Synchronous generator and frequency converter in wind turbine applications: system design and efficiency

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Technical Report No. 175 L

1994

ISBN 91-7032-968-0

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by

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Submitted to the School of Electrical and Computer Engineering
Chalmers University of Technology
in partial fullfillment of the requirements
for the degree of
Licentiate of Engineering

Department of Electrical Machines and Power Electronics
Chalmers University of Technology
Göteborg, Sweden
May 1994

Abstract

This report deals with an electrical system for variable-speed wind power plants. It consists of a synchronous generator, a diode rectifier and a thyristor inverter. The aim is to discuss the system design and control, to model the losses and to compare the average efficiency of this variable-speed system with the average efficiency of a constant-speed and a two-speed system. Only the steady state operation of the system is discussed. Losses in the system are modelled, and the loss model is verified for a 50 kVA generator. The proposed simple loss model is found to be accurate enough to be used for the torque control of a wind turbine generator system. The most efficient generator rating is discussed, and it is shown how the voltage control of the generator can be used to maximize the generator and converter efficiency. The average efficiency of the system is calculated. It depends on the median wind speed of the turbine site. It is found that a variable-speed system, consisting of a generator and a converter, can have an average efficiency almost as high as a constant-speed or a two-speed system. Three different control strategies and their effect on the system efficiency are investigated.

Acknowledgement

I would like to thank my supervisor, Dr Ola Carlson, for his support in this research project. Also my examinator Dr Karl-Erik Hallenius, Professor Jorma Luomi and Professor Kjeld Thorborg have given me valuable comments and suggestions during the work on this report. Further, I would like to thank Margot Bolinder for linguistic help.

The financial support for this project is given by the Swedish National Board for Industrial and Technical Development (NUTEK) and it is gratefully acknowleged.

List of contents

List of symbols

Quantities

B	Magnetic flux density
C	Capacitance
d	Turbine diameter
E	Induced voltage
e	Per unit induced voltage
f	Frequency
I	Current
i	Per unit current
L	Inductance
n	Rotational speed
n'	Per unit rotational speed
P	Power
p	Per unit power
R	Resistance
r	Per unit resistance
S	Apparent power
T	Torque
t	Per unit torque
U	Voltage
u	Per unit voltage
v	Per unit wind speed
X	Reactance
x	Per unit reactance
Z	Impedance
α	Firing angle of the inverter
η	Efficiency
λ	Tip speed ratio of the turbine
ω	Electrical angular frequency
Ψ	Flux linkage
ψ	Per unit flux linkage

Constants and components

C	Constant, coefficient
Th	Thyristor
VDR	Voltage depending resistor (ZnO)

Indices for parts of the system:

a	Armature
c	Converter
d	Dc link
E	Exciter
f	Field
g	Generator
gear	Gear
i	Inverter
net	Network
r	Rectifier
rotor	Rotor
t	Turbine
to	Turn-off circuit
damp	Damper circuit

Other indices:

ad	Additional losses
b	Base value
com	Commutation
Cu	Copper losses
d axis	D-axis of the synchronous generator
diode	Diode loaded
est	Estimated value
Fe	Core losses
Ft	Eddy current losses
Hy	Hysteresis losses
lim	Limit value
loss	Losses
max	Maximum value
mesh	Gear mesh (losses)
min	Minimum value
N	Rated value
opt	Optimum
P	Power (-Coefficient)
p-p	Peak-to-peak value
q axis	Q-axis of the synchronous generator
ref	Reference value
res	Resistively loaded
s	Synchronous (reactance)
ss	Standstill
tot	Total
(k)	kth harmonic
(1)	Fundamental component
0	No load
μ	Friction
σ	Leakage

1 Introduction

In the design of a modern wind turbine generator system, variable speed is often considered. It can increase the power production of the turbine by about 5 %, the noise is reduced and forces on the wind turbine generator system can be reduced. Its major drawbacks are the high price and complexity of the converter equipment.

This report deals with a variable-speed system consisting of synchronous generator, diode rectifier and thyristor inverter. The advantages of the synchronous generator and a diode rectifier are the high efficiency of the rectifier and the low price. There are two disadvantages that can be important in wind turbine generator systems. Motor start of the turbine is not possible without auxiliary equipment and the torque control is normally not faster than about 8 Hz [1]. The aim of this report is to describe an efficient variable-speed system and to model the generator and converter losses. The loss model is intendend to be used for steady state torque control and to maximize the system efficiency.

The synchronous generator system has been investigated earlier. Ernst [1], for example, describes the system possibilities by presenting various system configurations, methods for modelling and control strategies. Hoeijmakers derives an electric model for the generator and converter [2] and a simplified model intended for control use [3], not including the effects of ripple and harmonics. Carlson presents a detailed model for the simulation of the generator and converter system by numerical solution of the equations [4].

This report focuses on system design, modelling of the system losses, maximizing the efficiency and calculation of average efficiency. To be able to find reasonable parameters for the loss model, the generator rating as well as the converter design are discussed in Chapter 2. In Chapter 3, the loss model is derived and compared with measurments. In Chapter 4, the generator voltage control is optimized and the influence of the generator rating on the system efficiency is discussed. A comparison is made between the losses and average efficiency of a variable-speed, a constant-speed and a two-speed system in Chapter 5. The report deals only with the steady-state behaviour of the system.

1.1 Description of variable-speed generator systems

1.1.1 Synchronous generator and diode-thyristor converter.

The generator system discussed in this report is a system consisting of a synchronous generator, a diode rectifier, a dc filter and a thyristor inverter. The inverter may have a harmonic filter on the network side if it is necessary to comply with utility demands. The harmonic filter is, however, not included in the efficiency calculations in this report. Figure 1.6 shows the total power-generating system.

The advantage of a synchronous generator is that it can be connected to a diode or thyristor rectifier. The low losses and the low price of the rectifier make the total cost much lower than that of the induction generator with a self-commutated rectifier [5]. When using a diode rectifier the fundamental of the armature current has almost unity power factor. The induction generator needs higher current rating because of the magnetization current.

The disadvantage is that it is not possible to use the main frequency converter for motor start of the turbine. If the turbine cannot start by itself it is necessary to use auxiliary start equipment. If a very fast torque control is important, then a generator with a self-commutated rectifier allows faster torque response. A normal synchronous generator with a diode rectifier will possibly be able to control the shaft torque up to about 10 Hz, which should be fast enough for most wind turbine generator systems.

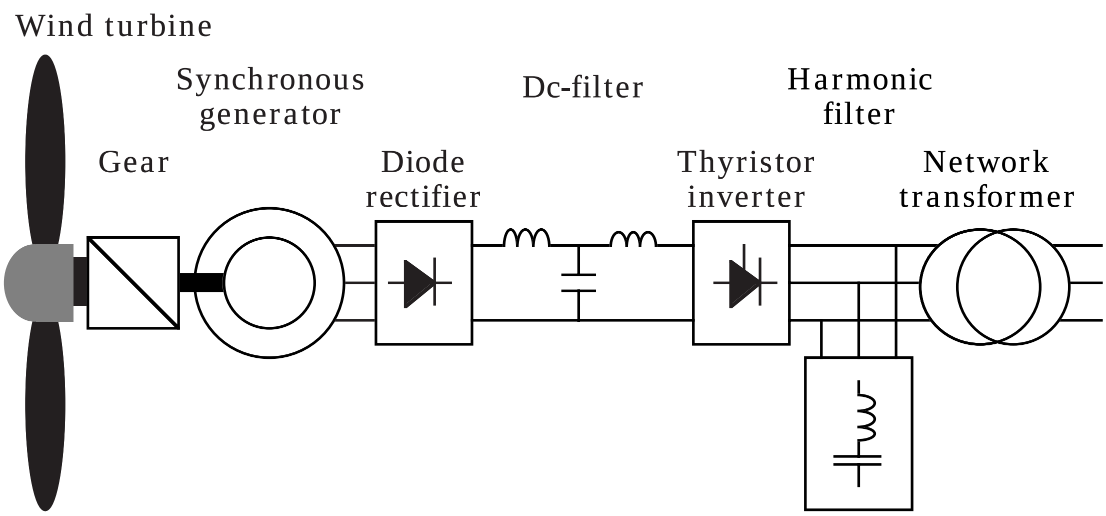

Figure 1.6 The proposed generator and converter system for a wind turbine generator system.

The armature current of a synchronous generator with a diode rectifier can be instable. This instability can, according to Hoeijmakers, be avoided by using a current-controlled thyristor rectifier [3]. However, using a thyristor rectifier is much more expensive than using a diode rectifier and it also makes it neccesary to use a larger generator. Therefore, a diode rectifier should be used if the rectifier current can be controlled by other means. That is possible by means of the inverter current control. The control may, however, be slightly slower than that of a thyristor rectifier.

Enclosed generators (IP54) are preferred in wind turbine generator systems. But standard synchronous generators are usually open (IP23) and cooled by ambient air ventilated through the generator. Enclosed synchronous generators are manufactured, but they can be rather expensive. Open generators can maybe be used if the windings are vacuum-impregnated. Standard induction generators, with a rated power up to at least 400 kW, are enclosed.

A thyristor inverter is used in the system investigated in this report, mainly because it is available as a standard product at a low price and also for high power. In the future, when the size of the transistor inverters is increased and the price reduced, they will be an interesting alternative to the thyristor inverter.

1.1.2 Generators and rectifiers

In this section different generators for variable-speed systems are compared.

A cage induction generator is normally used together with a self-commutated rectifier because it must be magnetized by a reactive stator current. The self-commutated rectifier allows a fast torque control but it is much more expensive than the diode rectifier and it is less efficient. An alternative to the expensive self-commutated rectifier would be an induction generator magnetized by capacitors and feeding a diode rectifier. The disadvantages of that system are that the generator iron core must be saturated to stabilize the voltage, which leads to a poor efficiency, and the capacitance value must be changed with the generator speed. The two different cage induction generator and rectifier combinations are shown in Figure 1.1.

An induction generator and a rotor cascade has the stator connected directly to the network and the rotor windings are connected to the network via a frequency converter, see Figure 1.2. This system is interesting mainly if a small speed range is used because then the frequency converter can be smaller than in the other systems. A speed range of ± 20 % from the synchronous speed can be used with a frequency converter rated only about 20 % of the total generator power. The main part of the power is transferred by the stator windings directly to the network. The rest is transferred by the frequency converter from the rotor windings. The disadvantage of this system is that the generator must have slip rings and therefore needs more maintenance than generators without slip rings.

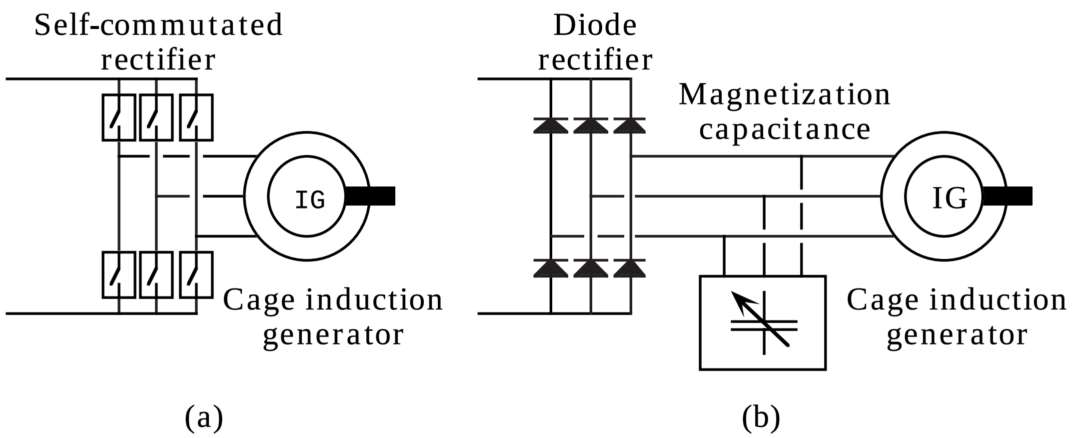

Figure 1.1 Cage induction generator IG with (a) a self-commutated rectifier or (b) self excited with a diode rectifier.

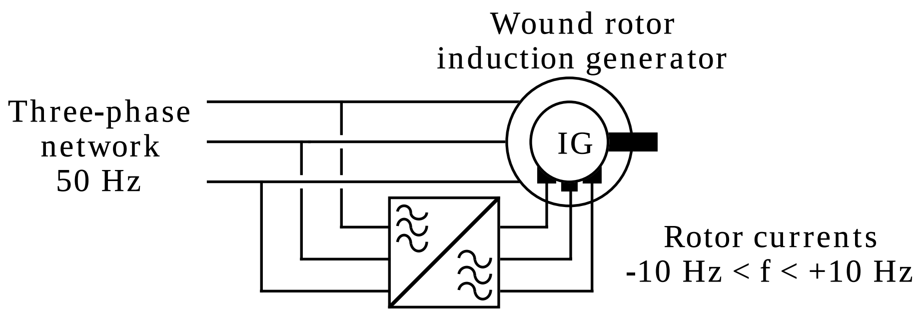

Figure 1.2 Wound rotor induction generator IG and a rotor cascade frequency converter.

The conventional synchronous generator can be used with a very cheap and efficient diode rectifier. The synchronous generator is more complicated than the induction generator and should therefore be somewhat more expensive. However, standard synchronous generators are generally cheaper than standard induction generators. A fair comparison can not be made since the standard induction generator is enclosed while the synchronous generator is open-circuit ventilated. The low cost of the rectifier as well as the low rectifier losses make the synchronous generator system probably the most economic one today. The drawback of this generator and rectifier combination is that motor start of the turbine is not possible by means of the main frequency converter.

Permanent magnet machines are today manufactured only up to a rated power of about 5 kW. They are more efficient than the conventional synchronous machine and simpler because no exciter is needed. Like other synchronous generators the permanent magnet generators can be used with diode rectifiers. High energy permanent magnet material is expensive today and therefore this generator type will not yet be competitive in relation to standard synchronous generators. For low-speed gearless wind turbine generators the permanent magnet generator is more competitive because it can have higher pole number than a conventional synchronous generator. In Figure 1.3 the two types of synchronous generators are shown.

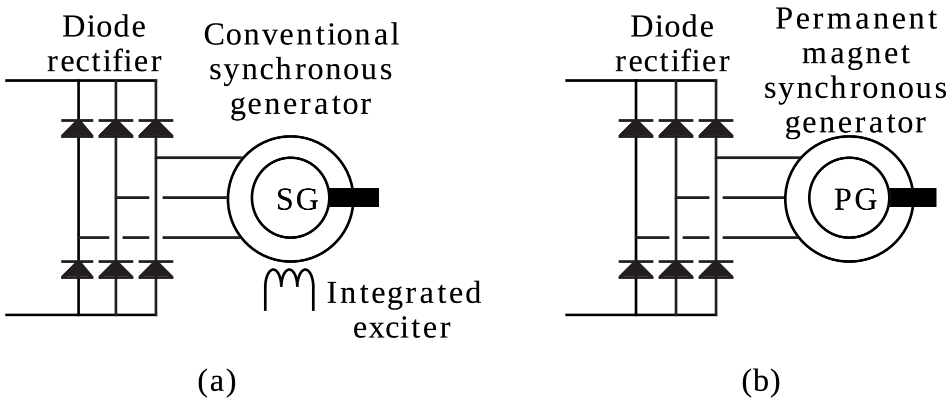

Figure 1.3 (a) Conventional synchronous generator SG and (b) permanent magnet synchronous generator PG connected to diode rectifiers.

1.1.3 Inverters

Many types of inverters can be used in variable-speed wind turbine generator systems today. They can be characterized as either network-commutated or self-commutated. Self-commutated inverters are either current source or voltage source inverters. Below the various types are presented. The rated power considered is in the range of 200 kW to 1 MW.

Self-commutated inverters: These are interesting because their network disturbance can be reduced to low levels. By using high switching frequencies, up to several kHz, the harmonics can be filtered easier than for a network-commutated thyristor inverter. Control of the reactive power flow is possible for this type of inverter making it easier to connect them to weak networks. Self-commutated inverters use pulse width modulation technique to reduce the harmonics. To make the harmonics low the switching frequency is often 3 kHz or higher.

Self commutated inverters are usually made either with Gate Turn Off thyristors, GTOs, or transistors. The GTO inverters are not capable of higher switching frequencies than about 1 kHz. That is not enough for reducing the harmonics substantially below those of a thyristor inverter with filter. Therefore, the GTO inverter is not considered as a choice for the future. It has been made obsolete by the transistor inverters in the range up to 100-200 kW. Today the most common transistor for this type of application is the insulated gate bipolar transistor, IGBT. It is capable of handling large phase currents, about 400 A, and it is today used in converters with an rated ac voltage up to 400 V. IGBT converters for 690 V networks are supposed to be available soon. The drawback of the IGBT inverter today is that the largest inverters that can be made without parallelling the IGBTs are only about 200 kW. A new technology, like the IGBT inverter, is expensive until large series are manufactured. These reasons make the IGBT inverters expensive to use for large wind turbine generator systems. When the price of self-commutated inverters decreases they are likely to be used for wind turbine generator systems because of their lower harmonics.

A self commutated inverter can be either a voltage source inverter or a current source inverter, see Figures 1.4 and 1.5. Today the voltage source inverter is the most usual type. If it is used to feed power to the network it must have a constant voltage of the dc capacitor that is higher than the peak voltage of the network. The generator is not capable of generating a constant high voltage at low speed and a dc-dc step-up converter must therefore be used to raise the voltage of the diode rectifier. In a system where the generator is connected to a self-commutated rectifier this is not a problem since that rectifier directly can produce a high voltage.

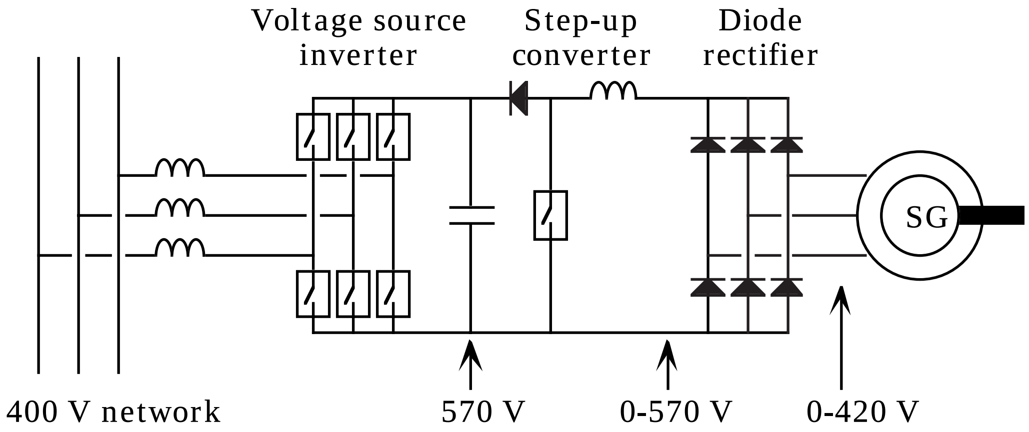

Figure 1.4 *A variable speed generator system. The frequency converter consists of a diode rectifier, a step up converter and a voltage source inverter. The transitors are shown as idealized switches.*

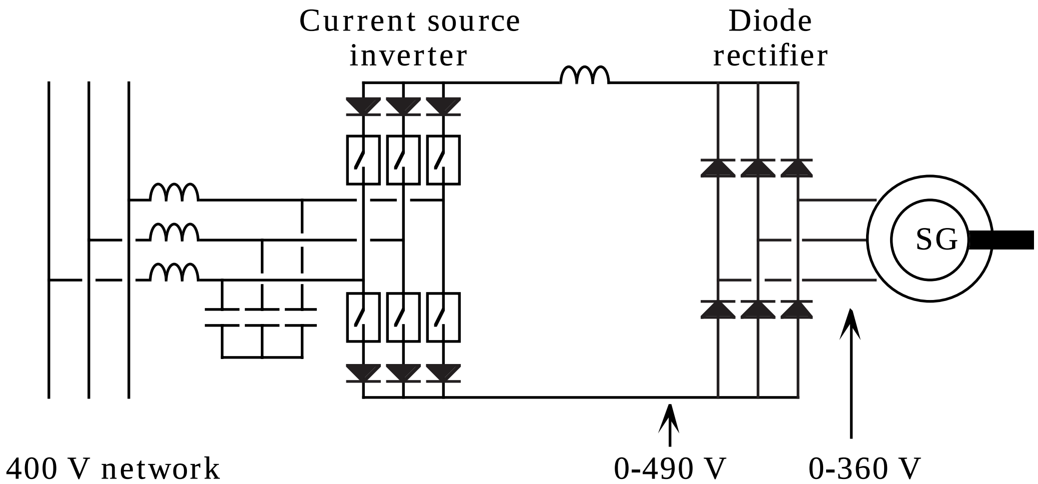

Figure 1.5 *A variable speed generator system. The inverter is a current source inverter with the transistors shown as idealized switches.*

For a generator connected to a diode rectifier the self commutated current source inverter is interesting. It is, like the thyristor inverter, capable of feeding power to the network from very low voltages. Since the network is a voltage-stiff system it is from a control point of view good to use a current source inverter. The drawback of the current source inverter is a lower efficiency than that of the voltage source inverter with step-up converter.

Network-commutated inverters: The usual type of network-commutated inverter is the thyristor inverter. It is a very efficient, cheap and reliable inverter. It consumes reactive power and produces a lot of current harmonics.

Cycloconverters with thyristors are common for large low-speed machines. They are only used with low frequencies, up to about 20 Hz and therefore they do not fit the standard four-pole generators used in wind turbine generator systems. For rotor-cascade connected induction generators the low frequency range is no disadvantage. The harmonics from the cycloconverter are large and difficult to filter.

1.2 Wind turbine characteristics

A wind turbine as power source leads to special conditions. The shaft speed-power function is pre-determined because aerodynamic efficiency of the turbine depends on the ratio between the blade tip speed and the wind speed, called tip speed ratio. Maximum aerodynamic efficiency is obtained at a fixed tip speed ratio. To keep the turbine efficiency at its maximum, the speed of the turbine should be changed linearly with the wind speed.

The wind power is proportional to the cube of the wind speed. If a turbine control program that is designed to optimize the energy production is used the wind speed turbine power function is also a cubic function. The turbine power curve is shown in Figure 1.7 together with the turbine speed curve. In this report the turbine speed is assumed to be controllable above the rated wind speed by blade pitch control. The generator speed can then be considered nearly constant at wind speeds above the rated wind speed.

An ordinary wind turbine has a rated wind speed of about 13 to 14 m/s but the median wind speed is much lower, about 5 to 7 m/s. Therefore, the power of the turbine is most of the time considerably less than the rated power. The probability density of different wind speeds at the harbour in Falkenberg, Sweden, is shown in Figure 1.8.

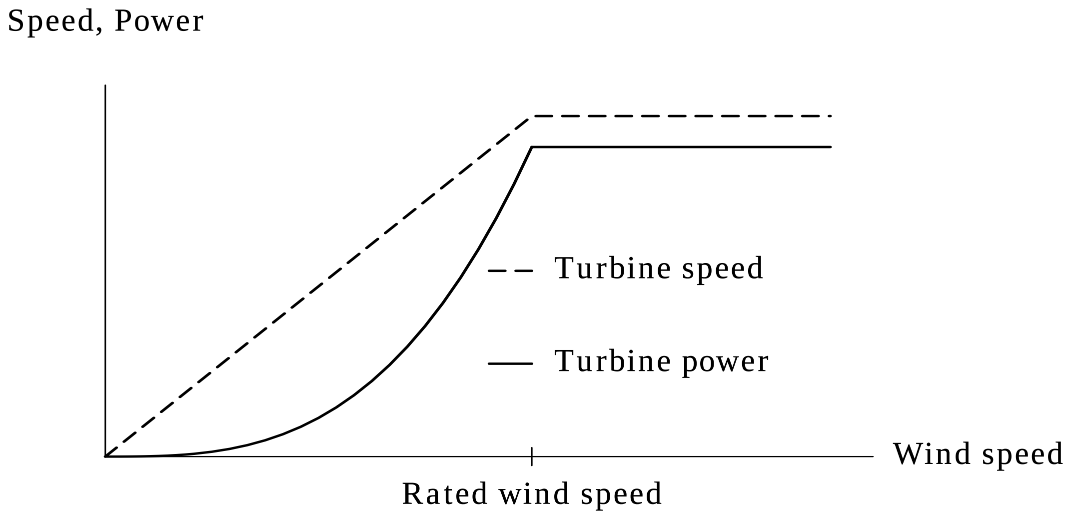

Figure 1.7 The turbine power and turbine speed versus wind speed.

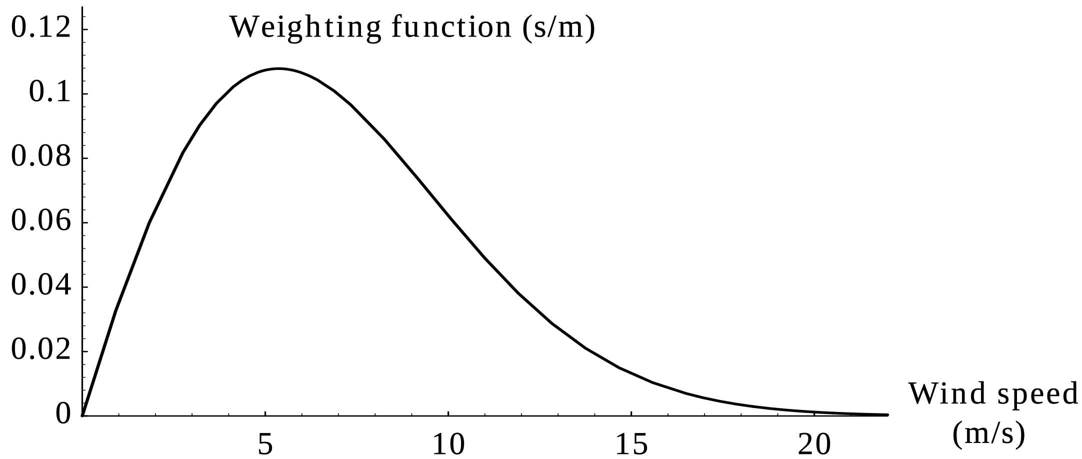

Figure 1.8 The weighting function of wind speeds at the harbour in Falkenberg, Sweden.

It can be seen that the wind speed usually is about half of the rated wind speed. Only during a small fraction of the time, less than 10 % of the year, the turbine produces rated power. Therefore, a generator system for a wind turbine benefits more of low losses at low power than it does of low losses at rated power. At high power a variable-speed generator and converter have higher losses than what a similar generator connected directly to the network has. However, at low power the variable-speed system can have lower losses than the network-connected generator. Therefore, the annual average efficiency can be almost the same for both the systems.

1.3 Variable-speed wind turbines

Today most wind turbines run at constant generator speed and thus constant turbine speed. The reason for this is mainly that grid-connected ac generators demand a fixed or almost fixed speed. Other reasons may be that resonance problems are more easily avoided if the speed is constant and that a passive stall control can be used to limit the power at wind speeds higher than the rated wind speed.

Reasons for using variable speed instead of fixed speed is that the turbine efficiency can be increased, which raises the energy production a few percent. The noise emission at low wind speeds can be reduced. Variable-speed systems also allow torque control of the generator and therefore the mechanical stresses in the drive train can be reduced. Resonances in the turbine and drive train can also be damped and the power output can be kept smoother. By lowering the mechanical stress the variable-speed system allows a lighter design of the wind turbine. The economical benefits of this are very difficult to estimate but they may be rather large.

1.4 A design example system

As an example a system for a 26 meter wind turbine generator system will be presented in this report. The chosen turbine is a two-blade turbine with a passive pitch control. Its speed is limited by the pitch control which is activated by aerodynamical forces. The turbine blade tips will be unpitched until the turbine speed reaches a pre-set speed, at which the blade tips start to pitch. The speed will then be kept almost constant with variations of about ± 5 %. This pitch system is completely passive and has no connection with the power control in the electrical system. The power above rated wind speed can be kept constant by the generator control. Below rated wind speed the generator torque will be controlled to keep the optimum tip speed ratio. The passive pitch system will be inactive and the blades unpitched. At the optimum tip speed ratio, the turbine can produce 300 kW. The rated wind speed is then 13 m/s and the turbine speed 72 rpm. 72 rpm is a high speed for this size of turbine. The speed can be reduced by designing the turbine blades for a lower optimum tip speed ratio.

2 The synchronous generator system

This chapter describes the generator and converter system as well as some aspects of its design. The component values for the 300 kW design example system are calculated. Problems are discussed more from an engineers point of view than from a theoretical point of view.

The complete generator system and its main components are shown in Figure 2.1. The turbine is described by its power P_t and speed n_t. The speed is raised to the generator speed n_g via a gear. P_g is the input power to the generator shaft. The generator can be magnetized either directly by the field current I_f fed from slip rings or by the exciter current I_E. The exciter is an integrated brushless exciter with rotating rectifier. The output electrical power from the generator armature is denoted by P_a. The generator armature current I_a and voltage U_a are rectified by a three-phase diode rectifier.

The rectifier creates a dc voltage U_{dr} and a dc current I_{dr}. On the other side of the dc filter the inverter controls the inverter dc voltage U_{di} and dc current I_{di}. U_d is the mean dc voltage and I_d is the mean dc current. The power of the dc link P_d is the mean value of the dc power, equal to I_d U_d. The inverter ac current is denoted I_i and the inverter ac voltage U_i. The ac power from the inverter is denoted P_i.

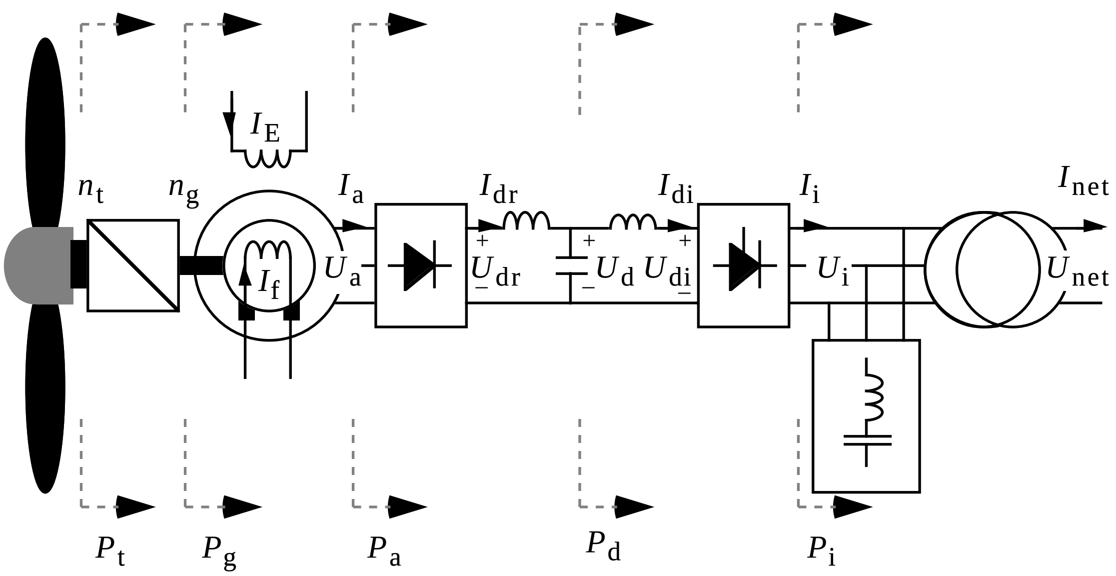

Figure 2.1 The total system and the quantities used.The generator can be magnetized either by slip rings or by an integrated exciter.

The filter is used to take care of the current harmonics by short circuiting the major part. The output of the generator system is the network current I_{net}. The network voltage is denoted U_{net}.

2.1 The control system

The control system of the generator and converter is used to control the generator torque by current control. In addition to this it can also, by voltage control with $U_{a\ ref}$, either control the reactive power consumed by the inverter or optimize the generator-converter efficiency. The two control functions are described below.

A voltage control diagram is shown in Figure 2.2. The control of the generator voltage is achieved by controlling the exciter current by $I_{E\ ref}$. The control must be designed to keep the voltage of the generator below about 90 % of the inverter ac voltage $U_{a\ lim}$. Otherwise the inverter will not be able to control the dc-current which will then increase uncontrollably. On the other hand, the voltage of the generator should not be lower than necessary at rated power because that leads to a poor power factor of the inverter ac current. Since the network voltage is not constant these two objectives can only be reached if the generator voltage is controlled by the measured

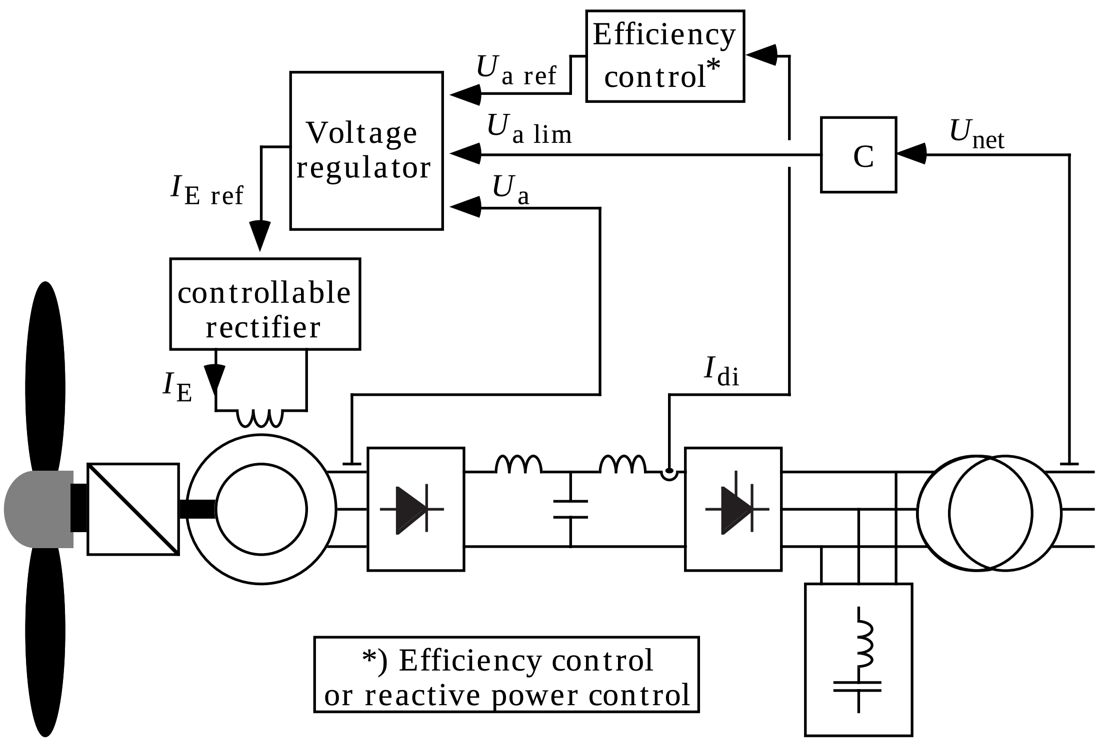

Figure 2.2 The steady state voltage control of the generator.

network voltage. The voltage control must also limit the generator flux. If this is not done the generator will be saturated which will lead to unacceptable core losses.

The second item to be controlled is the generator current. It is controlled by the current reference value to the inverter $I_{di\ ref}$. At rated power and rated speed it is kept constant. Below rated power the current is controlled to obtain a generator shaft torque $T_{g\ ref}$ according to the optimal speed-torque curve of the turbine. The current demand is calculated from the torque demand. In Figure 2.3 a diagram for a torque control system is shown. Because the field current in the rotor and the flux linkage Ψ of the stator can not be directly measured they are estimated from the armature voltage, armature current and shaft speed.

A fast voltage control is important to keep a high power factor without commutation problems during voltage dips on the network. If a fast torque control is required due to, for instance, resonance problems in the drive train, the two control systems must be designed together. Otherwise they will disturb each other. Because the current control is obtained by voltage control of the inverter it is easily disturbed by the voltage control of the generator. The generator voltage depends on the generator current due to armature

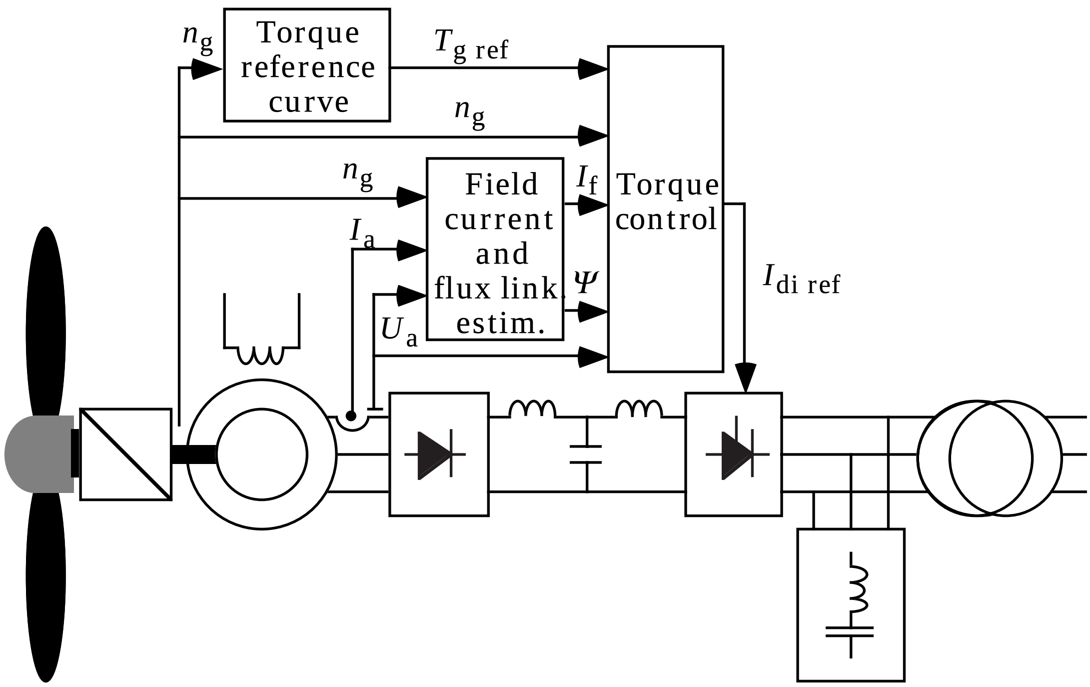

Figure 2.3 The steady state current control and torque control of the generator.

reaction and thus the voltage control is easily disturbed by the current control. One simple solution is to design a fast controller for the generator voltage and a slower one for the generator current.

2.2 The generator

The generator is assumed to be a standard synchronous generator. Usually it is a four-pole, 1500 rpm, generator equipped with an integrated exciter and a rotating rectifier. All the measurements in this report were made on a 50 kVA synchronous generator. It is a Van Kaick generator that is modified by Myrén & Co AB. The generator, which has an integrated exciter, has also been equipped with slip rings. This allows magnetization either by the exciter or by the slip rings. In Figure 2.4 the rating plate of the generator is shown.

2.2.1 Speed rating

In a variable speed system the speed of the generator is not restricted to the synchronous speed at the network frequency, i.e. 1500 rpm for a 50 Hz network. Most small generators are designed to operate up to 1800 rpm, 60 Hz, and the only upper limit is their survival speed, 2250 rpm for Mecc Alte and Leroy Somer generators. Such high speed can, however, not be used as rated speed. The rated speed must be low enough to allow over-speed under fault conditions, before the wind turbine emergency brakes are activated.

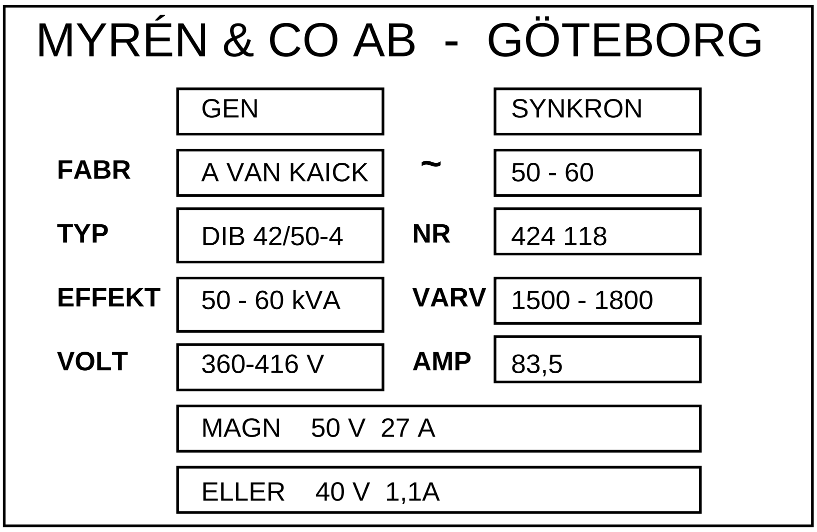

Figure 2.4 The rating plate of the 50 kVA generator used in the measurements.

The efficiency of a generator is usually increased slightly with increasing speed. Using high speed also means that a smaller generator can be used to produce the same power. A generator for 50 Hz operation is 20 % heavier than a generator for 60 Hz and the same rated power.

A second limitation of the rated speed is the possible gear ratio. Speed ratio larger than 1:25 between the generator speed and the turbine speed is not possible for a normal two-stage gear. If higher ratios must be used a three-stage gear will be necessary. Each extra stage in the gear means 0.5 to 1 % extra losses. Since the efficiency of the generator only increases some tenths of a percent there is no reason to use a three-stage gear to reach high generator speeds. For a two-stage planetary gear the limit of speed ratio is higher, about 1:50.

2.2.2 Current rating

Harmonics in the armature current make it necessary to reduce the fundamental current from the rated current to avoid overheating of the armature windings. The diode rectifier leads to generator currents that are non-sinusoidal, instead they are more like square-shaped current pulses, see Figure 2.5. In a standard generator only the fundamental component of the currents can produce useful torque on the generator shaft. The generator windings must be rated for the total r.m.s. value of the generator current

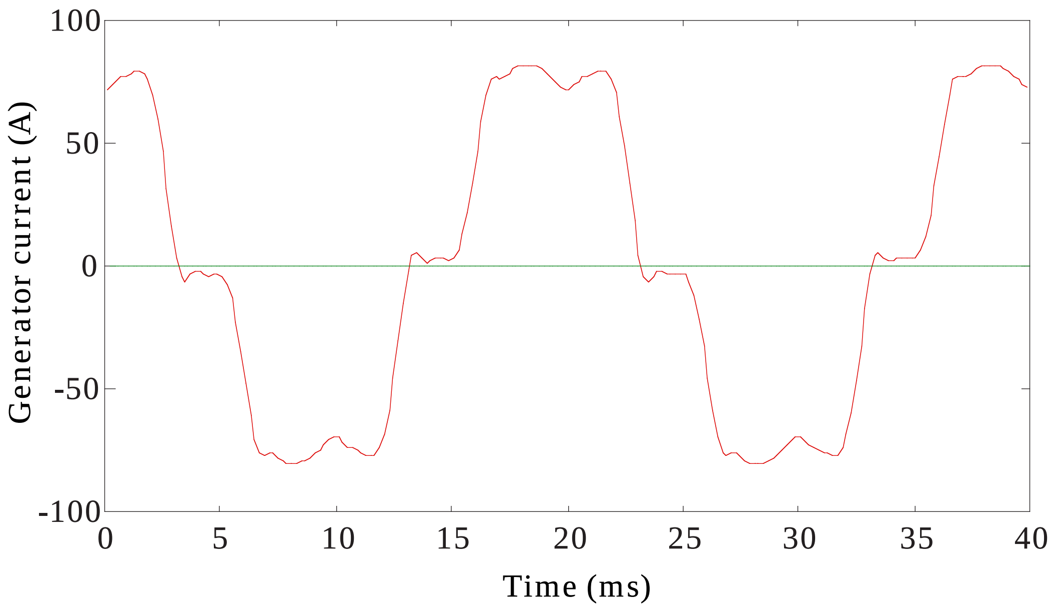

Figure 2.5 Armature current wave shape in a generator connected to a diode rectifier.

even if the active power is produced only by the fundamental component. The armature current of a generator loaded by a diode rectifier has an r.m.s. value that is about 5 to 7 % higher than the r.m.s. value of its fundamental component. This means that the generator must have a current rating at least 5 % higher than what would be necessary if sinusoidal currents were used.

2.2.3 Voltage rating

An other cause for derating when a diode rectifier is used is the voltage drop in the commutation inductance. The diode commutation is a short-circuit of two armature phase windings during the time of the commutation. This short-circuit leads to a lower rectified voltage compared to the possible voltage if the commutation was instantaneous. The relative voltage drop due to commutation can at rated load be approximately determined [6] by the per unit commutation reactance of the armature windings $x_{\mathrm{r\,com}}$ as

$$\frac{\Delta U_{\mathrm{N}}}{U_{\mathrm{N\,0}}} \approx \frac{1}{2}\, x_{\mathrm{r\,com}} \tag{2.1}$$

where ΔU_{N} is the commutation voltage drop at rated load and $U_{\mathrm{N\,0}}$ is the voltage at no load and rated flux.

Due to the commutations the voltage of the diode-loaded generator has commutation notches. They can be seen in Figure 2.6 where the measured line-to-line voltage of the generator is plotted. An undisturbed wave shape is also shown for the first half-period. Each half-period has three commutation notches.

The per unit commutation reactance can be approximately calculated from the subtransient reactances of the generator [7] as

$$x_{\mathrm{r\,com}} \approx \frac{x''_{\mathrm{d\,axis}} + x''_{\mathrm{q\,axis}}}{2} \tag{2.2}$$

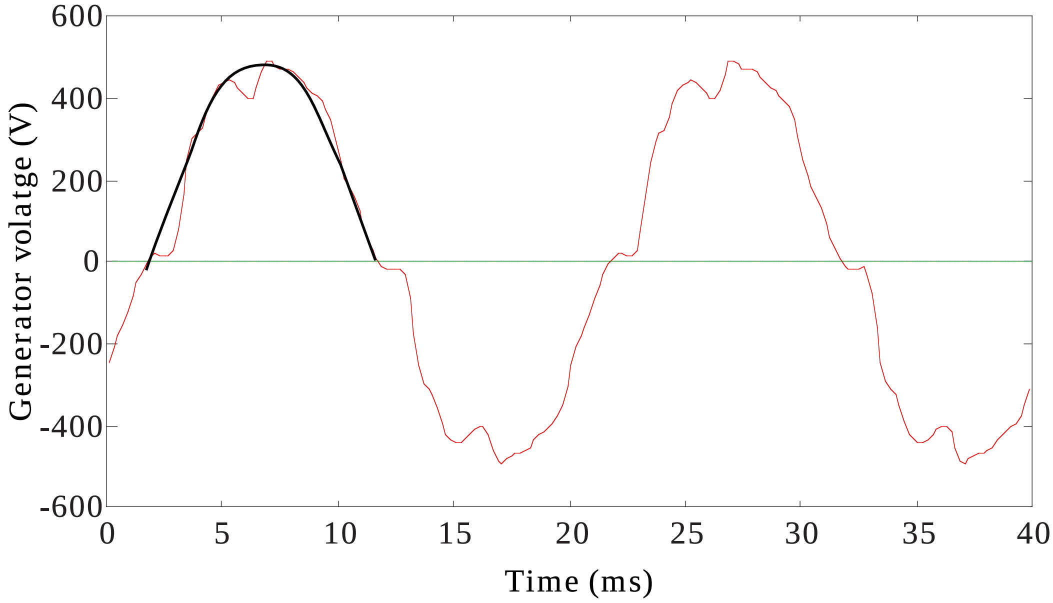

Figure 2.6 Line-to-line armature voltage with commutation notches at almost rated current. The no load voltage is shown for the first half-period.

The per unit commutation reactance of standard synchronous generators, between 200 kVA and 1000 kVA and from two different manufacturers, have been investigated. The commutation reactance is in the range of 10 % to 26 % with a mean value of about 15 %. The voltage drop of the commutation is then about 5 to 13 %. If the same generators are used with resistive load the reduction of armature voltage, when the generator is loaded, is lower. The voltage drop is then due to the leakage reactance and the armature resistance. The resistive voltage drop is almost equal for both these cases. It remains to compare the commutation voltage drop of a diode-loaded generator with the leakage reactance voltage drop of a resistively loaded generator. The leakage reactance voltage drop is only a few percent, and being 90 degree phase-shifted to the armature voltage it does not reduce the armature voltage significantly. Hence, the equivalent armature voltage for a diode-loaded generator is about 5 to 13 % lower than for the same generator resistively loaded.

2.2.4 Other aspects of the rating

With a diode rectifier the harmonics of the armature current induce current in the damper windings under steady state operation. How large these currents are and how much losses the damper winding thermally can withstand has not been included in this study. However, simulations in [4] indicate that they are about 0.2 % at rated current for the 50 kVA generator. They are not likely to overheat the damper windings and thus these losses give no reason to derate the generator.

Other additional losses of diode loaded synchronous generators must be included when the rating is decided. These losses can for example be eddy current losses in the end region due to the harmonic flux from the end windings. They make overrating necessary only if they cause overheating of some part of the generator. The measurements made on the 50 kVA generator show only about 0.67 % additional losses due to the diode rectifier. These are such small losses that they probably can be neglected.

2.2.5 Generator rating

The harmonics of the armature current at diode load decrease the permissible fundamental current about 5 to 7 % compared with a resistively loaded generator. Due to reactive voltage drop of the commutation inductance the possible rectified generator voltage is reduced about 5 to 13 %. Additional losses due to the diode load are small, and they are generally no reason for derating, if they do not occur in a critical hot spot of the generator.

The generator should have an apparent power rating, for sinusoidal currents, that is about 10 to 20 % larger than the active power that will be used with diode load. If the generator is operated at a higher speed than the rated one the permissible voltage will be raised proportionally to the speed. So, using a 50 Hz machine at 60 Hz increases the voltage rating by 20 %. The limit for the voltage is set by the isolation of the armature winding. Standard isolation for 230/400V machines can be used for line-to-line voltages up to 700 V.

The conclusion is that a diode-loaded generator does not need to be bigger than a generator, for the same active power, connected to a 50 Hz network. The fundamental component of the armature current has to be lower than the rated armature current. Also, the possible output voltage is decreased by the commutations. However, the generator can instead be used with 20 % higher speed which compensates both for the current and voltage derating at 50 Hz operation.

2.2.6 Generator efficiency

When the generator is connected to a diode rectifier the efficiency is lower than when it is connected to a resistive three-phase load. The reduction does not only depend on the increase in additional losses, but it is to a large extent depending on reduced output power at rated current and rated flux. Except for the additional losses the losses are the same at rated load for the resistive load as well as for the diode load. The output power is, however, reduced due to the voltage drop of the commutation and lower fundamental current when a diode rectifier is used.

At rated current the fundamental of the armature current is about 5 to 7 % lower with a diode load than with a resistive load. As mentioned earlier the voltage at rated generator flux is about 5 to 13 % lower with a diode load. Totally the output power of the generator is 10 to 20 % lower with a diode load than with a resistive load. Constant losses and lower power reduce the efficiency. The maximum power of the generator loaded by a diode rectifier $P_{\mathrm{N\ diode}}$ can be expressed as a fraction C_{diode} of the maximum power for the same generator loaded by a three phase resistive load $P_{\mathrm{N\ res}}$

$$P_{\mathrm{N\ diode}} = C_{\mathrm{diode}}\ P_{\mathrm{N\ res}} \tag{2.3}$$

C_{diode} is about 80 to 90 % for the considered generators. The decrease in rated efficiency due to the derating at diode load, $\Delta\eta_{\mathrm{N}}$, is calculated. $P_{\mathrm{loss\ N}}$ is the total generator losses at rated current and rated flux and P_{N} is the rated load. The rated efficiency of generators from 200 kVA to 1000 kVA is about 94 to 96 % at $\cos(\varphi) = 1.0$, here the efficiency with resistive load is assumed to be 95 %. The reduction of efficiency when the generator is loaded by a diode rectifier instead of a resistive three phase load is

$$\Delta\eta_{\mathrm{N}} = \eta_{\mathrm{N\ res}} - \eta_{\mathrm{N\ diode}} = \left(1 - \frac{P_{\mathrm{loss\ N}}}{P_{\mathrm{N\ diode}}}\right) - \left(1 - \frac{P_{\mathrm{loss\ N}}}{P_{\mathrm{N\ res}}}\right) =$$

$$= \begin{cases} \dfrac{5\ \%}{80\ \%} - \dfrac{5\ \%}{100\ \%} = 1.25\ \% & \text{for} \quad C_{\mathrm{diode}} = 80\ \% \\[2ex] \dfrac{5\ \%}{90\ \%} - \dfrac{5\ \%}{100\ \%} = 0.56\ \% & \text{for} \quad C_{\mathrm{diode}} = 90\ \% \end{cases} \tag{2.4}$$

The increase in additional losses for the 50 kVA generator when it is connected to a diode rectifier is

$$\frac{\Delta P_{ad}}{P_N} \approx 0.67\ \% \qquad \text{(from measurements in Section 3.4.2)} \qquad (2.5)$$

The relative increase in additional losses for generators from 200 to 1000 kVA has not been found. Therefore, the value for the 50 kVA generator is used instead. The relative increase is probably smaller for the larger generators because their per unit losses are generally smaller than for the 50 kVA generator.

The total efficiency reduction when a synchronous generator is loaded by a diode rectifier compared with resistive load is approximately 1.2 to 2.0 %. About half or more of the decrease in efficiency is because of decreased output power and not because of increased losses. If the speed of the generator is higher for the diode-loaded generator compared to the resistively loaded generator, the difference in efficiency will be a little less.

2.2.7 Design example

The maximum continuous power of the generator system should be 300 kW at a rated dc voltage of $U_{d\,N}$ = 600 V. This voltage is used because it is the maximum dc voltage of a standard thyristor inverter and using the maximum voltage maximizes the efficiency. This means that the rated dc current is $I_{dr\,N}$ = 500 A. The r.m.s. value of the generator current can be calculated approximately

$$I_a \approx \sqrt{\frac{2}{3}}\ I_{dr} = 0.82\ I_{dr} \qquad (2.6)$$

$$I_{a\,N} \approx 0.82\ I_{dr\,N} = 0.82 \cdot 500\ \text{A} = 410\ \text{A} \qquad (2.7)$$

This formula is exact if the dc current is completely smooth. This is not the case but the increase due to current ripple is only a few percent. Thus the rated current of the generator should be a little more than 410 A.

According to Ekström [6] the dc voltage can be expressed as a function of the generator voltage and the dc current

$$U_d = \frac{3\sqrt{2}}{\pi} U_a - \frac{3\,\omega\, L_{r\,com}}{\pi} I_{dr} \tag{2.8}$$

By solving U_a from this equation and using the rated values of the other quantities, the rated generator voltage can be found as

$$U_{a\,N} = \frac{\pi}{3\sqrt{2}} \left(U_{d\,N} + \frac{3\,\omega_N\, L_{r\,com}}{\pi} I_{dr\,N} \right) \tag{2.9}$$

An LSA 47.5 generator from Leroy Somer is chosen. The per unit commutation inductance is 12.6 % at 50 Hz and 410 A which corresponds to 0.226 mH. The generator should, according to Equation (2.9), have a rated voltage of about 470 V if it is used at 50 Hz and 475 V at 60 Hz.

The voltage can be adjusted not only by choosing generators of different voltage rating. It can also be adjusted by changing the maximum speed of the generator. The maximum voltage of a generator is a linear function of speed

$$U_{a\,max}(n_N) = \frac{n}{n_N} U_{a\,N} \tag{2.10}$$

For the design example turbine the optimum tip speed ratio λ_{opt} is 7.5 and the diameter d_t is 26 m. The rated wind speed v_N is about 13 m/s. The tip speed ratio is calculated using the following formula

$$\lambda = \frac{n_t\, \pi\, d_t}{v} \tag{2.11}$$

The rated speed of the turbine should then be

$$n_{t\,N} = \frac{v_N\, \lambda_{opt}}{\pi\, d_t} = 72 \text{ rpm} \tag{2.12}$$

The maximum corresponding generator speed with a gear ratio of 1:25 is

$$n_{g\,N} = 25\, n_{t\,N} = 25 \cdot 72 \text{ rpm} = 1800 \text{ rpm} \tag{2.13}$$

The voltage rating of the generator at 1500 rpm should according to Equation (2.10) be

$$U_{a\,N} = \frac{1500 \text{ rpm}}{1800 \text{ rpm}} \; 475 \text{ V} = 395 \text{ V} \qquad (2.14)$$

Summary: A generator with at least 410 A current rating and 395 V at 1500 rpm should be used. In other words, a 284 kVA generator (50 Hz) allows about 300 kW maximum power at 1800 rpm. This is the smallest possible generator. According to the data sheets of Leroy Somer generators an LSA 47.5 M4 will be sufficient. It can continuously operate with a 290 kVA load at 1500 rpm, 400 V and a class B temperature rise.

2.3 Rectifier

In the rectifier circuit the rectifier reactor L_{dr} is also included. The diagram of the generator and rectifier circuit can be seen in Figure 2.7. The dc voltage U_d can be considered as a stiff voltage under steady state conditions if the dc capacitance C_d is large. U_{a0} is the voltage induced by the airgap flux of the generator and $L_{r\,com}$ is the commutation inductance of the generator armature.

2.3.1 Diode commutation

The commutation of the dc current between the armature phases of the synchronous machine is slow because the armature windings have a large inductance. At rated current the commutation can take up to about 1 ms. This leads to a lower mean voltage on the dc link at rated load compared with no load. In Figure 2.8 the potentials of the dc link are shown. A commutation

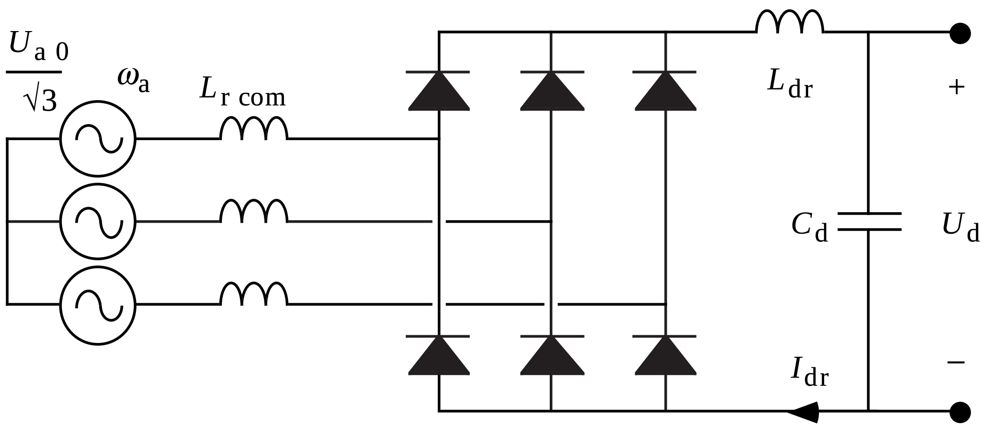

Figure 2.7 The rectifier circuit including the rectifier reactor L_{dr} and the commutation inductance $L_{r\,com}$.

on the positive side of the diode rectifier takes place between t_1 and t_2. The dc potential is during this time equal to the mean value of two phase voltages instead of the highest phase potential.

2.3.2 Equivalent circuit

The commutation voltage drop can be modelled as a resistance in the dc link $R_{\mathrm{r\ com}}$. The resistance value depends on the commutation inductance and the frequency of the ac source. From Equation (2.8) the resistance value can be identified

$$R_{\mathrm{r\ com}} = \frac{3\,\omega\,L_{\mathrm{r\ com}}}{\pi} \qquad (2.15)$$

This resistance represents an inductive voltage drop on the ac side and is, of course, not a source of losses.

The commutation inductance also helps smoothing the dc current. Between two commutations the dc current passes a series connection of two commutation inductances, see Figure 2.9. The effective inductance is between the commutation $2\,L_{\mathrm{r\ com}}$.

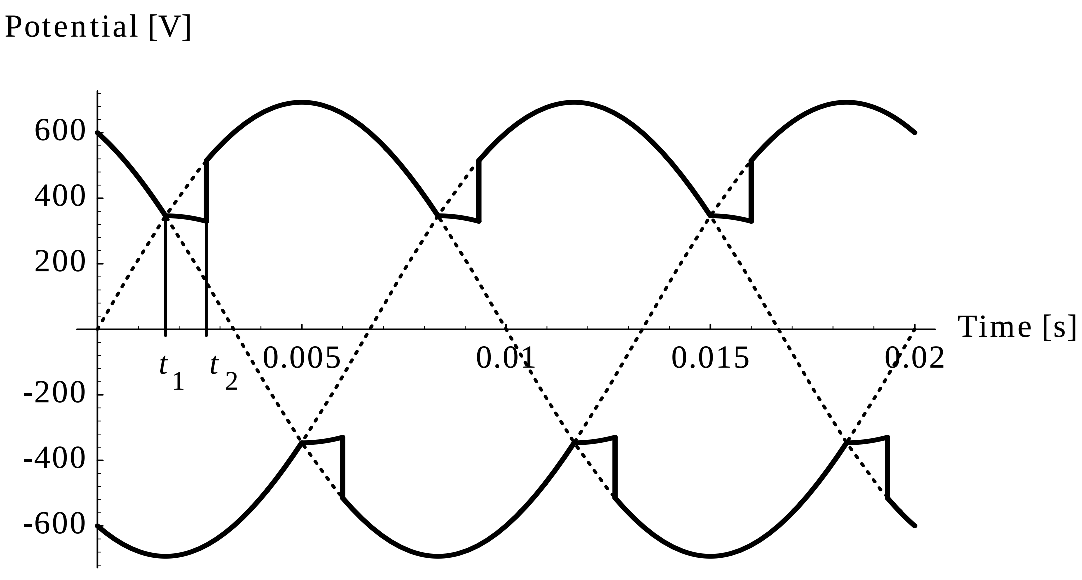

Figure 2.8 The positive and negative potentials of the dc side of the rectifier.

During a commutation the dc current passes through one commutation inductance and a parallel connection of two commutation inductances, see Figure 2.10. The effective inductance is then 1.5 $L_{r\ com}$.

The commutation inductances will act as a smoothing inductance that is about twice the per phase commutation inductance of the rectifier.

The no load dc voltage can be calculated from the generator no load voltage

$$U_{dr\ 0} = \frac{3\sqrt{2}}{\pi}\ U_{a\ 0} \qquad (2.16)$$

The real rectifier circuit can now be replaced in calculations by an equivalent circuit, Figure 2.11. It includes the effect of the smoothing inductance L_{dr} as

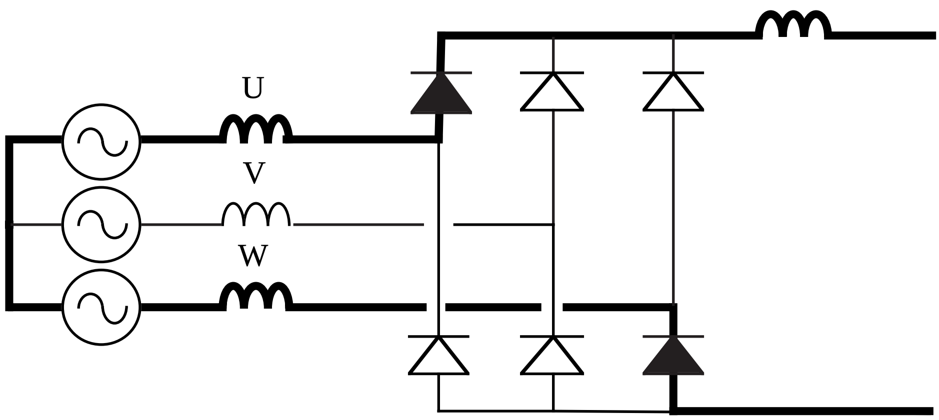

Figure 2.9 The current path of the dc current between two commutations.

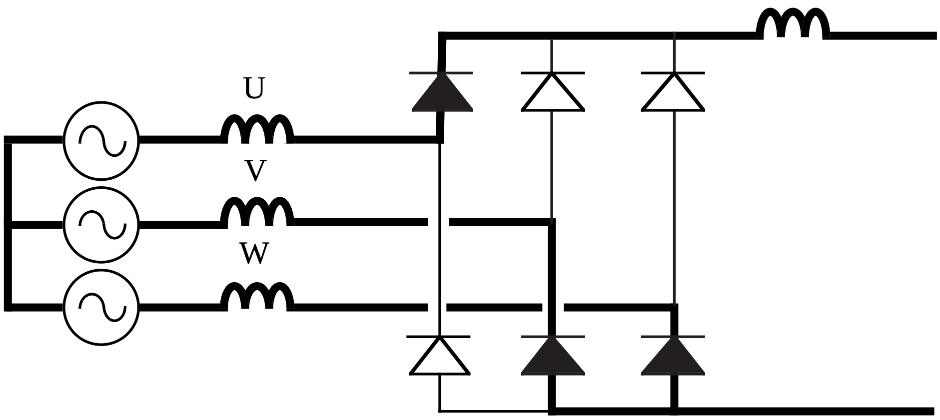

Figure 2.10 The current path of the dc current during a commutation from phase W to V.

well as the commutation inductance 2 $L_{r\ com}$. The voltage drop due to the commutations is modelled as a resistance $R_{r\ com}$. For a complete model also the dc resistance and generator armature resistance should be included. However, the influence of these is small except for the losses of the circuit. The voltage harmonics are not included in this equivalent circuit.

2.3.3 Design example

In the design example the ratings of the system have been chosen to 300 kW at a dc voltage of 600 V. Therefore, the diode rectifier should have a rated dc-current of at least 500 A and a rated dc voltage of 600 V. A diode bridge consisting of three Semikron SKKD 260 diode modules and a isolated heat sink is chosen. With appropriate cooling this rectifier can continuously operate at a dc current of 655 A.

The isolated heat sink is advantageous because the power circuit in a wind turbine generator system should not be exposed to the ambient air. The heat sink must, however, be cooled by ambient air since the dissipated power is high, about 1.5 kW at rated power. This can be solved by using an isolated heat sink which is earth-connected and is a part of the enclosure for the power circuit. The cooling fan is placed outside the enclosure while all the wiring as well as the diode modules are inside.

The voltage drop of each diode in a SKKD 260 module is 1 V, independent of the load, plus the voltage drop of 0.4 mΩ resistance. The total losses of the diodes in the rectifier can be expressed as

$$P_{loss\ r} = 2\ \text{V}\ I_d + 0.8\ \text{m}\Omega\ (I_d)^2 \qquad (2.17)$$

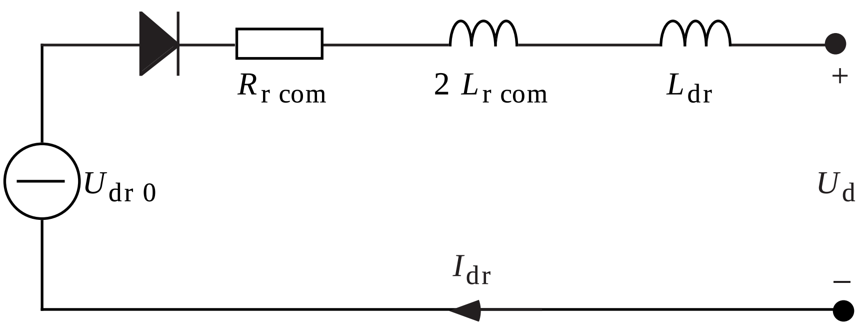

Figure 2.11 The rectifier and generator equivalent circuit at steady state when the voltage ripple of the rectifier is neglected.

Expressed in per unit of the rectifier rated current and rated power the losses are

$$p_{\mathrm{loss\ r}} = 0.33\ \%\ i_{\mathrm{d}} + 0.07\ \%\ (i_{\mathrm{d}})^2 \tag{2.18}$$

Also some resistance in the connections and the cables should be included in the losses leading to a higher resistive loss. The total rectifier losses can then be expressed as

$$p_{\mathrm{loss\ r}} = 0.33\ \%\ i_{\mathrm{d}} + 0.17\ \%\ (i_{\mathrm{d}})^2 \tag{2.19}$$

2.4 Dc filter

In this section the dc harmonics will be described as well as some aspects of the design of the dc filter.

The dc-filter is used for four purposes:

(1) It is supposed to prevent harmonics from the rectifier to reach the network. If there are harmonics from the rectifier in the network current they can not be easily filtered since their frequency changes with the generator speed. They can also cause resonance in the filter for the inverter harmonics because it has resonance frequencies below the frequencies of the characteristic harmonics.

(2) The dc filter should also keep the harmonics from the inverter low in the rectifier dc current, since they would otherwise cause power oscillations and generator torque oscillations. For generator frequencies close to the network frequency these oscillations have low frequency and then they can cause mechanical resonance.

(3) The harmonic content of the generator current depends to some extent on the dc filter. The filter should be designed to keep the harmonic content low because the harmonics cause extra losses in the generator.

(4) The dc filter design also affects the amount of harmonics produced by the inverter. The fourth purpose of the dc filter design is to assure that the inverter ac current harmonics are low and easy to filter.

If the dc filter consists of both inductances and capacitances it has resonance frequencies. They must not be excited by any of the larger harmonics that may occur during normal operation. Dc link harmonics occurring only under fault conditions can be allowed to be amplified by the resonances, if the converter is disconnected before the resonance has caused any damage. Since the generator fundamental frequency has a wide range, the filter resonance probably has to be damped because it is practically impossible to avoid all the harmonic frequencies.

2.4.1 Filter types

Three simple types of dc-filters have been investigated and they are shown in Figure 2.12. The simplest filter possible, type A, has only one inductance. All the current harmonics generated by the rectifier will appear as inter harmonics in the inverter current. To reduce these inter harmonics L_{d} has to be large. This is expensive and leads to a slow current control and therefore slow torque control.

A short circuit link can be used to make the dc filter more effective in reducing the inter harmonics in the inverter current. The second filter type B is a filter with a capacitance between two dc reactors. The capacitance will short-circuit most of the harmonics and it adds almost no extra losses. By stabilizing the voltage it separates the problem of current smoothing into two parts. The network side dc-current is smoothened by L_{di} and the generator side dc-current is smoothened by L_{dr}. The capacitance must be large enough to filter the low rectifier harmonics well.

The third filter type C is a variant of the type B filter. An inductance is introduced in the short-circuit link and the link is tuned to more effectively

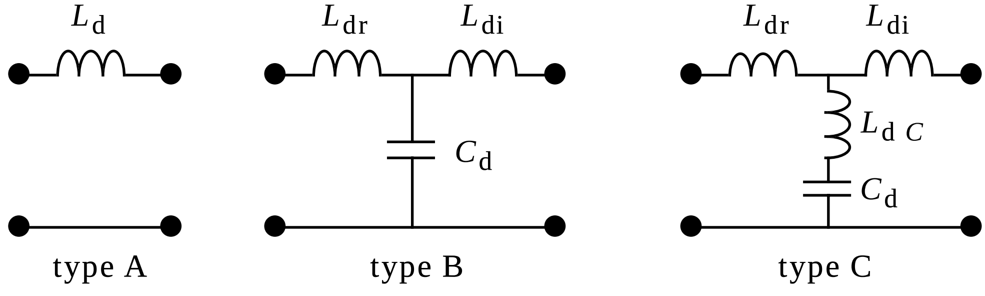

Figure 2.12 The investigated dc filter types.

short-circuit the largest fixed frequency harmonic. Only the harmonics from the inverter have constant frequencies. The largest harmonic from the inverter is the 300 Hz harmonic. But even without L_{dC} the 300 Hz current is damped very well and the higher harmonics are reduced better without L_{dC}.

The harmonic current in the inverter dc current relative to the rectifier harmonic voltage, I_{di} / U_{dr}, for the three types of dc filter is shown in Figure 2.13. The choice of dc filter will probably be between type A and type B. The filter of type B has much better damping of the harmonics. The single inductance L_d in filter A is higher than L_{di} plus L_{dr} in filter B. On the other hand, filter B is more complicated, has more parts and it probably has to have a circuit to damp its resonance. Non-characteristic harmonics in the inverter current can cause resonance in the ac filter. These harmonics can be reduced much better by filter B than by filter A. Therefore, a filter of type B is chosen for this design example, but this choice is **not** based on a complete study of all the important aspects.

2.4.2 Harmonics in the dc link

The harmonics in the dc link are originating from the frequencies of the network and the generator. The thyristor inverter and the diode rectifier generate a dc voltage with a superimposed ac voltage. Under ideal conditions

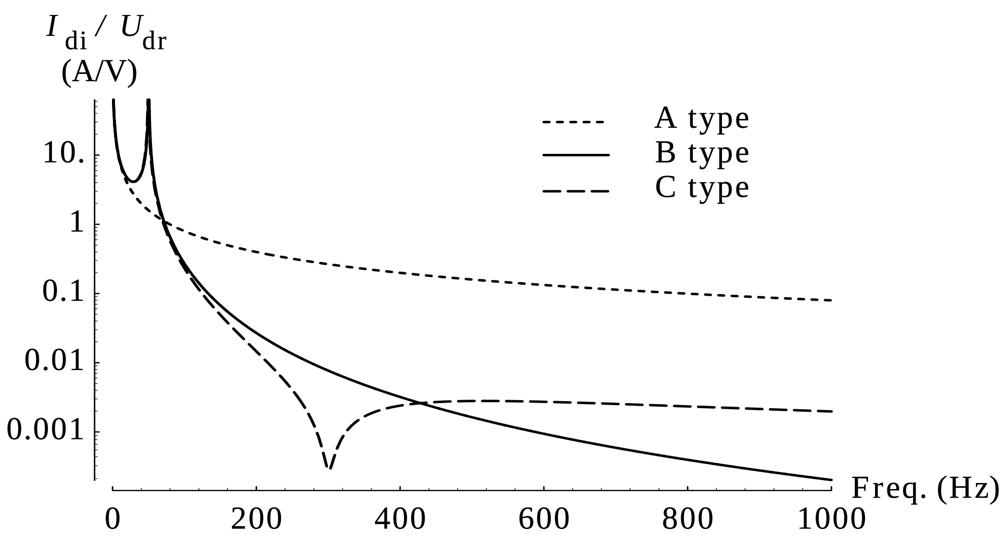

Figure 2.13 The inverter harmonic current relative to the rectifier harmonic voltage, I_{di} / U_{dr}.

the harmonic frequencies of the dc voltages are integer multiples of six times the ac frequencies. Only the sixth and twelfth harmonics cause ripple currents of considerable magnitude. From the inverter side a 300 Hz and a 600 Hz current are generated. Depending on the generator frequency, from 25 to 60 Hz, the diode rectifier generates a current harmonic with a frequency between 150 Hz and 360 Hz. The twelfth harmonic generated by the diode rectifier has a frequency between 300 Hz and 720 Hz. The magnitude of these voltage harmonics are depending on the generator voltage and on the firing angle of the inverter.

Under non-ideal conditions also other harmonics occur. If, for instance, the network voltage or the generator voltage is unsymmetrical, a second harmonic will also be generated. This should under normal conditions be small, but must not be amplified by resonance in the dc filter. Non-ideal firing of the inverter thyristors also causes other harmonics. They can be of any multiple of the fundamental frequency, but should for well-designed firing control systems be small. In Figure 2.14 the harmonics from the inverter and rectifier are illustrated.

A reason for unusual harmonics in the dc link is fault conditions. These harmonics must of course not damage the converter and therefore their effect must be calculated. If one ac phase is disconnected, because of for instance a blown fuse, a very large second harmonic is generated. The three-phase rectifier will then start to act as a one phase rectifier.

If a diode or a thyristor valve is short-circuited due to a component failure, a current of the fundamental frequency is generated in the dc link. The result should be that a fuse is blown.

All the above mentioned voltage harmonics can cause high currents if their frequencies are close to the dc link resonance frequencies. Therefore, the dc link resonance frequencies have to be carefully chosen. It is clear that the resonance frequencies have to be below 150 Hz due to rectifier harmonics. The second harmonic of both the network frequency and the generator frequency must also be avoided, if the resonance is not well damped. Very low resonance frequencies should also be avoided because they lead to a slow step response of the current control. In the design example a filter with a rectifier side resonance at 75 Hz is suggested.

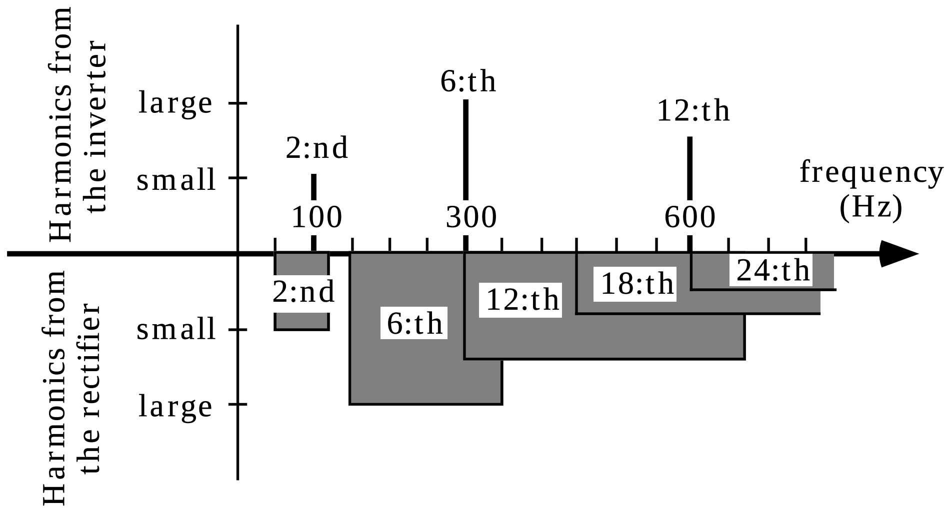

Figure 2.14 The harmonic frequencies in the dc filter under normal conditions and symmetrical firing.

2.4.3 Smoothing reactor of the diode rectifier

The current harmonics of the rectifier dc current depend on the magnitude of the harmonic voltages from the rectifier and on the smoothing inductance. For economical reasons the inductance should be minimized. The maximum acceptable ripple in the dc current must, therefore, be determined. On the generator side, the rectifier-induced harmonics are interesting mainly because they cause losses in the generator. Higher ripple means higher r.m.s. current and makes it necessary to use a higher current rating of the armature winding.

The harmonics from the inverter are small if a filter of type B or C is used. They do not have to be considered when the size of L_{dr} is calculated.

The r.m.s. value of the generator current can be calculated for different ripple magnitudes. This is done assuming a ripple-free dc voltage U_d over the dc filter capacitor and instantaneous commutations. The r.m.s. value as well as the fundamental component of the generator current are calculated. In Figure 2.15 the relation between the r.m.s. value and the fundamental of the armature current are plotted. For a perfectly smoothed dc current the r.m.s. value of the generator armature current is 4.7 % higher than its fundamental component. When the ripple increase the r.m.s. value of the generator current increases slowly. At a peak-to-peak ripple of 20 % of the rated dc current the armature current r.m.s. value is about 5 % higher than the fundamental component. At a 60 % ripple the r.m.s. value of the armature current is 7 % higher than the fundamental.

The increase in the r.m.s. current will be small, if the ripple is less than 60 % of the dc current mean value. As the peak-to-peak ripple increases from 20 % to 60 % the r.m.s. value of the current only increases from 1.05 to 1.07 times the fundamental component. The r.m.s. current only increases about 2 % while the ripple increases three times. Three times higher ripple allows a three times smaller total smoothing inductance. A 2 % increase in armature current increases the copper losses of the generator by about 4 %. At the same time the dc link losses should decrease as least as much since the smoothing inductance is decreased to a third.

A complete design study may show that other restrictions than generator losses determine the value of the smoothing inductance. The resonance frequencies must be kept at certain frequencies and a high ripple leads to a high peak value of the dc current. The peak value of the current determines the size of the iron core of the dc reactor. Therefore, higher peak current means a more expensive reactor.

The first step in determining the rectifier smoothing inductance is to chose the maximum allowed peak-to-peak ripple at rated current. Then the neccesary inductance can be calculated. The ac current through the rectifier

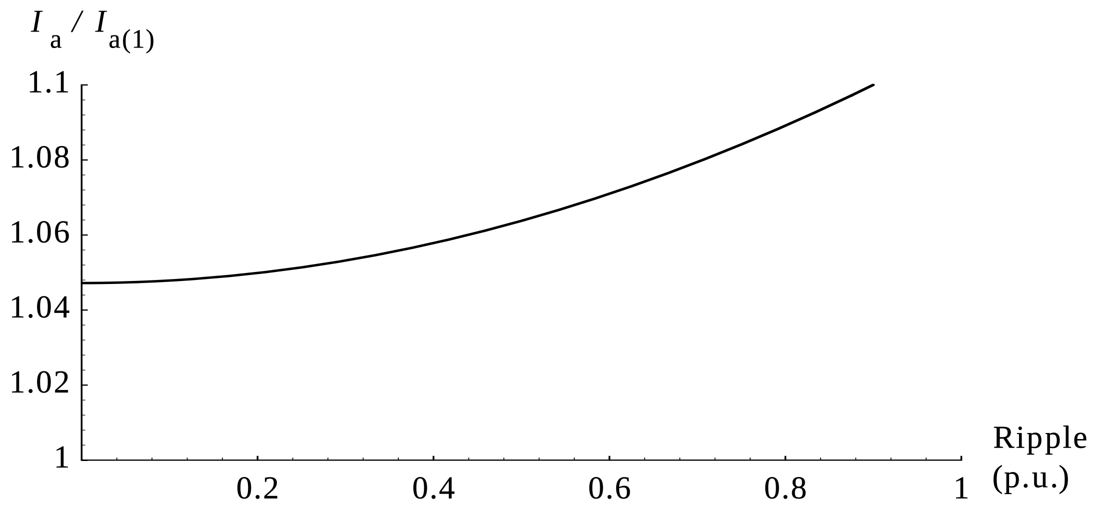

Figure 2.15 The r.m.s. value of the generator current relative to the fundamental component versus the relative peak-to-peak ripple.

dc reactor L_{dr} can under stationary conditions be found by integrating the voltage over the total smoothing inductance. The voltage over the dc filter capacitance is assumed to be a perfectly smooth dc voltage. The ac component of the rectifier dc current is calculated as

$$I_{dr}(t) = \int \frac{1}{L_{tot}} \left(U_{dr}(t) - U_d \right) dt \tag{2.20}$$

To find the peak-to-peak ripple the integral (2.20) is evaluated from t_3 to t_4. The integration interval is the part of the voltage ripple period where the voltage over the smoothing inductance is positive. The voltage on both sides of the inductance as well as the dc current can be seen in Figure 2.16.

The relation between peak-to-peak ripple, generator voltage and total smoothing inductance can now be calculated for the rectifier as

$$\Delta I_{dr\ p\text{-}p} = \int_{t_3}^{t_4} \frac{\sqrt{2}\,U_a}{L_{tot}} \left(\sin(\omega t + \frac{\pi}{3}) - \frac{3}{\pi} \right) dt \tag{2.21}$$

where
- $L_{tot} = L_{dr} + 2\,L_{r\,com}$
- t_3: when the voltage over the inductance becomes positive
- t_4: the voltage over the inductance becomes negative again
- U_a is the no-load armature voltage

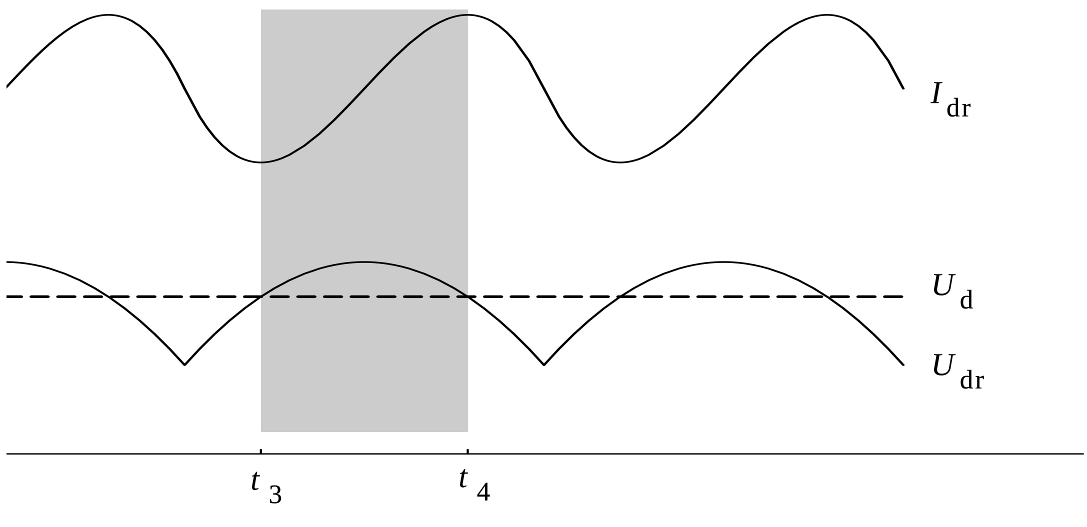

Figure 2.16 The rectifier dc voltage U_{dr}, dc capacitor voltage U_d and the rectifier dc current I_{dr}. The integration interval to find the peak-to-peak value is from t_3 to t_4.

Both t_3 and t_4 are found as solutions for t in the equation

$$\sin(\omega t + \frac{\pi}{3}) = \frac{3}{\pi} \tag{2.22}$$

for which $0 < \omega t_3 < \frac{\pi}{6}$ and $\frac{\pi}{6} < \omega t_4 < \frac{\pi}{3}$

2.4.4 Smoothing reactor of the inverter

The total r.m.s. value of the network ac current is also depending on the dc reactor L_{di} just as for the rectifier. However, there are other aspects that are more important for the inverter current than just minimizing the total r.m.s. value. The ac harmonics of the inverter current are very important to evaluate. They must be below certain limits to be accepted by the utility. If the dc current is assumed perfectly smooth it can be shown that the current harmonics are inversely proportional to their frequencies as described by the formula

$$I_{i(k)} = \frac{I_{i(1)}}{k} \tag{2.23}$$

where k is the order of the harmonic.

If the ripple on the dc current increases most of the ac harmonics will decrease. Only the fifth current harmonic increases with higher dc current ripple, see Figure 2.17. The magnitude of the harmonics is calculated assuming a ripple-free dc voltage U_d, no overlap of the inverter ac currents and a second order approximation of the ripple current wave shape.
The increase of the fifth harmonic is, of course, important since it is the largest current harmonic. However, being that large also makes it the one that is almost always necessary to filter. If a good harmonic filter already is installed for the fifth harmonic, the effect of increasing it can be rather small.

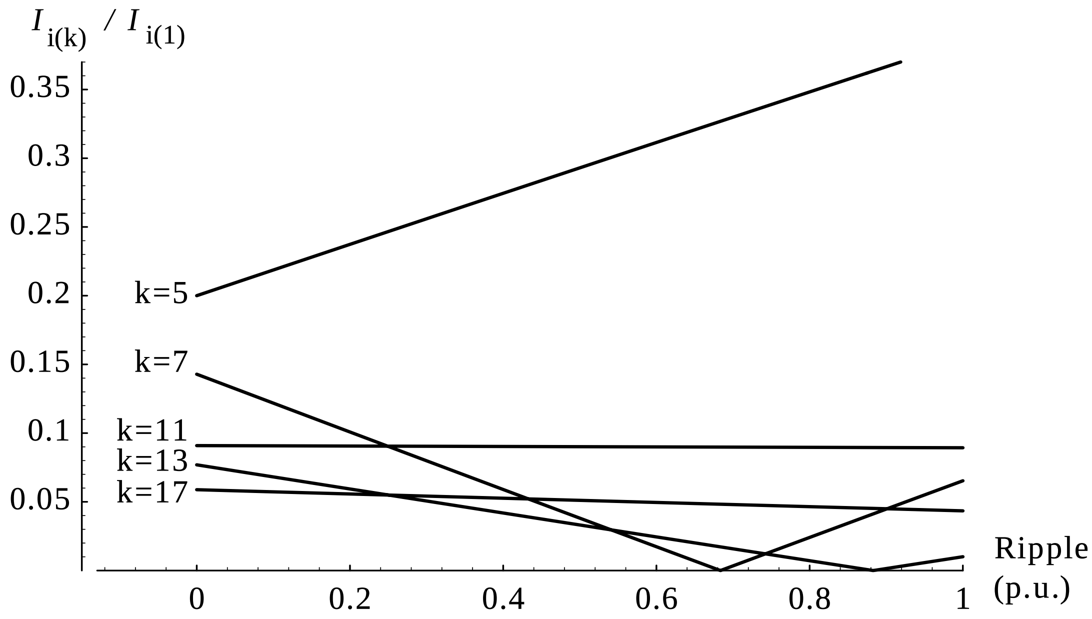

Figure 2.17 The ac current harmonics at rated power relative to the fundamental current at different dc current peak-to-peak ripple. No overlap and a second order approximation of the ripple current wave shape is assumed.

The seventh, thirteenth and nineteenth current harmonics etc. are decreased significantly by the ripple. The most interesting of these harmonics is the seventh one because it is often necessary to filter. If it can be reduced significantly, the seventh harmonic filter link may be unnecessary.

The eleventh, seventeenth and twentythird harmonics etc. are not reduced as much as the others. Therefore, they have to be filtered. This can be done by means of a filter link for the eleventh harmonic with a high pass characteristic.

As can be seen in Figure 2.18 the seventh harmonic is low at high power but will increase when the power is reduced below 0.6 p.u. It is, therefore, not sufficient only to make sure that the magnitude of the seventh harmonic is low at rated power; it is not allowed to increase too much at lower power either. A seventh harmonic that is higher at low power than at rated power can, however, be acceptable if most of the other harmonics then are lower.

There is, of course, a drawback of reducing ac harmonics by increasing the dc current ripple. The peak value of the inverter dc current then increases, demanding a higher current rating of the dc reactor.

No clear rules for choosing the inverter inductance can be given here. An interesting prospect, however, is to have a large current ripple of the dc current at rated current, approximately a peak-to-peak ripple in the order of 35 % of the mean current. By doing so, it ought to be possible to design an appropriate ac filter with only two LC-links.

The first step in determining the inverter smoothing inductance is to chose the maximum allowed peak-to-peak ripple at rated current. When it has been decided the smoothing inductance can be calculated. Under stationary conditions the ac current through the inverter dc reactor L_{di} can be found by integrating the voltage over the total smoothing inductance. The ac component of the inverter current I_{di} can be calculated from the inverter voltage U_{di} and the dc voltage U_d as

$$I_{di}(t) = \int \frac{1}{L_{tot}} \left(U_{di}(t) - U_d \right) dt \tag{2.24}$$

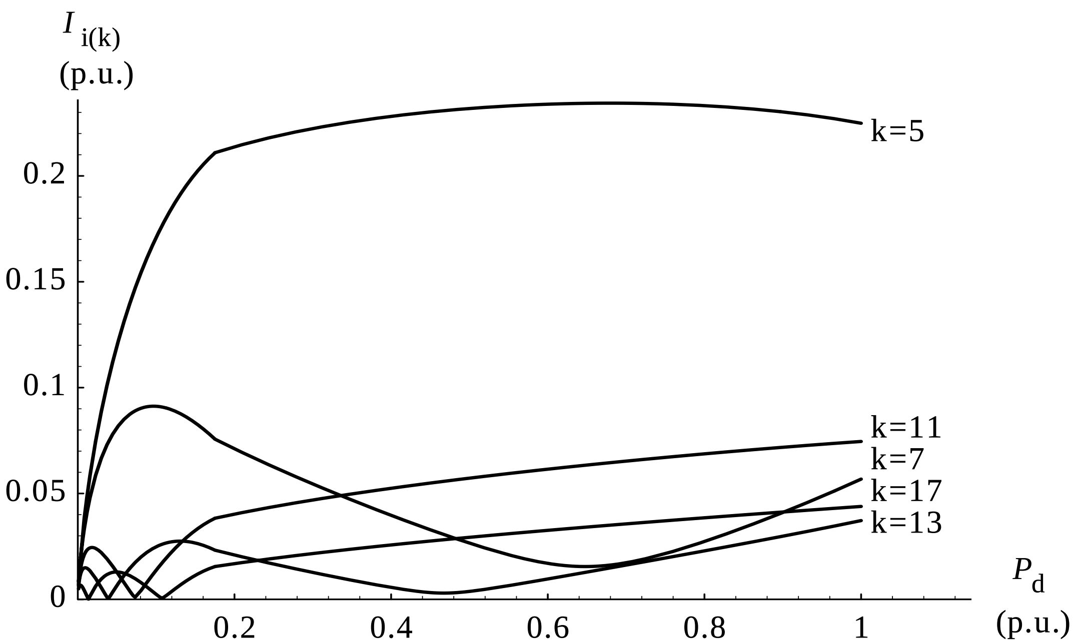

Figure 2.18 The magnitude of the current harmonics as a function of power. At rated power the dc current ripple is 35 % peak-to-peak. The harmonics are calculated from a wave shape including the effect of changing fire angle but not including overlap.

To find the peak-to-peak value of the ripple, the integral is evaluated with a lower limit t_5 and an upper limit t_6. The integration interval is equal to the part of the voltage ripple period where the voltage over the smoothing inductance is positive. The voltage on booth sides of the inductance as well as the dc current can be seen in Figure 2.19. The firing angle is 150˚.

Now the relation between peak-to-peak ripple, ac voltage, smoothing inductance and firing angle can be expressed as

$$\Delta I_{\mathrm{di\ p\text{-}p}} = \int_{t_5}^{t_6} \frac{\sqrt{2}\,U_{\mathrm{i}}}{L_{\mathrm{tot}}} \left(\sin(\omega t + \frac{\pi}{3}) + \frac{3}{\pi}\cos(\alpha) \right) \mathrm{d}t \qquad (2.25)$$

where
- $L_{\mathrm{tot}} = L_{\mathrm{di}} + 2\,L_{\mathrm{i\,com}}$
- U_{i} is the inverter ac voltage
- t_5: the firing time of a thyristor
- t_6: the time the voltage over the inductance becomes negative

The time instants t_5 and t_6 are determined by the following equations

$$t_5 = \frac{\alpha}{\omega} \qquad (2.26)$$

$$\sin(\omega t_6 + \frac{\pi}{3}) = -\frac{3}{\pi}\cos(\alpha_{\mathrm{N}}) \quad \text{and} \quad \alpha < \omega\, t_6 < \frac{4\pi}{3} \qquad (2.27)$$

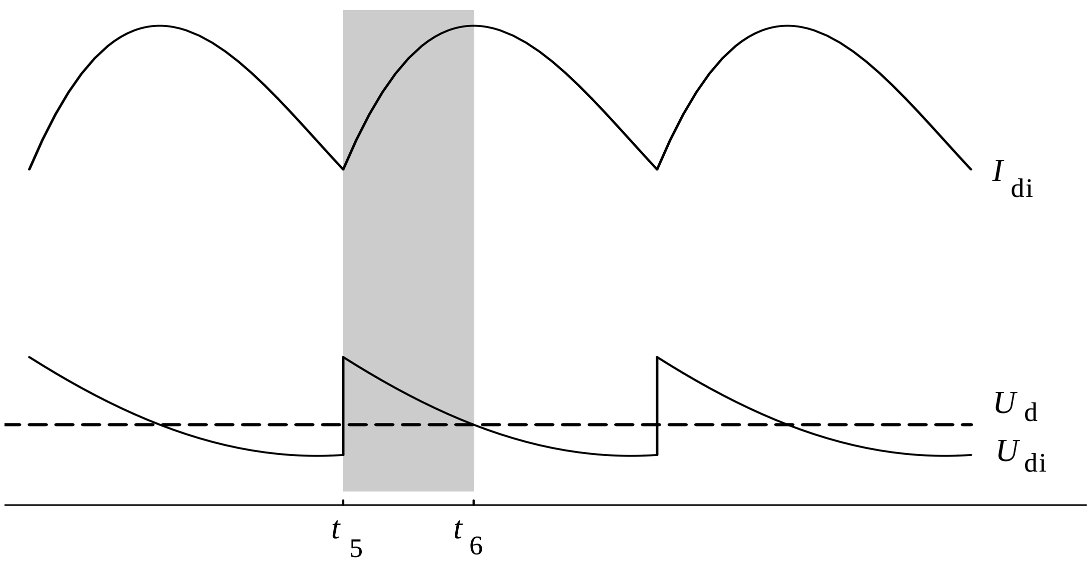

Figure 2.19 The inverter dc voltage U_{di}, dc capacitor voltage U_d and the inverter dc current I_{di}. The integration interval to find the peak-to-peak value is from t_5 to t_6.

For a thyristor inverter the firing angle α is about 150° to 155° at rated voltage.

2.4.5 Dc capacitance

When L_{dr} and L_{di} have been chosen the capacitance C_d can be calculated. It is determined by the desired resonance frequency

$$C_d = \frac{1}{(L_{dr} + 2\, L_{r\,com})\,(2\,\pi\, f_r)^2} \tag{2.28}$$

where f_r is the chosen resonance frequency for the rectifier side harmonics.

If C_d is very large the values of the inductances already calculated can of course be increased. An important reason to keep them small is, however, their resistive losses. The losses must be included in such a trade-off between capacitance and inductance.

2.4.6 Resonance damping

The resonance of the dc filter can be damped by means of an RLC circuit tuned to the resonance frequency, see Figure 2.20. If only one damping circuit should be used and both the rectifier side and the inverter side resonance frequencies must be damped, the dc filter including the commutation inductances, must be symmetrical. In this way the two resonance frequencies become equal because the total smoothing inductance on both sides are equal

$$L_{di} + 2\, L_{i\,com} = L_{dr} + 2\, L_{r\,com} \tag{2.29}$$

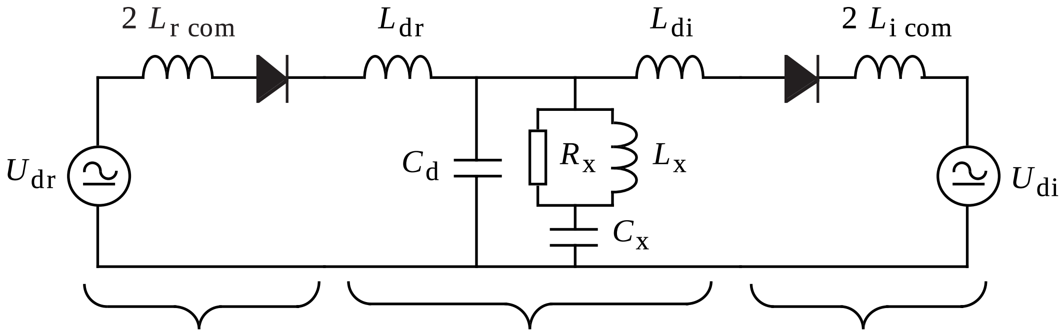

Figure 2.20 The dc filter with damping circuit, rectifier and inverter model.

The the effect of the damping circuit on the transfer function of the dc filter is shown in Figure 2.21. For high harmonics (>100 Hz) the damping circuit can be neglected and considered as an open circuit.

2.4.7 Dc filter calculations for the design example system

The design example generator and converter system has the following data:

Ac voltage of the inverter	$U_{i\,N}$	= 500 V
Network angular frequency	ω_i	= 2π 50 rad/s
Inverter commutation reactance	$x_{i\,com}$	= 5 %
Firing angle at rated load	α_N	= 155°
Rated dc current	$I_{d\,N}$	= 500 A
Rated generator voltage	$U_{a\,N}$	= 475 V
Rated generator angular frequency	$\omega_{g\,N}$	= 2π 60 rad/s
Rect. commutation reactance	$x_{r\,com}$	= 12.6 %
Network per unit base impedance	$Z_{b\,net}$	= 0.69 Ω
Generator per unit base impedance	$Z_{b\,g}$	= 0.67 Ω

The damping circuit is not included in this design.

The peak-to-peak ripple of the inverter side dc current I_{di} at rated power is chosen to 35 % of the rated dc current. Then the value of L_{di} can be calculated from Equations (2.25), (2.26) and (2.27)

$$t_5 = \frac{\alpha_N}{\omega_i} = 8.61 \text{ ms} \qquad (2.30)$$

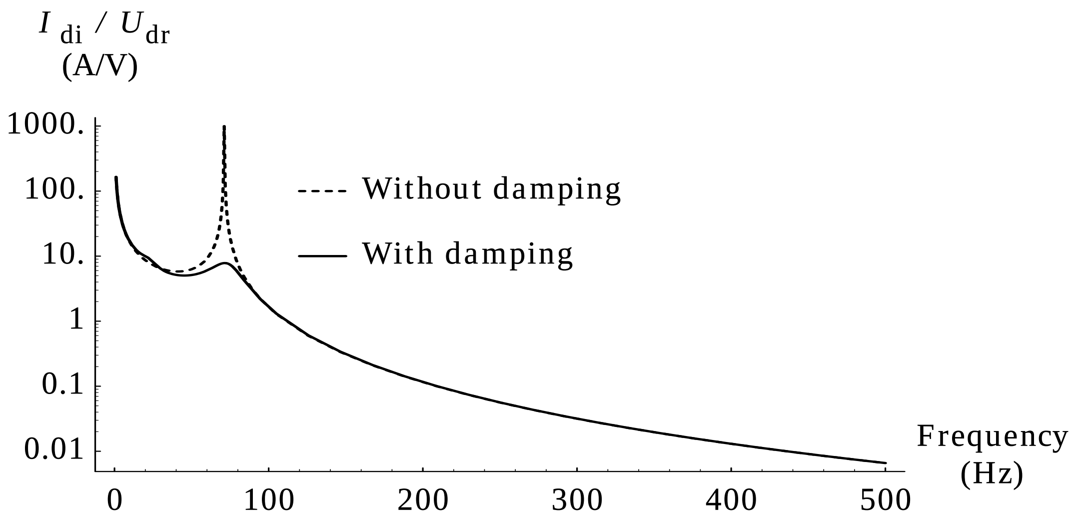

Figure 2.21 The transfer function of the dc filter with and without damping.

$$\sin(\omega_i \; t_6 + \frac{\pi}{3}) = \frac{3}{\pi} \; \cos(\alpha_N) \qquad \text{and} \qquad \alpha < \omega_i \; t_6 < \frac{4\,\pi}{3} \qquad \Rightarrow$$

$$\Rightarrow \qquad t_6 = 10.0 \text{ ms}$$
(2.31)

$$L_{di} + 2\,L_{i\,com} = \frac{\sqrt{2}\,U_{i\,N}}{0.35\,I_{d\,N}} \int_{t_5}^{t_6} \left(\sin(\omega_i\,t + \frac{\pi}{3}) + \frac{3}{\pi}\cos(\alpha_N) \right) \mathrm{d}t =$$

$$= \frac{\sqrt{2}\,U_{i\,N}}{0.35\,I_{d\,N}} \left[\frac{-\cos(\omega_i\,t + \frac{\pi}{3})}{\omega_i} + t\,\frac{3}{\pi}\cos(\alpha_N) \right]_{t_5}^{t_6} = 0.75 \text{ mH} \qquad (2.32)$$

The inverter commutation inductance is the transformer leakage inductance plus a small contribution from the network reactance that can be neglected

$$L_{i\,com} = x_{i\,com}\,\frac{Z_{b\,net}}{\omega_i} = 0.05\,\frac{0.69\,\Omega}{100\,\pi\text{ rad/s}} = 0.1 \text{ mH} \qquad (2.33)$$

This makes the dc filter inductance

$$L_{di} = 0.55 \text{ mH} \qquad (2.34)$$

The rated dc current is 500 A. The ripple current peak value is 0.5·35 % times the rated dc current. That makes the peak value of the dc current

$$\hat{I}_{\mathrm{di}} \approx \left(1 + \frac{0.35}{2}\right) \bar{I}_{\mathrm{di}} = 590 \text{ A} \tag{2.35}$$

The r.m.s. value of the rated current is approximately

$$I_{\mathrm{di}} \approx \bar{I}_{\mathrm{di}} = 500 \text{ A} \tag{2.36}$$

The inverter side smoothing reactor should have a core large enough for 590 A peak current, but the inductor winding needs only be rated for about 500 A r.m.s. value, and the inductance should be 0.55 mH.

The rectifier side smoothing inductance is calculated using Equations (2.21) and (2.22)

$$\sin(\omega_{\mathrm{g\,N}}\ t_{\mathrm{x}} + \frac{\pi}{3}) = \frac{3}{\pi} \quad \Rightarrow \quad \omega_{\mathrm{g\,N}}\ t_{\mathrm{x}} = \begin{cases} 0.222 \pm \mathrm{n}\ 2\ \pi \\ 0.825 \pm \mathrm{n}\ 2\ \pi \end{cases} \text{rad} \tag{2.37}$$

$$0 < \omega_{\mathrm{g\,N}}\ t_3 < \frac{\pi}{6} \quad \Rightarrow \quad \mathrm{t}_3 = 0.59 \text{ ms}$$

(2.38)

$$\frac{\pi}{6} < \omega_{\mathrm{g\,N}}\ t_4 < \frac{\pi}{3} \quad \Rightarrow \quad t_4 = 2.19 \text{ ms}$$

(2.39)

$$L_{\mathrm{dr}} + 2\ L_{\mathrm{r\,com}} = \frac{\sqrt{2}\ U_{\mathrm{a\,N}}}{\Delta I_{\mathrm{dr\ \ p\text{-}p}}} \int_{t_3}^{t_4} \left(\sin(\omega_{\mathrm{g\,N}}\ t\ +\ \frac{\pi}{3})\ -\ \frac{3}{\pi} \right) \mathrm{d}t\ =$$

$$= \frac{\sqrt{2}\ U_{\mathrm{a\,N}}}{0.35\ I_{\mathrm{d\,N}}} \left[\frac{-\cos(\omega_{\mathrm{g\,N}}\ t + \frac{\pi}{3})}{\omega_{\mathrm{g\,N}}}\ +\ t\ \frac{3}{\pi} \right]_{t_3}^{t_4} = 0.18 \text{ mH} \tag{2.40}$$

The commutation inductance of the generator is 12.6%

$$L_{\mathrm{r\,com}} = x_{\mathrm{r\,com}}\ \frac{Z_{\mathrm{b\,g}}}{\omega_{\mathrm{g\,N}}}\ =\ 0.126\ \ \frac{0.67\ \Omega}{60\ 2\ \pi\ \mathrm{rad/s}}\ = 0.224 \text{ mH} \tag{2.41}$$

which makes the rectifier dc inductance unnecessary.

$$L_{dr} = 0 \text{ mH} \qquad (2.42)$$

Even without the rectifier inductance the ripple of the rectifier dc current will only be about 70 A.

The dc capacitance is determined by the chosen resonance frequency. In this example the rectifier side resonance frequency is chosen to be 75 Hz. From Equation (2.28) the dc capacitance can be calculated

$$C_d = \frac{1}{(L_{dr} + 2\, L_{r\,com})\, (2\, \pi\, f_r)^2} = 10\,000\ \mu\text{F} \qquad (2.43)$$

The filter has now two resonance frequencies. The rectifier side resonance frequency is 75 Hz and the inverter side resonance frequency is

$$f_i = \frac{1}{2\, \pi \sqrt{(L_{di} + 2\, L_{i\,com})\, C_d}} = 58 \text{ Hz} \qquad (2.44)$$

If both resonances must be damped with one damping circuit the rectifier should be equipped with a reactor to make the resonance frequency equal on both sides. In that case

$$L_{dr} = L_{di} + 2\, L_{i\,com} - 2\, L_{r\,com} = 0.3 \text{ mH} \qquad (2.45)$$

The losses of the dc filter have not been calculated exactly, but they are estimated to be 0.7 % at rated load.

2.5 Inverter

Major reasons to choose the line-commutated thyristor inverter are the high efficiency, about 99 %, and the low price compared with other inverter types. Disadvantages are that it generates harmonic currents and consumes reactive power. The thyristor inverter is also difficult to protect at network faults.

2.5.1 Inverter pulse number

Large thyristor inverters are often made of two six-pulse bridges in a twelve-pulse connection to reduce the current harmonics. The twelve-pulse connection eliminates every second of the characteristic harmonics generated from a six-pulse inverter. This is done by connecting the two six-pulse inverters in series on the dc side, see Figure 2.22. On the ac side they are connected to two phase-shifted three-phase systems created by a three-winding transformer.

The drawbacks of the twelve-pulse connection for a medium size wind turbine generator system are both technical and economical.

The first technical drawback is that if the reactive power must be compensated, the network harmonic filters for the twelve-pulse connection will not be smaller than the ones used for a six-pulse bridge. The size of the filter is determined by the reactive power consumed by the inverter and the twelve-pulse inverter consumes as much reactive power as the six-pulse inverter.

In the twelve-pulse connection the filtering must be made on either both low voltage three-phase systems or on the high-voltage side of the transformer. Both these alternatives complicate the design and the manufacturing. A

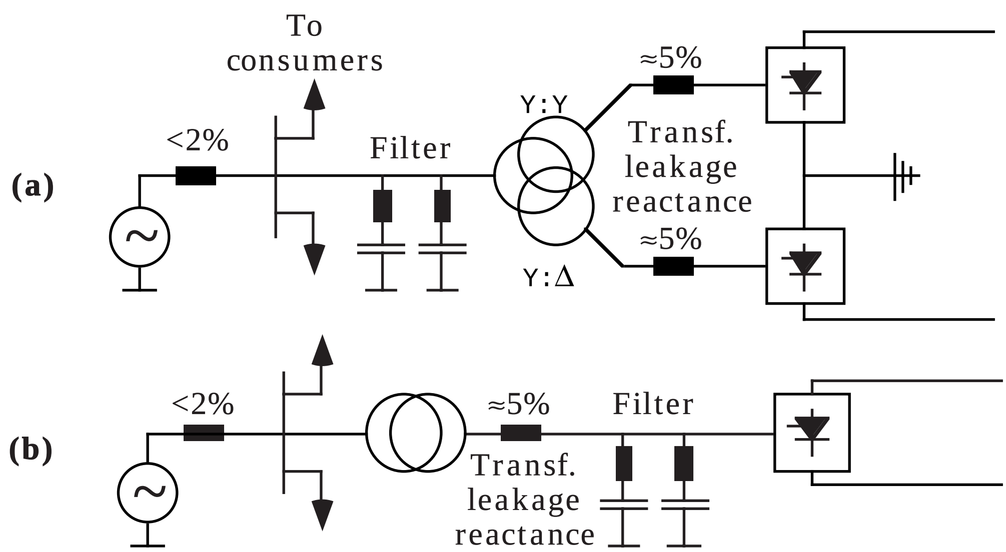

Figure 2.22 (a) Twelve-pulse and (b) six-pulse connected inverter. Equivalent single line scheme including the transformer leakage reactance and network short-circuit reactance.

filter connected to the 10 kV network can not easily be integrated with the windmill electrical system. If the filter of the twelve-pulse inverter is connected to the network side of the transformer it does not benefit of the leakage inductance of the transformer which makes a filter on the low voltage side several times more effective. In Figure 2.22 it can be seen that the harmonic voltages of the network, for the six-pulse connection, are only a fraction of the harmonic voltages of the filter. The harmonic voltages are reduced because the voltage of the filter is divided by the network impedance and the transformer impedance. In this example the harmonic voltages of the filter are reduced at least to 2/7. For the twelve-pulse connection the harmonic voltages of the filter are instead the same as those of the network. The filter impedance must be lower in the twelve-pulse connection than in the six pulse connection to reduce the network harmonic voltages to an equally low level.

It is also easier to calculate the filtering effect and the resonance frequency if the filter is connected to the low voltage side of the transformer. The transformer reactance can for low harmonics be assumed to be substantially larger than the network impedance. Therefore, the usually unknown variations in the network impedance do not change the effect of the filter much. A filter connected directly to the network must also be designed to filter harmonics from other sources otherwise it might be overloaded. The filter connected on the low-voltage side of the transformer might also be burdened with harmonics from the network but to a much smaller extent.

The economical drawbacks of the twelve-pulse connection are a more expensive transformer and converter. The transformer is more expensive due to the doubled secondary windings. For small converters, less than about 1 MW, the six-pulse inverter is a standard equipment. It is cheaper to buy a large six-pulse inverter than to use two smaller inverters in a twelve-pulse connection.

A twelve-pulse connection is, for several reasons, not likely to be used in small systems, at least not in systems less than 1 MW. The transformer and the converter are more expensive. Even though every second of the harmonics are eliminated by the twelve-pulse inverter it is difficult to filter the rest.

2.5.2 Protection circuits

Short-circuit of the ac network can cause problems for the inverter, because the fuses will blow, if there is no turn-off circuit. The turn-off circuit must be capable of breaking the dc current of the inverter and the energy stored in the inverter inductance must be dissipated. A direct short-circuit at the inverter ac supply is one cause for this problem, but that is an unusual event. More important is that each time the high-voltage network is disconnected the dc current from the inverter will saturate the transformer core and the transformer will start to act as a short-circuit. This type of network fault is a difficult problem for the thyristor inverter. When the network voltage disappears the converter can not control the dc-current, hence the current increases uncontrollably until the fuses blow. The inverter does not suffer any damage of the short-circuit but it is expensive to have to change fuses in all wind turbine generator systems as soon as the network has had a failure. The inverter must therefore have ways to disconnect at over-current. This can be achieved by a turn-off circuit connected to the three thyristors on one side of the inverter.

An example of a turn-off circuit is shown in Figure 2.23. The capacitor of the turn-off circuit should always be charged to a positive voltage that is used to turn off the conducting thyristor in the upper part of the six-pulse inverter. The dc current is instead forced to pass through the varistor of the turn-off circuit. Energy stored in L_{di} is dissipated in the varistor and the current decreases to zero within a few milliseconds. A turn-off circuit can be triggered by over-current. At the same time as the turn-off circuit is triggered the

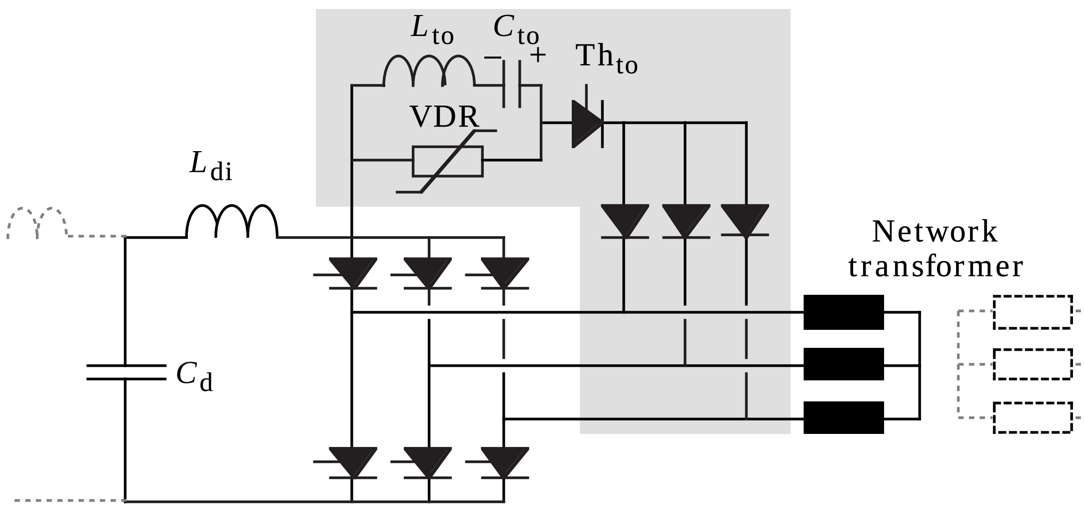

Figure 2.23 Thyristor inverter, turn-off circuit (shaded) and network transformer.

inverter thyristor firing will be blocked.

Thyristor converters for high power, several MW, are often made without fuses and with fast ac breakers instead. This technique might be useful also for smaller converters instead of a turn-off circuit. The difference between converters with fuses and converters with fast breakers is that the thyristors must withstand higher fault currents and for a longer time if they are only protected by fast breakers. An other drawback is that fast breakers are very expensive.

2.5.3 Design example

As the design example inverter an ABB Tyrak Midi II is chosen. It is a two-quadrant six pulse thyristor module with a rated current of 530 A and a rated ac voltage of 500 V. The rated dc voltage is then 600 V. The total losses at rated current are 2200 W, at 50 % of rated current 1200 W and at no load 350 W. The losses of the inverter can be separated into a constant power loss, a current-independent voltage drop and a resistive voltage drop. Expressed in per unit of the 300 kW system the inverter losses are

$$p_{\text{loss i}}(i_\text{d}) = 0.12\,\% + 0.52\,\%\ i_\text{d} + 0.10\,\%\ i_\text{d}^2 \qquad (2.46)$$

The total losses are 0.74 % at the rated current. The losses with cables, fuses, main switch and other auxiliary parts are of course higher. Since these losses are equal for both variable-speed and constant-speed systems they are not included in the loss model.

3 Model of generator and converter losses

In this chapter theoretical models of the losses of a synchronous generator, a diode-thyristor converter and a gear are derived. The model of the generator losses is verified for a 50 kVA generator. This loss model can be used to calculate the generator shaft torque from measurements of the armature power and the shaft speed. It also allows efficiency optimization by controlling the generator flux. Finally, the model parameters are derived for the 300 kW design example system.

The friction and windage losses as well as the core losses are calculated and expressed as their equivalent braking torque on the generator shaft. That is convenient in the torque control point of view. It is also a natural way to calculate friction and windage losses and core losses because they have the character of a speed-dependent braking torque. The copper losses in the armature and field windings are not speed-dependent and they are therefore expressed as power losses.

The loss model is a per unit model, but note that it is not the usual per unit system that is used. Since the generator and converter have many separate circuits, different base values can be used, and are used, for the currents in the different circuits. The principle of the used per unit system is that all powers in all circuits should be comparable to each other while all currents, voltages, speed and torque should have the value of 1 p.u. at rated load of the generator converter system. To be able to see easily what effect each loss component has on the system efficiency, all powers and losses are related to the rated input power of the system. The per unit quantities are generally denoted by lower case letters and the normal quantities by upper case letters. The exception is the speed n which in per unit is denoted n'.

3.1 Model of machine losses

The losses in the machine can be divided into several independent parts, see Figure 3.1.

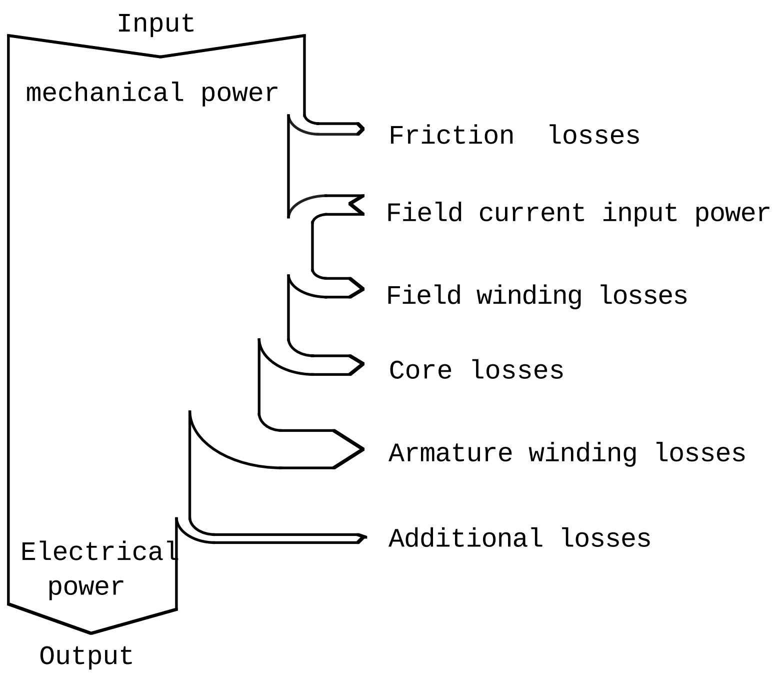

Figure 3.1 A schematic picture of the power flow in the synchronous generator when the field current is fed by slip rings.

3.1.1 Friction and windage loss torque

The friction and windage losses include the friction losses of the bearings, the windage losses in the machine and the losses of the cooling fan. The bearings are usually roller bearings which can be assumed to have an almost constant braking torque [8]. The windage and fan loss torque is mainly quadratically dependent on the shaft speed. There is also a small component of the friction and windage loss torque that is linearly dependent on the shaft speed.

For a standard four-pole generator it is assumed that the friction and windage loss torque can be described as a constant torque and a torque proportional to the square of the generator speed. The manufacturer can give values of the friction and windage torque at rated speed in per unit, $t_{\mu\ N}$. The standstill torque $t_{\mu\ ss}$ is either given by the manufacturer or it is measured or estimated. The windage and friction torque can be expressed in per unit as

$$t_{\mu}(n_g') = t_{\mu\ ss} + (t_{\mu\ N} - t_{\mu\ ss})\ n_g'^2 \quad (3.1)$$

where n_g' is the per unit shaft speed of the generator.

3.1.2 Core losses

The core losses P_{Fe} can be separated into two parts, hysteresis losses P_{Hy} and eddy current losses P_{Ft}. Both are functions of the magnitude of the alternating flux B and the frequency f.

$$P_{Fe} = P_{Hy}(B,f)) + P_{Ft}(B,f) \tag{3.2}$$

Eddy current losses in an iron core can be expressed as

$$P_{Ft}(B,f) \sim B^2 \; f^{\,y} \tag{3.3}$$

where $1.9 \leq y \leq 2$, according to [9]. In the same way the hysteresis losses can be expressed as

$$P_{Hy}(B,f) \sim B^x \; f \tag{3.4}$$

where $1.5 \leq x \leq 2.3$, according to [9].

For electrical machines these functions are generally used with y = 2 and x = 2. These values are within the limits found in [9]. To use them simplifies the calculation of the total core losses because both the eddy current losses and the hysteresis losses then change in the same way with changing flux. That allows a separation of the total core losses into a product of the flux dependent hysteresis losses and a frequency-dependent eddy current factor ($1 + f$ C) that includes the effect of the eddy current losses

$$P_{Fe}(B,f) = P_{Hy}(B,f) \; (1 + f \, C) \tag{3.5}$$

where C is a constant and P_{Hy}(B,f) is

$$P_{Hy}(B,f) \sim \; B^2 \; f \tag{3.6}$$

The value of B in the above equations is usually the peak value of the alternating flux density. In an electric machine the flux linkage can be used in the loss formulas, instead of the peak value of the flux, if the flux wave-shape does not change too much when the load change.

The generator flux wave shape is not constant due to armature reaction and saturation. But the only practical way to estimate the peak value of the flux is by using the flux linkage of the stator winding. That method is used for this loss model. Instead of the flux density and frequency, B and f, the flux linkage and the generator speed, Ψ and n_g, can be used

$$P_{Fe}(\Psi, n_g) \sim \Psi^2 \; n_g \,(1 + n_g \, C) \tag{3.7}$$

Since the hysteresis loss function includes a flux-dependent factor times the shaft speed the power losses can be calculated as an equivalent braking torque

$$T_{Fe} = \frac{P_{Fe}}{\omega_g} \sim \frac{P_{Fe}}{n_g} \tag{3.8}$$

$$\Rightarrow \quad T_{Fe}(\Psi, n_g) = C_{Hy} \; \Psi^2 \; (1 + n_g \, C_{Ft}) \tag{3.9}$$

where C_{Hy} and C_{Ft} are machine dependent core loss constants.

The use of the speed as a variable instead of the frequency is chosen because the speed is already used as a variable for the friction and windage losses and it is usual to measure the generator speed in a wind turbine generator system. For a synchronous generator in steady state operation the speed and frequency are equal when they are expressed in per unit.

The presented theory does not take the effects of saturation into account. The saturation makes the core losses increase more than the theory predicts when the flux increases. To approximate the core loss torque with a resonable accurracy is, however, possible even with this simple model. Only the core loss torque at rated flux and speed as well as the eddy current factor at rated speed have to be known. By using values of the core loss torque at rated flux which includes the effect of saturation the absolute error of the core losses is kept low even though the theoretical flux dependency of the core loss torque is not exact. The hysteresis loss function will only have a quadratic term according to the theoretical equation. The per unit model of the core loss torque is

$$t_{Fe}(n_g', \psi) = \frac{t_{Fe\,N}}{1 + C_{Ft}} \; \psi^2 \; (1 + C_{Ft} \, n_g') \tag{3.10}$$

where t_{feN} is the total core loss torque at rated load and rated speed and C_{Ft} is the ratio of the eddy current losses $P_{Ft\,N}$ and the hysteresis losses $P_{Hy\,N}$ at rated flux and speed

$$C_{Ft} = \frac{P_{Ft\,N}}{P_{Hy\,N}} \tag{3.11}$$

3.1.3 Winding losses

For sinusoidal currents the copper losses of the armature windings can be expressed as

$$P_{Cu\,a} = 3\, R_a\, I_a^2 \tag{3.12}$$

where I_a is the r.m.s. armature current and R_a is the equivalent per phase armature reistance. Expressed in per unit the armature copper losses are

$$p_{Cu\,a} = r_a\; i_a^2 \tag{3.13}$$

For nonsinusoidal currents the calculation of the losses can be much more complicated. The fundamental current component and the current harmonics do not meet the same effective resistance. The skin effect gives rise to a higher resistance for the harmonics. However, when using a diode rectifier the low-order harmonics dominate and the resistance for the fifth and seventh harmonics can for a normal stator winding be assumed to be about the same as the resistance for the fundamental component. Therefore, the model uses the measured total r.m.s. value of the armature current to calculate the armature winding losses.

The field winding losses can be calculated in the same way as the armature winding losses

$$P_{Cu\,f} = R_f\; I_f^2 \tag{3.14}$$

where R_f is the field winding resistance and I_f is the field current. Expressed in per unit the field winding losses are

$$p_{\mathrm{Cu\,f}} = r_{\mathrm{f}}\, i_{\mathrm{f}}^{2} \tag{3.15}$$

3.1.4 Exciter losses

Most four-pole synchronous generators in the range of 10 kW to 1 MW have an integrated exciter with a rotating rectifier. The exciter is a small generator mounted on the shaft of the main generator. It generates the field current of the main generator without the use of slip rings. Since it is only supplying the power to the rotor windings, the rated power of the exciter is only 1-2 % of the main generator rated power. The exciter and main generator circuits are shown in Figure 3.2.

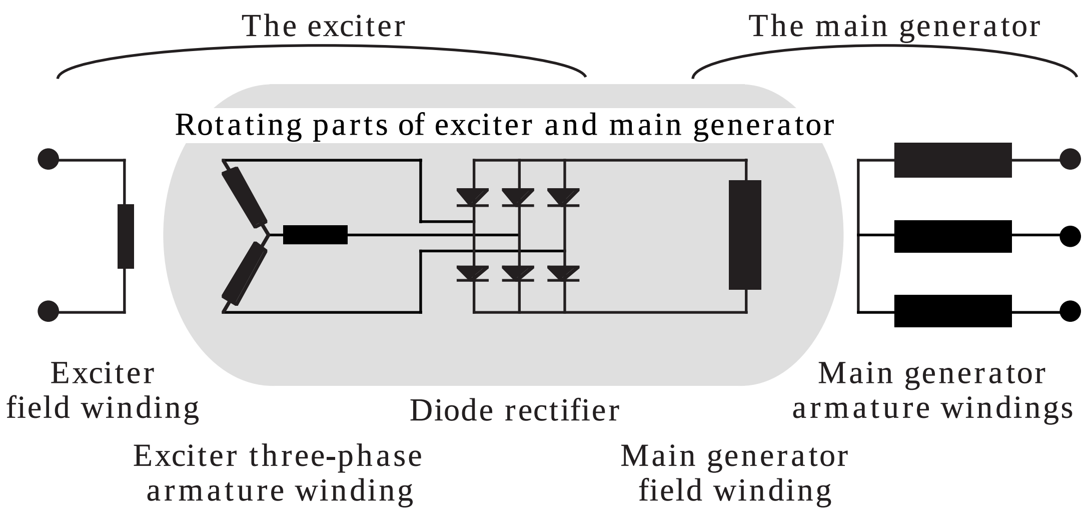

Figure 3.2 Circuit diagram of the exciter and the main generator.

The model of the generator losses can be extended to include the exciter losses. The main difference is that when the exciter is used the power consumed in the rotor windings is fed by the exciter from the mechanical shaft power. Therefore, there is a contribution to the braking torque from the losses in the rotor windings. The other losses of the exciter, its stator winding losses, core losses and additional losses, can be neglected. Even if the exciter efficiency is very low these losses are small. The total copper losses of the rotor windings are

$$p_{\mathrm{Cu\,rotor}}(i_{\mathrm{f}}) = r_{\mathrm{rotor}}\, i_{\mathrm{f}}^{2} \tag{3.16}$$

where r_{rotor} is the resistance of the main generator field winding and two times the per phase resistance of the rotor winding of the exciter r_{aE}

$$r_{rotor} = r_f + 2\, r_{aE} \tag{3.17}$$

One problem in finding the rotor losses in a generator with exciter is that the main field current is not possible to measure. In some way the field current must be modelled as a function of the exciter current or, as used later, by estimating the field current from the flux linkage and the armature current.

3.1.5 Additional losses

One part of the additional losses is the losses in the damper windings. At steady state operation and sinusoidal armature currents the damper winding currents are almost zero. They should not cause losses when the generator is loaded resistively. However, when the generator is loaded by a diode rectifier there are steady state losses in the damper windings. Because of the harmonics in the armature mmf wave, currents flow in the damper windings. The currents in the damper windings are approximately proportional to the armature current. Other parts of the additional losses are for instance the core losses associated with the distortion of the flux wave and the stray flux in the end regions that cause extra core losses.

According to [10] the additional losses can be approximated as being proportional to the square of the armature current. They can, therefore, easiest be included in the loss modell by adding a fictitious resistance to the armature resistance in the loss calculations. If the additional losses at rated load, $P_{ad\,N}$, are known, the fictitious armature resistance of the additional losses can be calculated as

$$R_{ad} = \frac{P_{ad\,N}}{3\; I_{a\,N}^2} \tag{3.18}$$

The additional losses are, expressed in per unit

$$p_{ad\,N} = r_{ad}\; i_a^2 \tag{3.19}$$

3.1.6 Complete generator loss model

The total per unit generator losses can be modelled as the sum of five different types of losses, using only four variables. For a generator with slip rings the losses are

$$p_{\text{loss g}}(n_g',\psi,i_a,i_f) =$$

$$= n_g' \left(t_{\mu}(n_g') + t_{\text{Fe}}(n_g',\psi) \right) + p_{\text{Cu a}}(i_a) + p_{\text{Cu f}}(i_f) + p_{\text{ad}}(i_a) \qquad (3.20)$$

If slip rings are used, the field winding losses are not fed from mechanical power from the generator shaft and therefore they do not contribute to the braking torque

$$t_{\text{loss g}}(n_g',\psi,i_a) = t_{\mu}(n_g') + t_{\text{Fe}}(n_g',\psi) + \frac{p_{\text{Cu a}}(i_a) + p_{\text{ad}}(i_a)}{n_g'} \qquad (3.21)$$

where the different losses are defined as

$$t_{\mu}(n_g') = t_{\mu\,\text{ss}} + (t_{\mu\,\text{N}} - t_{\mu\,\text{ss}})\, n_g'^2 \qquad (3.1)$$

$$t_{\text{Fe}}(n_g',\psi) = \frac{t_{\text{Fe N}}}{1 + C_{\text{Ft}}}\, \psi^2\, (1 + C_{\text{Ft}}\, n_g') \qquad (3.10)$$

$$p_{\text{Cu a}}(i_a) = r_a\, i_a^2 \qquad (3.13)$$

$$p_{\text{Cu f}}(i_f) = r_f\, i_f^2 \qquad (3.15)$$

$$p_{\text{ad}}(i_a) = r_{\text{ad}}\, i_a^2 \qquad (3.19)$$

The loss torque formula, Equation (3.21), can be used to calculate the shaft torque if the armature power p_a is known

$$t_g(p_a,n_g',\psi,i_a) = \frac{p_a}{n_g'} + t_{\text{loss g}}(n_g',\psi,i_a) \qquad (3.22)$$

If the total generator losses should be minimized also the field losses must be included. Then the power loss formula, Equation (3.20), is used to minimize the total losses by changing the generator flux.

For generators having an integrated exciter the power loss formula is changed. The total rotor losses increase because both the field winding losses and the exciter winding losses are included

$$p_{\text{loss g}}(n_g',\psi,i_a,i_f) =$$

$$n_g'\left(t_{\mu}(n_g') + t_{\text{Fe}}(n_g',\psi)\right) + p_{\text{Cu a}}(i_a) + p_{\text{ad}}(i_a) + p_{\text{Cu rotor}}(i_f) \qquad (3.23)$$

In this case the rotor losses also contribute to the braking torque:

$$t_{\text{loss g}}(n_g',\psi,i_a,i_f) =$$

$$t_{\mu}(n_g') + t_{\text{Fe}}(n_g',\psi) + \frac{p_{\text{Cu a}}(i_a) + p_{\text{ad}}(i_a) + p_{\text{Cu rotor}}(i_f)}{n_g'} \qquad (3.24)$$

where the rotor losses are defined as

$$p_{\text{Cu rotor}}(i_f) = r_{\text{rotor}}\ i_f^{\,2} \qquad (3.16)$$

3.1.7 Calculating the generator flux

In order to use the model of the generator core losses, the airgap flux linkage of the generator must be known. At no load the generator armature voltage divided by the speed of the generator is used to calculate the flux linkage. When the generator is loaded, the same method can be used. The difference is that the flux linkage is then calculated using the induced voltage of the armature divided by the generator speed. The induced voltage E_a must be calculated from the armature voltage U_a. For sinusoidal currents the induced voltage can be found simply by adding the voltage drop in the armature winding. For resistive load the induced voltage is

$$E_a = \sqrt{(U_a + R_a I_a)^2 + (\omega L_{a\sigma} I_a)^2} \qquad (3.25)$$

where $L_{a\sigma}$ is the armature leakage inductance.

If a diode rectifier is used the generator currents are nonsinusoidal and the equation will be different. Due to the commutation inductance the voltage drop is larger than for sinusoidal currents and it can be found if the model in Figure 2.11 is used. There the induced armature voltage can be calculated by adding the voltage drop over $R_{r\,com}$ to the measured dc voltage and dividing by $(3\sqrt{2})/\pi$. The induced voltage is calculated, neglecting the armature resistance

$$E_a = \frac{\pi}{3\sqrt{2}} (U_d + R_{r\,com}\, I_d) \tag{3.26}$$

From this induced voltage of the armature winding the generator flux linkage can be calculated

$$\Psi = \frac{E_a}{\omega_g} = \frac{E_a}{p\, n_g} \tag{3.27}$$

where p is the pole pair number of the generator

3.1.8 Estimating the field current

For a generator magnetized by an integral exciter the field current can not be measured. Therefore, it has to be estimated. From a simple linear theory, neglecting saturation effects, the total magnetization current of the generator can be calculated. For a linear generator the magnetization current is proportional to the flux linkage. The magnetization current phasor is the field current phasor plus the armature current phasor. A resonable approximation for a generator loaded by a diode rectifier is that the fundamental of the armature current is in phase with the induced armature voltage. That is equal to assuming that the rectifier commutations are instantaneous.

In Figure 3.3 the current distributions of the machine can be seen. $\underline{E}_a$ is the induced airgap voltage phasor and $\underline{I}_m$ is the total magnetization current phasor. From the figure it can be seen that

$$|\underline{I}_m|^2 + |\underline{I}_a|^2 = |\underline{I}_f|^2 \tag{3.28}$$

where $$\begin{cases} |\underline{I}_m| = K_m\, |\underline{\Psi}| = K_m\, \Psi \\ |\underline{I}_a| = K_a\, I_a \\ |\underline{I}_f| = K_f\, I_f \end{cases}$$

K_m, K_a and K_f are machine dependent factors. They are used to reduce all the currents to equivalent airgap current densities. By using these expressions for the current phasor magnitudes in Equation (3.28) the field current can be calculated

$$(K_f\, I_f)^2 = (K_m\, \Psi)^2 + (K_a\, I_a)^2 \tag{3.29}$$

The same equation can be used for the per unit quantities

$$(k_f\, i_f)^2 = (k_m\, \psi)^2 + (k_a\, i_a)^2 \tag{3.30}$$

where $\begin{cases} k_f = 1 + x_s^2 \\ k_m = 1 \\ k_a = x_s \end{cases}$ for the used per unit system

Saturation can also be included in this model if the flux linkage as a function of the magnetizing current is known. That function is then used instead of the linear relationship assumed here.

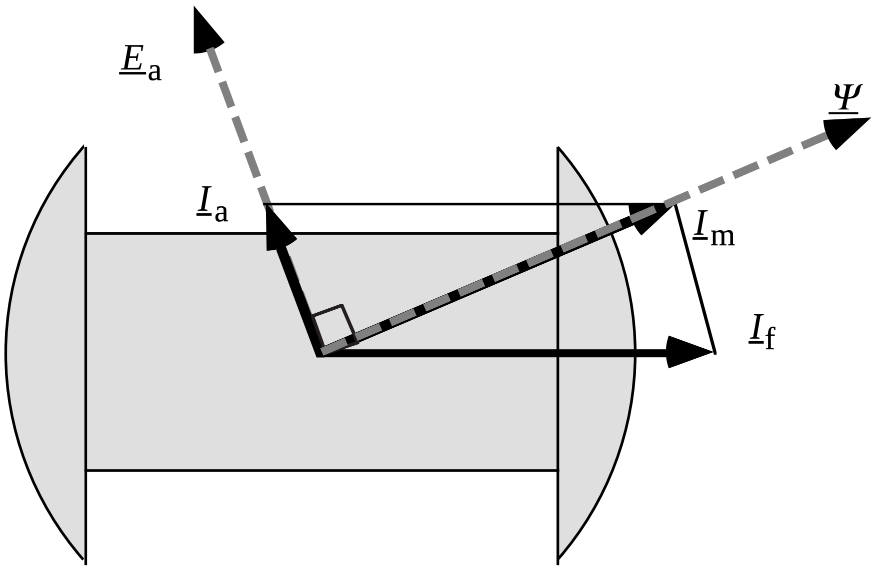

Figure 3.3 The generator currents, flux linkage and induced voltage phasors.

3.1.9 Parameters for the generator loss model

The parameters needed for the simplified model are found in Table 3.1. On the ordinary data sheet the stator resistance, field winding resistance, synchronous reactance and subtransient reactances can be found. Also the core losses at rated flux and speed, the friction losses at rated speed as well as the exciter armature resistance should be possible to get from the manufacturer but they are normally not explicitly found on the data sheet.

Table 3.1 Parameters for the proposed model of generator losses and parameters needed for the flux linkage and field current estimation.

Parameter	Description	Source
$t_{\mu\ N}$	Friction and windage torque at n_N	From the manufacturer*
$t_{\mu\ ss}$	Standstill friction torque	Measurement or estimation
$t_{Fe\ N}$	Core loss torque at ψ_N and n_N	From the manufacturer*
C_{Ft}	Eddy current constant	Measurement or estimation
r_a	Armature resistance	From data sheet
r_f	Field winding resistance	From data sheet
r_{aE}	Exciter per phase armature resistance	From the manufacturer*
r_{ad}	Equivalent resistance of the additional losses	Measurement or estimation
Parameters to estimate the flux linkage and the field current:		
x_s	Synchronous reactance	From data sheet
x''_d	Subtransient d-reactance	From data sheet
x''_q	Subtransient q-reactance	From data sheet

*) Data that the manufacturer should be able to give but that usually not are available on the data sheet.

The standstill friction torque, the eddy current constant and the additional losses at diode load are not necessarily known by the manufacturer and must somehow be estimated or measured. If the standstill friction torque and the eddy current constant should be estimated, the manufacturer can provide useful information. For instance, what bearings the generator has and what type of iron the stator is made of as well as its material data.
The loss model use several variables but only some of them have to be measured. The other variables can be calculated, see Table 3.2. In the wind turbine generator system only three quantities have to be measured to be able to use the loss model and the steady state torque control.

Table 3.2 Variables needed for the loss model.

Variable	
I_d	measured
U_d	measured
n_g	measured
P_a	$= I_d \; U_d$ – diode losses
I_a	$= 0.78 \; I_d$
Ψ	$= \dfrac{\pi \; (U_d + R_{r\,com} I_d)}{3\sqrt{2} \quad p \;\; n_g}$ (*
I_f	$= \dfrac{1}{K_f} \sqrt{(K_m \; \Psi)^2 + (K_a \; I_a)^2}$

*) p is the pole pair number of the generator

3.1.10 Errors of the generator model

The errors of the loss model are of three different types. First there is an error due to the simplifications and assumptions made. This error is often difficult to estimate since the simplifications usually are made because the real functions are not known. Secondly there is always an error in the determination of the model parameters. These errors can usually be estimated from instrument accuracy and measurement method. Finally, the parameters may change with the load and the environmental conditions. For example, winding resistances depend on the temperature.

3.1.11 Error in the windage and friction losses

The model of friction and windage torque is not exact due to the errors of the used parameters and the errors of the approximate speed dependency. The model has two parameters: the friction and windage torque at rated speed $t_{\mu\,N}$ and the standstill torque $t_{\mu\,ss}$. Both these parameters are determined by measurement or estimation. The error of the parameters can be estimated and their maximum and minimum value can be found. The variations in the speed dependency of the torque is much more difficult to find. It has only been estimated based on measurements on three different electrical machines. To estimate the total error of the friction and windage torque the worst case maximum and minimum friction and windage torque functions are estimated. It is here assumed that the maximum worst case torque has a linear term that at rated speed is as large as the quadratic term. Maximum torques at rated speed and standstill are used as parameters. The maximum torque is estimated

$$t_{\mu\,\max}(n_g') = t_{\mu\,ss\,\max} + (t_{\mu\,N\,\max} - t_{\mu\,ss\,\max})\ \frac{n_g' + n_g'^2}{2} \qquad (3.31)$$

The worst case minimum torque is assumed to have no first-order term. Minimum torques at rated speed and standstill are used as parameters

$$t_{\mu\,\min}(n_g') = t_{\mu\,ss\,\min} + (t_{\mu\,N\,\min} - t_{\mu\,ss\,\min})\ n_g'^2 \qquad (3.32)$$

If the model torque function and the estimated maximum and minimum torque functions are plotted in the same diagram, an estimation of the model error can be made, see Figure 3.4. In this case the error in the rated friction torque, $t_{\mu\,N}$, is assumed to be ±20 %. The error in the standstill friction torque, $t_{\mu\,ss}$, is assumed to be ±50 %. The total error of the friction and windage model is found to be about 0.25 times the friction torque at rated speed

$$\Delta T_\mu = 0.25\ T_{\mu\,N} = 0.25\ (\,t_{\mu\,N}\ T_N) \qquad (3.33)$$

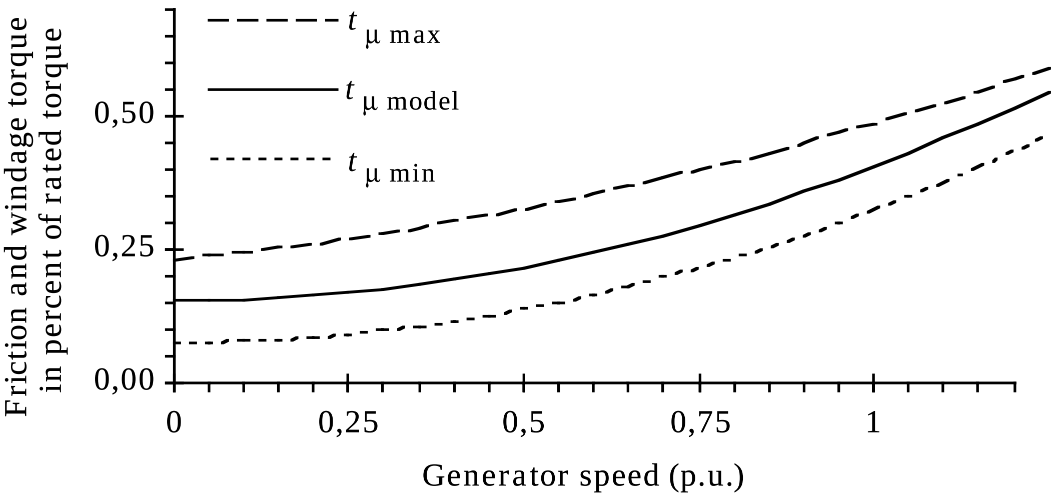

Figure 3.4 The model friction and windage torque and the estimated maximum and minimum limits for the torque.

Error in the core losses

The core loss torque model has two parameters: the core loss torque at rated load $t_{Fe\,N}$ and the eddy current constant C_{Ft}. The model of the core loss torque is

$$t_{Fe}(n_g',\psi) = t_{Fe\,N}\ \psi^2\ \frac{1 + C_{Ft}\, n_g'}{1 + C_{Ft}} \quad (3.10)$$

It is a product of the hysteresis loss torque and the eddy current factor. These two parts have different types of error. The parameters maximum and minimum value have to be estimated: $t_{Fe\,N\,min}$, $t_{Fe\,N\,max}$, $C_{Ft\,min}$ and $C_{Ft\,max}$. First the error of the hysteresis loss torque is estimated. Using x = 1.5 in Equation (3.4) and $t_{Fe\,N\,max}$ the maximum hysteresis loss torque is

$$t_{Hy\,max}(\psi) \sim \psi^{1.5}\ t_{Fe\,N\,max} \quad (3.34)$$

If x = 2.3 and $t_{Fe\,N\,min}$ is used the minimum hysteresis loss torque will be

$$t_{Hy\,min}(\psi) \sim \psi^{2.3}\ t_{Fe\,N\,min} \quad (3.35)$$

The hysteresis loss torque at rated flux is assumed to have an error of ±10 %. From Figure 3.5 the error of the hysteresis loss torque can then be estimated to be about 20 % of the hysteresis loss torque at rated flux. The worst case error of the hysteresis loss approximation is at about 0.5 p.u. flux linkage.

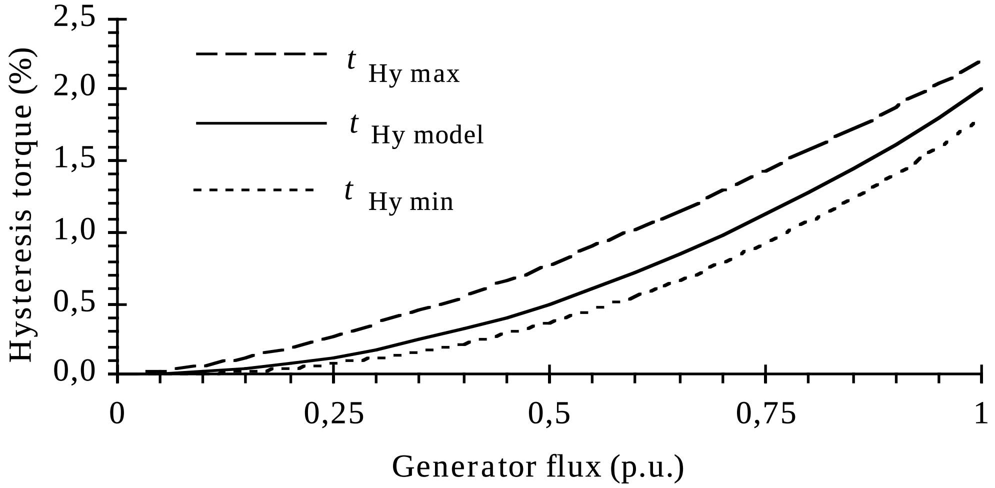

Figure 3.5 Model of hysteresis losses and an estimation of its error.

In Figure 3.6 the error of the eddy current factor is shown. The maximum eddy current factor $C_{Fe\,max}$ is derived from Equations (3.3) and (3.5). In Equation (3.3) y = 1.9 and $C_{Ft\,min}$ is used

$$C_{Fe\,max} = \frac{1 + C_{Ft\,min}\,(n_g')^{0.9}}{1 + C_{Ft\,min}} \quad (3.36)$$

From the same equations the minimum eddy current factor can be derived if y = 2.0 and $C_{Ft\,max}$ is used

$$C_{Fe\,min} = \frac{1 + C_{Ft\,max}\, n_g'}{1 + C_{Ft\,max}} \tag{3.37}$$

The error is larger at lower speed because the value of the core loss torque is known at rated speed. The error in the total eddy current factor can be estimated to be about 10 % when the error in C_{Ft} is assumed to be about 20 %.

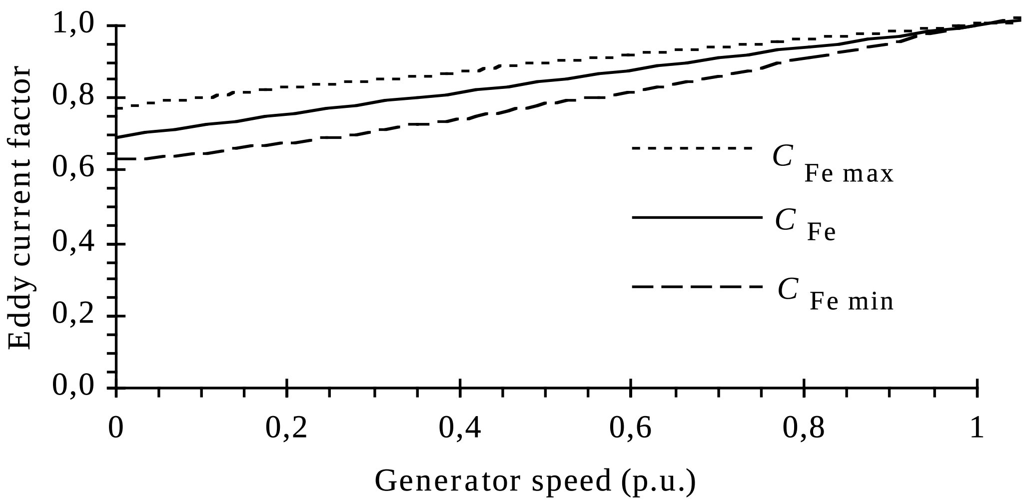

Figure 3.6 The simplified model of the eddy current factor and an estimations of its maximum and minimum values.

The total error of the core loss model can be found as 20 % of the core losses at rated load, due to the hysteresis torque error, plus 10 % of the actual core losses, due to the eddy current factor error. These figures of the errors are based on an error of the core losses at rated load of 10 % and an error of the eddy current constant C_{Ft} of 20 %. The total error is smallest at rated flux and speed and larger at lower speed and lower flux. For simplicity the total core loss error is assumed to be constant. In this example the core loss torque error is

$$\Delta T_{Fe} = (0.20 + 0.10)\, T_{Fe\,N} = 0.30\,(\, t_{Fe\,N}\;\; T_N) \tag{3.38}$$

Error in the winding losses

The theoretical formula for resistive losses can be assumed to be very accurate. The largerst error of the resistive winding losses is due to the temperature dependence of the winding resistance. In a normal wind turbine generator the winding temperature can in the extreme case vary between about –20˚ and +120˚ C. This gives a variation of the winding resistance of ±25 % if a resistance value for 50˚ C is used. In a generator rated for a temperature rise according to class B, max 80˚ C, it is however not usual with winding temperature outside the range of +10˚ to +90˚ C. The change of resistance is then ±15 % if a resistance value for 50˚ C is used.

The error of the winding losses is estimated to be about ±20 % of the actual losses. About 15 % is due to normal temperature changes and about 5 % due to an error in the measured winding resistance. The temperature of the windings may under extreme weather conditions pass these limits giving a larger error of the winding losses. In Sweden that will probably only occur for some percent of the time. The errors of the resistive winding losses can be expressed as

$$\Delta P_{Cu\ a} = 0.20\ P_{Cu\ a} = 0.20\ (3\ R_a\ I_a^2) = 0.20\ (r_a\ i_a^2\ P_N) \qquad (3.39)$$

$$\Delta P_{Cu\ f} = 0.20\ P_{Cu\ f} = 0.20\ (R_f\ I_f^2) = 0.20\ (r_f\ i_f^2\ P_N) \qquad (3.40)$$

If the error of the model must be reduced, the resistance value can be changed according to a measurement of the winding temperature.

Error in the additional losses

Since the mechanisms of the additional losses are not investigated, the error of their approximation can not be derived. If they are measured at rated load the error can be estimated to be less than 50 %

$$\Delta P_{ad} = 0.50\ P_{ad} = 0.50\ (3\ R_{ad}\ I_a^2) = 0.50\ (r_{ad}\ i_a^2\ P_N) \qquad (3.41)$$

Total model error

The error of the power loss is smaller at partial load than at rated load and the total error can be estimated as an error dependent on the speed, plus one part that changes with armature current and one that changes with the field current

$$\frac{\Delta P_{\text{loss}}}{P_{\text{N}}} = \left(\frac{n_{\text{g}}}{n_{\text{g N}}} \frac{\Delta T_{\mu}}{T_{\text{N}}} + \frac{n_{\text{g}}}{n_{\text{g N}}} \frac{\Delta T_{\text{Fe}}}{T_{\text{N}}} \right) + \left(\frac{\Delta P_{\text{Cu a}}}{P_{\text{N}}} + \frac{\Delta P_{\text{ad}}}{P_{\text{N}}} \right) + \frac{\Delta P_{\text{Cu f}}}{P_{\text{N}}} =$$

$$= (0.25\, t_{\mu \text{ N}} + 0.30\, t_{\text{Fe N}})\, n_{\text{g}}' + (0.20\, r_{\text{a}} + 0.50\, r_{\text{ad}})\, i_{\text{a}}^2 + 0.20\, r_{\text{f}}\, i_{\text{f}}^2 \qquad (3.42)$$

The error of the calculated power loss decreases to zero if the speed, armature current and field current all are decreasing to zero. The error can also be expressed as a loss torque error

$$\frac{\Delta T_{\text{loss}}}{T_{\text{N}}} = \frac{\Delta T_{\mu}}{T_{\text{N}}} + \frac{\Delta T_{\text{Fe}}}{T_{\text{N}}} + \frac{\Delta P_{\text{Cu a}} / n_{\text{g}}}{P_{\text{N}} / n_{\text{g N}}} + \frac{\Delta P_{\text{ad}} / n_{\text{g}}}{P_{\text{N}} / n_{\text{g N}}} + \frac{\Delta P_{\text{Cu f}} / n_{\text{g}}}{P_{\text{N}} / n_{\text{g N}}} =$$

$$= (0.25\, t_{\mu \text{ N}} + 0.30\, t_{\text{Fe N}}) + \frac{(0.20\, r_{\text{a}} + 0.50\, r_{\text{ad}})\, i_{\text{a}}^2 + 0.20\, r_{\text{f}}\, i_{\text{f}}^2}{n_{\text{g}}'} \qquad (3.43)$$

From Equation (3.43) it can be seen that the torque error does not decrease to zero even if the currents decrease to zero.

The higher the generator efficiency the lower the error is in the calculated shaft torque, because the error is in percent of the losses and not in percent of the power of the generator. The error described in this chapter is the model error. The total error can be larger because of errors in the measurements of the generator armature power, armature voltage, armature current, field current and shaft speed. If an exciter is used there will also be an error in the estimation of the field current.

3.2 Model of the converter losses

The converter losses have to be modelled to be able to compare the average efficiency of a variable speed generator and converter system with the average efficiency of a constant speed generator. The converter losses are divided into rectifier losses $P_{\text{loss r}}$, dc filter losses $P_{\text{loss d}}$ and inverter losses $P_{\text{loss i}}$. Losses due to the dc current ripple are neglected.

The losses of the diode bridge are due to the voltage drop in the semiconductor material and to the switching losses. The voltage drop has two parts:

resistive voltage drop from the rectifier resistance R_r and the no load voltage drop $U_{0\,r}$. By including these two types of losses the total diode losses are determined accurately enough since the switching losses are very small for low frequency rectifiers. The rectifier losses are

$$P_{loss\,r}(I_d) = U_{0\,r}\ I_d + R_r\ I_d^2 \tag{3.44}$$

The suggested dc filter has two inductors and a capacitor bank. The losses in the inductors are resistive losses and core losses. But the core losses are relatively small in an inductor for a dc-current with ripple. The dominating losses are the resistive ones in the winding. The capacitors have much lower losses than the inductors have, only about some percent of the inductor losses, and can therefore be neglected without introducing any significant errors in the calculations. By adding the resistance of the two dc inductors the dc filter losses can be expressed as

$$P_{loss\,d}(I_d) = R_d\ I_d^2 \tag{3.45}$$

where R_d is the total resistance of the dc filter.

The thyristor losses are similar to the diode losses. The difference is that the thyristor has a somewhat larger voltage drop. Using the same model as the one for the diode bridge the thyristor inverter losses can be calculated. But the inverter also has no-load losses $P_{0\,i}$ from the cooling fan and the auxiliary power supply to the control computer and the firing circuits. Therefore the inverter losses are

$$P_{loss\,i}(I_d) = P_{0\,i} + U_{0\,i}\ I_d + R_i\ I_d^2 \tag{3.46}$$

The total converter losses $P_{loss\,c}$ can be described as a sum of the no-load losses of the inverter, the voltage drop losses of the diode rectifier and the thyristor inverter and the resistive losses of the rectifier, dc filter and inverter.

$$P_{loss\,c}(I_d) = P_{0\,i} + (U_{0\,i} + U_{0\,r})\,I_d + (R_i + R_d + R_r)\,I_d^2 \tag{3.47}$$

The converter loss model error has not been estimated.

3.3 Model of the gear losses

The gear losses have not been measured. A theoretical model of the losses of a normal gear is presented in [11]. The losses of the gear are divided into two parts. The gear mesh losses which are a fixed percentage of the input power independent of the gear shaft speed. The gear mesh losses are determined by the design of the teeth of the cog-wheels. Friction losses are the other part of the losses and they are mainly due to bearing friction, windage and oil churning losses. The bearings, normally being roller bearings, give rise to an almost constant breaking torque. Windage power losses are generally proportional to the speed in cube. Expressed as a braking torque they are proportional to the speed in square. The oil churning losses are difficult to determine but the breaking torque should increase at least proportionally to the rotational speed of the gear. If it is not known how the bearing, oil churning and windage losses depend on the speed, a simplified function can be used. It is certain that those losses increase at least linearly with the speed. The following approximation of gear losses over-estimates the losses for all speeds up to the rated speed

$$p_{\text{loss gear}}(p_{\text{t}},n'_{\text{t}}) = t_{0\text{ gear}}\; n'_{\text{t}} + (1 - \eta_{\text{mesh}})\, p_{\text{t}} \tag{3.48}$$

where $t_{0\text{ gear}}$ is the per unit friction torque at rated speed and η_{mesh} the gear mesh efficiency.

3.4 Verification of the generator loss model

The losses are measured at various loads and under different conditions to verify the loss model. A first step is to verify the generator loss model for sinusoidal currents at resistive load. Then the model is used to predict the losses for a diode loaded generator. The error when the loss model is used to calculate the shaft torque from the armature power is also presented.

The losses are measured only indirectly by measuring the input mechanical power and the output armature power of the generator. Therefore, the model error is calculated as the shaft torque predicted by the model minus the measured generator shaft torque.

When comparing the model and the measurements the error consists of two parts. Besides the error of the model also the error due to the inaccuracy of the measured variables will show in this comparison. The error in the torque measurement is totally about 1.5 Nm. The predicted torque of the model is also suffering from the error in the output power. The output power of the generator is measured with a wattmeter that has an error of 0.5 % of the actual power range. That range changes during the measurement but the maximum error is always larger than 0.5 % of the actual power. The errors of the measured variables for the loss model, like armature current and generator speed, do not much affect the error of the predicted torque. The total effect of the inaccuracy of the measurements is equal to about 3.0 Nm at rated load and about 1.5 Nm at no load.

3.4.1 The laboratory system

Measurements were made on a system with the 50 kVA generator earlier described. For that purpose a system with generator and frequency converter or resistive three-phase load has been built in the laboratory. The laboratory system and the measurement equipment used are shown in Figure 3.7. All the measurements are made at steady state operation.

The generator is driven by a dc machine fed from a thyristor rectifier with speed control. No gear is included in the laboratory system. On the shaft between the dc motor and the synchronous generator the shaft torque and speed are measured. The generator is magnetized mainly by sliprings but for comparison it has also been magnetized by its integrated exciter. When it is magnetized by the sliprings both the field current and the field voltage are measured. The field current is fed from a current-controlled three-phase thyristor rectifier via a fourth order LC-filter. The ripple on the field current is only about one percent.

The exciter current is fed by a current regulating dc power supply. To be able to find the relation between the exciter current and the field current the field voltage is measured also when the exciter is used. From the field voltage and the field resistance the field current can then be calculated.

The armature power is measured by a three-phase digital power meter including harmonics up to 1 kHz. To estimate the generator flux at resistive load the armature r.m.s. voltage is measured and to calculate the stator winding copper losses the r.m.s. value of the armature current is also measured.

The generator power is either fed to a three-phase resistive load or to a frequency converter. The frequency converter consists of a three-phase diode rectifier, a dc filter and a thyristor inverter. In the dc filter the dc power as well as the dc current and voltage are measured.

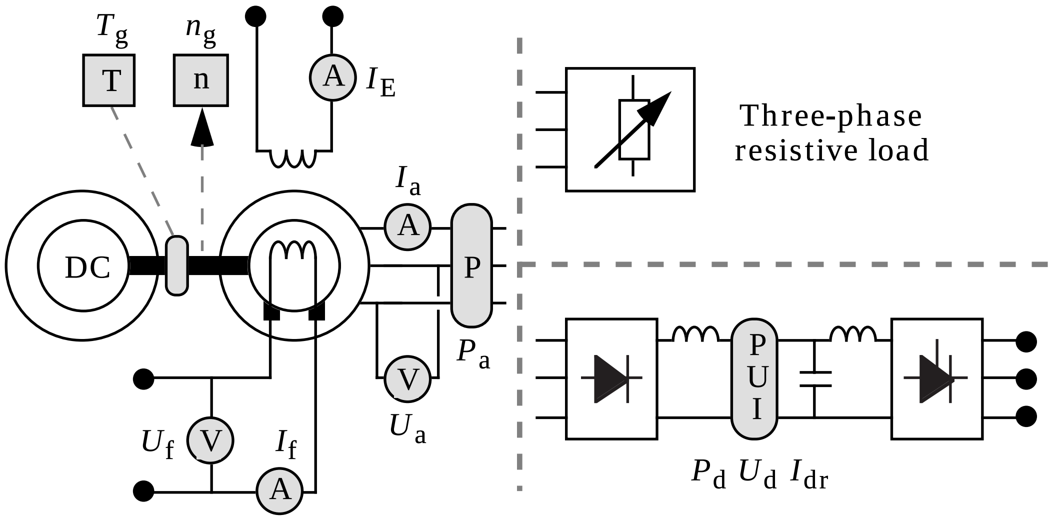

Figure 3.7 The laboratory set-up with measurement instrumentation.

3.4.2 Parameter determination of the laboratory system

The per unit quantities are presented in Table 3.3 together with the corresponding base values for the laboratory system. Note that the rated values of the system are used as base values, and the rated values of the generator can differ from these. There are also two current base values: one for the field current and one for the armature current. All of the base values in Table 3.3 can not be chosen independently. The power, speed and armature current base values can be chosen. Then the torque, field current, flux linkage and resistance base values can be calculated.

Table 3.3 The per unit quantities and their base values for the 50 kVA generator.

Quantity	Notation	Per unit quantity	Base quantity	Base value
Mechanical power	P_g	p_g	$P_{g\,N}$	47 438 W
Shaft speed	n_g	n_g'	$n_{g\,N}$	1500 rpm
Armature current	I_a	i_a	$I_{a\,N}$	78 A
Derived quantities:				
Shaft torque	T_g	t_g	$\left(\frac{P_{g\,N}}{n_{g\,N}}\right)$	302 Nm
Field current	I_f	i_f	$I_{f\,N}$	19 A
Flux linkage	Ψ	ψ	Ψ_N	1.12 Vs
Armature resistance	R_a	r_a	$\left(\frac{P_{g\,N}}{I_{a\,N}^2}\right)$	2.60 Ω
Field resistance	R_f	r_f	$\left(\frac{P_{g\,N}}{I_{f\,N}^2}\right)$	122 Ω

Friction and windage losses

The friction and windage losses of the generator can be measured on an electrically disconnected machine. They are simply measured as the input shaft power at different speeds if there is no magnetic flux in the generator. For the friction and windage loss model, only the friction and windage braking torque at rated speed and at standstill have to be measured.

If the rotor can not be demagnetized the friction and windage torque can be found from no load measurements at low magnetizations. The friction and windage braking torque for a certain speed is found by extrapolating the torque-voltage curve to zero voltage. In Figure 3.8 a torque-voltage curve for 1000 rpm can be seen, in which the friction torque at 1000 rpm is found as the no-load torque extrapolated to zero voltage.

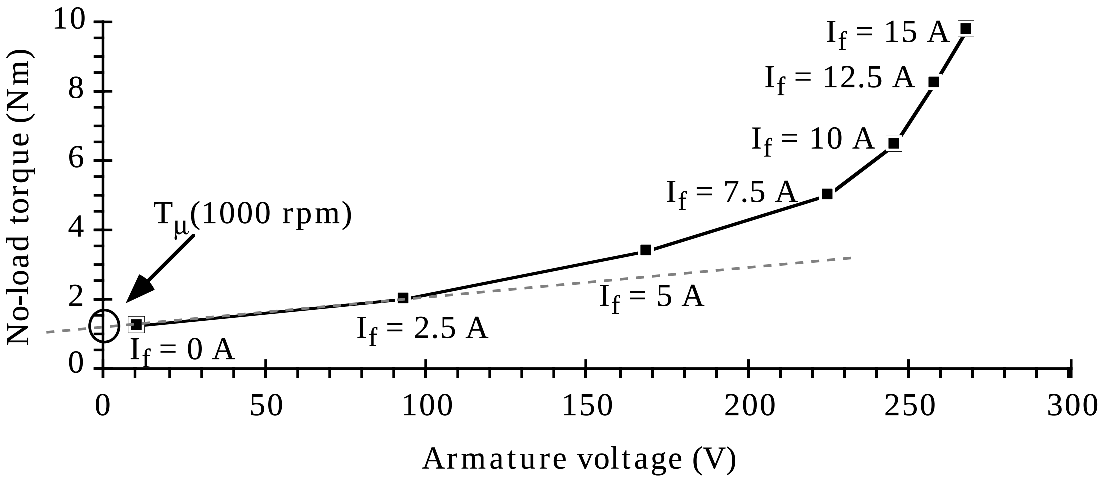

Figure 3.8 A no-load torque-voltage curve used to find the friction loss torque at 1000 rpm for the 50 kVA generator.

In Figure 3.9 the zero voltage torque from a number of such curves has been plotted in the same diagram to form the torque-speed curve for the friction and windage losses.

The standstill friction torque can be found by extrapolating the friction and windage loss torque for low speeds down to zero speed. For the 50 kVA generator the friction and windage parameters are

$T_{\mu\,ss} = 0.468$ Nm and $T_{\mu\,N} = 1.694$ Nm (3.49)

$t_{\mu\,ss} = 0.155$ % and $t_{\mu\,N} = 0.407$ % (3.50)

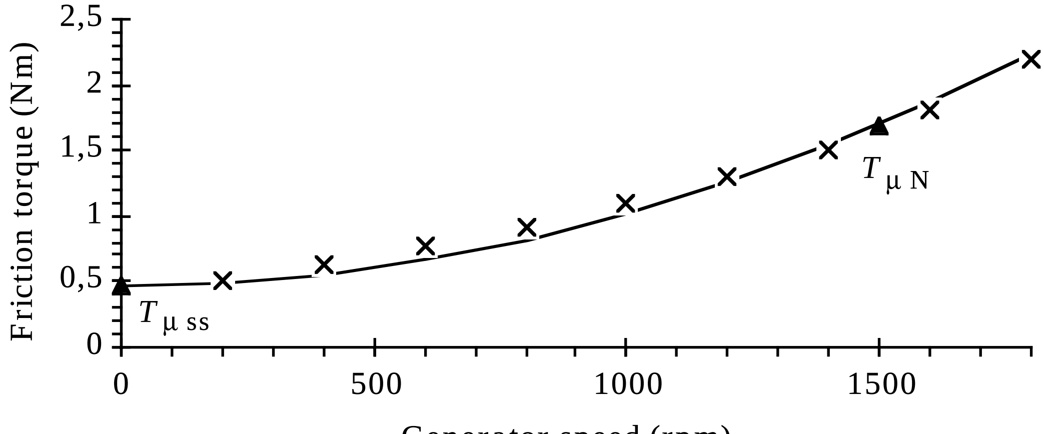

Figure 3.9 The torque-speed points from measurements of the friction and windage losses of the 50 kVA generator, and the model function drawn as a line.

Core losses

Measurements made at different speeds are necessary for separating the hysteresis losses and the eddy current losses. From no-load measurements the core losses can be calculated as the input mechanical power minus the friction losses. First the eddy current constant is determined and then the hysteresis loss torque is determined.

To separate the hysteresis losses from the eddy current losses the measured total core loss torque is plotted as a function of the generator speed for some fixed values of the field current. At no load a fixed field current is equal to a fixed flux linkage. The measured core loss torque for the 50 kVA generator is shown in Figure 3.10. The hysteresis torque can be determined if the curve is extrapolated to zero speed. The speed dependency of the data should form straight lines, according to Equation (3.10). Figure 3.10 shows that the speed dependency for high flux is not linear, especially not for low speeds of the generator. But if the model is to be used in a wind turbine generator system, speeds below 500 rpm will be of no interest. The curve fit should be made only for the data between the lowest and the highest speeds used in that particular wind turbine generator system.

Based on the measured data, it is possible to get one value of the eddy current constant for each value of the flux linkage (field current). The eddy current constant can for each flux linkage be calculated by the following equation

$$C_{Ft}(\Psi) = \frac{T_{Fe}(\Psi, 1500 \text{ rpm}) - T_{Fe}(\Psi, 0 \text{ rpm})}{T_{Fe}(\Psi, 0 \text{ rpm})} \qquad (3.51)$$

The value of the eddy current constant used in the model is the mean value of the constants for the different flux linkages. The results can be found in Table 3.4. The mean value of the eddy current constant is calculated

$$C_{Ft} = 0.44 \qquad (3.52)$$

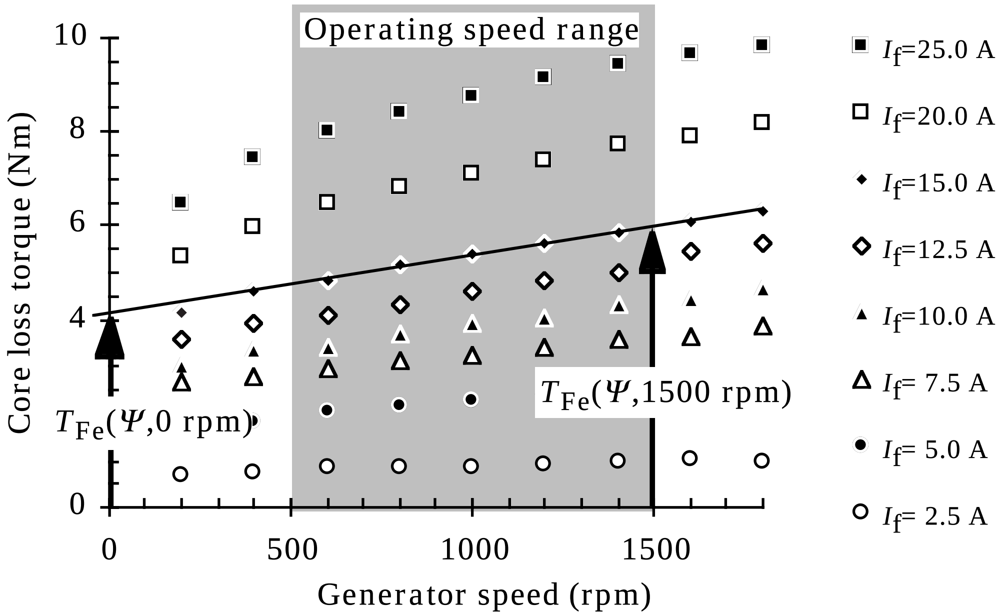

Figure 3.10 The core loss torque of the 50 kVA generator versus the generator speed for some fixed field currents.

The variation in the eddy current constant C_{Ft} with flux linkage is as large as ±25 % according to Table 3.4, but the resulting error in the total eddy current factor $(1 + C_{Ft}\, n_g')$ is much smaller. It is less than 3.5 % as can be seen in Figure 3.11. This small error is achieved by determining the hysteresis torque from the data in the middle of the used speed range. The eddy current factor is then correct for that speed, here 1000 rpm.

Table 3.4 The eddy current constant for different flux linkages and the mean value used.

I_f (A)	Ψ (Vs)	$T_{Fe}(\Psi,1500\ rpm)$ (Nm)	$T_{Fe}(\Psi,0\ rpm)$ (Nm)	$C_{Ft}(\Psi)$
2.5	0.45	1.00	0.72	0.389
5.0	0.81	2.55	1.78	0.431
7.5	0.99	3.64	2.54	0.433
10.0	1.07	4.39	2.86	0.536
15.0	1.13	5.24	3.36	0.536
20.0	1.23	7.78	5.58	0.394
25.0	1.27	9.47	7.12	0.330
			mean value ⇒	0.44

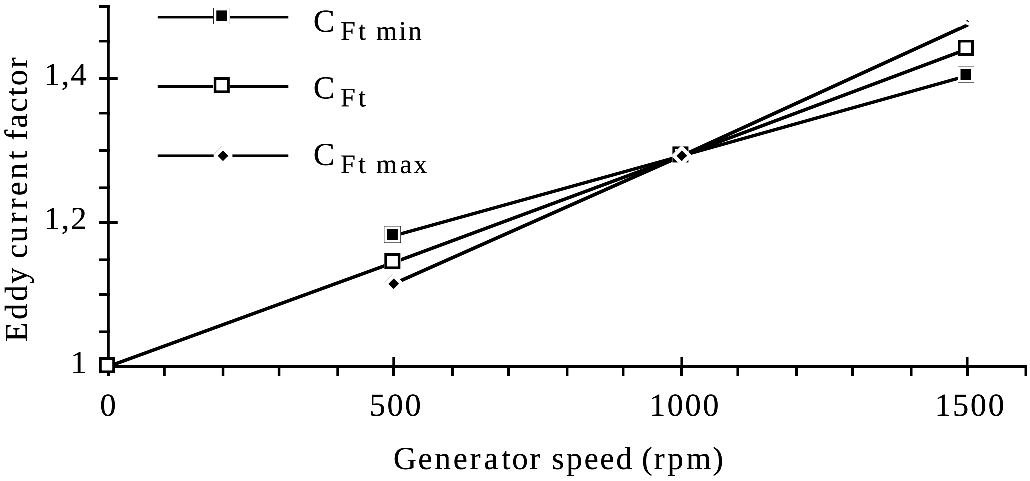

Figure 3.11 The error of the eddy current factor.

To find the relation between the hysteresis loss torque and the flux linkage, the core loss torque from the measurement above is used. The core loss torque is plotted versus the flux for one speed. The speed that should be used is the one in the middle of the used speed range of the wind turbine generator system. This is neccesary in order to reduce the error of assuming that all the torque-speed lines have the same slope. For the 50 kVA generator the speed range is 500 to 1500 rpm, and the hysteresis loss torque is therefore approximated from the loss torque at 1000 rpm. To reduce the absolute error, the values of the core loss torque should be taken from the straight lines that already have been used to approximate the eddy current factor, *not directly from measurements at 1000 rpm*. The chosen core loss torque values do not only contain the hysteresis torque but also the eddy current torque, in this case the eddy current torque of 1000 rpm. The eddy current loss torque is excluded before the curve fit is made by using the formula for the relation between hysteresis losses and eddy current losses at different speeds

$$T_{\mathrm{Hy}}(\Psi) = \frac{T_{\mathrm{Fe}}(\Psi, 1000\ \mathrm{rpm})}{\left(1 + 0.44\,\frac{1000\ \mathrm{rpm}}{1500\ \mathrm{rpm}}\right)} \tag{3.53}$$

After the division by the eddy current factor the hysteresis losses at rated flux linkage can be found. The measured hysteresis loss torque as well as the model of it is shown in Figure 3.12. The hysteresis loss torque may have a very steep increase when the flux exceeds the rated flux linkage.

The model parameter for the hysteresis loss torque of the 50 kVA generator is

$$T_{Hy\ N} = 3.47\ \text{Nm} \tag{3.54}$$

and in per unit the hysteresis loss torque is

$$t_{Hy\ N} = 1.15\ \% \tag{3.55}$$

The parameter $t_{Fe\ N}$ for the model can now be calculated

$$t_{Fe\ N} = t_{Hy\ N}\ (1 + C_{Ft}) = 1.15\ \%\ (1 + 0.44) = 1.656\ \% \tag{3.56}$$

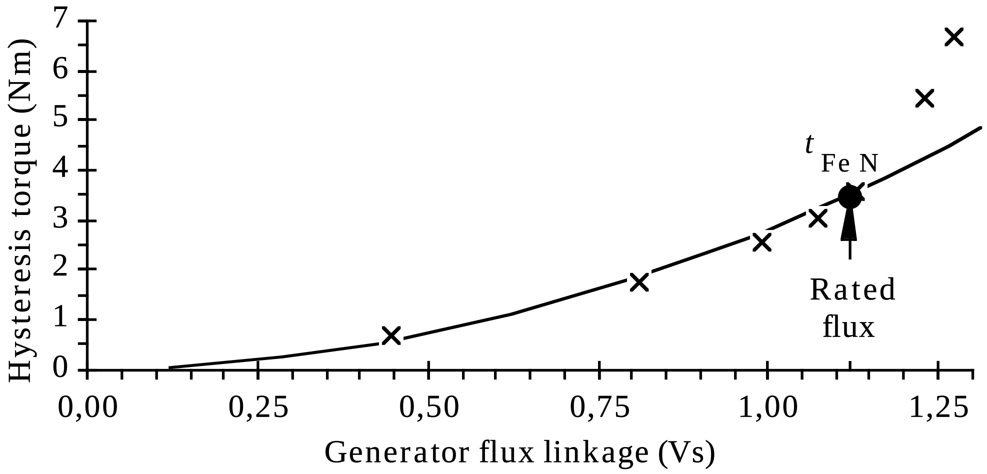

Figure 3.12 The model of and the measured hysteresis loss torque.

Armature resistance

For the 50 kVA generator the armature resistance is 66 mΩ per phase. The resistive losses can then be expressed in per unit of the rated generator power as

$$r_a = \frac{P_{cu\ a\ N}}{P_{g\ N}} = \frac{3\ R_a\ I_{a\ N}^2}{P_{g\ N}} = 2.54\ \% \tag{3.57}$$

Field winding resistance

For the 50 kVA generator the field winding resistance is 1.37 Ω which make the per unit field winding resistance

$$r_{f} = \frac{P_{cu\,f\,N}}{P_{g\,N}} = \frac{R_{f} \;\; I_{f\,N}^{2}}{P_{g\,N}} = 1.04\ \% \tag{3.58}$$

Exciter rotor resistance

The per phase resistance of the exciter armature was measured by disconnecting the rotating diode rectifier

$$R_{a\,E} = 0.135\ \Omega \tag{3.59}$$

$$r_{a\,E} = \frac{P_{cu\,E\,N}}{P_{g\,N}} = \frac{2 \;\; R_{a\,E} \;\; I_{f\,N}^{2}}{P_{g\,N}} = 0.21\ \% \tag{3.60}$$

Additional losses

The additional losses in the generator are smaller than the measurement accuracy of the laboratory system, which makes it difficult to trace them from single measurements. Instead the error of the loss model is plotted as a function of armature current, when no additional losses are included in the model. At resistive load no systematic correlation is found between the error of the model and the armature current, see Figure 3.13. Thus the additional losses can be assumed to be close to zero.

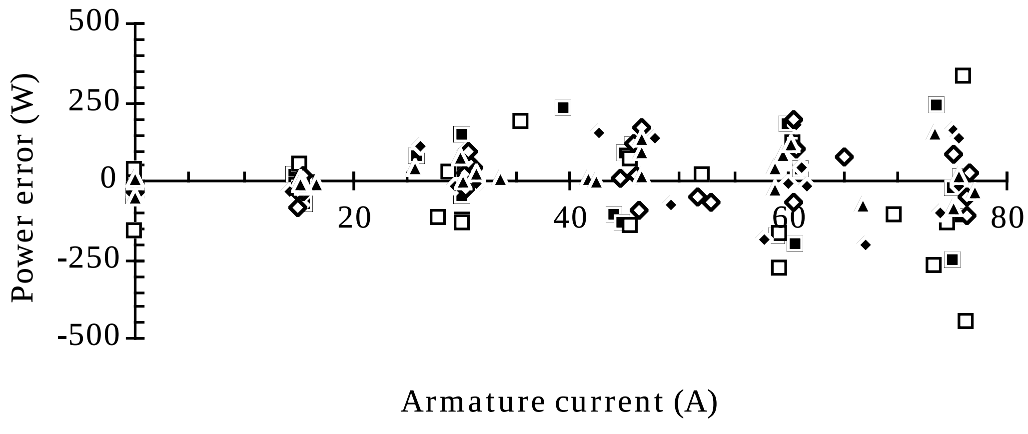

Figure 3.13 The model error at resistive load, when additional losses are not modelled.

The additional losses at diode load are also small compared with the measurement accuracy and can not be exactly determined, see Figure 3.14. Measurements at 1500 rpm show that the additional losses can be estimated to about 320 W at rated armature current. The additional losses at diode load can be represented by an equivalent armature resistance

$$r_{ad} = \frac{P_{ad\,N}}{P_{g\,N}} = 0.67\ \% \qquad (3.61)$$

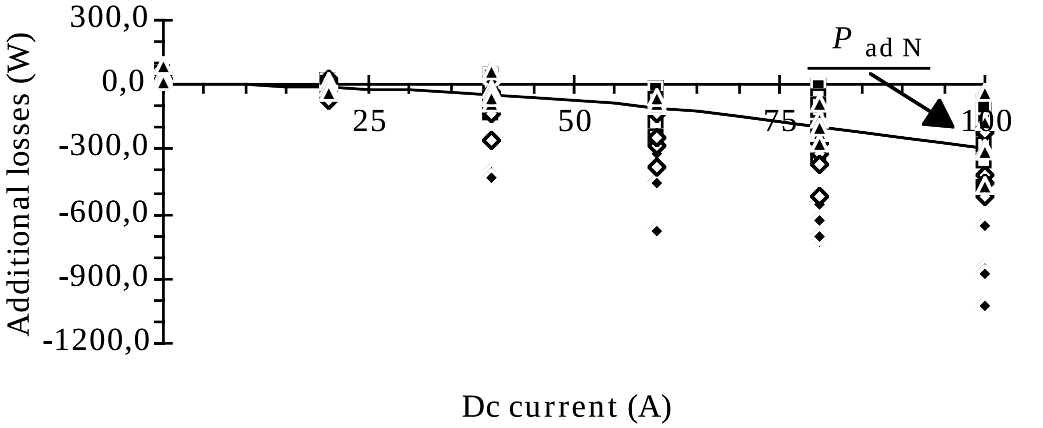

Figure 3.14 The model error at diode load, when additional losses are not modelled. The additional losses can be found as the current-dependent part of the loss model error. An approximation of the additional losses is also shown as a line.

Error in the model for the 50 kVA generator

The total error in percent of the rated power is, according to Equation (3.42)

$$\frac{\Delta P_{loss}}{P_N} = (0.14\ \% + 0.50\ \%)\ n_g' + (0.51\ \% + 0.34\ \%)\ i_a^2 + 0.21\ \%\ i_f^2 \qquad (3.62)$$

The error expressed as a percentage of the rated shaft torque is, according to Equation (3.43)

$$\frac{\Delta T_{loss}}{T_N} = 0.14\ \% + 0.50\ \% + \frac{1}{n_g'}\left[\left(0.51\ \% + 0.34\ \%\right) i_a^2 + 0.21\ \%\ i_f^2\right] \qquad (3.63)$$

The maximum error in the loss model is, for the 50 kVA generator, about 1.7 % of the rated generator power at rated load. The error of the calculated shaft torque is also 1.7 % of the rated shaft torque.

3.4.3 Verification of the exciter losses

In Figure 3.15 the exciter losses plus field winding losses have been calculated from the measurements. It can be seen that only the resistive losses in the rotor must be included in the model.

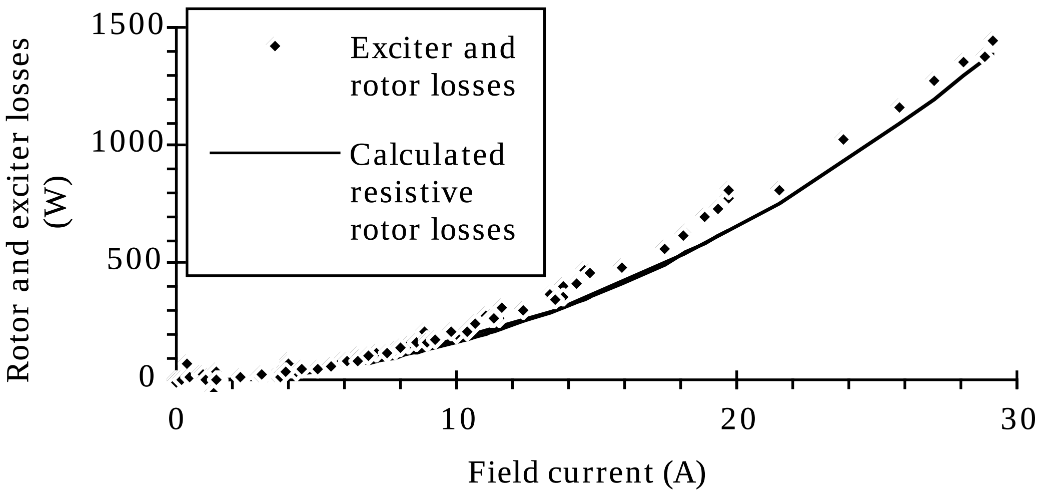

Figure 3.15 The losses of the exciter and main field winding versus main field current.

3.4.4 Model error at resistive load

To find out how accurate the loss model is, first the error between the model and the measured losses is calculated for the generator with resistive load. In the next section the same comparison is made for the generator loaded by a diode rectifier.

The losses are measured at all the combinations of five different generator speeds, five different armature currents and five different generator flux linkages. That is a total of 125 different load combinations that cover all possible loadings of the generator. For each measurement the generator speed, shaft torque, field current, field winding voltage, armature voltage, armature current and electrical output power are measured. The model error is defined as the shaft power or torque predicted by the model minus the measured shaft power or torque.

For the resistivly loaded generator no additional losses are included in the model. The torque error is always less than the total measurement error, ±3 Nm. So, just by looking at the magnitude of the error it can not be judged whether the error depends on the model or the inaccuracy of the measurement. But if the error is plotted versus for instance the generator current, the generator flux linkage or the speed it will be possible to see if there are any correlation between the errors and different quantities. By looking at how the error changes with a certain quantity, it shows if there are systematic errors even if those errors are smaller than the stochastic ones.

The model torque error is plotted versus the generator shaft speed. It can be seen that the magnitude of the error is almost independent of the speed, see Figure 3.16. The mean value of the model error is not perfectly zero for all speeds but it is such a small correlation to the speed that it is well within what should be expected.

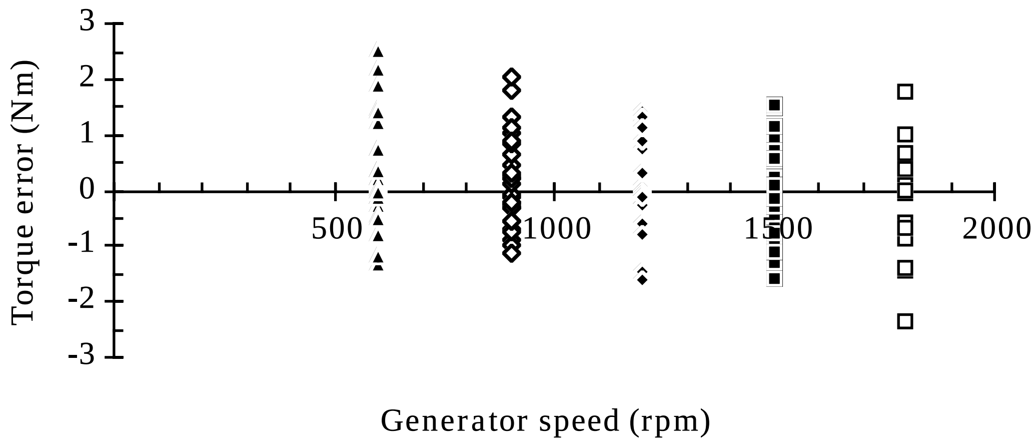

Figure 3.16 The torque error at resistive load and at different generator speeds.

The error plotted versus the generator flux linkage, Figure 3.17, shows a definite correlation between the error and the flux linkage. At low generator flux linkage the model underestimates the losses and at high flux linkage it overestimates them. This is probably difficult to correct without a lot of calculations for each new generator to be modelled. However, the error is also here small and well within the desired accuracy of the model.

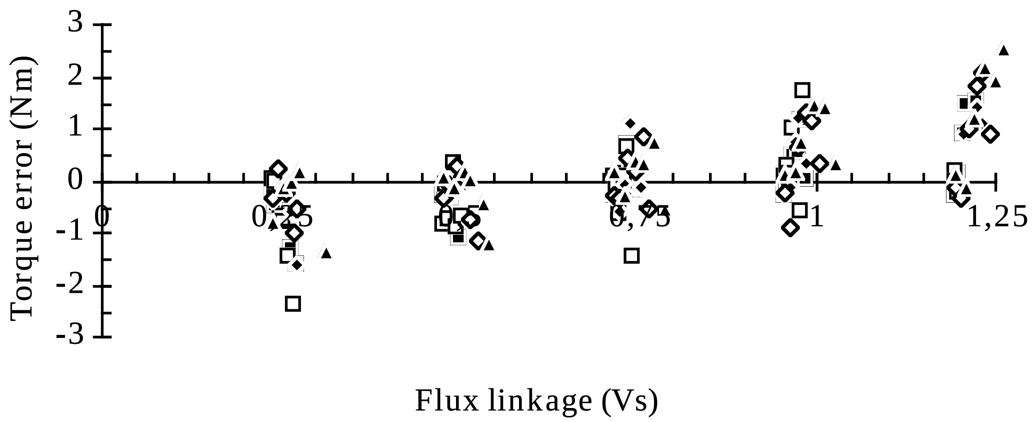

Figure 3.17 The torque error at resistive load and at different generator flux linkages.

It can be seen, in Figure 3.18, that the size of the power error is to a large extent depending on the armature current but the mean value of the error is close to zero for all currents, so the model can not be corrected by changing for instance the resistance value.

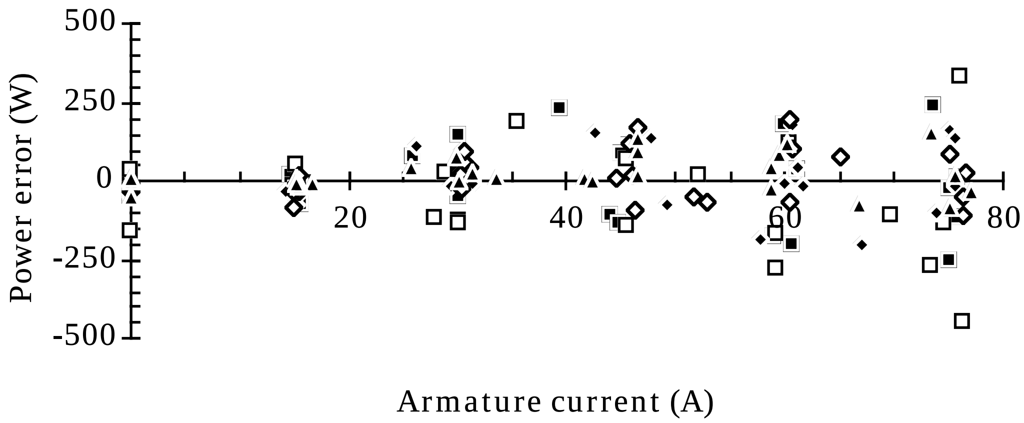

Figure 3.18 The power error at resistive load and at different armature currents.

All the model and measurement errors with resistive load are less than 3 Nm which is about 1 % of the rated torque or or 500 W which is about 1 % of the rated power. The measurement errors can amount to 1 % so it is not possible to say how large the actual model error is.

3.4.5 Model error at diode load

When the generator is loaded by a diode rectifier the losses increase a little compared with resistive load. The increase is expected, since there will be losses in the damper windings that do not occur at resistive load. There will also be more harmonics in the stator current leading to higher copper losses. Because of the larger proportion of high frequency components in the flux distribution the eddy current losses increase more than the hysteresis losses.

At resistive load the additional losses are low enough to be neglected. To take the additional losses into account at diode load the model now includes a fictitious armature resistance representing the additional losses. The error of the calculated shaft torque is plotted for different speeds, dc current, and generator flux linkage.

Figure 3.19 show the model torque error for some speeds, it can be seen that the error changes with the speed. The loss model underestimates the losses at higher speeds which indicates that the eddy current losses have increased compared with no-load. The speed dependence of the error is larger than that at resistive load: compare Figures 3.16 and 3.19.

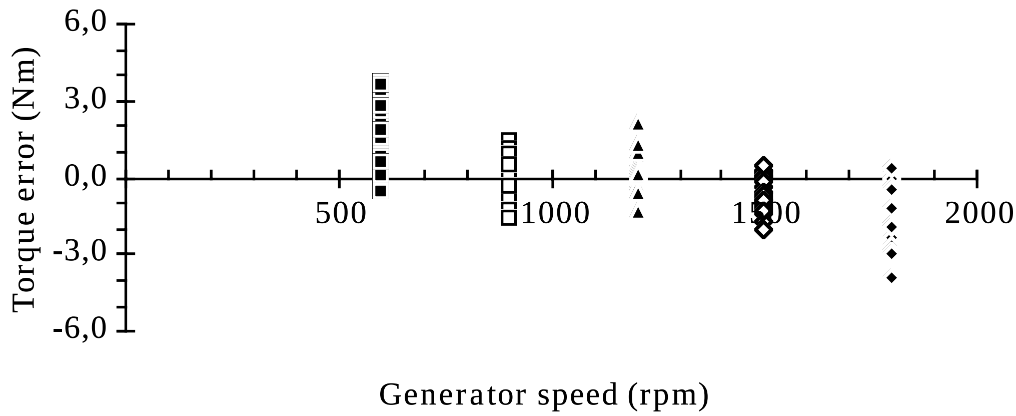

Figure 3.19 The torque error at diode load and at different generator speeds.

Figure 3.20 shows no simple correlation between the generator flux linkage and the torque error. The correlation is different from that at resistive load, compare Figures 3.17 and 3.20. The difference may depend only on the fact that there are different ways of calculating the flux linkage with resistive load and with diode load.

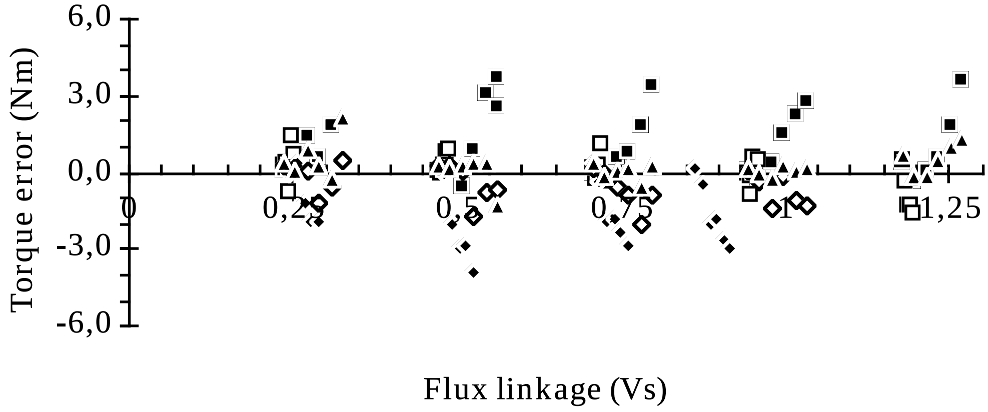

Figure 3.20 The torque error at diode load and at different generator flux linkages.

The armature current clearly effect the magnitude of the power error in the same way as it does at resistive load, compare Figures 3.18 and 3.21. Although the additional losses are taken into account, the model is not as accurate at diode load as it is at resistive load. The total error when comparing model and measurements is, for a diode-loaded generator, up to 2 % of the rated power or torque. The measurement error can contribute with no more than 1 %.

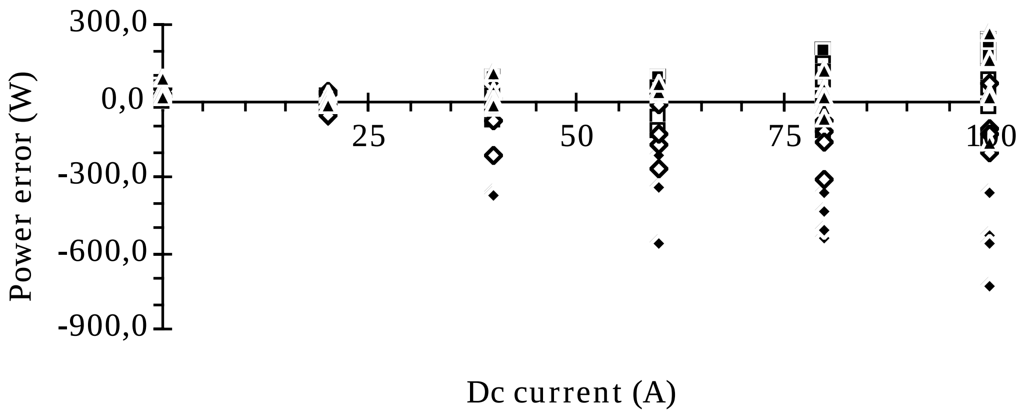

Figure 3.21 The error in estimated power at different dc currents.

3.4.6 Error in the torque control

The loss model can be used for torque control of the generator. The error of such a torque control is easiest found if the torque error of the model is plotted with the measured shaft torque as a parameter. Since the model is intended for use in a variable speed wind turbine generator system only the error at diode load is presented here. In Figure 3.22 the torque error is plotted for all possible combinations of speed, armature current and flux linkages.

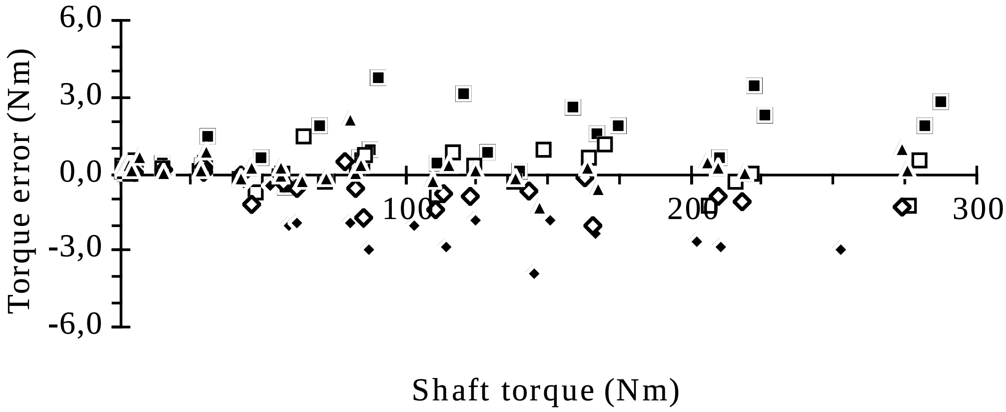

Figure 3.22 The error, at diode load, in the calculated torque compared with the actual torque, for all possible combinations of speed, armature current and flux linkages.

In this comparison of torque error versus shaft torque the error is almost zero at zero torque, but this is because the parameters for the friction losses and core losses are measured. If they were estimated with an error, that would show as an offset error at zero shaft torque. The error decreases for low shaft torque, but not linearly with the torque. This means that the total error will never be more than about 2 % of the rated generator torque but the relative torque error can be larger than 2 % at part load.

In a wind turbine generator system not all of the above measured load combinations are realistic. For instance, high current at high flux linkage and low speed will never occur. Since the most extrem load combinations have the largest errors it is interesting to find the error of only the load combinations that will be used in a wind turbine generator system. These load combinations follow the torque-speed curve of the optimum load of a wind turbine. For wind turbine loads it can be seen that the model error is generally smaller than for other loadings, see Figure 3.23. Large errors only occur with low flux linkage combined with high current, probably due to armature reaction effects. If these low magnetizations are avoided the maximum error will be less than 1 % percent for the 50 kVA generator.

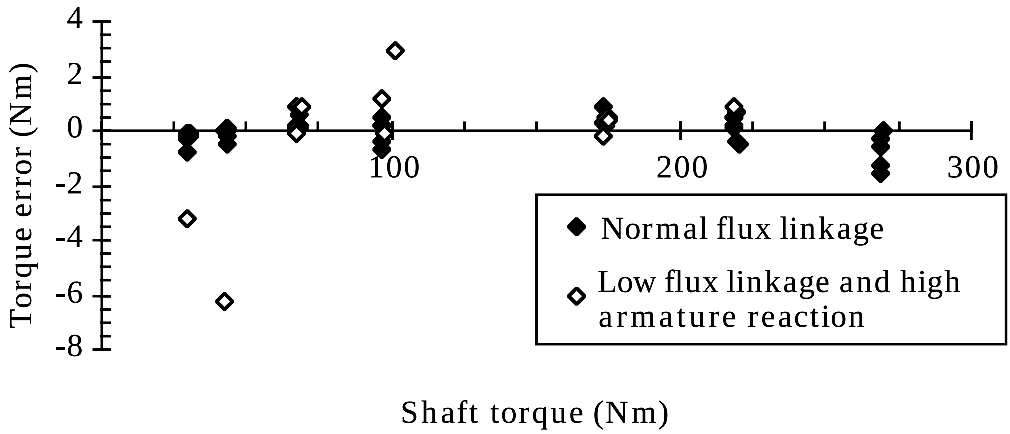

Figure 3.23 The torque error of the model with normal wind turbine loads. Normal flux linkage (filled dots) and low flux linkage and high armature reaction (unfilled dots).

3.5 Model for the 300 kW design example

In the following chapters, the loss model is used in the design of the system and to calculate the average efficiency of the generator and converter system. These calculations are made for the 300 kW design example system and here the parameters for that system are derived.

3.5.1 Generator parameters

For the 300 kW generator with exciter the loss model can be determined mainly by data from the manufacturer [12], but also with estimations based on scaling of known data. In Table 3.5 the 50 and 60 Hz data from the generator manufacturer are presented. The data are also recalculated for the lower rated current and voltage used in the design example system. Some parameters have only been estimated.

The parameters of the simplified loss model for the 300 kW generator can now be determined. The friction and windage torque parameters are estimated to

$t_{\mu\,N} = 0.66\ \%$ (estimated) (3.64)

$t_{\mu\,ss} = 0.22\ \%$ (estimated) (3.65)

Table 3.5 Data for the design example generator. Data are available for class H loading at 50 and 60 Hz and those are recalculated for the ratings used in the design example.

Data for synchronous gen. LSA 47.5 M4	50 Hz 1500 rpm	60 Hz 1800 rpm	design example 1800 rpm
Temperature rise	class H	class H	class B
$S_{a\,N}$	350 kVA	420 kVA	334 kVA
$P_{g\,N}$			≈320 kW
$I_{a\,N}$	505 A	505 A	410 A
$U_{a\,N}$ / n_N	400 V/1500 rpm	480 V/1800 rpm	475 V/1800 rpm
$P_{loss\,0}$ (No load losses)	5400 W	7600 W	7600 W
x_d''	13.7 %	14.3 %	11.7 %
x_q''	17.4 %	18.1 %	14.8 %
R_a (at 50° C)	0.0128 Ω	0.0128 Ω	0.0128 Ω
$x_s \approx x_d$	355 %	370 %	304 %
Estimated losses:			
$n_{g\,N}$ $T_{\mu N}$	1480 W / 0.4 %	2100 W / 0.48 %	2100 W / 0.66 %
$P_{ad\,N}$	1940 W / 0.52 %	1940 W / 0.44 %	1280 W / 0.4 %
$P_{Cu\,f\,N}$	4200 W / 1.2 %	4200 W / 0.95 %	2900 W / 0.9 %

The field winding losses at no load are very small even at rated flux. The large synchronous reactance makes the no load field current only about 25 % of the rated field current. Therefore, the field winding losses at no load, $p_{Cu\,f\,0}$, are only 6 % of the field winding losses at rated load and they are neglected. The core loss torque at rated flux can be determined approximately from the no load losses as

$$t_{Fe\,N} = \frac{p_{loss\,0} - p_{Cu\,f\,0}}{n'_{g\,N}} - t_{\mu\,N} = \left\{ p_{Cu\,f\,0} \approx 0 \right\} \approx 1.72\,\% \qquad (3.66)$$

No value of C_{Ft} has been found and for this example it is estimated to be

$$C_{Ft} = 0.5 \qquad \text{(estimated)} \qquad (3.67)$$

$$r_{\mathrm{a}} = \frac{3\, R_{\mathrm{a}}\ I_{\mathrm{a\,N}}^{2}}{P_{\mathrm{g\,N}}} = 2.02\ \% \tag{3.68}$$

$$r_{\mathrm{ad}} = \frac{P_{\mathrm{ad\,N}}}{P_{\mathrm{g\,N}}} = 0.40\ \% \qquad \text{(estimated)} \tag{3.69}$$

$$r_{\mathrm{f}} = \frac{P_{\mathrm{Cu\,f\,N}}}{P_{\mathrm{g\,N}}} = 0.90\ \% \tag{3.70}$$

$$R_{\mathrm{r\,com}} = \frac{1}{2}\ x_{\mathrm{r\,com}} = \frac{1}{2}\ \frac{x_{\mathrm{d}}'' + x_{\mathrm{q}}''}{2} = 6.58\ \% \tag{3.71}$$

$$x_{\mathrm{s}} = 304\ \% \tag{3.72}$$

3.5.2 Converter parameters

For the design example system the converter losses are in Chapter 2 found to be

$$p_{\mathrm{loss\ c}}(i_{\mathrm{d}}) = 0.12\ \% + (0.52{+}0.33)\ \%\ i_{\mathrm{d}} + (0.10{+}0.70{+}0.17)\ \%\ i_{\mathrm{d}}^{2} \tag{3.73}$$

The converter efficiency at rated load is 98 %.

3.5.3 Gear parameters

A gear in the 300 kW range would have gear mesh losses of about 1 % for each stage and friction losses of about 0.5 % at rated load and at rated speed. In this model the gear friction torque is assumed to be constant. The braking torque of the gear losses, for a gearbox of 97 % rated efficiency, is

$$t_{\mathrm{loss\ gear}}(t_{\mathrm{t}}) = 0.5\ \% + 2.5\ \%\ t_{\mathrm{t}} \tag{3.74}$$

where t_{t} is the turbine shaft torque in per unit.

4 The use of the loss model in control and design

In this chapter, the system efficiency is optimized. The model of losses in the generator and converter can be used to maximize the efficiency of the system during operation. The system design can also be optimized by comparing different generators of various rated power and rated speed.

4.1 Optimum generator voltage control

The frequency converter does not only allow variations in the generator frequency. It also allows variations of the generator voltage. In a wind turbine generator system the optimum shaft torque is pre-determined as a function of speed. The optimum torque can, however, be obtained by different combinations of generator current and voltage. This control possibility can be used to minimize the generator and converter losses by means of the voltage control.

The maximum allowed generator voltage is limited by the inverter ac voltage at full load and at low load and low speed by the maximum allowed generator flux. At full load the generator voltage is limited to 90 % of the inverter ac voltage to insure safe commutation of the inverter. At low load and low speed the generator flux has to be lower than 105 % of the rated generator flux and this limits the generator voltage. According to standards the generator must be able to continuously operate at a flux 5 % higher than the rated value [13]. On the other hand, the generator voltage may not be so low that the armature current increases above its rated value. Within these limits, the voltage can be controlled freely.

The generator core losses decrease with decreasing flux and the armature copper losses decrease with decreasing current. Also the field winding losses change with the flux. If the armature reaction is small, the field winding losses will decrease with decreasing voltage, and if it is high the field winding losses will increase with decreased voltage. The increase in field winding losses at high armature reaction occurs because the field current must increase to balance the increasing armature currents even though the voltage is decreased. Also the efficiency of the converter changes with the voltage. Since most of the losses are due to voltage drops of the semiconductors and resistive voltage drops of the dc filter, the losses increase with increasing current. For a fixed power the converter losses thus increase with decreasing voltage. The generator voltage should be controlled to minimize the sum of core losses, field winding losses, copper losses and converter losses, see Figure 4.1.

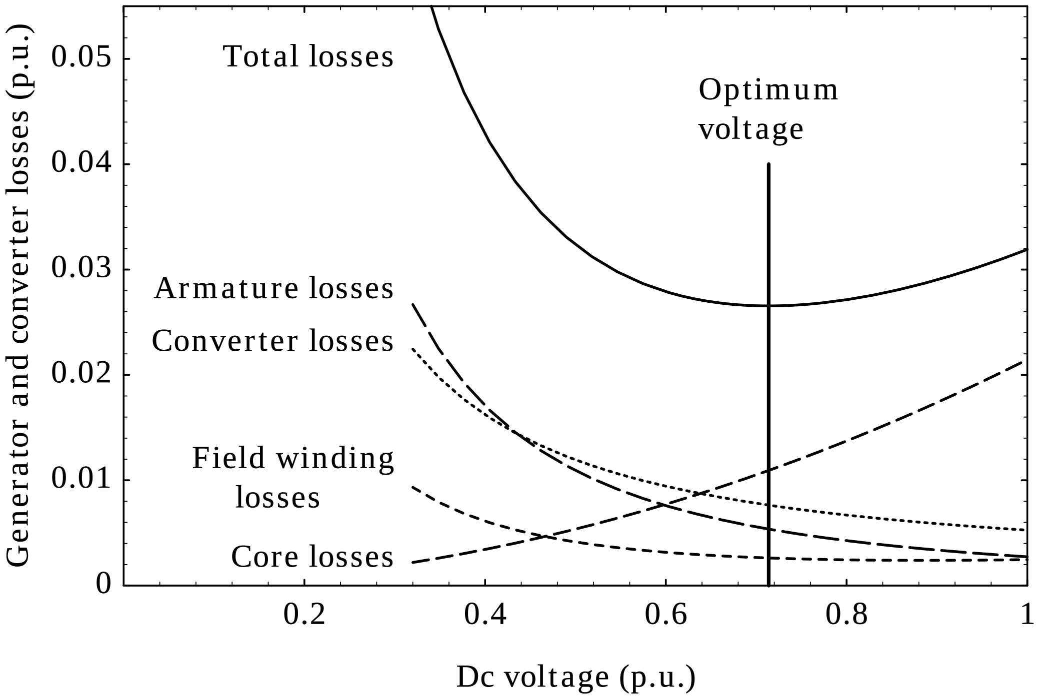

Figure 4.1 The core losses, field winding losses, armature copper losses, converter losses and the total losses versus dc voltage at a fixed speed and power.

In Figure 4.2 the total generator and converter efficiency versus the input power of the generator can be seen both when an optimized voltage control is used and when the flux is kept constant at the rated flux.

From the loss model the optimum voltage-speed curve can be calculated theoretically. This curve is together with the voltage limits shown in Figure 4.3. If low voltages are used, there may be problems with the voltage control even if the current is not higher than the rated current. These problems arise because the armature reaction eventually becomes dominating in the generator voltage control. Normally, the voltage is reduced by reducing the field current. At the same time, the armature current is increased to keep the shaft torque constant. But, if the armature reaction is large, it may be necessary to raise the field current when the armature current is increased even though the voltage is reduced. The coupling between the voltage control and the current control may in that case cause problems.

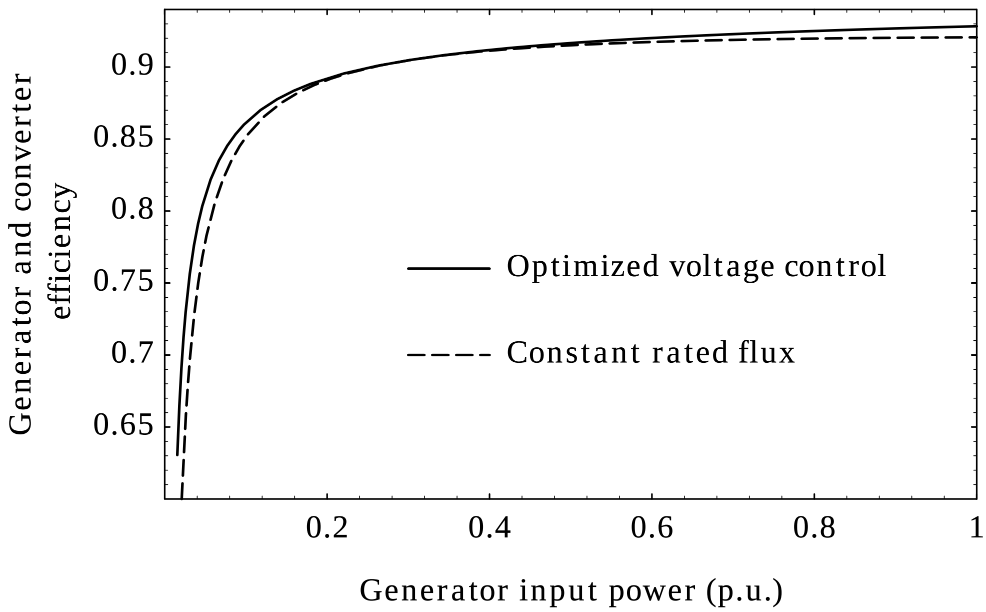

Figure 4.2 The generator and converter efficiency versus generator input power using an optimized voltage control and using constant rated flux.

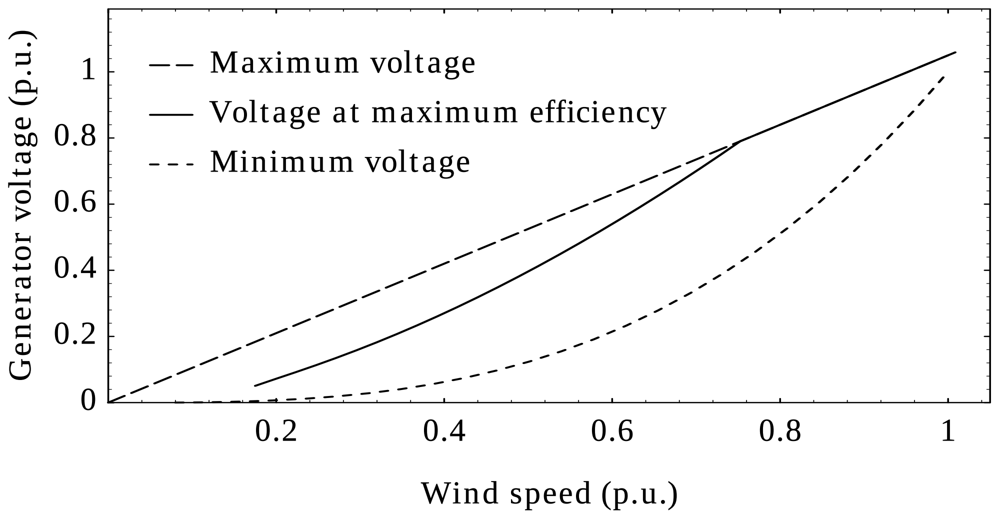

Figure 4.3 The maximum, optimum and minimum voltage of the generator in a variable speed wind turbine generator system.

4.2 Efficiency as a function of generator size

The generator rating should be chosen to minimize the total cost of both the generator and its losses. A large generator may be the most economic choice, even though it is more expensive, if it is more efficient.

When comparing data for different sizes of the same generator type, e.g. for Leroy Somer generators [12], it can be seen that the different per unit losses do not always decrease when the size of the generator increases, because the generators are made in different standard frame sizes. Increasing the rated efficiency is not always done by increasing the generator frame size. When comparing the losses between two close generator sizes the smaller generator may, therefore, sometimes have lower armature resistance although its rated current is smaller. But only on very rare occasions it can be found that a generator has a lower rated efficiency than one that is smaller.

The efficiency of three generators of different sizes is compared. It is assumed that they have the same efficiency at their respective rated powers. The generator sizes are chosen so that one generator will have a rated power of only 80 % of the wind turbine generator system maximum power. The rated power of the next generator is 100 % and of the last generator 120 % of the maximum turbine power. In Figure 4.4 the efficiency is plotted and it is clear that an oversized generator does not have higher efficiency if the per unit losses are equal. An undersized generator has the highest efficiency but it can of course not be used because it will be overloaded. A larger generator will give a higher efficiency only if the increase of rated efficiency is larger than the decrease in efficiency by reducing the generator per unit load. At a certain power the difference in efficiency between generators of different sizes can generally be expected to be small.

An other reason to use a larger generator than necessary would be, besides a higher generator efficiency, that the insulation limit the generator life. Since the generator in a wind turbine generator system should have a very long operational life compared with many motor applications, the rating for the temperature class H or F may be too high leading to isolation failure after less than 20 to 30 year. A generator, made with class H insulation, can instead be used with a rated power that only leads to temperature rises according to class B to increase the life of the insulation. This is the same as using a larger generator for a specific power.

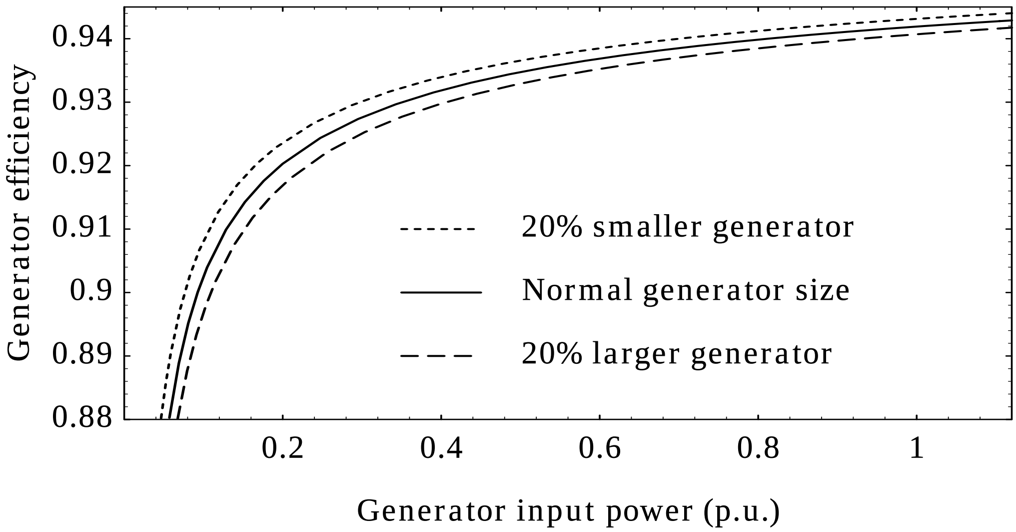

Figure 4.4 The efficiency of generators of different rated power.

4.3 Optimum generator speed

For network-connected ac generators only some few fixed speeds can be used. These speeds are determined by the network frequency and the number of pole pairs of the generator. For a 50 Hz network the available speeds are 3000, 1500, 1000, 750 rpm and lower.

For a variable-speed wind turbine generator system the choice of the generator speed is not restricted to a choice of pole pair number. The frequency of the generator can also be chosen freely which allows any generator speed. For instance, a four-pole generator can either be used at 1200 rpm and a frequency of 40 Hz or at 1800 rpm and 60 Hz. A six-pole generator can also be used at 1800 rpm and the frequency is then 90 Hz.

Even though the turbine speed is determined by its optimum tip-speed ratio, the speed of the generator can be changed by using different gear ratios. From the loss model it can be found how the efficiency change with the generator speed. The change in efficiency when the speed is changed depend on how the power and generator flux are changed with the speed. Two comparisons are made. First the generator efficiency is calculated at various speeds but at constant power and secondly the generator efficiency is calculated when it is loaded as much as possible at each speed.

When the power of the generator is the same at all different speeds the armature voltage can be kept constant. If the voltage is constant, the flux of the generator will be approximately inversely proportional to the speed of the generator. The power being constant as well as the voltage leads to a constant armature current. The friction and windage losses increase almost by the speed raised to a power of three. Armature winding copper losses remain constant in this example since the current is constant. The flux is, however, reduced which reduces the hysteresis losses. Also the eddy current losses are reduced but not as much as the hysteresis losses. Field winding losses are reduced too, because of the reduced flux.

The efficiency can, however, be better optimized by controlling the voltage to maximize the efficiency for each generator speed. Calculations on the efficiency with this type of control are also made. The armature current is now decreased a little as the speed increase since the voltage may increase. Not only the core losses and field winding losses decrease but also the armature copper losses.

The loss model of the generator is used to calculate the efficiency versus the speed of the generator at a fixed input power. The resulting efficiency for the 50 kVA generator used at a constant voltage or at a voltage controlled to maximize the efficiency can be seen in Figure 4.5.

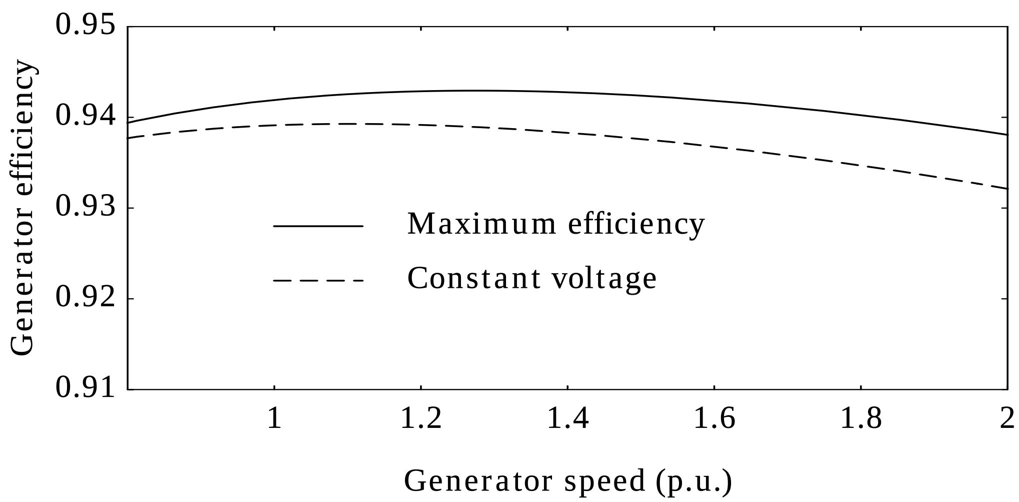

Figure 4.5 The theoretical efficiency of the 50 kVA generator at a constant power.

In the diagram it can be seen that the efficiency of the 50 kVA generator at diode load has its peak value for a speed of 1.1 p.u., if the voltage and power are both kept constant. The efficiency is then 93.7%. If the efficiency is optimized by raising the voltage, the efficiency can be even higher, 94.1%, and have its peak value at 1.25 p.u. speed. It is clear that the generator speed should be kept high to increase efficiency. A realistic limit is probably 1800 rpm, that is equal to 1.2 p.u.

The speed dependency of the generator efficiency will not be the same if the power of the generator is allowed to increase with the speed, see Figure 4.6. This calculation is interesting because it shows how the generator efficiency changes if the generator is always maximally utilized. To avoid overcurrent in the windings the voltage must at least be raised proportionally to the generator speed, corresponding to a constant flux.

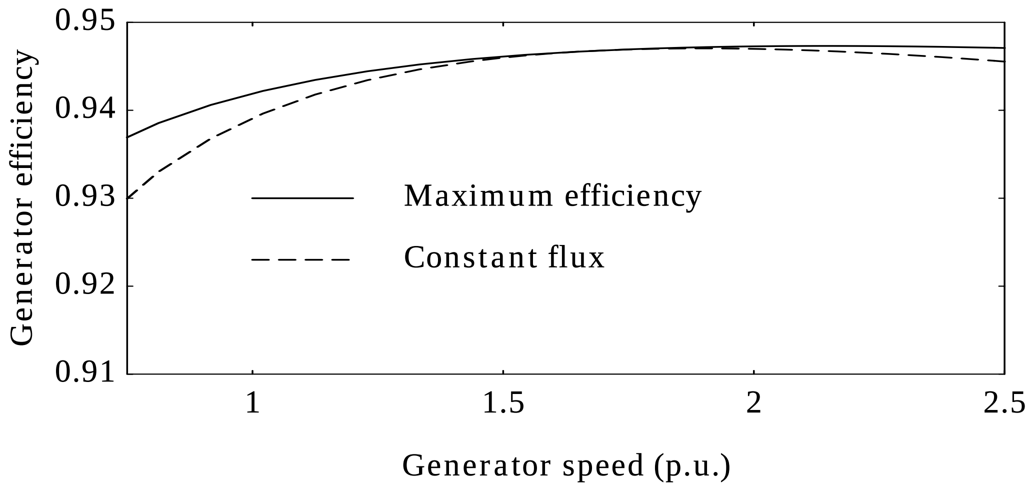

Figure 4.6 The theoretical maximum efficiency of the 50 kVA generator at its maximum power.

If the generator is fully utilized, the efficiency will be even higher than if the power is kept at its rated value for 1500 rpm. The maximum efficiency is 94.6 % but it is at a speed far too high for ordinary generators, 2.2 p.u. Using rated generator flux the maximum generator efficiency is only slightly lower and at a speed of 2.05 p.u. These theoretical maximum efficiencies cannot be reached because the generator will be overloaded. It is, however, clear that a high speed and a high utilization increase generator efficiency.

The results above show how the generator efficiency changes with the generator speed. The converter efficiency does not depend on the speed of the generator, only on the rated voltage. The rated voltage is determined by the network voltage and therefore the converter efficiency is not depending directly on the rated speed of the generator. The change in rated generator speed must instead be compensated by changing the voltage rating of the generator windings to fit the converter voltage. The theoretical generator and converter efficiency is plotted for different generator speeds in Figure 4.7.

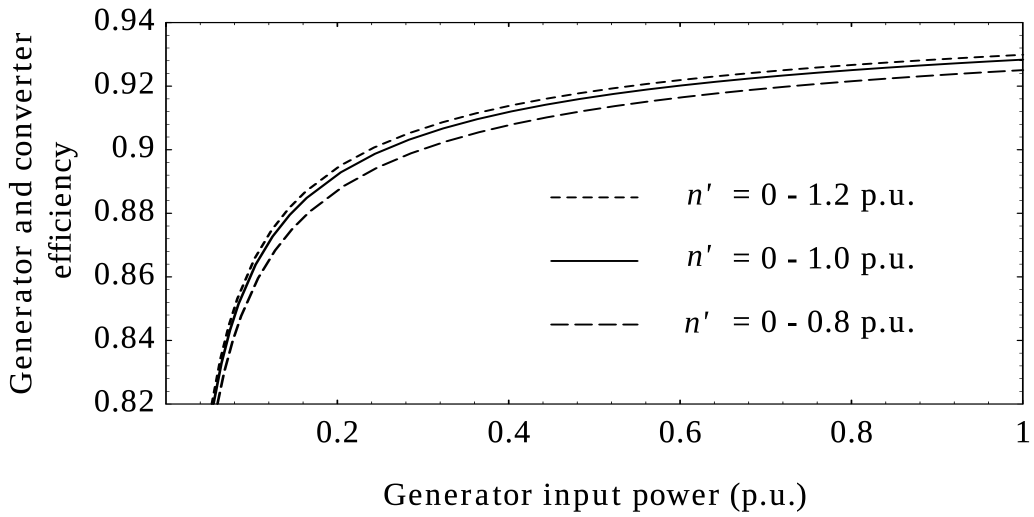

Figure 4.7 The maximum theoretical efficiency of the 50 kVA generator and converter system for various rated speeds.

To verify what difference the generator speed makes, the efficiency of the generator and converter system was measured using speed-power functions representing three different gear ratios. The maximum speeds were 1393 rpm, 1500 rpm and 1700 rpm and the maximum power were 42.1 kW for all three gear ratios. The maximum efficiency of the electrical system for these three gear ratios is compared in Figure 4.8.

It is also clear from these measurements that the efficiency of a generator converter system increases if higher generator speed can be used. The difference in efficiency is about 1% for the 50 kVA system when comparing 1500 rpm with 1700 rpm. This difference between different speeds is very large, mainly because of the low efficiency of the laboratory converter. A more efficient generator converter system will also have higher efficiency at higher speed, but the difference should not be expected to be larger than some tenths of a percent.

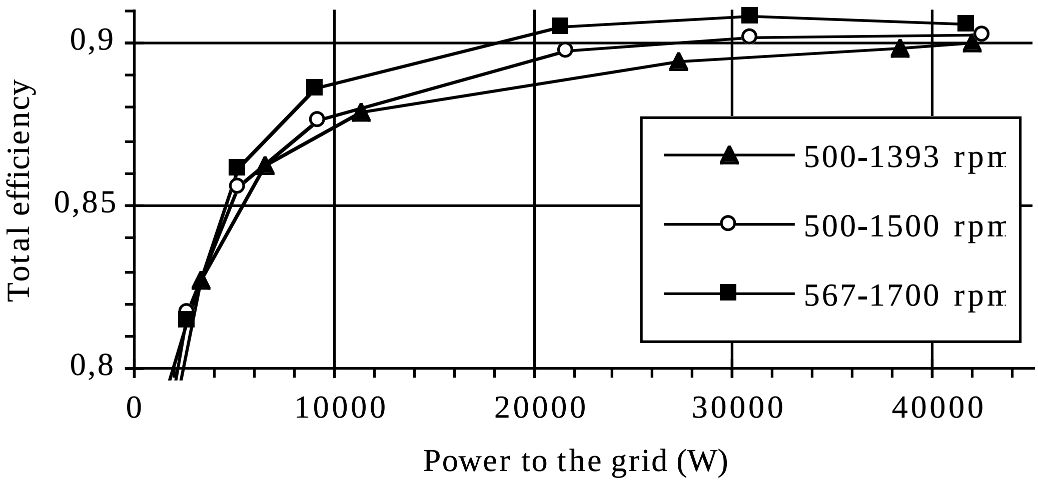

Figure 4.8 The measured maximum efficiency of the 50 kVA generator and converter system for three different gear ratios.

5 Comparison of constant and variable speed

In this chapter the per unit model is used to find the power from different parts of the wind converter system as functions of wind speed. These functions are used to see how the losses change with the control strategies. Constant-speed and two-speed operation of the turbine are compared to variable speed. For the variable-speed operation two different rated speeds and two different voltage controls are considered.

By using a wind distribution model the annual energy passing through different parts of the system can be found. From these annual energy values, the average efficiency of the gear, the generator and the total mechanical to electrical power convertion is calculated. Also approximate values of the difference in energy production between a constant-speed, a two-speed and a variable-speed turbine are calculated. All these efficiencies and the energy production are calculated for turbine sites with various median wind speeds, from 0.35 p.u. to 0.70 p.u.

This comparison is based on equally efficient generators for the variable-speed and the constant-speed systems. The differences between the generators in the two systems are that the variable-speed generator has additional losses and a commutation voltage drop due to the diode rectifier.

5.1 The per unit turbine model

The calculations are made for the 300 kW design example system. For these calculations only a few of the quantities used in Chapter 3 are needed. The quantities used are shown in Figure 5.1. The power values are in this chapter always related to the turbine shaft power at rated operation. This is important when the parameters for the model are determined, since the losses of the generator and converter are not in per unit of the rated generator and converter power. The reason for this is that the total losses should be the sum of the per unit losses in the different components. Values of the loss parameters in Chapter 3 are all related to the rated power of the described component. Now, they will be a little smaller since the losses are related to a larger power. In Table 5.1 the per unit quantities used in the calculations are shown. To separate the different control strategies the indices in Table 5.2 are added to the quantity names.

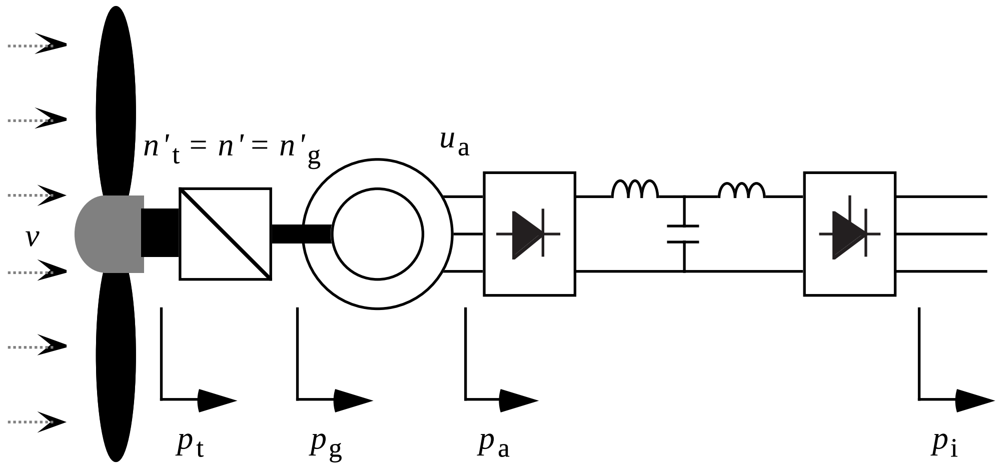

Figure 5.1 The quantities used in the per unit calculations in Chapter 5.

Table 5.1 Per unit quantities and constants used in this chapter and the base values.

Quantity	Notation	Base value
Per unit wind speed	v	v_N
Per unit start wind speed	v_0	v_N
Per unit wind speed of rated power	v_N	v_N
Max operational per unit wind speed	v_{max}	v_N
Per unit median wind speed	v_m	v_N
Per unit turbine power	p_t	$P_{t\ N}$
Per unit generator speed (= turbine speed)	n'	$n_{g\ N}$ $(n_{t\ N})$
Per unit generator mechanical power	p_g	$P_{t\ N}$
Per unit armature voltage	u_a	$\frac{P_{a\ N}}{\sqrt{3}\, I_{a\ N}}$
Per unit generator electrical power	p_a	$P_{t\ N}$
Per unit power from the inverter	p_i	$P_{t\ N}$
Per unit power losses	p_{loss}	$P_{t\ N}$
Power coefficient	C_P	$C_{P\ max}$
Per unit annual energy capture of the turbine	e_t	$P_{t\ N}$ 8760 h*
Per unit annual input energy of the generator	e_g	$P_{t\ N}$ 8760 h*
Per unit annual output energy from the gen.	e_a	$P_{t\ N}$ 8760 h*
Per unit annual output energy from the inverter	e_i	$P_{t\ N}$ 8760 h*
Per unit Weibull probability density	w	—

*) one year is 8760 hours.

Table 5.2 The indices used for the constants and functions in this chapter.

Indices	Notation
Constant speed	CS
Two speeds	TS
Low speed (of two)	TS1
High speed (of two)	TS2
Variable speed	VS
Variable speed, 1.2 p.u. rated speed	VS12
Optimum voltage control	VSopt
Optimum voltage control with 1.2 p.u. as rated speed	VSopt12

5.2 Power and losses as functions of the wind speed

5.2.1 Assumptions for the power functions

It is assumed that the wind turbine generator system is designed for a certain mechanical power from the wind turbine. When comparing the constant-speed system with the variable-speed system, the maximum input power from the turbine is the same but not the output power to the grid. The variable-speed system thus has a little lower rated electric power than the constant-speed system due to increased generator losses and the converter losses. The rated generator input power is, however, the same in both the constant-speed system and the variable-speed system because the gear losses *at rated power* are equal for both systems.

To be able to find the difference between a variable-speed and a constant-speed system, without including the different efficiency of different generator types, it is assumed that the generator used in the constant-speed system is the same as the one used in the variable-speed system. However, since the variable-speed generator is connected to a frequency converter, it has higher losses compared with the network-connected generator. The voltage drop of the variable-speed generator is also higher due to the diode commutations.

The efficiency of the two-speed generator is based on efficiency data for a 250 kW/75 kW 4/6-pole ABB induction generator and not on the loss model. That loss data have been modified to be comparable to the losses of the 300 kW design example generator. When compared with generators of the same size but with only one speed the efficiency is roughly 1 % lower for a two-speed generator. Such a difference is included in this comparison as a 0.7 % lower efficiency at rated power for the two-speed generator than for the constant-speed generator.

Since all functions will be expressed with the wind speed as a parameter, the turbine speed as a function of the wind speed must be defined. That is simple for the cases considered in this report. Either the wind turbine runs at constant speed with a rated speed of 1 p.u. and a low speed for the two-speed generator equal to 2/3 p.u. or variable speed with optimal C_P control is used and the tip-speed ratio is kept constant. Hence the turbine speed is proportional to the wind speed up to the rated wind speed. Above the rated wind speed the turbine speed is assumed to be kept constant.

$$n'_{CS} = 1 \qquad \text{(Speed of the constant-speed generator)} \qquad (5.1)$$

$$n'_{TS1} = \frac{2}{3} \qquad \text{(Low speed of the two-speed generator)} \qquad (5.2)$$

$$n'_{TS2} = 1 \qquad \text{(High speed of the two-speed generator)} \qquad (5.3)$$

$$n'_{VS}(v) = v \qquad \text{(Speed of the variable-speed generator)} \qquad (5.4)$$

$$n'_{VSopt12}(v) = 1.2\ v \qquad \text{(Higher variable speed)} \qquad (5.5)$$

The generator is started as soon as the wind speed is high enough for the turbine to produce more than the total system losses. These include losses in the gear plus generator and for the variable-speed system also the converter no-load losses. The start-up wind speed is not the same for the different control strategies because the losses are different. The start-up wind speed can for the constant- and two-speed systems be found as the lowest wind speed for which the generator output power is zero. At a lower wind speed the no load losses will make the generator power negative. The start-up wind speed v_0 is found by solving the following equation

$$p_a(v_0) = 0 \qquad (5.6)$$

The two-speed system changes speed at the wind speed for which the higher speed produces as much power as the lower speed. This wind speed v_{0TS2} is found by solving the following equation

$$p_{a\,TS1}(v_{0\,TS2}) = p_{a\,TS2}(v_{0\,TS2}) \tag{5.7}$$

For the variable-speed system the start-up wind speed is found as the lowest wind speed for which the output power of the inverter is zero

$$p_i(v_{0\,VS}) = 0 \tag{5.8}$$

The rated wind speed of the turbine is here defined as the lowest wind speed at which the turbine can produce rated power. This wind speed is used as base quantity for the per unit wind speeds. The rated wind speed of the complete wind turbine generator system depend on how the turbine speed is controlled. With the used definition of the rated wind speed the constant-speed turbine reaches rated power at a wind speed above 1 p.u. The reason for this is that the gear ratio is chosen to maximize the turbine efficiency at a wind speed of about 0.7 p.u. to maximize the energy production. The variable-speed turbine also reaches the rated power at a wind speed slightly higher than 1 p.u., because it is not assumed possible to keep the turbine perfectly at its optimum tip-speed ratio.

The rated wind speeds for the different systems, v_N, are found by solving the following equation:

$$p_t(v_N) = 1 \tag{5.9}$$

The turbine is shut down when the wind speed exceeds 1.7 p.u.

$$v_{max} = 1.7 \text{ p.u.} \tag{5.10}$$

The start-up wind speed, rated wind speed and shutdown wind speed for the different systems are found in Table 5.3.

To be able to use the model the turbine power coefficient as a function of tip-speed ratio must first be modelled. Data are used for a three-bladed pitch-controlled 12 m turbine. The approximate turbine C_P curve is a sixth-order curve fit and can be seen in Figure 5.2.

Table 5.3 The start-up wind speed, speed-change wind speed, rated wind speed and shutdown wind speed for different systems.

	CS	TS	VS	VSopt	VSopt12
v_0	0.38	0.29	0.20	0.18	0.18
v_{0TS2}	–	0.62	–	–	–
v_N	1.05	1.05	1.01	1.01	1.01
v_{max}	1.70				

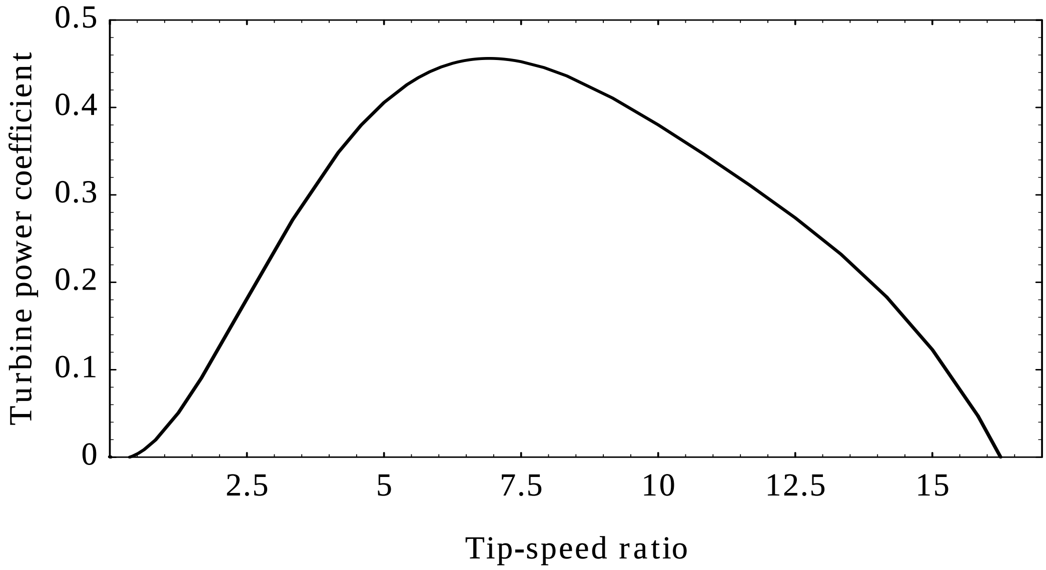

Figure 5.2 Approximation of the power coefficient curve of the turbine.

In the variable-speed system the generator speed is controlled to keep the turbine power coefficient C_P at its maximum value for all wind speeds. However, the turbine speed can not change as fast as the wind speed and, therefore, the turbine can not keep a constant maximum C_P. To include this effect in the calculations without making dynamic simulations the variable-speed turbine is supposed to maintain an average C_P a little lower than the maximum C_P. A lower average C_P means a loss of energy production. The magnitude of this energy loss depends on the control of the turbine. A study of the optimum control of a wind turbine has been made and it shows that with a shaft torque variation of about 20 % the mean power loss is only about 2.5 %, [14]. This is only an estimation of the average C_P but the error of the estimation does not affect the calculated average efficiencies much. The accuracy of the calculated energy production is on the other hand directly affected by the error in average C_P.

5.2.2 Power functions

First the parameters of the gear loss model, the generator loss model and the converter loss model must be determined. This is done by using the results in Chapter 3.

Now the turbine energy-capture function, $p_t(v)$, can be calculated. It is different for the variable-speed turbine, the two-speed turbine and the constant-speed turbine. Therefore, different power functions are defined for the different systems. For the two-speed system two different functions are used. In the C_P function the tip-speed ratio, λ, is replaced by

$$\lambda = \frac{C\, n'}{v} \tag{5.11}$$

where C is a constant determined by the rated wind speed v_N the turbine diameter d_t and the rated turbine speed $n_{t\,N}$. The constant is

$$C = \frac{n_{t\,N}\ \pi\ d_t}{v_N} \tag{5.12}$$

The turbine power functions $p_t(v)$ can now be expressed, below rated power, as

$$p_t(v) = v^3\ Cp\left(\frac{C\, n'(v)}{v}\right) \tag{5.13}$$

where $Cp(\lambda)$ is the approximation of the turbine power coefficient curve. Then the output power of the gear $p_g(v)$ is calculated

$$p_g(v) = p_t(v) - p_{loss\ gear}(\,p_t(v)\,,\,n'(v)\,) \tag{5.14}$$

where $p_{loss\ gear}(\,p_t\,,\,n'\,)$ is the losses of the gear.

The losses of the generator are defined by the loss model with armature voltage, armature current and shaft speed as variables. The armature current is, however, not known yet. Therefore, the generator losses can not be calculated explicitly. Instead, the output power of the generator is calculated as a function of input power, speed and armature voltage. The output power p_a is defined by

$$p_a = p_g - p_{loss\ g}(\ p_a/u_a\ ,\ u_a\ ,\ n'\ ) \tag{5.15}$$

where the unknown armature current simply has been replaced by p_a/u_a. $p_{loss\ g}$ is the loss function from the loss model and p_g is the gear output power. The result is armature output power as a function of p_g , u_a and n'_g. Note that the loss parameters for the generator loss function are not the same for constant-speed operation and variable-speed operation.

Only for the two-speed generator the losses are expressed as explicit functions because the losses for this generator type are not based on the loss model but on empirical data for an ABB generator. The loss data are first adjusted to be comparable to the design example generator, then the loss functions are obtained as curve fits to the data. The approximate loss functions of the two speed generator are

$$p_{loss\ gTS1}(p_g) = 0.013\ +\ 0.100\ \frac{p_g + 2\ p_g^2}{3} \tag{5.16}$$

$$p_{loss\ gTS2}(p_g) = 0.026\ +\ 0.033\ \frac{p_g + 2\ p_g^2}{3} \tag{5.17}$$

Now the output power of the generator $p_a(v)$ can be calculated for the three types of turbine control as well as for two different gear ratios in the variable-speed system.

The inverter output power $p_i(v)$ is expressed for three different control strategies. This function is only used for the variable-speed system, since the constant-speed and two-speed systems do not have any converter. The variable-speed generator voltage is either controlled to have a constant flux or to maximize the generator and converter efficiency. Two gear ratios are used which gives 1.0 and 1.2 p.u. generator speed at rated power. The optimum efficiency functions can not be explicitly defined. They are instead defined as the maximum value of p_i when u_a is changed.

Now the harmonics filter losses and the transformer losses can be added to the loss model. This is, however, not included in this report.

5.2.3 Turbine power

The turbine power for the variable-speed turbine, the two-speed and the constant-speed turbine is calculated for different wind speeds. The power versus wind speed curves for the design example turbine with constant- or variable-speed operation is shown in Figure 5.3.

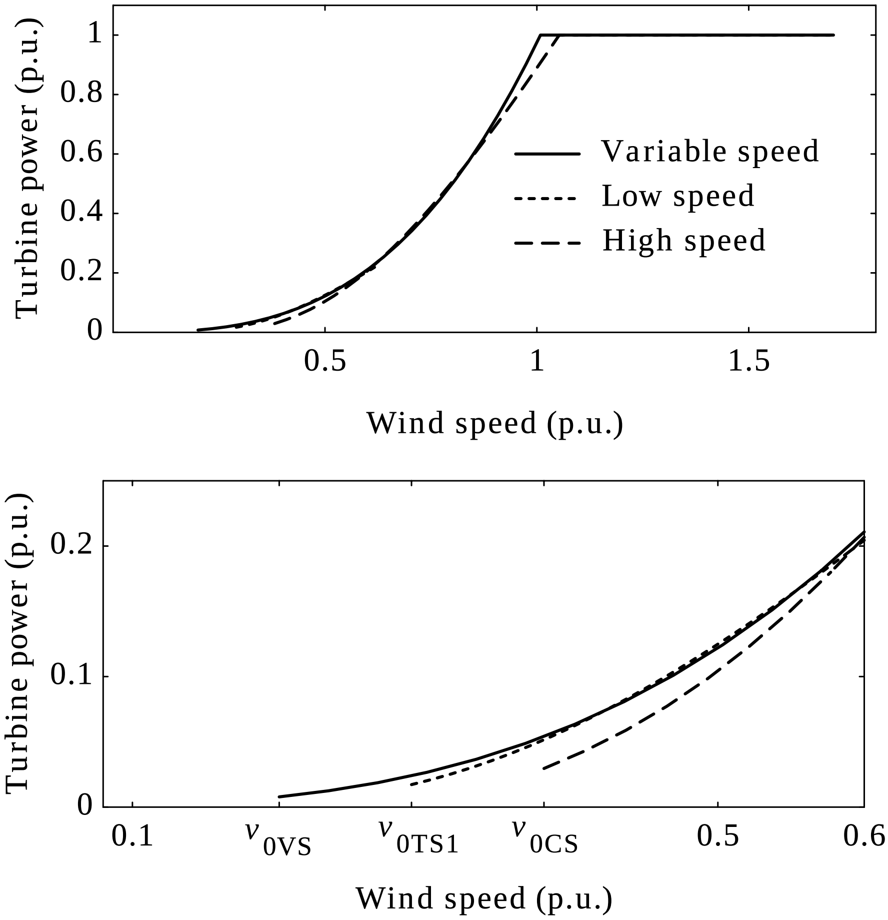

Figure 5.3 The power produced by a constant-speed, a two-speed and a variable-speed turbine. The low wind speed range is enlarged to show the difference between variable-speed and two-speed operations.

The power production of the turbine is not much higher for a variable-speed turbine than for a constant-speed turbine. The difference is that the variable-speed turbine produces more at low wind speeds. For medium wind speeds the constant-speed turbine produces just as much as the variable-speed turbine. Close to rated wind speed the variable-speed turbine produces more and it reaches rated power at a little lower wind speed than the constant-speed turbine. By using a two-speed turbine, the power production at low wind speed is almost equal to that of the variable-speed turbine.

5.2.4 Gear losses

The gear losses only depend on the speed of the turbine and the power from the turbine. They have two parts, the no-load losses which decrease with the speed of the turbine and the gear mesh losses which are a fixed percentage of the turbine power. In the constant-speed system the no-load gear losses are constant, while they are reduced at low speed in the variable speed system. The gear mesh losses are, for a certain turbine power, the same for all systems. In the two-speed system the no-load losses are reduced when the speed is reduced. Figure 5.4 shows the losses of the gear versus wind speed in the different systems.

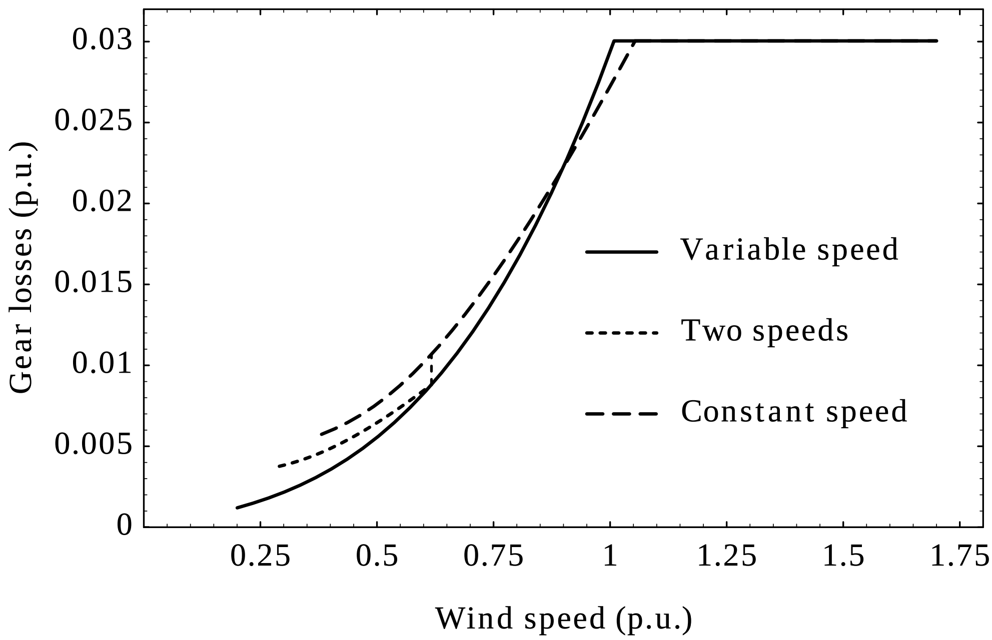

Figure 5.4 The losses of the gear in a constant-speed, two-speed and a variable-speed wind turbine generator system.

5.2.5 Generator and converter losses

The losses of the constant-speed and two-speed generators are compared with the losses of the variable-speed generator and converter. The variable-speed system has a rated speed of 1 p.u. and optimized voltage control.

In Figure 5.5 it can be seen that the variable-speed system has lower losses than the network-connected constant- and two-speed generators up to about 0.7 p.u. wind speed. The lower total losses are achieved by reducing the no-load losses of the generator by the voltage control. At high wind speed, the variable-speed system has higher losses than the network-connected generators due to the losses in the frequency converter and additional generator losses.

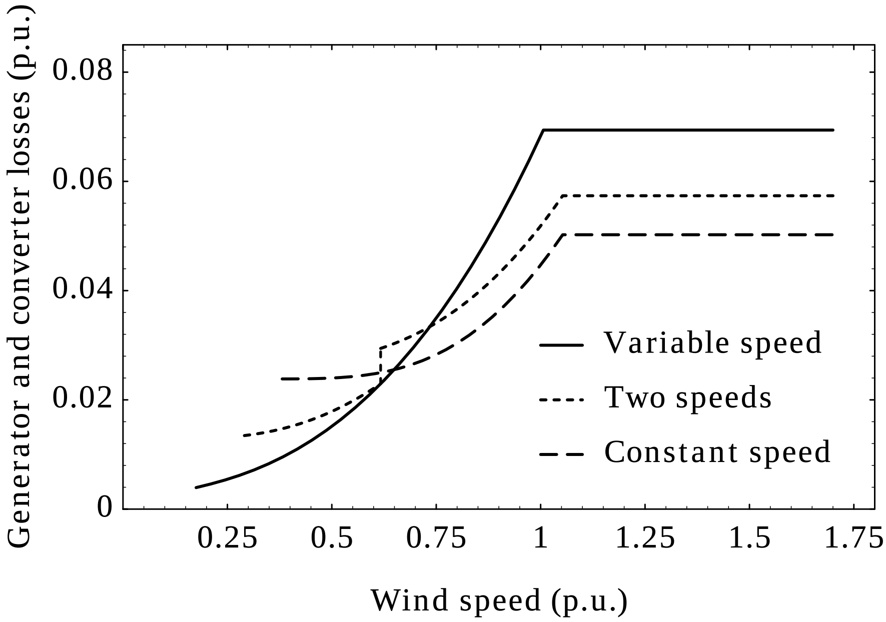

Figure 5.5 The losses of the constant-speed and two-speed generators compared to the generator and converter losses of the variable-speed system.

A two-speed generator can not be utilized fully for both speeds and therefore it has higher losses than the constant-speed generator when it runs on the high speed. At the low speed the two-speed generator has lower losses because the friction, windage and core losses are reduced.

5.2.6 Losses at different voltage controls

The variable-speed system can be controlled in different ways. The voltage control can be used to minimize the losses of the generator and converter. The effect of such an optimization is shown in Figure 5.6 where the losses of the generator and converter at constant rated flux and with minimized losses are compared.

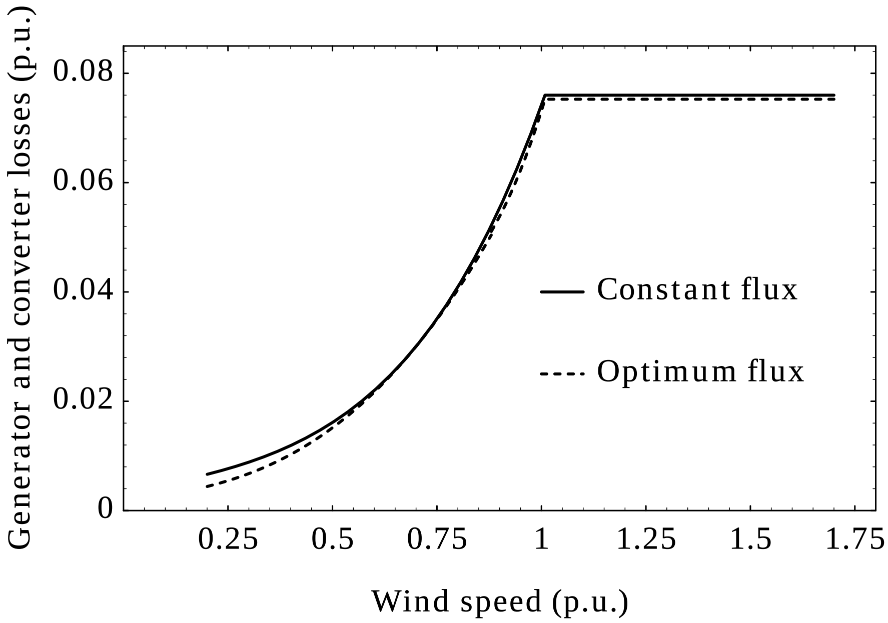

Figure 5.6 The losses of the variable-speed generator and converter at constant rated flux and with minimized losses.

In Figure 5.6 the difference in losses in the variable-speed generator and converter system can be seen. If the flux is kept constant at its rated value the losses are unnecessarily high. By optimizing the flux, the losses at low loads are reduced because of reduced core losses. At rated power the optimized flux is a little higher than rated flux leading to a higher voltage, and thus the copper losses are reduced. The losses are reduced by raising the speed, but the difference between normal rated speed and 20 % higher speed is small and can not be clearly seen in this type of diagram.

5.2.7 Produced electric power

The electric power versus wind speed is shown in Figure 5.7. The power production of the variable-speed and two-speed systems is higher than the production of the constant-speed system at low wind speeds. At medium wind speed the constant-speed system produces a little more because of the lower losses and because the variable-speed turbine can not keep the tip-speed ratio perfectly. Close to the rated wind speed, the variable-speed turbine produces more, and it also reaches the rated power at a lower wind speed than the constant-speed turbine does. Above the rated wind speed, the constant-speed system produces more because it has lower losses. The difference between the constant-speed and two-speed systems can only be seen at low wind speed. The two-speed system has a lower start-up wind speed than the constant-speed system and the produced power is higher up to the speed-change wind speed.

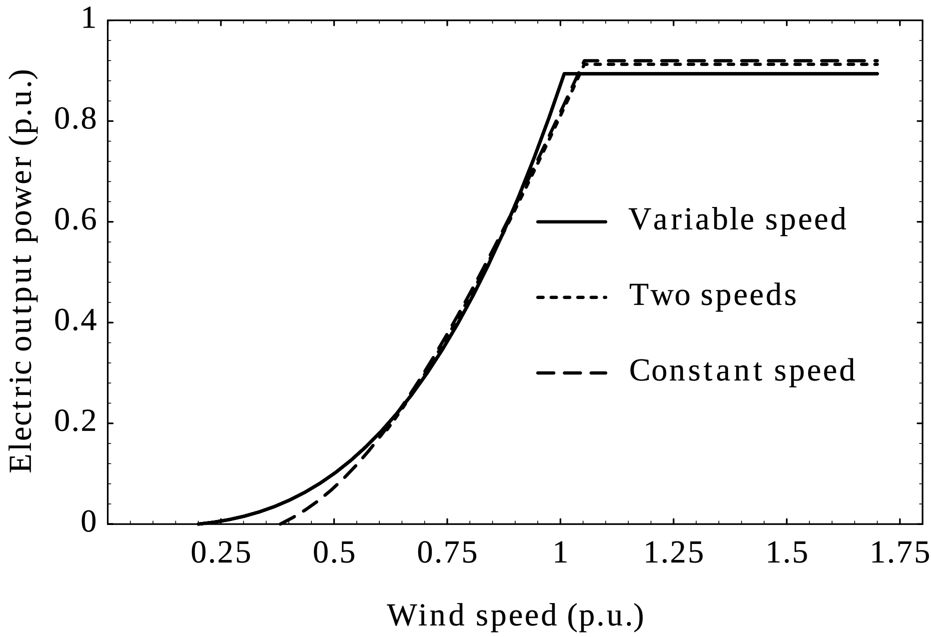

Figure 5.7 The electric power produced by a constant-speed turbine, two-speed turbine and a variable-speed turbine.

5.3 Energy and average efficiency

From the above presented power outputs at different wind speeds an annual energy can be calculated. This is done by integrating the power, from the start-up wind speed to the shutdown wind speed, with the wind speed probability function as a weighting function. A Weibull distribution of wind speeds is assumed when the weighting function is derived, see Figure 5.8. The integral of the weigthing function over all wind speeds from zero to infinity is by definition equal to 1. The Weibull distribution is the usual way to specify the wind resources for different turbine sites. The distribution has two parameters, here the median wind speed v_m and a shape factor c. For normal wind distribution c is about 2, which is assumed here. The Weibull probability distribution is defined as

$$w(v,c,v_m) = v_m^{-c} \ \mathrm{Log}(2) \ c \ v^{(c-1)} \ e^{\left(-\mathrm{Log}(2)\left(\frac{v}{v_m}\right)^c\right)} \qquad (5.18)$$

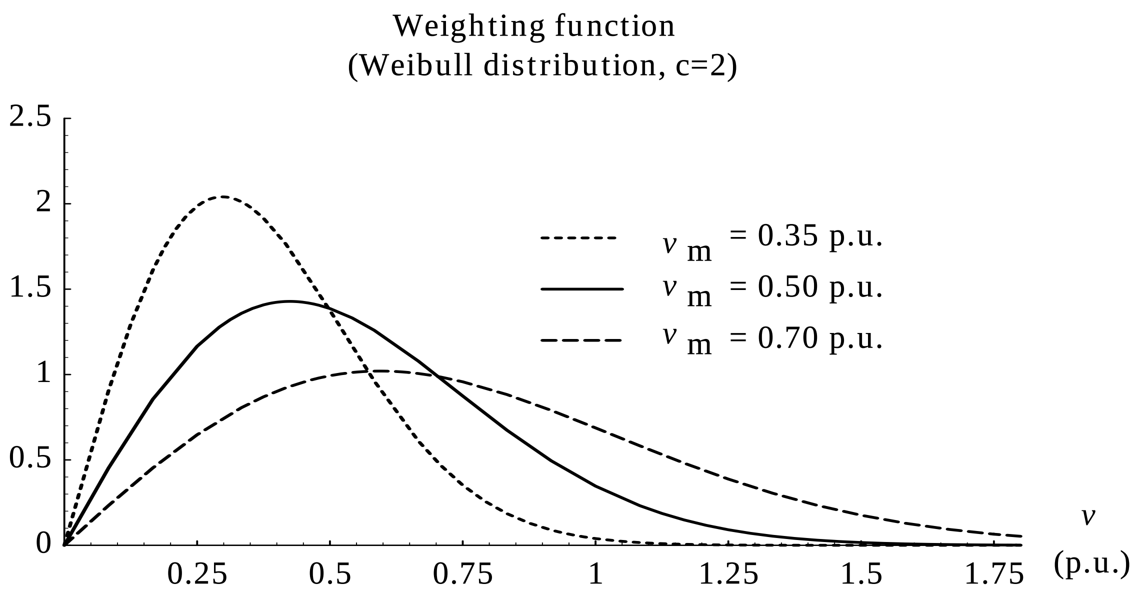

Figure 5.8 The weighting functions for three different median wind speeds.

In Figure 5.9 the energy density function shown. It is the product of the power and the weighting function. The integral of energy density function, from zero wind speed to the shutdown wind speed, is the annual energy in per unit.

In the energy density diagram it can be seen that the energy production at wind speeds just below rated wind speed gives the most important contribution to the total energy production. The energy production above rated wind speed is not as important because the probability of so high wind speeds is low. Contrary to what can be guessed from the power versus wind speed function the energy production at low wind speed is not negligible. The power is low at low wind speeds but the probability of these wind speeds is high making the contribution to the energy production significant.

5.3.1 Assumptions for the energy calculations

The main objective of the comparison between variable-speed and constant-speed systems is to find the average energy conversion efficiency. As a step in the calculation of the average efficiency the energy production is also calculated. Average efficiency is here defined as the output energy divided by the input energy. Since the calculation is made in per unit the calculated energy production is by definition the same as the average power production because the energy is calculated for a time equal to 1 p.u.

Since the Weibull distribution parameters are derived from 10 minutes average wind speeds, the result of the energy calculations has errors, especially for the variable-speed system. However, the error of the output energy is almost the same as the error of the input energy. Since the efficiency is the quotient of output and input energy, this error is small in the efficiency values.

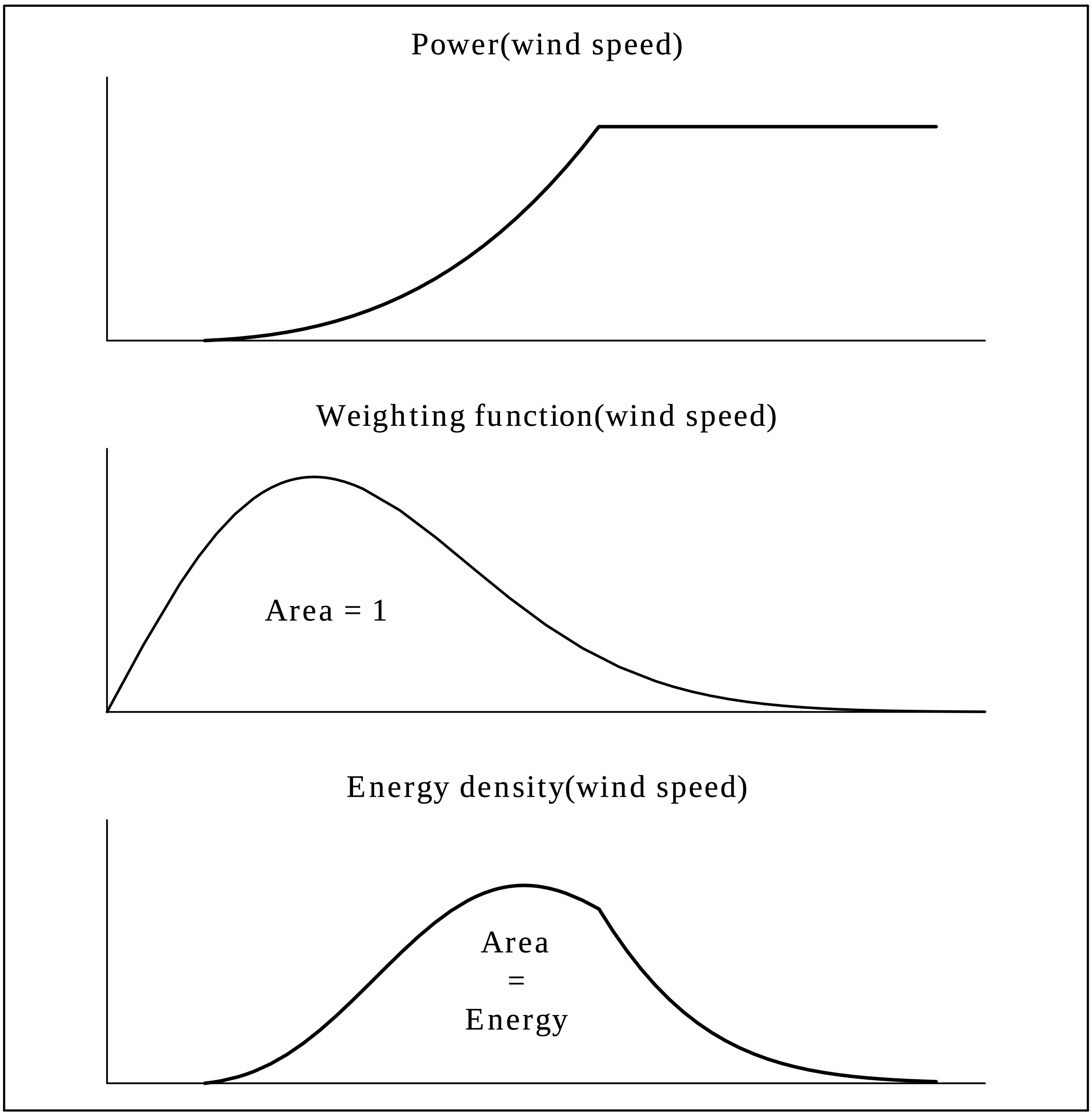

Figure 5.9 The energy density function, equal to the power times the weighting function.

The energy integrations are made for sites with different median wind speeds, between 4.55 m/s and 9.1 m/s. The rated wind speed of the turbine is here assumed to be 13 m/s and the median wind speeds considered are then from

0.35 to 0.7 p.u. At low wind speed sites the median wind speed is in the range 0.35 to 0.45 p.u. (4.55 to 5.85 m/s). Wind turbine generator systems are usually not located at these sites. If the median wind speed is in the range 0.45 to 0.55 p.u. (5.85 to 7.15 m/s) the site is a normal wind speed site and most wind turbine generator systems are located at these sites. Sites of a median wind speed between 0.55 and 0.70 p.u. (7.15 to 9.1 m/s) is high wind speed sites and they are rarely found in Sweden.

5.3.2 Wind energy captured by the turbine

The turbine energy capture is calculated first by integrating the turbine power functions $P_t(v)$ multiplied by the weighting function from the system start-up wind speed to the rated wind speed. Then the rated power multiplied by the total probability of wind speed between rated wind speed and the shutdown wind speed is added. The result from this calculation is the per unit energy captured by the turbine during a year with the chosen wind speed probability curve. The wind speeds for start-up, rated power and shutdown of the turbine are v_0, v_N and v_{max}. The energy captured by the turbine is defined as

$$e_t(c,v_m) = \int_{v_0}^{v_N} w(v,c,v_m)\, p_t(v)\, dv \quad + \quad p_t(v_N) \int_{v_N}^{v_{max}} w(v,c,v_m)\, dv \qquad (5.19)$$

5.3.3 Gear energy output and average gear efficiency

The per unit energy output from the gear is defined in the same way as the turbine energy

$$e_g(c,v_m) = \int_{v_0}^{v_N} w(v,c,v_m)\, p_g(v)\, dv \quad + \quad p_g(v_N) \int_{v_N}^{v_{max}} w(v,c,v_m)\, dv \qquad (5.20)$$

The energy from the gear can, together with the turbine energy, be used to calculate the average efficiency of the gear. The average gear efficiency for a site with the median wind speed v_m can be found as

$$\eta_{gear} = \frac{e_g(c,v_m)}{e_t(c,v_m)} \qquad (5.21)$$

The average gear efficiency is calculated for different median wind speeds from 0.35 to 0.7 p.u. and plotted in Figure 5.10.

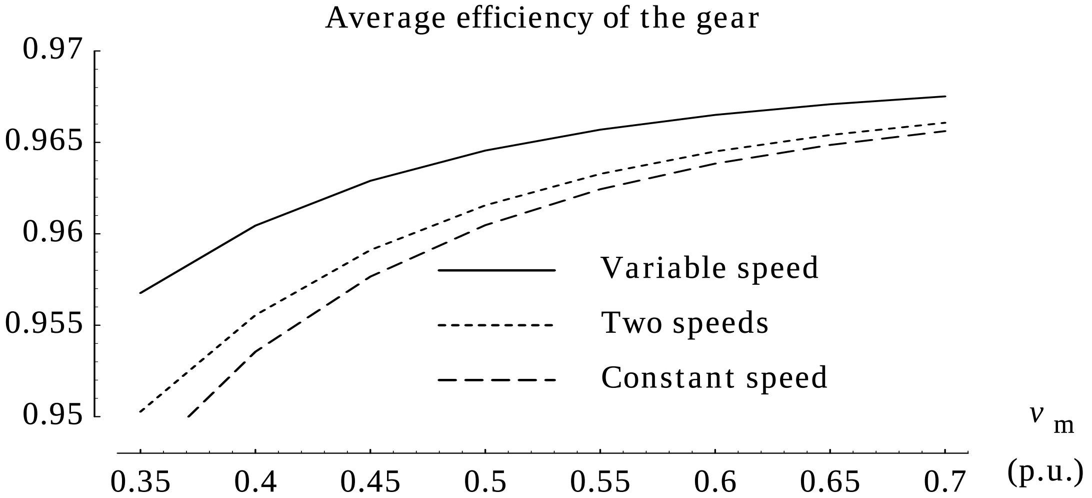

Figure 5.10 The average efficiency of the gear in a variable-speed, a two-speed and a constant-speed turbine.

The average gear efficiency is always higher in a variable-speed system than in a constant-speed system. This is obvious since the gear losses in a variable speed system are never higher than in a constant speed system at equal power. The difference in average efficiency is not large, only 0.2 % for high wind speed sites, 0.4 % for medium wind speed sites and about 0.7 % for low wind speed sites. It is a small, but clear, advantage of the variable-speed wind turbine generator system.

5.3.4 Electric energy and average electric efficiency

In this section the average efficiency of the generator of the constant-speed system is compared with the average efficiency of the generator and converter of the variable-speed system. Later in Section 5.3.5 the total efficiency, including the gear, is presented. The per unit output electrical energy of the constant-speed generator can be calculated as

$$e_{aCS}(c,v_m) = \int_{v_{0CS}}^{v_{NCS}} w(v,c,v_m)\, p_{aCS}(v)\, dv \quad + \; p_{aCS}(v_N) \int_{v_{NCS}}^{v_{max}} w(v,c,v_m)\, dv \tag{5.22}$$

For the two-speed system the integration is divided into three parts

$$e_{aTS}(c,v_m) = \int_{v_{0TS1}}^{v_{0TS2}} w(v,c,v_m)\, p_{aTS1}(v)\, dv + \int_{v_{0TS2}}^{v_{NTS}} w(v,c,v_m)\, p_{aTS2}(v)\, dv +$$

$$+ \ p_{aTS2}(v_{NTS}) \int_{v_{NTS}}^{v_{max}} w(v,c,v_m)\, dv \qquad (5.23)$$

For the constant-flux variable-speed system the output energy is the energy from the inverter

$$e_{iVS}(c,v_m) = \int_{v_{0VS}}^{v_{NVS}} w(v,c,v_m)\, p_{iVS}(v)\, dv + p_{iVS}(v_{NVS}) \int_{v_{NVS}}^{v_{max}} w(v,c,v_m)\, dv \qquad (5.24)$$

The energy produced when optimized flux and a higher speed is used is calculated in a similar way.

The average efficiency of the generator system can be calculated by dividing the output electrical energy by the input mechanical energy from the gear. A comparison of the average efficiency of the generator system is made to find how efficient a variable-speed generator system is compared to a constant-speed system. First the variable-speed system with optimized efficiency is compared with a two-speed system and a constant-speed system.

It is found, from Figure 5.11, that the optimized variable-speed system often is about as efficient as the constant-speed system in converting the mechanical energy of the generator shaft into electric energy to the grid. On sites with low median wind speed the variable-speed system is more efficient because of its low losses at low power. The efficiency is a little lower or as high as the efficiency of a constant-speed system for normal wind speed sites. For high wind speed sites the variable-speed generator system is always less efficient. The average efficiency of the two-speed system is rather similar to the one of the constant-speed system. It is a little lower at high wind speed sites and a little higher at low wind speed sites.

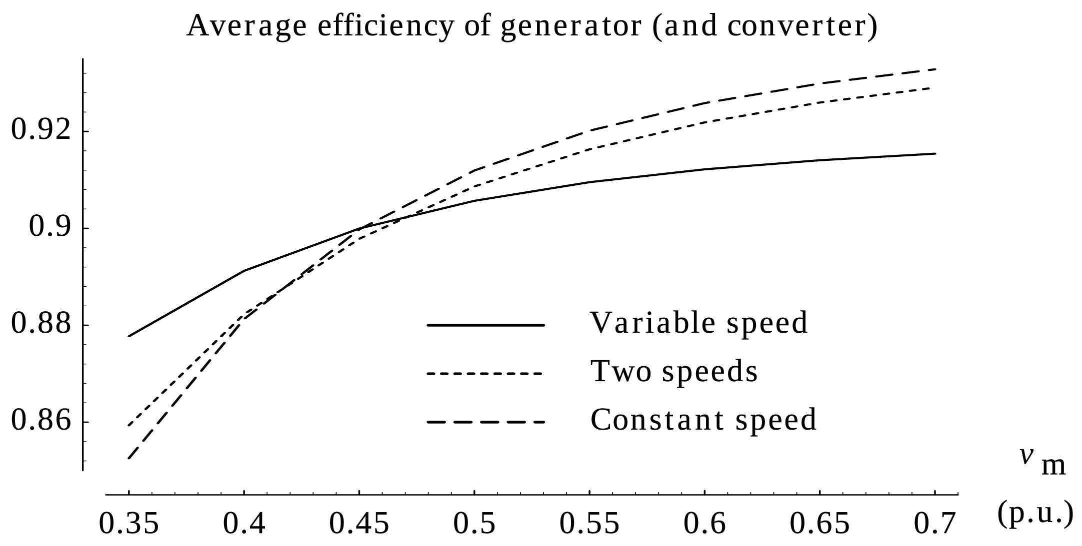

Figure 5.11 Average electric efficiency of a two-speed, a constant-speed system and a variable-speed system using optimized flux and 1.0 p.u. rated speed.

The difference in average efficiency between an optimized voltage control and the often used constant flux voltage control can be seen in Figure 5.12.

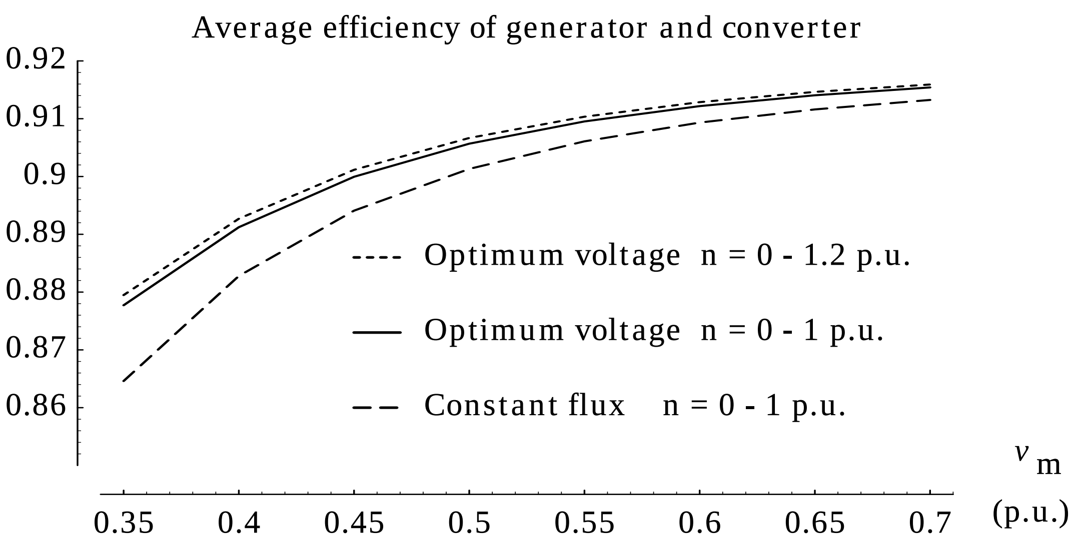

Figure 5.12 The average efficiency of a variable-speed system with constant flux or optimized efficiency and either a rated speed of 1 p.u. or 1.2 p.u.

If optimized voltage control is used instead of constant rated flux the efficiency will be about 0.5 to 0.8 % higher on sites with normal median wind speed. On sites with low wind speed the difference in efficiency, between optimized voltage control and constant flux, can be up to more than 1 %. If a higher generator speed is used than the speed at 50 Hz, the average efficiency will also improve. The increase in efficiency by using a higher speed is small, less than 0.2 % for all median wind speeds.

5.3.5 Total efficiency including the gear

To find the average efficiency in converting the turbine shaft energy into electrical energy, the output electrical energy is divided by the turbine energy. In Figure 5.13 the resulting average efficiency can be seen. The turbine efficiency is not included in these figures.

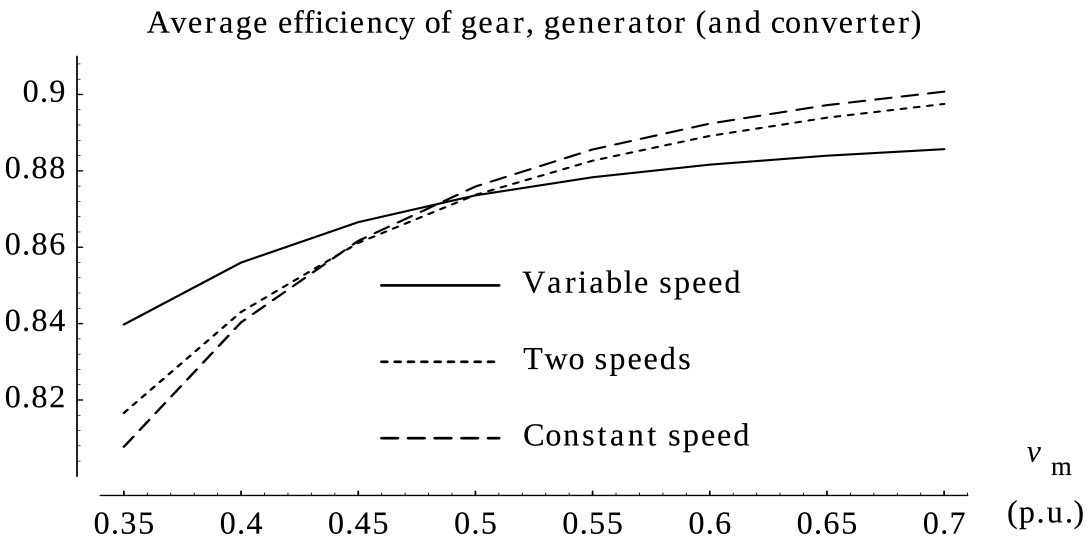

Figure 5.13 The total efficiency in converting the turbine energy into electric energy fed to the network.

The result is similar to the average efficiency of only the generator and converter. The only difference is that the gear losses make the constant-speed system less efficient compared with the variable-speed system.

The laboratory system has a low converter efficiency (95.6 %) compared with the design example system (98 %). This difference is found to be very important when a constant-speed and the corresponding variable-speed system are compared, see Figure 5.14. The lower converter efficiency makes the average efficiency of the variable-speed system lower than the average efficiency of the constant-speed system for all median wind speeds. This shows that an efficient converter is very important if the variable-speed system shall be as efficient as the constant-speed system.

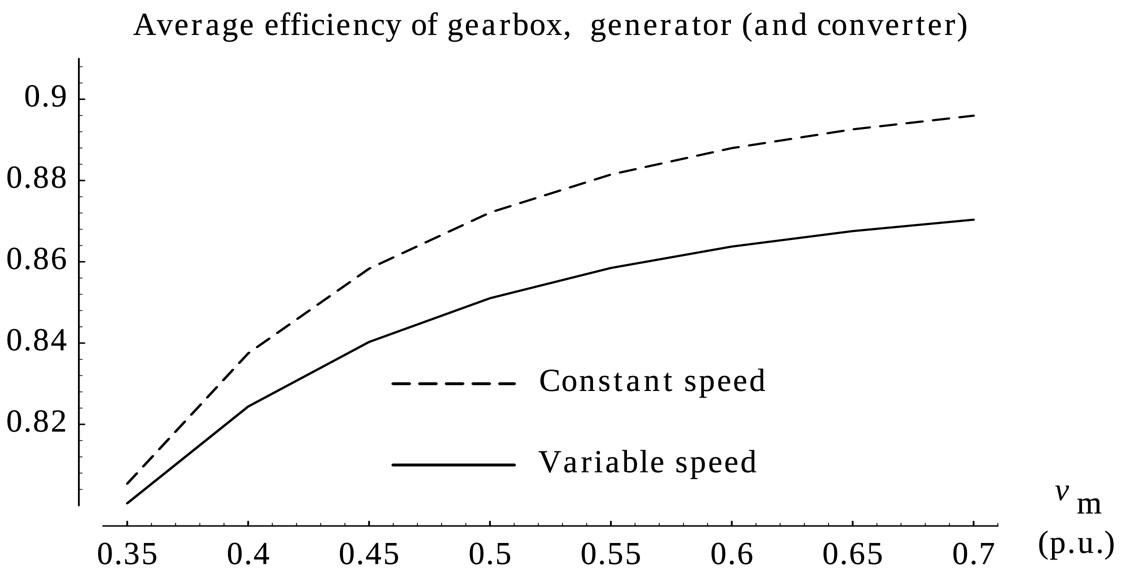

Figure 5.14 Calculated average electric efficiency of the 50 kVA generator system at constant speed and at variable speed, using optimized flux and 1.0 p.u. rated speed.

5.3.6 Produced energy

When the average efficiencies are calculated, there are also automatically results showing the difference in produced electric energy. The calculation method have been derived for constant-speed turbines and, therefore, the accuracy of this comparison depends on how accurate the energy calculation method is for variable-speed turbines. Because of this uncertainty, the predicted difference must be seen only as a hint of what the real difference may be.

The capacity factor is defined as the average power production divided by the rated electric power. In per unit the average electric power is equal to the produced electric energy. Therefore, the capacity factor C_{cap} for the constant-speed and two-speed systems can be defined as

$$C_{cap} = \frac{e_a(c, v_m)}{p_a(v_N)} \tag{5.25}$$

For the variable-speed system the capacity factor is defined as

$$C_{cap} = \frac{e_i(c, v_m)}{p_i(v_N)} \tag{5.26}$$

The capacity factor of the turbine can be calculated for different control strategies. The comparison is made for a constant-speed , a two-speed and a variable-speed wind turbine generator system using optimized flux and a rated generator speed of 1 p.u. The results are shown in figure 5.15.

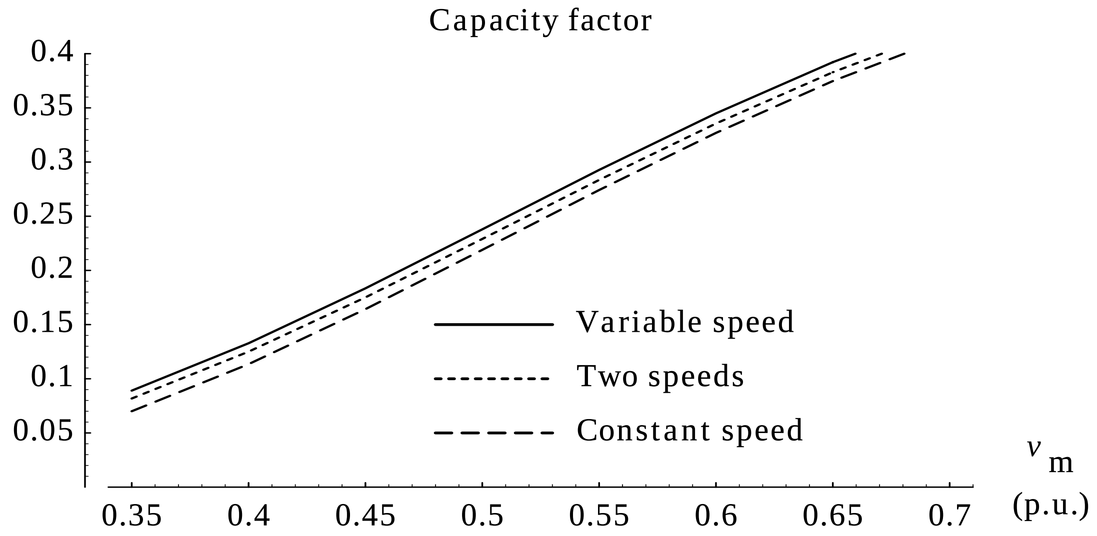

Figure 5.15 The capacity factor of a wind turbine generator system at constant-speed, two-speed and variable-speed operation.

It can be seen that the capacity factor of the variable-speed system is higher than that of the constant-speed system. The two-speed system also has a high capacity factor compared with the constant-speed system. The figure shows the absolute energy capture, expressed as the capacity factor for different systems. It is, however, difficult to find the relative increase in the energy production when a constant-speed system is changed to an equal two-speed or variable-speed system from Figure 5.15. The relative increase in production is shown in Figure 5.16. The increase in energy production has been calculated for the variable-speed system as

$$\frac{e_{\mathrm{iVSopt}}(\mathrm{c},v_{\mathrm{m}})}{e_{\mathrm{aCS}}(\mathrm{c},v_{\mathrm{m}})} \tag{5.27}$$

and for the two-speed system

$$\frac{e_{\mathrm{aTS}}(\mathrm{c},v_{\mathrm{m}})}{e_{\mathrm{aCS}}(\mathrm{c},v_{\mathrm{m}})} \tag{5.28}$$

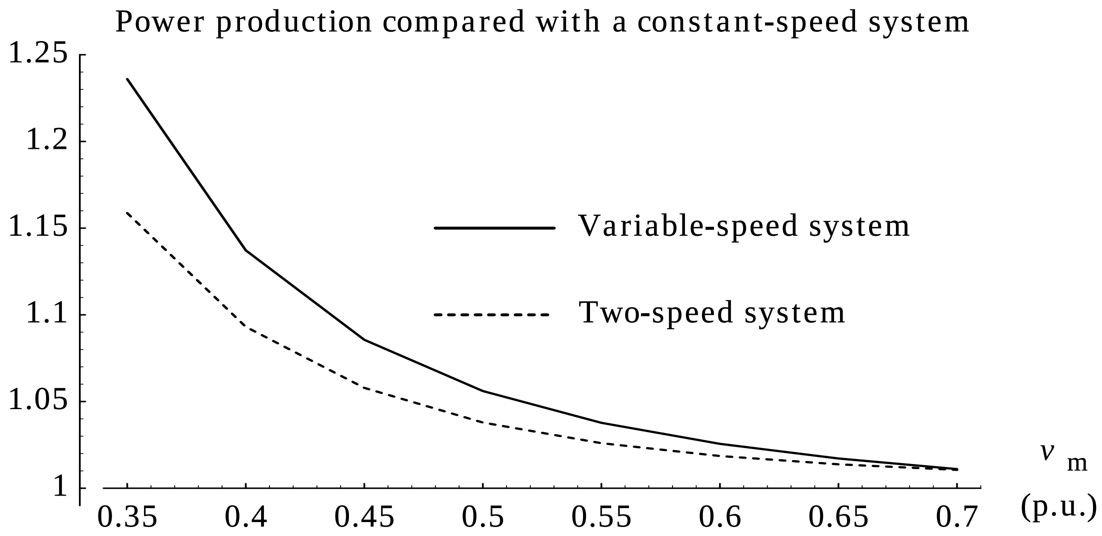

Figure 5.16 The relative increase in produced electric energy if a two-speed or variable-speed system is used instead of a constant-speed system.

It can be seen that the two-speed system produces more than the constant-speed system. The difference between two-speed and variable-speed system is not so large as the difference between constant-speed and two-speed systems. For a normal median wind speed the increase in energy production is about 5.2 % if a variable-speed system is used instead of a constant-speed system. If a two-speed system is used the increase is 3.8 %. This comparison is made for systems with equal rated turbine power and unequal rated output power.

5.4 Summary of average efficiency comparison

Although a variable-speed system has extra losses in the generator and converter it can usually be about as efficient as a constant-speed generator. At low wind speed sites it is more efficient, at high wind speed sites it is less efficient. The extra losses in the frequency converter have often been said to be a disadvantage of the variable-speed system. However, the calculations in this chapter show that the decrease in generator and gear losses can compensate for the increase in losses due to the frequency converter.

The calculations are based on the use of an efficient frequency converter, with a rated efficiency of 98 %. If a transistorized inverter is used, in order to reduce the network disturbance, the total efficiency will decrease a few percents. Still, the difference in average efficiency between variable-speed and constant-speed systems will be small at medium wind speed sites.

6. Conclusions

A model of the losses in the generator and converter has been derived and verified for a 50 kVA generator. The model can be used to predict the shaft torque of the generator with an error of less than 2 % of the rated torque. This should be sufficient for the steady-state torque control of a wind turbine. The model only needs measurements of the generator speed, the dc voltage and the dc current of the converter. Most of the model parameters are, for normal generators, available from the manufacturer. The rest of the parameters can be estimated if the demand on the accuracy is not higher than about 2 %, otherwise they have to be measured.

The loss model can be used to maximize the generator and converter efficiency. By changing the generator voltage, the efficiency of the system can be maximized. If the voltage is controlled to maximize the efficiency, the generator and converter system is about 0.5 to 0.8 % more efficient, in average, than if the common constant flux control is used. It has also been found that a variable-speed generator should use a high speed to increase the efficiency and decrease the generator size. To use a larger standard generator than necessary does not normally improve the efficiency.

Earlier, it has often been said that the losses in the frequency converter of a variable-speed system are a drawback. In this report it is, however, shown that the total energy losses do not have to increase because of the frequency converter. The generator and gear losses can be reduced when the converter is used, and this reduction may be large enough to compensate for the losses in an efficient converter. This means that the annual average efficiency of a variable-speed generator system can be as high as that of a constant-speed system, at least for turbine sites of normal wind speed. At high wind speed sites the average efficiency is lower and at low wind speed sites it is higher in the variable-speed system than in the constant-speed system.

The loss model has errors in modelling the additional losses and the core losses. If the accuracy is critical, the additional losses and the core losses should be investigated more thoroughly.

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