LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

CASE NO. 2005-00142
CASE NO. 2005-00154
CASE NO. 2005-00155

Response to Commission Staff's First Data Request
Dated: June 30, 2005

Question No. 15

Responding Witness: Michael G. Toll

Q-15. Provide a map that geographically shows the placement and identification of transmission electrical facilities of the NERC reliability region.

A-15. Please see attached.

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Response to Commission Staff's First Data Request
Dated: June 30, 2005

Question No. 16

Responding Witness: Michael G. Toll

Q-16. Provide all LG&E?KU, MISO, and NERC reliability, operating, or voltage criteria used by LG&E/KU to ensure the adequacy of its system. If certain criteria apply only to certain components or areas of the system, describe the criteria that are applicable to those areas or components.

A-16. The referenced criteria are described in the attached documents:

1. NERC Standard TPL-001-0 through TPL-004-0

2. ECAR Document No. 1

3. LG&E Energy FERC Form No. 715

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**
2. **Number:** TPL-001-0
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 1, 2005

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, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered 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 A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

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

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no 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.

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

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_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-001-0_R3_1 and TPL-001-0_R3-2.

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-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
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

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	April 1, 2005	Effective Date	New

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

Standard TPL-001-0 — System Performance Under Normal Conditions

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

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.

A. Introduction

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

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

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 1, 2005

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	April 1, 2005	Effective Date	New

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

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

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.

A. Introduction

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

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

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 1, 2005

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	April 1, 2005	Effective Date	New

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

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

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.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-0

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 1, 2005

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 evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

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 D contingencies of Table I. The specific elements selected (from within 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 D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

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. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. 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. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' 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 for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

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: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

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

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

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.

ECAR DOCUMENT NO. 1

RELIABILITY CRITERIA FOR EVALUATION AND SIMULATED TESTING OF THE ECAR BULK POWER SUPPLY SYSTEMS

Approved by the Coordination Review Committee
September 1967
Revised October 15, 1980
Revised May 27, 1998

Approved by the ECAR Executive Board
October, 1967
Revised November 6, 1980
Revised July 27, 1998

East Central Area Reliability Coordination Agreement

Document No. 1

RELIABILITY CRITERIA FOR EVALUATION AND SIMULATED TESTING OF THE BULK ELECTRIC SYSTEMS

TABLE OF CONTENTS

This document contains the standards that Transmission Providers are expected to adhere to in their simulated testing and system performance evaluations in order to ensure reliable transmission performance in the ECAR region. These standards include:

- System performance standards.
- Reliability assessment standards.
- System data modeling standards.

The standards and requirements in this document should guide individual ECAR Transmission Providers in establishing their own specific Bulk Electric System planning criteria. In doing so, the individual ECAR Transmission Providers should be able to meet, at a minimum, the Transmission System Performance and Reliability Assessment standards set forth herein.

In implementing these standards, ECAR members recognize:

1. The need to plan Bulk Electric Systems that will withstand adverse credible disturbances without experiencing uncontrolled interruptions.

2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100 percent reliability to every customer or every local area.

3. The importance of considering local conditions and requirements in establishing transmission reliability criteria for the local area power supply and the need, therefore, to view reliability in local areas primarily as the responsibility of the individual ECAR members. However, local area disturbances must not jeopardize the overall integrity of the Bulk Electric Systems within ECAR.

4. The importance of mitigating the frequency, duration and extent of major Bulk Electric System outages.

5. The importance of mitigating the effect of conditions that might result from events such as national emergencies, strikes, or major outages on other regional networks.

In addition to the above, the ECAR members recognize the impossibility of anticipating, and testing for, all possible contingencies that could occur on either the present or the future Bulk Electric Systems within ECAR. They believe, therefore, that the transmission reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies, that may or may not be readily visualized, rather than comprise a detailed listing of probable disturbances. Ultimately, the strength of the system as planned and operated must be sufficient to assure that any load loss has not been the result of or does not result in uncontrolled power interruptions. In view of this, the selection of reliability criteria is based not on whether the specific contingencies for which the system is being tested are themselves highly probable but rather on whether they constitute an effective and practical means to stress the system and thus to test its ability to avoid uncontrolled power interruptions.

The ECAR members believe the most effective safeguard against a possible occurrence of uncontrolled power interruptions is strict adherence to basic principles of Bulk Electric Systems planning, with recognition of the entire range of anticipated operating requirements.

A. SYSTEM PERFORMANCE

Introduction

Individual member transmission systems provide the means to serve the load with generation resources of each area. The interconnection of Bulk Electric Systems within ECAR has allowed each system to reduce its installed reserve capacity, take advantage of short term regional transfers and increase transmission reliability. The Bulk Electric Systems should be capable of performing this function under a wide variety of system conditions (e.g., forced and maintenance outages, continuously varying loads) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Bulk Electric Systems must be planned to withstand the more probable forced and maintenance outage contingencies at projected demand and firm electricity transfer levels. Transmission Providers within ECAR may apply more stringent system performance criteria than those described herein in order to address the particular needs and concerns of the Transmission Provider.

Standards

1. Individual systems shall be planned such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected demands and provide contracted firm transmission services.

2. Individual systems shall be planned such that the network can be operated to supply projected demands and contracted firm transmission services with any single outage of a transmission line, transformer, special control device or generator due either to a forced outage or the failure of a primary protective device or special protective scheme.

   The transmission systems shall also be capable of accommodating bulk facility maintenance outages scheduled prior to such contingencies.

3. Individual systems shall be planned such that the network can be operated to supply projected demands and contracted firm transmission services with contingencies such as the loss of a bus section, breaker failure, double circuit tower outage or the delayed clearing of a single line to ground fault of a generator, bus section, or transmission element. Such contingencies can result in the outage of more than one element or facility. The controlled interruption of demand, the planned removal of generators, or the curtailment of contracted firm power transfers is permitted.

4. The transmission systems shall also be capable of accommodating facility maintenance outages, scheduled prior to such contingencies.

5. Individual systems shall be planned such that Cascading shall not result from the condition of a single outage of a transmission line, transformer, special control device or generator due either to a forced outage or the failure of a primary protective device or special protective scheme, followed by a second single outage. Before or after the second contingency, the controlled interruption of demand, the planned removal of generators, manual intervention or the curtailment of contracted firm power is permitted.

Requirements

1. Transmission Providers shall ensure that transmission system performance with respect to Standard 1 is as summarized below:

   a. Line and equipment loadings shall be within normal ratings.
   b. Voltage levels shall be maintained within normal limits.
   c. Stability of the network shall be maintained.
   d. No unplanned loss of load, generation or contracted firm power transfers shall occur.

2. Transmission Providers shall ensure that transmission system performance with respect to Standard 2 is as summarized below:

   a. Line and equipment loadings shall be within applicable ratings.
   b. Voltage levels shall be maintained within applicable limits.
   c. Stability of the network shall be maintained.
   d. Planned or controlled interruption of generators or electric supply to radial customers or some local network customers, connected to or supplied by the faulted component or by the affected area, is permitted as long as it does not impact the overall security of the interconnected transmission systems. No unplanned loss of load, generation or contracted firm power transfers shall occur.

3. Transmission Providers shall ensure that transmission system performance with respect to Standard 3 is as summarized below:

   a. Line and equipment loadings shall be within applicable ratings after all manual and automatic intervention has been completed. Intervention may include opening of transmission lines and transformers.
   b. Voltage levels shall be maintained within applicable limits after all manual and automatic intervention has been completed. Intervention may include opening of transmission lines and transformers.
   c. Stability of the network shall be maintained.
   d. Planned outages of load or generation are permitted, and contracted firm power transfers may be curtailed.
   e. Cascading shall not occur.

4. Transmission Providers shall ensure that transmission system performance with respect to Standard 4 is as summarized below:

   a. Stability of the network shall be maintained.
   b. Planned outages of load or generation are permitted, and contracted firm power transfers may be curtailed in the analysis.
   c. Line and equipment loadings shall be within applicable ratings after all manual and automatic intervention has been completed. Intervention may include opening of transmission lines and transformers.
   d. Voltage levels shall be maintained within applicable limits after all manual and automatic intervention has been completed. Intervention may include opening of transmission lines and transformers.
   e. Cascading shall not occur.

Guides

1. A balanced relationship among power system elements, in terms of size of load, size of generating units and plants, strength of interconnections, and the amount of power being carried on any single transmission channel should be maintained.

   This implies:

   a. Avoiding excessive dependence on generating capacity in one unit, at one location, or in one area,
   b. Avoiding excessive concentrations of power being carried on any single transformer, transmission circuit, tower line, or right-of-way, as well as through any one transmission station, and
   c. Provision of interconnection capability that is commensurate with the size of the system load and with the size of generating units and plants.

2. Primary switching arrangements and secondary control facilities should be utilized that permit effective maintenance of equipment without excessive risk of uncontrolled, area-wide power interruptions on the interconnected network of ECAR systems.

3. Switching arrangements, associated relay schemes, and controls should be utilized that permit effective use of transmission capability without excessive risk of uncontrolled, area-wide power interruptions on the interconnected network of ECAR systems.

4. Switching and control arrangements should be utilized that provide for restoration of any part of the interconnected network within acceptable time constraints.

5. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems.

6. In order to maintain appropriate bulk transmission bus voltages, to alleviate bulk transmission facility thermal loadings and to maintain voltage stability, adequate reactive sources, with a balance of static and dynamic characteristics, should be planned and distributed throughout the Systems.

7. With respect to Requirement 3 and 4, if manual intervention is used, the Transmission Provider should demonstrate that such intervention can be implemented in a timely manner relative to the dynamic response of the system. Such intervention should be restricted to those actions that can be accomplished within thirty minutes. Manual intervention is sometimes used in seasonal assessments but should normally not be used in long term assessments.

B. RELIABILITY ASSESSMENTS

Introduction

This section contains the requirements for studies to be conducted by Transmission Providers to assess the reliability of their transmission system over a short and long-term horizon. The results of these studies, in conjunction with ECAR studies conducted under the direction of the ECAR CRC will be used to assess the reliability of the ECAR interconnected transmission systems.

Standards

The reliability of the existing and planned Bulk Electric Systems of the ECAR region shall be assessed to ensure that each Transmission Provider conforms to the System Performance section of this document.

Requirements

1. Each Transmission Provider shall participate in seasonal reliability assessments prior to both the summer and winter seasons. Results of these studies shall be available to the ECAR CRC.

2. These seasonal assessments shall address the anticipated thermal, voltage, and stability performance for the conditions specified in the System Performance section of this document, Standards 1 and 2. Any potential violations of Standards 1 and 2 for the upcoming season, along with the planned operating strategies to alleviate the violations, shall be reported to the ECAR CRC.

3. Each Transmission Provider shall participate in reliability assessments for representative future years for a 10-year horizon to evaluate the anticipated performance and reliability of the planned systems. The results of these long-term studies shall be available to the ECAR CRC.

4. The long-term assessments shall address the anticipated thermal, voltage and stability performance for the conditions specified in the System Performance section, Standards 1, 2, 3 and 4 of this document.

5. Each Transmission Provider shall assess the risks and system responses for multiple contingency events. Where such events could lead to Cascading or system instability, the Transmission Provider shall document and may at their discretion, implement measures and procedures to mitigate the extent of these events. Documentation of these assessments shall be made available to the ECAR CRC.

Multiple contingency events include the loss of:

- A tower-line with three or more circuits
- All transmission lines on a common right-of-way
- Any transmission station including associated generation
- All generating units at a power plant
- A transmission line or transformer when another transmission line or transformer is out of service
- A large load or load center

Other events to be assessed include:

- Failure of a fully redundant Special Protection System to operate when required
- Operation, partial operation, or mis-operation of a fully redundant Special Protection System for an event for which it was not intended
- Impact of severe power swings or oscillations from disturbances originating outside the Transmission Provider's system.

6. Each Transmission Provider shall document their assessment activities in compliance with these standards. This documentation shall be available to the ECAR CRC upon request.

Guides

1. Reliability Assessments should be conducted for peak, shoulder, light-load, and heavy loading conditions.

2. If steady-state analysis indicates possible insufficient voltage stability margins, power flow simulation of contingencies, including P-V and Q-V curve analyses, should be used and verified by dynamic simulation.

3. The transmission system reliability assessment should take into account the maintenance plans of the transmission facility owners.

4. Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, Cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm transmission services. Models should be benchmarked and adjusted to reflect conditions and impacts originating from elsewhere on the interconnected system.

5. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

6. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal

effectively with such events. Although it is not practical to construct a system to withstand all possible extreme contingencies without Cascading, it is desirable to control or limit the scope of such Cascading or system instability events and the significant economic and social impacts that can result.

7. Extreme contingency assessments should be conducted on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of Cascading or system instability events.

C. SYSTEM MODELING

Introduction

This section contains the requirements for system modeling data to be submitted by Transmission Providers to assess regional transmission system reliability.
Complete, accurate, and timely data is needed for system analyses to ensure the adequacy and security of the interconnected transmission systems, meet projected demands, and determine the need for system enhancements or reinforcements.

System analyses include steady-state and dynamic (all time frames) simulations of the electrical networks. Data requirements for such simulated modeling include information on system components, system configuration, demands and electric power transactions.

Standards

Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained by each Transmission Provider and made available to ECAR upon request.

Requirements

1. The appropriate ECAR panel shall identify the scope and specificity of the steady-state and dynamics data required for reliability analyses and the procedures for data reporting. These requirements shall be documented, published in the ECAR Base Case Development (BCD) Procedural Manual and periodically (at least every five years) reviewed.

2. Each Transmission Provider shall provide appropriate equipment characteristics and system data in compliance with the ECAR BCD Procedure Manual for the modeling and simulation

of the steady-state behavior of their respective systems. This data shall be provided to ECAR, who will provide it to interested parties on request.

3. Each Transmission Provider shall provide appropriate equipment characteristics and system data in compliance with the ECAR BCD Procedure Manual for the modeling and simulation of the dynamic behavior of the systems. This data shall be provided to ECAR, who will provide it to interested parties on request.

Definitions

Transmission Provider - Any entity that owns and/or operates a network transmission system rated 100 kV or higher in the ECAR region.

Cascading - The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

LG&ENERGY®

Operating Companies
(Kentucky Utilities Company / Louisville Gas & Electric Company)
Annual Transmission Planning
and Evaluation Report

FERC Form No. 715

April 1, 2005

Part 1: Identification and Certification

1. Transmitting Utility Name
   LG&E Energy LLC
   Operating Companies (KU/LG&E)

2. Transmitting Utility Mailing Address
   One Quality Street
   Lexington, KY 40507

3. Contact Person Name
   Michael G. Toll

4. Contact Person Title
   Manager, Transmission Planning & Substations

5. Contact Person Telephone Number
   (859) 367-1167

6. Contact Person Facsimile Number
   (859) 367-5766

7. Certification
   The undersigned certifies that he has examined the accompanying report; that to the best of his knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the projected ability of the bulk electric transmission of the above named respondent to deliver power to load reliability.

8. Certifying Official Signature

   ____

9. Certifying Official Name
   Mark S. Johnson

10. Certifying Official Title
    Director, Transmission

Part 2: Power Flow Base Cases

United States of America
Federal Energy Regulatory Commission

2005 FERC Form 715
Annual Transmission Planning and Evaluation Report
Part 2:

LG&E Energy LLC, is a Member of the East Central Area Reliability Coordination Agreement (ECAR) and participates in its regional process for consolidating and sharing of power flow information. As such, the respondent hereby authorizes the ECAR Region to release to FERC and to the public in accordance with FERC and ECAR policies, the most current regional power flow data models.

By: ______________________

Title:

Director, Transmisson

Date: ______________

Regional organization name, mailing address, contact person and title, telephone and facsimile information:

East Central Area Reliability Coordination Agreement
220 Market Avenue South, Suite 501
Canton, OH 44702-2182
S.C. Rao, P.E.
Staff Engineer
TEL: 330-580-8003
FAX: 330-456-3648

The East Central Area Reliability Coordination Agreement (ECAR) hereby submits power flow data in response to Part 2 of FERC Form 715 for the following ECAR members:

Company Name	**Power Flow Data Acronym**
Allegheny Power (Includes	AP
American Electric Power	AEP
Big Rivers Electric Corporation	BREC
Cinergy Corporation	CIN
The Dayton Power and Light Company	DPL
Duquesne Light Company	DLCO
East Kentucky Power Cooperative, Inc.	EKPC
FirstEnergy Corporation	FE
Hoosier Energy Rural Electric Coop., Inc.	HE
Indianapolis Power & Light Company	IPL
International Transmission Company	ITC
LG&E Energy Corporation	LGEE
Michigan Electric Transmission Co. LLC	METC
Northern Indiana Public Service Company	NIPS
Ohio Valley Electric Corporation	OVEC
Vectren Energy Delivery of Indiana	VEDI

Each of these utilities participates in the ECAR regional process for consolidating and sharing of power flow information. Additionally, power flow base case models developed by ECAR include imbedded system representations of the following ECAR Associate Members:

American Municipal Power - Ohio	AMPO
Buckeye Power, Inc.	BPI
Indiana Municipal Power Agency	IMPA
Municipal Cooperative Coordinated Pool (Michigan)	MCCP
Wabash Valley Power Association	WVPA

The following ECAR Members and Associate Members have no transmission systems within ECAR and are, therefore, not represented in the ECAR portion of these models:

BP Energy Co.
Cargill Power Marketers, LLC
CMS Marketing., Servs., &Trading
Connective Energy Supply, Inc.
Constellation Power Source, Inc.
Consumers Energy (ECAR Full member)
Duke Energy North America (ECAR Full member)
Detriot Edison Co (ECAR Full member)
Edison Mission Marketing & Trading T
First Energy Solutions,Inc.
Commonwealth Edison
Independent Electricity Market Operator
Midwest ISO (ECAR Full member)
Mirant Americas LLP
PJM Interconnection, LLC (ECAR Full member)
PSEG Power, LLC.
Tennessee Valley Power association

The ECAR Members have authorized the ECAR Region to release to FERC and to the public in accordance with FERC and ECAR policies, the most current regional power flow data models.

Regional organization name, mailing address, contact person and title, telephone and facsimile information:

East Central Area Reliability Coordination Agreement
220 Market Avenue South, Suite 501
Canton, OH 44702-2182
S.C. Rao, P.E.
Staff Engineer
raos@ecar.org
TEL: 330-580-8003 FAX: 330-456-3648

Process for public access to regional power flow information:

Requests should be submitted in writing with pre-paid fees and the recommendation of the CRC representative from an ECAR transmission provider who has a system modeled in the base cases to the regional contact person above. Data will be sent via first class U. S. Mail (via UPS for paper hard copies) no later than 10 working days following receipt by the regional organization contact person of a written request and pre-paid fees.

Information will be made available electronically on an as-is, non-supported basis. Each model will include:

Input data in PTI PSS/E Rev. 28, Activity RAWD card image format, or in GE PSLF (EPC) Rev. 14.2 format (please specify in request letter).
Corresponding solved output listing.
A data dictionary cross-referencing ECAR bus or line terminal names in the model to actual substation or switching station names commonly used by the utility.

Electronic Media: Self-decompressing MS DOS ASCII format on 3.5 inch, 1.44 MB diskettes or via electronic mail.

On-Site Inspection: Powerflow data are available for inspection by appointment only at the ECAR Executive Office, 220 Market Avenue South, Suite 501, Canton, Ohio 44702. Contact S.C.Rao, P.E., Staff Engineer, at (330) 580-8003 for appointments. Orders for data will be accepted during on-site inspections for shipping within ten (10) working days.

Fees: Fees must be pre-paid before requests will be honored.
Electronic Media: $70 fee for first model requested and $15 for each additional model in the same written request.
Paper Hard-copy: $250 per model requested.
Data Dictionary Hard-Copy (during on-site inspection only): $0.10 per page

Powerflow models available as of April 1, 2005 are:

Current Power Flow Cases Filed April 1, 2005 with FERC

Case Name	**Case File Designator**
2004/05 Winter Peak ECAR Assessment Case (2003 Series)	04WS
2005 Spring Peak Case	05GF
2005 Summer Peak Case	05SF
2005 Summer Peak ECAR Assessment Study Case	05SS
2005 Fall Peak Case	05FF
2005/06 Winter Peak Case	05WF
2005 Light Load Case[1]	05LF
2006 Spring Peak Case	06GF
2006 Summer Peak Case	06SF
2006 Fall Peak Case	06FF
2006/07 Winter Peak Case	06WF
2009 Summer Peak Case	09SF
2009/10 Winter Peak Case	09WF
2014 Summer Peak Case	14SF

Non-Current Cases Available on Request[2]

2003/04 Winter Peak ECAR Assessment Case 2002 Series)	03WS
2004 Spring Peak Case	04GF
2004 Summer Peak Case	04SF
2004 Summer Peak ECAR Assessment Study Case	04SS
2004 Fall Peak Case	04FF
2004/05 Winter Peak Case	04WF
2004 Light Load Case[3]	04LF
2005 Spring Peak Case	05GF
2005 Summer Peak Case	05SF
2005 Fall Peak Case	05FF
2005/06 Winter Peak Case	05WF
2010 Summer Peak Case	10SF
2010/11 Winter Peak Case	10WF
2013 Summer Peak Case	13SF

The East Central Area Reliability Coordination Agreement (ECAR) Region is providing this power flow base case data on behalf of its Member systems in compliance with the
Disclaimer

[1] A Light Load case is defined as a typical early morning load level in April with pumped storage hydro units in pumping mode. The intent is to model near minimum load levels. Summer equipment ratings are used.

[2] Non-Current cases in the ECAR Base Case Library that were previously filed with the FERC, and are available on request.

[3] A Light Load case is defined as a typical early morning load level in April with pumped storage hydro units in pumping mode. The intent is to model near minimum load levels. Summer equipment ratings are used.

The East Central Area Reliability Coordination Agreement (ECAR) Region is providing this power flow base case data on behalf of its Member systems in compliance with the requirements of FERC Form 715, Part 2 (18 C.F. R. § 141.300), Annual Transmission Planning and Evaluation Report. These data were compiled in compliance with those requirements, and ECAR does not warrant or represent its use for any other purpose.

These base case data are compiled directly from information supplied to ECAR by its Members, and external system representations developed under the auspices of the North American Electric Reliability Council Multiregional Modeling Working Group. The ECAR Region is not responsible for the accuracy of the contents other than replacement of diskettes damaged in transit.

Level of Detail

The power flow base cases provided contain sufficient detail of the bulk transmission systems in the ECAR Region to perform screening analysis of the availability of transmission system capacity within the ECAR Region.

Voltage and/or equipment loading violations appearing in cases may have specific operating procedures to alleviate them which have not been invoked in the case, depending upon system conditions.

External Models

This powerflow base case contains reduced or equivalent representations of systems external to the ECAR Region Member systems. Those external representations are of sufficient detail to simulate power transactions to/from those systems. However, the representations are not intended for study of the transmission capacity in those external systems.

Solution Tolerances

GE PSLF Program: Powerflow base cases are solved using the Full Solution (option 1) iteration technique of the GE PSLF (Revision 12.0) powerflow program on a personal computer. It was solved with a zero impedance cutoff value of 0.00011 p.u., a Newton tolerance of 1.0 MVA, and a MVAr bandwith of 20.0. Attempts at solution to stricter tolerances may not be successful.

PTI PSS/E Program: Powerflow base cases are solved using the Fixed Slope Decoupled Newton-Raphson Iteration technique on an IBM RS6000 computer. They were solved with a zero impedance cutoff value of 0.0001 p.u., and a plus or minus 1 MVA bus mismatch tolerance. Attempts at solution to stricter tolerances may not be successful.

Memory Requirements
The set of self-decompressing data files for each case requires a total up to 20 MB of disk space per case when decompressed.

Part 3: Transmitting Utility Maps and Diagrams

Part 4: Transmission Planning Reliability Criteria

1. NERC transmission reliability criteria

   LG&E Energy, LLC designs its transmission system to conform to the fundamental characteristics of a reliable interconnected bulk electric system recommended by NERC.

2. ECAR transmission reliability criteria

   Document No. 1 - Reliability Criteria For Evaluation and Simulated Testing of the ECAR Bulk Power Supply Systems, Revised July 1998 documents the standards to which Transmission Providers in ECAR are expected to adhere. LEC adheres to the basic bulk power supply planning principles set forth in that document.

3. LG&E Energy, LLC transmission planning guidelines are documented in Appendix A.

Part 5: Transmission Planning Assessment Practices

Special assessment practices to be used for simulation of generation dispatch and transmission switching are included in LG&E Energy LLC's Transmission System Planning Guidelines submitted in response to Part 4: Transmission Planning Reliability Criteria.

Part 6: Evaluation of Transmission System Performance

LG&E Energy LLC's transmission system is evaluated through several ongoing processes:

1) Interregional Studies

Each year ECAR participates in interregional studies with MAAC, MAIN, NPCC, TVA, and VACAR to identify First Contingency Incremental Transfer Capability (FCITC) limits between the regions.

2) ECAR Seasonal Assessments

Semiannually, the ECAR Transmission System Performance Working Group (TSPWG) performs an assessment of the ECAR bulk transmission system. The purpose of these assessments is to provide insight into the expected performance of the ECAR bulk transmission system under a wide range of system conditions for the upcoming peak load season.

3) Midwest ISO MTEP Assessments

4) LG&E Energy LLC's Annual Transmission Plan Development

LG&E Energy LLC annually develops power flow models to simulate future system performance. Detailed studies and economic analysis are utilized to select immediate construction requirements from optimal long-range plans. Additionally, screening studies are routinely performed to identify long-range problems and potential construction projects are identified. New construction and major system upgrades currently planned during the next 5-year period to maintain the adequacy of LG&E Energy's bulk transmission network (138 kV and above) are summarized below.

Description	Year
Construct Virginia City to Clinch River (AEP) 138 kV line (8 miles)	2006
Construct Mill Creek to Hardin Co 345 kV line (43 miles)	2009
Loop Ghent-Speed 345 kV line into Trimble Co (3 miles)	2009
Construct West Lexington to Higby Mill 138 kV line (12 miles)	2009
Construct West Frankfort to Tyrone 138 kV line (10 miles)	2009
Reconductor Ghent to Owen Co 138 kV line (13 miles)	2009
Reconductor Elizabethtown to Hardin Co 138 kV line (1 mile)	2009
Install a 345-138 kV, 450 MVA transformer at Hardin Co	2010
Install a 345-138 kV, 450 MVA transformer at Middletown	2010

Appendix A:

LG&E ENERGY®

Transmission System Planning Guidelines

March 11, 2005

1 Overview

The primary purpose of LG&E Energy's (LEC) transmission system is to reliably transmit electrical energy from company owned generating resources to native load customers. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide access to other economic and emergency generating sources for native load customers.

LEC subscribes to and designs its transmission system to conform to the fundamental characteristics of a reliable interconnected bulk electric system recommended by the North American Electric Reliability Council (NERC). Additionally, LEC is a member of the East Central Area Reliability Coordination Agreement (ECAR) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth in the ECAR Documents.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs. LEC's Operating Companies (KU/LG&E) have an OATT tariff on file with FERC to provide firm and non-firm point-to-point transmission service for other entities, as well as firm network service. LEC's Operating Companies are committed to provide the same reliability and priority of service to firm transmission service for other entities as they do to their own native load customers.

The American National Standards Institute (ANSI) and The Institute of Electrical and Electronic Engineers, Inc (IEEE) publish standards for power system equipment design and application. LEC incorporates ANSI and IEEE standards in the design and application of equipment utilized in the transmission system.

Section 2 elaborates on the NERC and ECAR Standards and Section 3 presents LEC's Planning Guidelines.

2 Reliability Council Planning Standards

NERC in its Planning Standards report states the fundamental requirements for planning reliable interconnected bulk electric systems and the required actions or system performance necessary to comply. The Regions, subregions, power pools, and their members have the responsibility to develop their own appropriate or more detailed planning criteria and guides that are based on the Planning Standards.

LEC is a member of ECAR. ECAR has developed Document 1, "Reliability Criteria for Evaluation and Simulated Testing of the Bulk Systems", in compliance with the NERC Planning Standards report. ECAR Document 1 contains the standards that transmission providers are expected to adhere to in their simulated testing and system performance evaluations. LEC has developed and adopted planning criteria and guides that meet or exceed the ECAR Document 1 standards and requirements.

3 LEC Planning Guidelines

LEC's transmission system is planned to deliver company owned generator output and purchased generation (economic and/or emergency) to meet projected customer demands and to provide contracted firm transmission services. The transmission system is planned to withstand forced outages of generators and transmission facilities.

LEC plans its transmission system to meet or exceed the fundamental requirements of a reliable bulk electric system as recommended by the NERC Planning Standards report and ECAR Document 1.

Table 1 describes the contingencies and measurements LEC utilizes in testing and assessing the performance of its transmission system. Stability of the network should be maintained and cascading outages should not occur. Section 3.1 discusses the applicable voltage limits for Normal and Contingency conditions. Section 3.2 discusses modeling considerations that should be considered.

Additionally, LEC periodically evaluates the risk and consequences of extreme contingency events.

Table 1
Transmission Contingencies and Measurements

Contingencies	System Limits or Impacts: Thermal Limits	Voltage Limits	Loss of Demand Or Curtailed Firm Transfers
No Contingencies	Normal	Normal	No
Outage of a generator, transmission circuit or transformer. [a,b]	Emergency	Contingency	No
Outage of two generators. [b]	Emergency	Contingency	No
Outage of a generator and a transmission circuit. [b]	Emergency	Contingency	No
Outage of a generator and a transformer. [b]	Emergency	Contingency	No
Outage of a transmission circuit or transformer with plant at maximum output. [f]	Emergency	Contingency	No
Outage of two transmission circuits. [b]	Emergency	Contingency	Yes
Outage of a transmission circuit and a transformer. [b]	Emergency	Contingency	Yes
Outage of two transformers. [b]	Emergency	Contingency	Yes
Outage of a bus section. [c]	Emergency	Contingency	Yes
Outage of a breaker. [c]	Emergency	Contingency	Yes
Outage of a double circuit towerline. [d]	Emergency	Contingency	Yes
Outage of a generator, transmission circuit, transformer or bus section. [e]	Emergency	Contingency	Yes

Notes:
Fault Types
a) None
b) Single Line Ground or 3-Phase, with Normal Clearing
c) Single Line Ground, with Normal Clearing
d) Non 3-Phase, with Normal Clearing
e) Single Line Ground, with Delayed Clearing
f) With one unit off and additional redispatch prorated amongst all on-line units at other plants

3.1 Voltage Limits

A transmission voltage of 94 percent of the nominal value is the minimum acceptable for normal load service and should be maintained at all load serving busses with normal generation and normal transmission system conditions. Any 500 kV system bus voltage should not exceed 110 percent of the nominal value and any other transmission bus voltage should not exceed 105 percent of the nominal value.

Transmission level voltage at the major power plants should be maintainable with normal generation and normal transmission system conditions as follows:

Table 2
Normal Plant Voltages

Power Plant	Transmission Bus (kV)	Scheduled Voltage (kV)	Per Unit Voltage
Brown	Brown N 138	142	1.029
Cane Run	Cane Run Sw 138	138	1.000
Ghent	Ghent 345	355	1.029
Green River	Green River 138	142	1.029
Mill Creek	Mill Creek 345	345	1.000
Trimble County	Trimble Co 345	352	1.020
Elmer Smith	Smith 138	142	1.029

A transmission voltage of 90 percent of the nominal value is the minimum acceptable for contingency load service and should be maintained at all load serving busses during any transmission system contingency or generation and transmission system contingency.

Generators and plant auxiliary systems are generally designed to operate within +/- 5% of the nameplate or nominal voltage. Table 3, on the following page, shows the required transmission level voltage at each generating unit to maintain generator voltage and auxiliary bus voltage above 95% of nominal with the unit operating at maximum MW and MVAR output. The transmission level voltage should exceed the voltage specified in Table 3 during any contingency condition. Only on-line generators are applicable to the analysis.

3.2 Modeling Considerations

Replacement generation required to offset unit outages should be simulated from the most restrictive of internal sources, AEP, Cinergy, and/or TVA.

A single outage may include multiple transmission components in the common zone of relay protection.

Post-fault conditions and conditions after load restoration should be evaluated. Post-contingency operator-initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process but load should not be taken off-line to perform switching. Post-contingency operator-initiated actions may be simulated to reduce the flow through transformers or increase voltages but not to reduce line flows.

Transmission capacitor status (on/off) should be simulated consistent with automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Manual energization of capacitors should not be simulated to eliminate low voltage conditions that result from a contingency.

Seasonal adjustment of fixed taps on transmission transformers should not be required to control voltages within the acceptable ranges.

Switching EHV system facilities out of service to reduce off-peak voltages is undesirable.

Table 3
Minimum Operating Voltage at Generators

Transmission Bus	Generator	Minimum Voltage	Limit
Brown Plant 138	Brown 1	0.935	Gen
	Brown 2	0.964	Aux
Brown North 138	Brown 3	0.931	Aux
Brown CT 138	Brown 5	0.928	Gen
	Brown 6	0.929	Gen
	Brown 7	0.929	Gen
	Brown 8	0.918	Gen
	Brown 9	0.918	Gen
	Brown 10	0.918	Gen
	Brown 11	0.918	Gen
Cane Run Sw 138	Cane Run 4	0.936	Gen
	Cane Run 5	0.941	Gen
	Cane Run 6	0.940	Gen
Ghent 138	Ghent 1	0.947	Aux
Ghent 345	Ghent 2	0.959	Gen
	Ghent 3	0.964	Gen
	Ghent 4	0.963	Gen
Green River 138	Green River 3	0.926	Aux
	Green River 4	0.944	Aux
Mill Creek 345	Mill Creek 1	0.958	Gen
	Mill Creek 2	0.958	Gen
	Mill Creek 3	0.953	Gen
	Mill Creek 4	0.953	Gen
Paddys Run 138	Paddys Run 13	0.937	Gen

Transmission Bus	Generator	Minimum Voltage	Limit
Trimble Co 345	Trimble Co 1	0.960	Gen
	Trimble Co 5	0.943	Gen
	Trimble Co 6	0.943	Gen
	Trimble Co 7	0.943	Gen
	Trimble Co 8	0.943	Gen
	Trimble Co 9	0.943	Gen
	Trimble Co 10	0.943	Gen
Smith 138	Smith 1	0.942	Gen
	Smith 2	0.945	Gen

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

CASE NO. 2005-00142
CASE NO. 2005-00154
CASE NO. 2005-00155

Response to Commission Staff's First Data Request
Dated: June 30, 2005

Question No. 17

Responding Witness: Kent W. Blake

Q-17. Describe the contractual requirements to provide power or service to utilities in Indiana and Kentucky.

A-17. LG&E/KU have no contractual requirements or obligation to serve retail customers in Indiana.

As noted in Paragraph 9 of the Application *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Expansion of the Trimble County Generating Station*, Case No. 2004-00507, and subject to the necessary approvals, LG&E and KU will collectively own 75% of the TC2 generating unit. The remaining 25% share of TC2 will be owned by the Illinois Municipal Electric Agency ("IMEA") and the Indiana Municipal Power Authority ("IMPA"). The ownership is more fully described in the direct testimonies of Mr. Blake and Mr. Malloy in that proceeding.

LG&E/KU have the obligation to serve retail electric customers within their certified service territories in Kentucky