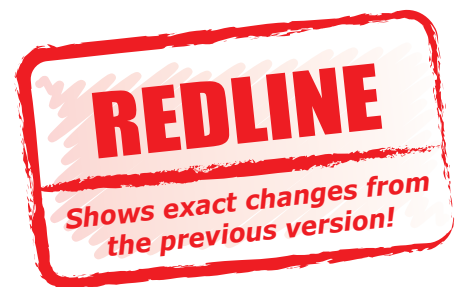




IEEE Guide for AC Generator Protection

IEEE Power Engineering Society

Sponsored by the
Power System Relaying Committee



IEEE
3 Park Avenue
New York, NY 10016-5997, USA

16 February 2007

IEEE Std C37.102™-2006
(Revision of
IEEE Std C37.102-1995)

This is a Redline Document produced by Techstreet, a business of Thomson Reuters.

This document is intended to provide users with an indication of changes from one edition to the next. It includes a full-text version of the new document, plus an indication of changes from the previous version.

Redlines are designed to save time and improve efficiencies by using the latest software technology to find and highlight document changes. More professionals are using valuable new technologies like redlines, to help improve outcomes in a fastpaced global business world.

Because it may not be technically possible to capture all changes accurately, it is recommended that users consult previous editions as appropriate. In all cases, only the current base version of this publication is to be considered the official document.

Redline Processing Notes:

1. ~~Red Text~~ - Red strikethrough text denotes deletions.
2. Blue Text - Blue underlined text denotes modifications and additions.

IEEE Std C37.102™-2006

(Revision of
IEEE Std C37.102-1995)

IEEE Guide for AC Generator Protection

Sponsor

**Power System Relaying Committee
of the
IEEE Power Engineering Society**

Approved 16 November 2006

IEEE-SA Standards Board

The IEEE thanks the International Electrotechnical Commission (IEC) for permission to reproduce information from its International Standard IEC 60034-3:2005, "Rotating Electrical Machinery, Part 3: Specific requirements for cylindrical rotor synchronous machines." All such extracts are copyright of IEC, Geneva, Switzerland. All rights reserved. Further information on the IEC is available from www.iec.ch. IEC has no responsibility for the placement and context in which the extracts and contents are reproduced by the author, nor is IEC in any way responsible for the content or accuracy therein.

Abstract: A review of the generally accepted forms of relay protection for the synchronous generator and its excitation system is presented. This guide is primarily concerned with protection against faults and abnormal operating conditions for large hydraulic, steam, and combustion turbine generators.

Keywords: ac generator protection, relay protection, synchronous generator

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

Copyright © 2007 by the Institute of Electrical and Electronics Engineers, Inc.
All rights reserved. Published 16 February 2007. Printed in the United States of America.

IEEE is a registered trademark in the U.S. Patent & Trademark Office, owned by the Institute of Electrical and Electronics Engineers, Incorporated.

Print: ISBN 0-7381-5249-8 SH95584
PDF: ISBN 0-7381-5250-1 SS95584

No part of this publication may be reproduced in any form, in an electronic retrieval system or otherwise, without the prior written permission of the publisher.

IEEE Standards documents are developed within the IEEE Societies and the Standards Coordinating Committees of the IEEE Standards Association (IEEE-SA) Standards Board. The IEEE develops its standards through a consensus development process, approved by the American National Standards Institute, which brings together volunteers representing varied viewpoints and interests to achieve the final product. Volunteers are not necessarily members of the Institute and serve without compensation. While the IEEE administers the process and establishes rules to promote fairness in the consensus development process, the IEEE does not independently evaluate, test, or verify the accuracy of any of the information contained in its standards.

Use of an IEEE Standard is wholly voluntary. The IEEE disclaims liability for any personal injury, property or other damage, of any nature whatsoever, whether special, indirect, consequential, or compensatory, directly or indirectly resulting from the publication, use of, or reliance upon this, or any other IEEE Standard document.

The IEEE does not warrant or represent the accuracy or content of the material contained herein, and expressly disclaims any express or implied warranty, including any implied warranty of merchantability or fitness for a specific purpose, or that the use of the material contained herein is free from patent infringement. IEEE Standards documents are supplied “**AS IS.**”

The existence of an IEEE Standard does not imply that there are no other ways to produce, test, measure, purchase, market, or provide other goods and services related to the scope of the IEEE Standard. Furthermore, the viewpoint expressed at the time a standard is approved and issued is subject to change brought about through developments in the state of the art and comments received from users of the standard. Every IEEE Standard is subjected to review at least every five years for revision or reaffirmation. When a document is more than five years old and has not been reaffirmed, it is reasonable to conclude that its contents, although still of some value, do not wholly reflect the present state of the art. Users are cautioned to check to determine that they have the latest edition of any IEEE Standard.

In publishing and making this document available, the IEEE is not suggesting or rendering professional or other services for, or on behalf of, any person or entity. Nor is the IEEE undertaking to perform any duty owed by any other person or entity to another. Any person utilizing this, and any other IEEE Standards document, should rely upon the advice of a competent professional in determining the exercise of reasonable care in any given circumstances.

Interpretations: Occasionally questions may arise regarding the meaning of portions of standards as they relate to specific applications. When the need for interpretations is brought to the attention of IEEE, the Institute will initiate action to prepare appropriate responses. Since IEEE Standards represent a consensus of concerned interests, it is important to ensure that any interpretation has also received the concurrence of a balance of interests. For this reason, IEEE and the members of its societies and Standards Coordinating Committees are not able to provide an instant response to interpretation requests except in those cases where the matter has previously received formal consideration. At lectures, symposia, seminars, or educational courses, an individual presenting information on IEEE standards shall make it clear that his or her views should be considered the personal views of that individual rather than the formal position, explanation, or interpretation of the IEEE.

Comments for revision of IEEE Standards are welcome from any interested party, regardless of membership affiliation with IEEE. Suggestions for changes in documents should be in the form of a proposed change of text, together with appropriate supporting comments. Comments on standards and requests for interpretations should be addressed to:

Secretary, IEEE-SA Standards Board
445 Hoes Lane
Piscataway, NJ 08854
USA

Authorization to photocopy portions of any individual standard for internal or personal use is granted by the Institute of Electrical and Electronics Engineers, Inc., provided that the appropriate fee is paid to Copyright Clearance Center. To arrange for payment of licensing fee, please contact Copyright Clearance Center, Customer Service, 222 Rosewood Drive, Danvers, MA 01923 USA; +1 978 750 8400. Permission to photocopy portions of any individual standard for educational classroom use can also be obtained through the Copyright Clearance Center.

Introduction

This introduction is not part of IEEE Std C37.102-2006, IEEE Guide for AC Generator Protection.

IEEE Std C37.102 was initially published in 1987. It was subsequently revised in 1995 and reaffirmed in 2002. The guide is designed for the protection of typical steam, hydraulic, and combustion turbine generators (CTGs). Schemes that are judged to be good alternative practice for generator protection are included. New schemes that have gained acceptance and usage have been added to the guide.

In this revision of IEEE Std C37.102-1995, several areas were improved. Among the most notable are the following additions:

- A new clause (Clause 6) on multifunction generator protection systems (MGPS)
- A new annex (Annex A) on sample calculations for setting of generator protection functions

Notice to users

Errata

Errata, if any, for this and all other standards can be accessed at the following URL: <http://standards.ieee.org/reading/ieee/updates/errata/index.html>. Users are encouraged to check this URL for errata periodically.

Interpretations

Current interpretations can be accessed at the following URL: <http://standards.ieee.org/reading/ieee/interp/index.html>.

Patents

Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken with respect to the existence or validity of any patent rights in connection therewith. The IEEE shall not be responsible for identifying patents or patent applications for which a license may be required to implement an IEEE standard or for conducting inquiries into the legal validity or scope of those patents that are brought to its attention.

Participants

The following is a list of participants in the Revision of AC Generator Protection Guide Working Group:

Murty V.V.S. Yalla, *Chair*

Kevin Stephan, *Vice Chair*

Munnu Bajpai
Matt Basler
Gabriel Benmouyal
Zeeky Bukhala
Steve Conrad
Terry Crawley
Albert Darlington
Ratan Das

Everett Fennell
Jonathan Gardell
Wayne Hartmann
Patrick Kerrigan
Shoukat Khan
Prem Kumar
Raimo Marttila
Charles Mozina
Subhash Patel

Robert Pettigrew
R.Vittal Rebbapragada
Michael Reichard
Sam N. Sambasivan
Michael Thompson
Joe Uchiyama
Sahib Usman
W. Phil Waudby

The following members of the individual balloting committee voted on this standard. Balloters may have voted for approval, disapproval, or abstention.

William Ackerman	Wayne Hartmann	Pratap Mysore
Ali Al Awazi	Roger Hedding	Krste Najdenkoski
Jay Anders	Adrienne Hendrickson	Brad Nelson
Marcos Andrade	Charles Henville	Michael Newman
John Appleyard	Gary Heuston	Nils Nilsson
Stan J. Arnot	Robert Hoerauf	Greg Nolan
Sabir Azizi-Ghannad	Jerry Hohn	T. W. Olsen
Munnu Bajpai	Edward Horgan Jr.	Carlos Peixoto
Michael Baldwin	John Horwath	Lorraine Padden
George Bartok	Dennis Horwitz	Subhash Patel
Farouk Baxter	James D. Huddleston, III	Robert Pettigrew
Thomas Beckwith	James Ingleson	Iulian Profir
Gabriel Benmouyal	David Jackson	Madan Rana
Thomas Bishop	Joseph Jancauskas	R. Vittal
Thomas Blackburn, III	Brian Johnson	Rebbapragada
Oscar Bolado	Gerald Johnson	Michael Reichard
Stuart Borlase	Reinhard Joho	Michael Roberts
Stuart Bouchev	James H. Jones	Charles Rogers
Steven Brockschink	Innocent Kamwa	James Ruggieri
Daniel Brosnan	Patrick Kerrigan	Tarkeshwar Singh
Gustavo Brunello	Yuri Khersonsky	Daniel Sabin
Jeff Burnworth	Geoffrey Klempner	Mohindar S. Sachdev
Weijen Chen	Joseph L. Koepfinger	Sam N. Sambasivan
Simon R. Chano	David Kornegay	Steven Sano
Simon H. Cheng	Edward Krizauskas	Robert Schuerger
Keith Chow	Prem Kumar	Stephen Shull
Terry Conrad	James Lau	Tarlochan Sidhu
Luis Coronado	Quang-Minh Le	Chuck Simmons
Terry Crawley	Wei-Jen Lee	Dave Singleton
John Crouse	Boyd Leuenberger	James E. Smith
Stephen Dare	Blane Leuschner	Jerry Smith
Ratan Das	Jason Lin	Allan St. Peter
R. Daubert	Bill Lockley	Kevin Stephan
Byron Davenport	Lisardo Lourido	Peter Stevens
Matthew Davis	William Lowe	Charles Sufana
Paul Drum	Gregory Luri	Rick Taylor
Donald Dunn	Al Maguire	Shanmugan
Ahmed El-Serafi	Keith Malmedal	Thamilarasan
Walter Elmore	William Marsh	Michael Thompson
Ahmed Elneweih	Jesus Martinez	Demetrios Tziouvaras
Gary Engmann	Raimo Marttila	Eric Udren
Jorge Fernández-Daher	Michael McDonald	Gerald Vaughn
Jay Fischer	Mark McGranaghan	Joe Watson
Carl Fredericks	Nigel McQuin	W. Phil Waudby
Jonathan Gardell	Michael Meisinger	Thomas Wiedman
Trilok Garg	James Michalec	James Wilson
Anthony Giuliant	Gary Michel	John Yale
Ron Greenthaler	Bill Moncrief	Murty V.V.S. Yalla
William Griesacker	Charles Morse	Larry Yonce
Travis Griffith	William Moylan	Luis Zambrano
Ajit Gwal	Charles Mozina	Karl Zimmerman
Paul Hamer	Brian Mugalian	Ahmed Zobaa
	Jerry Murphy	

When the IEEE-SA Standards Board approved this standard on 16 November 2006, it had the following membership:

Steve M. Mills, *Chair*
Richard H. Hulett, *Vice Chair*
Don Wright, *Past Chair*
Judith Gorman, *Secretary*

Mark D. Bowman
Dennis B. Brophy
William R. Goldbach
Arnold M. Greenspan
Robert M. Grow
Joanna N. Guenin
Julian Forster*
Mark S. Halpin
Kenneth S. Hanus

William B. Hopf
Joseph L. Koepfinger*
David J. Law
Daleep C. Mohla
T. W. Olsen
Glenn Parsons
Ronald C. Petersen
Tom A. Prevost

Greg Ratta
Robby Robson
Anne-Marie Sahazizian
Virginia C. Sulzberger
Malcolm V. Thaden
Richard L. Townsend
Walter Weigel
Howard L. Wolfman

*Member Emeritus

Also included are the following nonvoting IEEE-SA Standards Board liaisons:

Satish K. Aggarwal, *NRC Representative*
Richard DeBlasio, *DOE Representative*
Alan H. Cookson, *NIST Representative*

Don Messina
IEEE Standards Program Manager, Document Development

Matthew J. Ceglia
IEEE Standards Program Manager, Technical Program Development

Contents

1.	Scope.....	1
1.1	Description of the guide.....	1
2.	Normative references	2
3.	Description of generators, excitation systems, and generating station arrangements.....	3
3.1	Generator winding design and arrangements.....	3
3.2	Generator grounding	4
3.3	Excitation systems	7
3.4	Generating station arrangements.....	10
4.	Protection requirements	14
4.1	Generator stator thermal protection	14
4.2	Field thermal protection.....	17
4.3	Generator stator fault protection	19
4.4	Generator rotor field protection	46
4.5	Generator abnormal operating conditions.....	50
4.6	Backup protection	74
4.7	Generator breaker failure protection.....	79
4.8	Excitation system protection.....	81
4.9	Power transformer protection through mechanical fault detection.....	84
5.	Other protective considerations	85
5.1	Current transformers	85
5.2	Voltage transformers.....	86
5.3	Protection during start-up or shutdown.....	90
5.4	Inadvertent energizing	94
5.5	Subsynchronous resonance (SSR)	97
5.6	Transmission line reclosing near generating stations	98
5.7	Synchronizing	99
6.	Multifunction generator protection systems	101
6.1	Introduction.....	101
6.2	Application on a typical generating unit.....	102
6.3	Testing of MGPSs.....	106
7.	Protection specification.....	107
7.1	Protective arrangements.....	108
7.2	Protective functions	116
	Annex A (informative) Sample calculations for settings of generator protection functions	124
	Annex B (informative) Bibliography.....	155

IEEE Guide for AC Generator Protection

1. Overview Scope

This application guide for the relay protection of synchronous generators presents a review of the generally accepted forms of protection for the [synchronous](#) generator and its excitation system. It summarizes the use of relays and devices and serves as a guide for the selection of equipment to obtain adequate protection. The guide is primarily concerned with protection against faults and abnormal operating conditions for large hydraulic, steam, and combustion turbine generators. Basing generator protection on machine size is difficult because the desired protection may be determined more by the importance of the generator to the power system than by the size of the generator.

The recommendations made pertain to typical [synchronous](#) generator installations. However, sufficient background information relating to protection requirements, applications, and setting philosophy is given to enable the reader to evaluate the need, to select, and to apply suitable protection for most situations.

The protective functions discussed in this guide may be implemented with a multifunction microprocessor based protection system (digital system). The protection philosophy, practices, and limits are essentially identical to those of the implementation using discrete component relays. The algorithms used to perform some of the protection functions may be different, but should produce equal or better protection. However, the performance and capability may be superior using the digital systems such as improved frequency response (bandwidth) and thresholds (pickup settings). Other additional features may be available from these digital systems that enhance the functionality.

This guide does not purport to detail the protective requirements of all generators in every situation. [For example](#), standby and emergency-use generators are specifically excluded.

1.1 Description of the guide

~~Clause 3: Description of generators, excitation systems, and generating station arrangements.~~

Clause 3 presents a brief description of typical generator design and connections, generator grounding practices, excitation systems design, and generating station arrangements. The intent of this clause is to present information that affects the protection arrangement and selection of protective relays.

A discussion of auxiliary system transfer and the possible negative impacts of misoperation and faults on these systems ~~is not included in this clause~~ [are beyond the scope of this guide](#).

The methods employed for grounding and fusing the secondary circuits of voltage transformers (VTs) and the methods for grounding current transformer (CT) secondary circuits are not generally the same for all installations.

~~For this reason, no secondary fuses or ground points are indicated in the figures throughout this guide. However, all current~~ CT and VT secondary circuits should be grounded in accordance with IEEE Std C57.13.3^{TM 1}.

~~Clause 4: Protection requirements.~~ Clause 4 briefly describes the damaging effects of faults and abnormal operating conditions and the type of devices and their settings commonly used to detect these conditions. A clear understanding of the effects of abnormalities on generators will assist the reader in evaluating the need for and the means of obtaining adequate generator protection in any specific situation.

~~Clause 5: Other protective considerations.~~ Clause 5 presents a discussion of other forms of protection and factors that may be considered in the generator zone.

~~Clause 6: Protection specifications. Clause 6 presents detailed tabulations and~~ Clause 6 describes multifunction generator protection systems (MGPS) and presents an application on a typical generating unit and includes information on testing of MGPS.

Clause 7 presents detailed diagrams that are classified according to the method by which the generator is connected to the system. These ~~tables and~~ diagrams show the combination of relays (and their control function) often applied for generator and excitation system protection in accordance with good engineering practices. These ~~tables and~~ diagrams also consider the protective devices on other equipment in or adjacent to the generating station that are connected to trip or shut down the generator.

Annex A describes sample calculations for settings of generator protection functions.

2. Normative references

~~This standard shall be used in conjunction with the following publications. When the following standards are superseded by an approved revision, the revision shall apply~~ The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

~~ANSI C50.12-1982 (Reaff 1989), American National Standard Requirement for Salient Pole Synchronous Generators and Generator/Motors Hydraulic Turbine Applications.²~~

IEC 60034-1, Rotating Electrical Machines—Part 1: Rating and Performance.²

IEC 60034-3, Rotating Electrical Machines—Part 3: Specific Requirements for ~~ANSI C50.13-1989, American National Standard Requirement for Rotating Electrical Machinery—Cylindrical Rotor Synchronous~~ Machines.

IEEE Std 67-~~1990~~TM, IEEE Guide for Operation and Maintenance of Turbine Generators-~~(ANSI).~~^{3, 4}

IEEE Std 142-~~1991~~TM, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems ~~ANSI.~~ (IEEE Green Book).

IEEE Std 421.1TM, IEEE Standard Definitions for Excitation Systems for Synchronous Machines.

IEEE Std 502-~~1985 (Reaff 1992).~~TM IEEE Guide for Protection, Interlocking, and Control of Fossil-Fueled Unit-Connected Steam Stations-~~(ANSI).~~

IEEE Std C37.91TM, IEEE Guide for Protective Relay Applications to Power Transformers.

~~IEEE Std C37.106-1987 (Reaff 1992), IEEE Guide for Abnormal Frequency Protection for Plants (ANSI).~~

~~IEEE Std C57.13-1993, IEEE Standard Requirements for Instrument Transformers (ANSI).~~

¹For information on references ~~see~~⁺ can be found in Clause 2.

²~~ANSI~~² IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembe, CH-1211, Genève 20, Switzerland/Suisse (<http://www.iec.ch/>). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, ~~1125~~ West ~~42nd~~^{43rd} Street,

~~13th~~ 4th Floor, New York, NY 10036, USA ([http:// www.ansi.org/](http://www.ansi.org/)).

³IEEE publications are available from the Institute of Electrical and Electronics Engineers, Inc., 445 Hoes Lane, P.O. Box ~~1331~~, Piscataway, NJ 08854, USA (<http://standards.ieee.org/>). ~~1331, Piscataway, NJ 08855-1331, USA.~~

⁴The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

[IEEE Std C37.110™, IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.](#)

[IEEE Std C50.12™, IEEE Standard for Salient-Pole 50 and 60 Hz Synchronous Generators and Generator/ Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.](#)

[IEEE Std C50.13™, IEEE Standard for Cylindrical-Rotor 50 and 60 Hz, Synchronous Generators Rated 10 MVA and Above.](#)

[IEEE Std C57.13™, IEEE Standard Requirements for Instrument Transformers.](#)

IEEE Std C57.13.3 ~~1983 (Reaff 1991)~~,TM IEEE Guide for ~~the~~ Grounding of Instrument Transformer Secondary Circuits and Cases ~~(ANSI)~~.

IEEE Std C62.92.2 ~~1989~~TM, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II—Grounding of Synchronous Generator Systems ~~(ANSI)~~.

3. Description of generators, excitation systems, and generating station arrangements

3.1 Generator winding design and arrangements

The stator windings of a three-phase synchronous generator consist of a number of single-turn or multi-turn coils that are connected in series to form a single-phase circuit. One of these circuits or several circuits connected in parallel are used to form a complete phase winding. The phase windings are normally connected in wye with the neutral grounded through some external impedance. Delta-connected phase windings are used occasionally but this is not a common connection. Figure 3-1 illustrates the possible winding arrangements and connections.

The winding arrangements shown in parts a) and b) in Figure 3-1 are the configurations most commonly used for all types of generators. When more than one circuit is used per phase as shown in part b) of Figure 3-1, these circuits will be connected in parallel inside the machine and two leads brought out to external connections. In general, up to three current transformers (CTs) may be provided at each end of the phase winding for relaying and instrumentation purposes.

In some hydrogenerator designs, there may be a number of circuits per phase and each circuit may consist of a number of multi-turn coils connected in series. In these machines, the parallel-connected circuits may be formed into two groups that are paralleled, and only two leads are brought out to external connections. There may be an equal or unequal number of circuits in each group. In this design, CTs ~~can~~ [may](#) be provided in each phase group and in the leads to the external connections.

Part c) in Figure 3-1 illustrates the wye-connected double-winding construction sometimes used in large steam turbine generators. Each phase has two separate windings that are connected externally to form two wye connections. The high-voltage terminals of each phase are connected in parallel to form a single three-phase output. Separate wye connections are formed on the neutral end of each winding. These neutrals may be physically at opposite ends of the machine. This arrangement is sometimes referred to as the *double-ended, 12-bushing* machine and is used where the total full-load phase current exceeds the current carrying capability of a single bushing. The bushings at each end of the winding may accommodate three CTs.

In the delta-connected generator, there may be one or more paralleled circuits per phase with two leads brought out to external connections. CTs ~~can~~ may be provided inside the delta, at the ends of each winding, or outside the delta, or both.

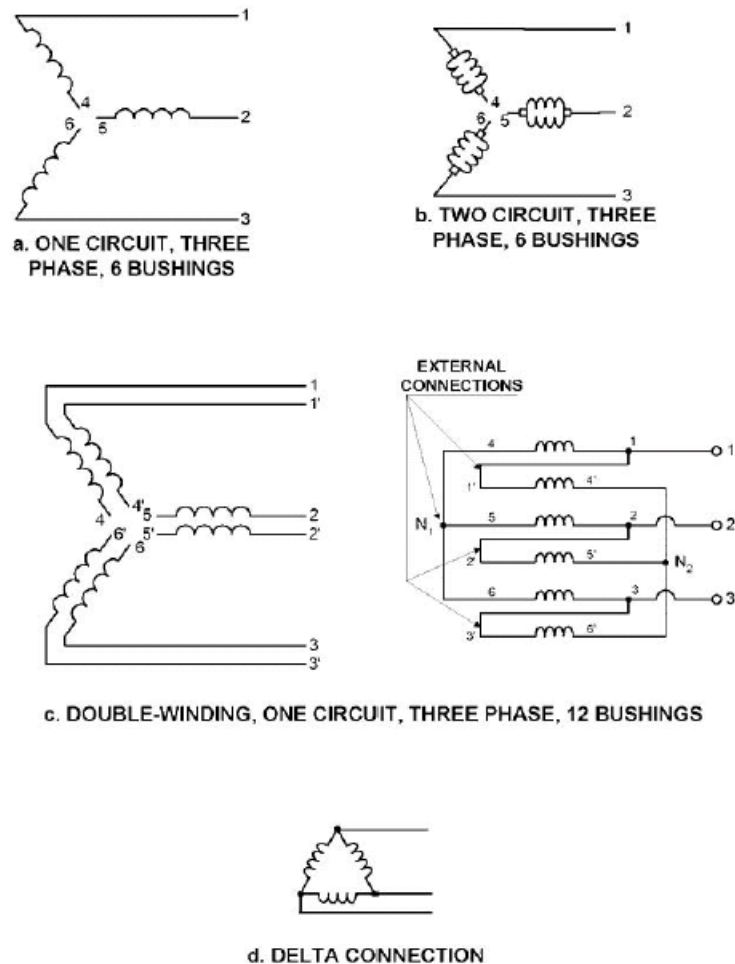


Figure 3-1—Winding configurations

3.2 Generator grounding

It is common practice to ground all types of generators through some form of external impedance. The purpose of this grounding is to limit the mechanical stresses and fault damage in the machine, to limit transient voltages during faults, and to provide a means for detecting ground faults within the machine. A complete discussion of all grounding and ground protection methods may be found in IEEE Std C62.92.2 and IEEE Std C37.101™-1993 [B62].⁵

The methods most commonly used for generator grounding will be discussed in this guide. They are listed in four broad categories, as follows:

- a) High-impedance grounding
- b) Low-resistance grounding
- c) Reactance grounding
- d) Grounding-transformer grounding

⁵[The numbers in brackets correspond to those of the bibliography in Annex B.](#)

Solid grounding of a generator neutral is not generally used since this practice may result in high mechanical stresses and excessive fault damage in the machine. According to IEEE Std C50.13, the maximum stresses that a generator is normally designed to withstand is that associated with the currents of a three-phase fault at the machine terminals. Because of the relatively low zero-sequence impedance inherent in most synchronous generators, a solid phase-to-ground fault at the machine terminals will produce winding currents that are higher than those for a three-phase fault. Therefore, to comply with this [guide standard](#), generators are grounded in such a manner to limit the maximum phase-to-ground fault current to a magnitude equal to, or less than, the three-phase fault current.

Generators are not often operated ungrounded. While this approach greatly limits the phase-to-ground fault currents, and consequently limits damage to the machine, it may produce high transient overvoltages during faults and also makes the fault location difficult to determine.

The following subclauses provide a very brief description and typical applications of the above grounding methods.

3.2.1 High-impedance grounding

Two methods of high-impedance grounding are in use today: [high-resistance grounding and ground fault neutralizer grounding](#). In both methods, the primary of a distribution transformer is connected between the generator neutral and ground, while the secondary winding rating is 120 V or 240 V. Note that distribution transformers with internal fuses or circuit breakers should not be used, as they could inadvertently be open and the grounding and protection scheme could be inoperative at the time of fault. The two methods differ in their secondary connection as shown in the following subclauses.

3.2.1.1 High-resistance grounding

~~In this~~ [The high-resistance grounding method](#), ~~a distribution transformer is connected between the generator neutral and ground, and utilizes~~ a resistor ~~is~~ connected across the secondary. ~~The primary voltage rating of the distribution transformer is usually equal to, or greater than, rated generator line to neutral voltage, while the secondary winding rating is 120V or 240 V, to limit the maximum ground fault current.~~ The ~~secondary~~ resistor is selected so that for a single-phase-to-ground fault at the generator terminals, the power dissipated in the resistor is equal to, or greater than, three times the [total](#) zero-sequence capacitive kVA to ground.

The capacitive kVA to ground includes the generator windings and all other equipment ~~that may be~~ connected to the machine terminals. With this resistor rating, the transient overvoltages during faults will be kept to safe values. ~~This arrangement is considered high resistance grounding.~~ For a single-phase-to-ground fault at the machine terminals, the primary fault current will be limited to a value in the range of about 3 A to 25 A. If possible, the ground fault current level should be chosen to coordinate with the primary fuses (when used) of wye-wye-connected includes the generator VTs with grounded neutrals. ~~Note that distribution transformers with internal fuses or circuit breakers should not be used, as they could inadvertently be open and the grounding and protection scheme could be inoperative at the time of fault.~~

In some cases, the distribution transformer is omitted and a high value of resistance is connected directly between the generator neutral and ground. The resistor size is selected to limit ground fault current to the range of 3 A to 25 A. While this method of grounding is used in ~~Europe~~[some parts of the world](#), the physical size of the resistors, the required resistor insulation level, and the cost may ~~preclude~~[discourage](#) the use of this method.

3.2.1.2 Ground fault neutralizer grounding (tuned inductive reactor)

~~In this grounding method, a distribution type transformer with a ratio selected as above is used with a secondary tunable reactor.~~[The ground fault neutralizer grounding method utilizes a secondary tunable reactor to limit the maximum ground fault current.](#) The ohmic value of this secondary reactor is selected so that, when reflected into the primary circuit, its reactance is equal to one-third of the [total](#) zero-sequence capacitive reactance. [This capacitive reactance includes](#) the generator and all equipment connected to the generator terminals up to and including the delta-connected windings of the main step-up and station service transformers. This type of grounding limits the single-phase-to-ground fault current to 1 A or less. This low fault current will not sustain an arc or cause damage to the generator stator iron. [Therefore, ground fault neutralizer grounding may detect much higher impedance grounds than is possible with high-resistance ground.](#) Ground fault-neutralizer grounding ~~can~~[may](#) be used with all unit-system installations where a single generator is connected through its individual ~~grounded~~-wye delta step-up transformer (or transformers) to the system.

Also, ground fault neutralizer grounding may detect much higher impedance grounds than is possible with high-resistance grounding. For example, the calculated maximum detectable fault impedance for a typical nuclear unit of 975 MVA is 3.5 M Ω for ground fault neutralizer grounding. Calculated maximum stator fault current for a typical 975 MVA nuclear unit is 0.45 A. ~~This contrasts with~~[If this generator is grounded through](#) a high-resistance grounding, the maximum fault impedance that may be detected is 67 k Ω (see Gulachenski and Courville [B82]).

If protection from iron burning and greater sensitivity of detecting incipient faults is deemed desirable (for example an existing older generator equipped with high-resistance grounding), retrofitting with ground fault neutralizer grounding may be done by replacing the resistor with a reactor.

Along with these desirable features, [there](#) are several that may be considered undesirable:

- a) If automatic tripping is used, coordination with generator VT fuses may not be possible. ~~VT~~[Faults on the](#) secondary wiring may cause ground indications where wye-wye connected generator VTs are used. Coordination ~~can~~[may](#) be achieved by various methods, see IEEE Committee Report [B17].
- b) High zero-sequence voltages on the generator system are possible if too high a reactor coil constant is selected for the neutralizer.
- c) If surge protective equipment is used on the generator, it ~~should be~~[is](#) selected on the basis of possible higher temporary overvoltages during ground faults. Voltages may be kept to within reasonable limits by selecting a reactor coil constant in a range from 10 to 50 without reducing sensitivity of the fault detection system.

3.2.2 Low-resistance grounding

In this method, a resistor is connected directly between the generator neutral and ground. The resistor is selected to provide sufficient current for selective ground relaying of several machines, feeders, or both. In general, the grounding resistor is selected to limit the generator's contribution to a single-phase-to-ground fault at its terminals to a value in the range of 200 A up to 150% of rated full-load current. Resistor cost and size usually preclude the use of resistors to limit the current below 200 A or to permit currents above machine rated current.

This method of grounding is generally used where two or more generators are bused at generator voltage and connected to a system through one step-up transformer or where the generator is connected directly to a distribution system having a low-impedance grounding source on the generator bus.

3.2.3 Reactance grounding

This method uses an inductive reactance between the generator neutral and ground. The inductive reactance is selected to produce an X_0/X_1 ratio at the machine terminals in the range of 1 to 10. Common practice is to maintain an effectively grounded system by keeping the X_0/X_1 ratio at 3 or less, see IEEE Std C62.92.2. This method of grounding produces relatively high levels of phase-to-ground fault currents ranging from approximately 25% to 100% of the three-phase fault current.

This grounding method is generally used where the generator is connected directly to a solidly grounded distribution system.

~~⁴The numbers in brackets correspond to those bibliographical items listed in annex B.~~

3.2.4 Grounding transformer grounding

This method involves the use of a grounding transformer connected to the machine terminals or to the generator bus. The grounding may be provided by a zigzag transformer or a grounded wye-delta transformer, or by a grounded wye-broken delta transformer with a resistor connected across a corner of the broken delta.

When a zigzag or a grounded wye-delta transformer is used, the effective grounding impedance is selected to provide sufficient current for selective ground relaying.

The grounded wye-broken delta transformer with a resistance in the corner of the broken delta is generally a high-resistance grounded system. The resistance would be selected in the same manner as for the distribution transformer with secondary resistor. This method limits the single-phase-to-ground fault current to a range of 3 A to 25 A primary.

A zigzag or grounded wye-delta transformer may be used as an alternate grounding source when a generator with neutral reactor grounding is connected directly to a distribution system. This approach may also be used where several ungrounded-wye or delta-connected generators are bused at generator voltage.

A grounded wye-broken delta transformer with a resistor across the corner of the broken delta may be used to provide a means for detecting ground faults in ungrounded-wye or delta-connected generators.

3.3 Excitation systems

There are four basic types of excitation systems that are used to control the output of ac machines:

- the dc generator commutator exciter,
- the alternator rectifier exciter with stationary rectifier system,
- the alternator rectifier exciter with rotating rectifier system, and
- the static excitation system

In terms of response times, excitation systems fall into two categories: rotating and static. Rotating exciters respond slower than static exciters. The speed of response of the excitation system is commonly expressed in terms of the nominal response ~~ratio~~, which indicates the speed of response during a period of 0.5 s after a sudden 20% reduction in generator terminal voltage. Rotating exciters have nominal response ~~ratios~~ in the range of 0.5 per unit to 1.0 per unit exciter volts per second. Static exciters have nominal response in the range of 2.5 per unit to 3.5 per unit exciter volts per second. The detailed effects of the excitation system nominal response on the fault current characteristics of the generator is beyond the scope of this guide but is well-documented in Higgins, Holly, and Wall [B16]. While a detailed description of these systems is beyond the scope of this standard, their general characteristics will be briefly described in the following subclauses.

3.3.1 System with dc generator-commutator exciter

Figure 3-2 shows a schematic of the primary elements of this system. Not shown on this diagram and the succeeding Figure 3-3, Figure 3-4, Figure 3-5, and Figure 3-6 are the power supplies, such as pilot exciters, the current and potential intelligence inputs to the excitation control, etc., since they are essentially functionally the same for all systems.

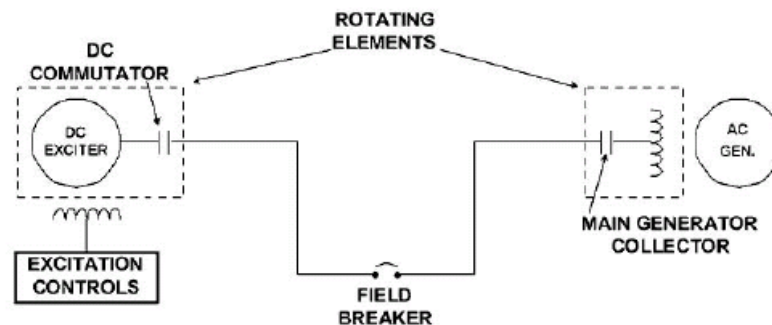


Figure 3-2—System with dc generator commutator exciter

In this system, a dc control signal is fed from the excitation control to the stationary field of the dc exciter. The rotating element of the exciter then supplies a direct current through a field breaker to the field winding of the main ac generator. The rotating armature of the dc exciter is either driven from the same shaft as the rotating main field of the generator or may be on a separate motor-driven shaft. In either case, a dc commutator is required on the exciter and brushes and collector rings are required on the rotating generator field to transmit the main generator field current. This system is used only on the smaller or older machines.

3.3.2 System with alternator rectifier exciter and stationary rectifiers

To eliminate the problems of high-current commutation for medium and large machines, the dc exciter is replaced by an alternator. The system of Figure 3-3 uses an alternator with a rotating dc field winding driven from the shaft of the main ac generator. Current for this field winding is obtained from the excitation controls through brushes and collector rings. The three-phase ac output of the alternator is rectified through a stationary three-phase diode bridge and the direct-current output is fed to the field winding of the generator through brushes and collector rings.

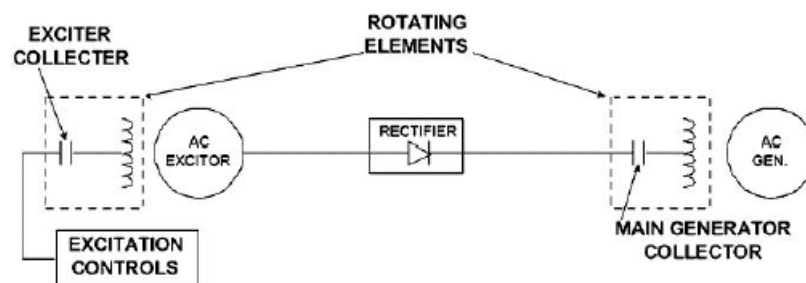


Figure 3-3—System with alternator rectifier exciter and stationary exciter and stationary rectifier

3.3.3 System with alternator rectifier exciter and rotating rectifiers (brushless exciters)

The system of Figure 3-4 again uses an alternator but by mounting the dc field winding on the stator of the exciter and the ac armature winding on the rotor, all brushes and commutators have been eliminated. In this system, the ac armature of the exciter, the rotating three-phase diode bridge rectifier, and the main field of the ac generator are all mounted on the same rotating shaft system. All electrical connections are made along or through the center of this shaft.

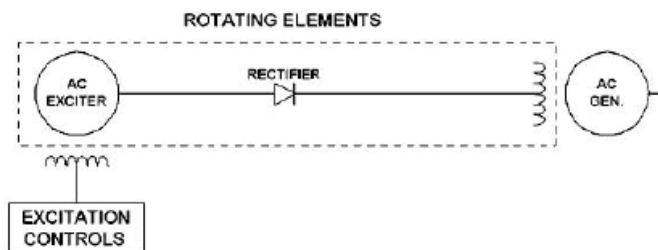


Figure 3-4—System with alternator rectifier exciter and rectifiers (brushless exciters)

3.3.4 System with static exciter

The preceding schemes utilize the energy directly from the prime-mover shaft to obtain the required excitation power. Static excitation systems obtain this power from the electrical output of the generator or the connected system. In Figure 3-5, external power CTs or power VTs (or both) feed rectifiers in the regulating system that, in turn, supply direct current to the main field winding of the generator through brushes and collector rings.

Some systems use only potential transformers as input power, while some use additional CTs to boost the input during fault conditions when the terminal voltage is reduced. During close-in faults, excitation systems using only potential transformers as input power may be unable to sustain fault currents long enough for the protective relaying to operate (see Higgins, Holly, and Wall [B16]).

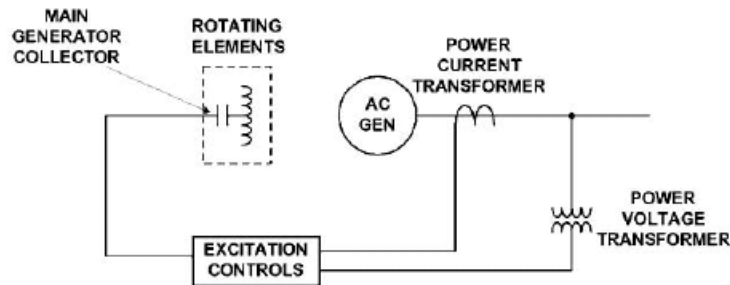


Figure 3-5—System with static exciter

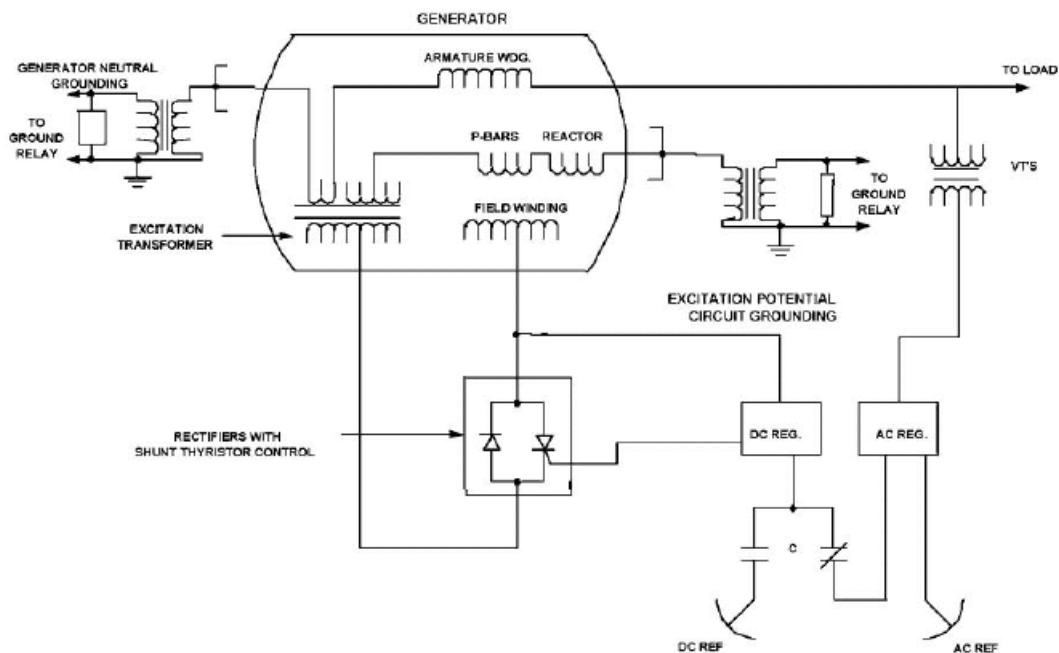


Figure 3-6—Static excitation system with internal supply

In Figure 3-6 the excitation power is provided from a voltage and current source within the main generator. The voltage source is a set of three-phase windings mounted in three generator stator winding slots (P-bars in Figure 3-6). These potential windings are connected to each phase of an ungrounded-wye excitation transformer.

The current source is achieved by passing each of the three stator main winding leads through a window in each phase excitation transformer.

The output windings of the three single-phase excitation transformers are connected in delta to supply the external bridge rectifier circuits. As indicated in Figure 3-6, the potential windings in the stator are connected in wye through linear reactors. The neutral is high-resistance grounded through a distribution transformer, thereby providing a means for detecting possible ground faults in the potential windings and excitation transformer.

3.4 Generating station arrangements

The selection and arrangement of protection for generators is influenced to some degree by the method in which the generators are connected to the system and by the overall generating station arrangement. For purposes of this guide, the following generator connections and station arrangements will be considered:

- a) Unit generator-transformer configuration
- b) Unit generator-transformer configuration with generator breaker
- c) Cross-compound generators
- d) Generators sharing a unit transformer
- e) Generators connected directly to a distribution system

~~For the most part, the~~ [These](#) configurations represent ~~the most~~ widely used generating station arrangements.

3.4.1 Unit generator-transformer configuration

In this arrangement, a generator and its transformer (unit transformer) are connected as a unit to the system as shown in Figure 3-7. The generator is usually wye-connected and high-resistance grounded through a distribution transformer. The unit transformer is most commonly a grounded wye-delta connection.

In some large steam turbine generator installations, the generator may be connected to the system through two parallel-connected unit transformers, each transformer having one-half the total generator rating.

There may be one or two unit auxiliaries transformers. These may be two-winding or three-winding transformers, depending upon the size of the generator unit. In most instances the unit auxiliaries transformer(s) is connected delta-wye with the neutral of the wye connected to ground through some impedance.

3.4.2 Unit generator-transformer configuration with generator breakers

This arrangement, illustrated in Figure 3-8, has been used with some large generators. The generator is wye-connected and high-resistance grounded through a distribution transformer. Two half-size grounded wye-delta connected unit transformers are used to connect the generator to the system. As shown in this figure, two unit auxiliaries transformers are used in this arrangement. [For small and medium sized generators, a typical configuration is shown in Figure 7-6.](#)

[The benefits of this configuration are fast fault removal for generator step-up \(GSU\) and auxiliary transformer faults and to allow the auxiliary transformer to be used as a start-up source.](#)

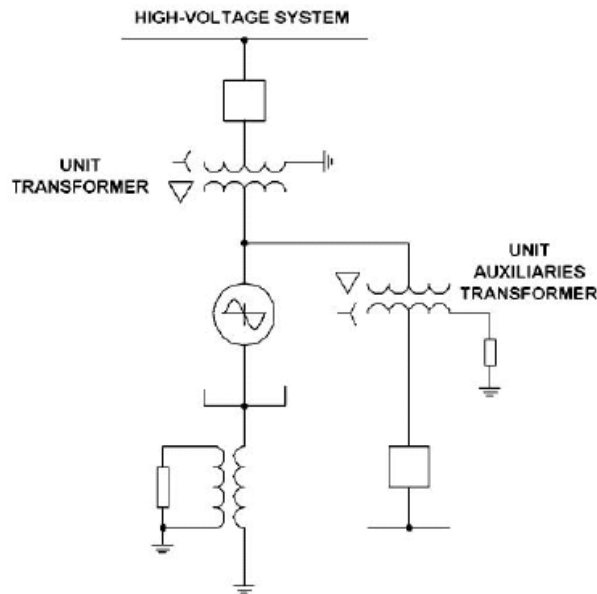


Figure 3-7—Unit generator-transformer configuration

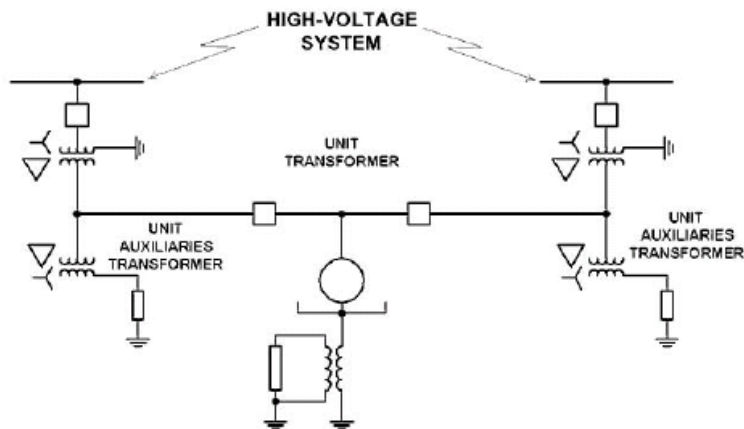


Figure 3-8—Unit generator-transformer configuration with generator breakers

3.4.3 Cross-compound generators

The most common method for connecting a cross-compound generator to a system is shown in Figure 3-9. The low-pressure (LP) and the high-pressure (HP) units are bused at generator voltage and connected to the system through a grounded wye-delta unit transformer. Both the low-pressure and high-pressure units are usually wye-connected, and it is recommended practice to ground only one of the neutrals. High-resistance grounding through a distribution transformer is commonly used.

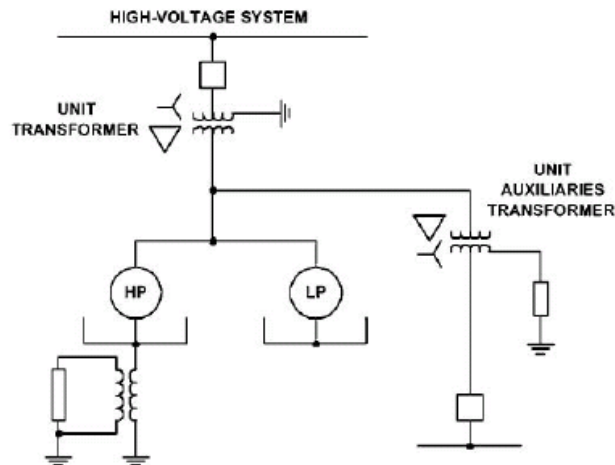


Figure 3-9—Cross-compound generators

3.4.4 Generators sharing a unit transformer

Figure 3-10 illustrates two methods for connecting two or more generators to a system using one step-up transformer. In part A of Figure 3-10, two or more generators are bused at generator voltage and a two-winding grounded wye-delta unit transformer is used to connect the machines to the system. In part B of Figure 3-10, a number of generators are connected to the system through a three-winding grounded wye-delta-delta transformer. Either of these approaches may be used with small ~~hydro~~hydraulic or combustion turbine generators (CTGs).

In either approach, neutral-resistor grounding of the generators may be used in order to achieve selective ground fault protection for the machines. In some instances, the generators may be high-resistance grounded through a distribution transformer in order to minimize damage due to phase-to-ground faults. However, this grounding method has the disadvantage that it may not provide sufficient current for selective relaying.

Figure 3-11 shows a typical installation where generators are connected directly to a distribution system. If the system is effectively grounded ($X_0/X_1 \leq 3$, $R_0/X_1 \leq 1$), the generator neutral, ~~or the neutral of the bus grounding transformer if the generator neutral is isolated (as noted in 3.2.4)~~, will be grounded with a neutral inductive reactance. As an alternative as noted 3.2.4 a bus-grounding transformer with a neutral reactor may be applied if the generator neutral is ungrounded. If the system is not effectively grounded, ~~as for some three-wire distribution systems~~, the generator neutral or grounding transformer neutral will generally be grounded through a low ohmic value resistor. Where this is used, the feeders off of the bus shall be of the three-wire type (no phase to neutral loads may be permitted)

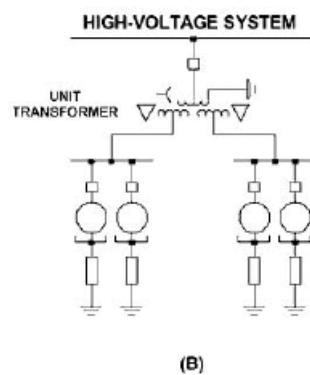
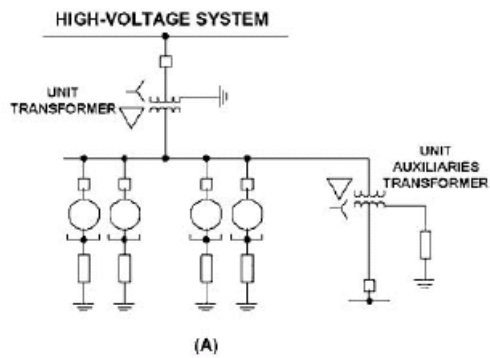


Figure 3-10—Generators sharing a transformer

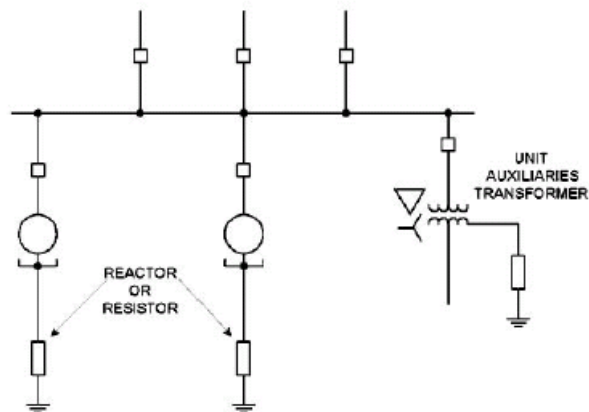


Figure 3-11—Generator connected directly to a distribution system

4. Protection requirements

4.1 Generator stator thermal protection

Thermal protection for the generator stator core and windings may be provided for the following contingencies:

- a) Generator overload
- b) Failure of cooling systems
- c) Localized hot spots caused by core lamination insulation failures or by localized or rapidly developing winding failures

4.1.1 Generator overload

The continuous output capability of a generator is expressed in kilovolt-amperes (kVA) available at the terminals at a specified frequency, voltage, and power factor. For hydrogen-cooled generators, the output rating is usually given at the maximum and several lesser hydrogen pressures. For CTGs, this capability is given at an inlet air temperature in the range of ~~15°C at sea level~~, 20° C to 50° C. In general, generators ~~can~~may operate successfully at rated kVA, frequency, and power factor for a voltage variation of 5% above or below rated voltage.

Under emergency conditions, it is permissible to exceed the continuous output capability for a short time. In accordance with IEEE Std C50.13, the armature winding short time thermal capability is given by the following:

Time (seconds)	10	30	60	120
Armature current (percent)	218	150	127	115

where

100% current is the rated current of the machine at maximum hydrogen pressure.

A plot of this short time capability is shown in Figure 4-1. Protective schemes to prevent thermal damage to the stator winding utilize winding temperature (curve drawn using data from IEEE Std C50.13) detectors or relays having time-current characteristics that conform to the short time capability curve.

4.1.1.1 Winding-temperature protection

Most generators are supplied with a number of temperature sensors to monitor the stator windings. These sensors are usually resistance temperature detectors (RTDs) and thermocouples (TCs). As the name implies, the RTD detects temperature by the change in resistance of the sensor. A TC detects temperature by the change in thermoelectric voltage induced at the TC junction.

These sensors are used to continuously monitor the stator winding. In attended generating stations, the sensors may be connected to a data acquisition system for recording or alarm purposes.

In unattended stations, the sensors may be used with a relay to alarm, to initiate corrective action, or to trip the unit if preset temperature limits are exceeded.

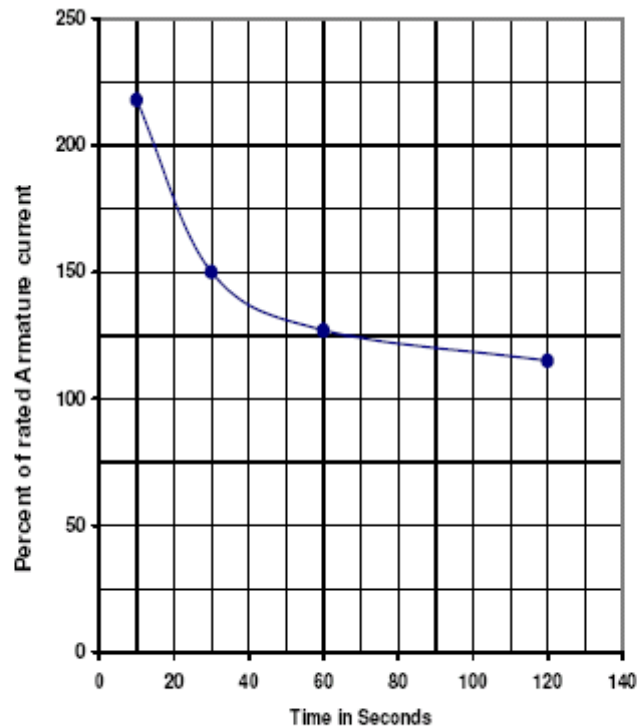


Figure 4-1—Turbine-generator short time thermal capability for balanced three-phase loading

For generators with conventional (indirectly cooled) stator windings, RTDs embedded between the top and bottom bars are used to monitor winding temperatures. For generators with inner-cooled (directly cooled) stator windings, the stator bar coolant discharge temperature is used along with the embedded RTDs [\(if equipped\)](#) to monitor the winding temperature.

The generator manufacturer should be consulted for specific recommendations on the preferred method of monitoring these sensors and temperature limits for alarm and trip purposes.

4.1.1.2 Overcurrent protection

In some instances, generator overload protection ~~can~~[may](#) be provided through the use of a torque controlled overcurrent relay that is coordinated with the IEEE C50.13 short time capability curve of Figure 4-1 [\(curve drawn using data from IEEE Std C50.13\)](#). This relay consists of an instantaneous overcurrent (IOC) unit and a time overcurrent unit having an extremely inverse characteristic. The instantaneous unit is set to pick up at 115% of full-load current and is used to torque control the time overcurrent unit. The instantaneous unit dropout should be 95% or higher of pickup setting.

The time-overcurrent unit is set to pick up at 75% to 100% of full-load current, and a time setting is chosen so that the relay operating time is 7.0 s at 218% of full-load current. With this approach, the relay is prevented from tripping for overloads below 115% of full-load current and yet provides tripping in a prescribed time for overloads above 115% of full-load current. [The overcurrent relay settings should be provided to transmission system protection personnel for coordination purposes.](#)

An overload alarm may be desirable to give the operator an opportunity to reduce load in an orderly manner. This alarm should not give nuisance alarms for external faults and should coordinate with the generator overload protection if this protection is provided.

For air-cooled generators that may operate in a wide range of ambient temperatures, it is necessary to coordinate the IEEE C50.13 thermal capability and the relay setting with the increased capability of the turbine and the generator at reduced ambient temperature. Conversely, it may be difficult to protect the generator for its reduced capability when the ambient temperature is high.

4.1.2 Failure of cooling systems

4.1.2.1 General

Depending upon rating and design, the generator stator core and windings may be cooled by air, oil, hydrogen, or water. In direct-cooled (or so-called conductor-cooled) generators, the coolant is in direct contact with the heat-producing conductors of the stator winding. In indirectly or conventionally cooled generators, the coolant cools the generator by relying on heat transfer through the insulation. For any type of generator, a failure of the cooling system ~~can~~ may result in rapid deterioration of the stator core lamination insulation and/or stator winding conductors and insulation.

4.1.2.2 Protection

In general, the generator manufacturer provides all of the necessary protection for the cooling system. This protection is in the form of sensors such as RTDs, TCs, and flow and pressure sensors. These devices are used to monitor the winding temperatures or the coolant temperature, flow, or pressure. They may be connected to alarm, to automatically reduce load to safe levels, or to trip.

For a particular machine, the user should check with the generator manufacturer to ascertain the temperature limits, the protection provided, and the recommended operating procedures for a loss of coolant.

4.1.3 Core hot spots

4.1.3.1 General

Localized hot spots in the stator core may be produced by lamination insulation failure caused by misoperation (such as excessive leading power factor operation or over fluxing), by vibration due to looseness (wear of insulation or fatigue of laminations), by foreign objects left in the machine, by damage to the core during installation or maintenance, or by objects that are normally a part of the machine (such as a nut, wedge, etc.), but become detached from their normal position and move to the core.

The hot spots are the result of high eddy currents, produced from core flux, that find conducting paths across the insulation between laminations. In some designs, stator laminations are electrically shorted together on the outer diameter of the core where it attaches to the stator frame. Any contact between laminations on the inner bore will result in a circuit for eddy currents. The shorting of laminations may cause melting of core steel that may be costly to repair.

4.1.3.2 Protection

A means for detecting hot spots in air-cooled generators is through the use of RTDs and/or TCs embedded in strategic locations. Since it is not possible or practical to cover the entire core and windings with these detectors, this approach may provide only partial detection of hot spots.

On hydrogen-cooled generators, the presence, but not the exact location of local hot spots, may be detected by the use of a generator core (or condition) monitor. The core monitor is an ion particle detector that is connected to a generator in a manner that permits a constant flow of cooling gas to pass through the monitor. Under normal conditions, the gas coolant contains no particles that may be detected by the monitor. However, when overheating occurs, the thermal decomposition of organic material, epoxy paint, core

lamination enamel or other insulating material produces a large number of particles. These particles are of submicron size and are detected by the monitor.

The general location of the hot spot may be determined by laboratory analysis of the particles and through the use of selective coatings on various parts of the machine.

At present, this type of protection is normally supplied on large steam turbine generators and is connected to sound an alarm.

4.2 Field thermal protection

Thermal protection for the generator field may be divided into two categories, as follows:

- a) Protection for the main field winding circuit
- b) Protection for the main rotor body, wedges, retaining ring, and amortisseur winding

4.2.1 Field winding protection

The field winding may operate continuously at a current equal to or less than that required to produce rated kVA at rated power factor and voltage. For power factors less than rated, the generator output should be reduced to keep the field current within these limits. The capability curves as defined in IEEE Std 67 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 Std C50.13 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 ~~voltage~~current as a function of time as follows:

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

A plot of this short time capability is shown in Figure 4-2 ([curve drawn using data from IEEE Std C50.13](#)). Protection schemes utilize this characteristic to prevent thermal damage to the field winding circuit.

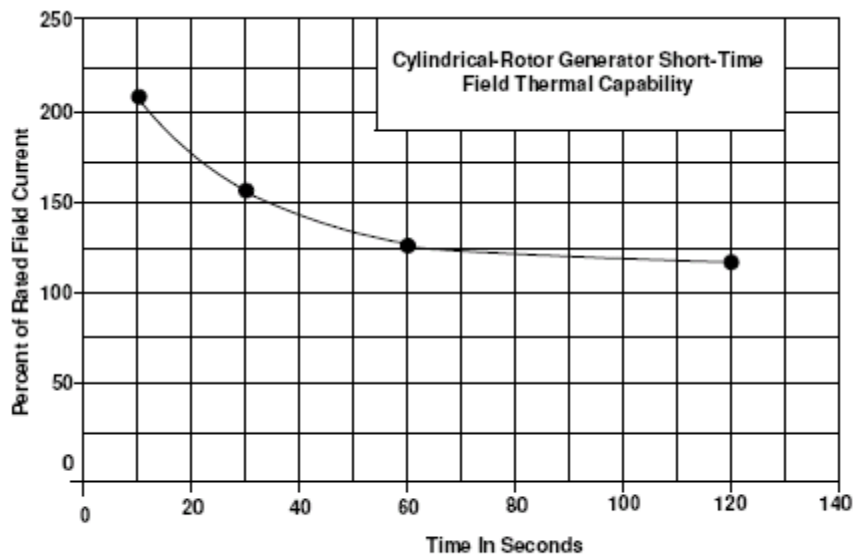


Figure 4-2—Generator field short time thermal capability

4.2.1.1 Thermal protection

Since it is not practical to put temperature sensors directly in the field windings, only indirect monitoring of the field winding temperature is normally possible. For excitation systems employing main field collector rings, the average temperature of the field winding may be approximated by calculating the field resistance using simultaneous field current and voltage readings. This resistance, in conjunction with the known cold resistance, is a measure of the operating temperature.

This method, described in IEEE Std 67, gives only an indication of the average temperature throughout the field winding and not the ~~more important~~ hot-spot temperature.

Moreover, this method is not applicable with brushless excitation systems where the actual main field current and voltage are not available for measurement.

If a generator is equipped with a core monitor as described in 4.1.3, the monitor ~~will~~may also detect overheating of the field winding.

4.2.1.2 Protection for field overexcitation

Some form of over excitation protection for the field winding is generally provided utilizing the short time capability curve of Figure 4-2. Several different schemes are available using relays or excitation system control elements, or both.

4.2.1.2.1 Fixed time-delay relaying scheme

~~The simplest~~One form of field protection utilizes a contact making milliammeter or voltmeter connected in either the main field circuit or in the field of the ac exciter. This device is set to pick up when the field current exceeds its rated full-load value. When an overexcitation condition occurs, the device picks up and performs the following functions:

- a) Sound an alarm.
- b) Adjust field excitation to a preselected value corresponding to rated full-load level or less.
- c) After a fixed time delay, trip the generator regulator or transfer to an alternate control.
- d) If overexcitation is not eliminated after some additional short time interval, trip the unit.

This scheme protects the field for overexcitation conditions during system disturbances and for the rare occurrence of a faulty excitation system component. While simple in form, this scheme has the disadvantage that it overprotects the machine, since the fixed time-delay relay ~~must be~~ is typically set for the maximum possible overexcitation condition that may occur. This means that for less severe overexcitation conditions, tripping occurs at shorter times than is required, and therefore, full advantage of the inverse-time thermal capability of the field winding characteristic ~~cannot be~~ is obtained.

4.2.1.2.2 Inverse time-delay relaying scheme

To maximize the probability of machine remaining online after a system disturbance, an excitation system that boosts and operates with a set margin along the inverse time protection characteristic should be considered. This approach utilizes a voltage relay whose characteristic approximately matches the inverse time characteristic of Figure 4-2. This relay may be connected at the terminals of an ac exciter alternator, in the main generator field, or in the field of the ac exciter. When connected to a field circuit, a transducer is used to convert the dc signal to an ac quantity. The relay is normally set so that there is 5% to 10% margin between the relay characteristic and the field capability curve.

This relay, in conjunction with one or more timers, performs the same functions as the preceding scheme. For an overexcitation condition, it will:

- a) Sound an alarm.
- b) Adjust the field excitation to a preselected value corresponding to rated full-load level or less.
- c) After some delay, trip the generator regulator or transfer to an alternate control.
- d) If overexcitation is not eliminated, trip the unit.

This scheme provides protection for overexcitation conditions as well as for possible excitation system failures.

4.2.1.2.3 Voltage regulator system

Modern excitation systems ~~usually incorporate the~~ may provide field protective functions as well as the regulating function. These systems may have built-in circuitry that duplicates the fixed time and/or the inverse time relaying function. When an overexcitation condition occurs and field current exceeds a safe value for a specified period of time, these protective functions reduce field current to the full-load value or to some other predetermined level. On some excitation systems, if the overexcitation condition persists after an attempt to reduce field current is made, the protective function trips the regulator or transfer to an alternate exciter after a short period of time. If this does not eliminate the problem, the generator may be tripped. In this type of excitation system, the protective function is separate from the excitation function, and therefore, may provide protection when there are failures in the regulating systems or when the regulator is not in the control circuit.

If the protective function is part of the regulating system, the protection ~~would be~~ is eliminated when the regulator is tripped or is out of service. For this type of system, supplementary relay protection as described in the preceding may be provided.

4.2.2 Rotor body

There are no simple methods for direct thermal protection of the rotor. Various indirect methods are used either to approximate rotor temperatures or to act directly on the quantities that would lead to excessive rotor temperatures. Protection schemes for the rotor are, therefore, directed at the potential causes of thermal distress. For example, negative-sequence currents in the stator, loss of excitation or loss of synchronism may cause excessive rotor temperatures due to circulating currents in various paths of the rotor body. These phenomena and associated protective schemes are covered in 4.5.

4.3 Generator stator fault protection

4.3.1 General consideration

Generator faults are 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.

As a consequence, for faults in or near the generator that produce high magnitudes of short-circuit currents, some form of high-speed protection is normally used to trip and shut down the machine as quickly as possible in order to minimize damage. Where external impedances are used to limit fault currents to a few amperes, slower forms of protection may be justified. In certain cases, it may be justified to consider the use of rapid de-excitation methods that produce a faster decay of fault currents.

4.3.2 Phase fault protection

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.

~~The high impedance differential relay may be less tolerant to ct errors caused by proximity effects than the percentage restrained type of differential relay.~~ [Three types of high-speed differential relays are used for stator phase fault detection: percentage differential, high-impedance differential, and self-balancing differential.](#)

4.3.2.1 Variable slope percentage differential relay

The variable slope percentage differential relay is ~~the most~~ [a](#) widely used form of differential relaying for generator protection. In this type of relay, the percentage slope characteristic may vary from about 5% at low values of through current up to 50% or more at high values of through current as illustrated in Figure 4-3. This characteristic results in a relay that is very sensitive to internal faults and insensitive to CT error currents during

severe external faults.

CTs with identical characteristics should be used in a generator differential scheme. Proper operation of the scheme requires that the CT's performance during fault conditions is not degraded due to excessive burdens in the circuits. Therefore, care shall be exercised when other relays or devices are used in these current circuits. [See IEEE Std C37.110 for more details. CTs of high accuracy class and of low remanence type \(i.e., CTs with a gapped core\) may be required.](#)

In some cases, proximity effects ~~can~~[may](#) affect the accuracy of the CTs, particularly at the neutral ends of generators, where CTs on one phase may be physically close to other phase conductors. In such cases, care is required to ensure that the resulting differential currents are less than the minimum sensitivity of the percentage restrained relay.

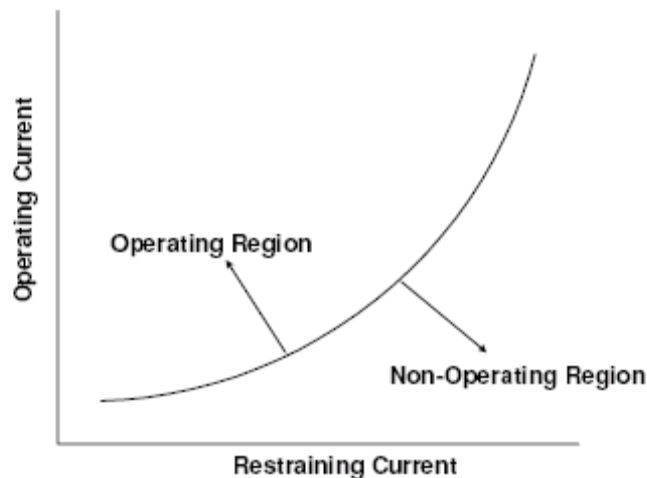


Figure 4-3—Variable slope differential relay

4.3.2.2 High-impedance differential relay

As the name implies, this is a high-impedance relay connected in a differential circuit as shown in Figure 4-4. The relay discriminates between internal and external faults by the voltage that appears across the relay. On external faults, the voltage across the relay will be low, while for internal faults, the voltage across the relay is relatively high.

The relay may be set to operate for stator winding three-phase or phase-to-phase fault currents as low as 2% of rated generator current.

The CTs used in this scheme, such as bushing CTs with fully distributed secondary windings, should have identical characteristics and should have negligible leakage reactance.

[This scheme has higher sensitivity than the percentage differential relay, and thus may be more susceptible to misoperation caused by proximity effects.](#)

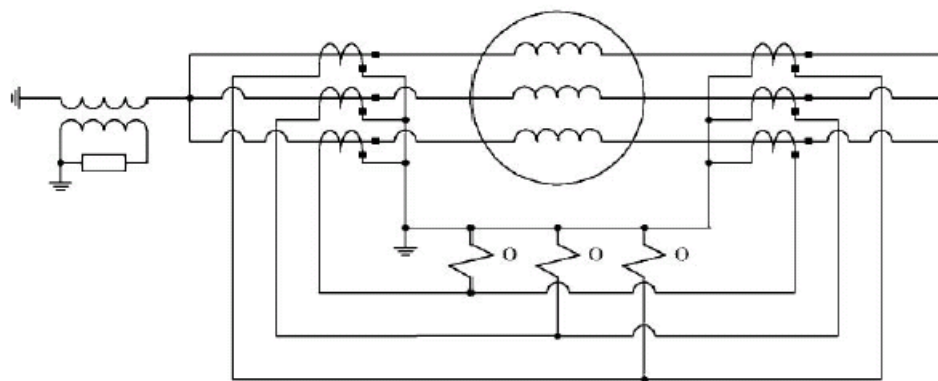


Figure 4-4—High-impedance differential

4.3.2.3 Self-balancing differential scheme

The self-balancing differential scheme has been used for phase and ground faults on small generators with low-resistance neutral grounding. This scheme is illustrated in Figure 4-5. As shown, leads from both ends of the phase winding are placed in the opening of a window-type CT. Any difference between the currents entering and leaving the winding is detected by an IOC relay.

Where applicable, this scheme is capable of providing very sensitive phase and ground fault protection.

Since these CTS see a difference current that is normally near zero under nominal system conditions, they are usually not designed to carry continuous load current. This allows the use of CTs with low ANSI accuracy designation and very low CT ratios. The measuring of difference current allows the relay to be set very sensitively to detect very low ground faults within the stator. Use of a low ratio may cause the fault current to be much higher than the 20 times rated current of the CT. Because of this, care should be taken to evaluate the relay burden and the CT saturation characteristics at the required fault current levels to assure accurate pickup of the relay and sufficient secondary current to operate the relay.

The application of phase fault protection to the various machine configurations discussed in 3.1 of this guide is illustrated in Figure 4-6, Figure 4-7, Figure 4-8, Figure 4-9, and Figure 4-10. Figure 4-6 illustrates the differential connections for a six-bushing machine having single-turn coils and one or more circuits per phase. This is the most widely used machine configuration.

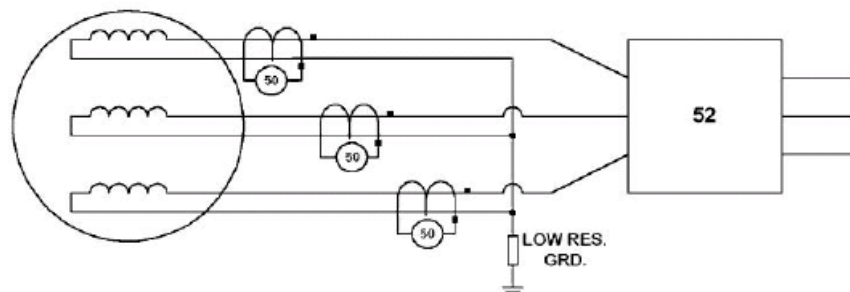


Figure 4-5—Self-balancing protection scheme

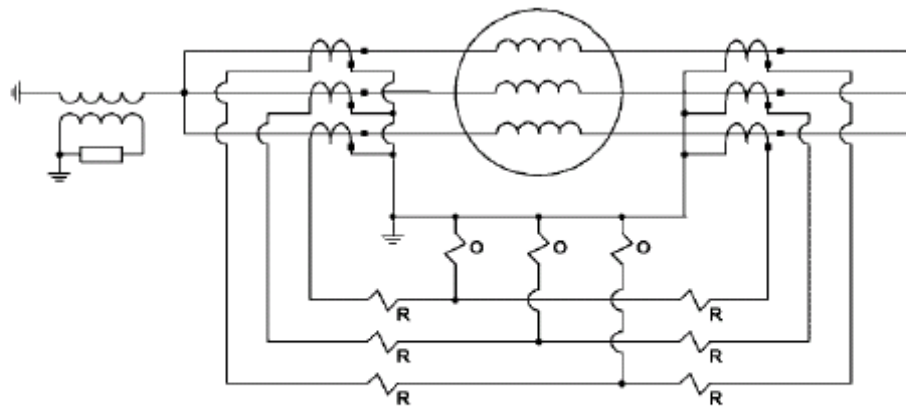


Figure 4-6—Percentage differential relay connection for six-bushing wye-connected generator

4.3.2.4 Application of differential relaying to different machine configurations

Figure 4-7 illustrates the application of split-phase relaying and differential protection on generators having multi-turn coils and two or more circuits per phase. This combination is often used on hydrogenerators. The application of split-phase relaying should be specified in the design of the generator so that the CTs required for this protection may be economically and appropriately engineered into the design.

Another scheme that has been used on this type of generator is shown in Figure 4-8. This arrangement is an attempt to get the benefits of split-phase and differential protection ~~with~~^{at} a ~~reduction~~^{saving} in ~~the number of~~ CTs and relays. However, this arrangement is not as sensitive as the separate split-phase relaying and differential relaying scheme shown in Figure 4-7. The scheme in Figure 4-8 requires neutral-end CTs having half the turns ratio of the terminal-end CTs.

Figure 4-9 illustrates the protection for a two-winding 12-bushing generator. In this arrangement, separate differential relaying is used to protect each winding. This provides protection for faults between windings and for phase-to-phase and three-phase faults. In general, it is not recommended that the CTs in each winding be paralleled and a single differential relay used. Such an approach would not provide protection for all faults between windings, since for some conditions the fault current would circulate only between the paralleled CTs and would not appear in the relay.

Figure 4-10 shows the typical differential relaying arrangement used for a delta-connected generator.

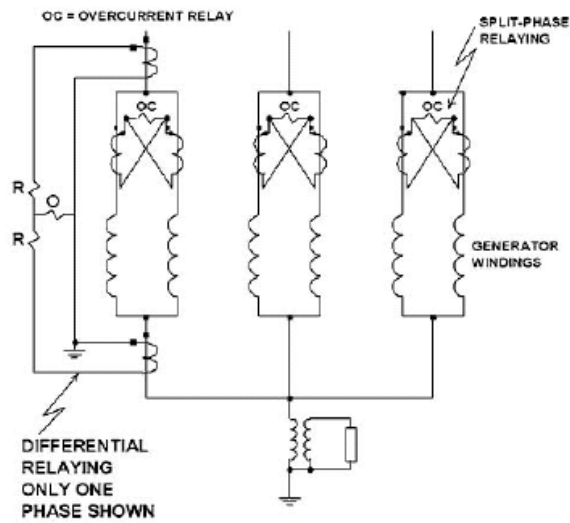


Figure 4-7—Applications of split-phase and differential relaying

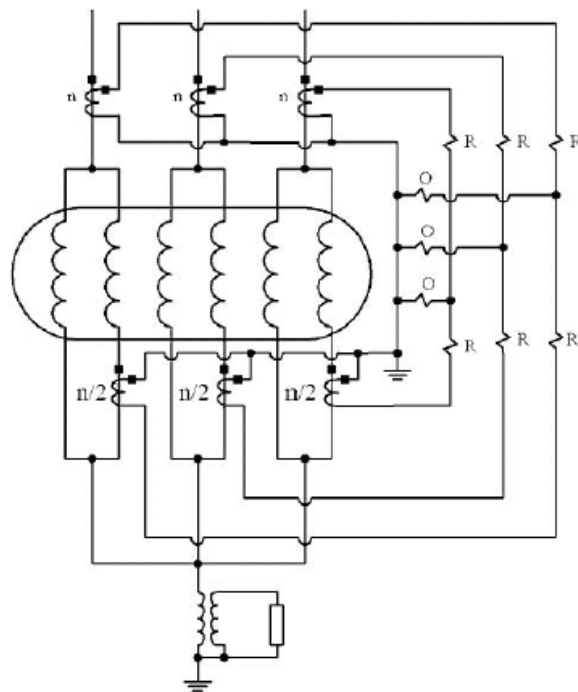


Figure 4-8—Combination split-phase and differential relaying

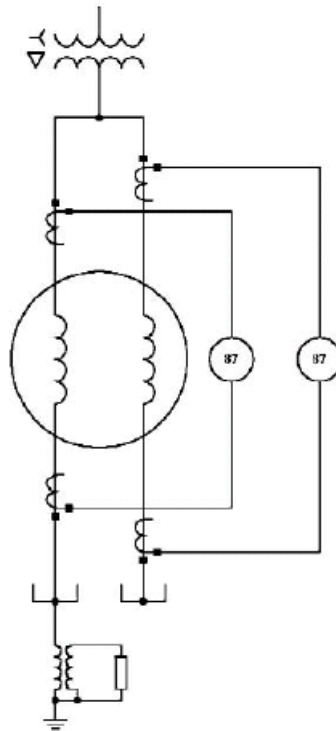


Figure 4-9—Twelve-bushing generator (single phase shown)

4.3.2.5 Turn fault protection

4.3.2.5.1 Split-phase protection

Most turbine generators have single-turn stator windings. If a generator has stator windings with multi-turn coils and with two or more circuits per phase, the split-phase relaying scheme may be used to provide turn fault protection. In this scheme, the circuits in each phase of the stator winding are split into two equal groups and the currents of each group are compared. A difference in these currents indicates an unbalance caused by a single-turn fault. Figure 4-11 illustrates the basic split-phase relaying system using bushing type CTs. The relays used in this scheme usually consist of an IOC relay and a very inverse time overcurrent relay.

Since there is normally some current unbalance between windings, the time overcurrent relay is set so that it will not respond to this normal unbalance but will pick up for the unbalance caused by a single-turn fault. Time delay is employed to prevent operation on CT transient error currents that may occur during external faults.

The pickup of the instantaneous unit should be set above the CT error currents that may occur during external faults. The resulting setting ~~will generally be such that it will~~ offers little turn fault protection. However, it may provide inexpensive backup for multi-turn and phase faults.

The problem of CT error currents with the arrangement of Figure 4-11 may be eliminated by using single window or double window CTs.

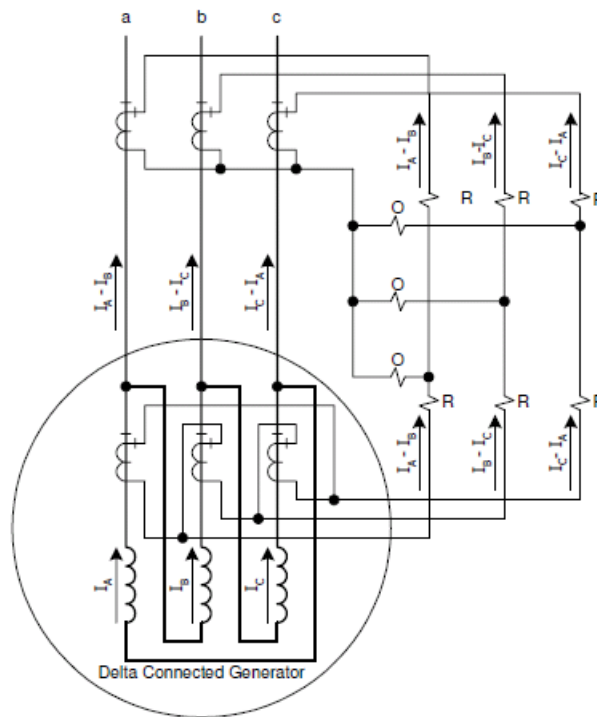


Figure 4-10—Percentage differential relay connection—delta-connected generator

Figure 4-12 illustrates the single window CT arrangement. In this approach, the single window CT eliminates the error currents because of its common core design. The fluxes produced by the primary currents balance each other in the magnetic structure and only the difference current produces an output in the secondary circuit. Therefore, the relays in the secondary more nearly see only the unbalanced current between the circuit groupings.

This permits more sensitive instantaneous relay settings. The single window CT approach is generally restricted to small machines because of physical and insulation problems in arranging the winding leads in the window CT.

The double window CT provides the same advantages of the single window approach but without its physical restrictions. The double window CT approach is shown in Figure 4-13. Again, in this approach only the difference between the primary currents produces an output in the secondary circuit, therefore permitting more sensitive instantaneous relay settings.

If the generator has an odd number of circuits per phase, it still may be possible to provide split-phase protection using separate CTs as shown in Figure 4-11. The currents in the two circuit grouping would not be equal in this case, and therefore, CT ratios would have to be selected to give equal secondary currents during balanced conditions.

In this instance, the single or double window CT approach would not be applicable since the relays would have to be set above a large difference current, making the scheme virtually insensitive to turn faults.

Split-phase protection will detect phase and some ground faults in the stator winding. However, because of the slow operating time of this protection, it is common practice to provide standard high-speed differential protection for each phase and separate ground fault protection.

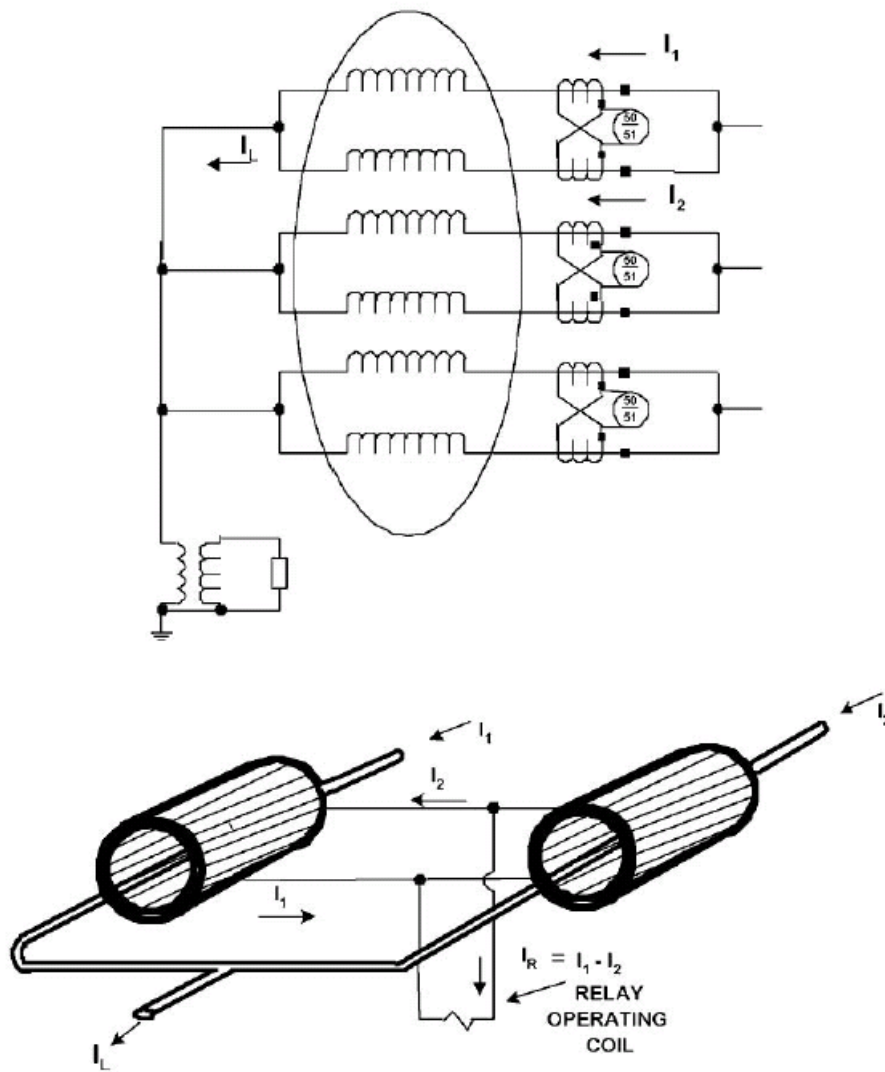


Figure 4-11—Split-phase protection using separate CTs

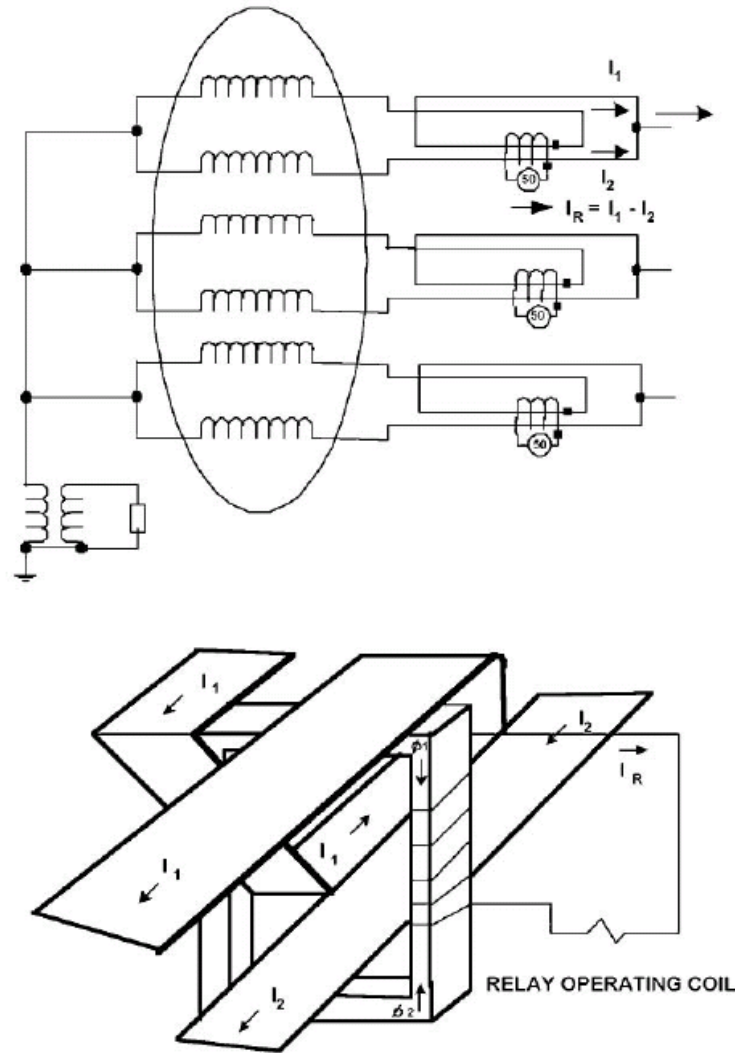


Figure 4-12—Split-phase protection using a single window CT

For generators where the stator winding configuration does not allow the application of split-phase differential, a neutral voltage method may be used to detect turn-to-turn stator winding faults. Figure 4-14 illustrates this method. Three VTs are connected in w, and the primary ground lead is tied to the generator neutral. The secondary is connected in a “broken delta” with an overvoltage relay connected across its open delta to measure unbalance voltage.

By connecting the primary ground lead to the generator neutral, the 59N relay is made insensitive to stator ground faults. The relay will, however, operate for turn-to-turn faults, which increase the unbalance voltage above low normal levels. This scheme is widely used outside of the U.S. The installation requires the cable from the neutral of the VT to the generator neutral be insulated for the system line-to-ground voltage. The 59N relay is tuned to fundamental frequency (60/50 Hz) voltage since some third harmonic voltages will be present across the broken-delta VT input.

One of the drawbacks of this scheme is that if the line to neutral insulated cable that connects the VT neutral to the generator neutral points sustains a ground fault, it will solidly ground the generator. For this reason, periodic testing of the cable is recommended.

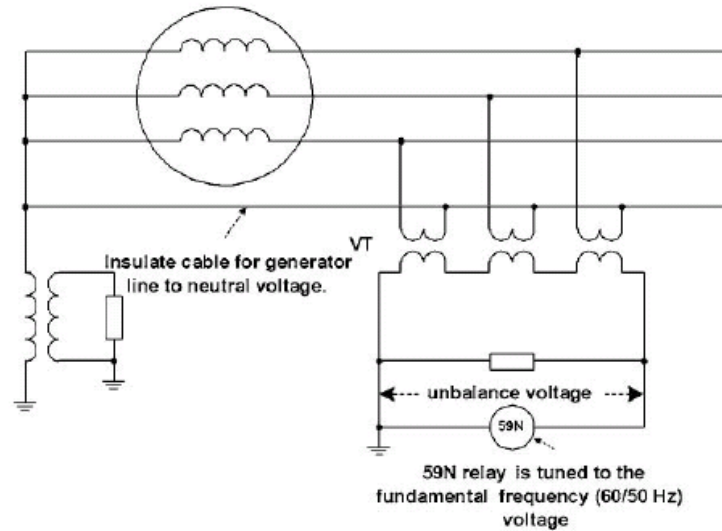


Figure 4-14—Turn-to-turn stator winding fault protection—zero-sequence unbalance overvoltage method (59N)

4.3.2.6 Backup protection

The type and sophistication of backup protection provided is dependent to some degree upon the size of the generator and on the method of connecting the generator to the system.

When a generator is connected to the system in the unit generator-transformer configuration, high-speed phase fault backup protection may be obtained by extending the protective zone of the unit transformer differential relay scheme to include the generator, the interconnecting leads, and the unit auxiliaries transformer. This backup is often referred to as the overall differential scheme and is illustrated in Figure 4-15.

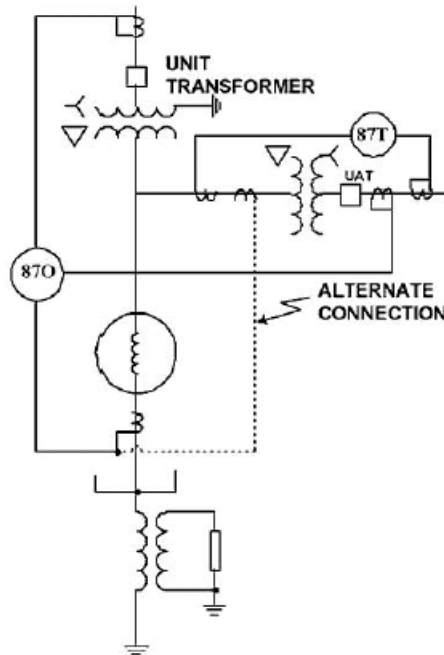


Figure 4-15—Generator phase fault backup overall differential scheme

In this arrangement, the CTs in the unit auxiliaries transformer circuit should be high-ratio CTs in order to balance the differential circuit. The required ratio may be obtained with a single bushing CT or with a combination of bushing and auxiliary CT.

In some cases, the unit auxiliaries transformer may be excluded from the overall differential scheme as indicated by the alternate connection. This approach may introduce a blind spot in the protection for the unit auxiliaries transformer. For faults near the high side of this transformer, the available fault current may be

150 to 200 times the rating of the CTs used in the differential scheme for the unit auxiliaries transformer. This high current level would drive the CTs into saturation, resulting in little or no current output to the differential relays. This blind spot is eliminated by connecting the overall differential scheme to the low side of the unit auxiliaries transformer. The overall scheme will detect the severe faults, while the unit auxiliaries differential will detect the low-level faults.

Figure 4-16 and Figure 4-17 illustrate the application of the overall differential scheme on a two-winding generator and on a cross-compound generator, respectively, where both types of generators are connected in a unit generator-transformer configuration.

Where generators are bused at generator voltage as shown in Figure 3-10 and Figure 3-11, or where generator breakers are used in the unit generator-transformer configuration as shown in Figure 3-8, the overall differential scheme is not applicable and a duplicate differential scheme is rarely used to provide phase fault backup protection.

In these configurations, it is common practice to use the unbalanced current protection (negative-sequence current relay) and system backup protection to provide backup for all generator phase faults. This protection is discussed in detail in 4.5.2 and 4.6 of this guide. This backup relaying is generally less sensitive than differential relaying and has time delay associated with it.

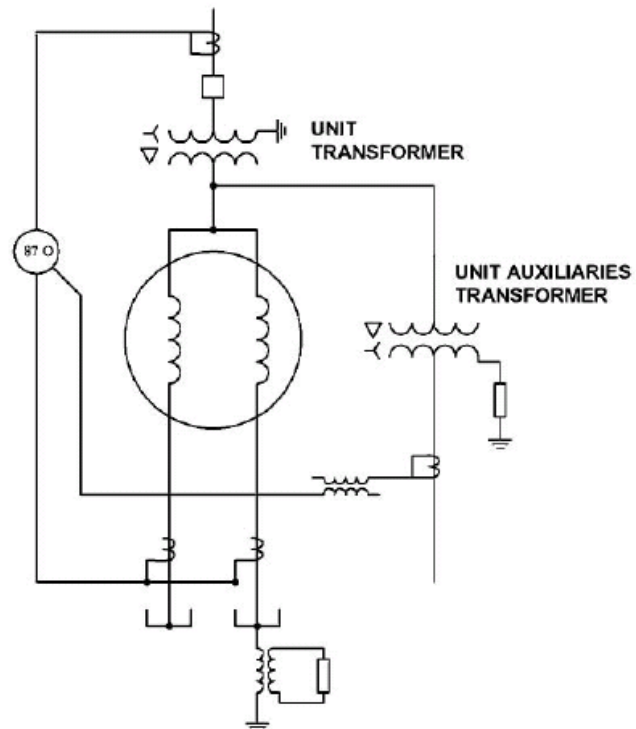


Figure 4-16—Phase fault backup for a two-winding generator

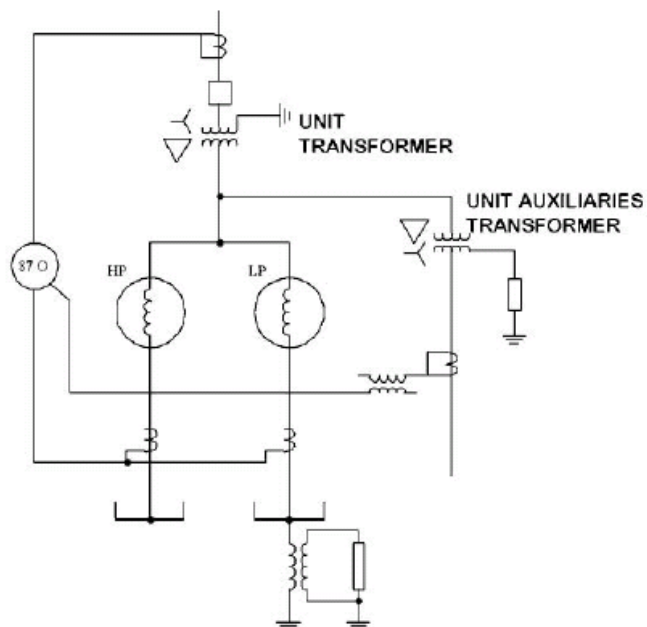


Figure 4-17—Phase fault backup for cross-compound generator

4.3.2.7 Tripping mode

It is common practice to have the primary and backup protection energize separate hand-reset multi-contact auxiliary relays. These auxiliary relays simultaneously initiate the following:

- a) Trip the main generator breaker(s)
- b) Trip the field and/or exciter breakers
- c) Trip the prime mover
- d) Turn on CO₂ internal generator fire protection if provided
- e) Operate an alarm and/or annunciator
- f) Transfer the station service to the standby source

4.3.3 Ground fault protection

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 subclause, differential relaying will not provide ground fault protection on high-impedance-grounded machines where primary fault current levels are limited to 3A 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.

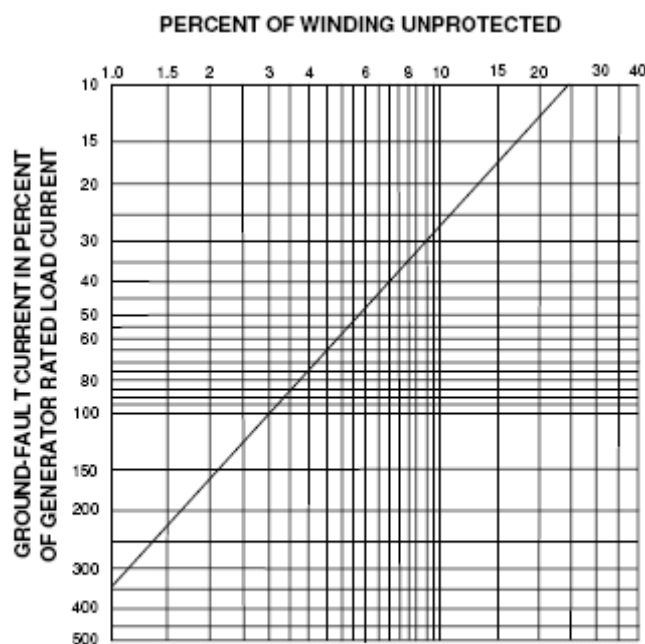


Figure 4-18—Percent of stator winding unprotected by differential relay for phase-to-ground fault

Since the available ground fault current may be small or limited to low values, it is common practice to provide separate sensitive ground fault protection for generators. Depending on the generator grounding method, the protection provided may include both primary and backup relaying or may be used to supplement whatever protection may be provided by differential relaying.

Numerous schemes have been developed and used to provide sensitive ground fault protection for generators and are discussed in considerable detail in IEEE Std C37.101-1993 [B62].

High-impedance grounding is generally used with unit system installations where a single generator or cross-compound generators are connected to the system through individual grounded wye-delta step-up transformers. The protection on a single unit generator-transformer arrangement is illustrated in Figure 4-19 and Figure 4-20.

Where cross-compound generators are bused at generator voltage or where a single generator has double windings, it is the practice to ground only one unit or winding as shown in Figure 4-20. Protection for both units and/or windings is provided by the one set of ground relays. Some types of 100% stator ground fault protection require relays for each neutral. The following discussion covers ~~only the most widely used~~ [various](#) schemes for the four grounding methods considered in 3.2 of this guide.

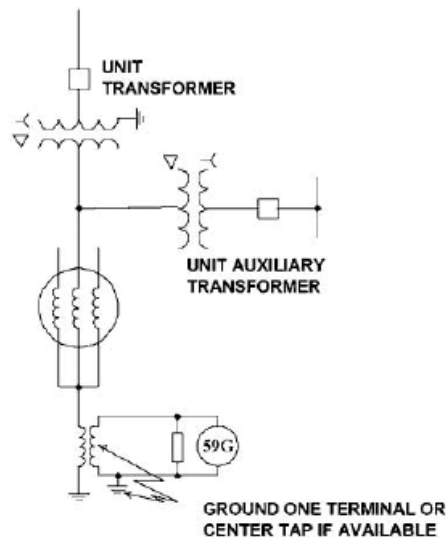


Figure 4-19—Generator ground fault protection for high-impedance grounded generator

4.3.3.1 High-impedance grounding

As noted in 3.2.1, two types of high-impedance grounding are in use today:

- a) High-resistance grounding
- b) Ground fault neutralizer grounding

In both cases, the ground fault current is limited to such low levels that differential relaying will not detect phase-to-ground faults. Therefore, for high-impedance grounded generators, it is common practice to provide separate primary and backup relaying for ground fault protection.

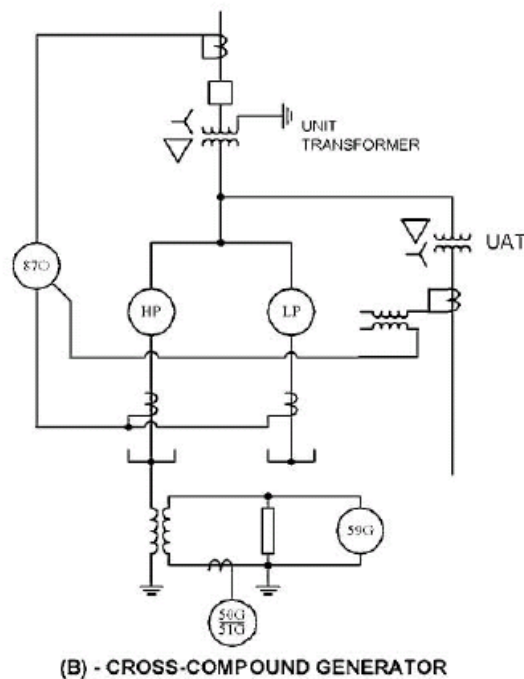
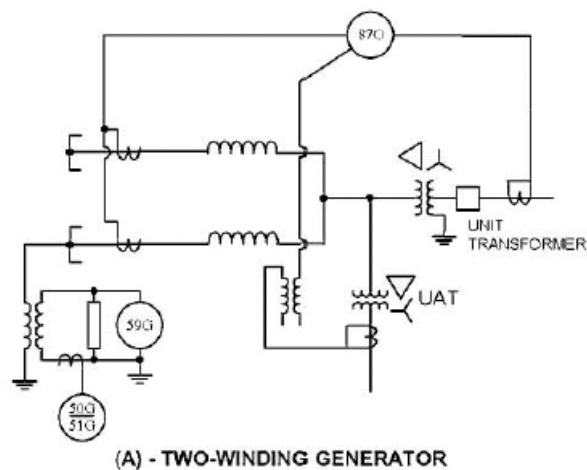


Figure 4-20—Ground protection for a two-winding and/or cross-compound generator

4.3.3.1.1 Protection

The most widely used [An accepted](#) protective scheme with the resistance-loaded distribution transformer method of grounding is a time-delay overvoltage relay, 59G, connected across the grounding impedance to sense zero-sequence voltage as shown in Figure 4-19.

The relay used for this function is designed to be sensitive to fundamental-frequency voltage and insensitive to third harmonic and other higher harmonic voltages that may be present at the generator neutral.

Since the grounding impedance is large compared to the generator impedance and other impedances in the circuit, the full phase-to-neutral voltage will be impressed across the grounding device for a phase-to-ground fault at the generator terminals. The voltage on the relay is a function of the distribution transformer ratio and the location of

the fault. The voltage will be at a maximum for a terminal fault and decreases in magnitude as the fault location moves from the generator terminals toward the neutral.

Typically, the overvoltage relay has minimum pickup setting of approximately 5 V. With this setting and with typical distribution transformer ratios, this scheme is capable of detecting faults to within 2% to 5% of the stator neutral.

It should be noted that for personnel safety the distribution transformer secondary winding ~~is usually~~ should be grounded at one point as shown in Figure 4-19. This point may be at one terminal of the secondary winding or at a center tap, if available.

The time setting for the voltage relay is selected to provide coordination with other system protective devices (see IEEE Std C37.101-1993 [B62]). Specific areas of concern include:

- a) When grounded-wye/grounded-wye VTs are connected at the machine terminals, the ~~voltage~~ 59G relay should be time coordinated with VT fuses for faults on the transformer secondary windings. If relay time delay for coordination is not acceptable, the coordination problem may be alleviated by grounding one of the secondary phase conductors instead of the secondary neutral. When this technique is used, the coordination problem still exists for ground faults on the secondary neutral. Thus its usefulness is limited to those applications where the exposure on the secondary neutral to ground faults is small.
- b) The voltage relay may have to be coordinated with system relaying for system ground faults. System phase-to-ground faults will induce zero-sequence voltages at the generator due to capacitive coupling between the windings of the unit transformer. This induced voltage will appear on the secondary of the grounding distribution transformer and may cause operation of the zero-sequence voltage relay.

c) If a bus ground fault relay, device 59BN (see Figure 7-4, for example), is used to protect the section of bus between the generator and the unit step-up transformer, the voltage relay should also be coordinated with it. In particular, care should be taken that both devices have similar time-voltage characteristics, such as definite time or inverse time, in order to prevent mis-coordination.

In general, for cases a) and b) a long time-delay setting for an inverse time relay has been found necessary to provide adequate coordination with VT fuses and system ground relaying. Shorter time delays have been used where the VT secondary neutral is isolated and a secondary phase conductor grounded and where high-speed ground relaying is used on the high-voltage system.

A time-overcurrent relay with instantaneous element may be used as primary or backup protection when the generator is grounded through a distribution transformer with a secondary resistor. The CT supplying the overcurrent relay may be located in the generator neutral or in the secondary circuit of the distribution transformer as shown in Figure 4-21. When the CT is connected directly in the neutral, a 5:5 A CT ratio is employed. When the CT is connected in the distribution transformer secondary circuit, the CT ratio should be selected so that the maximum current in the 50/51G relay is approximately the same as the maximum generator ground fault amperes. ~~In either case, the accuracy of the CT must be carefully assessed, bearing in mind the possible high burden if electromechanical relays with sensitive settings are connected~~ In either case, a CT of high relaying accuracy (C100 or better) with a voltage rating determined by the generator phase-to-neutral voltage should be employed.

With the generator online, there will be a continuous flow of current in the 50/51G relay caused by the stray capacitances of the system being protected. This current will consist mostly of harmonics of the fundamental frequency, principally the third. It will vary directly with the real and reactive power on the machine, so that the maximum current flow will occur with the unit fully loaded. If the secondary resistor is properly selected, this value will seldom exceed 0.5 A, where the maximum fault current (in the generator and in the ground relay) approaches 10 A.

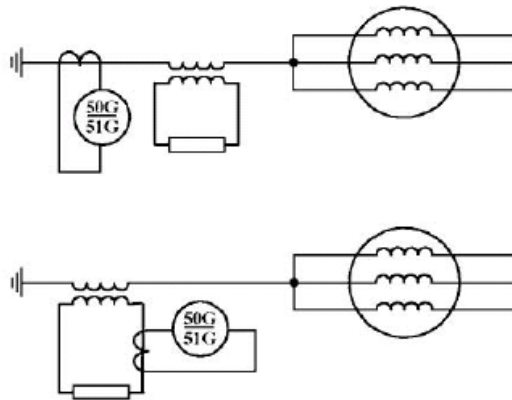


Figure 4-21—Backup ground overcurrent protection

It is important that the current in the 50/51G relay be measured with the unit running at full load. For example, if the relay pickup is set for 135% of the measured value, this protection will typically provide for 90% to 95% of the stator winding. See IEEE Std C37.101-1993 [B62]. A relay insensitive to harmonics may be set at a lower pickup, providing more protection to the stator.

Since a voltage may exist at the generator neutral when a fault occurs on the high-tension side of the GSU transformer, some time delay should be provided for the 50/51G time overcurrent (TOC) unit. Otherwise, the machine may be incorrectly tripped for a transmission system fault. The setting should also prove adequate for coordination with the generator potential transformer fuses.

~~The IOC unit in the 50/51GN relay will provide high-speed tripping of the generator field and generator high-side breakers for ground faults in the transformer delta windings and the bus work connected to the generator terminals. It will also give high-speed protection for all faults in the first 50–70% of the generator, measuring in from the high-voltage end of the machine. Thus, the~~ The 50/51G relay should generally be equipped with an IOC unit. The IOC unit is extremely valuable in limiting machine damage, particularly in the case of nearly simultaneous ground faults on two different phases. However, if it is desired to coordinate the 50/51G relay with the generator potential transformer fuses, the IOC unit will have to be connected to alarm only. This will still prove of considerable value, since the action or inaction of this unit will aid in the frequently difficult task of determining fault location.

Some utilities have used overcurrent relays on generators grounded through a ground fault neutralizer. In this case an overcurrent relay will provide protection only in case of failure of the tunable reactor or distribution transformer.

As noted previously, the zero-sequence voltage relay will detect faults to within 2% to 5% of the stator neutral. There are several schemes for detecting ground faults at or near the neutral, thereby extending the grounding impedance records the harmonic voltages which are always present at the generator neutral. A sudden reduction in voltage reading would indicate a phase-to-ground fault in the vicinity protection to 100% of the stator ~~neutral or a failure in the grounding equipment. An increase in voltage may indicate possible insulation deterioration~~ winding.

Several schemes use third harmonic voltage at the neutral or at the generator terminals as a means to detect faults near the stator neutral. These schemes supplement the fundamental frequency zero-sequence voltage relay and are illustrated in Figure 4-22, Figure 4-23, and Figure 4-24. Note that these schemes assume that adequate harmonic voltage is present at the neutral of the machine. Typical values needed are approximately 1% of rated voltage. Some generators are designed in a way that there is no significant amount of third harmonic voltage generated. In these situations 100% stator ground fault protection based on third harmonic voltage measurement may not be appropriate and other methods such as the one shown in Figure 4-25 should be considered.

In Figure 4-22, a third harmonic undervoltage relay (27TH) is placed across the grounding impedance. The relay operates (27TH contact closes) on the decrease in third harmonic voltage at the neutral that will occur during a stator phase-to-ground fault ~~near the neutral~~. The 27TH relay is supervised by a voltage relay to prevent the relay from operating when excitation is removed from the generator. Other means of supervising the 27TH relay may also ~~available~~ be used.

In Figure 4-23, an overvoltage relay (59TH) is connected to measure the third harmonic voltage at the machine terminals. When a stator phase-to-ground fault occurs ~~at or near the generator neutral~~, there will be an increase in third harmonic voltage ~~at the generator terminals~~, which will cause relay operation.

Figure 4-24 illustrates a third harmonic voltage differential (59THD) scheme. This scheme compares the third harmonic voltage appearing at the neutral to ~~that which appears~~ the third harmonic voltage appearing at the generator terminals. The ratio of these third harmonic voltages is relatively constant for all load conditions. A stator phase-to-ground fault will disrupt this balance, thus causing operation of the differential relay. ~~This scheme will not operate for a phase-to-ground fault near the generator winding midpoint and requires an additional relay scheme for complete protection.~~

One additional important advantage of this scheme is that it continuously monitors the grounding transformer primary and secondary connections and VT at the terminals of the machine. It operates for ~~certain~~ opens or shorts that might prevent the overvoltage relay or other relays from operating. Thus a problem could be detected before a stator ground occurs. This aspect of the protection scheme may favor an alarm rather than trip output. These characteristics also apply to Figure 4-22 and Figure 4-23.

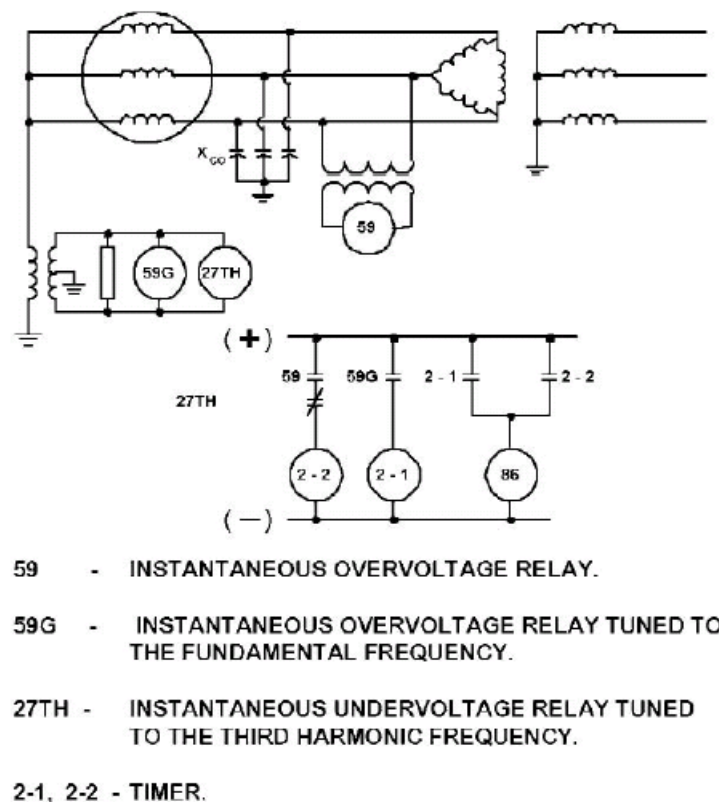


Figure 4-22—Third harmonic undervoltage scheme for generator ground protection