The Frequency of the Frequency
On Hydropower and Grid Frequency Control

LINN SAARINEN
Variations in the electricity consumption and production connected to the power system have to be balanced by active control. Hydropower is the most important balancing resource in the Nordic system, and will become even more important as the share of variable renewable energy sources increases. This thesis concerns balancing of active power, especially the real-time balancing called frequency control. The thesis starts in a description of the situation today, setting up models for the behaviour of hydropower units and the power system relevant to frequency control, and comparing the models with experiments on several hydropower units and on the response of the Nordic grid. It is found that backlash in the regulating mechanisms in hydropower units have a strong impact on the quality of the delivered frequency control. Then, an analysis of what can be done right now to improve frequency control and decrease its costs is made, discussing governor tuning, filters and strategies for allocation of frequency control reserves. The results show that grid frequency quality could be improved considerably by retuning of hydropower governors. However, clear technical requirements and incentives for good frequency control performance are needed. The last part of the thesis concerns the impact from increased electricity production from variable renewable energy sources. The induced balancing need in terms of energy storage volume and balancing power is quantified, and it is found that with large shares of wind power in the system, the energy storage need over the intra-week time horizon is drastically increased. Reduced system inertia due to higher shares of inverter connected production is identified as a problem for the frequency control of the system. A new, linear synthetic inertia concept is suggested to replace the lost inertia and damping. It is shown that continuously active, linear synthetic inertia can improve the frequency quality in normal operation and decrease wear and tear of hydropower units delivering frequency control.

**Keywords:** hydropower, frequency control, governors, power system stability, inertia, primary control

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To my parents
This thesis is based on the following papers, which are referred to in the text by their Roman numerals.


VIII E. Dahlborg, L. Saarinen and P. Norrlund, "Primary Frequency Control - Pay for Performance", in manuscript.


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<th>Physical unit</th>
<th>Description</th>
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<tr>
<td>$\alpha$</td>
<td>$^\circ$</td>
<td>Runner blade angle</td>
</tr>
<tr>
<td>$\alpha_{mv}$</td>
<td>$^\circ$</td>
<td>Runner blade angle measured value</td>
</tr>
<tr>
<td>$\alpha_{sp}$</td>
<td>$^\circ$</td>
<td>Runner blade angle setpoint</td>
</tr>
<tr>
<td>$\delta$</td>
<td>pu</td>
<td>Rotor angle</td>
</tr>
<tr>
<td>$\omega$</td>
<td>rad/s</td>
<td>Angular frequency</td>
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## Symbols (latin)

<table>
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<th>Symbol</th>
<th>Physical unit</th>
<th>Description</th>
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<tbody>
<tr>
<td>$B_{\alpha}$</td>
<td>$\circ$</td>
<td>Amplitude of backlash in runner regulation</td>
</tr>
<tr>
<td>$B_Y$</td>
<td>% (GV%)</td>
<td>Amplitude of backlash in guide vane regulation</td>
</tr>
<tr>
<td>$D$</td>
<td>MW/Hz</td>
<td>Damping constant, frequency dependency of the load</td>
</tr>
<tr>
<td>$E_p$</td>
<td>Hz/%</td>
<td>Droop, inverse static gain of controller</td>
</tr>
<tr>
<td>$E$</td>
<td>MWh</td>
<td>Energy</td>
</tr>
<tr>
<td>$f$</td>
<td>Hz</td>
<td>Grid frequency</td>
</tr>
<tr>
<td>$F$</td>
<td>Transfer function of controller</td>
<td></td>
</tr>
<tr>
<td>$G$</td>
<td>Transfer function of system</td>
<td></td>
</tr>
<tr>
<td>$G_s$</td>
<td>Transfer function of servo</td>
<td></td>
</tr>
<tr>
<td>$G_t$</td>
<td>Transfer function of turbine and waterways</td>
<td></td>
</tr>
<tr>
<td>$H$</td>
<td>m</td>
<td>Head</td>
</tr>
<tr>
<td>$H$</td>
<td>s</td>
<td>Inertia constant</td>
</tr>
<tr>
<td>$K_i$</td>
<td>Integral gain of controller</td>
<td></td>
</tr>
<tr>
<td>$K_p$</td>
<td>Proportional gain of controller</td>
<td></td>
</tr>
<tr>
<td>$M$</td>
<td>s</td>
<td>System inertia constant, $2H$</td>
</tr>
<tr>
<td>$n$</td>
<td>Measurement disturbance</td>
<td></td>
</tr>
<tr>
<td>$P$</td>
<td>MW</td>
<td>Power</td>
</tr>
<tr>
<td>$P_L$</td>
<td>MW</td>
<td>Load disturbance</td>
</tr>
<tr>
<td>$Pr$</td>
<td>Probability</td>
<td></td>
</tr>
<tr>
<td>$s$</td>
<td>Laplace variable</td>
<td></td>
</tr>
<tr>
<td>$S$</td>
<td>VA</td>
<td>Apparent power</td>
</tr>
<tr>
<td>$S_k$</td>
<td>MWh</td>
<td>Energy storage need over the time horizon $k$</td>
</tr>
<tr>
<td>$T_f$</td>
<td>s</td>
<td>Filter time constant</td>
</tr>
<tr>
<td>$T_i$</td>
<td>s</td>
<td>Integration time constant or feedback time constant</td>
</tr>
<tr>
<td>$T_w$</td>
<td>s</td>
<td>Water time constant</td>
</tr>
<tr>
<td>$T_y$</td>
<td>s</td>
<td>Servo time constant</td>
</tr>
<tr>
<td>$Y$</td>
<td>% (GV%)</td>
<td>Guide vane opening</td>
</tr>
<tr>
<td>$Y_c$</td>
<td>% (GV%)</td>
<td>Guide vane opening control signal</td>
</tr>
<tr>
<td>$Y_{mv}$</td>
<td>% (GV%)</td>
<td>Guide vane opening measured value</td>
</tr>
<tr>
<td>$Y_{pos}$</td>
<td>% (GV%)</td>
<td>Guide vane opening position</td>
</tr>
<tr>
<td>$Y_{sp}$</td>
<td>% (GV%)</td>
<td>Guide vane opening setpoint</td>
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In many cases, the per unit values of the parameters are used.
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tr>
<td>ACE</td>
<td>Area control error</td>
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| aFRR | Automatic frequency restoration reserve  
(a secondary frequency control reserve) |
| BEP | Best efficiency point |
| BRP | Balance responsible parties |
| Ep0-Ep3 | Frequency controller parameter settings used in Vattenfall AB |
| FCR-D | Frequency containment reserve, disturbed operation  
(a primary frequency control reserve) |
| FCR-N | Frequency containment reserve, normal operation  
(a primary frequency control reserve) |
| GV | Guide vane |
| HPP | Hydropower plant |
| IMC | Internal model control |
| LFC | Load frequency control, secondary control |
| mFRR | Manual frequency restoration reserve  
(a tertiary frequency control reserve) |
| PID | Proportional, integral, derivative controller |
| PIP | Proportional, integral, proportional controller |
| PLC | Programmable logic controller |
| PMU | Phasor measurement unit |
| PV | Photovoltaics |
| RMSE | Root mean square error |
| ROCOF | Rate of change of frequency |
| SI | Synthetic inertia |
| TSO | Transmission system operator |
| VRE | Varying renewable energy |
| VSM | Virtual synchronous machine |
| WP | Wind power |
1. Introduction

Electrical power systems consist of production units, transmission and distribution lines, substations with transformers, breakers and other equipment and consumers. This thesis is focused on the use of production units, especially hydropower units, to keep power systems reliable with respect to the balancing of active power, i.e. to make sure that there is always enough production to cover the consumption and that the grid frequency is stable. From one point of view, the power system is always in balance, since it is merely converting and transmitting energy from one place to another. From another point of view, the balance between production and consumption of electricity in the power system has to be maintained by active control. The system has a certain electrical frequency, related to the rotational speed of the directly connected synchronous machines. To maintain the rotational speed of the machines, and thereby the kinetic energy of the system, the mechanical power driving the generators must be regulated to match the electric power withdrawn from the system by the consumers and changes in the production. Any mismatch will lead to an acceleration or deceleration of the electrical machines and thereby adding to or borrowing from their rotational energy.

The rotational speed of the machines, and thereby the electrical frequency of the grid, has to be kept close to its nominal value (e.g. 50 Hz in Europe or 60 Hz in the USA). Grid frequency deviations are especially harmful to thermal power plants, and if the grid frequency drops too low or rises too high, they will disconnect in order to protect themselves. Otherwise a sub-synchronous resonance frequency of the grid may coincide with a torsional resonance frequency of the axis of the shaft of the machine and shear it. If thermal units starts to disconnect due to a low grid frequency, the grid frequency will start to drop even faster due to the increased mismatch between production and consumption, and eventually there will be a blackout. The objective of grid frequency control is to make sure that this never happens.

In most power systems, the balancing of active power is split into several different tasks on different time horizons, problems that are handled separately. Seasonal, intra-week and intra-day balancing are handled by planning carried out by utilities or by settlements on energy markets. Typically, both the load and some part of the production is season and weather dependent, while another part of the production is dispatchable and used to balance the system. In real time, the production is dispatched either by the transmission system operator (TSO) or by the owners of the production units. Balancing actions in real time which are not planned in advance, but carried out as a response to the real time situation in the grid, are called frequency control.
Normally, there are several levels of frequency control in a power system. Primary frequency control, also called Frequency Containment Reserve (FCR), is a decentralised droop control, where governors on production units measure the frequency and adjust the output power proportionally to the frequency deviation (for hydropower, the proportional control is modified to a PI control with droop, which has a steady state response that is proportional to the grid frequency deviation). The steady state error in the grid frequency is non-zero in a system with only primary frequency control. Secondary control is centralised and controlled by the TSO. Automatic secondary control goes under many names: Automatic generation control (AGC), load frequency control (LFC) and frequency restoration reserve (FRR) which also includes tertiary control. The objective of secondary control is normally both to restore the grid frequency to its nominal value and to restore the tie-line power flow between different system areas to the scheduled values.

The area control error (ACE) is constructed as a weighted sum of the frequency deviation and the deviation from the scheduled tie-line power flow, and a controller tries to regulate the ACE to zero by sending setpoint adjustments to the power plants that participate in secondary control. In some systems, like the Nordic, LFC is used to control the frequency only, and not the ACE. Tertiary control (sometimes denoted manual secondary control) is also centralised and controlled by the TSO, but is activated manually and normally in larger steps than LFC. Typically, the TSO either starts up a new unit or orders a generating company to do so.

Power grid frequency control has been an active research area for over 50 years [1, 2], taking part in the development of power systems worldwide. Up until the 1980’s, governors were mechanical and analogue; now power plants have digital controllers implemented in programmable logic controllers (PLCs). The power systems are growing and becoming more complex, as are the system models. It is becoming possible to model and simulate very large systems in great detail. It is also becoming increasingly difficult to ensure that the parameters of these complex models are correct and corresponding to the reality of the system with all its generation units. The vast majority of power system studies present results based on simulation, while published results from experiments, measurements and validation of models are scarce. At the same time, the power systems are facing rapid changes due to the shift from conventional to variable renewable energy sources (VRE). Further changes stem from the deregulation and marketisation that are taking place in many systems. There are concurrent developments towards more interconnection on the one hand and more self-sufficiency in local micro grids on the other hand.

This thesis addresses some issues connected to these global developments, using the Nordic system as an example. The problems faced in the Nordic system are also faced by other power systems, but the local conditions make some aspects stand out and draw attention to specific problems.
1.1 Global challenges in a Nordic context

The development of the Nordic power system has many similarities with the development of other systems in the world. In Sweden, the first hydropower stations were built in the late 19th century. Most of the hydropower stations were built in the 1950’s and 1960’s, and nuclear power in the 1970’s and 1980’s. To enable the nuclear power to run on constant load, the flexibility of the hydropower was increased by installing extra capacity in many stations. Mechanical governors were gradually replaced by digital PI controllers during the 1980’s, and an increase of the hydraulic pressure in the regulating systems from 40 bar towards 160 bar was initiated. In the 1990’s, the power system went through a large organisational change. The operation of the transmission grid was separated from the production of electricity, and the market for electricity was deregulated. Now, in the 2010’s, nuclear power is being decommissioned, at least to some extent, and the share of wind power (WP) in the system is growing.

Since the deregulation in the 1990’s, there has been a gradual deterioration of the grid frequency quality in the Nordic system. From 1995 to 2011, the average time when the grid frequency was outside the normal band 49.9-50.1 Hz gradually increased from 100 to 1100 minutes per month [3]. The Swedish TSO, Svenska Kraftnät, has a goal that the time outside the normal band should not exceed 10 000 minutes per year. The result for 2016 is likely to be considerably higher, since the accumulated time after the first six months was 8 236 minutes [4].

One reason for the increased grid frequency deviations is the design of the electricity market, where electricity is bought and sold in hourly blocks. The production schedule, settled by the market, follows the load changes, but only in hourly steps. This means that when the load is increasing, the scheduled production is too low at the end of the hour, and then too high in the beginning of the next hour, when more production is started to match the average load of the next hour. The frequency containment reserve for normal operation (FCR-N) is not sufficient to handle these large power deviations.

Another cause of the deteriorated grid frequency quality is the so called 60 second oscillation. Figure 1.1 shows an example of a record of the Nordic grid frequency. The grid frequency has a random variation, but a dominating period of approximately one minute is clearly visible. The period of this oscillation varies between 30-90 s over time. The amplitude varies, but typically the oscillation is visible to the eye like in this example.

This type of oscillation is called very low frequency oscillation, to distinguish it from inter-area oscillations that have periods of a few seconds and sometimes are referred to as low frequency oscillations. The very low frequency oscillations correspond to a mode where the whole synchronous grid swings in unison, with a typical period of 10-100 s, depending on the size and dynamic properties of the grid. These oscillations are also found in the grids
Figure 1.1. Example of the grid frequency in the Nordic system measured during 10 minutes the 3rd of February 2014. There is a clearly visible dominating period of approximately one minute.

of Ireland, Iceland, Turkey, New Zeeland and Colombia. In Colombia, the period is 12-20 s, and it has been shown that the oscillation is connected to the tuning of hydropower governors [5]. It has also been shown that backlash in hydropower governor systems can create limit cycle oscillations with periods in this range [6].

The 60 second oscillation is problematic in two ways. Firstly, it decreases the margins for stability with respect to large disturbances, since it makes it more likely that the frequency is already at a low value when a large disturbance occurs. The system is designed to withstand what is called the n-1 criterion, i.e. a sudden disconnection of the largest unit of the system. In the Nordic grid, the largest unit is a 1400 MW nuclear power production unit. Secondly, the 60 s oscillation induces wear and tear in the hydropower units that provide FCR to the system.

The turbines are regulated by adjustment of the guide vane opening and, for Kaplan turbines, the runner blade angle, changing the flow of water through the turbine, and thereby the power output. Frequency control is characterised by many small movements of the turbine regulating mechanism, on top of slower trends that may take the turbine away from the best efficiency point (BEP). The wear on the guide vane and runner bearings is proportional to the sliding distance of the bearings, which in turn is related to the changes of the guide vane control signal [7]. Direction changes in the control signal give rise to load changes on the guide vanes and runner blades, and each load cycle may add to the fatigue of the turbine [8, 9]. Operation away from the BEP is also connected to increased wear and tear of the turbines. Especially for Francis turbines, such operation can be harmful to the turbines due to cavitation, vortex break down and high pressure pulsations [10–12].
Hydropower is the main balancing resource in the Nordic system and is also contributing to balancing of the European continental system [13]. The need for balancing, communicated to the production companies via variations in the electricity spot price and incorporated in production plans via optimisation tools, leads to more operation away from the BEP of individual hydropower units. Frequency control action adds on top of this, and may push the unit even further away from the BEP during operation. In recent years, there have been some failures of Kaplan runners in Sweden, which has lead to an increased industry and research interest in Kaplan hubs and bearing wear. Although the underlying cause may have been poor design or construction errors rather than frequency control, the process of failure was probably accelerated by the frequency control.

In the Nordic system as well as worldwide, the electricity production from wind power, photovoltaics (PV) and other VRE sources is increasing. This development comes with several challenges for the system. The first challenge is the variability of electricity production; that it is weather dependent and non-dispatchable. The variable production increases the need for balancing over some time horizons and may decrease the need over other, depending on the correlation between the variable production and the load. The second challenge is that the VRE does not contribute to the system inertia. Photovoltaics do not have inertia, and the inertia of wind turbines is not contributing to the grid inertia if they are connected to the grid through inverters. The third challenge is that VRE cannot provide frequency control reserves unless they curtail some of the available power. This means that when conventional power production is replaced by VRE, the variation of the net load (or residual load, i.e. the difference between load and VRE production) increases, while the total inertia of the system and the available FCR and FRR resources decreases.

The main question of this thesis is: What is the role of hydropower when it comes to balancing active power on the grid, especially through frequency control, and how can hydropower enable the shift to renewable power production? The thesis starts in a description of the situation today, setting up models for the behaviour of hydropower units and the grid relevant to frequency control, and comparing the models with experiments on several hydropower units and on the response of the Nordic grid. The thesis continues with an analysis of what can be done right now to improve frequency control and decrease its costs, discussing governor tuning, filters and strategies for allocation of frequency control reserves. The thesis ends with an outlook into the future, addressing how the role of hydropower may change and how some of the challenges could be handled. The energy storage need induced by VRE is quantified and a new, linear synthetic inertia concept is suggested, which can improve frequency quality in normal operation and decrease wear and tear of units delivering FCR.
1.2 Modelling for frequency control applications

The first part of this thesis, including Paper I-IV, concerns the frequency control dynamics of the system today, especially with regard to the performance of hydropower units providing frequency control, and its impact on the units in terms of wear and tear.

Hydropower plants are highly nonlinear and complex systems, and much research effort has over the years been put into modelling hydropower plants with different levels of detail. The amount of detail needed in the model depends on the type of phenomenon studied [14]. To be able to study fast hydraulic transients, for example due to load rejections, models including the waterhammer effect with compressible water, elastic penstock and nonlinear turbine equations are needed [15,16]. To be able to study more than one operational point, the nonlinear (steady state) relation between guide vane opening and power needs to be taken into account [17,18]. Dynamics from surge tanks [19], shared waterways [20] and the runner angle regulation of Kaplan turbines [21,22] may also be of importance. For frequency control studies, when small signal amplitudes are studied and the interesting dynamics are in the range below 0.1 Hz, a linear model of the water acceleration in the penstock is often considered to be enough [23].

The dynamic response of a hydropower plant can be measured and defined in different ways. One suggestion is that step response, ramp response and random signal response should be used to benchmark the frequency control performance of hydropower plants [24]. The response to load rejection [17,25] or the frequency response [25–27] can also be tested. Technical requirements for frequency control reserves defined by TSOs are often given in terms of response to a frequency step disturbance.

On the generator side, the inertia of the machine is modelled by the swing equation. Generator models of different complexities can be used to describe faster dynamics [23].

Power systems comprises a large number of units as well as other components, and can also be modelled with varying levels of details. Small signal stability is typically studied with linearised models of the system. For frequency control studies, lumped models can be used since the relatively slow dynamics of frequency control take place in a lower frequency band than the electromechanical oscillations of individual units [28]. A more detailed representation of the grid is needed if there are limitations in the transmission capacity within the grid that should be taken into account [29]. For LFC studies, the power flow between the interconnected area of each LFC controller has to be represented in the model.

The parameters of lumped power system models can be derived either from reduction of larger models, from general system data or by estimation from measurements in the system. The system inertia can be calculated from the rate of change of frequency after a known large disturbance (see e.g. [30]). The
deployment time of the frequency control can be calculated from the grid frequency signal, once the inertia is determined [31]. If phasor measurement unit (PMU) measurements of the power output of the units are available, representative governor parameters can also be estimated [32]. Data from normal operation of the power system can also be used to estimate grid parameters [33] or to predict the grid frequency [34].

The inter-area modes of a power system typically occur in a higher frequency band than the frequency control, but there may still be some interaction. The occurrence and frequency of inter-area oscillations can be found from spectral analysis of PMU data [35], but the damping factor is more difficult to determine directly from measurements. One way is to use a Kalman filter to estimate parameters in a model and calculate oscillation frequency and damping from the eigenvalues of the estimated model [36].

In general, there is a lack of published research on measurements that validate the theoretical models of the power system and of hydropower units. There is also great uncertainty as to how the governors of hydropower units active in the system today are tuned. In the Nordic system, the uncertainty can partially be explained by the somewhat vague technical requirements on primary frequency control defined by the TSOs. The requirements are formulated in different ways in the different countries. In Norway, the ability to operate in island operation is considered important and has shaped the requirements. In Sweden, island operation capabilities have not traditionally been needed and the requirements are aimed at supporting a strong grid.

There is also a lack of studies on frequency control in normal operation. In previous research, the main focus of modelling related to frequency control dynamics has been the response to large disturbances, e.g. n-1 disturbances. In normal operation, backlash nonlinearities in hydropower units have more impact on the response, since they are more severe for small signal amplitudes. The response of the controller can also be different, if automatic parameter shift triggered by low grid frequency or large negative derivative of the grid frequency is implemented, like in many governors in Sweden. Previous research on frequency control response also needs to be completed with studies of other types of disturbances than steps, such as typical grid frequency time series and sinusoidal disturbances.

This thesis contributes to the area with measurements and empirical modelling of the normal operation frequency control response of hydropower units (Paper I). It also contributes with measurements and modelling of the power system response to small, sinusoidal power disturbances with 15-150 s periods (Paper II). The emphasis of the analysis is on the response to typical random load or frequency deviations and sinusoidal load or frequency deviations. Modelling of the start-up, no load operation and load rejection as well as normal operation of hydropower units are described in Paper III. The relation between governor parameter settings and wear and tear of hydropower units is investigated in Paper IV.
1.3 Frequency control tuning and strategies

The second part of the thesis, including Paper V-VIII, addresses some ideas on measures that can be taken here and now to improve frequency control, both from a hydropower perspective and from a grid perspective. Paper V suggests a robust method for governor tuning that takes both the grid frequency quality and wear and tear of hydropower units into account. Paper VI describes pros and cons of filtering the grid frequency input signal to the governor with different types of filters. Paper VII evaluates different strategies for allocation of frequency control reserves on a hydropower fleet. Paper VIII suggests a new remuneration method for frequency control reserves that would give incentives to improve the quality of the delivered control.

Frequency control has been subject to a lot of research, but there is surprisingly little on primary frequency control. Some studies were made in the 70’s and 80’s [37–39], but since then, the focus has been on automatic secondary control. Many different types of controllers have been evaluated for LFC, mostly by simulation [1, 2]. The most common controller, both for primary and secondary control, is the proportional, integral and derivative (PID) controller (PI(D) with droop for primary control). There is a continued research interest in PID tuning for LFC [40–42]. Robust $H_\infty$ controllers [43] and methods for robust tuning of PID controllers [41, 44] are interesting, since they provide a systematic way of taking model uncertainties into account, and the model uncertainties are great since power systems are changing all the time. Traditionally, inter-area modes are not considered in LFC studies, since they take place in a higher frequency band, but there can be some interaction in certain cases [45].

Allocation of frequency control reserves has been studied as a part of production planning research and as a part of LFC design, but not so much as a topic of its own. In the field of production planning, the focus has been on making sure that enough units that can provide frequency control reserves are in operation. This consideration normally puts a limit on the maximal VRE production that the grid can handle. Temporary overloading of units has been considered as a means to increase the reserve available from each unit [46]. Continuous re-dispatch to restore reserves and improvement of the system behaviour by restoring fast-responding reserves first have also been discussed [47].

In the field of LFC design, reserve allocation has been considered as an integral part of the controller design. Allocation strategies where the objective is to avoid saturation of the units [48] and allocation strategies taking the production costs of the units into account [49] have been suggested. Limitations in transmission capabilities have also been considered [29,50]. Some control design methods take wear into account by limiting the high-frequency response of the controllers [51]. However, the connection between the allocation of the
reserves and the wear and tear of the units has not been thoroughly investigated. Neither has the interaction between primary and secondary control.

The lack of research on primary control may be explained by the fact that most large systems have LFC, and that the LFC controller is directly accessible to the TSO, unlike the decentralized primary controllers. There may also exist preconceptions that governor settings cannot be changed, that all governors have to have the same settings and the same droop, etc. The unit droops are fixed in many systems, whereas in the Nordic system the droops can normally be changed from the control centres. For thermal power, there is no need to have transient droop or integration in the governor, so there is actually not much room for tuning. Instead, there are often deadbands and ramp limiters that certainly do have an impact on the performance of the primary control, but may be seen as unit limitations that are non-negotiable. In systems like the Nordic, where all the frequency control is provided by hydropower, and where traditionally there have been no LFC, studies of the tuning of primary frequency control would seem much more urgent.

The contribution of this thesis is to define measures for the wear and tear on hydropower units induced by frequency control, and to relate the wear and tear to the system benefits like frequency quality and stability, so that an explicit trade-off can be made. A governor tuning method is suggested in Paper V, taking robustness to system changes into account and highlighting the trade-off between the "costs" for the units and the "benefits" for the system. Two methods for evaluation of the frequency control performance of a unit are developed - one method based on the correlation between the grid frequency and the power output, which neglects the system feedback, and one method that uses a back-calculated load disturbance and takes system feedback into account. The correlation method is suggested to form the base of a new type of remuneration for frequency control reserves in Paper VIII.

This thesis also contributes with analysis of the interaction between primary and secondary frequency control, with special focus on how to minimise the induced wear and tear on hydropower units. Strategies for selection of the droop of individual units within a fleet are evaluated in Paper VII, and allocation of secondary control reserves in relation to the allocation of primary control reserves is analysed.

1.4 Future impact from VRE - variability and inertia

The third part of this thesis gives an outlook into the future for hydropower and frequency control. Two main challenges are discussed: The increasing need for balancing over different time horizons due to the increase of intermittent production from VRE, in Paper IX, and the decreasing system inertia as directly connected synchronous machines are replaced by inverter connected VRE, in Paper X.
The balancing problem can be split into several separate problems with different time horizons. Both the load and the production from VRE varies with the weather, the season and the time of day. The energy reserve of the hydropower is also intermittent, but it has been constructed to overcome the variability, with large reservoirs and high capacity, and is therefore not only dispatchable but even more flexible than thermal power. Hydropower contributes to the balancing of the grid on every time horizon from seasonal to intra-second. In Sweden, some studies show that hydropower could be utilised to balance a 100% renewable power system [52]. The balancing contribution of a unit can be quantified as the correlation between the net load (the load minus the VRE production) and the production of the unit, on a certain time horizon [13]. In the Nordic power system, flexible operation of the hydropower on the seasonal to hourly time horizon is pushed by price variations on the electricity spot market. An increasing share of electricity from VRE changes the balancing needs of the system, and will therefore have consequences for hydropower operation.

The future variability of wind power production can be estimated from scaling of production data from the production today [53]. However, to account for geographical smoothing effects, meteorological models combined with information on the location of future wind power plants are needed [54, 55].

The firmness of VRE is a concept that describes the ability of a production unit or fleet to provide a certain power with a certain probability. A production unit can be considered firm if the probability is high that it can deliver close to its rated power. Alternatively, a unit can be considered to have a certain firm production, corresponding to the power that it can deliver with a high probability. A single VRE unit typically has a low firmness since its power output depends on stochastic weather variations, while a larger fleet of VRE units typically has a higher firmness, due to geographical smoothing effects.

Energy storage as a means of providing balancing on the intra-day and intra-hour time scale has been analysed by several researchers [56–60], as well as the flexibility needs in terms of need for regulating power [53]. Optimal sizing, design and operation of energy storage to firm wind power has also been investigated [61–63], as well as the use of conventional hydropower to firm wind power both in the intra-day timescale [64, 65] and in the seasonal timescale [66].

From a system perspective, backup power, energy storage and transmission capacity are complementary strategies to handle balancing of VRE [67, 68]. Loads can also contribute to balancing [69]. The mix of wind power and photovoltaics [70] and the amount of overcapacity in the system [71] also affects the system flexibility need.

The transition towards a fully renewable energy system is leading to fewer directly connected synchronous machines in the system, and thereby less inertia. The Nordic TSOs estimate that the kinetic energy of the Nordic system during low loads (typically summer nights) will be 124 GWs in 2020 and pos-
ibly as low as 80 GWs in 2025, which can be compared to the 250 GWs that is normal today [3]. Other power systems are going through similar changes, and an idea is spreading that VRE, which does not contribute with synchronous inertia, should be required to provide some type of actively controlled synthetic/virtual/emulated inertia to the grid.

Decreasing inertia can have an impact on several aspects of grid stability. The aspect that has drawn most attention so far in the global power system community is the impact on the rate of change of frequency (ROCOF) and the lowest frequency (the nadir) after a sudden disconnection of the largest unit in the system (the n-1 disturbance). Early grid code requirements on synthetic inertia (SI), like Hydro-Québec [72] and EirGrid [73], are clearly focusing on this aspect, and commercial implementations of SI, such as GE’s WindINERTIA [74] and ENERCON’s IE [75] are designed to support the grid only during large frequency events.

Another aspect is the frequency quality during normal operation. Reduced inertia makes the frequency more volatile, and thereby increases the possibility that the frequency is already at a low value when an n-1 disturbance occurs. It also changes the operational pattern of FCR, which may lead to increased wear and tear and losses for units delivering FCR. The impact on normal operation has been overlooked in studies on synthetic inertia so far.

A third aspect is that reduced inertia may impact the modes and damping of electro-mechanical oscillations in the system. Both synthetic damping [76], specialized controllers using notch filters [77] and Power Oscillation Damping (POD) controllers for wind power [78] have been suggested for damping of inter-area oscillations.

A wide range of solutions to the problem of decreasing inertia has been investigated. At one end of the spectrum are virtual synchronous machines or virtual synchronous generators (VISMA, VSM, VSG) [79–82] or synchronverters [83], that aim at creating an interface between the VRE and the grid that totally emulates a synchronous machine with inertia, damping, voltage control etc, which is continuously active. At the other end of the spectrum is emulated inertia as defined by for example Hydro-Québec, i.e. a fixed power output for a certain time period, that is triggered by large frequency events but otherwise inactive. The terms synthetic/emulated/virtual inertia tend to be used for the types of grid support that are only active during large disturbances. They can be either fixed power profile [72,84], proportional to the grid frequency deviation (P-controller) [85] or proportional to the derivative of the grid frequency deviation (D-controller) [86, 87]. Mathematically, D-control corresponds to inertia and P-control corresponds to damping, frequency dependent load or super fast droop control.

Synthetic inertia can be delivered by various sources, for example flywheels, superconducting magnetic energy storage [88], capacitors [89, 90], batteries [79, 80] or wind turbines [84–86, 91]. In the case of wind turbines, it is the actual mechanical inertia of the unit that is the power source of the synthetic
inertia. If the wind speed is higher than the rated wind speed, or if some power is being curtailed to create a margin for power increase, extra power extracted from the wind can also be utilised. As an alternative, the inertia of the unit can be used to smooth the output power of the unit [92]. To maintain production efficiency, the wind turbine must be returned to its optimal rotational speed and pitch as soon as possible. This may explain why research on SI from wind power is oriented towards temporary grid support during large disturbances, while continuously active VSM research normally assumes a large battery as the energy source. However, as long as the energy source is not inexhaustible, some type of energy recovery scheme will be needed in the end. Such schemes have not yet been discussed in research on VSM.

This thesis contributes with a new method to assess the flexibility need induced by the variability of VRE, in terms of storage volume and balancing power, described in Paper IX. The method enables comparisons between different time horizons and different firmness levels. The aim is to describe the character of the needed flexibility, without assumptions on the source that will provide it. The focus is time horizons of 1-14 days, which has been less investigated by previous research than the seasonal and the intra-day time horizons.

With respect to the inertia problem, this thesis suggests a new, linear SI controller which is continuously active, automatically recovers the energy of its energy source and can emulate both inertia and damping. The impact from reduced inertia and damping on the system during normal operation is described, and compared to a scenario where the lost inertia and damping are replaced with active control by the suggested linear SI controller. Furthermore, the impact of the energy recovery time constant of the SI is investigated, both in terms of linear and nonlinear (limit cycle) aspects.

1.5 Power system balancing in a market system

Balancing of power systems is not purely a technical problem, but highly impacted by the legal and economical framework and organisation of the system. In parallel with the technical changes of the power systems, due to the transition towards renewable sources, many systems are going through great organisational changes. The Nordic countries were forerunners when the Nordic market for electricity was founded in the 1990’s; since then many systems worldwide have gone through similar developments. This section gives an introduction to the electricity and balancing market system in Sweden and the Nordic countries, which is an important piece of the puzzle of how the system is operated.

There are many ways to organise balancing of production and consumption on the grid. Generally, production units are dispatched according to some sort of merit order, where production units with low running cost are selected first and units with high running cost are selected last. In many systems, the
dispatch is carried out by the TSO but in the Nordic countries the production schedules are settled on the NordPool spot market. The power producers then dispatch their own production and are responsible for their own "balance", i.e. to produce or procure the amount of energy that they have sold each hour. In the same way, the electricity consumers, through the electricity trading and sales companies, are responsible to consume the amount they have bought. Both sides are called balancing responsible parties (BRPs). After the spot market has closed, at 12:00 one day ahead of delivery, the market prices are calculated by NordPool, and if there are congestions (bottlenecks in the grid), these are relieved by introduction of different area prices. Once the market prices for each hour are calculated, the trades are settled. At 14:00, the capacities for intra-day trade are announced, and changes to the balances settled on the spot market are traded continuously on the intra-day market until it closes, one hour ahead of delivery.

Intra-hour, the BRP:s dispatch their production to keep their hourly balances, while the TSO is responsible for the real-time balancing of the system. For this purpose, they purchase reserves from the BRP:s.

For primary control, there are frequency containment reserves, FCR-N and FCR-D. These are decentralised, automatic reserves. FCR-N is active in normal operation and FCR-D is activated when there is a larger disturbance, i.e. when the grid frequency drops below 49.9 Hz. Both are purchased one or two days before delivery. The remuneration for delivery of FCR-N and FCR-D has a capacity part and an energy part. The capacity remuneration is pay-as-bid. It is meant to cover the costs for providing the reserve, and the bids are calculated according to principles set by the TSO [93]. The energy remuneration is calculated from the time deviation at the hour shift, and the price is determined by the price of secondary control during that hour.

For secondary control, an automatic frequency restoration reserve, aFRR, was tested in the Nordic countries from 2013 to 2015. In 2016, the test period was evaluated, and aFRR was re-introduced in September the same year. The reserve is currently only active during a few hours in the morning and a few hours in the evening, when the load is changing rapidly. The aFRR is a centrally controlled reserve, where setpoints are distributed from a central controller to the units that participate. The remuneration has one capacity part, which is pay-as-bid, and one energy part, which is remunerated with the regulating price (the market price for tertiary control) [4, 94].

For tertiary control, there is a manual frequency restoration reserve, mFRR, which is activated by telephone calls from the TSO to the BRP. This reserve is normally referred to as "regulating power". The prices are marginal prices set on a the regulating power market, and the price of up-regulation and down-regulation are normally not the same. The regulating prices determines the "cost" of being unbalanced. For each hour, it is determined which was the dominating direction (up or down), and the balances are settled accordingly. If it was an up-regulation hour, BRP:s that had an unbalance in the wrong
direction, i.e. produced less than agreed or consumed more than agreed, have to pay the up-regulation price for the energy they failed to deliver. BRP:s that had an unbalance that was favourable to the system, i.e. produced more than agreed or consumed less than agreed, get paid with the up-regulation price for the extra production [94].

1.6 Hydropower research at Uppsala University
The hydropower research at the Department of Engineering Sciences at Uppsala University started in 2003. Since then, three PhD thesis’s has been published on hydropower generators [95–97]. Currently, axial magnetic leakage flux in hydropower generators, actively controlled magnetic bearings, brushless exciter systems and frequency control are the main topics of the hydropower research at the department.

1.7 The frequency of the frequency
In this thesis, two different frequency concepts are used. Firstly, the grid frequency is the frequency of the voltages and currents of the grid, which are tightly connected to the speed of the directly connected synchronous machines. The objective of (grid) frequency control is to keep the grid frequency close to its nominal value, i.e. 50 Hz in the Nordic system.

Secondly, there is the frequency content of any signal (for example the frequency content of the grid frequency signal), derived from the Fourier transform of the signal. This is a means to describe the dynamic characteristics of the signal, that is, if it changes slowly or quickly in time. In this thesis, the word "frequency" will generally be used for the concept related to the Fourier transform, and "grid frequency" will be used for the concept of grid frequency. The exception to this principle is the widely established notion "frequency control", which will be used instead of the somewhat cumbersome "grid frequency control".

1.8 Outline of the thesis
This thesis contains 11 papers, which are ordered thematically, and a comprehensive introduction. Chapter 1 gives an introduction to the thesis and its relation to the research field. Chapter 2 describes the theory used in the thesis and Chapter 3 describes the methods and discusses methodological choices. Chapter 4-5 describes the main results and Chapter 6 gives a short discussion. Some conclusions are drawn in Chapter 7, Chapter 8 gives an outlook and some suggestions on future research are given in Chapter 9. The thesis also includes a list of the papers, acknowledgements and a summary in Swedish.
2. Theory

In this chapter, the theoretical foundations of this thesis are presented briefly. First, a model of the power grid, valid for small deviations from the operating point and for frequencies below 0.1 Hz, is derived. Primary and secondary frequency control are added to the model and the function of a hydropower governor is described. Then, a corresponding small signal analysis model of a hydropower plant is derived. These parts are mostly based on Kundur [23], except for the more detailed governor model. After that, some useful concepts from control theory are presented briefly. These parts are based on Glad and Ljung [98], Skogestad and Postlethwaite [99] and Åström [100].

2.1 The swing equation

The rotational speed of the rotor of a synchronous machine is governed by the swing equation, stating that the difference between the mechanical torque, $T_m$ [Nm], and the electrical torque, $T_e$ [Nm], is proportional to the acceleration of the rotor

$$J \frac{d\omega_m}{dt} = T_m - T_e. \quad (2.1)$$

The constant $J$ [kgm$^2$] is the moment of inertia of the rotor and $\omega_m$ [rad/s] is the mechanical rotational speed. The torques $T_m$ and $T_e$ are positive when the machine works as a generator, and negative for a motor. In a hydropower unit, the mechanical torque is originated in the turbine, where the potential and kinetic energy of the water is transferred to the machine. The mechanical torque is driving the machine and the electrical torque is braking it.

Defining the inertia constant $H$ [s] as the kinetic energy at rated speed $\omega_{0m}$ divided by the apparent power per unit base

$$H = \frac{1}{2} \frac{J \omega_{0m}^2}{S_{base}} \quad (2.2)$$

and acknowledging that the torque base is $T_{base} = S_{base}/\omega_{0m}$ and that the per unit electrical angular velocity, $\bar{\omega}_r$, is the same as the per unit mechanical angular velocity, $\bar{\omega}_m$, the per unit equation of motion of the machine is

$$2H \frac{d\bar{\omega}_r}{dt} = \bar{T}_m - \bar{T}_e, \quad (2.3)$$

where the superscript bar is used to denote the per unit values.
The relation between power, $P$ [W], torque and angular speed is given by

$$ P = \omega_r T. \quad (2.4) $$

Small deviations from the initial values (denoted with subscript 0) can be expressed by

$$ P_0 + \Delta P = (\omega_0 + \Delta \omega_r)(T_0 + \Delta T) \quad (2.5) $$

which can be approximated by

$$ \Delta P = \omega_0 \Delta T + T_0 \Delta \omega_r \quad (2.6) $$

since the term $\Delta \omega_r \Delta T$ is small. The torque on the machine is the difference between the driving mechanical torque $T_m$ and the braking electrical torque $T_e$, giving the equation

$$ \Delta P - \Delta P_e = \omega_0 (\Delta T_m - \Delta T_e) + (T_m - T_e) \Delta \omega_r \quad (2.7) $$

The last term is equal to zero, since the mechanical torque and the electrical torque are equal in steady state. The speed in the point of linearisation is $\omega_0 = 1$ if expressed in per unit. This means that

$$ \Delta \tilde{P}_m - \Delta \tilde{P}_e = \Delta \tilde{T}_m - \Delta \tilde{T}_e \quad (2.8) $$

and the relation between power and frequency is the same as the relation between torque and speed. Defining a new constant $M = 2H$ and utilising the Laplace transform, (2.3) can be then be rewritten as

$$ \Delta \tilde{\omega}_r = \frac{\Delta \tilde{P}_m - \Delta \tilde{P}_e}{Ms} \quad (2.9) $$

where bold font is used for the Laplace transform of signals. The change in braking electrical power is the sum of the load change, $\Delta P_L$ [W], and the frequency dependency of the load, expressed with the load-damping constant, $D$ [W/Hz], in per unit,

$$ \Delta \tilde{P}_e = \Delta \tilde{P}_L + D \Delta \tilde{\omega}_r \quad (2.10) $$

which inserted in (2.9) gives

$$ \Delta \tilde{\omega}_r = \frac{\Delta \tilde{P}_m - \Delta \tilde{P}_L}{Ms + D} \quad (2.11) $$

This equation describes the basic dynamics of a synchronous generator connected to a load. The power system can be described with the same equation, if all the connected machines are lumped into one, and the grid frequency is assumed to be the same all over the system. This is a good approximation in the low-frequency band where the frequency control operates [23]. In a higher frequency band, machines and groups of machines oscillate electro-mechanically against each other, and the frequency varies across the grid.
2.2 Interconnected system model

The lumped, one-area power system model derived from the swing equation is encircled by dashed line in Figure 2.1. This model can be extended to a multi-machine or multi-area model, where each area corresponds to a number of machines lumped into one. If each machine or area is represented by a voltage source \( E \angle \delta \) (magnitude \( E \) and angle \( \delta \)) behind a reactance \( X \), and the tie line is represented by a reactance \( X_{tie} \), the power flow from area 1 to area 2 is given by

\[
P_{12} = \frac{E_1 E_2}{X_1 + X_2 + X_{tie}} \sin(\delta_1 - \delta_2). \tag{2.12}
\]

Linearisation around the initial operating point \( \delta_1 = \delta_{10}, \delta_2 = \delta_{20} \) gives

\[
\Delta P_{12} = \frac{E_1 E_2 \cos(\delta_{10} - \delta_{10})}{X_1 + X_2 + X_{tie}} (\Delta \delta_1 - \Delta \delta_2) = T_{12} (\Delta \delta_1 - \Delta \delta_2), \tag{2.13}
\]

where \( T_{12} \) is the synchronising torque coefficient. Figure 2.1 shows the block diagram of the two-area system model.

2.3 Frequency control

Without active control, load disturbances would result in large deviations of the grid frequency. To keep the grid frequency within acceptable limits, the mechanical power of some units is changed automatically to balance changes in the load or production in the system. In Figure 2.2, the block diagram of the system is extended with primary and secondary control loops. Here, \( F_1(s) \) and \( F_2(s) \) are lumped representations of the governors which handles the primary
Figure 2.2. Block diagram of a two-area interconnected power system with primary and secondary frequency control. This representation deviates from Kundur [23] in that the LFC signal is fed directly to the servo and does not pass the primary frequency controller $F$. This is how LFC is implemented in the hydropower plants studied in this thesis.

frequency control, $G_{t,1}$ and $G_{t,2}$ are the lumped representation of the turbine (and waterway) dynamics of the units participating in frequency control in area 1 and area 2, and $F_{LFC,1}$ and $F_{LFC,2}$ are the LFC controllers of the two areas. $K_{LFC,1}$ and $K_{LFC,2}$ are scaling factors. This representation is simplified in the sense that in practice, the LFC control loop includes some of the governor dynamics.

2.3.1 Primary frequency control

Primary frequency control is carried out by the governors of individual units, in a decentralised manner. Primary control is basically a proportional control, and in thermal power plants, there is typically no PI controller but only a gain, which is the inverse of the droop. Hydropower units need to soften their response due to the non-minimum phase response of the waterways, which leads to an initial response in the wrong direction, cf. Section 2.5. Therefore, PI controllers with droop are normally used in hydropower governors.

A system with parallel controllers is controllable only if there is maximally one controller with pure integral action. If several parallel controllers tries to control the integral of the same signal, measurement errors can cause the controllers to diverge, some controllers trying to decrease the grid frequency
and some trying to increase it [98]. This is the reason why pure integral action is avoided in primary control.

The gain of the primary control on a system level is the sum of the gains of the units providing primary frequency control,

\[ \frac{1}{R_{\text{sys}}} = \frac{K_1}{E_{p,1}} + \frac{K_2}{E_{p,1}} + ... + \frac{K_n}{E_{p,n}} \]  

(2.14)

where \( R_{\text{sys}} \) [Hz/MW] is the regulation or droop of the system, \( K_n \) [MW/GV\%] is the incremental gain from guide vane (GV) opening to power of the unit \( n \), and \( E_{p,n} \) [Hz/GV\%] is the droop of the unit \( n \), all in per unit. Here, the units are assumed to be operated with GV opening feedback, which is the normal case for Swedish hydropower units. A deadband around the nominal frequency is sometimes allowed in governors.

2.3.2 Secondary frequency control

Secondary frequency control is centralised and controlled by the TSO. An interconnected system can have several LFC controllers, each controlling one area of the system. The problem of multiple integrations of the same signal is then avoided by the construction of another quantity to control, the area control error (ACE) so that

\[ \text{ACE}_1 = \Delta P_{12} + B_1 \Delta f \]
\[ \text{ACE}_2 = \Delta P_{21} + B_2 \Delta f, \]  

(2.15)

where \( P_{12} \) is the active power flow from area 1 to area 2, and \( P_{21} \) is the active power flow from area 2 to area 1, i.e. \( P_{21} = -P_{12} \). \( B_1 \) and \( B_2 \) are bias factors. Since the power flow is approximately proportional to the rotor angle difference between area 1 and area 2, the ACE contains the integral of the grid frequency. A P-controller working on the ACE is therefore enough to restore the grid frequency to its nominal value. However, to achieve zero steady state error of the tie-line power flow, a PI-controller is needed. The bias factors \( B_n \) are normally chosen as

\[ B_n = \frac{1}{R_n} + D_n \]  

(2.16)

where \( R_n \) is the droop or regulation of the area \( n \) and \( D_n \) is the frequency dependency of the load in area \( n \) [23].

It is also possible to consider the whole system as one area, and have only one LFC controller which works only on the grid frequency error. The LFC implementation in the Nordic grid is such a one area LFC.
2.4 Hydropower governor

The term governor refers to the turbine controller and turbine servo or servos of the hydropower unit. The governor changes the guide vane opening of the unit in order to control the active power (power feedback), the water level in the upstream or downstream reservoir (water level control), or simply the guide vane opening (opening feedback). If the turbine is a Kaplan turbine, the governor also includes a combinator, that calculates the optimal runner blade angle from the guide vane opening and the head, and a servo controlling the runner blade angle.

Figure 2.3-2.4 show part of the guide vane regulating mechanism of two different units. The guide vanes can be regulated by individual servos (Figure 2.3) or by a regulating ring with one or several larger servos (Figure 2.4).

Figure 2.5 shows a block diagram of a governor with a PI controller with droop. This governor is used in the Vattenfall hydropower units which are
studied in this thesis. Older governors typically have a dashpot governor with a transient droop and a permanent droop instead of a PI controller, but the functionality is similar. The droop, $E_p$, makes the PI controller into a PIP controller with constant steady state gain $1/E_p$. Changes in the setpoint, $Y_{sp}$, goes directly to the servo, without passing the dynamics of the PI controller. The ramp speed of setpoint changes is typically limited to 1%/s, while the ramp limiter that affects the frequency control response allows for higher speeds.

Figure 2.6 shows a block diagram of the hydraulic servo which regulates the guide vane opening of a hydropower unit. This representation of the servo corresponds to the servos in the studied hydropower units in Vattenfall. The gain $K_{p,y}$ works on the control error $Y_c - Y_{mv}$, and calls for increase or decrease of the opening of the proportional valve of the servo, which is modelled here as a pure integration and a gain $K_{s,y}$. In many cases there is also some backlash in the servo system. The servo model depicted in Figure 2.6 is often simplified as

$$G_s(s) = \frac{1}{sK_{p,y}K_{s,y} + 1} = \frac{1}{sT_s + 1}. \quad (2.17)$$
Figure 2.5. Block diagram of a turbine governor, corresponding to the Vattenfall governor. The $\Delta f$ is the grid frequency deviation from the nominal value (but in practice a rescaled generator frequency is used), $Y_c$, $Y_{mv}$ and $Y_{sp}$ are the guide vane opening control signal, measured value and setpoint, $K_p$ and $K_i$ are the proportional and integral gains of the PI controller and $E_p$ is the droop. The guide vane opening control signal and the guide vane setpoint signal are ramp limited.

Figure 2.6. Block diagram of a guide vane regulation servo, corresponding to the Vattenfall governor. The signals $Y_c$ and $Y_{mv}$ are guide vane opening control signal and measured value respectively, $K_{p,y}$ is the guide vane servo controller gain and $K_{s,y}$ is the gain of the hydraulic system of the servo. The control signal fed to the hydraulic system is limited to some range. Typically, there is some backlash in the system.
2.5 Hydropower turbine and waterways

The average velocity \( U \) [m/s] of the water in the penstock of a hydropower plant is

\[
U = K_u Y \sqrt{H},
\]  

(2.18)

with guide vane opening \( Y \) [%], head \( H \) [m] and the proportionality constant \( K_u \). Assuming small deviations from the initial values, the change of the water velocity can be approximated as

\[
\Delta U = \frac{\partial U}{\partial H} \Delta H + \frac{\partial U}{\partial Y} \Delta Y.
\]  

(2.19)

Inserting the partial derivatives and normalising the signals by their initial (steady state) values gives the equation

\[
\Delta \bar{U} = \frac{1}{2} \Delta \bar{H} + \Delta \bar{Y}
\]  

(2.20)

which describes the linearised relation between the water velocity, the head and the guide vane opening.

The mechanical power \( P_m \) [W] of the turbine is given by

\[
P_m = KHU
\]  

(2.21)

with a proportionality constant \( K \).

Again assuming small deviations from the initial values, and normalising with \( P_{m0} = KH_0U_0 \), the change of the normalised power can be approximated as

\[
\Delta \bar{P}_m = \Delta \bar{H} + \Delta \bar{U}.
\]  

(2.22)

Inserting the expression for \( \Delta \bar{H} \) in (2.20), the power is

\[
\Delta \bar{P}_m = 3 \Delta \bar{U} - 2 \Delta \bar{Y}.
\]  

(2.23)

When the head over the turbine changes, Newton’s second law of motion gives the following equation for the acceleration of the water in the penstock:

\[
\rho L A \frac{d \Delta U}{dt} = -\rho g \Delta H.
\]  

(2.24)

Here \( \rho \) [kg/m³] is the density of the water, \( L \) [m] and \( A \) [m²] are the length and cross sectional area of the conduit, \( g \) [m/s²] is the acceleration due to gravity and \( t \) [s] is the time. The factor \( \rho L A \) is the mass of the water in the conduit and \( \rho g \Delta H \) is the incremental change in pressure at the turbine. The equation on normalised form becomes (by dividing both sides by \( A \rho g H_0 \))

\[
T_w \frac{d \Delta \bar{U}}{dt} = -\Delta \bar{H} = 2 (\Delta \bar{Y} - \Delta \bar{U}),
\]  

(2.25)
with
\[ T_w = \frac{LU_0}{gH_0}. \] (2.26)

Taking the Laplace transform of (2.25) and solving for \( \Delta \bar{U} \) gives
\[ \Delta \bar{U} = \frac{1}{1 + \frac{1}{2} T_w s} \Delta \bar{Y}. \] (2.27)

Using (2.23), \( \Delta \bar{U} \) can now be substituted. Taking into consideration that \( T_w \) varies with the point of operation, \( Y_0 \), according to (2.26), the relation between the guide vane opening and the power is
\[ \Delta \bar{P}_m = \frac{1 - Y_0 T_w s}{1 + \frac{1}{2} Y_0 T_w s} \Delta \bar{Y}. \] (2.28)

This transfer function describes how the mechanical power responds to changes in the guide vane opening of an ideal, lossless hydraulic turbine [23].

In a Kaplan turbine, the runner blade angle is adjustable and the water flow through the turbine is determined by the combination of the guide vane opening and the runner blade angle. One way to model a Kaplan turbine is to use the method of Virtual Gate Opening [22,101]. The deviation of the guide vane opening, \( \Delta Y \), is then replaced by a weighted sum of \( \Delta Y \) and the runner blade angle deviation, \( \Delta \alpha \). This method is further described in Section 3.1.4.

2.6 Stability and control

A generalised closed loop system is depicted in Figure 2.7, with the system \( G(s) \) and the controller \( F(s) \), consisting of one feedforward link \( F_r(s) \) and one feedback link \( F_y(s) \). In many cases, for example the controllers studied in this thesis, \( F_r = F_y = F \). The input signals to the system are the reference signal \( r(t) \), the input disturbance \( w_u(t) \), the output disturbance \( w(t) \), and measurement noise \( n(t) \). The control signal is called \( u(t) \) and the controlled quantity is called \( y(t) \). The closed loop system can be expressed as
\[ y = (I + GF_y)^{-1} GF_r r + (I + GF_y)^{-1} w - (I + GF_y)^{-1} GF_y n + (I + GF_y)^{-1} G w_u, \] (2.29)
where \( I \) is the identity matrix and bold font denotes the Laplace transform of the signals. For simplicity, the argument of the transfer functions and signals are omitted. Equation (2.29) can also be expressed as
\[ y = G_c r + S w - T n + G S_u w_u \] (2.30)
where \( G_c \) is the closed loop transfer function from \( r \) to \( y \); \( S \) is the sensitivity function i.e. the transfer function from \( w \) to \( y \); \( T \) is the complementary
Figure 2.7. A generalised closed loop system.

sensitivity function i.e. the transfer function from \(n\) to \(y\); and \(S_u\) is the input sensitivity function i.e. the transfer function from \(w_u\) to \(u\).

The control signal can be expressed as

\[
\begin{align*}
  u &= (I + F_y G)^{-1} F_r r - (I + F_y G)^{-1} F_y (w + n) + (I + F_y G)^{-1} w_u = \\
  &= G_{ru} r + G_{wu} (w + n) + S_u w_u \quad (2.31)
\end{align*}
\]

with the transfer function \(G_{ru}\) from \(r\) to \(u\) and the transfer function \(G_{wu}\) from \(w\) to \(u\).

A transfer function is stable if and only if all poles are located in the left half plane, excluding the imaginary axis.

The stability of a simple feedback system (Figure 2.7 with \(F_r = F_y\), \(w_u = w = n = 0\) and \(G_0 = F_r G\)) can be evaluated with the Nyquist criterion, which states that if the open loop system \(G_0\) is stable, then the closed loop system is stable if the Nyquist curve \((G_0(i\omega)\) plotted in the complex plane) does not encircle the critical point \((-1, i0)\). The gain margin, \(g_m\), is defined as the inverse of the distance from the origin to the point where the Nyquist curve crosses the real axis, see Figure 2.8. The phase margin is defined as the angle between the negative real axis and the point where the Nyquist curve crosses the unit circle. These two measures can be combined into one measure, the stability margin, \(s_m\), which is the shortest distance from the Nyquist curve to the critical point \((-1, i0)\). The inverse of the stability margin is also the maximal value of the sensitivity transfer function of the system, \(\|S(i\omega)\|_\infty = 1/s_m\) [100].

However, the more general system in Figure 2.7 is not necessarily stable just because the Nyquist criterion is fulfilled. Due to the possibility of cancellations of zeros and poles, the system is stable if and only if all four transfer
Figure 2.8. Nyquist plot of the open loop transfer function $G$ with gain margin $g_m$, phase margin $\phi_m$ and stability margin $s_m$.

functions

\[
S_u = G_{wu} = (I + F_y G)^{-1} \\
G_{wy} = (I + GF_y)^{-1} G \\
G_{wu} = (I + F_y G)^{-1} F_y \\
S = G_{wy} = (I + GF_y)^{-1} 
\]

are stable and $F_r$ is stable [98]. This is called internal stability. If the system $G(s)$ is stable, it is enough to check that the transfer function $F_y/(1 + F_y G)$ is stable [99].

2.6.1 Application to frequency control

Applied to the case of primary frequency control of a one-area system, the systems and signals in Figure 2.7 can be interpreted as follows:

- $F_r = F_y$
- $G$ is the grid, $G(s) = 1/(Ms + D)$
- $F_y$ is the governor, turbine and waterways
- $r$ is the grid frequency deviation reference signal, i.e. 0
- $w_u$ is the load disturbance, $P_L$
- $w$ is grid frequency disturbances
- $y$ is the grid frequency
- $n$ is the measurement noise in the grid frequency measurement.

In this case, the system $G$ is stable if there is some frequency dependent load $(D > 0)$, so the system is internally stable if and only if the closed loop transfer function from measurement disturbance $n$ to FCR output power $P_{FCR}$, i.e. $-F_y/(1 + F_y G)$, is stable.
In the case of secondary control, the system $G$ is not inherently stable if the rotor angle $\delta$ or the tie-line power flow which is proportional to $\delta$ is considered as output signals from $G$. It is therefore necessary to check that all the transfer functions (2.32) are stable.

2.6.2 Robust control

In the context of control theory, the concept of robustness means insensitivity to model errors and disturbances. In some applications, the robustness of the controller is very important, for example due to large or unknown disturbances or uncertain or time varying system dynamics. Several methods to design robust controllers have been developed. Two of the most well known methods are called $H_2$ and $H_\infty$ controller design. Both these design methods aims at minimising the transfer functions $S(s)$, $T(s)$ and $G_{wu}(s)$ of the system, which describe the system sensitivity to model errors and disturbances. It is not possible to make all these transfer functions small on all frequencies, so part of the design method is to choose weighting functions in frequency domain, in order to prioritise in what frequency band each of the transfer functions should be pushed down, and in what frequency band it is allowed to be larger. The $H_2$ design methods minimises the total energy of the weighted transfer functions (the $H_2$-norm), while the $H_\infty$ design minimises the highest peaks of the weighted transfer functions (the $H_\infty$-norm) [98].

2.6.3 PID control

Proportional-integral-derivative (PID) controllers are commonly used for control of industrial processes. In many cases only the PI part is used, and the derivative part is set to zero. The most basic form of the PID controller is

$$u = \left( K_p + \frac{K_i}{s} + K_ds \right) e$$

(2.33)

where $e = r - y$, $K_p$ is the proportional gain of the controller, $K_i$ is the integration gain and $K_d$ is the derivative gain. The inverse of $K_i$ is often called the integration time, $T_i$, of the controller. However, in this thesis, $T_i = \frac{1}{EpKi}$ denotes the feedback time constant of the PI controller with droop which is implemented in the hydropower plants of Vattenfall, so $T_i \neq \frac{1}{K_i}$.

The derivative part of a PID controller is very sensitive to high-frequency disturbances. In general, it is therefore necessary to filter $e$ before calculating the derivative of the signal.
2.7 Describing functions

Describing functions is a method to study stability and limit cycle oscillations in nonlinear systems with static nonlinearities. Figure 2.9 shows a system with a static nonlinearity \( f(e) \) and a linear transfer function \( G(s) \), connected by negative feedback. If a sinusoidal signal

\[
e(t) = C \sin(\omega t)
\]

is fed to the static nonlinearity \( f(e) \), the output \( w \) will be a periodic function

\[
f(C \sin(\omega t))
\]

This signal can be decomposed into a Fourier series

\[
w(t) = f(C \sin(\omega t)) = f_0(C) + A(C) \sin(\omega t + \phi(C)) + A_2(C) \sin(2\omega t + \phi_2(C)) + A_3(C) \sin(3\omega t + \phi_3(C)) + \ldots
\]

with coefficients that are functions of the amplitude \( C \) but not the angular frequency \( \omega \).

With the assumption that \( f_0(C) = 0 \) and that the linear system \( G(s) \) has a low-pass characteristic, so that the components with angular frequencies \( 2\omega, 3\omega \) etc are suppressed, the output from the linear system is

\[
y(t) \approx A(C) |G(i\omega)| \sin(\omega t + \phi(C) + \psi(\omega)).
\]

If the negative output signal \(-y(t)\) in Figure 2.9 is equal to the input signal \( e(t) \), there can be an oscillation in the system. Using (2.34) and (2.36), \(-y(t)\) is equal to \( e(t) \) if

\[
A(C)|G(i\omega)| = C
\]

\[
\phi(C) + \psi(\omega) = \pi + \nu 2\pi
\]

where \( \nu \) is an integer. The unknown parameters \( C \) and \( \omega \) are the amplitude and angular frequency of a possible oscillation in the system.

The describing function of the nonlinearity is then defined as

\[
Y_f(C) = \frac{A(C)e^{i\phi(C)}}{C}.
\]

The linear system \( G(i\omega) \) can also be expressed in polar form

\[
G(i\omega) = |G(i\omega)| e^{i\psi(\omega)}
\]
and (2.37) and (2.38) can be written as

\[ Y_f(C)G(i\omega) = -1. \quad (2.41) \]

The amplitude and angular frequency of the oscillation can be calculated by solving (2.37)-(2.38) or (2.41). These equations can also be solved graphically, by drawing \( G(i\omega) \) and \(-1/Y_f(C)\) in the complex plane. An intersection of the two curves indicates an oscillation. If the curve \(-1/Y_f(C)\) crosses the function \( G(i\omega) \) from the right to the left as it goes toward larger values of \( C \), it indicates a stable limit cycle oscillation. If \(-1/Y_f(C)\) crosses \( G(i\omega) \) from the left to the right, it indicates an unstable oscillation. Furthermore, if the whole of \(-1/Y_f(C)\) is to the left of \( G(i\omega) \), there may be a damped oscillation in the system, while if the whole of \(-1/Y_f(C)\) is to the right of \( G(i\omega) \), there may be an oscillation with increasing amplitude.

The method of describing functions is an approximative method, which gives an indication of the possible existence of oscillations but does not give a necessary or sufficient condition [98].
3. Method

The overall method of this thesis is to build mathematical models of hydropower units and the power system that are valid for analysis of frequency control dynamics in normal operation, i.e. small amplitudes and a time scale of approximately 10-1000 s, and validate the models with experimental data. The models are then used to analyse the performance of the frequency control of today and to suggest improvements that are easily implemented, as well as to analyse the consequences of an increased share of VRE in the system. This chapter describes the used methods and discusses some methodological choices. The details are further described in the respective papers.

3.1 Modelling of hydropower units

Models of hydropower units are used in Paper I-VIII and X. In Paper III, a detailed model of the turbine and waterways including the elastic water hammer effect is described, which can be used for simulation of normal operation as well as other modes of operation like start and stop. Paper XI describes modelling of hydropower generators and parameter estimation from a standstill frequency response test of a generator. However, for studies of frequency control, and especially normal operation frequency control, this level of detailed modelling is not necessary. For Paper I, II, IV-VIII and X, the linearised model described in Section 2.5 is used as a starting point and some static nonlinearities and some additional linear dynamics are included when necessary. The approach to modelling in this thesis is to start simple, utilise available unit data and make experiments to validate the models and evaluate if and what sort of complexity should be added to the models to get an acceptable correspondence between the frequency control response of the unit and the model. The research in this thesis is based on data and experiments on hydropower units owned by Vattenfall AB, made available for research by the company.

3.1.1 Available data

Within Vattenfall, hydropower units are characterised by data sheets called "QP", "OPT" and "SOPT" data. These data sheets are constructed from physical model tests and "index testing" of the units, repeated every 10 years. Alternatively, efficiency tests with absolute measurement of the flow are made. The
tables describe the steady state relation between guide vane opening, flow, head, power and efficiency of the unit. In stations with more than one unit, there is one set of data for each combination of units.

The water time constants of the units, calculated from drawings of the waterways of the stations, are also available.

The same governor controller program is implemented in all stations, with some smaller variations between older and newer versions and brands. The available sets of parameter settings are the same for all units. There are some exceptions – units that do not participate in frequency control at all, or are limited in some ways due to special circumstances. Information on the settings of each governor is also available.

### 3.1.2 Experiments

The dynamical behaviour of some units were investigated further through experiments. Paper I describes experiments carried out on three Swedish hydropower stations (A, B and C). Similar experiments were later carried out on two additional Kaplan units in Vattenfall, and although the results of these experiments are not described in detail in this thesis, they influenced the way Kaplan turbines are modelled in Paper VII.

Hydropower plant A has one diagonal turbine which is similar to a Kaplan turbine in the sense that the runner blades are adjustable. Plant B has three Francis turbines with separate intakes and a common tail race tunnel. Plant C has three Francis turbines with a common free surface tail race tunnel. More information about the plants can be found in Paper I.

The following signals were measured during the experiments (Figure 3.2):

- $f$: grid frequency (generator frequency), from signal generator
- $Y_c$: guide vane opening control signal
- $Y_{mv}$: guide vane opening measured value (feedback signal)
- $P$: active power output
- $\alpha_{mv}$: runner angle measured value (feedback signal) in Plant A

The guide vane opening setpoint, $Y_{sp}$, and head were noted.

Three types of experiments were carried out on each unit, at several points of operation and with different droop settings when possible:

- **Step in $f$, ±0.1 Hz or ±0.4 Hz.**
- **Sinusoidal $f$, amplitude 0.1 Hz, periods of 4-600 s, 10 periods each.**
- **Step in $Y_{sp}$ with varying sizes, typically 10-20%.**
Figure 3.1. Turbine controller cabinet in a Vattenfall hydropower plant. A signal generator (in the lower right corner of the picture) is connected and gives the controller an external guide vane opening control signal. Another equipment was used to feed the controller with a grid frequency signal in the experiments described in Paper I.

Figure 3.1 shows the turbine controller cabinet of a Vattenfall hydropower unit. In this case, the guide vane opening control signal is controlled by a signal generator.

3.1.3 Greybox modelling
The measured data was used for system identification of a servo model, $G_s(s)$, and a model of the turbine and waterways, $G_t(s)$, according to the block diagram in Figure 3.2.

Backlash was observed in the guide vane regulating mechanism after the point of measurement of $Y_{mv}$ in unit C and in the runner regulating mechanism in unit A. Based on this observation, the hypothesis that the turbine model
could be improved by inclusion of backlash was tested. The following procedure was used:

1. Create the new signal $Y_{pos}$ through simulation of a backlash of a certain size, with $Y_{mv}$ as input signal.
2. Estimate $G_t(s)$ from $Y_{pos}$ to $P$.
3. Simulate the system from $Y_{mv}$ to $P$, using the backlash and the new $G_t(s)$ and compare the simulated $P$ to the measured $P$. If the $P$ simulated with backlash and the new $G_t(s)$ has a better fit to the measured $P$ than $P$ simulated with the old $G_t(s)$ has, then there is reason to include backlash in the model.
4. Repeat the procedure for different sizes of backlash and determine which size of backlash that leads to the best overall model.

This method can be used to include a nonlinearity when it is situated on the input signal to a model, but not if it is situated on the output signal inside a feedback loop. There may be significant backlashes both before and after the feedback, depending on where in the system the measurement of $Y_{mv}$ is made.

The static gain of the turbine and waterways transfer function, $G_t(s)$, also denoted the incremental gain, was considered as a static nonlinearity, depending on the point of operation. The incremental gain was estimated at the different points of operation where the experiments were carried out, and compared to the tabulated values.

3.1.4 Kaplan model

In Paper I, the regulation of the runner of the diagonal turbine in Plant A is not modelled explicitly, while in Paper VII, the runner regulation is included by the method of virtual gate opening [22], [101]. A block diagram of the model

---

**Figure 3.2.** Model of governor and plant. Input signals are the frequency deviation $\Delta f$ (created by a signal generator) and guide vane opening setpoint $Y_{sp}$ (manually controlled). Output signals are the governor control signal $Y_c$, the guide vane measured value $Y_{mv}$ (used as feedback signal) and the output power $P$. 

- $K_p$ and $K_i$ are the proportional and integral gains of the governor.
- $G_t(s)$ is the transfer function of the turbine and waterways.
- $E_p$ is the error signal between the setpoint and the measured power.
can be seen in Figure 3.3. In reality, the runner angle setpoint is determined by the combinator, which makes an interpolation from combination curves describing the combination of $\alpha$ and $Y$ that gives the best efficiency at different heads. In the model, the head variations are neglected and the runner servo time constant is assumed to be independent of $Y$. The virtual gate opening is a weighted sum of $Y$ and $\alpha$, with the weighing factors $R_Y$ and $R_\alpha$.

### 3.1.5 Linearisation of backlash

To be able to use linear methods from control theory, but still take the backlash in hydropower units into account, it is useful to have a linearisation of the backlash. For frequency domain analysis, one option is to linearise the backlash in each point of the Bode diagram (cf. Paper IV). This method gives a precise linearisation that is valid for a specific input signal amplitude for each point in the Bode diagram. The amplitude dependent gain, $K_{\text{backlash}}$ and phase shift, $\varphi_{\text{backlash}}$, of the backlash are

$$K_{\text{backlash}} = \frac{A_{in} - B_Y}{A_{in}}$$  \hspace{1cm} \text{if } A_{in} \geq B_Y \quad (3.1)

$$\varphi_{\text{backlash}} = -\arcsin\left(\frac{B_Y}{A_{in}}\right)$$  \hspace{1cm} \text{if } A_{in} \geq B_Y \quad (3.2)

where $A_{in}$ is the amplitude of the input signal to the backlash and $B_Y$ is the amplitude of the backlash.

Another option is to use the fact that since the turbine governor has low-pass characteristics, the amplitude of the input signal decreases as the frequency increases. Taking this into account it is possible to make a crude, but reasonable, amplitude independent approximation of the backlash as the first order system

$$G_{BL}(s) = \frac{K_{BL}}{T_{BSL} + 1}. \quad (3.3)$$

With a sinusoidal grid frequency with amplitude 0.1 Hz, the amplitude of the output of the controller which is the input to the backlash is

$$A_{in}(i\omega) = 0.1 \left| \frac{K_p i\omega + K_i}{T_y(i\omega)^2 + (E_p K_p + 1)i\omega + E_p K_i} \right|. \quad (3.4)$$
Figure 3.4. Gain and phase of two types of linearisation of backlash ($B_Y = 0.0005 \text{ pu}$), when the input signal is $A_{\text{in}}(i\omega)$. Approximation 1 is the amplitude dependent approximation given by (3.1)-(3.2). Approximation 2 is the amplitude independent approximation given by (3.3), linearised at $\omega = 2\pi/30$ ($K_{BL} = 0.9$ and $T_{BL} = 1.6$) and at $\omega = 2\pi/100$ ($K_{BL} = 0.8$ and $T_{BL} = 1$).

A linearisation point, $\omega_0$, is selected and $A_{\text{in}}(i\omega_0)$ is inserted in (3.1)-(3.2). The amplitude independent backlash approximation (3.3) is equal to the amplitude dependent approximation in the point of linearisation if

$$\| G_{BL} \| = K_{\text{backlash}},$$

$$\arg(G_{BL}) = \phi_{\text{backlash}},$$

which gives the following expressions for the parameters of (3.3):

$$K_{BL} = (\tan^2 \phi_{\text{backlash}} + 1)K_{\text{backlash}} \cos \phi_{\text{backlash}},$$

$$T_{BL} = -\frac{\tan \phi_{\text{backlash}}}{\omega_0}.$$

The two approximations are compared in Figure 3.4. Here, the amplitude independent linearisation is made at the point $\omega_0 = 2\pi/100$, giving the parameters are $K_{BL} = 0.9$ and $T_{BL} = 1.6$ for $B_Y = 0.0005 \text{ pu}$. The phase shift is relatively well captured by the amplitude independent approximation up to $\omega = 2\pi/30$ with linearisation in the point $\omega = 2\pi/30$ and up to $\omega = 2\pi/60$ with linearisation in the point $\omega = 2\pi/100$. The gain is underestimated at low and at high frequencies.

The amplitude independent approximation (3.3) is crude but at least better than just excluding the backlash in a linear analysis. When possible, the amplitude dependent linearisation should be used rather than the amplitude
independent one. For simulation purposes, the nonlinear backlash function is superior to the linear approximations.

3.2 Modelling of the power system

In most of the thesis, a one-area power system model is used, where all production and consumption is sharing a common rotating mass and a common frequency. This approximation of the system is valid for frequencies lower than approximately 0.1 Hz, and disregards the wave dispersion of signals in the system, electromechanical oscillations and other faster dynamics. The slowest of the electro-mechanical oscillations are called inter-area oscillations. In the Nordic system, the main inter-area oscillation frequencies are 0.33 Hz and 0.48 Hz. The lower frequency corresponds to a mode where Finland oscillates against the south of Norway. The higher frequency corresponds to either Sweden/Denmark oscillating against the south of Norway [102], or the north of Sweden against Finland, eastern Denmark, Norway and the south of Sweden, or the south of Sweden against the south of Norway [103]. In Paper II, a three-area model of the Nordic system is developed which has modes that match these modes to the extent that they have the same frequencies and that the slower mode involves Finland while the faster mode involves Norway. The reason for using a three-area model in this case was to be able to compare the power flow between the Nordic countries in addition to the measured grid frequency during a full-scale test in the system. However, the damping of the inter-area oscillations becomes unreasonably low in this model.

Both the one-area and the three-area power system models are linear models which are derived using the assumption that the frequency deviations and the load angle deviations are small. The grid signal amplitudes during normal operation, which is studied in this thesis, can certainly be categorised as small enough, since this type of models are commonly used also for analysis of n-1 frequency disturbances [104].

3.2.1 Full-scale test in the Nordic grid

A full-scale test of the Nordic system response to sinusoidal power disturbances was carried out in 2014, in cooperation with Nordic TSOs, Vattenfall AB and Gothia Power AB. Sinusoidal power output variations with amplitude 50 MW and periods 15, 25, 40, 60, 100 and 150 seconds were fed to the grid from a hydropower station in Luleälven in the north of Sweden, and the response of the grid frequency and the power flow between the Nordic countries were measured, see Figure 3.5.

A three-area model of the Nordic system was developed and simulations of the system were compared to the measured data. Production data from the time of the test were used to estimate the inertia and frequency dependent
Figure 3.5. The Nordic system with the tie-lines where the power flow was measured during the full-scale test marked with pink and the hydropower station creating the power disturbance marked with a yellow star. Map courtesy of Svenska Kraftnät.
load of each area. The technical requirements on FCR in each country and the amount of FCR bought by the TSO in each country were used to calculate the governor parameters in the model of each area. The aim at first was to use system identification methods to estimate model parameters from the full-scale test measurements, but it was found that the model structure was not suitable for system identification, at least not for the greybox estimation methods implemented in the Matlab System Identification Toolbox. The estimated parameters were highly dependent on the initial guesses of the parameters. Therefore, only a frequency domain comparison of the model and the measured data was made, and the system identification problem was postponed to future research with new methods.

3.3 Governor tuning

Paper V and Paper VIII both deals with the problem of governor tuning, but from different points of view. Paper V suggests a method for tuning of one
unit, and the whole system, taking stability and robustness criteria into account. Paper VIII investigates the possibility to create incentives through the remuneration of FCR to improve the performance of governors.

One fundamental difficulty when it comes to FCR tuning is the fact that one unit alone normally does not have a significant impact on the frequency of the whole grid, but the sum of the contributions from the units determine the system performance. Therefore, it is possible for some units to have settings that are harmful to the system, without being discovered. It is also possible for some units to have settings that are performing well in some frequency band but would be harmful to the grid in other frequency bands if they were not supported by other units stabilising the grid.

There are basically three ways to take the dynamics of the grid into account in the governor tuning:

1. Island mode. Consider the unit’s own inertia and some load, that may or may not be frequency dependent.
2. Scale the unit. Consider the inertia of the whole system, and scale the unit so that its static gain in frequency control corresponds to the total FCR gain of all the units in the system.
3. Incremental change. Consider the system with all the other units connected, and study the incremental change on system stability and performance from changes in the tuning of the studied unit.

The second method has been used in this thesis. The argument against the first method is that due to the strong grid, island operation capability has traditionally not been required of Swedish units. Many plants have in fact been hydraulically designed in a way that does not allow for island operation. Therefore it is not reasonable to tune the governor for this type of operation either. The argument against the third method is that the results would depend on the assumptions about the dynamical behaviour of the other units. It is desirable that each unit should perform well regardless of which other units it is cooperating with, so that the units are as interchangeable as possible.

Thermal power plants use governors that are basically just proportional controllers. This is not possible for hydropower, due to the non-minimum phase response of the waterways. Figure 3.7 illustrates this. The Bode diagram of the open loop system controlled by a lumped hydropower unit is plotted. The system is stable only if the phase is \( \geq -180^\circ \) when the gain \( > 1 \). With purely proportional control, the phase crossover frequency is 0.6 rad/s, and the gain at this frequency is higher than one, meaning that the system is unstable. With purely integral control with droop, the phase crossover frequency is 0.1 rad/s, where the gain is just below one, and the system is barely stable. With PI control with droop, the gain curve looks similar to the integral control curve, but the phase crossover is pushed towards a higher frequency, increasing the stability margin considerably. This is why hydropower units use PI-control with droop instead of pure droop control (P-control).
Figure 3.7. Bode diagram of the open loop system controlled by a hydropower unit. Gain and phase from grid frequency reference signal to grid frequency. The black line shows the magnitude and phase of the critical point (-1,i0). Purely proportional as well as purely integral control with droop leads to stability problems, while a PI controller with droop can achieve a better stability margin. Model parameters from Paper V are used.

3.3.1 Requirements on the closed loop system

In Paper V, a method for governor tuning based on frequency domain requirements on the closed loop system is suggested. Some variants of these criteria are also used in the new technical requirements on FCR, drafted by the Nordic TSOs. The system model in Figure 3.8 is used. In this model, the studied unit is scaled to be large enough to be the sole provider of FCR, and other units are disregarded except for their contribution to the total system inertia.

**Suppression of load disturbances:** The main objective of the primary frequency control is to suppress load disturbances, i.e., to adjust the production in the system to match the consumption. The transfer function from load disturbance, $P_L$, to grid frequency, $f$, describes the disturbance suppression of the system. In Paper V, the requirements on disturbance suppression are formulated as a maximum low frequency gain and a maximum peak gain.

**Robustness to varying operating conditions:** The power system operates in a wide range of operating conditions, and there is a considerable uncertainty about system parameters. It should be required that the system is stable for all
operating conditions. Using the small gain theorem [98], it can be shown that the system $H_0 = (I + \Delta H)H$, where $H$ is the model of the open loop system and $\Delta H$ is the model error, is stable if the complementary sensitivity function, $T(i\omega)$, fulfills the condition

$$|T(i\omega)| \equiv \left| \frac{H(i\omega)}{1 + H(i\omega)} \right| < \frac{1}{|\Delta H(i\omega)|}, \quad (3.9)$$

given that $H$ and $H_0$ has the same number of unstable poles. The model uncertainties can be expressed as a set of transfer functions $\Delta H_i(i\omega)$. Stability is ensured if the closed loop transfer function from measurement disturbance, $n$, to $f$ is smaller than the minimum of $1/|\Delta H_i(i\omega)|$ for all $\omega$.

**Stability margin:** It is also desirable that when the operating condition of the power system changes, the grid frequency quality should not deteriorate too much. The impact of a relative model error on the output signal $f$ is determined by the sensitivity function of the system, $S(i\omega)$, i.e. the closed loop transfer function from $f_{dist}$ to $f$,

$$S(i\omega) = \frac{1}{1 + F(i\omega)G(i\omega)}. \quad (3.10)$$

The peak of the sensitivity function is the inverse distance from the Nyquist curve to the point (-1,i0). It is called the maximum sensitivity, $m_s$, and can be seen as a combination of the classical measures phase margin and amplitude margin, cf. Section 2.6. In order to limit the impact on grid frequency quality from changes in the operating condition, the peak of the sensitivity function should be limited.

**Wear and tear:** Frequent regulation of a power plant induces wear and tear of the turbine and bearings, driving costs for maintenance and reduced life time. The wear is correlated to the travelled distance of the actuator and turbine and to the number of direction changes. To reduce wear, the high frequency content of the closed loop transfer function to the guide vane opening $Y$ should be limited. The fact that there are unmodelled electro-mechanical dynamics in the high frequency band (inter-area oscillations with periods up to 5 s) is another reason to limit the gain from $f_{dist}$ to $Y$. 

---

*Figure 3.8. Block diagram of the system.*
The results from the governor tuning using the one-area model of the power system has later been validated by simulation in a 32 node model of the Nordic power system. The existing governor parameters "Ep0" were compared with the new parameters suggested in Paper V. The change of the governor tuning improved the grid frequency quality in time domain simulations with the 32 node model, and did not have any significant impact on the inter-area oscillations of the system [105].

3.4 Calculation of a load disturbance signal from the grid frequency

To be able to evaluate changes in the frequency control of the system and compare different control strategies and tunings with time domain simulations, it is necessary to have a realistic input signal to the system, i.e. a realistic load disturbance signal, $P_L(t)$. Unfortunately, there are no suitable measurement data of the total load and generation of the system available. There are several possibilities in how to create a load disturbance signal that can be used as input to simulations:

1. Assume white noise. When nothing is known about the input signal, white noise is the assumption normally used in the field of control theory. This approach was used in Paper V.

2. Assume random walk. A random walk is the integral of white noise. This is a reasonable assumption, if it is assumed that the randomness of the signal comes from loads and production being turned on or off and then as default staying in the new state. However, a random walk can take values that deviate a lot from the starting point. In the power system, this is unrealistic since the larger variations of the load and production are balanced through production planning and dispatch. The random walk can be modified to white noise filtered by a first order system with a suitable time constant, to reduce the gain on very low frequencies.

3. Calculate from the measured grid frequency, using an inverse model of the system. This approach was used in Paper VI-VIII and X.

The third approach has not, to my knowledge, been used in previous research, and will therefore be described in detail here. Consider the one-area model in Figure 3.8, disregarding all input signals except the load disturbance, $P_L$. The transfer function from $P_L$ to $f$ is

$$f(s) = \frac{G(s)}{1 + F(s)G(s)}P_L(s), \quad (3.11)$$

where $G(s) = 1/(Ms + D)$ is the representation of the grid and $F(s)$ is the transfer function from grid frequency to power output from the lumped hy-
Figure 3.9. Simulated load disturbance $P_L$ and grid frequency deviation $\Delta f$ with varying time constant $\lambda$. The last subfigure shows the difference between the simulated and the measured grid frequency for each $\lambda$.

dropower unit that provides FCR to the system. The load disturbance is then

$$P_L(s) = \left( \frac{G(s)}{1 + F(s)G(s)} \right)^{-1} f(s) = \left( \frac{sM + D}{1 - F(s)} \right) f(s). \quad (3.12)$$

The inverse of the grid contains a pure derivative, which amplifies the frequency noise in $f$ when a calculation of $P_L$ is attempted. In Internal Model Control (IMC), this problem is solved by replacing $G^{-1}(s)$ with a transfer function $Q(s) = \frac{1}{(\lambda s + 1)^n} G^{-1}(s)$, where $n$ is the difference between the number of poles and the number of zeros of $G(s)$. The constant $\lambda$ is a design parameter that can be adjusted to achieve the required bandwidth of the system [98].
Using the method from IMC, the load disturbance can be approximated by

\[ P_L(s) = \left( \frac{sM + D}{\lambda s + 1} - F(s) \right) f(s). \]  

(3.13)

To find a suitable value of \( \lambda \), \( P_L \) can be simulated using the model (3.13). The simulated \( P_L \) can then be used to simulate the grid frequency, \( f \), using the model (3.11). Finally, the simulated \( f \) can be compared to the original frequency signal, and a suitable \( \lambda \) can be selected. An example is given in Figure 3.9. Here, \( \lambda = 0.1 \) is considered to give a good enough approximation of the load disturbance.

The disadvantage of using this approach (number 3) is that it requires a model of the system, including frequency control. If the model has a bias, e.g. too high or too low damping in a certain frequency band, the simulated load disturbance will inherit this bias. The advantage is that as long as the model is reasonably good, the simulated load disturbance will reflect the characteristics of the real load disturbance. If there are some dominating frequencies in the load, these will be present in the input signal if the third approach is used, but not with the first or second approach. Therefore, despite its disadvantages, the third approach is preferable.

3.5 Statistical measures

Much of the analysis in this thesis is based on statistical measures. In research on frequency control, this is not so common. In most studies, the frequency control behaviour is evaluated by simulation of an n-1 disturbance, i.e. loss of the largest unit in the system, and the performance is characterised by the rate of change of frequency, ROCOF, and the lowest frequency value, the nadir. Since the focus of this thesis is normal operation rather than large disturbances, there was a need to define and use other measures of system performance. Statistical measures of frequency quality and/or FCR control work are used in Paper IV-VIII and X, and a measure related to the energy storage need induced by VRE is developed in Paper IX.

3.5.1 Grid frequency quality

An example of the Nordic grid frequency is given in Figure 3.10. There is a diurnal periodicity in the load which is reflected by the typical frequency deviation. Most of the load variation is balanced already in the scheduling of the electricity production, but apparently there are systematic mismatches between the system balance and the scheduled balance. While the load increases gradually in the morning, the production schedules are fixed per hour. In the middle subfigure of Figure 3.10, the production is increased at 7:00, causing
over-frequency. The load is gradually increasing, and the over-frequency turns to under-frequency by the end of the hour. Then the production is increased again, causing a new over-frequency that slowly turns to under-frequency as the load catches up again. The same, but opposite, happens at 22:00 and 23:00. The load is gradually decreasing, and the production is decreased in steps at the hour shifts, causing under-frequency.

In the bottom subfigure of Figure 3.10, the so-called 60 second oscillation of the grid frequency can be seen. The amplitude is moderate, but since the grid frequency is already low, the oscillation takes the grid frequency to the edge of the normal band at 03:28-03:29.

The slow variations (diurnal down to approximately 5 minutes) in the grid frequency depend on the load variations in the system, and especially how well the production schedules follow these load variations. They also depend on the amount and efficiency of secondary and tertiary control in the system,
which are deployed to bring the frequency back to nominal. In the case where these controls do not restore the grid frequency, the deviations depend on the droop of the primary control.

The faster variations (approx. 5 minutes down to 10 seconds) depend on the dynamical behaviour of the primary control and to some extent the automatic secondary control, if it exists in the system.

The Nordic TSOs use the number of minutes per month outside the normal operation band, 49.9-50.1 Hz, to define the quality of the grid frequency in the Nordic system. This measure captures large amplitudes in the frequency deviation. From the example in Figure 3.10, it can be expected that secondary and tertiary control has the largest impact on this measure, together with the droop of the primary control. The 60 s oscillation has an impact in driving the frequency further down or up past the edge of the normal band if the grid frequency is already low or high.

The standard deviation and the root mean square error (RMSE) of the grid frequency are used as measures of the grid frequency quality in this thesis. These measures are dominated by the slow, large amplitude variations of the grid frequency, but also take into account the behaviour within the normal frequency band. If the mean value of the grid frequency is 50 Hz, the standard deviation and the RMSE of the grid frequency are the same. The RMSE is a preferable measure if the mean value is not 50 Hz, since it still measures the deviation from 50 Hz, while the standard deviation measures the deviation from the mean value.

Since the standard deviation and the RMSE are dominated by the slow dynamics of the grid frequency, they are supplemented with spectral analysis and Bode diagrams of the system in Paper V and VII.

3.5.2 Control work

Part of the evaluation of different strategies for frequency control in this thesis is to compare the amount of control work. The control work is measured by the travelled distance of the guide vane regulating mechanism, \( Y_{\text{dist}} \), and the number of load cycles, \( Y_{\text{cycles}} \), i.e. half the number of direction changes of the guide vane regulating mechanism. For Kaplan turbines, the travelled distance and number of load cycles of the runner regulating mechanism are used as additional measures. These measures of the control work are selected since they are related to the contribution from frequency control to wear and fatigue of the hydropower unit.

The simplest model of the wear of a bearing states that it is proportional to the sliding distance of the bearing,

\[
w = kpS_r
\]

where \( w \) is the linear wear [m], \( k \) is the wear rate \([\text{m}^2/\text{N}] \), \( p \) is the specific load \([\text{N/m}^2] \) and \( S_r \) is the sliding distance [m] [12]. The sliding distance of the guide
vane and runner bearings are not necessarily proportional to travelled distance of the guide vane and runner regulating mechanisms, since the geometries are nonlinear, but they are certainly related to $Y_{\text{dist}}$ and $\alpha_{\text{dist}}$. The advantage of the measures $Y_{\text{dist}}$ and $\alpha_{\text{dist}}$ is that they are generic measures, which only depend on the turbine governor settings and the grid frequency. Therefore they are suitable measures of the wear induced by frequency control on hydropower turbine bearings in general.

In order to turn the guide vanes or runner blades of a turbine, the friction and hydraulic loads has to be overcome [8]. The hydraulic load can be in either the opening or closing direction, depending on the point of operation of the unit. Direction changes in the guide vane or runner regulation movement causes load cycles on the turbine guide vanes and blades. These load cycles may contribute to fatigue of the guide vanes and runner blades, depending on the size of the load. The number of load cycles at different loads that the turbine shall survive is a turbine design criterion, which can vary between units. Although the load cycles induced by frequency control action may not always contribute to fatigue of the turbine, the number of load cycles is a generic measure that is suitable as an indicator of the contribution to fatigue of hydropower turbines in general.

The measures $Y_{\text{dist}}$, $\alpha_{\text{dist}}$, $Y_{\text{cycles}}$ and $\alpha_{\text{cycles}}$ can also be seen as indicators of increased risk of premature failures of units. The main cause of the failure may be design flaws which are manifested at an earlier stage due to the increased wear and tear of the unit.

In Section 3.1.3, the difference between the guide vane opening measured value, $Y_{\text{mv}}$, and the guide vane position, $Y_{\text{pos}}$, was pointed out. Due to backlash, some of the movement requested by the controller will not be actuated all the way and actually change the guide vane position. Some of the backlash may be located before and some after the measurement of the guide vane opening, depending on the location of the measurement transducer (on the servo, on the guide vane link or the guide vane stem) and the properties of the regulating mechanism. Taking this into account, the quantities $Y_{\text{dist}}$ and $Y_{\text{cycles}}$ will not be the same at the two locations $Y_{\text{mv}}$ and $Y_{\text{pos}}$. Since it is the movement in the bearings and the load cycles of the guide vanes that are considered most important, $Y_{\text{dist}}$ and $Y_{\text{cycles}}$ of the signal $Y_{\text{pos}}$ are most interesting to study. The corresponding measures applied on the signal $Y_{\text{mv}}$ can be used as a complement, to describe the movements of the servo system.

The same line of reasoning can be applied to the runner regulating mechanism, and the signals $\alpha_{\text{mv}}$ and $\alpha_{\text{pos}}$.

### 3.5.3 Control quality

The quality of the FCR or FRR provided by a certain unit is assessed in three ways in this thesis. The first method is to study the Bode diagram of the
linearised response of the unit. This method is used in Paper I, both by experiments where sinusoidal grid frequency signals are fed to the studied units, and theoretically by analysis of the frequency response of the estimated models. It is also used in Paper V and X.

The second method is to simulate a system where the studied unit is scaled to be large enough to be the sole provider of frequency control, and evaluate the grid frequency quality in this system. Either white noise or a load disturbance calculated from historical grid frequency measurements can be used as input signal, as described in Section 3.4. This method is used in Paper V-VIII and X. A slightly different take on this method is to use a model with more than one unit, and study the change in grid frequency quality when the parameters of the studied unit are changed. This take on the method is used in Paper VII.

The third method is to calculate the correlation coefficient, $k$, of the grid frequency, $f$, and the frequency control power output, $P$, over a certain time horizon, $n$,

$$
k = \frac{\sum_{i=1}^{n} (f_i - \bar{f})(P_i - \bar{P})}{\sqrt{\sum_{i=1}^{n} (f_i - \bar{f})^2 \sum_{i=1}^{n} (P_i - \bar{P})^2}},
$$

where superbars denote the average values. The correlation coefficient has a value between -1 and 1, where uncorrelated signals give $k = 0$, while $P(t) = -f(t)$ gives $k = -1$ and $P(t) = f(t)$ gives $k = 1$. Negative correlation between $f$ and $P$ or positive correlation between $f$ and $-P$ is desired.

Either simulated or measured data can be used. The advantage of this method is that data from normal operation of a unit can be used, as long as the data has sufficient quality. The disadvantage is that the impact from feedback via the grid frequency is disregarded, since the unit is too small to have a significant impact on it. If this method is used for evaluation of the tuning of a governor, a sluggish governor will get bad results, a well tuned governor will get good results but a too aggressively tuned governor may also get good results, since it can rely on the stability created by other governors in the system. Therefore, this method should be supplemented with some stability analysis to ensure that even if all units had this behaviour, the system stability would be maintained. This method is used in Paper VIII and in Section 4.2.1.

### 3.5.4 Flexibility and energy storage need

There are many different ways to quantify the need of balancing and flexibility in a power system. In Paper IX, a method to assess the flexibility in terms of energy storage need over different time horizons is developed. A similar approach is used in Paper X to describe the power and energy needed to provide synthetic inertia and damping to the power system.
Figure 3.11. Variation of the gross and net load during one week (top), and the accumulated gross and net load (bottom), corresponding to the loading or level of an energy storage which is balancing the gross or net load variations.

Hydropower with reservoirs and extra power capacity can be seen as a type of energy storage system. The primary objective of the reservoirs is to compensate for the variable inflow of water to the river, and firm the production. However, the regulating capacity can also be used to balance the grid. The relative balancing contribution of hydropower [13] is a correlation-based measure of this property.

The net load (or residual load), $P_{NL}$, of the system is defined as the difference between the gross load, $P_{GL}$, and the VRE production, $P_{VRE}$,

$$P_{NL} = P_{GL} - P_{VRE}. \quad (3.16)$$

The net load is calculated from load data and scaled VRE production data from Germany in Paper IX.

Figure 3.11 shows the gross and net load variation (with mean value withdrawn) over one week, and its integral. The storage need can be defined as difference between the maximum and minimum value of the accumulated load. The storage need induced by VRE is then the difference between the storage need of the net load and the storage need of the gross load. Using a longer time series, the storage need can be calculated using a moving window the size of the time horizon,
\[ S_k(t_m) = \max_{j \in [m,m+k]} \sum_{i=0}^{j} \left[ P(t_{m+i}) - \frac{1}{k} \sum_{n=0}^{m+k} P(t_n) \right] - \min_{j \in [m,m+k]} \sum_{i=0}^{j} \left[ P(t_{m+i}) - \frac{1}{k} \sum_{n=0}^{m+k} P(t_n) \right] \] (3.17)

with energy storage requirement \( S \), time horizon \( k \) and load \( P \). The focus in Paper IX is on time horizons of 1-14 days. Statistical properties of \( S_k \) can then be calculated. The cumulative distribution function, \( F(s_k) \), of the storage need \( S_k \) is the probability that \( S_k \) will have a value smaller than \( s_k \), i.e.

\[ F(s_k) = Pr(S_k \leq s_k) . \] (3.18)

The cumulative distribution function can be used as a measure of the firmness level. To reach a firmness level of 90\%, a storage volume \( s_k \) is needed such that \( 0.9 = F(s_k) \). The storage need at a 90% firmness level can be interpreted as the storage volume that is large enough to cover 90\% of all occasions.

A similar method is used to calculate the energy requirement of a source providing synthetic inertia to the system in Paper X, but here, no time horizon perspective is applied. The energy reserve required by the SI controller does not grow with the time horizon the same way that the system balancing storage need \( S_k \) does, since there are other balancing schemes active on the longer time scales: production scheduling and tertiary, secondary and primary frequency control. Therefore, there is no need to use sliding windows; instead, the statistical properties of interest can be calculated from the energy output of the SI, \( E_{SI} \), directly. With the requirement that the energy storage should be able to cover the energy needed by the SI to a 95\% probability, the required energy storage volume \( E_{req} \) is

\[ Pr(E_{SI} \leq E_{max}) = 97.5\%, \ Pr(E_{SI} \geq E_{min}) = 97.5\% \]

\[ E_{req} = E_{max} - E_{min} . \] (3.19)

Using data for one week, the value should be reasonably representative for the normal operation, but to get maximum and minimum values, simulation of relevant extreme cases would be needed.

Figure 3.12 shows the energy used by the SI-controller, \( E_{SI} \), during the simulated week. In the top subfigure, the SI is replacing system inertia, and in the bottom subfigure, the SI is replacing system damping. Here, the energy recovery scheme is inactive. \( E_{SI} \) is still not growing indefinitely, since the grid frequency and its integral are restored by other frequency control reserves.
Figure 3.12. Energy output of the SI-controller delivering inertia (top) and damping (bottom) during one week, without active energy recovery. The energy needed to provide damping is a factor of 10 larger than the energy needed to provide inertia.
This chapter describes the main results of the thesis. The detailed results can be found in Papers I-XI. Some additional results, which are not included in any of the papers, are presented in Section 4.2.1. The results concern the automatic reserves that are active in normal operation, i.e. FCR-N and aFRR, which will be referred to as simply FCR and FRR in this chapter.

4.1 Modelling for frequency control applications

The commonly used linear model of a hydropower unit, the "\( T_w \)-model", combined with an incremental gain \( K(Y,H) \) which is a function of the guide vane opening and head of the unit, and a backlash in the guide vane regulating mechanism, can reasonably well describe the dynamic behaviour of a Francis unit delivering FCR in normal operation. Backlash has a substantial impact on the frequency control performance since the signal amplitudes are small in normal operation. Considerable backlash was found in the guide vane or runner regulating mechanisms in two of the three investigated hydropower units. Figure 4.1 shows the measured response to sine-in sine-out experiments on HPP C (Francis with regulating ring) together with the response from models of the unit with and without backlash. When the tabulated values of \( T_w \) and \( K(Y,H) \) are used, the gain is overestimated for periods below 100 s, and the negative phase shift is underestimated (blue curve). If a model without backlash is estimated from the data, the gain is still overestimated but the phase shift is also overestimated (green curve). If backlash is included in the model, the gain and phase shift can be reproduced correctly (yellow curve).

The loss of gain and the additional negative phase shift caused by backlash is more severe for small input signal amplitudes than for large amplitudes. Therefore, it is inadvisable to use high droop (low gain) in the turbine governor. Today, many units run with droops corresponding to a gain of 20 \%/Hz in Sweden and 16 \%/Hz in Norway. These low gains may lead to bad performance of units that have backlash.

The 60 second oscillation in the Nordic grid can be excited by a \( \pm 50 \) MW sinusoidal power disturbance with a period around 60 seconds. This can be seen in Figure 4.2, where measured data from a full-scale test on the Nordic grid carried out in 2014 is plotted together with the response from a linear one-area and three-area model of the system. The linear models have a peak in the gain from load disturbance to grid frequency which can explain the 60
Figure 4.1. Bode diagram from $Y_{mv}$ to $P$ for the unit G1 of HPP C, based on sine-in sine-out experiments, compared with a model with tabulated $T_w$ and $K(Y,H)$, without backlash (blue), a model with $T_w$ and $K(Y,H)$ estimated from the measured data, without backlash (green) and a model with $T_w$ and $K(Y,H)$ estimated from the measured data, with backlash (yellow). Measurements for two governor parameter settings ($E_p$-settings), two load levels (guide vane opening 70% and 80%) and two modes of the other turbine G2 (constant or in frequency control with Ep0-setting) are presented with different markers. The models are simulated with the input data from the experiment marked with solid line (Ep2, 70%, G2 const.), and should be compared with that curve. In the shaded area, the input signal amplitude is small and too much significance should not be attached to the results. Cf. Paper I.
second oscillation observed in the grid frequency. The location and height of the peak depends on the system inertia, the frequency dependency of the load and the dynamic performance of the FCR. All of these parameters are to some extent uncertain.

4.2 Frequency control tuning and strategies

The frequency quality in the Nordic system could be improved by retuning of the governors of the hydropower units delivering FCR. In particular, the 60 second oscillation could be decreased by increasing the proportional part of the governors studied in this thesis. This can be seen in Figure 4.3. The peak gain from load disturbance to grid frequency (top subfigure) could be decreased by almost half with the tuning suggested in Paper V compared to the, in Vattenfall, currently used Ep0 setting. This would also improve the robustness (middle left) and the stability margin (middle right) of the system. However, it would lead to some increase in the governor’s sensitivity to frequency disturbances (bottom left) and increase the typical speed of the guide vane movements somewhat but on the other hand decrease the movements with 60 s periods (bottom right).

Due to the stochastic nature of load variations and thereby the grid frequency in the system, turbine governors call for a lot of small movements of the guide vanes of hydropower units. The very small movements are not servicing the grid, since they result in small or no change of the power output of the unit, and typically out of phase. However, any attempt to eliminate the small movements is likely to have a negative influence on the quality of the larger and more important movements. In many systems, a deadband on the measured grid frequency is allowed. Such a deadband around the nominal grid frequency can then be implemented in the FCR controller to reduce the small movements of the regulating mechanism. However, as can be seen in Table 4.1, frequency deadbands are not very efficient at reducing the travelled distance or the number of load cycles of the regulating mechanisms, while they have a strong negative impact on the grid frequency quality of the system. A floating deadband on the controller output signal is more efficient in reducing the guide vane movements, and has less adverse effects on the grid frequency.

<table>
<thead>
<tr>
<th>Filter</th>
<th>$\Delta Y_{\text{dist}}$</th>
<th>$\Delta Y_{\text{cycles}}$</th>
<th>$\Delta f_{\text{std}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency deadband, $\pm 5$ mHz</td>
<td>90%</td>
<td>99%</td>
<td>109%</td>
</tr>
<tr>
<td>GV floating deadband, $\pm 0.5 % Y$</td>
<td>78%</td>
<td>57%</td>
<td>107%</td>
</tr>
</tbody>
</table>

A certain amount of FCR (in MW/%) can be provided by a small number of units with low droop (i.e. high gain) or a large number of units with
Figure 4.2. Measured response from a full-scale test of the Nordic grid in 2014, compared to the response of linear models. From the top: Gain and phase shift from load disturbance to grid frequency, gain and phase shift from load disturbance to power flow from Sweden to Norway, and gain and phase shift from load disturbance to power flow from Sweden to Finland. The three-area model includes two inter-area modes of the system, which were not subject to the test. Cf. Paper II.
Figure 4.3. Gain of the closed loop transfer functions of the power system with one lumped hydropower unit providing FCR. The currently used tuning "Ep0" is compared to three different retuned controllers. The tuning goals are marked with black lines. C1 is tuned with all the tuning goals, C2 is tuned disregarding the goal of limited high frequency gain from $f_{\text{dist}}$ to $Y$, and C3 is tuned with less strict goal for the low frequency gain from $P_{\text{dist}}$ to $f$, cf. Paper V.
high droop. FCR from few units with high gain reduces the number of load cycles compared to FCR from many units with low gain, and improves the quality due to less influence from backlash. However, the production losses increases since the units move further away from their BEPs. This can be seen in Figure 4.4. Here, the total FCR gain of a fleet of units is constant but the allocation of the reserve over the units of the fleet is varied. The results are based on simulations of one week in February 2014.

![Figure 4.4. Results from simulation of a week with a certain volume of FCR allocated to a varying number of units (marked with black numbers in the top left subfigure). The units are selected according to a prioritisation order, were refurbished Francis units are prioritised. Therefore no Kaplan units are active when the unit FCR gain is higher than 50%/Hz, so then $\alpha_{dist} = 0$. The middle right subfigure shows how the control work of the other units of in the system (lumped into one unit U0) is affected by the changes in allocation of the FCR within the fleet. Low unit FCR gain in the fleet leads to increased control work for the other units in the system, and decreased grid frequency quality. High unit FCR gain in the fleet leads to increased production losses. Cf. Paper VII.](image)

The division of frequency control into primary and secondary reserves leads to double work for the units providing frequency control reserves. This can be seen from the black dashed line in 4.5, showing that in the ideal linear case, the control work could be reduced if the two reserves were provided by the same
unit, for which the two reserves would be merged to one (the shift from one reserve to the other could be done without moving the guide vanes). However, taking nonlinear backlash in the regulating mechanisms of the units and a 10 s sampling time of the FRR into account, it would in practice not be possible to avoid much of the double work by allocating the two reserves to the same units. With the right combination of FCR and FRR, and the right droop, it may be possible to reduce the number of load cycles, but only to a very small extent the travelled distance of the guide vanes.

Figure 4.5. Relative difference between the amount of control work when FCR and FRR are delivered by the same unit compared to the same reserves being delivered from separate units. Results from simulation of one unit with varying FCR gain (colour) and varying FRR gain (x-axis). The linear results are marked with black dashed line, and the nonlinear results are marked with colour. In the linear case, both $Y_{dist}$ and $Y_{cycles}$ are reduced when FCR and FRR are delivered by the same unit, compared to separate units. When nonlinearities and slow sampling of the FRR signal are taken into account, the control work is not reduced as much, and even increases if the FCR gain is low. Cf. Paper VII.

Simulation of a fleet of hydropower units providing a certain amount of FCR and a varying amount of FRR to the system also indicates that FCR delivered by the same unit reduces the number of load cycles and somewhat improves the quality, compared to delivery by separate units, see Figure 4.6. Francis turbines are in general more suitable to provide FCR than
FRR, since they are faster to control than Kaplan turbines but are less suited to operate away from their BEPs, since they have more pointy efficiency curves. Kaplan turbines, on the other hand, are in general more suitable to provide FRR than FCR, since they often have a slow runner control mechanism that slows down the FCR response and may cause off-cam operation when the runner control lags behind the GV control. The size of the units providing the reserves strongly influences the amount of control work. Small units have a longer distance to travel in GV% to reach the same change in MW, and the number of direction changes increases when more units are needed to provide the reserves.

Figure 4.6. Results from simulation of one week with a certain amount of FCR and a varying amount of FRR provided by the fleet. Three allocation strategies are compared: S1 with FCR and FRR from the same Francis units (i.e. both reserves combined on each unit), S2 with FCR provided by Francis units and FRR provided by other, separate Francis units, and S3 with FCR provided by Francis units and FRR provided by separate Kaplan units. Combining FCR and FRR on the same Francis units gives the best grid frequency quality and the least amount of $Y_{cycles}$. Allocating FRR to Kaplan units gives the smallest production losses but the most control work. Cf. Paper VII.
The correlation of the FCR power signal from a unit and the grid frequency signal is a good measure of the quality of the FCR provided by the unit. The correlation can be computed over different time horizons in order to quantify the quality of the FCR in different frequency bands. It could be used to differentiate the remuneration of FCR to give incentives for a tuning of hydropower governors that is not just passing some technical criteria, but delivers the best possible FCR quality from a grid perspective. This is shown in Figure 4.7-4.8.

![Figure 4.7. Impact on the 60 second oscillation by governor parameter settings. The color scale shows the change of the power of the grid frequency in the frequency band from 0.07 rad/s to 0.6 rad/s (10-90 s periods) with a certain set of parameters compared to the Ep0-setting (\(K_p = 1, K_i = 0.167\), marked by a black diamond).](image)

Figure 4.7 shows how the proportional and integral gain of the governor of a hydropower unit impacts the 60 second oscillation of the grid frequency. The impact is given as the percent change compared to the case with the Ep0-setting. Here, a one area model of the system is used, and the studied hydropower unit is scaled so that it provides all the system FCR, cf. Paper VIII. Figure 4.8 shows the change of the average remunerated work for each parameter setting as compared to the Ep0-setting, when the remuneration is based on the correlation of the grid frequency and the power output from the unit over a 10 minutes time horizon. The trend is similar in Figure 4.7 and 4.8, which means that a remuneration method based on this correlation gives incentives for a governor tuning which reduces the 60 second oscillation.

However, it should be noted that the correlation between the grid frequency and the measured power output from an individual unit would be disregarding the impact from feedback via the grid frequency of the system, since the unit typically would be too small to have a significant impact on the system frequency. This means that a unit with good correlation still can have a negative impact on the stability of the system, if the governor is too aggressively tuned.
4.2.1 Additional results

Similar measurements as the ones described in Section 3.1.2 were carried out on a new Kaplan unit in a power plant that will be referred to as Plant D. A retuning of the governor parameters were attempted after a quick parameter estimation on site. A modified version of the tuning goals described in Paper V were used. These modified tuning goals correspond to the new technical requirements drafted by the Nordic TSOs. A full evaluation of the retuned governor was not made, but 10 minutes of normal operation with the new parameters were recorded and compared to operation with the corresponding old parameter setting, Ep1.

Figure 4.9 shows measured signals from the unit operating in Ep1. Backlash in the guide vane regulating mechanism and the runner regulating mechanism are indicated by the plateaus in the signals. The guide vane position, $Y_{pos}$, was measured with an angular transducer on the guide vane lever.

With a well performing FCR, the power output should be well correlated to the negative grid frequency. The correlation coefficient calculated for varying time horizons is plotted in Figure 4.10. The correlation between the negative grid frequency and the governor control signal is around 0.4, just positive for the guide vane feedback signal and negative for the power output. The unit is clearly not delivering FCR of good quality using the original Ep1 setting.

Retuning of the governor leads to much better correlation between the negative grid frequency and the guide vane signals, but the correlation with the output power is still just barely positive, as can be seen in Figure 4.11.

The main reason for the bad performance of this unit is probably bad tuning of the guide vane and runner servo control loops, leading to long servo time...
Figure 4.9. Measurements on a unit in Plant D delivering FCR with the governor parameter setting Ep1. From the top, grid frequency, guide vane opening (control signal, measured value used for feedback and position measured on the guide vane lever), runner angle (setpoint and measured value) and electrical power.
Figure 4.10. Correlation between the negative grid frequency and the guide vane opening signals and power output respectively, in operation of a unit in Plant D with the Ep1-setting ($K_p = 1, K_i = 0.417$).

Figure 4.11. Correlation between the negative grid frequency and the guide vane opening signals and power output respectively, in operation with the retuned governor parameters ($K_p = 5, K_i = 0.294$).
Step responses with increased guide vane servo amplifier gain showed that the servo time constant could be decreased without causing any overshoot in the servo response. A thorough retuning of the servo control loops would improve the performance of the FCR, and also change the basis for the governor parameter tuning somewhat.

4.3 Future impact from VRE - variability and inertia

The increase of electricity production from variable renewable energy sources will lead to an increased need of balancing power and energy over some time horizons. The balancing need can be quantified as an energy storage need over different time horizons and a need for balancing power (capacity). The balancing need induced by VRE is analysed in Paper IX, based on load and production data from Germany. It is found that wind power shares of 20-100% (meaning the share of yearly electricity production from wind power with respect to the yearly load) would increase the energy storage need over the 1-2 week time horizon with 20-30% of the WP production over the same horizon, as can be seen in Table 4.2. The values in the table should be interpreted as the share of the electricity production from a certain source that needs to be stored to ensure that there is enough energy in the storage to cover the need at least 90% of the time. Some additional resources are needed for the worst cases (the last 10 percents).

**Table 4.2. Increased storage need \((S_{k,\text{net}} - S_{k,\text{gross}})/k\) at 90% firmness level, in % of the VRE production, for different VRE shares. In 2012 the WP share was 8% and the PV share was 4%.

<table>
<thead>
<tr>
<th>VRE share</th>
<th>2012</th>
<th>20%</th>
<th>40%</th>
<th>60%</th>
<th>80%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind power</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>1 days</td>
<td>5%</td>
<td>9%</td>
<td>14%</td>
<td>17%</td>
<td>19%</td>
<td>21%</td>
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<tr>
<td>7 days</td>
<td>15%</td>
<td>21%</td>
<td>27%</td>
<td>30%</td>
<td>33%</td>
<td>34%</td>
</tr>
<tr>
<td>14 days</td>
<td>11%</td>
<td>22%</td>
<td>29%</td>
<td>31%</td>
<td>32%</td>
<td>33%</td>
</tr>
<tr>
<td>Photovoltaics</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 days</td>
<td>-26%</td>
<td>27%</td>
<td>60%</td>
<td>71%</td>
<td>77%</td>
<td>80%</td>
</tr>
<tr>
<td>7 days</td>
<td>-2%</td>
<td>5%</td>
<td>12%</td>
<td>16%</td>
<td>18%</td>
<td>19%</td>
</tr>
<tr>
<td>14 days</td>
<td>-3%</td>
<td>4%</td>
<td>8%</td>
<td>11%</td>
<td>12%</td>
<td>13%</td>
</tr>
<tr>
<td>Wind power and photovoltaics</td>
<td></td>
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<tr>
<td>1 days</td>
<td>-7%</td>
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<td>18%</td>
<td>23%</td>
<td>27%</td>
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<td>7 days</td>
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<td>17%</td>
<td>18%</td>
<td>18%</td>
</tr>
</tbody>
</table>

Large shares of PV production increases the energy storage need over the diurnal time horizon with up to 80% of the PV production. The storage need
over the 1-2 week horizon is however smaller than for WP. If WP and PV are combined, the storage need is not increased as much, since they have different production patterns.

Figure 4.12 shows the cumulative distribution function of the gross and net load with different shares of VRE. The load has to be matched by production, so the cumulative distribution function of the load describes the need for balancing power in the system. Large shares VRE of in the system do not decrease the peak need of balancing power very much, but greatly decreases the median net load. For dispatchable power plants, this means less full load hours and more part load operation. This can lead to profitability problems for the dispatchable units unless the electricity price variations increases drastically, so that production during a few high-price hours is enough to cover their costs.

![Figure 4.12. Power flexibility need of a system with varying shares of VRE. Cumulative distribution function of the power $P$ of the gross load (GL) and net load (NL).](image)

The increase of electricity production from VRE is also leading to a reduction of the system inertia, since VRE normally either does not have inertia, or is connected to the grid through inverters. The damping of the system from frequency dependent loads is also expected to decrease in the future. Reduced system inertia leads to increased amplitude and frequency of the grid frequency variations and increases the high frequency control work of the FCR, as shown in Figure 4.13. Reduced damping leads to increased amplitude of the dominant frequencies of the grid frequency variations and increases the mid-range frequency control work of the FCR.

Active control with linear, continuously active SI-controllers can substitute synchronous inertia and damping that are lost from the system and retain the system performance. If the active control is delivered by a battery or another source with a limited energy reserve, an energy recovery scheme can be included in the SI-controller to ensure that the energy reservoir does not get
Figure 4.13. Bode diagram of the gain from load disturbance to grid frequency and guide vane opening in the closed loop system. When the inertia is reduced by half (blue line), the peak moves towards higher frequencies compared to the nominal system (black line). When the damping is reduced by half (green line), the peak gain increases. When both the inertia and damping are reduced by half, the peak gain increases and the width of the peak increases (red line).

entirely full or empty. However, if such an energy recovery scheme has too high an integration gain (i.e. too short integration time constant), it can deteriorate the performance of the controller and cause limit cycle oscillations in the guide vane regulating mechanisms of hydropower units connected to the system. Figure 4.14 shows how a short integration time constant (high integration gain) in the energy recovery loop leads to a growing peak gain from load disturbance to grid frequency deviation, hydropower guide vane opening and power and energy output from the SI-controller.
Figure 4.14. System with half the system inertia replaced by SI with varying energy recovery feedback loop settings, in frequency domain. C_3 has the fastest energy recovery and C_0 has no energy recovery scheme at all. Gain from load disturbance $P_L$ to grid frequency deviation $\Delta f$, guide vane opening deviation $\Delta Y$, SI power output $P_{SI}$ and SI energy output $E_{SI}$. 
5. Summary of results

Modelling for frequency control applications

- Backlash in the guide vane and runner regulating mechanisms substantially impacts the performance of normal operation primary frequency control delivered by hydropower units in the system today, and should be included in models of hydropower units.
- A linear representation of the waterways combined with an incremental gain that is depending on the point of operation (for example calculated from index tests) and a governor model including servo dynamics and backlash is suitable for governor tuning of Francis units. For Kaplan units, the runner regulation dynamics can be included using the method of virtual gate opening. However, tuning of the servo control loops is very important for the performance and should be done before the governor tuning.
- The correlation of the FCR power signal from a unit and the grid frequency signal is a good measure of the quality of the FCR provided by the unit, if it is calculated over a suitable time horizon.
- The 60 second oscillation in the grid frequency of the Nordic power system can be explained with a linear one-area power system model.
- The one-area model is relevant for governor tuning and FCR studies, as long as its limitations are taken into account, for example by considering the impact from grid frequency disturbances. The one-area model is a representation of the dominating dynamics of the system in the frequency band relevant for FCR. The the impact from retuning of governors in the one-area model can be reproduced in more complex representations of the grid, like the Nordic 32 node model.
- An inverse one-area model of the power system can be used to calculate an approximate load disturbance time series from measurements of the grid frequency. This method makes it possible to include the approximate statistical properties of the typical system load disturbance in the analysis of how changes in for example governor tuning or filtering affects the grid frequency of the system, even when measurements of the system load are unavailable.
Control tuning and strategies

- The frequency quality can be improved by retuning of governors. In particular, in the Nordic system, the damping of the 60 second oscillation can be increased by increasing the proportional gain of the studied governors.
- High droop on hydropower units is disadvantageous since it increases the adverse effect of backlash with regards to the FCR quality.
- Grid frequency deadbands in governors have a negative impact on the grid frequency quality and do not substantially decrease wear and tear of units delivering FCR.
- Floating deadbands on the output signal from governors have some negative impact on the grid frequency quality but are efficient in reducing the number of load cycles of hydropower units delivering FCR.
- FCR from few units with high gain (i.e. low droop) reduces the number of load cycles and improves the FCR quality due to less influence from backlash but increases the production losses compared to using many units with low gain.
- The division of frequency control into primary and secondary reserves leads to double work for the units delivering FCR and FRR.
- The double work cannot in practice be avoided by allocating primary and secondary reserves to the same units, although that would be possible in an ideal system.
- FCR and FRR delivered by the same unit reduces the number of load cycles and somewhat improves the quality of the delivered reserves, compared to delivery by separate units.
- Francis turbines are in general more suitable to provide FCR than FRR, since they are faster to control than Kaplan turbines and have more pointy efficiency curves.
- Kaplan turbines are in general more suitable to provide FRR than FCR, since they often have a slow runner control mechanism that slows down the FCR response.
- The size of the units providing the reserves strongly influences the amount of control work. Small units have a longer distance to travel in GV% to reach the same change in MW, and the number of direction changes increases when more units are needed to provide the reserves.
The impact from VRE - variability and inertia

- Large shares of wind power production (more than 40% of the yearly energy consumption) increases the need of balancing in terms of energy storage volume over the 1-2 week time horizon with around 30% of the WP production.
- Large shares of electricity production from photovoltaics (more than 40% of the yearly energy consumption) increases the need for balancing in terms of energy storage volume over the diurnal time horizon with 60-80% of the PV production.
- Large shares VRE in the system does not decrease the peak need of balancing power very much, but greatly decreases the average net load. For dispatchable power plants which balance the system, this means less full load hours and more part load operation.
- Reduced system inertia leads to increased amplitude and frequency of the variations of the grid frequency and increases the high frequency control work of the FCR.
- Reduced system damping leads to increased amplitude of the dominant frequencies of the grid frequency variations and increases the mid-range frequency control work of the FCR.
- Active control with linear, continuously active SI-controllers can substitute synchronous inertia and damping that are lost from the system and retain the system performance.
- Ill-advised energy recovery schemes of SI-controllers can deteriorate the performance of the controller and may cause limit cycles in the guide vane regulating mechanisms of hydropower units in the system.
6. Discussion

Models are built on simplifications and approximations of the systems they are meant to represent. One crucial question is which details and behaviours to include and which to simplify or disregard for the purpose of a certain study. In this thesis, the power system is linearised and lumped into one rotating mass, neglecting electromechanical oscillations, transmission limitations, voltage dependency, etc. The hydropower unit dynamics are also linearised, assuming inelastic waterways, incompressible water and negligible hydraulic resistance and linearising the square relation between flow and power. The combination and runner regulation and its impact on the power output are simplified, as well as the dynamics of the guide vane and runner servos. However, selected static nonlinearities (backlash and variable incremental gain) are included in the model.

The model choices in this thesis are based on previous research, but they are also discussed and validated by experiments and comparisons to other models, and some modifications to the commonly used models are found to be necessary. The validity of a lumped representation of the power system is tested with a full-scale experiment on the Nordic grid, described in Paper II, and by comparison with results from a 32-node model of the system [105]. The validity of the hydropower unit model is tested by experiments on three Swedish hydropower units, described in Paper I, and by applying the whole process of experiments, modelling, retuning and evaluation by new experiments on one unit, as described in Section 4.2.1.

Measurement data from a full-scale test of the dynamic response of the Nordic system is compared to models of the system in this thesis. The intention was initially to estimate the model parameters from the experimental data. However, it was found that the model structure was not well suited for parameter identification with this data. The estimated parameters turned out to depend very much on the initial guesses. To make a successful parameter identification, either another model structure has to be used, or some more advanced identification methods are needed. The strongest argument not to change the model structure is that the parameters of this structure are related to physical quantities. With a blackbox structure that is linear in its parameters, it would be possible to successfully estimate parameters, but no information of the interesting physical quantities would be gained, since the parameters would not be directly related to them.

Three transfer functions are compared to measured data from the full-scale test; load disturbance to grid frequency, to power flow from Sweden to Norway.
and power flow from Sweden to Finland. The modelled grid frequency and power flow to Norway has a relatively good fit to the data, but the fit is poor for the power flow to Finland. One reason is that the response from Finland is smaller, which makes the signal to noise ratio of this measurement smaller. Another reason may be that there is some response from actively controlled HVDC cables which are not included in the model.

The governor tuning method suggested in Paper V uses a criterion for robustness that can be considered overly conservative. This criterion is derived from the small gain theorem, which is sufficient but not necessary for stability. If the type of uncertainty in the system model is known, the phase and not only the magnitude of the signals can be taken into account, and a less strict requirement could be formulated. This is attempted in Paper VIII, where the stability in the "worst case grid", i.e. a low inertia grid with low frequency dependency of the load, is used as a criterion for robust stability.

Assumptions on the uncertainty of system parameters are important not only for tuning of individual governors but also for how to set up relevant technical requirements on the FCR. Large uncertainties lead to strict requirements on the dynamic response from the FCR units, which may be difficult for some units to fulfil. Another approach to this problem is to try to reduce the variation in system parameters. When the kinetic energy of the system is decreasing due to a larger share of inverter connected power production, it could be replaced by linear synthetic inertia from active control of fast reserves. If a high and stable kinetic energy (and damping) in the system can be ensured, a wider range of production units could be able to deliver FCR. That could solve the problem occurring e.g. on windy summer nights when almost only wind power and Kaplan turbines are in operation.

The linear synthetic inertia controller suggested in Paper X is sensitive to measurement errors and noise in the grid frequency signal, since it is a proportional-derivative controller. A second order low pass filter is used on the input signal to decrease the sensitivity to noise. The tuning of this filter should be adjusted to the local conditions and the measurement quality. The simulations in the paper are made with interpolations of a signal with 1 second sampling time. In addition, the SI controller has been simulated with a grid frequency signal with a higher sampling rate, measured at a wind farm. With this input signal, the suggested filter time constant still seems reasonable.

The localisation in the grid of the SI controller is not important from the perspective of normal operation frequency control, but it may be important with respect to transmission capability, transient stability and impact on inter-area modes. This aspect needs further study.

A method for estimation of the flexibility need induced by VRE is suggested in Paper IX. The assessed flexibility need is probably somewhat over-estimated, since the input data is linearly scaled production data. This means that geographical smoothing effects are not taken enough into account. The analysis could be refined by using a meteorological model and information on
where new VRE plants are planned [55] to construct more reliable input data to the analysis.

The tradition of governor tuning and also the technical guidelines formulated by the TSOs are different in Norway and Sweden. In Norway, the grid is sometimes split into smaller parts, and island mode capability is considered important for the hydropower units. In Sweden, the grid is strong and hydropower units in general are not hydraulically designed for island mode, but rely on a stabilising effect from the grid. Some units have surge areas that are much smaller than what is required by the Thoma criterion [106] for stability with respect to surge. Therefore, connection to a strong grid is assumed also when it comes to governor tuning, which is reflected in the tradition within Vattenfall to use the same governor settings for all units. This thesis is influenced by the Swedish tradition, and does not consider island operation in the analysis of primary frequency control.
The main conclusion of this thesis is that the frequency control in normal operation in the Nordic system can be improved by retuning of hydropower governors and their subsystems. To achieve this, adequate technical requirements on the frequency response of the units are needed. Such technical requirements typically set a minimum level of accepted performance. To give incentives to hydropower owners to make their units perform better, a remuneration method that takes quality into account could be used. Such a method is suggested in Paper VIII. Delivering FCR, especially FCR with high static and dynamic gain, increases the wear and tear in hydropower units. Ideally, good tuning of governors and their subsystems leads to better grid frequency quality, which in turn leads to less control work for the hydropower units. However, retuning of the governor of an individual unit can lead to either increased or decreased control work, depending on the previous tuning. Some units have the prerequisites to deliver fast frequency control with good quality, while others can deliver slow frequency control but would have quality problems if they attempted faster control. If the technical requirements set a minimum level of accepted performance, which many units can fulfil, the former units will need some incentives in order to deliver faster control than the requirement, since it will increase their wear and tear.

The amount of kinetic energy and damping from frequency dependent loads in the system affects the stability and performance of the frequency control. If these parameters can be kept fairly constant, governors can be tuned to perform as good as possible, without excessively large margins for changes in the system parameters. Active control of some fast responding units, e.g. batteries, could replace some of the inertia and damping that is lost from the system as the share of inverter connected production units, e.g. wind power, increases. Such a control scheme, i.e. linear synthetic inertia, is described in Paper X.

In the introduction to the thesis, the following question was asked: What is the role of hydropower when it comes to balancing active power on the grid, especially through frequency control, and how can hydropower enable the shift to renewable power production? The answer given by this thesis is that in addition to the regulation made by hydropower today, more regulation over time horizons of 1-2 weeks and longer will be required if the wind power expansion continues. This long term balancing will affect the amount and type of units available for frequency control. There will be some situations with a lot of hydropower in operation and other situations with very little. Therefore it will become important to ensure that as many units as possible can provide
FCR. At the same time, the requirements on the speed and quality of the response might increase due to reduced inertia and damping in the system. To some extent, the quality of the FCR delivered by hydropower can be improved by governor retuning, but the problem of reduced inertia and damping cannot in the long run be solved by hydropower alone.
8. Outlook

A 100% renewable power system with large shares of VRE comes with three main challenges when it comes to balancing of active power. The first challenge is the variability of the VRE production. In the Nordic system, this challenge is less of a challenge than in other power systems, due to the large amount of hydropower with seasonal storages and extra capacity for balancing. However, the VRE will change the operational patterns of hydropower. The variations of the VRE production on the weekly to monthly time horizon will result in some periods with high hydropower production and high water flow in the rivers, and other periods with low production and low flows. The regulation of intermediate size reservoirs will also increase, due to uncertainty in the predictions of the VRE production over the intra-week time horizon.

The changed operational pattern of the hydropower plants may have negative impacts on the river environment. Both the increased flow variations and the increased regulation of the reservoirs may be problematic. The trade-off between the need for balancing of VRE and the need for good river environment will be a difficult and urgent question in the years to come. The rapidly growing research field of eco-hydraulics may hold a piece of the puzzle. At present, the EU Water Framework Directive is being implemented in Sweden. The interpretation of the directive will have high impact on how the Swedish hydropower fleet will be operated in the future.

The increase of the VRE production will also have an impact on the economy of hydropower and other conventional power production. On the European level, the increase of VRE has led to low wholesale electricity prices, more part-load operation of thermal power plants and less intra-day price difference, pushing pumped storage hydropower almost out of business. There is a risk that the current situation with over capacity and low prices will lead to shut-downs of many production units, which in turn could lead to power deficiency in situations when the load is high but the VRE production is low. This risk has prompted some actors to call for capacity markets or even renationalisation of the power sector. The UK has already introduced a capacity market. At the same time, the EU is moving in the other direction with the Energy Union, which promotes a pan European energy only market and pan European grid codes, some of which already are being implemented.

The second challenge in a power system with large shares of VRE is that VRE cannot provide FCR unless some of its production is curtailed to create margins for regulation. This could become a problem especially in low load situations. A windy summer night, when the entire electricity production is
provided by wind power and some Kaplan hydropower units, how will the system be regulated? By responsive loads, by wind power curtailing some production, by batteries?

The third challenge in a power system with large shares of VRE is reduced system inertia. While conventional, directly connected synchronous machines adds to the rotational energy of the power system, many VRE production units are connected through inverters and do not contribute. Lack of inertia makes the power system more difficult to control. One way to handle this problem is to tighten the requirements on the performance of the FCR. With a faster and better timed FCR response, the system can operate with less inertia than today. The downside of this solution is that it may disqualify many hydropower units from participating in the FCR, due to long water time constants, slow servos, backlash and other properties of the units. This leads back to the problem of lack of FCR.

Another way to handle the problem of low inertia is to give the TSO the task to ensure that the system always has a certain inertia and a certain damping. The inertia and damping can be provided by synchronous inertia from hydropower or other conventional units, or by linear synthetic inertia, i.e. active control of quickly responding energy reserves like batteries, as described in Paper X. This could be organised through a market system or by other types of agreements. When the basic dynamic properties of the power system are fixed, the FCR controllers can be tuned to perform well in this system configuration. The requirements on their performance can be set in a way that does not disqualify too many units from participating in the FCR, and units that perform better can be remunerated extra using the Pay for Performance scheme suggested in Paper VIII. This solution would make more reserves available and improve the stability and performance of the power system.
Modelling and tuning of guide vane and runner servo systems including the combinator deserves more attention. Experiences from the hydropower units studied in this thesis show that servo control loop tuning could have great potential to improve the dynamic response of hydropower units.

Further analysis of measured data from the full-scale test would be interesting, for example system identification with more advanced methods than the ones attempted so far. Measurements of the response from individual units during a new full-scale test could be used both for assessment of the quality of the FCR delivered by individual units and for analysis of the inertial response from the units.

The interaction between frequency control and inertia, both synthetic and synchronous, deserves more attention. A first step could be to measure the inertial response from a hydropower unit subject to grid frequency deviations, to see how closely it resembles the ideal response. The impact from voltage control and power system stabilisers could be further investigated. A second step could be to test the synthetic inertia controller suggested in this thesis, using a battery as energy source, and compare its response to the response of the hydropower inertia. A demonstration of the linear synthetic inertia could be made in an island grid together with a real or simulated hydropower unit and a controllable load. It could also be tested by connection to the Nordic power system. A third step could be to look into how to construct efficient remuneration systems for inertia. As shown in Paper VIII, remuneration schemes can be designed to give incentives for a certain desired dynamical behaviour. Inertia could become a new product on a separate market, or be included in the market for frequency control reserves in some way.
10. Summary of papers

Paper I
Field measurements and system identification of three frequency controlling hydropower plants. The dynamic behaviour of hydropower plants participating in primary frequency control is investigated in this paper through frequency response, step response and setpoint change tests on three Swedish hydropower plants. Grey-box system identification is used to estimate the parameters of simple linear models suitable for power system analysis and the major shortcomings of the linear models are discussed.

I participated in field measurements, performed the major part of the analysis and wrote the paper.

The paper was published in IEEE Transactions on Energy Conversion in September 2015.

Paper II
Full-scale test and modelling of the frequency control dynamics of the Nordic power system. A three-area and a one-area model of the Nordic power system is developed in this paper, and compared to measurements during a full-scale test of the frequency response of the system. A sinusoidal power disturbance with 50 MW amplitude and period from 15 to 150 seconds is fed to the system from a large hydropower plant, and the grid frequency and tie-line power flow response are recorded and compared to the model in frequency domain.

I performed the analysis and wrote the paper.

The paper was presented in the session Best Conference Papers on Power System Stability and Protection at the IEEE Power and Energy Society General Meeting in Boston, USA in July 2016, and published in the conference proceedings.

Paper III
A mathematical model and its application for hydropower units under different operating conditions. The paper presents a mathematical model of hydropower units, especially the governor system model. The model is compared to measurements from one Swedish and three Chinese power plants.

I took part in discussions about the governor model and revised the paper.

The paper was published in Energies in 2015.
Paper IV

**Wear and tear on hydro power turbines - Influence from primary frequency control.** The paper studies the wear and tear on hydropower units induced from primary frequency control. The impact by governor parameter settings and opening or power feedback is evaluated for sinusoidal input signals and with measured grid frequency input signal.

I took part in discussions about the results and revised the paper.

*The paper was published in Renewable Energy in 2016.*

Paper V

**Tuning primary frequency controllers using robust control theory in a power system dominated by hydropower.** In this paper, the parameters of primary frequency controllers currently used in the Nordic power system are optimised using a robust control approach. The trade-off between performance, actuator work and robustness is analysed in frequency domain and time domain, and the sensitivity to disturbances and model errors is discussed.

I performed the analysis and wrote the paper.

*The paper was presented at the System Operation and Control session at the CIGRE Session in Paris, France in August 2016, and published in the conference proceedings.*

Paper VI

**Wear Reduction for Hydropower Turbines Considering Frequency Quality of Power Systems: A Study on Controller Filters.** The paper compares linear and nonlinear filters as a means to reduce the wear and tear of hydropower units providing primary frequency control to the grid. The trade-off between the regulation quality and wear and tear is studied, and stability aspects are discussed.

I developed the method for backward calculation of the power disturbance from the grid frequency and derived the parameter values for the lumped power system model. I took part in discussions about the method, in particular the filter types and the describing functions method, and results. I revised the paper.

*The paper was published in IEEE Transactions on Power System in 2016.*
Paper VII

Allocation of Frequency Control Reserves and its Impact on Wear on a Hydropower Fleet. The paper discusses different strategies for allocation of frequency control reserves on a fleet of hydropower units. High or low droop of primary control and the interaction of primary and secondary control on an individual unit and in the fleet are investigated. The allocation strategies are evaluated with respect to quality of the delivered reserve (impact on the grid frequency), wear and tear of the hydropower units and production losses.

I performed the analysis and wrote the paper.

The paper was submitted to IEEE Transactions on Power Systems in August 2016.

Paper VIII

Primary Frequency Control - Pay for Performance. This paper suggests and evaluates a remuneration method for frequency control reserves based on the correlation over different time horizons between the power output of a unit delivering frequency control and the measured grid frequency.

I came up with the idea, suggested the remuneration method and supervised the work.

In manuscript.

Paper IX

Power system flexibility need induced by wind and solar power intermittency on time scales of 1-14 days. This paper describes a method to assess the needed production flexibility to adapt the power system to the production from varying renewable energy sources such as wind power and photovoltaics over time horizons of 1-14 days. Load and production data from the German power system are used to quantify the flexibility need in terms of power and energy storage requirement due to higher shares of renewable energy (20-80%).

I performed the analysis and wrote the paper.

The paper was published in Renewable Energy in April 2015.
Paper X

Linear Synthetic Inertia for Improved Frequency Quality and Reduced Hydropower Wear and Tear. This paper investigates the consequences of reduced system inertia and damping, and suggests a new, linear synthetic inertia controller that could be used to replace the inertia and damping lost due to increased use of inverter connected power production and loads.

I came up with the idea, performed the analysis and wrote the paper.

The paper was submitted to IEEE Transactions on Sustainable Energy in November 2016.

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Paper XI

Standstill Frequency Response Test on a Synchronous Machine Extended With Damper Bar Measurements. The paper presents test data from a standstill frequency response (SSFR) on a salient-pole synchronous machine with reconfigurable damper windings. An extension to the standard SSFR test analysis scheme is suggested, where the stator-to-damper transfer functions are included.

I participated in discussions on the empirical modelling method and results.

The paper was published in IEEE Transactions on Energy Conversion in September 2012.
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Allt uttag av elektrisk effekt från elnätet balancersas av elproduktion vid kraftstationer. När uttagen ökar så tas energin initialt från kraftsystemets rörelseenergi, som finns upplagrader i de stora roterande maskinerna som är direktkoppade till nätet. Hela systemet saktar in, vilket också syns på frekvensen av nätets växelspänning. Den minskande frekvensen mäts upp på vissa vattenkraftstationer som har till uppgift att balansera nätet, och de svarar med att öka pådraget, det vill säga ändra vinkeln på ledskovlarna som styr vattenflödet genom turbinen så att uteffekten ökar. På samma sätt minskar de pådraget om frekvensen ökar för att lasten minskar. Denna frekvensreglering balanserar kortvariga och oförutsedda förändringar i konsumtion och produktion. På längre sikt balanseras variationerna genom produktionsplanering som i Norden är knuten till elspotmarknaden. Även denna planerade balansering utförs i stor utsträckning av vattenkraftverk.


I avhandlingens andra del undersöks olika vägar att förbättra frekvensregleringen och minska det slitage den åsamar vattenkraftturbinerna. En metod för intrimning av turbinregulatorer utarbetas och testas. Inverkan av olika filter som skulle kunna minska slitage utvärderas, och strategier för fördelning av reglerarbetet mellan olika vattenkraftstationer analyseras. Resultaten pekar på att en bättre intrimning av turbinregulatorerna skulle kunna ge stora förbättringar i frekvenskvalitet. Framför allt är det regulatorernas proportionaldel som ofta är satt för låg, vilket leder till dålig dämpning av störningar med periodtider omkring 60 sekunder. Frekvenskvaliteten skulle också kunna förbättras genom undvikande av småregleringar. Om färre aggregat reglerar med
större reglerstyrka så minskar den negativa inverkan av glappliknande olinjäriteter, jämfört med när många aggregat reglerar med liten reglerstyrka.


Avhandlingens sista del blickar framåt på de utmaningar som vattenkraften står inför de närmaste åren. När den varierande förnybara elproduktionen från bland annat vind och sol ökar så ökar också behovet av energilagring och balansering. Vattenkraften lagrar redan stora mängder energi i säsongsmagasin, men vattenkraftens körsätt kommer att påverkas av en storregelad utbyggnad av vindkraft och solcells. Vindkraftens variation är mestadels långsamt, och kommer att leda till vissa veckor med höga flöden i älvarna, när det inte blåser så mycket, och andra veckor med låga flöden. Osäkerheten i vindprognoserna kan leda till att de mindre magasinen längre ner i älvarna behöver utnyttjas mer, och att ytterligare effektutbyggnad kan behövas på vissa ställen. De förändrade körsätten kan ha konsekvenser för miljön i och runt älvarna. Avvägningar mellan behovet av reglering och påverkan på miljön kommer att bli viktiga.

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