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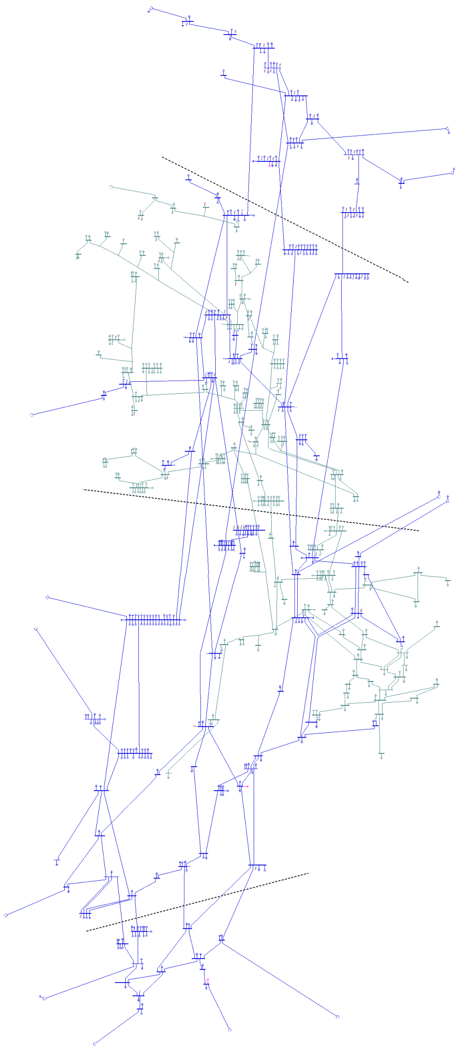

Swedish Transmission Grid Model Based on Open Sources

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Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2017

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Cover: Single line diagram of the Swedish transmission grid on 220 kV and 400 kV level.
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Abstract

With new production units becoming smaller and smaller due to movement for renewable sources the electricity market contains an ever increasing amount of actors. The access to load flow data for smaller actors is limited due to security concerns making it difficult to perform pre-studies on the grid. A grid model of the Swedish transmission system has been created in the simulation software PSS/E. The model is based entirely on open sources which was one of the main aims of the project. The constructed model in PSS/E consists of 221 buses, 472 individual generators, 283 branches and 191 loads placed in the system. The 400 and 220 kV transmission model have been validated with the help of historical load flow data available from the power trading site Nord Pool and data made available publicly from the Swedish Transmission System Operator Svenska Kraftnät. Studies have shown that the average inter-trade deviation between the areas of Sweden is below 10% while it in most cases won't differ more than a single percentage of the measured values. Transient stability studies have been performed in the model to compare the fault ride through requirement stipulated in the Swedish grid code. This was done to compare how conservative these requirements are in comparison to a real fault in the system. It was found that the voltage profile in some cases were more aggressive than what the measured voltage were on the generator bus. However, when applying a more realistic fault scenario including a disconnection of a faulted transmission line, the voltage profile was found in most cases to be too conservative as compared to the grid code requirement.

Acknowledgements

First and foremost i would like to thank my supervisor at DNV GL, Evert Agneholm. His support and insight have been essential in the work regarding the Swedish transmission grid model and the transient studies that were performed. I would also like to thank my examiner at teacher at Chalmers, Peiyuan Chen for his help with the report and answers given during the project. Also Andreas Petersson at DNV GL should receive thanks for his support with Python scripts. Lastly i would like to thank all my other colleagues here at DNV GL who has been very supportive and answered all my questions to the best of their ability.

Anton Thorslund, Gothenburg, May 2017

Contents

List of Figures

List of Tables

Abbreviations

TSO	Transmission system operator
SvK	Svenska Kraftnät
p.u.	Per unit
ENTSO-E	European Network of Transmission System Operators for Electricity
HVDC	High voltage direct current
ULTC	Under load tap changer
H	Inertia
AVR	Automatic voltage regulator
PSS	Power system stabilizer
FCT	Fault clearing time

1 Introduction

1.1 Background

In some countries, transmission grid models and data regarding the transmission grid are considered confidential. This means that manufactures and other consultants doing work regarding the grid have strict limits on how to handle the information given to them from the transmission system operator(TSO). This will in turn make it harder to conduct grid and pilot studies for some projects when there is a need to make calculations and simulations on the transmission grid. This is because the access to data is limited. Therefore, a model built on open source gathered material can be useful since the model can be freely used with no ties to data given from the TSO. It has been seen in earlier projects in other countries at DNV GL/Gothia Powers that this can be done to an acceptable accuracy together with experience and engineering assessments. Studies can then be made for different operational scenarios to give a better understanding of the current stability of the grid and how different parameters can affect this.

1.2 Aim

The aim of the project is to develop a detailed model of the Swedish transmission grid in PSS/E based on open source information, including production sources and connection points. The model should be used for both static and dynamic studies with sufficient accuracy. The second aim will be to perform static and dynamic studies on the model to compare some grid code requirements with a real scenario.

1.3 Problem

The work consists of several parts that will be handled throughout the duration of the project. It can roughly be split into three parts, model building, static load flow studies and dynamic studies.

- Build a model of the Nordic transmission grid in PSS/E. The transmission model should contain three parts: transmission grid, production sources and connection points to the external and the distribution grid. The production sources should contain data for both dynamic and static studies, including frequency and voltage control.
- Static studies should be performed on the model to validate the data and structure. Static load flow analysis will be performed and compared with public historical data given from Svenska Kraftnät(SvK).

- Perform dynamic studies on the model when the load flow has been validated. The transient stability should be studied for several configurations. Scenarios to be studied includes critical fault clearing time and the time until a generator drop its synchronization to the grid. This will be compared with the low voltage ride through profile presented in different grid codes. The idea is how these requirements from the Swedish grid code concerning generating units [2], corresponding to the simulated cases from the dynamic model. One example is the low voltage profile in the requirements that units should be able to manage a case when the grid voltage drops to 0 during 0.25s then stepping back to 25%. After stepping to 25% the voltage then rises gradually up to 90% during 0.5s then staying at this level. The requirement from SvK is that the generating unit should be able to manage this low voltage profile while keeping synchronization to the grid.

1.4 Scope

The final model should cover the transmission grid, production sources as well as connection points to the external grid and the distribution grid. The production sources should contain both static and dynamic data as well as frequency and voltage control. The model will be limited to the grid solely owned by Svenska Kraftnät (SvK), i.e. voltages between 220 kV and 400 kV. Grids owned by other system operators as well as grids existing outside Sweden will not be considered. To reduce the size of the model and for simplifications, smaller production sources will be lumped together in the grid model.

1.5 Method

By gathering material from open sources regarding the position of substations and transmission lines, a grid will be built in the PSS/E software. The material will be gathered from grid maps displayed by several sources such as the SvK and the European Network of Transmission System Operators, Entsoe. To accurately decide the impedance of the transmission lines, the line length will be measured through mapping software such as Google Earth. With the help of standardized impedance data for transmission lines the total impedance can then be estimated. Larger production sources will be placed at the respective transmission bus in the model. Smaller production sources will be lumped together and then placed at the closest bus in the transmission system. The reason is that these are rarely directly connected to the 220 kV or 400 kV level. Exciter, generator and turbine models will have to be estimated or researched for the generating units. Simulations will then be run on the system for both static load flow and dynamic scenarios. The load flow can be compared with historical data given from the TSO. Data can be found for several years back with detailed information given from every hour on how much is produced and from where in the grid. This data will be used to verify the load flow of the model. Regarding dynamic simulations, the grid code for the Swedish transmission grid can be easily accessed from the SvK web-page. The grid code documents will then be compared with the results from the dynamic simulations in the PSS/E model.

1.6 Structure of the report

The first chapter explains the project background, the reason why it is important and why it is carried out. It will also include a precise problem description and describe the final aim of the project. It also contains a clear scope of the project and a short sub chapter of how the project is carried out. The second main chapter of the report, The Swedish Transmission grid, which also shares its name with the title of the report explains how the model was created. The third major chapter explains how the created model was verified against the actual measured values with detailed reports on the static load flow in the model. Finally, a chapter containing the dynamic studies that was performed on the model. This chapter will also include studies on the Nordic grid code, voltage stability and how the model can be used to verify this.

2 Transient Stability Theory

2.1 Transient stability

Transient stability is the ability of the system to stay synchronised during major disturbances in the grid [1]. Such examples can be sudden loss of large loads or different types of fault on the system [11]. Transient stability is part of the larger area of stability which also covers the phenomena of small and slow disturbances [11]. However, the topic of this report covers the transient stability which will be the focus of the chapter.

2.1.1 Synchronous machine

The total amount of transmitted power through a transmission line can be explained by the following equation,

$$P_e = \frac{E_S E_R}{X_T} sin\delta \tag{1}$$

where P_e is the transmitted power, E_s and E_R are the voltages at the sending and receiving bus, X_T is the effective reactance between the voltages and δ the transmission angle [1]. The maximum transmittable power is reached when the transmission angle is 90 degrees, then (1) becomes

$$P_{max} = \frac{E_S E_R}{X_T}. \tag{2}$$

Below in Figure 1 the transferable power can be seen for two levels of P_e. This curve is called the power angle curve and shows the relation between the transmission angle and generator power output [11].

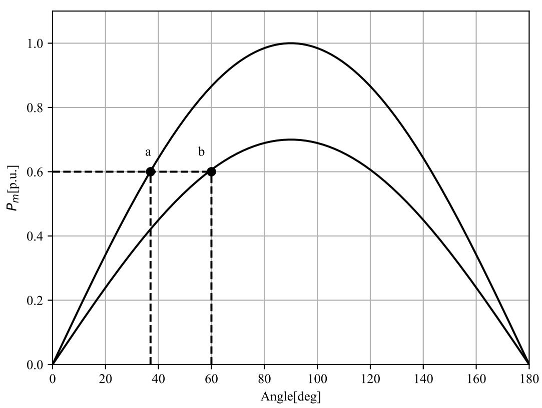

Figure 1: Operating points due to different line reactance.

The mechanical power on the generator is shown as the dashed horizontal line which in this example is around 0.6 p.u. The angle which the generator is operating at can then be seen when the mechanical power meets the electric power output curve. Depending on how much power that can be transmitted the generator can work either in operating point A or B. The impact and the difference between running on either operating point a or b will be discussed further below.

According to [1] several factors influence the transient stability of a generator. How heavily the generator is loaded, fault clearing time, the system reactance after a fault, generator reactance, generator inertia, internal voltage magnitude and the type of fault.

2.1.2 Equal-area criterion

The ability of the machine to maintain stable can be explained by the equal area criterion. The idea of the equal area criteria builds further on the operating points explained in the chapter above. The relation between rotor angle and accelerating power is given by the follow equation,

$$\frac{d^2\delta}{dt^2} = \frac{\omega_0}{2H}(P_m - P_e) \tag{3}$$

where δ in the angular displacement, ω is the angular frequency, H is the in the inertia, P_m is the mechanical power and P_e is the electrical output power [1]. By multiplying both sides with $\frac{2d\delta}{dt}$ and integrating for the angle leads to the following expression,

$$\int_{\delta_m}^{\delta_0} \frac{w_o}{H}(P_m - P_e)d\delta = 0 \tag{4}$$

where δ_0 is the initial angle and δ_m the maximum angle [1]. The total energy gained during a change of angle between δ_0 and δ_1 can then be explained by the following expression,

$$\int_{\delta_0}^{\delta_1} (P_m - P_e)d\delta = E_1 \tag{5}$$

where E_1 is the energy gained [1]. Below in Figure 2 a scenario is shown with varying system reactance during pre-fault, during fault and post fault.

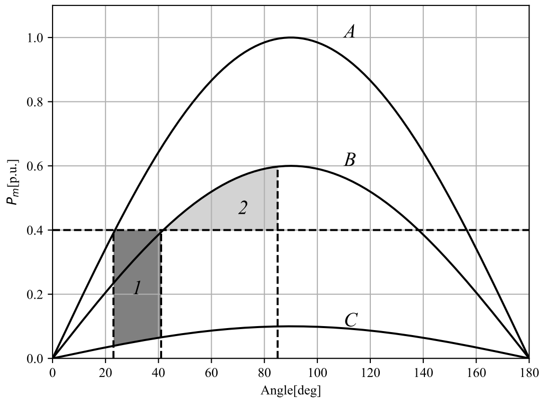

Figure 2: Equal area criterion [1].

In the figure three curves can be seen displaying the maximum transferable power in relation to the transmission angle during different instances. The first pre-fault curve is A, during fault it is C and post fault it is B. The dashed line is the mechanical power output of the machine. The system single line diagram can be seen below in Figure 3.

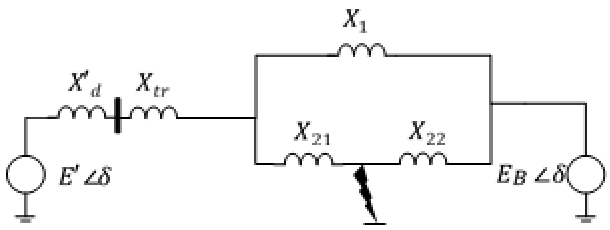

Figure 3: Equivalent circuit when studying equal area criteria [1].

Where E' is the voltage of the generator, X'_d is the transient reactance of the generator, X_{tr} is the step-up transformer reactance, X_1,X_{21} and X_{22} is the transmission line reactances and E_B is the infinite bus voltage. The transient reactance is used in this case due to the the time of the transient period. Which is usually around 1 to 2 seconds before the transient period dies out [11].

If a fault occurs in the point between X_{21} and X_{22} the total transferable power of the system is reduced due to a disconnection of a transmission line. This gives the C curve in Figure 2. If the total transferable power of the system is then lower than the mechanical power of the generator, the generator will increase in speed.

This is explained by (3) where a reduction of P_e leads to an increase of the angle acceleration $\frac{d^2\delta}{dt^2}$. The acceleration will then continue for as long as the mechanical power is higher then the maximum transferable power.

After a time, the faulted line is disconnected with the help of circuit breakers. The time it takes before the line is disconnected is due to how fast detection of the fault takes place and the time for the breakers to perform the switching action. When the line has been disconnected the maximum transferable power rises again, shown in Figure 2 by curve B. P_{max} is still lower then A due to the disconnection of the faulted line giving a higher reactance i the circuit. When P_{mech} is lower then P_{max} the generator will start to decelerate according to (3). During the deceleration period the energy gained during the acceleration is supposed to be dissipated. These energies can be seen as area 1 and area 2 in Figure 2. If area 1 is greater then area 2 then the generator will become unstable and lead to loss of synchronization. There are several methods to improve the transient stability of a generator. These methods will be dealt with in the following section 2.2.

2.2 Improving transient stability

There are a number of ways to improve the transient stability of a system. From the simulations the different measures can be seen and compared.

2.2.1 Fast-valving

As can be seen from the figures below the amount of gained energy during the fault depends on the level of P_{mech} and P_e during the fault. If one could reduce the level of P_{mech} after a fault the acceleration of the generator could be reduced. This can be done with the help of fast valving which reduces the steam, in the case of a thermal plant, that is sent to the turbine [1].

If this is done fast enough the amount of mechanical power applied to the generator during and post fault can be reduced and the system improved against transient instability. The method of fast valving is not possible for every type of generating unit. It is for example not possible for hydro power plants due to the slow response of changes in power output and the time it takes to regulate the flow of water [1].

2.2.2 Fast fault clearing

Another method in reducing the amount of gained energy during the fault is to clear the fault faster. For example in Figure 2 by clearing the fault faster, the fault can be cleared at an lower angle. This increases the area available for the machine to break the rotor on the power-angle curve. To clear the fault faster a number of solution exists such as improving the time to find the fault and then the time to isolate it. To find the fault faster, new and improved relay protection could be installed, such as telecommunication [1]. These can also help to find the most optimized way to isolate the fault and thereby not taken more objects of out service than necessary. To isolate that fault faster, improved breakers that can switch faster is necessary.

2.2.3 Lower system reactance

According to (1) the amount of power that can be transferred between two buses are heavily dependent on the system reactance. This has been explained earlier during the discussion around operating points in Figure 1. There are two ways to increase the transient stability by lowering the reactance, both pre-fault and post fault [1]. The improvement pre-fault is the obvious solution of increasing the amount of transmission capacity from the generating unit. This will not only cause the starting angle to be reduced but also increase the P_{max} of the generator. The other method is reducing the reactance post fault. When a transmission line is taken out of service due to a fault the system could try to reconnect the line after a certain time to see if the fault disappeared or still persists [1]. If the fault has somehow been cleared, a re-connection of the line would return the system to its pre-fault state. There is, however, a risk associated with this if the fault still persist. This will cause an even greater risk for the generator to fall out of phase.

2.2.4 Tripping generator

Disconnecting the generator from the system might be a solution to avoid transient instability according to [1]. By tripping specific generators the amount of power that is transferred on a congested line can be reduced and in turn increase the transient stability. However, not all units can easily be tripped. Hydro power plants can easily be shut down and be ready to start up again when the conditions are right. The fossil-fuel or nuclear plants are, however, more problematic. These plants can have a start up time that span hours it is often not suitable to trip these units. Though today many plants are equipped with a feature that allows the plants to reduce the amount of power produced to only supply the plant auxiliaries, while staying disconnected to the grid. This give the unit a possibility to keep running off the grid until it can be reconnected again [1]. Tripping of a generator should be seen as a last solution since it can cause high levels of shaft torque that might damage the rotor [1].

2.2.5 Fast excitation system

According to [1] significant improvement to the transient stability can be done by adding fast excitation systems. The idea of the system is to increase generator field voltage during a fault. This will also increase the internal voltage of the machine which will lead to a higher electrical output of the generator [1]. The settings on the excitation system heavily affects the possibility to increase transient stability. A high ceiling voltage together with a fast response time have the best effect on stability increase [1].

2.3 Requirements for generating units

Most, if not all TSOs, have rules and requirements in place for actors on the power market. These are called grid codes and stipulates the requirements that has to be followed for generating units, loads and so on. For a generating unit these can cover voltage regulation, power control, voltage ride through requirements, start and stop after blackout, communication and control-ability. The low voltage ride through requirement is a lower limit voltage for which the generator are not allowed to trip above [12]. The generating unit should be able to manage a certain voltage on its connecting bus without losing synchronization and having to disconnect from the grid. These are different for each transmission grid where every TSO have their opinion on what the generators should be able to handle i regards to voltage drops [12].

2.3.1 Swedish requirements

In the Swedish grid code, which are a part of the Nordic transmission system, there are two different requirements in regard to low voltage ride through. The requirements are set after type of production unit and the size in MW. Generating units below 25 MW are denoted small, units between 25 MW and 100 MW are of medium size with the exception of hydro units which are between 25 and 50 MW. All units greater than 100 MW(for hydro, larger than 50 MW) are denoted as large units. Depending on the size of the unit different rules apply when it comes to short circuits and voltage variations. The Swedish low voltage variations can be seen below in Figure 4.

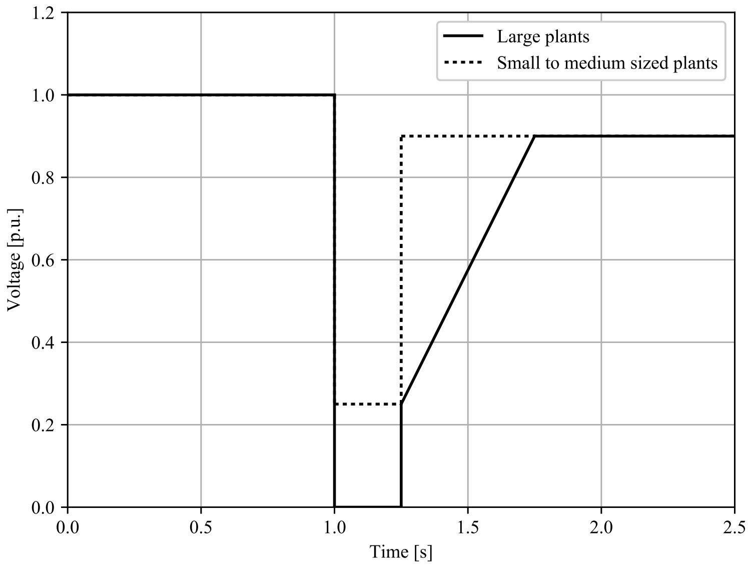

Figure 4: Voltage variations for small, medium and large plants [2].

Production units denoted as large should be able to manage voltage variation on the terminal down to 0 % during a time period of 0.25s. It should then be able to maintain stability during a step to 25% following a linear increase to 90% during 0.25s which are then kept at that level. For units denoted as small or of medium size different rules apply. These units should maintain stability during a voltage drop down to 25% during 0.25s which are then stepped to 90% and kept at this level.

3 A Swedish transmission grid model in PSS/E

In general The Swedish transmission grid is characterised by a lot of hydro power production plants in the northern part and a lot of consumption in the southern part of the country. This requires a good transmission system to transmit the electric power to the loads in the south. This is mainly done by the eight 400kV transmission lines between trade area SE2 and SE3. These lines are also equipped with series compensation to further increase the transfer capability and the transient stability. The electric areas of the Swedish grid can be seen below in Figure 5.

Figure 5: Map of the Swedish transmission grid [3].

3.1 Assumptions made and simplifications

To create a model of Swedish transmission grid based on open sources, a lot of assumptions and simplifications have been made. The system was large enough with just the 400 kV and 220 kV buses in mind with 221 buses, 191 loads, 478 generators and 283 branches. Since the model only supports 400 kV and 220 kV buses it was decided that the step up and step down transformers were not to be modeled. If these were to be included, the number of buses would have increased by 2-3 times as compared to the current amount. This could, however, be interesting to further develop. Due to the difficulty of finding the real parameters of the generating units, a lot of these values have been taken from earlier models of lumped networks or standard parameters from the literature. Therefore, most of the generating units share the same values between each other depending on the type. No solar power was added to the model due to the low installed capacity and generated energy. Also the only type of wind turbines added were the ones belonging to larger wind farms. It was not realistic to add the other units one by one. The reason for this would be that the amount would simply be to high. Regarding the transmission lines it was assumed that all lines were of the same material, area and type. The only thing that differs due to voltage level would be the amount of conductors per phase. Finally all loads within a county are evenly distributed among the buses inside the county due to simplicity reasons. No differentiation was made if the bus was close to a high population area or out on the country side .The assumptions and simplification will be discussed further under respective chapter.

3.2 Generation data

As mentioned earlier the power produced in Sweden comes roughly from 40% hydro power and 40% nuclear power. The rest constitutes of wind power and excess electric power generated from thermal plants. In Table 1 below the total installed capacity of the model can be seen. This can be compared with the official numbers from [6] to the left.

Table 1: Comparison between installed capacity in the model and actual capacity [6].

	Installed capacity [MW]	Installed capacity in the model [MW]
Hydro	16184	16312
Nuclear	9714	9076
Wind	6029	1940
Thermal	7920	7920
Solar	104	0
Total	39951	35782

As can be seen in Table 1 the installed solar power in the model was zero. The reason for this was simply that it was to small to have any real impact in the model. Another thing to notice is the difference between the installed hydro power and the hydro power that was added to the model. The total installed hydro power in Sweden was for the year of 2015, and only including plants that were in operation that year. However the source listing the individual plants listed all plants in Sweden above 10 MW. Due to the difficulty of finding which of all the hydro power plants that were not in use during the year, all hydro power plants above 10 MW was added to the model. This is the reason why the modeled amount of installed hydro power is larger than what was listed as installed capacity for 2015.

The installed capacity given for generators, including wind generators, were assumed to be on a power factor of 0.9. This assumption was made in accordance to typical data from [1]. This was then used to calculate the M_{base} of the machine since the size of a production unit was often given as their installed active power capacity. The reactive power capability of the machine was then set to never exceed a power factor of either 0.9 leading or 0.9 lagging.

3.2.1 Hydro power

The majority of the production units in the model are hydro power and a list of all of the major, above 10 MW, hydro plants in Sweden can be found in [13]. This website was used to list all hydro power plants in Sweden and was used together with the book [14] which lists the number of units per hydro power plant. It was decided to disregard any plants lower than 10 MW since the total amount of plants would have been too large. No consideration was taken to the type of hydro power plant or the type of turbine installed on the unit. This caused problems in area SE3-SE4 where the total modeled capacity was lower than the installed capacity. Therefore the generators had to seen as aggregated models where each generator has around 20-30% higher capacity than the real value.

Two different types of generators are used in the power system, round rotors and salient pole rotors [1]. The most commonly used rotor structure for hydro power plants are the salient pole rotor since it is beneficial during lower rotor speeds [1]. Therefore to model the salient pole rotors dynamically in PSS/E the GENSAL generator model was used according to the Program Application Guide Volume 2 for PSS/E.

One of the harder tasks was to find the machine dynamic models for generators to perform dynamic studies. However, by studying earlier work such as [7] and [15] some parameters could be extracted for use in the created model. The first system used by [7] was based on the Nordic 32 model and [15] was based on the Nordic 44 model. The Nordic 44 models Sweden, Norway and Finland system with increased focus on Norway while Nordic 32 models only Sweden. Most of the dynamic parameters used in the created model are based on the model used in [15] since it had the most information about the system that was used. With a few exceptions the parameters given by [15] were also in line with the standard parameters given by [1].

The report [15] was therefore followed when the type of exciter and power system stabilizer had to be chosen. Nordic 44 in [15] used the exciter SCRX for all generating units with the exception of the thermal units. The same argument was used for the selection of the stabilizer. STAB1 was used for the hydro electric units. The problem of finding parameters to the dynamic model was equally as hard as finding the correct models. A combination of sources were used such as [15], [7], [1] and the PSS/E program application guide to populate the dynamic models.

No governors were added to the dynamic model. This will be left to future work with development of a model used for studying frequency control of the power system. Further, no distinction was made between small scale hydro and large scale hydro regarding the inertia constant. However, this will be discussed later in the report.

3.2.2 Nuclear power plants

According to [6] the nuclear power plants that were in operation during 2015 were Oskarshamn, Forsmark and Ringhals. These reactors were added into the model. However, Oskarshamn 2, O2, was not used during the year and therefore it was chosen to exclude this from the model. The same method of finding dynamic models and their parameters were used for the nuclear power plants as for the hydro power plants. In contrast with the hydro power plants the turbines for nuclear power plants are powered by steam instead of water. This gives that the rotors are of a different construction due to the higher speed [1]. The rotor used for steam turbines are of solid type and the recommended generator model according to PSS/E is therefore GENROU. However, the same exciter and stabilizer was used as for the hydro plants.

3.2.3 Wind power plants

Only the larger wind farms listed by [6] were added to the model and each farm was presented as one lumped generator. The total amount of installed wind turbines would add up into the thousands with very low installed power per unit and would therefore not be feasible to add them one by one. This, however, led to an installed power of around 1940 MW in the model. Since the power generated from wind usually is way below the installed capacity this was not seemed as a problem. An alternative solution could be to use aggregated generators, a solution that was used for the thermal plants. This is shown with Figure 6 below.

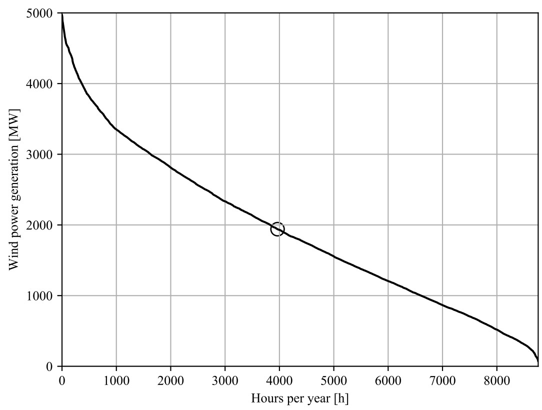

Figure 6: Duration curve of wind power production in Sweden.

From the figure it can be seen that the power production from wind is below the installed amount in the model more than 55 % of the time. Since this value can vary quite a lot depending on the hourly data that is used, attention must be paid if the value goes beyond the modeled amount. This was the case for wind power production in SE3 and SE4. Therefore the wind in this area was aggregated to the buses where the wind parks were modeled. Future work on the model should improve the implementation of the wind model. The wind turbines are modeled dynamically with the help of the GENCLS generator model. The GENCLS is a very simple model where the only input parameters were damping constant and inertia constant. The inertia value in the wind turbine dynamic model was set to zero during simulations. This caused the frequency at the wind turbine buses to become stiff. In turn this means that one should be careful about making any conclusion of the result with regard to the frequency. However, what impacts most when studying the relation between transient stability and inertia is the inertia of the independent generator. Likewise one should be careful when analyzing any dynamic result of buses with a fixed frequency.

3.2.4 Thermal power plants

The main purpose for the thermal power plants is by definition to produce heat to the residential and commercial buildings. Therefore the individual electrical power contribution by each thermal power plant is quite low. In the created model all thermal power plants are lumped together according to each area with the exception of SE3 which has two thermal power plants modelled separately. The lumped thermal power plants are placed at the following buses listed below.

Table 2: Placement of lumped thermal power plants.

	Bus
1	HAMRA.4
2	LETSI.4
3	VÄRTAN.2
4	LÅNGBJ.4
5	HURVA.4

As for the nuclear power plants, thermal power plant generators are powered by steam turbines. And with the same argument as for nuclear power plants the selected generator model was GENROU. According to [15] the exciter used for the thermal plants was IEEET2. This exciter was therefore used in this model as well. The same stabilizer was used as for the other generating units in the model, STAB1.

3.2.5 Synchronous machine data

Earlier work on grid models were studied to find approximate parameters to be used in the created model. This was the case for both the synchronous machine data and the parameters to be used in the dynamic models. The used machine reactances can be seen below in Table 3.

Table 3: Representative synchronous machine data from [7].

	Salient pole [p.u.]	Round rotor [p.u.]
X_d	1.1	2.2
X'_d	0.25	0.3
X''_d	0.2	0.2

3.3 Substations

Several grid maps could be found for the Swedish transmission grid, both an official one from the TSO, SvK and from other organizations. The one that was mainly used to create the model was the European grid map from ENTSO-E [10]. The reason for this was that the map featured a zoom function which gave a superior detail and names for the Substations for the 220 kV and 400 kV grid. The names chosen for the PSS/E model comes mainly from this map. The map was also used to find the transmission lines that connect the substations to each other. Below in Figure 7 the created model can be seen together with the transmission lines. However, the series compensation stations are not shown. The implementation of these are discussed further in chapter 3.4.1.

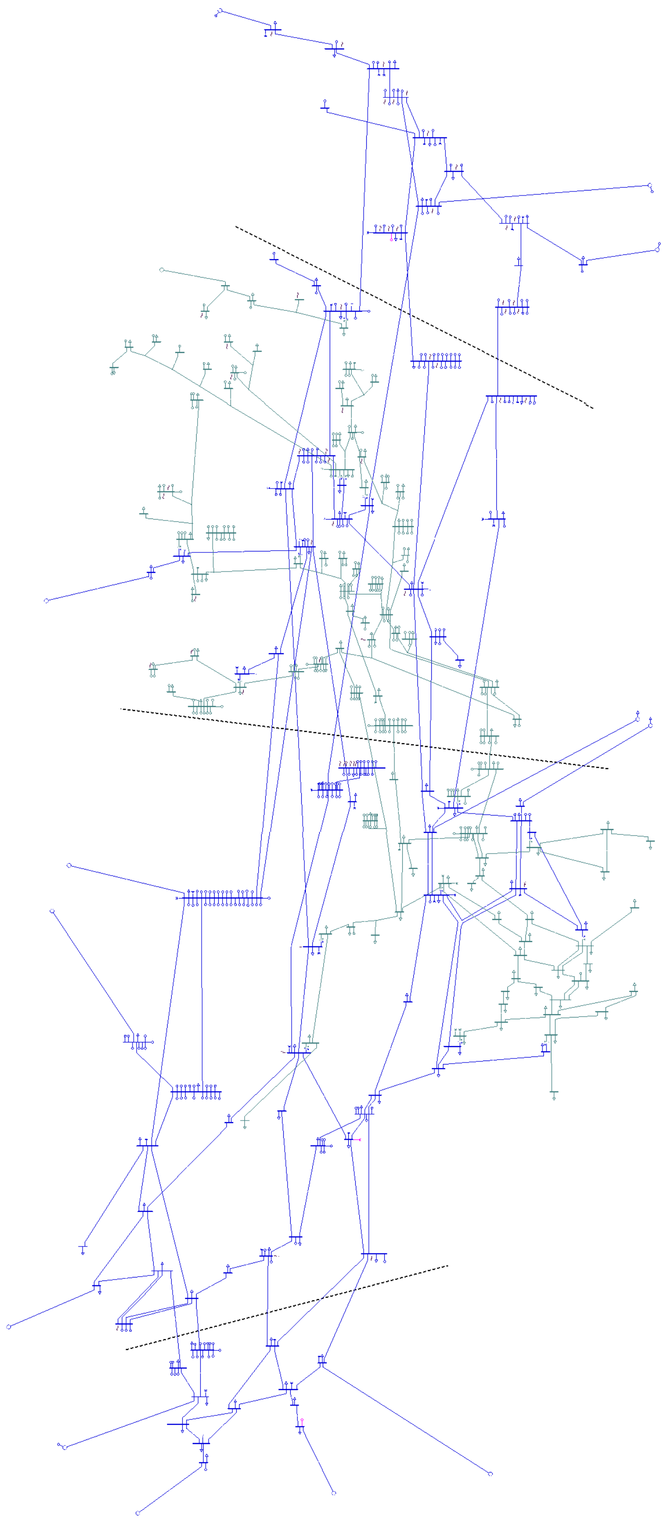

Figure 7: The slider file of the created model. Blue color indicates 400 kV and gray 220 kV.

The dashed lines in Figure 7 represent the borders between the four economical trade areas of the Swedish transmission grid. The inter-trade between these borders helped to validate the model which will be discussed later on in the report.

In the first area SE1, furthest to the north, there are three trade lines to other countries. Two are going east to Finland and one going west to Norway. In area 2, SE2, there are two lines extending into Norway one 220 kV line and one 400 kV line. In SE3, where most of the loads were situated, there are two HVDC lines going to Finland, two 400kV lines to Norway and one HVDC line to Denmark. The area furthest to the south SE4 has a 400 kV line to Denmark and one HVDC line each to Germany, Poland and Lithuania respectively.

3.3.1 Stockholm transmission grid

In the grid maps from SvK and from the other organizations, the Stockholm area was only mapped as one large bus with several connecting transmission lines. When studying aerial photos from mapping sites mentioned earlier, it was seen that this was not the case. A problem then arose since many of the transmission lines within the capital were cable connections impossible to spot on aerial photos. However, it was possible to acquire grid maps for this area since a large reconstruction of the Stockholm transmission grid are currently taken place called Stockholm Ström. From the Stockholm Ström project web page detailed grid maps featured all substations and transmission lines were given to be downloaded. The map that was used to map the Stockholm transmission grid can be found below as Figure 8[1] .

[1]Map used with explicit permission from copyright holder Svenska Kraftnät.

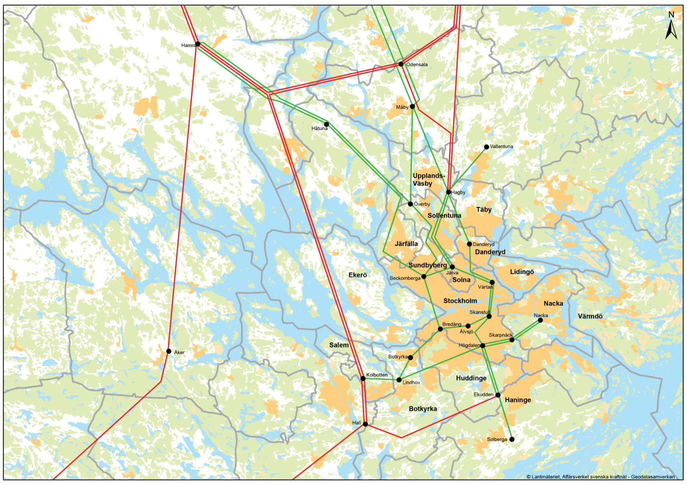

Figure 8: The transmission system of Stockholm area [4].

From the figure a detailed view can be seen of the Stockholm transmission grid with the major feeding 400 kV substations Ekudden, Kolbotten, Hagby and Hamra. The double transmission line between Hamra/Odensala to Hall/Kolbotten are used to feed the Stockholm area from the south in addition to the northern lines. The resulting slider of the Stockholm area can be seen below in figure 9.

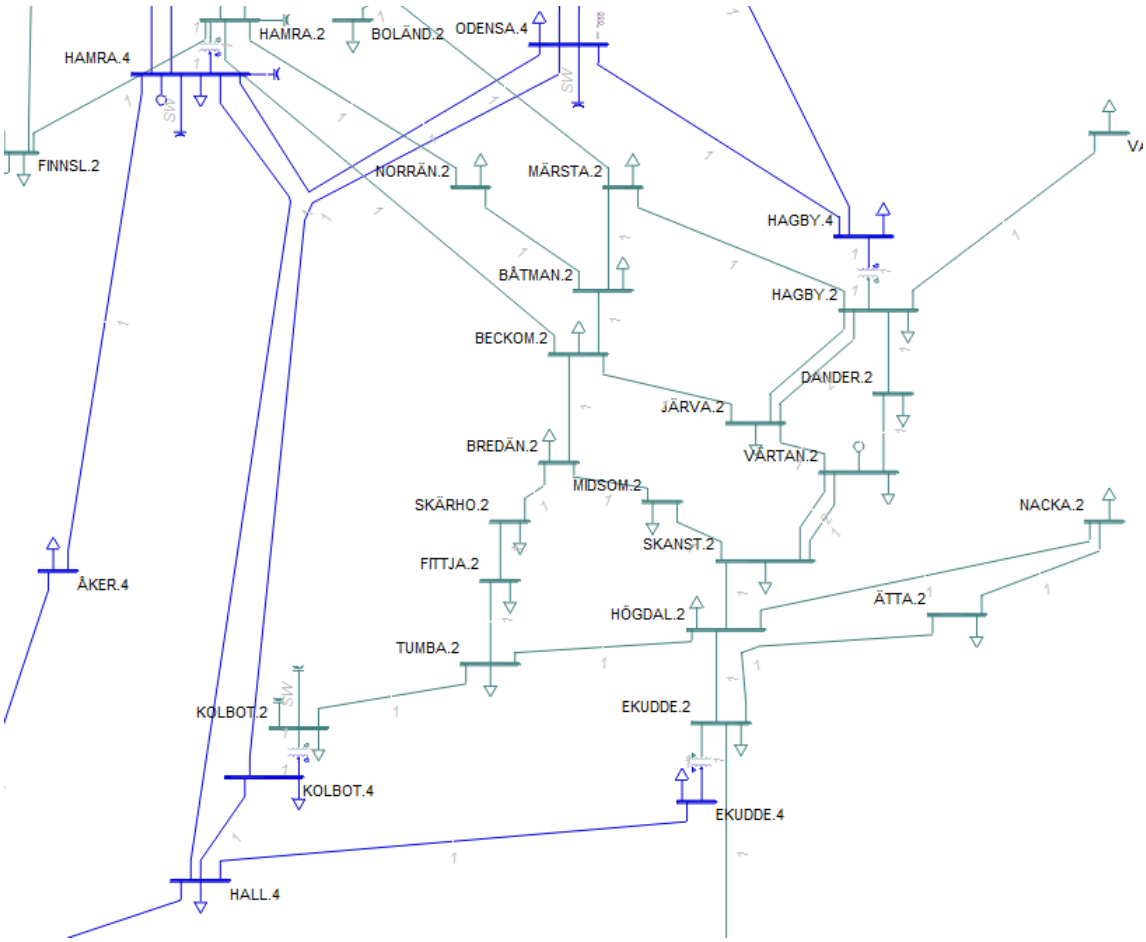

Figure 9: The created slider file of the Stockholm area.

In the figure all of the important substations can be seen represented by a bus in the slider file. By starting in the top left corner and moving clockwise the 400 kV substations in blue can be identified. The main substations, that were mentioned above, were Hamra, Odensala, Hagby, Ekudden, Hall and Kolbotten. Also the substation named Åker can be seen to the outer left of the slider.

3.3.2 Transformers

Three types of transformers should be included in the model, step-up transformers, step-down transformers and 220/400 kV transformers. However, since the loads and the generators were directly connected to the buses, the model only contains the 220/400 kV transformers. Due to the difficulty of obtaining first hand information on the transformer reactances some approximations had to be made. By studying earlier work on the Nordic 32-bus system some information regarding the parameters could be found. In [7] the step up transformers were given a reactance of 0.15 p.u., of the machine base, for the generators and the 220/400 kV transformer were given a reactance of 0.1 p.u.

In a future update of the model a move of the load to a bus behind a step down transformer with ULTC should be done. This would give a more detailed model and a step to create a model capable of simulating voltage collapse scenarios.

3.3.3 Shunt compensation

To keep the voltage at rated level shunt capacitors and reactors are installed in the transmission grid. These were also added to the model according to the list given by [16]. The list given by [16] was taken from a thesis done 2006. There are of course a possibility that there have been constructions of additional shunt components. The list do, however, contain 1190 MVAr of installed capacitors and 6405 MVAr of installed reactors.

Data added to the shunt components includes at which bus they are placed, type, reactive power and at which voltage levels the shunt is automatically connected or disconnected. The time for the shunt to connect or disconnect are also given to be used in dynamic simulations. However, the automatic switching of the reactors and capacitors were not done correctly in the model. Instead most of the reactive power consumption/production were made by the synchronous generators. This led to generators reaching the Q_{min} and Q_{max} and caused instability during the dynamic simulations. To solve this the shunts were changed to fixed shunts that were switched on and off by hand instead. This led to a decrease in the portion of reactive power control that was taken by the generators.

3.4 Transmission lines and impedance

The resistance, reactance and susceptance of the transmission lines had to be estimated. From [8] it was found that the most commonly used transmission line was the 593 mm^2 FeAl line. The 593 mm^2 FeAl line is used for both 220 kV and 400 kV. The difference, however, is that 400 kV always use a bundle of two or three conductors per phase while only a single of a bundle of two conductors per phase were used for the lower voltage levels. Resistance, reactance and susceptance in a per kilometer value was found from [8]. Data was given for single line per phase, duplex (2 lines per phase) or triplex (3 lines per phase). Triplex was only used for a few lines, mainly connecting nuclear power plants and transmission lines between area 2 and 3 where they were easily seen via maps. The values can be seen below in Table 4 displaying the impedance and susceptance for different number of lines per phase.

Table 4: Line data for transmission lines on a power base of 100 MVA [8].

	Voltage[kV]	Lines/phase	R_0[p.u./km]	X_0[p.u./km]	B_0[p.u./km]
1	220	1	0.000111364	0.00085124	0.001383
2	380	2	1.69375E-05	0.000205	0.005714
3	500	3	0.00001125	0.00018125	0.0064

To calculate the impedance of the transmission lines their lengths then had to be determined. This was done by measuring the length with the help of the map website [17]. This site was used instead of mapping software such as Google Earth since the website featured more detailed aerial photos of transmission lines and substations. The method to calculate the impedance and susceptance differs depending on the total length of the lines [11]. There are three models for calculation, short line model, medium line model and long line model. For short line model (line length below 80km) the length of a line is simply multiplied with the per unit impedance for the line type. The equation is very simple and can be seen below,

$$Z = (r + jwL)l = R + jX \tag{6}$$

where Z is the total impedance per phase, r the resistance per kilometer and phase, w the angular frequency, L the inductance per kilometer and phase, R the total resistance per phase and X the total reactance per phase. Since the values for PSS/E were set in per unit all values were divided with the impedance base, i.e.

$$Z_b = \frac{V^2}{S_b}. \tag{7}$$

The calculated impedance base for 400 kV was 1600 Ω and for 220 kV 484 Ω.

For lines longer than 80 km but shorter than 250 kilometers the medium line model was used. For medium long lines the shunt admittance had to be taken into consideration and was calculated as following,

$$Y = (g + jwC)l \tag{8}$$

Where Y was the total admittance per phase, g the shunt conductance per phase and kilometer and C the shunt capacitance per phase and kilometer. The shunt conductance was the leakage current over the insulators or can be due to corona effect and can be considered negligible. It was therefore not taken into consideration during the construction of the model [11]. The third line model was the long line model and was used for lines longer than 250 km and shorter than

500 km. For longer lines a more accurate calculation had to be made calculating the the distributed effect of the parameters [1]. The parameters were calculated with the following approximate equations given by [18].

$$R' \approx rl(1 - xbl^2/3) \tag{9}$$

$$X' \approx xl(1 - xbl^2/6) \tag{10}$$

$$B' \approx bl(1 + xbl^2/12) \tag{11}$$

$$G' \approx 0 \tag{12}$$

The total impedance of the line was calculated with the per kilometer value for each type of line which constitutes of r, x and b. The total resistance, R', reactance, X' and susceptance, B' of the line could then be calculated. For simplicity reasons it was assumed that all transmission lines were overhead lines. This is the case except for a few instances such as a cable that was drawn to a wind farm and some lines within the Stockholm area.

3.4.1 Series compensation

All of the 400 kV transmission lines between SE2 and SE3 are fitted with series compensation. These stations are placed roughly in the middle of the distance between the two connecting substations of the compensated transmission line. The purpose of series compensation is to reduce the reactive part of line impedance to increase both transient stability and maximum active power flow on the line. Due to the difficulty of obtaining first hand information, second hand source information was used. The book [19] from 1985 gives the degree of compensation for seven of the lines between area 2 and area 3. The reactance in the model was therefore compensated with the given level. However, since the eight line was constructed after 1985 the data for this was not given. Due to the degree of compensation varies between 40-60 % the eighth line compensation was approximated to 50%.

3.5 Load modeling and demand data

System loads are present at all domestic buses to represent consumption and connection to distribution grids. The power consumption was calculated on a county basis with the help of information from [20] which lists the yearly consumption for each county in Sweden. With the help of the yearly consumption for each county a percentage representation could be calculated. This percentage could in turn be used together with the hourly demand data from Nord pool to give a gross approximation of the hourly consumption for each county in Sweden. A list of the load per county are given below in Table 5 together with two different load levels. The two columns to the right show the load demand during the 90th percentile demand and the 10th percentile demand for Sweden.

Table 5: Power demand for respective county of Sweden [7] [9].

	County	Ratio	High demand [MW]	Low demand [MW]
1	Stockholms län	16%	3106.18	1824.056
2	Uppsala län	2%	442.9197	260.0977
3	Södermanlands län	3%	502.3081	294.9727
4	Östergötlands län	5%	924.525	542.913
5	Jönköpings län	3%	628.7919	369.2483
6	Kronobergs län	2%	444.2798	260.8964
7	Kalmar län	2%	396.225	232.677
8	*Gotlands län*	*1%*	*133.8884*	*78.62388*
9	Blekinge län	1%	260.8255	153.1657
10	Skåne län	10%	1887.131	1108.188
11	Hallands län	3%	629.3963	369.6032
12	Västra Götalands län	15%	2831.452	1662.726
13	Värmlands län	4%	766.0048	449.8244
14	Örebro län	3%	587.5373	345.0222
15	Västmanlands län	2%	415.2656	243.8583
16	Dalarnas län	5%	1017.461	597.4882
17	Gävleborgs län	4%	771.1427	452.8416
18	Västernorrlands län	7%	1376.965	808.6013
19	Jämtlands län	1%	251.9096	147.93
20	Västerbottens län	3%	623.3517	366.0536
21	Norrbottens län	6%	1163.59	683.3001
22	Total	100%	19161	11252

Gotland is in italic since neither the load nor the generation at Gotland is represented in the model. The per county load is then evenly distributed among the total number of substations within that county. No further refinement than this was done to the distribution of the loads in the model. To further refine the model, the loads could be shifted around within the county, e.g. moving load to buses in close proximity to larger cities, or other large consumption areas within the county.

3.5.1 Load conversion factor

The major TSOs in the Nordic system, Fingrid, Svenska Kraftnät and Statnett all use different types of load conversion when modeling the transmission grid [15]. The loads can be converted to constant current, admittance and power or a mix in between all three. SvK uses a conversion factor of 0/40/60 [15]. Which means zero percent load with constant current, 40 % constant admittance and 60 % constant power. Since the created model was for the Swedish grid it was decided to also use this load conversion factor in the model simulating dynamic scenarios.

3.5.2 Load characteristics

To correctly model the load one should account for the power factor of each type of load connected to the model. However, this would not be feasible in this model since all loads are lumped together at every bus in the modeled power system. Although assumption can be made in regard to the power factor of the load. This can be seen in [1] which lists load characteristics depending on residential, commercial and industrial loads during winter or summer. However, according to Svenska Kraftnät [21] the TSO strives to have a zero sum exchange of reactive power against the distribution grid during normal operation. Only during disruptions should the distribution grid support the transmission grid with reactive power exchange [21]. Therefore it was decided that all outgoing power to the distribution grid modeled as load where set as active power only.

3.6 Connection to the external grid

Fourteen connections to the external grid is present in the created model. Depending on the type of connection, two methods were used to set the transmitted power over the connecting lines. HVDC lines were modelled as a normal load with purely active power. Depending on if it was importing or exporting a simple change of signs where made on the load. A similar method was used to model the external AC connection. However, instead of using a fixed load a generator unit was used. Since a generating unit can have either positive power consumption or negative this pose no problem with the implementation. One external connection that was not modelled was the 220kV connection between Kalix and Ossauskoski. The reason for this was that there are no 220 or 400 kV connection to Kalix within Sweden. The connection between Kalix and the rest of the Swedish national grid is instead connected via lower voltage levels, e.g. 130kV which was outside of the project scope. To add the transmission line a grid had to either be modelled for the northern Finland, connect Kalix via lower than 220 kV within Sweden or model it as an island with a second swing bus. A list of the external connections can be seen in Table 6 below. Lines in italic are not added in the model.

Table 6: Transmission lines between Sweden and other countries in the Nordic synchronous power system [10].

	Connecting bus	Voltage level	Country
1	Vietas - Ofoten	400 kV	Norway
2	Gejmån - Rössoga	220 kV	Norway
3	Högåsen - Nea	400 kV	Norway
4	*Lutufallet - Höljes*	*132- 150 kV*	*Norway*
5	*Charlottenberg - Skotterud*	*132 - 150 kV*	*Norway*
6	Borgvik - Hasle	400 kV	Norway
7	Loviseholm - Halden	400 kV	Norway
8	Lindome - Vester Hassing	DC - Link	Denmark
9	Söderåsen - Görlösegård	400 kV	Denmark
10	Kruseberg - Herrenwyk	DC - Link	Germany
11	*Borryby - Bornholm*	*132 - 150 kV*	*Denmark*
12	Stärnö - Słupsk Wierzbięcino	DC - Link	Poland
13	Nybro - Klaipèda	DC - Link	Lithuania
14	*Senneby - Tingsbacka*	*132 - 150 kV*	*Åland (Finland)*
15	Dannebo - Rauma	DC - Link	Finland
16	Finnböle - Rauma	DC - Link	Finland
17	*Kalix - Ossauskoski*	*220 kV*	*Finland*
18	Djuptjärn - Keminmaa	400 kV	Finland
19	Letsi - Petäjäskoski	400 kV	Finland

As can be seen a few of the lines were not added. The reason for this was simply that the voltage level were too low and not part of the 220-400kV transmission system.

It was decided not to use the PSS/E model for HVDC lines due to the limited impact they would have on the load flow and transient studies. They do pose an impact during frequency studies where they help to inject emergency power to the system during large frequency drops. This is, however, a future work to be completed.

3.7 Total system inertia

Finding the system inertia on an hourly basis became a complicated process since this information was not made available in public sources. The data came from crude graphs displaying the kinetic energy in the system over a longer period of time. Data was extracted for the dates that were of interest during the load flow analysis, one high demand case in February and one low demand during June. From the report Future System Inertia [22] it was given that the amount of kinetic energy in the system could be approximated by monitoring the generator circuit breaker position [22]. If the breaker is closed then the generator is assumed to be in operation and contributing to the total system kinetic energy [22]. The total system kinetic energy can then be calculated with the following equation according to [22],

$$E_{k,sys} = S_{n,sys} H_{sys} = \sum_{i=1}^{N} S_{ni} H_i. \tag{13}$$

The total system kinetic energy in this equation is denoted as $E_{k,sys}$ in MWs where S_{ni} is the base of the generator and H_i the specific generator inertia constant. From Figure 4.8 and 4.9 in [22] an estimation of the kinetic energy was made and approximated to 240 GWs during high demand and 150 GWs during low demand.

Equation (13) was used to estimate the total kinetic energy of the model due to the generators implemented in the model. According to [23] a rule of thumb is that for every 1000 MW of installed generators corresponds to following inertia in Table 7 below[2].

Table 7: Recommended inertia constant from SvK and how much inertia it represents for 1000 MW installed capacity.

	H[s]	Kinetic energy[GWs]
Hydro	3.4	3.4
Nuclear	6.4	6.4
Wind	0	0
Thermal	2.8	2.8
Synchronous condenser	5	5

3.7.1 Inertia in Sweden

With this data the inertia in the model could be modeled to fit the two measured levels that were decided earlier. The method to adjust the inertia level of the system was to set generators in and out of service. The main focus was to keep the production of each unit above 80 % to model a realistic scenario. The resulting kinetic energy can be seen in Table 8 below.

[2] Due to using an inertia value of 0 in the dynamic model the wind generation buses became frequency stiff.

Table 8: Measured and simulated kinetic energy in the model for Sweden.

	Measured [GWs]	Simulated [GWs]
High load case	91.2	96.4
Low load case	57	52.2

As can be seen from Table 8 above, there was a slight deviation in the measured and simulated system inertia. The impact of the system inertia can be seen in chapter 5 on how it affects the transient stability of the system.

3.7.2 Inertia of Nordic system

By studying the data given in [22], a rough estimate could be done on how the total system kinetic energy in the Nordic system was distributed. From the graph the distribution between the countries Sweden, Denmark, Finland and Norway could be decided. The result between the countries can be seen below in Table 9.

Table 9: Distribution of kinetic energy in the Nordic countries.

	Ratio [%]
Sweden	38
Denmark	4.3
Finland	22
Norway	35

These values are represented in the model by varying the M_{base} of the equivalent AC generators that represent the connecting countries to Sweden. The specific inertia was adjusted depending on the type of case that was run, e.g. high load or low load flow case.

4 Load flow and load flow validation

The only way to verify the created model was to compare calculated results with historical data that was publicly available. Available data that can be seen includes power flow between areas, export/import between Sweden and neighbouring countries as well as consumption and production for each area. The total produced power for each production source can also be found on an hourly basis. To control the amount of inertia in the system several units were disconnected during both of the cases. This was also necessary to avoid having the generators run on a very low power output in comparison to their maximum output.

4.1 Historical data

It was decided that the model should be tested for two cases. The first one being when the load is at the 10% load duration level and the second one at the 90% level. The load level for the entire year of 2015 can be seen below. On the y-axis the current load can be seen and x-axis shows the hour of the year.

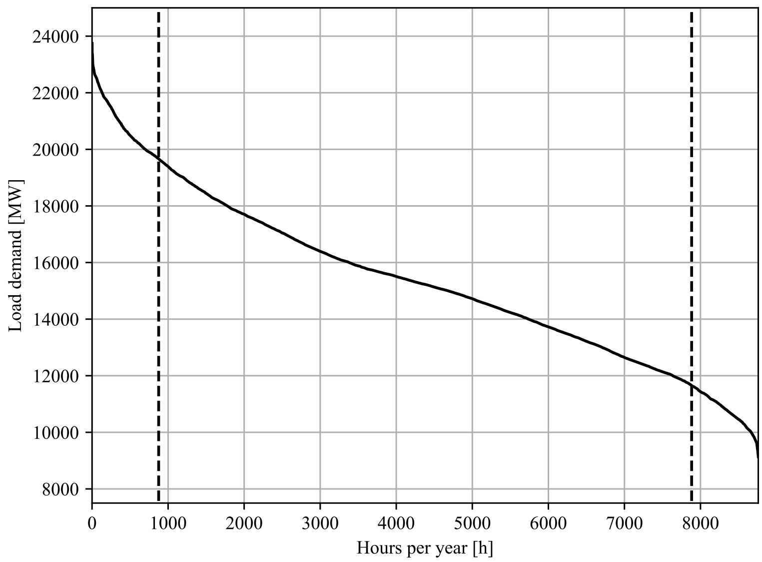

Figure 10: Load duration curve for the year of 2015 in Sweden.

As can be seen in the figure above, the load varies between approximately 25 000 MW and 9000 MW over the length of the year. The 10 % load duration level can be extracted from the data to around 11700 MW and the 90 % load duration level to 19700 MW. This gives two different time instants for a high load case on 14th of February, a Saturday, between 17:00-18:00 and a low load case between 21:00-22:00 the third of July, a Friday.

4.1.1 Low demand case

Below in Table 10 the results can be seen for the low demand case with a total consumption of 11623 MW including losses and a total production of 16526 MW. The difference between these values constitutes the export to other countries. The left column gives the type of data that was compared, the center column the actual data and the right column the result from the load flow calculation. The entered data were given from Svenska Kraftnät and Nord Spot. Parameters entered was power demand for each area and power generation from respective source to respective area. As mentioned earlier in the report, only hydro, thermal, wind and nuclear power were modeled. Two results are presented for each case. The first shows the result before any corrections and the second with corrections made to the model. A negative power flow gives that the flow of power is southbound while a positive values gives that it flows northbound.

Table 10: Low demand result before load correction.

		Actual	Calculated	ΔP
Inter-area trade	SE1-SE2	443	161	-63.66%
	SE2-SE3	-4159	-3862	-7.14%
	SE3-SE4	-3946	-3953	0.18%
Production	SE1	1429	1429	0.00%
	SE2	5931	5826	-1.77%
	SE3	8525	8525	0.00%
	SE4	473	473	0.00%
Demand	SE1	1023	741	-27.57%
	SE2	1252	1875	49.76%
	SE3	7307	6968	-4.64%
	SE4	2070	1994	-3.67%

As can be seen from Table 10, the flow between SE1-SE2 and SE2-SE3 was to low. This was most likely due to the fact that the distribution of load was done county wise in the model. The economic areas are not done with consideration to county borders which means that some counties can have multiple economic areas within its borders. Therefore some scaling had to be made in the model. In this case shifting of load distribution in SE2 to SE1 and SE3. This would increase the flow on power out from SE2 to these areas. The result after rescaling loads between the economic areas can be seen in Table 11 below.

Table 11: Low demand result after load correction.

		Actual	Calculated	ΔP
Inter-area trade	SE1-SE2	443	444	0.23%
	SE2-SE3	-4159	-4256	2.33%
	SE3-SE4	-3946	-4037	2.31%
Production	SE1	1429	1429	0.00%
	SE2	5931	5945	0.24%
	SE3	8525	8525	0.00%
	SE4	473	473	0.00%
Demand	SE1	1023	1024	0.10%
	SE2	1252	1265	1.04%
	SE3	7307	7330	0.31%
	SE4	2070	2078	0.39%

Generation and demand deviation from actual values were at 2% or below. From the result it can be seen that the model follows a good correlation with the actual values given from the measured data. Due to the slack bus, STORFI.4, ended up on a negative value, numerically correct but realistically not so since it was bus with generators, a small correction was made. By reducing the total hydro power generation in SE2 the generation from the slack bus was increased by the same amount. In total a zero-sum power shift takes places that did not change demand, generation or inter-area power flow. The total production broken down into area and type can be seen in Table 12.

Table 12: Production per type and area during low demand.

Type	Area	Production [MW]
Hydro	SE1	1301
	SE2	5110
	SE3	1112
	SE4	78
Wind	SE1	123
	SE2	802
	SE3	592
	SE4	329
Nuclear	SE3	6611
Thermal	SE1	5
	SE2	20
	SE3	209
	SE4	66

4.1.2 High demand case

For the high demand case the total consumption was approximately 19688 MW including transmission losses. The demand is supplied by a generation of 21063 MW exporting the surplus to neighbouring countries. The result from the high demand simulation can be seen below in Table 13.

Table 13: Result before shifting of load.

		Actual	Calculated	ΔP
Inter-area trade	SE1-SE2	-314	-424	35.03%
	SE2-SE3	-4033	-3231	-19.89%
	SE3-SE4	-3420	-3268	-4.44%
Production	SE1	3142	3142	0.00%
	SE2	6423	6377	-0.72%
	SE3	10361	10361	0.00%
	SE4	1138	1138	0.00%
Demand	SE1	1410	1260	-10.64%
	SE2	2395	3159	31.90%
	SE3	12341	11787	-4.49%
	SE4	3452	3293	-4.61%

Similar to the low load demand case the load flow deviated quite much without any scaling done in the model. For the high load case the power demand was too high in the SE2 area and too low in the other three economic areas. This was solved by shifting load demand from SE2 to the other areas, the same as was done for the low demand case. The result after shifting around the power demand between the economic areas can be seen below in Table 14.

Table 14: Result after shifting of load.

		Actual	Calculated	ΔP
Inter-area trade	SE1-SE2	-314	-273	-13.06%
	SE2-SE3	-4033	-3967	-1.64%
	SE3-SE4	-3420	-3424	0.12%
Production	SE1	3142	3142	0.00%
	SE2	6423	6518	1.48%
	SE3	10361	10361	0.00%
	SE4	1138	1138	0.00%
Demand	SE1	1410	1411	0.07%
	SE2	2395	2415	0.84%
	SE3	12341	12367	0.21%
	SE4	3452	3449	-0.09%

As can be seen from Table 14 above the production and demand deviation from actual results were fairly good. The power trade deviation between SE1 and SE2 stands out due to the low amount of power being transferred. The shifting of load also led to a better result of the inter-area trade between the economic areas. The result from the scaling did cause the slack bus to reach a negative value. This was solved by reducing the total hydro power generation in SE2 of all sources. This causes the swing bus generation sources to compensate for this reduction by increasing the slack bus generation to a positive value. In total a zero-sum power shifting took place that did not change the total generation, consumption and inter-area load flow. The total production per type and area can be seen for the high demand case in Table 15.

Table 15: Production per type and area during high demand.

Type	Area	Production [MW]
Hydro	SE1	2964
	SE2	6063
	SE3	1839
	SE4	300
Wind	SE1	137
	SE2	210
	SE3	250
	SE4	244
Nuclear	SE3	7355
Thermal	SE1	42
	SE2	150
	SE3	918
	SE4	595

5 Transient stability studies

Several simulations were done to study the transient response of the generators connected to the transmission grid in the model. Two different load flow cases were used, the same cases that were discussed under the chapter Static load flow and validation. However, most of the simulations were performed on the high load flow case. The type of contingencies that were tested will be found below. Through out the testing most of the simulations were done on the bus NÄMFOR.2 in SE3 and the surrounding transmission lines. The reason why this bus was chosen is the meshed transmission that the bus is connected to. This gave a possibility to switch transmission lines in close vicinity to the bus without islanding the bus.

5.1 The contingencies

Three types of contingencies will be tested on the model and NÄMFOR.2 will be used as the example bus to show the three contingencies. The bus has three generating units of equal size and one connecting transmission line to tap point NÄMFOR.P. The single line diagram of the bus can be seen below.

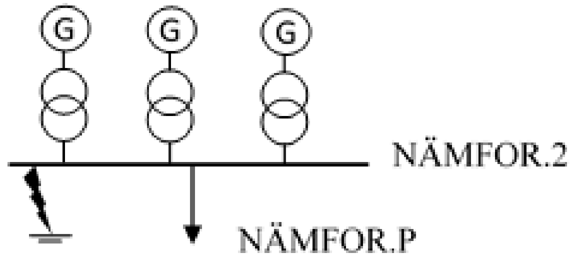

Figure 11: SLD of NÄMFOR.2 bus.

The first one being a fault that occurs on the generator bus reducing its capability of transferring power. A typical fault scenario can be seen in Table 16 below.

Table 16: Fault on bus.

Time [seconds]	Event
0	Start of Simulation
1	Fault applied at NÄMFOR.2
1.25	Fault cleared
5	End of simulation

The second being a fault applied to a connecting transmission line connected to the tap point of the generator bus. The fault on the transmission was isolated after certain time leading to it being taken out of service.

Table 17: Fault on transmission line.

Time [seconds]	Event
0	Start of Simulation
1	Fault applied on transmission line between NÄMFOR.P and LASELE.2
1.25	Faulted line is taken out of service
5	End of simulation

The third and last type of contingency that was performed was a combination of the first two studies. A fault occurs on one of the transmission lines connected to the bus where the machine of interest is connected to. The fault was assumed to be very close to the substation so the fault was applied to the bus in PSS/E, similar to the fault explained in [1]. As for the previous cases the fault was a bolted fault with zero impedance. The fault scenario can be seen in Table 18 below.

Table 18: Fault on line close to bus.

Time [seconds]	Event
0	Start of Simulation
1	Fault applied at bus NÄMFOR.P
1.25	Fault cleared and trip transmission line between NÄMFOR.P and LASELE.2
5	End of simulation

5.1.1 Reference case I: Bus fault

The first simulation was done on both the low load case and the high load case and will pose as a reference case to have something to compare to. A bolted fault was applied on the bus and the critical fault clearing time was studied for both cases. The bus of interest was NÄMFOR.2[3] situated in northern Sweden with a nominal voltage level of 220 kV. The hydro power plant feeds the bus with the help of three generating units with a installed capacity of 38 MW each, 114 MW in total for the entire hydro plant.

[3]The bus was named after the hydro power plant Nämforsen which lies in the lower part of the river Ångermanälven, close to Sollefteå.

The loading of the generator on the bus was 92 % of maximum generator active power output during the simulation. The relative angle of the machine on the bus can be seen in the figure below. The three curves corresponds to 200 ms, 256 ms and 257 ms fault clearing time.

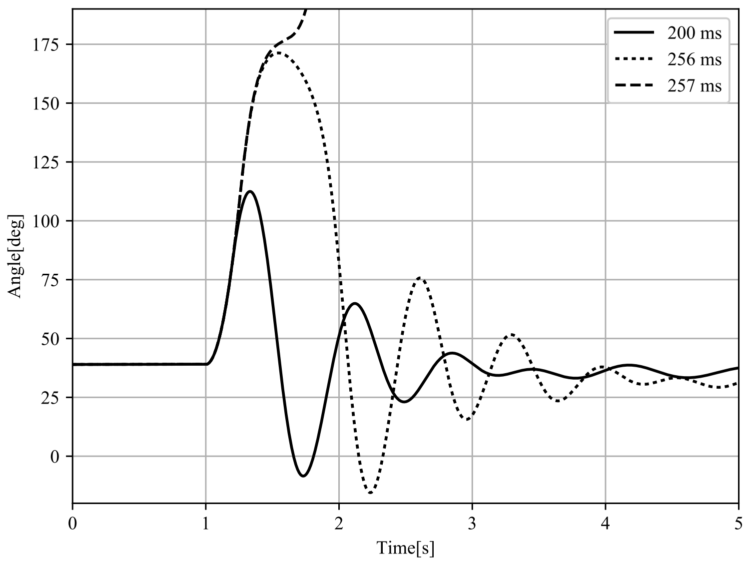

Figure 12: Oscillations in the machine angle after bus fault during the high demand scenario.

The critical fault clearing time for this setup was found to be 256 ms. Any fault clearing time above this caused any of the generators connected to the bus to lose synchronization to the grid. The unstable case can be seen in the figure above as the dashed line in the graph. A reference case was also done for low load demand and the result can be seen below. The difference between these cases was that one of the generators was shut down on the bus to keep the loading level per generator to a reasonable operating level above 80 %. The fault times simulated were 200ms, 246ms and 247ms.

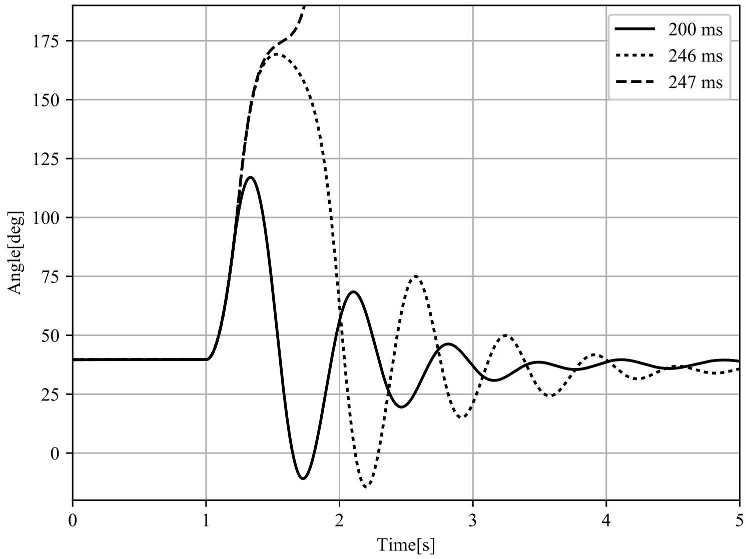

Figure 13: Oscillations in the machine angle after bus fault during the low demand scenario.

As can be seen from the graph the highest fault clearing time to maintain synchronization was 246 ms since loss of synchronization occurred at 247 ms. It can be concluded from these two reference cases that the difference between the cases were close to non-existent. The critical fault clearing time for the low load flow case was 10 ms lower than for the high load flow case. However, it should be noted that generators in the low load flow case had a higher loading than the high load case, a difference of 1.9 MW. This can have a big impact on the transient stability, which will be discussed later in the report.

5.1.2 Reference case II: Fault on transmission line.

The second reference case followed the scenario explained in Table 18 where a fault was applied to a connecting transmission line. Again the bus of interest was NÄMFOR.2 where the generators were studied. The line that had a fault applied was one of the lines connecting to the power station line tap point, NÄMFOR.P, as can be seen in the figure below.

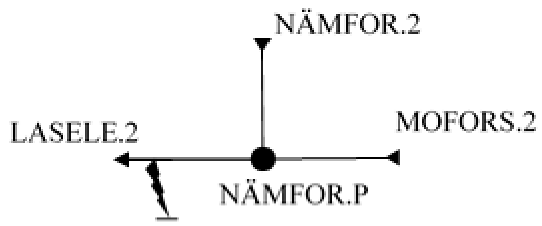

Figure 14: Single line diagram displaying the transmission lines between hydro power station at Nämforsen and rest of the system.

Pre-fault the power flow was directed to the left in the picture, going from NÄMFOR.2 and MOFORS.P to LASELE.2. Due to the outage of the transmission line between LASELE.2 and NÄMFOR.P the direction instead changes to MOFORS.P. This would in theory reduce the angle at the bus LASELE.2 and increase the angle at NÄMFOR.2. This can be seen from (1) where a reduction of P_e leads to a reduction in δ.

The transient response for the generators at Nämforsen, solid, and Lasele, dashed, can be seen below in figure 15. Figure 16 shows the voltage drop at NÄMFOR.2 due to the faulted transmission line.

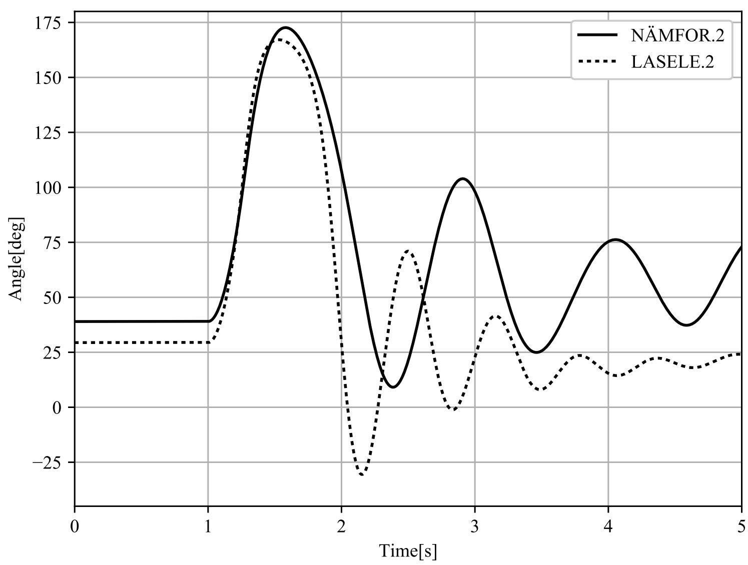

Figure 15: Response in the machine angle at Lasele, dashed, and Nämforsen during fault on transmission line.

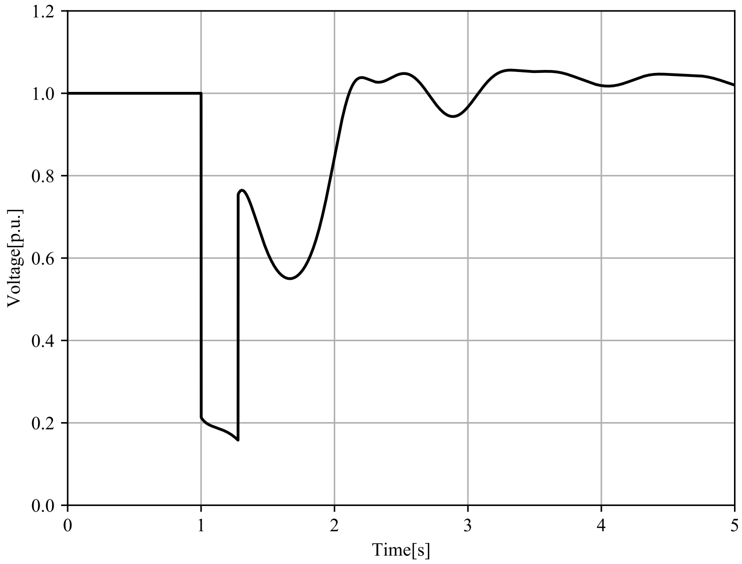

Figure 16: Voltage drop at bus NÄMFOR.2 due to faulted transmission line.

As expected the angle at bus LASELE.2 dropped slightly while the angle at bus NÄMFOR.2 increased. The reason why the angle increases in the beginning for Lasele was due to the generators connected at that station. The voltage at bus NÄMFOR.2 dropped to around 0.2 p.u. on a 220 kV base when one of the connecting transmission lines suffered a bolted fault. The reason for the second voltage drop after the fault was cleared was the angle separation between the generator and the infinite bus. The high load angle of the machine gave a large reactive power output from the machine. This leads to a larger voltage drop over the source impedance and the step-up transformer impedance due to the increased current. The critical fault clearing time for the generators were around 283 ms. However, this caused the generator at LASELE.2 to lose synchronization so the time had to be reduced. With a fault clearing time of 277 ms the generator kept synchronization at both Lasele and Nämforsen power station.

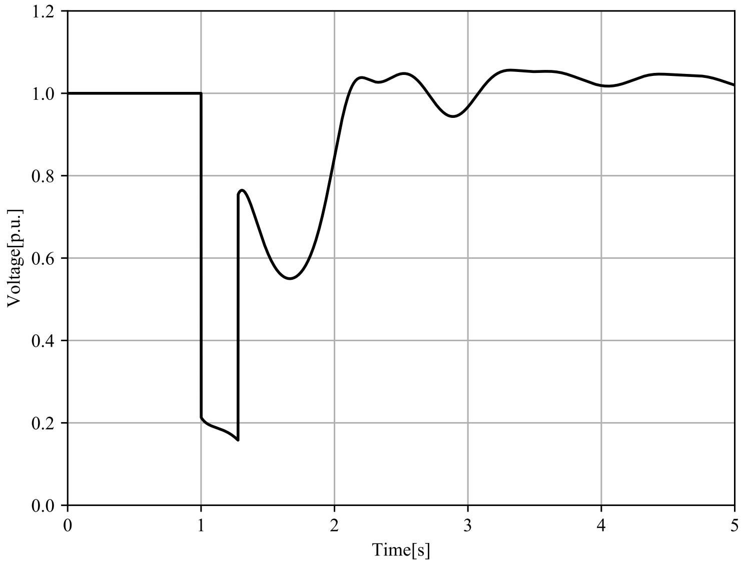

Figure 17: Voltage drop at bus NÄMFOR.2 due to faulted transmission line.

5.1.3 Reference case III: Fault on bus to tripping of transmission line.

The third reference case followed the scenario as of Table 18. This gave a more realistic example with a bus fault leading to a change in system reactance post fault. This differed from the other bus fault where the grid returned to a normal state after the fault was cleared. A 3-phase bolted fault was applied to the NÄMFOR.P bus, the fault was then cleared by tripping one of the connecting transmission lines. The result can be seen below in Figure 18.

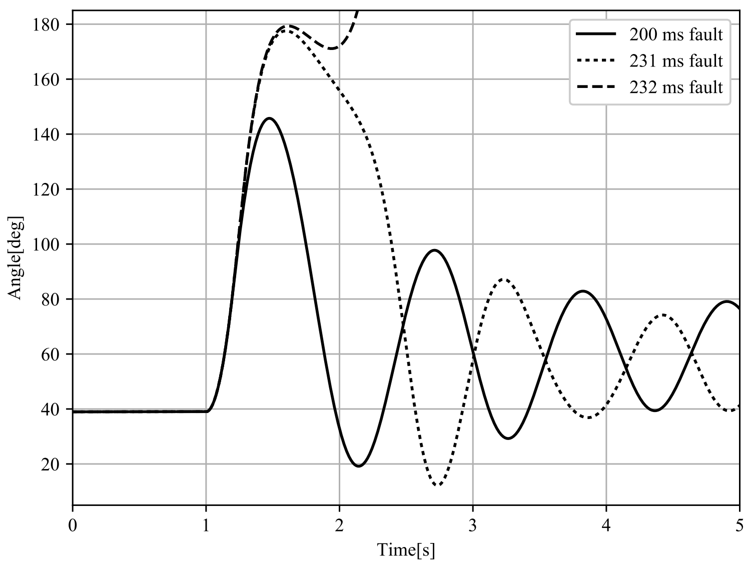

Figure 18: Response in the machine angle at different fault clearing times.

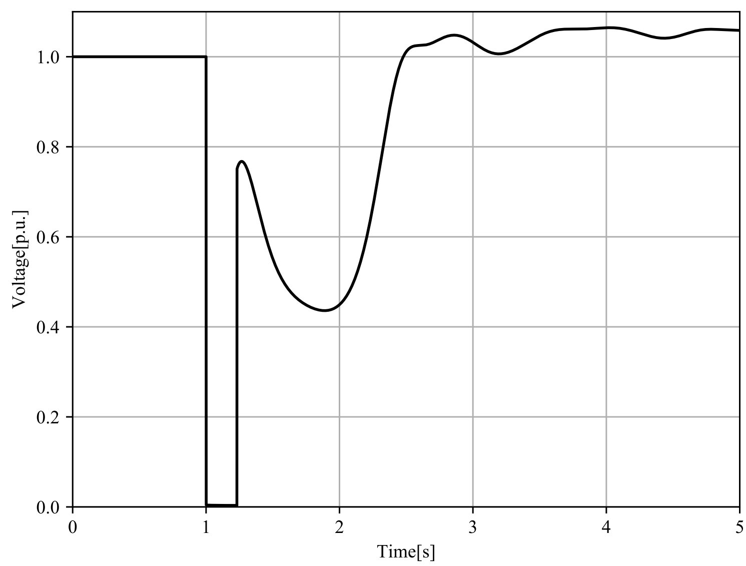

Figure 19: Voltage drop at bus NÄMFOR.2 due to a bolted 231 ms fault.

The critical fault clearing time was found to be 231 ms. This time was lower than the time found in the first reference case which was 256 ms. The reason for this might be due to the higher system reactance post fault since one of the connecting transmission lines are taken out of service due to the fault. The voltage shown in Figure 19 was measured on the generator bus NÄMFOR.2. The voltage drops to zero p.u. even though the fault was applied on the tap point. This since the distance was fairly short, slightly above a kilometer. After the fault was cleared the voltage rises back to around 0.8 p.u.. The voltage then suffers a dip down to slightly above 0.4 before rising back to 1 p.u. again after 1.1 second.

5.2 Impact of AVR on transient stability

As mentioned earlier in the report one of the improvements that can be done to the transient stability is by using fast automatic voltage control(AVR) [1]. The generators at NÄMFOR.2 were simulated both with and without AVR. The contingency is a bolted fault on the bus during a time period of 256 ms. The left figure of Fig.20 displays the voltage at the generator terminal during the fault with and without automatic voltage control. The right figure shows the response in field voltage with and without an AVR.

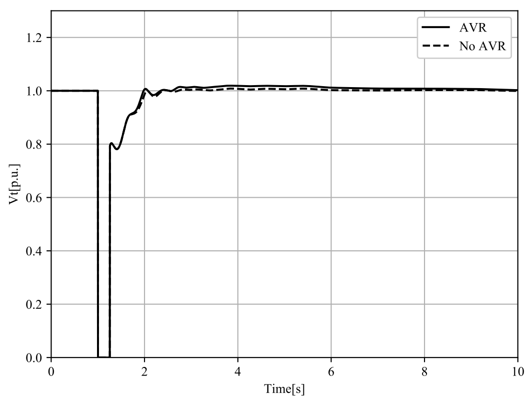

Figure 20: Voltage at bus with and without AVR.

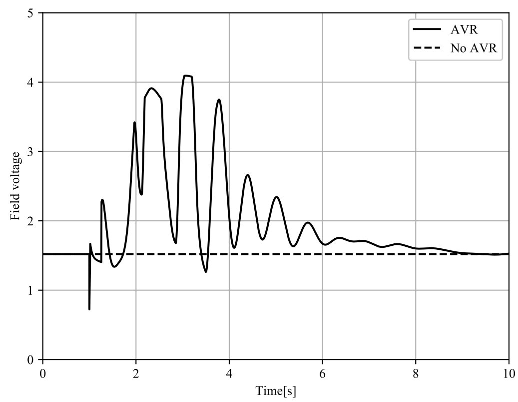

Figure 21: Response in field voltage due to use of AVR.

As can be seen from the two figures the difference between the two terminal voltages were negligible. They both settle at 1 p.u. after 20 seconds. The same result was found when simulating the critical fault clearing time. For both with and with out AVR the time was found to be the same 256 ms. A reason for this might be that the parameter settings for the exciters were not individually tuned for each generating unit resulting in a non optimal setting. For example the time response of the exciter function was too slow to act during transient faults. For a more correct model representing the real system, time should be spent on tuning the exciter parameters for each unit.

This becomes more evident if the fault is prolonged giving time for the exciter to react. Below a simulation can be seen where the fault clearing time was extended to 10 seconds. This is of course not realistic since the fault clearing time is usually much lower, but helps to show a difference. Governors would start to have an impact to a fault of this length, something that was not implemented in the model. To keep the generators from falling out of phase the fault impedance was increased to leave the voltage of the bus on a higher level.

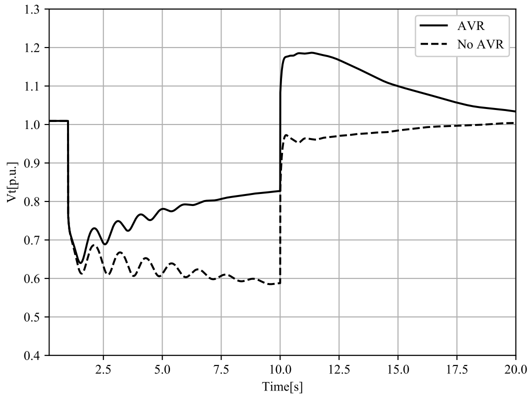

Figure 22: Voltage at generator terminal with and without AVR.

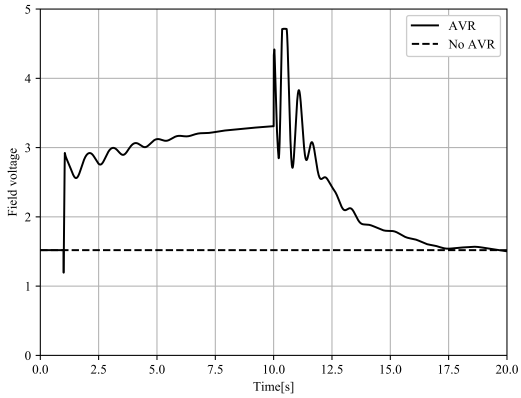

Figure 23: Response in field voltage due to use of AVR.

The left graph shows the terminal voltage of the generator with and without AVR. The right shows the difference in field voltage for the two cases. Here it became clear that the reason for the slow response did not belong to the exciter model. It can clearly be seen that the exciter reacted fast to the fault by stepping up the field voltage. Interestingly it was the generator that did not react quickly enough despite with the help of a higher field voltage. This gives that the non-optimal setting in the model lies within the generator, in this case GENSAL. Below the difference in machine angle can be seen for a prolonged fault with high impedance with and without AVR.

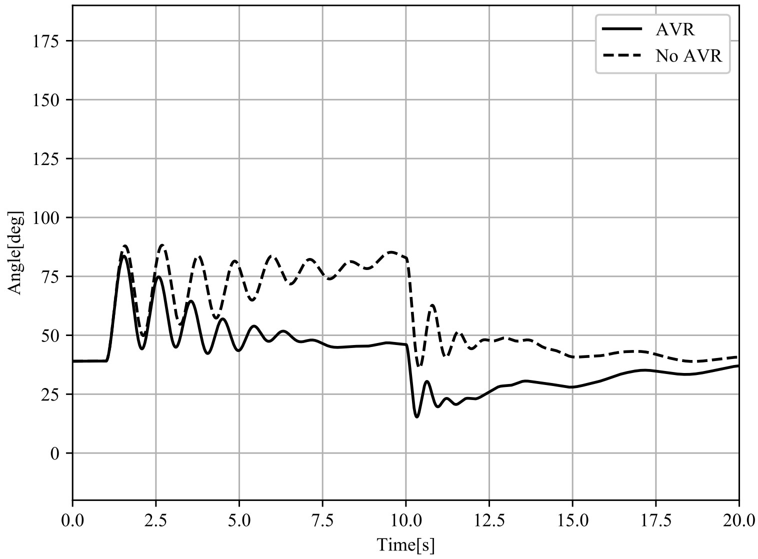

Figure 24: Machine angle during fault with and without AVR.

Here it can clearly be seen that the AVR assisted in the transient stability by keeping the angle down during the fault. This is done by increasing the field voltage with the help of the exciter. This in turn leads to a increase of the internal voltage which then increases the maximum active power transfer [1]. However, in this case the fault impedance was high enough so the generator was able to stay synchronous during the fault even without the addition of a AVR.

5.3 Varying reactive power production pre-fault

The reactive power output of a generator can be varied by stepping the voltage reference of the AVR for each respective unit. To see how a change of reactive power output could affect the transient stability of a generator this was done to the three generators connected at NÄMFOR.2. The voltage was stepped at the beginning of the simulation and was then allowed to reach the desired level for 10 seconds. A bolted fault was then applied to the bus to find the critical fault clearing time. In the first simulation the voltage was stepped up to approximately 1.05 p.u. This in turn caused the reactive power output to increase to level higher than normal for the generator. The critical fault clearing time was then found to have increased to 268ms which was an increase with 12 ms. However, a reduction of reactive power production led to a decrease in the critical fault clearing time. By reducing the terminal voltage for the machine down to approximately 0.95 led to a critical FCT of 233 ms. This was a reduction of 23 ms compared to reference case I. Below in Figure 25 and Figure 26 the result from a simulation can be seen with a 200 ms bus fault.

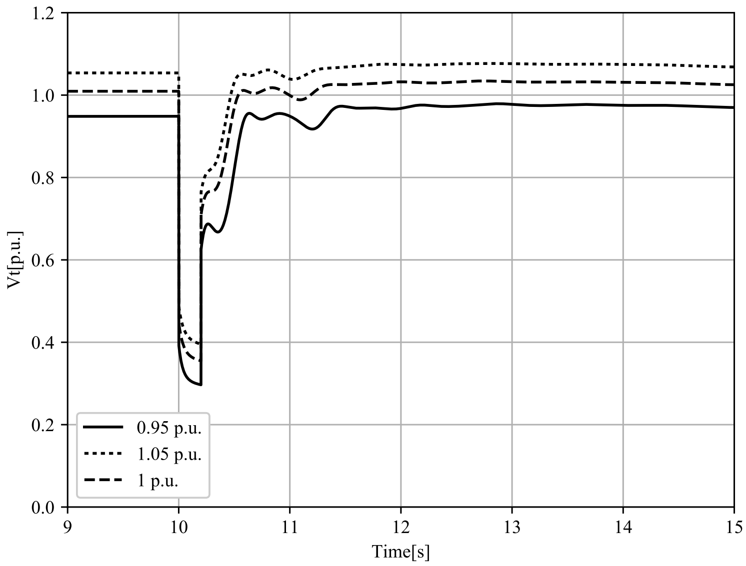

Figure 25: Terminal voltage during fault with and without AVR.

The difference between three different voltage settings of 0.95 p.u. , 1 p.u. and 1.05 p.u. reference voltage on the generator terminal. From Figure 25 it can be seen that the pre-fault voltage has a direct impact on the lowest voltage that the generator are exposed to.

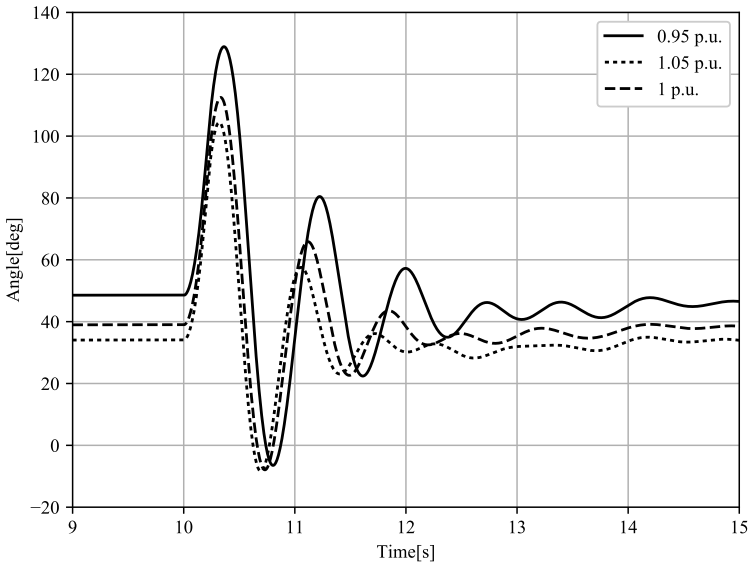

Figure 26: Machine angle during fault with and without AVR.

The highest angle was reached by the lowest pre-fault voltage setting. This was expected, since it follows by theory that a higher voltage on the sending bus increases the maximum active power transfer according to (1). An increase in electric power output reduces in turn the transmission angle before the fault, which given more margin when a fault occurs. Furthermore, a higher pre-fault terminal voltage indicates a higher back-emf of the generator. During the fault, the generator has a higher fault current that can keep the terminal voltage higher. This also slows down the rotor acceleration. Consequently, the corresponding critical fault clearing time can be increased if the pre-fault voltage is higher. The relation between angle acceleration and electrical power output is given by the following equation,

$$\frac{d^2\delta}{dt^2} = \frac{\omega}{2H}(P_m - P_e), \tag{14}$$

where δ is the angle, ω the angular frequency, H the inertia, P_m the mechanical power and P_e the electrical output power [24]. It is hard to draw any form of conclusion of this considering that the change in critical fault clearing time might as well be due to the change of the bus voltage.

5.4 Impact of active power production

From the theory chapter regarding transient stability it could be seen that there was a strong correlation between the level of P_{mech} and the ability of a generator to maintain synchronization. With a too high level of active power production the machine will not have enough room to brake which will cause instability. This was tested in the model by regulating the level of active power produced by the machine and comparing the critical fault clearing time between the cases. The same fault as in the reference case was used, i.e. a bolted fault on the bus connecting the generators with the grid. The same bus, i.e. NÄMFOR.2 was used as for the reference cases. The values that are plotted and shown in Table 19 are all from the machine denoted as "1" out of three units in total. All units had the same result when it came to the relative angle since all units were of the same type and had the same load level.

The results are represented by finding the critical fault clearing time for specific load levels of the generator. The load level of the generator was stepped from 20 MW, close to half of the installed capacity, up to 37.9 with increments of 5 MW. The level 37.9 MW was chosen instead of 38 MW due to problems with generating units operating at the max level. The reason for this was that the initial conditions were not calculated correctly.

Table 19: Change in critical fault clearing time with increasing load level.

Load level of generator [MW]	Critical fault clearing time [ms]
20	382
25	330
30	297
35	256
37.9	238

The result of simulating with the critical fault clearing time can be seen in Figure 27. It could be seen that the steady state angle follows the load level of the machine which was discussed during the theory chapter. Higher loading of the generator gave less margin for a fault. If the generator only had a loading close to half of the maximum value it had a much larger ability to sustain prolonged faults since it started on a lower angle.

When the power production was close to the maximum capacity the generators were no longer able to comply with the grid code for production units stated earlier in the the report. According to the requirements the generating unit should be able to remain connected during a bolted fault over 250 ms.

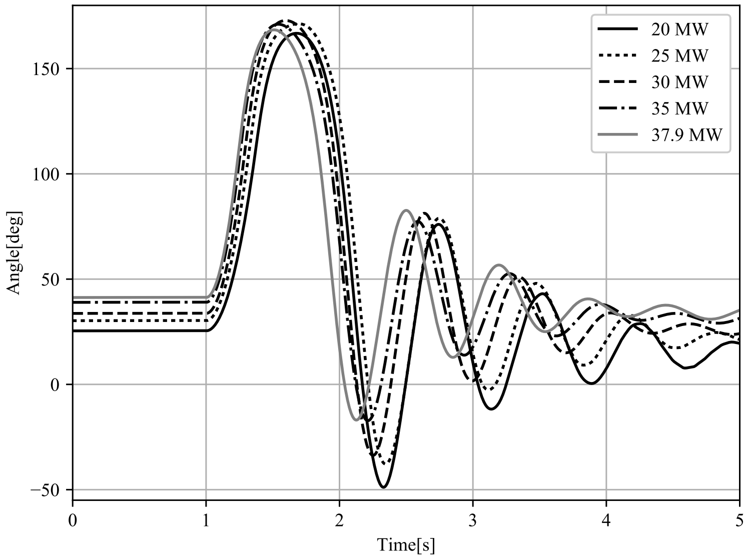

Figure 27: The critical fault clearing time with different load levels and the response in the angle.

5.5 Impact of varying inertia constant

The inertia constant poses a great impact of the transient response of the generator. The higher inertia constant the less is the risk of the generator to lose synchronization with the grid. This can be seen from the swing equation,

$$\frac{d^2\delta}{dt^2} = \frac{w_0}{2H}(P_m - P_{max} sin\delta), \tag{15}$$

where a lower inertia constant increases the rate of change of angle and the other way around. The result of varying inertia constant in the simulation can be seen below. The simulation was run in a similar way as for the varying load simulation. However, this time the P_{gen} was fixed but the inertia value was changed instead.

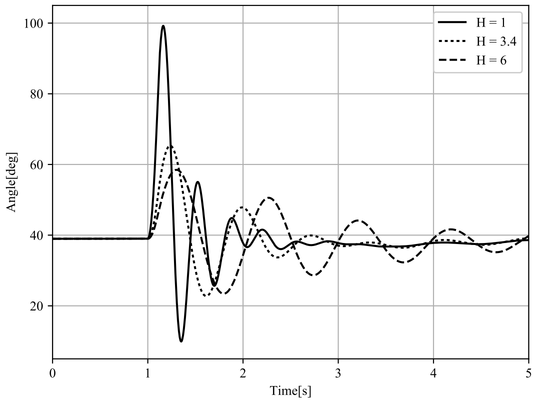

Figure 28: Response in angle with different values of inertia.

Inertia [MWs/MVA]	Time [ms]
H = 1	142
H = 3.4	256
H = 6	318

Table 20: Critical fault clearing time with different values of inertia.

According to (15), it can be seen that the angular response is higher with a lower inertia. In the same way it can be seen that with a higher inertia the angular response is lower than the default value of $H = 3.4$ MWs/MVA.

5.6 Bus fed vs. solid AVR

The excitation system used for most of the generators in the model has a setting for either bus fed or solid fed excitation system. If the excitation system is fed from the bus it will be dependent on the voltage level on the bus. This means that if a fault occurs on the connecting generator bus the excitation system will be affected negatively reducing the ability of the AVR to perform. However, if the AVR is solid fed it will be independent of the bus voltage. The control scheme of the excitation can be seen below in Figure 29. The second block from the right multiplies the signal with either the bus voltage, if it is bus-fed, or an integer of one, if it is solid fed.

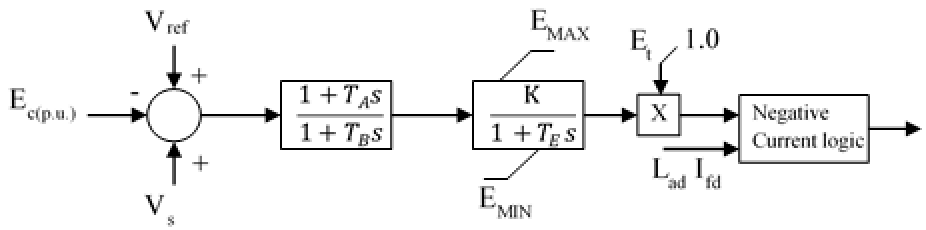

Figure 29: Excitation system used for most of the machines in the model. Note the second block from the right where the signal is multiplied with the bus voltage or one [5].

A simulation with both of these two settings were made to see how they compare against each other. The simulated fault was the one mentioned in reference case I and the bus of interest will be NÄMFOR.2, specifically machine with identity 1. The difference can be seen below in Table 21.

Table 21: Difference in fault clearing time between solid fed and bus fed AVR.

Type of AVR	Critical fault clearing time [ms]
Solid-fed	260
Bus-fed	256

As can be seen from the result in Table 21 the difference between the two types of AVR was very low. The reason for this is most likely due to the low impact that the AVR was found to have during fast fault clearing times, something that was discussed earlier. However, the result was clear in the way that the AVR was found to be more effective if it was solid-fed.

5.7 Effect of alternative load conversions

As mentioned earlier during in the report the active load conversion was set to 0/40/60 in PSS/E. This means that the load was split to 40 % constant admittance and 60% constant power. The reactive power consumption was set to 100% admittance following an example scenario from [1]. However, since these settings vary depending on the type of load currently connected to the grid, it could be of interest to change these settings. A handful of simulations were performed with different settings on the load conversion to see how this affected the transient stability of a generator in the system. Below in Table 22 the difference in critical fault clearing time is displayed for respective load conversion scenario.

Table 22: Critical fault clearing time for different load conversions. Reactive power conversion set to 100% in all cases.

Load conversion factor	Critical fault clearing time [ms]
P = 40% Y, 60% P	256
P = 100% I	257
P = 100% Y	259
P = 100% P	252

As can be seen from Table 22 the difference between the load conversions were negligible. It was expected that the scenario with a constant power load would have the highest fault clearing time since this would mean that the load would be constant during a low voltage condition. However, this was not the case since the load drops to zero if the voltage reaches a specific level in PSS/E. When the voltage varies between the specific level the load behaves as constant current and constant admittance, even with a constant power load conversion in PSS/E.

5.8 Voltage drop on generator terminal

One of the main consideration that has to be dealt with regarding the voltage drop is the power supply to power station auxiliary systems. Depending on the type of power plant, different levels of the generating power are consumed by the plant itself. In thermal and nuclear power plants pumps, cooling and other electrical equipment all require power drawn from the generator. Below in Figure 30, a typical setup can been seen to feed the auxiliary parts of a power plant.

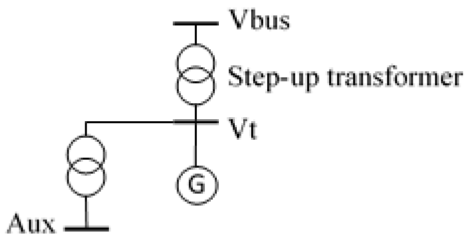

Figure 30: Typical feed to auxiliary power.

When a fault occurs on the connection bus on the high voltage side of the transformer this will affect the terminal of the generator as well. This can be seen below in some of the simulations that was made with different types of faults and fault clearing times. Do note that the highest fault clearing time for both cases led to the generator falling out of phase. These two cases are displayed in the figures with a dashed curve.

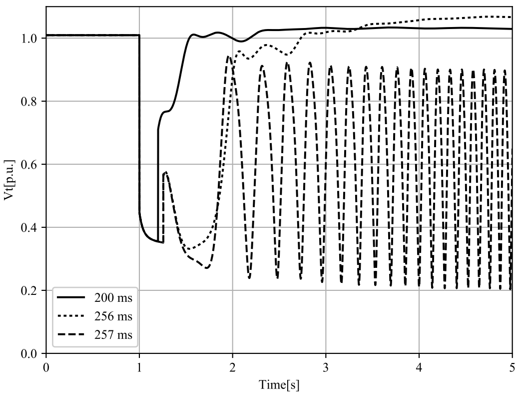

Figure 31: Voltage at generator terminal during bus fault.

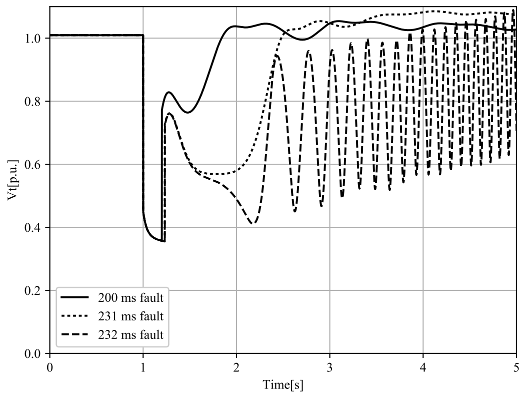

Figure 32: Voltage at generator terminal during bus fault leading to line outage.

These two figures are taken from reference case I and III displaying the voltage on the terminal of a generating unit at NÄMFOR.2 hydro plant. Although the auxiliary power consumption of a hydro plant is quite low in comparison to a nuclear plant, it can be an example to demonstrate the problem. From the figures it can be seen that the voltage during the fault and post fault dropped to 0.4 p.u. of the nominal value. This will severely affect the amount of power that can be transmitted to auxiliary parts of the plant. The low voltage can also lead to parts of the auxiliary system tripping due to under voltage. It is of importance for a power plant to be able to function without the possibility of a connection to the grid. If the power plant is able to slow down its production to only sustain its own load demand it can be kept running during the time of the fault. When the fault is later cleared, the power plant can be connected to grid again. In this way the process is made faster and the plant can supply its own auxiliary power demand [25].

5.9 Comparison between fault scenarios and grid code requirements.

The applied faults on either a connecting transmission line or the generator bus gives deviating voltages as compared to the requirements stipulated by the TSO, SvK. To find out how conservative these requirements are a comparison have been made between the resulting voltage on the bus and the low voltage ride through requirements. A few results have been presented earlier in some simulations, e.g. the transmission line fault reference case. This caused the voltage on the generating bus to drop to a value of 0.2 p.u. on a 220 kV base during the fault. After the fault was cleared, by tripping the line, the voltage stepped to a value slightly below 0.8 and then rose back to 1 p.u. The time between the fault was cleared and the voltage to rose back to 1 p.u. took around 0.9 seconds. This resulting voltage profile can be compared with the one presented below, which is the requirements for larger production units. Depending on the size of the power station different requirements are set in the grid code. If a hydro power station has a larger installed capacity than 50 MW it is to be considered as a large power station. This means that Nämforsen hydro plant has to maintain synchronization to the grid when exposed to the more stricter requirement from the grid code.

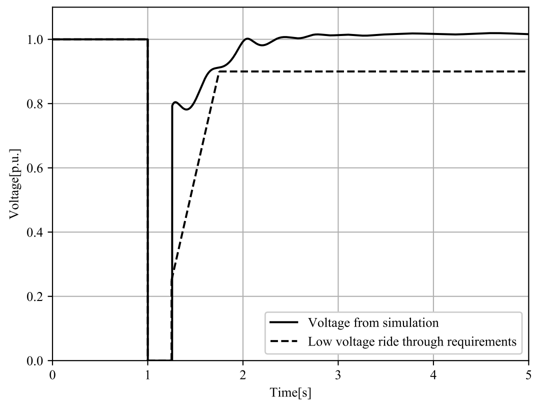

Figure 33: Comparison between grid code requirements and simulated voltage response.

As can be seen in the comparison between the grid code and the simulated case the grid code requirements is more aggressive when it comes to the voltage drop. However, the fault simulated was a very special case that might not represent a realistic scenario. The requirements stipulates that the fault is more or less cleared after 250 ms, causing the voltage to rise back again. When a bus or a line suffers from a fault, the object is taken out of service. A reconnection then takes place after a certain time to see if the fault is temporary, which normally is the case [1]. If that is not the case, a new short circuit takes place tripping the line again. Depending on the setting of the protection this event can repeat itself for a few times until the object is taken out of service. If a transmission line for example is taken out of service, that can severely affect the the generator's ability to decelerate post fault. The reason for this is the increased system reactance.

A more realistic scenario to look at would for example be the Reference case III, i.e. a faulted transmission line close to a bus that in turn causes the line to be taken out of service. This will not only cause the voltage on the generating bus to drop sharply but also reduce the system reactance post fault. This in turn reduces the transient stability due to decreased deceleration ability after the fault is cleared. The corresponding generator terminal voltage can be seen below in Figure 34.

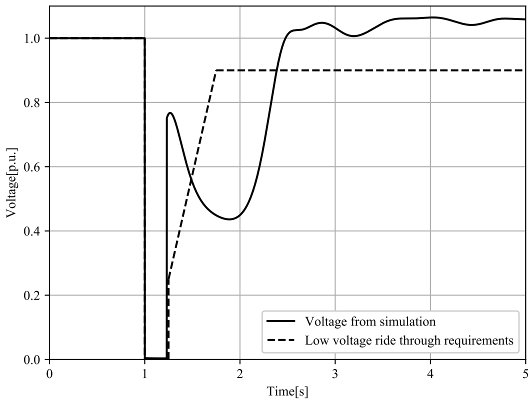

Figure 34: Comparison between grid code regulation and simulated voltage response.

It should be noted that the fault that was applied in that case was only 231 ms and not the full 250 ms since it was not able to maintain synchronization to the grid, i.e. it did not fulfill the requirement of staying connected to the grid. Here it can be seen that the voltage takes much longer time to rise back to its nominal value than what the requirement stipulates. The lower voltage post-fault reduces the maximum active power transfer and thereby the ability of the generator to keep synchronization. Another difference in the defense of the regulated voltage profile was that the voltage jumps up to a higher level in the simulated scenario after the fault was removed. This was also the case with a faulted generator bus without any object taken out of service post fault. To conclude from the comparison, it should be noted that when an object has been taken out of service, the requirements are more conservative than what is stipulated from the grid code. This is due to the higher system reactance reducing the ability of the generator to decelerate.

5.10 Application of low voltage ride through profile

It could be of interest so see how the generators reacts when they are exposed to the regulation set by the grid codes from SvK. To simulate this a smaller two-bus system was created. A generator on one of the buses were then controlled with the help of a user made exciter model written by Andreas Petersson at DNV GL in FORTRAN and implemented in PSS/E. The model has two settings making it possible to either set the voltage to either of the two production unit regulations, large or small unit.

5.10.1 Test system with meshed grid

As mentioned above a smaller test system was created to be able to apply a correct voltage to the generating bus. This was done by representing the meshed grid with the help of a generator on a swing bus. The result was a two-bus system with the meshed grid represented by a generator on one bus and the other bus being identical to the NÄMFOR.2 bus that was used earlier in the simulations. The system that was used can be seen below in Figure 35.

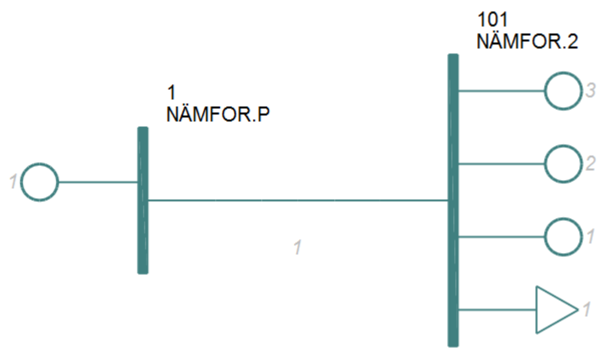

Figure 35: Two-bus system used for application of voltage ride through profile on generating bus.

To get the custom model to function correctly a few simplifications had to be made. The transmission line between the two buses was a zero impedance line to help the custom exciter set the bus voltage for bus 101. The ZSOURCE had to be reduced to a very low value and the impedance of the step up transformer between the generator and the swing bus was removed. By doing these changes the custom exciter can control the voltage on the generator bus for the three generators seen in the Figure 35 above.

5.10.2 Results from simulations

Two simulations were done with two different settings on the model. The first simulation was done with requirements set for smaller plants. This means that the voltage dropped to 0.25 p.u. during 250 ms and then back up to 0.9 p.u. during the rest of the simulation. The result can be seen below for one of the three generators connected to the grid.

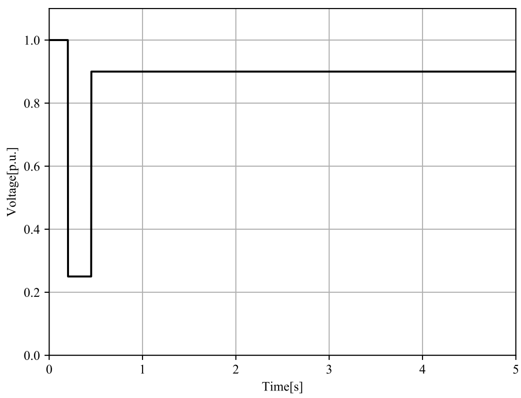

Figure 36: Voltage at generator bus with applied voltage from meshed grid.

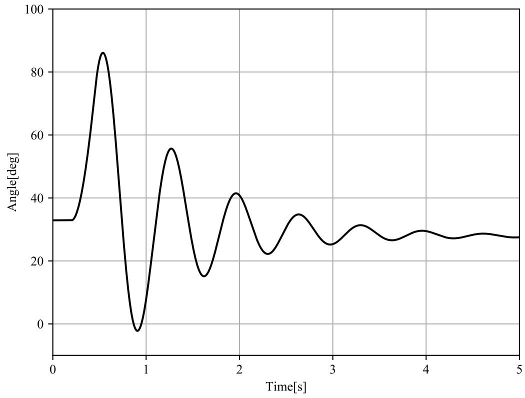

Figure 37: Angle due to change in voltage according to grid code regulation.

From this it can be seen that the generators can handle the applied voltage from the voltage ride through regulations stipulated in the grid code. This was also expected since the requirement was found to be quite conservative in relation to the fault scenarios simulated earlier in the report. However, the second simulation was made with the more aggressive requirement for larger production units where the voltage ramps to 0.9 p.u. The same two-bus system was used and the result can be seen below.

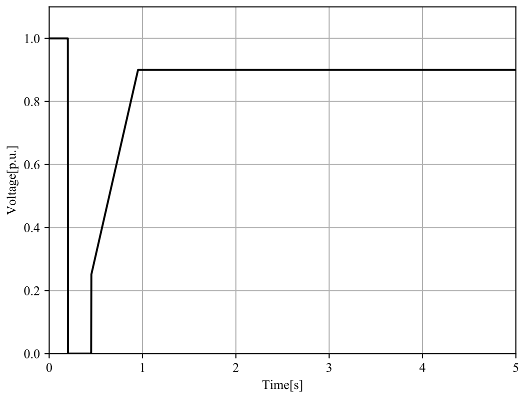

Figure 38: Voltage at generator bus with applied voltage from meshed grid.

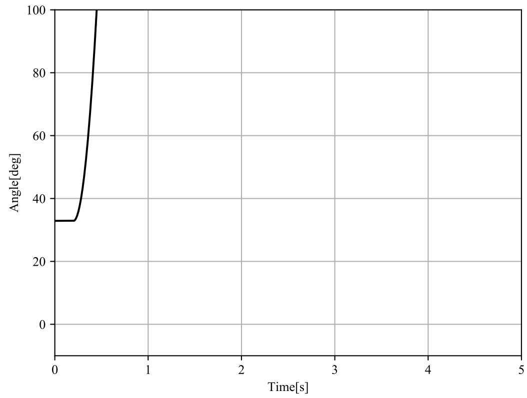

Figure 39: Angle due to change in voltage according to grid code regulation.

With the application of the voltage profile for larger generating units stability was not achieved. This gives that the faults that was applied earlier might be more conservative than the voltage profile and not the other way around. Most likely the reason for this was the voltage level post fault eventually rose back to 1 p.u. as this was not the case in the profile where it was kept at 0.9 p.u. With a generating unit not fulfilling the low voltage ride through criteria it is under the responsibility of the plant owner to improve the transient stability of the unit. This can be done with the help of the mentioned actions in section 2.2 .

6 Sustainability and ethics

6.1 Sustainability aspect

With an electricity market becoming more and more complex with the inclusion of renewables the need for data is ever increasing. Smaller and smaller actors appear on the market with construction of wind turbines and solar power. By creating a load flow model based on open sources, previously confidential data can now be accessed by smaller actors on the market for important pre-studies on the grid. Hopefully this model can be used by smaller actors on the electricity market to further increase the share of renewables in Swedish power production.

6.2 Ethical issues

There are a number of ethical issues associated with the work done regarding the transmission grid model. Since large amount of data was based on second hand sources one must be careful to draw any conclusion from the result. Especially the parameter settings in the dynamic modelling can have a large impact on the final result of the transient studies. This together with some of the simplifications that had to be made in order to finish the task within the time frame of the project.

Another ethical issue one should consider is the reason why the project was made. The difficulty of obtaining first hand sources is for a reason. Access to some of the data is regulated due to security reasons and any construction of a similar model might cause harm to the owner of the transmission grid. This if the model would be to close to actual confidential model.

7 Conclusions

7.1 Grid model and load flow data

Development of a detailed transmission grid model was a complicated procedure. To simply develop a load flow model with generating units and transmission lines was possible and did not pose such a great challenge once the data was collected. Verification of the result was made with the help of historical load flow data. Correlation between measured and calculated values were very good and one could say that the load flow model was indeed successfully constructed.

The problem lies in the dynamic model where most of the data was very hard to obtain. Using second hand sources from earlier work together with previous master's theses gave a possibility to populate, i.e. adding data, to the model with adequate parameters. Earlier work have been done regarding dynamic modelling of the Nordic grid, but not to the extent and detail performed in this thesis. Most of the work have instead been on already constructed load flow/dynamic models and never from scratch. To validate the model with official data was therefore not possible and one should be careful to draw conclusions based on the result.

7.2 Transient stability and fault ride through studies

When studying the transient response of a generator and in particular with regards to the fault ride through requirements careful consideration must be taken. Since each TSO more or less have a unique low voltage profile that a generating unit should sustain, vastly different results are given depending on the profile used. One of the generators was for example able to sustain the requirement for small plants but not for larger plants. It is also not stipulated in the grid code what the operating point should be pre-fault. Something that very few TSO stipulate in their demands. This will of course have a vast impact on the outcome if the generator can maintain synchronization or not.

8 Further Work

Extending the reach of the model should be the priority in further work. This includes, but not limited to, adding correct DC-links to neighbouring countries, adding step-up transformers, modeling of distribution network, adding additional dynamic model to generators and an overhaul of the implementation of wind power in the system. Some of these can be done quite easily while some would take vast amount of time and would be very hard to do without sufficient data, such as the modeling of the distribution network. This would especially be hard with a restriction to open sources due to the amount of cable that increases dramatically on the lower voltage levels. However, it would be necessary if one would want to include step down transformers and a more detailed modeling of the grid. There are a lot that can be done to the model but the time it would take, including the time to find sufficient sources, would increase drastically.

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