also result in large MW swings and increased losses which will negatively impact the voltage profile and reactive resources
- Real power import, export, and flow-through characteristics, e.g. large power transfers within or between sub-sets can significantly increase reactive power losses which will negatively impact the voltage profile and reactive resources
- Transmission topology and characteristic, e.g., high surge impedance loading where real power transfers can reach a point where reactive consumption of the transmission system exceeds available reactive supply which will negatively impact the voltage profile
- Charging from cables or long overhead lines during light load periods where these facilities may produce voltages so high that leading reactive capability is exhausted and circuits must be opened to reduce voltages
- Types of reactive resources available which will have different lead/lag characteristics:
  - Synchronous vs. nonsynchronous/inverter based resources,
  - Static devices, i.e., shunt capacitors, reactors, etc,
  - Dynamic devices, i.e., SVCs, STATCOMs, DVARS, etc,
  - HVDC terminals, such as Voltage Source Converters that can supply reactive capability,
  - Line compensation that can be switched in and out such as series compensation.
- Real and reactive load distribution, (while this is the distribution area of the system, real load and LPF can have both a positive and negative impact on the BES and that contribution must be accounted for).

Once appropriate subareas have been defined, the planners and operators must ensure compliance with all applicable NERC standards. This does not mean that more stringent regional or local criteria may also be utilized. In a general sense the subareas that are defined should be somewhat autonomous relative to their reactive and voltage performance for N-1-1 conditions. This construct negates one subarea relying too heavily on adjacent subareas for reactive support thereby increasing the chance of a cascading event. This also inherently builds in reactive margin so that in real-time where N-k events may occur there is enough robustness to prevent a widespread event from occurring. The end result is to plan and operate each subset so that the reliability of the broader BES is maintained. There are numerous tried and true methods of studying, planning, building and operating the BES. At a high level those aspects are addressed in the accompanying NERC Reliability Guideline: Reactive Power Planning and Operations.

DRAFT Reliability Guideline:

Reactive Power Planning and Operations

Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; Operating Committee (OC), Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters[1] are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary set of recommendations, considerations and industry best practices on a particular topic for use by BES users, owners, and operators in assessing and ensuring BES reliability. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on voltage and reactive power planning and operations which are critical in maintaining the highest levels of BES reliability. Reliability guidelines are not to provide binding norms or create compliance type parameters similar to compliance standards that are monitored or enforced. Guideline practices are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to achieve the highest levels of reliability for the BES. Further, these guidelines are not intended to take precedence over regional procedures or requirements.

NERC as the FERC certified ERO[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program and mandatory reliability standards. Each entity as registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of their portions of the BES. Entities should review this guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration and business practices.

[1] http://www.nerc.com/docs/docs/oc/OC_Charter_approved_02.16.10.pdf
http://www.nerc.com/docs/cip/CIPC_Charter_Aug2010.pdf
http://www.nerc.com/docs/pc/Board%20Approved%20PC%20Charter%20August%204%202011.pdf
[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

Purpose

This Reliability Guideline provides strategies and recommended practices for reactive power planning and voltage control. It is meant to provide utilities with guidance and direction related to the modeling, study, and placement of reactive power resources in support of robust voltage profiles. The strategies set forth in this Reliability Guideline center around the need for static and dynamic reactive power resource planning and operational planning, as outlined in relevant NERC Reliability Standards. In addition, this Reliability Guideline aligns with the NERC's mission of improved reliability through sharing industry practices for planning and operating the bulk power system.

The Reliability Guideline applies primarily to Planning Coordinators, Transmission Planners, Transmission Operators, Generator Operators, Generator Owners, and Reliability Coordinators.

The intent of this document is to provide guidance for establishing required practices related to the relevant NERC Reliability Standards, namely VAR and TPL standards. The following topics are considered in this guideline:

1. **Voltage Performance Criteria:** fundamentals of voltage control and static and dynamic reactive resources; determining steady-state voltage limits and post-contingency voltage deviations; transient voltage response criteria; and protecting against voltage instability.
2. **Voltage Operating Criteria:** defining system voltage schedules; and determining sufficient reactive resources and/or margins to regulate voltage levels under normal and contingency conditions.
3. **Dynamic Reactive Considerations:** reactive power generation scheduling; automatic voltage control modes; methods for converting scheduled voltage to set point voltage; and coordination with static devices and other controls.
4. **Transmission Level Considerations:** transmission line and reactive resource switching; controllable loads; and modeling and forecasting loads.
5. **Coordination:** interface coordination between operating entities; and distribution of reactive resources among transmission, distribution, and generation.
6. **Industry Practices on Reactive Power Planning**
7. **Industry Transient Voltage Response Criteria**

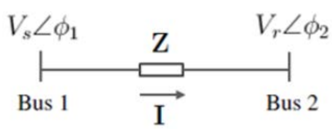
Reactive power planning and operational techniques can vary based on the unique characteristics of each system – in some areas steady state voltage control and/or transient voltage response are of greater concern than in other areas. In areas with reactive power problems, planning and operational techniques need to be documented and disseminated to all entities that have a reliability role within an interconnection. This Reliability Guideline is meant to provide guidance for establishing required practices.

Background

Reactive power is defined by NERC as[3]:

> "The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influence electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar)."

Real power is the component of apparent power that does real work, defined as the component of the current in phase with the voltage. Reactive power is produced when the current waveform is out of phase with the voltage waveform due to inductive (current lags voltage) and capacitive (current leads voltage) loads, and is measured in volt-ampere reactive (var). Fundamentally, reactive power is necessary to produce the electric and magnetic fields inherent in an alternating current (AC) network and AC loads such as motors. Neglecting line resistance and capacitance (Z = jωL), reactive power transfer across a short transmission line can be expressed as



$$Q_r = \frac{V_r}{X}(V_s \cos\delta - V_r)$$

where V_s and V_r are the sending and receiving end voltage magnitudes, respectively; X is the line reactance; and δ is the phase angle difference ("power angle") between the two ends of the line. It is clear from this equation that reactive power is a function of voltage difference, angle difference, and electrical impedance; however, angle difference has a relatively small influence while voltage difference and impedance are much stronger drivers. For this reason, voltage control is tightly coupled with reactive power control, and vice versa.

Voltage is supported through supply of reactive power; hence, reactive power is required to transfer large amounts of real power across the grid for serving the loads. Reactive power must be supplied locally mainly because of its dependence on voltage difference, and it is usually necessary to site reactive devices very near or at the location that is deficient; typically reactive power supply is provided where it is needed to minimize losses. Voltage stability is the ability of a power system to maintain acceptable voltage at all buses under normal and contingency operating conditions.

Reactive power resources are generally differentiated between static and dynamic resources, generally defined by the reactive power output and controllability once connected to the grid:

- Dynamic reactive resources adjust reactive power output in real-time over a continuous range automatically in response to changes in grid voltage. These resources operate to maintain a set point

[3] NERC Glossary of Terms. Available: http://www.nerc.com/files/glossary_of_terms.pdf

voltage or operate in a voltage droop mode. Many dynamic reactive resources, particularly newer ones employing power electronics, can respond within electrical cycles using fast-acting controls. For example, STATCOMs have a response time constant of around 50 ms.
- Static reactive resources have fixed reactive power ratings and are switched in or out of service based on system conditions. Switching action can be manual or automatic but once connected, the resource provides a fixed nominal contribution of reactive power to the grid.

Static reactive resources generally include the following elements:

- **Fixed Shunt Devices** – fixed shunt reactive devices include shunt capacitors and reactors. These devices have a fixed nominal rating and their reactive power production or consumption is dependent on terminal voltage. While these types of devices are relatively cheap, their operating characteristic and inability to provide dynamic voltage support limit their applicability in some situations.
- **Switched Shunt Devices –** switched shunt capacitors and reactors are simply fixed shunt devices that have capability to automatically be switched in service based on control settings. These devices may have relatively short operating times (less than a second to multiple seconds or minutes); however, their inability to change reactive power output in real-time differentiates them from dynamic reactive devices.
- **Transmission Circuits –** Transmission lines have an operating characteristic known as the surge impedance loading (SIL) which is the real power loading at which reactive power produced and consumed by the line are balanced. Lines produce reactive power due to their natural capacitance, and the amount produced is dependent on the capacitive reactance (X_C) of the line and the voltage. Lines also consume reactive power due to their inductive reactance (X_L). The SIL occurs when vars produced equal vars consumed, defined by

$$VAR_{produced} = \frac{V^2}{X_C}$$

$$VAR_{consumed} = I^2 X_L$$

$$Z_{SI} = \sqrt{\frac{L}{C}}$$

$$SIL = \frac{V^2}{Z_{SI}}$$

Dynamic reactive resources generally include the following elements:

- **Static Synchronous Compensators (STATCOM)** – a voltage source converter[4] (VSC) device part of the Flexible AC Transmission System (FACTS) family that consists of a DC voltage source behind a power electronic interface connected to the AC grid through a transformer. This essentially results in a

[4] A voltage source converter (VSC) is a self-commutated device that synthesizes a voltage waveform with variable magnitude with respect to the system voltage to control the reactive power production and consumption of the device.

controllable voltage source, and hence reactive power output, behind a reactance. A simple configuration and electrical representation of a STATCOM is shown in Figure XXX.

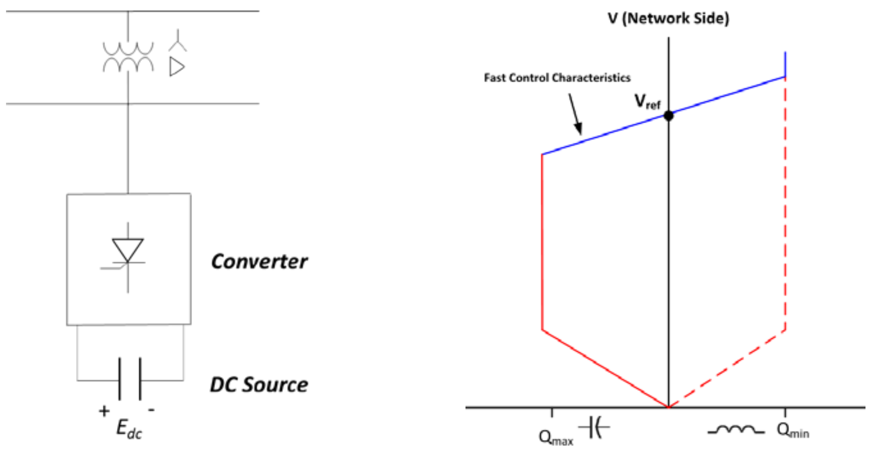


Figure XXX: Static Synchronous Compensator (STATCOM) Oneline and Characteristic

- **Static Var Compensator (SVC)** – a FACTS device typically consisting of thyristor-controlled reactors (TCR), thyristor-switched capacitors (TSC), and fixed capacitors acting as a harmonic filter. The TCR consists of reactors in series with thyristor valves that continuously control the reactive power output by varying the current flow through the reactor. The TSC consists of capacitors, reactors, and thyristor valves that simply switch the capacitor in and out of service. The fixed capacitor simply absorbs the harmonics generated by the thyristor switching, supplying a fixed reactive power to the grid. A simple configuration and operating characteristic are shown in Figure XXX.

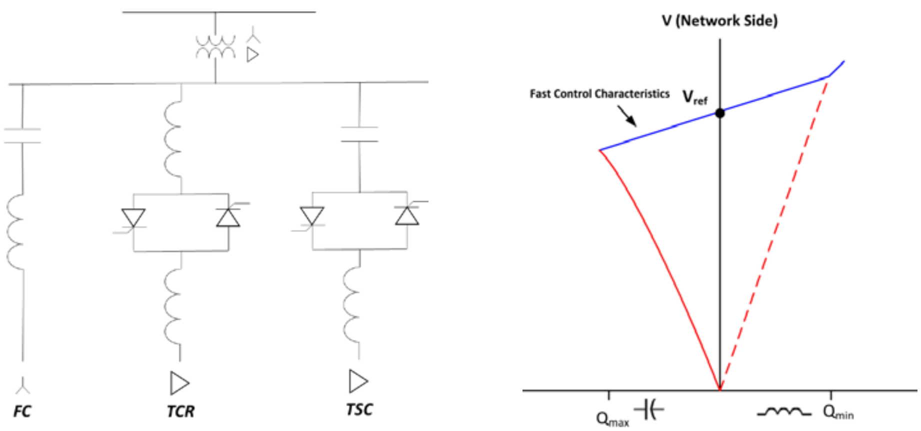


Figure XXX: Static Var Compensator (SVC) Oneline

- **Synchronous Condensers** – A synchronous condenser is a (synchronous) electric machine whose shaft is not driven by a prime mover; rather, the shaft spins freely and the field voltage is controlled to produce or consume reactive power by adjusting set point voltage and thus contributes to overall power factor correction or/and local voltage control. The reactive power flow is controlled through field current control. Synchronous condensers have several advantages as they contribute to system short-circuit capacity, have 10-20% overload capability for up to 30 minutes, and provide system inertia.

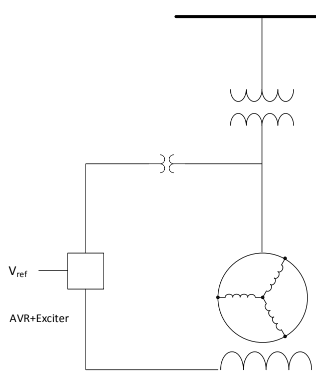


Figure XXX: Synchronous Condenser Oneline

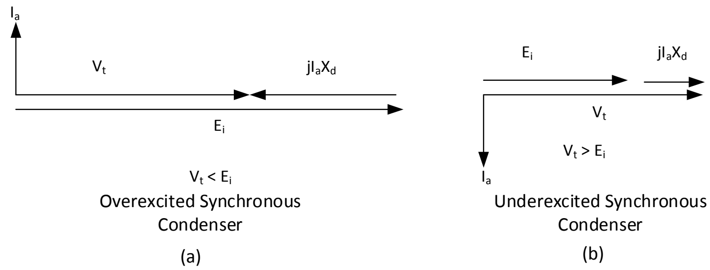


Figure XXX: Synchronous Condenser Phasor Diagram

- **Generators** – Synchronous generators are the primary source of real power in the electric power system, and can provide or consume large amounts of reactive power. This is driven by the excitation voltage provided to the rotor of the machine, similar to a synchronous condenser. Limits on reactive power capability are dependent on stator winding rating, field current rating, terminal voltage rating, and the real power output of the machine. Figure XXX shows a generator capability ("D") curve and the influence real power has on reactive power output capability. Generators consuming reactive power are considered in "bucking" mode while generators producing reactive power are operating in "boosting" mode. The generator excitation limiters are intended to limit operation of the generator to within its continuous capabilities. Generally the setting of the underexcitation limiter (UEL) will be coordinated with the steady-state stability limit of the generator. The overexcitation limiter (OEL) limits generator operation in the overexcited region to within the generator capability curve. There are examples where reactive power capability can be increased such as increasing pressure in the hydrogen cooling system; however, the excitation limiter must be adjusted to actually utilize that additional capability.

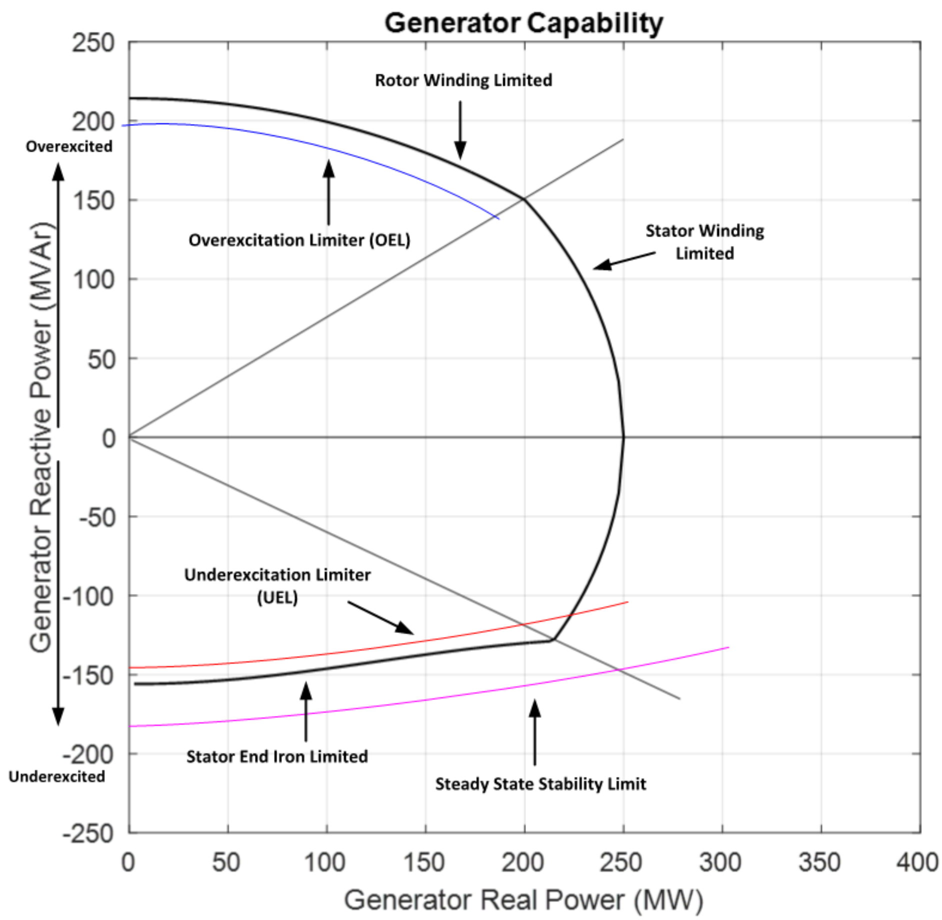


Figure XXX: Generator Capability Curve

- **Voltage Source Converter (VSC) HVDC** – Unlike conventional line commutated HVDC[5], VSC HVDC uses a voltage source on the DC side of conversion, enabling direct control of active as well as reactive power output on each end of the converter. Reactive power output takes a constant-current characteristic and is directly proportional to voltage. Reactive power capability tends to decrease as real power increases (similar to a traditional generator D-curve). Figure XXX illustrates the basic configuration of a VSC HVDC circuit.

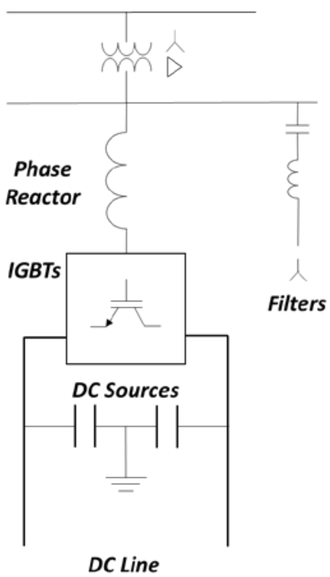


Figure XXX: Voltage Source Converter (VSC) High Voltage DC (HVDC) Circuit Oneline

[5] Conventional HVDC technology uses current-source, line-commutated converters that require a synchronous voltage source to operate. The converters demand large amounts of reactive power, and filters (shunt capacitors and reactors) are required to offset these demands and reduce levels of harmonic current caused by thyristor switching.

Relevant NERC Reliability Standards

While reactive power planning and operational needs vary significantly across North America and Canada based on local system characteristics and practices, the NERC Reliability Standards define a minimum set of requirements to ensure reliable planning and operation of the bulk power system. The primary standards codifying reactive power requirements in the operations and planning timeframes include VAR-001-4, VAR-002-4, TPL-001-4, and TOP-004-2. This section summarizes the language and focus of each standard.

VAR-001-4 and VAR-002-4 Summary

VAR-001-4 sets forth the requirements applicable to Transmission Operators to "ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection." VAR-002-4 sets forth the requirements applicable to Generator Operators and Generator Owners to "ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection." Generators are the largest and most reliable Reactive Power resource and play an integral role in maintaining voltage stability on the Bulk-Power System. Collectively, these Reliability Standards seek to prevent severe voltage deviations, voltage instability, and voltage collapse on the bulk power system.

VAR-001-4 requires each Transmission Operator to:

- Specify a system-wide voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within SOLs and IROLs, and to provide the voltage schedule to its Reliability Coordinator and adjacent Transmission Operators upon request (Requirement R1);
- Schedule sufficient reactive resources to regulate voltage within the specified tolerance levels (Requirement R2);
- Operate or direct the operation of devices to regulate transmission voltage and reactive flows (Requirement R3);
- Develop a set of criteria to exempt generators from certain requirements under Reliability Standard VAR-002-4 related to voltage operations, maintenance, and control, and notify a Generator Operator if its generator satisfies the exemption criteria (Requirement R4);
- Specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) for generators at either the high- or low-side of the generator step-up (GSU) transformer, provide the schedule to the associated Generator Operator, direct the Generator Operator to comply with that schedule, provide the Generator Operator the notification requirements for deviating from the schedule, and, if requested, provide the Generator Operator the criteria used to develop the schedule (Requirement R5); and
- Communicate step-up transformer tap changes, the time frame for completion, and the justification for these changes to Generator Owners (Requirement R6).

VAR-002-4 requires each Generator Operator to:

- Operate each of its generators connected to the interconnected transmission system in automatic voltage control mode or in a different control mode as instructed by their Transmission Operator, unless the Generator Operator (1) is exempted pursuant to the criteria developed under proposed Reliability Standards VAR-001-4, Requirement R4, or (2) makes certain notifications to the Transmission Operator specifying the reasons it cannot do so (Requirement R1);
- Maintain the Transmission Operator's generator voltage or Reactive Power schedule, unless the Generator Operator (1) is exempted or (2) complies with the notification requirements for deviation established by the Transmission Operator pursuant to VAR-001-4, Requirement R5 (Requirement R2);
- Notify its Transmission Operator of a change in status of its voltage controlling device lasting longer than 30 minutes (Requirement R3); and
- Notify its Transmission Operator of a change in reactive capability due to factors other than those described in VAR-002-3, Requirement R3 and lasting longer than 30 minutes (Requirement R4).

VAR-002-4 also requires each Generator Owner to:

- Provide information on its step-up transformers and auxiliary transformers within 30 days of a request from the Transmission Operator or Transmission Planner (Requirement R5); and
- Comply with the Transmission Operator's step-up transformer tap change directives unless compliance would violate applicable laws, rules or regulations (Requirement R6).

Standards VAR-001-4 and VAR-002-4 act in concert to ensure that, in the operational horizon, the bulk power system operates at acceptable voltage levels and that sufficient Reactive Power is available on the bulk power system to provide the voltage support necessary to maintain voltage stability.

TPL-001-4 Summary

TPL-001-4 establishes "Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." The standard applies to each Planning Coordinator (PC) and Transmission Planner (TP). Reactive power planning is a critical component of long-term reliability planning and system studies, as outlined in a number of the requirements in TPL-001-4. With respect to reactive power planning, TPL-001-4 requires each PC and TP to:

- Have criteria for acceptable system steady state voltage limits, post-contingency voltage deviations, and transient voltage response for its system. The transient voltage response criteria must specify, at a minimum, a low-voltage level and maximum length of time that transient voltages may remain below that level (Requirement 5). This requirement will establish more robust transmission planning for organizations and greater consistency as these voltage criteria are shared (Requirement R8).
- Define and document the criteria or methodology used to identify system instability for conditions such as cascading, voltage instability, or uncontrolled islanding within its planning assessment (Requirement R6).

- Trip generators in simulations where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady-state or ride-through voltage limitations. Assumptions for these tripping levels must be documented appropriately. (Requirement R3 for steady state; Requirement R4 for stability).

- Use a dynamic load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable (Requirement R2).

- Coordinate responsibilities between the Planning Coordinator and Transmission Planner(s), intended to eliminate confusion regarding the responsibilities of the applicable entities. This ensures that all elements needed for regional and wide area studies are defined with a specific entity responsible for each element and that no gaps will exist in planning for the Bulk-Power System (Requirement R7).

- Share planning assessments with neighboring systems, ensuring that information is shared with and input received from adjacent entities and other entities with a reliability related need that may be affected by an entity's system planning (Requirement R8).

TOP-004-2 Summary

The purpose of TOP-004-2 is to ensure the Bulk-Power System (BPS) is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

TOP-004-2 requires each Transmission Operator to:

- Operate within Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs), where IROLs and SOLs include voltage stability ratings and system voltage limits (Requirement R1);
- Operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency (Requirement R2);
- Operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator (Requirement R3);
- If the Transmission Operator enters an unknown operating state (i.e., any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes (Requirement R4);
- Make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take actions, as it deems necessary, to protect its area (Requirement R5); and
- Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including (Requirement R6):
    - Monitoring and controlling voltage levels and active and reactive power flows.
    - Switching transmission elements.
    - Planned outages of transmission elements.
    - Responding to IROL and SOL violations.

Reactive Power Analysis Timeframes

Reactive power planning and voltage control can be separated by timeframe to comprehensively understand system reactive capability requirements – these generic timeframes[6] and the considerations for each are addressed below.

Steady-State – Pre-Contingency

In steady-state operation, voltages are maintained within scheduled voltage ranges on the bulk power grid, with individual elements such as generators and dynamic reactive resources maintaining a terminal voltage set point value. Manual readjustment of network elements is performed to maintain these schedules throughout the day as load and transfer levels change. Automatic devices also continuously operate to maintain their set points. In these conditions, the system is at a planned operating condition in which all facilities are in-service or out-of-service on planned maintenance[7]. The grid is said to be operating in a "secure" state, meaning that there are no existing operating limit violations and analytical tools show no violations of emergency limits following any defined outage conditions. In the event that the analytical tools identify a post-contingency low (or high) voltage, actions are taken pre-contingency to mitigate this potential future state. This usually consists of inserting (or removing) shunt reactive devices on the system. All system controls are considered in (modeling) this system condition, including under-load tap changer action, automatic action of continuously responding resources, and voltage control modes.

Transient[8]

Following a major system disturbance, transient voltage stability is a concern and is studied using transient stability tools. In this timeframe, the following considerations are made:

- Generator automatic voltage regulator (AVR) excitation system response
- AVR over-excitation and under-excitation limiters (where applicable) may come into effect depending on design
- Generator turbine-governor controls, HVDC controls, and other fast-acting FACTS controls effects
- Automatic transformer tap changing is not considered due to their slow controls and intentional time delays
- Automated local or wide-area Remedial Action Schemes (RAS) such as generator shedding, automatic load shedding, line tripping, and other automatic actions are considered.

In this timeframe, dynamic reactive resources to sustain transient voltage support during the natural swings of the system are crucial. Figure XXX explains why voltage support, particularly in the middle of interconnected systems is critical. As power transfer between areas (and during power swings) increases, the angle difference between the areas, δ, increases. Assuming the voltage is held at each end due to generator terminal voltage controls, it is clear that the midpoint voltage magnitude, V_M, will change (decrease) when that angle difference increases. As the two ends of the system swing in terms of angle difference and power transfer, voltage magnitude also oscillates greatest at the midpoint. For this reason, transient voltage stability is generally a concern for systems with long transmission lines and high transfers between interconnected areas.

[6] These timeframes vary based on phenomenon, system configuration, planning procedures, etc.
[7] Also assuming that any pre-existing forced or unplanned outages have been dealt with.
[8] Typically 0 – 3 seconds.

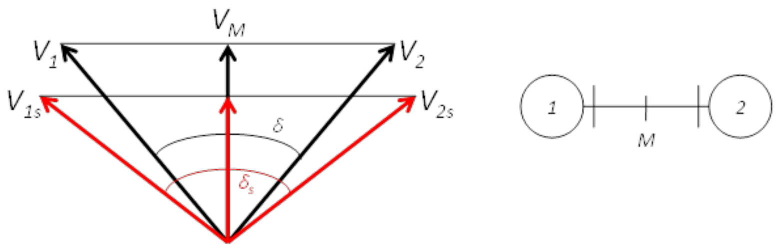


Figure XXX: Two-Area Vector Diagram – Voltage Oscillations

While pre-contingency voltages can be maintained using static reactive resources[9], this timeframe focuses primarily on dynamic reactive capability due to the transient nature of large power and voltage swings and the short response time required. It is important to differentiate between two distinct transient voltage responses:

- **Transient Voltage Dip:** voltage dips or sags caused by inter-area or local oscillations that result in large changes of active and reactive power flow and subsequently voltage.
- **Delayed Voltage Recovery:** delayed recovery of voltage primarily due to Fault Induced Delayed Voltage Recovery (FIDVR)[10] and stalling and restarting of induction motor load resulting in large draws of reactive power demand.

Figure XXX illustrates the fundamental difference between transient voltage dip events and delayed voltage recovery events. Transient voltage dips are a result of large power swings where significant voltage deviations can occur during the dynamic response of the grid to a major system event. This response is driven by inter-area transfer levels, system dispatch, dynamic reactive resources available, and system topology. Delayed voltage recovery events (FIDVR) are driven by load composition and end-use load behavior to major voltage sags caused by faults. Generally, FIDVR are relatively localized events within the transmission network rather than a wide-area response. Modeling delayed voltage recovery events is driven predominantly by the dynamic load model used and the capability to represent motor load(s) and stalling of induction motors. Appendix B provides transient voltage response criteria for operating entities across the interconnections, as required per TPL-001-4 Requirement R5.

[9] Static reactive devices should maintain pre-contingency voltages as much as possible to maximize dynamic reactive capability on the system. It is critical that dynamic reactive devices do not use their reserves in the pre-contingency operating state.

[10] 2015 NERC-DOE Dynamic Load Modeling & Fault Induced Delayed Voltage Recovery (FIDVR) Workshop Materials, Available: http://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/Workshop%20Presentations%20Fault-Induced%20Delayed%20Voltage%20Recovery%20(FIDVR).pdf

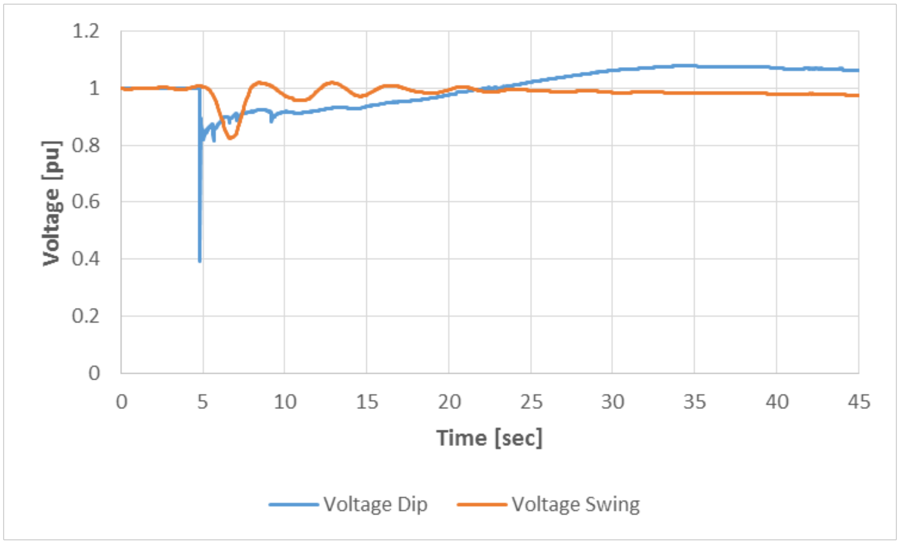


Figure XXX: Transient Voltage Response – Voltage Dip vs. Delayed Voltage Recovery

Mid-Term Dynamics[11]

After the first swing transient voltage response, the system (if stable) will begin to dampen oscillations and return to a new steady-state condition. As the transient oscillations dampen out, the system is in a transitory state termed "mid-term dynamic". During this timeframe, automated controls such as fast switched shunt reactive devices may be operating, dynamic resources are continually adjusting, and generator excitation systems are responding to maintain terminal voltage. This timeframe may or may not consider automatic load tap changing based on the control delays associated with ULTC action. Slower manual controls such as manual tap changing, operator-controlled capacitor switching, manually tripped interruptible load, etc., are not included in the analysis.

Long-Term Dynamics: Post-Contingency[12]

Once the system has found a new equilibrium point following the contingency, post-contingency analysis is performed to assess voltage stability and security. This analysis includes the results of all automatic control device that respond within this defined timeframe (3 mins). These include excitation systems maintaining voltage schedule, power factor, etc., governor response, Automatic Generation Control (AGC), and other continuous control devices including FACTS. Automatic tap changers[13] are acting in this timeframe to maintain voltage levels within control bands, and are modeled appropriately in the analysis. Manual controls such as manual tap changing,

[11] Typically 3 – 30 seconds.
[12] Typically 30 seconds – 3 minutes.
[13] Automatic tap changers between the boundary of the Transmission and Distribution systems should be considered in this timeframe, where applicable. These automatic devices can have an impact on load response.

capacitor switching, load shedding, etc., are not considered in this timeframe – it is assumed that operators are not acting this quickly to major system events.

Steady-State: Post-Contingency[14]

The last timeframe encompasses the applicable time associated with short term emergency ratings, generally 30 minutes. This means that the system must be within acceptable operating limits within 30 minutes following an event, and therefore the analysis timeframe ends at this point. All manual readjustments and automatic controls are considered within this timeframe. This include generation redispatch, transformer tap changing, manual and automatic capacitor switching, fast- or slow-acting RAS, and any other form of system adjustment relevant to the contingency.

[14] Typically 3 – 30 minutes.

Assessment Techniques for Ensuring Adequate Reactive Resources in the Planning and Operations Horizons

This section highlights the predominantly used techniques for reactive power planning and voltage stability analysis.

Analysis Techniques

There are various types of planning techniques for studying reactive power control and requirements for reliable operation of the bulk power system. This section briefly describes each type of planning technique and the situations where these analyses are useful.

QV Analysis

QV analysis provides the sensitivity of bus voltage with respect to injections of reactive power at a given bus location. The purpose of QV analysis is to determine how much reactive margin a particular bus has before voltage collapse would occur under pre- and post-contingency operating conditions. A system is defined as voltage stable if the V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for any one bus. QV curves are generated by placing a fictitious generator at the bus being analyzed. The voltage set point of the dummy generator is varied over a range and its var output is adjusted to meet this scheduled set point. The vertical axis output of a QV curve shows the output of the generator Mvar and the horizontal axis shows the voltage set point. Positive Q represents reactive power output from the dummy generator while negative Q represents reactive power consumption. The base case operating point is represented by the intersection of the curve with the x-axis (zero reactive power output of the dummy generator) of the curve. As voltage decreases from this point, reactive power is consumed by the fictitious generator. The minimum point ("bottom") of the curve represents the voltage stability point, which is the maximum allowable increase in load Mvar at the tested bus. The Q value at this minimum point is defined as the reactive power margin for this bus. That value must be below the x-axis (negative value, meaning consumption) for stable operating condition; otherwise a minimum above the x-axis is an unstable operating condition.

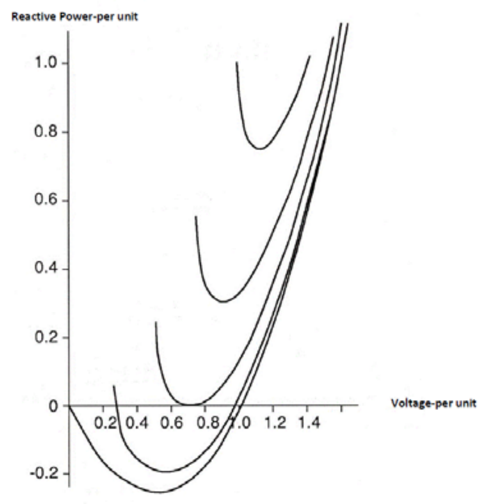


Figure XXX: QV Curve[15] [©CIGRE, 1986]

QV analysis is performed for both pre-contingency and post-contingency operating conditions. For post-contingency simulations, the contingent line is removed from service to establish a new operating condition. Then QV curves are generated for that condition to establish the stability points for that contingency event. Prior to varying the voltage setpoint of the dummy generator, all static var devices are typically locked (switched shunts, LTCs, etc.). Dynamic reactive devices (i.e., devices expected to respond prior to voltage collapse) are allowed to respond as the set point voltage of the dummy generator is varied. When a nearby reactive device reaches its maximum or minimum output limit, there is a discontinuity in the QV curve. A main advantage of QV analysis is that reactive power requirements can be computed without being affected by load flow convergence problems. At the same time, being a full AC power flow implementation, it is capable of representing all system effects and controls without numerical compromise. However, the method has the drawback that a bus, representative of a particular voltage collapse condition, must be preselected. Another drawback is evaluation speed; QV analysis is relatively slow, similar to PV analysis, running a series of power flow studies. However, parallel computing tools[16] can be used in these studies to eliminate speed concerns.

Although any positive margin is technically stable, utilities generally establish an 'adequate margin' which is typically the size of a nearby capacitor group or other reactive device. For example, if a 500 kV bus has 320 Mvar of margin and that same bus also has a 300 Mvar capacitor, this is considered adequate margin because failure of the capacitor to switch would still provide margin to the collapse point. Another situation that can happen is if the Q_{min}

[15] CIGRÉ TF 38.01.03, "Planning Against Voltage Collapse," technical brochure No. 24, October 1986.
[16] "MPjobs – running PSS®E in parallel," PSS®E User Group Meeting, May 2015.

point occurs at a very low voltage. For example, Q_{min} may occur at V = 0.70 pu; however, the grid is not operated at that voltage magnitude. Instead it may be useful to look at how much margin you have at higher voltages (i.e., V = 0.85 pu) and use that as the reactive margin even if it is not the Q_{min} point. This provides an assessment of the margin of failure before serious problems occur at other operating voltages. However, determining which bus in an area has the least reactive margin for a given contingency is also a challenge; often many buses will be screened for each contingency

PV Analysis

PV analysis provides the sensitivity of bus voltages with respect to increasing transfers of real power (MW) between a source and sink. PV analysis is the key tool in computing transfer capability and operating limits for interfaces and transmission paths that are known to be limited by voltage stability. PV analysis is the only technique that provides the proximity to voltage collapse in terms of real power transfer. The analysis can be performed for pre- or post-contingency conditions.

The real power transfer is increased using a combination of generation and load changes in the source and sink areas. Generally, generation is ramped up in the source area and load is increased in the sink area (G-L transfer); however, other transfers strategies include generation increase in the source area while generation is decreased in the sink area (G-G transfer) or load is decreased in the source area while load is increased in the sink area (L-L transfer). For a post-contingency analysis, a contingency is applied following each step increase in the transfer. As described in the previous section, in the pre-contingency timeframe all controls are modeled; whereas in the post-contingency (3-30 minute) timeframe only automatic controls are modeled. As with all steady-state analysis, interactions between the controls and the operation of undervoltage load shedding, under frequency load shedding, and remedial action schemes cannot be properly studied.

The maximum power transfer point ("nose" or "knee" of the curve) is the point where an incremental transfer will result in an inverse, unstable relationship between voltage and power (voltage instability). Near the nose of the curve, the magnitude of the voltage sensitivity, dV/dP increases rapidly. A load flow will generally be non-convergent at the nose of the curve. For convergent load flows, the transfer may also be limited by voltage violations such as pre- or post-contingency steady-state voltage limits, or voltage deviation limits. The voltage stability limit is the maximum power transfer point. To determine the Total Transfer Capability (TTC) a margin is used to account for possible inaccuracies in the modeling. The margin may be a constant MW value, but generally it is calculated as a percentage of the maximum power transfer using a voltage security factor. Typically, voltage security factors are 5% for single contingencies and 2.5% for double contingencies. However, as a note for using margin, one should not using arbitrary margin on a PV curve. Extensive studies are necessary to assign an appropriate margin. These same studies may show that a single margin does not work well system-wide. Figure XXX illustrates the functions of a PV curve for determining system limits.

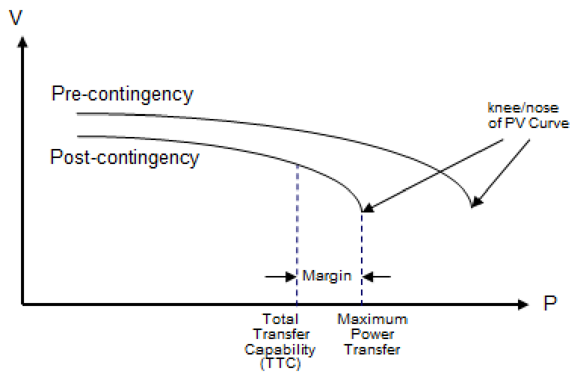


Figure XXX: PV Curve Examples

Contingency Analysis

Contingency analysis is conducted to ensure all transmission equipment will operate within their respective normal thermal ratings and voltage limits when the system is operating with all scheduled elements in service (Normal condition), and within its emergency thermal ratings and voltage limits immediately after a disturbance involving the loss of an element (single contingency or "N-1" condition), but without operator intervention. The system should be capable of such performance at all times, including operations during minimum and maximum forecasted load conditions. This "N-1" condition applies to both steady state and stability requirements. In addition to satisfactory performance for normal system conditions and for single contingencies, the system should be able to withstand extreme (more severe but less probable) disturbances without suffering voltage collapse, cascading or instability.

For voltage criteria testing, contingency analysis routinely checks for both voltage drop criteria and an absolute voltage criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow and it ranges from 2% to 6% depending on the adopted value by the region/utility. The absolute voltage criteria is examined for the same contingency set and it constitutes the acceptable lower and upper bus voltage magnitude limits immediately after a disturbance, e.g. 0.95 p.u and 1.05 p.u.

Transient Stability Analysis

Following the clearing of a fault, voltage will swing back up and then swing down. On the swing back down following the clearing of a fault, avoiding excessively large transient voltage dips is important both from a power quality perspective and from a bulk electric reliability perspective. The swing should not be so large as to cause additional facilities to trip (load or generation). Also, the dip should not be so large as to cause a voltage collapse. Many factors influence how large the transient dip is, including pre-contingency MW transfer levels, MW load levels, pre-contingency voltage levels and pre-contingency dynamic reactive reserve levels. A smaller MW transfer amount, a higher pre-contingency voltage, and larger amount of well-situated local dynamic reactive reserve will result in a smaller transient voltage dip following a disturbance. If a simulation shows that a transient voltage dip is

unacceptably large, the dip can be reduced by either reducing MW transfer levels, increasing pre-contingency voltages by bringing on more static reactive devices or dynamic reactive devices, or increasing dynamic reactive reserve by bringing on more well-situated local static reactive devices (thereby reducing output of dynamic reactive devices in pre-contingency).

Reactive Reserve Requirements

Having an appropriate amount of reactive reserve in pre-contingency is important to ensure that a transient or post-transient voltage collapse does not occur following a disturbance. Because a voltage collapse may be fast, typically only dynamic reactive reserve is counted as reactive reserve. Typically a system which is more stressed in pre-contingency state will have larger pre-contingency reactive reserve requirements in order to maintain stability following a contingency. System stress is increased as MW transfers across the system are increased. For example a system with a small pre-contingency MW transfer level may have a small reactive reserve requirement, and then as that MW transfer level increases the reactive reserve requirement will also increase. In order to meet the increased reactive reserve requirement an operator may switch in capacitors in the pre-contingency state to reduce var output of dynamic device, or the operator may bring more dynamic devices (i.e. more generators) online.

Dynamic reactive reserve of a device is measured as the difference between its present var output and its maximum var output. Its maximum var output is typically defined as that which can be sustained for an extended period (30 minutes or longer). For example the 1 to 2 minute overload capability of a STATCOM is not included as dynamic reactive reserve. For a generator, the maximum var limit is its steady state limit (i.e. from the “D” curve) not its transient maximum var output prior to over excitation limiter action.

Online PV analysis provides the maximum power transfer for critical contingencies and allows the real-time operator to be able to determine the *proximity to voltage collapse* for the prevailing system conditions. Without PV analysis to look ahead at the effect of increasing transfers, imports into an area may be allowed to increase until real-time contingency analysis shows highly depressed voltages or failure of the load flow to solve. At this point the system is operating in a high risk condition and the next contingency results in voltage instability.

Generally, the operator will maintain a margin to ensure that transfers are lower than the maximum power transfer point. Defining the reactive reserve requirements as the margin on a PV curve is often preferable than to using a constant Mvar reactive reserve value because it reflects the prevailing system conditions, specifically transmission outages and real and reactive power dispatch.

Addressing “Sufficient” Reactive Resources

Reactive power planning and reactive needs in the operating horizon vary significantly between Transmission Operators across the NERC footprint. In the operating horizon, sufficient reactive resources need to be available to ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection. In the planning horizon, sufficient reactive resources need to be planned for, such that the transmission system can meet planning performance requirements and result in a system that can be operated reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

Deriving Voltage Schedules

A Transmission Operator develops system voltage schedules, often based on nominal voltage level and system-specific requirements. The schedule is provided to the Generator Owner as either a set point voltage level, range of acceptable operating voltages (set point with range), or power factor control set point. This operating point is generally required at the Point of Interconnection between the generator and transmission system. Generators are required to provide voltage or reactive power control to maintain system voltage levels for reliable transfer of active power to serve the load. Reactive resources are operated to stay within applicable facility ratings to protect equipment from abnormal voltage levels.

Generators interconnecting to the Bulk Electric System are issued a voltage schedule or reactive power schedule to be maintained at the Point of Interconnection (POI). Generally a voltage range or target value and tolerance band are provided to the Generator Owner, as determined by the Transmission Operator, for normal operating conditions:

- **Range:** a range of acceptable operating voltages (e.g., 1.02-1.04 pu)
- **Target Set Point**: the preferred voltage or power factor under normal operating conditions.
    - **Target Voltage**: typically slightly above nominal voltage level (e.g., 1.02-1.05 pu)
    - **Target Power Factor**: typically around unity power factor (e.g., 1.0 pu)
- **Tolerance Band**: minimum and maximum voltage or power factor range under normal operating conditions.
    - **Voltage Tolerance**: typically a small bandwidth around the target set point (e.g., 1%)
    - **Power Factor Tolerance**: typically a small bandwidth around the target power factor (e.g., 0.01 pu)

As specified in VAR-001 and VAR-002, the Transmission Operator may modify the voltage range or target set point and tolerance band based on impending system conditions within mutually agreed upon capabilities of the generating facility, including ad hoc modifications to the voltage or reactive power schedules based on unplanned or unexpected operating conditions. While the voltage or power factor setpoint and tolerance band or range accounts for normal operating conditions, there generally is a wider range of acceptable maximum and minimum voltage schedule. Often times the scheduled operating voltage are defined in a manual or table used by the TOP, and voltage set point values may change based on peak and off-peak system conditions based on expected operating voltages.

Table XXX: Typical Operating Voltage Schedule Tables

Typical Operational Voltage Schedules - On-Peak Period			Typical Operational Voltage Schedules - Off-Peak Period			Typical Acceptable Max/Min Voltage Schedule Range	
	Tolerance Band			Tolerance Band			
kV Sched	kV High	kV Low	kV Sched	kV High	kV Low	Max kV	Min kV
356	359	353	356	359	353	362	327
116	118	114	116	118	114	121	109
118	120	116	117	119	115	121	110
119	121	117	117	119	115	121	110

<table>
<tr><td colspan="3">Typical Operational Voltage Schedules - On-Peak Period</td><td colspan="3">Typical Operational Voltage Schedules - Off-Peak Period</td><td colspan="2">Typical Acceptable Max/Min Voltage Schedule Range</td></tr>
<tr><td rowspan="2">kV Sched</td><td colspan="2">Tolerance Band</td><td rowspan="2">kV Sched</td><td colspan="2">Tolerance Band</td><td rowspan="2">Max kV</td><td rowspan="2">Min kV</td></tr>
<tr><td>kV High</td><td>kV Low</td><td>kV High</td><td>kV Low</td></tr>
<tr><td>358</td><td>361</td><td>355</td><td>356</td><td>359</td><td>353</td><td>362</td><td>335</td></tr>
<tr><td>118</td><td>120</td><td>116</td><td>118</td><td>120</td><td>116</td><td>121</td><td>109</td></tr>
</table>

Generator target voltages should be set to support secure operation of the BES for pre- and post-contingency conditions. Determining these schedules is based on operating experience and coordinated with voltages of neighboring Transmission Operators and other reactive power devices. Typical maximum and minimum voltage ranges are generally determined with mutual agreement between the TOP and Generator Owner and based on:

- Bulk-Power System reliability and security
- Internal generator operating constraints limiting plant capabilities including auxiliary bus voltage and plant-level loads
- Iterative communication process between Transmission Operator and Generator Operator
- IEEE Standard C57.116[17]: transformers directly connected to generators and the concept that generators can deliver a broad range of reactive power to the low voltage side of the GSU to keep system voltage near target voltage and within the tolerance band.
- IEEE Standard C50.13[18]: states that “the generator shall operate successfully at rated kilovoltampere, frequency, and power factor at any voltage range not more than 5% above or below rated voltage…”

Operating voltage schedules for normal conditions are generally set narrower than planning criteria to provide margin for conditions with multiple outages. For example, the maximum/minimum voltage schedule range may be set to 0.95 - 1.05 p.u. for operating voltages and 0.9 - 1.1 p.u. limits in the planning criteria[19].

This voltage range or tolerance band does not preclude temporary voltage or power factor excursions beyond the specified limits set by the TOP, particularly due to abnormal system conditions. Excursions outside of specified schedule are unavoidable due to contingency events; however, these temporary excursions are generally limited in extent, frequency, and duration. When they do occur, corrective actions are taken to return system voltage to within scheduled tolerance as soon as possible. Transmission Operators, working with the Reliability Coordinator, make determinations of the timing and actions to be taken to return values to within the specified voltage schedule. In addition, automatic controls (particularly dynamic reactive resources) also support post-contingency voltage by quickly responding to abnormal voltage conditions.

[17] *IEEE Guide for Transformer Directly Connected to Generators*, IEEE Standard C57.116-2014, 2014.

[18] *IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above*, IEEE Standard C50.13-2014, 2014.

[19] These maximum and minimum voltage ranges are the absolute maximum deviations determined by the Transmission Operator based on mutual agreement with the Generator Owner; this range is different than the voltage target and tolerance band, and is based on impending system conditions. The values provided in this example are illustrative; actual values change based on utility practices and nominal voltage level.)

Generator Voltage Control

Generators are the largest and most reliable Reactive Power resource and play an integral role in maintaining voltage stability of the Bulk-Power System. The dynamic reactive capability available on most generators contributes to the robustness of reactive resources available to respond to a wide array of postulated contingencies.

The Transmission Operators provide a voltage schedule (which is either a range or a target value with an associated tolerance band) for generators at either the high side or low side of the generator step-up (GSU) transformer. In addition, to ensure that the generator provides dynamic reactive support to the system, the Generator Operator should ensure that the generator operates with its Automatic Voltage Regulator (AVR) in service at all times unless exempted by its Transmission Operator, or unless the AVR is temporarily unavailable for maintenance or repairs. Notifications from the Generator Operator to its Transmission Operator are required anytime the AVR is out of service.

A Generator Operator that does not monitor voltage at the location specified by the Transmission Operator needs to convert the schedule to the voltage point monitored by the Generator Operator.

The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Units are often equipped with AVR's that can automatically compensate for calculated voltage drops from the control point to an external point on the system such as the high side of the GSU. In these occurrences the AVR signal is automatically adjusted to account for the voltage drop across the external equipment. In instances where several units are tied to the same bus there are often automatic schemes to adjust the units such that all the units contribute a share of the plant reactive output.

For those instances where the AVR cannot, or the entity chooses not to, use automatic volt drop compensation the Generator Operator that does not monitor voltage at the location specified by the Transmission Operator needs to convert the schedule to the voltage point monitored by the Generator Operator. There are many ways to convert the voltage schedule, including the development of voltage regulation curves for to account for the transformers losses or the use of straight ratio conversion.

Under certain circumstances the Transmission Operator can specify an alternative method of control to a Generator Operator such as a Reactive Power Schedule. Whichever the method of control; the Generator Operator needs to convert the schedule to a control point monitored by the Generator Operator.

Dynamic and Static Reactive Resources

Along with the magnitude of the reactive resource, one of the critical factors in scheduling or planning "sufficient reactive resources" is the operational characteristics of the resource. Static reactive resources provide a fixed nominal contribution when in-service while dynamic reactive resources provide controllable reactive power output in real-time to maintain a set point power output or voltage. The amount of "sufficient" resources depends on the

type of resource available. A balance between dynamic and static resources must be robust enough to support acceptable steady-state voltage limits, post-contingency voltage deviations, and transient voltage response when subjected to an array of potential contingencies.

Static reactive resources are committed pre-contingency and generally not allowed to switch post-contingency in the planning studies. An overreliance on static resources can result in acceptable or even high voltages pre-contingency but unacceptable post contingency voltages. Due to the static nature of the resource, operational constraints may develop due to minimal automatic control of voltage or reactive power output. Developing an acceptable mix of static and dynamic reactive resources is highly dependent on local system characteristics and practices. Figure XXX illustrates the fundamental change in P-V characteristic for increasing dependence on static resources. As the ratio of static to dynamic reactive resources increases, the pre- and post-contingency voltages remain flatter but the "nose" of the P-V curve becomes substantially steeper. Voltage magnitude becomes less indicative of system collapse and reactive margins become harder to determine.

It is noted that dynamic reactive devices can also create a flatter voltage profile when operating in voltage control mode; however, hitting maximum capabilities can create discontinuities in the P-V curve and should be analyzed accordingly.

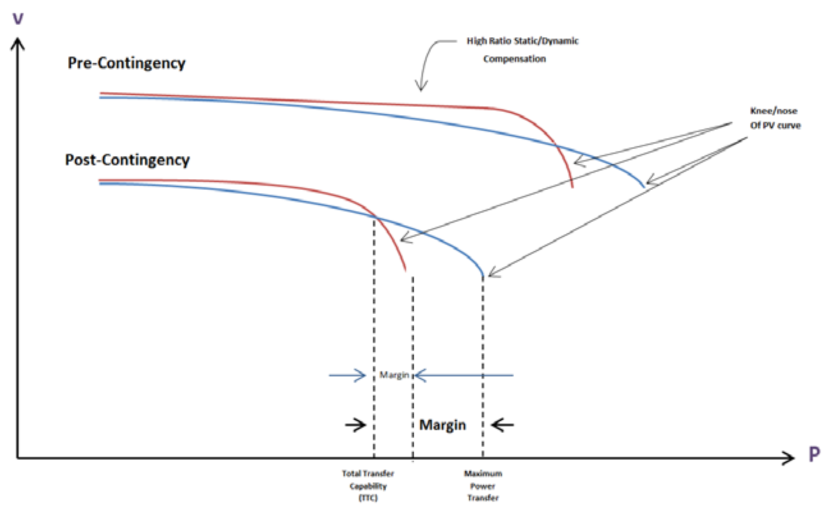


Figure XXX: PV Curve Results for High Ratio of Static/Dynamic Reactive Compensation

Operational Time-Dependent Voltage Limits

The use of general planning default pre- and post-contingency voltage limits (e.g., 0.95 to 1.05 p.u.), can often be unattainable in the real-time operating space. Specifically, the planning post-contingent voltage limits have no time variable associated with them which if used in real-time requires the operator to assume the limits are applicable immediately post-contingency. The inherent limits and assumptions used in planning generally account for

corrective devices to operate such as LTC action, switched shunts, SPS activation, etc. which are not available in real-time operations at $T = 0^+$. This assumption leaves no time for operators to utilize normal post-contingent actions, and potentially could force pre-contingent operator actions such as load shedding to protect for post contingent low voltage or equipment switching (remove cable / line charging) to protect for post contingent high voltage.

Drawing a parallel with the use of time dependent thermal limits (normal, LTE, STE), Transmission Operators may opt to consider time dependent voltage limits both high and low, to allow for post-contingent Operator actions to preclude pre-contingent actions. There is an acknowledgment that short duration exposure to potential high or low post contingency voltages represents an acceptable risk knowing Operator action within that short period of time can eliminate the exceedance. This is illustrated in Table XXX.

TABLE XXX: Time Dependent Voltage Limit Example

Normal Voltage Limits (NORMVL)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	109.0	121.0	328.0	362.0
TO 2	109.3	122.0	327.8	362.0
TO 3	109.3	121.0	327.8	362.0

Long Time Emergency Voltage Limits (LTEVL)

	115 kV			345 kV		
TO	Time Applicable	Low Voltage Limits (kV)	High Voltage Limits (kV)	Time Applicable	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	Infinite	105.0	121.0	N.A.	N.A.	N.A.
TO 2	30 minutes	105.8	124.0	N.A.	N.A.	N.A.
TO 3	Load cycle	103.5	121.0	Load cycle	310.5	362.0

Short Time Emergency Voltage Limits (STEVL 15 Minutes only)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High voltage limits (kV)
TO 1	102.0	121.0	N.A.	N.A.
TO 2	N.A.	N.A.	327.8	369.0
TO 3	100.0	121.0	N.A.	N.A.

Drastic Action Voltage Limits (DAVL 5 Minutes only)

TO	115 kV		345 kV	
	Low Voltage Limits (kV)	High Voltage Limits (kV)	Low Voltage Limits (kV)	High Voltage Limits (kV)
TO 1	100.0	121.0	N.A.	N.A.
TO 2	N.A.	N.A.	N.A.	N.A.
TO 3	98.0	121.0	N.A.	N.A.

Voltage Response

The voltage drop and recovery resulting from a system short circuit or fault depends on the location of the fault in relation to the measured voltage, and may vary from zero to a few percent of normal. The duration of the voltage response is determined by the fault clearing time and ranges from as low as 3 cycles on 345kV systems to one or more seconds on 34.5 kV sub-transmission systems. Following the fault clearing, the voltage passes through a transient recovery period before settling to the post-fault value. During this oscillatory transient period, additional voltage dips typically occur immediately after the voltage attempts to return to the pre-fault level due to motor reacceleration. The starting voltage, transient voltage response, and duration of the response are a measure of the system strength.

During the fault period, active power transferred from the generators to the system is reduced, causing the generators' internal angles to advance. When the fault is cleared, the generators have to supply the pre-fault active load again and their internal angle moves toward their pre-fault value. This slowing of the local generators draws inrush decelerating power from the remote generators and, coupled with motors' demand for accelerating power (the motors have slowed down during the lower fault voltage), causes a new voltage dip on the system. This second dip in voltage is then followed by an oscillatory transition to the post-fault steady-state voltage, as the machine prime mover power is again in balance with the electric load.

Voltage disturbances caused by high voltage transmission faults are classified as "instantaneous sags" in IEEE Standard 1159-1995 Table 2 (0.4 cycles to 30 cycles, 0.1 to 0.9 per-unit voltage) and the post-fault voltage dips are categorized as "momentary" (30 cycles to 3 seconds, 0.1 to 0.9 per-unit voltage). Instantaneous sags affect customers depending on the sensitivity of their equipment and the extent of their power conditioning. IEEE Standard 493-1997[20] ("Gold Book") reports that voltages to 85-90% of nominal as short as 16 milliseconds have triggered immediate outages of critical industrial processes. In the same standard, Table 9-12 accounts for sags ranging from 90% to 70% with durations up to 1250 milliseconds to include the effect of motor starting. Voltage dips tend to affect sensitive loads such as computer, computer-based equipment, power conversion, etc. Domestic and commercial electronic (computer) loads are more likely to ride through a sag if the magnitude and duration are within the ITIC[21] curve. Single-phase air-conditioners may stall, consuming up to 7 time rated reactive power due to locked rotor conditions. These compressor motors will remain stalled until their thermal protection trips them offline[22]. Industrial loads are the most vulnerable to severe voltage disturbances[23]. If a motor or energy management system (EMS) control contactor is unable to ride through a voltage sag, the motor and associated process is interrupted.

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 446-1987[24]. In Section 4.3.6 of this Standard, typical transfer threshold settings of 75% to 95% of pickup are given, with pickup settings ranging from 85% to 98% of nominal. Time delays are on the

Commented [RQ1]: This has been superseded by 1159-2009. Update reference and Section number.

Commented [RQ2]: This has been superseded by IEEE 493-2007.

Commented [RQ3]: This has been superseded by IEEE 446-1995. Update reference and Section number.

[20] *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems*, IEEE Standard 493-1997, 1997.
[21] Information Technology Industrial Council
[22] *Technical Reference Paper: Fault Induced Delayed Voltage Recovery*, Princeton, NJ: North American Electric Reliability Corporation, 2009.
[23] *IEEE Recommended Practice for Electric Power Distribution for Industrial Plants*, IEEE Standard 141-1993.
[24] *IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications*, IEEE Standard 446-1987.

order of 1 second. This means that voltages below 80% (the limit suggested on the ITIC curve) are likely to initiate automatic load transfers.

Voltage sags in power systems are unavoidable; however, the system can be designed and operated to minimize severe voltage sags. High speed fault clearing, special protection systems, field forcing, transmission reinforcements, and transmission interface transfer limits can be considered by Generator Owners and Transmission Owners as options to improve voltage sag performance. Customers can apply power-conditioning technologies such as Uninterruptible Power Supplies (UPS) to sensitive loads.

Light Load Operating Conditions

The system must be designed and operated to meet system performance criteria for conditions ranging from the peak period of a heavy load day through an extremely light load period such as the early morning hours during a spring or fall holiday weekend. To ensure there is necessary operational flexibility, Transmission Planners must consider a sufficient mix of lagging and leading reactive power resources for controlling system voltages over the full range of possible load levels.

Maximum voltage limits should not be exceeded in real-time on both a pre- and post-contingency basis. While high voltage conditions are not as likely to propagate across the interconnection as extremely low voltage conditions, they can result in significant equipment damage. Additionally, high-voltage conditions, either in the steady-state or transient time frames, can lead to tripping of generation (especially inverter-based generation such as intermittent renewable resources). Planning studies should pay careful attention to transient high voltages when interconnecting these resources, to ensure both that the new resources can ride through expected high-voltage events and also that they do not worsen high-voltage conditions for other nearby units.

Operations personnel use real-time reliability monitoring and analysis capabilities to evaluate the actual pre-/post-contingency state of the system and a forward looking forecasted state of the system. If actual or simulated post-contingency conditions indicate high voltage limits may be exceeded, the operator will take action to reduce the voltage. Typical techniques to control high voltages include:

- Switching shunt capacitors out-of-service
- Switching shunt reactors in-service
- Operating synchronous generators/condensers in leading power factor (var absorbing) mode by changing generator voltage setpoints
- Adjusting voltage set point of dynamic reactive resources (SVC, DVAR, STATCOM)
- Changing transformer tap positions
- Changing phase angle regulating transformer (PAR) settings to adjust real-power flows,
- Switching transmission facilities in/out of service

Transmission to Distribution Boundary

Modeling

The boundary between Transmission Owner (TO) and Distribution Provider (DP) in power flow, stability analysis, and real-time is usually defined by explicit loads modeled as MW and Mvar. These loads may simply be modeled on the high side of the bus/substation or potentially modeled behind the step down transformers and/or equivalent distribution impedances. The voltage and reactive power performance of the BES can be impacted by the load power factor (LPF) modeled across the TO-DP boundary. Loads should not over-rely on reactive support (lagging or leading) from the BES; conversely, the BES should not solely depend on the load for reactive support (lagging or leading). Coordination between TO and DP is important in determining what the proposed LPF should be at critical load levels such as peak and light load.

Planning

To conduct necessary future studies the planners must use a forecasted active power demand and a representative load power factor (LPF). Joint studies between TO and DP may be required to determine a set of mutually agreed upon minimum and maximum LPF to assure that the system is planned and operated in an efficient and reliable manner. The determination of an optimal LPF will inherently result in the appropriate level of reactive support installed on both the distribution and BES systems. Having a minimum and maximum LPF will also ensure the reactive component of the load will not contribute to low or high voltages on the BES. If power factor falls outside this bandwidth, the DP should take action in their reactive power plan to correct their LPF to meet or exceed this agreed upon bandwidth. The LPF at the TO/DP boundary does not need to be unity power factor; however, a reasonable and acceptable range is recommended. Definition of the LPF should clearly differentiate and consider all applicable reactive compensation at both the DP- and TO-side of the boundary point as well as all relevant contingencies.

Operations

MW and Mvar loads are actively displayed to system operators in the EMS via SCADA. In the event of real-time voltage events or predicated post contingency voltage events as seen in RTCA, the TO operator may opt to further coordinate with the DP in real-time to potentially adjust distribution compensation to alter the LPF to provide additional support to the BES. This is generally in the form of switching distribution side reactive devises to alter the net LPF as seen by the BES.

Recommended Practices

Forecasted LPF should be reviewed periodically using real-time measured MW and Mvar values at the load aggregation points for operating conditions modeled in the case (e.g., heavy summer peak, off-peak shoulder, heavy winter peak, etc.). Depending on SCADA availability at the metering locations relative to actual load location, an agreed upon methodology should be established to accurately measure and report the LPF at the TO-DP boundary. LPF’s outside the defined bandwidth should be reconciled on a periodic basis by the TO and DP.

NERC Reliability Standards do not require any specific LPF or specify any minimum LPF requirements at the TO-DP boundary. This is left up to the TO to specify in their tariffs, other mandatory operating procedures, or documented coordination agreements with the DP.

Transmission to Generation Boundary

FERC has established the reactive power capabilities at the Point of Interconnection for new Large and Small Generating Facilities. Existing generators must provide the reactive power capabilities in accordance with the most recently signed Interconnection Service Agreement. The TO should periodically review with the GO the expected

reactive power performance for each generator. MOD-025 requires that the generator real and reactive power capability be verified and reported to the Transmission Planner for accurate system studies[25]. The TO should also require the GO to provide information on future changes to any generator that would change the reactive power capabilities of the generator. The TO should assure that the assessments of near term and long term system performance during normal and contingency conditions for both steady-state and dynamic conditions utilize realistic performance capabilities of the generators. This should include overexcited and underexcited operation. The TO should periodically review data from real-time operations to confirm that reactive power performance matches the capabilities being used in the simulations of power system.

Planning Coordinator to Planning Coordinator Boundary

Planning Coordinators should develop processes to assure adequate reactive power resource capabilities within their own footprint and in coordination with adjacent Planning Coordinator areas. These processes should include mechanisms to assure that the periodic assessments of near term and long term performance of the transmission system are based on correct projections of reactive power requirements and reactive power resource capabilities. In general, each TO should provide reactive power resource capabilities to match their reactive power requirements. Similarly, in general, each PC should assure that the reactive power resource capabilities within that PC footprint will meet the reactive power requirements within that footprint. Actual reactive energy demand on the boundary between PCs would not be scheduled in actual operation. However, each PC should have the reactive resource 'capability' to balance reactive demand under RC direction and TOP operator control within 30 minutes. In some cases electrically coherent PCs and their associated PCs may span more than one RC. In such cases PC/PCs must coordinate with multiple RCs. In these cases the operational implementation plan will affect more than one RC. Both traditional reactive sources and contract demand side management should be under RC/TOP operator control within 30 minutes. If not, those reactive resources would not be counted as part of the RC/TOP reactive resources. Real time security analyses should consider reactive power requirements and resource capabilities in the near-term operating environment.

[25] NERC Reliability Standard MOD-025-2: Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability. Available: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-025-2&title=Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability&jurisdiction=United States

Appendix A: Industry Reactive Power Planning Practices & Procedures

Appendix A provides reactive power planning practices, procedures, and requirements for an array of entities across North America. This section includes analysis tools, techniques, planning horizons, and relevant reference materials.

Electric Reliability Council of Texas (ERCOT)

ERCOT Planning Guides provide criteria to maintain a reliable power system and in particular reliable reactive planning. There are direct and indirect requirements on all network Elements related to voltage or reactive power. ERCOT requires the following:

- Compliance with NERC Reliability Standard TPL-001-4
- Voltage Support [ERCOT Protocol 3.15]: ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish the ERCOT System Voltage Profile for all Electrical Buses used for Voltage Support in the ERCOT System including synchronous generation capability to maintain a power factor in the range of +/- 0.95, AVR in voltage control, and automatic operating mode. Wind-powered Generation Resources (WGRs) must be capable of producing a defined quantity of Reactive Power to maintain an established Voltage Profile. New Generation is required to have voltage ride through (low- and high- voltage ride through.
- Extended modeling - The ERCOT System consists of those generation and Transmission Facilities (voltages 60 kV and higher) that function as part of an integrated and coordinated system.
- Steady State Voltage Response Criteria [ERCOT Planning Guide 4.1.1.4]
  - In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following steady state voltage response and post-contingency voltage deviation criteria:
    - 0.95 – 1.05 p.u. in the pre-contingency state following the occurrence of any operating condition in category P0 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
    - 0.90 – 1.05 p.u. in the post-contingency state following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
  - Following the occurrence of any operating condition in categories P1 through P7 of the NERC Reliability Standard TPL-001-4, further analysis to assess voltage stability is required in the event of a post-contingency steady-state voltage deviation that exceeds 8% at any load-serving bus above 100 kV. This is exclusive of buses on a radial system that serve only Resource Entities and/or Load. After further analysis, ERCOT and the TSPs shall endeavor to resolve any voltage instability.
  - If a TSP has communicated to ERCOT that a Facility has unique characteristics and may operate outside of the above ranges and deviation (e.g. Facilities located near a series capacitor) or the Facility needs to be operated in a more restrictive range (e.g. a nuclear plant, UVLS relay settings) or its system is designed to operate with different voltage limits or voltage deviation, then the TSP’s specified limits will be considered acceptable.

- Voltage Stability Criteria [ERCOT Planning Guide 4.1.1.3] - In conducting its planning analyses, ERCOT and each TSP shall ensure that the voltage stability margin is sufficient to maintain post-transient voltage stability under the following study conditions for each ERCOT or TSP-defined area:
  - A 5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P0 and P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements; and
  - A 2.5% increase in Load above expected peak supplied from resources external to the ERCOT or TSP-defined areas and operating conditions in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements.
- Higher performance for selected contingencies – Some TPL-001-4 contingencies are given a higher system response performance, which translates to a better voltage and reactive profile.
  - P1 performance - A common tower outage is the contingency loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater.
  - P1 performance - The contingency loss of a single generating unit shall include the loss of an entire Combined Cycle Train, if that is the expected consequence.
- Regional Reliability Performance Criteria [ERCOT Planning Guide 4.1.1.2]
  - The following performance criteria (summarized in Table 1, ERCOT-specific Reliability Performance Criteria, below) shall be applicable to planning analyses in the ERCOT Region:
    - (a) With all Facilities in their normal state, following a common tower outage, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss.
    - (b) With any single generating unit unavailable, followed by Manual System Adjustments, followed by a common tower outage, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss.
    - (c) With any single 345/138 kV transformer unavailable, followed by Manual System Adjustments, followed by a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, or FACTS device, all Facilities shall be within their applicable Ratings, the ERCOT System shall remain stable with no cascading or uncontrolled Islanding, and there shall be no non-consequential Load loss. An operational solution may be planned on a permanent basis to resolve a performance deficiency under this condition.
    - (d) Assessments, including proposed solutions, associated with criteria in paragraph (c), above, and line 3 of Table 1 below, shall be completed by no later than May 1, 2015.

Table XXX: ERCOT-specific Reliability Performance Criteria

Initial Condition		Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-Consequential Load Loss Allowed
1	Normal System	Common tower outage	Yes	No

Initial Condition		Event	Facilities within Applicable Ratings and System Stable with No Cascading or Uncontrolled Outages	Non-Consequential Load Loss Allowed
2	Unavailability of a generating unit, followed by Manual System Adjustments	Common tower outage	Yes	No
3	Unavailability of a 345/138 kV transformer, followed by Manual System Adjustments	Common tower outage; or Contingency loss of one of the following: 1. Generating unit; 2. Transmission circuit; 3. Transformer; 4. Shunt device; or 5. FACTS device	Yes	No

- ERCOT and the TSPs shall endeavor to resolve any performance deficiencies as appropriate. If a Transmission Facility improvement is required to meet the criteria in this Section 4.1.1.2, but the improvement cannot be implemented in time to resolve the performance deficiency, an interim solution may be used to resolve the deficiency until the improvement has been implemented.

FRCC

With all facilities in-service, imports into Florida are known to be limited by voltage stability. In the FRCC the voltage stability limits of the Southern/Florida interface are studied in the Transmission Planning, Operations Planning, and real-time horizons. In the Transmission Planning and Operations Planning horizons a voltage security factor of 5% of single contingencies and 2.5% for double contingencies is used to provide a margin between the maximum power transfer and the TTC. The maximum power transfer is considered to be an Interconnection Reliability Operating Limit (IROL) since critical contingencies above that import level may result in voltage instability throughout the FRCC. The studies are coordinated with Southern Company.

In the Transmission Planning Horizon PV analysis is performed in PSSE for critical single and double contingencies to determine the IROL and the Total Transmission Capability. Peak summer and winter base cases are used.

PV analysis is performed daily in PSSE for transfers into the FRCC using the expected load, transmission outages, generation outages, and any confirmed transmission transactions for the next day. The day-ahead PV analysis is used to set the TTC for the next day, which may be higher or lower than the value determined in the long-term studies.

As a last line of defense, PV analysis is ran automatically in the Energy Management Systems used by the FRCC Reliability Coordinator. The reliability coordinator receives an alarm if the post-contingency PV margin falls below 200 MW. The reliability coordinator may also run PV analysis manually if he is aware of upcoming system changes that may affect voltage stability.

Independent System Operator of New England (ISO-NE)

Operational horizon

ISO New England operates its system to perform acceptably, pre- and post-contingency, for a defined set of operating contingencies, within the voltage limits provided by the transmission equipment owners utilizing the regional operating procedures, guidelines, and standards. Voltage limits include both low and high limits, and are time dependent. Equipment owners can provide any or all of the normal and emergency voltage limits defined for use, which may be effective continuously (normal), over a long time duration (long time emergency, or LTE), a shorter duration (short time emergency, or STE – a 15 minute limit), or brief duration for emergent concerns (drastic action limit, or DAL – a 5 minute limit). The possibility of voltage collapse is also recognized and used in determining steady state limits while operating the system.

ISO New England examines system voltage / reactive needs in the operations horizon from two or more years out up to real time. Long term studies focus on determining system voltage / reactive needs in defined portions of New England, how reactive resources must be utilized to meet voltage limits under all potential stresses (peak, intermediate, and light load conditions; with and without heavy transfers) under defined single contingency (N-1) or multiple contingent (N-1-1) events. This longer term operational planning analysis also examines and documents the envelope of acceptable load power factor required to attain acceptable transmission system performance over the continuum of system conditions. This load power factor requirement information is provided to the local distribution companies to allow them to adjust and change their reactive compensation programs, at the distribution level, to provide integrated reactive power support with local transmission / generation facilities and maintain system reliability. These analyses also provide a feedback path into the transmission planning process when they find reactive resource deficiencies that cannot be met with the existing portfolio of reactive resources.

These operational reactive planning efforts support other operational evaluations of system reactive needs. These analyses focus on analyzing and capturing, in transmission operating guide form, any unit commitment or defined reactive resource use for reliability needs for N-0 and N-1 conditions. These include voltage / reactive issues ranging from peak load / low voltage concerns to minimum load / high voltage concerns. The analyses may also support the creation or revision of operator tools and aids in monitoring system voltage / reactive performance for the transmission operating guides in outage coordination and real-time operations.

These voltage / reactive evaluations are continued through the outage coordination process, which allows outages to be provided by asset owners, and evaluated by local and ISO-NE outage coordination staff, up to two years out. ISO-NE's outage coordination staff (both short term and long term) performs AC power flow analyses for forecast loads, generation, system transfers and scheduled / approved outages, and identifies any voltage / reactive issues. They propose solutions (i.e. reactive resource posturing, generation dispatch, outage re-scheduling) and request, as needed, additional engineering analysis support. The engineering support can result in outage topology dependent operating guidance, which may take the form of operational guidance on the outage application, or a temporary operating guide, which describes the operating actions required for reliable operation during the defined outage scenario. These actions / limits are used by operators in real time, as well as their real time tools, which perform real-time AC contingency analysis, reactive reserve monitoring and voltage transfer limit evaluations. Voltage schedules for significant generation and transmission reactive assets are monitored in real time to support acceptable system voltage and stability performance. Deviations from the defined upper and lower limit voltage schedule bands are alarmed and acted upon by ISO operators to maintain system security.

Planning horizon

ISO New England plans its system consistent with NERC, NPCC[26], and ISO New England[27] planning criteria, with additional guidance provided by the ISO New England Transmission Planning Technical Guide[28] ("Technical Guide"). Section 4 of the Technical Guide describes the voltage criteria used in planning the system.

Voltage standards have been established to satisfy three constraints: maintaining voltages on the distribution system and experienced by the end-use load customers within required limits, maintaining voltages for transmission equipment and equipment connected to the transmission system within that equipment's rating, and avoiding voltage collapse. Generally the maximum voltages are limited by equipment and the minimum voltages are limited by customer requirements and voltage collapse. The standards apply to networked facilities operated at a nominal voltage of 69 kV or above.

The voltage standards prior to equipment operation apply to voltages at a location that last for seconds or minutes, such as voltages that occur prior to transformer load tap changer ("LTC") operation or capacitor switching. The voltage standards prior to equipment operation do not apply to transient voltage excursions such as switching surges, or voltage excursions during a fault or during disconnection of faulted equipment.

Pre-Contingency Voltages

The voltages at all networked buses must be in the range of 0.95-1.05 p.u. with all lines in service.

There are two exceptions to this requirement. The first is voltage limits at nuclear units, which are described below. The second exception is that higher voltages are permitted at buses where the affected Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. Often the limiting equipment under steady-state high voltage conditions is a circuit breaker. Maximum breaker voltages are based on IEEE Standard C37.06[29].

Table XXX: Maximum Operating Voltages for Breakers

Breaker Nominal Voltage [kV]	Maximum Operating Voltage [kV]
345	362
230	245
138	145
115	123*
69	72.5

* Older 115kV breakers may have different maximum voltage limits.

For N-1 contingencies, shunt VAR devices are modeled in or out of service pre-contingency, to prepare for high or low voltage caused by the contingency, as long as the pre-contingency voltage standard is satisfied. For testing of an N-1-1 contingency, shunt VAR devices are switched between the first and second contingencies to prepare for

[26] https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf
[27] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf
[28] http://www.iso-ne.com/static-assets/documents/2016/01/planning_technical_guide_1_15_16.pdf
[29] *IEEE Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities for Voltages Above 1000 V*, IEEE Standard C37.06-2009, 2009.

the second contingency as long as the post contingency voltage standard is satisfied following the first contingency and prior to the second contingency.

Post-Contingency Low Voltages Prior to and After Equipment Operation

The lowest post-contingency voltages at all networked buses must be equal to or higher than 0.90 per unit prior to the automatic or manual switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors. Dynamic devices such as generator voltage regulators, STATCOMs, SVCs, DVARs, and HVDC equipment are assumed to have operated properly to provide voltage support when calculating these voltages. Also capacitor banks that switch automatically with no intentional time delay (switching time is the time for the sensing relay and the control scheme to operate, usually a few cycles up to a second) may be assumed to have operated when calculating these voltages. No N-1 or N-1-1 contingency (described in Technical Guide Sections 12.4 and 12.5) is allowed to cause a voltage collapse.

The lowest voltages at all networked buses must be equal to or higher than 0.95 per unit after the switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors. There are two exceptions to this standard. The first is voltage limits at nuclear units. The other exception is that voltages as low as 0.90 per unit are allowed at a limited number of networked buses where the affected Transmission Owner has confirmed that the associated lower voltage system has been designed to accept these lower voltages and where the change in voltage pre-contingency to post-contingency is not greater than 0.1 per unit.

Post-Contingency High Voltages Prior to and After Equipment Operation

ISO New England is currently developing a standard for high voltages prior to corrective action. After equipment operation, the highest voltages at all networked buses must be equal to or lower than 1.05 per unit. The only exception is that higher voltages are permitted where the affected Transmission Owner has confirmed that all equipment at those buses is rated to operate at the higher voltage.

Voltage Limits for Line End Open Contingencies

There is no minimum voltage limit for the open end of a line if there is no load connected to the line section with the open end. If there is load connected the above standards for post-contingency low voltage apply. ISO New England is currently developing a standard for the maximum voltage limit for the open end of a line.

Transient Voltage Response

ISO New England employs the criteria described in Appendix E of the Technical Guide[30].

[30] http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_e_voltage_sag_guideline.pdf

Voltage Limits at Buses Associated with Nuclear Units

The minimum voltage limits at the following buses serving nuclear units, both for pre-contingency and for post-contingency after the switching of capacitors and operation of transformer load tap changers, are listed below. These limits apply whether or not the generation is dispatched in the study.

Table XXX: Nuclear Unit Minimum Voltages

Critical Bus	Minimum Bus Voltage
Millstone 345 kV bus	345 kV
Pilgrim 345 kV bus	343.5 kV
Seabrook 345 kV bus	345 kV
Vermont Yankee 115 kV bus	112 kV[31]

The minimum voltage requirements at buses serving nuclear units are provided in accordance with NERC Standard NUC-001.

[31] Due to the retirement of Vermont Yankee, the unique minimum voltage limit at Vermont Yankee 345 kV will be eliminated. The unique voltage limit at Vermont Yankee 115 kV will temporarily be 112 kV and will be eliminated within about three years dependent on NRC approval.

MISO Energy

MISO's voltage and reactive power assessment, control, coordination and planning practices are largely governed by the following two documents:

- Voltage and Reactive Power Management Business Practice Manual (BPM-020), and
- Transmission Planning Business Practices Manual[32] (BPM-018)

These documents outline the voltage and reactive power management processes undertaken by MISO and the companies within the MISO footprint in accordance with and beyond the requirements of the NERC standards for Transmission Operations, Transmission Planning and for Voltage and Reactive Power Control (NERC TOP, TPL and VAR Standards). These documents also note the roles and responsibilities of MISO and its member companies in analyzing, maintaining, monitoring, and controlling voltage levels, reactive resources, and reactive power flows within the MISO footprint. Specifically, as it pertains to voltage and reactive power, the complementary roles of MISO as the Reliability Coordinator and the Transmission Operators (TOPs) and Generation Operators (GOPs) are delineated.

Voltage and Reactive Power Planning: MISO ensures efficient and reliable system operations through detailed evaluations and assessments performed for a range of system conditions from real-time operations to the long-term planning horizon covering the next 10 years. Analyses performed typically include:

- Steady-state contingency analyses
- Transient stability/dynamics analyses
- Transfer studies
- P-V/Q-V analyses
- Static/dynamic real-time reactive power reserves calculations
- Generator interconnection and deliverability analyses

Voltage coordination: Conflicting voltage levels and set-points/targets on neighboring systems can cause operational issues as well as incorrect planning of the system. MISO works with its neighbors to develop coordinated reactive power and voltage management policies to ensure the mutual objectives of ensuring system reliability and efficiency are fulfilled.

[32] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Peak Reliability

Peak uses a real-time voltage stability tool, V&R Energy ROSE software, and uses P-V and Q-V analysis for all identified IROLs. These are used to calculate the reactive margin for specific buses. Peak will be extending this analysis for other Paths that might have voltage stability issues.

Peak monitors system bus voltages WECC-wide in real time in the EMS state estimator and using Real-Time Contingency Analysis (RTCA) for N-1 contingency analysis. These voltages are compared against their respective limits. Voltage limits are also monitored for all operational planning studies (next day, near real-time). The limits are provided by the Balancing Authorities and Transmission Operators.

Peak also monitors transient voltage response for online transient stability assessment. While there is no operational requirements related to transient voltage response, Peak is working with the WECC entities to determine an appropriate voltage response level based on expected consequences of delayed voltage recovery or severe voltage dips (e.g., based on under- or overvoltage relay settings).

PJM Interconnection

Operational horizon

PJM directs the operation of the PJM system according to approved NERC Standards. In doing this, PJM considers transmission constraints, restrictions, and/or limitations in the overall operation of the PJM RTO. The PJM RTO is operated such that the following are not exceeded:

- Transmission facility thermal limits
- Voltage limits
- Transfer limits
- Stability limits
- Interconnection Reliability Operating Limits (IROL)

The PJM RTO is operated so that loading on all PJM SOLs are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.

This principle requires that action be taken before a malfunction or failure occurs in order to control post-contingency loading on a pre-contingency basis. In addition to traditional thermal limitations; PJM operates the PJM RTO considering voltage and stability related transmission limits. These limitations are:

- **Voltage Limits:** High, Low, and Load Dump actual voltage limits, high and low emergency voltage limits for contingency simulation, and voltage drop limits for wide area transfer simulations to protect against wide area voltage collapse.
- **Transfer Limits:** The MW flow limitation across an interface to protect the system from large voltage drops or collapse caused by any viable contingency.
- **Stability Limits:** Limit based on voltage phase angle difference to protect portions of the PJM RTO from separation or unstable operation.

PJM will operate the facilities that are under PJM's operational control such that no PJM monitored facility will violate normal voltage limits on a continuous basis and that no monitored facility will violate emergency voltage limits following any simulated facility malfunction or failure. Typically, high voltage emergency limits are equipment-related while low voltage limits are system-related.

Transfer Limits (Reactive/Voltage Transfer Limits)

Post-contingency voltage constraints can limit the amount of energy that can be imported from and through portions of the PJM RTO. PJM utilizes a real-time Transfer Limit Calculator (TLC) Program within the PJM EMS System to evaluate the reactive interface for voltage instability. TLC is utilized to establish inter-regional and intra-regional Transfer Capability and to determine Transfer Limits for the use in real-time operation.

Stability Limits

The PJM RTO established stability limits for preventing electrical separation of a generating unit or a portion of the PJM RTO. PJM recognizes three types of stability:

- **Steady State Stability:** A gradual slow change to generation that is balanced by load.

- **Transient Stability:** The ability of a generating unit or a group of generating units to maintain synchronism following a relatively severe and sudden system disturbance. The first few cycles are the most critical time period.
- **Dynamic Stability:** The ability of a generating unit or a group of generating units to damp oscillations caused by relatively minor disturbances through the action of properly tuned control systems.

PJM will operate the facilities that are under PJM operational control such that the PJM system will maintain angular and voltage stability following any single facility malfunction or failure. PJM utilizes a real-time Transient Stability Assessment (TSA) tool that interfaces with the PJM EMS System to perform this analysis in real time. PJM Manual 3: Transmission Operations[33] discusses specific transmission conditions and procedures for the management of transmission facilities within the PJM control area.

Planning Horizon

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM Regional Transmission Expansion Planning (RTEP) reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for a period of 5 years out from the current year. The longer term view is applicable for a period of 6 to 15 years out from the current year. Each review entails multiple analysis steps subject to specific criteria that depends on the facilities and the type of analysis being performed.

Reactive planning is accomplished via the PJM RTEP process. The robustness of the PJM network is achieved by conducting analysis over a wide range of system conditions. This includes a Reference case, seasonal analysis, a load deliverability analysis, and a generation delivery analysis. There are several steps in an annual near-term reliability review. They are:

- Baseline analysis
- Load Deliverability analysis
- Generation Deliverability analysis
- Stability analysis

<u>Baseline Analysis</u>

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability purposes. Baseline analysis is a thorough analysis of the reference power flow to ensure adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) thermal limits or voltage criteria. It is based on a 50/50 load forecast from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load).

[33] http://www.pjm.com/~/media/documents/manuals/m03.ashx

- **Load Deliverability Analysis:** Suite of tests to ensure that the Transmission System provides adequate deliverability of power flow to each load area's requirements from the aggregate of system generation. The tests use an array of probabilistic dispatches to determine "expected loading" to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 failure event in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.
- **Generation Deliverability Analysis:** The Generation Deliverability test ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each "area".

PJM Manual 14[34] series (14a, 14b, 14c, 14d, and 14e) provides information regarding PJM's Planning Process. Details of the Transmission Planning Process are contained in manual 14b

Southern Company

Satisfactory voltage performance is determined by evaluating steady-state and transient voltages during normal, contingency, and post-contingency conditions. This evaluation covers projected system load levels and conditions in the Planning horizon. Power flow analysis is performed to assess the system during steady-state conditions. The general steady-state screening criteria for post-contingency networked 300kV and below BES transmission buses are as follows:

- Voltage magnitudes are planned to be in the range of .95-1.05 pu for P0 no contingency conditions
- Voltage magnitudes should generally be in the range of 0.92-1.05 pu for P1-P2 single contingencies
- Voltage magnitudes should generally be in the range of 0.90-1.05 pu for P3-P7 multiple contingencies
- For load serving stations with voltage regulation equipment, the voltage deviation should be less than 8%
- For load serving stations without voltage regulation equipment, the voltage deviation should be less than 5%

The screening criteria for 500kV transmission buses is generally 0.97 – 1.075 p.u. for all Planning Events (P0-P7).

Bus voltages found in the power flow analysis which do not meet these guidelines will generally result in the addition of static reactive resources to the system.

In addition to power flow analysis, a static voltage stability analysis is performed using the so-called P-V curve technique. Voltage instability is defined as the knee of the P-V curve. The system is planned such that it will operate with 5% or greater margin from the voltage instability point for P1-P2 single contingencies and for P3 contingencies.

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[34] PJM Manual 14 Series. Available: http://www.pjm.com/~/media/documents/manuals/m14b.ashx

For other contingencies resulting in taking out multiple elements/units (P4-P7), voltage stability margins should be 2.5% or greater from the voltage instability point.

Transient voltage stability is evaluated using time-domain simulations which model the dynamic behavior of induction motor loads. Appropriate voltage recovery criteria for post-contingency networked transmission buses are used to determine the adequacy of voltage resources. When voltages do not recover sufficiently, dynamic var sources are generally added to the system.

Appendix B: Transient Voltage Response Criteria Practices

Appendix B details transient voltage response criteria as per NERC Reliability Standard TPL-001-4 Requirement R5 and a description of the criteria developed.

Electric Reliability Council of Texas (ERCOT)

Transient voltage response criteria is defined in ERCOT Planning Guide 4.1.1.5 Transient Voltage Response Criteria. In conducting its planning analyses, ERCOT and each TSP shall ensure that all transmission level buses above 100 kV meet the following transient voltage response criteria:

1. For any operating condition in category P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within five seconds after clearing the fault.
2. For any operating condition in categories P2 through P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within ten seconds after clearing the fault.

Contingency P1 has a high probability of occurrence and it is recommended a quicker voltage recovery response than the group of contingencies in P2 to P7, which have a lower probability of occurrence.

Voltage Ride Through Capability

Voltage Ride Through (VRT) requirements in ERCOT specify that a Generation Facility must not disconnect during transients, following a voltages vs. times profile. Figure XXX provides an example of the ERCOT VRT curve for Intermittent Renewable Resources (IRR). This requirement prescribes that the generator voltage protective relays must be set according to the VRT Standard. Dynamic reactive devices will inject or absorb reactive power automatically to satisfy the VRT requirement. Low voltage ride through (LVRT) requirements are generally accepted by industry. Now, High voltage ride through (HVRT) is equally important but less understood because its need becomes important for regions under specific operating conditions. For regions with low load conditions and large penetration of renewable power (wind or solar) a transmission contingency will reduce the loading of the network, causing higher transmission line charging being injected into the network, resulting in higher bus voltages. These higher voltage could cause generation to disconnect due to protection relay tripping on high voltage, feeding the high voltage condition by losing leading reactive support from such tripped generation. These events could induce a cascade of generation tripping on high voltage. Hence, the HVRT standard serve as a way to support injection of leading reactive power into the grid while LVRT supports injection of lagging reactive power into the grid.

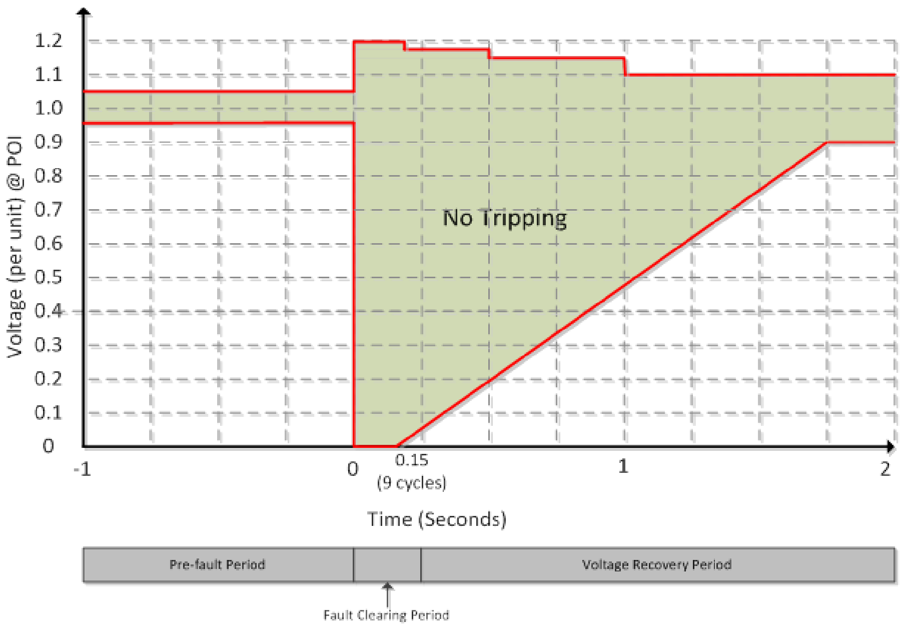


Figure XXX: ERCOT Voltage Ride Through Profile

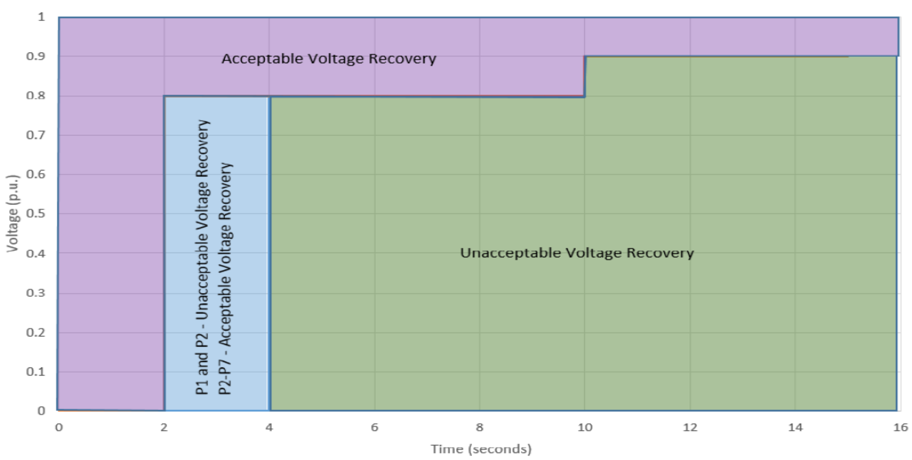
FRCC

The FRCC transient voltage criteria are the same for all Transmission Planners within the region. The transient voltage response criteria applies to the time period immediately following fault clearing or any other event being simulated. During this time period there may be depressed voltages and voltage swings due to the event. The transient voltage dip criteria are intended to indicate unacceptably sluggish voltage recovery after an event.

FRCC's transient voltage response criteria are summarized below. Times in the table are seconds after fault clearing. In the plot below, 0 seconds corresponds to the moment of fault clearing. The FRCC transient voltage response criteria are applicable only to planning events P1 – P7 and only at load buses. FRCC plans and evaluates the low voltage ride through capability at generator buses using the PRC-024 criteria as discussed above in response to R4.3.1.2.

Table XXX: FRCC Transient Voltage Response Criteria

Planning Events P1-P2		**Planning Events P3-P7**	
Load Bus Voltage Must Recover To [pu]	At or Before Time [sec]	Load Bus Voltage Must Recover To [pu]	At or Before Time [sec]
0.8	2.0	0.8	4.0
0.9	10.0	0.9	10.0



Note: Zero seconds corresponds to the time at which a fault is cleared.

Figure XXX: FRCC Transient Voltage Response Criteria Profile

Independent System Operator of New England (ISO-NE)

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not exceed 250 milliseconds below 80% of nominal voltage within 10 seconds following a fault. These limits are supported by the typical sag tolerances shown in Figures C.5 to C.10 in IEEE Standard 1346-1998.

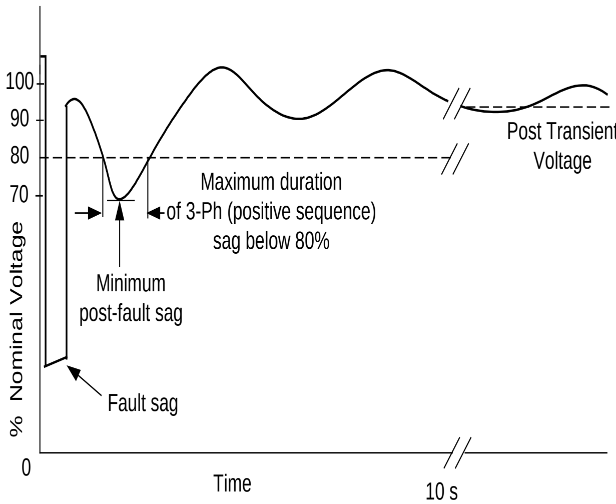


Figure XXX: Transient Voltage Sag Parameters

MISO Energy

MISO has established standard voltage criteria for planning and operating the transmission system. These criteria are informed by guidelines and criteria used by MISO member companies, who are also NERC registered entities (TOPs, TPs, TOs, etc.). Members may request MISO to monitor voltage and reactive power performance on their system based on criteria different (more stringent) than the standard criteria established by MISO. Transient voltage monitoring criteria are specified in BPM-020. MISO member TO planning criteria are available at https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=433.

Voltage criteria are used during steady-state and transient stability analyses performed for system planning, outage coordination, operational planning, and real-time operation studies. The voltage criteria are periodically reviewed with the member companies as needed to ensure they are current.

PJM Interconnection

PJM planning analysis ensures the system is transiently stable and that all system oscillations display positive damping. Stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission Owner designated faults are examined for plants on their respective systems. The quantities monitored for generator stability include:

- Generator rotor angles and speed;
- Generator active power output;
- Generator field voltage (EFD) and terminal voltage; and
- Bus voltages magnitudes in the same area.

Acceptable Damping:

Following the disturbance, the oscillations of the monitored parameters must display positive damping, calculated with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on the trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over a prolonged time. To limit this system exposure, PJM uses a 3% damping ratio margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required

Acceptable Transient Voltage Recovery:

When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics. The transient voltage recovery criteria should be satisfied at BES buses. Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 p.u. after 2.5 seconds. If a plant-specific document (such as Nuclear Plant Interface Coordination (NPIR)) or local Transmission Owner specific planning criteria requires a more conservative voltage recovery criterion, that specific criterion will be applied.

Generator Ride Through Capability:

PJM evaluates the voltage ride through capability at generator buses as specified in PRC-024 or applicable TO criteria which require Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.

Southern Company

Southern Company uses different criteria based on peak versus off-peak study conditions and differentiates criteria based on type of contingency studied. Below are descriptions of the criteria for different system conditions:

Criteria for Peak Load Stability Studies:

- For normally-cleared, three-phase fault contingencies (P1-P3), the transient voltage response criteria is the following: all transmission networked buses must recover above 80% voltage within 2 seconds of the initial fault.
- For P4-P7 and Extreme contingencies, the transient voltage response criteria is the following: all transmission networked buses must recover above 80% voltage within 4 seconds of the initial fault.

Criteria for Off-Peak Stability Studies (50% of Peak Load):

- For normally-cleared, three-phase fault contingencies (P1-P3), voltages must not stay below 80% for more than 40 cycles (transient voltage dip).
- No transient voltage response criteria are used for P4-P7 and Extreme contingencies.

For peak load studies, a complex load model which includes induction motors effects is used. The rationale behind the 2-second response criteria for the higher probability contingencies (normally-cleared, three-phase fault) is:

1. IEEE 45 (IEEE Recommended Practice for Electrical Installations on Shipboard) provides a precedent for a 2 second recovery criterion.
2. Various IEEE technical papers documenting induction motor testing which indicate that a voltage recovery greater than 2 seconds could result in a large percentage of stalled motors.

By choosing this criteria, the loss of load is minimized for higher probability contingencies. For lower probability contingencies, the criteria is to recover above 80% in 4 seconds. For these lower probability contingencies, some loss of load is considered to be acceptable.

For off-peak studies, voltage recovery is rarely an issue. A ZIP load model is used for these studies. The transient voltage dip criteria is intended to flag cases where a more complex load model might contribute to an angular stability issue.

Southwest Power Pool (SPP)

SPP requires that after the fault is cleared bus voltages on the Bulk Electric System shall recover above 0.70 per unit within 2.5 seconds. Bus voltage 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. Figure XXX shows this criteria visually[35].

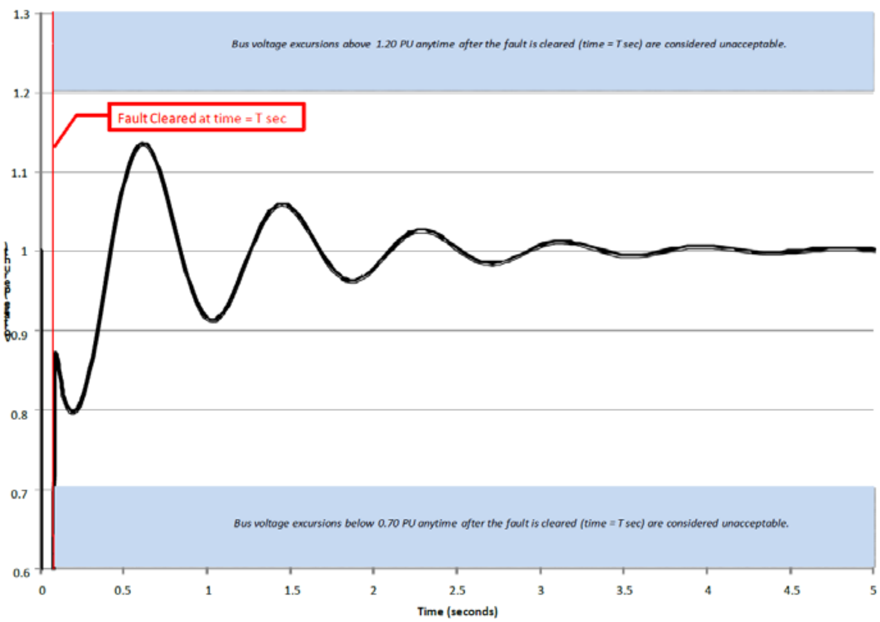


Figure XXX: SPP Transient Voltage Recovery Requirement Visual

35 Available: http://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements_twg%20approved%2012_16_2015.pdf.

Revision History:

Date	Version Number	Reason/Comments
3/XX/2016	1.0	Initial Version – *"Reactive Power Planning and Operations"*

Synchronous inertia sufficiency guideline

Do we need to repeat here again briefly of what is happening with frequency after a large generation trip and all frequency response stages? Or should we assume people have read the previous report? [I do not think that is necessary]

The purpose of this guideline is to examine the system capability under low inertia condition to arrest frequency decay and avoid under-frequency load shedding after large generator trip based on each region's existing frequency control capabilities and practices. Once system inertia, based on historical data (Measure 1&3) starts approaching the minimum sufficient value, as described in this document, each region should consider revising the existing frequency control practices and capabilities and introduce additional measures to ensure the availability of the necessary rate of change of frequency (RoCoF) after the largest contingency.

Keeping a minimum level of synchronous inertia to provide sufficient RoCoF may not be the most efficient way to operate the grid. Out-of-merit unit commitment for inertia may have adverse effect on market prices. Generators committed for inertia will operate at least at their minimum stable production level affecting energy prices and potentially causing curtailments of non-synchronous generation. Thus, it is recommended that other frequency control measures to address decreasing inertia trend are implemented. Several examples are provided below:

For example, in ERCOT Load Resources with under frequency relays are providing a portion of Responsive Reserve Service (Ancillary Service with a function to arrest, stabilize, and recover frequency after an event). These load resources trip offline, providing full response within 0.5 second[1] after system frequency falls at or below 59.7 Hz. This capability can be viewed as fast frequency response. This type of response, i.e. response to a frequency trigger, is very efficient at arresting frequency after an event. Battery storage can be used for the same purpose, i.e. to provide full response very quickly once the system frequency reaches a certain threshold. Time of response and frequency triggers can be optimized to meet particular system needs.

Hydro Quebec has adopted a different approach to address low synchronous inertia concern. In 2006 they have updated their grid code with specific requirement for emulated (or synthetic) inertia response requirement for wind power plants (WPPs). WPP frequency control must reduce large, short-term frequency deviations at least as much as the inertial response of a conventional generator whose inertia constant equals 3.5 s does [Ref to GC document]. Simulations at the time have shown that this target performance is met, for instance, when the wind turbine generators vary their active power dynamically and rapidly by about 5% for 10 s when a large frequency deviation occurs. This requirement is still in effect. Synthetic inertia from wind generation is another means of very fast active power injection that can help address high initial RoCoF after a contingency.

[1] Underfrequency relays at the participating load resources in ERCOT have a time delay set at 0.33 seconds (or 20 cycles). The timer will start after triggering frequency is reached and will reset if the system frequency increases above triggering frequency during that period. This delay is introduced to avoid nuisance tripping, but the time can potentially be reduced. Additionally, about 0.17 second (or 10 cycles) is necessary for a breaker to open and disconnect a load resource. This time delay is based on physical capabilities of a breaker.

Methodology for determining sufficient synchronous inertia under existing frequency control practices:

1. Calculate system inertia for every hour in a year in MVA*seconds. This is calculated as a sum of individual inertial contributions from all online generators. Find the lowest inertia instance in a year. This is basically covered under Measures 1& 3.
2. At that lowest inertia condition, calculate Rate of Change of Frequency (RoCoF), Hz/s based on the Interconnect's resource contingency criteria (RCC), which is the largest identified simultaneous category C (N-2) event, except for the Eastern Interconnection, which uses the largest event in the last 10 years. This is a part of the Measure 2 calculation.
3. ~~Assume there are no other means of frequency response. This is not a realistic assumption, but the purpose is, with~~ With the RoCoF from the previous step, ~~to~~ calculate how long it takes to reach the first stage of under frequency load shedding (UFLS) after the RCC event. If this time is sufficient (e.g. ~~3~~1-1.5 seconds[2]) for the existing means of frequency response (fast frequency response, primary frequency response) to start deploying and to help arrest frequency above the first stage of UFLS, then this RoCoF is not critical.
4. Gradually, scale down the minimum inertia found in step 1, in steps of, say 10%. Repeat steps 2 and 3, until the resulting RoCoF is such that a Prevailing UFLS First Step is reached before the primary frequency response can become effective (1-1.5 second)~~[3]~~. Return to the last inertia value that still is sufficient. This is the first approximation of the minimum necessary system inertia.

   Note: *The Eastern Interconnection 59.5 Hz UFLS set point listed in BAL-003-1.1 is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba. Since it's possible that 59.7 Hz will lead to UFLS in Florida and Manitoba, this frequency threshold should be used for the calculation steps 1-4 above.*

Commented [SC21]: Reads rather awkwardly!

Commented [MJ2]: I tried to re-phrase hope it reads better now.

[2] The purpose here is to make sure the RoCoF does not result in UFLF within 1-1.5 s, i.e. before frequency response (fast and/or primary) can become effective. Times when fast and primary frequency response becomes affective may vary for different systems and different synchronous inertia conditions. Those could be verified from historic event analysis and dynamic simulations. For example in ERCOT Load Resources with under frequency relays are providing a portion of Responsive Reserve Service (Ancillary Service with a function to arrest, stabilize, and recover frequency after an event). These load resources trip offline within 0.5 second after system frequency falls at or below 59.7 Hz. Therefore, in ERCOT, the RoCoF that leads to 59.7 Hz within few hundred milliseconds after an event and the then first stage of UFLS within the next 0.5 second, becomes important. If UFLS is not reached within this time frame, Load Resources would trip and would be very efficient at arresting frequency above the UFLS threshold.

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~~[3] The purpose here is to find the RoCoF resulting in UFLF within 1-1.5 s, i.e. before primary frequency response can become effective. For example in ERCOT Load Resources with under frequency relays are providing a portion of Responsive Reserve Service (Ancillary Service with a function to arrest, stabilize, and recover frequency after an event). These load resources trip offline within 0.5 second after system frequency falls at or below 59.7 Hz. Therefore, in ERCOT, the RoCoF that leads to 59.7 Hz within few hundred milliseconds after an event and the then first stage of UFLS within the next 0.5 second, becomes important. If UFLS is not reached within this time frame, Load Resources would trip and would be very efficient at arresting frequency above the UFLS threshold.~~

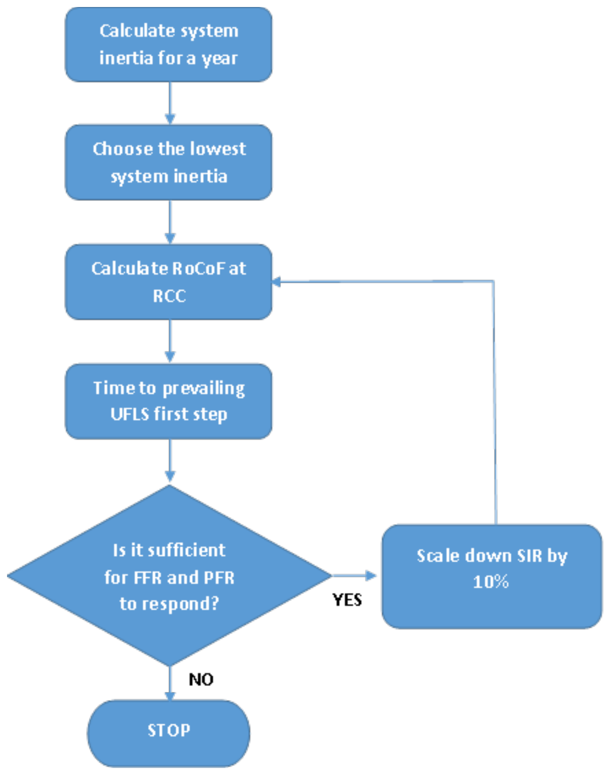

Figure 1: Top-down Approach to determine minimum sufficient synchronous inertia

5. The system inertia value determined above is a theoretical top down approximation. It is possible that there is always more synchronous generation online at any given time due to other considerations. In order to obtain a more accurate value, one can use bottom up approach. Start with minimum synchronous inertia that will always be online for a system. For example:
    i. Are there any must-run units (e.g. for voltage support or fault current)
    ii. Are there any industrial behind-the-meter generators that are always online?
    iii. Are there nuclear units,
    iv. How many synchronous generators are online to provide required reserves, what are those generators? Here it is important to consider if there are any physical limitations or regulatory restrictions on how much a single resource can or is allowed to contribute towards a reserve requirement. In ERCOT, for example a generating unit is not allowed (by protocols) to provide more than 20% of its high sustainable limit towards Responsive Reserve Service.

    Calculate the total inertia contribution for all these "must run" units.
6. Compare the inertia calculated in step 5 and the approximated "sufficient" inertia in step 4.

7. If Inertia from step 5 is higher or equal to the inertia in step 4, then the system will always have sufficient synchronous inertia, unless
    i. Any operations principles of the "must run" units change
    ii. Reserve requirements decrease.
    iii. Contribution from a single resource towards any of the online reserve requirement changes.
    iv. New reserves are introduced or entry of new resources (not providing synchronous inertia) into Ancillary Services market becomes possible.
8. If inertia from step 5 is lower that one in step 4, then starting from the unit commitment and total inertia value obtained in step 5 bring additional synchronous units online one by one, based on unit merit order. Stop once the total system inertia value is close to the required in step 4, i.e. initial sufficient inertia estimate.

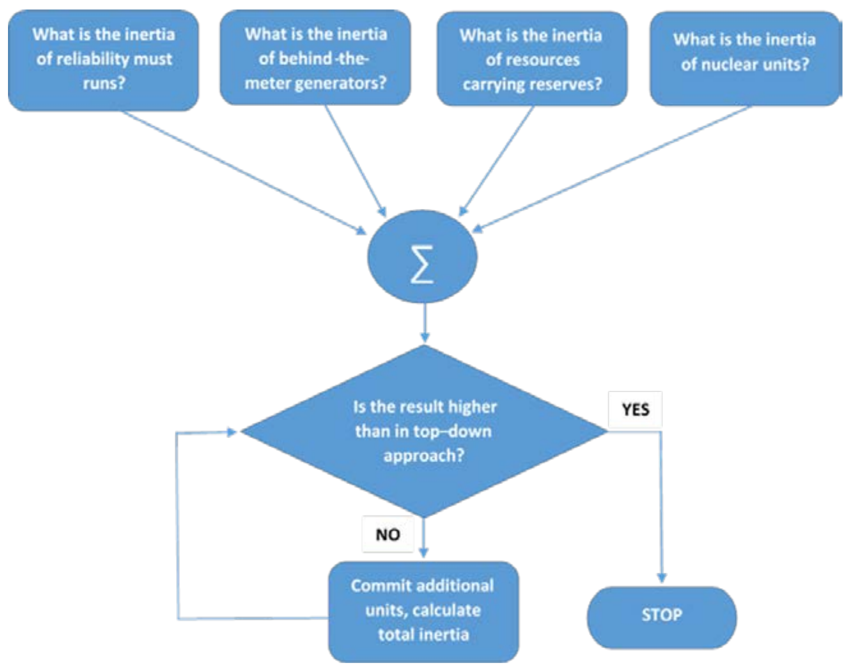

Figure 2: Bottom-up Approach to verify minimum sufficient synchronous inertia determined via top-down approach

9. The result from step 8 can then be verified with dynamic simulations, using unit commitment from step 8 and simulating the RCC event. Since the above calculation does not take into account load damping and primary frequency response, it's possible that the actual, sufficient synchronous inertia value is slightly lower than the initial estimate. Note, however, that load

damping and governor response do not significantly change RoCoF in the first second of an event.

Once minimum sufficient inertia value is identified, actual synchronous inertia of the system (Measure 1) has to be monitored against this value. If synchronous inertia is approaching minimum sufficient value, frequency control measures need to be revised and additional means of fast frequency support put in place.

Note that fast frequency response may also be introduced to address other issues such as resource adequacy, need for flexibility and to improve energy market efficiency, i.e. to make generation resources available for energy production while allowing other resources, e.g. load or storage, provide frequency reserves. In this case, minimum sufficient synchronous inertia needs to be revised by repeating steps 1-9 and including fast frequency response characteristics into the analysis.

[Later on I can add example here of the studies done at ERCOT for different system inertia conditions determining necessary PFR requirements, though I am not quite sure if and where it fits here]

From Charlie: I think you need to bring the additional FFR options into Step 8. I am concerned that as it is, Step 8 leaves the impression that you must restore synchronous inertia to some minimum level, and I don't believe that is the intent. So in Step 8, I think you need to bring in the options of Responsive Reserve Service from load resources (RRS), energy storage, and synthetic inertia from wind plants. I know it says that you are planning to add such options in Step 9, but I think it should be introduced in Step 8 to be clear.

To Charlie's comment my original idea with step 8 was to arrive to minimum synchronous inertia value (with current frequency control practices in each interconnection) and have a unit commitment case that can be verified through dynamic studies, since those may show that the estimate was too pessimistic… After minimum sufficient synchronous inertia based on current frequency control practices is found then other frequency support mechanisms can be investigated. But I added some text to say that fast frequency response may be introduced ahead of inertia insufficiency problem.

Net Load ramping variability sufficiency guideline

The purpose of this guideline is for BAs expecting high levels of renewable penetration to examine their system ramping capabilities under various operating conditions, especially during light load conditions. Having sufficient ramping capability is now a critical component in planning and operating the bulk electric system so it's prudent for BAs to evaluate their system to identify any increase in ramping needs. Ramping needs varies among BAs and depend on many factors such as the BA's existing fleet make-up, dispatch practice and expected renewable addition on a look ahead horizon. With over 12,000 MW of transmission and distributed connected solar resources within its footprint, the CAISO now evaluates its net-load ramping needs on a monthly basis to evaluate the adequacy of its fleet make-up and recommend changes as necessary.

Other BAs may have to examine their fleet make-up to determine if changes are needed in their unit commitment practice to adequately balance generation and load in real-time and help meet their shared responsibility of supporting the interconnection steady state frequency. It is therefore important for BAs to identify any potential ramping deficiencies ahead of time to meet expected as well as unexpected intra hour and multiple hour ramping needs.

For BAs such as the CAISO, balancing generation and load in real-time is becoming more of a challenge because of the significant increase in net-load ramping variability. In 2012, the CAISO maximum three-hour upward ramping needs was approximately 6,000 MW. However, in 2016, the CAISO's three-hour upward ramping needs has already exceeded 10,800 MW. Any BA can get early indications weather it is prepared to integrate higher levels of renewables by evaluating its historical ramps against its real-time control performance standard (CPS1[1]) on a more granular level, such as hourly or daily. Keeping sufficient minimum levels of fast ramping resources may not be the most efficient way to address higher ramping needs. Exceptional dispatch or out-of-market unit commitment for faster ramping capability may have adverse effect on energy prices, which may not result in least cost dispatch. Generators committed for ramping capability through exceptional dispatches would have to be compensated for the services they provide.

Insufficient ramping capability at the system level can impact neighboring BAs and affect overall BES operation when a ramp deficient BA leans on the interconnection. Leaning on the interconnection at times is permissible, however a BA should not be leaning on the interconnection during the same hours each day. Knowing the intra-hour

[1] CPS1 is a statistical measure of a BA's area control error (ACE) variability in combination with the interconnection frequency error from scheduled frequency. It measures the covariance between the ACE of a BA and the frequency deviation of the interconnection, which is equal to the sum of the ACEs of all of the BAs. CPS1 assigns each BA a share of the responsibility for controlling the interconnection's steady-state frequency. The CPS1 score is reported to NERC on a monthly basis and averaged over a 12-month moving window. A violation of CPS1 occurs whenever a BA's CPS1 score for the 12-month moving window falls below 100 percent.

ramping needs ahead of time assures adequate ramping capacity is available for dispatch in real-time.

Similarly, three-hour ramp capacity needs are basically driven by BAs expecting higher penetration of solar. During sunrise the BA must ensure adequate downward ramping capability is available as the solar production increases and adequate upward ramping capability is available to meet the drop off in solar production during sunset.

The CAISO monitors its CPS1 scores on an hourly basis to ensure it does not unnecessarily lean on the interconnection during hours of greatest ramping needs. By evaluating its CPS1 score on an hourly basis, the CAISO was able to identify a strong correlation between significant intra-hour and multi-hour ramps and CPS1 excursions below 100 percent across the same time frame.

BAs can also ensure adequate ramping capability are available when needed by recommending that renewable resources install smart inverters with the capability to provide active power control during the interconnection process so that renewable resources could be a part of the solution and avoid being curtailed due to potential ramping deficiencies.

Methodology for determining sufficient net demand ramping variability:

1. Calculate hourly and three-hour net-load ramping variability to insure committed resources have the ramping capability to meet expected and unexpected changes within an operating hour. Multiple three-hour ramps is also important for BAs with high penetration of solar because of the higher ramping needs during sunrise and sunset.
2. Determine the potential for over-generation during high renewable production and minimum load conditions such as weekends. This could be late at night or early morning hours when wind production is high and load is low. This could also occur during the day when solar production is high and load is low.
3. Determine the level of non-dispatchable resources within a BA’s fleet, which can limit the amount of flexible resources that can be committed with ramping capability,
4. Evaluate the added impact of DER on ramping needs by determining the amount of distributed load that’s off-set during sunrise and the amount of load that has to be served from the transmission during sunset,
5. Identify any bottlenecks on the transmission network that could result in congestion, which may require the distribution of resources with adequate ramping capability on both sides of the congested path,
6. Determine the impact of solar PV tracking vs. solar PV non tracking on ramping needs. This is required because faster ramping resources would have to be committed because solar PV tracking resources creates higher ramping needs on the system,

7. Identify the headroom needed on "must run" resources to meet other real-time standards such as BAL-001, BAL-002 and BAL-003. Sufficient ramping capability has to be procured separate from this needed headroom,
8. Evaluate the fleet ramping capability against ramping needs of the system to ensure unit commitment factor in speed of needed ramps. If ramping capability is always more than ramping needs, then the BA may not have a ramping concern.
9. Ensure the ramp-rate of committed resources are not double counted. For example, a resource providing energy and contingency reserve must be able to deliver both awarded contingency reserve and energy simultaneously.
10. Identify must run resources for local reliability requirement,
11. Evaluate the loss of a resource providing fast ramping capability to ensure adequate ramping capability is maintained in the short term.
12. Identify Jointly owned units and dedicated imports to determine the amount of flexibility that can be obtained from neighboring BAs,
13. BAs with unique operating characteristics such as spring snow-melt resulting in high levels of hydro production could result in hydro units operating close to their maximum capability because of the abundance of water or risk spilling water to maintain headroom on resources.
14. Identify resources with CO_2 emission limitations,
15. Dispatch may no longer be based on economics but some level of ramps, inertia, FRO must be taken into consideration during the commitment process.

BA Screening Test to determine if net ramping variability assessment should be done

1. Determine the amount of solar PV that's scheduled to be operational in a given year (Y_{SPV}),
2. Determine the amount of wind production that's is expected during sunset in the given year (Y_{Wind}),
3. Determine the expected Load (Y_{Load}) during sunset in a given year,
4. Determine expected minimum net-load for a given year (Y_{ML}),
5. Determine the amount of non-dispatchable resources (Y_{ND}) that's expected to be operational on any given day,
6. Determine the maximum amount regulation up (Ru) requirement,
7. Determine the contingency reserve (CR) that's needed to cover the BA's MSSC,

8. Determine the maximum expected load increase ($Y_{Load\_Increase}$) that is expected to occur during sunset in the given year,

$$\mathbf{Y_{SPV} + Y_{Load\text{-}Increase} > Y_{ML} + Ru + CR}$$

Where: $Y_{ML} = Y_{Load} - Y_{SPV} - Y_{Wind} - Y_{ND}$