Southwest Power Pool

CRITERIA

LATEST REVISION: July 29, 2014

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FOREWORD

All members of Southwest Power Pool (SPP) adopted the NAPSIC (now North American Electric Reliability Council or NERC) Operating Guides on March 11, 1970. Over the years, these documents have developed into policies, procedures, principles, criteria, standards and guides. In some instances, the NERC documents are not in sufficient detail to meet specific needs of SPP. Additional necessary details have been adopted by SPP as Criteria. This Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the interconnected electric system is achieved. Reference to SPP in terms of responsibilities for activities means SPP organizational groups which are defined in SPP Bylaws and the SPP Directory. Reference to the SPP bulk electric system means the combined interconnected electric systems of members. Reliability Coordination (Coordinator) and Security Coordination (Coordinator) are used interchangeably in this Criteria.

INTRODUCTION

A primary purpose of SPP is to facilitate joint planning and coordination in the construction and operation of the generation and transmission network of the individual members so as to provide for increased operating efficiency and continuing service reliability, both in SPP and the contiguous regions. To assist in achieving these objectives, the members of SPP recognize that common criteria and procedures must be used in the planning and operation of the combined electric system for cost effective, adequate and reliable bulk power supply. This Criteria presents the characteristics of a well-planned bulk power electric system, describes the basis for model testing and lists the reliability and adequacy tests to be used to evaluate the performance of the SPP bulk electric system, and describes coordinated operating procedures necessary to maintain a reliable and efficient electric system. Reliable operation of the interconnected bulk electric system of SPP requires that all members comply with this minimum Criteria. Compliance with this Criteria is considered essential to a well planned and operated electric system, and is mandatory for all SPP members. Adherence can be expected to provide adequate and effective safeguards against the occurrence of uncontrolled area-wide power disturbances and will also provide efficient utilization of the electric system resources. This Criteria is also intended to serve as a guideline for developing more specific and definitive criteria by each member of SPP.

It is the policy of SPP to maintain as high an interconnection capability with adjoining regions as is economically prudent. Interconnections with adjoining regions shall be designed such that SPP will remain interconnected following all of the more probable transmission and generation outage contingencies. Emergencies that occur in adjoining regions can affect SPP, just as the emergencies within SPP can affect adjoining regions. Therefore, joint studies shall be made on a regular basis to investigate various system emergencies that can occur and their effects on the electric system. In this way, the effectiveness of existing and planned interconnections shall be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability shall be maintained.

1.0 OPEN

Each member shall provide annually to the SPP Office a 10-year forecast of peak demand and net energy requirements. This information is to conform with requirements set by SPP in conjunction with NERC and government agencies. The forecasts so provided shall be produced in accordance with generally recognized methodologies and also in accordance with the following principles.

a. Each member shall select its own load forecasting methodology and establish its own load forecast.

b. Each member shall forecast load based on expected weather conditions.

c. Method used, factors considered and assumptions made shall be submitted along with the forecast.

d. The SPP forecast shall be the total of the member forecasts.

e. High and low growth rate and extreme weather scenario bands shall be produced for the SPP Regional and Subregional demand and energy forecasts.

f. Economic, technological, sociological, demographic and any other significant factors shall be considered in producing the forecast.

2.0 CAPACITY MARGIN

This Criteria requires and provides for the sharing of reserve generating capacity as a means of reducing capacity requirements of each Member and providing reliable electric service to firm customers due to the equitable purchase, sale and exchange of generating capacity among Members.

2.1 Definitions

2.1.1 Load Serving Member

A Load Serving Member shall mean any SPP Member assuming legal obligation to provide firm electric service to a customer or group of customers within SPP.

2.1.2 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined Capacity Margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Power purchased shall only be considered to be Firm Power if Firm Transmission Service is in place to the Load Serving Member for delivery of such power. Firm Power does not include “financially firm” power.

2.1.3 System Capacity

A Load Serving Member’s System Capacity shall be equal to the capability of its generating facilities, including its ownership share of jointly owned units, demonstrated under procedures set forth in SPP Rating of Generating Equipment Criteria, adjusted to reflect the purchase from and/or sale to any other party of generating capacity or SPP defined Operating Reserve, under any appropriate agreement. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Capacity purchases shall only be considered if Firm Transmission Service is in place to the Load Serving Member for delivery of power from such capacity.

Unless reported separately, generating facilities owned by others within the Load Serving Member's system that are obligated to furnish firm power to customers within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements with the host Control Area, the host Control Area will not be required to be responsible for capacity and/or reserve requirements. The reporting of generating facilities owned by others does not constitute an obligation on the Load Serving Member's part to furnish reserves or back up power for that generation.

2.1.4 Net Load

The term Net Load for any Load Serving Member shall mean, for any clock hour:
(a) Net generation by the Load Serving Member's facilities; plus
(b) Net receipts into the Load Serving Member's system; minus
(c) Net deliveries out of such Load Serving Member's system

Unless reported separately, the Net Load of other non-Load Serving Members located within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements, the reporting of these loads does not constitute an obligation on the Load Serving Member's part to furnish reserves, back up power, or incur financial obligations from SPP for that load.

2.1.5 Capacity Year

Capacity Year shall mean a period of twelve consecutive months beginning on October 1 of each calendar year. Any period less than a Capacity Year shall be designated as Short Term.

2.1.6 System Peak Responsibility

System Peak Responsibility of a Load Serving Member for any Capacity Year shall mean the Load Serving Member's greatest Net Load during that Capacity Year plus:
(a) The contract amount of Firm Power sold to others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the sale of a specified amount of Firm Power; and minus
(b) The contract amount of Firm Power purchased from others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the purchase of a specified amount of Firm Power.

In each case, the contract amount governs regardless of the amount actually delivered at the time of a Load Serving Member's greatest Net Load.

2.1.7 Capacity Margin

Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

2.1.8 Percent Capacity Margin

Percent Capacity Margin shall be defined by the formula:

Percent Capacity Margin = (Capacity Margin/System Capacity) x 100

2.1.9 Minimum Required Capacity Margin

Each Load Serving Member’s Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent.

2.1.10 System Capacity Responsibility

A Load Serving Member’s System Capacity Responsibility for any Capacity Year shall mean the sum of that Load Serving Member's System Peak Responsibility and its Minimum Required Capacity Margin.

2.1.11 Capacity Balance

Capacity Balance shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Capacity Responsibility.

2.1.12 Firm Transmission Service

Firm Transmission Service is that service defined in any applicable transmission service provider tariff.

2.2 Capacity Responsibility

(a) Each Capacity Year, each Load Serving Member shall possess System Capacity at least equal to its System Capacity Responsibility.

(b) Prior to the establishment of its System Peak Responsibility for each Capacity Year, each Load Serving Member shall provide System Capacity by one or more of the following means:

- (i) Establishing a unit rating consistent with SPP generating equipment rating Criteria, prior to establishing its System Peak Responsibility;
- (ii) Reducing its System Peak Responsibility by purchase of Firm Power from any Member or non-Member by separate agreement;
- (iii) Separate written agreement with another Member or a non-Member for purchase of a specified amount of capacity; and/or
- (iv) Reducing its Net Load.

(c) A Load Serving Member may purchase Short Term capacity to provide a part of its System Capacity or Short Term Firm Power to reduce its System Peak Responsibility subject to each of the following restrictions:

- (i) Such Short Term period shall not be less than four consecutive months, and shall include the day the Load Serving Member establishes its System Peak Responsibility. Such period shall begin during May 1 to June 1 or November 1 to December 1;
- (ii) The amount of Short Term capacity or Short Term Firm Power purchased shall not exceed 25% of the Load Serving Member's System Peak Responsibility; and
- (iii) The Load Serving Member shall purchase such Short Term Capacity or Short Term Firm Power prior to the start of the Short Term period.

(d) A Load Serving Member may sell Short Term Capacity or Short Term Firm Power from resources comprising its Capacity Balance, provided that its System Capacity Responsibility is met.

2.3 Records

Each Load Serving Member, upon request, shall provide accurate and detailed records of information related to this Criteria to the SPP Staff. Except for System Peak Responsibility, all other information shall be provided prior to establishing System Peak Responsibility for a Capacity Year and shall include; validation of System Capacity per SPP Rating of Generating Equipment Criteria, Capacity purchase and sale contracts, Firm Power purchase and sale contracts, and firm transmission service agreements. The SPP Staff shall verify information supplied by each Load Serving Member. Calculations shall be based on the highest peak load of each of the Load Serving Members during the Capacity Year. All capacity and demand values will be rounded to the nearest whole MW for purposes of this Criteria. All data submitted to SPP related to this Criteria shall be considered confidential by the SPP Staff and shall not be released in any form except by force of law.

2.4 Generation Planning

2.4.1 Design Features

a. In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.

b. Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of loss of external power.

c. In each major load area of SPP, a unit capable of black start shall be provided having the capability of restarting the other units in the area.

d. Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.

2.4.2 Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for capacity margin requirements.

3.0 REGIONAL TRANSMISSION PLANNING

3.1 Concepts

The interconnected transmission system shall be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. The transmission system shall be planned to withstand all single element contingencies and maintenance outages over the load conditions of all seasonal models as developed by MDWG. Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The *NERC Reliability Standards* define specific requirements that provide a high degree of reliability for the bulk electric system. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related “Coordinated Planning Procedures” in the *SPP Open Access Transmission Tariff*.

3.2 Definitions

All capitalized terms shall have their meaning as contemplated in the SPP OATT, unless defined below.

Bulk Electric System – Bulk Electric System shall have the definition as provided in the NERC Glossary of Terms Used In Reliability Standards, as may be amended from time to time.

NERC – The North American Electric Reliability Corporation, or its successor organization, which is an organization of all segments of the electric industry that recommends, sets, oversees, and implements policies and standards to ensure the continued reliability of North America’s bulk electric system.

Nominal Voltage – The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV. SPP shall evaluate contingencies on the transmission system for all system elements with a Nominal Voltage of 60 kV or greater.

Planned Project – A transmission project, driven by system needs and the recommended solution among considered alternatives, which is a specific commitment to upgrade the transmission system, which has little, if any, outstanding issues, including, but not limited to: budgetary processes, siting, permitting, equipment procurement, installation, regulatory or other approvals, that could delay implementation beyond the expected in-service date.

3.3 Coordinated Planning

SPP members operate in a highly interconnected system and shall coordinate transmission planning. This coordination shall include voluntary efforts between interconnected SPP members and non-members. SPP shall be the primary responsible party for coordinated transmission planning.

The planning and development of transmission facilities shall be coordinated with neighboring systems and regions to preserve the reliability benefits of interconnected operations. The transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Reliability Standards* for transmission planning. The Model Development Working Group (MDWG) shall annually assemble and verify power flow models, short circuit models, and stability models, which shall be used by SPP staff to check compliance with NERC Reliability Standards for transmission planning. Extreme contingency evaluations shall be conducted to measure the robustness of the 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 understand the risks and consequences of such events and to attempt to limit the significant economic and social impacts that may result.

Sufficient reactive capacity shall be planned within the SPP electric system at appropriate places to maintain transmission system voltages 60 kV and above within plus or minus 5% of nominal voltage on all buses under normal conditions and plus 5% or minus 10% of nominal voltage on load serving buses under single contingency conditions.

3.3.1 Planning Criteria

Individual members may develop Planning Criteria that shall, at a minimum, conform to *NERC Reliability Standards* and SPP *Criteria*. Individual member Criteria shall consider the following:

- **a.** Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any single transmission station shall be avoided.
- **b.** Intra-regional, inter-regional, and trans-regional power flows shall not result in excessive risk to the electric system under normal and contingency conditions as outlined in this criteria.
- **c.** Switching arrangements shall be planned to permit effective maintenance of equipment without excessive risk to the electric system.
- **d.** Switching arrangements and associated protective relay systems for all facilities defined in section 12.4 shall be planned to not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.
- **e.** Sufficient reactive capacity shall be planned within the SPP electric system at appropriate places to maintain applicable transmission system voltages under base case and contingency conditions.
- **f.** Facilities shall be rated as assigned in *SPP Criteria* section 12.

3.3.2 Planning Assessment Studies

Individual transmission owners shall perform individual transmission planning studies and shall cooperate in the SPP Transmission Expansion Plan and other SPP coordinated studies. These planning studies are for the purposes of identifying any planning criteria violations that may exist and developing plans to mitigate such violations. Members shall contact the Transmission Working Group whenever new facilities are in the conceptual planning stage so that optimal integration of any new facilities and potentially benefiting parties can be identified. Studies affecting more than one system owner or user will be conducted on a joint system basis. Reliability studies shall examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Updates to the transmission assessments will be performed, as appropriate, to reflect anticipated significant changes in system conditions.

3.3.3 Benchmark SPP Models

SPP staff shall benchmark model data against actual SPP system conditions (e.g., generation dispatch, load, and load power factor) which correspond to the time frames for which the models are created. As a minimum the results shall be reported semiannually.

3.4 SPP Compliance with NERC Reliability Standards for Transmission Planning

3.4.1.1 **Base Case (TPL-001) –** All power flow models developed by the MDWG shall be evaluated for compliance with the NERC Reliability Standard for system performance under normal (no contingency) conditions (Category A of Table 1). In addition to the NERC requirements, SPP requires that these models shall conform to the following standards:

§ Normal Operations – Any established normal (pre-contingency) operating procedures shall be filed by the applicable Transmission Owner with SPP and shall be kept on file by the SPP staff liaison to the SPP MDWG. Normal operations shall reflect a reasonable unit commitment which reflects any contracted or operational limitations. System facilities shall be modeled to reflect normal operation.

§ Transmission Project Inclusion – All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.

Compliance with NERC Table 1 – Category A System Performance Standards – All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category A, subject to the following clarifications:

- § Thermal Limits Within Applicable Rating – Applicable Rating shall be defined as the Normal Rating per SPP Criteria 12, Section 12.2.a. The thermal limit shall be 100% of the Applicable Rating.

- § Voltage Limits Within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage per Criteria 3. Voltage limits shall be set at plus or minus five percent
(+/- 5%) of Applicable Rating.

- § System Stability – Both dynamic and steady state stability of the Transmission System shall be maintained. Cascading outages shall not occur.

- § Modeling of Projected Firm Transfers - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.

The MDWG shall work with the Transmission Working Group (TWG) to resolve issues not considered data errors.

3.4.1.2 **Loss of Single Bulk Electric System Element (TPL-002) –** SPP staff shall conduct an assessment of the power flow models by MDWG to assess compliance with the NERC Reliability Standard for system performance following the loss of a single element (Category B). In addition to the NERC requirements, SPP requires that the power flow models conform to the following standards:

- § Normal Operations - Initiating incident results in a single Bulk Electric System element out of service. Both non-fault and fault initiated events should be evaluated for severity of impact.
- § Transmission Project Inclusion – All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.
- § Compliance with NERC Table 1 – Category B System Performance

Standards - All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category B, subject to the following clarifications:

- o Thermal Limits within Applicable Rating - Applicable Rating shall be defined as the Emergency Rating per SPP Criteria 12, Section 12.2.b. The thermal limit shall be 100% of the Applicable Rating.
- o Voltage Limits Within Applicable Rating – Applicable Rating shall have the
  meaning of Nominal Voltage per Criteria 3. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%) of Applicable Rating for systems operating at 60 kV or above on load serving buses.
- o System Stability – Stability of the Transmission System (angular and voltage) shall be maintained. Cascading outages shall not occur.
- o Modeling of Projected Firm Transfers - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.

§ Loss of Demand - No loss of firm customer demand (except as noted in NERC Reliability Standards Table I, Transmission System Standards – Normal and Emergency Conditions, Footnote b), nor the curtailment of contracted firm (non-recallable reserved) transfers shall be required.

§ Mitigation Plans – Mitigation plans shall be submitted to SPP to verify effectiveness. Mitigation plans may include Transmission Operating Directives or additional system elements. A mitigation plan is deemed effective if it shall return all system voltages and line and equipment ratings to within the Applicable Rating as defined above. SPP shall document the corrective plans necessary to mitigate effects of those events.

3.4.1.3 **Loss of Two or More Elements (TPL-003) –** SPP staff shall conduct an assessment of the power flow models by MDWG to assess compliance with the NERC Reliability Standard for system performance following the loss of two or more elements (Category C). In addition to the NERC requirements, SPP requires that the power flow models conform to the following standards:

- § Normal Operations - Initiating incident may result in two or more (multiple) components out of service. Both non-fault and fault initiated events should be evaluated for severity of impact.

- § <u>Transmission Project Inclusion</u> – All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.
- § <u>Compliance with NERC Table 1 – Category C System Performance Standards</u> - All

MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category C, subject to the following clarifications:

  - o <u>Thermal Limits within Applicable Rating</u> - Applicable Rating shall be defined as the Emergency Rating per SPP Criteria 12, Section 12.2.b. The thermal limit shall be 100% of the Applicable Rating.
  - o Voltage Limits Within Applicable Rating – Applicable Rating shall have the meaning of Nominal Voltage per Criteria 3. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%) of Applicable Rating for systems operating at 60 kV or above on load serving buses.
- § System Stability - Stability of the Transmission System (angular and voltage) shall be maintained. Cascading outages shall not occur.
  - o Modeling of Projected Firm Transfers - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.
- § Loss of Demand - Planned outages of customer demand or generation (as noted in NERC Reliability Standards Table I Transmission System Standards – Normal and Emergency Conditions) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
- § Mitigation Plans – Mitigation plans shall be submitted to SPP to verify effectiveness. Mitigation plans may include Transmission Operating

Directives or additional system elements. A mitigation plan is deemed effective if it shall return all system voltages and line and equipment ratings to within the Applicable Rating as defined above. SPP shall document the corrective plans necessary to mitigate effects of those events.

3.4.1.4 **Extreme Event (TPL-004) –** An extreme event shall have the meaning consistent with Category D of NERC Reliability Standards Table 1, Transmission System Standards – Normal and Emergency Conditions. SPP shall run contingency studies as provided by the transmission owners under the following conditions:

- Initiating event(s) shall result in multiple elements out of service.
- SPP shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion recommend such measures and procedures where extreme contingency events could lead to uncontrolled cascading outages or system instability.

3.4.2 Study Requirements

System contingency studies should be based on system simulation models that should incorporate:

§ Evaluation of reactive power resources
§ Existing protection systems
§ Any existing backup or redundancy protection systems
§ All projected firm transfers (including rollover rights of long-term firm transactions)
§ All existing and Planned Projects

These studies shall assist to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in appropriate Category of NERC Reliability Standards Table I, Transmission System Standards – Normal and Emergency Conditions. Studies shall consider all contingencies applicable to the appropriate Category and document the selection rationale. Studies shall be conducted or reviewed annually, shall cover seasonal or expected critical system conditions for near (current or next year) and intermediate (two to five year recommended) planning horizons, and address both intra- and interregional reliability. Detailed analyses of the systems will not be conducted annually if changes to system conditions do not warrant such analyses.

The longer-term (beyond five years) simulations will identify concerns that may surface in the period beyond the more certain intermediate year period. Focus of simulations for the longer term will be on marginal system conditions evident from the intermediate year cases. Cases beyond the five-year horizon will be evaluated as needed to address identified marginal conditions.

3.4.3 **Mitigation Plans –** When simulations indicate an inability of the systems

to respond as prescribed by this Criterion, responsible entities must provide a written summary of their mitigation plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon. Mitigation plan summaries should discuss expected required in-service dates of facilities, should consider lead-times necessary to implement plans, and will be reviewed for continuing need in subsequent annual assessments.

3.4.4 **Transmission Operating Directives –** A Transmission Operating Directive qualifies as a valid mitigation measure when the Transmission Operating Directive is effective as written.

3.4.5 **Reporting Requirements –** Entities responsible for the reliability of interconnected transmission systems shall report annually on the performance of their systems in connection with NERC *Reliability Standards* to the SPP Region. The SPP will annually provide a summary of intra- and interregional studies to the NERC. Regional and interregional reliability assessments shall include the results of the system simulation testing as stated in the NERC Reliability Standards.

3.5 Interconnection Review Process

Southwest Power Pool Criteria 3.3.2 and the Regional Open Access Transmission Tariff both require members to contact the SPP and the Transmission Working Group whenever new transmission facilities that impact the interconnected operation are in the conceptual planning stage so that the optimal integration of any new facilities can be identified. Under this criterion an interconnection involves two or more SPP members or an SPP member and a non-member. A project that creates a non-radial, non-generation interconnection at 69 kV or above or that removes an interconnection at 230 kV or above shall be reviewed for impacts in accordance with Appendix 11. A Transmission Service Provider shall be subject to provisions of this criterion.

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported.

This Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity, with the exception of response factor thresholds for short-term transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical opportunity. The response factor thresholds for short-term and long-term service are included in Appendix 9.

4.1 DEFINITIONS

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

4.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

4.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

4.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

4.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at anytime for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

4.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

4.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff (OATT) or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as:

> "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:
>
> 1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
> 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
> 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

4.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in the Flowgate Determination section.

4.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

4.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

4.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

4.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

4.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

4.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

4.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

4.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

4.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

4.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

4.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is not offered.

4.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

4.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

4.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

4.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF – The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

4.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

4.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

4.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

4.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

4.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

4.1.31 TRM multipliers (a & b)

"a"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

"b"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

4.2 CONCEPTS

4.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1. **System Conditions** - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

2. **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3. **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

4.2.2 Available Transfer Capability

NERC Available Transfer Capability Definitions and Determinations, reference document (June

1996) states: "Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses."
SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non-firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

> **Firm ATC** = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor
> (FATC = FAFC/TDF)
> of the associated path.
>
> Likewise,
>
> **Non-Firm ATC** = the non firm Available Flowgate Capacity divided by the Transmission Distribution Factor
> (NFATC = NFAFC/TDF)
> of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC. However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non firm Available Flowgate Capacity or firm Available

Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

4.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Appendix 9.

(1) **Transfer Distribution Factor** - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in the System Limitations section of the criteria.

(2) **Line Outage Distribution Factor** - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) **Power Transfer Distribution Factor** - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable short-term or long-term threshold.

(4) **Outage Transfer Distribution Factor** - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability limitations. To be considered a valid limit to transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.

(5) **Power Transfer Voltage Factor** - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

4.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

1. **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

2. **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally

expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

3. **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

4. **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time

4.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

- An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
- Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
- The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
- The limiting facility is the result of over-generation/under-generation at a participation

point.

- The contingency is considered improper implementation of an operating procedure.
- The facility represents an equivalent circuit.
- The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

4.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

- OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
- PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce.

To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

4.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in the Limitations Section.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be:

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing.

Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

4.2.8 Flowgate Capacity

4.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

4.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the Available Flowgate Capacity (AFC) remaining for path ATC. AFC is classified as firm or non-firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for Available Flowgate Capacity:

(AFC = TFC – FBL – Impacts of existing commitments – transmission margins).

4.2.9 System Impacts

4.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

- Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
- Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.
- Check for proper reflection of capacity profiles of reservations.
- Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

4.2.9.2 Positive Impacts

The scope of "Impacts of existing commitments" in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the "Impacts of existing commitments" in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

4.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

4.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners.

In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

4.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

4.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system’s constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

4.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM.

- Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas.

Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

- Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

- Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions.

Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TWG shall have the authority to grant or reject requests for the additional TRM requests.

· SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

· Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

4.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TWG.

4.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The ‘a’ and ‘b’ multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

4.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

4.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. SPP does not utilize CBM for calculations of ATC for some or all of the following reasons:

- the existing level of internal capacity margin of each member is adequate
- historical reliability indicators of transmission strength of the SPP area
- Open Access transmission usage environment allows greater purchasing options

Since SPP does not utilize CBM for any flowgate within the SPP footprint, the CBM value used in any calculations will be zero.

4.4 FLOWGATE AND TFC DETERMINATION

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system.

4.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TWG, the Operating Reliability Working Group (ORWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

- Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

- Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

- All other Flowgates proposed by Transmission Owners must have TWG and ORWG approval. The Reliability Authority can provide interim approval until the TWG and ORWG can convene to assess the request. Examples of such Flowgates are PTDF

Flowgates with two or more elements, OTDF Flowgates with three or more elements, or Flowgates involving operating procedures.

There may be times when significant topological changes occur during operations that create unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Reliability Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

4.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TWG using seasonal power flow models. This annual assessment will be performed following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in the "ATC Calculation Procedures" section.

4.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing a reduced load level, as specified in the MDWG Powerflow Procedure Manual, will be used in the determination process.

4.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

- A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.
- All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.
- Any additional facilities below 100 kV to be monitored.
- High and low voltage limits for system and/or individual buses.
- All Contractual Requirements.

4.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

- For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.
- The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points. (i.e., PMAX-PGEN).
- For imports, all on-line generators will be decreased prorated by their capable generation (i.e., PGEN-PMIN).
- Transfer directions will be a set of all commercial paths.
- Exports from merchant power plants will be considered in the determination of Flowgates.
- The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.
- All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.
- Voltage limits will be as specified in Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

4.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

4.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in the “Parameters Supplied by the Transmission Owners” section or “Default Parameters” section as applicable.

4.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

4.4.2.7 Identification of Flowgate Changes

TWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

4.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TWG before being reported.

The Transmission Owner should review the TWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TWG proposed changes should be returned to the TWG. Further dialog and justification may be required of a Transmission Owner if the TWG has concerns about their modifications.

TWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

4.4.2.9 Initiating Interim Review of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TWG for consideration. Should the TWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

4.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

- The contingency used for the Flowgate is not valid.
- There is an operating procedure that corrects the violation that is not being properly taken into account.
- An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TWG will review all of the arguments. Additional analyses will be performed if necessary. SPP TWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

4.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TWG.

4.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

4.5 ATC CALCULATION PROCEDURES

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

- establishes a network representation (power flow model)
- identifies potential limits to transfer (thermal, voltage, stability, contract)
- determines response factors of identified limits relative to transfer directions (TDF)
- determines impacts of existing commitments (firm, non-firm)
- applies margins (TRM, CBM, a & b multipliers)

- determines maximum transfer capabilities allowed by limits and applied margins (ATC, FATC, NFATC)

4.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their own OASIS nodes.

4.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

4.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate Capacity. However, there are many transactions within the monthly models that are duplicated on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

4.5.4 Transfer Distribution Factor Determinations (TDF)

For export and import participation points all on-line generators, unless otherwise denoted (e.g., nuclear units), will be scaled prorated by their machine base (MBASE). TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

4.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

4.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the transmission system. The long-term threshold is shown in Appendix 9 and is applied to all elements above 60kV.

4.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows will be determined by the projection models. The impacts of OASIS reservations that are in Study mode will be applied to each Flowgate according to the TDF values determined. Positive impacts on a Flowgate due to Confirmed reservations that are not expected to be scheduled based on actual historical scheduling data will be removed and allowed to increase firm Available Flowgate Capacity. Counter flow impacts of Confirmed reservations that are expected to be scheduled based on actual historical scheduling data will be allowed to increase firm Available Flowgate Capacity. Up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed to increase non-firm Available Flowgate Capacity.

4.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

4.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

4.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates' ATC and posted to the OASIS.

4.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

4.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in the Reliability Margins section.

4.5.10 ATC Determination

The following equations are used in ATC determination:

4.5.10.1 Firm Base Loading (FBL)*, **:

- Firm Base Loading = (Flows resultant of DNR) + (S Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) – (100% of S Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

4.5.10.2 Non-Firm Base Loading (NFBL)*, **:

- Non-Firm Base Loading = (Flows resultant of DNR) + (S Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) – (up to 50% of S Counter Impacts due to Confirmed Firm OASIS Commitments)

4.5.10.3 Firm Available Flowgate Capacity (FAFC):

- Firm Available Flowgate Capacity = (Total Flowgate Capacity) – (TRM) – (CBM) – (Firm Base Loading)

4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):

- Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) – (b*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):

- Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) – (a*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.6 Firm Available Transfer Capability (FATC):

- Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

4.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):

· Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):

· Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

* Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The ATC for requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

4.5.11 Annual Review of ATC Process

The SPP TWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process. The applicable long-term TRM is listed in Appendix 9.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

4.5.12 Dialog With Transmission Users

Transmission Users may contact the TWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TWG. The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Markets and Operations Policy Committee.

5.0 RELIABILITY COORDINATION

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

The Reliability Coordinator has the responsibility and authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise that authority to alleviate capacity and energy emergencies and coordinate restoration activities between individual Transmission Operators, The Reliability Coordinator also shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

5.1 Information Exchange

Balancing Authorities and Transmission Operators shall share operating data as defined in Appendix 7 to the SPP Criteria and approved by the Operating Reliability Working Group (ORWG). Non-Balancing Authorities shall share operating data deemed necessary for assessment of regional reliability by the Reliability Coordinator. Generator data for all generating units whose size is greater than or equal to the smaller of 10 MW or 5% of the reporting Balancing Authority's peak load, transmission circuit data for all interconnections, and transmission facilities operated at 60 kV or greater shall be automatically shared via secure interregional telecommunications network. All other necessary operational data listed in Appendix 7 of this Critieria shall also be made available via secure interregional telecommunications network to support the requirements in this Criteria. This near real-time data will be exchanged as specified in Appendix 7 and approved by the ORWG. This data shall be made available to the Reliability Coordinator and any other entity with immediate responsibility for interconnection reliability. The Reliability Coordinator shall obtain a current signed NERC Confidentiality Agreement from entities receiving such data ensuring that the data will not be used for marketing purposes.

The Reliability Coordinator shall provide its SOLs and IROLs to any other Reliability

Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider or Planning Authority that has a reliability-related need for those limits within 5 business days.

5.2 Responsibilities

5.2.1 Member

Transmission Operators shall determine System Operating Limits (SOLs), as defined by NERC, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix 7 and notify the Reliability Coordinator of any SOL violations. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with the SOL Methodology in Criteria 12.3.

5.2.1.1 Outage Reporting and Coordination

Balancing Authorities and Transmission Operators shall notify the Reliability Coordinator of current or foreseen operating conditions that may adversely affect interconnection reliability. Transmission Operators shall submit scheduled outages of all transmission facilities greater than 100kV to the Reliability Coordinator. Scheduled outages of transmission facilities between 60kV and 100kV should be submitted for those facilities identified by the RC and included in the regional models.

Scheduled outages of the following types of transmission facilities must be approved by the Reliability Coordinator prior to implementing the outage:

a. All transmission facilities rated at 230kV or above—for transformers, use the low-side voltage class.
b. All tie lines, 60kV and above.
c. All facilities, monitored and contingent elements, associated with flowgates
d. Other facilities specified by the Transmission Operator or the Reliability Coordinator as having a major impact on the transmission system or that affect the capability and reliability of generating facilities (backup station power, etc).

Forced outages of all transmission facilities identified above shall be submitted to the Reliability Coordinator along with estimated return-to-service time of the facility no later than 30 minutes after the outage. Forced outages of all other transmission facilities greater than 100kV and those identified facilities between 60kV and 100kV should be submitted as soon as practical after the outage. Any known updates to the return time should be submitted promptly to the Reliability Coordinator.

The Transmission Operator shall immediately inform the Reliability Coordinator of the status of any Special Protection System, that may have an inter-Balancing Authority, or inter-Transmission Operator impact, including any degradation or potential failure to operate as expected.

If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify the Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

Balancing Authorities or Generator Operators, as appropriate, shall notify SPP of any generation derates resulting from Operational Flow Orders (OFOs) or Critical Notices or any other type of fuel delivery constraint. The parties submitting the information shall indicate that the derate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them.

Whenever an OFO, Critical Notices, or fuel delivery constraint causes an inability for the Generator Operator to meet its firm obligations, it must use the normal established communication protocols to notify its host Balancing Authority.

Furthermore, Balancing Authorities shall notify the SPP Reliability Coordinator should it be necessary to request a NERC Energy Emergency Alert and/or a SPP Other Extreme Conditions as a result of the OFO or Critical Notice.

5.2.1.2 Vegetation Management

This section of the SPP Criteria is applicable to all entities in the SPP Regional Entity footprint and the SPP Reliability Coordinator footprint.

For the purpose of this Criteria and NERC Reliability Standard FAC-003, the SPP Regional Entity [SPP RE], the SPP Reliability Coordinator and the SPP Operating Reliability Working Group are collaborating to act as the Regional Reliability Organization [RRO] as identified in the Standard.

NERC Reliability Standard FAC-003-1requires a vegetation management program for ‘transmission lines operating at 200kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region’ (applicable lines).

For the purpose of implementing FAC-003-1 and proposed revisions to the FAC-003 standard, the SPP RC will designate the applicable facilities that are to be monitored for compliance to the standard in consultation with the SPP ORWG.

The SPP Reliability Coordinator designates the following transmission lines as being subject to the FAC-003 standard:

1. All transmission lines operating at 200kV and above; and
2. All transmission lines, not included in 1. above that are listed as monitored or contingent elements of an Interconnection Reliability Operating Limit (IROL) flowgate as published in the *SPP IROL Relief Guides.*

The SPP Reliability Coordinator develops and identifies IROL flowgates on a continual basis to ensure reliability, However, IROL flowgate facilities will only be added to the applicable lines list annually to provide adequate time for Transmission Owners to incorporate those facilities into their Transmission Vegetation Management Plans.

The SPP Reliability Coordinator will maintain the master list of the applicable transmission lines. The facilities identified will become applicable to the standard 12 months after being identified by the RC.

The SPP RC is responsible for communicating to the appropriate Transmission Owners those transmission lines designated as applicable transmission lines by the SPP RC and subject to compliance monitoring and reporting of vegetation contacts as detailed in NERC Reliability Standard FAC-003. The Transmission Owner shall develop communications and notification protocols for the purposes of implementing changes to the applicable transmission line list and for reporting vegetation contacts to the SPP RE.

5.2.2 Operating Reliability Working Group

The Operating Reliability Working Group shall be responsible for policy oversight of implementation and on-going reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Markets and Operations Policy Committee.

5.2.3 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

5.2.4 Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following activities:

5.2.4.1 Reliability Assessments

a. Monitor the collection of real-time operating information, schedules and daily forecasts from Balancing Authorities as specified in Appendix 7.
b. Develop and use operational models to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, and determining the adequacy of operating reserve for the current operating day and the next day.
c. Perform Day Ahead Contingency Analysis to assess the impact of any single transmission contingency 100kV and above while monitoring all facilities 100kV and above within the entire SPP RC Footprint and neighboring Balancing Authority Areas or Transmission Operators systems.
d. Develop mitigation plans or operating guides for any potential interface, SOLs or IROLs

found in the Day Ahead Contingency Analysis that is forecast to exceed 100% of the emergency rating of any facility 100kV and above or any pre-contingent bus voltages of +/- 5% and/or post-contingent bus voltages in excess of +/- 10%.

e. During conditions where system reliability is threatened, notify and coordinate with affected Transmission Operators, Balancing Authorities, or Transmission Service Providers in determining appropriate control action.
f. Sharing the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time.

5.2.4.2 Operational Coordination

a. Coordinate and grant permission for bulk transmission equipment maintenance.
b. Coordinate pending generator maintenance.
c. Manage the SPP Open Access Same-Time Information System (OASIS) node and Available Transfer Capability (ATC) calculation.
d. Monitor the NERC Hot line and NERC Reliability Coordinator Information System (RCIS) and disseminating information.
e. Initiating time error corrections (TEC).
f. Initiating Geo-magnetic Disturbance (GMD) notifications and assist as needed in the development of any required response plans.
g. in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs, and/or mitigate CPS or DCS violations.

5.2.4.3 Monitoring

a. Monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

b. Identifying sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

c. Monitor Special Protection Systems that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

d. Monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

e. Coordinate bilateral inadvertent energy accounting and payback.

5.2.4.4 Emergency Procedure Implementation

a. Monitor and coordinate implementation of Operating Reserve Criteria.

b. Monitor and coordinate implementation of Transmission Loading Relief and other congestion management procedures.

c. Monitor and coordinate implementation of Load Shedding and Restoration Criteria.

d. Monitor and coordinate implementation of Black Start Criteria.

e. Issue short supply advisories.

f. Issue weather advisories.

Evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits

5.2.4.5 Interregional Coordination

a. Coordinate normal and emergency operations with other Reliability Coordinators.

b. Authoritatively act on behalf of SPP Members to resolve interregional issues.

5.2.5 Other Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following additional activities:

a.. Coordinate implementation of Black Start procedures as outlined in Criteria.

b. Implement Transmission Loading Relief Procedures and other congestion management procedures as required.

c. Administer the SPP Reserve Sharing Group.

d. Provide reports to the ORWG of congestion management activities performed by the RC. These reports shall also be posted periodically.

5.2.6 Reliability Coordinator Performance Standards

The SPP Reliability Coordinator shall have the following performance standards:

a. The SPP Reliability Coordinator shall act in accordance with Good Utility Practice including NERC Standards and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice or NERC Standards, and shall allow SPP members to take any actions required by Good Utility Practice and NERC Standards.

b. The SPP Reliability Coordinator shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency or NERC Standard.

c. The SPP Reliability Coordinator shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Standards and SPP Criteria.

d. The SPP Reliability Coordinator shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.

e. The SPP Reliability Coordinator shall possess the applicable NERC Certification

f. .The SPP Reliability Coordinator shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.

6.0 OPERATING RESERVE

6.1 Purpose

In the continuous operation of the electric power network, Operating Capacity is required to meet forecasted load, including an allowance for uncertainty, to provide protection against equipment failure and to provide adequate regulation of frequency and Balancing Authority Area tie line power flow. Operating Reserves are needed to regulate load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales.

This Criteria establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group.

A purpose of this Criteria is to ensure a high level of reliability in the SPP Reserve Sharing Group by assuring that there is available at all times capacity resources that can be used quickly to relieve stress placed on the interconnected electric system during an Operating Reserve Contingency. Another purpose of these Criteria is to utilize efficiently the operating reserve resources of the SPP Reserve Sharing Group.

This Criteria describes practices to be followed by all SPP Reserve Sharing Group members to ensure prompt response to Operating Reserve Contingencies. The methods prescribed by this Criteria to jointly activate Contingency Reserve are intended to ensure that the combined area control error (ACE) of the SPP Reserve Sharing Group is quickly reduced by the Reserve Sharing Group simultaneously scheduling assistance soon after an Operating Reserve Contingency.

6.2 Definitions

6.2.1 Balancing Authority

NERC defines a Balancing Authority as “The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time.” A Balancing Authority is required to meet all NERC Reliability Standards, SPP Criteria and the policies of the NERC Regional Reliability Council of which they are a member.

6.2.1.1 Balancing Authority Area

NERC defines a Balancing Authority Area as “The collection of transmission, generation and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

6.2.2 Balancing Authority Daily Peak Load Obligation

Balancing Authority Annual Peak Load Obligation is the peak hour load plus Firm Power sales minus Firm Power purchases during the peak hour for all entities within the Balancing Authority Area.

6.2.3 Operating Capacity

Operating Capacity is the dispatchable capability claimed for any generating source, which will be used for supplying Operating Reserve. Operating Capacity shall include capacity purchases that can be used to supply the buyer’s Operating Reserves minus capacity sales that cannot be used to supply the seller’s Operating Reserves. Operating Capacity shall recognize any temporary de-ratings, proven loading rates, starting times and equipment limitations including transmission-operating limits. This capacity is not intended to be the tested seasonal net capability; instead it is the normal operating rating of a generator on a given day.

6.2.4 Operating Reserve

Operating Reserve is the sum of Regulating Reserve and Contingency Reserve.

6.2.4.1 Regulating Reserve

Regulating Reserve is an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin. The Balancing Authority minimum Regulating Reserve is equal to an amount necessary to maintain compliance with control performance standards while scheduling all Contingency Reserves to other Balancing Authorities.

6.2.4.2 Contingency Reserve

Contingency Reserve is that Operating Capacity that can be produced and applied to reduce ACE to meet the NERC Disturbance Control Standard (DCS) following the Operating Reserve Contingency. Contingency Reserve is the sum of Spinning Reserve and Supplemental Reserve. At least half of the Contingency Reserve shall be Spinning Reserve.

6.2.5 Spinning Reserve

Spinning Reserve shall mean the amount of MW a resource in the Eastern Interconnection can increase or a load can decrease within the Disturbance Recovery Period as defined in the NERC Standard BAL-002. This resource must be synchronized whether it is a generator or a load.

6.2.6 Supplemental Reserve

Supplemental Reserve is that amount of Operating Capacity or the equivalent, some or all of which may not be connected to the interconnected network but which can be connected and fully applied to meet the NERC DCS requirements, such as any or a combination of the following:

a. The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset.

b. That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized.

c. Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use.

d. Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call

e. Interruptible or curtailment of loads under contract.

f. Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction.

g. Generating units operating in a synchronous condenser mode.

h. Interruptible pumping load on pumped hydro units.

i. Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.

j. Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.

6.2.7 Assistance Period

Assistance Period is that time frame when any SPP Reserve Sharing Group member receives Contingency Reserve assistance from other SPP Reserve Sharing Group members. The Assistance Period will normally not exceed 60 minutes. The SPP Operating Reliability Working Group will set the ending time for Assistance Period and may change the length of the Assistance Period.

6.2.8 Group

A Group is defined for each member of the SPP Reserve Sharing Group on a daily basis to include itself and all other members with which there exists contractual interchange agreements, which include provisions for the exchange of Operating Reserve energy. Each member of the Reserve Sharing Group may include any other member, with which they can directly schedule interchange transactions, within their group as long as both members agree.

6.2.9 Contingency Area

The Contingency Area is defined as the Balancing Authority Area suffering an Operating Reserve Contingency.

6.2.10 Assisting Areas

The Assisting Areas are defined as the other Balancing Authority Areas in the SPP Reserve Sharing Group, which are called upon to supply Operating Reserves to the Contingency Area.

6.2.11

6.2.12 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. Power purchased shall only be considered to be Firm Power if firm transmission service is in place to the load serving member for delivery of such power. Firm Power does not include “financially firm” power.

6.2.13 Other Extreme Conditions

Other Extreme Conditions include but are not limited to the:

a. Interruption of firm transmission service, or

b. An inability to use prescheduled firm transmission service due to transmission loading relief, or

c. When a Balancing Authority requires assistance to prevent shedding firm load or Firm Power sales, or

d. When a Balancing Authority is unable to maintain its Operating Reserves.

6.2.14 Operating Reserve Contingency

An Operating Reserve Contingency is defined as the sudden and complete loss of a generating unit, sudden partial loss of generating capacity, loss of a capacity purchase which a Balancing Authority is unable to replace, or an Other Extreme Conditions.

6.2.15 Reserve Sharing Group

NERC defines a Reserve Sharing Group as "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the areas become a Reserve Sharing Group."

6.2.16 Reserve Sharing Group Annual Contingency Reserve Requirement

The minimum amount of Contingency Reserve that must be collectively carried by the Balancing Authorities participating in the SPP Reserve Sharing Group at a given time.

6.2.17 Balancing Authority Annual Contingency Reserve Requirement

A Balancing Authority member's share of the total SPP Reserve Sharing Group System Peak Responsibility. The Balancing Authority's Annual Contingency Reserve Requirement Ratio shall be determined by dividing the Balancing Authority's System Peak Responsibility by the sum of all of the RSG member Balancing Authority's System Peak Responsibilities.

6.2.18 Balancing Authority Minimum Daily Contingency Reserve Requirement

A Balancing Authority member's Contingency Reserve Requirement Ratio multiplied by the Reserve Sharing Group Total Contingency Reserve Requirement. Each Balancing Authority's Daily Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

6.3 Minimum Annual Daily Contingency Reserve Requirement

The Operating Reliability Working Group (ORWG) will set the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a Minimum Daily Contingency Reserve, over and above any Regulating Reserves, equal to the generating capacity of the largest unit within the metered boundaries of any RSG member Balancing Authority plus one-half of the capacity of the next largest generating unit within the metered boundaries of any RSG member Balancing Authority. Generation capacity is considered to be added at the first injection of test power of the generator, regardless of commercial status.

If the SPP Reliability Coordinator foresees an operating condition in which reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Daily Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

Each day, by 7:00am, the SPP Reliability Coordinator will notify each member Balancing Authority of its Daily Contingency Reserve Requirement for the following operating day.

6.3.1 Minimum Annual Balancing Authority Contingency Reserve Requirement Share Calculation

A member Balancing Authority's Minimum Annual Contingency Reserve Requirement is equal to a prorated amount of the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement as calculated per Criteria section 6.3. The Balancing Authority's Minimum Annual Contingency Reserve Requirement shall be determined by dividing the Balancing Authority's System Peak Responsibility as calculated per Criteria 2.1.6 by the sum of all of the RSG member Balancing Authority's System Peak Responsibility and multiplying the resultant by the Annual Group Contingency Reserve Requirement. Each Balancing Authority's Annual Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

If the SPP Reliability Coordinator foresees an operating condition that reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

A member Balancing Authority whose historical information used as the basis of the Minimum Annual Contingency Reserve Requirement has changed significantly due to extreme circumstances may apply to the ORWG for a temporary waiver of all or a portion of its Minimum Annual Contingency Reserve Requirement. For example, the BA may request such a waiver due to (i) the shifting of load from one BA to another or (ii) drought conditions for Balancing Authorities whose system Capacity is comprised of more than 75% hydro based generation resources. ORWG will review such requests and make a recommendation to be considered by the MOPC at its next regularly scheduled meeting.

6.3.2 Minimum Annual Contingency Reserve Requirement Review Process

By May 1 each year, each Balancing Authority will submit to SPP its System Peak Responsibility as calculated per Criteria section 2.1.6 from the previous calendar year. SPP will calculate the Reserve Sharing Group's Total System Peak Responsibilityand each member Balancing Authority's Annual Contingency Reserve Requirement Ratio. The results of these calculations will be presented for review and approval by the OWRG to be made effective June 1 of each year.

A member Balancing Authority whose historical information used as the basis of the Annual Contingency Reserve Requirement Ratio has changed significantly due to extreme circumstances may apply to the ORWG for a recalculation of its Annual Contingency Reserve Requirement Ratio. For example, the BA may request such a recalculation due to (i) the shifting of load from one BA to another or (ii) drought conditions for Balancing Authorities whose system Capacity is comprised of more than 75% hydro based generation resources. ORWG will review such requests and make a recommendation to be considered by the MOPC at its next regularly scheduled meeting.

6.4 Procedures

All SPP Reserve Sharing Group members shall participate in this procedure to jointly activate Contingency Reserve.

6.4.1 Normal Daily Operation

a. Each Balancing Authority's Operating Reserve shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings, transfer limitations, or a unit's capability to apply the reserve to meet the NERC DCS requirements.

b. Each Balancing Authority shall schedule Operating Capacity and firm obligations so its requirements for Operating Reserve are met at all times.

c. Energy associated with <u>Supplemental</u> Reserve, except Assistance Schedules, may be sold with the understanding that it is recallable to meet the NERC DCS requirements.

The buyer shall therefore maintain resources to support the withdrawal of this energy in addition to meeting its Operating Reserve Requirement.

d. Generating capacity associated with the required Spinning Reserve shall not be sold unless allocated during an Assistance Period.

e. Each Balancing Authority may contract with another Balancing Authority to provide part or its entire Operating Reserve obligation, provided the Balancing Authority accepting this additional Operating Reserve obligation maintains the Operating Reserve obligation of both Balancing Authorities and the firm transmission service required to deliver Operating Reserve energy is obtained.

f. When a Balancing Authority foresees it will be unable to provide its Minimum Daily Reserve Requirement with available resources because load is greater than anticipated, forced outages or other limitations, it shall obtain Operating Capacity and firm transmission service. Such capacity shall not be from another Balancing Authority's Minimum Daily Reserve Requirement.

6.4.2 Contingency Operation

These procedures may be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude, but are required to be implemented for Operating Reserve Contingencies as specified below.

o A complete or partial loss of r 200 MW magnitude or greater of a resource, or

o

o

o A loss of Operating Capacity resulting in the BA possessing less than its Minimum Daily Reserve Requirement, or,

o Any “Other Extreme Conditions” event.

These procedures are to be implemented in a non-discriminatory manner.

a. Immediately following an Operating Reserve Contingency, the Contingency Area shall report the occurrence via the SPP Reserve Sharing System. This report shall contain a description of the contingency; the net MW lost due to the contingency and any MW amount of Contingency Reserve being carried on the contingency unit. For those generating units whose station auxiliaries do not decrease to essentially zero or increase after a unit trip, gross MWs lost shall be used instead of net MWs lost. The operating owner of jointly owned generating units shall be responsible for reporting outages and the MW amount lost by each owner.

b. Within the constraints described in this Criteria, allocation magnitudes shall be determined and notices distributed to the members of the Reserve Sharing Group

c. The Assistance Schedule becomes part of each Assisting Area's scheduled net interchange and shall therefore be reflected in its ACE. The schedule shall be implemented at a zero time ramp rate immediately following allocation notification. If obvious and significant errors exist in assistance schedules, the Contingency Area system operator shall dictate appropriate corrective action during the Contingency Period, and notify the SPP.

d. Assisting Areas shall immediately acknowledge receipt of the allocation notice via the SPP Reserve Sharing System. If a Contingency Area fails to receive acknowledgment from an Assisting Area, the SPP Reliability Coordinator shall notify the Assisting Area of the assistance schedule.

e. The Contingency Area(s) and Assisting Areas shall provide the requested assistance within the requirements established in the Disturbance Recovery Criterion of the NERC Reliability Standards.

f. The Contingency Reserve Requirement of each Balancing Authority involved in the Assistance Period shall be updated to reflect the reduction of responsibility until the end of the Assistance Period.

g. All allocations shall be rounded to the nearest whole MW with a minimum of 2 MW and the smallest amount of energy to be allocated shall be one MWH.

h. After the contingency notification has been completed, the Contingency Area shall promptly make arrangements to replace the energy requirement created by the Operating Reserve Contingency (including its Contingency Reserve Allocation) prior to the end of the Assistance Period. The Contingency Area shall make a reasonable effort to purchase capacity and firm transmission service after utilization of its own resources.

i. If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, then this becomes an Other Extreme Condition and shall be reported as a separate contingency.

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j. For each reportable contingency (as defined per section 6.4.4), the Contingency Area and Assisting Areas will send to SPP upon request, an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data.

k. If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, then this becomes an Other Extreme Condition and shall be reported as a separate contingency.

l. Each transmission provider shall immediately notify the SPP of the loss of transmission interconnection capability affecting its interchange transfer capability. The SPP shall update Group assignments for use during subsequent Assistance Periods. Each transmission provider is responsible for notifying the SPP once the contingency loss in the interchange transfer capability has been restored so that Group assignments can be updated.

m. For each reportable contingency (as defined by the Operating Reliability Working Group), the Contingency Area and Assisting Areas will send to SPP an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data. If electronic data is not available, this data will be supplied on the NERC required charts.

6.4.3 Subsequent Contingencies

In the event that a subsequent Operating Reserve Contingency occurs during a period when assistance is already in progress, the same procedures shall be followed to allocate responsibility for the additional Operating Reserve Contingency.

6.4.4 Assistance Reports

Energy and transmission service reports shall be issued following the Assistance Period. These reports shall be used as verification of associated energy schedules and transmission service reservations. The Operating Reliability Working Group shall distribute monthly summary reports of Other Extreme Conditions activity for use.

SPP Staff will report to NERC quarterly the performance of the SPP Reserve Sharing Group. Performance will be calculated based on the data that Balancing Authorities provide and any additional data required for each reportable contingency. At a minimum, reportable contingencies will be of a magnitude between 80% and 100% of the capacity of the largest generating unit scheduled to be on-line within the SPP each day. The Operating Reliability Working Group may lower the 80% factor in order to provide a more realistic picture of the performance of the SPP Reserve Sharing Group.

6.4.5 Other Extreme Conditions Events

Other Extreme Conditions (OEC) Events may be requested by any Balancing Authority member of the SPP Reserve Sharing Group. OECs may be implemented for any of the following reasons, but shall be implemented when the requesting Balancing Authority has used all or a portion of its reserve obligation due to the event:

1. Loss of a Capacity Import Schedule
2. Loss of Reserves
3. Initial or additional assistance is required and no other mechanism is available within the confines of the SPP computer communication system.

Any member not having their Minimum Contingency Reserve Daily Requirement shall enter an Other Extreme Conditions for the amount of the deficiency. A NERC Energy Emergency Alert (EEA) may or may not be required. If the Balancing Authority determines an EEA must be issued, the Balancing Authority shall notify the Reliability Coordinator. If the OEC is requested along with an EEA, the Balancing Authority shall be prepared to demonstrate the emergency condition by taking the steps required by the EEA.

The SPP Reserve Sharing Group member submitting an Other Extreme Conditions event shall submit a written report to OECEEAReports@spp.org within 2 business days of the event. The written report will describe the operating conditions that precipitated the event. Other Extreme

Conditions shall be investigated as required by the SPP Operating Reliability Working Group to ensure compliance with SPP Criteria and NERC Reliability Standards.

6.5 Compensation for Assistance

6.5.1 Energy Charge

The charge for energy assistance delivered by Assisting Areas under the application of this Criteria shall be determined by interchange agreements between the members involved in the Reserve Sharing Group.

6.5.2 Accounting

All compensation for energy associated with the application of this Criteria shall be handled by contractual agreements and standard accounting procedures being utilized by the SPP Reserve Sharing Group members. All energy billing shall take place between SPP Reserve Sharing Group members and shall not involve the SPP computer communication system or the SPP Staff.

6.5.3 Transmission Service

All compensation for transmission service shall be in accordance with the appropriate transmission service tariffs. The SPP staff shall be responsible for all billings for transmission service provided under the SPP Regional Transmission Tariff. The individual transmission provider shall be responsible for all billings under the transmission provider’s transmission tariff. It shall be the SPP staff’s responsibility to provide the required transmission service information to the transmission provider for all transmission service under an individual transmission provider’s transmission tariff.

6.6 Responsibilities

6.6.1 Balancing Authorities

It shall be the responsibility of each Balancing Authority to observe the policies and procedures contained herein; maintaining Operating Reserve, ensuring connectivity to the SPP computer communications system, reporting daily information, identifying and reporting an Operating Reserve Contingency within its Balancing Authority Area, acknowledging schedules and supplying assistance to members of the SPP Reserve Sharing Group.

6.6.2 Operating Reliability Working Group

In order to review the adequacy in SPP Reserve Sharing Group, reports shall be compiled and distributed by the SPP for review by members and the Operating Reliability Working Group.

These reports shall contain compliance information and a summary of Assistance Period events

7.0 SYSTEM PROTECTION EQUIPMENT

7.1 Disturbance Monitoring Equipment

'Disturbance Monitoring Equipment' (DME), as the term is used in this Section, refers to equipment such as Digital Fault Recorders (DFR), Sequence of Events Recorders (SOE and/or SER), Dynamic Disturbance Recorders (DDR), and other devices connected to the power system for the purpose of monitoring performance of the system. This equipment is used to capture data during disturbances defined as (i) any perturbation to the power system, or (ii) the unexpected change in the power system that is caused by the sudden loss of generation, transmission or interruption of load. Disturbance monitoring equipment collect and store (a) "fault data" from a line or equipment trip for abnormal conditions, or (b) "disturbance data" for power system performance swings or deviations outside of a predefined operating range (frequency, voltage, current, power, transients, etc.). Digital fault recorders (DFR) are capable of producing date and time stamped fault records, consisting of instantaneous values of power system quantities collected many times per cycle, for a specific period of time. In general, DFR's are continuously monitoring devices that use triggering methods to capture, over a period of several cycles, specific system events, such as line trips for fault conditions. Sequence of Events Recorders (SER) capture and time stamp events in the sequence in which they occur. The facility owner should be responsible for interpreting the information from SER's due to the equipment specific and detailed nature of these records. Typically, SER's record the sequence of breaker operations needed for higher-level event reconstruction and analysis. Information provided by SER's may be obtained from other devices such as fault recording equipment, SCADA, or other real time computer records. Dynamic disturbance recorders (DDR) record date and time stamped incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz-3Hz) oscillations and abnormal frequency, power, current, or voltage excursions. DDRs are also commonly referred to as dynamic swing recorders (DSR).

7.1.1 General Minimum Technical Requirements

Disturbance Monitoring Equipment, as a minimum, must be capable of producing time stamped event records (some pre-fault and some post-fault data) including waveforms for voltages and currents as well as power circuit breaker position indications. All DME including DFRs, SERs, and DDRs as required in 7.1.2 shall be synchronized to within 2 milliseconds or less of Universal Coordinated Time scale (UTC). Recorded data from each disturbance shall be retrievable for at least ten calendar days per PRC-018-1, R1-2. The Disturbance data reporting after 5-1-2007 shall be in a format which is capable of being viewed, read and analyzed with a generic Common Format for Transient Data Exchange for Power Systems (COMTRADE) or its successor standard. Per PRC-002-1, new DME required per 7.1.2 shall include naming of data files in conformance with the IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files effective 6 months after IEEE C37.232 is approved.

Disturbance Monitoring Equipment will also be required to meet the NERC PRC-002-1 and PRC-018-1 Reliability Standards.

7.1.1.1 DFR Minimum Technical Requirements

DFRs as required in 7.1.2 shall be capable of recording at least 5 events of not less than 30 cycles in duration with a sampling rate of not less than 64 samples per cycle. Event data shall be retrievable within a period of not less than 72 hours. A minimum of three (3) cycles of pre-disturbance data shall be recorded with each event. Disturbance records shall be continuous until the system returns to a non-faulted condition, or the 30 cycle minimum record duration has been reached. DFRs shall record, at a minimum, the quantities listed below in a single recording system. This single recording system shall be capable of and configured to simultaneously capture and time synchronize all required quantities at a substation for each event in a single record.

1) One set of voltages for each operating voltage at 100 KV and above in a substation. A set of voltages shall consist of each phase voltage waveform. If potential devices are not required for protection or metering purposes at a particular voltage level, then this particular voltage level need not be monitored.
2) For all lines, operating at 100KV and above either three phase current waveforms or two phase current waveforms and neutral (residual) current waveform.
3) For all autotransformers, current waveform for three phases and either neutral/residual current waveform or current waveform in delta windings.
4) Status – circuit breaker trip circuit energization for all breakers operating at 100KV and above.
5) Status – carrier transmit/receive if carrier relaying is used for all lines operating at 100KV and above.
6) Date and time stamp.
7) For equipment installed after 1-1-2007, frequency, MW and MVARS shall be recorded and displayed or be able to be derived from collected information, using

industry standard software. Sampling rate minimum for this data shall be one sample per cycle.

8) For equipment installed after 5-1-2007, polarizing currents and voltages, if used, on lines operating at 100KV and above.

Regarding event triggering thresholds, quantities as derived from SPP or members' studies, when available, shall be used in lieu of those defined below. If none are clearly defined from load flow and stability studies, then the following requirements shall be used as a guide:

1) Phase current greater than or equal to 150% of the equipment rating.
2) Neutral (residual) current greater than or equal to 20% of the rating of the equipment.
3) Voltage excursions greater than or equal to 10% from operating range of equipment.

7.1.1.2 SOE/SER Minimum Technical Requirements

SER's, as required in 7.1.2, as a minimum, must be capable of producing time stamped power circuit breaker position indications. Sequence of Events Recorders may not be required as long as an appropriate monitoring device provides breaker indication and meets the general technical requirements in 7.1.1

7.1.1.3 DDR Minimum Technical Requirements

DDRs as required in 7.1.2 shall be capable of recording 960 samples per second and shall record the true RMS value of electrical quantities at a rate of at least 6 records per second. For DDR's installed after January 1, 2009 continuous recording shall be required. DDRs shall be capable of recording electrical quantities for each monitored element sufficient to determine and display voltage, current, frequency, megawatts and megavars. DDRs shall record, at a minimum, the quantities listed below:

1. One set of voltage and current for each line operated at 100kV and above. A set shall consist of phase to neutral voltage and the corresponding phase line current.
2. One set of voltage and current for each auto-transformer with a secondary voltage operated at 100kV and above. A set shall consist of phase to neutral

voltage and the corresponding phase line current.

3. Date and time stamp.
4. Frequency, MW and MVARS shall be recorded and displayed or be able to be derived from collected information, using industry standard software.

7.1.2 Required Location for Disturbance Monitoring Equipment

DFR and SER capabilities are required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2002. In addition, any new substation placed in service after January 1, 2002 containing six (6) or more lines operating at 100 KV and above will be required to have DFR, and SER capabilities. However, when additional lines placed in service after January 1, 2002 are added to an existing substation that results in six (6) or more total lines, then DFRs and SERs shall be required for monitoring all elements within the substation as defined in 7.1.1. 1 and 7.1.1.2. These requirements may be waived at SPP's discretion, if a DFR is already located at an adjacent substation.

DDR capabilities are required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2008. In addition, any new substation placed in service after January 1, 2008 containing six (6) or more lines operating at 100 KV and above will be required to have DDR capabilities. However, when additional lines placed in service after January 1, 2008 are added to an existing substation that results in six (6) or more total lines, then DDR shall be required for monitoring all elements within the substation as defined in 7.1.1.3 These requirements may be waived at SPP's discretion.

The number, type and location of disturbance monitoring equipment will normally be the responsibility of the facility owners based on recommendations by the owners' studies and this criteria. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in a database by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor this database. The Transmission Working Group and Operating Reliability Working Group will review the database to recommend that equipment with adequate capabilities -- including digital fault recorders and dynamic disturbance recorders --be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

7.1.3 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the Disturbance Monitoring Equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. For newer DME's with self-monitoring, having SCADA reporting for a DME failure, and with successful downloading of events occurring at least annually, then such activity and application shall satisfy the testing and maintenance procedure requirements. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.1.4 Periodic Review of Disturbance Monitoring Equipment

SPP members shall maintain a list of substations where Disturbance Monitoring Equipment is located for generation and transmission facilities including those designated as being critical by the Transmission Assessment and Security Working Groups. The facility owner shall be responsible for providing required data on a form developed by the System Protection & Control Working Group and supplied by SPP. Required data should include type of DME, make and model of equipment, installation location, operational status, date last tested, monitored elements, monitored devices, and monitored electrical quantities. Each facility owner shall provide updates to the SPP upon request. The SPP staff will maintain and update the Disturbance Monitoring Equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.1.2. The SPCWG will update, if necessary, this System Protection Equipment Criteria every three (3) years.

7.1.5 Requests for Disturbance Data and Retention Requirements

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility owners shall provide requested equipment lists and disturbance data within 30 business days with a copy of the requested information forwarded to the SPP. SPP shall provide installation and reporting requirements to other regions and NERC within five (5) business days. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

A narrative description of each disturbance, pursuant to the requirements of SPP Criteria 11 addressing System Disturbance Reporting, to be provided by the facility owner shall include, at a minimum, a brief description of the event as identified on a form supplied by SPP. Additional items that shall be included are the cause of the incident, its consequences, service interrupted, corrective actions taken and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. Attachments shall be provided including relevant information from the DME that substantiates the determination of cause(s) of the disturbance. This information shall include all quantities based on the equipment requirements specified in 7.1.1, Minimum Technical Requirements. Facility owners shall retain disturbance data for a period of not less than one (1) year in a common format to the extent possible given the different manufacturers and types of equipment. Disturbance data recorded after 5-1-2007 shall be stored in a format which is capable of being viewed, read and analyzed with a generic COMTRADE analysis tool or its successor standard. However, the units of the data and source such as line, transformer and generator terminal shall be clearly identifiable in a consistent, time-synchronized format.

7.2 Transmission Protection Systems

7.2.1 Introduction

The goal of transmission Protection Systems (TPS) is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network to preserve electric system integrity. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred. The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure, misoperation of the protection system, and the need to maintain overall system reliability. All reviews of facilities as included in Criteria 7.2 shall be for those operated at 100kV or above.

7.2.2 Protection System Review

7.2.2.1 Assessment Of System Performance

The transmission or protection system owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of Standard I.A. (NERC Planning Standard). These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in NERC Standard I.A. and associated Table I. Therefore, the relative effects on the interconnected transmission systems due to a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters. All non-compliance findings shall be documented including a plan for achieving compliance. These assessments should be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems within 30 days of the request.

7.2.2.2 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the transmission protection system to assure that components and systems function as desired to minimize outages. All non-compliance findings, as a result of this review, shall be documented including a plan for achieving compliance. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.2.4. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, switches, fuses, etc.).
4) Breaker failure and transfer trip schemes.
5) Communications systems used in protection.

Models used for determining protection settings should take into account significant mutual and zero sequence impedances. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered. Protection system applications and settings should not normally limit transmission use. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible. Communications systems used in protection should be either continuously monitored or alarmed, or automatically or manually tested.

7.2.3 System Redundancy

Transmission Protection Systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I (NERC). Each Transmission or Protection System Provider shall develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Where redundancy in the protection systems (due to single protection system component failures) is necessary to meet the system performance requirements (of the I.A. Standards on Transmission Systems and associated Table I), the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated.

Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault while maintaining performance requirements. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition. When two independent protection systems are required, dual circuit breaker trip coils should be considered. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

7.2.4 Monitoring, Analysis And Notification Of Misoperations

Each Transmission or protection system owner shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations. Any of the following events constitute a reportable TPS misoperation:

1) Failure to trip – Any failure of a Protection System element to operate when a fault or abnormal condition occurs within a zone of protection. (Note: Lack of targeting, such as when a high-speed pilot system is beat out by a high-speed zone, is not a reportable misoperation. If a fault or abnormal condition is cleared in the time normally expected with proper functioning of at least one Protection System, failure of a Protection System element is not a reportable misoperation.)
2) Slow Trip – Any failure of a Protection System element that is slower than planned to operate when a fault or abnormal condition occurs within the zone of protection. (Note: Delayed Fault Clearing, where a high-speed system is employed but is not essential for transmission system performance, is not a reportable misoperation.)
3) Unnecessary Trip During a Fault – Any unnecessary Protection System operation for a fault not within the zone of protection. An example of this type of Misoperation is an over-trip due to lack of coordination between Protection Systems. (Note: Operation as properly coordinated backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable Misoperation.)
4) Unnecessary Trip Other Than Fault – Any unnecessary Protection System operation when no fault or other abnormal condition has occurred. (Note that an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable Misoperation.)

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. An operation of a TPS that only has an effect on a non-transmission component operated at less than 100kV need not be reported. Documentation of all protection trip misoperations shall be provided to SPP and NERC within five (5) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all TPS trip operations. It shall also provide consistent documentation of all TPS trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided to SPP and include all fault and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.2.5 Transmission Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing and that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request. Each facility owner shall periodically test the protection system components and system on a frequency as needed to assure that the system is functional and correct. Protection System component maintenance and testing shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer TPS with self-monitoring, having SCADA reporting for a TPS failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements. The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Transmission protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.2.6 Requests for Transmission Protection Systems Data

SPP shall function as a requesting agent and clearinghouse for the collection of TPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.2.7 Transmission Protection Systems Criteria Updates

The SPCWG will update, if necessary, this transmission Protection Systems Criteria every three (3) years.

7.3 UNDER-FREQUENCY LOAD SHEDDING AND RESTORATION

7.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established. For more details refer to SPP UFLS Plan and NERC PRC-006-1.

7.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

7.3.1.2 Operating Principles

a. To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated under-frequency relays on a member system shall be in service at all times. Under-frequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

7.3.1.3-OPEN

7.3.1.4-OPEN

7.3.1.5 Requirements for Testing and Maintenance Procedures

Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UFLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.3.1.6-OPEN

7.3.1.7-OPEN

7.3.1.8 Restoration

After the frequency has stabilized the following procedure shall be followed.

a. In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

b. At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

c. System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

d. Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

e. It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

7.3.2 -OPEN

7.3.3 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

7.3.3.1 Conservation

a. Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

b. Reduction of load in company facilities.

c. Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

d. Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

e. Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

f. Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

7.3.3.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

a. Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D", "E", and "F" until the generation deficiency is eliminated.

b. The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

c. When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

7.4 Special Protection Systems Equipment

A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. All reviews of facilities as included in Criteria 7.4 shall be for those used to monitor and control transmission facilities operated at 100kV or above.

The SPS design shall not create cascading transmission outages or system instability. One possible SPS may be the automatic and sequential dropping of load, generation, or adjacent high voltage (HV) lines, if a HV line trips. A SPS does not include (a) underfrequency load shedding or undervoltage load shedding as they are addressed under NERC Planning Standards III.D, Criteria 7.3, and III.E or (b) fault conditions that must be isolated or (c) out-of-step relaying. The SPS shall not require operator action, and all actions of the SPS are automatic. SPS shall be automatically armed without human intervention when appropriate. The status indication of any automatic or manual arming of SPS shall be provided as SCADA alarm inputs.

7.4.1 Operating Requirements and System Redundancy

Special Protection Systems shall include redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of NERC I.A. Standards on Transmission Systems in Categories A, B or C of the associated Table I. Each facility owner shall develop a plan for reviewing the need for redundancy in its existing special protection systems and for implementing any required redundancy. Documentation of these reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Also, the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Category C of Table I of the NERC I.A Standards on transmission systems.

7.4.2 Location And Data Reporting For Special Protection Systems Equipment

The number, type and location of SPS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' and SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least five (5) years. These databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall represent the designed functionality of the system. Documentation by facility owners for each SPS utilized shall include details on its design, its operation, its control, its functional testing, and coordination with other schemes that are part of or impact the SPS.

7.4.3 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the SPS equipment in service. Component testing and maintenance shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests and maintains on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for one testing period. SPS shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design. Each facility owner will provide updates to the SPP or NERC upon request.

7.4.4 Periodic Review of Special Protection Systems Equipment

SPP members shall maintain a list of substations where SPS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the SPCWG and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the SPS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.4.2. The SPCWG will update, if necessary, this SPS Criteria every three (3) years.

Based upon (a) a five year interval or other interval as required by electric system changes, or (b) if a new SPS, or (c) if a modified SPS, each facility owner will review and document their SPS for compliance with Regional planning criteria and guides, and the NERC Planning Standard I.A including the associated Table I. This review shall include system studies to evaluate the consequences of: 1) the proper operation of the SPS, 2) the failure of an SPS to operate due to a single component failure of the SPS, and 3) the misoperation, incorrect operation, or the unintended operation of an SPS when considered by itself without any other system contingency. These consequences shall not include cascading transmission outages or system instability. These studies shall include the date that they were performed, who performed them, the methodology of the study, the results of the study, and when the next study is anticipated.

7.4.5 Requests for Special Protection Systems Data.

SPP shall function as a requesting agent and clearing house for the collection of SPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.4.6 Submittals Of Special Protection Systems Misoperations.

All misoperations of a SPS shall be reported to the SPP within five (5) business days after receipt of the request, or as soon as possible thereafter. Any of the following events constitute a reportable SPS misoperation:

1) Failure to Operate – Any failure of a SPS to perform its intended function within the designated time when system conditions intended to trigger the SPS occur.
2) Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.

3) Unnecessary Operation – Any failure of a SPS that occurs without the occurrence of the intended system trigger condition(s) including human error.
4) Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s).
5) Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

Misoperations at lower voltages that cause an operation of a SPS, in systems 100kV or higher, shall be reported. A detailed analysis of the misoperation, its consequences, and the corrective actions taken to prevent a reoccurrence will be reported to the SPP within thirty (30) days. SPP shall be notified of any delay and the anticipated date of forwarding the required data. This analysis to be provided by the facility owner shall include, at a minimum, the description of facility as identified on a form, developed by the SPCWG and supplied by SPP, including a complete summary report of the misoperation, its consequences, corrective actions taken, and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. The analysis and corrective actions shall be reviewed by the SPCWG. If these reported corrective actions are deemed inadequate, then the corrective actions that SPP recommends shall be completed as soon as possible subject to equipment availability.

7.4.7 Submittals For New, Modified (including Removal) or Renewed Special Protection Systems

The owner of the SPS shall notify SPP of its intent to construct a new, modified, or renewed SPS with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the SPS would have local, inter-company, inter-area or interregional consequences, when the SPS is planned for service, how long it is expected to remain in service, what specific contingency(s) it is designed to operate for and whether the SPS will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified SPS prior to construction of facilities, one (1) electronic version in legible format and three (3) hard copies of all applicable studies supporting the design requirements of the SPS including a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system. For renewed SPS prior to the expiration date, the facility owner shall supply all the above information plus any changes in the original coordination studies, operation history, maintenance history, and any change in the original coordination with other schemes that are part of or impact the SPS.

The System Protection and Control, Transmission and Operating Reliability Working Groups will assess the SPS's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the SPS.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior for new or modified SPS. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.5 UNDERVOLTAGE LOAD SHEDDING

One characteristic of electric systems that experience heavy loadings on transmission facilities with relatively limited reactive power control is the susceptibility to voltage instability. Such instability can cause tripping of generation and transmission facilities resulting in loss of customer demand as well as collapse of the bulk transmission system. A major disturbance among the interconnected bulk electric systems may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. Since voltage collapse can occur rapidly, operators may not have sufficient time to stabilize the systems. Therefore, a load-shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

7.5.1 Program Participants

Facility Owners who determine it beneficial to install undervoltage load shedding (UVLS) equipment may do so. However, UVLS schemes must coordinate with all protection and underfrequency load shedding schemes for the reliable operation of facilities operated at 100kV and above. Also, members are not required to install such equipment unless deemed necessary by either SPP or NERC to ensure the reliability of bulk transmission systems.

7.5.2 Operating Reserve And Principles

All SPP operating reserve shall be utilized before resorting to shedding firm load. All generator governors and voltage regulators shall be kept in automatic service as much as practical so that generating units may be used to their maximum capability for supplying voltage support during disturbances.

a. To realize the maximum benefit from a load shedding program, the points at which the load is shed in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

b. The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining voltage. One practical way to remove load from a member in an attempt to stabilize the voltage is to do so automatically by the use of undervoltage relays. All of the designated undervoltage relays on a member system shall be in service at all times. Undervoltage relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

c. Loads may be shed in multiple steps. Whatever actions are planned or implemented by one member, including actions other than load shedding, shall be coordinated with neighboring members and SPP. All UVLS programs shall coordinate with underfrequency load shedding requirements of other members and SPP to maintain the reliability of the bulk transmission system operated at 100kV and above.

d. Should the utilization of various assets, such as responsive voltage-supporting resources, generation, capacitors and static var systems, fail to stop a voltage decline, load shedding shall be initiated as determined by the member of which is conditional upon the regional requirements of SPP. The relays used to accomplish load shedding shall be high speed with the necessary external intentional time delay devices employed to eliminate nuisance trips during faults, reclosing delays, etc.

7.5.3 Location And Data Reporting

The determination of the number, type and location of UVLS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, trip voltages, amount of load shed by trip voltage, relay and breaker operating times, and any intentional delay of breaker clearing. Also required will be any related generation protection, tie tripping schemes, islanding schemes, or any other schemes that are part of or impact the UVLS programs.

7.5.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all UVLS trip operations. Any of the following constitute a reportable UVLS misoperation:

1) Failure to trip – Any failure of UVLS equipment to initiate a trip to the appropriate terminal when a voltage level is less than or equal to a low-voltage set point.
2) Slow Trip – A correct operation of UVLS equipment for a low-voltage condition where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip With Acceptable Voltage – Any relay initiated operation of a circuit breaker when the voltage is within acceptable limits.
4) Unnecessary Trip Within Period Of Time Delay – Any relay initiated operation of a circuit breaker before an intended time delay has expired.
5) Unnecessary Trip, Other– The unintentional operation of a UVLS scheme which causes a circuit breaker to trip when no low-voltage condition is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.

5) Procedures for analysis of all trip misoperations.

7.5.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means (i.e. self-testing microprocessor relays) to periodically check the functionality and availability of the UVLS equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

7.5.6 Periodic Review of Undervoltage Load Shedding Equipment

SPP members shall maintain a list of substations where UVLS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the UVLS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.5.3. The SPCWG will update, if necessary, this UVLS Criteria every three (3) years.

7.5.7 Requests for Undervoltage Load Shedding Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within thirty (30) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.5.8 Coordination of Undervoltage Load Shedding Programs

The facility owners and operators of an UVLS program shall ensure that their programs are consistent with Regional UVLS program requirements including automatically shedding load in the amounts and at the locations, voltages, rates and times consistent with those Regional requirements. When an undervoltage event occurs which is below the initializing set points of their UVLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.5.7.

7.6 AUTOMATIC RESTORATION OF LOAD

Following a disturbance when the frequency and voltage have stabilized, properly coordinated and implemented programs for the automatic restoration of load can be useful to minimize the duration of interrupted electric service. However, the design of such plans must ensure that the automatic restoration of load does not impede the restoration of the interconnected bulk electric facilities operated at 100kV or higher. After the automatic shedding of load by either underfrequency or undervoltage relaying schemes has occurred, the interconnected bulk electric facilities must first be stabilized with regard to both nominal frequency and voltage within appropriate limits prior to arming an automatic restoration of load system. Also, sufficient spinning reserves must be available such that the recreation of an underfrequency or undervoltage condition does not occur when electric service is restored. Then automatic load restoration programs can be used to effectively expedite the restoration of electric service to accommodate customer demands.

7.6.1 Program Participants

Facility Owners who determine it beneficial to install equipment for the automatic restoration of load (ARL) may do so. However, ARL schemes must coordinate with all protection as well as underfrequency (UFLS) and undervoltage load shedding (UVLS) schemes for the reliable operation of facilities operated at 100kV and above while not overloading any of these facilities. Also, members who install such equipment shall meet all requirements of SPP and NERC to ensure that the reliability of bulk transmission systems is maintained.

7.6.2 Operating Reserve And Principles

Available spinning reserves within SPP and each control area must be sufficient to serve the load to be energized by ARL schemes before arming such schemes. To prevent the use of ARL schemes when insufficient spinning reserves are available, ARL schemes shall be armed by automatic generation control systems of which are operated by or are coordinated with the appropriate control area(s). All generator governors and excitation equipment including voltage regulators shall be kept in automatic service when ARL schemes are armed so that the spinning reserve of available generating units may be used to their maximum capability for supplying real and reactive power during restoration. Additional requirements for the application of programs involving the automatic restoration of load are listed below.

a. Whatever actions are planned or implemented by one member involving the automatic restoration of load shall be coordinated with other members, SPP and other Regions. All ARL programs shall coordinate with underfrequency and undervoltage load shedding programs as well as ARL programs of other members to maintain the reliability of the bulk transmission system operated at 100kV and above.

b. An ARL system shall not be armed unless all pre-designated conditions are satisfied within the control area unless a designated island or sub-area is specified. Unless removed from service for testing and maintenance purposes, an ARL system shall be automatically armed and remain so only when 1) indication that an UFLS or UVLS scheme has operated, 2) the governor and excitation systems of available generation are in the automatic mode, 3) spinning reserves of available generation are greater than or equal to the real and reactive power requirements of the pre-event load to be restored, adjusted to the forecasted daily load curve and changes in diversity, plus incremental losses, 4) an adequate system frequency has been achieved, 5) voltages throughout the transmission system are within valid limits, 6) all intended transmission system interconnects are closed, and 7) all intended breakers including those used for islanding are closed. However, operators of an island or control area that has separated from the remainder of the bulk transmission system may arm an ARL system for this specific area if 1) a neighboring system(s) has not achieved or maintained an adequate frequency or voltage levels within acceptable limits, and 2) all of the conditions specified above are met except that all intended transmission system interconnects or islanding breakers may not be closed.

c. The time intervals involved in the automatic restoration of loads is of extreme importance. The restoration of too much load at one or over time relative to the capacity of available generating units given their dynamic characteristics may result in an unstable system. Therefore, loads to be automatically restored over time shall not exceed the ramping capabilities of the available generation. Also, upon being armed, ARL equipment shall restore load in multiple blocks by design to minimize the possibility of causing an underfrequency or undervoltage condition.

d. When any portion of the generation required to serve restored load is physically separated from the load by facilities within another control area, then adequate facilities between the generation and load with sufficient capacity to transfer the power shall be verified and applicable breakers shall be closed before the ARL system is armed.

e. Only those loads interrupted by UFLS and UVLS schemes may be restored by ARL equipment. Therefore, if either a UFLS or UVLS scheme did not interrupt a given load, then the use of ARL equipment shall not be used to restore the load. When UVLS equipment is used to trip loads, then the local voltage shall be within acceptable limits before the local ARL equipment energizes the load.

f. The points at which the load is restored in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be restored can be selected.

g. Should the utilization of spinning reserve fail to adequately stabilize either frequency or voltage in a control area or designated portion thereof after restoring service to loads, or portions thereof, controlled by ARL equipment, the ARL equipment of said area shall be automatically disarmed. ARL schemes shall be designed and installed to restore load only once before being rearmed manually or by system operators via SCADA.

7.6.3 Location And Data Reporting

The determination of the number, type and location of ARL equipment will normally be the responsibility of the facility owners based on recommendations by the owners' or SPP's studies.

The technical assessments of ARL applications conducted by or on behalf of the facility owner shall validate the coordination with underfrequency and undervoltage programs within SPP and other Regions as necessary. Facility owners shall provide information about these installations to the SPP in accordance with NERC Standards within five (5) business days upon receipt of the request. This information will be maintained in databases by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor these databases as necessary. The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases as well as technical assessments conducted by facility owners and recommend that equipment with adequate capabilities be installed, or removed as necessary, at critical locations throughout the system as determined in power flow and dynamic stability studies.

The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall include, but not be limited to, type of equipment, location, breaker, minimum voltage and frequency thresholds, amount of load shed that is to be restored, relay and breaker operating times, and any intentional delay of breaker closing. Also required will be any related generation protection, tie-closing schemes, islanding schemes, or any other schemes that are part of or impact the ARL programs.

7.6.4 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all ARL closing operations. Any of the following constitute a reportable ARL misoperation:

1) Failure to close – Any failure of armed ARL equipment to initiate a close to the appropriate circuit breaker when a local voltage and/or frequency level is greater than or equal to applicable set points.
2) Slow Close – A correct operation of armed ARL equipment where the relay system initiates closing slower than the system design intends.
3) Unnecessary Close By Unarmed Equipment – Any initiated closing of a circuit breaker when all pre-designated conditions are not met.
4) Unnecessary Close, Other– The unintentional operation of an unarmed ARL scheme that causes a circuit breaker to close when no event had previously

occurred. This may be due to vibration, improper settings, faulty relay, or human error.

Documentation of all misoperations shall be provided to SPP and NERC within thirty (30) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all trip operations. It shall also provide consistent documentation of all closing misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form, developed by the SPCWG and supplied by SPP, with applicable attachments. These attachments shall include all voltage, frequency and sequence of events data relevant to the cause of the misoperation of which is the basis for the documentation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all closing misoperations.

7.6.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality and availability of the ARL equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

ARL systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than three (3) years to verify the dependability and security aspects of the design. The maintenance and testing program of the ARL system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker closure testing. All maintenance and testing shall be documented as described below:

1) Automatic Restoration of Load system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.6.6 Periodic Review of Equipment

SPP members shall maintain a list of substations where ARL equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the ARL equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.6.3. The SPCWG will update, if necessary, this ARL Criteria every three (3) years.

7.6.7 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, 2) an implemented maintenance program, and 3) an applicable technical assessment. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.6.8 Coordination of Programs

The facility owners and operators of an ARL program shall ensure that their programs are consistent with Regional ARL program requirements including automatically restoring load in the amounts and at the locations, range of voltages and frequencies, rates and times consistent with those Regional requirements. When an undervoltage or underfrequency event occurs which initiates the utilization of ARL programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 7.6.7.

7.6.9 Submittals For New And Modified ARL Systems

The owner of the ARL system shall notify SPP of its intent to install a new or modify an existing ARL with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the ARL system would have local, inter-company, inter-area or interregional consequences, when the ARL system is planned for service, how long it is expected to remain in service and whether the ARL system will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified ARL system prior to installation of facilities, three (3) copies of all applicable studies supporting the design requirements of the ARL system and three (3) copies of a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system.

The System Protection And Control, Transmission Assessment and Operating Reliability Working Groups will assess the ARL system's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the ARL.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately four months prior to the presentation and by providing copies of the materials to be presented 30 days prior. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

7.7 Generation Control and Protection

The objectives of protective relaying and control schemes within generation facilities are to promptly detect abnormal conditions and isolate or control equipment to minimize damage to equipment. Some of these abnormal conditions which will result in an alarm or tripping of generation include faults, overload, overheating, off-frequency, loss of field, motoring, single-phase or unbalance current operation, and out-of-step. The selection and settings of equipment should not result in erroneous tripping for acceptable operating conditions or for faults outside the intended zones of protection.

Generation Control and Protection Systems (GCP) must be coordinated with excitation and governor controls to minimize generator tripping during disturbance-caused abnormal voltage, current and frequency conditions. Therefore, protection and control schemes should be designed and installed with appropriate settings to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generator equipment from damage. All reviews, monitoring and analysis of each generator, rated at 20MW or above, shall be completed as described in Criteria 7.7.

7.7.1 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the generation protection system to assure that components and systems function as desired to minimize outages. The design and implementation of all new protection schemes shall be in accordance with IEEE and ANSI Standards, Guides and Recommended Practices as well as NERC Standards and Guides. Should it be determined that the design and application of protection equipment do not adhere to such requirements, then these findings, as a result of this review, shall be documented including a plan for achieving the necessary results. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.7.2. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Bus, cables, lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, fuses, etc.).
4) Breaker failure and trip schemes.

The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

All underfrequency, overfrequency, undervoltage and overvoltage protection systems shall be coordinated with system underfrequency and undervoltage load shedding schemes. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B and C of NERC I.A Standards unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Redundant generator protection schemes are required for all new generator installations and all re-powering projects where the generator is rated at 20MW or above. Redundant generator protection schemes for the step-up transformer and the main auxiliary transformer (if any) are not required but encouraged. Where redundant protection systems are being used, efforts should be made to use separate current transformers, potential transformers, and DC control power circuits to minimize the risk of both systems being disabled by a single event or condition.

The use of dual trip coils, if available, on both generator and unit circuit breakers are required for all new generator installations at 20MW or above. The installation of breaker failure relaying for generator and unit circuit breakers are also required for all new generator installations at 20MW or above. The addition of breaker failure relaying for all generator and unit circuit breakers at existing sites is not required but encouraged.

7.7.2 Monitoring, Analysis And Notification Of Misoperations

Each facility owner shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Any of the following constitute a reportable misoperation of generation protection equipment and schemes:

1) Failure to trip – Any failure of a GCP system element to operate when a fault or abnormal condition occurs within a zone of protection. (Note: Lack of targeting, such as when a high-speed pilot system is beat out by a high-speed zone, is not a reportable misoperation. If a fault or abnormal condition is cleared in the time normally expected with proper functioning of at least one GCP system, failure of a GCP system element is not a reportable misoperation.).
2) Slow Trip – Any failure of a GCP system element that is slower than planned to operate when a fault or abnormal condition occurs within the zone of protection. (Note: Delayed Fault Clearing, where a high-speed system is employed but is not essential for transmission system performance, is not a reportable misoperation.)
3) Unnecessary Trip During a Fault – Any unnecessary GCP system operation for a fault not within the zone of protection. (Note: Operation as properly coordinated backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable misoperation.)
4) Unnecessary Trip Other Than a Fault – Any unnecessary GCP system operation when no fault or other abnormal condition has occurred. (Note that an operation that

occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable misoperation.)

Misoperations occuring prior to synchronization need not be reported, but shall be investigated and corrected to prevent possible misoperations when the unit is synchronized to the system. Documentation of all protection misoperations shall be provided to SPP and NERC within thirty (30) business days of the request.

Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all GCP trip operations. It shall also provide consistent documentation of all GCP trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided and include all fault, disturbance, load and sequence of events data relevant to the cause of the misoperation.

The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform documentation format to the extent possible.
2) Content guidelines.
3) Requirements for periodic review.
4) Requirements for updating data.
5) Procedures for analysis of all trip misoperations.

7.7.3 Generation Protection System Maintenance And Testing Programs

Facility owners shall have a protection system maintenance and testing program in place. The facility owner shall demonstrate full compliance to the program for protection system maintenance and testing, demonstrating that all required activities have been completed on schedule. The program shall be maintained and documented. The facility owner will be responsible for maintaining and providing required data for each facility. Each facility owner will provide updates to SPP or NERC within 30 days of a request.

The facility owner shall maintain the documentation of all maintenance and tests records for one test period. Protection systems and their associated maintenance and testing procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation or inadvertent disabling. Protection and control systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than five (5) years to verify the dependability and security aspects of the design.

Each facility owner shall periodically test the protection system components on a frequency as needed to assure that the system is functional and correct. The maintenance and testing of system components, i.e. relays, shall be completed based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation but at least every three (3) years. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. For newer GCP Systems with self-monitoring, having SCADA reporting for a GCP failure, and with successful downloading or viewing of data following operations, then such activity and application shall satisfy the testing and maintenance procedure requirements.

The maintenance and testing program of the protection system should include provisions for relay calibration, functional trip testing, and breaker trip testing. All maintenance and testing shall be documented as described below:

1) Generation protection system identification.
2) Summary of testing procedures.
3) Frequency of testing.
4) Date last tested.
5) Results of last testing.

7.7.4 Requests for Data

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility Owners shall provide program information including equipment data within five (5) business days upon receipt of a request with a copy of the requested information forwarded to the SPP. Facility owners shall also provide documentation, within thirty (30) business days upon receipt of a request, relating to 1) all misoperations within the requested time frame, and 2) an implemented maintenance and testing program. SPP shall provide program information including equipment data to NERC within five (5) business days upon receipt of a request. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

7.7.5 Coordination of Programs

The facility owners and operators of a GCP program shall ensure that their programs are consistent with Regional GCP program requirements effective January 1, 2002. When a disturbance, fault, or misoperation occurs which initiates the utilization of GCP equipment and schemes, the owners or operators shall analyze and document the event. Documentation of all misoperations shall be provided to SPP and NERC on request in the time frames established in 7.7.4. Generator owners/operators shall have a generator protection system maintenance and testing program in place.

7.7.6 Generation Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Generation Control and Protection Systems Criteria every three (3) years.

7.8 Generator Controls – Status and Operation

7.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator.

7.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators' automatic voltage control regulator. The procedures shall include the following.

a. Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the "Generator Owner/Operator Excitation System Summary Report" supplied by SPP, if control area operator does not have its own form.

b. Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar month. Information shall be provided on the “Generator Unit Excitation System Status Report” supplied by SPP, if control area operator does not have its own form.
c. The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

7.8.1.2 Exempt Generators

Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

a. Generator output less than 20MW
b. Other criteria as control area operator deems appropriate.

7.8.2 Generator Operation for maintaining Network Voltage

Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

7.8.2.1 Control Area Responsibilities

a. Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the “Generator Owner/Operator Voltage Schedule Requirements” report supplied by SPP, if the control area operator does not have its own form. This information shall be made available to SPP and NERC on request (30 business days).
b. Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on “Control Area Operator’s List of Exempt Generators” report supplied by SPP, if control area does not have its own form.

7.8.2.2 Generator Owner/Operator Responsibility

a. Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator.
b. When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on the "Generator Unit Voltage Schedule Status Report" supplied by SPP, if control area operator does not have its own form.

7.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

7.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

a. Owner/Operators shall provide current tap settings, tap setting ranges, and impedence data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on 'Generator Unit Transformer Tap Setting Report" supplied by SPP is control area operator does not have its own form.
b. When tap setting changes are necessary, the control area operator shall notify generator owner/operator with "Generator Unit Transformer Tap Setting Change Request" supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.
c. Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new "Generator Unit Transformer Tap Setting Report" for the affected generating station.
d. Criteria for Generating units whose GSU and AUX transformers would be exempted.

e. List of generating units that meet exemption criteria shall be documented on “Generation Units Exempt from Tap Setting Reporting Procedures” report supplied by SPP, if Control Area Operator does not have its own form.

7.8.4 Generator Performance during Temporary Excursions

7.8.4.1 Excursions Voltage

During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

7.8.4.2 Excursions in Real and Reactive Power Output

Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit’s Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.

7.8.4.3 Exempt Generators

Generators shall be exempt from this section if they meet the following criteria:

Generator output less than 20MW

7.8.5 Generator Voltage Regulator Controls and Limit Functions

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator’s short term duration capabilities and protective relays.

7.8.5.1 Reporting Procedures

Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the "Voltage Regulator Control Setting Status Report" as supplied by SPP is control area operator does not have its own form.

7.8.6 Governor Control Operation

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors' speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

7.8.6.1 Reporting Procedures

a. Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on "Generator Governor Characteristic Reporting" report supplied by SPP if control area operator does not have its own form.
b. Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on "Non-Functioning Governor Control" report supplied by SPP if control area operator does not have its own form.

7.9 Inter-Connection Revenue Metering

7.9.1 Meter Technical and Data Reporting Protocols

The protection design may also include various types and accuracies of metering and associated equipment. The metering may include, but not be limited to, the following: local station or plant annunciated / displayed metering, SCADA type operational metering exchanged among parties within a station or plant, SCADA type station to control center metering used for operational purposes, control center to control center ICCP type metering, and inter-connection revenue metering. These metering types may or may not have specific SPP criteria requirements. Other metering design requirements may need to be referenced when creating metering and protection design, especially those that include the control center to control center metering and revenue metering. SPP has specific functional and design type requirements for Inter-Connection Revenue Metering.

7.9.2 Revenue "Meter Technical and Data Reporting Protocols" Cross Reference

The Southwest Power Pool (SPP) Market Working Group's (MWG) Settlement Data and Meter Standards Task Force (SDMSTF) subcommittee has jurisdictional control over the power plant and transmission system "inter-connection settlement revenue metering". The SPP System Protection and Control Working Group (SPCWG) and other parties providing inter-connection settlement revenue metering designs in the SPP area must refer to the MWG - - SDMSTF Market Protocol Document "Appendix D: Meter Technical and Data Reporting Protocols" for inter-connection settlement revenue metering equipment design requirements. Per the SPP Market Protocol Document, the inter-connection revenue metering design requirements must be met for all new installations.

8.0 OPEN

9.0 OPEN

10.0 EMERGENCY COMMUNICATION

Dependable communications are critical to maintaining the reliability of the Bulk Electric System. Accordingly, NERC has outlined necessary communication links in the reliability standards applying to Transmission Operators, Balancing Authorities, and Reliability Coordinators. It is vital that communication channels are functional and disturbances to the communication network should be addressed.

Key critical paths:

- Internal communications
- Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
- With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
- Where applicable, these facilities shall be redundant and diversely routed.

The communication paths should be verified periodically and an action plan should exist to maintain and recommend solutions to communication problems.

10.1 SPP Emergency Communication Network

The SPP Emergency Communication Network is comprised of Satellite Phones located at the SPP primary and backup control centers, control centers of each member Balancing Authority and/or Transmission Operator. If loss of any primary communication facilities are encountered, the SPP Emergency Communication Network shall be used to exchange information. Therefore, it is important for operators to be familiar and comfortable with the operation of the Satellite Phones. The Reliability Coordinator shall ensure proper training.

Balancing Authorities, Transmission Operators and Reliability Coordinators shall participate in weekly testing of the SPP Emergency Communication Network. Testing will ensure reliability and it will also give users practice on the system. The Reliability Coordinator shall initiate and monitor the SPP Satellite Phone testing.

During actual emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Communication is vital to an orderly recovery. Operating personnel shall keep conversations concise to keep channels clear. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths.

10.2 Information Priority during Emergencies

System status conditions to be surveyed include but are not limited to the following items:

a. Areas of the electric system which are de-energized,

b. Areas of the electric system which are functioning,

c. Amount of generation and generating reserve available in functioning areas,

d. Power plant availability and time required to restart,

e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,

f. Status of transmission breakers and sectionalizing equipment at tie points to other areas,

g. Status of fuel supply from external suppliers,

h. Under-frequency relay operation,

i. Relay flags associated with circuits tripped by protective relays.

j. Status of communication systems.

* Refer to COM-001 and COM-002 for more information on maintaining reliable communications

11.0 OPEN

12.0 ELECTRICAL FACILITY RATINGS

12.1 Rating of Generating Equipment

To provide a basis for comparing operating margin of various entities and to assure reasonable distribution of the margin, generating equipment shall be uniformly and consistently rated to permit accurate planning. Procedures are herein established for rating generating units and establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the ratings established pursuant to these procedures shall be used for SPP purposes, including determining capacity margins for both planning and operating purposes, scheduling maintenance, and preparation of reports of other information for industry organizations, news media, and governmental agencies. These ratings are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is referenced in many NERC documents as net dependable capacity that is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generating equipment which is designated as a part of the resource for supplying its own peak load and minimum capacity margin requirement of these Criteria. The seasonal net capabilities, gross capabilities, and auxiliary loads shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary. The generating capability limits will be equal to or less than the most limiting component including but not limited to bus, breakers, switches, transformers, or generator protection relays. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort and insure that the generator limits are used in determining the data contained in SPP power flow models. During the capability test the net capability shall be reported. Additionally, the unit’s gross capability and auxiliary load shall be reported. The gross capability and auxiliary load shall be determined from the test or using such methods as use of manufacturer data, commissioning data, performance tracking, etc. Data used to determine net capability shall be obtained from testing.

12.1.1 Capability Test

Capability Tests are required to demonstrate the claimed capability of all generating units, excluding run-of-the-river hydroelectric plants and wind plants. During a Capability Test, a unit shall generate its rated net capability for a specified Test Period following a specified Settling Period. The length of these periods is determined by the type and size of unit. The unit will be within 5% of its rated capability throughout the Settling Period. Only minor changes in unit controls shall be made during this time as required to bring the unit into normal, steady-state operation. The following table specifies the duration of these periods. The reduced duration tests on the specified unit types are generally considered to be a fair and practical demonstration of unit capability. If operating experience for a given unit suggests otherwise, the system shall use this experience in establishing the time periods or use the periods in the table associated with large steam units.

Unit Type	Settling Period	Test Period
Steam > 100 MW net	2.0 hours	2.0 hours
Steam < 100 MW net	1.0 hour	1.0 hour
All other units	0.0 hour	1.0 hour

12.1.2 Operational Test

An Operational Test is used to demonstrate the ability of a generating unit to be loaded to its nominal rating. Operational tests shall be conducted at a minimum of 90% of claimed summer capability for a minimum of 1 hour. Any normal operating hour with the unit at or above 90% of claimed capability may be deemed an Operational Test.

12.1.3 Frequency of Testing

Summer Capability Tests shall be conducted once every 3 years. If the winter capability rating is greater than summer, winter tests shall also be conducted once every 3 years. Operational Tests shall be conducted once every year during the summer season. New units or units undergoing a physical or operational modification which could impact capability shall be given a capability test.

12.1.4 Rating and Testing Conditions

Ambient conditions at the time of running capability tests shall be recorded so that appropriate adjustments can be made when establishing seasonal capabilities. Conditions to be recorded are: dry-bulb temperature, wet-bulb temperature, barometric pressure, and condenser cooling water inlet temperature. Summer Capability Tests are to be conducted at an ambient temperature within 10 degrees Fahrenheit of Rating dry-bulb temperature.

Winter Capability Tests are to be conducted at an ambient temperature equal to or greater than the minimum dry-bulb temperature for winter testing and rating defined in paragraph 2.1.5.2.g.

12.1.5 Procedures For Establishing Capability Ratings

12.1.5.1 External Factors

a. Units dependent upon common systems which can restrict total output shall be tested simultaneously.

b. When the total output of a member's system is reduced due to restrictions placed upon the output of individual generating units through the operation of the Clean Air Act, or similar legislation, then the total of the individual unit ratings of a member's generating resources shall not exceed the modified system capacity.

c. The fuel used during testing shall be the general type expected to be used during peak load conditions or adjustments made to test data if an alternate fuel is used.

d. Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

e. The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a rating by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a rating by apportioning the combined capability among the units.

12.1.5.2 Seasonality

a. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February, and March. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, scheduled reservoir discharge, and wind speed.

b. The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

c. The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Rating Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

d. The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook, Climatic Design Information. The handbook is published every four years; 1997, 2001, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in SPP

Criteria Appendix 2.

e. If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both dry-bulb and wet-bulb temperatures.

f. Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-bulb) and MWB (mean wet-bulb). According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.

g. The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99%. According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and rating shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

h. Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Appendix 2.

i. For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the month concurrent with the Load Serving Member’s peak load of the year, averaged over the past ten years.

j. Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

12.1.5.3 Rating Adjustments

a. The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Rating Conditions, with the exception of units with winter season ratings greater than their summer rating. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No rating adjustment for ambient conditions shall be made.

b. Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

c. Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

d. The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

e. The seasonal net capability established for hydro electric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

f. The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

g. The recommended methodology to evaluate the net capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

i. Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

ii. Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

iii. Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

iv. A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity's peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and 110 hours for a 5 year period).

v. Facilities in commercial operation 3 years or less:

   a. The data must include the most recent 3 years.

   b. Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific data.

   c. If the Load Serving Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

vi. Facilities in commercial operation 4 years and greater:

   a. The data must include all available data up to the most recent 10 years of commercial operation.

   b. Only metered hourly net power output (MWH) data may be used.

c. After three years of commercial operations, if the Load Serving Entity does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW.

vii. The net capability calculation shall be updated at least once every three years.

12.1.6 Reactive Capability Verification

12.1.6.1 Verification Required Every Five Years

12.1.6.1.1 Verification Frequency

Initial verification of the gross and net reactive capabilities (leading and lagging) of each generating unit and synchronous condenser (hereinafter referred to as "unit") within the SPP footprint shall be provided to SPP on or before the in-service date of the unit. Thereafter, documentation verifying the unit's gross and net leading and lagging reactive capability shall be provided on or before the fifth anniversary of the most recent date that verification documentation was submitted. In addition, documentation verifying gross and net reactive capabilities shall be provided after repairs or equipment changes that may affect reactive capability.

12.1.6.1.2 Exemptions

A. Generating plants/facilities with one or more generators having a maximum aggregate generator nameplate capability rating less than 50 MVA MW are exempted from the verification requirements.
B. The generating unit owner or operator, with adequate justification, may request from the Transmission Planner an exemption of other units from the verification process.
C. Generating plants/facilities shall provide the form as specified in Paragraph 12.1.6.2, but will mark the unit as exempt and state the reason it is exempted.
D. Regardless of the generator exemptions stated above, the Planning Coordinator or Transmission Planner may require reactive capability verification for any generator that the Planning Coordinator or Transmission Planner determines is critical to system reliability.

12.1.6.2 Entity Responsible for Verification

The unit's operator shall be the entity responsible for verification of the gross and net leading and lagging capabilities of the unit. This data shall be provided to the SPP Member who is responsible for modeling the unit in power flow and stability models. Data should be provided using Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.3 Leading and Lagging Capabilities Verified

Both the leading capability of the unit (the ability of the unit to absorb megavolt-amps reactive (MVAR) from the electric grid) and the lagging capability of the unit (the ability of the unit to inject MVAR into the electric grid) shall be verified as specified in section 12.1.6.4.

12.1.6.4 Method of Verification

Verification of a unit's gross and net reactive capabilities may be demonstrated:

(a) by submitting documentation showing the maximum leading or lagging MVAR produced by the unit during actual operations; or

(b) by submitting an engineering analysis that demonstrates the expected maximum leading and lagging MVAR of the unit; or

(c) by submitting commissioning data provided that no major modifications have been performed to the unit that would affect its MVAR rating; or

(d) by verifying the unit capability as further described in this criteria. In the event a unit is incapable of being verified as specified in criteria, then the unit's gross and net reactive capabilities must be demonstrated using one of the other methods set forth above. If testing is used to verify reactive capabilities, there is no limitation on the time period between the test for leading capability and the test for lagging capability, provided that each of these capabilities are tested/validated at least once every five years.

12.1.6.5 Reactive Capability Test/Verification

12.1.6.5.1 Test/Verification Objective.

(a) Gross and net leading reactive capability. Under system conditions that are likely to induce the maximum leading response (i.e., the point at which the unit absorbs the largest quantity of MVAR from the electric grid), obtain one data point that shows the gross and net leading reactive capability versus energy production (real power) of the unit.

(b) Gross and net lagging reactive capability. Under system conditions that are likely to induce the maximum lagging response (i.e., the point at which the unit injects the largest quantity of MVAR into the electric grid), obtain one data point that shows the gross and net lagging reactive capability versus energy production (real power) of the unit.

These points shall reflect either the maximum leading or lagging MVAR at or near maximum real power or at such other real power output level as may be specified in the interconnect agreement with the transmission owner.

12.1.6.5.2 Test/Verification Conditions.

As discussed in this section, conditions on the grid should be such that the reactive response of the unit will approach the unit's maximum. System conditions for leading and lagging capability verification are diametrically opposed (leading capability is demonstrated during light loading conditions while lagging capability is demonstrated during heavy loading conditions). Therefore, a complete verification for both leading and lagging capabilities will require collection of data points during different seasons.

(a) Unit parameters. During the verification, parameters for unit load, unit temperature, and unit pressure (hydrogen, boiler, etc.) should be as close as practicable to those experienced during normal operating conditions, or as specified by the unit manufacturer.

(b) Power factor and grid conditions. The validation should be conducted at the unit's power factor as specified in the Interconnection Agreement. If the Interconnection Agreement does not specify the unit's power factor, then the verification should be conducted in a manner that will determine the maximum leading or lagging MVAR the unit is capable of producing while it is operating at or near its maximum real power capability. The conditions that will provide this result for leading reactive capability involve light system loads and light transmission line loading during the Spring or Fall. The conditions that will yield this result for lagging reactive capability involve peak or near peak Winter or Summer conditions. When possible, other synchronous machines or power system components should be used to obtain the most advantageous terminal voltage during the verification. Additionally, communication with the transmission provider may help optimize verification conditions.

(c) Data collection point. Unit verification data shall be collected at the point of interconnection to the transmission system.

12.1.6.5.3 Test/Verification procedure.

(a) Procedure for Verification of Unit Reactive Lagging Limits. While operating in a steady state mode at gross and net dependable mega-watt (MW) capability (near rated output), raise excitation in automatic voltage control until one of the following conditions occurs:

i. The 100% megavolt-amp (MVA) rating of the machine is reached (reach capability curve);
ii. Rated field current or field voltage is reached;
iii. Terminal voltage limit is reached (105-110%, depending on unit);
iv. Generator temperature limits are reached;
v. The maximum over-excitation limiter is reached or alarms;
vi. The maximum reference adjuster travel or limit is reached;
vii. Maximum auxiliary bus voltage is reached; or
viii. Transmission constraints prevent any further increase in lagging MVAR.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

(b) Procedure for Verification of Unit Reactive Leading Limits. While operating in a steady state mode at or near gross and net dependable MW capability, lower excitation in automatic voltage control until one of the following conditions occurs:

i. Under-excitation limiters (UELs) are activated;
ii. 100% MVA rating is reached;

iii. Generator temperature limits are reached;

iv. Minimum reference adjuster travel or limit is reached;

v. Minimum auxiliary bus voltage is reached;

vi. Minimum terminal voltage is reached; or

vii. Transmission constraints prevent any further increase in leading reactive power.

At the point that one of the above conditions is met, maintain unit output for a minimum of 15 minutes, and then record the data specified in Appendix 10, "Unit Reactive Limits (Lead and Lag) Verification FORM".

12.1.6.6 Test/Verification Results.

A validation will be rejected if the unit is verified under conditions other than those specified in this criteria. If a test/verification is rejected, the unit must either be revalidated within the next 12 months or gross and net reactive capability demonstrated through one of the alternative methods specified in section 12.1.6.4.

12.2 Rating of Transmission Circuits

Each SPP member shall rate transmission circuits operated at 69 kV and above in accordance with this criteria. A transmission circuit shall consist of all elements load carrying between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to this criteria. The circuit ratings will be specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating shall be determined as described in this criteria and members shall maintain transmission right-of-way to operate at this rating. However, SPP members may use circuit ratings higher than these minimums. Each element of a circuit shall have a normal and an emergency rating. For certain equipment, (switches, wave traps, current transformers and circuit breakers), these two ratings are identical and are defined as follows:

a. NORMAL RATING: Normal circuit ratings specify the level of power flow that facilities can carry continuously without loss of life to the facility involved.

b. EMERGENCY RATING: Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

At a minimum, each member shall compute summer and winter seasonal ratings for each circuit element. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February and March. The seasonal rating shall be based upon an ambient temperature (either maximum or average) developed using the methodology described in Appendix 6A. A member may elect to compute a third set of seasonal ratings for the remaining months of the year (April, May, October and November). If that election is not made, summer ratings shall be used for these remaining months.

12.2.1 Power Transformer

Power transformer ratings are discussed in ANSI/IEEE C5791, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers. Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55°C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

12.2.2.1 Normal Rating

The normal circuit rating for power transformers shall be its highest nameplate rating. The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

12.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.

12.2.1.3 Loss of Life

In ANSI/IEEE C57.91, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. In ANSI/IEEE C57.91, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

12.2.1.4 Ambient Temperature

Average ambient temperature is an important factor in determining the load capability of a transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating. Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher normal and emergency ratings. However, this circuit rating criteria does not call for seasonal transformer ratings. In ANSI/IEEE C57.91, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

a. Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.
b. Average ambient temperature, 30°C.
c. Equivalent load before peak load, 90% of nameplate rating.
d. Hours of peak load, 8 hour load cycle.
e. Acceptable annual loss of life, 1%.

12.2.2 Overhead Conductor

Overhead conductor ratings are discussed in IEEE Standard 738, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex B of IEEE Standard 738 or an equivalent program, such as the DYNMAP program which is part of the EPRI TLWorkstation ™ software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not acceptable.

12.2.2.1 Conductor Properties

Some computer programs used to compute ampacity values have a conductor property library whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex B of IEEE Standard 738 or another computer program that does not have a conductor property library will obtain conductor properties from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

12.2.2.2 Line Geographic Location

These factors specify the location of the line, its predominant direction and its predominant inclination. These numbers can either be line specific or they can represent a general line within the control area. One ambient temperature shall be agreed upon for tie lines traversing several geographic areas and interconnections among different control areas.

12.2.2.3 Radiation Properties

The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

Solar Absorptivity The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value shall be between 0 and 1. Recommended values are given in the following tables:

COPPER CONDUCTORS	
Oxidation Level	**Absorptivity**
None	0.23
Light	0.5
Normal	0.7
Heavy	1.0

ALUMINUM CONDUCTORS	
Service Years	**Absorptivity**
0<5	0.43
□ 5	1.00

Source: Glenn A. Davidson, Thomas E. Donoho, George Hakun III, P. W. Hofmann, T. E Bethke, Pierre R. H. Landrieu and Robert T. McElhaney, "Thermal Ratings for Bare Overhead Conductors", IEEE Trans., PAS Vol. 88, No.3, pp. 200-05, March 1969.

Infrared Emissivity The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value shall be between 0 and 1. Recommended values are given in tables below:

COPPER CONDUCTORS	
Oxidation Level	**Emissivity**
None	0.03
Light	0.3
Normal	0.5
Heavy	0.8

ALUMINUM CONDUCTORS	
Service Years	**Emissivity**
0	0.23
5-10	0.82
10-20	0.88
□ 20	0.90

Source: W. S. Rigdon, H. E. House, R. J. Grosh and W. B. Cottingham, "Emissivity of Weathered Conductors After Service in Rural and Industrial Environments," AIEE Trans., Vol. 82, pp. 891-896, Feb. 1963.

12.2.2.4 Weather Conditions

Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Appendix 6A contains a methodology to compute maximum ambient temperature. Wind speed is assumed at 2 ft/sec (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

12.2.2.5 Maximum Conductor Temperature

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed. The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria specifies a maximum conductor temperature that could be met by current line design practices, consideration must be given to existing lines that were built according to an earlier standard. This Circuit Rating Criteria specifies a maximum conductor temperature (for both normal and emergency operating conditions) that shall be used for seasonal circuit ratings. For those existing lines that were designed to meet an earlier standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature requirements in Section 12.2.2.6, whichever is lower.

12.2.2.6 Determination of Maximum Conductor Temperature

The maximum conductor temperature for normal ratings may be limited by conductor clearance concerns. Normal ratings are at a level where loss of strength is not a concern. The maximum conductor temperature for emergency ratings have both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures shall be used. This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members practices.

	Maximum Conductor Temperature	
	Normal Rating	**Emergency Rating**
ACSR	85°C	100°C
ACAR	85°C	100°C
Copper	85°C	100°C
Copperweld	85°C	100°C
AAC	85°C	100°C
AAAC	85°C	100°C
SSAC	200°C	200°C
Note: Annealing of copper and aluminum begins near 100°C.		

12.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for 4 hours 8 times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1000 hours. For an all aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the emergency rating shall not exceed 4 hours. This load cycle duration for conductors operating at the emergency rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings shall allow transmission lines to achieve a maximum conductor temperature throughout the year, not just days when the ambient exceeds 78°F.

12.2.3 Underground Cables

Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the circuit is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method. The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

12.2.3.1 Cable Ampacity

Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:

- Peak current and load-cycle shape;
- Conductor size, material and construction;
- Dielectric loss in the insulation;
- Current-dependent losses in conductor, shields, sheath and pipe;
- Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;
- Thermal capacitances of these components of the thermal circuit;
- Mutual-heating effects of other cables and other heat sources; and
- Ambient earth temperatures.

Both steady-state and emergency ampacities depend upon these factors, although emergency ratings have a greater dependency upon the thermal capacitances of each of the thermal circuit components.

12.2.3.2 Conductor Temperature

The maximum allowable conductor temperature is 85°C for high-pressure fluid-filled (HPFF), pipe-type cables and 90°C for crosslinked, extruded-dielectric cables.

The table below summarizes allowable conductor temperatures for different insulation materials. Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF circuit. The maximum conductor temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

Insulation Material	Maximum Temperature	
	Normal	Emergency
Impregnated paper (AEIC CS2-90 for HPFF and HPGF (AEIC CS4-79 for SCLF)	85°C (75°C)	105°C for 100 hr 100°C for 300 hr
Laminated paper-polypropylene (AEIC CS2-90)	85°C (75°C)	105°C for 100 hr 100°C for 300 hr
Crosslinked polyethylene (AEIC CS7-87)	90°C (80°C)	105°C cumulative for 1500 hr
Ethylene-propylene rubber (AEIC CS6-87)	90°C (80°C)	105°C* cumulative for 1500 hr
Electronegative gas/spacer	Consult manufacturer for specific designs	

* Emergency operation at conductor temperatures up to 130°C may be used if mutually agreed between purchaser and manufacturer and verified by qualification and prequalification tests.

12.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be used:

Climate	Ambient Air Temperature °C	Ambient Ground Temperature °C
Tropical	55	40
Sub-tropical	40	30
Temperature	25	20

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface. This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Appendix 6B and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in Appendix 6B.

12.2.4 Switches

Appendix 6C contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted normal and 4 hour emergency ratings. The summer normal and emergency switch ratings can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature (40°C or the summer maximum ambient temperature determined in Appendix 6A), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature (0°C or the winter maximum ambient temperature determined in Appendix 6A). Appendix 6C contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Appendix 6C allows for emergency ratings to be greater than normal ratings. This Criteria does not require the emergency rating to be greater than the normal rating.

12.2.5 Wave Traps

Appendix 6D contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a 40°C maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four-hour emergency rating that is also a function of the maximum ambient temperature. The newer epoxy encapsulated type does not have an emergency rating.

12.2.6 Current Transformers

Appendix 6E contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a 30°C average ambient temperature.

12.2.6.1 Separately Mounted Current Transformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings. Separately-mounted current transformers do not have emergency ratings.

12.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Appendix 6E. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an emergency rating for bushing current transformers.

12.2.7 Circuit Breakers

Appendix 6F contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and emergency ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Appendix 6F would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than doing that, this circuit rating criteria specifies that the nameplate rating shall be used for seasonal normal and emergency ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element in a circuit and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Appendix 6F to determine the circuit breakers seasonal normal and emergency rating.

12.2.8 Ratings of Series and Reactive Elements

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit. Shunt reactive elements (e.g., capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

12.2.9 Ratings of Energy Storage Devices

The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.

12.2.10 Circuit Rating Issues

12.2.10.1 Dynamic (Real Time) Ratings

The calculation of static thermal ratings specified in Section 12.2.2.6 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time. Consequently, a static rating may understate the thermal capacity of the circuit. For operation purposes, some members have elected to monitor the factors that affect circuit ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if transmission line ratings are changed dynamically, the required clearances shall still be met.

12.2.10.2 Non-Thermal Limitations

There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

12.2.10.3 Tie Lines

When a tie line exists between two member systems, use of this criteria shall result in a uniform circuit rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member shall follow this criteria to rate the circuit elements owned by them and shall coordinate the rating of the tie line with the non-member system such that it utilizes the lowest rating between the two systems.

12.2.10.4 Rating Inconsistencies

A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Members shall use good faith effort to amend their transmission line agreements to reflect the effects of new circuit ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission circuits in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

12.2.10.5 Damaged Equipment

There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

12.2.11 Reporting Requirements

Each member will administer this Criteria and will make available upon request the application of this Criteria for those facilities that impact another member (i.e. force them to curtail schedules due to line loadings, denies them access to transmission service or requires them to build new transmission facilities or pay opportunity costs to receive transmission service).

12.3 System Operating Limits (SOLs)

The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation of the Bulk Electric System (BES) within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings), Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits), Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability), and System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). SPP monitors and controls the BES using Flowgates and the NERC TLR process.

SPP also monitors numerous other BES facilities within its footprint and creates temporary flowgates when operating conditions reveal any additional limiting system configurations. Since SPP is utilizing these flowgates to ensure the system is operating within acceptable reliability criteria, these flowgate limits serve as the SPP System Operating Limits.

12.3.1 Methodology for Determination of Operating Horizon SOLs

- This methodology is applicable for developing SOLs used in the operating horizon.
- Based on results of system studies (as described below), SOLs are determined per the definition.
- SOLs shall not exceed Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc.
- Anticipated system topology, generation dispatch, and load levels are utilized daily via SPP member submission on OPS1 and NERC SDX for non-members.
- Pre-contingency and first contingency studies will be conducted to investigate thermal and voltage violations for current and next day.
- Voltage and angular stability issues are investigated off-line as deemed necessary by operator and engineer experience and engineering judgment.
- As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL violations may be produced. These guides may be temporary or permanent, depending whether the violation is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:
    1. Statement of type(s) of violations revealed by study (voltage/thermal/stability)
    2. Applicable dates

3. Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

- Identified SOLs are screened to compile a list of potential IROLs per the following criteria:
  1. Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored facility.
  2. Potential IROLs will also be investigated when a contingency analysis highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES facilities.

  The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in another BES facility being overloaded to greater than 120% of its SOL or three or more additional BES facilities with bus voltages in the area experiencing projected post-contingency voltages less than 90%, unless there are studies or system knowledge that the SOL is not an IROL.
- The IROL T_V is 30 minutes.
- Special Protection Schemes (SPS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability. The Transmission Owner shall provide the RC with the location and description of each SPS, and shall notify the RC when the schemes are enabled/disabled.

12.3.1.1 SOL Provisions

- In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.

- Following single contingencies as defined in (a) and (b) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and with their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

  a. Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.

  b. Loss of any generator, line, transformer, or shunt device without a Fault.

- In determining the system's response to a single Contingency, the following shall be acceptable:

  a. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

  b. Interruption of other network customers, only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or, if the real-time operating conditions are more adverse than anticipated in the corresponding studies, e.g., load greater than studied.

  c. System reconfiguration through manual or automatic control or protection actions.

- To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

12.3.1.2 System Modeling and Contingency Definition

- All offline models are based on the ERAG MMWG model of the Eastern Interconnect power system. The model includes all TOs within the SPP RC footprint.

- The model includes all non-radial facilities within the BES. Loads served over radial lines are typically modeled as aggregate at the delivery bus. Many systems are modeled in greater detail down to subtransmission level voltages (<69kV). This is typically true only when the subtransmission system is networked (non-radial). In a few cases distribution level voltages (26kV/13kV) are also modeled. Distribution capacitors can be modeled as aggregate at a load bus.
- The online model used by the SPP EMS application is constructed from data in the offline model (PSS/E).
- At a minimum the contingency list used in the operating horizon should include all non-radial BES transmission lines and transformers > 100kV and all generators rated 300MW and above. Additional contingencies will be included as provided by BA's and/or TOs within the RC footprint.

12.3.1.3 Methodology Distribution

SPP shall issue this methodology and any changes to the methodology, prior to the changes taking effect, to all the following:

- Adjacent RCs and each RC that has indicated it has a reliability-related need for the methodology
- Each PA and Transmission Planner that models any portion of the RC footprint
- Each TOP within the RC footprint.

12.3.1.4 Comments on Methodology

- If a recipient of the SOL methodology provides documented technical comments on the methodology, the RC will provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response will indicate whether a change will be made to the SOL methodology and, if no change will be made to the SOL methodology, the reason why.

12.3.2 Methodology for Determination of Planning Horizon SOLs

- This methodology is applicable for developing SOLs used in the planning horizon.

- Based on results of planning studies (as described below), SOLs are determined per the definition.

- SOLs shall not exceed applicable Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc.

- Anticipated system topology, generation dispatch, and load levels are based on the modeling data provided in the annual Loadflow Model Development process coordinated by the MDWG. Individual Transmission Owners may request development of additional models for SOL analysis as needed to evaluate regional transfer conditions which are not captured in existing MDWG models.

- Pre-contingency, first contingency and multiple contingency studies will be conducted to investigate thermal and voltage violations for all those future year loadflow models developed by the MDWG.

- Voltage and angular stability issues are studied in the annual Dynamic Stability models developed by the MDWG.

- As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL violations may be produced. These guides may be temporary or permanent, depending whether the violation is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:
    1. Statement of type(s) of violations revealed by study (voltage/thermal/stability)
    2. Applicable dates
    3. Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

- Identified SOLs are screened to compile a list of potential IROLs per the following criteria:
    1. Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored facility.

2. Potential IROLs will also be investigated when a contingency analysis highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES facilities.

The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in another BES facility being overloaded to greater than 120% of its SOL or three or more additional BES facilities with bus voltages in the area experiencing projected post contingency voltages less than 90%, unless there are studies or system knowledge that the SOL is not an IROL.

- The IROL T_V is 30 minutes.

- Special Protection Schemes (SPS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability. The Transmission Owner shall provide the RC with the location and description of each SPS, and shall notify the RC when the schemes are enabled/disabled.

12.3.2.1 SOL Provisions

- In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect future system conditions with all facilities operated in their normal operating condition.

- Following single contingencies as defined in (a) and (b) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

a. Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.

b. Loss of any generator, line, transformer, or shunt device without a Fault.

- In determining the system's response to a single Contingency starting with all facilities operated in their normal operating condition, the following shall be acceptable:

  a. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

  b. System reconfiguration through manual or automatic control or protection actions.

- To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- Starting with all facilities operated in their normal operating condition and following any of the multiple contingencies identified in Reliability standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all facilities shall be operating within their facility ratings and within their thermal, voltage and stability limits; and cascading or uncontrolled separation shall not occur.
- In determining the system's response to any of the multiple contingencies identified in Reliability standard TPL-003, in addition to the actions identified in (a) and (b) above, the following shall be acceptable:
  a. Planned or controlled interruption of electric supply to customers (load shedding) the planned removal from service of certain generators, and/or curtailment of contracted firm electric power transfers. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

12.3.2.2 System Modeling and Contingency Definition

- All planning models are based on the ERAG MMWG model of the Eastern Interconnect power system. The model includes all TOs within the SPP RC footprint. Updates shall be made to reflect the most accurate system configuration, generation, and load representation for each pertinent individual balancing authority area for the study period. The following guidelines for system representation in modeling shall be applied:

  a. Full loop representation is to be used with the entire Eastern Interconnect power system modeled. The model includes all non-radial facilities within the BES. Loads served over radial lines are typically modeled as aggregate at the delivery bus. Many systems are modeled in greater detail down to subtransmission level voltages (<69kV). This is typically true only when the subtransmission system is networked (nonradial). In a few cases distribution level voltages are also modeled. Distribution capacitors can be modeled as aggregate at a load bus.
  b. The study model will assume all facilities in their normal operating condition, with no planned outages, except those facilities normally operated in a de-energized condition.
  c. System transfer levels for major Eastern Interconnect paths should be agreed upon and listed. Additional transfer paths should be included as appropriate.
  d. Voltage profile and equipment loading will be within the ratings of the facilities and will be determined using existing criteria.
  e. The phase shifter methodology to be followed for all applicable phase shifters should be identified.
  f. Generation and load shedding may exceed the minimum requirement to ensure margin for system security.
  g. A MMWG model base case will be selected based on the generation dispatch, load level (peak/off-peak) for seasonal (i.e. winter, spring, summer, and/or fall) system conditions. The generation dispatch may vary due to wind, hydro or other conditions.
  h. Residential, commercial, and industrial load models, with constant power, current and impedance should be included as appropriate. Transient stability models shall represent voltage and frequency characteristics, either actual load models when available, or accepted industry models. Loads shall be modeled as

accurately as possible, including the appropriate load power factor. Margins provided to allow for load model uncertainty shall be explicitly stated.

- At a minimum the contingency list used in the planning horizon should include all non-radial BES transmission lines and transformers > 100kV and all generators rated 300MW and above. Additional contingencies will be included as provided by BA's and/or TOs within the RC footprint.

- Special Protection Schemes (SPS) All SPS required to obtain the Accepted Rating should be described in details and modeled as they will be applied in operation.

12.3.2.3 Methodology Distribution

SPP shall issue this methodology and any changes to the methodology, prior to the changes taking effect, to all the following:

- Adjacent Planning Coordinator and each Planning Coordinator that has indicated it has a reliability-related need for the methodology

- Each PA and Transmission Planner that models any portion of the RC footprint

- Each TOP within the RC footprint.

12.3.2.4 Comments on Methodology

- If a recipient of the SOL methodology provides documented technical comments on the methodology, the Planning Coordinator will provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response will indicate whether a change will be made to the SOL methodology and, if no change will be made to the SOL methodology, the reason why.

13.0 OPEN

14.0 OPEN

15.0 OPEN

4.0 EXAMPLE

Given: Plant site is 39°, 15‘ latitude; 94°, 58’ longitude.
Elevation is 750 feet.
Find: Generator rating conditions.

1. Determine the three nearest weather stations and temperatures from the ASHRAE Handbook.

Station	Latitude	Longitude	Elevation	Td	Tw
Kansas City, MO	39°, 07’	94°, 35’	791	99	75
Atchison, KS	39°, 34’	95°, 07’	945	96	77
Topeka, KS	39°, 04’	95°, 38’	877	99	75

2. Correct the temperatures to the plant elevation

Station	Elevation above Plant	Effect on Td	Effect on Tw	Corrected Td	Corrected Tw
Kansas City, MO	41	0.2	0.1	99.2	75.1
Atchison, KS	195	1	0.4	97	77.4
Topeka, KS	127	0.6	0.3	99.6	75.3

3. Using 39°, 00’; 94°, 00’ as the origin determine the relative location of each point A, B, and C from the plant P. To obtain the east-west dimensions, multiply the longitude minutes from 94°, 00’ by the cosine of plant latitude; cos (39.25) = 0.7744. Doing so, the following coordinates are obtained:

	North	West	Point
Plant	15	44.9	P
Kansas City, MO	7	27.1	A
Atchison, KS	34	51.9	B
Topeka, KS	4	75.9	C

4. Calculate the distance between P and points A, B, and C, and then temperatures at P.

$$D_{PA} = ((y_P - y_A)^2 + (x_P - x_A)^2)^{½} = 19.5$$
$$D_{PB} = ((y_P - y_B)^2 + (x_P - x_B)^2)^{½} = 20.2$$
$$D_{PC} = ((y_P - y_C)^2 + (x_P - x_C)^2)^{½} = 32.9$$

so,

$$T_i = \Sigma(T_i/D_i) \,/\, \Sigma(1/D_i)$$
$$T_d = (T_{dA}/D_{PA} + T_{dB}/D_{PB} + T_{dC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 98.46°F$$
$$T_w = (T_{wA}/D_{PA} + T_{wB}/D_{PB} + T_{wC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 76.01°F$$

5. The standard barometric pressure for the site is:

$$P_{SB} = 29.921 \text{ x } (1 - 6.8753 \text{ x } 0.000001 \text{ x Elevation})^{5.2559} = 29.12 \text{ inches Hg}$$

MAJOR DISTURBANCE REPORT

SYSTEM ____________________
REPORTED BY ____________________

SYSTEM AND/OR AREA AFFECTED____________________
CONTROLLED AREAS AFFECTED____________________
____
____

DATE AND TIME OF INITIAL DISTURBANCE
DATE AND TIME OF INITIAL SERVICE RESTORATION
NUMBER OF CUSTOMERS AFFECTED____________________

AMOUNT OF LOAD INVOLVED ____________________

INITIATING CAUSES____________________
____

GENERATORS AND TRANSMISSION LINES WHICH WERE LOST INCLUDING OUTAGE TIMES.
____
____
____

SYSTEM LOAD: PRE-DISTURBANCE____MW POST-DISTURBANCE____MW

SYSTEM GENERATION: PRE-DISTURBANCE____MW POST-DISTURBANCE____
MW

POWER TRANSFERS: PRE-DISTURBANCE_ MW (EXPORT OR IMPORT)
POST-DISTURBANCE_MW (EXPORT OR IMPORT)

CASCADING OUTAGE? YES___ NO___
INSTABILITY? YES___ NO___
UNDERFREQUENCY TRIPPING? YES___ NO___
ISLANDING? YES___ NO___

Appendix A- Ambient Temperature

1.0 Purpose

The purpose of this Appendix is to describe the methodology to be used when determining ambient temperature for circuit rating purposes. This methodology allows for the flexibility of computing ambient temperatures that are location specific and allows for the ease of using default values.

2.0 Types of Ambient Temperature

Maximum ambient temperatures are used when calculating seasonal ratings for overhead conductors, disconnect switches, circuit breakers and wave traps. Average ambient temperatures are used when calculating seasonal ratings for power transformers and current transformers.

2.1 Maximum Ambient Temperature

Circuit rating criteria specify the maximum temperature an overhead conductor, switch, circuit breaker, and wave trap may experience. As the ambient temperature increases, the temperature rise that produces the same maximum equipment temperature is reduced. The reduced temperature rise results in a reduced load carrying capability. Consequently, increases in the maximum ambient temperature does not alter the maximum temperature the equipment was designed to withstand, but it does reduce the current carrying capability for the same maximum equipment temperature.

Selection of the maximum ambient temperature used in rating transmission circuits involves trade-offs. If you select an ambient temperature that is the highest temperature ever recorded for your control area, you may be limiting the use of the transmission system on an ongoing basis for a temperature that has a very small likelihood of occurring. On the other hand, if you select an ambient temperature that is frequently exceeded, you put the transmission system at risk of operating equipment at temperatures in excess of design when it is carrying rated load.

This circuit rating criteria attempts to achieve a balance by specifying a method for determining the maximum ambient temperature that allows for full utilization of the transmission system without experiencing frequent violations of equipment design temperatures. When selecting a maximum ambient temperature for seasonal ratings, a system may choose to either compute a temperature based on local weather station data or may use a default value.

Switches, circuit breakers and wave traps have nameplate ratings based on a 40°C (104°F) maximum ambient temperature (if designed according to ANSI/IEEE standards). The 40°C shall be used as the summer default value for this equipment along with overhead conductors. A system that elects to use the summer default value shall utilize the nameplate rating. Those systems wanting to compute their own maximum ambient temperature shall use the procedure described in section 3.1 and must adjust the nameplate rating using the procedure described in the appropriate appendix for that piece of equipment. The winter default temperature is 10ƏC (50°F). Whether a system elects to use the winter default value or compute its own, it shall still need to determine winter ratings for overhead conductors, switches, circuit breakers and wave traps using the procedures described in the appropriate appendix (nameplate ratings apply for summer months only).

The maximum ambient temperature, whether based on a default value or a computed value, represents a ceiling or highest number that can be used for rating circuits. A system may rate their equipment at some lower temperature but cannot exceed the default value or the computed value. This allows systems that have historically computed their circuit ratings using an ambient temperature below the default value or the computed value to continue using this value for rating purposes.

However, for a system that has historically utilized an ambient temperature that exceeds both the default value and the computed value, it must lower the maximum ambient temperature it is using for rating purposes such that it equals either the default value or the computed value, whichever of the two the system elects to use.

2.2 Average Ambient Temperature

According to ANSI standards, both power transformers and current transformers are rated using average ambient temperature. The average temperature is calculated by averaging 24 consecutive hourly readings. The maximum daily temperature should not be more than 10^0C greater than the average temperature. Power transformers and current transformers both have nameplate ratings based on a 30°C (86°F) average ambient temperature. The 30°C shall be used as the summer default value for this equipment. Using the 30°C average ambient temperature allows for a maximum daily temperature of 40°C that is consistent with the summer default value used for other equipment. The winter default value is 0^0C (32°F). It allows a maximum daily temperature of 10^0C (50°F) for the winter months and is consistent with the winter default value used for other equipment. A system can elect to compute its own average temperature using the procedure described in Section 3.2. Using a computed average ambient temperature (either summer or winter) for power transformers shall require adjusting its nameplate rating. The default average ambient temperature value of the transformer has been used to determine its emergency rating and an acceptable loss of life. This circuit rating criteria uses the power transformer nameplate rating as a year-round rating (both summer and winter). Consequently, even though an average ambient temperature can be computed, using it to adjust transformer nameplate ratings will affect emergency ratings and is not recommended.

Similar to the maximum ambient temperature the default or computed average ambient temperature represents a ceiling or highest number that can be used for rating power transformers and current transformers. A system can use an average ambient temperature that is less than the default or computed amount but cannot use one that exceeds the default or computed amount.

3.0 Procedure for Computing Ambient Temperature

Systems have the option of either using default values or computing maximum ambient temperature and average ambient temperature. This section describes the procedure for computing ambient temperatures. In general, it is intended that a system would use this procedure a single time and once they have determined their maximum and average ambient temperature, these amounts would remain constant for all future circuit ratings.

When computing ambient temperature, systems shall use temperature readings from nearest weather stations. Some control areas span a large area that may encompass several weather stations. If a large enough geographic area is involved, it is also possible that the computed ambient temperature could be significantly higher at one or more of the weather stations. For these control areas, they may choose to either divide the control area into sections using the highest ambient temperature readings from weather stations within the section or, to maintain consistent ratings throughout the control area, they may choose to use the highest ambient temperature of all weather stations within the control area.

A system is not required to use the same weather station when computing summer and winter ambient temperature. However, the weather station selected must be within the control area or, if there are no weather stations within the control area, it must be the nearest weather station to the control area. Once a weather station is selected for either summer readings or winter readings, all or the readings for each season must come from the same weather station.

3.1 Maximum Ambient Temperature

The summer maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the summer months (June through September). The summer average shall be computed each year for the past five years and the highest average shall be selected as the summer maximum ambient temperature.

The winter maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the winter months (December through February). The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter maximum ambient temperature.

3.2 Average Ambient Temperature

The summer average ambient temperature is determined by averaging the 24 consecutive hourly temperature readings from the nearest weather station for the summer months (June through September). This summer average shall be computed using an average of the five hottest days during the four months. It shall be computed for each year for the past five years and the highest average shall be selected as the summer average ambient temperature.

The winter average ambient temperature shall be computed in a similar manner but shall use the average of the hottest 24 consecutive hourly temperature readings from the nearest weather station for the winter months (December through February). The winter months are defined as the three consecutive months that overlap the end of the year. The winter average shall be computed similar to the summer average using an average of the five hottest days during the three months. The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter average ambient temperature.

Appendix B - Underground Cables

The determination of the ampacity of an underground cable is dependent upon the maximum temperature the conductor can withstand without causing significant thermal deterioration. This temperature can refer to steady-state, emergency or short-circuit conditions. It is the specification of this temperature limit that limits the cable's ampacity. The Neher-McGrath procedure is the basis of steady-state ampacity calculations. This current rating can be calculated by solving the thermal equivalent of Ohm's Law and in its

$$I = \sqrt{\frac{T_c - T_a - \Delta T_d}{R_{el} \times R_{th}}} \times 10^{3} \ A$$

basic form is shown by the equation below:

where

T_c =allowable conductor temperature, ^{o}C
T_a =ambient earth temperature, ^{o}C
ΔT_d =temperature rise due to dielectric loss, ^{o}C
R_{el} = electrical resistance, $\mu\Omega / ft$
R_{th} = thermal resistance, TOF (thermal ohm-feet)

The basic thermal circuit consists of cable heat (in watts) that corresponds to electrical current (in amperes), thermal resistance (in thermal ohm-feet) that corresponds to electrical resistance (in ohms) and temperature drop (in C^{o}) that corresponds to voltage drop (in volts). The electrical analogy and thermal circuit are shown below.

Simply stated, the ampacity calculation consists of the calculation of losses and the temperature rise due to those losses flowing through the various resistances. The procedure can be summarized as follows:

1. Determine the cable construction and conductor size of the existing cable.

2. Refer to AEIC specifications for the maximum allowable conductor temperature for this cable. Determine the temperature rise over ambient earth temperature that will give this value.

3. Calculate dielectric loss.

4. Calculate the electrical resistances of each current-carrying component of the system for the expected operating temperature of that component.

5. Calculate the thermal resistance of each component of the system, including the earth.

6. Calculate the temperature rise due to dielectric loss flowing through the thermal resistances, and subtract that number from the total available temperature rise.

7. Solve the Ohm's law equivalent circuit to determine the ampacity that achieves the allowable temperature rise.

The total thermal circuit for a self-cooled buried transmission cable is shown as an electrical analog in figure below.

The following equations summarize the calculation of the allowable current.

Calculating Allowable Current

$$I = \sqrt{\frac{\Delta.T}{\sum Rac*Rth}}\ (kA)$$

Temperature Rise Due to Dielectric Losses

for pipe-type cables,

$$\Delta T_d = W_d \left(\frac{1}{2}\overline{R_i} + \overline{R_{sd}} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcor}} \right),\ (C^\circ)$$

for single-conductor cables,

$$\Delta T_d = W_d \left(\frac{1}{2}\overline{R_i} + \overline{R_j} + \overline{R_{sd}} + \overline{R_d} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcor}} \right),\ (C^\circ)$$

where

R; = insulation thermal resistance (TOF)
Ri = Rsd jacket thermal resistance (TOF)
= thermal resistance between cable surface and surrounding enclosure (TOF)
Rd = Rpc duct thermal resistance (TOF)
= Rde' = pipe-covering thermal resistance (TOF)
Rdcorr = earth thermal resistance for dielectric losses (TOF)
correction factor for controlled backfill or concrete-encased duct (TOF)

Available Temperature Rise for Current-Dependent Losses

$$\Delta T_c = T_c - T_a - \Delta T_d - \Delta T_{int},\ (C^\circ)$$

where

Tc = allowable conductor temperature (C^o)
T_a = ambient earth temperature (C^o

ΔT_d = conductor temperature rise due to dielectric and charging-current losses (C^o}

ΔTint = temperature rise due to extraneous heat source (C^o)

Summation of Electrical and Thermal Resistances
for pipe-type cables:

$$\sum R_{ac}\overline{R_{th}}°C/kA^2 \quad R_{acc}R_i + R_{acs}R_{sd} + R_{acp}R_{pc} + R_{acp}R_{dx} + R_{acp}R_{earth} + R_{acp}R_{mut} + R_{acp}R_{ccorr}$$

for single-conductor cables:

$$\sum R_{ac}\overline{R_{th}}°C/kA^2 = R_{acc}\overline{R_i} + R_{acs}\overline{R_j} + R_{acs}\overline{R_{sd}} + R_{acs}\overline{R_d} + R_{acs}\overline{R_{dx}} + R_{acs}\overline{R_{earth}} + R_{acs}\overline{R_{mut}} + R_{acs}\overline{R_{ccorr}}$$

where

De	=	diameter at start of the earth or external portion of the thermal circuit (in.)
D_x	=	fictitious diameter at which the effect of loss factor begins (in.)
Race	=	conductor ac resistance (µQ/ft)
Racp	=	ac resistance at pipe (µQ/ft)
Racs	=	ac resistance at shield (µQ/ft)
Rcccrr	=	correction factor, current-dependent losses (TOF)
Rdx	=	thermal resistance from De to diameter D_x (TOF)
Rearth	=	thermal resistance from Dx to ambient earth (TOF)
Rmut	=	mutual-heating earth thermal resistance term (TOF)

For further and more detailed information see the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity. The above equations apply to buried cable installations. For above ground installation (e.g. bridge crossings, tunnel installations or riser sections), there are three main differences. First, solar radiation provides heat input. The Neher-McGrath method does not consider this factor. Second, heat transfer by conduction is negligible. And third, heat transfer for cables in air is by free or forced convection and by radiation. Generally, the ampacity of an identical cable circuit installed in the air will be greater than that for a buried cable circuit. The equations will not be presented here and may be found in the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity.

Under emergency conditions it may become necessary to exceed the normal temperature limit of the cable. A new cable rating may be calculated by substituting the new temperature limit into the equations seen above. The key to calculating the emergency rating will be establishing the allowable temperature increase. One must be careful not to overestimate the ability of the cable to withstand higher temperatures as well as not to underestimate the loss of life that will occur with operation above normal temperatures.

APPENDIX 6.C

APPENDIX 6.C Switches

Remove Year

Switch ratings are discussed in ANSI/IEEE C37.37 **Loading Guide for AC High-Voltage Air Switches (in excess of 1000 volts)** and in ANSI/IEEE C37.37a- IEEE Loading Guide for AC High-Voltage Air Switches Under Emergency Conditions. In general, the allowable continuous current of a switch is based on the allowable maximum temperature of the switch parts and is affected by the ambient temperature. Provisions are made for loading the switches under emergency conditions in the above referenced ANSI/IEEE Standard C37.37a–Therefore, both Normal and Four-Hour Emergency circuit ratings will be developed based upon the allowable continuous current capability rating of the switch. These ratings will be treated as the loading limits for normal and emergency conditions.

A switch is made up of a number of different switch parts, which are classified and grouped in accordance with their material and function into switch part classes, each of which is given a switch part class designation of the form xO#. Examples of the switch part class designations are A01, OO6, J010, N01, and W09. The loadability factors of each switch part class, as a function of ambient temperature, are represented by a curve. Tabular representations of these curves for normal continuous load conditions are contained in Table C- 3 for non-enclosed indoor and outdoor switches and in Table C- 4 for enclosed indoor and outdoor switches. Tabular representations of these curves for emergency load conditions with a maximum emergency loading duration of four hours are contained in Table C - 5 for non-enclosed
indoor and outdoor switches and in Table C- 6 for enclosed indoor and outdoor switches.

Remove Year

The Allowable Continuous Current Class (ACCC) designation of a switch is a code which identifies a composite loadability curve made up from the limiting switch part classes. In most instances, the ACCC designation will be contained on the switch's nameplate. However, air switches designed in accordance with ANSI C37.30- and earlier may not have an ACCC designation on the nameplate. Such non-- enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 40°C, indicative of an allowable maximum temperature of 70°C, are assigned an ACCC designation of AO1. In like manner, such enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 55°C, indicative of an allowable maximum temperature of 85°C, are assigned an ACCC designation of N01.

ACCC designations were developed such that the first character, x, designates that the specific normal loadability factors for that class are represented by Curve x when the ambient is between 60°C and 25°C.; the second character in the ACCC designation, O, represents the specific normal loadability factor for that class at 25°C. (All curves intersect at O and have a loadability factor of 1.22 at 25°C ambient); and the third character, #, designates that the specific normal loadability factors for that class are represented by Curve# when the ambient is between 25°C and -30°C.

In some instances, a composite curve must be developed due to the fact that the switch is constructed such that some parts of the switch have different switch part class designations than other parts of the switch. In this situation, the switch's ACCC designation will differ from the standard ACCC designations listed in the tables and instead will be a composite of two of the standard ACCC designations. An example of this would be a switch having a designation of OO6, signifying that the switch is constructed using some parts having the switch part class designations of OO4 and some parts having the switch part class designations of F06.

Based upon the ACCC designation of a switch, a normal loadability factor curve can be developed for the switch in the following manner.

1. Using Table C - 2 for non-enclosed indoor and outdoor switches or Table C- 3 for enclosed indoor and outdoor switches, the appropriate values for Curve x, Curve 0, and Curve# are determined based upon the switch's ACCC designation. These curves will be joined together to form a composite normal loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2. The normal loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the normal loadability factor for a specific temperature, which is not represented in the composite table, is desired, the normal loadability factor may be calculated by interpolating between the nearest known values. In no case shall the normal loadability factor exceed 2.00.

3. The Allowable Continuous Current Capability of a switch at a given ambient temperature is equal to the normal loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Allowable Continuous Current Capability of a switch at a given ambient temperature will be treated as the normal ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

(a) Develop a loadability factor table for a 1200-amp non-enclosed switch with ACCC designation D06.

(b) Using this table, determine the Allowable Continuous Current Capability of this switch at an ambient temperature of 0°C.

Solution:

(a) The normal loadability factor table, Table C - 1, was created using Table C - 3 for a non-enclosed switch with ACCC designation 006. For the temperatures from 25°C to 60°C, the loadability factors from Curve D were used. The standard loadability factor of 1.22 was used for an ambient of 25°C. The loadability factors from Curve 6 were used for the temperatures from 20°C to -30°C.

(b) Based upon Table C- 1, the Allowable Continuous Current Capability of a 1200-A non-enclosed switch designated D06 at 0°C would be:

Loadability Factor @ 0°C * Rated Current

or

1.41 * 1200 amps= 1692 amps

For operation at 0°C, the Normal rating of switch would be 1692 amps.

Maximum Ambient Temperature	Loadability Factor	Curve Used
60°C	0.84	Curve D
50°C	0.96	
40°C	1.07	
30°C	1.18	
25°C	1.22	Standard
20°C	1.27	Curve 6
10°C	1.34	
0°C	1.41	
-10°C	1.47	
-20°C	1.54	
-30°C	1.60	

Table C -1: Normal Loadability Factors for a Type 006 Switch

The Four-Hour Emergency Load Current carrying capability of a switch can be determined based upon the switch's ACCC designation. A four-hour emergency loadability factor curve can be developed for the switch in the following manner.

1. Using Table C- 5 for non-enclosed indoor and outdoor switches or Table C- 6 for enclosed indoor and outdoor switches, the appropriate emergency loadability factors are determined based upon the switch's ACCC designation. In developing the composite curve, the emergency loadability factor curves of the two standard ACCC designations must be examined and the most limiting loadability factor at each ambient temperature will be used to form a composite emergency loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2. The emergency loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the emergency loadability factor for a specific temperature, which is not represented in the composite table, is desired, the emergency loadability factor may be calculated by interpolating between the nearest known values. In no case shall the emergency loadability factor exceed 2.00.

3. The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature is equal to the emergency loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature will be treated as the Emergency ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

(a) Develop an emergency loadability factor table for a 1200-amp non-enclosed switch with ACCC designation 006.

(b) Using this table, determine the Four-Hour Emergency Load Current Capability of this switch at an ambient temperature of 0°C..

Solution:

(a) The emergency loadability factor table, Table C- 2, was created using Table C- 5 for a non-enclosed switch with ACCC designation D06. The composite curve was developed by examining the emergency loadability curves for switches having ACCC designations of 004 and F06. At each of the ambient temperatures, the most limiting loadability factor was chosen from the D04 and F06 curves to form the composite curve.

(b) Based upon Table C- 3, the Four-Hour Emergency Load Current Capability of a 1200-A non-enclosed switch designated D06 at 0°C would be:

Emergency Loadability Factor@ 0°C * Rated Current

or

1.54 * 1200 amps = 1848 amps

For operation at 0°C, the Four-Hour Emergency ratings of the switch would be 1848 amps.

Maximum Ambient Temperature	Loadability Factor Curve 004	Loadability Factor Curve F06	Composite Curve for a 006 Switch
60°C	1.08	1.11	1.08
50°C	1.18	1.19	1.18
40°C	1.28	1.27	1.27
35°C	1.32	1.30	1.30
30°C	1.36	1.34	1.34
25°C	1.41	1.37	1.37
20°C	1.45	1.41	1.41
10°C	1.53	1.47	1.47
0°C	1.60	1.54	1.54
-10°C	1.67	1.60	1.60
-20°C	1.74	1.65	1.65
-30°C	1.81	1.71	1.71

Table C- 2: Four-Hour Emergency Loadabillty Factors for a Type D06 Switch

Maximum Ambient Temperature		ACCC Designation																					
		A01		B02		C03		DO4		E05		F06		GO7		H08		109		J010		K011	
°C	°F																						
60	140	0.58	Curve A	0.67	Curve B	0.74	Curve C	0.84	Curve D	0.86	Curve E	0.92	Curve F	0.94	Curve G	0.98	Curve H	1.03	Curve I	1.06	Curve J	1.10	Curve K
50	122	0.82		0.87		0.90		0.96		0.96		1.02		1.03		1.05		1.09		1.12		1.14	
40	104	1.00		1.03		1.04		1.07		1.06		1.11		1.11		1.13		1.15		1.16		1.16	
30	66	1.15		1.17		1.17		1.16		1.16		1.19		1.19		1.20		1.20		1 20		1.21	
25	77	1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	66	1.29	Curve 1	1.29	Curve 2	1.26	Curve 3	1.28	Curve 4	1.27	Curve 5	1.27	Curve 6	1.27	Curve 7	1.26	Curve 6	1.25	Curve 9	1.24	Curve 10	1.24	Curve 11
10	50	1.41		1.40		1.36		1.36		1.34		1.34		1.32		1.32		1.30		1.26		1.28	
0	32	1.53		1.51		1.47		1.45		1.42		1.41		1.39		1.38		1.34		1.32		1.31	
-10	14	1.63		1.60		1.56		1.52		1.49		1.47		1.45		1.44		1.39		1.36		1.34	
-20	-4	1.73		1.70		1.64		1.60		1.56		1.54		1.51		1.49		1.44		1.40		1.37	
-30	-22	1.63		1.78		1.72		1.67		1.63		1.60		1.57		1.54		1.46		1.44		1.40	

Table C 3: Non-enclosed Indoor and Outdoor Switches
Switch Part Normal Loadability Factors (LF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation																					
		Q0 3 3		P0 2 2		N01		R04		S05		T06		U07		V08		W09		X010		Y011	
°C	°F																						
60	140	0.00	Curve Q	0.45	Curve P	0.58	Curve N	0.67	Curve R	0.74	Curve S	0.84	Curve T	0.86	Curve U	0.92	Curve V	1.00	Curve W	1.05	Curve X	1.09	Curve y
50	122	0.71		0.77		0.82		0.87		0.90		0.96		0.98		1.02		1.07		1.10		1.13	
40	104	1.00		1.00		1.00		1.03		1.04		1.08		1.08		1.11		1.13		1.15		1.17	
30	86	1.22	Curve 3	1.18	Curve 2	1.15		1.16		1.16		1.18		1.18		1.19		1.20		1.20		1.20	
25	77	1.32		1.26		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	68	1.41		1.34		1.29	Curve 1	1.29	Curve 4	1.28	Curve 5	1.28	Curve 6	1.26	Curve 7	1.26	Curve 8	1.25	Curve 9	1.25	Curve 10	1.24	Curve 11
10	50	1.58		148		1.41		1.40		1.38		1.36		1.35		1.34		1.31		1.29		1.28	
0	32	1.73		1.61		1.53		1.51		1.47		1.45		1.42		1.41		1.36		1.34		1.31	
-10	14	1.87		1.73		1.63		1.61		1.56		1.53		1.50		1.47		1.41		1.40		1.35	
-20	-4	2.00		1.84		1.73		1.70		1.64		1.60		1.56		1.54		1.46		1.42		1.38	
-30	-22	2.00		1.95		1.83		1.78		1.72		1.67		1.63		1.60		1.51		1.46		1.41	

Table C - 4: Enclosed Indoor and Outdoor Switches
Switch Part Normal Loadability Factors {LF} for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		A01	802	C03	D04	E05	F06	GO7	HOB	I09	J010	K011
^{0}C	^{0}F											
60	140	1.00	1.03	1.04	1.08	1.08	1.11	1.11	1.13	1.15	1.16	1.18
50	122	1.15	1.17	1.16	1.18	1.18	1.19	1.18	1.20	1.20	1.20	1.21
40	104	1.29	1.29	1.27	1.28	1.26	1.27	1.26	1.26	1.25	1.24	1.24
35	95	1.35	1.35	1.33	1.32	1.30	1.30	1.29	1.29	1.27	1.26	1.26
30	86	1.41	1.40	1.38	1.36	1.34	1.34	1.32	1.32	1.30	1.28	1.28
25	77	1.47	1.46	1.42	1.41	1.38	1.37	1.36	1.35	1.32	1.30	1.29
20	68	1.53	1.51	1.47	1.45	1.42	1.41	1.39	1.38	1.35	1.32	1.31
10	50	1.63	1.61	1.56	1.53	1.49	1.47	1.45	1.44	1.39	1.36	1.34
0	32	1.73	1.70	1.64	1.60	1.56	1.54	1.51	1.49	1.44	1.40	1.37
-10	14	1.83	1.78	1.72	1.67	1.63	1.60	1.57	1.54	1.48	1.44	1.40
-20	-4	1.92	1.87	1.80	1.74	1.69	1.65	1.62	1.59	1.52	1.47	1.43
-30	-22	2.00	1.95	1.87	1.80	1.76	1.71	1.68	1.64	1.56	1.51	1.45

Table C - 5: Non-enclosed Indoor and Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		Q03	P02	N01	R04	S05	T06	U07	V08	W09	X010	YO11
^0C	^0F											
60	140	1.00	1.00	1.00	1.03	1.04	1.08	1.08	1.11	1.13	1.15	1.17
50	122	1.22	1.18	1.15	1.17	1.16	1.18	1.18	1.19	1.20	1.20	1.21
40	104	1.41	1.34	1.29	1.29	1.27	1.28	1.26	1.27	1.25	1.25	1.24
35	95	1.50	1.41	1.35	1.35	1.33	1.32	1.30	1.30	1.28	1.27	1.26
30	86	1.58	1.48	1.41	1.40	1.38	1.36	1.34	1.34	1.31	1.29	1.28
25	77	1.66	1.55	1.47	1.46	1.42	1.41	1.38	1.37	1.34	1.31	1.30
20	68	1.73	1.61	1.53	1.51	1.47	1.45	1.42	1.41	1.36	1.33	1.31
10	50	1.87	1.73	1.63	1.61	1.56	1.53	1.49	1.47	1.41	1.38	1.35
0	32	2.00	1.84	1.73	1.70	1.64	1.60	1.56	1.54	1.46	1.42	1.38
-10	14	2.00	1.95	1.83	1.78	1.72	1.67	1.63	1.60	1.51	1.46	1.41
-20	-4	2.00	2.00	1.92	1.87	1.80	1.74	1.69	1.65	1.56	1.50	1.44
-30	-22	2.00	2.00	2.00	1.95	1.87	1.80	1.76	1.71	1.60	1.54	1.47

Table C-6: Enclosed Indoor and Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

APPENDIX D - Wave Traps

Wave trap ratings are discussed in several sources. The ratings for the older wave traps in which the main coil is designed as a single-phase, air-cored inductor of the dry type are discussed in ANSI C93.3-1981, **Requirements for Power-Line Carrier Line Traps** and in Westinghouse Electric's Curve No. 511545 (Copy included in this Appendix). The ratings of the newer type of wave traps consisting of a coil of wire encapsulated in an epoxy resin are not covered in an ANSI/IEEE standard. The ratings for this type of wave trap were developed based upon guidelines supplied by the manufacturer, Trench Electric, (Copy included in this Appendix). In general, the rated continuous current for wave traps is based on the maximum permissible temperature rise limitations of the wave trap when it is carrying rated current at an ambient temperature of 40°C. The total temperature of the wave trap under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature rise limitation is not exceeded.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of both types of wave traps. These seasonal ratings will be based on the nameplate rating of the wave trap with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The ambient-compensated normal loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D- 1 and were obtained from Westinghouse Electric's Curve No. 511545. The ambient-compensated loadability factors for Epoxy-Encapsulated Inductor wave traps were developed from Trench Electric's loadability curves and are given in Table D- 2. To determine the normal seasonal circuit rating, simply multiply the wave trap's nameplate rating by the appropriate normal loadability factor. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Normal life expectancy will occur with a wave trap operated at or below its ambient-compensated normal current rating. Any value of currents in excess of the ambient-compensated normal current ratings may cause the designed temperature rise to be exceeded and may shorten the life expectancy of the wave trap. For wave traps utilizing an air-cored inductor, an acceptable level of emergency overload current has been determined and is specified in ANSI Standard C93.3-1981, **Requirements for Power-Line Carrier Line Traps.** Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of wave traps utilizing an air-cored inductor. These seasonal ratings will be based on the Four-Hour Emergency Overload Current-Carrying capability of the wave trap with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The wave traps may be loaded to this emergency level for a maximum of four hours per cycle. Before an emergency load cycle, the wave trap loading must be at or below the normal seasonal loading level for at least two hours.

The emergency seasonal circuit rating can be developed by simply multiplying the wave trap's nameplate rating by the appropriate emergency loadability factor. The ambient-compensated emergency loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D- 1 and were obtained from ANSI Standard C93.3-1981, **Requirements for Power-Line Carrier Line Traps.** Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Average Ambient Air Temperature	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	1.10
20°C	1.05	1.15
0^0C	1.10	1.20
-20°C	1.10	1.25

Table D- 1: Loadab1hty Factors for Dry-Type A1r-Cored Inductor Wave Traps

Average Ambient Air TemperaOure	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	N/A
20°C	1.13	N/A
0^0C	1.25	N/A
-20°C	1.36	N/A

Table D - 2: Loadability Factors for Epoxy-Encapsulated Inductor Wave Traps

Trench Electric, the manufacturer of the newer type of wave traps which consist of a coil of wire encapsulated in an epoxy resin, has stated that no overload capability is available on this type of wave trap. For this reason, no separate emergency rating will be assigned to this type of wave trap and the ambient-compensated current rating will be used for both the circuit's normal and emergency ratings.

July 16, 1985

Westinghouse Electric Corporation

Subject: Line Trap Loadings

Attached is one copy of the Appendix to ANSI Standard C93.3-1981 titled "Guide for Emergency Overload Current Capability of Line Traps".

This guide is current and, all Westinghouse traps built since 1970 conforms to the overload capability designated therein.

The Curve No. 511545 supplied applies to Westinghouse Line Traps built prior to 1970. Note that the overload capability of traps 2000 amperes and below on this curve are the same as that specified in the Standard. The larger traps were modified in design in order to conform to the Standard requirement.

July 25, 1985

Trench Electric

Attached are three copies of the overload current U.S. temperature curves. General Electric did not send any such information when we purchased their Line Trap division but the curves should be approximately the same.

APPENDIX E - Current Transformers

Current transformer ratings are discussed in ANSI/IEEE C57.13 **IEEE Standard Requirements for Instrument Transformers** and in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers**" (Copy included in this Appendix). In general, the rated continuous current for current transformers is based on the maximum permissible temperature limitations of the various parts of the current transformer when it is carrying rated current at a 24-hour average ambient temperature of 30°C (with a maximum hourly temperature of 40°C). The total temperature of these parts under service conditions depends both on the actual load current, the actual average ambient temperature, and the service environment of the current transformer. Depending on the environment, it is, therefore, possible to operate at a current higher than rated continuous current when the average ambient temperature is less than 30 °C, provided that the allowable total temperature limit is not exceeded. Similarly, when the average ambient temperature is greater than 30°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

The environment in which a current transformer operates has a large effect on the current-carrying capability of the current transformer. Separately mounted current transformers have been assigned rated primary and secondary currents and continuous-thermal-current rating factors by the manufacturer. Separately mounted current transformers are designed to meet these characteristics by the independent control of such parameters as: current density in the primary and secondary windings, geometry, area of radiating surfaces, and heat transfer characteristics. Permissible loading as a function of ambient temperatures and continuous-thermal-current rating factors, and permissible overloading under emergency conditions, is covered in **ANSI/IEEE C57.13 IEEE Standard Requirements for Instrument Transformers.**

Bushing current transformers mounted in power circuit breakers and power transformers differ from separately mounted current transformers in that the design parameters cannot be independently controlled since they are restricted by the characteristics of the power apparatus in which they are mounted. Bushing current transformers, when attached to various power apparatus, are subjected to wide variations in their environmental ambient temperature. This variation is dependent upon the thermal characteristics of the power apparatus and the relative current loading with respect to the rated current of the power apparatus and its bushing current transformer. For this reason, continuous-thermal-current rating factors are not typically calculated by the manufacturer for bushing current transformers. Instead, the continuous-thermal-current rating factors must be determined for each application. Permissible loading and permissible overloading of bushing current transformers is covered in Westinghouse Electric's technical paper titled "**Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers".**

Rating Separately Mounted Current Transformers: The maximum continuous-thermal-current ratings for separately-mounted current transformers designed for 55°C temperature rise above 30°C average ambient air temperature will vary according to actual ambient cooling air temperature. The adjusted continuous current ratings will be based on three items:

1. The nameplate primary and secondary current ratings at the ratio setting being used.

2. The average cooling air temperature at which the rating is being calculated. Note: The maximum cooling air temperature must not exceed the average cooling air temperature by more than 10°C.

3. The ambient-adjusted Continuous-Thermal-Current rating factor from Table E - 1. The value used from this table is based upon the nameplate Continuous-Thermal-Current rating factor of the current transformer and the average ambient air temperature.

Average Cooling Temperature (°C)	Nameplate Continuous-Thermal-Current Rating Factor					
	1.00	1.33	1.50	2.00	3.00	4.00
60°C	0.65	0.85	1.00	1.35	2.00	2.70
50°C	0.80	1.05	1.20	1.60	2.40	3.20
40°C	0.90	1.20	1.35	1.80	2.70	3.65
30°C	1.00	1.33	1.50	2.00	3.00	4.00
20°C	1.05	1.45	1.65	2.20	3.30	4.35
10°C	1.20	1.55	1.75	2.35	3.50	4.70
0°C	1.30	1.65	1.85	2.45	3.70	5.00

Table E-1: Ambient-Adjusted Continuous-Thermal-Current Rating Factors

The ambient-adjusted continuous-thermal-current rating of a separately-mounted current transformer is equal to the ambient adjusted continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified. According to ANSI/IEEE C57.13-1978, **IEEE Standard Requirements for Instrument Transformers**, no overload capability is available on separately-mounted current transformers. For this reason, normal rating of the separately-mounted current transformer will be used for both the normal seasonal circuit rating and the emergency seasonal circuit rating.

Example: The following example should serve to clarify this process:

Problem:

(a) Determine the summer seasonal normal and emergency ratings for a separately-mounted current Transformer operating on a 2000:5 amp ratio with a nameplate Continuous-Thermal-Current rating of 1.50. Assume the average ambient air temperature is 30°C with a maximum temperature of 40°C for the summer period.

(b) Determine the winter seasonal normal and emergency ratings for this same separately-mounted current transformer assuming an average ambient air temperature of 0°C with a maximum temperature of 10°C for the winter period.

Solution

(a) From Table E - 1, the 30°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.50 (They are the same due to the fact that the nameplate C-T-C rating factor is developed at an average ambient of 30°C). The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 30°C • Rated Primary Current of CT Ratio

or

1.50 • 2000 amps = 3000 amps

For operation at 30°C, both the Summer Normal and Emergency ratings of current transformer would be 3000 amps. **Note:** When the primary current is 3000 amps, the secondary current would be 7.5 amps due to the 2000:5 ratio used in the current transformer.

(b) From Table E - 1, the 0^0C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.85. The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 0^0C *Rated Primary Current of CT Ratio

or

1.85 * 2000 amps = 3700 amps

For operation at 0°C, both the Winter Normal and Emergency ratings of current transformer would be 3700 amps. **Note:** When the primary current is 3700 amps, the secondary current would be 9.25 amps due to the 2000:5 ratio used in the current transformer.

Rating Bushing Current Transformers Mounted in Power Apparatus: The continuous current rating of current transformers mounted in power circuit breakers or power transformers is determined as follows:

1. When the bushing current transformer ratio being used has the same primary current rating as the breaker continuous current rating or the power transformer rated current, the continuous current rating factor of the current transformer is 1.0 (unity).

2. When the primary current rating of the ratio being used on the current transformer is greater than the continuous current rating of the breaker or greater than the power transformer rated current, then the maximum load current is limited by the breaker or power transformer rating, which ever is applicable.

3. When the primary current rating of the ratio being used is Jess than the continuous current rating of the breaker or the power transformer rated current, then the maximum load current is limited by the continuous thermal current rating of the current transformer when operating on that ratio. Under these conditions, the temperature rises of the current transformer and the power apparatus would be lower, and therefore, the current transformer can be operated at a continuous thermal rating factor greater than 1.0. In this situation, the permissible continuous-thermal-current rating factor is calculated based upon constant maximum power dissipation, using the following equation:

$$R.F. = \left[\frac{I_{pa}}{I_{ct}}\right]^{1/2}$$

where

R.F. =Continuous-thermal-current rating factor

I_{pa} = Power apparatus continuous current rating (amps)

I_{ct} = Primary current rating of bushing current transformer ratio used (amps)

The results calculated from this equation should be so limited that the maximum rating factor does not exceed 2.0 and that the continuous current rating of the breaker or the rated current of the power transformer is not exceeded.

Note: The situation, in which the primary current rating of the current transformer ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, is an unusual case and should be viewed as the exception rather than the rule.

The normal rating of a bushing current transformer is equal to the continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified.

Some short-term emergency overload capability is typically available on bushing current transformers mounted on power circuit breakers and power transformers. However, when utilizing this emergency overload capability, care must be taken to coordinate the loading limit of the current transformer with the overall application limitations of the other equipment affected by the current transformer loading. Particular care should be taken to avoid exceeding the maximum metering capablity of metering equipment attached to the current transformer secondary.

APPENDIX 6.F

APPENDIX F - Circuit Breakers

Remove Year

Circuit breaker ratings are discussed in ANSI/IEEE C37.010· 1EEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis and in ANSI/IEEE C37.010b–IEEE Standard for Emergency Load Current-Carrying Capability. These standards discuss the development of ratings for circuit breakers from the standpoint of the manufacturers. From a practical standpoint. the application of the methods discussed in these standards to circuit breakers in operation will be very difficult. due to the fact that this application would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Therefore, it is recommended that for any circuit breakers which do not limit flows on the transmission system, the nameplate rated continuous current be used as the circuit breaker's normal and emergency circuit ratings. For circuit breakers which limit flows on the transmission system, the manufacturer could be consulted and ambient-compensated normal and emergency ratings could be developed for the circuit breaker using the methods described in the ANSI/IEEE Standards. These methods are described in the remainder of this Appendix.

In general, the rated continuous current for circuit breakers is based on the maximum permissible temperature limitations of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The total temperature of these parts under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature limit is not exceeded. Similarly, when the ambient temperature is greater than 40°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the nameplate rating of the circuit breaker with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The seasonal loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers. (See other appropriate appendices to determine limitations on the other equipment.) For circuit breakers used in metal-clad switchgear, no seasonal ratings will be calculated. Instead, the loading limit shall be coordinated with the overall application limitations of the switchgear.

The seasonal normal circuit breaker ratings can be determined in the following manner:

1. A circuit breaker's rated continuous current is based on the maximum permissible total temperature limitations, $\emptyset_{max}$ and $\emptyset_r$, of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The constructional features of a circuit breaker dictate the appropriate values of $\emptyset_{max}$ and $\emptyset_r$ to be used in the calculation of ambient-compensated ratings. The major components of a circuit breaker have several different temperature limitations which are shown in Table F - 1.
   In order that none of these temperature limitations be exceeded when the load current is Adjusted to the value permitted by the actual ambient temperature, the values of $\emptyset_{max}$ and $\emptyset_r$ should be determined as follows:

   (a) If the actual temperature is Jess than 40°C, the applicable component with the highest specified values of allowable temperature limitations should be used for determining $\emptyset_{max}$ and $\emptyset_r$.

   (b) If the actual temperature is greater than 40°C, the applicable component with the lowest specified values of allowable temperature limitations should be used for determining $\emptyset_{max}$ and $\emptyset_r$.

Component Description	Limit of Temperature Rise, °C θ_r	limit of Total Temperature, °C θ_{max}
Circuit breaker parts handled by the operator in the normal course of his duties	10	50
Copper contacts, copper-to-copper conducting joints, external surfaces accessible to the operator in the normal course of his duties, external terminal connected to bushing	30	70
Top oil	40	80
Breaker terminals to be connected to 85"C insulated cable	45	85
Hottest spot temperature of parts where they contact oil; silver (or equal) contacts in oil; Silver (or equal) conducting joints in oil	50	90
Silver (or equal) contacts in air; silver (or equal) conducting joints in air, hottest spot of bushing conductor or of bushing metal parts in contact with Class A insulation or with oil; hottest spot winding temperature 55"C rise of current transformers	65	105
External surfaces not accessible to an operator in the normal course of his duties	70	110
Hottest spot winding temperature of BO"C dry-type current transformers	110	150

Table F - 1: Summary of Temperature L1m1tat1ons for C1-rcu1t Breaker Components

2. The continuous current which a circuit breaker can carry at a given ambient temperature without exceeding its total temperature limitations is given by the formula:

$$I_a = I_r \left[\frac{\theta_{max} - \theta_a}{\theta_r} \right]^{1/1.8}$$

where

I_a = allowable continuous load current, in amperes, at the actual ambient temperature θ_a (I_a is not to exceed two times I_r)
I_r = rated continuous current, in amperes
θ_{max} = allowable hottest spot total temperature ($\theta_{max} = \theta_r + 40$°C), in degrees Celsius
θ_a = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius
θ_r = allowable hottest spot temperature rise at rated current, in degrees Celsius

3. The ambient-compensated allowable continuous load current, I_a, calculated in Step 2 will be treated as the seasonal normal rating of the circuit breaker.

Remove Year

Normal life expectancy will occur with a circuit breaker operated at continuous nameplate rating. When operated for one or more load cycles above nameplate rating, the material used in manufacturing the circuit breaker deteriorates at a faster rate than normal. The rate of deterioration is commonly expressed as a percentage loss *of* life. According to ANSI/IEEE C37.010b- IEEE **Standard for Emergency Load Current-Carrying Capability,** a circuit breaker can experience operation at 10°C above the limits of total temperature for which the circuit breaker was designed for up to two periods of an emergency cycle of eight hours before an unreasonable loss of life occurs and maintenance is required. Inspection and maintenance must be performed in accordance with manufacturer's recommendations before the circuit breaker can be subjected to additional emergency cycles. In addition, following each emergency cycle, the load current shall be limited to 95% of the rated continuous current as modified by ambient compensation for a minimum of two hours.

Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the Eight-Hour Emergency Load Current-Carrying capability of the circuit breaker with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The seasonal emergency loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers.

The seasonal emergency circuit breaker ratings can be determined in the following manner:

1. Emergency load current-carrying capability factors with ambient temperatures at 40°C are listed in Table F-2 for each limiting temperature of various circuit breaker components. The factors have been selected to allow operation at 10°C above the limits of total temperature for an emergency period of eight hours. The factors are expressed as the ratio of emergency load current allowed at an ambient temperature of 40°C, I_e to the rated continuous current, I_r, and can be applied with the following restrictions:

   (a) The circuit breaker component with the highest values of limiting temperature, θ_{max} and θ_r, shall be used to select the proper emergency load current-carrying capability factor from Table F-2.

   (b) The Eight-Hour factor shall be used for a cycle of operation consisting of separate periods of no longer than eight hours each, with not more than two such occurrences before maintenance.

   (c) Each cycle of operation is separate, and no time-current integration is permissible to increase the number of periods within a given maintenance cycle.

	Limiting Temperatures (°C) of Different Breaker Components						
$Ø_{max}$	70	80	85	90	105	110	150
$Ø_r$	30	40	45	50	65	70	110
	1.17	1.13	1.11	1.10	1.08	1.07	1.05

Table F-2: Emergency Load Current-Carrying Capability Factor (I_e/I_r)

2. The emergency load current, I_{ea} of a circuit breaker operating at an ambient temperature other than 40°C can be calculated by the equation:

$$I_{ea} = I_r \left[\frac{\theta_{max} - \theta_a}{\theta_r} \right]^{1/1.8}$$

where

I_{ea} = emergency load current, in amperes, at the actual ambient temperature θ_a (I_{ea} is not to exceed two times I_r)

I_r = Rated continuous current, in amperes emergency load current, in amperes, at 40°C ambient temperature

θ_{max} = allowable hottest spot total temperature ($\theta_{max} = \theta_r + 40$°C), in degrees Celsius

θ_a = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius

θ_r = allowable hottest spot temperature rise at rated current, in degrees Celsius

$\frac{I_{ea}}{I_r}$ = emergency load current-carrying capability factor from Table F - 2

3. The ambient-compensated emergency load current, I_{ea} calculated in Step 2 will be treated as the seasonal emergency rating of the circuit breaker.

Reliability Coordinator Data Specification and Collection

Introduction

The data and terms described here are intended as a definition and clarification of the electric system security data required by SPP Criteria and NERC Standards. Each term is defined and its current or expected method of exchange is specified.

Assumptions and Standard Conventions

1. All presently telemetered values must be supplied as specified in this appendix.

2. Any registered entity that cannot meet some portion of the requirements of this appendix may seek a waiver from the Operating Reliability Working Group (ORWG). The request for waiver shall indicate, if appropriate, when the registered entity will comply with the requirement for which the waiver is being sought.

3. It is assumed that Ampere measurements are used only for thermal limits calculations, and therefore, only an absolute value is required.

4. With respect to sign convention, positive is expected to be out of the bus and out of the generating unit at the point of measurement. The ISN Data Definition File, Usage Multiplier value must be defined as a negative value (normally –1.0) if the measurement does not follow this convention.

5. The ICCP standard does not discuss the scaling of analog quantities. Conversion to correct units is the responsibility of the originating host. Where that is not possible, the Usage Adder and Usage Multiplier values on the ISN Data Definition File must define the appropriate scaling factors. Sign (direction) conversion is the responsibility of the receiver.

6. ICCP data will be exchanged via the following blocks:
   - BLOCK 1: Periodic dataset at the defined periodicity
   - BLOCK 2: Exception triggered dataset, Report by Exception, 5 second buffering period, 10 minute integrity (full dataset) transmission.

7. The acceptable values assigned to the indication status point are prescribed in IEC 870-6-802 *TASE.2 Object Models*, Section 8.1 Use of Indication Point Models. Specifically, the following values are expected:
   - 0 Between
   - 1 Tripped, Open, Off, Out-of-service
   - 2 Closed, On, In-service

   If the sender of the data cannot accommodate the above standard, documentation of the possible values and their meaning must be provided to SPP.

8. All measurements to be exchanged via ICCP will be defined in the NERC ISN Data Definition File. The ISN Data Definition File will be updated per the following criteria:

- At least 14 calendar days prior to a planned topology change but not effective until notified by company representative. Changes submitted within the 14 day requirement, will be evaluated and accepted at the discretion of the SPP RC.
- Within 20 business days, upon request of SPP.
- Six months elapsed since last submitted.

9. Each Transmission Operator and Balancing Authority shall provide topological updates, including System One-Line Diagrams, in a format acceptable to SPP. The topological updates will be provided per the following timing criteria:
   - At least 21 calendar days prior to a topology change becoming effective (i.e. energizing the revised system). Changes submitted within the 21 day requirement, will be evaluated and accepted at the discretion of the SPP RC.
   - Within 20 business days, upon request of SPP.

10. Each Transmission Operator and Balancing Authority shall provide model data updates, such as line and transformer ratings (for the EMS model), optional SCADA limits (used for display/operator alarming), line characteristics, transformer characteristics, and unit characteristics in a format acceptable to SPP. The model data updates will be provided per the following timing criteria:
    - At least 7 calendar days prior to the updated system model data becoming effective (i.e. energizing the revised system). Changes submitted within the 7 day requirement, will be evaluated and accepted at the discretion of the SPP RC.
    - Within 20 business days, upon request of SPP.

11. Each Transmission Operator and Balancing Authority shall provide to SPP, either gross or net generation measurements (MW and MVAR). If gross measurements are supplied, the station auxiliary measurements must also be supplied so that net measurements can be derived.

12. **Changes to Model data or system topology information shall be provided to SPP via the ENGModelChanges@spp.org email address.**
13. **Changes to ISN Data Definition Files shall be provided to SPP via the OpsEMSEng@spp.org email address.**
14. Where written/email notification is indicated, if email is unavailable, phone /satellite phone communication or fax communication of data or outages is satisfactory.

Node Connectivity Requirement

SPP operates ICCP nodes at both the primary and disaster recovery (backup) sites. Both the primary and backup site ICCP servers feed real-time data to the primary and backup site Energy Management Systems. To ensure maximum availability of ICCP data required for operating reliability, the following connectivity requirements are required:

- SPP members are required to configure their ICCP servers to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.

- SPP will normally reference the same ICCP Object ID from both nodes when reading member data, thus imposing no additional maintenance workload upon the member companies.

- Members operating a backup site may choose to concurrently serve data from that site. In that instance, SPP will configure the SPP primary ICCP node to communicate with the member's primary site node and will configure the SPP backup site ICCP node to communicate with the member backup site node. This is required per the TASE.2 standard and NERC Standard COM-001-1.1 R1.4.

- SPP will configure the SPP backup site ICCP nodes to serve data to member sites using a separate and distinct ICCP Object ID in order to permit them to concurrently read operating reliability data from redundant nodes. This is required per the TASE.2standard and NERC Standard COM-001-1.1 R1.4.

Effective Date/Change History

June 6, 2001: Modified submission interval criteria for Unit Commitment Report.

March 11, 2002: Added update periodicity for ISN Data Definition File. Added requirement to require submission of System One-Line and Overview diagrams.

February 10, 2004: Changed references from Security Working Group (SWG) to Operating Reliability Working Group (ORWG). Added reference to the reporting requirements of the NERC Cyber Security Standard and removed references to the InfraGard and SCIS reporting mechanisms. Added requirement for concurrent connection and data transfer from member ICCP nodes to the SPP primary and backup site ICCP nodes.

March 12, 2004: Clarified the requirement to submit topology change documentation.

March 26, 2004: Added requirement to submit model data updates

June 30, 2004: Revised timing requirements for submitting ISN Data Definition Files, topology and system model updates. Replaced Unit Commitment Report with Resource Plan

April 4, 2005: Replaced Special Operating Security Limits with System Operating Limits and added reporting requirements.

June 4, 2007: Removed temperature reporting requirements from Hourly Load Report

September 6, 2007: Revised Inadvertent Accounting Report to reflect reporting via NERC Inadvertent Monitoring Application.

November 10, 2011: Format change to tabular form, improved clarity on reporting methods and requirements effective Feb 1, 2012.

Load and Capability/Reserve Obligation Information					
Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date	Data Retirement Date (Data no longer required by SPP after this date)
Actual and Forecast Peak Demand	Estimate of the Balancing Authority's peak demands for the previous, current, and next operating day. Unit of measurement is MW.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Anticipated Firm Interruptions	Estimate of the interruptions of Balancing Authority Area Load at time of system peak; Not included in Forecast Peak Demand. Unit of measurement is MW.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Firm Power Sales	Firm Power Sales as defined in SPP Criteria 6; Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Firm Power Purchases	Firm Power Purchases as defined in SPP Criteria 6; Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast On-Line Generating Capability	Total Generating Capability on-line or expected on-line at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Capacity Sales without Reserves	Scheduled or Available Capacity Sales not backed by Reserves at time of system peak (Also known as Unit Contingent Sales); Not included in Firm Power Sales. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Capacity Purchases without Reserves	Scheduled or Available Capacity Purchases not backed by Reserves at time of system peak (Also known as Unit Contingent Purchases); Not included in Firm Power Purchases. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Off-line Capacity Available	Total Available Generating Capability not included in On-line Generating Capability but that can be brought on-line by time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Interruptible Available	Available Interruptible Load not included in Firm Interruptions but can be interrupted by time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Curtailable Resources (Economy Sales)	Scheduled or Available Economy Sales that can be curtailed. Not included in Capacity Sales without Reserves or Firm Power Sales. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Curtailable Resources (Economy Purchases)	Scheduled or Available Economy Purchases that can be curtailed. Not included in Capacity Purchases without Reserves or Firm Power Purchases. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast 10-Minute On-Line Generating Capability	Amount of On-Line Generating Capability available in 10 minutes at time of system peak. ctual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast 10-Minute Capacity Sales without Reserves	Amount of Capacity Sales without Reserves that others can call on in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast 10-Minute Capacity Purchases without Reserves	Amount of Capacity Purchases without Reserves that you can call on in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast 10-Minute Quick-Start Capacity Available	Amount of Off-line Capacity Available in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast 10-Minute Interruptible Available	Amount of Interruptible Available in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Other Sales (10-Minute)	Amount of Other Sales that can be cut in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013
Actual and Forecast Other Purchases (10-Minute)	Amount of Other Purchases that can be cut in 10 minutes at time of system peak. Actual values for previous day, Estimated values for current and next day.	Load & Capability Report	Balancing Authority/ Reserve Sharing Group Member	February 1, 2012	June 1, 2013

Generator Data

Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date
Status	Instantaneous status of the generator as telemetered, o as derived from the status of the breaker associated witl the generator unit. Possible values are In-service, Out-of service, and Between, or On, Off, and Between.	ICCP Block 2	Transmission Operator or Balancing Authority or Generator Operator	February 1, 2012
MW Capability	Limit on the gross or net real power (MW) output of a generator unit. This value may be either a static or dynamic limit. Unit of measurement is in MW.	For Dynamic limits: ICCP Block 1	Transmission Operator or Balancing Authority or Generator Operator	February 1, 2012
		For Static Limits: Network model exchange or written notification to "EngModelChanges@spp.org"	Transmission Operator or Balancing Authority or Generator Operator	
Mvar Capability Curve	Gross or net reactive power (Mvar) output capability (leading and lagging) of a generator unit for various real power operating points. This is expected to be provided as either a plot or dataset of the capability curve for the generating unit. Appropriate data shall be provided for each possible configuration of the unit (ex. Combined Cycle operation). Unit of measurement is in MVar.	Per Reactive Verification Requirements as found in Criteria 12.1.6.	Generator Operator	February 1, 2012
MW Output	Instantaneous measurement of the gross or net real output power from the generator. If gross measurements are supplied, the station auxiliary measurements must also be supplied so that net measurements can be derived. Unit of measurement is in MW.	ICCP Block 1	Transmission Operator or Balancing Authority or Generator Operator	February 1, 2012
Mvar Output	Instantaneous measurement of the gross or net reactive output power from the generator. If gross measurements are supplied, the station auxiliary measurements must also be supplied so that net measurements can be derived. Unit of measurement is in MW.	ICCP Block 1	Transmission Operator or Balancing Authority or Generator Operator	February 1, 2012
Resource Plan	Resource plans for generating facilities within the SPP RC region to be submitted by SPP members for the current day and next 6 days. An hourly MW plan must be submitted. The plan may be submitted on a unit-by-unit o plant basis as the unit or plant is modeled in the SPP EMS. Data requirements to be submitted are found in the SPP EIS Market Protocols.	SPP Defined XML format found in the SPP Market Protocols. Current day must be submitted by 7:00 am Central Time.	For Market Registered Resources, the Resource's Registered Owner For others, the Generator Operator	February 1, 2012
Status of System Voltage Regulating Equipment	Instantaneous telemetered or derived status of automatic voltage regulators, supplementary excitation control, synchronouse condensors, static var compensators, shunt and series capacitors, reactors, etc. Possible values are In-service, Out-of-service, and Between, or On, Off, and Between	ICCP Block 2	Transmission Operator or Balancing Authority or Generator Operator	February 1, 2012

Balancing Authority Data				
Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date
10 Minute Reserve	The instantaneous amount of additional power that can be applied to the system within 10 minutes, as defined in SPP Criteria 6.	ICCP Block 1	Balancing Authority	February 1, 2012
Balancing Authority Area Demand	Instantaneous calculation of the generation minus actual interchange for the Balancing Authority Area. The unit of measurement is MW. Coordination surrounding inclusion of behind the meter load and generation must be made with the Reliability Coordinator. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.	ICCP Block 1	Balancing Authority	February 1, 2012
Current and Future Interchange Schedules with each Balancing Authority Area by Individual Interchange Transaction	Interchange schedules with each Balancing Authority Area by individual interchange transaction for the period encompassing the current hour to 24 hours into the future.	Electronic Tagging	Balancing Authority	February 1, 2012
Current Scheduled Net Interchange with each Balancing Authority Area	Currently Scheduled net MW flow between Balancing Authority Areas.	Electronic Tagging	Balancing Authority	February 1, 2012
Scheduled Net Interchange	Instantaneous total net scheduled MW flow into or out of the Balancing Authority Area.	ICCP Block 1	Balancing Authority	February 1, 2012
Actual Interchange	Instantaneous total net MW flow into or out of the Balancing Authority Area.	ICCP Block 1	Balancing Authority	February 1, 2012
Area Control Error (ACE)	Instantaneous measurement of the area control error (ACE). Unit of measurement is MW. Value may be positive or negative.	ICCP Block 1	Balancing Authority	February 1, 2012
System Frequency	Instantaneous readings of the actual frequency in Hz measured at several locations in the Balancing Authority Area. This is not the deviation from scheduled frequency but should be the actual measured frequency value.	ICCP Block 1	Balancing Authority	February 1, 2012
Scheduled Base Frequency	Instantaneous reading of the scheduled (base) frequency in Hz. This is not the deviation from a value (nominally 60 Hz). If this value is only valid during periods of time error correction, then a status indication value must also be supplied to indicate whether time correction is in effect or not.	Scheduled Frequency: ICCP Block 1 Time Error Correction Status: ICCP Block 2	Balancing Authority	February 1, 2012

Balancing Authority Data (cont)				
CPS Report	For those Balancing Authorities within the SPP RE footprint, this report shall be provided monthly to SPP and SPP will report to the SPP RE the Balancing Authority's CPS1 and CPS2 data as required by NERC. Report must be submitted by the 10th calendar day of the month for the previous month.	OPS1 or ftp upload	Balancing Authority within the SPP RE footprint	February 1, 2012
Inadvertent Accounting Report	Report provided monthly to the appropriate RE that includes the Balancing Authority's Inadvertent data as required by NERC. Report must be submitted by the 10th calendar day of the month for the previous month.	NERC Inadvertent Monitoring Application	Balancing Authority	February 1, 2012
Load Forecast Report	Hourly forecast/actual integrated load, in MW, for the prior, current, and next six days. Prior day actual loads are mandatory. Current and next six day forecast loads are requested. If the current and future day forecast is not supplied, a forecast will be derived from previously reported actual loads and forecast weather information. It is expected that this is the entire load found within the metered boundaries of the Balancing Authority. This load may be larger and include more entities than the Market Participant load values. This load must be submitted in addition to any Market load forecast data submissions.	OPS1 or ftp upload	Balancing Authority	February 1, 2012

Transmission Data				
Definition:	Transmission Facility: All facilities 100kV and above, or other lower voltage facilities as specifically requested by the Reliability Coordinator. For Transformers, the low side voltage measurement shall be 100kV and above.			
Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date
Facility Status	Current status of the switching devices (breakers, switches, disconnects) at each end of a transmission facility. Facilities include generators, transformers, lines, and reactive devices. Possible values are Open and Closed for two-state devices and Open, Closed, and Between for three-state devices. Status is only required on those facilities requested by the Reliability Coordinator in (insert document name here).	ICCP Block 2 For devices without telemetered status, voice notification to the RC is acceptable.	Transmission Operator and/or Balancing Authority	February 1, 2012
Facility Loading MW	Instantaneous Real Power flow in MW on the transmission facility. Unit of measurement is in MW.	ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
Facility Loading Mvar	Instantaneous Reactive Power flow in Mvar on the transmission facility. Unit of measurement is in Mvar.	ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
MVA Capability Normal (Normal Rating)	Normal (long term) rating for transmission facilities. Capability must reflect the most limiting element of the facility pursuant to Criteria 12.2. Unit of measurement is in MVA.	For Dynamic limits: ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
		For Static Limits: Network model exchange or written notification to "ENGModelChanges@spp.org"	Transmission Operator and/or Balancing Authority	
MVA Capability Emergency (Emergency Rating)	Emergency (short term) rating for transmission facilities. Capability must reflect the most limiting element of the facility pursuant to Criteria 12.2. Unit of measurement is in MVA.	For Dynamic limits: ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
		For Static Limits: Network model exchange or written notification to "ENGModelChanges@spp.org"	Transmission Operator and/or Balancing Authority	
Transformer Tap Setting	Predefined, fixed positions on one or both sides of a transformer. Each Tap postion represents a specific voltage value. (i.e. changing a Tap Position changes the voltage.) There is no standard numbering scheme for the tap position. Documentation defining the possible values and their meaning must be provided to SPP.	Telemetered/Derived tap positions: ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
		Non-telemetered/no-load tap information: Network Model Exchange or written notification to "ENGModelChanges@spp.org"	Transmission Operator and/or Balancing Authority	

Transmission Data (cont)				
Phase Shifting Transformer Phase Angle Setting	Represents the Phase Angle between the current and voltage (i.e. changing the Phase Angle changes the power.) The angle settings can typically vary between -90 and +90. The unit of measurement is Degrees.	ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
Voltage	Instantaneous voltage measurement for all telemetered locations on Transmission Facilities as defined above. Unit of measurement is kV. Per Unit, 100Base, 120Base, etc. voltages must be converted to simple kV readings by the originator, or if not possible, the appropriate scaling factors must be defined.	ICCP Block 1	Transmission Operator and/or Balancing Authority	February 1, 2012
Special Protection System Status	Instantaneous notification of changes to the status of Special Protection Schemes and Systems. For example, possible values are Armed, Deployed, and Out-of-service, or Available, Deployed, and Unavailable. Documentation defining the possible values and their meaning must be provided to SPP.	ICCP Block 2	Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012

Outage Scheduling Information				
Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date
Telemetering and Control System Status	Notification of expected or known removal of service time and associated expected return to service time of all Telemetering and Control facilities (such as ICCP, EMS, voice, etc.) between the Transmission Operator(s), Balancing Authority(ies), or Generator Operator(s) and Reliability Coordinator(s). Also required is a brief explanation of the work being done or other reason for the outage. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.) Only outages expected to exceed 15 minutes are required to receive approval from the RC prior to implementation. All other outages/work/risks required to be provided to the RC as notification but approval is not required unless stated by the RC. Outages expected to last less than 5 minutes are not required to be submitted. Individual RTU outages are not expected to be entered.	For Required notifications, written/Email notification (ICCPRequest@spp.org) a minimum of one business day in advance. (Future -- electronic submission in the SPP Outage Scheduling Tool)	Reliability Coordinator, Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
Transmission Lines/Transformer	Notification of expected or known risks to or removal of service time and associated expected return to service time of all Transmission Facilities as defined in Criteria 5. This includes hot-line work or removal of re-closing capabilities that are not intended to remove the line from service, but may expose the facility to increased risk of contingency. Also required is an explanation of the work being done or other reason for the outage. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.)	CROW Outage Scheduler	Transmission Operator	February 1, 2012
Reactive Devices	Notification of expected or known risks to or removal of service time and associated expected return to service time of all Static and Dynamic Reactive Devices such as Capacitors, Inductors, Reactors, D-VAR's, SVC's, etc. Also required is an explanation of the work being done or other reason for the outage. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.)	Written notification to "OutageCoordination@spp.org"	Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
Generation	Notification of expected or known risks to or removal of service time and associated expected return to service time of all Generation units as required in the SPP Membership Agreement. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.) (Risks may include fuel supply issues)	CROW Outage Scheduler	Generator Operator	February 1, 2012
Generator Derates	Notification of expected time of reduced real power production capability and associated return to service time of full real power production capability. Also, the amount of capability lost shall be provided along with an explanation (OFO, fuel supply issues, mechanical problems, outlet constraints, etc.) of the reason for the derate. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.)	CROW Outage Scheduler	Generator Operator	February 1, 2012
Special Protection Systems	Notification of expected removal of service time and associated return to service time of all Special Protection Systems. Also, notification of degradation to the Special Protection System shall be provided. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.)	Written notification to "OutageCoordination@spp.org"	Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012

Other Operating Information				
Data Type	Description/Requirements	Required Exchange Mechanism	Applicability	Required Effective Date
SOL and IROL Limits	Notification of new or revised SOL and IROL facility ratings.	Written notification to "EngModelChanges@spp.org" at least one calendar day prior to the effective date of planned changes to SOL and/or IROL facility ratings. Any deviation from planned SOL or IROL ratings in real-time will be communicated by voice or telemetry.	Transmission Operator or Balancing Authority	February 1, 2012
New Facilities	Notification of new equipment, including Transmission Lines, Transformers, Generators, Breakers, Buses, Switches, etc. and the expected in-service date of that equipment.	As defined in the Assumptions and Standard Conventions section in this document.	Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
System One-Line Diagrams	Diagram showing the detailed generation or transmission subsstation topology including switching elements, transformers, reactive devices, generation, and load withdrawal points.	As defined in the Assumptions and Standard Conventions section in this document.	Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
Emergency Operating Procedures in Effect	Notification of Emergency Conditions and procedures and expected duration. This may also include TLR states, Energy Emergency Alerts and relevant information such as action taken or planned.	IDC, RSS, email to "Security@spp.org", voice, or satellite phone blast calls but not limited to any of these.	Reliability Coordinator, Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
Severe Weather, Fire, or Earthquake	Notification of severe weather condition such as hurricanes, tornadoes, and severe thunderstorms. May also include tornad and severe weather warnings and watches, and solar magnetic disturbance alerts. Also includes notification of earthquakes and fires that affect or could potentially affect the operation of the Bulk Electric System.	Email to "Security@spp.org" voice, or satellite phone blas calls but not limited to any o these.	Reliability Coordinator, Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012
Multi-Site Sabotage	Notification of cases of sabotage to power system equipment at multiple sites.	As specified by ESISAC/NERC Reporting Procedures, voice contact with the RC, and the NERC Cyber Security Standards.	Reliability Coordinator, Transmission Operator, Balancing Authority, and/or Generator Operator	February 1, 2012

Appendix 8

Southwest Power Pool Generator Owner/Operator Excitation System Summary Report

Instructions: Generator Owner/Operator shall fill out summary information for all units under your control concerning the number of hours the Excitation System was not operated in Automatic Voltage Control Mode.

Generator Owner/Operator	
Month Reporting Data	
Contact Name	
Contact Phone	

Station	**Unit #**	**# Hours Excitation System not operated in Automatic Voltage Control Mode**

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Generator Unit Excitation System Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of events of a particular generating unit's excitaton system not being operated in automatic voltage control mode.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date (unit not operated in automatic mode)	**Unit #**	**Reason unit's excitation system was operated out of automated voltage control mode**

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool Generator Owner/Operator Voltage Schedule Requirements

Instructions: Control Area Operator shall specify voltage schedule to be maintained by each Generator Owner/Operator’s units at a specified bus.

Generator Owner/Operator	
Control Area	
Voltage Schedule Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Station	Unit #	Specified Voltage	Specified Bus

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool Generator Unit Voltage Schedule Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of periods in which particular generating units did not adhere to control area's prescribed voltage schedule. If event was approved by control area operator, please attach written approvals.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date	**Duration (hr:min)**	**Reason unit did not adhere to voltage schedule**	**Approved (yes/no)**

Dev. February, 2001

By SPP GWG

Southwest Power Pool
Control Area's List of Exempt Generators

Instructions: Control Area Operator shall list units in their area of responsibility that are exempt from following prescribed Control Area Voltage Schedules.

Control Area Operator	
Last Updated	
Contact Name	
Contact Phone	

Generator Owner/Operator	**Generating Station**	**Unit**

Southwest Power Pool
Generator Unit Transformer Tap Setting Report

Instructions: Generator Owner/Operators shall fill out information concerning the tap settings and impedances of all GSU and AUX transformers under their control.

Generator Owner/Operator	
Generating Station	
Last Updated	
Contact Name	
Contact Phone	

GSU/AUX Transformer I.D.	**Current Tap Setting**	**Tap Setting Range**	**Transformer Impedence (OA Base)**

Appendix 8

By SPP GWG

Southwest Power Pool
Generator Unit Transformer Tap Setting Change Request

Instructions: Control Area Operator shall complete information necessary to let affected Generator Owner/Operator know of needed Generator Unit Transformer settings changes.

Generator Owner/Operator	
Generating Station	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

GSU/AUX Transformer I.D.	**Current Tap Setting**	**New Tap Setting**	**Technical Justification for Tap Setting Change**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Generator Units Exempt from Tap Setting Reporting Procedures

Instructions: Generator Owner/Operators shall fill out information for all units under their control that are exempt from Transformer Tap Setting Procedures. The criteria that is met must also be documented

Generator Owner/Operator	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Generating Station	**Unit #**	**Exemption Criteria Met**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Voltage Regulator Control Setting Status Report

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Date	
Contact Name	
Contact Phone	

Generating Control	**Control Setting**	**Generator Short Term Capability**	**Protective Relay Setting**
Overexcitation Limiter			
Underexcitation Limiter			
Volts/Hertz Limiter			

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Generator Governor Characteristic Reporting

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Last Updated	
Contact Name	
Contact Phone	

Governor Control	**Control Setting**
Speed Regulation	

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Non-Functioning Governor Controls

Instructions: Generator Owner/Operators shall fill out information for all units under their control that has a non-functioning or a blocked speed/load governor control.

Generator Owner/Operator	
Last Updated	
Contact Name	
Contact Phone	

Generating Station	**Unit**	**Governor Status (Blocked/Non-functioning)**

Dev. February, 2001
By SPP GWG

SPP Misoperation Report

Reporting Utility: ______________________________ **Date:** ______________

Contact Person:

Name	
Phone	
Fax	
E-Mail	
Address	

Equipment Category and Operating Voltage:

DME (Yes/No):	**TPS (Yes/No):**	**GCP (Yes/No):**
SPS (Yes/No):	**UFLS (Yes/No):**	**UVLS (Yes/No):**
ARL (Yes/No):		**Voltage (kV):**

Time, Equipment Location & Description:

Incident Date:	**Incident Time:**	**Time Zone:**
Relay MFGR:	**Relay Type:**	**Relay Flags:**
Substation Name/Number:	**Line/Bus/Auto/Unit Name/No.:**	**Circuit Breaker Numbers:**

Description of Misoperation/Failure:

Investigation Results:

Corrective Action:

Target Date To Complete Recommendations:

Recommendations:

Person Verifying That All Corrective Actions And Recommendations Have Been Completed:

Name:	**Title:**	**Date:**

Note: Equipment categories include DME – Disturbance Monitoring Equip, TPS – Transmission Protection Systems, GCP – Generator Control & Protection, SPS – Special Protection Systems, UFLS –

Factor	Short-term	Long-term *	Date Approved	Comments
PTDF	3%	3%	4/27/2004	
OTDF	3%	3%	4/27/2004	
PTVF	0.02 p.u.	0.02 p.u.	12/12/2001	
TRM		0%	12/12/2001	See SPP website for short-term TRM

* Long-term factors apply to all elements above 60kV.

Appendix 10: Unit Reactive Limits (Lead and Lag) Verification FORM

General Information

Unit operating _______________ Entity Contact person: __________________________
Plant _____________________________ Unit No.: __________________________________
Location (State): ___________________Transmission Modeler: ______________________

Is this Unit Exempt? ☐Yes ☐

No If yes, please attach reason to this form.

Test/Verification Details

Instructions:
Maximum leading and lagging reactive test/verification should be conducted under conditions that are likely to induce reactive response that approaches the unit's maximum capability, as further described in Criteria 12.1.6.5.2.

The procedures for the test/verification are specified in Criteria 12.1.6.5.3.

Upon completion of a test/verification (which includes data points for both leading or lagging capability), this completed form shall be submitted to the SPP Member that is responsible for modeling the unit in power flow and stability models.

MAXIMUM LAGGING **(Unit injects VARs) (4): Date of Test: ________________**

Gross bus Generation	Auxiliary Voltage @ POI (1)	NetGen. @ Load	Generator POI (1)	Transmission Terminal Voltage
______MW	MW	MW	_____ Ph.1 _kV (5)	_____ Ph.1 kV
______MVAR	______MVAR	______MVAR	_____ Ph.2 _kV	_____ Ph.2 kV
			_____ Ph.3 _kV	_____ Ph.3 kV

Data point at Near Maximum Rated MW.

MAXIMUM LEADING **(Unit absorbs VARs) (4): Date of Test: ________________**

Gross bus Generation	Auxiliary Voltage @ POI (1)	NetGen. @ Load	Generator POI (1)	Transmission Terminal Voltage
______MW	MW	MW	_____ Ph.1 _kV (5)	_____ Ph.1 kV
______MVAR	______MVAR	______MVAR	_____ Ph.2 _kV	_____ Ph.2 kV
			_____ Ph.3 _kV	_____ Ph.3 kV

Data point at Near Maximum Rated MW.

VERIFICATION METHOD:
☐Operational Data ☐Engineering Analysis
☐Commissioning Data ☐Testing/Validating
MOPC-GWG 12.6.1 doc

TEST PERFORMED:
☐Maximum Leading Reactive ☐Maximum Lagging Reactive

VERIFICATION CONDITIONS:

Date: ______________________________

Start Time: ____________Stop Time: ________________

Ambient Air Temperature (°F): _________(2)

GENERATOR STEP-UP NAMEPLATE DATA:

Fixed Tap Setting _____kV Impedance: ____% Capability: _______MVA (3)

GENERATOR NAMEPLATE DATA:

Maximum Gross Dependable Unit Generation: _______________ MW

Maximum Net Dependable Unit Generation: _________________ MW

Rated Power Factor: ___________

Unit Rating: ______MVA

Nominal Terminal Bus Voltage: _________ kV

Abnormal Conditions at Time of Test:

____

____

____

FACTORS THAT LIMITED REACTIVE CAPABILITY DURING TEST:

☐ Maximum Generator Voltage with Auxiliary loads
☐ Maximum Generator Voltage without Auxiliary loads
☐ Minimum Generator Voltage with Auxiliary loads
☐ Minimum Generator Voltage without Auxiliary loads
☐ Main transformer capability plus Auxiliary loads
☐ Transmission system constraint
☐ Other:
☐ Steady State Stability Limit
☐ Maximum Gross MW capability
☐ Minimum Gross MW capability
☐ Minimum Excitation Limiter
☐ Loss of Field Relay

____

____

SUBMITTAL:

Date submitted to SPP Control Area Authority Representative: ____________________________

NOTES:

(1) Point of Interconnect.
(2) Degrees Fahrenheit if limiting, outside air or generator air.
(3) Actual tap setting – not nominal tap setting.
(4) Maximum Leading and Maximum Lagging test/verification may be conducted at different times of the year.
VARs – Volt-Amps reactive
(5) kV – kilovolt which is equal to 1000 volts.

Appendix 11 – Interconnection Review Process Details

This appendix shall be subject to review and approval of the Transmission Working Group. Given the limited amount of time during a regular Transmission Working Group meeting, and given the need for timely responses, the majority of the interconnection review process will take place outside of a regular meeting. A Transmission Assessment Report will be prepared by the parties to the proposed interconnection and presented to the TWG for review. Once received, the Transmission Working Group will review the information provided in the assessment of impacts on the interconnected system. This appendix details the technical requirements which shall be the minimum necessary.

Coordination

1. The party proposing the interconnection shall appoint a person who will serve as the primary contact with SPP staff and with the Transmission Working Group.
2. If the proposal for interconnection comes from the SPP, then SPP shall appoint its primary contact.
3. The primary contact shall ensure that all affected parties are identified, shall provide a proposed timeline for the studies shall ensure that all affected parties are notified of and kept informed of progress, and provided the opportunity to review all study results prior to submission to the Transmission Working Group. The rationale for determining affected parties shall be included.
4. The primary contact shall coordinate any joint studies that may be necessary and shall report the results to all affected parties.
5. All affected parties shall cooperate in joint planning efforts.
6. All affected parties will work together to develop an estimated timeline for the completion of the study.
7. SPP shall coordinate activities that affect other regions pursuant to an applicable seams agreement.

Prior To The Review

Affected parties shall jointly develop and evaluate both the proposed interconnection and any mitigation plans. The primary contact shall submit a request for review of the interconnection request to the Transmission Working Group through the group's Secretary. The request for review shall include the following:

1. A list of all affected parties and the contact person at each affected party. The rationale for determining affected parties shall be included.
2. A brief summary of the results of planning studies. Each affected party shall provide a copy of its own planning criteria as documentation of the need of mitigations that exceed regional requirements.
3. A detailed description of the project including: in-service date; design information; ratings of the interconnection; a geographic map of the interconnection area; electrical one-line diagrams of the facilities being connected.
4. A summary of the results of power flow, short circuit, and dynamic analyses specifically addressing compliance to NERC Reliability Standards, SPP Criteria, other regional requirements, and affected party planning criteria.
5. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
6. Details of any required mitigation plans including identification of the parties responsible for mitigation. The detailed description of mitigation plans shall include such information as detailed in Item 3 above.

7. Any comments of the affected parties.

<u>Technical Study Requirements</u>
The following are minimum requirements for power flow analysis:

1. Impact analysis shall be performed using an N-1 contingency assessment of all single elements in the entire first-tier area of the combined areas which the proposed interconnection connects. This area maybe expanded or reduced as mutually agreed upon. The rationale for expansion or reduction of the study area shall be documented and agreed upon by all affected areas.
2. N-1 contingency assessment shall not be limited to a breaker-to-breaker outage assessment, but such assessment may also be included.
3. A review of impacts shall utilize all applicable Scenario Cases developed by the SPP extending to the planning horizon year.
4. If, at any time, impacts are identified affecting a nuclear power plant, it shall be included separately as an affected party.
5. Affected parties shall report adverse impacts and required mitigations.

The TWG may request additional studies at its discretion. The rationale for requesting additional studies shall be provided to all affected parties. If the proposed interconnection was previously evaluated by SPP and included in the most recent STEP, the power flow analysis described here does not need to be repeated.

The following are minimum requirements for short circuit analysis:

1. The model(s) assessed shall be determined by the affected parties. The rationale for the model(s) assessed shall be included
2. Assessment shall consist of 3-phase and phase-to-ground faults applied at the buses of the proposed interconnection plus all first-tier buses to the interconnection.
3. Additional buses may be studied as mutually agreed upon and documentation for including such additional buses shall be included.
4. Assessments shall document the before and after fault currents on all monitored busses.
5. Affected parties shall report adverse impacts and the required mitigation.

The following are minimum requirements for dynamics analysis:

1. The model(s) assessed shall be determined by the affected parties. The rationale for the model(s) assessed shall be included. If no dynamics analysis is performed the rationale for not performing such studies shall be provided.
2. The assessments performed shall be determined by the affected parties. The rationale for the assessments shall be included.
3. Assessments shall document the before and after dynamic performance on all monitored busses.
4. Affected parties shall report adverse impacts and the required mitigation.
5. If the interconnection is to be made at 345 kV or higher voltage, an assessment of reactive power impacts and management shall be made and provided for review. This assessment may include but is not limited to power flow, transient network analysis, or electromagnetics transients studies, insulation coordination studies and dynamics studies clearly indicating any required levels of shunt compensation.

<u>Dispute Resolution</u>

All disputes between SPP members shall be resolved using the procedures of Section 3.13 of the SPP Bylaws.

Review and Ballot by the Transmission Working Group

1. The Transmission Working Group Secretary shall review the request for interconnection for completeness.
2. Any deficiencies shall be reported to the primary contact.
3. Once a complete request is received, it shall be forwarded to the Transmission Working Group for a 14 day review and comment period.
4. The primary contact shall be responsible for coordinating any response necessary to comments and questions raised by the Transmission Working Group.
5. The Transmission Working Group shall schedule a ballot to accept or to reject the interconnection request.
6. Any action taken by the Transmission Working Group will be included in the minutes.

Transmission Interconnection Review Data Checklist

1. Primary contact and all affected parties' contact information.
2. Overview of the proposed interconnection and its need.
3. Estimated or proposed in-service date.
4. List of all studies run by season.
    a. Power flow studies minimum requirements met.
    b. Short circuit studies minimum requirements met.
    c. Dynamics studies minimum requirements met.
5. Affected parties planning criteria, if applicable.
6. A detailed description of the proposed interconnection.
    a. In-service date
    b. Design information
    c. Ratings of the interconnection
    d. A geographic map of the interconnection area
    e. Electrical one-line diagrams of the facilities being connected.
7. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
8. Details of any required mitigation plans including identification of the affected parties responsible for mitigation.
    a. In-service date
    b. Design information
    c. Ratings of the facilities
    d. A geographic map of the facility area
    e. Electrical one-line diagrams of the facilities being connected.
9. Comments of affected parties covering agreement or points of disagreement of the proposed interconnection, if any.

The Transmission Working Group shall review and modify this appendix as needed but not less frequently than once every 3 years.

Appendix 12: Outage Coordination Methodology

Change History:

8/16/2011	**Initial version approved by ORWG**
8/30/2011	**Corrected typo on Generator Planned Outages Min Lead Time – corrected to “2 Days” from “None”.**
9/22/2011	**Added clarification on Reserve Shutdown submittals and created “Opportunity” outage Priority for Generators.**
2/21/2013	**Added clarification on business rules of outage priorities detailing which priorities are allowed to be entered in CROW with start times either in the future or in the past. Replaced “members” with Transmission Operators and Generator Operators. Added more language describing SPP’s outage request evaluation process. Added further language describing Reserve Shutdown resources.**
6/26/2013	**Added “Info” Informational Outage Request Type as an available type for Generation Outages.**
12/18/2013	**Added “Operational” priority and “Upcoming Model Change” as outage reason, misc clarification changes.**

Purpose

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to submission of Transmission and Generation outages to the SPP Reliability Coordinator and SPP Balancing Authority when it becomes effective via the SPP CROW Outage Scheduler web tool. Outage submissions will be shared with other Reliability Coordinators, Transmission Operators, and Balancing Authorities via the NERC System Data Exchange (SDX) and will be used for assessing real-time and future reliability of the Bulk Electric System.

1. Transmission Outages and Operations

For the purpose of identifying applicable facilities, the nominal kV level of the facility will be used. For transformers, use the low side voltage class. Example: A 161/69kV transformer shall be classified as a 69kV facility for the purposes of this methodology.

a. Major Transmission Elements (MTE)

- All transmission facilities rated at 230kV or above.
- All tie lines, 60kV and above.
- All facilities, monitored and contingent elements, associated with flowgates
- Other facilities specified by the Transmission Operator or the Reliability Coordinator as having a major impact on the Bulk Electric System or that affect the capability and reliability of generating facilities (backup station power, etc).

b. Forced Transmission Outage Submission Requirements

Forced outages of all transmission facilities greater than 100kV and facilities between 60kV and 100kV that are modeled in the SPP regional models and have been modeled in the Outage Scheduler should be submitted within 30 minutes or as soon as practical after the outage. Each outage submission must be accompanied by a Planned Outage Start Time and End Time, an associated Outage Priority, an associated Outage Request Type, and a reason for the outage. Forced Outage Priory outages will be considered Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. The Planned Start Time of the outage should reflect the best known time of the actual outage. The Outage Scheduler system will ensure that the Actual Start Time and Planned Start Time are equal. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the Outage Scheduler.

c. Scheduled Transmission Outage Submission Requirements

Scheduled outages of Major Transmission Elements (MTE's) elements must be submitted to the Outage Scheduler and approved by the Reliability Coordinator prior to implementing the outage. Scheduled outages of all other transmission elements greater than 100kV must be submitted to the Reliability Coordinator's Outage Scheduler for coordination and review. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, an associated Outage Priority, an associated Outage Request Type, and a reason for the outage. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the Outage Scheduler. When the outage has ended, the Actual End Time of the outage must be updated.

d. Transmission Outage Priority and Timing Requirements

Each Transmission Outage submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW Outage Scheduler will enforce the lead time requirements of each Outage Priority.

Priority	Definition	Minimum Lead Time	Maximum Lead Time
Planned	Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence.	**7 Days**	**None**
Discretionary	Equipment is known to be operable with little risk of leading to a forced outage; however the timeline for submission of Planned outage priority has passed. Discretionary outages are required to be submitted at least 2 calendar days in advance. Due to the shorter lead time, this outage priority has increased risk of being denied based upon higher priority outage requests.	**2 Days**	**7 Days**

Opportunity	Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Generator suddenly offline for forced outage allows transmission work to be done).	**None**	**7 Days**
Operational	Equipment is removed from service for operational reasons such as voltage control, constraint mitigation as identified in an operating procedure, etc.	**None**	**None**
Urgent	Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work.	**2 Hours**	**48 Hours**
Emergency	Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security.	**None**	**2 Hours**
Forced	Equipment is out of service at the time of the request.	**None**	**1 Hour**

e. Transmission Outage Equipment Request Types

Each Transmission outage (scheduled and forced) request submitted must include one of the following Outage Request Types.

Outage Request Type	Definition	Modeling Assumptions
Out of Service (OOS)	Equipment is out of service.	**SDX = Open** **EMS = Open**
Normally Open (NO)	Equipment is normally out of service and is identified as normally open in the SPP regional models. Normally Open request type is used to close (place in service) a normally open facility.	**SDX = Closed** **EMS = Closed**
Informational (INF)	Used for outage events that are not covered by one of the other Outage Equipment Request Types. Not an out of service event.	**None – Informational Only**
Hot Line Work (HLW)	Work is being performed on live or energized equipment.	**None – Informational Only**
General System Protection (GSP)	Work is being performed on protection systems. Requestor shall specifically identify protection systems out of service and any modification to operation or behavior of system contingencies.	**None – Informational Only**

f. Transmission Outage Request Reasons/Causes

Each Transmission Outage Request must be submitted with one of the following reasons for the outage.

Reason/Cause	Definition
Maintenance & Construction	Outages to facilitate repair, maintain, or upgrade of facility related equipment. This includes clearances to perform vegetation management. Does not include outages to support Maintenance & Construction of other facilities. Those should be submitted as Voltage or SOL Mitigation.
Third Party Request	Non-transmission facility related requests for clearance or work such as highway construction.
Voltage Mitigation	Operation of facilities to preserve or correct Bulk Electric System voltage.
SOL Mitigation (Thermal)	Operation of facilities to preserve or correct Bulk Electric System thermal loading issues.
Weather/Environmental/Fire (excluding Lightning)	Outages caused by wind, ice, snow, fire, flood, etc. All weather or environmental causes excluding lightning strikes.
Lightning	Outages caused by direct or indirect Lightning strikes.
Foreign Interference (including contamination)	Outages caused by blown debris, bird droppings, kites, falling conductors, airplanes, etc.

Vandalism/Terrorism/Malicious Acts	Outages resulting from known or suspected vandalism, terrorism, or other malicious acts.
Equipment Failure	Outages resulting from failure of facility related equipment.
Imminent Equipment Failure	Operation of facilities due to expected imminent facility rated equipment failure.
Protection System Failure including Undesired Operations	Operation of facilities due to failure or undesired operation of the facility protection systems.
Vegetation	Outages resulting from contact with vegetation. This does not include outages due to clearances required to perform vegetation management which should be submitted as Maintenance & Construction. This does not include vegetation blown into rights of way or into contact with facilities which should be submitted as Foreign Interference.
BES Condition (Stability, Loading)	Outages resulting from Bulk Electric System conditions such as islanding, cascading outages, sudden thermal loading due to other contingencies, transient stability conditions, etc.
Unknown	Operation of facilities due to an unknown reason. Most forced outages will be submitted with an initial reason of Unknown. Once the actual reason for the operation is known, the outage requestor should update the outage request. SPP Staff will follow up after some time to determine the actual outage reason for any outages which still have a reason of Unknown submitted.
Upcoming Model Change	Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.
Other	Operation of facilities due to a reason not listed here.

2. Generation Outages/Derates

For the purpose of identifying applicable reportable facilities, the generator or other Resource shall have a gross capability greater than 25 MW. Due to specific reliability reasons, SPP, upon written notice to the equipment operator or market participant, may require outages to be entered into the outage scheduler where otherwise they may not be required. All Generation Outages and De-rates are required to be accompanied by a reason for the outage or limitation. NOTE: Derates in the CROW system require a new maximum capability of the generator to be submitted. Historically, SPP's systems required the derate amount to be entered in the form of the amount of MW's the capability should be decremented by. This has changed with the implementation of the CROW outage scheduler.

a. Forced Generation Outages/Derate submission requirements

Forced outages or capability limitations in the form of Derates of all generation facilities that are modeled in the SPP regional models and have been modeled in the Outage Scheduler should be submitted within 30 minutes or as soon as practical after the outage. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, an associated Outage Priority, an associated Outage Request Type, and a reason for the outage. Forced Outage Priority requests will be assumed to be Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. The Planned Start Time of the outage should reflect the best known time of the actual outage. The Outage Scheduler system will ensure that the Actual Start Time and Planned Start Time are equal. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the Outage Scheduler. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event, or Resource Plan submission.

b. Scheduled Generation Outages/Derate submission requirements

Scheduled outages or capability limitations in the form of Derates of all generation facilities that are modeled in the SPP regional models and have been modeled in the Outage Scheduler should be submitted as soon as possible and to the extent possible on an annual rolling basis. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, an associated Outage Priority, an associated Outage Request Type, and a reason for the outage. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the Outage Scheduler. When the outage has ended, the Actual End Time of the outage must be updated. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event or Resource Plan submission.

1. Reserve Shutdown

Resources in SPP are considered to be in a Reserve Shutdown outage status when SPP has approved an outage request via the Outage Scheduler, making the Resource unavailable for SPP commitment and dispatch due to reasons other than to perform maintenance or to repair equipment. These resources will be reflected in Planned Outage for a reason of Excess Capacity/Economic.

Resources that are offline for economic or excess capacity reasons and can be recalled, started, and synchronized to pick up load within 7 days are not required to request an outage via the Outage Scheduler. However, these Resources may request and be shown in Reserve Shutdown outage status if the outage is approved by SPP.

c. Generation Outage/Derate Priority and Timing Requirements

Each Generation Outage or Derate submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW Outage Scheduler will enforce the lead time requirements of each Outage Priority.

Priority	Definition	Minimum Lead Time	Maximum Lead Time
Planned	Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity	**2 Calendar Days**	**None**

	upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence.		
Opportunity	Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Loading conditions allow planned work to occur with short lead time).	**None**	**7 Calendar Days**
Operational	Equipment is removed from service for operational reasons. This could include outages or derates due to reliability directives or other operational concerns not necessarily related to the generating equipment or capability, and outages entered to correct system topology in operating models.	**None**	**None**
Urgent	Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work.	**24 Hours**	**7 Calendar Days**
Emergency	Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security.	**None**	**24 Hours**
Forced	Equipment is out of service at the time of the request.	**None**	**None**

d. Generation Outage/Derate Request Type

Each Generation outage or Derate request submitted must include one of the following Outage Request Types.

Request Type	Definition	Modeling Assumption
Out of Service	Generator or Resource is out of service.	SDX = offline EMS = offline
Derate	Generator or Resource maximum capability is lowered from normal operation. A new maximum capability is required to be submitted with each Outage Request Type of Derate.	SDX = online, with new lower PMAX EMS = online, with new lower PMAX
Informational (INF)	Used for communicating and documenting information to SPP regarding the resource. This status is not interpreted as a loss of capability or capacity. This status may be used to communicate anticipated fuel delivery issues.	None – Informational Only

e. Generation Outage/Derate Request Reasons/Causes

Each Generation Outage or Derate Request must be submitted with one of the following reasons for the outage.

Reason/Cause	Definition
Equipment Failure	Failure in station generation, prime mover, or other equipment has occurred. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).
Imminent Equipment Failure	Expected failure in station generation, prime mover, or other equipment. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).
BES Reliability	Removal from service or limitation to preserve or correct Bulk Electric System reliability issues either through action of a Special Protection System, runback scheme, or as mitigation of another reliability event.
Loss of Interconnection	Failure in interconnection equipment such as GSU transformers or other interconnection facilities.

	Does not include loss of synchronization due to stability or islanding type events.
BES Stability	Removal from service or limitation due to Bulk Electric System stability issues. Includes loss of synchronization due to transient stability and/or islanding issues.
Fuel Supply	Removal from service or limitation due to fuel supply interruption. Does not include local equipment failures related to fuel supply. Includes loss of gas pressure due to offsite issue, coal supply exhaustion, lack of headwater issues for hydro, etc.
Regulatory/Safety/Environmental	Removal from service or limitation due to Regulatory/Safety/Environmental restrictions such as emission limits, OSHA, NRC, or other regulatory body limitations. Includes damage caused by weather including but not limited to lightning, flood, earthquake, etc. This may also include limitations to hydro due to low dissolved oxygen in tailwater or to control downstream flooding.
Unknown	The default Forced Outage/Derate reason will be pre-populated with Unknown at the time of submittal. Either during the initial outage submittal or at a later time, the Unknown reason must be changed to reflect the actual experienced issue.
Routine Generator Maintenance	Removal from service or limitation in order to perform repair or inspection of generation equipment.
Supporting Transmission Outage	Removal from service or limitation in order to support a scheduled transmission outage.
Excess Capacity/Economic	Removal from service or limitation due to seasonal or system capacity need. This includes peaker units not expected to be used during winter months.
Upcoming Model Change	Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.

3. Outage Review / Approval Process

All outages submitted will be studied to determine if any potential reliability conflicts are found. The general study method employed by SPP staff involves building representative models of the study time period and implementing all outage requests submitted for that time period. The resulting modeled system is then studied to determine if any reliability issues can be identified. If issues are identified, various mitigation steps are then studied including but not limited to, generation redispatch, system reconfiguration, rescheduling of lower priority outages, and facility rating reviews. If mitigations are unsuccessful in resolving the conflict, an outage request may need to be rescheduled or denied. Priority of outage requests is reviewed based upon initial submission time, outage priority category, reason for the outage, and impact to reliability. To the extent possible, higher priority category requests will be given preference, but ultimately it is up to the SPP RC to resolve any scheduling conflicts.

An outage that has been studied will receive a status change to one of the following statuses: Approved, Denied, or Pre-Approved. Pre-Approval will be provided in certain cases where an outage has been submitted, but for various reasons SPP is unable to adequately study the outage or determine that no reliability conflicts exist. The Pre-Approval may also be dependent upon a specific operating condition that may need to be met but cannot be guaranteed at the time the Pre-Approval is issued such as but not limited to a load forecast threshold, simultaneous outage, new facilities in-service, etc. When the outage request can be adequately studied to determine that no reliability conflict exists, the status may be changed to Pre-Approved.

All outages submitted within the appropriate advance timeframe will be reviewed as soon as possible by SPP Operations Staff. The review timelines for SPP are as follows:

a. Major Transmission Elements (MTE)
    1. For all MTE outage requests submitted 30 days or more prior to scheduled start time, Pre-approval or denial will be provided within 5 business days.
    2. For all MTE outage requests submitted 14 days or more but less than 30 days prior to scheduled start time, pre-approval or denial will be provided within 3 business days.
    3. For all MTE outage requests submitted 14 days or less prior to scheduled start time, pre-approval or denial will be provided within 2 business days.
b. All other transmission elements
    1. Prior approval of outages for non-MTEs by the RC is not required.
c. Generators
    1. For all Generator outage requests submitted 30 days or more prior to scheduled start time, Pre-approval or denial will be provided within 5 business days.
    2. For all Generator outage requests submitted 14 days or more but less than 30 days prior to scheduled start time, Approval, Pre-approval or denial will be provided within 3 business days.
    3. For all Generator outage requests submitted 14 days or less prior to scheduled start time, Approval, Pre-approval or denial will be provided within 2 business days.
    4. SPP will provide their best effort for outages submitted within 2 business days.

4. Outage Status Changes

All outages submitted will reside in one of several status types throughout the life cycle of the outage. These status types and their associated definition are:

Status	Definition
Proposed	The outage request has been saved in the outage scheduler system and remains under the full revision control until the outage is entered into a Submitted state by the requestor. If the requestor does not move a proposed request to the submitted status within 30 days of the planned start date, the outage is automatically Withdrawn. Proposed outage request status dates DO NOT qualify for outage queuing in conflict resolution. Proposed outage requests are not provided to external systems such as NERC SDX/IDC or SPP's EMS.
Submitted	The outage request has been submitted into the outage scheduler system and is ready for review by SPP. The outage requestor does not possess revision control of the outage in this status. A revision request may be submitted to SPP regarding an outage in Submitted status. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS.

Study	SPP will change the status type to Study once the active study process begins. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS.
Preliminary Approved	Outage requests with Preliminary Approved status have been approved based on long lead studies and may need additional analysis closer to the planned start date or finalization of an Operating Guide. Once the restudy is complete or final opguide posted, the outage status is changed to Approved. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS.
Approved	Approved state indicates SPP has completed the study process and the outage request is ready for implementation. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS.
Implemented	Once the outage request actual start time has been entered, signifying that the outage has begun, the outage status is changed to Implemented. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS.
Completed	Once the outage request actual end time has been entered, signifying that the outage has ended, the outage status is changed to Completed. Outage requests in this state are NO LONGER provided to external systems such as NERC SDX/IDC or SPP's EMS.

Certain outage requests may result in a need by the outage requestor to withdraw or cancel the outage request. SPP's study results and coordination may also result in status changes to an outage reflecting the inability of the outage request to be approved or implemented. These status types are:

Status	**Definition**
Withdrawn	The outage requestor can withdraw an outage request while it is still in Proposed status. Once in Study or Approved status, the request must be Cancelled. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS.
Cancelled	The outage requestor can cancel a Submitted or Approved outage. Cancelled outages can be reinstated by the requestor, provided the planned start of the outage falls within the business rules for lead time submission. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS.
Denied	An outage request that is in Submitted or Study status can be Denied. If SPP denies the request, the status changes to Denied. This state indicates the outage request was not approved for implementation. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS.
Revoked	Once an outage request has been Approved, it can be Revoked at an time (ie, before or during the outage). Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS.

Document ID	Ver. No.	Rev. Date	Eff. Date	Revised By	Summary of Changes
20070724 SPP Criteria	1	7/24/2007	7/24/2007	ORWG	Transfer of Criteria to new template; updates to section 6
20071030 SPP Criteria	2	10/30/2007	10/30/2007	GWG	Updates to section 12
20080729 SPP Criteria	3	7/29/2008	7/29/2008	MDWG, TWG, ORWG, GWG, SPCWG	Updates to sections 3, 4,6, 7; added Appendices
20090127 SPP Criteria	4	1/27/2009	1/27/2009	ORWG, GWG	Updates to sections 5 and 12
20090428 SPP Criteria	5	4/28/2009	4/28/2009	MDWG, TWG, ORWG	Updates to sections 3, 4, 5; removed section 8; added Appendix 11
20090728 SPP Criteria	6	7/28/2009	7/28/2009	GWG, ORWG	Updates to sections 12 and 14
20100204 SPP Criteria	7	2/4/2010	2/4/2010	TWG	Updates to Appendix 11
20100427 SPP Criteria	8	4/27/2010	4/27/2010	ORWG, GWG, SPCWG	Updates to sections 5, 7, 12, and Appendix 2
20100727 SPP Criteria	9	7/27/2010	7/27/2010	GWG	Updates to section 12 and Appendix 10
20101026 SPP Criteria	10	10/26/2010	10/26/2010	ORWG, TWG	Updates to Criteria 5, 6, and 10, removal of Criteria 14 & Appendix 3; Updates to Criteria 3, 12; Removal of Appendix 1
20110125 SPP Criteria	11	1/27/2011	1/25/2011	GWG	Updates to section 12.1.5.3.g
20110425 SPP Criteria	12	4/25/2011	4/25/2011	SPCWG	Update to Criteria 7
20110425 SPP Criteria	13	4/25/2011	4/25/2011	TWG	Update to section 4.3.5
20110425 SPP Criteria	14	4/25/2011	4/25/2011	TWG	Update to section 4.4.2
20110725 SPP Criteria	15	7/25/2011	7/25/2011	TWG	Update to section 3.4
20110725 SPP Criteria	16	7/25/2011	7/25/2011	TWG	Update to section 12
20110725 SPP Criteria	17	7/25/2011	7/25/2011	ORWG	Removed section 9.0, update to section 10, Removed Appendix 4 (see MOPC minutes October 2011)
20111024 SPP Criteria	18	10/24/2011	10/24/2011	ORWG	Added Appendix 12
20120130 SPP Criteria	19	1/30/2012	1/30/2012	TWG, ORWG	Update to Appendix 6C, 6E, 6F, & 7; Update to Criteria 12
20130430 SPP Criteria	20	4/30/2013	4/30/2013	ORWG	Updates to Criteria 6, Update to Appendix 12
20130730 SPP Criteria	21	7/30/2013	7/30/2013	ORWG	Update to Appendix 7
20131029 SPP Criteria	22	10/29/2013	10/29/2013	ORWG	Updates to Criteria 6
20131029 SPP Criteria	23	10/29/2013	10/29/2013	SPCWG	Updates to Criteria 7.3, 7.8.4
20140128 SPP Criteria	24	1/28/2014	1/28/2014	TWG, ORWG	Removed Criteria Sections 12.4 & 11, Update to Appendix 12
20140729 SPP Criteria	25	7/29/2014	7/29/2014	TWG, GWG	Updated Criteria 12.1.5.3.g; 12.2