## A. Introduction

**1. Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

**2. Number:** TPL-002-0b

**3. Purpose:** System simulations and associated assessments are 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.

**4. Applicability:**

**4.1.** Planning Authority

**4.2.** Transmission Planner

**5. Effective Date:** Immediately after approval of applicable regulatory authorities.

## B. Requirements

**R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned 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 as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

**R1.1.** Be made annually.

**R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

**R1.3.** 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 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.1.** 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.

**R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.

**R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

**R1.3.5.** Have all projected firm transfers modeled.

**R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

**R1.3.7.** Demonstrate that system performance meets Category B contingencies.

**R1.3.8.** Include existing and planned facilities.

**R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

**R1.3.11.** Include the effects of existing and planned control devices.

**R1.3.12.** 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.

**R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

**R1.5.** Consider all contingencies applicable to Category B.

**R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

**R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

**R2.1.1.** Including a schedule for implementation.

**R2.1.2.** Including a discussion of expected required in-service dates of facilities.

**R2.1.3.** Consider lead times necessary to implement plans.

**R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

**R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

## C. Measures

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

**M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

**Compliance Monitor:** Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

**1.** None identified.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | February 8, 2005 | Adopted by NERC Board of Trustees | New |
| 0 | April 1, 2005 | Effective Date | New |
| 0a | July 30, 2008 | Adopted by NERC Board of Trustees | New |
| 0a | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised |
| 0b | November 5, 2009 | Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009 | Interpretation |
| 0b | September 15, 2011 | FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011) | Interpretation |

## Table I. Transmission 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: | | | |
| | 1. Generator | Yes | No [b] | No |
| | 2. Transmission Circuit | Yes | No [b] | No |
| | 3. Transformer | Yes | No [b] | No |
| | Loss of an Element without a Fault. | Yes | No [b] | 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]: | | | |
| | 1. Bus Section | Yes | Planned/ Controlled[c] | No |
| | 2. Breaker (failure or internal Fault) | Yes | Planned/ Controlled[c] | No |
| | SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, 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]: | | | |
| | 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: | Yes | Planned/ Controlled[c] | No |
| | 5. Any two circuits of a multiple circuit towerline[f] | Yes | Planned/ Controlled[c] | No |
| | SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): | | | |
| | 6. Generator | Yes | Planned/ Controlled[c] | No |
| | 7. Transformer | Yes | Planned/ Controlled[c] | No |
| | 8. Transmission Circuit | Yes | Planned/ Controlled[c] | No |
| | 9. Bus Section | Yes | Planned/ Controlled[c] | No |

| | | |
|---|---|---|
| **D** [d]<br><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<br>2. Transmission Circuit<br>3. Transformer<br>4. Bus Section<br>- - - - - - - - - -<br>3Ø Fault, with Normal Clearing[e]:<br>5. Breaker (failure or internal Fault)<br>- - - - - - - - - -<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 Reliability Organization. | 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 Reliability 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 reliability 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 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.

# Appendix 1

## Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** 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 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** 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.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** 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 C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** 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.

## Requirement R1.3.2

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

## Requirement R1.3.12

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

*MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

## Appendix 2

| Requirement Number and Text of Requirement |
|---|
| **R1.3.** 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 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).<br>**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems. |
| **Background Information for Interpretation** |
| Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:<br>1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."<br>2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."<br>3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."<br>*Category B of Table 1 (single Contingencies) specifies:*<br>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>Single Pole Block, Normal Clearing[e]:<br>4. Single Pole (dc) Line<br>*Note e specifies*:<br>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.<br>The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems." |
| **Conclusion** |
| TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.<br>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk |

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

**In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:**

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan.  Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

## A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are 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.

4. **Applicability:**

   **4.1.** Planning Authority

   **4.2.** Transmission Planner

5. **Effective Date:** April 23, 2010

## B. Requirements

**R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned 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 as defined in Category C of Table I (attached). 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. To be valid, the Planning Authority and Transmission Planner assessments shall:

**R1.1.** Be made annually.

**R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

**R1.3.** 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 C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.1.** 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.

**R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.

**R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

**R1.3.5.** Have all projected firm transfers modeled.

**R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.

**R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.

**R1.3.8.** Include existing and planned facilities.

**R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

**R1.3.11.** Include the effects of existing and planned control devices.

**R1.3.12.** 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.

**R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.

**R1.5.** Consider all contingencies applicable to Category C.

**R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

**R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

**R2.1.1.** Including a schedule for implementation.

**R2.1.2.** Including a discussion of expected required in-service dates of facilities.

**R2.1.3.** Consider lead times necessary to implement plans.

**R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

**R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

## C. Measures

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

**M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

**1.2. Compliance Monitoring Period and Reset Timeframe**

Annually.

**1.3. Data Retention**

None specified.

**1.4. Additional Compliance Information**

None.

**2. Levels of Non-Compliance**

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

**1.** None identified.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | February 8, 2005 | Adopted by NERC Board of Trustees | New |
| 0 | April 1, 2005 | Effective Date | New |
| 0 | April 1, 2005 | Add parenthesis to item “e” on page 8. | Errata |
| 0a | July 30, 2008 | Adopted by NERC Board of Trustees | |
| 0a | October 23, 2008 | Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO | Revised |
| 0a | April 23, 2010 | FERC approval of interpretation of TPL-003-0 R1.3.12 | Interpretation |

Table I. Transmission 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 [c] 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. | Yes<br>Yes<br>Yes<br>Yes | No [b]<br>No [b]<br>No [b]<br>No [b] | 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) | Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No |
| | SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, 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 Fault (non 3Ø), with Normal Clearing[e]:<br>5. Any two circuits of a multiple circuit towerline[f] | Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No |
| | SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section | Yes<br>Yes<br>Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c]<br>Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No<br>No<br>No |

| | | |
|---|---|---|
| **D** [d]<br><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><br>3Ø Fault, with Normal Clearing[e]:<br>5. Breaker (failure or internal Fault)<br><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 Reliability Organization. | 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 Reliability 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 reliability 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 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.

## Appendix 1

### Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

**TPL-002-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** 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 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** 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.

**TPL-003-0:**

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

**R1.3** 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 C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.12** 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.

### Requirement R1.3.2

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

*Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

## Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

*MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.*

*MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:**

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

## Requirement R1.3.12

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

*Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*

### Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

*MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?*

*If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?*

*The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

*If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?*

**The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:**

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

# AMEREN‟s
# (On Behalf of Its Transmission Owning Affiliates, Including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois)
## TRANSMISSION PLANNING
### CRITERIA AND GUIDELINES

March 28, 2003
Revised April 29, 2003
Revised March 29, 2004
Revised March 29, 2005
Revised March 29, 2006
Revised March 27, 2007
Revised March 31, 2008
Revised March 25, 2009
Revised March 31, 2010
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## TABLE OF CONTENTS

# 1.0 INTRODUCTION

At Ameren, the Transmission Planning Department is responsible for planning the orderly and economic development of the Ameren bulk power supply system facilities 100 kV and above, and for performing operational planning to assess reliability under near-term conditions on behalf of its transmission owning affiliates, including Ameren Missouri, Ameren Illinois, and Ameren Transmission Company of Illinois. Such activities include the analysis and evaluation of the Ameren transmission system as it is affected by local and regional generation and transmission system expansion plans and the impact of regional capacity and energy market activity through short-term and long-range transmission planning studies. The transmission system analysis is carried out through active participation in NERC, RRO, and RTO committee work, as well as internal Ameren transmission planning studies. The objective of the Transmission Planning Department is to plan for adequate electrical capacity and system voltages to serve Ameren customer load with acceptable reliability, commensurate with cost.

Ameren transmission planning is based on compliance with NERC reliability standards and SERC regional criteria, this Criteria and Guidelines document, applicable state regulations, and public policy requirements.

The criteria, guidelines, and performance standards compiled in this document are used by Transmission Planning Department engineers as an aid to planning and can be used by others to assess the capabilities of the Ameren transmission system when performing their own planning or screening studies and to better understand the process of determining transmission capability.

There is a definite distinction between criteria and guidelines as used in this document. A criterion is a rule or standard applied in planning work that has had specific management approval or recognition because of its importance to the system or its applicability to NERC reliability standards compliance. Any possible deviation from planning criteria would be specifically noted and called to the attention of management. A guideline is usually of lesser importance and more subject to judgmental influence in specific cases. A guideline may reflect generally accepted practice, normal procedure, or a general philosophy to be applied depending on the particular circumstances and costs in a specific case.

A glossary of planning terms used in this document is included in Section 5.0.

## 1.1 Purpose

This document combines the criteria and guidelines which have been established and used by Ameren‟s Transmission & Interconnections Group (formerly Union Electric‟s Transmission Planning Department, Central Illinois Public Service‟s Planning Department, Central Illinois Light Company‟s Transmission Planning Department, and Illinois Power Company‟s Planning Department) over the years to evaluate transmission system performance. This effort has been undertaken for the following reasons:

1. To provide a readily available reference covering Ameren planning practices for management, regulatory bodies, or other parties having a legitimate interest (e.g: compliance with NERC reliability standards);

2. To afford a convenient, well-documented guide for Ameren engineers involved in planning work and studies;

3. To form a convenient basis for review and updating of Ameren"s Transmission Planning criteria and guidelines by gathering all such material together, and

4. To meet the specific instructions of FERC Form No. 715 and to aid in the assessment of Ameren transmission capability needed to meet potential transmission connection and delivery requests as well as its own native load requirements.

## 1.2 General Use

It must be recognized that the transmission planning criteria contained in this document are unconditional, for they are the principles by which a reliable Ameren transmission system is planned. Each need, problem, or circumstance requiring a planning study, is different, and should be considered under the particular conditions existing at that time using transmission planning criteria and guidelines as the basis for evaluation.

Though a project may be identified as a result of this document"s application, project timing may be dependent on several factors including the company"s ability to raise capital, regulatory restrictions, management directives, contractual relations with others, and/or socio-environmental considerations. Also, changes to project timing or modifications to a project"s minimum requirements as concluded from a planning study may occur based on engineering judgment in conjunction with good utility practice.

These criteria and guidelines have evolved over a number of years, and reflect considerable planning and operating experience for the Ameren transmission system. Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analysis. Sensitivity analyses, reliability margins, and adequacy assessments are used in conjunction with the criteria and guidelines to plan a robust transmission system. The criteria and guidelines included herein remain fluid and are revised as needed.

## 1.3 Recognition of Differences in Actual System

While the following criteria and guidelines provide a framework for planning the Ameren transmission system, it must be recognized that the system that exists at any point in time will likely be different from planned conditions because of:

1. Failure to complete the construction of generation or transmission facilities on time.
2. Involvement of other utilities and variations in their systems from those modeled.
3. Egregious transmission loading conditions caused by natural catastrophes, adverse regulatory or legal actions, fuel availability, multiple generation or transmission outages, or excessive market activity.
4. Capital restrictions, which may limit construction.
5. Variations in system operating conditions from those assumed in planning models including generation dispatch, regional load diversity, facility outage status, and regional market activity.

## 2.0 RELIABILITY CRITERIA AND GUIDELINES

The measure of successful transmission system planning is the attainment of a system that provides dependable service at a reasonable cost over a long period of years, and in the process of its growth and development, acquires no significant weakness that stands in the way of substantially greater growth or utilization. Each individual piece of system equipment must be selected so as to meet probable future demands; even more important, the basic system pattern must be such that it can grow without causing the obsolescence or the major rebuilding of facilities already installed.

### 2.1 NERC Reliability Standards and SERC Regional Criteria

Ameren intends to comply with all NERC Reliability Standards. Ameren‟s transmission planning criteria and guidelines, at a minimum, are intended to provide full compliance with the NERC Planning Standards, as they pertain to transmission system planning.

SERC regional criteria are detailed regional criteria and guidelines describing the process to be used at the regional level to be compliant with the NERC Reliability Standards.

### 2.2 General Transmission Planning Criteria and NERC Reliability Standards TPL-001 through TPL-004, version 0

#### 2.2.1 General Transmission Planning Criteria

Listed below are long-standing general planning criteria that Ameren has used over the years to plan the transmission system. These planning criteria were developed and used by many companies in the utility industry following the formation of NERC in the late-1960s, long before the establishment of mandatory NERC Reliability Standards. These criteria have been more or less accepted by the industry and have developed into the NERC TPL-001 through TPL-004 Reliability Standards in their present Version 0 form. A reference to the NERC Reliability Standard is included following each criterion. Items 6, 6.1, and 6.2 below represent a recent clarification to these criteria in regards to the concurrent outage of two transmission elements.

---------------------------------------Description---------------------------------

1. With all facilities in service, the Ameren system shall operate (perform) with all equipment loaded at or below normal ratings and with voltages within acceptable limits. (NERC Standard TPL-001)
2. For the outage of any one transmission circuit, transmission element or generator, the Ameren system shall operate with all equipment loaded at

or below emergency ratings and with voltages within acceptable limits. (NERC Standard TPL-002)

3. To account for variations in regional dispatch and/or extended generation outages, the system shall operate with all equipment loaded at or below emergency ratings and with voltages within acceptable limits for the coincident outage of any one transmission circuit (line or transformer) coincident and any generator or intermittent or peaking plant. The displaced generation may be replaced with generation inside of the Ameren system or through regional dispatch. Note that mitigating such facility overloads through generator re-dispatch or through long-term use of special protection systems would not be considered acceptable. (NERC Standard TPL-002)
4. The system shall be able to withstand the loss of all transmission lines on a single right-of-way. The word "withstand" as used here means that the system would not collapse, even though there might be local low voltage conditions and possible transmission line or transformer overloads in some areas. Some redispatch or local load shedding might be required to mitigate loading or voltage issues. (NERC Standard TPL-004)
5. The system shall be able to survive the loss of an entire power plant and switchyard or an entire substation or switching station. Survive in this case indicates that the disturbance would remain local, and that the system would neither collapse nor separate into islands. Some local load and/or generation would probably be lost for these conditions. (NERC Standard TPL-004)

6 System conditions covered in NERC Reliability Standard TPL-003 include the concurrent outage of any two transmission elements (transmission line, transformer, etc.), an outage to a bus section, or failure of a breaker. The Standard requires all remaining system elements to be within applicable thermal and voltage limits but allows operator initiated system adjustments where applicable and also allows loss of demand (load shedding). The Standard also states that the event should not cause cascading outages. Ameren has parsed the allowance of "loss of demand" in the Standard into two categories. In the first category, load is shed via automatic or operator-initiated actions following the loss of two transmission elements in order to keep the loading of system elements within established ratings and system voltages within established limits. Loadings should be within short-term ratings (either explicitly calculated or based on good utility practice) due to conditions associated with the concurrent outage of two transmission elements. Note that, due to issues of safety, short-term emergency ratings are typically not available for sag-limited transmission lines. A capital project would be initiated to address situations where a sag-limited transmission line could be subjected to loading beyond its emergency rating. Load shedding is allowed to reduce equipment loadings below longer-term ratings.

In the second category, supply to a defined pocket of load is lost as the direct consequence of the system topology and/or the natural response of the system. An example of the second category would be a substation which serves distribution load and has only two supplies. The concurrent outage of both supplies will result in the load at that substation being lost/dropped as a consequence of system topology. Another example of the second category would be a substation which has three supplies, but if two supplies are outaged, the substation experiences a local voltage collapse and the load is lost/dropped as a consequence of the natural response of the system because of excessive voltage drop through the remaining substation supply or characteristics of the system load.
For the concurrent outage of any two transmission elements (transmission line, transformer, etc.), an outage to a bus section, or failure of a breaker, and including operator-initiated system adjustments where applicable:

6.1 The controlled shedding of system load as an emergency operational procedure is allowed but with a limit on the magnitude of load exposed. The amount of load exposed to being shed shall be less than 100 MW. This load shedding includes automatic actions or operator-initiated actions expected to be taken to reduce the loading of transmission elements or to return voltages to acceptable levels. *The 100 MW level for load shedding represents the threshold of a NERC reportable event under NERC Standard EOP-004 and also the threshold for the DOE Energy Emergency Incident and Disturbance Reporting Requirement per Form EIA-417.*

6.2 The loss of load for more than 15 minutes due to system topology and/or the natural response of the system is allowed but with a limit on the magnitude of load exposed. The amount of load exposed to being dropped due to system topology and/or the natural response of the system shall be less than 300 MW. *The 300 MW level for loss of load for more than 15 minutes due to equipment failures represents the threshold of a NERC reportable event under NERC Standard EOP-004 and also the threshold for the DOE Energy Emergency Incident and Disturbance Reporting Requirement per Form EIA-417.* Load restoration via manual transfers (to reduce the magnitude of the load loss) shall *not* be considered when determining if the 300 MW threshold will be exceeded.

Corrective action should be investigated and implemented as soon as practicable to eliminate the projected exposure to either automatic or operator-initiated shedding of 100 MW or more of load, or the loss of 300 MW or more of load related to system topology or load characteristics associated with the concurrent outage of any two transmission elements.

For those contingency events for which it would not be appropriate to address by the addition of a capital project, or in the interim prior to completion of a budgeted system expansion, the feasibility of operational solutions (switching procedure, generator redispatch, or load reduction) will be explored.

2.2.2 NERC Reliability Standards TPL-001 through TPL-004

Appendix II contains a listing of Table I from NERC Reliability Standards TPL-001 through TPL-004, version 0. These standards are used extensively in planning of the transmission system.

2.2.3 Use of Special Protection Systems to Meet Reliability Standards

Special protection systems (SPS) may be used as an interim solution to alleviate transmission constraints pending the completion of planned and committed network upgrades to meet national and regional standards and Ameren transmission planning criteria. SPS may be considered, on an interim basis, as generation plants can often be constructed and operational before the necessary transmission facilities can be upgraded to allow network resource (NR) status or resolution of injection-related transmission constraints to allow energy resource (ER) status. Special protection systems may be used on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events.

2.2.4 Special Protection Systems – Exceptions

Presently, three special protection systems (SPS) are operational on the Ameren system to alleviate thermal overloads following specific contingency conditions. These SPS are installed at the Audrain, Goose Creek, and Gibson City Plants. For Audrain and Goose Creek, transmission system expansions at some time in the future would be expected to alleviate the need to maintain these special protection systems. In the case of Gibson City, regulatory approval to construct a second Gibson City-Paxton 138 kV line was denied, which would have alleviated the need for this special protection system.

2.3 Transmission Interconnection Planning

The basic premise of transmission interconnection planning is to provide, under assumed operating conditions, sufficient transmission interconnection capability between reliability regions, subregions, and between Ameren and its neighboring utilities to accommodate energy transfers. Such energy transfers could be associated with normal market activity, regional load diversity, and abnormal operating conditions such as might be caused by fuel supply interruptions or other widespread disruption.

Ameren performs a series of non-simultaneous and simultaneous incremental transfer studies as a means of performing sensitivity analysis on the assumptions associated with forecast local and regional system conditions. The Ameren planning process considers the values of incremental transfer capability as well as trends in these values to judge the reliability of the Ameren system under forecast and atypical conditions.

The planning of interconnection transmission follows "General Transmission Planning Criteria", plus additional criteria and guidelines for certain specific items including adequate nonsimultaneous import capability, adequate simultaneous import capability, maximum simultaneous import capability for the St Louis Metro Area, adequate transmission interconnection capability including stability considerations, nonsimultaneous import capability in regional studies, and export capability.

This section describes guidelines for simulation testing as described in earlier sections.

A primary purpose of using incremental transfer capability in planning is to assess the margin between contingency loading and facility ratings so as to take into consideration uncertainties in load levels, interchange schedules, generation dispatch, transmission commitments made by the transmission provider, and regional load and generation diversity. A trend in incremental transfer capability should be considered in planning the system. That is, a declining trend in comparable studies would indicate a need for further investigation.

### 2.3.1 Import Capability Criteria and Guidelines

#### 2.3.1.1 Guidelines for Nonsimultaneous Import Capability Testing

The Ameren transmission system is tested for nonsimultaneous transfer capability for imports (FCITC) from all directions. An import capability level of approximately 1200 MW, as limited by an Ameren transmission element, would be used as a proxy for each of the Ameren Illinois and Ameren Missouri systems. The Ameren Illinois system consists of the portion of the Ameren system east of the Mississippi River , while the Ameren Missouri system consists of the portion of the Ameren system west of the Mississippi River . Some loads and generating units telemetered into one of the Ameren control areas are physically located in the other control area. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists. Powerflow simulations would be run to confirm that the area voltages would be acceptable to support the levels of transfer identified in the linear analysis.

#### 2.3.1.2 Criteria for Import Capability Related to Generation Reserve

Unless a level of import capability requirement for generation reserves is otherwise specified by RRO or RTO requirements, a minimum simultaneous import capability (FCITC) of 2000 MW as limited by an Ameren transmission element would be used as a proxy to maintain transmission capability related to generation reserves in the Ameren Missouri or Ameren Illinois footprint. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

2.3.1.3 Guidelines for Voltage Constrained Maximum Simultaneous Import Capability for St. Louis Metro Area

Voltage constrained maximum simultaneous import capability is an assessment of the adequacy of reactive resources in the St. Louis Metro area[1]. The basis of this assessment is the coincident outage of multiple generating units within roughly 100 miles of the St. Louis Metro area with all transmission facilities in service. Simultaneous import capability simulation is performed so as to identify and prioritize locations for reactive compensation and/or system upgrades. Ameren‟s maximum simultaneous import capability shall be considered adequate if there are neither significant facility overloads, nor any metropolitan area bulk substations with 34.5 kV and 69 kV voltages below 95% of nominal.

For simulating this test, the coincident outage of any seven generating units within 100 miles of the St. Louis Metro area should be considered, with system loads based on the Ameren corporate load forecast.

Additional considerations for this test should include the coincident outage of a transmission facility and any five generating units within 100 miles of the St. Louis Metro area.

2.3.1.4 Guidelines for Adequate Transmission Interconnection Capability

The following two test simulations are to be used in determining adequate transmission interconnection (tie) capability:

Transient Stability Simulations

A transient stability simulation of loss of any plant and its outlet transmission, while importing about 1200 MW from the direction in which the most inertial swing inflow will occur (generally from the east), demonstrates sufficient transmission interconnection capacity from a transient stability perspective. The imports should be directed to either the Ameren Illinois or Ameren Missouri systems.

Steady-state Simulations

Post-fault power flow simulations following the transient stability simulations above, also indicate sufficient transmission interconnection capacity if all

[1] St. Louis Metro area includes St. Louis City, St. Louis County, Jefferson, Franklin, and St. Charles Counties in Missouri, and Madison, St. Clair, and Monroe Counties in Illinois.

transmission interconnection elements (tie-lines) are loaded below their emergency ratings. In addition, the system should not collapse, even though there might be local low voltage conditions and possible transmission line or transformer overloads in some areas. Some local load might be lost.

2.3.1.5 Guidelines for Determination of Adequate Nonsimultaneous Import Capability in Regional Studies

Ameren transfer capabilities are generally determined in SERC and ERAG regional and interregional studies, in which Ameren transmission planning engineers are participants. Linear analysis methods are used to calculate transfer capabilities, with AC power flow solutions used to confirm that the area voltages would be acceptable to support the transfer levels identified. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists.

In general, if required in the regional study process, Ameren judges the adequacy of the nonsimultaneous import FCITC in part on the need to address variations in local and regional generation dispatch, net scheduled interchange, and uncertainties in the powerflows associated with them. Less than adequate transfer capability may limit Ameren‟s options to import power from specific directions during both economic and emergency conditions. Economic considerations may require higher import capabilities than stated here for reliability purposes.

Typically, values of nonsimultaneous import FCITC into Ameren Illinois or Ameren Missouri from any direction in excess of 1200 MW would be considered as adequate. Values less than or equal to approximately 2/3 of the "Adequate" levels would be considered as less than adequate, and would require further review of the constraints.

The above magnitudes of transfer capability reflect the requirements of the transmission system to supply the Ameren customer load with the desired reliability levels for a variety of system operating conditions considering:

1. The geographic location of the Ameren, Ameren Illinois, and Ameren Missouri systems and its electrical connections in the Eastern Interconnection,
2. The existing capability of the Ameren, Ameren Illinois, and Ameren Missouri systems and its interconnections to supply the Ameren customer load during beyond first contingency conditions,
3. The response of the Ameren transmission system to system transfers, including those not involving Ameren,
4. The magnitude and economics of available generation in the Midwest,
5. The increased utilization of the transmission system for economic benefits, to

maintain adequate generation reserve levels, to defer capacity additions, and/or to reduce fossil fuel emissions, and

6. The impact of simultaneous power transfers and other actions on day-to-day system operation.
7. Transmission service reservations impacting Ameren facilities.

Operating guides, procedures which may or may not involve operator intervention to alleviate the loading on a particular transmission facility, may be used to enhance transfer capability between areas.

### 2.3.2 Export Capability Testing Guidelines

The Ameren transmission system is tested for nonsimultaneous transfer capability for exports (FCITC) to all directions. Note that valid limits to the transfers tested would consist of those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists. The Ameren transmission system will be tested as follows:

1. At summer and winter peak times, an export capability level of approximately 1000 MW, as limited by an Ameren transmission element, would be used as a proxy for each of the Ameren Illinois and Ameren Missouri systems, as well as the entire Ameren footprint.

2. At a shoulder peak level of 80% of summer peak, an export capability level of approximately 1500 MW, as limited by an Ameren transmission element, would be used as a proxy for each of the Ameren Illinois and Ameren Missouri systems, as well as the entire Ameren footprint.

### 2.3.3 Generation Outage Modeling

A robust Ameren transmission system should not be dependent on any single generator, peaking plant, or intermittent plant generation. Make-up power due to changes in assumed generation dispatch should be modeled from Ameren network resources and/or neighboring systems. Intermittent or peaking plants should be considered as a single generator outage for the purposes of variations in generation dispatch in the planning of the Ameren transmission system.

## 2.4 Generation Connection and Outlet Transmission Criteria

The general Transmission Planning philosophy is to provide adequate and sufficiently reliable generating plant outlet transmission capability to assure that it is not necessary to consider variations in the dispatch of existing generation to compensate for single-contingency transmission deficiencies.

The planning of generation outlet transmission follows "General Transmission Planning Criteria", plus additional criteria for certain specific items such as stability considerations and high-speed reclosing of EHV circuits.

The administration of generator connection requests and related study work is handled by MISO. The full procedures are found on MISO‟s website at the following address: https://www.midwestiso.org/Planning/GeneratorInterconnection/Pages/GeneratorInterconnection.aspxThe MISO process includes application of a Transmission Owner‟s Local Planning Criteria. As this applies to Ameren transmission facilities, Ameren‟s Local Planning Criteria are stated in this document.

A distribution factor threshold of 3% will be used when considering the responsibility of the new generator to pay for the system improvements required to mitigate the overloaded facilities for a test that is required by Ameren‟s Local Planning Criteria. Mitigating these facility overloads through generator re-dispatch or through long-term use of special protection systems is not acceptable.

When applying the Ameren import and export capability criteria and guidelines found in sections 2.3.1 and 2.3.2, the new generator would be responsible for system improvements required to mitigate limitations to transfer capability for those facilities for which a PTDF (power transfer distribution factor) or OTDF (outage transfer distribution factor) of 3% or greater exists, and for which a 200 MW or greater reduction in transfer capability would result.

The new generator will be responsible to pay for system upgrades to mitigate overloads related to tests specified by the Ameren Planning Criteria only when the overload was not identified by the non-Ameren Planning Criteria tests performed as part of the generator connection request, or when the application of the Ameren Planning Criteria increases the amount of overload by more than 5% of the facility‟s rating.

2.4.1 Generator Power Factor

As a minimum criterion, a gross rated power factor of 90% is specified for synchronous generating units connecting to the Ameren system so as to provide a minimum net power factor of 95% at the point of interconnection.

A gross power factor of 85% is desirable when large synchronous generators (greater than 100 MW) are connected to the 138 kV or 345 kV transmission system in the St. Louis Metropolitan area[1]. This criterion for power factor is consistent with good utility practice for providing reactive capability which would be useful in maintaining adequate system voltages for a variety of system

[1] St. Louis Metro area includes St. Louis City, St. Louis County, Jefferson, Franklin, and St. Charles Counties in Missouri, and Madison, St. Clair, and Monroe Counties in Illinois.

conditions.

A generator capability curve is to be supplied as part of the information provided by the generator owner to MISO as part of the generator connection process. The generator and plant auxiliary systems should be designed to permit operation within the full range of real and reactive power as depicted in the generator capability curve, for generator terminal voltages within the range of 95% to 105% of nominal. Note that prevailing system conditions at any particular time could limit the actual range of reactive power generation or absorption in operation. See section 2.4.5 for discussion of generator underexcitation limits.

Non-synchronous generators, such as wind farms, are required to operate across the power factor range of 0.95 leading to 0.95 lagging at the point of interconnection should the system impact study demonstrate the need for dynamic reactive power capability to maintain the assigned voltage schedule range.

2.4.2 Plant Bus Configuration Criteria

For future connections to Ameren"s transmission system with a voltage above 100 kV, the following minimum criteria apply as indicated in the table below. These criteria are consistent with past planning philosophy that provides the highest reliability configurations on the 345 kV system and highly reliable circuit arrangements at 230 kV, 161 kV and 138 kV. These configurations permit Ameren to maintain contiguous ownership of the transmission system.

| Connection Type | Configurations Allowed | Ownership |
|---|---|---|
| 345 kV single or multiple connections | Ring Bus<br>Breaker-and-a-Half | Ameren owns all substation facilities at the connection point (network facilities). Ameren or IPP may own the lead line(s) connecting the IPP facility and Ameren substation (interconnection facilities). |
| 230 kV, 161 kV or 138 kV multiple connections | Ring Bus<br>Breaker-and-a-Half<br>Straight Bus | Same as above<br>Note that a Straight Bus connection would only be permitted at an existing substation |
| 230 kV, 161 kV, or 138 kV single connection | Ring Bus<br>Breaker-and-a-Half<br>Straight Bus | Same as above<br>Note that a Straight Bus connection would only be permitted at an existing substation |

Prior to 1980, AmerenUE had designed the plant connection at 345 kV at Labadie and Rush Island Plants via a straight bus arrangement. Because of the difficulties encountered (typically space requirements) in converting the straight bus style of connection, it is not intended to retroactively apply the current design configuration requirements to the existing plants, even for planned future generation connections at these facilities.

2.4.3 Plant Outlet Transmission Line Outage Criteria

Plant outlet transmission is considered adequate when, with the plant at full rated output, and with other generation in electrical proximity to the plant under study which contributes in an additive manner to the critical circuit loading dispatched so as to maximize facility loading such that the outage of any plant outlet circuit or other valid local single contingency does not result in the loading of any circuit above its emergency rating, and there are no transmission system voltages below 95% of nominal. Special protection systems may also be considered as an interim solution to alleviate transmission constraints for network resources pending completion of planned and committed network upgrades. Special protection systems may be used on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events. A case-by-case review would be made if either one generating plant is constrained by several transmission elements, or if several generating plants are constrained by a single transmission limit. Reliance on multiple SPS in an area should be avoided in long term planning, as should the reliance on a single SPS for multiple generators.

2.4.4 Steady-State Stability Criteria

Plant outlet transmission is considered adequate, from the standpoint of steady-state stability, when it will pass both of the following simulated tests:

1. With the plant at full real power output and lagging power factor, with an outage of any one of the transmission outlet circuits, all generating units at the plant should remain stable in the steady-state.
2. With the plant at full real power output and lagging power factor, with an outage of transmission outlet circuits on a common tower, all generating units at the plant should remain stable in the steady-state.

If the Test #2 listed above is not met, use of operating guides including reduced generation at the plant may be considered for a limited time until a committed reinforcement is implemented. Dynamic models representing winter peak load conditions should be used for the stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power.

Small signal analysis would show satisfactorily damped post-disturbance response with damping ratios of 3% or higher with modeled excitation system parameters based on field-tested data. Otherwise, damping ratios of 5% or greater would demonstrate satisfactory damping.

2.4.5 Guidelines for Determination of Generator Underexcitation Limits

A generator‟s underexcitation limit consists of operating points at which the generator is on the verge of losing synchronism with the remainder of the system. For a particular real power output, this occurs when the generator‟s excitation is gradually decreased so that the generator voltage behind the saturated synchronous reactance leads the Thevenin equivalent system voltage by 90°. Usually the generator is underexcited (absorbing reactive power) at this absolute underexcitation limit.

To allow for possible generator governor action in response to system disturbances, an appropriate margin is selected. Typically, these margins would be 3% of the generator capability with automatic voltage regulating equipment in-service, 5% for a non-continuous acting voltage regulator in-service, or 10% of the generator capability if automatic voltage regulating equipment is assumed to be out-of-service or is not present. Calculation of this minimum excitation limit for various real power output levels for a particular generator yields minimum excitation values which would result in the generator reaching its absolute minimum excitation limit should the generator governor call for an increase in generator real power output.

Typically, light load system conditions are used as a basis to determine minimum generator excitation limits, with the strongest source (outlet line) assumed out-of-service at the plant under study.

2.4.6 High-Speed Reclosing of the 345 kV Circuits Criteria

High-speed reclosing after the tripping of 345 kV circuits terminating at power plants is not allowed. The reason for this criterion is to reduce the probability of torsional oscillations causing damage to the shafts of the turbine-generators, in accordance with manufacturer‟s recommendations.

Recommended reclosing of these EHV circuits is to be delayed by approximately ten seconds.

2.4.7 Transient Stability and Circuit Breaker Clearing Times Criteria

Plant outlet transmission is considered adequate, from the standpoint of transient stability, when

| Contingency Test | Contingency Event Description and Outcome | Corresponding NERC Reliability Standard and Contingency Category |
|---|---|---|
| 1. | With all lines in service, the plant and remainder of the system shall remain stable when a sustained close-in three-phase fault on any outlet facility is cleared in primary clearing time. | TPL-002-0<br>B2,3 |
| 2. | With all lines in service, the plant and the remainder of the system shall remain stable when a sustained close-in single-line-to-ground fault on any two circuits of a multiple circuit tower line is cleared in primary clearing time. | TPL-003-0<br>C5 |
| 3. | With one outlet facility out of service, the plant and the remainder of the system shall remain stable when a sustained close-in three-phase fault on any of the remaining facilities is cleared in primary clearing time. | TPL-003-0<br>C3 |
| 4. | With all lines in service, the system and the remainder of the plant units shall remain stable when a sustained close-in double-line-to-ground (2-L-G) fault* on any Ameren 345 kV, 230, 161 or 138 kV plant bus section or outlet facility is cleared in breaker-failure back-up clearing time including tripping of a transmission facility and generating unit(s), if any, on the bus associated with the "stuck breaker". | TPL-003-0<br>C6, 7, 8 (possible equivalent to C9)<br>Also covers C1 and C2 as a breaker failure for a line fault would result in the clearing of a straight bus or the adjacent facility in a ring bus or breaker and a half arrangement. |

*: Callaway Plant shall meet the three-phase fault test as outlet for this plant was designed for three-phase faults. Note that Ameren"s general use of 2-L-G fault conditions with delayed clearing (breaker-failure) conditions is more stringent than the consideration of single-line-to-ground (S-L-G) fault conditions as specified in NERC Reliability Standard TPL-003-0.

Simulations and Other Considerations

a) The impact of loss of system protection should be investigated for those locations where back-up protection systems on plant outlet lines are significantly slower than primary relaying schemes. Double-line-to-ground fault conditions should be tested assuming primary protection scheme failures that would result in breaker clearing times that are greater than the clearing time associated with the breaker failure protection scheme. This testing is generally required because of older system protection schemes associated with older power plants or substations. (See item 4 above.)

b) Dynamic models representing winter peak load conditions should be used for stability analysis, as the loads in these models provide less damping than the load in summer peak models and fewer generating units are available to provide synchronizing power. Winter peak output (MW and Mvar) of the generating unit(s) shall be considered.

c) Plant voltages will be modeled at the low end of their scheduled voltage range.

d) The transient stability Tests 2, 3, and 4 above are considered a double-contingency test. The "stuck breaker" is considered one of the contingencies in test 4.

e) Any of the Tests 1, 2, 3, or 4 for outlet of new generation shall not in anyway degrade existing stability limits including critical clearing times of any of the nearby plants.

f) The term “stable” in above Tests 1 through 4 means the generating unit(s) which remain connected to the system following fault clearing remain in synchronism.

g) Plant outlet transmission configuration resulting in no outlet transmission for Test 3 or 4 or both shall require installation of out-of-step-protection on generators, and shall not in anyway degrade existing stability limits including critical clearing times of any of the nearby plants or result in system instability.

h) In Test 4 for the “stuck breaker” simulation, a due consideration shall be given to down-grading of the initiating double-line-to ground fault (three phase fault for Callaway) to a single-line-to ground fault if the associated breakers are equipped with the independent pole operated (IPO) mechanism.

i) For the non-peaking units at plants connected to the 345 kV system, light load system conditions shall also be considered. Due consideration should be given to breakers equipped with independent pole operated (IPO) mechanisms.

j) For Test 3 above, a planned reduction in generation associated with the out-of-service outlet line may be considered to maintain plant stability.

k) Use of special protection systems (SPS) shall not be allowed for Test 1 or 2. If SPS is used to meet Test 3 or 4 above, it shall meet the requirements of the NERC Reliability Standards and/or SERC regional criteria. Special protection systems may be utilized on a long-term basis for maintaining transient stability of one or more generating units in response to a specified set of contingency events related to Test 3 or 4 above.

l) The transient stability Tests 1, 2, 3, and 4 above are also applicable to wind generation farms.

2.4.8 Transient Stability Fault Scenario Selection

As a guide to selection of fault conditions for development of a portfolio of transient stability simulations for assessment of the transmission system, the following should be considered:

a) The most severe fault for each Category B, C, or D contingency should be simulated for each power plant on the Ameren system which has units on-line in the stability power flow model being used. Typically, the element that is faulted has the longest clearing time, is the strongest source to the system, or results in the greatest number of facilities being removed from service. Close-in faults are usually the most severe from a generator perspective but remote faults should also be given consideration. Often the fault selection is based on the knowledge gained from performing a plant stability study which is updated when major changes at the plant or on the nearby system occur.

b) The most severe fault for each Category B, C, or D contingency should be simulated at each substation or switchyard on the Ameren system with 345 or 230 kV facilities. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

c) The most severe fault for each Category B, C, or D contingency should be simulated at each substation or switchyard on the Ameren system with 8 or more 161 or 138 kV lines. Typically, the element that is faulted has the longest clearing time or results in the greatest number of facilities being removed from service.

d) The most severe fault for each Category B, C, or D contingency should be simulated for each substation on the Ameren system that serves more than 300 MW of customer load. Typically, the element that is faulted is a transformer or lead line serving the substation in order to determine the impact of losing the load on the stability of the transmission system.

e) Faults that historically have been known to present stability issues on the Ameren or nearby transmission systems should be simulated until upgrades are implemented to completely resolve these issues. These fault simulations are based on the historical events and circumstance that led to the stability concerns, and could include relay misoperations as part of the events.

f) All faults required to meet the Clinton and Callaway NPOA agreements should be simulated. These faults scenarios are prescribed in the NPOA agreements.

2.4.9 <u>Generator Out-of-Step Protection</u>

To provide protection for generating equipment should synchronism be lost following a contingency event, new generators to be connected to the Ameren transmission system with capacity of greater than 100 MW, would be required to have out-of-step protection installed.

Retrofitting to install out-of-step protection on existing generators connected to the Ameren transmission system with capacity of greater than 100 MW should commence, with the objective of completing such retrofit by the end of 2016.

2.4.10 <u>Wind Farm</u>

A wind farm, that is a plant with one or several wind generators, shall meet all the requirements specified in FERC Order 661A. Also, Ameren will follow any MISO guidelines related to wind generation. Wind farms should also meet power quality requirements as specified in section 3.1.4. The general procedure for performing an assessment of a wind farm facility is covered in the Ameren document "Guide to Wind Power Facility Interconnection Studies", dated March 7, 2011. This document is attached as Appendix IV.

Subsequent to the connection of any wind generators to Ameren transmission system, performance of the wind generating capacity will be reviewed periodically to determine that the wind generation still meets the requirements in FERC Order 661A and any applicable MISO guidelines for the conditions identified in section 2.7.11.

## 2.5 Short Circuit Criteria

The interrupting requirements of all Ameren circuit breakers must remain within circuit breaker interrupting capabilities considering the impacts of asymmetry, reclosing, and actual system operating voltage for the appropriate type of circuit breaker in the field (breakers rated on a total current basis or symmetrical current basis). The following test criteria are applied to determine both the three-phase and single-phase short circuit interrupting requirements for both new and existing circuit breakers:

With all other transmission facilities in service and with the maximum generation on the system, a close-in, zero impedance fault is applied with the remote end of the line or transformer open.

Circuit breakers with fault duties in excess of interrupting capabilities are candidates for immediate replacement or other acceptable mitigation alternative that meets power flow, relay coordination, and system stability requirements. Such mitigation may include the opening of bus-tie circuit breakers.

## 2.6 Nuclear Plants and Transmission Operator Agreements

### 2.6.1 Callaway Plant

In accordance with NERC Standard NUC-001, Callaway Plant Nuclear Engineering and Operations Departments and Ameren Services Company have entered into an agreement which includes rights and responsibilities of each party. This agreement includes rights and responsibilities of the Transmission Planning Department to evaluate the transmission system"s ability to support Callaway Plant needs from voltage levels, short circuit, and stability considerations. These needs are to be considered along with other criteria and guidelines contained in this document in developing overall transmission plans.

Ameren will enter into any appropriate agreements with the Transmission Provider and Callaway Plant regarding study requirements.

### 2.6.2 Clinton Plant

In accordance with NERC Standard NUC-001, Clinton Plant and Ameren Services Company have entered into an agreement which includes rights and responsibilities of each party. This agreement includes rights and responsibilities of the Transmission Planning Department to evaluate the transmission system"s ability to support Clinton Plant needs from voltage levels, short circuit, and stability considerations. These needs are to be considered along with other criteria and guidelines contained in this document in developing overall transmission plans.

Ameren will enter into any appropriate agreements with the Transmission Provider and Clinton Plant regarding study requirements

2.7 System Conditions Assumptions

System conditions that are assumed to be in effect when the criteria are tested can have a great influence on the results obtained.

The following conditions are assumed in developing the base case power flow and stability models for testing system capability to satisfy Ameren‟s transmission planning criteria and guidelines:

1. The Ameren system peak loads used in general purpose power flow models are based on the peak corporate load forecast, which assumes a statistical probability of one occurrence in two years (50/50 load forecast).
2. All Ameren Missouri and Ameren Illinois Balancing Authority load should be represented in the model as agreed to with all applicable parties. These agreements include municipal and cooperative loads with network integrated transmission service (NITS) modeled within the Ameren Balancing Authority Areas.
3. Generation within the boundaries of the Ameren transmission system will be dispatched in accordance with contractual and local or regional economic dispatch considerations as applicable. Net scheduled interchange for the Ameren Balancing Authority will be established accordingly and coordinated with the necessary regional and interregional parties. Ameren network resources external to Ameren‟s transmission boundaries will be dispatched in a similar manner in coordination with the host Transmission Owner/Transmission Planner. Plant voltage setpoints will be modeled at the low end of the scheduled voltage range.
4. Designated Network Resources will be dispatched out of merit order if they have been identified as Reliability Must Run (RMR) units.
5. Sensitivity of other system conditions should be considered, including but not limited to variations in system load (shoulder peak load, light load, 1 in 10 years load) or non-coincident local area load conditions, high bias and different transfer scenarios, different resource dispatch scenarios (such as Taum Sauk operating in pumping mode during off peak conditions), and system conditions reflecting historical operating experience. Inclusion of peaking generation in base case dispatch may be omitted if a critical system condition would occur as a result of the CTG(s) in question being offline. The use of a 90/10 load forecast for an area may be used as a sensitivity to adjust the scope and timing for a transmission project.
6. Long term firm transmission service commitments shall be considered.
7. All Ameren transmission circuit breakers and switches to be operated and modeled as normally closed except those that are listed in the Attachment III Schedule of Ameren Normally Open Transmission Circuit Breakers and

Disconnect Switches.

8. Normally open subtransmission circuit breakers and switches would be provided by the Missouri and Illinois Distribution System Planning groups as part of their detailed subtransmission powerflow models.
9. All known planned outages to generation or transmission equipment would be included in the appropriate models.
10. All planned transmission projects in the Ameren budget would be included in the subsequent round of MMWG powerflow model building process. From a practical perspective, the budget is generally approved by January 1, and the subsequent round of model building activities would begin in the Spring. Planned projects in the models should reflect the current lead times for permitting, right-of-way acquisition, equipment purchase and delivery, construction, and testing provided by Transmission & Distribution Design groups. MISO models could include additional identified projects necessary for compliance with NERC Standards or Ameren Criteria & Guidelines. These projects may be included in Appendix B or C of the MISO Transmission Expansion Plan.*
11. For areas of the system with significant wind power installed, assessments to determine compliance with NERC Standards and other Ameren Criteria related to power flow on system elements will include at least the following critical system conditions:

    11.1Wind generation represented at 0% of the aggregated MW level and system loads at projected peak.

    11.2Wind generation under study for connection to the system represented at 100% of the aggregated MW level and system loads in the range of 70% to 80% of projected peak. To reflect the fact that all wind farms over a wide geographic area will rarely be operating at 100% of nameplate capacity at the same time, wind generation located outside the immediate study area should be represented at 90% of the aggregated MW level. General system studies would be performed with wind generation represented at 90% of aggregated MW level.

12. As a proxy for cascading conditions in study work, facilities found with loadings of 120% of emergency rating or greater should be considered to have tripped offline.
13. In the course of study work, should post-contingency transmission voltages in a general area drop to 90% of nominal or below, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely. Distribution bus voltages less than or equal to 90% would indicate possible motor stalling (considering voltage drop of 5-7% on distribution feeders). Transmission voltages of 85% is the level at which a voltage collapse is essentially assured. Situations which show transmission voltages in the range of 86% -89% in a steady state analysis carry significant risk for voltage collapse. When performing a detailed study of an area that may be exposed to voltage

collapse, distribution line capacitors should be modeled as a separate element from distribution reactive load. Transformer LTC‟s should be locked at the pre-contingency position when evaluating exposure to voltage collapse.

14. **For those conditions and events that do not meet performance requirements as specified in section 2.2.1, corrective plans involving capital projects would be developed. With the exception of Gibson City, where regulatory approval to construct a second Gibson City-Paxton 138 kV line was denied, note that special protection systems or other operating guides would only be used as interim solutions, prior to completion of system upgrades. Owners of new generator connections to the Ameren transmission system would not be permitted to propose a special protection system or other operating guide in lieu of such system upgrades. However, special protection systems may be used on a long-term basis for maintaining transient stability of one or more generating units. Generation redispatch would not be considered as an option, except as a response to multiple outage events.**

*Generally „Planned‟ projects are those which represent the best solution for a given problem, and have received budgetary approval. These projects become candidates for moving to MISO Appendix A. „Proposed‟ projects are those which are a tentative solution for a particular problem, but haven‟t been fully studied as yet, and for which there may be other alternatives. Proposed projects are listed in MISO Appendix B or C, along with any planned projects that have not received MISO endorsement.

## 2.8 Guidelines for Source and Sink Considerations for Ameren non-Regional Transfer Capability Studies

### 2.8.1 Import Capability

1. To test the capabilities of the Ameren transmission system, different combinations of sink points should be selected for development of import subsystems. These import subsystems should, at a minimum, reflect generating units in close proximity and within the same relative geographic areas, such as Ameren Illinois, Ameren Missouri, or the St. Louis metropolitan area. The import subsystem participation file can also include the largest unit at each base-load plant in the Missouri and Illinois sides of the Ameren footprint. Other import subsystems can be developed based on fuel type, specific rail carrier or type of transportation, specific gas pipeline supply, system voltage, or other common concern. The status of generating units on interfaces should also be considered, including units in neighboring powerflow control areas electrically close to the Ameren system (e.g. Kincaid, Thomas Hill, New Madrid, Powerton, Gibson, etc.) to determine the impacts on import capability.

2. Source subsystem definitions should consider combinations of increased

generation or decreased loads in powerflow control areas outside of the Ameren footprint. Control areas inside as well as outside of the MISO footprint should be considered for these exporting areas. System transfers from all cardinal compass directions should be considered.

2.8.2 Export Capability

1. To test the capabilities of the Ameren transmission system, different combinations of undispatched network resources should be selected for development of export subsystems. These export subsystems should, at a minimum, reflect generating units in close proximity and within the same relative geographic areas, such as Ameren Illinois or Ameren Missouri. Energy Resource generating units, particularly those in close proximity to network resource units, may be used to determine the impacts on export capability. Exports from Ameren system load may also be considered. The status of network resource generating units on Ameren interfaces should also be considered, as appropriate.

2. Choices for sink subsystem definitions in which generation deficiencies are modeled should consider control areas inside as well as outside of the MISO footprint. System transfers to all cardinal compass directions should be considered.

## 2.9 Load Connection and Power Factor

Load connections to a single Ameren transmission line will generally be provided through the establishment of a breaker station consisting of a ring bus configuration for the connection point. A four breaker ring bus arrangement is preferred to avoid involving remote transmission line terminals in local breaker failure scenarios involving line faults. Exceptions to this rule would be permitted, allowing the installation of a straight bus configuration, in situations where, for example, the new transmission substation was likely to become a major facility. Tapping two transmission lines would be considered on a case by case basis provided that each line does not already have a tap. A fault interrupting device is required, generally at the point of interconnection or other mutually agreed to location, to protect the transmission system from faults on load serving equipment.

A power factor of 98% at the point of interconnection or high voltage side of the distribution customer's transformer is recommended to minimize the reactive power burden on the transmission system and to minimize the reactive power losses by providing the reactive power resources as close to the load as control techniques and physical limitations will permit. This philosophy will result in the system reactive load being supplied by the distribution and subtransmission voltage levels, leaving the var capability in the generators able to supply the transmission system voltages during periods of imports, exports, and/or contingencies. By keeping a reserve of var generating capability in the generators, maximum flexibility is provided for a variety of system operating conditions.

The power factor of large customer loads served from the transmission system should follow the appropriate tariff requirements.

2.10 Development of Contingency Lists and Scenarios

Contingency lists and scenarios used in planning the Ameren transmission system are developed to reflect the assumed operating state of the system for the time study work is performed, taking into consideration all relaying and special protection systems. The contingency lists should address all applicable national and regional reliability standards, and local planning criteria. The contingency lists shall consider all Ameren facilities as well as those from neighboring companies that would be expected to impact Ameren transmission reliability. At a minimum, these neighboring facilities should include all tie-lines with Ameren, lines and transformers and large generators in close proximity to these tie-lines, and EHV lines and transformers within a 50 mile radius of an Ameren facility. Other significant EHV facilities located beyond a 50 mile radius of an Ameren facility may also be included. These neighboring contingencies of interest can be developed from contingency lists used in inter-regional studies.

1. Single Element Contingencies (NERC Category B)

For single generator outage scenarios (NERC Category B1), the loss of the largest generating unit at each plant bus connected to the Ameren system should be considered for study. Make-up power to cover generator outages should be modeled from network resources located inside the Ameren footprint and/or from neighboring systems within the MISO footprint. Outages of generating units in neighboring control areas and connected near Ameren facilities should also be considered in the outage analysis.

Intermittent or peaking plants should be considered as a single generator outage for the purposes of variations in generation dispatch in the planning of the Ameren transmission system.

For single transmission circuit (NERC Category B2) or transformer outage scenarios (NERC Category B3), the list of single transmission contingencies should include all valid single segment and multi-terminal lines and transformers, as well as all single segments of multi-terminal transmission facilities. EHV transformers that are part of multi-terminal transmission facilities should also be modeled as single contingencies to reflect long-term outages and any automatic switching or operator remedial action to restore the unfaulted facilities to service. The loss of an element without a fault (outage of all single branches) should also be considered.

Single pole DC line outages (NERC Category B4) need not be considered, as Ameren does not have any DC lines, and the outage of the nearest DC line does not have any significant impact on the Ameren system.

1A. Circuit and Generator Contingencies (NERC Category C)

For combination line and generator or peaking plant outage scenarios (NERC Category C3), the outage of the largest unit at a bus connected within the Ameren footprint should be considered and included with single transmission circuit or transformer outages. (Note: branches which represent bus-tie breakers in the powerflow models would **not** be considered as a transmission outage to include with a generator outage.) Make-up power to cover generator outages should be modeled from network resources located inside the Ameren footprint and/or from neighboring systems within the MISO footprint. Outages of generating units in neighboring control areas and connected near Ameren facilities should also be considered. (Because of numerical convergence issues in the PSS/E solutions, multiple outages involving generators are better handled by making modifications to the generation dispatch in the powerflow models and developing a separate base case than by coupling generation outages with transmission elements in a modified contingency list.)

2. Multiple Element Contingencies (NERC Category C)

The list of multiple transmission contingencies is developed based on the use of screening tools to meet the simulation testing requirements of the NERC Reliability Standards, as augmented by engineering judgment and experience. Modifications to the system models may be necessary to add bus-tie circuit breakers and move line terminals to model some bus section/breaker failure outages.

At a minimum, bus faults (NERC Category C1) should be simulated on all straight busses 100 kV and above that would remove 3 or more transmission elements. Circuit breaker faults or bus faults that would remove 2 or more elements would be considered as NERC Category C2 contingencies. Contingencies involving faults on a ring bus or breaker and a half arrangement are included as NERC Category C3 events. The impact of internal faults on the normally open circuit breakers listed in the Schedule of 138 kV Bus Splits (see Attachment III) would also be considered.

Because of the numerous combinations of multiple element outages (NERC Category C3) that may be simulated to meet the requirements of NERC Standard TPL-003, analytical assessments and engineering judgment can be used to help pare down the list of contingencies knowing that facilities in parallel, or those that serve the same area, or those that terminate at the same substation or switchyard are the most critical. Transmission transformers that supply the same general area of the system should be included in the multiple contingency analyses. Worst case contingency combinations may be developed considering short lists of the worst case single contingency events in terms of loading or voltage, or other appropriate method.

For two generator outage scenarios (NERC Category C3), the loss of all units greater than 50 MW connected within the Ameren footprint should be considered for study. At generating plants where there are more than two generators connected to a bus that would lead to multiple combinations of outages, only the worst combination needs to be studied. Generating units in neighboring control areas and connected near Ameren facilities should also be considered in the contingency analysis.

Bipolar DC line outages (NERC Category C4) need not be considered, as Ameren does not have any DC lines, and the outage of the nearest DC line does not have any significant impact on the Ameren system.

At a minimum, transmission lines on common towers for a length of one mile or greater should be included in modeling double-circuit tower outages (NERC Category C5).

Contingencies involving single line to ground faults and delayed clearing of generators, transformers, transmission circuits, or bus sections (NERC Category C6-C9) are covered from a steady state perspective with NERC Category C1-C3 contingencies. The stability aspects of the more severe contingencies are studied as described in Section 2.4.7.

3. Extreme Contingencies (NERC Category D)

The development of Category D (Extreme BES Events) contingency scenarios should follow the following guidelines:

- Engineering judgment should be used to develop the scenarios considering the various geographical regions and transmission voltage levels that make up the Ameren system. Known marginal areas of the system should be evaluated in addition to contingencies involving the critical plants and substations. The goal of extreme contingency analysis is to identify any potential cascading situations.

- Each year, a variety of contingencies should be simulated to meet the Standard TPL-004 requirements, such that over time, a portfolio of severe contingency events and results would be developed for periodic review and possible modification, based on system expansion requirements. Studies in support of compliance should not be more than five years old, and all geographic areas of the Ameren system should be covered over a 3-5 year time period. Contingencies involving critical Ameren facilities, as defined in the methodology to support NERC Reliability Standard CIP-002-1, should be reevaluated over a three-year period.

- At a minimum, powerflow and stability analyses should be performed and evaluated for those contingencies that would produce the more severe system results or impacts. For the Ameren system, the most severe contingencies from a dynamic perspective involve close-in 3-phase faults near power plants or 3-

phase faults with delayed clearing. Typically, the double-line-to-ground fault with breaker failure and delayed clearing scenarios required to meet Ameren planning criteria are also simulated considering 3-phase fault and delayed clearing scenarios for Standard TPL-004 analyses. These plant stability studies are performed throughout the year.

- For scenarios involving 3-phase faults with delayed clearing on generators, transmission circuits, transformers, bus sections, or breakers (NERC Category D1 through D5), these contingency conditions should be evaluated when a new plant is connected and reevaluated whenever there is a major change at a plant, or a change to an outlet line to a plant. From a steady-state perspective, these contingencies are covered by NERC Category C1-C3 events described above.

- For outages of tower-lines with three or more circuits (NERC Category D6), the loss of the two triple-circuit 138 kV tower-lines connected to the Sioux Plant should be simulated. These are the only tower-lines that carry more than two transmission circuits over a significant distance on the Ameren system.

- For outages of all transmission lines on a common right-of-way (NERC Category D7), several rights-of-way near power plants or major substations in the St. Louis metropolitan area should be considered for study as they can involve 3 or 4 345 kV or 138 kV circuits. Some rights-of-way in the Peoria area also contain 3 or 4 transmission lines. Other Ameren rights-of-way contingencies are generally covered with Category C3 or C5 events.

- For outages of substations or switching stations (NERC Category D8 and 9, respectively), facilities that have 4 or more 345 kV elements and are located less than 50 miles from an Ameren load center should be evaluated at a minimum. Critical power plant switchyards meeting these same criteria would also be considered. In addition, transmission substations or plant switchyards with 8 or more lines and transformers connected at less than 345 kV would be considered for evaluation. These guidelines follow the Ameren methodology to identify critical substation facilities. The outage of additional stations may be studied, but many would be covered by Category C1 or C3 events.

- For the loss of all generating units at a station (NERC Category D10), the most severe contingencies should be studied involving the outage of the largest plants connected to the Ameren system, such as Labadie and Baldwin. The outage of other large multiple unit plants should also be reviewed. The loss of single or 2-unit generators would be covered by NERC Category B or C3 contingency events. The outages of intermittent or peaking plants are covered under other Ameren criteria.

- For the loss of a large load or major load center (NERC Category D11), major industrial customers, major distribution substations, or larger load pockets may be considered for outage. Some of these contingencies would also be covered by NERC Category C events, or other Category D events described above. Loss of load response is typically not considered as critical from an Ameren system perspective.

- There are a few plants on the Ameren system that require a special protection system to meet thermal loading requirements for single contingency conditions. The system performance should be reviewed considering the failure of a fully redundant SPS to operate when required or the misoperation of a fully redundant SPS (NERC Category D12 and D13).

- The impact of severe power swings from events in other regional reliability organizations (NERC Category D14) are best assessed for cascading through participation in regional or inter-regional reliability studies. The Midwest ISO also performs stability studies in the RFC and MRO systems. In-house studies should consider 3-phase faults with reasonable delayed clearing times at those power plants connected close to the Ameren system (e.g. Kincaid, Powerton, Gibson, Rockport, Sibley, Thomas Hill, New Madrid, Shawnee, etc.) to assess the potential for cascading.

# 3.0 VOLTAGE CRITERIA

Voltage criteria are used to assess the transmission system reliability during assumed normal and contingency conditions. The transmission system response to various contingencies, whether steady state or transient conditions, must be assessed on the basis of these and other criteria. These criteria are presented below and are used by the transmission planning engineers to determine the level of reliability of the transmission system. Depending on the type of analysis being performed, steady state or transient, most or all of the following voltage criteria are used to determine the reliability of the transmission system through the use of computer simulations. The voltage limits and criteria used in planning the Ameren transmission system are presented below. These voltage limits are also used by transmission system operators to ensure that the transmission system is operated in a safe and reliable manner.

## 3.1 Transmission Voltage Levels and Limits

Transmission voltage levels on the Ameren system include 138 kV and above.

The power system must be planned to have sufficient var generating capacity and adequate var control to assure that system voltages will be within prescribed limits at all times. Depending on the function of the circuitry, the effect on customers, and the tolerances of equipment, some general voltage limits have been developed for the transmission system voltage levels.

The Ameren Distribution System Planning groups are responsible for specifying voltage requirements at the secondary (low voltage) side of the distribution and bulk substation transformers connected to the Ameren transmission system. The following transmission system voltage ranges have been developed considering these voltage requirements to identify locations that may need further investigation.

### 3.1.1 345 kV Transmission

The normally accepted voltage range for the 345 kV transmission system is from 100 percent to 105 percent of nominal. In general, equipment should not be exposed to voltages in excess of 105% of nominal. Operation in the range 105% to 107.5% of nominal would be permitted on a case-by-case basis, as allowed by ANSI guides, Ameren standards, or manufacturer‟s exception. The 345 kV system is normally operated at 104 percent to 105 percent at plant switchyards. The minimum system voltage is 95 percent of nominal under single contingency (line, transformer, or generator) conditions.

Under conditions beyond single contingencies, voltages above 105 percent or below 95 percent of nominal may occur. These conditions should be investigated to determine what actions, if any, are required so that they would not result in wide-spread outages. EHV transformers with off-nominal taps connected at less than 345 kV should be reviewed to ensure that these units would not be overexcited. Should post-contingency transmission voltages in a general area drop to 90% of nominal or below, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely.

3.1.2 138 kV, 161 kV, and 230 kV Transmission

The normally accepted voltage range for the 138 kV, 161 kV, and 230 kV systems during normal conditions is from 100 percent to 105 percent of nominal. Voltages outside this range would still be considered acceptable if they meet the contingency criteria detailed below. In general, equipment should not be exposed to voltages in excess of 105% of nominal. Operation in the range 105% to 107.5% of nominal would be permitted on a case-by-case basis, as allowed by ANSI guides, Ameren standards, or manufacturer"s exception.

Under single (line, transformer, or generator) contingencies, voltages of roughly 95 percent of nominal is used as a screening tool to flag the need for further analysis. Voltages below this threshold would initiate further analysis and/or discussion with the Distribution System Planning groups to ensure that adequate distribution voltages would be provided for these conditions.

For single customers supplied from the transmission system, the following minimum voltage limits would apply at the point of delivery: Normal: 92% Single Contingency: 90%. These limits are in line with governing tariffs in both Missouri and Illinois.

Under conditions beyond single contingencies, voltages above 105 percent or below 95 percent of nominal may occur. These conditions should be investigated to determine what actions, if any, are required so that they would not result in wide-spread outages. Should post-contingency transmission voltages in a general area drop to 90% of nominal or below, closer examination is warranted to determine whether voltage collapse for such contingency conditions is likely.

3.1.3 Maximum Allowable Voltage Change Following Contingency

Post-single contingency scenarios where voltage change, when compared to pre-contingency conditions, is greater than 5% of nominal will be investigated to determine what actions, if any, are required so that they would not result in wide-spread outages.

### 3.1.4 Conformance with IEEE Standards 1453 and 519

#### 3.1.4.1 Voltage Fluctuation

Based on IEEE Standard 1453 and Good Utility Practice, steady state voltage fluctuation resulting from capacitor switching would be limited to a maximum of 3.3% of nominal. Single contingency conditions will be evaluated for capacitor switching voltage fluctuation considering the outage of the strongest area source element or facility (largest contributor of short circuit current).

#### 3.1.4.2 Harmonics

All generation and load connections to the Ameren system should conform to IEEE Standard 519 with respect to voltage distortion. These limits restrict individual harmonic distortion limits to 1.5% between 69 kV and 161 kV, and 1.0% at 161 kV and above, with Total Harmonic Distortion limited to 2.5% between 69 kV and 161 kV, and 1.5% at 161 kV and above.

### 3.1.5 Voltage and Reactive Control

A generating plant should maintain either a specified voltage or reactive power schedule (in accordance with NERC Reliability Standard VAR-002-1). Those plants with synchronous generators connected to the Ameren transmission system shall be assigned voltage schedules to maintain system voltages at the plant switchyards during steady-state conditions. Voltage schedules are selected to maintain transmission system voltages in electric load centers at or above a minimum of 100% of nominal with all facilities in service, and within Ameren system voltage limits. Plants connected to the 345 kV transmission system have voltage schedules of 104-105.9% of nominal, while plants connected to the 138 kV, 161 kV, or 230 kV transmission system have voltages schedules typically between 102.9% and 105% of nominal.

A voltage schedule will be specified for non-synchronous generating units by the Transmission Operator. Study work will be performed to determine whether the voltage schedule at the point of interconnection can be met with the non-synchronous generating units operating at unity power factor at the point of interconnection under normal and contingency conditions. If the voltage schedule at the point of interconnection cannot be met with the generator operating at unity power factor at the point of interconnection, the generator would be required to operate across a power factor range of 0.95 lagging to 0.95 leading at the point of interconnection to attempt to meet its voltage schedule.

Present voltage schedules for plants connected to the Ameren transmission system are listed in Appendix V.

# 4.0 Thermal Rating Criteria

4.1 Introduction

Thermal rating criteria are used to assess the transmission system reliability during normal and contingency conditions. The transmission system response to various contingencies, whether steady state or transient conditions, must be assessed on the bases of these and other criteria. The Ameren steady-state thermal rating criteria are presented below and are used by the transmission planning engineers to determine the reliability of the transmission system through the use of computer simulations. These ratings are also used by transmission system operators to ensure that the transmission system is operated in a safe and reliable manner.

4.2 Circuit Ratings Based on the Limiting Circuit Element

For the Ameren system, the facility rating shall equal the most limiting (minimum) applicable equipment rating of the individual equipment that comprises the facility. All circuit or branch (facility) ratings are identified as the minimum of the ratings of all the series connected elements from bus to bus or from line tap to bus for seasonal normal and emergency conditions. Multiple branches within a circuit are each assigned appropriate ratings based on Sections 4.4 and 4.5 below. These ratings represent the minimum current carrying capability of all series connected electrical equipment including terminal equipment (bus conductors, disconnect switches, circuit breakers, wave traps, current transformers, series reactors, protective relaying devices, and relay loading limits), line conductors (includes minimum ground clearance and thermal limitations), and power transformers.

Note that various pieces of equipment, such as circuit breakers, disconnect switches, wave traps, CTs, protective relaying devices, and line and substation conductors, comprise a single „facility" when these components are connected in series.

Typically, the ratings of circuits (branches/facilities) should assume that adjacent circuit breakers in breaker-and-a-half or ring bus configurations are open to reflect the outage of adjacent circuits or maintenance conditions. However, points of current division should be recognized to handle those special cases of explicit flowgates or contingency/limit pairs when the contingency is not an adjacent element and all circuit breakers are in service.

4.3 Circuit Ratings of Jointly Owned Electrical Facilities Are Coordinated

For all jointly owned facilities, circuit or branch ratings are identified as the most limiting (minimum) of the ratings of all the series connected elements for seasonal normal and emergency conditions, as specified by the owner(s). These ratings represent the minimum current carrying capability of all series connected electrical equipment including terminal equipment (bus conductors, disconnect switches, circuit breakers, wave traps, current transformers, series reactors, protective relaying devices, and relay loading limits), line conductors (includes sag and thermal limitations), and power transformers. Ratings of jointly owned facilities shall not be changed without verification and agreement of all owners.

### 4.4 Thermal Rating of Equipment - Overview

Normal ratings are generally considered as continuous ratings and are used for the conditions with all facilities in service or the assumed base operating state of the system. Emergency ratings are used for all single or multiple contingency conditions. (Note that there is no limit on the duration of the contingency.) These ratings are used in both the planning and operating horizons. Short-term emergency and limited-life ratings are used in the operating horizon on a case by case basis, as needed.

Ameren transmission planning and operations recognize the philosophy of safe-loading limits. The safe-loading limit is the limit to which a particular element may be loaded under a specific set of circumstances so that, if another facility is suddenly outaged, the facility in question would load to no higher than its emergency rating. The general loading philosophy for Ameren's transmission equipment is such that the equipment would be loaded below safe loading limits during normal conditions and up to the emergency ratings during contingency conditions. For those instances where the normal ratings are less than the safe loading limits, facility loadings would be maintained at or below the normal ratings for the conditions with all facilities in service.

As equipment ampacity ratings tend to be a proxy for maximum operating temperatures based on assumed ambient conditions, ampacity ratings may be adjusted in the operating horizon if ambient conditions are different than the design ratings. Thus ampacity ratings may also be developed by considering the actual ambient temperatures and comparing with the system design temperatures that are used in the development of longer-term ratings so as not to exceed established equipment operating temperatures, loss of life or strength concerns, or violate clearances to ground. Night-time ratings considering no solar heating and less than summer peak ambient temperature conditions may also be developed as needed.

For most Ameren electrical substation equipment, unless otherwise stated, manufacturers‟ nameplate ratings are used for all conditions with no allowance for variances in seasonal ambient temperatures. Previous criteria and guideline documents included percentage multipliers to extend ratings on some equipment, but use of these multipliers has been eliminated for continuous or emergency ratings.

For any new equipment not presently addressed in this document which will be installed on the Ameren system in the future, Ameren planning processes would use manufacturer‟s nameplate ratings for all simulated conditions to assess the reliability of the Ameren system, unless specific values have been provided by substation design engineers and/or system protection engineers.

Ameren line conductor rating assumptions are based on the House and Tuttle method of calculating heat transfers and ampacities considering rating parameters that are generally accepted in the industry, and modified only slightly to fit Ameren‟s geographical location. These are the same thermal equations used in IEEE Standard 738-1993 for calculation of the current-temperature relationship of bare overhead conductors.

4.4.1 Normal Ratings

Normal ratings are generally continuous ratings and are used when the system is in a state of normal operation. Normal ratings would be applied to equipment for those conditions with all facilities in service or the assumed base operating state of the system for that time period, including planned equipment outages for maintenance and/or construction. Normal ratings would be used unless the system is in an emergency state of operation.

4.4.2 Emergency Ratings

Emergency ratings are generally continuous or maximum design ratings and are used for the time when the system is in a contingent state or emergency operation. These ratings, based on eight hours duration, would be applied to equipment for the time period following the forced outage of one or more transmission elements. Emergency ratings would be in use until the system is restored to normal operation.

4.4.3 Short-Term Emergency Ratings

Short-term emergency ratings are equipment specific and generally for use in the operating horizon (less than one year) to provide flexibility in system operation on a case-by-case basis. Facilities that have operating guides or SPS installed to maintain facilities within emergency ratings may need short-term emergency ratings until the operating guide can be implemented or the SPS can be activated. Short-term emergency ratings effectively expand the region of safe-loading, as they allow time for operator remedial action to redispatch generation or perform switching on the transmission system on a post-contingency basis without sacrificing safety or reliability. Upon request by Transmission Planning or Transmission Operations, Transmission & Distribution Design in conjunction with operations and maintenance groups develop these ratings. The duration for short-term emergency ratings would be up to 30 minutes.

Considerations for determining short-term emergency ratings of the specific equipment of concern would include the physical condition of the equipment, its loading and performance history and that of other similar such equipment, manufacturer information and agreements, consistency with industry standards, thermal time constants, general design specifications, and remedial diagnostics to assess the equipment capability following a thermal loading event. (See Substation Design Standard No. 32G Design Guide: Process for Establishing 30 Minute Load Ratings for Ameren Transmission Substation Equipment, Revision 0, dated 12/22/2009.)

#### 4.4.4 Limited-Life Equipment Ratings

Equipment that is scheduled to be replaced within one year may have a limited-life rating assigned in the operating horizon on a case-by-case basis. Limited-life ratings would allow some use of the remaining capability of equipment that is in service, knowing that it will be replaced within one year and not reused. Equipment operating temperatures may be increased and long-term loss of life or strength concerns may be relaxed while meeting all code and/or safety requirements. Upon request by Transmission Planning or Transmission Operations, limited-life ratings would be developed by Transmission and Distribution Design in conjunction with operations and maintenance groups to provide flexibility in system operation.

Considerations for determining limited-life ratings of the specific equipment of concern would include the physical condition of the equipment, its loading and performance history and that of other similar such equipment, manufacturer information and agreements, consistency with industry standards, general design specifications, and remedial diagnostics to assess the equipment capability following a thermal loading event.

### 4.5 Equipment Ratings

#### 4.5.1 Transmission Transformer Ratings

Transmission transformers connect the 345 kV, the 230 kV, the 161 kV, and the 138 kV transmission systems together. These transformers usually carry the top nameplate MVA as their rating. A rating other than nameplate may be used by Ameren if an appropriate agreement is obtained from the transformer manufacturer.

The general loading philosophy for Ameren's transmission transformers is such that the transformers would be loaded below safe loading limits during normal conditions and up to top nameplate during emergency conditions.

#### 4.5.2 Transmission Line Ratings

Transmission line or circuit ratings consider the minimum capabilities of the line conductors, line hardware, and terminal equipment, as well as ground and other object clearance limitations based on seasonal ambient conditions. Unless otherwise stated, only the ambient temperature and solar heating constants are adjusted for seasonal ratings for Ameren electrical equipment.

The general loading philosophy for Ameren's transmission circuits is such that the circuits would be loaded below safe loading limits during normal conditions and up to the emergency ratings during contingency conditions. For those instances where the normal ratings are less than the safe loading limits, facility loadings would be maintained at or below the normal ratings for the conditions with all facilities in service.

To meet the NERC issued Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings, dated October 7, 2010, Ameren has implemented a program to verify line ratings based on field conditions. As of the date of this filing, this verification effort is scheduled to be completed by December 31, 2013 but could change based on a variety of factors and constraints. Each circuit facility rating will be assessed individually for appropriate remediation, if any, considering the impact on the reliability of the BES. The remediation might include, but is not limited to, facility modification, temporary or permanent re-rating of the facility, temporary operating procedures, or topographical/access modification. It is expected that each remediation will be accomplished within one year of the discovery of each discrepancy. However, depending on the magnitude of the number of discrepancies found, the impact of facility re-rating, or other factors or constraints, some remediation may require more than one year to implement. Such instances will be documented in a mitigation plan and submitted to SERC, Ameren‟s Regional Entity.

4.5.2.1 <u>Transmission Line Conductor</u>

Transmission line conductor ratings are considered separately from circuit ratings because of the difficulties in establishing capabilities above nameplate ratings for terminal equipment. Conductor ratings are based only on thermal limits associated with current carrying capability assuming specific ambient conditions without consideration for ground clearance or terminal equipment limitations. The following list of constants represents the parameters used to help standardize and define the system of Ameren transmission line conductor ratings:

**<u>Stranded Conductor Operating Temperatures</u>**

| <u>Conductor Type</u> | Ameren | Ameren |
|---|---|---|
| | Normal | Emergency |
| Cu | 90 °C | 100 °C |
| ACSR | 90 °C | 120 °C |
| ACAR | 90 °C | 100 °C |

| | | |
|---|---|---|
| AAAC (SAC) | 90 °C | 100 °C |
| ACSS (SSAC) | 160 °C | 200 °C |

Based on an investigation by the Ameren Transmission Line Design group, a maximum allowable conductor temperature of 120°C was established for ACSR line conductors. Use of this maximum conductor temperature would only be for circuits that have undergone a verification that clearances are adequate and that the appropriate line hardware has been installed to allow for the high temperature operation.

**Stranded Conductor Rating Parameters**

| Rating Parameter | Ameren |
|---|---|
| Coefficient of Emissivity | 0.5 |
| Solar Absorption Constant | 0.5 |
| Wind Velocity | 2 ft/sec |
| Duration of Emergency Rating | 8 hours continuous |
| Wind Angle | 90° to conductor |
| Summer Ambient Temperature | 40 °C |
| Winter Ambient Temperature | 10 °C |
| Latitude | 38° N |
| Elevation above Sea Level | 470 ft |
| Time of Day – Summer | 2:00 p.m. |
| Time of Day – Winter | 12:00 p.m. |
| Direction of Line | East-West |
| Sun Angle of Declination - Summer | 27° |
| Sun Angle of Declination - Winter | 0° |
| Solar Heating Constant - Summer | 93 Watts/sq. foot |
| Solar Heating Constant - Winter | 82.2 Watts/sq. foot |

4.5.2.2 Minimum Clearances for Transmission Lines

Prior to 2011, transmission lines were assigned a clearance rating based on design drawings and the minimum allowable clearances as dictated by the applicable National Electrical Safety Code (NESC) or other governing body in effect at the time that the line was constructed, or by Ameren transmission line design criteria. As of the date of this filing, a verification effort is scheduled to be completed by December 31, 2013, but could change based on a variety of factors and constraints. If the effort is expected to extend beyond the three year NERC-established period, a revised project plan will be submitted to SERC, Ameren‟s Regional Entity.

4.5.2.3 Bundled Conductors

Bundled conductors in transmission lines are assigned ratings based on the sum of the individual conductor ratings for both normal and emergency conditions. No rating reduction is necessary to account for the "proximity effect" heating because the spacing between bundled conductors is at least 12 inches, and the current carrying requirements of the conductors are 3000 A or less. For additional information, refer to Item #6 and Table 11 of Ameren"s Transmission and Distribution Design Department Standard No. 8G, "Design Guide for Outdoor Substation Conductor Current Ratings", dated June 10, 2004.

4.5.2.4 Line Hardware

The appropriate line hardware is selected by the Ameren Transmission Line Design group to meet or exceed the operating temperature requirements of the line conductors. All ACSR lines would be limited to a maximum of 110 degrees C operation unless Transmission Line Design has reviewed the line construction and equipment to determine if the appropriate line hardware is adequate for a maximum operating temperature of 120 degrees C.

4.5.2.5 Line Switches

Unless specific values have been provided by transmission line design engineers, disconnect switches are rated at their manufacturer"s nameplate continuous current rating for all conditions. No allowance is made for seasonal temperature differences or emergency operation, even though most disconnect switches have some additional capability during winter peak conditions or less than 40 °C ambient temperatures. See Appendix I for those situations where rating above nameplate may be allowed.

4.5.3 Substation Equipment Ratings

Substation equipment ratings consider the minimum capabilities of the substation conductors, substation and terminal equipment, and relay limits based on seasonal ambient conditions. Manufacturer"s nameplate continuous ratings are generally used to rate substation equipment connected at the transmission voltage level. Unless otherwise stated, only the ambient temperature is adjusted for seasonal ratings for Ameren electrical substation equipment.

The general loading philosophy for Ameren's transmission substation equipment follows the same philosophy as transmission line and transformer loading.

4.5.3.1 Substation and Bus Conductor Ratings

In determining the current carrying capability of various types of conductors used in Ameren Substations, reliance is placed on Ameren‟s Transmission and Distribution Design Department Standard No. 8G, "Design Guide for Outdoor Substation Conductor Current Ratings", dated June 10, 2004. The philosophy for rating stranded substation conductors follows the same philosophy for rating stranded line conductors (see section 4.5.2.1 above) except for differences in allowable conductor operating temperatures, as noted below:

**Substation Conductor Operating Temperatures**

| Conductor Type | Ameren | Ameren |
|---|---|---|
| | Normal | Emergency |
| Cu | 90° C | 100° C |
| Al | 90° C | 100° C |

Ratings for rigid substation conductors are based on the IEEE Guide for the Design of Substation Rigid-Bus Structures 605-1998, and are also provided in Transmission and Distribution Design Department Standard No. 8G.

4.5.3.2 Circuit Breakers and Switchers

Unless specific values have been provided by substation design engineers, circuit breakers and switchers are rated at their nameplate continuous current rating for all conditions. No allowance is made for seasonal temperature differences or emergency operation even though most breakers have some additional capability during winter peak conditions or less than 40 °C ambient temperatures. See Appendix I for those situations where rating above nameplate may be allowed.

4.5.3.3 Disconnect Switches

Unless specific values have been provided by substation design engineers, disconnect switches are rated at their nameplate continuous current rating for all conditions. No allowance is made for seasonal temperature differences or emergency operation even though most disconnect switches have some additional capability during winter peak conditions or less than 40 °C ambient temperatures. See Appendix I for those situations where rating above nameplate may be allowed.

4.5.3.4 Wave (Line) Traps

Unless specific values have been provided by substation design engineers, wave (line) traps are rated at their nameplate continuous current rating for all conditions. No allowance is made for seasonal temperature differences or emergency operation even though most wave traps have some additional capability during winter peak conditions or less than 40 °C ambient temperatures. See Appendix I for those situations where rating above nameplate may be allowed.

4.5.3.5 Current Transformers

Unless specific values have been obtained from substation design or system protection engineers, current transformers are rated at their connected ratio for all conditions and considering the thermal rating factor. No allowance is made for seasonal differences even though most current transformers have some additional capability particularly during winter peak conditions or less than 40 °C ambient temperatures. See Appendix I for those situations where rating above nameplate may be allowed. CT ratings incorporate the associated thermal rating of all secondary connected wiring, metering, and protective devices. Ratios of current transformers used in protective relaying are selected so as not to overburden the secondary of the CTs or the protective relaying devices.

4.5.3.6 Series Reactors

Unless specific values have been obtained from substation design engineers, series reactors (inductors) are rated at their nameplate continuous current rating for all conditions. No allowance is made for seasonal differences even though most series reactors have some additional capability at less than 40 °C ambient conditions.

4.5.3.7 Relay Load Limits

Relay Load Limits (RLL) are provided by the System Protection group of Transmission & Distribution Design. Relay Load Limits consider the CT ratios in the protective relaying circuits and the trip settings are selected such that they would not exceed the thermal ratings of the relays (typically 10 A secondary), based on the following:

For the longest reaching distance relay used for step distance or pilot schemes, the Relay Load Limit is calculated as follows:

For non-critical facilities 200 kV and below, the Relay Load Limit is calculated as:

RLL = 0.7 ∗ I-base / [ Zpu-reach ∗ cos( /<u>Z-relay</u> - 26° ) ]

Where the 0.7 is a multiplier and 26° corresponds to a 90% lagging power factor.

For critical facilities, which include all 230 and 345 kV lines and other 138 and 161 kV lines listed with SERC Reliability Region, the Relay Load Limit is calculated per NERC criteria as:

RLL = 0.85 ∗ I-base / [ 1.5 ∗ Zpu-reach ∗ cos( /<u>Z-line</u> - 30° ) ]

Where the multiplier of 0.85 considers low system voltage, the multiplier of 1.5 considers overcurrent, and 30° corresponds to an 86.6% lagging power factor.

Technical exceptions to the above Relay Load Limit requirements for critical facilities are allowed per published NERC reliability standards. No allowances are made for seasonal differences or emergency operation. The Relay Load Limit methodology is further documented in Transmission and Distribution Design Department Standard No.15G.

4.5.3.8 <u>Shunt Reactors</u>

Unless specific values have been obtained from substation design engineers, shunt reactors (inductors) are rated at their nameplate rating, adjusted for nominal system voltage, for all conditions.

4.5.3.9 <u>Shunt Capacitors</u>

Unless specific values have been obtained from substation design engineers, shunt capacitors are rated at their nameplate rating, adjusted for nominal system voltage, for all conditions.

4.5.3.10 <u>Protective Relaying Devices</u>

Unless specific values have been obtained from System Protection engineers, protective relay devices are rated at their manufacturer specified rating for all conditions. Thermal limits of protective relaying devices are incorporated within the CT ratings.

## 4.5 Contact Information

Questions or comments to Ameren regarding its Rating Criteria should be directed to:

Mr. Dennis Kramer
Manager Transmission Policy & Planning
Ameren Services Company
P.O. Box 66149, MC 635
St. Louis, MO 63133-6149

## 5.0 GLOSSARY OF TERMS

Adequacy

Adequacy is the ability of the bulk electric power system to supply the aggregate electrical power and energy requirements of the customers at all times, considering scheduled and unscheduled outages of system components.

Bulk Substation

On the Ameren system, bulk substations provide transformation from transmission to subtransmission voltage levels. In general, these substations step the voltage down from 138 kV to 34.5 kV in the St. Louis Metropolitan area and close-in Regional areas, and from 161 kV to either 34.5 kV or 69 kV in the outer Regional areas.

Collapse

The uncontrolled loss of customer load over a widespread area (usually referred to in a system context). System collapse can generally be attributed to cascading transmission outages, islanding situations with a large imbalance between available generation and connected load, or excessive power imports without sufficient local area reactive support to maintain system voltages.

Emergency Operation

Emergency Operation is the period of time when one or more transmission elements (line, generator, or transformer) would experience a forced outage. Emergency ratings, based on eight hours duration, would be applied to equipment loadings and all system voltages should fall within emergency ranges.

Facility

A collection of electrical components, such as breakers, disconnect switches, CTs, wavetraps, overhead line conductors and substation conductors, which, when assembled together, function as a single unit.

FCITC

First Contingency Incremental Transfer Capability (FCITC) is the maximum amount of power in excess of the base case interchange schedule that can be safely transferred in a specific direction under peak load conditions without any facility becoming loaded above its emergency rating following the outage of the most critical element.

FCTTC

First Contingency Total Transfer Capability (FCITC) is the algebraic sum of the FCITC and the base interchange schedule in the direction of interest.

IITC

Incremental Transfer Capability is the amount of power, in excess of the base case interchange schedule that can be transferred over the transmission network without giving consideration to the effect of transmission facility outages.

Interconnection Reliability Operating Limit (IROL)

The value (such as MW, Mvar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits (SOL), which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

MISO

Midwest Independent System Operator

NERC

NERC is the North American Electric Reliability Corporation, an organization consisting of eight regional reliability councils and one affiliate, which encompasses all of the power systems of the continental United States, the seven bordering provinces of Canada, and the Baja California area of Mexico.

Normal Operation

Normal Operation is the period of time when all transmission facilities are either in service or one or more scheduled outages are in effect. Continuous or normal ratings would be applied to equipment loadings and all system voltages should fall within normal ranges.

One-in-Ten Load Level

One-in-ten load levels are based on the statistical probability of the Ameren system load reaching or exceeding this level only once in ten years. This load level is used to model Ameren system loads for some short-term operational studies, and for specific local area bulk supply studies. This is also referred to as the 90/10 forecast load level.

One-in-Two Load Level

One-in-two load levels are based on the statistical probability of the Ameren system load reaching or exceeding this level once in two years. This load level is typically used for Ameren miscellaneous transmission planning studies, SERC studies, and other transfer capability studies. This is also referred to as the 50/50 forecast load level.

Operating Guide

An Operating Guide is an operating procedure that is considered available for use in determining transfer capabilities if implemented on a precontingency basis or on a post-contingency basis without operator intervention. In addition to this, an operating guide requiring operator intervention on a post-contingency basis would also be considered if the affected system will withstand any resulting overloads until the operating guide is implemented and no undue burden is placed on neighboring systems. An Operating Guide could involve the redispatch of local generation or the manual switching of transmission elements. An operating guide would only be considered as a short-term solution to a transmission loading problem as a result of single contingency conditions until additional facilities can be constructed. For beyond single contingency conditions, the use of an operating guide would be permitted for an extended period until system reinforcement is implemented.

Reliability

Reliability in a bulk electric power system is the degree to which the performance of the elements of that system results in power being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. Bulk electric power system reliability can be addressed by considering two basic and fundamental aspects of the bulk power system - Adequacy and Security.

RFC

Reliability*First* Corporation -- A regional reliability organization (RRO) formed in June, 2005 by the combination of many of the members of the East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN), three regional reliability organizations (RROs) of the North American Electric Reliability Corporation (NERC). The purpose of Reliability*First* is to preserve and enhance electric service reliability and security of the interconnected electric system and to be a regional entity under the framework of NERC or other entity established under the recently signed U.S. federal energy legislation.

Safe Loading Limit

The safe loading limit is the limit to which a particular line or transformer may be loaded under a specific set of circumstances so that, if another facility is suddenly outaged, the facility in question would load to no higher than its emergency rating. Ameren‟s Transmission Planning generally recognizes this philosophy.

Security

Security is the ability of the bulk electric power system to withstand sudden disturbances such as electric short circuits or the unanticipated loss of system components.

SERC

SERC is the Southeastern Electric Reliability Corporation, Inc., one of the eight reliability organizations of NERC, and it is composed of members from Alabama, Arkansas, the Carolinas, Georgia, Illinois, Iowa, Kentucky, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Virginia. SERC is divided into five subregions: Entergy, Gateway, Southern, TVA, and Virginia-Carolinas area. Its primary purpose is to promote, coordinate, and insure the reliability and adequacy of the bulk power supply systems in the area served by its Member Systems.

Subtransmission

On the Ameren system, subtransmission is the portion of the power delivery system from the dead-end insulators or potheads at the bulk substation feeder positions to the high-side bushings at the distribution substation transformers. Subtransmission also includes the taps to large customers supplied directly from the 34.5 kV or 69 kV systems.

System Operating Limit (SOL)

The value (such as MW, Mvar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)

- Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)

- Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability

- System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)

Transmission Line Loading Limit

The transmission line loading limit of each transmission line is determined by a review of the thermal capability of each component of the circuit and its terminals, as well as a review of any relay or sag limitations. Through this review, the element which is the most limiting is determined for each of the following conditions: Summer Normal, Summer Emergency, Winter Normal, and Winter Emergency.

Transmission Substation

In Transmission Planning, transmission substation is a station in which two or more transmission circuits (138 kV or above) connect, or where voltage transformation takes place between transmission voltage levels.

Transmission System

The document uses “transmission system” to refer to all bulk power supply system facilities 100 kV and above, including radial facilities.

## 6.0 LIST OF DOCUMENTED SOURCES OF OTHER PLANNING CRITERIA

6.1 North American Electric Reliability Corporation (NERC) Reliability Standards.
65.2 Federal Energy Regulatory Commission (FERC) Order 661A "Interconnection for Wind Energy", Issued December 12, 2005

Appendix II for Table I from NERC Reliability Standards TPL-001 through TPL-004

Appendix IV for "Guide to Wind Power Facility Interconnection Studies", dated March 30, 2012.

# Justification for Rating Assumptions

I.1.1 Transmission Transformers

Ameren uses manufacturer"s nameplate ratings for network power transformers for both normal and emergency conditions. Ameren has attempted to develop ratings beyond nameplate for these large autotransformers, but the manufacturers typically have not agreed to any extended ratings. If a transformer would become limiting on the Ameren system, a short-term emergency rating may be developed as described in section 4.4.3. The IEEE Guide for Loading Mineral-Oil-Immersed Transformers (IEEE Standard C57.91-1995) may be consulted to help determine an appropriate rating.

I.1.2 Line Conductors

Ameren line conductor rating assumptions are based on the House and Tuttle method of calculating heat transfers and ampacities assuming common weather parameters for all Ameren companies. The values for the rating parameters used by Ameren are generally accepted in the industry, and modified only slightly to fit the geographical location. An internal computer program calculates the conductor ampacities based on the parameters provided using the same thermal equations used in IEEE Standard 738-1993 for calculation of the current-temperature relationship of bare overhead conductors.

I.1.3 Bus Conductors

For Ameren stranded bus conductors, the rating assumptions are based on the House and Tuttle method of calculating heat transfers and ampacities. Ratings for rigid-bus conductors are based on the IEEE Guide for the Design of Substation Rigid-Bus Structures 605-1998. Tables of conductor ratings are included in Transmission and Distribution Design Department Standard No. 8G.

I.1.4 Circuit Breakers

Ameren uses manufacturer nameplate ratings for circuit breakers for both normal and emergency conditions. If a circuit breaker becomes limiting on the Ameren system, an extended rating may be applied based on ANSI standard C37.010b (1985).

I.1.5 Disconnect Switches

Ameren uses manufacturers nameplate ratings for disconnect switches for both normal and emergency conditions. An extended rating, particularly for conditions with lower ambient temperatures, may be applied based on ANSI standard C37.37 (1979) if a disconnect switch becomes limiting on the Ameren system. The use of an extended rating will depend on the condition of the switch.

I.1.6 Wave Traps

Ameren uses manufacturer nameplate ratings for rating wave traps under normal conditions. An extended rating, particularly for conditions with lower ambient temperatures, may be applied based on ANSI standard C.93.3 (1981) Appendix Table A1. This table shows emergency loading multipliers of 120% for one hour and 110% for four hours based on a 40 degree C ambient temperature.

I.1.7 Current Transformers

Ameren uses manufacturer nameplate ratings, including the continuous thermal current rating factor, for current transformers for both normal and emergency conditions.

An extended rating, particularly for conditions with lower ambient temperatures, may be applied based on ANSI Standard C57.13 (1978) Figure 1. This figure shows a rating multiplier of 125% can be used for an average ambient temperature of 0 degrees C with a thermal rating factor of 1.0.

I.1.8 Series Reactors

Ameren uses manufacturer nameplate ratings for series reactors for both normal and emergency conditions.

I.1.9 Shunt Reactors

Ameren uses manufacturer nameplate ratings adjusted for nominal system voltage to rate shunt reactors connected to the transmission system. These voltage adjusted ratings are used for both normal and emergency conditions.

I.1.10 Shunt Capacitors

Ameren uses manufacturer nameplate ratings adjusted for nominal system voltage to rate shunt capacitors connected to the transmission system. These voltage adjusted ratings are used for both normal and emergency conditions.

I.1.11 Protective Relaying Devices

Ameren uses manufacturer nameplate ratings for protective relaying devices for both normal and emergency conditions. Thermal limits of protective relaying devices are incorporated within the CT ratings.

Table I. Transmission 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><br>Yes<br>Yes<br>Yes<br>Yes | <br><br>No [b]<br>No [b]<br>No [b]<br>No [b] | <br><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) | Yes<br>Yes | Planned/ Controlled [c]<br>Planned/ Controlled [c] | No<br>No |
| | SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, 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 Fault (non 3Ø), with Normal Clearing [e]:<br>5. Any two circuits of a multiple circuit towerline [f] | Yes<br>Yes | Planned/ Controlled [c]<br>Planned/ Controlled [c] | No<br>No |
| | SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):<br>6. Generator<br>7 Transformer<br>8. Transmission Circuit<br>9. Bus Section | <br>Yes<br>Yes<br>Yes<br>Yes | <br>Planned/ Controlled [c]<br>Planned/ Controlled [c]<br>Planned/ Controlled [c]<br>Planned/ Controlled [c] | <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<br>2. Transmission Circuit<br>3. Transformer<br>4. Bus Section<br><br>3Ø Fault, with Normal Clearing[e]:<br>5. Breaker (failure or internal Fault)<br><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 Reliability Organization. | 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 Reliability 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.

## Schedules of Ameren Normally Open Transmission Circuit Breakers and Disconnect Switches

The Ameren operating utilities have installed a number of circuit breakers and disconnect switches at the transmission level that are operated normally open to limit fault levels, to control power flow, to enhance reliability to the customer load, and to provide for operating flexibility during maintenance, construction, or outage of transmission facilities. These normally open devices are identified below and are noted on the various system operating and one-line diagrams. This information is also used to model the Ameren transmission system in powerflow, short circuit, and stability simulations.

### A. Schedule of Ameren 138 kV Bus Splits

The following transmission circuit breakers and disconnect switches are operated normally open to limit short circuit currents and/or transmission flows on the Ameren system.

| 138 kV Bus Split | Open Circuit Breaker or Switch | Fault or Powerflow Control | Suggested Allowable Closing/Reclosing |
|---|---|---|---|
| Berkeley (UE) | Bus-Tie 1-2 Breaker | Fault | Automatic closure when Bus-Tie 1-4, Bus-Tie 2-3, or a Berkeley 138 kV line breaker opens |
| Cahokia (CIPS) * | Position H25 Breaker | Fault | None Recommended |
| Euclid (UE) | Bus-Tie 2-3 Breaker | Fault (Page) and Powerflow | Close if Page-Euclid-1 or Campbell-Euclid-4 Out of Service |
| Laclede - Alton Steel (CIPS) | Bus-Tie Switch | Fault (Wood River) | Close if Line 1436 or Line 1456 Out of Service |
| Mason (UE) | Bus-Tie 2-3 Breaker | Fault | None Recommended |
| Meramec (UE) | Bus-Tie 3-4 Breaker | Fault | Close if no Meramec units synchronized |
| North Decatur (IP) | Bus-Tie 1351 Breaker | Fault | None Recommended |
| Sioux (UE) ** | Position 23H Breaker | Fault | Close if no Sioux units synchronized |
| Taum Sauk (UE) | Position 3H Breaker (no relaying) | Fault and Powerflow | Close if one Taum Sauk unit is not synchronized |

* The Cahokia 230/138 kV transformer should be connected to Cahokia 138 kV Bus 2 (breaker H17 closed and breaker H23 opened) for the conditions with all facilities in service. For conditions with Cahokia 345/138 kV transformer #9 out of service, the Cahokia 230/138 kV transformer may be connected to Cahokia 138 kV Bus 3 (breaker H25 closed and breaker H17 opened) to provide for a stronger source with Pinckneyville generation on.

** The Sioux 345/138 kV transformer should be connected to Sioux 138 kV Bus 1A (breaker 15H closed and breaker 23H opened) for the conditions with all facilities in service. For conditions with

Sioux generator #2 off, the Sioux 345/138 kV transformer may be connected to Sioux 138 kV Bus 2 (breaker 23H closed and breaker 15H opened) to provide for a stronger source.

## B. Schedule of Ameren Substations with Normally Open Transmission Bus-Tie Switches

The following distribution and bulk substations are connected to the Ameren transmission system with two or three supply lines, but with normally open bus-tie disconnect switches at the transmission level. The line and bus-tie disconnect switches at many of these two unit distribution substations are equipped with motor operators to allow both transformers to be supplied from the remaining transmission line following a transmission line outage. The line and bus-tie disconnect switches at the bulk and larger distribution substations typically do not have motor operators and these switches must be operated manually to allow a transmission line to supply more than one transformer.

| Substation | Open Switch | Facility |
|---|---|---|
| | | |
| Barrett Station (UE) | 1462 | Bus-Tie 1-2 |
| Brennen (UE) | 998 | Bus-Tie 1-2 |
| Buick Mine (UE) | B6250 | Bus-Tie 1-2 |
| Buick Smelter (UE) | B6850 | Bus-Tie 1-2 |
| Clarkson (UE) | 1257 | Bus-Tie 1-2 |
| Diamond Star (IP) | 1303 | Bus-Tie 1-2 |
| Dorsett (UE) | 1204 | Bus-Tie 1-2 |
| Eatherton (UE) | 1438 | Bus-Tie 1-2 |
| Florissant (UE) | 1167 | Bus-Tie 1-2 |
| Fort Zumwalt (UE) | Pos H7 | Bus-Tie 1-3 |
| Gratiot (UE) | 89 1-2 | Bus-Tie 1-2 |
| Gratiot (UE) | 89 2-3 | Bus-Tie 2-3 |
| North Park (UE) | 1650 | Bus-Tie 1-2 |
| Orchard Gardens (UE) | 1174 | Bus-Tie 1-2 |
| Ringer (UE) | 1172 | Bus-Tie 1-2 |
| Robinson-Marathon N (CIPS) | 1326 | Bus-Tie 1-2 |
| Rudder (UE) | 1143 | Bus-Tie 1-2 |
| Russell (UE) | 89 1-2 | Bus-Tie 1-2 |
| Russell (UE) | 89 2-3 | Bus-Tie 2-3 |
| Schuetz (UE) | 1190 | Bus-Tie 1-2 |
| State Farm (IP) | 1305 | Bus-Tie 1-2 |

## C. Schedule of Ameren Emergency Transmission Supplies

Normally open transmission line or substation switches have been installed at the following substations to allow for the manual reestablishment of a transmission supply line for a river crossing or other major transmission line outage(s) for an extended period of time. Except for the Miller-Zion 161 kV line, all of the other transmission facilities are in service. The Miller–Zion 138 kV line would be able to supply the Zion dual high-side 161-138 x 69 kV transformer for extended outages of the 161 kV Mariosa-Zion-Apache Flats 161 kV line.

| Substation | Open Switch | Facility |
|---|---|---|
| Lemay (UE) | 21 (line) | Meramec-Watson-2 |
| Lemay (UE) | 22 (line) | Meramec-Watson-2 |
| Miller (UE) | 13062 | Miller-Zion-1 |
| Mississippi (CIPS) | Pos H13 | Wood River-N Staunton 1436 |
| Russell (UE) | Pos W | Cahokia-Poplar-5 |
| Turris Coal (IP) | 8003 (line) | N Decatur-Latham 1342C |

## D. Schedule of Ameren Substations with Preferred /Reserve Connection Arrangements

The following distribution and bulk substations connected to the Ameren transmission system have preferred/reserve connection arrangements where the preferred connection is to be used to supply the substation load for all times except during transmission contingencies. The reserve connection is operated as normally open and is used for those conditions when the preferred connection transmission is unavailable.

| Substation | Preferred Supply (Normally Closed) | Reserve Supply (Normally Open) |
|---|---|---|
| Belle (UE) | Tegeler-Osage-1 | Gasco-Osage-2 |
| Calumet (UE) | Pike-Dundee-3 | Pike-Dundee-4 |
| Fountain Lakes (UE) | Sioux-Huster-3 | Sioux-Huster-1 |
| Gasco (UE) | Gasco-Osage-2 | Tegeler-Osage-1 |
| Meta (UE) | Gasco-Osage-2 | Tegeler-Osage-1 |
| Miller (UE) | Tegeler-Osage-1 | Gasco-Osage-2 |
| North Decatur (IP) | West Bus (breaker 1566-W) | East Bus (breaker 1566-E) |
| Taum Sauk (UE) | Rivermines-Taum Sauk-2 | Rivermines-Taum Sauk-1 |

## E. Schedule of Other Ameren Connection Arrangements

A number of substations in the IP and CILCO areas were built with substation bus arrangements, including multiple sets of disconnect switches, that allow generators, transmission lines and transformers to connect to either one or both 138 kV substation busses. As the transmission system was developing in the 1950s and early 1960s, this operating flexibility allowed for a high level of reliability in the event of breaker failures, transmission bus outages, or other conditions with multiple transmission facilities out of service at the same time. However, as the transmission system has developed since that time with the 345 kV network feeding into the 138 kV system via multiple 345/138 kV transformers, the need to transfer transmission facilities from one substation bus to another to maintain reliability has diminished significantly. The following 138 kV disconnect switches are operated normally open with no suggested closing.

| Substation | Open Switch | Facility |
|---|---|---|
| | | |
| East Springfield (CILCO) | 98-31 | Line 1398 Connection to West Bus |
| East Springfield (CILCO) | 22-32 | Line 1422 Connection to East Bus |
| East Springfield (CILCO) | 68-14 | Xfmr #1 Connection to East Bus |
| East Springfield (CILCO) | 38-31 | Xfmr #3 Connection to West Bus |
| Havana (IP) | 1329 | Xfmr B060 Connection to East Bus |
| Havana (IP) | 1332 | Unit #6 Connection to West Bus |
| Havana (IP) | 1337 | Bus Tie |
| Hennepin (IP) | 1313 | Bus Tie |
| Hennepin (IP) | 1316 | Unit 1 Connection to North Bus |
| Hennepin (IP) | 1322 | Line 1512 Connection to South Bus |
| Hennepin (IP) | 1326 | Line 1516 Connection to South Bus |
| Hennepin (IP) | 1329 | Bus Tie |
| Midway (IP) | 1412 | Line 1626 Connection to East Bus |
| Midway (IP) | 1409 | Bus Tie |
| Midway (IP) | 1405 | Bus Tie |
| Midway (IP) | 1417 | Line 1466 Connection to West Bus |
| Mt. Vernon West (IP) | 1417 | Bus Tie |
| Mt. Vernon West (IP) | 1412 | Line 1546 Connection to West Bus |
| Mt. Vernon West (IP) | 1410 | Line 1336 Connection to East Bus |
| Mt. Vernon West (IP) | 1422 | Xfmr 4 Connection to East Bus |
| North Champaign (IP) | 1314 | Line 1396 Connection to East Bus |
| North Champaign (IP) | 1309 | Line 1386 Connection to West Bus |
| North Champaign (IP) | 1305 | Bus Tie |
| North Decatur (IP) | B059 | Xfmr 5 Connection to East Bus |
| North Decatur (IP) | B089 | Xfmr 8 Connection to West Bus |
| Oglesby (IP) | 1499 | Line 1496 Connection to Bus 2 |
| Oglesby (IP) | 7719 | Line 7713 Connection to Bus 2 |
| Oglesby (IP) | 1555 | Line 1556 Connection to Bus 1 |
| Oglesby (IP) | 1381 | Line 1382 connection to Bus 1 |
| Oglesby (IP) | 387 | PT Connection to bus 1 |
| Oglesby (IP) | 1519 | Line 1516 Connection to Bus 2 |
| | | |
| | | |
| | | |
| South Centralia (IP) | 1306 | Xfmr 1 Connection to South Bus |

| | | |
|---|---|---|
| South Centralia (IP) | 1310 | Line 1546 Connection to South Bus |
| Stallings (IP) | 1322 | Xfmr 5 Connection to North Bus |
| Stallings (IP) | 1304 | Xfmr 3 Connection to South Bus |
| | | |
| | | |
| Stallings (IP) | 1316 | Xfmr 6 Connection to South Bus |
| Wood River (IP) | 1313 | Bus Tie |
| Wood River (IP) | 1318 | Line 1456 Connection to Northeast Bus |
| Wood River (IP) | 1322 | Line 1502 Connection to Northeast Bus |
| Wood River (IP) | 1324 | Xfmr 5 Connection to Southwest Bus |
| Wood River (IP) | 1329 | Line 1506 Connection to Southwest Bus |

## F. Schedule of Ameren Bypass Disconnect Switches

Past practices by some of the operating utilities in the late 1950s and early 1960s resulted in the installation of normally open circuit breaker and meter bypass switches. These switches would only be used in the event of a circuit breaker or metering element outage to be able to restore customer load more quickly to minimize the outage time to the customer. However, system protection was often compromised by using these devices as required relaying changes were often not implemented or not reset when the outaged equipment was returned to service. As the 138 kV transmission network developed, with transmission supplies to substations from more than one source, the installation of these bypass disconnect switches became unnecessary. Further, the infrequent use of these bypass switches resulted in reliability concerns. Therefore, the practice of installing bypass disconnect switches was discontinued, and more recently, the practice has been changed to remove the disconnect switches (the live parts as a minimum) whenever other construction work in a substation is performed. Below is a list of the bypass disconnect switches that are candidates for removal or disabling. Note that there are just a few of these bypass disconnect switches located on the Ameren Missouri transmission system.

| Substation | Open Switch | Facility |
|---|---|---|
| | | |
| Cape Clark (UE) | 163 | Breaker 160 Bypass |
| Cat 1 (CILCO) | 1361-27 | Meter Bypass |
| Cat 1 (CILCO) | 1362-15 | Breaker 1362 and Meter Bypass |
| Cat 2 (CILCO) | 1331-15 | Meter Bypass |
| Cat Mapleton (CILCO) | 4594-19 | Meter Bypass |
| Cat Mossville (CILCO) | 77-27 | Meter Bypass |
| Cominco (UE) | B7791 | Breaker B7714 Bypass |
| East Kewanee (IP) | B019 | Breaker B010 Bypass |
| East Kewanee (IP) | 1554 | Breaker 1552 Bypass |
| Keystone (CILCO) | 99-15 | Meter and Breaker 1389 Bypass |
| Keystone (CILCO) | 9697-28 | Meter Bypass |
| Keystone (CILCO) | 87-15 | Meter and Breaker 1387 Bypass |

| | | |
|---|---|---|
| | | |
| Kickapoo (CILCO) | 1325-15 | Breaker 1325 Bypass |
| | | |
| Midway (IP) | 1544 | Breaker 1542 Bypass |
| Midway (IP) | B019 | Breaker B010 Bypass |
| | | |
| Mt. Vernon West (IP) | B0139 | Breaker B013 Bypass |
| Mt. Vernon West (IP) | 1548 | Breaker 1546 Bypass |
| Mt. Vernon West (IP) | 1338 | Breaker 1336 Bypass |
| | | |
| | | |
| South Centralia (IP) | 1544 | Breaker 1542 Bypass |
| South Centralia (IP) | 1548 | Breaker 1546 Bypass |
| Stallings (IP) | 1458 | Breaker 1456 Bypass |
| Stallings (IP) | 1454 | Breaker 1452 Bypass |
| | | |
| Viaduct (UE) | 5243 | Breaker 5240 Bypass |
| Wood River (IP) | B403 | Breaker B400 Bypass |
| Wood River (IP) | B503 | Breaker B500 Bypass |
| Wood River (IP) | 1454 | Breaker 1452 Bypass |
| Wood River (IP) | 1508 | Breaker 1506 Bypass |

# Guide to Wind Power Facility Interconnection Studies

REVISION 3

**Transmission Planning & Interconnections**
**Ameren**
March 30, 2012

TABLE OF CONTENTS

1. INTRODUCTION

All Wind Power Facilities (**WPFs**) that connect to transmission system voltages on the Ameren Transmission System are required to comply with the Guide to Wind Power Facility Interconnection Studies (**GWPFIS**). The electrical behavior of Wind Turbine Generators (**WTG**) can be significantly different from the characteristics of synchronous generators. Therefore technical requirements for **WPFs** interconnection studies are defined which are applicable to **WPFs** interconnecting with the Ameren Transmission System.

The guide specified in this document incorporates Federal Energy Regulatory Commission (FERC) Order 661A rules and criteria, and could be subject to change in the event that North American Electric Reliability Corporation (NERC), Federal Energy Regulatory Commission (FERC), or Southeast Electric Reliability Corporation (SERC) Wind Power requirements are modified. The technical requirements also take into consideration that some issues need to be studied further before implementing specific technical requirements arising from the variability of wind power.

The purpose of this document is to define the required technical requirements from a **Wind Power Interconnection** perspective to ensure that wind power facilities contribute to continued safe and reliable operation of the Ameren Electric System

2. OBJECTIVE

The primary objective of the **GWPFIS** is to establish the technical rules and requirements that a WPF must comply with in relation to their connection to the Ameren Transmission System.

3. WIND POWER FACILITY DESCRIPTION

A WPF typically will have several Wind Turbine Generators (**WTGs**) connected to individual **WTG** step-up transformers. The **WTG** transformers will step-up voltages from a typical 600-volt level to a typical 25 kV to 34.5 kV level called the collector level. A **WPF** may have several collectors that will connect to the collector bus. The collector bus is connected to the low side of the transmission step-up transformer(s). Figure 3.0 shows the typical Wind Power Facility Configuration.

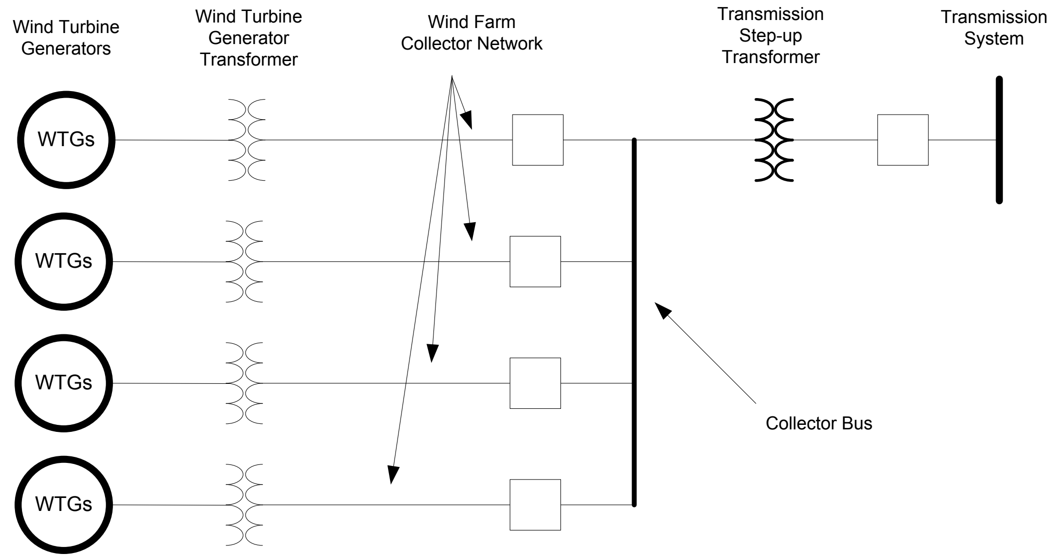



Figure 3.0 – Typical Wind Power Facility Configuration

4. MODELING REQUIREMENTS

   a) The procedures for studying generator connections to the Ameren transmission system are governed by MISO. The MISO Generator Interconnection Manual, MISO Attachment X: Generator Interconnection Procedures (GIP) would be applicable.

   b) Where an appropriate model is not available within PSS/E, the **WPF** Owner must supply a working user written PSS/E model.

   c) **WPF** Owners that provide user written model(s) must provide compiled code of the model and are responsible to maintain the user written model compatible with current and new release of PSS/E until such time as a standard model is provided.

5. TECHNICAL REQUIREMENTS FOR WIND POWER FACILITIES INTERCONNECTION STUDY

   5.1. Wind Power Facility Aggregated MW Capability

   A **WPF** owner must provide Ameren with the **WPF** aggregated MW capacity as determined at the collector bus(es). The **WPF** aggregated MW capacity shall be used to determine the **WPF** requirements associated with real and reactive power capability.

   5.2. Low Voltage Ride Through (LVRT) Requirements

a) LVRT requirements are applicable to all transmission connected generating facilities where the **WPF** aggregated MW capability is greater than 5 MW. Ameren will continue to monitor development of facilities 5 MW and less and may revise the MW threshold.

b) **WPF**(s) are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4-9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to **prefault voltage** unless clearing the fault effectively disconnects the generator from system.

c) The fault clearing time requirement for a three-phase fault will be specific to the **WPF** substation location, as determined by and documented by Ameren. The maximum clearing time the **WPF** shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u, for the transition period, and 0 p.u. for the post transition period, after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the **WPF** may disconnect from the transmission system.

Note: The transition period covers wind generating plants subject to FERC Order 661A that have either: 1) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or 2) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

d) Voltage described in c) is measured at the **high side of the WPF step-up transformer** (i.e. the transformer that steps the voltage up to the transmission interconnection voltage).

e) Exceptions:

   i. **WPFs** are not required to ride through transmission system faults that cause a forced outage of a radial line to the **WPF**.

   ii. **WPFs** are not expected to ride through faults that would occur between the wind generator terminals and the high side of the GSU serving the facility (including GSU, Collector Bus(es), Collector Systems or **WTG(s)).**

   iii. **WPFs** may be tripped after the fault period if this action is intended as part of a special protection system.

f) WPFs may meet the LVRT requirements of this Guide through generator performance or by the installation of additional equipment (e.g., StatCom, Dvar, etc) within the WPFs or by a combination of generator performance and additional equipment.

5.3. Voltage Regulation / Reactive Power Requirements

All synchronous generator interconnections must be designed to operate across the power factor range of 0.95 leading (absorbing reactive power from the network) to 0.95 lagging (providing reactive power to the network) at the Point of Interconnection (**POI**). A non-synchronous generator, such as a **WPF**, is also required to operate across the power factor range of 0.95 leading to 0.95 lagging at the **POI**, if the System Impact Study related to the generator connection demonstrates this is necessary for the safety or reliability of the system (FERC Order 661A). Ameren‟s interpretation of FERC Order 661A requires a non-synchronous generator to be capable of assisting with system voltage control if the system impact study related to the generator connection shows the voltage at the **POI** will not stay within the voltage schedule specified by the Transmission Operator if the non-synchronous generator operates as var neutral.

The need for a **WPF** to have reactive capability in the system impact study is determined with the following methodology. The **WPF** is modeled as var neutral in both the summer peak and off-peak models. If the **POI** does not stay within the assigned voltage schedule for NERC Category A or B contingency conditions, or for Line + Generator contingency (Ameren Criteria) conditions, then the wind farm will be required to provide assistance in controlling voltage by being designed to operate from 0.95 lagging to 0.95 leading at the **POI**. If the voltage schedule is met with the WPF modeled as var neutral, then the **WPF** would be allowed to operate as var neutral at the **POI**.

Voltage regulation and reactive power capability from **WPF** can vary with technology. Some **WPFs** may utilize reactive capability from WTGs, other WPFs may use dynamic var devices, and some **WPFs** may be aggregated with synchronous generators.

Some **WPFs** may wish to connect to a common transmission substation and may wish to consider aggregating voltage regulation and reactive power from a single source for multiple **WPFs**. Such a proposal would be subject to review and approval by Ameren.

Voltage regulation is essential for reliable system operation and requires some reactive capability in order to perform. Voltage regulation and reactive power performance of a **WPF** will be assessed at the **POI** of a **WPF**. All reactive power requirements are based on the rated **POI** voltage. The **WPF** must be able to regulate the system voltage both under system non-disturbance and system disturbance conditions.

The Guide identifies a minimum requirement for dynamic vars and permits some controlled reactive devices such as capacitor banks to satisfy total reactive power requirements.

5.3.1. **WPF** Total Reactive Power Capability

a) A WPF shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the point of interconnection, if Ameren"s System Impact Study shows that such a requirement is necessary to ensure safety or reliability of the system (FERC Order 661A).

b) The power factor range requirement can be met by the automatic voltage regulation at the generator excitation system, or by using the dynamic reactive devices (e.g., StatCom, Dvar, etc) or by using non-dynamic reactive devices (e.g., fixed and switched capacitor banks), or a combination of these means of providing reactive power.

5.3.2. Dynamic Reactive Power Capability

a) A **WPF**"s lagging dynamic reactive power capability is determined by LVRT analysis in section 5.2, which is performed on a case by case basis.

b) A **WPF**"s leading dynamic reactive power capability is determined by High Voltage Ride Through (HVRT) analysis. Since there is no HVRT requirement For Wind Power in FERC Order 661A, for the time being, Ameren assume the leading dynamic reactive power to be zero.

c) A **WPF** shall be able to provide sufficient dynamic voltage support in lieu of the automatic voltage regulation at the generator excitation system if the System Impact Study shows this is to be required for system safety or reliability.

5.3.3. Non-Dynamic Reactive Power Capability

Within the total reactive power capability, the non-dynamic reactive power capability and dynamic reactive power capability are closely related with each other.

Figure 5.3.a illustrates the procedure to perform the WPF interconnection study, and Figure 5.3.b illustrates the procedure to perform a reactive power capability calculation, and it also illustrates the procedure to determine the optimal non-dynamic reactive power capability and dynamic reactive power capability for the particular location. The goal is to minimize the dynamic reactive capability, and meanwhile keep the system safe and reliable.

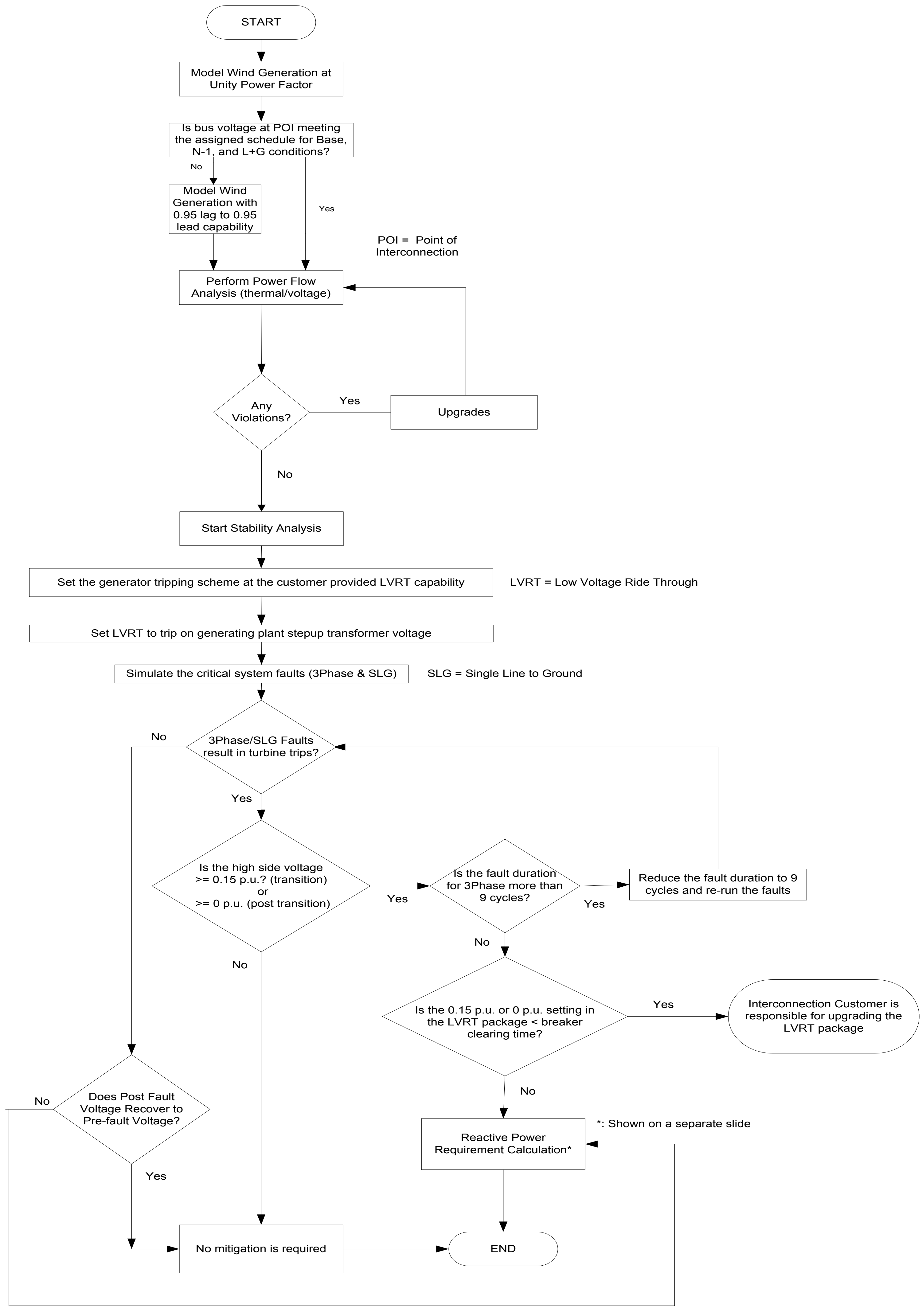



Figure 5.3.a – Wind Power Facility Connection Procedure

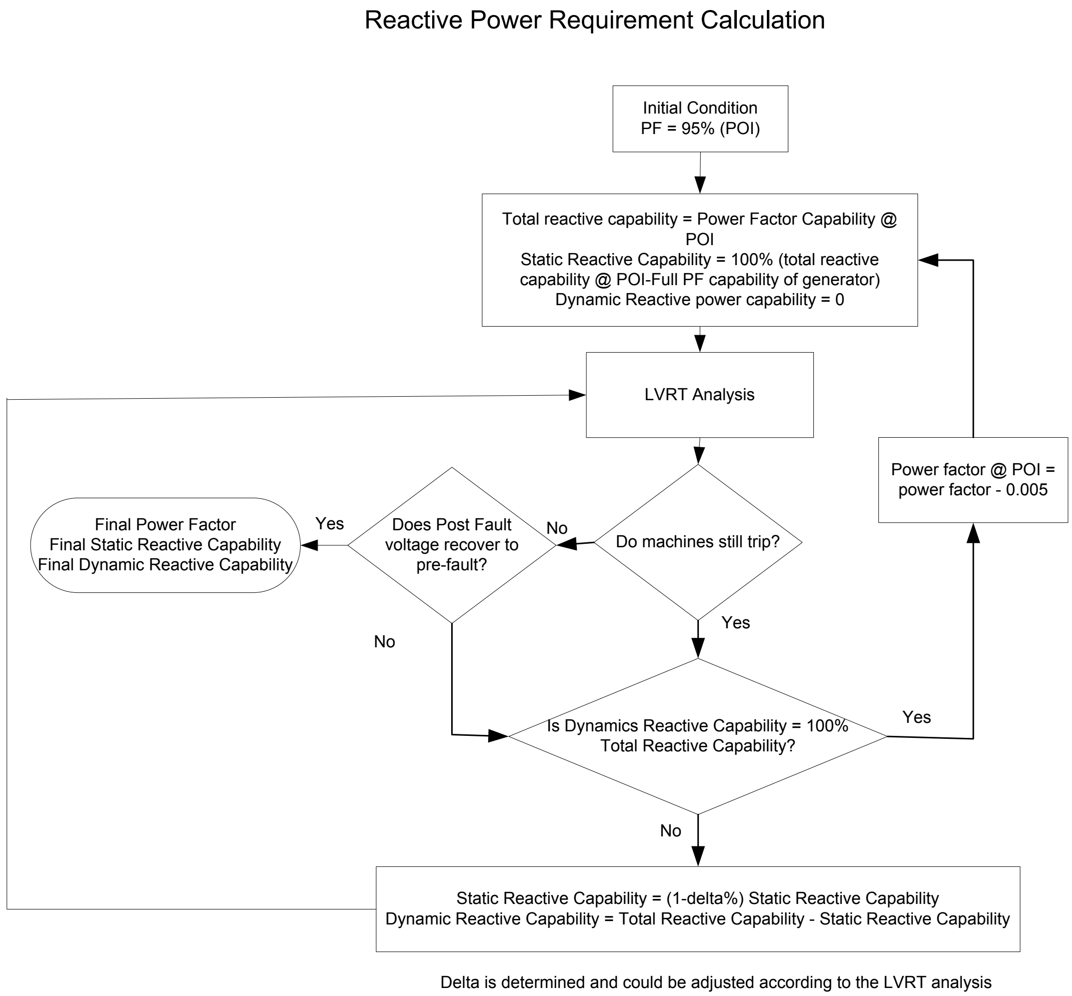



Figure 5.3.b – Reactive Power Capability Calculation

## 5.4. Power Quality

The **WPF** shall comply with industry standards and guidelines for power quality including but not limit to the following.

### 5.4.1. Voltage Flicker

Refer to Ameren‟s Transmission Planning Criteria and Guidelines document, Section 3.1.4.

5.4.2. Harmonics

Refer to Ameren"s Transmission Planning Criteria and Guidelines document, Section 3.1.4.

a) Upon request from the WPF owner, Ameren will provide the WPF owner with information describing the specific harmonic-impedance envelope at the proposed Point of Connection.

b) The WPF owner is required to mitigate harmonic currents resulting from non-compliance with IEEE Standard 519.

5.4.3. Voltage Unbalance

The voltage unbalance on the electrical system under normal operating conditions may reach 3%. A WPF should not cause voltage unbalance to exceed 3%. The voltage unbalance is calculated using the following formula:

Unbalance (%) = 100* (deviation from average)/ (average)

The calculation is derived from NEMA MG 1-14.33.

5.4.4. Resonance

The WPF owner must design the facility to avoid introducing undue resonance on the Ameren system. Of particular concern are self-excitation of induction machines, transformer ferroresonance, and the resonant effects of capacitor additions and the capacitance of the WPF collector cables.

5.5 System Conditions for Modeling

For areas of the system with significant WPF, assessments to determine compliance with NERC Standards and other Ameren Criteria related to power flow on system elements will include at least the following critical system conditions:

5.5.1 WPF shown at 20% of the aggregated MW level and system loads at projected peak.

5.5.2 WPF shown at 100% of the aggregated MW level and system loads in the range of 70% to 80% of projected peak for wind generation in the immediate study area. To reflect the fact that all wind farms in a wide geographic area will rarely be operating at 100% of nameplate capacity at the same time, wind generation located outside the immediate study area should be represented at 90% of the aggregated MW level. General system studies would be performed with wind generation represented at 90% of aggregated MW level.

# Ameren Missouri Plant Voltage Schedules

| Unit | Owner | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|---|
| **Callaway** | Ameren Missouri | 345 | MTGY-CAL-7 PT | Bus A | 358.8-365.5 |
| **Fairgrounds** | Ameren Missouri | 69 | 69 kV Bus | ------ | 71.1 - 72.5 |
| **Howard Bend** | Ameren Missouri | 13.8 | Howard Bend transformer | ------ | 13.8-14.2 |
| **Keokuk (all units)*** | Ameren Missouri | 69 | Bus 1 | Bus 3 | 71.1 - 72.5 |
| **Kirksville** | Ameren Missouri | 34.5 | 34.5 kV Bus | ------ | 35.5 - 36.2 |
| **Labadie (all units)*** | Ameren Missouri | 345 | Bus 4 | Bus 3 | 358.8-365.5 |
| **Meramec 1/4** | Ameren Missouri | 138 | Bus 4 | Bus 1 | 142 - 144.9 |
| **Meramec 2/3*** | Ameren Missouri | 138 | Bus 2 | Bus 3 | 142 - 144.9 |
| **Mexico** | Ameren Missouri | 69 | TBD | TBD | 71.1 - 72.5 |
| **Moberly** | Ameren Missouri | 69 | 69 kV Bus | ------ | 71.1 - 72.5 |
| **Moreau** | Ameren Missouri | 69 | Bus | ------ | 71.1 - 72.5 |
| **Osage*** | Ameren Missouri | 138 | Bus 1 | Bus 2 | 142 - 144.9 |
| **Peno Creek** | Ameren Missouri | 161 | Bus 1 | GSU Transformer | 166 - 169 |
| **Rush Island (Both Units)** | Ameren Missouri | 345 | Bus 1 | Bus 2 | 358.8-365.5 |
| **Sioux 1** | Ameren Missouri | 138 | Bus 1 | Bus 1A | 142 - 144.9 |
| **Sioux 2** | Ameren Missouri | 138 | Bus 2 | None | 142 - 144.9 |
| **Viaduct** | Ameren Missouri | 34.5 | Bus 1 | ------ | 35.5 - 36.2 |
| **Venice** | Ameren Missouri | 138 | Bus 2 | Bus 3 | 142 - 144.9 |
| **Kinmundy (all units)** | Ameren Missouri | 138 | North Bus | South Bus | 142 - 144.9 |
| **Pinckneyville (all units)** | Ameren Missouri | 230 | Bus between V7 and V1 | Bus between V7 and V5 | 236.9 - 241.5 |
| **Audrain (all units)** | Ameren Missouri | 345 | Bus | ------ | 358.8-365.5 |
| **Raccoon Creek** | Ameren Missouri | 345 | Bus | ------ | 358.8-365.5 |
| **Goose Creek** | Ameren Missouri | 345 | Bus between PCB 4545 and 4575 | Bus between PCB 4555 and 4575 | 358.8-365.5 |
| **Taum Sauk Unit 1** | Ameren Missouri | 138 | Generator 1 Potential Transformer | Rivermines-Taum Sauk 1 CCVT | 142-144.9 |
| **Taum Sauk Unit 2** | Ameren Missouri | 138 | Generator 2 Potential Transformer | Rivermines-Taum Sauk 2 CCVT | 142-144.9 |

* **Interim Schedule in effect as units are being operated controlled with attention to generator bus voltage.**

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**

2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**

3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**

4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## AEG and AERG Plant Voltage Schedules

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Coffeen (both units)** | 345 | Bus between PCBs 3411 and 3414 | Bus between PCBs 3412 and 3413 | 358.8 - 365.5 |
| **Gibson City (both units)** | 138 | Bus at Gibson City Plant | West Bus at Gibson City Substation | 142 - 144.9 |
| **Grand Tower (all units)** | 138 | Bus between PCBs 1449 and 1459 | Bus between PCBs 1409 and 1489 | 142 - 144.9 |
| **Newton (both units** | 345 | East Bus | West Bus | 358.8 - 365.5 |
| **Duck Creek** | 345 | North Bus | South Bus | 358.8 - 365.5 |
| **Edwards 3** | 138 | West Bus | East Bus | 142 - 144.9 |
| **Edwards 1&2 (both units)** | 69 | West Bus | East Bus | 71.1 - 72.5 |
| **Tazewell (all units)** | 69 | Transformer 4 | Transformer 3 | 71.1 - 72.5 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## DMG Plant Voltage Schedules

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Baldwin (all units)** | 345 | West Bus | East Bus | 358.8 - 365.5 |
| **Havana Unit 6** | 138 | West Bus | ------ | 142 - 144.9 |
| **Hennepin (all units)** | 138 | South Bus | North Bus | 142 - 144.9 |
| **Oglesby (all units)** | 138 | Bus #2 | Bus #1 | 142 - 144.9 |
| **Stallings CTG (all units)** | 138 | Line 1452 | Line 1456 | 142 - 144.9 |
| **Wood River 4&5 (all units)** | 138 | Southwest Bus | Northeast Bus | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## Holland Energy Plant Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Holland (all units)** | 345 | Plant 345 kV Bus between PCBs 52-1, 52-2, 52-3, and 52-4 | -------- | 358.8 - 365.5 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## LS Power Plant Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Tilton** | 138 | Line 1572 | Line 1576 | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## RRI Energy Plant Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Reliant/Neoga (all units)** | 138 | Bus | -------- | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## AmerGen Plant Voltage Schedules

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Clinton** | 345 | South Bus | ------ | 358.8 - 362.2 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## Rail Splitter Wind Farm Voltage Schedule

| | Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|---|
| | **Rail Splitter Wind Farm (all units)** | 138 | Line Voltage at San Jose Rail Substation | Bus Voltage at San Jose Rail Substation | 142 - 144.9 |
| | | | | | |
| | | | | | |
| | | | | | |
| **1.** | **Voltage schedules do not apply if no unit which affects the measurement point is online.** | | | | |
| | | | | | |
| **2.** | **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.** | | | | |
| | | | | | |
| **3.** | **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.** | | | | |
| | | | | | |
| **4.** | **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.** | | | | |

## Trigen Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Trigen (all units)** | 138 | Between PCB 52L and Transformer | ------- | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**

2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**

3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**

4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## Alsey Plant Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Alsey (all units)** | 138 | Alsey Bus between PCB AS8006, PCB AS8004, Switch AS8003, Switch AS8002, and AS8001 | ------- | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

# Prairie State Plant Voltage Schedule

| Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|
| **Prairie State Energy Campus (both units)** | 345 | Bus between disconnects V21B and V23A | Bus between disconnects V31B and V33A | 358.8 - 363.0 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## E.On Wind Farm Voltage Schedules

| | Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|---|
| | **Pioneer Trail Wind Farm (all units)** | 138 | South Bus Voltage at Paxton East Substation | North Bus Voltage at Paxton East Substation | 142 - 144.9 |
| | **Settlers Trail Wind Farm (all units)** | 138 | Bus Voltage at Position H6 to which incoming line from Settlers Trail is connected | Line Voltage on Sheldon South-Watseka 1702 | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

## White Oak Wind Farm Voltage Schedule

| | Unit | Nominal Voltage (kV) | Primary Measurement Point | Secondary Measurement Point | Scheduled Voltage Range (kV) |
|---|---|---|---|---|---|
| | **White Oak Wind Farm (all units)** | 138 | Line side of disconnect 1389 at McLean County Substation | Bus at McLean county Substation | 142 - 144.9 |

1. **Voltage schedules do not apply if no unit which affects the measurement point is online.**
2. **If all online units that affect a measurement point are operating to the limit of their unit specifications at .95 power factor lead or lag at the interconnection point, no further VAR contribution is required.**
3. **A unit will be considered off-line for the purposes of following voltage schedule when the unit is below its minimum operating output.**
4. **These voltage schedules constitute the normal operating voltages which the plant should follow. In all cases, generator operators are required to follow directives from the Reliability Coordinator or Transmission Operator as needed to meet situations on the bulk electric system.**

Ameren
Transmission Line
Minimum Required Right-of-Way Widths

Ameren establishes its minimum right-of-way width requirement to provide a controlled area with certain restrictions that are designed to provide for public safety, proper NESC code clearances and reliable high voltage line operation.

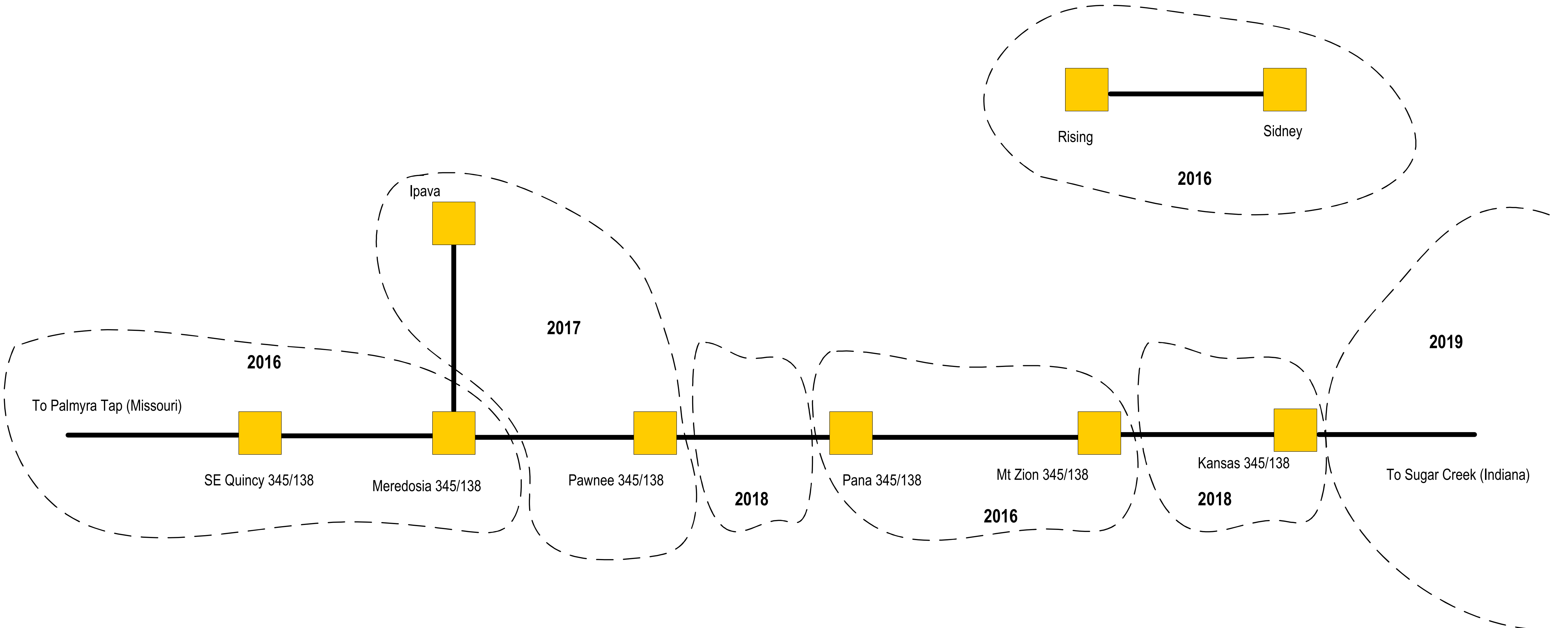
Several factors are considered when establishing the minimum width criteria. These factors include:

1. Adequate construction area to build and maintain the line.
2. Provide adequate distance for public safety.
3. Provide proper distance to prevent tree contact with the energized wires that would disrupt electrical operation of the line, whether due to tree growth or falling trees.
4. Provide control for adequate NESC code clearances to various objects, like buildings, antennas, tanks, swimming pools, and future subdivision development.
5. Provide adequate horizontal distance from potential flammable objects (buildings, etc.) to prevent fire hazards to the line that can interfere with the electrical operation or mechanical stability.
6. Provide for proper NESC code clearances for long span wire blow out to adjacent objects.

On future projects the following are Ameren‟s minimum right-of-way widths:

- 138/161 kV ---- 100 ft.
- 345 kV ---------- 150 ft.

# Illinois Rivers 345 kV development

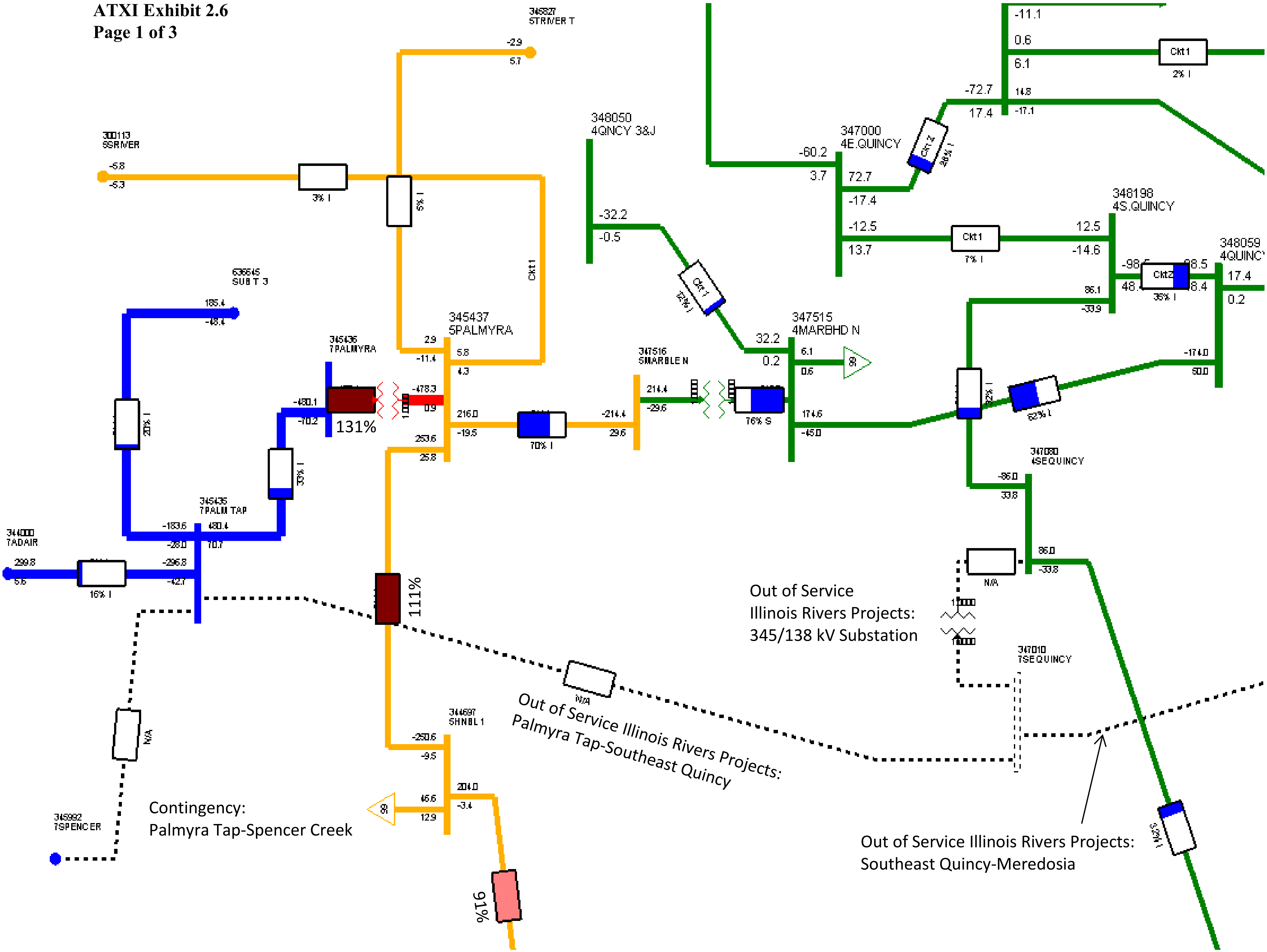



All new 345 kV circuits to be rated at 3000 A minimum under summer emergency conditions

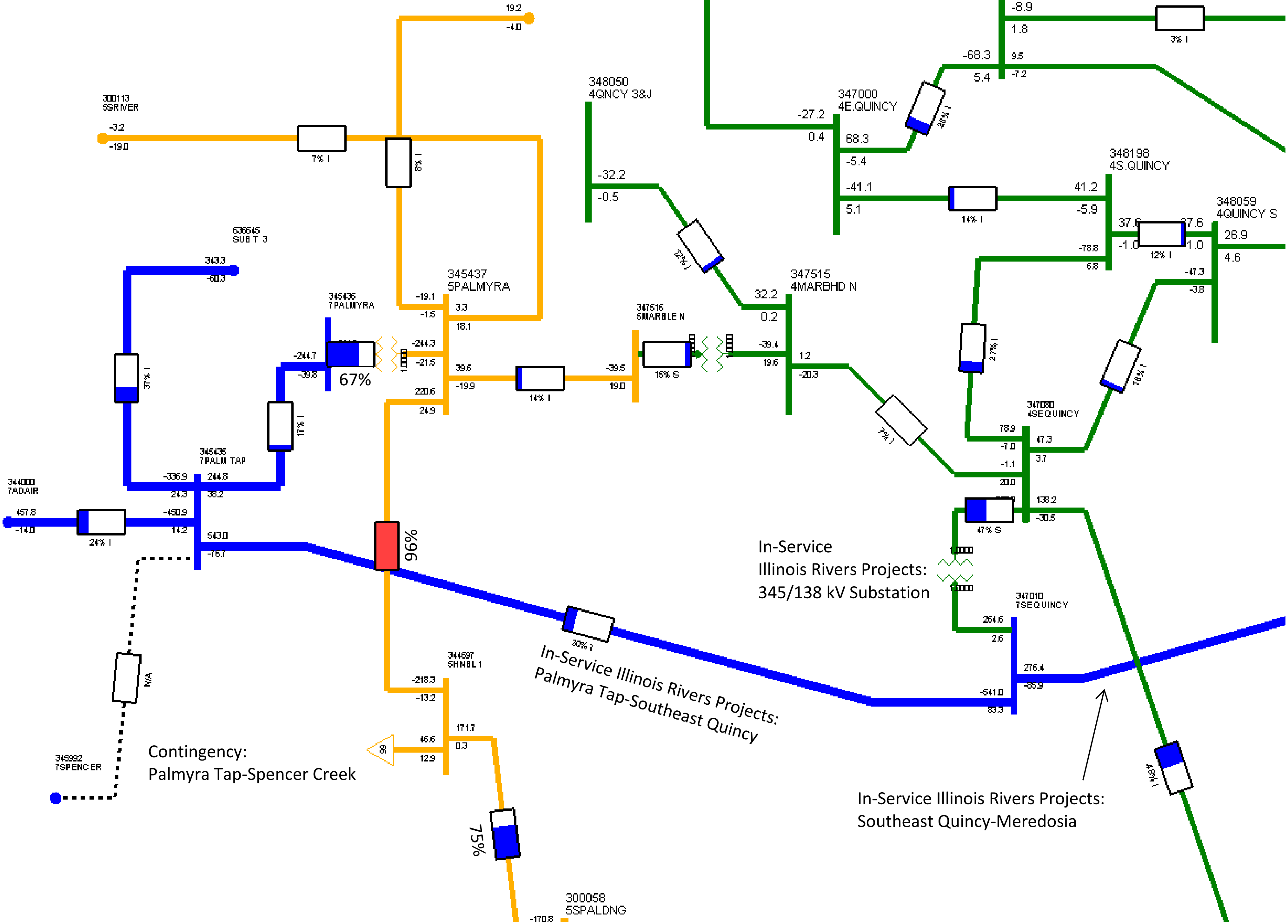
2021 Shoulder Category B events mitigated by Illinois Rivers - based on DC Contingency analysis.
(Corresponding AC power flow diagram exhibit number shown for comparison).

| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| Hannibal-Palmyra 161 kV line | 345435 7PALM TAP 345 345992 7SPENCER 345 1 (EX 2.6) | 227 | 108 | <95% |
| Hannibal-Palmyra 161 kV line | 345230 7MONTGMRY 345 345992 7SPENCER 345 1 | 227 | 108 | <95% |
| Hannibal-Palmyra 161 kV line | MTGY-SPCK-1 | 227 | 108 | <95% |
| Hannibal-Palmyra 161 kV line | PLMY-SPCK | 227 | 108 | <95% |
| Hannibal-Palmyra 161 kV line | PLMY-NMRB-1 | 227 | 97.4 | <95% |
| Hannibal-Palmyra 161 kV line | BELU-MTGY-6 | 227 | 95.6 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 345435 7PALM TAP 345 345992 7SPENCER 345 1 (EX 2.6) | 370 | 129.2 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 345230 7MONTGMRY 345 345992 7SPENCER 345 1 | 370 | 129.2 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | MTGY-SPCK-1 | 370 | 129.2 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | PLMY-SPCK | 370 | 129.2 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | SRIV-ADIR-1 | 370 | 106.5 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | AI01 | 370 | 106.3 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | ADAIR-XFMR | 370 | 106.1 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 300106 5NOVELY 161 300363 5NEWARK 161 1 | 370 | 102 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | AI02 | 370 | 102 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 300339 5EMERSN 161 300363 5NEWARK 161 1 | 370 | 101.4 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 300113 5SRIVER 161 300339 5EMERSN 161 1 | 370 | 101 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | BELU-MTGY-6 | 370 | 100 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 344535 7ENON 345 345230 7MONTGMRY 345 1 | 370 | 99.5 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | OAKG-GLSB2 | 370 | 99.1 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | 348944 7GALSBURG HI 345 636635 OAKGROV3 345 1 | 370 | 96.1 | <95% |
| PALMYRA 345/161 kV transformer (AECI) | OAKG-GLSB | 370 | 96.1 | <95% |
| Rising 345/138 kV transformer | 348846 7CLINTON 345 348847 7BROKAW T1 345 1 (EX 2.8) | 560 | 105.9 | <95% |

| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| Rising 345/138 kV transformer | CLNT-BROK-35 | 560 | 105.9 | <95% |
| Rising 345/138 kV transformer | L11215 | 560 | 104.7 | <95% |
| Rising 345/138 kV transformer | 345-L8012B | 560 | 101 | <95% |
| Rising 345/138 kV transformer | 345-L8012A | 560 | 100.2 | <95% |
| Rising 345/138 kV transformer | 346809 7CASEY 345 347340 7KANSAS 345 1 | 560 | 99.8 | <95% |
| Rising 345/138 kV transformer | CSYW-KANS | 560 | 99.8 | <95% |
| Rising 345/138 kV transformer | 347821 7NEOGA 345 348491 7HOLLAND 345 1 | 560 | 99.5 | <95% |
| Rising 345/138 kV transformer | HDNW-NEGS-1 | 560 | 99.5 | <95% |
| Rising 345/138 kV transformer | BROK-PONT | 560 | 99.1 | <95% |
| Rising 345/138 kV transformer | KNCD-PANA | 560 | 99 | <95% |
| Rising 345/138 kV transformer | COFN-HDNW-1 | 560 | 97.6 | <95% |
| Rising 345/138 kV transformer | 348067 7RAMSEY 345 348491 7HOLLAND 345 1 | 560 | 97.3 | <95% |
| Rising 345/138 kV transformer | 347340 7KANSAS 345 348887 7SIDNEY 345 1 | 560 | 96.7 | <95% |
| Rising 345/138 kV transformer | SDNY-KANS | 560 | 96.7 | <95% |
| Rising 345/138 kV transformer | BROK-MAHO | 560 | 96.5 | <95% |
| Rising 345/138 kV transformer | 345-L8002 | 560 | 95.7 | <95% |
| Rising 345/138 kV transformer | 346886 7COFFEN N 345 348067 7RAMSEY 345 1 | 560 | 95.7 | <95% |
| Weedman-Mahomet 138 kV line | CLNT-GOSC-45 (EX 2.7) | 202 | 100.8 | <95% |
| Weedman-Mahomet 138 kV line | 348770 7GOOS_CRK 345 348850 7MAROA E JCT 345 1 | 202 | 100 | <95% |
| Weedman-Mahomet 138 kV line | 348770 7GOOS_CRK 345 348882 7RISING 345 1 | 202 | 99.6 | <95% |
| Weedman-Mahomet 138 kV line | GOSC-RISN | 202 | 99.6 | <95% |
| Weedman-Mahomet 138 kV line | RISN-XMFR | 202 | 99 | <95% |
| Weedman-N Leroy Tap 138 kV line | CLNT-GOSC-45 (EX 2.7) | 202 | 108.4 | <95% |
| Weedman-N Leroy Tap 138 kV line | 348770 7GOOS_CRK 345 348850 7MAROA E JCT 345 1 | 202 | 107.7 | <95% |
| Weedman-N Leroy Tap 138 kV line | 348770 7GOOS_CRK 345 348882 7RISING 345 1 | 202 | 107.3 | <95% |
| Weedman-N Leroy Tap 138 kV line | GOSC-RISN | 202 | 107.3 | <95% |
| Weedman-N Leroy Tap 138 kV line | RISN-XMFR | 202 | 106.7 | <95% |


345827
STRMER T
300113
5SRIVER
636645
SUB T 3
345437
5PALMYRA
345436
7PALMYRA
131%
345435
7PALM TAP
344000
7ADAIR
111%
344697
SHNBL 1
345992
7SPENCER
91%
Contingency:
Palmyra Tap-Spencer Creek
348050
4QNCY 3&J
347000
4E.QUINCY
347516
SMARBLE N
347515
4MARBHD N
348198
4S.QUINCY
348059
4QUINCY
347080
4SEQUINCY
347010
7SEQUINCY
Out of Service
Illinois Rivers Projects:
345/138 kV Substation
Out of Service Illinois Rivers Projects:
Palmyra Tap-Southeast Quincy
Out of Service Illinois Rivers Projects:
Southeast Quincy-Meredosia

**ATXI Exhibit 2.6**
**Page 2 of 3**



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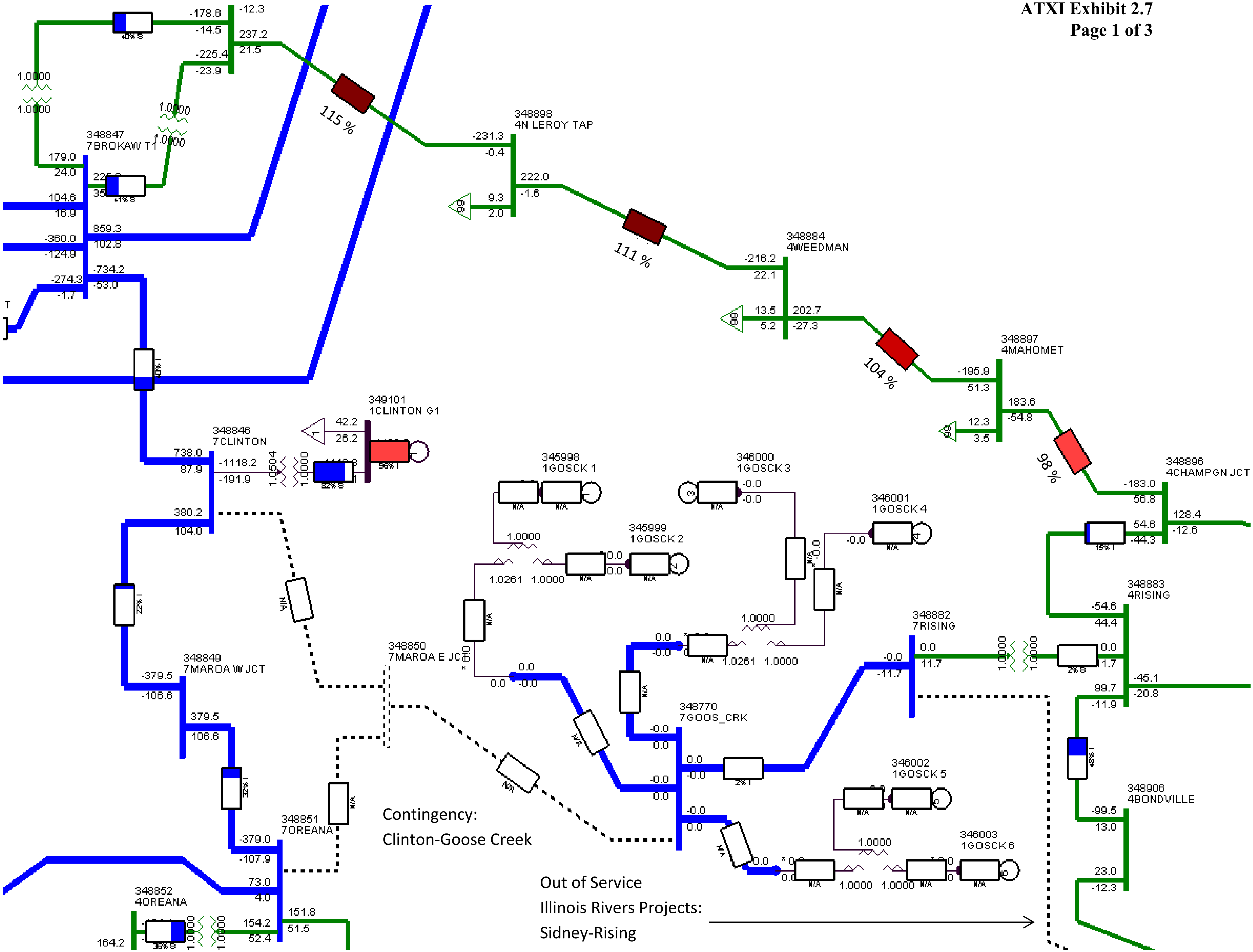
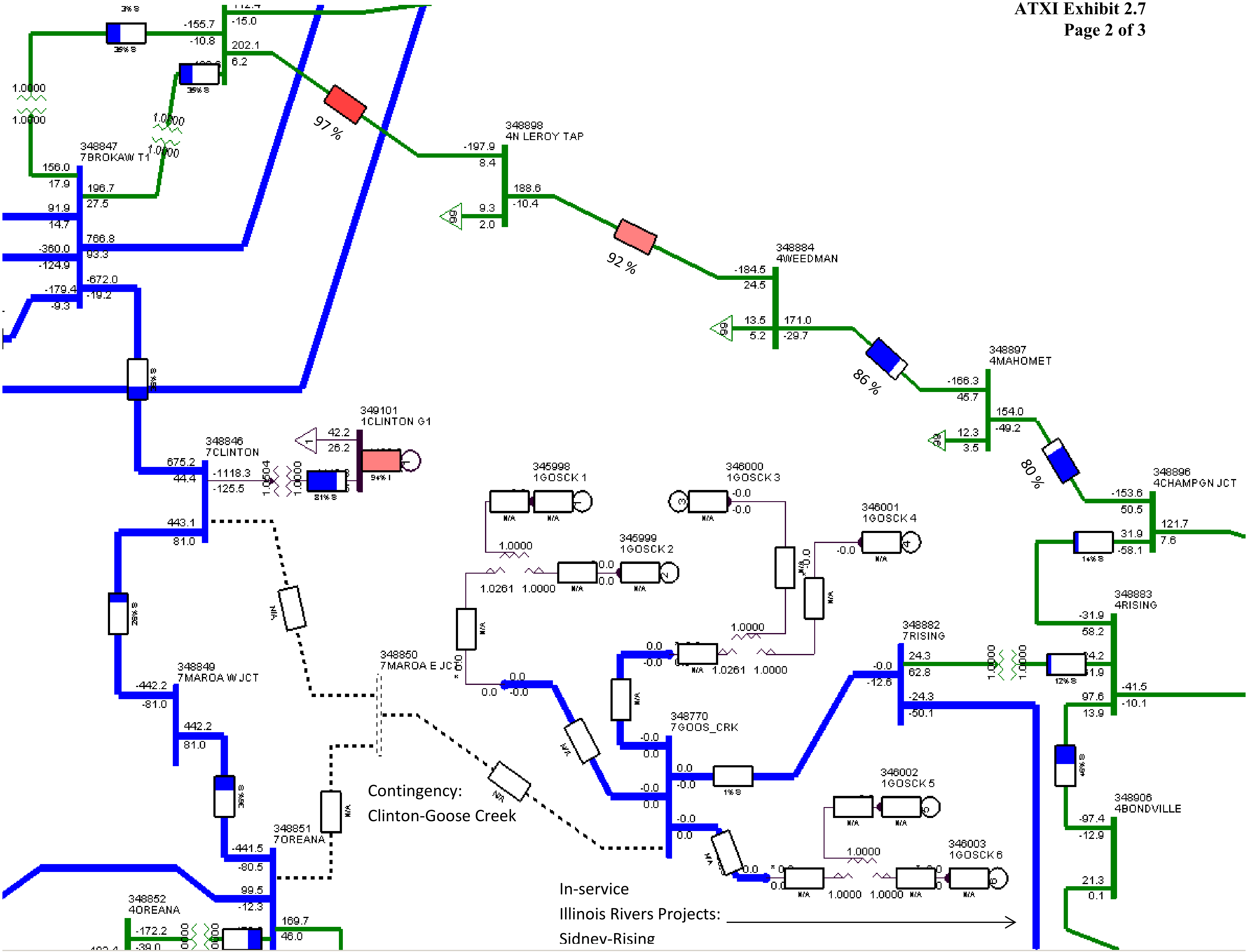
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, OCT 24 2012  11:18
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11  Illinois Rivers Projects Out of Service
MOD TOPOLOGY UPDATED 2/3/11
                      OUTPUT FOR AREA 356 [AMMO        ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE  95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

X--------- FROM BUS ----------X X---------- TO BUS -----------X
  BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
344697 5HNBL 1     161.00*  356 345437 5PALMYRA    161.00   356  1    252.8   227.0   111.4
345436 7PALMYRA    345.00*  356 345437 5PALMYRA    161.00   356  1    485.2   370.0   131.1
```

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, OCT 24 2012  13:59
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11  Illinois Rivers Projects In-Service
MOD TOPOLOGY UPDATED 2/3/11
                      OUTPUT FOR AREA 356 [AMMO        ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE  95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

X--------- FROM BUS ----------X X---------- TO BUS -----------X
  BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
344697 5HNBL 1     161.00*  356 345437 5PALMYRA    161.00   356  1    217.5   227.0    95.8
```


348847
7BROKAW T1
348898
4N LEROY TAP
115 %
111 %
348884
4WEEDMAN
104 %
348897
4MAHOMET
98 %
348896
4CHAMPGN JCT
349101
1CLINTON G1
348846
7CLINTON
345998
1GOSCK 1
346000
1GOSCK 3
345999
1GOSCK 2
346001
1GOSCK 4
348883
4RISING
348882
7RISING
348850
7MAROA E JCT
348849
7MAROA W JCT
348770
7GOOS_CRK
346002
1GOSCK 5
346003
1GOSCK 6
348906
4BONDVILLE
348851
7OREANA
348852
4OREANA
Contingency:
Clinton-Goose Creek
Out of Service
Illinois Rivers Projects:
Sidney-Rising

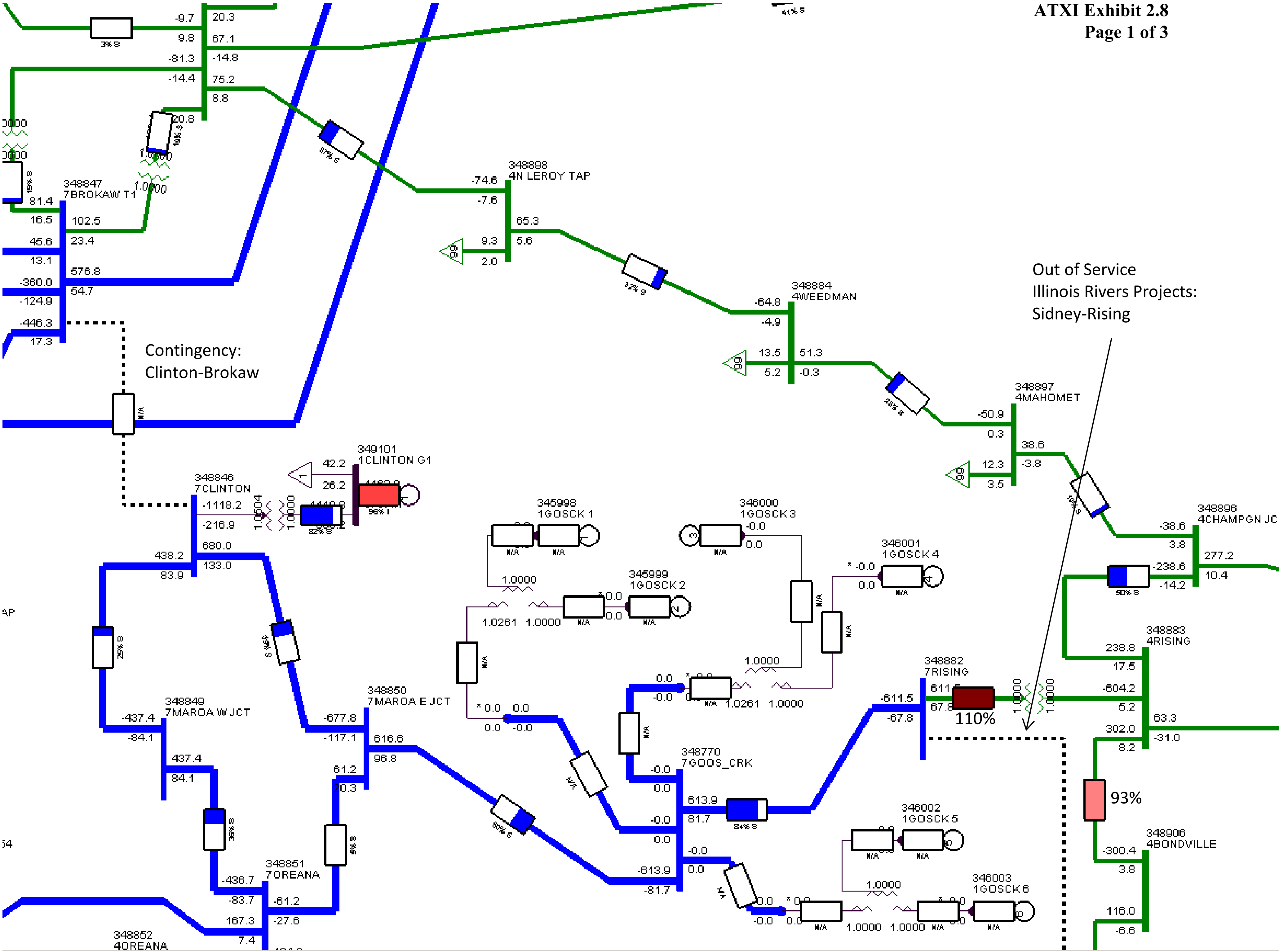

348847
7BROKAW T1
348898
4N LEROY TAP
97 %
92 %
348884
4WEEDMAN
86 %
348897
4MAHOMET
80 %
348896
4CHAMPGN JCT
349101
1CLINTON G1
348846
7CLINTON
345998
1GOSCK 1
346000
1GOSCK 3
346001
1GOSCK 4
345999
1GOSCK 2
348883
4RISING
348882
7RISING
348850
7MAROA E JCT
348849
7MAROA W JCT
348770
7GOOS_CRK
346002
1GOSCK 5
348906
4BONDVILLE
348851
7OREANA
346003
1GOSCK 6
348852
4OREANA
Contingency:
Clinton-Goose Creek
In-service
Illinois Rivers Projects:
Sidney-Rising

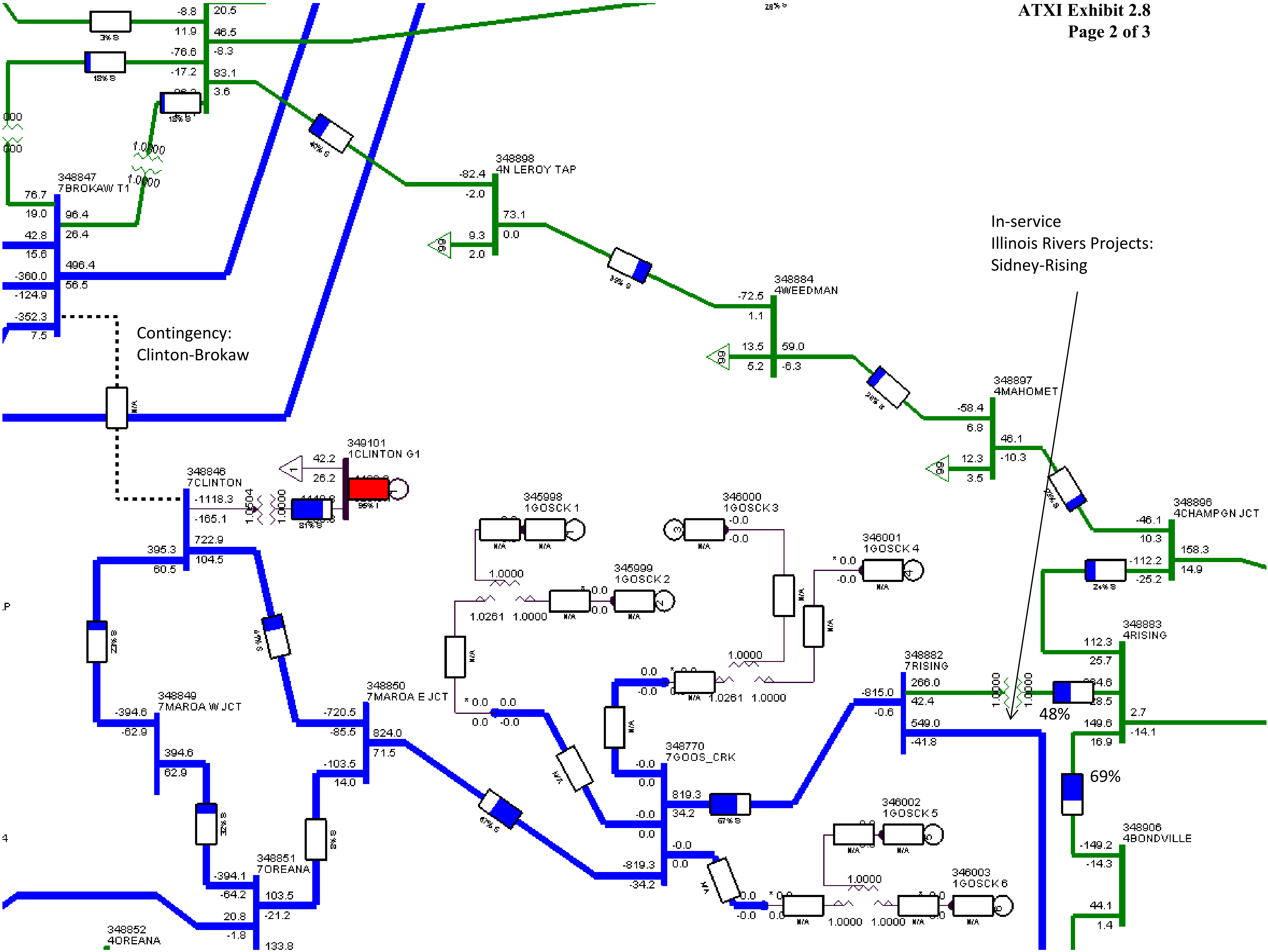
PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 14:55
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11 Illinois Rivers Projects Out of Service
MOD TOPOLOGY UPDATED 2/3/11
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS | ----------X | | | X---------- TO BUS | -----------X | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 348848 | 4BROKAW | 138.00 | 357 | 348898 | 4N LEROY TAP | 138.00* | 357 | 1 | 231.6 | 202.0 | 114.6 |
| 348884 | 4WEEDMAN | 138.00* | 357 | 348897 | 4MAHOMET | 138.00 | 357 | 1 | 209.1 | 202.0 | 103.5 |
| 348884 | 4WEEDMAN | 138.00 | 357 | 348898 | 4N LEROY TAP | 138.00* | 357 | 1 | 222.2 | 202.0 | 110.0 |
| 348896 | 4CHAMPGN JCT | 138.00 | 357 | 348897 | 4MAHOMET | 138.00* | 357 | 1 | 197.6 | 202.0 | 97.8 |

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 14:53
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11 Illinois Rivers Projects In-Service
MOD TOPOLOGY UPDATED 2/3/11
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS | ----------X | | | X---------- TO BUS | -----------X | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 348848 | 4BROKAW | 138.00* | 357 | 348898 | 4N LEROY TAP | 138.00 | 357 | 1 | 195.3 | 202.0 | 96.7 |


348847
7BROKAW T1
348898
4N LEROY TAP
348884
4WEEDMAN
348897
4MAHOMET
348896
4CHAMPGN JCT
348883
4RISING
348882
7RISING
110%
93%
348906
4BONDVILLE
Out of Service
Illinois Rivers Projects:
Sidney-Rising
Contingency:
Clinton-Brokaw
349101
1CLINTON G1
348846
7CLINTON
345998
1GOSCK 1
345999
1GOSCK 2
346000
1GOSCK 3
346001
1GOSCK 4
346002
1GOSCK 5
346003
1GOSCK 6
348770
7GOOS_CRK
348849
7MAROA W JCT
348850
7MAROA E JCT
348851
7OREANA
348852
4OREANA


348847
7BROKAW T1
Contingency:
Clinton-Brokaw
348898
4N LEROY TAP
348884
4WEEDMAN
348897
4MAHOMET
348896
4CHAMPGN JCT
In-service
Illinois Rivers Projects:
Sidney-Rising
349101
1CLINTON G1
348846
7CLINTON
345998
1GOSCK 1
345999
1GOSCK 2
346000
1GOSCK 3
346001
1GOSCK 4
348883
4RISING
348882
7RISING
48%
69%
348849
7MAROA W JCT
348850
7MAROA E JCT
348770
7GOOS_CRK
346002
1GOSCK 5
346003
1GOSCK 6
348906
4BONDVILLE
348851
7OREANA
348852
4OREANA

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, OCT 24 2012  15:20
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11      Illinois Rivers Projects Out of Service
MOD TOPOLOGY UPDATED 2/3/11
                      OUTPUT FOR AREA 357 [AMIL        ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE  95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

X--------- FROM BUS ----------X X---------- TO BUS -----------X
  BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
348882 7RISING     345.00*  357 348883 4RISING     138.00   357  1    615.2   560.0   109.9
```

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    PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E      WED, OCT 24 2012  15:19
MTEP11 2021 SH RMD 2ND PASS MODEL 2/8/11      Illinois Rivers Projects In Service
MOD TOPOLOGY UPDATED 2/3/11
                      OUTPUT FOR AREA 357 [AMIL        ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE  95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

X--------- FROM BUS ----------X X---------- TO BUS -----------X
  BUS# X-- NAME --X BASKV  AREA   BUS# X-- NAME --X BASKV  AREA CKT LOADING  RATING PERCENT
                              * NONE *
```

2021 Shoulder Category C Events mitigated or improved by Illinois Rivers - based on DC Contingency analysis.

| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | MTGRY V13 | 227 | 116 | 100.8 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7ENON -7MONTGMR1 | 227 | 114.2 | 98.6 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7MCCREDI-7MONTGMR1 | 227 | 114.2 | 97.4 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7CALAWY -7MONTGMR1 | 227 | 108.3 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7CALAWY -7MONTGMR2 | 227 | 108.3 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7AUDRAIN-7SPENCER1 +7MONTGMR-7SPENCER1 | 227 | 108 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7AUDRAIN-7SPENCER1 +7PALM TA-7SPENCER1 | 227 | 108 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7PALM TA-7SPENCER1 | 227 | 108 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7LABADIE-7MONTGMR1 | 227 | 107.7 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | AMRN_DCT-7 | 227 | 103.9 | 99.3 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | AMRN_DCT-8 | 227 | 102.6 | 98 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | BELU-V31 | 227 | 101.3 | 97.5 |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7PALM TA-7SPENCER1 +7PALM TA-SUB T 31 | 227 | 99.1 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7ENON -7MONTGMR1 +7LABADIE-7MONTGMR1 | 227 | 97.9 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | AMRN_DCT-9 | 227 | 96.9 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | MRBHDN BUS | 227 | 96.9 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | MRBN-1855 | 227 | 96.9 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | AMRN_DCT-10 | 227 | 96.1 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7ENON -7MONTGMR1 +7BELLEAU-7ENON 1 | 227 | 95.6 | <95% |
| 344697 5HNBL 1 161 345437 5PALMYRA 161 1 | D:7PALM TA-7SPENCER1 +7PALM TA-7ADAIR 1 | 227 | 95.1 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7MCCREDI-7MONTGMR1 | 370 | 132.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | MTGRY V13 | 370 | 132.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7ENON -7MONTGMR1 | 370 | 132.4 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7CALAWY -7MONTGMR1 | 370 | 129.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7CALAWY -7MONTGMR2 | 370 | 129.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7AUDRAIN-7SPENCER1 +7MONTGMR-7SPENCER1 | 370 | 129.2 | <95% |

| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7AUDRAIN-7SPENCER1 +7PALM TA-7SPENCER1 | 370 | 129.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7LABADIE-7MONTGMR1 | 370 | 129.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7MONTGMR-7SPENCER1 +7PALM TA-7SPENCER1 | 370 | 129.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7PALM TA-7SPENCER1 +7PALM TA-SUB T 31 | 370 | 108.5 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | ADR-B23 | 370 | 106.5 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7ENON -7MONTGMR1 +7LABADIE-7MONTGMR1 | 370 | 106.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-7 | 370 | 105.7 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-8 | 370 | 104.8 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | BELU-V31 | 370 | 101.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-9 | 370 | 100.7 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-10 | 370 | 100.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7ENON -7MONTGMR1 +7BELLEAU-7ENON 1 | 370 | 100 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-11 | 370 | 99.6 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7CALAWY -7MONTGMR1 +7ENON -7MONTGMR1 | 370 | 99.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7CALAWY -7MONTGMR2 +7ENON -7MONTGMR1 | 370 | 99.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:OAKGROV3-LOUISA 31 +OAKGROV3-7GALSBUR1 | 370 | 99.3 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:OAKGROV3-LOUISA 31 +SB 39 3-OAKGROV31 | 370 | 97.8 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | LAB 15H | 370 | 97.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:SUB 92 3-LOUISA 31 +OAKGROV3-LOUISA 31 | 370 | 97.1 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7FARGO -7GALSBUR1 +OAKGROV3-7GALSBUR1 | 370 | 96.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | EGAL-1 | 370 | 96.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | EGAL-3 | 370 | 96.9 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | EGAL-2 | 370 | 96.8 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:OAKGROV3-7GALSBUR1 +SB 39 3-OAKGROV31 | 370 | 96.2 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | IPAVA SOUTH | 370 | 95.6 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | IPAVA-1510 | 370 | 95.6 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | AMRN_DCT-6A | 370 | 95.4 | <95% |
| 345436 7PALMYRA 345 345437 5PALMYRA 161 1 | D:7CALAWY -7LOOSECR1 +7BLAND -7CALAWY 1 | 370 | 95.4 | <95% |

| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| 348882 7RISING 345 348883 4RISING 138 1 | D:7CLINTON-7BROKAW 1 +7CLINTON-7MAROA W1 | 560 | 109.3 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | CASEY-3528 | 560 | 107.2 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | CASEY 3526 | 560 | 107.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7CASEY -7NEOGA 1 +7CASEY -7NEWTON 1 | 560 | 107.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | BRKW-2 | 560 | 106.8 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | BRKW-1 | 560 | 106.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7BROKAW -7SBLOOMG1 +7CLINTON-7BROKAW 1 | 560 | 106.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | NEGS-XFMR-B | 560 | 105.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7BROKAW -WZ_IL-F Z +7CLINTON-7BROKAW 1 | 560 | 103 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | BRKW-3 | 560 | 102.2 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | CASEY-3529 | 560 | 101.9 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7CASEY -7KANSAS 1 +7CASEY -7NEOGA 1 | 560 | 101.9 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7CASEY -7KANSAS 1 +7CASEY -7NEWTON 1 | 560 | 100.7 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7CLINTON-7BROKAW 1 +7CLINTON-7MAROA E1 | 560 | 100.7 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7KANSAS -7SIDNEY 1 +7CASEY -7KANSAS 1 | 560 | 100 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | KANSAS-2 | 560 | 99.8 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7NEOGA -7HOLLAND1 +7CASEY -7NEOGA 1 | 560 | 99.4 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | NEOGA | 560 | 99.4 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | COFU2L2 | 560 | 99.2 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | RMSY-1640 | 560 | 99.2 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | COFU1L1 | 560 | 99 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | PANA-1 | 560 | 99 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | COFN3544 | 560 | 98.8 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | HLND-3518 | 560 | 98.6 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | PANA NORTH | 560 | 98.6 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | BRKW-4 | 560 | 98.5 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7NEOGA -7HOLLAND1 +7RAMSEY -7HOLLAND1 | 560 | 98.3 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7RAMSEY -7HOLLAND1 +7COFFEN -7RAMSEY 1 | 560 | 97.6 | <95% |

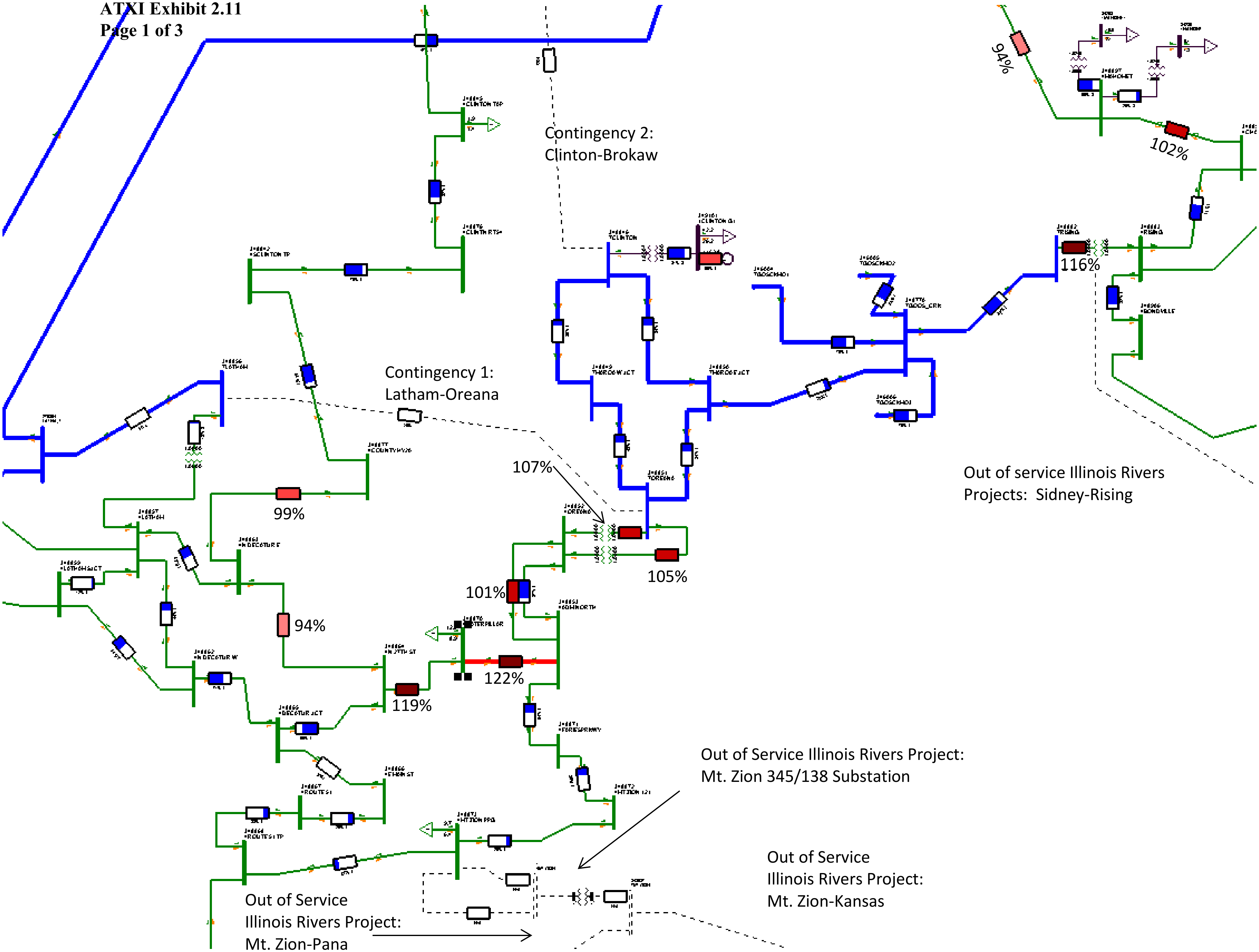
| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| 348882 7RISING 345 348883 4RISING 138 1 | RAMSEY | 560 | 97.6 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7COFFEN -7COFFEEN1 +7COFFEN -7COFFEEN2 | 560 | 97.3 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | BRKW-1376 | 560 | 97.1 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | KANSAS-1 | 560 | 96.7 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7COFFEN -7COFFEEN1 +7COFFEN -7RAMSEY 1 | 560 | 95.7 | <95% |
| 348882 7RISING 345 348883 4RISING 138 1 | D:7COFFEN -7COFFEEN2 +7COFFEN -7RAMSEY 1 | 560 | 95.7 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | 4571-4545 | 202 | 106.9 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | ORNA-1 | 202 | 106.9 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | ORNA-4575 | 202 | 101 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7GOOS_CR-7MAROA E1 +7CLINTON-7MAROA E1 | 202 | 100.8 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7MAROA E-7OREANA 1 +7CLINTON-7MAROA E1 | 202 | 100.8 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7MAROA E-7OREANA 1 +7GOOS_CR-7MAROA E1 | 202 | 100.8 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | GCRK | 202 | 100.4 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7GOOS_CR-7MAROA E1 +7GOSCKMO-7GOOS_CRZ | 202 | 100 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7GOOS_CR-7MAROA E1 +7GOOS_CR-7RISING 1 | 202 | 99.7 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | D:7GOOS_CR-7RISING 1 +7GOSCKMO-7GOOS_CRZ | 202 | 99.6 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | RISN-3 | 202 | 99.6 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | RISN-1 | 202 | 99.2 | <95% |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | RISN-2 | 202 | 99 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | 4571-4545 | 202 | 114.6 | 100.8 |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | ORNA-1 | 202 | 114.6 | 100.8 |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | ORNA-4575 | 202 | 108.7 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7GOOS_CR-7MAROA E1 +7CLINTON-7MAROA E1 | 202 | 108.4 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7MAROA E-7OREANA 1 +7CLINTON-7MAROA E1 | 202 | 108.4 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7MAROA E-7OREANA 1 +7GOOS_CR-7MAROA E1 | 202 | 108.4 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | GCRK | 202 | 108.1 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7GOOS_CR-7MAROA E1 +7GOSCKMO-7GOOS_CRZ | 202 | 107.7 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7GOOS_CR-7MAROA E1 +7GOOS_CR-7RISING 1 | 202 | 107.4 | <95% |

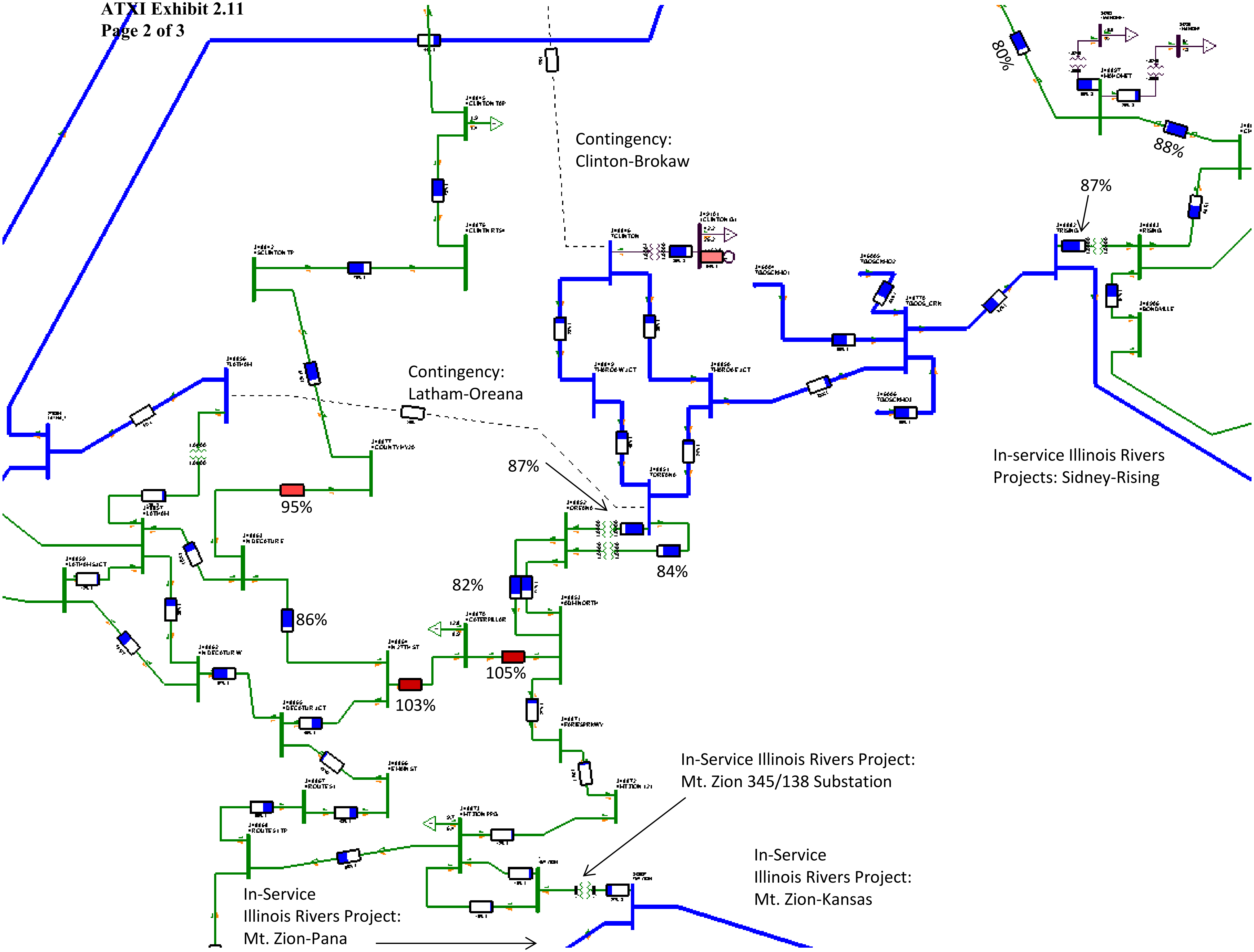
| Overloaded Element | Contingency Description | Rating | 2021Sh no IL_RIV Max of ContLd% | 2021Sh with IL_RIV Max of ContLd% |
|---|---|---|---|---|
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | D:7GOOS_CR-7RISING 1 +7GOSCKMO-7GOOS_CRZ | 202 | 107.3 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | RISN-3 | 202 | 107.3 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | RISN-1 | 202 | 106.8 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | RISN-2 | 202 | 106.7 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | RISING | 202 | 102.1 | <95% |
| 348884 4WEEDMAN 138 348898 4N LEROY TAP 138 1 | RISN-B100 | 202 | 102.1 | <95% |
| 348896 4CHAMPGN JCT 138 348897 4MAHOMET 138 1 | 4571-4545 | 202 | 100.9 | <95% |
| 348896 4CHAMPGN JCT 138 348897 4MAHOMET 138 1 | ORNA-1 | 202 | 100.9 | <95% |

2021 Summer Peak Category C events mitigated or improved by Illinois Rivers - based on DC Contingency analysis.
(Corresponding AC power flow diagram exhibit number shown for comparison).

| **Max of ContLd%** | | | | |
|---|---|---|---|---|
| **** From bus ** ** To bus ** CKT** | **Rating** | **Contingency Description** | **2021S 1-10 with MVPs** | **2021S 1-10 _MVPs-no ILRIV** |
| 348851 7OREANA 345 348852 4OREANA 138 1 | 448 | CLNT-BROK-35+LATM-OREA (EX 2.11) | <95% | 101.2 |
| 348851 7OREANA 345 348852 4OREANA 138 2 | 448 | CLNT-BROK-35+LATM-OREA (EX 2.11) | <95% | 102.8 |
| 348852 4OREANA 138 348853 4ADM NORTH 138 1 | 477 | CLNT-BROK-35+LATM-OREA (EX 2.11) | <95% | 100.5 |
| 348853 4ADM NORTH 138 348870 4CATERPILLAR 138 1 | 478 | CLNT-BROK-35+LATM-OREA (EX 2.11) | 106.4 | 122.3 |
| 348864 4N 27TH ST 138 348870 4CATERPILLAR 138 1 | 478 | CLNT-BROK-35+LATM-OREA (EX 2.11) | 103.7 | 119.6 |
| 348882 7RISING 345 348883 4RISING 138 1 | 560 | CLNT-BROK-35+LATM-OREA (EX 2.11) | <95% | 114.2 |
| 348882 7RISING 345 348883 4RISING 138 1 | 560 | CLNT-BROK-35+LATM-BLMD | <95% | 101.1 |
| 348884 4WEEDMAN 138 348897 4MAHOMET 138 1 | 202 | BROK-LNVL+CLNT-BROK-35 (EX 2.12) | <95% | 98.9 |

**ATXI Exhibit 2.11**
**Page 1 of 3**



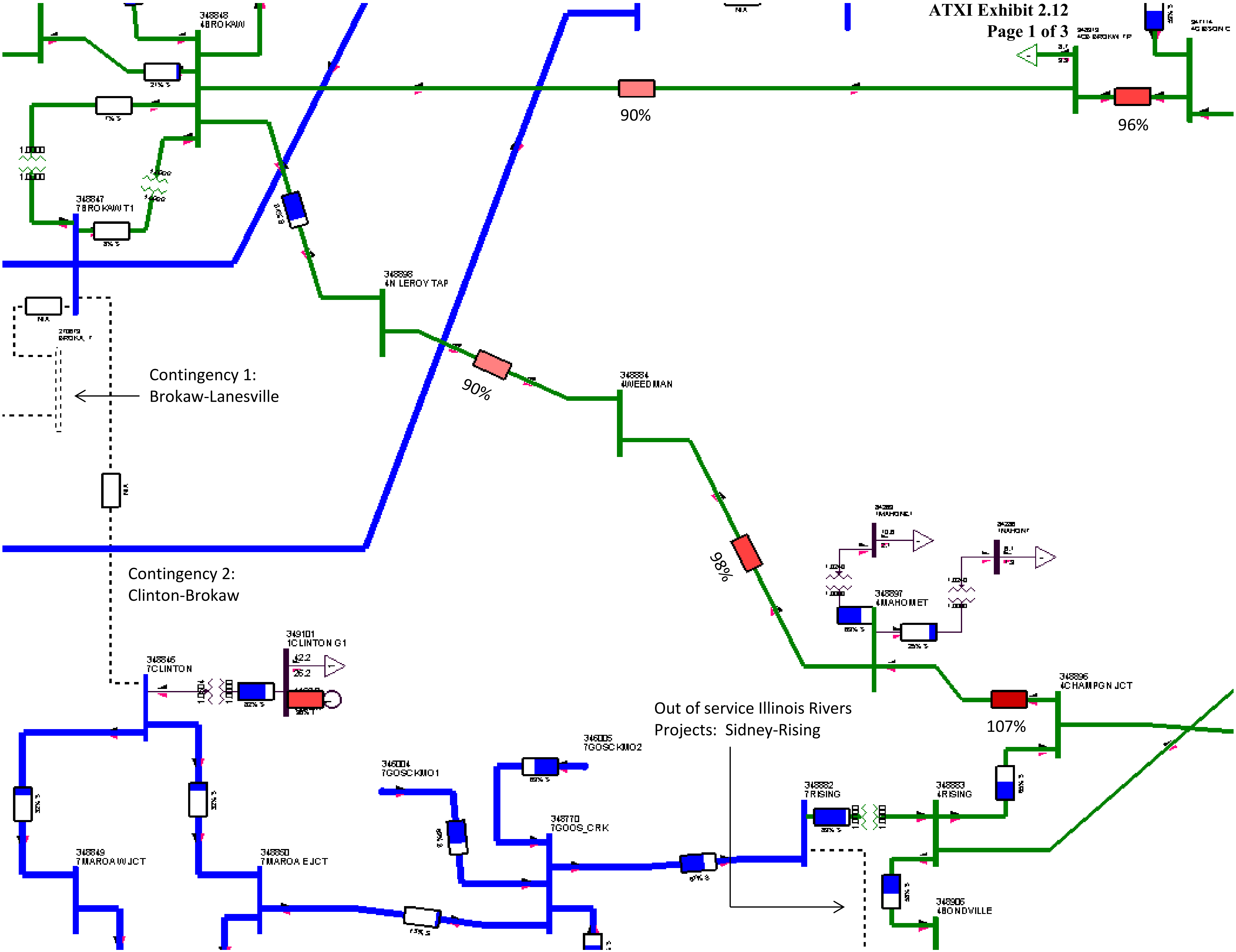

Contingency:
Clinton-Brokaw
80%
88%
87%
Contingency:
Latham-Oreana
87%
In-service Illinois Rivers
Projects: Sidney-Rising
95%
84%
82%
86%
105%
103%
In-Service Illinois Rivers Project:
Mt. Zion 345/138 Substation
In-Service
Illinois Rivers Project:
Mt. Zion-Kansas
In-Service
Illinois Rivers Project:
Mt. Zion-Pana

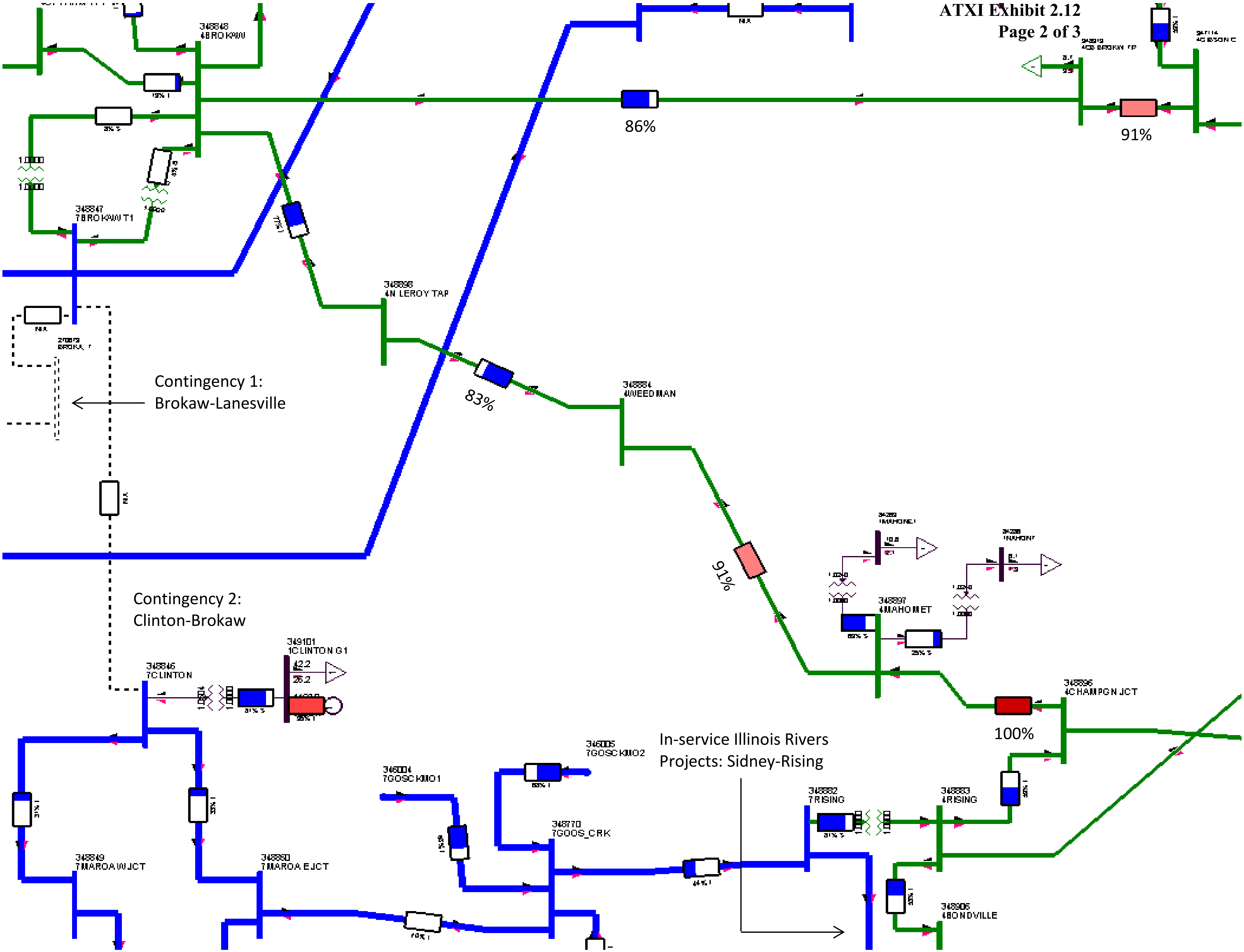
PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 16:28
2010 SERIES, ERAG/MMWG BASE CASE LIBRARY Illinois Rivers Projects Out of Service
2021 SUMMER PEAK CASE, FINAL
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS | ----------X | | | X---------- TO BUS | -----------X | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 348851 | 7OREANA | 345.00* | 357 | 348852 | 4OREANA | 138.00 | 357 | 1 | 469.9 | 448.0 | 104.9 |
| 348851 | 7OREANA | 345.00* | 357 | 348852 | 4OREANA | 138.00 | 357 | 2 | 477.4 | 448.0 | 106.6 |
| 348852 | 4OREANA | 138.00 | 357 | 348853 | 4ADM NORTH | 138.00* | 357 | 1 | 480.0 | 477.0 | 100.6 |
| 348853 | 4ADM NORTH | 138.00* | 357 | 348870 | 4CATERPILLAR | 138.00 | 357 | 1 | 582.8 | 478.0 | 121.9 |
| 348863 | 4N DECATUR E | 138.00* | 357 | 348877 | 4COUNTY HY20 | 138.00 | 357 | 1 | 158.6 | 161.0 | 98.5 |
| 348864 | 4N 27TH ST | 138.00 | 357 | 348870 | 4CATERPILLAR | 138.00* | 357 | 1 | 570.5 | 478.0 | 119.3 |
| 348882 | 7RISING | 345.00* | 357 | 348883 | 4RISING | 138.00 | 357 | 1 | 648.1 | 560.0 | 115.7 |
| 348896 | 4CHAMPGN JCT | 138.00* | 357 | 348897 | 4MAHOMET | 138.00 | 357 | 1 | 205.6 | 202.0 | 101.8 |

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 16:32
2010 SERIES, ERAG/MMWG BASE CASE LIBRARY Illinois Rivers Projects In-Service
2021 SUMMER PEAK CASE, FINAL
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS | ----------X | | | X---------- TO BUS | -----------X | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 348853 | 4ADM NORTH | 138.00* | 357 | 348870 | 4CATERPILLAR | 138.00 | 357 | 1 | 502.2 | 478.0 | 105.1 |
| 348863 | 4N DECATUR E | 138.00* | 357 | 348877 | 4COUNTY HY20 | 138.00 | 357 | 1 | 153.0 | 161.0 | 95.0 |
| 348864 | 4N 27TH ST | 138.00 | 357 | 348870 | 4CATERPILLAR | 138.00* | 357 | 1 | 490.1 | 478.0 | 102.5 |


348848
4BROKAW
348847
7BROKAW T1
348898
4N LEROY TAP
348884
4WEEDMAN
348897
4MAHOMET
348896
4CHAMPGN JCT
90%
96%
90%
98%
107%
Contingency 1:
Brokaw-Lanesville
Contingency 2:
Clinton-Brokaw
348846
7CLINTON
349101
1CLINTON G1
42.2
26.2
Out of service Illinois Rivers
Projects: Sidney-Rising
346005
7GOSCKMO2
346004
7GOSCKMO1
348770
7GOOS_CRK
348882
7RISING
348883
4RISING
348905
4BONDVILLE
348849
7MAROA W JCT
348850
7MAROA E JCT
1.0000
N/A


348848
4BROKAW
348847
7BROKAW T1
348898
4N LEROY TAP
348884
4WEEDMAN
86%
91%
83%
91%
Contingency 1:
Brokaw-Lanesville
Contingency 2:
Clinton-Brokaw
349101
1CLINTON G1
348846
7CLINTON
348897
4MAHOMET
348896
4CHAMPGN JCT
100%
In-service Illinois Rivers
Projects: Sidney-Rising
346005
7GOSCKMO2
346004
7GOSCKMO1
348770
7GOOS_CRK
348882
7RISING
348883
4RISING
348906
4BONDVILLE
348849
7MAROA W JCT
348850
7MAROA E JCT

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 11:11
2010 SERIES, ERAG/MMWG BASE CASE LIBRARY Illinois Rivers Projects Out of Service
2021 SUMMER PEAK CASE, FINAL
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS ----------X | | | | X---------- TO BUS -----------X | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 347114 | 4GIBSON C | 138.00 | 357 | 348913 | 4CB BROKW TP | 138.00* | 357 | 1 | 157.7 | 165.0 | 95.6 |
| 348884 | 4WEEDMAN | 138.00 | 357 | 348897 | 4MAHOMET | 138.00* | 357 | 1 | 198.8 | 202.0 | 98.4 |
| 348896 | 4CHAMPGN JCT | 138.00 | 357 | 348897 | 4MAHOMET | 138.00* | 357 | 1 | 215.6 | 202.0 | 106.7 |

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS®E WED, OCT 24 2012 11:10
2010 SERIES, ERAG/MMWG BASE CASE LIBRARY Illinois Rivers Projects In-Service
2021 SUMMER PEAK CASE, FINAL
OUTPUT FOR AREA 357 [AMIL ]
SUBSYSTEM LOADING CHECK (INCLUDED: LINES; BREAKERS AND SWITCHES; TRANSFORMERS) (EXCLUDED: NONE)
LOADINGS ABOVE 95.0 % OF RATING SET B (MVA FOR TRANSFORMERS, CURRENT FOR NON-TRANSFORMER BRANCHES):

| X--------- FROM BUS ----------X | | | | X---------- TO BUS -----------X | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| BUS# | X-- NAME --X | BASKV | AREA | BUS# | X-- NAME --X | BASKV | AREA | CKT | LOADING | RATING | PERCENT |
| 348896 | 4CHAMPGN JCT | 138.00 | 357 | 348897 | 4MAHOMET | 138.00* | 357 | 1 | 201.2 | 202.0 | 99.6 |