1. INTRODUCTION

This document presents the criteria and assumptions to be used as the basis for Transmission Planning studies conducted for the Near-Term and Long-Term Planning Horizon for the Tucson Electric Power (TEP) system, unless specified otherwise. This includes TEP's Extra High Voltage (EHV) transmission system (500 and 345kV) and High Voltage local area transmission system (138kV). TEP evaluates all Transmission Planning studies against applicable requirements of the North American Electric Reliability Corporation (NERC) TPL-001-4 Standard and the TPL-001-WECC-CRT-3.1 Criterion developed by the Western Electricity Coordinating Council (WECC). TEP's Transmission Planning department performs the function of Transmission Planner and Planning Coordinator for TEP.

2. PLANNING PROCESS

TEP's planning process is a two-year process that happens on an annual basis. In the first year, TEP performs a study to determine the projects that are needed to accommodate new load growth in its service area and to determine the impacts of project additions, retirements, and system upgrades over the Planning Horizon. This results in a Ten-Year Plan that is filed with the Arizona Corporation Commission (ACC) at the beginning of the second year of the two-year cycle (January 31st).

In the second year of the two-year cycle, TEP coordinates with neighboring entities to update the models with the most recent plans for each entity and uses these models to perform studies in the Planning Horizon. Please see Attachment A for a visual representation of the planning process.

3. MODEL DEVELOPMENT AND ANALYSIS

The base system models used in the Planning horizon are created and maintained by TEP using the WECC base case compilation procedures as detailed in the WECC Data Preparation Manual. TEP submits System Model updates to WECC using data that is consistent with the MOD-032-1[1] standard based on the case description developed by WECC for the cases in its Annual Study Program. WECC compiles the information provided by each entity into one base case as defined in the case request. Selected approved WECC base cases are then reviewed and updated by the

[1] At the time this document was written, the NERC TPL-001-4 referred to NERC MOD-010 and MOD-012. Those two standards were replaced by MOD-032 on June 2016.

Arizona entities (APS, AEPCO, SRP, TEP, WAPA-DSW) to ensure they accurately represent these systems in the WECC Region.

The system models used by TEP represent:

- Known outage(s) of generation or Transmission facility (ies) with a duration of at least six months
- Existing facilities
- New planned Facilities and changes to existing facilities
- Real and reactive Load forecasts
- Known commitments for Firm Transmission Service and Interchange
- Resources (supply or demand side) required for Load

3.1. STUDY PROCESS

The TEP Transmission Planning Department will consult with the TEP System Control and Reliability (SC&R) Department to identify any issues observed on the system by the System Operators prior to conducting the assessment. The TEP Transmission Planning Department will incorporate these operational issues into the planning process.

3.2. MODELS

TEP evaluates models for the Near-Term (year One through five) and Long-Term (years six through ten) Planning Horizons based on power flow and transient stability studies. The evaluation will depend on what type of planning study is being conducted. Peak conditions are evaluated using a Heavy Summer condition and Off-Peak conditions are evaluated using spring, summer, winter, or fall conditions. Approved WECC models will differ from case to case and year to year. If a WECC model for the year being studied does not exist, then an existing case will be updated to represent the forecasted conditions for that year.

3.3. POWERFLOW STUDIES

Reliability planning will consist of steady state evaluations on Peak and Off-Peak cases (including a 5% load margin to the TEP load pocket) for load pocket studies. TEP bases its studies on computer simulations using GE PSLF (Positive Sequence Load Flow) software for its power flow studies. The purpose of the steady-state power flow analysis is to analyze the performance of the transmission system facilities under pre and post contingency conditions. It involves two distinct analyses: thermal analysis and voltage analysis during normal and emergency conditions.

3.4. TRANSIENT STABILITY STUDIES

Transient stability simulations are performed for load pocket studies will be conducted for select planning events P1 through P7 with three-phase or single-line-to-ground faults with normal clearing or with delayed clearing with all lines in service (ALIS) or initially out of service (IOS) conditions. If the extreme event evaluation of a three-phase fault shows that Planning Event P2, P4, P5, or P7 performance measures are not met, the event will be re-evaluated with a single-line-to-ground fault as required.

In addition, TEP will include a no-disturbance simulation to confirm a "flat-line" response is achieved with the data. TEP bases its studies on computer simulations using GE PSLF software for its Stability studies. A 5% load margin will be included to the load within the TEP load pocket for all stability runs for load pocket studies.

Per TEP's PCA&M Department, normal clearing is four cycles and delayed clearing is 13 cycles on the TEP EHV transmission system. For the TEP HV system, normal clearing is 5 cycles and delayed clearing is 14 cycles.

TEP simulates the removal of all elements in its Dynamic studies that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention; this may include tripping of generators, generator step-up transformers, and other transmission elements. However, high speed reclosing (less than one second) is not utilized on the TEP EHV system.

3.5. SHORT CIRCUIT STUDIES

Short circuit studies will be conducted addressing the Near-Term Planning Horizon, as required. Three-Phase and single-line-to-ground faults will be simulated to help identify locations on the TEP system where fault currents may exceed the interrupting capability of the breakers. Fault currents should not exceed the breaker interrupting limits as defined per study. All planned generation and Transmission Facilities that could impact the study area will be represented.

TEP bases its Short Circuit studies on computer simulations using Aspen Oneliner software. The solution method used with Aspen to determine short circuit fault currents are listed below.

- Prefault voltages were from a linear network solution
- Loads were ignored
- Line G +jB were ignored
- Line impedance and mutual coupling were used
- Sub transient generator impedances were used

• MOV (Metal Oxide Varistor) protected series capacitor

3.6. REACTIVE MARGIN STUDIES

Reactive margin studies will be conducted as necessary on the TEP load pocket using the Load Area methodology. If the load-margin test fails, V-Q analysis will be conducted at critical buses to demonstrate adequate reactive power resources throughout the TEP load pocket for normal conditions and critical contingencies for the Near-Term and Long-Term Planning Horizon.

TEP includes a 5% load margin in all load pocket study cases for normal and emergency conditions and evaluates thermal loading against this higher load. If any Planning Event P2-P7 fails to meet the performance requirements with the 5% load margin, TEP will re-evaluate that contingency with a 2.5% load margin. Please see **section 3.7 for Voltage Stability**.

3.7. VOLTAGE STABILITY

WECC requires the following minimum load margin when identifying voltage stability for load areas and transfer paths:

1.) For Planning Events P0-P1: 5% load margin (of forecasted peak load or transfer path flow)

2.) For Planning Events P2-P7: 2.5% load margin (of forecasted peak load or transfer path flow)

4. PROTECTION AND CONTROL

4.1. RAS SCHEME (TOLS)

The TEP Tie-Open Load Shed (TOLS) scheme is a Wide Area Protection Scheme (WAPS) that arms fast-switched reactive devices and customer load in anticipation of a forced outage. The fast-switched reactive devices are available for arming only if the Northeast SVC is out of service. Customer load is armed for direct load tripping for select Planning Events (P2, P4-P7) that are included in the TOLS scheme and allowed by NERC TPL-001-4.

4.2. SUBSTATION CONFIGURATIONS

TEP's existing EHV substation layouts are ring bus or breaker-and-a-half and existing 138 kV substation layouts are main-and-transfer, ring bus, breaker-and-a-half, and double-bus-double-breaker. The EHV substations with a ring bus layout are designed such that they can be converted to a breaker-and-a-half layout when expansion limits are reached. Future 138kV construction will be designed as a ring bus unless the number of terminations require a breaker and a half configuration. With normal operation of the protection system, only one element will be removed from service in each configuration. If delayed clearing or breaker failure occurs, a maximum of two elements will be removed from service except for the 138 kV main-and-transfer substations.

5. PLANNING EVENTS

TEP considers all contingencies applicable to NERC Planning Events P1-P7 and Extreme Events when developing contingency lists for steady state power flow and stability analysis. The following criteria is used to create the contingency list for a Transmission Planning Study.

a) Planning Event P0 (No Contingency)

This planning event requires that TEP study its system with no contingencies (system intact) and all facilities in service. Also known as an N-0 condition.

b) Planning Event P1 (Single Contingency or N-1)

This planning event is a single contingency resulting in the loss of a single element, also known as an N-1 condition. TEP evaluates the following P1 contingencies:

1.) Any single EHV or HV transmission line in the TEP Transmission Planning area;
2.) Any single transmission transformer with a low-side voltage greater than or equal to 100kV in the TEP Transmission Planner area;
3.) Loss of any tie line or tie transformer between the TEP Transmission Planner area and neighboring Planning Coordinator/Transmission Planning areas;
4.) Loss of any single generating unit in the TEP Transmission Planner area;
5.) Loss of all shunt devices protected by a single breaker in the TEP Transmission Planner area except shunt capacitors at TEP's Northeast Loop Substation[2];
6.) P1 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners.

[2] Outages of the shunt capacitors at TEP's Northeast Loop substation will have negligible impact due to the response of the SVC located at this facility. The outage of the SVC will be simulated.

c) Planning Event P2 (Single Contingency)

This planning event is a single contingency resulting in multiple Facilities being removed from service or in opening a line section without a fault. TEP evaluates the following P2 contingencies:

1.) Single bus section faults on Main-and-Transfer buses in the TEP Transmission Planner area;
2.) Opening of a line section without a fault in the TEP Transmission Planner area. This means opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point;
3.) Internal breaker fault on a non-Bus tie Breaker in the TEP Transmission Planner area;
4.) Internal Breaker fault on a Bus-tie Breaker in the TEP Transmission Planner area. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker;
5.) P2 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners

d) Planning Event P3 (Multiple Contingency)

This planning event is a multiple contingency beginning with the loss of a generator unit (G-1 contingency) followed by System adjustments and then the loss of one of the following:

1.) Generator in the TEP Transmission Planner area
2.) Transmission Circuit in the TEP Transmission Planner area
3.) Transformer with low-side voltage greater than or equal to 100kV in the TEP Transmission Planner area;
4.) Transmission Circuit or transformer, or between the TEP Transmission Planner area and a neighboring Planning Coordinator/Transmission Planner area, or;
5.) Shunt device in the TEP Transmission Planner area.
6.) TEP will evaluate P3 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners

e) Planning Event P4 (Multiple Contingency due to Stuck Breaker)

This planning event is a multiple contingency event due to a fault plus a stuck breaker which results in delayed fault clearing. When any two specified system elements are lost simultaneously, this is known as an N-2 event. TEP evaluates the following P4 contingencies:
Resulting in the loss of multiple elements caused by a stuck breaker (a non-Bus tie Breaker) attempting to clear a fault on one of the following:

1.) Generator in the TEP Transmission Planner area;
2.) Transmission Circuit in the TEP Transmission Planner area;
3.) Transformer with a low-side voltage greater than or equal to 100kV in the TEP PC area;
4.) Transmission Circuit or transformer between the TEP Transmission Planner area and a neighboring Planning Coordinator/Transmission Planner area;
5.) Shunt Device in the TEP Transmission Planner area;
6.) Bus Section in the TEP Transmission Planner area.
7.) Loss of multiple elements caused by a stuck breaker (bus-tie breaker) attempting to clear a fault on the associated bus in the TEP Transmission Planning Area.
8.) TEP will evaluate P4 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners

f) Planning Event P5 (Multiple Contingency due to Relay Failure)

This planning event is a multiple contingency due to the failure of a non-redundant relay protecting the Faulted element to operate as designed for one of the following:

1.) Generator in the TEP Transmission Planner area;
2.) Transmission Circuit in the TEP Transmission Planner area;
3.) Transformer in the TEP Transmission Planner area;
4.) Shunt Device in the TEP Transmission Planner area, or;
5.) Bus Section in the TEP Transmission Planning Area.
6.) P5 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners

There are no P5 events on the TEP system because TEP does not have non-redundant relays

g) Planning Event P6 (Multiple Contingency)

This planning event is a multiple contingency beginning with the loss of one Transmission Circuit, Transformer, Shunt Device, or single pole of a DC line followed by System adjustments then loss of one of the following:

1.) Transmission Circuit in the TEP Transmission Planner area;
2.) Transformer in the TEP Transmission Planner area;
3.) Shunt Device in the TEP Transmission Planner area, or;
4.) Single pole of a DC line in the TEP Transmission Planner area;
5.) TEP will evaluate P6 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners

In other words, two overlapping singles or N-1-1 contingency. TEP will conduct a screening analysis to determine which elements will be IOS be for evaluation for N-1-1 performance.

Contingencies involving direct current (dc) elements are not included in the TEP assessment of its system because TEP does not own or operate any dc facilities

h) Planning Event P7 (Multiple Contingency)

This planning event is a multiple contingency involving the loss of two adjacent circuits on a common structure or the loss of a bipolar DC line in the TEP Transmission Planning Area. TEP will evaluate P7 contingencies that may impact the TEP system as identified by adjacent Planning Coordinators or Transmission Planners.

** Contingencies involving direct current (dc) elements are not included in the TEP assessment of its system because TEP does not own or operate any dc facilities**

i) Extreme Event

An Extreme event is a multiple contingency event that occur before system adjustments, Local Area events, and Wide Area events not defined in Planning Events P0-P7. Extreme events that are evaluated include:

1.) Loss of a single generator, Transmission Circuit, shunt device, or transformer forced out of service followed by loss of another single generator, Transmission Circuit, shunt device, or transformer forced out of service prior to system adjustments;

2.) Local Area events affecting the Transmission System such as:
   i. Loss of a tower line with three or more circuits;
   ii. Loss of all Transmission lines on a common Right-of-Way.

In addition, for Transient Stability, P2-P7 events that are required to be evaluated with single-line-to-ground faults were evaluated with three-phase faults which are classified as extreme events.

6. NORMAL CONDITIONS (P0) PRE-CONTINGENCY

6.1. VOLTAGE CRITERIA

The following criteria in Table 1 applies to normal conditions where all lines are normally operated-in-service. Steady State voltages at all Bulk-Electric System (BES) buses shall stay within each of the following limits per the approved WECC Regional Criteria TPL-001-WECC-CRT-3.1:

Table 1: Pre-Contingency Voltage Criteria

Voltage Class	Base kV (1.0 p.u.)	Low Limit		High Limit	
		kV	p.u.	kV	p.u.
138 kV	138	131	0.95	145	1.05
345 kV	345	328	0.95	362	1.05
500 kV[3]	500	500	1.00	550	1.10

Buses used to model transformer terminated lines, three-winding transformer internal buses or other fictitious buses, are not subject to these criteria.

Internally, TEP uses more stringent criteria for modeling cases. For study models, the TEP PA area must meet the following:

- TEP Pre-Contingency 138kV average bus voltage between 1.0210 and 1.0235 pu, as possible
- TEP Pre-Contingency 345kV and 500kV bus voltage between 1.03 and 1.04 pu, as possible
- TEP Pre-Contingency 138kV buses voltage between 1.0145 and 1.025 pu, as possible

6.2.VAR OUTPUT AND FLOW REQUIREMENTS

TEP plans to operate its system with specific VAR requirements set for TEP's local generating units, the Northeast SVC, and VAR flow at the Saguaro/ Tortolita interface. Table 2 identifies the MVAR planning output requirement for TEP's local generating units.

Table 2: MVAR Requirements

[3] 500V facilities are modeled with a base kV of 500kV but are actually 525kV designed facilities.

Unit(s)	MVAR Planning Dispatch
Sundt 1-4	-1 to +1 MVAR
Sundt CTs 1-2	-1 to +1 MVAR
North Loop CTs 1-4	-1 to +1 MVAR
DMP CT 1	-1 to +1 MVAR

6.3. REACTIVE DEVICES

TEP owns and operates line reactors on its 345 kV transmission network and shunt capacitors on its 138 kV transmission and distribution systems. TEP's Engineering Department has identified existing 138 kV substations that can accommodate additional capacitor banks. In addition, the TEP standard 138 kV substation design will accommodate up to three capacitor banks each with capacity for 52.8 MVAR of capacitor cans insulated at 143.4 kV. TEP will properly design the capacitor size at the time it is needed. These locations are identified to ensure that adequate reactive power resources are available to meet system performance measures. Any capacitors modeled in the case but not currently available for use are part of TEP's 5-year capacitor plan and will only be used if all existing and planned capacitors are modeled in-service.

6.3.1. Northeast SVC VAR Output

The MVAR capability of the Northeast SVC is -75/+200 MVAR and has the ability to control four 50.8 MVAR mechanically switched capacitor banks, for a total VAR range of -75+403.2 MVAR. The normal planning output of the SVC is between -30 /+30 MVAR with (2) 138 kV capacitor banks in-service.

6.3.2. Tortolita Interface

MVAR flow should be outbound from Tortolita 138 kV to Tortolita 500 kV bus and should not be greater than 15 MVAR out of each transformer.

6.4. LINE AND TRANSFORMER LOADING

Loading on all TEP transmission lines and transmission transformers must be at or below the continuous rating assuming ALIS or following system adjustment for generator or transmission IOS conditions.

6.5. SERIES COMPENSATION

All planning studies for normal conditions will be conducted with "full" compensation on the TEP EHV transmission system, unless results indicate a need to bypass selected banks to meet performance measures. TEP has four series capacitor banks installed on the transmission lines in the Springerville to Vail corridor at the following locations:

1. Springerville – Vail 345 kV line at Greenlee (18% compensation)
2. Springerville – Vail 345 kV line at Vail (20% compensation)
3. Winchester – Vail 345 kV line at Vail (28% compensation of Greenlee to Vail line)
4. Springerville – Greenlee 345 kV line at Greenlee (39% compensation)

"Full" compensation means it has all of the above in service except the Springerville – Greenlee series capacitor bank.

For IOS conditions, system adjustments may require raising local generation and switching shunt capacitor banks to keep generator and SVC VAR output within normal limits and to keep flows on lines and transformers below their continuous ratings.

Bypassing series compensation in the Springerville – Vail corridor is an additional adjustment made when necessary.

7. EMERGENCY CONDITIONS (P1-P7) CONTINGENCY

7.1. VOLTAGE CRITERIA

Table 3 below shows the post-contingency voltage criteria for steady state analysis.

Table 3: Post Contingency Voltage Criteria

Voltage Class	Base kV (1.0 p.u.)	Low Limit		High Limit	
		kV	p.u.	kV	p.u.
138 kV	138	124	0.90	152	1.1
345 kV	345	311	0.90	380	1.1
500 kV[4]	500	475	0.95	575	1.15

Post-Contingency steady state voltage deviation at each applicable BES bus serving load shall not exceed 8% for P1 events. Buses used to model transformer terminated lines, three-winding transformer internal buses or other fictitious buses, are not subject to this criteria.

7.2. LINE AND TRANSFORMER LOADING

Loading on all transmission lines and transmission transformers must be at or below the emergency rating following the contingency but prior to system adjustment.

7.3. DIRECT LOAD TRIPPING

TEP has a Tie-Open Load Shed (TOLS) scheme which can be activated for specific contingencies. Direct load-tripping of firm demand will only be used where allowed by the NERC TPL-001-4 standard for select P2, P4-P7 Planning Events, and Extreme Events.

7.4. CASCADING /UNCONTROLLED SEPARATION

Cascading outages are not allowed for Planning Events P0-P7 contingencies. For power flow analysis, if any branch or transformer is overloaded above 150% of its emergency rating or known trip settings following the initial disturbance, then the branch or transformer will be tripped and the system will be re-evaluated for overloads. During the re-evaluation, if any additional branches are overloaded above 150% of their emergency rating, or known trip settings, then this will be considered cascading since additional branches will need to be tripped

[4] 500kV facilities are modeled with a base kV of 500kV but are actually 525kV designed facilities

by the protection systems. If a bus voltage drops below 0.8pu this will also be considered cascading.

7.5. TRANSIENT STABILITY

7.5.1. P1 Performance Requirements:

- following fault clearing, the voltage shall: recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event
- Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds
- For Contingencies without a fault (P2.1 category event), voltage dips at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds
- All oscillations that do not show positive damping within 30-seconds after the start of the studied event shall be deemed unstable
- Positive damping exists as demonstrated by the damping of relative rotor angles and frequency swings. If the rotor angle plots show units tripping off line, the simulations will be reviewed to verify the units were tripped in the simulation.

7.5.2. Additional P1 Performance Requirements:

- No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism

7.5.3. Additional P2-P7 Performance Requirements:

- When 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 its directly connected Facilities.

IV. VERSION HISTORY

Version	Date	Action	Change Tracking
0	9/12//2017	**NEW** –This document is replacing "Transmission Planning Process and Guidelines". For TPL-001-4 studies, the "TPL Study Plan" and the "Transmission Planning Criteria and Assumptions" will replace the "Transmission Planning Process and Guidelines".	Carmelina Spina

ATTACHMENT A- Planning Process Diagram