Burlington – Lamar 345/230 kV Impact and 2013 Post TPL Assessment Study

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Background

The transmission infrastructure serving the Boone - Lamar area (Figure 1) consists of two primary systems: 1) an underlying 115 kV load serving system; and 2) a 230 kV system consisting primarily of the Boone - Lamar 230 kV line. The 115 kV load serving system provides approximately 133 MW at peak primarily to the Vilas, City of Lamar, Willow Creek, and La Junta 115 kV substations. The 230 kV system is primarily utilized to transfer power into and out of the area. Power is imported from Boone 230 kV to Lamar 230 kV to serve Tri-State's network loads. PSCO utilizes the 230 kV system to transfer energy from Lamar to Boone for utilization on PSCo's network. 447 MW of generation is connected at Lamar 230 kV, including:

1) Lamar DC Tie (± 210 MW),
2) Colorado East Wind (81 MW),
3) Colorado West Wind (81 MW), and
4) Twin Butte Wind (75 MW).

The underlying 115 kV system is unable to transfer this amount of energy. The generation connected at Lamar 230 kV is fully curtailed via a cross trip scheme whenever the Boone – Lamar 230 kV line is out of service. Prior TPL assessments have also shown that by itself, the underlying 115 kV system is unable to deliver sufficient transmission capacity to reliably serve Vilas loads for the subsequent loss of the Boone – Lamar 230 kV line. In summary, loss of this single 230 kV element disables the area's ability to adequately serve loads and deliver all available generation.

Several prior studies have identified the need to interconnect the transmission systems in the northern and southern parts of eastern Colorado.

- To accommodate significant generation resource injections in and around Lamar, the Lamar Front Range studies identified the need for two parallel 345 kV lines between Lamar and Burlington, among other things.

- The High Plains Express initiative, whose goals are to significantly strengthen the eastern portion of the Western grid, includes major transmission ties between Wray, Burlington, Lamar, and Vilas.

- Tri-State's 10 year Loads and Resource studies have identified the need for increased transmission between Lamar and Burlington to accommodate future network loads and resources.

- Recent generator Interconnection studies for potential Tri-State wind resources connected at Burlington (150 MW) show limitations in the existing system that are mitigated by a new Burlington – Lamar 230 kV line.

Tri-State's 2013 TPL assessment specifically showed voltage collapse in Boone-Lamar area for the Boone – Lamar 230 kV line outage with cross trips of all generation injected at Lamar 230 kV. While it was expected that a new 230 kV line would mitigate these violations, studies specifically addressing the voltage collapse issues were required as a follow up to the 2013 TPL assessment. Further analysis was also required to ensure other system impacts were taken into consideration.

To address these multiple needs including load serving, reliability, and the accommodation of potential new generation, Tri-State has included a new Burlington – Lamar 345/230 kV project in its 2014 Ten-Year Plan.

Objectives

A new transmission source is needed in the Lamar area. Prior studies have identified a new Burlington – Lamar 230 kV line as a preferred alternative to meet various system needs. The objectives of this study are to compare the impact of three potential alternatives to mitigate the violations identified in Tri-State's 2013 TPL assessment and to ensure the adequacy of the Burlington – Lamar 230 kV line option.

The three alternatives include:

1) Burlington – Lamar 345/230 kV line, (100 miles, 345 kV constructed, operated at 230 kV).
2) Lamar - Lincoln 230 kV line (97 miles).
3) Lamar - Midway 230 kV line (121 miles).

Alternative 1 assumed bundled 1272 ACSR conductor constructed for 100 ^{o}C (1285 MVA).

Alternatives 2 and 3 assumed single 1272 ACSR conductor constructed for 100 ^{o}C (643 MVA).

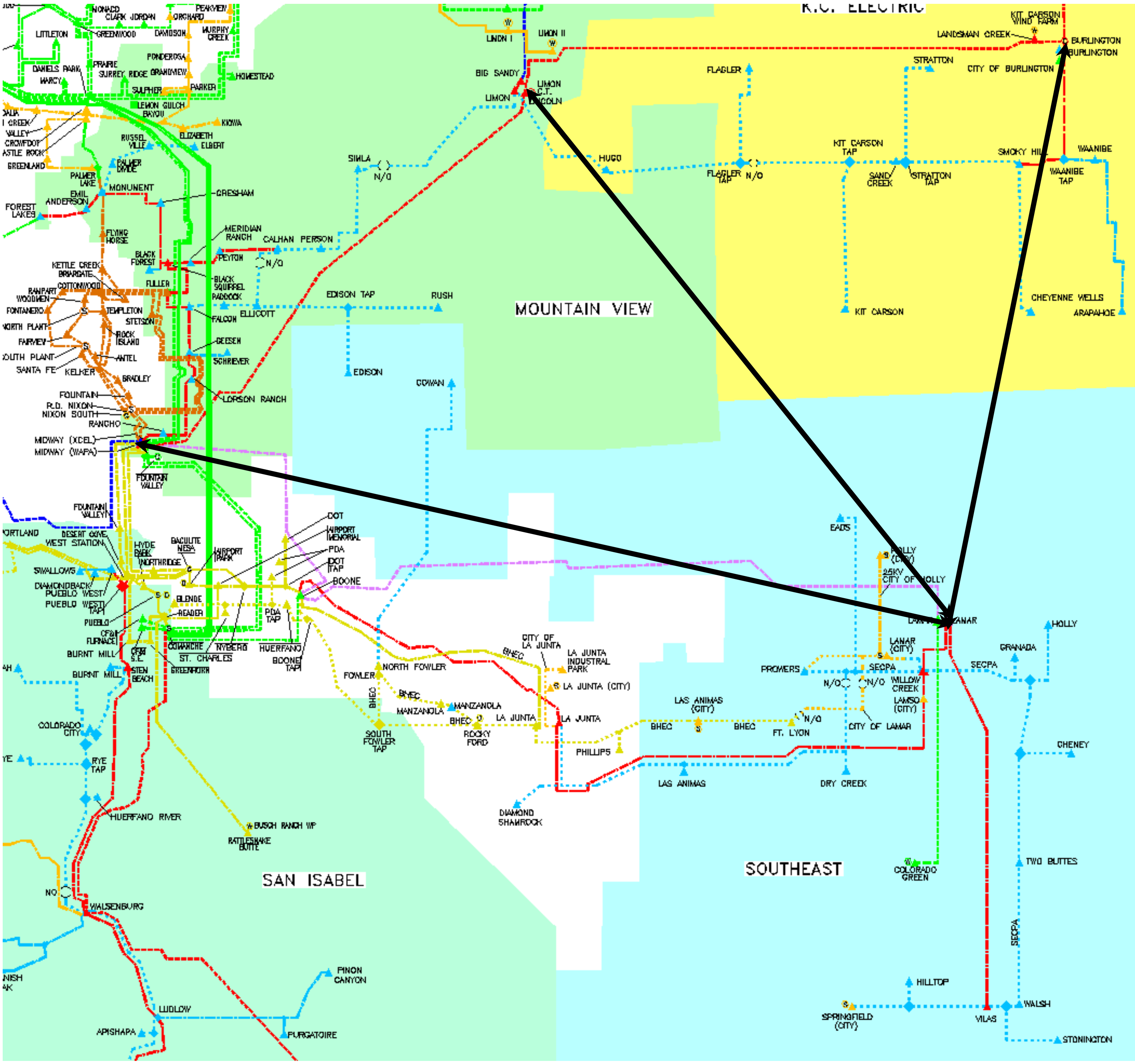

Figure 1: Southeastern Colorado Transmission System

Study Case Assumptions

Tri-State's latest 2019 heavy summer case (19HS) and 2019 light autumn case (19LA) were utilized for this study. The cases were updated with the following:

- 7.5 MVAR capacitors at La Junta 115 kV.
- 2 x 7.5 MVAR capacitors at Willow Creek.
- Second Lamar 230/115 kV (150 MVA) transformer and sectionalizing upgrades to the Lamar (TS) Substation.
- La Junta 115 kV Tie.
- Boone-Nyberg 115 kV line.
- Burlington-Wray 230 kV line.

The following limiting line ratings were filtered out to realize the conductor ratings assuming terminal CTs and metering upgrades were made to the following transmission lines:

- Lamar (PSCO) – Lamar (TS) 230 kV (494 MVA).
- Lamar – Willow Creek 115 kV (203 MVA).
- Willow Creek-La Junta 115 kV (130 MVA).
- Sand Hill-Alvin 115 kV (98 MVA).
- Alvin – Wauneta 115 kV (68 MVA).
- Olive Creek Tap – Wray 115 kV (147 MVA).

Also, the Lamar 230 kV bus was updated to model as two buses: Lamar 230 kV (PSCO) and Lamar 230 kV (TSGT) joined by a 0.5 mile bus tie line.

Methodology

Power flow studies were performed for the 19HS and 19LA cases in accordance with Tri-State's planning criteria (Appendix A) for all lines in service and single line outage conditions using PTI PSS/E Version 33. The planning criteria are consistent with the criteria of Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC).

The study was performed using the PSS/E ACCC module. All transmission facilities in Areas 70 and 73 were monitored during the power flow simulations.

Scenarios with varying Lamar DC Tie and wind generation at Lamar, together with stressed generation dispatches in nearby eastern Colorado were examined. The details of these generation dispatches for the 19HS and 19LA cases are shown in Appendix B and Appendix C; respectively.

The 19HS case scenarios were as follows:

19HS0: This is the modified 2019HS GIP case with the original generation dispatches.

19HS1: This is 19HS0 case stressed with maximum generation in the Boone - Lamar area, together with 20% wind generation and maximum conventional generation in northeastern Colorado. Note that this case has 0 MW for Carousel/Burlington wind and full generation injection at Lamar(PSCO) 230 kV :

- Lamar DC Tie importing 210 MW,
- Colorado East Wind at 81 MW,
- Colorado West Wind at 81 MW, and
- Twin Butte Wind at 75 MW.

19HS2: This is 19HS1 case further stressed with 150 MW Carousel/Burlington generation but without any new transmission line.

19HS2_LB: This is 19HS2 case (suffix _LB for _XX in Appendix B) with the new Burlington - Lamar 345/230 kV line.

19HS2_LL: This is 19HS2 case with the new Lamar-Lincoln 230 kV line.

19HS2_LM: This is 19HS2 case with the new Lamar-Midway 230 kV line.

Similarly, for 19LA cases:

19LA0: This is the modified 19LA GIP case with the original generation dispatches.

19LA1: This is 19LA0 case stressed with maximum generation in the Boone - Lamar area, together with 30% wind generation and maximum conventional generation in northeastern Colorado. Note that this case has 0 MW for Carousel/Burlington wind and full generation injection at Lamar(PSCO) 230kV:

- Lamar DC Tie importing 210 MW,
- Colorado East Wind at 81 MW,
- Colorado West Wind at 81 MW, and
- Twin Butte Wind at 75 MW.

19LA2: This is 19LA1 case further stressed with 150 MW Carousel/Burlington generation but without any new transmission line.

19LA2_LB: This is 19LA2 case (suffix _LB for _XX in Appendix C) with the new Burlington - Lamar 345/230 kV line.

19LA2_LL: This is 19LA2 case with the new Lamar-Lincoln 230 kV line.

19LA2_LM: This is 19LA2 case with the new Lamar-Midway 230 kV line.

19LA3_LB: Identical to 19LA2_LB but with reduced generation injection at Lamar(PSCO) 230 kV:

- Lamar DC Tie importing 210 MW,
- Colorado East Wind at 35 MW,
- Colorado West Wind at 0 MW, and
- Twin Butte Wind at 0 MW.

19LA3_LL: Identical to 19LA3_LB, except with the Lamar - Lincoln 230 kV alternative.

19LA3_LM: Identical to 19LA3_LB, except with the Lamar - Midway 230 kV alternative.

Sensitivity analysis was also performed to evaluate the impacts on system performance for differences caused by constructing the Burlington – Lamar 345/230 kV alternative for either 345 kV or 230 kV operation.

In additional to the all-lines-in-service (N-0) study, forty five single line outages (breaker-to-breaker), with bus numbers shown, were selected for the contingency study (N-1), as shown in Appendix D.

Results

The resulting planning criteria violations for single line contingency conditions (N-1) are listed in Table 1. Note that the results only show thermal loading problems. There are no new problems found for high or low voltages and voltage deviations that exceed 7%. Also, existing overloaded facilities are excluded.

From Table 1, the following issues are observed:

- As with the 2013 TPL assessment, cases 19HS0 and 19LA0 did not solve for either the Lamar – Boone 230 kV or Lamar (PSCO) – Lamar (TS) 230 kV bus tie outage. Similarly, these cases did not solve for the Lamar-Boone 230 kV line outage with the existing generation cross trips. However, adding any of the three alternatives solved this outage problem.

- The existing Lamar 230/115 kV T1 (100 MVA) overloads for a loss of the parallel T2 (150 MVA) in the 19HS0 case. While not completely mitigated for a single contingency, the addition of a second 230 kV source at Lamar significantly reduces the T1 overload. The T1 overload issue is not caused by the alternatives. As this issue only appears in 2018 and later cases, it will be monitored in future system assessments.

- The analysis demonstrated that with a second Lamar 230 kV source, between 245 MW and 447 MW of generation could remain connected at Lamar following a Boone – Lamar 230 kV outage. The amount of generation that can remain connected depends on load levels (HS or LA).

- The 19LA2 cases showed overloading on Western's Wray – Eckley – East Yuma Tap – Deering Lake 115 kV line for the Wray-North Yuma 230 kV line outage with or without adding any of the three alternatives. Therefore this overload is not directly caused by adding any of the three alternatives. It is primarily impacted by the amount of generation injected at Burlington.

- In the 19LA3 cases (with 245 MW injecting into Lamar(PSCO) 230 kV), the Wray – Eckley – East Yuma Tap – Deering Lake 115 kV line overload was corrected with the smaller level of injection at Lamar 230 kV. Nevertheless, further studies of the limiting elements on Western's Wray – Eckley

– East Yuma Tap – Deering Lake 115 kV line may correct this problem, allowing full generation injection (477 MW) at Lamar following the Boone-Lamar 230 kV line outage.

- Results of the sensitivity analysis of the transmission line impedance differences caused by constructing the Burlington – Lamar 345/230 kV alternative for either 345 kV or 230 kV operation showed negligible system impacts.

Cost Estimates

Planning level cost estimates (± 30%) for the proposed alternatives are shown in Table 2 below. These costs include two line positions for each alternative. Bundled (2-1272) ACSR conductor is assumed for the 345 kV line. Single (1-1272) ACSR conductor is assumed for the 230 kV lines. Costs for 345 kV substations are not included in the Burlington – Lamar 345 kV alternative as operation was assumed to be at 230 kV.

Table 1: Planning Level Cost Estimates
(Two Line Positions Included)

Alternative	Description	Conductor (ACSR)	2014 ($000)
1	Burlington – Lamar 345 kV Lattice Steel (100 miles) (operate at 230 kV without Burlington 345/230 kV transformer)	2-1272	164,000
1A	Burlington – Lamar 230 kV Wood H-Frame (100 miles)	1272	81,000
2	Lamar-Lincoln 230 kV Wood H-Frame (97 miles)	1272	79,000
3	Lamar-Midway 230 kV Wood H-Frame (121 miles)	1272	98,000

Conclusions

The impacts for three potential alternatives to mitigate system violations identified in Tri-State's 2013 TPL assessment were compared and all three were found to be adequate. Specifically, the adequacy of the planned Burlington – Lamar 345/230 kV option was confirmed to mitigate the performance violations found in Tri-State's 2013 TPL assessment. Further, the Burlington – Lamar 345/230 kV alternative was not found to cause any other subsequent performance issues.

A new 230 kV tie between northeastern and southeastern Colorado will greatly improve the transmission system performance in eastern Colorado:

1) Load serving reliability in the Boone-Lamar area will be improved.
2) The potential voltage collapse in the Boone-Lamar area for an outage of the Lama (PSCO)-Lamar (TS) 230 kV bus tie line will be mitigated.
3) The amount of generation to be cross tripped for the Boone-Lamar 230 kV line outage will be reduced or eliminated for upgrading Western's Wray – Eckley – East Yuma Tap – Deering Lake 115 kV line rating.
4) Congestion in and around Burlington Substation will be greatly reduced.

Table 2: Power Flow Study Results for Single Contingency Conditions (N-1)

MONITORED ELEMENTS	CONTINGENCY	19HS0	19HS1	19HS2	19HS2_LB	19HS2_LL	19HS2_LM	19LA0	19LA1	19LA2	19LA2_LB	19LA2_LL	19LA2_LM	19LA3_LB	19LA3_LL	19LA3_LM
70061 BOONE 230.00 70254 LAMAR_CO 230.00 1	LAMAR(PSCO)- LAMAR(TS) 230 KV BUS TIE	Not Solved	Not Solved	Not Solved			99.70% 445MVA (0x)	Not Solved	Not Solved	Not Solved						
	LAMAR-BOONE 230 KV, WITH CROSS TRIPS	Not Solved	Not Solved	Not Solved				Not Solved	Not Solved	Not Solved						
70247 LAJUNTAT 115.00 70472 WILOW_CK 115.00 1	LAMAR-BOONE 230 KV, WITHOUT CROSS TRIPS		Not Solved	Not Solved					Not Solved	Not Solved		99.50% 127MVA (0x)				
70253 LAMAR_TS 115.00 72135 LAMAR_TS 230.00 T1	LAMA 230/115 KV T2 (150 MVA)		146.10% 146MVA (1x)	146.10% 146MVA (1x)	129.30% 129MVA (1x)	129.30% 129MVA (1x)	120.90% 121MVA (1x)		110.70% 111MVA (1x)	110.70% 111MVA (1x)						
73053 ECKLEY 115.00 73223 WRAY 115.00 1	WRAY-NORTH YUMA 230 KV									104.70% 89MVA (1x)	125.50% 107MVA (1x)	115.60% 98MVA (1x)	105.50% 90MVA (1x)	100.10% 86MVA (1x)	104.00% 89MVA (1x)	101.10% 86MVA (1x)
72100 E_YUMA_T 115.00 73053 ECKLEY 115.00 1										99.30% 84MVA (0x)	120.10% 101MVA (1x)	110.20% 93MVA (1x)	100.20% 85MVA (1x)			
72100 E_YUMA_T 115.00 73047 DEERINGL 115.00 1											117.80% 99MVA (1x)	108.00% 91MVA (1x)				
73005 ALVIN 115.00 73210 WAUNETA 115.00 1											102.20% 70MVA (1x)					

Appendix A: 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	Areas	Bus List Name in Spreadsheet
Normal	0.95 - 1.05			
Contingency N-1	0.90 - 1.10	7%	Northeastern New Mexico	NE New Mexico
Contingency N-1	0.90 - 1.10	7%	Southern New Mexico	S New Mexico
Contingency N-1	0.90 - 1.10	6%	Other buses in PNM area	O New Mexico
Contingency N-1	0.90 - 1.10	7%	Western Colorado	W Colorado
Contingency N-1	0.90 - 1.10	7%	Southern Colorado	S Colorado
Contingency N-1	0.90 - 1.10	6%	Other Tri-State areas	
Contingency N-2	0.90 - 1.10	10%	All	

Tri-State Generation and Transmission Assoc. (TP) –Reactive Power & Voltage Regulation Requirements for Generation Interconnections

A. Tri-State's Steady State VAR, and Voltage Regulation Requirements:
Note - while these generally make reference to wind generation facilities, they shall apply to all generation interconnections; PV solar plants may be exempt if the requirement is not feasible.

1) All interconnections are subject to detailed study and may require mitigation in excess of minimums imposed by published standards, according to the best judgment of Tri-State engineers. The IC's Large Generating Facilities (LGF) shall be capable of either producing or absorbing reactive power (VAR) as measured at the HV POI bus at an equivalent 0.95 p.f., across the range of near 0% to 100% of facility MW rating, with the magnitude of VAR calculated on the basis of nominal POI voltage (1.0 p.u. V). This would be the net MVAR able to be either produced or absorbed by the IF facility, depending upon the voltage regulating conditions at the POI (see next item).

2) The POI voltage range where the IC's LGF may be required to produce VAR is from 0.90 p.u. V through 1.04 p.u. V. In this range the IC facilities are being utilized to help support or raise the POI bus voltage.

3) The POI voltage range where the IC's LGF may be required to absorb VAR is from 1.02 p.u. V through 1.10 p.u. V. In this range the IC facilities are being utilized to help reduce the POI bus voltage.

4) Note that the POI voltage range where the IC's LGF may be required to either produce VAR or absorb VAR is 1.02 p.u. V through 1.04 p.u. V, with the typical target regulating voltage being 1.03 p.u. V.

5) The IC's LGF may supply reactive power from the generators, from the generators' inverter systems alone (if capable), or a combination of the generators, generators' inverter systems plus switched capacitor banks and/or reactors, or continuously variable STATCOM or SVC type systems. The IC's LGF is required to supply a portion of the reactive power (VAR) in a continuously variable fashion, such as supplied from either the generators, the generators' inverter systems, or a STATCOM or SVC system. The amount of continuously variable VAR shall be a value equivalent to a minimum of 0.95 p.f. produced or absorbed at the generator terminal Low Voltage (LV) bus, across the full range (0 to 100%) of rated MW output. The remainder of VAR required to meet the 0.95 p.f. net criteria at the HV POI bus may be achieved with switched capacitors and reactors, so long as the resultant step-change voltage is no greater than 3% of the POI operating bus voltage. This step change voltage magnitude shall be initially calculated based upon the minimum system (N-1) short circuit POI bus MVA level as supplied by the TP.

6) Under conditions when the IC's LGF is not producing any real power (near 0 MW, and typically less than 2 MVAR), the reactive power exchange at the POI shall be near 0 MVAR ("VAR neutral"). This condition assumes that the facility needs to remain energized to supply base-level station-service "house power" for the control facilities, maintain wind turbines on turning gear, etc., and that tripping open the IC transmission line supply is not a normal or acceptable means to create this VAR neutral condition. In this non-generating mode, the IC Facility appears as a transmission connected load customer, and therefore must meet TP's requirements for load p.f., which requires that the load p.f. be 0.95 or better.

7) All interconnections are subject to additional detailed study, utilizing more complex models and software such as PSCAD, EMTP, or similar, and may require mitigation in excess of minimums imposed by published standards, according to the best judgement of the TP's engineers.

Basic WECC Dynamic Criteria:

Tri-State's dynamic reactive power and voltage control / regulation criteria are in accordance with the NERC/WECC dynamic performance standard shown in Figure W-1 and Table W-1 of the "TPL-(001 thru 004)-WECC-1-CR, System Performance Criteria" dated April 18, 2008.. Additional Tri-State dynamic reactive power and voltage criteria are listed below.

B. Tri-State's Dynamic VAR and Low Voltage Ride-Through Requirements (consistent with FERC Order 661-A):

Note - while these requirements generally make reference to wind generation facilities, they shall apply to all types of generation interconnections. PV solar plants may be exempt if the requirement is not feasible.

1) The IC's LGF shall be able to meet the dynamic response Low Voltage Ride-Through (LVRT) requirements consistent with the latest WECC / NERC criteria. In particular, as per the Tri-State LGIP, Appendix G: Transmission Transfer Capability Assessment and FERC Order 661A for LVRT (applicable to Wind Generation Facilities).

2) Generating plants are required to remain in service during and after faults, three-phase or single line-to-ground (SLG) whichever is worse, with normal total clearing times in the range of approximately 4 to 9 cycles, SLG faults with delayed clearing, and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the circuit breaker clearing times of the effected system to which the IC facilities are interconnecting. The maximum clearing time the generating plant shall be required to withstand for a fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the Point of Interconnection (POI). To elaborate, before time 0.0, the voltage at the POI is the nominal voltage. At time 0.0, the voltage drops. The plant must stay online for at least 0.15 seconds regardless of voltage during the fault. Further, if the voltage returns to 90 percent of the nominal voltage within 3 seconds of the beginning of the voltage drop, the plant must continuously stay online. The Interconnection Customer may not disable low voltage ride-through equipment while the wind plant is in operation.

3) This requirement does not apply to faults that would occur between the generator terminals and the POI.

4) Generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

5) Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAR Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

Table A 3

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d]	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
Extreme event resulting in two or more (multiple) elements removed or Cascading out of service		

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed 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 the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Table A 4

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

Notes:

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

3. *Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.*

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

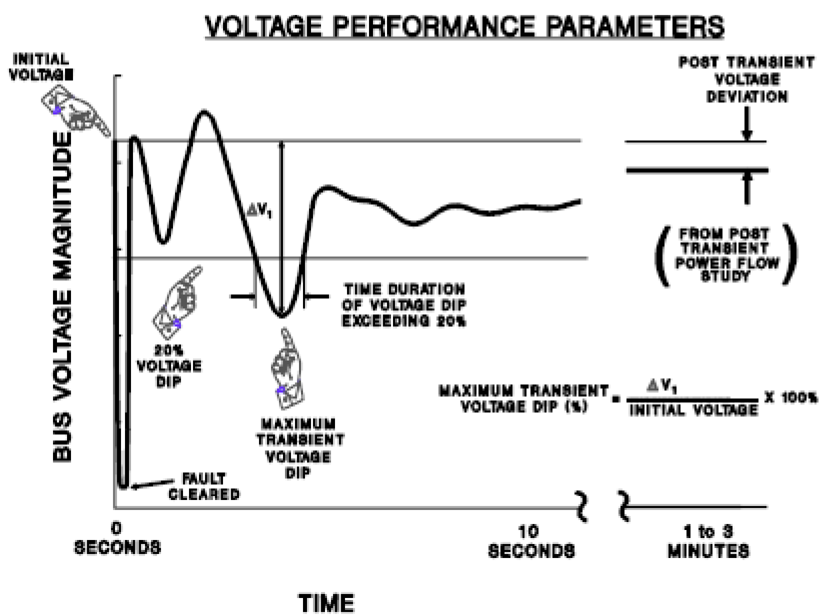

Figure W-1

Table A 5

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	$\geq$ 5%	Worst Case Scenario (8)
B	Bus Section	$\geq$ 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	$\geq$ 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.

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Appendix B: Generation Dispatches for 19HS Cases

Number	Name	ID	Pmax	Pmin	Case 19HS0	Case 19HS1	Case 19HS2	Case 19HS2_XX
			(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
72131	**CAROSEL/BURLINGTON_W (New)**	1	150.0	0.0	0.0	0.0	150.0	150.0
70560	LAMAR_DC 230.0	DC	210.0	-210.0	100.0	210.0	210.0	210.0
70701	CO_GRN_E 0.575	W1	81.0	10.8	17.0	81.0	81.0	81.0
70702	CO_GRN_W 0.575	W2	81.0	10.8	17.0	81.0	81.0	81.0
70703	TWNBUTTE 34.5	W1	75.0	0.0	15.8	75.0	75.0	75.0
73302	BRLNGTN1 13.8	1	50.0	25.0	0.0	50.0	50.0	50.0
73303	BRLNGTN2 13.8	1	50.0	25.0	0.0	50.0	50.0	50.0
72714	KIT.CARSON 0.69	G1	51.0	2.4	10.2	51.0	51.0	51.0
73532	LINCOLN1 13.8	1	68.0	40.0	49.3	68.0	68.0	68.0
73533	LINCOLN2 13.8	1	68.0	40.0	45.9	68.0	68.0	68.0
73129	MBPP-1 24	1	605.0	0.0	600.0	605.0	605.0	605.0
73130	MBPP-2 24	1	605.0	0.0	605.0	605.0	605.0	605.0
73188	STEGALDC 230	TS	100.0	0.0	100.0	100.0	100.0	100.0
73181	SIDNEYDC 230	1	200.0	-200.0	200.0	200.0	200.0	200.0
70721	SPRNGCAN 34.5	W1	60.0	0.0	12.6	12.0	12.0	12.0
70710	PTZLOGN1 34.5	W1	201.0	0.0	42.2	40.2	40.2	40.2
70712	PTZLOGN2 34.5	W2	120.0	0.0	25.2	24.0	24.0	24.0
70713	PTZLOGN3 34.5	W3	79.5	0.0	16.7	15.9	15.9	15.9
70714	PTZLOGN4 34.5	W4	175.0	0.0	36.8	35.0	35.0	35.0
73631	COHIWND_G1 0.69	W	67.2	3.2	14.3	13.4	13.4	13.4
73635	COHIWND_G2 0.69	W	23.8	3.2	0.0	4.8	4.8	4.8
70622	CEDAR PT/MISSLE SITE 34.5	W1	250.0	0.0	52.5	50.0	50.0	50.0
70499	QF_B4-4T 13.8	G4	24.0	7.0	24.0	24.0	24.0	24.0
70499	QF_B4-4T 13.8	G5	25.0	7.0	25.0	25.0	25.0	25.0
70556	QF_B4D4T 12.5	ST	70.0	17.0	50.0	70.0	70.0	70.0
70498	QF_BCP2T 13.8	G3	30.0	17.0	20.4	30.0	30.0	30.0
70498	QF_BCP2T 13.8	ST	36.0	17.0	20.4	36.0	36.0	36.0
70500	QF_CPP1T 13.8	G1	24.0	10.0	0.0	24.0	24.0	24.0
70500	QF_CPP1T 13.8	G2	24.0	10.0	0.0	24.0	24.0	24.0
70501	QF_CPP3T 13.8	ST	27.0	10.0	0.0	27.0	27.0	27.0
73418	RD_NIXON 20	1	240.0	110.9	239.6	240.0	240.0	240.0
73507	FTRNG1CC 18	1	142.0	71.0	139.4	142.0	142.0	142.0
73508	FTRNG2CC 18	1	142.0	71.6	139.8	142.0	142.0	142.0
71001	BAC_MSA 13.8	G1	90.0	0.0	90.0	90.0	90.0	90.0
71002	BAC_MSA 13.8	G1	90.6	0.0	90.0	90.6	90.6	90.6
71003	BAC_MSA 13.8	G1	40.0	0.0	40.0	40.0	40.0	40.0
71003	BAC_MSA 13.8	G2	40.0	0.0	40.0	40.0	40.0	40.0
71003	BAC_MSA 13.8	S1	24.8	0.0	24.0	24.8	24.8	24.8
71004	BAC_MSA 13.8	G1	40.0	0.0	40.0	40.0	40.0	40.0
71004	BAC_MSA 13.8	G2	40.0	0.0	40.0	40.0	40.0	40.0
71004	BAC_MSA 13.8	S1	24.8	0.0	24.0	24.8	24.8	24.8
71005	BAC_MSA 13.8	G1	40.0	0.0	40.0	40.0	40.0	40.0
70119	COMAN_1 24.000	C1	360.0	200.0	353.0	360.0	360.0	360.0
70120	COMAN_2 24.000	C2	365.0	200.0	362.0	365.0	365.0	365.0
70777	COMAN_3 24.000	C3	805.0	200.0	805.0	805.0	805.0	805.0
Total					4,567.1	5,183.5	5,333.5	5,333.5
Increased Generation to be reduced in Northwest area						616.4	766.4	766.4
Area 40	NORTHWEST		38,859.4	80.5	31,480.6	30,864.2	30,714.2	30,714.2

Appendix C: Generation Dispatches for 19LA Cases

Number	Name	ID	Pmax	Pmin	Case 19LA0	Case 19LA1	Case 19LA2	Case 19LA2_XX	Case 19LA3_XX
			(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
72131	**CAROUSEL/BURLINGTON_W (New)**	1	150.0	0.0	0.0	0.0	150.0	150.0	150.0
70560	LAMAR_DC 230.0	DC	210.0	-210.0	100.0	210.0	210.0	210.0	210.0
70701	CO_GRN_E 0.575	W1	81.0	10.8	18.0	81.0	81.0	81.0	35.0
70702	CO_GRN_W 0.575	W2	81.0	10.8	18.0	81.0	81.0	81.0	0.0
70703	TWNBUTTE 34.5	W1	75.0	0.0	16.5	75.0	75.0	75.0	0.0
73302	BRLNGTN1 13.8	1	50.0	25.0	0.0	50.0	50.0	50.0	50.0
73303	BRLNGTN2 13.8	1	50.0	25.0	0.0	50.0	50.0	50.0	50.0
72714	KIT.CARSON 0.69	G1	51.0	2.4	51.2	51.0	51.0	51.0	51.0
73532	LINCOLN1 13.8	1	68.0	40.0	0.0	68.0	68.0	68.0	68.0
73533	LINCOLN2 13.8	1	68.0	40.0	0.0	68.0	68.0	68.0	68.0
73129	MBPP-1 24	1	605.0	0.0	230.6	605.0	605.0	605.0	605.0
73130	MBPP-2 24	1	605.0	0.0	605.0	605.0	605.0	605.0	605.0
73188	STEGALDC 230	TS	100.0	0.0	0.0	100.0	100.0	100.0	100.0
73181	SIDNEYDC 230	1	200.0	-200.0	200.0	200.0	200.0	200.0	200.0
70721	SPRNGCAN 34.5	W1	60.0	0.0	13.5	18.0	18.0	18.0	18.0
70710	PTZLOGN1 34.5	W1	201.0	0.0	45.0	60.3	60.3	60.3	60.3
70712	PTZLOGN2 34.5	W2	120.0	0.0	27.0	36.0	36.0	36.0	36.0
70713	PTZLOGN3 34.5	W3	79.5	0.0	18.0	23.9	23.9	23.9	23.9
70714	PTZLOGN4 34.5	W4	175.0	0.0	39.0	52.5	52.5	52.5	52.5
73631	COHIWND_G1 0.69	W	67.2	3.2	67.0	20.2	20.2	20.2	20.2
73635	COHIWND_G2 0.69	W	23.8	3.2	6.5	7.1	7.1	7.1	7.1
70622	CEDAR PT/MISSLE SITE 34.5	W1	250.0	0.0	40.0	75.0	75.0	75.0	75.0
70499	QF_B4-4T 13.8	G4	24.0	7.0	18.0	24.0	24.0	24.0	24.0
70499	QF_B4-4T 13.8	G5	25.0	7.0	18.8	25.0	25.0	25.0	25.0
70556	QF_B4D4T 12.5	ST	70.0	17.0	37.5	70.0	70.0	70.0	70.0
70498	QF_BCP2T 13.8	G3	30.0	17.0	0.0	30.0	30.0	30.0	30.0
70498	QF_BCP2T 13.8	ST	36.0	17.0	0.0	36.0	36.0	36.0	36.0
70500	QF_CPP1T 13.8	G1	24.0	10.0	0.0	24.0	24.0	24.0	24.0
70500	QF_CPP1T 13.8	G2	24.0	10.0	0.0	24.0	24.0	24.0	24.0
70501	QF_CPP3T 13.8	ST	27.0	10.0	0.0	27.0	27.0	27.0	27.0
73418	RD_NIXON 20	1	240.0	110.9	239.6	240.0	240.0	240.0	240.0
73507	FTRNG1CC 18	1	142.0	71.0	118.2	142.0	142.0	142.0	142.0
73508	FTRNG2CC 18	1	142.0	71.6	0.0	142.0	142.0	142.0	142.0
71001	BAC_MSA 13.8	G1	90.0	0.0	90.0	90.0	90.0	90.0	90.0
71002	BAC_MSA 13.8	G1	90.6	0.0	90.0	90.6	90.6	90.6	90.6
71003	BAC_MSA 13.8	G1	40.0	0.0	40.0	40.0	40.0	40.0	40.0
71003	BAC_MSA 13.8	G2	40.0	0.0	40.0	40.0	40.0	40.0	40.0
71003	BAC_MSA 13.8	S1	24.8	0.0	19.0	24.8	24.8	24.8	24.8
71004	BAC_MSA 13.8	G1	40.0	0.0	40.0	40.0	40.0	40.0	40.0
71004	BAC_MSA 13.8	G2	40.0	0.0	40.0	40.0	40.0	40.0	40.0
71004	BAC_MSA 13.8	S1	24.8	0.0	0.0	24.8	24.8	24.8	24.8
71005	BAC_MSA 13.8	G1	40.0	0.0	0.0	40.0	40.0	40.0	40.0
70119	COMAN_1 24.000	C1	360.0	200.0	300.0	360.0	360.0	360.0	360.0
70120	COMAN_2 24.000	C2	365.0	200.0	335.0	365.0	365.0	365.0	365.0
70777	COMAN_3 24.000	C3	805.0	200.0	800.0	805.0	805.0	805.0	805.0
Total					3,721.4	5,281.2	5,431.2	5,431.2	5,229.2
Increased Generation to be reduced in Northwest area						1,559.8	1,709.8	1,709.8	1,507.8
Area 40	NORTHWEST		38,859.4	80.5	31,517.9	29,958.2	29,808.2	29,808.2	30,010.2

Appendix D: Single Line Outage List (N-1)

1) Lamar-Boone 230 kV and cross trips (70254-70061):
    a) the Colorado West and East Green wind (70702 and 70701),
    b) the Twin Butte wind (70703),
    c) the Lamar DC Tie generation (70560), and
2) Lamar-Boone 230 kV without the above mentioned cross trips (70254-70061),
3) Lamar (PSCO)-Lamar (TS) 230 kV Tie (70254-72135),
4) Burlington - Lamar 230 kV (new line, 72135-73036),
5) Lamar-Lincoln 230 kV (new line, 72135-73531),
6) Lamar-Midway(WAPA) 230 kV (new line, 72135-73413),
7) Second Lamar 230/115 kV T2 with 150 MVA rating (72135-70253),
8) Burlington-Wray 230 kV (73036-73224),
9) Burlington-Landsman Creek 230 kV (73036-72710),
10) Burlington 230/115 kV #2 with 167 MVA rating (73036-73035),
11) Wray-North Yuma 230 kV (73224-73143),
12) Wray 230/115 kV #1 (73224-73223),
13) North Yuma-Spring Canyon 230 kV (73143-73579) and trips the Spring Canyon Wind generation,
14) North Yuma-Story 230 kV (73143-73192),
15) North Yuma 230/115 kV #1 (73143-73142),
16) Spring Canyon-Sidney 230 kV (73579-73180),
17) Story-Henry Lake 230 kV (73192-70605),
18) Lincoln-Big Sandy 230 kV (73531-73018),
19) Lincoln-Midway 230 kV (73531-73413),
20) Midway-Boone 230 kV 70286-70061),
21) Midway-Comanche 230 kV #1 (70286-70122),
22) Midway-Fuller 230 kV (70286-73477),
23) Midway-West Canyon 230 kV (73413-73551),
24) Midway-R.D._Nixon 230 kV (73413-73419),
25) MidwayPS-MidwayBR 230 kV Tie (70286-73413),
26) Boone-Comanche 230 kV (70061-70122),
27) Boone 230/115 kV (70061-70060),
28) Lamar-Willow Creek 115 kV (70253-70472),
29) La Junta (TS)-Boone 115 kV (70247-70060),
30) Midway-Rancho-Lorson Ranch-Geesen 115 kV (73412-73416-73458-73405),
31) Midway-R.D. Nixon 115 kV (73412-73417),
32) Midway-Fountain Valley 115 kV (73412-70193),
33) Midway-North Ridge-Overton-Baculite 115 kV (70285-70301-70007-70031),
34) Midway-West Station 115 kV (70285-70456),
35) Big Sandy-Last Chance 115 kV (73017-73125),
36) Last Chance-South Woodrow-Woodrow-Gary-Beaver Creek 115 kV (73125-73194-73221-73065-73020),
37) Burlington-Bonny Creek-South Fork 115 kV (73035-73025-73185),
38) South Fork-Idalia-Vernon Switch 115 kV (73185-73091-73206),
39) Vernon Switch-Olive Tap-Wray 115 kV (73206-72130-73223),
40) Burlington-Burlington KC-Burlington PSC-Waanibe Tap 115 kV (73035-73485-73034-73209),
41) Wray-Eckley 115 kV (73223-73053),
42) Wray-Wray City Tap-Sandhills-Alvin-Wauneta 115 kV (73223-72103-73175-73005-73210),
43) North Yuma-Deering Lake 115 kV (73142-73047),
44) North Yuma-Redwillow-Wages-Wauneta 115 kV (73142-73166-73208-73210),
45) Dearing Lake-Otis-Akron 115 kV (73047-73372-73003).