# MidAmerican Energy Company

# Reliability Planning Criteria for 100 kV and Above

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1.0 SCOPE

This document defines the criteria to be used in assessing the reliability of MidAmerican Energy Company's (MidAmerican Energy's) 100 kV and above system.[1]

2.0 GENERAL

Reliability assessments of the MidAmerican Energy 100 kV and above system are performed to identify areas of the system where the reliability criteria are not expected to be met. Reliability assessments are also performed to evaluate impacts on the MidAmerican Energy 100 kV and above system of interconnections of new generation, transmission, or loads[2]. In the reliability assessments, contingencies are analyzed for reliability criteria violations such as overloads, low voltage, high voltage, transient instability, voltage instability and cascading outages.

3.0 PURPOSE

The purpose of these 100 kV and above reliability planning criteria, henceforth 'Criteria', is to provide a basis for the development and operation of MidAmerican Energy's 100 kV and above[3] system in the interest of its customers, communities served, and owners in a consistent, reliable, and economic manner. It is intended that these Criteria conform to the North American Electric Reliability Corporation (NERC) Reliability Standards and the Midwest Reliability Organization (MRO) Standards, as appropriate. Further, it is intended that these Criteria conform to applicable rules and regulations of the Federal Energy Regulatory Commission (FERC) and other regulatory bodies having jurisdiction.

These Criteria are subject to review and change at any time to conform to the MRO, NERC and FERC criteria, rules and regulation changes in the future. On December 6, 2007, the MRO Board approved MRO Standard TPL-503-MRO-01 System Performance. This standard contains planning reliability criteria for implementation by MidAmerican Energy. The MRO is monitoring this standard for compliance. The MRO standard is provided as an attachment to the MidAmerican Energy Reliability Planning Criteria for 100 kV and Above.

[1] It should be noted that MidAmerican Energy has used the FERC Seven Indicators of local distribution in Order 888 to determine which MidAmerican Energy facilities are distribution and which are transmission. As a result, most MidAmerican Energy 345 kV facilities and most 161 kV facilities are considered transmission.

[2] Reliability assessments of the MidAmerican 100 kV and above system are performed, as appropriate, for interconnections to the MidAmerican Energy system or the systems of surrounding utilities.

[3] For transformers, at least two windings must be connected at a voltage above 100 kV in order for the transformer to be considered a part of the 100 kV and above system.

## 4.0 SYSTEM PLANNING PERFORMANCE STANDARDS

In this document, system planning standards performed for MidAmerican Energy's 100 kV and above system are provided.

### A. Reliability Assessment of the 100 kV and above system

1. The MidAmerican Energy 100 kV and above system shall be planned, designed, and constructed such that with all facilities in service and with normal (pre-contingency) operating procedures in effect, the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services at all demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I (no contingencies) (see Appendix for Table I) without exceeding stability limits, applicable thermal and voltage limits and without resulting in cascading outages. The system shall be planned, designed, and constructed to avoid creating a subsynchronous resonance condition. To be considered valid, the system assessments to demonstrate that the system is so planned shall:

   a) Be made annually.
   b) Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
   c) Be supported by a current or past study and/ or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table I (no contingencies).
      i) Cover critical system conditions and study years as deemed appropriate.
      ii) Be conducted annually unless changes to system conditions do not warrant such analyses.
      iii) Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
      iv) Have established normal (pre-contingency) operating procedures in place.
      v) Have all projected firm transfers modeled.
      vi) Be performed for selected demand levels over the range of forecast system demands.
      vii) Demonstrate that system performance meets Table I for Category A (no contingencies).
      viii) Include existing and planned facilities.
      ix) Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

d) Address any planned upgrades needed to meet the performance requirements of Category A.

2. The MidAmerican Energy 100 kV and above system shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions defined in Category B of Tables I and III (single contingencies) (see Appendix for Tables I and III) without exceeding stability limits, applicable thermal and voltage limits and without resulting in cascading outages. The system shall be planned, designed, and constructed to avoid creating a subsynchronous resonance condition. To be considered valid, the system assessments to demonstrate that the system is so planned shall:

   a) Be made annually.
   b) Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
   c) Be supported by a current or past study and/ or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table I (single contingencies).
      i) Be performed and evaluated only for those Category B contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. Contingencies shall only include facilities at voltages of 100 kV and above.
      ii) Cover critical system conditions and study years as deemed appropriate.
      iii) Be conducted annually unless changes to system conditions do not warrant such analyses.
      iv) Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
      v) Have all projected firm transfers modeled.
      vi) Be performed and evaluated for selected demand levels over the range of forecast system demands.
      vii) Demonstrate that system performance meets Category B contingencies.
      viii) Include existing and planned facilities.

- ix) Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- x) Include the effects of existing and planned protection systems, including any backup or redundant systems.
- xi) Include the effects of existing and planned control devices.
- xii) Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

d) Address any planned upgrades needed to meet the performance requirements of Category B of Table I

e) Consider all contingencies applicable to Category B.

3. The MidAmerican Energy 100 kV and above system shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions of the contingencies defined in Category C of Tables I and III (see Appendix for Tables I and III) without exceeding stability limits, applicable thermal and voltage limits and without resulting in cascading outages. The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard (refer to section 5.0 Mitigation Alternatives to Meet Reliability Criteria for additional details). The MidAmerican Energy system shall be planned, designed and constructed to avoid creating a subsynchronous resonance condition. To be considered valid, the system assessments to demonstrate that the system is so planned shall:

a) Be made annually.

b) Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

c) Be supported by a current or past study and/ or system simulation testing that address each of the following categories, showing system performance following Category C of Table I (multiple contingencies).

- i) Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. Contingencies shall only include facilities at voltages of 100 kV and above.

ii) Cover critical system conditions and study years as deemed appropriate.

iii) Be conducted annually unless changes to system conditions do not warrant such analyses.

iv) Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

v) Have all projected firm transfers modeled.

vi) Be performed and evaluated for selected demand levels over the range of forecast system demands.

vii) Demonstrate that system performance meets Table I for Category C contingencies.

viii) Include existing and planned facilities.

ix) Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

x) Include the effects of existing and planned protection systems, including any backup or redundant systems.

xi) Include the effects of existing and planned control devices.

xii) Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

d) Address any planned upgrades needed to meet the performance requirements of Category C of Table I.

e) Consider all contingencies applicable to Category C.

4. The MidAmerican Energy 100 kV and above system shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be considered valid, the system assessments to demonstrate that the system is so evaluated shall:

a) Be made annually.

b) Be conducted for near-term (years one through five).

c) Be supported by a current or past study and/ or system simulation testing that address each of the following categories, showing system performance following Category D of Table I (multiple contingencies).

i) Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

ii) Cover critical system conditions and study years as deemed appropriate.

iii) Be conducted annually unless changes to system conditions do not warrant such analyses.

iii) Have all projected firm transfers modeled.

iv) Include existing and planned facilities.

v) Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

vi) Include the effects of existing and planned protection systems, including any backup or redundant systems.

vii) Include the effects of existing and planned control devices.

viii) Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

d) Consider all contingencies applicable to Category D.

## B. STEADY-STATE VOLTAGE CRITERIA

The steady-state voltage provided to customers must comply with ANSI Standard C84.1. This standard defines two voltage ranges within which the customer's voltage must be maintained. Range A covers voltages for which the system is designed to provide under normal conditions. The occurrence of service voltages outside this range should be infrequent. Range B covers voltages above and below Range A that necessarily result from practical design and operating conditions on supply or user systems, but which are to be limited in extent, frequency, and duration. Corrective measures are to be taken within a reasonable time to bring voltages back within Range A.

The devices and techniques used to maintain voltages within ranges A and B vary from case to case. The voltages listed in Table II (see Appendix for Table II) are those found in practice to provide voltages to users within the required ranges and shall apply to the MidAmerican 100 kV and above system. Note the major assumptions and considerations listed below the table.

Reliability assessments of the MidAmerican 100 kV and above system shall include evaluation of bus voltages on the MidAmerican system using a spring light load case to reflect conditions during minimum projected load levels, which typically coincide with maximum system voltage conditions. The evaluation shall include NERC Category A, B, C, and D contingencies. In addition, the removal from service of non-dispatchable units within the MidAmerican local balancing authority area, such as wind farms, is considered a valid base case condition due to the high occurrence of such resources being offline. Category A, B, C, and D contingencies shall be performed in addition to the base case modeling of the non-dispatchable units as offline. Base case adjustments to reflect a the non-dispatchable resources as being offline shall include adjustments to generation dispatch and appropriate representation of the MW and MVAR loads of the non-dispatchable resources when they are offline.

## C. VOLTAGE STABILITY

The MidAmerican Energy 100 kV and above system shall be planned, designed and constructed to provide sufficient reactive capacity and voltage control facilities at all demand levels and committed Total Transfer Capability levels to satisfy the reactive requirements and to ensure performance defined in Categories A, B, C, and D of Table I and III (see Appendix for tables). The system shall be planned so that there is sufficient margin between normal operating point and the collapse point for voltage stability to allow for reliable system.

Voltage stability studies shall be performed to demonstrate that there is sufficient margin between the normal operating point and the collapse point. The studies shall include voltage versus power transfer or system demand (P-V curve). Sufficient margin is maintained by operating at or below $P_{limit}$. $P_{limit}$ is determined by developing P-V curves for those buses that have the largest contribution to voltage instability due to the most limiting disturbance as defined in Category B in Table I. $P_{limit}$ is calculated as the lesser of:

- (0.9) * $P_{crit}$ where $P_{crit}$ is defined as the maximum power transfer or system demand (nose of P-V curve) or
- The maximum power transfer or system demand before a bus voltage falls below 0.9 P.U. (shown below in Fig. 1 as point “a”) or
- The Total Transfer Capability or system demand which does not result in a post-contingency voltage violation.

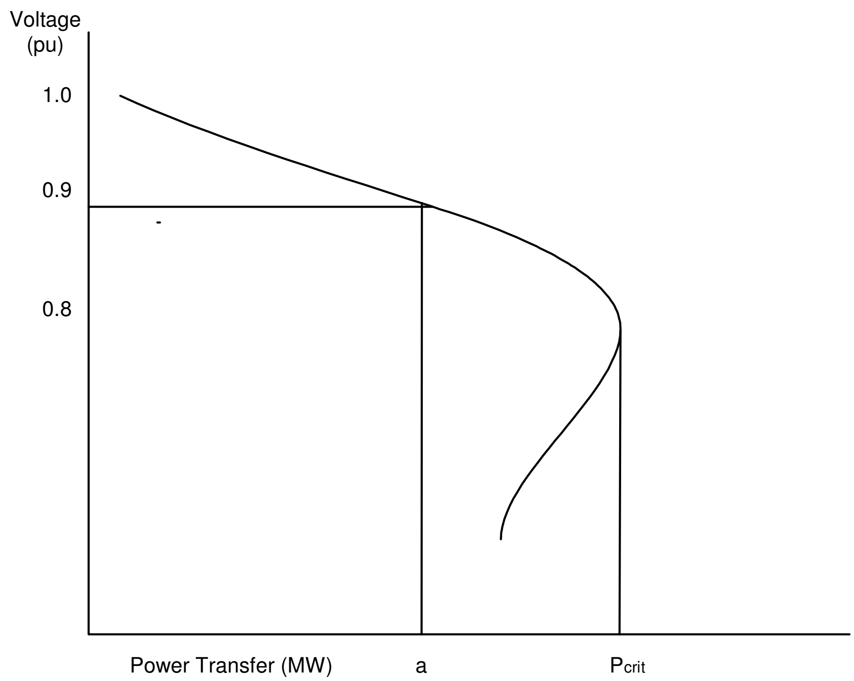


Fig. 1 P-V Curve

## 5.0 MITIGATION ALTERNATIVES TO MEET RELIABILITY CRITERIA

When system simulations indicate an inability of the 100 kV and above system to meet the performance requirements of Table I, the deficiencies must be resolved by a mitigation plan. Below is a summary of the available mitigation alternatives for each contingency category of Table I.

A. NERC Category A criteria violations

Violation of facility normal ratings or bus voltages outside of "Normal" as defined in Table II under NERC Category A conditions require physical upgrades to meet system performance requirements.

B. NERC Category B criteria violations and NERC Category C (excluding C3) criteria violations

Category B or Category C (excluding C3) contingencies resulting in facility loading between normal and emergency ratings or causing bus voltages between "Normal" and "After 1st Contingency" voltage levels as defined in Table II may rely on an operating guide, subject to the requirements in section 5.0.D, to return to the facility normal rating and "Normal" bus voltage. If an operating guide is not capable of implementation within the applicable facility emergency rating duration or the applicable voltage readjustment period (1-hour as identified in footnote 4 of Table II), then a physical upgrade is required.

Category B or Category C (excluding C3) contingencies resulting in facility loading above emergency ratings, or causing bus voltages below "After 1st Contingency" voltage levels as defined in Table II, or causing voltage levels above the "Maximum Voltage" levels as defined in Table II require physical upgrades to meet system performance requirements. A temporary operating guide may be allowed, subject to the requirements in section 5.0.D, until the physical upgrade is completed, assuming that there is firm commitment to proceed with the physical upgrade. If required to accommodate planning criteria of another transmission owner, an abnormal operating configuration (i.e. operating a ring-bus breaker as normally open) may be allowed as the long term mitigation for a Category B or Category C contingency resulting in facility loading or bus voltages outside the ranges described above in this paragraph, assuming that the abnormal operating configuration can be reasonably accommodated and does not cause load shedding, violation of thermal ratings or bus voltages, or significant operational issues.

C. NERC Category C3 criteria violations

Category C3 contingencies resulting in facility loading above normal or emergency ratings and/or causing bus voltages below minimum "After 2nd Contingency" voltage levels as defined in Table II, or causing voltage levels above the "Maximum Voltage" levels as defined in Table II may rely on an operating guide, subject to the requirements in section 5.0.D, to return to the facility normal rating and minimum "After 1st Contingency" bus voltage and "Maximum Voltage" levels. If an operating guide is not capable of implementation within the applicable readjustment period then a physical upgrade is required.

If the NERC Category C3 contingency event prior to system readjustment results in facility loading above 125% of emergency rating for thermal constraints or below 0.80 pu for voltage constraints, then the applicable readjustment period shall be 30 minutes plus the applicable emergency rating duration for thermal constraints or 30 minutes plus an additional 1 hour for voltage constraints. For all other NERC Category C3 contingency events, the applicable readjustment period shall be 2 hours plus the applicable emergency rating duration for thermal constraints or 2 hours plus an additional 1 hour for voltage constraints as identified in footnote 5 of Table II.

D. General Requirements of Operating Guides

An operating guide, when available as a mitigation solution, may include generation redispatch (according to the requirements of the following section) and/or system reconfiguration, assuming that such reconfiguration does not result in load shedding and does not cause additional thermal or voltage violations. In situations where a physical upgrade is planned to mitigate the criteria violation and a temporary operating guide is needed as a bridge, then as a last resort the temporary operating guide may include controlled load shedding.

Approved operating guides will be re-evaluated on a regular basis to confirm the continued ability to meet the performance requirements of Table I through implementation of the operating guide. This includes a requirement that additional thermal or voltage violations not be created through implementation of the operating guide.

E. Generation Redispatch Limitations

The following criteria shall be met to consider a generation redispatch as a viable mitigation alternative.

1. Due to the uncertainty that any existing generating unit will continue to be a viable unit over the planning horizon, a redispatch mitigation alternative must demonstrate that there are sufficient generating units that are available to provide the incremental capacity necessary to maintain loadings and voltages within applicable ratings, without reliance on any single unit. In general, all generators within the Midwest ISO footprint, regardless of firm or non-firm transmission service requests that may be associated with a generator, are candidates for decrementing as their output can be reduced to minimum levels or turned off, including wind plants. If generating units are to be turned off, the reliability impacts of the generation change, including a voltage analysis, would need to be evaluated.

2. When generation redispatch is used as a mitigation alternative to thermal constraints, the participating generators must have a distribution factor of greater than 3% on the thermal constraint. Distribution factor is defined as the sensitivity of the generating unit to the thermal constraint resulting from the contingent event. Lower than 3% distribution factor is indicative of an inefficient redispatch.

3. No more than 10 units shall be used in any redispatch scenario.

4. No more than 1,000 MW shall be used to increment and no more than 1,000 MW shall be used to decrement in any redispatch scenario. Therefore, no more than a total amount of 2,000 MW of generation shift shall be allowed to redispatch around a constraint.

5. Non dispatchable units will be excluded from incrementing generators. Nuclear generating units will also be excluded unless otherwise required by their operating agreements. Feedback from other Midwest ISO market participants may be requested regarding the reasonableness of units considered in the redispatch options.

6. Consideration of external generation in redispatch calculations:
   a. If the identified constraint is a PJM-MISO reciprocal coordinated flowgate (RCF) eligible for market to market redispatch, PJM units may be included in the redispatch.
   b. If the identified constraint is not currently a PJM-MISO reciprocal coordinated flowgate (RCF), the flowgate will be recommended for RCF qualification study. If not eligible, PJM units will not be included in the redispatch.
   c. Generators considered within existing operating guides, procedures and Special Protection Schemes (SPS) will be included as applicable to the overloaded facilities.
   d. No other non-Midwest ISO units along seams will be used in redispatch.

## 6.0 UNCERTAINTY IN SYSTEM PLANNING

System planning must provide a reserve that ensures the reliability of the 100 kV and above system. All system users benefit from the assurance that transmission services will be reliable under a broad range of potential system conditions. System planning is to account for the inherent uncertainty associated with planning, and the need for operating flexibility to ensure reliable system operation as system conditions change.

System planning depends upon a myriad of assumptions and projections of system conditions, which may include such items as system topology, projected customer demand and its distribution, generation dispatch, location of future generators, future weather conditions, availability of facilities, and existing and future electric power transactions. Such parameters are assembled to produce scenarios used in planning the system under a reasonable range of contingencies as specified in Regional, sub regional, power pool, and individual system reliability operating and planning policies, criteria, or guides.

Therefore, system planning must be conducted in a manner that considers the inherent uncertainties in projecting such system parameters over longer time periods. Generally, the uncertainties of system planning increase for the longer term due to greater difficulty in being able to predict the various system assumptions and parameters over longer time periods. For instance, locations of future customer demands and generation sources are often quite uncertain, and these parameters have a potentially large impact on system planning results. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on facility loading. Therefore, system planning must be conducted recognizing that uncertainty is time dependent generally with a larger amount of uncertainty necessary for longer term projections than for near-term conditions. System planning must be updated as necessary as system conditions change.

## 7.0. 100 KV AND ABOVE FACILITY RATING METHODOLOGY

MidAmerican Energy's 100 kV and Above Facility Ratings Methodology shall be used to establish and communicate MidAmerican Energy's facility ratings for the 100 kV and above system.

## 8.0 CONCLUSIONS

This document presents the criteria for planning the MidAmerican Energy 100 kV and above system. The purpose of these criteria is to provide a basis for system simulations and associated assessments needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

The 100 kV and above system must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and anticipated electricity transfer levels. Extreme but less probable contingencies measure the robustness of the system and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed for the reliability of the 100 kV and above system.

The ability of the 100 kV and above system to withstand probable and extreme contingencies must be determined by simulated testing of the MidAmerican Energy 100 kV and above system. System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

System planning must provide a reserve that ensures the reliability of the 100 kV and above system. All system users benefit from the assurance that transmission services will be reliable under a broad range of potential system conditions. System planning is to account for the inherent uncertainty associated with planning, and the need for operating flexibility to ensure reliable system operation as system conditions change.

8.0 REFERENCES (USE LATEST REVISION)

[1] NERC Standards TPL-001-0 through TPL-004-0
[2] MidAmerican Energy 100 kV and Above Facility Ratings Methodology
[3] MRO Standards TPL-503-MRO-01.

## APPENDIX

## Table I. 100 kV and Above System Standards – Normal and Emergency Conditions

| 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<br>No Contingencies | All Facilities in Service | Yes | No | No |
| B<br>Event resulting in the loss of a single element. | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault. | <br>Yes<br>Yes<br>Yes<br>Yes | <br>No[b]<br>No[b]<br>No[b]<br>No[b] | <br>No<br>No<br>No<br>No |
| | Single Pole Block, Normal Clearing[e]:<br>4. Single Pole (dc) Line | Yes | No[b] | No |
| C<br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing [e]:<br>1. Bus Section<br>2. Breaker (failure or internal fault) | <br>Yes<br>Yes | <br>Planned/Controlled[c]<br>Planned/Controlled[c] | <br>No<br>No |
| | SLG or 3Ø Fault, with Normal Clearing [e,] Manual System Adjustments [MEC a], followed by another SLG or 3Ø Fault, with Normal Clearing [e]:<br>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]:<br>4. Bipolar (dc) Line<br>Fault (non 3Ø), with Normal Clearing[f]:<br>5. Any two circuits of a multiple circuit towerline f | <br>Yes<br><br>Yes | <br>Planned/Controlled[c]<br><br>Planned/Controlled[c] | <br>No<br><br>No |
| | SLG Fault, with Delayed Clearing [e]<br>(stuck breaker or protection system failure):<br>6.Generator<br>7.Transmission Circuit<br>8. Transformer<br>9. Bus Section | <br><br>Yes<br>Yes<br>Yes<br>Yes | <br><br>Planned/Controlled[c]<br>Planned/Controlled[c]<br>Planned/Controlled[c]<br>Planned/Controlled[c] | <br><br>No<br>No<br>No<br>No |

| | | |
|---|---|---|
| D [d]<br>Extreme event resulting in two or more (multiple) elements removed or cascading out of service | 3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):<br>1. Generator 3. Transformer<br>2. Transmission Circuit 4. Bus Section<br>3Ø Fault, with Normal Clearing[e]:<br>5. Breaker (failure or internal fault)<br>6. Loss of towerline with three or more circuits<br>7. All transmission lines on a common right-of way<br>8. Loss of a substation (one voltage level plus transformers)<br>9. Loss of a switching station (one voltage level plus transformers)<br>10. Loss of all generating units at a station<br>11. Loss of a large load or major load center<br>12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required<br>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<br>14. Impact of severe power swings or oscillations from disturbances in another Regional Council. | Evaluate for risks and consequences.<br>▪ May involve substantial loss of customer demand and generation in a widespread area or areas.<br>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.<br>▪ Evaluation of these events may require joint studies with neighboring systems. |

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 Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

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 security 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.

MEC a) Applicable time period for Manual System Adjustments between the first Category B contingency and second Category B contingency is assumed to be 2 hours.

## Table II. 100 kV and Above Steady-State Bus Voltage Levels

| Bus Type | Nominal kV | Minimum Voltage, p.u.[1] | | | Maximum Voltage, p.u.[2] |
|---|---|---|---|---|---|
| | | Normal[3] | After 1st Contingency[4] | After 2nd Contingency[5] | |
| Transmission Substations | 161.0 | 0.95 | 0.93 | 0.90 | 1.05 |
| | 345.0 | 0.96 | 0.94 | 0.90 | 1.05 |
| | | | | | |
| Generation Substations[6] | 161.0 or 345.0 | 1.00 | 0.95 | 0.95 | 1.05 |

Notes:

1. Minimum Voltage values are based on the following assumptions: No peaking or intermediate generation will be assumed on line to support voltage prior to the occurrence of contingencies (outages) except for certain must-run generators required to maintain facility loadings within facility ratings.

2. Maximum Voltage. The maximum limit is 1.05 p.u,. Temporary excursions temporary beyond the maximum voltage criteria may be caused by abnormal system conditions; however, these shall be limited in extent, frequency, and duration.

3. Normal switching, no outages.

4. Minimum Voltage Following 1st Contingency. Voltage must be restorable to minimum normal level after system adjustments that follow a Category B or Category C.1, C.2 or C.5 contingency within 1 hour of the contingency. System adjustments include adjustment of transformer load tap changers, switching of capacitor banks and/or reactors, and opening of lines or transformers that do not result in the loss of demand.

5. Minimum Voltage Following 2nd Contingency. Voltage must be restorable to 1st contingency minimum level after system adjustments that follow the 2nd Category B contingency within 1 hour following the second contingency, plus an additional 2 hours to reflect system adjustments that may occur between the first and second Category B contingencies. System adjustments include those items listed in note 4 plus startup of generation (usually peaking), redispatch of generation, and curtailment of firm (non-recallable) power transfers.

6. Generation Voltages. Values specified in the table refer to the voltage requirements at the point of interconnection to the 100 kV and above system.

## Table III. Disturbance-Performance Requirements[1]

| NERC Categories | Transient Voltage Deviation Limits | Rotor Angle Oscillation Damping Ratio Limits |
|---|---|---|
| A | Nothing in addition to NERC Requirements | |
| B (See Notes 2 and 6) | Minimum 0.70 p.u. at any bus. (See Note 5) | Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7) |
| C (See Notes 2, 3, and 6) | Minimum 0.70 p.u. at any bus. (See Note 5) | Not to be less than 0.0081633 for disturbances with faults or less than 0.0167660 for line trips. (See Note 7) |
| D (See Notes 2, 3, and 4) | Nothing in addition to NERC | |

Notes:

1. The MRO System Performance Table including the notes applies to the initial transient period following the contingency (up to 20 seconds) and the post-disturbance period (20 seconds to the end of the allowed readjustment period as described in MRO Regional Reliability Standard TPL-503-MRO-01_R1.4).

2. The following summarizes the automatic and manual readjustments that are permissible for all NERC Category B disturbances.

   A. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units.
   B. Capacitor and reactor switching - The number of capacitors and reactors which may be switched is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period.

   C. Adjustment of Load Tap Changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the allowed readjustment period.

   D. Adjustment of phase shifters to the extent possible within the allowed readjustment period.

E. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period.

F. Generation rejection to the extent possible within the allowed readjustment period. Shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.

G. Transmission reconfiguration - Automatic and operator initiated tripping of transmission lines or transformers to the extent possible within the allowed readjustment period.

H. Automatic or manual tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Point-to-Point Transmission Service to the extent possible within the allowed readjustment period. Curtailment of Firm Transmission Service within the readjustment period is permitted only to prepare for the next contingency.

3. The following additional readjustment may be considered for all NERC Category C contingencies.

   A. Automatic or manual tripping of firm Network or Native Load or curtailment of or predetermined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.

4. The following additional readjustments may be considered for all NERC Category D contingencies.

   A. Planned and/or controlled islanding - Automatic underfrequency load shedding, as specified in NERC PRC-006-0, is permitted to arrest declining frequency and generation rejection is permitted to arrest increasing frequency in order to assure continued operation within the resulting islands.

   B. Automatic undervoltage load shedding is permissible to arrest declining voltages and prevent widespread voltage collapse.

5. The voltage of 0.7 per unit is the point at which load dropping begins to occur due to motor contactors dropping out and induction motors stalling and also the point where sensitive (power electronics) begin to drop out.

6. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category B disturbances, unless documentation is provided showing the actual relays will not trip for the event. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC Category C disturbances, unless documentation is provided that demonstrates that a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

7. Damping is required during the initial transient period following the disturbance (up to 20 seconds). The machine rotor angle damping ratio is determined by appropriate modal analysis (for example. Prony analysis). Alternatively, the Rotor Angle Oscillation Damping Factor or Successive Positive Peak Ratio (SPPR) can be calculated directly from the rotor angle, where the rotor angle response allows such direct calculation. For a disturbance with a fault, the SPPR must be less than 0.95 or the damping factor must be greater than 5%. For a disturbance without a fault, the SPPR must be less than 0.90 or the damping factor must be greater than 10%. (The SPPR criteria were chosen to define positive rotor angle damping for

study purposes in MAPP. The Rotor Angle Oscillation Damping Ratio Limits were derived from the SPPR criteria.)

## Attachments to MidAmerican Energy Company Reliability Planning Criteria

1) TPL-503-MRO-01 (7 Pages)