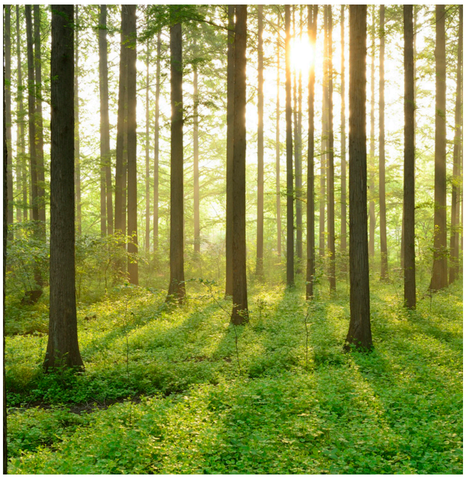
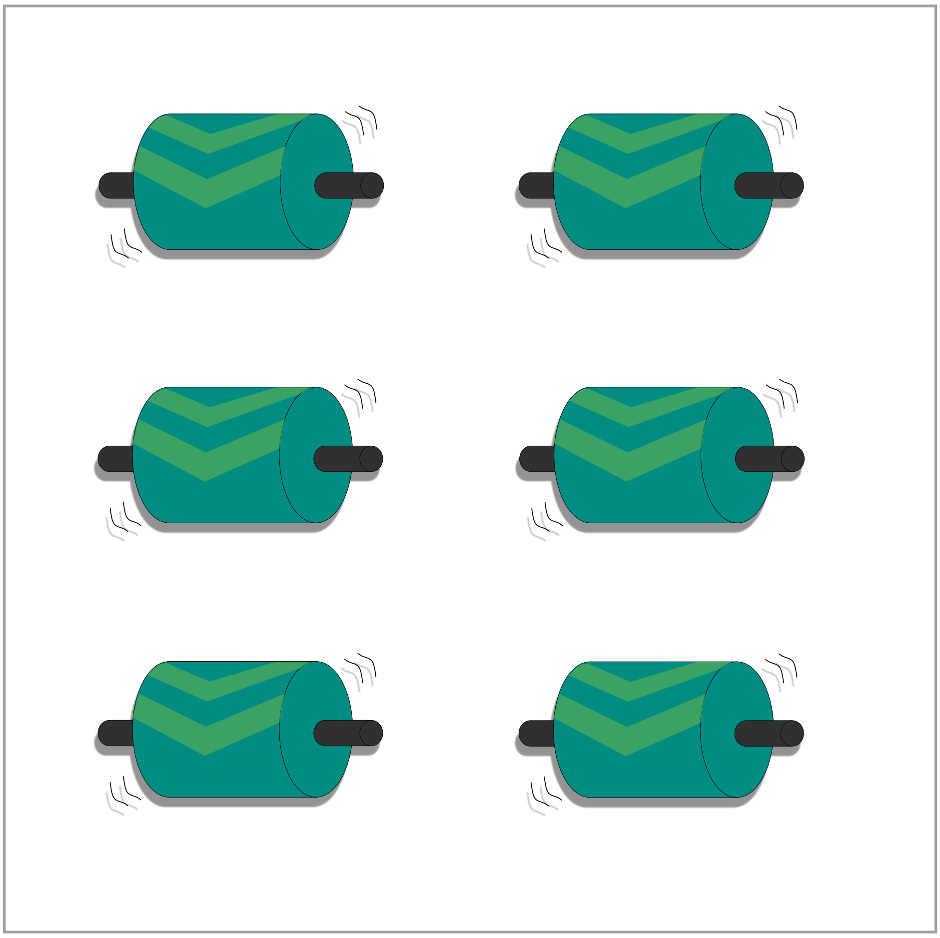
SYNTHETIC INERTIA TO IMPROVE FREQUENCY STABILITY AND HOW OFTEN IT IS NEEDED

REPORT 2015:224



SYNTHETIC INERTIA



Energiforsk

Synthetic inertia to improve frequency and how often it is needed

RUJIROJ LEELARUJI AND MATH BOLLEN, STRI AB

ISBN 978-91-7673-224-3 | © 2015 ENERGIFORSK

Energiforsk AB | Phone: 08-677 25 30 | E-mail: kontakt@energiforsk.se | www.energiforsk.se

Foreword

Sweden and other Nordic countries have ambitious renewable energy source (RES) integration targets. This will represent a significant share of wind power in the future generation mix of Nordic countries.

In this regard, it is important to build up comprehensive knowledge of integrating wind power plants into the power system for ensuring security and reliability of power system operation with large amounts of wind power. In particular, much attention has been paid to the deterioration of frequency stability from replacing conventional power plants by converter-based wind power plants, which will lead to a decrease of physical kinetic energy in the power system. Thus, wind power plants will be required to contribute for frequency control support in a higher wind power penetration.

The Vindforsk IV program started in 2013, and runs for four years. The main focus of Vindforsk IV is largely similar to that of the Vindforsk III program. Its research areas are "wind resource, planning and establishment", "operation and maintenance" and "wind in power system." The objective is to contribute to the skills and knowledge needed for designing, constructing and operating and integrating wind farms into power system with highly penetrated wind energy. The Swedish Energy Agency (Energimyndighet) supports more than 50% of the program budget.

This project is one of seven projects within the research area “wind power in power system”. The topic of the project is to study the use of synthetic inertia from wind turbines for improving frequency stability and to determine how often the synthetic inertia is needed in a power system with high wind power integration.

The work has been carried out by Rujiroj Leelaruji as a project engineer together with Math Bollen as project leader and supervisory support.

Cooperative support and invaluable comments are given by a reference group with the following members:

Katherine Elkington,	Svenska Kraftnät
Urban Axelsson,	Vattenfall

Stockholm September 2015

Åsa Elmqvist

Programme manager Vindforsk- IV

Electricity and heat production, Elforsk AB

Sammanfattning

I detta projekt har en studie av hur ökad vindproduktion påverkar kraftsystemfrekvensen gjorts. Under de första sekunderna efter att en stor produktionskälla förlorats så sjunker frekvensen fort. Storleken av frekvensfallet i det befintliga kraftsystemet beror på trögheten i de synkrona generatorerna som används för tillfället. Frekvensfallet kan begränsas under de första 7 till 10 sekunderna efter att produktionskällan förlorats. Det möjliggör primär frekvenskontroll för att återfå elnätets nominella frekvens efter dessa 7 till 10 sekunder.

Under driftlägen med stor andel produktion från vindkraft, och därmed små andelar synkrona generatorer kopplade till nätet, skulle frekvensen gå ner mycket snabbt vilket skulle äventyra systemets stabilitet. En möjlig lösning för att förebygga (frekvens)instabilitet är att förse vindturbinerna med så-kallad ”syntetiskt tröghetsmoment”, dvs ett bidrag från den vindproduktion som har möjlighet att injektera extra energi in i systemet vid en snabb och/eller stor sänkning av frekvensen. Tekniskt sett fås energin temporärt från vindturbinens rotationsmassa. Utöver det anpassas turbinbladens vinkel mot vinden för att få ytterligare energi från vinden som stöder primär frekvenskontroll. Tidigare studier har visat att syntetiskt tröghetsmoment kan hålla systemet stabilt tills att den primära frekvensregleringen tar över.

Ett av resultaten från den här studien visar att trögheten (i form av ökad produktion under ett allvarligt frekvensfall) från vindturbinen begränsas inte bara av den tillgängliga mängden rörelseenergi utan också av inställningarna för de olika reglersystemen. En återhämtningsperiod behövs då vindkraftverken accelereras tillbaka till hastigheten de hade innan störningen. Det är särskilt under denna period som inställningen av olika reglersystem spelar en viktig roll. Simuleringar har visat särskilt effekterna av övervarvsskydd och styrning av lutningsvinkeln (”pitch angle”).

För höga vindhastigheter, kan ytterligare kraft extraheras från vinden, genom att ändra lutningsvinkeln hos bladen. Detta är mer effektivt för högre vindhastigheter.

Studierna bekräftar att standardvärdena som tillverkaren tillhandahåller eller de som tagits fram i en studie av ett annat nät ej nödvändigtvis ger optimalt bidrag till det syntetiska tröghetsmomentet. Resultaten från simuleringarna visar att frekvenskontrollen för vindturbinerna har betydande inverkan.

Den här rapporten visar också att lägsta stabila frekvens ej påverkas i hög grad av ökad vindkraftsproduktion. Detta innebär att det är möjligt att ha bra frekvenskontroll med ökad vindkraftsproduktion under förutsättning att denna är utrustad med det syntetiska tröghetsmoment som finns kommersiellt tillgängligt idag.

Ytterligare en studie gjordes för att visa behovet av syntetiskt tröghetsmoment. Analysen gjordes med hjälp av en stokastisk modell med en databas innehållande faktisk vindproduktion som utgångspunkt. Det gjordes vissa antaganden som t.ex. utökade fiktiva vindkraftverk för att skapa framtidsscenarier av årlig energiproduktion baserat på timvärden från vindkraftproduktionen. Ett tröskelvärde valdes för den minsta mängd kinetisk energi som behövde finnas tillgänglig för att säkerställa ett stabilt system. Studien visade att redan vid 20 TWh vindproduktion i Sverige och liknande mängd i grannländerna skulle den tillgängliga kinetiska energin under vissa timmar gå under det bestämda tröskelvärdet. För att undvika detta kan man använda

syntetiskt tröghetsmoment men driftinskränkning av vindkraft dessa timmar kan vara ett annat alternativ.

Det har gjorts en uppskattning av det antal timmar per år under vilka en driftinskränkning av vindkraften skulle behövas. Mängden energi som ej kan levereras till elnätet har också estimerats. Som förväntat ökar antalet timmar och mängden energi som förloras då vindproduktionen ökar. Vid 20 TWh vindproduktion i Sverige är behovet av driftinskränkning litet. Vid 30 TWh vindproduktion är behovet av driftinskränkning till stor del beroende av vindproduktionen i grannländerna. Vid 50 TWh vindproduktion är behovet av driftinskränkning så stort att andra alternativ behöver ses över, t.ex. användandet av syntetiskt tröghetsmoment.

En kvalitativ studie har gjorts för att undersöka sambandet mellan vindproduktion, tröghet och rotorvinkelstabilitet. Slutsatsen blev att nuvarande teknologi för syntetiskt tröghetsmoment inte bidrar till rotorvinkelstabilitet.

Summary

In this project, the frequency response of the electric power system has been studied with increasing amount of wind penetration. In the first few seconds following the loss of a large generating plant, the frequency drops quickly. In the existing power system, the frequency drop is limited by the inertia response of the on-line synchronous generation. This limits the frequency drop during the first 7 to 10 seconds after the initial loss of production and allows the primary power-frequency control to restore the grid frequency to its nominal value.

During operational states with large amounts of wind power, and hence small amounts of on-line synchronous generation, the frequency would drop so fast that the system stability is endangered. A possible solution to avoid (frequency) instability is to employ so-called "synthetic inertia", i.e. a contribution of wind power generation with inertia control functionality. The inertia control temporarily provides an amount of additional power in response to significant under-frequency events. Technically, the inertia response from the wind turbines uses the rotational mass in the turbine to provide this temporary power increase. It has been shown in earlier studies that synthetic inertia is able to limit the initial frequency drop after the loss of a large production unit and keep the system stable until the primary frequency control takes over.

One of the studies presented in this project shows that the inertia support (in the form of additional power production during a severe drop in frequency) of the wind turbine is limited not only by the available kinetic energy in the rotational mass but also by the setting of various controllers. A recovery period is needed during which the wind turbines are accelerated again back to their pre-disturbance speed. It is during this acceleration period that the setting of various controllers plays an important role. Simulations have shown the impact of the overspeed protection and of the pitch-angle control.

For high wind speeds, additional power can be extracted from the wind by changing the tilt angle of the blades. This is more effective for higher wind speeds.

It is also confirmed by this study that the values provided by the manufacturer or obtained from a study in another system might not deliver optimal synthetic inertia response.

It is further demonstrated in this report that the minimum frequency is not degraded with significant levels of wind generation including synthetic inertia. It is possible to have good system frequency response when using wind turbines equipped with inertia-support controls available commercially today.

A further study was done on the need for synthetic inertia. The analysis has been performed by using a stochastic model with the database of actual wind power projects as a starting point and certain assumptions e.g. repowered and/or reconstructed wind turbines to create future scenarios of annual energy production with hourly time-series of wind power production. A threshold was selected for the minimum amount of kinetic energy that should be available to the system to remain secure. It was shown that 20 TWh wind power in the Swedish system and equivalent amounts in neighboring countries would result in hours during which the actual amount of kinetic energy was less than this threshold. Synthetic inertia would be one solution, but curtailment of wind-power production during those hours is another option.

An estimation has been made of the number of hours per year during which it will be needed to reduce wind power generation, The amount of wind energy not delivered to the grid due to this power curtailment has also been estimated. As expected the number of hours and the amount of energy increase with the increase of annual energy production from wind turbines For 20 TWh wind power in Sweden, the need for curtailment is small. For 30 TWh, the need for curtailment depends strongly on the involvement of wind power generation in neighboring countries. For 50 TWh the need for curtailment and the non-delivered wind energy will become so big that alternative solutions, like synthetic inertia need to be considered.

A qualitative study has been done to understand the relations between wind power, inertia support and rotor-angle stability. It is concluded that the existing technology for synthetic inertia does not contribute to rotor-angle stability.

List of content

1 Introduction

Project Motivations

The stability of the electric power system related to system frequency and rotor angle relies on the kinetic energy of rotating machines (motors and generators) that are connected to the power system. Equipment connected through power electronic converters does not contribute to the available kinetic energy from power system operational perspective [1].

Both solar and large wind power are generally interconnected with the power system through a power electronic interface. Accordingly, the mechanical and electrical behaviour of variable-speed wind turbines is decoupled by power electronic converters; large amounts of wind power can have a negative impact on frequency stability.

One of the consequences of integrating large amount of wind power is that the amount of kinetic energy (inertia), which is available for system operation, is decreased. If the inertia of the system becomes too small, it can jeopardize frequency stability upon failure of large production units or HVDC links [2, 3, 4, 5, 6]. The smaller the moment of inertia in the system, the faster the frequency changes after an unbalance between production and consumption.

In addition, if system inertia is reduced due to the replacement of synchronous generators by wind power, this may also jeopardize rotor angle stability. Rotor angle stability is related to local unbalances in production and consumption and the resulting differences in frequency and rotor angle. Less inertia will also give faster changes in frequency and rotor angle and an increased probability of instability.

The lack of inertia may set a limit on how much wind and solar power can be accepted in the power system (the so-called "hosting capacity" [7, 8]). Synthetic inertia is expected to replace physical inertia and increase the hosting capacity. Thus, this project is primarily to study how synthetic inertia may contribute to power system stability and in such a way to enable more renewable electricity production in the power system.

Aims

The main objectives of the project are to gain experience with the use of synthetic inertia in the Nordic power system. The project would initially focus on two specific objectives:

- To understand the relationship between synthetic inertia and the need for additional primary reserve (frequency containment reserves for disturbances). How can the need for additional primary reserves be reduced by proper selection of parameters in the control algorithm for synthetic inertia?
- To understand the relationship between synthetic inertia and angular stability. How can you get the benefits of synthetic inertia to prevent large increases of generator angle between two areas with angular instability consistency?

The first specific objective still holds. Concerning the second specific objective, there is uncertainty on how fast the frequency deviation and rate of change of frequency (ROCOF) can be measured. Also, angular stability was considered not to be an issue in the Swedish grid during the second reference group meeting. Therefore, the second specific objective (the benefits of synthetic inertia on angular instability) was replaced by:

- To review the impact of wind power on angular stability and indicate the limitations of synthetic inertia as a solution against angular stability.

Next to this a third specific objective was added:

- To estimate the variation of natural inertia in the system over a multi-year period for different amounts of energy from wind and from this to estimate how often synthetic inertia is needed.

Scope of activities

The main scope of activities within this project consists of the following four parts:

- Define a test system (Nordic-32 system) for frequency stability study.
- Perform simulation for synthetic inertia and frequency stability by using the test system and wind turbine equipped with inertia response control system
- Analyze test scenarios of the time-series wind power fluctuation to estimate time-series of the need for additional inertia to maintain a secure system.
- A qualitative description of the limitations of synthetic inertia to avoid rotor angle instability in a system with low amount of physical inertia.

2 Literature Review

2.1 FREQUENCY AND ANGULAR STABILITY IN POWER SYSTEMS

The basic concepts of rotor angle stability and frequency stability are reviewed in this chapter.

2.1.1 Brief summary of power system stability problems

Power system stability may be broadly defined as the property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance [9]. Power system stability is generally classified as illustrated in Figure 2.1 [10].

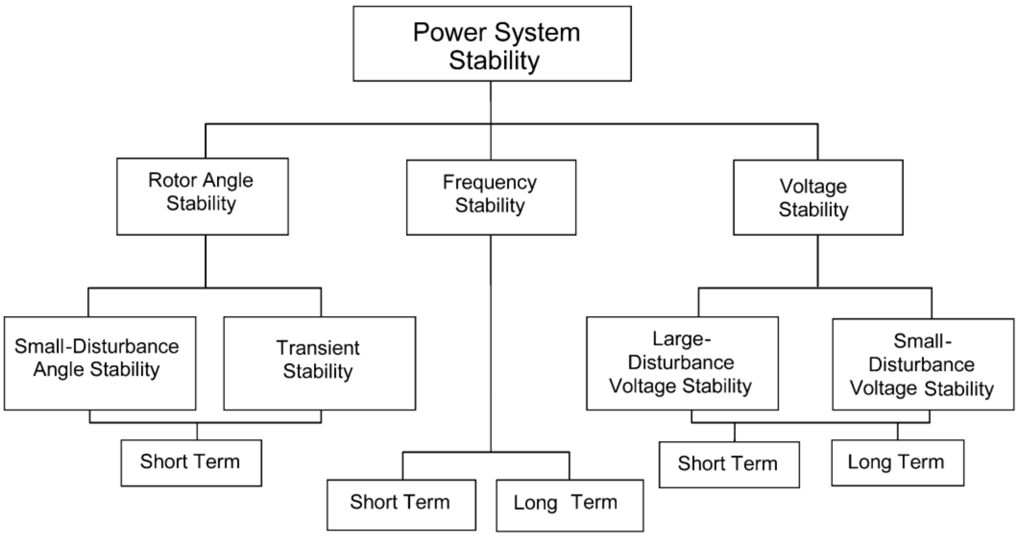


Figure 2-1 Classification of stability in power systems [10]

Based on [10], power system stability problems are briefly defined as below.

- **Rotor angle stability**: Rotor angle stability refers to the ability of synchronous machines of an interconnected power system to remain in synchronism under normal operating conditions and after being subjected to a disturbance. It depends on the ability to maintain and restore equilibrium between electromagnetic torque and mechanical torque of each synchronous machine in the system. The time frame of interest is generally between 3 to 5 seconds following disturbance.
- **Frequency stability**: Frequency stability is the ability of a power system to maintain the frequency within a nominal range, following a severe system upset that may or may not result in the system being divided into subsystems. It depends on the ability to restore balance between system generation and load

with minimum loss of load. The time frame of interest for a frequency stability study varies from tens of seconds to several minutes.

- **Voltage stability**: Voltage stability is concerned with the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. Large disturbance voltage stability is concerned with a system's ability to maintain steady voltages following large disturbances. Small disturbance voltage stability is concerned with a system's ability to control voltages following small perturbations, such as incremental changes in system load.

However, the reality of stability problem is very complex and thus system stability raised by a disturbance may be needed to be interpreted by multiple stability perspectives [9].

2.1.2 Load-frequency control for frequency stability

Under normal power system operating conditions, the physical balance between generation and consumption (load) should be managed to maintain system frequency on the entire grid, ensuring that generators connected to the grid rotate at the same electric speed. For this, the physical balance should account for instantaneously variable demand and unpredicted generator disturbance, leading to frequency excursion (deviation) from system frequency (50 Hz in Nordic region).

In actual system operation, the load-frequency control issue is generally divided into different frequency restoration stages after power imbalance disturbance dependent on their time-frame of restoration response as illustrated in Figure 2.2 [11].

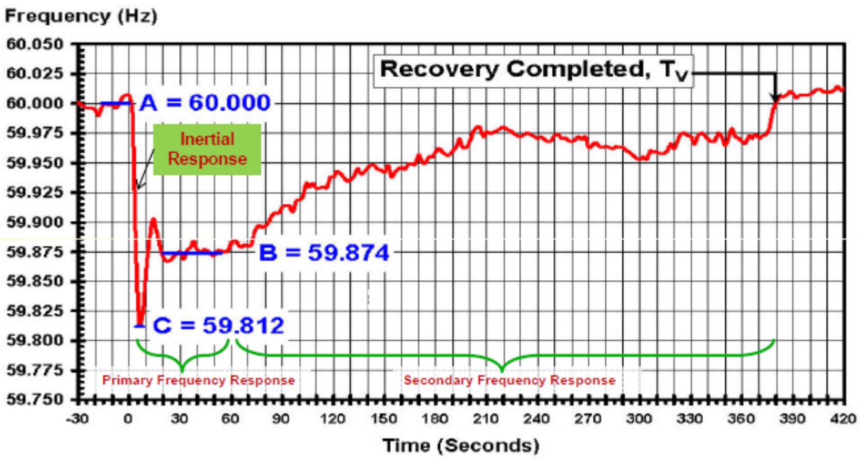


Figure 2-2 Typical frequency event and system response (Note that 60 Hz is the nominal frequency in this example)

As observed in Figure 2.2, it is known that load-frequency control relies on both physical kinetic energy and generator control system to restore system frequency drop [10, 11, 12]. A qualitative study for system behaviour will be described in Chapter 5 of this report.

Rotor swings in the generators (Inertia response)

The sudden disconnection of one of the generators in an interconnected system will initially produce rotor swings between remaining generating units within the same power plant and generators at other locations in the system. This inertia response is started by consuming the kinetic energy stored on turbine rotor, because the release of this energy is faster than the time response of controllers.

Before the start of the contribution by the frequency control, the kinetic energy in the rotating mass is the only thing that limits the frequency drop. Accordingly, all the generators in the system start to use kinetic energy, and slow down, causing system frequency to drop. During this stage the share of any one generator in meeting the power imbalance depends solely on its inertia and not on its electrical distance from the disturbance. This inertia response generally lasts until the frequency control takes over, which is after several seconds.

Primary frequency control by governor

Primary control is carried out by control loops ("speed controllers") situated on the generating units. Rapid (in a matter of seconds) and decentralised adjustment makes it possible to restore the generation-load balance after a disturbance, provided that the available primary reserve is sufficient.

The primary control is mainly achieved by speed governor within the generator turbine system. As system frequency drops, turbine governor is operated to increase the turbine mechanical power output. However the primary control merely restores the balance between supply and demand, and does not bring back the frequency to the pre-disturbance value.

Secondary frequency control by AGC (automatic generator control)

The quick adaptation of generation to load carried out by primary control leaves a frequency deviation at the end of the action. It also brings about flow variations among control regions; all the generation sets of the various control regions react to the variation of the common frequency, even if the disturbance has occurred in another region of the synchronously interconnected system.

The aims of the secondary control are to bring the frequency back to its reference value as well as bring the flow exchanges between control regions back to their scheduled values. For this purpose, TSOs rely on the automatic generation control system (AGC), and its time frame of frequency control lies in the range from several seconds to a minute.

There are several differences on how to utilize AGC in the Nordic system compared to Continental Europe. For example, the AGC in the Nordic system is activated every 10 sec with a block of 10 MW whereas the activation can be various with a block of 1MW for Continental Europe. More details regarding the AGC of Nordic and Continental European systems can be found in [13].

2.1.3 Protective fault clearing for angular stability

Following a large system disturbance, the rotor shaft of synchronous machine is accelerated due to synchronising torque, leading to larger power angle (angular separation between stator and rotor). If the fault is cleared fast enough, the probability of the system remaining stable after the fault clearance depends on synchronising torque. However if the fault persists for a longer time, the likelihood of instability is increased. Thus the fault should be cleared within a certain time, referred to as the critical clearing time (CCT), which is the maximum time to clear the fault for maintaining stability.

The critical clearing time can be obtained from:

$$t_{\text{crit}} = 2\sqrt{\frac{\theta_{\text{crit}} - \theta_1}{\omega_0} \times \frac{SH}{P_{\text{corr}}}}$$

where SH is the total kinetic energy of the rotating mass in the area

θ_1: Prefault angle between areas

θ_{crit}: Critical clearing angle

P_{corr}: Power transfer between areas

More details regarding the CCT can be found in [7].

Thus, most TSOs use high speed fault clearing to prevent angular instability after a large system disturbance. For example, typical fault-clearing times in the Swedish transmission grid are 110 msec and 80 msec at 220 kV and 400 kV, respectively. A fast acting circuit breaker is used to clear the fault within the designed fault clearing time.

In interconnected power systems, synchronous machines maintain synchronism with one another through synchronising torque, which acts whenever there are forces tending to accelerate or decelerate one or more machines with respect to other machines. If one generator temporary runs faster than another, the resulting angular difference between synchronous machines transfers part of the load from the slow machine to fast machine, reducing speed difference and rotor angle difference.

Finally, it is found that higher machine inertia provides greater system stability under faults and thus the machines are less accelerated and decelerated during a grid disturbance. This implies that higher damping can extend critical clearing time [16]. Thus system inertia has an important impact on rotor angle stability.

2.2 IMPACT OF WIND POWER ON FREQUENCY AND ANGULAR STABILITY

The transmission system operator (TSO) is responsible to maintain the quality of supply (QoS) in delivering electric energy from generation to consumer. Some TSO's experience on 'frequency quality of supply' as obtained from the literature is summarised in this section. The studies presented in this section consider wind power without synthetic inertia.

2.2.1 TSO's experience

Taking into account that our main interest of system inertia is related to transient response for frequency deviation and rotor angle stability, some field and simulated experience of large power systems with wind power integration is briefly investigated below.

Impact of wind power on frequency stability: Nordic system

The Nordic system is often studied by the CIGRE Nordic-32 benchmark model, which contains 32 high voltage buses, and represents both 400 kV transmission and some regional systems at 220 kV and 130 kV.

In [9], generator disturbance (i.e. loss of generation) is studied with staged increased wind power capacity (full power converter turbine) by replacing conventional synchronous generation. The results show that large wind power penetration might reduce the frequency nadir (i.e. the lowest point of frequency after disturbance) and increase rate of change of frequency (ROCOF).

In [17], the impact of synthetic inertia, as a function of the loss of production (in percent of the total production), shows that the frequency drop is larger (i.e. lower frequency nadir) with increasing size of the generation outage.

Impact of wind power on frequency stability: UK system

In [15], the national grid company (NGC), which is responsible to maintain the quality of system frequency, monitored system inertia trend over 3 years, showing that overall system inertia has gradually decreased. Taking into account that large wind power is connected at the same period in the UK power system, the national grid carried studies over three years and suspected that the reduction of inertia has occurred as synchronous generation have been displaced by asynchronous sources such as wind and interconnectors.

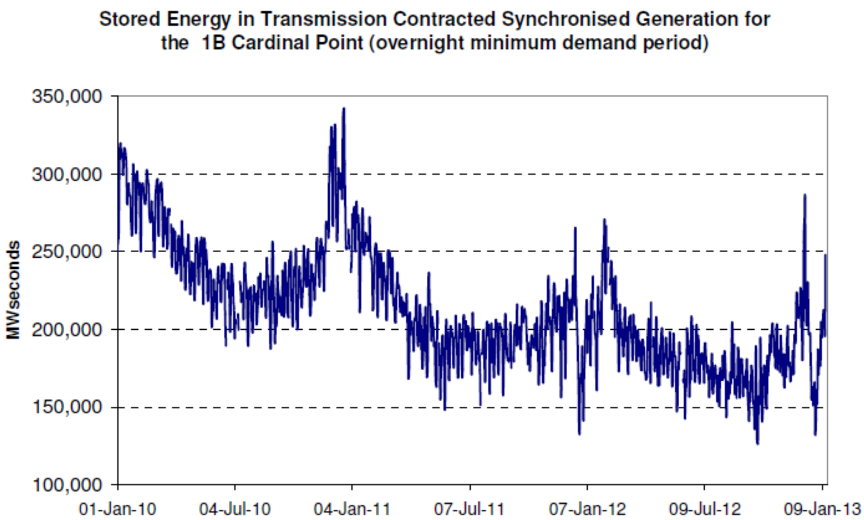


Figure 2-3 Recent system inertia trend in UK power system [15]

In addition, ROCOF forecast analysis has been studied based on the Gone Green dataset used in the 2012 Electricity Ten Year Statement [19]. The analysis includes a sensitivity study including demand size and wind penetration.

Given the wind penetration size is fixed and loss of generation (1800 MW) is assumed as disturbance, the increase of demand size (from 20 GW to 35 GW) shows improvement of ROCOF from 0.33 Hz/s to 0.17 Hz/s over 500 msec observation due to the help of increase of system inertia of synchronous generation. This is because the ROCOF of 0.33 Hz/s and 20 GW production will give inertia constant (H) equal to

6.8 MJ/MW meanwhile the ROCOF of 0.17 Hz/s and 35 GW production will give H equal to 7.6 MJ/MW. The method to calculate inertia constant is described in Chapter 6.

Meanwhile, given that demand size is fixed and the loss of generation (1800 MW) is assumed as disturbance, the increase of wind power penetration may deteriorate the ROCOF regardless of demand size.

In [16], simulation studies are performed by using a similar UK system as above (30 GW demand and 1800 MW loss of generation). Wind turbine is modelled by full power converter turbine. As system demand is increased with fixed wind power capacity, both frequency Nadir and ROCOF are improved. However, higher penetration of wind power may deteriorate ROCOF (from 0.28 Hz/s to 0.40 Hz/s for initial 2 sec).

Impact of wind power on frequency stability: Ireland region

In [20], all-island simulations, which include 2284 MW demand, wind power (1380 MW), two interconnections (EWIC and Moyle), demonstrated that in the case where there was a fault on EWIC (East-West Interconnector) while operating at maximum export, a maximum ROCOF is 0.63 Hz/s. In addition, in the case of a system separation event occurring, following a fault on the Northern Ireland System, the resulting ROCOF levels seen on the isolated SONI system were of a significant level. ROCOF values in excess of 2 Hz/s were observed over 500 msec windows.

Impact of wind power on angular stability: China

DFIG wind farm is connected to 500 kV transmissions in the modelled network [21]. The control of the wind farm is modelled as constant power factor (i.e. equals 1.00 and remains constant during steady state), Under this control mode, the reactive power between wind farm and the grid is zero. Three capacity sizes of wind farm are assumed; 8.36%, 12.3% and more than 12.3% of entire generation capacity.

Simulation studies show that wind power integration obviously impacts the rotor angle stability of synchronous generators, which are remotely located in the system. For low amounts of wind power, the angular stability improved, but for larger amounts it deteriorates. For the case studied in [21] the stability improved when connecting 8.36% of wind power. The stability deteriorated with 12.3% or more of wind power. It was shown that if wind power capacity size is increased over 12.3%, synchronous generators are regulated to support the voltage drop at PCC (point of common coupling), deteriorating rotor angle stability.

Impact of wind power on angular stability: New England

The study in [22] shows that by controlling active power of DFIG turbine to change flow minimally, the turbine can provide reactive power support to maintain rotor angle stability of conventional units in the system. The New England system is used to test the control methodology.

Simulation studies show that the improvement in stability is achieved by supporting bus voltages using reactive power injections from wind generation. This reduces the reactive power requirement from conventional synchronous generation and minimizes deviation in the field voltage. As a result, this allows synchronous generators to maintain their reactive power output inside their limits. By preventing reactive power from the synchronous generation from collapsing, the balance between electrical power output and mechanical input is maintained. This balance minimizes rotor angle deviation and improves rotor angle stability.

2.2.2 New Grid Code trends

Presumably, regulation of rotational speed through governor action is used to control system frequency, while inertia of the rotational masses of synchronous machines plays a role in limiting the rate of change of frequency (ROCOF) just after the start of a large disturbance (i.e. transient time at post-disturbance).

Selected international grid codes, which specify the frequency control requirement from wind power, are briefly reviewed to present TSO’s regulatory requirements.

Grid Code for controlling system frequency from wind turbine

Some frequency control requirements for wind power are observed. Some selected grid codes are reviewed [23] for this issue and are summarised as follows.

The wind turbine is required to change the operation mode between ’limited frequency sensitivity mode’ and ’frequency regulation capability’ as the need arises. Firstly, wind turbine is required to reduce power output at a pre-defined rate of the generator’s instantaneous available capacity per hertz when the system frequency rises above a pre-defined frequency (e.g., 50.2 Hz in Germany Transpower) in the limited frequency sensitivity mode (Germany, Ireland, UK, and ENTSO-E).

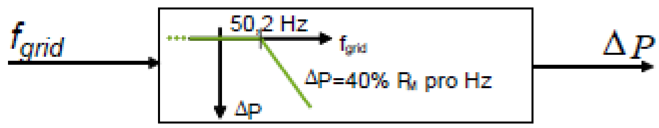


Figure 2-4 Example of limited frequency sensitivity mode

Secondly, the wind farm is required to operate at a level below its instantaneous available capacity for providing upward frequency regulation capability (Ireland, UK and Spain). Typically, droop characteristic and control dead-band are included in the control.

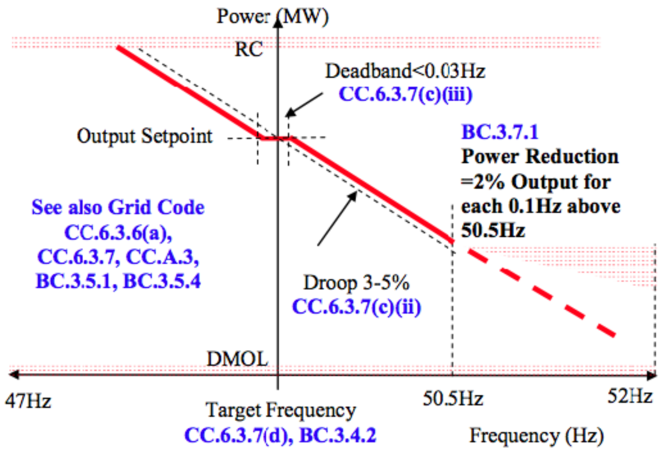


Figure 2-5 Example of frequency regulation capability (frequency sensitivity mode in UK)

Thirdly, the wind turbine is required to have frequency regulation with 'multi-stage response'. This requirement is very similar to the droop characteristic mentioned above, but features additional configurable points which provide for a two-stage response with different droop characteristic and frequency insensitivity ranges (ENTSO-E and Denmark).

Grid Code for withstanding frequency deviation at initial time of disturbance

In Ireland, the ROCOF capability for all generation units in the Ireland region is specified as 0.5 Hz/s in the Ireland grid Code. With the observed concern of higher ROCOF, EirGrid, Irish TSO, proposed the modification of ROCOF capacity of all generation units from 0.5 Hz/s into 1.0 Hz/s in 2012 [24], requiring the generation units to tolerate more severe frequency deviation.

According to the modification proposal, all generation units should remain synchronised to the transmission system for a rate of change of frequency of up to 1 Hz per second averaged over 500 milliseconds. Voltage dips may cause localised ROCOF values in excess of 1 Hz per second for short periods, and in these cases, the fault-ride through supersedes this ROCOF capability.

In Spain, the Spanish Wind Energy Association (AEE) recommends that wind power facilities are required to withstand frequency variations of at least ±2 Hz/s. This requirement is more severe than that of the Ireland grid code. In addition, wind power is required to have the ability to emulate inertia (same as synthetic inertia). It that case, the equipment for inertia emulation shall generate increments or decreases of active power proportional to the derivative of the frequency at the grid connection point. The inertia emulation system shall meet the requirements such as it can provide active power at least 0.05 p.u. within 50 msec or the insensitivity range for frequency measurements will not be higher than ±10 mHz. Others requirement can be found in [25]. In addition, the use of synthetic inertia is also being discussed as part of the ENTSO-E requirements for the connection of generators [26]. The European Grid code recommends three alternative options to maintain the security of the system. This is because most European countries are expecting particularly high penetration levels of wind-power generation in the coming years. One of the options is to add an additional control function to the wind turbines in order to deliver synthetic inertia and/or fast frequency response capability. The requirements have to be carefully balanced to avoid internal wind turbine stability issues.

Finally, simulation studies from the TSO perspective show that synthetic inertia is needed to improve minimum frequency during a disturbance in the Hydro-Quebec (Canada) and Transpower (New Zealand) regions [27, 28].

2.3 SYNTHETIC INERTIA TECHNIQUES

The state-of-art technical trends for implementing synthetic inertia within a wind turbine are investigated to get the modelling idea of synthetic inertia, which will be used for simulation studies in this project.

2.3.1 Generic active power control of wind turbine

Generic active power control model of wind turbine

In general, four different types of wind turbine generator (WTG) have been used in wind power conversion [29]. But, there are common generic components to four WTG; turbine mechanical controls (i.e. pitch control or stall control) and aerodynamics, shaft dynamics, generator electric characteristics, electrical controls (such as converter controls, switching of shunt capacitor banks etc.) protection, and measurement equipment.

Of these modules, turbine mechanical control and aerodynamic are related to active power control (APC) of WTG. The APC module of WTG is quite similar among the four types of WTG, illustrating in Figure 2.6.

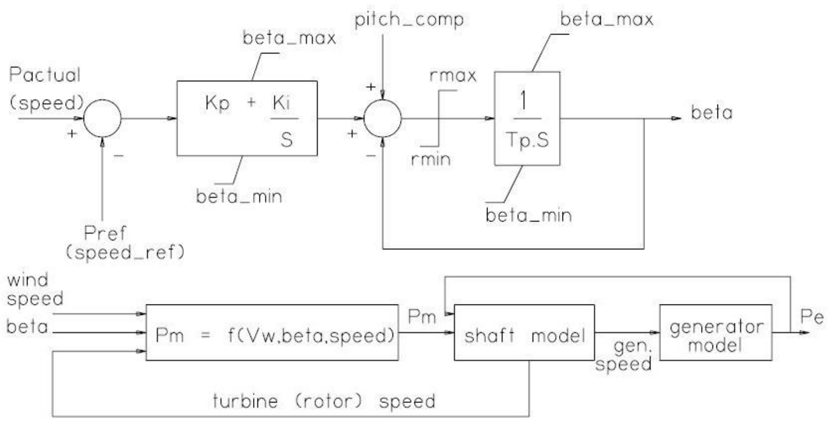


Figure 2-6 Generic mechanical system and pitch control (governor) of wind turbine generator [29]

In pitch control, a non-windup proportional-integral (PI) controller is regulated with respect to the error between actual and reference speed of generator (for variable speed turbines). The actual power (speed) is as measured from the turbine-generator output, whereas the reference power (speed) is defined by the user. In the case of variable speed turbines, the reference speed is generally defined as a function of power output by the manufacturer. The additional signal Pitch_comp is for pitch compensation used in some controller designs, but this could be ignored. The output of pitch control (pitch angle of turbine blade) is fed into mechanical control system. The importance of pitch control will be demonstrated in Section 4.1.2.

In mechanical control, mechanical power (Pm) is calculated as a function of the three input variables such as pitch angle (beta), wind speed (Vw) and rotor speed (ω). The mechanical power and electrical power are then used as inputs to the shaft dynamics equation.

Operating interface with grid for active power

Type 1 (fixed speed wind turbine) and Type 2 (limited variable speed wind turbine) wind turbine generators have been installed in the past. However, with the help of converter technology, both Type 3 (DFIG wind turbine) and Type 4 (full power converter wind turbine) will be dominantly installed. Type 3 and Type 4 wind turbine generation system are shown in Figure 2.7.

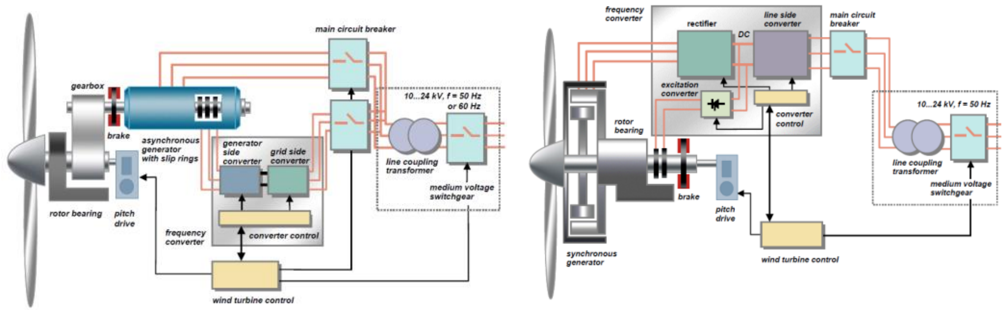


Figure 2-7 WTG Type 3 (DFIG) and Type 4 (FPC) [29]

Commonly, modern wind turbine generation (Type 3 and Type 4, or converter-based wind turbine generator) are integrated with the grid through a power-electronic converter. In Type 4 WTG (FPC), the full electrical output of the generator can be converted from a wide range of frequencies to grid frequency through the use of a frequency converter. This means that the wind turbine generator may operate at a wide range of speeds.

In addition, with the usage of a voltage-source converter, the grid side converter (sometimes referred to as inverter) can independently control real and reactive power. The speed of a wind turbine is not synchronous with the grid and is controlled to maximize active power production. The wind turbine generator is inherently decoupled from the grid. There are several advantages to this, but the drawback is that the turbine does not contribute to system inertia.

2.3.2 Synthetic inertia models

Some selected publications of synthetic inertia model of wind turbines are reviewed to investigate the state-of-art available control methods of implementing synthetic inertia wind turbine generator.

GE wind turbine

GE wind turbine has an active power control (APC) module (WindCONTROL) and a synthetic inertia module (WindINERTIA) as shown in Figure 2.8.

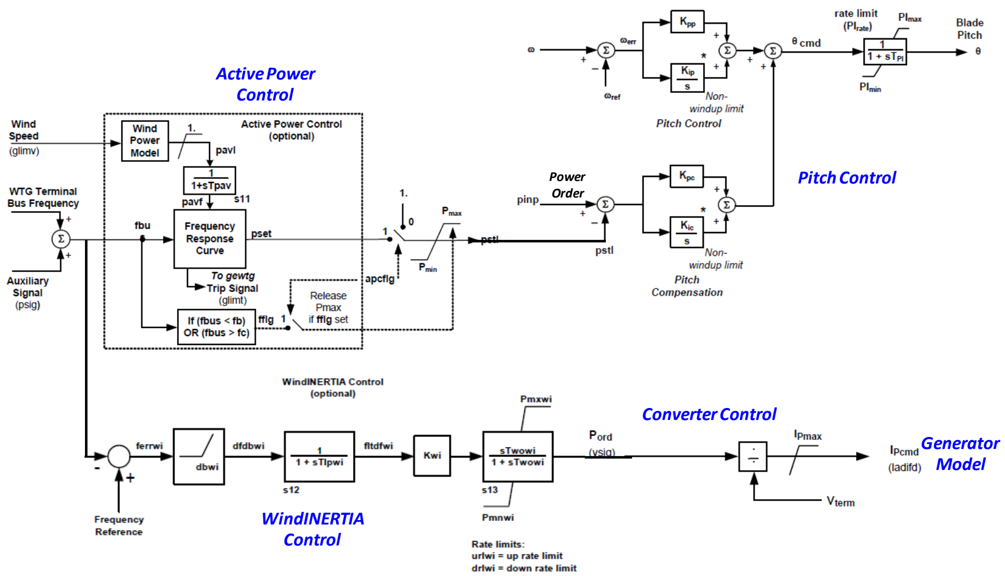


Figure 2-8 Active power control and synthetic inertia of GE wind turbine [30]

In addition to generic turbine control by controlling pitch angle, plant power order, which is calculated as a function of frequency using the frequency response curve (similar to droop characteristics) in APC module, is fed into pitch controller as input signal. APC module is designed to request a lower power than is available from the wind to create headroom to increase active power during low-frequency events.

In WindINERTIA control, the inertia response capability is designed for large low-frequency events. The WindINERTIA has an asymmetric control so that it only responds to low frequencies.

The control philosophy of synthetic inertia is to sense significant grid frequency depressions, as observed at the terminals of the individual wind turbine generators, and to temporarily increase power output. Frequency error is the deviation from nominal frequency. A positive frequency error means the frequency is low and extra power is needed. The dead band suppresses response of the controller until the error exceeds a threshold. This limits the WindINERTIA response to large events - those for which inertia response is important to maintain grid stability. The continuous small perturbations in frequency that characterize normal grid operation are not passed through to the controller. The dead band output signal is further filtered. The final WindINERTIA command is added to the power order and implemented by the WTG converter controls, ultimately resulting in additional power delivery.

Releasing the Hidden Inertia

In [31], releasing the "hidden" inertia control loop is suggested to increase electric power output during the initial stages of a significant downward frequency event. Implementation of releasing hidden inertia controllers is depicted in Figure 2.9.

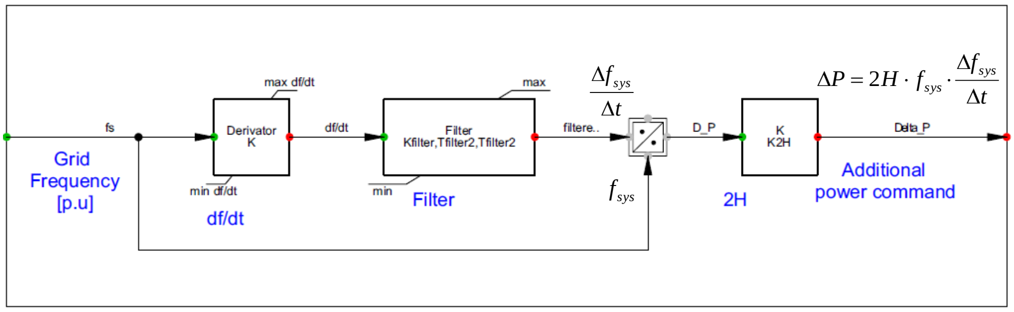


Figure 2-9 Hidden inertia concept proposed in [31]

In the proposed hidden inertia concept, a WTG can quickly store and release a large amount of kinetic energy of rotating masses in proportion to system frequency deviation. Control model is quite similar to GE WindINERTIA, including dead band, signal filtering and proportional gain.

Hydro-Quebec Transenergie (HQT)'s Inertia Emulation

The HQT's transmission connection requirement stipulated in detail that wind power plants must be equipped with an inertia emulation system. The emulation system should only act on major frequency deviations and its performance should be at least as much as the inertia response of synchronous generator whose inertia constant (H) equals 3.5 sec [27].

HQT developed inertia emulator negative model scheme as shown in Figure 2.10 (a), and the emulator is programmed to respond both 'active power contribution stage' and 'recovery stage' as shown in Figure 2.10 (b).

In the inertia emulator model, the model can emulate the injection of the active power contribution as well as the recovery period by adjusting the sign of proportional gain (Kp). The combination of the inertia emulator model's output and wind power plant represents the behaviour of a wind power plant equipped with synthetic inertia. Control model is simpler than GE synthetic inertia model, only consisting of dead band and proportional gain.

In the active power contribution stage, the synthetic inertia of WTG provides power into grid to maintain the frequency nadir of wind power integrated power system. Following system inertia response and primary reserve, WTG returns to initial speed, since WTG's additional active power injection slows down blade rotation speed. Thus wind turbine re-acceleration may be achieved by temporarily reducing power into grid in the recovery stage.

The end of the active power contribution and the start of the recovery stage (transition from point 3 through point 4 to point 5 in Figure 2.10) is equivalent to the system as an additional loss of production. Strict requirements on the turbines are needed to avoid system collapse, which in turn define requirements for the settings of the control parameters.

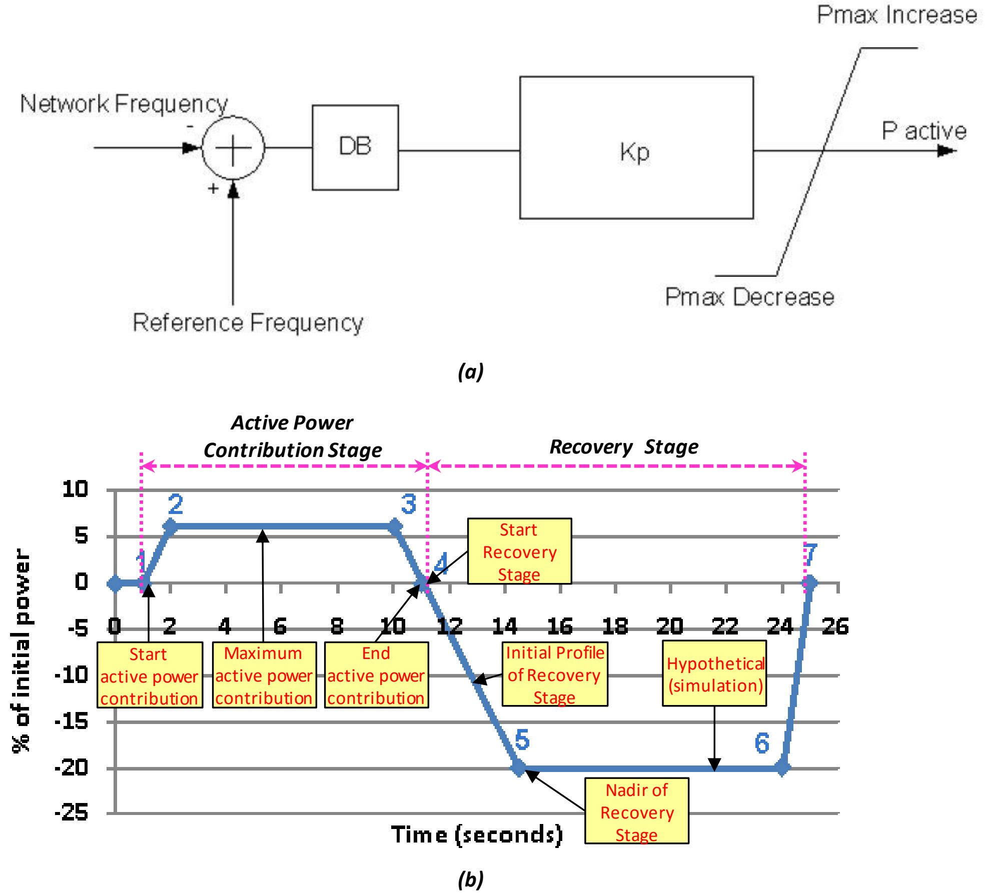


Figure 2-10 HQT's synthetic inertia scheme (a) Inertia emulation model block diagram (b) programmed contribution of inertia emulator [27]

Modified wind turbine controller

In [32, 33], modified wind turbine controller is proposed to achieve two purposes: smoothing output power and response to external frequency disturbance. The proposed wind turbine controller does not include 'synthetic inertia'. The control principle of the modified wind turbine controller is that the frequency deviation is fed into pitch controller through ACP module as well as power order to converter as shown in Figure 2.11. Thus its control feature is quite similar to that in the GE WindINERTIA model.

The pitch controller is designed to respond by changing the pitch angle for small frequency errors, making for a smoother and steadier power output from the wind turbine. Meanwhile, the modified speed controller is mainly aimed to respond fast when a grid disturbance occurs. Load step response simulations with the modified wind turbine controller show that ROCOF is obviously improved right after load tripping and load shedding.

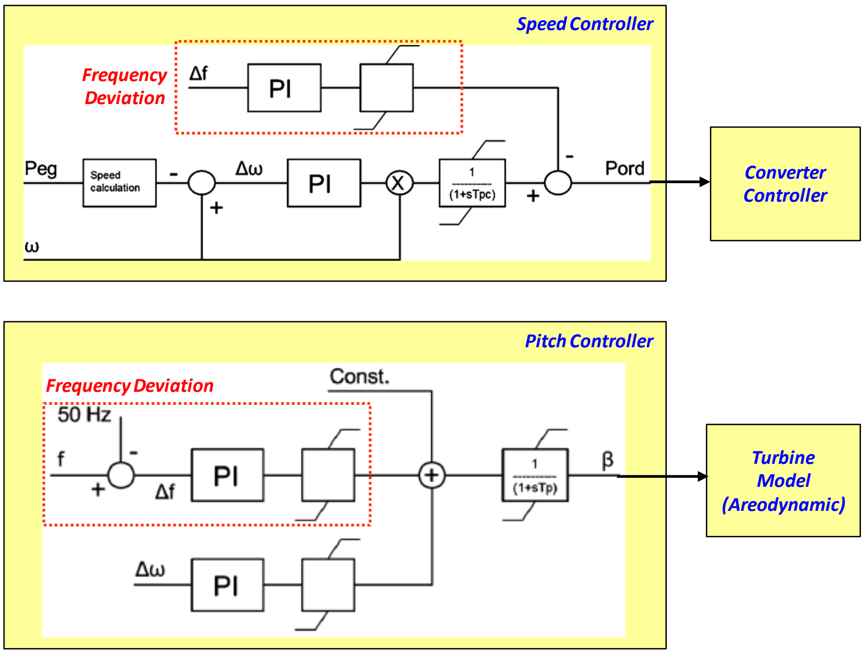


Figure 2-11 Modified speed controller and pitch controller proposed in [32] for combining power smoothing and frequency control

As the summary of reviewing synthetic inertia techniques, the frequency deviation from a grid disturbance is directly fed into the converter in order to change the reference power setting (power order) without time-delay, feeding active power into the grid at the early stage of disturbance before primary reserve (governor) starts to support the frequency. In the controller model, a dead band is used to provide threshold of measurement and a low pass filter is included to remove the noise of steady state error of frequency deviation measurements.

3 Modelling Network, Synthetic Inertia and study scenarios

The simulation network model and synthetic inertia controller are presented in this chapter. PSS/e software is used as the main simulation package.

3.1 MODELLING NETWORK AND STUDY SCENARIOS

A modified Nordic-32 model is used as the simulation network model.

3.1.1 Network model

Base case operation condition

The flow exchange within the base operation condition is benchmarked based on actual power condition in Sweden at 11:00 hrs, on the 25th of January 2013 [34]. This hour is selected because it represents the peak power generation, i.e. the operating stage with lowest primary reserve. However, the power flow being used for simulation in this study is scaled down to a factor of 0.3, i.e. reduced by 70%. Moreover, to investigate the effect of the synthetic inertia produced by wind turbines, it is assumed that there is no power exchange with other European countries and wind power is not considered in the base operation condition.

In addition, it is assumed that power production is shared between hydro (24%), nuclear (74%) and thermal (2%) in the Swedish grid. Table 3.1 shows the generation dispatch which has been used as the base operation condition in the Nordic-32 system. Table 3.2 and Table 3.3 represent the active power for all generating plants and active loads in the Nordic-32 test system, respectively. Consumption is 7517 MW, production is 7604 MW, and the difference of about 1.1% is due to the transmission system losses.

Table 3-1 Power balance for base case

Generation	Actual Power Flow		Nordic-32 system	
	MW	%	MW	%
Hydro Power	13042	51.3%	4077	54%
Nuclear Power	8864	34.9%	2777	37%
Thermal Power	2551	10.0%	750	10%
Wind Power	960	3.8%	0	0.0%
Total Generation	**25417**	**100%**	**7604**	**100%**
Total Demand	**25073**		**7517**	
Import/export	**344**		**0**	

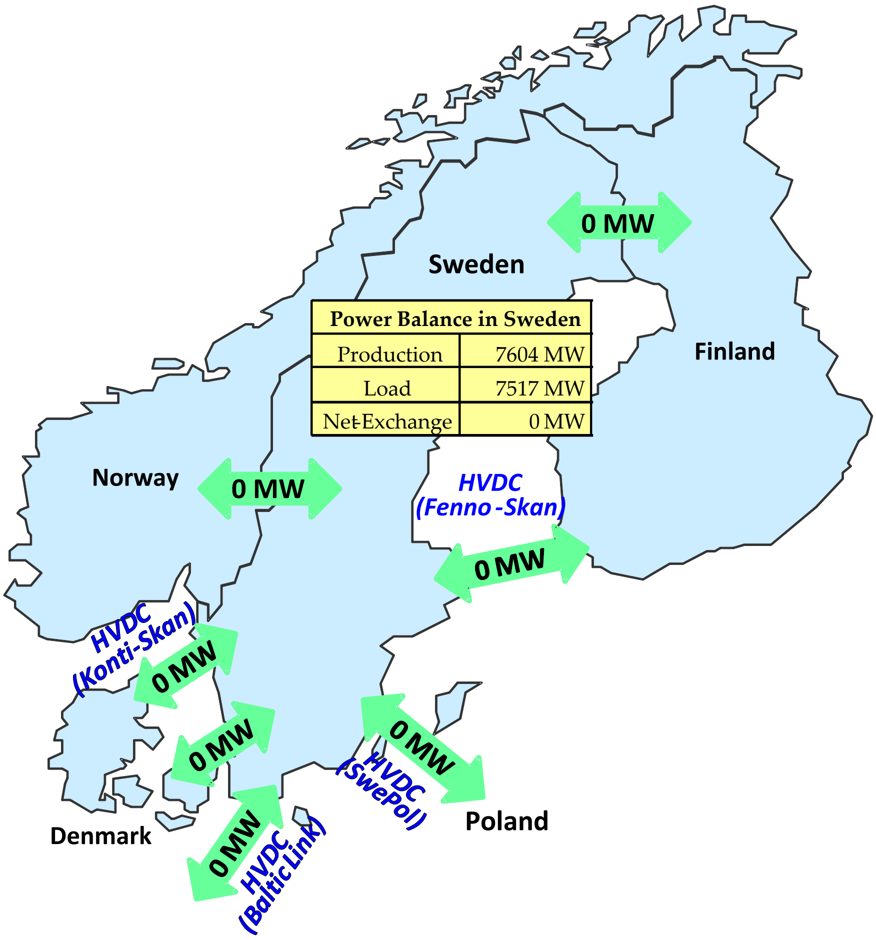


Figure 3-1 Operating condition of base case for frequency stability

Table 3-2 Generator active production in base condition

Gen	Types	Pg [MW]	Mbase [MVA]
1012	Hydro	464.1	700
1013	Hydro	331.5	500
1014	Hydro	397.8	600
1021	Hydro	331.5	500
1022	Hydro	165.75	250
1042	Thermal	450	600
1043	Thermal	300	400
2032	Hydro	563.55	850
4011	Hydro	663	1000
4012	Hydro	530.4	800
4021	Hydro	198.9	300
4031	Hydro	232.05	350
4041	Hydro	198.9	300
4042	Nuclear	589.05	700
4047	Nuclear	504.9	600
4047	Nuclear	504.9	600
4051	Nuclear	589.05	700
4051	Nuclear	589.05	700
Total		7604.4	

Table 3-3 Active loads in base condition

Bus	Pload [MW]
41	549
42	419
43	939
46	723
47	101
51	824
1011	202
1012	312
1013	116
1022	289
1041	621
1042	318
1043	246
1044	832
2031	723
2031	101
2032	202
Total	7517

System inertia capability

Two generator models are included in the base case operation of the modified Nordic-32 network; salient pole type for hydro generation and round rotor type (thermal and nuclear). It is assumed that all generators of one type have the same inertia constant. In addition, the hydro power plant located at bus 4011 is the swing bus.

Based on the assumed inertia constant, the stored energy in generator rotating mass is calculated for the modelled system as shown in Table 3.4.

Table 3-4 Stored energy on mass in base case condition

Fuel	Inertia Constant [MW·s/MVA]	Capacity [MVA]	Stored Energy in Mass [MW·s]
Hydro	5	6550	32750
Thermal/Nuclear	7	3900	27300
Total	-	10450	60050

Table 3-5 Power factor of generator

Nordic-32 model	
Installed capacity (MVA)	10450
Power factor of generator	0.85
Production availability (MW)	**8883**

With the total generation shown in Table 3.5 and the 0.85 power factor, the maximum primary reserve for this test case is equal to 16.8% i.e. 7604 MW of 8883 MW. The details regarding the PSS/E models used in this project can be found in Appendix A.

3.1.2 Study scenarios

Simulation scenarios are created for investigating the long-term wind power integration, where the wind power integration might replace the energy production of conventional generation units. Some selected control parameters of synthetic inertia within wind turbine are investigated to assess how they could impact on the frequency control stability.

The test scenarios can be summarized as follows:

- **Scenario 1**: Impact of inertia control

  This scenario is aimed to quantify the difference in frequency response for systems containing wind turbines with and without synthetic inertia control.

- **Scenario 2**: Impact of tuning controllers

  This scenario is aimed to demonstrate which control parameters should be changed in order to improve the frequency stability

- **Scenario 3**: Impact of Active Power Control (APC) activation

  This scenario is aimed to assess the impact of different active power control strategies on the frequency response of an interconnected system which can become an additional source of flexibility for power system operators

- **Scenario 4**: Impact of Wind Power Penetration Level

  This scenario shows the impact of the increase of wind power penetration on the performance (frequency nadir and settling frequency)

- **Scenario 5**: Impact of different wind speeds
  This scenario investigates the impact of changing the wind conditions. Three wind speeds are simulated (low wind speed at 7 m/s, rated wind speed at 14 m/s and high wind speed at 25 m/s) to see their effect on frequency response.

4 Simulations and Results

Simulation studies are performed to evaluate the impact of wind power penetration on frequency stability. PSS/e software (Version 33) is used as the simulation tool.

4.1 FREQUENCY STABILITY SIMULATION

Both disturbance event and simulation cases are described as below.

System disturbance for frequency stability

It is assumed that the loss of a large generation unit results in a system disturbance with decreasing system frequency. A thermal plant at Bus 1014 is disconnected with the power production loss of 398 MW. This accounts to 5.2% of total generation (with respect to production) in base case operation. This event is used for the examination of frequency response.

From the data in Chapter 3 it follows that the available kinetic energy after the loss of the 398-MW production from the thermal unit, is equal to 55 850 MWs. That gives for the initial rate of change of frequency:

$$\frac{df}{dt} = -\frac{f_0}{2} \times \frac{\Delta P}{E_{kin}} = -178 \text{ mHz/s}$$

To examine the effect of synthetic inertia, some conventional generators are replaced by wind turbines. From a power flow perspective, there is no difference between a wind-power generator and a conventional generator. Both are modeled as a source specified with four parameters from active and reactive power outputs, bus voltage magnitude and bus voltage angle. Moreover, it is assumed that wind turbines are located at the same bus where the conventional generators were located. Therefore, the same power flow provided the initial conditions for all of the dynamic simulations. This means that the modification is implemented by modifying only the dynamic data. The load and power flows remain unchanged. This approach ensures that the performance differences are associated with a change in generation technology and not due to a change in generation location.

4.1.1 Scenario 1: Impact of inertia control

In this scenario, two of the nuclear plants at Bus 4047 are replaced by wind power with the same amount of produced active power to demonstrate a substantial impact on system performance. These two thermal plants generate 1010 MW which is about 13.3% of total power generation. A wind speed equal to 14 m/s has been assumed for all locations.

Figure 4.1 shows the frequency response at Bus 1014 when the hydro plant at this bus is tripped. A comparison has been made between the system without wind power production (denoted as the "no-wind"), wind power without inertia control (denotes as the "13.3% wind") and with inertia control (denoted as the "13.3% wind with inertia").

The frequency nadir of 13.3% wind" and "no-wind" and "13.3% wind with inertia" are 48.98 Hz and 49.05 Hz, respectively. As shown in Figure 4.2, the wind power without inertia control provides constant power whereas the one with inertia control increases the output of the wind plants substantially. This extra energy (area A) raises the minimum frequency, allowing time for the active governors to respond. The inertia controller improves the nadir point by bringing the minimum frequency up to about the level of the “no-wind” case.

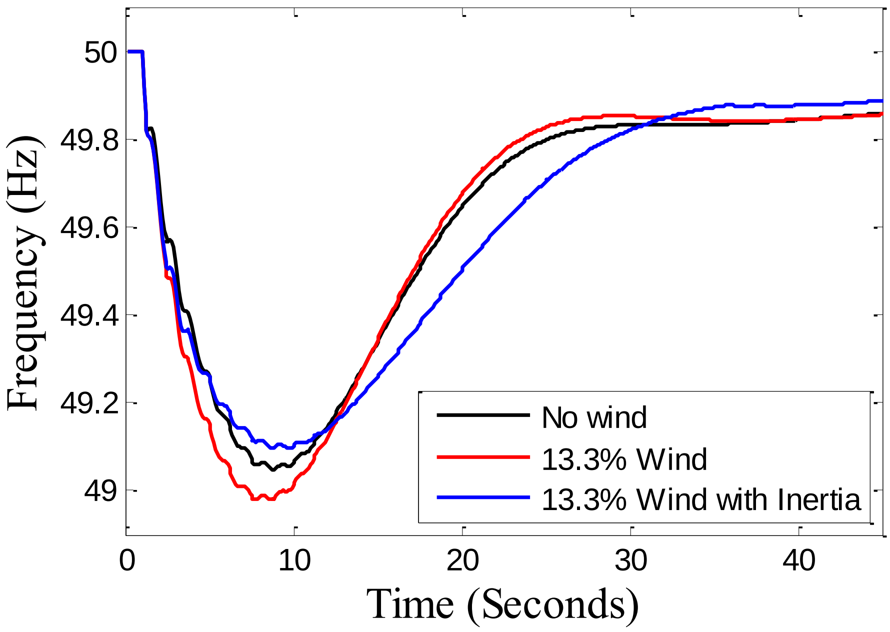


Figure 4-1 Frequency response to loss of generation of Scenario 1

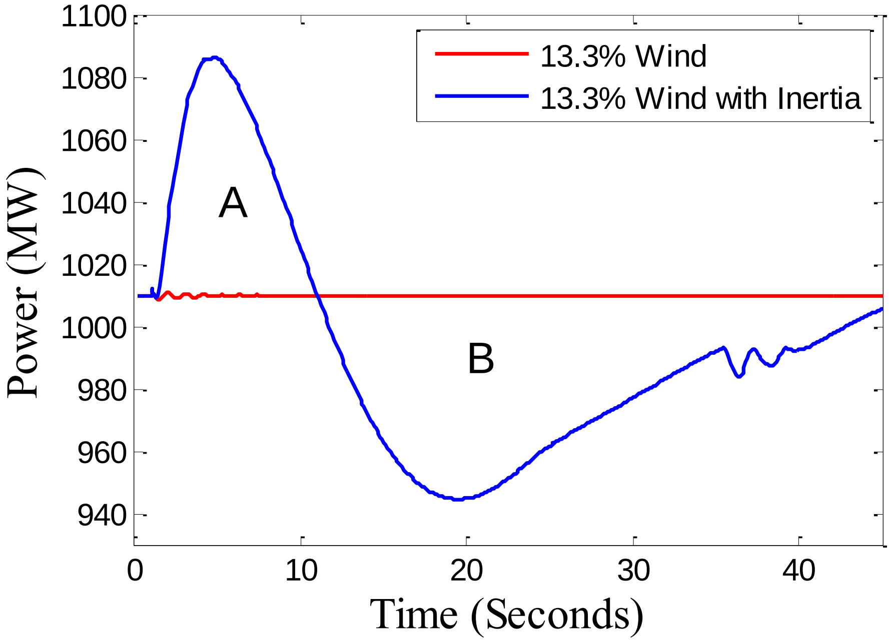


Figure 4-2 Wind power response from inertia control of Scenario 1

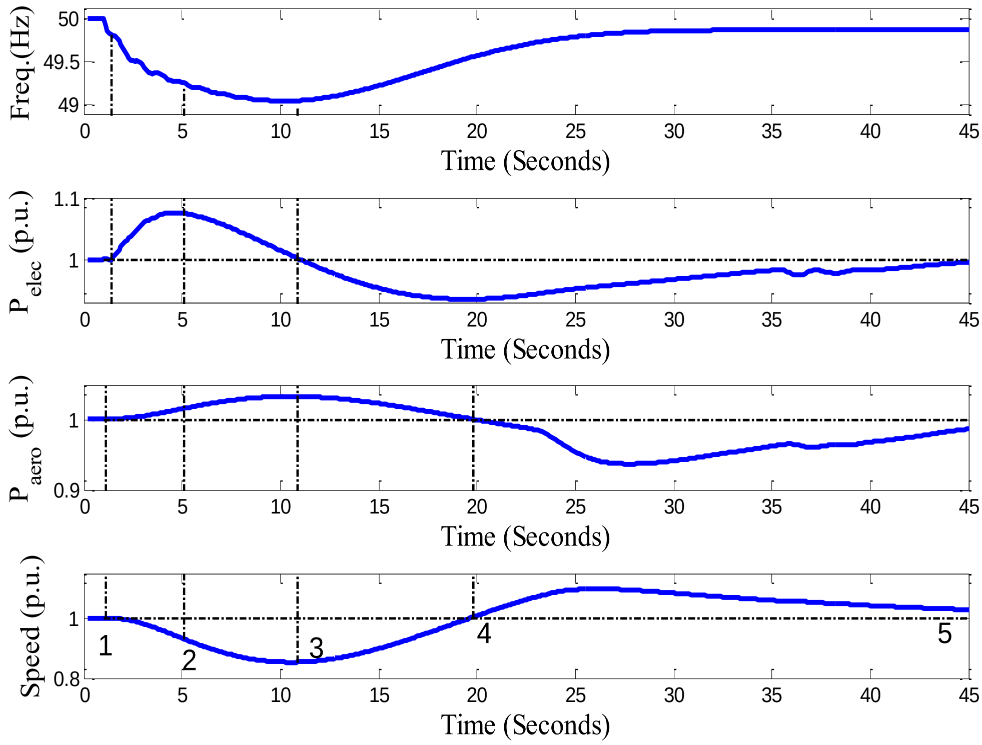


Figure 4-3 Frequency (top), Electrical power (second), Aerodynamic power (third) and Speed (bottom) responses of wind turbine of Scenario 1

The impact on system frequency can be better understood by demonstrating the active power response of the wind turbines along with the speed of turbine and the aerodynamic power (see Figure 4.3). Once inertia control is activated (at point “1”) which is about 1 sec after the disconnection of the generator, it provides an additional injected power to the system; at the same time, the turbine speed starts declining. The energy for the additional power injection is drawn from the rotational mass of wind turbine when a turbine is commanded to increase power production. For this study, the electrical power reaches the maximum about 5.1 seconds (point “2”) into the event before the system frequency reaches its nadir. This additional power is delivered for about 10.9 seconds (point “3”) before the power drops below the initial level and the speed of the wind turbine reaches its minimum speed at the same point.

Then, the energy extracted from the rotating energy of the wind turbines must be recovered to accomplish the re-acceleration process. This can be done by both reducing power generation of wind turbine and by increasing the aerodynamic power. Therefore, the turbine speed starts restoring to its initial point i.e. from point “3” to point “4” as shown in Figure 4.3. However, the wind turbine overspeeds hence the pitch controller changes its angle to extract less power from the wind to avoid this phenomenon. Consequently, the wind power production is gradually brought back (from point “4” to point “5”) to the pre-fault value. This phase of returning to normal speed, from point “3” to point “5” is called the recovery period.

4.1.2 Scenario 2: Impact of tuning controllers

Similar to Scenario 1, however the rate at which the wind turbine accelerates during the recovery period is improved by tuning the controllers' parameter in both inertia and pitch control systems. Figure 4.4 shows that the frequency nadir with tuned controller is 0.14 Hz better than the "13.3% wind" case. It can be seen by comparing Figure 4.5 with Figure 4.2 that the maximum support (highest value in area A) of the tuned-controller case is bigger but that the recovery energy (size of area B) of the tuned case is smaller compared to the non-tuned case by only changing some parameters' value. In this study, area A can be increased by changing the default values (provided by the manufacturer) as follows: the up ramp rate limit (urlwi) from 0.1 p.u. to 0.005 p.u. whereas area B can be decreased by making the following changes

- pitch integrator gain, from 30 p.u. to 3 p.u
- torque's proportional gain, from 0.3 p.u. to 7.5 p.u
- torque's integrator gain 0.1 p.u. to 0.05 p.u.
- torque's filter time constant from 0.05 s to 4 s

Figure 4.6 shows that by tuning the pitch controller's parameters, the pitch angle can be quickly adjusted to remain at its optimal operating point (9.7 degree in this study) i.e. extract more power from the wind in lesser time compared to the previous scenario. As a result, the frequency nadir is improved from 49.05 Hz to 49.12 Hz as shown in Figure 4.4. It is worth noting that the "tuned with inertia" case gives an even higher nadir than the "no wind" case.

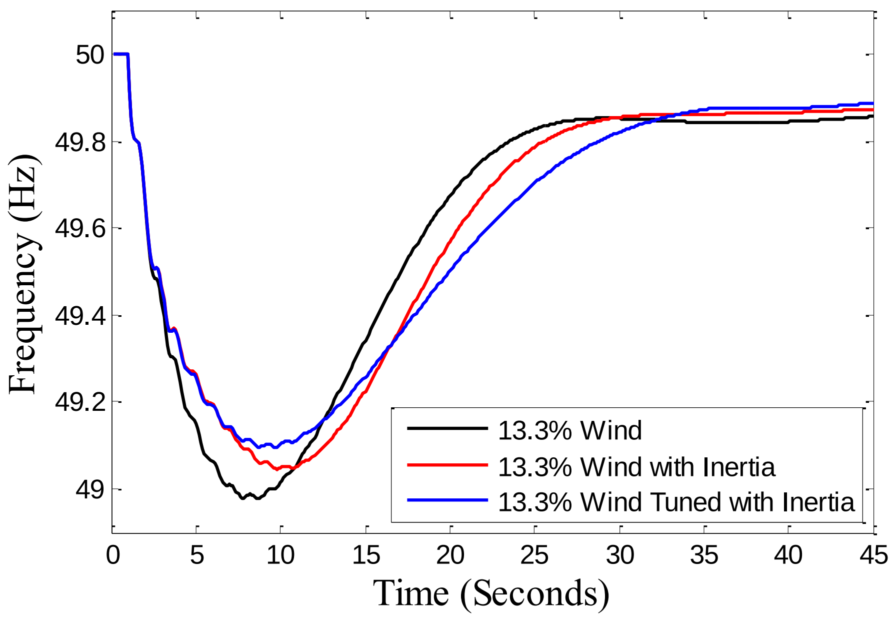


Figure 4-4 Frequency response to loss of generation of Scenario 2

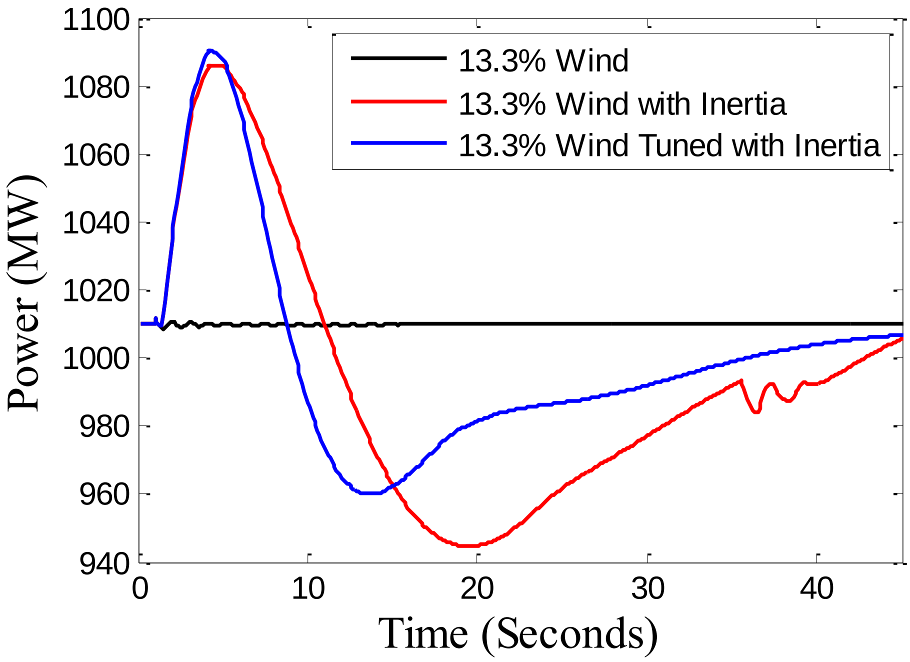


Figure 4-5 Wind power response from inertia control of Scenario

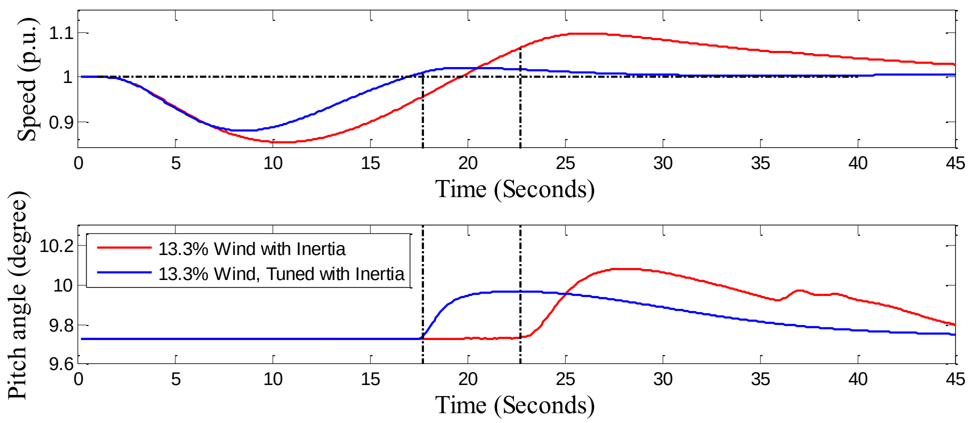


Figure 4-6 Speed (top) and Pitch angle (bottom) responses of Scenario 2

4.1.3 Scenario 3: Impact of Active Power Control (APC) activation

Previously, the wind turbine generators were operated at their maximum power when the loss-of-production occurred. In this scenario, the wind turbines operate below their maximum power (curtailed operation) to provide primary reserves. The Active Power Control (APC) mode (see Figure 2.8) is activated to demonstrate the impact of different active power control strategies. This mode commands a wind turbine to operate in a curtailed manner to provide a specified margin by producing less power than is available from the wind, similar to the frequency regulation capability of conventional stations as shown in Figure 2.5. Therefore, there is more headroom for additional power increase when both inertia and APC controls are combined. In this study 5% margin is set for APC; this means that the wind turbine generates only 95% of the available power under normal operating conditions. For the simulation, the wind speed is increased such that the wind turbines generate 95% but the total wind power production stays at the same level as in the previous scenarios. Figure 4.7 and Figure 4.8 show the frequency and wind power responses for different control strategies, respectively.

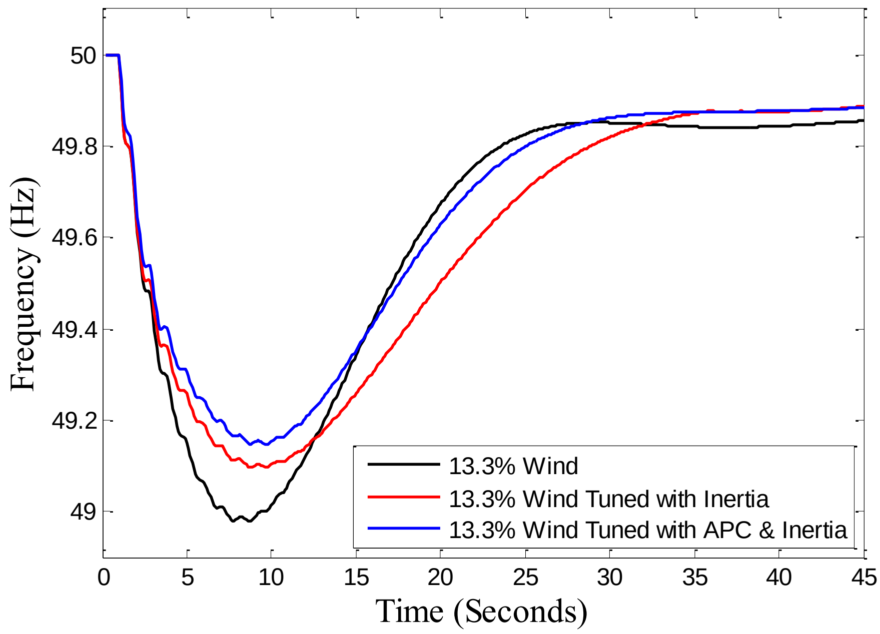


Figure 4-7 Frequency response to loss of generation of Scenario 3

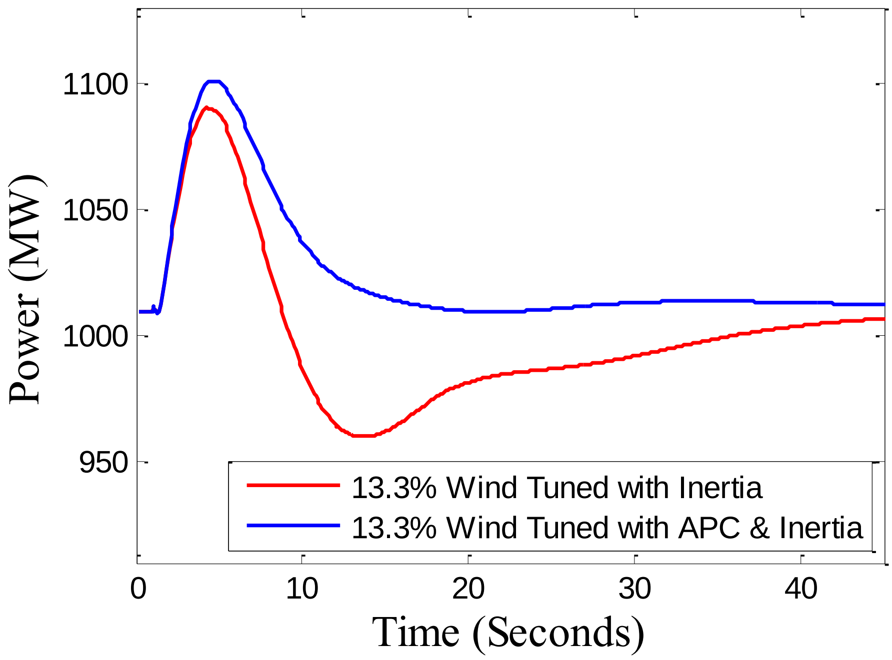


Figure 4-8 Wind power response of Scenario 3

As shown in Figure 4.7, the frequency nadir with activation of APC and inertia (tuned) controls is 49.18 Hz which is about 0.06 Hz and 0.2 Hz higher than the nadir point of on inertia control activation and the no control case, respectively. Moreover, the combined response of the APC and inertia controls contribute to much higher additional power response from the wind turbine to the loss of generation compared with either solely APC or inertia control.

4.1.4 Scenario 4: Impact of Wind Power Penetration Level

In this scenario, the impact of different wind power penetration levels has been investigated. In addition to Scenario 1, two additional 590 MW nuclear plants at Bus 4051 (about 6.64% of total power generation each) are replaced by wind turbines to obtain 28.8% wind power production. Another 590 MW plant at Bus 4042 is replaced by wind turbines to obtain the total of 36.6% wind power production. The summary of different wind power penetration levels is as follow:

- Two nuclear generators at Bus 4047 → 13.3%
- Two nuclear generators at Bus 4047 and two at Bus 4051 → 28.8%
- All nuclear generators (two at Bus 4047, two at Bus 4051, one at Bus 4042) → 36.6%

In the same way as before, the available kinetic energy (after the loss of the nuclear plant) and rate of change of frequency have been calculated.

- For the 28.8% case, there is 37 650 MWs available, resulting in a ROCOF equal to -264 mHz/s
- For the 36.6% case, the values are 32 759 MWs and -304 mHz/s

Figure 4.9 and Figure 4.10 show the frequency response for 28.8% and 36.6% wind power penetration levels, respectively. It can be seen that the increase of wind power penetration has an impact on both frequency nadir and settling frequency. The value of frequency nadir is lower in the case of higher penetration level without either inertia or APC control. This can be explained that, as wind generation displaces synchronous generation, the overall system inertia decreases due to fewer synchronous machines. Moreover, the activation of only inertia control creates some overshoot and delay in settling frequency. This is because inertia control only decreases the rate of frequency change which slows down the speed of wind turbines where this slowdown leads the wind turbines to depart from their maximum power point. Therefore, it creates a deficiency of active power which results in longer frequency recovery time.

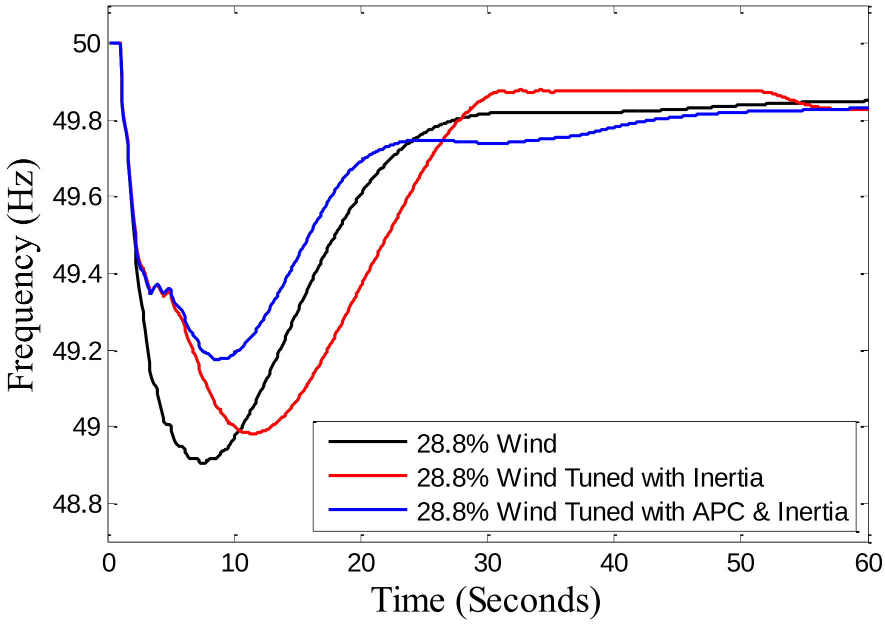


Figure 4-9 Frequency response of 28.8% Wind Power

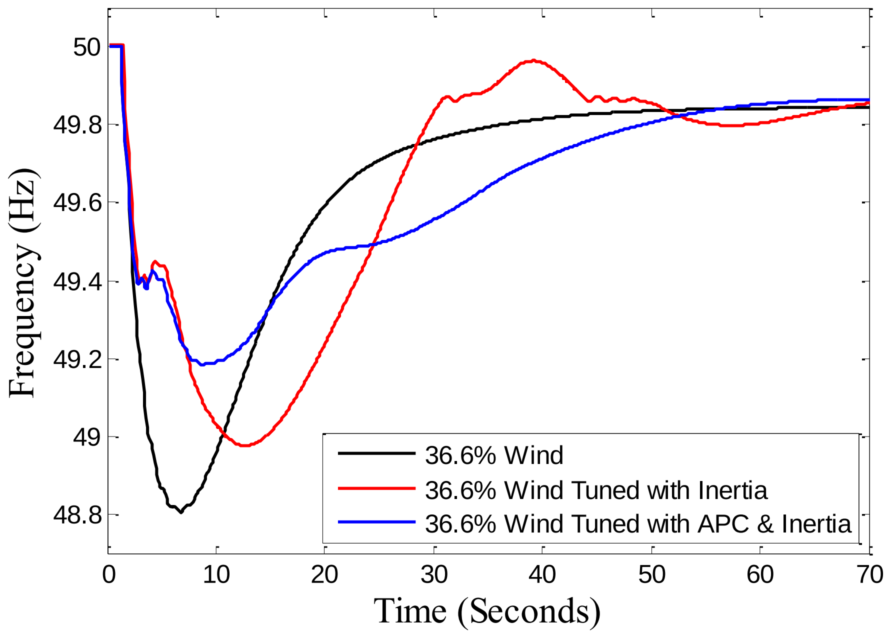


Figure 4-10 Frequency response of 36.6% Wind Power

Table 4.1 shows the consolidated results and the impact of the penetration level on frequency nadir and frequency settling time for different cases. As mentioned earlier, the combination of inertia and APC controls provide the best nadir and settling frequency performance at any wind power penetration level. However, it is worth noting that this improvement is not proportionally increased with the higher penetration level. There are several factors behind this result such as different ratings of nuclear plants replaced by wind power plants and different active power orders (productions) for generators located at different buses. Particularly, the APC control's parameters are also needed to be tuned for obtaining the optimal solutions in terms of frequency nadir and frequency settling time.

Table 4-1 Frequency nadir and settling frequency of different penetration levels

Wind %	No inertia control		With inertia control		With APC and inertia	
	Frequency nadir (Hz)	frequency settling time (sec)	Frequency nadir (Hz)	frequency settling time (sec)	Frequency nadir (Hz)	frequency settling time (sec)
0%	49.05					
13.3%	48.98	27.0	49.12	34.8	49.16	31.5
28.8%	48.91	43.3	48.98	55.4	49.19	48.2
36.6%	48.81	55.5	48.95	69.4	49.20	61.5

4.1.5 Scenario 5: Impact of different wind speeds

In this scenario, the impact of different wind speeds on the frequency nadir is investigated. The wind speed is assumed to be constant and uniform across the system. This means that the effect of wind fluctuation is ignored, resulting in constant power production from wind turbines. The "wind tuned with inertia" case has been used for the control settings.

Figure 4.12 shows the frequency impact of changing the wind conditions to the nadir point for 31.3% wind power production. The inertia response, during the first few seconds is independent of the wind speed. After about 4 seconds into the event, the inertia response is exhausted, as is shown among others in Figure 4.5. The primary reserve has not yet been fully activated and the frequency starts to drop again.

The depth of the second dip (with its nadir somewhere around 10 seconds into the event) depends strongly on the wind speed. This is due to the activation of the pitch-angle control increasing the aerodynamic power into the turbine. This is shown in Figure 4.12 (bottom). The higher the wind speed, the more un-used energy is available in the wind and the more the second dip can be mitigated.

Figure 4.13 depicts the frequency nadir points for different wind power penetration levels (also summarized in Table 4.2). It can be seen that the difference between nadirs for low wind speed (11 m/s) and high wind speed (21 m/s) become larger when the penetration level is increased.

The low and high wind speed thresholds are at 3 m/s and 25 m/s, respectively. The "nominal wind speed" is 14 m/s for the 4 MW turbine that has been modelled[1]. (The nominal wind speed is the speed at which the turbine reaches its nominal production; for higher wind speed stall control or pitch control limits the production.)

[1] http://www.thewindpower.net/turbine_en_9_ge-energy_4000.php

The three wind speeds being studied thus correspond to: somewhat below the nominal speed (11 m/s); at the nominal speed (14 m/s) and well above the nominal speed (21 m/s).

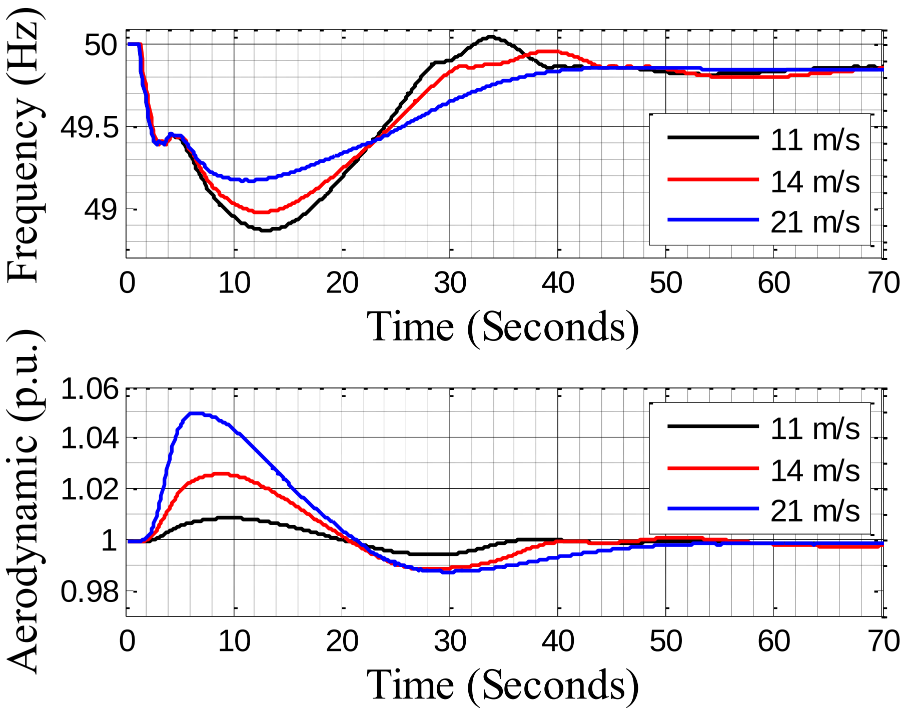


Figure 4-11 Frequency (top) and aerodynamic power (bottom) response for different wind speed (31.3% wind power penetration)

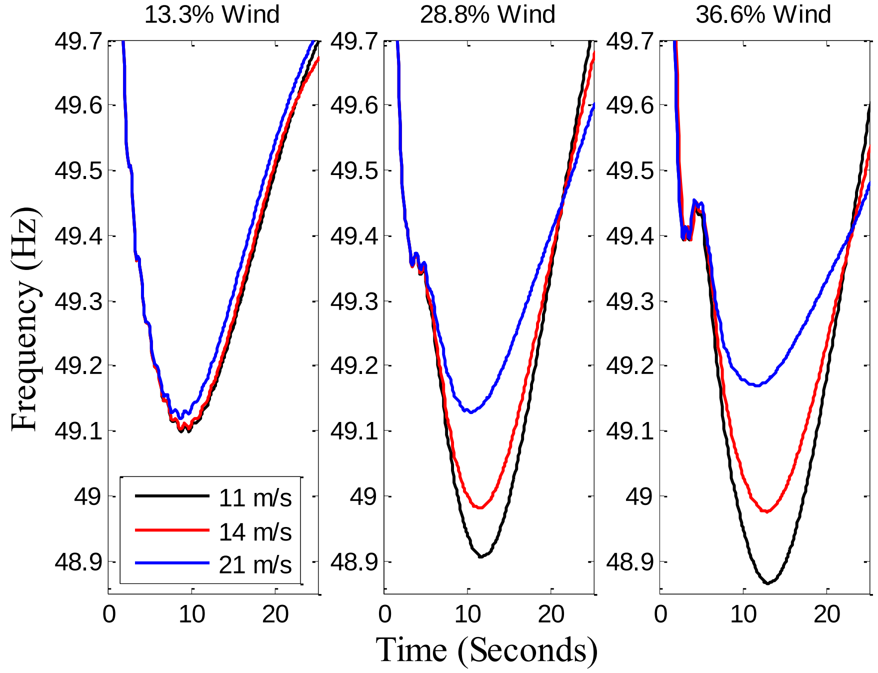


Figure 4-12 Frequency nadirs of different wind speed for different penetration levels

Table 4-2 Frequency nadirs of different wind speed for different penetration levels

Wind %	11m/s	14m/s	21m/s
	Frequency nadir (Hz)	Frequency nadir (Hz)	Frequency nadir (Hz)
13.3%	49.10	49.12	49.12
28.8%	48.91	48.98	49.13
36.6%	48.87	48.95	49.17

5 Estimated amount of inertia available to the system

Among renewable resources, wind power is one of the favorable technical and economic prospects. Wind power production is predicted to grow up to 20 % by 2050 for the purpose of reducing greenhouse gas emissions [37]. According to this reason, some conventional synchronous generators will inevitably be replaced by a large penetration of wind turbines. Although, the majority of wind turbines available commercially are equipped with inertia control (as described in Chapter 2) this function is rarely used to provide inertia support to the grid. This results in the depletion of inertia response, consequently reducing an overall kinetic energy which has importance for securing system's stability when subjected to disturbances.

This chapter illustrates how the expansion of wind power might endanger the frequency stability of the grid. The analysis is based on the time-series wind power production that is provided by Uppsala University. This time-series data is simulated by using the model based on Modern Era Retrospective-Analysis for Research and Applications (MERRA) reanalysis data and information on wind energy converters (WECs) in Sweden [38]. Three cases, denoted as A1, B1, and C1, were taken from the database, with current and planned WECs and assumptions influencing which wind farms are most likely to be built, given different total annual energy production (20, 30, and 50 TWh, respectively) from onshore and offshore wind turbines. Moreover, one additional case (denoted as A8) is included. The difference of the A8 case compared to other cases is that only the WECs which are already built and under construction are considered for the total annual energy production of 14.3 TWh.

More details about the MERRA model and how to obtain the time-series wind power production can be found in [39]. Finally, wind power curtailment will be demonstrated to fulfill the requirement in terms of minimum kinetic energy for those cases in different scenarios.

5.1 SCENARIO 1: WIND POWER PRODUCTION ONLY IN SWEDEN

In this scenario, the power demands of three Nordic countries i.e. Sweden, Finland, and Norway, where the eastern part of Denmark is neglected, are considered but only wind power produced in Sweden is considered for calculating minimum kinetic energy and wind power curtailment.

The conventional generated power is determined as:

$$Pconv_{scandinavia}(h) = PL_{sweden}(h) + PL_{norway}(h) + PL_{finland}(h) - Pwp_{sweden}(h) \quad (5.1)$$

where;

$PL_{sweden}(h)$ is the time-series of consumption obtained from Svenska kraftnät's website.

$Pwp_{sweden}(h)$ is the time-series of wind power obtained from Svenska kraftnät's website.

$PL_{finland}(h)$ is the time-series of consumption obtained from Fingrid's website.

$Pwp_{finland}(h)$ is the time-series of wind power obtained from Fingrid's website.

$PL_{norway}(h)$ is the time-series of consumption obtained from Statnett's website.

$Pwp_{norway}(h)$ is the time-series of wind power obtained from Statnett's website.

5.1.1 System inertia constant

The kinetic energy in the system has been estimated as:

$$E_{kin}(h) = H_{sys} * Pconv_{scandinavian}(h) \tag{5.2}$$

where the average inertia constant of the whole power system (H_{sys}) is obtained from:

$$\frac{df}{dt} = \frac{P_g - P_l}{2H_{sys}} f_0 \tag{5.3}$$

where P_g, P_l, and f_0 are the generated power, the power demand, and nominal frequency, respectively. For calculation purposes in this study, H_{sys} is assumed to be 7.6 s. This value is calculated based on the numerical example provided in [40]. It stated that between 10:00 hrs and 11:00 hrs on November 28, 2010 there was 1050 MW loss of production which responses to the rate of change of frequency ($\frac{df}{dt}$) equal to 62 mHz. Meanwhile the total production in the Nordic system at that time was 55700 MW.

Hence; H_{sys} =(1050/55700)/(2*0.062) *50Hz = 7.6 s.

This selection is also confirmed by the actual measurement shown in [41] that the value of system's inertia constant, (with the total consumption as a base), is in the range of 7 to 9 seconds. The system inertia constant for this study is equal to 7.6 seconds.

The calculations in the remainder of this chapter all assume that the available kinetical energy is constant in terms of MJ per MW power produced from conventional generation. It would be more realistic to assume that this energy to be constant in terms of MJ per MVA installed capacity of conventional generation. The latter would for example also include the "spinning reserve" and the fact that some units may be operating at less than maximum capacity. That would however have required a more detailed model that would be reasonable considering the other assumptions made.

5.1.2 Kinetic energy threshold

It is assumed that a lower threshold exists for the amount of kinetic energy (δ_{kin}) than should be present for the system to be secure:

$$E_{kin}(h) \geq \delta_{kin} \tag{5.4}$$

To estimate the "kinetic energy threshold" the following reasoning has been used. It is assumed that all past operational states were secure (in this case that means: frequency stable after the dimensioning failure). It is further assumed that a 10% margin exists between the lowest historical amount of kinetic energy and the amount needed to keep the system secure.

The threshold is obtained from the actual wind power production from 00:00 hrs of January 1, 2008 through 23:00 hrs of December 31, 2013 and consumption with the assumption of no import/export.

The threshold is calculated as:

$$\delta_{kin} = 90\% * minimum\ E_{kin}(h) \tag{5.5}$$

From the data obtained from Svenska kraftnät's website, the lowest historic amount of kinetic energy by using equation (5.2) is 45.65 GJ. Hence, the δ_{kin} is set to 45.65 GJ * 90% = 41.085 GJ.

Figure 5.1 show the time-series of wind power (top plot) and power consumption (middle) obtained from Svenska kraftnät's website and the time-series (calculated) of kinetic energy obtained from using equation (5.2) (bottom plot). The red-dashed line in the kinetic energy plot represents the calculated threshold using equation (5.5).

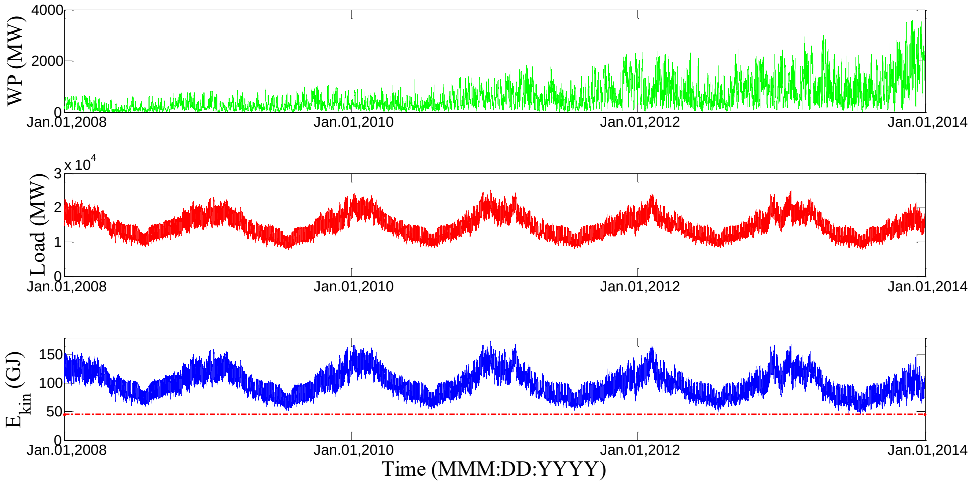


Figure 5-1 Wind Power Svenska kraftnät (top), Power Consumption Svenska kraftnät (middle), Calculated Kinetic Energy (bottom)

Repeating equations (5.2), (5.4) and (5.5); the new threshold value of the minimum kinetic energy for this case ($\delta_{kin\ scandinavia}$) equals to 139.27 GJ. The result is as follows:

Case A1: 0 hrs ≈ 0 hrs/yr

Case A8: 0 hrs ≈ 0 hrs/yr

Case B1: 32 hrs ≈ 5 hrs/yr

Case C1: 713 hrs ≈ 119 hrs/yr

This percentage is calculated based on 52584 hours which is the number of hours between January 1, 2008 and December 31, 2013.

5.1.3 Curtailment of wind power

An alternative solution, instead of synthetic inertia, is curtailment of wind power production during a limited number of hours per year. During hours with insufficient kinetic energy the wind power production is curtailed and therewith the conventional production increased.

During those hours, the wind power production is reduced such that

$$E_{kin}(h) = \delta_{kin} \qquad (5.6)$$

Combining equation (4.6) with (4.1) and (4.2); the reduced production is expressed as:

$$Pwp_{reduced}(h) = PL_{Scandinavian}(h) - \frac{\delta_{kin}}{H_{sys}} \quad (5.7)$$

Thus, the reduction in wind power production equals to

$$\Delta Pwp(h) = Pwp_{Scandinavian}(h) - Pwp_{reduced}(h) \quad (5.8)$$

Figure 5.2 shows the amount of curtailment for Case B1 and C1 whereas Figure 5.3 depicts the kinetic energy calculated from those original and curtailed wind power for both cases.

As shown in Figure 5.2 the need for curtailment is strongly seasonal and mainly limited to the summer season when consumption is low. Despite the higher production of wind power during winter, there is no need for curtailment because of the higher consumption.

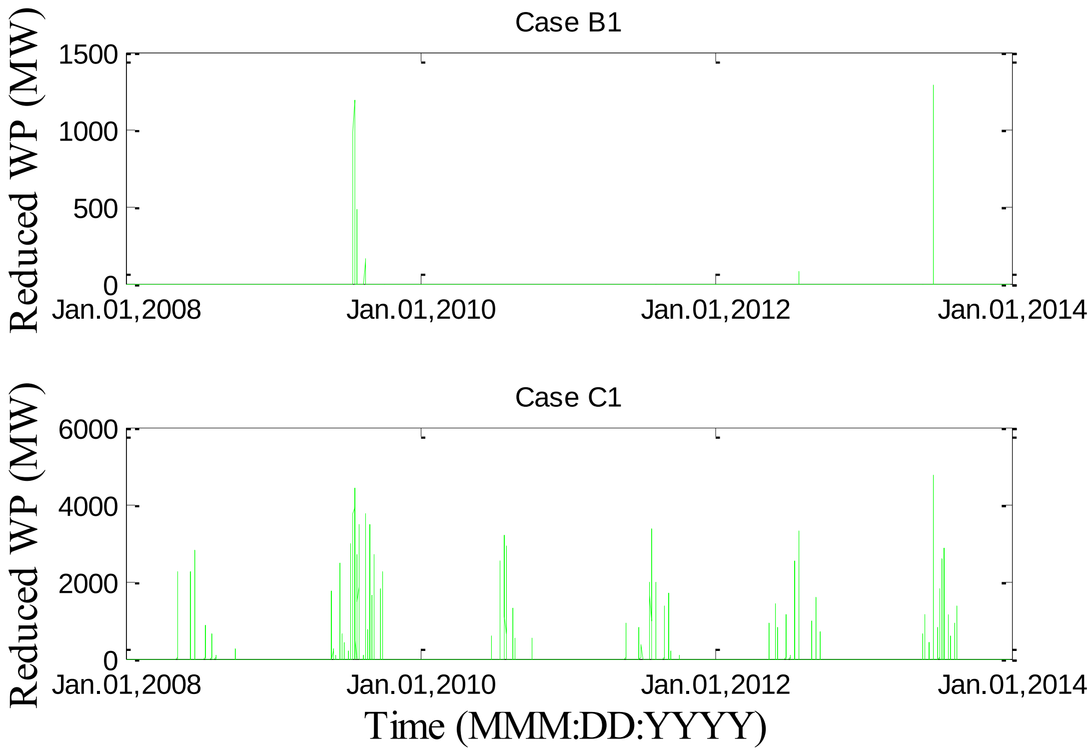


Figure 5-2 Amount of curtailment of wind power production (Scenario 2) for Case B1 and C1

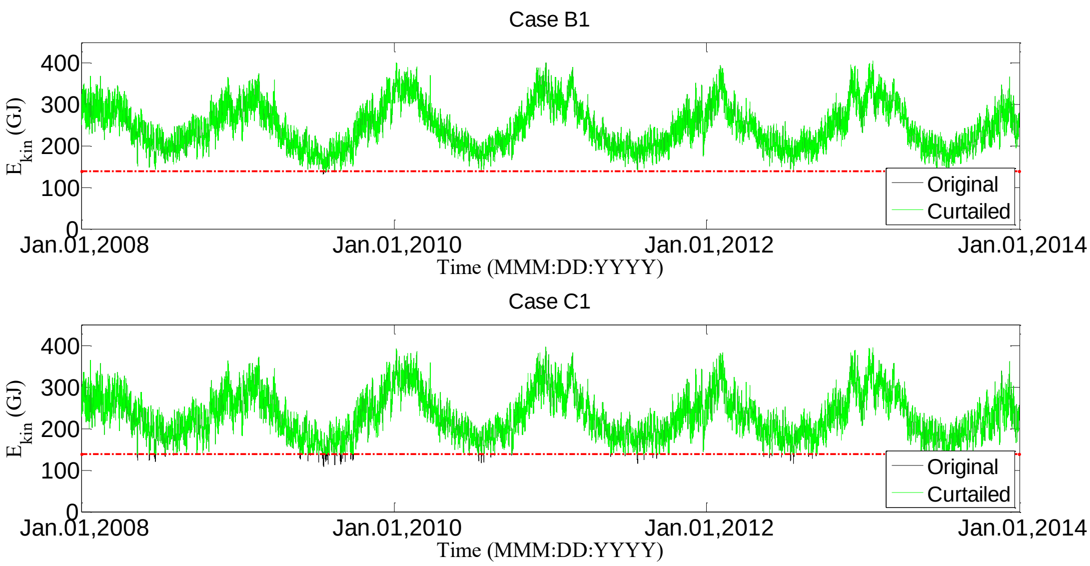


Figure 5-3 Kinetic Energy of original and Curtailed wind power (Scenario 3)

The loss of produced energy due to curtailment is calculated as:

Total of $\Delta Pwp(h) = \sum_{h=i}^{\propto} \Delta Pwp(h)$ (5.9)

where $\Delta Pwp(h)$ is equal to zero for hours without curtailment and is obtained from equation (5.8) for hours with curtailment.

Therefore, the losses of production for four wind power production cases are:

Case A1: no curtailment (0%)

Case A8: no curtailment (0%)

Case B1: 16.9 GWh curtailed out of 176.6 TWh potential wind power production (i.e. in case there would not be any curtailment) (0.01 %) = 2.8 GWh/yr

Case C1: 831.5 GWh out of 294.8 TWh (0. 28 %) = 138.6 GWh/yr

5.2 SCENARIO 2: WIND POWER PRODUCTION IN ALL NORDIC COUNTRIES

Similar to Scenario 1 but the wind power production of Norway and Finland is included. From the historical data shown in [44] and reproduced in Figure 5.4, it depicts graphically that the percentage of wind power in Norway and Finland are on average 15% and 8%, respectively, of the amount in Sweden. The same percentage figure is applied to the simulated wind power production obtained from the model developed by Uppsala University.

The calculated generated (conventional) power can be determined as:

$$Pconv_{scandinavia}(h) = (PL_{sweden}(h) + PL_{norway}(h) + PL_{finland}(h)) - (Pwp_{sweden}(h) + Pwp_{norway}(h) + Pwp_{finland}(h)) \quad (5.9)$$

where $Pwp_{statnett}(h) = 15\% * Pwp_{svk}(h)$ and $Pwp_{fingrid}(h) = 8\% * Pwp_{svk}(h)$

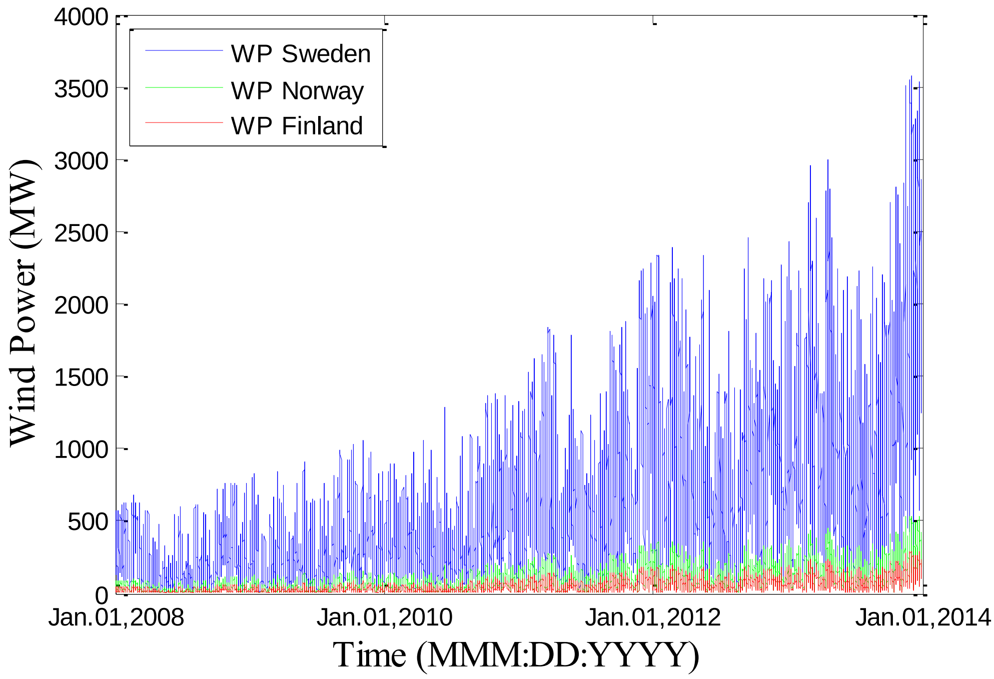


Figure 5-4 5.4 shows the wind power production of Sweden, Norway, and Finland

Repeating equation (5.2), (5.4) and (5.5); thus the new threshold value of the minimum kinetic energy for this scenario equals to 136.65 GJ which is similar to that of the previous scenario but smaller because the wind power production in Norway and Finland are included.

The simulated wind power production of Sweden is based on MERRA reanalysis data meanwhile the production of Norway and Finland has been obtained merely as a constant percentage of the Swedish one based on the historical ratio in annual produced energy. It may be interesting to see the sensitivity in applying this approach to the simulated wind power on the minimum kinetic energy. The result of this sensitivity analysis for different simulated wind power cases is presented in Table 5.1 to Table 5.4.

Table 5-1 Sensitivity analysis for Case A1

$\% \; of \; Pwp_{sweden}(h)$	$E_{kin}(h) < \delta_{kin}$ (hrs)	ΔPwp (MWh/yr)
$Pwp_{norway}(h) = 15\%$ $Pwp_{finland}(h) = 8\%$	0	0
$Pwp_{norway}(h) = 30\%$ $Pwp_{finland}(h) = 16\%$	15 hr/yr	0.6 GWh/yr
$Pwp_{norway}(h) = 45\%$ $Pwp_{finland}(h) = 24\%$	35 hr/yr	3.4 GWh/yr
$Pwp_{norway}(h) = 60\%$ $Pwp_{finland}(h) = 32\%$	110 hr/yr	12.8 GWh/yr

Table 5-2 Sensitivity analysis for Case A8

$\% \ of \ Pwp_{sweden}(h)$	$E_{kin}(h) < \delta_{kin}$ (hrs)	ΔPwp (MWh/yr)
$Pwp_{norway}(h) = 15\%$ $Pwp_{finland}(h) = 8\%$	0	0
$Pwp_{norway}(h) = 30\%$ $Pwp_{finland}(h) = 16\%$	13 hr/yr	0.5 GWh/yr
$Pwp_{norway}(h) = 45\%$ $Pwp_{finland}(h) = 24\%$	33 hr/yr	3.3 GWh/yr
$Pwp_{norway}(h) = 60\%$ $Pwp_{finland}(h) = 32\%$	102 hr/yr	11.6 GWh/yr

Table 5-3 Sensitivity analysis for Case B1

$\% \ of \ Pwp_{sweden}(h)$	$E_{kin}(h) < \delta_{kin}$ (hrs)	ΔPwp (MWh/yr)
$Pwp_{norway}(h) = 15\%$ $Pwp_{finland}(h) = 8\%$	78 hr/yr	9.6 GWh/yr
$Pwp_{norway}(h) = 30\%$ $Pwp_{finland}(h) = 16\%$	234 hr/yr	39.5 GWh/yr
$Pwp_{norway}(h) = 45\%$ $Pwp_{finland}(h) = 24\%$	650 hr/yr	123.3 GWh/yr
$Pwp_{norway}(h) = 60\%$ $Pwp_{finland}(h) = 32\%$	1219 hr/yr	310.5 GWh/yr

Table 5-4 Sensitivity analysis for Case C1

$\% \ of \ Pwp_{sweden}(h)$	$E_{kin}(h) < \delta_{kin}$ (hrs)	ΔPwp (MWh/yr)
$Pwp_{norway}(h) = 15\%$ $Pwp_{finland}(h) = 8\%$	1578 hr/yr	430 GWh/yr
$Pwp_{norway}(h) = 30\%$ $Pwp_{finland}(h) = 16\%$	3229 hr/yr	1 193 GWh/yr
$Pwp_{norway}(h) = 45\%$ $Pwp_{finland}(h) = 24\%$	5437 hr/yr	2 564 GWh/yr
$Pwp_{norway}(h) = 60\%$ $Pwp_{finland}(h) = 32\%$	8078 hr/yr	4 668 GWh/yr

In comparison with Scenario 1, the 23% increase of wind power production does not make system to confront with security issue for Case A1 and A8. However, it indicates a significant need of wind power curtailment for Case B1 and C1 as around 3 times higher compared to the previous scenario (from 2.8 GWh/yr to 9.6 GWh/yr and from 139 GWh/yr to 430 GWh/yr for Case B1 and Case C1, respectively). More qualitative analysis will be provided in Chapter 7.

6 A qualitative description of the limitations of synthetic inertia against rotor angle stability

This section of the report briefly describes some limitations in the use of synthetic inertia for improving angular stability. The qualitative analysis is demonstrated by using the simplified model shown in Figure 4.33. It is assumed that two areas of the power system are connected through a number of interconnectors and that a fault occurs near the sending or receiving end of one of the interconnectors.

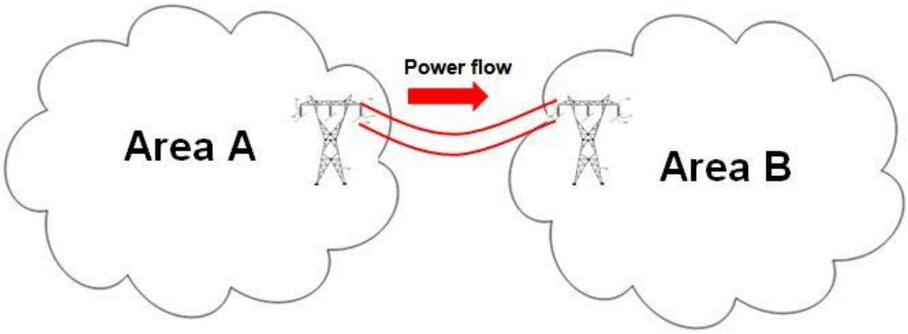


Figure 6-1 Simplied interconnected two power system areas

During the fault, part of the power flow between A and B is interrupted because of the drop in voltage. One area will experience a shortage of power with a decrease in frequency as a result; the other area will experience a surplus of power and a rise in frequency. Despite that the two areas are interconnected, they will experience different frequencies during the fault and even during a certain period after the fault.

Rotor angle stability is normally described in terms of angular difference between two regions. However, synthetic inertia uses local voltage measurements to estimate the frequency and injection of active power is based on that frequency estimation. Therefore, we will describe rotor-angle stability here mainly in terms of frequency and rate of change of frequency.

Assume the worst case that the active power exchange between the two areas, during the fault, is zero. Neglect the load reduction due to the voltage reduction during the fault and the increase in losses due to the fault current.

There is a pre-fault power flow from area A to area B, the kinetic energy in the two areas is E_{kinA} and E_{kinB}. Thus, the frequency values in area A and area B can be written as follows:

The frequency in area A will increase because the export disappears:

$$\frac{df_A}{dt} = \frac{f_0}{2} \times \frac{P}{E_{kinA}}$$

The frequency in area B decreases because the import disappears:

$$\frac{df_B}{dt} = -\frac{f_0}{2} \times \frac{P}{E_{kinB}}$$

With T_{FC} the fault-clearing time, the frequency at the instant of fault clearing is, in area A:

$$f_A = f_0 + \frac{f_0}{2} \times \frac{P}{E_{kinA}} \times T_{FC}$$

And in area B:

$$f_B = f_0 - \frac{f_0}{2} \times \frac{P}{E_{kinB}} \times T_{FC}$$

Here it is assumed that there is no change in consumption or production during this period. The fault-clearing time is short, so that this is a reasonable assumption.

In comparison between rotor angle and frequency stability, the relative imbalance between production and consumption is much bigger in case of a fault on an interconnector than in the case of the loss of a large production unit. The result is that the ROCOF is much higher during such a fault. However the fault duration, which is typically around 100 ms in the transmission system, is much less than the time it takes for the inertia control to be activated (about 1 second e.g. see Figure 4.3) . Therefore, it will in practice be difficult to obtain a contribution of synthetic inertia to angular stability.

For synthetic inertia to make any contribution to improve rotor-angle stability there is a need for a fast algorithm to measure either frequency or ROCOF (depends on input signal of the synthetic inertia control) and to activate the controller when a suitable threshold is exceeded. Otherwise synthetic inertia control will not be able to provide any support to angular stability.

To illustrate this issue clearer, two numerical examples are provided in the two following sections.

6.1.1 Scenario 1: Without wind power generation

In this scenario, it is assumed that area A has a production equal to 15 000 MW with an inertia constant equal to 6 MJ/MW (per MW production). The consumption in area A is 10 000 MW. Meanwhile, area B has a production equal to 10 000 MW with an inertia constant equal to 7 MJ/MW. The consumption in area B is 15 000 MW, so that there is power transfer equal to 5000 MW from area A to area B. The scenario is loosely based on the Swedish transmission system with production mainly in the north and consumption mainly in the south.

The ROCOF for these two areas can be calculated as:

$$E_{kinA} = 90\ \text{GJ}$$

$$E_{kinB} = 70\ \text{GJ}$$

$$\frac{df_A}{dt} = \frac{50\ \text{Hz}}{2} \times \frac{5000\ \text{MW}}{90\ \text{GJ}} = 1.39\ \text{Hz/s}$$

$$\frac{df_B}{dt} = -\frac{50\ \text{Hz}}{2} \times \frac{5000\ \text{MW}}{70\ \text{GJ}} = -1.79\ \text{Hz/s}$$

Then, the frequency of two areas and the increase in angular difference between area A and area B can be determined as shown in Table 4.5. Whether the system is stable after fault clearing depends on the impedance of the interconnection between the two areas, before as well as after the fault.

Table 6-1 Calculated frequency and increase in angular difference between area A and area B for scenario 1

After (ms)	Area A	Area B	Angular difference (degrees)
100	50.14 Hz	49.82 Hz	5.7
200	50.28 Hz	49.64 Hz	22.8

Where the phase angle difference has been calculated by integrating the frequency difference:

$$\Delta\phi = \frac{1}{2}\left[f_B(T_{fc}) - f_A(T_{fc})\right] \times T_{fc} \times 360°$$

The angular increase at which the system becomes instable depends among others on the pre-fault power flow in relation to the so-called steady-state limit. Typical angular increases at which the system becomes instable are some tens of degrees. In Sweden, the transfer capacity is set by voltage stability, not by angular stability, hence the allowable angular increase will be relatively high. For a more accurate estimation, a detailed study is needed, which was deemed beyond the scope of this project.

6.1.2 Scenario 2: With wind power generation

In this scenario, we assume 80% wind power (in relation to the consumption) . In an interconnected system there is not only inertia on production side but also some inertia on the consumption side (in direct-driven motors). This will make that the reduction in inertia will be less than the reduction in production from conventional production. The need for spinning reserve will remain about the same (assuming that the size of the larhets unit remains about the same) and spinning reserve does not contribute to production, but it does contribute to inertia. This will further make that the reduction in inertia is less than the reduction in production from conventional units. Therefore it has been assumed, somewhat arbitrary, that 80% wind power production results in inertia reduction by 60%.

The power production and consumption in two areas are kept constant however due to wind power generation, the inertia constant in area A and area B becomes equal to 2.4 MJ/MW and 2.8 MJ/MW (with respect to MW consumption), respectively. Therefore, the ROCOF for these two areas can be calculated as:

$$E_{kinA} = 36 \text{ GJ}$$

$$E_{kinB} = 28 \text{ GJ}$$

$$\frac{df_A}{dt} = \frac{50 \text{ Hz}}{2} \times \frac{5000 \text{ MW}}{36 \text{ GJ}} = 3.47 \text{ Hz/s}$$

$$\frac{df_B}{dt} = -\frac{50 \text{ Hz}}{2} \times \frac{5000 \text{ MW}}{28 \text{ GJ}} = -4.46 \text{ Hz/s}$$

Then, the frequency of the two areas and the increase in angular difference can be determined as shown in Table 4.5

Table 6-2 Calculated frequency and increase in angular difference between area A and area B for scenario 2

After (ms)	Area A	Area B	Angular difference (degrees)
100	50.45 Hz	49.65 Hz	14.2
200	50.89 Hz	49.31 Hz	57.1

Table 4.4 and 4.5 show that it would be beneficial if the inertia control can reduce the ROCOF. However, as mentioned earlier, the exact definition of ROCOF is still ambiguous. The Irish Grid Code [17] only mentions 0.5 Hz/s, but the time frame to measure the quantity is not stated. The EirGrid also carried some simulation experiments to show that the ROCOF values are closely related to the window over which they are measured. The result depicts that a ROCOF value calculated over measuring windows of 100 ms and 500 ms can be significantly different as illustrated in Figure 4.34. Nevertheless, it is recommended by both EirGrid and SONI that 500ms is an appropriate time frame to calculate ROCOF. This is because it usually takes this length of time for the generators to return to a coherent state [45].

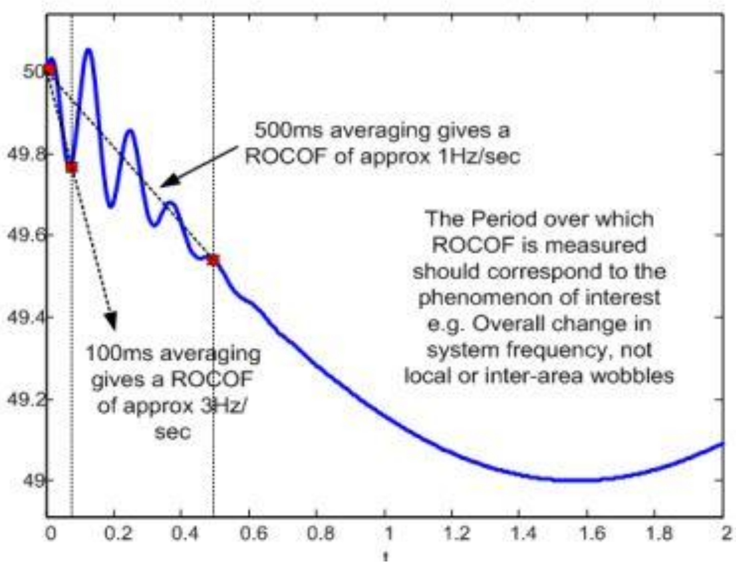


Figure 6-2 The effect of using different measuring windows [46]

That conclusion is true when the ROCOF value is used to estimate the amount of inertia connected to the system. Even for the activation of synthetic inertia to support frequency stability that may be a useful recommendation. However, after 500 ms, the fault has certainly been cleared already and any contribution from synthetic inertia will have limited if any impact on the rotor-angle stability.

For synthetic inertia to contribute to rotor-angle stability, it should be activated within something like 50 ms. The change in frequency during such a period is small even for large unbalances between production and consumption. To detect the rotor-angle instability, either the frequency should be compared with an average of recent values, or the rate of change of frequency should be used. In either case, there are serious measurement and signal-processing issues related with this.

There is another issue that should be solved before synthetic inertia can be used to support rotor-angle stability. It will require both fast up-regulation and fast down-regulation of production. Down-regulation is relatively easy with wind turbines but there may still be some time delay involved here. The literature on synthetic inertia does not address this issue.

7 Conclusions

7.1 FINDINGS

7.1.1 Frequency stability

Synthetic inertia limits the frequency drop during the first few seconds after the loss of a large production unit, before the primary frequency control of the conventional production units is able to stop the frequency drop and restore balance between production and consumption. It has been shown in earlier studies that synthetic inertia is able to keep the system stable until the primary frequency control takes over, even during operational states with large amounts of wind power.

A recovery period is needed for the wind turbines equipped with synthetic inertia during which the wind turbines are accelerated again back to their pre-disturbance speed. The additional power needed for this increases the need for primary reserve.

The need for power during the recovery period is strongly dependent on the wind speed. For higher wind speeds the need for power is less or even zero. For high wind speeds, additional power can be extracted from the wind by changing the tilt angle of the blades. This impacts the need for additional primary reserve and the recovery of the frequency after the nadir has been reached.

The control settings have a significant impact on the performance of the synthetic inertia. The manufacturer setting did not give the optimal performance. It was confirmed that optimal settings obtained in another system do not necessarily give optimal results in the system under study.

7.1.2 Need for frequency support

For 20 TWh wind in Sweden and up to 4.6 TWh in Norway and Finland, there is no need for additional frequency support. For higher amounts of wind power in the Nordic system, some kind of frequency support or curtailment of wind power production during certain operational hours is needed.

For 30 TWh, the need for curtailment depends strongly on the involvement of wind power generation in neighboring countries.

For 50 TWh wind in Sweden, the need for curtailment becomes large and alternative solutions need to be considered. Synthetic inertia is one of those, but also other alternatives, like storage and demand-side response, should be considered.

7.1.3 Rotor-angle stability

The existing technology for synthetic inertia does not contribute to rotor-angle stability.

7.2 DISCUSSION

7.2.1 Frequency stability

In this project, the system frequency response has been studied with increasing amounts of wind-power penetration. In the first few seconds following the loss of a large generating plant, the frequency drops quickly. This frequency drop is affected by the inertia response of the on-line synchronous generation and by the contribution of wind power generation with inertia control functionality. The latter feature provides additional operational security to the power system by reducing the risk of frequency instability. The inertia control temporarily provides an amount of additional power in response to significant under-frequency grid events. This limits the frequency drop during the first 7 to 10 seconds after the initial loss of production and allows the primary power-frequency control to restore the grid frequency to its nominal value. Technically, the inertia response from the wind turbines uses the rotational mass in the turbine and the blades to provide this temporary power increase.

One of the studies presented in this project shows that the inertia support (in the form of additional power production during a severe drop in frequency) of the wind turbine is limited not only by the available kinetic energy in the rotational mass but also by the setting of various controllers. Both inertia and active power control parameter values play a vital role to the turbine's optimal operating point. According to optimal tuning performance studies, the default parameter values provided by the manufacturer are deemed as non-optimal parameters for this Nordic-32 test case. It is therefore concluded that the values provided by the manufacturer or obtained from a study in another system might not deliver optimal synthetic inertia response. The simulation results show that frequency sensitive controls of wind turbines have substantial impact.

It is also worth noting that there are drawbacks to using pitch angle controllers for improvement of frequency nadir. The optimal tuning used in this report does not consider any adverse impacts of the increased use of pitch angle controllers. The increased use of the pitch angle controllers could lead to increased wear of the blades and reduce the life length and/or increase the need for maintenance. This kind of tuning should be performed in consultation with the manufacturer. It is difficult to estimate how much more the wear will be when synthetic inertia is being used, but possible increased wear should be considered in future studies.

It is further demonstrated in this report that the minimum frequency is not degraded with significant levels of wind generation including synthetic inertia. It is possible to have good system frequency response when using wind turbines equipped with inertia-support controls available commercially today.

7.2.2 Need for frequency support

A threshold has been set equal to 90% of the lowest historically-estimated amount of kinetic energy connected to the grid. Already for relatively small amounts of wind power, situations will occur where less kinetic energy than this threshold is connected to the system. Several different cases have been considered:

- For 20 TWh wind power production per year in Sweden, no wind power or 4.6 TWh in Finland and Norway, and consumption in Sweden, Finland and Norway, the threshold will not be crossed.
- In all other cases, there will be hours during which the threshold is crossed.

From the study, we cannot decide if this is a reasonable threshold below which the system is no longer secure. But it can be concluded that situations with lower inertia (and thus, higher rate of change of frequency and lower frequency nadir) will occur in the future.

Instead of synthetic inertia, curtailment of wind-power production can be used to ensure secure operation even during hours with high wind-power potential. That will result in loss of delivered energy.

The different study cases and the results are summarized in Table 7.1 through Table 7.3 below.

For 20 TWh wind power in Sweden for Scenario A1 the need for curtailment and the amount of curtailed energy are small or even zero. Curtailment is a suitable alternative for synthetic inertia. Even in the worst scenario (with similar amounts of wind power in Finland and Norway as well) curtailment will only be needed during about 100 hours per year and the curtailed energy is much less than 1%.

Table 7-1 Summary of 20 TWh wind power production for different scenarios

load	Sweden	Finland	Norway	% hours	% energy
SE+FI+NO	20 TWh	0	0	0	0
SE+FI+NO	20 TWh	1.6 TWh	3.0 TWh	0	0
SE+FI+NO	20 TWh	3.2 TWh	6.0 TWh	0.2%	0.002%
SE+FI+NO	20 TWh	4.8 TWh	9.0 TWh	0.4%	0.01%
SE+FI+NO	20 TWh	6.4 TWh	12 TWh	1.3%	0.03%

For 30 TWh wind power production per year in Sweden, the need for curtailment of wind power depends strongly on the developments in neighbouring countries.

Considering the Nordic system as a whole the number of hours during which curtailment is needed may become significant, up to 1200 hours per year (13.9%), but the non-delivered energy is only up to 0.5%. Also for this scenario curtailment remains a suitable option, although it should be noted that this is a lower bound for the curtailment. There may be other types of instability that set limits; limits in transport capacity may also require curtailment.

Here it should also be noted that massive amounts of offshore wind-power production could result in more than 18 TWh being produced in Norway. In that case the need for curtailment will increase beyond what is shown in the table.

Table 7-2 Summary of 30 TWh wind power production for different scenarios

load	Sweden	Finland	Norway	% hours	% energy
SE+FI+NO	30 TWh	0	0	0.06%	0.01%
SE+FI+NO	30 TWh	2.4 TWh	4.5 TWh	0.9%	0.03%
SE+FI+NO	30 TWh	4.8 TWh	9.0 TWh	2.7%	0.09%
SE+FI+NO	30 TWh	7.2 TWh	13.5 TWh	7.4%	0.24%
SE+FI+NO	30 TWh	9.6 TWh	18 TWh	13.9%	0.54%

For 50 TWh wind power in Sweden, the need for curtailment becomes large. When no wind-power is assumed in neighbouring countries, the need for curtailment remains limited to about 100 hours per year. But once it is assumed that Finland and Norway will also increase the amount of wind power produced in their countries, the need for curtailment becomes so large that it will no longer be worth building more wind power.

Table 7-3 Summary of 50 TWh wind power production for different scenarios

load	Sweden	Finland	Norway	% hours	% energy
SE+FI+NO	50 TWh	0	0	1.4%	0.3%
SE+FI+NO	50 TWh	4.0 TWh	7.5 TWh	18%	0.7%
SE+FI+NO	50 TWh	8.0 TWh	15.0 TWh	37%	1.6%
SE+FI+NO	50 TWh	12.0 TWh	22.5 TWh	62%	3.0%
SE+FI+NO	50 TWh	16 TWh	30 TWh	92%	4.9%

The additional potential of wind energy between each two consecutive rows in Table 7.3 is 11.5 TWh. The increase in delivered energy is increasingly less than this because of the increased use of curtailment. Between the last two rows, only 81.1% of the additional potential is used. This means that the cost per kWh increase by 23% compared to the case without curtailment. Installing synthetic inertia will most likely be cheaper than this.

A detailed model has been used to predict time series of wind power production in Sweden. However, no such models were used for Norway and Finland. Instead it was assumed that the production in those countries was a constant percentage of the production in Sweden. In reality this will not be the case and there will be less than this 100% of correlation. The number of hours with insufficient kinetic energy is therefore overestimated. Especially the very high percentages in the last two columns in Table 7.3 are most likely a significant overestimation.

Despite this it is still concluded that with 50 TWh wind power production per year in Sweden there will be a need for alternative solutions. The situation that there would be 50 TWh energy from wind in Sweden and very small amounts in the rest of the Nordic system does not seem a realistic scenario.

7.2.3 Rotor-angle stability

It is concluded that the existing technology for synthetic inertia does not contribute to rotor-angle stability.

The use of curtailment to guarantee rotor-angle stability has not been specifically studied.

7.3 RECOMMENDATIONS

7.3.1 Frequency stability

From this project, it is recommended that grid codes should be modified to include some type of inertia response requirement from wind power generation. As shown earlier, the development of this feature is commercially available and beneficial for system stability. However, the inertia response of wind power generation is limited to large under-frequency events that represent operational security risks to the grid.

It is well-known that conventional generators inherently provide some of their stored kinetic energy to the system grid. Modern wind turbines normally do not contribute. However, once equipped with inertia and active power controls they contribute with a similar response as conventional generators. However one of the differences between synchronous and wind power plants is that the longer-term frequency response and recovery is driven by the governor action whereas wind turbine does not contribute to these primary reserves. Therefore, it is recommended that a new controller scheme be implemented to coordinate the inertia control with synchronous machines to improve system's frequency stability.

7.3.2 Need for frequency support

The historical data of wind power production for Finland and Norway (see Section 5.2) should be replaced by a more appropriate model to represent wind power production. This model can be similar to the MERRA model which provides time-series of wind power production based on actual built and planned wind turbines in those two countries.

An electricity market mechanism should be developed to decide wind power curtailment choices. This model should include not only the location of wind power curtailment but also, for example, the electricity price areas, the power transfer between areas, etc. The aim to include this model is to help the system operator to maximize the profit from cutting down wind power as well as secure the system's security. It also can be used as a guideline for where in the system the additional conventional generation should be built in the future.

Next to curtailment of power production that does not provide inertia support, market mechanisms should be developed that support an increase in consumption for instance in the form of storage or export to the European continent. Care should be taken, for example by designing the right market mechanisms and other incentives, that such mechanisms do not result in a net increase of consumption from non-renewable sources.

7.3.3 Rotor-angle stability

Algorithms need to be developed for fast and accurate estimation of frequency and rate of change of frequency. To contribute to rotor-angle stability, the synthetic inertia needs to be activated in about 50 milliseconds.

Alternative methods need to be studied to guarantee rotor-angle stability during periods with low amounts of conventional production connected to the grid.

8 References

[1] J. G. Slootweg and W. L. Kling, "Impacts of Wind Power on Power System Dynamics", in Wind Power in Power Systems. Thomas Ackermann, Ed., John Wiley & Sons, 2005, pp. 630-651.

[2] Math Bollen, Fainan Hassan, Integration of distributed generation in the power system, Wiley IEEE Press, July 2011.

[3] K Svenska Kraftnät, Integrering av vindkraft, 13 mars 2013.

[4] Johan Björnstedt, Integration of non-synchronous generation-frequency dynamics, Doctoral dissertation, Lund University, 2012.

[5] Mohammad Seyedi, Math Bollen, The utilization of synthetic inertia from wind farms and its impact on existing speed governors and system performance, Elforsk Report 13:02, January 2013.

[6] Mats Wang-Hansen Robert Josefsson Haris Mehmedovic, Frequency Controlling Wind Power: Modeling of control strategies, Elforsk Report 12:43, January 2012.

[7] Math Bollen, Fainan Hassan, Integration of Distributed Generation in Power System, 1st edition Wiley, New Jersey, 2011

[8] Nicholas Etherden, Increasing the hosting capacity of distributed energy resources using storage and communication. Luleå tekniska universitiet, 2014 (Doctoral thesis / Luleå University of Technology.

[9] P. Kundur, “Power System Stability and Control”, MacGraw Hill, 1992.

[10] P. Kundur, J. Paserba, V. Ajjarapu, G. Andersson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. Van Cutsem, and V. Vittal, “Definition and classification of power system stability ieee/cigre joint task force on stability terms and definitions,” IEEE Transactions on Power Systems, vol. 19, pp. 1387-1401, August. 2004.

[11] Hugo E. Mena, Primary Frequency Response Requirements for Wind Generators: What are the Technical Challenges? AWEA Wind Power Conference 2012, June 2012.

[12] RTE (Réseau de Transport d’Electricité), Memento of Power System Reliability, 2006 Edition.

[13] James McCalley, Impact of Increased DFIG Penetration on Transient Frequency Response and Regulation, PSERC Report: 09-10 (Part 2), Iowa State University, October 2009.

[14] Jan Machowski, Janusz W. Bialek, and James R. Bumby, Power System Dynamics: Stability and Control, Wiley IEEE Press, 1997.

[15] O. Gjerde, D. Whiteley, LFC/AGC – Nordic and European perspective Exchange of balancing services international workshop 26-27 Jan 2011, available online:

http://www.sintef.no/globalassets/project/balance-management/gardermoen/8---gjerde-statnett---lfc-and-agc---nordic-perspective.pdf

[16] Atif Z. Khan, Effects of power system parameters on critical clearing time: comprehensive analysis, Electric Power System Research, Vol.49, pp37-44, 1999.

[17] H.R. Chamorro, M. Ghandhari, and R. Eriksson, Wind Power Impact on Power System Frequency Response, Power Systems Conference and Exposition (PSCE), 2006.

[18] Joint Grid Code and Distribution Code Workgroup Report, Frequency Changes during Large Disturbances and their Impact on the Total System, July 2013.

[19] Ian F Moore, Inertial Response from Wind Turbines, Ph.D Thesis, Cardiff University, 2012.

[20] Salim Temtem and Karen Creighton, Summary of Studies on Rate of Change of Frequency events on the All-Island System, EirGrid Report, August 2012.

[21] Hongjing Hou, Li Lin, Tao Wu and Youzhong Miao, Comparison of Transient Stability between Wind Farm based on DFIG and Traditional Power Plant in an Actual Grid, Asia-Pacific Power and Energy Engineering Conference (APPEEC), 2010.

[22] Eknath Vittal, Mark O'Mally, Andrew Keane, Rotor Angle Stability With High Penetration of Wind Generation

[23] ECAR Energy, Wind Integration: International Experience -WP2: Review of Grid Code, AEMO Report, October 2011.

[24] Malin Sjölund, Study of Grid Code Compliance: Thanet Wind Farm, Thesis, Uppsala University, August 2012.

[25] REE Grid Code, Offprint of the outline of O.P. 12.2 Restricted to the technical requirements of wind power and photovoltaic facilities, October 2008.

[26] ENSTO-E Working Draft, "Requirements for Grid Connection Applicable to all Generators", 24 January 2012.

[27] Jonathan Brisebois and Noël Aubut, Wind Farm Inertia Emulation to Fulfill Hydro-Québec's Specific Need, IEEE PES General Meeting, 2011.

[28] M. A. Pelletier, M. E. Phethean, and S. Nutt, Grid code requirements for artificial inertia control systems in the New Zealand Power System, IEEE PES General Meeting, 2012.

[29] CIGRE WG C4.601, Modelling and Dynamic Behaviour of Wind Generation As It Relates to Power System Control and Dynamic Performance, CIGRE TB-328, August, 2007.

[30] Kara Clark, Nicholas W. Miller, and Juan J. Sanchez-Gasca, Modeling of GE Wind Turbine-Generators for Grid Studies, Version 4.5, General Electric International, 2010.

[31] F. Gonzalez-Longatt, Impact of Synthetic Inertia from Wind Power on the Protection/Control Schemes of Future Power Systems: Simulation Study, International Conference on Developments in Power Systems Protection (DSDP), 2012.

[32] Mats Wang-Hansen, Robert Josefsson, and Haris Mehmedovic, Frequency Controlling Wind Power Modeling of Control Strategies, IEEE Transactions on Sustainable Energy, vol. 4, No. 4 pp.954-959, 2012.

[33] Mats Wang-Hansen, Robert Josefsson,and Haris Mehmedovic, Frequency Controlling Wind Power: Modeling of control strategies, Elforsk Report 12:43, June 2012.

[34] Statnett, Nordic Power Flow (13, August, 2014). Available: http://www.statnett.no/en/market-and-operations/data-from-the-power-system/nordic-power-flow/.

[35] Siemens PTI, PSS/E 33.3 Model Library, September, Siemens.

[36] Siemens PTI, PSS/E 33.3 Program Application Guide: Volume 2, September, Siemens.

[37] Edenhofer, O., Renewable Energy Sources and Climate change mitigation. New York: Cambridge University Press, May 2009

[38] Olsson J, Skoglund L, Carlsson F, Bertling L. Future wind power production variations in the Swedish power system. Innovative Smart Grid Technologies Conference Europe (ISGT Europe), Oct 2010

[39] Olsson J, Bergström H, Bergkvist M, Scenarios and time series of future wind power production in Sweden, available online: http://www.elforsk.se/Global/Vindforsk/Konferenser/Inertia%20seminar/Jon.pdf

[40] Svenska kraftnäts rapport: Integrering av vindkraft, available online: http://www.svk.se/PageFiles/54963/20130313-Integrering-av-vindkraft.pdf

[41] T. Inoue, H. Taniguchi, Y. Ikeguchi, and K. Yoshida, “Estimation of power system inertia constant and capacity of spinning-reserve support generators using measured frequency transients,” IEEE Transactions on Power Systems, vol. 12 no. 1 , Feb. 1997, pp. 136–143

[42] http://www.fingrid.fi/en/electricity-market/load-and-generation/Pages/default.aspx

[43] http://www.statnett.no/Drift-og-marked/Data-fra-kraftsystemet/Produksjon-og-forbruk/

[44] www.thewindpower.net

[45] Rate of Change of Frequency (ROCOF) Review of TSO and Generator Submissions Final Report, available online: http://www.cer.ie/docs/000260/cer13143-(a)-ppa-tnei-rocof-final-report.pdf

[46] RoCoF Modification Proposal– TSOs’ Recommendations, available online: http://www.eirgrid.com/media/RoCoF%20Modification%20Proposal%20TSOs%20Opinion.pdf

9 Appendix A

9.1 GENERATOR TURBINE-GOVERNOR MODELS

The following block diagrams are dynamic models for hydro, nuclear, and thermal generators, exciters and stabilizers which used in this project. The selected models are the standard models, which are generally used in the most power system simulation software including PSS/E [35].

- GENSAL

  It represents a salient pole generator and is used for all hydro power generating units. The block diagram of the generator is shown in Figure 9.1.

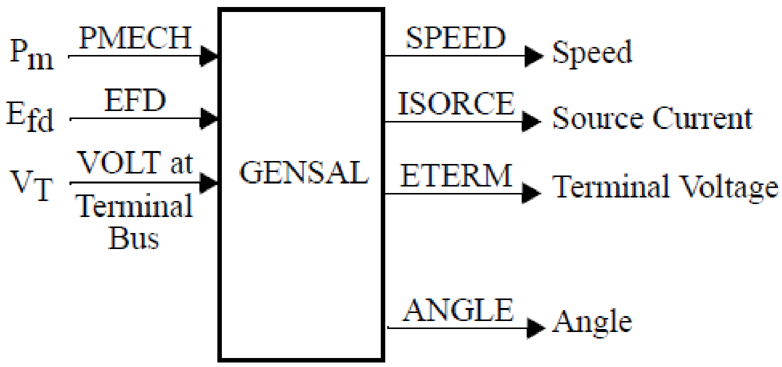


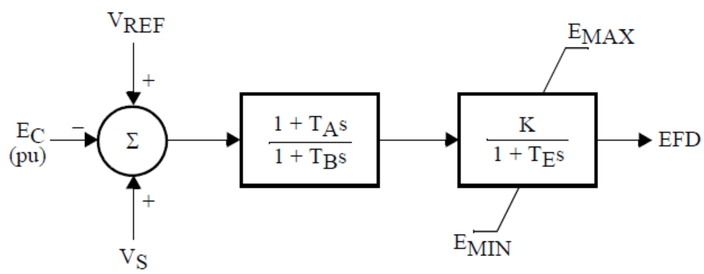
Figure 9-1 Block diagram of GENSAL and GENROU generators

- GENROU

  It is a cylindrical round rotor type and represents the synchronous thermal power units. The block diagram is as the same of GENSAL.

- SEXS

  It represents the excitation dynamic model and is used for all types of synchronous generators. The control diagram is shown in Figure 9.2.



V_S = VOTHSG + VUEL + VOEL

Figure 9-2 The control diagram for SEXS excitation dynamic model

- STAB2A

  It is the name for stabilizer which is an ASEA power sensitive stabilizer model and damps the oscillation in electrical output power.

  The dynamic control model for this type of stabilizer is illustrated in Figure 9.3.

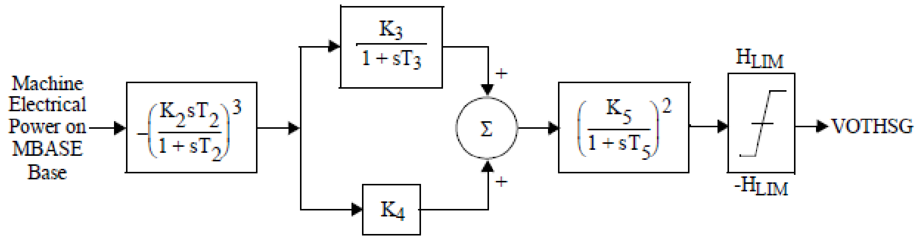


Figure 9-3 The dynamic control model for STAB2A

  where VOTHSG is the auxiliary voltage signal

- HYGOV

  It represents the hydro-turbine governor. The block diagram is shown in Figure 9.4.

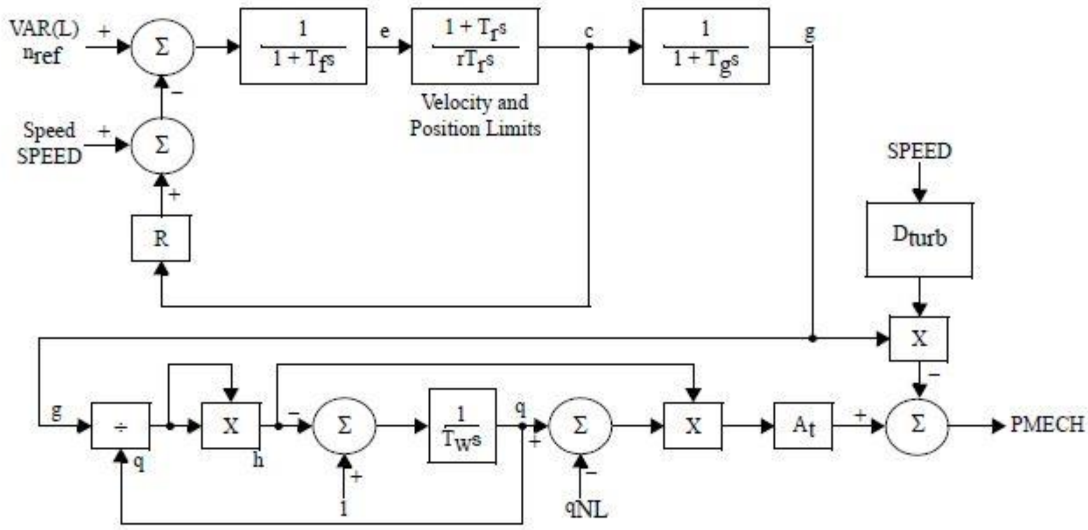


Figure 9-4 Block diagram for HYGOV hydro-turbine governor

9.2 WIND TURBINE MODEL

The wind turbines used in this project are the 4.0 MW full converter type from GE. The load flow data of this turbine can be found in Table 9.1 [5]. Moreover, the description of this turbine in terms of turbine layout, connection scheme with step-up transformer and dynamic model can also be found in [6].

Table 9-1 Individual GE 4.0 MW Wind Turbine

Full Converter Generator Rating	4.8 MVA
Pmax	4.0 MW
Pmin	0.0 MW
Qmax	1.93 MVar
Qmin	-1.93 MVar
Rated voltage, 50Hz	0.69 kV
XSOURCE	9999 p.u
Unit Transformer Rating	4. 5 MVA
Unit Transformer Impedance	6.0%
Unit Transformer X/R ratio	7.5

SYNTHETIC INERTIA TO IMPROVE FREQUENCY STABILITY AND HOW OFTEN IT IS NEEDED

During operational states with large amounts of wind power, and hence small amounts of on-line synchronous generation, the frequency would drop so fast that the system stability is endangered.

A possible solution to avoid (frequency) instability is to employ so-called "synthetic inertia", i.e. a contribution of wind power generation with inertia control functionality. The inertia control temporarily provides an amount of additional power in response to significant under-frequency events. Technically, the inertia response from the wind turbines uses the rotational mass in the turbine to provide this temporary power increase. It has been shown in earlier studies that synthetic inertia is able to limit the initial frequency drop after the loss of a large production unit and keep the system stable until the primary frequency control takes over.

In this project, the frequency response of the electric power system has been studied with increasing amount of wind penetration.

Another step forward in Swedish energy research

Energiforsk – Swedish Energy Research Centre is a research and knowledge based organization that brings together large parts of Swedish research and development on energy. The goal is to increase the efficiency and implementation of scientific results to meet future challenges in the energy sector. We work in a number of research areas such as hydropower, energy gases and liquid automotive fuels, fuel based combined heat and power generation, and energy management in the forest industry. Our mission also includes the generation of knowledge about resource-efficient sourcing of energy in an overall perspective, via its transformation and transmission to its end-use. Read more: www.energiforsk.se

Energiforsk