

Problem Description

There is an increasing interest in the development of distributed generation (DG) in Norway as a result of significant water and wind energy potentials and green certificates. In the distribution grid it is primarily small-scale hydroelectric power that is used in distributed generation, but small-scale wind power is also relevant. New DG units will be installed in areas that already have high penetration of distributed generation, in networks without current production or in areas where there is no power grid at all. Small-scale hydro and wind power is unregulated production, and when errors occur in the grid it is required of DG units to disconnect from the network. This implicates that they can't effortlessly be utilized as a reserve supply when disruptions occur. DG is also a source of errors in itself (from errors occurring in the device itself or as a result of capacity problems) that may result in disconnection of both production and the associated grid resulting in increased disruption to end users. Increasing the proportion of DG in combination with smart solutions for the distribution network can, on the other hand, lead to new opportunities. In fallout situations, using controlled island mode on device(s) that are regulated can provide power locally when the network loses the connection to the underlying network or when errors occur in the distribution network itself.

In this thesis the objective is to analyze how distributed production affects delivery reliability, for example the number and duration of interruptions. The reliability calculations are to be carried out in PowerFactory for realistic distribution grids resulting in the estimated reliability of delivery in today's operations. Similarly the grid will be modeled in PowerFactory when taking advantage of the opportunities for controlled islanding in a future grid.

The problem description is as follows:

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 - Technical requirements for the connection of distributed generation in the current grid
 - Issues regarding driving forces, challenges, and opportunities with distributed generation in the current system and in future power systems with emphasis on reliability
- Analyze how reliability of supply is affected by distributed generation with the current operation of distribution grids
- Describe the prerequisites for being able to run controlled islanding in a faulted grid and research into what has been experienced in cases where islanding mode of DG units has been allowed
- Analyze how reliability of supply is affected by a future network operation scheme where DG units are properly equipped to operate in controlled islanding mode for different networks
- Make comparisons and evaluate with respect to distributed generations impact on reliability of supply
- Describe how reliability analysis in principle is computed in PowerFactory, what assumptions are made for the analysis and the challenges faced by PowerFactory users (including practical hints and tips for the analysis)

Abstract

As a consequence of increased government efforts to reduce local Norwegian CO_2 -emissions the development of small distributed generators have increased. This development is assumed to continue, but at an increasing incremental cost due to the inferior profitability of remaining prospects. To maintain profitability of smaller and high cost distributed generators, cost savings must be implemented. Quality of supply is a significant factor in determining potential profitability. Hence, a significant potential in cost reduction lies in increasing quality of supply. This can be achieved by utilizing the decentralized nature of these power producers by enabling intended island operation. By enabling these generators to run in intended island mode, they are able to supply their local grid with power when fallout of the main grid or other components occurs. This increases the uptime for local customers and therefore increases quality of supply.

Five different grids are modeled in PowerFactory based on collected empirical data for the evaluation of the potential for islanding in Norway. With these models different cases utilizing islanding schemes are simulated and the reliability of these configurations compared to a base case representing normal operations. The results from this analysis suggest big reductions in the reliability indices “Energy Not Supplied” and “System Average Interruption Frequency” are possible. In the thesis the reductions achieved are in the 10%-60% range of the base case. The estimated savings earned from increased reliability of supply does not justify the assumed investment needed, but the numbers are not conclusive. Better estimates of expenses and assessing other grids with better prerequisites for islanding could indicate to be profitability.

Sammendrag

Som en konsekvens av økte statlige innsatsen for å redusere lokale norske CO_2 -utslipp har utbyggingen av små distribuerte generatorer har økt. Denne utviklingen antas å fortsette, men med en økende marginalkostnad på grunn av dårligere lønnsomhet for gjenværende prospekter. For å opprettholde lønnsomheten av distribuerte generatorer, må kostnadsbesparelser iverksettes. Leveringskvalitet er en vesentlig faktor i å bestemme potensiell lønnsomhet. Derfor ligger det et betydelig potensial i kostnadsreduksjon ved å øke leveringspåliteligheten. Dette kan oppnås ved å utnytte den desentraliserte naturen til disse kraftprodusentene ved at de gjøres i stand til å operere i planlagt øydrift. Ved å tilrettelegge disse generatorene for intendert øydrift, vil de være i stand til å levere strøm lokalt når utfall av sentralnettet eller andre komponenter oppstår. Dette øker opptiden for lokale kunder og dermed også leveringspåliteligheten.

Fem ulike nett er modellert i PowerFactory, basert på innsamlede empiriske data, for vurdering av potensialet for øydrift i Norge. I disse modellene er ulike caser ment for å representere aspekter ved øydrift implementert og en pålitelighetsanalyse av disse er utført. Påliteligheten av disse konfigurasjonene vil bli sammenlignet med en «base case» som representerer normal drift av nettet. Resultatene fra denne analysen tyder på store reduksjoner i pålitelighet indeksene "Energy Not Supplied" og "System Average Interruption Frequency" er mulig. I avhandlingen oppnådde man reduksjoner som lå på 10%-60% av «base case»-indeksene. De estimerte besparelsene fra økt forsyningssikkerhet rettferdiggjør ikke de antatte investeringene som trengs, men tallene er ikke konkluderende. Bedre estimer på kostnader og vurderinger av andre nett med bedre forutsetninger for øydrift kan vise seg å indikere lønnsomhet.

Preface

This Master Thesis is written at the Department of Electric Power Engineering in the Norwegian University of Science and Technology (NTNU) during the spring semester, 2012. The theme of this project was suggested by Gerd Kjølle at SINTEF Energi AS and was a continuation from my autumn semester 2011. The intention of the thesis was both to make preliminary evaluations of the possibility of islanding generators in Norway, as well as researching into what was already known about this in other countries and to better understand the PowerFactory tool. Supervision of the thesis was done by Gerd Kjølle and Tarjei Solvang.

I would like to thank the DIgSILENT support team and especially Désirée Bangert for tirelessly answering questions about the workings of PowerFactory. Thanks also to Traian Preda for taking with him questions and bringing back answers from DIgSILENT conventions in Germany and for helping me work out load flow problems. Rune Paulsen deserves mention for digging up all kinds of numbers and datasets. Oddbjørn Gjerde for helping me out with license issues with DIgSILENT. All Woodruff and all the other involved at BC Hydro for digging up ancient reports on the Boston Bar system. Lastly, thanks to Rolf Erlend Grundt at Agder Energi for pushing the grid strategy department to produce previously unavailable statistics.

Anders Hegvik

June 22, 2012

Definitions

Deep connection tariff/costs	The tariff charged by the grid company to the DG operator covers all the expenses that the grid company incurs due to the connection of the DG.	(1)
DG unit	According to Statnett they understand DG units as all equipment that is connected on/off the distribution grid by the same circuit breaker (or similar device). DG units include generators and eventually transformers with its respective control system. If the DG unit consists of several generators the DG units the DG unit's maximum active power production is understood as the sum of all the generators maximum active power production.	(2)
ELMEK (Electromagnetic Installation)	Mechanical and electronic installation that has implications for the DG units' grid connection. Ex. Turbine, generator, transformer, relay and cables.	(3)
Intentional islanding	Intentional islanding is a planned or non-planned state where one or more DG units supply a part of the distribution grid that is isolated from the rest of the grid.	(3)
Interruption	An event that causes a relay to trip the circuit breaker zone and disconnection of a component for more than three minutes.	
IPP (Independent Power Producer)	A person, organization or company that is licensed and operates a generator to feed power into the grid.	
IPS (Islanding Power System)	A power system that is isolated from the main grid but is supplied by one or more DG units.	(2)
Modeling Scenario (Case)	A network topology combined with a set of analysis settings intended to simulate a specific real life scenario.	
Nominal Voltage (U_n)	The rated voltage for a component or grid section of a grid.	
Production Unit	Production unit is understood to be any rotating machine (turbine or generator) or any converter with production behind it	(2)
REN (Rasjonell Elektrisk Nettdrift)		www.ren.no
Sectioning	The operation of locating a faulted component in a de-energized grid, disconnect it using the nearest disconnectors and close the tripped circuit breaker.	

Sectioning Time	The duration from when the circuit breaker is tripped to when it is re-closed again.	
Shallow connection tariff/costs	The connection tariff charged by the grid operator to the DG operator only covers the costs of connection between the location of the DG and the nearest point of the grid with an appropriate voltage level , independent of whether or not the grid at this location has sufficient capacity to transport the DG's power output or not.	(1)
Topology Contribution/Topology ENS	Loosely: the part of an index (i.e. ENS) that is caused by the topology. Normally, for ENS, this would be all contributions apart from external grid contribution and sectioning time contribution.	Self-defined
Unintentional Islanding	A non-intended state where one or more DG units supply a part of the distribution grid that is not connected to the rest of the grid.	(3)
LP (Load Point)	Any constellation of loads consuming active and reactive power from the same feeder.	
Circuit Breaker Failure Rate	The probability of a circuit breaker to not properly open when a fault occurs within its circuit breaker zone.	
Circuit Breaker Zone	The zone in which faults in any of the components are tripped by the same circuit breakers.	Self-defined
External Grid	In this thesis normally refers to the connection point where the transmission or regional grid is connected to the grid being discussed or modeled. Normally functions as an infinite bus.	
Voltage Band	Upper and lower boundary for the connected components (usually a DG unit) voltage in the connection point.	(3)
Interruption Frequency, λ	The frequency of interruptions on a component or grid in $[1/a]$	
Interruption Duration, μ	The average time a component is disconnected from the grid once an interruption occurs in $[h]$	

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1. Introduction

There is an increasing interest in the development of distributed generation (DG) in Norway as a result of significant water and wind energy potentials and green certificates. In the distribution grid it is primarily small-scale hydroelectric power that is used in distributed generation, but small-scale wind power is also relevant. New DG units will be installed in areas that already have high penetration of distributed generation, in networks without current production or in areas where there is no power grid at all. Small-scale hydro and wind power is unregulated production, and when errors occur in the grid it is required of DG units to disconnect from the network. This implicates that they can't effortlessly be utilized as a reserve supply when disruptions occur. DG is also a source of errors in itself (from errors occurring in the device itself or as a result of capacity problems) that may result in disconnection of both production and the associated grid resulting in increased disruption to end users. Increasing the proportion of DG in combination with smart solutions for the distribution network can, on the other hand, lead to new opportunities. In fallout situations, using controlled island mode on device(s) that are regulated can provide power locally when the network loses the connection to the underlying network or when errors occur in the distribution network itself.

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- Analyze how reliability of supply is affected by a future network operation scheme where DG units are properly equipped to operate in controlled islanding mode for different networks
- Make comparisons and evaluate with respect to distributed generations impact on reliability of supply
- Describe how reliability analysis in principle is computed in PowerFactory, what assumptions are made for the analysis and the challenges faced by PowerFactory users (including practical hints and tips for the analysis)

Structure of the report

Chapter 1 introduces the thesis and the problems it aims to solve. **Chapter 2** explains the theoretical background starting with an outline on the legal system. Then it presents the empirical facts that are known about islanding of generators. Lastly it defines and explains the breed of reliability theory employed in this thesis. **Chapter 3** presents the test cases and comments on how the analysis was done. **Chapter 4** discusses the overall result of the test case results. **Chapter 5** concludes the master with suggestions of what could have been done in continuation of this thesis.

2. Theoretical Background

2.1 Legal framework for grid connection in Norway

The laws under which IPPs have to comply in Norway are quite strict compared to international standards. Below a summary that contains the laws detailing legal obligations for all operators in the Norwegian power grid is included. There are also more specific guidelines enacted for DG power suppliers, which will be the main focus for this chapter.

2.1.1 The Energy Law

- LOV 1990-06-29 nr. 50: Lov om produksjon, omforming, overføring, omsetning og bruk av energi m.m. (energiloven).
- FOR-1990-12-07 nr. 959: Forskrift om produksjon, omforming, overføring, omsetning, fordeling og bruk av energi m.m. (energilovforskriften).
- FOR 1999-03-11 nr. 302: Forskrift om økonomisk og teknisk rapportering, inntektsramme for nettvirksomheten og tariffer.
- FOR-2004-11-30 nr. 1557: Forskrifter om leveringskvalitet i kraftsystemet.
- FOR-1999-03-11 nr. 301: Forskrift om måling, avregning og samordnet opptreden ved kraftomsetning og fakturering av netttjenester.
- FIKS – Funksjonskrav i kraftsystemet.
- Statnetts praktisering av systemansvaret.

2.1.2 The Electric Monitoring Law

- LOV-1929-05-24 nr. 4 Lov om tilsyn med elektriske anlegg og elektrisk utstyr (EI-tilsynsloven)
- FOR-2005-12-20 nr. 1626 Forskrift om elektriske forsyningsanlegg
- FOR-1998-11-06 nr. 1060 Forskrift om elektriske lavspenningsanlegg.
- FOR-2006-04-28 nr. 458: Forskrift om sikkerhet ved arbeid i og drift av elektriske anlegg.
- FOR-1005-03-01 nr. 190: Forskrifter om kvalifikasjoner for elektrofagfolk.
- FOR-2002-11-22 nr. 1323: Forskrift om registrering av virksomheter som prosjekterer, utfører og vedlikeholder elektriske anlegg.

2.1.3 The Labour Laws

- FOR-1998-10-30 nr. 1048: Forskrift om sikkerhet ved arbeid i og drift av høyspenningsanlegg.

These are collected from the technical Sintef report “Technical guidance for connection of generation with maximum effect active power production less than 10MW to distribution grid” (4) and the REN (5) standard. The most important and defining of these laws is the energy law mentioned first on the list. However, the focus will be on the REN guidelines for DG power suppliers as they also cover the requirements listed in the energy law and are updated regularly.

2.1.4 KILE and Compensation for Energy Not Delivered in Norway

Since 2001 there has been a compensation requirement for net operators in Norway (6). If the net operator fails to deliver energy as per the agreement with the customer the operator has to compensate the customer according to the FASIT calculations of cost to society. This compensation only regards interruptions of duration over 3 minutes and is set according to table 2.1.

Customer group	Cost function for $k_{p,ref}$		Unit
	All durations		
Agricultural	$10,6 \cdot r + 4$		kr/kW
Households	$8,8 \cdot r + 1$		kr/kW
	0-4 timer	> 4 timer	
Industry	$55,6 \cdot r + 17$	$18,4 \cdot r + 166$	kr/kW
Sales and Service	$97,5 \cdot r + 20$	$33,1 \cdot r + 280$	kr/kW
Public Sector	$14,6 \cdot r + 1$	$4,1 \cdot r + 44$	kr/kW
Lumber mills and Power Intensive Industry	$7,7 \cdot r + 6$	$3,1 \cdot r + 23$	kr/kW

Table 2.1 - Interruption Costs According to Norwegian Regulations

Here r is the time in hours, $k_{p,ref}$ specific cost in 2006 Norwegian Kroner adjusted by the consumer price index. Different costs apply to warned outages due to maintenance. These compensation costs are also adjusted by a correction factor which adjusts for the time of day and the month and how the sector is considered to be hit by the timing of the outage. As an example, the public sector is deemed only to get a 60% compensation if an outage occurs in July. If the outage happens on a Sunday in July the public sector can only demand 24% compensation. However, these correction factors will not be detailed here but can be found in the *Forskrift om økonomisk og teknisk rapportering, inntektsramme for nettvirksomheten og tariffer* (6). To calculate KILE costs in this paper the NVE simplification for economic and technical reporting is used (7). Adjusted for CPI (Consumer Price Index) the formula is shown below.

$$KILE_{2012} = ENS_{2012} * k_{p,ref} * \frac{CPI_{2012}}{CPI_{2006}}$$

Here $k_{p,ref} = 9,4$ as per 2008 prices and CPI is the consumer price index as per the SSB (8).

2.2 General Norwegian Connection Requirements for DG Units

This chapter will outline the main requirements for non-islanding requirements suggested by REN for DG units in the distribution grid. The main criterion stated in the law and in Statnetts “Funksjonskrav I Kraftsystemet” (FoK) (2) is that the DG unit shall be configured for the conditions at the connection point. More specifically this means that the DG unit shall have impedance values and other important generator parameters adapted for the connection point. If needed, the DG unit must also have a regulation system for active effect, reactive effect and voltage. All these solutions must also be configured to collaborate with tap-changing maneuvers and other generators in the grid. Errors in the grid can’t be ruled out when adjusting relay settings for the DG unit protection systems.

2.2.1 DG Unit Voltage Requirements

The DG unit requirement on voltage quality is defined by the net operator to which it supplies power. There are two main requirements to voltage. One is the voltage band, and the other is the agreed upon output voltage of the generator. The voltage band is set by the net operator after they’ve done an assessment of the DG units’ impact in the surround grid. Output voltage of the generator, U_{avtalt} , is then agreed upon between the owner of the generator and the net operator. From this, a $\%U_{stasjonær}$ and a $\%U_{maks}$ are defined, as per *Forskrift om leveringskvalitet i kraftsystemet* (9).

$$\%U_{stasjonær} = \frac{\Delta U_{stasjonær}}{U_{avtalt}} \quad \%U_{maks} = \frac{\Delta U_{maks}}{U_{avtalt}}$$

Where $\Delta U_{stationær}$ and ΔU_{maks} are effective voltage changes evaluated each 10 ms between time periods where the voltage has been stable in minimum one second. The voltage is considered stable when it does not change more than 0.5% of U_{avtalt} per second. These values are then constrained as shown on table 2.2.

Voltage Jumps at Connection Point	Number of allowed daily incidents
$\Delta U_{stationary} > 3\%$	3
$\Delta U_{max} > 5\%$	3

Table 2.2 - Allowed voltage jumps at connection point (10)

Protection mechanism settings must trip if the voltages described in table 2.3 are measured at the connection point.

DG unit is connected to:	Voltage band in p.u.on nominal base U_N	Max. disconnection duration [s]
Low Voltage Net	$U > 1.15$	0.2
	$U > 1.1$	1.5
	$U < 0.85$	1.5
	$U < 0.5$	0.2
High Voltage Net	$U > 1.15$	0.2
	$U > 1.06$	1.5
	$U < 0.85$	1.5
	$U < 0.5$	0.2

Table 2.3 - Required DG Unit Protection Equipment Response to Voltage Measurement at Connection Point

These are the DG units' legal obligations to the net operator. The net operator then has the responsibility to set these values in a way that ensures that the end user has a stationary voltage band of +/- 10%. This is also suggested in a report from SINTEF (4) to be limited to a +8% / -6,5% band on stationary voltage delivered to consumers in the same grid as the DG unit.

2.2.2 Harmonics

The requirements regarding harmonics control are somewhat more extensive than what is necessary for this paper and will not be covered in great detail here. Generally the generator shall not contribute so that the individual boundaries displayed in table 2.4 for over harmonic voltages in the connection point are breached. All the values displayed in table 2.4 are averaged over ten minutes (10).

Odd harmonic				Even harmonic	
Not Multiple of 3		Multiple of 3			
Orden h	U_h	Orden h	U_h	Orden h	U_h
5	6,00 %	3	5,00 %	2	2,00 %
7	5,00 %	9	1,50 %	4	1,00 %
11	3,50 %	> 9	0,50 %	> 4	0,50 %
13	3,00 %				
17	2,00 %				
19, 23, 25	1,50 %				
> 25	1,00 %				

Table 2.4 - Boundry Levels for Allowed Harmonic Voltages at Connection Point, as sited in (9)

2.2.3 Fibrillation

Net operators are obligated to supply power within the following limits. It is the net operators' responsibility to ensure that the DG unit does not contribute to such conditions.

	$0,23 \leq U_N \leq 35$	$35 < U_N$	<i>Time interval</i>
Fibrillation short term intensity, P_{st} [pu]	1,2	1	95% of the week
Fibrillation long term intensity, P_{lt} [pu]	1	0,8	100% of the week

2.2.4 Frequency

The only requirement to a DG unit when it comes to frequency is that when the DG unit experiences abnormal frequencies, the DG unit must be tripped. This is not set by Norwegian law, but is listed as a requirement in RENs agreement framework. The conditions and requirements of such a situation are listed in table 2.5. It is also added that if the net operator demands it, the upper frequency bound should be reduced.

Frequency Band [Hz]	Max. disconnection duration [s]
$f > 51$	0,2
$f < 48$	0,2

Table 2.5- Required protection response to abnormal frequency at measurement point

The appointed ("systemansvarlig") is required by law to preserve a frequency that is "normally" within +/- 2% of 50 Hz.

2.3 Introduction to Distributed Generation and Islanding

In 2008 the Norwegian parliament reached an agreement on a climate proposition which committed Norway to cut national carbon emissions by 2030. This deal also stressed that two thirds of the emission reductions has to come “from home”. When looking at how Norway can fulfill these targets and also manage to provide for the increased power demand of the future there are a few options. The profitable and sizable hydro power resources are all developed. Reducing demand by increasing the energy efficiency of buildings and redirecting electricity consumption away from heating purposes are good measures, but they are not enough to fulfill the 2030 targets. An array of different measures has to be set in motion if we hope to reach the goals set in the climate report from 2008, among these is development of distributed energy resources. In 2008 the potential for distributed electricity production was estimated to be around 18 TWh/a. In the new climate report from the government which was published in 2012 the estimate is increased to 28 TWh/a with a production cost of less than or equal to 3 NOK/kWh (11). This is a 22.6% increase from the 124 TWh/a we are currently consuming and could be enough to cover some of our increased demand for electrical energy in the near future. 3 NOK/kWh is, however in another order of magnitude than what is normally paid for electricity in Norway (between 20 and 30 øre/kWh according to Nordpool). This discrepancy in price is mostly subsidized by the “green certificates” scheme for renewable energy.

Since most of these distributed resources are close to distribution grids the distribution grids are also their most natural point of connection. This poses technical difficulties as the distribution grids in Norway were often built some time ago, and not with the intention of exporting power into the transmission grid. These technical difficulties include new and unintended voltage profiles in radials, protection systems that are not meant for two way transport of power and thermal limits in lines that are exceeded because of new load flow dynamics. Today net operators are responsible by law to upgrade grids and facilitate for new approved DG units that are to be introduced into their distribution grids. The cost of implementing DG units is therefore passed on to the consumers.

It is a benefit from DG that power is produced closer to the customer and will result in less line loss and potentially less infrastructure upgrades, thus reducing costs for the net operator and customer. The size of the generators makes them ideal for assembly line production. Potential for exploiting economies of scale while producing these units is therefore big. As capital costs are often the main expense for DG operators’ cheap production is important for DG profitability.

A number of possibilities have been proposed to smooth the introduction of distributed generation in the Norwegian distribution grids. For example, in older radials that are no longer properly dimensioned for the loads they are carrying, the introduction of one or more DG units further out in the line could improve low voltage issues. In specific cases thermal limits of the line could also be alleviated if the DG unit has a sufficiently stable output all through the year. However, this is normally not the case as DG units are often hydro based generators with low output during winter when demand is peaking. Until now commissions for regulating river runs with dams have not commonly been granted by NVE as a cautious measure to not disturb ecosystems and general environment in the developed area. In an e-mail conversation with NVE they said that NVE would be open to commission damming river runs if it was documented low impact on surroundings and ecosystems and a sufficient improvement to DG operations could be documented. However, they also noted that the size of the dams normally requested were not sufficient to perform long term

islanding operations (12). This paper will discuss islanding at length later on, but in short this means enabling radials to be supplied with energy from DG units when the main grid is unavailable.

There are also ambitions for enabling DG units to operate in intended island modes. The benefits of managing to do this are many. A radial with a functioning islanding system could potentially reduce the costs imposed on net operators substantially. As per Norwegian law, the net operator has to reimburse the customer for energy not supplied.

Most radials consist mostly of households, which receives the smallest reimbursement rate of all the rate categories. Even so, the reduction in energy loss could still amount to sufficient amounts to improve the margins of a DG unit scheme. And if a radial with agricultural, industrial or private businesses there are big possibilities for reducing costs. These savings could not only apply for the net operator, but businesses who are focused on IT and other activities sensitive to blackouts could receive imperative improvements to reliability of supply.

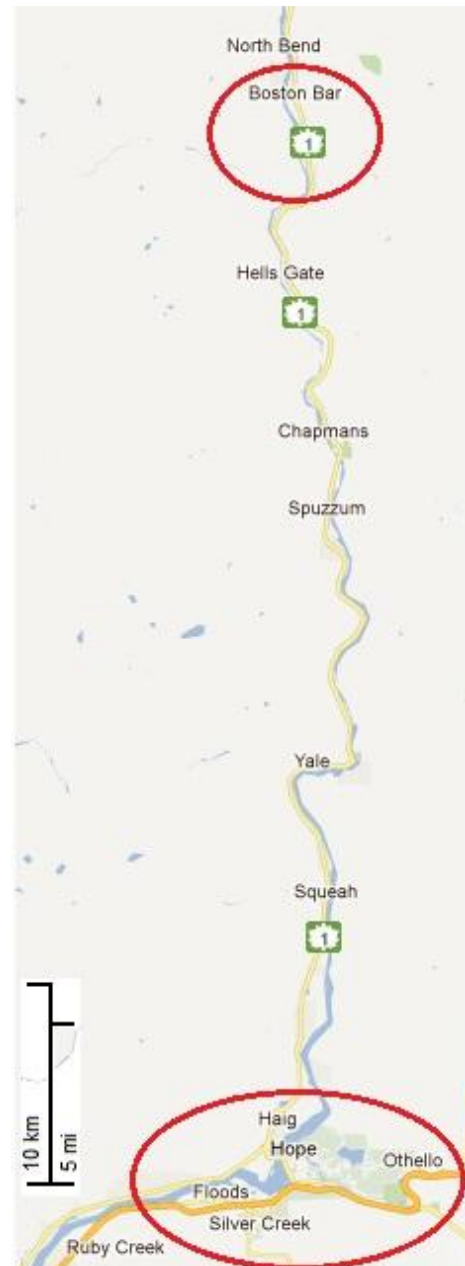
As a part of a smart grid concept which can react intelligently to information gathered in other parts of the grid more elaborate schemes could be implemented. For example, it has been suggested that islanding enabled zones or radials in a national power grid could help prevent cascading blackouts (13). Mainly by creating low threshold load shedding options, but also as a part of a more advanced control architecture which divides power systems into zones. Another concept being discussed is using these islanded zones to help synchronize and black start a grid once a blackout has occurred. Some of these concepts are mentioned in the government statement *Energi- og Kraftbalansen mot 2020* (14).

2.4 BC Hydro Islanding Practices

BC Hydro, one of the largest electrical utilities in Canada, is a company which has employed islanding practices for some of their rural feeders. The first and most notable of these is the feeder branching off from Hope and supplying the Boston Bar radial. This distribution system has 12 kV, 25 kV and 34,5 kV DG units installed throughout the radial. Most of these are run-of-the-river hydro generators with capacities of between 1 and 15 MW. This line is mostly built off the highway and runs through a steep canyon. As a consequence of this the line is frequently subjected to rock-, mud- and snow slides. Accessing the line for maintenance and repairs is difficult because of the terrain. On average the line experiences two 12-20 hours outages a year (1). Because of this BC hydro decided to implement islanding as a way to improve the reliability of the local power supply in Boston Bar. This pioneer project has resulted in a paper named “Distribution Power Generator Islanding Guideline” (15) and later a report was written on the results of the Boston Bar Islanding implementation (16).

2.4.1 Distribution Equipment Requirements to Feeders with Islanding Possibilities

The distribution system contains overhead and underground equipment and operates at 35 kV and below. In 2009 the DG size was limited to 17MVA at 25kV. The thermal capacity for primary feeder conductors or cables has to be verified for the implementation of any DG rated above 1MVA. Voltage regulators also have to be refitted or replaced for the new voltage profile and they have to be capable of reversed power sensing and two-way tap-changing operations. This is because the line set-up of voltage regulators normally is intended for one-way supply of power to the customer. A one-way power flow drastically reduces the set of acceptable operational scenarios for the equipment in question, and can therefor run on simpler protection systems. Potential fault currents may also increase, so a review of the relay ratings in the feeder must be conducted. Reclosers must be refitted or replaced if their protection systems are not coordinated with both normal operations and islanding practices, as a recloser closing when islanding operation is engaged could be dangerous and harm equipment.



Map 1 – Boston Bar feeder branching off from Hope

Considering this an industrial islanded power system with a high penetration of electrical motors could give a dampening effect on frequency changes thus making the whole system more stable. Alternatively, the industrial process could be very sensitive to frequency changes and therefore not suited for exposure to a more unstable frequency.

BC Hydro argues that since a smaller power system tends to have less stiffness, these considerations are particularly important when planning an IPS.

2.4.3 Generator Ride Trough or Load Pick-up

When the protection relay of the islanded feeder is opened due to failure in the feeder or some other reason, there are two options on how to restore power in the IPS suggested by BC Hydro. If the IPS is equipped with a “ride-trough” system the prime mover of the IPS receives a signal from the now open protection relay indicating a switch from constant power to load-following isochronous control mode. The generator then attempts to maintain voltage and power flow into the island. If the generator can’t do this, a synchronous relay opening of all the generators in the IPS will be executed, thus blacking out the whole island. If this happens, or the IPS does not contain a ride-through system, a black start is attempted. The system will be checked to see if the generators present and operational in the system have the capacity to maintain the total load in the IPS. This is done either manually or by an automated check of governor, controls, exciter and inertia to see if the generators can pick up and hold the dead feeder load. If so, a black start is attempted. If not, a manual or automated load shed or sectionalizing procedure is required (16).

2.4.4 Protection Coordination

The main change in overcurrent protection relays in the feeder is that they must be bi-directional. This is because they have to be able to switch between exporting power and importing power. There also has to be some kind of synchronization is needed to switch relays from normal feeder operations to islanding operations. This control can again be a manually triggered system (for example by a telephone call) or an automated signaling system.

2.4.5 Canadian requirements

When comparing Canadian and Norwegian standards for quality of supply the general Canadian law regarding this will not be elaborated on. The net operator, BC Hydro, in the Boston Bar region has been permitted to outline their own requirements in collaboration with the local government. The following tables outline the sort of power quality BC Hydro normally operates with and the sort of power quality they can supply in different stages of islanding mode.

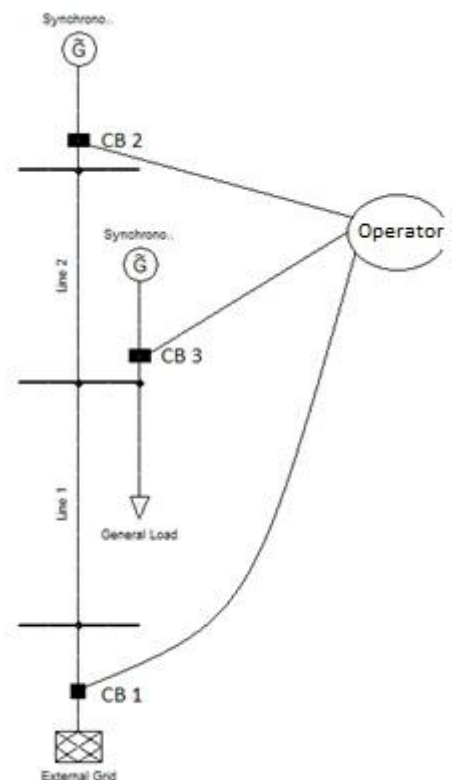


Figure 2.1 - Protection coordination illustration

Under/Over Frequency as per Canadian Nominal Standards				
	Nominal	Instantaneous Trip	As percentage	Delay Trip (1 sec)
Grid-connected	60 Hz	59.5 Hz > f, f > 60.5 Hz	+/- 0.83%	Not Applicable
Dead Load Pickup	60 Hz	55 Hz > f, f > 65 Hz	+/- 8.33%	Not Applicable
Island Steady State	60 Hz	53 Hz > f, f > 67 Hz	+/- 11.67%	59.5 Hz > f, f > 60.5 Hz

Table 2.6 - Under and over frequency standards in Canada

Under/Over Voltage as per Canadian Nominal Standards			
	Continuous Range	Delay (1sec)	As Percentage
V[p.u.](any phase)	0.9 < V < 1.1	0.9 < V < 1.1	+/- 10%

Table 2.7 - Under and over voltage standards in Canada

2.4.6 Boston Bar Islanding Results

The Boston Bar project will be briefly introduced. The one line schematics are presented in figure 2.2 below. The financing of the Boston Bar is done by BC Hydro through paying the IPP a bonus when it is able to sustain the island during an outage. This is paid as a compensation for its incremental capital cost for islanding capability. The incremental capital cost was about \$500,000 CDN on a capital cost base of \$12 million CDN.

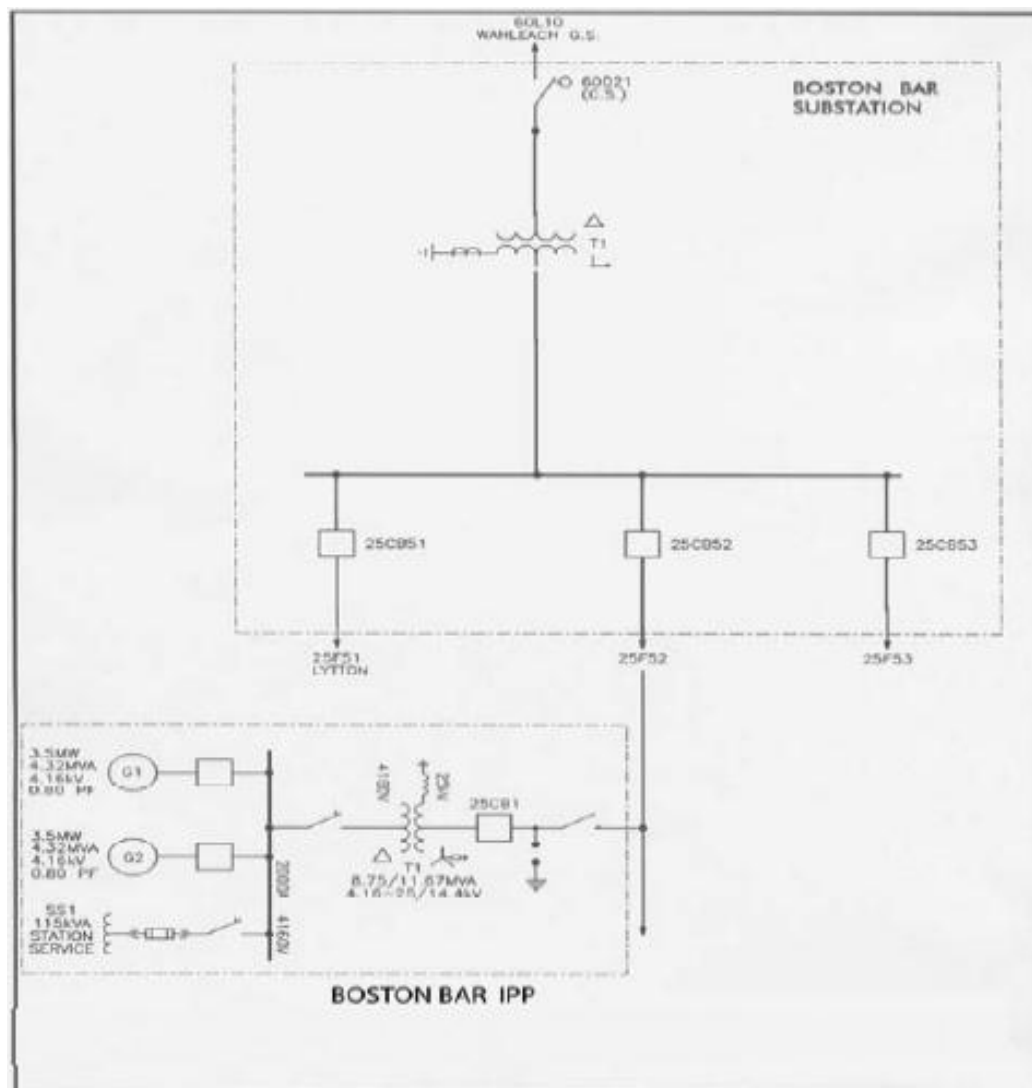


Figure 2.2 - One line schematics for Boston Bar

The reliability improvements shown below are the ones presented by BC hydro themselves. It shows the average for that region as presented by the Canadian Energy Association (CEA) compared to what BC Hydro (BCH) achieved at the Boston Bar with the islanding system. Curiously enough the BC Hydro report (15) presenting these results does not do a before and after evaluation. But the resulting SAIFI and SAIDI shows roughly half the average interruption frequency and half the average interruption duration.

Year	SAIFI		SAIDI	
	BCH	CEA	BCH	CEA
2000	1,22	2,59	2,28	4,31
2001	1,18	2,26	2,51	3,23
2002	1,41	2,41	3,6	3,67
2003	1,45	2,33	3,77	4,06
2004	1,63	2,67	4,51	10,65
2005	1,47	1,98	3,96	3,95

Table 2.8 - The reliability indices for BC Hydro islanding scheme compared to Canadian Energy Association

2.4.7 Boston Bar Islanding Guidelines

When the islanding capability was implemented in Boston Bar, eight points had to be conducted according to the BC Hydro summary report (17).

1. Automatic Voltage Regulators (AVR)

Voltage regulation must be a priority for DGs when operating in an island as there is no other entity inclining the voltage to stay within island standards. The exciters also had to have positive field forcing for current boost during feeder outage in order to assist overcurrent protection.

2. Black Start Capability

A 55kW diesel aggregate provides the Boston Bar island black start capability. This is for situations where the ride through isn't able to stay within limits and generators have to be tripped.

3. Engineered Mass for Turbines and Generators

This is done to increase the system inertia, H [MWsec/MVA] as described by the swing equation (1). This is intended to increase the stiffness in the IPS by reducing the impact of droop in production on the initial slope of the frequency change, as demonstrated in equation (3).

$$\frac{df}{dt} = \frac{\Delta P}{2H} \quad (3)$$

A small power system tends to have less stability with regards to frequency. This will be discussed in more detail in the discussion of empirical data later in this paper.

4. Net operator approval of exciters, AVR and turbine speed control governors

Since BC Hydro owns the grid and is responsible for customers serviced by the ISP the independent power supplier must have approval to engage in black start and/or ride trough.

5. Grid and off grid settings for 25kV line power quality and overcurrent protection

As discussed earlier in the *Protection Coordination* sub-chapter a revamp of protection settings and functions is needed for any DG operation.

6. Synchronized capability at feeder breaker substation

This is imperative to be able to reconnect to the main grid. It is also important if the IPS is to be used as a black-start aid for a generator without black-start capabilities.

7. Real-time IPP data telemetry (remote measuring)

This is intended to provide the control center with real time information. Control can monitor the situation for customers in the IPS and evaluate reconnection to the main grid. The telemetry can be done via telephone lease copper wire, internet, satellite or other practical means of data transfer.

8. Commissioning test for island operation

This is done as per regulating government's standard.

2.5 Reliability Theory

In its essence, reliability theory is the science of assessing what proportion of time a system can be expected to perform its designated task. There are many different ways to do this, and different systems are often best analyzed with their own specific approach. Yet, there are common denominators. Normally a system is described as a graph. In this graph nodes represent components in the system. These components and their relation to each other in this graph are defined according to the intended functionality of the system, and by how the different components are dependent on each other. There are many ways in which to define such a stochastic model. The 'homogenous Markov-model' which is a highly simplified but generally used model is the basis for the modeling program PowerFactory that will be presented later and used for analysis of test cases.

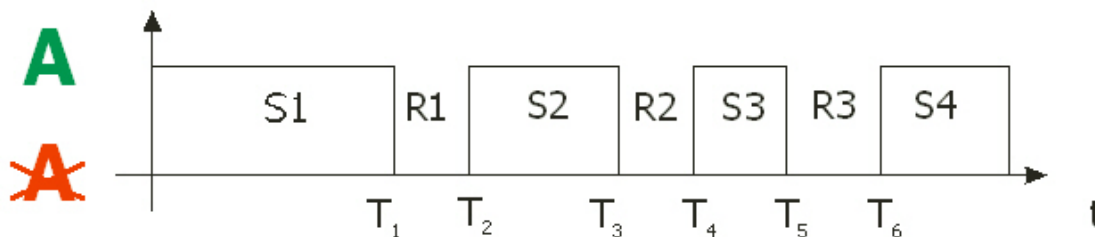


Figure 2.3 – Component timeline with two states. S, “in service” and R, “under repair”.

Component A in the example in figure 2.3 fails at time T_1 after which it is repaired and put back into service at T_2 . It fails again at T_3 , is repaired again, etc. The repair durations $R_1 = T_2 - T_1$, $R_2 = T_4 - T_3$, etc. are exaggerated in this example. The repair durations are also called the 'Time to Repair' or 'TTR'. The service durations $S_1 = T_1$, $S_2 = T_3 - T_2$, etc. are called the 'life-time', 'Time to Failure' or 'TTF'.

Both the TTR and the TTF are stochastic quantities. By gathering failure data about a large group of similar components in system, statistical information about the TTR and TTF, such as the mean value and the standard deviation, can be calculated. The statistical information is then used to define a stochastic model, such as the homogenous Markov model. Components can have any number of characteristics defined for them, but in the homogenous Markov two properties are imperative. Interruption frequency, defined as λ , and interruption duration defined as μ . These are both normally averaged value over some time, some amount of components or both. This gives us the possibility to define two states for a component, “in service” or “under repair” as explained above.

Using these two parameters we can define a set of equations that define the homogenous Markov model:

- **Mean Time To Failure, TTF** $= \frac{1}{\lambda}$
- **Mean Time To Repair, TTR** $= \frac{1}{\mu}$
- **Availability, P** $= \frac{TTF}{TTF+TTR}$
- **Unavailability, Q** $= \frac{TTR}{TTF+TTR}$
- **Annual Expected Repair Duration, AERD** $= \lambda\mu$

2.6 PowerFactory

PowerFactory is a power systems analysis software designed by the software developer DlgSILENT. It's intended to model a variety of aspects concerning power systems planning and operation. The focus of DlgSILENT seems to be developing informative graphical representations and intuitive interfaces for analyzing the power systems. As a proof of this they claim to be the first company ever to include a one-line drawing system for developing power system models.

Since DlgSILENT won't disclose how their algorithms work in detail it has been difficult to produce an exact text on how PowerFactory analyses the models that are created in it. The two biggest challenges this paper has had to overcome are mainly related to this lack of knowledge of these algorithms. Primarily, the problem of knowing what decisions has been done by the program when mitigating contingencies. Secondly, get an overview of what parameters data input that is included in the analysis based on what contingency mitigation procedure is chosen. These two aspects of analyzing in PowerFactory will be discussed in the *Test Cases* chapter. The first task of this chapter shall be to describe the overall reliability assessment algorithm. After this the key steps composing this process shall be explained, followed by an explanation of the different settings that has been used in this paper and a subchapter giving hints and tips on to perform an analysis in PowerFactory.

2.6.1 General PowerFactory Algorithm Architecture

Figure 2.4 shows a flowchart outlining the algorithm used in PF. It requires two major inputs. The electrical system model consists of the total topology of the grid and the parameters for defining each component in that grid. Basically this means any model on which a power flow analysis can be performed. Secondly a failure model has to be input. This input consists of the failure statistics defined for each component. Normally characteristic is an interruption frequency and an outage duration parameter pair, but other varieties also exist. This characteristic is then put into a loop with three steps which are presented in the following subchapters.

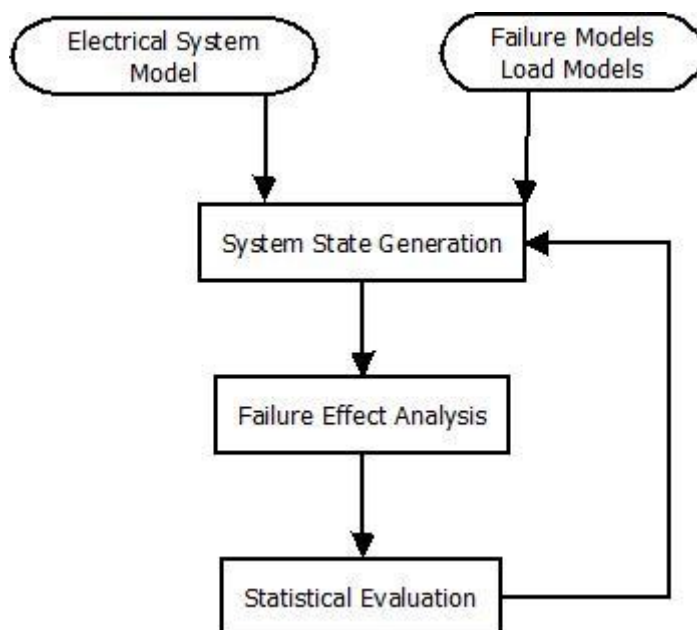


Figure 2.4 – Flow Chart for PowerFactory Reliability Assessment (18)

2.6.2 System State Generation

When a reliability analysis is conducted in PF the program first compiles a contingency list. This list is composed of all the components which are susceptible to contingencies as per their failure characteristics. Each component contingency is then generated as a system state with its own topology. The topology created is coined as contingency topology. Figure 2.5 demonstrates how the contingency topology is formed. In this figure the red lightning symbol indicates a fault. The resulting contingency topology after sectioning is demonstrated to the right in the figure. One such contingency topology is created for every component with a fault characteristic. If common mode or “Independent Second Failure” is enabled, even more contingency scenarios and their respective contingency topologies will be created. This is what’s called the “System State Generation” in figure 2.4, and is the first step of the reliability assessment iteration.

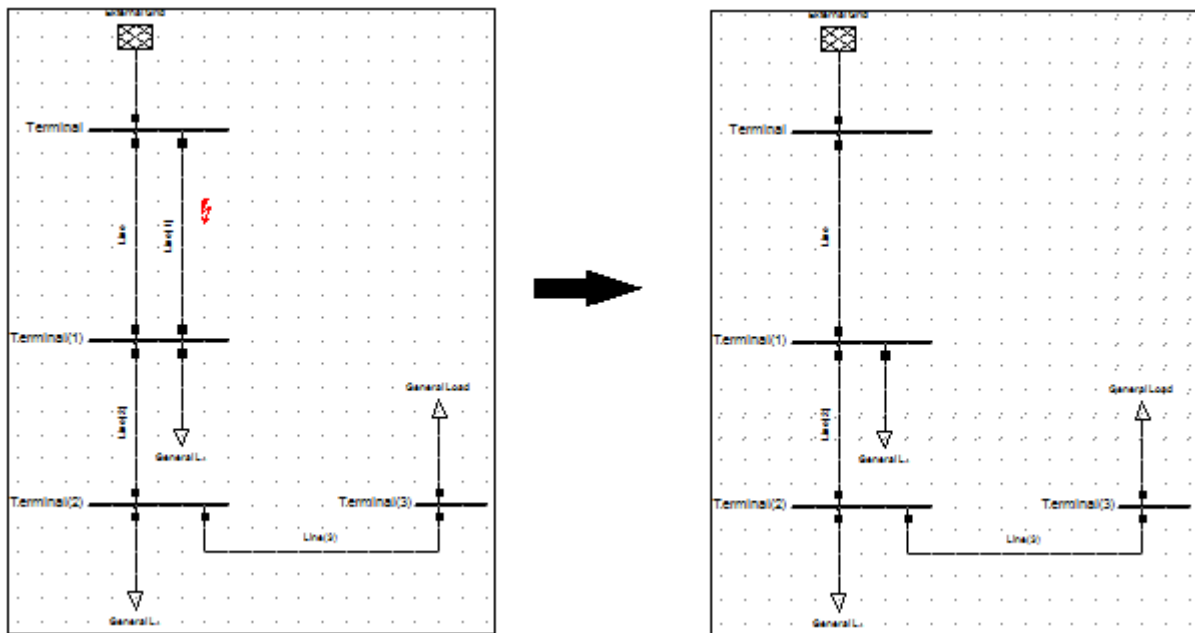


Figure 2.5 – Example of contingency and resulting contingency topology

2.6.3 Failure Effect Analysis (FEA)

After the contingency list is generated and enumerated the first contingency topology is sent to the “Failure Effect Analysis”. This is the most comprehensive step of the assessment algorithm. Put simply, the input contingency topology is checked to see if it is within the limits set in the analysis options. If it is not, then mitigating measures are performed as defined in the *analysis option*. The *analysis option* is presented in the next chapter. From this process a series of contingency parameters are calculated. These are listed below.

- r_m : Duration of an interruption event m . Based on μ_k and the duration of mitigating measures like sectionalizing etc.
- Pd_i : The weighted average amount of power disconnected at load point i
- Ps_i : The weighted average amount of power shed at load point i
- $frack_{i,k}$: The fraction of the load lost in Load Point i for contingency m
- Fr_k : The frequency of occurrence of contingency k

There are a lot of different options and limits which can be set for the FEA, but in this paper a checklist has been made where all the relevant settings has been listed. The different analysis options define the analysis. These tables will be included for each case analysis performed on in the test grid analysis part of this paper filled out with the analysis options chosen for the respective case.

2.6.4 Reliability Assessment Options and its Impact on FEA

Table 2.9 shows an example checklist of the “Reliability Assessment” which is the function in PowerFactory that performs a reliability analysis. What is seen in table 2.9 is the most important settings that define the analysis.

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	
	Sequential	x
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 2.9 – Reliability Assessment Checklist Example

Connectivity Analysis

This option enables failure effect analysis without considering thermal and voltage constraints. A load is assumed to be supplied if it is connected to a source of power. After a contingency the load is assumed to undergo a loss of supply if the fault or the process of fault clearance separates the load from all power sources. Because constraints are not considered, no load-flow is required for this option and hence the analysis will be faster and more robust than when using the alternative load flow analysis option. This option will not be utilized much in this paper, but is important when building a grid model to get preliminary results before the load flow algorithm converges.

Load flow analysis

When this option is selected a load flow check will be performed as defined in the *load flow checklist* presented later in this chapter. Constraints are considered by completing load flows for each contingency topology. Loads might be disconnected to alleviate voltage or thermal constraints. For

the transmission analysis option, Generator re-dispatch, load transfer and load shedding are used to alleviate overloads. These three alleviate options are also explained later in this chapter.

Distribution

The reliability assessment will try to remove overloading at components and voltage violations (at terminals) by optimizing the switch positions in the radial system. If constraints occur in the power restoration process, loads will be shed by opening available switches. This algorithm does not work unless the grid structure is radial, and a check to confirm this is done in the beginning of the algorithm.

Transmission

Thermal overloads are removed by generator re-dispatch, load transfer and load shedding. First generators are re-dispatched and load transfer is attempted. If this cannot be completed or does not remove the thermal overload, load shedding actions will occur. Generator re-dispatch and load transfer do not affect the reliability indices. However, by contrast, load shedding leads to unsupplied loads and therefore affects the reliability indices.

Contingency Definition

Contingency definition is the list of component types that are to be included in the contingency list. The common mode box is checked when you have implemented specific common mode failures and you want to add them to the contingency list.

Secondary independent failures indicate that you want to run an n-2 reliability check with two independent failures occurring at the same time with the probability equaling the two separate probabilities multiplied with each other.

Use All Switches as Circuit Breakers

All switches in the system whose Usage is set to Circuit Breaker can be used for fault clearance. As Circuit Breaker is the default usage of all switches, this normally gives you a grid which is cleared for faults very fast. Since this paper is mostly working with radials which employ more disconnectors than circuit breakers this option is not used much in this paper. But it is used during “calibration” of the models. The stage where you check if the protection equipment is behaving as it is intended to.

Use Only Circuit Breakers with Protection Device

With this option all circuit breakers in the system that are controlled by a protection device (i.e. fuse or relay) can be used for fault clearance. This is the mode normally used in the case analysis.

Concurrent Switching

It is assumed that the switching actions can be performed immediately following the specified switching time. However, a switch can be closed for power restoration only after the faulted element was disconnected. The analogy for this mode is if there were a large number of operators in the field that were able to communicate with each other to coordinate the switching actions as quickly as possible. Therefore, this option gives an optimistic assessment of the 'smart power restoration'.

Sequential Switching

It's assumed that all switching actions are performed sequential. The analogy for this mode is if there is only a single operator responsible for the grid and he is required to complete all switching actions. The fault separation and power restoration is therefore slower when using this mode compared with the 'concurrent' mode.

Protection/Switch Failures

PowerFactory can consider the failure of the protection system to clear the fault as a stochastic probability within the reliability calculation. This is enabled by entering a 'Probability of Failure' into the switch object. 'Fault Clearance: circuit breaker fails to open probability' in percent. For example, a 5 % failure rate means that on average 1 out of 20 attempted fault clearance operations will fail. This again means that the whole circuit breaker zone outside the circuit breaker that is failing will be affected and has to be sectionalized off. Also note that this failure characteristic is different than what's normally used in PowerFactory, namely the outage frequency coupled with outage duration.

2.6.5 Load Flow Options

The load flow analysis options in PF are somewhat extensive. Only the most relevant settings are included here. In table 2.10 below an example checklist is presented.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 2.10 – Load Flow Checklist Example

Generally load flow analysis will be used in this paper as it is necessary to check whether or not thermal limits and voltage limits are upheld. Connectivity analysis is mostly used for the construction part of the modeling process when it can be difficult to get the load flow calculation algorithms to converge. If the load flow analysis option is checked, you need to define your load flow analysis. As seen in table 2.10, both AC load flows and DC load flows are viable for the calculation method. The rest of the options are explained below.

Reactive Power Control

The reactive power control is one way for the PF load flow algorithm to directly mitigate busses which have voltages outside the voltage limit set by the operator. It also gives the algorithm the

ability to control the amount of reactive power exported/imported from/to other parts of the grid. This can be done by either adjusting tap settings in transformers and/or adjusting shunt tap settings. The increase/decrease in reactive power flow through the lines will be adjusted by tapping either the transformer or the shunt within its predefined limits. These adjustments will be aimed at mitigating over/under voltages at the problem busses.

Active Power Control

Besides the traditional approach of using a slack generator to establish the power balance within the system, PowerFactory's load flow calculation tool provides other active power balancing mechanisms which more closely represent the reality of transmission networks. These mechanisms are implemented in the steady-state according to the control processes that follow the loss of large power stations.

As dispatched:

Ticking this option indicates that you will define the dispatch that the different generators will output when the analysis initializes the grid power flow calculation. The active power dispatched does not have to be an exact match of what is consumed by the lines and the loads in the grid, but the numbers don't match a balancing measure will be engaged. Balancing options are explained later in this chapter.

According to primary control, secondary control or inertias:

These options are designed to give you a dispatch control which is often used in real life power plants. In this paper they are not used much in a direct form, but they are sometimes used in the less robust test nets where relieving the reference machine or slack buss is desirable. It can also be used to explore a somewhat realistic frequency response to a fault, given that the modeling of the synchronous machines is detailed enough.

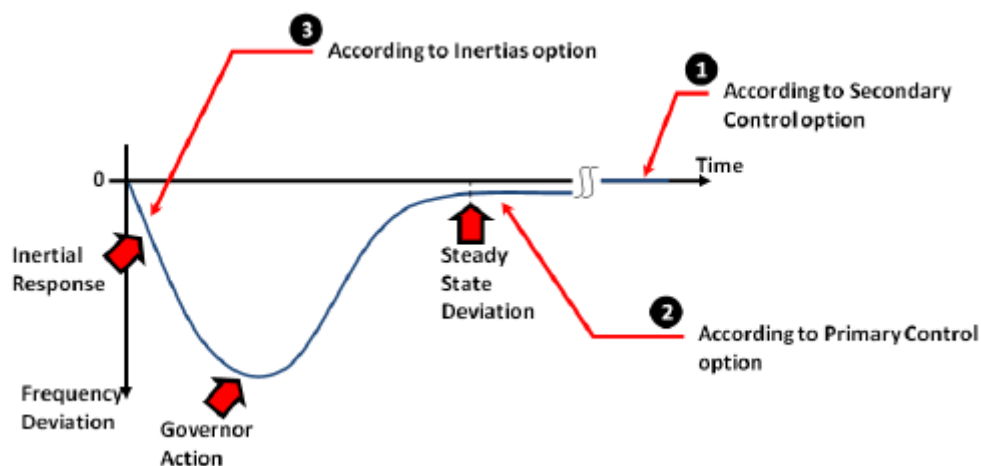


Figure 2.6 - Example of inertia, secondary and primary control

The Secondary Control option will take into account the participation factors of the machines defined within a *Power-Frequency Controller* in order to compensate for the frequency deviation. The final steady state frequency is considered to be the nominal value when active power balancing is needed.

This is demonstrated as number 1 in figure 2.6. The Primary Control option will take into account the frequency droop (MW/Hz). This needs to be defined for every machine in order to determine the active power contribution. Depending on the power unbalance, the steady state frequency will deviate from the nominal value. This is indicated as number two in figure 2.6. The According to Inertias option will take into account the inertia of each machine. This needs to be defined for every machine in order to determine its active power contribution. In this case, depending on the power unbalance, the steady state frequency will deviate from the nominal value. This is shown as number 3 in figure 2.6.

Consider Active Power Limits

This option is mostly used when tuning a model for load flow algorithm for iteration converging. This basically allows generators to be dispatched outside their active power limit when balancing or dispatching.

Balancing of Production/Load

The Balancing part of the load flow checklist could easily be confused with the *Active Power Control*. The difference is not crystal clear either as both options can behave a bit differently depending on what the other options are ticked off for the analysis. The rule of thumb, however, is that active power control is mainly used to initialize a grid and set preferences for dynamic analysis of the model. The balancing settings have first priority when it comes to balance the general power flow. This means that unless commented otherwise in the case, what is defined in the balancing settings will control the power flow during both load flow analysis and the general reliability analysis.

By Reference Machine

If the balancing is set to this option a calculation will be done to see how much active power is lost in the lines, cables, transformers and loads. Then this load will be checked against the dispatch from external grid and generators modeled in the grid to see how much surplus/deficit of active power there is. The generator set to be reference machine will then be re-dispatched to make up for this difference.

By Slack Bus

This option works identically to the reference machine option, except now the external grid is supplying the difference in active power. The only real difference is that the external grid can be treated as an infinite bus, while generators have capacity limits.

Distributed Slack by Load

Under this setting, the active power of the selected group of loads will be modified so that the power balance is met while leaving the scheduled active power of each generator unchanged. In this paper only load priority will be used to define which loads are to receive a reduction in demand. If this is used in a case, the case will specify which loads are to be reduced and what kind of schedule they are under.

Distributed Slack by Synchronous Generators

This balancing considers the participation of all synchronous generators according to their scheduled active power. If this option is utilized a schedule will be defined in the case text.

Load dependencies are checked at nearby bus:

This option is checked when a bus' voltage dependencies are not considered by the analysis itself. The busses are by default what is voltage sensitive in the analysis. This means that if a load can't have a difference in voltage of more than 10% then the bus will be set to a 10% voltage limit, but not the load itself. This has little practical implications for the analysis, but should be clarified for documentation.

2.6.6 Statistical Evaluation of Indices

In this part the statistical evaluation step of the general reliability assessment algorithm in PowerFactory will be explained. The PowerFactory reliability indices are based on the Markov model outlined in the *Reliability Theory* chapter, but with indices defined by DIgSILENT.

The units used for the different quantities are defined as follows:

- Frequencies are expressed in **[1/a]** = 'per annum' = per year
- Lifetimes are expressed in **[a]** = 'annum'
- Repair times are expressed in **[h]** = 'hours'
- Probabilities or expectancies are expressed as a fraction or as time per year, **[h/a]** or **[min/a]**.

This means out interruption frequency, λ is a quantity with the unit [1/a] and our expected outage duration, μ is a quantity in [h]. From this basic Markov model we can now begin to define the analysis indices. How these are calculated in practice will be elaborated on in the PowerFactory chapter, and is different reliability analysis practices does this in different ways. Mathematically, the reliability indices used in this paper are defined using the following added characteristics.

- C_i : The number of customers supplied by load point i
- A_i : The affected number of customers for an interruption at load point i
- λ_k : The frequency of interruption in component k
- C: Total number of customers in grid
- L_m : Total connected load interrupted for each interruption event m
- μ_k : Duration of interruption to component k

In PowerFactory as in most power system reliability analysis regimes, the focus of the analysis is to see how well the load points on average are supplied with electricity. The first indices that have to be calculated are therefore the load point indices. In the general PowerFactory reliability assessment algorithm architecture the load point list will therefore be the

Load Point Indices

These are the load point indices as defined in the PowerFactory manual (18).

- **ACIF** Average Customer Interruption Frequency

$$\circ \quad ACIF_i = \sum_k \lambda_k * frack_{i,k} \left[\frac{1}{a} \right]$$

- **ACIT** Average Customer Interruption Time

$$\circ \quad ACIT_i = \sum_k \lambda_k * \mu_k * frack_{i,k} \left[\frac{h}{a} \right]$$

- **LPIF** Load Point Interruption Frequency

$$\circ \quad LPIF_i = ACIF_i * C_i \left[\frac{1}{a} \right]$$

- **LPIT** Load Point Interruption Time

$$\circ \quad LPIT_i = ACIT_i * C_i \left[\frac{h}{a} \right]$$

- **AID** Average Interruption Duration

$$\circ \quad AID_i = \frac{ACIT_i}{ACIF_i} [h]$$

In these equations k is the contingency index and $frack_{i,k}$ is the fraction of the load which is lost at load point i , for contingency k . For unsupplied loads, or for loads that are shed completely, $frack_{i,k} = 1$. For loads that are partially shed, $0 \leq frack_{i,k} < 1$. Once all this is calculated, the system load indices can be calculated.

Load Point Energy Indices

Perhaps the most crucial of these most crucial of the load point indices are the energy indices.

- **LPENS** Load Point Energy Not Supplied

$$\circ \quad LPENS_i = ACIT_i * (Pd_i + Ps_i) \left[\frac{MWh}{a} \right]$$

- **LPES** Load Point Energy Shed

$$\circ \quad LPES_i = ACIT_i * Ps_i \left[\frac{MWh}{a} \right]$$

In these equations:

- Pd_i is the weighted average amount of power disconnected at load point i
- Ps_i is the weighted average amount of power shed at load point i

From these the *System Energy Indices* can be defined, which are the most utilized and discussed in this paper.

System Energy Indices

- **ENS Energy Not Supplied**
 - The most important index for this paper. The total amount on average not delivered to the system over the one year analysis period.
 - $ENS = \sum_i LPENS_i \left[\frac{MWh}{a} \right]$
- **SES System Energy Shed**
 - Total amount of energy on average expected to be shed in the system.
 - $SES = \sum_i LPES_i \left[\frac{MWh}{a} \right]$
- **AENS Average Energy Not Supplied**
 - The average amount of energy every customer can expect on average not to be supplied.
 - $AENS = \frac{ENS}{\sum_i C_i} \left[\frac{MWh}{a} \right]$

System Load Indices

There are many indexes defined in the PowerFactory manual, but only the relevant will be defined and mentioned here. This does not necessary mean that the specific index is debated in the discussion, but is included in the output and/or used to calculate other indices which are relevant.

- **SAIFI System Average Interruption Frequency Index**
 - Indicates how often the average customer experiences a sustained interruption during the period specified in the calculation.
 - $SAIFI = \frac{\sum_i ACIF_i * C_i}{\sum_i C_i} \left[\frac{1}{Ca} \right]$
- **CAIFI Customer Average Interruption Frequency Index**
 - The mean frequency of sustained interruptions for those customers experiencing sustained interruptions. Each customer is counted once regardless of the number of times interrupted for this calculation.
 - $CAIFI = \frac{\sum_i ACIF_i * C_i}{\sum_i A_i} \left[\frac{1}{a} \right]$
- **SAIDI System Average Interruption Duration Index**
 - Indicates the total duration of interruption for the average customer during the period in the calculation.
 - $SAIDI = \frac{\sum_i ACIT_i * C_i}{\sum_i C_i} \left[\frac{h}{Ca} \right]$
- **CAIDI Customer Average Interruption Duration Index**
 - The mean duration required to restore energy supply to a customer.
 - $AID_i = \frac{SAIDI}{SAIFI} [h]$
- **ASIDI Average System Interruption Duration Index**
 - This is the equivalent of SAIDI but based on load, rather than customers affected.
 - $ASIDI = \frac{\sum_i (r_m * L_m)}{L_T} \left[\frac{h}{a} \right]$
 - In this equation L_T is the total load.
- **ASUI Average Service Unavailability Index**
 - The probability of having all loads supplied.
 - $ASUI = \frac{\sum_i ACIT_i * C_i}{8760 * \sum_i C_i} \left[\frac{h}{a} \right]$

General System Index Calculation Algorithm

The general algorithm for these calculations is shown in the flowchart in figure 2.7. Note that this flowchart is not entirely consistent with the general architecture shown in figure 2.4 in the subchapter about general architecture. In the general architecture flowchart a list of contingency parameters is not created, but calculated in the outer loop of the general architecture flowchart. However, the resulting calculations will be the same. The flowchart in figure 2.7 was created to give a better overview of the index calculation process.

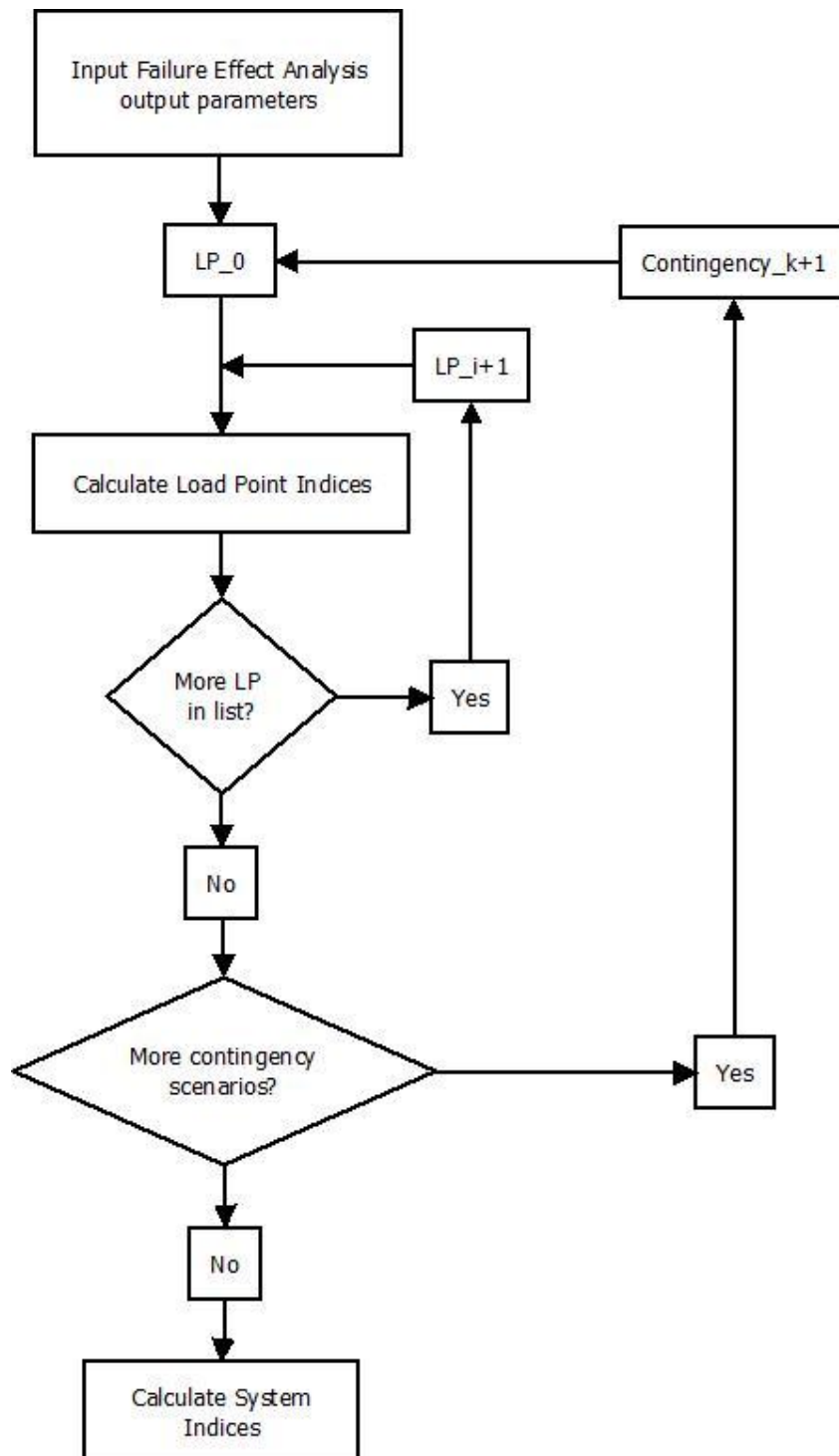


Figure 2.7 - Index Calculation Algorithm Flowchart

2.6.7 Practical Hints and Tips for PowerFactory

During the period I have used to learn PowerFactory, it has been cumbersome not to have people with actual experience with reliability analysis in PowerFactory to speak to. In the beginning this was mostly due to lack of information in the manual and frequent mails were exchanged between the support and me. Later on, however, the chapters explaining reliability analysis in the PowerFactory manual have become much more detailed. There are still two main questions that remain unanswered by DIgSILENT.

- Lack of Information on Mitigating Measures Procedure

This has been mentioned earlier in this chapter and is the main uncertainty I have had with PowerFactory. The selection of mitigating measures when several not entirely comparable options are available. For example, if there is the possibility of either re-dispatching a generator or open a backup cable, which option is prioritized? If a meshed island with insufficient production capacity can be created for a period while a critical line is being repaired, how is the production/load shedding performed? The answer to the first question, according to the manual, is that an evaluation of all the mitigating measures available are performed and judged by an objective function (minimize cost, minimize loss, minimize ENS etc.). The answer to the second question is that loads are prioritized according to priority or predefined costs for shedding the load. However, in practice it is often difficult to see how or if PowerFactory is actually performing these measures as the results can be very contradictory. The “Optimal Power Flow” function which analyzes the objective functions in both these cases is notoriously unstable, and no error message is given if it does not converge during reliability assessment. I consider this important to be aware of when analyzing reliability in PowerFactory. And of course, ideally, DIgSILENT should document this better in the manual for the future.

- Adding Failure Effects on Protection Equipment

Adding a failure effect to a protection device in itself is not very complicated (in the *reliability* section of that “type” or that “component”). The effect on for example a single line supplying a faultless load and bus bar system like in figure 2.8 should be easy to predict. Let the two red circles indicate circuit breaker and the upper line have an interruption frequency of 5 [1/a]. The upper circuit breaker has a fault chance of 5%. In this situation $5\% \cdot 5 [1/a] = 0.25 [1/a]$ should give the amount of times the system would have to sectionalize all the way down to the second circuit breaker. However, in practice this works only some of the time and I have even experienced decreased ENS as a result of introducing failure effects. This problem can be experienced in even very simple systems with complete control over all disconnectors and circuit breakers.

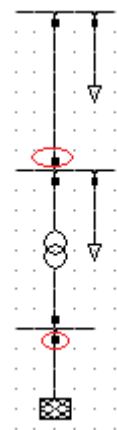


Figure 2.8 - Circuit Breaker Failure Example

Hints and Tips

- My best tip for performing reliability analysis in PowerFactory is to get the basic power system model right and with sensible load flow results. An unstable net which is not well within its voltage boundaries and thermal boundaries is much harder to analyze correctly in a load flow check in a reliability analysis. If you are not experienced in this yourself, get help from people with experience in load flow analysis if possible. The more reliable and stable your net is, the easier it is to get predictable and plausible results.

- The reliability analysis also gets exponentially more difficult to manage the more complexity you add to the model. This might seem obvious, but is very helpful to keep in mind. Take a step by step approach to building your net and checking of the numbers seem legitimate for every step. Figure 2.9 below is an example suggested in the PowerFactory manual. I suggest leaving out maintenance plans and load characteristics until everything else works, as checking if your results are reasonable becomes more difficult including these settings.
- Lastly, this might be obvious to some as well, but it took me some time to find this out on my own. When you edit switches, the *reliability* section includes a section called “power restoration”. The option *remote controlled* is best used when you want the switch to work as a circuit breaker (You still need to add a *relay* to the switch, as described in the manual. Any relay type will do, but I normally used *overcurrent*.) Setting the switch to *manual* gives it disconnecter-like properties (you can set sectioning times etc.).

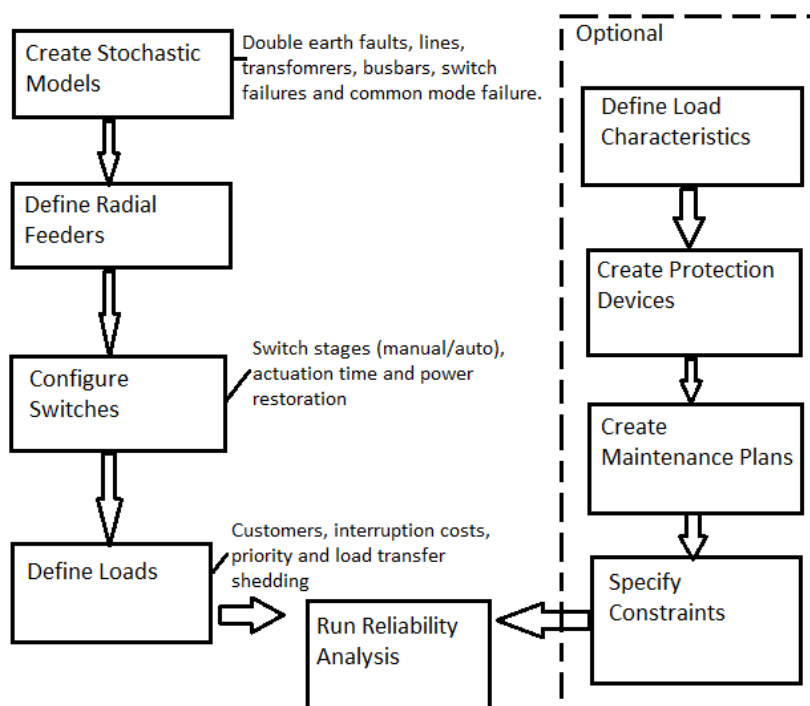


Figure 2.9 - DlgSILENT Reliability Assessment Suggestion

3. Test Net Analysis

This section is quite long and tedious. As it's not possible to verify these results with a 100% certainty it's been included discussions and estimates to substantiate the results of the analysis. The chapter is structured with subchapters, each including a grid to be analyzed. The grid is introduced with component data, structure and a few notes. Then test cases and analysis follows for each grid with a small summary at the end for each grid. The summary will only include ENS differences and SAIFI (System Average Interruption Frequency Index) differences. Changes in interruption frequencies and load point indices could also be included and elaborated on when substantiating the results, but the analysis already seemed extensive enough. There are possibilities for including different cost vectors which could have calculated the KILE costs as according to *Forskrift om økonomisk teknisk rapportering* (6), but there were problems with implementing these. However, a rough cost estimate will be considered good enough for this paper, as the radials are assumed to contain mostly households as no other information had been given. Most interruption durations are set to be less than 4 hours, which makes the KILE cost easy to calculate using the simplified KILE formulation used by NVE.

3.1 Empirical line A

The Empirical line A is the most detailed real life radial grid which is analyzed in this paper. The reliability data is directly measured in the region and should therefore be very accurate. This also imposes a bigger need for anonymity. Figure 3.1 shows the actual grid which was constructed as modeled by the grid company. Figure 3.2 shows a simplified version of the grid with external grid connection and generators implicated.

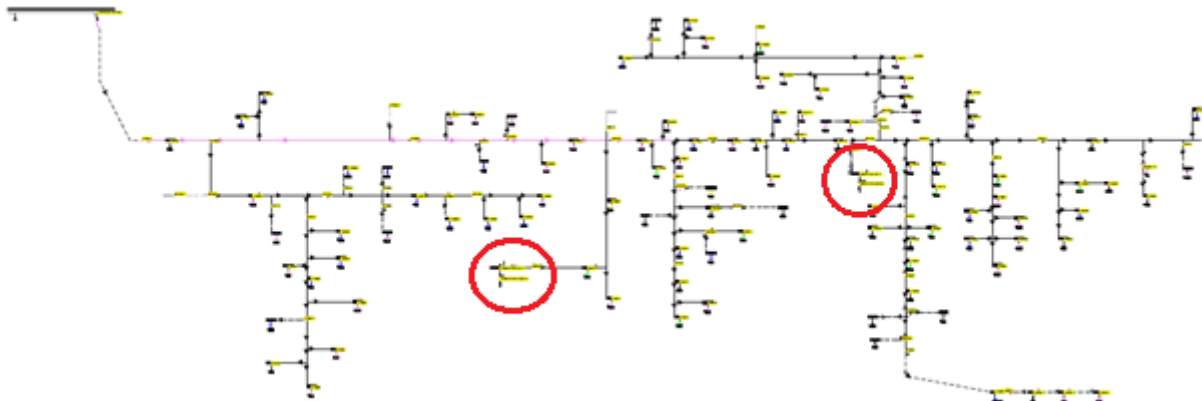


Figure 3.1 - Anonymous line A, poor resolution as imposed by confidentiality clause

Simplifications and assumptions

A few of the loads have been left out due to lack of information and parts of the net have been simplified. The loads left out were assumed not to be included in the line anymore. They are greyed out on sketches and are excluded from the excel tables with measurements received from the operator. The majority of simplifications consist of leaving out nodes that seemed to be relevant for reliability analysis purposes.

The significant simplifications are the following.

- Nodes midway in lines between loads which are assumed to be of importance to operators, but who are inconsequential for reliability assessment purposes.
- Nodes with disconnectors in places where they will have no effect on the reliability simulation result. For example a disconnector at the beginning and at the end of a feeder line which instead can be isolated at the nearest bus bar connected to a load with no implication for the load point failure frequencies or downtime of other loads. These disconnectors are assumed to be present in the line for maintenance or other purposes rather than for reliability enhancement.

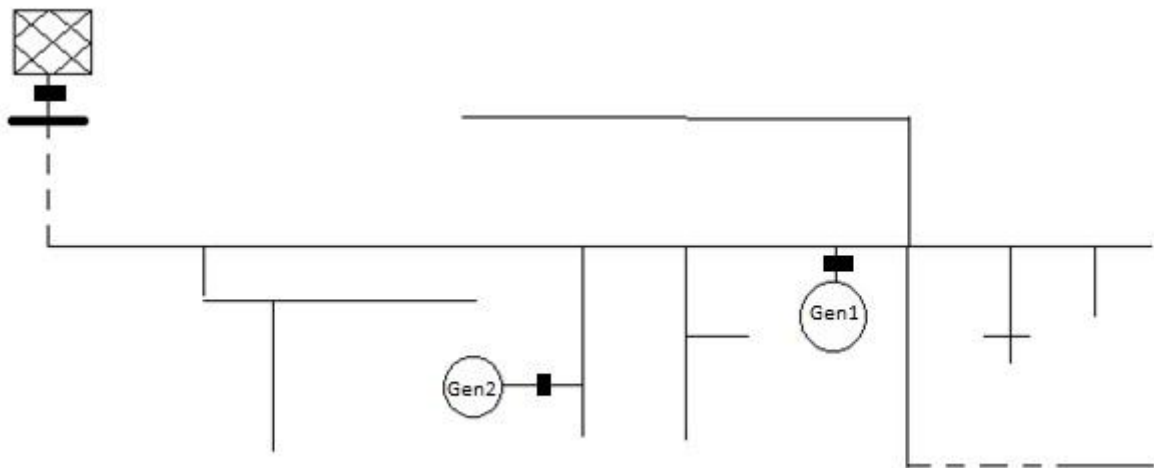


Figure 3.2 - Simplified sketch of line A

Loads, switching and relays

The loads are spread out with relative homogeneity in size and quantity throughout the line and are

Total heavy load	3 MW
Number of loads	100
Total line length	73km
Sectioning time	1 hour
Number of nodes in model	370
Distribution voltage	22 kV
Customer voltage	230 V
Circuit Breaker Failure Rate	1,3%

Table 3.1 - General grid data for line A

about the size you could expect from households. Each load is connected to the distribution grid with a distribution transformer. Between these transformers and the distribution grid there are disconnectors in case a faulted transformer needs to be sectioned off the grid together with its load. All nodes with more than two distribution lines connected to them are connected through disconnectors. These disconnectors are tripped manually, and the sectioning time average

which is operated with in this paper is one hour. The external grid and all DG units are connected through circuit breakers. These generators are normally tripped when external grid connection trough an anti-islanding protection relay.

Reliability data

The reliability data is the grid operators own data collected from the area. Because of this, and because the general data available from the operator for this grid, the results from assessing

	Repair Duration	Interruption Frequency
Transformers	5.35 [h]	0.00105 [1/a]
External Grid	1.507 [h]	5.604 [1/a]
Lines	3.55 [h]	0.0041 [1/a*km]
Cables	7.7 [h]	0.0215 [1/a*km]
Generators	50 [h]	5 [1/a]

Table 3.2 - Line A reliability data

different scenarios of this grid will be the most accurate of all the grids. As can be estimated from the table 3.2 data, a significant proportion of the outage time is

contributed from the external grid. A scenario where the only

protection system present was a circuit breaker between the distribution grid and the external grid would have a contribution to outage time from the lines in the range of $3.55h * 0.0041 \frac{1}{a} * km * 73km * 3MW = 3.2MWh/a$. This represents a maximum. A similar calculation for the external grid yields 25.3 MWh/a

Line and component data

Since line info was not given from the grid operator it was assumed that a cheap FerAl 50 1/6 was used. The cable type in this model is a N2XSEY 12mm. N2XSEY was not the actual type cable used,

	R'[ohm/km]	X'[ohm/km]	B'[ohm/km]
Lines	1.27	0.4	2e-6
Cables	0.2	0.1	60e-6
Transformer	0	0	0

Table 3.3 - Line A component impedance data

but it was chosen because it had plausible impedance values and an informative data sheet available publicly. Transformer impedances are set to zero

due to lack of data. In this specific model the impedances are not vital, as the load flows are well within limits even in heavy load combined with low production scenarios, such as the base case described below.

1. Base Case

Line A was originally modeled to control the grid operators own reliability assessment results. This modeling scenario consisted of heavy loading coupled with DG units who had anti-islanding protection systems. This implies that any fault in the grid will trip generators until sectioning has been performed. If grid connection is restored to the portion of the grid where the DG unit is located, the generator attempts to reconnect to the grid. Since there are no available reliability data for generators they have no implications for the reliability assessment of this scenario, and can therefore be disregarded completely. Another thing worth noting here is that since the loads did not come with any reactive power data, reactive power limits are not considered, as can be seen from table 3.4.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 3.4 - Load Flow Calculation settings

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	x
	Transmission	
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failures	x
Fault Clearance Breakers	Use All Circuit Breakers	x
	Use Switches With Protection Devices Only	
Switching Procedure	Concurrently	
	Sequential	x
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.5 - Reliability Assessment settings in PF for Base Case Line A

System Summary				
System Average Interruption Frequency Index	: SAIFI =	6,137403	1/Ca	
Customer Average Interruption Frequency Index	: CAIFI =	6,137403	1/Ca	
System Average Interruption Duration Index	: SAIDI =	9,910	h/Ca	
Customer Average Interruption Duration Index	: CAIDI =	1,615	h	
Average Service Availability Index	: ASAI =	0,9990050744		
Average Service Unavailability Index	: ASUI =	0,0009949256		
Energy Not Supplied	: ENS =	29,315	MWh/a	
Average Energy Not Supplied	: AENS =	0,262	MWh/Ca	
Average Customer Curtailment Index	: ACCI =	0,259	MWh/Ca	
Expected Interruption Cost	: EIC =	0,000	m\$/a	
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh	
System energy shed	: SES =	0,000	MWh/a	
Average System Interruption Frequency Index	: ASIFI =	6,028698	1/a	
Average System Interruption Duration Index	: ASIDI =	9,732747	h/a	
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca	

Table 3.6 – Case 1 Reliability Assessment Results

From table 3.5 we see that a distribution analysis was done. This is only for practical reasons as the level of detail of the model makes a complete load flow time consuming. The external connection point is chosen as the slack bus for balancing.

Table 3.6 shows us an ENS of 29.315MWh/a. Compared to the 13 MWh/a ENS (19) which is demonstrated in the reference simulation from the net operator this result is more than the double of what the result should be. This is because variable load was not implemented, and the senior engineer responsible for line A commented that 29.3MWh/a was very plausible number for a constant heavy load scenario. Since this example in principle is relatively simple we can get an estimate of the plausibility of this ENS result. There are only a few kilometers of cable compared to lines, and they have roughly the same expected downtime we include the cables as lines in this estimate calculation.

$$\begin{aligned}
 &0.0041[\text{interruptions/a} \cdot \text{km}] \cdot 73[\text{km}] \cdot 1[\text{h}] \cdot 3[\text{MW}] \\
 &0.00105[\text{interruptions/a}] \cdot 100 \cdot 1[\text{h}] \cdot 3[\text{MW}] \\
 &+ 1.507[\text{interruptions/a}] \cdot 5.6[\text{h}] \cdot 3[\text{MW}] \\
 \hline
 &= 26.53 [\text{MWh/a}]
 \end{aligned}$$

The first line in this calculation is the sum of all the interrupts caused by lines and cables multiplied by the sectioning time and complete heavy load. The second line multiplies the average interruption frequency of the distribution transformers by the number of transformers in line A. The last line in the estimate calculation is the average number of hours the external grid is disconnected or de-energized throughout a year multiplied by the total load in the grid. This estimates the lowest threshold of ENS in a system with the Base Case protection and modeling setup.

2. Original Generators with Islanding Capability, Heavy Load

According to the BC Hydro heuristics explained in the BC Hydro chapters, a 6MW of producing maximum capacity is needed in the grid to sustain a grid with 3MW heavy load. As can be seen from table 3.7 this is not the case for line A with a generator maximum production of 2.975 MW. This case will see how much these two generators can alleviate the total ENS on their own without considering the framework conditions that needs to be fulfilled for this system to be allowed under Norwegian law.

	Max Capacity	Type	Rated Voltage	Role	Dispatched Power	PF
Gen 1	2 MVA	Synch. Gen.	22 kV	Swing Machine	0 MW	0.85
Gen 2	1.5 MVA	Synch. Gen.	22 kV		1.275 MW	0.85
Gen 3	3 MVA	Synch. Gen.	22 kV	Not yet implemented	-	0.85

Table 3.7 - Generator data for Original Generators Heavy Load Case

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 3.8 - Load Flow Settings for Original Generators Heavy Load Case

As we can see from table 3.9 a ride through mechanism has been applied to the islanding system. This means we will not have to calculate for black starts in our outage durations. The transmission analysis method has been checked to perform load shedding according to priority and balancing of the reference machine. When the analysis is performed according to table 3.9 setup, the results are as presented in table 3.10 on the next page.

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Protection Failures	
	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	
	Sequential	x
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.9 - Reliability Assessment analysis setup for Heavy Load Islanding Case

System Summary				
System Average Interruption Frequency Index	:	SAIFI	=	0,516622 1/Ca
Customer Average Interruption Frequency Index	:	CAIFI	=	0,516622 1/Ca
System Average Interruption Duration Index	:	SAIDI	=	0,863 h/Ca
Customer Average Interruption Duration Index	:	CAIDI	=	1,670 h
Average Service Availability Index	:	ASAI	=	0,9999015149
Average Service Unavailability Index	:	ASUI	=	0,0000984851
Energy Not Supplied	:	ENS	=	2,540 MWh/a
Average Energy Not Supplied	:	AENS	=	0,025 MWh/Ca
Average Customer Curtailment Index	:	ACCI	=	0,049 MWh/Ca
Expected Interruption Cost	:	EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	:	IEAR	=	0,000 \$/kwh
System energy shed	:	SES	=	0,000 MWh/a
Average System Interruption Frequency Index	:	ASIFI	=	0,502963 1/a
Average System Interruption Duration Index	:	ASIDI	=	0,843188 h/a
Momentary Average Interruption Frequency Index	:	MAIFI	=	0,000000 1/Ca

Table 3.10 – Case 2 Reliability Assessment Results

The reliability assessment outputs an ENS of 2.54 MWh/a. If we consider the Base Case modeling result from table 3.10 and subtract the contribution from the external grid (averaging 25.4 MWh/a) we get an estimate on the lowest ENS for this scenario, given that the radial was supplied from the external grid with no reference machine inside the grid.

$$29.315 \frac{MWh}{a} - 25.355 \frac{MWh}{a} = 3.96 \frac{MWh}{a}$$

Curiously, this number is higher than the modeling results from 3.10 indicate (2.54 MWh). However, by changing the balancing settings so that the reference machine (Gen 1) is used to dispatch the slack we have a change in topology. For example, if the cable connecting the external grid to Line A was faulted and had to be repaired, Gen 1 would still provide power to most of the line after sectioning has been done. All the different contingency scenarios where repairing the line between Gen 1 and the external grid would normally cause a big portion of loads to become de-energized, are now mostly supplied by Gen 1. This difference probably amounts to the general reduction in ENS shown by the simulation. If only considering ENS this is a good result, but it is worth noting that a setup which allows for flexible group of load points to be islanded might require a far more sophisticated protection system setup.

Minimum Required Upgrades for this scenario:

- Refitting circuit breakers with proper two way relay system
- Sufficient AVR and frequency regulating mechanism for Generators
- Synchronization equipment for reconnecting to external grid
- Engineered mass for generators
- Telematics and independently supplied communication equipment for contacting net operator

3. Only Original Generators and Reduced Sectioning Radius Case

This scenario is a more realistic approach to how the existing power producing capabilities can be used to supply an islanding system. The heuristics from Bolton Bar states that maximum production capacity of DG units should be double that of heavy load for islanding to become feasible. Available information from Line A is not very specific about specifications for Gen 1 and Gen 2, but capacity and type of generator is supplied. They are 2MVA and 1.5MVA respectively. If we place a circuit

breaker in the spot marked as “Circuit Breaker 4” in figure 3.3, we have defined an island of about 1.7 MW. This is roughly half the 3.5 MVA at 0.85 pf (3MW) the original DG units in line A can output.

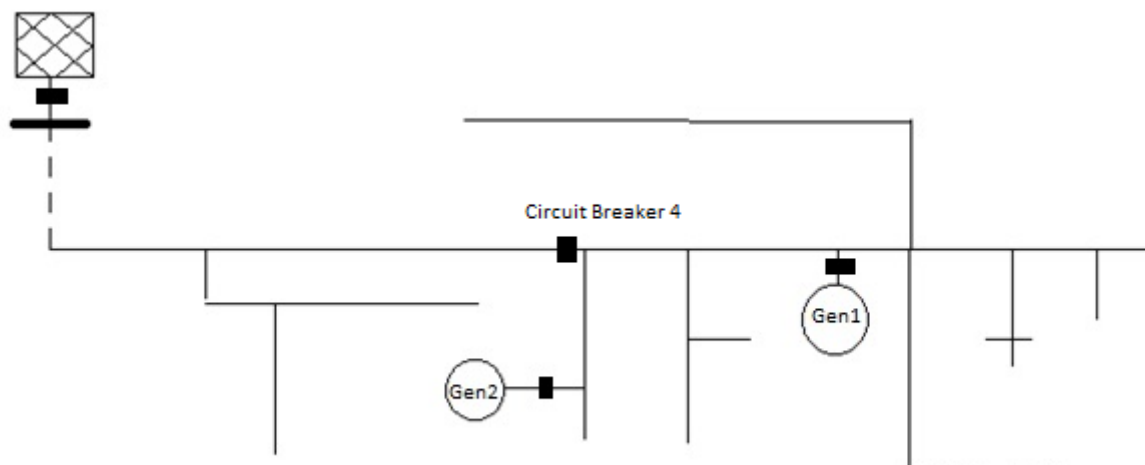


Figure 3.3 - Line A case 3 circuit breaker placement

The same load flow and reliability assessment settings can be used as in case 2, as shown in table 3.11 and table 3.12 on the next page. Normally the PF algorithm is set to load shedding, but since we in this case always have either enough power production or no power at all in any part of the grid at any contingency this is not strictly necessary. Placing Circuit Breaker 4 could have been done more optimal if we are very keen on upholding the Boston Bar heuristics, but that would have come at the cost of a bigger ENS and more circuit breakers would have to be installed. This would also increase the complexity of the system, which again would have made protection coordination even more difficult.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 3.11 - Case 3 Load Flow Settings

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	
	Sequential	x
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.12 - Case 3 Reliability Analysis Settings

System Summary			
System Average Interruption Frequency Index	: SAIFI =	0,438978	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	0,438978	1/Ca
System Average Interruption Duration Index	: SAIDI =	0,754	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	1,718	h
Average Service Availability Index	: ASAI =	0,9999139239	
Average Service Unavailability Index	: ASUI =	0,0000860761	
Energy Not Supplied	: ENS =	2,228	MWh/a
Average Energy Not Supplied	: AENS =	0,022	MWh/Ca
Average Customer Curtailment Index	: ACCI =	0,052	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	0,429121	1/a
Average System Interruption Duration Index	: ASIDI =	0,739663	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.13 - Reliability assessment results for case 3

When we run the analysis we get the results shown in table 3.13. We can see a slight reduction in the ENS from 2.54 MWh to 2.228MWh. Since we now have a smaller islanding scheme in terms of load, this might seem curious. The reason is that in this scenario we are forced to invest in a fourth circuit breaker, which makes sectionalizing out faults in the outer parts of the grid demand less time. The drawback is, that we have to invest in another circuit breaker.

Minimum Required Upgrades for this scenario:

- New circuit breaker with proper two way relay system
- Sufficient AVR and frequency regulating mechanism for Generators
- Synchronization equipment for reconnecting to external grid
- Engineered mass for generators
- Telematics and independently supplied communication equipment for contacting net operator

4. Black starting after external grid fallout case

With the level of PowerFactory competence and programming experience the author of this paper currently has, a black start case can't be modeled directly in PowerFactory with default power control settings. However, looking at what will happen in the grid we see that it is possible to divide it into two separate scenarios which can be added together. For simplicity, the islanding zone will have to be the whole radial starting from the circuit breaker dividing the external grid from line A. By removing the contingency situation caused by external grid fallout, all we have left is the internal fault handling. This fault handling is independent of the black start capability anyway, as a fault within the primary circuit breaker will cause a sectionalizing procedure to be engaged regardless. This sectionalizing procedure takes 60 minutes compared to the black start duration which is 10 minutes. Thus, removing the external grid contingency and setting the reliability analysis to table

2.16 we get the results shown

Time from tripped external grid to black start	10 [min]
External grid contribution to ENS	4.22 [MWh/a]

in table 2.15, which are also the same as in case 2.

Table 3.14 - Additional information concerning black start emulation

System Summary			
System Average Interruption Frequency Index	: SAIFI =	0,516622	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	0,516622	1/Ca
System Average Interruption Duration Index	: SAIDI =	0,863	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	1,670	h
Average Service Availability Index	: ASAI =	0,9999015149	
Average Service Unavailability Index	: ASUI =	0,0000984851	
Energy Not Supplied	: ENS =	2,540	MWh/a
Average Energy Not Supplied	: AENS =	0,025	MWh/Ca
Average Customer Curtailment Index	: ACCI =	0,049	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	0,502963	1/a
Average System Interruption Duration Index	: ASIDI =	0,843188	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.15 - Case 4 Reliability Assessment Results (no external grid fallout)

By multiplying the 8.4452 [h/a] average outage duration of the external grid with the 10 [minutes] and the total load of 3 [MW] we get the contribution to ENS shown in table 3.15. Adding the external grid/black start contribution to the inherent ENS in the grid topology contribution of 2.54 MWh we get 6.7626 MWh. Depending on what proportion of time is spent by operators evaluating the black start, and how long the black start requires mechanically, these numbers should be realistic.

It is assumed, for example, that the black start duration of ten minutes is mostly operators verifying the go ahead. If not the ten minutes would have to be added to sectioning time, and only added when the main grid is down. This would make it a much more complex operation in PF. No specific numbers are given in Boston Bar report on the black start timings.

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	
	Sequential	x
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	x
	Ride Through	

Table 3.16 - Case 4 Reliability Assessment Settings

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 3.17 - Case 4 Load Flow Settings

Minimum Required Upgrades for this scenario:

- Refitting circuit breakers with proper two way relay system
- Sufficient AVR and frequency regulation mechanisms for generators
- Synchronization equipment for reconnecting to external grid
- Engineered mass for generators
- Telematics and independently supplied communication equipment for contacting net operator
- Extra aggregate to black start power island

5. Protection and Generator Failure

To calculate the minimum and estimate a good average contribution from a failure rate in the protection mechanism for the generating units in Line A we need to estimate a circuit breaker failure rate and a generator failure rate. The circuit breaker estimate needs to be in a format of “percentage chance of not tripping when failure occurs”. This is not how failure in circuit breakers is logged in Nordic countries. The paper *The Reliability of Breaker Failure Scheme for Transmission line Feeders* (20) describes a circuit breaker failure rate of 1.3% as an average failure rate for modern circuit breakers. Other sources suggest even higher failure rates of up to 5% are common in distribution grids. The generator failure characteristics of generators in Nordic countries are not very well monitored either. In the paper *Reliability Modeling of Distributed Generation in Conventional Distribution Systems Planning and Analysis* (21) an interruption frequency of 5 [1/a] and an average repair time of 50 [h] is used as an estimate, and the same characteristic will be employed here. When not employing the *Independent Second Failure* option in the reliability analysis settings PF defines each contingency case as independent of each other. Since simulating a proper failure response to circuit breaker failure was not possible, generator failure will assumed to be independent of other failures in the grid. This is a reasonable estimate for a distribution grid as even though the average outage time for a generator is 250 [h] a year, the generator still has an uptime of 97.15%. Since the contingencies are independent, the external grid will be available for all loads in the grid whenever a generator circuit breaker failure occurs. This means ENS contribution will be solely the duration of sectionalizing off the generator for all loads in the line. This means we can calculate the ENS contribution as:

$$ENS_{genContrib} = 1 \left[\frac{h}{interruptions} \right] * 5 \left[\frac{interruptions}{a * generators} \right] * 2[generators] * 3[MW] * 1.3\% = 0.39 \left[\frac{MWh}{a} \right]$$

This equals about 1.3% of the base case ENS.

3.1.1 Summary of Line A results

- **Case 1:** Base case
- **Case 2:** Islanding original generators with heavy load
 - Refitting circuit breakers with proper two way relay system
 - Sufficient AVR and frequency regulating mechanism for Generators
 - Synchronization equipment for reconnecting to external grid
 - Engineered mass for generators
 - Telematics and independently supplied communication equipment for contacting net operator
- **Case 3:** Original generators islanding with reduced island load due to separation by circuit breaker
 - Additional circuit breaker and refitting old circuit breakers with proper two way relay system
 - Sufficient AVR and frequency regulating mechanism for Generators
 - Synchronization equipment for reconnecting to external grid
 - Engineered mass for generators
 - Telematics and independently supplied communication equipment for contacting net operator

- **Case 4:** Blackstart enabled generators
 - Additional circuit breaker for new generator and refitting old circuit breakers with proper two way relay system
 - Sufficient AVR and frequency regulating mechanism for Generators
 - Synchronization equipment for reconnecting to external grid
 - Engineered mass for generators
 - Telematics and independently supplied communication equipment for contacting net operator
- **Case 5:** Base case with fault characteristics included for circuit breakers

	ENS [MWh/a]	ENS in percentage of base case	SAIFI [1/a]	SAIFI as percentage of base case
Case 1	29,315	-	6,137	-
Case 2	2,54	8,66 %	0,5166	8,4%
Case 3	2,228	7,60 %	0,4389	7,15%
Case 4	6,7626	23,07 %	0,5166	8,4%
Case 5	29,705	101,33 %	-	-

Table 3.18 - ENS and SAIFI summary for Test Net A

	KILE [NOK/a]	KILE as percentage of base case	Accumulated KILE over 20 years with 3% discount rate [NOK]	Savings over 20 years from base case [NOK]
Case 1	31645	-	875 822	-
Case 2	2741	8,66 %	75 861	800 000
Case 3	2405	7,60 %	66 562	809 260
Case 4	7300	23,07 %	20 238	673 784
Case 5	32066	101,33 %	88 747	-11 651

Table 3.19 - KILE Summary for Test Net A

As can be seen from the tables Line A responds well to measures to reduce ENS. It's difficult to conclude on whether or not it's a good investment to invest in ENS reducing measures like a system to island generators from this simulation alone. Still, if we assume the price of a circuit breaker installation to be around 400,000 NOK total, the case 3 approach already seem economically farfetched considering all the other equipment that has to be provided. Expenses on labor, training and such will also factor in. Case 2 does not entirely fulfill the BC Hydro guidelines for an islanding radial system.

3.2 Extended Billington Test Net for Educational Purposes (RBTS)

The RBTS (22) net was initially introduced to analyze a radial net containing several branches and backup cables (seen as dotted lines on top and bottom of the figure 3.4). The backup cables were implemented as faultless since were only be utilized when an error occurs in the feeders. In this analysis backup cables will not be utilized as it will add several extra dimensions to the analysis which are uncertain. Questions such as the priority of different mitigating measures such as for example “open back-up cable” or “re-dispatch generators” would have to be answered. Because of the lack of technical information on analysis provided by DigSILENT these types of questions are difficult to answer with certainty.

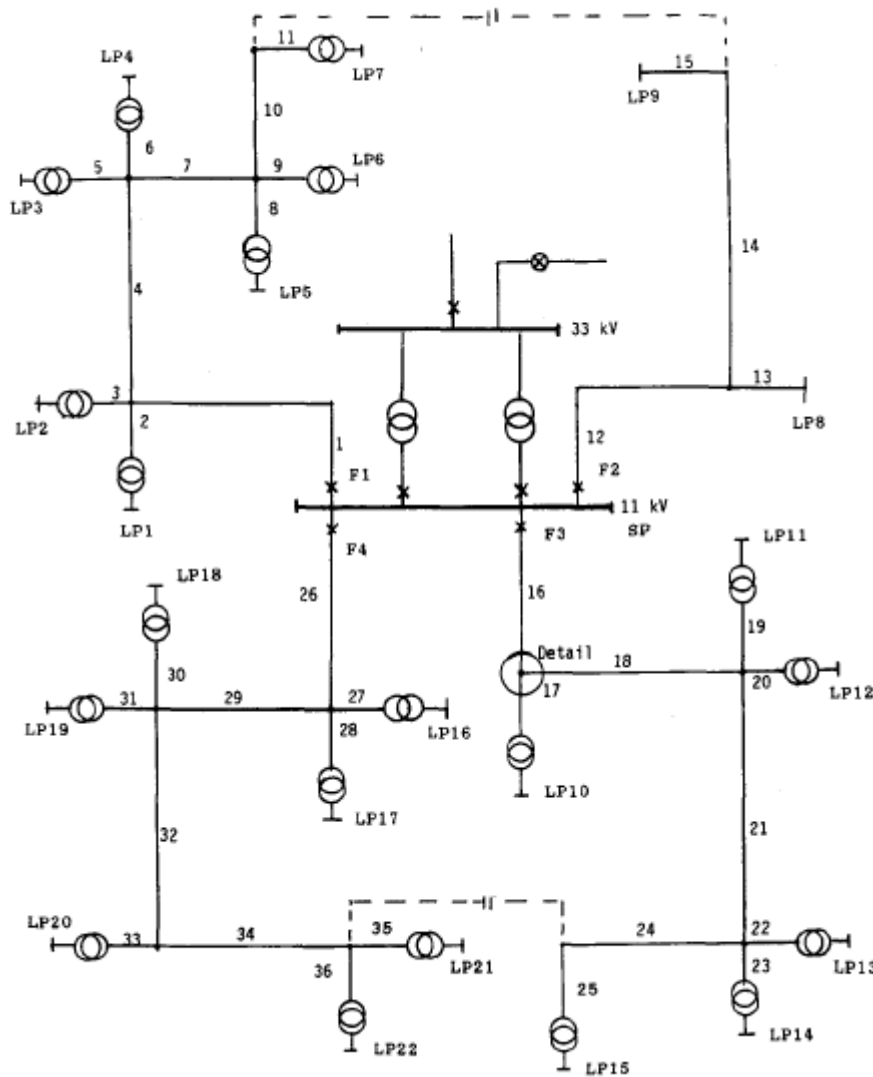


Figure 3.4 - RBTS One Line Schematics

Each branch from the main bus 11 kV (F1, F2, F3 and F4) is isolated by a circuit breaker. The first thing to note about this case is that the two main transformers connecting the main 11kV bus to the grid seem to be in the same circuit breaker zone judging from the drawing shown figure 3.4. This is because the bus bar connecting the two transformers to the external grid there is only one circuit breaker disconnecting the external grid, but no circuit breakers isolating the two transformers from

each other. With this setup a single fault in one of the main transformers would leave the whole grid de-energized for three hours a year. This alone would accumulate to a 2x60MWh ENS per year, which is far from the reference result shown in the original analysis report (22). In my PF analysis I assumed that the main transformers could be separated with circuit breakers on each side so that at least one transformer could continue to feed the grid while the other was being repaired.

Total Active Load in RBTS Radial	20 [MW]
Total Reactive Load in RBTS Radial	0 [MVar]
Total Line Length in RBTS Radial	25.5 [km]
Number of Load Points	22
Sectioning Time	60 [min]
Number of Distribution Transformers	20

Table 3.21 - RBTS Radial Basic Data

specific empirical data of external grid reliability is not available. Since preliminary deduction indicates that external grid failures seem to be the reliability oriented problem that islanding DG units are the most apt at combating, an external grid failure characteristic will be defined for this grid. The failure characteristic that is provided for the regional grid is similar to the one supplied for

Comments on Data

Since this is grid constructed for educational purposes the reliability data is either well defined or it is non-existent. As with many of the grids that are analyzed in this paper

	Repair Duration	Interruption Frequency
Lines	8 [h]	0.04875 [1/km*a]
Cables	-	-
External Grid	0.12 [h]	0.675 [1/a]
Distribution Transformers	200 [h]	0.015 [1/a]
Main Transformers	120 [h]	0.015 [1/a]

Table 3.20 - Component Reliability Data

Line A. Since Statnett provides numbers indicating how often a distribution net is affected by a failure in the regional grid, the original external grid failure characteristics will be modified so that it more precisely indicates how regional failure affects the distribution grid. This is done by taking the raw numbers on interruptions and repair time from Statnett (23) and modifying them using NVEs ratios of "interruption in regional grid"/"interruption in distribution grid" (24).

	R' [ohm/km]	X' [ohm/km]	B' [ohm/km]	Capacity
Line	0.35	0.4	2e-6	-
Cable	-	-	-	-
Main Transformer	0	0	0	16 MVA
Distribution Transformer	0	0	0	2 MVA

Table 3.22 - Component Impedance Data

1. Base Case

The base case chosen for the RBTS radial is a standard load and no DG production. From table 3.23 we can see that reactive power is not to be considered in this case. In the reference paper on this grid reactive power is not a part of the analysis. Thus, data on reactive power is not provided. Originally the grid is well inside voltage boundaries and with plenty of capacity to spare. This base test will therefore only check the sectionalizing response of the grid during normal fault scenarios. Transmission is chosen for mitigating faults. Distribution could have been used for easier analysis, but the Distribution type of analysis checks for meshed structures. A mesh is rightly detected in the system formed by the two main transformers connecting the 33 kV bus and the 11 kV. There are no generators present in the grid for this analysis.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.23 - Load Flow Settings for Case 1

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	

Table 3.24 - Reliability Assessment Settings Case 1

The system analysis summary is shown in table 3.25. Given the relatively complicated structure of the grid it is difficult to assess whether or not the 66 MWh/a suggested in the simulation results are accurate.

System Summary				
System Average Interruption Frequency Index	:	SAIFI	=	1,030745 1/Ca
Customer Average Interruption Frequency Index	:	CAIFI	=	1,030745 1/Ca
System Average Interruption Duration Index	:	SAIDI	=	3,763 h/Ca
Customer Average Interruption Duration Index	:	CAIDI	=	3,651 h
Average Service Availability Index	:	ASAI	=	0,9995704164
Average Service Unavailability Index	:	ASUI	=	0,0004295836
Energy Not Supplied	:	ENS	=	65,979 MWh/a
Average Energy Not Supplied	:	AENS	=	2,999 MWh/Ca
Average Customer Curtailment Index	:	ACCI	=	4,773 MWh/Ca
Expected Interruption Cost	:	EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	:	IEAR	=	0,000 \$/kwh
System energy shed	:	SES	=	0,000 MWh/a
Average System Interruption Frequency Index	:	ASIFI	=	0,912319 1/a
Average System Interruption Duration Index	:	ASIDI	=	3,298865 h/a
Momentary Average Interruption Frequency Index	:	MAIFI	=	0,000000 1/Ca

Table 3.25 - Case 1 Analysis Results

- One thing that can be deducted with certainty is that there is a limiting factor in the two main transformers connecting the 33 kV bus to the 11 kV bus. These transformers are 16 MVA each. Fallout in one of the transformers in this case scenario would lead to a supply of maximum 16 MW. This is 4 MW short of the 20 MW load implemented in the scenario. If we factor in that the average outage time of these main transformers is 1.8 [h] we can estimate the ENS supplied from these two transformers alone.

$$ENS_{mainTrans} = 2[transformers] * 4[MW] * 1.8 \left[\frac{h}{a * transformers} \right] = 14.4 \left[\frac{MWh}{a} \right]$$

- One other step we can do to get more clarity about the analysis result is to run an auxiliary analysis. In this analysis you can replace all disconnectors with circuit breakers to see how much of the ENS that is caused by the sectionalizing. Circuit breakers with relay systems detect failures close to them instantly, and can trip instantly. Thus no sectionalizing will be required. From table 3.26 we can see that such a scenario produces an ENS of about 62.56 MWh/a. Subtracting this from the original ENS from table 3.25 shows that sectionalizing is directly responsible for about 4.5 MWh/a of ENS.

System Summary				
System Average Interruption Frequency Index	:	SAIFI	=	0,788789 1/Ca
Customer Average Interruption Frequency Index	:	CAIFI	=	0,788789 1/Ca
System Average Interruption Duration Index	:	SAIDI	=	3,521 h/Ca
Customer Average Interruption Duration Index	:	CAIDI	=	4,464 h
Average Service Availability Index	:	ASAI	=	0,9995980371
Average Service Unavailability Index	:	ASUI	=	0,0004019629
Energy Not Supplied	:	ENS	=	62,560 MWh/a
Average Energy Not Supplied	:	AENS	=	2,844 MWh/Ca
Average Customer Curtailment Index	:	ACCI	=	5,284 MWh/Ca
Expected Interruption Cost	:	EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	:	IEAR	=	0,000 \$/kwh
System energy shed	:	SES	=	0,000 MWh/a
Average System Interruption Frequency Index	:	ASIFI	=	0,741350 1/a
Average System Interruption Duration Index	:	ASIDI	=	3,127897 h/a
Momentary Average Interruption Frequency Index	:	MAIFI	=	0,000000 1/Ca

Table 3.26 - Base Case Analysis Results utilizing all Disconnectors as Circuit Breakers

- Thirdly, adding all the individual transformer failures up we can get another indicator of where the minimum ENS for the base case should be. Each distribution transformer is supplying about between 0.75 [MW] and 1.9 [MW] of load. We use 0.75[MW] to get a minimum estimate They have an average annual outage expectancy of 3 [h].

$$ENS_{distTrans} = 20 [\text{transformers}] * 0.75 \left[\frac{MW}{\text{transformers}} \right] * 3 \left[\frac{h}{a} \right] = 45 \left[\frac{MWh}{a} \right]$$

Adding these estimates together we get:

$$45 [\text{MWh/a}] + 14.4 [\text{MWh/a}] + 4.5 [\text{MWh/a}] = 63.9 [\text{MWh/a}]$$

This might seem a bit too close to the original 66 [MWh/a] ENS displayed in table 3.25, but the only ENS lacking in these estimates is the topology contribution to ENS from the lines, which is normally relatively small when not including the sectionalizing contribution to ENS. The base case result provided here should be close to the intended value.

2. Distributed Generation Case

When including a DG generator in this net, it is prudent to note that this net was never intended for DG and/or islanding. Most of the ENS contribution in this net comes from the distribution transformers themselves. This type of ENS will not be alleviated by any DG placement. The DG chosen will be put on the main bus, as indicated in figure 3.5.

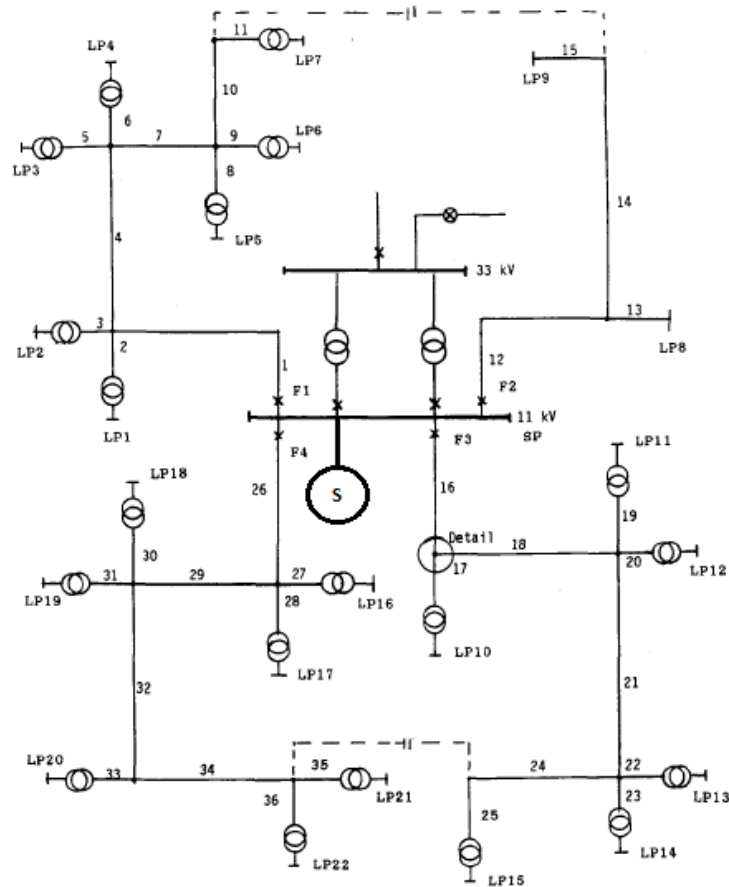


Figure 3.5 - DG Unit Placement in Case 2

The DG unit will be equipped with a maximum capacity that is double that of the total load in the

Capacity	40 [MVA]
Type	Synchronous
Dispatch	20 [MW]

Table 3.27 - DG Unit Specifications

grid. This is not strictly necessary for this modeling scenario, but since the model was constructed after BC Hydro guidelines 40 MVA was implemented in case other aspects were to be modeled. From table 3.30 we can see that ride through will be the mode of analysis. Black start modeling is possible to model, but if a ride through does not give decisive improvements to ENS, there is little use in performing a less reliable analysis with an even smaller implication for ENS.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.28 - Load Flow Settings for Case 2

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.95 p.u. < u < 1.05 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.29 - Reliability Assessment Settings for Case 2

System Summary				
System Average Interruption Frequency Index	: SAIFI	=	0,355745	1/Ca
Customer Average Interruption Frequency Index	: CAIFI	=	0,355745	1/Ca
System Average Interruption Duration Index	: SAIDI	=	3,682	h/Ca
Customer Average Interruption Duration Index	: CAIDI	=	10,351	h
Average Service Availability Index	: ASAI	=	0,9995796630	
Average Service Unavailability Index	: ASUI	=	0,0004203370	
Energy Not Supplied	: ENS	=	64,419	MWh/a
Average Energy Not Supplied	: AENS	=	2,928	MWh/Ca
Average Customer Curtailment Index	: ACCI	=	10,847	MWh/Ca
Expected Interruption Cost	: EIC	=	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR	=	0,000	\$/kwh
System energy shed	: SES	=	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI	=	0,261933	1/a
Average System Interruption Duration Index	: ASIDI	=	3,220844	h/a
Momentary Average Interruption Frequency Index	: MAIFI	=	0,000000	1/Ca

Table 3.30 - Case 2 Reliability Assessment Summary

The ENS simulation result outputted by the simulation is somewhat puzzling. There is an overlap between sectioning contributions to ENS and topology contributions to ENS, but in this modeling case it was expected that at least most of the 14.4 MWh/a ENS contribution from the two main transformers were to be eliminated. Since the two transformers have a very low interruption frequency and high repair duration a DG alleviating the outage should have had big impact considering how little contribution sectioning would have had in that case.

3. Protection Failure Case

The implications for a DG unit placed at the main bus in this scenario would have negligible influence since all branches off the bus are isolated by circuit breakers. If the whole grid was setup with circuit breakers with failure rates, there would be notably or even big implications for the ENS. Alas, this report has not been able to provide good results for circuit breaker failure cases.

3.2.1 Summary of RBTS net Analysis Result

- **Case 1:** Base case
- **Case 2:** Islanding mode enabled on installed generator
 - Refitting circuit breakers with proper two way relay system
 - Sufficient AVR and frequency regulating mechanism for Generators
 - Generator
 - Synchronization equipment for reconnecting to external grid
 - Engineered mass for generators
 - Telematics and independently supplied communication equipment for contacting net operator
- **Case 3:** Protection Failure Case

	ENS [MWh/a]	ENS in percentage of base case	SAIFI [1/a]	SAIFI as percentage of base case
Case 1	65,979	-	1,03	-
Case 2	64,419	97,6%	0,3557	34,5%
Case 3	-	-	-	-

Table 3.31 - ENS and SAIFI summary for the RBTS net

	KILE [NOK/a]	KILE as percentage of base case	Accumulated KILE over 20 years with 3% discount rate [NOK]	Saving from base case over 20 years [NOK]
Case 1	71224	-	1 971 230	-
Case 2	69540	97,64 %	1 924 623	46 607

Table 3.32- KILE summary for the RBTS net

As has been mentioned in the analysis of RBTS this grid is not very well suited for responding to islanding measures to reduce ENS. This is not a real net and the “local” contributions to ENS are far too big to give the islanded generator any impact. A reduction in SAIFI is the only real asset here, and it can be discussed how valuable this is to a household supply radial.

3.3 Snåsa

Figure 3.6 shows the Snåsa grid as it was presented in a master thesis by Tina Bystøl (25). It is a radial distribution grid which is being considered for DG unit implementation. The DG units that are being considered are drawn in figure 3.6 as DG1 (4.2 MW), DG2 (2.1 MW), DG3 (2.6 MW) and DG4 (2.1 MW). DG5 (13.1 MW) is also considered for implementation in the Snåsa grid, but due to its size a line will have to be built from the bus where DG5 is located in this drawing (BUS10 in the model) connecting it directly to the Snåsa node. The lines and cables have been modeled after standard FeAl lines as described in the SINTEF report “Distribusjonsnett i Norge” (26). Because DG5 requires an extra line and therefore breaks the radial structure of the grid it will not be considered for analysis. The placement of protection systems and relays has not been given in the original thesis, but in this thesis it is assumed that every generator is behind a circuit breaker, the main grid is isolated by a circuit breaker and that disconnectors are located around every bus. Circuit breaker placement is marked as black cubicles in figure 3.6.

	Capacity	Voltage	Type	Bus Placement
DG 1	4.6 MVA	6.6 kV	Synch.	Bus 4
DG 2	2.1 MW	0.69 kV	Asynch.	Bus 14
DG 3	2.6 MVA	6.6 kV	Synch.	Bus 15
DG 4	2.1 MVA	6.6 kV	Synch.	Bus 13
DG 5	-	-	-	Bus 10

Table 3.33 - DG Unit Component Data for Snåsa Grid

Different analysis cases will be considered and performed on this grid. The data presented in the Bystøl master is a heavy load scenario with a total load of 7MW distributed as shown in table 3.35 on the next page.

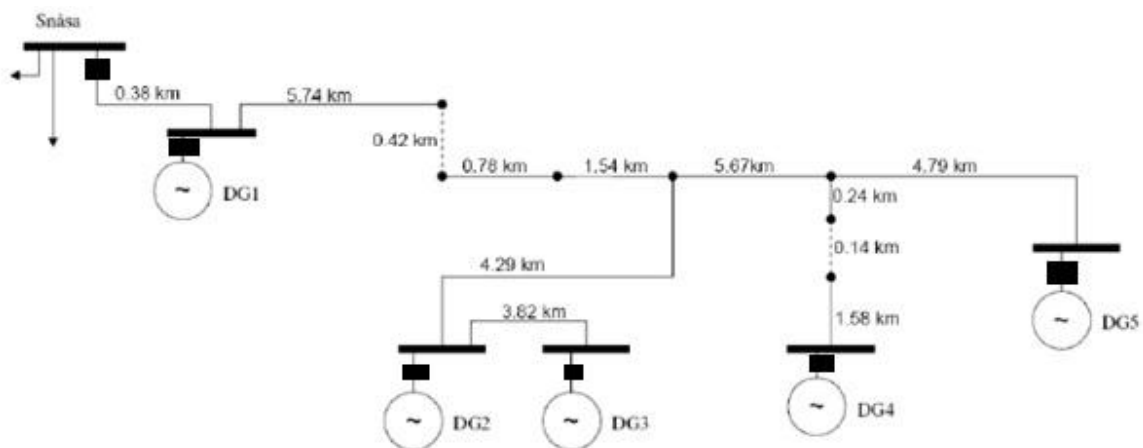


Figure 3.6 - Snåsa grid one line schematics

transmission grid will not equal the interruption frequency experienced by each load point/feeder branch-off in that region. However, 5.6 [interruptions/a] is the frequency logged in NTE Nett's system and will therefore be the operating parameter in this paper.

As for protection devices, they were not given in the original material and have been implemented as per the standard of this paper. Circuit breakers isolate all generators and the external grid. All nodes, loads and components are connected through disconnectors.

1. Base Case Heavy Load

This case uses the same relevant parameters and dispatches as the original modeling case. To simulate a radial solely consisting of loads all branches containing generators have been removed for this case. This means that the Snåsa grid gets a very basic design as demonstrated in figure 3.8.

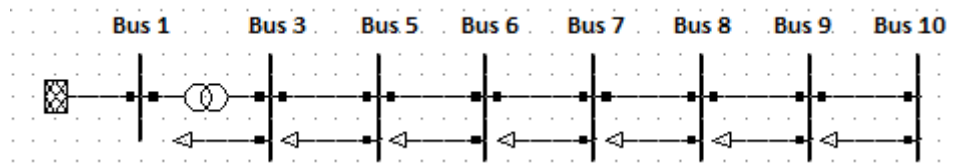


Figure 3.8 - Snåsa Grid Radial Structure Stripped of Generator Branches

A basic distribution reliability analysis is run using the settings displayed in table 3.37 and 3.38 on the next page. As the only mitigating measure that is possible to perform in such a basic grid is sectioning. The resulting ENS is easily verifiable. There is only one transformer in this grid, and all line interruption frequencies are very small. This means that the majority of the outage time will consist of the main transformer outage duration and the external grid outage duration. An estimate can be done by multiplying the average outage times of these two components with the total load of the grid.

$$ENS_{externalGrid} + ENS_{mainTrans} = \left(9.6 \left[\frac{h}{a} \right] + 1.2 \left[\frac{h}{a} \right] \right) * 7 [MW] = 75.6 \left[\frac{MWh}{a} \right]$$

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	
Active Power Control	As dispatched.	
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	

Table 3.36 - Case 1 Load Flow Settings

Method	Connectivity Analysis	x
	Load Flow Analysis	
Network	Distribution	x
	Transmission	
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	x
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	x
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	

Table 3.37 - Reliability Assessment Settings for Case 1

System Summary			
System Average Interruption Frequency Index	: SAIFI	=	5,717459 1/Ca
Customer Average Interruption Frequency Index	: CAIFI	=	5,717459 1/Ca
System Average Interruption Duration Index	: SAIDI	=	10,905 h/Ca
Customer Average Interruption Duration Index	: CAIDI	=	1,907 h
Average Service Availability Index	: ASAI	=	0,9987551528
Average Service Unavailability Index	: ASUI	=	0,0012448472
Energy Not Supplied	: ENS	=	75,677 MWh/a
Average Energy Not Supplied	: AENS	=	10,811 MWh/Ca
Average Customer Curtailment Index	: ACCI	=	10,334 MWh/Ca
Expected Interruption Cost	: EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	: IEAR	=	0,000 \$/kWh
System energy shed	: SES	=	0,000 MWh/a
Average System Interruption Frequency Index	: ASIFI	=	5,709021 1/a
Average System Interruption Duration Index	: ASIDI	=	10,873109 h/a
Momentary Average Interruption Frequency Index	: MAIFI	=	0,000000 1/Ca

Table 3.38 - Reliability Analysis Results for Case 1

As can be seen there is only 7.7 kWh more ENS in the complete simulation as compared to the estimate. The estimate will include some of the sectioning time contribution to the ENS, so the topology contribution here is probably bigger than 7.7 kWh, but not much. Given the low line length and very low interruption frequency per kilometer this result seems likely.

2. DG Units Set to Ride Through Islanding

In this case all the generator branches are connected to the model again, as depicted in figure 3.6. The dispatch is set to around 80% of maximum dispatch capacity as displayed in 3.40. There is a little

	Active Power	Reactive Power
DG 1	2 MW	0.31 MVar
DG 2	1 MW	0.69 MVar
DG 3	2 MW	0 MVar
DG 4	2 MW	0.57 MVar

Table 3.39 DG Unit Dispatch for Case 2

more production capacity than load in the grid now. A ride through scenario is chosen. This makes modeling easier, but given that most of the outage duration in the grid comes from the external grid and main transformer choke point, a black start would probably have been almost equally effective when accounting for

ENS alone. As can be seen from table 3.42, the ENS is drastically reduced. Since line contribution to ENS is very low, most of the remaining ENS contribution can be assumed to come from the generator transformers. A quick simulation reveals that ENS without generator transformer failure results in an ENS of about 3.353 MWh/a. This is only about a 1.65 MWh/a reduction in ENS as a consequence transformer failure and sectioning time.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.40 - Load Flow Settings for Case 2

System Summary			
System Average Interruption Frequency Index	: SAIFI =	0,401816	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	0,401816	1/Ca
System Average Interruption Duration Index	: SAIDI =	0,939	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	2,336	h
Average Service Availability Index	: ASAI =	0,9998928297	
Average Service Unavailability Index	: ASUI =	0,0001071703	
Energy Not Supplied	: ENS =	4,888	MWh/a
Average Energy Not Supplied	: AENS =	0,698	MWh/Ca
Average Customer Curtailment Index	: ACCI =	4,670	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kWh
System energy shed	: SES =	1,840	MWh/a
Average System Interruption Frequency Index	: ASIFI =	0,288934	1/a
Average System Interruption Duration Index	: ASIDI =	0,702279	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.41 - Case 2 Reliability Assessment Results

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	x
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.42 - Reliability Assessment Settings for Case 2

3. Effects of Failure in DG Unit Circuit Breakers

Before estimating the impact of circuit breaker failure, a complete simulation with no islanding had to be conducted. This time the branches with generators on them were included in the simulation. Then the impact of each DG unit has to be added to this simulations output ENS.

The general formula for finding the ENS contribution for a DG unit circuit breaker failure is linear and very basic during independent events. Since it is assumed that even though a circuit breaker failure

occurs, the DG can still be tripped by using the circuit breaker as a disconnector or by using the disconnectors connecting

	Interruption Frequency	Repair Time
Generator Failure Characteristics	5 [1/a]	50 [h]
Circuit Breaker Failure Rate	1.3 % failure to trip during contingency	

Table 3.43 - Failure Characteristics for DG Units and Circuit Breakers

the grid to the generator transformer. This analysis also assumes independent contingencies. This means that when a generator experiences a contingency, the external grid will be able to supply power, leaving only sectioning time contributions to ENS. The formula for calculating the extra ENS under these circumstances becomes the equation shown below.

$$ENS_{gen} = N * \lambda_{gen} * t_{sect} * p_{CB\ fail} * P_{totLoad}$$

Where N is the number of generators, λ_{gen} is the interruption frequency of the generator, t_{sect} is the sectioning time, $p_{CB\ fail}$ is the failure rate of the circuit breaker and $P_{totLoad}$ is the total grid load. In the Snåsa case, this equation would give us the following result.

$$ENS_{gen} = 4 * 5 \left[\frac{1}{a} \right] * 1[h] * 1.3\% * 7MW = 1.82 \left[\frac{MWh}{a} \right]$$

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.44 - Case 3 Load Flow Analysis Settings

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	x
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	

Table 3.45 - Case 3 Reliability Assessment Settings

System Summary			
System Average Interruption Frequency Index	: SAIFI =	5,792652	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	5,792652	1/Ca
System Average Interruption Duration Index	: SAIDI =	10,980	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	1,896	h
Average Service Availability Index	: ASAI =	0,9987465691	
Average Service Unavailability Index	: ASUI =	0,0012534309	
Energy Not Supplied	: ENS =	76,256	MWh/a
Average Energy Not Supplied	: AENS =	10,894	MWh/Ca
Average Customer Curtailment Index	: ACCI =	9,506	MWh/Ca
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	5,792256	1/a
Average System Interruption Duration Index	: ASIDI =	10,956349	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.46 - Case 3 Reliability Assessment Results

Now adding the two ENS results for the grid and the generator circuit breakers gets us the ENS we are looking for.

$$ENS_{GenCB} + ENS_{grid} = 76.256 \left[\frac{MWh}{a} \right] + 1.82 \left[\frac{MWh}{a} \right] = 78.076 \left[\frac{MWh}{a} \right]$$

3.3.1 Summary of Snåsa Case Results

- **Case 1:** Base case
- **Case 2:** DG units set to ride through islanding mode
 - o Refitting circuit breakers with proper two way relay system
 - o Sufficient AVR and frequency regulating mechanism for generators
 - o Synchronization equipment for reconnecting to external grid
 - o Engineered mass for generators
 - o Telematics and independently supplied communication equipment for contacting net operator
- **Case 3:** Failure effects in DG generators

	ENS [MWh/a]	ENS in percentage of base case	SAIFI [1/a]	SAIFI as percentage of base case
Case 1	75,677	-	5,72	-
Case 2	4,888	6,46%	0,40	7%
Case 3	78,076	103,2%	5,79	101,2%

Table 3.47 - ENS and SAIFI summary for the Snåsa grid

	KILE [NOK/a]	KILE as percentage of base case	Accumulated KILE over 20 years with 3% discount rate [NOK]	Saving from base case over 20 years [NOK]
Case 1	81693	-	2 260 975	-
Case 2	5276	6,46 %	146 021	2 115 000
Case 3	84283	103,17 %	2 332 657	-716 820

Table 3.48 - KILE summary for Test Net A

Given that Snåsa actually experiences as big an exposure to central grid fallout as is claimed, there are economic incentives here to justify an investment of two million over a period of twenty years. The uncertain nature of an untried technique lacking assembly band solutions however, this is probably not enough to justify an investment.

3.4 Øie-Kvinesdal

The Øie-Kvinesdal grid is a radial with ample DG production. The base case as described in the report “Distribusjonsnett 2020” (27) contains some voltage problems at the end of the radial (around Knabeheia) which will have to be considered when working through the different contingency scenarios. The line data for the original model was not available, so standard values for FeAl lines were chosen from *Distribusjonsnettet i Norge- oppbygning, komponenter og data* (26). The load flow analysis of the base case scenario seemed consistent with what was found in the Distribusjonsnett 2020 report. This will later be discussed in the base case section of the analysis.

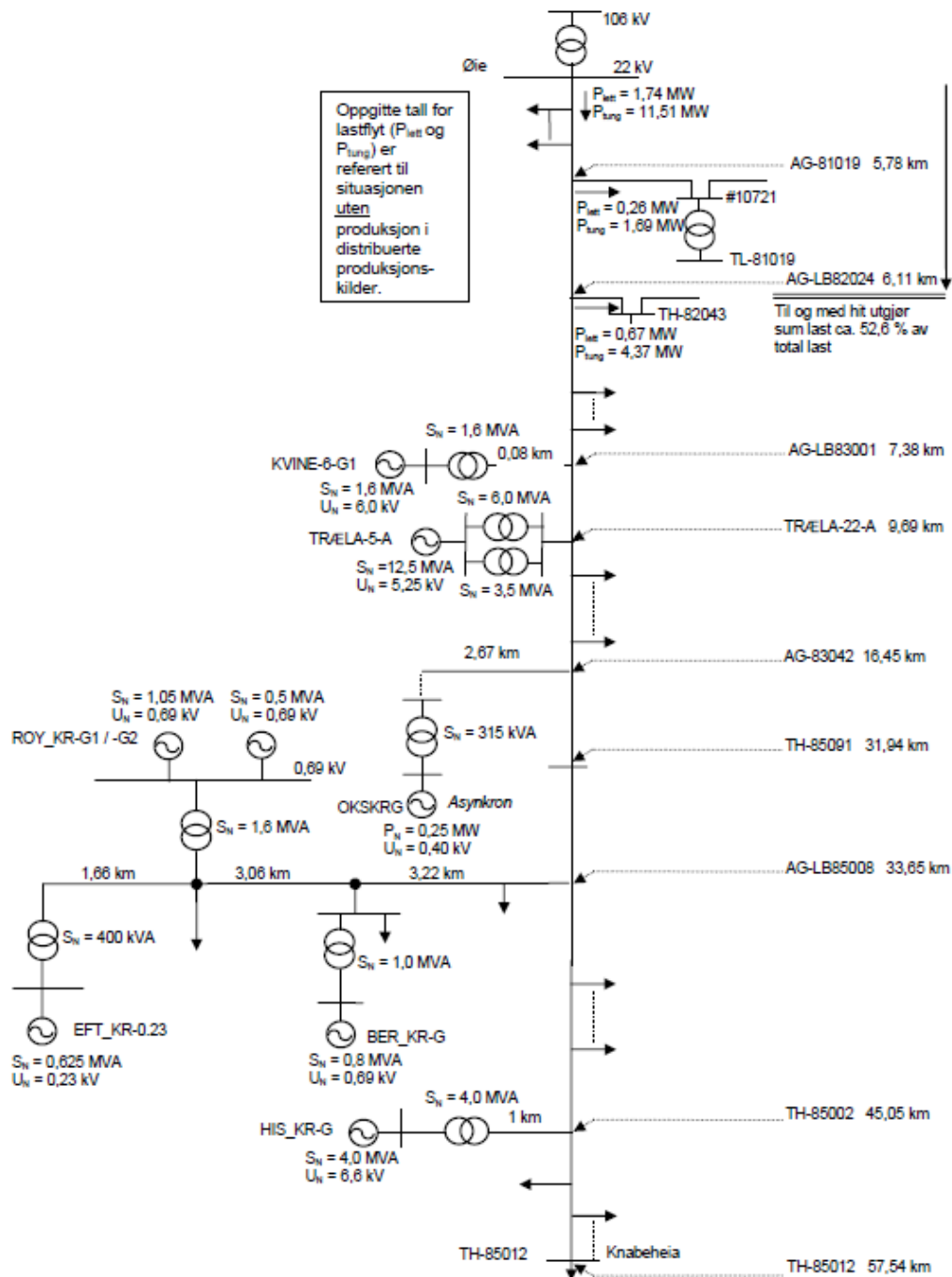


Figure 3.9 - Kvinesdal-Øie one line schematics

	R'[ohm/km]	X'[ohm/km]	B'[ohm/km]
22kV Line	0,325	0,125	2e-6
22kV Cable	0,35	0,765	60e-6

Table 3.50 - Øie-Kvinesdal Line Impedance Data

Total Active Load in Radial	11 [MW]
Total Reactive Load in Radial	0.73 [MVar]
Total Line Length in Radial	70 [km]
Number of Load Points	5
Sectioning Time	60 [min]

Table 3.49 - Basic Data Øie-Kvinesdal

contingency topologies which can't fulfill the voltage requirements will have to be mediated before a reliability assessment can be performed in PowerFactory. The impedances and other parameters used in the *Distribusjonsnett 2020* report describing these generators can be found in the appendix. The reliability data in table 3.53 are rough estimates calculated from the *Årsstatistikk 2010* (23) by Statnett.

Connection Node	Capacity [MVA]	Nominal Voltage [kV]	Generator Type	Distance from main grid feeder [km]	Role
KVINE-6-G1	1,6	6	Synchronous	7,46	
TRÆLA-5-A	12,5	5,25	Synchronous	6,69	Swing Gen
OKS_KR-0.4	0,5	0,69	Asynchronous	19,12	
BER_KR-G	0,8	0,69	Synchronous	36,87	
RØY_KR-G1	0,5	0,69	Synchronous	39,93	
RØY_KR-G2	1,05	0,69	Synchronous	39,93	
EFT_KR-G	0,625	0,23	Synchronous	41,59	
HIS_KR-G	4	6,6	Synchronous	46,05	Voltage Regulation

Table 3.51 - Generator data (27)

TRÆLA-5-A is chosen to be the swing generator in this model. This is because it's necessary to have a DG unit with spacious capacity to pick up the slack when the external grid is disconnected. HIS_KR-G is in some cases used to produce reactive effect to keep the Knabeheia load within voltage boundaries. To combat this same voltage drop at the end of the radial the stiff grid connected to the Øie node is set to 1.03 pu. to increase voltage throughout to the end. A shunt capacitor has been placed in the Knabeheia node to put the grid within Norwegian steady state voltage constraints.

	Interruption Frequency	Outage Duration
Line	0.00346 [1/a*km]	4 [h]
Cable	0.00204 [1/a*km]	7 [h]
Transformer	0.0066 [1/a]	8 [h]
External Grid	0.12 [1/a]	0.675 [h]

Table 3.52 - Øie-Kvinesdal Component Reliability Data

The DG units are implemented in the Øie-Kvinesdal model as described in the original report.

However, voltage regulators and impedances for generators were not implemented quite as

meticulously as in the *Distribusjonsnett 2020* report. This is partly because this thesis does not evaluate any dynamic analysis, and partly because PowerFactory and Netbas do not seem to model generators in the same way. This should not be of grave importance as any scenario

with voltages outside the acceptable range or

Normally tap changing the main transformer and the HIS_KR-22 transformer would be enough, but as will be shown there are instances where this is not possible.

HV node	LV node	Capacity [MVA]	er [p.u.]	ex [p.u.]	Voltage [kV]
KVINA-22-A	KVINE-6-G1	1,6	0,005	0,07	22/6
TRÆLA-22-A	TRÆLA-5-A	6	0,008	0,0392	20/5,25
TRÆLA-22-A	TRÆLA-5-A	3,5	0,008	0,0392	20/5,25
TH-83036	TL-83036	0,315	0,0122	0,0496	22/0,415
BER_KR-22	BER_KR-G	1	0,006	0,06	22/0,69
ROY_KR-22	ROY_KRO_69	1,6	0,0072	0,0583	22/0,69
TH-85079	TL-85079	0,4	0,01	0,05	21/0,24
HIS_KR-22	HIS_KR-6_6	4	0,006	0,06	22/6,6
OIE-22-A	OIE-110-A	25	0,0057	0,1239	100/22

Table 3.53 - Transformer data

1. Base Case

The base case devised for Øie-Kvinesdal is a heavy load and no production scenario. This is done to test the basic load flow capabilities of the radial. The voltage level furthest out in the grid will be checked at the worst case scenario possible when only varying the loads and the dispatch. First off

	Power[MW]	Reactive Power[MVAr]
L1	1,69	0
L2	4,37	0
L3	1	0,15
L4	0,2	0,15
L5	3,68	0,43

Table 3.54 - Load parameters in heavy load scenario

we will do a load flow assessment to see if normal load flow requirements are upheld. The buss furthest out in the grid, depicted in figure 3.9 as TH-85012, upholds the 0,9 [p.u.] limit barely. The 10% voltage limit was upheld because the external grid was set to 1.06 [p.u.]. This paper does not aim to improve voltage quality in itself, so satisfying the legal constraints will in this paper be

considered to be sufficient.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.55 - Load Flow Settings for Case 1

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
	Protection Failure	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	80%
Islanding Capability	Black Start	
	Ride Through	

Table 3.56 - Reliability Assessment Settings for Case 1

System Summary			
System Average Interruption Frequency Index	: SAIFI =	2,000149	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	2,000149	1/Ca
System Average Interruption Duration Index	: SAIDI =	5,347	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	2,673	h
Average Service Availability Index	: ASAI =	0,9993896575	
Average Service Unavailability Index	: ASUI =	0,0006103425	
Energy Not Supplied	: ENS =	48,883	MWh/a
Average Energy Not Supplied	: AENS =	9,777	MWh/Ca
Average Customer Curtailment Index	: ACCI =	6,706	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kWh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	1,910659	1/a
Average System Interruption Duration Index	: ASIDI =	4,468282	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.57 - Case 1 Analysis Results

If a standard estimate is done to check the ENS resulting from sectioning outage time for the complete line length and all transformers we get the following estimate.

$$ENS_{line} + ENS_{trans} = \left(70[km] * 0.00346 \left[\frac{h}{a * km} \right] + 9 * 0.0066 \left[\frac{h}{a} \right] \right) * 11[MW] = 27.3 \left[\frac{MWh}{a} \right]$$

Now looking at the choke point consisting of the main transformer and the external grid we can get an estimate on what kind of ENS choke point outage time would add. This estimate is done by multiplying their average outage duration with the total load.

$$ENS_{extGrid} + ENS_{mainTrans} = \left(0.132 \left[\frac{h}{a} \right] + 0.802 \left[\frac{h}{a} \right] \right) * 11[MW] = 10.25 \left[\frac{MWh}{a} \right]$$

These two estimates adds up to an ENS of 37.55 [MWh/a]. This leaves us with a topology induced ENS of a little more than 11 [MWh/a]. Despite the low interruption frequency, the total line length makes this result seem plausible.

2. Islanding Capabilities on DG Units

	Dispatched Active Power
KVINE-6-G1	1.4 [MW]
TRÆLA-5-A	0 [MW]
OKS_KR-0.4	3.5 [MW]
BER_KR-G	0.6 [MW]
RØY_KR-G1	0.4 [MW]
RØY_KR-G2	0.8 [MW]
EFT_KR-G	0.5 [MW]
HIS_KR-G	3.5 [MW]

Table 3.58 - Case 2 Generator Dispatch

When exploring the islanding capabilities of the Øie-Kvinesdal case, we can start by noting that the total max capacity of the generators is roughly the size of the total heavy load. The Træla generator in itself could in theory supply the whole grid load of 11 MW with its 12.5 MVA capacity. Putting such a generator as a reference machine makes the transparency of the analysis much better. Sensitivity analyzing and evaluating the impact of different dispatches can give confusing results which needs to be trouble shooted. Using Træla as reference machine provides results that are easier to interpret and more consistent. The other generators are dispatched at around 80% of their capacity. Voltage levels are easier to uphold now that generators can be used to dispatch reactive power, and automatic tap changing is engaged.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.59 - Case 2 Load Flow Analysis Settings

Table 3.62 on the next page shows us that the simulation results gives us an ENS of about 32.3 MWh/a. It is difficult to precisely assess the legitimacy of this result, but we can note that the base case heavy load scenario ENS minus the choke point ENS from outage time on the main transformer and the external grid should give us an upper limit estimate to what we can assume the case 2 ENS to be. On the other hand, outage due to sectionalizing time will give us a lower limit. The reason sectionalizing time can be used to define a lower limit is that whenever a fault occurs inside the circuit breaker isolating the Øie-Kvinesdal radial from the external grid the complete radial will have to be de-energized.

$$ENS_{upperLim} = ENS_{baseCase} - ENS_{chokePoint} = 48.9 \left[\frac{MWh}{a} \right] - 10.25 \left[\frac{MWh}{a} \right] = 38.65 \left[\frac{MWh}{a} \right]$$

$$ENS_{lowerLim} = ENS_{sectionTot} = 27.3 \left[\frac{MWh}{a} \right]$$

The obtained 32.3 MWh/a estimate falls safely in between these two limits.

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	x
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Protection Failure	
	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	80%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.60 - Case 2 Reliability Assessment Settings

System Summary			
System Average Interruption Frequency Index	: SAIFI =	0,796779	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	0,796779	1/Ca
System Average Interruption Duration Index	: SAIDI =	3,229	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	4,053	h
Average Service Availability Index	: ASAI =	0,9996313519	
Average Service Unavailability Index	: ASUI =	0,0003686481	
Energy Not Supplied	: ENS =	32,289	MWh/a
Average Energy Not Supplied	: AENS =	6,458	MWh/Ca
Average Customer Curtailment Index	: ACCI =	13,699	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	0,733349	1/a
Average System Interruption Duration Index	: ASIDI =	2,951481	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.61 - Case 2 Reliability Assessment Results

3. Tripping off Producing Branches

It is also worth noting that in the Øie-Kvinesdal grid you can achieve significant reduction in ENS by tripping the non-necessary lines connecting the generators and their transformers to the radial. To model this scenario we set up a grid similar to the base case, but pre-trip unnecessary branches. This creates a topology as displayed in figure 3.10. A distribution reliability assessment is then run as defined on the next page.

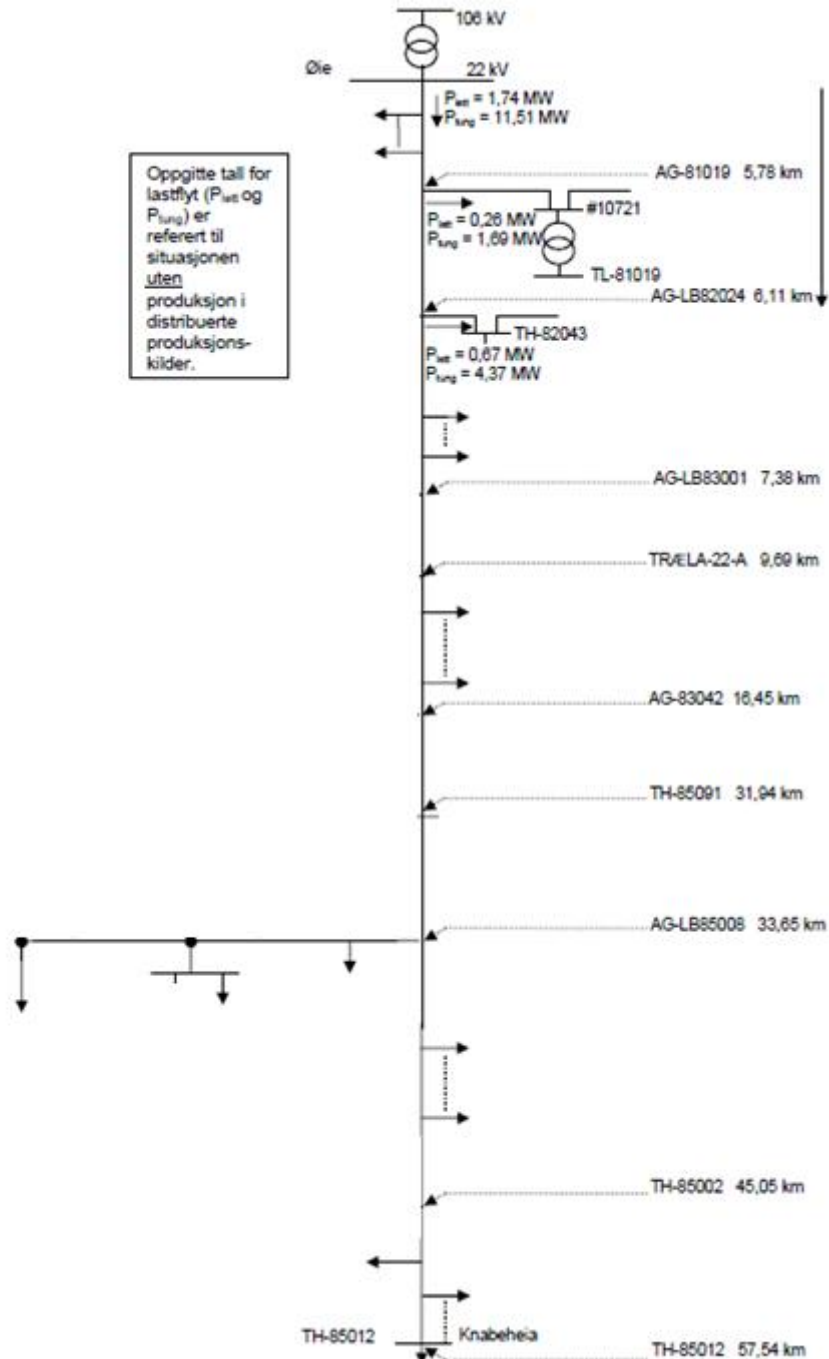


Figure 3.10 - One Line Schematics of Pre-tripped Branches Containing Generators Removed

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	x
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.62 - Load Flow Analysis Settings Case 3

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	x
	Transmission	
Contingency Definition	Lines/Cables	x
	Transformers	x
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	x
Switching Procedure	Concurrently	x
	Sequential	
	Consider Sectionalizing	x
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	

Table 3.63 - Reliability Assessment Settings for Case 3

System Summary			
System Average Interruption Frequency Index	: SAIFI =	2,000149	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	2,000149	1/Ca
System Average Interruption Duration Index	: SAIDI =	5,347	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	2,673	h
Average Service Availability Index	: ASAI =	0,9993896575	
Average Service Unavailability Index	: ASUI =	0,0006103425	
Energy Not Supplied	: ENS =	32,735	MWh/a
Average Energy Not Supplied	: AENS =	6,547	MWh/Ca
Average Customer Curtailment Index	: ACCI =	4,491	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	1,361905	1/a
Average System Interruption Duration Index	: ASIDI =	2,992272	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.64 - Reliability Assessment Results for Case 3

As can be seen from table 3.64 the *distribution* option is checked and the only mitigating measure used for restoring power after a contingency in this simulation is sectionalizing. This makes the lower estimate easily defined as the ENS contribution from the choke point formed by the external grid and the main transformer and the sectionalizing time. It has to be noted as ever that there is an overlap between sectioning time and outage time when choke point is concerned. That is why this number is only an estimate.

$$ENS_{sectioning} = \left(2 * 0.0066 \left[\frac{1}{a} \right] + 0.0346 \left[\frac{1}{a * km} \right] * 65 [km] \right) * 1 [h] * 11 [MW] = 24.81 \left[\frac{MWh}{a} \right]$$

In this calculation the 0.0066 [1/a] is the failure frequency of the transformer and 0.0346 [1/a*km] is the failure frequency per year per kilometer of the line. 65 [km] is the remaining line length in the grid. The choke point ENS was calculated to be 10.25 MWh/a in case 2. Adding these two gives us a total of 35.06 MWh/a. This is higher than the 32.735 MWh/a ENS calculated in the PF simulation. Possibly this is due to the previously mentioned overlap in sectioning time and repair time. Since the majority of the load is located close to the main transformer, we would not expect the topology to make a big contribution to ENS. This is because when a line further out in the radial is being repaired, the majority of the load will still be supplied from the external grid. This effect is enhanced by the fact that the longest line distances, and thus most of the line faults, are located further out in the radial.

3.4.1 Summary of Øie-Kvinesdal Case Results

- **Case 1:** Base case
- **Case 2:** Islanding capabilities for DG units
 - o Refitting circuit breakers with proper two way relay system
 - o Sufficient AVR and frequency regulating mechanism for generators
 - o Synchronization equipment for reconnecting to external grid
 - o Engineered mass for generators
 - o Telematics and independently supplied communication equipment for contacting net operator
- **Case 3:** Tripping producing branches

	ENS [MWh/a]	ENS in percentage of base case	SAIFI [1/a]	SAIFI as percentage of base case
Case 1	48,883	-	2	-
Case 2	32,289	66%	0,796	39,8%
Case 3	32,735	67%	2	100%

Table 3.65 - ENS and SAIFI summary for the Øie-Kvinesdal grid

	KILE [NOK/a]	KILE as percentage of base case	Accumulated KILE over 20 years with 3% discount rate [NOK]	Savings over 20 years from base case [NOK]
Case 1	52 769	-	1 460 460	-
Case 2	34 856	66,05 %	964 692	495 800
Case 3	35 337	66,97 %	978 004	482 500

Table 3.66 - KILE summary for the Øie-Kvinesdal grid

In the Øie-Kvinesdal case there are savings to be made from including an islanding function on the generators. This happens to coincide with the savings that can be made from removing the lines and transformers used to connect the DG units. The savings are in either case technically sufficient to introduce some sort of islanding, but in such a long grid islanding does not seem to make an impact in general. It should be noted that case 1 could also add the 1.3 [MWh/a] ENS from protection devices failing to trip on the base case to get an image on how much circuit breaker failure on generators has an impact on the grid.

3.5 Hitra

The only non-radial grid in this paper is the Hitra complex. Test scenarios here will focus on establishing an islanding isolation capability at the Malnes transformer. The DG unit located at bus 90 will then supply loads that are affiliated with bus 85 and 91. At bus 80 Hitra is connected to the main transmission grid and in normal operation mode this also acts as the swing bus. For this set of simulations the generator at bus 90 will be put as swing bus as this will be its acting roll when an error occurs in the main part of the Hitra grid. The lines are not modeled as detailed as they are in the original Simpow as all details are not given in the data material.

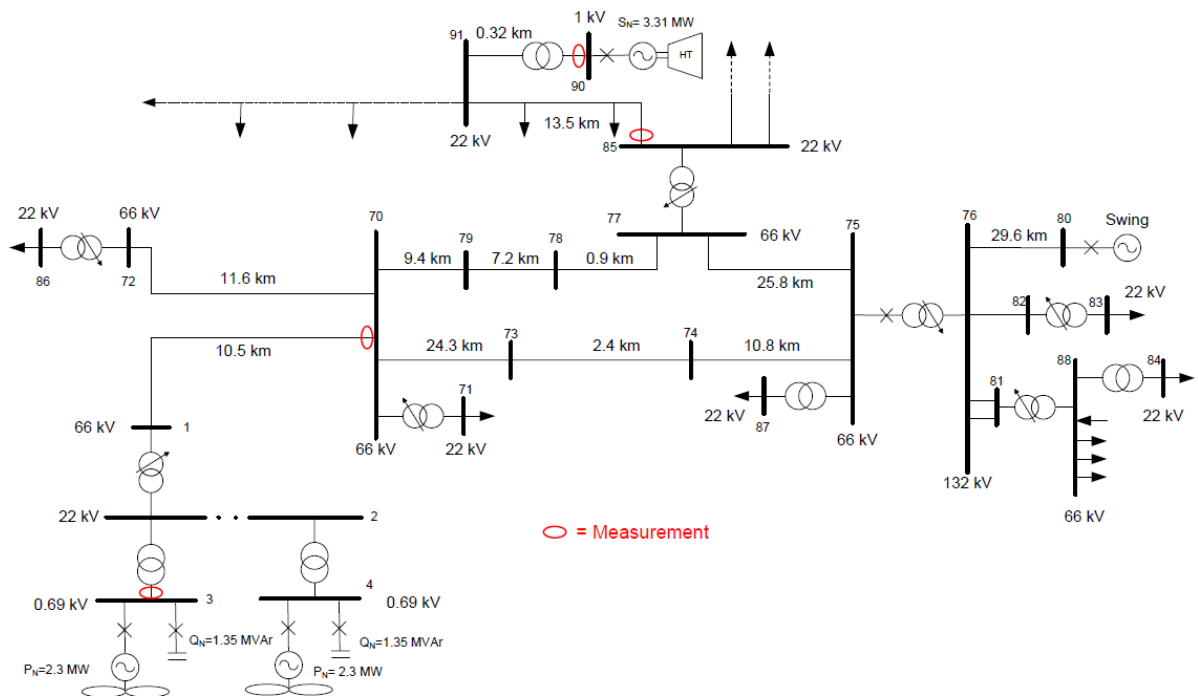


Figure 3.11 - Hitra One Line Schematics

The load points and their placements are presented in table 3.68. These are the original load point settings as presented in the original Simpow simulations. When different scenarios are modeled they will be presented as scalars of these settings, meaning that the proportionality if the loads will be intact. Line data for Hitra are somewhat detailed, but is presented in the appendix and will remain the same for all modeling scenarios.

At bus 1 a wind farm is connected. This wind farm is a more intricately constructed system of lines, transformers and nodes. But for simplicity and since this paper can't disclose the original topology, a version where all the 24 wind mills are connected to bus 2 as per figure 3.11 is utilized. It's worth noting that by doing this we are unable to see how this wind farm topology affects the reliability of supply at Hitra.

	Bus number	Active Load [MW]	Reactive Load [MVar]
Malnes	85	0.8	0.16
Vikstrøm	86	11.28	2.28
Fillan	71	7.5	1.5
Snillfjord	87	0.84	0.16
Agdenes	84	2.32	0.48
Orkdal	80	-	-
Hemne	83	4.48	1.08
Utheim	88	11.4	2.32
Ålmo	88	8.6	1.72
Eide	88	5.2	1.36
Total	-	54.03	11.6

Table 3.67 - Load data for Hitra

Reliability Data

The reliability data that will be used for this net is the same as that logged at NTE Nett. The average repair duration of the external grid is increased a little to imitate the fact that it's an underwater cable. It should also be noted that the transformer average repair duration used here is logged for

	Interruption Frequency	Outage Duration
Line	0.09625 [1/a*km]	3.55 [h]
Cable	0.0725 [1/a*km]	5.5 [h]
Transformer	0.0066 [1/a]	6 [h]
External Grid	0.22 [1/a]	2.675 [h]

Table 3.68 - Reliability Data for Components in Hitra

distribution transformers, which normally have somewhat different reliability characteristics than say windmill transformers or HV transformers. Table 3.69 shows the reliability characteristics used.

These characteristics are mostly estimates based on logged empirical data from Statnett (23). The estimates are produced by looking at general fault statistics for the type of component, then multiply that fault frequency by the percentage of faults that normally cause interruption in supply. Repair durations are also found in the Statnett statistics, and are estimated by calculating weighted averages of the Statnett numbers.

1. Base Case

The base case for Hitra will be a normal load as according to table 3.68 and no dispatch from the generators. Transformers and lines connecting the wind park and the generator at bus 90 to the grid will be out of service so they won't be a part of the contingency list. Since the grid contains meshed structures, a distribution analysis won't be applicable to any analysis. Thermal limits will not be considered since thermal limit data was not provided with the original dataset. If the lines have an ampere limit of below 300 A this would have started to affect the analysis results. The same line type is used in the critical meshed line structure in the middle as in the line connecting the wind mill park to the rest of the grid. If the transformer and the line connected to it are in the same capacity range, the line type holds around 700 A. 700 A is more than enough to enable each of the lines in the meshed structure of Hitra to hold the complete power flow necessary to export the maximum wind farm production or supply the heavy load scenario for bus 71 and 86. This paper will therefor assume thermal limit induced ENS is negligible.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	
Balancing of Production/Load	By Reference Machine	
	By Slack Bus	x
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.69 - Case 1 Load Flow Analysis Settings

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	X
Contingency Definition	Lines/Cables	X
	Transformers	X
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	X
Switching Procedure	Concurrently	X
	Sequential	
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	

Table 3.70 - Case 1 Reliability Assessment Settings

System Summary			
System Average Interruption Frequency Index	: SAIFI =	12,723560	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	12,723560	1/Ca
System Average Interruption Duration Index	: SAIDI =	21,301	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	1,674	h
Average Service Availability Index	: ASAI =	0,9975683490	
Average Service Unavailability Index	: ASUI =	0,0024316510	
Energy Not Supplied	: ENS =	1037,015	MWh/a
Average Energy Not Supplied	: AENS =	103,701	MWh/Ca
Average Customer Curtailment Index	: ACCI =	0,000	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	10,753660	1/a
Average System Interruption Duration Index	: ASIDI =	19,193317	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.71 - Case 1 Reliability Assessment Results

The ENS shown in table 3.72 has no trivially calculated lower bound as there is a circuit breaker dividing the loads into roughly equal halves in two different circuit breaker zones. We can note that the ASIF index value is roughly eight times the size of the other grids modeled in this paper. Without empirical data from the net operator we can't conclude on the quality of these numbers, but the line interruption frequency might be too high.

2. Base case with dispatched generators and no islanding

This case will look at how the grid handles dispatched generators and how these will affect the yearly ENS. Protection failure in generators will also be estimated and added on later to give an impression on how this affects the grid as a whole. In the PF model the wind farm has been implemented as the

	Bus Placement	Dispatch	
		[MW]	[MVar]
Svartelva hydro unit	90	2	-2.2
Wind farm	2	22.02	0.78
External Grid	80	31.21	3.23

Table 3.72 - Case 2 Generator Dispatch

structure shown in figure 3.11, but in will be treated as a virtual power plant without the ability to be set as a reference machine. The wind farm dispatch is set to 46% which is enough to supply the whole circuit breaker zone behind the circuit breaker isolating bus

75 from bus 76. Such a setup is not considered in reality for Hitra, since the islanded zone would have almost 90% wind penetration. However, due to the meshed structure of the Hitra grid, it is very difficult to model a case where the generators are not dispatched as if they had an islanding capability (since the "distribution" option is not available for meshed structures).

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.73 - Case 2 Load Flow Analysis Settings

As can be seen from table 3.75 on the next page, a 43% reduction in ENS is achieved by running Svartelva as a reference machine and utilizing the wind farm as a base production. This does not include effects from protection failure. A rough calculation using our default DG unit reliability data and protection device data gives us the following ENS contribution from the reference machine.

$$ENS_{refMach} = 1.3\% * 5 \left[\frac{interruption}{a} \right] * 1[h] * 22[MW] = 1.42 \left[\frac{MWh}{a} \right]$$

System Summary			
System Average Interruption Frequency Index	: SAIFI	=	10,462437 1/Ca
Customer Average Interruption Frequency Index	: CAIFI	=	10,462437 1/Ca
System Average Interruption Duration Index	: SAIDI	=	11,407 h/Ca
Customer Average Interruption Duration Index	: CAIDI	=	1,090 h
Average Service Availability Index	: ASAI	=	0,9986978663
Average Service Unavailability Index	: ASUI	=	0,0013021337
Energy Not Supplied	: ENS	=	596,063 MWh/a
Average Energy Not Supplied	: AENS	=	59,606 MWh/Ca
Average Customer Curtailment Index	: ACCI	=	0,000 MWh/Ca
Expected Interruption Cost	: EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	: IEAR	=	0,000 \$/kwh
System energy shed	: SES	=	0,000 MWh/a
Average System Interruption Frequency Index	: ASIFI	=	9,885986 1/a
Average System Interruption Duration Index	: ASIDI	=	11,032069 h/a
Momentary Average Interruption Frequency Index	: MAIFI	=	0,000000 1/Ca

Table 3.74 - Case 2 Reliability Assessment Results

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	X
Contingency Definition	Lines/Cables	X
	Transformers	X
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	X
Switching Procedure	Concurrently	X
	Sequential	
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.75 - Case 2 Reliability Assessment Settings

In the previous pages calculation 1.3% is the protection failure rate, 22 MW is the total load in the same circuit breaker zone as the DG unit and 5 is the number of interruptions per year experienced by the generator. 1 hour is the sectioning time required to trip the generator using a disconnector. Using the same principle to calculate the ENS contribution from the wind farm would give us an ENS contribution of $24 \times 1.42 [\text{MWh/a}] = 34.08 [\text{MWh/a}]$.

3. Islanding at the Malnes transformer

The original intent for islanding in the Hitra grid was to put bus 85, 91 and 90 in a circuit breaker zone to create an island to support the 0.8 MW and 1.61 MW load during an outage. The Svartelva generator is set to be the IPS in this island. Figure 3.12 shows the placement for the circuit breaker which isolates this circuit breaker zone, now dubbed the Malnes radial. Due to difficulties with the load flow it was not possible to run a

	Bus Placement	Dispatch	
		[MW]	[MVar]
Svartelva DG unit	90	2	-2.2
Wind farm	2	24	0.78
External Grid	80	29.32	3.58

Table 3.76 - Production Dispatch for Case 3

scenario where only the Malnes radial was islanded. Many of the contingency scenarios got load flow equation sets that would not converge when this was tried. These contingencies are then removed from the contingency list without adding anything to the ENS index.

generator is set to be the IPS in this island. Figure 3.12 shows the placement for the circuit breaker which isolates this circuit breaker zone, now dubbed the Malnes radial. Due to difficulties with the load flow it was not possible to run a

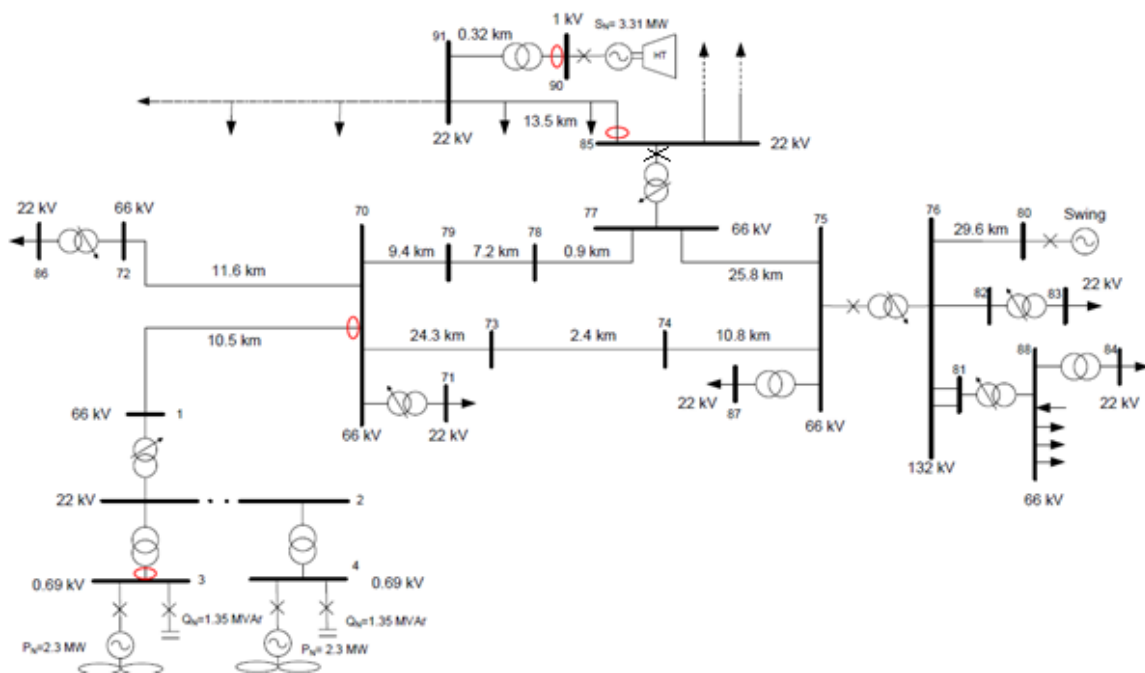


Figure 3.12 - New One Line Schematics for Case 3. Circuit Breaker Added Between Bus 85 and Transformer

As can be seen from table 3.80 on the next page the ENS is decreased markedly by 13.6%. However, if simulations are done without islanding the Malnes radial we can see that the islanding properties are only contributing 12.6 MWh/a (non-islanding reliability assessment results are shown in table 3.82). This is a relevant amount compared to the total load in the Malnes radial, but compared to the whole system it's not a big improvement.

Calculation Method	AC Load Flow. Balanced Positive Sequence	x
	DC Load Flow (linear)	
Reactive Power Control	Automatic Tap Adjustment of Transformers	x
	Automatic Shunt Adjustment	
	Consider Reactive Power Limits	x
Active Power Control	As dispatched.	x
	According to Primary/Secondary Control	
	According to inertias	
	Considering Active Power Limits	
Balancing of Production/Load	By Reference Machine	x
	By Slack Bus	
	Distributed Slack by Loads	
	Distributed Slack by Generation (Synch. Generators)	
Load Options	Voltage dependencies checked at nearest bus	x

Table 3.77 - Case 3 Load Flow Analysis Settings

Method	Connectivity Analysis	
	Load Flow Analysis	x
Network	Distribution	
	Transmission	X
Contingency Definition	Lines/Cables	X
	Transformers	X
	Common Mode	
	Independent Second Failures	
Fault Clearance Breakers	Use All Circuit Breakers	
	Use Switches With Protection Devices Only	X
Switching Procedure	Concurrently	X
	Sequential	
	Consider Sectionalizing	
Time to open switches manually	60 min	
Voltage limits	0.9 p.u. < u < 1.1 p.u.	
Thermal Constraints	Maximum thermal loading	100%
Islanding Capability	Black Start	
	Ride Through	x

Table 3.78 - Case 3 Reliability Assessment Settings

System Summary			
System Average Interruption Frequency Index	: SAIFI =	3,836045	1/Ca
Customer Average Interruption Frequency Index	: CAIFI =	3,836045	1/Ca
System Average Interruption Duration Index	: SAIDI =	9,384	h/Ca
Customer Average Interruption Duration Index	: CAIDI =	2,446	h
Average Service Availability Index	: ASAI =	0,9989287542	
Average Service Unavailability Index	: ASUI =	0,0010712458	
Energy Not Supplied	: ENS =	515,141	MWh/a
Average Energy Not Supplied	: AENS =	51,514	MWh/Ca
Average Customer Curtailment Index	: ACCI =	52,814	MWh/Ca
Expected Interruption Cost	: EIC =	0,000	M\$/a
Interrupted Energy Assessment Rate	: IEAR =	0,000	\$/kwh
System energy shed	: SES =	0,000	MWh/a
Average System Interruption Frequency Index	: ASIFI =	4,219844	1/a
Average System Interruption Duration Index	: ASIDI =	9,534349	h/a
Momentary Average Interruption Frequency Index	: MAIFI =	0,000000	1/Ca

Table 3.79 - Case 3 Reliability Assessment Results

System Summary				
System Average Interruption Frequency Index	:	SAIFI	=	10,242372 1/Ca
Customer Average Interruption Frequency Index	:	CAIFI	=	10,242372 1/Ca
System Average Interruption Duration Index	:	SAIDI	=	11,187 h/Ca
Customer Average Interruption Duration Index	:	CAIDI	=	1,092 h
Average Service Availability Index	:	ASAI	=	0,9987229879
Average Service Unavailability Index	:	ASUI	=	0,0012770121
Energy Not Supplied	:	ENS	=	527,722 MWh/a
Average Energy Not Supplied	:	AENS	=	52,772 MWh/Ca
Average Customer Curtailment Index	:	ACCI	=	0,000 MWh/Ca
Expected Interruption Cost	:	EIC	=	0,000 M\$/a
Interrupted Energy Assessment Rate	:	IEAR	=	0,000 \$/kwh
System energy shed	:	SES	=	0,000 MWh/a
Average System Interruption Frequency Index	:	ASIFI	=	8,621123 1/a
Average System Interruption Duration Index	:	ASIDI	=	9,767206 h/a
Momentary Average Interruption Frequency Index	:	MAIFI	=	0,000000 1/Ca

Table 3.80 - Case 3 Reliability Assessment Without Islanding

3.5.1 Summary of Results of Hitra Cases

- **Case 1:** Base case
- **Case 2:** Base case with dispatched generators and no islanding
- **Case 3:** Dispatched generators and Islanding of the Malnes transformer
 - o Refitting circuit breakers with proper two way relay system
 - o Sufficient AVR and frequency regulating mechanism for generators
 - o Synchronization equipment for reconnecting to external grid
 - o Engineered mass for generators
 - o Telematics and independently supplied communication equipment for contacting net operator

	ENS [MWh/a]	ENS in percentage of base case	SAIFI [1/a]	SAIFI as percentage of base case
Case 1	1037	-	12,72	-
Case 2	596	57,5%	10,46	82,2%
Case 3	515	49,7%	3,83	30,1%

Table 3.81 - ENS and SAIFI summary for the Hitra grid

	KILE [NOK/a]	KILE as percentage of base case	Accumulated KILE over 20 years with 3% discount rate [NOK]	Savings over 20 years of base case [NOK]
Case 1	1 119 450	-	30 982 442	-
Case 2	643 386	57,47 %	17 806 663	13 175 799
Case 3	555 946	49,66 %	15 386 632	15 596 000

Table 3.82 -KILE summary for the Hitra grid

This grid and the available data were not ideal for stating sound conclusions about the aptness of islanding procedures as a means to decrease ENS. The initial ENS from the base case justifies investments of 31 million NOK, and that is a low estimate if we assume that the expected ENS is correct. When initially building up the Hitra model circuit breakers were put into different parts of the meshed structure in the middle of the Hitra grid, and big reductions in ENS were accomplished with relatively small investments in equipment. This leads me to suspect that the failure characteristics used are wrong as they were not provided by the net operator. Either that or the net operator has a big potential for both saving money and increase uptime for the wind farm by investing in one or two circuit breakers.

The second case assumes that the wind farm working as an islanding generator. This is done for modeling purposes. The third case the Malnes generator is set as the reference machine in an islanding system alongside the wind farm. The difference in savings accumulate to 2,42 million NOK which is then the estimate of how much impact the Malnes generator islanding is saving in KILE. The number, however, is too high due to the influence of the wind farm.

4. Discussion

4.1 Criticism of Analysis Data Material and Sensitivity Analysis

To start of the discussion a few notes should be made on the reliability of the data and models themselves. The uncertainties with regards to how mitigating measures were chosen and performed have been discussed with some gravity in this text. But in truth, the reliability data that has been the basis for these test cases are an even bigger factor when judging the validity of the analysis. Data that has been used in most cases are taken directly from the net operator that is responsible for the grid in question. This data suggest very low failure frequencies and outage durations for lines and cables in general. But at the same time, it suggests a very high failure frequency for the external grid, regardless of whether or not it is regional or transmission. This paper does not have sufficient material to properly question the material delivered by the net operator, but the Statnett statistics seem to suggest much lower interruption frequencies from the transmission/regional grid. Regardless of the quality of the reliability data used in this analysis, islanding generators cases simulated here deliver much better results when line failure characteristics are low and external grid failure characteristics are high. A slight local increase in the statistics for interruption frequencies for the lines in most cases modeled here, and a slight decrease in the interruption frequency of the external grid would greatly shift the balance. A sensitivity analysis of Line A, which is the most detailed grid available for this paper, suggests almost no effect of islanding generators if failure characteristics closer to the Statnett statistics are used. There is a big difference between the net operator failure characteristic and the Statnett characteristic. The net operator numbers are almost tenfold that of the Statnett numbers, and the line statistic that Statnett operates with are almost five times bigger than the net operator statistics. The Hitra grid has the longest total line length of about 200km and should therefore be the most affected of variation in the reliability. But it is difficult to do a proper sensitivity analysis of it due to its non-radial structure. Øie-Kvinesdal has a radial structure and the next highest total line length of 70 km. The islanding generator has a markedly smaller impact on Øie-Kvinesdal than on Line A. Where Line A gets reductions to about 8% Øie-Kvinesdal experiences a slightly lower than 40% reduction. Increasing the interruption frequency of the line types in Øie-Kvinesdal by 30% increases the ENS to about 60% of the base case.

It could also be noted that the average reduction in indices experienced by the islanding practices at Boston Bar reduced the indices by 50%. This corresponds ok with the results experienced in these modeling scenarios. This could be taken as a sign of validity.

4.2 How DG affects reliability of supply in today's grid

This paper has had some problems with regards to the analysis of failure in protection devices. This is further hampered by the fact that little or no data could be found on DG unit reliability characteristics in a Norwegian setting. Data on reliability characteristics for circuit breakers in Norway is also scarce. Even so, from the material that has been modeled in this paper there are a few points that can be made. In the distribution nets modeled here there has normally been a circuit breaker separating the external grid and the DG units. The exception is the Hitra grid, which also contains meshed structures. The consequence of this single circuit breaker zone is that the impact of

DG units and its circuit breaker on the ENS has a relatively linear relation with the size of the interruption frequencies and interruption duration. The DG units used here have had an average of 250 hours expected outage duration and an interruption frequency of about five interruptions a year. If we state that 50 hours is a plausible average repair duration the connection from interruption frequency and failure to trip probability relates to ENS roughly like this:

$ENS_{DG} = a * \lambda_{gen} * p_{CBfail}$. Here a is some constant based on grid topology and total load, λ_{gen} the interruption frequency of the generator and p_{CBfail} the probability of failure to trip in the circuit breaker. This means that doubling both the failure to trip and interruption frequency of the generator will result in a four times higher ENS addition. No grid modeled in this paper has had significantly more than 3% impact on ENS from DG units and their respective transformer/line connection to the grid it. This suggests that even big DG penetration in a distribution net does not increase ENS by more than 12%.

If deep costs are applied to DG operators a 12% increase in ENS could have big impact on margins for that producer. However, a three percent increase is still a rather large estimate on the magnitude of the impact DG production is having on the grids modeled here. No matter, there are many factors that need to be taken into account when assessing the impact of DG units in distribution grids. A net with a bigger total load will also have bigger ENS impacts of generators (a bigger a in the ENS formula above). These same grids might also be better suited for DG production for this very same reason since the power sink is close to the power source.

4.3 Assessment of Islanding Mode Enabled Generators' Impact on Grid ENS and KILE

- With the data material available for this paper and assuming the models are representative, there seems to be a relatively big potential for reducing ENS in general in the Norwegian grid. However, considering that the models presented here do not clearly indicate that investing in preventive measures is profitable, a lack of real life investment in these measures seems legitimate. No cost estimates have been worked out for islanding measure installations in Norway to my knowledge. Neither are there companies specializing in this field offering cheap "retail" solutions for islanding measures. Some of the cases modeled experienced improved ENS using other tried and proven methods just as well as by implementing controlled islanding. Considering this it seems more likely that if islanding was to be implemented in Norway, it would have to be as a subsidized research project. Having said that, the KILE costs operated with in this paper is a lower bound estimate assuming ENS calculations are correct. If, for example, industry or retail businesses were affected the possibility of saving money would drastically increase due to increased KILE rates.
- It should also be noted that the effectiveness of islanding increases drastically when the "choke point" failure characteristics increase. By choke point it is meant external grid fallout, main transformer connecting the grid to the external line or any line/cable connecting the grid to the external grid. From the Danish paper (13) on island control it was pointed out geographical (non-power) islands connected to land by cable with sea traffic in the strait between land were often very prone to "choke point" fallouts and these islands were considered as very good targets for controlled islanding projects in Denmark. Main land Denmark has a smaller geographical area combined with a bigger population. The Danish islands are also more habitable than Norwegian ones and contain more people and thus also load. However, it should be possible to find

geographical islands in Norway with better properties for islanding generators than the ones used for modeling in this paper and thus find grids much more applicable for islanding than the grids tested here.

- The Hitra model sticks out from the other modeled grids in this paper. The potential reducing ENS by investing in preventive measures in this grid is substantial according to the model. Installing two circuit breakers could reduce the twenty year KILE by several million NOK. This should maybe be taken more as an argument against the Hitra models validity. In general this paper would have benefitted from knowing more about real life KILE and ENS of net operators so as to do evaluations of models and how they perform. The exception of this is Line A, where the net operator has confirmed the base case ENS to be very precise.
- It seems like refitting existing grids would be technically more difficult and more expensive. Appropriate circuit breaker zones could be chosen if the islanding mode was considered from the beginning of the planning process. Engineering the mass of an already implemented generator is probably technically challenging and expensive, especially if the generator is some sort of retail type product. Implementing the correct AVR and circuit breaker relay systems correctly from the start would reduce costs. This is not a surprising conclusion, but it should be noted in the paper.

5. Conclusion

In this thesis it was briefly pointed out that in small scale distributed power production in Scandinavia, the driving forces of expansion are state regulations. State regulations requiring power producers to produce power within the green certificates scheme and reduce CO_2 -emissions in Norway. To reduce costs resulting from these regulations the potential benefits of decentralized power production has been evaluated. Increasing the quality of supply will reduce compensation costs for net operators. In this evaluation it was concluded that increasing quality of supply through islanding systems was feasible.

An experimental project in Canada conducted by BC Hydro has developed eight guidelines for how they implemented islanding generators in one of their radials. These guidelines were used as a benchmark for describing technical and economical requirements in this thesis. Under the conditions described by BC Hydro, the Boston Bar islanding test project was determined a success.

The current implication of distributed generation in distribution grids has been difficult to estimate properly in PowerFactory. This is mostly due to lack of empirical data from Norwegian settings and because PowerFactory uses different standards for input data on protection mechanism failure than what is used in the Scandinavian standard for logging statistics. From the analysis results that were produced the implications on indices were minor. Even within large margins of error and high estimates on interruption frequencies in generators, the impact does not go above a 10% increase in ENS. In the models ENS increase due to protection failure in generators is estimated to be on average between 1-3%. There has not been conducted extensive investigation to assess the economic implications of this on DG operators, which could be notable if margins were small. The production to load ratio in the grid, the failure characteristics of the equipment as well as the number of generators the ENS impact of generators and their respective in a grid.

The models analyzed in this paper responded for the most part well to islanding measures intended to reduce ENS. In general the indices were lowered to between 10-60% of base case indices. Compared to the 500 000 CND incremental costs incurred at Boston Bar no grid was able to reduce costs enough to justify investments. The expenses related to islanding are very uncertain, and it is pointed out that there are many things which could reduce costs and increase savings. The most effective of these is to find a radial with high choke point failure characteristic and a sufficiently high load.

5.1 Further Work

Other more optimal grids modeled

The best way of answering questions regarding the plausibility of islanding in Norway is to find more optimal Norwegian case grids and model them. More optimal grids implies that they respond better to implementing islanding generators. Characteristics of such grids would be grids with big loads, high fault characteristics at *the* main choke point or other choke points and potential for DG unit installation or existing DG units. The grids chosen for this paper were more often chosen because of

the availability of data sets on these grids. Some of them, like the Hitra grid, were considered for islanding already by the net operator but proved difficult to model precisely with the data quality available. These more optimal grids would tell us something about the upper limit of developing islanding systems and thus the profitability/efficiency of developing competence/systems for implementing islanding DG units.

Expanding on legal issues

Legal issues have been briefly discussed in this paper, but there are many issues that are vague, not defined or defined between partners locally. If we limit the legal issues to islanding the issues of sovereignty with regards to ownership and operation of the DG unit. This could be especially relevant in an islanding situation. What level of power quality can be expected in islanding mode? What would be sensible to include in a commissioning process?

More detailed analysis

Technical analysis of critical contingency topologies with regards to dynamic analysis of voltage response to for example black start or ride through scenarios would be crucial to understand whether or not the proposed islanding grids are actually possible to run as islands. More crucially, how will the system frequency respond to different events in the islanded grid? What are the consequences of such frequency and voltage responses to electric equipment in that same grid? Modeling these things for at least some of the critical cases would be useful for shedding light on the possibilities of islanding in Norway.

Modeling with better reliability data

Acquiring a proper set of reliability data for grids to be modeled is perhaps the single most effort that could be made to improve precision on analysis results drastically. As mentioned before the failure characteristics of choke points between loads and the external grid are very important to analyze the impact of islanding mode on total ENS. The numbers provided by the net operators have either been suspiciously high and the numbers used when net operator characteristics were not available were generic at best. If the net operator numbers is proved to be a better match for most other distribution grids, a lot of distribution grids could suddenly become very profitable to run in island mode. However, judging from Statnett statistics it is not very likely that this is the case. Regardless of this, further research on reliability statistics for specific areas would make analysis results markedly more precise.

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APPENDIX

Snåsa

Linje/Kabel	Fra node	Til node	Type	R [ohm/km]	X [ohm/km]	Lengde [km]	Max driftsstrøm [kA]
Linje 1	3	4	FeAl 120	0,151	0,344	0,38	0,624
Linje 2	4	5	FeAl 120	0,151	0,344	5,74	0,624
Kabel 3	5	6	TXSP 3*1*95 Al	0,32	0,12	0,42	0,275
Linje 4	6	7	FeAl 50	0,359	0,373	0,78	0,362
Linje 5	7	8	FeAl 25	0,721	0,395	1,54	0,235
Linje 6	8	14	FeAl 25	0,721	0,395	4,29	0,235
Linje 7	14	15	FeAl 25	0,721	0,395	3,82	0,235
Linje 8	8	9	FeAl 25	0,721	0,395	5,67	0,235
Linje 9	9	11	FeAl 25	0,721	0,395	0,24	0,235
Kabel 10	11	12	TSLE 3*1*95 Al	0,32	0,12	0,14	0,275
Linje 11	12	13	FeAl 25	0,721	0,395	1,58	0,235
Linje 12	9	10	FeAl 25	0,721	0,395	4,79	0,235
66kV linje*	1	2	FeAl 120	0,127	0,3259	0,842	

Table A.1 – Line and cable data for the Snåsa grid

Transformator	SN [MVA]	Un1[kV]	Un2 [kV]	er [p.u]	ex[p.u]
Snåsa hovedtransformator*	25	22	66	0,0032	0,07523
Step up transformator					
Til 4,6MVA generator	4,6	6,6	22	0,006	0,06
Til 1,6MVA generator	1,6	0,69	22	0,0072	0,0583
Til DG2*	1	0,69	22	0,0073	0,05441

Table A.2 - Transformer data for the Snåsa grid

Øie-Kvinesdal

Ratings and parameters	Symbol/Unit	Value
Direct axis synchronous reactance	X_d [p.u.]	2,04
Direct axis transient reactance	X_d' [p.u.]	0,238
Direct axis subtransient reactance	X_d'' [p.u.]	0,143
Quadrature axis synchronous reactance	X_q [p.u.]	1,16
Quadrature axis subtransient reactance	X_q'' [p.u.]	0,137
Armature resistance (°C)	r_a [p.u.]	0,00219
Leakage reactance	X_l [p.u.]	0,130
Direct axis open-circuit transient time constant	T_{d0}' [s]	2,38
Direct axis open-circuit subtransient time constant	T_{d0}'' [s]	0,0117
Quadrature axis open-circuit subtransient time constant	T_{q0}'' [s]	0,11
Direct-axis air-gap flux at which the saturation factor SE1D is given	V1D [p.u.]	1,0
Direct-axis air-gap flux at which the saturation factor SE2D is given	V2D [p.u.]	
The saturation factor at the direct-axis air-gap flux V1D	SE1D [p.u.]	0,1
The saturation factor at the direct-axis air-gap flux V2D	SE2D [p.u.]	0,3
Inertia constant	H [s]	0,3504

Table A.3 - Parameters for synchronous generators in the Øie-Kvinesdal radial

Figure A.3 - Base case heavy load on Snåsa grid. Basic load flow results

Line A

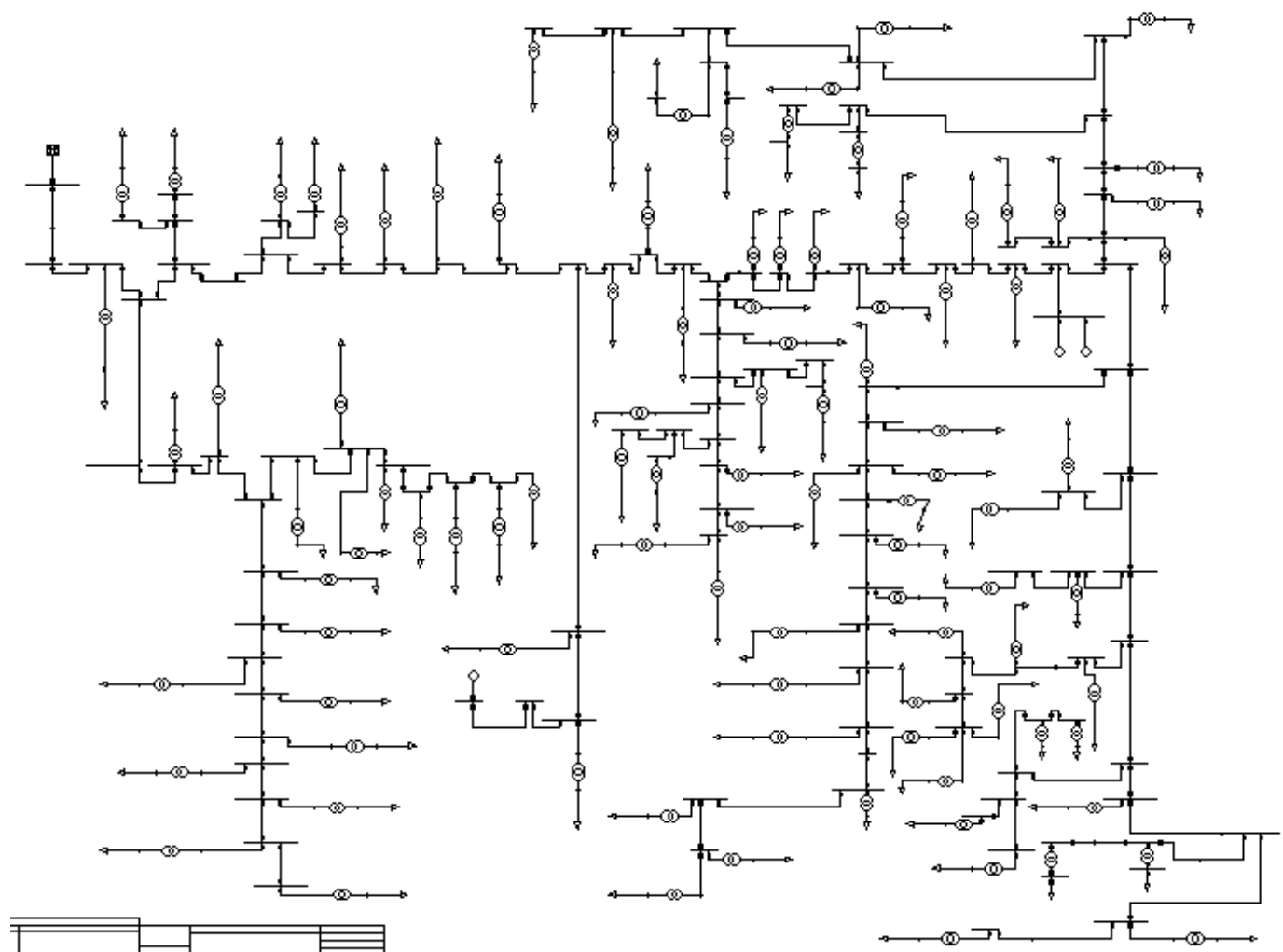


Figure A.1 - Line A model in PF

Line Type Name	L'[mH/km]	X'[Ohm/km]	R'[Ohm/km]	Cable/Overhead	Nominal Freq. [Hz]	Rated Current [kA]	Rated Voltage [kV]
132 kV B76-B80	1,228676	0,386	0,151	ohl	50	1	132
132 kV B76-B81 (6.5)	1,320986	0,415	0,394	cab	50	1	132
132kV B76-B81 (22.1)	1,228676	0,386	0,151	ohl	50	1	132
132kV B76-B82	1,206395	0,379	0,121	ohl	50	1	132
66kV B1-B70	1,139549	0,358	0,061	ohl	50	1	66
66kV B70-B73	1,254141	0,394	0,191	ohl	50	1	66
66kV B70-B79	1,228676	0,386	0,151	ohl	50	1	66
66kV B74-B75	1,320986	0,415	0,395	ohl	50	1	66
66kV B77-B78	1,289155	0,405	0,257	ohl	50	1	66
66kV Cable B73-B74	0,6366198	0,2	0,193	cab	50	1	66
66kV Cable B78-B79	0,6684507	0,21	0,206	cab	50	1	66
B70-B72	1,320986	0,415	0,395	ohl	50	1	66
FeAl 1x16 6/1 22kV	1,301888	0,409	1,126	ohl	50	1	22
TSLE 3x1x95 Al	0,6366198	0,2	0,32	cab	50	1	22

Table A.4 - Line Data for the Hitra Grid

Correspondings

Hei igjen!

Da ser det faktisk ut som du treffer veldig bra sammenlignet med våre egne tall. LPENS vil bli høyere i din analyse ettersom man forutsetter at lastene ikke varierer gjennom året.

Så dette lover bra ☺

Med vennlig hilsen

Rune Paulsen
overingeniør
NTE Nett AS
7736 Steinkjer

Fil: Resultater – NetBas.txt

Figure A.2 - Mail 1 Rune Paulsen

Hei!

Beklager sen tilbakemelding. Vedlagt er lastflyt for **Snåsa** på samme format som du tidligere har fått for Frol-avgangen i Levanger. I tillegg har jeg vedlagt et enlinjeskjema for **Snåsa**-nettet fra NetBas, men som sist gang kan det være noe vanskelig å lese alt i enlinjeskjemaet.

Når det gjelder pålitelighetsdata for **Snåsa**, så kan du bruke samme underlaget som du fikk tilsendt ifm. Frol-linjen. Det er de samme dataene som benyttes i dag. Vi har dessverre ikke loggført seksjoneringstider på mange år, så jeg har ingen gode tall å gi deg for **Snåsa** i den sammenheng. Så der blir du bare nødt til å estimere noe.

Håper dette var til hjelp. Ta kontakt om du har behov for noe annet eller dersom du har andre spørsmål.

Med vennlig hilsen

Rune Paulsen
overingeniør
NTE Nett AS
7736 Steinkjer

Figure A.3 - Mail 2 Rune Paulsen

Hei

NVE har ingen generell regel mot ikke å tillate reguleringer for småkraftverk, men det er ikke så mange som søke om det.

Det kan skyldes flere forhold, som flere og/eller andre grunneiere, allmenne interesser rundt eller i tiknytning til vannet eller at viktige biologiske verdier blir berørt.

Det forekommer fra tid til annen at vi får søknader som innebærer reguleringer og noen har vi sagt ja til når ulempene er begrenset. Vi er klar over de fordelene du nevner, men i mange tilfelle vil slike magasiner være så små at de i mindre grad vil kunne bidra til sikker forsyning ved utfall, i hvert fall ikke over særlig tid. De kan imidlertid få en lenger driftstid i kraftverket året sett under ett, og dermed gi et positivt bidrag i en utbygging.

mvh

Øystein Grundt

Norges vassdrags- og energidirektorat (NVE)

Seksjonssjef

Seksjon for småkraftverk og vassdragsinngrep

Figure A.4 - Mail 1 Øystein Grundt