GREAT RIVER ENERGY	**Transmission Division Operating Guidelines**	**Transmission Planning Procedures and Planning Criteria TDOG108**	Page 1 of 33

Approved by: William R. Kaul, Vice President Transmission	Approved date: 10/13/16
Reviewed by: Mike Steckelberg	Review date: 9/1/2016
Revision number: 4.0	

OBJECTIVE: TDOG108 (Transmission Planning Procedures and Planning Criteria) provides information to those entities who are considering interconnecting to the GRE transmission system. *(NERC FAC-001)*

SCOPE: This document describes the procedures and criteria that the Great River Energy (GRE) Transmission Planning Department utilizes during the development of transmission plans for the transmission system. This includes the evaluation of new and materially modified existing interconnections.

The GRE Transmission Planning Department has the responsibility to analyze the existing transmission system to determine whether expansion (new transmission projects) is required to continue to provide reliable and economic service to GRE load, generation and transmission service customers.

As necessary and at GRE's discretion, this document may be revised from time to time as changes in procedures or criteria may be needed to meet changing system requirements such as new technologies, changes in transmission usage (load, generation, or transmission service) or changes in regional or local criteria. This includes changes to standards or criteria developed by the North American Electric Reliability Corporation (NERC), the Midcontinent Independent System Operator (MISO), or the Midwest Reliability Organization (MRO) as well as other, adjacent transmission owners and operators.

Reference Documents

NERC Reliability Standards
TDOG 202: Generator Interconnection Guidelines
TDOG 204: Tie-Line and Substation Interconnection Guideline
GRE Facility Rating Methodology

All revisions prior to January 2013 are contained in the Record of Revisions document. Please refer to the electronic copy on the GRE intranet to view changes prior to those listed below.

Document Review History

Version	Reviewed date (MM/DD/YY)	Review by	Description	Approved date (MM/DD/YY)	Approved by
2.0	**02/22/13**	**David Kempf**	Updates and changes to SPS and DR sections		
3.0	**02/21/14**	**David Kempf**	Annual Review, updates to study requirements for interconnection		
4.0	**09/01/16**	**Mike Steckelberg**	Restructure the TDOG into separate parts (planning procedures and planning criteria). Update contingency types to new, TPL-001-4 nomenclature. Add NERC performance requirements.	**09/27/16**	**Dave Kempf**
	09/01/2017				

Versions reviewed no less frequently than every 15 months.

Any inconsistencies in dating prior to 09/30/2015 are acceptable. All future reviews must follow instructions established in Step 6.0 of TDIV-01, Transmission Division Operating Guideline (TDOG) and Department Process Initiation/Approval

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1.0 Introduction

The GRE Transmission Planning Department has the responsibility to ensure that the GRE-owned transmission system and the transmission systems of adjacent transmission owners have sufficient capability to reliably and economically serve GRE-member load. GRE is responsible for planning of the Bulk Electric System (BES) which GRE-owns and may affect service to GRE customers.

In addition, GRE has contracted to perform the transmission planning functions for Hutchinson Municipal Utilities, Willmar Municipal Utilities, and Missouri River Energy Services.[1]

The procedures and criteria included in this document are intended to be a *minimum set* of information needed to analyze the existing system and develop new projects to ensure continued reliable and economic service into the future. GRE planners are encouraged to add additional analysis, criteria, and procedures as necessary to enhance the service to GRE customers and members. *(NERC FAC-001)*

2.0 Planning Study Procedures and Coordination

GRE will conduct system planning analysis in accordance with the GRE's planning criteria (see Appendix I). Analysis and planning for the Bulk Electric System (BES) will include the contingences and performance requirements of Categories P0-P7 in NERC Standard TPL-001-4. For the remainder of the system, including GRE's underlying transmission system less than 100 kV, Category P0, P1, and P2 contingency analysis will be conducted. *(NERC TPL-001-4)*

For all new interconnections (generation, transmission and end-user) to GRE transmission system GRE transmission planners will perform analysis to assess the reliability impact of the interconnection. *(NERC FAC-002-2)*

For modifications to existing interconnections (generation, transmission, or end-user) to the GRE transmission system GRE transmission planners will determine whether the modification should be considered a material modification. Based on this determination, additional analysis may be conducted to determine whether the modification has adverse impacts to system reliability and mitigation is required to address those impacts. *(NERC FAC-002-2,R1(ii))*

GRE will coordinate its analysis with the Business Practice Manuals (BPMs) of MISO[2] (Planning Coordinator) and potentially affected transmission owners to evaluate any requests for new or materially-modified interconnections to the GRE-owned transmission system, including generation interconnection requests. GRE's local planning criteria will apply in addition to other applicable NERC standards and regional or local planning criteria. *(NERC FAC-002-2)*

GRE will conduct system planning studies to develop long-range plans for the GRE transmission system as a whole, as well as plans for specified areas within the boundaries of GRE's transmission system. These plans will address future customer needs, problems and/or other developments in the areas served the GRE transmission system. The scope of the planning studies may be tailored to address specific areas of concern, such as high load growth areas, to manage the scope of the planning study.

The goal within the GRE footprint is to develop an "umbrella" plan for the area, that is, a combined, coordinated, overall plan that emphasizes projects that serve multiple purposes or solve multiple problems within the transmission system. The area approach is intended to address requirements for support to the local distribution systems in that area on a least cost basis. It is anticipated, however, that several projects that span more than one area or possibly even beyond the GRE transmission system boundaries, may evolve. Such projects will involve coordination with other transmission owners or regional transmission organizations.

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[1] This list of entities for which GRE provides transmission planning services may change from time to time.

[2] MISO (Midcontinent Independent System Operator)

When planning, GRE will consider alternatives to transmission solutions to problems on the transmission system as appropriate or as required for regulatory approval. Such alternatives could include, but not be limited to, central station generation, distributed generation, load management and conservation measures. GRE will use sound judgment in assessing whether non-transmission solutions are applicable on a case-by-case basis, keeping in mind that GRE is a generation and transmission company and does not serve as a load serving entity for retail load.

3.0 Types of Planning Studies

3.1 Annual Planning Assessment

On a periodic basis as determined by GRE's Planning Coordinator, the Midcontinent Independent System Operator, GRE will conduct an assessment of the GRE portion of the transmission grid for a near-term period (1 to 5 years) and a long-term period (6 to 10 years). These assessments are usually conducted as part of the Minnesota Transmission Assessment and Compliance Team (MNTACT). The assessments will investigate if potential system performance issues that may arise based upon NERC Standards and MRO requirements. Such assessments will involve steady state simulations using regional models created through the regional model building process. Dynamic simulations are also performed using models created by the Upper MISO Transmission Assessment Group (UMTAG) or equivalent models provided by similar groups for stability purposes.

The results of the annual assessment are included in a report that is shared with GRE's planning coordinator, neighboring transmission planners and other entities that request a copy of the report. *(NERC TPL-001-4)*

3.2 Load Serving Studies

GRE also maintains a 10-year plan with the primary purpose of assessing the continued capability of the transmission system to maintain or improve the reliability of service to loads, both existing and projected. This plan includes consideration of costs, economics, reliability and aesthetics. If needed, a 20-year assessment will be included in the plan.

The 10-year plan is used as a source of information to parties interested in the development of the GRE transmission system. A primary use of the 10-year plan is for projecting financial obligations and forecasting construction activities. Planning engineers can also use this document as a guide to identify areas of need, a source of information of the existing system and a planning tool to determine alternatives, particularly distributed generation and demand-side management, for an integrated resource plan. Due to the uncertainty of load growth in the future, the facilities included in the 10-year plan may be changed, delayed, advanced or canceled in lieu of a lower cost alternative.

Other area studies will be performed if certain planning areas have received unanticipated growth, such as a new industrial plant. These plans may use information and transmission development alternatives from the 10-year plan if applicable or create new options depending on the load requirements.

Load serving studies will involve at minimum both summer and winter peak scenarios. Other scenarios will be studied as necessary for those conditions where, for example, local loading of the transmission is more stressful that the summer or winter peak load conditions. Consideration will also be given to the impacts of local generation outages that result from market dispatch conditions or forced outages.

3.3 Generation and Transmission Interconnection Studies

3.3.1 Generation Interconnection Studies

Generation interconnection studies will involve, at a minimum, summer peak and summer off-peak for most generation plants. A light load (minimal load) analysis will also be performed if the generation is likely to be on during those periods of time. Energy storage devices such as battery storage or pumped hydro may be treated as both a generator and a load depending on the planning engineering concerns about reliability.

Other considerations should include:

1. The loss of the largest distribution load in the vicinity of the generator as a valid n-1 event;
2. All local network resources at rated Pmax.;
3. All local energy resources at Pmax;
4. Local generation should not be included in the generation adjustment for the addition of the new generation resource;
5. Power transfers through the region; and
6. Winter peak analysis if in an area is impacted by winter power flow patterns and reduced loads.
7. Dynamic (transient) stability analysis may, based on engineering judgment, may be performed.
8. Other applicable NERC Standards

There are additional requirements for the planning and construction of generator interconnections which can be found in GRE's **TDOG 202: Generation Interconnection Guidelines.**

3.3.2 Transmission Interconnection Studies

Transmission interconnection studies will be analyzed necessary to ensure that the modified transmission system meets all local and regional planning criteria and applicable NERC standards. Power flow models, similar to those required for generation interconnection studies, will be developed as necessary to accommodate the analysis. Additional studies, such as small signal, short-circuit, or voltage stability, may also be required depending on the nature of interconnection request.

There are additional requirements for the planning and construction of generator interconnections which can be found in GRE's **TDOG 204: Tie-Line and Substation Interconnection Guideline.**

3.4 Dynamic (Transient) Stability Analysis

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism, prevention of system voltage collapse and determine whether there are sufficient system reactive power resources within 20 seconds after a system disturbance.

GRE will perform dynamic stability assessments when a need is indicated or on an annual basis per NERC Standards. These assessments will include, but are not limited to, consideration of the following system load conditions:

1) Summer peak

2) Summer off-peak

3) Winter peak

4) Light load

The first and third conditions are typically used for voltage stability studies. The second condition is primarily used for angular stability studies.

3.5 Transfer Capability Studies

GRE will rely on MISO as the Planning Coordinator to perform all the necessary studies to determine Transfer Capability. GRE will support the MISO methodology so long that GRE planning criteria are met. *(NERC FAC-013—2)*

3.6 System Operating Limit Analysis

GRE establishes System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) for its transmission planning area that covers the planning horizon. The SOLs and IROLs are consistent with the MISO methodology[3] through the following procedure. *(FAC-014-r2)*

1. GRE provides modeling data and receives modeling data for the GRE transmission planning area through the MISO model-on-demand process.
2. Engineering staff at the MISO performs preliminary calculations of SOLs and IROLs and prepares the results for review by GRE (and the other MISO transmission planners)
3. GRE planning engineers review the preliminary results to determine whether the results are valid for establishing SOLs and IROLs for the GRE transmission planning area.
4. GRE provides comments to MISO as to whether the results need to be updated based due to system changes (topology, ratings) or operating procedures (guides) are in place.
5. Engineering staff at the MISO updates the results
6. GRE reviews the updated results.
7. GRE indicates to the MISO that the results represent the SOLs and IROLs for the GRE system.
8. GRE provides GRE planning horizon SOL/IROL results to those entities who request the information.

3.7 Reliability Analysis

3.7.1 MW-Mile Analysis

In order to assess the planned reliability of the transmission system, GRE performs a MW-Mile analysis to prevent a single-contingency outage of a transmission circuits from affecting a large number of customers or a large geographic area.

The methods used for calculating radial and looped transmission circuits MW-Mile values and the criteria for the analysis is included in the Appendix.

Radial MW-Mile Analysis

This analysis involves radial fed loads on the GRE system. MW-mile calculations are used to determine when radial fed substations may be qualified to receive looped service. Other factors include:

- The reliability of the radials;
- The cost of looping the system;
- Effects of the loop on the system power flow;
- Future needs in the area;
- Backfeed capability of the distribution system; and
- Double-end of distribution substation.

When developing new transmission facility plans, GRE favors alternatives that will provide a looped feed to the new substation. GRE tries to minimize the use of radial lines because of potentially lower reliability. Radial lines are acceptable if the resulting quality of service is compatible with the customer's needs.

[3] The current version of the MISO methodology is contained in Appendix L of BPM-020-r13 (May 10, 2016)

Breaker MW-Mile Analysis

This analysis is for the looped transmission system between circuit breakers. Breaker MW-mile calculations are used to determine when line exposure between two or three circuit breakers affect the load being served by the respective line. Breaker MW-mile values above the criteria may lead to additions of sectionalizing equipment to limit the load outage. Sectionalizing will consist of new circuit breakers, motor-operated switches or normally open switches on the system. Timing of system restoration is also a factor. Circuit breakers can return a load almost instantaneously, whereas switching operations will take a few minutes with motor-operated switches and possibly a few hours to open or close manual switches in limited access areas.

3.7.2 Facility Condition Assessment

The facility condition criteria to be utilized by GRE for system planning purposes will include:

1) Any transmission line on structures that are beyond their design life, any transmission line that has exhibited below-average availability or any transmission line that has required above-average maintenance will be considered a candidate for replacement. In assessing potential line replacements, consideration will be given to other needs in the area of the candidate line to determine whether rebuilding the line to a higher voltage would fit into the “umbrella” plan for that planning area. GRE engineering, operation and maintenance, and environmental employees work together to coordinate such assessments.

2) Any substation bus that is beyond its design life, has exhibited below-average availability or has required above-average maintenance will be considered a candidate for rebuilding and potential redesign. In assessing potential bus rebuilds, consideration will be given to likely and potential expansion at candidate substations, including consideration of the “umbrella” plan for the planning area. GRE engineering, operation and maintenance, and environmental employees work together to coordinate such assessments.

3) Any substation whose design or configuration prevents maintenance in a safe manner on substation equipment or lines terminating at the substation will be considered a candidate for rebuilding and/or potential redesign/reconfiguration. In assessing such rebuilds/redesigns/reconfigurations, consideration will be given to likely and potential expansion at candidate substations, including consideration of the “umbrella” plan for the planning area. GRE engineering, operation and maintenance, and environmental employees work together to coordinate such assessments.

4) Any underground cable that is beyond its design life, has exhibited below-average availability or has required above-average maintenance will be considered a candidate for replacement. In assessing potential cable replacements, consideration will be given to other needs in the area of the candidate cable to determine whether replacing the cable with a cable with a higher ampacity, with a cable capable of a higher voltage or with an equivalent overhead line would fit into the “umbrella” plan for that planning area. GRE engineering, operation and maintenance, and environmental employees work together to coordinate such assessments.

5) GRE will strive to verify the efficacy of all operating guides that require on-site operations.

3.7.3 Historical Reliability Assessment

GRE system operations also maintains records of transmission that reflect the reliability of the system. This outage information, along with other operational records, influences system improvement decisions. GRE planners will use this information to make rational decisions on new facilities. GRE will also provide these records to parties of concern upon request.

4.0 Facility Rating Methodology

4.1 Steady State Facility Ratings

GRE facility ratings are determined by the GRE "Facility Rating Methodology" document. The GRE facility ratings criteria are consistently applied among GRE planning, engineering and operations. *(NERC FAC-008-3)*

Facilities to be considered include, but are not limited to, overhead line conductors, underground cable, bus conductors, transformers, autotransformers, circuit breakers, disconnect switches, series and shunt reactive elements, VAR compensators, current transformers, wave traps, jumpers, bushings, lightning arrestors, meters and relays (both overcurrent/directional overcurrent/impedance settings and thermal limits). GRE will establish facility ratings for its solely and jointly owned facilities that are consistent with the associated "Facility Ratings Methodology".

For jointly owned facilities where GRE is the majority owner, GRE will coordinate the equipment owner's information with its own information to determine the appropriate facility rating. When GRE is the minority owner, GRE will coordinate and provide the GRE-owned equipment data to the responsible modeling parties or as requested to any appropriate entities.

GRE will provide facility ratings for its solely and jointly owned facilities that are new facilities, existing facilities, modifications to existing facilities and re-ratings of existing facilities to its associated reliability coordinator(s), planning coordinator(s), transmission owner(s), transmission planner(s) and transmission operator(s) as scheduled by such requesting entities. *(NERC FAC-008-3,R8)*

Updates to facility ratings are usually done regularly (annually) via the MISO Webtool[4], the MISO Model on Demand (MOD) and, when a valid request is made, via direct communications. In some cases, a facility rating may not match an off the shelf model as a facility may have been upgraded, degraded or removed from service based since the model was developed.

4.2 Dynamic Operating Ratings

Dynamic Operating Ratings (DOR) are time dependent facility ratings based on GRE's Facility Ratings Methodology that allow for a facility to be operated outside the steady-state rating for a short period of time, typically 5 to 10 minutes. DORs are generally intended for use during a limited timeframe (usually less than 5 years) as a result of a forced outage of other transmission facilities or a delay of projects under construction.

The DOR will be cancelled when a permanent fix is installed, in the event NERC or MISO's reliability criteria affecting the facilities change or at the discretion of GRE in the event implementation of the DOR becomes burdensome. In any event, the allowed use of the DOR will terminate in five years unless GRE deems extension is warranted.

GRE will not allow DOR of its transmission facilities to be used as a temporary fix to delay the installation of facilities required for generation interconnection requirements or for as a substitute for transmission upgrades to allow for the addition of generation capacity. If completions of the proposed infrastructure is delayed, the generation plant will be limited to output levels that do not put the existing system at risk.

GRE will only allow an emergency DOR of facilities if the following criteria are met:

- GRE engineering has performed an evaluation confirming the capability of a DOR.
- The DOR will be based on GRE Facility Rating Methodology.

[4] Data entered by GRE System Operations

- The long-term mitigation plan must be already identified or a facility study must be in progress before the DOR can be utilized.
- Real time data needed to calculate the DOR is scanned directly by the GRE Energy Management System. This may include monitoring of conditions local to the facility such as ambient temperature, facility temperature, or wind speed.
- DOR can only be utilized on facilities where redispatch can reduce the transmission line to or below its normal rating within the time limit for which the DOR was calculated.
- DORs are not allowed for approval of a Transmission Service Request (TSR) because TSRs represent firm transmission service. DOR lines do not have firm ratings beyond the static limit.
- Only one DOR operation guide will be allowed per facility.
- In the event that data communication is lost, the normal rating of the line continues to be the static limit.

5.0 Reliability Criteria

5.1 GRE Planning Criteria

In addition to the NERC Standards, regional and local planning criteria are established to address the reliability issues unique to the regional and local transmission systems, respectively. In order to continue to provide acceptable service for the needs of the customers served by the GRE transmission system, other local planning criteria are used to measure system performance. Some of the items included in GRE's local transmission planning criteria are:

- Voltage limits
- Facility loading
- MW-Mile limits
- Maximum number of source terminals
- Voltage flicker
- Harmonic Voltage Distortion
- Allowed use of Remedial Action Schemes

GRE's local transmission planning criteria is included in Appendix I of this document.

5.2 Variations to GRE transmission planning procedures and criteria

The GRE transmission system consists of assets within the five transmission operating areas of the Minnesota system. Each of the original asset owners planned their system to separate planning criteria, particularly in regard to transient and dynamic performance. Therefore, as GRE has implemented its own planning criteria, portions of the system may require upgrades to meet the more stringent GRE criteria.

This section describes the philosophy that will be followed for completing projects in a portion of the system identified as deficient with respect to the GRE criteria.

1) Area does not meet NERC Planning Standards with respect to stability.

a. Complete projects required for bringing the existing system into compliance with NERC Standards with no intentional delay.

b. New generator interconnections are not permitted until the NERC standards are met with the addition of the generator, if the new generator interconnection aggravates the stability condition. [A new generation interconnection is deemed to aggravate the stability performance of an area if a change in scope is required to meet NERC Planning Standards.]

c. Depending on the level of risk associated with the deficiency, special operating procedures (restrictions or guides) may be required to mitigate the risk until the system is in compliance. If a new generator interconnection is permitted but still negatively influences the stability condition, the operating restriction may follow a "last interconnected, first restricted" approach.

2) Area meets NERC Planning Standards but not GRE criteria with respect to stability.

a. Normal schedule for projects required for bringing the existing system into compliance with GRE criteria.

b. New generator interconnections are permitted as long as the system continues to meet the NERC Planning Standards. If the new generator interconnection causes a violation of NERC Standards, 1.b above applies.

c. Operating procedures will not be required in the interim period until the projects to meet GRE criteria are completed.

3) Area meets GRE planning criteria for existing system but a new generator interconnection causes a violation of:

a. GRE planning criteria – New generator interconnection is not permitted until GRE criteria are met with the addition of the new generator.

b. NERC Planning Standards – New generator interconnection is not permitted until both NERC standards and GRE criteria are met.

6.0 Load Forecasting & Modeling

GRE gathers historical load data measured at its metered locations and then scales the data using the load growth projections to produce GRE's forecasted load. The historical data gathered includes peak values for summer, fall, and winter seasons. GRE forecasts peak load levels for these four seasons, as well as for light load and summer off-peak situations. The GRE methodology for developing, aggregating and maintaining load forecast information are in accordance with NERC Standard MOD-031.

GRE models several different loading situations, which are defined in the "MISO MOD-032 Model Data Requirements and Reporting Procedures"[5]

Summer peak is the peak demand expected during the months June, July and August. A reduction in load is included for controlled demand-side management and peak shaving loads.

Winter peak is the peak demand expected during the months December, January and February. A reduction in load is included for controlled demand-side management and peak shaving loads.

[5] GRE will update the list of models to stay in concert with the MISO MOD-032 requirements.

Summer off-peak or summer shoulder peak is defined as 70 percent of the summer peak value. This case is modeled because high interchange has been observed in the north-central MRO region under this condition.

Fall peak is the peak demand expected during the months September, October and November.

Spring light load is typically expected during early morning hours but could occur at any time during the year. GRE defines this load level to be 40 percent of the summer peak load for that year.

GRE applies a baseline power factor requirement[6] at every delivery point with its member systems and other load serving entities. GRE TDOG-107 (Power Factor Requirement for Delivery Points) contains the guidelines for power factor standards for Member Delivery Points and the corrective actions for improving power factor. In general, GRE models 0.98 leading power factor in minimum load studies and 0.98 lagging power factor in peak load studies.

7.0 System Performance Analysis

7.1 Model development

7.1.1 Power flow models

The starting point for the GRE power flow models is the NERC modeling databases and modeling data submitted by others through the planning coordinators and other transmission planners.

The following powerflow models are usually developed:

1) Summer peak
2) Winter peak
3) Summer off-peak
4) Fall peak
5) Spring light load

Variations of the above models will be developed as necessary to properly model other conditions such as high-transfer, low-wind, high-wind, or extremely light load events. Model data (loads, generation output, facility ratings, etc.) may be adjusted as appropriate for the type of study being conducted.

7.1.2 Dynamic Models

For dynamic assessments, GRE uses dynamic models that are part of the MISO model development process. The dynamic models will be modified as required to add, delete, or modify parameters in order to meet the scope requirements of a particular dynamic study.

7.2 PSS/E tools

GRE uses the PSS/E developed by Siemens PTI for steady state and dynamic simulations of the power system. GRE also uses post-processing tools for summarizing the output of multiple PSS/E calculations to compare results of the different simulations.

[6] As measured at the Point of Interconnection or the high-side of distribution transformers (including losses).

7.3 Other tools

Other software tools may be used for engineering calculations of short-circuit current, harmonic distortion, small-signal analysis, etc. as necessary to properly analyze the performance of the transmission system.

8.0 Development of Transmission Alternatives

8.1 General procedures for developing alternatives

The fundamental purpose of transmission planning is to develop a future transmission system that can be operated reliably and economically serves customers, including GRE member customers. The development of new transmission projects comes from the analysis of alternatives that are proposed based on a transmission planning engineer's experience. It will also require the consultation of other planners, system operators, design engineers, and regulatory permitting staff as alternatives are evaluated, accepted for further consideration, or are rejected based on the discussions.

The sections below describe some of the evaluation that take place when considering alternatives. Additional areas of discussion will likely be required based on the unique nature of each alternative.

8.2 Planning Criteria

8.2.1 Any new alternatives that are developed to correct criteria violations found during planning assessments should be analyzed in accordance with GRE's planning criteria and NERC Standards. Each alternative should be compared using the same assumptions as any other alternatives that may be considered to correction a deficiency.

8.3 Engineering standards

8.3.1 All alternatives should meet GRE's engineering standards. GRE substation and transmission engineering departments should be consulted as necessary during this review.

8.4 Operational feasibility

8.4.1 All transmission alternatives, including reconfiguration of the topology or operational procedures, should be reviewed by GRE System Operations at an appropriate time. Generally, transmission planners have some insight into the operational requirements through experience with past projects or review of GRE's operating reports and procedures.

8.5 Facility age and condition

8.5.1 During the development of transmission alternatives, there should be a consideration of the age and condition of the existing transmission facilities. This should including operating reports that may highlight areas of the transmission system that experience above average outages due to local conditions such as weather or equipment access. It may be possible to justify a project based on operational improvements in addition to the benefits of mitigating criteria.

8.6 Use of Remedial Action Schemes (RAS)

8.6.1 GRE does not allow the use of new, permanent Remedial Action Schemes (RAS), previously known as Special Protection Systems (SPS), on the transmission system in order to meet reliability criteria. The use of a RAS on a temporary basis, not to exceed five years, is allowed provided that transmission system upgrades required to permit operation without the RAS have been approved for construction.

8.7 Environmental Analysis

8.7.1 The environmental impacts of each alternative must be included in the analysis. In some cases, the adverse environmental impacts may eliminate some alternatives from continued engineering and economic consideration.

8.8 Economic analysis

8.8.1 The overall cost of a proposed alternative should include not only construction costs, but permitting (regulatory filings, environmental assessments, etc.) and operating costs. Operating cost should include, if possible, an assessment of any increased or decreased system losses caused by the project.

8.8.2 The economic analysis should be conducted to bring the cost of each alternative to a common base-point during the economic analysis. This could be total annual costs over the entire life of the project or a net total cost (present worth) to a common starting year.

Appendix I – GRE Planning Criteria

(includes Table 1- Steady State & Stability Performance Planning Events)

GREAT RIVER ENERGY.	**Transmission Planning Criteria**	Department	Transmission Planning
		Issue Date:	January 30, 2015
		Previous Date:	February 21, 2014

1.0 SCOPE/PURPOSE

This document contains the planning criteria that Great River Energy (GRE) uses to ensure that its transmission system is adequate to reliably deliver power to customers, provide support to interconnected distribution systems, deliver energy from existing and new generation facilities, and support effective competition in energy markets. This document may be revised from time to time as appropriate, in response to new system conditions, new technologies being employed and new operating procedures.

The criteria described below will be subject to change at any time at GRE's discretion. Situations that could precipitate such a change could include, but are not limited to new system conditions, extraordinary events, safety issues, operational issues, maintenance issues, customer requests, Midcontinent Independent Transmission System Operator (MISO), regulatory requirements and Regional Entity (RE), e.g. Midwest Reliability Organization (MRO) or North American Electric Reliability Corporation (NERC) requirements.

New or materially modified interconnections to the GRE transmission system will be analyzed[7] to determine whether system performance is degraded to the point where it violates the planning criteria. When GRE is required to model the facilities of foreign transmission owners to conduct an assessment, GRE will adhere to the facility owner's planning criteria requirements.

2.0 REQUIREMENTS IN NERC STANDARDS

The transmission system will be evaluated for compliance with the requirements in NERC Standard[8] TPL-001-4[9] (Categories P0 to P7). Both GRE-owned facilities and facilities in foreign areas will be evaluated.

3.0 SYSTEM MODELING CRITERIA

Steady state and transient assessments are performed to assure avoidance of equipment overloads, prevention of unacceptable system voltage levels and satisfactory system reactive power resources. A detailed analysis will be conducted on the system conditions which are likely to cause the most severe

[77] Per GRE TDOG-108, "GRE Transmission Planning Procedures and Planning Criteria"
[8] NERC Standards can be found at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf
[9] Table 1 from NERC Standard TPL-001-4 is included as Appendix I

impact to criteria. Assessments will include consideration of the following system load conditions for possible further analysis:

1) Summer peak
2) Winter peak
3) Summer off-peak
4) Spring peak
5) Fall peak
6) Minimum load

For generator interconnection studies, the analysis will be conducted with the new generation and all other local generation at full output, at both minimum load and peak load conditions, to determine whether the aggregate of the generation in the local area can be delivered to the aggregate of load on the transmission system.[10]

[10] MISO Tariff, Attachment X, section 3.2.2.2, effective November 14, 2014.

4.0 VOLTAGE CRITERIA

GRE's planning criteria regarding voltage limits on equipment are shown in Table 1.

Table 1
GRE Voltage Criteria

Voltage Ranges	Allowable Planned Voltage Tolerances					
	Per Unit of Nominal					
	Normal		Emergency		Transient	
Facility	Max	Min	Max	Min	Max	Min
Hubbard 230 & 115 kV [11]	1.05	0.97	1.10	0.92	1.20	0.75
Wing River 230 & 115 kV [12]	1.05	0.97	1.10	0.92	1.20	0.75
Ramsey 230 kV	1.05	0.95	1.15	0.90	1.30 for 200 msec[13]	0.70
Balta 230 kV	1.05	0.95	1.10	0.90	1.30 for 200 msec[14]	0.70
Coal Creek 230 kV[15]	1.05	0.95	1.10	0.90	1.18	0.70
Dickinson 345 kV	1.05	0.95	1.10	0.90	1.17	0.70
Fond du Lac 69 kV	1.10	0.95	1.10	0.9	1.20	0.70
Load Serving Buses	1.05	0.95	1.10	0.92	1.20	0.70
Remaining Buses	1.05	0.95	1.10	0.90	1.20	0.70
Voltage Flicker (%)	3%	NA	5%	NA	NA	NA

[11] Minnesota Power planning criteria applies.
[12] Minnesota Power planning criteria applies.
[13] The Ramsey bus is allowed 1.65 per unit for 5 cycles.
[14] The Balta bus is allowed 1.65 per unit for 5 cycles.
[15] This bus has a 1.20 p.u. overvoltage criteria for CU DC Bi-pole fault (ei2).

5.0 FACILITY LOADING CRITERIA

GRE's planning criteria for the loading of transmission facilities is shown in Table 2.

Table 2
GRE Facility Loading Criteria

Facility Ratings	Line		Station Equipment		Transformer	
Condition	Loading	Duration	Loading	Duration	Loading	Duration
Normal	100%	Continuous	100%	Continuous	100%	Continuous
Emergency[16]	100%	NA	100%	NA	100%	NA

6.0 MW-MILE CRITERIA

6.1 Radial MW-Mile Analysis

- The MW-mile value for a radially fed circuit is calculated by summing the flow across each radial line segment times the length (in miles) of the respective segment.
- The MW-mile value of the circuit should not exceed 100 MW-miles.

6.2 Breaker MW-Mile Analysis

- The Breaker MW-Mile calculation is based on the product of the total real power components (load and generation) on the line(s) between the circuit breakers and the total line mileage of the same line(s) between the same circuit breakers.
- MW-mile magnitudes of less than 1000 are typical and acceptable.
- MW-mile magnitudes between 1000 and 2000 are higher than usual. If records indicate poor reliability, then corrective action shall be investigated.
- MW-mile magnitudes higher than 2000 indicate a high amount of exposure and risk to the system. Corrective action shall be investigated.

[16] GRE will conduct an engineering analysis, when needed, to determine whether a specific facility is capable a short-term emergency rating for a limited time duration.

7.0 MAXIMUM OF THREE SOURCE TERMINALS

New interconnection requests will be reviewed to determine if the proposed configuration will result in more than three, normally-closed source terminals into protected line sections. Additional breakers or new breaker stations will need to be added to limit the number of source terminals to three. In some cases, breakers many be operated normally open to limit the number of sources.

In addition, new three-terminal circuits will be reviewed to determine whether adequate relay protection exists in the proposed configuration. Resolution of potential relaying concerns can be accomplished by adding additional breaker protection or by opening the system.

Also, any newly proposed transmission system topology should be analyzed for compliance with other portions of this planning criteria including, but not limited to, contingency analysis.

8.0 TRANSMISSION SYSTEM PLANNING PERFORMANCE REQUIREMENTS

8.1 Steady State Assessments

GRE will maintain appropriate planning criteria for all categories of events allowing for some loss in demand for some Category P2 events. Please refer to NERC Standard TPL-001-4, Table 1 for a further description of the performance requirements for the various event categories. A copy of Table 1 is located in the appendix to this criteria.

In addition, generation interconnection analysis will include the loss of a large, local load that might affect the loading on the local transmission system.

8.2 Transient Stability Assessments

Transient and dynamic stability assessments are generally performed to assure the avoidance of loss of generator synchronism, prevention of system voltage collapse and the adequacy of system reactive power resources during the 20 seconds following a system disturbance. The transient and dynamic system stability performance criteria to be utilized by GRE shall include the following factors.

GRE will perform transient stability assessments when a need is indicated or on a regular basis per NERC Standards. These assessments will include, but are not limited to, consideration of the following system load conditions:

1) Summer peak
2) Summer off-peak
3) Winter peak
4) Minimum load

The first and third conditions are typically used for voltage stability studies. The second and fourth conditions are primarily used for angular stability studies.

GRE will simulate local and regional disturbances for assessment purposes on Category P1 through P7 events. All disturbances will be given a one (1) cycle margin on breaker clearing time.

The performance assessment will be based on:

a. Voltage stability based on meeting GRE transient criteria or the criteria of the facility owner.
b. Voltage stability will be maintained by operating at or below the P_{limit} defined as the power transfer limit across the critical interface. P_{limit} will be 90 percent of the $P_{critical}$ where $P_{critical}$ is defined as the maximum power transfer (the nose of P-V curve).
c. Angular stability will avoid separation of the system unless some generation units are deliberately islanded.
d. Cascade tripping of transmission lines will be monitored and avoided unless planned cascading is initiated.
e. Uncontrolled loss of load will be avoided.
f. No unit will exhibit poorly damped angular oscillations or unacceptable power swings. All machine rotor angle oscillations will be positively damped and calculated from the Successive Positive Peak Ratio (SPPR) of the peak-to-peak amplitude of the rotor oscillation. SPPR and the associated Damping Factor will be calculated as:

SPPR = Successive swing amplitude / Previous swing amplitude and,
Damping Factor = (1 - SPPR) * 100 (in %)

The damping criteria are as follows (with increased damping required for higher probability events):

For disturbances (with faults): SPPR (maximum) = 0.95; Damping Factor (minimum) = 5%

For line trips: SPPR (maximum) = 0.90; Damping Factor (minimum) = 10%

The calculation of damping is based on successive positive peak ratios. In some cases, the SPPR calculation fails due to a constant rate of change of rotor angles caused by a significant generation loss and resulting significant frequency change. In these cases, Prony[17] analysis should be utilized to calculate damping ratios on the appropriate modes of oscillation, and the damping ratio criteria (equivalent to the damping factor criteria above) are as follows:

- For disturbances (with faults): Minimum Damping Ratio = 0.0081633
- For line trips: Minimum Equivalent Damping Ratio = 0.016766

8.3 Voltage Flicker

Voltage fluctuations may be noticeable as visual lighting variations (flicker) and can damage or disrupt the operation of electronic equipment. Sources of flicker are not allowed to produce flicker to adjacent customers that exceeds the GRE guideline shown below (Figure 1). The source will be responsible and liable for corrections if the interconnecting Facility is the cause of objectionable flicker levels.

[17] Prony analysis is a process that will determine whether the dynamic performance if properly damped in order to avoid system instability and subsequent collapse.

The flicker limits defined below are applicable to all interconnections made to the GRE system. The criteria for acceptable voltage flicker levels are defined by the requirements of regulatory entities in the states in which GRE owns and operates transmission facilities, IEEE recommended practices and requirements and the judgment of GRE.

The following flicker level criteria will be modeled at periods that the element causing the flicker is expected to be integrated into or removed from the transmission grid. If electrically close, generation should be scheduled off-line if not a baseload plant. GRE requires that studies be performed for normal conditions and with an outage.

If the limits defined below are exceeded under intact or outage conditions, the flicker producing source must be operated in a manner that does not adversely affect other loads. Planned outages can be dealt with by coordinating transmission and flicker producing load outages. Because operating restrictions during unplanned outages may be severe, it would be prudent for the owner of the harmonic producing load to study the effect of known critical or long-term outages before they occur so that remedial actions or operating restrictions can be designed before an outage occurs.

All GRE buses are required to adhere to the following two criteria.

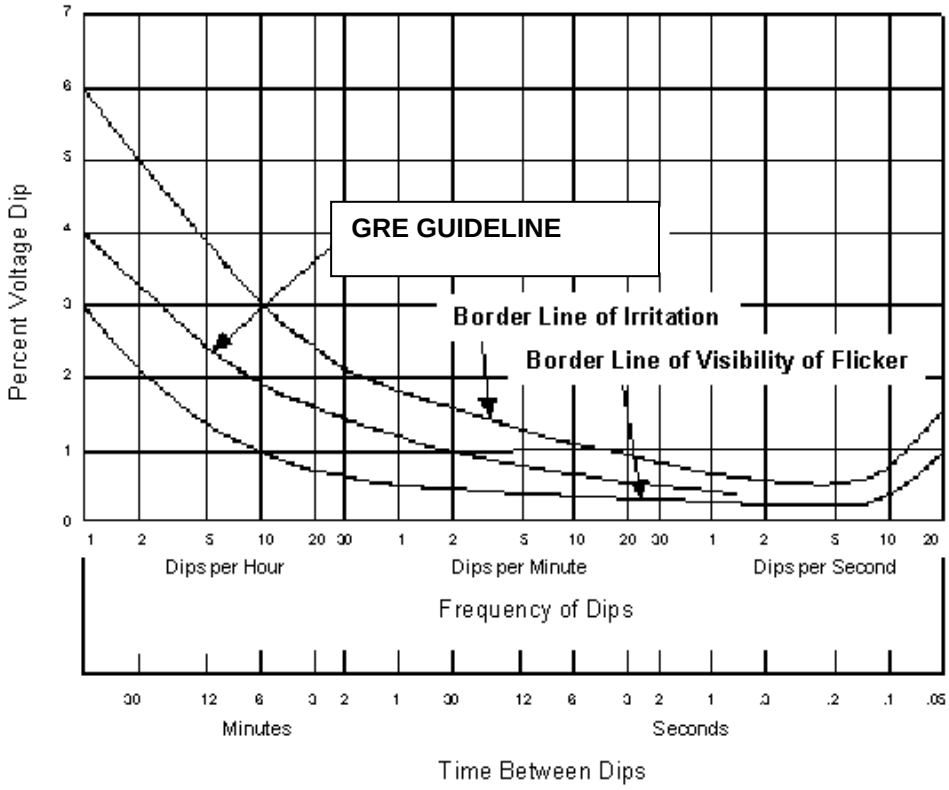
1) Relative steady state voltage change is limited to 3 percent of the nominal voltage for intact system condition simulations. The relative steady state voltage change is the difference in voltage before and after an event, such as capacitor switching or large motor starting.

2) Relative steady state voltage change is limited to 5 percent of the nominal voltage for contingency condition simulations.

GRE uses the following flicker curve found in IEEE Standard 141-1993 (commonly referred to as "The Modified GE Flicker Curve") to determine the acceptability of single frequency flicker.

Figure 1

GRE Voltage Flicker Guideline



8.4 Harmonic Voltage Distortion

GRE advises the interconnecting customer to account for harmonics during the early planning and design stages. The interconnected customer's equipment shall not introduce excessive distortion to the transmission system voltage and current waveforms per IEEE 519-1992. Refer to Tables 3 and 4 below for voltage distortion limits.

Table 3

Voltage Distortion Limits

Bus Voltage At PCC	Individual Voltage Distortion IHD %	Total Voltage Distortion THD %
Below 69 kV	3.0	5.0
69 kV to 115 kV	1.5	2.5
115 kV and above	1.0	1.5
Source: IEEE 519, Table 11.1		

Table 4
Current Distortion Limits For Non-Linear Loads
At The Point Of Common Coupling
(PCC) From 120 To 69,000 Volts

Maximum Harmonic Current Distribution in % of Fundamental Harmonic Order (Odd Harmonics)						
I(sc)/I(l)	**<11**	**11<h<17**	**17<h<23**	**23<h<35**	**35<h**	**THD**
20	4.0	2.0	1.5	0.6	0.3	5.0
20-50	7.0	3.5	2.5	1.0	0.5	8.0
50-100	10.0	4.5	4.0	1.5	0.7	12.0
100-1000	12.0	5.5	5.0	2.0	1.0	15.0
1000	15.0	7.0	6.0	2.5	1.4	20.0

Where:
I(sc) = Maximum short circuit current at PCC

I(l) = Maximum load current (fundamental frequency) at PCC

PCC = Point of Common Coupling between Applicant and utility

Generation equipment is subject to the lowest I(sc)/I(l) values

Even harmonics are limited to 25% of odd harmonic limits given above

Source: IEEE 519, Table 10.3

A special study will be required for situations when the fault to load ratio is less than 10.

9.0 REMEDIAL ACTION SCHEMES

GRE as a rule does not permit the addition of new, permanent Remedial Action Schemes (RASs).

A Temporary RAS can be installed provided the following is met:

The installed RAS must be temporary and will only be valid for a maximum of five (5) years to allow for planned transmission upgrades to be completed while serving new load or generation. The transmission resolution must be placed into the MISO Transmission Expansion Plan (MTEP) process, a scope and schedule must be approved by GRE prior to the installation and granting of the RAS. An extension of the RAS will be granted unless transmission cascading, system collapse or large loss of load are an issue. Any cost of extending the RAS will be borne by the requesting party including any cost for documentation requirements to the Regional Entity, Planning Coordinator or Reliability Coordinator.

Legacy RASs

A legacy RAS may be maintained if there is a significant reliability benefit such as preventing cascading, system collapse or large loss of load.

All RASs must meet all the criteria and guidelines of a NERC and Regional Entity defined RAS including dual redundancy of all components of the RAS and the ability to stay within all applicable reliability criteria with the failure of a component of the RAS. Testing of the RAS and documentation of the testing is also required.

10.0 REFERENCES

1. GRE TDOG-108, Transmission Planning Procedures and Planning Criteria
2. North America Electric Reliability Corporation, http://www.nerc.com/pa/Stand/Pages/default.aspx
3. NERC Reliability Standards Complete Set: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf
4. IEEE Standard 141-1993, “IEEE Recommended Guide for Electric Power Distribution for Industrial Plants”

5. IEEE Standard 519-1992, “IEEE Recommended Practices and requirements for Harmonic Control in Electric Power Systems”

Appendix

From the NERC TPL-001-4 Reliability Standard

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [9]	SLG	EHV, HV	Yes	Yes

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Standard TPL-001-4 — Transmission System Planning Performance Requirements

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker [10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay [13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

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Standard TPL-001-4 — Transmission System Planning Performance Requirements

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

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Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

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Standard TPL-001-4 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

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