Agenda Item 5.h
Attachment 2

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

A Technical Reference Document

Power Plant and Transmission System Protection Coordination

Draft 6.~~5~~9 – ~~September 1~~November 19, 2009

NERC System Protection and Control Subcommittee

to ensure the reliability of the bulk power system

~~September~~November 2009

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Table of Contents

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Field Code Changed ... [42]
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Field Code Changed ... [44]
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Field Code Changed ... [46]
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List of Tables

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List of Figures

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1. Introduction

"Goal: to reduce the number unnecessary trips of generators during system disturbances"

The record of Generator Trips (290 units, about 52,745 MW) during the North American disturbance on August 14, 2003, included thirteen types of generation-related protection functions that operated to initiate generator tripping. There was no information available that directly addresses which of those generator trips were appropriate for the Bulk Electric System (BES) conditions, and which were nuisance trips.

"A reliable electric system requires: proper protection and control coordination between power plants and transmission system."

The list of protection element types that tripped were: mho-distance (21), voltage-controlled -restrained overcurrent (51V), volts-per-hertz (24), undervoltage (27), overvoltage (59), reverse power (32), loss-of-field(40), negative sequence (46), breaker failure (50BF), inadvertent ~~energization~~energizing (50/27), out-of-step (78), over/underfrequency (81), transformer differential (87T), and a significant number of unknown trips. The number of each type of protective function that generator units were tripped from during the disturbance is shown below: This Technical Reference concentrates on the bulk electric system reliability and resulting performance implications of protection system coordination with the power plant protection elements.

Table 1 — 2003 Blackout Generation Protection Trips

Device Type	21	24	27	32	40	46	50/27	50 BF	51V	59	78	81	87T	Unknown	Total
Number of Units Tripped	**8**	**1**	**35**	8	**13**	5	7	1	**20**	**26**	7	**59**	4	96	290

Table 1 summarizes the number of generators that were tripped and the generator protection function that initiated the generator trip. This technical report addresses the coordination of each one of these generator protection with the transmission system protection depicted in Figure 1.1.

Additionally, the following protection elements are also discussed in this report to provide guidance on complete coordination to the owners of the transmission system and the generating stations: plant auxiliary undervoltage protection, transformer over-current (51T), transformer ground over-current (51TG), generator neutral over-voltage (59GN), generator differential (87G), and overall unit differential (87U).

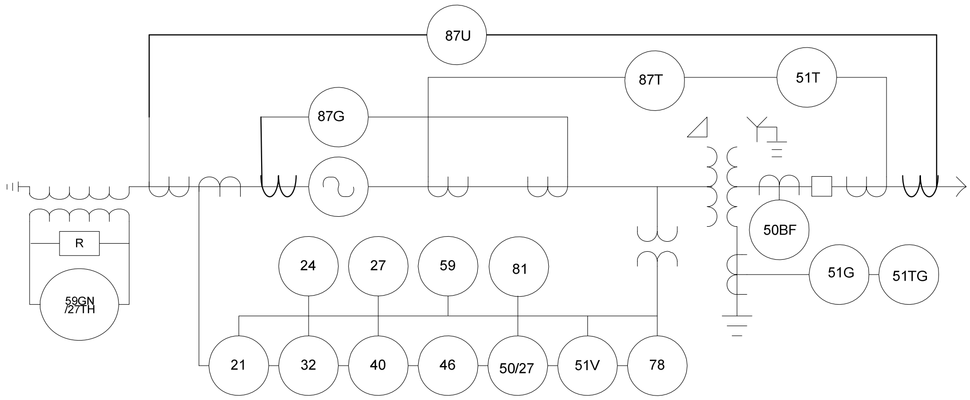

Figure 1.1 – Relay Configuration

The generator trip types that were listed as unknown for the 2003 blackout event are being addressed through the ongoing analysis of subsequent system disturbances for root causes via the NERC Events Analysis program. Other types of generation tripping~~s~~ that have since been identified include: lean blowout trips of combustion turbines, power load unbalance actuations during system disturbances, response of nuclear and other types of generation undervoltage protection to system disturbances and other unit control actuations.

1.1. Goal of this Report

The goal of this Technical Reference Document is to explore generating plant protection schemes and their settings, and to provide guidance for coordination with transmission protection and control systems to minimize unnecessary trips of generation during system disturbances.

1.2. Scope

This Technical Reference Document is applicable to all generators but concentrates on those generators connected at 100-kV and above. Also, this document includes information exchange requirements between Generator Owners and Transmission Owners to facilitate coordination between their protection schemes. This document provides a technical basis to evaluate the coordination between generator protection and transmission protection system. The protection coordination discussed in this document applies only to situations where the specific protection functions are present and applied. There are generator protection schemes that do not include some of these functions based on the application or need. This Technical Reference is not an endorsement of using these functions, good industry guidance such as IEEE C37.102 "IEEE Guide to AC Generator Protection" and recommendations from the generator and other equipment manufacturers should take precedence as to which protection functions are applied.

Distributed Generation (DG) facilities connected to distribution systems are outside the scope of this report. Such DG protection requirements and guidance are covered by IEEE 1547 – 2003 – IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

1.3. Coordination Definition

For purposes of this document and as guidance to the entities, coordination is defined as the following:

> ***Coordination of generation and transmission protection systems (for events external to the plant), means that power plant protection and related control elements must be set and configured to prevent unnecessarily tripping the generator prior to any transmission protection and related control systems acting first, unless the generator is in jeopardy by exceeding its design limits due to operating conditions, generator system faults, or other adverse potentially damaging conditions.***

1.4. Multi-Function Protection Devices

The application of a protective function should be based on a specific need to protect the turbine-generator. If that protection function is not needed, DON'T USE IT! DON'T USE IT!

Recently it has become possible to purchase a multifunction generator protection system that contains all the protection functions that could be imagined for all possible applications. There is a strong tendency for users to want to enable and set all these functions. In the past each separate generator protective function required a separate relay; therefore the tendency today is to utilize numerous and unnecessary protective functions in many generation applications. It is definitely not appropriate that some of the available protection functions be used in any given application! The decision to enable one of these protective functions should be based on a specific need to protect the turbine-generator or a need to provide backup protection functions for the interconnecting power system. If there is no specific protection need for making a setting, that protection function should not be enabled. On the subject of system backup, and as an example of protection elements that should not be enabled at the same time, are the 21 and 51V. These two protection elements are designed to provide the same protective function for very different applications and purposes, and therefore, should NOT be enabled together. This is explained in the sections covering those protection functions.

1.5. Assumed System Stressed Voltage Level

In this report, 0.85 per unit voltage at the system high side of the generator step-up transformer is used as the stressed system voltage condition for an extreme system event. This is based on Recommendation 8a, footnote 6 of the *NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts* (Approved by the Board of Trustees February 10, 2004).

The impetus for writing this Technical Reference Document is to address the recommendations contained within Blackout Recommendation Review Task Force (BRRTF), recommendation TR-22 – Generator Backup Protection Responses in Cohesive Generation Groups, (see Appendix C).

During system disturbances and stressed system conditions, a cohesive generator group can experience lower voltage, underfrequency, and large power flows brought on by large angles across its ties to the Interconnection. During the system cascade, a number of relaying schemes intended to trip generators for their own protection operated for the event.

The TR-22 recommended that NERC should evaluate these protection schemes and their settings for appropriateness including coordination of protection and controls when operating within a coherent generation area weakly connected to an interconnection or in an electrical island. One example to be considered is, generators directly connected to the transmission system using a 51V protective function should consider the use of an impedance protective function (device 21) instead, for generator system backup protection.

1.6. Modeling Considerations

A significant element in assuring reliable and stable operation of the overall electric system is the ability to predict the behavior of generation and transmission acting as a single system. While the transmission system and its system controls are currently well modeled and understood, transmission system protection modeling is only rarely modeled in dynamic simulations. It is generally assumed in the models that those protection systems will operate normally and that they are coordinated. Analysis of significant system disturbances since 2007 have shown that out of 39 protection system misoperations during those events, 12 have been due to miscoordination of generation and transmission protection systems, usually resulting in the unnecessary tripping of generators.

The purpose of this Technical Reference Document is to provide guidance for the coordination of two key system elements: transmission system and generation protection. This document provides additional guidance for IEEE generation protection standards and guides and NERC standard. NERC ~~Standard PRC-001~~Standards Development Project 2007-06 System Protection Coordination is intended to codify the coordination tenets expressed in this technical reference in a revision to Standard PRC-001.

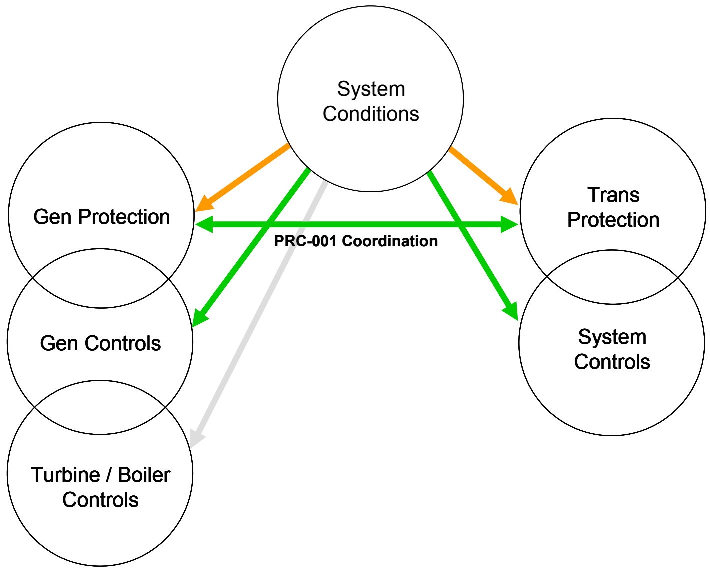

Figure 1.2 — Protection and Controls Coordination Goals

Figure 1.2 illustrates the interrelationships between control and protection systems in a power plant (on the left) and the transmission protection and controls (on the right). While generator exciters, governors, and power system stabilizers (generator controls) are commonly modeled in dynamic simulations, the transient stability behavior and interaction of generator protection and turbine/boiler controls during transient and post-transient conditions are not. Consequently, transmission planning and operations engineers never see the consequences of those interactions with the rest of the system. The transmission system is judged to be in a safe operating condition if there are no overloads, voltage is acceptable, and all generators remain stable. To maintain overall reliability of the Bulk Electric System, all of those elements must act in a coordinated fashion. That coordination must be done regardless of ownership of the facilities.

2. Coordination and Data Exchange Summary

Table 2 and its contents act as and provide an executive summary for the protection system element coordination described in this technical report. The columns are for the following:

Column 1 — the protective functions that require coordination by the Generator Owner.

Column 2 — the corresponding protective functions that require coordination by the Transmission Owner.

Column 3 — the system concerns the Transmission Owner and Generator Owner must, as a minimum, jointly address in their protection coordination review.

Table 3 provides the detailed information required from each entity ~~and~~ to be exchanged. The table lists protection set points, time delays and the detailed data required to be exchanged for each function between the entities. The columns are for the following:

Column 1 — the detailed data the Generator Owner must provide to the Transmission Owner

Column 2 — the detailed data the Transmission Owner must provide to the Generator Owner

Column 3 — concerns that need to be addressed with the Planning Coordinator

A step by step procedure is presented for each appropriate protective function to be followed by the Generator Owner and Transmission Owner to complete the coordination process. Each protective device and setting criteria section will have the following basic subsections:

1. Purpose
2. Coordination of Generator and Transmission System
   a. Faults
   b. Loadability
3. Considerations and Issues
4. Setting Validation for the coordination
   a. Test procedure for validation
   b. Setting Considerations
5. Example
   a. Proper Coordination
   b. Improper Coordination
6. Summary of Detailed Data Required for Coordination of the Protection Function
7. Table of Data and Information that must be Exchanged

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
21 – Phase distance	21 87B 87T 50BF	• Both 21 relays have to coordinate, • Trip dependability, • Breaker failure time, • System swings (out-of-step blocking), • Protective Function Loadability for extreme system conditions that are recoverable • System relay failure • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring impedance swings at the device location in the stability program and applying engineering judgment.

Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
24 – Volts/Hz	UFLS UFLS design is generally the responsibility of the Planning Coordinator	• Generator V/Hz protection characteristics shall be determined and be recognized in the development of any UFLS system for all required voltage conditions ~~(exchange information of UFLS setpoints and V/Hz setpoints between the Generator Owner and Transmission Owner).~~ The Generator Owner (and the Transmission Owner when the GSU transformer is owned by the Transmission Owner) exchange information of V/Hz setpoints and UFLS setpoints with the Planning Coordinator. • Coordinate with the V/Hz withstand capability and V/Hz limiter in the excitation control system of the generator. • Coordinate with V/Hz conditions during islanding (high voltage with low frequency system conditions that may require system mitigation actions). • Regional UFLS program design must be coordinated with these settings. • Islanding issues (high voltage & low frequency) may require planning studies and require reactive element mitigation strategies • ~~Must coordinate UFLS~~ • Settings should be used for planning and system studies~~.~~ either through explicit modeling of the device, or through monitoring voltage and frequency performance at the device location in the stability program and applying engineering judgment.

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
27 – Generator Unit Undervoltage Protection **** Should Not Be Set to Trip, Alarm Only**** **If device 27 tripping is used for an unmanned facility** – the settings must coordinate with the stressed system conditions of 0.85 per unit voltage and time delays set to allow for clearing of system faults by transmission system protection, including breaker failure times.	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions. • UVLS set points and coordination if applicable. • Settings should be used for planning and system studies. either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment. • Must coordinate with transmission line reclosing.
27 – Plant Auxiliary Undervoltage **If Tripping is used** – the Correct Set Point and Adequate Time Delay so it does not trip for All System Faults and Recoverable Extreme Events	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Coordinate the auxiliary bus protection and control when connected directly to High Voltage System. • Generator Owner to validate the proper operation of auxiliary system at 80~-85 percent voltage. The undervoltage trip setting is preferred at 80 percent. • Generator Owners validate the proper operation of auxiliary system at 0.8~-0.85 per unit voltage. • -Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment.

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
27 – Plant High Voltage System Side Undervoltage **If Tripping is used** – the Correct Set Point and Adequate Time Delay so it does not trip for All System Faults and Recoverable Extreme Events	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions. • UVLS set points and coordination if applicable. • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment.
32 – Reverse Power	None	• Older ~~Electromechanical Relays~~electromechanical relays can be susceptible to ~~high Var loading and lead to~~ misoperation~~.~~ at high leading Var loading

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
40 – Loss of Field (LOF)	Settings used for planning and system studies	• Out-of-Step (OOS) – survive stable swings • Preventing encroachment on reactive capability curve • Transmission Owner(s) need to exchange Reactive power (VAR) capability from Generator Owner(s) • See details from sections 4.5.1 & A.2.1 of C37.102-2006 • The setting information for the LOF relay should be provided by the Generator Owner to the Transmission Owner and Planning Coordinator in order for this information to be available to the appropriate planning entity. The impedance trajectory of most units with a lagging power factor (reactive power into the power system) for stable swings will pass into and back out of the first and second quadrants. It is imperative that the LOF relay does not operate for stable power swings. • The LOF relay settings must be provided to the appropriate planning entity by the Generator Owner so that the planning entity can determine if any stable swings encroach long enough in the LOF relay trip zone to cause an inadvertent trip. The appropriate planning entity has the responsibility to continually verify that power system modifications never send stable swings into the trip zone(s) of the LOF relay causing an inadvertent trip. If permanent modifications to the power system cause the stable swing impedance trajectory to enter the LOF characteristic, then the planning entity must notify the Transmission Owner who in turn must notify the Generator Owner that new LOF relay settings are required. The planning entity should provide the new stable swing impedance trajectory so that the new LOF settings will accommodate stable swings with adequate time delay. The new settings must be provided to the planning entity from the Generator Owner through the Transmission Owner for future continuous monitoring. • Transmission Owners must provide system information and appropriate parameters to enable the Generator Owners to conduct a system study. This enables the Generator Owner to fine tune LOF settings if required.

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
46 – Negative phase sequence overcurrent	21 21G 46 67N 51N Longest time delay of transmission system protection including breaker failure time	• Should be coordinated with system protection for unbalanced system faults • Plant and system operations awareness when experiencing an open-pole on the system~~,~~ • Transposition of transmission lines • System studies, when it is required by system condition • Open phase, single-pole tripping • Reclosing • ~~Settings should be used for planning and system studies~~If there is alarm, Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator and they must work together to resolve the alarm
50 / 27 – Inadvertent energizing	None	• The device 27 must be set lower than 50 percent of the nominal voltage. • Instantaneous overcurrent (device 50) relay (or element) should be set to the most sensitive to detect inadvertent energizing (Breaker Close). • Timer setting should be adequately long to avoid ~~nuisance~~undesired operations due to transients. • Relay elements (27, 50, and timers) having higher Dropout Ratio (ratio of dropout to pickup of a relay) should be selected to avoid ~~nuisance~~undesired operations.

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
50BF – Breaker failure (plant) on synchronizing breaker	Critical clearing times from system stability studies 50BF on line(s) & buses	• Check for single-points-of-failure • Current and 52a contact considerations • Critical clearing time • Coordination with zone 2 and zone 3 timers • Settings should be used for planning and system studies • Line distances relay reach and time delay settings with respect to each generator zone. • Bus differential relay (usually instantaneous) timing for HV bus faults including breaker failure adjacent bus. • Line and Bus Breaker failure timers and line zone 1 and zone 2 timers on all possible faults. • Type of protective relays, Manufacturers, Models, etc. • Single line diagram(s) including CTs and VTs arrangement • PCB test data (interrupting time)
51T – Phase fault backup overcurrent 51TG – Ground fault backup overcurrent	21 51 67 51G 51N 67N Open phase, single-pole tripping and reclosing	• Must have adequate margin over GSU protection & nameplate rating • 51T not recommended when the ~~transmission system~~Transmission Owner uses distance line protection functions • Generator Owners(s) needs to get Relay Data (devices 21, 51, 67, 67N, etc) and Single line diagram (including CT ~~&~~ and PT arrangement and ratings) from Transmission Owner(s) for device 51T coordination studies • Transmission Owner(s) needs to get ~~Transformer~~transformer data (tap settings, available fixed tap ranges, impedance data, the +/- voltage range with step-change in percent for load-tap changing GSU transformers) from Generator Owner(s) or Operator(s)

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
51V – Voltage controlled / ~~restraint~~restrained	21 51 67 87B	• 51V not recommended when ~~transmission system applies~~Transmission Owner uses distance ~~relays~~line protection functions • Short circuit studies for time coordination • Total clearing time • Review voltage setting for extreme system conditions • 51V controlled function has only limited system backup protection capability • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage and current performance at the device location in the stability program and applying engineering judgment.
59 – Overvoltage	When applicable, pickup and time delay information of each 59 function applied for system protection.	• Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance in the stability program and applying engineering judgment.
59GN/27TH – Generator Stator Ground	~~None~~Longest time delay for Transmission System Protection to Clear a close-in phase-to-ground or phase-to-phase-to-ground Fault	• Ensure that proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds. • Ensure that there is sufficient time delay to ride through the longest clearing time of the transmission line protection.
78 – Out-of-step	21 (Coordination of OOS blocking and tripping) Any OOS if applicable	• System studies are required. • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring impedance swings at the device location in the stability program and applying engineering judgment.

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Table 2 — Protection Coordination Considerations		
Generator Protection Function	**Transmission System Protection Function**	**System Concerns**
81U – Under frequency 81O – Over frequency	81U (Coordination with system UFLS set points and time delay) achieved through compliance with Regional frequency standards for generators 81O (Coordinate with system OF set points) UFLS design is generally the responsibility of the Planning Coordinator	• Coordination with system UFLS set points and time delay, • Meet Standard PRC-024-2 under-and over-frequency requirements • Caution on auto-restart of distributed generation • Wind generation during over-frequency conditions • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring frequency performance at the device location in the stability program and applying engineering judgment.
87T – Transformer Differential 87G – Generator Differential 87U – Overall Differential	None – Zone Selective None None – Zone selective	Proper Overlap of the Overall differential zone and bus differential zone, etc., should be verified.

Table 3 — ~~Detailed~~ Data to be Exchanged Between Entities		
Generator Owner	**Transmission System Owner**	**Planning Coordinator**
Device 21 Relay settings in the R-X plane in primary ohms at the generator terminals.	One line diagram of the transmission system up to one bus away from the generator high-side bus[1].	Feedback on coordination problems found in stability studies.
Relay timer settings.	Impedances of all transmission elements connected to the generator high-side bus.	~~None~~
Total clearing times for the generator breakers.	Relay settings on all transmission elements connected to the generator high-side bus.	~~None~~

[1] *See Appendix F, example 4, where the remote bus is a ring bus. In that case, the one line diagram exchanged may need to extend beyond one bus away.

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Table 3 — ~~Detailed~~ Data to be Exchanged Between Entities		
Generator Owner	**Transmission System Owner**	**Planning Coordinator**
	Total clearing times for all transmission elements connected to the generator high-side bus.	~~None~~
	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus.	~~None~~
Device 24 The overexcitation protection characteristics, including time delays and relay location, for the generator and the GSU transformer (if owned by the Generator Owner).	The overexcitation protection characteristics for the GSU transformer (if owned by the Transmission Owner)	Feedback on problems found between overexcitation settings and UFLS programs.
Device 27 - Generator Relay settings: Under Voltage Set Point if applicable, including time delays, at the generator terminals.	Time Delay of Transmission System Protection	Feedback on problems found in coordinating with stressed voltage condition studies and if applicable, UVLS studies
Device 27 – Plant Auxiliary System Relay settings: Under Voltage Set Point if applicable , including time delays, at the power plant auxiliary bus	Time Delay of Transmission System Protection	Feedback on problems found in coordinating with stressed voltage condition studies and if applicable, UVLS studies
Device 27 – High Voltage System Side Relay settings: Under Voltage Set Point if applicable, including time delays, at high side bus.	Time Delay of Transmission System Protection	Feedback on problems found in coordinating with stressed voltage condition studies and if applicable, UVLS studies
Device 32 None	None	None

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Table 3 — ~~Detailed~~ Data to be Exchanged Between Entities		
Generator Owner	**Transmission System Owner**	**Planning Coordinator**
Device 40 Relay settings: loss of field characteristics, including time delays, at the generator terminals.	~~Impedance trajectory from system stability studies for the strongest and weakest available system.~~The Transmission Owner provides the Planning Coordinator with the worst case clearing time for each of the power system elements connected to the transmission bus at which the generator is connected.	Impedance trajectory from system stability studies for the strongest and weakest available system. Feedback on problems found in coordination and stability studies
Device 46 Relay settings: negative phase sequence overcurrent protection characteristics, including time delays, at the generator terminals. Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator for resolution if significant unbalance is observed.	The time-to-operate curves for the system relays that respond to unbalanced system faults. This would include the 51TG if the GSU is owned by the Transmission Owner.	~~System Planning entity needs to provide continuous I_2 from the system.~~None.
Device 50/27 – Inadvertent Energizing Under voltage setting and current detector settings pick-up and time delay	Review method of disconnect and operating procedures.	None
Device 50BF – Breaker Failure Times to operate of generator protection Breaker Failure Relaying times	Times to operate, including timers, of transmission system protection Breaker Failure Relaying times	None

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Table 3 — ~~Detailed~~ Data to be Exchanged Between Entities		
Generator Owner	**Transmission System Owner**	**Planning Coordinator**
Relay settings **Device 51T –** Phase fault backup overcurrent **Device 51TG –** Ground fault backup overcurrent	One line diagram of the transmission system up to one bus away from the generator high-side bus.	Feedback on coordination problems found in stability studies.
Relay timer settings.	Impedances of all transmission elements connected to the generator high-side bus.	~~None~~
Total clearing times for the generator breakers.	Relay settings on all transmission elements connected to the generator high-side bus.	~~None~~
	Total clearing times for all transmission elements connected to the generator high-side bus.	~~None~~
	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus.	~~None~~
Device 51V – Voltage controlled / ~~restraint~~**restrained** Provide settings for pickup and time delay (May need to provide relay manual for proper interpretation of the voltage controlled/restrained relay)	Times to operate, including timers, of transmission system protection Breaker Failure Relaying times	• ~~51V not recommended when transmission system applies distance relays~~ • ~~Short circuit studies for time coordination~~ • ~~Total clearing time~~ • ~~Review voltage setting for extreme system conditions~~ • ~~51V controlled function has only limited system backup protection capability~~ ~~Settings should be used for planning and system studies~~None
Device 59 Relay settings: setting and characteristics, including time ~~delays~~delay setting or inverse time characteristic, at the generator terminals.	Pickup and time delay information of each 59 function applied for system protection	~~Settings should be used for planning and system studies~~None

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Table 3 — ~~Detailed~~ Data to be Exchanged Between Entities		
Generator Owner	**Transmission System Owner**	**Planning Coordinator**
Device 59GN/27TH Provide time Delay setting of the 59GN/27TH	Provide worst case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time.	None
Device 78 Relay Settings, Time Delays and Characteristics for out-of-step trip and blocking	Provide relay settings, time delays and characteristics for the out-of-step block and trip if used	Determine if there is a need for transmission line out-of-step blocking/tripping related to the generator Feedback on coordination problems found in stability studies.
Device 81 Relay settings and time delays	None	Feedback on problems found between underfrequency settings and UFLS programs.
Device 87T – Transformer Differential	None – Zone Selective	None
Device 87G – Generator Differential	None	None
Device 87U – Overall Differential None	None - Zone Selective	None

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3. Discussion of Specific Protection Functions

This report does not prescribe practices to Generator Owners and ~~operators~~Generator Operators, but is intended to provide useful information and guidance for self-examination of their generator protection and schemes as well the data exchange and coordination with transmission system protection. It is envisioned that this self-examination and coordination process will significantly reduce the number of nuisance trips in future events. These suggested processes should be simple and easy to perform for generator protection applications review. The following are General Data and Information Requirements that must, at a minimum, be exchanged by the Generator and Transmission Owners.

Generator Owner Data and Information Requirements[2]

In addition to the protective device settings as detailed in Table 3 above, the Generator Owner should provide additional general and specific application information as requested including the following, where applicable:

- Relay scheme descriptions
- Generator off nominal frequency operating limits
- CT and VT/CCVT configurations
- Main transformer connection configuration
- Main transformer tap position(s) and impedance (positive and zero sequence) and neutral grounding impedances
- High voltage transmission line impedances (positive and zero sequence) and mutual coupled impedances (zero sequence)
- Generator impedances (saturated and unsaturated reactances that include direct and quadrature axis, negative and zero sequence impedances and their associated time constants)
- Documentation showing the function of all protective elements listed above

Transmission or Distribution Owner Data and Information Requirements[2]

In addition to the protective device settings listed, the ~~transmission~~Transmission Owner or ~~distribution owner~~Distribution Provider should provide additional information as requested including the following, where applicable:

- Relay scheme descriptions
- Regional Reliability Organization's off-nominal frequency plan
- CT and VT/CCVT configurations
- Any transformer connection configuration with transformer tap position(s) and impedance (positive and zero sequence) and neutral grounding impedances
- High voltage transmission line impedances (positive and zero sequence) and mutual coupled impedances (zero sequence)

[2] Based on initial work of the PRC-001-2 drafting team.

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- Documentation showing the function of all protective elements listed above
- Results of fault study or short circuit model
- Results of stability study
- Communication-aided schemes

This information is required to gain a complete understanding of the schemes in place for all involved entities and if necessary allow the Planning Coordinator to include the plant in models for system studies.

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3.1. Phase Distance Protection (Device 21)

3.1.1. Purpose of Generator Device 21 — Impedance Protection

The Device 21 relay measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. When it is applied, its function is to provide backup protection for system faults that have not been cleared by transmission system circuit breakers via their protective relays. Note that Device 51V (Section 3.10) is another method of providing backup for system faults, and it is never appropriate to enable both Device 51V and Device 21. The function of Device 21 is further described in Section 4.6.1.1 of the IEEE C37.102-2006 – Guide for AC Generator Protection, as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***which is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition which causes the generator voltage regulator to boost generator excitation for a sustained period that may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150 to 200% of the generator MVA rating at its rated power factor* (sic: This setting can be re-stated in terms of ohms as 0.66 – 0.50 per unit ohms on the machine base.) *has been shown to provide good coordination for stable swings, system faults involving infeed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine-generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment blinders can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of*

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> *multifunction generator protection relays, it is becoming more common to use two phase distance zones. In this case, the second zone would be set as described above. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the generator step-up transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. Your normal zone-2 time delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and isolated-phase bus with partial coverage of the generator step-up transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

In addition to the purposes described for generator protection in C37.102 – 2006, is the need to consider the protection of the power system as a whole with regard to the intended function of the impedance relay. It is just as important to protect the reliability of the power system as the generator. If the generator is over-protected, meaning that the impedance relay can operate when the generator is not at risk thermally or from a stability perspective, then it can trip leaving other generators to shoulder its share of the system load. If any of these other generators also are overprotected and trip the remaining generators become at risk to damage. This is especially of concern in stressed or extreme contingency conditions. Sequential tripping of generators under such conditions can lead to cascade tripping of system elements, potentially leading to a system blackout. As with PRC-023, the loadability standard for transmission lines, this Technical Reference will define a stressed system condition as a bus voltage of 0.85 per unit at the high voltage side of the generator step up (GSU) transformer. This is not a worst case voltage but a voltage that was observed in the August 14, 2003 blackout at many buses before the cascade portion of the blackout. It was in a time frame at which automatic action to return the power system to within limits was quite possible. For the purposes of this document, the thermal rating applied to the unit to be protected is the maximum exciter field current rating and the real component of generator stator current associated with maximum MW output.

Annex A.2.3 of the IEEE C37-102 Guide provides a settings example for the impedance relay. Although annexes are not a part of the guide, they do provide useful explanations. In C37.102, Annex A describes settings calculations for generator relays using a particular example. For the impedance relay that is used to detect system relay failures,

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called zone 2 in the annex, it states the following settings rules from the IEEE C37-102 Guide:

"Set zone 2 to the smallest of the three following criteria:

A. 120% of longest line (with in-feed). If the unit is connected to a breaker and a half bus, this would be the length of the adjacent line.

B. 50% to 66.7% of load impedance (200% to 150% of the generator capability curve) at the rated power factor angle.

C. 80% to 90% of load impedance (125% to 111% of the generator capability curve) at the maximum torque angle."

In a stressed system condition, it is likely that the generator exciter may be undergoing field forcing. We examine this operating condition when the unit is at maximum real power out and the generator step-up transformer high side voltage is at 0.85 per unit. Based on these conditions, a settings criterion for impedance relay loadability is stated.

There are two common approaches to the setting of device 21 as applied to the protection of generators. One approach is to set the relay focusing on thermal protection of the generator for a transmission fault that is not cleared by transmission relays. Often this approach leads to setting the relay at about 150 percent to 200 percent of the generator MVA rating at its rated power factor. This approach is not intended to provide backup protection for the transmissions system as could be needed for transmission line relay failure. Protection for system faults when a transmission relay fails must be provided by the Transmission Owner. It is necessary to evaluate the setting to assure it will not operate for system loading during extreme system conditions.

The other approach is to provide for relay failure protection by all sources that supply the faulted line including a generator. In this approach, two zones of impedance relays are often used. Zone 1 and zone 2 are time delayed. Zone 1 is set to detect faults on the high side of the GSU and the high voltage bus. Zone 1 must be set short of the transmission line zone 1 relays with margin. Zone 1 is a backup function and must be time delayed. Its time delay is set longer than the primary relaying time [zone 1 transmission line distance protection (device 21), generator differential (device 87G), transformer differential (device 87T), overall differential (device 87O), bus differential (device 87B)], plus circuit breaker failure time (device 50BF) and a reasonable margin. The generator zone 2 is set to detect the fault on the longest line (with in-feed). Zone 2 time delay is set longer than all transmission line relay times for all zones in which it can detect a fault including breaker failure time and a reasonable margin.

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It is necessary to evaluate the zone 2 setting to assure it will not operate for system loading during extreme system conditions. During extreme system contingencies, it is likely that the power system generators may swing with respect to each other. Often these swings dampen and the system returns to a steady state. It is essential that relays that can respond to stable swings do not trip the generator unnecessarily. The device 21 ~~Impedance~~impedance function is such a device.

3.1.2. Coordination of Generator and Transmission Systems

The relays settings as determined by the Generator Owner require affirmation by the Transmission Owner for faults detection and time coordination. The relay setting must also be tested to assure that it will not respond incorrectly to system loads at extreme contingencies when the generator is not at risk of thermal damage. Maximum exciter output (field forcing) and the real component of generator output current associated with maximum MW output will be used for this test along with 0.85 per unit voltage impressed on the high side of the generator step-up transformer (GSU) as representations of a stressed system.

3.1.2.1. Faults

The detection of a fault is most easily demonstrated by the examples in section 3.1.5. In the examples, it will be assumed that transmission line relay failure has occurred and the fault is at the far end of the protected line. The examples will present solutions that can be used to permit tripping for the fault while not tripping for non-fault conditions when the generator is not at risk.

3.1.2.2. Loadability

C37.102 presented a range of likely acceptable settings for the impedance relay of 150 percent-200 percent of the generator MVA rating at rated power factor as settings that will not operate for normal generator outputs. This setting can be re-stated in terms of ohms as 0.66 – 0.50 per unit ohms on the machine base. This document goes beyond. It looks at generator outputs under stressed conditions. Most exciters have a field forcing function [2], IEEE Standard 421.1-2007 (appendix A reference 2), that enables the exciter to go beyond its full load output. These outputs can last up to 10 seconds before controls reduce the exciter field currents to rated output.

Section 4.2.1 of C37.102 states (emphasis added):

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"The field winding may operate continuously at a current equal to or less than that required producing rated-kVA at rated power factor and voltage. For power factors less than rated, the generator output must be reduced to keep the field current within these limits.

*The capability curves as defined in IEEE Std 67-1990 are determined on this basis. Under abnormal conditions, such as short circuits and other system disturbances, **it is permissible to exceed these limits for a short time. IEEE C50.13-2005**, lists the short-time thermal capability for cylindrical-rotor machines. In this standard, the field winding short-time thermal capability is given in terms of permissible field current as a function of time as noted below."*

Time (seconds)	*10*	*30*	*60*	*120*
Field current (percent)	*209*	*146*	*125*	*113*

A generator impedance relay has a time delay greater than 1.0 second but much less than 10 seconds. Time coordination with any excitation control that activates to lower field current is not likely. The 209 percent field current per the standard **or a higher value of field current, as specified by the exciter manufacturer, during field forcing is likely and becomes the recommended basis for the loadability test.** Appendix ~~F~~E Example 1 describes a loadability test for a given device 21 setting. The likelihood of this level of short time field forcing has been corroborated with members of the IEEE PES Excitation Subcommittee of the Energy Delivery and Power Generation Committee. Further, this level of exciter output was recorded for two large steam units, one nuclear and one fossil, that were on the perimeter of the blacked out area on August 14, 2003. These units were not damaged and had they tripped, the blacked out region could have widened considerably. The apparent impedance measured at the generator terminals for these two generators during the blackout are presented in Table 3.2. The calculation method that derived these apparent impedances is included in ~~Annex G~~Appendix E. **Based on these analyses, it is concluded that the range of per unit impedance within C37.102 of 0.66 per unit – 0.50 per unit is appropriate for these actual system conditions.**

Also in Table 3.2 are two columns that demonstrate an appropriate and inappropriate relay setting for the example in Section 3.1.5 in terms of relay loadability. The difference is due to relay reach requirements caused by infeed from other lines. Relay loadability under extreme contingencies is defined by a 0.85 pu voltage on the high side of the generator step up transformer and excitation field forcing of 209 percent.

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3.1.2.3. Coordination with Breaker Failure

The 21 relay will detect transmission system faults. These faults will be cleared by the transmission system relays. Should a circuit breaker fail at the time it is called upon to interrupt the fault, breaker failure relaying will initiate time-delayed backup clearing by tripping all circuit breakers adjacent to the failed breaker. The 21 relay time delay must be set to coordinate with the breaker failure clearing times with a reasonable margin. This requirement is necessary for all transmission protection zones (protected elements) within which the 21 relay can detect a fault. For example, a 21 relay can detect a fault on a transmission line connected to a bus that is adjacent to the bus that the generator is connected. Time coordination is needed should the transmission line fault and its breaker fail.

3.1.3. Considerations and Issues

From a trip dependability perspective, for example relay failure protection, it may be necessary to set the impedance relay to detect faults in another zone of protection. For some system configurations, the impedance relay may not be able to detect these faults due to the effect of infeed from other fault current sources. In these cases, other means for providing relay failure protection for the zone is required. Generator protection for unbalance system faults are detected by negative sequence relays which are immune to balanced load. The three phase fault is the most challenging to detect because of the need to not trip for load and because the generator reactance increases with time from subtransient to transient and then approaches synchronous reactance. For the three phase fault, the generator over-frequency protection and the overspeed protection may detect the three phase fault before any thermal damage can occur.

The impedance relay must not operate for stable system swings. When the impedance relay is set to provide remote backup, the relay becomes increasingly susceptible to tripping for stable swings as the apparent impedance setting of the relay increases. The best way to evaluate susceptibility to tripping is with a stability study. The study typically is performed by the ~~transmission planner~~Planning Coordinator or Transmission Planner with input from the Generator Owner, since the ~~transmission planner~~Planning Coordinator and Transmission Planner possesses the analysis expertise and the system models necessary to perform the study. The Generator Owner should provide the transmission planner with the impedance relay setting and the basis for the setting. For the critical stable swing, the swing loci of apparent impedances should not enter the relay characteristic. Adjustment of time delay is not sufficient to assure coordination for stable

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swings. Should the swing penetrate the relay characteristic, the relay should be reset or control methods such as out-of-step blocking should be incorporated into the impedance relay tripping logic to assure the relay will not operate for stable swings.

For unstable swings, the phase distance function should not be used to trip as the angle at which the breaker opens cannot be controlled with a 21 relay. The voltage across the breaker can reach dangerous values if the breaker is opened when the angle is near 180 degrees. Under these conditions a 78 (out-of-step) function should be used to trip such that the breaker opening can be controlled to occur at a safe angle using blinder settings of the 78 function.

3.1.4. Coordination Procedure

Reminder to Generator Owners: At all times, the generation protection settings must coordinate with the response times of the over-excitation limiter (OEL) and V/Hz limiter on the excitation control system of the generator.

Step 1 — Generator Owner and Transmission Owner work out and agree on the reach and time delay settings for the system and generator protection 21 functions.

Step 2 — Generator Owner verifies that the generator 21 relay is coordinated with OEL functions of the excitation system. This is especially important when the excitation system of the machine is replaced.

Step 3 — Generator Owner and Transmission Owner review any setting changes found to be necessary as a result of step two.

Depending on the results of step 2, this may be an iterative process, and may require additional changes to the transmission Protection System.

3.1.4.1. For System Trip Dependability (relay failure coverage)

- 120 percent of longest line (with in-feed).
- This setting, including a reasonable margin, should not exceed a load impedance that is calculated from the generator terminal voltage and stator current. The generator terminal voltage is calculated from a generator step-up transformer (GSU) high side voltage of 0.85 per unit. The stator current is calculated using maximum real power output and a generator field current of 209 percent per the standard or a higher value of field current if as specified by the exciter manufacturer.

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3.1.4.2. For Machine-Only Coverage

- 50 percent to 66.7 percent of load impedance (200 percent to 150 percent of the generator capability curve) at the rated power factor angle.
- This setting, including a reasonable margin, should not exceed a load impedance that is calculated from the generator terminal voltage and stator current. The generator terminal voltage is calculated from a GSU high side voltage of 0.85 per unit. The stator current is calculated using maximum real power output and a generator field current of 209 percent per the standard or a higher value of field current if as specified by the exciter manufacturer.

3.1.5. Examples

3.1.5.1. Proper Coordination

In this example, the impedance relay is required to protect the generator by providing transmission line relay failure protection. A hypothetical 625 MVA generator is connected to a 345-kV system by three lines (see Figure 3.1.1).

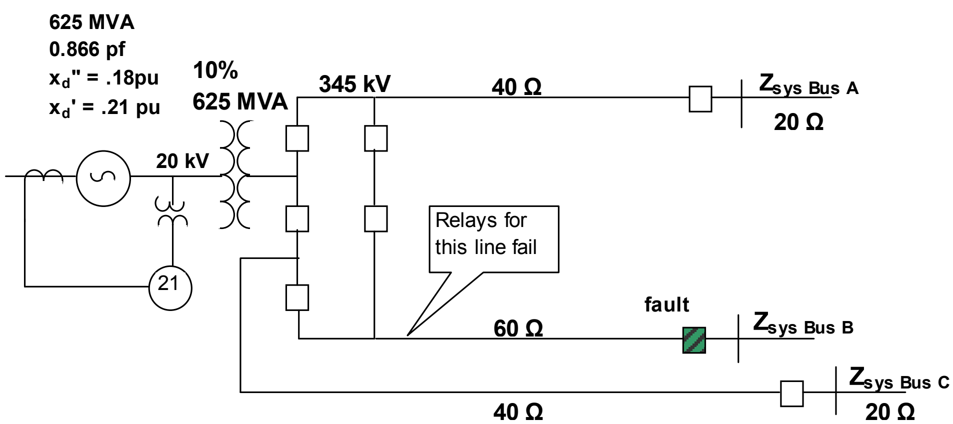

Figure 3.1.1 — Unit Connected with Three 345-kV Circuits

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3.1.5.1.1. System Faults – Transmission Line Relay Failure Protection

Figure 3.1.2 demonstrates time and reach coordination of the Device 21 with transmission line relays when the Device 21 is set to detect faults at the end of the longest transmission line connected to the station high voltage bus.

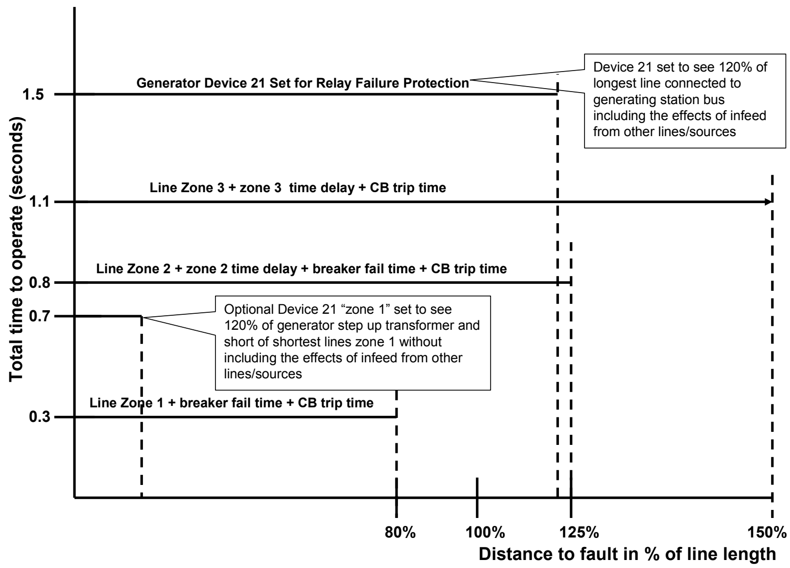

Figure 3.1.2 — Trip Dependability (relay failure) Reach Time Coordination Graph

3.1.5.1.2. System Faults – Machine Coverage Only

Figure 3.1.3 demonstrates time and reach coordination of the Device 21 with transmission line relays when the Device 21 is set 150 percent to 200 percent of the machine at rated power factor.

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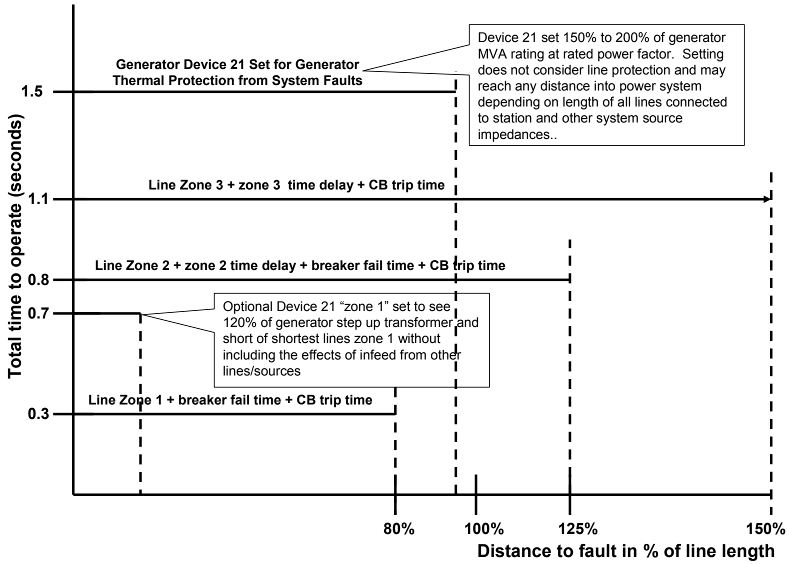

Figure 3.1.3 — Trip Dependability Reach Time Coordination Graph (Machine-only thermal protection)

3.1.5.1.3. Loadability – Transmission Line Relay Failure Protection Setting Method

The relay reach along the 30 degree load line is calculated to be 0.69 pu ohms (Table 3.1 first row- last column). This setting exceeds the 150 percent (0.66 pu ohms) – 200 percent (0.5 pu ohms) criteria established by C37.102 suggesting further evaluation is needed. Table 3.1 summarizes the calculations for this example, row 1, and a number of other examples. The other examples use the same system configuration but vary parameters such as the length of the unfaulted lines, high side voltages and system impedances. It is interesting to point out that the second row example is varied from the first example only by changing the non-faulted lines from 40 ohms to 20 ohms. This change increases the apparent impedance infeed and thus the setting of the 21 relay from 1.2 pu to 1.56 pu ohms along the maximum reach angle.

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Table 3.1 — Calculations for Example									
Nominal Voltage at GSU High Side (kV)	Nominal Voltage at Generator Terminal (kV)	Size of Gen. (MVA)	Impedance of Faulted Line (Ω)	Impedance of Non-Faulted Lines (Ω)	21 Setting EHV Ohms (Ω)	21 Setting in Gen. Side (Ω)	Base Impedance Gen. Side (Ω)	21 Setting at Max Reach (pu)	21 Reach at (30º) (pu)
345	20	625	60	40	227.8	0.766	0.64	1.20	0.69*
345	20	625	60	20	296.7	0.997	0.64	1.56	1.11**
230	20	625	60	20	171.9	1.300	0.64	2.03	1.16*
230	20	625	40	20	117.3	0.887	0.64	1.39	0.79*
138	20	625	30	20	55.4	1.164	0.64	1.82	1.04*
138	12	300	30	20	76.5	0.578	0.48	1.20	0.69

*** Exceeds IEEE 37.102 acceptable loadability reach range – further evaluations needed**
**** This setting results in a failure to coordinate with extreme contingency loading – see Table 3.2 results**

An evaluation was performed for the top two rows in Table 3.1 using a simple two machine system to calculate the impedance the relay would measure for the loading conditions associated with a 0.85 per unit voltage on the high side of the GSU. For Table 3.1 row 1, these calculations demonstrate that the relay will not operate for stressed system loading conditions. On the other hand, the second example of Table 3.1 where the unfaulted line impedance was 20Ω (instead of the 40Ω lines in the first example) shows that the 21 device will trip on load for the stressed system condition. Table 3.2 columns three and four report the results of these calculations. The method for calculation and details are in ~~Annex G~~Appendix E of this report.

Table 3.2: Columns one and two summarize the analyses of two large units, one nuclear and one coal, that did not trip during the August 14, 2003 Blackout but were on the perimeter of it. Had these units tripped, the blacked out region would have widened. Columns three and four present the hypothetical 625 MVA Unit with two reaches; one that would not cause the generator to trip and a second that would cause a trip. Note that the calculated apparent impedances taken from recorded data is quite similar to the calculation using the 0.85 per unit voltage and 2.09 internal voltage method. The method for calculation and details are in ~~Annex G~~Appendix E of this report.

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Table 3.2 — Comparison of Device 21 Applications on Three Units				
	Actual 900 MVA Nuclear Unit During 8/14/2003 Blackout	Actual 860 MW Coal Unit During 8/14/2003 Blackout	Hypothetical 625 MVA Unit Relay Reach 120 pu	Hypothetical 625 MVA Unit Relay Reach 1.56 pu
Real Power (MW)	764	542	542	542
MVA	904	1,135	625	625
Rated PF	0.84	0.79	0.866	0.866
GSU High Side Voltage (pu)	0.913	0.869	0.85	0.85
X_d			1.65	1.65
X_{TR}	0.1	0.161	0.1	0.1
Max Generator Internal Voltage (PU)			2.09	3
Calculated Current (PU)	1.13 @ -35°	1.081@-29.05°	1.028@-7.7°	1.181 @-30.4°
Calculated Generator Terminal Voltage (PU)	0.9822 @ 5.4°	.9653 @9.06 º	0.87 @6.7°	0.9154 @ 6.39°
Relay Max Reach			1.2 @ 85°	1.55 @ 75°
Relay Reach at Load Angle			0.399@ 14.4°	1.23@ 36.18°
Calculated Load Impedance(PU)	0.869 @ 40.4°	0.89 @38°	0.85@ 14.4°*	0.78@36.18°**
Will relay trip on load?			No	Yes
Comments	760 MW Nuclear Unit that did not trip during blackout	Actual Coal Unit that did not trip during blackout	Proper Coordination Calculated load impedance outside relay set characteristic	Improper Coordination Calculated load impedance inside relay set characteristic

3.1.5.1.4. Loadability – Machine Thermal Protection Only Method

Figure 3.1.4 shows relay settings at 150 percent and at 200 percent of the machine's full rated MVA at rated power factor. The setting in the R-X plane is performed to compare the two settings with the machine capability curve during stressed system conditions. This method compares machine capability to the setting of the relay.

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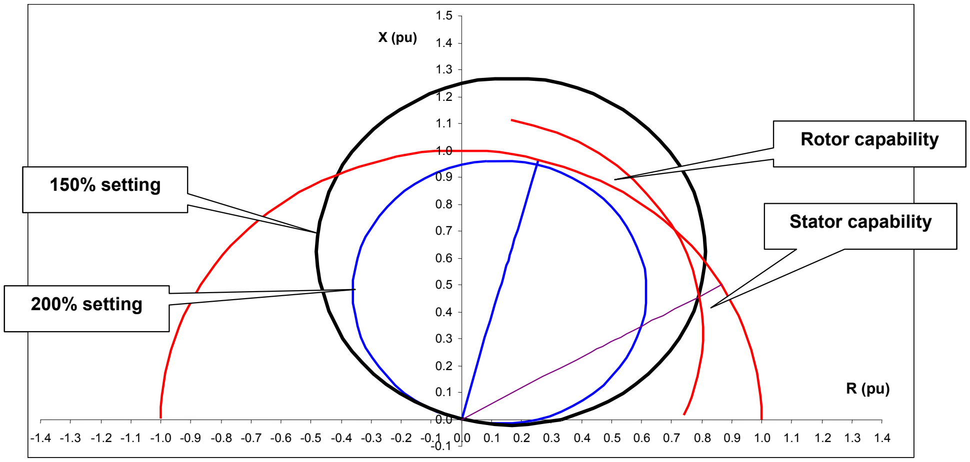

Figure 3.1.4 — 150% and 200% Setting versus Machine Capability

Figure 3.1.4 also demonstrates that a setting of 150 percent of rated MVA at rated power factor will trip on load during a stressed system condition if the machine is operating at 100 percent real power and 209 percent field; the 200 percent setting will not. It is recommended that a power flow be performed to further substantiate this claim.

3.1.5.1.5. Methods To Increase Loadability:

In the examples, there were cases where the relay's reach along the 30º load line exceeded the 0.5 – 0.66 pu guideline offered by IEEE C37.102 resulting in a possible need to reduce reach for non-fault conditions. Methods to reduce reach for loading conditions while maintaining the required reach for system faults are presented below:

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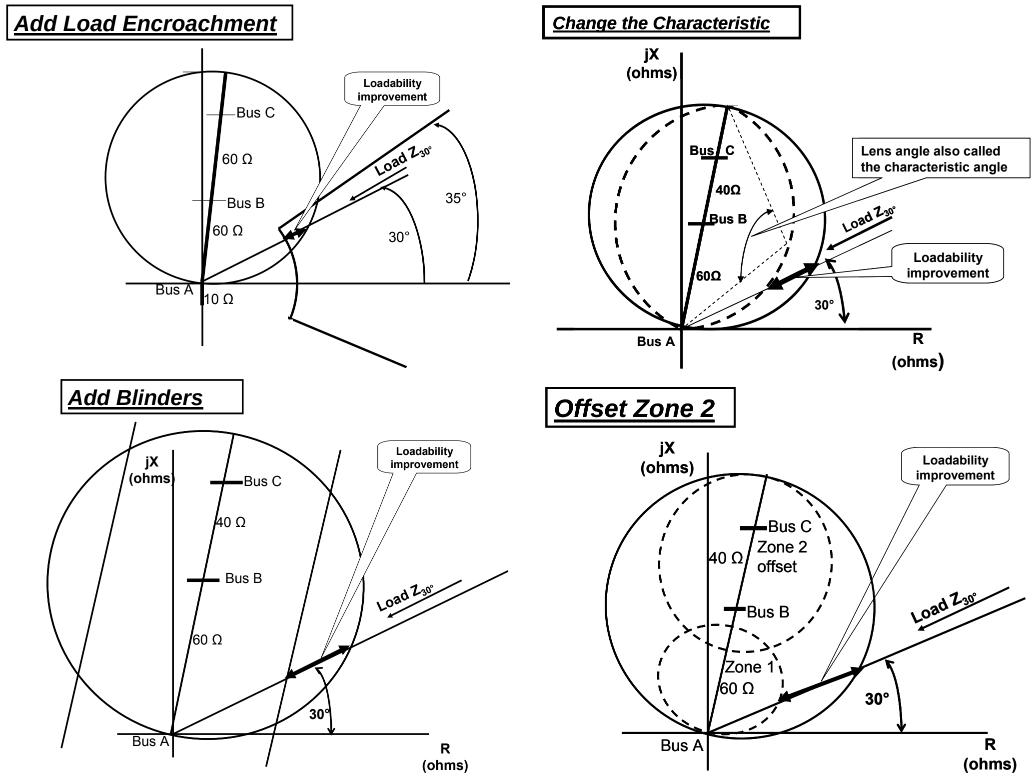

Figure 3.1.5 — Methods to Increase Loadability

3.1.5.2. Improper Coordination

No example is given for the improper coordination of Device 21 for generator system backup protection.

3.1.6. Summary of Protection Function required for Coordination

The generator impedance relay can be set to provide trip dependability for faults on transmission lines when relays fail. To enhance loadability, the impedance relay's reach at the load angle can be increased with the addition of load encroachment or blinder function or its characteristic can be offset or changed to a lens. To enhance security for extreme system contingencies as defined by 0.85 per unit voltage on the high side of the

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GSU transformer, studies must be completed specific to the unit and the connected system.

Table 2 Excerpt — Device 21 Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
21 – Phase distance	21 87B 87T 50BF	• Both 21s have to coordinate, • Trip dependability, • Breaker failure time, • System swings (out-of-step blocking), • Protective Function Loadability for extreme system conditions that are recoverable • System relay failure • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring impedance swings at the device location in the stability program and applying engineering judgment.

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3.1.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s). The protection coordination may be iterative and require multiple exchanges of these data before coordination is achieved.

Table 3 Excerpt — Device 21 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings in the R-X plane in primary ohms at the generator terminals.	One line diagram of the transmission system up to one bus away from the generator high-side bus[3].	Feedback on coordination problems found in stability studies.
Relay timer settings.	Impedances of all transmission elements connected to the generator high-side bus.	~~None~~
Total clearing times for the generator breakers.	Relay settings on all transmission elements connected to the generator high-side bus.	~~None~~

[3] *See Appendix ~~F~~E, Example 4, where the remote bus is a ring bus. In that case, the one line diagram exchanged may need to extend beyond one bus away.

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Table 3 Excerpt — Device 21 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
None	Total clearing times for all transmission elements connected to the generator high-side bus.	~~None~~
None	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus.	~~None~~

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3.2. Overexcitation or V/Hz (Device 24)

3.2.1. Purpose of the Generator Device 24 — Overexcitation Protection

Overexcitation protection uses the measurement of the ratio of generator terminal voltage to frequency as described in section 4.5.4 of the "Guide for AC Generator Protection" IEEE Standard C37.102-2006.

> *"Overexcitation of a generator or any transformers connected to the generator terminals will occur whenever the ratio of the voltage to frequency (V/Hz) applied to the terminals of the equipment exceeds 105% (generator base) for a generator; and 105% (transformer base) at full load, 0.8 pf or 110% at no load at the secondary terminals for a transformer.*
>
> *Over excitation causes saturation of the magnetic core of the generator or connected transformers, and stray flux may be induced in non-laminated components that are not designed to carry flux.*
>
> *Excessive flux may also cause excessive eddy currents in the generator laminations that result in excessive voltages between laminations. This may cause severe overheating in the generator or transformer and eventual breakdown in insulation.*
>
> *The field current in the generator could also be excessive."*

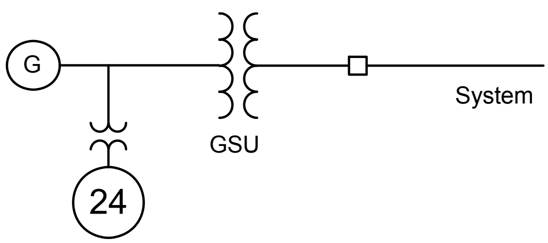

Figure 3.2.1 — Generator Overexcitation Protection

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3.2.2. Coordination of Generator and Transmission System

3.2.2.1. Faults

There are no coordination issues for system faults for this function.

3.2.2.2. Loadability

There are no coordination issues related to loadability for this function.

3.2.2.3. Other Operating Conditions

Coordination between generating plant overexcitation protection and the transmission system is necessary for off-nominal frequency events during which system frequency declines low enough to initiate operation of underfrequency load shedding (UFLS) relays. In most interconnections, frequency can decline low enough to initiate UFLS operation only during an island condition. However, adequate frequency decline may occur to initiate UFLS operation as a result of tripping generators and tie lines on smaller interconnections or on weakly connected portions of interconnections.

Coordination is necessary to ensure that the UFLS program can operate to restore a balance between generation and load to recover and stabilize frequency at a sustainable operating condition. Without coordination, generation may trip by operation of overexcitation protection to exacerbate the unbalance between load and generation resulting in tripping of more load than necessary, or in the worst case, resulting in system collapse if the resulting imbalance exceeds the design basis of the UFLS program. The need for coordination may not be readily apparent since the relays respond to different quantities and are deployed remote from each other (as shown in figure 3.2.2), however, the coordination is necessary for reliability of the overall power system. It is important to note that the coordination is not a relay-to-relay coordination in the traditional sense, rather it is a coordination between the generator and transformer withstand characteristics, the overexcitation protection, and the UFLS program and transmission system design.

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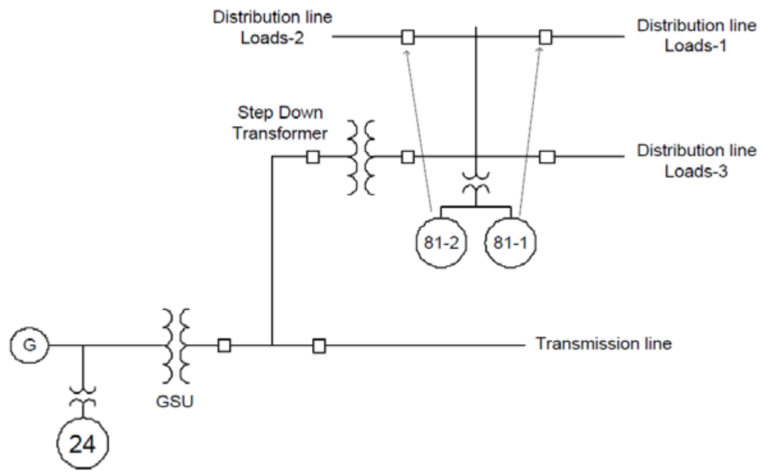

Figure 3.2.2 — Coordination between UFLS scheme and Device 24 on Generator

3.2.3. Considerations and Issues

Overexcitation withstand limit characteristics of generators and transformers should be requested from the equipment manufacturer whenever possible.

During an event that initiates UFLS operation, excitation levels typically would remain within equipment capability provided that system voltage can be controlled within normal operating ranges. However, abnormal system voltage during UFLS events is not uncommon, particularly when such events occur during heavy load conditions. Following UFLS operation the transfer of active power to supply loads is reduced, resulting in lower reactive power losses and high system voltage. Under such conditions restoring a balance between load and generation to recover system frequency may be insufficient to control excitation to acceptable levels. Additional coordination may be required to remove reactive compensation (e.g., shunt capacitor banks) or to connect shunt reactors.

3.2.4. Coordination Procedure

The following data and information exchange steps should be taken by the Generator Owner and Planning Coordinator. Note that in cases where the generator step-up

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transformer is owned by the Transmission Owner~~s~~, the Transmission Owner would have the same responsibility as the Generator Owner.

Step 1 — Generator Owner to ~~Provide~~provide Settings, Time Delays, and Protection Characteristics to the ~~Transmission Owner and~~ Planning Coordinator for both the Generator and Generator Step Up Transformer.

Step 2 — The Generator Owner~~, Transmission Owner,~~ and Planning Coordinator confirm that the Protection settings allow the UFLS actions first and coordinate.

Step 3 — The Planning Coordinator performs studies to verify this if necessary.

3.2.4.1. Setting Procedure

A. Plot the V/Hz withstand capability curves of the GSU transformer and generator similar to the ones shown in figure 3.2.3.

B. Plot the overexcitation (V/Hz) protection characteristic on the same graph.

C. Check proper coordination between the relay characteristic curves time and timing settings of excitation control limiter(s). The limiters in the excitation control system limiter should act first. The settings for the protective relay must be set so that the relay will only operate if the excitation is greater than the limiter setting but before the capability of the protected equipment is reached. Short time excursions beyond the overexcitation limit should not cause the protection systems to trip the generator because the over-excitation limiter time delay setting is used to prevent tripping during these conditions. Protection system tripping times are generally long enough so that coordination with exciter response is not a problem.

D. If UFLS is used on the system connected to the generator (shown in Figure 3.2.2) then the UFLS program and the overexcitation settings should be coordinated such that UFLS is given a chance to act before overexcitation protection trips the unit. The overexcitation protection should be set with adequate margin above the withstand capability to ensure equipment protection, while providing as much operating range as possible for design of the UFLS program.

Coordination between the overexcitation protection and the UFLS program design can be validated only through a stability study. The study should either monitor excitation at all buses at which overexcitation protection is utilized for comparison against tripping characteristics, or the overexcitation protection should be modeled in the study. With either approach a determination that coordination exists should be

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based on observing that no generators would trip by overexcitation protection. In a limited number of cases, conditions may exist that coordination cannot be achieved for every generating unit. In such cases coordination may be deemed acceptable if tripping does not cascade and is limited to a small amount of generation (as a percentage of the load in the affected portion of the system). Protection models should be added to system models for any units for which coordination cannot be obtained. In any case, stability studies should have sufficient margin and a sufficient number of scenarios should be simulated to provide confidence in the determination.

3.2.5. Examples

Figure 3.2.3 shows a setting example for overexcitation protection using definite time and inverse time overexcitation (V/Hz) relays.

Generator and transformer manufacturers should be consulted for the information on overexcitation withstand capability. An example withstand curve shown in Figure 3.2.2 is given in the Table 3.2.1.

Table 3.2.1 – Example V/Hz Withstand Capability of GSU Transformer

Time (Min.)	40	30	20	10	6	2	1	0.5	0.3
V/Hz (%)	106.4	106.9	107.4	108.4	109.3	112.1	114.3	118.0	123.5

Table 3.2.2 – Example V/Hz withstand Capability of Generator

Time (Min.)	33	25	20	15	10	5	2	1	0.5	0.2
V/Hz (%)	110	111	111.5	112.5	113.5	115.5	118.0	120.0	122.0	125.0

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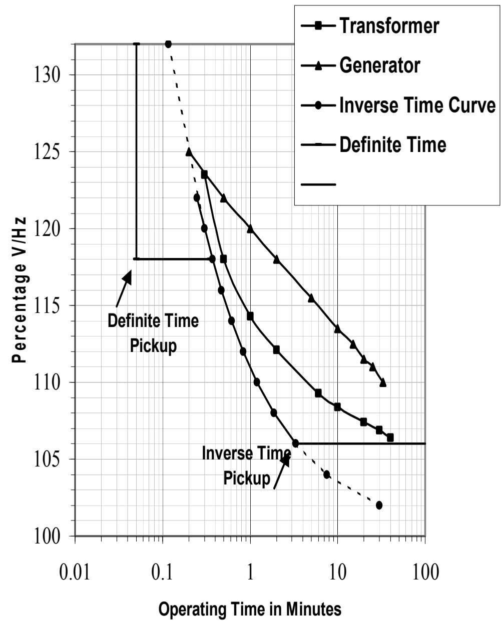

Figure 3.2.3 — Setting Example with Inverse & Definite Time V/Hz Relays

3.2.5.1. Proper Coordination

Proper coordination between the overexcitation setting and the generator or transformer withstand characteristic can be demonstrated on a plot of excitation versus time. Coordination between the overexcitation protection and the UFLS program design cannot be demonstrated in this traditional manner; a transient stability study is necessary to demonstrate this coordination (see section 3.14 for further information). A transient stability study is necessary due to the time varying nature of the excitation, which may vary significantly prior to and following UFLS operation and between different locations within the system. The protection and load shedding scheme should be evaluated for all expected recoverable events to assure coordination. This includes conditions where high voltage and low frequency occur that may require mitigation actions such as tripping capacitor banks. UFLS design parameters (threshold settings, block size, time delays, etc) and resultant voltage-frequency relationships should be checked against the overexcitation relay setting characteristics. If tripping a generator by overexcitation protection is unavoidable,

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the overexcitation protection for that generator should be accounted for in the system models used for planning and operational studies.

3.2.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 24 Protection Coordination Data Exchange Requirements		
Generator Protection Device	Transmission System Protection Relays	System Concerns

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Table 2 Excerpt — Device 24 Protection Coordination Data Exchange Requirements

Generator Protection Device	Transmission System Protection Relays	System Concerns
24 – Volts/Hz	UFLS UFLS design is generally the responsibility of the Planning Coordinator	• ~~Overexcitation~~Generator V/Hz protection characteristics ~~must coordinate~~shall be determined and be recognized in the development of any UFLS system for all required voltage conditions. The Generator Owner (and the Transmission Owner when the GSU transformer is owned by the Transmission Owner) exchange information of V/Hz setpoints and UFLS setpoints with the Planning Coordinator. • Coordinate with the V/Hz withstand capability and ~~the response times of the overexcitation limiter (OEL) and~~ V/Hz limiter in the excitation control system of the generator. ~~Overexcitation protection characteristics and the UFLS program design must coordinate (requires exchange of information on UFLS set points and overexcitation protection characteristics between the Generator Owner, Transmission Owner, and Planning Coordinator). Coordination must be verified through system studies.~~ • ~~Conditions of~~Coordinate with V/Hz conditions during islanding (high voltage ~~and~~with low ~~system~~ frequency system conditions that may require system mitigation actions ~~such as capacitor tripping or reactor insertion~~). • ~~Overexcitation protection that cannot be coordinated with the UFLS program design should be accounted for in system models used for planning and operational studies.~~Regional UFLS program design must be coordinated with these settings. • Islanding issues (high voltage & low frequency) may require planning studies and require reactive element mitigation strategies • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage and frequency performance at the device location in the stability program and applying engineering judgment.

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3.2.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s). Whenever a miscoordination between the over-excitation setting of a generator and the UFLS program cannot be resolved, the UFLS program may have to be redesigned to compensate for the loss of that generation in order to be fully coordinated.

Table 3 Excerpt — Device 24 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
The overexcitation protection characteristics, including time delays and relay location, for the generator and the GSU transformer (if owned by the Generator Owner).	The overexcitation protection characteristics for the GSU transformer (if owned by the Transmission Owner)	Feedback on problems found between overexcitation settings and UFLS programs.

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3.3. Under-Voltage Protection (Device 27)

3.3.1. Generator Unit Undervoltage Protection

3.3.1.1. Purpose of Generator Device 27 — Undervoltage Protection

The device 27 protection uses the measurement of generator terminal voltage. Section 4.5.7 of the IEEE C37.102 -2006 — Guide for AC Generator Protection describes the purpose of this protection as follows:

> "*For the generating unit, undervoltage protection that trips the unit is rarely applied to generators. It is frequently used as an interlock element for other protection function or schemes, such as loss-of-field relay (40), distance relay (21), inadvertent energizing relay (50/27), out-of-step relay (78), etc, where the abnormality to be detected leads directly or indirectly to an undervoltage condition. (See Sections 2.1, 2.5,2.8 for further details)*
>
> *Generators are usually designed to operate continuously at a minimum voltage of 95% of its rated voltage, while delivering rated power at rated frequency. Operating a generator with terminal voltage lower than 95% of its rated voltage may result in undesirable effects such as reduction in stability limit, import of excessive reactive power from the grid to which it is connected, and malfunctioning of voltage sensitive devices and equipment. This effect however is a function of time. If applied, the undervoltage protection is generally connected to alarm and not trip the unit, so that the operator can take appropriate action to remedy the undervoltage condition (if possible).*"

IEEE C37.102 — IEEE Guide for AC Generator Protection does not recommend use of the 27 function for tripping, but only to alarm to alert operators to take necessary actions.

Tripping units on undervoltage is not recommended by the IEEE C37.102 ~~standard~~guide on generator protection.

Undervoltage alarms as experienced by hydro, fossil, combustion and nuclear units are an indicator of possible abnormal operating conditions such as excitation problems and thermal issues within the unit. Other alarms from Resistance Temperature Detectors (RTDs) and hydrogen pressure are better indicators of thermal concerns. Manufacturers recommend operator action up to and including reduction in unit output rather than a unit trip. Tripping units on undervoltage is not recommended by the IEEE C37.102 ~~standard~~guide on generator protection. Rather,

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C37.102 recommends an alarm to alert the operator to the abnormal conditions that require operator intervention. Each type of unit, hydro, fossil, nuclear, combustion and renewable have different abnormal operating issues relating to system undervoltage.

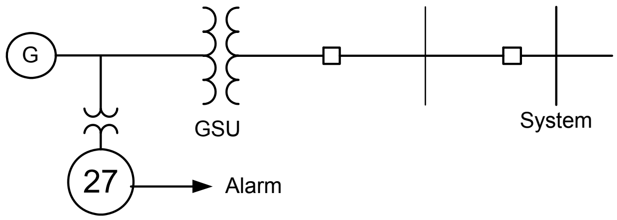

Figure 3.3.1.1 — Typical Unit Generator Undervoltage Scheme

3.3.1.2. Coordination of Generator and Transmission System

An undervoltage relay(s) is used for detecting a pre-determined low voltage level, and alarming or supervising other relays such as loss-of-field relay (40), distance relay (21), inadvertent energizing relay (50/27), out-of-step relay (78), etc.

In a few occasions such as unmanned plants, the 27 Function may be used to trip the generator (when on line). The 27 function to trip is applied as a surrogate for machine thermal current protection and detection of other abnormal conditions detrimental to the generator where an operator is not available to take appropriate action to mitigate the problem.

3.3.1.2.1. Faults

There are several considerations for use of the 27 function:

- There are coordination issues regarding system faults.
- The undervoltage function should never trip for any transmission system fault condition.
- The Transmission Owner needs to provide the longest clearing time and reclosing times for faults on transmission system elements connected to the high-side bus.
- This coordination should be validated by both the Generator Owner and Transmission Owner.

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3.3.1.2.1.1. Alarm Only — Preferred Method

- Follow IEEE C37.012 – set 27 function for alarm only
- Have written procedure for operators to follow when the 27 undervoltage alarm occurs.

NOTE: If the MVA output range of the generator is proportionately reduced with voltage, then an alarm initiated by the 27 function is sufficient because the unit is being operated within it thermal capability limits.

3.3.1.2.1.2. Tripping for Faults (not recommended, except as noted above)

- Utilize the 27 undervoltage function for tripping with a maximum setting of 0.9 pu for pickup and with a minimum time delay of 10 seconds.
- All planning and operational studies should model this undervoltage tripping of the generator to properly reflect its performance under transient or abnormal steady-state conditions.

NOTE: The alternative method in step 2 is being studied to provide better settings guidance based on thermal capability of older units. It is highly recommended to use more direct temperature and thermal detection methods versus an undervoltage protection function to protect the generator, such as RTD, thermocouples, and cooling medium temperature measurements.

3.3.1.2.2. Loadability

As noted above, the preferred method is to alarm only with the undervoltage function. If the undervoltage function is used to trip the unit, the additional coordination issues must be addressed by the Transmission and Generator Owners.

1. The Transmission and Generator Owners exchange and utilize the information below to analyze the coordination of the undervoltage protection.
    a. Set point and ~~Time Delay~~time delay should be given to the Transmission Owner.

    The undervoltage function should not trip the generator for a Recoverable System Event that is defined as a continuous transmission system voltage at the high side of the generator transformer of 0.85 per unit.

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2. This coordination should be validated by both the Generator Owner and Transmission Owner.

3.3.1.3. Considerations and Issues

The loss of generating units due to tripping of the under voltage elements or operator action during a system fault or a recoverable system event must be avoided. A Recoverable System Event is defined as a continuous transmission system voltage at the high side of the generator transformer of 0.85 per unit.

If undervoltage tripping is used for the generator and an Undervoltage Load Shedding (UVLS) scheme is used in the transmission system, the UVLS set points and time delays must be coordinated with the generator undervoltage trips. In this case, the generator set points should be modeled in system studies to verify coordination. A simple relay-to-relay setting coordination is inadequate due to differences in voltage between the generator terminals and transmission or distribution buses where the UVLS protection is implemented.

3.3.1.4. Coordination Procedure

Step 1 — The Generator Owner determines the proper undervoltage trip setpoint for his machine. This should be based on manufacturer's recommendation or protection applications circumstances for the generating station.

Step 2 — The Transmission Owner determines the local or remote backup clearing times for all transmission elements connected to the high-side bus.

Step 3 — The Generator Owner and Transmission Owner collaboratively analyze the settings to determine if they are coordinated. The time delay of the undervoltage element trip must be longer than the greater of the local or remote backup clearing times for all transmission elements connected to the high-side bus, but not less than 10 seconds.

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3.3.1.4.1. Alarm Only — Preferred Method

IEEE C37.102 — IEEE Guide for AC Generator Protection does not recommend use of the 27 function for tripping, but only to alarm to alert operators to take necessary actions.

Undervoltage element (device 27) calculation:

V_{27} = 90% of $V_{nominal}$ = 0.9 x 120 V = 108 V with a 10 second time delay to prevent nuisance alarms (per IEEE standard C37.102).

3.3.1.4.2. Tripping Used (not recommended)

CAUTION: If the Generator Owner uses the 27 function for tripping, the following conditions must be met at a minimum: Time delay of the undervoltage element trip must be longer than the greater of the local or remote backup clearing times for all transmission elements connected to the high-side bus, but not less than 10 seconds.

Undervoltage element (device 27) calculation:

V_{27} = 87% of $V_{nominal}$ = 0.87 x 120 V = 104 V with a coordinated time delay

Note: An 87 percent set point was chosen because the power plant is not capable of continued operation at this voltage level, and allows for a reasonable margin for extreme system contingencies.

3.3.1.5. Examples

3.3.1.5.1. Proper Coordination

If the undervoltage function is set to trip the generator, a threshold setting below 90 percent voltage at the generator terminals and an adequate time delay is necessary to allow system recovery above this level.

3.3.1.5.2. Improper Coordination

A threshold setting higher than 90 percent voltage at the generator terminals and/or an inadequate time delay.

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3.3.1.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 27 (Gen. Prot.) Protection Coordination Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
27 – Generator Unit Undervoltage Protection— **** Should Not Be Set to Trip, Alarm Only**** **If ~~the 27~~ device 27 tripping is used~~,~~ for an unmanned ~~units,~~facility –** the settings must coordinate with the stressed system conditions of 0.85 per unit voltage and time delays set to allow for clearing of system faults by transmission system protection, including breaker failure times.	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions. • UVLS set points and coordination if applicable. • Settings should be used for planning and system studies~~.~~ either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment. • Must coordinate with transmission line reclosing.

3.3.1.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s).

Table 3 Excerpt — Device 27 (Gen. Prot.) Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: ~~under voltage set point at the generator terminals~~Under Voltage Set Point if applicable, including time delays, at the generator terminals.	Time Delay of Transmission System Protection	Feedback on problems found in coordinating with stressed voltage condition studies and if applicable, UVLS studies

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3.3.2. Generating Plant Auxiliary Power Supply Systems Undervoltage Protection

3.3.2.1. Purpose of the Generator Auxiliary System Device 27 — Undervoltage Protection

This device 27 protection uses the measurement of auxiliary system voltage.

When the voltage levels of the auxiliary system reaches the undervoltage set-point, this protection initiates alarming, automatic transfer to alternative power supply, if available with transfer capability, starting of emergency generator(s), or, if necessary, tripping.

This function is used to transfer loads to the backup auxiliary power supply, as well as, to protect auxiliary system equipment from severe undervoltage conditions that would have serious consequences, such as auxiliary motors stalling or voltage collapse for the generating unit(s).

This function also protects the integrity of the power supply to safety related buses applied to support the reactor of nuclear power plants. In these applications two undervoltage thresholds are utilized; the first undervoltage (UV) level (device 27SB1) initiates auxiliary load transfers to an alternative power supply and the second UV level (device 27SB2) initiates a unit trip. (See section 3.3.4 for further details)

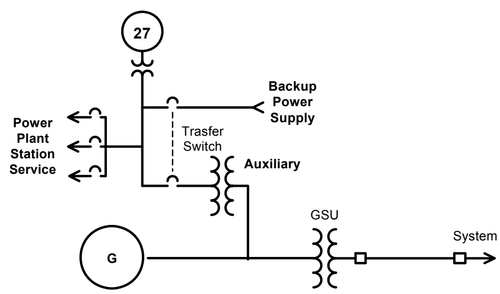

Figure 3.3.2.1 — Generating Plant Auxiliary Power System Undervoltage Protection Scheme

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3.3.2.2. Coordination of Generator and Transmission System

3.3.2.2.1. Faults

Coordination issues can exist regarding system faults when this function is used to trip the generator. This protection should not react to any transmission system faults.

3.3.2.2.2. Loadability

Step 1 — If the undervoltage function is used to trip the auxiliaries system which would lead to tripping the generator, the Transmission and Generator Owners exchange and utilize the information below to analyze the coordination of the undervoltage protection.

a. The setpoint and time delay should given to the Transmission Owner

b. The Transmission Owner needs to provide the longest clearing time and reclosing times for faults on transmission system elements connected to the high side bus.

Step 2 — Check to see that the auxiliary system trip level will not preclude the unit from riding through a recoverable system event as defined as:

a. A transmission system voltage of 0.85 per unit at the high side of a system-connected auxiliary transformer.

b A transmission system voltage of 0.85 per unit at the high side of a generator step up transformer for generator-connected auxiliary systems.

Step 3 — For nuclear unit coordination between the Transmission Owner and Nuclear Power Generating Unit(s) is required for Preferred Power Supply and Nuclear Plant Interface Requirements (NPIRs) — see NERC Standard NUC-001-1. Please also see Section 3.3.4 of this report for further details.

3.3.2.3. Considerations and Issues

- Auxiliary power supply system — auxiliary motors with 80 percent to 85 percent motor terminal voltage create approximately 64 percent to 72 percent motor torque. Motor torque is approximately equal to the supplied motor terminal voltage squared in per unit or percent of rated motor voltage. Lack of adequate voltage can cause auxiliary motors to cascade into a voltage collapse and a stall

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condition as well as the possibility of contactors dropping out. In some applications the motor rated terminal voltage is less than system nominal to allow for inherent system voltage drops (e.g., 4,000 volts on a 4,160 volt bus). This needs to be taken into consideration when evaluating the motor capability based on reduced voltages.

- The loss of nuclear units during system disturbances is of great concern especially for system voltages above 85% of rated system voltage. Some units start tripping auxiliaries at voltages from 90% to 95%. These under-voltage settings were determined by engineering studies supporting the nuclear plant and safe shut-down during the nuclear licensing procedure. As such, they are not likely to be changed. Therefore, Transmission Owners, Transmission Operators, Planning Coordinators and Reliability Coordinators should recognize the under-voltage sensitivity of those units to tripping during voltage perturbations.
- The Generator Owner should consider auxiliary motor contactor low voltage drop out points when reviewing undervoltage protection on the plant auxiliary systems.

3.3.2.4. Coordination Procedure

3.3.2.4.1. Setting Procedure

Step 1 — Verify that the relay setting is set to prevent operation for voltage greater than or equal to 85 percent of nominal voltage at the high-side of a system-connected auxiliary transformer of the GSU transformer for generator-connected auxiliary systems.

Step 2 — Verify that the timer setting is set long enough to prevent operation for a transient condition on the order of two to three seconds or more.

Step 3 — Some nuclear power plants use a voltage relay, commonly set around 90 percent, on the safety related bus, based on their design basis to support safe shutdown of the reactor.

3.3.2.4.2. Setting Considerations

- Undervoltage protection should not trip for a recoverable transmission system event; that is a system voltage of 85 percent nominal during the event.

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- Undervoltage element calculation for a safety related bus in a nuclear power plant needs to be completed based on IEEE 741; see section 2.3.2.1 for further details.

- NRC design basis studies are required to determine the UV level set points. (Standard IEEE 741 & 765) see section 2.3.2.1.

- IEEE Standard C37.96-2000 (IEEE Guide for AC Motor Protection) suggests an undervoltage setting of 80 percent voltage, with a two – three second time delay.

- Motor applications that cause voltage drops during starting that approach 80 percent may require a lower setting. This consideration should be applied based on the specific application.

- In some cases undervoltage is not applied for auxiliary systems.

For further information on Device 27 issues, see Sections 4.5.7 and A.2.13 of C37.102-2006 (Guide for AC Generator Protection) and IEEE C37.96-2000 (IEEE Guide for AC Motor Protection) see Section 7.2.4.

NOTE: Caution should be used in setting device 27 for auxiliary tripping when variable speed drives are used.

3.3.2.5. Examples

3.3.2.5.1. Proper Coordination

- Undervoltage element (device 27) calculation:

  V_{27} = 80% of $V_{nominal}$ = 0.8 x 120 V = 96 V and a time delay of 2 to 3 seconds

- Avoid the loss of generating unit due to tripping of the auxiliary system elements during a recoverable system event. A recoverable system event is defined as a transmission system voltage at the high side of the generator transformer of 0.85 per unit.

- A time delay of two to three seconds should allow system protection to act first to remove the adverse/fault condition.

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3.3.2.5.2. Improper Coordination

Improper coordination would result from a threshold setting higher than 90 percent voltage at the auxiliary system bus and/or an inadequate time delay.

3.3.2.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 27 (Plant Aux.) Protection Coordination Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
27 – Plant Auxiliary Undervoltage **If Tripping is used** – the Correct Set Point and Adequate Time Delay so it does not trip for All System Faults and Recoverable Extreme Events	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Coordinate the auxiliary bus protection and control when connected directly to ~~the transmission system.~~ High Voltage System. • Generator ~~Owners~~ Owner to validate the proper operation of auxiliary system~~s~~ at 80~~–~~-85 percent voltage. The undervoltage trip setting is preferred at 80 percent. • Generator Owners validate the proper operation of auxiliary system at 0.8-0.85 per unit voltage. • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment.

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3.3.2.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s).

Table 3 Excerpt — Device 27 (Plant Aux.) Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: Under Voltage Set Point if applicable , including time delays, at the power plant auxiliary bus	Time Delay of Transmission System Protection	Feedback on problems found in coordinating with stressed voltage condition studies, and if applicable, UVLS studies

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3.3.3. Undervoltage Relays (Device 27) Applied at the Point of Common Coupling

IEEE 1547–2003 — IEEE Standard for Interconnecting Distributed Generation Resources with the Electric Power Systems, prescribes under voltage (UV) protection at the point of common coupling (PCC), i.e., the point of interconnection. The function of this relay is to trip the distributed resource on undervoltage if the distributed resource is islanded from the interconnected distribution system along with local load or is measuring a prolonged system fault. **IEEE 1547 applies to generator of less than 10 MW and connected to the distribution system.**

Some large generators connected to the transmission system have added this function at its point of common coupling. It is possible that some interconnection agreements include this protection as a requirement. IEEE 1547 does not apply to the transmission system connection of generators as addressed in this NERC technical reference. Anti-islanding protection is not recommended because the isolation of the generator from the transmission system will not isolate the generator on system load, nor will there likely be an undervoltage if the islanded generator is not isolated with load that is greater than generation. Any isolation will be detected by overspeed and overfrequency protection functions. An UV function connected to the high voltage side of the GSU at a generating station should not be used unless it serves an alarm function. If an UV function is used it should be connected to the voltage transformers on the terminal of the generator in alarm mode. See also Section 3.3.1.

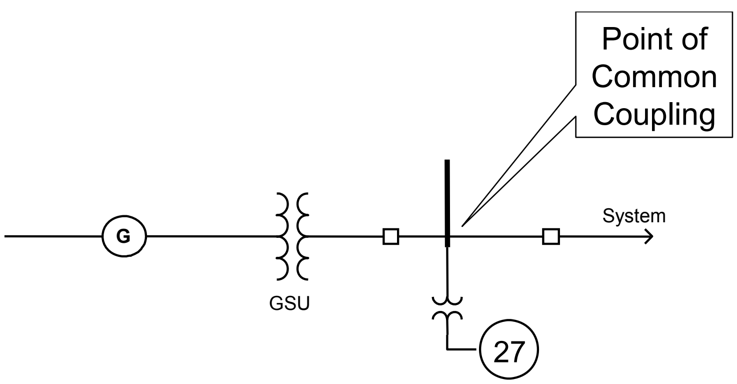

Figure 3.3.3.1 — Undervoltage Relay Applied at the Point of Common Coupling

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3.3.3.1. Purpose of the Device 27 at Point of Common Coupling

The function of these relays is to alarm the generator that an undervoltage on the transmission system is occurring and that the operator should be on a heightened state of awareness matching this alarm with others that may be occurring within the plant. See section 3.3.1.

3.3.3.2. Coordination of Generator and Transmission System

If an UVLS protection is deployed in the vicinity of the generator, the generator operator should be cognizant of UVLS and including its settings within the transmission system. The generator operator should be aware of all studies that demonstrate the need for UVLS and should be trained on the impact of transmission undervoltage on plant operation.

3.3.3.2.1. Faults

UV relays sensing transmission voltages can alarm for system faults. UV relays may alarm for phase-ground faults and multi-phase faults. The generator operator should then, upon alarm, focus attention on in-plant alarms especially per generator manufacturer recommended plant alarm conditions.

3.3.3.2.2. Loadability

PCC undervoltage functions should alarm for stressed system conditions. This means that these relays should alarm for 0.85 per unit system voltage or less. System studies may be performed to quantify and qualify the likely nature of the system undervoltage relay alarms to assertion the severity of stressed system conditions. Since this function should only alarm, it should be immune to loadability tripping.

3.3.3.3. Considerations and Issues

There should be no loss of generation due to system undervoltage alarms or operator action during a system fault or a recoverable system event. A Recoverable System Event is defined as a continuous transmission system voltage at the high side of the generator transformer of 0.85 per unit. UVLS studies should include UV alarm setpoints so that the Transmission Owner can alert and provide operator training input

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with regards to the studied changing voltages that can occur as UVLS is performing the system return to planned voltage levels.

3.3.3.4. Coordination Procedure

Step 1 — Generator Owner to Provide Settings, Time Delays, and Protection Output alarm functions to the Transmission Owner and Planning Coordinator for both the generator and Generator Step Up Transformer.

Step 2 — The Transmission Owner and Planning Coordinator confirm that any UVLS actions are conveyed to the Generator Owner.

Step 3 — The Generator Owner conveys and confirms operator actions steps to the Transmission Owner and Planning Coordinator for their concurrence based on a joint understanding of system study results.

3.3.3.4.1. Setting Considerations

If an alarm is used by Generator Owners

Undervoltage element (device 27) calculation:

V_{27} = 85% of $V_{nominal}$ = 0.~~80~~85 x 120 V = ~~96~~102 V with a coordinated time delay

Note: An 85 percent set point was chosen to allow for a reasonable margin for extreme system contingencies.

3.3.3.5. Examples

~~A system~~In this example a stressed system condition is occurring. The Generator Operator observes the condition and measures the PCC voltage. The Generator Owner contacts the Transmission Owner requesting information and conveys the plant PCC voltage value to the Transmission Owner. As per joint training, including simulation training, the Generator Owner conveys plant status to the Transmission Owner and both agree on the next step in plant operations based on all alarm and status information both inside the plant and within the transmission system.

3.3.3.5.1. Proper Coordination

PCC UV function is alarm only. Both Generator Owner and Transmission Owner share system and plant alarm, change in equipment status and next step activities using three way communication and operational planning studied results.

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3.3.3.5.2. Improper Coordination

There is no improper coordination for an alarm-only function.

3.3.3.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 27 (Plant HV System Side) Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
27 – Plant High Voltage System Side Undervoltage **If Tripping is used** – the Correct Set Point and Adequate Time Delay so it does not trip for All System Faults and Recoverable Extreme Events	21 27 if applicable 87B 87T 50BF Longest time delay for Transmission System Protection to Clear a Fault	• Must not trip prematurely for a recoverable extreme system event with low voltage or system fault conditions. • UVLS set points and coordination if applicable. • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance at the device location in the stability program and applying engineering judgment.

3.3.3.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s).

Table 3 Excerpt — Device 27 (Plant HV System Side) Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
~~Setpoints of PCC UV alarm. All plant studies leading to plant operations subsequent to receiving alarms.~~Relay settings: Under Voltage Set Point if applicable, including time delays, at high side bus.	~~Results of all studies that may lead to plant PCC alarm.~~Time Delay of Transmission System Protection	~~If PC performs studies listed under Transmission Owner then the same.~~Feedback on problems found in coordinating with stressed voltage condition studies and if applicable, UVLS studies

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3.3.4. Nuclear Power Plants — Undervoltage Protection and Control Requirements for Class 1E Safety Related Auxiliaries Design Guidelines and Preferred Power Supply (PPS)

The base standards for these nuclear requirements are NERC Standard NUC-001 — Nuclear Plant Interface Requirements (NPIR), IEEE 741-2007, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations and IEEE 765-2006, IEEE Standard for Preferred Power Supply (PPS) For Nuclear Power Generating Stations (NPGS).

NERC Standard NUC-001 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.

Section B of NERC standard NUC-001 describes the requirements R1 – R9 that are necessary to meet the intent of the interface between the nuclear generating plant and the other entities.

Additionally, the IEEE Nuclear Committee guidelines for protection and control action during degraded voltage conditions for Class 1E systems is found in IEEE 741's Appendix A, "Illustration of concepts associated with degraded voltage protection".

As well, the guidelines for the types of transmission systems studies and data requirements to ensure voltage adequacy of preferred power supply based on the Nuclear Power Generating Stations design basis are contained in informative Appendix B of IEEE 765. The Transmission Owner must perform the transmission systems studies that demonstrate and validate that the preferred power supply (PPS) performance and that it meets the post event voltage requirements for the design basis of the plant. This must be valid for all reasonably expected system conditions otherwise alternatives need to be investigated (0.85 per unit transmission system voltage as an example for extreme event contingency).

A strong communications tie between the nuclear plant owner and Transmission Owner is critical.

The following information needs to be exchanged and agreed to by both parties:

A. Input Data for Models

B. Modeling Methods

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C. Design and Licensing Bases

D. Interpretation of Study Results

The minimum required steady-state post event grid voltage is to be based on the nuclear unit maintaining acceptable requirements and possible continued operation.

A recognition and notification process for unacceptable PPS voltages at the Nuclear Plant Substations must be in place from the Transmission Owner to the Nuclear Plant Operations.

Please refer to NERC NUC-001, IEEE 741-2007, and IEEE 765-2006 for further details.

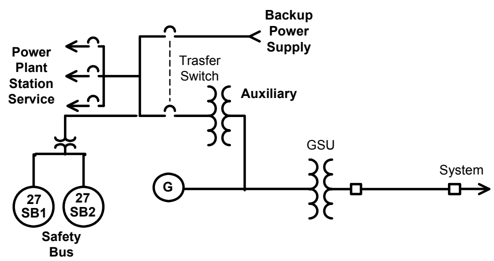

Figure 3.3.4.1 — Nuclear Power Plant Auxiliary System Power Supply

Once the criteria and plan is established between the Nuclear Plant and Transmission Owner, the Transmission System Planning Entities must incorporate this strategy into any extreme event contingency analysis including if the analysis deems that the nuclear generating unit is tripped during the event. The Transmission System Planning Coordinator must then demonstrate the ability of the system to survive without the benefit of the nuclear generating unit.

3.3.5. Comparison of Stressed Transmission System Voltage Impact on Combustion Turbine Plants with Auxiliaries Directly Fed from the Transmission System versus Fed from the Generator Bus via a Unit Auxiliary Transformer

With the substantial addition of combustion turbine generating units to the electric grid in recent years, they are becoming a more significant part of the total generation. Due to cost reduction in designs to maintain competiveness; some of these plants were designed

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with transmission fed auxiliary system supply transformers in lieu of a unit auxiliary transformer fed from the generator bus. For these systems the auxiliary loads do not derive a direct benefit of field forcing (voltage boost) during system degraded voltage events. This field forcing can represent a significant amount of voltage for a brief period in time. The generator depending on its MVA size as compared to the size and stiffness of the system can provide a voltage boost of a few percent or more on the generator bus above the system voltage on the transmission high side. This was demonstrated in the Section 3.1 for the system back up protection with generator terminal voltages above the system voltage. A few percent higher voltages can prove to be valuable during these types of extreme reduced voltage events and may make the difference for continued operation of the auxiliary system and thus the generating unit(s).

To illustrate this condition a hypothetical combustion turbine generating unit will be used to show the difference between the two designs (system and generator fed auxiliary systems). There are a number of other factors that can impact whether the auxiliary system can survive during these extreme system contingencies reduced voltage events and are identified below. IEEE Standard 666 — "IEEE Design Guide for Electric Power Service Systems for Generating Stations" provides detailed information and guidance pertaining to these topics on auxiliary systems.

Some of these factors that have an impact are:

1. Motor rated voltage (i.e., 4,000 volt motors applied on 4,160 volt nominal system)
2. Motor rated torque capability at rated voltage, some motors have rated torque capability at a reduced voltage to provide margin.
3. Utilization of no-load taps on transformer

Utilization of these techniques can help optimize the auxiliary system performance during stressed system voltage events.

If a conservative five percent voltage drop is assumed for an auxiliary system to the motor terminals, for the two examples:

- Unit auxiliary transformer fed auxiliary system — Degraded System Voltage is 0.85 per unit, generator voltage is at 0.87 per unit due to field forcing, 0.05 per unit voltage drop yields a 0.82 per unit voltage at the motor terminals. If the trip setting is at 0.80 per unit, the motors will not be tripped.
- Transmission system transformer fed auxiliary system — Degraded System Voltage is 0.85 per unit, Transformer voltage is at 0.85 per unit, 0.05 per unit voltage drop

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yields a 0.80 per unit voltage at the motor terminals. If the trip setting is at 0.80 per unit, the motors will be tripped.

Figures 3.3.5.1 and 3.3.5.2 show the differences between the two supplies discussed in this section.

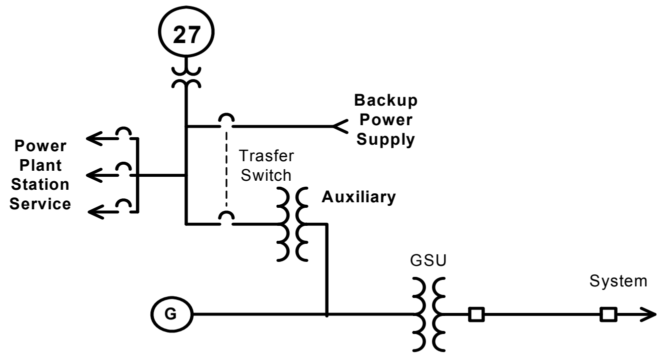

Figure 3.3.5.1 — Unit Auxiliary Transformer Supplied Scheme

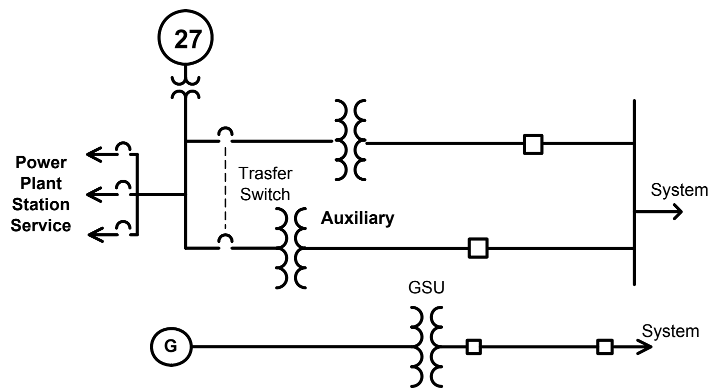

Figure 3.3.5.2 — Transmission System Transformer Supplied Scheme

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Design and application changes should be given consideration to benefit the reliability of the auxiliary system voltage during stressed system conditions such as sourcing off the generator bus or other methods less impacted by the transmission system. Please see IEEE Standard 666 — "IEEE Design Guide for Electric Power Service Systems for Generating Stations" for more background. **The fact that units with auxiliaries fed from the system (not the generator bus) could trip on undervoltage during system events must be recognized in system studies.**

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3.4. Reverse Power Protection (Device 32)

3.4.1. Purpose of the Generator Device 32 — Anti-Motoring Protection

The Device 32 protection measures reverse power derived from the real component of generator voltage times generator stator current times √3. Section 4.5.5 of the IEEE C37.102-2006 — Guide for AC Generator Protection describes the purpose of this protection as follows:

> *"Motoring of a generator occurs when the energy supply to the prime mover is cut off while the generator is still online. When this occurs, the generator will act as a synchronous motor and drive the prime mover. While this condition is defined as generator motoring, the primary concern is the protection of the prime mover that may be damaged during a motoring condition. In sequential tripping schemes for steam turbine generators, a deliberate motoring period is included in the control logic to prevent potential over-speeding of the unit (see also 7.2.3.4). While some of the devices used in the control logic for sequential tripping schemes are the same as those used in anti-motoring protection, the two functions should not be confused. Anti-motoring protection should provide backup protection for this control logic as well as for other possible motoring conditions that would not be detected by the sequential tripping control logic (such as inadvertent closure of governor valves or high system frequency conditions). Intentional motoring conditions may be permitted on both gas turbine and hydro applications, where the process is used to accelerate the rotor during starting conditions or the installation is operated in a pump/storage mode."*

Reverse power protection is applied to prevent mechanical damage (on turbine blades, shaft, gear box, etc.) in the event of failure of the prime mover.

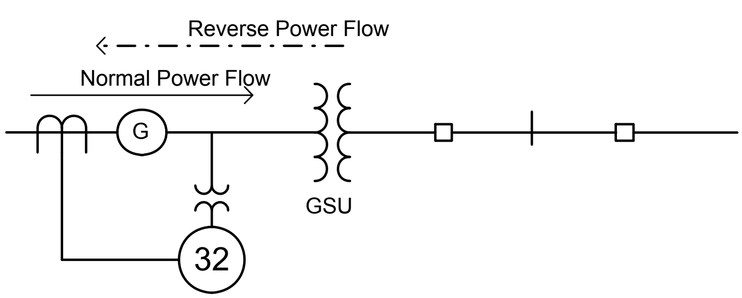

Figure 3.4.1 — Reverse Power Flow Detection

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3.4.2. Coordination of Generator and Transmission System

3.4.2.1. Faults

There are no coordination issues for system faults for this function.

3.4.2.2. Loadability

In general, there are no loadability issues with this function.

3.4.3. Considerations and Issues

The reverse power condition is undesired for generators. The power drawn by the generator during motoring is equal to the mechanical losses and they can be very low for large steam units (below 0.5 percent in some cases). Therefore, a reverse power relay typically is set very sensitive to prevent mechanical damage on turbine blades, shaft, gear box, etc.

When setting an older electromechanical relay it is important to note that these relays can be susceptible to tripping during conditions when the unit is operated under-excited (leading) with high reactive power (var) loading. In particular, this can occur when the active power (MW) loading is low, such as when a unit is initially synchronizing to the grid.

The following must be considered:

- Check the time delay setting. A typical setting is 10 to 30 seconds or longer, depending on the unit.
- The time delay should be set long enough that the unit will not trip for a system transient condition or power swing condition where a momentary reverse power is possible for short duration.

Further discussion is given in Section A.2.9 of C37.102-2006 (Guide for AC Generator Protection).

3.4.4. Coordination Procedure

Refer to C37.102-2006 for Device 32 setting recommendations.

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3.4.5. Examples

No coordination example is provided for this device.

3.4.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 32 Protection Coordination Data Exchange Requirements		
Generator Protection Device	Transmission System Protection Relays	System Concerns
32 – Reverse Power	None	• Older electromechanical relays can be susceptible to misoperation at high leading Var loading

3.4.7. Summary of Protection Function Data and Information Exchange required for Coordination

Table 3 Excerpt — Device 32 Data To be Provided		
Generator Owner	Transmission Owner	Planning Coordinator
~~Device 32~~ None	None	None

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3.5. Loss-of-Field Protection (LOF) — Device 40

3.5.1. Purpose of the Generator Device 40 — Loss-of-Field Protection

Loss-of-field protection uses a measurement of impedance derived from the quotient of generator terminal voltage divided by generator stator current as described in section 4.5.1 of the "Guide for AC Generator Protection" IEEE Standard C37.102-2006.

> *"The source of excitation for a generator may be completely or partially removed through such incidents as accidental tripping of a field breaker, field open circuit, field short circuit (flashover of the slip rings), voltage regulation system failure, or the loss of supply to the excitation system. Whatever the cause, a loss of excitation may present serious operating conditions for both the generator and the system.*
>
> *When a generator loses its excitation, it overspeeds and operates as an induction generator. It continues to supply some power to the system and receives its excitation from the system in the form of vars.*
>
> *If the generator is operating at full load, stator currents can be in excess of 2 per unit; and, because the generator has lost synchronism, high levels of slip-frequency currents can be induced in the rotor. These high current levels can cause dangerous overheating of the stator windings and cores of the rotor and stator within a short time.*
>
> *A loss of field condition causes devastating impact on the power system as a loss of reactive power support from a generator as well as creating a substantial reactive power drain from the system. On large generators this condition can contribute to or trigger a wide area system voltage collapse.*
>
> *Protection from Loss of field condition of the generator is provided: to prevent machine damage due to large stator currents and to prevent large reactive drain from the system resulting in voltage collapse and tripping of transmission lines.*
>
> *When the excitation (field) is reduced or lost, the terminal voltage begins to decrease and the stator current increases, resulting in a decrease in impedance (Z=V/I) viewed from the generator terminals. Also, the power factor changes from Lagging to Leading. The impedance moves into the fourth quadrant from first quadrant due to the Var (reactive power) flow from the system into the generator. For detecting this impedance change, there are two basic relaying schemes as shown in figures 3.4.1 (dual offset mho characteristics type) and 3.4.2 (dual offset mho characteristics with directional element).*
>
> *The LOF relays can misoperate during system disturbances and power swing conditions if they are not set properly considering coordination with generator*

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parameters and system conditions. This is especially true if only single offset mho characteristic is used with short or no time delay.

The purpose of section 3.4 is to describe the coordination issues with the setting of Loss of Field relaying and certain system conditions which can cause inadvertent tripping of the unit. The field current in the generator could also be excessive."

Figure 3.5.1 shows the problems associated where the swing results in a stable operating point is outside the excitation capabilities of the machine, resulting in a necessary trip of the LOF relay. ~~Find another unit to operate in condensing mode.~~

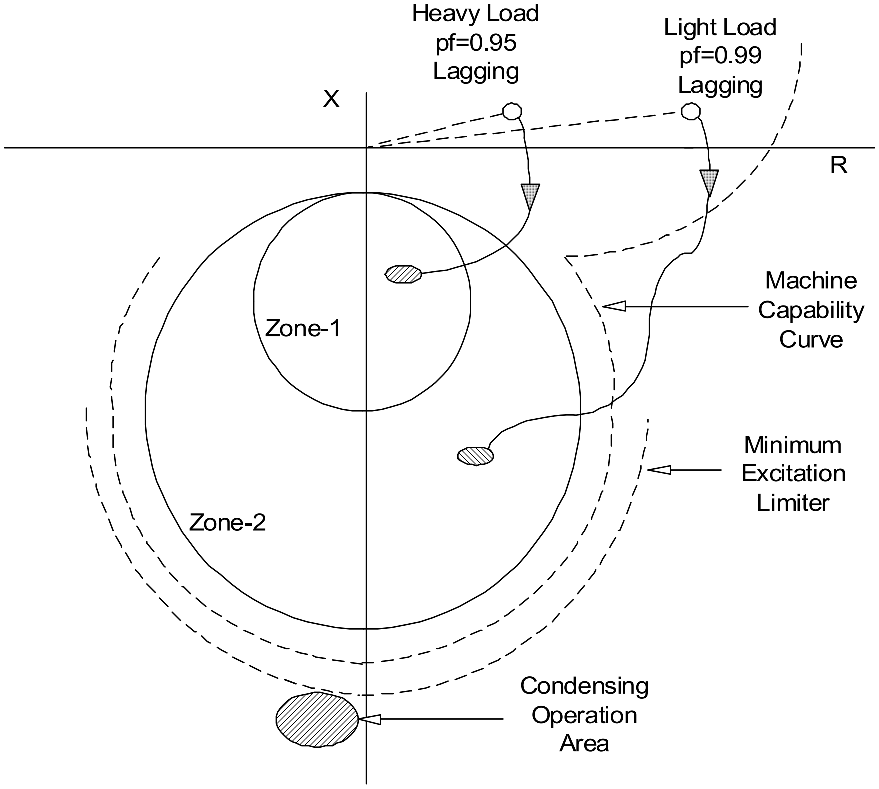

Figure 3.5.1 — (1) Locus of Swing Impedance during Light & Heavy Loads for LOF, and (2) Relationship between Minimum Excitation Limiter (MEL) or Under Excitation Limiter (UEL), and a Typical Condensing Operation Area

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Figure 3.5.1 Note:

- *Condensing operation of generator is depending on the unit operation schedule (Regional Agreement), and usually unit generator is operated large negative reactive power (or VAR) with small negative power (or Watts) in out side of minimum excitation limiter (MEL) or Under Excitation Limiter (UEL).*

3.5.2. Coordination of Generator and Transmission System

3.5.2.1. Faults

Step 1 — The Transmission Owner provides the ~~planning entity~~Planning Coordinator with the worst case clearing time for each of the power system elements connected to the transmission bus at which the generator ~~bus~~is connected.

Step 2 — The ~~transmission planner~~Planning Coordinator determines the stability impedance trajectory for the above conditions.

Step 3 — The ~~transmission planner~~Planning Coordinator provides these plots to the Generator Owner. The Generator Owner utilizes these plots to demonstrate that these impedance trajectories coordinate with the time delay setting of the loss-of-field (LOF) relay to prevent misoperations by having adequate time delay.

A system stability study may be required to evaluate the generator and system response to power system faults. The response of the LOF relays under these conditions must be studied to see if they respond to power swing conditions as a result of system faults. The Transmission Owner, Generator Owner, and ~~transmission planner~~Planning Coordinator must share information on these studies and LOF relay settings to prevent inadvertent tripping of generators for external fault conditions not related to a loss-of-field condition. If there is an out-of-step protection installed it should be coordinated with the LOF protection.

3.5.2.2. Loadability

Step 1 — The Generator Owners confirms that the LOF relay setting coordinates with the generator reactive capability and the excitation system capability to ensure that the LOF relay does not restrict operation of the generating unit.

Step 2 — A light load system study is completed in which the generator is taking in vars. A sufficient number of operating conditions and system contingencies are evaluated to identify the worst case operating condition for coordination with the

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LOF relay setting. The output of this study is provided to the Generator Owner to evaluate whether the worst case operating load condition(s) lies outside the LOF characteristic.

Step 3 — For any case where the operating load point lies within a properly set LOF characteristic a mutually agreed upon solution must be applied, (i.e., shunt reactor, turning off capacitor banks in the area, etc). Where the solution requires real-time action by an operator the solution is incorporated into a system operating procedure.

Coordination between Generator Owners, Transmission Owners, and Transmission Planners is necessary to prevent loadability considerations from restricting system operations. This is typically not a problem when the generator is supplying VARs because the LOF characteristics are set to operate in third and fourth quadrant. However, when the generator is taking in VARs due to light load and line charging conditions, or failure of a transmission capacitor bank to open due to control failures, loss-of-field relays can misoperate if the apparent impedance enters the relay characteristic in the fourth quadrant.

3.5.3. Considerations and Issues

There are two hazards to be concerned with when operating a generator under-excited. The first concern is the generator capability curve (GCC) limit. Operation of the generator beyond the under-excited operating limit of the GCC can result in damage to the unit. The primary protection for this is the under excitation limiter (UEL) control on the excitation system. LOF relays should be properly coordinated with GCC and UEL.

The other concern is the steady-state stability limit (SSSL). If the unit is operated with too little excitation, it can go out-of-step. The LOF relay settings should also properly coordinate with the SSSL.

Other considerations include operation of the generator as a synchronous condenser, generator connected to a long transmission line with line charging where the generator absorbs VARs from the system and large transmission capacitor banks near the generating plant. Procedures such as closing the remote end of the transmission first before reclosing the generator terminal of the line would minimize the effects of line charging causing misoperation of the LOF relay.

The setting information for the LOF relay should be provided by the Generator Owner to the Transmission Owner and the appropriate planning entity. The impedance trajectory

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of most units with a lagging power factor (VARs into the power system) for stable swings will pass into and back out of the first and second quadrants. It is imperative that the LOF relay does not operate for stable power swings.

The LOF relay settings must be provided to the appropriate planning entity by the Generator Owner so that the planning entity can determine if any stable swings encroach long enough in the LOF relay trip zone to cause an inadvertent trip. The appropriate planning entity has the responsibility to periodically verify that power system modifications do not result in stable swings entering the trip zone(s) of the LOF relay causing an inadvertent trip. If permanent modifications to the power system cause the stable swing impedance trajectory to enter the LOF characteristic, then the ~~planning entity~~Planning Coordinator must notify ~~the Transmission Owner who in turn must notify the~~ Generator Owner that new LOF relay settings are required. The ~~planning entity~~Planning Coordinator should provide the new stable swing impedance trajectory so that the new LOF settings will accommodate stable swings with adequate time delay. The new settings must be provided to the ~~planning entity~~Planning Coordinator from the Generator Owner ~~through the Transmission Owner~~ for future continuous monitoring.

In a limited number of cases, conditions may exist that coordination cannot be achieved for every generating unit. In such cases coordination may be deemed acceptable if tripping does not cascade and is limited to a small amount of generation (as a percentage of the load in the affected portion of the system). Protection models should be added to system models for any units for which coordination cannot be obtained.

3.5.4. Coordination Considerations

- The coordination requirements with generator controls are such that the loss of field relay must not operate before the UEL limit (with a margin) is reached. It is also important to determine if the UEL in the excitation control allows the quick change of Q (see figure 3.5.~~7~~1) beyond the limit. If it does then the setting should have an adequate margin between the UEL and LOF setting to prevent unnecessary operation of the LOF relay during this condition. The other concern is the steady-state stability limit (SSSL), particularly when the automatic voltage regulator (AVR) of the unit is operating in manual mode. If the unit is operated with too little excitation, it can go out-of-step. Therefore the unit should be tripped before a steady state stability limit is reached.

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- Some relay characteristics change with variation in frequency (this is especially true for electromechanical and static relays). These characteristic changes during power swing conditions (where the frequency can vary considerably from nominal values) can cause unnecessary tripping of the generator by the LOF relay. These characteristic changes need to be considered while setting the relay for hydro units, because hydro units can safely operate at speeds greater than 110 percent of nominal while separated from the power system. At frequencies above 60 Hz, the angle of maximum torque for some LOF relays will shift farther into the fourth quadrant and the circle diameter may increase by 200 percent to 300 percent. With this shift and increase in characteristic it is possible for the relay to operate on the increased line charging current caused by the temporary overspeed and overvoltage condition. Unnecessary operation of the LOF relay schemes for this condition may be prevented by supervising the schemes with either an undervoltage relay or an overfrequency relay. The overfrequency relay would be set to pick up at 110 percent of rated frequency and would be connected to block tripping when it is picked up and to permit tripping when it resets. An undervoltage relay would be set to pickup between 0.8 and 0.9 per unit of generator rated voltage and is used with the impedance elements to detect a complete loss of field condition where the system is not able to provide sufficient reactive power to the generator. Typically, a 0.25 to 1.0 second time delay is used with this function

- The protection scheme may use a single zone offset mho characteristic or a dual zone offset mho characteristic. Dual zone offset mho relays are preferred especially for steam and combustion turbine units where X_d typically is very large.

- The LOF scheme should be provided with an adequate time-delay for providing security against operation during stable power swings.

- The relay timers should have a fast reset ratio for secure operation.

- The setting for LOF should consider two system scenarios: the strongest available system (all transmission facilities in services and all generation on), and the weakest credible system (maximum transmission constraints and minimum generation dispatch). Special considerations for LOF setting may be necessary for blackstart operation of the unit.

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3.5.5. Example

3.5.5.1. Proper Coordination

The following describes how the typical loss of field relay should be set. These settings should be reflected in transmission system planning and operational planning analyses.

Typical Loss-of-Field Relay Setting Calculation for two zone offset mho characteristic.

Step-1 — Calculate the Base impedance = 17.56Ω/per unit

$$Z_{base} = \frac{20{,}000V/VTR\sqrt{3}}{14{,}202A/CTR} = \frac{20{,}000/166.67}{14{,}202/3600} = \frac{69.28}{3.945} = 17.56\Omega\text{/per unit}$$

Step-2 — Convert X'$_d$ and X $_d$ in per unit to Ohms:

$$X'_d = (0.20577\,pu)(17.56\Omega/\,pu) = 3.61\ \Omega$$
$$X_d = (1.1888\,pu)(17.56\Omega/\,pu) = 20.88\ \Omega$$

Step-3 — Element settings:

Offset = (50%) (X'_d) = (0.5) (3.61) = 1.8 Ω
Z1 = 1 pu = 17.6 Ω
Z2 = X_d = 20.88 Ω

Step-4 — Plot various characteristics as shown in figure 3.5.1

Step-5 — set the time delays for zone 1 and zone 2 elements.

Typical time delay settings are:

Zone 1: 0.1 sec

Zone 2: 0.5 sec

System ~~fault~~stability studies should be conducted to see if the above time delays are sufficient to prevent inadvertent tripping during stable power swings.

Figure~~s~~ 3.5.~~1, ~~3~~.5.2, 3.5.3, and 3.5.4 illustrate~~ illustrates some of these types of swing characteristics that need to be studied.

Step-6 — Set the undervoltage supervision (if appropriate):

V = 85% of $V_{nominal}$ = 0.85 x 120V =102 V

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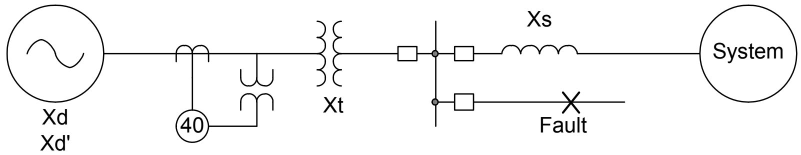

Figure 3.5.2 — Simplified System Configuration of Device 40 relay & Fault Locations.

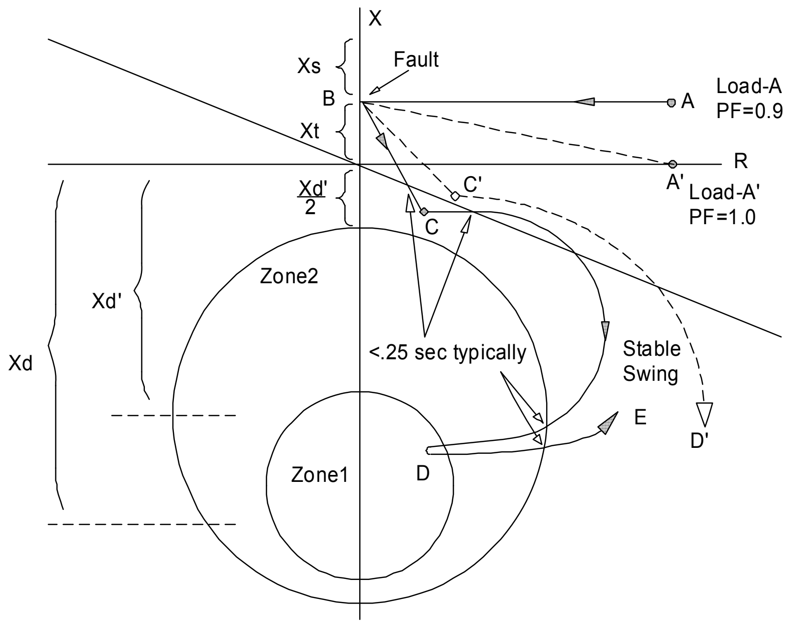

Figure 3.5.3 — "Two Zone Offset Mho with Directional Element" type Loss-of-Field Detector

Figure 3.5.3 Notes:

- *Load-A' — Unity Power Factor 1.0 per unit Load Impedance*
- *Load-A — 0.9 lagging Power Factor 1.0 per unit Load Impedance*
- *B — Three Phase Fault Location*
- *C — Apparent Impedance immediately after fault is cleared Lb load (P=1.0 pu @ pf = 0.9 lag)*
- *C' — Apparent Impedance immediately after fault is cleared La load (P=1.0 pu @ pf = 1.0)*
- *A'-B-C'-D' — Locus of Swing Impedance for unity power factor Load with fast fault clearing & Voltage Regulator in Service*

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- *A-B-C-D-E — Locus of Swing Impedance for lagging 0.9 power factor with fault clearing at critical switching time & Voltage Regulator out of service*

Figure 3.5.3 shows a stable swing incursion into the zone 1 of the LOF relay. This would result in an undesirable operation of the LOF relay if the zone 1 time delay is not sufficient.

When a dual offset Mho characteristic is used for LOF protection, it should be carefully studied for security to prevent operation for stable swings when the generation is connected to a weak transmission system.

For further details and discussion regarding interaction of this protective function, the excitation system controls and limiters please refer to Reference 8 (see Appendix A), *Coordination of Generator Protection with Generator Excitation Control and Generator Capability*.

3.5.6. Summary of Protection Functions Required for Coordination

Transmission Planner needs to get reactive power (VAR) capability from the Generator Owner(s) for planning and coordination studies.

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Table 2 Excerpt — Device 40 Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
40 – Loss of Field (LOF)	Settings used for planning and system studies	• Out-of-Step — survive stable swings • Preventing encroachment on reactive capability curve • Transmission Owner(s) need to exchange Reactive power (VAR) capability from Generator Owner(s) • See details from sections 4.5.1 & A.2.1 of C37.102-2006 • The setting information for the LOF relay should be provided by the Generator Owner to the Transmission Owner and Planning Coordinator in order for this information to be available to the appropriate planning entity. The impedance trajectory of most units with a lagging power factor (reactive power into the power system) for stable swings will pass into and back out of the first and second quadrants. It is imperative that the LOF relay does not operate for stable power swings. • The LOF relay settings must be provided to the appropriate planning entity by the Generator Owner so that the planning entity can determine if any stable swings encroach long enough in the LOF relay trip zone to cause an inadvertent trip. The appropriate planning entity has the responsibility to continually verify that power system modifications never send stable swings into the trip zone(s) of the LOF relay causing an inadvertent trip. If permanent modifications to the power system cause the stable swing impedance trajectory to enter the LOF characteristic, then the planning entity must notify the Transmission Owner who in turn must notify the Generator Owner that new LOF relay settings are required. The planning entity should provide the new stable swing impedance trajectory so that the new LOF settings will accommodate stable swings with adequate time delay. The new settings must be provided to the planning entity from the Generator Owner through the Transmission Owner for future continuous monitoring. • Transmission Owners must provide system information and appropriate parameters to enable the Generator Owners to conduct a system study. This enables the Generator Owner to fine tune LOF settings if required.

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3.5.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

Table 3 Excerpt — Device 40 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: loss of field characteristics, including time delays, at the generator terminals.	~~Impedance trajectory from system stability studies for the strongest and weakest available system.~~ The Transmission Owner provides the Planning Coordinator with the worst case clearing time for each of the power system elements connected to the transmission bus at which the generator is connected.	Impedance trajectory from system stability studies for the strongest and weakest available system. Feedback on problems found in coordination and stability studies

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3.6. Negative Phase Sequence or Unbalanced Overcurrent Protection (Device 46)

3.6.1. Purpose of the Generator Device 46 — Negative Phase Sequence Overcurrent Protection

The Device 46 protection uses the measurement of negative sequence current produced by the unbalanced conditions of the system to which the generator is connected. Section 4.5.2 of the IEEE C37.102-2006 — Guide for AC Generator Protection describes the purpose of this protection as follows:

> *"There are a number of system conditions that may cause unbalanced three-phase currents in a generator. The most common causes are system asymmetries (untransposed lines), unbalanced loads, unbalanced system faults, and open phases. These system conditions produce negative-phase-sequence components of current that induce a double-frequency current in the surface of the rotor, the retaining rings, the slot wedges, and to a smaller degree, in the field winding. These rotor currents may cause high and possibly dangerous temperatures in a very short time.*
>
> *The ability of a generator to accommodate unbalanced currents is specified by IEEE Std C50.12, IEEE Std C50.13, and IEC 60034-1 in terms of negative-sequence current (I_2). This guide specifies the continuous I_2 capability of a generator and the short time capability of a generator, specified in terms $I^2_2t=K$, as shown in Figure 4-39 (curve drawn using data from IEEE Std C50.13."*

Negative sequence component of current is similar to the positive sequence system, except that the resulting reaction field rotates in the opposite direction to the DC Field system. Hence, a flux is produced which cuts the rotor at twice the rotational velocity, thereby inducing double frequency currents in the field system and in the rotor body. The resulting eddy-currents can be very large and cause severe heating of the rotor.

Negative Sequence Overcurrent protection often includes two settings: one very sensitive setting that alarms for operator action, and a less-sensitive setting that results in tripping.

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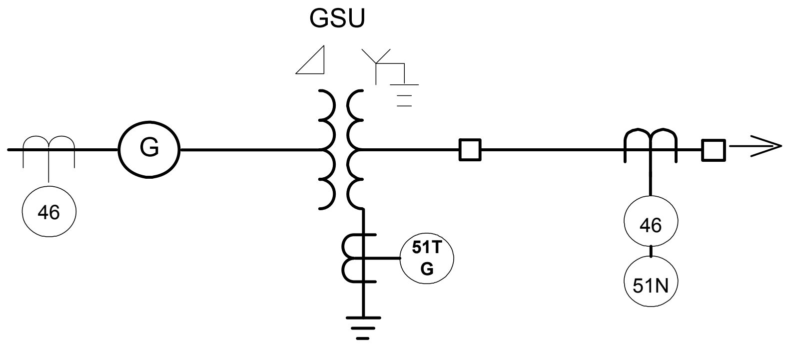

Figure 3.6.1 — Negative Phase Sequence Protection Coordination

3.6.2. Coordination of Generator and Transmission System

3.6.2.1. Faults

Step 1 — The Transmission Owner determines longest clearing time including breaker failure time for phase-to-phase and phase-to-ground faults.

Step 2 — The Transmission Owner and Generator Owner verify that the generator negative sequence relay time delay is properly coordinated with appropriate margin with the time delays determined in Step 1.

The transmission system design and operation of protection must take into consideration generator negative sequence concerns and capabilities:

Areas that need to be addressed by both the transmission and Generator Owners are:

- Single-pole tripping (or other open-phase conditions such as single-phase disconnect switch operation) on the transmission system will cause high short-term negative sequence currents until balanced operation is restored.
- Unbalanced faults will result in negative sequence currents until the fault is cleared.
- Open phases such as a pole on a circuit breaker

3.6.2.2. Loadability

At maximum generator output, there should be no negative sequence alarm.

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3.6.3. Considerations and Issues

For further discussion of negative sequence current protection see Section A.2.8 of C37.102-2006 — Guide for AC Generator Protection

The negative sequence protection function needs to be coordinated with all transmission system unbalanced fault protection.

- If there is alarm, both the Transmission Owner and Generator Owner must work together to resolve the alarm.
- Untransposed transmission lines can result in negative sequence current circulation on the transmission system, which can be reflected into generators and thus cause negative sequence overcurrent operation.

3.6.4. Coordination Procedure

The following areas should be examined to provide proper protection against excessive negative sequence current effects: short-time unbalanced current factor (K), and continuous negative sequence current level (%).

Refer to ANSI C37.102-2006, clause 4.5.2, and C50.12-2005, clause 4.1.6.1, respectively.

3.6.5. Example

3.6.5.1. Proper coordination

The Generator Negative Sequence Protection when set according to the IEEE Guide C37.102 will generally coordinate with system protection for unbalanced fault conditions due to the set point time delay. Even at 100 percent negative sequence current it will take seconds for the protection to trip the generator which is desired to protect the generator. The Generator Owner and Transmission Owner need to discuss the magnitude of negative sequence current resulting from open phases, untransposed lines and other operational unbalances exhibited by the Transmission system, and ensure that the generator negative sequence relay will not trip the generator for

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negative sequence currents that are less than the allowable continuous negative sequence current ratings of the machine.

Generator Name plate:

- Continuous negative sequence capability of the generator: 10%
- The K factor ($I_2^2 t = K$): 30

Relay Settings:

Inverse Time Element

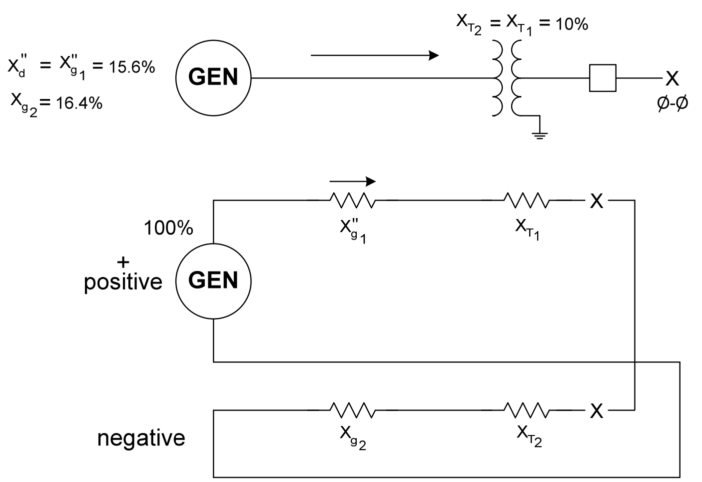
- Pick-up for the inverse time element ($I_2^2 t = K$) = 9 %
- K = 29

Set Definite Time Element for Alarm

- Pickup = 5%
- Time delay = 30 seconds

3.6.5.2. Time Delay Coordination

As an example the following generator configuration is used to verify coordination:



$$I_1 = I_2 = \frac{100}{X_{g1} + 2X_T + X_{g2}} = \frac{100}{15.6 + 20 + 16.4} = 1.92 \text{ pu}$$

Figure 3.6.2 — Sequence Diagram of a Phase-to-Phase Fault

The time delay of the inverse time element for 1.92 per unit negative sequence current is:

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$t = K/I_2^2 = 29/1.92^2 = 7.866$ sec.

This time delay is much longer than the second zone transmission line phase to phase fault protection time delay including the breaker failure time. The coordination is not a concern.

3.6.5.3. Improper Coordination

Proper setting of the time delays associated with negative sequence functions will inherently coordinate with system protection due to the wide disparity in time constants between the two protection systems.

3.6.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 46 Protection Coordination Data Exchange Requirements

Generator Protection Device	Transmission System Protection Relays	System Concerns
46 — Negative phase sequence overcurrent	21 21G 46 67N 51N Longest time delay of transmission system protection including breaker failure time	• Should be coordinated with system protection for unbalanced system faults • Plant and system operations awareness when experiencing an open-pole on the system • Transposition of transmission lines • System studies, when it is required by system condition • Open phase, single-pole tripping • Reclosing • If there is alarm, Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator and they must work together to resolve the alarm

3.6.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

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Table 3 Excerpt — Device 46 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings: negative phase sequence overcurrent protection characteristics, including time delays, at the generator terminals. Generator Owners must provide I_2 measurements to the Transmission Owner and Planning Coordinator for resolution if significant unbalance is observed.	The time-to-operate curves for system relays that respond to unbalanced system faults. This would include the 51TG ~~id~~if the GSU is owned by the Transmission Owner.	None

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3.7. Inadvertent Energizing Protection (Device 50/27)

3.7.1. Purpose of the Generator Device 50/27 — Inadvertent Energizing Protection

Inadvertent Energizing Protection uses a measurement of both generator terminal voltage and generator stator current to detect this condition as described in Section 5.4 of the IEEE C37.102-2006 — Guide for AC Generator Protection that describes the purpose of this protection as follows:

> *"Inadvertent or accidental energizing of off-line generators has occurred often enough to warrant installation of dedicated protection to detect this condition. Operating errors, breaker head flashovers (see 4.7.1), control circuit malfunctions, or a combination of these causes has resulted in generators being accidentally energized while off-line. The problem is particularly prevalent on large generators that are commonly connected through a disconnect switch to either a ring bus or breaker-and-a-half bus configuration. These bus configurations allow the high voltage generator breakers to be returned to service as bus breakers, to close a ring bus or breaker-and-a-half bay when the machine is off-line. The generator, under this condition, is isolated from the power system through only the high-voltage disconnect switch. While interlocks are commonly used to prevent accidental closure of this disconnect switch, a number of generators have been damaged or completely destroyed when interlocks were inadvertently bypassed or failed and the switch accidentally closed. When a generator on turning gear is energized from the power system (three-phase source), it will accelerate like an induction motor. The generator terminal voltage and the current are a function of the generator, transformer, and system impedances. Depending on the system, this current may be as high as 3 pu to 4 pu and as low as 1 pu to 2 pu of the machine rating. While the machine is accelerating, high currents induced into the rotor may cause significant damage in only a matter of seconds. If the generator is accidentally back fed from the station auxiliary transformer, the current may be as low as 0.1 pu to 0.2 pu. While this is of concern and has occurred, there have not been reports of extensive generator damage from this type of energizing; however, auxiliary transformers have failed."*

When a generator is off-line on turning gear and is inadvertently energized from the power system, it will develop an inrush current (similar to an induction motor start) that can be as high as 300 percent to 400 percent of the generator name plate (rating). This inrush current subjects the turbine shaft and blades to large forces, and with rapid overheating of the stator windings and potential for damage due to the excessive slip frequency currents. The impedance of the transformer and the stiffness of the system dictates the level of inrush current.

This protection is required when the unit is off-line and may or may not be armed when the unit is in service and connected to the system.

A significant number of large machines have been severely damaged, and in some cases, completely destroyed due to inadvertent energizing.

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Figure 3.7.1 shows a typical inadvertent energizing protection scheme.

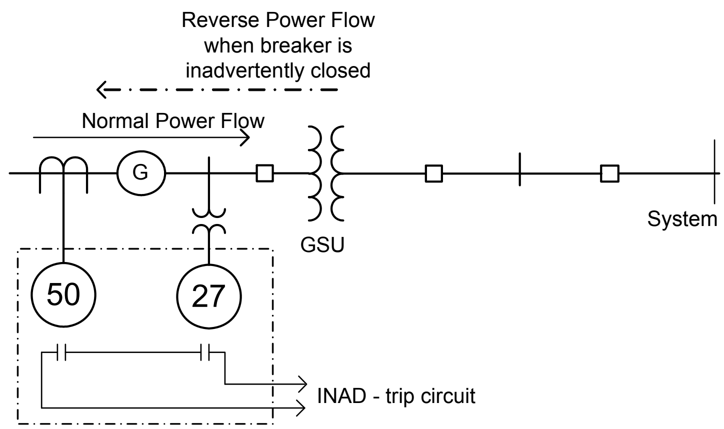

Figure 3.7.1 — Inadvertent Energizing (INAD) Protection Scheme

3.7.2. Coordination of Generator and Transmission System

3.7.2.1. Faults

Step 1 — Generator Owner ~~and Transmission Owner verify~~verifies the voltage supervision pick-up is 50 percent or less, as recommended by C37.102.

- It is highly desirable to remove the inadvertent energizing protection from service when the unit is synchronized to the system, or at a minimum, be provided with appropriate secure supervision, to assure that this function does not operate for synchronized generators during system disturbances with reduced voltages.
- The inadvertent energizing protection must be in service when the generator is out-of-service. If this function is not disarmed while the unit is in service, then in addition to assuring an undervoltage set point of less than 50 percent nominal the timer setting should be long enough to avoid undesired operations (two seconds or greater).

In the August 14, 2003 disturbance, system voltage was depressed significantly. During that event, seven units using inadvertent ~~energization~~energizing schemes operated on synchronized generators due to depressed voltage and unnecessarily

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removed those units from the system. It is believed that these units had the undervoltage supervision set higher than the recommended set point (i.e., the supervision was not set less than 50 percent of nominal voltage).

3.7.2.2. Loadability

There are no loadability concerns with this protection device.

3.7.3. Considerations and Issues

The undervoltage (27) supervision function must be set lower than 50 percent of the nominal voltage level or lower. The setting should be developed based on the specific application and engineering analysis.

3.7.4. Coordination Procedure

3.7.4.1. Test Procedure for Validation

Check that the device 27 is set lower than 50 percent of the nominal voltage level or lower based on the specific application and engineering analysis.

3.7.4.2. Setting Considerations

- The device 27 must be set lower than 50 percent of the nominal voltage level or lower to avoid undesired operations.
- Instantaneous overcurrent (device 50) relay (or element) should be set most sensitive to detect inadvertent energizing (Breaker Close).

3.7.5. Example

3.7.5.1. Proper Coordination

Undervoltage supervision settings of less than 50 percent of nominal voltage, or lower, and more than two seconds of time delay will reduce the possibility of undesired tripping. Note: Inadvertent Energizing schemes will be initiated when a condition exists with (1) overcurrent (undesired unit energizing), and (2) undervoltage (unit being off-line) with a delay time.

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3.7.5.2. Improper Coordination

Use of undervoltage supervision settings of greater than 50 percent nominal voltage, or use of time delays of less than two seconds will greatly increase the possibility of undesired tripping.

3.7.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 50 / 27 (Inadvertent Energization) Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
50 / 27 — Inadvertent energizing	None	• The device 27 must be set lower than 50 percent of the nominal voltage. • Instantaneous overcurrent (device 50) relay (or element) should be set to the most sensitive to detect inadvertent energizing (Breaker Close). • Timer setting should be adequately long to avoid undesired operations due to transients. • Relay elements (27, 50 and timers) having higher Dropout Ratio (ratio of dropout to pickup of a relay) should be selected to avoid undesired operations.

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3.7.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination.

Table 3 Excerpt — Device 50 / 27 (Inadvertent Energization) Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Under voltage setting and current detector settings pick-up and time delay	Review method of disconnect and operating procedures.	None

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3.8. Breaker Failure Protection (Device 50BF)

3.8.1. Purpose of the Generator Device 50BF — Breaker Failure Protection

Breaker Failure Protection uses a measurement of breaker current to detect this condition as found in Section 4.7 of the IEEE C37.102-2006 — Guide for AC Generator Protection describes the purpose of this protection as follows (emphasis added):

> *"Functional diagrams* **(from the IEEE ~~Standard~~Guide)** *of two typical generator zone breaker failure schemes are shown in Figure 4-52a and Figure 4-52b. Like all such schemes, when the protective relays detect an internal fault or an abnormal operating condition, they will attempt to trip the generator and at the same time initiate the breaker-failure timer. If a breaker does not clear the fault or abnormal condition in a specified time, the timer will trip the necessary breakers to remove the generator from the system. As shown in Figure 4-52a, the breaker-failure timer is initiated by the combination of a protective relay and either a current detector (CD) or a breaker "a" switch, which indicates that the breaker has failed to open. Figure 4-52b shows a variation of this scheme that times out and then permits the CD to trip if current continues to flow. The reset time of the CD need not enter into the setting of the BF timer. The breaker "a" switch is used since there are faults and/or abnormal operating conditions such as stator or bus ground faults, overexcitation (V/Hz), excessive negative sequence, excessive underfrequency, reverse power flow, etc., that may not produce sufficient current to operate the CDs. If each pole of the breaker operates independently, breaker "a" switches from all three poles should be paralleled and connected into the logic circuit."*

Breaker failure protection must be provided for large generators such that the generator is isolated in the event when its breakers fail to open subsequent to receiving a signal to trip.

When a generator unit breaker fails, it is required to initiate the tripping of backup breaker(s) for isolation of failed breaker. Figures 3.8.1 and 3.8.2 describe breaker failure relaying as it relates to generator and transmission line breaker failures.

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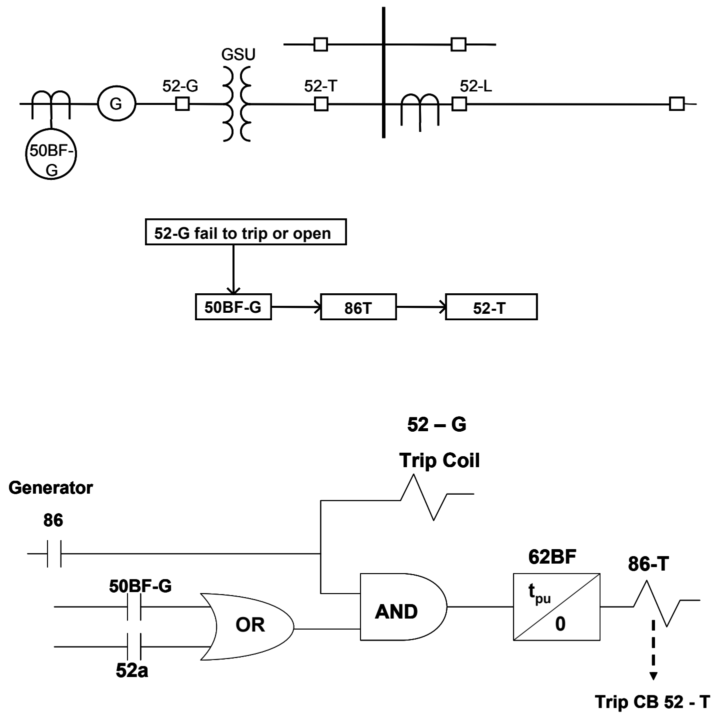

Figure 3.8.1 — Unit Breaker Failure Logic Diagram

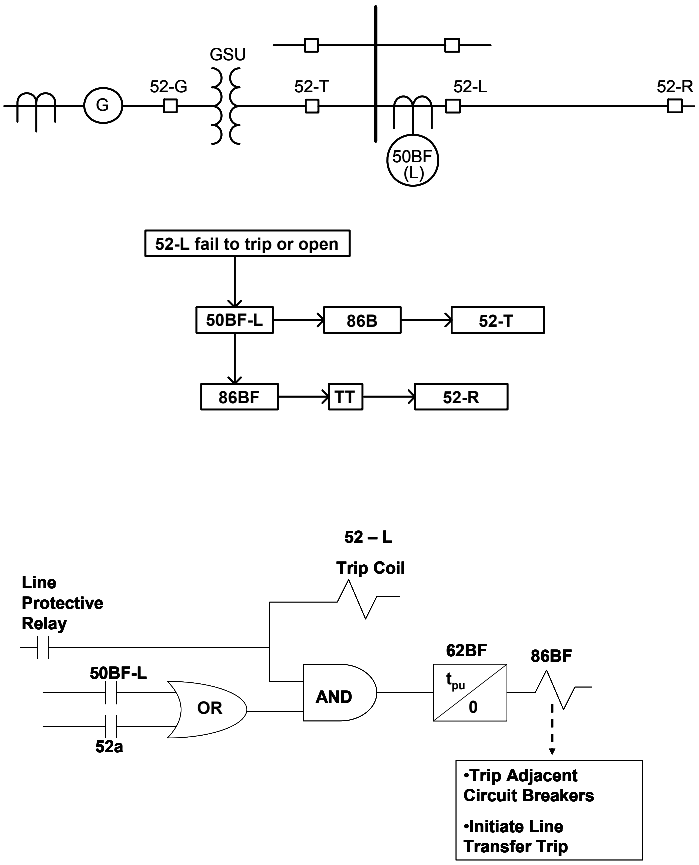

Figure 3.8.2 — Line Breaker Failure Logic Diagram

3.8.2. Coordination of Generator and Transmission System

3.8.2.1. Faults

The following coordination issues must be addressed:

Transmission Owner and Generator Owner for each set of relay coordination; verify that breaker failure time is accounted for properly.

For example,

- All generator unit backup relaying schemes are required to coordinate with protective relays on the next zone of protection including their breaker failure relaying time.
- For obtaining the security and reliability of power system stability, Generator Owner and Transmission Owner(s) are required to coordinate, plan, design, and test the scheme.
- There must be design coordination to assure that appropriate backup breakers are tripped for breaker failure operation.

3.8.2.2. Loadability

There are no loadability issues to be addressed.

3.8.3. Considerations and Issues

All upstream (next level) protection settings and systems must be considered when evaluating the performance of breaker failure devices associated with generators. Total clearing time, which includes breaker failure time, of each breaker in the generation station switchyard should coordinate with the critical clearing times associated with unit stability.

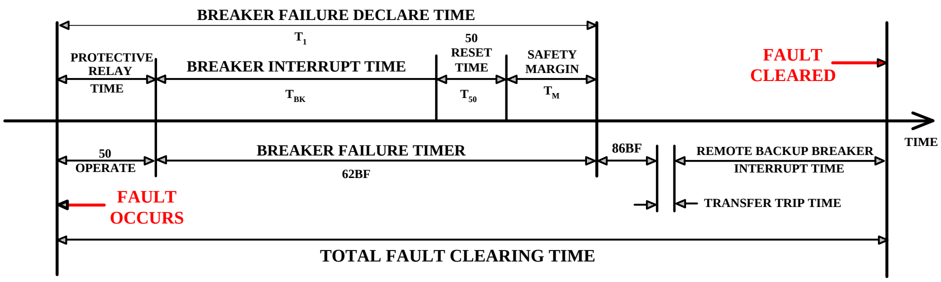

Figure 3.8.3 — Example of Breaker Failure Timing Chart[4]

[4] This chart is excerpted from the IEEE Std. C37.119-2005 "Guide for Breaker Failure Protection of Power Circuit Breakers."

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The following are examples of Breaker Failure Timer Settings (62BF) of a Breaker Failure Scheme for typical three-and five- cycle breakers:

Three Cycle Breaker — Breaker Failure Timer = Breaker Interrupting Time +50 Reset Time + Safety Margin

62BF = TBK + T50 + TM = 3.0 + 1.55 + 5.0 = 9.55 cycles or 159 milliseconds

Five Cycle Breaker — Breaker Failure Timer Setting (62BF) of Breaker Failure Scheme on Power Circuit Breaker - 3:

62BF = TBK + T50 + TM = 5.0 + 1.55 + 5.0 = 11.55 cycles or 193 ms

3.8.4. Coordination Procedure

3.8.4.1. Setting Considerations

- Total clearing time, which includes breaker failure time, of each breaker in the generation station switchyard should coordinate with the critical clearing times associated with unit stability. To provide proper Breaker Failure (BF) protection, the following should be considered: See C37.119 "IEEE Guide for Breaker Failure Protection of Power Circuit Breakers" for a well-designed breaker failure scheme.
- Clearing time issues are addressed further in Sections 4.7 and A.2.11 of C37.102-2006 — Guide for AC Generator Protection.
- Refer to Section 3.1 for coordination of upstream protective device 21 with the breaker failure scheme.

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3.8.5. Example

3.8.5.1. Proper Coordination – Critical Breaker Failure Coordination

This example addresses coordination with line relaying and line breaker failure conditions.

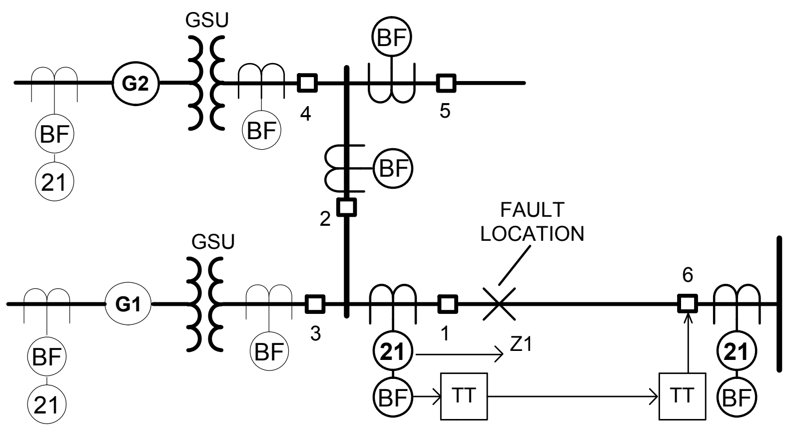

Figure 3.8.6 — Case-1 – Breaker Failure Coordination

To detect a fault within the zone 1 reach of the line beyond breaker-1 in Figure 3.8.4, the distance backup relaying (device 21) on generator G2 should be set far enough to detect the fault, with the fault contribution from the line connected to breaker-5, and the fault contribution from G1. Under minimum infeed, the reach of the G2 relay may extend beyond the zone 1 reach of the relaying for the line beyond breaker-1. In order to prevent misoperation, the time delay of the G2 relay must be set longer than the total time associated with a failure of breaker-1 to clear the fault and the resultant tripping of breaker-2. This time will be the summation of the breaker-1 line relaying zone 2 operating time and delay, breaker failure time delay for breaker-1, BF lockout time and breaker-2 clearing time.

In this example, G1 is lost whenever breaker-1 suffers a BF condition. However, the G1 backup distance protection must be set with a time delay long enough to allow the normal clearing of breaker-1 with some additional time coordination margin, or the mirror image of this example for breaker-5 coordination.

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In the example shown, a breaker-1 BF condition also sends direct transfer trip to breaker-6 to speed remote clearing if this line does not have pilot protection and to prevent breaker-6 from reclosing into the failed breaker.

3.8.5.2. Improper Coordination

Improper coordination results when upstream protective devices react faster than the breaker failure function.

3.8.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 50BF Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
50BF — Breaker failure (plant) on synchronizing breaker(s)	Critical clearing times from system stability studies 50BF on line(s) & buses	• Check for single-points-of-failure • Current and 52a contact considerations • Critical clearing time • Coordination with ~~Z2 & Z~~zone 2 and zone 3 timers • Settings should be used for planning and system studies • Line distances relay reach and time delay settings with respect to each generator zone. • Bus differential relay (usually instantaneous) timing for HV bus faults including breaker failure adjacent bus. • Line and Bus Breaker failure timers and line ~~Z1 & Z~~zone 1 and zone 2 timers on all possible faults. • Type of protective relays, Manufacturers, Models, etc. • Single line diagram(s) including CTs and VTs arrangement • PCB test data (interrupting time)

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3.8.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above examples.

Table 3 Excerpt — Device 50BF Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Times to operate of generator protection Breaker Failure Relaying times	Times to operate, including timers, of transmission system protection Breaker Failure Relaying times	None

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3.9. GSU Phase Overcurrent (Device 51T) and Ground Overcurrent (Device 51TG) Protection

3.9.1. Purpose of the GSU Device 51T — Backup Phase and Device 51TG – Backup Ground Overcurrent

3.9.1.1. GSU Backup Phase Overcurrent Protection — Device 51T

Neither IEEE C37.91 nor IEEE C37.102 supports the use of a phase overcurrent relay for backup protection for faults in both the GSU and generator, or for system faults. This applies regardless of whether the phase overcurrent protection applied is a discrete device or an overcurrent function in a multi-function protective device, such as overcurrent phase elements associated with restraint inputs on microprocessor differential relays.

IEEE C37.102 provides the following concerning phase overcurrent backup protection from Section 4.6.1.2 as follows:

In general, a simple time-overcurrent relay cannot be properly set to provide adequate backup protection. The pickup setting of this type of relay would normally have to be set from 1.5 to 2 times the maximum generator rated full-load current in order to prevent unnecessary tripping of the generator during some emergency overload condition. The settings should be reviewed to ensure that the relay will not operate during a system emergency, where the generator terminal voltage will be depressed and the rotor currents will be higher.

With this pickup setting and with time delays exceeding 0.5 s, the simple time-overcurrent relay may never operate since the generator fault current may have decayed below relay pickup. After 0.5 s or more, generator fault current will be determined by machine synchronous reactance and the current magnitude could be well below generator rated full-load current, which would be below the relay setting.

Figure 3.9.1 shows a multifunction transformer differential relay with the phase overcurrent element associated with the high-side GSU restraint enabled. However, these devices could be discrete devices also. As quoted above, IEEE C37.102 indicates that 51T relay pickup must be set from 1.5 to 2.0 of the generator rated full-load current. Based on information concerning field forcing found in section 3.1, this

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Technical Reference requires that pick up for the 51T must be at least 2.0 times the generator full-load rating. The use of 51T phase overcurrent protection for the GSU transformer phase overcurrent protection is STRONGLY discouraged due to coordination issues that are associated with fault sensing requirements in the 0.5 second or longer time frame

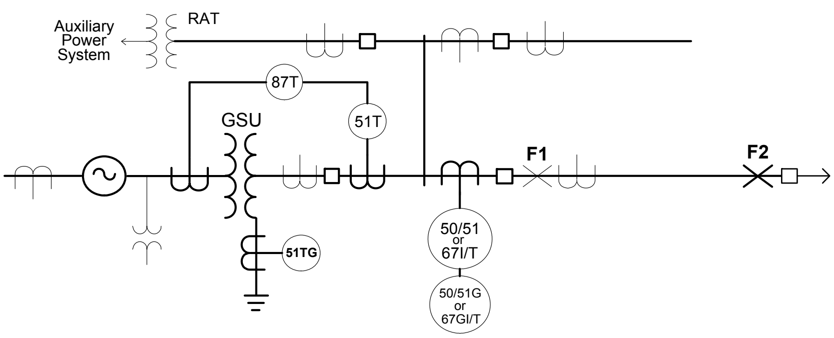

Figure 3.9.1 — Phase & Ground Backup Overcurrent Relays on GSU Transformer

3.9.1.2. GSU Backup Ground Overcurrent Protection — Device 51TG

The ground overcurrent device 51TG, as shown in Figure 3.9.1, is used to provide generator and GSU ground backup overcurrent protection for uncleared system ground faults. The ground backup overcurrent relay 51TG is connected to detect the ground current provided by the GSU transformer when connected as a ground source. It has no loading requirements, so it can be set for fault considerations. However, it should accommodate the worst-case system imbalance anticipated at the GSU. From a time/overcurrent perspective, the ~~51GT~~51TG needs to coordinate with the longest clearing time of the transmission ground protection systems as required by its application and the GSU transformer damage curve.

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3.9.2. GSU and Transmission System Coordination for Overcurrent Devices

3.9.2.1. Faults

Use of a GSU phase overcurrent element (51T) for backup protection is strongly discouraged. This document has two sections that describe relay elements that are better designed for this function (see section 3.1) for the distance function and see section 3.10 for the voltage supervised overcurrent protection function. These sections describe the use and application of phase distance and voltage supervised overcurrent relaying to provide the best phase backup protection that can be coordinated between the protective relaying of a Generator Owner and Transmission Owner. However, for completeness the issues required to utilize the 51T backup overcurrent protection function will be covered in this section. When used, the 51T function and associated settings need to consider the following:

- The 51T must be set to pickup for the worst-case backup fault on the transmission system based on the application. See the loadability section for compete requirements to determine 51T pickup.
- The 51T must have sufficient time delay with adequate margin to coordinate with the worst-case clearing time of the transmission protection with breaker failure clearing times included.
- The 51T must be set such that the generator has the ability to produce the fault current long enough to complete the overcurrent backup function.
- The 51T must meet the loadability requirements outlined in section 3.9.2.2.

The 51TG is used to backup uncleared system faults and must meet the following considerations for fault coordination:

- The 51TG must be set to pickup for the worst-case fault on the transmission system. The pickup value for the 51TG must also be capable of accommodating the greatest system imbalance with margin anticipated at the GSU.
- The 51TG must have sufficient time delay with adequate margin to coordinate with the worst-case clearing time of the transmission protection with breaker failure clearing times included.

The 51TG backup overcurrent provides backup and time delayed protection for ground faults when primary relaying or equipment does not operate properly. Relay

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failure and stuck breaker are two examples when the 51TG might be able to provide protection of the GSU. Great care must be used in determining the sensitivity (pickup value) and selectivity (time to operate value) in order to complete the backup function without causing any misoperation.

3.9.2.2. Loadability

The 51T device has the following loadability requirement:

- The 51T must have as a minimum 200 percent of the generator MVA rating at rated power factor.

The above requirement allows a generator to remain online through extreme operating system events, by allowing a generator to utilize it full capability of field forcing.

Note: Any 51 device utilized from the generator or GSU multi functional protective relays must meet the above loadability requirement.

3.9.3. Considerations and Issues for Utilizing 51T and 51TG

As noted above concerning the 51T function, other protective functions are available to provide this backup protection while providing better coordination with the transmission and generator protections.

The 51TG backup overcurrent provides backup and time delayed protection for ground faults when primary relaying or equipment does not operate properly. Relay failure and/or stuck breaker are example(s) when the 51TG might be able to provide protection for the GSU. The value of 51TG is that it covers that once in a lifetime event where a breaker's protective relaying and breaker failure relaying are unable to clear a transmission line fault. Great care must be used in determining the sensitivity (pickup value) and selectivity (time to operate value) in order to complete the backup function without causing any misoperation.

Device 51TG should be set to detect and operate for non-cleared transmission bus and line faults based on its application design requirements. When its application is for a generating station and system configuration that are simple (see figure 3.9.1), it is generally not difficult to obtain reasonable relay settings for 51TG.

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Refer to IEEE C37.102 section 4.6 and all subsections 4.6.1 – 4.6.4 for recommendations on setting the 21, 51V, and 51TG relays, and refer to the references in IEEE C37.102 that discourage the use of the 51T. The performance of these relays, during fault conditions, must be coordinated with the system fault protection to assure that the sensitivity and timing of the relaying results in tripping of the proper system elements, while permitting the generator to stay on line during system stressed conditions. Once the coordination is determined between the Generator and Transmission Owners for the 51T, the Generator Owner must evaluate coordination between the 51T and the GSU and generator protection for the fault current available from the system to ensure complete coordination. Short-circuit studies are required to determine fault values for which the overcurrent functions must operate and coordinate.

3.9.4. Coordination Procedure

3.9.4.1. Coordination of Device 51T

Device 51T must be set to the following requirements:

- The 51T must have a minimum pickup of twice the generator MVA rating at rated power factor.
- The 51T must operate slower with margin than the slowest transmission protection system that it must coordinate with based on protection design including breaker failure time.
- The 51T must sense the required fault based on the transmission protection design with the fault current available from the generator in the time frame that it is set to operate.
- The Generator Owner must determine that the setting for the 51T that coordinates with the transmission protection will also coordinate with the generator protection systems for the fault current available from the transmission system.

3.9.4.2. Coordination of Device 51TG

Device 51TG must be set to the following requirements:

- The 51TG must have a pickup with margin greater than the largest non–-fault system imbalance anticipated based on system design.

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- The 51TG must operate slower with margin than the slowest transmission protection system that it must coordinate with based on protection design including breaker failure time.

3.9.5. Example

3.9.5.1. Proper Coordination

For the system shown in Figure 3.9.2 below, coordination of the generation and transmission protection is described with the following assumptions. It will be assumed for the system shown that the transmission protection systems are overcurrent non-redundant schemes. It is also assumed that the line with fault locations F1 and F2 presented the worst-case coordination requirements for the generator backup protection. Also, the line used for a reserve auxiliary transformer (RAT) for the unit is out of service during normal operation. The line shown without a breaker termination at the remote terminal supplies a near by load with no fault contribution. Current transformer ratio for the HV side GSU transformer and the line protection are 3Y-2000/5A (CTR=400:1), multi-ratio CTs. The generator loadability requirement will be twice the unit MVA rating which is equal to twice the GSU Rating.

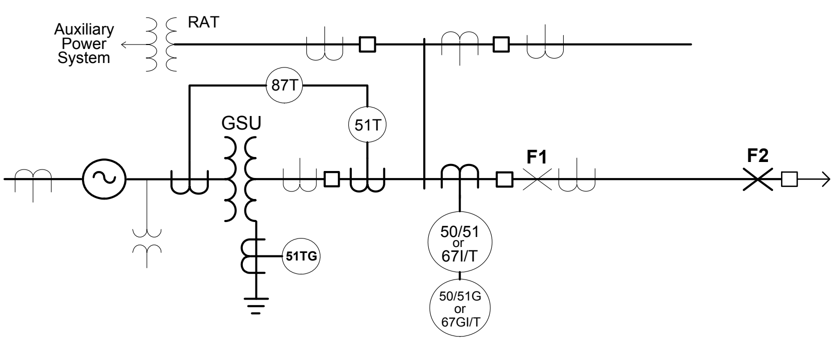

Figure 3.9.2 — Phase & Ground Backup Overcurrent Relays on GSU Transformer

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3.9.5.1.1. Settings for Device 51T

Step 1 — Rated current = $\frac{425MVA}{138kV\sqrt{3}}$ = 1,778 A, primary = (1,778A/400) = 4.445 A, secondary

Step 2 — Select a relay characteristic curve. [Note: Curve is typically chosen to match the curve used by the Transmission Owner i.e. a Very-Inverse Curve.]

Step 3 — Tap Setting of 51T = 2 X I rated = (4.445A) X (2) = 8.89A; choose Tap = 9.0A

Step 4 — From short-circuit studies; obtain the 3ϕ through-fault current for the fault located on the generator bus shown as F1 in the diagram. $I_{3\phi}$=11,587-A, primary through-fault current on GSU transformer. Relay current = 11,587 A, primary/400 = 28.96 A, secondary

Step 5 — Multiple = (relay current) / (Tap) = 28.96A/9.0A = 3.21, choose a Time Dial such that a time equal to approximate 30 cycles more than the slowest transmission overcurrent setting. The time delay setting with margin will result in a time setting in the 60 – 90 cycles range. The 30 cycles margin will accommodate breaker failure clearing timers up to 20 cycles with margin.

Step 6 — Ensure coordination with all appropriate transmission system protection elements. If the overcurrent relay will be used to backup the line protective relays then the minimum end line contribution from the generator has to be approximately 4,500 Amps or higher in the appropriate time range. Otherwise, the 51T will fail to operate as a backup protective element for the reasons stated throughout this section, resulting in the need to choose an overcurrent device with appropriate supervision to provide the overcurrent backup protection function. The 4,500 Amps was determined by taking the 51T relay pickup (400 x 9.0) x a margin of 1.25 as a minimum. This would be represented as F2 in Figure 3.9.2.

Step 7 — The Generator Owner takes the information concerning the 51T in the plot and determines that it will coordinate with the other generator protection for the available transmission system fault current for GSU and generator faults.

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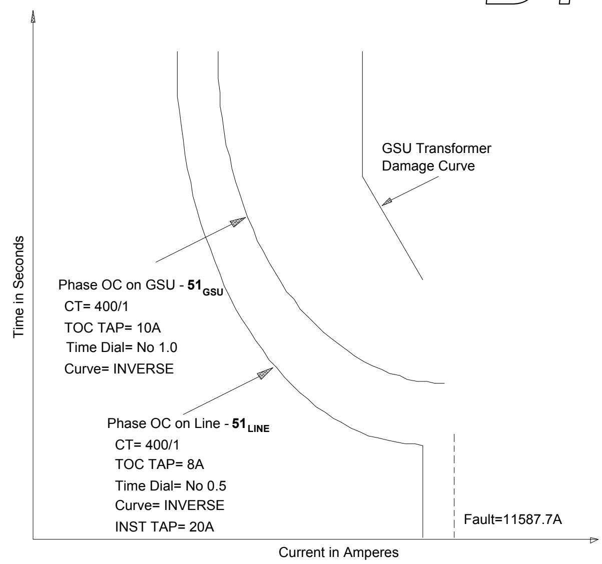

Figure 3.9.3 — Device 51TGSU & 51LINE (G or N) Overcurrent Relay Coordination Curves

3.9.5.1.2. Setting for the 51TG

Assumption: current transformer ratio for the neutral CT on the GSU transformer is 1-600/5A (CTR=120:1), multi-ratio.

Step 1 — Obtain 3I0 current from short-circuit studies for fault location F2 (the primary minimum fault current provided from the neutral of the GSU that must be detected by 51TG). F2 = 1930 Amperes primary.

Step 2 — Select a relay characteristic curve. [Note: Curve is typically chosen to match the curve used by the Transmission Owner, i.e. a very-inverse curve.]

Step 3 — Tap Setting of 51TG [Note: Tap is typically selected based on available minimum short-circuit current (F2) and current transformer ratio on the neutral of GSU transformer (120:1) such that two or higher times pickup is available for the fault that represents the minimum ground current that the 51TG is suppose to provide backup protection for a fault at F2, while providing for the worst case system imbalance.]. 51TG tap setting = (F2)/(2.0 margin *CTR) = 1930 Amp/(2.0 * 120) = 8.04, choose 8.0 tap.

Step 4 — From short-circuit studies; obtain the $3I_0$ through-fault current for the fault located on the generator bus shown as F1 in the diagram. $3I_0$ = 7,556-A,

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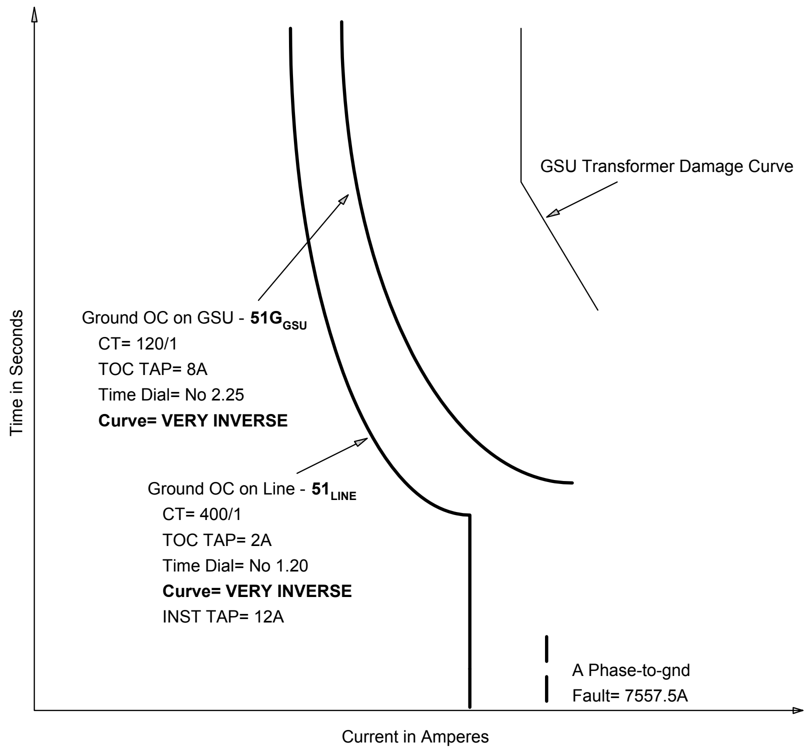
primary from the neutral of GSU transformer. Relay current = 7,556A/120 = 62.96A, secondary

Step 5 — Multiple = (relay current) / (Tap) = 62.96/8A = 7.87, choose a Time Dial equal to approximate 30 cycles or more than the slowest transmission overcurrent setting. The time delay setting with margin will result in a time setting in the 60 – 90 cycles range. The 30 cycle margin will accommodate



breaker failure clearing timers up to 20 cycles with margin.

Figure 3.9.4 — Device 51TG Overcurrent Relay Characteristic Curve

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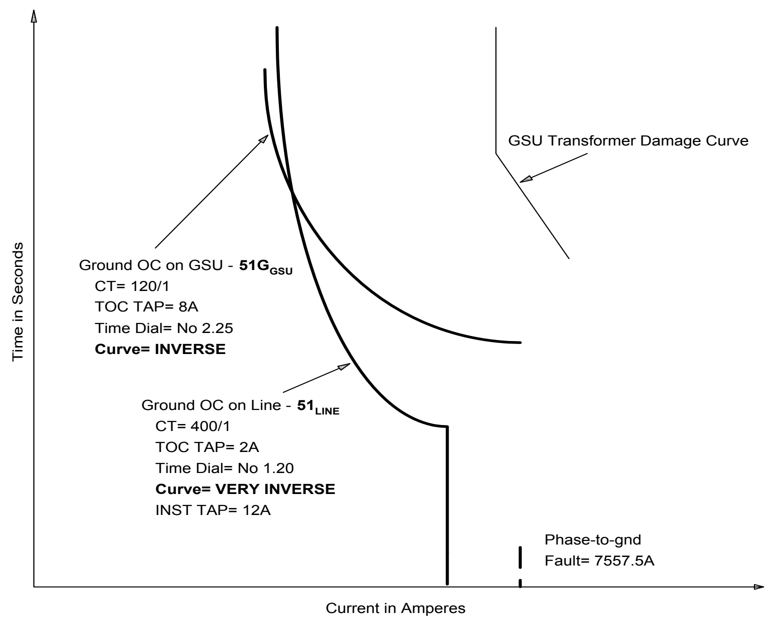
3.9.5.2. Improper Coordination

The miscoordination between the $51G_{LINE}$ (or $51N_{LINE}$) and the $51G_{GSU}$ is due to the selection of dissimilar curves for one-on-one coordination as was required in the above example. $51G_{LINE}$ is a very inverse curve and the $51G_{GSU}$ is an inverse curve.



Use similar curves to fix the mis-coordination.

Figure 3.9.5 — Mis-Coordination of 51GLINE and 51GGSU Settings

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3.9.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Devices 51T / 51TG Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
51T — Phase fault backup overcurrent 51TG — Ground fault backup overcurrent	51 67 51G 51N 67N Open phase, single-pole tripping an reclosing	• Must have adequate margin over GSU protection and nameplate rating • 51T not recommended, especially when the Transmission Owner uses distance ~~relays.~~line protection functions • Generator Owners(s) needs to get Relay Data (devices 51, 67, 67N, etc) and Single line diagram (including CT and PT arrangement and ratings) from Transmission Owner(s) for device 51T coordination studies • Transmission Owner(s) needs to get ~~Transformer~~transformer data (tap settings, available fixed tap ranges, impedance data, the +/- voltage range with step-change in percent for load-tap changing GSU transformers) from Generator Owner(s) or Operator(s)

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3.9.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example.

Table 3 Excerpt — Devices 51T / 51TG Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings **Device 51T** -— Phase fault backup overcurrent **Device 51TG** -— Ground fault backup overcurrent	One line diagram of the transmission system up to one bus away from the generator high-side bus.	Feedback on coordination problems found in stability studies.
Relay timer settings.	Impedances of all transmission elements connected to the generator high-side bus.	~~None~~

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Table 3 Excerpt — Devices 51T / 51TG Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Total clearing times for the generator breakers.	Relay settings on all transmission elements connected to the generator high-side bus.	~~None~~
None	Total clearing times for all transmission elements connected to the generator high-side bus.	~~None~~
None	Total clearing times for breaker failure, for all transmission elements connected to the generator high-side bus.	~~None~~

If Voltage-Controlled or Voltage-Restrained Overcurrent Relay is used in place of the 51T see Section 3.10 for proper utilization and coordination (Device 51V).

If a distance relay is used in place of the 51T see Section 3.1 for proper utilization and coordination (Device 21).

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3.10. Voltage-Controlled or -Restrained Overcurrent Relay (Device 51V)

3.10.1. Purpose of the Generator Device 51V — Voltage-Controlled or -Restrained Overcurrent Relay

Voltage-Controlled and Voltage-Restrained Overcurrent Protection measures generator terminal voltage and generator stator current. Its function is to provide backup protection for system faults when the power system to which the generator is connected is protected by time-current coordinated protections. Note that Device 21 (Section 3.1.1) is another method of providing backup for system faults, and it is never appropriate to enable both Device 21 and Device 51V. The function of Device 51V is further described in Section 4.6.1.2 of the IEEE C37.102-2006 — Guide for AC Generator Protection, as follows (emphasis added):

> *"The type of overcurrent device generally used for system phase fault backup protection is either a voltage–restrained or voltage-controlled time-overcurrent relay. Both types of relays are designed to restrain operation under emergency overload conditions and still provide adequate sensitivity for the detection of faults.*
>
> ***In the voltage-restrained relay, the current pickup varies as a function of the voltage applied to relay. In one type of relay with zero voltage restraint, the current pickup is 25% of the pickup setting with 100% voltage restraint.*** *On units that have a short, short-circuit time constant, the 51V voltage-restrained overcurrent relay should be used.*
>
> ***In the voltage-controlled relay, a sensitive low pickup time-overcurrent relay is torque controlled by a voltage relay. At normal and emergency operating voltage levels, the voltage relay is picked up and the relay is restrained from operating. Under fault conditions, the voltage relay will drop out, thereby permitting operation of the sensitive time-overcurrent relay. If applied properly, the overcurrent pickup level in both types of relays will be below the generator fault current level as determined by synchronous reactance.***
>
> ***The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip. However, during faults, within the protection zone of the relay, the relay will be enabled (51VC), or sensitized (51VR), to trip with the expected fault current level.***
>
> *To provide system phase fault backup, three voltage-restrained or voltage-controlled time-overcurrent relays are connected to receive currents and voltages in the same manner as the distance relays illustrated in Figure 4.6-1 (IEEE C37.102). In some small and medium size machine applications a single 51V relay is used, if a negative-sequence overcurrent is included. The two together provide phase backup protection for all types of external faults."*

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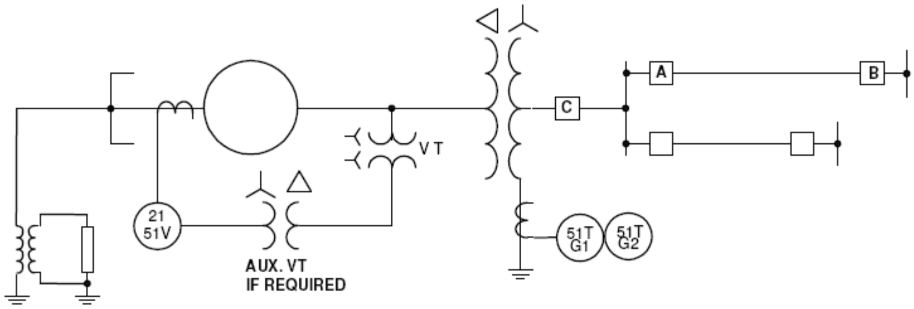

Figure 3.10.1 — Application of System Back-Up Relays – Unit Generator-Transformer Arrangement

3.10.2. Coordination of Generator and Transmission System

3.10.2.1. Faults

Generator Owner(s) and Transmission Owner(s) need to exchange the following data:

Generator Owner

- Unit ratings, subtransient, transient and synchronous reactance and time constants
- Station one line diagrams
- 51V- C or 51V-R relay type, CT ratio, VT ratio, settings and settings criteria
- Relay setting criteria
- Coordination curves for faults in the transmission system two buses away from generator high voltage bus

Transmission Owner

- Relay setting criteria
- Fault study values of current and voltage for all multi-phase faults two buses away from generator high voltage bus. This includes fault voltages at the high side of the generator step-up transformer.
- Relay types and operate times for multi-phase faults 2 buses away from generator high voltage bus.

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- Voltages on the high-side of the generator step-up transformer for extreme system contingencies. Use 0.75 per unit or power flow results for extreme system contingencies.

3.10.2.1.1. 51V-C Setting Considerations

Under fault conditions, the voltage element will drop out, thereby permitting operation of the sensitive time-overcurrent relay. The overcurrent pickup level will be below the generator fault current level as determined by synchronous reactance. It is possible that the overcurrent pickup level for the voltage controlled relay, 51V-C, may be below load current.

The voltage element must be set such that it will not drop out below extreme system contingencies. The 51V-C must be coordinated with the longest clearing time, including breaker failure, for any of the transmission protection schemes (devices 21, 51, 67, and 87B with the bus protection as inverse time delay) within the protected reach of the 51V-C device. A time margin of 0.5 seconds is typically considered adequate.

3.10.2.1.2. 51V-R Setting Considerations

Under fault conditions, the depressed voltage will make the time-overcurrent element more sensitive. The overcurrent pickup level must be set with a margin above the generator full-load current.

The 51V-R must be coordinated with the longest clearing time, including breaker failure, for any of the transmission protection schemes (devices 21, 51, 67, and 87B with the bus protection as inverse time delay) within the protected reach of the 51V-R device. A time margin of 0.5 seconds is typically considered adequate.

3.10.2.2. Loadability

- For the 51V-C relay, the voltage element must prevent operation for all system loading conditions as the overcurrent element will be set less than generator full load current. The voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip. A voltage setting of 0.75 per unit or less is acceptable.

- For the 51V-R relay, the voltage element will not prevent operation for system loading conditions. The overcurrent element must be set above generator full

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load current. IEEE C37.2 recommends the overcurrent element to be set 150 percent above full load current.

- Coordinate with stator thermal capability curve (IEEE C50.13).
- Special caution is required for VT fuse loss.

3.10.3. Considerations and Issues

The bolded portions of the above C37.102 standard capture the salient points of the application of the 51V function.

For trip dependability within the protected zone, the current portion of the function must be set using fault currents obtained by modeling the generator reactance as its synchronous reactance. This very well means that to set the current portion of the relay to detect faults within the protected zone, the minimum pickup of the current element will be less than maximum machine load current. In the below setting example, taken from C37.102 Appendix A, the current element is set 50 percent of the full load rating of the machine. The protected zone can be defined as:

Provide backup generator protection for prolonged multi-phase fault within the generator step up transformer (GSU), the high voltage bus, and a portion of a faulted transmission line, which has not been isolated by primary system relaying.

The undervoltage element is the security aspect of the 51V-C function. C37.102 states (emphasis added):

> ***"The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip."***

In C37.102 (see Appendix A reference), the undervoltage setting for the example is 75 percent of rated voltage. Seventy five percent ~~or~~of rated voltage is considered acceptable to avoid generator tripping during extreme emergency conditions.

The transmission system is usually protected with phase distance (impedance) relays. Time coordination is attained between distance relays using definite time settings. The 51V devices have varying time delays based on their time versus current time to operate curves. Time coordinating a 51V and a 21 lends to longer clearing times at lower currents. The 51V devices are often used effectively on generator connected to distribution system where distribution feeders are protected with time inverse characteristic relays. **For these reasons, it is recommended that an impedance**

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function be used rather than a 51V function for generators connected to the transmission system.

The voltage element of the 51V-C is set 0.75 per unit voltage or less to avoid operation for extreme system contingencies. A fault study must be performed to assure that this setting has reasonable margin for the faults that are to be cleared by the 51V. Backup clearing of system faults is not totally dependent on a 51V relay (or 21 relay). Clearing of unbalance multi-phase faults can be achieved by the negative sequence function. Clearing of three phase faults can be achieved by the over-frequency and over-speed tripping functions. The 51V function provides minimal transmission system backup protection for relay failure. It must not be relied upon to operate to complete an isolation of a system fault when a circuit breaker fails to operate as it does not have enough sensitivity. The 51V has a very slow operating time for multi-phase faults. This may lead to local system instability resulting in the tripping of generators in the area. A “zone 1” impedance relay would be recommended in its place to avoid instability as stated in C37.102. Voltage elements must be set less than extreme system contingency voltages or the voltage-controlled function will trip under load. The voltage-restrained function time to operate is variable dependent on voltage. For generators connected to the transmission system utilizing distance protection functions, the 21 function is recommended over the 51V function. It is not necessary to have both functions enabled in a multi-function relay. The 21 function can clearly define its zone of protection and clearly define its time to operate and therefore coordinate better with transmission system distance protection functions.

3.10.3.1. Special Considerations for Older Generators with Low Power Factors and Rotating Exciters

Older low power factor machines that have slower-responding rotating exciters present an additional susceptibility to tripping for the following reasons:

- The relatively low power factor (0.80 to 0.85) results in very high reactive current components in response to the exciter trying to support the system voltage.
- The slower response of the rotating exciters in both increasing and decreasing field current in those instances results in a longer time that the 51V element will be picked up, which increases the chances for tripping by the 51V.
- If it is impractical to mitigate this susceptibility, Transmission Owners, Transmission Operators, Planning Coordinators, and Reliability Coordinators should recognize this generator tripping susceptibility in their system studies.

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3.10.4. Coordination Procedure

3.10.4.1. Test Procedure for Validation

3.10.4.1.1. Voltage-Controlled Overcurrent Element (51VC)

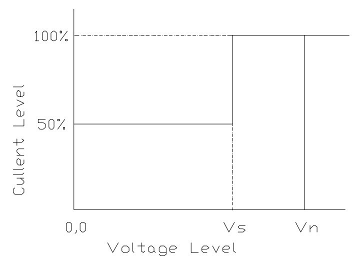

Figure 3.10.2 — Voltage Controlled Overcurrent Relay (51VC)

In the voltage-controlled relay, a sensitive low pickup time-overcurrent relay is torque controlled by a voltage relay. At normal and emergency operating voltage levels, the voltage relay is picked up and the relay is restrained from operating. Under fault conditions, the voltage relay will drop out, thereby permitting operation of the sensitive time-overcurrent relay.

- Overcurrent pickup is usually set at 50 percent of generator full load current as determined by maximum real power out and exciter at maximum field forcing.
- Undervoltage element should be set to dropout (enable overcurrent relay) at 0.75 per unit generator terminal voltage or less.
- Overcurrent element should not start timing until undervoltage element drops out.
- Time coordination for all faults on the high side of the GSU including breaker failure time and an agreed upon reasonable margin. Time coordination must also include zone 2 clearing times for a fault just beyond zone 1 for the shortest transmission line unless there are calculations to prove that the 51 V will not operate beyond zone 1 with reasonable margin.

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- Generator Owner's required margin is typically 0.5 seconds over 51 and 67 and instantaneous protection for Transmission System fault(s).

3.10.4.1.2. Voltage-Restrained Overcurrent Element (51VR)

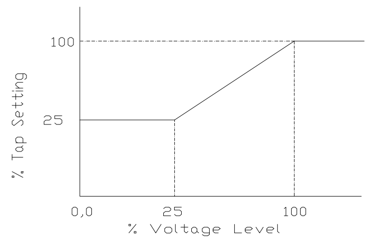

Figure 3.10.3 — Voltage Restrained OC Relay (51VR)

The characteristic of a voltage restrained overcurrent relay allows for a variable minimum pickup of the overcurrent element as determined by the generator terminal voltage. As shown in the above figure, at 100 percent generator terminal voltage the overcurrent element will pickup at 100 percent of its pickup setting. The minimum pickup of the overcurrent function become less linearly with voltage until 25 percent or less when the minimum pickup of the overcurrent function is 25 percent of its minimum pickup setting.

The 100 percent setting for the voltage setpoint must be at 0.75 per unit terminal voltage or less. Determine agreed upon margin for trip dependability (determine relay voltage for a fault on the terminal of the GSU). The voltage function should not drop out for extreme system contingencies (0.85 per unit GSU terminal voltage and generator at maximum real power out and exciter at maximum field forcing).

Time coordination for all faults on the high-side of the GSU must include breaker failure time and agreed upon margin. Time coordination must include zone 2 clearing times for transmission line relays unless there are calculations to prove that the 51 V will not operate beyond zone 1 with agreed upon margin, for example 0.5 seconds.

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3.10.4.2. Setting Considerations

- For the 51V-C relay, the voltage element must prevent operation for all system loading conditions as the overcurrent element will be set less than generator full load current. The voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip. A voltage setting of 0.75 per unit or less is acceptable.
- For the 51V-R relay, the voltage element will not prevent operation for system loading conditions. The overcurrent element must be set above generator full load current. IEEE C37.2 recommends the overcurrent element to be set 150 percent above full load current.

3.10.5. Example

Proper Coordination (From C37.102 Appendix A: Sample Calculations for Settings of Generator Protection Functions)

3.10.5.1. Voltage Controlled Overcurrent Element (51VC)

- $I_{Rate} = \dfrac{492MVA}{20kV\sqrt{3}}$ = 14,202 A, primary=3.945 A, secondary where 492 MVA is generator at maximum real power out and exciter at maximum field forcing.
- Current pickup = 50% of I_{Rate} = (0.5) (3.945-A) = 1.97 A ==> Use 2.0 A tap
- UV Element pickup Vs = 75% of V_{Rate} = (0.75) (120 V) = 90 V
- Coordination must be attained for fault cleared in high speed time + breaker failure time for a fault on the high side of the generator (multi-phase and three phase fault) and for a fault at the end of zone 1 of the shortest line cleared in zone 2 time plus breaker failure time. All coordination includes reasonable margin.

3.10.5.2. Voltage-Restrained Overcurrent Element (51VR)

- Current pickup = 150% of I Rate = (1.5) (3.945 A) (Note that at 25 percent voltage restraint this relay will pickup at 25 percent of 150 percent or 0.375 pu on the machine base when using a voltage-restrained overcurrent relay with a characteristic as shown above)
- Select a relay characteristic curve shape (Inverse, Very Inverse, etc.)

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- Coordination must be attained for fault cleared in high speed time + breaker failure time for a fault on the high side of the generator (multi-phase and three phase fault) and for a fault at the end of zone 1 of the shortest line cleared in zone 2 time plus breaker failure time. All coordination includes reasonable margin, for example 0.5 seconds.

3.10.5.3. Proper Coordination

Given the following system, set the 51V device to assure proper coordination.

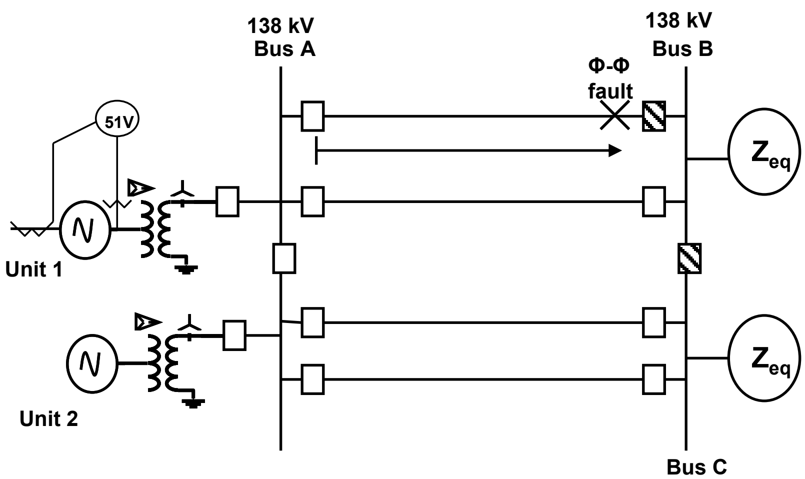

Figure 3.10.4 — System One-Line

Figure 3.10.5 depicts the proper coordination per the Transmission Owner's protective relaying settings criteria. In these criteria, the Transmission Owner requires coordination with all transmission line relays including zone 3, its timer and the breaker clearing time. The characteristic chosen for the time overcurrent function of the 51V is a definite time. The characteristic provides the "flattest" curve available. A more inverse curve would show much longer clearing times. Also shown is an impedance relay with time delay. The times to clear of this function also coordinates with the zone 3 per Transmission Owner requirement. Note that its 1.5 second timer allows for much less time to clear for faults even very close to the generator high voltage bus.

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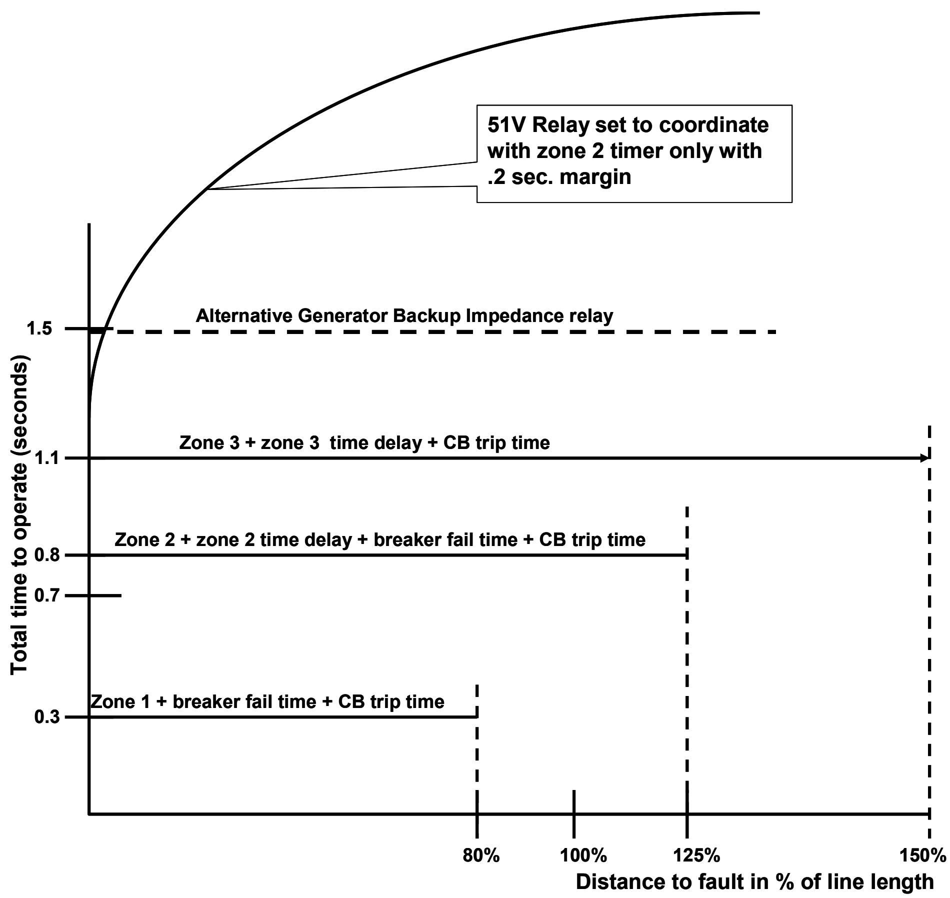

Figure 3.10.6 — Proper Coordination

3.10.5.4. Improper Coordination

This example is for the same one line diagram as in the first example. In the time chart below, the 51V was not set to coordinate with the total trip time of the zone 2 relay including breaker failure and circuit breaker trip time. The unit will unnecessarily trip for a line fault beyond 80 percent of its length if it must clear in breaker failure time. Further it does not coordinate with zone 3's total clearing time. Per the Transmission Owner's settings criteria, the 51V needs to be reset to coordinate with zone 2 + breaker failure total clearing time + margin and zone 3 total clearing time + margin.

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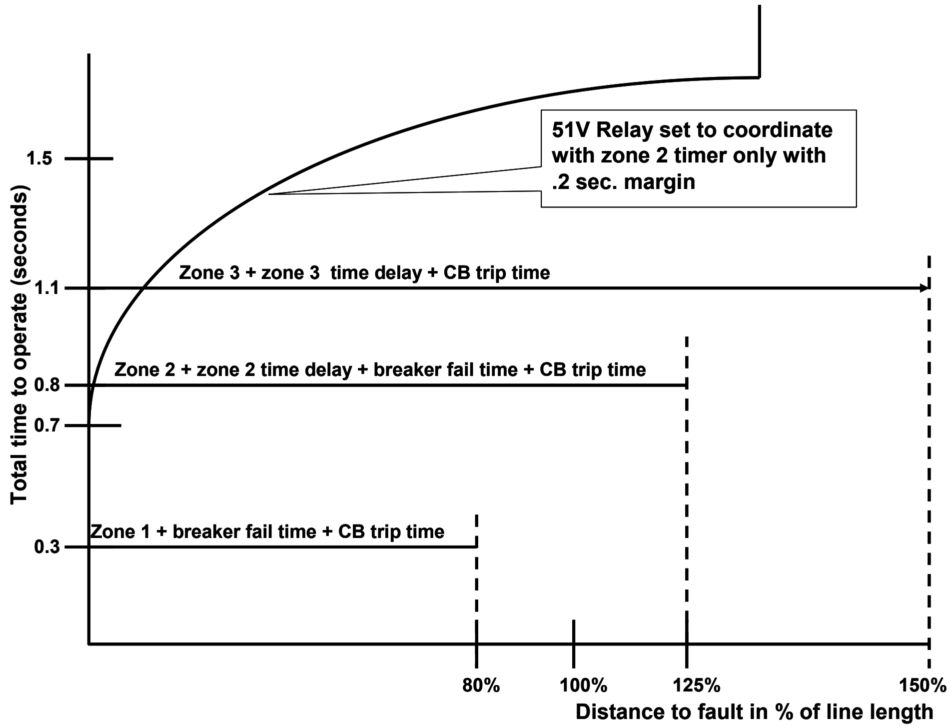

Figure 3.10.6 — Improper Coordination

3.10.6. Summary of Protection Functions Required for Coordination

- Coordinate with overcurrent protection and impedance relays on transmission system.
- Generator Owner and Transmission Owners must exchange data necessary to set the relay from a trip dependability perspective and from a coordination perspective. See Coordination of Generation and Transmission section for data exchange requirements.

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Table 2 Excerpt — Device 51V Protection Coordination Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
51V — Voltage controlled / ~~restraint~~restrained	21 51 67 87B	• 51V not recommended when ~~transmission system applies~~Transmission Owner uses distance ~~relays~~line protection functions • Short circuit studies for time coordination ~~required~~ • Total clearing time • Review voltage setting for extreme system loading conditions • 51V controlled function has only limited system backup protection capability • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage and current performance at the device location in the stability program and applying engineering judgment.

3.10.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s).

Table 3 Excerpt — Device 51V Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Provide settings for pickup and time delay (May need to provide relay manual for proper interpretation of the voltage controlled/~~restraint~~restrained relay)	Times to operate, including timers, of transmission system protection Breaker Failure Relaying times	None

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3.11. Over-Voltage Protection (Device 59)

3.11.1. Purpose of the Generator Device 59 — Overvoltage Protection

The device 59 overvoltage protection uses the measurement of generator terminal voltage. Section 4.5.6 of the IEEE C37.102 -2006 — Guide for AC Generator Protection describes the purpose of this protection as follows:

> *"Generator overvoltage may occur without necessarily exceeding the V/Hz limits of the machine. In general, this is a problem associated with hydro generators, where upon load rejection, the overspeed may exceed 200% of normal. Under this condition on a V/Hz basis, the overexcitation may not be excessive but the sustained voltage magnitude may be above permissible limits. Generator V/Hz relays will not detect this overvoltage condition and hence a separate overvoltage protection is required. In general, this is not a problem with steam and gas turbine generators because of the rapid response of the speed-control system and voltage regulators.*
>
> *Protection for generator overvoltage is provided with a frequency-compensated (or frequency-insensitive) overvoltage relay. The relay should have both an instantaneous unit and a time-delay unit with an inverse time characteristic. The instantaneous unit is generally set to pick up at 130% to 150% voltage while the inverse time unit is set to pick up at about 110% of normal voltage. Two definite time-delay relays can also be applied."*

Over-voltage protection is for preventing an insulation break-down from a sustained overvoltage. The generator insulation system is capable of operating at 105 percent overvoltage continuously.

Beyond 105 percent sustained overvoltage condition should normally not occur for a generator with a healthy voltage regulator, but it may be caused by the following contingencies; (1) defective automatic voltage regulator (AVR) operation, (2) manual operation w/o voltage regulator, and (3) sudden load loss.

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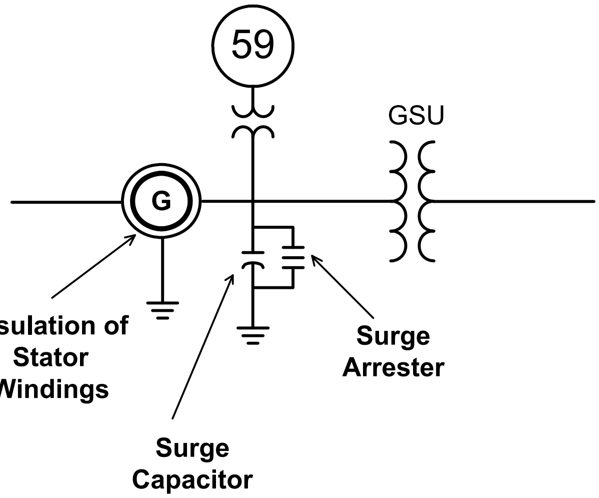

Figure 3.11.1 — Overvoltage Relay with Surge Devices shown connected to the Stator Windings

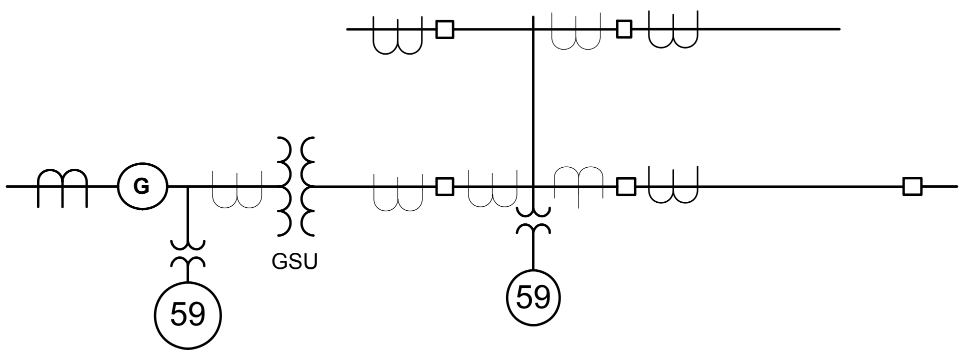

Figure 3.11.2 — Over-Voltage Relay Coordination

3.11.2. Coordination of Generator and Transmission System

3.11.2.1. Faults

There are no coordination requirements with the transmission protective relays for system faults given the high voltage set point and long delay; tens of seconds or

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longer. Additionally, most system fault conditions would cause a reduction in voltage.

Device 59 protection is mainly provided for the generator stator windings insulation. Surge arrestors protect the stator from over-voltages caused by lightning, impulses and inrush. The device 59 provides backup protection for these hazards. See the settings example below.

3.11.2.2. Loadability

If a long time setting of 1.1 per unit nominal voltage with significant time delay (as an example 10 seconds or longer is used to trip; coordination with extreme system events with over voltage should be considered. This is suggesting that for credible contingencies where overvoltage may occur, that all shunt reactors near the generator be placed in service or all capacitor banks near the generator be removed from service prior to the 10 second trip limit on the generator.

3.11.3. Considerations and Issues

Since the generator voltage regulator normally keeps the generator terminal voltage within 105 percent of nominal, there is not any system coordination issue.

Planners and operational planners need to know the performance of both the voltage regulator and the 59 overvoltage relay settings to study extended-time, over-voltage system conditions.

3.11.4. Coordination Procedure

3.11.4.1. Setting Considerations

- Two types of relays (or elements) are commonly used on a generator protection; one is an instantaneous (device 59I), and ~~(2)~~the other is a time-delay (device 59T) relay or element.
- "Generators shall operate successfully at rated kilovolts-amperes (kVA), frequency, and power factor at any voltage not more than five percent above or below rated voltage…" (By Clauses 4.1.5 of IEEE C50.12 & 4.1.7 of IEEE C50.13-2005).

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- "Generators shall be thermally capable of continuous operation within the confines of their reactive capability curves over the ranges of ±5% in voltage and ±2% in frequency. Clauses 4.15 of IEEE Std C50.12 & 4.1.7 of IEEE Std C50.12-2006).

3.11.5. Example

3.11.5.1. Proper Coordination

The following is an example of setting the 59T and 59I element time delays.

Step 1 — $V_{Nominal}$ = (20,000V) (120/20,000) = 120V

Step 2 — 59T =105% of 110% of =1.05x 1.10 x 120V =139V (=1.155 pu), with a time delay of 10 seconds or longer.

Step 3 — 59I =105% of 130% of =1.05 x 1.30 x 120V =184V (=1.365 pu)

Figure 3.11.3 is a typical load rejection response curve of a voltage regulator for an example of a hydro turbine generator. The regulator causes the generator to operate back near nominal voltage in about two seconds, well before any action by the overvoltage protection.

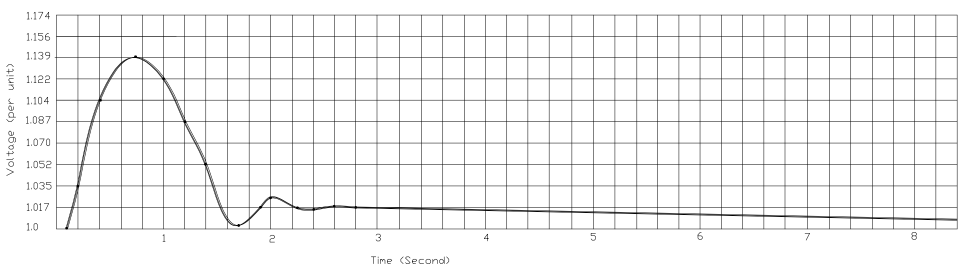

Figure 3.11.3 — Typical Example Load Rejection Data for Voltage Regulator Response Time

3.11.5.2. Improper Coordination

No example of improper coordination is given.

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3.11.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 59 Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
59 — Overvoltage	When applicable, pickup and time delay information of each 59 function applied for system protection	• Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring voltage performance in the stability program and applying engineering judgment.

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3.11.7. Summary of Protection Function Data and Information Exchange Required for Coordination

Table 3 Excerpt — Device 59 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
~~Provide pickup~~ Relay settings: setting and characteristics, including time ~~Delay~~delay setting or inverse time characteristic ~~of~~, at the ~~59~~generator terminals.	Pickup and time delay information of each 59 function applied for system protection	None

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3.12. Stator Ground Relay (Device 59GN/27TH)

3.12.1. Purpose of the Generator Device 59GN/27TH — Stator Ground Relay

Stator ground fault protection uses a measurement of zero sequence generator neutral voltage to detect generator system ground faults as described in Section 4.3.3 of the IEEE C37.102-2006 — Guide for AC Generator Protection that describes the purpose of this protection as follows:

> **"***Protective schemes that are designed to detect three-phase and phase-to-phase stator faults are not intended to provide protection for phase-to-ground faults in the generator zone. The degree of ground fault protection provided by these schemes is directly related to how the generator is grounded and, therefore, to the magnitude of the ground fault current available. The maximum phase-to-ground fault current available at the generator terminals may vary from three-phase fault current levels or higher to almost zero. In addition, the magnitude of stator ground fault current decreases almost linearly as the fault location moves from the stator terminals toward the neutral of the generator. For a ground fault near the neutral of a wye-connected generator, the available phase-to-ground fault current becomes small regardless of the grounding method.*
>
> *As noted in the preceding sub-clause, differential relaying will not provide ground fault protection on high impedance-grounded machines where primary fault current levels are limited to 3 A to 25 A. Differential relaying schemes may detect some stator phase-to-ground faults depending upon how the generator is grounded. Figure 4-18 illustrates the approximate relationship between available ground fault current and the percent of the stator winding protected by a current-differential scheme. When the ground fault current level is limited below generator rated load current, a large portion of the generator may be unprotected."*
>
> *"Generator faults are always considered to be serious since they may cause severe and costly damage to insulation, windings, and the core; they may also produce severe mechanical torsional shock to shafts and couplings. Moreover, fault currents in a generator do not cease to flow when the generator is tripped from the system and the field disconnected. Fault current may continue to flow for many seconds because of trapped flux within the machine, thereby increasing the amount of fault damage."*
>
> *"High-impedance grounding is standard for unit generators and is used in industrial systems. The discussion here centers on the common high-resistance grounding, where the fault current is limited to about 3 A to 25 A primary. This limit iron burning in the generator, to avoid very costly repairs."*

The stator ground relay (device 59GN) is intended to detect a ground fault on the stator windings to a delta-connected GSU transformer.

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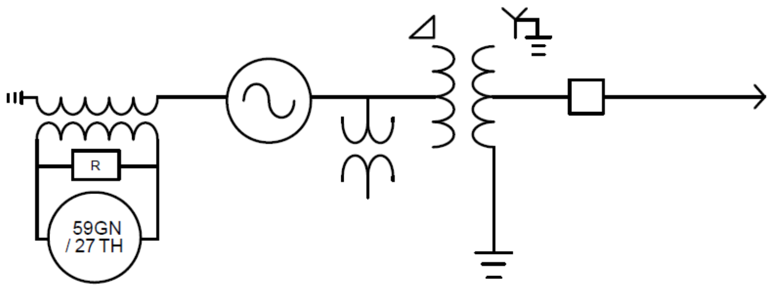

Figure 3.12.1 — Stator Ground Protection

3.12.2. Coordination of Generator and Transmission System

3.12.2.1. Faults

Step 1 — Transmission Owner determines worst case clearing time for close in phase to phase to ground or phase to ground faults on the system with breaker failure and total clearing times accounted for.

Step 2 — Generator Owner must ensure that the timer on the 59GN is longer than worst case provided above by the Transmission Owner with appropriate margin.

The performance of these relays, during fault conditions, must be coordinated with the system fault protection to assure that the sensitivity and timing of the relaying overall results in tripping of the proper system elements. Ensure that proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds.

3.12.2.2. Loadability

There are no loadability issues with this protection device.

3.12.3. Considerations and Issues

As stated in the purpose of this section, the 59GN relay is intended to detect a ground fault (phase-to-ground) within stator windings to a delta-connected to GSU transformer.

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3.12.4. Coordination Procedure and Considerations

Time delay settings for the 59GN/27TH relay must be coordinated with the worst case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time. This is done to avoid this relay tripping for system ground or unbalanced faults.

3.12.5. Example

No examples are necessary for device 59.

3.12.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Devices 59GN / 27TH Protection Coordination Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
59GN/27TH — Generator Stator Ground	~~None~~Longest time delay for Transmission System Protection to Clear a close-in phase-to-ground or phase-to-phase-to-ground Fault	• Ensure that proper time delay is used such that protection does not trip due to inter-winding capacitance issues or instrument secondary grounds. • Ensure that there is sufficient time delay to ride through the longest clearing time of the transmission line protection

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3.12.7. Summary of Protection Function Data and Information Exchange Required for Coordination

Table 3 Excerpt — Devices 59GN / 27TH Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Provide time delay setting of the 59GN/27TH	Provide worst case clearing time for phase-to-ground or phase-to-phase-to-ground close-in faults, including the breaker failure time.	None

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3.13. Out-of-Step or Loss-of-Synchronism Relay (Device 78)

3.13.1. Purpose of the Generator Device 78 — Loss of Synchronism Protection

The application of an out-of-step protective function to protect the turbine-generator should be based on a specific need determined by detailed stability studies and analysis.

Application of out-of-step relaying protection is not normally required by the Planning Coordinator unless stability studies, described in this section, determine that the protection function is necessary for the generator. The Planning Coordinator must also determine if there is a need for transmission line out-of-step blocking/tripping related to the generator, and if applied, that function must also be coordinated with the Transmission Owner and Generator Owner.

Device 78 uses a measure of apparent impedance derived from the quotient of generator terminal voltage divided by generator stator current. Section 4.5.3.1 of the IEEE C37.102-2006 — Guide for AC Generator Protection, which describes the purpose of this protection as follows:

> *"The protection normally applied in the generator zone, such as differential relaying, time-delay system backup, etc., will not detect loss of synchronism. The loss-of-excitation relay may provide some degree of protection but cannot be relied on to detect generator loss of synchronism under all system conditions. Therefore, if during a loss of synchronism the electrical center is located in the region from the high-voltage terminals of the GSU transformer down into the generator, separate out-of-step relaying should be provided to protect the machine. This is generally required for larger machines that are connected to EHV systems.*
>
> *On large machines the swing travels through either the generator or the main transformer. This protection may also be required even if the electrical center is out in the system and the system relaying is slow or cannot detect a loss of synchronism. Transmission line pilot-wire relaying, current-differential relaying, or phase comparison relaying will not detect a loss of synchronism. For generators connected to lower voltage systems, overcurrent relaying may not be sensitive enough to operate on loss of synchronism."*

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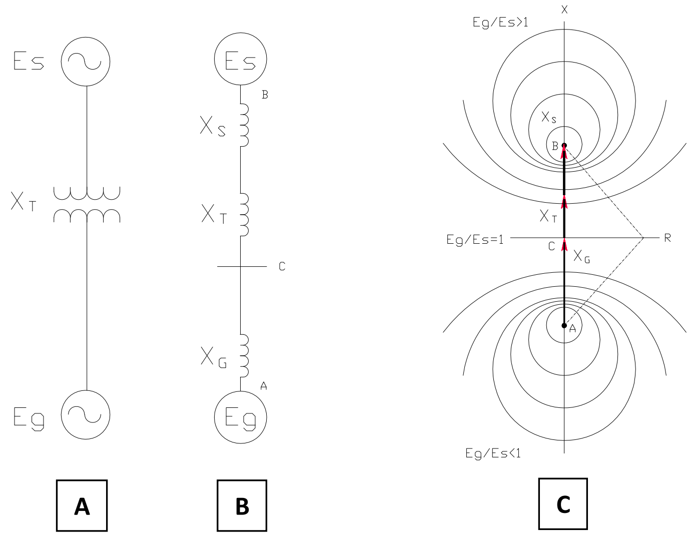

Figure 3.13.1 — Loci of Swing by E_g/E_s

Figures 3.13.1A and 3.13.1B illustrate a simple representation of two (2) systems E_s (power system) and E_g (a generator) connected through a GSU transformer.

Figure 3.13.1C shows typical power swing loci which are dependent on the ratio of E_g / E_s. When E_g is less than Es, which may occur when the generator is under-excited, the power swing loci will appear electrically "closer" to the generator than the power system. Due to the variability of the apparent impedance trajectory it is desirable to base out-of-step protection settings on transient stability simulations.

The point at which the apparent impedance swing crosses the impedance line between the generator and the system is referred to as the electrical center of the swing and represents the point at which zero voltage occurs when the generator and the system are 180 degrees out-of-phase. During pole slipping the voltage magnitude between the generator and the system reaches two per unit when the angle difference reaches 180 degrees, which can result in high currents that cause mechanical forces in the generator stator windings and undesired transient shaft torques. It is possible for the resulting torques to be of sufficient magnitude so that they cause the shaft to snap or damaged turbine blades.

Figure 3.13.2 shows relay CT and VT connections for out-of-step relay.

An out-of-step can also cause excessive overheating and shorting at the ends of the stator core. Out-of-step (pole-slip) operation can cause damaging transient forces in the windings of the GSU transformer as well.

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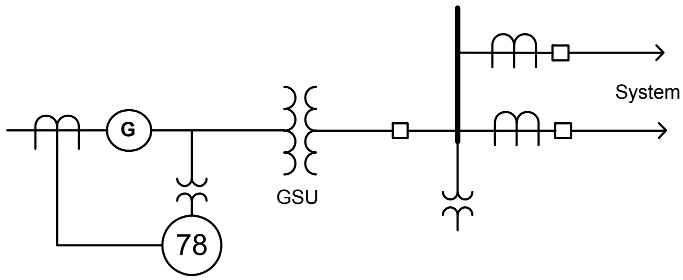

Figure 3.13.2 — Out-of-Step Relays on Generator & System

3.13.2. Coordination of Generator and Transmission System

3.13.2.1. Faults

There are no coordination issues for system faults for this function, although the apparent impedance swings for which out-of-step protection must be coordinated often occur as the result of system faults.

3.13.2.2. Loadability

There are no coordination issues related to loadability for this function.

3.13.2.3. Other Operating Conditions

- A generator may pole-slip (out-of-step or loss-of-synchronism), or fall out of synchronism with the power system for a number of reasons. The primary causes are: prolonged clearance of a low-impedance fault on the power system, generator operation at a high load angle close to its stability limit, or partial or complete loss of excitation.

- To properly apply this protection function, stability studies must be performed, involving extensive coordination between the Transmission Planner and/or Planning Coordinator, Transmission Owner and Generator Owner. The stability studies, which ~~will~~ usually are conducted by the Transmission Planner or Planning Coordinator, evaluate a wide variety of system contingency conditions. Out-of-step protection should not be applied unless stability studies indicate that it is needed, and should be applied in accordance with the results of those studies.

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The protection function application must be reviewed as system conditions change.

- Studies must be used to verify that the out-of-step protection operates only for unstable conditions and that it does not operate for load conditions or stable swing conditions. The critical conditions for setting the relay is the marginal condition representing the unstable swing that is closest to a stable condition and the fastest swing typically resulting from the most severe system condition.
- Typically the out-of-step settings are developed by calculating initial settings for blinders, time delay, etc. using a graphical approach. The settings are then refined as necessary based on transient stability simulations to ensure dependable tripping for unstable swings and secure operation for stable swings. This process requires an exchange of information between the Transmission Owner(s), the Generator Owners(s) and the ~~transmission planner~~Transmission Planner and/or Planning Coordinator.

3.13.3. Considerations and Issues

Stability studies must be performed to validate that the out-of-step protection will provide dependable operation for unstable swings and will not trip for stable system conditions and stable swings.

3.13.4. Coordination Procedure

The out-of-step protection characteristic using a single blinder scheme is shown in figure 3.13.3.

The mho supervisory relay restricts the operation area to swings that pass through or near the generator and its step-up transformer. Faults that occur between blinders A and B will cause both characteristics to pick up; thus, no tripping will be initiated. For operation of the blinder scheme, there must be a time differential between operation of the two blinders such that the swing originates outside the mho relay and progresses from one blinder to the other over a period of a few cycles.

The settings of the 78 element can be carried out with the procedure presented here. Figure 3.13.3 helps to illustrate the impedance settings.

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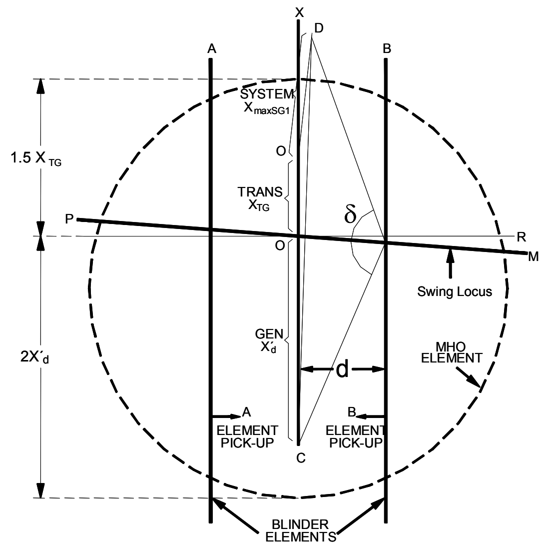

Figure 3.13.3 — Out-of-Step Protection Characteristic Using Single Blinder Scheme

1. Model the overall system and carry out transient stability runs for representative operating conditions. The modeling of the generators should include the voltage regulator, generator governor and power system stabilizer (PSS) if in service.

2. Determine values of generator transient reactance (X'_d), unit transformer reactance (X_{TG}) and system impedance under maximum generation (X_{maxSG1}).

3. Set the Mho unit to limit the reach to 1.5 times the transformer impedance in the system direction. In the generator direction the reach is typically set at twice generator transient reactance. Therefore the diameter of the MHO characteristic is $2\ X'_d + 1.5\ X_{TG}$.

4. Determine by means of the transient stability runs, the critical angle δ between the generator and the system by means of the transient stability simulations. This is the angle corresponding to fault clearing just greater than the critical clearing time.

5. Determine the blinder distance d, which is calculated with the following expression:

$$d = \left(\left(\frac{X'_d + X_{TG} + X_{\max SG1}}{2} \right) x \tan(90 - \delta/2) \right)$$

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6. Determine the time for the impedance trajectory to travel from the position corresponding to the critical angle δ to that corresponding to 180°. This time is obtained from the rotor angle vs. time curve which is generated by the transient stability study for the most severe transmission fault, when the system experiences the first slip.

7. The time delay of the 78 function should be set equal to the value obtained from the transient stability study in step 6. This value is equal to half the time for the apparent impedance to travel between the two blinders and provides adequate margin to permit tripping for faster swings, while providing security against operation for fault conditions.

A case study example is provided in the Appendix ~~G~~F to illustrate the steps involved in the setting process.

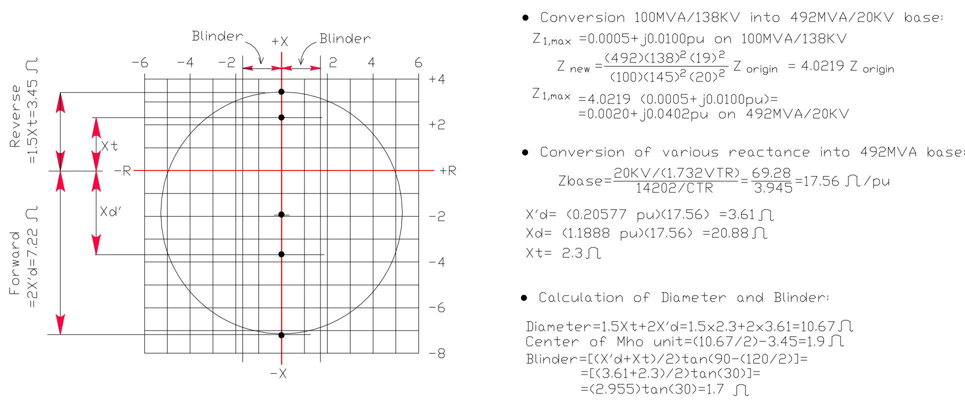

Figure 3.13.4 — Out-of-Step Mho and Blinders Characteristic Curves by C37.102-2006

3.13.4.1. Setting Considerations

3.13.4.1.1. Generators Connected to a Single Transmission Line

For a generator directly connected to a transmission line a determination is made whether existing clearing times on the adjacent transmission lines are adequate to assure stability of the generation. In some cases, relaying (for example, an existing stepped impedance scheme) may have to be replaced with a communication-assisted scheme to improve the clearing speed and to assure stability. Faults and clearing times on the line to which the generator is connected

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are of no consequence in terms of impacting the stability of the generator, because for a fault on the transmission line the generation will be disconnected from the system.

3.13.4.1.2. Check List

- The direct axis transient reactance (X_d') used in the setting calculation should be on the generator voltage base.
- The GSU transformer reactance (Xt) used in the setting calculation should be on the generator voltage base.
- The reverse reach should be greater than GSU transformer reactance (Xt).
- A proper angular separation δ~~5~~ between the generator and the system should be used to set the blinders (as determined by a transient stability study).
- A power system stability study should be performed for the relay time delay setting.

3.13.5. Examples

3.13.5.1. Proper Coordination

Several types of out-of-step algorithms and relay characteristics exist and details for developing settings are specific to the particular relay used. The following example illustrates the setting details associated with one particular relay type and provides an overview of the process used to ensure proper coordination.

3.13.5.1.1. Example of Calculation for Mho Element and Blinder Settings

Assumptions:

$Z_t =$ 2.26-Ω/phase, $Z_t =$ 50% of 2.26-Ω/phase = 1.13-Ω/phase, $KV_{HV} =$ 145-kV

- Reverse Reach – $Z_{reverse} = X_t =$ 2.26 -Ω/phase
- Forward Reach – $Z_{forward} = 2X'_d =$ 2 x 3.61 = 7.22-Ω/phase

~~[5] Note: Pursuant to C37.102, with regard to setting of the blinder, the angle δ is the angular separation between the generator and the system, at which the relay determines instability. If a stability study is not available, this angle is typically set at 120º.~~

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- Diameter of Mho Element – D = $Z_{reverse} + Z_{forward} = X_t + 2X'_d =$ 9.48-Ω
- Center of Mho Element – C = (D/2)- $Z_{reverse}$ = (9.48/2) – 2.26 = 2.48 ==> (-2.48, 0)
- Blinders – d1 & d2 = {(X'$_d$ + X$_t$)/2} tan {90˚-(140˚/2)} = {(3.61 + 2.3)/2}tan{90˚-(140˚/2)} = 2.955 tan 20˚ = 1.08-Ω

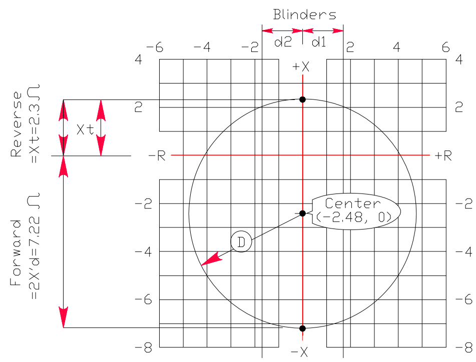

Figure 3.13.5 — New Reverse Reach – Mho and Blinder Elements

3.13.5.1.2. Example of Verifying Proper Coordination

- These initial settings are modeled in transient stability simulations to verify secure operation for stable swings and dependable operation for unstable swings.
- The limiting transmission fault identified by the Transmission Planner should be simulated with the fault clearing equal to the critical clearing time to ensure secure operation. The swing for this fault represents the furthest the apparent impedance should swing toward the out-of-step relay characteristic.
- The limiting transmission fault identified by the Transmission Planner should be simulated with the fault clearing just greater than the critical clearing time to ensure dependable operation. The swing for this fault represents the slowest unstable swing.
- The most severe transmission fault should be simulated to verify dependable operation. The swing for this fault represents the fastest unstable swing which must be differentiated from a change in apparent impedance associated with application of a fault.

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- The timing of the trip output from the relay should be verified for the unstable swings to ensure that the circuit breaker is not opened when the generator is 180 degrees out-of-phase with the transmission system.

If the above simulations do not result in both secure and dependable operation the relay characteristic and trip timer settings should be adjusted to obtain the desired operation. The simulations listed above represent a minimal set of simulations. The degree of confidence in the relay settings is improved by running more simulations which may be based on other contingencies and sensitivity to parameters such as fault type, fault impedance, system load level, pre-fault generator loading.

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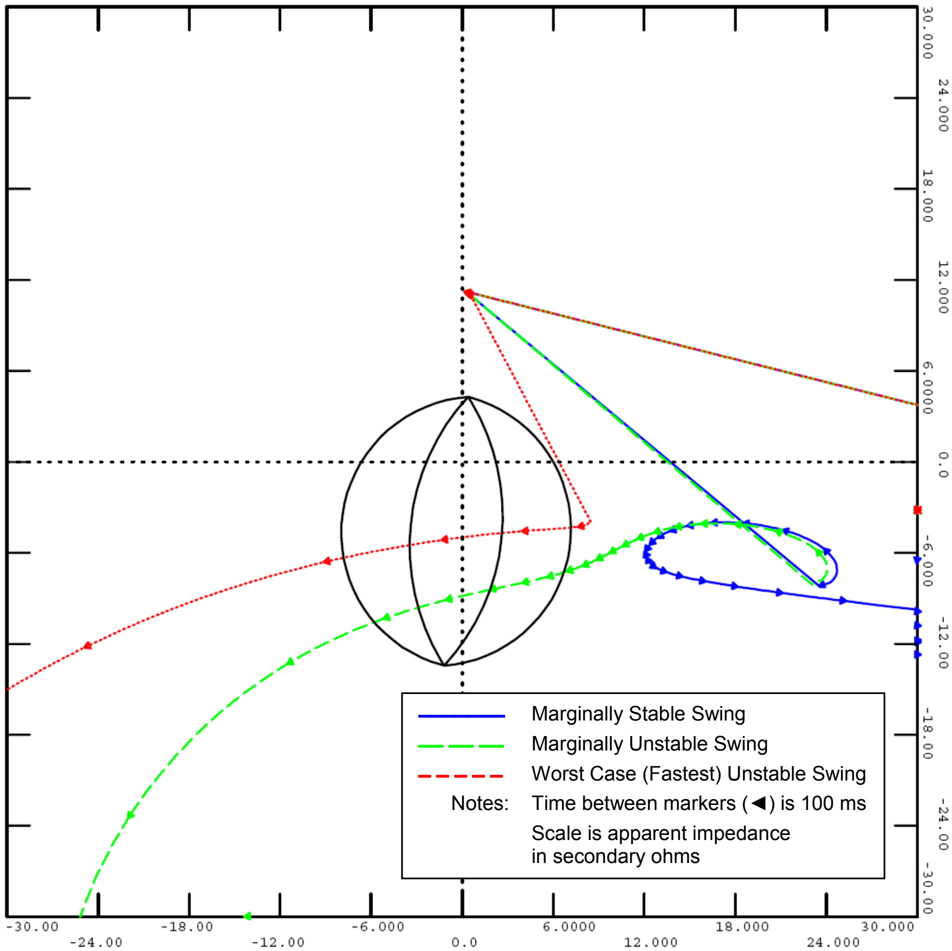

Figure 3.13.6 — Sample Apparent Impedance Swings

Sample apparent impedance swings are presented in Figure 3.13.6 for a dual lens characteristic out-of-step relay. In this figure the time interval between markers is 100 ms (6 cycles) such that the faster swings have greater distance between markers. The three traces represent marginally stable and unstable swings for fault clearing at and just beyond the critical clearing time, and a trace for the worst credible contingency representing the fastest unstable swing.

3.13.5.2. Power Swing Detection

In order to detect a power swing, the rate of change of the impedance vector is used. The rate-of-change may be calculated directly or used indirectly by measuring the

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time it takes the apparent impedance to pass between two blinders. Power swings are distinguished by the following characteristics:

- Stable swings have slow oscillations where the angles between two voltage sources vary, usually < 1 Hz, 0.5 to 0.8 Hz being common (greater than 1-sec period of oscillation)
- Unstable swings typically result in minimal oscillations and a monotonic increase in the angle until the voltage collapses at the electrical center of the swing and the relay operates
- Many power swings are caused by short circuits, auto-reclosures, line switching, and large changes in load(s)

A swing causes voltage phase shift between the system (Es) and generator voltage (E_g) as defined previously in Figure 3.13.6. Consequences of the swing include variation in system frequency, voltage, and power flow. Heavy load transfers in a power network can contribute to portions of the system losing stability.

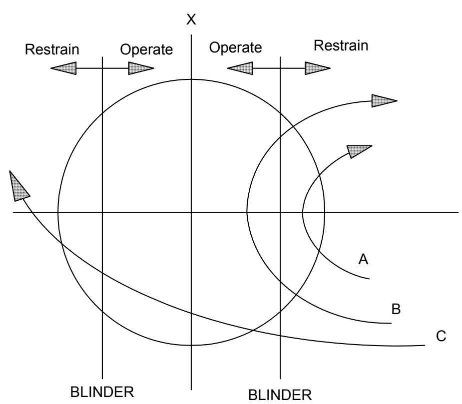

Figure 3.13.7 — "Mho"-Type Out-Of-Step Detector and a Single Blinder

Notes on Figure 3.13.7:
A — Z moves into OS zone and leaves slowly-Stable Swing
B — Z moves into OS and Trip zone and leaves slowly – Stable Swing
C — Z moves across the OS and trip zone and the generator slips a pole – Unstable Swing

Figure 3.13.~~8~~7 shows three different types of swing characteristics for the apparent impedance measured at the terminals of the generator.

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If the load impedance vector enters and remains within a distance element's protection zone, tripping may occur. Tripping during the power swing may be inhibited by the so-called power swing blocking function (or a Blinder).

During a power swing, the impedance vector exhibits a steady progression rather than rapid change that might indicate a fault. By measurement of rate-of-change of impedance and comparison with thresholds it is possible to distinguish between short-circuits and power swings.

When the criteria for power swing detection are not met and when out-of-step tripping is selected, a mho characteristic zone of the relay is blocked temporarily, in order to prevent premature tripping. When impedance vector "Z" leaves the power swing area, the vector is checked by its "R" component. If the "R" component still has the same sign as at the point of entry, the power swing is in the process of stabilizing. Otherwise, the vector has passed through the Mho characteristic (trace "C" in Figure 3.13.7) indicating loss of synchronism (or slipping poles).

Stability studies should be performed for the specific application of the generator out-of-step protection to validate that it will not trip for stable swings described above.

3.13.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Device 78 Protection Coordination Data Exchange Requirements

Generator Protection Device	Transmission System Protection Relays	System Concerns
78 — Out-of-Step	21 (Coordination of OOS blocking and tripping) Any OOS if applicable	• System studies are required • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring impedance swings at the device location in the stability program and applying engineering judgment.

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3.13.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s).

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Table 3 Excerpt — Device 78 Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
~~Provide relay~~Relay Settings, Time Delays and Characteristics for out-of -step ~~block &~~ trip ~~if used~~and blocking	Provide relay settings, time delays and characteristics for the out-of-step block and trip if used	Determine if there is a need for transmission line out-of-step blocking/tripping related to the generator Feedback on coordination problems found in stability studies.

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3.14. Over- and Under-Frequency Relay (Device 81)

3.14.1. Purpose of the Generator Device 81 — Over- and Under-Frequency Protection

The Device 81 protection uses the measurement of voltage frequency to detect over and underfrequency conditions. Section 4.5.8 of the IEEE C37.102-2006 — Guide for AC Generator Protection describes the purpose of this protection as follows:

> *"The operation of generators at abnormal frequencies (either overfrequency or underfrequency) can result from load rejection or mismatch between system loading and generation. Full- or partial-load rejection may be caused by clearing of system faults or by over-shedding of load during a major system disturbance. Load rejection will cause the generator to overspeed and operate at some frequency above normal. In general, the overfrequency condition does not pose serious problems since operator and/or control action may be used to quickly restore generator speed and frequency to normal without the need for tripping the generator.*
>
> *Mismatch between load and generation may be caused by a variety of system disturbances and/or operating conditions. However, of primary concern is the system disturbance caused by a major loss of generation that produces system separation and severe overloading on the remaining system generators. Under this condition, the system frequency will decay and the generators may be subjected to prolonged operation at reduced frequency. While load shedding schemes are designed to arrest the frequency decay and to restore frequency to normal during such disturbances, it is possible that under-shedding of load may occur. This may cause an extremely slow return of frequency to normal or the bottoming out of system frequency at some level below normal. In either case, there exists the possibility of operation at reduced frequency for sufficient time to damage steam or gas turbine generators. In general, underfrequency operation of a turbine generator is more critical than overfrequency operation since the operator does not have the option of control action."*

Overfrequency and underfrequency conditions occur as a result of a mismatch between load and generation. Typical levels of overfrequency and underfrequency resulting from tripping of generation or load, or sudden increases in load, do not pose a threat to equipment and are corrected through Automatic Generation Control (AGC) or operator action. Serious abnormal underfrequency and overfrequency conditions may occur as a

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result of conditions on the power system that result in a significant mismatch between load and generation. The amount by which frequency deviates from nominal is a function of the percentage mismatch, thus, the most significant frequency deviations typically occur when a portion of the system becomes isolated from the rest of the interconnection.

The governor controlling the prime mover normally limits overfrequency conditions below the operating thresholds of the generator frequency protection. The governor may also be capable of limiting underfrequency conditions depending on the operating mode and pre-disturbance output level of the generator. The over and under frequency protective functions primarily provide protection for the prime mover (turbine, etc.) rather than electrical protection for the generator itself. It is important to note when applying these protective functions that damage due to off-nominal frequency operation tends to be cumulative.

Steam turbine blades are designed and tuned for efficient operation at rated frequency of rotation. Operation with load at different frequencies can result in blade resonance and fatigue damage in the long blades in the turbine low-pressure unit. Transiently passing through a low frequency is not a problem; it is when a low frequency is sustained at a particular point that there could be a problem for a given turbine.

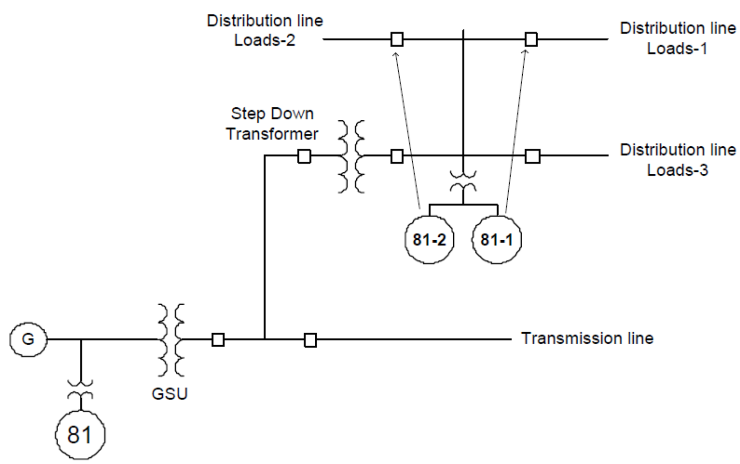

Figure 3.14.1 — Under-Frequency Relay & Load Shedding Coordination

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3.14.2. Coordination of Generator and Transmission System

3.14.2.1. Faults

There are no coordination issues for system faults for this function.

3.14.2.2. Loadability

There are no coordination issues related to loadability for this function.

3.14.2.3. Other Operating Conditions

Coordination between generating plant over and under frequency protection and the transmission system is necessary for off-nominal frequency events during which system frequency declines low enough to initiate operation of underfrequency load shedding (UFLS) relays. In most interconnections frequency can decline low enough to initiate UFLS operation only during an island condition. However, adequate frequency decline may occur to initiate UFLS operation as a result of tripping generators or tie lines on smaller interconnections or on weakly connected portions of interconnections.

Coordination is necessary to ensure that the UFLS program can operate to restore a balance between generation and load to recover and stabilize frequency at a sustainable operating condition. Without coordination, generation may trip by operation of underfrequency protection to exacerbate the unbalance between load and generation resulting in tripping of more load than necessary, or in the worst case, resulting in system collapse if the resulting imbalance exceeds the design basis of the UFLS program. Coordination also is necessary to ensure that overfrequency protection does not operate if frequency temporarily overshoots 60 Hz subsequent to UFLS operation and prior to frequency stabilizing at a sustainable operating condition. It is important to note that the coordination is not a relay-to-relay coordination in the traditional sense; rather it is coordination between the generator prime mover capabilities, the over and underfrequency protection, and the UFLS program and transmission system design.

A UFLS program that is designed properly and operates for a condition within its design parameters (typically for a generation deficiency of up to 25 – 30 percent of load) will recover frequency to nearly 60 Hz. For conditions that exceed the design parameters of the UFLS program, it is possible that frequency recovery will 'stall'

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and settle at a lower than normal frequency. If it is necessary to apply underfrequency protection, turbine limits that account for both frequency and time at frequency, must be obtained from the turbine manufacturer in order to properly set protection elements. The UFLS program always should be allowed to take action well before tripping a generating unit for turbine protection. If this is not possible, most regions require accounting for unit tripping in UFLS design assessments and require UFLS program modifications such as arming additional "compensating" load shedding equal to the capacity of the unit.

3.14.3. Considerations and Issues

Turbine limits must be obtained from the turbine manufacturer in order to properly set the over and underfrequency protection elements. The limits typically are expressed as the cumulative amount of time that the turbine can operate at off-nominal frequencies. IEEE Standard C50.12 (Standard for Salient-pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above) requires that “Generators shall be thermally capable of continuous operation within the confines of their reactive capability curves over the ranges of ±5% in voltage and ±2% in frequency, as defined by the shaded area of Figure 3.14.2.”

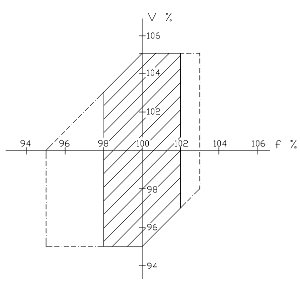

Figure 3.14.2 — Generator Operation Ranges

Details for setting the protection functions are provided in Section 4.58 and Figure 4.48 of IEEE Standard C37.102-2006 (Guide for AC Generator Protection). Generator off-nominal frequency protection should be coordinated with the governor settings to ensure that the protection does not trip the unit for a condition from which the governor could restore the unit to an acceptable operating condition.

In order to provide reliable, coordinated protection the over and underfrequency protection functions must have adequate pickup setting range (usually 55-65 Hz) and

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adequate time delay to coordinate with the UFLS program. It also is important to have adequate operating range in terms of system frequency. Most relays are designed to operate in a range of 40 – 70 Hz which is adequate. It is important to understand the protection function limitations as some relays are blocked automatically if the system frequency or voltage is outside the range of relay specifications, while other relays remain in-service but are subject to misoperations.

Proper load shedding on the power system is crucial to minimizing the impacts of under and overfrequency issues on steam and gas turbine generators. Reduced frequency operation may cause thermal damage and turbine blade resonance and fatigue in the long blades in the turbine low-pressure steam or gas turbine generators.

The generator underfrequency protection settings must be recognized in the development or evaluation of any UFLS system. Underfrequency tripping of generators should not occur before completion of the underfrequency load shedding, as defined by regional requirements. Properly planned UFLS programs, validated by system studies, are critical to the reliability of the transmission system. Selection of generation underfrequency performance specifications and protection settings for new generators should be matched to the existing regional UFLS programs. Further details are provided in IEEE Standard C37.106 (Guide for Abnormal Frequency Protection for Power Generating Plants).

3.14.4. Coordination Procedure

Step 1 — Planning Coordinator provides the regional underfrequency load shedding and generator off-nominal frequency protection setting criteria.

Step 2 — Generator Owner and Planning Coordinator verify that the generator off-nominal frequency protection is set to coordinate with the regional UFLS program design and generator off-nominal frequency protection setting criteria.

Step 3 — If coordination cannot be achieved without compromising protection of the generating unit, the Planning Coordinator performs studies to assess the impact on the UFLS program design and identify modifications, if necessary, to accommodate the generator protection setting while ensuring the UFLS program continues to meet its design objectives.

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3.14.4.1. Setting Validation for Coordination

Step 1 — Plot the generator and turbine capabilities on a graph of frequency versus time similar to the graph shown in Figure 3.14.3.

Step 2 — Plot the applicable NERC and regional requirements for setting over and underfrequency protection on generating units on the same graph. These requirements are coordinated with the UFLS program design and provide some margin for the system performance between the performance characteristics to which the regional UFLS program is designed and the frequency-time requirements for setting generator protection. Note that the generator protection is not coordinated directly with the UFLS relay settings because subsequent to the UFLS program operating to shed load, a time delay will exist before frequency decline is arrested and recovery begins. This time delay, as well as the rate at which frequency recovers, is a function of the physical characteristics of the system including types of load, generating unit inertia, and governing response.

Step 3 — Plot the protection settings on the same graph. Note that for some plant designs, critical station service load may be supplied from a motor-generator (M-G) set. When an over or underfrequency protection is located on the load side of the M-G set, the protection function trip setting must be adjusted to account for any frequency difference between the system and the load.

Step 4 — Verify whether the protection function settings coordinate with the generator and turbine capability and the regional requirements. If coordination cannot be achieved, set the protection based on the generator and turbine capability and follow the applicable processes to report the relay setting so the generator protection can be modeled by the Planning Coordinator in system studies.

3.14.5. Example

3.14.5.1. Proper Coordination

The following Figure 3.14.3 illustrates an example of how generator protection settings are coordinated with the turbine capability and the underfrequency protection setting limits for generating units. In this example the protection setting must be set above the green curve which defines the turbine capability provided by the manufacturer and on or below the red curve that defines the applicable generator underfrequency protection setting limits. In this example the protection is set with an

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instantaneous trip threshold at 57.7 Hz and a time delayed threshold setting at 58.5 Hz with a definite time delay of 60 seconds. Both settings coordinate in this example.

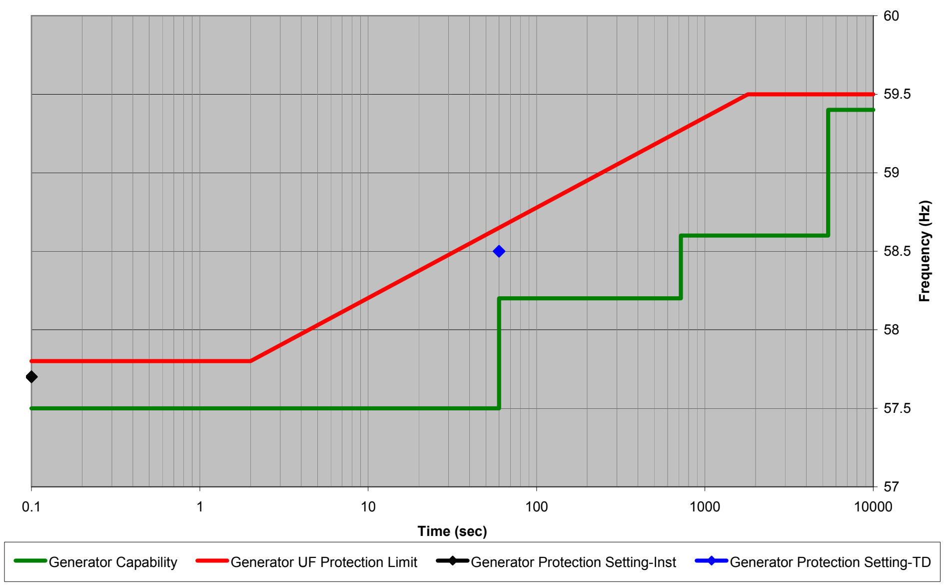

Figure 3.14.3 — Generator Underfrequency Protection Setting Example

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3.14.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Devices 81U / 81O Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
81U — Under frequency 81O — Over frequency	81U (Coordination with system UFLS set points and time delay) achieved through compliance with Regional frequency standards for generators 81O (Coordinate with system over-frequency set points) UFLS design is generally the responsibility of the Planning Coordinator	• Coordination with system UFLS set points and time delay, • Meet Standard PRC-024-2 under-and-over-frequency requirements • Caution on auto-restart of distributed generation • Wind generation during over-frequency conditions • Settings should be used for planning and system studies either through explicit modeling of the device, or through monitoring frequency performance at the device location in the stability program and applying engineering judgment.

3.14.7. Summary of Protection Function Data and Information Exchange required for Coordination

The following table presents the data and information that needs to be exchanged between the entities to validate and document appropriate coordination as demonstrated in the above example(s). Whenever a miscoordination between the under-frequency setting of a generator and the UFLS program cannot be resolved, the UFLS program may have to be redesigned to compensate for the loss of that generation in order to be fully coordinated.

Table 3 Excerpt — Devices 81U / 81O Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Relay settings and time delays	None	Feedback on problems found between underfrequency settings and UFLS programs.

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3.15. Transformer Differential Relay (Device 87T), Generator Differential Relay (Device 87G) Protection and (Device 87U) Overall Differential Protection

3.15.1. Purpose

3.15.1.1. Device 87T — Transformer Differential Relay

The Transformer Differential relay (device 87T) is used solely for protection of a GSU transformer.

3.15.1.2. Device 87G — Generator Differential Relay

The Generator Differential relay (device 87G) is used commonly for phase-fault protection of generator stator windings. Differential relaying will detect three phase faults, phase-to-phase faults, double-phase-to-ground faults and some single phase-to-ground depending upon how the generator is grounded.

> *"Some form of high-speed differential relaying is generally used for phase fault protection of generator stator windings. Differential relaying will detect three-phase faults, phase-to-phase faults, double-phase-to-ground faults, and some single-phase-to-ground faults, depending upon how the generator is grounded. Differential relaying will not detect turn-to-turn faults in the same phase since there is no difference in the current entering and leaving the phase winding. Where applicable, separate turn fault protection may be provided with the split-phase relaying scheme. This scheme will be discussed subsequently. Differential relaying will not detect stator ground faults on high-impedance grounded generators. The high impedance normally limits the fault current to levels considerably below the practical sensitivity of the differential relaying. Three types of high-speed differential relays are used for stator phase fault detection: percentage differential, high-impedance differential, and self-balancing differential."*

3.15.1.3. Device 87U — Overall Differential Protection

The Overall Differential relay is applied usually on the unit generator-transformer arrangement with or without ~~Low Voltage~~a low voltage generator unit breaker as

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shown in the figures 3.15.1 and 3.15.2. The advantage of this scheme is providing a redundancy protection of generator differential protection.

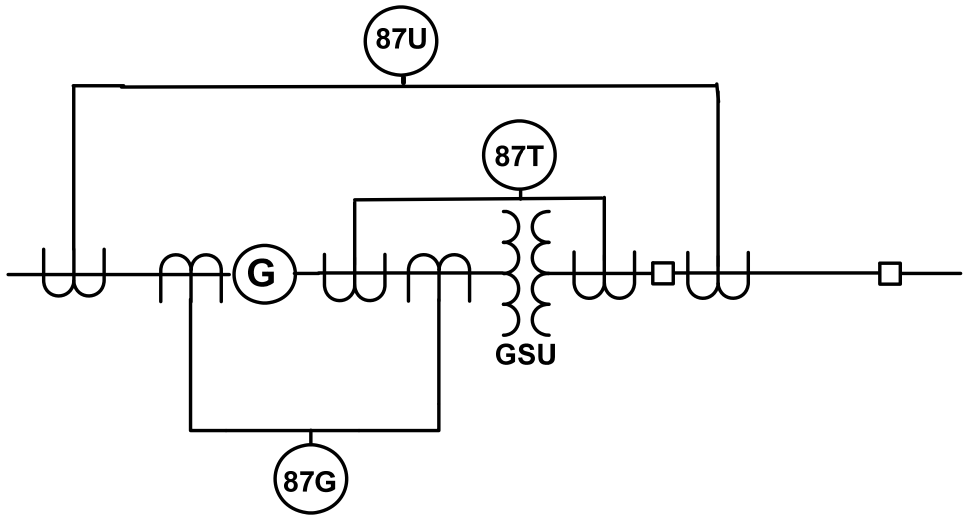

Figure 3.15.1 — Overall Differential, Transformer Differential , and Generator Differential Relays without Unit Circuit Breaker

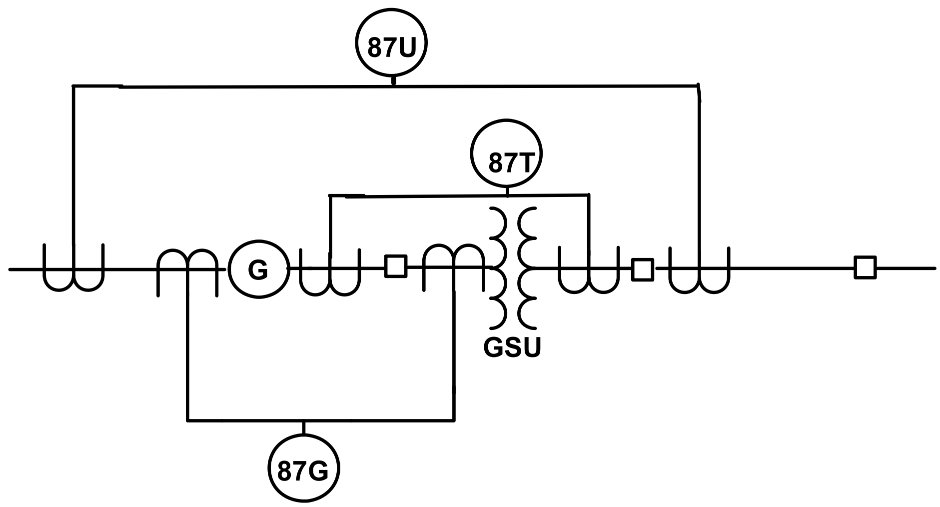

Figure 3.15.2 — Overall Differential, Transformer Differential , and Generator Generator Differential Relays with Unit Circuit Breaker

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3.15.2. Coordination of Generator and Transmission System

3.15.2.1. Faults

There are no fault considerations for this protective function.

3.15.2.2. Loadability

There are no loadability issues with this protection function.

3.15.3. Considerations and Issues

Transmission Owner and Generator Owner should verify proper overlap of differential zones.

3.15.4. Coordination Procedure and Considerations

The setting procedure for the 87G Generator Differential protection is discussed in C37.102 – 2006, section 4.3 Stator Fault Protection. The 87 Overall Unit Differential protection is discussed in C37.91 – 2008 IEEE Guide for Protective Relay Application to Power Transformers, Section 14.1. The 87T GSU Transformer Differential is discussed in C37.91 – 2008 IEEE Guide for Protective Relay Application to Power Transformers, Appendix C.1.

3.15.5. Example

3.15.5.1. Proper Coordination

No coordination required.

3.15.5.2. Improper Coordination

No coordination required.

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3.15.6. Summary of Protection Functions Required for Coordination

Table 2 Excerpt — Devices 87T / 87G / 87U Protection Coordination Data Exchange Requirements		
Generator Protection Device	**Transmission System Protection Relays**	**System Concerns**
87T — Transformer Differential	None – Zone Selective	Proper Overlap of the Overall differential zone and bus differential zone, etc., should be verified.
87G — Generator Differential	None	
87U — Overall Differential	None – Zone selective	

3.15.7. Summary of Protection Function Data and Information Exchange required for Coordination

No Coordination Required

Table 3 Excerpt — Devices 87T / 87G / 87U Data To be Provided		
Generator Owner	**Transmission Owner**	**Planning Coordinator**
Device 87T — Transformer Differential ~~Device 87G — Generator Differential~~ ~~Device 87U — Overall Differential~~	None – Zone Selective	None
Device 87G — Generator Differential	None	None
Device 87U — Overall Differential	None – Zone Selective	None

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Appendix A — References

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3. IEEE Std 421.5-2006 (IEEE Recommended Practice for **Excitation System Models**)
4. IEEE Std C50.12-2005 (Clause 4.1.6,1, IEEE Std for **Salient-Pole** Synchronous Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above),
5. IEEE Std C50.13.2005 (Clause 9.2.2.1.1, IEEE Std for **Cylindrical-Rotor** Synchronous Generators Rated 10 MVA and Above)
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7. IEEE C37.102-2006 (Guide for AC Generator Protection)
8. *Coordination of Generator Protection with Generator Excitation Control and Generator Capability*, IEEE/PSRC WG J-5 Paper/ **Power Engineering Society General Meeting, 2007. IEEE**, Publication Date: 24-28 June 2007, On page(s): 1-17, Location: Tampa, FL, USA, ISSN: 1932-5517, ISBN: 1-4244-1298-6, Digital Object Identifier: 10.1109 /PES.2007.386034, Posted online: 2007-07-23 09:42:51.0
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22. Draft NERC Standard PRC-024-2 — Generator Performance During Frequency and Voltage Excursions
23. IEEE/PSRC , Working Group Report C12 – Performance of Relaying during Wide-Area Stressed Conditions, May 14, 2008

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Appendix B — Step Response of Load Rejection Test on Hydro Generator

An Example of Load Rejection Test Result (100.5 MW, -4.5 MVAR)

Record No:	0003		
Time of Record:	06 Mar 00	11:52:12	
Record size:	29127 samples	Record window:	2.43 min
Pre-Trigger:	2912 samples	Post-trigger:	26215 samples
Playback time base:	200.00 ms/mm (or 1 sec/5 mm)		
Play back window:	3361-14624 samples		

Ch	Range	Offset	Dc/Gnd	Note
01	20.000 V	119.10 V	dc	Stator Voltage (Vn=13.8 KV)
02	10.000 V	5.00 V	dc	Stator Current
03	02.000 V	119.10 V	dc	5V Full Scale=200 RPM, Rated=120 RPM
04	150.00 V	119.10 V	dc	Field Breaker (41)

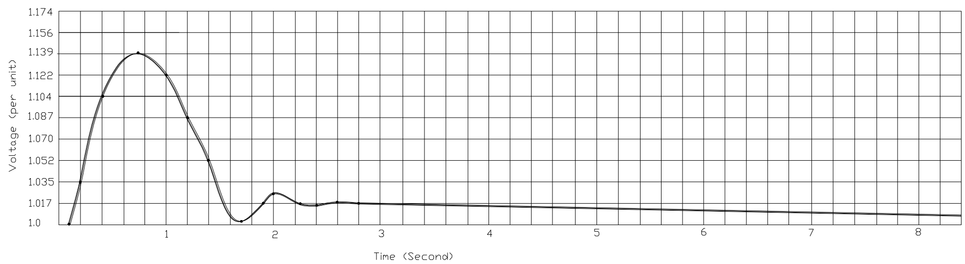

Figure B-1

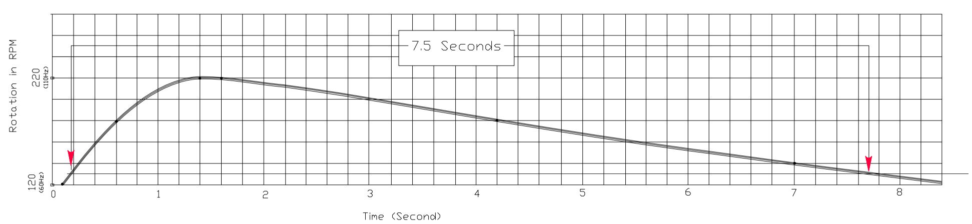

Figure B-2

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Appendix C — TR-22 Generator Backup Protection Responses in Cohesive Generation Groups

Observation

Generators that are electrically close to one another can behave as cohesive group, such as when islanded from the rest of the Interconnection. Generators can also remain in synchronism with each other within a zone and slip in frequency together with respect to the rest of the Interconnection when weakly tied to the Interconnection. Such was the case in southeast Michigan. In either case, protective relay functions can and did respond differently under such conditions.

The cohesive generator group can experience lower voltage, underfrequency, and large power flows brought on by large angles across its ties to the Interconnection. In the cascade, a number of relaying schemes intended to trip generators for their own protection operated. Examples include: inadvertent energization protection, volts/hertz overexcitation, voltage restrained overcurrent, undervoltage, and loss of excitation relays. The operations of these relays are sensitive to abnormal voltages and frequencies.

A number of generators reported tripping operations from these devices:

Initiating Tripping Relay	Number of Generators Tripped
Inadvertent energizing	6
Volts/Hertz	10
Voltage restrained overcurrent	4
Undervoltage	25
Overcurrent	15
Loss of excitation	11

Discussion

Inadvertent energizing is a protection scheme intended to detect an accidental energizing of a unit at standstill or a unit not yet synchronized to the power system. Two schemes used to detect inadvertent energizing are frequency supervised overcurrent and voltage supervised overcurrent. In frequency supervised overcurrent schemes, the underfrequency relays are set to close their contacts when the frequency falls below a setting, which is in the range of 48 – 55 Hz, thus enabling the overcurrent relay. Voltage supervised overcurrent schemes use under and overvoltage relays with pick-up and dropout time delays to supervise instantaneous overcurrent tripping relays. The undervoltage detectors automatically arm the over-current relays when its generation is taken off-line. Overvoltage relays disable the scheme when the machine is put back in service.

Volts/Hertz relays are used for overexcitation protection of generators. These relays become more prone to operation as frequency declines, given a particular voltage.

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Voltage restrained time-overcurrent relaying is remote backup protection used to protect generators for distant faults, and is not intended to trip on load.

Undervoltage relays respond to system conditions especially when connected to transmission level voltage transformers. Overcurrent relays respond to faults and to some non-fault conditions such as system swings.

The loss of excitation relay protects a generator in the event of an exciter failure. As with the Volts/Hertz relay, the loss of excitation relay should coordinate with generator excitation controls when these controls are functioning properly and exciter failures have not occurred.

51V Voltage Controlled Overcurrent protection is backup protection to use when overcurrent does not provide adequate sensitivity. It can discriminate between load current and steady state fault current. The latter can be smaller than full load current due to the large X_d and AVR constraints. It is susceptible to operation for sustained undervoltage conditions as confirmed during pre-blackout disturbance.

Recommendation TR–22

TR-22. NERC should evaluate these protection schemes and their settings for appropriateness including coordination of protection and controls when operating within a coherent generation weakly connected to an interconnection or in as an electrical island. Generators directly connected to the transmission system using a 51V should consider the use of an impedance relay instead.

~~Time (seconds)~~	~~.0095 to 2~~	~~600 to 10,000~~	~~1800 to 10,000~~	~~.0095 to 2~~

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Appendix D — Conversion Between P-Q And R-X

1 – From R-X to P-Q:

$$Sin\Theta = \frac{X}{\sqrt{R^2 + X^2}} \qquad Cos\Theta = \frac{R}{\sqrt{R^2 + X^2}}$$

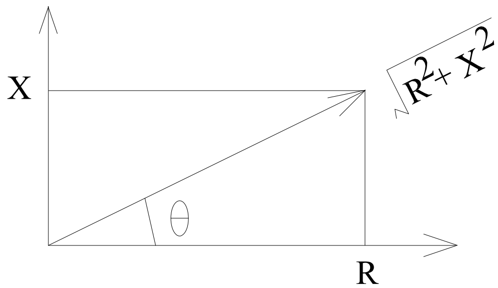

Figure D-1 — R-X Diagram

$$MVA_{prim} = \frac{V_{LL,prim}^2}{Z_{prim}} = \frac{V_{LL,prim}^2}{Z_{\sec}\left(\frac{VTR}{CTR}\right)} = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)$$

- $$P_{prim} = MVA_{prim}\cos\Theta = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)\left(\frac{R}{\sqrt{R^2+X^2}}\right) =$$
  $$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{R^2+X^2}}\right)\left(\frac{R}{\sqrt{R^2+X^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{R}{R^2+X^2}\right)$$

- $$Q_{prim} = MVA_{prim}\sin\Theta = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)\left(\frac{X}{\sqrt{R^2+X^2}}\right) =$$
  $$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{R^2+X^2}}\right)\left(\frac{X}{\sqrt{R^2+X^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{X}{R^2+X^2}\right)$$

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2 – From P-Q to R-X:

$$Sin\Theta = \frac{Q}{\sqrt{P^2+Q^2}} \qquad Cos\Theta = \frac{P}{\sqrt{P^2+Q^2}}$$

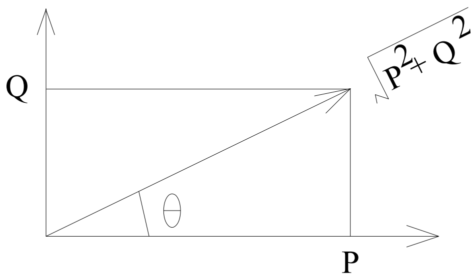

Figure D-2 — P-Q Diagram

$$MVA_{prim} = \frac{V_{LL,prim}^2}{Z_{prim}} = \frac{V_{LL,prim}^2}{Z_{\sec}\left(\frac{VTR}{CTR}\right)} = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{Z_{\sec}}\right)$$

$$Z_{prim} = \frac{V_{LL,prim}^2}{MVA_{prim}} = \frac{V_{LL,prim}^2}{\sqrt{P^2+Q^2}}$$

$$\text{Also, } Z_{\sec} = Z_{prim}\left(\frac{CTR}{VTR}\right) = \frac{V_{LL,prim}^2}{\sqrt{P^2+Q^2}}\left(\frac{CTR}{VTR}\right)$$

- $$R_{\sec} = Z_{\sec}\cos\Theta = \frac{V_{LL,prim}^2}{\sqrt{P^2+Q^2}}\left(\frac{CTR}{VTR}\right)\left(\frac{P}{\sqrt{P^2+Q^2}}\right) =$$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{P^2+Q^2}}\right)\left(\frac{P}{\sqrt{P^2+Q^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{P}{P^2+Q^2}\right)$$

- $$X_{\sec} = Z_{\sec}\sin\Theta = \frac{V_{LL,prim}^2}{\sqrt{P^2+Q^2}}\left(\frac{CTR}{VTR}\right)\left(\frac{Q}{\sqrt{P^2+Q^2}}\right) =$$

$$= V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{1}{\sqrt{P^2+Q^2}}\right)\left(\frac{Q}{\sqrt{P^2+Q^2}}\right) = V_{LL,prim}^2\left(\frac{CTR}{VTR}\right)\left(\frac{Q}{P^2+Q^2}\right)$$

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Appendix ~~F~~E — Supporting Calculations and Example Details for Section 3.1

Appendix ~~F~~E provides details in the form of equations and graphs to support the conclusions presented in Section 3.1 - Phase Distance Protection (Device 21). Section 3.1 describes two ways Device 21 can be set.

One way IEEE C37.102 recommends setting the Device 21 relay is 0.5 – 0.66 per unit (i.e. 200 percent – 150 percent) of the machine's load impedance at its rated power factor angle. In this approach, the setting provides generator stator thermal protection for transmission faults that do not clear due to relay failure. The Transmission Owner provides relay failure protection. It is not necessary to calculate reach into the power system as the setting is based only on the machine rating. A method for loadability testing this setting is presented using an example unit. Additionally, calculations are performed using recorded data from two units, one nuclear and one fossil that were on the perimeter of the blacked out region on August 14, 2003 that did not trip. These units did not use the Device 21. These calculations are an exercise to see if they would have tripped given a hypothetical Device 21 set at 0.5 – 0.66 per unit ohms using the actual machine data for August 14, 2003.

The second C37.102 approach to setting the Device 21 is to provide relay failure protection for transmission faults that do not trip. Two calculation examples demonstrate the impact of infeed from other lines (apparent impedance) when setting the Device 21. The calculations for these examples yield the results summarized in table 3.1 rows 1 and 2. A spreadsheet was developed to calculate device 21 settings for all of the rows in table 3.1. The setting impedances are presented in terms of transmission voltage level ohms and in terms of generator terminal voltage ohms. The latter being the most important in that the Device 21 measures impedance at this voltage. The settings are generally much larger than the 0.66 per unit impedance (machines base). The same loadability test is applied to these two examples to determine if the two settings will trip the unit for stressed system conditions.

Set the Device 21 relay at 0.5 – 0.66 per unit (i.e., 200 percent – 150 percent) of the machine's load impedance at its rated power factor angle.

The following equations will model a generating unit connected to a power system undergoing stress. Stress will be defined as a degraded transmission voltage at the terminals of the unit step-up transformer. Referring to Figure ~~F~~E-1 below:

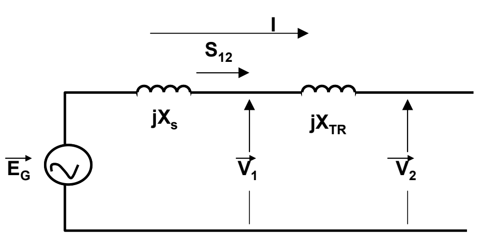

Figure ~~F~~E-1 — Generator and GSU Detail Model

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The basic equations[6] apply to the above circuit:

$$S_{12} = V_1 I_1^* = V_1 \left(\frac{V_1 - V_2}{Z} \right)^* = \frac{|V_1|^2}{|Z|} \angle z - \frac{|V_1||V_2|}{|Z|} \angle (z + \theta_{12})$$

θ_{12} is the angle across the step up transformer. If $\mathbf{V_2}$ is assumed to have the reference angle of 0 degrees then θ_{12} can be expressed as θ_1 and it is an unknown in the equation.

Substituting θ_1 and 90º for $\angle z$, then the equation can be simplified as follows:

$$S_{12} = V_1 I_1^* = j \frac{|V_1|^2}{|X_{TR}|} - \frac{|V_1||V_2|}{|X_{TR}|} \angle (90 + \theta_1)$$

V_2 will have a magnitude of 0.85 per unit and V_1 will be calculated based on the field forcing capability of the generator with a 2.09 per unit minimum.

> **Example 1: Given a Device 21 setting, perform a loadability test.** A 625 MVA unit has a Device 21 relay set at 0.66 per unit ohms on the machines base and at rated power factor.

Device 21 relays that are set at 0.5 – 0.66 per unit ohms on the machine base and at its rated power factor do not require a reach calculation as these relays are strictly set from a stator thermal rating perspective. A loadability calculation should be performed to assure the relays will not trip during stressed system conditions when the unit is not thermally stressed.

Machine Data:

- 625 MVA unit at .866 power factor
- Exciter maximum field forcing is 2.09 per unit for 10 seconds
- X_S, the synchronous reactance is 1.65 per unit reactance on the generator base
- X_{TR}, the generator step up transformer is 0.1 per unit reactance on the generator base.

Calculate the impedance measured by a device 21 set at 0.66 pu during a stressed system condition to assure that the relay as set will not trip the unit.

The test applies 0.85 pu steady state voltage on the terminals of the GSU and then calculates V_{relay}/I_{relay}, where V_{relay} equals the generator terminal voltage and I_{relay} equals the generator stator current. The machine exciter is in field forcing at 2.09 per unit as stated as the 10 second, short-time thermal limit for field windings in C50.13-2005 for cylindrical-rotor machines.

[6] Power System Analysis, Hadi Sadat, McGraw Hill Publishing, pp 26 - 28

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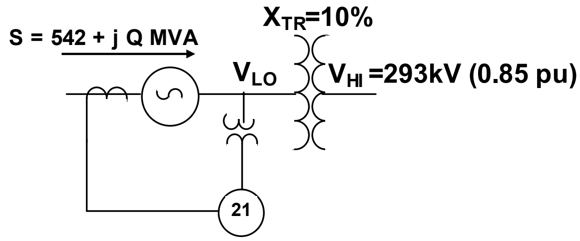

Figure ~~F~~E-2 — Example 1: Model of a Generator Connected to a Stressed System

Given:

1. $S_{Rated} = P_{Rated} + j\,Q_{Rated} = 542 + j312.5$ MVA = $625\angle 30°$ MVA (pf = .8666)
2. System stressed such that V_{HI} = 293-kV = 0.85 pu (V_{rated} = 345 kV)
3. Unit at full output = 625 MVA x .86666 = 542 MW
4. Exciter capable of 2.09 pu field current for 10 seconds (IEEE C50.13-2005).

Assuming saturation small, an approximation for internal machine voltage is:

$$E_{internal} = \omega_o M_F i_F / \sqrt{2} = 2.09\,pu$$

$$|E_{internal}| = \omega_o M_F i_F / \sqrt{2} = 2.09\,pu$$

$$P = .866 = \frac{|E_{internal}||V_{Hi}|}{1.65+0.1}\sin\delta = \frac{2.09\times .85}{1.75}\sin\delta$$

$$\delta = 58.5°$$

Calculate $Z_{Relay} = V_{LO}/I$:

From Figure ~~F~~E-2:

$$\vec{I} = \frac{\vec{E}_{internal} - \vec{V}_{Hi}}{j(X_S + X_{TR})}$$

$$= \frac{2.09\angle 58.5° - 0.85\angle 0°}{j(1.65+.1))} = \frac{1.0905 + j1.7829 - 0.85}{j1.75} = 1.028\angle -7.7°$$

$$V_{LO} = jX_{TR}\vec{I} + 0.85\angle 0 = 1.028\angle -7.7°(j0.1) + 0.85\angle 0$$
$$V_{LO} = 0.8698\angle 6.7°$$

$$Z_{Relay} = \frac{V_{LO}}{\vec{I}} = \frac{0.8698\angle 6.7°}{1.028\angle -7.7°} = .8461\angle 14.4°\,pu$$

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The relay "sees" .846 $\angle 14.4°$ pu ohms. This would be beyond a relay Mho circle if it were set 0.66 pu (along rated power factor angle) per IEEE C37.102 and it would not trip under load. A spreadsheet has been developed to perform the calculations for loadability for this example and examples 4, 5 and 6. The table below represents the spreadsheet calculation for example 1.

Table ~~F~~E-1 — Example 1: Device 21 Measured Impedance, Z_{relay} (pu)

θ_1 (°)	$\|V_2\|$	$\|X_{tr}\|$	S_{real}	X_S	$\|V_1\|$	$S_{12\ imaginary}$	$\|I\|$	$\theta_{current}$ (°)	$\|E_g\|$	θ_G (°)	$\|Z_{relay}\|$	θ_{relay} (°)
6.73	0.85	0.1	0.866	1.65	0.8732	0.2222	1.0280	-7.66	2.09	32.88	0.85	14.40

The next two examples are intended to evaluate loadability of a hypothetical Device 21 relay applied to actual generator data from the August 14, 2003 Blackout. These calculations are the basis for the results shown in table 3.2 of Section 3.1. In the two cases, the relay's calculated impedance is based on an actual unit data during the blackout. These units did not trip nor did they have Device 21 relays.

Example 2: Given an actual 900 MVA generator on the perimeter of the 8-14-2003 blacked-out region, calculate apparent impedance, Z_{relay} that could be measured by a hypothetical Device 21.

Given S_{Actual}, V_{HI}, S_{Rated}, P_{Rated}, Q_{Rated}, and V_{Rated}, calculate V_{LO}, I, Z_{Relay}

Metered Data:

$$S_{Actual} = P + jQ = 764 + j650 \text{ (MW + jMVAR)}$$

$$V_{HI} = 315 \text{ kV}$$

Ratings:

$$S_{Rated} = P_{Rated} + j\,Q_{Rated} = 760 + j490 \text{ MVA} = 904\angle 32.8° \text{ MVA (pf = .84)}$$

$$V_{Rated} = 345\text{-kV x } 1.00435 = 346.5 \text{ kV}$$

Base Quantities on Generator Base:

$$S_{PU} = S_{Actual}/|S_{Rated}| = 1.1095\angle 40.39°$$

$$\vec{V}_{HI} = \frac{315}{345}\angle 0° = 0.913\,pu \quad \text{(reference)}$$

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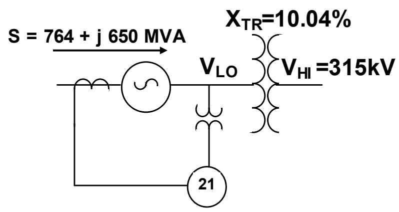

Figure ~~F~~E-3 — Example 2: Hypothetical Device 21 Applied to Actual Unit under Stressed Conditions

S_{12} is known as it is a measured quantity. Let it be 764 + j 650 MVA for a unit that has a rated MVA of 760 + j490 MVA (904 MVA unit with .84 pf). Then on a per unit basis, the unit output at this instant is 0.845 +j.719 or $1.109\angle 40.39°$ on the machine base. Let the transformer be 0.1 per unit also on the machine base. A stressed system will be defined as $|\mathbf{V}_2| = .913$ pu a measured quantity. From this data and assumptions, the unit terminal voltage, internal voltage and current can be calculated.

$$S_{12} = V_1 I_1^* = j\frac{|V_1|^2}{|0.1|} - \frac{|V_1|0.913}{|0.1|}\angle(90+\theta_1)$$

$$1.109\angle 40.39° = j10|V_1|^2 - 10(.913)|V_1|\angle(90+\theta_1)$$

Equating real and imaginary terms:

$0.84467 = -0.913\,|V_1|\cos(90+\theta_1)$ real component

$0.71897 = 10|V_1|^2 - 10(.913)|V_1|\sin(90+\theta_1)$ imaginary component

Solving for $|V_1|$ in the real equation:

$|V_1| = -.092558/\cos(90+\theta_1)$

Substituting for $|V_1|$ in the imaginary equation thus arriving as an equation with one unknown:

$$0.71894 = 10\left[\frac{-0.092558}{\cos(90+\theta_1)}\right]^2 - 9.13\left[\frac{-0.092558}{\cos(90+\theta_1}\right]\sin(90+\theta_1)$$

The equation can be solved iteratively for θ_1 which will then result is the solution of V_1 and I. Once I is solved, E_g can be determined as well.

Solving iteratively using the spreadsheet,

$\theta_1 = 5.407°$

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$$V_1 = \frac{-.092558}{\cos(95.4075°)} = .9822\,pu$$

$$I = \frac{V_1 - V_2}{jX_{TR}} = \frac{.98216\angle 5.407° - .913\angle 0}{j.1} = .9256 - j.648 = 1.13\angle -35°$$

As a check, $S_{12}=V_1I^*=.9822 \angle 5.4°$ x $1.13 \angle 35° = 1.1098 \angle 40.4°$

Having determined V_1 and I then the impedance measured by a backup impedance relay on the terminals of the machine becomes:

$$Z = \frac{V_1}{I} = \frac{.98216\angle 5.4°}{1.130\angle -35°} = .869\angle 40.4°\,pu$$

The impedance measured would be outside a mho circle of 0.66 pu as evaluated at the machines rated power factor angle (32.8º), the IEEE recommended maximum reach for a backup impedance relay.

Finally E_g is determined by adding IX_S to V_1. In this example Xs = 1.65 pu is assumed.

$\mathbf{E_g = V_1 + IX_S} = .9822 \angle 5.4° + 1.13 \angle -35°$ x $j1.65 = .9822 \angle 5.4° + 1.86 \angle 55°$

$\mathbf{E_g} = .9778 + j.0924 + 1.067 + j1.52 = 2.04 + j1.612 = 2.60 \angle 38.3°$ pu volts

Note that E_g is greater than 2.09 pu which if linear with the field current would have a 10 second thermal rating time limit per C50.13.

Example 3: Given actual metered data from an 860 MW generator during a stressed system condition, calculate apparent impedance, Z_{relay} that could be measured by a hypothetical Device 21.

For an 860 MW Fossil Unit on perimeter of 8/14/2003 Blacked Out Region, given nameplate data and recorded metering data (high-side GSU voltage and generator output MVA), calculate the apparent impedance measure by Device 21

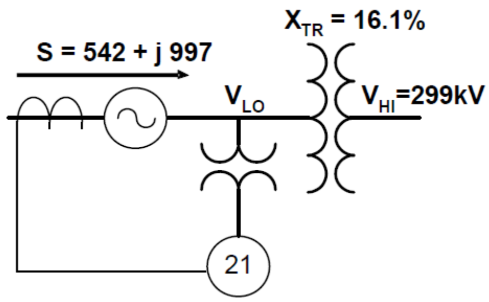

Figure ~~F-3~~E-4 — Example 3: Hypothetical Device 21 Applied to Actual Unit under Stressed Conditions

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Given S_{Actual}, V_{HI}, S_{Rated}, P_{Rated}, Q_{Rated}, and V_{Rated}, calculate V_{LO}, I, Z_{Relay}

Metered Data:

$$S_{Actual} = P + jQ = 542 + j997 \text{ (MW + jMVAR)} = 1134\angle 61.4°$$

$$V_{HI} = 299\text{-kV}$$

Ratings:

$$S_{Rated} = P_{Rated} + j\, Q_{Rated} = 860 + j667 \text{ MVA} = 1088\angle 37.8° \text{ MVA (pf = .79)}$$

$$V_{Rated} = 345\text{-kV}$$

Base Quantities on Generator Base

$$S_{PU} = S_{Actual}/|S_{Rated}| = 1.042\angle 61.4°$$

$$\vec{V}_{HI} = \frac{299}{345}\angle 0° = 0.866\,pu \quad \text{(reference)}$$

$$S_{12} = V_1 I_1^* = j\frac{|V_1|^2}{|X_{TR}|} - \frac{|V_1||V_2|}{|X_{TR}|}\angle(90+\theta_1)$$

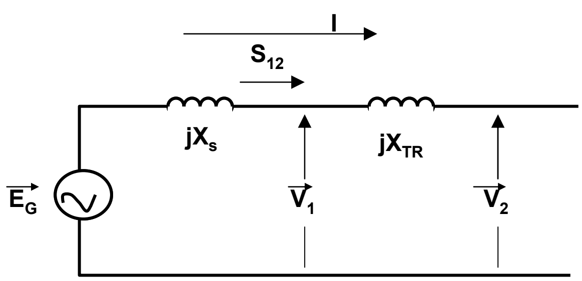

Figure ~~F-4~~E-5 — Example 3: Generator and GSU Model

S_{12} is known as it is a measured quantity. Let it be 542 + j 997 MVA for a unit that has a rated MVA of 860 + j667 MVA (1,088 MVA unit with 0.79 pf). On a per unit basis, the unit output at this instant is 0.499 +j.915 or 1.042 $\angle$61.4° on the machine base. Let the transformer be 0.161 per unit also on the machine base. A stressed system will be defined as $|\mathbf{V_2}|$ = .299 pu a measured quantity. From this data and assumptions, the unit terminal voltage, internal voltage and current can be calculated.

$$S_{12} = V_1 I_1^* = j\frac{|V_1|^2}{|0.161|} - \frac{|V_1|0.866}{|0.161|}\angle(90+\theta_1)$$

$$1.042\angle 61.4° = j6.211|V_1|^2 - 6.211(.866)|V_1|\angle(90+\theta_1)$$

Equating real and imaginary terms:

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$0.499 = -0.866 \times 6.211\, |V_1| \cos(90+\theta_1)$ real component

$0.915 = 6.211|V1|2 - 6.211(.866)|V1|\sin(90+\theta_1)$ imaginary component

Solving for $|V_1|$ in the real equation:

$|V1| = -.09277/\cos(90+\theta_1)$

Substituting for $|V_1|$ in the imaginary equation thus arriving as an equation with one unknown:

$0.915 = 6.211(-.09277/\cos(90+\theta_1))^2 - 6.211(.866)(-.09277/\cos(90+\theta_1))\sin(90+\theta_1)$

$$0.915 = 6.211\left[\frac{-0.09277}{\cos(90+\theta_1)}\right]^2 - 5.379\left[\frac{-0.09277}{\cos(90+\theta_1}\right]\sin(90+\theta_1)$$

The equation can be solved iteratively for θ_1 which will then result is the solution of V_1 and I. Once I is solved, E_g can be determined as well.

$\mathbf{E_g} = \mathbf{V_1} + \mathbf{IX_S} = 1.0099\ \angle 5.271^{\circ} + 1..0416\ \angle -56.3^{\circ} \times j1.65 = 2.65\ \angle 23.25^{\circ}$

Solving iteratively,

$\theta_1 = 5.271^{\circ}$

$$|V_1| = \frac{-.09277}{\cos(95.271^{\circ})} = 1.0099\, pu$$

$$I = \frac{V_1 - V_2}{jX_{TR}} = \frac{1.0099\angle 5.271^{\circ} - .866\angle 0}{j.161} = .5772 - j.867 = 1.0416\angle -56.3^{\circ}$$

As a check, $S_{12} = V_1 I^* = 1.00986\angle 5.27^{\circ} \times 1.0416\ \angle 56.3^{\circ} = 1.0518\ \angle 61.3^{\circ}$

Having determined V_1 and I then the impedance measured by a backup impedance relay on the terminals of the machine becomes:

$$Z = \frac{V_1}{I} = \frac{.1.00986\angle 5.27^{\circ}}{1.0416\angle -56.3^{\circ}} = .969\angle 61.6^{\circ}\, pu$$

Conclusion: For this unit also, a Device 21 set 0.5 – 0.66 pu ohms would not have operated.

The next two examples evaluate a 625 MVA unit under a 0.85 per unit criteria for high-side voltage and with its exciter in field forcing. The two examples set a backup impedance relay to detect a transmission line fault for transmission relay failure. These settings are evaluated against the IEEE C37.102 criteria of 0.5 – 0.66 per unit ohms along the machine's power factor angle without the additional proposed 0.85 per unit voltage extreme contingency criteria.

Example 4: Set the Device 21 to protect the unit and transmission system for transmission system relay failure. A loadability test will prove that this setting will not trip the unit for a stressed system condition.

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Set the Device 21 including the impacts of infeed from other sources of fault current.

In this example, the impedance relay is required to protect the generator by providing transmission system relay failure protection.

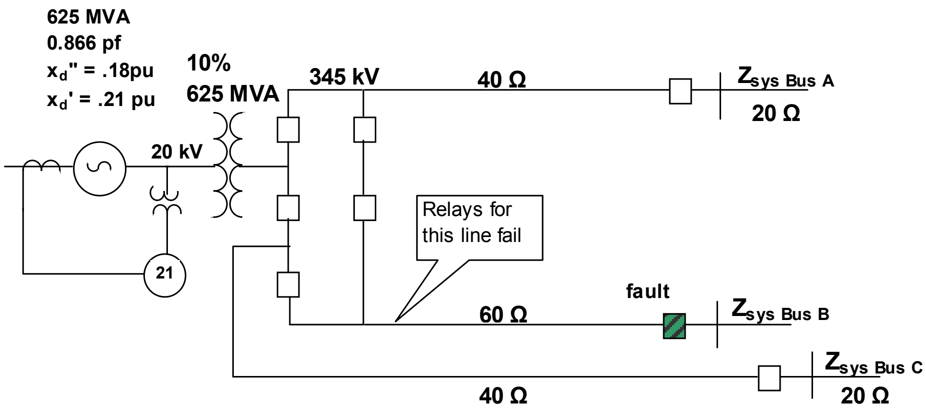

Figure ~~F-5~~E-6 — Example 4: Hypothetical 625 MVA Generator Connected to a 345-kV System by Three Lines

The longest line, 60 ohms, is faulted, three phase, at its Bus B end. Bus B circuit breaker for the line has opened. The backup relay for the generator must see this fault in the presence of infeed from Bus A and Bus C via their two 40 ohm lines.

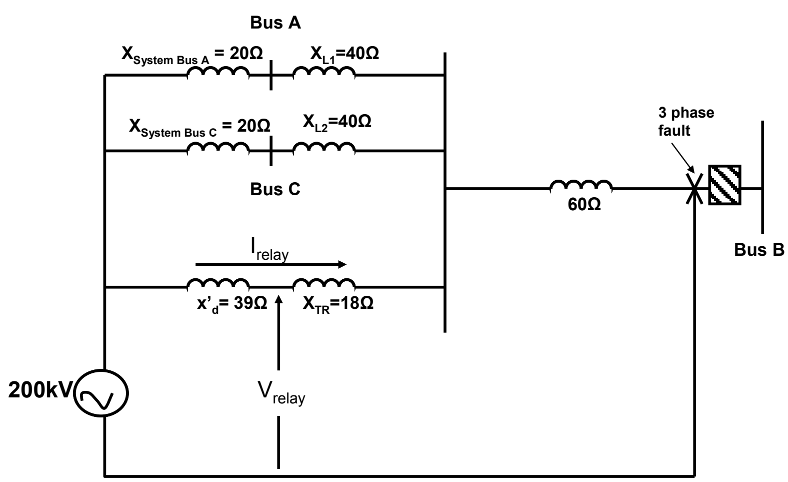

Figure ~~F-6~~E-7 — Example 4: Symmetrical Component Sequence Network

All system elements, generator transient reactance, transformer impedance, lines and equivalent impedances behind the buses A and C are given in ohms at 345-kV. The in 345-kV ohms, the 21 function relay, in the presence of infeed from Buses A and B see an impedance of:

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$$\frac{V_{Relay}}{I_{Relay}} = 18\Omega + \left[\frac{[30\Omega + 57\Omega]}{30\Omega}\right]60\Omega = 192\Omega$$

The relay must be set to see 120% of the longest line:

$$21_{setting at 345kV} = 18\Omega + \left[\frac{[30\Omega + 57\Omega]}{30\Omega}\right]1.2x60\Omega = 227.8\Omega$$

On a per unit basis and on the machine's base of 625 MVA, the device 21 setting at its angle of maximum reach is:

$$21_{setting pu} = \frac{227.8\Omega}{345^2 / 625} = 1.20\,pu$$

If the angle of maximum reach is 85º, then as can be seen from the geometry of the following diagram, the impedance magnitude (reach) along the 30º line is:

$$Z_{reach at 30^\circ} = Z_{\max reach angle} \cos(\theta_{\max reach} - 30^\circ) = 1.20\cos(85-30) = 0.69\,pu$$

In this case, the relay maximum reach angle is at its largest value per the manufacturer's instruction book. The reach is greater than the IEEE C37.102 guideline for loadability for normal conditions, 0.5 – 0.66 pu at the machines rated power factor angle which for this particular generator is 30º.

Note: System configurations can change the requirements for transmission system relay failure protection. In the below diagram, because the remote terminal is a ring bus, relay failure protection would require detection of faults on lines adjacent to the failed breaker as shown.

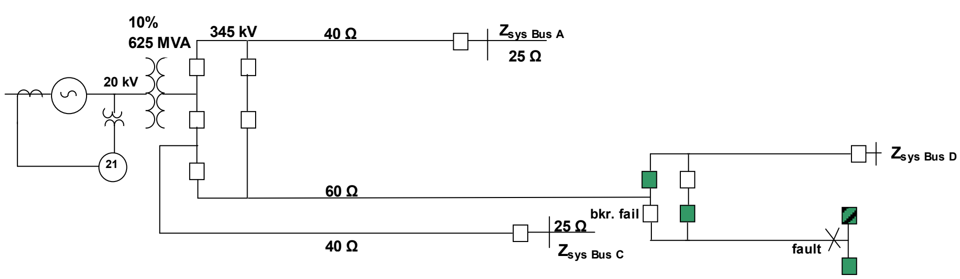

Figure ~~F-7~~E-8 — Connected to Remote Ring Bus

Example 4 Loadability Testing – Passing

Given the Example 4 settings just determined for the Device 21 (also summarized in Section 3.1 Table 3.1 row 1) that backup the transmission system check this setting for loadability using the definition of a stressed system condition 0.85 pu voltage on the high-side terminals of the generator step-up transformer and an internal machine voltage greater than or equal to 2.09 pu.

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The test applies 0.85 pu steady state voltage on the terminals of the GSU and then calculates V_{relay}/I_{relay}, where Vrelay equals the generator terminal voltage and I_{relay} equals the generator stator current. The machine exciter is in field forcing at 2.09 per unit as stated as the 10 second, short-time thermal limit for field windings in C50.13-2005 for cylindrical-rotor machines.

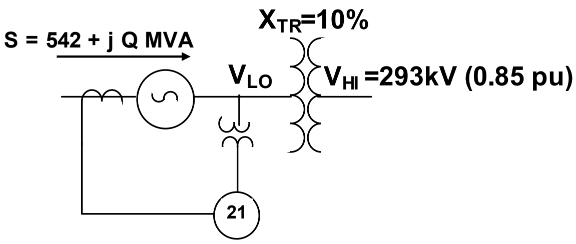

Figure ~~F-8~~E-9 — Example 4: Hypothetical Device 21 Applied to Actual Unit under Stressed Conditions

Given:

1. $S_{Rated} = P_{Rated} + j\,Q_{Rated} = 542 + j312.5$ MVA = $625\angle 30°$ MVA (pf = .8666)
2. System stressed such that V_{HI} = 293-kV = 0.85 pu (V_{rated} = 345-kV)
3. Unit at full output = 625 MVA x .86666 = 542 MW
4. Exciter capable of 2.09 pu field current for 10 seconds (IEEE C50.13-2005).

Assuming saturation small, an approximation for internal machine voltage is:

$$E_{internal} = \omega_o M_F i_F / \sqrt{2} = 2.09\,pu$$

$$|E_{internal}| = \omega_o M_F i_F / \sqrt{2} = 2.09\,pu$$

$$P = .866 = \frac{|E_{internal}||V_{Hi}|}{1.65 + 0.1}\sin\delta = \frac{2.09 \times .85}{1.75}\sin\delta$$

$$\delta = 58.5°$$

Calculate $Z_{Relay} = V_{LO}/I$:

From the figure:

$$\vec{I} = \frac{\vec{E}_{internal} - \vec{V}_{Hi}}{j(X_S + X_{TR})}$$

$$= \frac{2.09\angle 58.5° - 0.85\angle 0°}{j(1.65 + .1)} = \frac{1.0905 + j1.7829 - 0.85}{j1.75} = 1.028\angle -7.7°$$

$$V_{LO} = jX_{TR}\vec{I} + 0.85\angle 0 = 1.028\angle -7.7°(j0.1) + 0.85\angle 0$$
$$V_{LO} = 0.8698\angle 6.7°$$

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$$Z_{\text{Relay}} = \frac{V_{LO}}{\vec{I}} = \frac{0.8698\angle 6.7^\circ}{1.028\angle -7.7^\circ} = .8461\angle 14.4^\circ\, pu$$

The relay "sees" .846 $\angle 14.4^\circ$ pu ohms. This would be beyond a relay mho circle if it were set 0.69 pu (along rated power factor angle) per IEEE C37.102 and it would not trip under load.

A spreadsheet was developed to perform the above calculation. The results of its calculation is the measured impedance, Zrelay whose magnitude and phase angle, 0.85 pu $\angle 14.2^\circ$, is shown in columns 12 and 13 of Table ~~F~~E-2 when the machine internal voltage of 2.0902 pu. At 14.42º, a Device 21 relay set at 1.2 $\angle 85^\circ$, would measure:

$$Z_{setting}\angle 16.33^\circ = 1.2\,pu \times \cos(85^\circ - 16.33^\circ) = 0.44\,pu$$

This relay setting for this unit and this system configuration passes the loadability test since as $|Z_{setting}|$ = 0.399 pu is less than the relay measured impedance $|Z_{relay}|$ = 0.8461 pu..

Table ~~F~~E-2 — Example 4: Device 21 Measured Impedance, Z_{relay} pu

θ_1 (º)	$\lvert V_2\rvert$	$\lvert X_{tr}\rvert$	S_{real}	X_S	$\lvert V_1\rvert$	S_{12} imaginary	$\lvert I\rvert$	$\theta_{current}$ (º)	$\lvert E_g\rvert$	θ_G (º)	$\lvert Z_{relay}\rvert$	θ_{relay} (º)
6.727	0.85	0.1	0.866	1.65	0.8698	0.2227	1.0281	-7.70	2.0902	31.46	0.85	14.42

Example 5: Set the Device 21 including the impacts of infeed from other sources of fault current. A loadability test will prove that this setting will fail.

In this example, the impedance relay is required to protect the generator by providing relay failure protection. A 625 MVA generator is connected to a 345-kV system by three lines as in example 4. Using the same system configuration and now changing the impedances of the unfaulted lines from 40 ohms to 20 ohms, results in stronger sources of fault current from the unfaulted lines and their sources. To detect this fault with the generator Device 21 in the presence of this stronger infeed, the Device 21 must be set at 1.10 pu on the machine base. The settings results are determined exactly like the previous example. The results are presented in Section 3.1 Row 2 and shown below.

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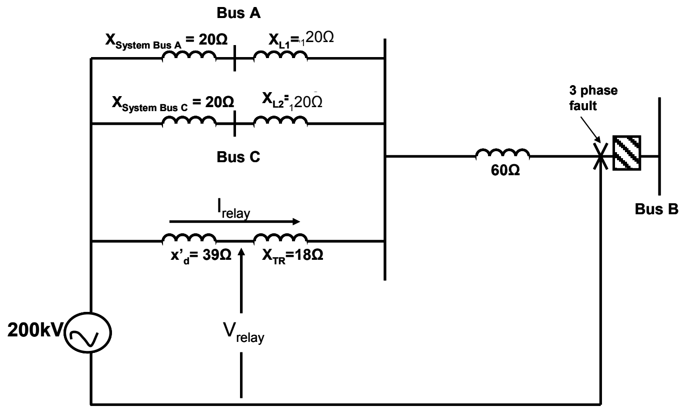

Figure ~~F-9~~E-10 — Example 5: Symmetrical Component Sequence Network

$$\frac{V_{\text{Relay}}}{I_{\text{Relay}}} = 18\Omega + \left[\frac{[20\Omega + 57\Omega]}{20\Omega}\right] 60\Omega = 249\Omega$$

The relay must be set to see 120 percent of the longest line:

$$21_{settingat345kV} = 18\Omega + \left[\frac{[20\Omega + 57\Omega]}{20\Omega}\right] 1.2x60\Omega = 295.2\Omega$$

On a per unit basis and on the machine's base of 625 MVA, the device 21 setting at its angle of maximum reach is:

$$21_{settingpu} = \frac{295.2\Omega}{345^2 / 625} = 1.55\,pu$$

If the angle of maximum reach is 75º, then as can be seen from the geometry of the following diagram, the impedance magnitude (reach) along the 30º line is:

$$Z_{reachat30^\circ} = Z_{\max reachangle} \cos(\theta_{\max reach} - 30^\circ) = 1.55\cos(75 - 30) = 1.10\,pu$$

Table ~~F~~E-3 — Example 5: Device 21 Calculated Setting, $Z_{setting}$ pu

Nominal Voltage at GSU Highside (kV)	Nominal Voltage at Generator Terminal (kV)	Size of Generator (MVA)	Impedance of Faulted Line (Ω)	Impedance of Non-faulted Line (Ω)	21 Setting EHV Ohms (Ω)	21 Setting Generator Side Ohms (Ω)	Base Impedance Generator Side (Ω)	21 Setting at Max Reach (pu)	21 Reach at (30º) (pu)
345	20	625	60	20	295.2	0.992	0.64	1.55	1.10

The same loadability testing method is used for this 1.10 pu ohm setting to determine if the unit will trip under stressed system conditions. The equations presented in Example 4 were programmed into a spread sheet to obtain the following results.

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The loadability test -was programmed into the spreadsheet as follows: Given the stressed system voltage, V_2 = 0.85 pu, X_{TR} and X_S, calculate -$Z_{relay} = V_1/I$ in both magnitude and phase angle. To do this, V_1 (Generator terminal voltage) is calculated in magnitude by inputting θ_1 (the angle of V_1) iteratively by rows via the power flow equation where $P = S_{real}$ (an input) is the machine's maximum real power output in per unit on the machines MVA base. $|E_G|$ (the machine internal voltage) is the known field forcing magnitude (e.g. = 2.09 or 3.00 pu or etc.). I_1 is calculated from the inputted real component of power and the calculated imaginary component of power. The above equations used to develop this spreadsheet.

In this example, the generator synchronous reactance, X_S = 2.0, and E_G during field forcing is 3.0 by machine design. These values are intended to represent modern machines installed within the last 5 years.

Table ~~F~~E-4 — Example 5: Device 21 Measured Impedance, Z_{relay} pu

θ_1 (º)	$\|V_2\|$	$\|X_{tr}\|$	S_{real}	X_S	$\|V_1\|$	S_{12} imaginary	$\|I\|$	$\theta_{current}$ (º)	$\|E_g\|$	θ_G (º)	$\|Z_{relay}\|$	θ_{relay} (º)
6.39	0.85	0.1	0.866	2	0.9154	0.6472	1.1810	-30.4	3.0010	44.53	0.78	36.77

The impedance measured by the Device 21 during stressed system conditions is 0.78 per unit ohms (on the machine base) at an angle of 36.18º. The relay is set at 1.56 per unit ohms on the machine base with an angle of maximum reach of 75º. This setting causes a trip at 1.10 per unit ohms a load angle of 30 degrees. At the study angle of 36.18º, the Device 21 will trip at 1.21 pu ohms or less. **Thus it is judged that this setting would cause the relay to trip during stressed system conditions.**

The remedy to this predicament is to provide relay failure protection at the transmission system level preferably. This can be attained by using redundant systems of protection for the transmission lines. Another possibility is to modify the characteristic of the Device 21 such as changing the angle of maximum reach, adding blinders, load encroachment or offsetting the relay from the origin. See **Methods to Increase Loadability** in Section 3.1. These methods must be utilized without changing the maximum reach of the Device 21 setting if relay failure protection is to remain effective.

Apparent Impedance Caused By Infeed From Other Fault Current Sources

The method of calculating the effect of infeed (also known as apparent impedance) is akin to a current divider relationship of two circuit paths in parallel. The positive sequence equivalent diagram for the example is shown below. The model combines impedances behind the faulted line. The generator impedance relay measures the quotient V_{gen}/I_{relay}

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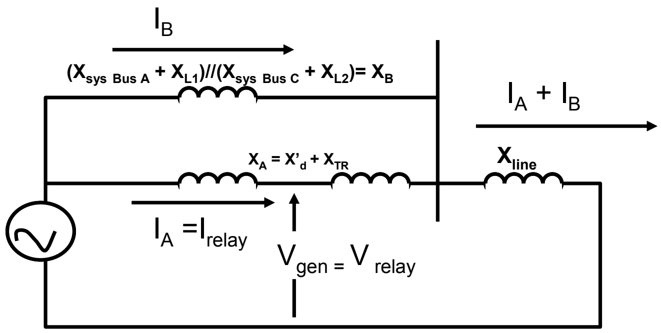

Figure ~~F-10~~E-11 — Reduced Positive Sequence Network

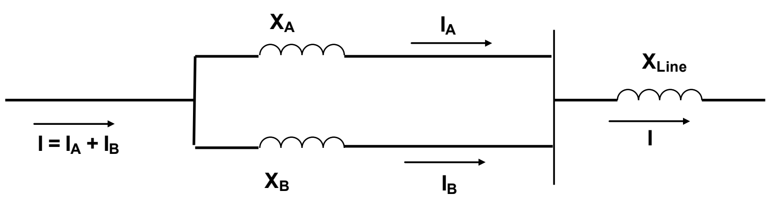

Figure ~~F-11~~E-12 — Current Divider Relationship

Restating I in terms of I_A and recognizing the current divider relationship of the impedance branches:

$$I_A = I\left(\frac{X_B}{X_A + X_B}\right)$$

$$I = I_A\left(\frac{X_B + X_A}{X_B}\right)$$

$$V_{Relay} = I_A X_{TR} + I_A\left(\frac{X_B + X_A}{X_B}\right) X_{Line}$$

$$I_{Relay} = I_A$$

$$Z_{Relay} = \frac{V_{Relay}}{I_{Relay}} = X_{TR} + \left(\frac{X_B + X_A}{X_B}\right) X_{Line}$$

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Appendix ~~G~~F — Setting Example For Out Of Step Protection

Consider the power system of the Figure ~~G~~F-1, corresponding to the Example 14.9 from the book *Elements of Power System Analysis* by William D. Stevenson. This case is used to illustrate the procedure to determine the critical clearing time and the traveling time within the blinders of an Out of Step relay by means of a transient stability study. The other settings of the relay are rather straightforward as they depend on the reactances of the elements and will not be illustrated here. The transient stability analysis will be carried out for a three-phase fault over line L_45, close to node 4.

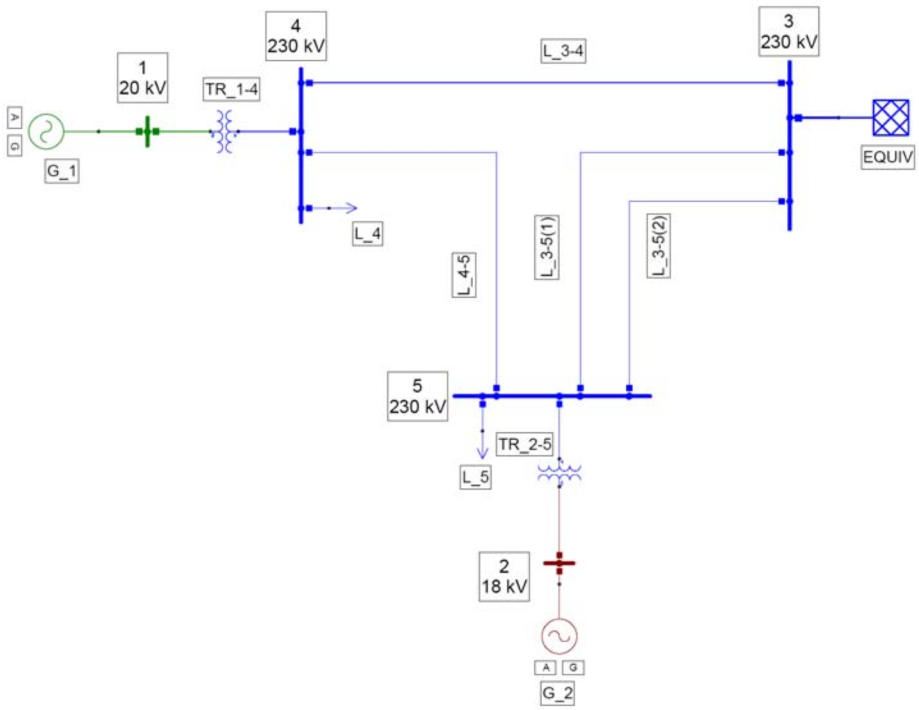

Figure ~~G~~F-1 — Example Power System

A. Considerations

The following considerations are used in the stability study:

- The fault inception will be considered at t = 0.5 seconds

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- Clearing times starting at t = 90 ms (approx. 5 cycles) will be used in consecutive steps of 10 ms.
- For simplicity, the fault is removed with the consequent outage of the line.
- The voltage regulator is IEEE type ST1 Excitation System. This voltage regulator is of static excitation type where the rectifiers provide enough DC current to feed the generator field. The model represents a system with the excitation power supplied from a transformer fed from the generator terminals or from the auxiliary services and is regulated by controlled rectifiers.
- The turbine-governor is IEEE type 1 Speed Governing Model. This model represents the system of speed control (Mechanical-Hydraulic) and steam turbine.
- For this machine no power system stabilizer is available.

The models for the voltage regulator and governor are shown in the figures G-2 and G-3.

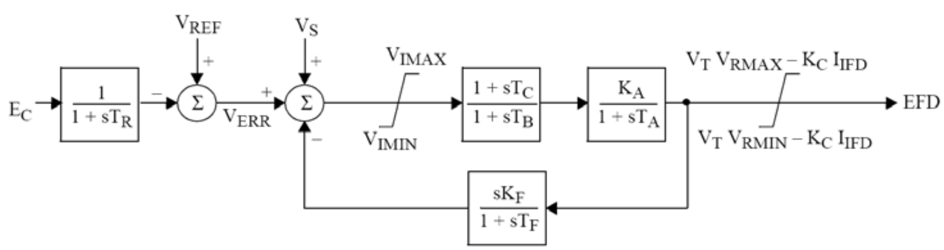

Figure ~~G~~F-2 — IEEE type ST1 Excitation System

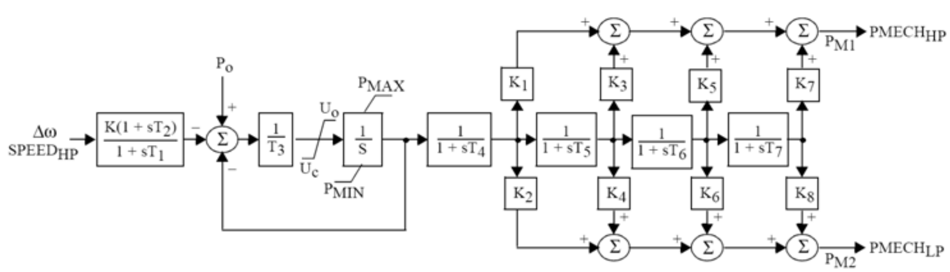

Figure ~~G~~F-3 — IEEE type 1 Speed Governing Model

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B. Critical Clearing Time

Determining the critical clearing time is perhaps the most elaborate part of the entire setting process. To achieve this, several runs of the transient stability study have to be done to determine when the system looses synchronism or has the first slip.

C. Results

The transient stability analysis is run for a three-phase fault on line L_45, near node 4. The solution can be obtained by using any commercially available software package.

Numerous cases were run with clearing times starting at t = 90 ms with increments of 10 ms in an iterative process until stability was lost. The results of three representative cases were analyzed and correspond to the critical clearing times obtained that are shown in the following table:

Table ~~G~~F-1 — Case Summary

Case	Fault Clearance Time (ms)
1	90
2	180
3	190

Several plots from the transient stability runs can be obtained for a myriad of applications. For setting out-of-step elements the most important information is the Rotor Angle vs. Time and R + j X vs. time. From the respective plots it can be observed that in Case 1, with a clearing time of 90 milliseconds, the system remains in synchronism. In Case 2, G1 and the system are still in synchronism with a clearing time of 180 milliseconds. For case 3, G1 looses synchronism with a clearing time is 190 ms. From the above it is evident that the critical time to clear the fault is equal to 180 ms after fault inception.

The rotor angles for the three cases are shown in Figure ~~G~~F-4, from which it can be seen that the critical angle is approximately 140°. The time for the swing locus to travel from the critical angle to 180° is approximately 250 milliseconds. Therefore the time delay setting should be set to 250 milliseconds.

This figure also illustrates the benefit of having voltage regulator and voltage governor responses which are shown with the continuous lines. Under these conditions, the performance of the system is much better than that of the case when there are no controls or the controls in manual mode.

It can be observed that when there are no controls, the excursions of the rotor angles are higher especially from the second oscillation upwards and also that the system tends to stabilize faster.

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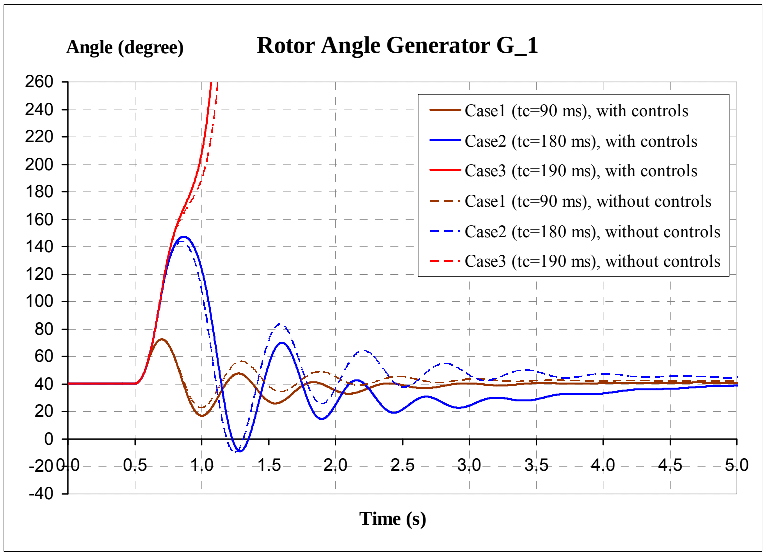

Figure ~~G~~F-4 — Rotor Angle vs Time from the Three Cases Considered

R vs. X diagrams for the three cases show the trajectory followed by the impedance seen by the relay during the disturbances. When there is an oscillation in the generator which is stable, the swing locus does not cross the impedance line.

When generator goes out-of-step, the transient swing crosses the system impedance line each time a slip is completed and the relay should trip the generator. Figures G-5.1 through G-5.3 show the diagram R vs. X for cases 1, 2, and 3. In the first two cases it is clear that the load point does not cross the system impedance line. For case 3, the load point crosses the system impedance line indicating that the synchronism is lost and therefore out-of-step tripping must be allowed. Figure ~~G~~F-6 shows the diagrams for all the three cases.

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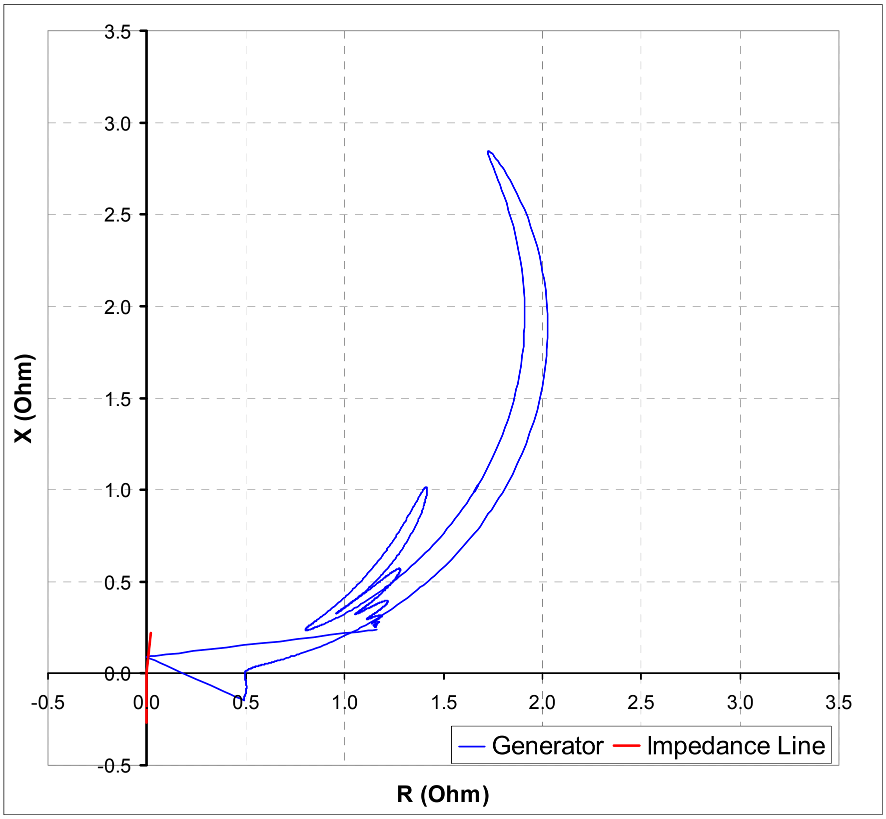

Figure ~~G~~F-5.1 — Diagram R vs X for Case 1

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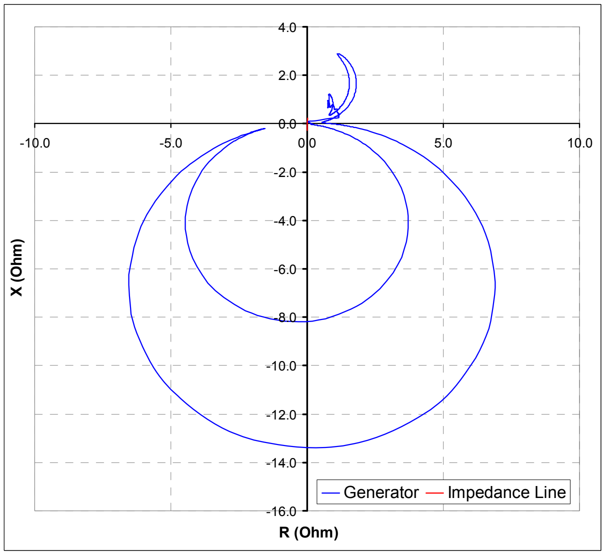

Figure ~~G~~F-5.2 — Diagram R vs X for Case 2

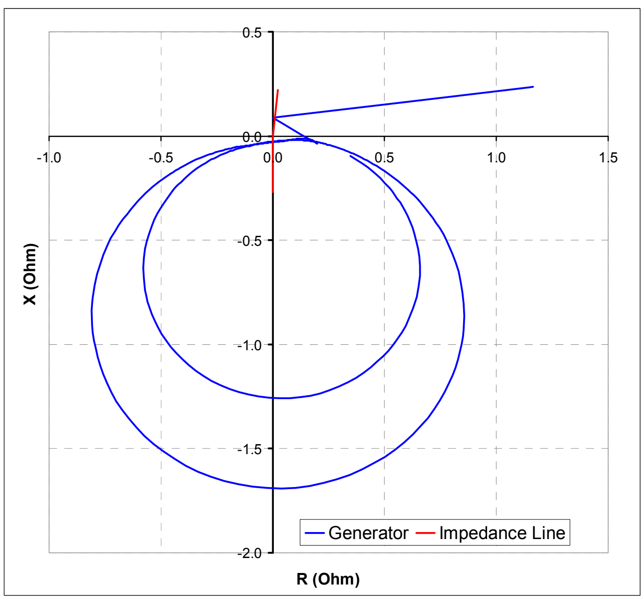

Figure ~~G~~F-5.3 — Diagram R vs X for Case 3

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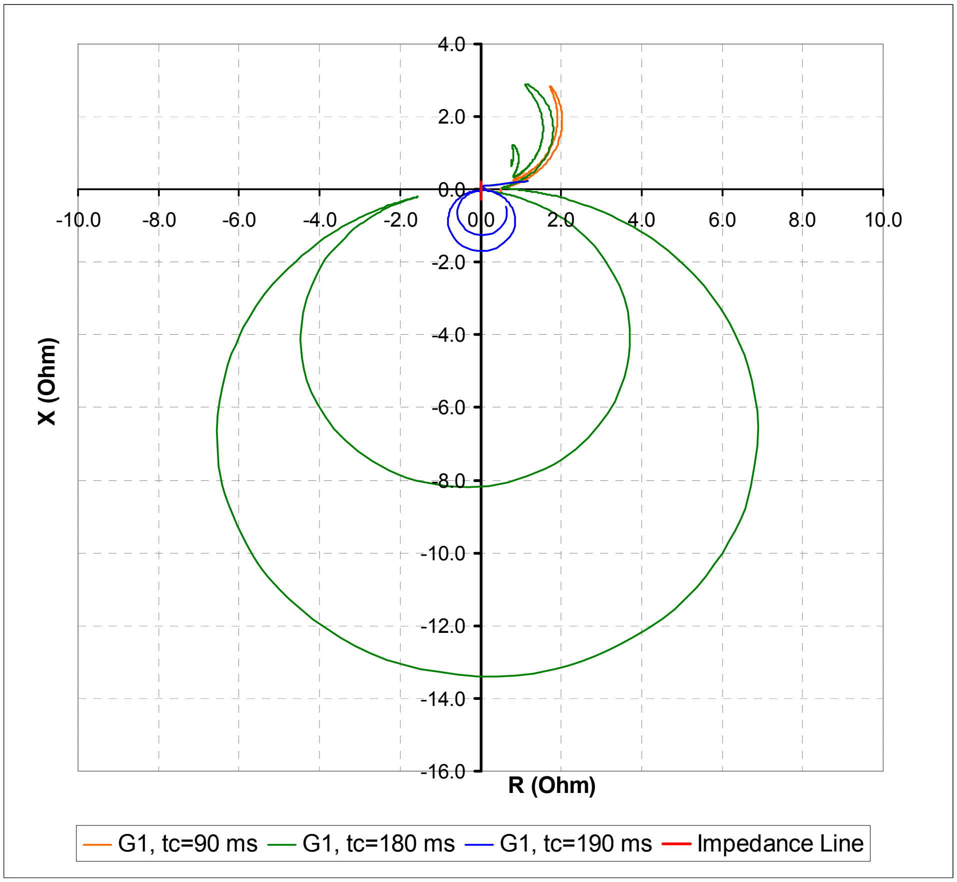

Figure ~~G~~F-6 — Diagram R vs X for cases 1, 2 and 3

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Appendix ~~H~~G — System Protection and Controls Subcommittee Roster

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