SCOPE

This document is the ATC system Planning Criteria. These criteria define system performance requirements. Consideration is given to ensure a safe and reliable transmission system. These criteria address customer expectations and compliance with NERC standards. These criteria apply to the ATC transmission system operated at 69-kV and above, unless noted otherwise.

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. The criteria described below will be subject to change at any time at ATC's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

Defined Terms

NERC, ATC, and industry terms are used throughout the document. Unless defined in the body of the document or in "Glossary of Terms NERC Reliability Standards"[1], any capitalized term herein shall have the meaning set forth in Section 9.

[1] NERC Glossary of Terms Used in NERC Reliability Standards Updated March 29, 2022

1. STEADY STATE CRITERIA AND IMPLEMENTATION

ATC's steady state system performance requirements must be in compliance with the currently enforceable version of NERC Reliability Standard TPL-001. Furthermore, the criteria and implementation requirements are applicable to non-BES[2] unless otherwise noted. The criteria and implementation requirements are summarized in Table A including P0 through P7 Contingencies and Extreme Events. Criteria and Implementation for Maintenance, Known Outages, and Long Lead Time Equipment is addressed in Note 13.

[2] NERC Bulk Electric System Definition Reference Document Version 3 | August 2018

Table A: Steady State Criteria and Implementation

Category	Event Description	Fault Type	Voltage Level (10)	Criteria							Implementation					
				Voltage (pu) (1) (2) (3) (7) (11)		Thermal Ratings	Voltage Deviation (4)(9)	Interruption of Firm Transmission Service Allowed (11)	Non-Consequential Load Loss Allowed (5)(6)(11)	Voltage Stability (8)	Automatic Model Adjustments Allowed	Automatic – RAS, UVLS, and SPS Allowed	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	NERC Cascading Allowed
				Min	Max											
P0	System Intact	NA	EHV, HV, non-BES	0.95	1.05	100% of Normal	NA	No	No	Stable w/Margin	Yes	No	No	No	No	No
P1	System Intact + Loss of the following events (Generator, Transmission Circuit, Transformer, Shunt Devices)	3Ø	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
P2.1	System Intact + Open line w/o fault	NA	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
P2.2	System Intact + Bus section fault	SLG	EHV	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P2.3	System Intact + Non-bus-tie breaker faults	SLG	EHV	0.9	1.1	100% of Emergency	10%	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P2.4	System Intact + Bus-tie breaker fault	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P3	**First Contingency**: Loss of generator unit	3Ø	EHV, HV	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	No	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1			0.9	1.1	100% of Emergency	NA	No	No	Stable	Yes	Yes	No	No	No	No
P3	**First Contingency**: Loss of generator unit	3Ø	non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	Yes	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1			0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable	Yes	Yes	No	No	No	No
P4.1-P4.5	System Intact + Stuck breaker event on all but bus tie breaker	SLG	EHV	0.9	1.1	100% of Emergency	NA	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P4.6	System Intact + Stuck bus-tie breakers	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No

Category	Event Description	Fault Type	Voltage Level (10)	Criteria: Voltage (pu) (1) (2) (3) (7) (11) Min	Criteria: Voltage (pu) Max	Criteria: Thermal Ratings	Criteria: Voltage Deviation (4)(9)	Criteria: Interruption of Firm Transmission Service Allowed (11)	Criteria: Non-Consequential Load Loss Allowed (5)(6)(11)	Criteria: Voltage Stability (8)	Implementation: Automatic Model Adjustments Allowed	Implementation: Automatic – RAS, UVLS, and SPS Allowed	Implementation: Manual Supervisory Adjustments Allowed	Implementation: Manual Field Switching Allowed	Implementation: Generation Redispatch Allowed	Implementation: NERC Cascading Allowed
P5 (12)	System Intact + Fault (Generator, Transmission Circuit, Transformers, Shunt Devices, Bus Section) + non-redundant component of a Protection System failure to operate	SLG	EHV	0.9	1.1	100% of Emergency	NA	No	No	Stable w/Margin	Yes	Yes	No	No	No	No
			HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
P6	**First Contingency**: Loss of P1(except gen)	3Ø	EHV, HV, non-BES	0.9	1.1	100% of Emergency	10%	No	No	Stable	Yes	Yes	No	No	No	No
	In-between outages (following First Contingency in anticipation of Second Contingency)			0.9	1.1	100% of Emergency	NA	Yes	No	Stable	Yes	Yes	Yes	No	Yes	No
	After Second Contingency: Loss of P1(except gen)			0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable	Yes	Yes	No	No	No	No
P7	System Intact + Loss of the following events (Any two adjacent circuits on common structure or of a bipolar DC line)	SLG	EHV, HV, non-BES	0.9	1.1	100% of Emergency	NA	Yes	Yes	Stable w/Margin	Yes	Yes	No	No	No	No
Extreme Events	More severe system impacts	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Yes

(1) All voltage limits should be met with the net generator reactive power limited to 90 percent of the reported maximum reactive power capability.

(2) The steady state voltage should be stable at all ATC buses

(3) Voltage levels that differ from this range will be considered, if they are acceptable to the affected transmission customer or needed to address specific ATC equipment limitations. Exceptions for certain interconnected entities are evaluated accordingly (e.g., agreements implemented for NERC standard NUC-001).

(4) Post contingency voltage deviation (percent change of actual pre-contingency and post contingency steady state voltage) of greater than 10% is not allowed

(5) For Categories where load curtailment is acceptable, consideration may be given to operating procedures that are designed to shed a minimum amount of load.

(6) For Categories where load curtailment is unacceptable, system design should ensure that element loading cannot exceed the applicable rating. Temporary excursions are acceptable if a Remedial Action Scheme (RAS) will reduce loadings automatically (i.e. no manual intervention) to acceptable loading levels in the applicable timeframe. The acceptable loading levels after RAS operation cannot exceed the applicable rating.

(7) For distribution transformers, voltage measurements shall be made at the high side.

(8) See Section 1.3 "Steady State Voltage Stability" for details

(9) NA means Not Available

(10) EHV is defined as ATC owned equipment at 300 kV and above, HV is defined as ATC owned equipment less than 300 kV and greater than or equal to 100 kV, and non-BES is defined as ATC owned equipment between 69 kV and 99 kV.

(11) For further details on re-dispatch and Non-Consequential Load Loss, refer to Note 9 and Note 12 in Table 1 of -TPL-001-4 and TPL-001-5[3]

[3] TPL-001-4 & TPL-001-5 Table 1 Footnotes:

TPL-001 Table 1 Footnote 9

An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Category	Event Description	Fault Type	Voltage Level (10)	Criteria							Implementation					
				Voltage (pu) (1) (2) (3) (7) (11)		Thermal Ratings	Voltage Deviation (4)(9)	Interruption of Firm Transmission Service Allowed (11)	Non-Consequential Load Loss Allowed (5)(6)(11)	Voltage Stability (8)	Automatic Model Adjustments Allowed	Automatic – RAS, UVLS, and SPS Allowed	Manual Supervisory Adjustments Allowed	Manual Field Switching Allowed	Generation Redispatch Allowed	NERC Cascading Allowed
				Min	Max											

(12)

a. For P5 events, ATC uses the TPL-001-5 Footnote 13.b exception. A single communications system that is both monitored and reported at a Control Center is not modeled as a valid non-redundant component of a Protection System.

b. For P5 events, ATC uses the TPL-001-5 Footnote 13.c exception. A single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit is not modeled as a valid non-redundant component of a Protection System.

c. Non-BES P5 events with relay and communication system outages are evaluated near generating units.

d. Non-BES P5 events with dc supply and control circuitry outages are not evaluated.

(13) Maintenance outages, combinations of known outages, and long lead time equipment outages are equivalent to P0 with Criteria and Implementation as described in Table A, except with generation redispatch and manual supervisory adjustments allowed in anticipation of valid contingencies.

a. Valid contingencies with maintenance outages are limited to P1 and P2.1 with Criteria and Implementation as described in Table A.

b. Valid contingencies with combinations of known outages are limited to P1 with Criteria and Implementation as described in Table A.

c. Valid contingencies with long lead time equipment outages are limited to P1 and P2 with Criteria and Implementation as described in Table A.

TPL-001 Table 1 Footnote 12

An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

1.1 Cascading Criteria

No NERC Cascading should occur for applicable P1 through P7 contingencies or maintenance outage (planned single element outage excluding bus and breaker) followed by a P1 Contingency.

If NERC Cascading occurs for Extreme Disturbance Events, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event should be performed.

A NERC cascading outage has occurred when Total Load at Risk exceeds ATC's Interconnection Reliability Operating Limit (IROL) threshold of 1,000 MW to enable restoration of the system to within normal limits.

1.2 NERC Uncontrolled Islanding

ATC's definition of NERC uncontrolled islanding has occurred when a total load of any island exceeds 1,000 MW.

1.3 Steady State Voltage Stability

The transmission system is required to be voltage stable and respect a Control Point for all P0 through P7 Contingencies. The Control Point is defined as the pre-Contingency real power flow that is 98 percent of the voltage stability System Operating Limit (SOL). Except for P3 and P6 Contingencies, the SOL is defined as the pre-Contingency real power flow that results in the post-Contingency real power flow that is 95 percent of the post-Contingency P-V curve nose. For P3 and P6 Contingencies, the SOL is defined as the pre-Contingency real power flow that results in the post-Contingency real power flow that is 100 percent of the post-Contingency P-V curve nose (i.e. no margin is required).

Steady state voltage stability assessments are performed when steady state analysis indicates a solution failure that is confirmed to be an unstable operating condition (not a numerical instability) and on a selective basis using engineering judgment. Otherwise, acceptable steady state voltage stability is assumed to exist. If analysis identifies steady state voltage instability, requiring the need for voltage stability flowgates, then the following definitions are applied.

- The Power-Voltage (P-V) curve nose is the short-term, steady state voltage stability transfer point where the maximum real power interface flow occurs. If there is no inflection point at the maximum transfer level on the P-V curve, then the last solved point will be used as the P-V curve nose.
- If an IROL is determined to exist, then the IROL is defined as the pre-Contingency real power flow that results in the post-Contingency P-V curve nose.
- If the calculated SOL occurs at a point on the P-V curve that results in a low voltage violation at the critical bus (the bus that is most voltage-sensitive to the power transfer), then the SOL is reduced to the maximum pre-Contingency real power flow that does not result in a voltage violation at the critical bus.

Steady state voltage stability analysis must demonstrate that the nose of the post-Contingency P-V curve occurs at a voltage that is less than or equal to the applicable bus low voltage limit as coordinated with the applicable Planning Coordinator and/or by any applicable Transmission Owner(s) (e.g., the Minnesota – Wisconsin Export Interface (MWEX) limitation of 95 percent of nominal voltage at the Arrowhead 230-kV bus). This requirement is in place to assure adequate system voltage stability and reactive power resources for P0 through P7 Contingencies.

The system is designed for all planning events to ensure that all applicable steady state voltage stability IROLs will not be exceeded.

Figure 1.3-1 depicts an example of the practical implementation of the ATC Steady State Voltage Stability Criteria.

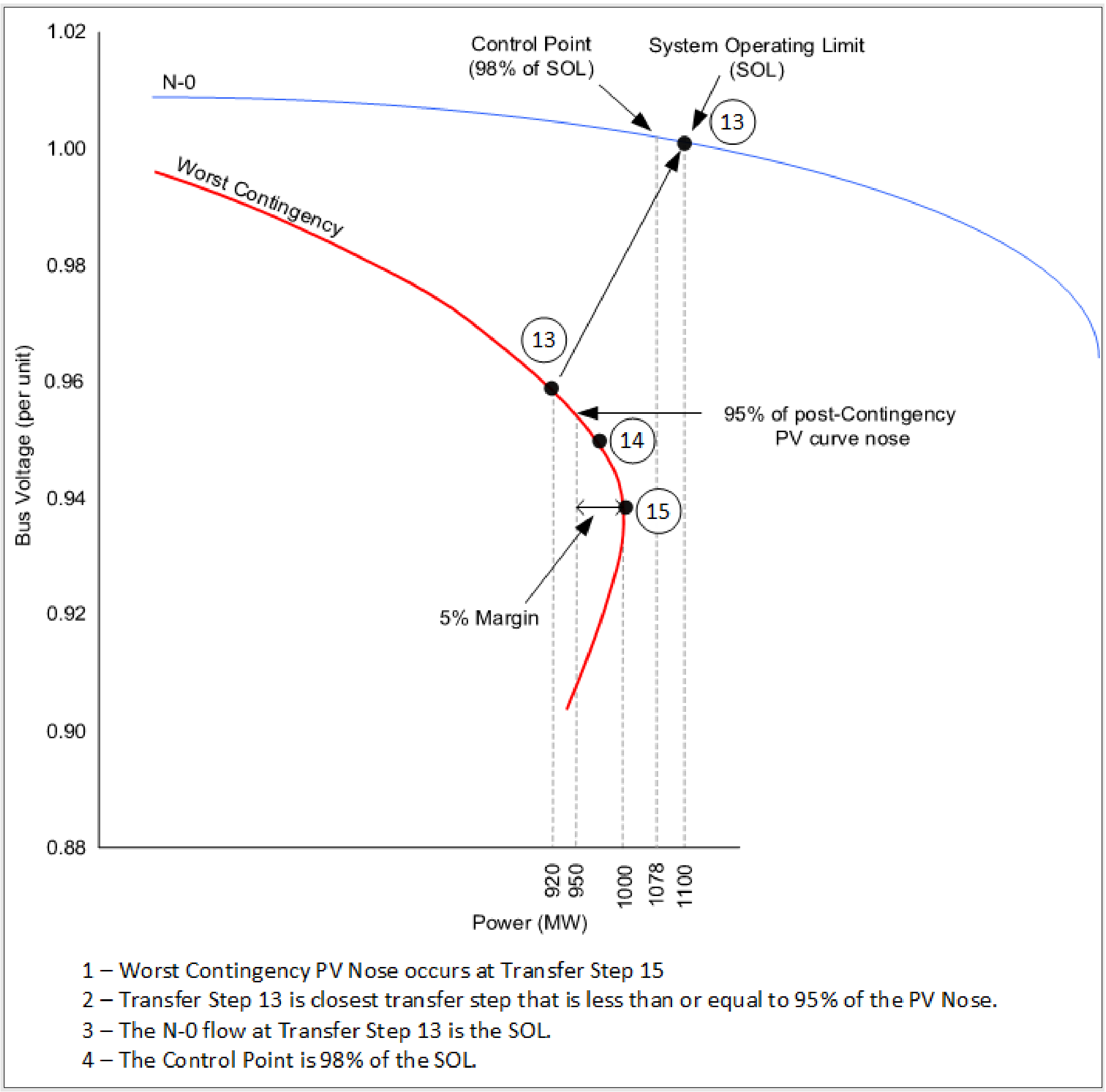


Figure 1.3-1: Practical Implementation of ATC Voltage Stability Criteria

1.4 Generation Redispatch Limitations

For events where generation redispatch is allowed as a mitigation option, redispatch of Hydro and Nuclear resources is not allowed. However, fast starting units (certain gas and diesel), solar (down only), wind (down only), and any other remaining online units in the study models are allowed. For Nuclear Generation redispatch exceptions, review PLG-GD-0012-V2.1 (System Planning Mitigation Options).

2. DYNAMIC STABILITY ASSESSMENTS OVERVIEW

The dynamics cases are built to be consistent with the regional dynamics database with loads represented by composite modeling. Dynamic stability assessments will include consideration of the summer peak load and light load conditions to ensure reliability over a range of load levels. Transient and dynamic stability assessments of the planning horizon are performed by the System Planning Department to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse, and system reactive power resources are available after a system disturbance based on 20 second simulations.

The transient and dynamic system stability performance criteria to be utilized by ATC for planning purposes shall include the following factors.

2.1 Large Disturbance Stability Performance Assessment

1) For generator transient stability, faults will be modeled on the high side bus at generating plants.
2) For generating units with actual “as built” or “field setting” dynamic data, a 0.5 cycle margin will be added to the expected clearing time (ECT) for dynamic Contingency simulations. For generating units with assumed, typical, or proposed dynamic data, a 1.0 cycle margin will be added to the ECT for dynamic Contingency simulations. The ECT margin will only be added to near end protective device for normal clearing faults (i.e. P1, P2, P3, P6 and P7) or it will be only added to the protective device with delayed clearing (i.e. P4 and P5). The total clearing time (ECT + margin) must be equal to or less than the calculated critical clearing time (CCT) from the simulation.
3) TPL-001-5 Footnote 13.a defines one type of a non-redundant component of a Protection System as “A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;” ATC defines comparable Normal Clearing time to be 3 cycles.
4) Generator transient stability will be demonstrated for at least one key Contingency for each applicable P1 through P7 Contingency[4]. Unacceptable transient stability performance occurs when any of the stability assessment criteria are not met.
5) Generator transient stability with combinations of known outages will be demonstrated for each applicable P1 Contingency as needed.
6) Generator transient stability with long lead time equipment outages will be demonstrated for each applicable P1 and P2 Contingency as needed.

[4] This criterion applies to all BES generating units and generating units required to submit “as-built” Generating Facility modeling data according to their Interconnection Agreement or comparable data as acceptable to ATC. For all other generating units, generator transient stability will be demonstrated for at least one key P1 Contingency only.

A. Angular Stability Assessment

i. Generating unit loses synchronism with the transmission system, unless it is deliberately islanded.

ii. Cascading tripping of transmission lines, tripping of transmission transformers or uncontrolled loss of load.

iii. Poorly damped angular oscillations where acceptable damping is defined in Section 2.2 below.

B. Voltage Stability Assessment

i. Transient stability voltage response at applicable Bulk-Electric System (BES) buses serving load shall recover to at least 80% of nominal voltage within 2 seconds after the initiating event is cleared for all P1 through P7 Contingencies

ii. For voltage swings after fault clearing and the first voltage recovery above 80%, voltage dips at each applicable BES bus serving load for all P1 through P7 Contingencies:

   a. Shall not dip below 70% of nominal voltage for more than 30 cycles continuous, or

   b. Shall not dip below 80% of nominal voltage for more than 2 seconds continuous.

C. Inverter-Based Resources Stability Assessment

Inverter-based resources (IBRs) refer to generating and energy storage resources that are asynchronously connected to the grid and are either completely or partially interfaced with the transmission system through power electronics.

i. An IBR shall not trip for any studied Planning Events unless it is deliberately islanded. This also applies to single line to ground (SLG) faults for Planning Events that are defined as three phase faults (e.g. certain P1, P3 and P6 events).

ii. An IBR's active power and reactive power as measured at the machine bus and bus voltage as measured at the Point-of-Interconnection (POI) shall be positively damped and meet one of the following two criteria:

   a. Time domain analysis indicates a 50% or greater reduction in oscillation magnitude over the last four oscillation periods.

   b. Peak-to-peak magnitudes during the last two seconds of the 20 second simulation shall not exceed 3% of their rated values (machine MVA base for active and reactive power and base kV at POI for voltage).

iii. IBRs shall not re-enter fault ride-through mode more than once in the time period beginning 6 cycles after the fault clears until the end of the 20 second simulation.

iv. For all P1 through P7 Contingencies the post-fault active power output of the IBR must recover to at least 90% of the pre-fault active power output within 1 second of the fault clearing. In addition to the Contingencies defined in TPL-001, Table 1, as three phase faults (e.g., certain P1, P3, and P6 Contingencies), this also applies to single line to ground (SLG) fault versions of these same contingencies.

Exceptions to these criteria (item ii, iii) within this section may be considered on a case-by-case basis (e.g., for existing IBRs or if NERC provides more specific IBR performance guidelines before ATC revises these criteria).

Where needed system reinforcement cannot be implemented in an appropriate timeframe, then a corrective plan must be established in order to respect SOLs and/or IROLs. Where appropriate, corrective plans may include generator redispatch, operating guides, and/or Remedial Action Schemes (RAS) as approved by ATC.

2.2 Angular Oscillation Damping

Well damped angular oscillations need to meet one of the following two criteria.

1) The generator rotor angle peak-to-peak magnitude is within 1.0 degree or less at the end of the 20 second simulation:
2) The generator average damping factor for the last five cycles of the 20 second simulation is 15.0 percent or greater after the switching event.

The Average Damping Factor is defined as:

$$\text{Average Damping Factor (\%)} = \left(\frac{d_1+d_2+d_3+d_4}{4}\right) \times 100 \qquad [2.2\text{-}1]$$

Where d_1, d_2, d_3 and d_4 are obtained from equation

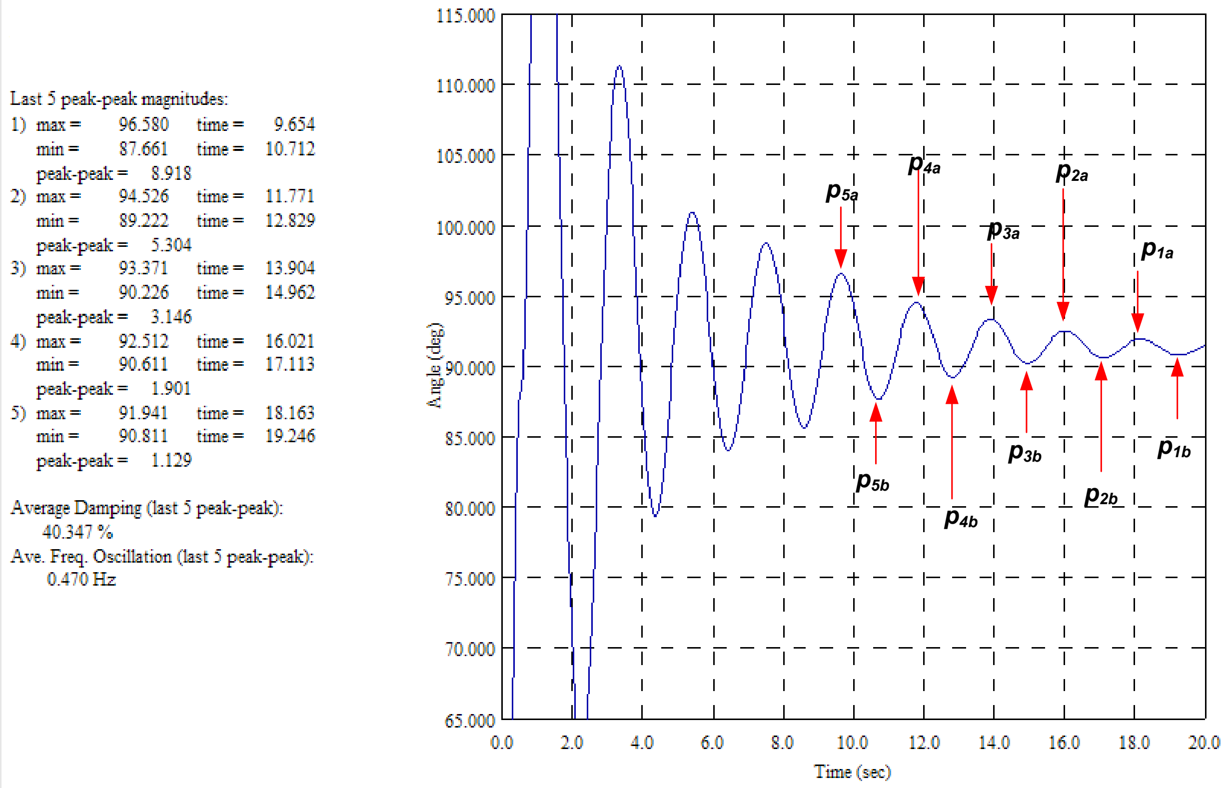
$$d_n = (1 - SPPR_n) \qquad [2.2\text{-}2]$$

Where $SPPR_n$ corresponds to the Successive Positive Peak Ratio) defined as the ratio of the peak-to-peak amplitude of a rotor angle swing (nth cycle back from the 20 second simulation time) to the peak-to-peak amplitude of a rotor angle swing on the previous cycle (n+1th cycle back from the 20 second simulation time). As shown in Figure 2.2-1, d_1, d_2, d_3 and d_4 are calculated as follows:

$$d_4 = 1 - \frac{p_4}{p_5},\ d_3 = 1 - \frac{p_3}{p_4},\ d_2 = 1 - \frac{p_2}{p_3},\ d_1 = 1 - \frac{p_1}{p_2} \qquad [2.2\text{-}3]$$

$$d_n = 1 - \frac{p_n}{p_{n+1}} = 1 - \frac{p_{n_a} - p_{n_b}}{p_{n+1_a} - p_{n+1_b}} \qquad [2.2\text{-}4]$$

Example



$p_1 = p_{1a} - p_{1b} = 1.129$

$p_2 = p_{2a} - p_{2b} = 1.901$

$p_3 = p_{3a} - p_{3b} = 3.146$

$p_4 = p_{4a} - p_{4b} = 5.304$

$p_5 = p_{5a} - p_{5b} = 8.918$

$d_1 = 1 - (1.129/1.901) = 0.406102$

$d_2 = 1 - (1.901/3.146) = 0.395741$

$d_3 = 1 - (3.146/5.304) = 0.406863$

$d_4 = 1 - (5.304/8.918) = 0.405248$

Average Damping Ratio = $(d_1+d_2+d_3+d_4) \times 100 / 4 = 40.35\%$

Figure 2.2-1: Average Damping Ratio Calculation Example

2.3 Extreme Disturbance Events (NERC Standard TPL-001, Table 1 Stability Extreme Events)

The NERC Stability Extreme Events that are expected to produce more severe system impacts should be evaluated to determine potential system impacts and vulnerabilities. If widespread Cascading may occur, then an evaluation of possible actions that would reduce the likelihood or mitigate the consequences of the extreme event should be performed.

3. RESOURCE FACILITY REQUIREMENTS

Resource facility requirements apply to plant facilities that produce real power, including generators and storage devices.

3.1 IBR Reactive Power Design Capability

All new IBRs connecting to ATC shall be designed to have the capability to support voltage by providing dynamic leading and lagging reactive power at all levels of real power output including zero MW. The maximum reactive power design capability in Mvar shall be at least 0.3287 per unit of the IBR nameplate capacity in MW, with this capability available at all levels of real power output. The IBR shall be designed to operate in a voltage support mode that will not be limited by any other IBR facility component.

3.2 Power Factor Minimum Operating Capabilities

Power factor requirements within this section refer to operational requirements, IBR design capability requirements are specified in Section 3.1.

Power Factor Requirements for Interconnection Generating Units are as follows. ATC's standard power factor range for synchronous and non-synchronous (e.g., wind turbines, solar) generation is 0.95 leading (when a Generating Facility is consuming reactive power from the transmission system) to 0.95 lagging (when a Generating Facility is supplying reactive power to the transmission system).

As illustrated in a generic example graph below, the Generating Facility must be capable of maintaining ATC's standard power factor range at all power output levels by providing continuous dynamic reactive power at the following locations (i.e. point of measurement):

a) The Point of Interconnection (POI) for all synchronous generators

b) The high-side of the generator substation for all non-synchronous generators[5]

[5] FERC Order No. 827, para 34.

Figure 3.2-1: A Generic Example Graph of Acceptable Power Factor Capability

This power factor requirement applies at all power output levels unless the Generating Facility is physically disconnected from the ATC transmission system. Physically disconnected means an open

1. generator step-up transformer high or low-side breaker(s) for a synchronous Generation Facility, or
2. generator substation step-up transformer high-side breaker(s) for a non-synchronous Generation Facility.

For synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer's side of the POI.

3. Dynamic reactive power provided by a synchronous Generating Facility may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the synchronous generator, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses.
4. Dynamic leading reactive power provided by a synchronous Generating Facility cannot use inductive losses from generator step-up transformer(s) and generator tie line(s) to meet the leading power factor calculation at POI. A synchronous

Generating Facility must be able to meet a 0.95 leading power factor, as measured at the generator terminal (i.e. the low side of the generator step-up transformer).

For non-synchronous generators, the interconnection studies will account for the net effect of all energy production devices and losses on the Customer’s side of generator substation step-up transformer.

5. Dynamic reactive power provided by a non-synchronous Generating Facility must meet the following requirement from FERC order 827 paragraph 35:
   a. “Non-synchronous generators may meet the dynamic reactive power requirement by utilizing a combination of the inherent dynamic reactive power capability of the inverter, dynamic reactive power devices (e.g., Static VAR Compensators), and static reactive power devices (e.g., capacitors) to make up for losses.”
6. Dynamic leading reactive power provided by a non-synchronous Generating Facility cannot use inductive losses from pad-mount and station step-up transformers and collector system to meet the leading power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a leading 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
7. Dynamic lagging reactive power provided by a non-synchronous Generating Facility cannot use collector system charging to meet the lagging power factor calculation at the high-side of the generator substation. A non-synchronous Generating Facility must be able to meet a lagging 0.95 power factor, as measured at the generator terminal (i.e. the low side of the pad-mount transformer).
8. When the Generating Facility is not generating active power (i.e. zero MW output):
   a. The reactive power injection to the transmission system at the high-side of the generator substation should be zero Mvar. Exceptions for a short transition period during the switching of inverter control modes may be granted on a case by case basis if there is no reliability concern. For example, solar PV facilities may have a transition period during sunrise and sunset periods. The transition period should be minimized by the non-synchronous Generating Facilities as much as possible.
   b. When the Generating Facility is physically connected but operating at zero MW and zero Mvar as measured at the high-side of the generator substation, the Generating Facility is not required to control system voltage as specified in Section 3.3 below.
   c. The requirements in bullet a and b above are minimum requirements. If a non-synchronous Generating Facility has the capability to provide dynamic voltage control and maintain ATC’s voltage schedule as specified in Section 3.3 below when it is at zero MW output, that is acceptable and preferred by ATC utilizing the design outlined in Section 3.1.

Static reactive power devices (e.g., capacitors and inductors) can only be used to make up for

9. inductive losses between the generator terminal and the POI for synchronous generators, or
10. inductive losses or collector system charging between the generator terminal and the high side of generator substation for non-synchronous generators.

All other reactive power needed to meet the power factor requirement must be provided by continuous and sustainable dynamic sources. Operation across the entire power factor range must be fully dynamic, variable, and capable of sustained indefinite operation.

Static sources can be switched on or off in the range of seconds and provide reactive power in large discrete blocks. Cap Banks are considered static sources of reactive power.

Dynamic sources can provide variable amounts of reactive power in a few milliseconds. Static Var Compensators (SVCs), Static Synchronous Compensators (STATCOMs), Flexible AC Transmission Systems (FACTS), inverters, and synchronous condensers are all considered dynamic sources of reactive power.

3.3 POI Voltage

The interconnecting generator must be capable of automatically and dynamically maintaining a POI voltage schedule that is specified by the Transmission Operator. Any generator interconnected within the ATC system is expected to maintain a voltage schedule (voltage setpoint) of 1.02 p.u. at its POI, within limits of its reactive capabilities, to facilitate transmission operations reliability under normal system conditions (system intact) and contingency conditions, unless another voltage level is communicated to the generator by the ATC Transmission Operator (cf. NERC Reliability Standard VAR-001).

3.4 IBR Momentary Cessation

IBRs shall be designed and configured to continue current injection (active, reactive, or a combination of current) inside the “No Trip Zone” of the frequency and voltage ride-through curves of the currently effective version of PRC-024 unless a reliability study identifies a system need to cease injecting current. IBRs shall be designed and configured to use momentary cessation only outside the “No Trip Zone” if this helps mitigate potential tripping conditions based on interconnection studies. Any use of momentary cessation shall be based on equipment limitations or based on reliability studies identifying a system need. Return from momentary cessation upon voltage recovery to within the continuous operation range shall occur as quickly as possible with no intentional time delay while maintaining stability.

3.5 IBR Power Priority Mode

IBRs shall be designed and configured to use a Q (reactive power) priority for the Power Plant Controller (PPC) and inverter in steady-state and transient operation.

3.6 IBR Performance Requirements

All IBRs connected to ATC shall meet the performance requirements shown in Table 3.6-1 and Table 3.6-2.

Table 3.6-1 Dynamic Active Power-Frequency Performance (1)

Parameter	Description	Performance Requirement
Reaction Time	Time between the step change in frequency and the time when the resource active power output begins responding to the change (has reached at least 10% of new steady state value).	< 0.5 seconds
Rise Time	Time between the step change in frequency and the time at which the resource has reached 90% of the new steady-state (target) active power output command.	< 4.0 seconds
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power output command.	< 10.0 seconds
Overshoot	Percentage of rated active power output that the resource can exceed while reaching the settling band.	< 5.0%
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time.	< 2.5%
(1) This performance requirement is tested in a model using a step increase (non-fault events) in frequency of 0.5% at the POM of the IBR. Plant active power should reduce by at least 8.8% (based on maximum 5% droop and +/- 0.036 Hz deadband, as defined in Order 842).		

Table 3.6-2 Disturbance Reactive Power (or Current)-Voltage Performance

Parameter	Description	Small Disturbance Performance Target (1)	Large Disturbance Performance Target (2)
Reaction Time	Time between the step change in voltage and when the resource reactive power (or current) output begins responding to the change with no intentional time delay.	< 200 ms	< 16 ms
Rise Time	Time between a step change in voltage and when the reactive power (or current) output has reached 90% of its final value.	< 10 seconds (3)	< 100 ms
Overshoot	Percentage of rated reactive power (or current) output that the resource can exceed while reaching the settling band.	< 5%	20% (4)
(1) Small Disturbance (e.g., normal switching-type events, changes in generation and load): For a small step change in voltage at the POM of the IBR (measure <u>reactive power</u> output). (2) Large Disturbance (e.g., fault-type events): For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the			

positive sequence component of the inverter reactive current response should meet the above performance specifications.

(3) The maximum Rise Time required may be reduced if studies determine that its required.

(4) Overshoot shall not negatively impact the system or nearby devices.

4. INVERTER-BASED RESOURCE EMT MODEL REQUIREMENTS

All IBRs connecting to ATC must submit an Electromagnetic Transient (EMT) model compatible with the version of PSCAD used by ATC.[6] The EMT model must be able to compile in the version of Fortran used by ATC.[7] The EMT model shall accurately reflect all customer equipment, relevant control and protection systems and settings, and capabilities on the IBR side of the POI.

The following model details must be provided and be clearly observable in the main schematic of the plant model.

- Submission date
- Project Name
- Primary contact information for model related questions
- Secondary contact information for model related questions
- Manufacturer/Vendor
- Model version
- Equipment type (e.g., PV or Wind)
- Equipment version (e.g., Inverter model)
- Documentation or support file(s)[8]
- List of model Files supplied

The model must have control or hardware options which are pertinent to the study accessible to the user[9]; however, when presented to ATC, the model must be configured to match expected site-specific equipment settings. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated, as far as they are known. Default parameters are not appropriate unless these will match the configuration in the installed equipment.

Model documentation is required for the inverter and PPC and must provide instruction for setup and running the model, as well as explaining parameters and model configurations. The model documentation must include a clear way to identify the specific settings (including protection settings) and equipment configuration which will be used in any study, such that during commissioning the settings used in the studies can be checked (including recommended range of simulation timesteps). This may be control revision codes, settings files, or a combination of these and other identification measures (e.g., description of trip/operation code signals produced by the model).

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[6] At the time of criteria approval, ATC presently uses PSCAD v4.6.3.

[7] At the time of criteria approval, ATC presently uses Intel(R) Visual Fortran Compiler 18.0.3.210.

[8] EMT model instructional documentation shall be provided and shall match the model version in the main schematic and include instructions for setup and running of the model.

[9] Examples could include protection thresholds, real power recovery ramp rates, frequency or voltage droop settings, voltage control response times, or SSCI damping controllers. All settings must be within realistic bounds in the real hardware. Diagnostic flags to show control mode changes or which protection has been activated (e.g., trip signals) should be visible to aid in analysis.

The model must also represent the full detailed inner control loops of the power electronics using actual firmware code from the inverter (i.e., a "real code" model). The model cannot use the same approximations classically used in transient stability modeling, and must fully represent all fast inner controls, as implemented in the real equipment.[10] The model also must represent all control features pertinent to the type of study being done (e.g., external voltage controllers, customized PLLs, ride-through controllers, SSCI damping controllers, etc.) and operating modes that require system specific adjustment must be user accessible.

The models must also represent and enable the associated Power Plant Controller (PPC). PPCs must be represented in sufficient detail to accurately represent short term performance, including specific measurement methods, communication delays (including any sample and hold type outputs), transitions into and out of ride-through modes, settable control parameters or options, and any other specific implementation details which may impact plant behavior. Generic PPC representations are not acceptable unless the final PPC controls are designed to exactly match the generic PPC model. If multiple plants are controlled by a common controller, or if the plant includes multiple types of IBRs (e.g., Hybrid BESS/PV) this functionality must be included in the plant control model. If external or multiple voltage control devices (e.g., STATCOM/DVAR, SVC, MSCs) are included in the plant, these should be coordinated with the PPC to prevent circulating VARs or oscillations. The PPC should also:

1. Accept external reference variables (e.g., active power setpoint, real and reactive power values for Q control modes, or voltage values (e.g., 1.02 p.u. for ATC) for voltage control modes).[11]
2. Have a mechanism to implement a settable voltage droop.
3. Respond to frequency changes by increasing or decreasing its active power as appropriate. This can be done at either the inverter level or via the PPC.[12]
4. Initialize to the setpoints specified in the PPC in 5 seconds or less.[13] Real power, reactive power, and RMS voltage should reach steady state after this initialization time.

The model must include all necessary documentation and a sample implementation test case. The test case must use a single machine infinite bus representation of the system, configured with an appropriate representative Short Circuit Ratio. The model should contain the modeling of all the facilities from the inverters to Point of Interconnection (POI) including, but not limited to, the facilities listed below. The facilities should be site specific according to the project design at 60 Hz grid frequency base. The EMT modeling data should match steady state modeling data.

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[10] The model must be a full power transistor (e.g., IGBT) representation. The controller source code may be compiled into DLLs or binaries if the source code is unavailable due to confidentiality restrictions.

[11] Model must accept these reference variables for initialization and be capable of changing these reference variables mid-simulation, i.e., dynamic signal references.

[12] If the model cannot respond in this manner, a description of the under/over frequency response capabilities of the actual equipment must be provided by the manufacturer.

[13] Model must be capable of initializing itself without external input.

- Aggregated generator model
- Equivalent pad mount transformer
- Equivalent collector system
- Main step-up transformers
- Generator tie line
- Power plant controller
- Capacitor banks, STATCOM, or any other types of voltage control devices
- AC equivalent source at the POI with an appropriate representative Short Circuit Ratio for the inverter

The model must represent all pertinent electrical and mechanical configurations. This includes any filters, specialized transformers, gearboxes, pitch controllers, or others if they impact electrical performance within the timeframe of the study. Any control or dynamic features of the actual equipment which are not represented or which are approximated, must be clearly identified.

Additionally, all pertinent protection devices and protection settings must be implemented in detail AND enabled for balanced and unbalanced fault conditions. This includes but is not limited to (voltage protections (OV and UV for individual phase and RMS), frequency protections, DC bus voltage protections, converter overcurrent protections, etc.). These must be available as inputs in the model. There must also be an option to disable protection models as needed. All protection settings should match provided positive sequence dynamic data files.

The model must also:

1. Operate and be accurate with a simulation timestep of 10 μs or greater.
2. Support multiple instances of its own definition in the same simulation case.
3. Not use or rely upon global variables in the PSCAD environment.
4. Include a plant level electrical single line diagram.
5. Not utilize multiple layers in the PSCAD environment, including ‘disabled’ layers.
6. Be capable of scaling plant capacity to represent any number of inverters or turbines, either externally by using a scaling transformer or internal scaling; but should not be using current injection to scale the plant.
7. Be capable of dispatching plant output to values less than nameplate to test plant behavior at various operating points.

The models should have the following minimum characteristics or functions:

- Instantaneous voltage and current waveforms should have minimal distortion, and no oscillations observed.
- Trip or block when the terminal voltage rises above 1.3 pu for one second.
- Trip or block when terminal voltage falls below 0.2 pu for one second.
- Capable of riding-through, recovering and meeting ATC’s stability criteria from a temporary (no line outage or drop in Short Circuit Ratio), 6-cycle, zero-impedance, three-phase fault at the high side of the station transformer, with an appropriate representative Short Circuit Ratio, measured at the POI, while dispatched at 20% and while dispatched at the maximum real power capability of the plant.

4.1 PSCAD Model Verification Process

The PSCAD Model Verification Process shown in Figure 4.1-1 is required to be followed for all IBRs that are required to submit a PSCAD model to ATC. The Parameter Verification Report, as mentioned below, is a comparison of every parameter for the plant owned by the Interconnection Customer (i.e., all equipment from the Point of Interconnection to the inverters). This includes but is not limited to all control and protection systems for Power Plant Controllers (PPCs), inverters, supplemental reactive power devices or other systems (e.g., STATCOMs, DVARs, BESS, etc.). As-built data for collector systems, transformers, and generator tie lines are also required. PPC data includes but is not limited to communication delays, any sample and hold type outputs, and all gains that are in the field.

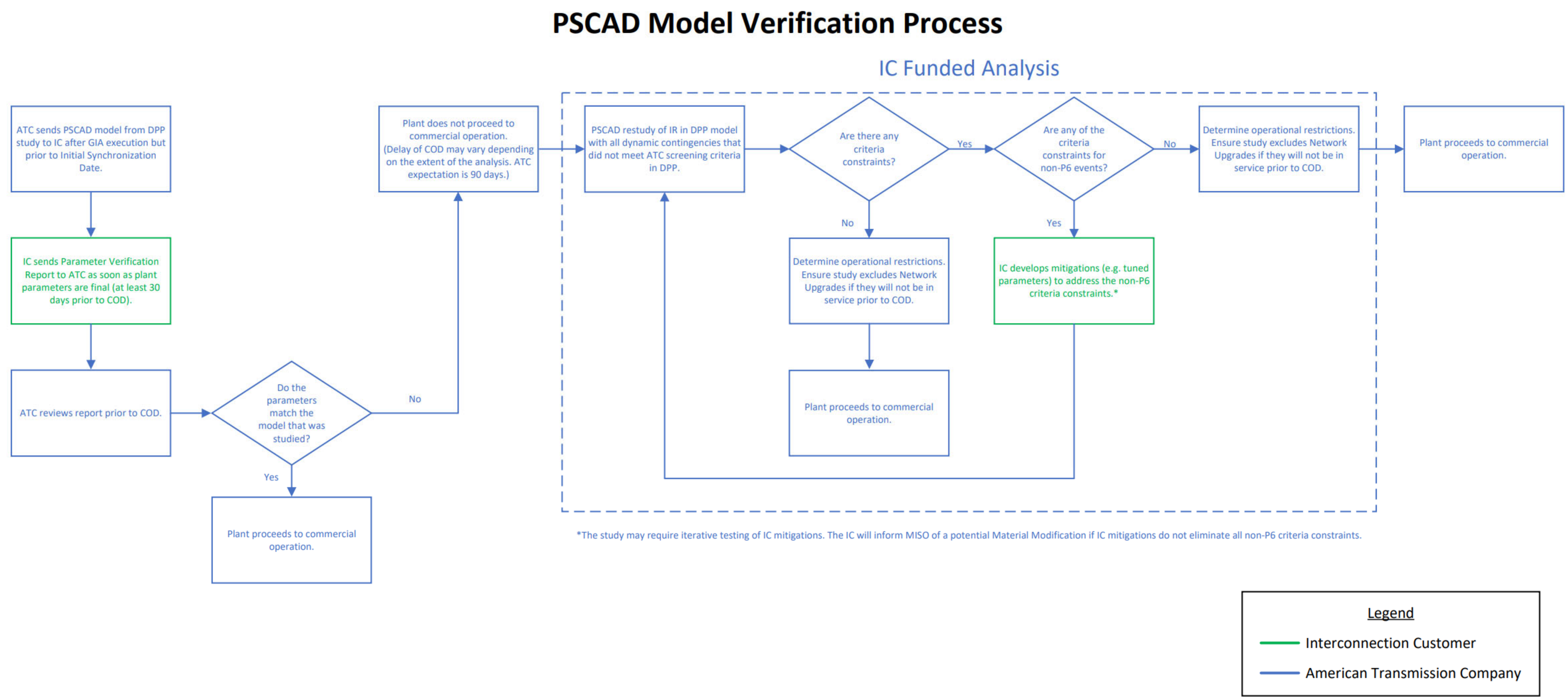


Figure 4.1-1: PSCAD Model Verification Flowchart

5. VOLTAGE FLUCTUATION AND FLICKER

In general, all equipment connected to the ATC system is required to meet these voltage fluctuation and flicker criteria. ATC may allow specific higher fluctuation and flicker levels at specific locations where ATC has determined through experience or analysis that exceeding these requirements will not cause system or customer issues. Additional information on the development and application of this criteria can be found in ATC Guide PLG-GD-0020, "Voltage Fluctuation and Flicker."

Voltage fluctuation is a step voltage change caused by a repeating switching event and is defined as the difference between two steady state voltage levels - one before and one after the event. Acceptable Step Voltages changes as a function of the number of changes per day and voltage level are given in Table 5-1.

Table 5-1 – Acceptable Step Voltage Change as a Function of the Number of Changes in a Given Time Period and Voltage (IEEE 1453-2015)

Number of Changes n	$\Delta V/V_{nominal}$	
	MV	HV/EHV
n ≤ 4 per day	6%	5%
n ≤ 2 per hour and > 4 per day	4%	3%
2 < n ≤ 10 per hour	3%	2.5%

Note: 1 kV < MV ≤ 35 kV, 35 kV < HV ≤ 230 kV, EHV > 230 kV

Capacitor Switching Step Voltage Change Limits. ATC generally limits Step Voltage changes due to capacitor switching to a maximum of 3% at minimum normal system strength. ATC may allow Relative Voltage Changes due to device switching to exceed 3% when the transmission system is not intact due to either planned or unplanned equipment outages, but this should not exceed 5%. Other infrequent switching events, such as line energization or tripping, that usually occur less than once a day, can cause severe voltage variations that must be evaluated in the planning stage and comply with the steady state limits in Table A.

ATC has three flicker criteria, one general criterion applicable to all cases and two criteria applicable to special cases. Although the limits described below are not required to be met during transmission system outages, if these limits are exceeded under outage conditions, the flicker producing load must be operated in a manner that does not adversely affect other loads.

The **General Flicker Criteria** (based on IEEE 1453) is applicable to all cases and uses Pst (short term perception – 10 minutes) and Plt (long term perception – 2 hours) as measured using an IEC standard flickermeter. Different Pst and Plt limits are used for compatibility (all equipment operates as intended) and planning (which includes some margin). A flickermeter calculates the 95% and 99% probability values $P_{st99\%}$, $P_{st95\%}$, $P_{lt99\%}$ and $P_{lt95\%}$, which represent values that are not exceeded 95% and 99% of the time. Compared to the system flicker planning levels in Table 5-2, (1) the 95% probability value should not exceed the planning level and (2) the 99% probability value may exceed the planning level by a factor (1−1.5) depending on system conditions to be determined by ATC. The limits shown in Table 5-2 apply to an individual customer's emissions at their point of common coupling (PCC).

Table 5-2 – Compatibility and Planning Flicker Limits

	Compatibility Levels	Planning Levels	
	LV ≤ 1 kV	1 kV < MV ≤ 35 kV	HV & EHV > 35 kV
Pst	1.0	0.9	0.8
Plt	0.8	0.7	0.6
Note: LV ≤ 1 kV, 1 kV < MV ≤ 35 kV, 35 kV < HV ≤ 230 kV, EHV > 230 kV			

Single Frequency Flicker. In the unlikely condition that the flicker to be analyzed consists of a single frequency caused by step changes in RMS voltage, the flicker tolerance curve shown in Figure 5-1 can be used to determine if the flicker is acceptable. ATC limits single frequency flicker to below the "borderline of irritation" on Figure 5-1. ATC does not have provisions for a margin or any time for this limit to be exceeded.

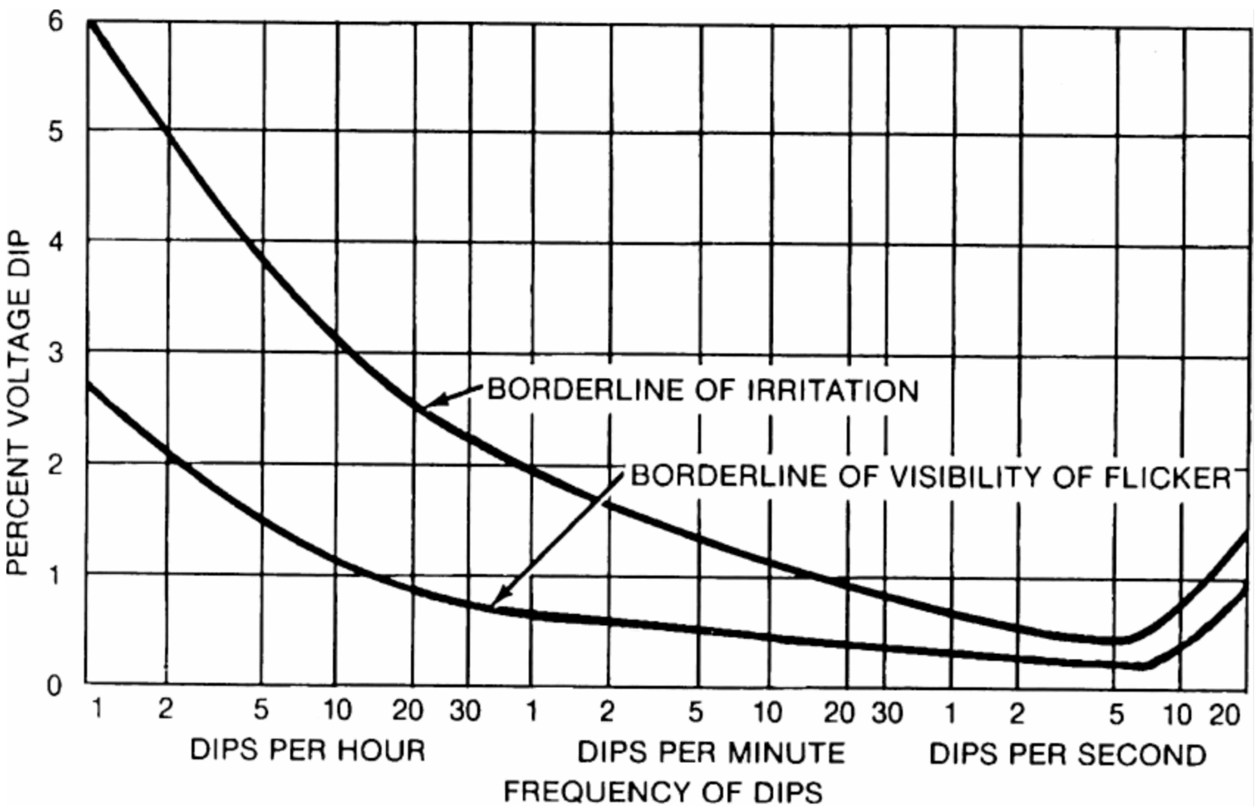


Figure 5-1: Flicker Tolerance Curve from IEEE Standards 141, 519, and 1453

Flicker Caused by Interharmonic Voltages below 120 Hz: Interharmonic voltages with frequencies up to 120 Hz can cause flicker and should be limited to the weekly 95th percentile short time interharmonic voltage values shown in Figure 5-2.

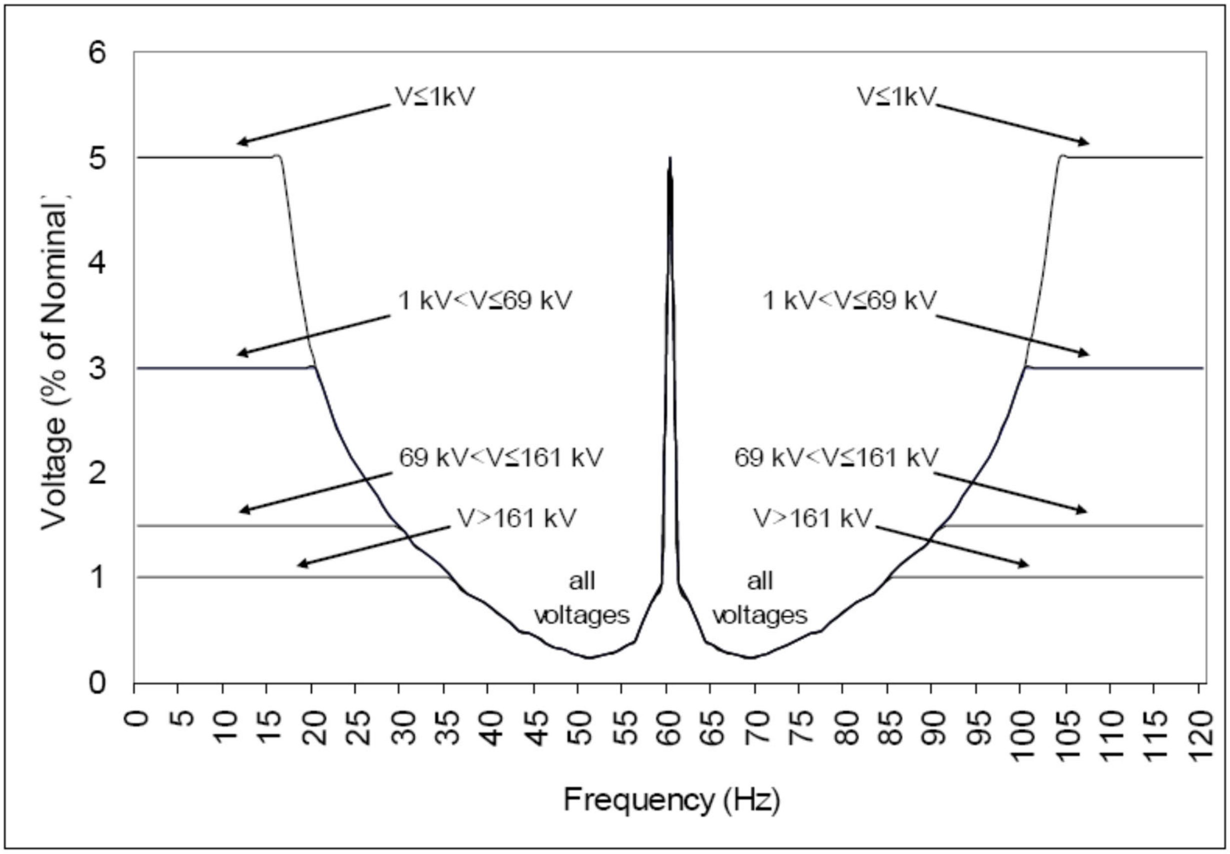


Figure 5-2: Flicker Limits Based on Interharmonic Voltages < 120 Hz (IEEE 519)

6. HARMONIC VOLTAGE AND CURRENT DISTORTION

In general, all equipment connected to the ATC system are required to meet these harmonic criteria. ATC may allow specific higher harmonic levels at specific locations where ATC has determined through experience or analysis that exceeding these requirements will not cause system or customer issues. Harmonic criteria are designed so that in most cases if harmonic current limits are met, harmonic voltage limits will also be met. It is the responsibility of loads to meet harmonic current limits at their PCC and ATC's responsibility to meet harmonic voltage limits.

These harmonic criteria are based on specific measurement techniques that use the harmonic measurement windows, short and very short time harmonic measurements, and statistical evaluation defined in IEEE 519-2014. Any harmonic meter used to measure harmonics on the ATC system should specify that they are IEEE 519-2014 compliant. Additional information on these measurements and application techniques can be found in ATC Guide PLG-GD-0019 "Harmonic Distortion" and IEEE-519-2014, "Recommended Practices and Requirements for Harmonic Control in Electric Power Systems."

Harmonic Voltage Limits. Table 6-1 lists limits for both Individual Harmonic and Total Harmonic Voltage Distortion (THVD) to be applied when large new harmonic loads are connected to the system and when harmonic related issues are discovered These limits are applied to line-to-neutral voltages at the Point of Common Coupling (PCC) and reported as the percentage of the rated power frequency voltage. Total Harmonic Distortion is calculated as the square root of the sum of the squares of the individual harmonic distortions (root square sum - RSS). Limits are given for four voltage ranges, with the limits being more restrictive at higher voltage levels.

Table 6-1 – IEEE 519-2014 Harmonic Voltage Distortion Limits

Line-to-neutral voltage harmonics should be limited as follows (% of rated voltage at PCC):
(1) Daily 99th percentile very short time (3 s) values should be < 1.5 times Table 6-1 values
(2) Weekly 95th percentile short time (10 min) values should be < the Table 6-1 values

Bus Voltage at Point of Common Coupling (PCC)	Individual Harmonic Voltage Distortion (%)	Total Harmonic Voltage Distortion (%)
V ≤ 1.0 kV	5.0%	8.0%
1 kV < V ≤ 69 kV	3.0%	5.0%
69 kV < V ≤ 161 kV	1.5%	2.5%
161 kV < V	1.0%	1.5%*
*High-voltage systems (V > 161 kV) can have up to 2.0% THVD where the cause is an HVDC terminal whose effects will have attenuated at points in the network where future users may be connected.		

Current Distortion Limits. Tables 6-2 to 6-4 list limits for both Individual and Total Harmonic Current Distortion to be applied at the Point of Common Coupling (PCC). Both are reported as percentages of the fundamental frequency component of the maximum demand load current (I_L) - the maximum demand during each of the twelve previous months divided by 12. Limits are given for three voltage ranges, with the limits being more restrictive at the higher voltages. These current limits vary with the size of the load (I_L) in relation to system strength (I_{SC}) and harmonic frequency. All generation, regardless of the I_{SC}/I_L ratio at its PCC, are held to the minimum I_{SC}/I_L limits for their voltage range.

Table 6-2 – Harmonic Current Distortion Limits for Systems Rated 120 V through 69 kV and All Power Generation Equipment

Daily 99th percentile very short time (3 s) harmonic currents should be < 2.0 times Table 6-2 values.
– Weekly 99th percentile short time (10 min) harmonic currents should be < 1.5 times Table 6-2 values.
– Weekly 95th percentile short time (10 min) harmonic currents should be < the Table 6-2 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]						
I_{SC}/I_L	3 ≤ *h* < 11	11 ≤ *h* < 17	17 ≤ *h* < 23	23 ≤ *h* < 35	35 ≤ *h* < *50*	TDD
<20[c]	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%

>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

a. Even Harmonics are limited to 25% of the odd harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
c. All power generation equipment is limited to these values, regardless of ISC/IL where ISC = maximum short circuit current at PCC and IL = maximum demand load current (fundamental frequency component) at PCC

Table 6-3 – Harmonic Current Distortion Limits for Systems Rated > 69 kV to 161 kV

Daily 99th percentile very short time (3 s) harmonic currents should be < 2.0 times Table 6-3 values.
– Weekly 99th percentile short time (10 min) harmonic currents should be < 1.5 times Table 6-3 values.
– Weekly 95th percentile short time (10 min) harmonic currents should be < the Table 6-3 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]

I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	TDD
<20[c]	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
20<50	3.5%	1.75%	1.25%	0.5%	0.25%	4.0%
50<100	5.0%	2.25%	2.0%	0.75%	0.35%	6.0%
100<1000	6.0%	2.75%	2.5%	1.0%	0.5%	7.5%
>1000	7.5%	3.5%	3.0%	1.25%	0.7%	10.0%

a. Even Harmonics are limited to 25% of the odd harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.
c. All power generation equipment is limited to these values, regardless of ISC/IL where ISC = maximum short circuit current at PCC and IL = maximum demand load current (fundamental frequency component) at PCC

Table 6-4 – Harmonic Current Distortion Limits for Systems Rated > 161 kV

Daily 99th percentile very short time (3 s) harmonic currents should be < 2.0 times Table 6-4 values.
– Weekly 99th percentile short time (10 min) harmonic currents should be < 1.5 times Table 6-4 values.
– Weekly 95th percentile short time (10 min) harmonic currents should be < the Table 6-4 values.

Maximum Harmonic Current Distortion for Individual Odd Harmonics and TDD (% of I_L)[a,b]

I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h < 50$	TDD
< 25[c]	1.0%	0.50%	0.38%	0.15%	0.10%	1.5%
25 < 50	2.0%	1.0%	0.75%	0.3%	0.15%	2.5%
≥ 50	3.0%	1.5%	1.15%	0.45%	0.22%	3.75%

a. Even Harmonics are limited to 25% of the odd harmonic limits listed above.
b. Current distortions that result in a dc offset, e.g. half-wave converters, are not allowed.

c. All power generation equipment is limited these values, regardless of I_{SC}/I_L where I_{SC} = maximum short circuit current at PCC and I_L = maximum demand load current (fundamental frequency component) at PCC

Recommendations for Increasing Harmonic Current Limits. The limits on certain frequencies given in Table 6-2, Table 6-3, and Table 6-4 can be increased by the multiplying factors in Table 6-5 when actions are taken to reduce other frequencies. The multipliers in Table 6-5 are applicable when steps are taken to reduce the harmonic orders listed in the first column. Taking the first row as an example, if a 12 pulse rectifier (which reduces the 5th and 7th harmonics) is used, all non-characteristic harmonic currents (all harmonics other than the 11th, 13th, 23rd, 25th, 35th, 37th, etc., i.e. h=kq+1, where k is any integer and q is the pulse number of the converter) are limited to 25% of their values in Tables 6-2 to 6-4, but the characteristic harmonic limits are increased by 40%.

Table 6-5 –Recommended Multipliers for Increases in Harmonic Limits

Harmonic Orders Limited to 25% of Values Given in Tables 6-2 to 6-4	Multiplier
5, 7 (12-pulse rectifier)	1.4
5, 7, 11, 13 (18 pulse rectifier)	1.7
5, 7, 11, 13, 17, 19 (24 pulse rectifier)	2.0
5, 7, 11, 13, 17, 18, 23, 25 (30 pulse rectifier)	2.2

7. UNDER-FREQUENCY LOAD SHEDDING

Under-frequency load shedding (UFLS) island identification is based on the following criteria. In general, UFLS is designed to arrest declining frequency after an under-frequency event. Island identification is the subdivision of the Bulk Electric System (BES) including the ATC transmission system into sub regions. UFLS analysis falls into two categories: frequency performance and dynamic volts per hertz performance.

7.1 Island Identification

The identification of UFLS islands is based on the NERC reliability standard PRC-006. The UFLS island identification that ATC uses is based on the following four criteria:

1) Actual Historical Island Event

   A UFLS island is identified as a portion of the BES including the ATC transmission system which was an actual historical island event within the past five years.

2) Non-UFLS System Studies

   A UFLS island is identified as a portion of the BES including the ATC transmission system which was determined to be an island through non-UFLS system studies.

3) Relay Scheme or a Remedial Action Scheme

A UFLS island is identified as a portion of the BES including the ATC transmission system which is planned to detach from the transmission system as a result of the operation of a relay scheme or a Remedial Action Scheme.

4) Large Single Island

A UFLS island is identified as a single island in the MRO area, the RF area, or the Eastern Interconnection that includes the entire ATC transmission system. The island shall be selected by applying the above criteria and coordinating with the criteria of MISO and PJM to verify that all ATC UFLS schemes meet the PRC-006 standard performance requirements when acting together with or without the programs of the BES.

7.2 Frequency Performance Assessment Criteria

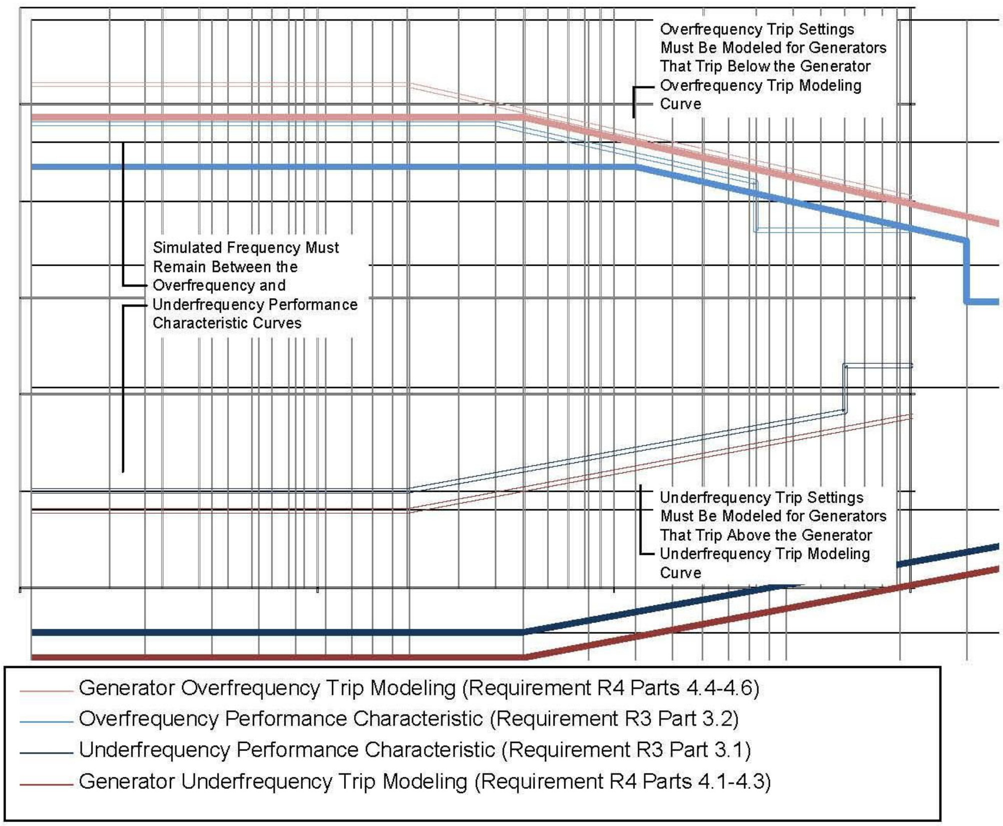
Transient island frequencies shall remain within the Under-frequency and Over-frequency Performance Characteristic Curves in PRC-006 Standard Attachment 1.

7.3 Volts Per Hertz Assessment Criteria

Transient Volts per Hertz values shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus.

PRC-006-1 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz

Figure 7.3-1: Performance Characteristic Curves for UFLS Frequency Performance Criteria

8. VARIATIONS ON ATC PLANNING CRITERIA

The ATC transmission system consists of assets contributed by entities within the five Balancing Authorities of the Wisconsin-Upper Michigan Systems. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as ATC has implemented its own planning criteria, portions of the system may require upgrades to meet the more stringent ATC criteria.

This section of the ATC planning criteria describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the ATC planning criteria.

Area does not meet the ATC planning criteria performance requirements.

1) Complete projects required for bringing the existing system up to the ATC planning criteria performance requirements with no intentional delay.
2) New generator interconnections are not permitted until the ATC planning criteria are met with the addition of the new generator, if the new generator interconnection aggravates the stability condition [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet the ATC planning criteria. See NERC Standard FAC-002-1 for new generator interconnections].
3) Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the projects are completed. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a "last interconnected, first restricted" approach.
4) Reinforcements to meet ATC Criteria will be reviewed to ensure the risk, cost and benefit are in the best interest of stakeholders. ATC Planning Leadership will have the discretion to determine exceptions to the criteria.

9. DEFINITIONS

9.1 Automatic Model Adjustments

For Planning purposes, automatic model adjustments include switched shunts[14], static var compensators, phase shifters[15], and load tap changers (LTCs)[16].

[14] Most switched shunts have automatic switching or are switched by operators using supervisory control. For the supervisory controlled shunts, automatic adjustment settings are used to approximate expected operator adjustment.

[15] Phase shifters that significantly affect the ATC system are at Lone Rock, Arrowhead and Stinson. Planning assumes Lone Rock and Stinson can adjust, and Arrowhead does not because the automatic adjustment settings are very wide. This is consistent with Operations' understanding.

[16] In Planning's models, LTCs are either modeled as automatic or fixed. Automatic LTCs will adjust when a model is solved, and the fixed LTCs will remain in place. Planning Methodology & Models group maintains a list of which transformer LTCs can automatically switch and models accordingly.

9.2 Cascading

The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

9.3 Extreme Disturbance Events

Selected events beyond P0 though P7 Contingencies based on operating experience. Typical examples are listed in NERC TPL-001 Table 1 - Steady State & Stability Performance Extreme Events.

9.4 Known Outage

The combination of all planned outages (scheduled and/or known) with schedules overlapping on a single date as described in MISO Business Practice Manual 020 *Transmission Planning* section 4.3.6 *Consideration of Planned Outages in the Near-Term Transmission Planning Horizon*.

9.5 Long Lead Time Equipment Outage

Outage of equipment that could take one year or more to replace.

9.6 Manual – Supervisory Controlled

Includes system reconfiguration, HVDC adjustment, and/or appropriate load transfer.

9.7 Manual – Field Switching

Manual operation of field switches outside of the control center for system reconfiguration or load transfer.

9.8 Maintenance Outage

The temporary operational removal of the Facility from service to perform work on specific components in accordance with a pre-planned operations schedule, such as for a planned annual overhaul, inspections, or testing of specific equipment of the Facility.

9.9 SPS, RAS, and UVLS

These mitigation options include existing Special Protection Systems (SPS), RAS, and Under Voltage Load Shedding (UVLS).

The TPL-001 standard requires removal of all elements that controls would automatically disconnect for the specific event. If conditions are met to trigger an SPS, RAS, or UVLS, the Contingency analysis must be rerun to include the appropriate option (SPS, RAS, or UVLS) as a mitigation measure. This type of mitigation is only allowed if there is an existing SPS, RAS, or UVLS defined, and the Planner should be aware of when and how to utilize these options appropriately.

9.10 Short Circuit Ratio

The short-circuit MVA capacity at the IBR POI divided by the maximum real power capacity of the IBR.

9.11 Short-term Steady State

The post-transient period before typical load tap changers and mechanically switched shunts can operate.

9.12 Total Load at Risk

Total Load at Risk is defined as the sum of the following four types of load loss, which are identified in steady state analyses.

Consequential Load Loss (NERC definition)

NERC definition is "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault." It represents the load that is outaged as a result of automatic fault protection for an event-based Contingency. It excludes load that is immediately restored via automatic switching to adjacent substations.

Interruptible Load Loss

Load that is outaged by other automatic controls for an event-based Contingency based on a documented agreement between ATC and the Load-Serving Entity. The end-use customer must make the load available for curtailment to the Load-Serving Entity via contract or agreement.

Subsequent Cascading Load Loss

Load that is outaged as a result of subsequent element-based outages during the remaining cascading analysis. This type of load loss is a result of either voltage sensitive load tripping when load buses are below 0.8 p.u. or load islanding due to lines/transformers tripping. The 0.8 p.u. load tripping threshold is used as a proxy to simulate the response of voltage sensitive load. The response of voltage sensitive load refers to the tripping of the load due to intrinsic voltage protection mechanisms that manufacturers build into their equipment.

Non-Consequential Load Loss (NERC definition)

NERC definition is "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It represents the non-interruptible load shed that may need to be performed by manual or automatic controls to restore the ATC system to be within emergency limits and the additional load curtailment that may need to be performed by manual or automatic control to restore the ATC system to be within normal limits.

9.13 Uncontrolled Islanding[17]

Islanding is the disconnection of one or more loads and/or generators from the Eastern Interconnection. The resulting island may contain just one load, just one generator or multiple loads and generators. The resulting island may collapse or survive depending on the mix of the load and generation in the island and the automatic controls (e.g., UFLS) present in the island.

Uncontrolled islanding is the disconnection of one or more loads and/or generators from the Eastern Interconnection. It is not caused by either automatic system fault protection in response to the initial fault contingency or system operator manual actions. Uncontrolled islanding is caused by subsequent (post fault clearing) system conditions, including but not limited to, circuit overloads and low voltages. Circuit overloads can automatically trip lines and transformers. Low bus voltage level can automatically trip generators and loads. The subsequent tripping of lines and/or transformers can result in loads and/or generators being islanded. Therefore, uncontrolled islanding can result in the loss of load and/or generation.

9.14 Voltage Stability Flowgate

A transmission facility or transmission element(s) that has been identified as limiting the amount of power that can be reliably transferred over the bulk transmission system due to voltage instability

10. ADMINISTRATION

10.1 Review

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. Annually the need for a full review will be evaluated.

10.2 Retention

The previous version of this document will be retained for at least five years after is becomes retired.

11. REVISION HISTORY

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
14	Connie Lunde, et alia	David Smith, Paul Walter	Ron Snead	Primary – split Criteria and Practices into separate documents, added voltage limit text, modified voltage stability margin text; Details – Summary of Planning Criteria V14 and Practices V1 Revisions document

[17] Steady State NERC Category P Events “Interruption of Firm Transmission Service and Non-Consequential Load Loss Assessment” PLG-PRO-0213-V06

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
15	Shane Ehster, et alia	David Smith, Paul Walter	Ron Snead	Primary – Addition of UFLS criteria, added low voltage limit text for the P-V nose, revised Category D generator stability requirements, moved Variations on ATC Planning Criteria section from Assessment Practices document
16	Curtis Roe, et alia	David Smith, Paul Walter	Ron Snead	Revised NERC references to TPL-001-4, revised annual review requirement, added criteria summary table, added maintenance plus in P1, and added TTL specifics
16.1	Curtis Roe, et alia	David Smith, Paul Walter	Ron Snead	Errata
17	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Added post-Contingency voltage deviation criteria, removed post fault voltage recovery threshold, revised the TTL terminology to cascading trip threshold.
18	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Updated references to IEEE 1453 and 519; and revised the transient response requirement.
19	Curtis Roe, et alia	David Smith, Paul Walter	Andy Dolan	Added non-BES rows to P1.1-P2.5 and P2.1 contingencies in Table A, removed Small Signal Stability criteria, added Section 3 Generating Facility Power Factor, and added Section 2 Variations bullet item #4.
19.1	Chengyue Guo	David Smith, Paul Walter	Andy Dolan	Added clarity around voltage limitations.
19.2	Curtis Roe	Paul Walter	Andy Dolan	Revised power factor limit (new limit 0.95 lagging).
19.3	Chengyue Guo, Damien Sommer, Mike Marz, Bob Krueger, et alia	Paul Walter Adam Manty	Andy Dolan	Added sub-section for “Inverter-Based Resources Stability Assessment”, improved languages in Voltage Stability Assessment criteria for clarification and cleaned up stability simulation time descriptions to be consistent
19.4	David Smith, et alia	Tom Dagenais	Andy Dolan	Added note 7 to the “General Steady State Performance Criteria” Table A, to clarify thermal emergency rating
19.5	Chengyue Guo, Damien Sommer, et alia	Paul Walter Adam Manty	Andy Dolan	Enhanced inverter-Based Resources Stability criteria and improved languages in Section 2.1.
20	David Smith	--	Andy Dolan	Changed version from 19.5 to 20 to match TYA year
20.1	Joel Berry Chengyue Guo	Adam Manty Paul Walter	Andy Dolan	Revised the Voltage Stability Margin requirement to 5% on a post-contingent basis. Clarified the application of margins on expected clearing times.
20.2	David Smith	Adam Manty	Andy Dolan	Corrected note numbers for the Table A
21	David Smith et alia	Adam Manty, Paul Walter, Robert Morton, Dale Burmester	Andy Dolan	Removed old footnote 1 related to emergency ratings, particularly in Table A. Specified generators for which stability criteria applies, particularly in Section 2. Replaced SPS with RAS.
21.1	Chengyue Guo Bob Krueger et alia	Paul Walter Adam Manty	Andy Dolan	Added clarity around ATC’s generator power factor requirement in Section 3.2
21.2	Chengyue Guo et alia	Paul Walter	Andy Dolan	Added the treatment of a short transition period in bullet a and clarified in bullet c that the requirements in bullet a and b are minimum requirements in Section 3.2 under when the Generating Facility is not generating active power.

Revision	Author(s)	Manager(s)	V.P.(s) Director(s)	Summary of Changes
22	Jamal Khudai et alia	Paul Walter	Andy Dolan	Rewritten Section 1 "Steady State Criteria and Implementation", Added Table A Non-Consequential load shed not allowed in-between P6 events Added Section 9 "Definitions"
22.1	Jamal Khudai, Joel Berry, Mike Marz, Stephanie Schmidt, Randy Johanning, et alia	Paul Walter	Tom Dagenais	TPL-001-5 compatibility related edits i.e. P5 Added known outage and long lead time equipment Added Resource Facility Requirements Section 3 Added IBR EMT Model Requirements Section 4 Updated Voltage Fluctuation and Flicker Section 5 and Harmonic Voltage and Current Distortion Section 6