NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

ERO Enterprise Endorsed Implementation Guidance

Determination of Practical Transmission Relaying Loadability Settings

Implementation Guidance for PRC-023-4
System Protection and Control Subcommittee

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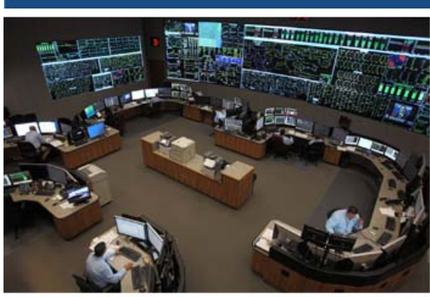
RELIABILITY | ACCOUNTABILITY

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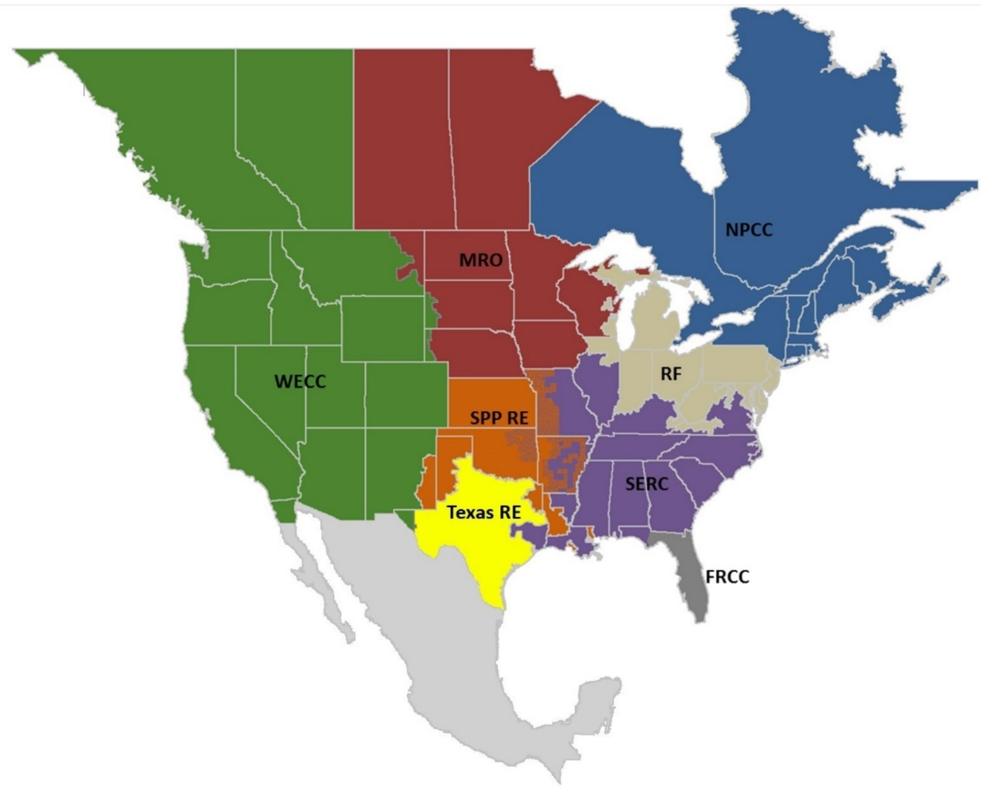
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Disclaimer

This supporting document may explain or facilitate implementation of a reliability standard PRC-023-4 — Transmission Relay Loadability but does not contain mandatory requirements subject to compliance review.

Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023-4 — Transmission Relay Loadability.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and 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. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard 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.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023-4; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC-023-4:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Generator protection relays
   - 2.4. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017

Chapter 1: Requirements Reference Material

R1 — Phase Relay Setting

Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [Risk Factor: High]

1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.5\ x\ I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a power factor angle of 30 degrees

$V_{L\text{-}L}$ = Rated line-to-line voltage

I_{rating} = Facility Rating

> Set the relay so it does not operate at or below 150% of the highest seasonal Facility Rating (I_{rating}) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
>
> Example: $Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.5\ x\ I_{rating}}$

1.2 — Transmission Line Established 15-Minute Rating

When the study to establish the original loadability parameters was performed, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the Facility 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% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute highest seasonal Facility Rating can be used to establish the loadability requirement for the protective relays.

> Set the tripping relay so it does not operate at or below 115% of the 15-minute highest seasonal Facility Rating (I_{rating}) 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: $Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{rating}}$

1.3 — Maximum Theoretical Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

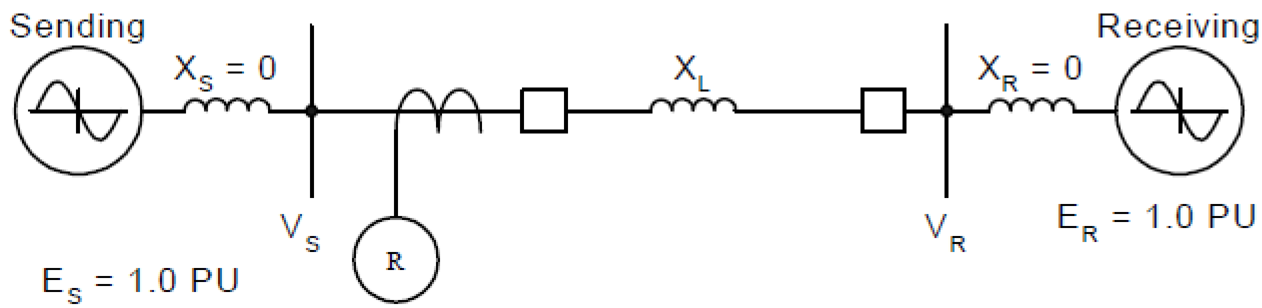


Figure 1: Maximum Power Transfer

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

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

Where:

P = the power flow across the transmission line

V_S = Line-to-Line voltage at the sending bus

V_R = Line-to-Line voltage at the receiving bus

δ = Voltage angle between Vs and V_R

X_L = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The 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. A number of conservative assumptions are made:

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

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

The equation for maximum power becomes:

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

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

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

Where:

P_{max} = Maximum power that can be transferred across a system

I_{real} = Real component of current

V = Nominal line-to-line bus voltage

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

$$I_{total} = \sqrt{2} x\, I_{real}$$

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

$$I_{total} = \frac{0.816\, x\, V}{X_L}$$

Where:

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

Set the tripping relay so it does not operate at or below 115% of I_{total} (where $I_{total} = \frac{0.816\, x\, V}{X_L}$).

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\, x\, 1.15\, x\, I_{total}}$$

Maximum Power Transfer with System Source Impedance

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 2*).

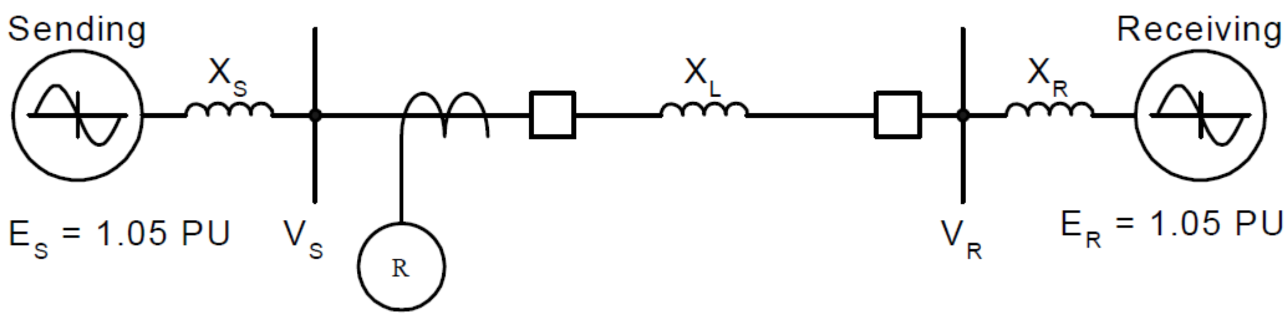


Figure 2: Site-Specific Maximum Power Transfer Limit

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 fixed at 90 degrees, and the current magnitude (I_{real}) for the maximum power transfer across the system is determined as follows[2]:

$$P_{max} = \frac{(1.05\ x\ V)^2}{X_s + X_r + X_l}$$

Where:

P_{max} = Maximum power that can be transferred across a system

E_S = the line-to-line internal voltage for the generator modeled behind the equivalent sending end reactance X_S

E_R = the line-to-line internal voltage for the generator modeled behind the equivalent receiving end reactance X_R

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

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

V = Line-to-Line bus voltage

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

$$I_{real} = \frac{0.606\ x\ V}{X_S + X_R + X_L}$$

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. A number of conservative assumptions are made:

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

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

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

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

$$I_{total} = \frac{0.857\ x\ V}{(X_S + X_R + X_L)}$$

Where:

I_{total} = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 115% of 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.

$$Z_{relay\ 30} = \frac{0.85\ \mathrm{x}\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{total}}$$

This should be re-verified whenever major system changes are made.

1.4 — 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. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

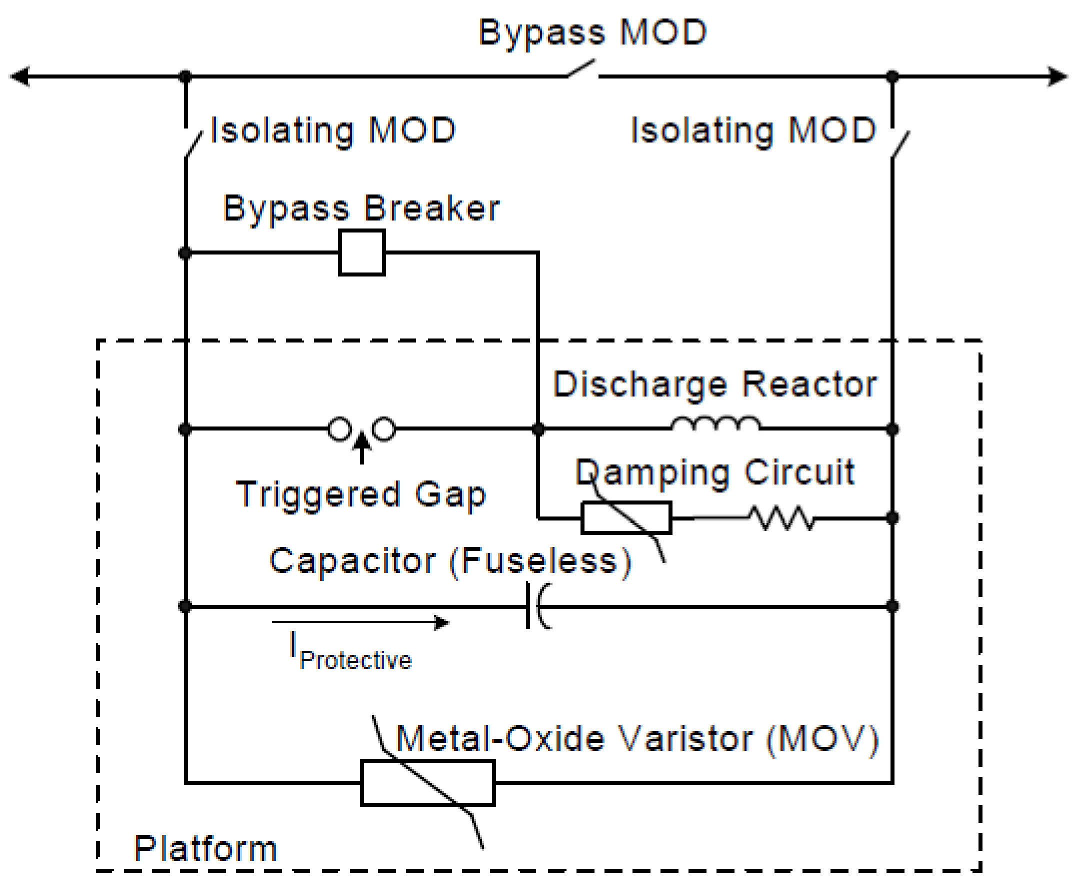


Figure 3: Series Capacitor Components

The capacitor banks are protected from overload conditions by triggered gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers or Motor Operated Disconnects (MODs). Triggered gaps and/or MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$) whichever may be present in a given installation.

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

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

Where:

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

X_C = Capacitive reactance

The 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 R1 Part 1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1 Part 1.3 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.

Set the tripping relay so it does not operate at or below the greater of:

1. 115% of 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 R1 Part 1.3 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.

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{total}}$$

1.5 — 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 4*).

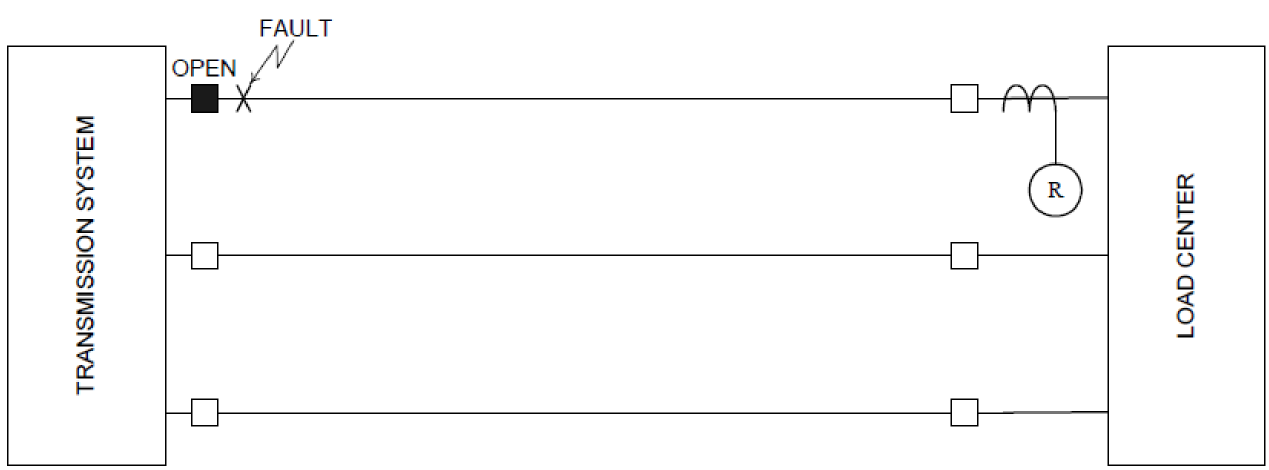


Figure 4: Weak Source Systems

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:

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

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 and by 115% to provide margin for device errors. An additional factor of 105% is also included due to the assumption that the voltage on each bus is 1.05 per unit.

$$I_{max} = 1.15\, x \sqrt{2}\, x\, 1.05\, x\, I_{fault}$$

$$I_{max} = 1.71\, x\, I_{fault}$$

Where:

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

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times I_{fault}, where I_{fault} 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.

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\, x\, 1.70\, x\, I_{fault}}$$

1.6 — Not Used

1.7 — 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 7*).

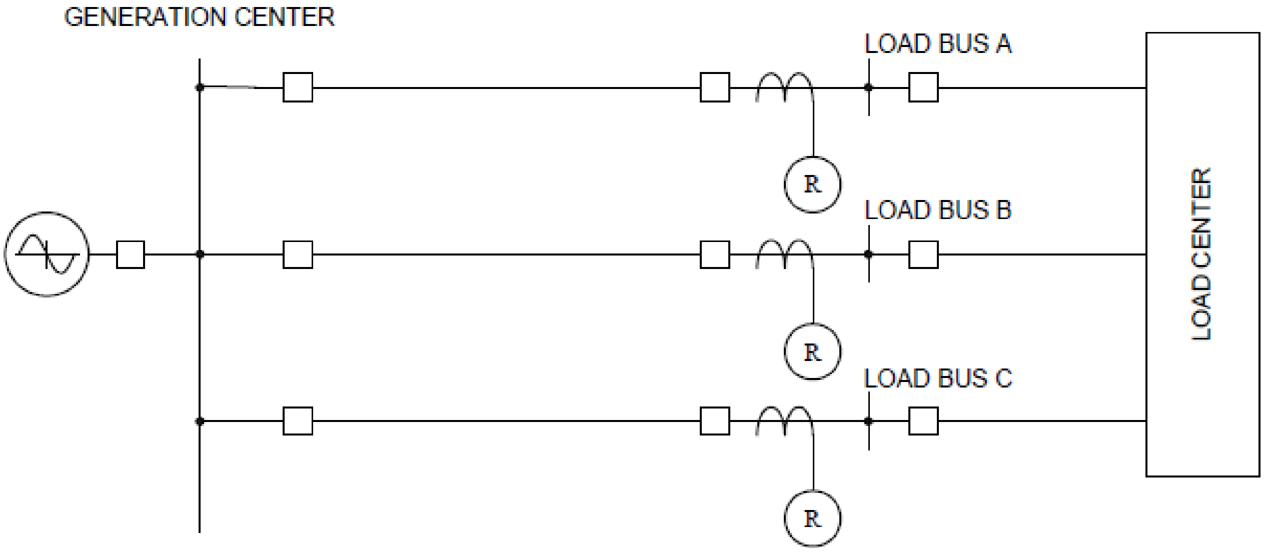


Figure 7 – Load Remote to Generation Center

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, one must determine the maximum current flow (I_{max}) from the load center to the generation center under any system configuration.

Set the tripping relay at the load center so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{max}}$$

1.8 — Remote Load Center

Some system configurations have one or more transmission lines connecting a remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

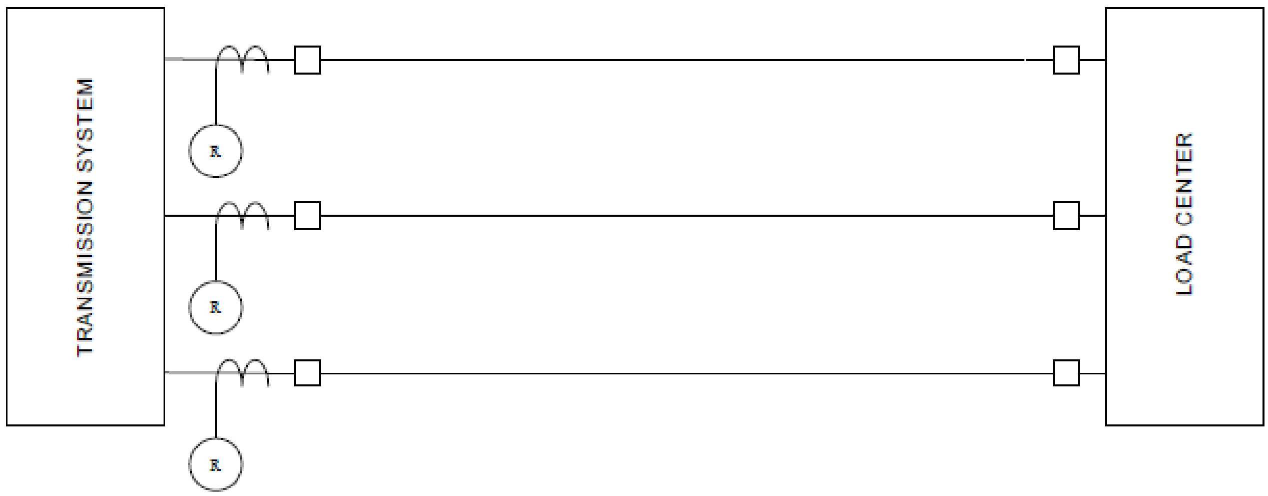


Figure 8 – Remote Load Center

Also, one must determine the maximum power flow on an individual line to the area (I_{max}) under all system configurations, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of I_{max} flow in the transmission lines.

> Set the tripping relay so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
>
> $$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{max}}$$

1.9 —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 9*, 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 R1 Part 1.8.

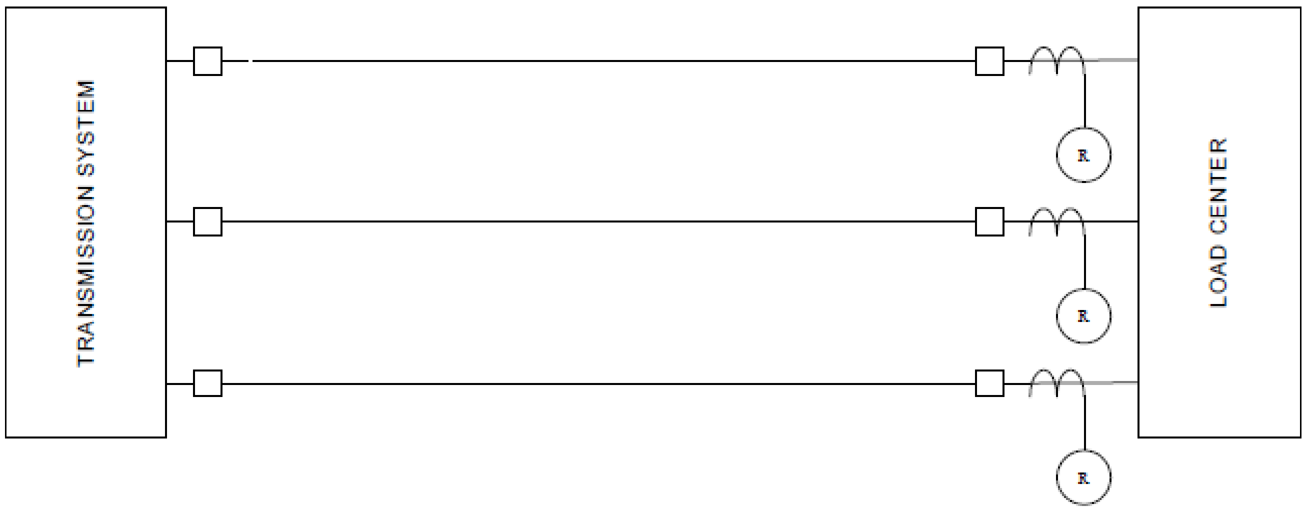


Figure 9 –Load Center Remote to Transmission System

However, under normal conditions, only minimal current can flow from the load center to the transmission system. 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, one must determine the maximum current flow (I_{max}) from the load center to the transmission system under any system configuration.

Set the tripping relay so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{relay\ 30} = \frac{0.85 \text{ x } V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{max}}$$

1.10 — 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[3] be sustained for several minutes without damage or appreciable loss of life to the transformer.

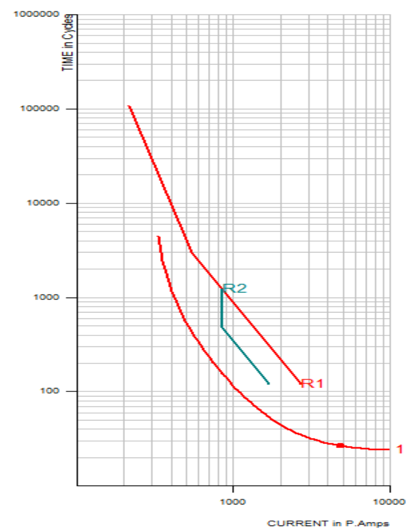
For transformers with operator established emergency ratings, the minimum overcurrent setting must be the greater of 115% of the highest established emergency rating, or 150% of the maximum nameplate rating.

This criterion is also applicable for transmission line relays on transmission lines terminated only with a transformer.

1.10.1 — Coordination with IEEE Damage Curve

Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability as illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] See ANSI/IEEE Standard C57.92, Table 3.



1.11 – Transformer Overload Protection

If the pickup of overcurrent relays is less than that specified in criterion 1.10, then the relays must be 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, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.

Alternatively, the relays may be set below the requirements of criterion 1.10 if tripping is supervised using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature.

1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal lines. For lines with other configurations, see R1 Part 1.12b, *Three (or more) Terminal Lines, and Lines with One or More Radial Taps*. 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 if the relays with mho characteristics are set at 125% of the line length. For available techniques see reference 14.

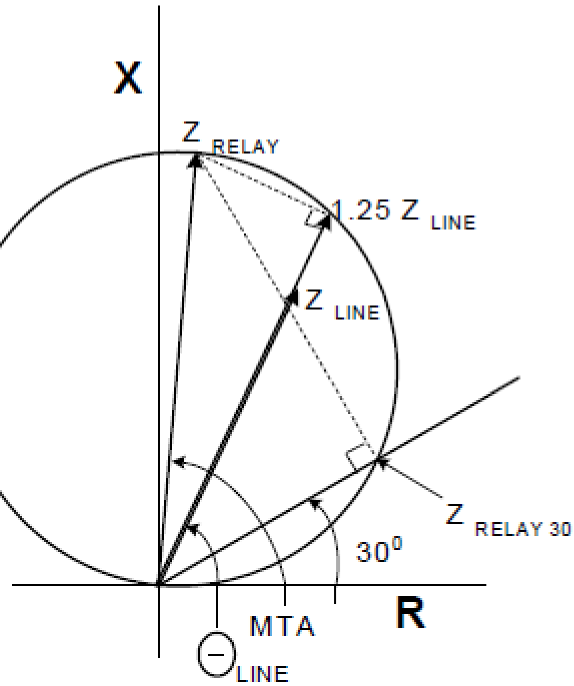


Figure 10 – Long Line relay Loadability

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 current loading is as follows:

V_{relay} = Line-to-Line voltage at the relay location

Z_{line} = Line impedance

Θ_{line} = Line impedance angle

Z_{relay} = Relay setting in ohms 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} = Relay operating current at 30 degrees with normal voltage

$I_{relay30}$ = 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-characteristic relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \ x \ Z_{line}}{\cos(MTA - \theta_{line})}$$

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

$$Z_{relay\,30} = \left[\frac{1.25\ x\ Z_{line}}{\cos(MTA - \ \theta_{line})}\right] x \cos(MTA - \ 30^{\circ})$$

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

$$I_{trip} = \frac{V_{relay}}{\sqrt{3}\ x\ Z_{relay\,30}}$$

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

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

$$i_{relay\,30} = \frac{0.85\ x\ I_{trip}}{1.15}$$

$$I_{relay\,30} = \frac{0.85\ x\ V_{relay}\ x \cos(MTA - \ \theta_{line})}{1.15\ x\ \sqrt{3}\ x\ 1.25\ x\ Z_{line}\ x \cos(MTA - 30°)}$$

$$I_{relay\,30} = \left(\frac{0.341\ x\ V_{relay}}{Z_{line}}\right) x \left(\frac{\cos(MTA - \theta_{line})}{\cos(MTA - 30°)}\right)$$

1.12 b — Long Line Relay Loadability — 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. 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:

The basis for the current loading is as follows:

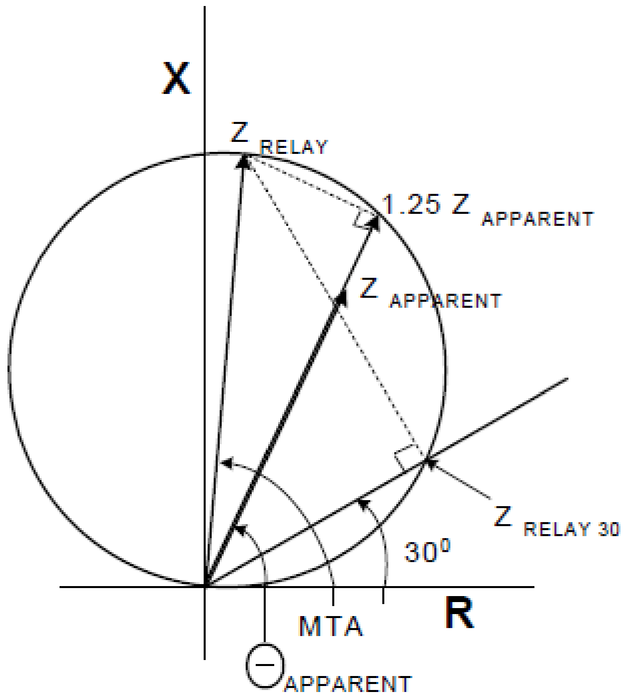


Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps

The basis for the 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) for a fault at the most electrically distant line terminal for system conditions normally used in 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

$I_{relay30}$ = 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-characteristic relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25\ x\ Z_{apparent}}{\cos(MTA - \theta_{apparent})}$$

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

$$Z_{relay\ 30} = \left[\frac{1.25\ x\ Z_{apparent}}{\cos(MTA - \theta_{apparent})}\right] x \cos(MTA - 30°)$$

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

$$I_{trip} = \frac{V_{relay}}{\sqrt{3}x\ Z_{relay\ 30}}$$

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

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

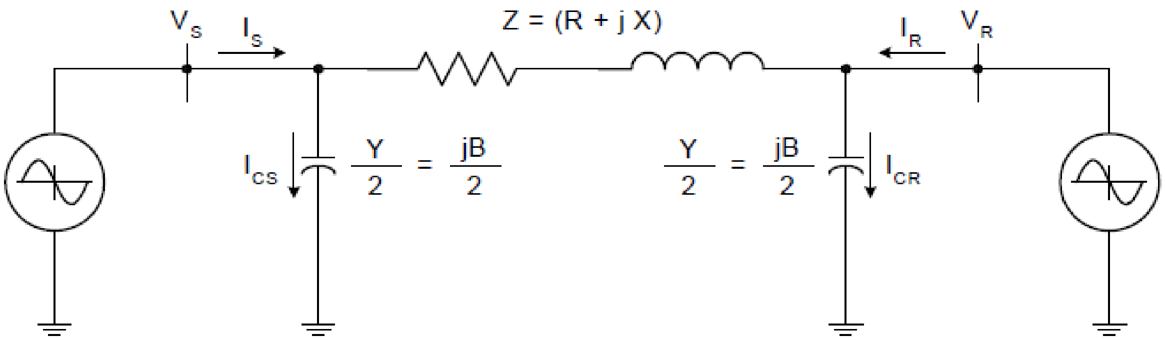
$$I_{relay\ 30} = \frac{0.85\ x\ I_{trip}}{1.15}$$

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

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

1.13 — No Explanation Necessary

Appendix A: Long Line Maximum Power Transfer Equations



Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\emptyset} = \frac{V_S^2}{|Z|}\cos(\theta°) - \frac{V_S V_R}{|Z|}\cos(\theta + \delta°)$$

$$Q_{S3-\emptyset} = \frac{V_S^2}{|Z|}\sin(\theta°) - V_S^2\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin(\theta + \delta°)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$I_{real} = \frac{V}{\sqrt{3}\,|Z|}(\cos(\theta°) + \sin(\theta°))$$

$$I_{reactive} = \frac{V}{\sqrt{3}\,|Z|}\left(\sin(\theta°) - |Z|\frac{B}{2} - \cos(\theta°)\right)$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$I_{total} = \sqrt{I_{real}^2 + I_{reactive}^2}$$

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

V = Nominal phase-to-phase bus voltage

δ = Voltage angle between V_S and V_R

Z = Reactance, including fixed shunt reactors, of the transmission line in ohms*

Θ = Line impedance angle

B = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

Appendix B: Impedance –Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023-4 Requirement R1 if all of the following conditions are satisfied.

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 purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

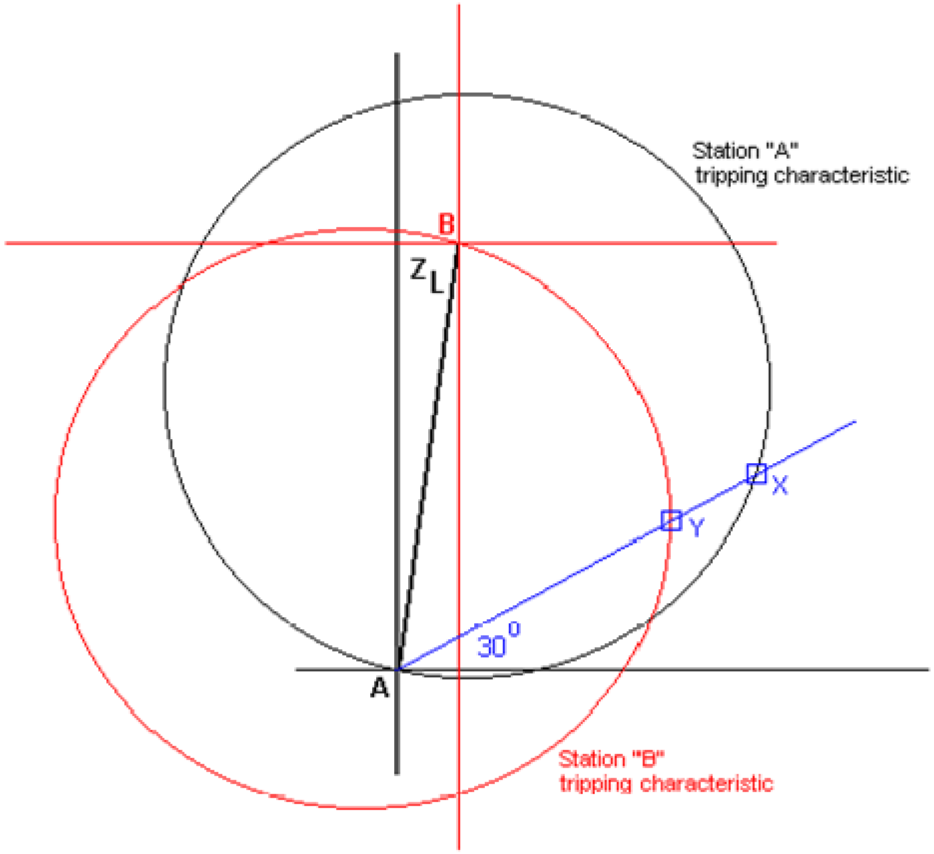


Figure B-1: Permissive Overreaching Transferred Trip (unmodified)

Unmodified Permissive Overreaching Transfer Trip

In a non-pilot application, the loadability of the tripping relay at Station “A” is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure B-1. In a POTT application, point “X” falls outside the tripping characteristic of the relay at Station “B”, preventing tripping at either terminal. Relay “A” becomes susceptible to tripping along its 30-degree line only when point “Y” is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

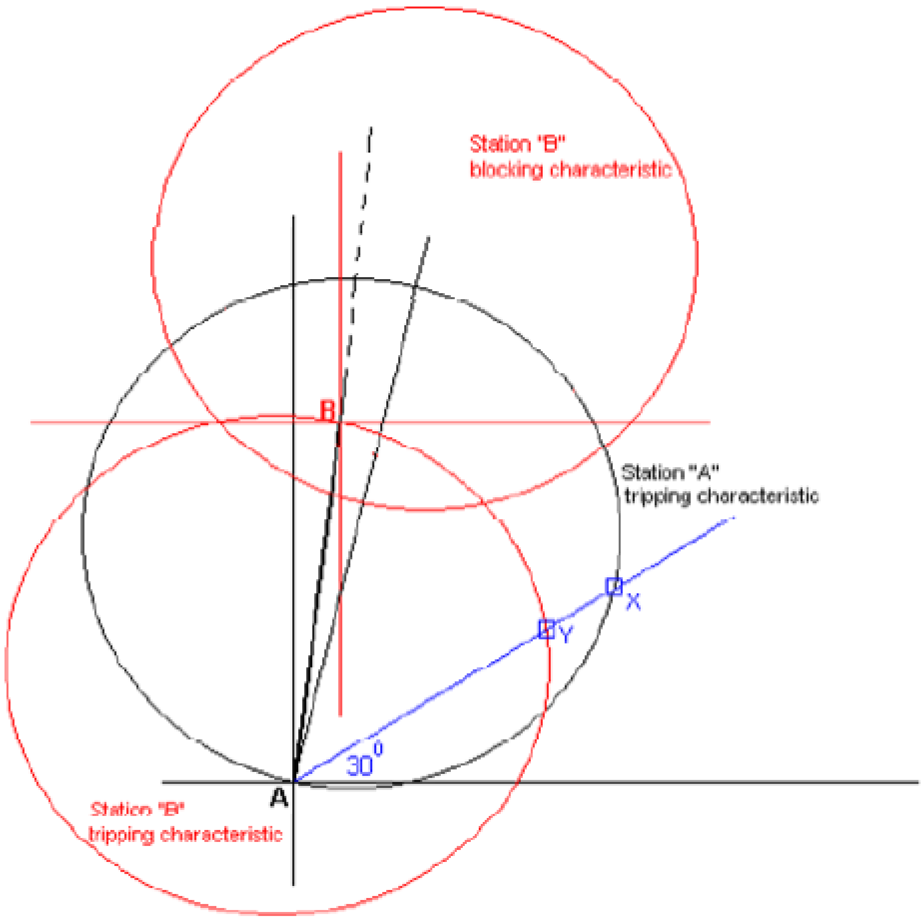


Figure B-2: Directional Comparison Blocking with Reverse-looking Blocking Elements

Directional Comparison Blocking

In Figure B-2, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

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, Pa, will be essentially zero. During system disturbances, Pa > 0. Pa is the difference between the mechanical power input, Pm, and the electrical power output, Pe, of the system, ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition Pa >> 1 resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa < 1, resulting in 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 traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure C-1 below.

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.

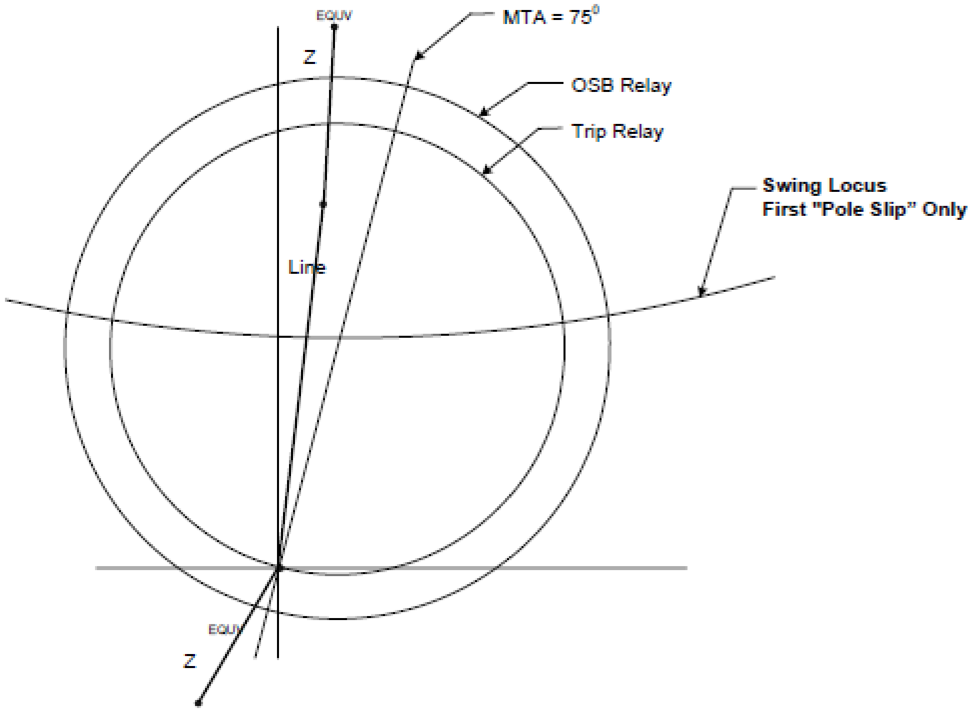


Figure C-1: Portion of an Unstable Swing

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

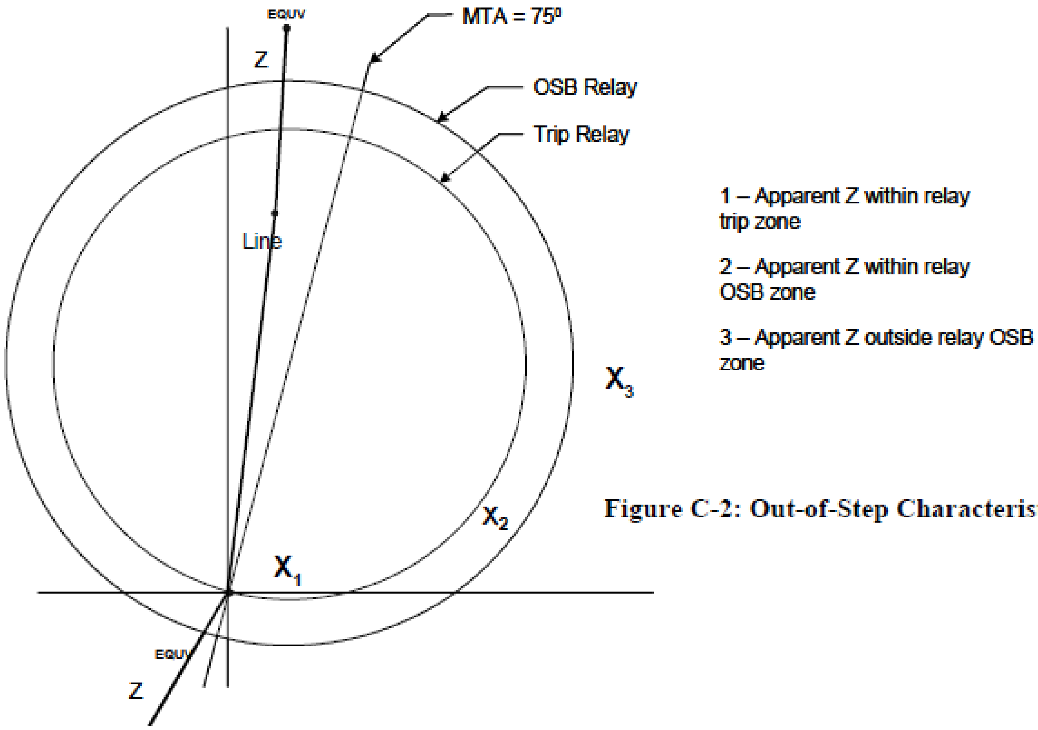


Figure C-2: Out-of-Step Characteristics with Load

Both the tripping relay and the out-of-step blocking relay have characteristics responsive to the impedance that is 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: Out-of-Step Blocking Relaying

Introduction

Switch-on-to-fault (SOTF) schemes (also known as "close-into-fault schemes or line-pickup schemes) are protection functions intended to trip a transmission line breaker when closed on to a faulted line. Dedicated SOTF schemes are available in various designs, but since the fault-detecting elements tend to be more sensitive than conventional, impedance-based line protection functions, they are designed to be "armed" only for a brief period following breaker closure. Depending on the details of scheme design and element settings, there may be implications for line relay loadability. This paper addresses those implications in the context of scheme design.

SOTF scheme applications

SOTF schemes are applied for one or more of three reasons:

1. When an impedance-based protection scheme uses line-side voltage transformers, SOTF logic is required to detect a close-in, three-phase fault to protect against a line breaker being closed into such a fault. Phase impedance relays whose steady-state tripping characteristics pass through the origin on an R-X diagram will generally not operate if there is zero voltage applied to the relay before closing into a zero-voltage fault. This condition typically occurs during when a breaker is closed into a set of three-phase grounds which operations/maintenance personnel failed to remove prior to re-energizing the line. When this occurs in the absence of SOTF protection, the breaker will not trip, nor will breaker failure protection be initiated, possibly resulting in time-delayed tripping at numerous remote terminals. Unit instability and dropping of massive blocks of load can also occur.
2. Current fault detector pickup settings must be low enough to allow positive fault detection under what is considered to be the "worst case" (highest) impedance to the source bus.
3. When an impedance protection scheme uses line-side voltage transformers, SOTF current fault detectors may operate significantly faster than impedance units when a breaker is closed into a fault anywhere on the line. The dynamic characteristics of typical impedance units are such that their speed of operation is impaired if polarizing voltages are not available prior to the fault.
4. Current fault detector pickup settings will generally be lower in this application than in (1) above. The greater the coverage desired, and the longer the line, the lower the setting.
5. Regardless of voltage transformer location, SOTF schemes may allow high-speed clearing of faults along the entire line without having to rely or wait on a communications-aided tripping scheme.
6. Current or impedance-based fault detectors must be set to reach the remote line terminal to achieve that objective.

SOTF line loadability considerations

This reference document is intended to provide guidance for the review of existing SOTF schemes to ensure that those schemes do not operate for non-SOTF conditions or under heavily stressed system conditions. This document also provides recommended practices for application of new SOTF schemes.

1. The SOTF protection must not operate assuming that the line terminals are closed at the outset and carrying up to 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023-4), when calculated in accordance with the methods described in this standard.
2. For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 85% of nominal at the local terminal. For SOTF schemes commissioned after formal adoption of this report, the protection should not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal at the local terminal.

SOTF scheme designs

1. Direct-tripping high-set instantaneous phase overcurrent

   This scheme is technically not a SOTF scheme, in that it is in service at all times, but it can be effectively applied under appropriate circumstances for clearing zero-voltage faults. It uses a continuously-enabled, high-set instantaneous phase overcurrent unit or units set to detect the fault under "worst case" (lowest source impedance) conditions. The main considerations in the use of such a scheme involve detecting the fault while not overreaching the remote line terminal under external fault conditions, and while not operating for stable load swings. Under NERC line loadability requirements, the overcurrent unit setting also must be greater than 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023-4), when calculated in accordance with the methods described in this standard.

2. Dedicated SOTF schemes

   Dedicated SOTF schemes generally include logic designed to detect an open breaker and to arm instantaneous tripping by current or impedance elements only for a brief period following breaker closing. The differences in the schemes lie (a) in the method by which breaker closing is declared, (b) in whether there is a scheme requirement that the line be dead prior to breaker closing, and (c) in the choice of tripping elements. In the case of modern relays, every manufacturer has its own design, in some cases with user choices for scheme logic as well as element settings.

   In some SOTF schemes the use of breaker auxiliary contacts and/or breaker "close" signaling is included, which limits scheme exposure to actual breaker closing situations. With others, the breaker-closing declaration is based solely on the status of voltage and current elements. This is regarded as marginally less secure from misoperation when the line terminals are (and have been) closed, but can reduce scheme complexity when the line terminates in multiple breakers, any of which can be closed to energize the line.

SOTF and Automatic Reclosing

With appropriate consideration of dead-line reclosing voltage supervision, there are no coordination issues between SOTF and automatic reclosing into a de-energized line. If pre-closing line voltage is the primary means for preventing SOTF tripping under heavy loading conditions, it is clearly desirable from a security standpoint that the SOTF line voltage detectors be set to pick up at a voltage level below the automatic reclosing live-line voltage detectors and below 0.8 per-unit voltage.

Where this is not possible, the SOTF fault detecting elements are susceptible to operation for closing into an energized line, and should be set no higher than required to detect a close-in, three-phase fault under worst case (highest source impedance) conditions assuming that they cannot be set above 1.5 times the Facility Rating (as specified in Reliability Standard PRC-023-4). Immunity to false tripping on high-speed reclosure may be enhanced by using scheme logic which delays the action of the fault detectors long enough for the line voltage detectors to pick up and instantaneously block SOTF tripping.

Appendix E: Out-of-Step Blocking Relaying

The listed IEEE technical papers are available at:

http://www.pes-psrc.org/Reports/Apublications_new_format.htm

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

http://www.techstreet.com/ieee

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

https://webstore.ansi.org/default.aspx

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1. *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.

2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.

3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.

4. *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.

5. *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.

6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.

7. IEEE Standard C37.113*, IEEE Guide for Protective Relay Applications to Transmission Lines.*

8. ANSI Standard C50.13*, American National Standard for Cylindrical Rotor Synchronous Generators.*

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

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

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

12. *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.

13. 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.

14. Increase Line Loadability by Enabling Load Encroachment Functions of Digital Relays, System Protection and Control Task Force, North American Electric Reliability Council, December 7, 2005.