Protective Relaying Philosophy and Design Guidelines

PJM Relay Subcommittee

July 12, 2018

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SECTION 1: Introduction

Introduction

This document supplements PJM Manual 07 which contains the minimum design standards and requirements for the protection systems associated with the bulk power facilities within PJM. This document provides recommendations, background and philosophy on relay protection that is not available in M07. The facilities to which this Document applies are generally comprised of the following:

- all 100 MVA and above generators connected to the BES facilities,
- all 200 kV and above transmission facilities
- all transmission facilities 100 kV to 200 kV critical to the reliability of the BES as defined by PRC-023 and determined by PJM System Planning

- PJM System Planning will also investigate the criticality of equipment (generators, buses, breakers, transformers, capacitors and shunt reactors) associated with the PRC-023 determined lines

In analyzing the relaying practices to meet the broad objectives set forth, consideration must be given to the type of equipment to be protected, e.g., generator, line, transformer, bus, etc., as well as the importance of the particular equipment to the integrity of the PJM Interconnection. Thus, practices may vary for different equipment. While it is recognized that the probability of failure should not negate the single contingency principle, the practices adopted may vary based on judgment and experience as to the probability in order to adopt a workable and practical set of guidelines. Special local conditions or considerations may necessitate the use of more stringent design criteria and practices.

Protection systems are only one of several factors governing power system performance under specified operating and fault conditions. Accordingly, the design of such protection systems must be clearly coordinated with the system design and operation.

Advances in technology, such as the microprocessor and fiber optics, will continue to produce relays, systems, and schemes with more capabilities than existing equipment. Application of these new devices may produce system protection with more security and dependability. Although the application may appear to be in conflict with the wording of the document, it may still fulfill the intent. As these new devices become available and are applied, the PJM Relay Subcommittee will incorporate them initially into these philosophy and design guidelines as an interpretation of a specific section and finally upon revision of the document.

SECTION 2: Protective Relaying Philosophy

2.1 Objectives

The basic design objectives of any protective scheme are to:

- Maintain dynamic stability.
- Prevent or minimize equipment damage.
- Minimize the equipment outage time.
- Minimize the system outage area.
- Minimize system voltage disturbances.
- Allow the continuous flow of power within the emergency ratings of equipment on the system.

2.2 Design Criteria

To accomplish the design objectives, four criteria for protection should be considered: fault clearing time; selectivity; sensitivity and reliability (dependability and security).

2.2.1 Fault clearing time is defined as the time required to interrupt all sources supplying a faulted piece of equipment. In order to minimize the effect on customers and maintain system stability, fault clearing time should be kept to a minimum. This normally requires the application of a pilot relay scheme on transmission lines and high speed differential relaying on generators, buses and transformers.

2.2.2 Selectivity is the ability of the protective relaying to trip the minimum circuits or equipment to isolate the fault. Coordination is required with the adjacent protection schemes including breaker failure, generator potential transformer fuses and station auxiliary protection.

2.2.3 Sensitivity demands that the relays be capable of sensing minimum fault conditions without imposing limitations on circuit or equipment capabilities. The settings must be investigated to determine that they will perform correctly during transient power swings from which the system can recover.

2.2.4 Reliability is a measure of the protective relaying system's certainty to trip when required (dependability) and not to trip falsely (security).

2.2.4.1 Dependability should be based on a single contingency, such that the failure of any one component of equipment, e.g., relay, current transformer, breaker, communication channel, etc., will not result in failure to isolate the fault. Protection in depth (i.e., primary and back-up schemes) necessary to accomplish this must be designed so as not to compromise the security of the system.

The following should be considered when designing protective schemes:

- Additional dependability can be gained through physical separation of the primary and back-up schemes.
- The use of different types of relays for primary and backup schemes will enhance dependability.

2.2.4.2 Security will be enhanced by limiting the complexity of the primary and back-up relay protection schemes to avoid undue exposure to component failure and personnel errors.

These schemes should be insensitive to:

- Peak circuit emergency ratings to assure the transfer of power within PJM considering the impact of a recoverable system transient swing.

- System faults outside the protective zones of the relays for a single contingency primary equipment outage (line, transformer, etc.) or a single contingency failure of another relay scheme.

2.3 Equipment Considerations

In comparing protection design to the objectives and criteria set forth, consideration must be given to the type of equipment to be protected as well as the importance of this equipment to the system. While protection should not be defeated by the failure of a single component, several considerations should be weighed when judging the sophistication of the protection design:

- Type of equipment to be protected (e.g., bus, transformer, generator, lines, etc.).
- Importance of the equipment to the system (e.g., impact on transfer capability, generation, etc.).
- Replacement cost (and replacement time) of the protected equipment.
- Probability of a specific fault occurring.
- Protection design in a particular system may vary based upon judgment and experience.

SECTION 3: Generator Protection

Generator protection requirements vary with the size of the unit. For units 500 MVA and above, the requirements identified in this section apply in full. The requirements are generally less strict for units below 500 MVA. The document will identify the differences in the requirements.

For units below 100 MVA and not connected at 200 kV or above, see Appendix H of this document.

3.1 Generator Stator Fault Protection

3.1.1 General Consideration

Generator stator faults can be very serious and cause costly damage. Therefore, the fault must be detected and cleared in the least amount of time possible. Because of the generator field decay time, damage may occur after all the required breakers have been tripped.

3.1.2 Ground Fault Protection

Grounding the generator through a high impedance is the most common industry practice for large generators. This is done to limit the magnitude of ground fault current, and with proper selection of components, reduces the risk of transient over-voltages during ground faults.

3.2 Generator Rotor Field Protection

The generator rotor field winding is normally ungrounded. The presence of one ground, therefore, will not affect the generator's operation. The presence of the first ground, however, greatly increases the probability that a second ground will occur, causing imbalances, and overheating.

3.3 Generator Abnormal Operating Conditions

3.3.1 Loss of Field

Loss of field (excitation) will cause the generator to lose synchronism, subject the generator to thermal damage, and may impose an intolerable VAR load on the power system. Detection of the loss of field condition is usually done with impedance relays.

3.3.2 Unbalanced Currents

Unbalanced currents are a result of unbalanced loading (e.g., one phase open) or uncleared unbalanced system faults. These unbalanced currents produce negative sequence current (I_2) in the generator rotor causing overheating.

3.3.3 Loss of Synchronism

Loss of synchronism, out-of-step operation, and pole slipping are synonymous and can result from transients, dynamic instability, or loss of excitation. This condition may be both damaging to the unit and highly disruptive to the power system.

3.3.4 Overexcitation

Overexcitation is excessive flux in the generator core. This condition can cause rapid overheating, even to the point of core failure. Volts/Hertz is a measure of an overexcitation condition.

It should be recognized that the most severe overexcitation events are the result of inadvertent application of excessive field current prior to generator synchronizing. It is strongly recommended that with the generator off-line, the protection be armed to trip the excitation system with minimum time delay for excitation levels above the setpoint of the lowest tripping element.

3.3.5 Reverse Power (Anti-Motoring)

Generator motoring is caused by the lack of energy supplied to the prime mover resulting in the electrical system driving the machine as a motor. Sustained synchronous motoring will not damage the generator, but may damage the prime mover.

3.3.6 Abnormal Frequencies

The generator can withstand off-frequency operation for long periods of time provided the load and voltage are reduced a sufficient amount. The turbine, however, is usually limited in its capability due to possible mechanical resonance caused by off-frequency operation under load. Automatic system-wide load shedding is the primary protection against abnormal frequency operation. However, for protection of the turbine, underfrequency relays are generally required unless the turbine manufacturer states that this protection is unnecessary. (The turbine manufacturer should be consulted for comprehensive requirements.)

When underfrequency protection is employed, two underfrequency relays connected with “AND” tripping logic and connected to separate voltage sources are recommended to enhance scheme security. A sequential trip of the turbine valves, excitation system, and generator breakers is recommended.

Units with output ratings under 500 MVA would be exempt from the two-relay security recommendation.

3.4 Generator Breaker Failure Protection

Refer to M07. No supplementary information available

3.5 Excitation System Tripping

Refer to M07. No supplementary information available.

3.6 Generator Open Breaker Flashover Protection

Open breaker flashover is more likely on generator breakers since 2.0 per-unit voltage will appear across the open contacts prior to synchronizing.

3.7 Protection during Start-Up or Shut-Down

Since some relays are frequency-sensitive, each of the relay's operating characteristics vs. frequencies should be checked to ensure proper operation at frequencies below 60 Hz.

3.8 Protection for Accidentally Energizing a Generator on Turning Gear

The accidental energizing of a generator from the high voltage system has become an increasing concern in recent years. Severe damage to the generator can result in a very short time for this condition.

Consideration should also be given to potential damage from accidental energizing from the low-voltage side of the unit auxiliary station service transformer.

SECTION 4: Unit Power Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 5: Unit Auxiliary Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 6: Start-up Station Service Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 7: Line Protection

7.1 General Requirements

Fault incidents on transmission lines are high due to their relatively long lengths and exposure to the elements. Highly reliable transmission line protective systems are critical to system reliability. M07 states that the systems applied must be capable of detecting all types of faults, including maximum expected arc resistance that may occur at any location on the protected line. This includes:

- Three phase faults
- Phase-to-phase faults
- Phase-to-phase-to-ground faults
- Phase-to-ground faults

A single protection system is considered adequate for detecting faults with low probability or system impact:

- Restricted phase-to-ground faults
- Zero-voltage faults

The design and settings of the transmission line protection systems must should be secure during faults external to the line or under non-fault conditions.

See Appendix G, 'Voltage Transformers' for a description of acceptable VT arrangements.

7.2 Primary Protection

Refer to M07. No supplementary information available

7.3 Back-up Protection

- Back-up protection should have sufficient speed to provide the clearing times necessary to maintain system stability as defined in the NERC TPL Transmission Planning Standards
    - Non-pilot Zone 1 should be set to operate without any intentional time delay and to be insensitive to faults external to the protected line.
    - Non-pilot Zone 2 should be set with sufficient time delay to coordinate with adjacent circuit protection including breaker failure protection and with sufficient sensitivity to provide complete line coverage.

See Appendix E guidelines on the use of dual pilot channels

7.4 Restricted Ground Fault Protection

Refer to M07. No supplementary information available

7.5 Close-in Multi-Phase Fault Protection (Switch onto Fault Protection)

Refer to M07. No supplementary information available

7.6 Out-of-Step Protection – Transmission Line Applications

Out-of-step relays are sometimes used in the following applications associated with transmission line protection:

- Block Automatic Reclosing – The use of out-of-step relays to block automatic reclosing in the event tripping is caused by instability.
- Block Tripping – the use of out-of-step relays to block tripping of phase distance relays during power swings.
- Preselected Permissive Tripping – The use of out-of-step relays to block tripping at selected locations and permit tripping at others during unstable conditions so that load and generation in each of the separated systems will be in balance.

These applications require system studies and usually go beyond the scope of protective relaying.

7.7 Single-Phase Tripping

Single-phase tripping of transmission lines may be applied as a means to enhance transient stability. In such schemes, only the faulted phase of the transmission line is opened for a phase-to-ground fault. Power can therefore still be transferred across the line after it trips over the two phases that remain in service. A number of details need to be considered when applying single-phase tripping schemes compared to three phase tripping schemes. These issues include: faulted phase selection, arc deionization, automatic reclosing considerations, pole disagreement, and the effects of unbalanced currents. Such schemes have not been typically applied on the PJM system.

SECTION 8: Substation Transformer Protection

8.1 Transformer Protection

Substation transformers tapped to lines should have provisions to automatically isolate a faulted transformer and permit automatic restoration of the line. If the transformer is connected to a bus, the decision about whether or not to automatically isolate the transformer and restore the bus should consider the bus configuration and the importance of the interrupted transmission paths.

8.2 Isolation of a Faulted Transformer Tapped to a Line

8.2.1 Transformer HV Isolation Device Requirements

Refer to M07. No supplementary information available

8.2.2 Protection Scheme Requirements

When a fault interrupting device is used on the tapped side of the transformer that is fully rated for all faults on the transformer, the use of a motor-operated disconnect switch beyond the ground switch for stuck breaker protection allows the line to be restored after motor-operated disconnect switch opens to isolate the high-side interrupting device.

False operation of ground switches can present unnecessary risks to nearby equipment due to fault current stresses, increase the potential for adjacent line over-trips, and decrease customer service quality due to voltage sags. As such, schemes employing direct transfer trip equipment are preferred over ground switches.

8.2.3 Protection Scheme Recommendations

If transformer rate-of-rise of pressure relays are connected to trip, and if protection redundancy requirements are fully satisfied by other means (e.g. two independent differential relays), then the use of transformer primary isolation switch auxiliary contacts for trip supervision of the rate-of-rise of pressure relay(s) is acceptable This is in recognition of the relative insecurity of rate-of-rise of pressure relays during transformer maintenance.

8.3 Transformer Leads

Refer to M07. No supplementary information available

8.4 Overexcitation

Overexcitation protection should be considered on transformers connected to 500 kV and higher systems. While Overexcitation protection is usually only a concern for generator step-up transformers, it can occasionally be a problem for transformers remote from generation stations during periods of light load or system restoration conditions. In Appendix D of the EHV Engineering Committee report entitled " Conemaugh Project - Relay Protection for 500 kV Transmission System, January 1971" discusses the development of PJM autotransformer overvoltage protection guidelines.

It is recommended that the relay be connected to the secondary side of the transformer.

SECTION 9: Bus Protection

Refer to M07. The only supplementary information is that two examples of high-speed protection schemes are current differential or high impedance differential.

SECTION 10: Shunt Reactor Protection

Shunt reactors are used to provide inductive reactance to compensate for the effects of high charging current of long open-wire transmission lines and pipe-type cables. At transmission voltages, only oil-immersed reactors are used which are generally wye-connected and solidly grounded. Reactors are built as either three-phase or single-phase units.
It should be recognized that details associated with effective application of protective relays and other devices for the protection of shunt reactors is a subject too broad to be covered in detail in this document.

10.1 Reactor Protection

Shunt reactors tapped to lines should have provisions to automatically isolate a faulted shunt reactor and permit automatic restoration of the line. If the shunt reactor is connected to a bus, the need to both automatically isolate the reactor and restore the bus will depend on the bus configuration and the importance of the interrupted transmission paths.

It is recommended that an over-temperature tripping device be provided if single phasing, which results in considerable heating, is possible.

10.2 Isolation of a Faulted Shunt Reactor Tapped to a Line

For protection requirements, follow the requirements/recommendations in PJM Manual 07 set forth in Section 8.2 for a Substation Transformer tapped to a line.

In cases where the increased exposure of line tripping is a reliability concern, the use of a high side-interrupting device is recommended

SECTION 11: Shunt Capacitor Protection

Refer to M07. No supplementary information available.

SECTION 12: Breaker Failure Protection

12.1 Local breaker failure protection requirements

Refer to M07. No supplementary information available

12.2 Direct transfer trip requirements (See also Appendix C)

Refer to M07. No supplementary information available

12.3 Breaker failure scheme design requirements

A direct transfer trip signal initiated by a remote stuck breaker scheme should not operate a hand-reset lockout relay at the receiving terminal.

Consideration of pickup and dropout times of auxiliary devices used in a scheme should ensure adequate coordination margins.

When protected apparatus (transformer, reactor, breaker) is capable of being isolated with a switch (especially a motor-operated switch), auxiliary contacts of that switch are sometimes used in the associated breaker failure schemes. This can result in degradation to the dependability of the breaker failure protection. Recommendations regarding the use of auxiliary switches follow. Note that the recommendations represent "good engineering practice" and are not specifically mandated.

(1) Other than as noted below, apparatus isolation switch auxiliary contacts should preferably not be used in the apparatus protection scheme in such a manner that if the auxiliary switch (e.g.., 89a/b) contact falsely indicates that the isolation switch is open, breaker failure initiation would be defeated or the breaker failure scheme otherwise compromised. Breaker failure initiation logic of the form BFI = 94+ BFI * 89a is permissible. Breaker failure initiation logic of the form BFI = 94 * 89a is not recommended.

The same principle applies for the breaker failure outputs, e.g., the tripping of local breakers and the sending of transfer trip for the tripping of remote breakers. In the specific case of transfer trip an auxiliary switch contact should preferably not be used such that its failure would prevent the initial sending of transfer trip. The auxiliary switch may be used to terminate sending of transfer trip once the transfer trip input is removed.

(2) If the protected apparatus is tapped in such a manner that it is switchable between two sources, there may be no alternative other than to use auxiliary switch contacts to determine which breakers to initiate breaker failure on, which breakers to

trip with the breaker failure output, etc. Auxiliary switch redundancy is not specifically required provided that breaker tripping and breaker failure initiation and outputs are not supervised by the same auxiliary switch or auxiliary switch assembly. Redundancy in breaker failure initiation will be achieved automatically if breaker failure is initiated by a contact from the same auxiliary relay that initiates tripping of the breaker, and that relay is connected in a manner which satisfies auxiliary switch redundancy requirements. (See the sections of this document on isolation of faulted transformers and reactors.)

SECTION 13: Phase Angle Regulator Protection

Refer to M07. No supplementary information available.

SECTION 14: Transmission Line Reclosing

Transmission Line Reclosing

14.1 Philosophy

Experience indicates that the majority of overhead line faults are transient and can be cleared by momentarily de-energizing the line. It is therefore feasible to improve service continuity and stability of power systems by automatically reclosing those breakers required to restore the line after a relay operation. Also, reclosing can restore the line quickly in case of a relay misoperation.

Section 14 provides information on reclosing of transmission line on the PJM system. For greater detail on reclosing, refer to the latest version of the ANSI/IEEE Std. C37.104

14.2 Definitions

- Reclosing

  Automatic closing of a circuit breaker by a relay system without operator initiation Note: For the purpose of this document, all reference to "reclosing" will be considered as "automatic reclosing."

  Reclosing should always be effected using a single or multiple shot reclosing device. The use of the reclosing function in a microprocessor relay is an acceptable substitute for a discrete reclosing relay.

- High-Speed Autoreclosing

  Refers to the autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

- High-Speed Line Reclosing

  The practice of using high-speed autoreclosing on both terminals of a line to allow the fastest restoration of the transmission path

- Delayed Reclosing

  Reclosing after a time delay of more than 60 cycles

- Reclosing Through Synchronism Check

  A reclosing operation supervised by a synchronism check relay which permits reclosing only when it has determined that proper voltages exist on both sides of the

open breaker and the phase angle between them is within a specified limit for a specified time.

- Single-Shot Reclosing

  A reclose sequence consisting of only one reclose operation. If the reclose is unsuccessful, no further attempts to reclose can be made until a successful manual closure has been completed.

- Multiple-Shot Reclosing

  A reclose sequence consisting of two or more reclose operations initiated at preset time intervals. If unsuccessful on the last operation, no further attempts to reclose can be made until a successful manual closure has been completed.

- Dead Time

  The period of time the line is de-energized between the opening of the breaker(s) by the protective relays and the reclose attempt.

- Initiating terminal

  The first terminal closed into the de-energized line; also, referred to as the leader.

- Following terminal

  The terminal which recloses following the successful reclosure of the initiating terminal; also, referred to as the follower. The following terminal is supervised by voltage and/or synchronism check functions.

14.3 Prevailing Practices

The following information on prevailing practices is provided for reference. Each application must be reviewed to determine the most appropriate reclosing scheme.

- General

  Normally, one reclosure is used for 500 kV lines and one or more reclosures for 230 kV lines. High-speed reclosing of both ends of a transmission line is generally not used at 230kV and above.

- Lines Electrically Remote from Generating Stations

  The initiating terminal will reclose on live bus-dead line in approximately one second and the following terminals will reclose through synchrocheck approximately one second later. The synchrocheck relay setting is generally 60 degrees. Longer reclosing times and smaller angle settings of the synchrocheck relays are applied under certain conditions.

- Lines Electrically Close to Generating Stations

  Turbine generator shaft damage could occur due to oscillations created by reclosing operations on nearby transmission lines. If the initiating terminal is electrically close to a generating station, reclosing is delayed a minimum of 10 seconds. The synchrocheck relay setting should be determined with regard to shaft torque considerations.

- Multiple Breaker Line Termination

  For reclosing at a terminal with more than one breaker per line, it is recommended to reclose with a pre-selected breaker. After a successful autoreclose operation, the other breaker(s) associated with the line at that terminal may be reclosed.

- Preventing reclosing on a failed transformer or reactor, or failed breaker
  - Automatic reclosing of transmission line circuit breakers should be blocked while a direct transfer trip (DTT) signal is being received.
  - The operation of the breaker failure relay scheme on a breaker should block reclosing on adjacent breakers. If the failed breaker can be automatically isolated, the reclose function may be restored to the adjacent breakers.
  - The operation of a transformer or bus protective relay scheme may also be a reason for blocking reclosing.

- Adaptive Reclosing

  Most adaptive reclosing autoreclosing schemes or selective reclosing schemes use the operation of specific relays or relay elements to initiate the scheme. Some schemes only permit reclosing for pilot relay operations, while others permit reclosing for all instantaneous relay operations. Others only block (or fail to initiate) reclosing for conditions such as multi-phase faults where system stability is of concern or where sensitive or critical loads may be affected.

SECTION 15: Supervision and Alarming of Relaying and Associated Control Circuits

In order to assure the reliability of protective relaying to the greatest practical extent, it is essential that adequate supervision of associated AC and DC control circuits be provided. Supervisory lamps or other devices may adequately supervise most of a given circuit. It is very difficult to supervise some parts, such as open relay contacts and AC current circuits. Back-up protection will provide reasonable assurance against a failure to trip which may originate in a portion of a circuit that is difficult to supervise.

SECTION 16: Underfrequency Load Shedding

Refer to M07. The only supplementary information is that the underfrequency detection scheme should be secure for a failure of a potential supply.

Note: Time delays incorporated into the scheme are subjected to Regional Reliability requirements

SECTION 17: Special Protection Schemes

Refer to M07. No supplementary information available

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APPENDIX A - Use of Dual Trip Coils

Refer to M07. The only supplementary information is that "Cross-trip" auxiliary relays in the breaker tripping control scheme are sometimes provided as a standard by the breaker manufacturer. While this solution covers an open trip coil, it does not cover an open circuit on the source side of both the trip coil and the cross-trip auxiliary.

APPENDIX B - Disturbance Monitoring Equipment

Disturbance Monitoring Equipment (DME) should be installed at locations on the entity's Bulk Electric System (BES) as per applicable NERC PRC standards to facilitate analyses of events.

The Disturbance Monitoring Equipment includes Sequence of Events (SOE) recording, fault recording, most commonly termed Digital Fault Recording (DFR), and Dynamic Disturbance Recording (DDR)

APPENDIX C - Direct Transfer Trip Application

Background

Until the mid-to-late 1980's, only two types of direct transfer trip (DTT) transceivers were available: (1) power-line carrier units operating at high frequency; (2) audio-tone units operating into commercial or privately-owned voice-channels. In either case dual frequency-shift transmitter-receiver pairs are used in conjunction with appropriate logic. The requirement for a valid trip involves the shift from "guard" to "trip" for each of the two channels—the intent being to provide security against the possibility of a noise burst appearing as a valid trip condition to a single channel. The logic imposes the further requirement that the above-described shift occurs nearly simultaneously on both channels. Loss of the guard signal on either channel without a shift to trip is interpreted as a potential channel problem—tripping through the DTT system is automatically blocked until proper guard signaling is reestablished. For the permanent loss of one channel, the DTT system may be manually switched to allow single-channel operation using the remaining channel while repairs are undertaken.

In the case of audio-tone units, it has been typical to shift the frequency "up" on one channel and "down" on the other to guard against the effects of possible frequency-translation in the associated multiplex equipment.

An additional benefit of the dual-channel approach is the relative ease of channel testing. Facilities are typically provided for keying the channels one-at-a-time, either manually or using a semiautomatic check-back technique.

Modern Trends in Transfer Trip Equipment

The advent of digital communications has stimulated the development of digital transfer trip equipment. Rather than transmitting an analog signal, digital equipment generates a sequential, binary code which may be transmitted directly over a dedicated fiber or multiplexed with other services in a pulse-code-modulation (PCM) format. Given the nature of digital transmission, these systems are considered, and have proven to be, more secure, more dependable, and faster than conventional analog systems.

DTT Systems

- Carrier/Audio Tone systems – Dual-channel systems is a common practice. In For dual-channel systems, single-channel operation has been allowed only for testing or while repairs are underway subsequent to a channel failure.

Audio tone transceivers operating over digital multiplexed systems False trips have been experienced in conjunction with the momentary loss and subsequent reestablishment of the digital system.

- Digital systems – The use of dual channels is not a requirement with this type of equipment. Retention of dual-channel configuration is allowed, however, if preferred by the user for standardization of end-to-end procedures or other reasons.

APPENDIX D - Tapping of Bulk Power Transmission Circuits for Distribution Loads

For economic reasons, it has become increasingly popular to tap existing bulk power transmission circuits as a convenient supply for distribution type loads. The following discussion is presented in recognition of the need to protect the integrity of the bulk transmission system.

It should be pointed out that the tapping of transmission lines for distribution load increases the likelihood of interruptions (natural or by human error) to the bulk power path. Per M07 Section 8.2, bulk power lines operated at greater than 300 kV shall not be tapped. Lines operated at less than 300 kV lines may be tapped with the concurrence of the transmission line owner(s).

Distribution station transformer low voltage leads and bus work is more susceptible to faults than higher voltage equipment. The bulk power path should be protected from interruption due to any such faults by the use of local fault-interrupting devices applied on the transformer high side. (The source terminal relays should not initiate the interruption of the bulk power path for low side faults.)

The local interrupting device may be either a breaker or a circuit switcher. In either case, provisions must be made for a failure of the device to clear a fault. These provisions are enumerated in the PJM Manual 07: PJM Protection Standards, Section 8.2.

If the device selected is a circuit breaker (presumably fully rated for interruption of both high and low voltage faults), there are several ways in which it can be applied as part of the overall line protection scheme. Two are listed and discussed below.

1. Selective clearing for all faults beyond the breaker.

2. Clearing of all faults, but on a selective basis for low voltage faults only.

With respect to item (1) above, while it might seem questionable to install a breaker and then not require selective clearing for all faults downstream of same, there may be situations where this is preferred, based on the following considerations:

a. The amount of exposure beyond the breaker and the impact of a momentary outage to the bulk power path.

b. The availability of economic and reliable telecommunication channels between the breaker and the source terminals.

c. The probable increase in the complexity of the pilot relaying scheme.

d. The probable necessity of "pulling back" the Zone 1 settings of the source terminals, and therefore degrading the non-pilot protection of the circuit.

In recognition of these considerations, it may be preferable to tolerate a momentary outage on the bulk power circuit for faults beyond the breaker but within the high voltage system. The relaying would be designed to trip the breaker instantaneously for such faults, allowing the source terminals to reclose automatically as they would for a line fault. As implied in item (2) above, complete selectivity is required for low voltage faults, which are both more prevalent and easier to immunize the source terminals against.

When deciding which of the various possible schemes to utilize, take the above considerations into account and make the evaluation on a case by case basis.

APPENDIX E - Dual Pilot Channels for Protective Relaying

Pilot Relaying

Pilot relaying provides a means for clearing faults at all locations on a transmission line by action of high speed relaying. Such schemes require the use of a communication system to provide a means for each terminal of the protected line to recognize the status of related relaying at all associated remote terminals. Media commonly used to provide communications for pilot relaying systems include power line carrier, microwave, leased telephone lines, and fiber optics.

Requirements for Dual Pilot Relaying

In some instances, high speed clearing of all faults on a transmission line is required due to system stability or protection coordination constraints. In such cases, a pilot relaying scheme is applied on both the primary and backup relaying systems. Such application is referred to as dual pilot relaying.

Channel Independence Considerations

Communication facilities for pilot relaying are an integral part of the pilot protection system.
An extremely low probability must exist that a single failure involving the communications system could prevent tripping through both pilot systems for a fault on the protected line. During repair or maintenance of either the primary or backup communication channel, one pilot protection scheme should remain functional.

Per NERC Transmission Planning Standards, transmission protection systems should provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements as outlined in Table I of each standard. Dual pilot relaying is required if delayed clearing results in miscoordination allowing the potential for overtripping an additional transmission path. In pilot relaying, the communication channel and associated equipment are considered part of the protective system. As such, if dual pilot channels are required to meet the above performance criteria, then the communication channel and associated equipment for the primary and back-up relaying must be held to this same standard.

Applications

A. Power Line Carrier

Power line carrier communication systems utilize the conductors of the transmission line to carry the communication signals. Pilot systems utilizing power line carrier for communications typically use 'blocking' logic since a fault on the line may disrupt the signal.

It should be noted that pilot systems that use blocking logic are inherently insecure since a failure to receive the blocking signal will result in an overtrip. Utilizing two such systems on a line results in an even more degradation in security. For this reason, use of 'unblocking' logic for one of the pilot systems should be given consideration.

In some cases, the extended high speed clearing coverage provided by the dual pilot systems to meet stability constraints is only required for multi-phase faults. In such cases, with power line carrier applications, security can be enhanced by enabling one of the pilot systems only for multi-phase faults.

General Recommendations for Power Line Carrier

- Directional Comparison Blocking (DCB)
    - Phase to Ground Coupling - Single Phase: Unacceptable for a dual pilot protection scheme as defined in the beginning of this appendix, but its benefits merit its mention.

        Advantages
        - Provides dependable high speed clearing for internal faults, even with the loss of the channel, for both the primary and backup protection schemes.
        - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system.
        - Requires one set of primary equipment (line tuner, CCVT, wave trap, and coaxial cable).
        - Modern relays use logic to ride through carrier holes.

        Disadvantages
        - A protection overtrip can occur for an external fault if a carrier hole occurs
        - The loss of the channel would not allow the a blocking signal to be transmitted, exposing the protection on the channel to over tripping for external faults on the system.

    - Phase to Ground Coupling – Two Phases: Acceptable but not recommended

        Advantages
        - Two totally separate channels connected to two phases.
        - Loss of any channel would not prevent high speed tripping for internal faults for both primary and backup protection.
        - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system.
        - Modern relays use logic to ride through carrier holes.

        Disadvantages
        - The loss of one channel would not allow the a blocking signal to be transmitted, exposing the protection on that channel to over tripping for external faults on the system
        - One channel would be couple to the outer phase which has very poor coupling efficiency
        - There is minimal isolation between transmitters which can cause intermodulation distortion

        - A protection over trip can occur for an external fault if a carrier hole occurs
        - Requires two sets of primary equipment (line tuner, CCVT, wave trap, and coaxial cable)

    - Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable

    - Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

- Directional Comparison Unblocking (DCUB)

    - Phase to Ground Coupling – Single Phase: Unacceptable for a dual pilot protection scheme.

    - Phase to Ground Coupling – Two Phases: Acceptable but not recommended
        - The two totally separate channels connected to two phases.
        - The block signal (guard) is continuously monitored and, if lost, should alarm after a short time delay pickup.

    - Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable

    - Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

        <u>Advantages</u>
        - Loss of any channel would not prevent high speed tripping for internal faults for both primary and backup protection
        - Cross channel coupling to allow both systems to transmit a block signal with the loss of primary equipment on one channel
        - Better coupling efficiency than single phase to center coupling and phase to phase outer to outer coupling
        - Modern relays use logic to ride through carrier holes
        - Center phase less likely to experience a phase to ground fault
        - Better isolation with the additional hybrids
        - All hybrids should be located in control house and two coaxial cable runs to the yard to strengthen redundancy
        - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system

        <u>Disadvantages</u>
        - Higher losses with the additional hybrids
        - The loss of one channel would not allow the a blocking signal to be transmitted, and may expose the protection on that channel to over tripping for external faults on the system
        - A protection over trip can occur for an external fault if a carrier hole occurs
        - Requires two sets of primary equipment (line tuner, CCVT, wave trap, and coaxial cable)

Another disadvantage of power line carrier is that repair or maintenance on associated wave traps requires that the related transmission line be taken out of service.

For additional application details on utilizing power line carrier in protective systems see IEEE 643—IEEE Guide for Power Line Carrier Applications.

B. Microwave Radio Channels

Modern digital communications may utilize microwave radio and optical fiber either alone or in combination. In either case, transmission is independent of the power system and is therefore frequently applied in pilot protection schemes using 'permissive' logic rather than 'blocking' logic.

C. Leased Telephone Circuits

If dual pilot channels are required, they may not both utilize leased telephone circuits.
Historically, problems have been experienced with the performance of leased telephone circuits utilized in protection applications due to the receivers being incapable of discriminating between valid signals and spurious signals which may be introduced into the voice grade audio channels particularly during power system disturbances. Also, control of the phone circuits themselves may be an issue in such applications since ownership of the channels exists within an entity separate from the transmission owner. Care should be taken to deal with these issues when applying telephone circuits in pilot protection systems.

For additional application details on utilizing audio tone signals in protective systems see ANSI/IEEE C37.93—IEEE Guide for Power System Protective Relay Applications of Audio Tones over Voice Grade Channels.

A. Fiber Optics

1. Fiber Routing
   Applications of fiber optic systems for communications in pilot relaying systems can be categorized based on the physical location of the routing of the fibers:

   a) Routing in close physical proximity to that of the associated protected transmission line. (Fiber may be integral to the shield wire, suspended from the towers themselves, or buried in the right of way.)

   b) Routing on a path that is completely independent of that of the associated protected transmission line.

   c) Routing as in (a) above but with a backup system that is automatically utilized and routed independently of the protected transmission line. (Self-healing ring topology.)

For routings as in (b) and (c) above, there exists a low probability for a failure on the protected line to disrupt the channels in a manner that would prevent tripping through both systems utilized for a dual pilot relaying system.

Fibers that are above ground and routed as in (a) have a chance of being physically involved in a fault on the protected line. For instance, the shield wire may contact the phase wire resulting in a fault. For such cases, the conditions that relate to the specific application must be evaluated to determine if an adequate level of redundancy is being provided.

Dual pilot protection systems utilizing fiber optic communications channels must be designed to maintain high speed coverage for the transmission line in the event of a single contingency. In evaluating the level of redundancy, both the fiber path routing and protection scheme types must be considered. The following protection fiber optic path examples are presented as with protection scheme scenarios of the analysis which must be performed to determine adequate redundancy:

Underbuilt optical fiber cable

It is possible, although unlikely, that an underbuilt fiber cable will break and cause a fault on the protected circuit.

Conditions to consider when applying dual pilot fiber optic communication channels with common failure mode:

a) Cause of fiber failure can result in a simultaneous line fault:

pilot systems that use blocking logic are inherently insecure since a failure to receive the blocking signal will result in an overtrip. Utilizing two such systems on a line results in even more degradation in security. However, blocking schemes using dedicated fiber offer a tremendous improvement in security over those using power line carrier.)

Note: In regard to the above-mentioned compromise in security, the use of blocking schemes may be particularly unwise if, for example, four parallel transmission lines were protected identically with pilot communications in a common shield wire. Three lines would be subject to an overtrip for a broken fiber-optic shield wire which involves only one of the lines.

b) Steady-state loss of both fiber channels

For the loss of both fibers channels for required dual pilot protection systems, the associated transmission line is requested to be taken out of service or, if possible, tripping delay time immediately reduced to a level at which stability requirements are met and relay coordination is maintained for normal clearing of faults. Allowing for potential overtrips is not acceptable unless specifically approved by the system operator.

2. Fiber Optic Multiplexed Communications

   The use of dedicated fibers for relaying is preferable, but not always practical. The prevailing trend is to combine teleprotection with other services on the same fiber using a DS1 (digital channel bank with 24 separate DS0 channels) operating either directly into a fiber, or, in many cases, into a higher-order multiplexer connected to a fiber.

   Blocking schemes are not recommended over multiplexed channels.

3. Fiber Optic Self-Healing Ring Topology

   Ring topologies can be utilized for purposes of path redundancy such that when a break in a fiber occurs, the affected traffic is quickly re-routed along an alternate path. While this is a very useful feature, especially for non-protection-related services such as voice, SCADA, telemetry, etc which are not themselves redundant, it may not of itself eliminate all failure modes common to the tele-protection channels. For example, it would be unacceptable to utilize a common DS1 multiplexer for both teleprotection channels even when the multiplexer is connected to a switched system.

B. Communication Channel Speed

Speed of a protective relay communication channel is a measure of the time it takes to assert an element in the receiving relay after a logic status change is initiated in the transmitting relay. Channel time includes time delays associated with operation of input/output devices, communications equipment, and channel propagation.

Channel speed may impact the overall operating time of a pilot relay scheme and, as such, needs to be considered in the application analysis. Also, variations in channel speed may cause operating problems in some schemes. Pilot schemes that use blocking or differential type logic are particularly sensitive to variations in channel time. When operating channel speed and consistent channel time is critical to a pilot application, use of communication facilities that operates into a higher order switched network, in which an array of alternate paths may be arbitrarily switched into use for the channel routing, is not recommended. In applications with a fixed number of known alternate paths, channel time for all paths should be considered in evaluating the pilot scheme application.

APPENDIX F - Calculation of Relay Transient Loading Limits

The loadability of bulk power transmission lines is not usually limited by the settings of the relays protecting the line. However, under certain emergency loading situations, there is a possibility that a relay setting could be exceeded, resulting in unexpected tripping. Relay settings are chosen to adequately protect the system from electrical faults and other disturbances, which would affect the safe and reliable operation of the power system. Sometimes this results in relay settings which could restrict line loading. When necessary, techniques such as load encroachment logic and blinders can be used to increase the relay loading limit. The system planner must incorporate relay limitations into equipment loadability limits. The system operator must abide by those equipment loadability limits, so as not to allow loading of sufficient magnitude as to invite relay tripping.

Transient swings precipitated by sudden large load changes, faults, or switching procedures can cause the load characteristic to travel within the operating characteristic of the relay for a period of time, even though under normal steady state conditions it might be well outside the characteristic. To account for this transient condition a safety margin is applied to the calculation based on the operating speed of the relay. Additional safety factors are used to account for CT and PT errors, drift in relay calibration, and for Mho distance elements – deviation from a perfect circle on the R-X diagram. The load limits are calculated and reported based on nominal PJM system voltages (500, 230, 138, 115, and 69 kV). However, it must be kept in mind that the load limit expressed in MVA will decrease with lower than nominal system voltages. In the case of distance relays, since the load limit varies with the square of the voltage, the load limit at 95% system voltage will be $(0.95)^2$ or 90% of the calculated nominal MVA load limit.

OVERCURRENT RELAYS

Overcurrent Relay Transient Load Limit (MVA) = Ke x Kt x (Relay pick-up in MVA)

Where, Ke = 0.92 to account for errors in relay setting, calibration, and CT performance
Kt = 0.90 for inverse time overcurrent relays,
0.53 for instantaneous overcurrent relays,
See Figure F-4 for definite time overcurrent relays

Overcurrent Relay Example: Consider an inverse time phase overcurrent relay applied to a terminal of a 138 kV transmission line. The relay is set on an 8.0 ampere tap with a 1200/5 A CT ratio. The overcurrent relay transient load limit would be calculated as follows:

Overcurrent Relay Transient Load Limit (MVA) = Ke x Kt x (Relay pick-up in MVA)
= 0.92 x 0.90 x (8 x 1200/5 x 138/1000 x √3)
= 380 MVA

DISTANCE RELAYS

Distance relay transient load limits are determined based on the characteristics of the relay when plotted on an R-X diagram. For Mho relays, or lens characteristics, the loading limit is referenced to a maximum "bulge point" or maximum projection along the R axis (See Figures F-1 & F-2). For relays with straight line or blinder characteristics, a slightly different procedure is required. In those instances the bulge point is determined by drawing a line perpendicular to the transmission line impedance and which passes through

the midpoint of the transmission line impedance. Where this line intersects the relay operating characteristic is defined as the maximum bulge point (See Figure F-3). In all subsequent examples the relay load limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics, which fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

The Distance Relay Transient Load Limit (DRTLL) should be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Where, Ke = 0.93 to account for errors in relay setting, calibration, and CT and PT performance
Kt = See Figure F-4 for definite time delay relays
Zr = Impedance (in ohms primary) from the origin to the max. bulge point
kV = Nominal voltage in kV at which relay is applied

Figure F-1 Mho Relay Characteristic showing Maximum Bulge Point

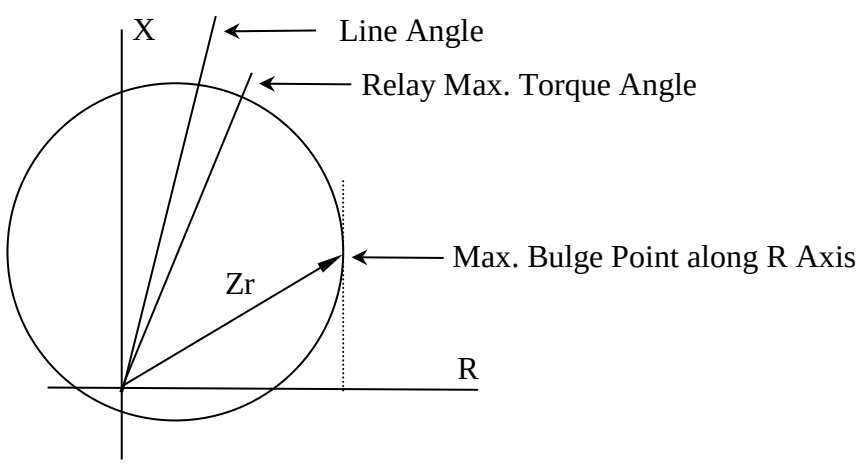


Figure F-2 Lens Relay Characteristic showing Maximum Bulge Point

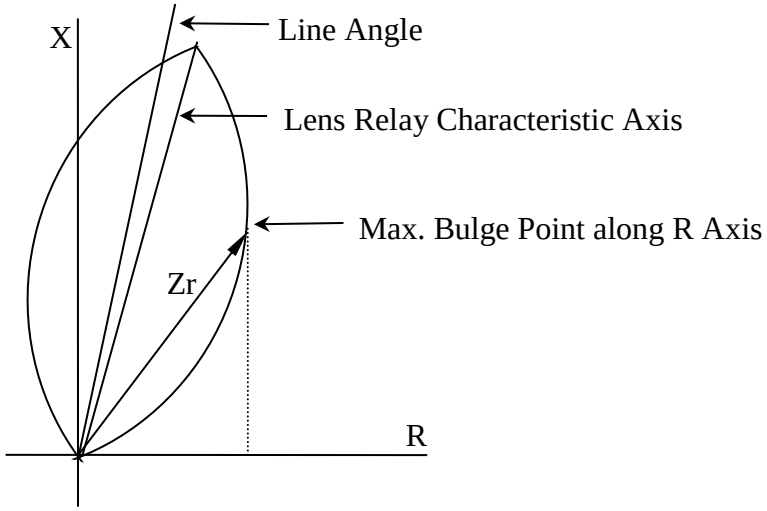
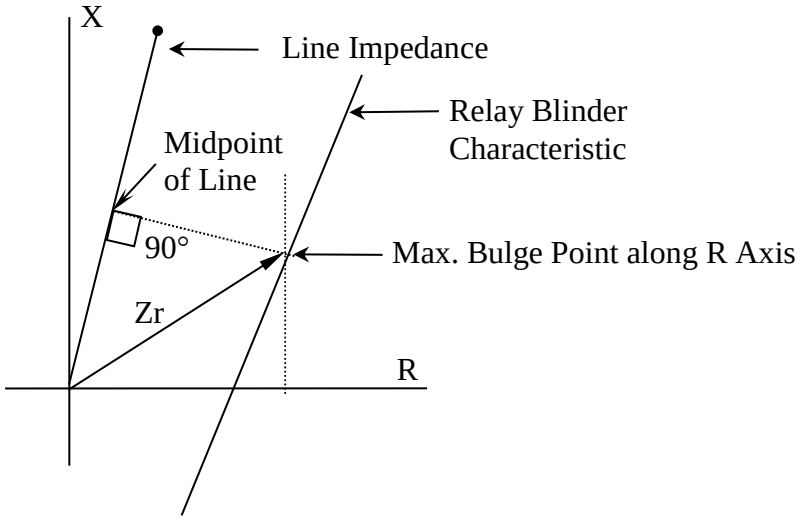


Figure F-3 Straight Line / Blinder Relay Characteristic showing Maximum Bulge Point

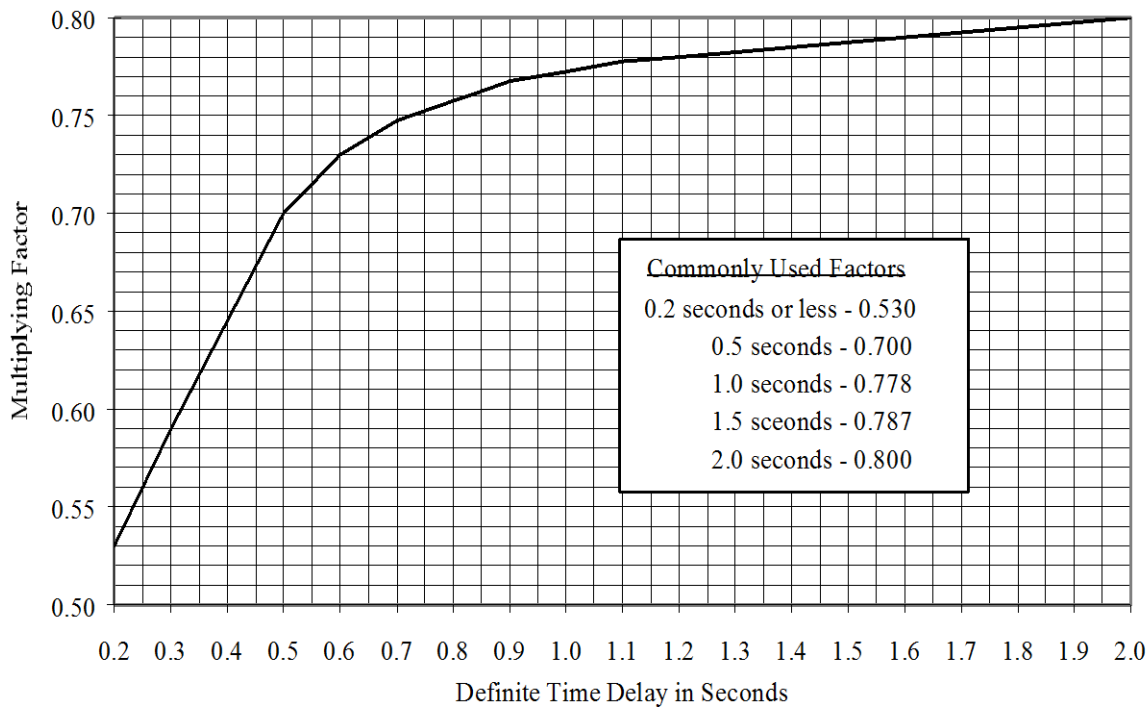


Mho Distance Relay Example: Consider a Mho distance relay applied in a Zone 2 application on a 230 kV transmission line terminal. The relay is set with a 15.0 ohms primary reach and a maximum torque angle of 75 degrees. A 0.5 second time delay is used. Assuming no offset (i.e. circular characteristic passes through the origin) it can be shown that the maximum bulge point occurs at a location where the angle that Zr makes with the +R axis is equal to ½ the relay maximum torque angle. As such, Zr = 15.0 Cos (75/2) = 11.9 ohms primary. From Figure F-4 the Kt adjustment factor for a 0.5 second time delay is 0.70. The distance relay transient load limit would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

= 0.93 x 0.70 x $(230)^2$ / 11.9
= 2894 MVA

Figure F-4 Definite Time Relay Transient Load Limit Adjustment Factor



REACTANCE RELAYS

Relay transient load limits for reactance relays are also determined based on the characteristics of the relay when plotted on an R-X diagram. Similar to Mho relays the loading limit is referenced to a maximum "bulge point" or maximum projection along the R axis (See Figures F-5A, F-5B & F-5C). For relays with multiple reactance zones, the distance relay transient load limit (DRTLL) should be computed for all zones up to and including the zone where the maximum bulge point is located. In all subsequent examples the relay load limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics that fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

The distance relay transient load limit should be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Where, Ke = 0.93 to account for errors in relay setting, calibration, and CT and PT performance
Kt = See Figure F-4 for definite time delay relays
Zr = Impedance (in ohms primary) from the origin to the max. zone reach or bulge point projection along the R axis
kV = Nominal voltage in kV at which relay is applied

Figure F-5A Reactance Relay Characteristics with Maximum Bulge Point in Zone 3 Area

DRTLL should be computed for All Three Zones
Using Zr = Zr_1, Zr_2, & Zr_m with corresponding Kt time delay factors for each Zone

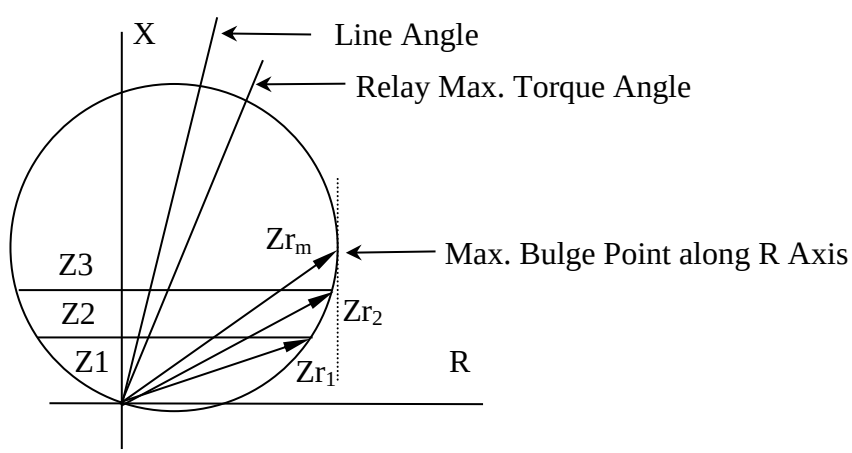
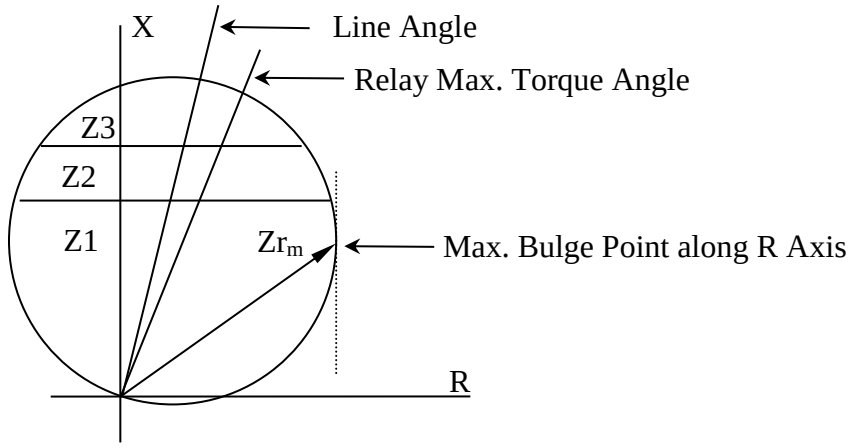


Figure F-5C Reactance Relay Characteristics with Maximum Bulge Point in Zone 1 Area

DRTLL ~~must~~ should be computed for Zone 1 only

Using Zr = Zr_m with corresponding Kt time delay factor for Zone 1



Reactance Relay Example: Consider a three zone Mho supervised reactance relay applied in a back up application on a 230 kV transmission line terminal. The Mho relay is set with a 15.0 ohms primary reach and a maximum torque angle of 75 degrees. The Zone 1 element is set for 3.0 ohms primary reactance with no intentional time delay. The Zone 2 element is set for 5.0 ohms primary reactance with a 0.5 second time delay. The Zone 3 element uses a 1.5 second time delay. Using Figure F-5A as an example, the following impedance can be calculated: Zr_1= 8.66 ohms, Zr_2 = 10.38 ohms, and Zr_m= 11.9 ohms primary. From Figure F-4 the Kt adjustment factors for Zones 1, 2, and 3 will be 0.53, 0.70, and 0.787 respectively. The distance relay transient load limits would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Zone 1 = 0.93 x 0.530 x $(230)^2$ / 6.88 = 3011 MVA

Zone 2 = 0.93 x 0.700 x $(230)^2$ / 10.38 = 3,318 MVA

Zone 3 = 0.93 x 0.787 x $(230)^2$ / 11.90 = 3,254 MVA

In this case, Zone 1 will be the most restrictive setting from a DRTLL standpoint, followed by Zone 3 and then Zone 2.

COMMUNICATION ASSISTED / PILOT RELAY SCHEMES

Relay schemes employing some form of line current differential protection technique (pilot wire, phase comparison, charge comparison, etc.) are not load limiting and, as such, no transient load limits are calculated. However, distance relays used in communication assisted / pilot schemes can have loading limitations that need to be calculated. This section addresses DRTLL of distance relays used in pilot schemes. If the same relays are also used to provide non-communication assisted zone backup protection, then additional DRTLL calculations, as discussed previously, also apply. In all subsequent examples the relay load

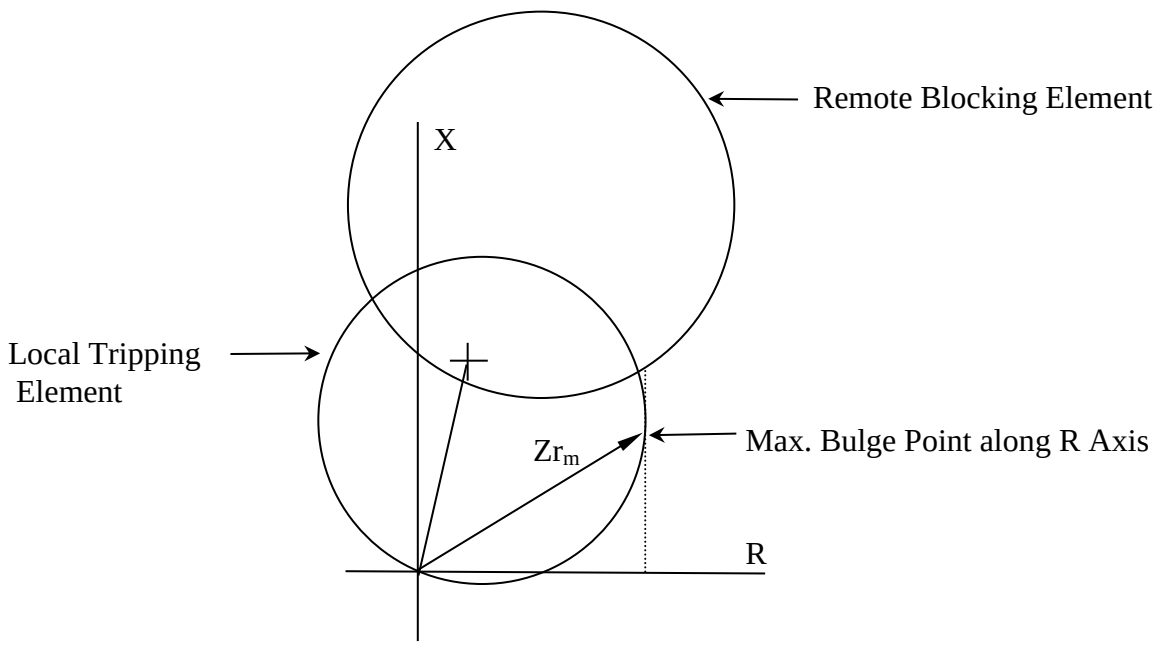
limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics that fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

Blocking Schemes

For blocking type schemes, any line loading which would result in operation of the tripping element at one end of a line, which would not simultaneously cause the blocking element to operate at the remote end of the line, needs to be calculated. In most cases, the maximum bulge point of the local tripping characteristic will not also fall within the blocking characteristic at the remote end of the line (See Figure F-6A). In these cases, the maximum bulge point of the phase tripping element should be used to calculate the DRTLL using the identical procedure discussed previously for distance relays. However, since the blocking scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-6A Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Blocking Characteristic

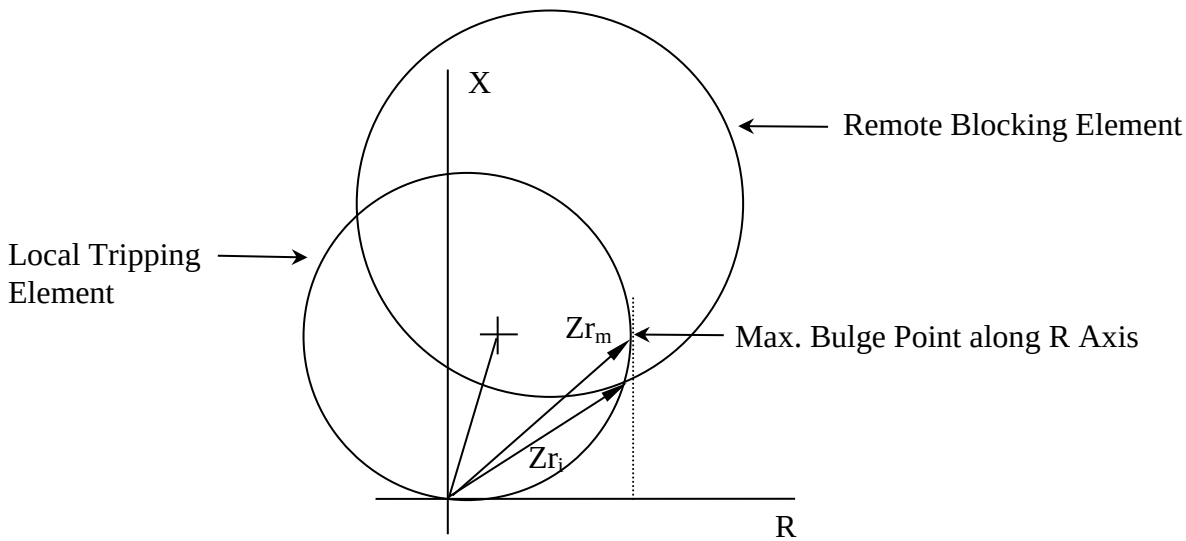
Use Zr_m to calculate DRTLL with Kt = 0.53



In rare cases, the maximum bulge point of the local tripping characteristic will fall within the blocking characteristic at the remote end of the line (See Figure F-6B). In these cases, a slightly higher loading limit can be realized by using the intersection of the tripping and blocking characteristic Zr_i to calculate the DRTLL. Again, since the blocking scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-6B Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Blocking Characteristic.

Use Zr_i to calculate DRTLL with Kt = 0.53

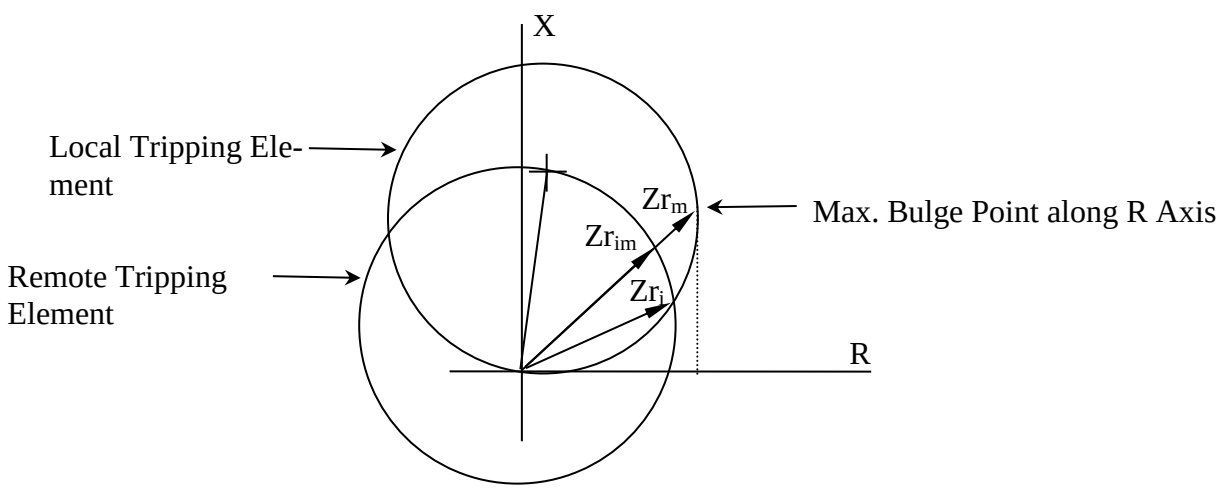


Permissive Schemes

For permissive type schemes, any line loading which would result in simultaneous operation of the tripping elements at both ends of a line needs to be calculated. Similar to blocking schemes, the maximum bulge point of the local tripping characteristic will usually fall outside the relay characteristic at the remote end of the line (See Figure F-7A). However, unlike blocking schemes, the local relay terminal will not trip unless the load is also within the remote tripping characteristic. Therefore, the impedance used to calculate the DRTLL must lie somewhere on the boundary of the overlapping characteristic formed from the two tripping elements. In these cases, two load points must be considered. One point, Zr_i, represents the intersection of the two tripping characteristics in the first quadrant. The second point, Zr_{im} represents the intersection of the overlapping tripping characteristic and a straight line drawn from the origin to the maximum bulge point of the local end tripping characteristic. In most cases, Zr_{im} will be larger than Zr_i , but not always. The larger of Zr_i or Zr_{im} should be used to calculate the DRTLL using the identical procedure discussed previously for distance relays. In no case should a value greater than Zr_m be used in the calculation. To simplify the analysis, many companies will simply use the maximum bulge point of the local tripping characteristic Zr_m in the calculation. In any event, since the permissive scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-7A Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Tripping Characteristic

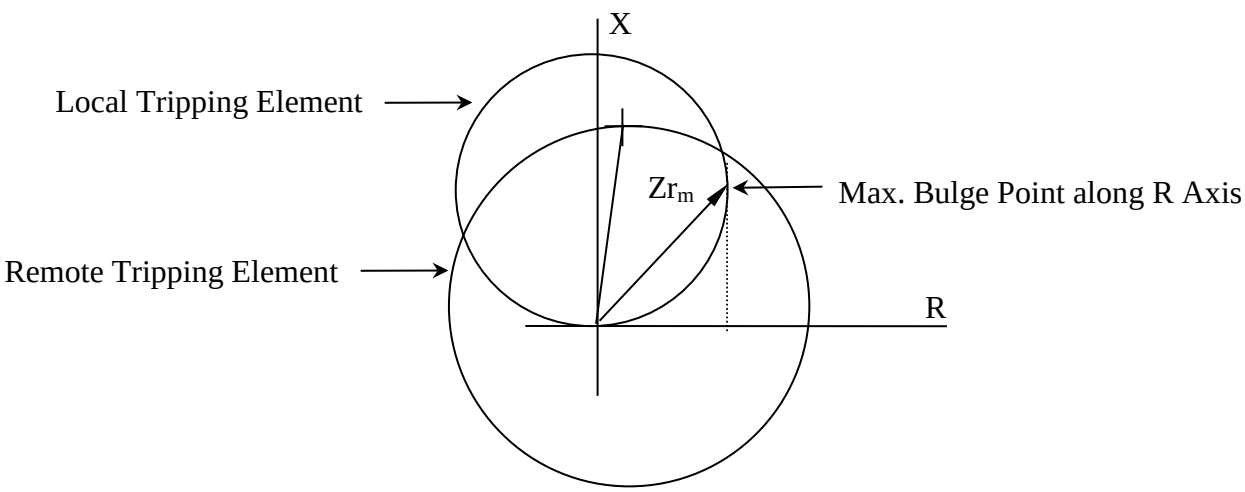
Use larger of Zr_{im} or Zr_i to calculate DRTLL with Kt = 0.53



In rare cases, the maximum bulge point of the local tripping characteristic will fall within the tripping characteristic at the remote end of the line (See Figure F-7B). In these cases, the maximum bulge point of the phase tripping element should be used to calculate the DRTLL. Again, since the pilot scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-7B Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Tripping Characteristic

Use Zr_m to calculate DRTLL with Kt = 0.53



Permissive Overreaching Transfer Trip (POTT) Pilot Scheme Example: Consider a 230 kV transmission line with positive sequence impedance of 10.0 ∠80° ohms primary. Both ends of the line use Mho type phase distance relays with a setting of 15.0 ohms primary and a maximum torque angle of 75 degrees. The relays are connected in a high-speed permissive overreaching transfer trip pilot scheme. The tripping elements are also connected to a discrete 0.5 second timer, so as to function as a traditional back-up Zone 2 function. Using Figure F-7A as an example, the following impedances can be calculated: Zr_l = 7.53 ∠15.1° ohms, Zr_{im} = 8.6 ∠37.5° ohms, and Zr_m= 11.9 ∠37.5° ohms primary. For the POTT case, since Zr_{im} is larger than Zr_1, 8.6 ohms is used in the calculation. From Figure F-4 the Kt adjustment factor for a high speed pilot scheme would be 0.53. When considering the back-up Zone 2 function, the Zr_m impedance is used with a Kt factor of 0.70 corresponding to a 0.5 second time delay. The distance relay transient load limit would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

POTT = 0.93 x 0.530 x $(230)^2$ / 8.60 = 3032 MVA
Zone 2 = 0.93 x 0.700 x $(230)^2$ / 11.90 = 2894 MVA

In this case, the Zone 2 function has a lower DRTLL than the POTT.

APPENDIX G - Voltage Transformers

Voltage Transformers

For new line protection scheme designs:

1. Independent AC voltage sources are required for primary and back-up protection schemes if both schemes require ac potential for normal operation. Independent Voltage Transformers (VTs) are preferred. Separate control cables for the secondary leads are recommended. A single set of VTs with electrically-independent secondary windings is acceptable, however it should be recognized that a VT primary failure may not only result in a fault, but will likely compromise both protection schemes. If a single set of VTs is used, it is recommended that upon detection of a loss-of-potential condition, the affected protection scheme(s) be automatically re-configured to protect the line using non-directional phase and ground overcurrent elements with suitable time delays. At a minimum, a ground overcurrent element should be enabled. This is considered adequate since the primary failure of a single VT necessarily involves ground.
2. In station configurations where a line can be supplied from multiple sources, VTs should be applied such that the line relays have the appropriate potential when the line is energized regardless of which source is supplying the line. For example, in a breaker-and-a-half arrangement, the VTs used for line protection should be connected to the line position rather than to a bus.

APPENDIX H - Generator Protection for Units Less Than 100 MVA and Connected Below 230 kV

GENERAL

The protection outlined in sections 3, 4, 5 and 6 of the PJM Manual 07: PJM Protection Standards is generally applicable to all synchronous generators and their connection to the utility system. However, below 100 MVA the variety of generation technologies and the diverse nature of their high voltage connections to the utility system make it difficult to outline a single guideline for protection. This class of generator includes both synchronous and induction machines, inverter systems, and hybrids. These installations may exist solely to export power or they may be integrated into a plant to serve local load, operating in parallel with the utility for reliability. Detailing the specific protection requirements for all of these possible combinations is beyond the scope of this appendix.

The purpose of this appendix is to provide an overview of the protection philosophy and point out some pitfalls encountered in the interconnection of smaller generating plants to the utility system. Protection of the generators themselves should be designed in accordance with the generator manufacturer specifications, applicable national standards, and the interconnected utility's requirements.

STANDARDS

Applicable standards include, but are not limited to:

ANSI/IEEE C37.101 Guide for Generator Ground Protection
ANSI/IEEE C37.102 Guide for AC Generator Protection
ANSI/IEEE C37.106 Guide for Abnormal Frequency Protection for Power Generating Plants
ANSI/IEEE C37.95 Guide for Protective Relaying of Utility-Consumer Interconnections
ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers
IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

ZONES OF PROTECTION

The protection zones of interest here can be loosely grouped into three overlapping areas: the generator, the step-up transformer and interconnection breaker, and the incoming distribution or transmission line. Protection must be provided to isolate the generator for faults in each zone.

REDUNDANCY

The protective system should be designed with sufficient redundancy to operate correctly for the single contingency failure of any protective relaying component. Protection provided specifically to isolate faults on the utility system, or to protect the utility from faults in the generator facility, must be fully redundant. In other words, it is required that two independent devices be able to detect and operate to clear any single contingency fault. Redundancy for generator protection, where the failure of that protection does not impact the utility, is only recommended.

SIGNAL DEPENDENT GENERATORS

In general, induction generators and inverter systems are signal dependent. That is they require a connection to the utility to provide excitation, or commutation, in order to generate power or to sustain fault current.

When the utility opens its breaker to interrupt a fault, the connection to the generator is removed and it can no longer sustain current flow. In this manner it is self-protecting and requires very little extra protection. If the system conditions could be such that the machine can become self-excited, or if the commutation circuit design will allow the inverter to sustain fault current, then the generator must be treated as if it is a synchronous generator and a full complement of protection is required.

GENERATOR ISOLATION DEVICE

All generators require a visible means of isolating the generator from the utility system. System conditions may dictate the use a three phase interrupting device to isolate the generator. Synchronous generators require a breaker for synchronizing to the utility system. The location of the generator breaker is a function of the plant design and operation.

STEP-UP TRANSFORMERS

Most generators will be connected to the utility system through a power transformer. The step-up transformer reduces harmonics, lowers fault currents, and decreases the likelihood of self-excitation for induction generators. While most transformer winding configurations can be used, there are protection issues that must be addressed with each different connection.

WYE (grounded) -WYE (grounded) CONNECTION

Protection is straight forward, but since the wye-wye connection does not provide zero sequence isolation particular care must be taken to coordinate the utility system ground relays with the generator/interconnection ground protection. In certain cases the sensitivity of the utility system ground relaying may be significantly reduced.

WYE (grounded) -DELTA CONNECTION

The delta connection on the generator side provides zero sequence isolation between the high and low sides of the transformer. This transformer can be a significant source of ground current to faults on the utility system. Depending on the system configuration, the sensitivity of the utility system ground relays may be reduced to the point where the protection is compromised. For these cases it may be advisable to ground the step up transformer neutral through a resistor. Note that the transformer has to have the proper insulation and terminating facilities to make this connection.

For ground faults on the delta side of the transformer, the generator protection should operate to isolate the unit from the fault. Depending on the configuration of the plant bus the fault may remain energized from the high side. This will increase the phase to ground voltage by as much as 173%. It is common practice, and highly recommended that the phase to ground insulation of the bus and equipment connected to the delta side of the transformer be rated for full phase-to-phase voltage. If this is not the case, high-speed phase or 3Vo overvoltage protection should be applied that will clear the fault by opening a high side interrupting device.

DELTA-WYE CONNECTION

The delta connection on the high side provides zero sequence isolation from the generator to ground faults on the utility system. After the utility source opens to clear the fault from the utility end, the fault may remain energized from the generator with no ground current flow. This may increase the phase to ground

voltage on the unfaulted phases by as much as 173%. Unless the phase-to-ground insulation level of the highside bus and connected equipment is rated for full phase-to-phase voltage, high-speed phase or 3Vo overvoltage protection connected on the utility side is recommended to be applied to isolate the generator from the faulted system. Direct transfer trip and/or sensitive directional power relays may also be used to augment this voltage protection.

FERRORESONANCE

Any delta or ungrounded wye transformer connection may be subject to ferroresonance under open phase conditions. If the system configuration is such that an open phase can create a series resonant path between the transformer windings and the phase to ground capacitance then ferroresonance is possible. For this reason ungrounded wye and delta transformers should use a three phase interrupting device on the high side. Additional relaying may be required to detect and clear the resonant condition.

UNDERFREQUENCY

The PJM specified underfrequency set point on generators is dependent upon the PJM control zone (PJM Mid-Atlantic, PJM West, PJM ComEd or PJM South); see PJM Manual 36, 2.3.1 Generator Frequency Trip Settings for the specific setpoints. These setpoints are designed to provide coordination with the utility system underfrequency load shedding scheme (UFLS). The UFLS scheme is designed to shed blocks of load in order to arrest a system frequency decline caused by a mismatch between generation and load. The specified underfrequency setpoint is usually adequate to provide satisfactory turbine protection. Some units and other generating technologies may have different underfrequency limitations for which the setpoint may not suffice. If generators apply underfrequency protection that is more sensitive than the UFLS scheme, those units will trip offline at precisely the time they are needed to bolster the utility system generating capacity.

Where it is possible, all generators should follow the PJM requirement for tripping. Where a generator (20 MW or greater) requires an underfrequency setting that does not coordinate with the system UFLS scheme, or a more sensitive underfrequency setting is required to detect an islanded condition, PJM should be notified.

UTILITY-GENERATOR INTERCONNECTION PROTECTION

Interconnection protection is applied to protect the utility system to which the generator connects from harm caused by the generating facility. These facilities will typically consist of protection to prevent island operation with part of the utility system, to assure that voltage and frequency are within acceptable limits, to assure the generator trips for faults on the intertie line, and to assure that faults within the generating facility are isolated by the intertie breaker rather than by other interrupting devices located on the utility system. The interconnection protection may be located at a dedicated location at the point of intertie or within the generator facility. In either case, however, the associated design and setpoints for these facilities require the approval of the involved intertie utility. Test documentation is also required to assure these facilities are properly set and maintained.

ISLANDING

In general, relaying must be installed to prevent a generator from operating inadvertently as an island. If the tie between the utility and a generator is opened there is no means of keeping the generator in synch with the utility. Depending on the system configuration, the point of separation between the two systems may not have provisions for re-synchronizing the generator prior to reestablishing the tie. Connecting the generator to the utility when it is out of synchronism may have catastrophic consequences for the generator and may impact the system power quality for other utility customers. Traditionally, under/over frequency and under/over voltage protection has been applied to detect islands. Where these devices are not sufficient to detect all the load/generation conditions for possible islands, supplemental anti-islanding protection (e.g. a rapid change in power factor or transfer trip from the utility supply should be applied).

Direct transfer trip (DTT) requirements may vary depending on the nature of the system of the intertie utility, specific design parameters of the generating station, and the ratio of minimum load connected to the intertie line to the total generation on the line. In general, the need for DTT facilities must be determined on specifics of an individual installation. Typically, larger units (5 MW and above) are probable candidates for the need for DTT. Automatic reclosing on the intertie line may need to be delayed, or supervised by voltage sensing relays, in order to ensure that the generator is disconnected before auto-reclosing takes place.

INTERTIE LINE FAULT PROTECTION

Protection must be provided to rapidly isolate the generator from the utility system for all types of faults, anywhere on the intertie line. Protection settings must take into account the effects of infeed from other generators that may be connected to the line.

Protection for multi-phase faults is generally provided by voltage controlled time overcurrent, or impedance relaying with an appropriate coordination timer. Three single-phase undervoltage relays may be used if adequate sensitivity can be maintained for line faults without sacrificing coordination for faults on other feeders supplied from the same bus. Open phase protection utilizing a negative sequence time overcurrent, or transformer neutral time overcurrent relay should be applied if loading is such that an unbalance can overload the utility transformer.

Protection for ground faults on the intertie line varies depending on the generator step-up transformer connection. Wye (grounded) –wye (grounded) connected transformers provide no isolation for zero sequence current between the generator and the utility. Protection can be provided by a neutral time overcurrent relay on either the generator or the transformer. Three single phase undervoltage relays may also be used if adequate sensitivity and coordination can be achieved.

For wye (grounded) -delta connected transformers (delta on the generator side), the transformer is a source of zero sequence current for ground faults on the utility system. Protection for ground faults is generally provided by a ground time overcurrent relay on the transformer neutral.

For transformer connections with an ungrounded winding on the utility system side, such as delta-wye and delta-delta connected transformers, the generator is isolated from the utility for ground faults on the intertie line. The transformer is not a source of ground current for this fault. Unless detected, a ground fault will remain energized from the generator. Voltage on the faulted phase will be reduced, but voltage on the un-

faulted phases may increase to 173% of nominal. This extreme overvoltage, can cause catastrophic failure of surge arresters and lead to other equipment insulation failures. This condition must be detected and removed rapidly (usually within 0.16 seconds based on typical arrester transient overvoltage (TOV) ratings). Protection for this condition is required (Fig 7A PJM Manual 14A) and may consist of three single phase overvoltage relays, or a 3Vo overvoltage relay, connected to phase-to-ground voltage transformers on the utility side of the transformer. As an alternative, a combination of a high-speed overvoltage and an undervoltage relay connected to a single phase may be used. However, because of the high speed with which this scheme must operate, the undervoltage relay may be prone to nuisance tripping.

If the phase-to-ground insulation of the faulted system is rated for full phase-to-phase voltage, a high speed scheme is not required. For this case, time delayed protection, such as directional power relays, may also be used. In addition to the protection listed above, the protection applied for anti-islanding, time delayed phase over/under voltage relays and sensitive definite time over and under frequency relays, provide a useful form of back-up intertie line fault protection.

SYSTEM PROTECTION FOR GENERATOR FACILITY FAULTS

The generator facility encompasses all of the equipment from the utility intertie line connection point to the generator. Protection should be applied to detect and clear any fault within the generator facility. These devices must be set to coordinate with the utility protection to assure isolation of only the faulted zone. Specific requirements depend on the electrical arrangement of the plant, but can generally be grouped into three areas: the primary bus; the step up transformer; and the low side bus.

Protection of the primary bus, that is the zone encompassing the utility interconnection device through the step-up transformer bushings, may be via bus differential relays, phase and ground time delayed and instantaneous overcurrent relays, or power fuses. If overcurrent relays are used, they may need to be made directional so as to properly coordinate with both up-stream and down-stream devices. Power fuses are not recommended for installations 10 MVA or greater, or where delta or ungrounded wye connected transformers are used due to the potential for overvoltage and ferroresonance problems.

Protection of the step-up transformer may be provided by the primary bus overcurrent devices, if they have sufficient sensitivity. More likely, this protection will be provided by dedicated overcurrent relays installed in the transformer high side bushing current transformers. For transformers 10 MVA and greater, a more sensitive method of detecting internal faults (i.e. transformer differential or sudden pressure relay) is recommended. The most complete protection package would combine a transformer differential with a fault pressure relay to detect low magnitude turn-to-turn faults. On grounded wye transformers, a more sensitive ground overcurrent relay can be installed on the transformer neutral to protect the grounded winding.

Faults on the low side bus must be isolated from both the utility side and the generator side. Protection for this zone is generally provided by phase and ground overcurrent relays. This protection should operate a high side breaker to isolate the fault from the utility. For transformer connections with a delta on the generator side, zero sequence overvoltage protection may be used to detect and trip the high side for ground faults.

GENERATOR PROTECTION

Generator protection is the responsibility of the IPP. Good protection practices for small generating facilities vary considerably with size and type of generation. Protection must be provided to comply with all applicable ANSI/IEEE Standards.

APPENDIX I - Acceptable Three Terminal Line Applications

Refer to M07. No supplementary information available

APPENDIX J - Application of Triggered Fault Current Limiters

This appendix describes the concerns and lists the recommendations for the application of triggered fault current limiters (FCL's) when proposed for the mitigation of increased fault current availability at a utility distribution bus resulting from the installation of new equipment or rearrangement of existing equipment at a non-utility station. Note: in the context of this document, "utility" means the delivery, or "wires" company whose equipment is being affected by the addition of the new equipment or rearrangement of existing equipment. Please note there are no formal PJM requirements for Triggered Fault Current Limiters.

General

The installation of new equipment or rearrangement of existing equipment at a non-utility station can result in an increase in fault current at the utility bus to a point beyond the momentary current withstand capability or the interrupting capability (or both) of one or more circuit breakers or other equipment connected to the utility bus. Possible solutions to this problem include the replacement of the underrated equipment, the installation of reactors, splitting buses that were formerly "solid", etc.

Recently a technique has been proposed involving the use of FCL's, which can be described as "smart fuses". If properly applied, the device will carry the required load current and yet operate very quickly to interrupt the fault current contribution from the new equipment, thereby limiting the fault current at the station bus to safe levels. The design of the FCL includes sensing and firing logic, a heavy copper bar fitted with explosive charges, and a current-limiting fuse in parallel with the copper bar. When the sensing logic detects a fault above its threshold setting, it fires the explosive charges to cut the copper bar, diverting all current through the fuse, which clears the fault very quickly. Depending on how fast the FCL is able to sense the fault and operate, the instantaneous fault current peak at the utility bus may be no higher than it would have been without the generators having been connected.

There are, however, a number of concerns surrounding the application of FCL's. The remainder of this discussion presents those concerns and lists requirements relating thereto.

Application Concerns and Recommendations

Selectivity

When a fault occurs on utility equipment and this fault causes the current through the FCL to exceed the threshold value, the FCL will be triggered in order to reduce the total fault current. The FCL may also be triggered for faults within the FCL owner's system. Both of these situations will result in the likelihood of "non-selective tripping", meaning that more power system elements were removed from service than would otherwise have been necessary to clear the original fault. To the extent that this lost equipment is important to the system, the system is degraded. The amount of time that the degradation will be in effect is a function of how long it will take the FCL owner to replace the expended parts of the affected FCL's.

Recommendations: All concerned parties must understand the exposure of the FCL to a range of faults on the utility system and to faults within the FCL owner's system which can result in operation of the FCL, and should formally agree that the loss of equipment resulting from the operation of the FCL for those faults is an acceptable consequence.

Proof of Design Adequacy

When a fault occurs on the utility system that, with the added contribution from the new equipment, exceeds the momentary or the interrupting rating of the utility breaker or other equipment, there is a concern that the FCL design and application may not operate sufficiently fast to protect the utility equipment.

Recommendations:

The FCL owner is expected to provide detailed calculations demonstrating that the fault current limiter will achieve its intended purpose of protecting the utility equipment from being subjected to current beyond its capability. The calculations must include the anticipated current-versus time waveforms of the total asymmetrical current flowing through the utility equipment for the maximum fault and minimum fault that will operate the FCL. The maximum current should be the maximum asymmetrical current available based on the calculated X/R ratio, and should include both the contributions from the system as well as the let-through contribution from the FCL. Detailed waveform analysis may become unnecessary if the calculation method used is sufficiently conservative (i.e. the arithmetic addition of the FCL peak let-through current and the system peak asymmetrical current). The calculations will require modeling of the utility system and the FCL owner's system, and should include the transient effects of induction and synchronous motors. Since the FCL will not operate for fault level values below its threshold, the RMS value of the threshold of the FCL should be added to the short circuit current of the breaker for determination of interrupting duty.

The utility should supply the FCL owner with sufficient modeling information of the utility system to allow the FCL owner to make the analysis described in the preceding paragraph.

The FCL owner should provide design information showing that the operation of the FCL will not be compromised under low AC voltage conditions at the FCL owner's facility resulting from any fault on the utility system requiring the FCL to operate.

Changes to the Electrical System

Changes to the FCL owner's electrical system may render the FCL application incapable of performing its originally-intended function.

Recommendations: If changes are made to the FCL owner's electrical system, the FCL owner should re-apply the analysis outlined in the section titled *Proof of Design Adequacy* and associated subsections and provide documentation of this analysis to the utility for review.

Redundancy

If the FCL, for some reason, fails to operate as intended, a fault on the utility may result in a catastrophic failure. It should be emphasized that this concern is not equivalent to concern for a stuck breaker or a failed relay. A failure of the FCL to operate when required is a substation safety hazard, especially in a situation where an operator may unknowingly be closing a breaker into a fault. Further, a catastrophic breaker failure may cause significant collateral damage to other equipment in the utility substation.

Recommendations: The FCL owner should provide design information showing that for the single-contingency failure of the FCL to perform its intended function, the overall intent of protecting the utility equipment from overduty conditions is still met.

FCL Bypass Arrangements

The FCL may undesirably be electrically bypassed by the owner.

Recommendations: The FCL owner should have a written procedure which prohibits bypassing the FCL unless it is demonstrated to the satisfaction of the utility that conditions do not require the potential operation of the FCL.

Maintenance and Testing

If the FCL is not tested and maintained properly, it may not be capable of operation when required.

Recommendations: Routine testing of FCL trigger levels, firing logic, and firing circuitry should be conducted at least every four years. Documentation of this testing should be available upon request by the utility. The utility should be granted physical access to inspect the FCL as deemed necessary by the utility.

Reference: "Limitations of Fault-Current Limiters for Expansion of Electrical Distribution Systems", J. C. Das, IEEE Transactions on Industry Applications, Vol. 33, No. 4, July/August 1997.