MidAmerican ENERGY

Des Moines, Iowa

MidAmerican Energy Company

Reliability Planning Criteria for 69 kV

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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's) 69 kV system.

2.0 GENERAL

Reliability assessments of the MidAmerican 69 kV system (which includes transformers with a 69 kV secondary winding) 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 69 kV system of interconnections of new generation, transmission, or loads[1]. In the reliability assessments, 69 kV contingencies are analyzed for reliability criteria violations including overloads, low voltage, high voltage, transient instability, voltage instability and cascading outages. In addition, circuit breaker interrupting capability, delivery point reliability, voltage flicker, and harmonics are analyzed. These 69 kV criteria provide a description of acceptable 69 kV performance or the allowable 69 kV limits that must be met for events that occur on the 69 kV system.

This MidAmerican 69 kV planning criteria augments the MidAmerican Energy Company Reliability Planning Criteria for 100 kV and above. This means that, for 100 kV and above outage events, the 69 kV system performance must be acceptable such that the 69 kV limits as provided in this 69 kV criteria are met on the 69 kV system. For example, when a 161 kV line outage causes overloads and/or voltage violations on the 69 kV system a Corrective Action Plan must be developed that mitigates these overloads or voltage violations on MidAmerican's 69 kV system.

3.0 PURPOSE

The purpose of these 69 kV reliability planning criteria, henceforth 'Criteria', is to provide a basis for the development and operation of MidAmerican's 69 kV system (including transformers with a 69 kV secondary winding) 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 appropriate industry reliability standards and the 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 changes in the appropriate industry reliability standards and the applicable

[1] Reliability assessments of the MidAmerican 69 kV system are performed, as appropriate, for interconnections to the MidAmerican system or the systems of surrounding utilities.

rules and regulations of the FERC and other regulatory bodies having jurisdiction.

4.0 SYSTEM PLANNING PERFORMANCE STANDARDS

A. System Performance Criteria for 69 kV System

The MidAmerican 69 kV system shall be planned, designed, and constructed so that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Service and firm Wholesale Distribution Service at all demand levels over the range of forecast system demands, under the contingency conditions defined in Table I (see Appendix for Table I) without exceeding stability limits, applicable thermal and voltage limits, applicable limits to loss of demand or curtailed firm transfer, and without resulting in cascading outages, uncontrolled separation, or instability. The 69 kV system shall also be planned to include sufficient Reactive Power resources to meet system performance criteria.

The controlled interruption of customer demand, the planned redispatch of generators including switching generators off-line, or the curtailment of Firm (non-recallable reserved) power transfers or other system readjustments may be necessary to meet Category C in Tables I through III (see Appendix for Tables). Such system adjustments and others are subject to the notes provided in Table I through III, Section 5.0 and in other requirements of the MRO Reliability Standards. The system shall be planned, designed, and constructed to prevent subsynchronous resonance issues, harmonic issues, voltage flicker issues, generator shaft torsional issues, and over dutied fault interrupting device conditions. System assessments shall be conducted at least annually to demonstrate that the system meets the latest Criteria and, as necessary, to evaluate impacts of material changes in generation, transmission, or loads on the MidAmerican 69 kV system.

It should be noted that Requirements R1 and R7 of NERC TPL-001-4 Transmission System Planning Performance Requirements became effective January 1, 2015. These requirements deal with respectively, system models and the determination and identification of the Planning Coordinator and Transmission Planner responsibilities for performing required studies for the Planning Assessment. The other requirements in NERC TPL-001-4 will become effective January 1, 2016, at which time, the standard will replace the existing NERC TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a system performance standards.

This document provides MidAmerican 69 kV Planning Criteria which augments the existing four standards for 100 kV and above until such time as the requirements in the new NERC TPL-001-4 become effective, at which time the MidAmerican 69 kV Planning Criteria will augment the requirements in the new standard. In order to provide a transition to NERC TPL-001-4, the tables in these Criteria have been annotated to show how Categories A through C from NERC TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a roughly correlate with the planning events in NERC TPL-001-4.

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 needed to provide voltages to users within the required ranges and shall apply to the MidAmerican 69 kV system. Note the major assumptions and considerations listed below the table.

Reliability assessments of the MidAmerican 69 kV system shall include evaluation of system voltages in a manner designed to:

- typically represent the minimum voltage conditions, for example, evaluation at summer peak load. Cases are to be adjusted to reflect generation resource dispatch that is expected to typically represent the voltage limit being evaluated and with appropriate representation of the MW and MVAR loads including those of generating stations, as appropriate.
- typically represent the maximum voltage conditions, for example, using a spring light load case with wind farms connected to the MidAmerican system operating with no real power output, collector circuit MVAR charging represented, and with the wind farm voltage control, if any, simulated.

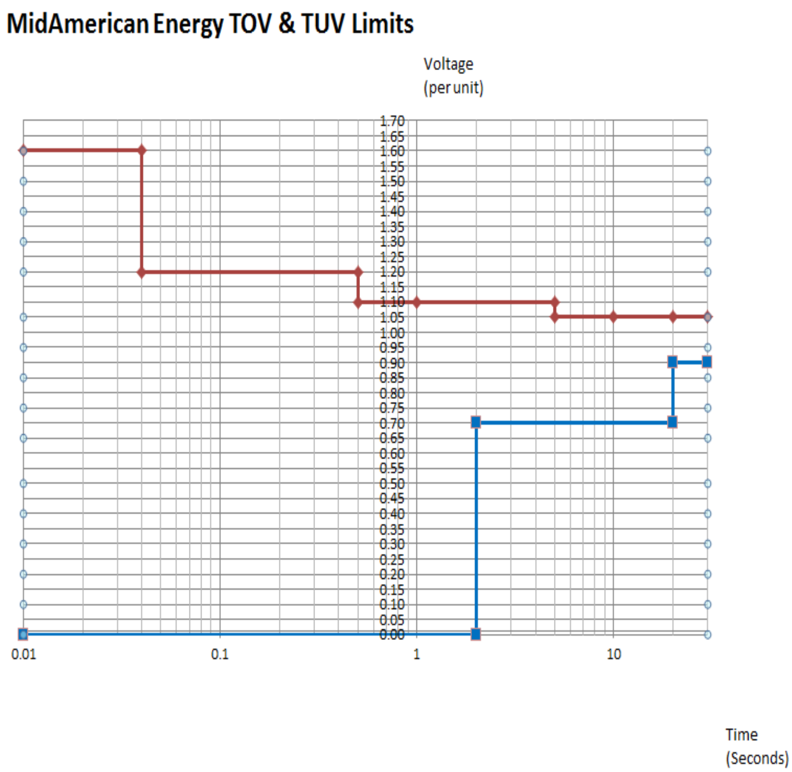
C. Dynamic Voltage Criteria

Generator Bus Transient Voltage Limits shall adhere to the high voltage duration curve and low voltage duration curve in Attachment 2 of NERC PRC-024.

Load Bus (includes buses with neither generators nor loads) Transient Over Voltage Limits (the period after the disturbance has occurred but not including the fault duration), maximum short-term AC voltage: 1.6 per unit voltage from 0.01 to and including 0.04 seconds; 1.2 per unit voltage from 0.04 to and including 0.5 seconds; 1.1 per unit voltage from 0.5 to and including 5 seconds; and 1.05 per unit voltage for greater than 5 seconds.

Load Bus Transient Low Voltage Recovery Limits are as follows: may be less than 0.7 per unit voltage from 0 to 2 seconds after fault clearing. Voltage shall remain above 0.7 per unit from 2 to 20 seconds after fault clearing. Voltage shall recover to 0.9 per unit 20 seconds after fault clearing.

The Load Bus Transient Over Voltage and Load Bus Transient Low Voltage Recovery Limits are illustrated in the graph below:



D.   Voltage stability

The MidAmerican 69 kV system shall be planned, designed and constructed to provide sufficient reactive capacity and voltage control facilities at all demand levels and projected firm transfers to satisfy the reactive requirements and to ensure performance defined in 69 kV Categories A, B, and C as provided for in Tables I, II 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 69 kV 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 maximum power transfer or system demand which does not result in a post-contingency voltage violation.

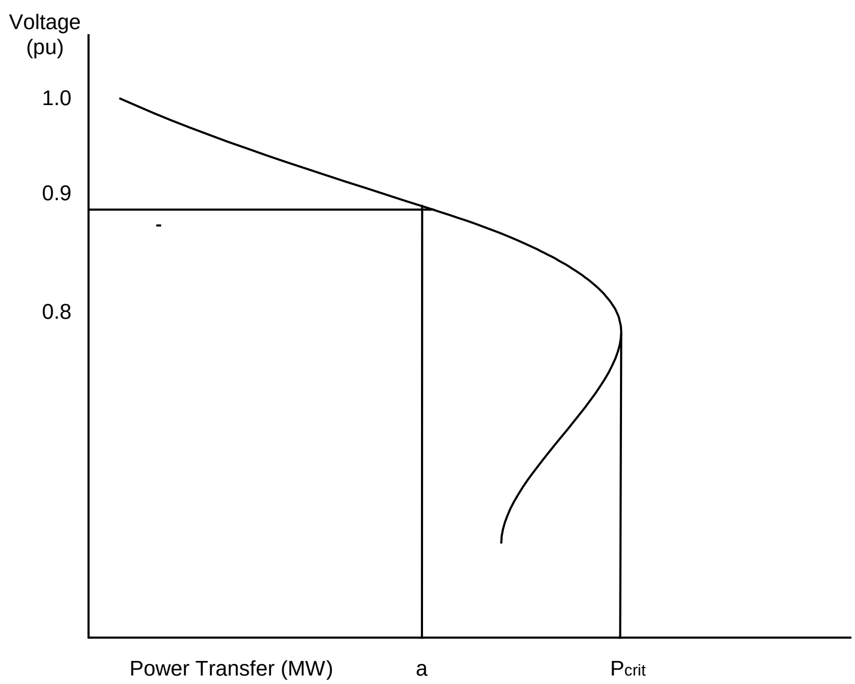


Fig. 1 P-V Curve

5.0 MITIGATION ALTERNATIVES TO MEET RELIABILITY CRITERIA

When system simulations indicate an inability of the 69 kV system to meet the performance requirements of Tables I through III, the deficiencies must be resolved by a mitigation plan. Below is a summary of the available mitigation alternatives for each 69 kV contingency category of Tables I through III. It should be noted that operating guides may be written for any type of system readjustment included in Tables I through III. This section is intended to add additional explanation of Tables I through III and explain how they are implemented. This section is intended to be consistent with or more stringent than Tables I through III.

A. 69 kV Category A criteria violations

Facility loadings exceeding facility normal ratings as provided in Reference D or bus voltages lower than the "Normal Minimum Voltage" and higher than the "Maximum Voltage" as defined in Table II under 69 kV Category A conditions require physical upgrades to meet system performance requirements.

B. 69 kV Category B criteria violations

69 kV Category B contingencies at peak, shoulder, off-peak, and high load conditions resulting in facility loading above emergency ratings, or causing bus voltages below "After 1st Contingency Minimum" 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. Manual readjustment during and after the contingency cannot be used to resolve these Category B criteria violations.

69 kV Category B contingencies at peak, shoulder, off-peak, and light load conditions resulting in facility loading between normal and emergency ratings or causing bus voltages between "Normal Minimum" and "After 1st Contingency Minimum" voltage levels as defined in Table II may rely on manual adjustment in an operating guide, subject to the requirements in Section 5.0 D, to return the facility loading to the facility normal rating and bus voltages to between "Normal Minimum Voltage" and the "Maximum Voltage". This is provided the readjustments do not result in load shedding, do not cause additional thermal or voltage violations, and meet the requirements of Section 5.0 D. and E. If manual readjustment is not capable of implementation within the applicable facility emergency rating duration or the applicable voltage readjustment period (one hour as identified in footnote 4 of Table II), then a physical upgrade is required.

C. 69 kV Category C3 in Tables I and II criteria violations

An operating guide with manual readjustment may be used after the first contingency of Category C3 (N-1-1) event to prevent reliability criteria violations following the second contingency of an N-1-1 event. The operating guide used between the first and second contingency must keep facility loadings after the second contingency of an N-1-1 event below their emergency ratings and bus voltages after the second contingency of an N-1-1 event between “After Second Contingency Voltage” and “Maximum Voltage” as defined in Table II.

An operating guide with manual readjustment may also be used after the second contingency of Category C3 contingencies, if the second contingency of the event results in:

- facility loadings between normal and emergency ratings
- bus voltages between “Normal Minimum Voltage” and the “After Second Contingency Voltage” as defined in Table II, or
- bus voltages between the “Normal Minimum Voltage” and the “Maximum Voltage” as defined in Table II.

However, any such operating guide is subject to the requirements in Section 5.0 D. and E., and must return facility loadings to the facility normal ratings and bus voltages between the “After 1st Contingency Minimum Voltage” and the “Maximum Voltage”. Such operating guides must be able to return facility loadings and bus voltages to acceptable levels within the applicable facility emergency rating duration or the applicable voltage readjustment period as identified in footnote 4 of Table II.

- System Operating Limitation

  If analysis shows after the second contingency of a 69 kV Category C3 event, facility loadings are between 100% and 125% of their emergency ratings, then the allowable readjustment period between the first and second contingency is no more than 2 hours.

  After the second contingency of the 69 kV Category C3 contingency event, the allowable system readjustment period is no more than the applicable emergency rating duration for thermal constraints, and up to 1 hour for voltage constraints.

- Significant Overload Limitation

  If analysis shows that after the second contingency of a 69 kV Category C3 contingency event, facility loadings exceed 125% of their emergency ratings, then the allowable readjustment period between the first and second contingency is no more than 60 minutes.

  After the second contingency of the 69 kV Category C3 contingency event, the allowable system readjustment period is no more than the applicable emergency rating duration for thermal constraints, and up to 1 hour for voltage constraints.

- Maximum Loading Limitation

  Manual system readjustments cannot be used after the first contingency of an N-1-1 event (C3) to prepare for the second contingency, if analysis shows that after the second contingency, without manual system readjustments:

  - o either facility loadings are at 125% or more of the emergency thermal rating, or
  - o system voltages are at 0.80 per unit or below.

A physical upgrade is required for a 69 kV Category C3 event if an operating guide cannot be used in accordance with the appropriate provision or provisions of 5.0 B, 5.0 C, or 5.0 D.

D. Maintenance Outages

Maintenance outages are to be studied for a 70% system load and 40% wind case for a complete set of 69 kV Category B (B1, B2, B3, and B4) in combination with 69 kV B1, B2, B3 and B4 events, but provide for a 10 years transition period for requiring system upgrades.

At 70% system load and 40% wind conditions, a maintenance outage of 69 kV Category B (B1, B2, B3, or B4) followed by system readjustment followed by a 69 kV Category B (B1, B2, B3, or B4) resulting in facility loadings above emergency ratings, bus voltages below the "After First Contingency Minimum Voltage" as defined in Table II or bus voltages above the "After First Contingency Maximum Voltage" as defined in Table II, a physical upgrade will be required. Manual readjustment after the outage combination is not an acceptable mitigating solution.

At 70% system load and 40% wind conditions, a maintenance outage of 69 kV Category B (B1, B2, B3, or B4) followed by system readjustment followed by a 69 kV Category B (B1, B2, B3, or B4) resulting in facility loadings between the normal rating and the emergency rating and bus voltages between the "Normal Minimum Voltage" and the "Maximum Voltage" as defined in Table II may rely on manual adjustment in an operating guide, subject to the requirements in Section 5.0 E. and F. If manual readjustment cannot be implemented within the applicable facility emergency rating duration or the applicable voltage readjustment period as identified in footnote 4 of Table II, a physical upgrade is required.

E. General Requirements of Operating Guides

An operating guide, when available as a mitigation solution, may include generation redispatch (limited according to the requirements of Section 5.0 E) and/or system reconfiguration. Such reconfiguration must not result in load shedding and must not cause additional thermal or voltage violations.

These readjustments may be implemented after a 69 kV Category B, the first contingency of a 69 kV Category C3 or the second contingency of a 69 kV Category C3. It should be noted that all 69 kV Category C3 contingencies include at least one generator contingency.

A temporary operating guide may be used to bridge a gap before the physical upgrade is completed to mitigate the criteria violation. The following measures are allowed in a temporary operating guide:

- a temporary short-time duration emergency limit provided the limit is consistent with the time required to complete the necessary operating steps to return to normal system limits,
- a temporary operating configuration (i.e. operating a ring-bus breaker as normally open) assuming that the temporary operating configuration can be reasonably accommodated and does not cause load shedding, violation of thermal ratings or bus voltages, or significant operational issues, or
- as a last resort, controlled load shedding after the contingency.[2] Last resort means that no temporary measure other than non-consequential load dropping can be taken to mitigate violations until a more permanent Corrective Action Plan can be adopted. For example, if facilities are being considered for retirement that cause the violations then such retirement must be delayed until a Corrective Action Plan such as an operating guide that does not require non-consequential load dropping is adopted or a system improvement is completed and put in-service.

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.

F. Limitations on Redispatch of Midcontinent ISO (MISO) Market Generation

In many cases, MISO Market Generation is not efficient in resolving 69 kV issues. MISO evaluates the potential of MISO Market Generation to resolve 69 kV issues on a case by case basis. MISO's criteria with regard to the limitations of MISO Market Generation to relieve particular 69 kV constraints shall be represented in 69 kV system assessments.

[2] It should be noted that note b of TPL Standard TPL-002-ob, Table 1 provides specific limitations to non-consequential load dropping for certain outage events. See Table1 in the Appendix.

G. Supplemental Protection Schemes (SUPPS)

A SUPPS is an automatic control scheme designed to alleviate overloads on monitored facilities below 100 kV for N-1-1 contingencies. Each SUPPS monitors a 69 kV facility, such as a 161-69 kV transformer or a 69 kV line. When loading on the monitored facility exceeds specified levels, the SUPPS reduces local generation to alleviate overloading of the monitored facility. Typically, SUPPS generation re-dispatch controls are implemented in the two following stages:

- Stage 1: Curtail generator output to pre-determined level if loading on the monitored element approaches or exceeds its normal rating
- Stage 2: Trip a pre-determined amount of generation if loading on the monitored element approaches or exceeds its emergency rating

For reliability reasons, Remedial Action Schemes at 100 kV and above are limited to certain situations as described in the MidAmerican Energy Company Reliability Planning Criteria for 100 kV and above. In a similar way, for reliability reasons, MidAmerican limits the application to SUPPS to certain situations as described in the following:

- SUPPS may only be used as a mitigation for issues on facilities below 100 kV for N-1-1 contingencies.
- SUPPS may only monitor conditions on facilities below 100 kV.
- SUPPS may only be used if, in MidAmerican's sole judgment, improvements to resolve the identified violations are not practical.

In order to minimize the risk of the SUPPS failing to operate (when required to maintain system reliability), all SUPPS installed subsequent to the effective date of this Criteria must be designed using design redundancy similar to what NERC and the MRO require of an RAS or a SPS. This means the SUPPS must be designed such that a single component failure will not prevent the SUPPS from operating when required to maintain system reliability. This means that the SUPPS should be designed considering redundant logic devices, redundant control outputs, redundant communication channels, and separate Voltage Transformer secondaries in order to meet the single component failure requirement.

6.0. SHORT CIRCUIT CRITERIA

When the short circuit analysis portion of the 69 kV reliability assessment is conducted, the analysis shall be used to determine whether circuit breakers have interrupting capability for faults that they will be expected to interrupt using the 69 kV system short circuit model with any planned generation and transmission facilities in service which could impact the study area.

Short circuit currents are evaluated in accordance with industry standards as specified in American National Standards report ANSI C37.5 for older breakers rated on the total current (asymmetrical) basis and American Standards Association report C37.010 for newer breakers rated on a symmetrical current basis.

In general, fault currents must be within specified momentary and/or interrupting ratings for studies made with all facilities in service, and with generators and synchronous motors represented by their appropriate (usually sub-transient saturated) reactances.

7.0. RELIABILITY CRITERIA FOR DELIVERY POINTS TO LOAD

The 69 kV system operated in a radial configuration is generally designed to provide cost effective service to customers without the improved reliability that having a loop would provide. Considerations and situations that can determine the need for a system upgrade from a radial configuration to a looped configuration with a normally open or normally closed tie include, but are not limited to:

- Customers willing to fund the conversion to increase reliability
- Significantly increasing load
- Effects of a large-scale outage
- Expected outage exposure, in load amount and hours at risk
- Estimated time to repair an outage
- Prevention of thermal overload or low-voltage situations
- Projected future system performance
- Economics

The benefits of converting a long-distance radial system to a looped system may not justify the expense to the ratepayer. In such situations, state utility commissions may provide advice as to how to proceed, and how (and when) to fund the expansion.

Three times annual net revenue of a new load in Iowa, Illinois, or South Dakota must equal or exceed the cost of new facilities for the addition of the second source to be considered justified.[3]

Three times the expected annual net revenue of an existing load in Iowa, Illinois, or South Dakota must equal or exceed the cost of new facilities for the addition of a second source plus the book value of existing facilities for the addition of the second source to be considered justified. [3]

[3] Consistent with MidAmerican‘s retail tariff and/or the administrative code for that state.

8.0 VOLTAGE FLICKER CRITERIA

Figure 2 provides MidAmerican's allowable fluctuations in supply voltage which is based upon industry guidelines and standards. MidAmerican utilizes the International Electrotechnical Commission (IEC) method in setting allowable voltage flicker levels for the MidAmerican system taking into account all flicker causing sources. The allowable voltage flicker limit for an individual customer is set to 3%. Arc furnaces must demonstrate through rigorous EMTP calculations and the MidAmerican performance requirements that voltage flicker levels will be acceptable to MidAmerican customers. Figure 2, as well as, industry information on arc furnaces will be considered in determining acceptable voltage flicker levels on a case by case basis for arc furnaces.

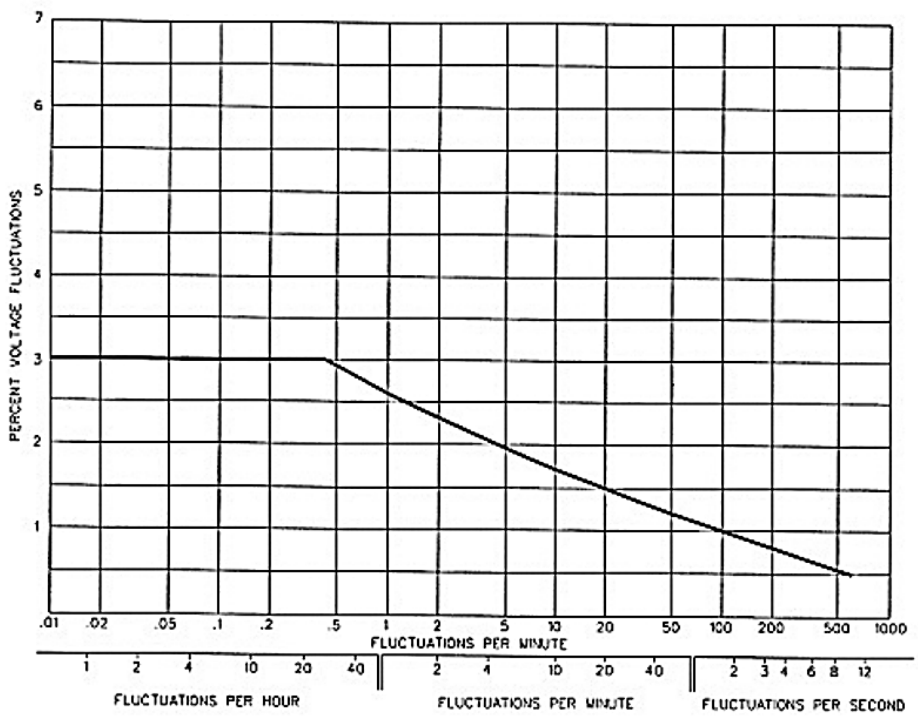


Figure 2 Allowable Voltage Flicker Curve

9.0 HARMONIC DISTORTION LEVEL CRITERIA

MidAmerican's harmonic distortion level criteria as provided in Tables 1 through 3 are intended to provide for allowable harmonic injection from individual customers so as not to degrade the performance of the equipment of other customers, cause abnormal heating in the MidAmerican's facilities, cause metering errors, or cause objectionable interference in communication facilities. Harmonic levels shall be monitored at customer locations where harmonic levels have or may exceed specified limits.

MidAmerican's allowable harmonic limits are those of IEEE 519-1992- IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems. MidAmerican's harmonic distortion limits focus on harmonics at either the point of common coupling (PCC), which is the point between the customer that is the harmonics source and other customers, the point of metering, or the point of interference (POI). The POI is a point that both MidAmerican and the customer can either access for direct measurement of the harmonic indices meaningful to both or estimate the harmonic indices through mutually agreed upon methods. The MidAmerican criteria is designed with the goal of reducing the harmonic effects at any point in the entire system by establishing limits on certain harmonic indices (currents and voltages) at either the PCC, a point of metering or a POI.

Nominal Voltage	**Individual Voltage Distortion (%)**	**Total Voltage Distortion THD (%)**
69 kV and below	3.0	5.0

Table 1 Voltage Distortion Limits[4]

Maximum Harmonic Current Distortion in Percent of I_L Individual Harmonic Order (Odd Harmonics)						
I_{sc}/I_L	**$3 \le h < 11$**	**$11 \le h < 17$**	**$17 \le h < 23$**	**$23 \le h < 35$**	**$35 \le h \le 50$**	**TDD**
<20[5]	4.0	2.0	1.5	0.6	0.3	5.0
$20 \le x < 50$	7.0	3.5	2.5	1.0	0.5	8.0
$50 \le x < 100$	10.0	4.5	4.0	1.5	0.7	12.0
$100 \le x < 1000$	12.0	5.5	5.0	2.0	1.0	15.0
≥ 1000	15.0	7.0	6.0	2.5	1.4	20.0

Table 2 - Current Distortion Limits for Systems 120 V through 69 kV[6,7,8]

[4] Table 1, IEEE 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, page 6.
[5] All power generation equipment is limited to these values regardless of actual I_{sc}/I_L.
[6] Table 2, IEEE 519-2014, page 7
[7] Even harmonics are limited to 25 % of the odd harmonic limits in the tables. Current distortions that result in a direct current offset, e.g. half wave converters, are not allowed.
[8] h = order of harmonic; I_{sc} = maximum short-circuit current at either the PCC, the metering point, or the POI; I_L = maximum demand load current (fundamental frequency component) at either the PCC,

10.0. 69 KV FACILITY RATING METHODOLOGY

MidAmerican's 69 kV Facility Ratings Methodology shall be used to establish and communicate MidAmerican's facility ratings for the 69 kV system.

11.0 DOCUMENT CONFLICTS

If there are conflicts in this document, the more stringent provision takes priority.

12.0 CONCLUSIONS

This document presents the criteria for planning the MidAmerican 69 kV 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.

13.0 REFERENCES (USE LATEST REVISION)

A. American National Standards Institute (ANSI)/ Institute of Electrical and Electronics Engineers (IEEE) C37.010—Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

B. ANSI C37.5—Guide for Calculation of Fault Currents for Application of AC High-Voltage Circuit Breakers Rated on a Total Current Basis

C. ANSI Standard C84.1—Electric Power Systems and Equipment-Voltage Ratings

D. MidAmerican Energy Company 69 kV Facility Ratings Methodology

E. NERC Glossary of Terms

F. Electric Utility Engineering Reference Book, Volume 3, pg. 347, ABB Power Systems Inc., February 1989.

G. IEEE 519 – IEEE Recommended Practices and requirements for Harmonic Control in Electrical Power Systems.

H. International Electrotechnical Commission (IEC), "IEC 1000 Electromagnetic compatibility (EMC) – Part 3: Limits – Section VII: Limitation of voltage fluctuations and flicker for equipment connected

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the metering point or the POI; TDD = the total root-sum-square harmonic current distortion, in percent of the maximum demand load current (15 or 30 min demand) at the PCC, the metering point, or the POI.

to medium and high voltage power supply systems – technical report type II", Project number 1000-3-7

I. IEC, "Disturbances in supply systems caused by household appliances and similar electrical equipment, Part 3: Voltage fluctuations", Publication 555-3

J. NERC TPL-001-0.1 - System Performance Under Normal (No Contingency) Conditions (Category A), effective date of May 13, 2009.

K. NERC TPL-002-0b - System Performance Following Loss of a Single Bulk Electric System Element (Category B), effective date October 24, 2011.

L. NERC TPL-003-0b - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), effective date June 20, 2013.

M. NERC TPL-004-0a - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), effective date June 20, 2013.

N. NERC TPL-001-4 - Transmission System Planning Performance Requirements, effective date for R1 and R7 of January 1, 2015 and effective date for remaining requirements of January 1, 2016.

APPENDIX

Table I. 69 kV System Standards – Normal and Emergency Conditions

69 kV Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s) [Similar TPL-001-4 Planning Event]	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages[e]
A No Contingencies	All Facilities in Service [P0]	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 [d]: 1. Generator [P1.1] 2. Transmission Circuit[P1.2] 3. Transformer[P1.3] 4. Shunt Device [P1.4] Loss of an Element without a Fault. [P2.1]	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG or 3Ø Fault, with Normal Clearing [d,] Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [d]: 3. 69 kV Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by a 69 kV Category B1 contingency[P3.1]	Yes	Planned/Controlled [c]	No
	Maintenance Outage with Manual System Adjustments, followed by a SLG or 3Ø Fault, with Normal Clearing at load levels at which maintenance outages are typically taken, such as 70% load and 40% wind conditions [e]: 3a. 69 kV Category B (B1, B2, B3, or B4) maintenance outage, manual system adjustments, followed by 69 kV Category B(B1,B2,B3 or B4) contingency	Yes	No	No
	SLG Fault, with Delayed Clearing [d] (stuck breaker or protection system failure): 6. Generator [P4.1 and P5.1] 7. Transmission Circuit[P4.2 and P5.2] 8. Transformer[P4.3 and P5.3] 9. Shunt Device[P4.4 and P5.4]	Yes Yes Yes	Planned/Controlled [c] Planned/Controlled [c] Planned/Controlled [c]	No No No

Notes

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 industry reliability standards addressing facility ratings.

b) An objective of the planning process is 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. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' 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.

   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 which are allowed only for temporary operating guides in accordance with the requirements of Section 5.0 D.

c) Depending on system design and expected system impacts, the planned removal from service of certain generators may be necessary to maintain the overall security of the interconnected transmission systems and are limited by the requirements of Section 5.0 D and Section 5.0 E.

Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding) 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 and are allowed only for temporary operating guides in accordance with the requirements of Section 5.0 D.

d) 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.

e) Cascading in steady state analysis is based, in part, upon the MISO default and is as follows:

- Four or more elements trip due to excessive loading, power swings, or abnormal system voltages in planning simulations where tripping is not due to primary or backup protection to clear faults or due to the expected operation of a Special Protection System (SPS).
- One or more elements trip due to excessive loading, power swings, or abnormal system voltages where tripping is not due to primary or backup protection to clear faults or due to the expected operation of an SPS and load loss due to tripping of these elements exceeds 1,000 MW. This load loss does not include consequential load loss due to elements that trip to clear the fault, either as primary or backup protection, load lost due to expected operation of an SPS or firm load shed performed in accordance with the NERC TPL Standards.
- Elements are defined as transmission lines, transformers, and generators. A group consisting of all elements within a protective zone is considered a single element. For example, a three-terminal line is a single element. By itself, a shunt device is not an element.
- Tripping is assumed to occur at load levels of 125% or higher of the highest emergency rating.

Table II. 69 kV Steady-State Bus Voltage Levels

Bus Type	Minimum Voltage, p.u.[1]			Maximum Voltage, p.u.[2]
	Normal[3]	After First Contingency[4]	After Second Contingency[5]	
Transmission Substations	0.95	0.93	0.90	1.05
Generation Substations[6]	1.00	0.95	0.95	1.05

Notes

1. Minimum Voltage values are based on the assumption that 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. Temporary excursions 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. After the First 69 kV Contingency, voltage must be restorable to the Normal Minimum Voltage level within one hour after the first contingency. System adjustments that may be used to restore voltage include adjustment of transformer load tap changers, switching of capacitor banks and/or reactors, opening of lines or transformers that do not result in the loss of demand, startup of generation (usually peaking) and redispatch of generation. The use of these system adjustments are limited by Section 5.0 D. and/or Section 5.0 E.

5. After the Second 69 kV Contingency, voltage must be restorable to the First Contingency Minimum Voltage within one hour after the second contingency. System adjustments include those items listed in Note 3 plus curtailment of firm (non-recallable) power transfers. The curtailment of firm (non-recallable) power transfers are limited to temporary operating guides in accordance with Section 5.0 D.

6. Generation Voltages in the table refer to the voltage requirements at the point of interconnection of the generator to the 69 kV system. Generation bus voltages must be met at buses where generation is connected, is on-line, and is able to control the bus voltage.

Table III. Disturbance-Performance Requirements

NERC Categories [Similar TPL-001-4 Planning Event]	Transient Voltage Deviation Limits	Rotor Angle Oscillation Damping Ratio Limits	Frequency Deviation Limits
A [P0]	Nothing in addition to NERC Requirements		
B (See Notes 1, 4 and 5) [P1.1 through P1.4 and P2.1]	Minimum 0.70 p.u. and maximum 1.20 p.u. at any bus immediately following the clearing of a disturbance and through the initial transient period of up to 20 seconds.	Not to be less than 0.03. (See Note 6)	Not to be less than 59.5 Hz or greater than 60.5 Hz for more than 20 cycles
C (See Notes 1, 2, 4 and 5) [P3.1, P4.1 through P4.4, and P5.1 through P5.4]	Minimum 0.70 p.u. and maximum 1.20 p.u. at any bus immediately following the clearing of a disturbance and through the initial transient period of up to 20 seconds.	Not to be less than 0.03. (See Note 6)	Not to be less than 59.5 Hz or greater than 60.5 Hz for more than 20 cycles

Notes:

1. 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.

2. 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.

3. 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.

4. A one-cycle safety margin must be added to the actual or planned fault clearing time.

5. 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).