Wind-Electric Pump System Design

by

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Declaration

By submitting this thesis electronically, I declare that the entirety of the work contained therein is my own, original work, that I am the owner of the copyright thereof (unless to the extent explicitly otherwise stated) and that I have not previously in its entirety or in part submitted it for obtaining any qualification.

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Name in full

March 2009

Date
Abstract

The aim of this study is to analyse the operation of a wind-electric pumping system (WEPS) as an alternative to conventional mechanical wind pumps for application in stand-alone water-pumping schemes. The steady-state as well as the dynamic operation of such a system is analysed. Through these analyses, practical guidelines are given in the design and sizing of the different system components to ensure efficient and reliable operation. Theoretical analyses are supported by measured results conducted on a small scale wind-electric pump system. The limitations involved in the design and implementation of a large scale wind-electric pump system are presented through a case study. It is firstly concluded that small-scale wind-electric pump systems have the potential of offering superior performance and flexibility to conventional mechanical wind pumps. It is secondly concluded that large-scale wind-electric pump systems are best suited, in terms of economic and practical feasibility, to pumping applications with low pressures and medium to high wind regimes at the turbine installation site.

Opsomming

Die doel van die studie is om die werking van `n wind-elektriese pompstelsel te analiseer vir moontlike toepassing vir onafhanklike water pompskemas. Beide die gestadigde toestand en dinamiiese werking van so `n skema is geanaliseer ten einde riglyne te formuleer wat die effektywes en betroubare werking van so `n stelsel sal verseker. Teoretiese analises word gesteun deur praktiese metings wat gedoen is op `n wind-elektriese pompstelsel wat op klein skaal ontwerp en gebou is. `n Gevalleystudie is gedoen waartydens `n groot skaalse ontwerp van `n wind-elektriese pompstelsel gedoen is. Die beperkings gebonde aan die ontwerp en implementering van so `n groot stelsel is uitgelig en bespreek. Dit is eerstens bevind dat kleinskaalse wind-elektriese pompstelsels beter verrigting bied, en makliker is om te implementeer en te onderhou, as tradisionele meganiese pompstelsels. Dit is tweedens bevind dat groot skaalse wind-elektriese stelsels slegs prakties en finansiëel sin maak by pomptoepassings met lae drukke en medium tot hoë windtoestande by die turbine installeringsterrein.
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List of Symbols and Abbreviations

Symbols

\( \rho \) - air density, \( \text{kg/m}^3 \)
\( v \) - wind speed, \( \text{m/s} \)
\( r \) - turbine blade radius, \( \text{m} \)
\( C_P \) - turbine power coefficient
\( \lambda \) - tip-speed-ratio
\( P_H \) - atmospheric air pressure, \( \text{kPa} \)
\( P_o \) - standard air pressure at sea level, \( \text{kPa} \)
\( T_H \) - temperature, \( \text{K} \)
\( H_{asl} \) - height above sea level, \( \text{m} \)
\( c \) - Weibull scale parameter
\( k \) - Weibull shape parameter
\( p \) - number of hours
\( \bar{v} \) - mean wind speed
\( \sigma \) - standard deviation
\( p_g \) - number of rotor poles of the PMSG
\( p_m \) - number of stator poles in the induction motor
\( \Phi_p \) - flux produced per pole, \( \text{Wb} \)
\( Q_c \) - total number of coils in stator
\( q \) - number of stator coils per phase
\( a \) - number of parallel circuits per phase
\( B_p \) - peak air-gap flux density, \( \text{T} \)
\( N \) - number of turns per stator coil
\( \omega \) - electrical speed, \( \text{rad/s} \)
\( \ell_a \) - active length of stator coil, \( \text{m} \)
\( \ell_e \) - total end-turn length of a stator coil, \( \text{m} \)
\( r_e \) - average radius of stator coil, \( \text{m} \)
\( r_i \) - inner radius of stator coil, \( \text{m} \)
\( r_o \) - outer radius of stator coil, \( \text{m} \)
\( n \) - number of coils in a coil phase group
$\theta_m$ - coil pitch or coil span
$\theta_{re}$ - coil width angle at radius $r_e$
$w$ - coil side width
$h$ - stator coil height, m
$d$ - stator coil conductor diameter, m
$k_p$ - pitch factor
$k_d$ - distribution factor
$k_m$ - winding mass factor
$k_f$ - fill factor of stator coil conductors
$k_s$ - stator factor
$k_w$ - winding factor
$k_e$ - end-winding factor
$k_r$ - radius factor
$J$ - current density in the stator conductors, A/mm$^2$
$R_G$ - stator phase resistance, $\Omega$
$L_G$ - stator phase inductance, H
$P_{cu}$ - copper losses in stator winding, W
$u$ - number of parallel strands per conductor
$d$ - stator coil conductor diameter, m
$P_e$ - eddy current losses in stator winding, W
$\rho_t$ - material resistivity, $\Omega m$
$M_{cu}$ - total copper mass of stator coils, kg
$\gamma_{cu}$ - mass density of copper, kg/m$^3$
$P_{fe}$ - varying iron power losses in induction motor stator, W
$P_{wf}$ - varying windage and friction loss of induction motor, W
$M_f$ - mass of induction motor stator yoke, kg
$M_t$ - mass of induction motor stator teeth, kg
$k_{sf}$ - stator lamination stack factor
$\ell_y$ - stator lamination stack length, m
$S$ - density of steel, g/cm$^3$
$D_i$ - inner diameter of stator lamination, m
$D_o$ - outer diameter of stator lamination, m
$\ell_t$ - length of stator slot, m
$C_n$ - total amount of stator coil slots
$A_t$ - total area of a stator coil slot, m²

$k_{wf}$ - winding factor for fundamental frequency

$N_{ph}$ - amount of windings in series per phase

$m$ - total number of phases

$h_y$ - stator yoke height, m

$c_p$ - coil pitch in terms of the number of stator slots per pole

$m$ - total number of phases

$r_p$ - number of stator slots per pole per phase

$B_{lt}$ - maximum flux density in the stator teeth, T

$B_{my}$ - maximum flux density in the stator yoke, T

$t_p$ - coil slot pitch

$t_w$ - width of the stator teeth, m

$\tau$ - pole pitch

$\rho_f$ - density of fluid, kg/m³

$D$ - pipe diameter, m

$L$ - pipe length, m

$C$ - Hazen-Williams roughness coefficient

$K$ - nominal loss coefficient

$P_{VP}$ - liquid vapour pressure, kPa

$H_s$ - static head of a pipeline, m

$H_f$ - frictional head loss in the piping, m

$H_m$ - minor head losses due to the various pipe fittings, m

$H_{ss}$ - static suction head, m

$H$ - centrifugal pump head, m

$Q$ - flow rate of water, m³/s

$P_h$ - Hydraulic pump power, W

$NPSH_R$ - required net positive suction head, m

$NPSH_A$ - available net positive suction head, m

$\Omega_1$ - rotational speed of turbine shaft, r/min

$\Omega_2$ - rotational speed of pump shaft, r/min

$s$ - induction motor slip

$J_T$ - inertia associated with the turbine blades and generator assembly, kg.m²

$J_S$ - combined inertia of the induction motor and centrifugal pump, kg.m²
## Abbreviations

<table>
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<th>Abbreviation</th>
<th>Description</th>
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<tr>
<td>WEPS</td>
<td>Wind-Electric Pump System</td>
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<tr>
<td>AFPMSG</td>
<td>Axial Flux Permanent Magnet Synchronous Generator</td>
</tr>
<tr>
<td>BDFIG</td>
<td>Brushless Doubly-Fed Induction Generator</td>
</tr>
<tr>
<td>DOL</td>
<td>Direct On Line</td>
</tr>
<tr>
<td>VSD</td>
<td>Variable Speed Drive</td>
</tr>
<tr>
<td>EMF</td>
<td>Electromotive Force</td>
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1. Introduction

1.1 Wind-Electric Pump Systems

Mechanical wind pump systems are used extensively around the world in regions with low to moderate wind conditions. Multi-blade turbines are used because they have good efficiency in low wind regimes. The types of pumps that are driven by these turbines are positive displacement and centrifugal pumps.

The most common positive displacement pump used with these systems is the piston pump. The pump is connected to the turbine by means of a mechanical linkage. This configuration makes the design simple and cost effective. This pump requires a high starting torque which is provided by the high solidity of the multi-blade turbine. These systems are optimised for low wind speed performance and can start pumping from as low as 2.5 m/s and reach peak efficiency at 4–7 m/s. This turbine-pump configuration, however, does have a few disadvantages. The most serious of these, is the mismatch between the power characteristics between the turbine and piston pump. The turbine has a cubic increase of power with rotational speed whereas the piston pump has a linear power increase with rotational speed. The pump would therefore not be able to utilise a large portion of the power developed by the wind turbine at higher wind speeds. This poor efficiency would result in reduced output from the pumps. Another disadvantage is the frequent failure of the mechanical linkage or lift rod between the turbine and pump. The acceleration and retardation of the linkage caused by the operation of the piston pump places undue forces on the linkage, causing it to fail. According to Mathew [1], linkage failure accounts for more than 40 % of total maintenance done on mechanical wind pumps. The linkage also necessitates the turbine to be erected directly above the water source. This limitation often means that the turbine can not be placed in areas, near the vicinity of the water source, with a greater wind resource potential. The piston pumps also generally need regular maintenance every 2-3 years to replace the pump seals which become brittle and start leaking, causing a reduction in pump output.

The use of centrifugal pumps instead of positive displacement pumps address the mismatch that exists between the turbine and piston pump, because the centrifugal pumps have the same cubic power increase with rotational speed characteristic as the
turbines. Centrifugal pumps also do not require the high starting torque associated with positive displacement pumps. Centrifugal pumps, however, operate under high rotational speeds in contrast to the low rotational speeds of the multi-blade turbines. This warrants the use of a transmission. A gear ratio is chosen as such to optimally match the cubic requirements of the pump to the optimal power delivery points of the turbine at each wind speed. The similar cubic power characteristic of both turbine and pumps means that if the pump is optimally matched to the turbine at low wind speeds, it will be optimally matched at higher wind speeds as well. This good power transfer efficiency between turbine and pump over a broad wind speed operating range is advantageous because the wind conditions of a site can vary extensively. Low solidity turbines are used for large installations in regions with moderate to high wind conditions in excess of 7 m/s because of their higher efficiency and superior performance over common multi-blade turbines configurations. The level of power generated at these moderate to high wind speeds makes the use of a mechanical transmission very expensive and complex. The vertical rotating shaft between the turbine transmission and centrifugal pump also hinders the optimal placement of the turbine near the water source.

Wind-electric pumps systems (WEPS) utilises low solidity wind turbines and centrifugal pumps but use permanent magnet synchronous generators (PMSG) and common 3-phase induction motors to transfer the harnessed wind power from the turbine to the pump. This configuration is shown in Figure 1. The generator is directly connected to the induction motor without any power electronics or control. The basis for this configuration is the ability of standard, industry proven, 50 Hz induction motors and centrifugal pumps to operate at variable shaft speeds due to the varying voltage and frequency supplied by the permanent magnet generator as the turbine speeds up or slows down in response to wind conditions. A major advantage of such a configuration is that the difference in the number of generator and motor poles forms an electrical gearbox between the turbine and pump, eliminating the need for a complex and expensive mechanical transmission. The permanent magnet generator also allows the system to operate as a stand-alone system. This mobility together with the electrical connection between the turbine and pump enable the turbine to be placed away from the water source at the optimal wind site. This configuration therefore solves the turbine mobility limitation imposed on both the mechanical wind pump configurations mentioned previously. The permanent magnet generator design
used in the WEPS configuration is of an axial flux, air-cored design with a simple concentrated, non-overlapping stator coil layout. The air core design allow for the concentrated stator coils to be cast in an epoxy mould. This configuration, together with the simple winding structure of the stator coils, adds to the simplicity and low cost of the manufacturing process of the generator. Therefore, the industry standard design of both motor and centrifugal pump, simple operation and manufacture of the permanent magnet generator and the absence of any power electronics or control, all increase the cost effectiveness of the WEPS configuration vs. conventional mechanical wind pump configurations.

The simplicity and high reliability of the components used in the wind-electric system thus requires no scheduled maintenance and can operate autonomously for periods of years between inspections. The simple construction and industry standard components in the WEPS configuration therefore mean that existing small-scale mechanical wind pump installations can easily be converted to accommodate the WEPS configuration for a more efficient and superior performance advantage at minimal cost. The simple construction and industry standard components also mean that the WEPS configuration can easily be designed and implemented on a larger scale. Applications on such a large scale may include pump-storage schemes for power generation and agricultural irrigation. The direct electrical connection between the generator and motor also has an added advantage of flexibility as the generator can easily be configured to generate electricity for other uses.

Figure 1: Diagram of a wind-electric pump system.
1.2 Literature Study

Theoretical analyses of wind-electric pump systems are presented by Muljadi et al. [2] and Velasco et al. [3]. These analyses provide a theoretical basis to analyse the steady-state operation of wind-electric pump systems. The steady-state analyses in these papers focus on the analysis methodology to determine the steady-state operating point of the wind-electric pump system for a given wind speed. The performance results obtained in these analyses are simulated results based on a derived system model for the system components. The modelling of the components used in these studies, however, is overly simplified and can be extended to provide a more thorough calculation and accurate prediction of the system performance. Such extensions can be made to:

i) The modelling of the centrifugal pump, where attention can be given to its optimal and safe operation.

ii) The per-phase equivalent circuit of the induction motor, where e.g. the stator iron losses at varying frequencies can be included to obtain a more accurate system model.

iii) The modelling of the permanent magnet generator where extensions can be made to the determination of the stator impedance and eddy current losses as used in the per-phase equivalent circuit model of the generator.

The article by Vick et al. [4] details the practical application of a wind-electric pump system for water-storage for drip irrigation of fruit trees. However, the specification of the different system components are chosen without a theoretical background and the steady-state operation of the system is analysed solely by using the pump performance data. No practical guidelines are given in Muljadi et al. [2] - Vick et al. [4] on the specification of the different system components to ensure optimum steady-state operating conditions for a specific pumping application. Specific areas of note are:
i) Guidelines in the sizing of the turbine and centrifugal pump in response to the wind conditions that exist at the turbine installation site and the nature of the pumping application.

ii) The power matching between the turbine and centrifugal pump to enable the optimum energy transfer between the two components under varying wind speed conditions.

iii) The design and supply specification of the permanent magnet generator needed to ensure safe and efficient operation of both generator and induction motor.

The dynamic analyses of wind-electric pump systems are discussed in Velasco et al. [3] and Bialasiewicz et al. [5]. The focus in these articles is placed on the start-up dynamics of a WEPS. Simulation results are presented in Bialasiewicz et al. [5] to illustrate various start-up scenarios. These simulations are based on a simulation program developed specifically for this purpose at the National Wind Technology Centre of the National Renewable Energy Laboratory based in Colorado, USA. The pump load and physical size of the turbine is changed in each scenario and the dynamic behaviour of various system parameters are documented at start-up. It is concluded that, to guarantee a successful start-up, the electrical connection between the generator and motor must be made when enough rotational kinetic energy is stored in the turbine upon connection. These papers, however, do not include any practical method in determining the amount of rotational kinetic necessary to ensure a successful start-up for a WEPS design of a given component size and rating.

Also not included in papers Muljadi et al. [2] - Bialasiewicz et al. [5] is a practical and cost-effective direct-on-line (DOL) method of establishing the electrical connection between the generator and motor. This switch must have hysteresis switching capability because it must ensure:

(i) That the minimum turbine rotational speed, necessary for a successful start-up, is reached before the electrical connection is made.
That the electrical connection is broken if the components are operated below or above a certain turbine rotational speed to ensure safe operation of the generator, motor and pump.

The main drawback in the use of permanent magnet synchronous generators is that the generators have to be designed and dimensioned for every specific WEPS application. This drawback could be resolved through the use of brushless doubly-fed induction generators (BDFIG). These generators have no brushes or slip rings and give the BDFIG the autonomous capability necessary for implementation in a WEPS. The use of such a generator instead of a PMSG is discussed in Comacardi et al. [6].

The principle stator winding of the generator is connected directly to the induction motor. The voltage and frequency output of the principle stator winding is fed back to the auxiliary stator winding via electronic voltage/frequency converters and control. The control consists of a torque and voltage control loop which enables the generator to follow the optimal turbine torque at each wind speed and to keep the V/Hz supply of the primary winding constant. A BDFIG of a certain rating could therefore be used in a variety of WEPS applications, with varying wind conditions and pumping applications, through the modification of the torque and voltage control loops used in the control of its voltage/frequency converters.

The use of electronic converters and control does, however, make the operation of the BDFIG more complex and thus more maintenance intensive which can compromise the autonomous capability of the WEPS. The power delivery per weight specification of a BDFIG is also lower than the PMSG due to the use of the auxiliary stator winding. The cooling of the enclosed BDFIG rotor is also a critical issue for large generator ratings.
1.3 Aim and Format of Study

The aim of this study is to analyse the operation of a wind-electric pumping system (WEPS) using axial flux permanent magnet synchronous generators (AFPMSG) for stand-alone water-pumping schemes. The steady-state as well as the dynamic operation of such a system is analysed. Through these analyses, practical guidelines are given in the design and sizing of the different system components to ensure optimal efficiency and reliable operation.

The application potential of a WEPS at a certain installation site is dependent on the wind regime that exists at the site and the wind turbine used to extract the power from the wind. Chapter 2 provides theoretical background in the use of wind turbines to extract mechanical power from wind. Insight is provided into the different turbine designs in an effort to validate the low solidity turbine design chosen for the WEPS. Practical insight is given in the placement of wind turbines to maximise turbine performance. Theoretical insight is also given into the analysis of wind regimes to accurately determine the long term performance potential of a turbine installation site for a typical WEPS application.

Chapter 3 elaborates on the modelling of the different components used in the construction of a WEPS, as presented in Figure 1. Each component is discussed separately with the necessary extensions made to the modelling of these components as discussed in Chapter 1.2.

In chapter 4, a small scale wind-electric pump system is built and the steady-state operation of the system analysed. Practical guidelines are provided in the sizing and specification of the different system components to ensure efficient and reliable steady-state operating conditions under varying wind speed conditions. Emphasis is placed on the specification, design and construction of the permanent magnet generator to ensure (i) safe and efficient electrical operation of the generator and induction motor and (ii) good power matching between the turbine and pump. The steady-state operation of the system is calculated using a Matlab program based on the system model derived in Chapter 3. The calculation procedures for this Matlab program are given in Appendix B. These calculated results are compared with practical measurements made on the small scale setup which are listed in Appendix C.
The system model and design methodology are thereby verified through this comparison.

Chapter 5 focuses on the transient operation of the turbine, particularly during start-up. A practical method is discussed to determine the minimum turbine rotational speed necessary whereby sufficient rotational kinetic energy would be available to ensure a successful start-up for a WEPS of a given size and rating. The effects of frequent direct-on-line starts on the service life of the permanent magnet generator and induction motor are discussed. A voltage monitor is introduced as a direct-on-line hysteresis switch which can be used to ensure a successful start-up of the system and safe steady-state operation of the WEPS and its components.

A case study for a large scale wind-electric pump system application is presented in Chapter 6. In this chapter, the feasibility of using the WEPS system is investigated for possible application at a planned hydro-electric scheme in Somerset-East, Eastern Cape. The WEPS would be used for pumped-storage to increase the generation potential of the proposed hydro-electric scheme. The WEPS design guidelines discussed in the previous chapters are used in this large scale design. The installation site chosen for this case study will provide a practical insight into the limitations involved in the design and implementation of a large scale WEPS. The chapter will also provide insight into the conditions necessary to make the installation of a large scale WEPS feasible.

A conclusion will finally be given to give a brief summary on the layout of this study and to comment on important findings. Possible further studies regarding the design and implementation of wind-electric pumping systems are also discussed.
2. Wind Energy Conversion

2.1 Basic Theory of Wind Energy Conversion

The power available from the wind which can be harvested from the surface area covered by the blades of a wind turbine is given by

\[ P_{\text{wind}} = \frac{1}{2} \rho \pi r^2 v^3, \quad (2.1) \]

where \( \rho \) is the air density at the turbine installation site above sea level, \( v \) the wind speed, and \( r \) is the radius of the turbine blades. The amount of mechanical power available from the turbine on its shaft can be given by

\[ P_{\text{turbine}} = \frac{1}{2} \rho A v^3 C_p, \quad (2.2) \]

where \( C_p \) is called the power coefficient and \( A \) the swept area of the turbine blades. \( C_p \) is irrespective of the size of the turbine and an indication of the turbine efficiency. \( C_p \) is a function of the tip-speed-ratio, \( C_p = f(\lambda) \), which can be calculated by

\[ \lambda = \frac{\omega r}{v}, \quad (2.3) \]

where \( \omega \) is the turbine angular rotational velocity in rad/s. The power coefficient versus tip-speed-ratio graphs depend on the type of wind turbine design being used. The power coefficients for various turbine designs are shown in Figure 2. A wind turbine can not capture all the power from the wind which passes through the swept area of the turbine blades. If this was the case, no wind would pass through the blades and the turbine would stall. According to Mathew [1] the theoretical maximum amount of wind power that can be captured by the blades of a turbine and be converted to mechanical energy is 59.3 %. This theoretical maximum efficiency is called the Betz limit and is indicated in Figure 2.
The number of turbine blades for a given turbine swept area, determines the solidity of the turbine. High solidity turbines are used in low wind speed conditions for high torque applications. In high wind speeds, however, the higher number of blades restricts the airflow through the swept area of the blades and causes the turbine efficiency to drop considerably.

Low solidity wind turbines have high efficiency at high wind speed conditions because the low number of blades allow for good airflow. The power available in the wind for a given turbine swept area has a cubic increase with an increase in wind speed. These low solidity turbines are therefore used in medium to high wind speed regimes because of the high power available in the wind and the high efficiency of the turbine.
2.2 Wind Turbine Classification

Wind turbines can be classified into two groups: (i) vertical axis wind turbines (VAWT) and (ii) horizontal axis wind turbines (HAWT).

2.2.1 Vertical Axis Wind Turbine

The two main vertical axis turbine designs are the Darrieus and Savonius as shown in Figure 3. These designs have the advantage of being omni-directional and do not need a tail vane to orient the turbine towards the wind. The towers needed for these designs are also cost effective and easy to manufacture and install. The swept area of a VAWT is half of its total physical turbine area because only half of its total turbine area is exposed to the wind at any one time. The size of the VAWT must therefore be much larger than a HAWT to deliver the same power. The Savonius turbine has a high solidity and has therefore a low power coefficient as shown in Figure 2. The design is ideal for high torque applications at low wind speeds like water pumping. A Darrieus design is designed to operate under high wind speeds where large wind energy exists. It also has a higher power coefficient than the Savonius and can be used for power generation. A major disadvantage of a Darrieus, however, is the absence of any starting torque. They have to be brought up to speed by an external excitation.

![Diagram of vertical axis wind turbine designs](image)

**Figure 3: Vertical axis wind turbine designs [11].**
2.2.2 Horizontal Axis Wind Turbine

The only design criterion of a horizontal turbine design is the number of blades that is used, as can be seen in Figure 4. The traditional multi blade design has a high number of blades. The multi blade design are similar to the Savonius design being that the high solidity of the multi blade turbine also makes it ideal for high torque applications under low wind speeds.

The three bladed HAWT is the optimal low solidity design. It is superior to the single and two bladed designs because the three blades make it dynamically balanced and reduce wind noise. The design has a self-starting capability and a higher power coefficient than the Darrieus design which makes it the preferred turbine choice for power generation at sites with medium to high wind regimes.

![Figure 4: Horizontal axis wind turbine designs [11].](image-url)
2.3 Analysis of Wind Regimes

2.3.1 Turbine Placement

A good knowledge of the prevailing wind conditions at the installation site of a wind turbine is essential in estimating the performance of the wind turbine. Wind data from meteorological stations in the near vicinity of the turbine installation can give you an indication of the wind conditions present at the installation. For a precise analysis of the wind regime at the turbine site, a weather station must be erected at the height of the turbine hub to record wind data. The wind data must be recorded for a minimum of 2-5 years to assess the seasonal change in wind conditions.

The turbine hub must be erected at a height that is clear of any obstructions like trees and buildings. These obstructions cause turbulence which not only reduces the air stream through the blades and reduces the power that can be developed, but also places fatigue loads on the blades. Very turbulent wind sites also include ridges and mountain passes. A good rule of thumb is to always place the hub away from the highest obstruction at a distance of more than twice the height of the this highest obstruction.

Winds speeds increase with an increase in height because the air offers less resistance to airflow than the surface of the earth. The turbine would therefore experience increased wind speeds when it is erected high and can potentially extract more power from the air. Air density must, however, be taken into account when installing turbines at sites with high elevations above sea level. This is because air density decrease at high altitudes and could reduce the power that can be extracted from the air by the turbine according to (2.1). The air density, \( \rho \), at a specific height above sea level can be calculated by the gas law:

\[
\rho = \frac{1000P_H}{RT_H}, \tag{2.4}
\]

where \( R \) is the gas constant, 287.04 J/Kg, \( P_H \) is the atmospheric air and \( T_H \) is the temperature in Kelvin at that specific height.
The environmental lapse rate is the decrease of temperature with elevation. For a height of up to 11,000 m, the lapse rate is 6.5 °C / 1000 m increase according to ICAO [7]. The hydrostatic equation can be used to calculate the atmospheric air pressure, \( P_H \), at a specific height above sea level:

\[
P_H = P_o \left[ \frac{(T_o - \Psi H_{as})}{T_o} \right] \frac{g}{R \Psi} ,
\]

where \( P_o \) is the standard pressure at sea level (101.325 kPa), \( T_o \) is the standard temperature at sea level (293.15 K), \( H_{as} \) is the height above sea level, \( \Psi \) is the environmental lapse rate (0.0065 °C/m) and \( g \) is the gravity acceleration (9.8 m/s²). The air temperature at a certain height, \( T_H \), can simply be calculated using the environmental lapse rate:

\[
T_H = T_o - \Psi H
\]

The environmental lapse rate (\( \Psi \)) does not always reflect the actual immediate temperature at a certain elevation; it is only a generalisation and the actual temperature value may vary. It does, however, deliver a good estimation of the air density level at different elevations. The power delivery curves of a wind turbine are determined at a specific air density which is typically the density at sea level, 1.225 kg/m³. The air density at any height above sea level can be approximated using (2.4) - (2.6). If the turbine is installed, for example, at a height of 1000 m, the air density will decrease to the value of \( \approx 1.16 \) kg/m³. The power delivery curves of the turbine would therefore have to be adjusted with a factor of \( 1.16/1.225 \approx 0.95 \).

2.3.2 Wind Speed Distribution

It is not only sufficient to know the average speed at a potential turbine installation site, but also the percentage distribution of the actual wind speed spectra available at that site. This distribution is called the wind frequency distribution and states the likelihood of occurrence of each wind speed over a chosen period of time. This is important because any system, which is powered by the turbine, can be designed and optimised for the wind speeds which are most likely to occur. The wind speed
distribution is also helpful in estimating the performance of the system for a period of time.

The wind speed distribution for a site can be created from recorded wind data by the use of probability density functions such as the Weibull or Rayleigh distribution functions. This estimation method has good accuracy levels according to Göçek et al. [8]. The Rayleigh function is a special case of the Weibull function. Although it is an easier function to work with, it is not as accurate as the Weibull function. The Weibull probability density function is given by

\[
f(v) = \frac{k}{c} \left(\frac{v}{c}\right)^{k-1} \exp\left[-\left(\frac{v}{c}\right)^k\right],
\]

where \( v \) is the wind speed, \( c \) is a Weibull scale parameter and \( k \) is a Weibull shape parameter. There are various methods of obtaining Weibull \( c \) and \( k \) parameters from wind data which are explained in Justus et al. [9]. The method used most commonly is the mean wind speed-standard deviation method. The average and standard deviation can easily be calculated from wind data as given by (2.8) and (2.9) respectively:

\[
\bar{v} = \frac{1}{p} \sum_{i=1}^{n} v_i
\]

(2.8)

\[
\sigma = \sqrt{\frac{1}{p} \sum_{i=1}^{n} (v_i - \bar{v})^2},
\]

(2.9)

where \( p \) is the number of hours for the time period being considered. The \( c \) and \( k \) parameters can then be calculated using (2.10) and (2.11) respectively.

\[
k = \left(\frac{\sigma}{\bar{v}}\right)^{-1.086}
\]

(2.10)
\[ c = \frac{\bar{v}}{\Gamma \left(1 + \frac{1}{k}\right)}, \]  
\[ (2.11) \]

where \( \bar{v} \) is the mean wind speed and \( \sigma \) is the standard deviation. An easier way to approximate the \( c \) parameter is given by (2.12) [10].

\[ c \approx \bar{v} \frac{k^{2.6674}}{0.184 + 0.816k^{2.73855}} \]

\[ (2.12) \]

The cumulative distribution function is the integral of the distribution function and provides the fraction of the amount of time for which a wind speed distribution will be equal to or lower than a specific wind velocity. This cumulative distribution is given by

\[ F(v) = 1 - \exp \left[-\left(\frac{v}{c}\right)^{k}\right]. \]

\[ (2.13) \]

The fraction of time for which wind is within a certain velocity interval, \( v_1 \) and \( v_2 \), can be estimated by

\[ F(V_1 < V < V_2) = F(V_2) - F(V_1) = \exp \left[-\left(\frac{v_1}{c}\right)^{k}\right] - \exp \left[-\left(\frac{v_2}{c}\right)^{k}\right]. \]

\[ (2.14) \]

The fraction or percentage of time which wind conditions at a potential turbine installation site would be above or between certain wind speeds could therefore be estimated using (2.13) - (2.14) from wind data measured at that site. This is useful because it could help in the sizing of the turbine and the various system components for economic considerations. For example, assume it is estimated at a certain installation site using (2.13) that the percentage of time per annum which wind speed conditions would be above 12 m/s, is less than 0.5 %. There may thus not be any financial justification in sizing the system components to handle the increase in the amount of power that is generated by the turbine above 12 m/s wind speed for such a short amount of time.
2.3.3 Estimating the Performance of a Wind-Electric Pumping System

The performance of a wind-electric pump system is defined as the volume of fluid delivered by the system in a given period of time, usually per annum. To estimate this system performance, the following must be known:

a) **Hydraulic output potential of the wind-electric pump system.**

A wind-electric pump system can be designed to operate as efficiently as possible for an application with a certain pumping application and an available wind regime at the turbine installation site. The hydraulic output or pump delivery potential can be defined as the flow rate per hour that can potentially be achieved by the system at each wind speed that is presented to the turbine at the installation site. This hydraulic output potential can be approximated during the steady-state design of the system which will be discussed in Chapter 4. An example of such a WEPS hydraulic output potential is shown in Figure 5.

![Figure 5: Example of a hydraulic output potential of a wind-electric system for each wind speed.](image-url)
b) The wind speed distribution at the site of the turbine application

It is a common error to use only the average wind speed at a turbine site to estimate the turbine performance. This method can underestimate or overestimate the actual performance of the turbine by up to 30% according to Gipe [11]. By using the wind speed distribution of a site, more accurate performance estimations can be made because the contribution of each wind speed is taken into account. An example of such a wind speed distribution is given in Figure 6 in terms of the amount of hours that each wind speed would occur during the year. The contribution in pumped volume of each wind speed can be calculated as shown in Figure 7 by multiplying the estimated delivery potential of the wind-electric system for each wind speed in Figure 5 with the amount of hours of occurrence of each wind speed in Figure 6. The sum of these contributions is the per annum performance of the wind-electric system. The total per annum hydraulic output achieved by the wind-electric pump system performance in this example is therefore estimated from Figure 7 to be \( \approx 358000 \) m\(^3\).

![Figure 6: Example of a wind speed distribution.](image-url)
Figure 7: The contribution in pumped volume of each wind speed achieved by the wind-electric pump system.
3. System Model

As shown in Figure 8, the mechanical power in the wind is harvested by the wind turbine, $P_{s1}$, and transferred to the shaft of the centrifugal pump, $P_{s2}$, via the permanent magnet generator and induction motor. A variable voltage, variable frequency AC supply is generated by the permanent magnet generator due to the varying turbine speeds, $\Omega_1$, in response to varying wind conditions. This supply is directly fed to the induction motor. The complete system model of a WEPS will be derived in this chapter. This model will be used in Chapter 4 to calculate the steady-state operation of a WEPS which will ultimately be used to estimate the hydraulic output potential of the WEPS, as shown by the example in Figure 5. The steady-state operating point of a wind-electric pump at a given wind speed is where the mechanical power delivered by the turbine equals the sum of the mechanical power required by the pump and the electrical losses in the generator and motor. This WEPS system model will therefore facilitate the estimation of the mechanical power required by the pump as well as the power loss in the generator and motor across the operating range of a WEPS.

Figure 8: Diagram of a wind-electric pump system.
3.1 Permanent Magnet Synchronous Generator

The permanent magnet generator used in the WEPS, is an air cored, axial flux permanent magnet (AFPM) machine. The theory concerning the design of such a machine as well as important findings to simplify and optimise the design of the machine is found in Kamper et al. [15]. Extensions to the work done in Kamper et al. [15] on concentrated winding layout topology are made in Rossouw [16]. These extensions include calculations to determine the winding inductance of the stator windings and eddy-current losses in these windings.

An air core is used because of (i) the simplicity and low manufacturing cost and (ii) the absence of iron losses normally associated with iron cores such as hysteresis and eddy current loss. The use of an air core also has the advantage of allowing the permanent magnet generator to be designed with low internal impedance. This low impedance allows for efficient operation of the generator throughout the operating range of a wind-electric pump system. It also allows for a fairly constant V/Hz generator supply which would produce a fairly constant air-gap flux in the induction motor. This is desirable because the constant flux allows the torque-speed curve of induction motor to remain essentially the same throughout the variable speed operation of the motor.

A disadvantage of air-cored machines is their larger physical size for a given supply rating compared to normal iron-cored machines. This difference in size can be attributed to the basic difference in permeability between air and iron. An air core has a much lower permeability than an iron core and will therefore produce a lower flux density than iron for the same permanent magnet field intensity. The field intensity, and thus also the size, of the magnets must therefore be bigger for an air-cored machine than an iron-cored machine to achieve the same flux density and therefore supply rating.

The chosen stator winding layout of the axial flux machine for this application has concentrated, non-overlapping coils as shown in Figure 9. An important advantage of this layout is the reduction in stator winding production costs due to the decrease in the number of coils used and the simple winding structure. A general drawback of the concentrated non-overlapping winding layout is the reduction in output torque compared to the overlapping winding layout.
Figure 9: Layout of a concentrated non-overlapping air-cored stator winding of an AFPM machine. [15]

However, it is reported in Kamper et al. [15] that non-overlapping winding machines with high pole numbers can have similar performance as normal overlapping winding machines. The combined per-phase equivalent circuit of the permanent magnet generator is shown in Figure 10. The phase voltage developed by the generator can be determined by (3.1)

\[
E_{PH} = \frac{4}{\sqrt{2}} q \omega B_p N \ell_a r_e k_p k_d, \tag{3.1}
\]

where \( q \) is the number of stator coils per phase, \( a \) is the number of parallel circuits per phase, \( p_g \) is the number of poles in the rotor of the generator, \( \omega \) is the electrical speed (rad/s), \( B_p \) is the peak air-gap flux density, \( N \) is the number of turns per coil, \( \ell_a \) is the active length and \( r_e \) is the average radius of the stator coil shown in Figure 9. The active length and the average radius of a the stator coil can be calculated using

\[
\ell_a = r_o - r_i \tag{3.2}
\]
and
\[ r_e = \frac{r_i + r_o}{2}, \tag{3.3} \]

where \( r_i \) and \( r_o \) is the inner and outer radius of the stator coil. The pitch factor, \( k_p \), and distribution factor, \( k_d \), can be calculated by

\[ k_p = \frac{\sin[0.5\theta_m(1-\kappa)]\sin(0.5\kappa\theta_m)}{0.5\kappa\theta_m}, \tag{3.4} \]

and

\[ k_d = \frac{\sin[0.5n(\theta_m - \pi)]}{n\sin[0.5(\theta_m - \pi)]}, \tag{3.5} \]

where \( n \) is the number of coils in a coil phase group. With the concentrated, non-overlapping winding layout shown in Figure 9, there exists only 1 coil per phase in a phase group. The distribution factor is thus \( k_d=1 \) using (3.5). \( \kappa \) in (3.4) is defined as

\[ \kappa = \frac{\theta_{re}}{\theta_m}, \tag{3.6} \]

where \( \theta_m \) is the coil pitch or coil span and \( \theta_{re} \) is the coil width angle at radius \( r_e \), as indicated in Figure 9. The coil pitch can be determined by

\[ \theta_m = \frac{\pi p_g}{Q_c}, \tag{3.7} \]

where \( Q_c \) is the total number of coils in the stator. The coil width angle, \( \theta_{re} \), determines the coil side width, \( w \), of the coils as
\[ w = \frac{2r_e \theta_{re}}{p_g}. \] \hspace{1cm} (3.8)

The maximum value of \( \kappa \) can be defined from Figure 9 as being

\[ \kappa_{\text{max}} = \frac{\theta_{re(\text{max})}}{\theta_m} = \frac{\sigma_r}{1 + \sigma_r} \quad \text{with} \quad \sigma_r = \frac{r_i}{r_o}. \] \hspace{1cm} (3.9)

It is found in Kamper et al. [15] that AFPM machines with the highest torque performance have a coil pitch of \( \theta_m = 4\pi/3 \) and a value of \( \kappa \) as used in (3.4) of \( \kappa = \kappa_{\text{max}} \).

The phase resistance, \( R_G \), of the AFPM generator as shown in the equivalent circuit of Figure 10 is determined analytically using

\[ R_G = \frac{N^2 q \rho_t (2\ell_e + \ell_o)}{a^2 k_f h w}, \] \hspace{1cm} (3.10)

where \( \rho_t \) is the resistivity of copper at a temperature \( t \), \( \ell_e \) is the total end-turn length of a stator coil, \( k_f \) is the fill factor for the stator conductors and \( h \) is the height of the stator coil. The resistivity of copper can be calculated at a certain temperature, \( t \), by

\[ \rho_t = 1.72 \times 10^{-8} (1 + 0.0039(t - 20)). \] \hspace{1cm} (3.11)

The total end-turn length, \( \ell_e \), is determined using:

\[ \ell_e = \frac{2\theta_m(r_i + r_o)(1 - 0.6\kappa)}{p_g}. \] \hspace{1cm} (3.12)
The stator phase inductance is derived in Rossouw [16] and determined by

\[ L_G = \frac{q(2\ell_a + \ell_e)^2 N^2}{a^2 h} \times 10^{-7} K_n, \]  

(3.13)

where \( K_n \) is a correction factor called the Nagaoka constant. This is, in turn, given by

\[ K_n = \frac{1}{1 + 0.9 \frac{2\ell_a + \ell_e}{2\pi h} + 0.32 \frac{2\pi w}{2\ell_a + \ell_e} + 0.84 \frac{w}{h}}. \]  

(3.14)

The 3-phase power loss caused by eddy currents in the stator conductors can be calculated simply by using (3.15)

\[ P_e = \frac{\pi \ell_a d^4 B_p^2 \omega^2 Q_c Nu}{32 \rho_t}, \]  

(3.15)

where \( u \) is the number of parallel strands per conductor and \( d \) is the diameter of the stator coil conductor given by

\[ d = \sqrt{\frac{4hwk_f}{\pi Nu}}. \]  

(3.16)

The eddy current effect of the machine is modelled as a resistance in Figure 10 and is determined by

\[ R_E = \frac{3E_{PH}}{P_e}. \]  

(3.17)
The total mass of copper used in the concentrated non-overlapping stator coil layout can be approximated using

\[ M_{cu} = k_m (2 + \zeta) C, \]  

(3.18)

where \( k_m \) is the winding mass factor and \( \zeta \) and \( C \) are machine constants. The winding mass factor is determined by

\[ k_m = \frac{(1 - \sigma_r^2) \theta_{rc} q}{p}. \]  

(3.19)

The two machine constants, \( \zeta \) and \( C \), are determined by

\[ \zeta = \frac{\ell_e}{\ell_a}, \]  

(3.20)

and

\[ C = 3r_a^2 k_f h \gamma_{cu}, \]  

(3.21)

where \( \gamma_{cu} \) is the mass density of copper (8954 kg/m\(^3\)). The torque being developed by the generator is determined by

\[ T = k_s k_p k_d C_1 \cos \theta. \]  

(3.22)

The power factor, \( \cos \theta \), is determined by the generator application. The stator factor, \( k_s \), is given by

\[ k_s = k_w \sqrt{k \pi / 3}. \]  

(3.23)

with \( k_w \) being the winding factor determined by

\[ k_w = k_p k_d. \]  

(3.24)
The end-winding factor, $k_e$, and the radius factor, $k_r$, is respectively given by

$$k_e = (2 + \zeta)^{-0.5}$$  \hspace{1cm} (3.25)

and

$$k_r = \sqrt{(1+\sigma_r)^3(1-\sigma_r)}.$$  \hspace{1cm} (3.26)

$C_I$ is a machine constant given by

$$C_I = r_o^2 B_p \sqrt{1.5 P_{cu} k_f h / \rho_t},$$  \hspace{1cm} (3.27)

where $P_{cu}$ is the copper loss caused by the stator winding resistance.

**Figure 10:** Combined per phase equivalent circuit of the axial flux permanent magnet generator and induction motor.
3.2 Induction Motor

The induction motor used in the WEPS configuration is of a commercially standard design. It is crucial to have an accurate equivalent circuit model of the induction motor because it would provide an accurate steady-state estimation of the electrical losses incurred by the induction motor, operating under the varying AFPM generator supply. The equivalent circuit parameters of the induction motor are indicated in Figure 10. These circuit parameters are not always readily available for a commercial induction motor and can be determined through the DC test, no-load test and the locked-rotor test. The voltage, current flow and power flow of the induction motor supply can be measured during the no-load and locked-rotor tests for which the measurement setup is shown in Figure 11. The equivalent circuit parameters are then calculated using these measurements as described in Wildi [17], Fitzgerald [18] and Hubert [19]. The application of the measuring and calculation methodologies explained in this section is shown in Appendix A for the induction motors used in Chapters 4 and 6.

3.2.1 Determination of Induction Motor Equivalent Circuit Parameters

![Figure 11: No-load and locked-rotor test measurement setup for the measurement of the equivalent circuit parameters of the induction motor.](image-url)
DC Test

The stator resistance is determined using the DC test given by

\[ R_s = \frac{R_{DC} - R_{LEAD}}{2}, \quad (3.28) \]

where it is assumed that the motor terminals are connected in wye and \( R_{LEAD} \) is the resistance of the measuring device test leads.

Locked-Rotor Test

With the locked-rotor test, the slip of the induction motor, indicated in Figure 10 as the parameter \( s \), is equal to 1. The excitation current, \( I_0 \), is much less than the rotor current, \( I_1 \), during the locked-rotor condition. The equivalent circuit of Figure 10 can therefore be simplified with the omission of the stator iron loss resistance, \( R_{FE} \), and the magnetizing reactance, \( X_m \). The 3-phase active power absorbed by the induction motor, \( P_{LR} \), is measured using the 2-Wattmeter method in the measuring setup shown in Figure 11. The rotor resistance, \( R_R \), in the equivalent circuit is then determined by

\[ R_R = \frac{P_{LR}}{3I_{LR}} - R_S. \quad (3.29) \]

The total locked rotor reactance in the circuit is calculated using the following equations:

\[ S_{LR} = \sqrt{3}E_{LR}I_{LR}, \quad (3.30) \]

\[ Q_{LR} = \sqrt{S_{LR}^2 - P_{LR}^2}, \quad (3.31) \]

and

\[ X_{LR} = \frac{Q_{LR}}{3I_{LR}}. \quad (3.32) \]
According to Wildi [17], the stator and rotor reactance can be determined as follows:

\[ X_S = X_R = 0.5X_{LR} \quad (3.33) \]

**No-Load Test**

With the no-load test, the motor is operating close to synchronous speed and the value of slip can be assumed as: \( s \approx 0 \). The rotor current, \( I_1 \), is now much lower than the excitation current, \( I_o \). The equivalent circuit in Figure 10 can therefore be simplified by omitting the rotor reactance, \( X_R \), and the rotor resistance, \( R_R \). The stator current is also relatively low under the no-load condition and the voltage drop across the stator resistance, \( R_S \), and the stator reactance, \( X_S \), can also be neglected. The total input reactive power can then be determined by

\[ S_{NL} = \sqrt{3}E_{NL}I_{NL} \quad (3.34) \]

and

\[ Q_{NL} = \sqrt{S_{NL}^2 - P_{NL}^2} \quad (3.35) \]

The magnetizing reactance can thus be solved using

\[ X_M = \frac{E_{NL}^2}{Q_{NL}} \quad (3.36) \]

The stator iron loss resistance parameter in Figure 10 represents the iron losses in the stator as well as the windage and friction loss caused by the rotation of the rotor. This parameter can be determined by

\[ R_{fe} = \frac{E_{NL}^2}{P_{rot}} \quad (3.37) \]
where $P_{rot}$ is rotational losses consisting of the iron loss in the stator and the windage and friction losses of the motor. At grid supply frequency, i.e. 50 Hz, the stator iron loss and the windage and friction losses are constant and can be determined by

$$P_{rot} = P_{NL} - 3I_{NL}^2 R_S.$$  \hspace{1cm} (3.38)

For a varying supply voltage and frequency, however, both the stator iron loss as well as the windage and friction losses of the motor varies. In such a case, the rotational losses used in (3.38) can then be rewritten as

$$P_{rot} = P_{fe} + P_{wf},$$  \hspace{1cm} (3.39)

where $P_{fe}$ is the varying iron power loss in the stator and $P_{wf}$ is the varying windage and friction power loss of the motor. Calculations in estimating the variation of these losses under a varying supply is discussed in Chapter 3.2.2 and Chapter 3.2.3.

### 3.2.2 Determining Varying Windage and Frictional Losses

Various methods are discussed in Fitzgerald [18] to determine the variation in windage and bearing losses at varying induction motor shaft speeds caused by varying supply frequencies. One such method is the decay test. This method calls for the induction motor to be brought up to a no-load shaft speed by using a variable speed drive and then suddenly disconnecting the supply. The rate of decay in the motor shaft speed is determined by the windage and friction losses of the motor only. Therefore, if the inertia, $J_1$, of the induction motor is known, the windage and friction losses of the induction motor at any angular rotational velocity, $\omega_2$, can be determined by

$$P_{wf} = -\omega_2 J_1 \frac{d\Omega_2}{dt}.$$  \hspace{1cm} (3.40)
3.2.3 Determining Varying Stator Iron Losses

The calculation of the varying stator iron loss in an induction motor operating under a varying fundamental frequency is explained among others by Kamper [20] and [21]. The varying iron loss can be calculated by

\[ P_{fe} = cf^x (B_{mt}^y M_t + B_{my}^y M_y) \]  

(3.41)

The values of \( c, x \) and \( y \) are determined in Kamper [21] from measurements and loss-frequency curves for low-cost sheet steel used in the production of industry standard induction motors as \( c = 0.0337, x = 1.32 \) and \( y = 2 \). \( B_{mt} \) and \( B_{my} \) are the maximum flux densities in the stator teeth and yoke respectively and \( M_t \) and \( M_y \) are the masses of the stator teeth and yoke respectively.

The mass of the stator teeth and yoke can be calculated using

\[ M_y = 1000k_{sf} S \ell_y \frac{\pi}{4} \left[ D_o^2 - (D_i + 2\ell_y)^2 \right] \]  

(3.42)

and

\[ M_t = 1000k_{sf} S \ell_y \left[ \frac{\pi}{4} \left( (D_i + 2\ell_y)^2 - D_i^2 \right) - C_{nt} A_t \right] \].  

(3.43)

Figure 12: Cut-away of an induction motor stator lamination.
where \( k_{sf} \) is the stack factor of the stator, \( S \) is the density of sheet steel and \( \ell_y \) is the stator lamination stack length. \( D_i \) and \( D_o \) are, respectively, the inner and outer diameter of the stator lamination, \( \ell_s \) is the length of the stator slot, \( C_n \) is the total amount of stator coil slots and \( A_t \) is the total area of a stator coil slot.

The maximum flux density in the stator teeth and yoke can be calculated by first determining the flux produced per pole of the induction motor:

\[
\Phi_p = \frac{E}{\sqrt{2\pi f_1 N_{ph} k_{wf}}}.
\]

\( E \) is the per phase voltage over the parallel circuit indicated in Figure 10, \( f_1 \) is the fundamental frequency supply, \( N_{ph} \) is the amount of windings in series per phase and \( k_{wf} \) is the winding factor for the fundamental harmonic. In order to simplify the calculation, the voltage loss across the series stator resistances and stator inductances of both generator and motor are assumed to be relatively small compared to the value of the supply voltage \( E_{P_{ph}} \) in Figure 10, and thus \( E \approx E_{P_{ph}} \). The amount of windings in series per phase can be determined by

\[
N_{ph} = \frac{r_p N_{pm}}{2a}
\]

with \( N \) being the number of turns per stator coil, \( p_m \) being the amount of stator poles and \( a \) being the amount of parallel circuits in the stator. The winding factor can be determined for the first harmonic by

\[
k_{wf} = \frac{\sin\left(\frac{\pi}{2m}\right)}{r_p \sin\left(\frac{\pi}{2mr_p}\right)} \cos\left(\frac{\pi}{2} \left[ 1 - \frac{c_p}{mr_p} \right]\right),
\]

where \( m \) is the total number of phases, \( r_p \) is the number of stator slots per pole per phase given by
\[ r_p = \frac{C_n}{mp_m} \]  
(3.47)

and \( c_p \) is the coil pitch in terms of the number of stator slots per pole given by

\[ c_p = \frac{C_n}{P_m}. \]  
(3.48)

The sinusoidal fundamental waveform of the flux density in the air gap of the induction motor is deformed due to magnetic saturation in the stator laminations. It is shown in Kamper [20] that the fundamental waveform of the flux density in the air gap is equal to the actual deformed waveform at a pole pitch of 60º or 120º electrical. To determine the actual maximum flux density in the stator teeth, the fundamental waveform must therefore be evaluated at a pole pitch of 60º or 120º electrical. The actual maximum flux density in the stator teeth is thus calculated at 120º of the pole pitch by

\[ B_{mt} = \frac{\Phi_p \pi \left( \sin 120^\circ \right) t_p}{2 \ell_y \tau k_s t_w}, \]  
(3.49)

where \( t_p \) and \( t_w \) are the slot pitch and the width of the stator teeth respectively, as indicated in Figure 12. The pole pitch, \( \tau \), can be determined by

\[ \tau = \frac{\pi D_l}{P_m}. \]  
(3.50)

The maximum flux density in the stator yoke can be determined by the following:

\[ B_{my} = \frac{\Phi_p}{2 h_y \ell_y k_{sf}}, \]  
(3.51)

where \( h_y \) is the yoke height as shown in Figure 12. The accuracy of using (3.40) - (3.51) in calculating the varying rotational loss of an induction motor operating under a varying supply is verified in Appendix A.
3.3 Centrifugal Pump

3.3.1 Basic Concepts

A centrifugal is characterized by the volume of fluid or capacity it can deliver in a given time and the pressure with which the pump can deliver the fluid volume. The capacity is measured in cubic meters per hour (m³/hr) and the pump pressure, called head, is measured in meters (m). These pressure and capacity characteristics are plotted on graphs called head-capacity curves or pump performance curves which are determined and supplied by the pump manufacturer. These characteristics are normally determined at a constant pump impeller rotational speed and diameter. The pump efficiencies of the centrifugal pump at these varying flows and pressures are also determined by the pump manufacturer and included on these curves.

The performance of the pump is determined by the pipeline to which the pump is introduced. The pipeline also has a head-capacity curve called a system curve and represents the opposing head against which the pump must operate to achieve flow. This opposing head is determined by the frictional losses in the piping and pipeline fittings, degree of elevation in water level at the supply and discharge sides of the pipeline, the type of liquid being pumped and the difference in pressures existing on the liquid at the supply and discharge sides. These two head-capacity curves are plotted on the same graph. The intersections of these two curves determines the head, capacity and efficiency at which a given pump would operate at a certain shaft speed in a given piping system as shown in Figure 13. The hydraulic power exerted by the pump on the fluid at this curve intersection is given by

\[ p_h = \rho f g Q H, \quad (3.52) \]

where \( \rho_f \) is the density of the water being pumped (1000 kg/m³), \( g \) the gravitational constant (9.81 m/s²), \( Q \) the flow rate (m³/s) and \( H \) the head of the centrifugal pump. The power required to drive the pump shaft at this intersection can also be calculated by

\[ P_{S2} = \frac{P_h}{\eta}, \quad (3.53) \]

where \( \eta \) is the efficiency of the pump at the intersection.
3.3.2 Determining the System Curve

The formula to determine the system curve, $H_{SC}$, for a pipeline is given as

$$H_{SC} = H_S + H_F.$$ \hspace{1cm} (3.54)

$H_S$ represents the opposing static head of a piping system. It is independent of flow and is the vertical distance between the supply and discharge fluid level of the piping system. $H_F$ is the total opposing frictional head of the pipeline and given as

$$H_F = H_f + H_m,$$ \hspace{1cm} (3.55)

where $H_f$ is the frictional head loss in the piping and $H_m$ is the minor head losses due to the various pipe fittings. There are different formulas available to calculate the frictional head loss in the piping which are discussed in Sayers [22] - Hicks [28]. The formula chosen for this application, due to its relative simplicity and reasonable level of accuracy, is the Hazen-Williams equation. The frictional loss in the piping system can therefore be expressed by

$$H_f = RQ^\beta,$$ \hspace{1cm} (3.56)

where $R$ is the resistance coefficient, $Q$ is the flow in the pipe and $\beta$ is a constant value of $\beta = 1.85$. The resistance coefficient can be expressed by

$$R = \frac{K_1L}{C^\beta D^m},$$ \hspace{1cm} (3.57)

where $K_1$ is a constant to adjust the formula for SI units (10.59), $D$ the diameter of the pipe, $L$ the length of the pipe, $C$ the Hazen-Williams roughness coefficient which depend on the type of pipe material, and the value of the exponent constants being $m = 4.87$ and $\beta = 1.85$. A method of calculating the minor loss in the piping systems is thoroughly discussed in Potter et al. [27] and expressed by

$$H_m = \frac{KQ^2}{2gA^2},$$ \hspace{1cm} (3.58)
where $K$ is the sum of the nominal loss coefficients which depend on the type of pipe fittings, and $A$ is the area of the circular pipe. The Hazen-Williams roughness coefficients, $C$, for different pipe materials and the nominal loss coefficients, $K$, for different pipe fittings are given in Sayers [22] – Hicks [28].

Figure 13: Example of pump performance curves at three different operating pump shaft speeds indicating pressure, flow rate and efficiency with a superimposed system curve.
3.3.3 Estimating Pump Performance at Varying Shaft Speeds

Pump performance curves are usually specified with constant pump speed and impeller diameter. To obtain the performance of the pump at varying shaft speeds, the characteristics of the pump can be approximated using the pump affinity laws given as

\[ \frac{N_1}{N_2} = \frac{Q_1}{Q_2} \quad (3.59) \]

and

\[ \left( \frac{N_1}{N_2} \right)^2 = \frac{H_1}{H_2}, \quad (3.60) \]

where \( N_1 \) is the initial shaft speed and \( N_2 \) is the final shaft speed of the pump in revolutions per minute (r/min). These laws were first determined experimentally but have a rigorous theoretical background Sayers [22]. The characteristic values obtained for \( N_2 \) has the same efficiency as the values depicted for \( N_1 \). These points of similar efficiency are connected on the pump performance curves to form lines of similar efficiency called iso-efficiency curves as indicated on Figure 13.

The power required to drive the pump can be calculated using (3.53) at each intersection between the system curve and the head-capacity curves of the pump at different pump shaft speeds. The load which the pump presents to the induction motor, \( P_{S2} \), can therefore be approximated under variable speed conditions.

It is important to note that when a centrifugal pump is utilised in a pipeline with static head, there is a minimum pump operating speed required to induce flow in the pipeline. This minimum speed is where the pressure created by the pump is equal to the static pressure of the pipeline. If the operating speed of the pump drops below this minimum operating speed, the flow through the pump becomes zero. Continuous operation in this sub-minimum speed condition will cause the water temperature in the pump to rise. Prolonged operation under these high temperature conditions, could (i) cause the pump seal to fail and (ii) cause bearing failure due to excessive vibration caused by the pump not being hydraulically balanced. In the example shown in
Figure 13, with a 4 m static head, the pump speed should not drop below about 1200 r/min for extended periods of time.

In addition to a minimum operating speed, centrifugal pumps also have a minimum flow rate that has to be maintained for every operating shaft speed to further prevent the water temperature in the pump from rising. This information is usually supplied by the pump manufacturer. The typical minimum flow rate for a small pump at a given operating shaft speed is normally 30% of the flow achieved at the maximum operating efficiency point of the pump at that specific shaft speed according to SAPMA [26]. For larger pumps this minimum flow percentage value can typically increase to 50%. This minimum flow requirement of the pump is especially important at the minimum operating shaft speed of the pump. The system curve for a normal pipeline is usually as such that if the minimum flow requirement of the pump is achieved at the minimum operating shaft speed of the pump, it will automatically be achieved at the higher operating shaft speeds as well.

3.3.4 Series and Parallel Operation

Centrifugal pumps can either be connected in series or parallel to extend the operating range of a pumping application. The combined pump performance curve for a series connection can be obtained by adding together the different levels of pressure heads of the respective pumps for the same flow rates at the same shaft speeds. An example of this is given in Figure 14 where two pumps with the same pump performance of \( P_1 \) and \( Q_1 \) at a given shaft speed are connected in series to form a combined performance of \( P_2 \) and \( Q_1 \). The only condition for pumps connected in series is that each individual pump must be able to accommodate the high combined pressure that is generated by the combined series operation.

There are series-connected pumps where the multiple pressure stages or impellers are housed in a single pump casing, called multi-stage pumps. These multiple impellers are mounted on the same impeller shaft. This impeller shaft can become very long if the stages are numerous which means that the pump can not be operated at high shaft speeds to prevent the shaft from warping. The high pressure generated by these multi-stage pumps also places a restriction on the flow rate which can be achieved. Multi-stage pumps are therefore not a feasible option for pump applications where high flow rates are required. These multi-stage centrifugal pumps
are, however, ideally suited for implementation at boreholes where high pumping pressures are required. There are multi-stage pumps designed specifically for borehole applications. These specifically designed multi-stage borehole pumps have long cylindrical shapes which houses the numerous impellers. Specially designed induction motors of equal shape are incorporated with these borehole pumps to form long cylindrical units which are commercially available.

In the case of a parallel connection, the combined pump performance curve can be obtained by adding the different flow capacities of the parallel-connected pumps together at the same pressure heads. An example of this is also shown Figure 14 where two pumps with the same pump performance of \( P_1 \) and \( Q_1 \) at a given shaft speed are connected in parallel to form a combined performance of \( P_1 \) and \( Q_3 \). The only condition for parallel pumping is the fitment of non-return check valves on the discharge nozzles of each pump to prevent the discharge from one pump to reverse the flow through the other parallel-connected pump, causing potential damage to the pump impeller.

![Figure 14: Example of the combined performance curves of two identical pumps connected in series and parallel. \( P_1, Q_1 \) is the pump performance curve of the pump indicated in Figure 13 at a shaft speed of 3000 \( r/min \).](image-url)
3.3.5 Cavitation

The velocity of a liquid increases when it enters through the suction side of the centrifugal pump. This causes a reduction in pressure within the pump. If this decrease in pressure falls below the vapour pressure of that specific liquid, some of the liquid will vaporise and form bubbles. These bubbles will collapse as they move through the pump to regions with pressures higher than the vapour pressure. This bubble collapse is known as cavitation and produces noise, vibration and extensive corrosion to the pump impeller.

The net positive suction head required (NPSH<sub>R</sub>) refers to the pressure required at the suction side of the pump to prevent vapourisation of the liquid. This requirement is a function of the pump design and independent of the type of liquid being pumped. It is supplied by the pump manufacturer and indicated on the pump performance curves. The net positive suction head available (NPSH<sub>A</sub>) refers to the pressure available at the suction side of the pump and is dependent on the pumping application. To prevent cavitation of the pump, the NPSH<sub>A</sub> must always be greater than the NPSH<sub>R</sub>, i.e. NPSH<sub>A</sub> ≥ NPSH<sub>R</sub>.

The available net positive head at the suction side of the pump can be calculated for the example in Figure 15 using

\[
\text{NPSH}_A = \frac{(P_H - P_{vp})}{10} - H_{Ss} - H_f, \quad (3.61)
\]

where \(P_H\) is the atmospheric air pressure, \(P_{vp}\) is the vapour pressure of water, \(H_{Ss}\) is the static suction head, \(H_f\) is the opposing friction head of the pipeline at the suction side of the pump. \(P_H\) can be determined at any height above sea level using (2.5). \(P_{vp}\) increases with an increase in temperature and this relation can be found in Stepanoff [24] - Hicks [28]. \(H_f\) is dependent on the flow rate and can be determined using (3.56) - (3.58). Note that the polarity of \(H_{Ss}\) in (3.61) changes if the water level in Figure 15 is above the pump impeller centre line. Examples of NPSH<sub>A</sub> calculations are given in SAPMA [26].
The following guidelines can be employed to prevent the advent of cavitation:

- Keep the static suction head as low as possible for pumping conditions similar to the condition illustrated in Figure 15. As a general rule, static suction heads below 4 m should not experience cavitation.
- A booster pump can be connected in series to the main pump to increase pressure for applications with excessive static suction heads.
- Minimize the number of pipe fittings such as valves and bends in the suction line to reduce head losses.
- Use bends with long radii to prevent the formation of air cavities.
- Suction pipe length should be as short as possible and be at least the same diameter as pump inlet connection to reduce losses.
- Do not allow air into the suction line by ensuring adequate submergence of the suction pipe below the water level.
- Use reducers at the pump inlet to increase inlet pressure and inhibit the formation of air cavities.
4. Steady State Analysis

The focus in this chapter is to give guidelines in the design and sizing of the different system components of a WEPS for optimal steady-state operating efficiency and reliability. A small scale wind-electric pump system is therefore designed, built and analysed in this chapter to formulate and showcase these guidelines. The steady-state operation of the system is tested and compared with the calculated operation. The system model and design guidelines are thereby verified through this comparison. All calculations made in this chapter regarding the steady-state operation of the WEPS are done using a program written in Matlab©. This Matlab program is based on the system model of the wind-electric pump system which is discussed in Chapter 3. The calculation methodology of this program is explained in Appendix B. The derivation of the induction motor equivalent circuit parameters is done in Appendix A.

4.1 Choice of System Components

The choice of the different components used in the construction of a WEPS must ensure that the components are (i) safely operated within their limits for reliability and (ii) fully utilised for cost effectiveness. To ensure that the choice of centrifugal pump meets these criteria for a typical WEPS installation, the following guidelines can be followed:

- The pump must start to generate the head necessary to overcome the static head of the pipeline at the lowest possible shaft speed. This will help in extending the operating range of the pump.
- The power consumption of the pump must start from as little as possible. This will increase the operating range of the wind turbine and give the WEPS the capability to start delivering flow at very low wind speeds.
- The induced flow rate in the pipeline must be above the minimum levels required by the pump for safe operation throughout the variable speed operation of the pump.
• The pump must not be operated past its maximum operating shaft speed. This is especially important for multi-stage pumps to prevent warping of the impeller shaft.

The choice of the wind turbine is dependent on the available wind regime at the installation site. For a WEPS application, the turbine must ideally generate the minimum power required by the pump at the lowest possible wind speed to increase the operating range of the turbine. Turbines are often oversized to extract sufficient power at sites with low-to-moderate wind regimes. This may, however, influence the economic viability of the installation, especially for large installations.

The permanent magnet generator and induction motor transfer the harnessed mechanical power from the wind turbine to the centrifugal pump. If the turbine is exposed to high wind speed conditions at its installation site, the generator and motor must be able to capitalise on this opportunity for increased water delivery. These components must therefore be rated appropriately to be able to safely transfer this high level of mechanical power for an extended period of time without overheating and possible winding damage. If high wind speeds are, however, in very slim existence over a course of time, there will be no financial justification to implement machines with such a large operational rating. To save on cost, a generator and motor with a smaller operational rating can then be used based on lower wind speeds that have a higher probability of occurrence. The choice of machine rating must therefore balance the cost of implementation with the probability of high wind occurrence. If high wind speeds, however, do occur and cause the generator and motor to operate above their operational rating, the electrical connection between them can be broken by the use of a voltage/frequency monitor device. These devices have hysteresis switching capability and can be programmed to operate within a pre-set upper and lower voltage limit. This will be discussed in further detail in Chapter 5.
4.2 Construction of Pump System

A pumping system was built in the Electrical Machine Laboratory (EML) at the Electrical Engineering Faculty located at the University of Stellenbosch. This was done to be able to properly analyse and test the system. The layout of the pipeline was limited to the structural layout inside the laboratory. A centrifugal pump was chosen for the piping system that was erected in the laboratory based on the pump selection guidelines presented in the previous section. A location for the installation of a wind turbine was chosen near the laboratory building. No reliable long-term wind data were available for the chosen site which meant that the turbine could not be chosen based on the statistical analysis of the prevailing wind regime. The turbine was thus chosen solely to best suit to power requirements of the pump. The turbine chosen had a rating of 3 kW at a wind speed of 11 m/s manufactured by Aero Energy.

The pumping system that was erected is re-circulating. As shown in Figure 16, the pumping system consists of two tanks with a 4 m elevation between the fluid level of tank 2 and the discharge fluid level of tank 1. Water is pumped from the lower tank 2 to upper tank 1 and then flows back to the lower tank by means of gravity flow.

![Figure 16: Graphical representation of the re-circulating pump system.](image-url)
Because it is a low static head application, a low pressure, high flow pump was chosen. This chosen pump is the ETA-X 32-125 model manufactured by KSB Pumps. The pump performance curves of the pump are supplied by the pump manufacturer for shaft speeds of 2900 r/min for a 2-pole induction motor and 1450 r/min for a 4-pole induction motor respectively. The pump performance curves are determined at other operating shaft speeds by using the pump affinity laws given by (3.59) - (3.60) which are shown in Figure 17.

The net positive suction head (NPSHr) required by the pump to prevent cavitation, is provided by the pump manufacturer as varying between 0.4 m - 1.3 m for flow rates between 0 - 40 m³/hr. Stellenbosch is located at a height of 107 m above sea level which translates to $P_H \approx 100$ kPa. The temperature is assumed to be 20ºC which corresponds to a water vapour pressure of $P_{VP} \approx 2.34$ kPa. The suction pipe is directly connected from the tank outlet to the pump inlet with $H_{Sv} = 0$. The type of piping used is PVC with a pipe diameter of 40 mm. The suction pipe length is 0.5 m. The only pipe fitting in the suction line is a gate valve. The value of $H_f$ can thus be calculated as being $H_f \approx 3.6$ m at the maximum flow rate of 40 m³/hr.

![Figure 17: Pump performance curves of the KSB centrifugal pump model ETA-X 32-125 for different operating shaft speeds.](image-url)
The minimum value of the net positive suction head available (NPSH$_A$) at the suction side of the pump can therefore be determined using (3.61) as being

$$\text{NPSH}_A = \frac{(100 - 2.34)}{10} - 0 - 3.6 \approx 6.36 \text{ m.} \quad (4.1)$$

The value of NPSH$_A$ is therefore always greater than NPSH$_R$ throughout the operating range of the pump and cavitation will thus never occur.

The system curve for the piping system is determined using (3.54) - (3.58). The total length of piping used in the installation is 10.5 m. The frictional loss in the piping is determined by firstly calculating the resistance coefficient, $R$, of the pipe given by (3.57) as

$$R = \frac{(10.59)(10.5)}{(140^{1.85})(0.04^{4.87})} \approx 76510. \quad (4.2)$$

The frictional loss can therefore be determined using (3.56) as

$$H_f = 76510Q^{1.85} \text{ m.} \quad (4.3)$$

The minor losses in the piping due to the various pipe fittings present in the piping are determined using (3.58).

$$H_m = \frac{(k_{\text{entrance}} + k_{\text{contraction}} + k_{\text{gate valve}} + 5 \times k_{\text{elbow 90}} + k_{\text{elbow 45}} + k_{\text{exit}})Q^2}{2gA^2}$$

$$= \frac{(0.5 + 0.18 + 0.2 + (5 \times 1.1) + 0.35 + 1)Q^2}{(2)(9.81)(\pi \times 0.02^2)^2} \quad (4.4)$$

$$\approx 250000Q^2 \text{ m.}$$

The system curve can ultimately be written as

$$H_{SC} = 4 + 76510Q^{1.85} + 250000Q^2 \text{ m.} \quad (4.5)$$

This system curve is superimposed on the pump performance curves of the chosen pump as shown in Figure 17. The intersections between the various pump
performance curves and this system curve will determine the mechanical power being absorbed by the pump at the different shaft speeds. The load that the pump presents to the wind turbine can thus be determined at varying pump speeds through (3.52) and (3.53). This pump generates the required pressure to overcome the 4 m static head of the system and produce flow at a relatively low shaft speed of \( \approx 1200 \text{ r/min} \).

The minimum flow required by the pump at this minimum operating speed is about 30% of the flow at the best efficiency point at this minimum speed according to SAPMA [26]. The flow at the maximum efficiency point of 62% is \( \approx 10 \text{ m}^3/\text{hr} \). This translates to a minimum flow requirement of \( \approx 0.3 \times 10 = 3 \text{ m}^3/\text{hr} \). The intersection between the system curve and the pump performance curve at the minimum operating speed of 1200 r/min translates to a flow of \( \approx 4 \text{ m}^3/\text{hr} \). The minimum flow rate required by the pump is therefore surpassed by this application at the minimum pump operating speed and the pump would therefore operate safely.

### 4.3 Power Matching

Power matching is important because it ensures optimum energy transfer between the turbine and pump under varying wind conditions. The maximum power delivery of the turbine at each wind speed and the power requirement of the pump have similar cubic power versus shaft speed characteristics. Therefore, if the pump could operate close to the turbine maximum at one wind speed, it could operate close to the maximum at all the other wind speeds. Power matching is done through the electrical gearbox formed by the difference in the number of poles in the permanent magnet generator and induction motor of the wind-electric pump system. The speed ratio of the two rotating shafts are given by

\[
\frac{\Omega_2}{\Omega_1} = \frac{p_g}{p_m}(1 - s),
\]

where \( p_g \) and \( p_m \) are the number of poles of the permanent magnet generator and induction motor respectively, \( s \) is the slip of the motor and \( \Omega_1 \) and \( \Omega_2 \) are respectively the rotational speeds of the turbine and pump shafts, shown in Figure 8. The power delivery curves of a 3 kW turbine manufactured by Aero Energy is shown in Figure 18 for wind speeds of 3 m/s – 11 m/s. The power requirements of the centrifugal
pump across its usable operating range are superimposed on Figure 18 using (4.6) for various shaft speed ratios. The value of motor slip in (4.6) is ignored at first to estimate the pole ratio required for good power matching. It can be seen from Figure 18 that a shaft speed ratio of 1:10 causes the pump to operate close to the optimum operation of the turbine and would provide good power matching between the turbine and the pump. A shaft speed ratio of 1:6 would, however, not provide as good a match. The steady-state operating turbine shaft speeds can, therefore, be estimated as between 125 r/min and 320 r/min for the 1:10 speed ratio. If a 4-pole induction motor is chosen, a 40-pole generator would have to be used which would generate a supply frequency of between 42 Hz and 106 Hz. If a 2-pole induction motor is used, a 20-pole generator would be needed which would generate a supply frequency of between 21 Hz and 53 Hz. The 4-pole induction motor is not a viable option in this application since the high frequency generated by the 40-pole generator would (i) cause unnecessarily high iron losses in the induction motor and (ii) reduce the bearing life since the induction motor would be operating at double its synchronous speed. In this application, the optimum power matching and utilisation of the turbine and pump is therefore achieved with the 1:10 speed ratio which, in turn, translates to a 20-pole generator and 2-pole induction motor.

![Figure 18: Estimated power flow between the 3 kW Aero Energy wind turbine and centrifugal pump for wind speed of 3 m/s – 11 m/s with shaft speed ratios of 1:10 and 1:6.](image-url)
4.4 Efficient Operation of Induction Motor

The wind turbine in Figure 18 has a rating of 3 kW at a wind speed of 11 m/s. It is assumed that this wind speed of 11 m/s would be the maximum intensity encountered by the system which has a reasonable probability of occurrence. The rating of the induction motor is therefore chosen to be smaller than this maximum power transfer, namely at 2.2 kW. The justification for this is:

(i) The reduction in the cost of the components.

(ii) The possible increase in operating efficiency of the induction motor. The smaller motor would operate closer to its full-load specification during lower wind speeds which have a higher probability of occurrence.

(iii) The 2.2 kW rating is a commercially standard induction motor design which is more cheap and easy to source.

The nameplate data concerning the rated performance of the 2.2 kW, 2-pole induction motor is shown in Table 1. The constant V/Hz that is generated by the permanent magnet generator would allow the torque-speed curve of induction motor to remain essentially the same throughout the variable speed operation of the motor. The frequency range of the 20-pole generator is estimated from Figure 18 as being between $\approx 20$ Hz – 50 Hz. The torque-speed curves of the 2.2 kW induction motor are calculated form the equivalent circuit parameters and shown in Figure 19 for the frequency range of 20 Hz – 50 Hz operating at a nominal V/Hz supply ratio of 400 V/50 Hz. It is noted in Figure 19 that the torque-speed curves of the 2.2 kW induction motor do not remain the same throughout the variable speed operation of the motor. This can be contributed to the high value of the stator resistance, $R_s$, normally associated with small induction motors. The resistance cause the supply voltage to drop and is dramatically evident at lower frequencies. The load curve of the chosen centrifugal pump is also included in Figure 19. The intersections between the various torque-speed curves and the pump load curve show the increase in induction motor slip value from almost zero until the rated value of 5 % as the V/Hz supply increases.
<table>
<thead>
<tr>
<th>Performance Rating</th>
<th>2.2 kW @ 2850 r/min</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated Voltage Supply</td>
<td>400 V, 3-Phase @ 50 Hz</td>
</tr>
<tr>
<td>Rated Efficiency</td>
<td>87.5 %</td>
</tr>
<tr>
<td>Rated Current</td>
<td>4.3 A</td>
</tr>
<tr>
<td>Number of Poles</td>
<td>2</td>
</tr>
<tr>
<td>Rated slip</td>
<td>5 %</td>
</tr>
<tr>
<td>Duty</td>
<td>0.86 PF</td>
</tr>
<tr>
<td>3-Phase Connection</td>
<td>Star</td>
</tr>
<tr>
<td>Insulation Class</td>
<td>F</td>
</tr>
</tbody>
</table>

Table 1: 2.2 kW Induction motor nameplate data

Figure 19: Calculated torque-speed curves of the 2.2 kW induction motor operating under constant V/Hz supply.
The V/Hz that is generated by the permanent magnet generator must ensure that the 2.2 kW induction motor is operated as efficiently as possible throughout the operating range of the wind turbine. The operating efficiency of the 2.2 kW induction motor is shown in Figure 20 and Figure 21. The operating efficiency in both figures is evaluated for V/Hz supply ratios of 400 V/50 Hz and 300 V/50 Hz respectively. The induction motor is operated at 100% of rated torque in Figure 20 and operated at 25% of rated torque in Figure 21. It is deduced from Figure 20 and Figure 21 that the induction motor require a higher V/Hz supply at high torque loads and a lower V/Hz supply at low torque loads in order to operate at the highest possible efficiency. The overall efficiency of the wind-electric pump system would not benefit much from an increased induction motor efficiency at low torque loads due to the low level of power flow involved. A higher efficiency at higher torque loads would have a much more significant effect in the overall efficiency of the wind-electric pump system. The value of induction motor slip throughout the operating range of the pump would also be lower at the higher V/Hz supply of 400 V/50 Hz than at the lower supply of 300 V/50 Hz. This lower slip value would allow the induction motor to draw less current and operate at a lower temperature which would prolong the service life of the induction motor. The higher V/Hz supply ratio of 400 V/50 Hz was therefore chosen for the permanent magnet generator supply in the small-scale wind-electric pump system setup.
Figure 20: Operating efficiency of the 2.2 kW induction motor operating at 100 % of rated torque and supplied by a V/Hz supply ratio of 400 V/50 Hz and 300 V/50 Hz respectively.

Figure 21: Operating efficiency of the 2.2 kW induction motor operating at 25 % of rated torque and supplied by a V/Hz supply ratio of 400 V/50 Hz and 300 V/50 Hz respectively.
4.5 Design of the Axial Flux Permanent Magnet Synchronous Generator

4.5.1 Design Guidelines

The design of the permanent magnet generator is done using (3.1) - (3.27). The generator must be designed as such as to deliver the desired V/Hz supply with the least possible stator impedance to allow for efficient voltage source operation throughout the operating range of the wind turbine. It is assumed that the maximum wind speed with a reasonable probability of occurrence at the wind turbine installation site is 11 m/s. A few guidelines are given in this chapter in order to simplify the design process. It is stated in Chapter 3.1 that the AFPM machines with the highest torque performance has a coil pitch of $\theta_m = \frac{4\pi}{3}$ and $\kappa = \kappa_{\text{max}}$. The total number of coils in the 20-pole generator must therefore be $Q_c = 15$ according to (3.7). The diameter of the copper conductor used for the stator coils must allow for a current density at the maximum operating wind speed of 11 m/s that is below the typical current density limit of 6-7 A/mm² considered for small air-cored stators. Exceeding this limit would cause extensive heat dissipation in the stator which can lead to winding damage if operated for extended periods of time. The current density in the stator conductors, $J$, can be calculated by

$$J = \frac{NI}{hwk_f},$$  \hspace{1cm} (4.7)

where $I$ is the current flow in the conductor. It is evident from (3.15) that the eddy current power loss is dependent on the $4^{th}$ power of the diameter of the copper conductor. The diameter of the conductor must therefore be as small as possible to curb these losses without exceeding the current density limit considered for the small air-cored stator. One way to reduce the conductor diameter to curb eddy current loss is to connect the stator coils in multiple parallel circuits i.e. $a > 1$. This would reduce the generated voltage according to (3.1). The number of turns per coil, $N$, would have to be increased to compensate for the reduction in generated voltage which would therefore reduce the conductor diameter, $d$, according to (3.16).
Another method of reducing the conductor diameter according to (3.16) is to divide the single stator coil conductor itself into several, thinner, parallel-connected conductors i.e. \( u > 1 \). The combined conductor area of these thin parallel conductors must be equal to the surface area of the original stator coil conductor. Eddy currents can however still circulate in these thin, parallel conductors and can be reduced by twisting and transpositioning these conductors according to Rossouw [16]. The twisting of these conductors, however, would reduce the fill factor of the stator coil, \( k_f \), which cause an increase in the phase resistance according to (3.10). The fill factor for stator coils wound with a single conductor was found experimentally to be \( k_f = 0.58 \). The fill factor coils wound with twisted parallel-connected conductors of reduced diameter could be as low as \( k_f = 0.42 \) according to Rossouw [16].

The energy product of the permanent magnets used in the rotor assembly of the axial flux permanent magnet synchronous generator is the flux density produced in the air gap of the generator for a given magnet volume. The maximum energy product for the permanent magnets is the maximum flux density that could be produced in the air gap for the minimum amount of magnet material. This provides the best balance between performance and cost. For the design of an axial flux permanent magnet synchronous generator, the maximum energy product of the magnets used typically equates to a maximum air-gap flux density in the region of \( B_p = 0.5 – 0.6 \) T.

According to the 1:10 shaft speed ratio in Figure 18, the wind turbine shaft speed at the maximum operating wind speed of 11 m/s is about 300 r/min and can potentially deliver \( \approx 3 \) kW to the pump. The design of the axial flux permanent magnet synchronous generator is optimised to operate at the maximum wind speed at a minimum efficiency of 90 % without exceeding the maximum considered current density. The generator supply of the optimised design must also be slightly higher at 430 V/50 Hz. This higher supply is necessary to account for the voltage drop across the generator stator impedance in order to deliver the proposed 400 V/50 Hz supply to the induction motor.
4.5.2 Calculated steady-state results

The design of the permanent magnet generator is optimised through the iterative calculation of the steady-state operation of the wind-electric pump system until a minimum operating efficiency of 90% was achieved at the maximum operating wind speed of 11 m/s whilst still keeping within the current density limits. The design parameters of the optimised generator design are given in Table 2. The optimised steady-state calculation results at the maximum operating wind speed of 11 m/s are given in Table 3. The eddy current loss in this small scale application was considered to be minimal. There was therefore no effort made in using multiple parallel circuits i.e. $a > 1$ or dividing the conductor into several, thinner, parallel-connected conductors i.e. $u > 1$. The stator phases were connected in a wye configuration as shown in Figure 22. It is noted in Table 3 that the generator efficiency at the maximum operating wind speed of 11 m/s is 90% which equates to a generator output rating of 2.70 kW. The current density in the stator conductors at this maximum operating wind speed is calculated using (4.7) as

$$J = \frac{(165)(4.5)}{(8.4)(42)(0.58)} \approx 3.63 \text{ A/mm}^2$$

(4.8)

Figure 22: Wye connection of stator phases with $q = 5$ and $a = 1$. 
This current density in the air-cored stator of the optimised permanent magnet generator design is below the 6-7 A/mm² current density limit at the maximum wind speed of 11 m/s. This permanent magnet generator design would therefore operate safely and reliably under this maximum operating condition and could even be safely operated at higher output ratings at higher wind speeds as well.

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>Symbol:</th>
<th>Value:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator coil total</td>
<td>$Q_c$</td>
<td>15</td>
</tr>
<tr>
<td>Stator coils per phase</td>
<td>$q$</td>
<td>5</td>
</tr>
<tr>
<td>Parallel circuits</td>
<td>$a$</td>
<td>1</td>
</tr>
<tr>
<td>Rotor poles</td>
<td>$p_g$</td>
<td>20</td>
</tr>
<tr>
<td>Stator winding turns</td>
<td>$N$</td>
<td>165</td>
</tr>
<tr>
<td>Parallel strands per conductor</td>
<td>$u$</td>
<td>1</td>
</tr>
<tr>
<td>Peak air-gap flux density</td>
<td>$B_p$</td>
<td>0.6 T</td>
</tr>
<tr>
<td>Inner radius of stator coil</td>
<td>$r_i$</td>
<td>200 mm</td>
</tr>
<tr>
<td>Outer radius of stator coil</td>
<td>$r_o$</td>
<td>260 mm</td>
</tr>
<tr>
<td>Kappa</td>
<td>$\kappa_{max}$</td>
<td>0.4347</td>
</tr>
<tr>
<td>Stator coil axial thickness</td>
<td>$h$</td>
<td>8.4 mm</td>
</tr>
<tr>
<td>Stator coil width</td>
<td>$w$</td>
<td>$\approx$ 42 mm</td>
</tr>
<tr>
<td>Stator conductor diameter:</td>
<td>$d$</td>
<td>$\approx$ 1.25 mm</td>
</tr>
<tr>
<td>Fill factor for stator conductors</td>
<td>$k_f$</td>
<td>0.58</td>
</tr>
</tbody>
</table>

Table 2: Optimised design parameters of the axial flux permanent magnet synchronous generator.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator back emf ($E_{30}$)</td>
<td>430 V</td>
</tr>
<tr>
<td>Generator terminal supply voltage ($V_{30}$)</td>
<td>400 V</td>
</tr>
<tr>
<td>Generator frequency</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Generator shaft speed ($\Omega_1$)</td>
<td>300 r/min</td>
</tr>
<tr>
<td>Generator phase resistance ($R_G$)</td>
<td>3 Ω</td>
</tr>
<tr>
<td>Generator phase inductance ($L_G$)</td>
<td>11.5 mH</td>
</tr>
<tr>
<td>Operating phase current ($I_{TOT}$)</td>
<td>4.3 A</td>
</tr>
<tr>
<td>Operating power factor</td>
<td>0.87</td>
</tr>
<tr>
<td>Generator input power</td>
<td>2980 kW</td>
</tr>
<tr>
<td>Generator copper loss ($P_{cu}$)</td>
<td>192 W</td>
</tr>
<tr>
<td>Induction motor shaft speed ($\Omega_2$)</td>
<td>2873 r/min</td>
</tr>
<tr>
<td>Induction motor slip ($s$)</td>
<td>≈ 4.5 %</td>
</tr>
<tr>
<td>Induction motor output power</td>
<td>2335 kW</td>
</tr>
<tr>
<td>Induction motor output torque</td>
<td>7.75 Nm</td>
</tr>
<tr>
<td>Generator operating efficiency</td>
<td>90 %</td>
</tr>
<tr>
<td>Induction motor operating efficiency :</td>
<td>87 %</td>
</tr>
<tr>
<td>Generator–motor operating efficiency</td>
<td>78.5 %</td>
</tr>
<tr>
<td>Eddy current losses ($P_E$)</td>
<td>73 W</td>
</tr>
<tr>
<td>Eddy current resistance ($R_E$)</td>
<td>2.580 kΩ</td>
</tr>
</tbody>
</table>

Table 3: Calculated steady-state operation of the wind-electric pump system operating at a wind turbine shaft speed of 300 r/min and 11 m/s wind speed.
The steady-state operation of the wind-electric pump system is calculated across the operating range of the wind turbine and shown in Figure 23. The pump load, electrical losses and the total mechanical input power required to drive the wind-electric pump system is calculated across the operating range of the wind turbine. These curves are superimposed on the turbine delivery curves of the 3 kW Aero Energy wind turbine for wind speeds ranging from 4 m/s – 11 m/s. The intersections between the total input power curve and the power delivery curves of the wind turbine, determine the steady-state operation of the wind-electric pump system at each wind speed. It is evident from Figure 23 that the optimised permanent magnet generator design allows the wind turbine to operate at its full capacity under all wind speed conditions. The wind turbine and centrifugal of the wind-electric system are therefore optimally matched. This optimal power matching increase the operating range of both wind turbine and pump and allow the wind-electric pump system to operate from a low wind speed of 4 m/s right up to the maximum wind speed of 11 m/s.

The operating efficiencies of the generator and motor that exist across the operating range of the wind turbine are shown in Figure 24. The relatively low internal impedance of the permanent magnet generator allows its efficiency to remain high between 90 - 95 % throughout the operating range of the turbine. As expected from the high V/Hz supply, the induction motor efficiency is low at low pump torque loads but increases as the pump torque load increases. The overall electrical efficiency of the generator and motor is therefore low at low wind speeds, reaching a maximum efficiency of ≈ 80 % at medium to high wind speeds. This low electrical efficiency at low wind speeds is acceptable in this application considering the low power flow that exists between the turbine and pump under these conditions.
Figure 23: Total mechanical input power, pump load and electrical power loss of the wind-electric pump system depicted on the power delivery curves of the Aero Energy wind turbine for wind speeds of 4 m/s to 11 m/s.

Figure 24: Calculated electrical efficiency of the permanent magnet generator and the induction motor across the operating range of the Aero Energy wind turbine.
4.6 Practical Measurement

4.6.1 Practical Generator Design

An axial flux permanent magnet synchronous generator is built and tested in this chapter to (i) illustrate the construction process of the generator and to (ii) validate the derived system model of Chapter 3 used in the steady-state calculations of the wind-electric pump system. The 2.7 kW, high-voltage axial flux permanent magnet synchronous generator design, described in the previous chapter, could not be built to exact specification because of time and budgetary constraints involved in the production of the generator components. The stator design of an existing low voltage 1 kW generator, of which the production and operating components were readily available, was modified in an effort to generate the high voltage required by the wind-electric system. The modified high voltage stator design had to ensure that it could be practically built using the existing dimensions of the 1 kW stator mould. The existing low voltage stator design was therefore modified for high voltage according to practical rather than efficiency considerations. The dimensions of the stator mould are given in Table 4. The rotor of the existing 1 kW generator had 24 poles and magnets producing a flux density of $B_p = 0.57$ T. To simplify the design process, the V/Hz supply ratio of the generator was chosen to be 400 V/50 Hz at a turbine speed of 250 r/min.

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>Symbol:</th>
<th>Value:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inner radius of stator coil</td>
<td>$r_i$</td>
<td>140 mm</td>
</tr>
<tr>
<td>Outer radius of stator coil</td>
<td>$r_o$</td>
<td>200 mm</td>
</tr>
<tr>
<td>Peak air-gap flux density</td>
<td>$B_p$</td>
<td>0.57 T</td>
</tr>
<tr>
<td>Stator coil axial thickness</td>
<td>$h$</td>
<td>8.4 mm</td>
</tr>
</tbody>
</table>

*Table 4: Dimensions of the existing 1 kW generator stator mould.*
Using $\theta_m = 4\pi/3$, the number of stator coils were determined as being $Q = 18$. To ensure that this number of stator coils would practically fit into the 1 kW stator mould, the coil width, $w$, and the number of windings per coil, $N$, needed to be as small as possible. The value of $\kappa$ was therefore deliberately chosen lower than the maximum value of $k_{\text{max}} \approx 0.41$, to be $\kappa = 0.35$. The stator coils were connected in the same configuration as the original design as shown in Figure 22 because the eddy current loss was again assumed to be minimal. The 400 V/50 Hz supply required a number of turns per coil to be $N = 200$. The rest of the design parameters are given in Table 5.

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>Symbol:</th>
<th>Value:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator coil total</td>
<td>$Q_c$</td>
<td>18</td>
</tr>
<tr>
<td>Stator coils per phase</td>
<td>$q$</td>
<td>6</td>
</tr>
<tr>
<td>Parallel circuits</td>
<td>$a$</td>
<td>1</td>
</tr>
<tr>
<td>Rotor poles</td>
<td>$p_g$</td>
<td>24</td>
</tr>
<tr>
<td>Stator winding turns</td>
<td>$N$</td>
<td>200</td>
</tr>
<tr>
<td>Parallel strands per conductor</td>
<td>$u$</td>
<td>1</td>
</tr>
<tr>
<td>Kappa</td>
<td>$\kappa$</td>
<td>0.35</td>
</tr>
<tr>
<td>Stator coil width</td>
<td>$w$</td>
<td>$\approx 21$ mm</td>
</tr>
<tr>
<td>Stator conductor diameter:</td>
<td>$d$</td>
<td>$\approx 0.8$ mm</td>
</tr>
<tr>
<td>Fill factor for stator conductors</td>
<td>$k_f$</td>
<td>0.58</td>
</tr>
</tbody>
</table>

Table 5: Design parameters of the manufactured generator design.
4.6.2 Manufacture of Modified Stator

The stator coils were wound according to the specifications in Table 5 and placed in the 1 kW stator casting mould as shown in Figure 25. The stator coils were connected in wye as shown in Figure 22. The spaces between the coils were filled with fibreglass fibres which would bond with the epoxy to give structural integrity to the stator mould. The mould was then closed, filled with epoxy and baked overnight. The rotor and modified stator were then assembled and the complete generator assembly mounted on the test bench as shown in Figure 26.

![Figure 25: Stator coil layout in the casting mould before adding the epoxy.](image)
4.6.3 Test Setup and Measuring Methodology

The steady-state operation of the system was tested in the laboratory using a test setup shown in Figure 27. The permanent magnet generator was driven at various shaft speed increments, $\Omega_i$, using a 55 kW induction motor which is supplied by a variable speed drive. Torque and speed sensors were placed at both generator and motor shafts as shown in Figure 28 and Figure 29. These sensors allow the measurement of the mechanical input power supplied to the generator as well as the mechanical output power generated by the motor at each speed increment. The overall electrical operating efficiency for each speed increment could be determined through these measurements. The generator supply was also measured at each increment using a power analyser. The measured supply parameters include the generated electrical power, voltage, phase current and system power factor. A temperature probe was inserted in the stator mould to monitor the temperature of the windings, especially at high turbine shaft speeds. The generated water pressure in the pipeline was measured
using a pressure gauge. The induced water flow is measured by measuring the volume of water displaced from tank 1 to tank 2 in Figure 16 within a given amount of time. All the measurements made at each increment are listed in Appendix C.

Figure 27: Block diagram of laboratory test setup.

Figure 28: Test setup at the shaft between the assembled generator with the modified high voltage stator and the 55 kW induction motor. The torque sensor, power analyser and VSD control of the induction motor panel can be observed.
4.6.4 Test Results

The total steady-state mechanical input power required to drive the wind-electric pump system is calculated across the operating range of the wind turbine based on the new set of permanent magnet generator design parameters given in Table 4 and Table 5 and shown in Figure 30. The 24 poles in the generator rotor mean that the wind-electric pump system, utilising the 2-pole motor, would have a shaft ratio of 1:12. The wind-electric pump system would therefore not operate as close to the optimum operation of the turbine as the 1:10 shaft ratio in Figure 23. The overall electrical operating efficiency of the generator and motor is also calculated across the operating range of the wind turbine and shown in Figure 31. The measurements made during the test setup are included in Figure 30 and Figure 31. The comparison between the calculated and measured steady-state operational data is shown in Figure 30 – Figure 31 to be accurate. This accurate steady-state operation comparison shows the system model derived in Chapter 3 and the calculation methodology in Appendix B to be accurate in estimating the steady-state operation of a wind-electric pump system.
Figure 30: Calculated and measured total mechanical input power superimposed on the 3 kW turbine delivery curves for wind speeds of 4 m/s – 11 m/s.

Figure 31: Calculated and measured combined efficiency of the permanent magnet generator and induction motor across the operating range of the wind turbine.
This accurate steady-state operation of the modified 1 kW generator design also serves to validate the design parameters and the steady-state operation of the original generator design discussed in Chapter 4.5.

The steady-state operation of the wind-electric pump system in Figure 30 is given in Table 6 for the maximum wind speed of 11 m/s. It can be deduced from the steady-state operating parameters in Table 6 that the limitations imposed on the modified high-voltage stator design resulted in the overloaded operation of the generator. The eddy current loss is very low due to the small diameter of the conductors used in the production of the modified stator, i.e. \( \approx 0.8 \) mm but the high stator resistance caused a considerable voltage drop which increased the slip operation of the induction motor.

The generator and motor efficiency of the tested system are measured across the operating range of the wind turbine and shown in Figure 32. The motor efficiency improves, as expected, at higher generator shaft speed due to the increase in V/Hz terminal supply. The generator efficiency is high at low generator shaft speeds but drops substantially at higher generator shaft speeds due to the overloading of the generator.

Figure 32: Measured electrical efficiency of the modified permanent magnet generator and the induction motor across the operating range of the Aero Energy wind turbine.
<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator back emf ( (E_{30}) )</td>
<td>375 V</td>
</tr>
<tr>
<td>Generator terminal supply voltage ( (V_{30}) )</td>
<td>290 V</td>
</tr>
<tr>
<td>Generator shaft speed ( (\Omega_1) )</td>
<td>235 r/min</td>
</tr>
<tr>
<td>Generator frequency</td>
<td>47 Hz</td>
</tr>
<tr>
<td>Generator phase resistance ( (R_G) )</td>
<td>8.61 Ω</td>
</tr>
<tr>
<td>Generator phase inductance ( (L_G) )</td>
<td>19 mH</td>
</tr>
<tr>
<td>Operating phase current ( (I_{TOT}) )</td>
<td>4.87 A</td>
</tr>
<tr>
<td>Operating power factor</td>
<td>0.87</td>
</tr>
<tr>
<td>Generator input power</td>
<td>2777 kW</td>
</tr>
<tr>
<td>Generator copper loss ( (P_{cu}) )</td>
<td>614 W</td>
</tr>
<tr>
<td>Generator operating efficiency</td>
<td>76 %</td>
</tr>
<tr>
<td>Induction motor shaft speed ( (\Omega_2) )</td>
<td>2620 r/min</td>
</tr>
<tr>
<td>Induction motor slip ( (s) )</td>
<td>( \approx 7 % )</td>
</tr>
<tr>
<td>Induction motor output power</td>
<td>1773 kW</td>
</tr>
<tr>
<td>Induction motor output torque</td>
<td>7.75 Nm</td>
</tr>
<tr>
<td>Induction motor operating efficiency</td>
<td>83.5 %</td>
</tr>
<tr>
<td>Generator–motor operating efficiency</td>
<td>64 %</td>
</tr>
<tr>
<td>Eddy current losses ( (P_E) )</td>
<td>14 W</td>
</tr>
<tr>
<td>Eddy current resistance ( (R_E) )</td>
<td>9.610 kΩ</td>
</tr>
</tbody>
</table>

**Table 6:** Calculated steady-state operation of the wind-electric pump system in Figure 30 operating at a wind turbine shaft speed of 235 r/min and 11 m/s wind speed.
The current density in the stator conductors of the modified high-voltage stator is shown in Figure 33 throughout the operating range of the wind turbine. The current density at the maximum operating wind speed of 11 m/s is indicated in Figure 33 and calculated using (4.9) as being

\[ J = \frac{(200)(4.87)}{(8.4)(21)(0.58)} \approx 9.8 \text{ A/mm}^2. \]  

(4.9)

It is therefore evident that the overloaded operation of the generator at 11 m/s wind speed caused the current density to be above the 6-7 A/mm² considered safe for the small air-cored stator. This extensive heat dissipation was also evident during testing. It is also shown in Figure 33 that the generator is operating within limits at a wind speed of about 9 m/s. The modified generator must therefore not be operated above a maximum wind speed of 9 m/s at a rating of 1.4 kW to ensure reliable and safe operation.

Figure 33: Current density in the conductors of the modified high voltage stator. The current density at the operating wind speeds of 9 m/s and 11 m/s are indicated.
The hydraulic delivery potential of the wind-electric system is measured and calculated at each wind speed and shown in Figure 34. The calculations are made using the steady-state operation of the WEPS shown in Figure 30 in conjunction with the performance curves of the ETA-X 32-125 pump shown in Figure 17. The copper losses caused by the high stator resistance of the permanent magnet stator mean that the tested wind-electric system can only start to operate at wind speeds above 5 m/s. This output potential can now be used in conjunction with a wind speed distribution at the turbine installation site to estimate the performance of the wind-electric pump system.

![Figure 34: Estimated and measured hydraulic output potential of a wind-electric system for each wind speed.](image)

4.6.5 Summary

An existing 1 kW axial flux permanent magnet generator design was modified and built for a high-voltage application. The generator was then analysed and tested to validate the system model of the wind-electric pump system derived in Chapter 3. The limitations imposed on the modified generator design reduced the generator rating. The operating range of both the wind turbine and centrifugal pump was therefore decreased which, in turn, decreased the hydraulic output potential of the wind-electric pump system. Chapter 4.5, however, shows that the performance of the wind-electric pump system can be much better if the guidelines given in the optimal design of the axial flux permanent magnet generator, are followed.
5. Transient Start-up Operation

The successful operation of a wind-electric pump system is not only dependent on its steady-state operation but also on the ability to start-up successfully. This chapter will describe an example of a start-up process of a wind-electric pump system in detail. A practical method will be derived to approximate the minimum turbine rotational speed necessary to ensure a successful start-up for a WEPS of a given size and rating. A voltage monitor is also introduced as a direct-on-line hysteresis switch which can be used to ensure a successful start-up and safe operation of the wind-electric pump system and its components.

5.1 Start-Up

The start-up process of a wind-electric pump system is initiated through the electrical connection made between the permanent magnet generator and induction motor. When the electrical connection between the generator and motor is made, rotational kinetic energy is transferred from the turbine inertia to the pump system inertia. The turbine inertia consists of the turbine blades and the permanent magnet generator assembly. This pump system inertia is composed of the sum of the inertias associated with the mechanical elements of the induction motor and centrifugal pump. These elements include the induction motor shaft, centrifugal pump shaft and impeller, and the column of water in the pump impeller casing. This transfer of rotational kinetic energy causes the shaft speed, $\Omega_1$, of the accelerating turbine to decelerate whilst simultaneously allowing the shaft speed, $\Omega_2$, of the induction motor and centrifugal pump to accelerate from standstill.

The start-up process of an arbitrary wind-electric pump system example is illustrated in Figure 35 and Figure 36. The rotational shaft speed of the centrifugal pump in this example is referred to the turbine side via an arbitrary shaft speed ratio. Figure 35 shows the torque delivery of the wind turbine for a given wind speed. Assume that the wind speed is constant and allows the wind turbine to accelerate from standstill. The wind turbine moves through its power delivery curve as its shaft speed increases.
Figure 35: Torque characteristics of a wind turbine, induction motor and centrifugal pump used
to illustrate the start-up process for a wind-electric pump system example.

Figure 36: An example of the transient start-up behaviour of the wind-electric pump system
eexample in Figure 35.
The electrical connection between the generator and motor is made when the accelerating turbine is at point A₁ on its power delivery curve at a rotational shaft speed of \( \approx 200 \text{ r/min} \). The transfer of rotational kinetic energy from the wind turbine to the system inertia causes the shaft speed of the accelerating turbine to decrease and the turbine to move up its torque delivery curve towards point B₁ at \( \approx 190 \text{ r/min} \). Assume that the turbine inertia will always be much larger than the pump system inertia. Also assume that enough rotational energy is stored in the turbine to keep the change in turbine speed relatively small and the generator supply relatively constant at start-up. The transfer of energy to the pump system inertia would therefore cause the induction motor to rapidly accelerate from standstill through its torque-speed curve, indicated by \( f_1 \), from point A₂ until the pump torque load is reached at point B₂. The induction motor slip accounts for the small shaft speed difference of \( \approx 10 \text{ r/min} \) between point B₁ on the turbine torque delivery curve at \( \approx 190 \text{ r/min} \) and point B₂ on the induction motor torque-speed curve at \( \approx 180 \text{ r/min} \). The system is not in steady-state operation at this time because the torque available from the turbine at point B₁ is much higher than the pump load at point B₂. The wind accelerates the wind turbine until steady-state operation is reached at point C₁ on its torque delivery curve at a rotational speed of \( \approx 315 \text{ r/min} \). The V/Hz supply at this point allows the induction motor to drive the pump load at point C₂ on its torque-speed curve indicated by \( f_2 \) at a rotational speed of \( \approx 300 \text{ r/min} \). The steady-state electrical power losses in the generator and induction motor account for the difference in torque between the turbine delivery at point C₁ and the induction motor output at point C₂. The transient operation of the start-up process described above is shown in Figure 36.

The rotational kinetic energy stored in the “fly wheel”, created by the turbine and permanent magnet generator assembly, can be determined by

\[
E_{\text{ROT}} = 0.5J_T\omega^2, \tag{5.1}
\]

where \( J_T \) is the inertia associated with the turbine blades and the generator assembly and \( \omega \) is the angular rotational velocity of the turbine shaft (rad/s). The transfer of the rotational kinetic energy from the turbine inertia to the pump system inertia can be approximated by the use of the energy conservation principle. This principle assumes that no wind energy is used to accelerate the wind turbine during the energy transfer.
Using this principle, the transfer of rotational kinetic energy from the turbine to the system inertia during the start-up time period AB in Figure 36 can be expressed as

\[
0.5J_T \omega_A^2 - 0.5J_T \omega_B^2 = 0.5J_S \omega_{B1}^2.
\] (5.2)

\(J_S\) represents the system inertia, \(\omega_A\) and \(\omega_B\) is the angular rotational velocity of the wind turbine at points A1 and B1 on its torque delivery curve and \(\omega_{B1}\) is the angular rotational velocity of the pump at point B2 on its load curve, as shown in Figure 35.

Sufficient rotational kinetic energy must be stored in the wind turbine upon start-up to allow the turbine to settle at or above a minimum steady-state operating shaft speed. This minimum steady-state turbine shaft speed is where the centrifugal pump is safely operated above its minimum steady-state shaft speed. The following equation is derived by substituting (4.6) into (5.2):

\[
0.5J_T \omega_A^2 = 0.5J_T \omega_B^2 + 0.5J_S \left[ \omega_B \frac{p_g}{p_m} (1 - s) \right]^2.
\] (5.3)

By ignoring the small value of the slip, the substitution can be given by

\[
\frac{\Omega^2_A}{\Omega^2_{B1}} = \frac{J_T + J_S \left( \frac{p_g}{p_m} \right)^2}{J_T}.
\] (5.4)

The turbine shaft speed \(\Omega_A\), in r/min, at which sufficient rotational energy would be stored in the turbine to allow it to settle above a certain minimum shaft speed \(\Omega_{B1}\) can thus be estimated. An example of such an estimation using (5.4) is given in the next section.
5.2 Voltage Monitor

A voltage monitor is used to initiate the start-up process between the generator and motor. It can either be programmed to monitor the voltage supply at the generator terminals for under-voltage or over-voltage conditions. If the voltage supply drops below or exceeds one of these pre-set voltage limits, the monitor relay will de-energise and the connection between the generator and motor will be broken. These monitoring devices are equipped with an adjustable hysteresis capability whereby the relay can only be re-energised once the voltage supply drops below an upper-limit or exceeds a lower limit by a certain programmable percentage. The relay time response setting of the voltage monitor can also be set to allow a certain period of time to pass before the relay is energised or de-energised once an under-voltage or over-voltage condition occurs.

The steady-state operation of the practical WEPS setup in the laboratory is illustrated in Figure 30 on Page 82 and used in this chapter as an example to illustrate the methodology in programming the voltage monitor to ensure a successful start-up and safe operation of a wind-electric pump system. The pump system inertia is given by the manufacturers of the induction motor and centrifugal pump to be \( J_S = 0.02 \) kgm². For this example, it is assumed that the turbine inertia is \( J_T = 5 \) kgm². From Figure 30 it is evident that the minimum steady-state turbine shaft speed, necessary for the safe operation of the centrifugal pump, is about 100 r/min at a minimum wind speed of 5 m/s. The turbine cut-in shaft speed at which sufficient rotational energy would be stored in the turbine to allow the turbine to settle at the minimum turbine shaft speed of \( \Omega_B \approx 100 \) r/min can therefore be approximated using (5.4) as being

\[
\Omega_A = \sqrt{\frac{5 + 0.02 \left( \frac{24}{2} \right)^2}{100^2}} \approx 130 \text{ r/min.} \quad (5.5)
\]

The maximum steady-state turbine shaft speed of 200 r/min occurs at the maximum considered wind speed of 9 m/s. The generator terminal supply voltage at this maximum turbine speed is calculated from steady-state calculations to be \( \approx 260 \) V. The steady-state operation calculation is performed again for the minimum turbine speed of 100 r/min and yielded a generator terminal supply of \( \approx 140 \) V.
The turbine cut-in shaft speed of 130 r/min results in a generator back emf of ≈ 210 V using the 400V/50 Hz generator supply ratio. The hysteresis settings on the voltage monitor can therefore be programmed with these voltage parameters as indicated in Figure 37. The connection between the generator and motor is made when a back emf voltage of about 210 V is generated. A generator terminal voltage above 260 V or below 140 V for a time duration surpassing the relay response time, will cause the relay to de-energise and break the connection between the generator and motor. The relay will then only re-energise once the generated emf again exceeds, or the terminal voltage reduces to, the cut-in voltage of 210 V.

There is a certain amount of direct-on-line start-up connections that can be made between the generator and motor per hour. Exceeding this number would cause abnormal temperature increases in the generator and motor windings. It is stated in SAPMA [26] that, as a general rule, induction motors with a rating of < 45 kW must not experience more than 15 start-ups/hour and induction motors with a rating of > 45 kW must not experience more than 5 start-up/hour. The fluctuating nature of wind may cause the voltage monitor relay to chatter and exceed the permissible number of start-ups/hour. For this reason, the variable relay time response functionality of the voltage monitor is advantageous because the advent of relay chatter can be reduced which would prolong the service life of the generator, motor and pump. The connection voltage of 210 V is also much lower than the 400 V rated supply of the induction motor. This reduced supply would also further inhibit the thermal stresses placed on the generator and motor windings during start-up and extend component life. Please note that the minimum, cut-in and maximum voltage settings in Figure 37 is very low because the modified generator used in the practical setup was operated above its rated performance which resulted in large voltage losses in the stator windings. These voltage settings can be much higher for a WEPS design utilizing a well designed permanent magnet generator.
Figure 37: Hysteresis parameter settings on the voltage monitor.
6. Case Study: Boschberg Development Project

This case study will serve as an example of a large scale WEPS design. The design guidelines followed in designing the small scale WEPS setup in the previous chapters will also be used in this chapter. The installation site chosen for this case study will provide a practical insight into the limitations involved in the design and implementation of a large scale WEPS. The chapter will also provide insight into the conditions necessary to make the installation of a large scale WEPS feasible.

6.1 Introduction

The Boschberg Dam has a capacity of 220 million litres and is situated on top of the Boschberg Mountain in Somerset-East at a height of 1483 m asl. Bestershoek Dam has a capacity of 118 million litres and is situated near the base of the mountain at a height of 848 m asl. Both dams are supplied by fountains. The collective flow rate achieved by the fountains at both dams is not known. A complete hydrological study is planned to estimate the flow rate of the water influx at both dams. Preliminary hydrological estimations at Boschberg Dam indicate a flow rate in the region of \( \approx 100 \text{ m}^3/\text{hr} \).

The town of Somerset-East is supplied by the water stored in Bestershoek Dam. A proposal has been made by the Blue Crane Development Agency (BCDA) in Somerset-East to enlarge the water supply of the town. This is done by enlarging the capacity of Boschberg Dam to 440 million litres and constructing a 150 mm UPVC pipeline to transfer the flow from Boschberg dam into Bestershoek dam.

An extension to this proposal has also been made to utilise the water flow between these dams in generating electricity for a planned new golf estate development situated at the base of Boschberg Mountain. The feasibility of using wind-electric water pump systems to possibly increase the generation potential of this proposed hydro-electric scheme is investigated in this chapter. No detailed wind analysis of the wind conditions in the area was available for this feasibility study. The study is therefore based on various wind conditions that might exist in the area which would give an indication on the wind regime necessary to make the use of wind-electric pump systems feasible for this application.
Figure 38: Contour map of Boschberg Mountain and surrounding areas indicating the location and elevation of Bestershoek Dam and Boschberg Dam. The proposed pipeline to transfer water from Boschberg Dam to Bestershoek Dam is also indicated.

6.2 Format of Study

A possible layout of the proposed hydro-electric scheme is discussed. The generation potential of the scheme is estimated based on the estimated flow rate of $\approx 100 \text{ m}^3/\text{hr}$. A complete design of the wind-electric pump system is done and presented. The limitations that this specific application imposed on the system design are highlighted and discussed. The increase in generation potential that the wind-electric pump system could add to the hydro-electric scheme is estimated for various wind regimes that might exist on Boschberg Mountain. An option of utilising the installed wind turbine capacity to connect directly to the grid instead of pumping water is also explored. A conclusion is finally given on the feasibility of the WEPS installation.
6.3 Hydro Power Generation Scheme

The static height between Boschberg and Bestershoke Dam is ≈ 600 m. Three hydro power plants would be situated along the pipeline at 200 m height intervals. These intervals are necessary to reduce the pressure rating of the 150 mm UPVC pipeline to commercially standard levels. A Pelton impulse turbine is ideally suited for the high pressure generated by the gravity flow between the dams. This turbine is expensive to manufacture but have a very high efficiency of 90 – 95% according to CEGB [29]. A cheaper option would be to operate a centrifugal pump as a turbine. The efficiency of a centrifugal pump operating as a turbine is normally 3 – 5% lower than maximum centrifugal pump efficiency. This cheaper turbine option would therefore have an operating efficiency in a lower region of 70 – 75% according to Chapallaz [30].

For the calculation of the generation potential of the proposed hydro scheme, the use of Pelton turbines and electrical generators is assumed with a collective efficiency of 80%. It is also assumed that the head loss in the 150 mm piping is 2.5 m per 100 m pipe length. The total electrical power generated by the three hydro power plants can be estimated by

\[ P_{\text{hydro}} = \frac{3 \rho_f g Q H \eta}{3600}, \quad (6.1) \]

where \( \rho_f \) is the density of the water being pumped (1000 kg/m\(^3\)), \( g \) the gravitational constant (9.81 m/s\(^2\)), \( Q \) the capacity (m\(^3\)/hr), \( H \) the head of the flow and \( \eta \) is the collective efficiency of the turbine and generator. The total continuous power being developed by the hydro scheme is therefore estimated using (6.1) as being

\[ P_{\text{hydro}} = \frac{(3)(1000)(9.81)(100)(195)(0.8)}{3600} \approx 126 \, \text{kW} \quad (6.2) \]
6.4 Wind-Electric Pump System Design

The wind-electric system scheme is used to pump water back from Bestershoek Dam to Boschberg Dam. This would increase the flow rate which could be extracted from Boschberg Dam, thus increasing the power that can be generated by the hydro power scheme. This would require a second UPVC pipeline to be constructed in parallel to the first pipeline used to transfer the water from Bestershoek Dam to Boschberg Dam.

6.4.1 System Layout

The high static head of $\approx 600$ m between Bestershoek Dam and Boschberg Dam imposes a considerable limitation on the operation and implementation of the wind-electric pump system. The centrifugal pumps operate at variable speed and must generate the required static head and achieve flow at as low a pump shaft speed as possible in order to extend the operating range of the pumps. The pressure rating of the UPVC pipeline must also be kept at a commercially available level. For these reasons, the pipeline is broken up into four separate pumping stations operating in series as shown in Figure 39. Each pump station has a large tank to break the pressure in the pipeline, leaving each station with a reduced, but still considerable, static head of 150 m.

![Graphical representation of the WEPS pipeline indicating the four pump stations.](Figure 39)
Large wind turbines operate at very low shaft speeds and generate low electrical power flows during low wind speed conditions. The low turbine shaft speeds and generated power, together with the considerably high static head of 150 m, necessitate the use of small multi-stage pumps. These multi-stage pumps can, however, not be operated at high shaft speeds and flow rates which render them inoperable during high wind speed conditions. For this reason, a larger pump must be used to capitalise on the high power generated by the wind turbine at higher wind speeds to generate larger flow rates. Each of the four identical pump stations would therefore have two centrifugal pumps, a smaller multi-stage pump for low wind speed conditions and a larger pump for higher wind speed conditions.

The electrical connection between turbine and pump allow the wind turbine to be placed on top of Boschberg Mountain where wind conditions are most optimal. A large wind turbine can be installed on top of the mountain to power the four pump stations. Four smaller wind turbines, a turbine for each pump station, can also be used to reduce the environmental impact of the turbine installation. The latter option is chosen for this feasibility study utilising four Aero Energy wind turbines rated at 323 kW at a maximum considered wind speed of 11.5 m/s. Boschberg Mountain is situated at an altitude of 1483 above sea level. The original power delivery of the 323 kW wind turbine are determined at a specific air density which is normally the density at sea level, i.e. 1.225 kg/m³. The air density on top of Boschberg Mountain is determined using (2.4) - (2.6) to be $\approx 1.10$ kg/m³. The power delivery curves of the 323 kW turbine at the different wind speeds would therefore have to be adjusted with a factor of $1.10/1.225 \approx 0.9$ according to (2.1). The 323 kW turbines are therefore effectively rated at $\approx 300$ kW at the maximum considered wind speed of 11.5 m/s.

The distance between the wind turbine on top of Boschberg Mountain and the farthest pump station near the bottom of the mountain, is in the region of 2-3 kilometres. This long distance would require a high voltage generator supply. A high voltage supply of 3 kV/50 Hz was therefore chosen. A transformer is used at each pump station to step the high voltage down to the commercial 400 V level required by the induction motors. The electrical diagram of the proposed wind-electric pump system installation for each pump station is shown in Figure 40.
6.4.2 Choice of Centrifugal Pumps

The multi-stage pump chosen for low wind speed conditions is the MTC 65 6.1/11 model manufactured by KSB Pumps. The pump performance curves for this pump are shown in Figure 41 for various operating shaft speeds. This pump generated the required static head of 150 m at a relatively low shaft speed of $\approx 1350$ r/min. The pump has eleven stages and could not be operated above 2000 r/min according to the operating manual. The flow rate at the maximum efficiency of 75.5 % at the 1350 r/min operating speed is $\approx 40$ m$^3$/hr. The minimum required flow rate required by the pump at the 1350 r/min shaft speed is therefore estimated at $\approx 0.3 \times 40 = 12$ m$^3$/hr. The total opposing head of the 150 mm UPVC pipeline is estimated using (3.54) - (3.58) with a static head of 150 m and a number of essential pipe fittings. The resulting system curve is included in Figure 41. It can be seen from the intersection between the system curve and the pump performance curve at the minimum operating shaft speed of 1350 r/min that the resulting flow rate is $\approx 15$ m$^3$/hr. This is close to the 12 m$^3$/hr pump requirement and the pump would therefore be operated safely.
The larger pump that was chosen is the WKLN 80/4 model manufactured by KSB Pumps. The pump performance curves of this multi-stage pump are shown in Figure 42. The pump has four stages and could not be operated above 3500 r/min according to the operating manual. The required static head is generated at a shaft speed of \( \approx 2100 \) r/min. The flow rate at the maximum efficiency of 74 % at the 2100 r/min operating speed is \( \approx 80 \) m\(^3\)/hr. The minimum flow rate required by the pump at this speed is estimated at \( \approx 0.5 \times 80 = 40 \) m\(^3\)/hr. It can also be deduced from the intersection between the system curve and the 2100 r/min pump performance curve in Figure 42 that this minimum flow rate is achieved by the pump at this minimum operating shaft speed.
6.4.3 Power Matching

The power delivery curves of the 323 kW wind turbine manufactured by Aero Energy is adjusted with the 0.9 factor and shown in Figure 43 for wind speeds of 3.5 m/s – 11.5 m/s. The power requirements of the two centrifugal pumps across their usable operating range are superimposed on the turbine power delivery curves using (4.6) for a shaft speed ratio of 1:60. The chosen shaft speed ratio would provide a good match between the wind turbine and the smaller pump under low wind speed conditions. The power matching between the wind turbine and larger pump during high wind speed conditions is within 95% of the optimum turbine power. For 2-pole induction motors, a 120-pole generator would be needed which would generate a supply frequency of between 20 Hz and 60 Hz. From Figure 43 it is estimated that the large induction motor must have a rated performance of at least 185 kW and the smaller induction motor must have a rated performance of at least 70 kW. The induction motors were therefore rated at commercially available ratings of 200 kW and 75 kW respectively.
6.4.4 Design of Axial Flux Permanent Magnet Synchronous Generator

The design of the axial flux permanent magnet synchronous generator is optimised to operate at the maximum wind speed of 11.5 m/s at a minimum efficiency of 90% without compromising the insulation properties of the stator epoxy through excessive current densities. The V/Hz supply of the generator is chosen to be 3000 kV/50 Hz. The large physical dimensions of this generator design mean that the air flow inside the air-cored stator would be more than in the small generator designs discussed in the previous chapters. The current density in the stator conductors can therefore be higher. The current density limit considered for the air-cored stator in this design is 10 A/mm².

The total number of coils in the 120-pole generator was chosen to be $Q_c = 90$ in keeping with the desired coil pitch of $\theta_m = 4\pi/3$. The axial thickness of the stator coils was chosen to be 20 mm. The peak flux density in the air-gap between the rotor-mounted magnets was also chosen as 0.6 T. Multiple parallel circuits i.e. $a > 1$ were used in this design to keep the diameter of the stator conductors to a minimum. This is

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**Figure 43:** The power requirements of the two centrifugal pumps across their usable operating ranges are superimposed on the adjusted power delivery curves of the Aero Energy wind turbine for wind speeds of 3.5 m/s – 10.5 m/s utilising a shaft speed ratio of 1:60.
done in order to curb the eddy current loss on the stator conductors whilst taking care not to exceed the current density limit of 10 A/mm². The design of the permanent magnet generator is optimised through the iterative calculation of the steady-state operation of the wind-electric pump system in an effort to achieve a minimum operating efficiency of 90 % throughout the operating range of the wind turbine whilst still keeping within the stator conductor current density limit of 10 A/mm². The design parameters of the optimised generator design are given in Table 7. The stator phases are connected in delta.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Value:</th>
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<tbody>
<tr>
<td>Stator coil total</td>
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</tr>
<tr>
<td>Stator coils per phase</td>
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<td>30</td>
</tr>
<tr>
<td>Parallel circuits</td>
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</tr>
<tr>
<td>Rotor poles</td>
<td>( p_g )</td>
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</tr>
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<td>Stator winding turns</td>
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</tr>
<tr>
<td>Parallel strands per conductor</td>
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</tr>
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<td>Peak air-gap flux density</td>
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<td>0.6 T</td>
</tr>
<tr>
<td>Inner radius of stator coil</td>
<td>( r_i )</td>
<td>1100 mm</td>
</tr>
<tr>
<td>Outer radius of stator coil</td>
<td>( r_o )</td>
<td>1500 mm</td>
</tr>
<tr>
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<tr>
<td>Stator coil axial thickness</td>
<td>( h )</td>
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</tr>
<tr>
<td>Stator conductor diameter:</td>
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<tr>
<td>Fill factor for stator conductors</td>
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<td>0.58</td>
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</table>

Table 7: Optimised design parameters of the permanent magnet synchronous generator.
6.4.5 Calculated Steady-State Operation

The 3000 kV/400 V step-down transformer used in this system has a delta phase connection on the primary and secondary side and is assumed to be ideal. The per-phase equivalent circuit of the system is modified with the induction motor parameters referred to the primary side of the transformer via the transformer ratio $t$, as shown in Figure 44. The transformer ratio, $t$, is defined as

$$t = \frac{E_p}{E_s}, \quad (6.3)$$

where $E_p$ is the voltage at the primary side and $E_s$ is the voltage at the secondary side of the transformer. The cable resistance, $R_c$, of the cable connecting the generator and motor is also included in the per-phase equivalent circuit of Figure 44.

The optimised steady-state operation of the WEPS is calculated and shown in Figure 45 for the smaller centrifugal pump and in Figure 46 for the larger centrifugal pump. The usable operating range of the smaller centrifugal pump allow the WEPS to start operating from a low wind speed of $\approx 4$ m/s up to a wind speed of 7.5 m/s. The usable operating range of the larger pump allow for WEPS operation above 7.5 m/s until the maximum wind speed of 11.5 m/s. The equivalent circuit parameters of the 75 kW and 200 kW induction motor used in the steady-state calculation are derived in Appendix A. The varying windage and friction loss of the motors were not included in the steady-state calculations.

Figure 44: Per-phase equivalent circuit of the permanent magnet generator and induction motor with the induction motor parameters referred to the primary side of the transformer.
Figure 45: Total mechanical input power, smaller centrifugal pump load and electrical power loss of the wind-electric pump system depicted on the power delivery curves of the 300 kW Aero Energy wind turbine for wind speeds of 3.5 m/s to 7.5 m/s.

Figure 46: Total mechanical input power, larger centrifugal pump load and electrical power loss of the wind-electric pump system depicted on the power delivery curves of the 300 kW Aero Energy wind turbine for wind speeds of 7.5 m/s to 11.5 m/s.
The operating efficiencies of the WEPS that exist across the operating range of the wind turbine are calculated and shown in Figure 47 for the system using the smaller 75 kW induction motor and centrifugal pump and in Figure 48 for the system using the larger 200 kW induction motor and centrifugal pump. Large induction motors generally have high operating efficiencies due to their low slip operation which are reflected in the high operating efficiencies that are calculated for both induction motors across the operating range of the wind turbine. The generator design was optimised for the least internal stator impedance. The permanent magnet generator design could, however, not be optimised to operate at a minimum efficiency of 90 % throughout the operating range of the wind turbine. The is due to the eddy-current loss in the stator conductors which could not be reduced enough whilst still keeping within the stator conductor current density limit of 10 A/mm². The calculated current density in the stator conductors is shown in Figure 49 for the two separate motor-pump configurations. It is noted that the current density at the maximum wind speed of 11.5 m/s is close to the limit at $\approx 9.5$ A/mm². The calculated operating efficiency of the permanent magnet generator throughout the operating range of the turbine is shown to be between 86 - 88 %. The transformer rating was calculated at the maximum considered operating wind speed of 11.5 m/s to be 250 kVA. The rating of the transformer was chosen with a safety factor to be 300 kVA as indicated in Figure 40.

**Figure 47**: Calculated electrical efficiency of the permanent magnet generator and the 75 kW induction motor across the operating range of the Aero Energy wind turbine.
Figure 48: Calculated electrical efficiency of the permanent magnet generator and the 200 kW induction motor across the operating range of the Aero Energy wind turbine.

Figure 49: Calculated current density in the stator conductors for WEPS operation under the two separate wind speed ranges required by the two separate motor-pump configurations.
6.5 Wind-Electric Pump System Performance

The delivery potential of the wind-electric pump system at each wind speed is estimated based on the calculated steady-state operation of the WEPS and the pump performance curves of the two pumps and shown in Figure 50. Three possible annual wind speed distributions at the turbine installation site are shown in Figure 51. The average wind speed, $\bar{v}$, is changed for each of the three wind speeds with only the standard deviation, $\sigma$, remaining the same. The performance of the wind-electric pump system is estimated using the pump output potential in Figure 50 in conjunction with the different possible annual wind speed distributions in Figure 51. The total annual pumped output achieved by the wind-electric pump system performance is given in Table 8 for each of the different wind speed distribution scenarios. The additional continuous power that could be developed by the hydro-electric scheme due to the increased flow of the wind-electric pump scheme is also given. Note that this continuous developed power is only an average value based on the annual wind speed distributions. Seasonal variation in the wind speed distribution may alter the contribution of the wind-electric pump system to the flow rate that can be extracted from Boschberg Dam. The total increase in generation potential that the wind-electric pump system could contribute to the generation potential of the hydro-electric scheme is also given in Table 8 as a percentage value.

![Figure 50: Example of the estimated wind-electric system delivery potential for each wind speed.](image-url)
It can be seen that a high wind speed distribution with an average value of 8 m/s is necessary for the wind-electric pump system scheme to almost double the generation potential of the hydro-electric scheme.

![Annual wind speed distribution for different average wind speeds](image)

**Figure 51: Annual wind speed distribution for different average wind speeds**

<table>
<thead>
<tr>
<th>Wind speed distribution</th>
<th>Total annual pumped volume output (m³)</th>
<th>Additional average continuous developed power (kW)</th>
<th>Increase in total generation potential of the hydro-electric scheme (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\bar{v} = 4, \sigma = 2$</td>
<td>180 000</td>
<td>26</td>
<td>21</td>
</tr>
<tr>
<td>$\bar{v} = 6, \sigma = 2$</td>
<td>465 000</td>
<td>67</td>
<td>53</td>
</tr>
<tr>
<td>$\bar{v} = 8, \sigma = 2$</td>
<td>804 000</td>
<td>115</td>
<td>92</td>
</tr>
</tbody>
</table>

**Table 8: Estimated generation potential of the wind-electric pump system installed at Boschberg mountain.**
6.6 Wind-Turbine Performance

The option of generating power using only the four effectively rated 300 kW wind turbines, or a single 1.2 MW wind turbine, is also investigated. The wind turbines, in this case, are connected directly to the supply grid via power electronic converters and control. It is assumed that the power electronic converters and control allow the four 300 kW wind turbines to operate at the maximum point on the turbine power delivery curves for each wind speed. The efficiency of the power electronic converters is assumed to be \( \approx 95 \% \). The total installed turbine capacity is therefore 1.14 MW. It is shown in Table 8 and Table 9 that the four wind turbines alone could contribute more generation potential to the supply grid, in addition to the hydro-electric scheme, than the installed wind-electric pump system when subjected to the various wind speed distributions shown in Figure 51.

<table>
<thead>
<tr>
<th>Wind speed distribution</th>
<th>Total annual harnessed Energy (kWh)</th>
<th>Additional average developed power (kW)</th>
<th>Percentage value of installed wind turbine capacity (%)</th>
<th>Increase in generation potential in addition to the hydro-electric scheme (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \bar{v} = 4, \sigma = 2 )</td>
<td>688 000</td>
<td>79</td>
<td>7</td>
<td>62</td>
</tr>
<tr>
<td>( \bar{v} = 6, \sigma = 2 )</td>
<td>1 728 000</td>
<td>197</td>
<td>17</td>
<td>156</td>
</tr>
<tr>
<td>( \bar{v} = 8, \sigma = 2 )</td>
<td>3 600 000</td>
<td>410</td>
<td>36</td>
<td>325</td>
</tr>
</tbody>
</table>

Table 9: Generation potential of the four 300 kW effectively rated wind turbines connected directly to the power grid.
6.7 Case Study Conclusion

The high static head that exists between Bestershoek Dam and Boschberg Dam dramatically reduces the performance of a wind-electric pump system scheme. The high pressures required by the pumps to induce flow between the two dams reduce the flows that can be delivered by the scheme. This reduced flow therefore reduces the impact that the wind-electric system could have on increasing the generation potential of the hydro-power scheme. The high static head also makes the installation of a wind-electric pump system complex and costly due to the multiple pump stations and centrifugal pumps that are required.

It is estimated and given in Table 8 and Table 9 that the use of wind turbines connected to the supply grid would have a larger impact over the wind-electric pump system, for the same installed wind turbine capacity, in increasing the possible power generation potential of the proposed hydro-electric scheme. The disadvantage of this configuration is the erratic behaviour in which the total annually generated power addition is delivered to the grid by the wind turbine. The advantage of using a wind-electric pump system scheme for pumped storage in this case, would offer a reduced but continuous annual power addition to the grid. The use of wind-electric pump systems for pumped storage would, however, be better financially suited to, and have a more pronounced impact on, hydro-power schemes with considerably lower static head. The reduced operating pressure required by the centrifugal pumps would increase the flow rate that can be achieved. The reduced operating pressure would also increase the operating range of the centrifugal pumps, eliminating the need for multiple centrifugal pumps and pumping stations. The ideal application for wind-electric pump schemes would therefore be for hydro-power generations with low static head used for peak power generation.

The 270 kW air-cored axial flux permanent magnet generator design in this chapter could not be optimised to operate at higher efficiencies due to the eddy-current losses which could not be reduced enough without exceeding the current density limit in the stator conductors. The physical size of the axial flux permanent magnet generator design is also very large and could compromise the installation feasibility of the WEPS installation. These limitations of the axial flux generator design regarding the reduced efficiency and large physical size can be addressed by designing two smaller axial flux generators and connecting the stators in parallel. This
would not only reduce the physical size of the generator but will also reduce the
current density in the stator conductors, leading to a reduced eddy-current loss and
higher overall generator operating efficiency.

The use of iron-cores can also be considered for the axial flux permanent
magnet generators designs to reduce the physical size of the generator. These iron
cores are, however, expensive to manufacture and the associated iron losses may
compromise the efficient operation of the generator.
7. Conclusion

A complete system model of a wind-electric system is derived and used to design a small scale wind-electric pump system. The design guidelines that were formulated and followed ensured optimal steady-state operating efficiency as well as safe operation of the system components throughout the operating range of the wind turbine. These design guidelines placed emphasis on

(i) The choice of centrifugal pump and the factors that contribute to the safe operation of the centrifugal pump in a specific pumping application.

(ii) The permanent constant V/Hz supply necessary to ensure efficient operation of the induction motor throughout the operating range of the wind turbine.

(iii) The specification of the generator and motor to ensure optimal power matching between the wind turbine and centrifugal pump.

(iv) The specification, design and construction of the axial flux permanent magnet generator for its reliable and efficient operation.

The calculated steady-state operation of the system is supported by measurements made on a small scale setup that was built in the laboratory. The system model and design methodology are verified through the comparative accuracy between the calculated and measured results.

Theoretical insight is given into the analysis of wind regimes where it is shown how the wind speed distribution is derived for potential turbine installation sites and how this is used in conjunction with the steady-state analysis of the system to accurately determine the long term performance of a wind-electric pump system.

The dynamic start-up operation of the wind-electric pump system is described in detail. A practical method is discussed to determine the minimum turbine rotational
speed necessary whereby sufficient rotational kinetic energy would be available upon
start-up to ensure a successful start-up for a system design of a given size and rating.

A case study is presented which features the design and implementation of a
large scale wind-electric pump system under extreme conditions. The design
guidelines formulated through the design of the small scale system are used in
designing the large scale wind-electric pump system. Limitations regarding the
practical implementation of the pump system operating under extreme discharge
heights are discussed. The limitations in designing the axial flux permanent magnet
generator on a large scale are also highlighted and discussed.

Wind-electric pump system schemes can be used to pump surface water
utilising low pressure centrifugal pumps or can be used to pump water from boreholes
utilising high pressure multi-stage centrifugal borehole pumps. It is concluded in this
study that small-scale wind-electric pump system schemes, utilising air-cored axial
flux permanent magnet generators, have the potential to offer superior performance
and flexibility to conventional mechanical wind pump systems in regions with
medium to high wind regimes. These systems are also cost-effective and do not
require scheduled maintenance due to the simplicity of the system operation and the
system layout.

It is also concluded through the case study that large-scale WEPS installation
are in general best suited, in terms of economic and practical feasibility, to pumping
applications with low operating pressures and medium to high wind regimes at the
turbine installation site. Evident during the case study was the large-scale design of
the air-cored axial flux permanent magnet generator which becomes expensive and
unpractical for large-scale WEPS applications due to the large physical size required.
For this reason, air-cored radial flux permanent magnet generator designs of reduced
size can also be investigated for possible application in wind-electric pump systems.
Appendix A: Determining Induction Motor Equivalent Circuit Parameters

The derivation of the equivalent circuit parameters of the induction motors used in Chapter 4 and Chapter 6 is shown in this chapter.

A.1 2.2 kW Induction Motor

The no-load and blocked-rotor test measurements on the 2.2 kW, 2-pole induction motor were made in the laboratory and the results given in Table 10. The circuit parameters are derived from these measurements using (3.28) - (3.36) and listed in Table 11. Also included in Table 11 is the equivalent circuit parameters derived from test data supplied by the manufacturer. It can be seen that the two sets of parameters compare well which validates the measuring methodology. The variation of the windage and friction loss was determined by using a variable speed drive to bring the motor up to various speeds and utilising (3.40) to determine the windage and friction loss at these various shaft speeds. These varying windage and friction losses are shown in Figure 52. The inertia of the motor shaft is supplied by the manufacturer to be $J = 0.0014 \text{ kgm}^2$.

<table>
<thead>
<tr>
<th>Test Data:</th>
<th>No-Load</th>
<th>Locked-Rotor</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E_{NL}$</td>
<td>340 V</td>
<td>$E_{LR}$</td>
</tr>
<tr>
<td>$I_{NL}$</td>
<td>1.5 A</td>
<td>$I_{LR}$</td>
</tr>
<tr>
<td>$P_{NL}$</td>
<td>120 W</td>
<td>$P_{LR}$</td>
</tr>
</tbody>
</table>

Table 10: No-load and locked-rotor test data of the 2.2 kW induction motor.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>From Measured Data:</th>
<th>From Manufacturer Data:</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_S$</td>
<td>$2.85 \ \Omega$</td>
<td>$2.8 \ \Omega$</td>
</tr>
<tr>
<td></td>
<td>($R_{LEAD} = 0.8 \ \Omega$)</td>
<td></td>
</tr>
<tr>
<td>$R_R$</td>
<td>$2.5 \ \Omega$</td>
<td>$2.9 \ \Omega$</td>
</tr>
<tr>
<td>$X_S$</td>
<td>$4.13 \ \Omega$</td>
<td>$4.8 \ \Omega$</td>
</tr>
<tr>
<td>$X_R$</td>
<td>$4.13 \ \Omega$</td>
<td>$4.8 \ \Omega$</td>
</tr>
<tr>
<td>$X_M$</td>
<td>$132 \ \Omega$</td>
<td>$122 \ \Omega$</td>
</tr>
<tr>
<td>$R_{FE}$</td>
<td>$1600 \ \Omega$</td>
<td>$1480 \ \Omega$</td>
</tr>
</tbody>
</table>

Table 11: Equivalent circuit parameters of the 2.2 kW induction motor derived from no-load and locked-rotor measurement data given in Table 10.

Figure 52: Windage and friction losses of the 2.2 kW induction motor versus various shaft speeds.
The design data of the 2.2 kW induction motor were determined through data supplied by the manufacturer and measurements made on the stator itself. This data is given in Table 12. The varying iron loss in the stator is determined analytically through (3.41) - (3.51) based upon this design data. The rotational loss of the motor at grid frequency is calculated from the no-load measurements in Table 10 using (3.38) as being

\[
P_{\text{ROT}} = 120 - (3)(1.5)^2(2.8) \approx 100 \text{ W.} \quad (A.1)
\]

The windage and friction loss for the motor operating grid frequency is deduced from Figure 52 as being \( P_{\text{wf}} \approx 30 \) Watt. The iron loss in the stator is then derived analytically from (3.41) at grid frequency using the 2.2 kW induction motor design data listed in Table 12 as being

\[
P_{\text{fe}} = (0.0337)(50^{1.32})[(1.43^2)(0.42) + (1.47^2)(5.12)] \approx 70 \text{ W.} \quad (A.2)
\]

The following conclusion can thus be drawn:

\[
P_{\text{wf}} + P_{\text{fe}} \approx 100 \text{ W} \approx P_{\text{ROT}}. \quad (A.3)
\]

It is therefore evident from (A.1) - (A.3) that the theory given in Chapter 3.2.2 − 3.2.3 is accurate in determining the varying nature of the stator iron loss as well as the windage and friction loss under varying supply conditions.
<table>
<thead>
<tr>
<th>Parameter:</th>
<th>Symbol:</th>
<th>Value:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stack factor</td>
<td>$k_s$</td>
<td>0.95</td>
</tr>
<tr>
<td>Density of sheet steel</td>
<td>$S$</td>
<td>7.88 g/cm³</td>
</tr>
<tr>
<td>Inner diameter of stator</td>
<td>$D_i$</td>
<td>72 mm</td>
</tr>
<tr>
<td>Outer diameter of stator</td>
<td>$D_o$</td>
<td>132 mm</td>
</tr>
<tr>
<td>Stator lamination stack length</td>
<td>$\ell_y$</td>
<td>110 mm</td>
</tr>
<tr>
<td>Stator yoke height</td>
<td>$h_y$</td>
<td>16.25 mm</td>
</tr>
<tr>
<td>Stator slot length</td>
<td>$\ell_t$</td>
<td>12.75 mm</td>
</tr>
<tr>
<td>Total area of stator slot</td>
<td>$A_t$</td>
<td>$\approx 0.00012$ m²</td>
</tr>
<tr>
<td>Amount of stator slots</td>
<td>$C_n$</td>
<td>18</td>
</tr>
<tr>
<td>Turns per stator coil</td>
<td>$N$</td>
<td>60</td>
</tr>
<tr>
<td>Amount of stator poles</td>
<td>$p_m$</td>
<td>2</td>
</tr>
<tr>
<td>Parallel circuits</td>
<td>$a$</td>
<td>1</td>
</tr>
<tr>
<td>Number of phases</td>
<td>$m$</td>
<td>3</td>
</tr>
<tr>
<td>Coil slot pitch</td>
<td>$t_p$</td>
<td>12.5 mm</td>
</tr>
<tr>
<td>Stator teeth width</td>
<td>$t_w$</td>
<td>5 mm</td>
</tr>
<tr>
<td>Amount of windings in series per phase</td>
<td>$N_{ph}$</td>
<td>180</td>
</tr>
</tbody>
</table>

Table 12: Design data of the 2.2 kW induction motor.
## A.2 75 kW and 200 kW Induction Motors

The design data for the 75 kW and 200 kW induction motors used to determine the varying induction motor stator iron loss in the steady-state calculations in Chapter 6 are given in Table 13. The equivalent circuit parameters of both motors were deduced from no-load and locked rotor test data supplied by the manufacturer and given in Table 14.

<table>
<thead>
<tr>
<th>Parameter:</th>
<th>Symbol:</th>
<th>75 kW</th>
<th>200 kW:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stack factor</td>
<td>$k_s$</td>
<td>0.95</td>
<td>0.95</td>
</tr>
<tr>
<td>Density of sheet steel</td>
<td>$S$</td>
<td>7.88 g/cm³</td>
<td>7.88 g/cm³</td>
</tr>
<tr>
<td>Inner diameter of stator</td>
<td>$D_i$</td>
<td>225 mm</td>
<td>300 mm</td>
</tr>
<tr>
<td>Outer diameter of stator</td>
<td>$D_o$</td>
<td>400 mm</td>
<td>520 mm</td>
</tr>
<tr>
<td>Stator lamination stack length</td>
<td>$\ell_y$</td>
<td>260 mm</td>
<td>380 mm</td>
</tr>
<tr>
<td>Stator yoke height</td>
<td>$h_y$</td>
<td>40 mm</td>
<td>45 mm</td>
</tr>
<tr>
<td>Stator slot length</td>
<td>$\ell_t$</td>
<td>47 mm</td>
<td>60 mm</td>
</tr>
<tr>
<td>Total area of stator slot</td>
<td>$A_t$</td>
<td>$\approx$ 0.0017 m²</td>
<td>$\approx$ 0.0028 m²</td>
</tr>
<tr>
<td>Amount of stator slots</td>
<td>$C_n$</td>
<td>36</td>
<td>48</td>
</tr>
<tr>
<td>Turns per stator coil</td>
<td>$N$</td>
<td>8</td>
<td>7</td>
</tr>
<tr>
<td>Amount of stator poles</td>
<td>$p_m$</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Parallel circuits</td>
<td>$a$</td>
<td>6</td>
<td>18</td>
</tr>
<tr>
<td>Number of phases</td>
<td>$m$</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>
### Table 13: Design data of the 75 kW and 200 kW induction motors

<table>
<thead>
<tr>
<th></th>
<th>75 kW</th>
<th>200 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coil slot pitch $t_p$</td>
<td>19.6 mm</td>
<td>19.6 mm</td>
</tr>
<tr>
<td>Stator teeth width $t_w$</td>
<td>4 mm</td>
<td>4.5 mm</td>
</tr>
<tr>
<td>Amount of windings in series $N_{ph}$</td>
<td>8</td>
<td>3</td>
</tr>
</tbody>
</table>

### Table 14: Equivalent circuit parameters of the 75 kW and 200 kW induction motors derived from no-load and locked-rotor test data supplied by the manufacturer.

<table>
<thead>
<tr>
<th></th>
<th>75 kW</th>
<th>200 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_S$</td>
<td>0.057 Ω</td>
<td>0.013 Ω</td>
</tr>
<tr>
<td>$R_R$</td>
<td>0.1 Ω</td>
<td>0.06 Ω</td>
</tr>
<tr>
<td>$X_S$</td>
<td>0.3 Ω</td>
<td>0.15 Ω</td>
</tr>
<tr>
<td>$X_R$</td>
<td>0.3 Ω</td>
<td>0.15 Ω</td>
</tr>
<tr>
<td>$X_M$</td>
<td>23 Ω</td>
<td>10 Ω</td>
</tr>
<tr>
<td>$R_{FE}$</td>
<td>150 Ω</td>
<td>100 Ω</td>
</tr>
</tbody>
</table>
Appendix B: Calculation Procedure for Steady-State WEPS Operation

Figure 53: Combined per phase equivalent circuit of the permanent magnet generator and induction motor.

The flow diagram for the calculation methodology implemented in the Matlab program in order to calculate the steady-state operation of a WEPS is shown in Figure 54. The combined per-phase equivalent circuit of the generator and motor, as shown in Figure 53, is used in the program to calculate the steady-state operation of the system at various turbine shaft speeds.

The first step in the program configuration is to determine the varying load, \( P_{S2} \), that the centrifugal pump would present to the turbine for the specific application using (3.52) and (3.53). The pump load can be written as

\[
P_{S2} = k\Omega_2,
\]  

(B.1)

with \( k \) being the \( n^{th} \) order equation describing relation of pump load vs. pump shaft speed. The second step in the program configuration is to specify the different equivalent circuit parameters of the permanent magnet generator and induction motor. The third step in the program configuration is to specify the turbine operating range over which the steady-state operation of the system is to be calculated and evaluated.
The turbine shaft speed is the incremented. At each turbine shaft speed increment, $\Omega_i$, the supply frequency is calculated and the accompanying voltage determined using the V/Hz supply of the generator design. The equivalent circuit parameters in Figure 10 are adjusted at each supply frequency. The generator supply is then applied to the equivalent circuit of Figure 10. The synchronous speed of the induction motor is calculated through

$$n_s = \frac{120 f}{P_m}. \quad (B.2)$$

The induction motor slip is then incremented ($s = s + 0.001$) until steady-state operating conditions are reached where the calculated mechanical power generated by the induction motor is equal to the pump load plus the windage and friction loss of the induction motor. The mechanical power, $P_{mech}$, produced by the induction motor is calculated through

$$P_{mech} = \frac{3|I_1|^2 R_R (1-s)}{s}, \quad (B.3)$$

with reference to the parameters found in Figure 10. This steady-state slip value is then used to calculate and record the steady-state parameters of the system such as operating efficiencies of the generator and motor, input torque required by the turbine etc. When the steady-state operation of the system is calculated over the entire specified turbine operating range, the recorded steady-state parameters are displayed as needed.
Figure 54: Flow diagram for the program used to calculate the steady-state operation of a WEPS.
### Appendix C: Practical Test Measurements

<table>
<thead>
<tr>
<th>Generator Shaft Speed ($\Omega_1$) [r/min]</th>
<th>Generator Terminal Voltage ($V$) [V]</th>
<th>Current Flow ($I_{rot}$) [A]</th>
<th>Generator Input Torque [Nm]</th>
<th>Motor Output Torque [Nm]</th>
<th>Motor Shaft Speed ($\Omega_2$) [r/min]</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>135</td>
<td>1.5</td>
<td>24</td>
<td>1.1</td>
<td>1175</td>
</tr>
<tr>
<td>110</td>
<td>150</td>
<td>1.6</td>
<td>25</td>
<td>1.2</td>
<td>1290</td>
</tr>
<tr>
<td>120</td>
<td>160</td>
<td>1.7</td>
<td>30</td>
<td>1.5</td>
<td>1400</td>
</tr>
<tr>
<td>130</td>
<td>170</td>
<td>1.8</td>
<td>36</td>
<td>1.8</td>
<td>1500</td>
</tr>
<tr>
<td>140</td>
<td>180</td>
<td>1.9</td>
<td>40</td>
<td>2.1</td>
<td>1610</td>
</tr>
<tr>
<td>150</td>
<td>195</td>
<td>2</td>
<td>45</td>
<td>2.43</td>
<td>1720</td>
</tr>
<tr>
<td>160</td>
<td>200</td>
<td>2.2</td>
<td>50</td>
<td>2.8</td>
<td>1830</td>
</tr>
<tr>
<td>170</td>
<td>215</td>
<td>2.42</td>
<td>54</td>
<td>3</td>
<td>1950</td>
</tr>
<tr>
<td>180</td>
<td>225</td>
<td>2.65</td>
<td>60</td>
<td>3.35</td>
<td>2060</td>
</tr>
<tr>
<td>190</td>
<td>230</td>
<td>2.9</td>
<td>67</td>
<td>3.65</td>
<td>2140</td>
</tr>
<tr>
<td>200</td>
<td>240</td>
<td>3.1</td>
<td>73</td>
<td>4</td>
<td>2240</td>
</tr>
<tr>
<td>210</td>
<td>250</td>
<td>3.4</td>
<td>80</td>
<td>4.3</td>
<td>2375</td>
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<tr>
<td>220</td>
<td>260</td>
<td>3.8</td>
<td>89</td>
<td>4.9</td>
<td>2480</td>
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<tr>
<td>230</td>
<td>265</td>
<td>4.15</td>
<td>98</td>
<td>5.3</td>
<td>2580</td>
</tr>
<tr>
<td>240</td>
<td>285</td>
<td>4.5</td>
<td>108</td>
<td>5.8</td>
<td>2660</td>
</tr>
<tr>
<td>250</td>
<td>300</td>
<td>5</td>
<td>117</td>
<td>6.3</td>
<td>2750</td>
</tr>
</tbody>
</table>

Table 15: Practical steady-state measurements made for small scale WEPS test setup.


