NTNU – Trondheim
Norwegian University of
Science and Technology

Analysis of relay protection for generators in offshore facilities

Eirik Sundal

Master of Energy and Environmental Engineering
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Supervisor: Hans Kristian Høidalen, ELKRAFT
Co-supervisor: Jens Erling Bjørck, ABB
Morten Stigen, ABB

Norwegian University of Science and Technology
Department of Electric Power Engineering

Problem description

Offshore oil and gas production platforms has a high-energy consumption. This energy may be supplied via power cable from shore, or generated locally within the facility. On the Norwegian continental shelf, local power generation is by far the most common choice. For main power supply, power is then generated in large turbines, driving electric generators. These generators tend to have very equal ratings, also among different facilities.

ABB has developed a generator protection relay, the ABB REG670. In projects for Statoil ASA, ABB deliver protective relays while a third party compute relay parameter values. ABB often experience large differences in these values among different facilities, despite very similar generator ratings. These are differences that no one really can explain. The goal of this project is to gain a better understanding for protection of generators used in offshore facilities and to contribute to a more standardized protection of such equipment.

Thesis content:

- Identify requirements that apply to relay protection of generators used in offshore facilities.
- Identify the functionality of ABB REG670 relay.
- Analysis of relay plans to identify present practice.
- Short circuit analysis for offshore facilities with Paladin DesignBase.
- Contribute to the development of a standard REG670 relay setting table for generators in offshore facilities.

Preface

This report is the authors Master's thesis at the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). The work for this report was performed during the spring of 2015, and concludes my study at the MSc program Energy and Environmental Engineering at NTNU. The project proposal came from ABB AS, and was supervised by Professor Hans Kristian Høidalen at NTNU and co-supervised by Morten Stigen and Jens Erling Bjørck at ABB AS.

I would like to thank my supervisor Professor Hans Kristian Høidalen at NTNU and my co-supervisors Jens Erling Bjørck and Morten Stigen at ABB AS for their good guidance and valuable feedback throughout the project. I am grateful to Roald Sporild at Unitech Power Systems AS, for sharing his knowledge and experience with me. Arild Larsen also deserves some gratitude for helping me with a license to the Paladin DesignBase software.

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Eirik Sundal

Abstract

This thesis study how to configure protective relays for protection of generators in offshore oil and gas facilities. On the Norwegian continental shelf, most platforms have isolated power systems with local power generation by a few synchronous generators. Normally, these generators have very similar ratings, also from facility to facility. Due to the natural inherent safety hazards of operating an electrical system in offshore oil and gas facilities, special standards regulate the practice. This applies especially to relay protection of generators because of its essential role for the facility operation combined with its wide range of failure mechanisms. In addition, the electrical system design is also very similar between facilities. All this, makes it possible to find a standard setup for protective relays that are used in such facilities.

The thesis identify present standards and regulations that applies to generator protection in these facilities. The underlying reasons for these are also explained. Based on this, the thesis propose functions in the ABB REG670 relay that can be used as a standard solution for all generators in such facilities, to achieve optimal generator protection and full compliance with existing requirements.

Relay setting tables for generators in five different facilities is studied to identify how relay protection for generators in these facilities is performed today. Based on this work, the thesis guide how to configure the proposed relay functions. In addition, function parameters that can be set equal for all generators are identified.

A study of short-circuits in the power system external to the generator zone is performed. This identifies current contributions from a single generator for different fault types and system configurations. The study showed that a generator relay is not able to detect short circuits on other buses than where it is connected. On this bus, the current contribution from a single generator is unaffected by other equipment connected to the bus. This prove that it is not necessary to perform such a study when upgrading the generator relay.

Sammendrag

Denne oppgaven undersøker hvordan vern av generatorer i offshore olje og gass anlegg skal konfigureres. De fleste plattformer på den norske kontinentalsokkelen driftes som isolerte kraftsystem hvor elektrisk energi genereres lokalt i et lite antall generatorer. Disse generatorene har som oftest veldig like egenskaper, også fra anlegg til anlegg. På grunn av de naturlige sikkerhetsrisikoene med å operere et elektrisk system på offshore olje og gass plattformer stilles det strenge krav til vern av systemet. Og da spesielt til vern av generatorer for deres essensielle rolle i driften av hele anlegget, kombinert med deres mange mulige feilmekanismer. Dette, i tillegg til at utformingen på det elektriske kraftsystemet er veldig likt for hvert enkelt anlegg, gjør det mulig å finne et standard oppsett som kan brukes for vern av alle generatorer i slike anlegg.

Oppgaven kartlegger gjeldende standarder og krav som stilles til vern av generatorer i denne typen anlegg. De bakenforliggende årsakene til påkrevde vern funksjoner er også forklart. Basert på dette foreslås det vern funksjoner i ABB REG670 vernet som kan benyttes som en standard løsning, for å gi en optimal beskyttelse av generatoren samtidig som alle gjeldende krav er oppfylt.

Vern parameter tabeller for generatorer i fem forskjellige anlegg er studert for å identifisere hvordan dagens praksis for vern av generatorer er i denne typen anlegg. Basert på dette arbeidet veileder oppgaven hvordan de forskjellige vern funksjonene skal konfigureres og identifiserer hvilke funksjonsverdier som kan være konstant for alle generatorer.

Det er gjennomført et studie av strømbidrag fra en enkelt generator ved kortslutninger i det utenforliggende nettet. Dette viste at generatorvernet ikke kan oppdage feil på lavereliggende samleskinner. I tillegg ble det funnet at strømbidraget fra en enkelt generator ved kortslutning på samleskinnen hvor generatoren er tilkoblet, er upåvirket av annet utstyr som er koblet til samleskinnen. Dette beviser at det ikke er nødvendig å gjennomføre en slik studie ved en oppgradering av generator vernet.

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Abbreviations

AC	Alternating current
AVR	Automatic voltage regulator
CB	Circuit breaker
CT	Current transformer
DC	Direct current
DFT	Discrete Fourier transform
HMI	Human machine interface
HV	High voltage
IED	Intelligent electronic device
IEEE	Institute of Electrical and Electronic Engineers
LV	Low voltage
MV	Medium voltage
NTNU	Norwegian university of science and technology
OC	Overcurrent
RMS	Root mean square
RTD	Resistance temperature detector
VT	Voltage transformer

Chapter 1

Introduction

Oil and gas production is an energy demanding process. On the Norwegian continental shelf, most production platforms have isolated electrical systems with local power generation. Total installed power at all facilities is approximately 3000 MW, with a yearly energy production at around 15 TWh [17]. At each facility, power is generated by a few large turbines, driving synchronous generators.

Generators in offshore facilities are essential components. If one has to be taken out of service due to damage, it may affect the further operation of the whole facility. To protect a generator against harmful faults and other types of abnormal conditions, relaying systems are installed. If unwanted operating conditions occurs for the generator, the generator relay will then isolate the generator as quickly as possible, to prevent any further damage to the generator and connected components.

Even more important than protecting the generator, is to protect personnel working and living at the facility. An offshore platform is mainly maid out of steel and concrete, surrounded by sea and located far from shore. Any fail in the electrical power system will in these conditions represent a safety hazard. In addition to the high risk of electrical shock, any electrical arcing increases the inherent risk of fire and explosions. Because of the special operating conditions, special standards and requirements apply to the operation of the electrical system.

Design of the electrical system at an offshore production facility is very similar for all facilities. In addition to this, generators for main power generation have very equal ratings, also from facility to facility. Therefore, it should be possible to find a standard solution for relay protection of generators. This report studies if this is possible and tries to find a proposal for such a solution.

To assure that the protective systems are up to date, relays are from time to time replaced with new ones. Normally, the old relays only have a few parameter values to define its operation characteristic. New modern relays have a much wider application capability, and allow operation characteristic to be tailor made for each application. If set correct, the new relays can provide a higher level of protection, but if this is done wrong, the level of protection might be worse than with the old relay. Configuration of modern relays require in addition to a basic understanding of power system operation and protection, an understanding of the relay function itself. This report, studies one such modern relay, the ABB REG670 relay.

Single-line diagrams and relay setting tables for five actual offshore facilities and computer models of the electrical systems at two of these, are given as background material for this report. This is confidential information, a non-disclosure agreement has been reached to gain permission to use this material. As part of this, no names or any other information that can link to a specific facility, is given in this report. Some of this data is presented, but only anonymous references are used.

This report can be roughly divided into three parts. The first part serves as an introduction to relay protection for generators. Chapter two starts with a general introduction to protective systems and basic relay philosophies. Chapter three shortly introduce different relaying schemes. Third chapter are based on the authors previous work within the same field, see reference [16]. Chapter four is a review of important theory of the synchronous generator.

The second part goes more specific into relay protection in offshore facilities. Here, chapter five introduces electrical system design in offshore units and a review of standards and requirements that apply to these systems. Chapter six present relaying techniques relevant to offshore generators. Chapter seven studies the REG670 relay more closely in relation to how to use its functionality to comply with the requirements. Chapter eight compare the relay setting tables given as background material, in an effort to find a standard function setting table. Chapter nine present a short circuit simulation study, exploring how the current contribution from a single generator is affected by fault location and system configuration.

The third part summarize the findings and points out strengths and weaknesses of the results. Chapter ten is a discussion of the proposed standard relay setting table found for REG670. Chapter eleven concludes the work, and chapter twelve proposes further work on this topic.

Chapter 2

Introduction to relay protection

The main purpose of a relaying system is to respond to intolerable conditions within an electrical system in order to protect personnel and limit equipment damage. No matter how well a system is designed, intolerable conditions will eventually occur due to unforeseen reasons and isolation deterioration. When these occur, fast detection and selective handling is key to limit the consequences, and to continue supply to healthy parts of the system. If they are not handled in time, the system will eventually become inoperable, and might oppose a risk for personnel in the vicinity of the system.

Protective equipment is installed in power systems to minimize the effects of faults and other abnormal phenomena on the operation of the system. The purpose of a protective system is to avoid or limit:

- Hazards to people and animals in the vicinity of electrical equipment
- Damage to equipment
- System instability
- Loss of supply and eventually a possibility of blackout

Power system protection is a field within electric power engineering concerned with detection and handling of faults and other types of abnormal conditions that might occur within a power system. The fundamental object is to differentiate between normal operation and a fault situation. The purpose is not to prevent such conditions from happening, but to limit damage to equipment, minimize danger to people, to reduce stress on other parts of the power system after such situations have occurred. In power system protection, normal operation refers to a situation where there are no faults within the protected area of the system.

This chapter is an introduction to protective system components, their attributes and important design criteria within power system protection, also known as protective relaying or relaying system.

2.1 Protective system main components

The term *protective system* indicates a combination of relays, circuit breakers and instrument transformers, working together. The interaction of these are essential, and there is no use of applying one without the other. This section introduce shortly the mentioned main components. In addition to these, fuses and power supply for circuit breakers and relays are also counted as part of a protective system.

2.1.1 Protective relays

Relays are devices connected to the power system via the secondary side of current and voltage transformers. Essentially, their function is to detect unwanted and abnormal conditions within the area of protection, and respond to these in the form of trip and alarm signals. When a relay detects a fault, it will send out a trip signal to the appropriate circuit breakers necessary for isolation of the fault, ordering them to open and interrupt the current flow.

With time, relay technology has gone through major changes. Originally, protective relays were electromechanical devices. In the late 1950s, solid state analog relays were developed [10]. A little later, digital relay technology was introduced. Modern relays are based on a microprocessor, the first production of these started in the 1980s.

Microprocessor based relays, often referred to as numerical relays, sample the analog input signals from current and voltage transformers, and perform logical and numerical operations on the data. The later generations of numerical relays are also referred to as IEDs (intelligent electronic devices), to reflect the wide application capabilities, which often include features for system control, monitoring, and communication. Although relay technology has been fast developing the last decades, the old principles that applied to electromechanical relays still applies to modern relays. An understanding of these are fundamental to the understanding of modern relays.

2.1.2 Instrument transformers

Instrument transformers is collective term for current and voltage transformers (CT and VT). Their function is to transform the high currents and voltages in the power system to a level that is safe for relays, as accurate as possible. Providing relays the ability to monitor the electrical quantities of the power system. Conventional instrument transformers provide continuous analog values and are based on an iron core with windings wrapped around it. Non-conventional transformers are digital and provide sampled system values.

2.1.3 Circuit breakers

Circuit breakers (CBs) provide the protective system with the ability to isolate a faulted area from the rest of the system. They are designed according to two criteria; the ability to transfer power with smallest possible losses, and the ability to interruption high currents as fast as possible. When a CB receive a trip signal from a relay, it opens its main contacts to interrupt the flow of current.

2.2 Design criteria

Protective relays are designed according to some common criteria. This section review the most important ones. For each individual system, there will always be a trade-off between some of these.

2.2.1 Reliability

Reliability is the ability to perform its purpose throughout its lifetime. There are two ways a protection device can fail its purpose; it can fail to operate when it is supposed to, or it can operate when it is not supposed to. Reliability is the combination of these two, respectively dependability and security. These are closely related and actions to increase one of them tend to lower the other.

Dependability

Dependability is the degree of certainty of correct operation. Meaning, the certainty that a relay will trip when it is supposed to trip.

Security

Security is the degree of certainty of no incorrect operation. Meaning, the certainty that a relay will not trip unless there is a fault in its area of protection.

Redundancy

Reliability applies both to a single device (i.e relay) and to hole systems. To increase reliability of a protection system it is normal to add redundancy. A redundant system has essentially equal performance as the original system but they do not have to be identical as long as both fulfills the requirements. The benefit of redundancy is increased dependability; if one system fails, the operation is still carried out by the redundant system(s). On the other hand, redundancy decreases security, since more components are introduced that can make a false trip. It is possible though, to increase both dependability and security by introducing a voting scheme. In such a scheme, the majority of relays have to detect a fault before a circuit breaker can be energized. It is advisably that redundant systems come from different manufacturers to avoid potential design errors. [18]

If a separate system exists, but have a lower degree of performance, this system is referred to as a backup system. A backup system can be installed locally or remote. If installed remotely the backup system has the main system in one its outer zones, and therefore it does not deliver the same performance. Usually, a remote backup relay does not provide the same selectivity as the primary relay. [18]

2.2.2 Operating speed

Rapid operation, both for fault detection and for operation, is a key factor for limiting equipment damage. Relay operate time is the time between a fault occurs and relay trip command is sent out. Relay operation is called *instantaneous* if there are no intentional added time delay. The total fault clearing time of a protective system is a sum of the relay operate time and the CB operate time.

2.2.3 Sensitivity

Sensitivity describes the ability to detect faults. The more sensitive a relay is, it can detect smaller abnormalities. However, this is normally not a problem with relays, as CTs are the major source of inaccuracy. As sensitivity affects a relays ability to detect a fault, sensitivity affects dependability.

2.2.4 Economy and performance

It is always a trade-of between cost and benefit. A relay system has high initial costs, but the risk of operating a system without adequate protection can be fatal. Actually, protective systems introduce more complexity, which increases the maintenance requirement. There are many different types of relays available, having very different performance and cost. Sometimes a higher performance is not justified by the cost. These are always be considered in conjunction of the risk.

2.2.5 Simplicity

Simplicity of the whole relay system can be a mark of good design, as a too complex system might lower the security. Too much protection can actually be as bad as too little protection.

2.3 Zones of protection

To facilitate continuity of power supply, the general philosophy of relay protection is to divide the system into different zones. This way, at the occurrence of a fault, only the area where the fault is located has to be isolated, such that power can still be supplied to healthy parts of the system. A zone is defined by the location of CTs supplying the different relays. If a relay detect a fault inside one of its zones, it sends a trip signal to the CBs at the ends of the faulted zone. Figure 2.1 shows a illustration of a power system, having several zones of protection. To assure that all system equipment are within a zone of protection, zones are set to overlap its neighboring zones. This is done to avoid the possibility of areas left unprotected for changed operating conditions.

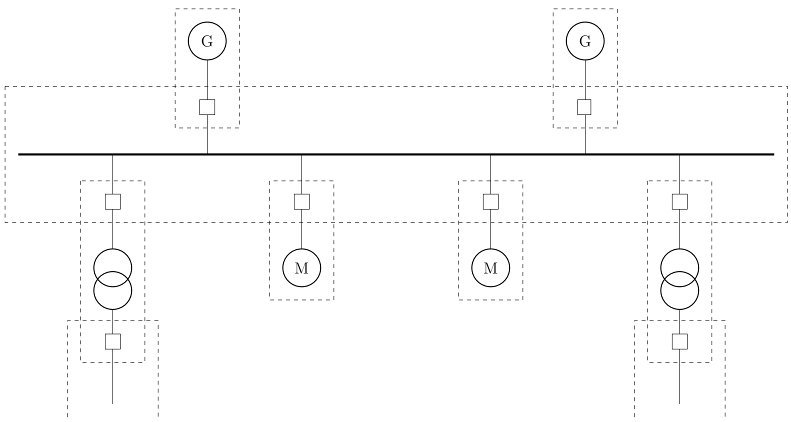


Figure 2.1: Illustration of a system divided into zones of protection.

Since faults do occur, backup protection is used to trip breakers or zones close to the fault, if the main protection fails. Backup is provided by relays nearby. Modern relays have possibilities for several zones, which means that a zone can be supervised by several relay.

Selectivity

Selectivity is an ability to isolate only faulted equipment, such that healthy parts of the system can still be operated. Good selectivity is important to assure a high system continuity.

Relay coordination

Often, several relays are able to detect the same fault. For selective operation, the relay, which has the fault in its main zone, should trip first. If this for some reason, fails to operate, the next relay should operate. To achieve this, relays have to be coordinated.

2.4 Applying protective relays

When applying protective relays, the first step is to state the protection requirements accurately. For further work, information about the following is required: [6] [8]

- Single-line diagram showing the system configuration.
- Loads and impedances of equipment, and their connection to the system.
- Existing protection and known problems.
- Existing operation procedures and practices.
- Degree of protection required.
- System fault study.
- Future expansions.

System configuration

System configuration is normally represented by a single-line diagram, which shows the location of system components. Information about voltage levels and system frequency should also be provided. [6]

Loads and impedances of equipment and their connection to the system

A single line diagram does not provide all necessary information about the system. For instance is system grounding often left out, but this is essential information for many relaying schemes. Location of CTs and VTs might be shown in the single line diagram, but additional information about connections, grounding and winding ratios are needed. In addition, maximum loads of connected equipment, impedances of lines, transformers and their connections to the system is important for system fault studies. Phase sequence influence how relays can be connected to the power system, and should be clearly defined.

Existing protection and known problems

Not applicable to new facilities, but for old installations, information about the existing protective equipment and known problems may be a valuable guide to improvements.

Existing operation procedures and practices

Whenever possible, changes in system protection should confirm with the existing operating procedures and practices. Exceptions from the standard may increase risk of personnel error. [8]

Degree of protection required

The degree of protection required is in general determined by how important the equipment that needs protection is to the power system and the risk of a fault occurrence.

System fault study

A system fault study is necessary for almost all relay applications. For phase fault protection the study should include three-phase faults and line-to-ground faults. For lines, faults on the line side of an open breaker (line-end fault) is also important. For ground fault protection, phase-to-ground faults including zero- and negative sequence quantities, is important.

Future expansions

System expansion and changes that are likely to occur in near future should be considered when designing a protective system, as this might change the operating conditions.

Chapter 3

Fundamental relay operation principles

There is a wide range of protective schemes in use today, but most of them are based on three fundamental techniques. These are the overcurrent, distance and differential protection principles. This chapter introduce these three operating principles.

3.1 Overcurrent relay

Overcurrent relays are based on the principle that a fault will cause a current increase in either phase, ground or both. Thus, overcurrent relays measures the current flow at a single point of a system and compares it with its operating characteristic. If current exceeds the specified pickup value, a timer starts. If the current magnitude is large enough for longer timer than the specified time delay, the relay trips. The relation between pickup current, I_p, and time delay is given by a relay time-current characteristic. Three widely used time characteristics are the instantaneous, definite or inverse time characteristics.

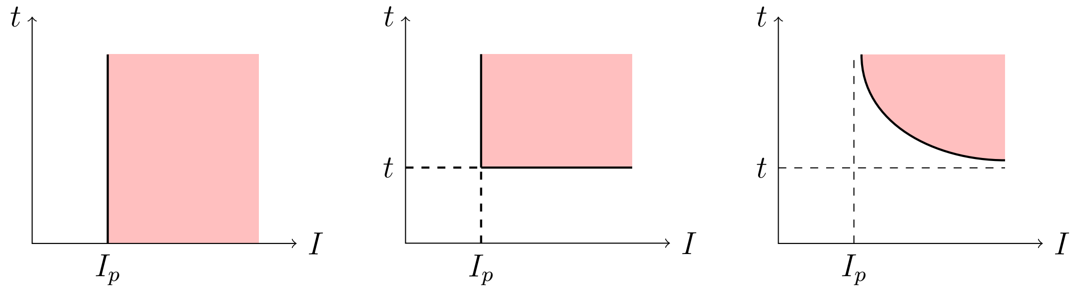
Instantaneous time characteristic Relays having an instantaneous time characteristic only respond to the current magnitude, as there are no intentionally added time delay. The only requirement for a trip is that $I > I_p$. Figure 3.1a shows a time current plot for this characteristic. The red area is the trip region of the characteristic.

Definite time characteristic Definite time characteristic has an added constant time delay. Trip time is the same for all current values as long as $I > I_p$. Figure 3.1b shows this characteristic.

Inverse time characteristic For inverse type, the current magnitude affects the time delay. The lower overcurrent, the longer the time delay. Figure 3.1c shows this characteristics.

3.1.1 Directional overcurrent relay

In many situations, for example in multiple source systems or looped network configurations, directional sensitivity for the overcurrent relay ease coordination with other relays. Directional relays require two inputs; the operating current and a reference quantity, also



(a) Instantaneous (b) Definite (c) Inverse

Figure 3.1: Current-time operate characteristics.

called polarizing quantity. This quantity should not be affected by a fault situation. Normally, system voltage is used as polarizing quantity, but it can also be a current value. When the polarizing quantity is compared with the operating current, the phase angle will change in the occurrence of a fault, and vary directly with the fault location. In normal operation the phase angle, ϕ, is determined by the power factor, which is typically quite high. However, if power flows in the opposite direction, the phase angle will be $180° - \phi$. [10]

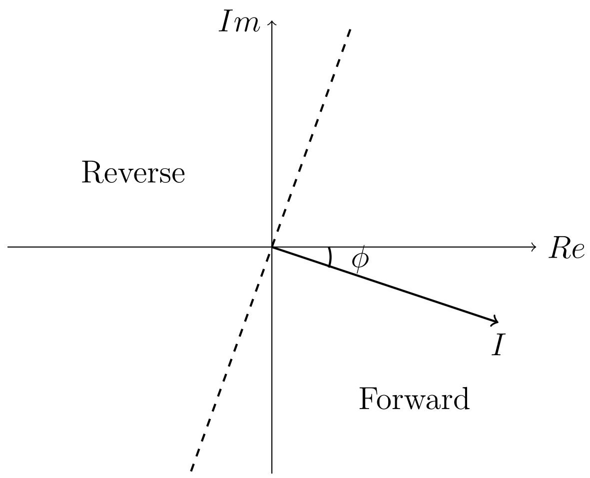


Figure 3.2: Directional overcurrent relay characteristic

3.2 Distance relay

Coordination of overcurrent (including directional overcurrent) relays can be difficult for looped networks with multiple sources. In addition, long radial lines create problems for overcurrent protection, because coordination of relays requires long delay times for those located close to the feeder. In such cases, it is better to use distance relays.

Distance relays respond to the ratio of voltage to current, at the location of the relay. Which corresponds to the impedance $Z = \frac{V}{I}$ seen by the relay. Since the impedance per distance for transmission lines and cables is fairly constant, distance relays are in fact responding to the distance between the relay and the fault. Hence their name. The relay characteristic are normally shown in a R-X diagram.

Figure 3.3 shows a simple impedance circle characteristic to illustrate the operation principle. The radius of the circle is the relay pick-up impedance, Z_r. During normal operation, the measured impedance correspond to the load impedance, Z_{load}, as seen by the relay. This is located outside the circle. if a fault occur, the measured impedance Z_f will be the short-circuit impedance between the relay location and the fault. Neglecting, arc and fault resistance, this impedance will be equal to the line impedance for all fault locations on the same line. In the R-X-diagram, this line is called the locus of impedance, and is indicated in figure 3.3 by a line that goes through origo. As the fault location moves toward the relay, the distance to the fault decreases, and the point Z_f^1 in the R-X diagram move towards origo on this straight line. If now $|Z| < |Z_r|$, the measured impedance is inside the circle, and the relay will operate according to its time characteristic. [10]

If we also account for arc and fault resistance, a resistive component must be added which offsets the fault impedance from the locus of impedance line, shown by Z_f^2. Since this impedance is mainly resistive, the short-circle angle is less then the angle of the locus of impedance. [20]

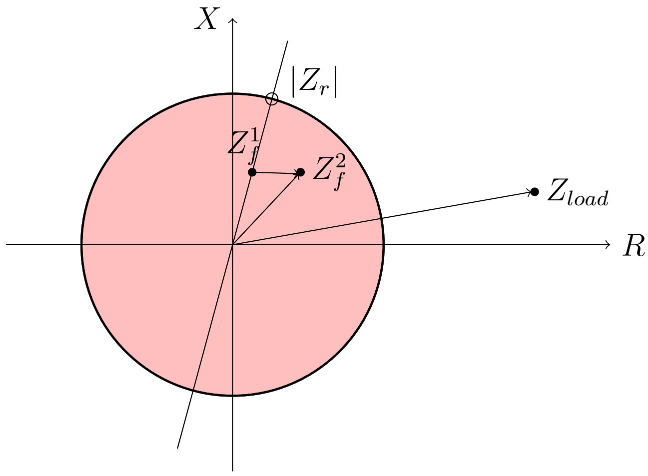
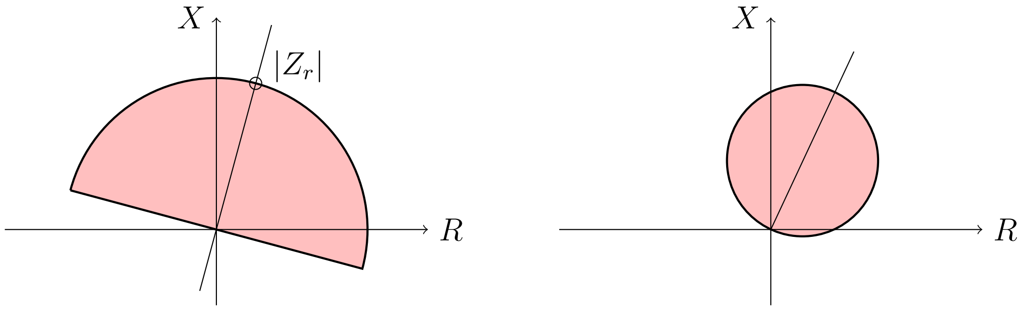


Figure 3.3: Distance relay characteristics in the R-X diagram.

As the distance relay requires both a current and a voltage measurement to operate, directional functionality is only specified by adjusting the relay operating characteristic. Figure 3.4 illustrates possible options. Figure 3.4a shows a distance relay with a directional restraint similar to directional overcurrent relay. Figure 3.4b shows a characteristic called mho characteristic. Here, the circumference of the circle passes through origo of the R-X diagram, while the circle itself can be moved around according to the locus of impedance to replicate the line as best as possible.

3.3 Differential protection

Differential protection is known to for being the best protection principle. In this scheme, all electrical quantities entering and leaving the protected zone are measured and compared. If the sum of all measurements are zero, it is assumed that there is no fault inside

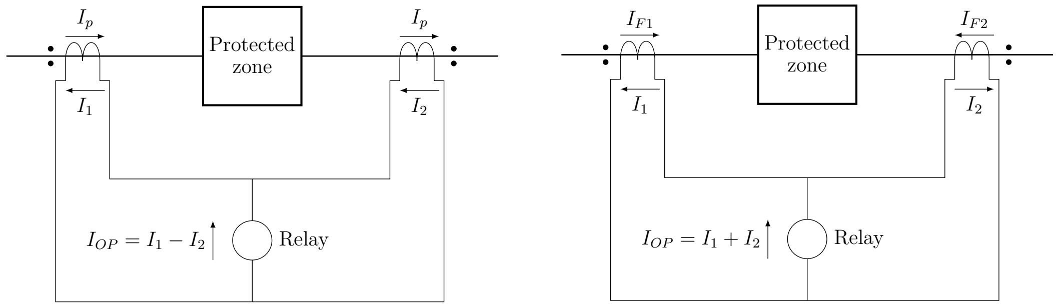


(a) Impedance with directional restraint.

(b) Mho

Figure 3.4: Distance relay characteristics with directional restriction.

the protected zone. However, if the net sum is different from zero, an internal problem exists, and the relay trips.



(a) No faults inside protected zone

(b) Internal fault

Figure 3.5: Basic current differential scheme.

Figure 3.5 illustrates a basic current differential scheme for normal normal operation and a internal fault situation. Currents entering and leaving the protected zone flows through CTs, and the difference of the secondary side currents flow through the relay. In normal operation and for external faults I_p is the primary side current flowing through the protected equipment. The two measured currents, I_1 and I_2, are then ideally equal, such that $I_1 - I_2 = 0$. however, there will in practice, be a small difference current because of losses within the protected equipment, transformer leakage current and CT errors. Therefore, as $I_1 = I_p - I_{e1}$ and $I_2 = I_p - I_{e2}$, then

$$I_{OP} = I_1 - I_2 = I_{e1} - I_{e2} \tag{3.1}$$

Different CTs and ratios produce an larger error, than if the same type of CTs are used. The error will be larger for larger through currents. For very high through currents, there is a risk of CT saturation, which can cause the differential relay to trip. Therefore, the relay pick-up should be set just above the maximum error that can occur during the worst case scenario in which the relay is not supposed to trip, which is a fault location just outside the protected zone.

For internal faults, as shown in figure 3.5b, current flowing through the relay is a sum of all secondary side fault current contributions:

$$I_{OP} = I_1 - I_2 = I_{F1} + I_{F2} - (I_{e1} + I_{e2}) \tag{3.2}$$

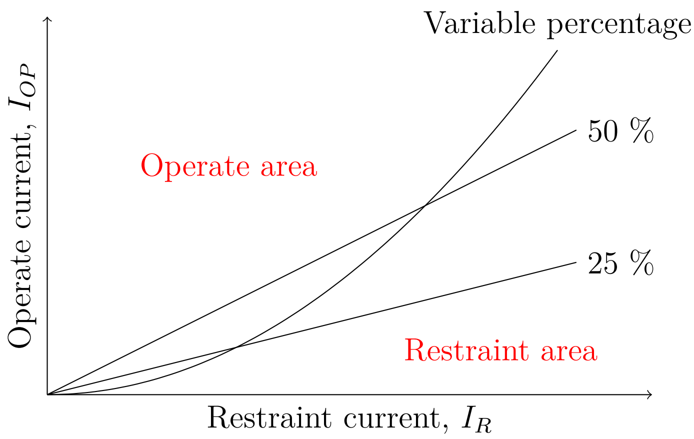


Figure 3.6: Differential relay operate and restraint areas of various percentage characteristics.

Currents can either enter the area from both sides, causing I_1 and I_2 to have opposite polarity, or from only one side. Either way, $I_1 - I_2 \neq 0$, and the relay will operate.

To provide high sensitivity for internal faults and high security for external faults, most differential relays are of a percentage differential type [6]. These use a restrain quantity, based on the secondary side magnitudes, together with the difference current for decision making. The net of all input currents, I_{OP}, is compared with the restrain current I_R, and the decision whether to operate or not, is based on this comparison. If a fixed percentage characteristic at 25 % is used while the through current is 10 A, the relay will operate for a difference of $I_{OP} \geq 2.5A$. As the through current increases, the required current for operation also increases.

With variable percentage relays the percentage changes. For small current levels the CT error is small and a small percentage can be used. For high through currents, where the CT performance is more unreliable, a higher percentage characteristic is used. This increases the sensitivity at low current levels, while providing better security at high current levels.

Chapter 4

The synchronous generator

This chapter reviews important characteristics of the synchronous generator. Emphasis is put on behavior during steady-state and transient conditions.

4.1 Basic operation principles

The electrical machine consist of two principal parts; stator and rotor. The rotor holds what is called the field winding. A dc current is supplied to this winding and it sets up the main magnetic field in the machine. A prime mover turns the rotor, causing a rotating magnetic field within the machine, which induce voltage in the armature windings. The armature windings are located in the stator.

Synchronous machine rotors can be of two principal constructions: salient or non-salient. Salient means that poles stick out from the rotor shaft. Non-salient or round rotor have windings embedded in the surface of the rotor, and have a cylindrical design. To set up a magnetic field in the rotor, it must either hold permanent magnets or a dc current must be supplied to its field winding. An exciter is used if current is used to set up the magnetic field. This can be mounted on the rotor shaft, or a separate dc source connected through brushes, sliding on slip rings. Large machines usually have brushless exciters, which essentially consists of a small ac generator with its armature windings mounted onto the rotor shaft, and a solid-state rectifier.

Electrical frequency produced in the stator, depends on the mechanical speed of the rotor. Equation 4.1 states the relationship.

$$f_{se} = \frac{n_m P}{120} \tag{4.1}$$

where f_{se} = electrical frequency in Hz, n_m = mechanical speed of rotor in rpm and P = number of poles. This means that a two-pole machine generating power at 60 Hz rotates at 3600 rpm, while at 50 Hz the speed will be 3000 rpm. For a four-pole machine, the speed is respectively 1800 rpm and 1500 rpm.

The magnitude of the induced voltage in a stator winding depends on the rotor speed and the available flux in the machine. The relationship is given in equation 4.2.

$$E_a = K\phi\omega \tag{4.2}$$

where E_a = induced voltage, K is a constant dependent on the machine construction, ϕ is the magnetic flux available in the air gap of the machine (produced by field current, I_f, in the filed winding) and ω is the angular velocity of the machine.

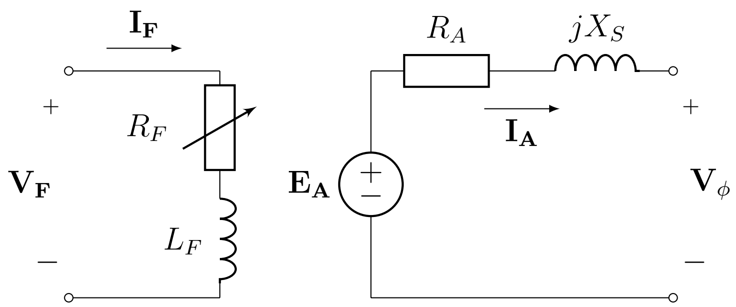
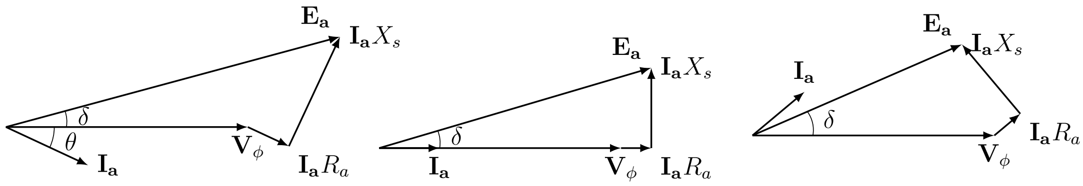


Figure 4.1: Per phase equivalent circuit of a synchronous generator



(a) Overexcited, lagging power factor.

(b) Unity power factor.

(c) Underexcited, leading power factor.

Figure 4.2: Phasor diagrams for a synchronous generator at different power factors.

Due to armature reaction, stator winding resistance and self-inductance, the internally generated voltage E_a does normally not appear at the machine terminals. The only time $V_\phi = E_a$ occurs is when there are no armature current flowing (no-load condition). This can be seen from the per-phase equivalent circuit of a synchronous generator, given in figure 4.1. Here X_s is the synchronous reactance, and it is a sum of $X_s = X + X_a$. X represent the armature reaction and X_a is the leakage reactance. R_a is the stator resistance. The left part represents the rotor which is fed by a DC voltage. L_f represents the winding inductance and R_f winding resistance, it is adjustable to control the filed current I_f. The phase voltage is described by equation 4.3, and can be verified from the equivalent circuit.

$$\mathbf{V}_\phi = \mathbf{E_a} - jX_s\mathbf{I_A} - R_a\mathbf{I_a} \tag{4.3}$$

Different phasor diagrams developed from equation 4.3 are illustrated in figure 4.2. For a given terminal voltage, armature current and internal voltage depends on the power factor of the load. Diagrams for synchronous generator operation at lagging, leading and unity power factor are shown.

Not all mechanical power input to the generator shaft is converted to electrical power. Some is lost due to stray losses, friction and windage losses, and core losses. The power converted after these losses is the mechanical power converted from mechanical to electrical power, and it is denoted P_{conv}. The mechanical power converted is equal to:

$$P_{conv} = \tau_{ind}\omega_m \tag{4.4}$$

τ_{ind} is the induced torque.

A machine capability diagram is a graphical representation of the machine operation limits, and is represented in the complex power plane. Three phase complex power

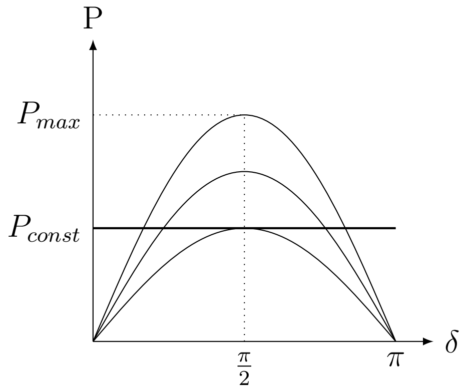


Figure 4.3: Machine power-angle characteristic for different magnetization levels

generated by the machine is

$$S_{3\phi} = 3V_\phi I_a^* = P + jQ = 3|V_\phi||I_a|\left(\cos\theta + j\sin\theta\right) \tag{4.5}$$

Normally, the stator resistance R_A is neglected as $X_S >> R_A$. Then the real and imaginary power can be expressed as:

$$P_{3\phi} = \frac{3|V_\phi||E_a|}{X_s}\sin\delta \tag{4.6}$$

$$Q_{3\phi} = \frac{3|V_\phi|}{X_s}\left(|E_a|\cos\delta - |V_\phi|\right) \tag{4.7}$$

If the three machine phases are Y-connected terminal voltage $V_t = \sqrt{3}V_\phi$. For Δ-connected windings the terminal voltage $V_t = V_\phi$.

As the speed of a synchronous generator is constant, the only means to change the active power output is to change the torque input from the prime mover. This is seen from equation 4.4. If the input power is changed while the field current is held constant, the angle δ will change accordingly. For an increased power input the angle δ will increase. δ is known as the power angle or torque angle. Obviously the maximum active power and torque is produced when $\delta = \frac{\pi}{2}$, which is the static stability limit of the machine. The maximum torque is also known as the pullout torque of the machine. If load is increased, such that $\delta > \frac{\pi}{2}$, the machine will lose synchronism. Electrical power output is plotted as a function of δ in figure 4.3. The three different curves corresponds to different excitation currents. This shows that for a generator operating in a large system, the same amount of active power can be generated at different power angles (reactive power).

To control the reactive power flow, the field current I_f, is used to change the magnetic flux in the air gap. As changing the magnetic field changes the induced voltage the machine excitation is determined by the following conditions:

$$\begin{aligned} \text{overexcited if} \quad & |E_A|\cos\delta > |V_\phi| \\ \text{normally excited if} \quad & |E_A|\cos\delta = |V_\phi| \\ \text{underexcited if} \quad & |E_A|\cos\delta < |V_\phi| \end{aligned} \tag{4.8}$$

An overexcited generator, as shown in 4.2a, supplies reactive power to the system. An underexcited generator, as shown in 4.2c, absorb reactive power from the system.

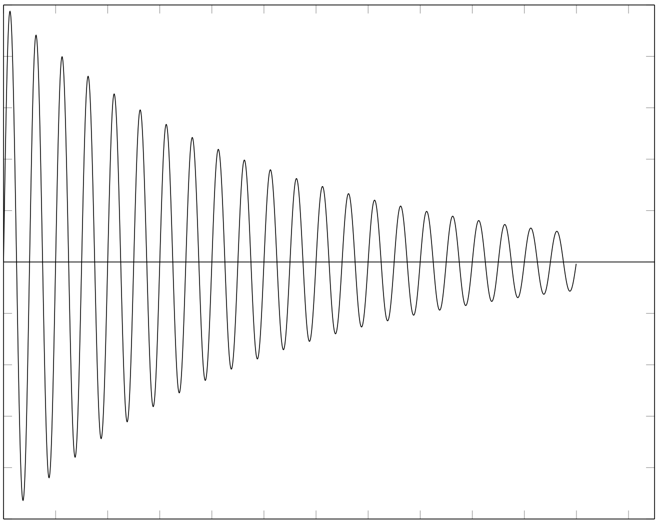


Figure 4.4: Plot of the symmetrical ac component of fault current from a generator.

4.2 Generator capability diagram

The steady state operational limits for a synchronous machine can be expressed in a single diagram called the loading capability diagram of the machine. This diagram is constructed from the machine phasor diagram. Figure 4.5 illustrates the principal construction of a capability diagram. As can be seen the operation area of the machine is limited by

- Armature heat limit, determined by the armature current.
- Field heat limit, determined by the field current.
- Underexcitation limit or steady-state stability limit.

4.3 Short circuit behavior

When a synchronous machine is short circuited, the resulting current flow include a dc component, offsetting the symmetrical ac component. The dc component is fast decaying. The relation is different for each phase, and in worst case, a phase current can have an instantaneous value that is 100 % offset. The symmetrical ac component will also decrease due to the generator reactance. Figure 4.4 shows a plot of the decaying symmetrical component after a short circuit at the generator terminals. Generally, the time is divided into three periods, relevant for different studies. These are the sub-transient, transient and the steady-state period. For each of these periods, the generator equivalent is represented by a different reactance values; the sub-transient reactance X'', the transient reactance value X' and the steady-state value reactance value X.

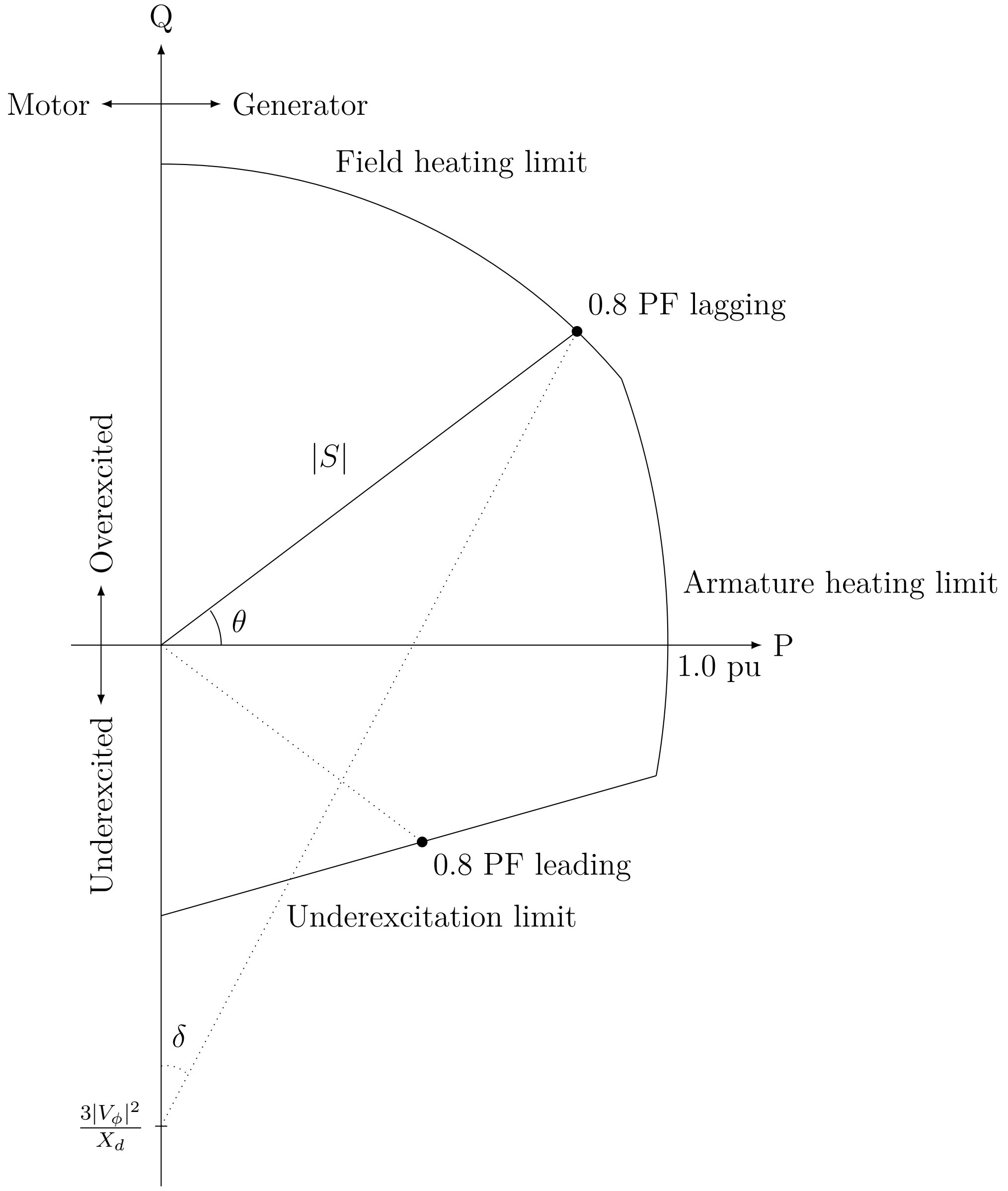


Figure 4.5: Illustration of an synchronous generator capability diagram

Chapter 5

Offshore facility power systems

There are many natural inherent operational hazards related to offshore oil and gas production. To overcome these and to assure a safe and reliable operation, special rules and regulations applies to the operation. This chapter is an introduction to the electrical power system design in offshore facilities, and provides a summary of important standards affecting relay protection of generators.

5.1 Electrical system design

Oil and gas production is an energy demanding process. The required power is different from field to field, and depend on several field specific conditions. Most influencing are the type of field, what phase the production has come to, well pressure and export requirements. Power requirements can be from 4 MW up to several hundred MWs [7]. Electric power may be supplied via cable from mains onshore or produced locally on the unit. With local production, power is produced by combustion of gas or diesel in gas turbines (single- or dual fuel) or in diesel generator sets. Some facilities also have steam turbines installed, utilizing waste heat from exhaust gases. On the Norwegian continental shelf, the majority of offshore platforms are isolated electrical systems, supplied by gas turbines. Most of these are modified aviation turbines, in the order of 20 - 30 MW. [17]

Electric power is normally generated centrally by a small number of turbine-generator sets, due to the complexity and space requirements for gas turbines. Smaller generators also installed to provide emergency power, but these are studied in this report. Different voltages and frequencies are in use; the American standard with 13.6 kV, 4.16 kV and 440 V at 60 Hz, and the European with 11 kV, 6.6 kV, 3.3 kV and 690 V at 50 Hz.

Figure 5.1 illustrates a typical single line diagram structure for an offshore unit. Main generators are connected to the HV switchboard, distributing power to large machines or to MV switchboards and LV switchboards via transformers. MV switchboards feed large consumers, while LV switchboards feed a mix of smaller machines and consumers. In normal operation, main generators supply power to all services at the facility. In the event of a failure of the main system, a separate emergency system will supply power to critical emergency system loads. At larger facilities, a third separate system, called essential system, might also be incorporated.

Naturally, special design criteria apply to the operation of electrical systems at offshore units. Several aspects affects the design and choice of equipment: [9]

- Space limitations.

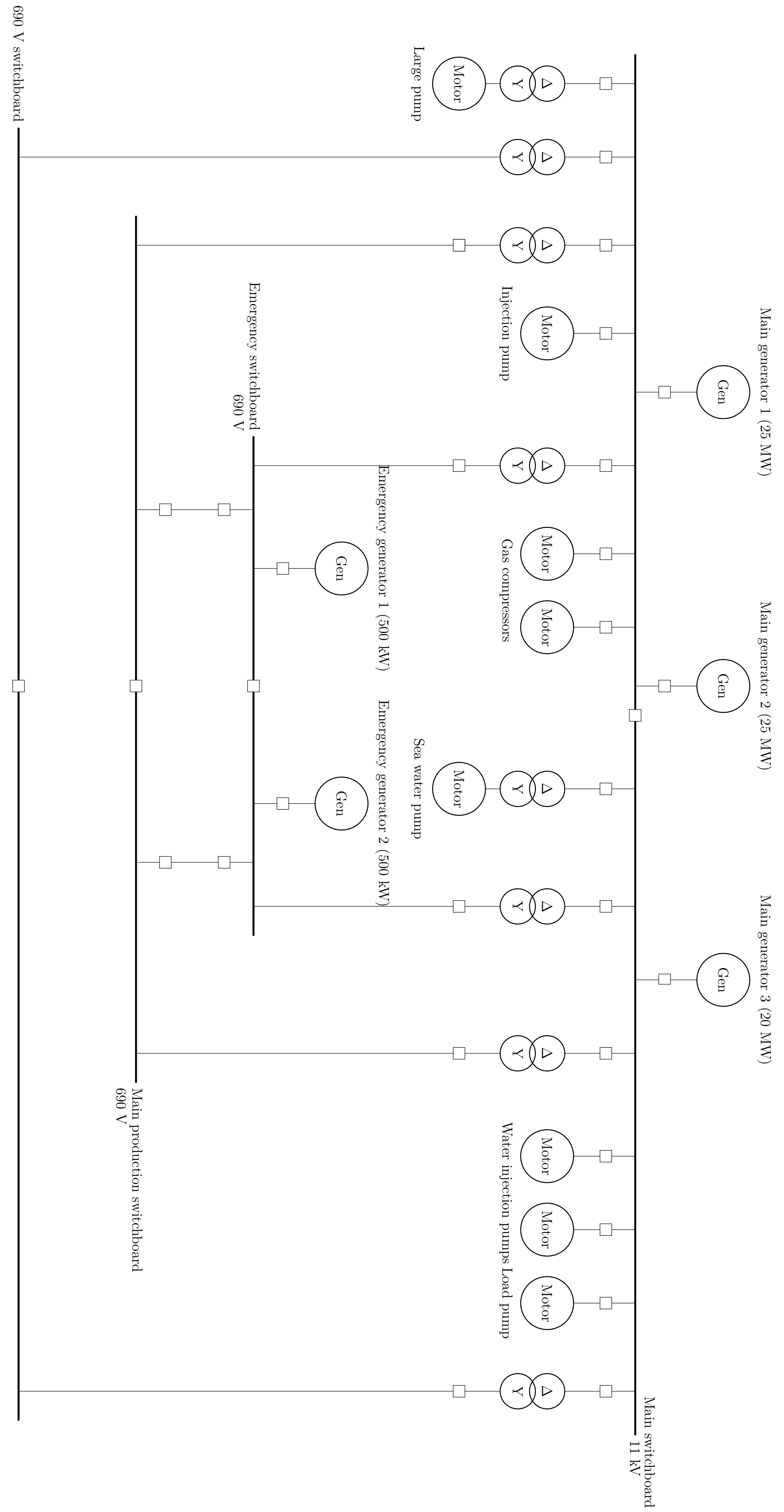


Figure 5.1: Single line diagram illustrating the structure of a typical offshore electrical power system.

- Weight limitations.
- The naturally inherent safety hazards of operating an electrical system at a steel or concrete structure, surrounded by sea.
- The corrosive marine environment.
- Fire and explosion hazards.
- User-friendliness.

As these applies to all facilities, the electrical system design and use of components tend to be very similar from facility to facility.

5.2 Criteria for relay protection of generators

Due to the special operating conditions, special rules and regulations apply to electrical systems at offshore units. For operation on the Norwegian shelf, the IEC standard *IEC 61892*, is the current standard for relay protection. In addition to this, operators might have their own set of standard requirements. In this report, Statoil ASAs *TR3021, Electrical system design, offshore units* and *TR3125, Generators and synchronous motors* are also included. These are based on the IEC standard but includes additional and more explicit requirements in cases where the IEC standard might be interpreted differently. The remaining of this section is a summary of relevant requirements from these standards. For more specific details, see reference [11], [12], [14] and [15].

5.2.1 Generator design

Some details about the generator design are of interest for relay protection. Most important criteria for the different parts are:

Stator

The stator winding shall be star connected. Star point and main terminals shall be brought out to terminal boxes on the outside of the generator hood.

Rotor

If a two pole machine is specified then the rotor shall be of the cylindrical design. A four or more pole rotor shall be of the salient pole design.

Exciter

The exciter shall be of brushless type and directly coupled to the generator field winding. Facilities shall be provided for remote alarming in the event of a diode failure, both for open circuit and short circuit conditions. Short circuit level of 350 % shall be sustained for minimum 2 s.

5.2.2 Current transformers

CTs for measuring generator line current and zero sequence current shall be mounted in the generator star point side. These current transformers shall give input to protections against short circuit and earth faults on the generator side of the circuit breaker.

5.2.3 System earthing

System earthing is different for the different voltage levels. For high voltage levels, system earthing should be high resistance earthed neutral. The resistive earth fault current shall, for generator neutral (at high voltage levels), be limited to maximum 20 A per generator. Alternatively, to perform system earthing in HV-systems, dedicated neutral transformers can be used. The neutral resistor shall be designed for the rated current for 10 s.

5.2.4 Circuit breakers

All circuits shall have an isolating device. Protection device shall (at least) control all line poles, which means that single pole protection is not accepted in three phase circuit.

5.2.5 Power system characteristics

Voltage characteristic

Voltage tolerance continuous (rms): -10 % / +6 %.

Voltage transients

Voltage transient variation on switchboards and distribution panels shall not exceed ±15 %.

Frequency characteristic

Frequency tolerance (continuous): ±5 %.

Frequency transients

Frequency transient tolerance: ±10 %.

Harmonic distortion

THD shall not exceed 8 %, and the 5th harmonic shall not exceed 5 %.

5.2.6 Protection

Solid state, microprocessor based multifunction protective relays with programmable release characteristics should be employed for protection of the electrical power generation, distribution system and electric motors. Relays with data communication features should be employed in centrally controlled systems.

5.2.7 Main generator protection

Main generator protection shall be according to table 5.1. Some of these functions have

Protective function	Trip generator breaker	Generator de-excitation	Trip prime mover (turbine)	Alarms
Differential protection[2]	X	X	X[3]	X
Overload	X			X
Short circuit	X	X	X	X
Earth fault	X	X	X	X
Rotor earth fault	X	X	X	X
Directional earth fault[1]	X	X	X	X
Overvoltage	X	X	X	X
Undervoltage	X			X
Reverse active power[1]	X			X
Reverse reactive power[1]	X			X
Negative phase sequence	X			X
Stator RTD, temp. high				X
Stator RTD, temp. high/high	X			X
AVR fault	X	X	X	X

[1]For generators in parallel operation only (parallel with other generator, other transformer or sub sea cable).
[2]For generators above 4 MVA.
[3]Differential protection shall give prime mover emergency trip, other protections shall give normal stop.

Table 5.1: Main generator protection requirements as given in [14].

special elaborations:

Overload

For overloads between 10 % - 50 %, the circuit-breaker should be tripped with a time delay corresponding to a maximum of 2 minutes at not more that 1.5 times the rated current of the generator. However, the figure of 50 % and the time delay of 2 minutes, may be exceeded if this is required by the operating conditions, and if the construction of the generator permits it. For over-currents in excess of 50 % where "instantaneous" tripping would be required, co-ordination with the discriminative protection of the system should be included.

Reverse power protection

AC generators arranged for parallel operation shall be provided with time delayed reverse active power protection. The setting of protection devices is recommended by [12] to be in the range of 2 % - 6 % of the rated power for turbines, and in the range of 8 % -

15 % of the rated power for diesel engines. A fall of 50 % in the applied voltage shall not render the reverse power protection inoperative, although it may alter the amount of reverse power required to open the breaker.

Undervoltage

For generators arranged in parallel operation or with a power feeder, measures shall be taken to prevent the generator from closing if the generator is not generating and to prevent the generator circuit breaker remaining connected to the bus if the voltage collapses. In case of an undervoltage release provided for this purpose, the operation shall be instantaneous when preventing closure of the breaker, but shall be delayed for discrimination purposes when tripping a breaker.

Overvoltage

Circuits such as generator and external power sources shall be provided with overvoltage protection to avoid damage to the connected equipment. Adequate precautions shall be taken in high voltage ac systems to limit or cope with overvoltage to ensure protection of ac machines.

5.2.8 High voltage bus relays

The following relays shall be installed in each bus bar section of HV switchboard:

- Undervoltage relay.
- Frequency relay.
- Arc detection relay.

5.2.9 Other HV feeders

All other HV circuits shall minimum have following protection:

- Short circuit protection (fuse or relay).
- Overload and/or overcurrent relay.
- Earth fault relay.

Chapter 6

Generator protection in offshore facilities

Generators are subject a wider range of faults and harmful abnormal conditions than most other system components. To add on this, it is often not enough to open the CB and isolate a faulted generator from the network. For an internal fault, the main field must also be removed and the rotor must be stopped. Due to residual flux in the machine, a current can be induced in stator if the rotor is turning. All this sets strict requirements to the protective system of a generator. Common fault types and other abnormal conditions that one should be concerned with are:

1. Internal faults
   - Stator phase and ground faults
   - Rotor ground faults
2. System disturbances and operational hazards
   - Loss of excitation and asynchronous operation
   - Generator motoring (loss of prime mover)
   - Overload
   - Overvoltage
   - Undervoltage
   - Unbalanced loading and negative sequence currents
   - Abnormal frequencies

This chapter discuss the above listed conditions. For each condition, there is a review of different protective schemes that can be used in offshore facilities.

6.1 Stator phase-to-phase faults

If a phase-to-phase fault occur in the stator, dangerously high currents can flow, causing magnetic unbalance, local hot spots, melting of the core, and possibly fire. In addition, large mechanical forces can harm couplings, shaft and the turbine. However, the fault current magnitude depend on the location of the fault in the stator winding; a fault close to the terminals results in higher fault current magnitudes than a fault located close to the neutral (star) point. As a fault current can be fed from both the external system and the generator itself, power to the prime mover and magnetization has to be reduced, as well as opening of the CB to disconnect the generator form the external system. However, fault currents can still be supplied for several seconds after the excitation field has been removed due to residual flux in the machine. Therefore, high speed tripping is important to minimize danger.

Luckily, stator phase and inter-turn faults are relatively uncommon. If they occur, they are most likely to occur at the ends of windings and in the terminal box [9].

6.1.1 Differential protection

Differential protection is the most sensitive scheme for detection of critical phase-to-phase faults. The basic principle was explained in 3.3. For generator protection, two sets of CTs are used; one set in the neutral leads and the other on the terminal side of the generator. To aid high performance margins for the CTs, burden should be kept low by using separate CTs for the differential circuit, where no other equipment is connected. The consequences of a stator short circuit depend on the fault clearing time, and therefore, a detection should result in an immediate trip.

At startup of generator, magnetizing inrush should not be a problem as voltage on the machine is developed gradually. However, recovery inrush current, can be significant after a fault that significantly lowered the voltage is cleared. [6]

6.1.2 Overcurrent protection

Overcurrent relay can also be used to protect against short circuits, however, the sensitivity is not as good as for differential protection. Therefore, it is normally provided as backup protection.

6.1.3 Stator inter-turn fault protection

The extra complication of the methods available to deal with inter-turn faults are often found to be not justifiable by the risk. [13] Inter-turn protection is often omitted because, if such a fault occur, it will quickly develop into an stator earth fault.

A neutral voltage relay can be used to detect inter-turn faults, by using a broken-delta VT and connecting the primary side ground leads to the generator neutral, as shown in figure 6.1. This way the relay will not respond to ground faults. This scheme requires a separate cable from the generator neutral to the VT. However, if a ground fault occurs on the cable, the generator becomes solidly grounded. [1]

6.2 Stator ground fault protection

Ground fault currents in the stator core can cause melting of core lamination, but as ground fault current is limited to maximum 20 A for each generator, the stator is not in immediate danger for single phase-to-ground faults. Due to this low ground fault current magnitude, differential relays are not able to detect single phase-to-ground faults,

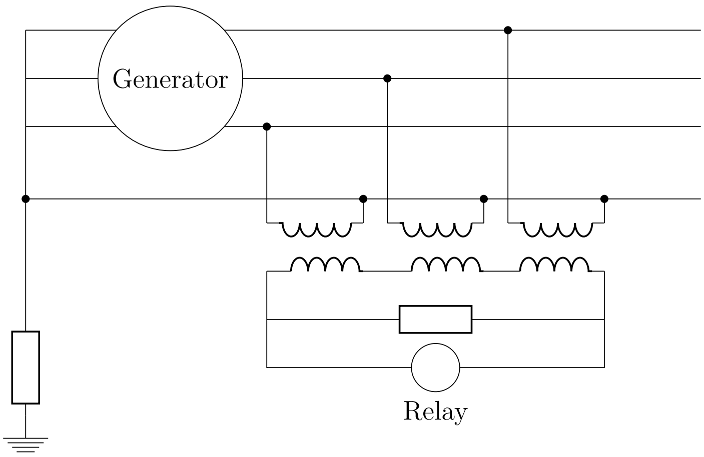


Figure 6.1: Turn-to-turn protection of stator winding with overvoltage relay

and dedicated ground fault protection is thus necessary. Ground fault protection is also important as the occurrence of one ground fault will accelerate the occurrence of a second fault, which is in that case is a dangerous short circuit as discussed in the previous section.

As generators are directly connected to a common bus, a ground fault in one of the generators or any other location in the connected circuits will cause a ground current to flow in all generator naturals. To achieve selective ground fault protection for each generator, direction of the residual current, $3I_0$, is used as criteria to determine whether a fault is located inside or outside the generator. If residual current flow is from the bus towards the generator, the fault location is inside the generator, and the relay should operate. If, however, current flows up through the generator neutral towards the bus, the fault location is outside the generator, and the relay should not operate.

6.2.1 95 % schemes

A ground fault in a high impedance grounded system cause a voltage shift with respect to ground. The voltage shift is dependent on the location of the ground fault; a ground fault at the terminals will cause a line-to-neutral voltage to appear between neutral and ground, while a fault in the neutral point, will not cause zero-sequence voltage. The same yields for current; low fault current magnitudes for faults close to the neutral point. Therefore, due to relay sensitivity, these schemes protects roughly 95 % of the winding, when seen from the machine terminals.

An overvoltage relay connected to measure the neutral voltage displacement of the generator respond to a rise in V_0. VTs can either be connected in the neutral point (across the grounding resistance), or at the terminal side of the generator (wye-wye, open-delta VT). V_0 can also be fund by numerical summation of the three phase voltages so there are many connection. The relay must be insensitive for 3. harmonics to avoid false operation.

Alternatively, an overcurrent relay can be used to measure the $3I_0$ current. CT can be located in the neutral, in the secondary circuit of the distribution transformer or elsewhere is using numerical summation of the three phases. Due to the stray capacitance of the system there will be a small continuous flow of current in the generator neutral, consisting mainly of harmonics. This current flow depend on the power drawn from the machine, so maximum current flow occurs at maximum load [1]. Pickup for the overcurrent relay must be set higher than the maximum current in the neutral circuit under normal operation.

The various schemes are shown in figure 6.2. To achieve directional functionality for sensitive ground fault protection, the direction of $3I_0$ can be utilized.

6.2.2 100% stator earth fault protection

Protective schemes for complete protection of the stator winding are complex and the cost is often not justified by the extra protection, as due to the low voltage close to the neutral point, insulation failure is less lightly to occur here. There are generally two basic principles; injection of sub-harmonic voltage and utilization of third harmonic voltage. However, the third harmonic principle cannot be used in offshore facility systems as generators are connected to a common bus.

Voltage injection

A sub-harmonic frequency voltage is injected via a neutral transformer or broken-delta transformer at the terminal side, into the neutral connection. The current the transformer and into the stator winding. The injected current is measured at the injection point and on the secondary side of the voltage transformer. Based on these measurements, the stator winding resistance is determined and compared with a preset value.

6.3 Rotor ground faults

The field winding of a synchronous machine is an ungrounded dc circuit. Thus, a single ground fault does not affect operation of the generator. However, if a second ground fault occurs, part of the field winding will be shorted, and high currents can flow in the rotor. Unbalanced currents produce unbalanced fluxes, causing violent rotor vibrations, strong enough to quickly damage bearings and displace the rotor. When a single ground is established, the probability for a second fault is increased, as electric stress at the healthy parts of the insulation is increased.

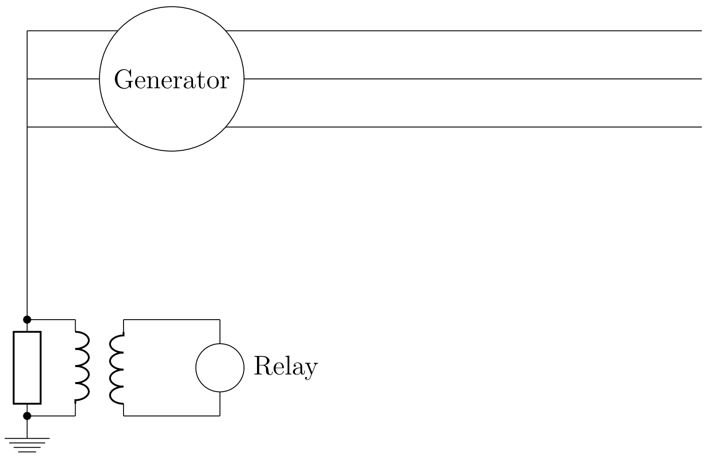
Ground fault detection for the exciter and field circuit is usually provided as part of the generator control system (AVR) from the manufacturer. For brushless exciters, where the field circuit connections are rotating, continuous monitoring is not possible by conventional relays. However, a few methods exists. One method is to periodically measure the field circuit insulation by dropping pilot brushes on slip rings. Other methods for continuously monitoring use telemetry or injection of a low frequency voltage wave [1].

6.4 System disturbances and operational hazards

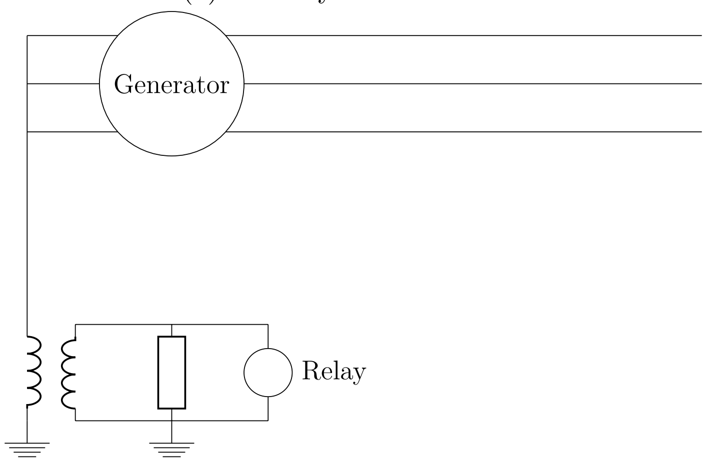
The previous sections covered possible generator fault mechanisms. However, a generator may also be subject to operational hazards that may not involve a fault. In this section, protection for such operational hazards are discussed. There are various reasons for their occurrence, but they are often caused by system disturbances and operator errors.

6.4.1 Loss of excitation and asynchronous operation

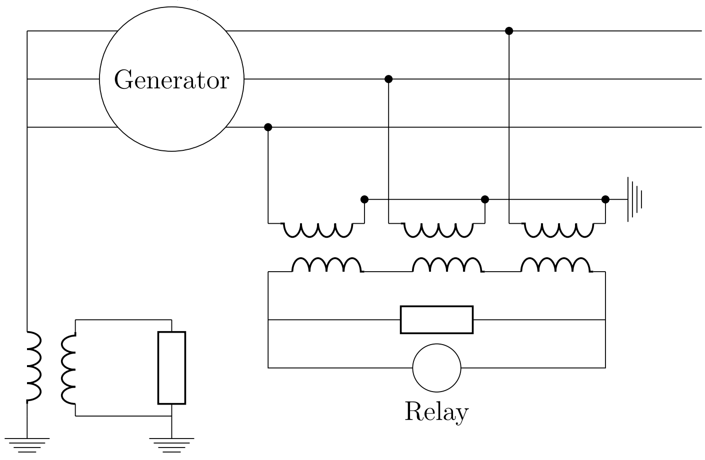
If a single generator is running as a sole supplier of power in a system and this machine, for some reason, loses its excitation, a blackout will result. However, if two or more generators



(a) Primary side resistance

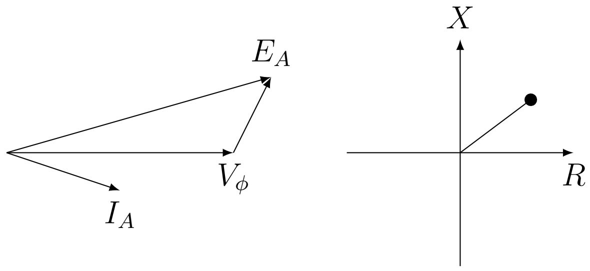


(b) Secondary side resistance

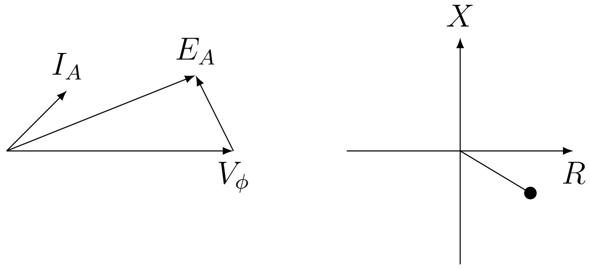


(c) Open-delta connection at the terminal

Figure 6.2: Different connection techniques for 95 % ground fault protection (non-directional).



(a) Overexcitation



(b) Underexcitation

Figure 6.3: Phasor diagram for operation and the corresponding impedance as seen from the terminals (stator resistance is neglected).

are running, and the excitation system at one of the machines fails, this machine might continue to run as an induction machine, demanding large amounts of reactive power. In that case, the governor load setting determines the machines power generation. Operation as an induction machine brings no immediate danger to it, but abnormal heating will take place. In addition, the healthy machines in the system might heat up, due to large reactive power generation. If there is a lack of reactive power in the system, the faulty machine will lose its synchronism. [9] [13]

Detection of loss of excitation is included in the excitation system, but additional means of protection might be necessary to provide backup for this system. There are two common ways to provide relay protection for loss of excitation; distance relay with mho characteristic or directional reactive power relay.

In normal operation, a synchronous generator field is slightly overexcited, producing power at a slightly lagging power factor, delivering reactive power to the system. With lagging power factor, the impedance phasor is located in the first quadrant of the R-X diagram, as shown in figure 6.3a. If the generator is operated at a leading power factor, than it has a slightly underexcited field and it will consume reactive power. In this case, the impedance phasor is located in the fourth quadrant, as shown in figure 6.3b. Synchronous generators have a lower stability limit for underexcited operation. If excitation is reduced or lost, the machine becomes more and more underexcited, and the power phasor moves slowly, as flux is decreasing, downwards in the fourth quadrant. When it crosses the stability limit of the machine, it cannot maintain synchronously operation for the same power input, and starts to operate as an induction machine. Slip speed and power output is determined from the initial loading, system impedances and governor (droop) characteristic.

An imagined path for the machine impedance is shown in figure 6.4. Here, also part

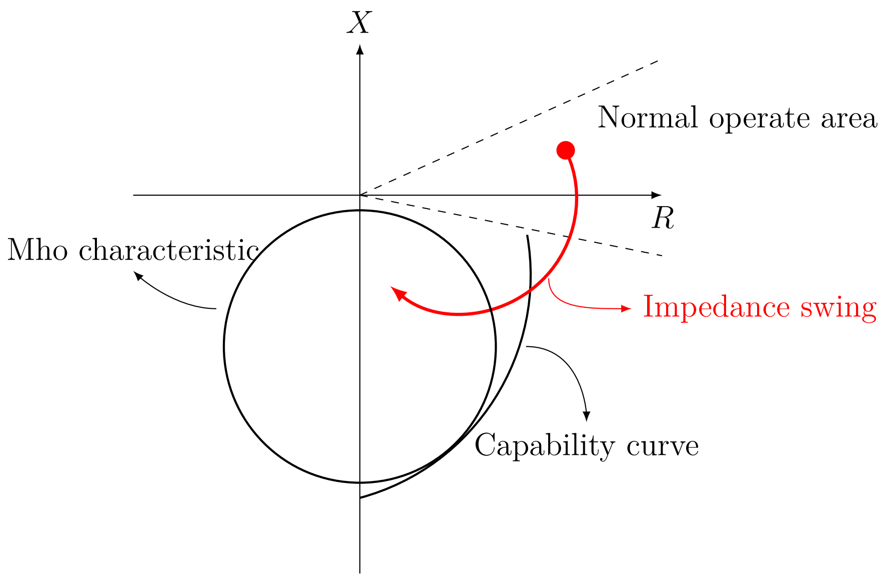


Figure 6.4: R-X diagram showing the capability curve of a generator, distance relay characteristic and a possible stability swing path.

of the machine capability curve, and a possible setting for the impedance relay is drawn.

Transformation between the power plane and the impedance plane is developed in equation 6.1.

$$Z = \frac{U^2}{S} = \frac{U^2}{P + jQ} = \frac{U^2(P - jQ)}{(P + jQ)(P - jQ)} = \frac{U^2 P}{P^2 + Q^2} + j\frac{U^2 Q}{P^2 + Q^2} = R + jX \qquad (6.1)$$

This equation shows that a constant reactive power Q in the power diagram, corresponds to a circle in the impedance diagram.

Distance relay (21)

To apply a distance relay as protection in case of loss of excitation, the power curves have to be converted to impedance circles. Reference [6] shows the principle. In case of loss of excitation, the impedance phasor moves slowly into the fourth quadrant of the R-X diagram with a circular locus. Well suited for mho characteristic. The relay measures at the machine terminals, looking into the machine.

Directional power relay

A directional power relay, set to operate for reactive power flow from the system towards the generator, can also provide protection in case of loss of excitation.

6.4.2 Motoring

If energy supply to the prime mover becomes too low or cut of while the generator is connected to the system, the generator starts to operate as a synchronous motor, consuming active power from the system. This condition is known as generator motoring. As the excitation should remain the same as before, the reactive power flow should also remain the same. Motoring operation oppose no immediate danger for the machine, the real danger is for the turbine, which can be severely damaged. This yield particularly steam turbines, where turbine and turbine blades can become overheated fast.

Detection of motoring operation should be part of the machine control unit, in addition, there might be temperature devices buried in the turbine to provide thermal protection. However, a reverse power relay (32) is recommended. It should operate for active power flow into the generator. The sensitivity and time delay are dependent on the type of prime mover involved. Power to required to motor at synchronous speed is a function of load and mechanical losses of the prime mover and machine. For gas turbines, up to 50 % of the name plate rating might be required. So relay sensitivity is not critical. For steam turbines, required power is between 0.5 - 3 %, so a sensitive relay is required. [1]

Reference [6] recommends an operate time of approximately 2 seconds. While reference [1] suggests up to 60 s (30 for steam turbines), but specifies that this should be coordinated with the allowable turbine motoring time fro the manufacturer.

6.4.3 Overload

A machine is able to supply power far above its rated power. However, if power output is above the rated level for too long, the machine becomes overheated causing effects like mechanical damage and severe isolation degradation. If power is allowed to exceed the machine capability, the machine will start to heat up. If this is allowed to continue for a long time, the core will melt and windings will burning out. However, generators are rarely troubled by overload, as the amount of electric power generated is determined by the energy supply to the prime mover, which is continuously monitored. Larger generators also have temperature sensors (RTDs) embedded in their stator windings, for continuous temperature monitoring.

Relay protection against machine overloading is achieved by an overcurrent relay, having an inverse operation characteristic. The operation curve should be fitted to the generator capability curve, with an additional safety margin.

6.4.4 Overvoltage

Reasons for power frequency overvoltages might be:

- Malfunctioning voltage regulator.
- Sudden variation or loss of load.
- Earth faults.

A too high overvoltage cause overexcitation of the stator core and deterioration of winding insulation, shortening the lifetime expectancy of the generator. Reference [1] recommend an instantaneous unit with pickup between 130 - 150 % of normal voltage, and an inverse time unit, with pickup around 110 %. It also suggests two definite time relays can be used. When specifying operate values, it is essential to consider the possible maximum voltage at non-faulted situations. The time delay should allow the AVR to correct the voltage level.

6.4.5 Undervoltage

Reasons for undervoltages might be:

- Malfunctioning voltage regulator.
- Overload.
- Short circuits.

Generators are usually designed to operate continuously at minimum 95 % of its rated voltage. Operation at lower voltages might result in reduced stability limit, import of reactive power and other undesirable effects like malfunctioning of sensitive equipment. There should be an added time delay for the undervoltage protection to allow the main protection to operate in case of short circuits.

6.4.6 Abnormal frequencies

In normal operation, frequency is controlled within close limits by generator controls. However, under- and over frequency relays may be required for backup of these controls. If there is a mismatch between power demand and power supply, the fundamental frequency will change according to this mismatch. If the power demand is in access of the power supply, the frequency will decrease. If a sudden loss of load occur, the power supply is in access of the demand, the generator will overspeed and cause frequency to increase. Frequency after these conditions depends on the governor droop characteristic, but usually load shedding schemes and turbine controls are quick to restore correct frequency, without need to trip the generator.

Both generator and turbine have restricted operation for abnormal frequencies. However, underfrequency operation is considered as more critical than operation at higher frequencies. [1] recommends some form of underfrequency protection for steam and gas turbine generators. As frequency is more critical in an isolated network, extra frequency protection might be provided. If additional protection is installed, it is important to use a time delay long enough to allow time for load shedding schemes to operate.

6.4.7 Unbalanced loading

Unbalanced loading or an open conductor might cause unsymmetrical conditions. Such conditions cause negative sequence currents to flow in the generator stator. These currents set up a magnetic field in the air gap, which rotates at synchronous speed in the opposite direction of the main field (or rotor), and induce double frequency currents in the rotor body and windings. These tend to heat the rotor, and put more stress on critical components like slot wedges and retaining rings [19]. Temperature can rise in short time, and severe overheating and melting might occur.

Manufacturers should provide generator ratings for continuous negative sequence current, I_2, and short time unbalanced current capability in terms of rotor heating criteria $I_2^2 t = K$. Continuous I_2 capabilities are often given in percent of the rated generator current. Short time capabilities are expressed in terms of a constant value K, given in seconds, which is determined by the machine design.

As the source of negative sequence current is external to a generator, all generators in a facility is affected. Therefore, if the source is not removed in time, generators are tripped, leading to production stops and eventually blackout. To avoid such situations, relays should sound an alarm before a trip is necessary, notifying operators about the situation and allowing them time to find and remove the problem. Pushing the relay trip to occur closer to the rotor capability, allows more time for the operator to locate and remove the offending load. [9]

Relays (46) should operate for negative sequence currents, following the inverse time characteristic $I_2^2t = K$ of the machine. The IEEE standard, reference [1], specifies a maximum continuous current I_2 that a generator must be capable of withstanding, without damage. In this table indirectly cooled cylindrical rotor (which is used at offshore facilities) has a permissible $I_2 = 10$ % of I_{rated}. The unbalanced I_2 fault capability (referred to as the short time capability in [4]) is set to $I_2^2t = 30$, where K and t are given in seconds, and I_2 is given in per unit of rated generator current.

6.4.8 Overexcitation

As generator voltage is proportional to frequency and magnetic flux in the machine, overexcitation results in an overvoltage. It is the AVR systems task to control the excitation, but a volt per hertz relay (24) can be used to provide backup. A volt per hertz relay have a constant pick up value given as the ratio of voltage to frequency.

Chapter 7

Generator protection with REG670

High service continuity is an important factor in the operation of offshore oil and gas production facilities. As any unscheduled system shut-down can be very costly, incorrect relay operation is highly undesirable. To assure reliable relay operation, relays should be replaced when they have outlived their lifetime. For modern relays, the recommended lifetime is normally between 15 - 25 years.

When relaying systems in offshore facilities are to be upgraded, it is beneficial to reduce the number of physical devices, and to include other logic functions into a single device. As this reduce the number of potential error sources and facilitate easy switchboard management and control. This is easily achievable with modern technology.

Modern relays are often referred to as IEDs, intelligent electronic devices, as this term describes their functionality better. The latest generation of relays include, in addition to traditional relay functions, also functionality for system control, measurement and supervision. Another important advantage is the communication possibilities, both towards other relays and towards a system bus. Allowing remote configuration and monitoring.

A modern relay, commonly used for generator protection, is the ABB REG670 relay. This chapter shortly introduce this relay and discus, based on the requirements listed in chapter 6, how to configure this relay to comply with the required functionality of table 5.1. To find the best suited function to use for each requirement, it is necessary to understand the underlying reasons for each requirement.

7.1 Introduction to REG670

The REG670 relay is a member of ABBs Relion 6 protection and control product family. It is a generator and generator-transformer block protection, control and monitoring IED. It also complies with the IEC 61850 standard for design of electrical substation automation. Figure 7.1 shows a picture of the front side with the HMI.

The REG670 relay operation time differs for each protective function, and is dependent of the measured current magnitude. However, the minimum operate time is 15 ms. Inaccuracies in measuring, and thus necessary safety margins for each function, are specified in the REG670 Technical manual, see reference [3].

Figure 7.1: Picture of REG670 IED, case size 1/1 x 19"

7.2 Recommended REG670 functions for generator protection

In this section, functions that can be used to satisfy the requirements of generator relay protection, as presented in 5, are shortly discussed. Further, operation characteristics of the best suited functions are shortly explained. See appendix A for a list of all available relay protective functions in REG670. For a more comprehensive review of relay function, see reference [4] and [3].

7.2.1 Differential protection

Generator differential protection is required to provide fast detection of internal short circuits in the stator. The best suited REG670 function for this is the GENPDIF function. The other differential protection functions offered are either not designed for generator protection or, as in case of high impedance differential function, requires additional units and demands strict requirements on CTs.

GENPDIF operation characteristic

The GENPDIF function consists of three sub-functions that evaluate different options of the function:

- *Percentage restrained differential analysis*
  The GENPDIF operate characteristic is specified within this sub-function. Figure 7.2 illustrates the principle. As can be seen, there are two areas where the function can operate; one is conditional operation and the other is unconditional operation. If, for instance, the differential current is above the set current value for the limit of unconditional operation area (*IdUnre*), the function trips immediately. The limit for this area is constant and not dependent on the restraint current. Therefore, this area should only be used for high currents where there are no doubt that the fault is internal.

  The conditional operation areas operate restrain characteristic is adjusted by five setting values (*IdMin, EndSection1, EndSection2, SlopeSection2* and *SlopeSection3*). In case the measured current is located within this area, the function cannot trip unless all per-specified conditions are met. These conditions are monitored by the two other sub-functions.

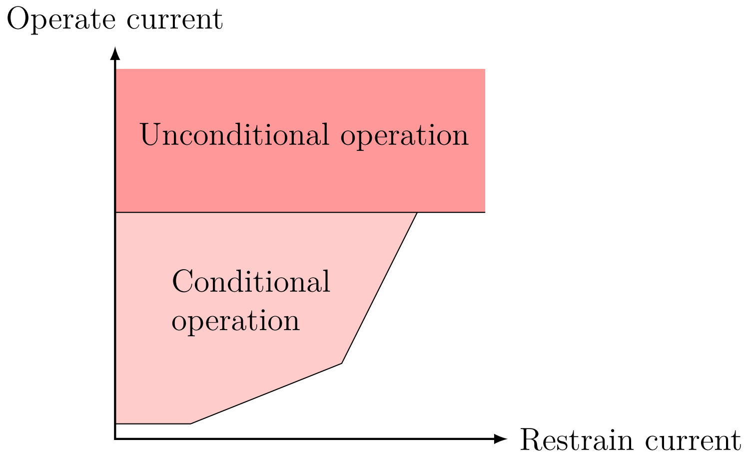


Figure 7.2: GENPDIF operation characteristic

The fundamental frequency RMS differential current is used as operate current. As bias (restrain) current, the largest measured phase current magnitude is used. Unless an additional time delay is added, a trip will be instantaneous in case of relay operation.

- *Negative sequence internal/external fault discriminator*
  This sub-function is turned on or off by the *OpNegSeqDiff* parameter. The REG670 Application manual recommend having this option activated. The internal/external fault discriminator can both enhance and block a trip signal. If a fault is classified as internal, the discriminator can override the harmonic criterion (explained next) and allow a trip to be made independent of this. If a fault is classified as external, any trip command will be blocked by this function. The internal/external fault discriminator use the relative phase angles of the negative sequence input currents as operate quantity. The internal/external boundary is defined by the setting *NegSeqROA*, which is called the relay operate angle. For this comparison to be made, the negative sequence currents must be above the threshold setting value *IMinNegSeq*. As long as both negative sequence input currents are above this value, no start signals are required for the operation of this feature.

- *DC, 2nd and 5th harmonic analysis*
  This sub-function is designed to prevent unwanted trip commands due to transformer magnetizing inrush currents and CT saturation due to external faults. This feature only operate after a start signal have been set, which means that it only blocks trip signals. However, if a fault is recognized as external and one or more start signals are set, the harmonic analysis is started. In case there are no higher harmonics in the currents when trip signals are set, an internal fault is assumed to have occurred simultaneously with an external one, and a trip is allowed. The harmonic restraint is only activated if the total harmonic distortion is above the pickup value *HarmDistLimit*.

The dc component of the differential current can be included in the restraint current if the option *OperDCBiasing* is activated. This is recommended if the CTs are of different make.

7.2.2 Overload

Overload protection is necessary to protect the stator from overheating. As discussed in chapter 6.4.3, this is achieved by an inverse current time function. REG670 product version 2.0 offers a special made function GSPTTS for this, but this function seems not to be available in product version 1.2. However, inverse time-current characteristic is available in the overcurrent function OC4PTOC. Thus, this is the recommended option.

OC4PTOC operation characteristic for overload protection

This function has four individual steps, with separate inverse or definite time delay. It also includes a directional restraint functionality (requires additional voltage measurements), and an second harmonic block level. However, none of these should be activated, as the purpose of overload protection is to protect the stator from overheating, and not to detect specific fault conditions (all current contributions produce heat). The number of phases necessary to have overcurrent for operation is specified via the *StartPhSel* setting. Setting values for step x are illustrated together with the time delay characteristic in figure 7.3.

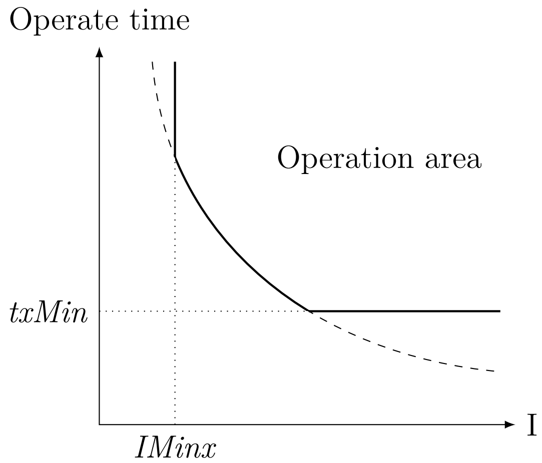


Figure 7.3: OC4PTOC inverse time delay for step x.

The general expression for an inverse time curve is:

$$t = \left(\frac{A}{\left(\frac{i}{in>}\right)^p - C} + B \right) \cdot k \tag{7.1}$$

Where t is the time delay, i the measured current, $in >$ the set operate current for step n, k a set time multiplier, and A, B, C and p constants dependent on the curve type.

Time delay for IEC inverse time characteristic is given in figure 7.2.

$$t = \frac{A}{\left(\frac{i}{in>}\right)^p - 1} \cdot k \tag{7.2}$$

Where t is the time delay, i is the measured current, $in >$ is the set operate level and A, p and k are constants specific for the inverse time curve used (see technical reference manual [3] for values).

7.2.3 Short circuit

Short circuit protection in the generator is provided by differential protection, and single phase-to-earth faults are handled by separate earth fault functions. Thus, the short circuit requirement is meant to assure protection for short circuits involving two or three phases in the external power system, outside the generator CB. An overcurrent or an impedance relay normally provide protection for these fault types. However, as large loads are located close to the generating elements in the system, the impedance seen from the generator terminals is very similar in normal operation to fault situations. Thus, the operate area of an impedance relay has to be very tight. Switching of large machines will be a problem, as the impedance relay might interpret such incidents as a fault due to large starting currents. As the security of an impedance rely is not good enough an overcurrent relay should be used.

As the overcurrent function will operate for faults outside the generator zone, it must be coordinated with other relays that might operate for the same faults. Thus, the function characteristic should be definite time, with an adjustable time delay. Again, the OC4PTOC function is the best option.

OC4PTOC operation characteristic for short circuit protection

As the OC4PTOC function is also used for overload protection, a second step is use for the short circuit protection. Function characteristic was shortly explained in relation to overload protection, and the general settings *StartPhSel* and *MeasType* applies to all function steps. Function operate characteristic is illustrated in figure 7.4.

The harmonic restraint functionality should be activated for this step to avoid unwanted operation for transformer inrush. The directional restraint functionality is not necessary, and if it is not used, this step will provide backup protection for the differential function. There are no coordination concerns for this, as the differential protection should trip immediately for an internal short circuit, while the overcurrent function has a time delay due to coordination with downstream relays.

7.2.4 Earth fault

As the maximum allowed earth fault current is 20 A per generator, phase-to-earth faults cannot be detected by differential or short circuit functions. Thus, a separate ground fault function is necessary. The earth fault requirement is used to assure protection for earth faults outside the generator zone, as protection for faults inside the zone is assured by a separate directional earth fault requirement. Thus, the non-directional function must be coordinated with both the directional function (which should trip first), and with relays in the external system that can operate for the same faults.

From section 6.2 we know that earth fault detection can have either residual voltage or residual current as operating quantity. In REG670, a residual overvoltage function, ROV2PTOC, is available. For residual current, two functions are available; EF4PTOC and EFPIOC. EFPIOC is an instantaneous function which cannot be used for selectivity

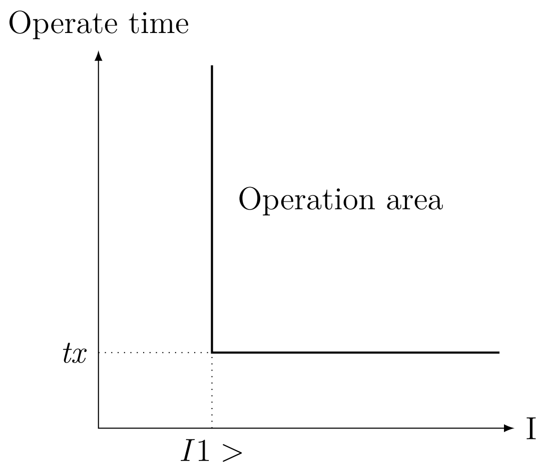


Figure 7.4: OC4PTOC definite time delay characteristic for step x.

reasons. The short time rating of the earthing resistance must also be considered for non-directional earth faults. Thus, residual current should be used as operation quantity. Therefore, the EF4PTOC function is best suited to fulfill this requirement.

EF4PTOC operation characteristic for earth fault protection

The EF4PTOC function have four individual steps with directional functionality. However, the directional element should not be used for this requirement. Function operating quantity is the residual current $3I_0$, which can be measured directly by a summation CT, CT in the neutral point or a Holm-Green connection, or internally calculated from a three phase CT input. The function also offer a second harmonic blocking element. Several inverse time characteristics and definite time characteristics are available, but as the requirement for earthing resistor is given as a definite time (see section 5.2.3), the time delay should be set according to this, including an additional security margin. Thus, the operation characteristic and setting parameters illustrated in figure 7.4 also applies for earth fault protection by EF4PTOC.

7.2.5 Rotor earth fault

As generators have brushless exciters, it is not possible to directly measure the rotor impedance to earth (see section 6.3). With REG670, additional units must be used to achieve this functionality. Two functions can be used for this; ROTIPHIZ with an additional injection unit named REX060, or CVGAPC with an additional injection unit named RXTTE4. At offshore units, the latter combination is normally used. Thus, the CVGAPC function must be part of the standard settings.

CVGAPC operation characteristic for rotor earth fault protection with RXTTE4 unit

The injection unit REXTTE4 is connected between one of the rotor circuit poles and earth. A fundamental frequency voltage is injected into the generator field winding. The resultant injected current and voltage values are connected to REG670 via internal transformers in the RXTTE4 unit. The injected voltage cause a current to flow through the field circuit to ground. In normal operation, the injected current is small, as the current has to flow through the rotor winding insulation and its distributed capacitance to ground. For healthy conditions, the injected current will lead the voltage by an angle close to 90^o, as the capacitance is the dominant component. If a single ground fault occurs, the field winding resistance will decrease, causing an increased active current component. Thus, to detect a ground fault condition, the CVGAPC use the fundamental frequency component of the injected current as operate quantity in a directional overcurrent function. Normally, the CVGAPC is implemented with two steps; one for alarm and one for trip. For more information see reference [2].

7.2.6 Directional earth fault

As explained in section 7.2.4, protection for earth faults in the generator zone must be directional to avoid blackout scenarios. In addition, due to the limited earth fault current, the protective function should use residual current (alternatively residual power) as operating quantity and residual voltage as polarizing quantity. Functions that might be used are the residual overcurrent function EF4PTOC and the sensitive directional residual overcurrent and power protection function SDEPSDE.

A ground fault inside the generator zone should result in a trip signal faster than for the same fault outside the generator CB. Therefore, the directional earth fault function should be more sensitive than the function for the external system. As SDEPSDE offers better sensitivity than the EF4PTOC function, it is the best function to use as it allows for faster operation, not only for generator faults, but also for external faults. As CTs for earth fault protection on the generator side of the CB are mounted in the generator start point side (section 5.2.2), the earth fault and directional earth fault function does not use the same CT. To avoid confusion and misunderstanding (REG670 handles several instances of a function), EF4PTOC should not be used again. Thus, the SDEPSDE is the recommended function for this requirement.

SDEPSDE operation characteristic

The SDEPSDE function have three different operational modes (*OpMode*), which use either residual current, residual voltage or a combination of these. Where each mode have a different operation characteristic.

Common for them all is that the polarizing quantity used for directionality is the reference voltage, and this is given as:

$$U_{ref} = -3U_0 e^{jRCADir} \tag{7.3}$$

The angle between the residual current and reference voltage is:

$$\phi = |ang(3I_0) - ang(U_r ef)| \tag{7.4}$$

For high impedance grounded networks with a neutral point resistor the relay characteristic angle, *RCADir*, is normally set to 0°. The relay operate angle, *ROADir*, defines an angle area around *RCADir* as the relay operate area. Operational conditions for the three operate modes are explained in the following.

- *OpMode: 3IOCosfi*
  This operation mode use the current component and operates if:

  - $3I_0 \cos\phi > \mathit{INCosPhi>}$
  - $3I_0 > \mathit{INRel>}$
  - $3U_0 > \mathit{UNRel>}$
  - $\phi \in [\mathit{RCADir} \pm \mathit{ROADir}]$

  Time delay from start to trip signal is given by a definite time delay of *tDef* seconds.

- *OpMode: 3IO3U0Cosfi*
  This operation mode use the apparent power component and operates if:

  - $3I_0 \cdot 3U_0 \cdot \cos\phi > \mathit{SN>}$
  - $3I_0 > \mathit{INRel>}$
  - $3U_0 > \mathit{UNRel>}$
  - $\phi \in [\mathit{RCADir} \pm \mathit{ROADir}]$

  Time delay from start to trip signal is given by a definite time delay *tDef* or a inverse time delay *kSN*.

- *OpMode: 3IO and fi*
  In this mode both the residual current component and the angle is used for operation. Operation occurs if:

  - $3I_0 > \mathit{INDir>}$ & $3I_0 > \mathit{INRel>}$
  - $3U_0 > \mathit{UNRel>}$
  - $\phi \in [\mathit{RCADir} \pm \mathit{ROADir}]$

  Time delay from start to trip signal is given by a definite time delay of *tDef* seconds.

7.2.7 Overvoltage

The overvoltage requirement assures protection for the whole HV bus. As generators are designed to withstand much higher voltages than the nominal system voltage for a short time period, settings for an overvoltage function should be based on requirements for more sensitive components such as rectifiers. In REG670, there is a dedicated overvoltage function, OV2PTOV. However, overvoltage protection can also be provided by a multipurpose current and voltage function, CVGAPC. As it is easier for an operator, to recognize and understand the purpose of a dedicated function, and as the CVGAPC is used to fulfill another requirement, the OV2PTOV is recommended in the standard solution proposal.

OV2PTOV operation characteristic

The OV2PTOV function has two steps, each with inverse or definite time characteristic. The number of phases required to have an overvoltage before operation can take place is specified for each step (*OpMode1*). The function measures either the fundamental frequency voltage (DFT) or the true RMS value that also includes dc offset and higher order harmonics, specified by the *ConnType* setting.

7.2.8 Undervoltage

The undervoltage requirement assures protection for generator and other components connected to the HV bus in case of undervoltage conditions (motors also have undervoltage relays). Power converters might become overheated if the supplied voltage becomes too low. Undervoltage protection with REG670 is provided by the UV2PTUV function (CVGAPC can provide undervoltage protection, but following the same argument as for OV2PTOV, the dedicated function is the one recommended).

UV2PTUV operation characteristic

Settings for the UV2PTUV function are equal to the OV2PTOV function.

7.2.9 Reverse active power

The reverse active power protection requirement protects the turbine by hindering generator motoring. This functionality is achieved by the directional underpower function GUPPDUP or the directional overpower function GOPPDOP. The underpower function set stricter operating levels than the overpower function, as the underpower function will operate if the power flow from the generator becomes lower than a set limit, while the overpower function operate only when the power flow is toward the generator. As it is desirable to connect and disconnect generators to the HV bus depending on the power demand, the GOPPDOP function should be used. This allows generators to be connected without immediate loading and off-loading before connection and disconnection.

GOPPDOP operation characteristic for reverse active power

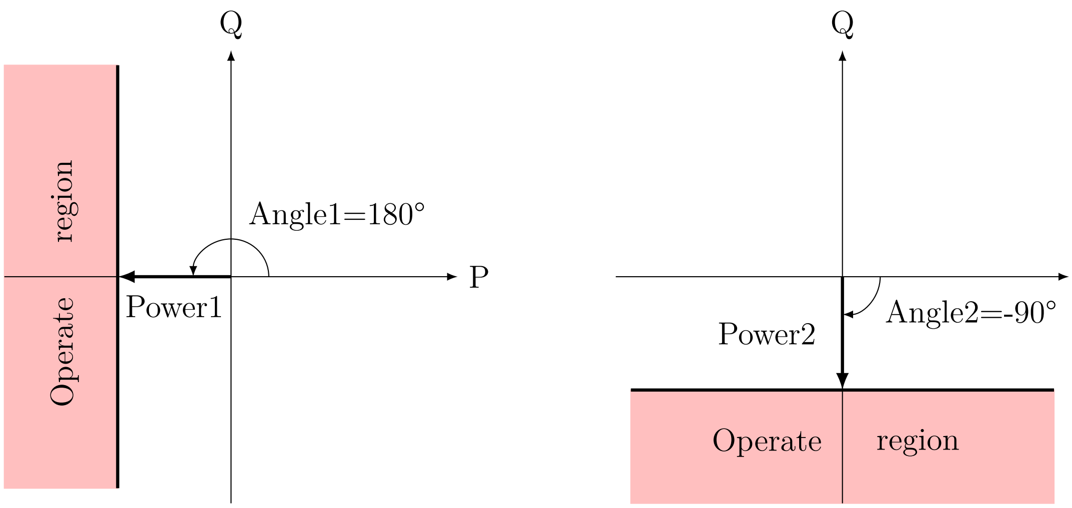
Depending on the available current and voltage inputs to the GOPPDOP function, different formulas can be used to calculate the apparent power S. S is than compared with a pick up setting *Powerx* in the direction of *Anglex*, for step x. Thus, to achieve reverse active power protection, the angle should be set to 180°. Figure 7.5a shows the operation characteristic with these settings values. Operation time delay is definite (*TripDelay1*) and set for each step.

7.2.10 Reverse reactive power

The reverse reactive power protection requirement assures protection in case of loss of excitation (explained in section 6.4.1). Due to many large induction machines in these systems, generators operate normally overexcited, producing reactive power. However, a synchronous generator can be set to consume power in cases where long cables are connected to the facility. Thus, the overpower function GOPPDOP is recommended for this requirement too.

GOPPDOP operation characteristic for reverse reactive power

As the function has two steps, the first step can be used for active power, and the second step for reactive power operation. Now, the *Anglex* should be set to -90°. Figure 7.5b shows the operation characteristic with these settings values.



(a) Reverse active power protection. (b) Reverse reactive power protection.

Figure 7.5: GOPPDOP operation characteristic with given setting values to achieve reverse active and reactive protection.

7.2.11 Negative phase sequence

Negative phase sequence functions protect the rotor from overheating due to unsymmetrical system operation. As mentioned in section 6.4.7, the generator manufacturer should provide ratings for continuous negative sequence current and short time unbalanced current capability of the rotor. The protection function applied should follow these characteristics with an added security margin. In REG670, the functions NS4PTOC and NS2PTOC have negative sequence current as its operation quantity. The latter one is intended for protection against rotor overheating and has a time delay characteristic that matches the rotor heating characteristic. Thus, NS2PTOC is the preferred function to fulfill the negative sequence requirement.

NS2PTOC operation characteristic

As mentioned, the function has a time characteristic matching the $K = I_2^2 t$ characteristic, where the value K is specified. Definite time characteristic is also available. Two steps are available, and it is recommended to use the first for alarm and the second for trip. Inverse characteristic approximating generator cooling rates is available for the function reset time.

7.2.12 Stator RTD, temp. high and high/high

Stator have RTD (resistance thermal detector) sensors built into it for continuously monitoring the stator winding temperature. These sensors detects temperature by measuring resistance. Monitoring of these devices are normally performed by the turbine control system or the safety automation system. It is therefore not necessary to included it in the generator relay. The relay overload function provides backup protection for this functionality.

7.2.13 AVR fault

The AVR is normally continuously monitored by other generator systems, thus a specific AVR fault detection function is not necessary. The relay over- and undervoltage functions provide backup protection.

7.2.14 REG670 function table summary

Table 7.1 is a summary of the above discussion regarding which REG670 functions are best suited to meet the minimum requirements from Statoil.

Protective function	**REG 670 function**
Differential protection	GENPDIF
Overload	OC4PTOC (step 1)
Short circuit	OC4PTOC (step 2)
Earth fault	EF4PTOC
Rotor earth fault	CVGAPC together RXTTE4 injection unit
Directional earth fault	SDEPSDE
Overvoltage	OV2PTOV
Undervoltage	UV2PTUV
Reverse active power	GOPPDOP (step 1)
Reverse reactive power	GOPPDOP (step 2)
Negative phase sequence	NS2PTOC

Table 7.1: Recommended REG670 functions to fulfill the requirements for main generator protection from table 5.1.

Chapter 8

Comparison of present REG670 settings

The present practice for generator protection is studied in this chapter, based on relay setting tables from five different facilities. To ease the comparability of the setting tables, parameter values are recalculated to a per unit quantity, having generator ratings as base. The recalculated values are found in appendix B. Here, generators having equal ratings (only found within the same facility) are listed only one time. In total, there ar seven different generator types (G1 - G7).

In the first section, functions used for the different generator types, are listed for comparison with the standard function proposal from the previous 7. In the subsequent sections, parameter values for the different functions are compared and discussed, function by function. Operating characteristic for each of the generator types (G1 - G7) is plotted for easy comparison of the operation characteristic. All discussions are based on the basic explanations presented for each function in chapter 7.

Based on the comparison of present protection practice, values that can be used for a standard protection solution are also studied. However, only the most important parameters influencing the function operation characteristic are discussed. The REG670 parameter controlling a given parameter is included in brackets.

8.1 Relay functions used

All functions specified in the five setting tables are summed up in table 8.1. This table shows that more or less the same functions are used for all generator types. Also, these complies well with the recommended functions found in chapter 7. In the following sections, parameter values for these functions are further discussed.

Figure 8.1 illustrates the connection of each function to the power system. As shown here, EF4PTOC is connected to a CT with lower winding ratio than the general-purpose star point side CT, but this is not required practice. Notice that the SDEPSDE function is connected to a summation CT and a three-phase voltage measurement. This means that U_0 is internally calculated, but an open delta transformer is also common practice. Notice that the CVGAPC function is listed two times. This is because the function is used for two different protective applications. It is important to keep the points of measurements in mind when function values are discussed.

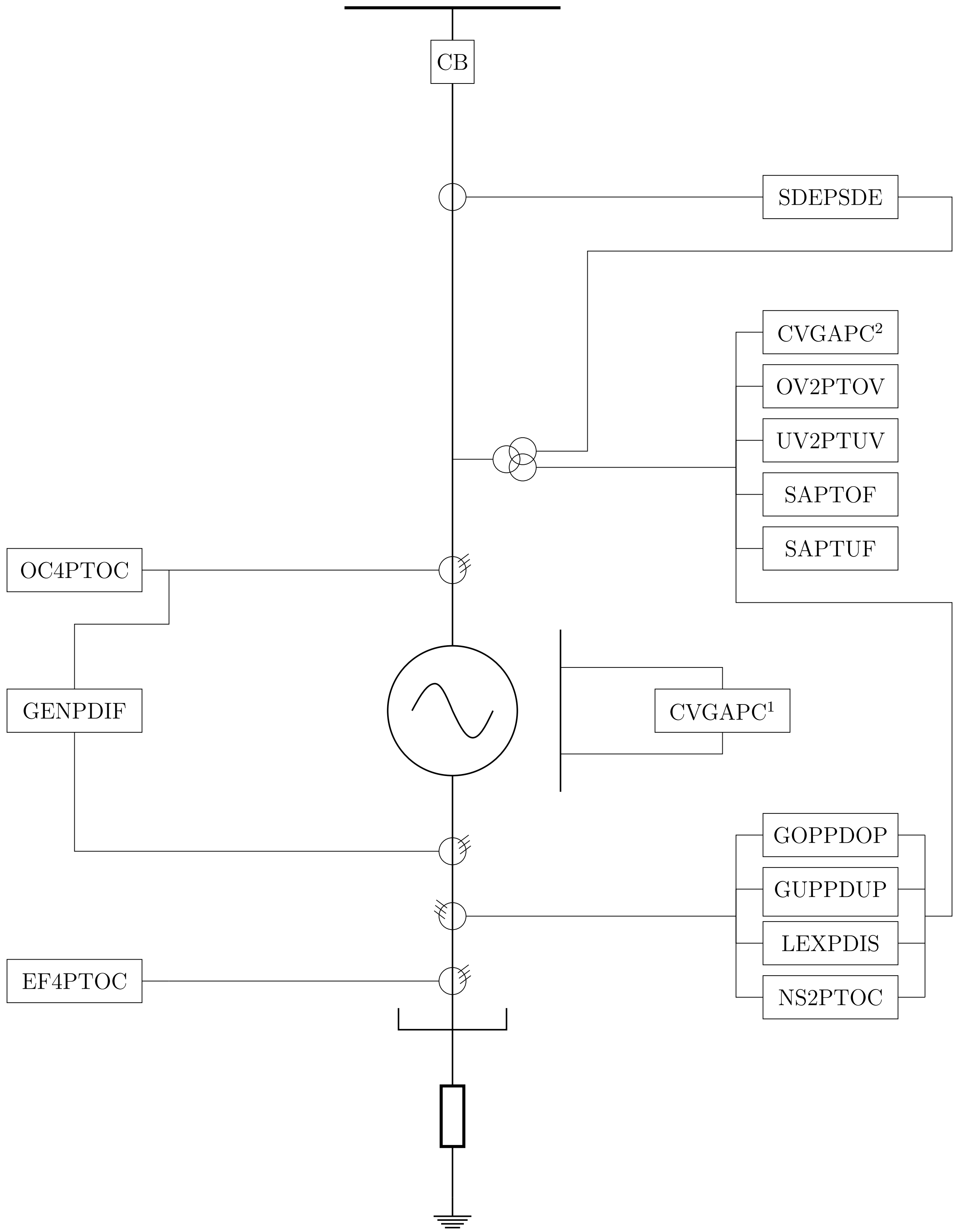


Figure 8.1: Implemented protective functions and their possible points of measurement. CVGAPC is used for two different functions: 1) rotor earth fault protection, 2) undervoltage protection.

Protective function	**REG670 name**	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**
Differential protection	GENPDIF	x	x			x	x	x
Phase overcurrent	OC4PTOC	x	x	x	x	x	x	x
Directional residual overcurrent	SDEPSDE	x	x	x	x	x	x	x
Directional over power (active)	GOPPDOP	x	x	x	x	x	x	x
Directional over power (reactive)	GOPPDOP	x				x	x	x
Non-directional residual overcurrent	EF4PTOC	x	x	x	x	x	x	x
Negative phase sequence protection	NS2PTOC	x	x	x	x	x	x	x
Overvoltage	OV2PTOV	x	x	x	x	x	x	x
Undervoltage	UV2PTUV	x		x	x	x	x	x
Loss of excitation	LEXPDIS		x	x	x	x		
Rotor earth fault	CVGAPC		x	x	x		x	x
Overfrequency	SAPTOF		x	x	x			
Underfrequency	SAPTUF		x	x	x			

Table 8.1: REG670 functions specified for the different generator types according to their respective relay plans.

8.2 GENPDIF - differential protection function

The GENPDIF function provides protection for phase-to-phase and three phase faults located in the generator zone. If such a fault occur, the function trips with no additional time delay. A plot of the different generator types operate characteristic is shown in figure 8.2. Here, one can observe the conditional and unconditional operation areas, as explained in section 7.2.1. Type G3 and G4 use a separate differential protection relays, and have not been included here.

Because phase-to-phase and three phase faults potentially can produce very large fault currents, the unconditional operation area can be set to a relatively high value, where there is no doubt that the fault is internal. As the generators have such equal ratings, in addition to very similar power system topologies, it should be possible to find a standard setting value. Such a setting value should be based on calculation of the maximum short-circuit current from the generator for a fault right outside the generator zone. Hence, for a three-phase fault on the HV bus. The minimum current level where there are no doubt that the fault is internal is then just above this value. This current magnitude are further investigated in chapter 9, where results of short circuit simulations are presented. Until then it is worth to remember that the different generator types have relatively equal values for this step, except for type G2, which is a bit higher at 10 times the rated generator current.

For the restrained operation area, the characteristic is determined by five parameters (*IdMin, EndSection1, EndSection2, SlopeSection2* and *SlopeSection3*), which should be set based on the risk of fault current. Hence, the possible errors of the CT class in use, relay measuring error and a safety factor. Therefore, the default values are used in the standard solution. In case different CTs are used, these values should be set higher, and the operation of DC biasing should be activated (*OperDCBiasing*).

For operation within the restricted operate area, both the negative sequence inter-

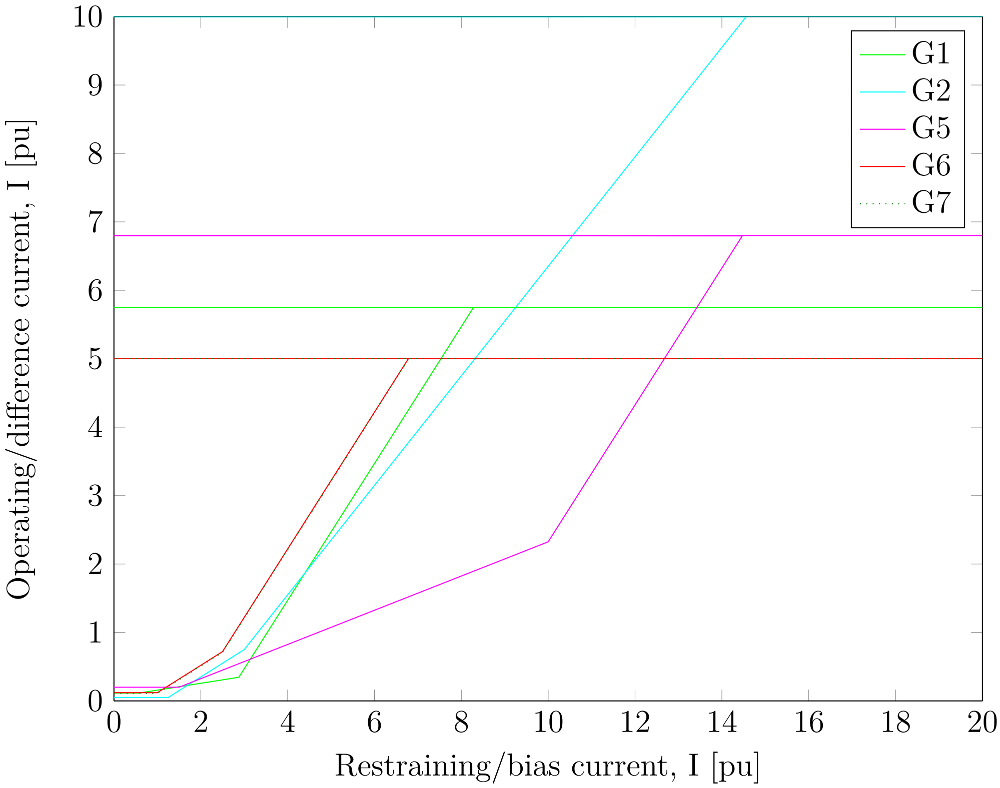


Figure 8.2: Operate characteristic for GENPDIF in pu with machine rated current as base.

nal/external fault discriminator and the harmonic analysis have an effect on operation. G1 and G5 have deactivated the internal/external fault discriminator sub-function (*OpNegSeqDiff*). However, it is recommended by the application manual ([4]) to have this sub-function activated. As there should be no internal source of negative sequence currents inside the generator zone, this sub-function add security to the differential operation. Thus, the standard solution have this sub-function activated. All generator types use the standard value for negative sequence current limit (*IMinNegSeq*).

Harmonic disturbance is also an important sub-function, and here the operation limit (*HarmDistLimit*) is set to very deviating values for the different generator types. The harmonic blocking level are normally set only based on harmonic content levels during transformer inrush, to avoid false operation for large magnetizing currents. The appropriate setting value is therefore very dependent on the specific transformers used in the facilities. However, as the GENPDIF function has no intentionally added time delay, it is important to set the value low enough to achieve fast blocking of a trip signal. With the given data, it is not possible to recommend any standard values, and the default function values are used.

8.3 OC4PTOC - overcurrent function

The OC4PTOC overcurrent function is active for all generator types with at least two steps. The first step has an inverse time characteristic which provides overload protection for the generator. The second (and third for G1) step provides short circuit protection

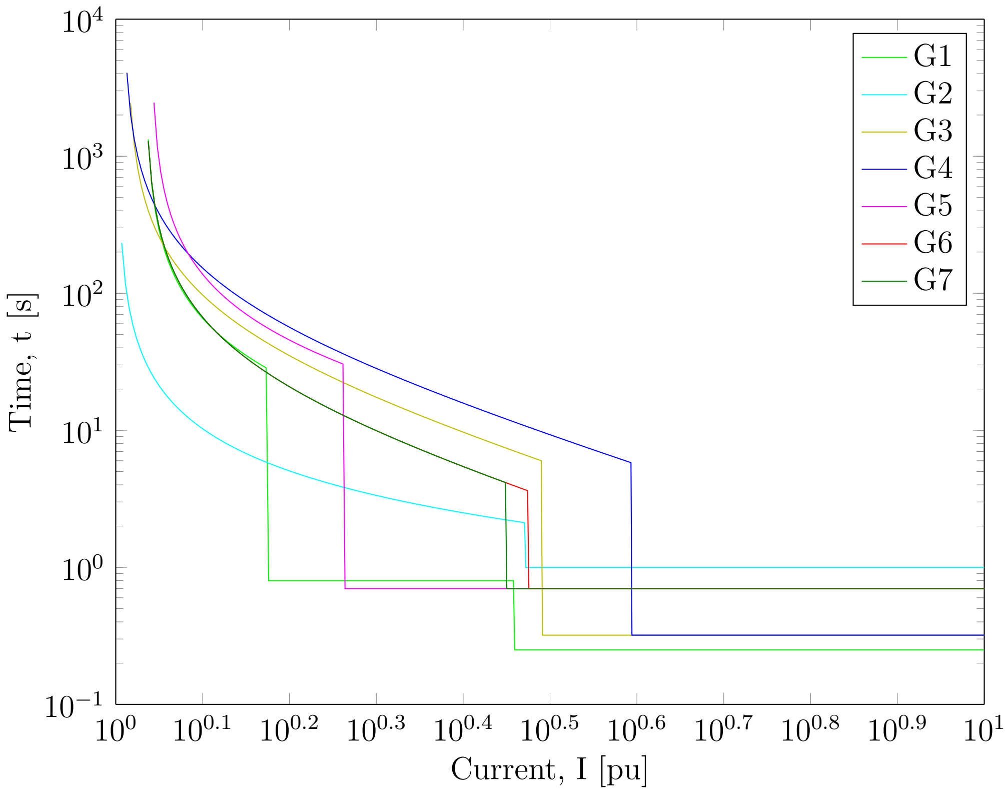


Figure 8.3: Time characteristic for OC4PTOC in pu (loglog plot) with generator rated current as base.

for the external system. A plot of the function operation characteristic, including both steps (three for G1), for the different generator types are shown in figure 8.3.

The overload step is the left part of the figure with an inverse time characteristic, ending with a clear distinction to where the definite time delay kicks in. As the purpose of the overload step is to protect the generator from overheating, setting values for this step should be determined from the generator capability only. Thus, the most secure setting values are the generator capability with an added security margin.

Even though the optimal time delay curve is different for each generator, some of the settings are so similar among the generator types that it is possible to find a standard value. For instance, only IEC inverse curve types are used, where the time multiplier parameter (k) are used to manipulate the curve vertically. Further, one can observe that the operate level (*I1>*) is set to a few percent higher than the rated current generator current. This start value is only dependent on the CT accuracy class, and a smaller error allows a lower value, closer to 100 %. For the standard solution, IEC very inverse curve type is set as the standard curve type, and a set 100 - 110 % is used to indicate the start level.

The minimum operate current for step 1 (*IMin1*) is set below the operate level (*I1>*), which means that it has no effect on the operation characteristic. This should also be the recommended practice, as it gives the best approximation to the actual generator heating characteristic. Thus, the standard solution can keep the default OC4PTOC function default value.

The short circuit step starts with a distinct difference from the overload step and has a constant time delay. From the plot in figure 8.3 one can observe that the minimum operate current for this step is very deviating among the generator types. However, this might be correct, as the minimum operate level should be determined by the minimum generator current contribution for a short circuit in the external system. Whether a standard value for this operate level *I2>* can be found is further investigated in chapter 9, and is not further addressed here.

As the second step is activated before the inverse curve of step 1 have reached its minimum time delay value (*t1Min*), the effect of this value cannot be observed in the operation characteristic. However, this value does affect the function operation. For instance, if $t1Min < t2$, then for the same current magnitude above the operate level of step 2, the function will trip according to the minimum time of step 1 and not the operate time of step 2. Therefore, the minimum operate time of step 1 (*t1Min*) should always be higher than the operate time for step 2 (*t2*). However, this value can be used as a safety factor, and should therefore not be set too high. The standard solution recommended value is therefore set to the operation time of step to with an additional time delay: $t1Min = I2> + 0.2$.

The time delay of step 2 (*I2>*) should be coordinated with any downstream relay that might operate for the same fault. Thus, the time delay will naturally depend on how far the generator relay can see, and how many other relays that can see the same fault. As the implemented values are set within a small range around the default value, the default value is kept as the standard solution.

The function offers two different current measurement methods (*MeasType*); a discrete Fourier filter (DFT) and a RMS filter. Where the DFT method calculate the RMS value of the fundamental frequency component only, while the RMS method also includes the dc component and higher order harmonic current components (the true RMS value). The RMS method is recommended as all currents flowing in the stator produce heat. Thus, all current contribution should be included in the measurement for overload protection.

8.4 EF4PTOC - non-directional earth fault protection

A plot of the different generator types operate characteristics for the non-directional earth fault function are shown in figure 8.4. Notice that current is given in real values. In case of an earth fault in the system this function should be the last to operate. As a zero sequence current cannot flow across a grounded star-delta transformer, this function can only detect ground faults located at the HV bus, which means that it only has to be coordinated with relays at this bus. As the zero sequence current is very limited, the generator can still operate without danger. The first equipment to be damaged by a ground fault current is the generator grounding resistance. This should be given with a continuous current rating, which has to be considered when defining the operation characteristic for the EF4PTOC function. As the generator relay only sees the earth fault current contribution through one grounding resistance, while other components relays sees the sum of all current contributions from all generators, the generator relay current operate level must be based on the grounding resistance continuous rating, while at the same time be coordinated with other relays that can see the same fault. However, it has not been possible to find a standard solution for these parameters (*IN1>* and *t1*) as

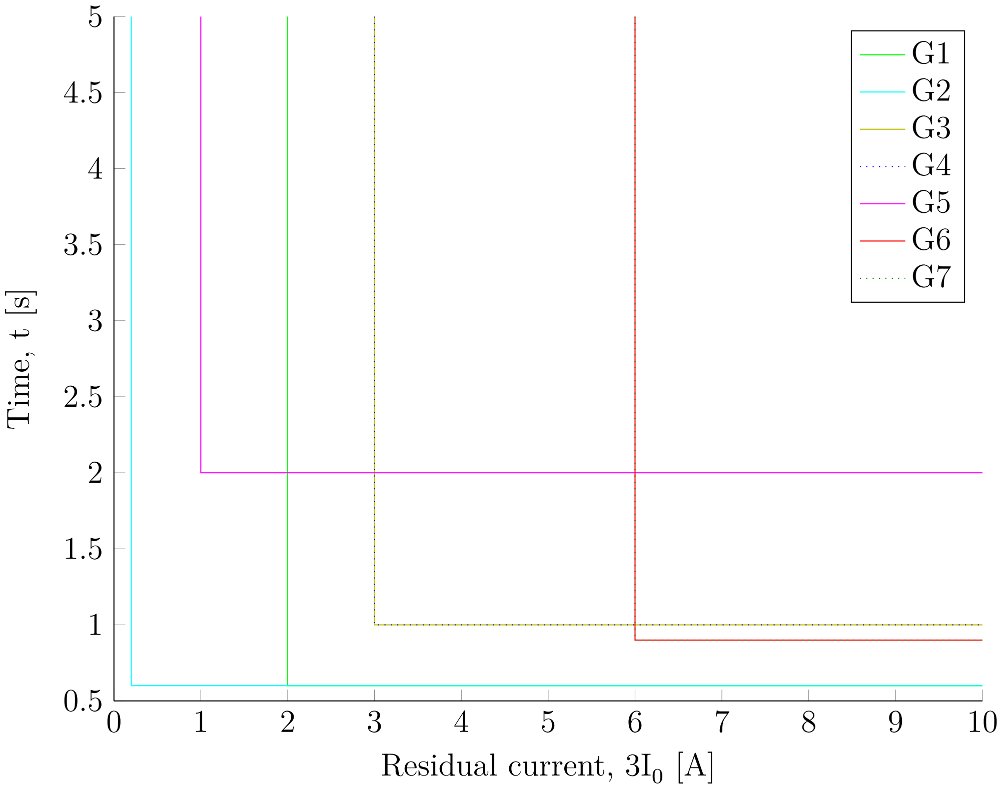


Figure 8.4: Time characteristic for EF4PTOC in real values.

ground fault current is limited to different values among the facilities and it is unclear how many relays the generator relay must be coordinated with.

8.5 SDEPSDE - directional earth fault protection

The directional earth fault function SDEPSDE provides protection in case an earth fault occur inside the generator zone. As seen from figure 8.1, this function measures current and voltage on the terminal side of the generator and due to the directional restraint, it can only see faults located in the generator zone. A plot of the different generator types characteristics are shown in figure 8.5. A relay will operate if the current phasor cross the generator characteristic (as long as $3U_0 > UNRel{>}$). All types have a small definite time delay, well below the time delay of the non-directional earth fault function.

As the ground fault current is mostly resistive, the relay characteristic angle ($RCADir$) can be set to 0°in the standard solution. As seen from the figure, the relay operating angle ($ROADir$) varies between 75 – 90°. However, as the ground fault current is mostly active, these large angles should make no difference in practice. Instead, they can be used as a security measure as to avoid unwanted operation for earth faults in the external system due to CT phase angle error.

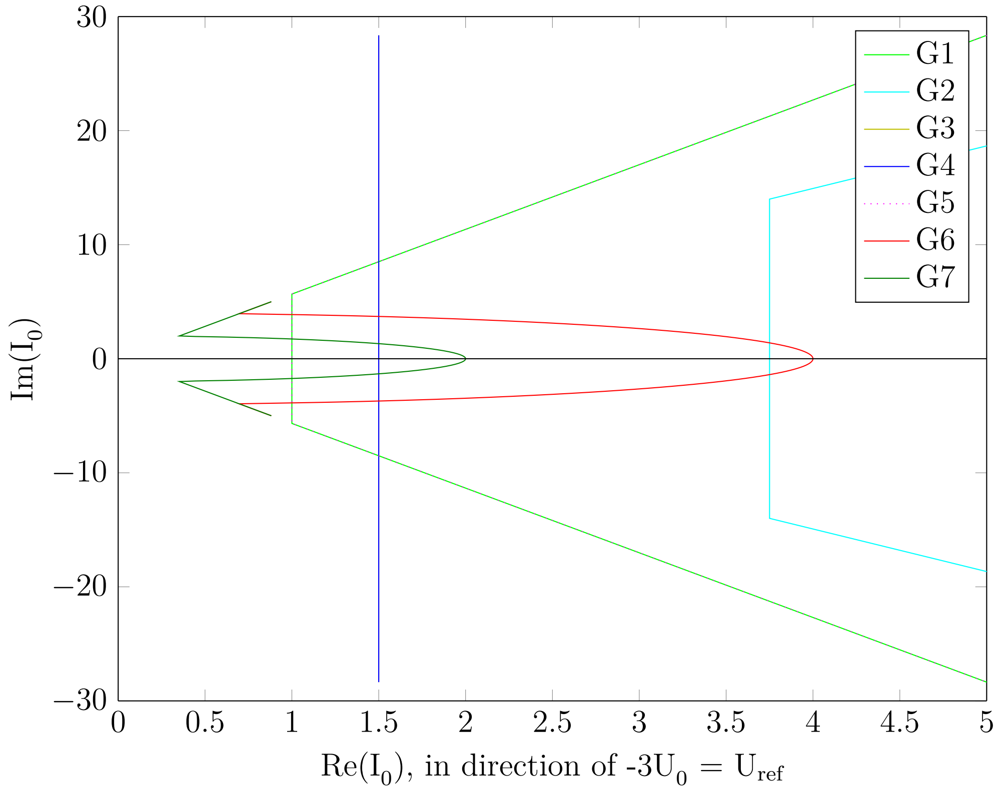


Figure 8.5: Characteristic for SDEPSDE in pu values based on machine ratings.

8.6 OV2PTOV - overvoltage protection

The overvoltage function provides protection for the whole HV bus. As explained in 7.2.7, settings should be based on the most voltage sensitive components in the system, as the generator can withstand high overvoltage for short time periods. Among the most voltage sensitive equipment are rectifiers. As all voltage components contributes to overvoltage, not only the fundamental component, true RMS measurement is chosen in the standard solution.

Figure 8.6 shows a plot of both the over- and undervoltage function characteristics together in a single plot for each generator type. As can be seen here, setting values are more or less equal for operate level (*U1>*), such that a standard value can be set to 120 %. For the time delay (*t1*), values are more deviating. The time delay should not be too short, as to allow the voltage regulator some time to adjust the voltage in case the overvoltage was caused by a sudden loss of load. The generator types use a time delay between 1 - 3 seconds for a setting of 120 %. However, the standard solution use the default function value as this value should be found for each individual generator or facility. Generator types G4 and G5 use two steps, however, only one step is recommended in the standard solution.

8.7 UV2PTUV - undervoltage protection

This function protects the generator and other equipment connected to the HV bus from undervoltages. G2 has not activated this function, as can be seen in figure 8.6, but use

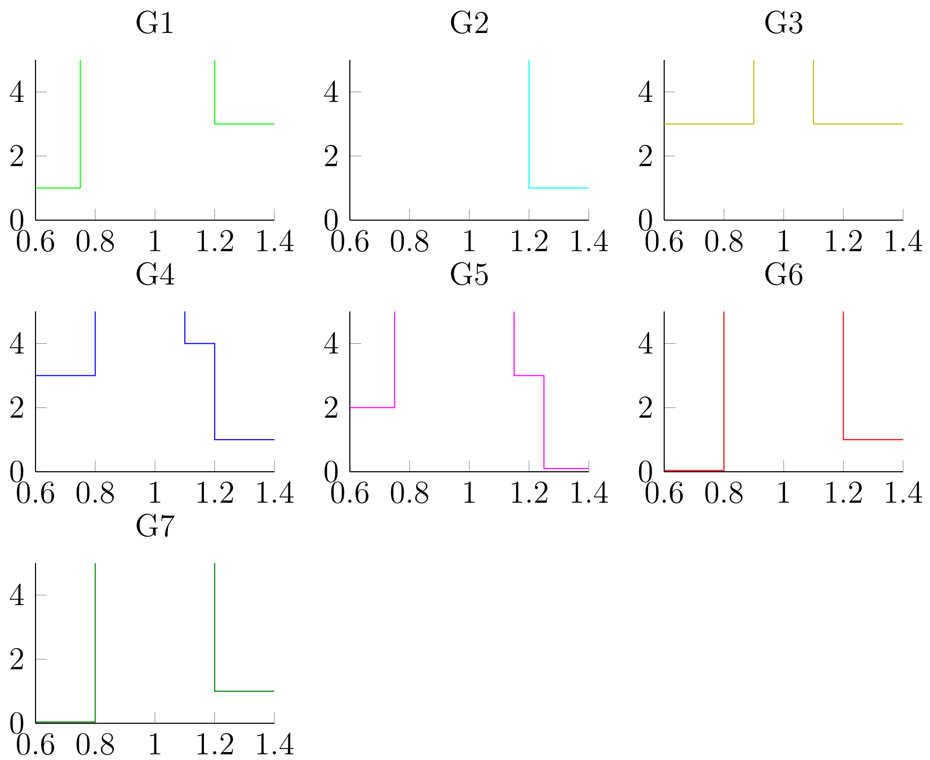


Figure 8.6: Time characteristic for both OV2PTOV and UV2PTUV in pu. On the x-axis is voltage in pu, on y-axis is time delay in seconds.

instead the CVGAPC function which is discussed in section 8.11. G3 and G4 use an operation mode where all three phases must have an undervoltage before operation can start. There might be some special reasons for that not known to the author, but the standard suggestion requires only 1 out of 3 (*ConnType*).

Function operate levels are a bit more deviating than for the overvoltage function, but a standard solution value is set to 80 % as this is more or less an average. A higher value should imply a longer time delay and a lower a shorter. An undervoltage function might operate for short circuits in the system, so the time delay should be coordination with earth fault functions if a longer time delay can be allowed. For instance, does generator type G6 and G7 use definite time delays equal to 0.04 seconds, which is shorter than the operate time of the non-directional short circuit function.

8.8 GOPPDOP - directional power protection

The GOPPDOP function is used to fulfill two different requirements; reverse active and reactive power protection. Figure 8.7 shows a plot of the function characteristic with both steps for the different generator types.

The vertical bar in the figure indicate the operation limit of the active power step. The overpower value (*Power1*) is set relatively equal for the generator types, to a few percent of the generator rating. As explained in section 6.4.2, generator motoring is more dangerous for steam turbines than for gas turbines, and should thus have a stricter power setting. It is therefore strange to observe that G4, as the only steam generator type, requires more reverse power than any of the gas turbine generator types. Following the

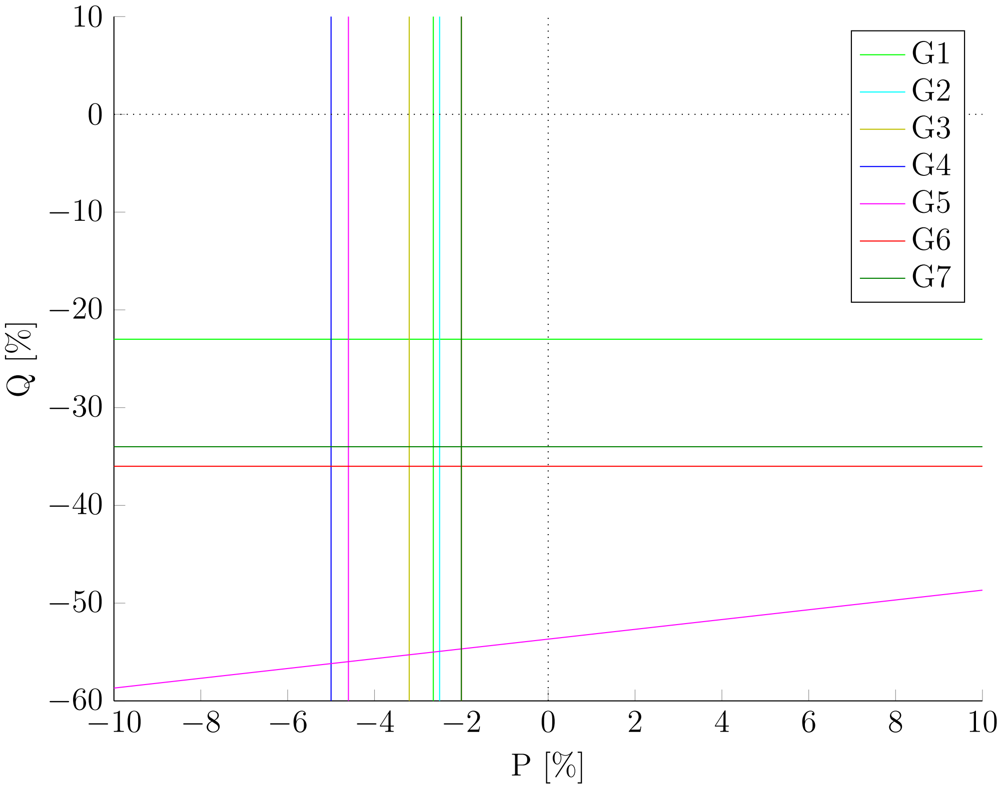


Figure 8.7: Pick up characteristic for GOPPDOP in percent with machine ratings as base.

values given in the IEEE guide ([1]), steam turbines should have a value below 3 %, while a much higher value can be allowed for gas turbines. As there should not flow power into a generator the standard solution value might only be dependent on the CT and VT accuracy class. However, as this is not available the standard suggestion value is based on the IEEE values and relay setting table values. For gas turbines the value is set to 2 %, while for steam turbines it is set to 1 %. Recommended time delay is set to 3 seconds based on the comparison of relay setting table values.

The reactive power step operation limit is indicated by the horizontal bars in figure 8.7. For G5, operation of this step is not set to only operate for reactive power, as the angle is less than 90°. A value of 90°is recommended in the standard solution proposal, because other angles can be misleading and, in theory, give operation also for large active power flows.

Operate levels are very deviating between the generators, as can be seen from the figure, and a standard value cannot be based on these values. Theoretically, if long cables are connected to a facility, reactive power can be fed from this cable into the facility. In some cases, it might be necessary to use the facility generators to consume some of this reactive power to achieve provide an acceptable power factor. Thus, if cables are connected to a facility, the reverse reactive power setting should be higher than if not.

Loss of excitation protection can also be achieved by other operating principles, as explained in section 6.4.1. The three generator types that does not use GOPPDOP for this use instead an impedance function, and are discussed in section 8.10.

8.9 NS2PTOC - negative sequence overcurrent function

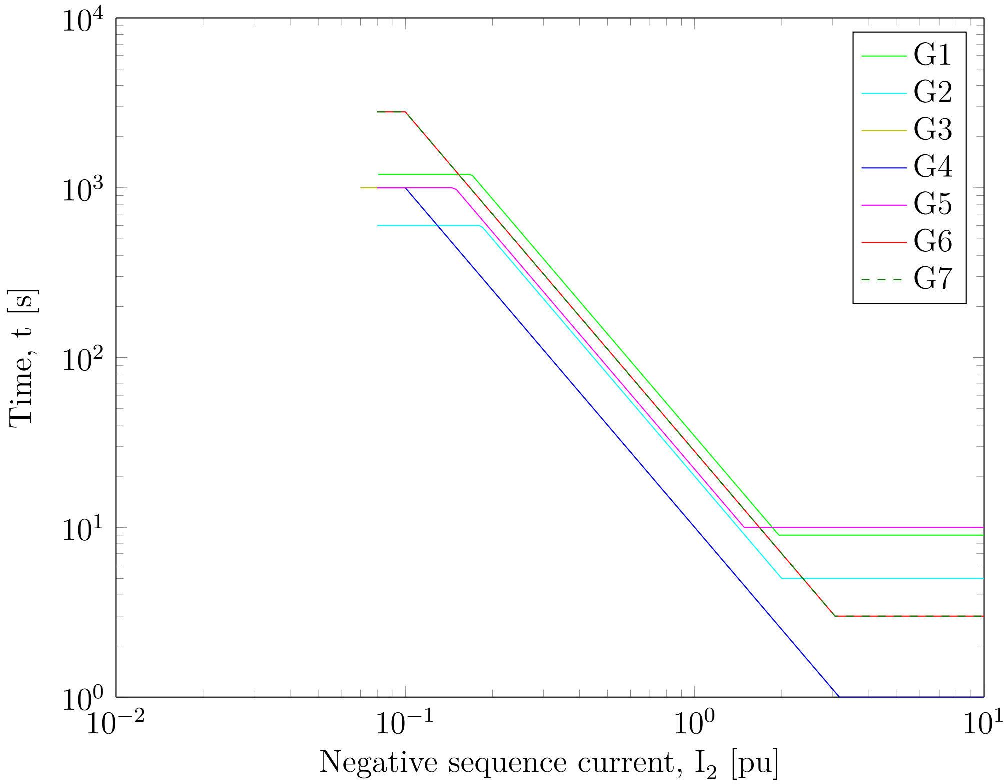


Figure 8.8: Time characteristic for NS2PTOC (loglog scale) in % of machine rated current.

The negative sequence current function protect the rotor from overheating due to unbalanced system operation. A plot of the operation characteristics for each of the generator types is shown in figure 8.8. Here,

To avoid unnecessary blackout situations, the NS2PTOC function should first sound an alarm, notifying the operator about an offending load. As continuity of supply is important, function trip should occur as close to the rotor capability as possible, allowing maximum time for the operator to locate and remove the offending load.

A plot of the operation characteristic for the generator types is shown in figure 8.8. Here, one can observe different inverse characteristic (*K1*) for the generator types, but very equal start current levels (*I2-1>*). The short-time negative sequence current capability (inverse time characteristic) is different by design for each generator, thus, based on the IEEE specifications mentioned in section 6.4.7, the standard solution proposal has set $K < 30$. G3 and G4 use a $K = 10$ which is somewhat lower than the other generator types, but the reason for this is unknown.

Continuous negative sequence current capability I_2 are normally given in percent of the rated generator current. This value are taken into account in the inverse operation step via the start current operate level (*CurrentI2-1>*). This level is almost equal for all types, at around 8 % of generator rated current. The IEEE standard specifies a continuous $I_2 = 10$ %. Thus a 8 % value is used in the standard solution proposal.

The time delay from the point in time when $I_{2measured} > I_{set}$, until the alarm is sounded

($tAlarm$), is mostly set to 1 second. However, G3 have set this to 35. As the purpose of the alarm is to give the operator time to remove I_2 producing loads in time to avoiding production shut down, the standard solution proposal recommend a setting at 1 second.

8.10 LEXPDIS - loss of excitation

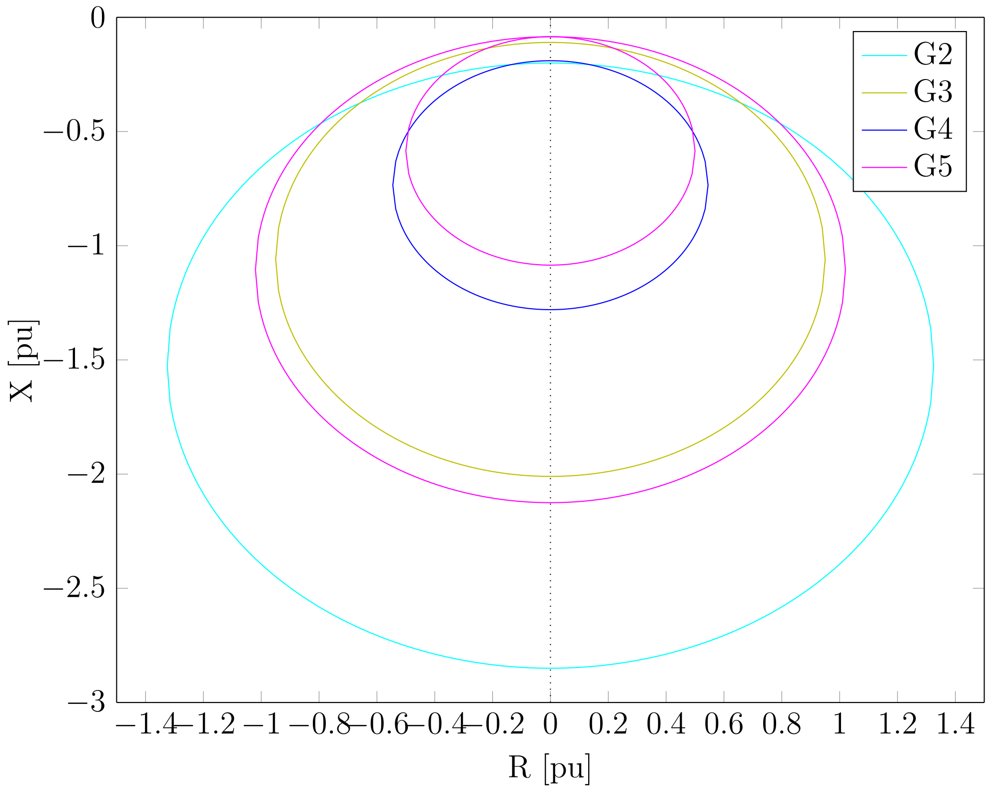


Figure 8.9: Impedance characteristic for LEXPDIS function in pu with Z_{base} as base.

The LEXPDIS function is not part of the standard REG670 function proposal to fulfill generator protection requirements from chapter 7, but it can be used as an alternative to the GOPPDOP function with reverse reactive power protection. As seen from table 8.1, there are three generator types that does not use the GOPPDOP function. Instead, these use the LEXPDIS impedance function. In addition, G5 use this function despite the fact that it also use the GOPPDOP function, but the G5 characteristic were not set to only operate on reactive power.

As explained in section 6.4.1, there are limits for the underexcited operation of a synchronous machine due to stability reasons. The LEXPDIS function takes current and voltage as input and calculates the impedance of the generator, seen from the generator neutral point. As this function is not part of the standard suggestion, it is shortly presented here.

LEXPDIS offer two zones with an offset mho characteristic and an directional criterion. The application manual recommend to set $XoffsetZ1$=$XoffsetZ2$= $-\frac{X_d^{'}}{2}$, $Z1diameter$= Z_{base} and $Z2diameter$= X_d. Where

$$Z_{base} = \frac{U_{base}}{\sqrt{3}I_{base}} \tag{8.1}$$

Time delays for each zone are definite. Recommended values are for the inner zone *tZ1*= 0.1 seconds, and for the outer *tZ2*= 2 seconds.

Non of the generator types that use LEXPDIS have the directional restraint activated. Impedance values used are also different from the recommended values. Figure 8.9 shows a plot of the impedance characteristics for the four generator types in pu values. Here, one can observe the large differences in settings, where G2 and G3 have a much higher setting than recommended.

As both the GOPPDOP and LEXPDIS function have very deviating setting values for each generator type these have been further examined. Function characteristic for GOPPDOP have been recalculated to impedance values by equation 6.1, and plotted together with characteristic for LEXPDIS in figure 8.10. Here, one can observe that the equivalent impedance circle from GOPPDOP does not have the offset that LEXPDIS have (setting *XoffsetZ1*), such that all GOPPDOP circles goes through the origin. If this sensitivity is required, for some special reason, then the LEXPDIS function should be used instead. Naturally, the more reverse reactive power allowed, the smaller is the radius in the impedance circle. Thus, G1 has a very strict setting, while G4 has a very mild setting. One can also see the effect of using an angle different from -90°in the reverse reactive power function; the circle for G5 is shifted into the fourth quadrant, with a small part in the first quadrant also.

Because of the deviating setting values, no further conclusions can be drawn.

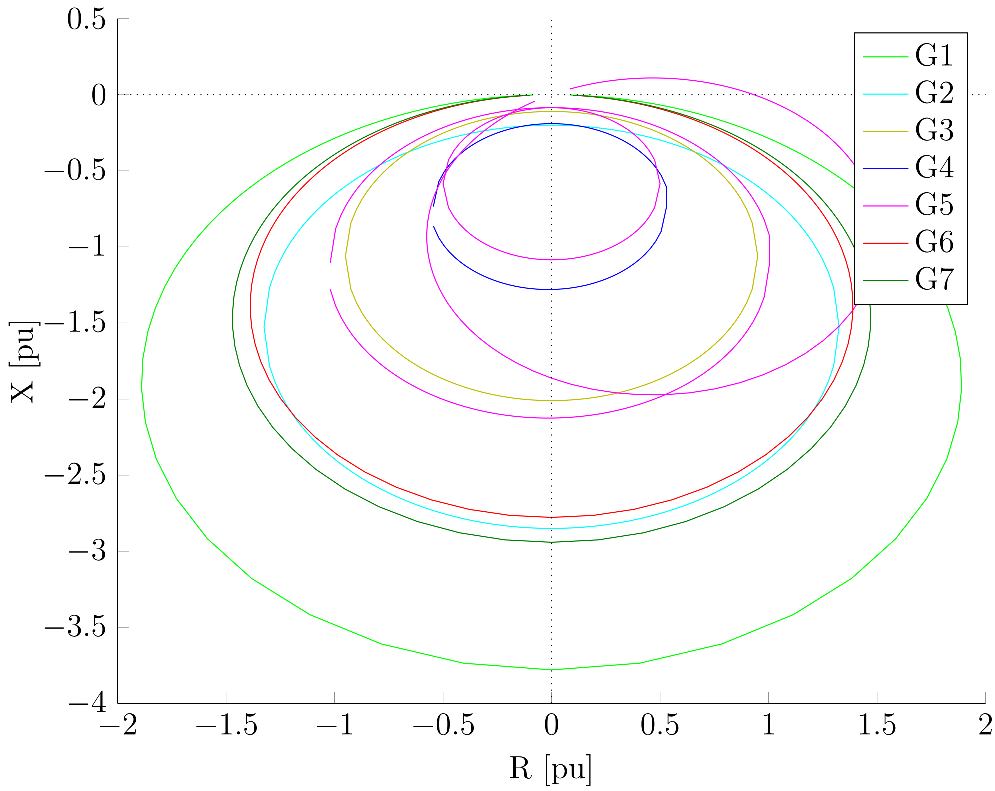


Figure 8.10: Impedance characteristic for GOPPDOP and LEXPDIS function in pu values with generator ratings as base.

8.11 CVGAPC - general current and voltage protection

The CVGAPC function is explained in section 7.2.5 in relation to rotor earth fault protection. The CVGAPC is used for this purpose by generator type G6 and G7, but it is also used by G2 to provide undervoltage protection. The two different uses requires different connections as shown in figure 8.1.

As was pointed out in section 8.7, G2 does not use the dedicated undervoltage function UV2PTUV. Instead, this generator type use the CVGAPC function for this. For undervoltage protection, this function would use the same VT measurement as the UV2PTUV function and can provide the same voltage functionality. Thus, the undervoltage settings for G2 are very equal to the other types, as seen in figure 8.11, where the CVGAPC characteristic for G2 is added to the other voltage characteristics.

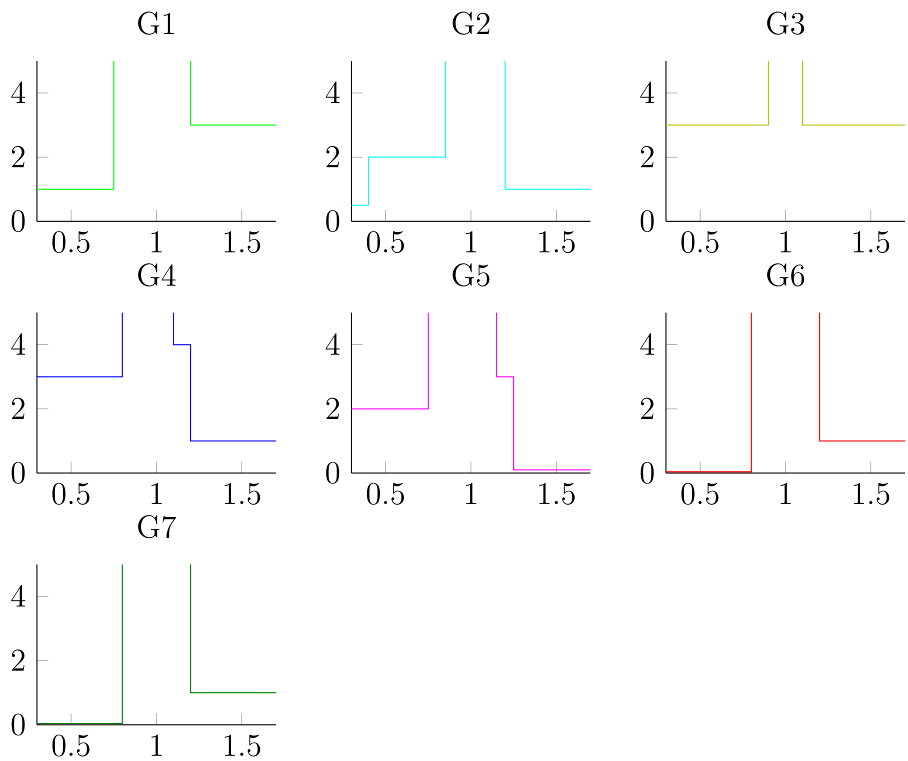


Figure 8.11: Time characteristic for CVGAPC together with the characteristics for OV2PTOV and UV2PTUV. The x-axis shows voltage in pu and on the y-axis is time delay in seconds.

G6 and G7 use CVGAPC for rotor earth fault protection. As explained in section 7.2.5, this requires an additional injection unit, connected to the field winding (see figure 8.1). The generator types have two overcurrent steps, where the first sound an alarm and the second trip the generator. Because the measured current value vary with rotor capacitance, additional added resistors and injected voltage magnitude, the operate level should be set individually for each unit based on on-site measurements.

8.12 SAPTUF - underfrequency protection

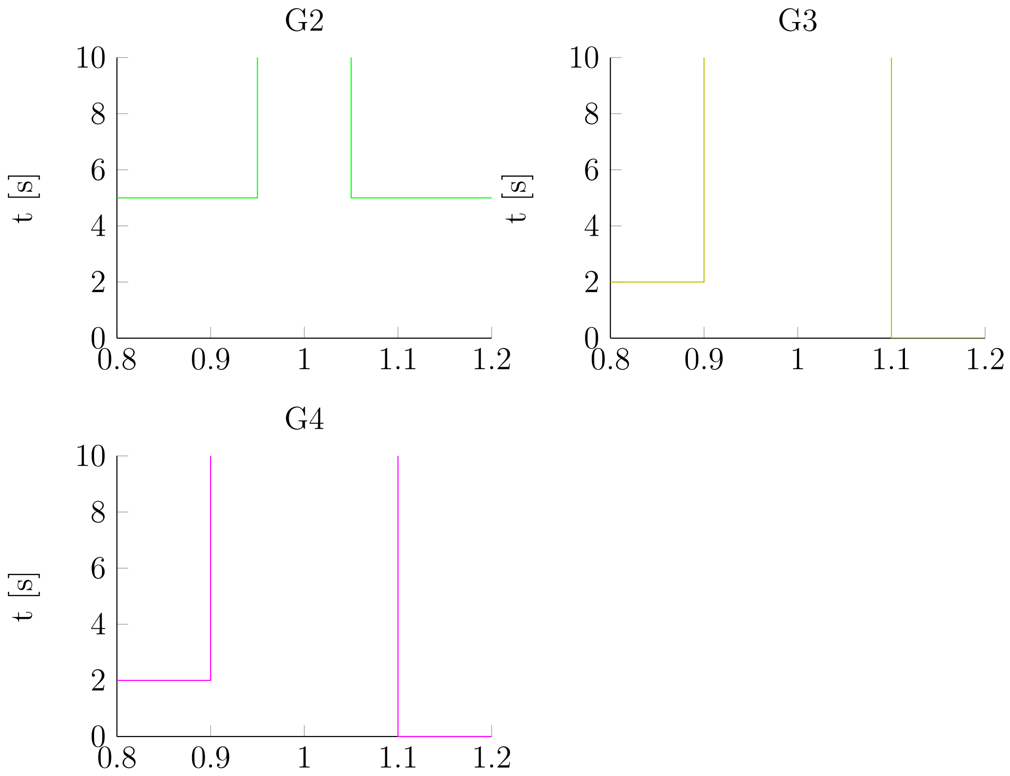


Figure 8.12: Time characteristic for both SAPTUF and SAPTOF in pu. On the x-axis is frequency in pu, the y-axis shows time delay in seconds.

Frequency protection is not part of the required relay protective functions for main generators, as this is normally provided by the turbine control. The SAPTUF function is an underfrequency function, measuring the fundamental frequency from a voltage input. The function is set to use a definite time delay for the generator types that use this function, and the operation characteristic for frequency protection (both over- and underfrequency functions) are shown in figure 8.12. The settings for this characteristic should be defined from the turbine operation limits and the implemented settings in the turbine control. As this is not part of the standard solution, no values are recommended for this function.

8.13 SAPTOF - overfrequency protection (81)

Figure 8.12 also shows the overfrequency function SAPTOF characteristics. On a general basis, the operate level should be determined form the maximum loss of load that can occur in the system, operation limits of the turbine and the settings of the turbine control (to allow this to adjust the power input to the turbine).

Chapter 9

External system short circuits

Operation characteristic for relay functions that can operate for short circuits in the external system, outside the generator CB, must be based on the available fault current magnitudes and coordinated with other relays that can see the same fault. For a standard relay solution proposal, it is therefore necessary to understand how the minimum and maximum fault current magnitudes for faults in the external system changes according to system configuration and operational mode.

In the standard solution proposal developed in earlier chapters, this only applies to the non-directional overcurrent function OC4PTOC. In an effort to understand how short-circuit current magnitudes change with different system configurations, short circuit simulations are performed for two offshore facility system models. Different system configurations and loadings are simulated by varying the number of generators (generation) and the number of motors (load) connected to the HV bus. This chapter explains further the simulation approach and presents the simulation results. A discussion of standardized relay settings for the OC4PTOC function, based on the simulation results, is presented at the end of this chapter.

9.1 Short circuit simulations

The maximum short-circuit current magnitude is produced by a three phase fault, located at the machine terminals. While the minimum fault current magnitude is produced by a phase-to-phase fault, as the ground fault current is very limited at the HV bus. However, when defining relay settings, the total fault current at the fault location is not of concerned, as the relay cannot see this current from its point of measurement. The generator relay only sees the current flowing out from the generator, called the generator fault current contribution. Thus the location of a short circuit, resulting in the minimum generator current contribution, is the location having the largest impedance towards the generator. This location must be found, and the minimum current contribution must be compared with maximum power flow from the generator, to see whether the relay is able to detect the fault.

9.1.1 Simulation method

Short circuit simulations are performed with Paladin DesignBase 5.0, a software program developed by Power Analytics Corporation (formerly EDSA). This software offer tools for power system modeling and analysis. It is used by Unitech Power Systems AS, the company that calculate relay settings for the new REG670 relays, which Statoil ASA install in their offshore facilities.

In Paladin DesignBase, short circuit analysis can be performed by methods according to different standards. In this research, all values are calculated according to the AC ANSI/IEEE method, at four different time instances. The simulations are run with constant temperature (20°C) and the designed system voltage (not load flow). In addition, short-circuits were only been applied to system buses. All these factors have an effect on the numerical current values found. However, the goal of the simulations were to investigate patterns for short-circuit current development for different system configurations, and not find accurate values for one specific case.

The bus producing the minimum generator current contribution was found by applying phase-to-phase short circuits at all system buses (one at the time), and comparing the results. The HV bus is naturally the location resulting in largest generator current contributions. After locating the buses, new short circuit simulations were performed with varying generator loading and total load. In other words, the number of motors (load) and generators (available supply) were changed for each simulation.

9.1.2 Simulation results

Simulation results are listed in appendix C. One model is used for most of the simulations, while the other is used to verify the results of the first model. Fault current contributions from a single generator have been calculated at four different time instances: instantaneous, 0.5 cycle, 1 cycle and steady state. The instantaneous value is a sum of the ac and dc component, while the values calculated at 0.5 cycle and 1 cycle is the symmetrical fault current component. For the steady state value, the dc component has died out, so the asymmetrical value is equal to the symmetrical current value. The following is a short summary of the simulation results.

Maximum fault current

The steady state short-circuit current contribution from a single generator is equal for all combinations of generators and motors, and is thus independent of the generator loading and total system load. There is neither any difference for the symmetrical current at 0.5 cycle and 1 cycle time instance. However, at these time instances, the asymmetrical current values are different due to a decaying dc component. The instantaneous, or peak, current value changes somewhat; for an increasing number of generators the magnitude increase, while it decreases for an increasing number of motors. However, the relative difference is so small that the maximum current level is more or less constant for all cases.

The constant value were expected, as the impedance between the generator and the fault is low compared to the generator impedance. This means that current is only limited by the generator impedance.

Minimum fault current

The minimum short-circuit current contribution from a generator is much more dependent on the system configuration. In this case, the 1 cycle and steady state value are independent of the number of motors, but is highly dependent on the number of generators.

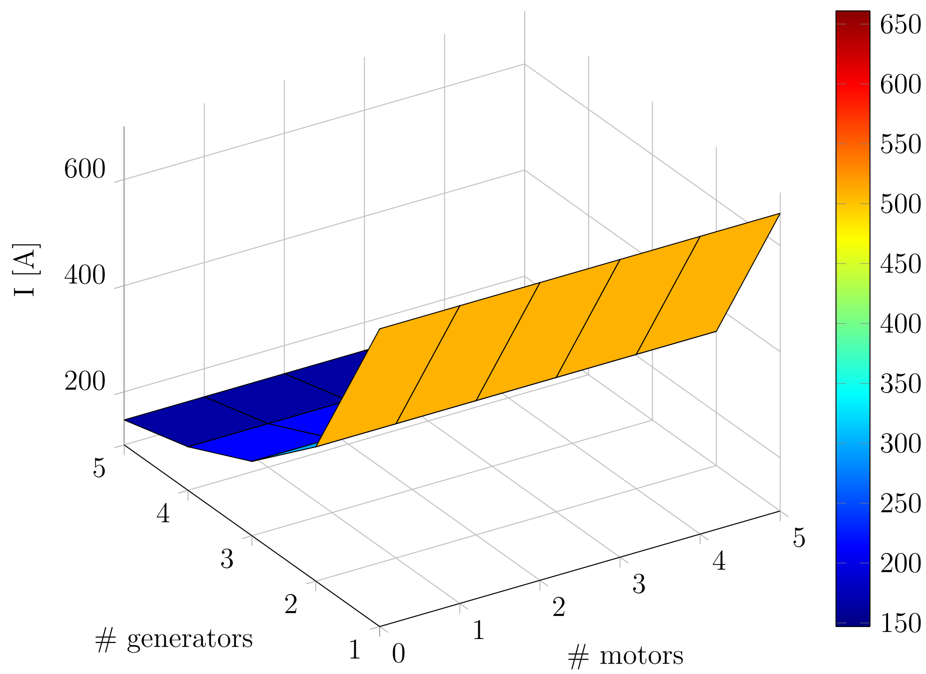


Figure 9.1: Steady state value for smallest phase-to-phase short-circuit current contribution.

For instance, the generator fault current is almost halved by operating two generators instead of only a single one. The instantaneous values of current contributions from a single generator is plotted in figure 9.1. Here, one can easily see the influence of number of motors (none) and generators (large influence). Instantaneous current values (in phase B) for the same fault are shown in figure 9.2. Here, one can observe that the current magnitude decrease for an increasing number of both generators and motors.

A second model (model 2 in appendix C), of another actual facility, has also been studied, using the same method as for the first model (model 1). These results confirmed the results of the first model.

Results of the simulation study can be summarized as the following: *For a single main generator, the...*

1. maximum short-circuit current contribution
   (a) instantaneous values
      i. are somewhat affected, but this effect is so small that it can be neglected.
   (b) steady state values
      i. are independent of the number of generators and motors.
2. minimum short-circuit current contribution
   (a) instantaneous values
      i. decrease for an increasing number of generators
      ii. decrease for an increasing number of motors.
   (b) steady state values

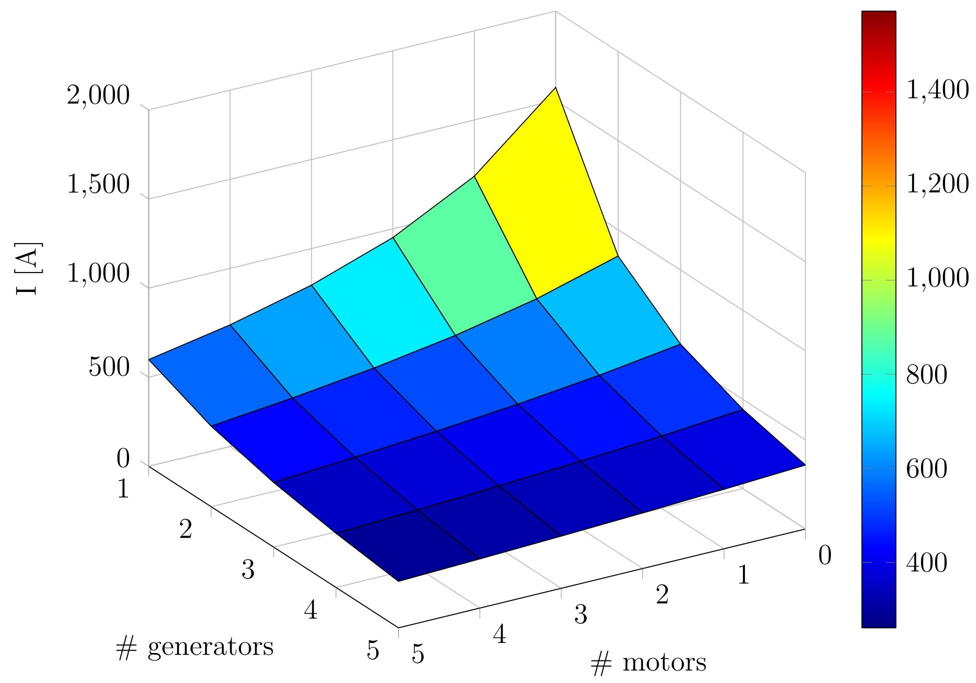


Figure 9.2: Smallest phase-to-phase instantaneous short-circuit current contribution, phase B current.

i. decrease for an increasing number of generators.
ii. are independent of the number of motors.

9.2 Relay setting values

The simulation shows some important correlations that can be used when finding relay values.

- The highest short-circuit current contribution from a generator is very large and is unaffected by the number of generators and motors connected to the HV bus.
- The smallest fault current contribution form a generator is very dependent on the number of generators in operation, but independent of the number of motors.

The overcurrent function OC4PTOC is used for detection of short circuits in the system external to the generator zone. Therefore, its operation characteristic has to be set according to the available short-circuit magnitudes, and further coordinated with other relays that might operate for the same fault. From this short circuit study, it is clear that the minimum fault current contribution from a generator is smaller than the rated generator current. This means that the generator relay cannot detect these faults, and other relays must handle these (transformers also have short circuit functions). Therefore, the OC4PTOC function should be set to operate only for short-circuits on the HV bus.

For short circuits at the HV bus, short-circuit current level is much higher than the rated generator current, for both three phase faults and phase-to-phase faults. In addition, the current magnitude is independent of generator loading. Thus, if a short circuit occurs at the HV bus, it should be relatively easy to detect, and high current operate levels can be allowed. On the other hand, due to the high current level, operate time must be as low as possible. As internal faults in motors and generator might results in the same current magnitude, the OC4PTOC function must be coordinated with the differential protection and other machine and transformer relays, connected at the HV bus.

As the generator relay should only operate for short circuits on the HV bus, it is not necessary to perform a new short circuit study for the specific system where a relay is to be installed, as the fault current is unaffected by other components.

Chapter 10

Discussion

Protective relaying is often referred to as both a science and an art. Different protective engineers might design significantly different protective systems for the same application. Based on previous experience and preferences for required protection and operation principles, each engineer finds solutions with different operating principles and protective coverage. This might explain the differences in REG670 setting values for the different facilities, found in chapter 8.

Based on the explicit requirements for protection of generators in offshore facilities, chapter 7 proposed a standard solution for REG670 functions that can be used for all generators in these facilities. The functions proposed, corresponds well with the present function use from relay setting tables. However, some facilities had two additional functions for frequency protection, providing backup for the turbine speed governor. Although they would increase the level of protection, these are not included in the proposal for standard functions, as they are not part of the requirements.

A standard solution for parameter values for each of the proposed functions is also developed. However, it does not contain many values that apply to generators in offshore facilities in special. Actually, most of the values are the default function setting. This is due to two reasons; either the parameter is only dependent on physical design and handling capabilities of the generator, or there was no basis for finding such value. For many of the values, the background material did not provide enough information to build a basis for understanding the logic behind the used values. In addition, these values were also very different among the facilities.

For the comparison of the relay setting tables from the five facilities, it was differentiated between generators having different ratings. Later, when comparing the values, it became clear that generator types located within the same facility have very similar parameter values. For many of the functions the operation characteristic is actually similar. When looking at the setting tables in general, it is also possible to see equalities between some of the facilities in terms of what functions are used and the operation characteristics. This is a source of error, as the proposal is not based on the of five different protective engineers.

Only two of the required functions should operate for faults in the external system. These are the non-directional overcurrent and the earth fault function. It was argued that the operation characteristic for the earth fault function were independent of the electrical quantities of the system, and could be based solely on the capabilities of the neutral resistor. However, this solution favour security an the expense of dependability. For the overcurrent function, it was concluded that the operation level could be based solely on the parameters of the generator itself, and were more or less independent of the external grid, based on short circuit simulations of two models. One of the models were very basic while the other very detailed, yet similar results were found.

It is clear that many of the functions required for generator protection can be based solely on the generator capability and the design parameters. When upgrading generator relays in offshore facilities, the operation characteristic of the old relay can therefore, for these functions, be used in the new relay. In fact, if there has been no system changes, operation characteristics for all functions proposed in REG670 can be based on the old relays.

Whether this is the best utilization of the new relays is a question worth asking. Modern relays offer possibilities for better protection in the form of increased sensitivity and flexibility for a tailor made operation characteristics. By transferring values from the old relays to the new relays these are no exploited, and the new relays are not utilized to its full potential. In order to better utilize the technology of the new relays, it is recommended to find parameter values for the new device.

Simplicity is an important factor in relaying systems. A complex system might provide very good and accurate protection, but if the operator does not understand how it operates, the system performance might actually become worse as the probability of malfunction by human operation is increased. There does not necessarily have to be a tradeoff between simplicity and level of protection. At first glance, the wide range of functionality offered by modern relays might be overwhelming compared to the old relays that are being replaced. However, this does not mean that modern relays are difficult to understand. In the author's experience, a non-consistent use of relay functions for the same type of protection can be very confusing. Therefore, a standard solution for relay functions can aid understanding of the protective system. In the end, the system operator is the one to use the system.

Short time delays for relay operation is desired for protection of components. However, a shorter time delay tend to decrease relay security. This tradeoff is inherent to relaying systems, and the settlement should be based on each component's importance to the system operation and the risk associated with the component. As a main generator is an essential component for the operation of an isolated power system at an offshore unit, it is obvious that a trip should not be made unless it is a certain fault. On the other hand, a damaged generator is even worse. In the proposal for relay settings, secure operation is favored on the expense of component protection. This means that settings for those functions operating for faults internal in the generator zone, settings have been pushed towards the generator capability. However, a safety margin to account for measuring errors is added, thus, permitted conditions should not exceed the generator capability. Nevertheless, operation conditions close to the generator capability will lead to more deterioration. However, as the generator capability is never exceeded, the generator should designed to cope with such conditions.

Chapter 11

Conclusion

The goal of this project was to gain a better understanding for protection of generators used in offshore facilities and to contribute to a more standardized protection of these. To achieve this, a list of five objectives was presented in the problem description:

- Identify requirements that apply to relay protection of generators used in offshore facilities. Relevant standards and requirements have been reviewed and presented in this report.

- Identify the functionality of ABB REG670 relay. Based on the requirements for generator protection, relevant REG670 functions that might be used to fulfill the requirements were discussed. The functionality of the best suited functions were further introduced, through an theoretical presentation of functionality, and through studying actual function parameter values implemented for five actual facilities.

- Analysis of relay plans to identify present practice. Relay plans from five different facilities have been compiled into a single table, where values are based on the generator ratings for easy comparison. Further, setting values for each applied function were compared and differences and equalities were identified. Function operating characteristics were plotted for visualization and easy comparison of important parameters.

- Short circuit analysis for offshore facilities with Paladin DesignBase. Two models of actual facilities are used in a short-circuit study. It was found that the generator relay cannot detect a fault on other buses than the HV bus. On the HV bus, the fault current contribution from a single generator was independent of the number of other machines and loads connected to the system.

- Contribute to the development of a standard REG670 relay setting table for generators in offshore facilities. A proposal for REG670 relay functions that can be part of a standard solution are presented. Further, based on presented theory and the identified present practice, this project has contributed to the work of developing a standard relay setting table for these functions.

The standard function proposal contributes to a better protection of generators in offshore facilities by assuring that all requirements are met, and avoiding overlapping functionality.

Chapter 12

Further work

This project contributed to the development of a standard REG670 setting table solution for protection of generators in offshore facilities. This solution is not complete and should be further developed to increase its use and value. Further work should include:

- Settings determined by CT accuracy class. A few different CT accuracy classes are installed in the five facilities studied as part of this project. Identifying the common types in use, and studying how these affect the function parameter values can further improve the standard solution.
- Study of harmonic voltages. Almost all REG670 functions in the standard solution proposal have parameters for harmonic blocking. Values for these are normally only based on harmonic voltage levels during transformer inrush. Large differences for were observed between the five facilities studied. A simulation model should be developed for study of the harmonic content during inrush for different types of transformers. The harmonic content of large power electronic components might also be of interest, and should be included in such a model.
- Manual for how to use the standard table solution. Each REG670 relay function includes many parameters, and at first glance, it may seem overwhelmingly. ABB spend a lot of time and resources on guiding third parties on how to calculate these settings. A standard solution contribute to eases this work, but an accompanying manual explaining each parameter and its relevance for protection of generators in offshore facilities, would enhance its value. It would also relieve the need for resources spent on guidance.
- Standard setting table in XRIO format. The REG670 relay is configured in the Protection and Control IED Manager PCM600 software. Setting tables can be imported to this software if they are written in XRIO file format. The idea behind a standard solution is that a limited number of values should have to be different for each facility. Thus, if the standard solution were available in such file format, the time necessary for configuring the relay should be reduced as only a couple of the values have to be changed.

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Appendix A

Available relay protection functions in REG670

All protective functions available in REG670 2.0 are listed here. [5]

Differential protection

T2WPDIF	87T	Transformer differential protection, two winding
T3WPDIF	87T	Transformer differential protection, three winding
HZPDIF	87	1Ph high impedance differential protection
GENPDIF	87G	Generator differential protection
REFPDIF	87N	Restricted earth fault protection, low impedance

Impedance protection

ZMHPDIS	21	Fullscheme distance protection, mho characteristic
ZDMRDIR	21D	Directional impedance element for mho characteristic
ZMFPDIS	21	High speed distance protection
ZMFCPDIS	21	High speed distance protection for series compensated lines
PSPPPAM	78	Pole slip/out-of-step protection
OOSPPAM	78	Out-of-step protection
LEXPDIS	40	Loss of excitation
ROTIPHIZ	64R	Sensitive rotor earth fault protection, injection based
STTIPHIZ	64S	100% stator earth fault protection, injection based
ZGVPDIS	21	Underimpedance for generators and transformers

Current protection

PHPIOC	50	Instantaneous phase overcurrent protection
OC4PTOC	51 67	Four step phase overcurrent protection
EFPIOC	50N	Instantaneous residual overcurrent protection
EF4PTOC	51N 67N	Four step residual overcurrent protection
NS4PTOC	46I2	Four step directional negative phase sequence overcurrent protection
SDEPSDE	67N	Sensitive directional residual overcurrent and power protection
TRPTTR	49	Thermal overload protection, two time constant

CCRBRF	50BF	Breaker failure protection
CCPDSC	52PD	Pole discordance protection
GUPPDUP	37	Directional underpower protection
GOPPDOP	32	Directional overpower protection
NS2PTOC	46I2	Negative sequence time overcurrent protection for machines
AEGPVOC	50AE	Accidental energizing protection for synchronous generator
VRPVOC	51V	Voltage restrained overcurrent protection
GSPTTR	49S	Stator overload protection
GRPTTR	49R	Rotor overload protection

Voltage protection

UV2PTUV	27	Two step undervoltage protection
OV2PTOV	59	Two step overvoltage protection
ROV2PTOV	59N	Two step residual overvoltage protection
OEXPVPH	24	Overexcitation protection
VDCPTOV	60	Voltage differential protection
STEFPHIZ	59THD	100% stator earth fault protection, 3rd harmonic based

Frequency protection

SAPTUF	81	Underfrequency protection
SAPTOF	81	Overfrequency protection
SAPFRC	81	Rate-of-change frequency protection
FTAQFVR	81A	Frequency time accumulation protection

Multipurpose protection

CVGAPC		General current and voltage protection

General calculation

SMAIHPAC		Multipurpose filter

Appendix B

Relay setting tables

Relay setting tables for main generators at five different facilities were given as background material for this research. These tables have been combined and values recalculated to pu values based on each machine's ratings for easy comparison. All functions and with its corresponding values are listed on the following pages. First is an overview of each machines ratings which are as pu base value.

Generator overview

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7
Number of generators		2	3	3	1	2	2	1
Ratings	MVA	26.50	32.2	28.87	22.83	31.25	25	26.5
System voltage	kV	11	11	13.8	13.8	11	13.8	13.8
System frequency	Hz	60	50	60	60	50	60	60
Rated current	A	1391	1690	1208	955	1640	1046	1108

GENPDIF

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
GENPDIF Group settings (basic)									
Operation		On	On	Off	Off	On	On	On	Off
IdMin	IB	0.1150	0.0500			0.2000	0.1200	0.1100	0
IdUnre	IB	5.7513	10.0000			6.8000	5.0000	5.0000	10
OpNegSeqDiff		No	Yes			No	Yes	Yes	Yes
IMinNegSeq	IB	0.0460	0.0400			0.0400	0.0400	0.0400	0.04
GENPDIF Group settings (advanced)									
EndSection1	IB	0.5751	1.2500			1.5000	1.0000	1.0000	1
EndSection2	IB	2.8756	3.0000			10.0000	2.5000	2.5000	3
SlopeSection2	%	10	40			25	40	40	40
SlopeSection3	%	100	80			100	100	100	80
OpCrossBlock		No	Yes			No	Yes	Yes	Yes
NegSeqROA	deg	30	60			30	60	60	60
HarmDistLimit	%	20	10			20	7	7	10
TempIdMin	IdMin	5	2			5	5	5	2
AddTripDelay	s	60	0.1			60	60	60	0.1
OperDCBiasing		Off	Off			Off	On	On	Off
OpenCTEnable		On	Off			Off	On	On	Off
tOCTAlarmDelay	s	3	1			3	3	3	1
tOCTResetDelay	s	1	0.25			1	1	1	0.25
tOCTUnrstDelay	s	1	10			1	1	1	10
GENPDIF Non group settings (basic)									
InvertCT2Curr		No	No			No	No	No	No

OC4PTOC

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
OC4PTOC Group settings (basic)									
Operation		On	On	On	On	On	On	On	Off
IBase	A	1600	2000	1208	955	2000	1046	1108	3000
UBase	kV	11	11	13.8	13.8	11	13.8	13.8	400
AngleRCA	deg	55	55	55	55	55	55	55	55
AngleROA	deg	80	80	80	80	80	80	80	80
StartPhSel		1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3
DirMode1		Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.

Characterist1		Very inverse	IEC normal inv	IEC extreme inv	IEC extreme inv	Very inverse	IEC extreme inv	IEC extreme inv	ANSI Def. Time
I1>	%IB	108.12	100.59	103.00	102.00	109.76	108.00	108.00	1000
t1	s	0	0	0	0	0	0	0	0
k1		0.8	0.33	0.6	1	1.5	0.3	0.3	0.05
IMin1	%IB	23.01	100.59	100.00	100.00	103.66	20.00	20.00	100
t1Min	s	1	1.2	2	2	1	1	1	0
I1Mult		1	1	1	1	1	1	1	2
DirMode2		Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.
Characterist2		Def. time	IEC def. time	IEC def. time	IEC def. time	Def. time	IEC def. time	IEC def. time	ANSI Def. Time
I2>	%IB	149.53	295.86	310.00	393.00	182.93	299.00	282.00	500
t2	s	0.8	1	0.32	0.32	0.7	0.7	0.7	0.4
k2		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
IMin2	%IB	138.03	236.69	50.00	50.00	146.34	150.00	150.00	50
t2Min	s	0.75	0	0	0	0.65	0	0	0
I2Mult		1	1	1	1	1	1	1	2
DirMode3		Non-dir.	Off	Off	Off	Off	Off	Off	Non-dir.
Characterist3		Def. time							ANSI Def. Time
I3>	%IB	287.56							250
t3	s	0.25							0.8
k3		0.05							0.05
IMin3	%IB	276.06							33
t3Min	s	1							0
I3Mult		1							2
DirMode4		Off	Off	Off	Off	Off	Off	Off	Non-dir.
Characterist4									ANSI Def. Time
I4>	%IB								175
t4	s								2
k4									0.05
IMin4	%IB								17
t4Min	s								0
I4Mult									2

OC4PTOC Group settings (advanced)

IMinOpPhSel	%IB	23.01	8.28	7.00	7.00	24.39	20.00	20.00	7
2ndHarmStab	%IB	23.01	23.67	20.00	20.00	24.39	15.00	15.00	20
ResetTypeCrv1		IEC Reset	Inst.	Inst.	Inst.	IEC Reset	IEC Reset	IEC Reset	Inst.
tReset1	s	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
HarmRestrain1		On	Off	Off	Off	On	On	On	Off

ResetTypeCrv2		IEC Reset	Inst.	Inst.	Inst.	IEC Reset	IEC Reset	IEC Reset	Inst.
tReset2	s	0.4	0.02	0.02	0.02	0.02	0.4	0.4	0.02
HarmRestrain2		On	Off	Off	Off	On	On	On	Off
ResetTypeCrv3		IEC Reset	Inst.	Inst.	Inst.	IEC Reset	Inst.	Inst.	Inst.
tReset3	s	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
HarmRestrain3		On	Off	Off	Off	Off	Off	Off	Off

OC4PTOC Non group settings (basic)

MeasType		RMS	DFT	DFT	DFT	RMS	RMS	RMS	DFT

SDEPSDE

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default

SDEPSDE Group settings (basic)

Operation		On	On	On	On	On	On	On	Off
OpMode		3I0Cosfi	3I0Cosfi	3I0Cosfi	3I0Cosfi	3I0Cosfi	3I0 and fi	3I0 and fi	3I0Cosfi
DirMode		Reverse	Reverse	Reverse	Reverse	Reverse	Reverse	Reverse	Forward
RCADir	deg	0	0	0	0	0	0	0	-90
RCAComp	deg	0	0	0	0	0	0	0	0
ROADir	deg	80	75	90	90	80	80	80	90
INCosPhi>	%IB	0.0719	0.2219	0.1242	0.1571	0.0610			1
SN>	%SB								10
INDir>	%IB						0.382409	0.180505	5
tDef	s	0.2	0.3	0.1	0.2	0.2	0.1	0.1	0.1
SRef	%SB								10
kSN									0.1
OpINNonDir>		Off	Off	Off	Off	Off	Off	Off	Off
INNonDir>	%IB								10
tINNonDir	s								1
TimeChar	s								IEC Norm. inv
tMin									0.04
kIN									1
OpUN>		Off	Off	Off	Off	Off	Off	Off	Off
UN>	%UB								20
tUN	s								0.1
INRel>	%IB	0.0719	0.2219	0.0621	0.0785	0.0488	0.1912	0.1805	1
UNRel>	%UB	0.0467	0.0195	0.1142	0.1445	0.0194	0.0457	0.0431	3

SDEPSDE Group settings (advanced)

tReset	s	0	0.04	0.04	0.04	0	0	0	0.04
tPCrv									1
tACrv									13.5

tBCrv									0
tCCrv									1
ResetTypeCrv		Immediate	IEC Reset	IEC Reset	IEC Reset	Immediate	Immediate	Immediate	IEC Reset
tPRCrv>									0.5
tTRCrv									13.5
tCRCrv									1

SDEPSDE Non group settings (basic)

SDEPSDE Non group settings (advanced)

RotResU		0 deg	180 deg	0 deg	0 deg	0 deg	0 deg	0 deg	180 deg

GOPPDOP

Parameter	**Unit**	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**Default**
GOPPDOP Group settings (basic)									
Operation		On	On	On	On	On	On	On	Off
OpMode1		OverPower	OverPower	OverPower	OverPower	OverPower	OverPower	OverPower	OverPower
Power1	%SB	2.6455787	2.5	3.2	5	4.6	2	2	120
Angle1	deg	180	180	180	180	180	180	180	0
TripDelay1	s	5	3	5	5	5	3	3	1
DropDelay1	s	0.06	0.01	1	1	0.06	1	1	0.06
OpMode2		OverPower	Off	Off	Off	OverPower	OverPower	OverPower	OverPower
Power2	%SB	23.005032				48	36	34	120
Angle2	deg	-90				-63.4	-90	-90	0
TripDelay2	s	3				60	3	3	1
DropDelay2	s	1				1	1	1	0.06
GOPPDOP Group settings (advanced)									
k		0	0	0	0	0	0	0	0
Hysteresis1	%SB	0.5751258	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Hysteresis2	%SB	0.5751258	0.5	0.5	0.5	0.5	1	1	0.5
IAmpComp5	%	0	0	0	0	0	0	0	0
IAmpComp30	%	0	0	0	0	0	0	0	0
IAmpComp100	%	0	0	0	0	0	0	0	0
UAmpComp5	%	0	0	0	0	0	0	0	0
UAmpComp30	%	0	0	0	0	0	0	0	0
UAmpComp100	%	0	0	0	0	0	0	0	0
IAngComp5	deg	0	0	0	0	0	0	0	0
IAngComp30	deg	0	0	0	0	0	0	0	0
IAngComp100	deg	0	0	0	0	0	0	0	0
GOPPDOP Non group settings (basic)									
Mode		L1,L2,L3	Pos Seq	Pos Seq	Pos Seq	L1,L2,L3	L1,L2,L3	L1,L2,L3	Pos Seq

EF4PTOC

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
EF4PTOC Group settings (basic)									
Operation		On	On	On	On	On	On	On	Off
IBase	A	25	10	50	50	20	50	100	3000
UBase	kV	11	11	13.8	13.8	11	13.8	13.8	400
AngleRCA	deg	0	0	65	65	0	0	0	65
polMethod		Current	Voltage	Voltage	Voltage	Current	Current	Current	Voltage
UPolMin	%UB	1	1	1	1	1	1	1	1
IPolMin	%IB	0.0359454	0.005917	0.206954	0.26178	0.02439	0.095602	0.180505	5
RNPol	ohm	1	5	5	5	1	1	1	5
XNPol	ohm	1	40	40	40	1	1	1	40
IN>Dir	%IB	0.0179727	0.059172	0.413907	0.52356	0.012195	0.047801	0.090253	10
2ndHarmStab	%IB	0.2695902	0.118343	0.827815	1.04712	0.182927	0.717017	1.353791	20
BlkParTransf		Off	Off	Off	Off	Off	Off	Off	Off
UseStartValue		IN4>	IN4>	IN4>	IN4>	IN4>	IN4>	IN4>	IN4>
SOTF		Off	Off	Off	Off	Off	Off	Off	Off
ActivationSOTF									Open
StepForSOTF									Step 2
HarmResSOTF									Off
tSOTF	s								0.2
t4U	s								1
ActUnderTime									CB position
tUnderTime	s								0.3
DirMode1		Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.	Non-dir.
Characterist1		IEC def. time	IEC def. time	IEC def. time	IEC def. time	IEC def. time	IEC def. Time	IEC def. Time	ANSI Def. Time
IN1>	%IB	0.1437815	0.011834	0.248344	0.314136	0.060976	0.573614	0.541516	100
t1	s	0.6	0.6	1	1	2	0.9	0.9	0
k1		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
IMin1	%IB	0.0718907	0.011834	4.139073	5.235602	0.04878	0.047801	0.090253	100
t1Min	s	0	0	0	0	0	0	0	0
IN1Mult		1	1	2	2	1	1	1	2
ResetTypeCrv1		Inst.	Inst.	Inst.	Inst.	Inst.	Inst.	Inst.	Inst.
tReset1	s	0.02	0.001	0.02	0.02	0.02	0.02	0.02	0.02
HarmRestrain1		On	Off	Off	Off	On	On	On	On

NS2PTOC

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
NS2PTOC Group settings (basic)									
Operation		On	On	On	On	On	On	On	Off

IBase	A	1600	1690	1208	955	1640	1046	1108	3000
tAlarm	s	1	3	35	1	1	1	1	3
OpStep1		On	On	On	On	On	On	On	On
I2-1>	%IB	8.0518	8	7	8	8	8	8	10
CurveType1		Inverse	Inverse	Inverse	Inverse	Inverse	Inverse	Inverse	Definite
t1	s	0	0	0	0	0	0	0	10
tResetDef1	s	0	0	0	0	0	1	1	0
K1	s	26	20	10	10	22	28	28	10
t1Min	s	9	5	1	1	10	3	3	5
t1Max	s	1200	600	1000	1000	1000	2800	2800	1000
ResetMultip1		10	20	1	1	1	1	1	1
OpStep2		Off	Off	Off	Off	Off	Off	Off	On

OV2PTOV

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
OV2PTOV Group settings (basic)									
Operation		On	On	On	On	On	On	On	Off
UBase	kV	11	11	13.8	13.8	11	13.8	13.8	400
OperationStep1		On	On	On	On	On	On	On	On
Characterist1		Def time	Def time	Def time	Def time	Def time	Def time	Def time	Def time
OpMode1		1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3
U1>	%UB	120	120	110	110	115	120	120	120
t1	s	3	1	3	4	3	1	1	5
t1Min	s	5	5	5	5	5	5	5	5
k1		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
HystAbs1	%UB	0.5	0.5	4	4	0.5	0.5	0.5	0.5
OperationStep2		Off	Off	Off	On	On	Off	Off	On
Characterist2		Def time	Def time	Def time	Def time	Def time	Def time	Def time	Def time
OpMode2		1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3
U2>	%UB	150	150	150	120	125	150	150	150
t2	s	5	5	5	1	0.1	5	5	5
t2Min	s	5	5	5	5	5	5	5	5
k2		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
HystAbs2	%UB	0.5	0.5	0.5	4	0.5	0.5	0.5	0.5
OV2PTOV Group settings (advanced)									
tReset1		0.02	0.025	0.025	0.025	0.02	0.02	0.02	0.025
ResetTypeCrv1		Inst.	Inst.	Inst.	Inst.	Inst.	Inst.	Inst.	Inst.
OV2PTOV Non group settings (basic)									
ConnType		PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhN DFT

UV2PTUV

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
UV2PTUV Group settings (basic)									
Operation		On	Off	On	On	On	On	On	Off
UBase	kV	11		13.8	13.8	11	13.8	13.8	400
OperationStep1		On		On	On	On	On	On	On
Characterist1		Def time		Def time	Def time	Def time	Def time	Def time	Def time
OpMode1		1 out of 3		3 out of 3	3 out of 3	1 out of 3	1 out of 3	1 out of 3	1 out of 3
U1<	%UB	75		90	80	75	80	80	70
t1	s	1		3	3	2	0.04	0.04	5
t1Min	s	5		5	5	5	5	5	5
k1		0.05		0.05	0.05	0.05	0.05	0.05	0.05
IntBlkSel1		Off		Off	Off	Off	Off	Off	Off
IntBlkStVal1	%UB	20		20	20	20	80	80	20
tBlkUV1	s	0		0	0	0	0	0	0
HystAbs1	%UB	0.5		4	4	0.5	0.5	0.5	0.5
OperationStep2		Off		Off	Off	Off	Off	Off	On
UV2PTUV Group settings (advanced)									
tReset1		0.02		0.025	0.025	0.02	0.02	0.02	0.025
ResetTypeCrv1		Inst.		Inst.	Inst.	Inst.	Inst.	Inst.	Inst.
UV2PTUV Non group settings (basic)									
ConnType		PhPh RMS		PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhPh RMS	PhN DFT

LEXPDIS

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
LEXPDIS Group settings (basic)									
Operation		Off	On	On	On	On	Off	Off	Off
OperationZ1			On	On	On	On			On
XoffsetZ1	%		-20	-11	-19	-8.5			-10
Z1diameter	%		265	190	109	100			100
tZ1	s		0.75	1	1	0.2			0.01
OperationZ2			Off	Off	Off	On			On
XoffsetZ2	%					-8.5			-10
Z2diameter	%					204			200
tZ2	s					5			1
LEXPDIS Group settings (advanced)									
DirSuperv			Off	Off	Off	Off			Off

XoffsetDirLine	%		0	0	0	0			0
DirAngle	Deg		-13	-13	-13	-13			-13
LEXPDIS Non group settings (basic)									
MeasureMode			PosSeq	PosSeq	PosSeq	PosSeq			PosSeq
LEXPDIS Group settings (advanced)									
InvertCTcurr		No	No	No	No	No	No	No	No

CVGAPC

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
CVGAPC Group settings (basic)									
Operation		Off	On	Off	Off	Off	On	On	Off
CurrentInput			MaxPh				MaxPh	MaxPh	MaxPh
IBase	A		1690				1000	1000	3000
VoltageInput			MinPh-Ph				MaxPh	MaxPh	MaxPh
UBase	kV		11				100	100	400
OperHarmRestr			Off				Off	Off	Off
l_2nd/l_fund	%		20				20	20	20
EnRestrainCurr			Off				Off	Off	Off
RestrCurrInput			PosSeq				PosSeq	PosSeq	PosSeq
RestrCurrCoeff			0				0	0	0
RCADir	Deg		-75				0	0	-75
ROADir	Deg		75				75	75	75
LowVolt_VM	%UB		0.5				3.623188	3.623188	0.5
Operation_OC1			Off				On	On	Off
Starturr_OC1	%IB						6.692161	6.31769	120
CurveType_OC1							IEC Def time	IEC Def time	ANSI Def. Time
tDef_OC1	s						10	10	0.5
k_OC1							0.3	0.3	0.3
IMin1	%IB						3.824092	3.610108	100
tMin_OC1	s						0.05	0.05	0.05
VCntrlMode_OC1							Off	Off	Off
VDepMode_OC1							Step	Step	Step
VDepFact_OC1							1	1	1
ULowLimit_OC1	%UB						362.3188	362.3188	50
UHighLimit_OC1	%UB						724.6377	724.6377	100
HarmRestr_OC1							Off	Off	Off
DirMode_OC1							Forward	Forward	Non-dir.
DirPrinc_OC1							IcosPhi&U	IcosPhi&U	I&U
ActLowVolt1_VM							Non-dir.	Non-dir.	Non-dir.

Operation_OC2		Off	On	On	Off
StartCurr_OC2	%IB		43.97706	42.41877	120
CurveType_OC2			IEC Def time	IEC Def time	ANSI Def. Time
tDef_OC2	s		2	2	0.5
k_OC2			0.3	0.3	0.3
IMin2	%IB		38.24092	36.10108	50
tMin_OC2	s		0.05	0.05	0.05
VCntrlMode_OC2			Off	Off	Off
VDepMode_OC2			Step	Step	Step
VDepFact_OC2			1	1	1
ULowLimit_OC2	%UB		362.3188	362.3188	50
UHighLimit_OC2	%UB		724.6377	724.6377	100
HarmRestr_OC2			Off	Off	Off
DirMode_OC2			Forward	Forward	Non-dir.
DirPrinc_OC2			IcosPhiU	IcosPhiU	I&U
ActLowVolt2_VM			Non-dir.	Non-dir.	Non-dir.
Operation_UC1		Off	Off	Off	Off
...					
Operation_UC2		Off	Off	Off	Off
...					
Operation_OV1		Off	Off	Off	
...					
Operation_OV2		Off	Off	Off	
...					
Operation_UV1		On	Off	Off	Off
StartVolt_UV1	%UB	85			50
CurveType_UV1		Def time			Definite time
tDef_UV1	s	2			1
tMin_UV1	s	0.05			0.05
k_UV1		0.3			0.3
EnBlkLowV_UV1		On			On
BlkLowVolt_UV1	%UB	0.5			0.5
Operation_UV2		On	Off	Off	Off
StartVolt_UV2	%UB	40			50
CurveType_UV2		Def time			Definite time
tDef_UV2	s	0.5			1
tMin_UV2	s	0.05			0.05
k_UV2		0.3			0.3
EnBlkLowV_UV2		On			On
BlkLowVolt_UV2	%UB	0.5			0.5

CVGAPC Group settings (advanced)

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
CurrMult_OC1 ...			2				2	2	2
CurrMult_OC2 ...			2				2	2	2

SAPTUF

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
SAPTUF Group settings (basic)									
Operation		Off	On	On	On	Off	Off	Off	Off
UBase	kV		11	13.8	13.8				400
StartFrequency	Hz		47.5	54	54				48.8
IntBlockLevel	%UB		50	0	0				50
TimeDlyOperate	s		5	2	2				0.2
TimeDlyReset	s		0	0	0				0
TimeDlyRestore	s		0	0	0				0
RestoreFreq	Hz		49.5	54.1	54.1				50.1
TimerOperation			Definite timer	Definite timer	Definite timer				Definite timer
UNom	%UB								100
UMin	%UB								90
Exponent									1
tMax	s								1
tMin	s								1

SAPTOF

Parameter	Unit	G1	G2	G3	G4	G5	G6	G7	Default
SAPTOF Group settings (basic)									
Operation		Off	On	On	On	Off	Off	Off	Off
UBase	kV		11	13.8	13.8				400
StartFrequency	Hz		52.5	66	66				51.2
IntBlockLevel	%UB		50	0	0				50
TimeDlyOperate	s		5	0	0				0
TimeDlyReset	s		0	0	0				0

Appendix C

Short circuit simulation results

In this appendix are all numerical results from the short circuit simulations listed.

C.1 Model 1

C.1.1 0 motors

# Gen	**Location**	**Fault type**	**Phase**	**Inst**	**0.5 cycle**	**1 cycle**	**Steady state**
1	HV bus	3 phase	A	27837	10979	10979	4958
			B	27837	10979	10979	4958
			C	27837	10979	10979	4958
	HV bus	LL	A	351	138	0	0
			B	20674	8154	8119	5347
			C	20584	8119	8119	5347
	Low Ik	LL	A	27	11	0	0
			B	1572	639	691	661
			C	1565	636	691	661
2	HV bus	3 phase	A	27943	10979	10979	4958
			B	27943	10979	10979	4958
			C	27943	10979	10979	4958
	HV bus	LL	A	185	73	0	0
			B	20711	8138	8119	5347
			C	20661	8118	8119	5347
	Low Ik	LL	A	8	3	0	0
			B	852	346	361	353
			C	849	345	361	353
3	HV bus	3 phase	A	27978	10979	10979	4958
			B	27978	10979	10979	4958
			C	27978	10979	10979	4958
	HV bus	LL	A	125	49	0	0
			B	20722	8132	8119	5347
			C	20688	8118	8119	5347
	Low Ik	LL	A	4	1	0	0
			B	584	237	244	240
			C	583	237	244	240
4	HV bus	3 phase	A	27996	10979	10979	4958
			B	27996	10979	10979	4958

			C	27996	10979	10979	4958
	HV bus	LL	A	95	37	0	0
			B	20728	8129	8119	5347
			C	20702	8118	8119	5347
	Low Ik	LL	A	2	1	0	0
			B	444	181	184	182
			C	444	180	184	182
5	HV bus	3 phase	A	28007	10979	10979	4958
			B	28007	10979	10979	4958
			C	28007	10979	10979	4958
	HV bus	LL	A	76	30	0	0
			B	20731	8127	8119	5347
			C	20710	8119	8119	5347
	Low Ik	LL	A	1	1	0	0
			B	359	146	148	147
			C	358	146	148	147

C.1.2 1 motor

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3 phase	A	27668	10979	10979	4958
			B	27668	10979	10979	4958
			C	27668	10979	10979	4958
	HV bus	LL	A	1159	460	0	0
			B	20648	8194	8119	5347
			C	20581	8167	8119	5347
	Low Ik	LL	A	66	27	0	0
			B	1184	481	691	661
			C	1180	480	691	661
2	HV bus	3 phase	A	27836	10979	10979	4958
			B	27836	10979	10979	4958
			C	27836	10979	10979	4958
	HV bus	LL	A	698	275	0	0
			B	20700	8165	8119	5347
			C	20651	8145	8119	5347
	Low Ik	LL	A	24	10	0	0
			B	723	294	361	353
			C	721	293	361	353
3	HV bus	3 phase	A	27902	10979	10979	4958
			B	27902	10979	10979	4958
			C	27902	10979	10979	4958
	HV bus	LL	A	499	196	0	0
			B	20716	8152	8119	5347
			C	20679	8137	8119	5347
	Low Ik	LL	A	13	5	0	0
			B	520	211	244	240
			C	519	211	244	240
4	HV bus	3 phase	A	27937	10979	10979	4958
			B	27937	10979	10979	4958
			C	27937	10979	10979	4958

	HV bus	LL	A	388	153	0	0
			B	20724	8145	8119	5347
			C	20694	8133	8119	5347
	Low Ik	LL	A	8	3	0	0
			B	406	165	184	182
			C	406	165	184	182
5	HV bus	3 phase	A	27958	10979	10979	4958
			B	27958	10979	10979	4958
			C	27958	10979	10979	4958
	HV bus	LL	A	318	125	0	0
			B	20728	8140	8119	5347
			C	20703	8130	8119	5347
	Low Ik	LL	A	5	2	0	0
			B	334	136	148	147
			C	333	135	148	147

C.1.3 2 motors

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3 phase	A	27554	10979	10979	4958
			B	27554	10979	10979	4958
			C	27554	10979	10979	4958
	HV bus	LL	A	1636	652	0	0
			B	20626	8219	8119	5347
			C	20572	8197	8119	5347
	Low Ik	LL	A	75	31	0	0
			B	951	387	691	661
			C	948	386	691	661
2	HV bus	3 phase	A	27751	10979	10979	4958
			B	27751	10979	10979	4958
			C	27751	10979	10979	4958
	HV bus	LL	A	1074	425	0	0
			B	20687	8185	8119	5347
			C	20641	8166	8119	5347
	Low Ik	LL	A	33	13	0	0
			B	628	255	361	353
			C	627	255	361	353
3	HV bus	3 phase	A	27836	10979	10979	4958
			B	27836	10979	10979	4958
			C	27836	10979	10979	4958
	HV bus	LL	A	799	315	0	0
			B	20708	8168	8119	5347
			C	20670	8153	8119	5347
	Low Ik	LL	A	18	7	0	0
			B	469	191	244	240
			C	469	190	244	240
4	HV bus	3 phase	A	27884	10979	10979	4958
			B	27884	10979	10979	4958
			C	27884	10979	10979	4958
	HV bus	LL	A	636	250	0	0

			B	20719	8158	8119	5347
			C	20686	8145	8119	5347
	Low Ik	LL	A	12	5	0	0
			B	375	152	184	182
			C	374	152	184	182
5	HV bus	3 phase	A	27914	10979	10979	4958
			B	27914	10979	10979	4958
			C	27914	10979	10979	4958
	HV bus	LL	A	528	208	0	0
			B	20724	8151	8119	5347
			C	20697	8141	8119	5347
	Low Ik	LL	A	8	3	0	0
			B	312	127	148	147
			C	311	127	148	147

C.1.4 3 motors

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3 phase	A	27472	10979	10979	4958
			B	27472	10979	10979	4958
			C	27472	10979	10979	4958
	HV bus	LL	A	1949	779	1	0
			B	20607	8236	8119	5347
			C	20562	8218	8119	5347
	Low Ik	LL	A	75	31	0	0
			B	795	323	691	661
			C	793	322	691	661
2	HV bus	3 phase	A	27681	10979	10979	4958
			B	27681	10979	10979	4958
			C	27681	10979	10979	4958
	HV bus	LL	A	1360	539	0	0
			B	20674	8200	8119	5347
			C	20631	8183	8119	5347
	Low Ik	LL	A	37	15	0	0
			B	556	226	361	353
			C	555	225	361	353
3	HV bus	3 phase	A	27779	10979	10979	4958
			B	27779	10979	10979	4958
			C	27779	10979	10979	4958
	HV bus	LL	A	1044	413	0	0
			B	20700	8181	8119	5347
			C	20662	8166	8119	5347
	Low Ik	LL	A	22	9	0	0
			B	428	174	244	240
			C	427	173	244	240
4	HV bus	3 phase	A	27836	10979	10979	4958
			B	27836	10979	10979	4958
			C	27836	10979	10979	4958
	HV bus	LL	A	847	334	0	0
			B	20713	8170	8119	5347

			C	20679	8156	8119	5347
	Low Ik	LL	A	14	6	0	0
			B	348	141	184	182
			C	347	141	184	182
5	HV bus	3 phase	A	27873	10979	10979	4958
			B	27873	10979	10979	4958
			C	27873	10979	10979	4958
	HV bus	LL	A	712	281	0	0
			B	20720	8162	8119	5347
			C	20690	8150	8119	5347
	Low Ik	LL	A	10	4	0	0
			B	293	119	148	147
			C	292	119	148	147

C.1.5 4 motors

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3 phase	A	27410	10979	10979	4958
			B	27410	10979	10979	4958
			C	27410	10979	10979	4958
	HV bus	LL	A	2169	869	1	0
			B	20591	8248	8119	5347
			C	20553	8233	8119	5347
	Low Ik	LL	A	72	29	0	0
			B	683	278	691	661
			C	682	277	691	661
2	HV bus	3 phase	A	27622	10979	10979	4958
			B	27622	10979	10979	4958
			C	27622	10979	10979	4958
	HV bus	LL	A	1585	630	1	0
			B	20662	8213	8119	5347
			C	20622	8197	8119	5347
	Low Ik	LL	A	38	16	0	0
			B	499	203	361	353
			C	498	202	361	353
3	HV bus	3 phase	A	27729	10979	10979	4958
			B	27729	10979	10979	4958
			C	27729	10979	10979	4958
	HV bus	LL	A	1248	494	0	0
			B	20691	8193	8119	5347
			C	20654	8178	8119	5347
	Low Ik	LL	A	24	10	0	0
			B	393	160	244	240
			C	392	159	244	240
4	HV bus	3 phase	A	27793	10979	10979	4958
			B	27793	10979	10979	4958
			C	27793	10979	10979	4958
	HV bus	LL	A	1029	406	0	0
			B	20706	8180	8119	5347
			C	20672	8166	8119	5347

	Low Ik	LL	A	16	7	0	0
			B	324	132	184	182
			C	324	132	184	182
5	HV bus	3 phase	A	27836	10979	10979	4958
			B	27836	10979	10979	4958
			C	27836	10979	10979	4958
	HV bus	LL	A	875	345	0	0
			B	20715	8171	8119	5347
			C	20684	8159	8119	5347
	Low Ik	LL	A	12	5	0	0
			B	276	112	148	147
			C	276	112	148	147

C.1.6 5 motors

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3 phase	A	27361	10979	10979	4958
			B	27361	10979	10979	4958
			C	27361	10979	10979	4958
	HV bus	LL	A	233	936	2	0
			B	20578	8258	8119	5347
			C	20545	8244	8119	5347
	Low Ik	LL	A	68	28	0	0
			B	599	243	690	661
			C	598	243	690	661
2	HV bus	3 phase	A	27572	10979	10979	4958
			B	27572	10979	10979	4958
			C	27572	10979	10979	4958
	HV bus	LL	A	1766	703	1	0
			B	20651	8223	8119	5347
			C	20613	8208	8119	5347
	Low Ik	LL	A	39	16	0	0
			B	452	184	361	353
			C	451	183	361	353
3	HV bus	3 phase	A	27685	10979	10979	4958
			B	27685	10979	10979	4958
			C	27685	10979	10979	4958
	HV bus	LL	A	1420	563	1	0
			B	20683	8202	8119	5347
			C	20646	8188	8119	5347
	Low Ik	LL	A	25	10	0	0
			B	363	148	244	240
			C	363	147	244	240
4	HV bus	3 phase	A	27754	10979	10979	4958
			B	27754	10979	10979	4958
			C	27754	10979	10979	4958
	HV bus	LL	A	1187	470	0	0
			B	20700	8189	8119	5347
			C	20665	8175	8119	5347
	Low Ik	LL	A	17	7	0	0

			B	304	123	184	182
			C	303	123	184	182
5	HV bus	3 phase	A	27802	10979	10979	4958
			B	27802	10979	10979	4958
			C	27802	10979	10979	4958
	HV bus	LL	A	1020	403	0	0
			B	20710	8179	8119	5347
			C	20678	8166	8119	5347
	Low Ik	LL	A	13	5	0	0
			B	261	106	148	147
			C	261	106	148	147

C.2 Model 2

C.2.1 No-load

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3-phase	A	20510	8004	8004	5049
			B	20510	8004	8004	5049
			C	20510	8004	8004	5049
	Low Ik	LL	A	0	0	0	0
			B	2401	1071	1071	1025
			C	2401	1071	1071	1025
2	HV bus	3-phase	A	20511	8004	8004	5049
			B	20511	8004	8004	5049
			C	20511	8004	8004	5049
	Low Ik	LL	A	0	0	0	0
			B	1300	585	585	571
			C	1300	585	585	571

C.2.2 Full load

# Gen	Location	Fault type	Phase	Inst	0.5 cycle	1 cycle	Steady state
1	HV bus	3-phase	A	19923	8004	8004	5049
			B	19923	8004	8004	5049
			C	19923	8004	8004	5049
	Low Ik	LL	A	67	31	22	0
			B	886	401	871	1025
			C	885	401	870	1025
2	HV bus	3-phase	A	20105	8004	8004	5049
			B	20105	8004	8004	5049
			C	20105	8004	8004	5049
	Low Ik	LL	A	39	18	7	0
			B	675	306	520	571

	C	674	305	519	571

Appendix D

Standard REG670 setting table proposal

Based on the research done in the authors master thesis work, the following is a proposal for a standard relay setting table for protection with REG670 relay of a generator in an offshore facility. The choice of functions were argued for in chapter 7, while function parameter values were discussed in chapter 8. This proposal should only be used as a guideline as there will always be some special considerations that has to be made for each facility. Most of the parameter values in this proposal are set equal to the default REG670 function value, as it has either not been possible to find a standard value, or because no value can be found because it naturally varies with the machine design. Notice that, due to space limitations, not all function settings has been included in this table.

GENPDIF

Parameter	**Unit**	
GENPDIF Group settings (basic)		
Operation		On
IdMin	IB	0
IdUnre	IB	10
OpNegSeqDiff		Yes
IMinNegSeq	IB	0.04
GENPDIF Group settings (advanced)		
EndSection1	IB	1
EndSection2	IB	3
SlopeSection2	%	40
SlopeSection3	%	80
OpCrossBlock		Yes
NegSeqROA	deg	60
HarmDistLimit	%	10
TempIdMin	IdMin	2
AddTripDelay	s	0.1
OperDCBiasing		Off
OpenCTEnable		Off
tOCTAlarmDelay	s	1
tOCTResetDelay	s	0.25
tOCTUnrstDelay	s	10
GENPDIF Non group settings (basic)		

IBase	A	5000
InvertCT2Curr		No

OC4PTOC

Parameter	**Unit**	
OC4PTOC Group settings (basic)		
IBase	A	3000
UBase	kV	400
AngleRCA	deg	55
AngleROA	deg	80
StartPhSel		1 out of 3
DirMode1		Non-directional
Characterist1		IEC Very inv.
I1>	%IB	[100 - 110]
t1	s	0
k1		0.05
IMin1	%IB	100
t1Min	s	I2>+ 0.2
I1Mult		2
DirMode2		Non-directional
Characterist2		IEC def. time
I2>	%IB	500
t2	s	0.4
k2		0.05
IMin2	%IB	50
t2Min	s	0
I2Mult		2
DirMode3		Off
Characterist3		ANSI Def. Time
I3>	%IB	250
t3	s	0.8
k3		0.05
IMin3	%IB	33
t3Min	s	0
I3Mult		2
DirMode4		Off
Characterist4		ANSI Def. Time
I4>	%IB	175
t4	s	2
k4		0.05
IMin4	%IB	17
t4Min	s	0
I4Mult		2
OC4PTOC Group settings (advanced)		
IMinOpPhSel	%IB	7
2ndHarmStab	%IB	20
ResetTypeCrv1		Instantaneous
tReset1	s	0.02
HarmRestrain1		Off

ResetTypeCrv2		Instantaneous
tReset2	s	0.02
HarmRestrain2		Off
ResetTypeCrv3		Instantaneous
tReset3	s	0.02
HarmRestrain3		Off
OC4PTOC Non group settings (basic)		
MeasType		RMS

EF4PTOC

Parameter	Unit	
EF4PTOC Group settings (basic)		
Operation		On
IBase	A	3000
UBase	kV	400
AngleRCA	deg	65
polMethod		Voltage
UPolMin	%UB	1
IPolMin	%IB	5
RNPol	ohm	5
XNPol	ohm	40
IN>Dir	%IB	10
2ndHarmStab	%IB	20
BlkParTransf		Off
UseStartValue		IN4>
SOTF		Off
ActivationSOTF		Open
StepForSOTF		Step 2
HarmResSOTF		Off
tSOTF	s	0.2
t4U	s	1
ActUnderTime		CB position
tUnderTime	s	0.3
DirMode1		Non-directional
Characterist1		ANSI Def. Time
IN1>	%IB	100
t1	s	0
k1		0.05
IMin1	%IB	100
t1Min	s	0
IN1Mult		2
ResetTypeCrv1		Instantaneous
tReset1	s	0.02
HarmRestrain1		On

SDEPSDE

Parameter	Unit	
SDEPSDE Group settings (basic)		
Operation		On
OpMode		3I0Cosfi

DirMode		Reverse
RCADir	deg	0
RCAComp	deg	0
ROADir	deg	80
INCosPhi>	%IB	1
SN>	%SB	10
INDir>	%IB	5
tDef	s	0.1
SRef	%SB	10
kSN		0.1
OpINNonDir>		Off
INNonDir>	%IB	10
tINNonDir	s	1
TimeChar	s	IEC Norm. inv
tMin		0.04
kIN		1
OpUN>		Off
UN>	%UB	20
tUN	s	0.1
INRel>	%IB	1
UNRel>	%UB	3
SDEPSDE Group settings (advanced)		
tReset	s	0.04
tPCrv		1
tACrv		13.5
tBCrv		0
tCCrv		1
ResetTypeCrv		IEC Reset
tPRCrv>		0.5
tTRCrv		13.5
tCRCrv		1
SDEPSDE Non group settings (basic)		
IBase	A	100
UBase	kV	63.5
SBasee	kVA	6350
SDEPSDE Non group settings (advanced)		
RotResU		0 deg

GOPPDOP

Parameter	**Unit**	
GOPPDOP Group settings (basic)		
Operation		On
OpMode1		OverPower
Power1	%SB	Gas turbine: 2, Steam turbine: 1
Angle1	deg	180
TripDelay1	s	3
DropDelay1	s	0.06
OpMode2		OverPower

Power2	%SB	120
Angle2	deg	-90
TripDelay2	s	1
DropDelay2	s	0.06
GOPPDOP Group settings (advanced)		
k		0
Hysteresis1	%SB	0.5
Hysteresis2	%SB	0.5
IAmpComp5	%	0
IAmpComp30	%	0
IAmpComp100	%	0
UAmpComp5	%	0
UAmpComp30	%	0
UAmpComp100	%	0
IAngComp5	deg	0
IAngComp30	deg	0
IAngComp100	deg	0
GOPPDOP Non group settings (basic)		
IBase	A	3000
UBase	kV	400
Mode		Pos Seq

NS2PTOC

Parameter	Unit	
NS2PTOC Group settings (basic)		
Operation		On
IBase	A	3000
tAlarm	s	1
OpStep1		On
I2-1>	%IB	8
CurveType1		Definite
t1	s	10
tResetDef1	s	0
K1	s	<30
t1Min	s	5
t1Max	s	1000
ResetMultip1		1
OpStep2		Off

OV2PTOV

Parameter	Unit	
OV2PTOV Group settings (basic)		
Operation		On
UBase	kV	400
OperationStep1		On
Characterist1		Def time
OpMode1		1 out of 3
U1>	%UB	120
t1	s	5
t1Min	s	5

k1		0.05
HystAbs1	%UB	0.5
OperationStep2		Off
Characterist2		Def time
OpMode2		1 out of 3
U2>	%UB	150
t2	s	5
t2Min	s	5
k2		0.05
HystAbs2	%UB	0.5
OV2PTOV Group settings (advanced)		
tReset1		0.025
ResetTypeCrv1		Instantaneous
OV2PTOV Non group settings (basic)		
ConnType		PhPh RMS

UV2PTUV

Parameter	**Unit**	
UV2PTUV Group settings (basic)		
Operation		On
UBase	kV	400
OperationStep1		On
Characterist1		Def time
OpMode1		1 out of 3
U1<	%UB	80
t1	s	5
t1Min	s	5
k1		0.05
IntBlkSel1		Off
IntBlkStVal1	%UB	20
tBlkUV1	s	0
HystAbs1	%UB	0.5
OperationStep2		Off
UV2PTUV Group settings (advanced)		
tReset1		0.025
ResetTypeCrv1		Instantaneous
UV2PTUV Non group settings (basic)		
ConnType		PhPh RMS

CVGAPC

Parameter	**Unit**	
CVGAPC Group settings (basic)		
Operation		On
CurrentInput		MaxPh
IBase	A	1000
VoltageInput		MaxPh
UBase	kV	100

OperHarmRestr		Off
l_2nd/l_fund	%	20
EnRestrainCurr		Off
RestrCurrInput		PosSeq
RestrCurrCoeff		0
RCADir	Deg	-75
ROADir	Deg	75
LowVolt_VM	%UB	0.5
Operation_OC1		On
Starturr_OC1	%IB	120
CurveType_OC1		IEC Def time
tDef_OC1	s	0.5
k_OC1		0.3
IMin1	%IB	100
tMin_OC1	s	0.05
VCntrlMode_OC1		Off
VDepMode_OC1		Step
VDepFact_OC1		1
ULowLimit_OC1	%UB	50
UHighLimit_OC1	%UB	100
HarmRestr_OC1		Off
DirMode_OC1		Non-directional
DirPrinc_OC1		I&U
ActLowVolt1_VM		Non-directional
Operation_OC2		Off
StartCurr_OC2	%IB	
CurveType_OC2		
tDef_OC2	s	
k_OC2		
IMin2	%IB	
tMin_OC2	s	
VCntrlMode_OC2		
VDepMode_OC2		
VDepFact_OC2		
ULowLimit_OC2	%UB	
UHighLimit_OC2	%UB	
HarmRestr_OC2		
DirMode_OC2		
DirPrinc_OC2		
ActLowVolt2_VM		
Operation_UC1		Off
...		
Operation_UC2		Off
...		
Operation_OV1		Off
...		
Operation_OV2		Off
...		
Operation_UV1		Off
StartVolt_UV1	%UB	
CurveType_UV1		
tDef_UV1	s	
tMin_UV1	s	
k_UV1		
EnBlkLowV_UV1		

BlkLowVolt_UV1	%UB	
Operation_UV2		Off
StartVolt_UV2	%UB	
CurveType_UV2		
tDef_UV2	s	
tMin_UV2	s	
k_UV2		
EnBlkLowV_UV2		
BlkLowVolt_UV2	%UB	

CVGAPC Group settings (advanced)

CurrMult_OC1		2
...		
CurrMult_OC2		2
...		