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Relay Protection of DG-units in Norway

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Submission date: June 2017
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Preface

This thesis is submitted to the Department of Electric Power Engineering, at the Norwegian University of Science and Technology (NTNU), Trondheim, as the primary evaluation requirement for the course TET4910, and final partial requirement for the degree; Master of Science in Electrical Power Engineering. The subject is given as a part of the research project ProSmart at NTNU in collaboration with Sunnfjord Energi AS.

At first I would like to thank my supervisor Professor Hans Kristian Høidalen for valuable guidance and support during the thesis work. A special thanks goes to Arne Tefre at Sunnfjord Energy AS, for dedicating time to me, even with his busy schedule. His knowledge and expertise was invaluable in gaining crucial insight into the challenges facing the industry today.

I would like to express my sincere gratitude to Trond Toftevaag at the Department of Electrical Engineering for enlightening discussions and valuable insight. I would also like to thank Konstantin Pandakov, for his essential guidance with PSCAD.

At Sunnfjord Energi AS, I am very grateful for the help from Simon Fleten Mo, Gaute Roska, Einar Midtbø and Jonny Hugøy. This thesis would not be the same without their technical proficiency and support during the on-site inspection.

Finally, I would like to thank Zhou Liu for sharing his knowledge regarding the relay lab. Without his experience in conducting experiments the on-site inspection would never have gone without incident.

Trondheim, 2017-06-19

Bendik Fossen

Abstract

The relay protection monitors the electrical power system for abnormal situations. Its protection settings define whether a production unit should stay online or decouple during abnormal situations. Reviewing the current protective relay settings, used by the Norwegian industry, one sees that there is ground which suggests that the established settings are too conservative. This causes unnecessary decoupling of production units leading to financial losses. With an increasing number of production units in the distribution system, areas with a high production density could lose significant in-feed during abnormal situations. Decreasing the downtime of a production unit will not only have financial benefits, but could additionally improve the local stability of the power system.

This work investigates the current requirements for production units between 1-10 MW, the industrial use of these units, and the methodology for selecting the optimal settings. The methodology suggested concerns itself to meet the requirements of today, and builds a foundation on which to meet the requirements of the future. An actual distribution network from the collaboration company Sunnfjord Energi AS with two production units were analyzed and modeled in the transient electromagnetic program PSCAD. To collect relevant data an on-site inspection was additionally conducted by this author.

The analyzed production units indicate conservative settings on production units built previous to 2011. Conservative protection settings limit the utilization of the fault-ride-through capabilities of the production units. This in turn inhibits their use in providing local stability. Many existing production units were found to include insufficient or inadequate documentation, and in some cases lacked any all together. As of lately, there has been an increased focus on production units influence on the distribution system.

This analyze of an actual network resulted in new protection settings for one of the production units in question. The findings suggest specific improvements should be made to the current requirements to achieve a sustainable operation of production units in the distribution system.

Samandrag

Relévern overvakar det elektriske kraftsystemet for unormale situasjonar. Når unormale situasjonar oppstår, er det verninstillingane som definerer om ei produksjonseining skal koplast frå - eller fortsette å vere tilkopla nettet. Indikasjonar frå bransjen tyder på at det er etablert ein konservativ bruk av verninnstillingar, noko som medfører unødvendig fråkopling av produksjonseiningar. Ytterlegare forventa utbygging av nye produksjonseiningar i distribusjonsnettet, kan føre til at områder med høg produksjon mistar kritisk innmating ved forstyrrelsar i nettet. Ved å halde produksjonseininga tilkopla kan dei forbetre den lokale stabiliteten til kraftsystemet.

Avhandlinga undersøker noverande krav til produksjonseiningar mellom ein til ti megawatt i distribusjonsnettet, bransjepraksis for einingane og grunnlaget for nye krav som vil bli implementert i framtida. Eit reelt distribusjonsnett frå samarbeidsfirmaet Sunnfjord Energi AS med to produksjonseiningar blir analysert og modellert i programmet PSCAD. For å samle relevante data, vart det utført ei befaring av dei aktuelle anlegga, der oppsettet av relèverna vart undersøkt.

Analyserte produksjonseiningar indikerar bruk av konservative verninnstillingar for produksjonseiningar som vart bygd før 2011. Dei konservative verninnstillingane avgrensar produksjonseiningane til å utnytte sine eigenskapar til å stå imot feil og motarbeider dei i å bidra til forbetring av lokal stabilitet. Eksisterande produksjonseiningar har tilsynelatande mangel på - eller utilstrekkeleg dokumentasjon, og i nokre tilfelle eksisterar det ikkje dokumentasjon i det heile. I seinare tid har det vorte eit aukande fokus på påverknaden innflytelsen produksjonseiningar har på distribusjonsnettet.

Analysen av det reelle nettet resulterte i nye verninnstillingar for ein av dei aktuelle produksjonseiningane. Dei viktigaste funna tyder på at det burde gjerast konkrete forbetringar til dagens krav for å oppnå ei berekraftig drift av produksjonseiningane i distribusjonsnettet.

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Abbreviations and Acronyms

Term	Description
AVR	Automatic Voltage Regulator
CB	Circuit Breaker
CFP	Common Feed Point
CIGRÉ	International Council on Large Electric Systems
Clearing time	Another term for disconnection time
Conservative protection	Protection that trips the CB for a smaller disturbance than the requirement or FRT-capability suggests
CT	Current Transfomer
DG	Distributed Generation
DG-owner	The owner of the DG-unit
DG-operators	Persons performing operational tasks at the DG-unit, e.g. operate GB after trip
DG-protection	Generator protection - Referred to as the relay operating the GB
DG-unit	A unit producing energy in the distribution network
Disconnection time	Time from a fault occurs until it is isolated from the circuit
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators of Electricity
Fault correction	Change in network topology after outages
GB	Generator circuit Breaker, CB operated by the DG-protection
Grid Protection	Relays protecting the grid, could be in DG-units or in the grid. Utility companies control and operate.
HV	High Voltage
kV	kilo Volt

kW	kilo Watt
LV	Low Voltage
MV	Medium Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere reactive
MW	Mega Watt
NIS	Network Information System
NVE	The Norwegian Water Resources and Energy Directorate
OC	Over-Current
FRT	Fault Ride Through
PF	Power Factor
pu	per unit
REN	Rasjonell Elektrisk Nettvirksomhet
RfG	Requirements for Grid Connection of Generators (Network Code)
RoCoF	Rate of Change of Frequency
SEAS	Sunnfjord Energi AS
SHP	Small-Hydropower Plant (1-10 MW)
TSO	Transmission System Operator
Trigger time	Time from incident occurs to trip signal is sent to CB
VT	Voltage Transformer

Chapter 1

Introduction

Traditionally a distribution networks main task is to deliver energy from the High Voltage (HV) transmission network to Low Voltage (LV) customers, e.g. households. Distribution networks consist of mixture of cables and overhead lines with nominal voltage from 1 kV to 24 kV. Cables are usually used in urban environments, while overhead lines are common on longer feeders in rural networks [13]. In general, electric power is produced by large power plants connected to the transmission network [39].

1.1 Background

The main purpose of a protection system in an electrical network is to protect personnel and equipment, prevent stresses to the machinery, and maintain a stable and reliable power system. This is accomplished by detecting abnormal situations and activating a trip signal to open the Circuit Breaker (CB) attached to the infected part of the system, isolating the fault [10, 25].

A number of Distributed Generation (DG) units in the distribution network have emerged the last decade. The term DG refers to units producing energy in the distribution system. Usually, the energy source is from renewables, such as wind-, solar or hydro power, but it also covers other energy sources, e.g. biomass or fossil fuel. They could be directly connected to the distributed network or through a converter. DG-units with ratings from 1-10 MW generally connect to the MV distribution level [18], while those below mainly connect to the LV distribution level [39].

When looking at the Norwegian market it is important to cover what is referred to as "small hydro power plants", due to their prevalence in the market. "Small hydro power plants" is a term commonly used to describe all hydro power plants with a rating below 10 MW. These are divided into three subcategories:

- Micro hydropower plants (< 0.1 MW)
- Mini hydropower plants (0.1 - 1 MW)
- Small-hydropower plants (1-10 MW)

According to [50], only Small-Hydropower Plants (SHP) (1-10MW) will have a significant effect on the power system. Therefore these will be the main foucs and referred to as SHP throughout this thesis.

575 SHPs are producing approximate 8.3 TWh per year in Norway (6.3 % of total production) [1, 27]. Fig. 1.1 illustrates the distribution of SHPs in Norway. The distribution shows that the previous lucrative tax policies for plants of 5.5 MVA or lower, have had a large impact on the development of SHPs. As of 2015, new regulations are in place which increase the upper bound to 10 MVA. If no behavioral changes are assumed to take place, it would imply that an increase of larger plants is to be expected. [27, 63].

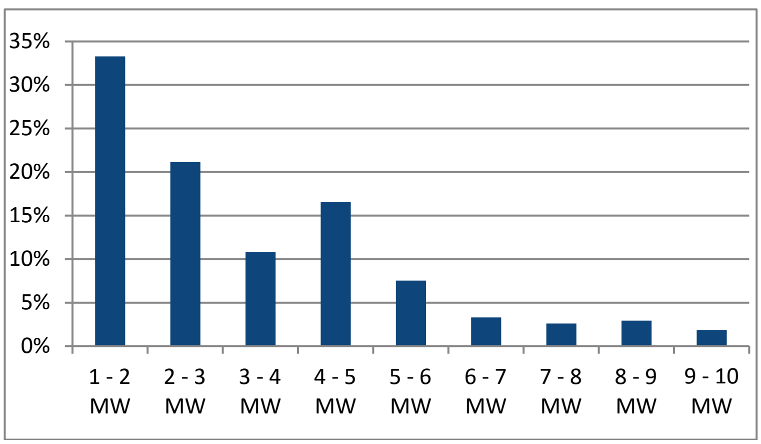


Figure 1.1: Distribution of SHPs in Norway [27]

At the time of writing, 492 SHP license application is currently under consideration at the Norwegian licensing authority[1]. While some have already been rejected it follows that the current activity on this subject is high [44]. These applications, together with a political[2] mandate to increase Norway's reliance on renewables and lowering the cost of green energy technologies indicates a bright future for further developments of DG-units in Norway.

[1]NVE. https://www.nve.no/english/

[2]Such as electricity certificates, https://www.regjeringen.no/en/topics/energy/renewable-energy/electricity-certificates/id517462/

The elevated water sources, which form the foundation for building SHP, are often found in rural areas with a weak network connection. However, areas with these water sources can often display a high SHP density. Therefore it is common to have several DG-units (SHPs) connected to a substation, either all on one feeder or divided between various feeders [39, 67].

SHP-owners are often landowners or companies who bought the land rights. The Distribution System Operators (DSO) have no ownership or direct economic interest in the SHP-units. SHP are often unregulated run-of-river power station which is dependent on rainfall[3] for energy production [45]. Since their income is reliant on the weather conditions, it is crucial for their financial stability to deliver[4] energy whenever the conditions present themselves. To show a profit, they often try to minimize the investment cost, e.g. interconnection to the network, generators, transformers, buildings, etc. A DG-unit could contribute to the DSO challenges, i.e. keep stable during faults and produce or consume reactive power to improve voltage quality. This ability would increase the investment cost of the plant, but not active power production and is therefore not contributing to the SHP-owner's income and profit. However, it is in their interest to minimize their downtime.

DG-units introduce new challenges for the DSO. Traditionally distribution networks are designed for one-way power flow and are protected by over-current (OC) relays that trips the CB at the feeder for any fault downstream. OC protection is not considered as sufficient protection with DG-units connected to the system.

To cope with the challenges of DG-units in Norway, specific terms and guidelines for new DG-units were developed. A research project in 2006 at SINTEF Energy published a report, [50], with new recommendations. Their intention was to establish a common ground to ensure DG-owners equal and fair terms, formed by an independent and reputable organization. Today, REN 0303 ([2]) and REN3008 ([3]) seems to be the common industry practice. These are mainly based on the recommendations in [50] and best practice from 30 years' experience at Jacobsen Elektro, a relay protection company [9].

Today, there is no direct economic disincentive[5] for the DSO to decouple DG-units during

[3]Depending on the catchment area; this could also be due to snow melting, high density of boggy land or other natural factors that influence the current-carrying of the river.

[4]SHPs income are based on how much energy they can deliver to the network/market.

[5]There is an economic disincentive for power loss in MV and HV power systems today, and there are indications for LV disincentive in the future. The term used for the disincentives in Norway is KILE [62]

faults, this has led to a secure practice for DG-units being decoupled as fast as possible during faults to prevent instability in the connected grid or two out-of-phase systems connecting when performing fault correction. Unnecessary decoupling could be due to incorrect protection settings or misguided use of under-voltage protection with too strict settings.

A DG-unit's capability to handle faults without contributing to instability or pulling out of synchronism is referred to as Fault-Ride-Through (FRT) capability. The protection settings should be the limiting factor for the DG-units FRT-capability, meaning that the protection settings should disconnect the DG-unit before it exceeds its FRT-capability and causes instability for the power system. Therefore, the FRT-capability is an essential part of protection schemes.

Problem Formulation

With a further expected growth of DG-units in the distribution systems, areas with high DG penetration could lose significant DG in-feed during faults. By keeping the DG-units online, they could contribute with voltage and energy, improving the local stability and reliability of the power system. Opposite, if the DG-unit is unnecessary decoupled during a voltage drop in the power system; it could lead to capacity constraints for the remaining transmission lines, which could cause disconnection of larger areas.

Experience from industry in Norway suggests that current FRT- and protection-requirements[6] should be re-evaluated [27]. ENTSO-E has formulated a future regulation for all production units with FRT-capability requirements.

A survey concerning operational problems after implementation of DG amongst 14 DSOs was performed in 2011 [42]. Fig. 1.2 displays the result of the survey; 8 out of 14 DSOs experienced problems related to protection and control equipment.

[6] [2, 3, 50]

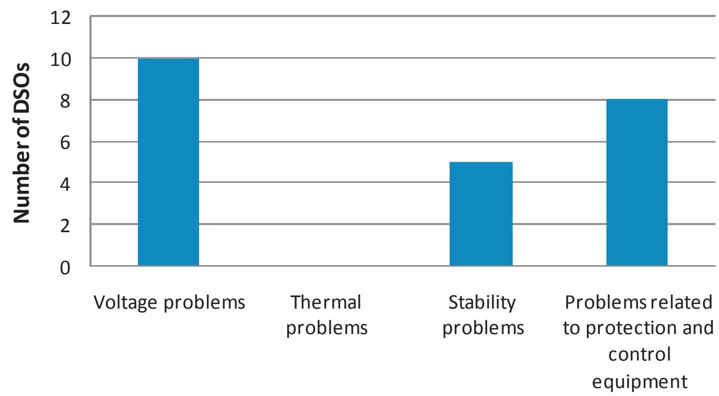


Figure 1.2: Operational problems experienced by DSOs in Norway after DG implementation [42]

This work examines the current requirements for protection of DG-units, how they are used by the industry today and current problems. A case study of two DG-units in SEAS network has been performed. This case study has resulted in new protection settings, for both grid and generator protection based on a dynamic analysis which ensures a sustainable operation.

1.2 Objectives

The primary focus of this work is to examine the protection in DG-units in Norway.

1. Analyze current requirements for DG-units in Norway.
2. Investigate current industrial practice for protection in DG-units and identify challenges.
3. Examine future requirements.
4. Simulate a distribution network with DG to study FRT-capability and under-voltage protection settings.
5. Perform an on-site inspection to collect relevant data and get first hand experience with relay protection

1.3 Limitations

Related topics are not covered in this thesis. This is due to to them not fitting under the scope of this work. They are:

- Earth-fault protection.
- The new trend of protection relays communication.
- Influence the DG-units have on voltage quality.
- Dynamic analysis outside the mentioned properties in current requirement ([50]).
- CB operation is assumed 0.1 s, this could deviate from actual and should be considered for each CB.
- All relays functions are considered ideal. Accuracies and tolerance limits are not considered for relay or transducers. e.g., trip time of 0.1 s, is assumed to execute trip signal at exactly 0.1 s.
- Out-of-step protection or other protection functions that could influence the FRT-capability.
- Protection of DG-units connected through converters is not covered in this report.
- Protection in PLS and voltage regulator is not considered. These could cause trip of CB if not coordinated with DG-protection.
- Detailed explanation of different protection functionalities.
- Reginal- and transmission protection.
- Alarm and warning functions in the relay protection.
- The rate of disturbances in the distribution system.
- Economic evaluation of proposed measures.

Also, there are various requirements in [50], but they do not pose any considerable influence on the protection setting of the DG-unit and are therefore not considered a part of this thesis scope.

Chapter 2

DG-protection

This chapter presents the current requirements for DG-units, industrial practice for DG-unit protection and the foundation for future requirements.

DG-protection or generator protection is referred to as the relay protection monitoring the LV values and operate the Generator circuit Breaker (GB) closest to the generator. Usually the utility company has their own relay protection, referred to as grid protection in the DG-unit. The grid protection monitors the HV values and operates the CB closest to the connection point. Fig. 2.1 illustrates a conventional setup for DG-units with the grid protection closest to the connection point, and with the DG-protection closest to the generator, operating their respectively CBs.

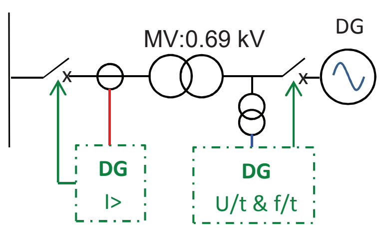


Figure 2.1: Simplified single line diagram with Grid- and DG- protection in a DG-unit [9]

In addition to the presented requirements, there are other requirements affecting the FRT-capabilities for DG-units in [28]. These are not specified protection settings and are therefore not presented. However, they are considered and mentioned when modeling the generators in Chapter 4.

In relay protection the characteristic time is generally given as the trigger[1] time, and for FRT-capability, disconnection or clearing time is often used. Disconnection time is defined as the trigger time plus the time to open the CB and interrupt the circuit. This includes

[1] Time from the event occurs in the power system to the trip signal is sent to the CB

measurement time, reaction time for protection and CB, and CB operation time. All times are explicitly specified for each instance used.

In general, CB reaction- and operation time is assumed to be 100 ms, which will be used throughout this thesis. If the time is given in trigger time, 100 ms is added to obtain disconnection time.

The FRT-requirement for a DG-unit is significantly influenced by the clearing time of the grid protection (see Chapter 3) in the network. Long clearing time in the network demands the DG-unit to operate during voltage drop for an extended time and could lead to unrealistic FRT-requirements.

2.1 Current Requirements for DG-protection

2.1.1 Utility Requirements for DG-protection

The current requirements presented in this section are not legal obligations from the authorities. Instead, they are considered as sustainable guidelines for the utility company in the interconnection process of a DG-unit since they are responsible for how the DC-unit impacts the power system. However, the utility companies can impose the DG-units to fulfill the requirements, i.e. each utility company choses whether to enforce the current requirements on DG-units or not. This thesis assumes the utility companies implement the guidelines and it is therefore referred to as a requirement throughout this thesis.

For the requirements to apply the DG-unit, it must be classified as transient stable. Transient stable is defined as the DG-unit's capability to maintain synchronism when exposed to a large disturbance, e.g. a three-phase short-circuit [50]. [50] recommends that the following DG-units are required to be classified as transient stable:

- Active power production above 0.5 MW
- Active power production above 0.25 MW if decoupling leads to voltage deviation more than 4 % from nominal voltage

The degree of influence the DG-unit has on the network must be considered. On feeders with many DG-units or connection to a weak network, the utility company can demand transient stable DG-units regardless of the 0.5 MW limit. The utility company can also make exceptions for the 0.5 MW limit. [50] specifies that there must be performed a dynamic stability analysis for all DG-units classified as transient stable. DG-units not classified as transient stable must be disconnected within 0.2 seconds for all voltages less than 85 % of nominal voltage [3].

A transient stable DG-unit should handle a three-phase fault at an adjacent feeder, as illustrated in figure 2.2 [50]. This would generally lead to a voltage drop below 40 % and experience from the industry suggest that the requirement should be re-evaluated [27, 59]. A voltage drop below 40 % could also conflict with the under-voltage protection setting (U≪) in Table 2.1, depending on the clearing time of the fault.

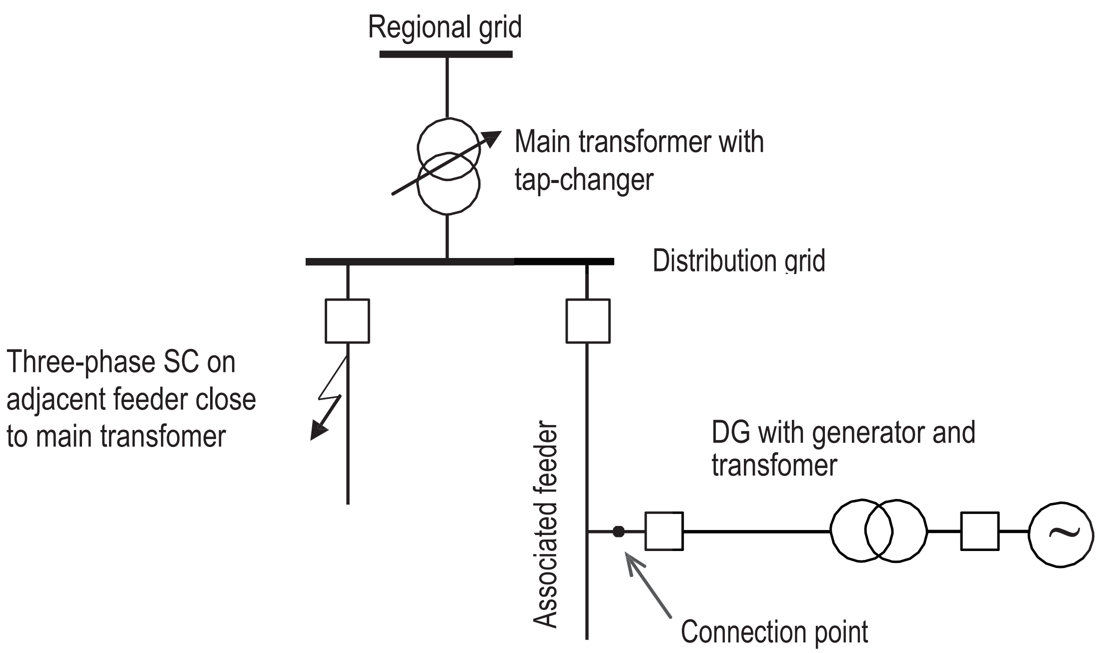


Figure 2.2: Three-phase short-circuit on adjacent feeder [50]

The current protection requirements for DG-units is based on the report [50] from SINTEF Energy in 2006. In co-operation with Jacobsen Elektro[2], REN[3] has reproduced [50] as practical guidelines in [2] and [3] for the utility companies to use in the connection process of new DG-units. Table 2.1 presents the main DG-protection settings given in [50][4]. For more details and

[2]Company with 30 years' experience in relay protection. http://www.jel.no/en/home/
[3]REN is a standardization organization for 67 utility companies in Norway. http://www.ren.no (Norwegian)
[4][2] and [3] contains the requirements from [50], however this report will refer to [50], since this is the origin for the requirements.

explanations regarding DG-protection please see Appendix A.

Table 2.1: Present voltage- and frequency protection settings for DG-units [50]

Parameter	**Value**	**Max. disconnection time***
U≫	1.15 pu	0.2 s
U>	1.10 pu	1.5 s
U<	0.85 pu	1.5 s
U≪	0.5** pu	0.2 s
f>	51.0 Hz	0.2 s
f<	48.0 Hz	0.2 s

* - Includes breaker operation time
** - [3] and [50] states the voltage limit is set by the utility company, however [2] recommend 0.5 pu, and [50] states that 0.5 pu is common practice and discuss selectivity problems with this setting.

The otherwise not specified U≪ value is assumed 0.5 pu throughout this thesis.

In addition, [50] requires that the DG-unit must disconnect within one second after island operation[5]. If over-/under-voltage protection and over-/under-frequency protection are not sufficient to fulfill the requirement, vector shift[6] or Rate of Change of Frequency (RoCoF) protection[7] can be installed [3]. Vector shift- and RoCoF- protection are very sensitive to faults and could cause unintentional disconnection. Thus they are not recommended on transient stable DG-units [3]. This author has not found any specific requirements for anti-island protection functionality. This may indicate that the DG-units are responsible for fulfilling the disconnection demand for one second, but stands freely to choose which anti-island protection functionality to use.

There are other various requirements in [50], but they do not pose any considerable influence on the protection settings for the DG-unit and are therefore not considered further.

[5]Island operation occurs when a DG-unit stays online after the feeder has decoupled it from the main power system [39]

[6]Please see appendix A.2.2 for more details

[7]Please see appendix A.2.3 for more information

2.1.2 Internal Standard Specification for Statkraft

Statkraft[8] has developed an internal standard specification for electrical protection functions of small hydro power plants. These are presented in Table 2.2. The purpose of several of the protection functions listed are to protect against or prevent internal faults. [50] states that the DG-unit should automatic disconnect during internal faults, but contains no specific protection requirements. Details regarding the protection functions can be found in [5].

Table 2.2: Statkrafts internal standard specification for small hydro power plants [25]

Electrical Protective Functions	**Micro <0.1 MW**	**Mini 0.1 - 1 MW**	**Small 1-10 MW**
Differential protection, unit		o	o
Earth fault protection, generator voltage level	o	o	o
Earth fault protection, transformer low voltage	v	v	v
Earth fault protection, grid voltage level	o	o	o
Earth fault protection, rotor			vs
Over-current	o	o	
Over-current/under-voltage protection			o
Over-voltage protection	o	o	o
Under-voltage protection	o	o	o
Over-frequency protection	o	o	o
Under-frequency protection	o	o	o
Loss of grid (ROCOF or Vector Shift)	v	v	v
Reverse power protection	v	v	v
Overload protection	o	o	o
Under-excitation protection			s
Asymmetry protection			o

o - Required function
s - Required function for synchronous generators
v - Function must be considered
vs - Function must be considered for synchronous generators

[8]Norway's largest power production company. https://www.statkraft.com/about-statkraft/

2.2 Industry Practice for DG-protection

The requirements in Ch. 2.1.1 are the guidelines for the utility companies in the interconnection process of a DG-unit.

Whether a DG-unit should be classified as transient stable or not is currently determined by the utility companies based on dynamic simulations for each individually case [27].

To determine if the current requirements are enforced by the utility companies and fulfilled by the DG-units, available protection documentation was analyzed and an on-site inspection to investigate two DG-units was performed. Only the requirements in Table 2.1 are considered. All the investigated DG-units have other protection functions for protecting the generators, these are not the main focus of this thesis, and therefore not considered.

2.2.1 DG-Protection Settings from SINTEF Report

[27] tested three actual transient stable SHPs FRT-capability, and the report presents their protection settings. Protection settings from [27] are shown in this section. Bruvollelva, Ullestad and Tverråna have a rating of 4.335 MVA, 5.5 MVA and 3.5 MVA, respectively. Further details regarding the generators can be found in Appendix F.

[27] experienced several deviations and defects between documented and real protection settings. Ullestad and Tverråna have installed a Siemens 7UM6215 relay protection. Table 2.3 presents the real protection settings from [27], compared with current requirements in Table 2.1. Ullestad and Tverråna are two separate DG-units, but have the same DG-protection settings. Conservative settings are highlighted with gold.

Bruvollelva is built in 2010, while Ullestad and Tverråna are built in 2016. Ullestad and Tverråna fulfill all the requirements, except a small deviation in its over-voltage setting. Bruvollelva has a conservative under-voltage setting. This could be due to the utility company's demand for selectivity or misguided use to secure safe operation from either the supplier or the utility company. Considering its construction date, it suggest that the current requirements have as of lately been incorporated to the industry.

Table 2.3: Generator protection settings from [27]

	Requirement [50]		Bruvollelva		Ullestad/Tverråna	
Parameter	**Value**	**Time[s]***	**Value**	**Time[s]***	**Value**	**Time[s]***
f>	51.0 Hz	0.2	51.0 Hz	0.2	51.0 Hz	0.2
f<	48.0 Hz	0.2	48.0 Hz	0.2	48.0 Hz	0.2
U>	1.10 pu	1.5	1.07 pu	1.5	1.06 pu	1.5
U≫	1.15 pu	0.2	1.15 pu	0.2	1.15 pu	0.2
U<	0.85 pu	1.5	0.90 pu	1.5	0.85 pu	1.5
U≪	0.5** pu	0.2	0.80 pu	0.2	0.50 pu	0.2

* - Disconnection time
** - Assumed 0.5 pu

Other DG-protection related from [27]:

- To complete SC-test, vector shift protection was deactivated.
- Other protection functions in the DG-unit needs to be considered in the context of FRT-capability, e.g. voltage regulator- and PLS-protection. These must be set selective with the generator protection, such that no unintentional decoupling is caused by other protection during or after a fault.
- A voltage overshoot can occur after a fault has been cleared due to the voltage regulator increases the excitation during the disturbance. If the overshoot exceeds the over-voltage settings, the CB is tripped.

2.2.2 Documented DG-Protection Settings from SEAS

SEAS provided DG-protection documentation for two DG-units (SHPs) which should be classified as transient stable, considering their rating. These are divided into two different rating categories due to confidentiality. 1-3 MVA and 3-6 MVA are built in, respectively, 2008 and 2010. Both DG-units have installed DEIF Multiline GPU relay protection. Protection settings for 1-3 MVA and 3-6 MVA are presented in Table 2.4 and compared with the current requirements from Table 2.1. The settings which are not in compliance with requirements are marked. Gold is conservative values, and red is exceeding required values.

Table 2.4: Documented SEAS protection settings from DG-units [57]

	Requirement [50]		1-3 MVA		3-6 MVA	
Parameter	**Value**	**Time*[s]**	**Value**	**Time*[s]**	**Value**	**Time*[s]**
f>	51.0 Hz	0.2	51.0 Hz	0.3	51.0 Hz	0.3
f<	48.0 Hz	0.2	49.0 Hz	0.3	49.0 Hz	0.3
U>	1.10 pu	1.5	1.07 pu	0.6	1.08 pu	1.5
U≫	1.15 pu	0.2	1.20 pu	0.3	1.15 pu	0.2
U<	0.85 pu	1.5	0.93 pu	0.6	0.92 pu	1.5
U≪	0.50** pu	0.2	0.80 pu	0.3	0.80 pu	0.2

* - Disconnection time
** - Assumed 0.5 pu

The protection settings are overall conservative for 1-3 MVA. The exceeding disconnection time could be explained with the conservative values, i.e. since the value is conservative a longer disconnection time could be allowed. No dynamic analysis was found for 1-3 MVA.

3-6 MVA has a conservative under-voltage and under-frequency value. The documentation for 3-6 MVA states the settings are set with base in the current requirements; however no requirements from the utility company was received, indicating that no dynamic analysis was performed.

Both DG-units have activated vector shift protection.

2.2.3 DG-Protection Settings DG1

DG1 is a DG-unit in SEAS network. After consulting with the utility company, DG1 is reviewed as not transient stable[9]. The protection settings are no less interesting considering the rating of 1.645 MVA.

An on-site inspection was performed to obtain the protection settings. The relay protection used is a DEIF multi-line GPU Hydro. Table 2.5 presents the settings for the generator relay protection in DG1 and current requirements from Table 2.1. Parameters noted BB are busbar measurements, parameter code is the internal relay code for the setting [16], the number in

[9] See Chapter 2.1.1 for details about the classification of transient stable DG-units

brackets is used to separate parameters with the same function (e.g. over-voltage), but with different values and time delays.

Settings that are not in compliance with current requirements that adhere transient stable DG-units are marked. Gold is conservative values, and red is exceeding values.

Table 2.5: Generator protection settings for DG1 and requirements [22]

	Requirement [50]		**DG1**		
Parameter	**Value**	**Time*[s]**	**Parameter Code**	**Value**	**Time*[s]**
U<(2)	0.85 pu	1.5	1180	0.90 pu	1.1
U<(3)			1190	0.70 pu	0.2
BB U<(3)	0.5** pu	0.2	1320	0.90 pu	0.1
BB U>(2)	1.10 pu	1.5	1280	1.08 pu	1.1
BB U>(3)	1.15 pu	0.2	1290	1.10 pu	0.1
BB f<(2)			1390	49.0 Hz	1.1
BB f<(3)	48.0 Hz	0.2	1400	48.0 Hz	1.1
BB f>(2)			1360	51.0 Hz	1.1
BB f>(3)	51.0 Hz	0.2	1370	52.0 Hz	0.2

* - Disconnection time
** - Assumed 0.5 pu

From Table 2.5 it can be seen that DG1 does not fulfill the current requirements, which are natural since DG1 is not transient stable. The requirement for not transient stable DG-units is to disconnect within 0.2 s when the voltage drops below 85 %. DG1 has a conservative under-voltage setting disconnecting instantly for voltages below 90 %, although DG1 is well above 0.5 MW. Still, frequency deviation is tolerated beyond current requirements. This is at the expense of the utility company and could cause island operation and violations of voltage quality regulations. DG1 has activated vector shift protection; this could prevent island operation.

Images of the BB U<(3) setting is provided in Appendix E

A dynamic analysis will be performed in Chapter 5, to investigate the FRT-capability of DG1. New protection settings will be suggested based on the dynamic analysis.

2.2.4 DG-Protection Settings DG2

DG2 is a DG-unit in SEAS network. An on-site inspection was performed to obtain the protection settings. In DG2 an ABB REG670 generator relay protection is installed. Table 2.6 displays the DG-protection settings for DG2 and current requirements from Table 2.1. Other protection functions were not obtained. The voltage protection operates if one of the three phases is exceeding the limit value within the given time interval.

Settings not in compliance with current requirements are highlighted. Gold is conservative values, and red is exceeding values.

Table 2.6: DG-protection settings for DG2 [22]

	Requirement [50]		**DG2**	
Parameter	**Value**	**Time delay***	**Value**	**Time delay***
f≫	51.0 Hz	0.2 s	51.0 Hz	0.3 s
f≪	48.0 Hz	0.2 s	48.0 Hz	0.3 s
U>	1.10 pu	1.5 s	1.08 pu	5.6 s
U≫	1.15 pu	0.2 s	1.17 pu	0.3 s
U<	0.85 pu	1.5 s	0.85 pu	1.6 s
U≪	0.5** pu	0.2 s	0.50 pu	0.3 s

* - Disconnection time
** - Assumed 0.5 pu

From Table 2.6 it can be seen that the settings are generally following the current requirements, except for time delays which exceeds with 0.1 s. Slightly conservative for the U> value, this could be the reason for why the time delay is set 4.1 s higher than required. No dynamic analysis was found for DG2.

DG2 also has a RoCoF protection activated.

2.2.5 Summary Industry Practice

Six DG-units in different ranges were analyzed. While this only covers a small sample set it might indicate a larger effect, but this can not be said for certain. SEASs documented values were not verified by control of real protection settings; this may deviate such as the documentation in [27]. Table 2.7 summarizes the DG-protection analyzed.

Table 2.7: DG-protection settings summary for industry practice

	Requirement [50]		**DG2 [22]**		**1-3 MVA [57]**		**3-6 MVA [57]**		**Bruvollelva [27]**		**Ullestad/Tverråna [27]**	
Parameter	**Value**	**Time***	**Value**	**Time***	**Value**	**Time***	**Value**	**Time***	**Value**	**Time***	**Value**	**Time***
f≫	51 Hz	0.2 s	51 Hz	0.3 s	51 Hz	0.3 s	51 Hz	0.3 s	51 Hz	0.2 s	51 Hz	0.2 s
f≪	48 Hz	0.2 s	48 Hz	0.3 s	49 Hz	0.3 s	49 Hz	0.3 s	48 Hz	0.2 s	48 Hz	0.2 s
U>	1.10 pu	1.5 s	1.08 pu	5.6 s	1.07 pu	0.6 s	1.08 pu	1.5 s	1.07 pu	1.5 s	1.06 pu	1.5 s
U≫	1.15 pu	0.2 s	1.17 pu	0.3 s	1.20 pu	0.3 s	1.15 pu	0.2 s	1.15 pu	0.2 s	1.15 pu	0.2 s
U<	0.85 pu	1.5 s	0.85 pu	1.6 s	0.93 pu	0.6 s	0.92 pu	1.5 s	0.90 pu	1.5 s	0.85 pu	1.5 s
U≪	0.5** pu	0.2 s	0.50 pu	0.3 s	0.80 pu	0.3 s	0.80 pu	0.2 s	0.80 pu	0.2 s	0.50 pu	0.2 s

* - Disconnection time

** - Assumed 0.5 pu

Table 2.8 presents the year of construction, dynamic analysis, conservative under-voltage setting and if vector shift- or RoCoF protection is activated for the DG-units.

Table 2.8: DG-units year of construction, dynamic analysis and conservative under-voltage

DG-unit	**Year**	**Dynamic analysis**	**Conservative U≪**	**Vector shift/RoCoF**
1-3 MVA	2008		X	X
3-6 MVA	2010		X	X
Bruvollelva	2010	(X)	X	X
DG2	2011			X
Ullestad/Tverråna	2016	(X)		X

From Table 2.8 it could be observed: DG-units built previous to 2011 seem to have conservative settings. The under-voltage requirement can be fulfilled without foundation in a dynamic analysis. Vector shift- or RoCoF protection is a common anti-island protection used.

- For DG2 neither utility company or DG-owner knew of any dynamic analysis performed in the planing process. Still, DG2 fulfills the current requirement for protection settings. It is uncertain whether the supplier[10] has performed dynamic analysis or not.

[10]An attempt to contact the supplier was performed without any response

- [50] states that dynamic analysis should be conducted for all transient stable DG-units and [27] states that this is common industry practice today.
- It is assumed that a dynamic analysis was performed for Bruvollelva and Ullestad/Tverråna since [27] states it is a common industry practice.
- Despite vector shift and RoCoF protection are not recommended, and [27] deactivated them to execute FRT tests; all DG-units had enabled one of the functions.

[27] detected several deviations and defects between documented and real protection settings[11]. This could indicate that defected documentation is a common challenge for the utility companies[12].

2.3 Future Requirements

ENTSO-E[13] has established new requirements for generators. These are given in the network code[14] Requirements for Grid Connection of Generators (RfG) ([21]). [21] contains technical functional requirements regarding frequency stability, voltage stability, roughness, recovery of the power system and general system design.

[21] will be implemented in Norway after it is included into the EØS-agreement. On a mission from NVE, Statnett[15] together with the industry is developing a suggestion for a method to implement [21] in Norway. The result from Statnett should be submitted after the summer of 2017, and the final requirement from NVE are scheduled to be brought into effect after the second quarter of 2019 [43]. However, a suggestion is given in [65] and will be presented in Chapter 2.3.3.

[21] contains regulations that authorize the utility companies to require test and simulation results to prove compliance with requirements.

[11] Also, other documentation was defective or deviated from real values, such as regulator settings

[12] Lyse Elnett and NTE was the utility companies in the area for the DG-units

[13] The European Network of Transmission System Operators, consist of 43 electricity transmission system operators from 36 countries. https://www.entsoe.eu/about-entso-e/Pages/default.aspx (Accessed on 29/05/2017)

[14] There are developed eight different network codes for various aspects of the future energy system. https://www.entsoe.eu/major-projects/network-code-development/Pages/default.aspx

[15] Statnett is the transmission system operator in Norway. http://statnett.no/en/About-Statnett/

2.3.1 Classification of Generators

Table 2.9 presents the classification of production units in [21] for the Nordic synchronous area[16]. The requirements will adhere to all production units, DG-units included. Threshold rated power is the smallest rated power from which a production unit belongs to a specified class. In Norway, the most common classes for DG-units will be A (0.8 kW - 1.5 MW) and B (1.5 MW - 10 MW). The requirements[17] for type A, will not be discussed in this thesis.

Table 2.9: Classification of production units in RfG [27].

Type production unit	Voltage level in interconnection	Threshold rated power
A	<110 kV	0.8 kW
B	<110 kV	1.5 MW
C	<110 kV	10 MW
D	<110 kV	30 MW
	>110 kV	All

2.3.2 FRT Requirement

Fig. 2.3 displays the voltage-against-time profile (not protection settings) at the interconnection point for synchronous generators[18] classified as type B (1.5-10 MW). The area above the curve represents the voltage a synchronous generator must operate in without losing synchronism, during and post fault. There are no requirements for the area under the curve. U_{ret} is the retained voltage at the interconnection point during a symmetrical fault, t_{clear} is the instant when the fault has been cleared. U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} specify certain point of lower limits of voltage recovery after fault clearance [21]. Table 2.10 presents the parameters in Fig.2.3.

[16]Synchronous area means an area covered by synchronously interconnected TSOs [21]
[17]Can be found in [21]
[18]Most of the SHPs above 1.5 MW is synchronous generators [7]

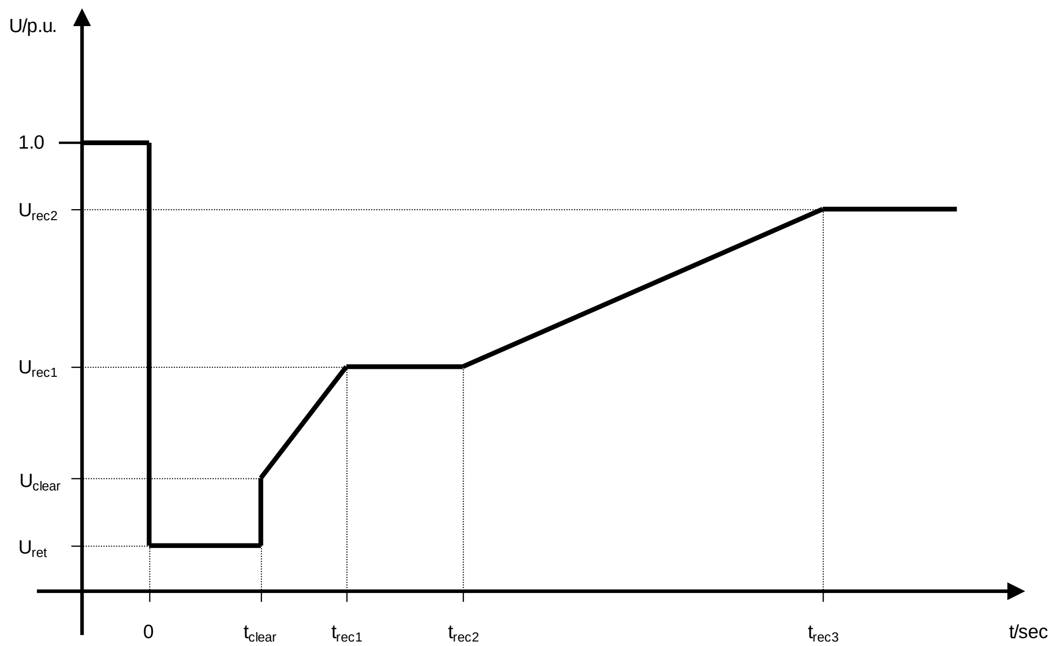


Figure 2.3: FRT-capability for power generating modules of type B in RfG [21].

Table 2.10: Parameters for Fig. 2.3 for FRT-capability for synchronous generators type B [21].

Voltage parameters [pu]		**Time parameters/Disconnection time[s]**
U_{ret}:	0.05 – 0.3	t_{clear}: 0.14 – 0.15 (or 0.14 - 0.25 if system protection and secure operation so requires)
U_{clear}:	0.7 – 0.9	t_{rec1}: t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}*: t_{rec1} – 0.7
U_{rec2}:	0.85 – 0.9 and $\geq U_{clear}$	t_{rec3}**: t_{rec2} – 1.5

* - Time can be defined between t_{rec1} and 0.7 s
** - Time can be defined between t_{rec2} and 1.5 s

From Table 2.10 it can be seen that there is no definite value for the parameters given in [21].

The future requirements are only given as FRT-capability and do not contain specified protection settings, such as the current requirement. Protection setting requirements are assumed to be announced in the final result from Statnett.

2.3.3 FRT Requirement Suggestion from Statnett

The specific values for the parameters in Table 2.10 should be set by the relevant Transmission System Operator (TSO) [21]. Statnett, together with the industry is deciding the specific values for the parameters and corresponding protection settings in Norway. Statnett has presented a suggestion for FRT requirement in [65], and the final result should be presented after the summer of 2017 [43].

Fig. 2.4 illustrates the minimum and maximum requirement from [21] and the suggested FRT requirement for type B generators in Norway. The dashed curves represent the minimum and maximum FRT requirement from [21] and the red solid curve represents the proposed FRT requirement from Statnett. The area between the dashed curves represent the range of the parameter values from Table 2.10. Table 2.11 presents the suggested parameters in Fig. 2.4.

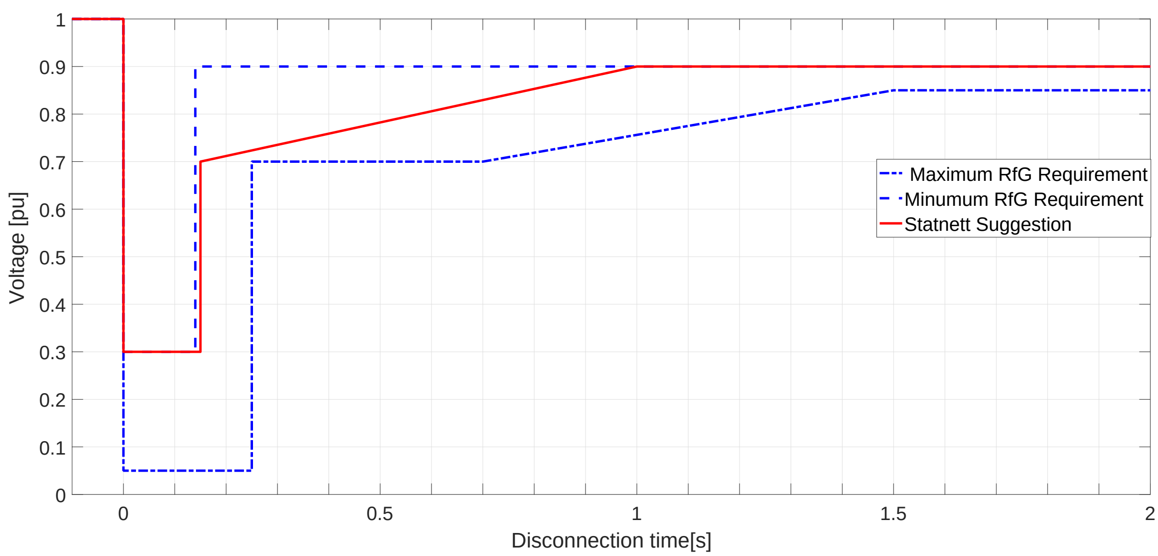


Figure 2.4: Suggested FRT requirement for production unit type B in Norway [65]

Table 2.11: Parameters to FRT requirement suggestion in Fig. 2.4 [65]

Voltage		**Time***	
U_{ret}	0.3 pu	t_{clear}	0.15 s
U_{clear}	0.3 pu	t_{rec1}	0.15 s
U_{rec1}	0.7 pu	t_{rec2}	0.15 s
U_{rec2}	0.9 pu	t_{rec3}	1.00 s

* - Disconnection time

The explanation for choosing the suggested parameters in Table 2.11 [65]:

- The retain voltage (U_{ret}) will not drop close to 0.0 pu for faults in the transmission grid. Thus the minimum required retain voltage of 0.3 pu is suggested.
- Faults in the transmission grid are cleared within 0.1 s. Clearing time (t_{clear}) is therefore set to 0.15 s.
- The recovery time (t_{rec2} - t_{rec3}) is set in agreement with current 132 kV requirement.

2.3.4 Frequency Requirements

Table 2.12 displays some of the RfG frequency requirements for generators classified as Type B (and A). Various other requirements affect the frequency, e.g. frequency droop. These are not considered in this report due to an insignificant influence on the protection settings. Table 2.12 presents the minimum time periods a synchronous generator must operate in with frequency deviating from the nominal value. These would dictate new protection setting requirements. The utility company, in coordination with the TSO and the power generating facility (DG-unit) owner, may agree on wider frequency ranges, longer minimum times for operation, or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities [21].

Table 2.12: Frequency range and time of operation for synchronous generators type B [21]

Synchronous area	**Frequency range**	**Time period for operation**
Nordic	47.5 Hz – 48.5 Hz	30 minutes
	48.5 Hz – 49.0 Hz	Specified by TSO, but not less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes

Chapter 3

Grid Protection of Distribution Network with Distributed Generation

3.1 Introduction

This chapter will present the basics concerning the protection of distribution networks and the relevant terms and recommendations for protection of a distribution network with DG. Regional- and transmission grid protection settings are not included, but these can be found in [28]. Further details about relay protection components are attached in Appendix B.

3.1.1 Over-Current Protection

OC protection is the traditional method to protect distribution network. Faults in the network cause an increase of current in the feeder. The OC protection on the feeder, monitors the current magnitude and detects the increase if a fault occurs. OC protection can have a current transformer (CT) for single phase measurements, or three CTs for three phase measurement.

OC relays operate mainly with inverse- and definite- time and instantaneous characteristics, these are illustrated in Fig. 3.1. The relationship between the magnitude of the current and the time needed for tripping is given by the inverse- or definite time characteristic. When the pick-up current, I_S is exceeded, the timer starts. If the current exceeds the specified pick-up current for a time interval given by the definite- or inverse time characteristic, the protection trips the CB [19]. t_D is the definite time the pick-up current must exceed for the protection to trip the CB. The inverse time characteristic decreases the operating time value as the current increases. The inverse characteristic is internationally standardized[1] into three degrees of inverse: normal

[1] IEC publication 60255-3

inverse, very inverse and extreme inverse [48]. In Fig. 3.1: I_H is the instantaneous trip current, and t_H is the corresponding time needed for instantaneous trip of the CB. t_H is set as low as practically possible, typically in the range of 30-100 ms [48].

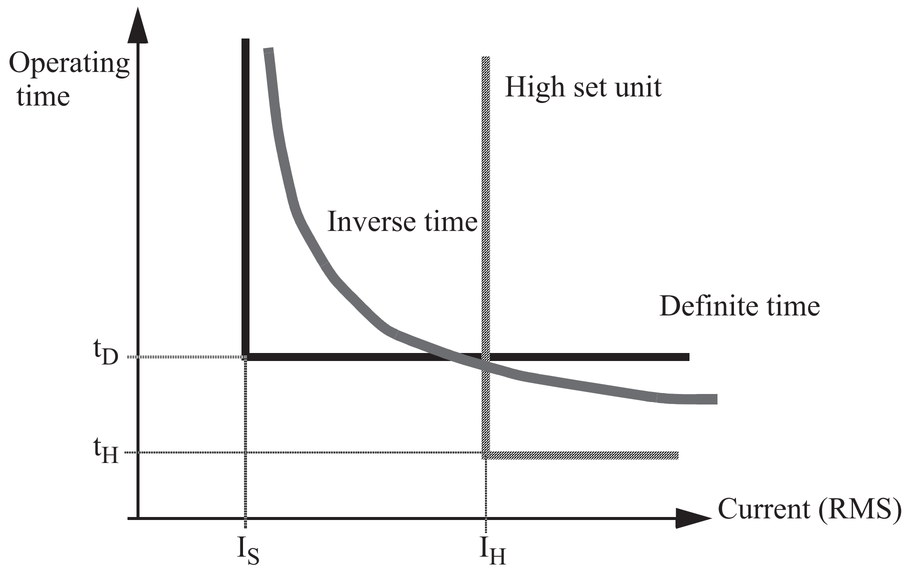


Figure 3.1: OC protection definite-, inverse- and instantaneous time characteristic [48].

The setting of the pick-up current is essential to ensure a reliable protection system. A general rule for determining the pickup current is presented in [26], here expressed in (3.1).

$$1.5 \cdot I_{load,max} < I_S < 0.8 \cdot I_{fault,min} \tag{3.1}$$

In (3.1) $I_{load,max}$ is the maximum load current that can occur at the feeder, I_S is the pickup current and $I_{fault,min}$ is the lowest possible fault current that can occur on the feeder (Two-phase fault).

There must be coordination between CBs on a radial, to ensure selectivity. As previously mentioned, the OC operates after definite- or inverse-time and instantaneous characteristics. Normally this is fulfilled by setting the disconnection time at the end CB to 0.2 s, then adding 0.2-0.3 s for each CB closer to the feeder. Coordination between CBs on a radial feeder with inverse time characteristics is illustrated in Fig. 3.2. $I_{sh,max}$ is the maximum short-circuit current, $I_{sh,min}$ is the minimum short-circuit current, I_{lmax} is the maximum load current for the corresponding relay.

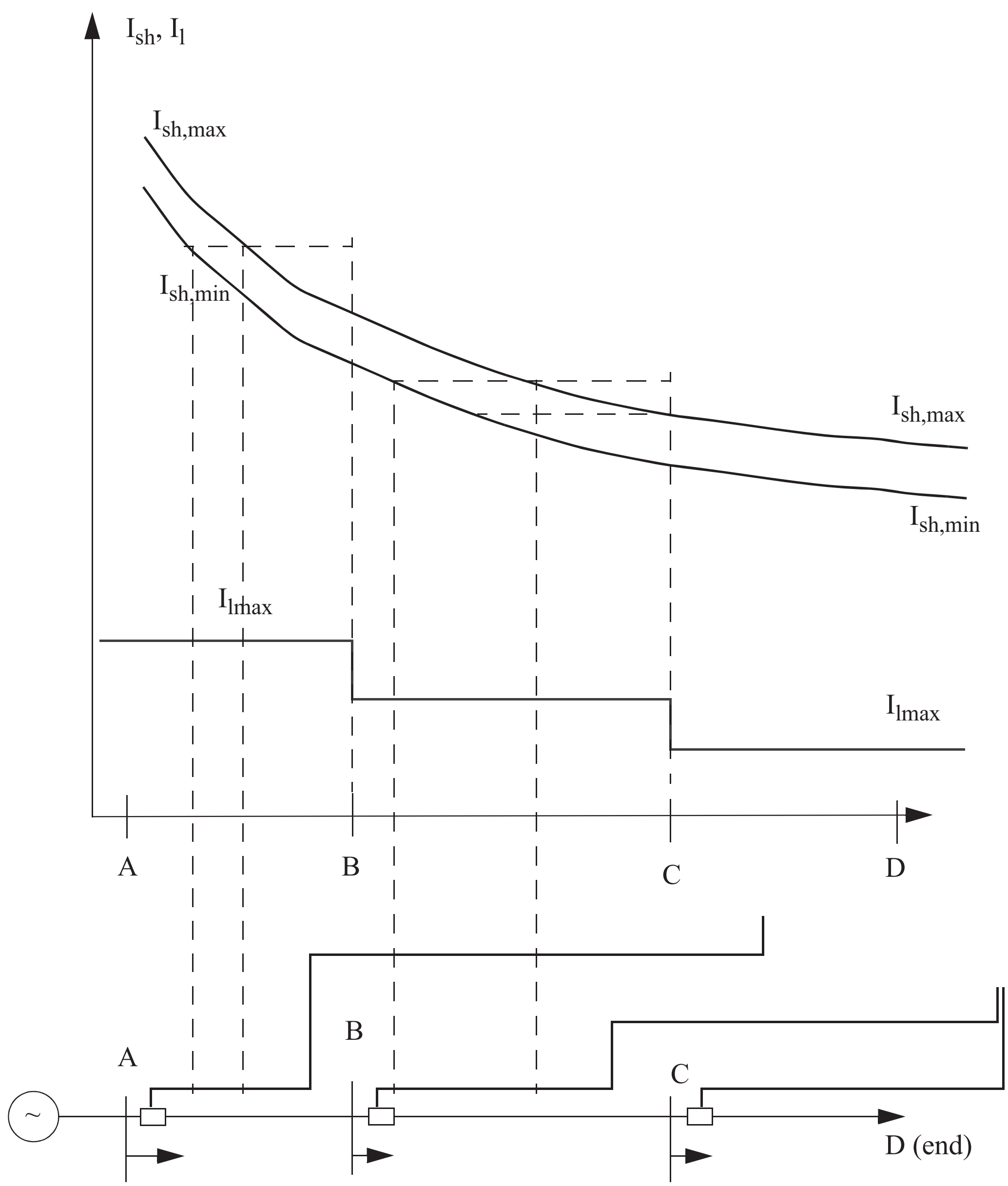


Figure 3.2: Overview of time coordination for OC protection in distribution network [48]

3.1.2 Directional Over-Current Protection

Directional OC protection has opposed to the traditionally OC protection, the additional function that determines the direction of the current, e.g. forward or backward, as illustrated in Fig. 3.3, where 67 is the ANSI[2] number of the directional OC relay. The determination of direction gives the protection the ability to trip both in forward and backward direction, with different settings. Forward is normally the direction towards the protected object [19].

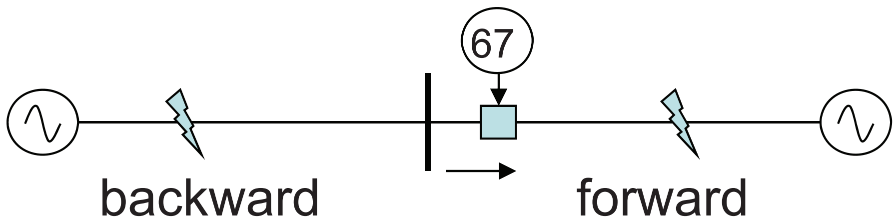


Figure 3.3: Directional OC protection directions during fault [26]

To determine the direction, a polarizing quantity is obtained, meaning CTs and minimum one voltage transformer (VT) is necessary[3]. Phasor diagram of the directional OC is illustrated in Fig. 3.4. The polarizing quantity is used to compare the angle, ϕ, between the measured current I_{CT} and the reference, U_{ref} [19].

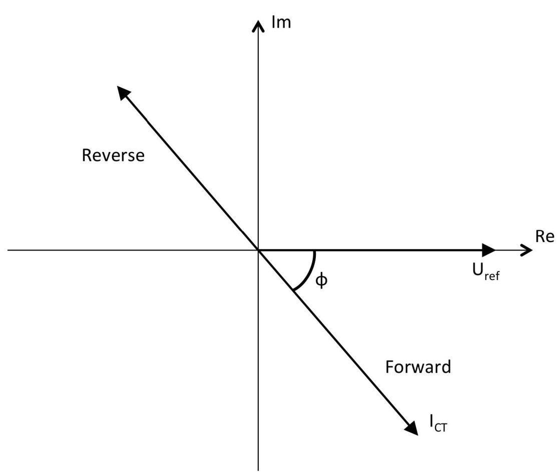


Figure 3.4: Phasor diagram for directional OC relay using voltage reference [19]

[2] https://library.e.abb.com/public/c1256d32004634bac1256e19006fe88a/1MRB520165-BEN_en_ANSI_numbers_IEEE_Standard_Electric_Power_System_Device_Function_Numbers.pdf

[3] Can use current as reference/polarizing quantity. However this is not common [19]

3.1.3 Distance Protection Settings

Distance protection[4] monitors the impedance $\left(Z = \frac{U}{I}\right)$ of the protected object, by measuring both current (CT) and voltage (VT). It can detect a fault in both directions. The calculated impedance of the protected object is continuously compared with the measured value. During faults, the measured impedance drops below the calculated impedance and the protection trips the CB. The distance protection often has two or three zones with different impedance limit and time delays to ensure selectivity and reliability downwards the protected object [19].

An example of different distance protection zones is illustrated in Fig. 3.5. In the distribution network, Zone 1[5] generally covers 80-85 % of the first line with a time delay of 0.2 seconds, to ensure it does not operate before the fuses[6] downstream [9, 19]. Zone 2 has a time delay of 0.4-0.5 seconds, that covers 120 % of Line 1 [9]. Zone 3 is used as a backup for relays downwards and has an additional time delay [19].

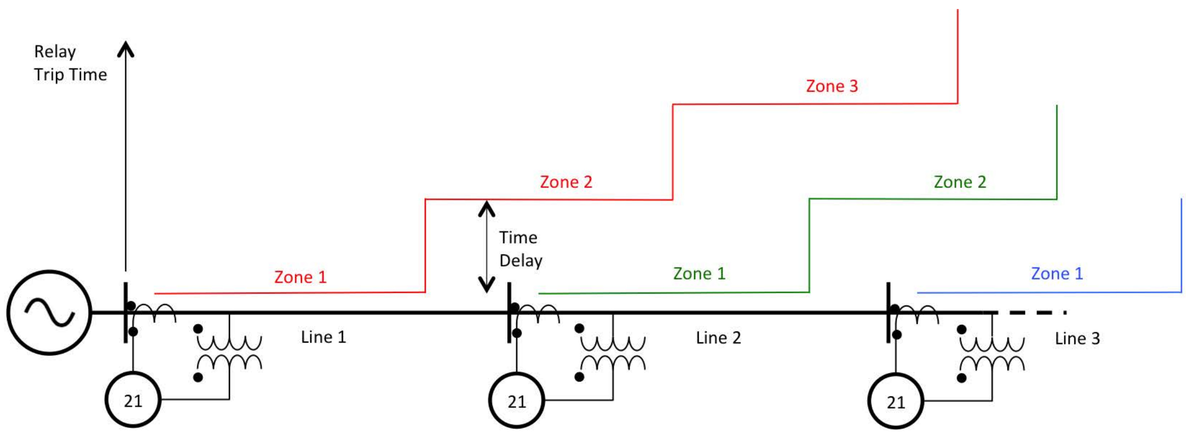


Figure 3.5: Example of distance protection zones [19]

[4]Can also be referred to as impedance protection

[5]Zone 1 could have an instantaneous setting for short-circuit during connection with zero time delay, often referred to as Zone 1B [9]. In network without fuses, such as transmission network, the time delay can be set to zero.

[6]Fuses for distribution transformers, in situations with faults on the transformer or LV side

Fig. 3.6 illustrates an example of a fault on line 1 in Fig. 3.5, with impedances during a fault. R_F is the fault impedance, Z_l is the line impedance, Z_{load} is the load impedance and Z_{lF} is the fault impedance the protection sees during the fault.

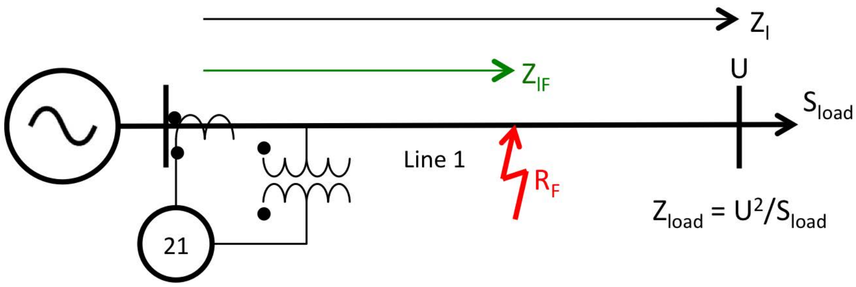
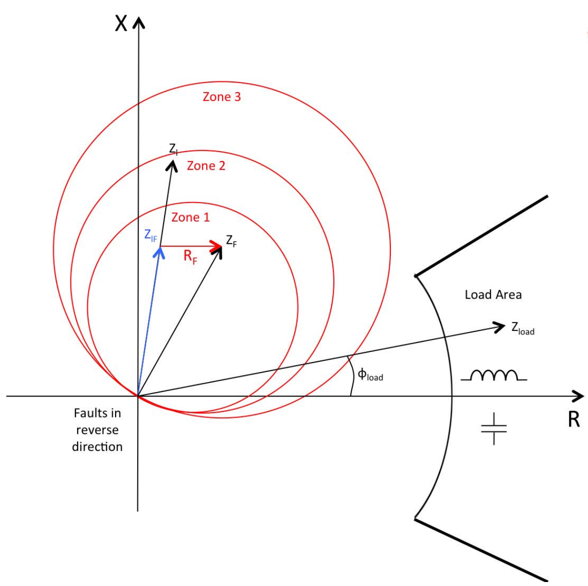
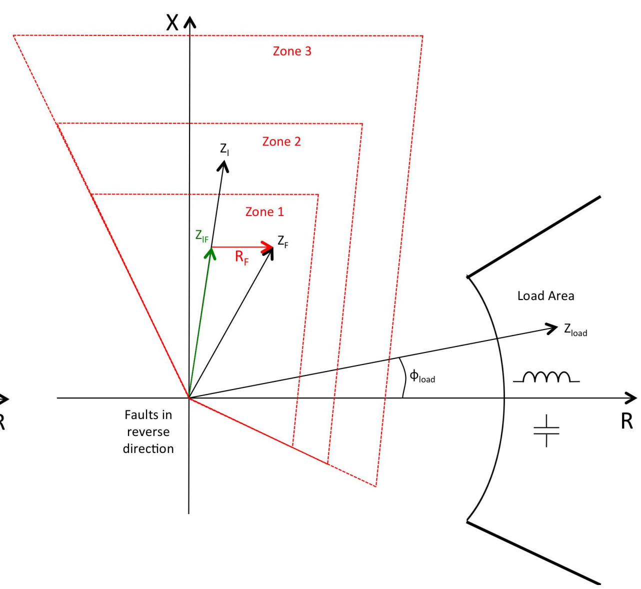


Figure 3.6: Line 1 from Fig. 3.5 [19]

The different zones are usually displayed in impedance or RX-diagram [48]. Modern numerical distance protection can design the impedance characteristics as desired. However, it is most common to design a quadrilateral- or circular- shape [70]. Fig. 3.7a and 3.7b present RX-diagrams of both quadrilateral- and circular- shape characteristics for the fault case displayed in Fig. 3.6. Z_{lF} drops below zone 1, and when the time delay is exceeded, the CB is tripped.



(a) Circular (Mho) zone settings



(b) Quadrilateral zone settings

Figure 3.7: RX-diagrams with Quadrilateral and Circular zone settings and line-, load- and fault-impedance for line 1 in Fig. 3.6 [19]

3.2 Grid Protection in Distribution Network

As previously mentioned, the traditional distribution network uses OC-protection for the feeders. OC protection could be sufficient if the DG impact is low, but as the number of DG-units increase, it has been a conversion to directional OC and distance protection for networks with DG [9]. The conversion has likely come from the recommendation in [3] for the use of directional OC and distance protection on feeders with DG.

3.2.1 Protection Challenges with Distributed Generation

Since the DG-units contribute with short-circuit current during faults, it introduce challenges for the traditional protection scheme of a distribution network [23]. This section will summarize the most common challenges and preventive measures.

In general, OC protection can lead to high clearing time for faults close to the substation due to time selectivity between CB in series (see Chapter 3.1.1). High clearing time causes additional stress to equipment and could demand unrealistic FRT-capabilities from transient stable DG-units. Distance protection can offer shorter clearing time for faults close to the substation and is recommended on feeders with several relay protection in series [3].

Blinding

A phenomenon that can occur with DG in the network is blinding; this is most common on DG far from the substation [36]. Blinding appears when the protection in the substation does not see a high enough current to trip the CB during a fault on the protected object, due to the fault current contribution from the DG-unit [39].

Fig. 3.8 presents a simplified example of blinding. The common feed point (CFP) is defined as the point closest to the fault, which the fault is fed in parallel by the generator and the network. Z_{gen} is the system impedance from generator to CFP, Z_{net} is the impedance from the network connection to CFP, Z_{fault_b} is the impedance from CFP to the fault, including the fault impedance, and U_{fault} is the pre-fault voltage at the fault location [38].

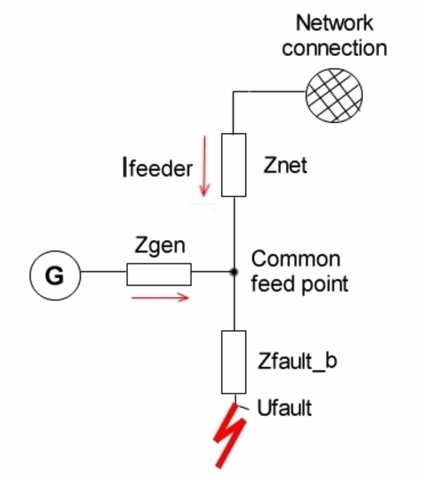


Figure 3.8: Example of blinding phenomena [38]

Without the generator connected in Fig. 3.8, the fault current can be explained as in (3.2) [38].

$$I_{feeder} = \frac{U_{fault}}{Z_{net} + Z_{fault\_b}} \tag{3.2}$$

If the generator is connected, the Thevenin impedance for the network becomes [38]:

$$Z_{th} = Z_{fault} + \left(\frac{Z_{gen} \cdot Z_{net}}{Z_{gen} + Z_{net}} \right) \tag{3.3}$$

I_{feeder} can further be found by the reduced parallel impedance and current division [38]:

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{gen} + Z_{net}} \right) \left(\frac{U_{fault}}{Z_{th}} \right) \tag{3.4}$$

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{gen} + Z_{net}} \right) \left(\frac{U_{fault}}{Z_{fault\_b} + \frac{Z_{gen} \cdot Z_{net}}{Z_{gen} + Z_{net}}} \right) \tag{3.5}$$

$$I_{feeder} = \left(\frac{Z_{gen}}{Z_{fault\_b}\left(Z_{gen} + Z_{net}\right) + Z_{gen} \cdot Z_{net}} \right) U_{fault} \tag{3.6}$$

$$I_{feeder} = \left(\frac{1}{Z_{net} + \frac{Z_{fault\_b} \cdot Z_{net}}{Z_{gen}} + Z_{fault\_b}} \right) U_{fault} \tag{3.7}$$

A comparison of (3.7) and (3.2) shows the difference for I_{feeder} with and without a DG-unit [38]:

$$\frac{U_{fault}}{Z_{net} + \frac{Z_{fault\_b} \cdot Z_{net}}{Z_{gen}} + Z_{fault\_b}} < \frac{U_{fault}}{Z_{net} + Z_{fault\_b}} \tag{3.8}$$

$$I_{feeder,withDG} < I_{feeder,withoutDG} \tag{3.9}$$

From (3.7) it can be seen that the DG-unit influence the feeder current (I_{feeder}), which is the current the grid protection measures. The ratio of impedance between the CFP to fault location (Z_{fault_b}) and the network (Z_{net}) dictates the degree of blinding. Meaning, if the fault branch impedance (Z_{fault_b}) is zero, the grid protection will see the same fault current as without a DG-unit. However, if the fault location is far from the CFP, Z_{fault_b} becomes larger and influence the blinding degree correspondingly [38].

To cope with the blinding, a common solution is to implement new protection characteristic with lower value limits. Lower value limits is often an economical and efficient solution; however, it goes on the cost of the safety margin. A consequence can be unintentional tripping due to faults on adjacent feeders, extreme load/generation situations or starting current of a DG-unit. It also directly conflicts with the measures to cope with sympathetic tripping [36].

Sympathetic tripping

Another challenge with DG in the network is sympathetic tripping and is most common with DG near the substation [36]. This is defined in the case an OC protection trips for a fault on an adjacent feeder. Fig. 3.9 illustrates an example of sympathetic tripping. I_{gen} is the fault current contribution from the DG-unit, I_{net} is the fault contribution from the main grid and CFP is the common feed point. The relay (protection) on the feeder with the DG-unit, sees a current magnitude that exceeds the value limit due to I_{gen} and trips the CB. I_{gen} causes disconnection of a healthy feeder and customer outage, which is not desired.

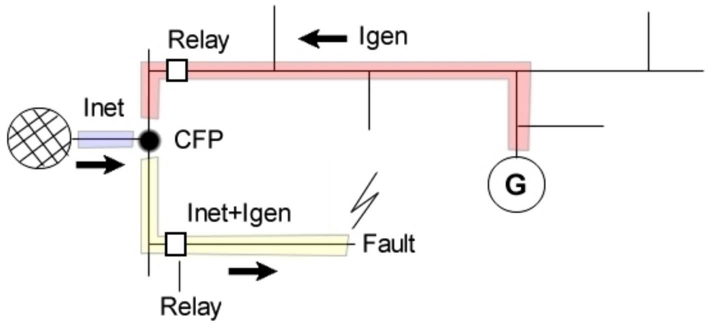


Figure 3.9: Example of sympathetic tripping phenomena [36]

The problem can be solved with a directional OC protection that has an additional time delay for backward direction. Accordingly, the relay on the adjacent feeder is given a chance to isolate the fault from the power system [39]. Directional OC is an expensive solution, especially if OC protection is the current protection. Another solution would be to set the tripping value limit higher. Though, this is opposite of the solution for the blinding phenomena. If a traditionally OC protection is used, a compromised solution needs to be found [39]. The third solution would be to set the time delay on the feeder with DG-unit higher than the other feeders. Increased time delay would cause more stress to the components during faults.

Islanding and Automatic Reconnection

Traditionally, automatic reconnection[7] is enabled since 80 % of all faults in the distribution network is temporary [11]. By disconnecting the feeder during a temporary fault, the arc at the fault point will extinguish [36]. Hence, the fault is cleared, and the feeder can be connected again. Automatic reconnection benefits the utility companies by minimizing downtime. To coordinate with fuses in the network the sequence[8] is typically fast-fast and slow-slow [24].

On a feeder with DG, an island operation can occur, meaning the feeder is energized by the DG-unit after the main grid is disconnected. The DG-unit can feed the fault, charging the arc if it is not disconnected during the fault.

If the intention is that the main grid should automatically reconnect while the DG-unit is still connected, synchronization check must be installed, or else two systems out-of-phase will

[7] Can also be referred to as automatic reclosure or autoreclose in literature. Known as "GIK (automatisk gjeninnkobling)" in Norway

[8] After two failed attempts without damaging the fuses, a slower breaker operation will try to clear the fault by fuse operation, such that the fault is isolated from the network [68]

try to connect[9]. Alternatively, automatic reconnection can be used together with a voltage interlock; this requires the DG to be disconnected before the reconnection can operate [3]. Synchronization check and voltage interlock require an additional VT on the feeder side of the CB. In existing compact substations, there are often not sufficient space to install an additional VT [3, 40]. If automatic reconnection is implemented on a feeder with DG without an additional VT, the first automatic reconnection must have longer time than the DG-unit's protection for disconnection, i.e. if automatic reconnection is enabled, it is on the condition that the DG-unit is disconnected.

Automatic reconnection is usually not recommended on feeders with DG-units in Norway [3].

[50] states that all DG-units must disconnect from the network within one second during island operation. Nevertheless, it seems that disconnection is not relied on in practice, and automatic reconnection is not used on feeders with DG-units [6].

Islanding can be a safety hazard for persons working on the feeder with DG. Since the main grid is disconnected, the workers can assume that the line is de-energized. However, the DG can energize the line. There are standard approved work practices that ensure the safety for working personnel [69].

[9] Can lead to an increased amount of voltage dips and disturbances, increased stress on substation equipment, damage to conductors and isolators, larger outages and stress on DG-unit [37]

3.3 Grid Protection in DG-units

3.3.1 Introduction

After a court decision, the utility companies control the interconnection point in DG-units [9]. The grid protection relay monitors the HV side values and operates the CB closest to the connection point, as illustrated to the left in Fig. 3.10. This section will present current requirements, industry guidelines and industrial practice for grid protection in DG-units.

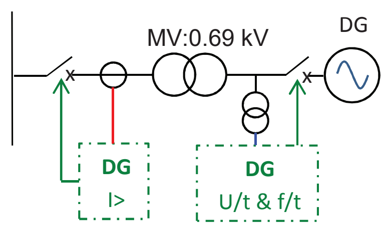


Figure 3.10: Simplified single line diagram of a DG-unit [9]

3.3.2 Current Requirement

[3] states that [28] requires earth fault protection on the grid voltage level side of the transformer that satisfies the regulations given in [20]. However, it is not included in the latest version of [28]. The most recent version states it should follow the requirement from the local utility company. Whether earth-fault protection is a requirement or not, is diffuse. The following sections will investigate if the requirement is used by the industry.

3.3.3 Industry Guidelines

Since it only exists a vague current requirement, an attempt on finding industry guideline was performed. An industry guideline was discovered in a summarizing report ([9]) and through private communication ([32]) with REN.

Normally a grid protection is set to guard the transformer and generator against internal faults [9]. A OC protection is sufficient and can be configured as in (3.10) and coordinated with the feeder protection in the distribution network [9, 32]. In (3.10), I_N is the nominal current for the CT, I_S is the pickup current and $I_{fault,min}$ is the lowest possible fault current (Two-phase short-circuit) the relay sees for an internal fault, i.e. the lowest fault current contribution from the grid [9].

$$1.2 \cdot I_N < I_S < 0.7 \cdot I_{fault,min} \tag{3.10}$$

A request for example documentation for grid protection for DG-units was sent to two suppliers[10] without any response. The industry guideline includes OC-protection and the current requirement includes earth-fault protection. Thus these are not corresponding.

3.3.4 Industry Practice for Grid Protection in DG-units

To determine present industry practice, available protection documentation were analyzed and an on-site inspection to investigate two DG-units (DG1 and DG2) was performed. The presented DG1 and DG2 are the same DG-units as in Chapter 4. DG-protection and further details about Bruvollelva, Tverråna and Ullestad can be found in Chapter 2.2.1.

Grid Protection in DG1

The single line diagram for DG1 is presented in Fig. 3.11. DG1 has a common setup for SHPs with a simple disconnector, C.DG1, near the connection point, B.DG1 is the CB on the HV side of the transformer, and A.DG1 is the GB on the low voltage side. T.DG1 is the power station transformer with a rated power of 1.6 MVA and voltage ratio 22/0.69 kV.

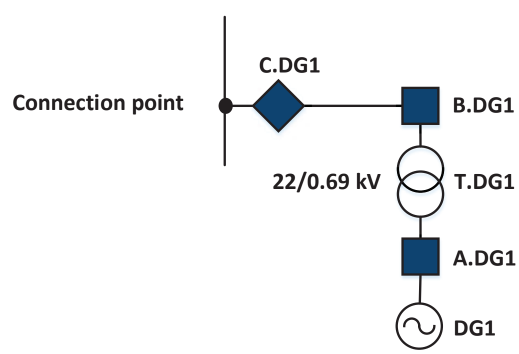


Figure 3.11: Simplified single line diagram for DG1

[10] Energiteknikk AS - http://www.energi-teknikk.no/ and Småkraft AS - http://www.smaakraft.no/

The grid protection monitors the values on the 22 kV side of the transformer and operates B.DG1. The relay protection used is an ABB REF615. Table 3.1 presents the values obtained[11] from the grid protection relay at DG1. The over-/under- frequency protection settings trip the CB if the limit value is exceeded within the given time interval. The OC protection settings monitor all three phases and trips if one of the phases exceeds the limit value within the given time interval. The over-/under- voltage setting monitors phase-to-phase voltages and trips the CB if one of the three values exceed the limit value within the given time interval. The inrush current detection is for transformer inrush current situations. If the limit value is exceeded within the given time interval, it blocks all the outputs and reset all timers [4]. I_{base} is 50 A and U_{base} is 22 kV, i.e. 1 pu is 50 A for current and 22 kV for voltage.

Table 3.1: Grid protection settings for DG1 [22]

Parameter	**Value**	**Time*[s]**	**Description**
f>	51 Hz	2.50	Over-frequency
f<	49 Hz	2.50	Under-frequency
3U>(1)	1.10 pu	5.00	Over-voltage 1
3U>(2)	1.15 pu	0.50	Over-voltage 2
3U<(1)	0.86 pu	0.50	Under-voltage 1
3U<(2)	0.85 pu	0.06	Under-voltage 2
3I>	1.20 pu	0.50	OC non-direction
3I≫	6.00 pu	0.05	Directional OC
3I2f	0.20 pu	0.02	Inrush current detection

* - Trip time, additional 0.1 s is assumed to be added to obtain disconnection time

From Table 3.1 it can be seen that the grid protection is likely set as a backup for the DG-protection in DG1. All functions from current requirements (Table 2.1) for DG-protection are activated. However, the time delays are set above the current requirement, probably to ensure decoupling during large disturbances in the network. The under-voltage is set in

[11] Parameters settings can be obtained from the relay display or through a computer connected to the relay. ABBs software program, PCM600 for relays are free and can be downloaded from their web page http://new.abb.com/substation-automation/products/tools/pcm600(Accessed 04/26/2017). Image of connection to relay can be found in Appendix E

agreement with the requirement for not transient stable DG-units[12]. 3I≫ is not set within the recommendation in (3.10), see Chapter 5.2 for details.

The use of grid protection as backup for DG-protection seems unnecessary and ineffective if the DG-protection is documented and in agreement with requirements. It will take the DG-operators longer time to get the DG-unit back online if the grid protection trips the grid CB since they can not operate this CB. In addition, the utility company must use resources to get it back online.

The fault recorder had sampled 57 faults. The fault recorder starts when a value is exceeded, thus not all of these 57 lead to a trip of the CB. Nevertheless, it indicates the rate of disturbances in the connected grid.

Grid Protection in DG2

The single line diagram for DG2 is presented in Fig. 3.12. DG2 has a trending setup[13] for SHPs with both CB on HV-side of the transformer. Further DG2 has a simple manual disconnector, C.DG2 at the connection point, grid protection controlling the B.DG2 CB and a generator protection controlling the GB, A.DG2. T.DG2 is the power station transformer with rated power of 5.3 MVA and voltage ratio 22/6.6 kV.

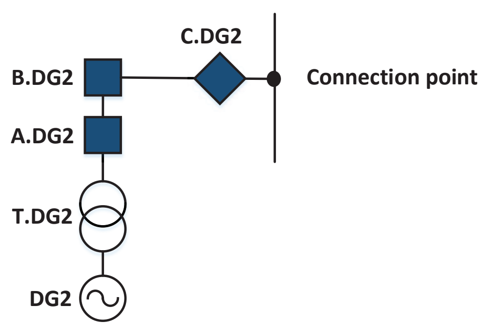


Figure 3.12: Simplified single line diagram for DG2

The grid protection relay monitors the values on the HV side of the transformer and operates B.DG2. The relay protection installed is ABB REF615. Table 3.2 displays the grid

[12]The requirement for not transient stable DG-units is to decouple within 0.2 s for voltage below 85 % of nominal voltage [50]

[13]In Norwegian it is referred to as "blokkobla anlegg" [40]

protection settings obtained from DG2. $I_o \gg$ monitors the measured residual current (I_o) and residual voltage (U_o) to detect earth-faults. For details regarding operation please see [4].

Table 3.2: Grid protection settings for DG2 [22]

Parameter	**Value**	**Time*[s]**
$I_o \gg$	0.10 x I_N	0.04
$I_o \gg$	0.05 x I_N	0.06

* - Trip time, additional 0.1 s is assumed to be added to obtain disconnection time

From Table 3.2 it can be noticed that the grid protection functions as an earth-fault protection only.

The fault recorder had sampled two faults.

Grid Protection in DG-units from SINTEF Report

To get a better foundation of the current practice of grid protection in DG-units, the grid protection settings from [27] were investigated. [27] does not state which CB the relay protection operates, but based on the settings and relay used; it is assumed that it operates the utility company's CB closest to the connection point. Ullestad and Tverråna have mutual grid CB and relay protection. Generator details can be found in Appendix F.

Table 3.3: Grid Protection settings in DG-units from SINTEF report [27]

	Bruvollelva		**Ullestad/Tverråna**	
Parameter	**Value**	**Time*[s]**	**Value**	**Time*[s]**
f>	N/A	N/A	N/A	N/A
f<	N/A	N/A	N/A	N/A
U>	N/A	N/A	1.10 pu	1.70
U<	N/A	N/A	0.85 pu	10.00
U≪	N/A	N/A	0.50 pu	0.20
I>	1.25 pu	1.50	N/A	N/A
I≫	3.97 pu	0.05	N/A	N/A
U_0>	0.23 pu	3.00	N/A	N/A

* - Trip time, additional 0.1 s is assumed to be added to obtain disconnection time

From Table 3.3 it can be seen that the grid protection varies for DG-units. Bruvollelva functions as an OC- and earth-fault protection and are set in compliance with (3.10). Ullestad and Tverråna act on voltage-deviation and seems to be a backup for the DG-protection (Table 2.3), set above for selectivity.

3.3.5 Summary Grid Protection in DG-units

Table 3.4 summarizes the investigated grid protection settings in the previous sections. DG1 is not classified as transient stable.

Table 3.4: Summary of grid protection settings

	Bruvollelva [27]		**Ullestad/Tverråna [27]**		**DG1 [22]**		**DG2 [22]**	
Parameter	**Value**	**Time ***	**Value**	**Time***	**Value**	**Time***	**Value**	**Time***
f>	*N/A*	*N/A*	*N/A*	*N/A*	**51 Hz**	**2.50 s**	*N/A*	*N/A*
f<	*N/A*	*N/A*	*N/A*	*N/A*	**49 Hz**	**2.50 s**	*N/A*	*N/A*
U>	*N/A*	*N/A*	**1.10 pu**	**1.70 s**	**1.10 pu**	**5.00 s**	*N/A*	*N/A*
U≫	*N/A*	*N/A*	*N/A*	*N/A*	**1.15 pu**	**0.50 s**	*N/A*	*N/A*
U<	*N/A*	*N/A*	**0.85 pu**	**10.00 s**	**0.86 pu**	**0.50 s**	*N/A*	*N/A*
U≪	*N/A*	*N/A*	**0.50 pu**	**0.20 s**	**0.85 pu**	**0.06 s**	*N/A*	*N/A*
I>	**1.25 pu**	**1.50 s**	*N/A*	*N/A*	**1.20 pu**	**0.50 s**	*N/A*	*N/A*
I≫	**3.97 pu**	**0.05 s**	*N/A*	*N/A*	**6.00 pu**	**0.05 s**	*N/A*	*N/A*
U_0>	**0.23 pu**	**3.00 s**	*N/A*	*N/A*	N/A	N/A	*N/A*	*N/A*
I_0≫	*N/A*	*N/A*	*N/A*	*N/A*	N/A	N/A	**0.10 pu**	**0.04 s**
I_0≫	*N/A*	*N/A*	*N/A*	*N/A*	N/A	N/A	**0.05 pu**	**0.06 s**
Inrush detection	*N/A*	*N/A*	*N/A*	*N/A*	**0.2 pu**	**0.02 s**	*N/A*	*N/A*

* - Trip time, additional 0.1 s is assumed to be added to obtain disconnection time

From Table 3.3 it becomes clear that grid protection in DG-units varies.

- Bruvollelva fulfills the industry guidelines in Chapter 3.3, I≫ is set in agreement with $0.7 \cdot I_{fault,min}$ [27].
- Ullestad/Tverråna does not have I≫. The only activated settings are concerning voltage protection. These are set time selectively above the DG-protection, and therefore are assumed to be a backup. It is not verified how the CBs is placed for Ullestad and Tverråna
- DG1 is reviewed as not transient stable, and therefore it could be thought that the utility company wishes to ensure decoupling during disturbances, this is reflected in the settings.
- DG2 do not have I≫. However, this is a DG-unit with both CBs on the HV side. The DG-protection would thus pick up internal faults, provided that I≫ is activated in the DG-protection (not investigated during the on-site inspection). If the intention with the guidelines are that the utility control center should have control and be alerted for internal faults in DG-units, it is not sufficient that the DG-protection have the I≫ covered for DG2.

- Bruvollelva and DG2 have activated earth-fault protection

Grid protection in DG-units does not seem to be in focus today. The current requirement was in the same chapter as DG-protection (in [3]) and appears to be expired. Industry guideline was found in a summarizing report and through private communication.

The current requirement does not correspond with industry guidelines and the variety in the use of grid protection indicates a need for a new and more extensive formal guideline.

Chapter 4

Simulation Model

4.1 Introduction

The simulation model is based on a actual distribution network provided by the co-operation firm Sunnfjord Energi AS (SEAS). The network consists of two DG-units (SHPs) in a rural area and one SHP directly connected to the substation. Based on experience data from the system control center, the grid protection in one of the DG-units appears to be more sensitive to disturbances than the other, causing a frequent decoupling of the DG-unit. As previously mentioned, DG-operators can not operate the grid protection and need to go through[1] the utility company to connect with the grid. The frequent decoupling is not favorable for either DG-owner or utility company; The DG-owner lose income, and the utility company must use unnecessary resources[2] to get it back online. The DG-unit could have poor qualities dictating that it must be decoupled. Still, the suspicion is that conservative grid protection settings restrain the FRT-capability as indications showed in Chapter 3.3.4.

All data in the model was obtained from the Network Information System (NIS), NETBAS. NETBAS is a NIS, developed by Powel AS and is used by SEAS and several large utility companies in Norway [64]. SEAS have their entire network documented in NETBAS (cables, generators, loads, customers, breakers, etc.). NETBAS has many functions that support tasks performed by a utility company. Though, only load flow and short-circuit calculation[3] tools are utilized in this work.

[1]The utility company can detect the disconnection without DG-operators contacting them, depending on the DG-units' operating agreement

[2]If the DG-unit can be remotely controlled (remote control and communication must be installed) from the control center, it may not occupy significant resources, however not all DG-units have this opportunity. An operator must then physical operate the CB on the HV side in the DG-unit, which is often in a rural area with late response time.

[3]Short-circuit calculation in NETBAS is based on the IEC60909 standard.

From the data obtained from NETBAS, a model is developed in PSCAD (EMTDC) for the purpose of dynamic analysis. PSCAD uses the trapezoidal rule as the method of calculation [66]. Trapezoidal rule is a well-known method that is used by various similar programs, e.g., ATP (EMTP). A study was performed to investigate the accuracy of dynamic simulations in different commercial programs[4] on the market in [34]. The study claim there is a marginal difference in the results [27].

The following sections will present the simulation model, further details regarding PSCAD can be found in [53].

All results in PSCAD are validated with corresponding results in NETBAS.

4.2 The Distribution Network

Fig. 4.1 illustrates a simplified single line diagram of the network modeled. The system consists of a stiff 66 kV regional grid connected to a substation through a 66/22 kV transformer with automatic tap changing and compensated neutral. The substation is simplified from five to three feeders due to program restrictions.

The DG-units in question is connected to feeder B. There is a station with CBs further out on the feeder, displayed as D, E and F. C represents the in-feed of power to the substation from other DG-units, and A accounts for the consumption. Only B is modeled in detail with lines, cables, loads, and DG-units.

The student version of PSCAD is restricted to 200 electrical nodes; simplifications must, therefore, be made. G1 represents various DG to get correct power flow at the substation. Details is presented in Chapter 4.7.

F represents the feeder with the sensitive DG-unit, henceforth referred to as DG1. DG2 is the more stable DG-unit connected to E, and G is the load consumption at the station. E and F are usually radials in a rural area, but H and I enable connection with other stations. However, this is not ideal during production, since the network is not intended for the purpose [59]. DG1 and DG2 are placed approximate 8 km and 2 km, respectively, from the station D, E, F and G.

Generally, only fundamental frequency components are considered in this study, and thus,

[4]PowerFactory, PSS/E, PSCAD and SIMPOW

the high-frequency behavior of the components are not important. This allows for some simplifications to be made.

A solution time step of 50 μs has been used. The simulation time became very high for this network with maximum electrical nodes of 200 and many components. Other programs could be considered for large networks.

The notations presented in Fig. 4.1 will be used and referred to throughout this thesis.

All data is made anonymous due to confidentiality towards SEAS. The objective of the simulation is to verify if DG1 could stay online during various fault cases in the network. Verification would lead to new protection settings.

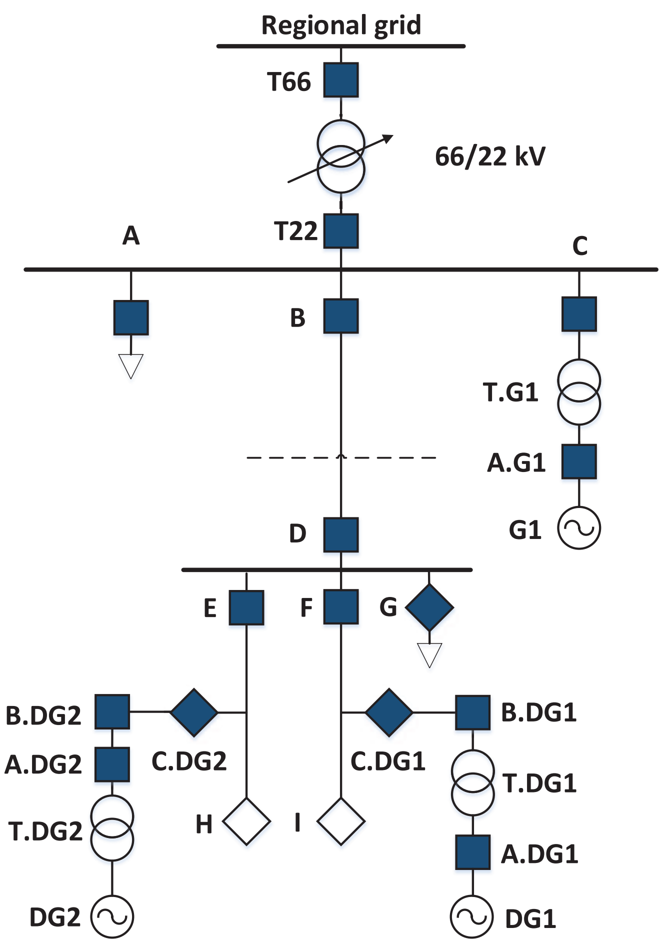


Figure 4.1: Single line diagram of the modeled network

4.2.1 High Voltage Network

The connection point for the regional grid has a short-circuit capacity of 838 MVA with a cos ϕ = 0.085. This is modeled as a Thevenin-equivalent with an ideal 66 kV source behind a resistance and a reactance, see Appendix C.7 for details.

4.2.2 Transformer

The substation transformer with ratio 66/22 kV is modeled with the 3-phase 2-winding transformer from the PSCAD library. The compensated neutral is neglected since no ground faults will be studied[5]. The transformer has a rating of 20 MVA, leakage reactance of 6.61 % and a copper loss of 0.5 %.

The transformer is equipped with a automatic tap changer with $\pm 4 \cdot 2.5$ % on the HV-side. Regulation requires that the voltage at LV customers should not deviate more than ± 10 % from rated value [47]. With varying DG this could be a challenge, and one of the most common measures is to install automatic tap changer on the substation transformer.

Simulations are only performed with worst-case scenario, meaning low-load and high-production. Voltage profiles in PSCAD and NETBAS are compared and presented in Table 4.1. In Table 4.1, trafo tap is the substation transformer tap position, U_{LL} is the line-to-line voltage at the location and difference U_{LL} is the deviation between the NETBAS and the PSCAD model in percentage.

Table 4.1: Voltage profile comparison PSCAD and NETBAS

	PSCAD			**NETBAS**			**Difference U_{LL}**
Location	**Trafo tap**	**U_{LL} [kV]**	**Per unit**	**Trafo tap**	**U_{LL} [kV]**	**Per unit**	**Percentage**
Substation 66/22	1	21.91	1.00	1	21.92	1.00	-0.04 %
Station D, E, F, G	1	22.48	1.02	1	22.48	1.02	0.01 %
DG1	1	22.69	1.03	1	22.67	1.03	0.09 %
DG2	1	22.59	1.03	1	22.59	1.03	-0.02 %

The voltage profile in PSCAD is corresponding with NETBAS and it is assumed that the

[5]Compensated neutral only affect ground faults (and corresponing protection settings), these are not in the scope of this thesis [49]

voltages are within the current requirements of ± 10 on LV side. Considering the purpose[6] of this work, the voltages are satisfying.

The short-circuit capacity on the 22 kV side of the transformer is 306 MVA, thus the transformer restricts the available short-circuit capacity from the 66 kV side significantly.

4.3 Overhead Lines and Cables

The detail modeled network from feeder B consists of both overhead lines and cables. Line and cable sections of same type are summarized due to electrical node limitations in software. A total line length of approximate 17 km is modeled. Lines shorter than approximate 80 km have negligible shunt capacitances and can be represented by their series impedances, therefore the simplification can be justified [31]. All components are assumed symmetrical and transposed.

The line sections are modeled by the use of the coupled PI-equivalent from the PSCAD library. The model is formed by using lumped R, L and C elements, with the R and L represented in matrix format, such that coupling between the three phases is provided [39]. It ensures correct fundamental frequency impedance, which is the scope of this work. The PI-equivalent model is an approved method for overhead lines <200 km and cables <60 km [31].

Positive sequence impedances for overhead lines and cables used in the network model are presented in Table 4.2 and 4.3, respectively. All data used is obtained from NETBAS standard data. Positive- and negative sequence is assumed equal and zero sequence is neglected.

Table 4.2: Positive sequence impedances for overhead lines used in the network model

Line type	**R+[Ω/km]**	**X+[Ω/km]**	**X_C,+[kΩ·km]**
FeAl 1x16	1.126	0.409	358.054
FeAl 1x25	0.721	0.395	345.238
FeAl 1x50	0.359	0.373	325.138
BLX 3x95	0.337	0.310	265.000

[6]See Appendix G for network influence on FRT-capability

Table 4.3: Positive sequence impedance for cables used in the network model

Cable type	R+[Ω/km]	X+[Ω/km]	X_C,+[kΩ·km]
TSLF 3x1x50	0.641	0.140	19.894
TSLF 3x1x95	0.320	0.120	15.158
TSLE 3x1x95	0.320	0.200	15.915
TXSP1x3x50	0.641	0.130	18.724
TXSE1x3x95	0.320	0.120	15.158

DG1 is approximate 17 km, and DG2 is approximate 10 km from substation 66/22 kV. The network consists mostly of overhead lines, but with cables from the interconnection point to the DG-units and around station D, E, F. Loads are connected directly to A and G. T.G1 is directly linked to C. No further details will be given due to confidentiality.

4.4 Load

Loads in the PSCAD simulation model are based on the load flow calculations[7] from NETBAS. The load flow is worst-case scenario with low load and high production. Loads are summarized due to software restrictions of electrical nodes. All loads are modeled as static response type load, which has been found adequate for modeling of large composite loads [56]. The static load model is depending on the voltage and/or frequency across the load at a instant of time [39].

Due to electrical node restrictions, the load characteristics is simplified to common characteristics for a distribution network. Active power is modeled with constant current and reactive power as constant impedance characteristics [31, 52]. This gives load resistance and reactance as in (4.1) [39].

$$R_L = R_L^{nom} \frac{|U_L|}{|U_L^{nom}|}, \quad X_L = X_L^{nom} \tag{4.1}$$

The loads are assumed independent of frequency variations. All loads are modeled by the

[7]Loads in NETBAS are based on customer history and industry standard coefficients

use of the fixed 3-phase line-to-ground load in the PSCAD library. Grounded loads can be applied since no ground faults are studied.

The network consists of high penetration of DG during a worst-case scenario; the simplified load modeling is therefore considered sufficient for the simulation performed. Further details can be found in Appendix C.6.

4.5 Load Flow

The load flow from a worst-case scenario with high production and low-load are obtained from NETBAS and modeled in PSCAD. The low-load scenario is approximate 20 % of normal load consumption. A comparison of the load flow in the stations are presented in Table 4.4 and 4.5. The tables refer to the notations in Fig. 4.1. D and T22 have positive measuring values for power flow towards the busbar, while remaining feeders have positive measurement of power flow away from the busbar. NETBAS and PSCAD are the values obtained from the respectively software. The values are compared and the difference is presented.

Table 4.4: Comparison of NETBAS and PSCAD load flow in substation 66/22 kV

	NETBAS		**PSCAD**		**Difference**	
Feeder	**P[MW]**	**Q[MVAr]**	**P[MW]**	**Q[MVAr]**	**P[MW]**	**Q[MVAr]**
T22	-11.624	-0.035	-11.616	-0.002	-0.008	-0.033
A	0.464	-0.140	0.464	-0.139	0.000	-0.001
B	-3.950	0.145	-3.952	0.141	0.002	0.004
C	-8.138	-0.040	-8.131	-0.004	-0.007	-0.036

Table 4.5: Comparison of NETBAS and PSCAD load flow in station D, E, F, G

	NETBAS		PSCAD		Difference	
Feeder	**P[MW]**	**Q[MVAr]**	**P[MW]**	**Q[MVAr]**	**P[MW]**	**Q[MVAr]**
D	-4.470	0.137	-4.462	0.113	-0.008	0.024
E	-3.521	0.128	-3.520	0.133	-0.001	-0.005
F	-1.193	-0.021	-1.195	-0.043	0.002	0.022
G	0.245	0.022	0.252	0.023	-0.007	-0.001

From Table 4.4 and 4.5 it is observed that the network has a high degree of generation. The difference between NETBAS and PSCAD is insignificant and can be ignored, considering the purpose of this work.

4.6 Short-Circuit Comparison

The short-circuit currents obtained from NETBAS and PSCAD are compared to verify the model. The three-phase short-circuits are applied on the 22 kV side of the transformers, results are presented in Table 4.6. I''_{kmax} is the highest possible total fault current feed to the fault point.

Table 4.6: Comparison of NETBAS and PSCAD short-circuit currents

	I''_{kmax}[kA]		Difference	
Generator	**NETBAS**	**PSCAD**	**[kA]**	**[%]**
DG1	1.564	1.505	0.059	3.77
DG2	2.590	2.547	0.043	1.66
G1	8.044	7.822	0.222	2.76

The deviation between NETBAS and PSCAD could be due to different calculation methods and level of model details. The difference is considered insignificant for the purpose of this work, and can be neglected.

4.7 Generators

4.7.1 General

All generators in the network are synchronous machines with salient poles. These are modeled by the use of the synchronous machine equivalent from the PSCAD library. The model is implemented with generalized machine theory and dq0-transformation. All values are obtained in generator format and implemented to the model.

DG1 and DG2 is based on data sheets from their manufacturer, however no data sheet were available for other generators. G1 is therefore a simplified generator to represent the remaining unknown generators. G1 is tuned to provide the correct in-feed of power and approximate the correct short-circuit contribution at the substation, as presented in the previous section. G1 is designed with base in common values from the industry ([8]).

The inertia constant for DG1 is obtained from the data sheet and adjusted for the turbine, see Appendix C.1 for further details. The inertia constant for DG2 is estimated to 1 s and G1 to 2 s [8].

PSCAD requires a value for the potier reactance entered. These are estimated togheter with [60], see Appendix C.4 for details.

The generators are not modeled with turbine regulators. A constant mechanical torque is applied and set in agreement with the nominal Power Factor (PF) of each generator, thus the nominal active power is produced when the generators operate with a PF equal to 1.

Table 4.7 presents ratings and parameters for DG1, DG2, and G1 implemented to the model. Further details can be found in Appendix C.

Table 4.7: Ratings and parameters for DG1, DG2 and G1

Ratings and parameters	**Symbol/Unit**	**DG1**	**DG2**	**G1**
Rated power	S_N [MVA]	1.645	4.170	8.570
Rated line-to-line voltage	U_{LL} [kV]	0.690	6.600	6.600
Rated phase-to-neutral voltage	U_{ph} [kV]	0.40	3.81	3.81
Rated current	I_N [kA]	1.376	0.365	0.750
Rated active power	P_N [MW]	1.400	3.753	8.570
Short-circuit capacity interconnection point	S_k [MVA]	48.5	81.0	306.0
Rated frequency	f_N [Hz]	50	50	50
Rated power factor	$\cos\phi_N$	0.9	0.9	1.0
Number of poles (equal to 2x number of pole pairs)	p	12	16	12
Direct axis synchronous reactance	x_d [p.u.]	1.750	1.330	1.000
Direct axis transient reactance	x'_d [p.u.]	0.311	0.303	0.200
Direct axis subtransient reactance	x''_d [p.u.]	0.242	0.209	0.140
Quadrature axis synchronous reactance	x_q [p.u.]	1.590	0.800	0.800
Quadrature axis subtransient reactance	x''_q [p.u.]	0.462	0.261	0.261
Armature resistance	r_a [p.u.]	0.009	0.008	0.002
Potier reactance	x_p [p.u]	0.175	0.133	0.100
Direct axis open-circuit transient time constant	T'_{d0} [s]	2.055	1.170	3.000
Direct axis open-circuit subtransient time constant	T''_{d0} [s]	0.111	0.019	0.050
Quadrature axis open-circuit subtransient time constant	T''_{q0} [s]	0.113	0.036	0.036
Inertia constant	H [s]	0.595	1.000	2.000
Air gap factor	constant	1.00	1.00	1.00

4.7.2 Power Transformers

The power transformers are modeled with the 3-phase 2-winding transformer model from the PSCAD library. Transformer ratings and parameters are presented in Table 4.8. It was not possible to obtain data sheets for the transformers. The values for leakage reactance and copper losses are estimated values from [39].

Table 4.8: Transformer rating and parameters

Parameter	**DG1**	**DG2**	**G1**
Rated power [kVA]	1600	5300	9000
Rated voltage HV side [kV]	22	22	22
Rated voltage LV side [kV]	0.69	6.60	6.60
Leakage reactance [pu]	0.075	0.075	0.075
Copper losses [pu]	0.0075	0.0075	0.0075
Vector group	Yd11	Yd11	Yd11

4.7.3 Excitation System

Unfortunately, it was not obtained information regarding excitation systems during the on-site inspection. The generators are thus assumed to have brushless excitation systems, which are common for SHPs [41]. Brushless excitation system principle is explained in Appendix C.5.

A digital voltage regulator, suited for modeling of brushless excitation systems, are implemented to all generators [29, 30]. All generators $\geq$ 0.5 MVA are required to have a PID-type voltage regulator [28]. The voltage regulator is implemented after the IEEE standard AC8B, which is found in the PSCAD library as AC exciter type AC8B. The block diagram for the AC8B model in PSCAD is presented in Fig. 4.2. Parameters and description are presented in Table 4.9, further details and explanations for the block diagram can be found in [30] and [54].

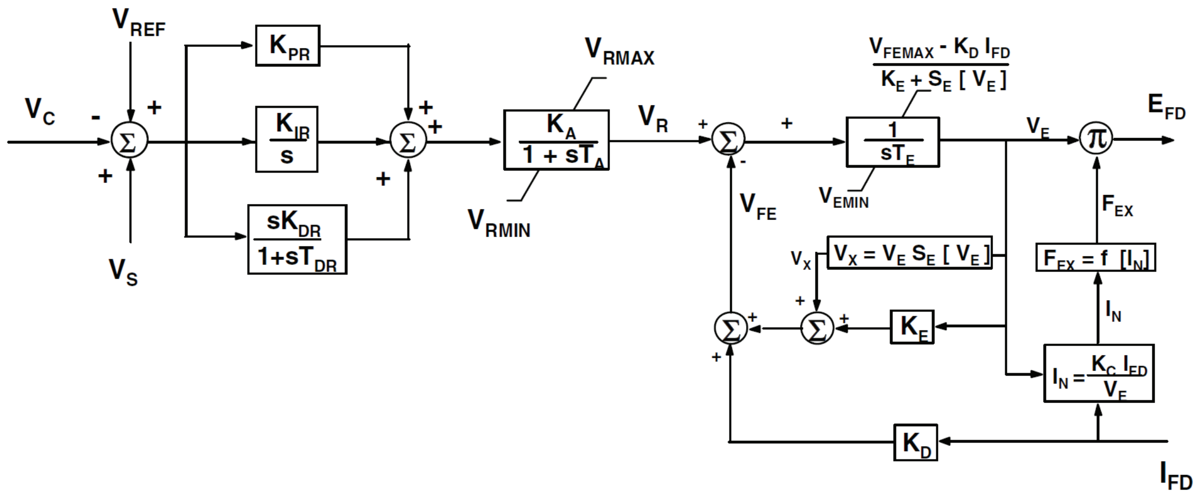


Figure 4.2: Block diagram of AC8B model in PSCAD [61]

To control the reactive power it is common for a synchronous generator to operate with Automatic Voltage Regulation (AVR), manual control of exciter or VAr-/PF control.

DG-units ≥ 1 MVA are required to have AVR as primary reactive power regulation and VAr-/PF- control as secondary [2]. However, it is common for DG-units to operate[8] with VAr control and a PF[9] ≈ 1 [39, 40]. This was confirmed for DG1 and DG2 during the on-site inspection, thus this is chosen for the simulation [17].

A slow[10] outer PI regulator to control the reactive (VAr) power is implemented. The PI regulator forms a slow outer VAr controller, and the voltage regulator, a fast inner voltage regulator [46]. During disturbances the voltage regulator act first, thus the VAr controller slowly adjusts the operation point back to the setpoint [27]. A block diagram of the VAr controller is illustrated in Fig. 4.3. Parameters and description are presented in Table 4.9

[8]If the generator operates with AVR, changes in the network, such as tap changing on transformer, could cause the generator to operate outside its capability curve. Operation outside the capability curve could lead to a trip of the DG-unit by the field protection.

[9]The influence of PF can be found in Appendix G

[10][28] requires a slow regulation, if VAr control is used

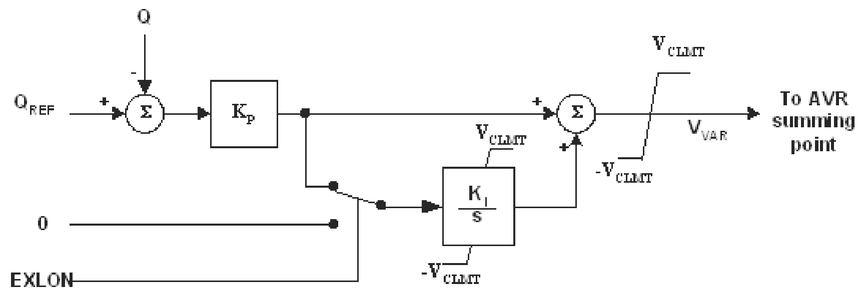


Figure 4.3: Block diagram of VAr controller in PSCAD [46]

The reactive power (Q) is measured at the 22 kV side of the power transformer and compared with the desired reactive power (Q_{REF}). Q_{REF} is set to 0, for all generators in simulations, to obtain a PF ≈ 1. The output of the VAr controller is used as input to the voltage regulator in Fig. 4.2. The slow VAr controller is assumed to have little influence[11] during the faults studied.

The parameters are tuned with base in the recommendations from [46] and set in agreement with [28]. [28] requires the following open-circuit response from synchronous generators with brushless excitation ≥ 0.5 MVA:

- The voltage response should be non-oscillatory.
- 90 % of the final value should be reached within 1 s (corresponds to a voltage of 1.045 pu for a step from 1 pu to 1.05 pu).
- The overshoot must be less than 15 % of the change in value (corresponds to a voltage of 1.0575 pu for a step from 1 pu to 1.05 pu).

Fig. 4.4 illustrates the open-circuit response for DG1 when a voltage step from 1 pu to 1.05 pu is applied. U_{REF} is the reference voltage applied to the voltage regulator and U_G is the voltage at the generator terminals. The dotted lines shows the requirements in [28]. DG2 and G1 are equally tuned, figures can be found in Appendix C.8.

[11] See Appendix G for VAr controller influence

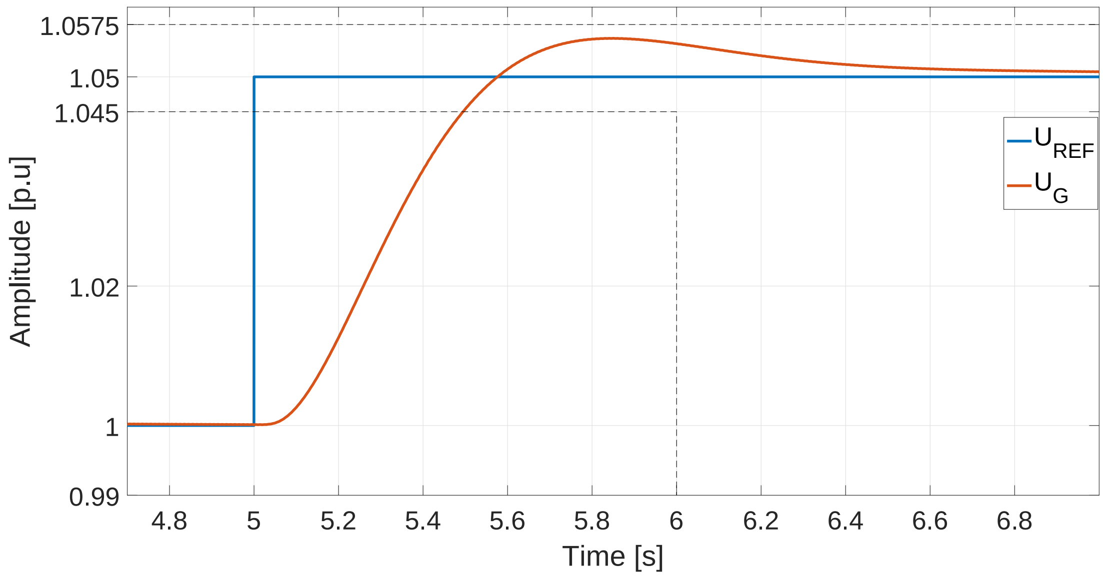


Figure 4.4: Open circuit voltage response for DG1

Table 4.9: Exciter and controller parameters

AC8B Regulator Constants	G1	DG1	DG2	IEEE [46]	Description [46]
K_{PR}	23	18	7	80	Voltage regulator proportional gain
K_{IR} [pu]	23	12	12	5	Voltage regulator integral gain
K_{DR} [pu]	4	2	1.5	10	Voltage regulator derivative gain
T_{DR} [s]	0.1	0.09	0.1	0.1	Lag time constant
K_A [pu]	1	1	1	-	Voltage regulator gain
T_A [s]	0	0	0	-	Voltage regulator time constants
V_{RMAX} [pu]	35	10	35	35	Maximum voltage regulator output
V_{RMIN} [pu]	0	0	0	0	Minimum voltage regulator ouput
AC8B Exciter Parameters					
V_{FEMAX} [pu]	15	35	15	-	Exciter field current limit reference
T_E [s]	0.5	0.5	0.5	1.2	Exciter time constant
K_E [pu]	1	1	1	1	Exciter constant related self-excited field
K_C [pu]	0	0	0	0.55	Rectifier loading factor
K_D [pu]	0	0	0	1.1	Demagnetizing factor
$S_{E1}(E_{FD1})$ [pu]	1.5	1.5	1.5	0.3	Exciter saturation function value, Efd1
E_{FD1} [pu]	4.5	4.5	4.5	6.5	Exciter voltages at exciter saturation
$S_{E2}(E_{FD2})$ [pu]	1.36	1.36	1.36	3	Exciter saturation function value Efd2
E_{FD2} [pu]	3.38	3.38	3.38	9	Exciter voltages at exciter saturation
VAr controller					
K_P [pu]	0.05	0.05	0.05	1	VAr controller proportional gain
K_I [pu]	2.5	2.5	2.5	1	VAr controller integral gain
V_{CLMT} [pu]	0.1	0.1	0.1	0.1	Maximum VAr controller output

To represent a digital based voltage regulator feeding a DC rotating main exciter, K_C and K_D are set to zero [46].

The exciter system is a source for misleading simulation results [27]. No parameters were obtained, thus all are estimated based on recommendations and requirements. However, in actual DG-units the parameters are set individual for each generator.

4.8 Fault

The fault type investigated in this work are three-phase and phase-phase. The faults are applied by the use of Three Phase Fault and Timed Fault Logic obtained from the PSCAD library. The fault resistance is adjusted to acquire the desired voltage drop, this is specified for each case studied.

4.9 Grid Protection in the Modeled Network

The grid protection clearing time is essential for setting the FRT-capabilities of the DG-units, thus they are presented in this section. If the DG-unit is meant to stay online during disturbances, it must withstand the fault until it is cleared by the grid protection. The grid protection on the feeders is in correspondence with the current recommendations using directional OC relays. Fig. 4.5 illustrates the OC protections settings in distribution network studied [6]. Green arrows and text indicate the setting for forward direction and red arrows and text indicate the backward direction. There was not installed relay protection for G, meaning D will trip for fault on feeder G. From the illustration, it can be seen that selectivity between the feeders are fulfilled.

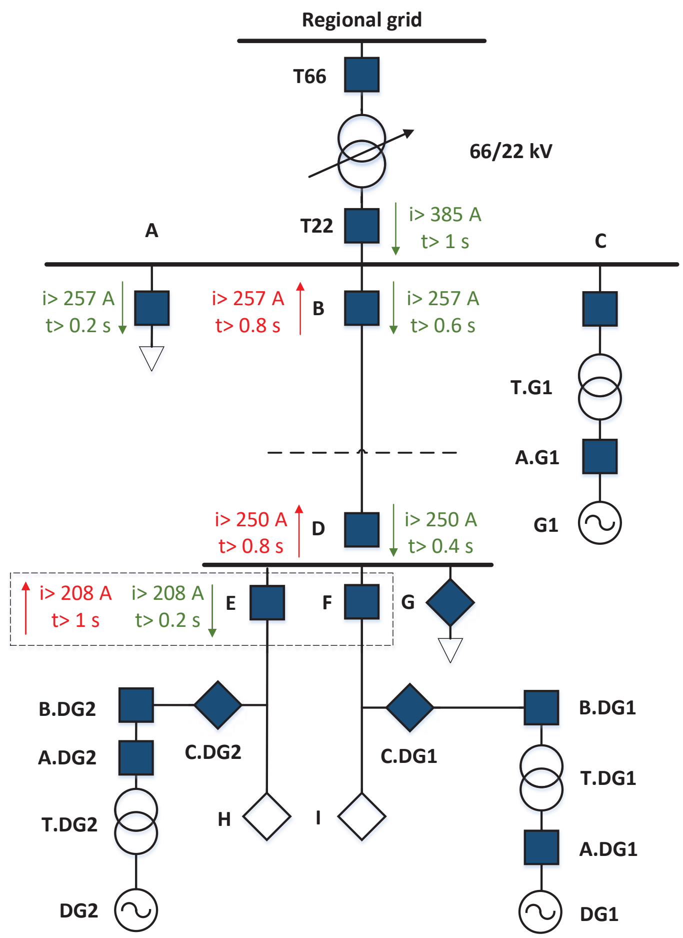


Figure 4.5: Grid protection settings for the case studied network

Automatic reconnection is disabled due to DG on the feeders [6]. Besides, there is implemented earth-fault detection; these are not relevant for the faults studied in this work and are therefore not included.

4.10 Model Improvements

The following should be improved in the simulation model for more accurate results:

- Documentation from the remaining DG-units should be acquired, such that G1 is not representing several DG-units. The DG-units should be modeled separately or examine if the methods presented in [51] or similar literature could be utilized for representation of the unknown DG-units in the network.

- Relay protection with all functions should be implemented to ensure no functions cause unintentional trip (all values are manually checked).
- Actual exciter system parameters should be obtained and applied to generators.
- Inertia constant for DG2 should be obtained.
- Data sheets for transformers should be obtained and implemented.

Chapter 5

Simulation

This Chapter examines if DG1 has adequate FRT-capability to be classified as transient stable. In addition, the industry guideline for grid protection are applied.

5.1 DG-protection in DG1

This section aims to investigate whether DG1 possess FRT-capability to be classified as transient stable and fulfill the requirements in Chapter 2.1. For DG1 to be transient stable, it must keep synchronism for all voltage drops which is not detected by the under-voltage protection setting, $U\ll$. Requirements from Table 2.1 and content from Chapter 4.9 will be the base for the fault scenarios studied.

DG2 and G1 are classified as transient stable. Therefore, results from these will not be presented. DG2 and G1 are kept online for all cases, except for case 2.2 in Chapter 5.1.3.

DG1 will be simulated with the DG-protection settings for a transient stable DG-unit, settings are displayed in Table 5.1. Protection functions are not implemented in the model; all values are manually checked. CBs, relays and transducers are assumed ideal, tolerance and accuracy are not considered.

Table 5.1: DG-protection settings DG1 in simulations

Parameter	**Value**	**Trigger time**
U≫	1.15 pu	0.1 s
U>	1.10 pu	1.4 s
U<	0.85 pu	1.4 s
U≪	0.50 pu	0.1 s
f>	51.0 Hz	0.1 s
f<	48.0 Hz	0.1 s

5.1.1 Fault Scenarios

Fig. 5.1 presents the relevant OC settings for the grid protection and the faults studied in this section. The displayed times are trigger times; additional 0.1 s must be added each to obtain disconnection times.

Faults which cause island operation will not be investigated.

All generators are operating with rated active power and a PF ≈ 1. DG1 produces 1.4 MW, DG2 3.75 MW, and G1 8.57 MW, further details are presented in Chapter 4.

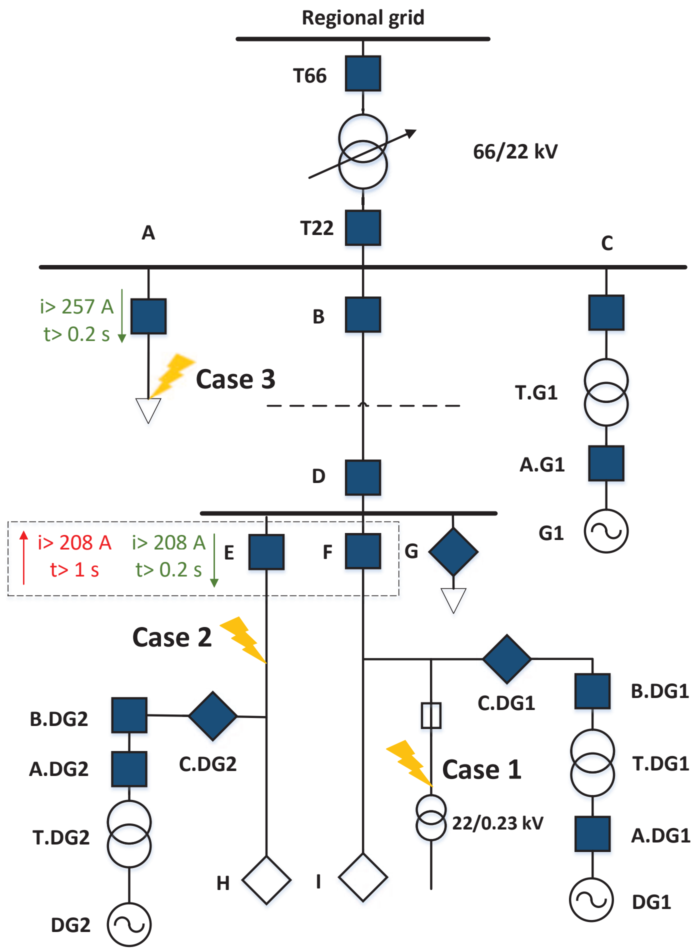


Figure 5.1: Simplified single line diagram with protection settings and fault locations for the cases studied

5.1.2 Case 1 - Fast Disconnected Fault

Case 1 is performed to verify that DG1 is stable for quick faults not detected by the U≪ setting. The fault is applied close to the interconnection point for DG1 with fast disconnection, as illustrated in Fig. 5.2.

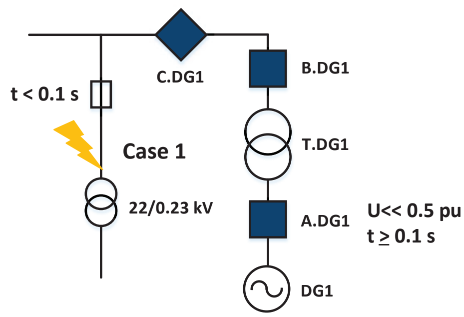


Figure 5.2: Simplified single line diagram for case 1 with relevant protection and fuse settings

The reasoning for case 1 is:

- The recommendation for U≪, is 0.50 pu (50 %) and a total disconnection time of 0.2 s [50]. To achieve a disconnection time of 0.2 s, the trigger time for the relay protection becomes 0.1 s, meaning faults < 0.1 s will not be detected by U≪.
- 0.0 voltage is applied to the interconnection point at DG1 for 0.1 s. The voltage of 0.0 pu would be the worst-case scenario U≪ do not detect and trip A.DG1.
- Case 1 is meant to reflect a fault on a distribution transformer close to the interconnection point for DG1 with fast clearing time. The fault is cleared by the HV fuses, faster than 0.1 s, if the fault current is high enough. DG1 is decoupled by U≪ if the fuse does not operate faster than 0.1 s. Case 1 is the worst-case fuse cleared fault DG1 can experience, i.e. if DG1 is stable for Case 1, it will be stable for all fuse cleared faults in the network.
- Fault resistance is adjusted to 0.01 Ω to reflect a full three-phase fault.

Fig 5.3 displays the voltage obtained from the simulation for substation 66/22 kV and at the interconnection point for DG1. The dotted lines represent the U≪ settings of 0.5 pu and 0.1 s.

The dotted left vertical line marks where $U_{DG1_{22kV}}$ exceeds 0.5 pu (U≪). The right is set 0.1 s after. Thus, the distance between them represents the trigger time.

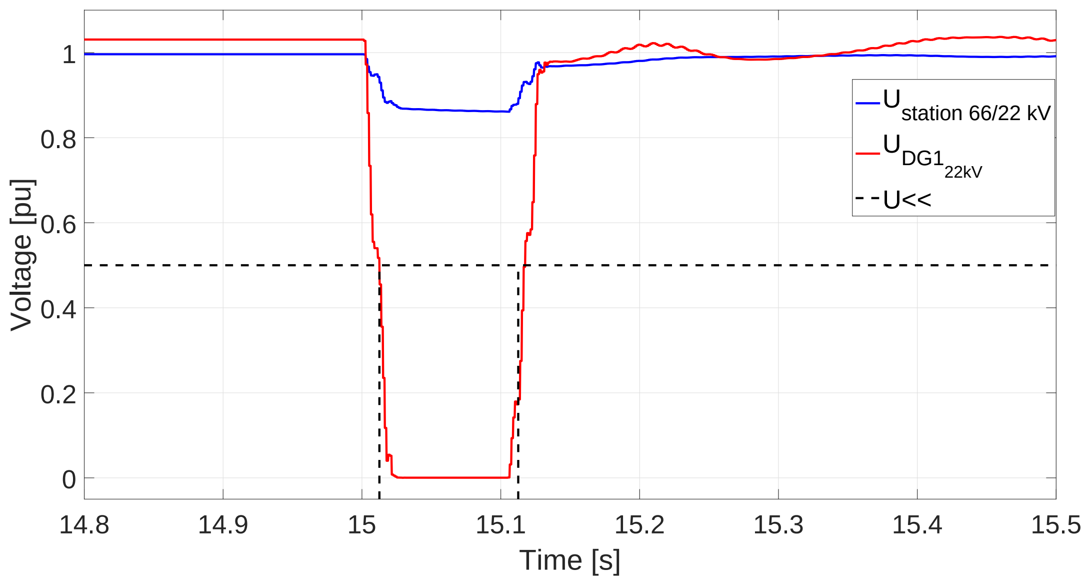


Figure 5.3: Voltage for Case 1

It is observed that the U≪ setting would trip A.DG1 for Case 1, since $U_{DG1_{22kV}}$ exceeds 0.5 pu slightly more than 0.1 s. A.DG1 was not tripped in the simulation; the following figures will present parameters showing DG1 is stable for Case 1.

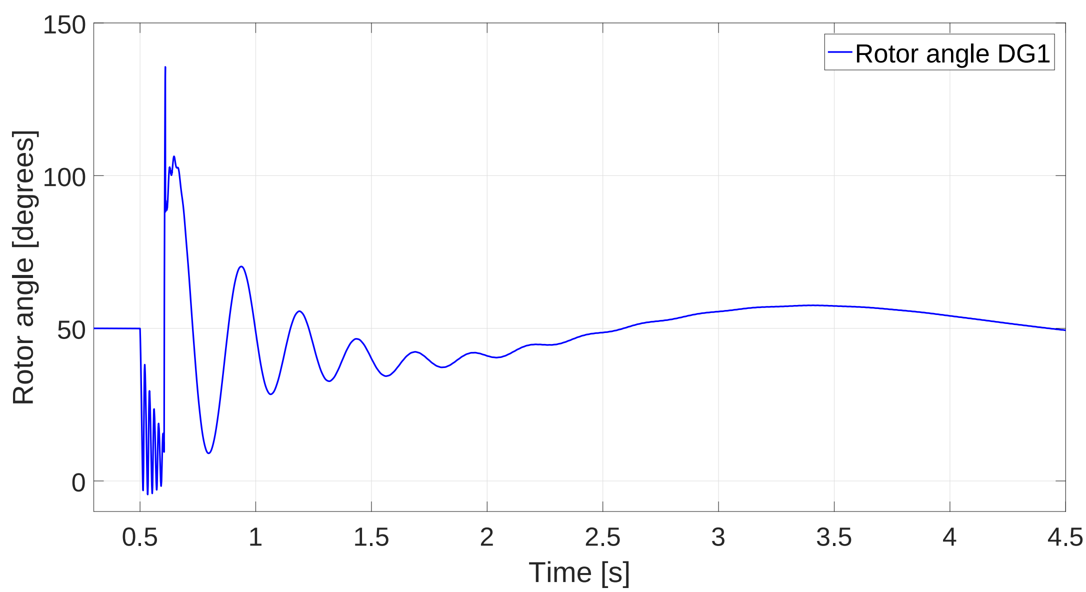


Figure 5.4: Rotor angle response DG1 for Case 1

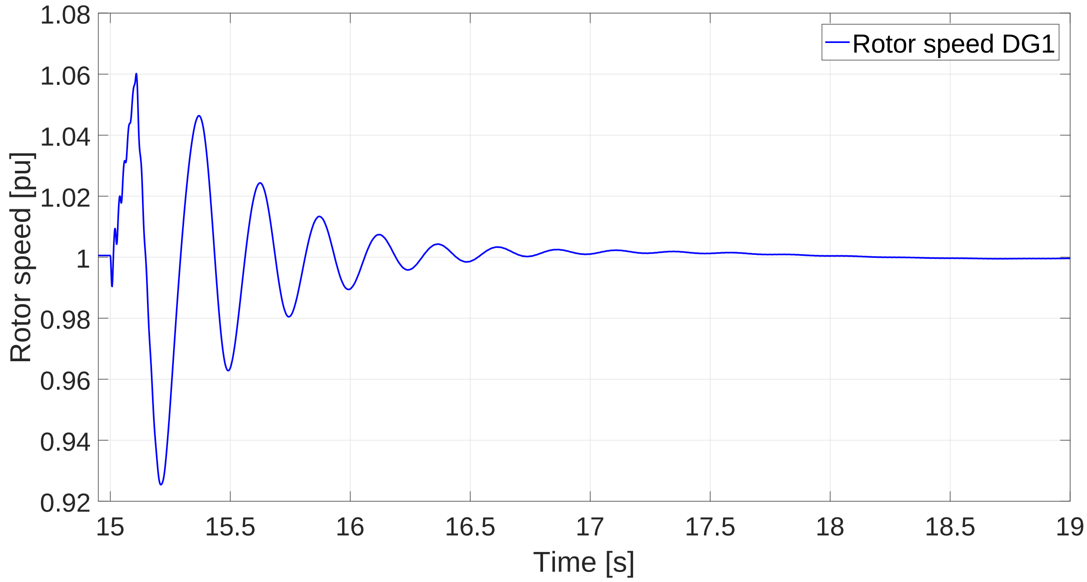


Figure 5.5: Rotor speed response DG1 for Case 1

It is clear from Fig. 5.4 and 5.5 that DG1 is stable for Case 1. The rotor angle and speed response stabilize back to the initial value. The response is considered within the requirement (Chapter 2.1) of keeping synchronism after a large disturbance.

Critical clearing time[1] for case 1 is 0.122 s, figures can be found in Appendix D.1. Critical clearing time gives a safety margin of approximate 22 % for model deviations from actual applications.

For case 1, the over-frequency protection (f>) needs to considered. Fig. 5.6 presents the frequency at DG1 during case 1. The dotted black line marks the DG-protection's f> value of 51 Hz (from Table 5.1), the red dotted lines represents the time interval, Δt_1, the frequency exceeds the f> value.

[1]Maximum time DG1 can stay online during the fault, before falling out of synchronism after the fault is cleared.

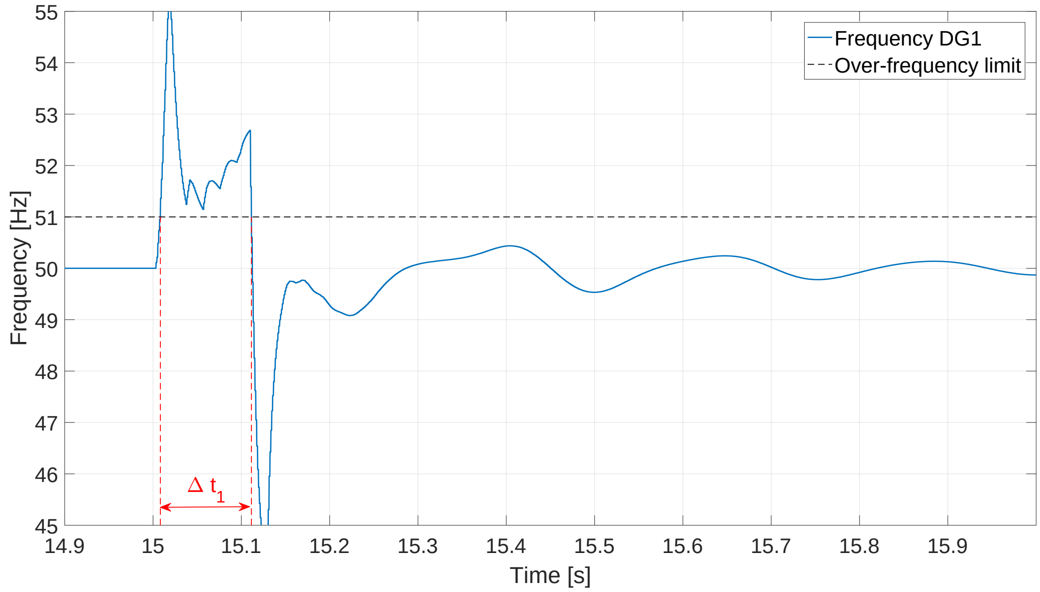


Figure 5.6: Frequency DG1 for Case 1

Δt_1 is 0.1084 s, and greater than the trigger time of 0.1 s from Table 5.1, meaning the A.DG1 would be tripped by the f> function for the assumed ideal protection response.

The relay protection used in DG1 is a DEIF multi-line GPU Hydro. The relay has a simple under-voltage setting that only considers the measured voltage value [14]. More advanced relays, such as the ABB REG670, has the option of blocking over-/under- frequency protection during voltage drops [5]. The blocking option would prevent the over-frequency from tripping during voltage drops. An image of a over-frequency setting with blocking is presented in Appendix A.2.

5.1.3 Case 2 - Fault on Adjacent Feeder

Case 2 is performed to verify that DG1 fulfill the requirement[2] of being transient stable during a three-phase fault on an adjacent feeder, as illustrated in Fig. 5.7.

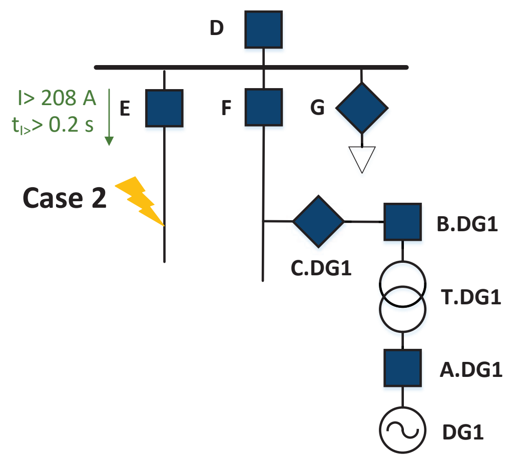


Figure 5.7: Simplified single line diagram for case 2 with relevant protection settings

- A fault on an adjacent feeder can occur at E or G for DG1. G do not have relay protection; meaning D will trip and cause island operation for faults on feeder G. Faults causing island operation is not in the scope of this work. Hence, a fault on feeder E is simulated.
- The three-phase fault applied feeder E, will be cleared by the OC protection[3] after 0.3[4] s.
- The U≪ protection will trip for voltage below 0.5 pu for more than 0.1 s. Since the fault is applied for 0.3 s, the voltage must be above 0.5 pu at DG1, such that the U≪ protection does not trip A.DG1.
- To achieve a retain voltage of approximate 0.5 pu at the interconnection point for DG1, the fault resistance is adjusted to 9 Ω .
- DG2 and G1 contribute to maintain the voltage during faults. Case 2 is therefore performed with and without DG2 and G1; to verify that DG1 could handle a fault on an adjacent feeder in worst-case scenario without other generators connected.

[2]See Chapter 2.1.1 for details
[3]A figure of the OC protection trip on feeder E for case 2.1, is presented in Appendix D.2.
[4]Trigger time + breaker operation time = 0.2 s + 0.1 s = 0.3 s

Case 2.1 - All Generators Connected

Fig. 5.8 presents the voltage at station D, E, F, G and interconnection point for DG1 during simulation of case 2.1 with all generators connected and producing rated active power.

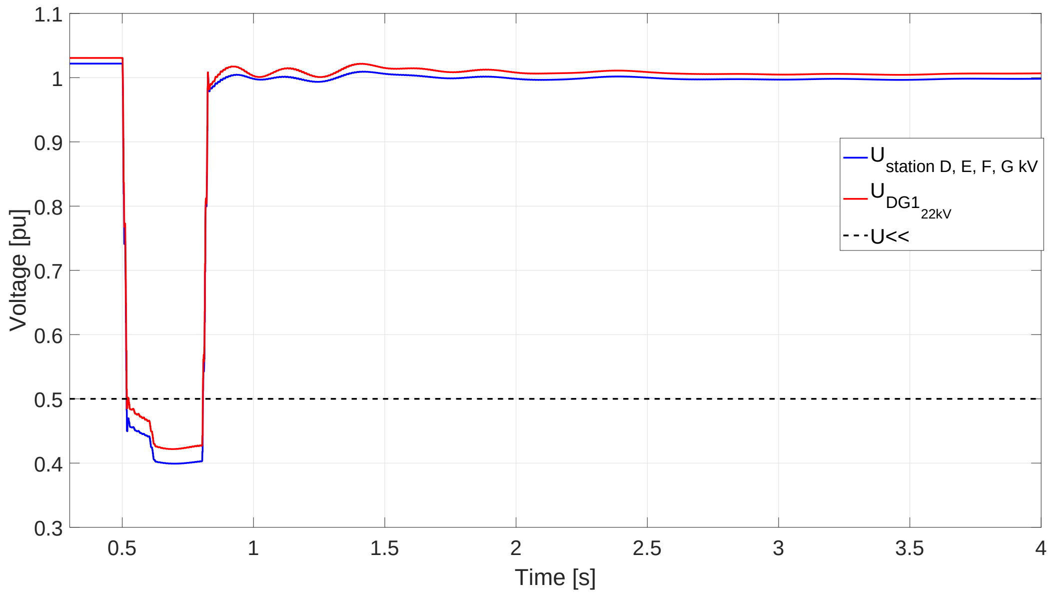


Figure 5.8: Voltage for Case 2.1 with all generators connected

As displayed in Fig. 5.8, the simulation is performed with voltage just below 0.5 pu, to ensure DG1 is stable for 0.5 pu. Fig. 5.9 and 5.10 illustrates the rotor angle and speed for case 2.1.

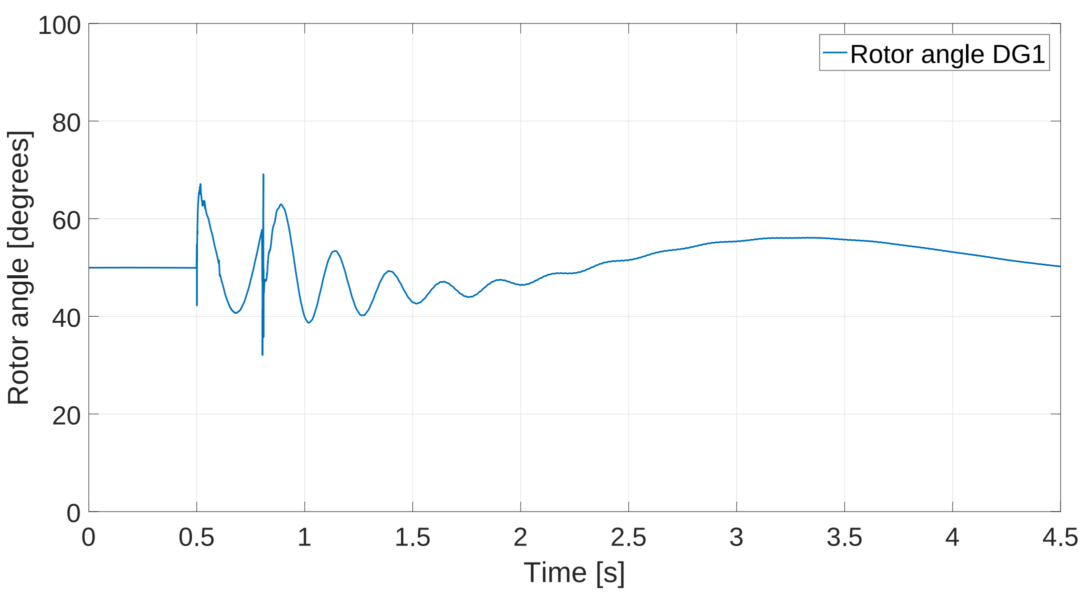


Figure 5.9: Rotor angle response DG1 for Case 2.1 with all generators connected

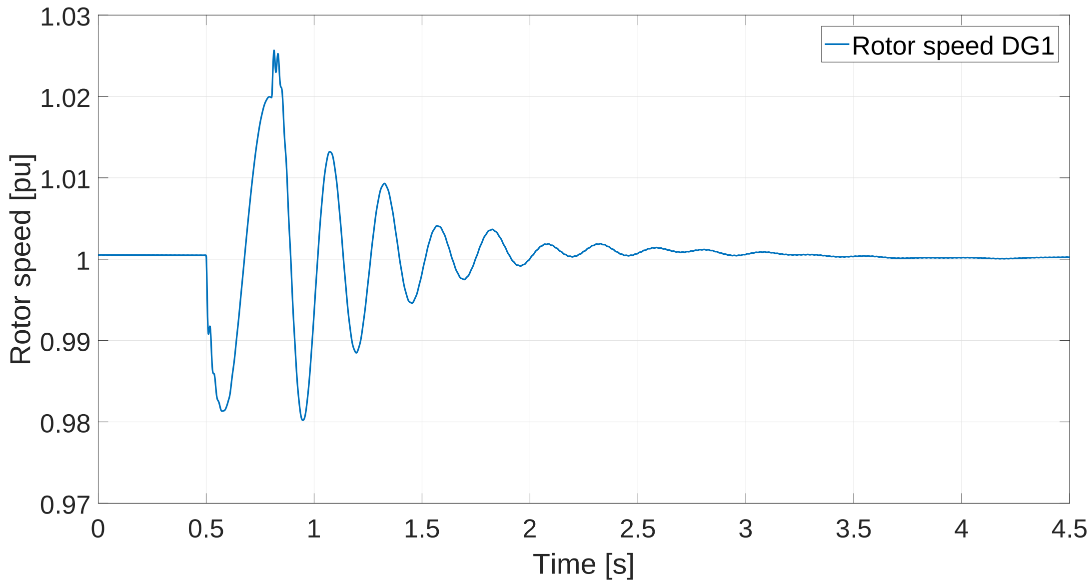


Figure 5.10: Rotor speed response DG1 for Case 2.1 with all generators connected

It could be seen that DG1 is stable for Case 2.1 with all generators connected. The rotor angle and speed response stabilize back to the initial value. The response is considered within the requirement (Chapter 2.1) of keeping synchronism after a large disturbance.

Case 2.2 - Worst-case scenario without DG2 and G1 Connected

To stimulate the worst-case scenario the fault resistance was reduced from 9 Ω to 6 Ω, and DG2 and G1 was disconnected from the grid. Fig. 5.11 presents the voltage at station D, E, F, G and interconnection point for DG1 during simulation of case 2.2 with only DG1 connected.

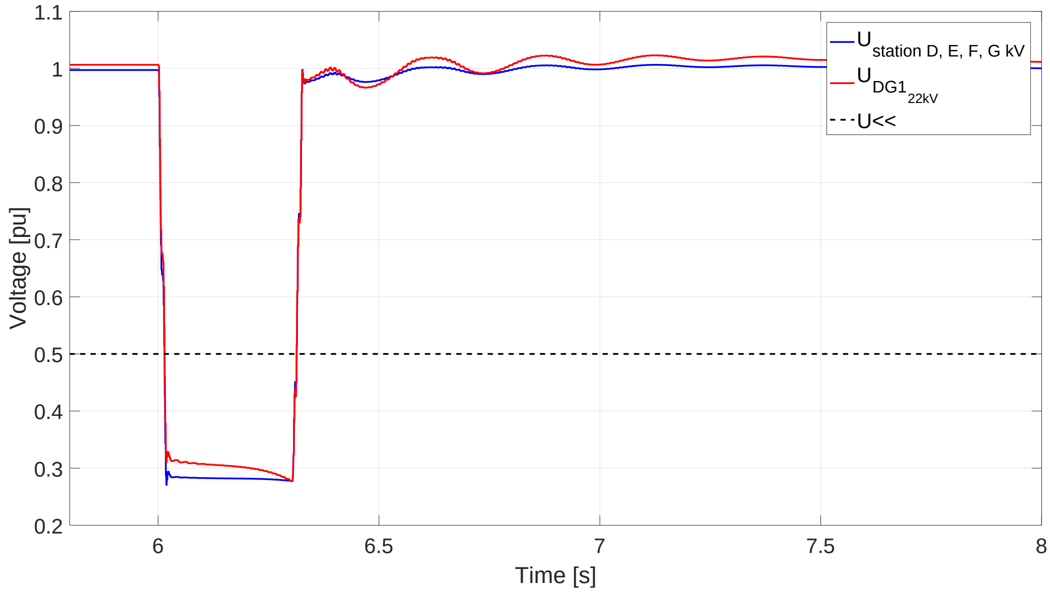


Figure 5.11: Voltage for Case 2.2 with only DG1 connected

As displayed in Fig. 5.11, the worst-case simulation is performed with a retain voltage of approximate 0.3 pu. Fig. 5.12 and 5.13 illustrates the rotor angle and speed for case 2.2.

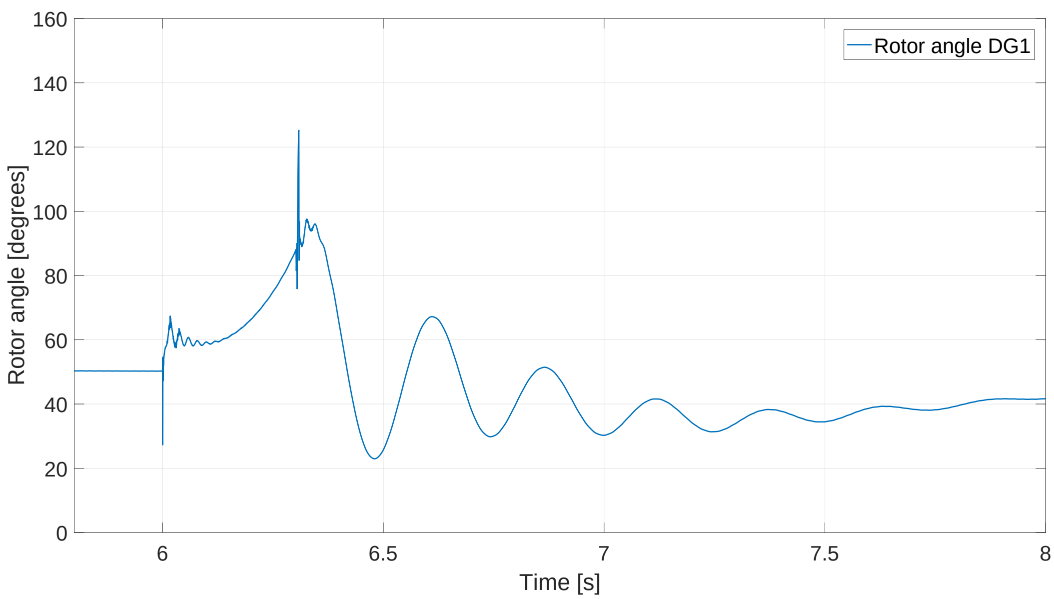


Figure 5.12: Rotor angle response DG1 for Case 2.2 with only DG1 connected

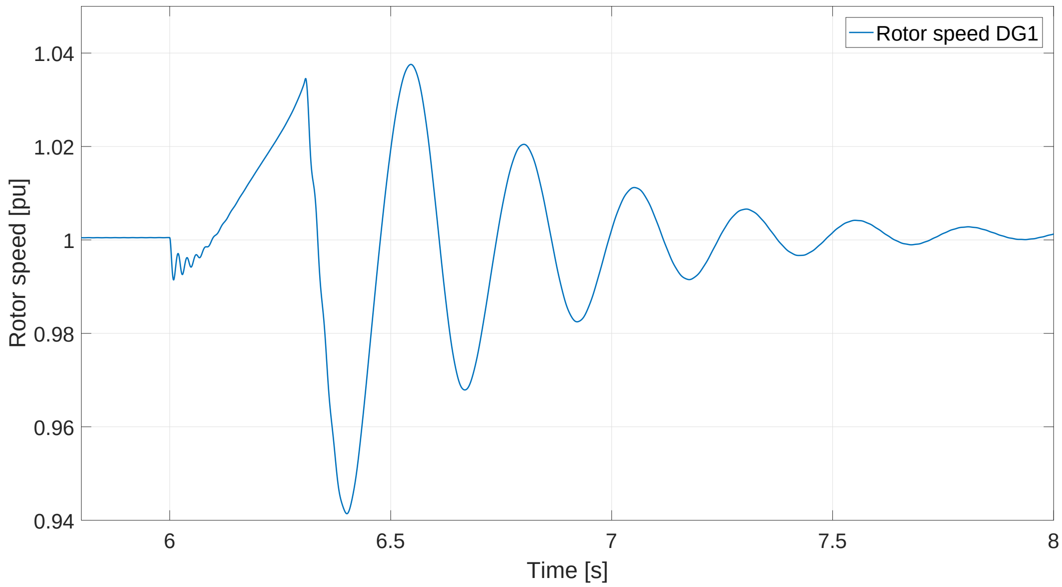


Figure 5.13: Rotor speed response DG1 for Case 2.2 with only DG1 connected

From Fig. 5.12 and 5.13 it could be understood that DG1 is stable for Case 2.2 with only DG1 connected. The rotor angle and speed response stabilize back to the initial value. The response is considered within the requirement (Chapter 2.1) of keeping synchronism after a large disturbance.

5.1.4 Case 3 - Fault at Substation 66/22 kV

Case 3 is performed to verify if DG1 possess the ability to keep stable for faults on feeders at substation 66/22 kV. Fig 5.14 illustrates a simplified single line diagram of case 3.

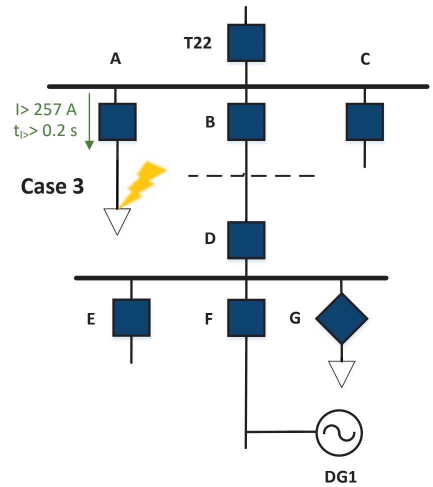


Figure 5.14: Simplified single line diagram for case 3 with relevant protection settings

- As explained in Chapter 4, substation 66/22 kV is a simplified substation. However, the representation of OC protection on feeder A is reflecting actual protection settings. A three-phase fault studied on feeder A will therefore be a realistic fault scenario for DG1.
- The three-phase fault applied feeder A, will be cleared by the OC protection after 0.3[5] s. After 0.3 s, the fault should be cleared by the grid protection on feeder A and DG1 can continue to deliver energy to the power system.
- Case 3 examines if DG1 holds the ability to keep stable for faults at substation 66/22 kV, not detected by the U<< protection.
- To achieve a retain voltage of approximate 0.5 pu at DG1, the fault resistance is adjusted to 2.2 Ω.

Fig. 5.15 presents the voltage at substation 66/22 kV and interconnection point for DG1 during simulation of Case 3.

[5] Trigger time + breaker operation time = 0.2 s + 0.1 s = 0.3 s

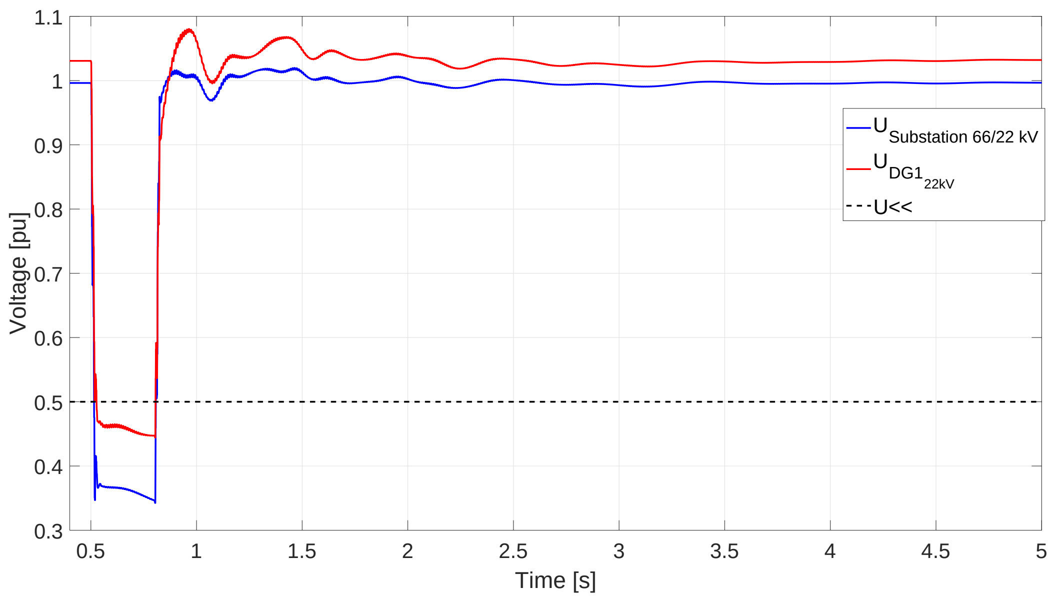


Figure 5.15: Voltage for Case 3

As can be seen in in Fig. 5.15, the simulation is performed with a voltage just below 0.5 pu, to ensure DG1 is stable for 0.5 pu. The difference between the voltage curves is due to the voltage support from DG2 and DG1 during the fault. The voltage regulator increases the excitation during a voltage drop, a consequence is an overshoot in voltage after the fault is cleared due to the response time of the voltage regulator. If the overshoot exceeds the over-voltage settings, A.DG1 is tripped. Case 3 have a sufficient margin to the over-voltage protection of 1.15 pu for 0.1 s (Table 5.1).

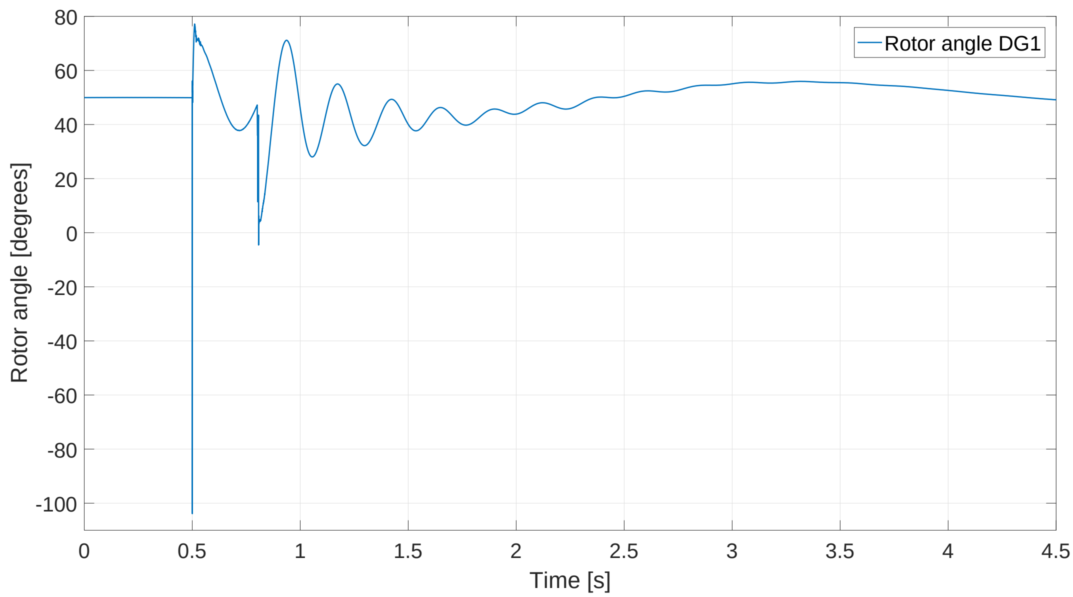


Figure 5.16: Rotor angle response DG1 for Case 3

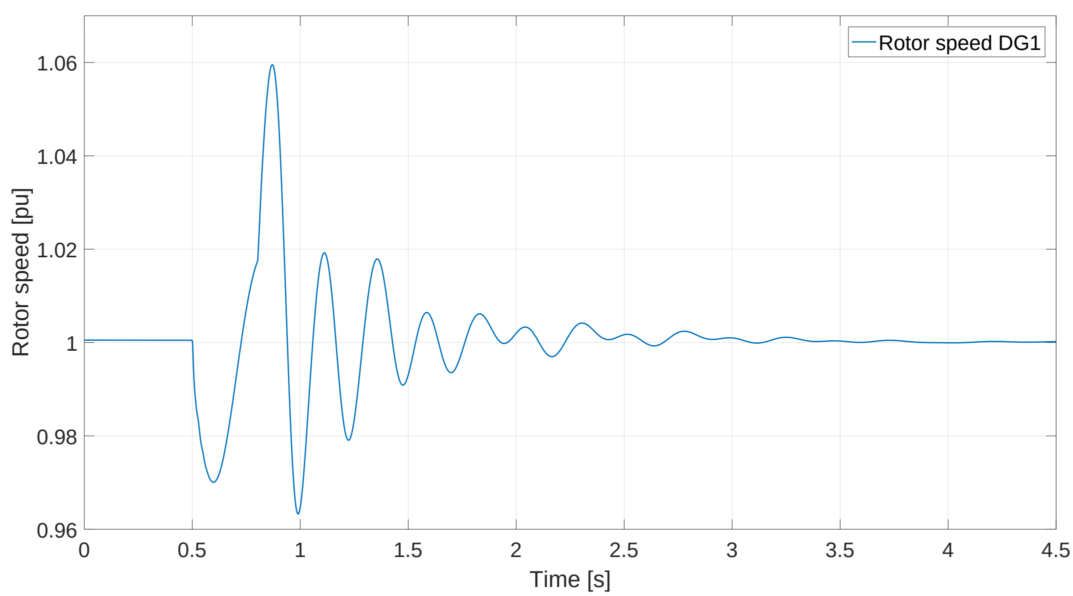


Figure 5.17: Rotor speed response DG1 for Case 3

From Fig. 5.16 and 5.17 it could be understood that DG1 is stable for Case 3. The rotor angle and speed response are to stabilize back to the initial value. The response is considered within the requirement (Chapter 2.1) of keeping synchronism after a large disturbance.

For case 3, the retain voltage at DG1 was adjusted, to investigate the critical voltage point where DG1 became unstable. DG1 handled faults on feeder A with a 0.3 pu retain voltage for 0.3 s without losing synchronism, figures are presented in Appendix D.3.

5.2 Grid Protection in DG1

The grid protection in DG1 is in question for case 4. The industry guidelines in Chapter 3.3 will be investigated, as a part of suggesting a new protection scheme for the grid protection in DG1. Fig. 5.18 illustrates a simplified single line diagram for case 4, with associated protection settings. The notations in Fig. 5.18 will be used throughout this section.

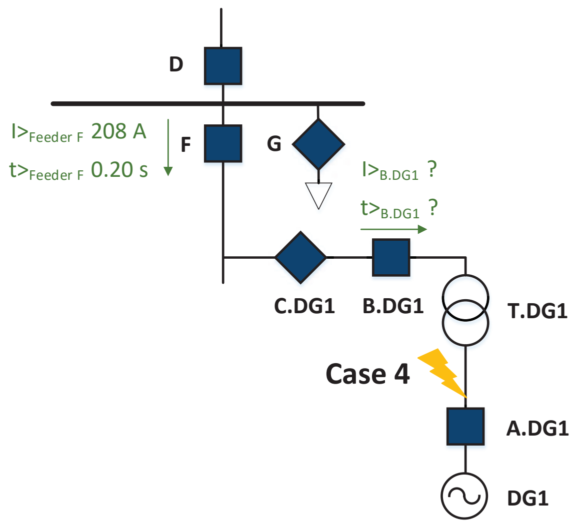


Figure 5.18: Simplified single line diagram for case 4 with relevant protection settings

From Chapter 3.3 the industry guidelines are given as:

- The grid protection should protect against internal faults.
- OC protection starting value should be set in agreement with (5.1).
- The OC protection, $I>_{B.DG1}$, should be set selective above the grid protection at feeder F, hence grid protection in DG1 trips B.DG1, before F is tripped. With a trip time of 0.2 s at feeder F, the fault has to be cleared by B.DG1 within 0.2 s.
- The lowest possible fault current (two-phase short-circuit) is applied on the LV side of T.DG1.

$$1.2 \cdot I_N < I_S < 0.7 \cdot I_{fault,min} \tag{5.1}$$

Table 5.2 presents the currents considered for the suggested grid protection. All values are referred to the 22 kV side of T.DG1, to agree with the values the grid protection monitor. Estimated transformer parameters could give an misleading result of the obtained values from PSCAD presented in Table 5.2.

Table 5.2: Currents considered for grid protection in DG1

Parameter	**Current$_{\mathbf{22\,kV}}$ [A]**	**Applying rule from (5.1)**
I_N	50	60 A
$I_{fault,min}$	311	218 A
$I''_{\text{k, max, DG1}}$	155	N/A
$I>_{\text{feeder F}}$	208	N/A

Applying values from Table 5.2 to (5.1) gives a starting current of:

$$60A \; < \; I_S \; < \; 218A \tag{5.2}$$

Most of the grid protection relays are equipped with a directional OC function (CT and VT installed). Directional OC should be used to prevent unintentional tripping for external fault, this is essential in cases were $I_S \geq I''_{\text{k, max, DG1}}$.

To achieve selectivity, $t>_{\text{B.DG1}}$ must be set below 0.1 s, such as the fault is cleared within the trigger time for $t>_{\text{Feeder F}}$ of 0.2 s.

To ensure selectivity, $I>_{\text{B.DG1}}$ should be set less or equal to $I>_{\text{feeder F}}$. If there is a large gap between them, the time $t>_{\text{B.DG1}}$ starts earlier than $t>_{\text{Feeder F}}$, which may endanger selectivity.

The suggested grid protection for DG1 is presented in Table 5.3.

Table 5.3: Suggested grid protection for DG1

Parameter	**Value**	**Time**	**Description**
$I>_{\text{B.DG1}}$	208 A/ 4.16 pu	0.05 s	Directional OC

Inrush current and earth-faults are not discussed in the industry guidelines, and therefore not in the scope of this work.

5.3 Analysis Improvements

Independent if the suggestions in Chapter 4.10 are implemented, a sensitivity analysis of all estimated parameters, specially the most influenced from Table G.1, should be performed.

5.4 Recommended Protection Settings for DG1

The simulation results indicate that DG1 holds the ability to be classified as transient stable. Table 5.4 and 5.5 presents the recommended protection settings for DG1. The settings are recommended on the condition that the suggested improvements in Chapter 4.10 and 5.3 is carried out. Tolerance and accuracy for the relay components: transducer, relay and CB should be acquired and considered to ensure that the safety margin for case 1 is sufficient.

Table 5.4: Recommended DG-protection settings for DG1

Parameter	**Value**	**Trigger time**
U≫	1.15 pu	0.1 s
U>	1.10 pu	1.4 s
U<	0.85 pu	1.4 s
U≪	0.50 pu	0.1 s
f>	51.0 Hz	0.1 s
f<	48.0 Hz	0.1 s

Table 5.5: Recommended grid protection settings for DG1

Parameter	**Value**	**Time**	**Description**
$I>_{B.DG1}$	208 A/ 4.16 pu	0.05 s	Directional OC

Chapter 6

Summary and Discussion

Relay protection is a broad theme with many variables in practical implementation, the most relevant findings in this thesis are discussed and presented in the following sections.

6.1 DG-protection

In the first part of Chapter 2, a summary of current requirements for DG-protection was presented. The current requirements adhere to DG-units which are classified as transient stable. For a transient stable DG-unit, DG-protection requirements mainly contain specified voltage- and frequency- settings (Table 2.1).

In general, generators above 0.5 MW are recommended to be transient stable. However, the influence a DG-unit has on the power system should be considered. It is not possible to determine this influence accurately without dynamic evaluation or analysis. The main advantages of a dynamic analysis for the DG-owner are:

- Create a solid basis for designing a well-operating DG-unit which results in reduced downtime.
- Utility companies could set high requirements with large margins to ensure the DG-unit does not cause problems. If the analysis concludes that the utility company's requirements are unreasonable, it could result in a reduced investment cost.

A dynamic analysis has an expense the DG-owner possibly cannot afford on a tight investment budget.

Six out of the seven investigated DG-units are assumed classified as transient stable, one out of seven, is not. Two of the transient stable DG-units are assumed to have a basis from a dynamic analysis (Table 2.8). There was not found any dynamic analyses for the remaining transient stable DG-units. Despite [50] requires, and [27] states dynamic analysis is common practice, this does not reflect current industrial behavior. The remaining DG-units are assumed transient stable due to their rating. This assumption could lead to a false impression of the actual industrial practice.

Faults in the power system will cause a voltage drop. Hence the under-voltage settings are the most crucial, with respect to FRT-capability. Dynamic analysis is a necessity to obtain accurate information about the FRT-capability of the DG-unit in the relevant power system. The protection settings should be the limiting factor of the FRT-capability, meaning the DG-unit must be decoupled by protection from the main grid previous to loss of synchronism. Configuring protection settings without unnecessary limiting the FRT-capability of a DG-unit, could therefore be impossible without a dynamic analysis.

DG-protection settings were examined for the six transient stable DG-units, to investigate if the current protection requirements (Table 2.1) have been enforced to DG-units by the utility companies. It could be perceived that DG-units built before 2011 have conservative under-voltage settings, compared to the current requirement (Table 2.8). [3] was published in late 2010, probably as a result of an increased focus on DG influence, and could explain the division. More DG-units should be investigated to see if the whole industry follows the trend found from the examined DG-units in this work (attempts of gathering more information from suppliers were unsuccessful).

The supplier provides a guarantee on the equipment, and without accurate information regarding FRT-capability of the DG-unit, the cheaper, simpler and safe solution will be to use conservative settings. This solution comes at the expense of the DG-owner and utility companies interest of a DG-unit with good FRT-capability. Still, the DG-owner and the utility company decide whether a dynamic analysis should be performed or not. If the supplier can freely decide the settings, it would naturally lean towards its own interest by protecting the equipment with conservative settings. If the supplier follows the requirement without foundation in a dynamic analysis; they would be left with all the risk, since a DG-unit not restrained by protection could lose synchronism due to lack of FRT-capability, and cause severe problems for the DG-unit and the connected power system.

The non transient stable DG-unit, DG1, had a rating of 1.4 MW and was above the recommended limit of 0.5 MW. Conservative under-voltage setting were observed, disconnecting DG1 instantly for voltages below 0.9 pu (Table 2.5), while the requirement for non transient stable DG-units is disconnection for voltages below 0.85 pu within 0.2 s. The rating suggests DG1 should be classified as transient stable. Therefore a dynamic analysis of DG1 was performed and is further discussed in Chapter 6.4.

As of lately, there has been an increased focus on DG integration as problems occurred with an increasing number of DG installations. The increased attention of the DG-units' influence on the power system demands more knowledge and information about the units themselves. To cope with the challenge of inadequate documentation, Statnett has an ongoing project where all utility companies must submit proper documentation for new and existing components. The deadline[1] for reporting existing production units is set to 1.8.2017. As a result of this, the utility companies are now gathering documentation from DG-units under their control.

The use of conservative protection settings on earlier DG-units could, as mentioned, be in the interest of the supplier. Whether the existing DG-units with conservative settings can handle lower value limits, in compliance with the current requirement, cannot be determined without a comprehensive dynamic analysis for each DG-unit. Dynamic analysis demands high qualifications and proper documentation. With 575 SHPs and apparently inadequate documentation in Norway, this could be a costly and time-consuming task. An increased focus on DG-protection, FRT-capability and documentation should contribute positively to the challenge. The conservative behavior regarding industrial practice, which was reviewed in this work, might be expanded to show systematic behavioral patterns present in the whole industry by the documentation gathered by Statnett. While the current work only cover a small subset of DG-units, its findings do present a good case for further investigation.

[1] http://www.statnett.no/Kraftsystemet/Systemansvaret/Fosweb/Fosweb-Kraftsystemdata/Tidsfrister/

Another aspect of the current requirements, which is of great concern for the utility companies, is the anti-island[2] protection. Island operation is not desired unless the DG-unit is designed for the purpose, which they rarely are. By keeping the transient stable DG-units online during faults, the risk of island operation increases. The current requirement states that the DG-unit must disconnect within 1 s after island operation and vector shift- and RoCoF- protection are not recommended on transient stable DG-units; this does not fit with the increased risk of island operation for transient stable DG-units. To perform FRT tests in [27], vector shift protection was deactivated. Deactivation during tests and the recommendation of not using conventional anti-island protection, such as vector shift- and RoCoF- protection indicate that the standard anti-island protection is not suitable for transient stable DG-units. This conflicts with all the investigated DG-units which had the functions activated. It can be understood that the traditional anti-island protection restricts the FRT-capabilities during faults and new anti-island methods should be used for transient stable DG-units. The indication could be confirmed by analyzing historical trip data at existing DG-units. If conventional anti-island protection is used, a dynamic analysis with protection functions implemented could verify that these do not limit the FRT-capabilities unnecessary during faults. This work has not recovered information of how anti-island protection settings are calculated.

The future FRT-requirements seems moderate compared to the current ones. The biggest change is that utility companies can require simulations and tests to prove compliance with the requirements, which they do not consistent require today. The inconsistent use of dynamic analysis could be due to a financial conflict between the utility company and the DG-owner. Statnett will present the final results of their suggestion at the end of summer 2017; protection settings are also assumed to be presented at that point. The final requirement from NVE are scheduled to be brought into effect after the second quarter of 2019.

[2]Island operation occurs when a DG-unit is decoupled from the main power system [39]

6.2 Grid Protection with DG

6.2.1 Grid Protection in DG-units

In Norway, the utility company control and operate a CB on the HV side of the power transformer in DG-units.

The lack of formal guidelines, such as the existing requirements for DG-protection, seem to cause a diversity in the use of grid protection. For the not transient stable DG1, the settings (Table 3.1) are configured as a backup for the DG-protection to ensure decoupling during disturbances. If the utility companies want to eliminate the negative consequences of the DG-unit, they can set the grid protection conservative, such as DG1. Conservative settings could especially be applied by the utility companies if there is no communication between the control center and the DG-unit since the status of the DG-units has to be manually checked during fault correction, when the time pressure is high. The conservative settings are a disadvantage for the DG-operators that must involve the utility company to operate the CB since DG-operators do not have this authority. If the control center can not remotely control the CB, e.g. in DG-units where communication is not installed, response time can become high and cause severe downtime and reduced production. Utility companies are responsible for the reliability of the power system, thus the DG-units are not a priority if there is not available capacity, e.g. during fault correction after large disturbances.

The industry guideline states that the grid protection should protect against internal faults, so the feeder protection does not trip. The condition to set the grid protection in agreement with the industry guideline is that the DG-protection is configured in compliance with current requirements. If the utility companies are uncertain whether DG-protection settings is adequate, naturally, they lean towards the safe conservative settings, i.e. conservative settings could be prevented with proper documentation, ensuring the utility companies to rely on the DG-protection.

6.2.2 Grid Protection on feeders with DG

The feeder protection recommendations seem to be well-adapted to DG with directional OC and distance protection.

Automatic reconnection is not recommended and appears to be disabled on feeders with DG. The utility companies consider the risk of DG-units operating in island operation too high. The risk of island operation is also an incentive for conservative settings in DG-protection.

A recommendation is to install an extra VT on the feeder side of the CB in the substation; this is often not possible due to space restriction in existing substations.

Alternatively, the dynamic analysis could include investigation of island operation. If the dynamic analysis verifies the time needed for the anti-island protection to trip during a loss of main grid, the automatic reconnection time can be adjusted accordingly. This may not be reliable enough in practice since the consequence is to large compared to the upside.

Control centers can have communication with the utility companies relay protection in the DG-units and the relays in the substations. The time response for island detection is not as strict as for other relay communication, e.g. differential protection. The potential of using existing communication for relay communication between the feeder relay and DG-unit relay might be sufficient as a redundant anti-island protection and should be further investigated.

A cost-effective and reliable solution to enable automatic reconnection on feeders with DG is also needed on the path towards a smart and self-healing network.

6.3 Simulation model

An actual network with two DG-units was modeled in PSCAD. Modeling of a such a network with many components is a comprehensive and time-consuming task. The challenge of inadequate documentation was exposed during modeling, which led to some assumptions being necessary. The most critical were the simplification of G1 that represents several other DG-units connected to other feeders at substation 66/22 kV. Comparison of short-circuit currents and power flow with NETBAS justified that the model was adequate to perform simulations. Improvements for the model was suggested in Chapter 4.10.

6.4 Simulation results

6.4.1 DG-protection in DG1

In Chapter 5.1 it was examined if DG1 possessed the FRT-capability to be classified as transient stable. Three cases was investigated for the purpose.

Case 1

Case 1 revealed a critical issue regarding dynamic analysis without protection functions implemented. DG-protection have several functions monitoring the power system, and none should unnecessary restrict the FRT-capability. DG1 remained synchronized after the fault in case 1, and the studied under-voltage protection appeared adequate. Still, the over-frequency function would have tripped the GB, restraining the FRT-capability of the DG-unit. [27] also experienced unintentional trip by protection functions during FRT tests. Implementing protection functions and parameters in the dynamic analysis to prevent unintended tripping and limitations of FRT-capabilities should be considered. A revised version of the presented functions in Table 2.2 could be a suitable basis for developing an analysis standard.

More advanced relays have blocking options during faults. The relay in DG1 does not have blocking options available. To avoid unintentional tripping during case 1, over-frequency limit or time delay should be increased. Considering it is a worst-case situation it could be ignored, nonetheless, it highlights the potential pitfall with dynamic analysis without implementation of protection functions.

Case 2

The disconnection time for the grid protection on nearby feeders has a significant influence for the FRT-requirement of the DG-unit. Case 2 (Chapter 5.1.3) was performed to investigate if DG1 could handle a fault on an adjacent feeder. Critical clearing time was found to be 1 s or more for case 2, giving a large safety margin. To eliminate the voltage support from other generators during a fault, case 2 was tested with and without DG2 and G1 connected. The retain voltage at the interconnection point was adjusted to approximat 0.3 pu and DG1 kept synchronism for the worst-case scenario without DG2 and G1 connected. The worst-case scenario verified that DG1 can handle faults on adjacent feeders independent of other production units in the network.

Case 3

Case 3 (Chapter 5.1.4) was performed similar to case 2 with a fault applied a feeder at substation 66/22 kV. DG kept stable for case 3. To investigate the margin for case 3, the retain voltage at the interconnection point for DG1 was lowered. For case 3, DG1 handled a fault that caused a retain voltage of 0.3 pu for 0.3 s at the interconnection point.

Summary

DG1 appear to possess the FRT-capability to be classified as transient stable. However, simulation model deviations should be considered. The critical clearing time for case 1, seems to be the most critical with a transient stability margin of 22 %. The voltage support from other generators should not contribute to the stability of DG1 during case 1 since the voltage is 0.0 pu at the interconnection point, thus case 1 is considered worst-case. Case 2 and 3 was tested thorough and indicate a sufficient margin. The protection components are assumed ideal, which do not consider tolerance limits or accuracy for neither the relay, CB or transducers. For quality assurance the following should be performed:

- The model should be improved with the suggestions in Chapter 4.10.
- Tolerance limit and accuracy of components should be taken into account.
- Obtain a second opinion from an experienced person with this field of expertise.

The quality assurance measures should be performed before DG-protection in DG1 is adapted to transient stable protection settings. Alternatively, the margin could be increased by reducing the under-voltage trip time to the suggested future requirement of 0.05 s (Chapter 2.3).

6.4.2 Grid Protection in DG1

In Chapter 5.2 the grid protection for DG1 was in question. The industry guidelines from Chapter 3.3.3 was applied and analyzed and resulted in new grid protection settings for DG1. Magnetizing current and earth-fault should also be considered; these are not regarded as a part of this work.

Chapter 7

Conclusion and Scope of Future Work

7.1 Conclusion

The main conclusions of this work are presented below:

- The industry has expressed that the current requirements for transient stable DG-units are too strict and should be re-evaluated. This concern is reflected in the industrial practice of applying conservative protection settings to disconnect DG-units during faults in the grid.
- The practice of applying conservative protection settings seem to predate 2011. In the companies reviewed, an increased focus along with the publication of utility standards have lead to more reasonable settings.
- Dynamic analysis should be performed to provide an accurate description of the DG-units influence on the power system. Four out of six examined DG-units had no basis in dynamic analysis. There was not found a clear correlation between dynamic analysis and conservative protection settings.
- Suppliers could act in their own interest and utilize a lack of requirements from the utility companies to set conservative protection settings.
- Lack of or inadequate documentation is a challenge for creating sustainable protection schemes and performing accurate dynamic analyses.
- Vector shift- and RoCoF- protection are common used for transient stable DG-units. The protection might restrict the FRT-capabilities of DG-units and could be used as a safety margin from the suppliers.
- Verifying anti-island protection through dynamic analysis or demanding new reliable anti-island protection, which does not compromise FRT-capability, should be

investigated, since the common industrial practice is reviewed to be inadequate. Reliable anti-island protection could also enable automatic reconnection on feeders with DG.

- The DG-protection could comply with current requirements. However, the DG-unit could still trip for other functions if these are not coordinated and accounted for. A protection standard covering all activated parameters should be established. The standard should be implemented to dynamic analyses.
- Future FRT-requirements follow a more moderate line compared to the current requirements. Utility companies could require dynamic analysis to prove compliance with these requirements; this solves the wide range of practices found today.
- DG-protection settings are highly influenced by the disconnection times for grid protection on feeders. A large disconnection time could cause unrealistic FRT-requirements for the DG-unit.
- The grid protection on DG-units lack formal guidelines, such as for DG-protection. As a result, the purpose of the grid protection varies and creates different and unfair conditions for DG-units depending on the utility company. Formal guidelines should be created with the current industrial guidelines as a foundation, and expanded to existing DG-units if possible.
- DG1 could be an example of the situation for many DG-units in Norway. The present DG1 protection settings are too conservative and restrict DG1 to utilize its FRT-capability, causing unnecessary downtime. New sustainable protection settings were suggested and recommended.
- The conservative behavior regarding industrial practice, which was reviewed in this work, might be expanded to show systematic behavioral patterns present in the whole industry by the documentation gathered by Statnett.

7.2 Future Work

The work performed in this thesis has led to promising conclusions regarding protection of DG-units. Challenges with current requirements were uncovered, and improvements have been suggested. However, some indications should be further investigated to confirm the suspicion and ensure all aspects are considered:

- Obtain DG- and grid- protection settings from suppliers and various utility companies to confirm indications on conservative protection settings.
- Get a supplier and dynamic analyst point of view on the findings. A neutral basis can be hard to obtain if not all parts are heard (Suppliers have been tried contacted without response).
- The suggestions presented in Chapter 4.10 and 5.3 should be carried out to quality assure the new protection recommendations for DG1.
- Recommend a protection function standard that can be used in dynamic analyses. The Statkraft internal standard could be a suitable basis. Further, it could include a coordination plan between DG-protection and other protection functions that could trip the GB, e.g. PLS and voltage regulator.
- Analyze the historical downtime for DG-units with and without conservative settings in the same network and calculate the economic impact of conservative protection settings.
- Investigate out-of-step protection as a redundancy to the under-voltage settings. Out-of-step protection could possible trip the GB, resulting in a reduced need for transient stability safety margin.
- Analyze historical trip data at existing DG-units to verify the indication of misguided use of vector shift- and RoCoF- protection.
- Consider accuracy and tolerance in CB, relays, and transducers. Find documentation on components and calculate the theoretical safety margin needed and compare with the safety margin for best-practice in the industry. Recommend a safety margin utility companies can use to verify the results from dynamic analyses.
- Perform a dynamic analysis with anti-island protection implemented on existing DG-units and compare with future and historical trip events. Could confirm if a dynamic analysis is a reliable solution to enable automatic reconnection on a feeders with DG.
- Examine if existing communication can be utilized as a cost-efficient and redundant anti-island protection.

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Appendix A

DG-protection Explanation

DG-protection or generator protection is referred to as the relay protection monitoring the low-voltage values of the power transformer and operating the GB.

A.1 Voltage Protection

If a change in reactive power occurs between the generator and network, this would lead to a change in voltage. The relay protection monitors the voltage and trips the CB if the limit value is exceeded [41]. Table A.1 displays the most common specified requirements for a DG-unit.

Table A.1: Explanation for over-/under- voltage protection limit values

Limit value	**Explanation**
$U\gg$	Upper limit value for momentary disconnection
$U>$	Upper limit value that disconnects if the voltage exceeds the limit value within a specified time delay
$U\ll$	Lower limit value for momentary disconnection
$U<$	Lower limit value that disconnects if the voltage exceeds the limit value within a specified time delay

Table A.1 shows the common settings, however some relays have more advanced functions, including several other parameters in the voltage protection. Fig. A.1 presents an example on a actual ABB REG670 under-voltage protection relay [22]. For details regarding parameters and their functions please see [5].

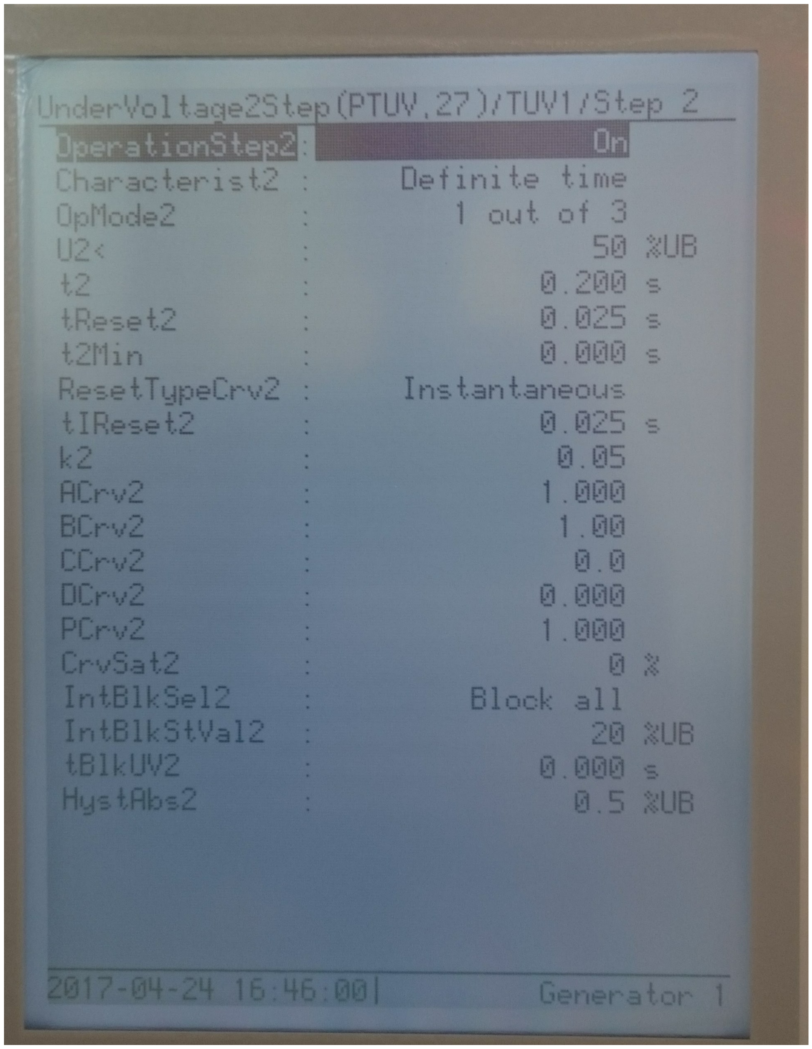

Figure A.1: Screen dump from an actual ABB REG670 under-voltage protection settings on a DG-unit [22]

A.2 Frequency Protection

A.2.1 Over-/under- Frequency Protection

Over-/under- frequency protection measures the phase voltages zero crossing. The change in frequency is compared with the protection limit value and CB is tripped if the limit value is exceeded.

Table A.2: General over-/under-frequency protection

Limit value	**Explanation**
f>	Upper limit value for momentary disconnection
f<	Lower limit value for momentary disconnection

Table A.2 shows the common settings, however some relays have more advanced functions, including other parameters in the frequency protection. Fig. A.2 presents an example on a real-life ABB REG670 over-frequency protection relay [22]. For details regarding parameters and their functions please see [5].

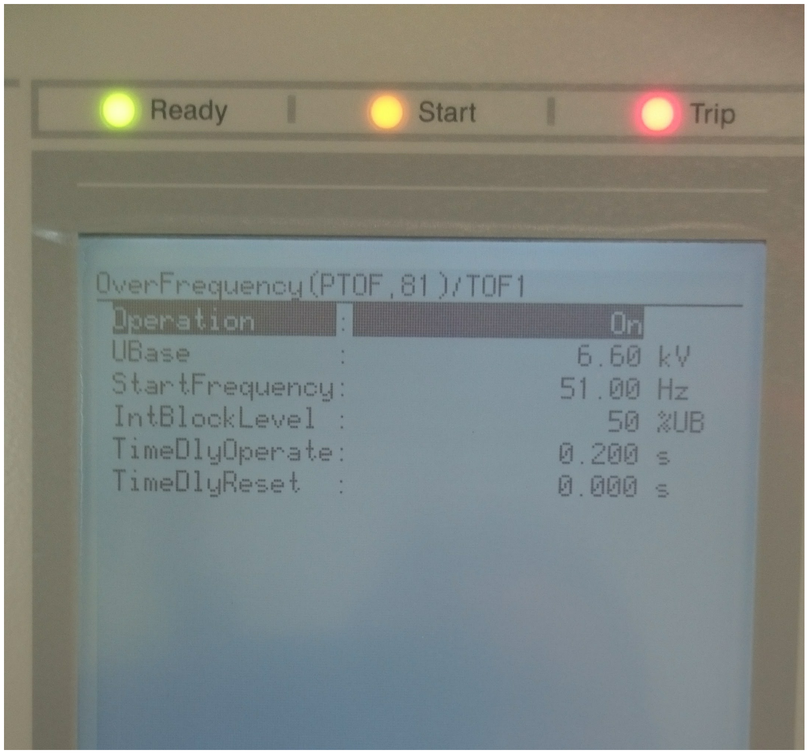

Figure A.2: Screen dump from an actual ABB REG670 over-frequency protection settings on a DG-unit [22]

A.2.2 Vector Shift Protection

Vector jump protection[1] are one of the most used anti-islanding protection today. Vector jump protection measures all three phase voltages zero crossing and uses the rotor angle[2] value change to determine if the CB should be tripped or not. The change in rotor angle is a consequence of the change in power flow between the generator and the grid. This is caused by the sudden imbalance of power in the network, since the main power system is disconnected and therefore do not supply or consume any power.

Detection time is between 20 - 30 ms, common limit values are between 2°- 20°, i.e. if the rotor angle change exceed specified limit value the vector jump protection sends trip signal to the CB after 20 - 30 ms [41].

Fig. A.3 illustrates a vector shift due to island operation. π is the time period before island operation, and the following time period is extended with x due to change in the rotor angle (due to sudden power flow increase from the island operation) [23].

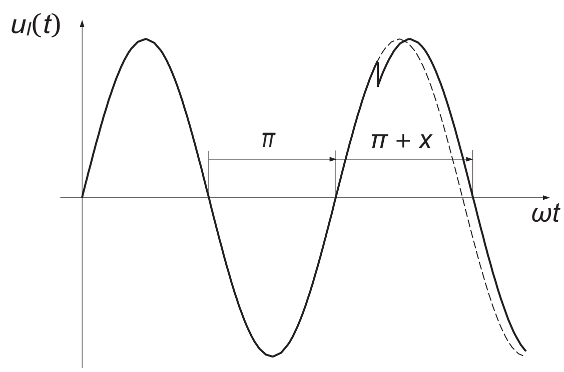

Figure A.3: Vector shift example [23]

[1]Can also be referred to as vector jump, phase displacement or phase jump protection [23]

[2]Rotor angle is referred to as the angle between the synchronous generators internal voltage and the terminal voltage

A.2.3 Rate of Change of Frequency (RoCoF)

RoCoF protection is togheter with vector shift protection one of the most common anti-island protection used [41].

In an islanding operation the frequency will change as a result of the difference in active power flow between the generator and the grid. The RoCoF measures the frequency using the same method as the vector shift protection (see Appendix A.2.2). What separates the RoCoF from the vector shift is that the RoCoF derivates the frequency $\left(\frac{df}{dt}\right)$ course and finds the slope of the frequency. The slope is given in frequency change per second $\left(\frac{Hz}{s}\right)$. If the frequency change exceeds a limit value within a specified time interval the protection sends a trip signal to the CB. The time interval is normally given in whole time periods and the limit value can be adjusted between 0.1-10 $\frac{Hz}{s}$ [41].

Fig. A.4 illustrates the change in frequency after loss of mains/islanding operation occurs. If the dotted generator frequency slope exceeds the limit value the protection trips the CB.

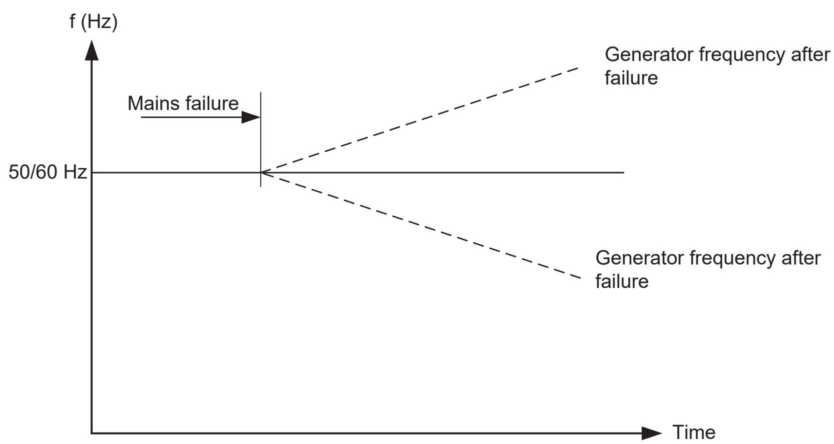

Figure A.4: Example of generator frequency after islanding operation/mains failure [14]

A.2.4 Wiring Diagram DG-Protection DG1

Fig. A.5 displays the wiring diagram for CTs and VTs for the relay protection in DG1.

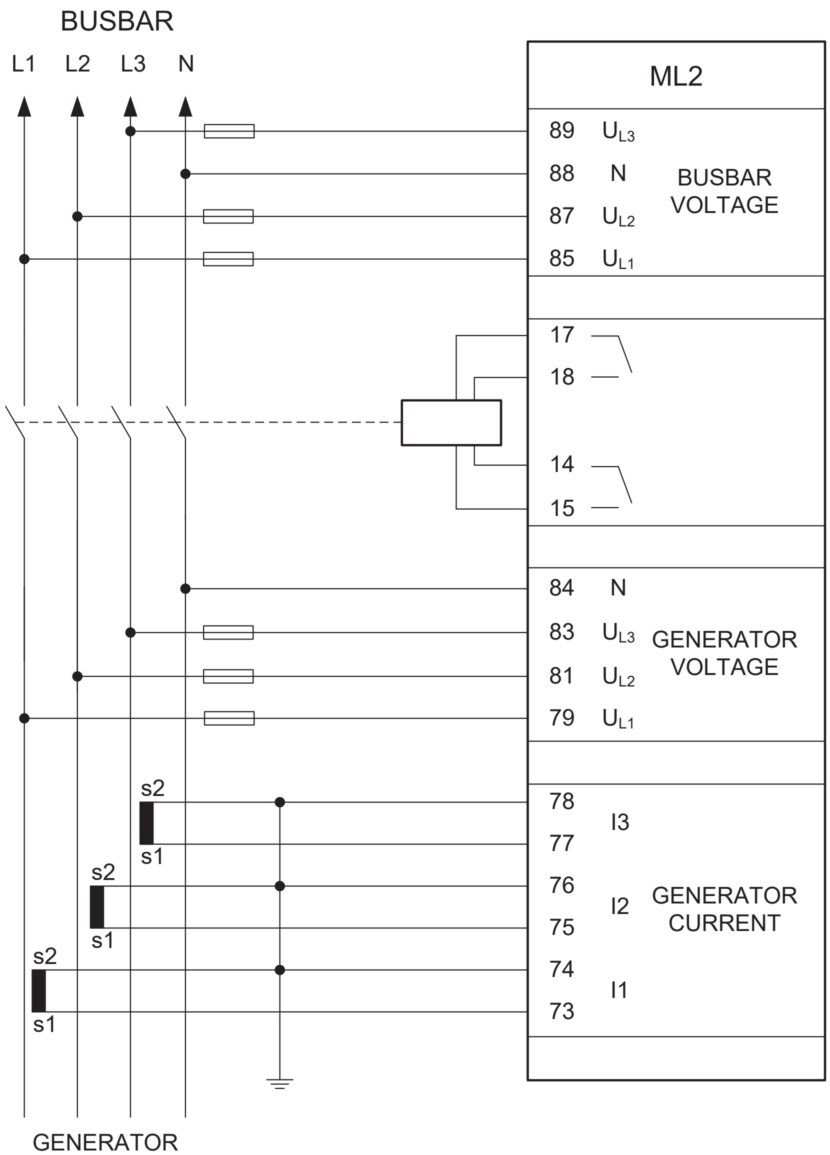

Figure A.5: Wiring diagram for CTs and VTs in DG1 [15]

Appendix B

Power System Protection Components

B.1 General

Protection of a power system consist of several components that together creates the foundation for detecting and clearing faults. Fig. B.1 illustrates the basic components of a protection system. It consist of Transducers (CT/VT), relay, power supply and CB [55].

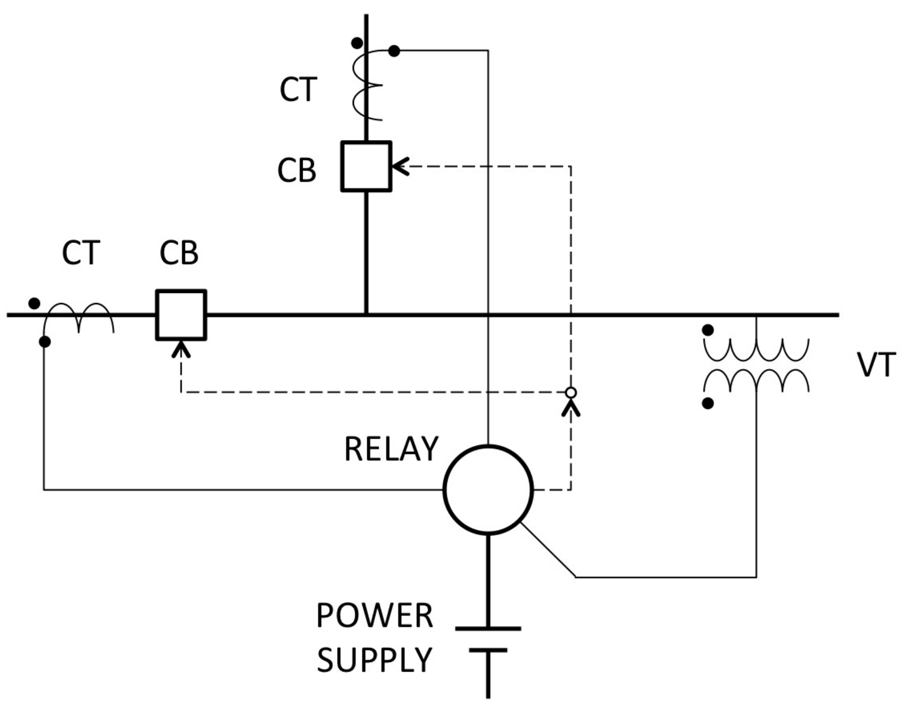

Figure B.1: Principle of power system protection [19]

B.1.1 Components

Transducers

The transducers is the current (CT)- and voltage- (VT) transformers, these are the sensors of the protection system. Their task is to continuous measure the current and voltage. They transform down the values to a safe level, and feed it directly as input to the relay [19].

Relays

Relays interpret the values received from the transducers. Relays have several functions/operational conditions and check if the received values exceed any specified value limit, e.g. over-/under- frequency. If the values exceed a specified time delay, the relay sends a trip signal to the CB [19]. Modern relays are fast micro-processor based. The trend is relays communicating with each other and control centers.

Power Supply

The power supply should be independent of grid voltage. This to make it reliable if the network voltage disappear during a fault. Therefore the power supply need battery backup for keeping the protection and operation of the CB intact during outage of the grid voltage [22, 40].

Circuit Breakers

CBs task are to connect and disconnect lines. Under normal conditions when the operator demands it and when the relay has detected a fault [19].

Appendix C

Modeling

C.1 DG1

C.1.1 Mechanical time constant

$$H = \frac{\frac{1}{2} \cdot J \cdot \omega_0^2}{S_n} \tag{C.1}$$

$$T_a = \frac{J \cdot \omega_0^2}{P_0} \tag{C.2}$$

$$H \approx \frac{T_a}{2} \tag{C.3}$$

C.1.2 DG1 Inertia

Generator data is given as H = 0.531 s for generator only, 12 % is added for turbine in consultancy with [58].

$$H = \frac{\frac{1}{2} \cdot J \cdot X_{turbine} \cdot \omega_0^2}{S_n} \tag{C.4}$$

Inserting numbers we get:

$$H = 0.531 \cdot 1.12 = 0.595 \ s \tag{C.5}$$

Table C.1: Ratings and parameters for DG1

Ratings and parameters	**Symbol**	**Value**
Rated power [MVA]	S_N	1.645
Rated voltage [kV]	U_N	0.690
Rated frequency [Hz]	f_N	50
Rated power factor [$cos\phi$]	$cos\phi_N$	0.9
Number of poles [p]	n_p	12
Weight [kg]		16000
Direct axis synchronous reactance [pu]	x_d	1.75
Direct axis transient reactance [pu]	x'_d	0.311
Direct axis subtransient reactance [pu]	x''_d	0.242
Quadrature axis synchronous reactance [pu]	x_q	1.59
Quadrature axis transient reactance [pu]	x'_q	1.59
Quadrature axis subtransient reactance [pu]	x''_q	0.462
Armature resistance [pu]	r_a	0.009
Leakage reactance/potier reactance [pu]	x_l/x_p	0.099
Direct axis open-circuit transient time constant [s]	T'_{d0}	2.055
Direct axis open-circuit subtransient time constant [s]	T''_{d0}	0.111
Quadrature axis open-circuit transient time constant [s]	T'_{q0}	2.055
Quadrature axis open-circuit subtransient time constant [s]	T''_{q0}	0.113
Direct axis short-circuit transient time constant [s]	T'_d	0.365
Direct axis short-circuit subtransient time constant [s]	T''_d	0.086
Quadrature axis short-circuit transient time constant [s]	T'_q	2.055
Quadrature axis short-circuit subtransient time constant [s]	T''_q	0.033
Saturated values		
Direct axis synchronous reactance [pu]	x_{ds}	1.25
Direct axis transient reactance [pu]	x'_{ds}	0.258
Direct axis subtransient reactance [pu]	x''_{ds}	0.178
Quadrature axis synchronous reactance [pu]	x_{qs}	0.75
Quadrature axis transient reactance [pu]	x'_{qs}	0.75
Quadrature axis subtransient reactance [pu]	x''_{qs}	0.222
Inertia constant [s]	H	0.595
Zero sequence reactance [pu]	X_0	0.028

C.2 DG2

Table C.2: Ratings and parameters for DG2

Ratings and parameters	**Symbol**	**Value**
Rated power [MVA]	S_N	4.17
Rated voltage [kV]	U_N	6.6
Rated frequency [Hz]	f_N	50
Rated power factor [$cos\phi$]	$cos\phi_N$	0.9
Number of poles [p]	n_p	16
Weight [kg]		30000
Direct axis synchronous reactance [p.u.]	x_d	1.33
Direct axis transient reactance [p.u.]	x'_d	0.303
Direct axis subtransient reactance [p.u.]	x''_d	0.209
Quadrature axis synchronous reactance [p.u.]	x_q	0.8
Quadrature axis transient reactance [p.u.]	x'_q	0.8
Quadrature axis subtransient reactance [p.u.]	x''_q	0.261
Armature resistance [p.u.]	r_a	0.008
Potier reactance [p.u.]	x_p	0.133
Direct axis open-circuit transient time constant [s]	T'_{d0}	1.17
Direct axis open-circuit subtransient time constant [s]	T''_{d0}	0.019
Quadrature axis open-circuit transient time constant [s]	T'_{q0}	N/A
Quadrature axis open-circuit subtransient time constant [s]	T''_{q0}	0.036
Direct axis short-circuit transient time constant [s]	T'_d	0.268
Direct axis short-circuit subtransient time constant [s]	T''_d	0.013
Quadrature axis short-circuit transient time constant [s]	T'_q	N/A
Quadrature axis short-circuit subtransient time constant [s]	T''_q	0.012
Saturated values		
Direct axis synchronous reactance [p.u.]	x_{ds}	1.25
Direct axis transient reactance [p.u.]	x'_{ds}	0.258
Direct axis subtransient reactance [p.u.]	x''_{ds}	0.178
Quadrature axis synchronous reactance [p.u.]	x_{qs}	0.75
Quadrature axis transient reactance [p.u.]	x'_{qs}	0.75
Quadrature axis subtransient reactance [p.u.]	x''_{qs}	0.222
Inertia constant [s]	H	1
Zero sequence reactance [p.u.]	X_0	0.001

C.3 Air gap factor

Air gap factor is a constant(c) for the relationship between the leakage reactance(x_l) and potier reactance(x_p), as described in (C.6).

$$x_l = c \cdot x_p \tag{C.6}$$

C.4 Potier Reactance

All generators is modeled with potier reactance, since PSCAD requires a value when using generator data entry format. The potier reactance provides an empirical correction of the saturation MMF obtained from the open circuit saturation curve to allow for load saturation [33]. The potier reactance should be approximate equal to the leakage reactance. For DG1 the leakage reactance is given, for DG2 and G1 it is estimated to be 10 % of the direct axis synchronous reactance [60]. A sensitivity analysis for the potier reactance parameter should be performed to verify the influence on the results.

C.5 Excitation System

The generators are assumed to have a brushless excitation system. Fig C.1 illustrates a simplified example of a brushless excitation system for a synchronous machine. A smaller synchronous machine (field generator) is installed on the main shaft together with the main generator. The field generator is an inside-out synchronous machine, opposite of a traditionally generator, by having the field winding in the stator and the armature winding on the rotor. The advantage of this solution is that no slip rings are required. The static field generator induce a three-phase current in the field generator rotor, which is rectified by the rotating rectifier and fed to the main synchronous machine field winding [12].

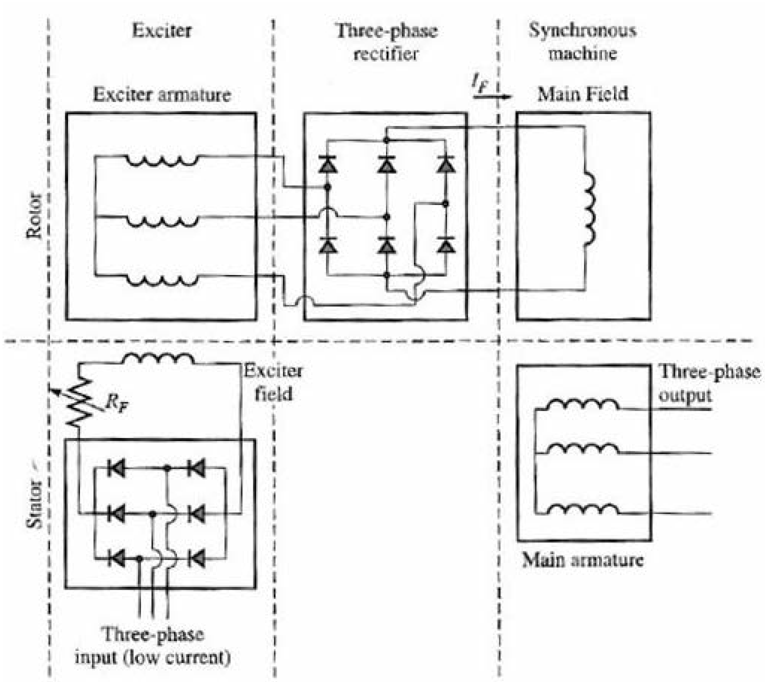

Figure C.1: Simplified brushless excitation system [12]

Brushless excitation system does not allow direct measurement of field current or voltage. The voltage is therefore measured at the main generator terminals and a signal is provided to the static rectifier [31]. This leads to an extra time delay that together with unfortunate regulator settings could result in a response time close to 300 ms [41]. This means that the excitation system may not affect the FRT-capability for the DG-units for faults less than 300 ms.

C.6 Load

The distribution network consist of loads with various characteristics. Load characteristics can be divided into one of the following features [35]:

- Constant power demand(P)
- Constant current demand(I)
- Constant impedance(Z)

The features are described by (C.7), where NP and NQ are set in accordance with the desired load characteristic [35, 39].

$$P_L = P_L^{nom}\left(\frac{|U_L|}{|U_L^{nom}|}\right)^{NP}, \quad Q_L = Q_L^{nom}\left(\frac{|U_L|}{|U_L^{nom}|}\right)^{NQ} \tag{C.7}$$

In (C.7), P_L is the active power consumption, P_L^{nom} is the nominal active power consumption, U_L is the measured voltage magnitude across the load, U_L^{nom} is the nominal voltage across the load, Q_L is the reactive power consumption and Q_L^{nom} is the nominal reactive power consumption. The simulations are performed with NP = 1 and NQ = 2.

C.7 Short-circuit Impedance

Obtained from NETBAS:

- Short-circuit capacity = 838 MVA
- Short-circuit impedance, Z = R +j X_L = 0.44 + j 5.18 Ω
- cos ϕ = 0.085

$$L = \frac{X_L}{2\pi f} = \frac{5.18\,\Omega}{2\pi f} \approx 0.01649H \tag{C.8}$$

C.8 Open Circuit Voltage Response for G1 and DG2

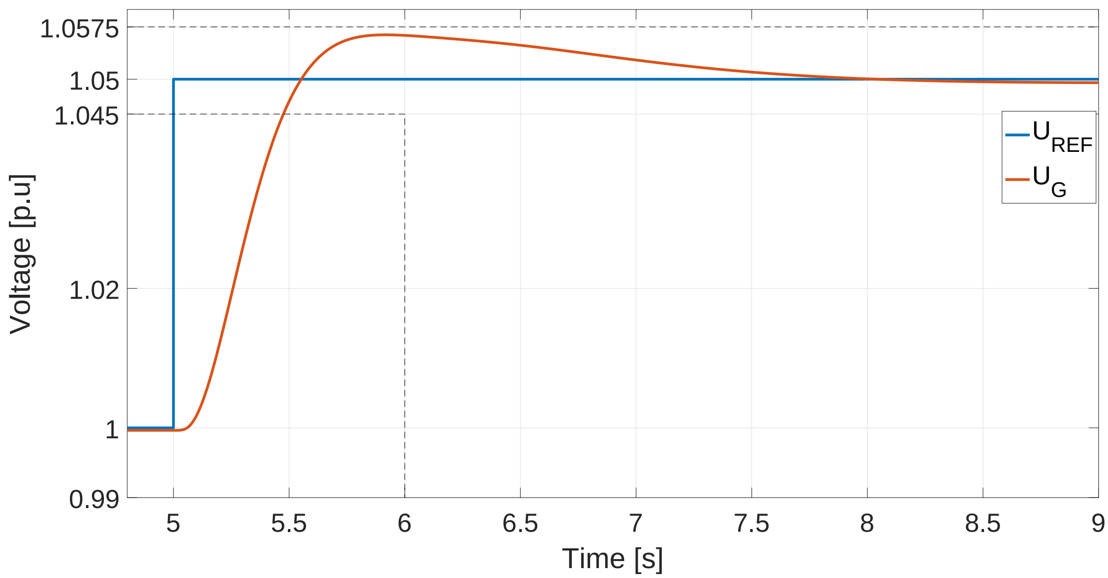

Figure C.2: Open circuit voltage response for G1

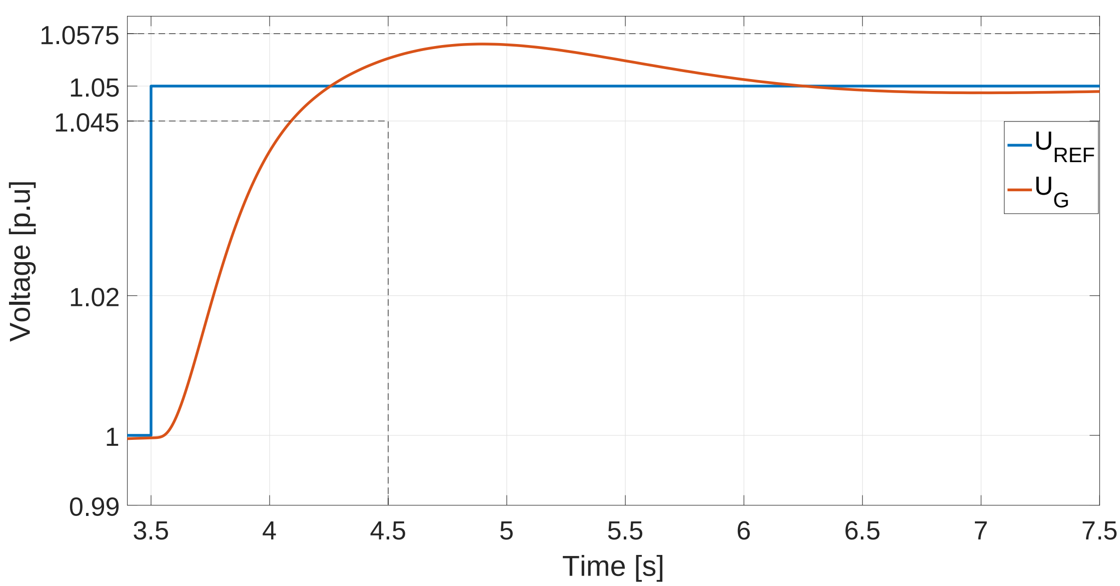

Figure C.3: Open circuit voltage response for DG2

Appendix D

Additional Data from Simulations

D.1 Critical Clearing Time for DG1

The critical clearing times for DG1 is presented in Table D.1.

Table D.1: Critical clearing time for cases studied

Case	Critical clearing time
1	0.122 s
2	1* s
3	1* s

* - Not simulated clearing time longer than 1 s

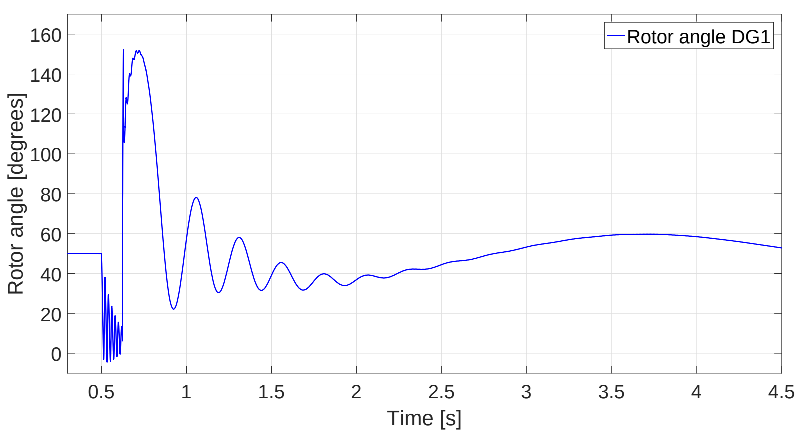

Figure D.1: Rotor angle with critical clearing time for case 1

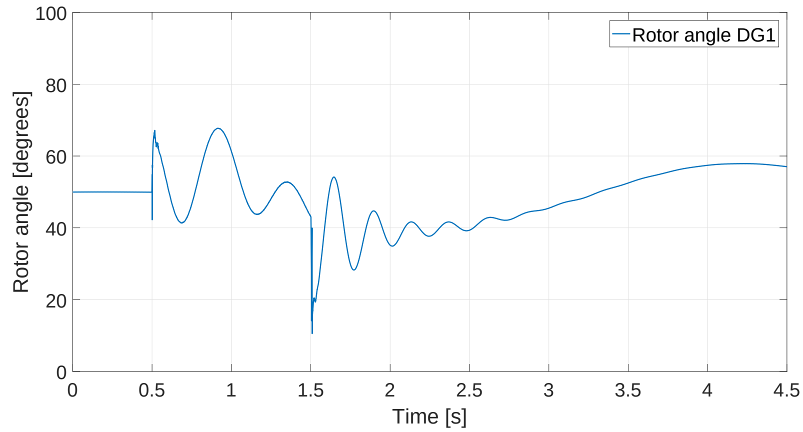

Figure D.2: Rotor angle with critical clearing time for case 2

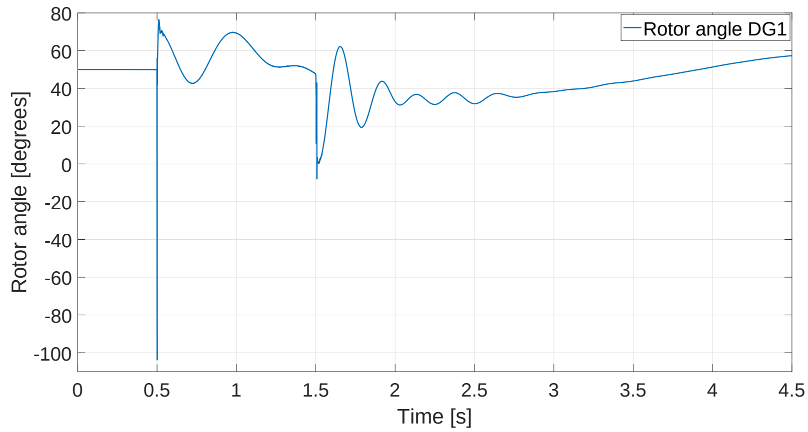

Figure D.3: Rotor angle with critical clearing time for case 3

D.2 Case 2

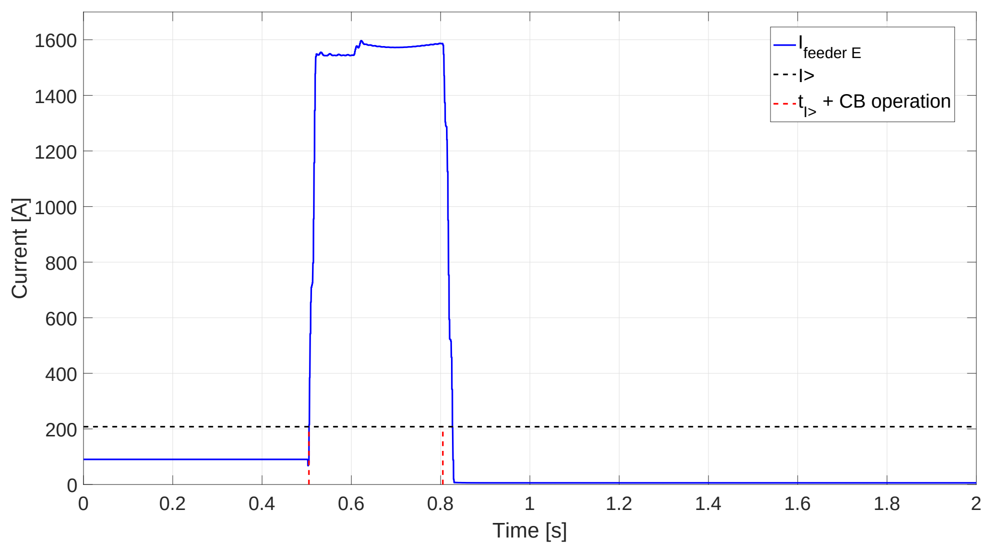

Figure D.4: Fault current through relay protecion on feeder E for case 2.1

D.3 Case 3

Fault resistance was adjusted to 1.15 Ω to obtain a voltage of 0.3 pu at DG1.

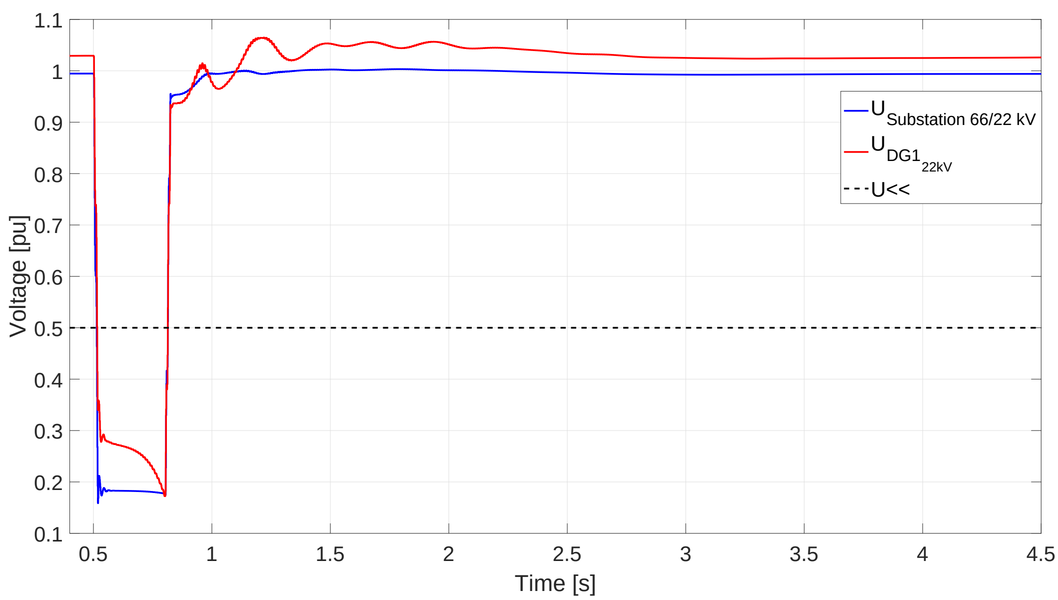

Figure D.5: Critical retain voltage for case 3

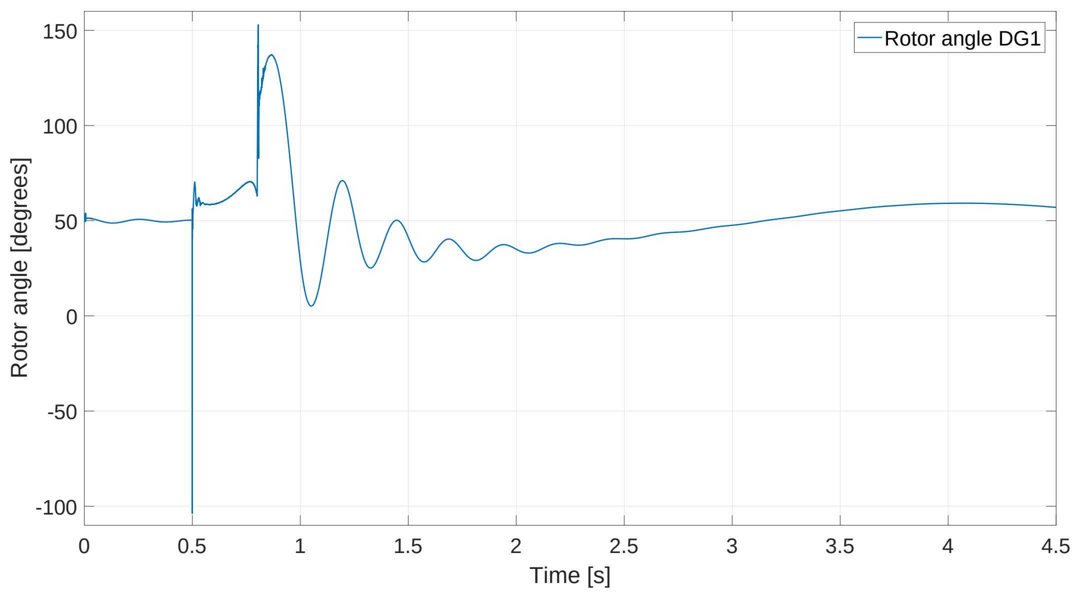

Figure D.6: Rotor angle critical retain voltage for case 3

Appendix E

Images from On-Site Inspection

Figure E.1: $U\ll$ set point setting for DG1

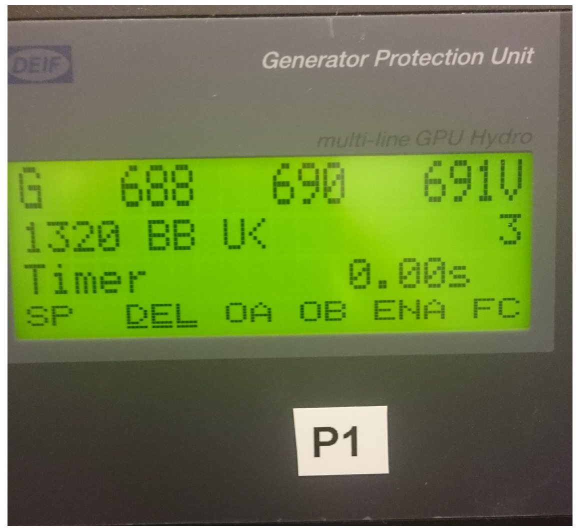

Figure E.2: $U\ll$ time delay setting for DG1

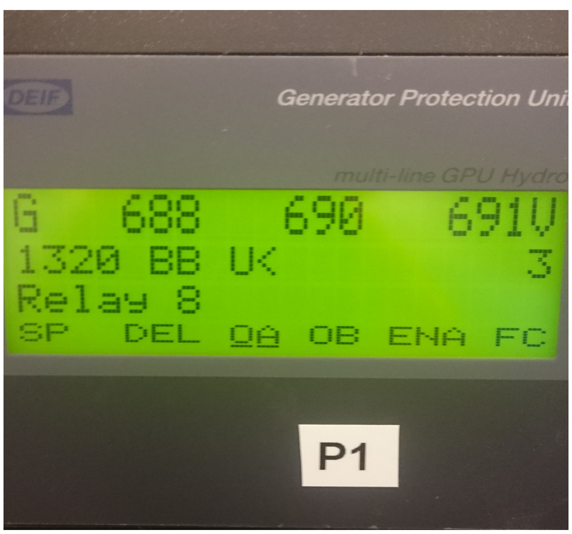

Figure E.3: Output A for $U\ll$ setting for DG1

Figure E.4: Output B for $U\ll$ setting for DG1

Figure E.5: Enable option U≪ setting for DG1

Figure E.6: Fail class/consequence of U≪ setting for DG1

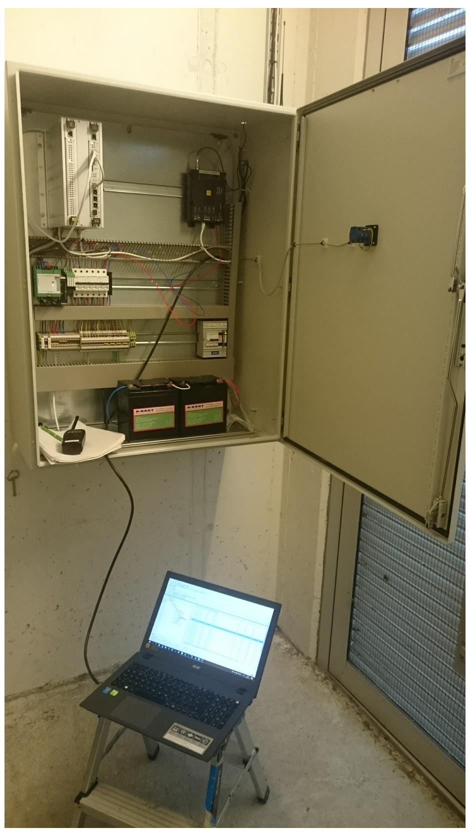

Figure E.7: Connection to grid protection through RTU in DG1.

Appendix F

Parameters from SINTEF Report

Table F.1: Generator parameters from [27]

Parameter	Bruvollelva	Ullestad	Tverråna
S_N [MVA]	4.335	5.500	3.500
P_N [MW]	3.900	4.940	3.160
U_N [kV]	6.6	6.6	6.6
f_N [Hz]	50	50	50
$\text{Cos}\phi_N$	0.9	0.9	0.9
p	8	12	6
x_d [pu]	2.360	1.372	1.413
x'_d [pu]	0.249	0.287	0.255
x''_d [pu]	0.161	0.176	0.160
x_q [pu]	2.320	1.335	1.401
x'_q [pu]	2.320	1.335	1.401
x''_q [pu]	0.189	0.210	0.192
r_a [pu]	0.007	0.005	0.006
x_l [pu]	0.151	0.122	0.104
T'_d [s]	0.184	0.350	0.280
T''_d [s]	0.059	0.020	0.020
T''_q [s]	0.007	0.030	0.020
T'_{d0} [s]	1.750	-	-
T''_{d0} [s]	0.092	-	-
T''_{q0} [s]	0,090	-	-
H [s]	0.370	1.210	1.250

Appendix G

Parameters Influencing FRT-Capability

Table G.1: Various parameters influence on FRT-capability for SHPs [27]

	Parameter	Influence on FRT-capability	Influence
Generator	Inertia constant, H	Large inertia constant is positive	Large
	Synchronous reactance, X_d	Low synchronous reactance is positive - leads to low power angle pre-fault	Medium
	Synchronous reactance, X_q	Low synchronous reactance is positive	Low
	Transient reactance, X'_d	Low transient reactance is positive - leads to high transient power	Large
	Subtransient reactance, X''_d and X''_q	Low subtransient reactances is positive, and $X''_d = X''_q$ (Well damped generator)	Low
	Active power production pre-fault, P	Low production of active power is positive	Large
	Reactive Power pre-fault, Q	High production positive, high consumption is very negative	Large
	Voltage pre-fault	High voltage is positive	Medium
	Voltage during fault	High voltage is positive	Large
	Voltage post-fault	High voltage is positive	Medium
Field exciter and voltage regulator	Voltage regulator (AVR)	Active voltage regulator is better than no voltage regulator	Large
	Proportional gain, K_{PR}	Tuned (see Table 4.9)	-
	Integral gain, K_{IR} (T_{IR})	Tuned (see Table 4.9)	-
	Derivative gain, K_{DR} and T_{DR}	Tuned (see Table 4.9)	-
	Time constant for exciter, T_E	Low time constant is positivt	Small (Larger with increasing duration of fault)
	Max. voltage, VRMAX / VEMAX	High ceiling voltage is positive	Small (above a certain limit)
	VAR/PF- controller	Active VAR/PF- controller is negative	Small/Medium
Network and fault	Change in voltage phase angle during fault	-	(Medium)
	Distance to fault	Large distance is positive - leads to higher voltage during fault	Large
	Distance to substation	Small distance is positive - leads to smaller Xs	Small
	Fault clearing time	Small fault clearing time is positive - giving less time for accelerating the rotor	Large
	Fault type	Two-phase fault substantially better than three-phase - Higher voltage during fault	Large
	X/R-ratio pre-fault	Low X / R ratio is positive - high resistance means that the generator can deliver more active power during fault	(Medium)
	Load in system	Low load is positive (But is very dependent on the type of load)	(Small)
	System impedance post-fault	Low impedance is positive - high impedance, e.g. can be due to disconnetion of a line.	Medium