Western Area Power Administration

Planning Criteria Document
Version 3.0

APPROVED:

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Western
AREA POWER
ADMINISTRATION

Approval History

Revision	Date	Action	Name of Editor
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2.0	11/06/13	Minor wording updates	TMPT
3.0	12/31/2015	Update document to be in accordance with NERC Standard TPL-001-4	TMPT

1. **Introduction**

As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted the North American Electric Reliability Corporation (NERC) the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. NERC is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through its Regional Reliability Organizations (RRO). Western Area Power Administration (Western) operates in two NERC regions, Western Electricity Coordinating Council (WECC) and Midwest Reliability Organization (MRO).

Western reliability and/or operation functions are located in various operating regions. Depending on the region, they are registered with NERC as Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TP), Transmission Service Provider (TSP) and Planning Coordinator (PC) and Balancing Authority (BA) and these functions may vary in regions. Western is committed to comply with the NERC Reliability Standards and as such all transmission planning and interconnection or facility connection studies are subject to NERC planning and operational performance.

The criteria were established to assure system planning continues to maintain reliability of the Bulk Electric System (BES) and does not adversely affect neighboring systems. Western's local planning criteria is intended to ensure compliance with the mandatory reliability standards that are in place since the enactment of the Energy Policy Act of 2005. This local planning criteria is periodically reviewed and may be updated as appropriate to reflect changes in Western's operating and planning requirements and adhere with the WECC and MRO Standards.

Western’s local planning criteria conforms to the NERC Reliability Standards, the MRO Standards and the WECC Standards, as appropriate. It is intended that this will provide an adequate level of service that is cost-effective, maintain service to firm loads (except for radial and tap feeds), no overloads beyond the emergency rating will occur, and no cascading is allowed.

In assessing the performance of the Western system, this local planning criteria as well as the applicable criteria established by the WECC and/or the Southwest Power Pool (SPP) shall be considered.

New transmission facilities may be required due to requests made through the Open Access Same-Time Transmission System (OASIS). These can be in the form of merchant generator interconnection or new end-use load substation interconnection requests, new firm transmission services, Point-to-Point requests or new end-use load or Network load interconnection requests. These studies are processed pursuant to the applicable governing tariff; Western’s or SPP’s.

2. System Planning Performance Standards

Western conducts powerflow, stability, and short-circuit studies to evaluate system performance and reliability according to the following local criteria as well as applicable regional criteria. The initial transient period refers to the first 20 seconds after the contingency. The post-disturbance period refers to the period 20 seconds to 30 minutes after the contingency.

These criteria can be utilized as guidelines for real-time operations, however depending upon operating conditions, the real-time voltages may vary outside of the recommended ranges below and the owner of the facility should be contacted for guidance on the application of criteria during real-time operations.

2.1 Powerflow Studies (Steady State)

2.1.1 System Normal Conditions (No Contingency: Category P0)

2.1.1.1 Facility Loading Limits

Facility loading limits shall not exceed the continuous rating or the established equipment operating limits as defined in Western's Facility Ratings Methodology. The Facility Ratings Methodology shall be used to establish Western's facility ratings.

2.1.1.2 Voltage Limitations

Typically, transmission bus voltage levels will be maintained between 0.95 p.u. and 1.05 p.u. of nominal system voltage unless otherwise noted. All steady state BES voltages in the study base case shall meet these criteria after all documented system adjustments have been made.

System	Facility	Maximum p.u.	Minimum p.u.
Western-All Regions	Default for all buses	1.05 p.u.	0.95 p.u.
Western-Upper Great Plains Region	Philip 230 kV bus	1.06 p.u.	0.95 p.u.
	Philip 230 kV tap	1.06 p.u.	0.95 p.u.
Western-Desert Southwest Region	Glen Canyon 230 kV, Kayenta 230 kV, Long House Valley 230 kV, Navajo 230 kV, Shiprock 230 kV	1.07 p.u.	0.95 p.u.

Historical voltage levels will be maintained for new interconnections, unless the historical voltages are above 1.0 p,u,, then the new interconnection would be allowed to meet 1.0 p.u.

2.1.1.3 Reactive Power

Power factor criteria for customer loads must be maintained at 0.95 p.u. leading to 0.95 p.u. lagging. Western's transmission system reactive reserve capabilities will be adequate for the requirement of its transmission system and contract obligations to customers. Interchange of reactive power flow at the system interconnections with the customers and other utilities should be kept to a minimum, unless other conditions are agreed to as being mutually advantageous to both parties.

2.1.1.4 Switching Criteria

Switching of reactive control devices (i.e., reactor or capacitor bank) as a general rule, will not result in a bus voltage step-change of more than 0.03 p.u. System conditions and configurations in certain areas may necessitate a somewhat altered criterion than noted here.

2.1.2 Post-Disturbance System

2.1.2.1 Facility Loading Limits

Facility loading limits shall not exceed the emergency rating or the established equipment operating limits as defined in Western's Facility Ratings Methodology. The Facility Ratings Methodology shall be used to establish Western's facility ratings.

2.1.2.2 Voltage Limitations

These criteria are intended to be applied to the post contingency conditions, prior to any operator intervention. Depending on the local transmission system characteristic, bus voltage levels are allowed to be between 0.90 p.u. and 1.10 p.u. of nominal system voltage for up to 30-minutes for planning and seasonal operating studies unless otherwise noted. Post-Contingency voltage deviations shall not exceed these limits.

System	Facility	Maximum p.u.	Minimum p.u.	Maximum Duration Allowed
Western-All Regions	Default for all buses	1.10 p.u.	0.90 p.u.	30 minutes
Western-Desert Southwest Region	Kayenta 230 kV, Long House Valley 230 kV, Navajo 230 kV	1.12 p.u.	0.90 p.u.	30 minutes
Western-Sierra Nevada Region	COPT 500 kV Facilities	1.15 p.u.	0.90 p.u.	30 minutes

2.1.2.3 Reactive Power Analysis

Western's transmission system shall be planned, designed and constructed to provide sufficient reactive capacity and voltage control facilities to satisfy reactive requirements. Reactive Power Margin analysis shall be performed when steady-state analyses indicate possible insufficient voltage stability margins. This can be assessed through a Power-Voltage (PV) and/or Reactive-Volt (QV) analysis. The voltage stability limits are defined based on a 5% margin from the nose point (or point before voltage collapse occurs).

2.1.3 System Adjustments

For all post-contingency event analysis, no system (operator initiated) adjustments other than automatic adjustments will be represented (no manual system adjustments such as capacitor, reactor switching, generator rescheduling, voltage regulator, or phase shifting transformer (PST) set point adjustments).

Manual system adjustments can be utilized for the post-recovery phase. These adjustments can include reactive device switching, adjustments of set points for load tap changing (LTC) transformers, adjustments of set points for phase shifting transformers, rescheduling of inter-area transfers, corrective sectionalizing on the high-voltage transmission system, and/or implementation of system operating guides.

With system adjustments, the loading on facilities and voltages must be reestablished to their continuous limits (provided in Section 2.1.1.1 and 2.1.1.2) within the allowed readjustment time period (post-recovery phase), generally 30-minutes following a contingency.

2.2 Short Circuit Evaluation

Short circuit studies are performed to determine whether circuit breakers have adequate interrupting capability for Faults that they will be expected to interrupt. Corrective Action Plans are developed for all instances where the maximum fault current a breaker is expected to interrupt exceeds 95% of its interrupting capability (short circuit rating).

Should a new interconnection result in affected facilities loading to 95% or greater of their interrupting capability, the interconnecting customer shall be responsible for all costs required to alleviate the issue as a condition of interconnection.

2.3 Stability Studies

Stability studies are performed by examining system performance following events to determine whether the BES meets the performance requirements in Table 1 of the NERC Reliability Standard TPL-001-4.

2.3.1 System Stability Evaluation

The system shall be designed to meet the performance requirements of NERC Reliability Standard TPL-001-4, Table 1.

If there is any instability associated with NERC Category P4 or P5 events, the area of instability should remain confined to a local area without jeopardizing the integrity of the BES or leading to cascading, voltage instability or uncontrolled separation (islanding).

High-speed automatic reclosure is not normally used on 500-kV and 345-kV lines. However, if reclosing is represented, the system must be able to withstand one unsuccessful reclosing. Normal total clearing times are 4-5 cycles for 230-kV, and 3-4 cycles for 345-kV and 500-kV breakers. These values include relay time, breaker time and one cycle margin. Backup clearing time after fault initiation for delayed clearing operations is normally 10 cycles plus normal clear time.

2.3.2 Transient Period Voltage Limitations

2.3.2.1 Voltage Response (Recovery)

For transient voltage response, the applicable criteria established by WECC and/or SPP shall be utilized to specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

2.3.2.2 Overvoltage Criteria

BES transmission bus voltages should not rise above 1.20 p.u. at any bus in the system following fault clearing, unless affected transmission system elements are designed to handle the rise above 1.20 p.u.

Bus voltages in the Western-UGP Region are allowed to increase to 1.30 p.u. for a duration up to 200 msec. unless otherwise noted.

In Western’s Upper Great Plains Region, the Miles City East and West 230 kV bus voltages are allowed to increase to 1.30 p.u. for a duration up to 270 msec. during Miles City Converter Station block/bypass operation. Dynamic overvoltage devices (zinc oxide arresters) are installed on both the East and West Miles City 230 kV buses to clip the transient overvoltage to a 1.30 p.u. maximum. The surrounding area buses will also experience transient overvoltages (less than the 1.30 p.u. maximum and reduced based upon their electrical distance from Miles City) during this condition. These are acceptable. No specific overvoltage criteria for this condition are listed for the surrounding area buses due to the variance in the overvoltages for different system configurations.

2.3.3 Transient Period Damping Criteria

All power oscillations must demonstrate positive damping within 20-seconds after the start of the studied event.

2.3.4 Generator Stability

All machines maintain synchronism as demonstrated by the relative rotor angles. For P1 planning events, no generating unit shall pull out of synchronism. In general, a generator is considered pulling out of synchronism if the rotor angle exceeds 180° from the system/area reference generator. A generator being disconnected from the Transmission System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism (TPL-001-4 R4.1.1).

For planning events P2 through P7, if a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and facilities directly connected to it (TPL-001-4 R4.3.1.3). If a generator pulls out of synchronism, an out-of-step check shall be performed to test if any cascading tripping would occur from the apparent impedance swings (TPL-001-4 R4.1.2).

2.4 Defining System Instability

2.4.1 Cascading

Cascading shall be identified in the steady-state simulation. This is determined by progressively greater instances of overloading. Transmission lines and transformers that are found to overload beyond their expected relay trip points and series capacitors that are found to overload to 100% of the 30-minute facility rating will be taken out of service and a new solution attempted. This process will be repeated until either no elements overload past their expected relay trip points or the process has been repeated at least three (3) times and continues to result in lines overloading past their expected relay trip points. Continuation of overloaded lines past three iterations shall indicate Cascading.

2.4.2 Voltage Instability

Voltage Instability shall be identified in both steady-state and transient analysis.

In the steady-state, for cases that converge post-contingency, loads at buses that fall below 0.70 p.u. will be considered to have tripped. Total load loss of greater than 1000 MW will be considered to be unstable. Cases that do not converge will be considered to be unstable.

In the transient simulation, load will be considered to have tripped at buses where the first post-recovery swing voltage dips below 0.70 p.u. Total load loss of greater than 1000 MW will be considered to be unstable.

2.4.3 Uncontrolled Islanding

Uncontrolled separation has occurred when the system as the result of dynamic instability breaks up into individual islands as the result of coherent clusters of buses loosing synchronism between each other. This is demonstrated by relative phase angle spread increasing beyond 180° among groups of buses across the system. To identify possible uncontrolled separation, high voltage buses (230 kV, 345 kV and 500 kV) will be checked for increasing angle spread across the system to monitor for islanding events.

2.5 Special Protection Systems (Remedial Action Schemes)

Western allows the use of Special Protection Systems to mitigate reliability concerns on a case-by-case basis.