Proposed Zonal Planning Criteria Zone 6 – Evergy Metro

Contents

1.0 Introduction

The primary purpose of the Zone's transmission is to supply its customers with reliable and economic electrical energy. To achieve this objective, the Zone has approved (TBD) this Zonal Planning Criteria (ZPC) that provides the minimum design and operating criteria of the transmission system which include complying with mandatory requirements established by local, state, or federal laws or regulations (i.e., enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether at the state or the federal level) or other non-discretionary requirements including but not limited to road moves, National Electrical Safety Code regulations, and North American Electric Reliability Corporation standards. The Zonal Planning Criteria shall meet or exceed all North American Electric Reliability Corporation (NERC) Reliability Standards and Southwest Power Pool (SPP) Transmission Planning Criteria. Transmission needs will be identified through transmission planning studies using the Zone's ZPC and solutions, including those for Local Operational Reliability, will be adopted through a zonal planning process.

2.0 Transmission Planning Studies

The interconnected transmission system should perform reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. Electric systems must be planned to withstand contingencies and maintenance outages. Extreme event contingencies, which measure the robustness of the electric systems, should be evaluated for risks and consequences. The NERC Reliability Standards define specific transmission planning requirements that provide reliability for the bulk interconnected electric system. SPP provides coordinated regional transmission planning requirements to promote reliability through its Planning Criteria Section 5, "Regional Transmission Planning", and related Attachment O, "Coordinated Planning Procedures", in the SPP Open Access Transmission Tariff (OATT).

Transmission planning criteria for the Zone's electric system shall at a minimum conform to the NERC Reliability Standards and SPP Transmission Planning Criteria Section 3 and meet the following:

- **a)** Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any one transmission station shall be avoided.
- **b)** Adequate transmission capability shall be maintained to provide for intra-regional, inter-regional and trans-regional power flows under normal and more probable contingency conditions as defined in Table 1 of the NERC Reliability Standards.
- **c)** Switching arrangements shall be utilized that permit effective maintenance of equipment without excessive risk to the electric system.
- **d)** Switching arrangements and associated protective relay systems shall be utilized that do not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.
- **e)** Sufficient reactive capacity shall be planned within the transmission system to maintain voltages within the criteria defined in Section 2.1. Some stations, such as those with combustion turbines connected to them, require higher voltage levels and thus may need additional reactive resources.

Transmission planning is performed for all planning horizons; operational (real time to 1 year in future), Near-term (1 to 5 years in future), and Long-term (5 to 10 years in future). It generally involves the analysis of the transmission system under various operating conditions, the identification of any potential violations, and the development of plans or actions to mitigate each violation.

Transmission planning must interface with the planning performed by the Distribution Provider and Resource Planner functions of the NERC Reliability Functional Model. The Distribution Provider provides input on the size and location of loads to the transmission planning process. The Resource Planner provides the size and locations of future resources through the SPP process. Long-term transmission planning is performed to develop an overall plan for expansion of the transmission system. This would include the approximate capacity and location of transmission assets required for future operations. Near-term transmission planning is performed to refine portions of the long-term transmission plan on localized areas and provide more definition of required transmission assets.

Another part of transmission expansion is driven by transmission service requests and generation interconnection requests made to SPP as the RTO. The Zone participates in SPP's transmission system planning process to assess the ability of the transmission system to provide these requested services. This includes development of plans or new transmission asset additions that will be required to meet reliability standards if the requested services are granted.

2.1 Steady State Transmission Contingency Analysis

The Zone's transmission system shall be planned and constructed to meet the applicable NERC Reliability Standards for Table 1 of TPL-001-5, SPP Planning Criteria and their applicable requirements and measurements, and Zonal Planning Criteria.

Table 1 was developed to thoroughly search out the most severe, credible contingencies for study, creating the assurance that the many possible contingencies not studied are less severe. It lists the normal and contingency conditions under which the electric transmission system is to be analyzed. It also lists the limits or impacts that the transmission system can sustain and still meet an acceptable performance level.

2.1.1 Base Case Analysis

The Zone will support and participate in the SPP Model Development Advisory Group (MDAG) development and verification of base case transmission system models. Base case models will maintain at least the following attributes:

- System facilities shall be modeled to reflect normal operating conditions and limits
- Line and equipment loading shall be within normal rating limits
- Voltage levels shall be maintained within plus or minus 5% of nominal voltage for all buses 69 kV
- All customer electrical demands shall be supplied, and all contracted firm (non-recallable reserved) transfers shall be maintained
- Stability (dynamic and steady state) of the network shall be maintained

- Cascading outages shall not occur

2.1.2 Loss of Single Component Analysis
Under single contingencies, the transmission system shall meet the following criteria:
- Initiating incident results in a single element out of service
- Line and equipment loadings shall be within emergency rating limits
- Voltage levels shall be maintained within plus 5% and minus 7% of nominal voltage for load-serving buses from 69 – 200 kV and within plus 5% and minus 5% of nominal voltage on all busses above 200 kV within the Zone
- No loss of customer electric demand (except as allowed through Attachment 1 of TPL-001-5)
- No curtailment of contracted firm (non-recallable reserved) transfers shall be required
- Stability (angular and voltage) of the network shall be maintained
- Cascading outages shall not occur

2.1.3 Loss of Two or More Transmission Components
Under multiple contingencies, the transmission system shall meet the following criteria:
- Initiating incident may result in two or more (multiple) components out of service including common right-of-way and common structure circuits
- Line and equipment loadings shall be within emergency thermal rating limits
- Voltage levels shall be maintained within plus 5% and minus 7% of nominal voltage for load-serving busses from 69 – 200 kV and within plus 5% and minus 5% of nominal voltage on all busses above 200 kV within the Zone
- Stability (angular and voltage) of the network shall be maintained
- Planned outages of customer demand or generation (as noted in Table 1 of TPL-001-5) may occur
- Contracted firm (non-recallable reserved) transfers may be curtailed
- Cascading outages shall not occur

2.1.4 Post-Contingency Voltage Deviation
Post-contingent voltage deviation is allowed unless the voltage falls outside applicable limits as outlined in Sections 2.1.1 through 2.1.3 above.

2.1.5 Extreme Contingency Events
Contingency studies will be performed where extreme contingency events could lead to uncontrolled cascading outages or system instability. The measures and procedures to mitigate or eliminate the extent and effects of those events will be documented.

2.2 Short Circuit Analysis

Short circuit analysis is performed by calculating the fault current at a given transmission bus and comparing that against the interrupt capability of the associated breakers. If any associated breaker is incapable of interrupting the calculated fault duty, each potentially underrated breaker will have its fault current recalculated with the applicable transmission element(s) out of service (i.e., line-out, or weak-system, conditions).

Line-out conditions for a given breaker represent any transmission element protected by the breaker individually removed from service and a fault applied. The larger of either three-phase or single-line-to-ground fault currents are compared against the interrupt duty of the breaker. If the worst-case line-out fault current exceeds the breaker interrupt rating, it shall be flagged as underrated and a corrective action plan will be identified.

2.3 Dynamic Stability Analysis

To assess positive damping of power oscillations and transient voltage recovery during dynamic stability simulations, the Zone follows the SPP Disturbance Performance Criteria.

2.3.1 Power Oscillation Damping Requirements

The SPP Criteria uses Successive Positive Peak Ratios (SPPR) of machine rotor angles to determine if power oscillations are positively damped as seen in Figure 1. SPPR1 (first and second positive peak magnitudes) and SPPR5 (first and sixth positive peak magnitudes) are used to evaluate power oscillation damping if: 1) the statistical range of the machine rotor angle for the entire simulation is 16-degrees or greater, or 2) the machine rotor angle does not converge to a steady-state value by the end of the simulation (as seen in Figure 2). If the machine rotor angle channel does not converge or if SPPR1 is greater than or equal to 0.950 and SPPR5 is greater than or equal to 0.774, the power oscillation for the observed machine is unstable.

Any time after a disturbance is cleared bus voltages on the transmission system shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit (shown in Figure).

2.3.2 Transient Voltage Recovery Requirements

Per the SPP Disturbance Performance Criteria (as seen in Figure 3), bus voltages on the transmission system shall recover above 0.70 per unit, within 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle such a rise.

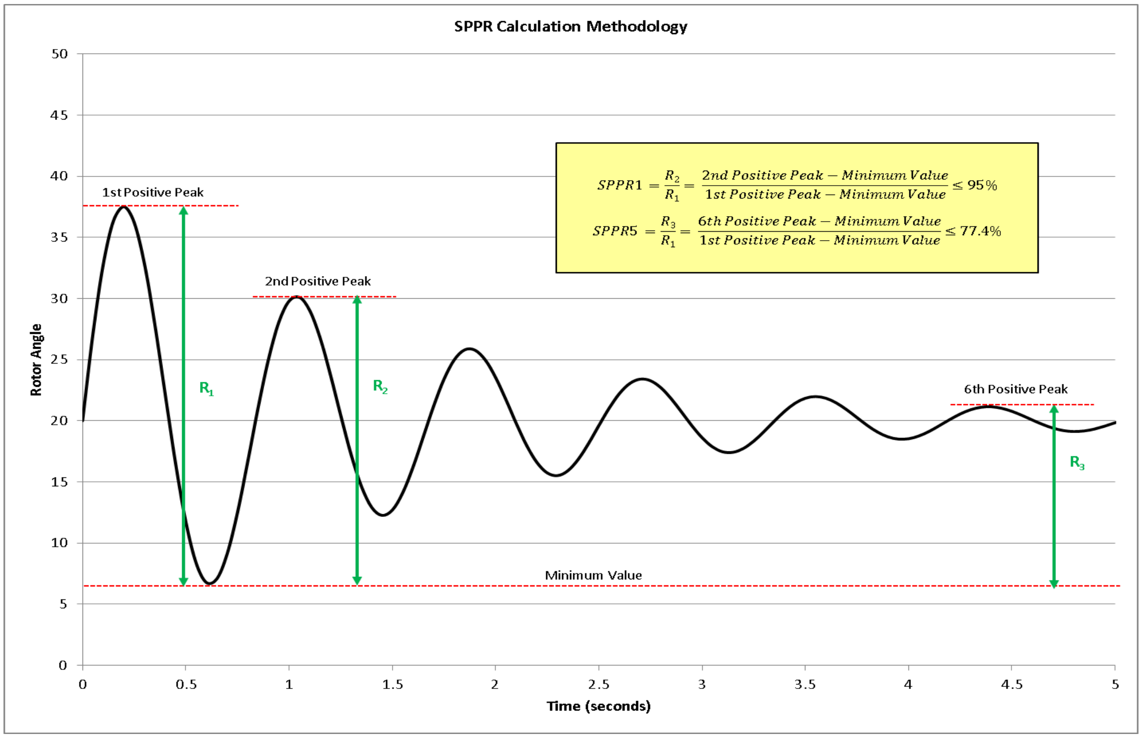

Figure 1: Successive Positive Peak Ratio (SPPR) Requirements

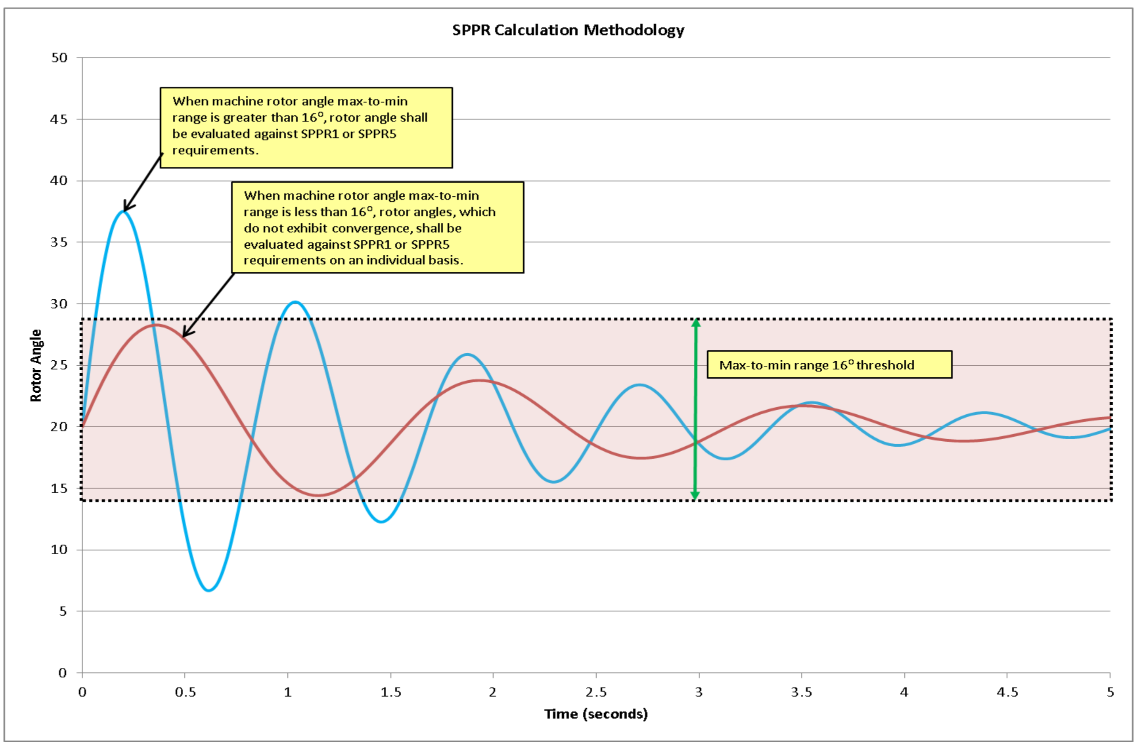

Figure 2: 16-Degree Minimum Rotor Angle Disturbance

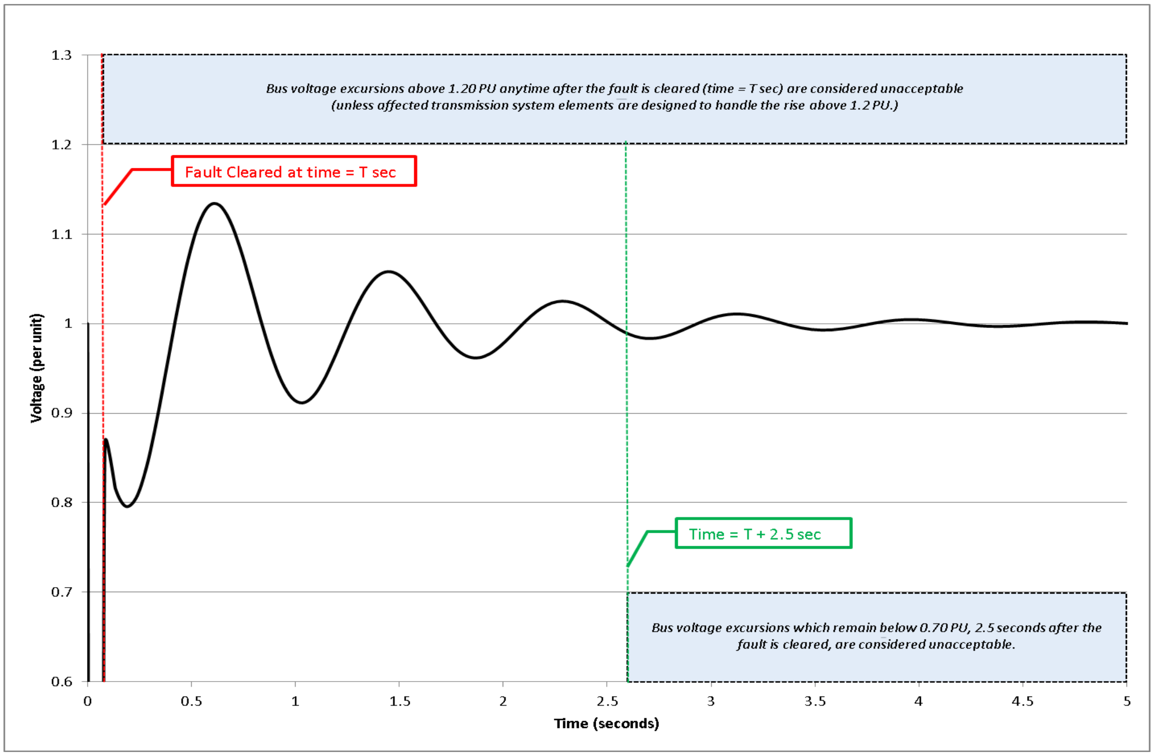

Figure 3: Transient Voltage Recovery Requirements

2.4 Voltage Limits for Geomagnetically Induced Current (GIC) Analysis

Per NERC Reliability Standard TPL-007-4, the Transmission Planner is required to have criteria for acceptable System steady state voltage performance for its System during a geomagnetic disturbance (GMD) event. The Zone uses the same steady state voltage criteria for GMD/GIC analysis as steady state contingency analysis:

- Voltage levels shall be maintained within plus 5% and minus 7% of nominal voltage for load-serving busses from 69 – 200 kV and within plus 5% and minus 5% of nominal voltage on all busses above 200 kV within the Zone

3.0 Looping of Radial Facilities

When any of the following criteria is met, the Zone will consider whether load service substations served at a transmission voltage level should have at least two sources of transmission service. The Zone will consider other factors (e.g., cost, future system needs, reliability of the loads, system effects, distribution backfeeds) in its evaluation.

1. Load level between breakers is greater than 40 MW.
2. MW-mile measuring load loss exposure is greater than 400 MW-mi.
3. Three or more taps or stations on a networked facility between breakered stations.

4.0 Protective Relaying

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the transmission system. Protective Relay Systems (PRS) requirements shall be considered during the planning and design of generation, transmission and substation configurations. Protective system relays shall conform to NERC Protection and Control (PRC) Standards and accepted IEEE/ANSI practices.

- The protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, transmission protection systems shall be installed as required to meet, at a minimum NERC PRC and Transmission Planning (TPL) Standards.
- Transmission Operators shall maintain communications systems to their generating stations, operation centers and to neighboring utilities, which shall provide adequate communication in the event of failure of any one element of the systems. In general, such communication systems should not be susceptible to failure during an interruption of the A.C. power supply in any part or all of their areas.
- Loading on the transmission system shall be monitored continually to ensure that operation is within safe limits.
- Suitable instrumentation, and/or other devices, shall be installed to measure appropriate quantities at key points in the electric system with appropriate automatic alarms.
- Underfrequency Load Shedding (UFLS) equipment shall be installed pursuant to the SPP Under-Frequency Load Shedding (UFLS) program, as detailed in the SPP UFLS Plan, for the purpose of maintaining a stable operating frequency.
- Automatic Restoration of Load schemes may be installed by the Transmission Owner to expedite load restoration. These systems shall be coordinated with all other schemes such as system protection, Underfrequency Load Shedding, Undervoltage Load Shedding, and Generation Control and Protection. These systems shall operate only after underfrequency and/or undervoltage events.
- Generation Control and Protection schemes shall be designed to conform to applicable NERC Standards and SPP Planning Criteria to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect generator equipment from damage.

5.0 Substation Bus Configuration

New substations or modifications to existing substations shall be designed using the bus configurations shown in Table 1, below, unless the stakeholders directly involved in the interconnection agree to another bus arrangement either -more or less complex, considering factors such as anticipated load growth or decline or transmission expansion in the planning horizon. For the purposes of this table, terminals are considered transmission lines, power transformers between transmission voltages (including 69kV), reactive device terminals, and generator interconnections. Load-serving distribution terminals may be considered on a case-by-case basis.

Table 1: Substation Bus Configurations by Voltage

Bus Voltage Level	Breaker Configuration		
	1-2 terminals	**3-6 terminals**	**7 or more terminals**
<100kV	Single Bus	Ring Bus	Breaker-and-Half
100kV - 200kV	Single Bus	Ring Bus or Breaker-and-Half	Breaker-and-Half
201kV - 499kV	Ring Bus	Ring Bus or Breaker-and-Half	Breaker-and-Half
500kV - 800 kV	Breaker-and-Half	Breaker-and-Half	Breaker-and-Half or Double Breaker Double Bus

6.0 Shunt Reactive Devices

Shunt reactive devices inherently cause transient voltage disturbances when they are switched in or out of service. If a new shunt reactive device is being added to the transmission system (69kV or above), or if an existing substation with a shunt reactive device is being rebuilt, the following considerations should be made:

- What size of shunt reactive device(s) is needed?
- Can the shunt reactive device(s) be eliminated?
- Should the shunt reactive device be split into multiple stages?

While not always possible, it is advisable to consider splitting large shunt reactive devices into multiple stages. Per IEEE Std. 1036-2020, the Transmission Owner will make reasonable effort to size transmission-connected shunt reactive devices such that the absolute value of the arithmetic sum of post-switching steady state voltage minus pre-switching steady state voltage steady state voltage is limited to 0.05 per-unit or less.

7.0 Power Quality Requirements

A project may be considered if harmonic distortion exceeds the recommended limits contained in IEEE Standard 519, which defines voltage waveform and harmonic content. Planning Level indices for voltage flicker will be governed by IEEE Standard 1453. Company criteria for voltage flicker and harmonic distortion at 161kV, 138kV, 115kV, or 69kV bus must meet the following criteria.

- Flicker level (short term) Pst95% ≤ 0.8
- Flicker level (long term) Plt95% ≤ 0.6
- Total harmonic voltage distortion THVD ≤ 2.5 %
- Individual harmonic voltage level ≤ 1.5 %

- Inductive power factor, monthly average cos phi ≥ 0.98
- Voltage fluctuation delta U ≤ 1.0 %

Load or generator interconnections in the Zone shall be held to the applicable power quality standards and required to make the necessary modifications to comply with these standards. The purpose of these power quality criteria is to make upgrades to the system to correct power quality problems where the problem cannot be attributed to a specific load or generator interconnection.

8.0 Local Operational Reliability

Upgrades to the transmission system may be identified to improve local operational reliability. Criteria to be considered when identifying upgrades could include, but is not limited to, the following:

- Mandatory requirements as described in Section 1
- Reduction in customer outages considering factors such as duration, frequency, and/or impact
- Reduction of safety hazards
- Improvement to the protection and control schemes
- Increased transmission and distribution system flexibility
- Decreased transmission loading under normal or contingent conditions

Document Version History

The following table documents changes to this document and its predecessors.

Date	Revision Number	Change Author	Description
5/15/2023	0	Katy Onnen	Document created.