West Station – Stem Beach - Walsenburg 115 kV Line TTC Study

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March 31, 2017

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Table of Contents

List of Tables and Figures

Appendices

Background

Total Transfer Capability (TTC) is defined as the amount of electric power that can be transferred bi-directionally and reliably from one area to another area of the interconnected transmission system by utilizing all available transmission lines (known as TTC path) between these areas under reasonably stressed system operating conditions.

In this particular study, the northern area of the TTC path consists of the West Station bus and the southern area consists of the Walsenburg bus. The available breaker-to-breaker transmission lines include the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines. The West Station – Stem Beach 115 kV line consists of the following line sections:

- West Station – Pueblo West Tap 115 kV
- Pueblo West Tap – Stem Beach 115 kV

The reasonably stressed system operating conditions include various generation dispatches for heavy summer and light winter loads for 2017.

Table 1 below shows the ratings and limiting elements of the studied lines and their associated line sections. Figure 1 below shows their location in the southern Colorado transmission system.

Table 1: Transmission Line Ratings

Breaker-to-Breaker Element	**Normal Summer Rating (MVA)**	**30 Minute Summer Rating (MVA)**	**Normal Winter Rating (MVA)**	**30 Minute Winter Rating (MVA)**	**Limiting Element**
West Station – Stem Beach 115 kV line	92.0	92.0	92.0	92.0	Conductor Rating
Stem Beach – Walsenburg 115 kV line	92.0	92.0	92.0	92.0	Conductor Rating
Line Section Rating					
West Station – Pueblo West Tap 115 kV	119.0	119.0	119.0	119.0	BHCE FAC-008 (CT/Switch at West Station)
Pueblo West Tap – Stem Beach 115 kV	92.0	92.0	92.0	92.0	Conductor Rating

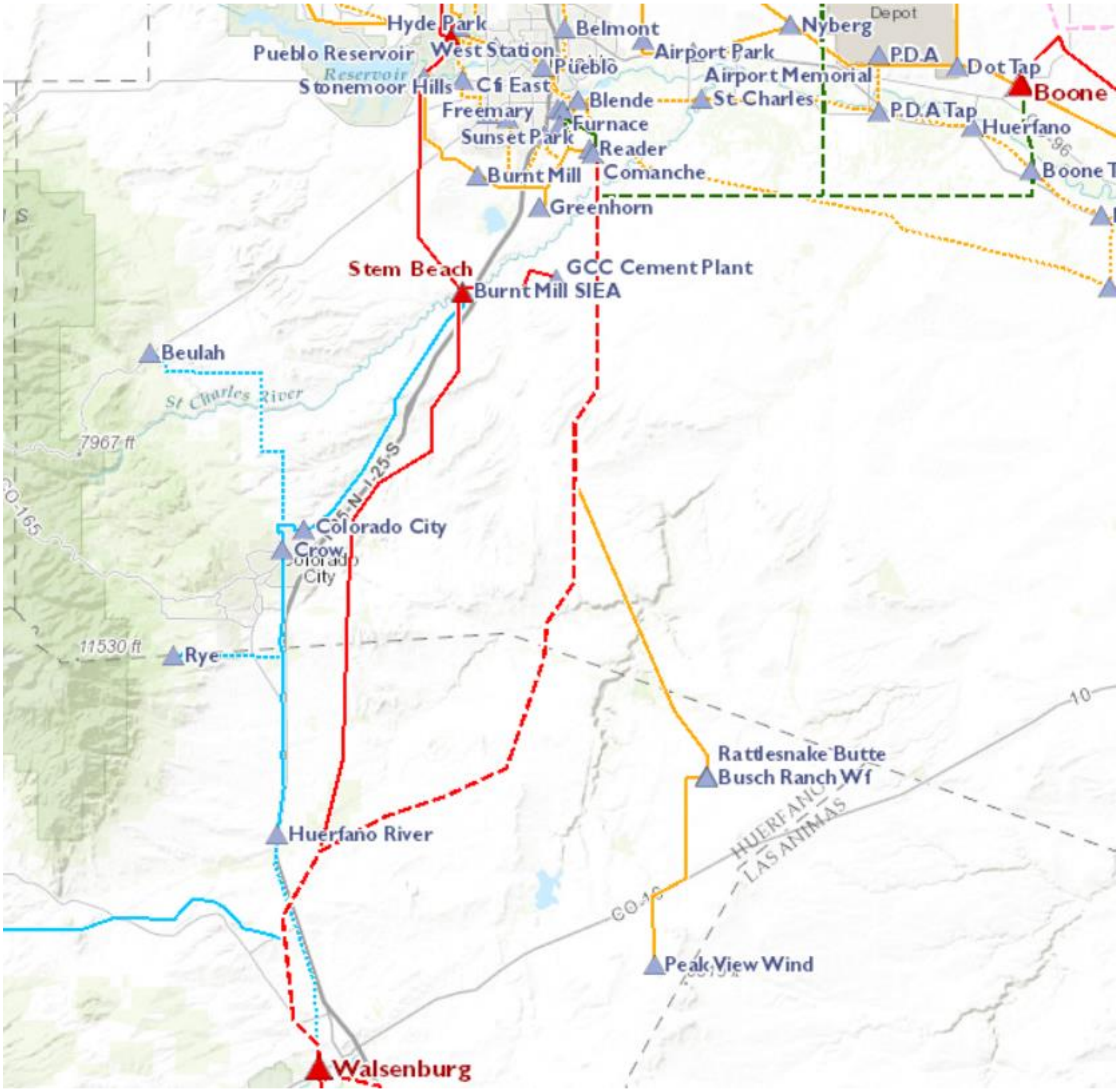

Figure 1: Southern Colorado Transmission System

Objective

The objective is to perform a study to determine the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines bi-directional TTCs in accordance with the Standard MOD-029-1a — Rated System Path Methodology (Appendix B).

Base Case Assumptions

The study used the WECC 2017 heavy summer operating (17HS) and 2017 light winter (17LW) cases. These cases consist of the modeling parameters as described in Requirement 1 (R1) of Standard MOD-029-1a and are shown below:

- All WECC base case elements such as transmission lines, transformers, shunt capacitors, etc.
- Latest load and generation forecast.
- Latest facility ratings.
- Existing and planned Special Protection System (SPS), if any.

Methodology

Power flow studies were performed for the selected cases to identify any transmission facility overloads, voltage magnitude violations, and voltage deviation violations in accordance with Tri-State's planning criteria (Appendix A) for all lines in service and contingency conditions. Tri-State's planning criteria are consistent with the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) planning criteria. They are summarized below:

- For all lines in service condition, all voltages should be within 1.05 per unit and 0.95 per unit and all loadings should not exceed 100% of the normal rating.

- For contingency condition, all voltages should be within 1.10 per unit and 0.90 per unit and all loadings should not exceed 100% of the emergency rating, or normal rating if emergency rating is not available. In addition, voltage deviation (voltage change before and after the contingency) should not exceed 8%.

Requirement 2 (R2) of Standard MOD-029-1a describes the methodology as follow:

- Adjust base case generation and load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria.

- Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

- For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit.

- For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

- The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

- Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

- For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

- Create a study report that describes the steps above, including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

- Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path.

- Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.

Study Results

Summary

This TTC study investigates the north to south and south to north bi-directional TTCs of the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines under reasonably stressed generation dispatch and loading conditions.

For both the north to south and south to north flow conditions, the study results showed no new planning criteria violations concerning transmission thermal overloads, unacceptable voltage magnitudes, and unacceptable voltage deviations.

There are no new transient stability issues expected by stressing the generation dispatches in the studied transmission system to change the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines.

Details

The power flow study was performed using the ACCC module of the PTI PSSE Version 33 power flow program. All transmission facilities in Area 10 (Public Service Company of New Mexico), Area 70 (Public Service Company of Colorado), and Area 73 (Western Area Power Administration) were monitored during the power flow simulations.

Below is a list of the selected 13 breaker-to-breaker contingencies studied in the transmission areas that are expected to be impacted:

1) Comanche – Daniels Park 345 kV line
2) Comanche – Walsenburg 230 kV line
3) Comanche – Boone 230 kV line
4) Comanche – Midway 230 kV line
5) Walsenburg – Gladstone 230 kV line
6) Stem Beach – Walsenburg 115 kV line
7) Walsenburg – Burro Canyon 115 kV line
8) West Station – Stem Beach 115 kV line
9) Stem Beach – Burnt Mill 115 kV line
10) Walsenburg 230/115 kV transformer T2
11) Walsenburg 230/115 kV transformer T3
12) Walsenburg 115/69 kV transformer T1
13) Stem Beach 115/69 kV transformer T1

North to South Flows

The 17HS_NS and 17LW_NS study cases, derived from the 17HS and 17LW base cases respectively, were used to perform the TTC study. The results are shown below in Table 2. The red numbers noted in the "Study Case" column are the generation dispatches that are different from the "Base Case" column. Negative values denote south to north flows.

17HS: This base case shows the flows on West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines equal to 58.6 MW and 9.9 MW.

17HS_NS: This study case stressed the generation dispatches in the 17HS base case to increase the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines to 71.4 MW and 22.5 MW.

17LW: This base case shows the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines equal to 40.6 MW and 15.1 MW.

17LW_NS: This study case stressed the generation dispatches in the 17LW base case to increase the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines to 53.7 MW and 28.0 MW.

Table 2: North to South Flow Results

Number	Name	ID	Pmax (MW)	Pmin (MW)	Base Case 17HS (MW)	Study Case 17HS_NS (MW)	Base Case 17LW (MW)	Study Case 17LW_NS (MW)
Considered source generation:								
Zone 757	ZONECS (generation immediately north of Midway)		1218.1 HS 776.6 LW	410.5 HS 254.9 LW	921.6	1080.7	516.5	516.5
70560	LAMAR_DC 230.00	DC	210	-210	0	200	0	0
70701	CO_GRN_E 34.500	W1	81	0	17	60	17	17
70702	CO_GRN_W 34.500	W2	81	0	17	60	17	17
70703	TWNBUTTE 34.500	W1	75	0	15.8	60	15.8	15.8
70119	COMAN_1 24.000	C1	360	200	355	355	200	350
70120	COMAN_2 24.000	C2	365	200	360	360	334.8	334.8
70777	COMAN_3 27.000	C3	780	450	780	780	450	750
Considered sink generation:								
Area 10	New Mexico generation		3873.6 HS 3228.2 LW	456.5 HS 260.5 LW	3239.3	2750	2229.9	1779.9
Total					5705.7	5705.7	3781	3781
North to south MW flows (*) under N-0 for the studied TTC lines:								
12181	Gladstone 230 kV PST				142.4	200	116.3	200
70456	West Station - Stem Beach 115 kV				58.6	70.0	40.6	50.5
70412	Stem Beach - Walsenburg 115 kV				9.9	21.2	15.1	24.9
Line section flows:								
	West Station - Pueblo West Tap 115 kV				58.6	70.0	40.6	50.5
	Pueblo West Tap - Stem Beach 115 kV				34.1	45.6	30.8	40.7

(*) Negative values denote south to north flows

South to North Flows

The 17HS_SN and 17LW_SN study cases, derived from the 17HS and 17LW base cases respectively, were used to perform the TTC study. The results are shown below in Table 3. The red numbers noted in the "Study Case" column are the generation dispatches that are different from the "Base Case" column. Negative values denote north to south flows.

17HS: This base case shows the flow on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines equal to -9.9 MW and -33.9 MW.

17HS_SN: This study case stressed the generation dispatches in the 17HS base case to increase the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines to -6.0 MW and -30.0 MW.

17LW: This base case shows the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines equal to -15.0 MW and -30.6 MW.

17LW_SN: This study case stressed the generation dispatches in the 17LW base case to increase the flows on the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines to -9.4 MW and -24.9 MW.

Table 3: South to North Flow Results

Number	Name	ID	Pmax (MW)	Pmin (MW)	Base Case 17HS (MW)	Study Case 17HS_SN (MW)	Base Case 17LW (MW)	Study Case 17LW_SN (MW)
Considered source generation:								
Area 10	New Mexico generation		3873.6 HS 3228.2 LW	456.5 HS 260.5 LW	3239.3	3550	2229.9	2700
Considered sink generation:								
Zone 757	ZONECS (generation immediately north of Midway)		1218.1 HS 776.6 LW	410.5 HS 254.9 LW	921.6	921.6	516.5	516.5
70560	LAMAR_DC 230.00	DC	210	-210	0	0	0	-135.3
70701	CO_GRN_E 34.500	W1	81	0	17	17	17	17
70702	CO_GRN_W 34.500	W2	81	0	17	17	17	17
70703	TWNBUTTE 34.500	W1	75	0	15.8	15.8	15.8	15.8
70119	COMAN_1 24.000	C1	360	200	355	355	200	200
70120	COMAN_2 24.000	C2	365	200	360	360	334.8	0
70777	COMAN_3 27.000	C3	780	450	780	469.3	450	450
Total					5705.7	5705.7	3781	3781
South to north MW flows (*) under N-0 for the studied TTC lines:								
12181	Gladstone 230 kV PST				-142.4	-100	-115.9	-65
70458	Walsenburg - Stem Beach 115 kV				-9.9	-5.2	-15.0	-8.1
70412	Stem Beach - West Station 115 kV				-33.9	-29.2	-30.6	-23.6
Line section flows:								
	Stem Beach - Pueblo West Tap 115 kV				-33.9	-29.2	-30.6	-23.6
	Pueblo West Tap - West Station 115 kV				-58.5	-53.7	-40.5	-33.5

(*) Negative values denote north to south flows

Conclusion

Table 4 below shows the north to south and south to north bi-directional TTCs for the West Station – Stem Beach and Stem Beach – Walsenburg 115 kV lines based on the power flow study results from Tables 2 and 3 above. The TTC is defaulted to the system operating limit of the line because the power flow study results could not find the reliability-limited flow under reasonably stressed generation dispatch and loading conditions.

Table 4: Bi-Directional TTCs

North to South TTC		
Breaker-to-Breaker Line	(MVA)	Reason
West Station – Stem Beach 115 kV	92.0	The TTC values are defaulted to the system operating limit of the line because the power flow study results could not find the reliability-limited flows on these lines under reasonably stressed generation dispatch and loading conditions.
Stem Beach – Walsenburg 115 kV	92.0	
South to North TTC		
West Station – Stem Beach 115 kV	92.0	According to R2 of MOD-029-1a: When it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows, set the TTCs for the non-prevailing direction equal to the TTCs in the prevailing direction.
Stem Beach – Walsenburg 115 kV	92.0	

Appendix A: Planning Criteria

(Consistent with the WECC and the NERC planning criteria.)

Table A 1

Summary of Tri-State Steady-State Planning Criteria

System Condition	Operating Voltages [1] (per unit)		Maximum Loading [2] (Percent of Continuous Rating)	
	Maximum	Minimum	Transmission Lines	Other Facilities
Normal	1.05	0.95	80/100	100
N – k	1.10	0.90	100	100

(1) Exceptions may be granted for high side buses of Load-Tap-Changing (LTC) transformers that violate this criterion, if the corresponding low side busses are well within the criterion.

(2) The continuous rating is synonymous with the static thermal rating. Facilities exceeding 80% criteria will be flagged for close scrutiny. By no means, shall the 100% rating be exceeded without regard in planning studies.

Table A 2

Tri-State Voltage Criteria		
Conditions	**Operating Voltages**	**Delta-V**
Normal (P0 event)	0.95 - 1.05	
Contingency (P1 event)	0.90 - 1.10	8%
Contingency (P2-P7 event)	0.90 - 1.10	-

Table A 3

Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault (non-Bus-tie Breaker)[8]	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments[9]. 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Basic WECC Dynamic Criteria:

Tri-State's dynamic reactive power and voltage control / regulation criteria are in accordance with the NERC/WECC dynamic performance criteria and are as follows:

- Transient stability voltage response at applicable BES buses should recover to 80 percent of pre-contingency voltage within 10 seconds of the initiating event.
- Oscillations should show positive damping within a 30-second time frame.

Table A 4

Table 1

WSCC VOLTAGE STABILITY CRITERIA(*)

Performance Level	Disturbance (1)(2)(3)(4) Initiated By: Fault or No Fault DC Disturbance	MW Margin (P-V Method) (5)(6)(7)	MVAR Margin (V-Q Method) (6)(7)
A	Any element such as: One Generator One Circuit One Transformer One Reactive Power Source One DC Monopole	≥ 5%	Worst Case Scenario (8)
B	Bus Section	≥ 2.5%	50% of Margin Requirement in Level A
C	Any combination of two elements such as: A Line and a Generator A Line and a Reactive Power Source Two Generators Two Circuits Two Transformers Two Reactive Power Sources DC Bipole	≥ 2.5%	50% of Margin Requirement in Level A
D	Any combination of three or more elements such as: Three or More Circuits on ROW Entire Substation Entire Plant Including Switchyard	> 0	> 0

(1) This table applies equally to the system with all elements in service and the system with one element removed and the system readjusted (see Section 2.2).

(2) For application of this criteria within a member system, controlled load shedding is allowed to meet Performance Level A (see Section 2.2 for a description of provisions for application of this criteria within a member system).

(3) The list of element outages in each Performance Level is not intended to be different than the Disturbance Performance Table in the WECC Reliability Criteria. Additional element outages have been added to this table to show more examples of contingencies. Determination of credibility for contingencies for each Performance Level is based on the definitions used in the existing WECC Reliability Criteria.

(4) Margin for N-0 (base case) conditions must be greater than the margin for Performance Level A.

(5) Maximum operating point on the P axis must have a MW margin equal to or greater than the values in this table as measured from the nose point of the P-V curve for each Performance Level.

(6) Post-transient analysis techniques shall be utilized in applying the criteria.

(7) Each member system should consider, as appropriate, the uncertainties in Section 2.3 to determine the required margin for its system.

(8) The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecasted loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

(*) Table 1 is an excerpt from the WSCC Reliability Criteria for Transmission System Planning in effect at the time of this document's approval. The most current version of the Council's Table of Allowable Effects on Other Systems should be referred to when conducting studies.

Table A 5

<table>
<tr><th colspan="2">Table A 6 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.

3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table A6 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. 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. 8. 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. 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. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

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.

13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Appendix B: Standard MOD-029-1a — Rated System Path Methodology

A. Introduction

1. **Title:** **Rated System Path Methodology**
2. **Number:** **MOD-029-1a**
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
   - **4.1.** Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
   - **4.2.** Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:

R1.1.1. Includes at least:

R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.

R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)

R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)

R1.1.2. Models all system Elements as in-service for the assumed initial conditions.

R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.

R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

R1.1.5. Uses Load forecast by Balancing Authority.

R1.1.6. Uses Transmission Facility additions and retirements.

R1.1.7. Uses Generation Facility additions and retirements.

R1.1.8. Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon.

R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.

R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.

R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner

R2. The Transmission Operator shall use the following process to determine TTC: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R2.1. Except where otherwise specified within MOD-029-1, adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:

R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.

R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.

R2.1.3. Uncontrolled separation shall not occur.

R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependant on a Special Protection System (SPS), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a SPS.

R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.

R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

R2.5. The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path.

Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

R2.6. Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.

R2.7. For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.

R2.8. Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.

R3. Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

R7. When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

Postbacks_F are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_F are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

R8. When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + \text{Postbacks}_{NF} + \text{counterflows}_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

M1. Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)

M1.1. Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)

M1.2. The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)

M1.3. The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)

M1.4. The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)

M2. Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).

M3. Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)

M4. Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)

M5. Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7and R8 for each ATC Path. (R3)

M6. Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)

M7. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

M8. The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)

M9. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)

M10. Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc…). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)	The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1. **OR** The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)
R2	One or both of the following: • The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include one required item in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include two required items in the study report required in R2.8.	One or both of the following: • The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. • The Transmission Operator does not include three required items in the study report required in R2.8.	One or more of the following: • The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. • The Transmission Operator did not apply R2.7. • The Transmission Operator does not include four or more required items in the study report required in R2.8

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-fim ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R5 and R6	Interpretation (Project 2009-15)

Appendix 1

Requirement Number and Text of Requirement
MOD-001-01 Requirement R2: **R2.** Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s): **R2.1.** Hourly values for at least the next 48 hours. **R2.2.** Daily values for at least the next 31 calendar days. **R2.3.** Monthly values for at least the next 12 months (months 2-13). **MOD-001-01 Requirement R8:** **R8.** Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed: **R8.1.** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. **R8.2.** Daily values, once per day. **R8.3.** Monthly values, once per week.
Question #1
Is the "advisory ATC" used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of "advisory" calculations in the responsible entity's Available Transfer Capability Implementation Document?
Response to Question #1
Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific "ATC Paths." The NERC definition of ATC Path is "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path." Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO's "advisory ATC" is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. The second part of NYISO's question is only applicable if the first part was answered in the

negative and therefore will not be addressed.

Requirement Number and Text of Requirement

MOD-029-01 Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

Question #2

Could OS_F in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

Response to Question #2

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.