Protection System Review Program

Beyond Zone 3

North American Electric Reliability Council

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

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This document was approved by the Planning Committee Executive Committee on August 8, 2005.

INTRODUCTION

The NERC Planning Committee formed the System Protection and Control Task Force to address NERC blackout Recommendation 8a and the US-Canada Task Force Recommendation 21a. The first stage of SPCTF work resulted in resolving NERC Recommendation 8a, which dealt with zone 3 relay loadability of transmission lines 230 kV and above. The SPCTF concluded that limiting the emergency loadability requirement of Recommendation 8a to only the zone 3 relays fails to adequately address the need of relays operating securely in the presence of emergency loading conditions, and need to be expanded. The Planning Committee approved the procedures for this additional "beyond zone 3" work on July 20, 2004 as recommended in *System Protection and Control Task Force's Initial Recommendations Concerning NERC Recommendation 8A Loadability Requirements on Transmission Protective Relaying Systems* (available at: http://www.nerc.com/~filez/spctf.html). This second stage review will include all phase protection relays applied to trip directly or as a backup on the bulk electric power system, other than Zone 3, and the lower voltage "critical circuit" protection system review cited in US-Canada Task Force Recommendation 21a.

The function of transmission protection systems is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. There is a general consensus of opinion that during emergency loading conditions on the transmission system, the system operators should be making the human decision to open overloaded facilities, if conditions so warrant. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. (This is a different operating philosophy than many protection systems on the distribution system. Most distribution protection systems are designed such that loads may be automatically tripped by relays at some multiple of the relay pickup current, often very near the 100% emergency rating of the distribution facilities.)

The system operator actions may include manual removal of the transmission circuit from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).

NERC has required utilities to design transmission protection schemes so that TPSOs/utilities accept equipment and "loss of life" for those few extreme emergency overload situations. Although some transmission protection systems may already be designed to accommodate the NERC loadability criteria, utilities must recognize that in some cases protection systems will need to be desensitized to accomplish the 150% overload capability, and in other cases, the protection systems may need mitigation, upgrading, and/or replacement. Per this "Beyond Zone 3 Review," transmission protection systems are required to be reviewed to confirm NERC relay loadability criteria.

BACKGROUND

The relay loadability review is designed within the context of NERC Blackout Recommendation 8a, and US-Canada Task Force Recommendation 21a, existing NERC Version 0 Reliability Standard PRC-001-0 — System Protection Coordination, the relay loadability review procedures approved by the Planning Committee, and the former NERC Planning Standard III.A.

NERC Recommendation 8a

> Recommendation 8a: All transmission owners shall, no later than September 30, 2004, evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions.[6] In each case that a zone 3 relay is set so as to trip on load under extreme conditions, the transmission operator shall reset, upgrade, replace, or otherwise mitigate the overreach of those relays as soon as possible and on a priority basis, but no later than December 31, 2005. Upon completing analysis of its application of zone 3 relays, each transmission owner may no later than December 31, 2004 submit justification to NERC for applying zone 3 relays outside of these recommended parameters. The Planning Committee shall review such exceptions to ensure they do not increase the risk of widening a cascading failure of the power system.
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>
> [6] The NERC investigation team recommends that the zone 3 relay, if used, should not operate at or below 150% of the emergency ampere rating of a line, assuming a .85 per unit voltage and a line phase angle of 30 degrees.

June 2004 Clarification of the Emergency Ampere Rating

The Planning Committee approved the following clarification of the term "emergency ampere rating" in the footnote to Recommendation 8a on June 22, 2004.

> **Emergency Ampere Rating** — "The highest seasonal ampere circuit rating (that most closely approximates a 4-hour rating) that must be accommodated by relay settings to prevent incursion." That rating will typically be the winter short-term (four-hour) emergency rating of the line and series elements. The line rating should be determined by the lowest ampere rated device in the line (conductor, airswitch, breaker1, wavetrap, series transformer, series capacitors, reactors, etc) or by the sag design limit of the transmission line for the selected conditions. The evaluation of all Zone 3 relays should use whatever ampere rating currently used that most closely approximates a 4-hour rating.

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1 Where parallel breakers are used to terminate a transmission line, the lowest ampere rated breaker should be used to determine if the breaker is the most limiting element on the line, assuming the higher rated breaker is open.

US – Canada Power System Outage Task Force Recommendation 21a

> Recommends that NERC broaden the review to include operationally significant 115 kV and 138 kV lines, e.g., lines that are part of monitored flowgates or interfaces. Transmission owners should also look for zone 2 relays set to operate like zone 3s.

Former NERC Planning Standard (superseded April 1, 2005)

III.A. Transmission System Protection

Coordination of protection and control systems is vital to the reliability of the transmission networks. The reliability of the transmission network can be jeopardized by unintentional and unexpected automatic control actions or loss of facilities caused by misoperation or uncoordinated protection and control systems. If protection and control systems are not properly coordinated, a system disturbance or contingency event could result in the unexpected loss of multiple facilities. Such unexpected consequences can result in unknowingly operating the electric systems under unreliable conditions including the risk of a blackout, if the event should occur.

The design of protection and control systems must be coordinated with the overall design and operation of the generation and transmission systems. Proper coordination requires an under-standing of:

The characteristics, operation, and behavior of the generation and transmission systems and their protection and control,

Normal and contingency system conditions, and Facility limitations that may be imposed by the protection and control systems.

III.A. Guides

G16. Protection system applications and settings should not normally limit transmission use.

G17. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

Approved Review Procedures (July 2004)

The protection system review procedures, approved by the Planning Committee in July 2004, state:

6. All other distance relays (other than Zone 3) on lines 230 kV and above that can trip directly or as part of a pilot tripping scheme that could violate the loadability criteria should likewise be identified, exception requests made, and corrections made.

7. In additional to the other distance relays mentioned in Item 6 above, the SPCTF recommends that all phase-overcurrent relays used on the transmission system at 230 kV and above be included in the review of Item 6 above and be governed by the same processes and timeline. These relays are sometimes used as backup protection for transmission lines and series or network transformers. The loadability requirement applies to transformers with secondary windings of 230 kV and above. The actual transformer loadability requirements will be developed by the SPCTF.

10. Each Regional Council should identify critical lines 115 kV and above (but less than 230 kV) that should fall under this loadability criteria and administer the guidelines for all relaying elements (including Zone 3) associated with these lines to more fully conform to Recommendation 21, part A, from the US – Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, issued in April 2004.

The full zone 3 review procedures can be found in the *System Protection and Control Task Force's Initial Recommendations Concerning NERC Recommendation 8A Loadability Requirements on Transmission Protective Relaying Systems* (approved by the Planning Committee in July 2004) at: http://www.nerc.com/~filez/spctf.html.

REVIEW REQUIREMENTS

All protection system owners shall evaluate all phase distance and overcurrent relay settings applied to protect transmission lines and transformers for the purpose of verifying that no relays are set to trip on load under extreme emergency conditions as defined in the Loadability Parameters section of this document. In each case where a relay is found to be set to trip on load under extreme conditions, the protection system owner shall reset, upgrade, replace, or otherwise mitigate the settings of those relays as soon as possible, on a priority basis.

The Review and Mitigation Schedules of this document outline the schedules for review and mitigation, depending on voltage class (see page 7).

Each owner will submit the results of their review to their regional reliability council using the NERC supplied reporting spreadsheets (samples in *Appendix E*), which can be found at: http://www.nerc.com/~filez/spctf.html.

POWER SYSTEM ELEMENTS COVERED BY THIS REVIEW

This review pertains to phase protection systems applied to the bulk electric power system 200 kV and above and critical elements 100 kV to 200 kV identified by the Region. Note: The voltages are expressed as 100 kV and 200 kV to ensure applicability to 105 kV and 220 kV.

Protection systems intended for the detection of ground fault conditions and protection during stable power swings are exempt from this review.

This review includes:

- Transmission lines operated at 200 kV and above
- Transmission lines operated at 100 kV to 200 kV, identified by the Region as critical power system elements
- Transformers with low voltage terminals connected at 200 kV and above voltage levels
- Transformers with low voltage terminals connected at 100 kV to 200 kV, identified by the Region as critical power system elements

RELAY ELEMENTS COVERED BY THIS REVIEW

Any protective functions which could trip with or without time delay, on emergency load current. This will include distance, out of step tripping, switch-on-to-fault, overcurrent relays, and communications aided schemes such as permissive overreach transfer trip (POTT), permissive under-reach transfer trip (PUTT), directional comparison blocking (DCB), etc.

Non-conforming relays shall be mitigated or applications may be made for Technical Exceptions, if appropriate.

More details on the evaluation and calculation of loadability for the relay elements discussed below can be found in the Appendices of this document.

Distance Relays

All phase distance relays and associated schemes shall be evaluated to verify that the relays or schemes will not trip for the loadability parameters defined in this document. This includes relays that trip directly and individual load responsive phase distance relays that trip as part of a communication assisted (pilot) tripping scheme. The load limitation for the forward-reaching unit in a pilot scheme should be considered as equal to the load limitation assuming that the relay was "stand-alone", i.e., stepped distance.

Pilot Relaying Scheme Considerations

The loadability of "pure" (unmodified) permissive tripping schemes may offer an improvement in loadability based on the requirement that relays at all terminals must see the load at that terminal as an internal fault condition before any terminal can trip. Where the apparent impedance of the sending-end relay is on the relay characteristic (at 0.85 per unit voltage and a 30-degree load angle), the apparent impedance to the receiving-end relay may fall outside its own characteristic, such that neither end will trip. If the TPSO can establish analytically that this is the case, it may be able to demonstrate a different (possibly higher) loadability limit. This will require that the TPSO apply for a technical exception supported with complete documentation.

Additional information on this topic is contained in Exception 14 and the related Appendix B of the *Relay Loadability Exceptions* document (Version 1.2 or later).

Phase Overcurrent Relays

Phase overcurrent relays, directional and non-directional, will be evaluated to verify that the relays or schemes will not trip for the loadability parameters defined in this document. The directional transmission line relay settings will be evaluated assuming a current phase angle of 30 degrees lagging.

Special Tripping Elements or Logic

Out-of-Step

Out-of-step tripping elements shall be reviewed to verify that they will not operate for emergency loading conditions.

Out-of-step trip blocking schemes shall be evaluated to ensure that they do not block trip for faults during emergency loading conditions.

Switch-On-To-Fault

Switch-on-to-fault schemes shall be reviewed to verify that they will not operate for emergency loading conditions.

RELAY ELEMENTS NOT COVERED BY THIS REVIEW

The requirements of recommendation 8a are for relay systems that are operating as designed. It is not applicable to relay or relay scheme failures that occur prior to a system disturbance. Therefore, the application of recommendation 8a is not required for relay elements that are only enabled when other relays or associated systems fail. Examples of this include overcurrent elements that are only enabled during loss of potential conditions, and elements that are only enabled during a loss of communications. Although not required, the SPCTF encourages the Transmission Owners to consider the loadability of these types of elements in their relay applications.

Protection systems intended for the detection of ground fault conditions and protection during stable power swings are exempt from this review.

Additionally, generator protection relays that are susceptible to load are not being addressed at this time[2]. The load susceptible relays associated with generators do not have a significant history of misoperation, and they are only a minor subset of the concerns of generator relaying and control system requirements during abnormal system conditions.

Special Protection Systems (SPS)

Relays elements used only for special protection systems or remedial action schemes (RAS), applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017, are exempt from this relay loadability review.

2 Reliability Standards addressing generation protection and control, and the coordination of generation and transmission protection and controls systems are either being developed or being proposed. Therefore, evaluation of generation protection systems for relay loadability should be reviewed after those standards are approved.

REVIEW AND MITIGATION SCHEDULES

Circuits 200 kV and Above

TPSOs shall review the relay loadability for circuits 200 kV and above (including transformers with low-side voltages 200 kV and above), and mitigate non-conforming in accordance with this document, under the following schedule:

August 31, 2005	Send the *Protection System Review Program – Beyond Zone 3* document, the revised *Relay Loadability Exceptions* (Version 1.2) document, and updated reporting forms to the Regions
June 30, 2006	TPSOs submit review status and report mitigation plans (including Temporary Exception Requests) and submit Technical Exception Requests to Regions for review and acceptance
August 31, 2006	Regions submit June 30 reports to SPCTF for review and approval
December 2006	SPCTF to provide report on the 200 kV and above protection review to the Planning Committee for approval at the December 2006 PC meeting
February 2007	PC to provide summary report to the NERC Board at its February 2007 meeting
December 31, 2007	TPSOs complete mitigation (except where Temporary Exception requests have been approved)

Operationally Significant Circuits 100 kV to 200 kV

TPSOs shall review the relay loadability for operationally significant circuits 100 kV to 200 kV (including transformers with low-side voltages 100 kV to 200 kV), and mitigate non-conforming in accordance with this document, under the following schedule:

August 31, 2005	Send the *Protection System Review Program – Beyond Zone 3* document, the revised *Relay Loadability Exceptions* (Version 1.2) document, and updated reporting forms to the Regions
December 31, 2005	Regions to define operationally significant lower-voltage-level circuits
December 31, 2006	TPSOs submit review status and report mitigation plans (including Temporary Exception Requests) and submit Technical Exception Requests to Regions for review and acceptance
March 31, 2007	Regions submit informational reports from December 31, 2006 TPSO reports to NERC on mitigation plans(including requests for Temporary Exceptions), and Technical Exceptions
June 2007	SPCTF to provide a summary report on the 100 kV to 200 kV protection review to the Planning Committee at their June 2007 meeting
August 2007	PC to provide summary report to the NERC Board at its August 2007 meeting
June 30, 2008	TPSOs complete mitigation (except where Temporary Exception requests have been approved)

LOADABILITY PARAMETERS

Transmission Line Loadability

The maximum emergency loading of a transmission line is defined as: "The highest seasonal ampere circuit rating (that most closely approximates a 4-hour rating) that must be accommodated by relay settings to prevent incursion." That rating will typically be the winter short-term (four-hour) emergency rating of the line and series elements. The line rating should be determined by the lowest ampere rated device in the line (conductor, air switch, breaker, wavetrap, series transformer, series capacitors, reactors, etc.) or by the sag design limit of the transmission line for the selected conditions. The evaluation of all relays should use whatever ampere rating currently used that most closely approximates a 4-hour rating.

The line protection relays will be reviewed to verify that the relay is not set to trip at or below 150% of the maximum emergency rating defined above. The relay settings will be evaluated assuming the sensing voltage to be 85% and a current phase angle of 30 degrees lagging. TPSOs may apply for exceptions to this requirement as necessary, as noted in *Appendix A*.

Transformer Terminated Lines

The TPSOs may use the Transformer Loadability Parameter, defined below, for lines that terminate into a bus where the only other bus element is a transformer.

Transformer Loadability

System conditions, particularly during emergency operations, may make it necessary for transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transformers out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability criterion has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

The system operator actions may include manual removal of the transformer from service at any loading level in accordance with the transmission owner's operating policies and planned operating procedures, if doing so does not violate a system operating limit (SOL) or an interconnection reliability operating limit (IROL).

If the TPSO uses transformer **fault** protection relays, they will be reviewed to verify that the relay is not set to operate at or below the greater of:

- 150% of the applicable maximum[3] transformer nameplate rating, or
- 115% of the highest operator established emergency transformer rating.

Where applicable, the relay settings will be evaluated assuming the terminal voltage, at the relay potential device location, to be 85%, and a current phase angle of 30 degrees lagging.

If the TPSO uses relays for **overload** protection for excessive load conditions (in addition to planned system operator action) that operates below the level stated above, this protection will be considered to conform as long as one of the following conditions apply:

3 Including the forced cooled ratings corresponding to all installed supplemental cooling equipment

1. The relays are set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
2. The relays are supervised by either a top oil or simulated winding hot spot element. The setting should be no less than 100° C for the top oil or 140° C[4] for the winding hot spot.

If the Transmission Owner has specific transformer protection requirements that conflict with the loadability requirement or has justification for thermal element supervision below those stated above, they may apply for a Technical Exception.

4 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

APPENDICES

APPENDIX A — EXCEPTIONS

This appendix is excerpted from the *Relay Loadability Exceptions – Determination and Application of Practical Relaying Loadability Ratings* interim document, approved by the Planning Committee in November, 2004. The complete document is available at: http://www.nerc.com/~filez/spctf.html

TPSOs may apply for two types of exceptions: temporary and technical. Any petition for temporary exceptions shall include all necessary supporting documentation to help the Regions and the SPCTF review the requested exception. Petitions for technical exceptions shall be submitted on the appropriate Technical Exception Template. Any technical exception beyond those contained in this document will require substantial supporting documentation to be submitted with the exception request.

Temporary Exceptions

Temporary Exceptions allow for a delayed implementation schedule for facilities that require modification due to the inability to complete the work within the prescribed time frame because of facility clearance (equipment maintenance outages) or work force issues. Temporary exceptions may also be granted for application of temporary mitigation plans until full implementation can be achieved.

All applications for temporary exceptions should include sufficient justification for the delay in mitigation as well as a mitigation plan with a planned schedule for completion.

For those facilities that are substantially outside the Recommendation 8A loadability requirements, the TPSO should have done everything practical with existing equipment to mitigate non-conforming relays and maximizing loadability before applying for temporary exceptions.

Such mitigation includes but is not limited to:

1. Elimination of unnecessary protection functions (beyond applicable protection needs)
2. Adjusting the maximum torque angle on the relay
3. Resetting of relays as possible while still meeting established protection practices

Every effort should be made to mitigate non-conforming critical lines as soon as possible on a priority basis.

Technical Exceptions

Technical Exceptions would be justified on technical merit where facilities could not, under any reasonable contingency, be loaded to a level that would initiate a protective relay operation, under current system conditions. Technical exceptions would be subject to review in light of future system changes.

If Technical Exceptions to the loadability requirement are required, the TPSO is encouraged to use one of the exception groups in this document. If none of those exception groups are applicable to the TPSO's situation, then specific exception details can be submitted, with regional concurrence, to the SPCTF for evaluation and approval. Complete documentation should be supplied with the exception request to allow the SPCTF to perform a timely and thorough review of the request.

The following are a number of potential technical exemptions that can be requested.

Exception 1 — Utilize the 15-Minute Rating of the Transmission Line

When the original loadability parameters were established, it was based on the 4-hour emergency rating. The intent of the 150% factor applied to the emergency ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been determined that a 115% safety margin is an appropriate margin. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

In the case that the 15-minute rating has been established, the loadability requirement is:

The tripping relay should not operate at or below 1.15 times the 15-minute winter emergency ampere rating ($I_{emergency}$) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{emergency}}$$

Transmission operators are instructed to take immediate remedial steps, including dropping load, if the current on the circuit reaches $I_{emergency}$.

Exception 2 — Maximum Power Transfer Limit Across a Transmission Line

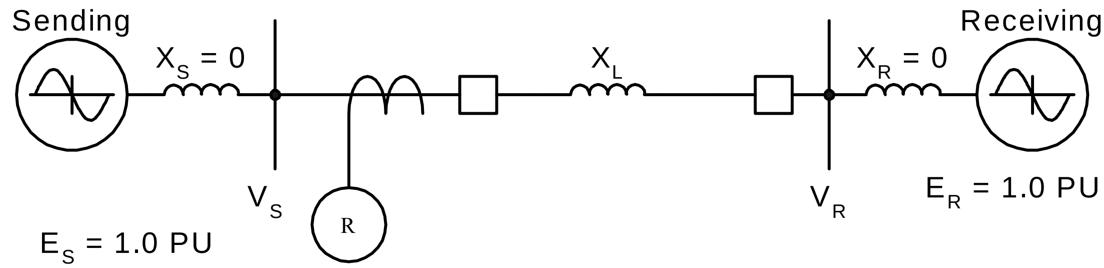

Figure 2 – Maximum Power Transfer

The power transfer across a transmission line (*Figure 2*) is defined by the equation[5]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where: P = the power flow across the transmission line

V_S = Phase-to-phase voltage at the sending bus

V_R = Phase-to-phase voltage at the receiving bus

δ = Voltage angle between V_S and V_R

X_L = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. For purposes of this exception, a number of conservative assumptions are made:

- δ is set at 90 degrees
- Voltage at each bus is set at 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

No additional margin is applied in this exception because the above factors establish an inherent margin.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

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[5] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

I_{real} = Real component of current

V = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

I_{total} is the total current at maximum power transfer.

For this exception:

The tripping relay should not operate at or below I_{total} (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 3 — Maximum Power Transfer Limit Across a Transmission Line Based on the Breaker Interrupting Ratings at Each End of the Line

The power transfer across the system shown in *Figure 3* is defined by the equation[6]: The source impedance for each terminal connected to the line is determined and the sending and receiving voltages set at 1.05 per unit.

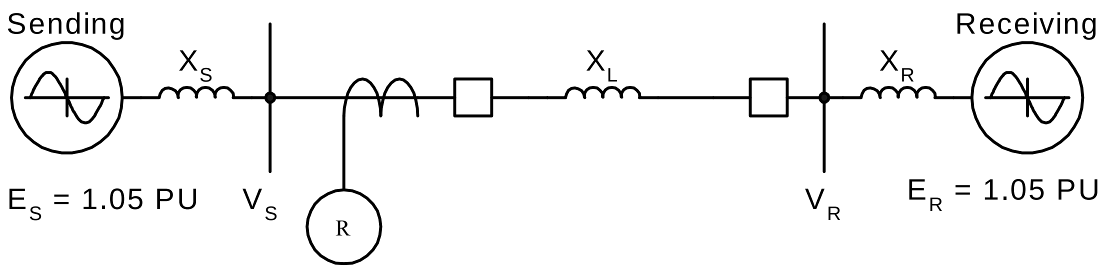

Figure 3– Maximum Power Transfer Based on Breaker Interrupting Ratings

$$P = \frac{(E_S \times E_R \times \sin\delta)}{(X_S + X_R + X_L)}$$

Where:

P	= Power flow across the transmission line
P_{max}	= Maximum power that can be transferred across a system
E_S	= Thévenin phase-to-phase voltage at the system sending bus
E_R	= Thévenin phase-to-phase voltage at the system receiving bus
δ	= Voltage angle between E_S and E_R
X_S	= Calculated reactance in ohms of the sending bus (based on breaker interrupting duty)
X_R	= Calculated reactance in ohms of the receiving bus (based on breaker interrupting duty)
X_L	= Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. For purposes of this exception, a number of conservative assumptions are made:

- δ is set at 90 degrees
- Voltage at each bus is set at 1.05 per unit
- The actual source impedance is typically greater than the source impedance calculated based on the actual breaker ratings.

[6] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

No additional margin is applied in this exception because the above factors establish an inherent margin.

For this exception, the source impedance that would limit the three-phase fault current on the line-side breaker bushing terminals is calculated based on the interrupting rating of the breaker.

$$X_S = \frac{V}{\sqrt{3} \times I_{BRS}} = \frac{0.577 \times V}{I_{BRS}}$$

$$X_R = \frac{V}{\sqrt{3} \times I_{BRR}} = \frac{0.577 \times V}{I_{BRR}}$$

Where:

V = Nominal phase-to-phase system voltage

I_{BRS} = Interrupting rating of the breaker in amps on the sending bus

I_{BRR} = Interrupting rating of the breaker in amps on the receiving bus

The maximum power transfer across the system occurs when δ is 90 degrees across a system. Therefore, the maximum power transfer equation becomes:

$$P_{\max} = \frac{1.05 \times V \times 1.05 \times V \times \sin\delta}{\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{P_{\max}}{\sqrt{3} \times 1.05 \times V}$$

$$I_{real} = \frac{1.05 \times V}{\sqrt{3} \times \left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

Where:

I_{real} = Real component of current

Substituting for X_S and X_R:

$$I_{real} = \frac{0.606 \times V}{\left[\dfrac{0.577 \times V}{I_{BRS}} + \dfrac{0.577 \times V}{I_{BRR}} + X_L\right]}$$

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{1.414 \times 0.606 \times V}{\left[\dfrac{0.577 \times V}{I_{BRS}} + \dfrac{0.577 \times V}{I_{BRR}} + X_L\right]}$$

$$I_{total} = \frac{0.857 \times V}{\left[\frac{0.577 \times V}{I_{BRS}} + \frac{0.577 \times V}{I_{BRR}} + X_L\right]}$$

Where:

I_{total} = Total current at maximum power transfer

The tripping relay should not operate at or below I_{total}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times I_{total}}$

This exception is valid as long as the breakers are not overdutied or replaced.

Exception 4 — System's Site-Specific Calculated Maximum Power Transfer Limit

For this exception, actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 4*).

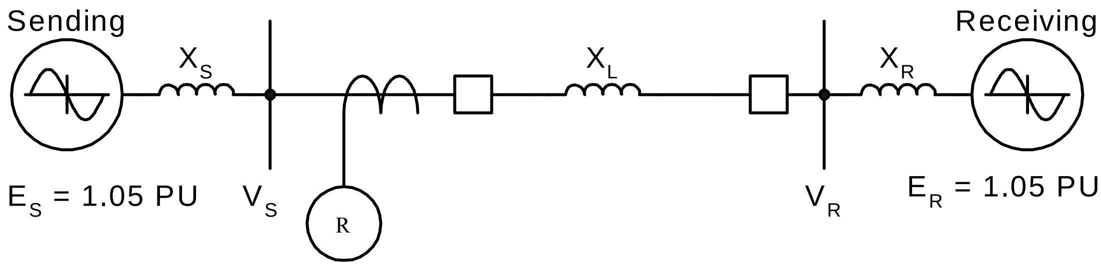

Figure 4 – Site-Specific Maximum Power Transfer Limit

The recommended procedure for determining X_S and X_R is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is set to 90 degrees, and the current magnitude (I_{max}) for the maximum power transfer across the system is determined as follows[7]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

P_{max}	= Maximum power that can be transferred across a system
E_S	= Thévenin phase-to-phase voltage at the system sending bus
E_R	= Thévenin phase-to-phase voltage at the system receiving bus
δ	= Voltage angle between E_S and E_R
X_S	= Thévenin equivalent reactance in ohms of the sending bus
X_R	= Thévenin equivalent reactance in ohms of the receiving bus
X_L	= Reactance of the transmission line in ohms

[7] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

V = Nominal phase-to-phase system voltage

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. For purposes of this exception, a number of conservative assumptions are made:

- δ is set at 90 degrees
- Voltage at each bus is set at 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

No additional margin is applied in this exception because the above factors establish an inherent margin.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{\left(X_S + X_R + X_L\right)}}$$

Where:

I_{total} = Total current at maximum power transfer

For this exception:

The tripping relay should not operate at or below a calculated I_{total}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times I_{total}}$$

This exception must be re-verified annually or whenever major system changes are made.

Exception 5 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected /bypassed by breakers. Protective gaps and MOVs (*Figure 5*) operate on the voltage across the capacitor ($V_{protective}$).

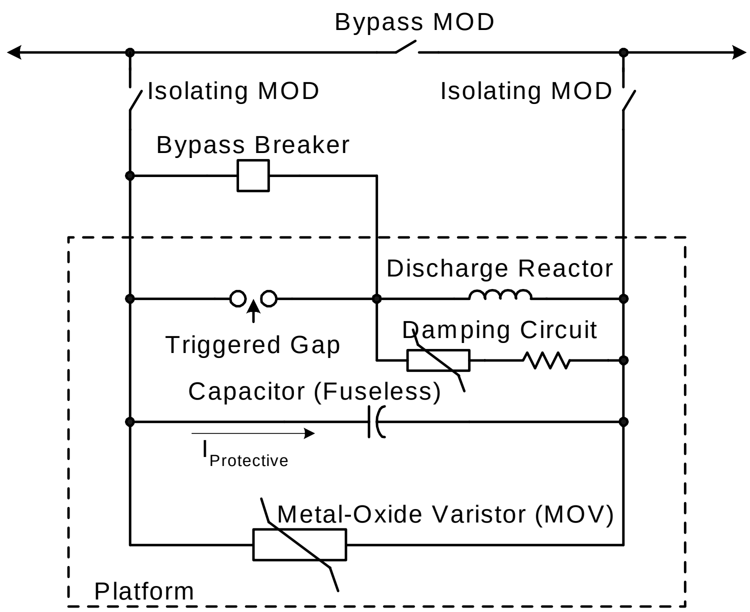

Figure 5 – Series Capacitor Components

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

X_C = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because I_{total}, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in Exception 2.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in Exceptions 2, 3 or 4 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

The tripping relay should not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. I_{total} (where I_{total} is calculated under Exception 2, 3, or 4 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 6 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 6*).

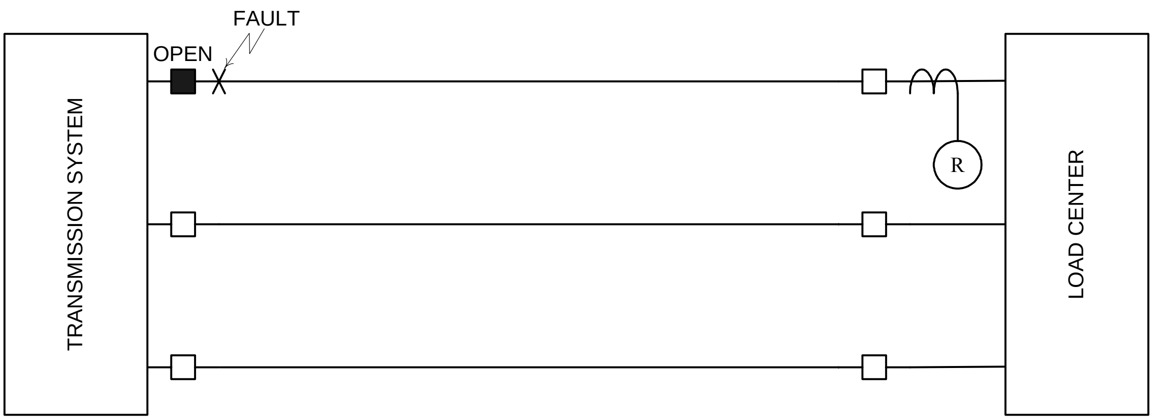

Figure 6 – Weak Source Systems

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{V_S{}^2 + V_R{}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current I_{fault} by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer.

$$I_{\max} = \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{max} = 1.485 \times I_{fault}$$

Where:

I_{fault} is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

For this exception:

The tripping relay should not operate at or below 1.15 times I_{max}, where I_{max} is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 7 — Long Line Relay Loadability

This exception applies only to classical two-terminal circuits. For lines with other configurations, see the exception for *Three (or more) Terminal Lines and Lines with One or More Radial Taps* (Exception 8). A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not “overly sensitive,” and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

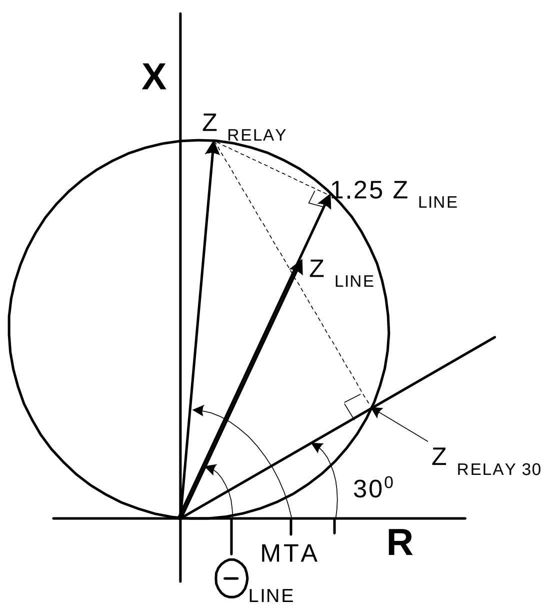

Figure 7 – Long Line relay Loadability

If this exception is required, it is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the emergency current loading is as follows:

V_{relay} = Phase-to-phase line voltage at the relay location

Z_{line} = Line impedance

Θ_{line} = Line impedance angle

Z_{relay} = Relay setting at the maximum torque angle

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{line})}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(MTA - 30°)}$$

The emergency load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{emergency} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{emergency} = \frac{0.85 \times V_{relay} \times cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times cos(MTA - 30°)}$$

$$\boxed{I_{emergency} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

For this exception:

The loadability requirement of lines that do not meet the thermal loadability requirement because of line length can be adjusted as long as ALL of the following conditions are met:

1. The most sensitive tripping relay is set for no more than 125% of the total line impedance.
2. The maximum torque angle (*MTA*) of the relay is set as close to 90 degrees as possible, as sanctioned by the protective relay manufacturer.
3. The short-term emergency rating ($I_{emergency}$) of the line is equal to or less than:

$$I_{emergency} = \left(\frac{0.341 \times V_{relay}}{Z_{line}} \right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)} \right)$$

   Where V is the nominal line-to-line voltage and Z_{line} is the impedance of the line in ohms.
4. $I_{emergency}$ of the circuit is used in all planning and operational modeling for the short-term (15-minute or that most closely approximates a 15-minute) emergency rating.
5. No current or subsequent planning contingency analyses identify any conditions where the recoverable flow is greater than $I_{emergency}$.
6. Transmission Operators are instructed to take immediate remedial steps, including dropping load, if the current on the circuit reaches $I_{emergency}$.

If any of these conditions are violated, then the condition must be fully mitigated to avoid the loadability issue.

Exception 8 — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. For this exception, the loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

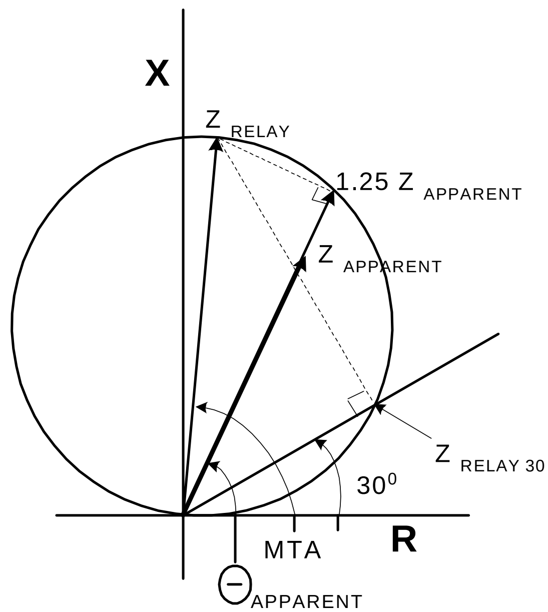

Figure 8 – Three (or more) Terminal Lines and Lines with One or More Radial Taps

The basis for the emergency current loading is as follows:

V_{relay} = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed where applicable) by the TPSO for a fault at the most electrically distant line terminal for system conditions normally used in their protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

Z_{relay} = Relay setting at the maximum torque angle.

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

$I_{emergency}$ = Emergency current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The emergency load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{emergency} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{emergency} = \frac{0.85 \times V_{relay} \times cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

$$\boxed{I_{emergency} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

For this exception:

The loadability requirement for a terminal on a three terminal line that does not meet the thermal loadability requirement because of apparent impedance can be adjusted as long as ALL of the following conditions are met:

1. The most sensitive tripping relay is set for no more than 125% of the apparent impedance as seen by that terminal.
2. The maximum torque angle of the relay is set as close to 90 degrees as sanctioned by the protective relay manufacturer.
3. The short term emergency rating $I_{emergency}$ of the line is:

   $$I_{emergency} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}} \right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)} \right)$$

   Where V is the nominal line-to-line voltage and $Z_{apparent}$ is the impedance of the line in ohms.
4. $I_{emergency}$ of the circuit is used in all planning and operational modeling for the short-term (15-minute) emergency rating.
5. No current or subsequent planning contingency identifies any conditions where the recoverable flow is greater than $I_{emergency}$.
6. Transmission Operators are instructed to take immediate remedial steps including dropping load if the current on the circuit reaches $I_{emergency}$.

If any of these conditions are violated, then the condition must be fully mitigated to avoid the loadability issue.

Exception 9 — Generation Remote to Load

Some system configurations have generation is remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 9a*), the total capability of the generator determines the maximum current (I_{max}) that the line will experience.

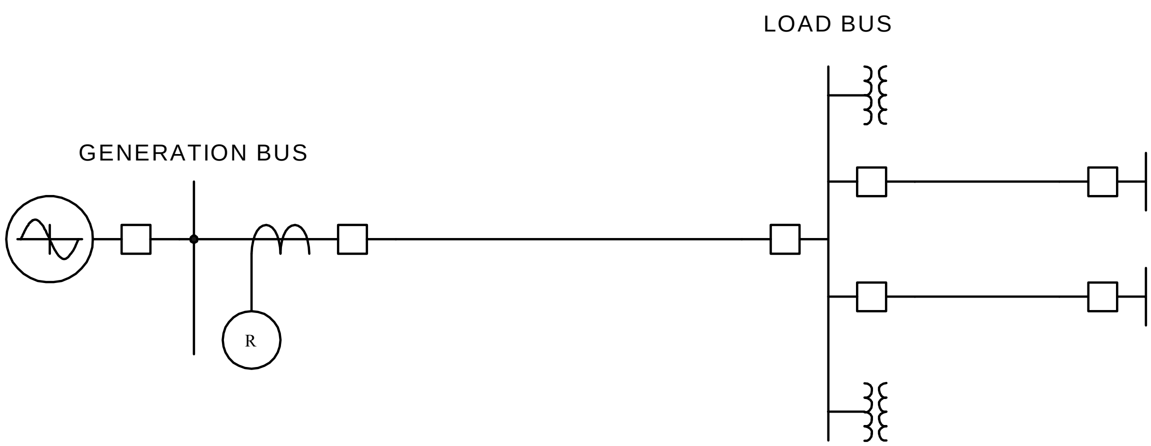

Figure 9a – Generation Remote to Load Center

For purposes of this exception the total generation output is defined as two times[8] the aggregate of the nameplate ratings of the generators in MVA converted to amps at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

$$\boxed{I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}}$$

Where:

V_{relay} = Phase-to-phase voltage at the relay location

N = Number of generators connected to the generation bus

[8] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

For this exception:

The tripping relay should not operate at or below 1.15 times the I_{max}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$$

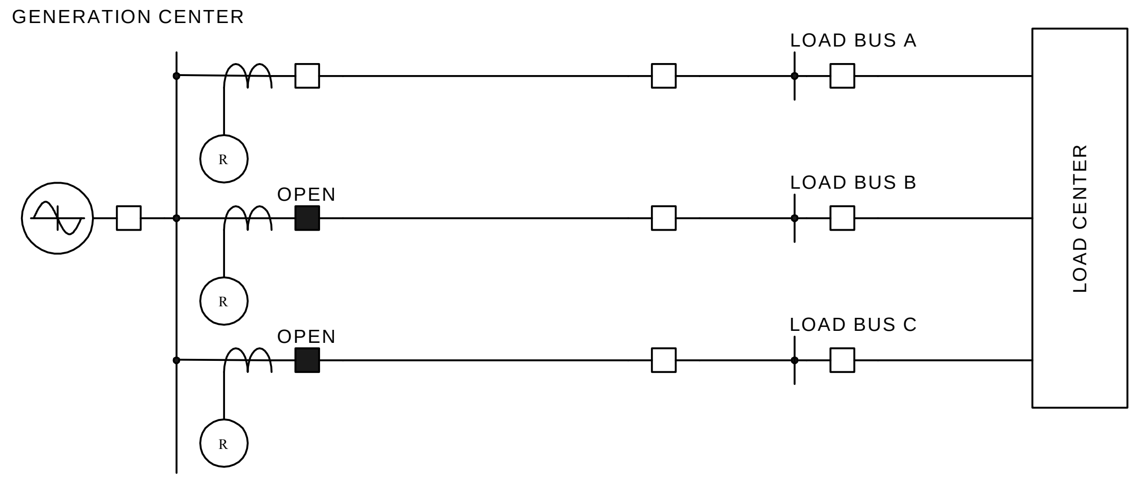

Figure 9b – Generation Connected to System – Multiple Lines

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 9b*). The I_{max} expressed above also applies in this case. To qualify for this exception, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. In using this exception, the TPSO must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds I_{max}.

For this exception:

The tripping relay should not operate at or below 1.15 times I_{max}, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$$

Exception 10 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 10*).

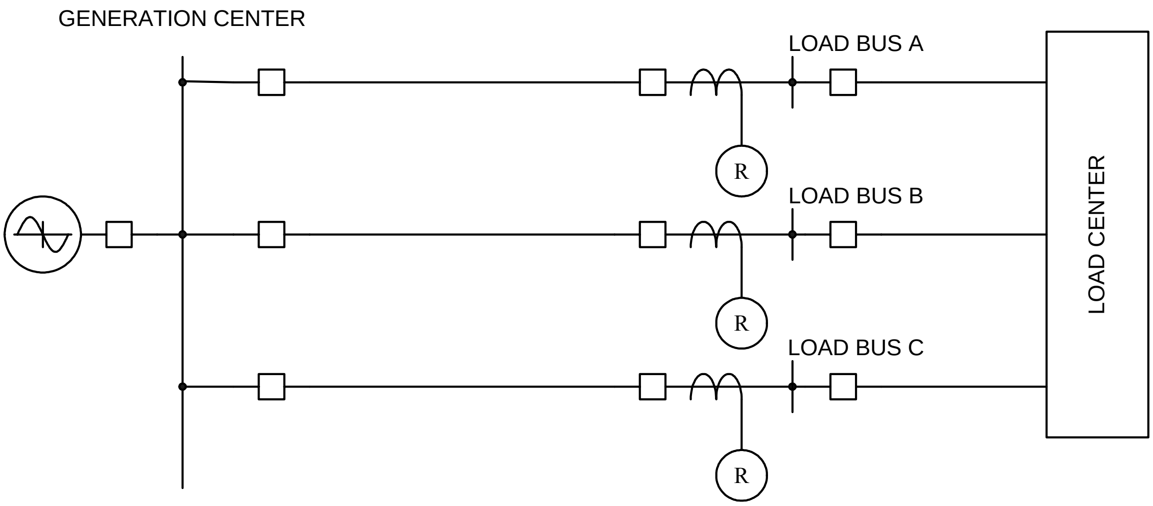

Figure 10 – Load Remote to Generation

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify for this exception, the TPSO must determine the maximum current flow from the load center to the generation center under any system contingency. The Reliability Coordinator must concur with this maximum flow.

For this exception:

The tripping relay should not operate at or below 1.15 times the maximum current flow as calculated by the TPSO. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 11 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 11*, the total maximum load at the load center defines the maximum load that a single line must carry.

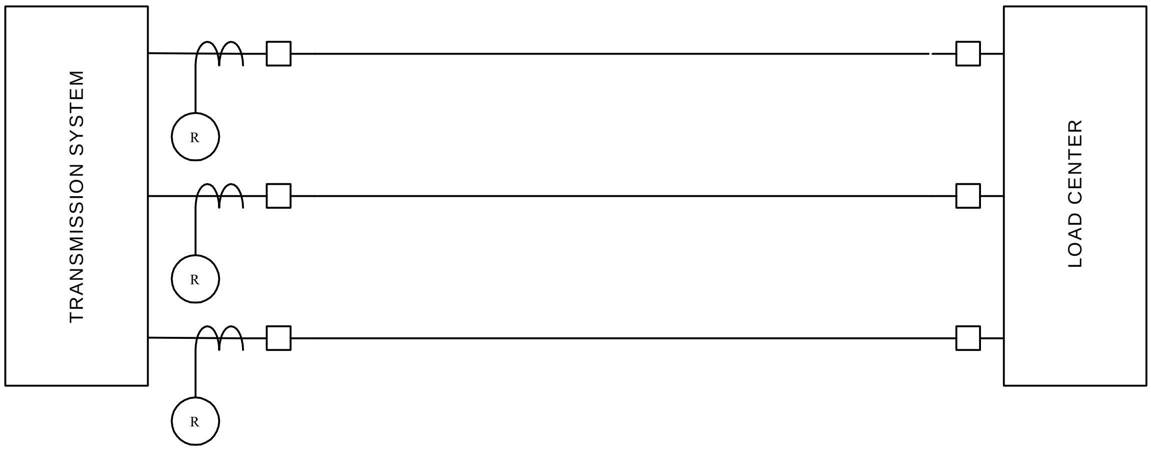

Figure 11 – Remote Cohesive Load Center

Also, to qualify for this exception, the TPSO must determine the maximum power flow on an individual line to the area ($I_{maxload}$) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines. The Reliability Coordinator must concur with this maximum flow.

For this exception:

The tripping relay should not operate at or below 1.15 times the maximum current flow as calculated by the TPSO. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 12 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 12*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in Exception 9.

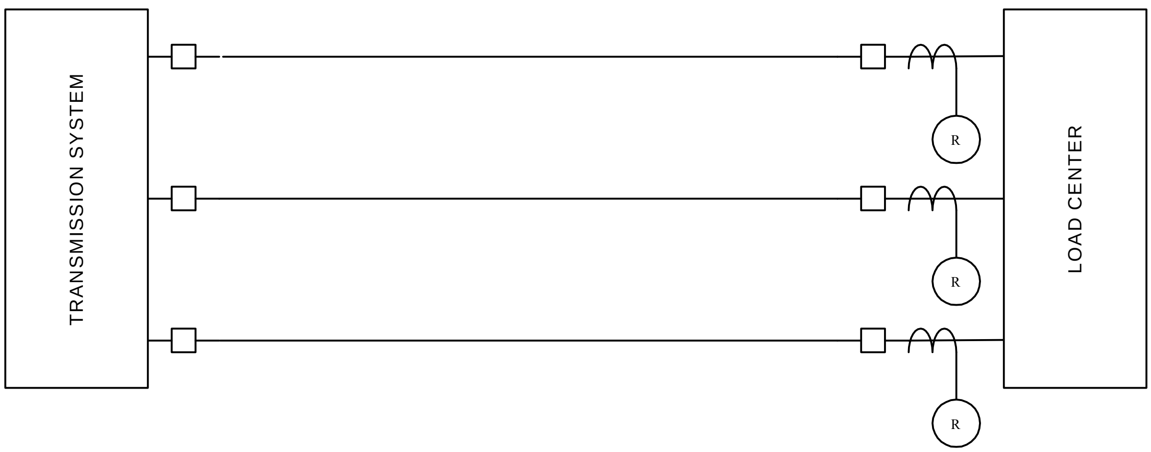

Figure 12 – Cohesive Load Center Remote to Transmission System

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify for this exception, the TPSO must determine the maximum current flow from the load center to the electrical network under any system contingency. The Reliability Coordinator must concur with this maximum flow.

For this exception:

The tripping relay should not operate at or below 1.15 times the maximum current flow as calculated by the TPSO. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

Exception 13 — Impedance-Based Pilot Relaying Schemes

Some TPSO's employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would be otherwise be implied by the setting of the forward (overreaching) impedance elements.

This may offer grounds for a technical exception provided the following criteria and requirements are met:

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify for this exception.
4. The TPSO shall furnish calculations which establish that the loadability of the scheme as a whole meets the NERC loadability requirement for the protected line.

Additional information on this topic is contained in Appendix B of the *Relay Loadability Exceptions* document (Version 1.2 or later).

Exception 14 — Transformer Overcurrent Protection

This exception provides for transformer overcurrent protection. The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[9] be sustained for several minutes without damage or appreciable loss of life to the transformer.

This exception may be used for those situations that the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer.

For this exception the TPSO must:

1.	Provide the protective relay set point(s) for all load-responsive relays on the transformer
2.	Provide the reason or basis for the reduced (below 150% of transformer nameplate or 115% of the operator-established emergency rating, whichever is higher) load capability
3.	Verify that no current or subsequent planning contingency analyses identify any conditions where the recoverable flow is less than reduced (150% of transformer nameplate or 115% of the highest operator-established emergency rating, whichever is higher) and greater than the TPSO's trip point.
4.	The TPSO's RRO and Reliability Coordinator must concur with the exception request.

If the TPSO uses an overcurrent relay that is supervised by either a top oil or simulated winding hot spot element less than 100° C and 140° C[10] respectively, justification for the reduced temperature must be provided.

9 See ANSI/IEEE Standard C57.92, Table 3.
10 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

APPENDIX B — SWITCH ON TO FAULT LOGIC

Switch on to fault schemes are protection functions intended to trip a transmission line breaker when closed on to a faulted line. There are two reasons for the application of this scheme. The first is for configurations of line-side potential devices. Logic is required to protect for the condition of close in three-phase faults that result in a near zero voltage. All phase directional and distance relays will not operate (cannot determine fault direction) during a zero voltage condition. The second purpose of the scheme is to provide high speed clearing of faults along the entire line without having to rely or wait on the communications aided tripping scheme.

There are numerous logic configurations implemented to create the switch on to fault tripping function. The following are a few of the methods employed:

1. Direct tripping high set instantaneous overcurrent
2. Breaker contact supervision of overcurrent elements allowing instantaneous tripping for a period of time after the breaker is closed.
3. Breaker contact supervision of overreaching distance elements allowing instantaneous tripping for a period of time after the breaker is closed.
4. Undervoltage supervision of overcurrent elements allowing short time delayed tripping once the undervoltage condition occurs.
5. Undervoltage supervision of overreaching distance elements allowing short time delayed tripping once the undervoltage condition occurs.
6. Combination of breaker and undervoltage supervision of the above tripping elements

Switch-on-to-fault schemes have misoperated during past system disturbances, and have tripped transmission lines during the disturbance and inhibited successful reclosing of line breakers. These schemes are subject to misoperation due to extreme emergency loading conditions resulting in high current and low voltage conditions. These conditions cause overcurrent elements to operate, undervoltage elements to pick up and overreaching distance relays to operate. When determining the switch on to fault element settings, each utility shall verify that the schemes will not operate for emergency loading conditions.

APPENDIX C — OUT-OF-STEP BLOCKING RELAYING

Out-of-step blocking is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability studies) or observed system swings.

There are many methods of providing the out-of-step blocking function; one common approach, used with distance tripping relays, uses a distance characteristic which is approximately concentric with the tripping characteristic. These characteristics may be circular mho characteristics, quadrilateral characteristics, or may be modified circular characteristics.

During normal system conditions the accelerating power, P_a, will be essentially zero. During system disturbances, $P_a > 0$. P_a is the difference between the mechanical power input, P_m, and the electrical power output, P_e, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of $P_a/2H$ radians per second squared, where H is the inertia constant of the system. During a fault condition $P_a >> 1$ resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, $P_a < 1$, resulting a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) which changes relative slowly at first; for a stable swing (where no generators “slip poles” or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly.

For simplicity, this appendix discusses the concentric-distance-characteristic method of out-of-step blocking, considering circular mho characteristics. As mentioned above, this approach uses a mho characteristic for the out-of-step blocking relay, which is approximately concentric to the related tripping relay characteristic. The out-of-step blocking characteristic is also equipped with a timer, such that a fault will transit the out-of-step blocking characteristic too quickly to operate the out-of-step blocking relay, but a swing will reside between the out-of-step blocking characteristic and the tripping characteristic for a sufficient period of time for the out-of-step blocking relay to trip. Operation of the out-of-step blocking relay (including the timer) will in turn inhibit the tripping relay from operating.

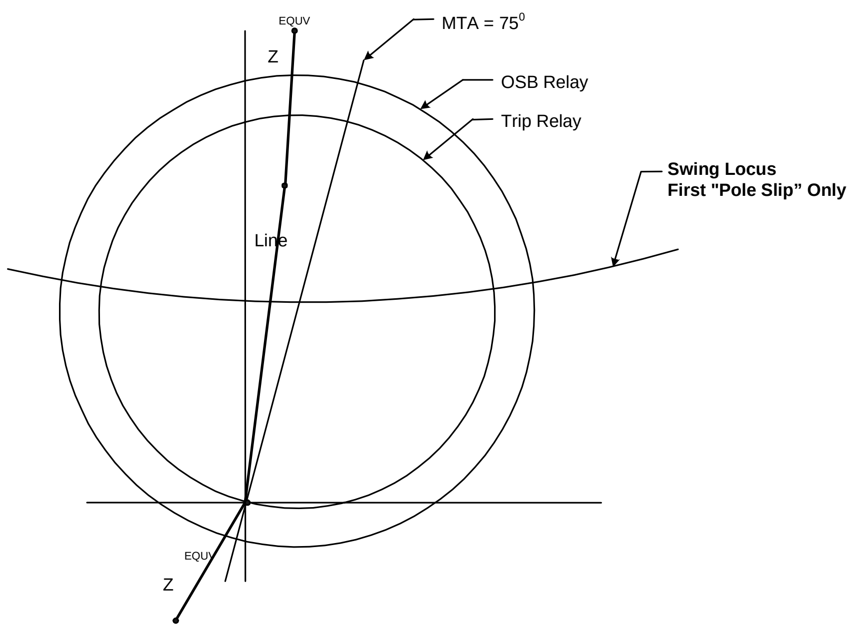

Figure 1 –

Figure 1 illustrates the relationship between the out-of-step blocking relay and the tripping relay, and shows a sample of a portion of an unstable swing.

Impact of System Loading of the Out-of-Step Relaying

Figure 2 illustrates a tripping relay and out-of-step blocking relay, and shows the relative effects of several apparent impedances.

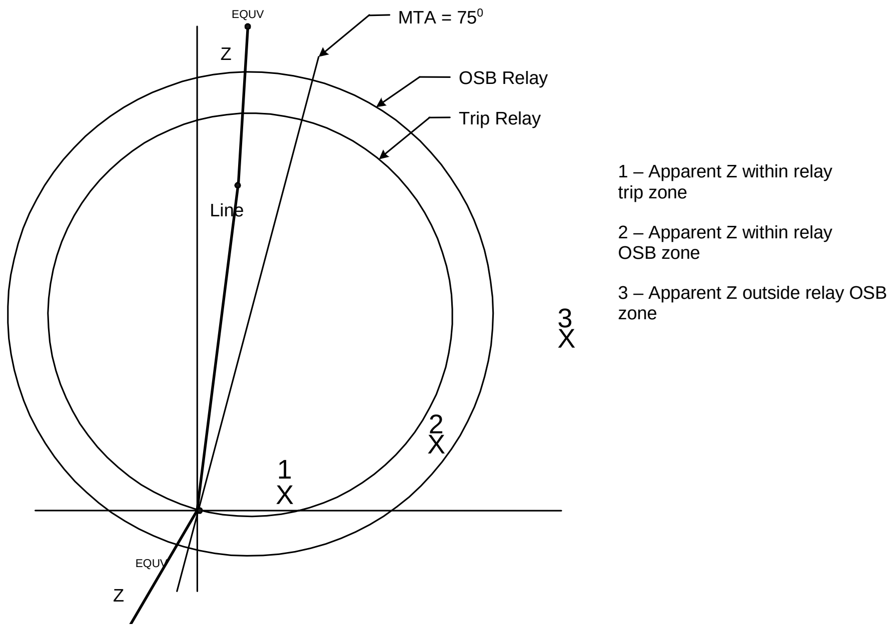

Figure 2 – Out-of-Step Characteristics with Load

Both the tripping relay and the out-of-step blocking relay have characteristics responsive to the impedance seen by the distance relay. In general, only the tripping relays are considered when evaluating the effect of system loads on relay characteristics (usually referred to as “relay loadability”). However, when the behavior of out-of-step blocking relays is considered, it becomes clear that they must also be included in the evaluation of system loads, as their reach must necessarily be longer than that of the tripping relays, making them even more responsive to load.

Three different load impedances are shown. Load impedance (1) shows an impedance (either load or fault) which would operate the tripping relay. Load impedance (3) shows a load impedance well outside both the tripping characteristic and the out-of-step blocking characteristic, and illustrates the desired result. The primary concern relates to the fact that, if an apparent impedance, shown as load impedance (2), resides within the out-of-step blocking characteristic (but outside the tripping characteristic) for the duration of the out-of-step blocking timer, the out-of-step blocking relay inhibits the operation of the tripping relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the out-of-step blocking relay, the tripping relay will be prevented from operating for a subsequent fault condition! A timer can be added such that the relay issues a trip if the out of step timer does not reset within a defined time.

APPENDIX D — QUICK SCREEN METHODS

A quick screen filter may be used to determine a maximum impedance setting (distance reach) such that any impedance setting selected below the maximum calculated impedance is acceptable, considering loadability criteria. The following are quick screen calculations examples that may be performed to speed up the protection loadability review process.

Zone 1

This screen applies to lines protected solely by standard mho characteristic distance elements with no load mitigating features.

NERC Technical Exception 7 provides a method to obtain the maximum loadability of an overreaching mho characteristic distance element. This loadability is obtained with a relay set to 125% of the line impedance (Z_{1L}) and a maximum torque angle (MTA) of 90 degrees. Any other overreaching setting that has been evaluated and met the NERC criteria for loadability has less loadability than that obtained by a setting of 125% Z_{1L} with a 90 degree MTA. Thus, if a zone 1 relay produces loadability greater than that of an overreaching element set at 125% Z_{1L} with a 90 degree MTA, the zone 1 relay's loadability meets NERC criteria.

The quick screen criteria below is obtained by equating the loadability of an overreaching zone set at 125% of Z_{1L} with a 90 degree MTA to the loadability of a generic zone 1 setting and solving.

$$I_{TripZone2} = \frac{V_{Relay} \times \cos(Z_{2MTA} - \Theta_{Line})}{(1.732 \times Z_{Relay30})}$$

$$I_{TripZone2} = \frac{V_{Relay} \times \cos(Z_{2MTA} - \Theta_{Line})}{(1.732 \times (1.25 \times Z_{1Line}) \times \cos(Z_{2MTA} - 30^o))}$$

Similarly,

$$I_{TripZone1} = \frac{V_{Relay} \times \cos(Z_{1MTA} - \Theta_{Line})}{(1.732 \times Z_{Relay30})}$$

$$I_{TripZone1} = \frac{V_{Relay} \times \cos(Z_{1MTA} - \Theta_{Line})}{(1.732 \times X\% \times Z_{1Line} \times \cos(Z_{1MTA} - 30^o))}$$

If $I_{TripZone2}$ is set equal to $I_{TripZone1}$, then:

$$\frac{V_{Relay} \times \cos(Z_{2MTA} - \Theta_{Line})}{(1.732 \times 1.25 \times Z_{1Line} \times \cos(Z_{2MTA} - 30^o))} = \frac{V_{Relay} \times \cos(Z_{1MTA} - \Theta_{Line})}{(1.732 \times X\% \times Z_{1Line} \times \cos(Z_{1MTA} - 30^o))}$$

or

$$X\% = \frac{1.25 \times \cos(Z_{2MTA} - 30^o) \times \cos(Z_{1MTA} - \Theta_{Line})}{\cos(Z_{1MTA} - 30^o)}$$

Note: For simplification, $\cos(Z_{2MTA} - \Theta_{\text{Line}})$ is assumed to be 1.0 for zone 2.

The table below shows allowable zone 1 reaches for mho relays with varying torque angles. For instance, a zone 1 relay set at 85% or less of the line impedance with a 75 degree maximum torque angle meets the NERC loadability criteria.

Zone 1 MTA	Assumed Worst Case Theta Line	Zone 2 MTA	Allowable Zone 1 Reach as a percentage of line length
60	90	90	63% Z_{1L}
65	90	90	69% Z_{1L}
70	90	90	77% Z_{1L}
75	90	90	85% Z_{1L}
80	90	90	96% Z_{1L}
85	70	90	* 105% Z_{1L}
90	70	90	* 117% Z_{1L}

* For all practical purposes, there is not a zone 1 constraint when these values are greater that 100% because zone 1 is never set above 100% of the line.

Theta Line has been assumed as shown as a worst case and line angles are assumed to vary between 70 and 90 degrees.

Any Distance Zone Quick Screen – 4 Hour

This screen applies to lines protected solely by standard mho characteristic distance elements.

This screen calculates a distance zone setting for any tripping distance element. If a distance element meets this screen, it will require no further review regardless of the relay maximum torque angle (MTA) setting based solely on the magnitude of the impedance setting of the relay.

This screen is based on calculating a $Z_{terminal}$ where the relay terminal voltage is fixed at 0.85 V pu and the current is fixed at a particular companies maximum 4 hour (or closest to 4 hour) transmission line rating (examples are shown in the table below). A 50% margin is added for consistency with NERC Recommendation 8a from the August 14th, 2003 Blackout. $Z_{terminal}$ as shown represents the magnitude of the impedance seen by a relay due to load at any angle at the relay terminal. $Z_{terminal}$ plots on an R-X diagram as a circle with a radius of $Z_{terminal}$. Load at any angle will not enter the relay characteristic of a relay set with the maximum calculated distance zone setting as shown at a relay terminal voltage of 0.85 V pu.

The quick screen criterion is shown below.

$$MaxAllowableSetting = \frac{\left(0.85 \times V_{\mathrm{Re}lay}\right)}{(1.732 \times I_{4HourMax} \times 1.5)}$$

Where:

V_{Relay} = Phase-to-phase line voltage at the relay location

$I_{4HourMax}$ = Companies maximum 4 hour (or closest to 4 hour) transmission line rating

V_{Relay}	Maximum System 4 Hour Transmission Line Rating (enter your companies rating)	$Z_{terminal}$ due to load at 0.85 V pu	Margin	Maximum Distance Zone Setting set at any MTA Requiring No Further Review
138,000	3,000	22.6	1.50	15.1
161,000	3,000	26.3	1.50	17.6
230,000	3,000	37.6	1.50	25.1
345,000	4,000	42.3	1.50	28.2
500,000	4,000	61.3	1.50	40.9
765,000	4,000	93.9	1.50	62.6

Any Distance Zone Quick Screen – 15 Minute

This screen applies to lines protected solely by standard mho characteristic distance elements.

This screen calculates a distance zone setting for any tripping distance element. If a distance element meets this screen, it will require no further review regardless of the relay maximum torque angle (MTA) setting based solely on the magnitude of the impedance setting of the relay.

This screen is based on calculating a $Z_{terminal}$ where the relay terminal voltage is fixed at 0.85 V pu and the current is fixed at a particular companies maximum 15 minute transmission line rating (examples are shown in the table below). A 15% margin is added for consistency with the NERC Relay Loadability Exceptions document Version 1.1 issued in November of 2004. $Z_{terminal}$ as shown represents the magnitude of the impedance seen by a relay due to load at any angle at the relay terminal. $Z_{terminal}$ plots on an R-X diagram as a circle with a radius of $Z_{terminal}$. Load at any angle will not enter the relay characteristic of a relay set with the maximum calculated distance zone setting as shown at a relay terminal voltage of 0.85 V pu.

The quick screen criterion is shown below.

$$MaxAllowableSetting = \frac{(0.85 \times V_{Relay})}{(1.732 \times I_{15MinuteMax} \times 1.15)}$$

Where:

V_{Relay} = Phase-to-phase line voltage at the relay location

$I_{15MinuteMax}$ = Companies maximum 15 minute transmission line rating

V_{Relay}	Maximum System 15 Minute Transmission Line Rating (enter your companies rating)	$Z_{terminal}$ due to load at 0.85 V pu	Margin	Maximum Distance Zone Setting set at any MTA Requiring No Further Review
138,000	3,000	22.6	1.15	19.6
161,000	3,000	26.3	1.15	22.9
230,000	3,000	37.6	1.15	32.7
345,000	4,000	42.3	1.15	36.8
500,000	4,000	61.3	1.15	53.3
765,000	4,000	93.9	1.15	81.6

APPENDIX E — REPORTING FORMS

The following are samples forms are to be used by the TPSOs to report back to their regions and to NERC. Forms include Job Aid spreadsheets available to assist the TPSOs in their protection system reviews.

The full Excel worksheets are available at: http://www.nerc.com/~filez/spctf.html

Review Summary Form

Summary of Relaying Reviews - Beyond Zone 3 (NERC Recommendation 21a Scope Expansion)

This form shall be used without modification to provide a summary of relaying reviews performed by each Transmisission System Protection Owner (TPSO) on June 30, 2006. Fill out this form in its entirety.

Transmission System Protection Owner Name	
Regional Reliability Council Name	
Reliability Coordinator Name	

Certification Statements

☐ We certify that our system meets all of the requirements of the loadability criteria.

☐ We certify that our system meets all of the requirements of the loadability criteria, except for the non-conformance identified in these forms

Submittal Date	
Contact Name	
Title	
Phone	
Fax	
E-mail	

Review Summary: 200kV and Above

Number of circuit terminals reviewed		
Number of circuit terminals not conforming to Loadability Requirement		
Number of circuit terminals to be mitigated by 12-31-07		*
Number of circuit terminals requiring Temporary Exceptions		(not expected to be completed by 12-31-07)
Number of circuit terminals requesting Technical Exceptions		

Mitigation Plans - 200 kV and Above (Number of circuit terminals)

	Already mitigated by 6/30/2006	Planned for mitigation between 6/30/2006 and 12/31/2007	Planned for mitigation after 12/31/07
Setting Changes			
Disable Function			
Equipment Replacement / Addition			
Other			
Total mitigations	0	0	0

Review Summary: Operationally Significant Circuits, 100 kV - 200 kV

Number of circuit terminals reviewed		
Number of circuit terminals not conforming to Loadability Requirement		
Number of circuit terminals to be mitigated by 12-31-07		*
Number of circuit terminals requiring Temporary Exceptions		(not expected to be completed by 12-31-07)
Number of circuit terminals requesting Technical Exceptions		

Mitigation Plans - Critical Circuits 100 kV - 200 kV (Number of circuit terminals)

	Already mitigated by 12/31/2006	Planned for mitigation between 12/31/2006 and 6/30/2008	Planned for mitigation after 6/30/2008
Setting Changes			
Disable Function			
Equipment Replacement / Addition			
Other			
Total mitigations	0	0	0 *

* Should Agree

Review Summary: Combined - Populated from Above Data

Number of circuit terminals not conforming to Loadability Requirement	0	
Number of circuit terminals to be mitigated by 12-31-07	0	*
Number of circuit terminals requiring Temporary Exceptions	0	(not expected to be completed by 12-31-07)
Number of circuit terminals requesting Technical Exceptions	0	

Mitigation Form (Optional)

Mitigation Reporting Form

This optional Form can be used by the TPSOs and the Regions to track all circuits not meeting the loadability parameters which will be mitigated by December 31, 2007.

Transmission System Owner Name	
Regional Reliability Council Name	
Reliability Coordinator Name	
Submittal Date	

		Unique Circuit Identifier (one or more as necessary)				Mitigation Dates		Mitigation Plan				
Station Name	**Nominal Voltage**	**Local Breaker ID(s)**	**Remote Terminal Name(s)**	**Circuit Name**	**Circuit Number**	**Planned**	**Actual**	**Setting Change**	**Disable Function**	**Equipment Replacement / Addition**	**Other**	**Region Recommendation**

Temporary Exceptions Form

Temporary Exception Reporting Form

This Form shall be used to report all Temporary Exception Requests for the Relay Loadability Review. All information requested in the table shall be provided for each Temporary Exception being requested.

Transmission System Owner Name	
Regional Reliability Council Name	
Reliability Coordinator Name	
Submittal Date	

		Unique Circuit Identifier (one or more as necessary)				Mitigation Dates		Mitigation Plan					
Station Name	Nominal Voltage	Local Breaker ID(s)	Remote Terminal Name(s)	Circuit Name	Circuit Number	Planned	Actual	Setting Change	Disable Function	Equipment Replacement / Addition	Other	Justification for Temporary Exception	Region Recommendation

Technical Exceptions Form

Technical Exception Reporting Form

This Form shall be used to report all Technical Exception Requests for the NERC Relay Loadability Review. All information requested in the table shall be provided for each Technical Exception being requested.

Note: Complete Supplemental Information Sheet for Exceptions 7-8. For Exceptions 9 through 12, submit system maps (physical, switching, and relaying, as appropriate), and sufficient system studies and working papers to facilitate adequate and timely review of the request by the SPCTF. If necessary, the SPCTF will request additional supporting information. All submissions should be in electronic format.

Transmission System Owner Name	
Regional Reliability Council Name	
Reliability Coordinator Name	
Submittal Date	

		Unique Circuit Identifier (one or more as necessary)								
Station Name	**Nominal Voltage**	**Local Breaker ID(s)**	**Remote Terminal Name(s)**	**Circuit Name**	**Circuit Number**	**Line Length in Miles**	**Line Impedance in Ohms (Z)**	**Transformer MVA Rating Evaluated**	**Exception Number**	**Region Recommendation**

Supporting Information Form for Exceptions 7 & 8

Technical Exception 7 and 8 Supplemental Data Reporting Form

Complete all information in this tabel for each Exception 7 or Exception 8 being requested.

Transmission System Owner Name	
Regional Reliability Council Name	
Reliability Coordinator Name	
Submittal Date	

		Unique Circuit Identifier (one or more as necessary)				Respond Yes or No				
Station Name	**Nominal Voltage**	**Local Breaker ID(s)**	**Remote Terminal Name(s)**	**Circuit Name**	**Circuit Number**	**Relay Reach < 125%?**	**MTA Closest to 90-deg**	**$I_{emergency}$ Used in all Studies**	**No Contingencies > $I_{emergency}$**	**Reliability Coordinator Commitment to Action for Current > $I_{emergency}$**

Exception 2 Job Aid

Exception Calculation - Exception 2 - Alternate Rating Based Transmission Line Parameters Only

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:	
Line Name:	

Line kV 345 kV Phase-to-phase

Input Quantities (primary Ohms/Mhos):

Line Parameters	Resistance	3.594	Ohms	Reactance	56.68	Ohms
				Line Susceptance (B/2):	0.00029	Mhos

Calculated Quantities:

Impedance Magnitude (ZL+Zs+Zr):	56.79383	Ohms		
Impedance Angle:	86.37181	Degrees	1.507472	radians
Power Transfer Angle:	90	Degrees	1.570796	radians
Equivalent Voltage:	1	per-unit	345	kV

Complex Power Flow Quantities

Sending End Real Power Flow:	2224.159	MW
Sending End Reactive Power Flow:	1924.399	MVAR
Sending End Complex Power Flow:	2941.122	MVA
Sending End Current Flow:	4921.905	Amperes

Note: The use of the complex power equations is optional, and may result in a lower maximum power transfer level. The equations, as listed in the "Relay Loadability Exceptions" document can be used directly if it provides the TPSO the necessary relief

Exception 3 Job Aid

Exception Calculation - Exception 3 - Alternate Rating Based on Breaker Ratings

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:
Line Name:

Line kV 345 kV Phase-to-phase

Input Quantities (primary Ohms/Mhos):

Line Parameters	Resistance	3.594	Ohms	Reactance	56.68 Ohms
				Line Susceptance (B/2):	0.00029 Mhos
Source Impedances from Breaker Ratings:					
Sending End Breaker Rating	40000	Amps		4.979646	Ohms Reactance
Receiving End Breaker Rating	63000	Amps		3.16168	Ohms Reactance

Calculated Quantities:

Impedance Magnitude (ZL+Zs+Zr):	64.92088	Ohms		
Impedance Angle:	86.8265	Degrees	1.515408	radians
Power Transfer Angle:	90	Degrees	1.570796	radians
Equivalent Voltage:	1.05	per-unit	362.25	kV

Complex Power Flow Quantities

Sending End Real Power Flow:	2130.107	MW
Sending End Reactive Power Flow:	1868.253	MVAR
Sending End Complex Power Flow:	2833.324	MVA
Sending End Current Flow:	4741.508	Amperes

Note: The use of the complex power equations is optional, and may result in a lower maximum power transfer level. The equations, as listed in the "Relay Loadability Exceptions" document can be used directly.

Exception 4 Job Aid

Exception Calculation - Exception 4 - Alternate Rating Based on Actual Source Impedances

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:
Line Name:

Line kV 345 kV Phase-to-phase

Input Quantities (primary Ohms/Mhos):

Line Parameters	Resistance	3.594	Ohms	Reactance	56.68	Ohms
				Line Susceptance (B/2):	0.00029	Mhos
Source Impedances:						
Sending End	Resistance	2.142	Ohms	Reactance	5.082	Ohms
Receiving End	Resistance	0.821	Ohms	Reactance	11.355	Ohms

Calculated Quantities:

Impedance Magnitude (ZL+Zs+Zr):	73.41042	Ohms		
Impedance Angle:	85.90397	Degrees	1.499307	radians
Power Transfer Angle:	90	Degrees	1.570796	radians
Equivalent Voltage:	1.05	per-unit	362.25	kV

Complex Power Flow Quantities

Sending End Real Power Flow:	1910.67	MW
Sending End Reactive Power Flow:	1617.25	MVAR
Sending End Complex Power Flow:	2503.229	MVA
Sending End Current Flow:	4189.102	Amperes

Note: The use of the complex power equations is optional, and may result in a lower maximum power transfer level. The equations, as listed in the "Relay Loadability Exceptions" document can be used directly.

Exception 6 Job Aid

Exception Calculation - Exception 6 - Alternate Rating Based on Line-End Fault Magnitude

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:
Line Name:

Line kV 345 kV Phase-to-phase

Input Quantities (primary Amperes):

Line-End Three Phase Fault Magnitude 2500 Amperes

Calculated Quantities:

I_{max} Per Exception 6 3712.311 Amperes

Exception 7 Job Aid

Exception Calculation - Exception 7 - Alternate Rating Based on Long Line Protection

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:
Line Name:

Line kV 345 kV Phase-to-phase

Input Quantities (primary Ohms/Mhos):

Line Parameters Resistance 3.594 Ohms Reactance 56.68 Ohms
Line Impedance: 56.79383 Ohms Line Angle: 86.37181 Degrees

Sending End Relay Information and Settings (Mho Relay Only)
Relay Manufacturer: Relay Model:
Primary Setting 70 Ohms Max Torque Angle 75 degrees 1.308997 radians
Maximum Sanctioned Relay Max Torque Angle: 75 degrees

Calculated Quantities:

Maximum Relay Reach (125% of Z_L) 72.4139 Ohms

$I_{emergency}$ Per Exception 7 Calculation - 125% of Line 2875.23 Amperes

Exception 8 Job Aid

Exception Calculation - Exception 8 - Alternate Rating Based on Multiterminal Line Protection

Instructions: Provide the Relevant Information for the Yellow-Shaded Boxes

Transmission Owner:
Line Name:

Line kV 345 kV Phase-to-phase

Input Quantities (primary Ohms/Mhos):
Line Parameters (Calculated Apparent Line Impedance)

Resistance	3.594	Ohms	Reactance	56.68	Ohms
Apparent Line Impedance:	56.79383	Ohms	Line Angle:	86.37181	Degrees

Sending End Relay Information and Settings (Mho Relay Only)

Relay Manufacturer:			Relay Model:				
Primary Setting	70	Ohms	Max Torque Angle	75	degrees	1.308997	radians
			Maximum Sanctioned Relay Max Torque Angle:	75	degrees		

Calculated Quantities:

Maximum Relay Reach (125% of $Z_{Apparent}$)	72.4139	Ohms
$I_{emergency}$ Per Exception 7 Calculation - 125% of Apparent Impedance	2875.23	Amperes

APPENDIX F — RELATED READING AND REFERENCES

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

The NERC documents referenced can be found at:

http://www.nerc.com/~filez/spctf.html

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1. NERC Zone 3 Review Procedures set forth in the *System Protection and Control Task Force's Initial Recommendations Concerning NERC Recommendation 8A Loadability Requirements on Transmission Protective Relaying Systems*, approved by the NERC Planning Committee on July 20, 2004.
2. NERC Letter to TPSOs *Clarification of the Transmission Line Emergency Ampere Rating to be Used to Determine Compliance with Loadability Requirements for Zone 3 Relays (Blackout Recommendation 8a)*, June 22, 2004.
3. NERC Reference Document *Relay Loadability Exceptions — Determination and Application of Practical Relaying Loadability Ratings*, Version 1.1, November 2004.
4. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
5. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
6. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
7. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
8. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
9. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
10. IEEE Standard C37.113*, IEEE Guide for Protective Relay Applications to Transmission Lines*
11. ANSI Standard C50.13*, American National Standard for Cylindrical Rotor Synchronous Generators.*

12. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)*, 1995

13. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.

14. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.

15. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.

16. *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts*, approved by the NERC Board of Trustees, February 10, 2004

Draft IEEE Power System Relay Committee paper, ballot resolution in progress:

Power Swing and Out-Of-Step Considerations on Transmission Lines, Draft, May 2005, IEEE Power System Relay Committee.

APPENDIX G — SYSTEM PROTECTION AND CONTROL TASK FORCE

Charles W. Rogers
Chairman / ECAR Representative
Principal Engineer
Consumers Energy Co.

W. Mark Carpenter
Vice Chairman / ERCOT Representative
System Protection manager
TXU Electric Delivery

John Mulhausen
FRCC Representative
Florida Power & Light Co.

Joseph M. Burdis
MAAC Representative
Senior Consultant / Engineer, Transmission and Interconnection Planning
PJM Interconnection, L.L.C.

William J. Miller
MAIN Representative
Consulting Engineer
Exelon Corporation

Deven Bhan
MAPP Representative
System Protection Engineer
Western Area Power Administration

Philip Tatro
NPCC Representative
Consulting Engineer
National Grid USA

Philip B. Winston
SERC Representative
Manager, Protection and Control
Georgia Power Company

Fred Ipock
SPP Representative
Senior Engineer – Substation Engineering
City Utilities of Springfield, Missouri

David Angell
WSCC Representative
System Protection & Communications Leader
Idaho Power Company

John L. Ciufo
Canada Member-at-Large
Team Leader – P&C / Telecom
Hydro One, Inc.

W. O. (Bill) Kennedy
Canada Member-at-Large
Principal Engineer
Alberta Electric System Operator

Jim Ingleson
ISO / RTO Representative
Senior Operations Engineer
New York Independent System Operator

Evan T. Sage
Investor Owned Utility
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